ATCO Electric
YUKON

September 28, 2023

Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Attention: **Richard Buchan**
Chair

Re: **ATCO Electric Yukon**
2023-2024 General Rate Application
Information Responses

In accordance with the Yukon Utilities Board (Board or YUB) Board Order 2023-18, dated August 29, 2023, attached are AEY's Responses to Information Requests submitted on September 6, 2023, from the YUB, Florian Boulais (FB), John Maissan (JM), Yukon NDP Caucus (NDP), the Yukon Utilities Consumers' Group (UCG), and Nathaniel Yee (NY).

Information required to fully respond to AEY-YUB-065 and AEY-YUB-066 remains outstanding despite best efforts, those responses will be filed on September 29, 2023.

If you have any questions, please contact me at Elizabeth.Rogers@atco.com or (780) 919-8190.

Yours truly,

Beth Rogers, CPA CMA
Director, Regulatory

ATCO Electric YUKON

September 28, 2023 AEY-FB-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Florian Boulais (FB)
Received: September 6, 2023

AEY-FB-001

References: ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)
Issues List
Section 1 Attachment 1.2 Page 1 of 1

Risk Premium	Section 08	AEY is requesting a risk premium as it faces greater business risk than the average Canadian or British Columbia benchmark utilities. Concentric has determined an appropriate risk premium to be 75 basis points.

SECTION 1B: ENERGY TRANSITION
1B.1 Summary
5. Meeting these targets is having a dramatic impact on AEY's business and responsibility to provide safe and reliable electricity at an affordable cost.

2023-2024 General Rate Application (GRA)
5.3.4 Public Information - 17
The public information function includes labour costs for the communications advisor and costs related to external public information activities. The costs are forecast to remain flat over the Test Period, as outlined in Table 5.6, with only minor increases for labour inflation.

Section 8 Attachment 8.1 p.17
Concentric Energy Advisors
IV. RISK ASSESSMENT

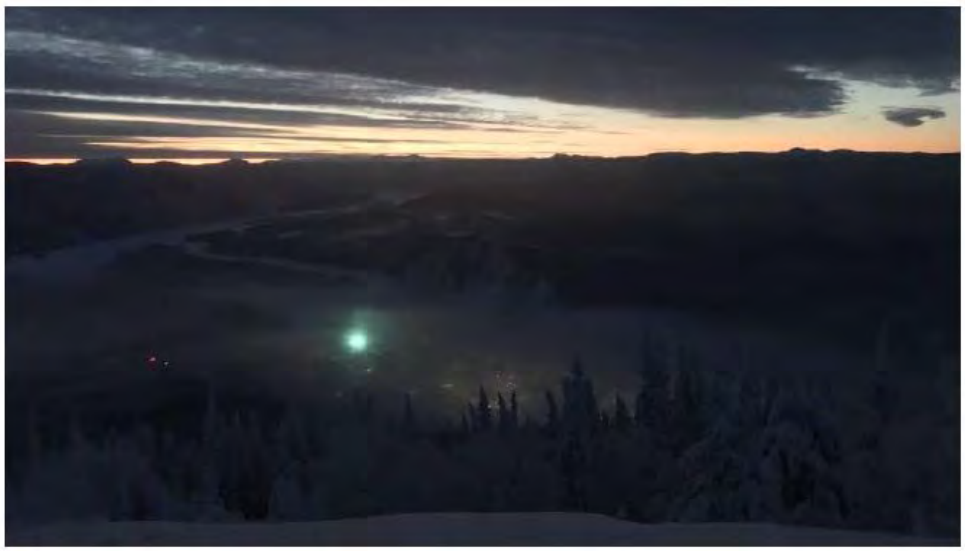
Issue: The matter at hand pertains to a significant overarching concern concerning the resilience of our geographical jurisdiction and its structural arrangement. This matter engenders inquiries into the allocation of accountability and the exercise of authority.

ATCO, in its public communications, presents itself as a provider of power supply that approaches near-perfection. However, it shall be

demonstrated herein that ATCO can indeed furnish a power supply characterized by a high degree of reliability but falls short in furnishing a power supply distinguished by resilience. Furthermore, ATCO lacks a discernible strategy for effectively imparting this distinction to its clientele, thereby hindering their capacity to undertake proactive measures to fortify their resilience against the prospective compounding disruptions that the future is anticipated to bestow upon them.

Preamble: In the ensuing discussion, I shall construct an argument contending that ATCO cannot provide an assurance of operation devoid of failures, given the intricate nature of the grid, the unique contextual factors pertinent to the Yukon region, and the rapidity of exponential changes in these circumstances.

Example of typical accident - Yukon Energy Dawson City December 2022



This photograph was captured in Dawson City on December 22, 2022, by a tourist positioned atop the Midnight Dome. The precise moment was marked by the failure of a fastening component on a riser wire, triggered by the extreme cold of -44°C. The severed wire descended, intersecting lower power lines, inducing a short circuit that initiated a chain reaction across Yukon Energy's infrastructure. The consequence was a sudden loss of electrical power, depriving Dawson City of a substantial portion of its energy supply.

Promptly following this incident, Yukon Energy's personnel embarked on an investigative endeavor to identify the root cause of the disruption. This endeavor was akin to locating a minute object in a vast expanse. After several hours of rigorous examination, a resident within the vicinity stepped forward, reporting a witnessed spark. This revelation was instrumental in isolating the origin of the problem, which was then promptly rectified.

By this juncture, the power had been offline for an extended duration. During the restoration process, an attempt to reinstate the grid encountered challenges due to the substantial load demand. This necessitated a gradual and sequential restart of grid segments. Regrettably, some residents were subjected to a power outage for up to 20 hours until the final restoration was achieved.

https://www.cbc.ca/news/canada/north/power-restored-dawson-city-outage-1.6696508

This issue happened to Yukon Energy but this could very well have happened to Atco.

These kinds of issues are practically unavoidable, especially since complex systems fail in complex ways. This reality is only exacerbated by the fact that a corporation such as Atco or Yukon Energy have a fiduciary responsibility to provide its shareholders with the highest return possible while offering the lowest price to customers. Utilities are thus incentivized to operate at the very edge of failure by complying with the bare minimum safety requirements.

Quotations extracted from a literary work - for the exclusive purpose of contemplation and reflection

> “Legally, a manufacturer has a duty to warn when it knows or should know of a product’s hazards. Manufacturers that fail to meet this duty can be judged negligent. Thus, when considered from a legal perspective, manufacturers are held to a high standard - that of an expert in understanding and anticipating risks.”

Handbook of Warnings, Michael S. Wogalter, 2006, p.620.

> “Complex systems fail in complex ways, a reality exacerbated by the business need to operate complex systems on the very edge of failure.”

Uptime Institute, Examining and Learning from Complex Systems Failures, October 9, 2015

> "Reliability assumes blue skies. Resilience is the ability to take a punch." says Scott Aaronson of the Edison Electric Institute (The National Academies Press, Communications, Cyber Resilience, and the Future of the U.S. Electric Power System: Proceedings of a Workshop, (2020), p.4 https://www.nap.edu/download/25782)

Power outage in Whitehorse in Dec 2022

On the 19th of December, an operational event occurred whereby a transformer in the Takhini substation underwent a protective tripping mechanism due to an elevated demand threshold. Notably, this event transpired against the backdrop of severe climatic conditions, characterized by an ambient temperature of -38°C. Consequentially, a localized power outage transpired, impacting geographical sectors encompassing the north side of Whitehorse, encompassing Crestview, Kulan, the Hot Springs, and the Whistle Bend vicinity.

Particularly relevant is the Whistle Bend neighborhood, a burgeoning subdivision, emblematic of Whitehorse's contemporary urban expansion. Noteworthy is the fact that a significant proportion of residential structures within this locale rely on electricity as the primary heating source. Consequently, this geographical segment experienced protracted power restoration timelines, culminating in the reinstatement of electrical services after a span of four hours from the onset of the incident.

Another pertinent consideration pertains to the dimensions of the municipality of Whitehorse and the quantity of isolated residences reliant on electric power. In the event of an extended power outage during severely frigid conditions impacting peripheral regions beyond the urban boundaries of Whitehorse, the capacity for both ATCO and the Emergency Management Organization to provide assistance would be significantly constrained.

A story to illustrate what happened in the IBEX valley during the outage - for the exclusive purpose of contemplation and reflection

A young single mother with an infant in her care was leasing a residence within the IBEX valley and found herself without heating for an extended period. Lacking an alternative heating source and devoid of her landlord's contact information, she endured several hours of the outage. Approximately two hours into the ordeal, with

the indoor temperature plummeting precipitously, she resolved to transport her infant to a neighboring location situated at a considerable distance. Unfortunately, her vehicle failed to start without the electric preheating, compelling her to embark on a frigid journey by foot to reach the adjacent property, ultimately arriving while her and her infant were suffering from severe cold-induced distress.

This was posted on Facebook on Dec 23 by Atco - after the power outage



This post was expeditiously withdrawn from Facebook subsequent to the observation of agitated comments that had surfaced underneath it. This prompt action undertaken by ATCO underscored its recognition of the incongruity of the "Power Pack" offering within

the specific Yukon context. Furthermore, this occurrence serves to underscore ATCO's apparent deficiency in possessing a coherent strategy for effectively engaging and apprising its clientele of the inherent impossibility for ATCO to furnish continuous and unceasing service. It seems quite incongruous that in no place whether it is on the government website or Atco that there is no mention of backup heat or energy source. One can imagine that there might contingency plans for urban dwellers but one can't imagine how either ATCO or the Emergency Management Organisation could possibly cover the huge rural area around Whitehorse or the different Yukon communities to make sure every one's basic needs for heat are met. This seems to be a significant overestimation of their combined capacity.

Most Yukoners (especially rural Yukoners)

- Have a generator in their shed - they could easily get a power switch installed on their meter in order to switch to generator power when needed.
- Could have a backup heat source installed.
- Could have agreements and plans with neighbours.

Requests:

(a) In what manner can ATCO's clientele undertake requisite measures to enhance their resilience when they are consistently inundated with ATCO's affirmations of service reliability and excellence, all the while being deprived of essential disclosure pertaining to the inherent impracticability of ATCO to confer perpetual and uninterrupted service?

(b) How is the issue of limited psychological capacity to plan for an extended outage addressed among citizens in the lower socioeconomic class, notably in the absence of adequate informational resources?

Response:

(a) It is important that all Yukoners are prepared for emergencies, including power outages, that can last up to 72 hours or longer. AEY provides information on its website to assist customers in ensuring they are prepared for such emergencies. While AEY works diligently to provide safe and reliable power to its customers,

certain factors beyond AEY's control, such as severe weather, can sometimes lead to unavoidable disruptions.

To enhance resilience during such situations, AEY recommends that its customers consider the following measures:

- Create an emergency preparedness kit.
- Establish a communication plan with your family and loved ones.
- Familiarize yourself with local emergency services and community resources available to assist during emergencies.

While AEY strives for service reliability and excellence, it is essential for customers to understand that no utility provider can guarantee perpetual and uninterrupted service.

(b) As noted above, AEY provides information on its website to all customers and it is important that all Yukoners are prepared for emergencies, including power outages, that can last up to 72 hours or longer.

In the event of an extended outage, AEY works closely with the Emergency Measures Organization (EMO) and other responding agencies to ensure that they have up-to-date information to make informed decisions regarding the need to provide supports to the community.

ATCO Electric YUKON

September 28, 2023 AEY-FB-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Florian Boulais (FB)
Received: September 6, 2023

AEY-FB-002

References: ATCO Electric Yukon (AEY) 2023 - 2024 General Rate Application (GRA)

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SECTION 1B: ENERGY TRANSITION
1B.1 Summary

> 5. Meeting these targets is having a dramatic impact on AEY's business and responsibility to provide safe and reliable electricity at an affordable cost.

2023-2024 General Rate Application (GRA)
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Section 8 Attachment 8.1 p.17
Concentric Energy Advisors
IV. RISK ASSESSMENT

Issue: Given the prevailing lack of widespread public understanding regarding energy matters and the imperative necessity for

substantial transformations to align with the objectives of "Our Green Future" within the territory and the increase in uncertainty the future holds, it raises the question as to why ATCO is not undertaking a concerted effort to enlighten its customer base concerning the remarkable services rendered by the electrical grid. Such an educational initiative could render ATCO's potential electricity cost increments more palatable. Consequently, this dual-pronged approach has the potential not only to enhance ATCO's standing as an engaged contributor to the territory's "Our Green Future" aspirations but also to furnish ATCO with additional financial resources to undertake modernization endeavors aimed at elevating the efficiency, resilience and expansion of the grid infrastructure.

Preamble: Quotations extracted from a literary work - for the exclusive purpose of contemplation and reflection

These principles apply now more than ever for the communication with the public:

- HSD Human Systems Dynamics Institute holds as a fundamental principle that a human system - such as ATCO's customer base - will not change until tension is introduced into it:

https://www.hsdinstitute.org/resources/four-principles-of-change-in-human-systems-tension-blog.html

- Social media crushes old school marketing. The rule of 7: it takes a person 7 exposures before registering a message.

https://digitaldealer.com/latest-news/rule-7-social-media-crushes-old-school-marketing/

- Ease of cognitive processing is equated with truth. The easier to understand, the truer it will seem:

https://medium.com/@andy.brockie/what-is-cognitive-fluency-d9e3e98b5922

- 2017-2018 Harvard Study finds that optimism can lead to inaction:

https://news.harvard.edu/gazette/story/2017/08/study-finds-optimism-can-lead-to-inaction/

- Irony can create a compelling call to action more effectively than traditional marketing strategies, particularly with less sexy topics:

https://opusfidelis.com/insights/unlocking-the-power-of-irony-in-marketing/

https://medium.com/nova-marketing-insights/how-to-exploit-irony-in-the-advertisement-world-3a33768c729c

Quotations extracted from a literary work - for the exclusive purpose of contemplation and reflection

> "Effective communication will always require some degree of irrationality in its creation because if it's perfectly rational it becomes, like water, entirely lacking in flavour… Quite simply, all powerful messages must contain an element of absurdity, illogicality, costliness, disproportion, inefficiency, scarcity, difficulty or extravagance—because rational behaviour and talk, for all their strengths, convey no meaning." – Rory Sutherland

Jevons paradox - for the exclusive purpose of contemplation and reflection

> Jevons paradox, also known as the Jevons effect, is an economic phenomenon that occurs when an increase in the efficiency of resource use leads to an overall increase in the consumption of that resource rather than a decrease. In other words, as technology or efficiency improvements make it possible to use a resource more effectively, people tend to use more of that resource rather than less. This paradox was first described by the 19th-century economist William Stanley Jevons in his book "The Coal Question," where he observed that improvements in steam engine efficiency actually led to an increase in coal consumption, rather than a decrease, because the engines became more widely used in various industries.
>
> The Jevons paradox is often cited in discussions about resource conservation and environmental

sustainability. It highlights the complexity of efforts to reduce resource consumption and the potential for rebound effects, where gains in efficiency may be offset by increased consumption, ultimately leading to continued resource depletion.

Habituation bias - for the exclusive purpose of contemplation and reflection

The habituation bias, also known as the hedonic adaptation or simply habituation, is a psychological phenomenon that refers to the tendency of individuals to become accustomed to or desensitized to a certain stimulus or situation over time. In other words, when people are exposed to a new and initially pleasurable or distressing experience, their emotional response to that experience tends to diminish or return to a baseline level of emotional well-being with continued exposure. This means that the initial impact, whether positive or negative, becomes less significant as it becomes more familiar.

For example, if someone gets a new car, they may initially feel very happy and excited about it, but over time, the novelty wears off, and the car's presence no longer brings the same level of joy. Conversely, if someone experiences a negative event, like a persistent noise in their environment, they may initially find it highly annoying, but they may gradually become less bothered by it as they become accustomed to the noise.

Understanding the habituation bias is important in psychology and behavioral economics because it can influence people's perceptions of happiness, satisfaction, and well-being. It suggests that pursuing material possessions or external experiences alone may not lead to sustained happiness because people tend to adapt to them.

Resilience in complex systems - for the exclusive purpose of contemplation and reflection

1. **Autonomy and Decision-Making**: Resilience in complex systems often involves granting a degree of autonomy to individual agents within the system. Agents, whether they are humans, machines, or natural entities, have the freedom to make decisions and take actions based on local information and context. This autonomy allows agents to respond adaptively to changing conditions and unforeseen challenges without needing centralized control.

2. **Distributed Control:** In resilient complex systems, decision-making authority is often distributed across multiple agents rather than concentrated in a single entity or center. Each agent can assess its environment, make decisions independently, and communicate or interact with other agents as needed. This distribution of control reduces vulnerability to system-wide failures and enhances the system's capacity to recover from disruptions.

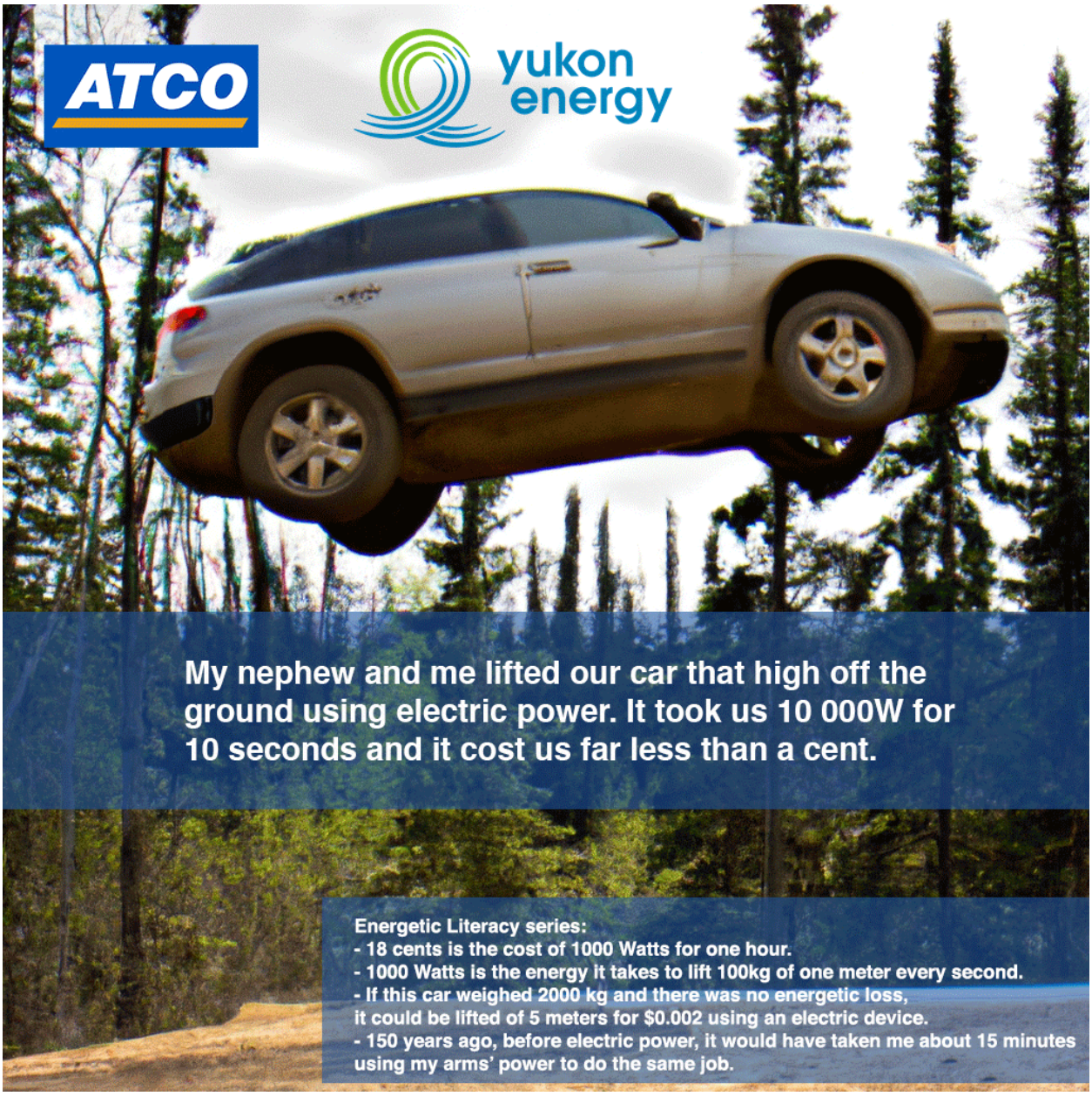
3. **Learning and Adaptation**: Resilience encourages agents within complex systems to possess learning and adaptation capabilities. Agents can adjust their behaviors, strategies, or rules based on past experiences and feedback from their interactions with the environment and other agents. This adaptability allows the system to evolve and improve its performance over time, especially in the face of novel challenges.

4. **Interactions and Feedback**: Agents in a resilient complex system engage in interactions with each other and with their environment, generating feedback loops. These interactions and feedback mechanisms enable agents to assess the consequences of their actions, detect changes in the system, and coordinate with other agents when necessary. Feedback loops provide a means for agents to self-regulate and maintain system stability.

Resilience in complex systems, with a focus on agency, acknowledges the importance of empowering individual agents to make decisions and take actions that contribute to the overall robustness and adaptability of the system. This approach values decentralized decision-making, adaptability, and the ability of agents

to respond effectively to uncertainties and disruptions, ultimately enhancing the system's capacity to endure and thrive in a dynamic and unpredictable environment.

Example of a humorous, surprising, yet scientifically accurate and educational pamphlet- for the exclusive purpose of contemplation and reflection



Requests:

(a) Why is ATCO not allocating additional resources to enhance its efforts in educating and/or reinforcing awareness within its customer base regarding the myriad of invaluable services electricity provides, all at an unparalleled cost?

(b) Why does ATCO not capitalize on its monthly billing communications to include an informative pamphlet discussing either the advantages of electric power or the potential pitfalls associated with the expectation of uninterrupted electric power supply?

Response:

(a) AEY is a regulated utility, which fundamentally distinguishes its business model from competitive enterprises. AEY's primary mission is to ensure the delivery of safe, reliable, and affordable power to all customers within its service area. As a result, AEY's focus revolves around fulfilling this mandate rather than engaging in marketing efforts to promote the value or benefits of electricity.

AEY's communications with customers are primarily centered on sharing critical safety messages, providing service updates, and conveying important operational information. This approach aligns with AEY's core mission of delivering power that is both dependable and cost-effective.

While AEY does not engage in extensive customer education campaigns focused on the value of its services, AEY remains committed to transparency and welcomes any inquiries from its customers seeking information about its operations or the electricity services provided.

(b) AEY is primarily a power distribution company, which means its primary responsibility lies in the maintenance and operation of the poles and wires that deliver electricity to its valued customers. In the context of the electricity supply chain, Yukon Energy serves as the primary entity responsible for electric generation on the Yukon Integrated System. Given this division of responsibilities

within the industry, AEY's primary focus is on ensuring the reliable distribution of electricity to homes and businesses in its service area.

That said, AEY's communication efforts with regards to supply are geared towards conveying essential information related to customer's electricity consumption, billing details, and any service-related updates that may impact power.

ATCO Electric YUKON

September 28, 2023 AEY-JM-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-001

Reference: Cover letter to 2023-2024 Application

Page 1 of 4, Proposed rate changes

Requests:

(a) Please clarify whether AEY is proposing to absorb the 2023 cost difference between the 2017 YUB approved price for diesel fuel and the actual price paid by AEY.

(b) If AEY is not proposing to absorb the cost difference referred to in (a) above, please confirm that this cost will be passed on to ratepayers in the 2023-2024 GRA period.

(c) If the diesel fuel cost difference referenced above is to be passed on to ratepayers, please confirm that the rate increase required for AEY to recover its proposed 2023 expenses is 3.3% as shown in Table 1.

Response:

(a) AEY is not proposing to absorb the 2023 fuel cost variance.

(b) Consistent with the methodology approved in Board Orders 2016-02 and 2017-01, AEY intends to combine the fuel variances with its Rate Adjustment Rider R in its Compliance Filing, at which time Rider F will be reset to reflect this transfer.

(c) The proposed overall 2023 rate increase (including the fuel cost variance), over primary retail revenue on existing rates, is 3.3 percent. However, the actual impact to customers is a net reduction, when final rates are calculated and Rider F is updated for fuel prices. Customers are currently paying a Rider F Fuel Adjustment Rider for differentials in actual and previous fuel prices embedded in Rider R. Once

the fuel price embedded in Rider R is updated, Rider F will be reduced. The table below shows that while the rate increase, before adjusting for Rider F, is 3.3 percent (Line 6, Column C), the net rate adjustment is a decrease of -1.6 percent, excluding the Rider F fuel adjustment (Line 5, Column B) or including the Rider F fuel adjustment (Line 5, Column C).

Table 1: ATCO Electric Yukon
2023 Rate Changes Including and Excluding Fuel Adjustments
($000)

Line	Description	Reference	A Current	B Interim (Excl Fuel)	C Final (Incl Fuel)
1	AEY + YEC Revenue	S.2, L59	74,585	74,585	74,585
2	Rider F Fuel Adjustment	S.2, L53	0	0	(3,698)
3	Rider R Rate Adjust	S.2, L50		(1,211)	2,487
4	Total Revenue		74,585	73,374	73,374
5	AEY % Rate Change from Current	=B/A & C/A		**-1.6%**	**-1.6%**
6	AEY Final Rider R Adjustment	=C3/A4			**3.3%**

ATCO Electric YUKON

September 28, 2023 AEY-JM-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-002

Reference: Cover letter to 2023-2024 Application

Application page 2 of 4 Terms and Conditions of Service

Requests:

(a) Statistics Canada website (accessed August 14, 2023) states that the January 2011 monthly consumer price index for all items for Whitehorse Yukon was 115.9 and for June 2023 was 156.4. This represents an increase of about 34.94%. Would AEY object to the YUB raising the maximum company investment levels in Schedule B parts (a) and (b) by this percentage effective immediately? This would not prevent AEY and YEC from having discussions on the more complicated and substantive portions of the Terms and Conditions of Service and bringing a comprehensive proposal to the YUB in 2024.

Response:

(a) While AEY is not opposed to the YUB raising the maximum investment levels based on inflation, AEY notes that these changes would result in increased revenue requirement. In addition, AEY's normal practice is to complete a study to determine what the company's investment levels should be; this study has not been completed; however, AEY can commit to working with YEC to complete a study following this Proceeding.

ATCO Electric YUKON

September 28, 2023 AEY-JM-003(1)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-003(1)

Reference: AEY letter responding to comments on AEY's request for interim rates

AEY letter page 4 of 8: "AEY submits that all parties have sufficient opportunity on a regular basis to review and assess AEY's operations through the annual filing process and as demonstrated through the Rate Relief Application, material issues and items that arise can be addressed in a limited scope between fulsome applications as needed."

Requests:

(a) Is it AEY's view that the Yukon Utilities Board has the legal authority to require AEY to come before it with either a limited scope application or a full GRA? Please explain.

(b) Regardless of the answer to (a) above, if the Yukon Utilities Board requested AEY to come forward with either a limited scope application or a full GRA in a non-test year, would AEY comply with the request?

(c) Is it AEY's view that the Yukon Utilities Board is either required to or has the responsibility to review AEY's annual and other filings submitted to the Board? Please explain.

(d) Can the Yukon Government require AEY to come before the Yukon Utilities Board with either a limited scope application or a full GRA? Please explain.

Response:

(a-d) AEY notes that, pursuant to the YUB Rules of Practice, parties may submit Information Requests in an effort to clarify another party's evidence, to simplify issues, to permit a fulsome understanding of matters to be considered in the proceeding, or to expedite the proceeding (Rules 13(1) and 13(2)(e)). Respectfully, requests regarding a legal interpretation of the Board's or the Yukon Government's authority to compel rate proceedings or the Board's review of annual filings are outside of the scope of this proceeding and are not aimed at clarifying AEY's evidence and furthering the Intervener's understanding of the Application. Accordingly, AEY declines to respond pursuant to Rule 14(4) of the Rules of Practice.

ATCO Electric YUKON

September 28, 2023 AEY-JM-003(2)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-003(2)

Reference: Application Section 1 Introduction

Page 1-2 Table 1.1 inflation rates:

Requests:

(a) Please provide the corresponding inflation rates for the period 2008 to 2017 inclusive.

Response:

(a) Please refer to the table below for the Whitehorse CPI inflation rates for the period 2008 to 2017.

Inflation Rate by Year

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Inflation Rate	3.6	0.4	0.8	3.0	2.3	1.7	1.3	(0.2)	1.0	1.7

ATCO Electric YUKON

September 28, 2023 AEY-JM-004

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-004

Reference: Application Section 1 Introduction

Page1.4 Table 1.2

Requests:

(a) AEY retail revenues of $62.203 million and $64.152 million for 2023 and 2024 respectively appear to exclude the portion of the cost for fuel presently collected through Rider F. Is it a correct reading of Schedule 2.1 that the requested rate changes including the cost of fuel would result in AEY retail revenue requirements of $64.690 million and $71.736 million for 2023 and 2024 respectively?

(b) Please provide the equivalent AEY retail revenue numbers presented in Table 2.1 for each of the years 2016 to 2022.

(c) Please also provide the AEY retail revenue numbers including the fuel cost for each of the years 2016 to 2022.

(d) In Schedule 2.1 why is there no YEC Revenue shortfall rider included in line 51 for the years 2023 and 2024?

Response:

(a) Correct. Consistent with previous GRAs, AEY does not include fuel cost changes in the applied for rate changes and includes all required true-ups at the time of setting AEY's final rates, in conjunction with updates to Rider F.

(b) Please refer to AEY-JM-004(b) Attachment 1 for a copy of Schedule 2.1 from AEY's 2016-2017 GRA, which includes the equivalent AEY retail revenue numbers for 2016 and 2017 on Line 52. As the years 2018 to 2022 were not Test Years

before the YUB, there are no equivalent retail numbers available for this time-period.

(c) AEY's retail revenue (including fuel costs)[1] and fuel costs[2] for the years 2016 to 2022 can be found in AEY's 2023-2024 GRA Regulatory Schedules.

(d) The YEC revenue shortfall does not factor into AEY's revenue on existing rates or revenue requirement since it pertains to YEC and is a flow through from AEY to YEC. As such, YEC's revenue shortfall amounts for 2023 and 2024 are not included in Line 51 of Schedule 2.1.

[1] Schedule 2.1, line 52.
[2] Schedule 4.1, line 4.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

2016 - 2017 General Rate Application Compliance Filing
Summary of Customers, Energy Sales and Revenue

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016 Existing	Test Period 2016 Proposed	Test Period 2017 Existing	Test Period 2017 Proposed
1	**Residential**											
2	Customers (average during year)		14,194	14,192	14,409	14,401	14,631	14,647	14,851		15,039	
3	Sales in MWh		148,780	148,010	147,253	154,384	148,605	157,032	148,444		155,827	
4	MWh sales per customer		10.48	10.43	10.22	10.72	10.16	10.72	10.00		10.36	
5	Revenue ($000s)		21,070	20,765	20,629	21,657	20,839	22,029	21,012		21,969	
6	Cents per kWh		14.16	14.03	14.01	14.03	14.02	14.03	14.15		14.10	
7	**Commercial**											
8	Customers (average during year)		2,918	2,922	2,938	2,903	2,988	2,948	2,998		3,039	
9	Sales in MWh		159,322	157,606	154,709	165,106	155,346	168,853	156,283		162,350	
10	MWh sales per customer		54.60	53.94	52.66	56.87	51.99	57.28	52.13		53.43	
11	Revenue ($000s)		26,305	25,753	25,509	27,016	25,534	27,652	25,601		26,519	
12	Cents per kWh		16.51	16.34	16.49	16.36	16.44	16.38	16.38		16.33	
13	**Industrial**											
14	Customers (average during year)		-	-	-	-	-	-	-		-	
15	Sales in MWh		-	-	-	-	-	-	-		-	
16	MWh sales per customer											
17	Revenue ($000s)		-	-	-	-	-	-	-		-	
18	Cents per kWh								-		-	
19	**Street Lights**											
20	Sales in MWh		3,719	3,725	3,765	3,789	3,886	3,854	3,944		4,008	
21	Revenue ($000s)		961	951	962	966	992	981	1,002		1,020	
22	Cents per kWh		25.84	25.54	25.54	25.49	25.52	25.45	25.41		25.46	
23	**Private Lights**											
24	Sales in MWh		551	554	544	544	519	534	493		472	
25	Revenue ($000s)		145	145	142	143	138	141	132		128	
26	Cents per kWh		26.33	26.23	26.05	26.27	26.58	26.31	26.87		27.06	
27	**Total Company - Retail - Primary**											
28	Customers		17,112	17,114	17,347	17,304	17,619	17,595	17,849		18,077	
29	Sales in MWh		312,372	309,894	306,272	323,823	308,356	330,274	309,164		322,656	
30	Revenue ($000s)		48,481	47,614	47,241	49,783	47,503	50,802	47,747		49,636	
31	Cents per kWh		15.52	15.36	15.42	15.37	15.41	15.38	15.44		15.38	
32	**Secondary Sales**											
33	Customers (average during year)		2	-	2	-	3	-	3		3	
34	Sales in MWh		3,959	-	5,415	-	7,030	-	9,429		9,429	
35	MWh sales per customer		1,980	-	2,708	-	2,812	-	3,429		3,143	
36	Revenue ($000s)		336	-	474	-	532	-	519		519	
37	**Cents per kWh**		8.49	-	8.75	-	7.57	-	5.50		5.50	
38	**Wholesale Sales**											
39	Customers (average during year)		2	2	2	2	2	2	2		2	
40	Sales in MWh		361	338	494	338	430	338	427		427	
41	MWh sales per customer		180.71	169.12	246.99	169.12	215.00	169.12	213.63		213.63	
42	Revenue ($000s)		30	28	41	28	36	28	35		35	
43	Cents per kWh		8.30	8.30	8.30	8.30	8.30	8.30	8.30		8.30	
44	**Total Company**											
45	Customers		17,116	17,116	17,351	17,306	17,624	17,597	17,854		18,082	
46	Sales in MWh	S.3.2 L.2	316,692	310,232	312,181	324,162	315,816	330,612	319,020		332,513	
47	Revenue ($000s)		48,847	47,642	47,756	49,811	48,071	50,830	48,301		50,190	
48	Cents per kWh		15.42	15.36	15.30	15.37	15.22	15.37	15.14		15.09	
49	Base Retail Revenues		48,847	47,642	47,756	49,811	48,071	50,830	48,301		50,190	
50	**RIDER R (RATE INCREASE @ CURRENT RATES)**		1,634	1,099	3,672	2,576	4,139	3,267	4,052	1,059	4,049	1,972
51	YEC Revenue Shortfall (Rider J)		5,829		6,259		5,266					
52	**Total Retail Revenue**		56,310	48,741	57,687	52,387	57,476	54,097	52,354	53,413	54,239	56,211
53	Fuel Variance Rider (Rider F)	Note 1		1,071		1,086		1,087		(1,342)		(1,351)
54	**NET REVENUES**	S.1.1 L.2	56,310	49,812	57,687	53,473	57,476	55,183	52,354	52,071	54,239	54,859
55	**% Rate Increase over Existing Rates**											
56	AEY Primary Retail Revenue	L.30		47,614		49,783		50,802	47,747		49,636	
57	YEC Firm Revenue			10,429		12,169		12,304	8,537		6,598	
58	Total YEC/AEY Retail Revenue Primary Rates ($000s)	L.56 + L.57		58,043		61,952		63,106	56,284		56,234	
59	**% Rate Increase Over Existing Rates**	L.50 / L.58		1.9%		4.2%		5.2%		1.9%		3.5%
60	**% Rate Increase - Net Customer Impact**	Note 2		3.7%		5.9%		6.9%		-0.5%		1.1%

61 Note 1 - 2016-2017 Rider F calculated based on average 2015 diesel price
62 Note 2 - Net impact of higher revenue requirement and fuel price variance to be flowed through to customers.

ATCO Electric YUKON

September 28, 2023 AEY-JM-005

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-005

Reference: Application Section 1 Introduction

Page 1.7 Staff positions.

Requests:

(a) Please provide a listing of each of the number of residential, commercial, and other customers (at year end or other convenient measurement point) by year from 2016 through 2022.

(b) What are AEY's forecast numbers for each of these groups of customers for 2023 and 2024?

(c) Which of these positions are primarily working on capital projects and what portion of their time is allocated to O&M costs vs. capital costs?

Response:

(a) Please refer to Schedule 2.1 for the breakdown of customer numbers by year.

(b) Please refer to Schedule 2.1 for the forecast number of customers in 2023 and 2024.

(c) Please refer to the table below for the Capital and O&M percentages by position.

Table 1: Capital and O&M Split by Position
(%)

Position	Capital	O&M
Program Manager, Renewables & Grid Modernization	90	10
Engineering Technologist, Renewables & Grid Modernization	90	10
Electrical Engineer 1	70	30
Electrical Engineer 2	60	40
Mechanical Engineer	25	75
Team Lead, Plant	0	100
Field Services Representative	0	100
Supervisor, Business Support Services	0	100
VP and VP Support Services	0	100
Head Office Personnel	0	100

ATCO Electric YUKON

September 28, 2023 AEY-JM-006

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-006

Reference: Section 1B Energy Transition

Page 1B-1 Increased electrification.

Requests:

(a) What forecast increases in use per customer (UPC) has AEY included in the sales forecast of this GRA?

(b) Regarding "conflicts" and changes in "customer demands", what demand side management programs has AEY included in this GRA to deal with undesirable effects on the grid, for example managing water heaters and other electrical loads, encouraging behind-the-meter energy storage by customers, etc., to overcome problems?

(c) Does the "dramatic impact" not include a significant increase in retail sales by AEY thereby also increasing revenues?

Response:

(a) AEY has applied the approved forecasting methodology for UPC.[1] The forecast results in an increase in residential and commercial UPC for 2024, as shown in the Application, Schedule 2.1, Lines 4 and 10, respectively.

(b) AEY has not included any demand side management programs as part of its 2023-2024 GRA.

[1] Board Order 2017-01, para. 40.

(c) Reference to “dramatic impact” is with respect to the changes in the sources of energy and the costs of transitioning to a lower emission electrical grid, not with respect to the change in retail sales due to customer behavior.

ATCO Electric YUKON

September 28, 2023 AEY-JM-007

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-007

Reference: Section 1B Energy Transition

Page 1B-2 Grid modernization.

Requests:

(a) AMI will prove to be a helpful tool in future for demand management and is a good thing to do, but why is it presented here within a list of complaints? Does AEY expect this project to be disallowed or challenged when it has been previously supported?

Response:

(a) AEY expects AMI to be an essential part of Grid Modernization. Section 1B.2 is part of Section 01 – Introduction, which is not in any way presented as a 'list of complaints'. The purpose of the section is to provide an overview of AEY's business, highlight various challenges and AEY's approach to addressing these challenges. AMI will be able to provide electricity use and demand data on a more granular level than has been possible in the Yukon to date. There is the ability for the AMI system to communicate and control devices on the customer's side of the meter, which further prepares AEY for the two-way flow and communication of electricity. AEY does not expect this project to be disallowed.

ATCO Electric YUKON

September 28, 2023 AEY-JM-008

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-008

Reference: Section 1B Energy Transition

Page 1B-3 EV charger network.

Requests:

(a) If an expansion of the EV charging network is paid for by the YG and federal governments, isn't the only risk to AEY that of increased sales?

Response:

(a) No, increased sales are not the only risk. EVs and EV charging networks are rapidly evolving technology with new and unique challenges for regulated utilities. There are risks associated with increased EV adoption and expansion of an EV charging network in the Yukon, which include:

- Sales risk: price signals to EV owners can lead to lower than forecast sales, or at least lead to forecasting challenges, which can make overall sales more volatile.
- Political and regulatory risk: As mentioned, EVs are a new and evolving technology. Changes in government leadership or policies can affect the adoption rate of EVs. Various jurisdictions approach EVs in different ways, which might impact consumer uptake and AEY's operations. The Federal Government's *2030 Emissions Reduction Plan (ERP)* is introducing mandates for rapid uptake of EVs, which may put new capacity strains on the grid that may need to be addressed with system upgrades. The desire for rapid EV adoption must also be balanced with any affordability and supply chain concerns.
- Technical and operational risk: Fast-charging equipment can put different strains on the electrical system depending on its size and location. For example, off-grid communities may have different capacity availabilities

than on-grid communities which would require different EV charging systems. With the large electrical load of fast charges, various substations, feeders and distribution lines may reach their capacity sooner than expected under normal load growth. If EV chargers are able to operate without centralized control, there can be large loads that appear intermittently on the system that can make energy supply more difficult.

ATCO Electric YUKON

September 28, 2023 AEY-JM-009

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-009

Reference: Section 1B Energy Transition

Page 1B-4 Microgeneration program.

Requests:

(a) Does a rapidly increasing population not mean rapidly increasing sales for AEY ?

(b) Does AEY expect that the microgeneration uptake by the new customers will mean an oversupply of electricity for these customers?

(c) Does new microgeneration supply not decrease line losses?

(d) Since YG pays for electricity fed back into the grid and which AEY re-sells at retail rates to other customers, without having to purchase it, is there not a net benefit to AEY?

Response:

(a) Generally, yes, sales increases are aligned with population growth and have been factored in to AEY's sales forecast as described in Section 2 of the Application.

(b) Generally, AEY will provide safe and reliable service to all customers and is unaware of any customers being over supplied. Sales could be lower if a significant proportion of new customers install micro-generation.

(c) The effect of micro generation on system line losses is not clear. For example, on review of total system losses, Schedule 3.2, Line 4, the total MWh of micro-generation production increased between 2018 and 2020; however, the percentage of losses also increased in the same time frame. As there are multiple

sources of generation on the YIS, that are not directly aligned with system load, the effect on losses of micro-generators spread across the system is not quantifiable at this time. When considering the annual MWh generated on the YIS, the contribution of micro-generation is minimal (less than 1 percent of total MWh).

(d) No, there is not a net benefit to AEY. As shown in Schedule 3.2, forecast micro-generation is an offset to power purchases. This offset lowers AEY's revenue requirement, which benefits ratepayers at current forecasts. However, AEY currently has the forecast risk for micro-generation production; if there is less (or more) micro-generation than forecast, AEY would have to purchase more (or less) power from YEC. This risk is affected depending on how the Yukon Government program is administered, which AEY does not control.

ATCO Electric YUKON

September 28, 2023 AEY-JM-010

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-010

Reference: Section 2 Sales and Revenue

Page 2-1 Table 2.1

Requests:

(a) Please provide the annual average primary retail sales growth for the period 2016 to 2022.

Response:

(a) The annual average primary retail sales growth for the period 2016 to 2022 was 2.4 percent.

ATCO Electric YUKON

September 28, 2023 AEY-JM-011

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-011

Reference: Section 2 Sales and Revenue

Page 2-2 near top "…the 2023 forecast anticipates UPCs returning to pre-pandemic levels for both Residential and Commercial customers."

Requests:

(a) Why does AEY believe that there will be a complete return to pre-pandemic UPCs when it appears that there will be some permanent changes such as increased working from home?

(b) Do the increasing number of new residential and commercial customers almost all of which use electric space heat, and a steady trickle of older customers in older homes and businesses switching away from fossil fuel heating to electric systems (e.g. ETS and heat pumps) not tend to increase the UPCs? Please explain.

Response:

(a) AEY submits that while there is an increase in full-time/hybrid work from home compared to pre-pandemic, the pre-pandemic environment is more indicative of the future for forecasting purposes, than the time during the pandemic when government mandated restrictions were in place. Students are attending school full-time, businesses don't have restrictions, travel has resumed, and the habits of the general public are more indicative of pre-pandemic times.

(b) The introduction of new homes and the retrofit of old homes with electric space heat should increase UPC, assuming other usage habits remain unchanged. The increase in load is due to the changes in space heat and other changes in usage habits, are included in AEY's data and forecast sales.

September 28, 2023 AEY-JM-012

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-012

Reference: Section 3 Purchase Power

Schedule 3.2

Requests:

(a) What is the average revenue per kWh that AEY realized in 2022 from the resale of micro-generation energy exported to AEY?

Response:

(a) AEY does not receive revenue for micro-generation. The micro-generation energy exported to AEY reduces the Wholesale purchases, which carries a charge of 0.0830 per kwh, as shown on Schedule 3.1, Line 7.

ATCO Electric YUKON

September 28, 2023 AEY-JM-013

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-013

Reference: Section 3 Purchase Power

Section 3.4 IPPs

Requests:

(a) Please provide two comprehensive sets of lists of all study and capital costs that each of the IPP and AEY incurs in developing an IPP project one for projects under the standing offer program and one for projects in small communities not eligible under the standing offer program (Old Crow, Burwash landing / Destruction Bay, and Beaver Creek).

(b) Please provide similar lists for operating and maintenance expenses.

(c) Please outline the cost savings realized by AEY on a per kWh basis when purchasing IPP generated power and describe if or how these benefit each of AEY and / or the ratepayers.

Response:

(a) The summary of the cost breakdown is as follows for the only completed off-grid (non-standing offer program IPP):

Table 1: Old Crow Capital Cost Summary
($000)

Costs	**Total**
Project Management & Design	40
Equipment & Installation	3,425
Capital Cost	**3,465**
Contribution	(3,465)
Net Cost	**-**

For capital costs of Standing Offer Program (SOP) projects on the YIS, please refer to S.9.2 L.175–177. The capital costs for the NOMAD IPP project was $144,000 and the SOLVEST IPP project was $37,000.[1] YEC is the Buyer for these SOP projects on the YIS, AEY's role is to interconnect the site to the distribution system as would happen for any New Extension project.

In the small communities, AEY is the responsible utility for all aspects of the IPP facility's integration. This includes distribution interconnection, generation adaptation and Buyer of the renewable energy. AEY has identified the system costs for these community IPP projects in S.9.2 L.133–136.

AEY does not report or have access to the IPPs costs for development of their project.

(b) Old Crow is the only IPP currently in operation in AEY's small communities. The following cost estimate is for the full year (i.e., post-commissioning) of operating costs related to this IPP facility. As the renewable project, and all ancillary equipment, is in-service, operating expenses are being incurred as they would for any electrical infrastructure operating in AEY's grid. AEY does not report or have access to the IPPs costs for operations and maintenance of their project.

[1] These costs are included in New Services Overhead and Underground in AEY 2023-2024 GRA Schedule 9-2 Line 42 (2020-2022). These costs will be reclassed into the IPP line in the Compliance Filing.

Table 2: Old Crow O&M Costs Summary

Description	2022	2023	2024
BESS & MGC service contract; preventative maintenance, warranty, firmware updates	$45,000	$45,000	$50,000
Remote technical support (MGC modifications, troubleshooting, HMI revision, libraries update)		$35,000	$15,000
Unscheduled Site Support		$20,000	
Repair (module and card, boiler fan motor)		$55,000	
Technical and Operational Training		$40,000	
Travel (and per diems)	$5,000	$10,000	$5,000
Inspection (battery fire suppression, boiler burner test)	$5,000	$5,000	$5,000
Total	**$55,000**	**$210,000**	**$75,000**

(c) As noted on page 1B-3, the IPP Policy was adopted by the Yukon Government in 2015. AEY, as a regulated utility, was required to respond to IPP proponents to integrate their respective renewable electricity projects into the isolated grids. The purpose of these renewable energy projects is to decrease the environmental footprint of producing electricity in isolated communities. This has been achieved through a reduction of diesel-powered electricity production and corresponding GHG emissions, a reduction in diesel fuel being transported to the community and the associated fuel release risk, and noise pollution reduction when the diesel power plant is in standby mode. This is done while ensuring a safe, reliable, and affordable supply of electricity to the community.

The intent is to pay the IPP for renewable energy at a similar rate to the cost of producing the same amount of energy with diesel generation. As the rate is similar to the existing rates, there is no benefit or cost savings to AEY. As defined in section 3(1) of the Order in Council (2019/25), the price for energy purchased from the IPP reflects the five-year weighted average price of avoided fuel cost, reduction of operation and maintenance costs, and deferred capital expenses as a result of the thermal generation displaced by the IPP.

ATCO Electric YUKON

September 28, 2023 AEY-JM-014

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-014

Reference: Section 4 Fuel Costs

Schedule 4.2 Isolated diesel-served communities

Requests:

(a) What are AEY's projected IPP power purchases in each of these communities for 2023 and 2024?

(b) What are AEY's projected micro-generation contributions (export plus behind-the-meter consumption) to each of these community microgrids?

(c) There are widely fluctuating heat rates in these communities in 2021 and 2022, are these real or a function of unusual adjustments? Please explain.

Response:

(a) AEY forecast 587 MWh and 649 MWh IPP power purchases in Old Crow in 2023 and 2024, respectively, as set out in Schedule 3.2 line 11.

(b) AEY's micro-generation energy export forecast is set out in the table below:

Table 1: Export Forecast

Rate Zone	2023	2024
Hydro	3,234	3,745
Old Crow	7	7
Destruction Bay	21	21
Beaver Creek	16	20
Total	**3,278**	**3,793**

AEY does not track behind the meter generation or consumption as it is not currently feasible to do so. AEY only has visibility of export energy for micro-generation customers.

(c) Beaver Creek and Destruction Bay heat rate are unusually high in 2021 possibly due to these plants receiving two major overhauls each.

The Old Crow heat rate is unusually high in 2022 mainly due to timing of production due to metering (i.e., kWh) issue in 2021. Production from 2021 is captured in 2022 when new meters were installed.

Standby Units: The standby heat rate is unusually low in 2021, because there was a metering (i.e., kWh) issue that did not accurately capture production in Pelly Crossing and Stewart Crossing, but then gets corrected in 2022.

ATCO Electric YUKON

September 28, 2023 AEY-JM-015

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-015

Reference: Section 5 Operations and Maintenance Expenses

Table 5.1 page 5.3 O&M expenses

Requests:

(a) During the 9-year period from 2012 through 2020 AEY's actual O&M expenses were relatively stable between $11 million and $12 million per year. [The 2012 data is from the YECL (AEY) 2013-2015 GRA Application Schedule 1.1 PDF page 19 of 1881; and the 2013 to 2015 data is from the AEY 2016-2017 GRA Application Schedule 1.1 PDF page 12 of 292.] Please describe the factors that maintained that stability and the factors that drove overall O&M costs up by $2 million in 2021 and a further $1 million in 2022.

Response:

(a) The following is a list of factors that enabled AEY to maintain stability in O&M costs during the referenced period:

- Continuous improvement: encourage a culture of continuous improvement among employees. Regularly review processes and workflows to identify and eliminate inefficiencies.
- Budgeting and cost control: develop a detailed O&M budget and closely monitor expenses against it on monthly basis.
- Regular Maintenance and Inspections: implemented a proactive maintenance schedule to prevent costly breakdowns and repairs.
- Asset testing – Poles, underground cables, street light davits, meters, breakers, and substation transformers.

The following table provides a breakdown of the overall O&M cost increase in 2021:

Table 1: 2020 vs. 2021 Overall O&M Cost Variances ($000)

	2020	2021	Variance	
Production	1,882	2,569	687	Note 1
Distribution	3,254	4,250	997	Note 2
General	281	429	148	Note 3
Other	6,549	6,565	16	
Total	**11,966**	**13,814**	**1,848**	

Note 1: Incremental costs for diesel generator top end overhaul maintenance, and diesel tank certified inspections (5 yr). AEY observed supply chain inflation and delays post-COVID.

Note 2: Incremental Brushing costs mainly due to optimal weather conditions and contractor availability allowing for above average kms of line to be covered annually in addition to higher contractor rates when the COVID restrictions lifted.

Note 3: Incremental Warehousing maintenance costs to address deficiencies due to aging of the building.

O&M costs increased in 2022 mainly due to inflation and the incremental costs noted in the following table:

Table 2: 2021 vs. 2022 Overall O&M Cost Variances ($000)

	2021	2022	Variance	
Production	2,569	3,107	538	Note 1
Distribution	4,250	4,481	231	Note 2
General	429	520	91	Note 3
Customer Accounting	1,964	2,168	204	Note 4
Other	4,601	4,517	(84)	
Total	**13,814**	**14,794**	**980**	

Note 1: Incremental Maintenance costs for diesel generator top end maintenance and overhaul costs.

Note 2: Incremental Brushing costs mainly due to optimal weather conditions and contractor availability allowing for above average kms of line to be

covered annually in addition to higher contractor rates when the COVID restrictions lifted.

Note 3: Incremental Warehousing maintenance costs to address deficiencies due to aging of the building.

Note 4: Incremental contractor services costs to integrate weather stations into Old Crow Control system.

ATCO Electric YUKON

September 28, 2023 AEY-JM-016

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-016

Reference: Section 5 Operations and Maintenance Expenses

Table 5.2 page 5-4 Labour Costs by function

Requests:

(a) Please explain the 22% increase requested for 2023 over 2022 for actual production labour cost.

(b) Please justify the request for the substantial increase requested for public information following a four-year period (2018-2021) with very modest costs.

Response:

(a) Please refer to the response to AEY-UCG-033(b).

(b) S5.2 Public Information costs is not considered to be a substantial increase. The labour costs were lower during the referenced four-year period mainly due to a vacancy for the Senior Communication Advisor. However, AEY has been charged for Head Office Marketing services during the referenced period. Please refer to the total costs for public information in the table below showing that the average costs per year, including the head office marketing costs, are $ 0.139 million, which is close to the approved amount in 2016.

September 28, 2023 AEY-JM-016

Table 1: Breakdown of Public Information
Labour and Other
($000)

	2018	2019	2020	2021	2023	2016
	Actuals				Test Year	Approved
70100 - Public Information Administration						
Labour	10	15	16	13	15	
Other	11	9	15	63	15	
Total	**21**	**24**	**31**	**76**	**30**	**14**
70200 - General Public Information						
Labour	11	-	-	12	79	
Other	26	50	53	68	70	
Total	**37**	**50**	**53**	**80**	**149**	**120**
Head Office Marketing						
S.5.3 L.13	25	52	52	57	-	-
Total	**83**	**126**	**136**	**213**	**179**	**134**
Average for 2018 - 2021	**139**					

Additional Marketing Costs required in 2023 are mainly for the following items:

- communication material and video costs for 'understanding your bill campaign' ($25,000);
- communication costs for graphic design and mailing for new billing system notification ($10,000); and
- graphic design and photography costs for all images on AEY website ($15,000).

ATCO Electric YUKON

September 28, 2023 AEY-JM-017

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-017

Reference: Section 5 Operations and Maintenance Expenses

Table 5.4 page 5-6 Distribution Costs

Requests:

(a) The maintenance and repair costs ranged from $0.597 in 2018 to $0.712 million in 2021. Please justify the 50% increase over 2021 for 2023 (and more for 2024).

(b) "... distribution maintenance costs have increased by $0.3 million for incremental right-of-way clearing and pole testing, due to additional maintenance requirements to support a larger asset base resulting from system growth in recent years." Please explain why recently built distribution lines require right-of-way clearing and pole testing. Were these new distribution line rights-of-way not properly brushed to begin with and build with salvaged poles? Please explain.

Response

(a) The maintenance and repair costs increased over 2021 for 2023 mainly due to the following reasons:

- Inflation impact: higher costs for materials and contractors due to inflation increase.
- Asset growth: the maintenance costs have increased to support a larger assets base resulting from system growth in recent years.
- Aging infrastructure: older infrastructure is more prone to frequent maintenance and repair services.

(b) AEY constructs new power lines to current standards. All ROWs are brushed to proper clearances and new materials are used to construct the line. AEY follows a five-year brushing plan. All areas are inspected and assessed. To keep up with the

brushing maintenance, it is more economical to mow ROWs before the growth requires slashing. Pole testing will follow an 8-10-year cycle. Even newly installed poles can be susceptible to various issues, including environmental factors, insects, and human interference. Depending on the year and visual inspection of the pole, a bore test may not be required.

ATCO Electric YUKON

September 28, 2023 AEY-JM-018

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-018

Reference: Section 5 Operations and Maintenance Expenses

Table 5.7 page 5-8 Customer Accounting Costs

Requests:

(a) Non-labour costs in 2016 to 2022 ranged from $0.467 million to $0.664 million per year. Please provide the details of the increases of 25% in 2023 and 73% in 2024 over the highest of the previous 7 years.

Response:

(a) Non-labour cost increases in 2023 and 2024 are mainly due to incremental O&M expenditure for the CCS program. The CCS program will require an increase in O&M expenditures to operate the cloud-based system. This is primarily driven by the annual subscription fees. Please refer to the breakdown below illustrating the operating cost changes in 2023 and 2024:

Table 1: CCS Program Operating and Maintenance Costs ($000)

	2023[1]	2024
Operating Costs	400	700

[1] The dollars in 2023 are prorated as CIS will not be in service for the entirety of 2023.

ATCO Electric YUKON

September 28, 2023 AEY-JM-019

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-019

Reference: Section 5 Operations and Maintenance Expenses

Page 5-8 Customer Accounting

Preamble: "… The primary driver for the increase in costs is the annual subscription fees required to operate the new Oracle Customer Cloud Service Solution (CCS) billing software … the annual subscription fee cannot be capitalized."

Requests:

(a) What are the annual AEY CCS subscription fees?

(b) Do these fees also cover the billing of Yukon Energy's customers?

(c) If the previous billing system was capitalized, what is the corresponding decrease in depreciation costs as a result of its discontinuance?

Response:

(a) The new billing software is a Cloud-based system which has subscription fees that incorporate licensing costs, cloud-based services, and systems support. These amount to $700,000 per year.

(b) Yes.

(c) Please refer to the response to AEY-JM-033(c).

ATCO Electric YUKON

September 28, 2023 AEY-JM-020

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-020

Reference: Section 5 Operations and Maintenance Expenses

DSM programs

Preamble: AEY DSM programs are conspicuous by their absence from O&M costs, yet Concentric Energy Advisors say in their report (in the Application on PDF page 144) that AEY has DSM programs delivered through Yukon Energy.

Requests:

(a) Does AEY have at present any active demand side management programs for residential and commercial customers, if so please describe them.

(b) Does AEY have any plans to expand its DSM programming? Please explain why or why not.

Response:

(a) No, AEY does not have any active programs available to Residential or Commercial customers.

(b) As part of the Grid Modernization initiative, AEY is exploring options to use the AMI communication network to manage various devices on the grid (including loads) during power quality and outage events. AEY is a member of the DSM Working Group along with Yukon Government and YEC to align our efforts and direction for the future of DSM in Yukon.

ATCO Electric YUKON

September 28, 2023 AEY-JM-021

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-021

Reference: Section 7 Depreciation

Tables 7.2 and 7.3 pages 7-1 and 7-2, and Schedule 7.1

Requests:

(a) For certainty in how the figures in these tables and schedule should be read, please explain if the correct interpretation of figures without brackets is that these are costs to ratepayers and figures in brackets are credits due to or held on behalf of ratepayers. If not correct, please provide the correct interpretation.

(b) Please explain the meaning of the term “salvage depreciation” and explain why these numbers are in brackets.

Response:

(a-b) Correct, in Table 7.2, the costs in brackets represent a reduction in revenue requirement. However, in Table 7.3 reflects the negative net salvage explained in the depreciation study which would be an increase in revenue requirement. Please also refer to the response to AEY-UCG-041(a).

ATCO Electric YUKON

September 28, 2023 AEY-JM-022

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-022

Reference: Section 8 Return on Rate Base

Page 8-3 paragraphs 11 and 12

Preamble other quotes from this GRA:

Page 1-2 "Since the last GRA the Yukon has experienced population and GDP growth rates amongst the highest in Canada…"

Page 1-9 "The volume of work has increased due to rapid system growth …"

Page 1B-1 "AEY has seen rapid population growth and new Government energy transition policies and legislation aimed at increased electrification …"

Requests:

(a) These quotes from earlier portions of this GRA application are at odds with the characterization of AEY's operating environment in the referenced paragraphs 11 and 12. Please explain.

(b) Please provide actual examples of realized risk in impact on sales and ROE since the last GRA was filed in 2016.

Response:

(a) AEY disagrees that the quotes identified are at odds with paragraphs 11 and 12. The Yukon has experienced rapid population growth which has led to risks and concerns with the load requirements of the area based on the current infrastructure. Even with this rapid population growth, AEY is still a small utility, when compared to most other utilities in other regions such as British Columbia

and Alberta. Being a relatively small utility, AEY carries additional risks when compared to larger utilities.

(b) AEY responds to risk on a continuous, ongoing basis through its day to day operations. It is neither efficient nor practical for AEY to track the impacts of every circumstance, or differentiate between multiple circumstances, that were not planned or required alternative and/or unplanned responses since 2016. As a rule of thumb, unplanned, unrecoverable expenses of $100,000 reduce AEY's return by approximately 20 basis points based on the 2023 Test Year capital structure.

Examples of specific circumstances AEY has faced and responsive actions and/or outcomes are as follows:

COVID 19 Pandemic: AEY, like many other utilities, responded to the implications of the global pandemic in the time-frame since 2016. AEY incurred additional costs to ensure that proper protective equipment was available and sanitization protocols were upheld. In addition, AEY adjusted practices with regards to vehicle usage and office space in accordance with officials' guidelines regarding social distancing. This resulted in increased vehicle charges as larger crews required more vehicles.

AEY also experienced implications with customer usage, in that time-frame, as work from home orders were issued, residential energy usage per customer increased, and commercial energy usage per customer declined. Downstream impacts of the financial strain on commercial customers, as a result of the pandemic, also had implications for AEY's customer numbers and usage. For example, while residential energy use per customer (UPC) increased during the pandemic, commercial UPC was lower.

The pandemic also had significant implications on the job market. Vaccine requirements saw reductions in staffing and increased costs for severance.

Unprecedented labour phenomena within the market, such as "the mass resignation" and "quiet quitting," were experienced through several industries, including the utility industry as people who worked through the pandemic shifted their perspectives on work life balance and the expectations of how their jobs are performed post-pandemic. It is generally accepted that the costs of retaining staff are less significant than costs associated with attaining and training external resources. As such, in response to these phenomena, market compensation rose in efforts to retain talented staff and AEY responded accordingly to ensure it attracts and retains the staffing resources required to provide safe and reliable service.

Industrial Factors: AEY forecast an increase in industrial sales as part of its 2016-2017 Application using forecast methods found to be reasonable in Board Order 2017-01. AEY has historically cited sales forecast risks associated with industrial customers, which were not accepted in Board Order 2014-06. AEY realized these risks following the 2016-2017 Test Period, albeit to AEY's benefit, which resulted in higher than forecast Rider R revenues from industrial customers creating unplanned variability in AEY's ROE.

The uptick in mining activities also has downstream implications for AEY and its sales forecast. Upticks and downturns in the mining industry have impacts on residential customers as people migrate to and from the Territory. With the uptick in mining activities in 2017-2019, AEY experienced increasing load on the system, which AEY has realized, requiring increasing maintenance costs and capital investment to ensure safe and reliable services. In this time-period, there were other factors contributing to population growth in the Yukon, such as growth within government operations.

Economic Conditions: Since 2016, AEY has responded to the economic impacts of the various conditions, including rising interest costs, material inflationary

pressures, and stagnation through the pandemic. AEY undertakes rigorous cash management and cost reviews throughout the various circumstances in which it operates to ensure that it is operating as effectively and prudently as possible. Closely monitoring the capital markets, to ensure lowest possible debt costs, and potentially deferring debt issuances to future periods when markets are expected to be more favourable to borrowers is one-way AEY can respond to these conditions. However, system needs cannot always be deferred and may result in higher costs than anticipated.

Commodity pricing also has implications to AEY's sales. As commodity prices fluctuate, consumer behavior responds accordingly. In the Yukon, consumers have choices with respect to the commodities used to heat their homes. Propane, wood pellet and heating oil prices implicate the degree to which consumers utilize electric heating options, creating peaks and valleys in AEY's load which, in addition to associated sales and revenue impacts, also has implications for system capacity requirements and reliability.

Supply Chain Risks: Global and economic factors contributed to significant supply issues, impeding AEY's ability to procure what is needed to complete required capital and maintenance. This has, and continues to, present challenges to complete its planned capital programs on time and on budget as the situation in Russia and Ukraine persists. Unavailability of materials and rising prices are outcomes of the global conditions and AEY has to respond accordingly through temporary solutions or paying premium prices to complete necessary work.

Political & Legislative Risks: The Yukon Government has been introducing policies geared towards transitioning the energy industry through increased electrification and reducing carbon emissions, as seen with the "Our Clean Future" initiative. The impact of these legislative changes, as outlined in Section 1B and the Concentric Report included in the Application, include impacts related to Grid

Modernization, Independent Power Production (IPP) legislation, the expansion of the Electric Vehicle (EV) Charger Network and Micro-Generation. These programs impact AEY either through a variance related to capacity demands or the cost of service. Further information on these programs can be found in AEY-YUB-002(f).

Federal policies regarding the energy transition also impact AEY's operations. In 2022, the Government of Canada published the *2030 Emissions Reduction Plan (ERP).* The ERP seeks to reduce national GHG emissions by 40 to 45 percent below 2005 levels by 2030 and achieve net-zero GHG emissions by 2050. The plan called for mandates requiring 100 percent of new passenger vehicles sold in Canada to be zero emission by 2035, with interim targets of 20 percent by 2026 and at 60 percent by 2030. Vehicle manufacturers have made significant commitments to introduce EV lineups. The new EV mandates will create new capacity demands on the system which may require significant investment to address. The recent draft *Clean Electricity Regulations (CER)* is another example of a federal regulation that is expected to significantly alter the utility industry.[1]

Operating Risks: AEY continues to respond to mechanical failures, inclement and/or unpredictable weather, environmental events such as wildfires and floods, and human interference (i.e., hit lines) to provide safe and reliable service. These risks are inherent to AEY's day to day operations and result in incremental, unplanned costs, such as, but not limited to:

- unplanned travel and accommodations into remote communities;
- operation of standby and/or mobile diesel generation units;
- unplanned maintenance costs and overtime expenses;
- higher purchased power expenses; and
- unplanned capital projects.

[1] AEY notes that the current draft of the *CER* would not currently affect its facilities in the Yukon as it targets generation units over 25 MW.

Unpredictable weather continues to also implicate sales and revenues as air conditioning and/or electric heating loads are directly correlated to weather. Periods of extreme cold temperatures increase load while warmer winters decrease load and vice versa in the summer months. In addition to the implications to AEY's sales and revenues, the unpredictable weather also impacts AEY's system capacity and reliability and requires AEY's response to provide safe and reliable service.

ATCO Electric YUKON

September 28, 2023 AEY-JM-023

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-023

Reference: Section 8 Return on Rate Base

Page 8-4 paragraph 16

Requests:

(a) What risk premium above the BCUC GCOC benchmark did the Yukon Utilities Board decide was appropriate in AEY's last GRA?

Response:

(a) In Board Decision 2017-01, the Board approved a risk premium of 25 basis points above the BCUC GCOC benchmark.

ATCO Electric YUKON

September 28, 2023 AEY-JM-024

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-024

Reference: Section 8 Return on Rate Base

Pages 8.6 and 8.7 Table 8.4 and 8.5

Requests:

(a) Please provide a table for the years 2016 through 2022 and projected into 2023 and 2024 of the actual capital expenditures less the actual contributions in aid of construction towards these actual capital expenditures.

Response:

Table 1: Net Capital Expenditures
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Capital Expenditures	14,784	10,476	9,491	13,529	13,001	15,147	18,914	31,234	25,073
Contribution in Aid of Construction	(1,241)	(2,204)	(3,212)	(5,969)	(4,220)	(5,251)	(8,362)	(16,538)	(6,405)
Net Capital Expenditures	**13,543**	**8,272**	**6,280**	**7,560**	**8,781**	**9,896**	**10,552**	**14,696**	**18,668**

ATCO Electric YUKON

September 28, 2023 AEY-JM-025

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-025

Reference: Section 8 Return on Rate Base

Application PDF pages 136 to 171, Concentric Energy Advisors report

Requests:

(a) PDF page 141 Figure 1: for each of the Canadian electric and gas utilities listed, including FortisBC Energy Inc., please provide a table showing the allowed and actual ROE earned over the past 10 years.

(b) Which of these companies have been able to operate 5 years between GRAs while still exceeding their allowed ROE?

(c) PDF page 144: Please list all of the referenced DSM programs that AEY presently supports which are available to residential and / or commercial customers.

(d) PDF Page 167 line 13: Does AEY pay the capital costs for the battery and the interconnection?

(e) PDF Page 167 line 14: Please provide the data that confirms that IPP projects generally reduce AEY sales.

(f) PDF Page 167 lines 22 and 23: Does the comment that because wind and solar are intermittent they are less reliable mean that they are not dispatchable as a diesel generator would be? If something different please explain.

(g) Is it not true that once a wind or solar project is built the cost of energy is far more stable than that of diesel fuel?

Response:

(a) Please refer to Attachment AEY-JM-025(a) Attachment 1 for authorized ROEs for the companies in Figure 1 for the years 2016-2023. Earned return data is generally

not publicly available for many of these companies as they are not required to file their results on the public record. While it may be possible to calculate an earned ROE from accounting data, Concentric has found that such calculations are fraught with peril because it is also necessary to make certain adjustments to the earned ROE for items such as goodwill on the balance sheet and regulatory accounts and mechanisms that affect the earned ROE of a utility. In our experience, many utilities in Canada earn close to their authorized ROE, while some earn above the authorized return. However, that is not uniformly true, especially for smaller companies.

(b) Please refer to the table below for the GRA's filed in the last 10-years. Note not all utilities file GRA's under the framework with which they are regulated.

Table 1: Filed GRAs

Canadian Gas & Electric Utilities	GRAs Filed
FortisBC Energy	n/a
FortisBC Electric	n/a
Ontario Electric Distributors	n/a
Newfoundland Power	2012, 2015, 2018, 2021
Maritime Electric Company Ltd	2010, 2015, 2018, 2022
ATCO Electric Distribution	n/a
Pacific Northern Gas-West	n/a

(c) As grid modernization and technologies associated with it develop, AEY is always assessing what can be used or leveraged for the betterment of its customers. Although AEY does not currently have any DSM programs for residential or commercial customers, the Company previously did. Concentric's risk assessment of AEY relative to the comparator group did not depend on whether AEY currently has any DSM programs. In addition, AEY is currently part of a working group to look at how DSM programs can be implemented. The AMI program is an example of a new technology AEY is implementing that could impact DSM programs.

Please refer to the response to AEY-YUB-065 for more information on the AMI project.

(d) No. The IPP is responsible for all costs including the battery and interconnection facilities on both the Generation and Distribution systems.

(e) The referenced excerpt from the Concentric Report refers to the demand for energy supplied by AEY, not AEY's sales to end use customers.

(f) Yes, the comment is that wind and solar are intermittent sources of power, or not available all the time, which means that AEY cannot always depend on these resources to supply electricity when needed. Diesel generation can be called upon at all times, regardless of wind or sun conditions.

(g) AEY cannot agree with this statement as it is difficult to compare fuels for energy that have completely different characteristics. Wind and solar fuel have stable costs, if available when needed. Unfortunately, there is no control over the availability for those energy fuels. Diesel fuel cost fluctuates but it is readily available and provides energy storage inherently.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Return of Equity (ROE)
2016-2022

Line No.	Authorized ROE (%)	2016	2017	2018	2019	2020	2021	2022	2023
1	ATCO Electric Yukon	8.75	9.00	9.00	9.00	9.00	9.00	9.00	9.00
2									
3	**Canadian Electric & Gas Utilities**								
4	FortisBC Energy	8.75	8.75	8.75	8.75	8.75	8.75	8.75	9.65
5	FortisBC Electric	9.15	9.15	9.15	9.15	9.15	9.15	9.15	9.65
6	Ontario Electric Distributors	9.19	8.78	9.00	8.98	8.52	8.34	8.66	9.36
7	Newfoundland Power	8.50	8.50	8.50	8.50	8.50	8.50	8.50	8.50
8	Maritime Electric Company Ltd	9.35	9.35	9.35	9.35	9.35	9.35	9.35	9.35
9	ATCO Electric Distribution	8.30	8.50	8.50	8.50	8.50	8.50	8.50	8.50
10	Pacific Northern Gas-West	9.50	9.50	9.50	9.50	9.50	9.50	9.50	9.50
11									
12									
13									
14	**Earned ROE (%)**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	
15	ATCO Electric Yukon	10.44	12.73	12.64	13.01	13.19	12.09	11.94	
16									
17	**Canadian Electric & Gas Utilities**								
18	FortisBC Energy	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
19	FortisBC Electric	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
20	Ontario Electric Distributors	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
21	Newfoundland Power	8.90	8.93	8.76	8.79	8.93	n/a	n/a	
22	Maritime Electric Company Ltd	n/a	n/a	n/a	n/a	9.30	9.35	9.35	
23	ATCO Electric Distribution	13.03	13.21	8.34	11.15	9.82	12.85	14.52	
24	Pacific Northern Gas-West	n/a	n/a	n/a	n/a	n/a	n/a	n/a	

ATCO Electric YUKON

September 28, 2023 AEY-JM-026

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-026

Reference: Section 9 Capital additions

Page 9-1 New CIS project at $8.4 million:

Requests:

(a) On page 5.8 we are told that the new CCS system (is this also the CIS system?) would be a subscription cost based system, yet here we are told that there is a capital cost of $8.4 million. Please clarify this project with respect to capital and / or operating costs.

Response:

(a) As outlined in the ATCO CIS Replacement Business Case #22, the ATCO Computer Information System (CIS) is being replaced with Oracle Customer Cloud Service (CCS). The replacement is required to mitigate risks associated with the current (end-of-life) system and to provide AEY with the right tools to perform Customer Care and Billing (CC&B) in an accurate, reliable and efficient manner.[1] The CIS Replacement Project includes both capital and operational spend. The $8.4 million in capital spend is outlined in paragraph 8 of the Business Case, and is related to configuration, data migration, and testing. The operating costs for the Test Period are outlined in paragraph 9 of the Business Case and are the ongoing costs required to operate the cloud-based system.

[1] 2023-2024 AEY GRA, ATCO CIS Replacement, 2023-2024 Business Case #22.

ATCO Electric YUKON

September 28, 2023 AEY-JM-027

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-027

Reference: Section 9 Capital additions

Section 9, Schedule 9.1,

Preamble: YECL 2013-2015 GRA Schedule 9.1 (2013-2015 GRA Application PDF page 495 of 1881), AEY 2016-2017 GRA Schedule 9.1 (AEY 2016-2017 GRA Application PDF page 171 of 292), and the present AEY 2023-2024 GRA Schedule 9.1 all show that AEY has been unable to complete the approved capital expenditures (which were all less than requested in the GRA).

Requests:

(a) Given this track record it appears unrealistic on AEY's part to (1) get YUB approval for the very large capital expenditures requested in this GRA, and (2) to expect to be able to deliver what is approved. Please explain.

(b) In Table 9.4 AEY is shown to be proposing distribution improvements in the range of 2 to 3 times the annual expenditures of the previous 5 years, all of which were lower than 2016 and 2017 expenditures. Please explain why these very large expenditures are necessary now, and why a number of these expenditures were not undertaken in the previous 5 years when AEY clearly had the financial resources to do so.

Response:

(a) Please refer to AEY's response to AEY-YUB-042.

(b) AEY has a mandate to provide safe and reliable service and has undertaken capital projects to ensure this is met. With the recent population growth in Yukon, there is additional load causing strain on the distribution network, which increases the risk to the reliability of the network. As a result, there are additional large capital

builds required, such new substations, to address this issue. Please refer to AEY's response to AEY-UCG-058(a) and (b) for details on population growth and AEY-JM-027(b) Attachment 1 for details on the load growth estimates in Whitehorse.

Summary

Less than 20% capacity remaining
Less than 10% capacity remaining

* All Values are in kVA

Arkell							
	Actual	Forecasted					
Percent Increase 2.72%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S8615 Normalized Load	3428	4380	4500	4622	4748		
S8619 Normalized Load	3068	3017	3099	3184	3270		
Transformer 1 Normalized Load	6266	7398	7599	7806	8018		
Regulator 1 Remaining Capacity	11055	9923	9721	9515	9302	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	3734	2602	2401	2194	1982	Transformer Rating	10000

Laberge							
	Actual	Forecasted					
Percent Increase 2.06%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S3600 Normalized Load	5600	5715	5833	5953	6075		
S8306 Normalized Load	1975	2016	2057	2099	2143		
Transformer 1 Normalized Load	7287	7730	7890	8052	8218		
Regulator 1 Remaining Capacity	10034	9590	9431	9268	9102	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	2713	2270	2110	1948	1782	Transformer Rating	10000

Lewes							
	Actual	Forecasted					
Percent Increase 0.58%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S6817 Normalized Load	2830	2807	2823	2839	2856		
S6822 Normalized Load	2139	2250	2263	2276	2289		
Transformer 1 Normalized Load	4851	5056	5086	5115	5145		
Regulator 1 Remaining Capacity	3809	3604	3575	3545	3515	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2649	2444	2414	2385	2355	Transformer Rating	7500

Logan							
	Actual	Forecasted					
Percent Increase 2.69%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9877 Normalized Load	1950	2122	2179	2237	2297		
S9878 Normalized Load	2677	2789	2864	2941	3020		
Transformer 1 Normalized Load	4447	4911	5043	5178	5318		
Regulator 1 Remaining Capacity	12874	12410	12278	12142	12003	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	5553	5089	4957	4822	4682	Transformer Rating	10000

Macrae							
	Actual	Forecasted					
Percent Increase 1.76%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S5953 Normalized Load	1861	1893	1927	1961	1995		
S9833 Normalized Load	4416	4494	4573	4654	4736		
Transformer 1 Normalized Load	6082	6387	6500	6614	6731		
Regulator 1 Remaining Capacity	2578	2273	2160	2046	1930	Regulator Rating (200A)	8660
Transformer 1 Remaining Capacity	3918	3613	3500	3386	3269	Transformer Rating	10000

Mountain View							
	Actual	Forecasted					
Percent Increase 2.52%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S8354 Normalized Load	1091	1118	1147	1176	1205		
S8358 Normalized Load	5630	5771	5917	6066	6219		
S8471 Normalized Load	1059	1086	1113	1141	1170		
Transformer 1 Normalized Load	7780	7976	8177	8383	8594		
Regulator 1 Remaining Capacity	1091	685	484	278	66	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2431	2024	1823	1617	1406	Transformer Rating	10000

Porter Creek							
	Actual	Forecasted					
Percent Increase 2.12%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9402 Normalized Load	2867	3101	3166	3233	3302		
S9403 Normalized Load	4189	4278	4369	4461	4556		
Transformer 1 Normalized Load	6772	7379	7535	7695	7858		
Regulator 1 Remaining Capacity	1888	1282	1125	966	802	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3228	2621	2465	2305	2142	Transformer Rating	10000

Riverdale							
	Actual	Forecasted					
Percent Increase 1.9%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9400 Normalized Load	2197	2386	2431	2477	2524		
S9401 Normalized Load	933	962	980	999	1018		
Transformer 1 Normalized Load	2985	3348	3412	3476	3543		
Regulator 1 Remaining Capacity	5675	5312	5249	5184	5118	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	4515	4152	4088	4024	3957	Transformer Rating	7500

Selkirk							
	Actual	Forecasted					
Percent Increase 2.72%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9977 Normalized Load	4675	4803	4934	5068	5207		
Transformer 1 Normalized Load	4675	4803	4934	5068	5207		
Regulator 1 Remaining Capacity	3985	3858	3727	3592	3454	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	5325	5197	5066	4932	4793	Transformer Rating	10000

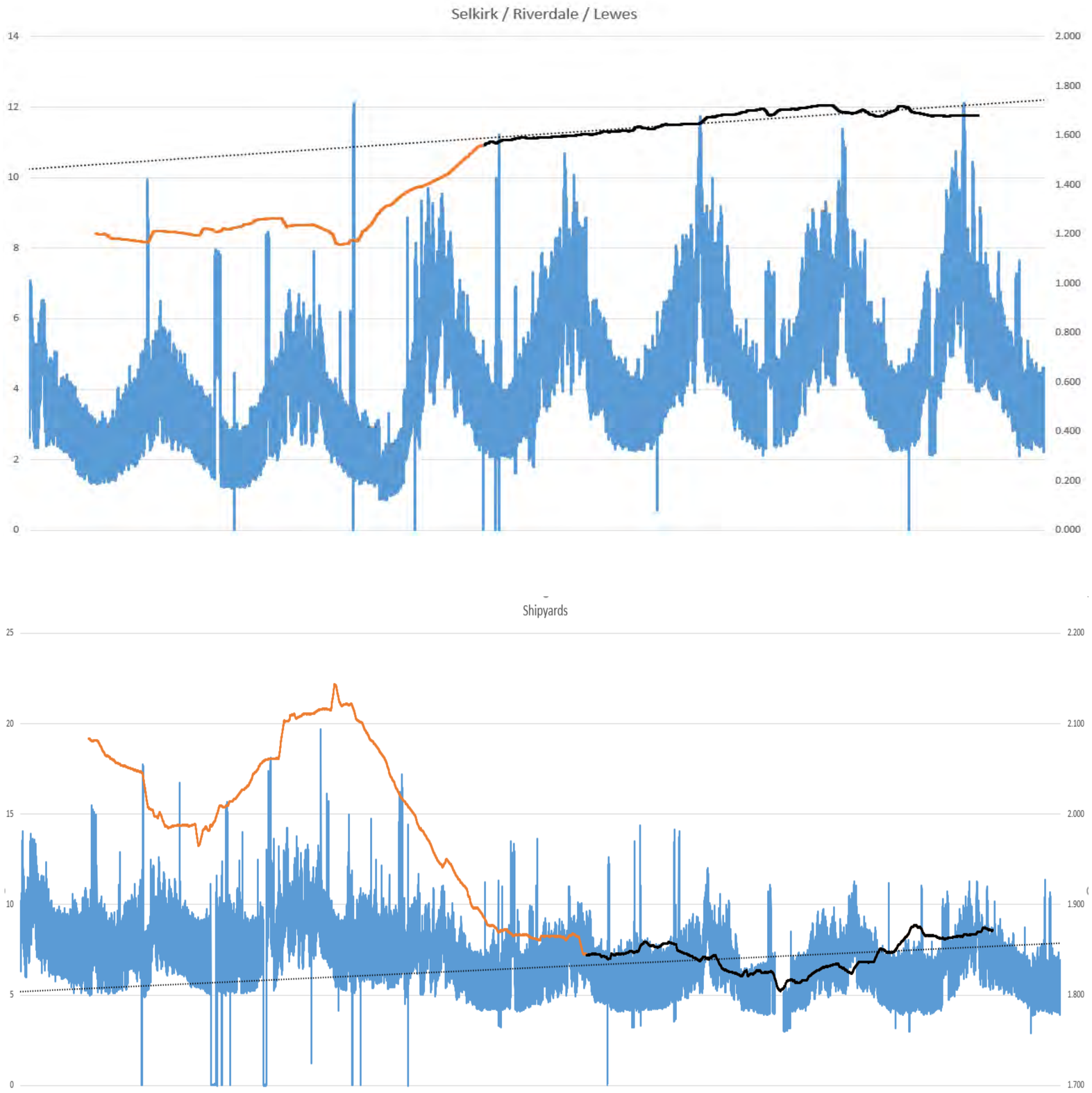
Services							
	Actual	Forecasted					
Percent Increase 0%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S7191 Normalized Load	3676	3676	3676	3676	3676		
Transformer 1 Normalized Load	3676	3676	3676	3676	5207		
Regulator 1 Remaining Capacity	5144	4984	4984	4984	4984	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3984	3824	3824	3824	3824	Transformer Rating	7500
S7192 Normalized Load	3268	3268	3268	3268	3268		
S7193 Normalized Load	1374	1374	1374	1374	1374		
Transformer 2 Normalized Load	4520	4642	4642	4642	4642		
Regulator 2 Remaining Capacity	4140	4019	4019	4019	4019	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	2980	2859	2859	2859	2859	Transformer Rating	7500

Shipyards							
	Actual	Forecasted					
Percent Increase 0.99%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S1020 Normalized Load	3720	3757	3794	3832	3870		
S1023 Normalized Load	3607	3643	3679	3715	3752		
Transformer 1 Normalized Load	6879	7400	7473	7547	7622		
Regulator 1 Remaining Capacity	1781	1260	1187	1113	1038	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3121	2600	2527	2453	2378	Transformer Rating	10000
S1011 Normalized Load	3550	3585	3620	3656	3692		
S1016 Normalized Load	1731	1748	1765	1782	1800		
Transformer 2 Normalized Load	4863	5333	5385	5439	5493		
Regulator 2 Remaining Capacity	3797	3328	3275	3222	3168	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	5137	4667	4615	4561	4507	Transformer Rating	10000

Whistlebend							
	Actual	Forecasted					
Percent Increase 11.26%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S3431 Normalized Load	593	660	735	817	909		
S3432 Normalized Load	2518	2802	3117	3468	3858		
Transformer 1 Normalized Load	3088	3462	3852	4285	4768		
Regulator 1 Remaining Capacity	14233	13859	13469	13035	12553	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	6912	6538	6148	5715	5232	Transformer Rating	10000
S3433 Normalized Load	5785	6436	7161	7967	8864		
S3434 Normalized Load	127	142	158	175	195		
Transformer 2 Normalized Load	5674	6578	7318	8142	9059		
Regulator 2 Remaining Capacity	11647	10743	10002	9178	8261	Regulator Rating (400A)	17321
Transformer 2 Remaining Capacity	4326	3422	2682	1858	941	Transformer Rating	10000

Substation	1yr moving avg	1yr moving avg with peak factor	Notes
Arkell	1.94%	2.72%	S150 SCADA (2015-2022) for the Arkell feeder supllied by YEC. This substation is servicing a mature residential subdivision, as well as some commercial along Range Road. No major development so moderate growth is expected
Laberge	1.47%	2.06%	This substation is servicing a large mature residential and industiral area that includes Hot Springs Road, the Alaska Hwy, and Kulan industrial. Therefore, a moderate yearly growth is to be expected. YEC SCADA data used
Lewes	0.42%	0.58%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Logan	1.92%	2.69%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Macrae	1.25%	1.76%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Mountain View	1.80%	2.52%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Porter Creek	1.52%	2.12%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Riverdale	1.35%	1.90%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Selkirk	1.95%	2.73%	Load from Services and Shipyards was shifted to Selkirk, this can be seen in the graph below. Data provided by YEC for S150 was used for the feeder that supplies Selkirk, Lewes, and Riverdale. The growth rate for Selkirk was calculated by taking the slope of the S150 feeder regression, minus the slope of the Riverdale regression, minus the slope of the Lewes regression. The remaining value is the slope of what would be the Selkirk regression.
Services	0.00%	0.00%	Both ATCO and YEC SCADA data show a steady decrease in load over the last four years (-5.19% and -3.56% respectively). There's uncertainty around why the decrease is occuring. Temporary load shifting within the data between Services, Arkell, Mountain View, and Porter Creek can all be accounted for.
Shipyards	0.71%	0.99%	Load from Shipyards was shifted to Selkirk. As seen in the graph below, the trendline was taken for the period of time after the load shift and once the 1 year moving average had stabalized.
Whistlebend	8.04%	11.26%	Growth at this substation is rapid due to on going development. Since ATCO has first hand knowledge of expected growth from the number of houses that are built each year, one of two approaches can be taken: Use the yearly growth percentage found from the moving average or apply a set load increase based on total number of homes built in a given year multiplied by average load per home. YEC SCADA data was used.

*Note regarding Laberge and Whistlebend - The growth percentage found from ATCO SCADA data subjectly high, whereas the growth seen from the YEC SCADA data for the feeder supllying Laberge and Whistlebend looked to be closer to what would be expected. To break up the YEC feeder data into its respective substations, the weight of growth percentages for each substation from ATCO SCADA was applied to the YEC data.


Selkirk / Riverdale / Lewes
14
12
10
8
6
4
2
0
2.000
1.800
1.600
1.400
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Shipyards
25
20
15
10
5
0
2.200
2.100
2.000
1.900
1.800
1.700

ATCO Electric YUKON

September 28, 2023 AEY-JM-028

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-028

Reference: Business Cases

Business case No. 5

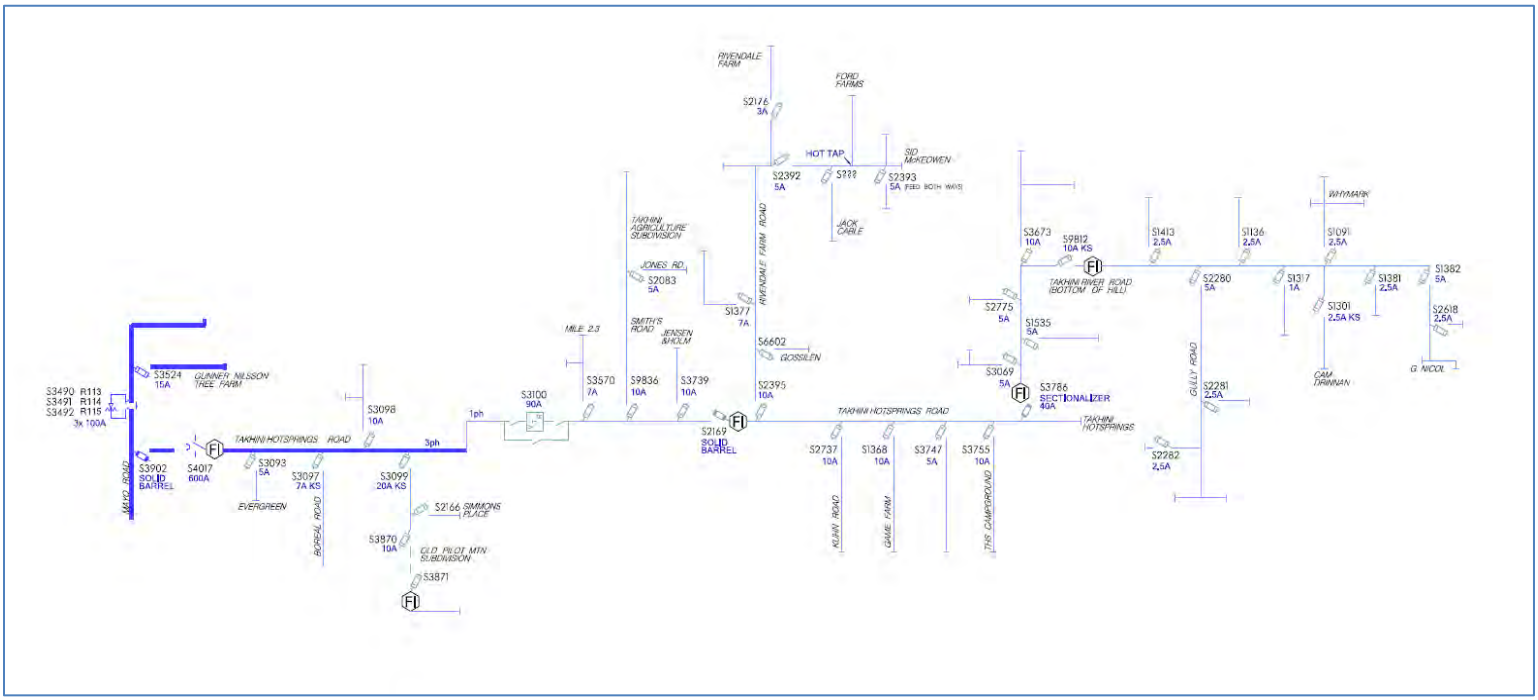
Requests:

(a) Please provide a readable (higher resolution) version of the single line diagram in this business plan.

Response:

(a)

Business Case No. 5 - Single Line Diagram



ATCO Electric YUKON

September 28, 2023 AEY-JM-029

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-029

Reference: Business Cases

Business case No. 6

Requests:

(a) What is the ampacity rating of new #1/0 conductor compared to #6 and #4 conductor?

(b) Did AEY consider going to the next larger conductor from #1/0? Please explain.

Response:

(a) Using the primary voltage of 24.9 kV, the summer ampacity of #6 is 108 A, #4 is 145 A and 1/0 is 261 A, and the winter ampacity of #6 is 144 A, #4 is 193 A and 1/0 is 351 A.

(b) AEY did not consider installing 2/0 ACSR, as modelling for load protection showed 1/0 ACSR ampacity to be sufficient for projected load growth on the system.

September 28, 2023 AEY-JM-030

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-030

Reference: Business Cases

Business case No. 12

Requests:

(a) In new construction are the ROWs brushed to the wider widths at the outset?

Response:

(a) AEY requires that all newly constructed ROWs are brushed to AEY standards at the time of new construction. Newly cleared ROWs as a result, will not require brushing to wider widths. Please refer to AEY-JM-030(a) Attachments 1-4 for copies of AEY brushing standards.

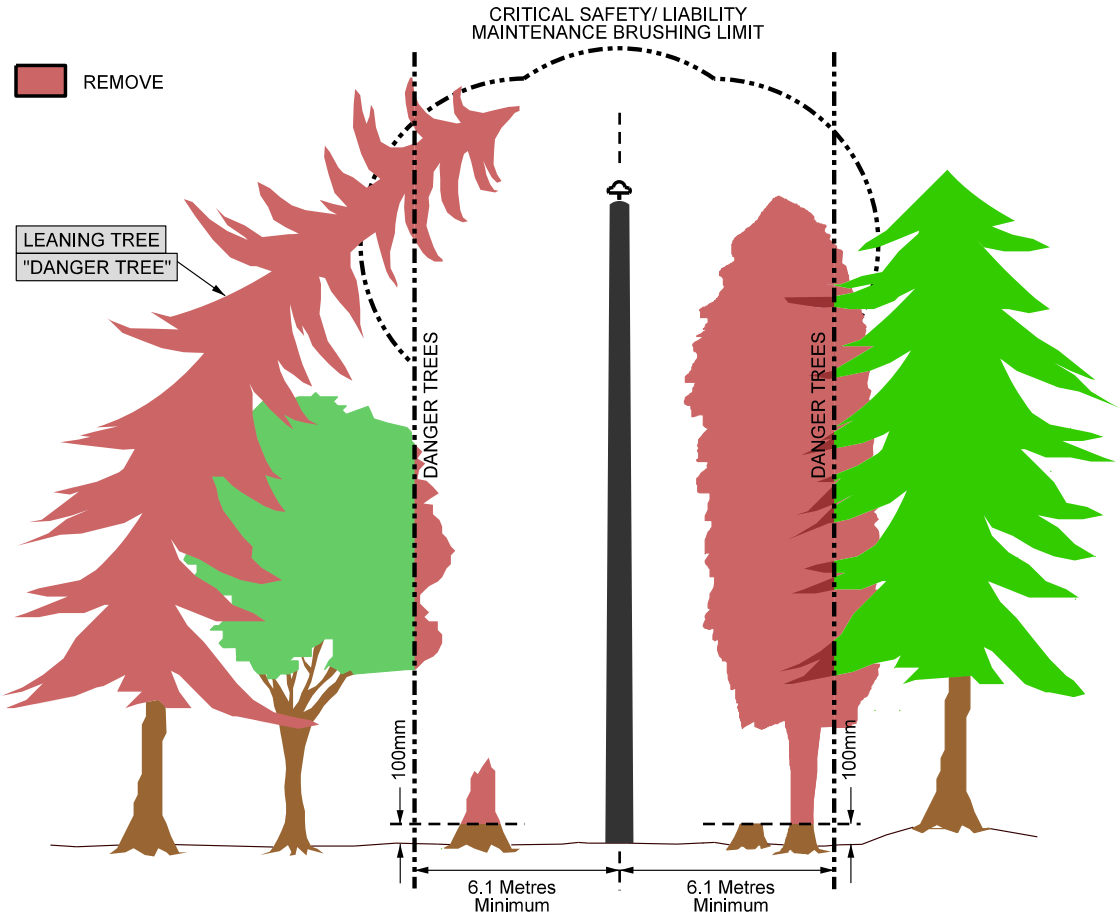
ATCO Electric YUKON

RIGHT OF WAY MAINTENANCE BRUSHING REQUIREMENT FOR SINGLE PHASE HIGH VOLTAGE LINES UP TO 14.4kV

- SINGLE PHASE PRIMARY -

LEGEND / NOTES

*ATCO Electric Yukon Qualified Brush Removal identified by Pink & Black striped flagging.



RIGHT OF WAY SITE NOTES

Trees or brush that have been flagged by "DANGER TREE" flagging are a threat to fall into an existing live powerline and the CUSTOMER IS NOT TO CUT DOWN.

ATCO Electric Yukon will arrange for the Powerline Crew to cut down at time of construction or send out a Qualified Utility Brusher to cut down.

VOLTAGE	RIGHT-OF-WAY WIDTH	TREE TO CONDUCTOR CLEARANCE
2400 V	-	3m
4160 V	-	3m
7200 V	12.2m (6.1m EACH SIDE)	5m
14000 V	12.2m (6.1m EACH SIDE)	5m
24940Y/14000 V	15.0m (7.5m EACH SIDE)	5m

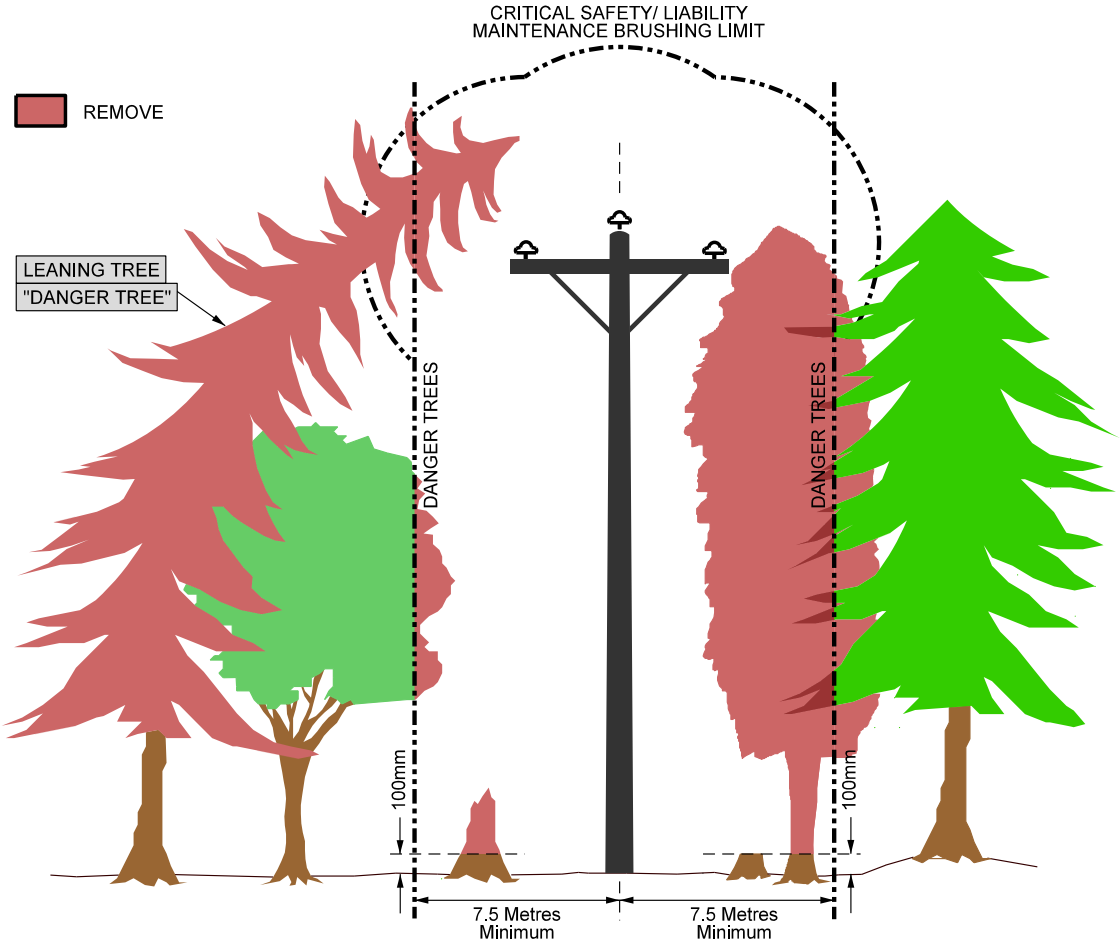
ATCO Electric YUKON

RIGHT OF WAY MAINTENANCE
BRUSHING REQUIREMENT FOR
THREE PHASE HIGH VOLTAGE LINES
UP TO 34kV

- THREE PHASE PRIMARY -

LEGEND / NOTES

*ATCO Electric Yukon Qualified Brush Removal identified by Pink & Black striped flagging.



RIGHT OF WAY SITE NOTES

Trees or brush that have been flagged by "DANGER TREE" flagging are a threat to fall into an existing live powerline and the CUSTOMER IS NOT TO CUT DOWN.

ATCO Electric Yukon will arrange for the Powerline Crew to cut down at time of construction or send out a Qualified Utility Brusher to cut down.

VOLTAGE	RIGHT-OF-WAY WIDTH	TREE TO CONDUCTOR CLEARANCE
2400 V	-	3m
4160 V	-	3m
7200 V	12.2m (6.1m EACH SIDE)	5m
14000 V	12.2m (6.1m EACH SIDE)	5m
24940Y/14000 V	15.0m (7.5m EACH SIDE)	5m

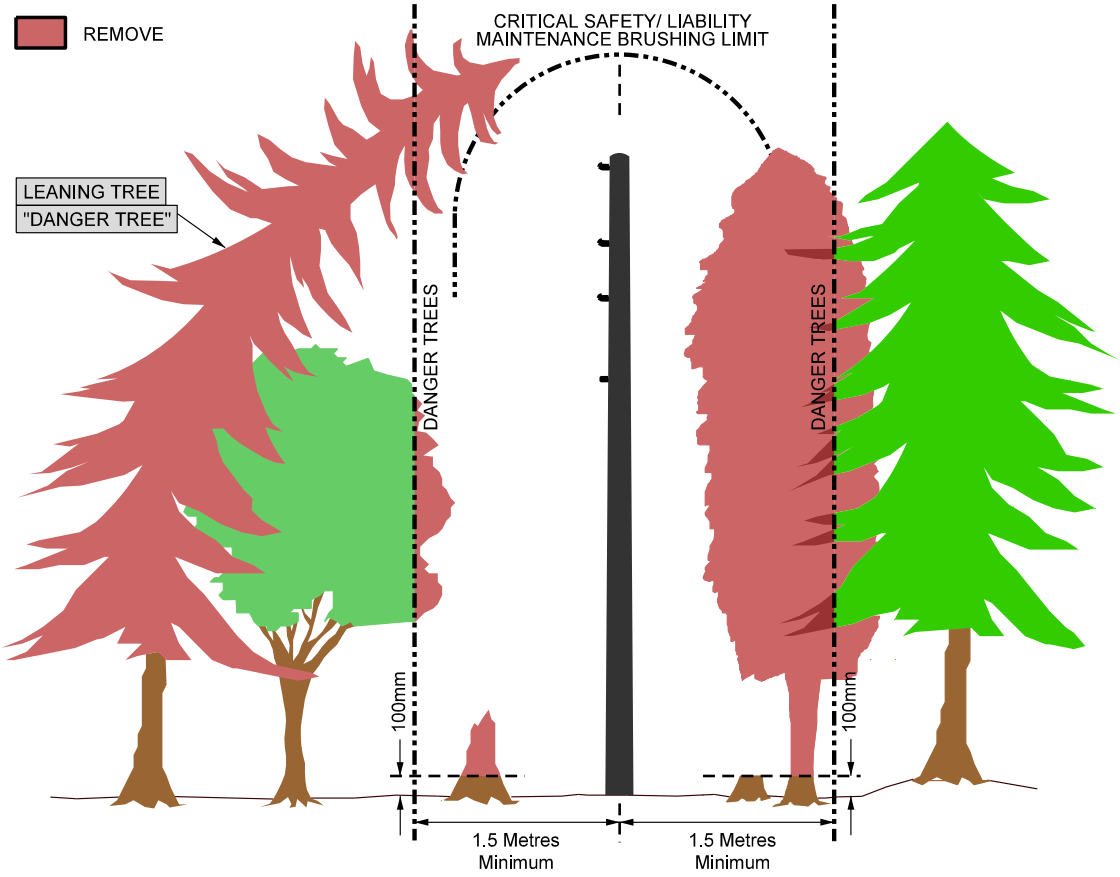
ATCO Electric YUKON

RIGHT OF WAY MAINTENANCE
BRUSHING REQUIREMENT FOR
ALL LOW VOLTAGE LINES UP TO 750 VOLTS

- MULTI SERVICE OPEN WIRE -

LEGEND / NOTES

*ATCO Electric Yukon Qualified Brush Removal identified by Pink & Black striped flagging.



RIGHT OF WAY SITE NOTES

Trees or brush that have been flagged by "DANGER TREE" flagging are a threat to fall into an existing live powerline and the CUSTOMER IS NOT TO CUT DOWN.

ATCO Electric Yukon will arrange for the Powerline Crew to cut down at time of construction or send out a Qualified Utility Brusher to cut down. It will be the customer's responsibility to clean up after the tree has been cut down.

VOLTAGE	RIGHT-OF-WAY WIDTH	TREE TO CONDUCTOR CLEARANCE
2400 V	-	3m
4160 V	-	3m
7200 V	12.2m (6.1m EACH SIDE)	5m
14000 V	12.2m (6.1m EACH SIDE)	5m
24940Y/14000 V	15.0m (7.5m EACH SIDE)	5m

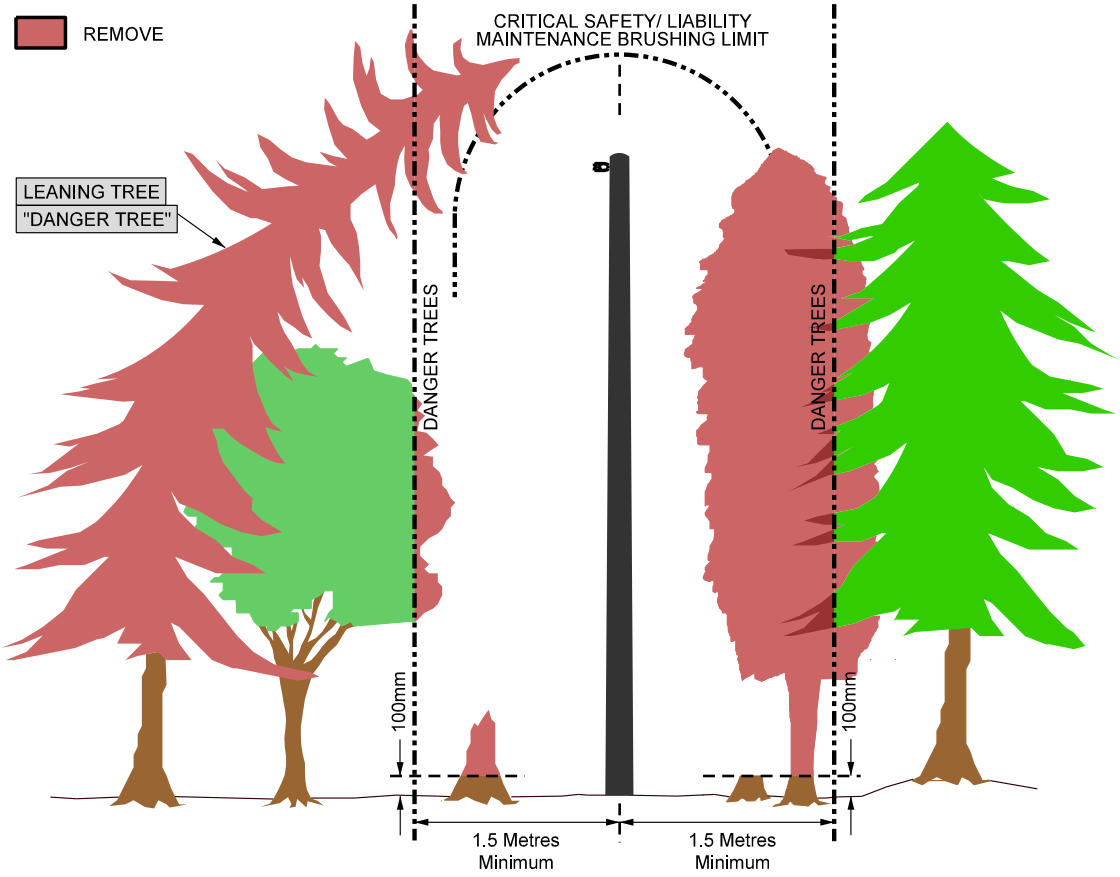
ATCO Electric YUKON

RIGHT OF WAY MAINTENANCE
BRUSHING REQUIREMENT FOR
ALL LOW VOLTAGE LINES UP TO 750 VOLTS

- SECONDARY LINES -

LEGEND / NOTES

*ATCO Electric Yukon Qualified Brush Removal identified by Pink & Black striped flagging.



RIGHT OF WAY SITE NOTES

Trees or brush that have been flagged by "DANGER TREE" flagging are a threat to fall into an existing live powerline and the CUSTOMER IS NOT TO CUT DOWN.

ATCO Electric Yukon will arrange for the Powerline Crew to cut down at time of construction or send out a Qualified Utility Brusher to cut down. It will be the customer's responsibility to clean up after the tree has been cut down.

VOLTAGE	RIGHT-OF-WAY WIDTH	TREE TO CONDUCTOR CLEARANCE
2400 V	-	3m
4160 V	-	3m
7200 V	12.2m (6.1m EACH SIDE)	5m
14000 V	12.2m (6.1m EACH SIDE)	5m
24940Y/14000 V	15.0m (7.5m EACH SIDE)	5m

September 28, 2023 AEY-JM-031

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-031

Reference: Business Cases

Business case No. 17

Requests:

(a) Has this project been completed?

(b) If so, when was it completed and what was the actual cost?

Response:

(a) Yes.

(b) The in-service date was December 9, 2020, and as stated in the business case it cost $196,387.

ATCO Electric YUKON

September 28, 2023 AEY-JM-032

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-032

Reference: Business Cases

Business case No. 21

Requests:

(a) A life of 30,000 hours for a diesel generator seems very short, please explain why a longer life unit would not make more sense.

Response:

(a) Swift River sizing criteria is for each prime duty unit to satisfy peak loading and operate within recommended loading parameters. This is the N-1 capacity that AEY uses for reliability risk management in Swift River. In addition, a mobile unit is stationed at the site to provide emergency manual restoration if both installed generators are unavailable. As a result of the sizing requirements, suppliers propose smaller units that operate at 1800 RPM. There are no interval maintenance guidelines for overhauls from manufacturers, and AEY's operational experience is that a normal lifespan is 30,000 hours. At this point, unplanned downtime becomes more regular, and units are at risk of failure and reactive replacement.

ATCO Electric YUKON

September 28, 2023 AEY-JM-033

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-033

Reference: Business Cases

Business Case No. 22

Requests:

(a) Is this project now complete? If not yet, when will it be operational?

(b) Over what period of time will the capital costs be depreciated?

(c) What is the annual saving in depreciation on the outgoing CIS?

(d) When does AEY propose to implement measures that this new system enables to generate savings for ratepayers, e.g. time of use rates to reduce peak demands so as to reduce YEC diesel generator rentals?

Response:

(a) AEY went live with the Oracle Customer Cloud Service (CCS) on August 1, 2023. While the new system is operational, the stabilization period continues until September 30, 2023, at which time it will fully transition to operations and be considered complete.

(b) The capital costs will be depreciated over a 10-year period.

(c) Including enhancements, the cost of the outgoing CIS system was $1.7 million. At a 10-year average service life, this equates to $170,000 per year in depreciation.

(d) Please refer to the response to AEY-YUB-067(e). Built on the foundation of the Oracle Utilities CC&B and Oracle Utilities MDM, the CCS delivers a cloud-optimized customer platform that keeps the technology current, and it is an

essential platform that AEY will rely on to support the business in finding new flexible products and services to the benefit of customers. AEY will continue to monitor the growing changes in the industry and will assess and implement any adjustments to the new billing system to meet new regulatory and customer requirements. AEY will actively participate in any coordinated pursuit to provide stable and cost-effective rates to Yukoners, including the development of time-of-use rates. Time-of-use rates are typically implemented to the benefit of the system Generator, which is YEC on the YIS.

ATCO Electric YUKON

September 28, 2023 AEY-JM-034

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-034

Reference: Business Case No. 24

Requests:

(a) Given the very high capital costs projected over 2023 and 2024, deferral of completion should be considered. Please explain if there would be any effects of completion deferral for 2 or 3 years.

Response:

(a) It is AEY's view that this project should be initiated as planned for several reasons. First, deferral would result in AEY facing additional integrated assets (i.e. during test years) along with existing, without the development of strategies and tools that other utility peers have incorporated to manage their assets more effectively. Second, due to multiple aging assets reaching end of life and requiring larger capital investment in the near term, there is an urgent need for a data-driven and risk-based approach to lifecycle costing and capital allocation, and the development of more robust project governance procedures. Finally, AEY believes the increasing capital trend may exist beyond the test years (as highlighted by projects forecast in Business Cases 39-41), along with the same operating pressures articulated within this GRA; customer growth, aging infrastructure, and grid modernization. Many of the initial elements in the Asset Management roadmap (i.e. within test years) are foundational, strategic, and structural developments that are necessary to move into more organizational, process, and tactical improvements in future years and be able to realize the performance and cost benefits that are articulated within the Asset Management

Assessment prepared by METSCO Energy Solutions Inc.. AEY intends to manage the ongoing execution of the Asset Management roadmap in reasonable and practical step wise organization changes, over a 5-8 year horizon, in concert with the capital program. We believe this program will result in AEY being able to better quantify and document business objectives and financial plans with performance data and risk management principles, for the benefit of ratepayers and the Board, within future applications.

ATCO Electric YUKON

September 28, 2023 AEY-JM-035

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-035

Reference: Business Case No. 25

Requests:

(a) Given the slow delivery of electrical equipment like transformers, it seems unrealistic to expect that this project could be completed by the end of 2024. Please explain.

(b) In light of the regulators installed in 2020 (Business Case No. 9) and very high capital and depreciation costs over the Test Years, please explain why this project could not be stretched out by a year or more even if it could be complete by the end of 2024?

Response:

(a) Please refer to the response to AEY-YUB-059.

(b) During Contingency Scenario 3, within Table 2 of Business Case No. 25, Laberge Substation does not have the capacity to provide full back up to the North 25 kV system. AEY needs additional capacity within the North 25 kV system to ensure outages can be fully restored in an efficient manner. Contingency Scenario 1 falls outside the scope of the Business Case as it evaluates the system upstream of the North 25 kV system. Contingency Scenarios 2 and 4 are currently adequately met by existing capacity. Therefore, AEY will be unable to efficiently resolve Contingency Scenario 3 and project timelines cannot be stretched.

ATCO Electric YUKON

September 28, 2023 AEY-JM-036

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-036

Reference: Business Case No. 26

Requests:

(a) Given the very high capital and depreciation costs in 2023 and 2024 is there any good reason not to defer this work for at least two years?

(b) Why was there not more ROW widening done on the years 2016 through 2022 when AEY had the financial resources?

Response:

(a) There are several good reasons not to defer this work for any period. AEY maintains an extensive overhead power system in Yukon. Continuing to be proactive in efforts to widen ROWs and remove danger trees reduces outages and improves public safety. Recent years have shown how devastating wildfires can be to public safety and property. Maintaining a robust ROW widening program is key to preventing fires and outages caused by trees contacting powerlines.

(b) The ROW widening program through 2016 to 2022 averaged $475,000 of completed work and continued to target all identified areas of the overhead system in terms of reliability and safety. During this time there were many capital projects underway that required brushing as well. AEY balanced a brushing budget while maintaining widening of existing ROWs and brushing for new customer connects.

ATCO Electric YUKON

September 28, 2023 AEY-JM-037

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-037

Reference: Business Case No. 27

Requests:

(a) Have these vehicles been purchased already?

(b) If not, would there be any impact of deferring the purchase of a few of them for a year?

(c) Why were some of these vehicles not purchased in 2022 when AEY had the financial resources to do so?

Response:

(a) The following table shows vehicles purchased. Please note that the unit numbers have been corrected in red to match fleet logs.

Table 1: Vehicles Purchased

Unit	Description	Year Purchased	Purchase Cost ($)
YT160 YT175 (Replaces YT116)	LD Service Body	2023	110,000
YT161 YT178 (Fleet Add)	Technologist Truck	2023	160,000
YT162 YT180 (Fleet Add)	Generation Truck	2023	160,000
YT163 YT176 (Replaces YT117)	LD Service Body	2023	110,000
YT164 YT177 (Replaces YT099)	LD Service Body	2023	110,000
Units under $100,000	Various[1]	2023	47,000
Total			**697,000**

[1] Category includes items such as trailers, snowmobiles, and all-terrain vehicles. These units are evaluated for replacement using the lifecycle criteria evaluation after seven-years of service or 200,000 km.

(b) Deferral of purchasing the remaining three units risk the following adverse business impacts:

- Units YT161 and YT162 are to be purchased for the generation department. These employees are required to travel to various AEY service locations and will each require their own separate units to carry out their trade functions. Deferral of purchasing these units would greatly reduce the effectiveness of their role by having them share resources with other positions within the work group.

- Unit YT164 is to be purchased for use by a power line technician. The position requires a unit to work independently for construction / service functions as well as assigned on call duties. Deferral of purchasing this unit would greatly reduce the effectiveness of their role by having them share resources with other positions within the work group as unit 099 has been decommissioned and sold.

- There has been an increasing trend in cost and decreased availability when purchasing new equipment. Deferral could risk increased cost and longer lead times when acquiring these units.

(c) Units are purchased / budgeted for as business needs require or as they reach the end of a typical life cycle.

ATCO Electric YUKON

September 28, 2023 AEY-JM-038

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-038

Reference: Business Case No. 28

Requests:

(a) If not, would there be any impact of deferring the purchase of a few of them for a year or two?

Response:

(a) Deferral of purchasing any of the units in Table 2: Fleet Purchased Fleet 2024 risk the following adverse business impacts:

- There has been an increasing trend in cost and decreased availability when purchasing new equipment. Deferral could risk increased cost and longer lead times when acquiring these units.
- Reduced reliability.
- Costs incurred from vehicle down time during repairs / maintenance. These costs may include vehicle rentals and contracting third parties.
- Reduction of electrical service.
- Less vehicles available for service and construction activities.

ATCO Electric YUKON

September 28, 2023 AEY-JM-039

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-039

Reference: Business Case No. 29

Requests:

(a) In light of the fact that the undervoltage was know on or before 2021, why were these improvements not made in 2022 or earlier while AEY had the financial resources to do so?

(b) Can the reconductoring proposed be deferred by a year or two? If not, why not?

Response:

(a) Delays in regulator procurement prevented the project from being completed in 2022.

(b) Reconductoring can be deferred on line 3L406, as noted in paragraph 8. "Rebalancing this line alone will leave 15 percent room for load growth which will allow for reconductoring to be delayed for a few years." Also noted in the recommended Alternative 4 in paragraph 11. "It is not imperative that the reconductor be done if the load balancing is optimized, but it will need to be done eventually."

Reconductoring cannot be deferred on line 3L405, as noted in paragraph 12. "Rebalancing the load alone will not fix the existing voltage issue down this branch." This is why Alternative 6 is the recommended alternative to address voltage issues on 3L405 East.

ATCO Electric YUKON

September 28, 2023 AEY-JM-040

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-040

Reference: Business Case No. 30

Requests:

(a) In light of the fact that the undervoltage under certain conditions must have been known (from work related to the Atlin project) why were these improvements not made in 2022 or earlier while AEY had the financial resources to do so?

(b) Would the upgrading of portions of this line to accommodate the Atlin project have solved these problems?

(c) Why would AEY not consider the partial line reconductoring contemplated for the Atlin project to solve the problem and facilitate the Atlin project both?

Response:

(a) The undervoltage issues were not fully known until the completion of the study which was finalized on April 4, 2023.

(b) No, upgrading portions of the line by reconductoring them would not be sufficient. Addressing the conductor size alone does not solve the problem.

(c) Long distances of conductor upgrades are considerably more expensive than regulator additions, and conductor upgrades alone do not solve the problem.

September 28, 2023 AEY-JM-041

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-041

Reference: Business Case No. 31

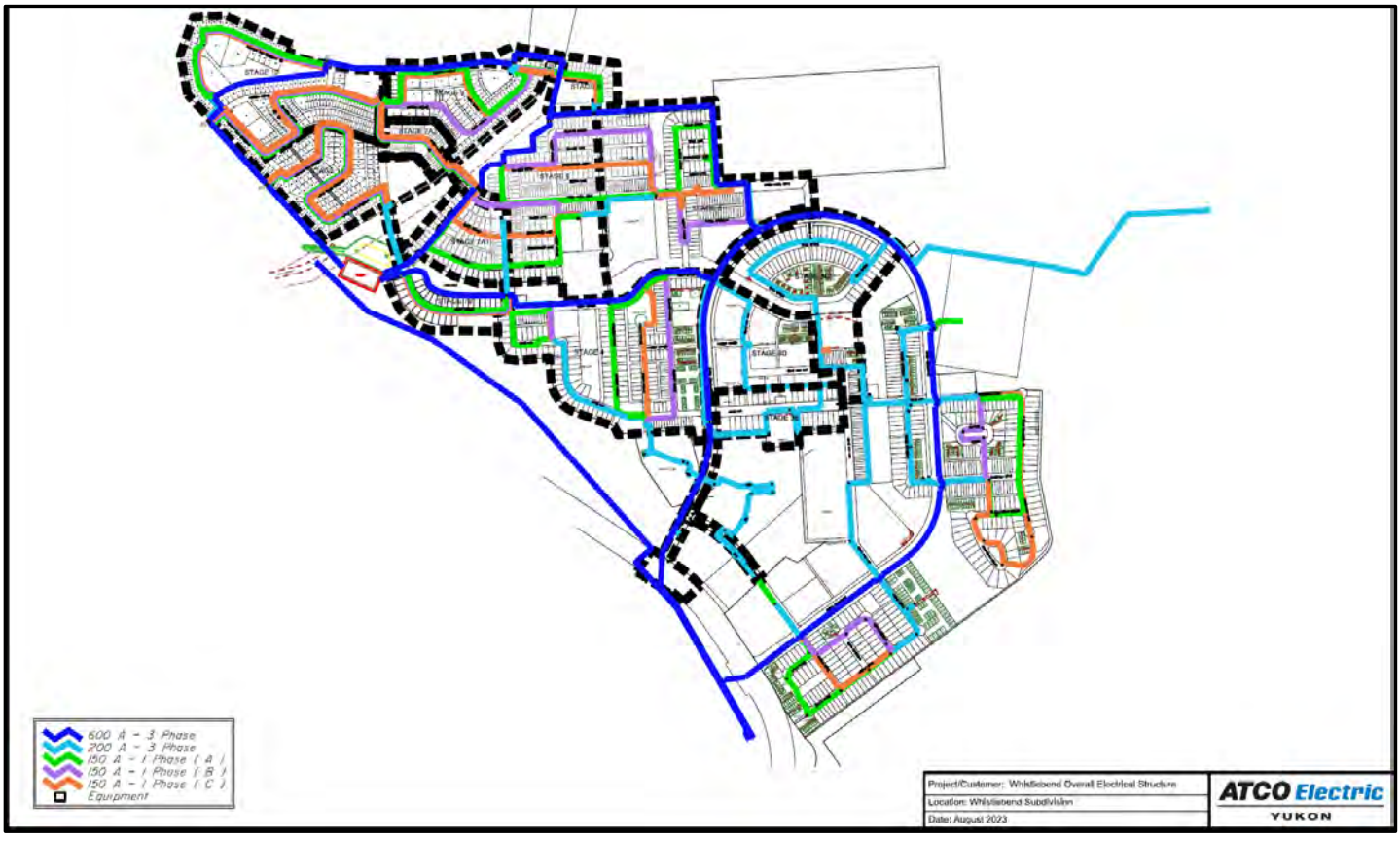
Requests:

(a) Please provide a readable (higher resolution) copy of Appendix A.

Response:

(a)

Business Case No 31 – Appendix A



ATCO Electric YUKON

September 28, 2023 AEY-JM-042

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-042

Reference: Business Case No. 33

Requests:

(a) Is it realistic to expect this project to be designed and constructed in one year?

Response:

(a) Yes.

ATCO Electric YUKON

September 28, 2023 AEY-JM-043

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-043

Reference: Business Case No. 40

Requests:

(a) Why were some of these condition assessments not done in previous years when AEY had the financial resources to do so?

Response:

(a) The focus at these sites has been on lifecycle extension and ongoing reliability since the last GRA. However, with upcoming IPP integrations in Beaver Creek and Destruction Bay, it has become obvious these sites need to be comprehensively evaluated in the short-term to ensure ongoing grid stability and quality of service into the future. AEY is proposing to prepare the lifecycle rehabilitation options, and progress design on prioritized assets (according to health and the strategic asset management plan to be developed) in a sequenced manner, in order to level the capital spend and workload.

ATCO Electric YUKON

September 28, 2023 AEY-JM-044

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
John Maissan (JM)
Received: September 6, 2023

AEY-JM-044

Reference: Business Case No. 41

Requests:

(a) Given the very high capital and depreciation costs in 2023 and 2024 is there any good reason not to defer this work for at least one year?

Response:

(a) The Old Crow Plant Design project was completed in December 2022. There is no anticipated work on the new facility in 2023 or 2024.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-001

Reference: General Questions

Requests:

(a) What was the regulated amount of profit set by the YUB based on fair return on equity in the AEY 2016 GRA for the years 2016-2022? By how much did AEY exceed that amount in each of those years?

(b) What were the over earnings by AEY from years 2016-2022 spent on? How much went to shareholders and dividends? How much was reinvested in the Yukon in infrastructure?

Response:

(a) Please refer to the response to AEY-UCG-042(d).

(b) AEY funds its capital investments with a combination of long-term financing and equity funding, ensuring it maintains the Board approved common equity ratio of 40 percent. AEY invested in over $58 million of capital infrastructure from 2016-2022. System and customer growth also require growing working capital requirements, which AEY has funded internally, in addition to funding the higher operating costs than what was included in the 2017 approved revenue requirement. Equity in excess of the approved common equity ratio is paid out to shareholders through dividends. Dividend payments, as noted in AEY's annual Financial Statements filed with the Board, are as follows:

Table 1: Dividend Payments
($Millions)

	2016	2017	2018	2019	2020	2021	2022
Dividend Payments	0.00	3.75	4.20	5.50	6.50	5.90	2.90

ATCO Electric YUKON

September 28, 2023 AEY-NDP-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-002

Reference: 2023-2024 AEY GRA Application

Table 1, page 1

It is important that the impact of these increases is made clear to ratepayers before they are approved. The way AEY has separated out the fuel increases, and the effects this will have on riders, it is not clear to rate payers what the actual impact will be on their bills.

Requests:

(a) Please provide three sample bills for a residential customer consuming the average amount of electricity for a residential customer in January, one under the current rates, and one each reflecting the 2023 and 2024 proposed increases.

(b) The table indicates that AEY plans to raise the cost of electricity by 3.3% in 2023, and then by 10% in 2024. Can AEY confirm that the effective increased cost to ratepayers will be 3.3% in 2023, and then an increase of 10% in 2024 on top of the increased 2023 rate? Can AEY please confirm what the total increase to customers bills will be after the two rate changes, including fuel costs.

Response:

(a) In Board Order 2023-22 received on September 15, 2023, the Board denied AEY's requested 2023 Rider R rate decrease and approved an Interim Rate Adjustment Rider R increase of 2.5 percent resulting in a total Rider R of 10.8 percent. Therefore, in this response, AEY is providing sample bills based on the current rates and the Interim Rate Rider R of 10.8 percent effective January 1, 2024. Please refer to AEY-NDP-002(a) Attachment 1 for the sample bills with the current rates and the approved Rider R increase.

(b) Not confirmed. The overall rate increase (including fuel costs) over primary retail revenue on existing rates is 3.3 percent in 2023. However, while the rate increase (including increased fuel costs) over existing rates for 2024 is 10 percent, the incremental rate increase for 2024 is 6.7 percent once you factor in the 2023 increase of 3.3 percent.

With respect to estimating final rate increases in the middle of 2024 (once all costs are incorporated into Rider F) and having regard to the complexities associated with the timing in implementation of the different riders, AEY is not able to precisely quantify the total increase to customers' bills, including fuel costs. In an effort to be helpful, based on preliminary high-level estimates, the rate increases are expected to be below the proposed 3.3 percent rate change for 2023 below and the proposed 6.7 percent rate change for 2024, as referenced above.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Current Rates Effective September 1, 2023

Line No.					
1	Consumption	800 kWh			
2		**Rate**			**Charge**
3					
4	Customer Charge (per month)	$ 14.65			$ 14.65
5					
6	Block 1 Energy Charge 1000 ($/kWh)	$ 0.1214	x	800	$ 97.12
7	Base Rate				$ 111.77
8					
9	Fuel Adjustment Rider $/kWh	$0.01635	x	800	$ 13.08
10	Rider J and J1 YEC Shortfall	37.85%	x	$ 111.77	$ 42.30
11	Rider R and R1 AEY Adjustment	8.30%	x	$ 111.77	$ 9.28
12	Rider S Purchase Power Adjustment Rider	$0.00100	x	800	$ 0.80
13	Interim Electrical Rebate	-$0.02262	x	800	$ (18.10)
14	Sub-Total				$ 159.13
15					
16	GST	5.0%	x	$ 159.13	$ 7.96
17	**TOTAL including GST**				**$ 167.09**

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Approved 10.8% Rider R (Board Order 2023-22) Effective: January 1, 2024

Line No.					
1	Consumption 800 kWh				
2		**Rate**			**Charge**
3					
4	Customer Charge (per month)	$ 14.65			$ 14.65
5					
6	Block 1 Energy Charge 1000 ($/kWh)	$ 0.1214	x	800	$ 97.12
7	Base Rate				$ 111.77
8					
9	Fuel Adjustment Rider $/kWh	$0.01635	x	800	$ 13.08
10	Rider J and J1 YEC Shortfall	37.85%	x	$ 111.77	$ 42.30
11	Rider R and R1 AEY Adjustment	10.80%	x	$ 111.77	$ 12.07
12	Rider S Purchase Power Adjustment Rider	$0.00100	x	800	$ 0.80
13	Interim Electrical Rebate	-$0.02262	x	800	$ (18.10)
14	Sub-Total				$ 161.92
15					
16	GST	5.0%	x	$ 161.92	$ 8.10
17	**TOTAL including GST**				**$ 170.02**

ATCO Electric YUKON

September 28, 2023 AEY-NDP-003

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-003

Reference: 2023-2024 AEY GRA Application - Section 1

Page 21

> "AEY has seen rapid population growth as well as new Government energy transition policies and legislation aimed at increased electrification and reduced carbon emissions. These two major cost drivers can lead to conflicts as the desire for renewable energy resources often cannot meet the demand required for a population growing as rapidly as that of the Yukon. This section of the Application outlines a number of cost drivers that are a direct result of the new Government policies and legislation, as well as changes in customer demands and behaviours that cause impacts outside of the control of AEY."

This rapid growth also means rapid growth of the AEY customer base. Due to the dense concentration of new customers in one area of Whitehorse (Whistlebend), AEY has benefited from a rapid increase in customers with little new capital requirement.

Requests:

(a) Can AEY provide more details on why a rapidly expanding customer base in a dense urban environment is considered a major cost driver, when it is also a leading driver of new revenues?

(b) Can AEY provide a table showing the costs of service and revenues from the Whistlebend neighbourhood since 2020?

Response:

(a) Please refer to the response to AEY-UCG-051(e).

(b) AEY is unable to provide this information as AEY does not track the costs of service at the level of granularity requested.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-004

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-004

Reference: 2023-2024 AEY GRA Application - Section 2

Table 2.1, page 26

Requests:

(a) Sales appear to have been underestimated in the last AEY GRA, for example by 7.7% in the 2017 test year. Please comment on the accuracy of historic ATCO sales forecasts.

(b) Please provide a table showing sales forecasts, actual sales, and the percentage of variance for all rate classes from 2016-2022.

Response:

(a) AEY submits that sales for 2017 exhibited relatively high growth whereby the Filed and Approved forecasts both resulted in larger variances than usual when compared to normalized actuals. However, as illustrated in the table below, over the five-year period prior to the 2016-2017 GRA, AEY's Actual sales averaged -0.4 percent variance compared to the Filed forecasts and -2.2 percent variance compared to the Approved forecasts.

ATCO Electric Yukon Sales Variance
2008-2009 GRA, 2023-2015 GRA, 2016-2017 GRA Forecasts

Year	Forecast (MWh)	Actual (Normalized) (MWh)	Variance (MWh)	Variance (%)
2008 Filed	269,913	269,799	-114	0.0
2008 Approved	275,224	269,799	-5,425	-2.0
2009 Filed	272,054	275,425	3,371	1.2
2009 Approved	278,133	275,425	-2,708	-1.0
2013 Filed	309,891	313,442	3,550	1.1
2013 Approved	309,894	313,442	3,547	1.1
2014 Filed	315,876	309,961	-5,915	-1.9
2014 Approved	323,823	309,961	-13,863	-4.3
2015 Filed	321,818	314,658	-7,160	-2.2
2015 Approved	330,274	314,658	-15,616	-4.7
2016 Filed	303,736	315,209	11,293	3.7
2016 Approved	309,164	315,209	5,865	1.9
2017 Filed	309,433	331,209	21,776	7.0
2017 Approved	322,656	331,209	8,552	2.7

(b) There were no sales forecasts submitted beyond the 2016-2017 GRA. Please refer to the table in response to part (a) for all historical comparisons available prior to 2018.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-005

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-005

Reference: 2023-2024 AEY GRA Application - Section 7

Table 7.1, page 124

Table 7.1 shows a significant increase in depreciation for the 2023 and 2024 test years compared to previous years. It appears to be one of the major drivers of increased costs in the GRA.

Requests:

(a) Please clarify if the increase in depreciation expense being cited as a reason for the need to increase rate.

Response:

(a) Please refer to the response to AEY-UCG-041(a).

ATCO Electric YUKON

September 28, 2023 AEY-NDP-006(1)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-006(1)

Reference: Section 8

Schedule 8.2.3, page 130

AEY states that: "AEY is requesting to link its ROE for the 2023-2024 Test Period to the soon to be determined BCUC GCOC benchmark rate plus a risk premium of 0.75 percent."

Requests:

(a) What risks exactly does AEY face for operating in a market as a loosely regulated, government protected monopoly?

(b) Please provide examples of the types of risks AEY faces, and the costs associated with bearing and mitigating these.

(c) Please provide examples of instances where these risks were realized and what the costs were to AEY.

(d) What work has AEY undertaken to reduce these risks?

Response:

(a) AEY does not agree with the characterization that it is loosely regulated, or government protected. AEY is subject to and operates in accordance with the requirements of, among other statues, regulatory requirements, and government policies, the *Public Utilities Act* as well as the oversight of the Board.

(b-c) Please refer to the response to AEY-JM-022(b).

(d) Please refer to the response to AEY-YUB-027.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-006(2)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-006(2)

Reference: Section 8

AEY states that: "In this Application, AEY has utilized the existing 8.75 percent as a placeholder and is proposing to true-up to the benchmark approved by the BCUC in its upcoming GCOC decision as part of AEY's Compliance Filing to this Application."

Requests:

(a) What is AEY's best estimate of the forthcoming BCUC benchmark? What is that estimate based on?

(b) Will AEY accept a reduction in ROE if the BCUC Benchmark is less than 8.75 percent?

(c) With many economists and analysts predicting a recession in 2023 and 2024 – how can AEY justify seeking to increase its ROE for the test years, when so many other smaller businesses will be expecting a reduction in their ROE and preparing for lean years?

Response:

(a-b) Please refer to the response to AEY-YUB-022. AEY would accept the BCUC ruling as proposed in its Application, regardless of the direction.

(c) Under utilities legislation in Canada, including Section 32 of the *Public Utilities Act,* utilities are entitled to earn a fair return on rate base. This principle was confirmed by the Supreme Court of Canada in 1929 as follows:

> The duty of the Board was to fix fair and reasonable rates; rates which under the circumstances, would be fair to the consumer on one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed

> as large a return on the capital invested … as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[1]

In essence, a fair return is reflective of what investors could expect in the market and is influenced by a variety of factors such as, but not limited to, level of risk, and economic conditions. The Board has historically relied on the BCUC benchmark to be reflective of a fair benchmark for Yukon market conditions and has allowed a premium for risks unique to the operational circumstances of AEY. The BCUC determinations have recently been made (September 5, 2023), which incorporated the most recent available economic inputs (including the impact of rising interest rates), and it is fair to accept that they are reflective of the expected market response to economic conditions.

[1] *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] SCR 186 at 192-93, [1929] 2 DLR 4 **[Tab *]**.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-006(3)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-006(3)

Reference: Section 8

Section II B, Attachment 8.1, subsection D, Figure 1 page 141

The Concentric Energy report provides a table with authorized ROE, equity ratios and business risk for AEY and other Canadian utilities. What this table does not present is the actual ROE for those utilities within their unique regulatory environment.

Requests:

(a) Please provide a table showing the authorized ROE and the actual ROE for each of the utilities listed in the table for the years 2016-2022.

(b) Please provide the dates for all General Rate Applications for each of the utilities listed in the table dating back to 2010.

Response:

(a-b) Please refer to the responses to AEY-JM-025(a) and AEY-JM-025(b).

September 28, 2023 AEY-NDP-006(4)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-006(4)

Reference: Section 8

Section II B, Attachment 8.1, page 147

AEY states that the YUB "historically has not accepted the Stand-Alone principle." AEY then provides that if the principle is not considered that the YUB should "take into consideration the benefits and cost savings that AEY customers receive through AEY's ability to access debt and equity capital though CUI instead of on its own."

If the board will not consider the Stand-Alone Principle and is assessing this GRA, as AEY has suggested, considering its parent company's financial positions, the Yukon NDP submits the following.

Requests:

(a) How much was paid out by ATCO Ltd. as shareholders dividends from 2016 to 2022?

(b) How can AEY, as a subsidiary of ATCO Ltd. be trusted to make the best decisions on behalf of ratepayers in the Yukon, when you are legally responsible to maximize profits for shareholders elsewhere in the world?

(c) According to the ATCO Ltd. website, the responsibility of those in charge of ATCO Ltd., the ATCO Ltd. Board of Directors, is "to enhance and preserve long-term shareholder value." How does that correspond to providing just and reasonable rates for electricity in the Yukon?

Response:

(a-c) AEY respectfully submits that the dividends paid by ATCO Ltd., assertions regarding ATCO Ltd. shareholders, and statements made by the ATCO Ltd. Board of Directors are not relevant to this Proceeding and declines to provide the

requested information pursuant to Rule 14(4)(a) of the YUB *Rules of Practice*. AEY is a regulated Yukon utility, its right to recover prudent costs, and its right to earn a fair return are subject to review by the Board. In determining the system requirements and operational needs within this Application, it is AEY's commitment to continuously strive for and maintain the highest standards of safe and reliable service while meeting the complex and diverse needs of its customers.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-007

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-007

Reference: 2023-2024 AEY Business Cases 1-03, 2023-2024 AEY Business Cases 04-21

Business cases #2-21, representing $13,104,286 in costs, were projects primarily completed between 2017 and 2022 – well prior to the test years.

Requests:

(a) How much of those costs, if any, were already added to the rate base?

(b) Is AEY seeking recovery for costs related to these projects not considered retroactive rate making? If not, why not?

(c) Has AEY reinvested their over earnings to pay for any portion of these projects? Please explain.

Response:

(a) Please refer to the response to AEY-UCG-065(b).

(b) Including the costs for these projects in rate base does not constitute retroactive rate making. Please refer to the response to AEY-UCG-065(b).

(c) AEY reinvests based on allowable equity thickness as approved by the Board.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-008

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-008

Reference: AEY Response to Intervener Submissions, August 10, 2023

Page 3

AEY "notes that approximately 40% of the proposed capital additions are fully contributed, resulting in no impact to the requested revenue requirements in the Test Period."

Requests:

(a) If some of these projects are fully contributed by third parties, why are they included in the submission as a business case?

(b) Should the submissions not be limited to those which have an affect on rates?

(c) Can AEY clarify which business cases are fully contributed by third parties?

(d) Can AEY Clarify which business cases are not considered in the requested revenue requirement?

Response:

(a-b) AEY included the Business Cases for contributed projects to aid in the explanation of capital expenditures and to provide the reader with a fulsome Application. Schedule 9.2 of the Application outlines capital expenditures but does not show whether a project is funded through a customer contribution, so AEY has included this additional context in the relevant Business Cases. For example, on Schedule 9.2. Kluane First Nation Wind Turbine Upgrades[1] shows an estimated capital spend of $4.2 million. Without the Business Case,[2] it may not have been

[1] 2023-2024 AEY GRA, Regulatory Schedules, Schedule 9.2, Line No. 133.
[2] 2023-2024 AEY GRA, Kluane Wind Turbine Integration, Business Case #37.

clear that this project is fully contributed by a third party. Furthermore, although contributed projects have no impact on requested revenue requirements in the Test Period, contributed projects will have an ongoing impact on revenue requirement outside of the Test Period, as the ongoing operations and maintenance of the infrastructure associated with contributed projects would be included in revenue requirement.

(c) Business Cases 35, 36, 37, and 38 are fully contributed by third parties.

(d) AEY confirms that Business Cases 35-38 mentioned in part (c) above as well as Business Cases 39-41 are not included in revenue requirement during the Test Period. Please also refer to the response to part (a-b) above.

Business Cases 39-41 are for capital projects which will not result in capitalized costs during the Test Period, but which are forecast to result in certain un-capitalized costs during the Test Period (or in the years 2016 to 2022) as well as large capital expenditures subsequent to the Test Period. AEY has included these Business Cases in the Application even though costs incurred during the Test Period will not be capitalized, in an effort to be transparent and to notify the Board and other stakeholders regarding larger upcoming capital expenditures.[3]

[3] 2023-2024 AEY GRA, Section 9, para. 22, PDF p. 181.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-009

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-009

Reference: AEY Response to Intervener Submissions, August 10, 2023

Page 4, Paragraph 1

> "AEY submits that all parties have sufficient opportunity on a regular basis to review and assess AEY's operations through the Annual Filing process and, as demonstrated through the Rate Relief Application, material issues and items that arise can be address in a limited scope between fulsome applications, as needed."

Requests:

(a) AEY began overearning in 2016, in the first test year of their last GRA. It took six years of overearnings before Yukoners were able to see rate relief from AEY. Is it the position of AEY that any future overearnings will be met annually with rate relief applications? If not, please explain why?

(b) Is it the view of AEY that annual, limited scope applications promote rate stability? Please explain.

(c) In the view of AEY, who is responsible for monitoring their earnings and operations and ensuring that the rates being charged are fair and reasonable as mandated by the Public Utilities Act, and not contributing to overearnings? Please explain.

Response:

(a) It is not AEY's position that earnings in excess of what is in approved revenue requirement will be met with annual rate relief applications. AEY's 2022 Rate Relief Application was prepared and filed with a view to mitigating the exceptional hyperinflation experienced in 2022, in alignment with government initiatives addressing the same issue.

Under the regulatory framework, utilities are incentivized to find efficiencies and cost savings on a go-forward basis and are entitled to benefit from any efficiencies achieved until rates are reset. For example, the efficiencies realized by AEY since its last GRA have been incorporated into the cost forecasts included in the Application and will be passed through to customers in the revenue requirements approved by the Board. Regulated utilities such as AEY are entitled to recover their prudent costs and to earn a fair return on and of capital. Both are widely accepted regulatory principles that the request appears to overlook. In accordance with the above referenced regulatory principles, AEY will continue to look for ways to find efficiencies to the benefit of both customers and its shareholders.

(b) No, it is not AEY's view that annual limited scope proceedings will promote rate stability as there can be large swings, year over year, which would lead to less rate stability (for example, hyperinflation in 2022 and supply chain issues). Since, AEY did not file an Application since the 2016-2017 GRA, customers were on the same rates for six years which provides more rate stability than changing rates every year.

In addition, Rate Applications, even those of a limited scope, are quite costly for customers, as indicated in Table 1 below. Even though the scope of an application may be limited, a full and robust process would be required to ensure fair and reasonable rates are set.

Table 1: General Rate Application (GRA)
Cost Awards

Applicant	**AEY**	**AEY**	**YEC**	**YEC**
GRA	2013-2015	2016-2017	2017-2018	2021
Board Order	2014-11	2017-07	2019-03	2023-02
Total Costs Awarded	$587,767.15	$532,124.23	$882,982.97	$903,487.96

(c) Please refer to AEY's response to part (a) above. With regards to the process for setting just and reasonable rates, please refer to the Mandate of the Board[1] and the *Public Utilities Act*.

[1] https://yukonutilitiesboard.yk.ca/about/mandate-of-the-board/.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-010

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-010

Reference: Investor Presentation ATCO Ltd. March 2023 (https://www.atco.com/content/dam/web/about-us/investors/Investor-Presentation-ATCO-March-2023.pdf)

In a presentation for investors prepared by parent company ATCO (March 2023), ATCO boasts of their market leading dividend growth.

Requests:

(a) With soaring profits leading to big payouts for shareholders outside the Yukon – why should the YUB approve the requested rate increases?

(b) In that same shareholder presentation, ATCO subsidiary Canadian Utilities Inc. shows how they over earn by more than 2% on average in Alberta for the last 10 years. Why should AEY be trusted to set rates that are fair and just, when they boast about regularly over earning in other jurisdictions?

Response:

(a) AEY has submitted its Application on a prospective basis. The benefits realized since AEY's last application through efficiencies, growing customer base and changes in government policies have been contemplated in AEY's forecast and passed through to customers in the applied-for revenue requirement. The rate increase in 2024 is largely driven by inflationary pressures, capital requirements to ensure safe, reliable service and AEY's response to Federal and Territorial carbon reduction targets, all as demonstrated in the Application.

(b) AEY does not consider the performance of its affiliates and/or parent company in other jurisdictions to be relevant to this Proceeding, nor does AEY set rates. Indeed, the setting of just and reasonable rates falls squarely within the purview of the Board.

ATCO Electric YUKON

September 28, 2023 AEY-NDP-011

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Yukon NDP Caucus (NDP)
Received: September 6, 2023

AEY-NDP-011

Reference: Investor Presentation Canadian Utilities Limited. March 2023 https://www.canadianutilities.com/content/dam/web/canadian-utilities/investors/Investor-Presentation-CUL-March-2023.pdf

Investor Presentation, page 18

In a March 2023 presentation for investors by AEY parent company and ATCO Ltd. subsidiary Canadian Utilities Limited, CUL boasts of having reduced its O&M costs for electricity distribution by 11%.

Requests:

(a) Why should Yukoners believe that the distribution costs at AEY are increasing, when they are being reduced across the board at other CUL business units?

(b) Please explain why AEY is less efficient in its O&M costs than other CUL business units.

Response:

(a-b) The 11 percent statistic in the above-referenced Canadian Utilities Limited Investor Presentation describes a reduction in operating costs per km of line, adjusted for inflation, and not an overall reduction to Canadian Utilities Limited O&M costs. However, the performance of AEY's affiliates or parent company, which are separate businesses that vary in size, operations and operate under different regulatory structures is not relevant to this Proceeding. Accordingly, AEY declines to respond pursuant to Rule 14(4)(a) of the YUB Rules of Practice.

ATCO Electric
YUKON

September 28, 2023 AEY-UCG-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-001

Reference: July 7, 2023-2024 AEY Application

Request:

(a) Provide details of all customer and stakeholder consultations conducted by ATCO Electric Yukon during development of this application prior to submitting it to the YUB.

(b) Provide specific details on how AEY's customers were informed of proposals being considered for inclusion in the application and how input from customers was used to develop details of the application.

(c) Provide all documentation related to issues discussed during these consultations and a list of all parties involved in the consultations.

(d) Provide how and when the leadership / owners of AEY approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

Response:

(a-c) Development of this Application required significant consultation to determine all cost and revenue on an actual and forecast basis with respect to the areas discussed below:

- Sales and revenue.
    - Determination of customer counts and electricity usage as determined through discussion with customers, consultants, suppliers, communities and local developers. AEY is in communication with municipal and territorial governments, First Nations, communities, builders, manufacturers, suppliers, property managers etc.

- Purchase power in consultation with Yukon Energy Corporation to forecast costs related to securing wholesale electricity and to review system project requirements.
- Fuel cost forecasts based on projections for each diesel community.

- Operation and maintenance forecasts:
  - Labour costs consultation including employees, labour associations, human resource groups, ATCO Electric, training and safety, pension and benefits managers.
  - A forecast of Non-labour areas is developed to determine ongoing operational and administrative activities. Areas of consultation include affiliate companies, insurance companies, accountants, auditors and numerous material and service providers.
- Capital additions for electrical system upgrades and additions as well as for property and other equipment are determined based on forecasts to meet customer needs. The diversity of projects involves a wide variety of stakeholders.

Following submission of the Application with the YUB, AEY published, in display-ad format, a Notice of the Application and Hearing in the local papers. AEY's Application was uploaded to AEY's website[1] and the YUB website[2] for public access. In addition, on July 27, 2023, AEY held a procedural conference that was open to the public.

(d) AEY received approval on July 6, 2023, from its executive leadership to file the GRA following their review. The Application was filed on July 7, 2023.

1 https://www.atcoelectricyukon.com/en-ca/customer-billing-rates/2023-general-rate-application.html.
2 https://yukonutilitiesboard.yk.ca/proceedings/atco-electric-yukons-2023-2024-general-rate-application/.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-002

Reference: July 7, 2023 Application page 2of 4

AEY states: *"As such, both parties would propose to address any required changes and/or updates to the T&Cs sometime in mid to late 2024, as a standalone limited scope filing, rather than including any changes as part of a GRA."*

Request:

(a) As YEC is proposing a GRA in late August, will AEY commit to working with YEC to file a T&C at the time of this hearing process.

Response:

(a) AEY continues to plan on working with YEC to address any required changes and/or updates to the T&Cs sometime in mid to late 2024, as a standalone limited scope filing, rather than including any changes as part of a GRA.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-003

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-003

Reference: July 7, 2023 Application pages 1&2 of 4

AEY states: *"In Section 13 of this Application, AEY has requested approval of a 6.68 percent Interim Refundable Rate Rider (Rider R) for electrical consumption between August 1, 2023 and December 31, 2023. By implementing the rate adjustment on August 1, 2023, Rider R will refund approximately 40 percent of its forecast surplus in 2023. AEY submits that its proposal to refund approximately 40 percent of its forecast surplus is reasonable, like the approach approved by the Board for AEY's 2016 Interim Refundable Rider in Board Order 2016-02 and will reduce future true-ups. For this reason, AEY respectfully requests approval of Rider R by July 21, 2023, to implement the new Rider R on August 1, 2023.*

Also, in Section 13, AEY is requesting approval for an Interim Refundable Rider R of 13.50 percent effective January 1, 2024. The derivation of the Rider R adjustment for 2024 is like the calculation for the proposed 2023 Rider R adjustment. Based on the expected timing of the Board Order and Compliance Filing to AEY's 2023-2024 GRA, being similar to AEY's 2016-2017 GRA process, AEY estimates that updated Rider R rate adjustments, in the middle of 2024, will result in minimizing future true-ups and promoting rate stability."

Request:

(a) Please provide details of all expected recoveries through Rider R by month for the period August 2023 through end December 2024 including all recoveries by Yukon Energy Corporation.

(b) Please provide details of how much of AEY's 2024 revenue shortfall will be recovered from AEY customers and details of how much will be recovered from customers of Yukon Energy Corporation.

(c) Please explain why customers of Yukon Energy Corporation are required to pay a higher Rider R to allow AEY to recover additional revenues.

(d) Provide bill calculations for each of these proposed rate adjustments.

Response:

(a) In Board Order 2023-22 received on September 15, 2023, the Board denied AEY's requested 2023 Rider R rate decrease and approved an Interim Rate Adjustment Rider R increase of 2.5 percent resulting in a total Rider R of 10.8 percent effective January 1, 2024. The calculations below are based on the approved Rider R rate.

As AEY expects final rates by mid-2024, the expected Rider R recoveries are provided for January to June 2024:

Total Rider R of 10.8%

AEY	$3.2 million
YEC	$1.0 million

(b) Expected Recovery of Shortfall January – June 2024:

Incremental Rider R of 2.5%

AEY	$0.7 million
YEC	$0.2 million

(c) The postage stamp rate design in the Yukon and relevant rate design regulations, including OIC 1995/090[1] requires that "rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers" in the Yukon. Therefore, rates are designed in such a way that AEY and YEC customers pay the same rates. With respect to bill charges and revenue collection, AEY's

[1] OIC 1995/90, Section 2.1.

Rider R revenue that YEC collects from its customers flows through to AEY, and YEC's Rider J revenue that AEY collects from its customers flows through to YEC.

(d) Please refer to AEY-UCG-003(d) Attachment 1 for sample bill calculations based on current rates and the approved Interim Rate Rider R of 10.8 percent effective January 1, 2024 for a typical non-government residential customer using 800 kWh.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Proposed 6.68% Rider R Effective: October 1, 2023

Line No.						
1	Consumption	800 kWh				
2			**Rate**			**Charge**
3						
4	Customer Charge (per month)		$ 14.65			$ 14.65
5						
6	Block 1 Energy Charge 1000 ($/kWh)		$ 0.1214	x	800	$ 97.12
7	Base Rate					$ 111.77
8						
9	Fuel Adjustment Rider $/KW.h		$0.01635	x	800	$ 13.08
10	Rider J and J1 YEC Shortfall		37.85%	x	$ 111.77	$ 42.30
11	Rider R and R1 AEY Adjustment		6.68%	x	$ 111.77	$ 7.47
12	Rider S Purchase Power Adjustment Rider		$0.00100	x	800	$ 0.80
13	Interim Electrical Rebate		-$0.02262	x	800	$ (18.10)
14	Sub-Total					$ 157.32
15						
16	GST		5.0%	x	$ 157.32	$ 7.87
17	**TOTAL including GST**					**$ 165.19**

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Approved 10.8% Rider R (Board Order 2023-22) Effective: January 1, 2024

Line No.						
1	Consumption	800 kWh				
2			**Rate**			**Charge**
3						
4	Customer Charge (per month)		$ 14.65			$ 14.65
5						
6	Block 1 Energy Charge 1000 ($/kWh)		$ 0.1214	x	800	$ 97.12
7	Base Rate					$ 111.77
8						
9	Fuel Adjustment Rider $/KW.h		$0.01635	x	800	$ 13.08
10	Rider J and J1 YEC Shortfall		37.85%	x	$ 111.77	$ 42.30
11	Rider R and R1 AEY Adjustment		10.80%	x	$ 111.77	$ 12.07
12	Rider S Purchase Power Adjustment Rider		$0.00100	x	800	$ 0.80
13	Interim Electrical Rebate		-$0.02262	x	800	$ (18.10)
14	Sub-Total					$ 161.92
15						
16	GST		5.0%	x	$ 161.92	$ 8.10
17	**TOTAL including GST**					**$ 170.02**

ATCO Electric YUKON

September 28, 2023 AEY-UCG-004

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-004

Reference: July 7, 2023 Application, Appendices pages iii and iv AEY charts out for Business Cases for: 2016-2017 (#1-3); 2018-2022 (#4-21); 2023-2024 Test Years (#22-38); and Significant Expenditures Outside of Test Years (#39-41).

Request:

(a) For the years 2016-17 provide same chart with $ amount for each project #'s 1-3 and explain how each was accounted for in rate base. Explain if these were referenced and accounted for in the 2016-17 rate base.

(b) For years 2018-2022 (#'s 4-21) provide same chart with the $ amount of each project and explain if these were accounted for in the rate base and for which year. If these were added to the rate base for each of those non-test years, explain under which part of the *Public Utilities Act* this can be done.

(c) For the years 2023-2024 Test Years #'s22-38 provide on the same chart with the $ amount for each project proposed to place into the rate base for each of the test years.

(d) For the proposed significant expenditures outside of test years #'s 39-41 provide the same chart with the forecast $ amount of each project and whether AEY plans to place these into the rate base outside of the test year period.

Response:

(a-d) Please refer to AEY-YUB-046(a) Attachment 1 for an itemized list showing which projects have a Business Case for 2016-2024. These projects are added to rate base when they go into service. As stated in AEY-UCG-065(b), the net cost of capital has been included in the 2023-2024 Revenue Requirement on a prospective basis and AEY is not seeking retroactive recovery of returns or depreciation costs incurred for the period since its last GRA. Opening rate base continues to be within scope for the Board's review and approval as part of this Application.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-005

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-005

Reference: July 7,2023 Application, page 1-5

1.8 Deferral Accounts

16, The previously accepted criteria for establishing a deferral account have not changed from AEY.s 2016-17 Phase 1 GRA. The criteria are as follows:

(a) Costs are not under the control of the company and are not reasonably forecastable; or

(b) A variance in forecasting could produce a loss or gain of a substantial order.

Deferral Accounts requested:

Sec. 1-B Board Orders or Legislative Changes
Sec. 2- Industrial Rider R Flow Through
Sec. 3- Purchase Power Flow Through
Sec. 3- IPP Flow Through
Sec. 4- Diesel Fuel Deferral Account (Rider F)

Request:

(a) Please fully explain (b) above. Does this mean that AEY plans to have a variance for surplus/ or loss of earnings that will be returned/charged to ratepayers?

(b) Will AEY be applying for Federal or Territorial grants for the Energy Transition proposals or fuel charges or other charges by various governments for climate change rebates? If not, why not?

(c) Will the Industrial Rider R extra earned income be returned to ratepayers?

(d) Will AEY confirm to working with YEC to propose a new wholesale rate during the upcoming YEC GRA?

(e) Is this Purchase Power Flow Through the same as ERA? Explain.

(f) Explain why an IPP flow-through mechanism is necessary when you have a contract with the providers.

(g) For Disel Rider F will there not be a diesel cost true-up for 2023 test year?

(h) Provide all the Rider F regulatory reports for actual costs from January to August 2023 and the Sept. to Dec.2023 forecast.

(i) Provide the Rider F reports for forecast 2024 test year.

Response:

(a) Part (b) of the Deferral account criteria refers to the potential for an account variance to be materially positive or negative and have a substantial impact on returns. This impact can result in higher or lower returns, depending on how actual costs compare to the original forecast. These savings or additional costs will be flowed through to customers.

(b) Yes. AEY intends to apply for any applicable Federal and Territorial grants.

(c) Please refer to the responses to AEY-YUB-006(a) and (b) for details respecting the deferral treatment of AEY's Industrial Rider R revenue.

(d) Not confirmed.

(e) No, the Purchase Power Flow Through deferral is not the same as ERA. The Purchase Power Flow Through deferral account has most recently been approved in Board Order 2017-01 and was also considered as part of AEY's Rider S Application, approved in Board Order 2023-17. The Purchase Power Flow Through deferral account includes any increases or decreases to the purchase power rate, including any ERA amounts.

(f) The IPP deferral account is necessary. Please refer to AEY-YUB-002(b)(ii) for the explanation.

(g) Subject to the Board's direction on AEY's 2023-2024 GRA, AEY will true up the fuel variance amounts in the Compliance Filing.

(h-i) As Rider F is a joint account with YEC and future fuel costs are unknown and unpredictable due to economic conditions, AEY is unable to produce an accurate forecast for the Rider F balance. Please refer to AEY-UCG-005(h) Attachment 1 for the most recent Rider F report up to June 2023. Third quarter balances are unavailable at this time and will be filed with the Yukon Utilities Board when available.

ATCO Electric YUKON

yukon energy
the power of yukon

September 20, 2023

Mr. Richard Buchan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Buchan:

Re: Rider F - Quarterly Report - Period Ending June 30, 2023

Yukon Utilities Board ("Board") Order 2010-13 directs the companies as follows:

> " ... to allow all interested parties to monitor the balance in the Rider F account, the Companies are to provide the Board quarterly acknowledgement filings stating the balance in the Rider F account... "

Please find attached the Q2 2023 report regarding the Companies' combined Diesel and LNG Fuel Price Variance ("FPVA/Rider F") account balance. The account balance exceeded the +/-$200,000 threshold set by the Board, therefore, to address the account balance, on November 29, 2022 the Companies filed Rider F rate change advisory letter with the Board with Rider F rate of 1.635 cents/kWh effective January 1, 2023.

The Board in its letter dated July 6, 2023 noted that "in the YEC Excel workbook, the totals from the YEC fuel variance calculations spreadsheet (columns C-E, row 207) do not match the totals in the FPVA Q1 2023 spreadsheet (column B rows 7-9). The Utilities, on a go forward basis, are to provide a reconciliation and explanation between the two worksheets." The numbers in the "FPVA 2023 balance" tab of the excel file are now linked to the YEC Fuel variance calculations with the explanation note added under the table for the variances in the monthly numbers [the variance for January 2023 in column B was corrected in the February 2023 row and the total for Jan-Feb at $431,665 reconciles to Jan-Feb fuel variance in "YEC Fuel variance calculations" tab].

The Board in its letter also noted that AEY "will provide a continuity schedule (for the interim period since its last compliance filing) for its DFPVA starting with the next quarterly filing." Attachment 2 to this report includes a continuity schedule for AEY fuel variance calculations since its last compliance filing. During the review, AEY identified an error in fuel variance calculations. AEY has corrected the necessary working papers and the variance is reflected in the FPVA balance as an adjustment.

As directed in Order 2010-13, this report will also be posted concurrently on the Companies' websites for public access. If any interested party has questions regarding Rider F, please contact one of the undersigned.

Sincerely,

ATCO ELECTRIC YUKON

Beth Rogers
Director, Regulatory

elizabeth.rogers@atco.com

YUKON ENERGY CORPORATION

Jason Epp
Vice President, Finance and
Chief Financial Officer
Jason.Epp@yec.yk.ca

Rider F – Quarterly Report

For the Period Ended – June 30, 2023

	Combined Company Balance				
	Fuel Price Variance[1]	**RS 32 – SS Adjustment**	**Rider F Surcharge**	**Cumulative Balance**	**Monthly Change**
Dec-22				(6,684,651)	
Jan-23	(906,386)	-	723,510	(6,867,527)	(182,876)
Feb-23	(397,005)	-	770,289	(6,494,243)	373,284
Mar-23	(522,603)	-	838,863	(6,177,982)	316,261
Apr-23	(379,851)	-	798,505	(5,759,329)	418,654
May-23	(141,719)	-	608,568	(5,292,480)	466,849
Jun-23	(397,507)	-	519,121	(5,170,865)	121,614

(1) Including AEY's correction adjustment

Notes:

- Positive balances represent amounts to the benefit of ratepayers.
- Negative balances are amounts owing to the companies.

Effective Date		**Rider F (¢ / kWh)**
August 1, 2022	December 31, 2022	0.865 cents per kWh charge
January 1, 2023	Current	1.635 cents per kWh charge

ATCO Electric YUKON

September 28, 2023 AEY-UCG-006

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-006

Reference: July 7,2023 Application, page 1-5

AEY states: "For 2023, in-scope (subject to Collective Agreement) labour has been escalated by 2.00 percent. This escalation is based on AEY's existing Collective Agreement that expires on December 31, 2023. For 2023, out-of-scope (not subject to a Collective Agreement) labour has been escalated by 2.90 percent, which is consistent with approved increases in Alberta. For 2024, in-scope and out-of-scope labour has been escalated by 2.50 percent. This escalation rate is consistent with the inflationary increase being applied for and approved in Alberta for 2024.

Request:

(a) Provide copies of the referenced Alberta approvals.

(b) Provide details of the labour cost escalation rates in the Yukon for 2023 and the source of the documents for these forecasts.

(c) What labour escalation rates are currently used for 2023 by Fortis BC Utilities, which AEY uses as their proxy? Provide details from Fortis.

Response:

(a) Please refer to Decision 27062-D01-2023, ATCO Electric 2023-2025 GTA and NSA (AEY-UCG-006(a) Attachment 1) and the AET 2023-2025 GTA Negotiated Settlement Agreement (AEY-UCG-006(a) Attachment 2) for details of the approved inflation rates.

(b) The Yukon's 2023–24 Fiscal and Economic Outlook (AEY-UCG-018(a) Attachment 1) is forecasting an increase in household income of 6.3 percent and CPI inflation of 3.8 percent for 2023.

(c) Please refer to the response to AEY-UCG-007(c).

Decision 27062-D01-2023

AUC
Alberta Utilities Commission

ATCO Electric Ltd.

2023-2025 General Tariff Application and Negotiated Settlement Agreement

May 5, 2023

Alberta Utilities Commission
Decision 27062-D01-2023
ATCO Electric. Ltd.
2023-2025 General Tariff Application and Negotiated Settlement Agreement
Proceeding 27062

May 5, 2023

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Website: www.auc.ab.ca

The Commission may, no later than 60 days from the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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Alberta Utilities Commission
Calgary, Alberta

ATCO Electric Ltd.
2023-2025 General Tariff Application and Negotiated Settlement Agreement
Decision 27062-D01-2023
Proceeding 27062

1 Decision summary

1. This decision provides the Alberta Utilities Commission's determinations regarding ATCO Electric Ltd.'s (ATCO Electric or AET) application for approval of a Negotiated Settlement Agreement (NSA) regarding its 2023-2025 general tariff application (GTA). It also provides the Commission's determinations on two issues that were excluded from the NSA by the Commission and a further issue that was initially part of the negotiated settlement process (NSP), but in respect of which parties were unable to reach agreement.

2. The Commission finds that the NSA between ATCO Electric and interveners was negotiated under a fair process, is in the public interest and results in just and reasonable rates. Therefore, the Commission approves the NSA application. Of the three issues that were not part of the NSA, the Commission has:

(i) Determined that the vegetation management reserve will apply to ATCO Electric's 2023 vegetation management costs only and approves the elimination of the vegetation management reserve beginning in 2024.

(ii) Approved ATCO Electric's amendments to the Variable Pay Program (VPP) reserve.

(iii) Denied ATCO Electric's request to collect $7.5 million in depreciation related to the Jasper Palisades amounts that were incorrectly accounted for, and determined that the correct undepreciated balance in relation to the Jasper Palisades switchgear assets should be $0.

3. The Commission requires ATCO Electric, in its compliance filing to this decision and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences, including presenting the equity portion of allowance for funds used during construction (AFUDC) as a permanent difference.

4. The Commission directs ATCO Electric to provide construction work in progress (CWIP) continuity schedules as requested by the Commission in its letter of July 13, 2022,[1] and in Section 6.1 below, in future GTAs.

5. ATCO Electric is to file its compliance filing to this decision no later than June 12, 2023. As detailed in Decision 26573-D01-2023,[2] ATCO Electric is to incorporate the findings,

[1] Exhibit 27062-X0242, Further process, paragraphs 12-14.
[2] Decision 26573-D01-2023: ATCO Electric Ltd., Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 26573, April 26, 2023.

conclusions and directions of the Commission in that decision together with its compliance filing addressing the Commission's directions in this decision.

2 Introduction and background

6. ATCO Electric is a transmission facility owner that provides regulated electric transmission service in Alberta. ATCO Electric recovers the costs of providing electric transmission service through its transmission tariff, which must be approved by the Commission. Once approved, ATCO Electric recovers its tariff amounts from Alberta ratepayers through the Alberta Electric System Operator (AESO), which collects the costs from the ratepayers' respective distribution facility owners, and from ratepayers directly connected to the transmission system.

7. ATCO Electric made the following applications seeking various approvals from the Commission in each of them:

(i) ATCO Electric's 2023, 2024 and 2025 GTA; and

(ii) the 2021 settlement of deferral accounts and adjustment balances.

8. In its letter,[3] dated July 13, 2022, the Commission:

(i) Determined that additional information was required in order for the Commission to consider the application complete, which included providing missing business cases, missing IBM/Kyndryl information technology (IT) Master Service Agreement and IBM/Kyndryl 2021 and 2022 IT cost information and confirmation of accounting policy updates.

(ii) Required supplementary information that included the CWIP continuity schedules for capital programs.

(iii) Denied ATCO Electric's request to update inflation parameters and isolated generation fuel forecast costs with its rebuttal evidence; and

(iv) Directed ATCO Electric to move its 2021 settlement of deferral accounts and adjustment balances from the 2023-2025 GTA to Proceeding 26573,[4] where the Commission was considering similar issues as part of ATCO Electric's 2018-2020 deferral application.

9. On July 28, 2022 ATCO Electric filed a motion asking the Commission to reconsider its ruling denying its request to update its proposed inflation factors and fuel prices when rebuttal evidence is filed. ATCO Electric admitted in its motion that it believed its originally filed application would not result in just and reasonable rates.[5] The Commission exercised its discretion to reconsider its July 13, 2022, ruling given the new information provided in ATCO Electric's motion. ATCO Electric was directed to submit its updated application, including

[3] Exhibit 27062-X0242.
[4] Proceeding 26573, ATCO Electric Transmission, Application for Disposal of 2018-2020 Transmission Deferral Accounts and Annual Filing for Adjustment Balance.
[5] Exhibit 27062-X0243, paragraph 6.

revised inflation and fuel prices, no later than September 5, 2022. The Commission also set out the issues list, provided its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of two issues,[6] and established the proceeding process schedule.

10. In its ruling, dated October 21, 2022, the Commission granted ATCO Electric's request for additional time to respond to information requests (IRs) and revised the proceeding schedule.[7] On December 21, 2022, ATCO Electric filed a letter[8] with the Commission advising that it had reached a NSA in principle with the intervening parties.[9] The Commission approved ATCO Electric's proposed timeline for the remainder of the proceeding process that concluded with oral argument and reply argument.[10] The Commission considers the close of record to be February 7, 2023, the date of oral reply argument.

11. The Commission has reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered.

12. This decision addresses the contentious cost items forecast in the application, and any matters that the Commission has otherwise determined are required to be specifically addressed. If a matter is not specifically addressed in this decision, it is because the Commission finds the applied-for costs associated with the matter to be reasonable and the applicant's request is therefore approved as filed. All directions in this decision are subject to all findings and other directions made elsewhere in this decision.

13. The Commission directs ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023.

3 Negotiated settlement

3.1 Requirements governing negotiated settlements

14. Section 6 of Rule 018: *Rules on Negotiated Settlements* under Section 132 of the *Electric Utilities Act*[11] sets out requirements for the contents of a negotiated settlement application, and places the onus on the applicant to provide sufficient evidence to support the application and to enable the Commission to understand and assess the agreement. Section 7 of Rule 018 includes requirements for the Commission's assessment of the agreement. The Commission structured the settlement process in this proceeding in accordance with Rule 018.

15. The Commission has previously considered negotiated settlements in rate cases where there has been unanimous agreement. The Commission has consistently indicated that the test requires consideration of three questions: (i) was the negotiation process fair, including with

[6] Those two issues were removal of the vegetation management reserve and modifications to the VPP reserve.
[7] Exhibit 27062-X0328, AUC letter - Ruling on ATCO Electric's request for time extension to file responses to information requests.
[8] Exhibit 27062-X0486, Letter to AUC re NSA - December 21 2022.
[9] Intervening parties included: Consumers' Coalition of Alberta, the Office of the Utilities Consumer Advocate, The City of Calgary, the Industrial Power Consumers Association of Alberta and the City of Grande Prairie
[10] Exhibit 27062-X0487, AUC letter - Ruling and process schedule update – negotiated settlement process.
[11] Section 132 of the *Electric Utilities Act* requires that the Commission recognize or establish rules, practices and procedures to facilitate the negotiated settlement of matters arising under the act.

respect to notice and the conduct of the process itself; (ii) will the settlement result in just and reasonable rates; and (iii) are any of the settlement provisions, individually or collectively, patently against the public interest or contrary to law?[12] Performing this assessment requires the Commission to review both the individual provisions of the NSA and the NSA as a whole.

16. In considering these requirements, the Commission has taken into account the direction of the Alberta Court of Appeal as set out in *ATCO Electric Limited v Alberta (Energy and Utilities Board)*[13] (ATCO Electric decision). In that decision, the court found that the ultimate responsibility for approving negotiated settlements resides with what is now the AUC. The Commission proceeds on that basis herein, as it has in the past, with a view to ensuring that the NSA will result in just and reasonable rates, that none of the NSA provisions, individually or collectively, are patently against the public interest or contrary to law, and that the process used to arrive at the NSA was fair.

17. In assessing a negotiated settlement, the Commission is aware that, while one or more of the interested parties to a settlement may represent certain stakeholders, none will represent all stakeholders. Further, as noted by the court at paragraph 138 of the ATCO Electric decision, "… even a broad range of Interveners will not necessarily translate into a wide spectrum of positions since parties may make trade-offs which leave other issues unresolved, unaddressed or compromised."[14] Consequently, the NSP and NSA do not replace a full and informed review by the Commission as to what is in the overall public interest. Because ATCO Electric had requested and received Commission approval to negotiate a settlement; subsequently negotiated with parties representing ratepayers; executed the NSA; and then applied to the Commission for approval of the NSA in its entirety, the Commission has proceeded on the basis that the NSA satisfies ATCO Electric's interests and has only assessed the NSA from the point of view of ratepayers. This is consistent with the ATCO Electric decision.[15]

18. Given the statutory requirements, Rule 018 and the relevant case law, the Commission has considered all of the following factors in making its determination on whether the NSA should be accepted or rejected in its entirety:

- **Review of the NSP:** Was the NSP procedurally fair, both with respect to adequate notice having been served and with respect to the conduct of the negotiation process itself?

[12] See, for example, Decision 21149-D01-2016 (Errata): ENMAX Power Corporation, Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor, Proceeding 21149, October 3, 2016, paragraph 29; Decision 25726-D01-2021: ENMAX Power Corporation, 2021-2022 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 25726, June 16, 2021, paragraph 23; Decision 23966-D01-2020 (Corrigenda): ENMAX Power Corporation, 2018-2020 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 23966, July 30, 2020; and Decision 26207-D01-2021: Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement, Proceeding 26207, June 4, 2021, paragraph 18.

[13] *ATCO Electric Limited v Alberta (Energy and Utilities Board),* 2004 ABCA 215.

[14] ATCO Electric decision, paragraph 138.

[15] ATCO Electric decision, paragraph 146.

- **Review of the NSA**
    - Does the settlement result in rates, and terms and conditions that are just and reasonable?
    - Is the settlement patently against the public interest or contrary to law?

19. The Commission's findings on the NSP and on the provisions of the NSA are discussed below. The Commission notes that while parties were permitted to negotiate the issue of ATCO Electric's proposed treatment of the one-time depreciation adjustment for the Jasper Palisades isolated generation plant, they did not reach a settlement on this matter. ATCO Electric's proposed treatment of the one-time depreciation adjustment for the Jasper Palisades isolated generation plant and the Commission excluded matters[16] are therefore addressed in Section 4.

3.2 Review of the NSP

20. The first factor that the Commission considers is whether the NSP that resulted in the NSA was fair.

21. Starting with the conduct of the negotiation process, ATCO Electric submitted that the settlement negotiations were fair, and that all parties were well-informed and able to meaningfully participate.[17] The CCA, the UCA, The City of Calgary, the City of Grande Prairie and the Industrial Power Consumers Association of Alberta also filed correspondence with the Commission attesting to the fair and open manner in which the negotiation was conducted.[18] The Commission notes that all participants in the negotiations are sophisticated parties, and considers that they represent a reasonable cross-section of ratepayers. The Commission is satisfied that parties had the opportunity to participate meaningfully, and that the negotiations were conducted in an open and fair manner.

22. Turning to the issue of adequate notice, Section 3 of Rule 018 deals with the provision of notice by a utility to parties who may be interested in participating in negotiations. Under Section 3, the Commission requires a statement in a settlement agreement confirming that proper notice was provided by the applicant to all interested parties. ATCO Electric submitted that adequate notice was provided to parties, noting that the Commission's approval of the NSP was posted on the public record of the proceeding, and that the NSA includes a statement confirming that ATCO Electric provided proper notice to all interested parties.[19] The Commission finds that ATCO Electric provided adequate notice to parties.

23. Finally, Section 6(1) of Rule 018 provides that, when an agreement is reached on all or some of the issues, the text of the agreement, including a representation that no party has withheld relevant information, must be circulated to all parties to the agreement. ATCO Electric

[16] Exhibit 27062-X0273: In its letter dated August 5, 2022, the Commission gave its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of the following two items: (i) Removal of the vegetation management reserve; and (ii) modifications to the variable pay program reserve
[17] Exhibit 27062-X0495.01, paragraphs 47-50.
[18] Exhibits 27062-X0489, 27062-X0490, 27062-X0491, 27062-X0493 and 27062-X0494.
[19] Exhibit 27062-X0495.01, paragraphs 19-21 and Section 8(b) on PDF page 27.

addressed this requirement under Section 8 of the NSA.[20] The Commission finds that the requirements of Section 6(1) of Rule 018 have been met with respect to relevant information.

24. In view of the above and having considered the parties' submissions with respect to the NSP, the Commission is satisfied that the NSP was fair and that ATCO Electric has complied with the requirements set out in sections 3, 6(1) and 6(3) of Rule 018.

3.3 Review of the NSA

25. The second factor the Commission must consider is whether the NSA is in the public interest, including whether it will result in just and reasonable rates, Section 8(1) of Rule 018. The Commission is also guided by the *Electric Utilities Act* and Rule 018 and, in particular, Section 8(2) of Rule 018, which states that the Commission must intervene if it determines that a unanimous settlement agreement is patently against the public interest or contrary to law.

26. In conducting the public interest assessment, the Commission considered each individual element of the NSA and the NSA as a whole. As to what constitutes the public interest when assessing the attributes and merits of an NSA, the Commission followed the guidance provided by the Alberta Court of Appeal in the ATCO Electric decision discussed above. That is, it considered the public interest from the perspective of ratepayers. In arriving at its findings, the Commission reviewed each of the material provisions of the NSA to determine if any of these provisions appears to be unusual, contrary to accepted regulatory practices, or could result in undue rate effects, service concerns, preferences or other concerns in future rate applications. The Commission has also considered whether the effect of the NSA would lead to rates and terms and conditions of service that are just and reasonable.

27. ATCO Electric submitted that the NSA results in just and reasonable tariffs for 2023, 2024 and 2025, is in the public interest and is not contrary to law.[21]

28. ATCO Electric filed a summary of the terms of the NSA for ATCO Electric's 2023-2025 GTA, reproduced in Table 1 below. All adjustments to the revenue requirement listed in Table 1 are in addition to the errors and omissions updates that were included in response to a Commission IR.[22] In total, the adjustments resulting from the NSA amount to a $113.8 million[23] reduction to ATCO Electric's 2023-2025 revenue requirements.

Table 1. Impact to revenue requirement of agreed adjustments

	2023	2024	2025
	($ million)		
O&M [operating and maintenance] Negotiated Items			
Diesel Fuel Volume Reduction	(0.3)	(0.3)	(0.3)
Vacancy Rate	(0.5)	(0.6)	(0.7)
Inflation - In/Out Scope, Contractor and Other	(1.0)	(1.5)	(1.8)
USA 560 - Supervision and Engineering	(0.1)	(0.1)	(0.1)
USA 561 - Control Centre Operations	(0.2)	(0.2)	(0.2)

[20] Exhibit 27062-X0495.01, PDF page 27.
[21] Exhibit 27062-X0495.01, paragraph 59.
[22] AET-AUC-2022SEP21-130.
[23] = $34.5 million + $38.2 million + $41.1 million.

	2023	2024	2025
	($ million)		
USA 562 - Station Equipment Expenses	(0.4)	(0.5)	(0.6)
Insurance Premiums	(0.3)	(0.2)	(0.2)
Variable Pay Program	(0.6)	(0.7)	(0.8)
Shared Services FTE Reduction	(0.2)	(0.2)	(0.1)
IT Transition Costs & Reduction of IT Costs per Decision 26616-D01-2022	(0.5)	(4.6)	(1.5)
General O&M Reduction	(0.3)	(0.3)	(0.3)
Total O&M Negotiated Items	(4.3)	(9.0)	(6.5)
Capital Negotiated Items			
IT Capital – Reduction to Opening Rate Base	(1.1)	(1.1)	(1.0)
Removal of DA Capital (CETO/PENVT)	0.0	0.2	(6.7)
Global TCM 7.5% Reduction	(0.2)	(1.2)	(2.0)
One-time TCM Reduction	(0.0)	(0.2)	(0.2)
Return on Increased Rate Base due to FIT Reserve Refund	0.6	2.0	3.3
Increase to Income Tax Expense due to Increase to Return on Rate Base	0.1	0.3	0.5
Total Capital Negotiated Items	(0.5)	0.0	(5.9)
Future Income Tax (FIT) Reserve Refund	(22.9)	(22.5)	(22.1)
Decrease to Income Tax Expense due to FIT Reserve Refund	(6.8)	(6.7)	(6.6)
Total Negotiated Reduction	(34.5)	(38.2)	(41.1)

Source: Exhibit 27062-X0495.01, Table 1, PDF page 11.

29. Parties to the NSA also agreed to implement two new deferral accounts in the test period, and to extend ATCO Electric's existing deferral account for statutory tax rates to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance. The NSA also includes commitments made by ATCO Electric to provide certain information in its next GTA. These commitments are included in Section 5 of the NSA, found in Appendix 4.

30. The NSA represents a unanimous agreement reached as a result of a successful negotiation. Such negotiations and the resultant NSA typically reflect a number of compromises of different interests and positions of the parties. The signatories to the NSA in this case, with the exception of the City of Grande Prairie, have historically participated in the testing of ATCO Electric's GTAs and represent a broad cross-section of Alberta ratepayers. The involvement of sophisticated participants representing a number of different constituencies supports a finding that the NSA is in the public interest.

31. Having reviewed the individual provisions of the NSA and considered the NSA as a whole as described above, along with the detailed analysis of the application and IR responses, the Commission finds that the NSA, taken as a whole, is not patently against the public interest or contrary to law, and finds that the NSA results in rates and terms and conditions that are just

and reasonable, as required by Section 8 of Rule 018. Accordingly, the Commission approves the NSA as filed, and attached as Appendix 4 to this decision.

4 Excluded matters

32. In its August 5, 2022, letter, the Commission gave its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of the following two items: (i) removal of the Vegetation Management reserve; and (ii) modifications to the Variable Pay Program reserve.[24]

33. ATCO Electric subsequently advised, as part of its NSA submission, that parties were unable to agree on the treatment of the $7.5 million undepreciated balance for the Jasper Palisades isolated generation plant. As a result, the Commission must likewise separately determine this issue (along with the other two formally excluded matters).[25]

34. In the following sections, the Commission provides its findings with respect to these three matters.

4.1 Vegetation management reserve

Why is ATCO Electric asking the Commission to remove the vegetation management reserve account?

35. ATCO Electric requested that the vegetation management reserve be discontinued because the reasons it was originally created no longer apply.[26] In particular, ATCO Electric indicated that the variances between forecast expenditures and actual expenditures that were once a concern to the Commission have diminished to the point where they are no longer material. ATCO Electric explained that it has diversified its contractor resources and converted its vegetation management program from mechanical removal to predominantly herbicide treatment, resulting in smaller and more predictable vegetation treatment volumes.[27]

Why was the vegetation management reserve established?

36. In Decision 20272-D01-2016,[28] the Commission expressed concern with the historical variances between forecast and actual vegetation management costs. The Commission found that a significant amount of ATCO Electric's 2015 actual vegetation management costs and its 2016 forecast costs had been deferred from prior years.[29] ATCO Electric attributed its inability to complete the vegetation management work from prior years to the unavailability of contractors and weather related difficulties.[30] As a result, the Commission determined that electricity ratepayers should not bear a disproportionate share of the risk that ATCO Electric may be unable to complete its forecast vegetation management work and therefore retain, for the benefit of its

[24] Exhibit 27062-X0273, AUC letter - Ruling on ATCO Electric motion to update application for inflation and fuel, issues list, negotiated settlement and process schedule, PDF pages 5-6.
[25] Exhibit 27062-X0273, AUC letter - Ruling on ATCO Electric motion to update application for inflation and fuel, issues list, negotiated settlement and process schedule, paragraph 27.
[26] Exhibit 27062-X0014.02, PDF page 17.
[27] Transcript, Volume 1, page 17, lines 8-25.
[28] Decision 20272-D01-2016: ATCO Electric Ltd. 2015-2017 Transmission General Tariff Application, Proceeding 20272, August 22, 2016.
[29] Decision 20272-D01-2016, paragraphs 256-259.
[30] Decision 20272-D01-2016, paragraph 260.

shareholders, revenues that were collected from ratepayers for forecast costs of vegetation management that were not spent.

The Commission has previously ruled on ATCO Electric requests to remove its vegetation management reserve account

37. ATCO Electric has requested the removal of the vegetation management reserve in each of its tariff applications following the Commission's direction in Decision 20272-D01-2016.

38. In Decision 22742-D01-2019,[31] the Commission denied ATCO Electric's request to remove the vegetation management reserve account. In that decision, the Commission found that there was merit in maintaining the reserve account, as it supported stability and aided ATCO Electric in managing its forecast costs.[32]

39. In Decision 24964-D02-2021,[33] the Commission again denied ATCO Electric's request to remove the vegetation management reserve account. While the Commission acknowledged ATCO Electric's improved forecast accuracy and a trend of cost reductions, it denied ATCO Electric's request for the following reason:[34]

> 196. However, the Commission finds that these improved costs do not outweigh the fact that the execution of ATCO Electric's Vegetation Management Program remains, to a large degree, unpredictable and subject to forecast risk. As acknowledged by ATCO Electric, weather conditions and contractor availability are factors that can influence the success of ATCO Electric's Vegetation Management Program.
>
> > Projected treatment volumes are based on ideal weather conditions and contractor availability. Actual treatment volumes may be different than projected volumes due to abnormally warm winters that increase the cost and reduce the productivity associated with mulching operations, or abnormally wet or windy summers that reduce the window for effective herbicide application.[173]

[173] Exhibit 24964-X0001.03, application update, paragraph 226, PDF page 189.

Is there sufficient support to justify removing the vegetation management reserve in the current proceeding?

40. In an IR from the Commission, ATCO Electric was asked to provide detailed vegetation management information by line number and substation that included the year work was deferred from (if applicable), removal method, volume of work performed and cost information.

[31] Decision 22742-D01-2019: ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application, Proceeding 22742, July 4, 2019, paragraphs 209-211.
[32] Decision 22742-D01-2019: paragraph 211
[33] Decision 24964-D02-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021, paragraphs 195-197.
[34] Decision 24964-D02-2021, paragraph 196.

41. As part of its response to the Commission's IR,[35] ATCO Electric stated the following:

> The information by line does not include any "Year work deferred from" information, as AET no longer defers vegetation work on lines. Lines are patrolled every three to four-years and assessed for vegetation risk. AET focuses its vegetation management activities on a risk-based approach. Work is done, as required, based on AET's risk assessment and timing of next planned patrol/program.[36]

42. While ATCO Electric explained that its lines are patrolled every three to four years, it did not indicate when the last patrol was done and what test period years' costs were forecast based on its last line patrol and risk assessment. The Commission therefore cannot ascertain whether the vegetation management forecasts in the test periods currently under consideration were all the subject of a risk-based assessment conducted following line patrols.

43. The Commission has reviewed the proportion of the actual costs and volumes of vegetation management work completed, to the approved forecast costs and volumes of work in past GTAs.

44. Based on the information provided by ATCO Electric in its IR response, it has spent almost 94 per cent (on average) of its approved forecast for line clearing, and completed 90 per cent of the work volume (on average) approved in its last GTA.

45. The Commission observes that ATCO Electric, in total, has managed its vegetation management spending to be in line with its approved forecast costs. It has also completed the volume of work it had forecast over the prior GTA period. The 2023 to 2025 test period forecast volume of work is less than in prior GTAs, which, in the Commission's view, reduces the risk that ATCO Electric will be unable to complete it. Given that the evidence demonstrates that ATCO Electric's forecasts have been more closely aligned with its actual vegetation management, the Commission finds that it is reasonable to transition away from the vegetation management reserve over the 2023-2025 test period as directed below.

46. The Commission directs ATCO Electric to maintain the reserve account treatment for 2023, but approves the elimination of the vegetation management reserve beginning in 2024. This transition period will permit the Commission to monitor the vegetation management program to ensure continued alignment of forecast and actual costs and work volumes at the time of the next GTA. For all test period years in the current and next GTA, ATCO Electric is directed to provide the same information that it filed in response to 27062-X0416, updated for the appropriate years. Should significant variances reoccur in the costs and volumes for ATCO Electric's vegetation management program, the Commission may reinstate the past reserve treatment.

[35] Exhibit 27062-X0330.02, AET Responses to AUC IRs, AET-AUC-2022SEP21-114, PDF pages 621-625; and exhibits 27062-X0416, AET-AUC-2022SEP21-114 Attachment 1, and 27062-X0417, AET-AUC-2022SEP21-114 Attachment 2.

[36] Exhibit 27062-X0330.02, AET Responses to AUC IRs, AET-AUC-2022SEP21-114, PDF page 622.

4.2 Variable Pay Program reserve

ATCO Electric's requested changes to the VPP reserve account

47. ATCO Electric requested two changes to its VPP reserve mechanics. In particular, it sought to:

(i) Exclude direct assigned capital VPP from the VPP reserve account; and

(ii) Include the revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs.

48. ATCO Electric explained that in Decision 24964-D02-2021, it was directed to manage the VPP reserve account by disaggregating O&M, direct assigned, and non-direct assigned capital VPP amounts effective January 1, 2020, and to prepare the continuity Schedule of Reserve for VPP on a disaggregated basis. As a result of that direction, ATCO Electric separately examined the mechanics of the O&M VPP, direct assigned capital VPP and non-direct assigned VPP components.[37]

49. In its application, ATCO Electric proposed to exclude direct assigned capital VPP from the VPP reserve account because differences between forecast and actual direct assigned capital amounts are already trued up through the settlement of the direct assigned capital deferral account.

50. ATCO Electric also submitted that the amount to include in the non-direct assigned VPP reserve account should never exceed the revenue requirement amount actually collected (being an amount equal to non-direct assigned VPP amounts capitalized). ATCO Electric argued that the revenue requirement impact is the appropriate amount to include in the reserve as it is the amount which ATCO Electric actually collects as a result of having the forecast VPP included in its rate base.

Why was the variable pay program reserve established?

51. In Decision 2013-358,[38] the Commission explained that deferral account treatment had originally been applied to VPP costs[39] because it was a new program and, absent a deferral account, the utility might be incented to keep, for the benefit of shareholders, funds collected from ratepayers to support the utility's recruitment and retention efforts. In Decision 2013-358, the Commission determined that deferral treatment was no longer required because ATCO Electric had established a history of paying the VPP amounts.

52. In Proceeding 27062, the Commission observed that ATCO Electric had not fully paid out VPP amounts in 2013 and 2014, and planned to withhold all VPP amounts initially forecast to be paid in 2015. It was unclear to the Commission, at that time, whether ATCO Electric would pay VPP to its employees in 2016 and 2017.

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37 Exhibit 27062-X0014.02, paragraphs 679-680.

38 Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Application 1608610, Proceeding 1989, September 24, 2013.

39 The deferral account for ATCO Electric's VPP was first approved in EUB Decision 2006-024: ATCO Electric Ltd. General Tariff Application, Application 1399997, March 17, 2006, PDF page 80.

53. In Decision 20272-D01-2016, the Commission directed ATCO Electric to establish a reserve account for its ratepayer funded VPP. The reserve account mechanics were structured such that ATCO Electric could not recover costs in excess of its approved VPP forecast amounts for a given year, nor carry over any unused VPP funds into a future test period. The Commission-approved, but unused, VPP amounts in any given GTA test period would be added to the VPP reserve account for the next GTA test period. As detailed in Decision 2013-358,[40] the VPP reserve was designed to address ATCO Electric's need to fund VPP in support of its recruitment, retention and operational performance goals, while ensuring that any incentive to withhold VPP amounts to increase the utility's retained earnings was removed.

54. The mechanics of the VPP reserve have evolved since its inception to ensure that the reserve continues to meet these objectives.

55. In reply argument, the CCA stated that it did not oppose ATCO Electric's proposed modifications to the VPP reserve or how the components were calculated.[41]

Are ATCO Electric's proposed changes to the VPP mechanics reasonable?

56. For the reasons set out below, the Commission finds that ATCO Electric's proposed changes to the mechanics of the VPP reserve are reasonable and approves them as filed.

57. The Commission agrees with ATCO Electric that as a result of disaggregating the three components of the VPP,[42] and given that variances between actual and approved capitalized expenditures are settled through the direct assigned capital deferral account, there is no need to track these costs through the VPP reserve. The Commission also acknowledges ATCO Electric's reply argument, in which it stated that "in future direct-assign capital deferral accounts, AET will continue to report on VPP paid and remove any amounts in excess of approved VPP amounts."[43]

58. The Commission also accepts ATCO Electric's proposed treatment of non-direct assigned capital VPP. A reserve account is used to fund specific expenses that are paid out infrequently or at unpredictable intervals, and are funded in advance through rates. Now that the VPP reserve account has been disaggregated, the revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs, is the proper amount that should be reflected in the VPP reserve account. This is because these amounts reflect what ATCO Electric has collected from ratepayers over each of the test periods towards the funding of ATCO Electric's non-direct assigned VPP, prior to ATCO Electric actually distributing the VPP payout to its employees.

40 Decision 2013-358.
41 Transcript, Volume 2, page 134, lines 5-18.
42 The three components being O&M, non-direct assigned capital and direct assigned capital.
43 Transcript, Volume 2, page 143, lines 1-9.

4.3 Proposed one-time adjustment to depreciation expense for the Jasper Palisades isolated generation plant

59. ATCO Electric proposed a one-time $7.5 million adjustment to its 2023 depreciation expense to correct an accounting error it made in recording certain Jasper Palisades switchgear assets (that are no longer in service)[44] to an incorrect depreciable asset account.

60. The Commission denies ATCO Electric's proposed adjustment to its 2023 depreciation expense. As detailed in the reasons that follow, ATCO Electric has failed to persuade the Commission that it is just and reasonable, in the circumstances of this case, for: (i) ATCO Electric to recover the undepreciated capital amounts associated with the Jasper Palisades switchgear assets which arose as a result of its historical accounting errors; and (ii) current Alberta electricity ratepayers to bear the financial burden of ATCO Electric's accounting errors in relation to the Jasper Palisades switchgear assets.

Background – Supply of electricity to Jasper

61. Prior to 2021, the Municipality of Jasper, Jasper National Park and the surrounding area were not connected to the Alberta Interconnected Electric System (AIES). Since 1975, these areas received electricity service from natural gas and diesel-powered generation produced by the Jasper Palisades Power Plant, which ATCO Electric owned and operated.

62. The Jasper Palisades Power Plant is an isolated generating unit under the *Isolated Generating Unit and Customer Choice Regulation* (*Iso Gen Regulation*).

63. In 2018, the Commission approved an application filed by ATCO Electric and AltaLink to construct and operate a transmission line, the Jasper Transmission Interconnection, that would connect the Municipality of Jasper, Jasper National Park and the surrounding area to the AIES.[45] The Jasper Palisades Power Plant would no longer be required once the Jasper Transmission Interconnection was placed into service.

64. In 2019,[46] the Commission authorized ATCO Electric to discontinue operation of the Jasper Palisades Power Plant, and to decommission and salvage it.

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44 The Jasper Palisades Power Plant comprises several isolated generation units.

45 Decision 22125-D01-2018. Jasper Interconnection Project, Alberta Electric System Operator, Needs Identification Document, Application 22125-A001; AltaLink Management Ltd., Facility Applications, Applications 22125-A002 and 22125-A003; ATCO Electric Ltd., Facility Applications, Applications 22125-A004 to 22125-A006, May 4, 2018.

46 Decision 24183-D03-2019: ATCO Electric Ltd., Decommission and Salvage of Palisades Power Plant, Proceeding 24183, Application 24183-A001, January 21, 2019.

Background – depreciation

65. At the time of ATCO Electric's last depreciation study, it anticipated that 2020 would be the year of final retirement for all of the assets comprising the Jasper Palisades Power Plant.[47] [48] [49] Accordingly, commencing in 2021, ATCO Electric set a depreciation rate for all Jasper Palisades Power Plant asset accounts to zero per cent, notwithstanding that ATCO Electric intended to continue to record an annual amortization of reserve differences true up amount over the 2023-2025 test period. ATCO Electric indicated that it would calculate an updated amortization of reserve differences true-up amount for the Jasper Palisades Power Plant asset accounts at the time of its next depreciation study. ATCO Electric anticipated that it would file its next depreciation study in its next GTA (commencing in 2026).[50]

66. The currently approved annual amortization of reserve differences true-up for the Jasper Palisades Power Plant assets, which was calculated as of December 31, 2018,[51] consists of a refund of "life" depreciation expense of $2.05 million and collection of "net salvage" depreciation expense of $3.37 million; or a net $1.32 million increase to depreciation expense in each of 2023-2025.

67. For greater clarity, the recovery of the net $1.32 million in each of the test years is part of the Commission-approved NSA. These amounts will be recovered through the amortization of reserve differences mechanism, do not include amounts requested by ATCO Electric in respect of the Jasper Palisades switchgear assets discussed below, and are unaffected by the findings below.

Discovery and nature of error

68. ATCO Electric advised that it discovered an accounting error "in the process of preparing the sales offering for the Jasper Palisades Isolated Generation plant."[52] ATCO Electric indicated that the error arose because certain Jasper Palisades assets (primarily "switchgear assets")[53] had

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47 Proceeding 24964, Exhibit 24964-X0033.02, Appendix D, Depreciation Study, PDF pages 43-44: In ATCO Electric's depreciation study, the year of final retirement for all Jasper Palisades power plant isolated generation facilities was expected to be 2020.

48 Decision 24964-D02-2021, Appendix 3, PDF pages 106-106. Please refer to the following accounts for Jasper Palisades isolated generation plant facilities:
USA 341.10 – Gas turbine structures;
USA 341.20 – Internal combustion structures – Palisades;
USA 343.10 – Gas turbine generators;
USA 342.20 – Internal combustion fuel holders – Palisades;
USA 343.25 – Internal combustion generators – Palisades;
USA 345.10 – Gas turbine accessory electric equipment;
USA 345.20 – Internal combustion accessory electrical equipment - Palisades;
USA 346.10 – Gas turbine miscellaneous equipment and
USA 346.20 – Internal combustion miscellaneous electrical equipment – Palisades.

49 Exhibit 27062-X0529, AET-AUC-2023FEB01-001, Table 1, PDF page 5: As of December 31, 2022, for all Jasper Palisades isolated generation assets there is Original Cost of $52.8 million, Accumulated Depreciation – Life of $41.4 million and Accumulated Depreciation – Net Salvage of $17.2 million for a net book value of $(5.9) million before additional sales proceeds or dismantling costs.

50 Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001(e), PDF page 6.

51 Exhibit 27062-X0015.02, MFR Schedule 6-4.1, Life Analysis, and Schedule 6-4.2, Net Salvage Analysis.

52 Exhibit 27062-X0014.02, application, PDF page 297, paragraph 285.

53 Exhibit 27062-X0014.02, application, PDF page 297, paragraph 285: "… AET identified that a switchgear building and associated equipment for the Palisades Isolated Generation plant had been misclassified as transmission assets upon capitalization rather than Isolated Generation assets."

been incorrectly recorded in the transmission function and general plant accounts, rather than the correct Jasper Palisades internal combustion accessory electrical equipment account (USA 345.20). ATCO Electric submitted that, as a result, from 2009 to 2020 these switchgear assets were depreciated incorrectly at depreciation rates consistent with longer-lived transmission and general plant assets, rather than at a depreciation rate reflecting the expected shorter-lived Jasper Palisades Power Plant assets. ATCO Electric indicated that in 2021 it transferred the historical cost and accumulated depreciation balances for these switchgear assets from the four incorrect transmission and general plant accounts to the correct account, being the Jasper Palisades internal combustion accessory electrical equipment account (USA 345.20), and which is applicable to the switchgear assets at issue.[54]

69. Had the assets been placed in the correct account from the outset, they would have been fully depreciated by the end of 2020. However, the accounting error resulted in a remaining undepreciated balance of $7.5 million at the time all Jasper Palisades Power Plant assets were removed from service. This was acknowledged by ATCO Electric in its application where it stated:

> AET has included a one-time adjustment of $7.5 million to its 2023 depreciation expense.… Had the switchgear building and associated equipment been appropriately classified as a Jasper Palisades Isolated Generation asset in Account 345.20 Accessory Electric Equipment in AET's last depreciation study filed in the 2020-2022 GTA, its original cost would have been fully reserved / depreciated by December 31, 2020 - the updated year of final retirement for the Jasper Palisades Isolated Generation site forecast in AET's last depreciation study.[55]

70. The following table identifies the historical cost and accumulated depreciation associated with each of the four (incorrect) accounts in which the switchgear assets resided, between 2009 and 2020, as well as the total combined amount that was transferred into the correct account, being USA 345.20.

Table 2. Commission-prepared summary of historical cost and accumulated depreciation for Jasper Palisades switchgear assets as of 2020 on a mid-year basis

	USA 353.00 Transmission substation	USA 353.10 Communication equipment	USA 390.00 Structures and improvements	USA 350.10 Land rights	USA 345.20* Jasper Palisades internal combustion accessory electrical equipment Total historical cost and accumulated depreciation transferred from incorrect accounts.
	($ million)				
Historical cost of additions:					
2009	9.6	0.4			10.0
2010			0.1		0.1
2015	0.1		0.1		0.2
Total historical cost 2020	9.7	0.4	0.2	0.0	10.3

[54] Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), PDF pages 616-617.
[55] Exhibit 27062-X0014.02, application, PDF page 297, paragraphs 285-286.

	USA 353.00 Transmission substation	USA 353.10 Communication equipment	USA 390.00 Structures and improvements	USA 350.10 Land rights	USA 345.20* Jasper Palisades internal combustion accessory electrical equipment Total historical cost and accumulated depreciation transferred from incorrect accounts.
Less: accumulated depreciation as of 2020	2.6	0.2	0.0	0.0	2.8
Net book value 2020	7.1	0.2	0.2	0.0	7.5

Source: Summarized from Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112, tables 1 and 2, PDF pages 619-620. Rounding may result in zero amounts reported.
*In Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001, footnote to Table 1, PDF page 4, ATCO Electric has also identified this account as Account 345.25: "The historical cost and accumulated depreciation of the switchgear building and associated equipment are included in Account 345.25 (USA Account 345.20) Int Combust Accessory Electric Equipment. …"

Request to recover $7.5 million through the tariff

71. ATCO Electric submitted that it is just and reasonable for the Commission to approve the proposed $7.5 million one-time true-up of the switchgear assets in its 2023 tariff because, among other things, ATCO Electric must have a reasonable opportunity to recover the costs and expenses associated with its prudent capital investment in the utility, including depreciation.

72. In the alternative, ATCO Electric argued that it was entitled to this amount under Section 22 of the *Iso Gen Regulation*, and would seek recovery of amounts not approved in this decision in a forthcoming *Iso Gen Regulation* application.

73. ATCO Electric explained that its proposed $7.5 million one-time true-up in 2023 of the Jasper Palisades switchgear assets would align with the anticipated timeline of the settlement process outlined in Section 22 of the *Iso Gen Regulation*. The provisions of the regulation allow ATCO Electric to seek recovery of (or provide payment for) any remaining net book value (NBV), which it had not recovered (or had over-recovered) from (to) the Balancing Pool. ATCO Electric expected that the currently outstanding decommissioning and salvaging activities for the Jasper Palisades isolated generation site would be completed in 2024. Accordingly, it said that the timelines between the Balancing Pool settlement and final decommissioning and salvaging activities were generally aligned with ATCO Electric's proposed 2023 true-up.[56]

74. As noted earlier, ATCO Electric stated that at the time of its next depreciation study, it will update the amortization of reserve differences true-up to incorporate any additional information available with respect to remediation and reclamation of the entire Jasper Palisades isolated generation site. This will result in a final true-up for the amortization of reserve differences for all Jasper Palisades isolated generation facilities and will occur after reclamation and remediation is complete, forecast as 2030.[57]

75. ATCO Electric further clarified that once the Jasper Palisades power plant isolated generation site has been "fully decommissioned, remediated and reclaimed" in 2030, all Jasper

[56] Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), (b), PDF pages 616-617 and 620.
[57] Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001, PDF pages 5-6.

Palisades isolated generation plant assets will be retired from the accounting records.[58] Until that time, ATCO Electric indicated that the historical cost of all Jasper Palisades isolated general plant asset accounts and the corresponding accumulated depreciation balances will remain on the accounting records of ATCO Electric, notwithstanding that the assets are no longer being used for the provision of utility service. This includes those assets that were held and depreciated within the wrong accounts during the period 2009-2020.

76. ATCO Electric submitted that Section 20 of the *Iso Gen Regulation* provides it with an entitlement to recover the undepreciated capital cost of an isolated generating unit, which it said is "even stronger and more specific" than the right of every owner of an electric utility, pursuant to Section 122 of the *Electric Utilities Act*, to a reasonable opportunity to recover its capital investment.[59] Specifically, ATCO Electric submitted that Section 20 of the *Iso Gen Regulation* constrains the Commission's authority to deny ATCO Electric's entitlement to the undepreciated capital costs of the Jasper Palisades switchgear assets at issue (which ATCO Electric submitted was $7.5 million). While ATCO Electric indicated that it was reasonable for the Commission to approve the $7.5 million as part of ATCO Electric's tariff in this proceeding, ATCO Electric argued that if the Commission did not approve the full amount, then it was entitled to collect the outstanding amount in a forthcoming Section 20 *Iso Gen Regulation* application.[60]

77. The CCA, the UCA and The City of Calgary, opposed ATCO Electric's request for a $7.5 million one-time adjustment to its depreciation expense.

78. Dustin Madsen, on behalf of the CCA, likened the proposed one-time adjustment to a "write-off of unrecovered investment" as opposed to a depreciation charge. Further, D. Madsen submitted that the requested adjustment does not fall within the amortization of reserve differences mechanism: first, because the amortization for reserve differences is intended to correct for a change in estimate, not for the correction of an error and second, because the Jasper Palisades assets no longer exist. Specifically, D. Madsen indicated that "it would be inappropriate to amortize the remaining cost of an asset over the life of other assets when the asset in question is no longer in service."[61] D. Madsen stated that the NBV of the assets should be recognized as a loss in 2021, not as an adjustment in any period in 2023 to 2025.

79. The UCA stated that ATCO Electric has already had an opportunity to recover the cost of the switchgear assets and was effectively asking to retroactively adjust past approved revenue requirements in the year 2023. The UCA also alleged that ATCO Electric would have earned a return during 2020-2022 on the switchgear assets in addition to charging depreciation expense for 2021 and 2022. This was in addition to ATCO Electric asking for the full $7.5 million (as of 2020) which it said constituted "double dipping" that the Commission should not permit.[62] The Commission discusses ATCO Electric's over recovery of return on rate base as a result of the rate base value declining more slowly than it would have had the switchgear assets been in the correct account in paragraph 94 below.

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58 Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), (b), PDF pages 616-617 and 620.
59 Transcript, Volume 2, pages 145-149.
60 ATCO Electric anticipated that further applications to settle amounts owing to and received from the Balancing Pool under the *Iso Gen Regulation* would be completed by 2024.
61 Exhibit 27062-X0450, CCA evidence of Dustin Madsen, PDF page 79.
62 Transcript, Volume 1, pages 95-97.

80. According to Calgary, the question to be addressed is who should bear the "responsibility and risk for the utility error or misallocation"[63] with respect to the switchgear assets. Calgary argued that ATCO Electric has had a number of opportunities to adjust for the "misallocation," and stated that the Commission elsewhere has set a two-year limitation period[64] for adjustments to the extent they arose due to the utility's own error. Calgary questioned whether, because the assets were no longer in service after 2020, the costs for those assets should be recovered from ratepayers who will receive no benefit of any service from those assets.[65] Calgary also made submissions with respect to the appropriateness of using of the amortization of reserve differences mechanism in the circumstances of this case.

Commission findings

81. For the reasons that follow, the Commission is not persuaded that it is reasonable to allow ATCO Electric to recover $7.5 million in depreciation expense (through a one-time adjustment or otherwise) related to the Jasper Palisades amounts that were incorrectly accounted for, and finds that the correct undepreciated balance in relation to the Jasper Palisades switchgear assets should be $0.

The unrecovered capital for the switchgear assets arose because of ATCO Electric's error

82. First, the Commission disagrees with ATCO Electric's description of the circumstances leading up to its request for a one-time collection of depreciation expense related to the Jasper Palisades switchgear assets. In particular, the Commission finds ATCO Electric's explanation of how the $7.5 million undepreciated balance arose to be incomplete. ATCO Electric emphasized its right to recovery of its prudently incurred investment in these assets and either downplayed, or offered no mention whatsoever of, specific events subsequent to that investment which, in the Commission's view, resulted in the $7.5 million undepreciated balance that it now seeks to collect from ratepayers.

83. In the Commission's view, the $7.5 million amount arose from the following three events:

(i) ATCO Electric's investment in the switchgear assets in 2009;

(ii) ATCO Electric's error in booking the investment in these assets into four incorrect uniform system of accounts at the time the investment was made. This resulted in ATCO Electric depreciating the investment at a rate that returned capital to ATCO Electric more slowly compared to the depreciation rate that would have been applied had the investment been booked into the correct Jasper Palisades uniform system of account; and

(iii) ATCO Electric's ongoing failure to discover and correct its error over a continuous period of at least 12 years, despite reasonable opportunities to do so, such that the

[63] Transcript, Volume 1, page 99.
[64] Transcript, Volume 1, page 101, referring to Decision 2006-042: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd., (This Decision is also applicable to Direct Energy Regulated Services and AltaGas Utilities Inc.), Deferred Gas Account Limitation Period, Application 1407502, May 11, 2006.
[65] Transcript, Volume 1, page 101, referring to Decision 2006-042.

> accumulated depreciation for the Jasper Palisades switchgear assets was $7.5 million less than it would have been had the assets been booked into the correct account.

84. Without events (ii) and (iii) above, ATCO Electric would not have applied to collect $7.5 million in this proceeding for the switchgear assets, as detailed in paragraph 68 above.

85. In so far as the existence of reasonable opportunities for ATCO Electric to discover and correct its mistake is concerned, it is noteworthy that, in 2016 in Decision 20272-D01-2016, the Commission directed ATCO Electric to confirm that its then calculated accumulated depreciation balances for the Jasper Palisades Power Plant were accurate. The Commission stated:

> 660. The Commission accepts ATCO Electric's revised year of final retirement of 2018 and net negative salvage estimates for Jasper Palisades generation assets as being related to the energization of the Jasper transmission interconnection thereby eliminating the need for the Jasper Palisades isolated generation plant.
>
> 661. However, as part of ATCO Electric's compliance filing, **the Commission requires confirmation that ATCO Electric's calculated accumulated depreciation balances related to life and net salvage as of December 2017 are correct in that approximately $12.7 million in life and net salvage remains to be recovered in the year 2018 and beyond. ATCO Electric is directed to provide the requested confirmation and explain why the unrecovered balance is so large. ATCO Electric is also directed to describe the proposed method and period of recovery of the $12.7 million.** [emphasis added]

86. Despite being required to verify its unrecovered balance regarding all of the Jasper Palisades Power Plant assets, ATCO Electric did not disclose any error with respect to the (misclassified) switchgear assets when it responded to this Commission direction in Proceeding 22050. There, ATCO Electric did disclose an error related to the balance of unrecovered investment, but that error did not relate to the switchgear assets at issue in this proceeding. ATCO Electric disclosed the following:

> AET has updated 20272-X1275.01 with the revised depreciation rates reflecting the 2018 year of final retirement. AET notes that 20272-X1275.01 erroneously excluded depreciation incurred in 2014. Inclusion of depreciation incurred in 2014 as well as the updated rates as provided by Gannett Fleming results in an updated forecast of $14.2 million rather than $12.7 million as indicated in the above direction.
>
> As shown in Schedule 6-3 of AET's 2015-17 compliance filing, AET's previous depreciation parameters were based on a forecast year of final retirement of 2026 to 2038 depending on the asset class. **With the proposed Jasper interconnection project scheduled to be completed by 2018, AET has adjusted the year of final retirement to 2018 and is recovering the remaining undepreciated capital cost and associated net salvage over this accelerated time frame**.
>
> AET will update the amount to be recovered in 2018 as part of its next GTA. At that time, it is expected that forecasts for future removal costs and capital requirements will be known with more certainty.[66] [emphasis added]

[66] Proceeding 22050, Exhibit 22050-X0019.01, AET 2015-2017 GTA Compliance Filing, PDF pages 69-70.

87. Had ATCO Electric, during the course of its response to the Commission direction, uncovered the error and thus properly verified the remaining unrecovered balances for all its Jasper Palisades isolated generation assets, including the switchgear assets, the matter would have been placed squarely before the Commission much earlier and under a different set of factual circumstances.

88. The Commission also disagrees with ATCO Electric that the Commission must approve its requested one-time collection to comply with the *Electric Utilities Act*, Section 122(1)(a). That section requires the Commission to have regard for the principle that a tariff approved by the Commission must provide a utility with a reasonable opportunity to recover its prudently incurred costs and expenses associated with capital related to the owner's investment in the electric utility, including depreciation.

89. ATCO Electric had a reasonable opportunity to recover its investment in the switchgear assets under its tariff from 2009 to 2020. The Commission's approved depreciation parameters for the Jasper Palisades assets, from which depreciation rates for these assets were derived, would have fully returned ATCO Electric's capital in the switchgear assets, had ATCO Electric not erroneously placed the switchgear assets into four incorrect asset accounts. There was no way for the Commission or ratepayers to know that the investment was being depreciated in the incorrect accounts. When the Commission flagged a concern regarding the size of the undepreciated balance in the Jasper Palisades isolated generation asset accounts, ATCO Electric did not apply sufficient diligence in addressing the Commission's direction to detect its longstanding error. The Commission finds that ATCO Electric had a reasonable opportunity to recover its investment in the assets, but through its own errors, on two separate occasions in relation to the same assets, was not able to realize on that opportunity.

90. When viewed in this context, the error that resulted in the $7.5 million in undepreciated capital costs associated with the switchgear assets can more fairly be characterized as ATCO Electric's forgone reasonable opportunity to recover its prudently incurred investment related to the switchgear assets under its approved tariff from 2009 to 2020.

Should Alberta ratepayers bear the risks associated with ATCO Electric's error?

91. In the Commission's view, the fundamental question raised by ATCO Electric's request is whether it is just and reasonable for Alberta's current ratepayers to bear the risk and associated costs of an electric utility's accounting error in relation to assets that were used by past ratepayers, whatever the circumstance. In other words, does Section 122 of the *Electric Utilities Act* guarantee the recovery of[67] a utility's investment, regardless of whether that utility exercised reasonable diligence in terms of its accounting practices, in relation to that investment? ATCO Electric did not persuade the Commission that this should be the case.[68]

[67] Section 122 of the *Electric Utilities Act* requires the Commission to provide the owner of an electric utility with a reasonable opportunity to recovery of and a return on its investment in the electric utility, but the Commission is here only concerned with the recovery "of" ATCO Electric's investment.

[68] The Commission has considered the evidence of ATCO Electric's depreciation expert, Larry Kennedy, regarding transfers of assets necessitated and/or occasioned by new depreciation studies, but finds that evidence to be neither particularly relevant nor helpful in the circumstances of ATCO Electric's current request.

92. Under the legislative scheme, the Commission has broad discretion to set just and reasonable rates.[69] In the circumstances of this case and for the reasons below, the Commission finds it neither just nor reasonable to impose upon current Alberta ratepayers, the costs associated with ATCO Electric's ongoing and discoverable accounting error. The Commission equally finds that it is neither just nor reasonable to shield ATCO Electric from the consequences of its accounting error and associated failure to take advantage of the reasonable opportunities available to it to recover its investment. ATCO Electric had a span of more than a decade in which to recover its capital investment. It is now requesting that current Alberta ratepayers bear (i) the risk of such error (over which Alberta ratepayers had no control or awareness); and (ii) the associated cost burden of keeping ATCO Electric financially whole despite having caused the error itself. In other words, ATCO electric is seeking to use Section 122 of the *Electric Utilities Act*, or, in the alternative, the *Iso Gen Regulation*, to be fully indemnified for its own errors in relation to the accounting treatment of the switchgear assets.

Incentives

93. The Commission finds that placing costs associated with ATCO Electric's error on Alberta ratepayers provides the wrong incentives to ATCO Electric. Doing so, does not incent ATCO Electric:

(i) to accurately record its investment in the proper USA account applicable to that investment;

(ii) to proactively review its books and accounts for errors either on its own initiative or in response to Commission directions; and

(iii) to raise with the Commission any errors that are found, as soon as possible after they are detected.[70]

94. The Commission's concerns about incentives are elevated in this case. Here, ATCO Electric has earned a greater return than it otherwise would have earned had it placed the switchgear assets in the correct account in 2009. This is because the switchgear assets were being depreciated (in the incorrect transmission accounts) over a longer period of time resulting in an overstated rate base between the years 2009 and 2022. As a result, since 2009 ATCO Electric has benefited from a higher return on rate base in relation to the Jasper Palisades Power Plant switchgear assets than would otherwise be the case had the assets been depreciated in a manner consistent with Commission-approved depreciation parameters. Indeed, ATCO Electric has asked to be held whole for the return of its capital investment without consideration of (and without accounting for) the additional return on rate base it has earned since 2009.[71]

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[69] See, e.g., *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142, paragraph 91; *ATCO Electric Ltd v Alberta Utilities Commission*, 2023 ABCA 129, paragraph 44.

[70] The Commission is not suggesting that in the present instance ATCO Electric in any way delayed disclosing to the Commission the particulars of its accounting error upon having discovered it. The Commission's point here relates solely to the absence of an incentive for prompt disclosure of newly discovered accounting errors if indemnification for those errors is automatic whatever the circumstances.

[71] In its response to Exhibit 27062-X0353, AET-UCA-2022SEP27-006(a), PDF pages 4-6, ATCO Electric provided "a schedule separately indicating the impact to the depreciation and return on rate base components of the 2020 through 2022 revenue requirement related to the Jasper Palisades assets if they had been properly recorded in the correct property accounts" to be a net increase in revenue requirement of $1.4 million.

Intergenerational equity

95. The Commission is also concerned about intergenerational equity issues that would arise if current Alberta ratepayers were required to bear the risk of ATCO Electric's error in this case. If the Commission were to approve ATCO Electric's request, Alberta's 2023 ratepayers would be responsible for paying $7.5 million attributable to switchgear assets that are no longer used to provide electricity service. ATCO Electric also seeks to recover the costs of assets from a generation of ratepayers, some of whom will have received no benefit whatsoever from the Jasper Palisades switchgear assets. The duration of the accounting error (over 12 years) and the magnitude of the amount to be recovered relative to the original historical cost of the assets[72] are also significant considerations for the Commission in coming to this finding.

Improper use of the amortization reserve for differences mechanism

96. ATCO Electric also argued that its adjustment was appropriate because it would be consistent with the amortization reserve for differences mechanism.

97. The amortization of reserve differences is a mechanism approved by the Commission that, in general terms, is used by utilities to recover no more or no less than their full capital investment in utility assets. The mechanism trues up differences between estimates of depreciation parameters, such as estimated versus actual services lives of assets, among other things.[73] This implies that the depreciation parameter elements (used by the utility to determine depreciation rates) are interim until better information becomes available. In the case before the Commission, however, ATCO Electric seeks a permanent true-up of capital costs that is unrelated to past mis-estimates of depreciation parameters.

98. The Commission finds that ATCO Electric's request is inconsistent with the purpose of the amortization of reserve differences mechanism, in the specific circumstances of this case and for reasons already discussed. In particular, the Commission rejects ATCO Electric's suggestion that this mechanism, in effect, confers a specific entitlement that provides it with an indemnity for its errors related to mass property accounting and depreciation practices.

The Iso Gen Regulation does not entitle ATCO Electric to recovery of the undepreciated capital

99. ATCO Electric relied heavily on the *Iso Gen Regulation* in support of its request. ATCO Electric points to the word "entitle" in Section 20 of the *Iso Gen Regulation*, as constraining the meaning of undepreciated capital cost, under both Section 122 of the *Electric Utilities Act* and Section 20 of the *Iso Gen Regulation*.

100. The Commission disagrees with ATCO Electric's interpretation.

101. The *Iso Gen Regulation* does not confer an unconstrained right on ATCO Electric to recover from the Balancing Pool amounts recorded on its books of account as undepreciated capital.

102. Section 20(1)(a)(i) of the *Iso Gen Regulation* is the relevant provision that applies in this case. Section 20(1)(a)(i) provides that the owner of an isolated generating unit is entitled to

[72] As noted in Table 4 above: As of 2020, the $7.5 million of undepreciated capital of the switchgear assets comprises $10.3 million historical cost less accumulated depreciation of $2.8 million.

[73] These include average service life, Iowa curve, net salvage per cents and capital-related forecasts.

receive from the Balancing Pool the undepreciated capital cost of the isolated generating unit. The Commission observes that the phrase "is entitled to receive" expresses a right to receive something or be benefited in some respect, and puts emphasis on the subject of the provision's claim. In this context, Section 20 of the *Iso Gen Regulation* creates a legal right for the owner to receive payment from the Balancing Pool (this is the right to receive a benefit) for the amount of the undepreciated capital cost of the generating unit, **as determined by the Commission** (this is the quantum of the benefit), which the Balancing Pool must honour.

103. The Commission emphasizes that the benefit at issue is "as determined by the Commission." The regulation confers discretion upon the Commission to make a determination about the amount of undepreciated capital cost of the isolated generating unit. The regulation would not have conferred upon the Commission that discretion, if the Commission had no choice but to accept that cost from ATCO Electric's books of account. The Commission is not persuaded by ATCO Electric's argument that the regulation's use of language highlighting an owner's claim to a benefit changes the nature of the benefit itself, particularly given that the Commission has discretion to determine the amount of benefit.

104. The discretion conferred on the Commission allows the Commission to order an amount to be paid to the Balancing Pool by, or from the Balancing Pool to, the owner of an isolated generating unit in cases where that amount is different from the amount set out on the owner's books of account. While in the normal course there is often no difference between the amount on an owner's books of account and what the Commission would order to be paid to or by the Balancing Pool, the circumstances of this case are not the normal course given ATCO Electric's failures already outlined.

105. In addition, the Commission is mindful that the *Iso Gen Regulation* is made under the *Electric Utilities Act.* It is presumed that subordinate legislative provisions are meant to work with their own enabling legislation. If conflict is unavoidable, in the absence of a contrary legislative intent, the statutory provision prevails.[74] Conflict should be avoided through interpretation, rather then resolved through paramountcy, if possible.

106. In reaching its conclusion on ATCO Electric's ability to recover any of the undepreciated capital cost of the switchgear assets, the Commission is of the view that the undepreciated capital cost of these assets is the same under either the *Electric Utilities Act* or the *Iso Gen Regulation*. Otherwise, this would mean that for regulatory purposes the same assets can have two different values. In the Commission's view, this result is nonsensical. Whether the costs are refunded or recovered through ATCO Electric's tariff or paid to or from the Balancing Pool, in either case recovery flows to Alberta ratepayers through the Independent System Operator tariff.[75] The amount of undepreciated capital cost should be the same for tariff-making purposes under the *Electric Utilities Act* and the *Iso Gen Regulation*.

Conclusion

107. The Commission finds that the $7.5 million of undepreciated capital cost connected with Jasper Palisades switchgear assets is not recoverable from current ratepayers and is a permanent

[74] *Friends of Oldman River Society v Canada (Minister of Transport)*, [1992] 1 SCR 3, paragraph 38.
[75] Transcript, Volume 1, page 29.

capital disallowance. ATCO Electric is directed to remove the historical cost and accumulated depreciation related to these assets from the accounting records of its regulated utility assets.

5 Compliance with prior directions

108. In its application, ATCO Electric responded to one direction issued in Decision 24964-D01-2021[76] and to four directions issued in Decision 24964-D02-2021[77] with respect to the ATCO Electric 2020-2023 GTA, one direction from Decision 26264-D01-2021[78] regarding the ATCO Electric 2018-2019 General Tariff Application Second Compliance Filing, and two directions from Decision 26519-D01-2021[79] from the ATCO Electric Stage 2 Review and Variance of 2018-2019 General Tariff Application Compliance.

109. The Commission asked ATCO Electric to confirm that the negotiated settlement made no determination in relation to compliance with prior outstanding Commission directions. In response, ATCO Electric stated:[80]

> … The NSA is intended to be a comprehensive settlement of AET's revenue requirement, except for the Excluded Matters. As such, to the extent that the Commission were to consider that AET's compliance with any prior Commission direction impacts AET's 2023-2025 revenue requirement, then the NSA is intended to settle any such revenue requirement impact. Regardless, however, should the Commission consider that further actions are required by AET in respect of the above-reference directions, AET submits that such further actions could be the subject of a further Commission direction, including for AET's next general tariff application.

110. In the current decision, the Commission has reviewed the record as it pertains to all outstanding directions. Where the Commission has identified issues or concerns with ATCO Electric's responses to a direction, the Commission has provided reasons for its specific findings. Where no specific finding is provided, the Commission has determined that ATCO Electric's responses comply with the directions given and that no further action is required.

111. In Decision 26519-D01-2021, the Commission issued the following direction:[81]

> In the Commission's July 8, 2021, letter, the Commission took note of ATCO Electric's treatment of the equity portion of AFUDC as a temporary rather than a permanent tax difference, despite acknowledgment by ATCO Electric that the equity portion of AFUDC is a permanent difference. The Commission confirms that it will consider, in ATCO Electric's next GTA, whether the collection of future income tax should continue. The Commission's consideration will also include whether ATCO Electric should be permitted to continue to treat the equity portion of AFUDC as a temporary rather than a

[76] Decision 24964-D01-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 1, 2021.
[77] Decision 24964-D02-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021.
[78] Decision 26264-D01-2021: ATCO Electric Ltd. 2018-2019 General Tariff Application Second Compliance Filing, Proceeding 26264, June 29, 2021.
[79] Decision 26519-D01-2021: ATCO Electric Ltd., Stage 2 Review and Variance of 2018-2019 General Tariff Application Compliance, Proceeding 26519, October 6, 2021.
[80] Exhibit 27062-X0505, AET Information Responses Round 2 to AUC, AET-AUC-2023JAN25-002, PDF page 6.
[81] Decision 26519-D01-2021, paragraph 30.

permanent tax difference in the calculation of its tax expense. ATCO Electric is therefore directed to provide relevant evidence on this issue in its next GTA.

112. In response to Decision 26519-D01-2021, Direction 3, ATCO Electric stated:[82]

> Given AET has proposed to discontinue collection of FIT in this application, the distinction between permanent and temporary differences is no longer relevant. Amounts collected based on the previous classification are held in no cost capital and will be refunded when appropriate. Refer to Section 7 where AET has proposed to discontinue the collection of FIT for the Test Period.

113. The Commission disagrees with ATCO Electric's assertion that the distinction between permanent and temporary differences is no longer relevant. First, ATCO Electric stated, in response to the direction, that the previously collected FIT amounts accumulated in the reserve account (no cost capital) will be refunded when appropriate. In its application, however, ATCO Electric did not provide a refund proposal nor an appropriate time to refund the accumulated FIT amounts. Ratepayers have funded the FIT reserve balance to offset current tax expense, at some future date, when the net income for tax purposes exceeds the calculated financial accounting net income. At a minimum, it would be appropriate for the accumulated FIT amounts in the reserve to be refunded to ratepayers when that occurs, regardless of whether ATCO Electric continues to collect FIT expense. In addition, Schedule 5 – Summary of utility income tax, in Rule 005[83] requires utilities to report on their permanent differences. The MFRs filed with a utility's tariff application should provide detailed support of the information disclosed in that utility's Rule 005 submissions.

114. ATCO Electric is directed in its compliance filing to this decision, and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences. This also includes presenting the equity portion of the AFUDC tax adjustment as a permanent difference.

6 Other – Proceeding efficiencies

115. The Commission continues to emphasize the importance of increasing regulatory efficiency. It has implemented a number of changes to its application review processes, including its GTA review process. Examples of the Commission's efforts in the current proceeding include the use of an issues list, establishing a limit on the number of IRs, limiting parties to one round of IRs, encouraging parties from the start of the proceeding process to pursue – to the extent possible – a negotiated settlement of the issues, holding a virtual process meeting regarding ATCO Electric's request for an extension to respond to IRs, undertaking a fully written evidentiary process, and the use of oral argument and reply argument.

116. The Commission emphasizes, however, that regulatory efficiency is a shared responsibility and the ability to achieve a more streamlined regulatory process requires effort and commitment by the Commission, applicants and interveners. For certain portions of ATCO Electric's application, the record was sufficient to support ATCO Electric's applied-for amounts. However, the Commission also identified deficiencies in the information on the record and was

[82] Exhibit 27062-X0014.02, application, PDF page 174.
[83] Rule 005: *Annual Reporting Requirements of Financial and Operational Results,* Appendix 1 – Schedules for an electric utility.

required to request information to consider ATCO Electric's application complete, such as missing business cases and missing IT cost information.

117. The Commission also notes that there were instances where information was ultimately provided, but not without significant process. An example of this is the Commission granting ATCO Electric approximately one month to revise its application for updates to the applied-for inflation factors and fuel prices, even though ATCO Electric should have filed its application using the inflation factors and fuel prices that it considered would result in just and reasonable rates when its application was first submitted. In addition, in its November 21, 2022, letter, the Commission identified a number of responses that required further and better responses, and also provided ATCO Electric further opportunity to provide more substantive responses to other Commission IRs that it deemed to be deficient or created factual discrepancies and further questions.[84]

118. The Commission has no statutory obligation to provide ATCO Electric the opportunity to repair its deficient responses to IRs or even to point them out after they have been made. ATCO Electric should consider the opportunity provided by the Commission to supplement responses an exception, and not an expectation going forward. The Commission expects that an applicant will provide all information necessary to support its requests in its application and will fully respond to all Commission IRs at the first instance or to clearly explain if the information cannot be provided. The onus is on ATCO Electric to show that its forecast tariffs are just and reasonable, and it must provide the necessary supporting evidence to make its case.

119. In the following two subsections, the Commission describes, as specifically as possible, what better information ATCO Electric must provide should it seek approval of costs for similar projects or programs in future GTAs. The Commission's intention is not to encourage ATCO Electric to file a greater volume of information. Rather, it is to ensure that future proceedings are more efficient, which requires a record that contains the specific and relevant information necessary for the Commission and parties to test the applied-for revenue requirement amounts and for the Commission to be able to more efficiently and effectively adjudicate ATCO Electric's GTAs.

6.1 Capital information

120. The Commission observed, in its initial review of ATCO Electric's application, that some of ATCO Electric's capital program business cases lacked specific information to evaluate their reasonableness. In several instances, ATCO Electric's business cases for individual projects also included several subprojects. However, in other instances, ATCO Electric aggregated the costs of several subprojects into a single line item identified as a capital expenditure (on a project level and not on a subproject level). This type of aggregation impairs the ability of the Commission and parties to scrutinize ATCO Electric's forecast costs.

121. In its July 13, 2022, letter,[85] the Commission directed ATCO Electric to provide the following supplemental information for each capital program, consistent with the requirements of Bulletin 2006-25:[86]

[84] Exhibit 27062-X0442, Process for further and better responses to Commission information requests.
[85] Exhibit 27062-X0242, AUC letter - Further process.
[86] Bulletin 2006-25, Announcing the Approval in Principle of the Form and Content of a Uniform System of Accounts and Minimum Filing Requirements for Alberta Electric Utilities, July 12, 2006.

(i) CWIP continuity schedule consisting of opening CWIP balances;

(ii) capital expenditures;

(iii) capital additions; and

(iv) closing CWIP balances detailed and identified by each individual project name (and subproject if multiple subprojects are included within a business case), and the applicable project number for all capital categories (transmission capital maintenance, Telecommunication, Supervisory Control and Data Acquisition/ Energy Management System, Direct General Property Plant and Equipment, Software, Buildings).

122. In response, ATCO Electric indicated that the detail requested by the Commission, by project level, was not available for every individual subproject identified in its Business Cases. ATCO Electric was able to provide additional detail in response to the request that was consistent with the level of detail that AltaLink was able to provide in its 2022-2023 GTA. ATCO Electric stated in order to provide the level of detail by each individual project or program identified in its Business Cases, it would have been required to update its Project Management and Regulated Project Accounting processes and procedures, and as a result the requested level of information would only be available for the year 2023 and beyond.[87]

123. ATCO Electric is directed to provide the project CWIP continuity schedules as requested by the Commission in its July 13, 2022, letter,[88] in all future GTA submissions.

6.2 Shared services, head office and common group allocations

124. In this proceeding, the Commission sought to obtain head office and shared services group information through the IR process. ATCO Electric stated it required additional time to respond. In a virtual process meeting, held October 20, 2022, to discuss ATCO Electric's extension request, ATCO Electric made submissions about the scope of work required by ATCO Electric employees and the need to co-ordinate with ATCO Electric's affiliates to complete the responses.[89]

125. Given the past Commission direction, quoted below, the Commission expected ATCO Electric to have the information that was requested in the IRs readily available.

126. In Decision 22859-D01-2018,[90] the Commission stated:

> 49. As noted above, the Commission did not find credible ATCO Electric - Transmission's explanation that it could not reconcile its updated placeholder amounts to the requested common group compliance filing amounts. In this regard, ATCO Electric has not met its onus. The limited information detailing the substantive adjustments that occurred in creating and supporting the entire pool of "common group" FTEs and costs is inadequate in justifying the portion of costs allocated to ATCO Electric's transmission

87 Exhibit 27062-X0243, AET Letter enclosing Supplemental Information.
88 Exhibit 27062-X0242, AUC letter - Further process.
89 Exhibit 27062-X0328, AUC letter - Ruling on ATCO Electric's request for time extension to file responses to information requests.
90 Decision 22859-D01-2018: ATCO Electric Ltd. Transmission Common Group Compliance Filing, Proceeding 22859, March 20, 2018, paragraph 49.

> function. The Commission acknowledges that ATCO Electric - Distribution is under performance-based regulation (PBR) and is only subject to minimum filing requirement (MFR) schedules. However, further information about common costs is required in future GTAs to support the costs allocated to ATCO Electric - Transmission. **ATCO Electric Ltd. is directed, on a go-forward basis, to provide all cost-information for every ATCO affiliate, comprising the total costs and supporting detail, that substantiate and justify the costs allocated to, or from, ATCO Electric's transmission function**.[91] [footnotes removed; emphasis added]

127. The Commission also notes that ATCO Electric's responses to some shared services and head office IRs were deficient. In particular, ATCO Electric's response to an IR asking it to describe new initiatives and services gave no indication of how the identified work or initiative related to transmission utility service.

128. The Commission expects that this information will be provided in compliance with the above direction in ATCO Electric's future GTAs. Should that not be the case, and to promote regulatory efficiency, the Commission cautions ATCO Electric that it may apply Section 6.3 part (b) or (c), of Rule 001 where information that is the subject of an ongoing direction or is otherwise fundamental to its GTA, is not provided as part of its application filings.[92]

7 Order

129. It is hereby ordered that:

(1) ATCO Electric submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023. As detailed in Decision 26573-D01-2023, ATCO Electric is to incorporate the findings, conclusions and directions of the Commission in that decision together with its compliance filing to the Commission's determinations in this decision.

Dated on May 5, 2023.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Vice-Chair

[91] Decision 22859-D01-2018: ATCO Electric Ltd., Transmission Common Group Compliance Filing, Proceeding 22859, March 20, 2018, PDF pages 16-17.
[92] Rule 001: *Rules of Practice*.

(original signed by)

Matthew Oliver, CD
Commission Member

(original signed by)

Vera Slawinski
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. (ATCO Electric or AET) Bennett Jones LLP Osler, Hoskin & Harcourt LLP
Consumers' Coalition of Alberta (CCA) J. Wachowich, KC Bema Enterprises LTD. Emrydia Consulting Corporation
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP InterGroup Consultants
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Industrial Power Consumers Association of Alberta Richard Penn
City of Grande Prairie Michelle Gairdner

Alberta Utilities Commission Commission panel K. Sebalj, Vice-Chair M. Oliver, CD, Commission Member V. Slawinski, Commission Member B. Romaniuk, Acting Commission Member Commission staff J. Graham (Commission counsel) C. Strasser A. Starkov E. Chu E. Davis L. Mullen

Appendix 2 – Virtual oral argument and reply argument – registered appearances

Name of organization (abbreviation) Name of counsel or representative
ATCO Electric Ltd. (ATCO Electric or AET) Deirdre Sheehan
Consumers' Coalition of Alberta (CCA) James Wachowich, KC
Office of the Utilities Consumer Advocate (UCA) Thomas Marriott, KC Keegan Rutherford
The City of Calgary (Calgary) Douglas Evanchuk

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Commission directs ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023. ..... paragraph 13
2. The Commission directs ATCO Electric to maintain the reserve account treatment for 2023, but approves the elimination of the vegetation management reserve beginning in 2024. This transition period will permit the Commission to monitor the vegetation management program to ensure continued alignment of forecast and actual costs and work volumes at the time of the next GTA. For all test period years in the current and next GTA, ATCO Electric is directed to provide the same information that it filed in response to 27062-X0416, updated for the appropriate years. Should significant variances reoccur in the costs and volumes for ATCO Electric's vegetation management program, the Commission may reinstate the past reserve treatment. ..... paragraph 46
3. The Commission finds that the $7.5 million of undepreciated capital cost connected with Jasper Palisades switchgear assets is not recoverable from current ratepayers and is a permanent capital disallowance. ATCO Electric is directed to remove the historical cost and accumulated depreciation related to these assets from the accounting records of its regulated utility assets. ..... paragraph 107
4. ATCO Electric is directed in its compliance filing to this decision, and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences. This also includes presenting the equity portion of the AFUDC tax adjustment as a permanent difference. ..... paragraph 114
5. ATCO Electric is directed to provide the project CWIP continuity schedules as requested by the Commission in its July 13, 2022, letter, in all future GTA submissions. .... paragraph 123

Appendix 4 - NSA

(return to text)



Appendix 4 - NSA

(consists of 23 pages)

NEGOTIATED SETTLEMENT AGREEMENT

ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION

THIS NEGOTIATED SETTLEMENT AGREEMENT for the negotiated settlement of the 2023-2025 General Tariff Application, which is the subject of Alberta Utilities Commission Proceeding No. 27062, is made and entered into as of **January 19, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("**AET**")

- and -

CONSUMERS' COALITION OF ALBERTA (the "**CCA**")

- and -

OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the "**UCA**")

- and -

THE CITY OF CALGARY ("**Calgary**")

- and -

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA ("**IPCAA**")

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

A. AET ("the **Applicant**") submitted its 2023-2025 General Tariff Application ("**Application")** to the Alberta Utilities Commission ("**AUC**" or "**Commission**") on May 19, 2022 for the purpose of

obtaining approval for its revenue requirement for the 2023-2025 Test Period, which is the subject of AUC Proceeding No. 27062;

B. On May 26, 2022, the Commission issued a Notice of Application informing potentially interested parties that it would be considering the Application, and inviting submissions for participation in AUC Proceeding 27062;

C. The CCA, the UCA, Calgary, IPCAA and Grande Prairie (collectively, the "**Interveners**") are participants in Proceeding 27062;

D. On August 5, 2022, the Commission issued an initial process schedule and an issues list for Proceeding 27062 and provided its approval for the Parties to enter into a negotiated settlement process under AUC Rule 018. The Commission directed that:

(i) the following issues be excluded from the negotiated settlement process: (a) removal of the Vegetation Management reserve; and (b) Modifications to the Variable Pay Program reserve; and

(ii) if the Parties negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to.

E. AET filed supplemental information for the Application on July 28, 2022 and an application update on September 6, 2022;

F. AET responded to information requests from the AUC and the Interveners on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022;

G. The Interveners filed evidence on December 2, 2022;

H. The Parties (AET, the CCA, the UCA, Calgary, IPCAA and Grande Prairie) entered into a negotiated settlement process commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022;

I. On December 20, 2022, the Parties reached an agreement in principle for a negotiated settlement on all elements of AET's 2023-2025 GTA, except for specifically excluded matters identified in section 2 below;

J. The term of this settlement is the 2023-2025 Test Years Period ("**Test Period**").

IN CONSIDERATION of the mutual promises made in this negotiated settlement agreement ("**Settlement Agreement**") and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Scope of this Settlement Agreement**

(a) This Settlement Agreement settles all aspects of and relief requested in the Application, except for the Excluded Items identified in section 2 below.

(b) Unless otherwise agreed by the Parties in writing, if the AUC declines to approve this Settlement Agreement in its entirety, the Settlement Agreement will be of no force and effect, in accordance with Section 135 of the *Electric Utilities Act*.

2. **Excluded Matters**

(a) AET and the Interveners agree that the following matters are specifically excluded from this Settlement Agreement:

(i) the removal of the Vegetation Management reserve;

(ii) modifications to the Variable Pay Program reserve; and

(iii) Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant of depreciation related to the Jasper Palisades Isolated Generation Plant;

collectively referred to herein as the "**Excluded Matters**".

3. **Revised Revenue Requirement**

(a) The overall revenue requirement adjustments agreed to in this Settlement Agreement are set out in Schedule 3-1 attached hereto as Appendix "A".

(b) Revised Minimum Filing Requirement ("**MFR**") schedules that reflect the specific adjustments and modifications agreed to herein are attached hereto as Appendix "A". A Summary of Changes to AET's Revenue Requirement is attached as Appendix "B" to this Settlement Agreement.

(c) Except for the Excluded Matters, the Parties agree that the AUC should approve the Application, with the specific adjustments and modifications identified in this Settlement Agreement and in Appendix "A" hereto. The Parties agree to support AET's application to the AUC for approval of this Settlement Agreement.

4. **Specific Adjustments and Modifications**

(a) **Errors and Omissions:** In addition to the adjustments and modifications identified herein, the revenue requirement shall reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130 filed on the record of Proceeding 27062.

(b) **Diesel Fuel Volume Forecast:** The forecast diesel fuel volumes set out in Table 4.2 of the Application, with the corrections identified in response to AET-AUC-2022SEP21-105(d), will be reduced by 5% in each year of the Test Period.

(c) **Fuel Price Deferral Account:** A fuel price deferral account, as proposed in the Application, will be implemented for the Test Period.

(d) **Vacancy Rate:** AET will apply a vacancy rate of 5% in each year of the Test Period. A schedule identifying the impact of the 5% vacancy rate to capital FTEs and O&M FTEs, and to O&M USAs, is attached hereto as Appendix "**C**".

(e) **Inflation Assumptions ("Other"):** Forecast inflation assumptions for "Inflation - Other" will be 4.4% in 2023, 3.0% in 2024, and 2.2% in 2025.

(f) **Information Technology ("IT") Transition Costs:** The Parties agree to the implementation of a temporary deferral account for potential IT transition costs following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025 as described in the Application, with a placeholder amount of $0.00 for such costs in the Test Period. The deferral account will have an opening balance of $0 and the disposition of any non-zero balance in this deferral account will be reviewed as part of AET's next general tariff application, including the prudency and recovery of any such costs incurred in AET's revenue requirement.

(g) **Supervision and Engineering (USA Acct No. 560):** Forecast costs for USA 560 will be $3.3 million in 2023, $3.4 million in 2024, and $3.5 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(h) **Control Centre Operations (USA Acct No. 561):** Forecast costs for USA 561 will be $5.4 million in 2023, $5.6 million in 2024, and $5.8 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(i) **Station Equipment Expenses (USA Acct No. 562):** Forecast costs for USA 562 will be $9.9 million in 2023, $10.0 million in 2024, and $10.1 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(j) **Insurance Premiums (USA Acct No. 924):** Forecast costs for insurance premiums included in USA 924 will be $5.3 million for 2023, $5.4 million for 2024, and $5.6 million for 2025.

(k) **Variable Pay Program ("VPP"):** Forecast VPP for the Test Period will be $4.5 million in 2023, $4.6 million in 2024, and $4.7 million in 2025.

(l) **In-scope Salaries:** Forecast in-scope salary inflation will be 1.0% in 2022, 2.5% in 2023, 3.0% in 2024, and 1.8% in 2025.

(m) **Out-of-Scope Salaries:** Out-of-scope salary inflation will be 2.9% in 2022, 2.9% in 2023, 2.5% in 2024, and 2.5% in 2025.

(n) **Income Tax:** AET agrees to expand the scope of its current deferral account for statutory tax rates during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance ("**ACCA**"), including if the ability to claim ACCA is discontinued or enhanced. To clarify, this deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in the direct assigned capital deferral account.

(o) **Shared Services FTEs:** Forecast pre-allocated Shared Services Innovation Function FTEs will be 10.4 FTEs in each year of the Test Period, consistent with 2021 actuals. Forecast pre-allocated Shared Services Indigenous and Government Relations & Sustainability Function FTEs will be 11.0 FTEs in each year of the Test Period, consistent with FTE

levels approved in Proceeding 24964. The impact of these FTE adjustments to capital FTEs and O&M FTEs, and to O&M USAs, is included in Appendix "**C**" attached hereto.

(p) **Additions to Opening 2023 Rate Base for 2022 Forecast IT Capital:** Forecast 2022 additions to GP&E Software opening rate base will be $12.3 million.

(q) **General Reductions in Operating Costs:** AET's applied-for forecast operating costs shall reflect a reduction in the amount of $0.25 million for each year in the Test Period This reduction is not tied to any specific USA account or accounts, but is a holistic reduction that AET may apply to any operating expense, USA account or accounts as it sees fit.. For presentation purposes, AET has included this adjustment within USA 566.

(r) **Project 57259 ("PENVTD"):** The forecast capital addition of $60.1 million associated with PENVTD will be removed from the Test Period.

(s) **Project 58112 ("CETO"):** For the purpose of setting interim rates for the Test Period, AET agrees to remove the financial impact of the forecast $141.1 million addition for the December 2025 energization of CETO Project from the Application. For clarity, AET's deferral application to establish the final revenue requirement related to CETO Project will be based on and include the financial impacts of the actual in-service date of the CETO Project.

(t) **Transmission Capital Maintenance ("TCM") and General Property and Equipment Projects ("GPE"):** AET agrees to an overall reduction of 7.5% to its combined TCM and GPE capital forecast over the Test Period and a one-time reduction of $2 million in 2023 to its combined TCM and GPE capital forecast. These reductions are not tied to any specific project or program, but are holistic reductions that AET may apply as it sees fit. AET shall retain discretion to manage the forecast reduction from projects or programs in assessing the impact on the safety and reliability of its assets.

(u) **Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of Federal FIT as applied-for in the Application, and AET will refund $30 million of previously collected FIT in each year of the Test Period.

(v) AET has assessed and confirms that the reductions in revenue requirement identified herein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period.

5. **Prospective Commitments**

(a) AET will conduct an analysis of property insurance level of deductibles and potential self-insurance and present the findings of this analysis in its next general tariff application.

(b) AET will present a refund strategy in its next general tariff application for refunding the remaining FIT reserve balance.

(c) AET agrees to review its existing risk assessment for Capital Maintenance programs, including enhancements to the numerical quantification of costs and benefits, and to report on this review in its next general tariff application. This review will focus on at least five new or existing sub-programs forecast in the next general tariff application test period.

(d) AET's operations and maintenance forecasts are activity-based. AET agrees to review and examine the level of detail provided to support its activity-based forecasts for USA 560, 561, 562 and 563/9. AET agrees to provide additional detail supporting these activity-based forecasts in its next general tariff application. Such additional details will include activities, activity volumes, time and costs to complete the activities, as applicable.

(e) AET will review and examine the data, the data's integrity, and its current processes supporting the Transmission Line to Ground Clearance Mitigation ("**LGCM**") and the Cross-Arms and Insulator Replacement programs and provide an update on its findings in its next general tariff application. The update will include additional explanation of how such data will be used in the next general tariff application test period to support the strategies chosen to correct LGCM issues and for cross-arm and insulator replacements, or if not used, a full justification as to why not.

(f) AET agrees to develop and maintain a contamination map of its service area depicting zones of contamination and insulation values based on IEC 60815-1-2-3, and to present the findings of such map and the associated potential implications for future transmission capital maintenance and operations and maintenance costs in the next general tariff application. Forecast costs for Project 50020 will be increased by $0.3 million in 2023 to fund the development of the contamination map.

(g) AET agrees to provide additional detail regarding the value engineering (whether different methods can be identified to provide the required function, and an assessment of the tradeoff between cost, risk and performance in evaluating alternatives) applied to LGCM, significant cross-arms and insulator replacements, and line rebuilds in its next general tariff application.

(h) AET agrees that, before undertaking any broad mitigation application to address performance issues of synthetic or polymer insulation effects, where Corona Rings are a potential solution, it will complete a full electrical and mechanical assessment by an independent lab on such suspect insulation according to specific manufacturer and specific insulator type before any installation of Corona Rings on synthetic or polymer insulators. AET agrees to report the results of these activities (if any) in its next general tariff application. The commitment is intended to capture a larger application of corona rings (for instance an entire line that has polymer/ synthetic lines performance issues) as opposed to mitigation of unique or isolated structures.

(i) AET agrees to provide the detailed information on total IT expenditures in one place in its next GTA, as was directed in Decision 26616-D01-2022 paragraph 390, for the ATCO Distribution Utilities. This information will include information on total IT expenditures (including IT O&M (direct, shared services, head office), and IT capital (including additions, indirect and direct capital)), the MFR accounts in which these costs are recorded, an identification of all IT corporate costs, and the method used to allocate IT costs to ATCO distribution and transmission utilities.

(j) AET will review and report on any savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660, in its next general tariff application.

6. **Prudence**

(a) The Parties agree that nothing in this Settlement Agreement, including the reductions to the 2023-2025 GTA revenue requirement, is an admission by AET that those revenue requirement amounts are imprudent. The Parties further agree that no Party may rely on anything in this Settlement Agreement as evidence in any future proceeding that any revenue requirement amounts are either prudent or imprudent.

7. **Confidentiality and Privilege Without Prejudice**

(a) The negotiated settlement reflected in this Settlement Agreement is a compromise and was reached in part as a result of the desire of the Parties to avoid the significant resources associated with a fully litigated process. This Settlement Agreement is for the purpose of AET's 2023-2025 GTA only, unless expressly stated otherwise, and it is without prejudice to the positions that any of the Parties may take in any subsequent negotiations and regulatory proceedings. For greater clarity, the Parties' proposal, which was accepted by the Commission, to not expend resources on advancing the preparation and filing of Information Request responses and rebuttal evidence on the issues included in this Settlement Agreement, does not constitute an admission by any Party that it accepts or agrees with the positions or evidence advanced in intervener evidence or information requests.

(b) All discussions among the Parties during the negotiated settlement process are privileged and confidential, and no matter discussed and no information provided during the negotiated settlement process may be disclosed to any person or to the AUC without the express written consent of all Parties.

8. **General**

(a) Each Party represents that it has not withheld relevant information.

(b) The Parties agree that proper notice of the negotiated settlement process was provided to all interested parties.

(c) The Parties further agree:

(i) The division of this Settlement Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Settlement Agreement.

(ii) This Settlement Agreement sets out the entire understanding and agreement of the Parties and there are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, among the Parties in connection with the subject matter of this Settlement Agreement except as specifically set out herein.

(iii) Any alteration or amendment of this Settlement Agreement must be in writing and signed by the Parties. This Settlement Agreement will be binding upon and inure to the benefit of the Parties and each of their respective successors and permitted assigns. A Party may not assign their rights and/or obligations under this Settlement Agreement without the consent of all other Parties, provided such

consent is not unreasonably withheld. This Settlement Agreement may be executed in any number of counterparts.

(iv) This Settlement Agreement is to be interpreted pursuant to the laws of the Province of Alberta.

(v) If any provision of this Settlement Agreement is found to be invalid by a court of law, this Settlement Agreement will be read and interpreted as if the provision were omitted.

(vi) The failure of any Party to exercise any right, power or option given to it under this Settlement Agreement or to insist upon the strict compliance with any of the terms or conditions in this Settlement Agreement will not constitute a waiver of any provision with respect to any other or subsequent breach.

(vii) Unless otherwise stated, any dollar amounts, prices or amounts stated in this Settlement Agreement are in the lawful currency of Canada.

(viii) Unless otherwise stated, all accounting matters or terms in this Settlement Agreement will be interpreted and construed in accordance with International Financial Reporting Standards.

(ix) References to any statute, legislation or regulation include all subsequent additions, amendments, re-enactments or replacements enacted from time to time during the period covered by this Settlement Agreement.

(d) This Settlement Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: _____
Name: Corinne Severson
Title: Vice President, Regulatory

Per: _____
Name: Melanie Bayley
Title: President ATCO Electric

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per:
Name:
Title:

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Per: _____
Name:
Title:

Per: _____
Name:
Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name: J.A. WACHOWICH
Title: Legal counsel to CCA
AET 2023-2025 GTA
I.D. 27062 / Jan 20 2023

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name: E. Lynne Davies
Title: Director - Law on behalf of the City Solicitor & General Counsel

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per:
Name:
Title:

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OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name: Richard Penn
Title: Executive Director IPCAA

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

WSLEGAL\008794\03001\33365887v1

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THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAAG7vm11Q1w0BT5ynoqTio1gacYoU5cX0X

AMENDING AGREEMENT

ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION

THIS AMENDING AGREEMENT is made and entered into as of **January 31, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("**AET**")

- and -

CONSUMERS' COALITION OF ALBERTA (the "**CCA**")

- and -

OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the "**UCA**")

- and -

THE CITY OF CALGARY ("**Calgary**")

- and -

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA ("**IPCAA**")

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

A. The Parties entered into a Negotiated Settlement Agreement made as of January 19, 2023 (the "**Settlement Agreement**") in respect of the negotiated settlement of the Application, which is the subject of AUC Proceeding No. 27062 (the "**Proceeding**");

B. On January 25, 2023, the Commission issued an information request to AET which raised questions regarding provision 4(u) of the Settlement Agreement related to Federal Future Income Taxes ("**FIT**");

C. Having reviewed such information request, AET acknowledges the presentation of the proposed FIT refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund;

D. In order to address this, the Parties have agreed to enter into this Amending Agreement pursuant to the terms and conditions contained herein.

IN CONSIDERATION of the mutual promises made in this Amending Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Definitions**

(a) Unless otherwise specified herein or unless otherwise required by the context hereof, capitalized terms utilized herein, including the recitals hereof will have the meanings given to them in the Settlement Agreement.

2. **Amendments to the Settlement Agreement**

(a) The Settlement Agreement is hereby amended as follows:

(i) Section 4(u) of the Settlement Agreement: Section 4(u) of the Settlement Agreement is amended by deleting the paragraph in its entirety and replacing it with the following:

"(u) Federal Future Income Taxes ("FIT"): AET will discontinue the collection of FIT as applied-for in the Application, and AET will refund previously collected FIT of $22.9 million in 2023, $22.5 million in 2024 and $22.1 million in 2025, and reflect the resulting impacts of such refunds on income tax expense and return on rate base in revenue requirement in each year of the Test Period."

(ii) Appendix "A" to the Settlement Agreement: Appendix "A" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix A – Revised MFRs Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0496.01.

(iii) Appendix "B" to the Settlement Agreement: Appendix "B" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix B – Summary of Changes to Rev Req Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0497.01.

3. **General**

(a) **Continuity**: The provisions of the Settlement Agreement shall, save as amended by this Amending Agreement, continue in full force and effect, and shall be read and construed as one document with this Amending Agreement.

(b) **Governing Law:** Section 8(c)(iv) of the Settlement Agreement shall apply to this Amending Agreement *mutatis mutandis*.

(c) **Counterparts:** This Amending Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if

all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Amending Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: _____
Name: Corinne Severson
Title: Vice President, Regulatory

Per: _____
Name: Melanie Bayley
Title: President, Electric

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

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ATCO ELECTRIC LTD.

Per: _____
Name:
Title:

Per: _____
Name:
Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name: JAMES A. WACHOWICH
Title: Legal Counsel to CCA
27062 Amended NSA-YCOBY
Jan 31/2023

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Per: _____
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CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name: Lynne Davies
Title: Director, Law by delegated authority from the City Solicitor & General Counsel

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

WSLEGAL\008794\03001\33466503v2

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OFFICE OF THE UTILITIES CONSUMER ADVOCATE

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THE CITY OF CALGARY

Per: _____
Name:
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INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name: Richard Penn
Title: Executive Director - IPCAA

CITY OF GRANDE PRAIRIE

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Name:
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WSLEGAL\008794\03001\33466503v2

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INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAAKFrhWszNt6P8mW1Ju32ms31QTw7QDhqg

January 23, 2023, as updated February 3, 2023

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

Attention: Cameron Strasser
Lead Application Officer

Re: ATCO Electric Transmission (AET)
2023-2025 General Tariff Application (2023-2025 GTA)
Proceeding 27062
Negotiated Settlement Agreement (Settlement Agreement)

Pursuant to Rule 018: Rules on Negotiated Settlements, enclosed for the Alberta Utilities Commission's (Commission or AUC) consideration are the following:

1. An application for approval of the negotiated settlement in respect of AET's 2023-2025 GTA, as encompassed in the Negotiated Settlement Agreement executed by AET, the Consumers' Coalition of Alberta, the Office of the Utilities Consumer Advocate, the City of Calgary, the Industrial Power Consumers Association of Alberta, and the City of Grande Prairie; and

2. A copy of the Negotiated Settlement Agreement, including the following Appendices:

    a. Appendix A – Revised 2023-2025 GTA MFR Schedules;
    b. Appendix B – Summary of Changes to Revenue Requirement; and
    c. Appendix C – Summary of Changes to FTEs.

AET acknowledges that per the Commission's correspondence of December 22, 2022,[1] AET was to file the Settlement Agreement on January 20, 2022. AET advised the Commission on January 20, 2023[2] the signing of the Settlement Agreement was delayed until January 23, 2023, due to a delay in signing by the City of Calgary.

[1] Exhibit 27062-X0487.
[2] Exhibit 27062-X0492.

ATCO

February 3, 2023 Update

Amending Agreement and Revised Exhibits

As discussed in AET's response to the Commission's Information Request AET-AUC-2023JAN25-001,[3] the presentation of the proposed Federal Future Income Taxes ("**FIT**") refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund. To address this, the Parties to the Settlement Agreement have agreed to enter into an Amending Agreement that amends section 4(u) and Appendices "A" and "B" of the Settlement Agreement.

As a result, AET is filing the following revised Exhibits:

(a) This Exhibit 27062-X0495.01: AET 2023-2025 GTA Negotiated Settlement Agreement Amended January 31, 2023;

(b) Exhibit 27062-X0496.01: Appendix A – Revised MFRs Amended January 31, 2023; and

(c) Exhibit 27062-X0497.01: Appendix B – Summary of Changes to Rev Req Amended January 31, 2023.

AET has made necessary revisions to the enclosed application for approval of the negotiated settlement, originally filed as part of Exhibit 27062-X0495, in this revised Exhibit 27062-X0495.01.

Clarification Note Regarding the Presentation of Amended Appendices "A" and "B"

Revised Exhibits 27062-X0496.01(BL) and 27062-X0497.01(BL) are the Appendices "A" and "B" that were circulated to and agreed upon by the Parties to the Amending Agreement. Revisions as per the Amending Agreement are blacklined in orange within the aforementioned Exhibits.

As explained in AET's application for approval of the negotiated settlement, enclosed,[4] the originally-filed version of Exhibit 27062-X0496 was a blackline that uses yellow

[3] Exhibit 27062-X0505, PDF pp. 1-4.
[4] See para. 33.

highlighting to show the differences between the MFR schedules filed in response to AET-AUC-2022SEP21-130[5] and the MFR schedules generated in accordance with the terms and conditions of the Settlement Agreement. Consistent with the presentation of the originally-filed version, the yellow highlighting in revised Exhibit 27062-X0496.01 shows the differences between the MFR schedules that AET filed in response to AET-AUC-2022SEP21-130[6] and the revised MFR schedules generated in accordance with the terms and conditions of the amended Settlement Agreement.

Should you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Yours truly,

Heather Goode, CPA, CA
Director, Regulatory

[5] Exhibit 27062-X0330.02.
[6] Exhibit 27062-X0330.02.

I. INTRODUCTION

1. ATCO Electric Transmission ("**AET**") applies to the Alberta Utilities Commission ("**AUC**" or "**Commission**") pursuant to sections 134 and 135 of the *Electric Utilities Act*, SA 2003, c E-5.1 ("***EUA***") for approval of a negotiated settlement agreement, as amended January 31, 2023 (the "**Settlement Agreement**", attached to this Application) between AET, the Consumers' Coalition of Alberta ("**CCA**"), the Office of the Utilities Consumer Advocate ("**UCA**"), the City of Calgary ("**Calgary**"), Industrial Power Consumers Association of Alberta ("**IPCAA**"), and the City of Grande Prairie ("**Grande Prairie**" and, collectively with the CCA, UCA, Calgary, and IPCAA, the "**Interveners**") in respect of AET's 2023-2025 General Tariff Application (the "**2023-2025 GTA**"). AET and the Interveners are collectively referred to herein as the "**Parties**."

2. This is AET's application for approval of the Settlement Agreement pursuant to AUC Rule 018 – Rules on Negotiated Settlements ("**Rule 018**").

3. As explained herein, AET submits that the negotiated settlement set out in the Settlement Agreement results in just and reasonable rates and that it is in the public interest and not contrary to law. As such, AET respectfully requests that the Commission approve the Settlement Agreement in its entirety.

4. In support of this application, AET relies on the following information and submissions:

- The 2023-2025 GTA and materials filed on the record of Proceeding 27062;
- The Settlement Agreement attached to this application, including its Appendices; and
- The information and submissions contained in this application.

II. PROCEDURAL HISTORY

5. AET submitted the 2023-2025 GTA to the Commission on May 19, 2022, in AUC Proceeding 27062, for the purpose of approving its Revenue Requirement for the 2023-2025 Test Period.

6. The Commission issued a Notice of Application on May 26, 2022. Each of the CCA, UCA, Calgary, IPCAA, and Grande Prairie submitted Statements of Intent to Participate in Proceeding 27062.[1]

7. On August 5, 2022, the Commission issued an initial process schedule and issues list for Proceeding 27062. It also granted approval for AET and the Interveners to enter into a Negotiated Settlement Process ("**NSP**") pursuant to AUC Rule 018.[2] The Commission issued two directions with respect to the NSP:

(a) that the following issues be excluded from the NSP: (i) removal of the Vegetation Management reserve; and (ii) Modifications to the Variable Pay Program reserve (together, the "**Commission Excluded Matters**"); and

(b) that if AET and the Interveners negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to. [3]

8. In its August 5, 2022 Ruling, the Commission set out an NSP timeline and directed AET to file any resulting Negotiated Settlement Agreement or notice that a settlement

1 Exhibit 27062-X0242.
2 Exhibit 27062-X0273, para 27.
3 Exhibit 27062-X0273, para 28.

could not be reached no later than October 28, 2022.[4] This process was subsequently extended to December 22, 2022.[5]

9. AET filed supplemental information for the Application on July 28, 2022, and an application update on September 6, 2022.[6]

10. AET responded to information requests from the AUC and the Interveners on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022.[7]

11. The Interveners filed evidence on December 2, 2022 ("**Intervener Evidence**").[8]

12. AET and the Interveners entered into a NSP commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022.

13. Extensive negotiations occurred among AET and the Interveners, resulting in all Parties' agreement in principle to a negotiated settlement on December 20, 2022, on all aspects of the Application, with the exception of the Commission Excluded Matters and the following additional matter –

> Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant (the "**Parties Excluded Matter**"). The Commission Excluded Matter and the Parties Excluded Matter are collectively referred to herein as the "**Excluded Matters**."

14. On December 21, 2022, AET formally advised the Commission that a negotiated settlement had been agreed to in principle amongst the Interveners and AET. AET

4 Exhibit 27062-X0273, para 29.
5 Exhibit 27062-X0328, para 11.
6 Exhibits 27062-X0243 to 27062-X0271; Exhibits 27062-X0282 to 27062-X0285.
7 Exhibits 27062-X0302 to 27062-X0327; Exhibits 27062-X0329 to 27062-X0362; Exhibit 27062-X0440; Exhibits 27062-X0443 to 27062-X0448.
8 Exhibits 27062-X0450 to 27062-X0466, Exhibits 27062-X0468.

requested an extension to January 20, 2022, to allow the Parties additional time to reach agreement on the language and terms of a final written negotiated settlement agreement and to review and complete documentation for AET's submission of the agreement and application to the Commission.[9]

15. In a letter dated December 22, 2022, the Commission approved AET's request to file the Settlement Agreement and application for approval with the Commission on January 20, 2023.[10]

III. AET'S SETTLEMENT APPLICATION COMPLIES WITH ALL REQUIREMENTS OF RULE 018

All Participants Had Full Access to All Relevant Information (Section 6(1) of Rule 018)

16. Prior to the Parties commencing settlement negotiations, AET responded to extensive information requests, the Commission made a number of rulings with respect to the 2023-2025 GTA, and the Interveners filed Intervener Evidence. Therefore, in addition to the comprehensive evidence provided by AET in its 2023-2025 GTA, all Parties had the benefit of extensive information discovery through information responses from AET, and the analysis undertaken by Interveners in their Intervener Evidence, to inform the NSP.

17. The Settlement Agreement attached hereto was circulated to and signed by all of the Parties.

18. Section 8(a) of the Settlement Agreement contains a representation that no party has withheld relevant information, in compliance with Section 6(1) of Rule 018.

[9] Exhibit 27062-X0486.
[10] Exhibit 27062-X0487.

All Interested Parties Had Adequate Notice (Section 6(3)(a) of Rule 018)

19. As set out in Section 8(b) of the Settlement Agreement, AET confirms that proper notice of the NSP was provided to all interested parties.

20. The Commission's approval to initiate the NSP was filed on the public record of Proceeding 27062,[11] thereby providing notice of the NSP to all parties interested in the Application and to the public generally. AET invited the Interveners to participate in the NSP, with a first meeting to discuss the NSP held on September 16, 2022. On October 20, 2022, the Commission held a virtual process meeting at which the participants provided the Commission with an update on the NSP. At that meeting, the participants noted that there was benefit in maintaining a NSP in the proceeding schedule and expressed interest to participate in settlement negotiations.[12]

21. Each of the Interveners was given the opportunity to participate fully in the NSP and have their respective issues addressed. All materials filed by AET and the Interveners, including Intervener Evidence, were available to the Interveners prior to the commencement of negotiation discussions.

The Settlement Agreement (Section 6(3)(b) of Rule 018)

22. A copy of the Settlement Agreement resulting from the NSP is attached to this Application.

Details of Issues Not Resolved (Section 6(3)(c) of Rule 018)

23. With the exception of the Excluded Matters, the Parties reached an agreement on all issues relating to AET's 2023-2025 GTA.

24. The details of the Commission Excluded Matters are included in the 2023-2025 GTA at Sections 5.3.21 (removal of the vegetation management reserve account) and 29.1.3 (modifications to the Variable Pay Program reserve), and the details

[11] Exhibit 27062-X0273.
[12] Exhibit 27062-X0328, para. 11.

of the Parties Excluded Matter (Jasper Palisades one-time depreciation adjustment) are included in the Application at Section 6.1.[13]

Outline of Issues Where Acceptance is Not Unanimous (Section 6(3)(d) of Rule 018)

25. The Parties reached unanimous agreement on all issues other than the Excluded Matters, as identified above.

The Rates That Will Result From the Settlement (Section 6(3)(e) of Rule 018)

26. The rates that will result from the Settlement Agreement are set out in the Revised 2023-2025 Negotiated Settlement GTA MFR Schedules and Summary of Changes to AET's Revenue Requirement, attached to the Settlement Agreement as Appendix A and Appendix B, respectively. Section VI of this application provides additional explanation regarding the rates that will result from the settlement.

The Text of Any Changes to the Terms and Conditions of Service (Section 6(3)(f) of Rule 018)

27. The Settlement Agreement does not contemplate any changes to the Terms and Conditions of Service.

A Description of Any Outstanding Issues (Section 6(3)(g) of Rule 018)

28. The Settlement Agreement is a comprehensive settlement. The only outstanding issues are the Excluded Matters, each of which is described above and in the above-referenced sections of the 2023-2025 GTA.

29. Through the NSP negotiations, the Parties successfully reached agreement on all other aspects of, and relief requested in the 2023-2025 GTA.

[13] Exhibit 27062-X0014.02.

Settlement Brief (Section 6(3)(h) of Rule 018)

30. A settlement brief explaining the Settlement Agreement and how it meets the interests of the Parties, and the public interest is contained below in Section IV of this application.

IV. SETTLEMENT BRIEF

A. Basis for Settlement

31. The terms of the negotiated settlement are set forth in the Settlement Agreement, which is attached to this application. As set out in Section 3(c) of the Settlement Agreement, the Parties agree that, except for the Excluded Matters, the Commission should approve the 2023-2025 GTA with the specific adjustments and modifications identified in the Settlement Agreement.

Adjustments to Revenue Requirement

32. The Settlement Agreement, if approved, results in an adjustment to AET's revenue requirement of $35.2 million, $38.9 million, and $41.8 million for the 2023-2025 Test Years respectively, as detailed in Table 1 below.

33. In addition to the above adjustments, the Parties agreed that the revenue requirement, should the Settlement Agreement be approved, will reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130.[14] As such, Appendix A reflects the MFR schedules filed in response to the above referenced IR and have been blacklined for the specific adjustments and modifications outlined in Section 4 of the NSA.

34. The adjustments and reductions agreed upon in the Settlement Agreement are itemized in Table 1 below and are detailed within Section 4 of the Settlement Agreement:

[14] Exhibit 27062-X0330.02.

Table 1: Summary of AET's Negotiated Settlement Revenue Requirement Reductions ($Millions)

	2023	2024	2025	Total Test Period	Reference to Settlement Agreement
O&M Negotiated Items					
Diesel Fuel Volume Reduction	(0.3)	(0.3)	(0.3)	(0.8)	4(b)
Vacancy Rate	(0.5)	(0.6)	(0.7)	(1.7)	4(d)
Inflation - In/Out Scope, Contractor and Other	(1.0)	(1.5)	(1.8)	(4.3)	4(e), 4(l), 4(m)
USA 560 - Supervision and Engineering	(0.1)	(0.1)	(0.1)	(0.2)	4(g)
USA 561 - Control Centre Operations	(0.2)	(0.2)	(0.2)	(0.6)	4(h)
USA 562 - Station Equipment Expenses	(0.4)	(0.5)	(0.6)	(1.5)	4(i)
Insurance Premiums	(0.3)	(0.2)	(0.2)	(0.7)	4(j)
Variable Pay Program	(0.6)	(0.7)	(0.8)	(2.2)	4(k)
Shared Services FTE Reduction	(0.2)	(0.2)	(0.1)	(0.5)	4(o)
IT Transition Costs & Reduction of IT Costs per Decision 26616-D01-2022	(0.5)	(4.6)	(1.5)	(6.6)	4(f)
General O&M Reduction	(0.3)	(0.3)	(0.3)	(0.8)	4(q)
Total O&M Negotiated Items	**(4.3)**	**(9.0)**	**(6.5)**	**(19.7)**	
Capital Negotiated Items					
IT Capital – Reduction to Opening Rate Base	(1.1)	(1.1)	(1.0)	(3.2)	4(p)
Removal of DA Capital (CETO/PENVT)	0.0	0.2	(6.7)	(6.5)	4(r), 4(s)
Global TCM 7.5% Reduction	(0.2)	(1.2)	(2.0)	(3.3)	4(t)
One-time TCM Reduction	(0.0)	(0.2)	(0.2)	(0.4)	4(t)
Return on Increased Rate Base due to FIT Reserve Refund	~~1.0~~ 0.6	~~3.1~~ 2.0	~~5.2~~ 3.3	~~9.3~~ 6.0	
Increase to Income Tax Expense due to Increase to Return on Rate Base	0.1	0.3	0.5	1.0	
Total Capital Negotiated Items	**~~(0.3)~~ (0.5)**	**~~0.8~~ 0.0**	**~~(4.6)~~ (5.9)**	**~~(4.1)~~ (6.5)**	
Future Income Tax (FIT) Reserve Refund	~~(30.0)~~ (22.9)	~~(30.0)~~ (22.5)	~~(30.0)~~ (22.1)	~~(90.0)~~ (67.5)	4(u)
Decrease to Income Tax Expense due to FIT Reserve Refund	(6.8)	(6.7)	(6.6)	(20.1)	
Total Negotiated Reduction	**(34.5)**	**(38.2)**	**(41.1)**	**(113.8)**	

35. The negotiation of the adjustments and reductions set out above involved various concessions and tradeoffs from each of AET and the Interveners, and is a compromise amongst the Parties. AET submits that this resulting compromise will result in just and reasonable rates.

Deferral Accounts

36. In the Settlement Agreement, the Parties agreed on the implementation of two new deferral accounts in the Test Period, both of which were proposed in the 2023-2025 GTA, and an expansion of AET's existing Deferral Account for Statutory Tax Rates:

(a) The Fuel Price Deferral Account (Section 4(c) of the Settlement Agreement): This new deferral account shall operate as proposed in the AET's 2023-2025 GTA and applies to the diesel unit price.[15] As noted in the 2023-2025 GTA, recent geopolitical events have led to volatility and uncertainty impacting AET's ability to forecast fuel prices for the 2023-2025 Test Period, resulting in a high risk of material forecast variances. AET's 2023-2025 GTA sets out how the Fuel Price Deferral Account meets the factors for evaluating deferral accounts.[16]

(b) The Temporary Deferral Account for Potential IT Transition Costs (Section 4(f) of the Settlement Agreement): This new, temporary deferral account will be implemented following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025, as described in the Application,[17] to allow for the disposition of potential IT transition costs. AET's 2023-2025 GTA sets out how the Temporary Deferral Account for Potential IT Transition Costs meetings the factors for evaluating deferral accounts.[18] However, instead of having a balance of $5.1 million as proposed in the 2023-2025 GTA, it will have an opening

15 Exhibit 27062-X0014.02, s 4.3.
16 Exhibit 27062-X0014.02, s 4.3.
17 Exhibit 27062-X0014.02, ss 1.6, 25.2.13, paras. 625 to 632.
18 Exhibit 27062-X0014.02, paras. 625 to 632.

balance of $0 and the disposition of any non-zero balance in the account will be reviewed as part of AET's next general tariff application, including the prudency and recovery of any such costs incurred in AET's rates.

(c) Expansion of the Deferral Account for Statutory Tax Rates (section 4(n) of the Settlement Agreement): The Parties agreed on an expansion of the scope of AET's current deferral account for statutory tax rates[19] during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim Accelerated Capital Cost Allowance ("**ACCA**"), including if the ability to claim ACCA is discontinued or enhanced. This deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in AET's direct assigned capital deferral account. The expansion of the scope to include changes to income tax legislation or policy that relate to the ability to claim ACCA is consistent with the purpose of AET's existing Deferral Account for Statutory Tax Rates, as it captures a legislatively introduced impact which is beyond the control of AET.

Prospective Commitments

37. The Settlement Agreement, if approved, also includes a number of prospective commitments which AET is to undertake for its next GTA, as set out in Section 5 of the Settlement Agreement. These prospective commitments relate to the following issues:

(a) Property insurance level of deductibles and potential self-insurance (Section 5(a)).

(b) A refund strategy for the remaining FIT reserve balance (Section 5(b)).

[19] Exhibit 27062-X0014.02, Table 1.5; Initial approval of the use of a deferral account for statutory tax rates in AUC Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application (September 24, 2013) at para 95.

(c) Information regarding AET's risk assessment for Capital Maintenance programs (Section 5(c)).

(d) Information regarding AET's activity-based forecasts for USA 560, 561, 562 and 563/9 (Section 5(d)).

(e) Information regarding AET's Transmission Line to Ground Clearance Mitigation ("**LGCM**"), Cross-Arms and Insulator Replacement programs, and line rebuilds (Section 5(e) and (g)).

(f) Information regarding the development of a contamination map in AET's service area (Section 5(f)).

(g) The application of Corona Rings to address performance issues for synthetic or polymer insulation (Section 5(h)).

(h) Information on total IT expenditures (Section 5(i)).

(i) Information on IT savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660 (Section 5(j)).

38. The scope of these commitments is as set out in Section 5 of the Settlement Agreement.

B. The Commission's Assessment of the Settlement Agreement

39. The Commission has jurisdiction to approve settlements negotiated for issues within its jurisdiction pursuant to Section 134 of the *EUA*. The issue of regulated rate tariffs is within the Commission's jurisdiction to regulate electric utility tariffs under Part 9 of the *EUA*.

40. The Settlement Agreement reflects compromises regarding different interests and positions of all Parties involved and was negotiated as a package. The Settlement Agreement was negotiated on the basis that it is contingent on the Commission accepting

the entire settlement, with the result that in accordance with Section 135 of the *EUA*, the Commission must either approve the entire settlement or refuse it.

41. Pursuant to section 8 of Rule 018, when presented with a unanimous settlement, the Commission must intervene only if it determines that the unanimous settlement is patently against the public interest or contrary to law.

42. Notwithstanding the above, AET respectfully requests that if the Commission is considering rejecting the Settlement Agreement because it is concerned with one or more provisions, it indicate which of the provisions are the source of the Commission's concern and provide the Parties with an opportunity to re-negotiate or remove the provision(s) that are the source of the Commission's concern.

Considerations of the Commission

43. The Commission recently confirmed that when it considers unanimous negotiated settlements the following factors are assessed:

> 25. Given the statutory requirements, Rule 018 and the relevant case law, the Commission has considered all of the following factors in making its determination on whether the negotiated settlement should be accepted or rejected in its entirety:
>
> • Fairness of the negotiated settlement process: assessing whether there was procedural fairness, both with respect to adequate notice having been served and with respect to the conduct of the negotiation process itself.
>
> • Just and reasonable rates: considering the reasonableness of the NSA. The Commission will consider the reasonableness of the individual elements that make up the application to the extent they have been set out in the NSA.
>
> • Patently against the public interest or contrary to law: conducting a review of each of the material provisions of the NSA in order for the Commission to determine whether these provisions, individually, appear contrary to accepted regulatory practices, or could resulting undue rate and service effects on customers or are clearly contrary to law.[20]

[20] Decision 23848-D01-2020. Also refer to Decision 26617-D01-2020, ENMX Power Corporation, EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review – Reasons for Approval of Negotiated Settlements (July 28, 2022) at para 11 [Decision 26617-D02-2022]. Also refer to AUC Decision 25726-D01-2021, ENMAX Power Corporation, 2021-2022 General Tariff Application, Negotiated Settlement Agreement and Excluded Matters (June 16, 2021) at para 23 [Decision 25726-D01-2021].

44. Section 8 of Rule 018 requires the Commission to assess if the negotiated settlement results in rates and Terms and Conditions that are just and reasonable. The Commission has recently confirmed that it must always "have regard to the requirements of Rule 018, including the fairness of the process" and that the central question to the Commission's public interest determination is whether the negotiated settlement will result in just and reasonable rates.[21]

45. With respect to fairness, the Commission has also recently commented that "[i]n order to demonstrate that an NSP is fair, the Commission must be satisfied that proper notice was given, that relevant information has been disclosed, and that parties were able to have meaningful participation."[22]

46. The Commission considers the questions of whether the settlement results in just and reasonable rates as part of its determination of whether the negotiated settlement is in the public interest.[23]

C. The Commission Should Approve the Negotiated Settlement

The NSP was Procedurally Fair

47. The NSP was procedurally fair. As discussed above and expressly acknowledged in Section 8(b) of the Settlement Agreement, adequate notice was provided with respect to the NSP. The Commission may also have regard to written confirmation filed by the Interveners as to the fairness of the negotiated settlement process, which are to be filed with the Commission by January 20, 2023.

48. Confidential and without-prejudice negotiations occurred between December 12, 2022 and December 20, 2022. Representatives from each of the Interveners (CCA, UCA, Calgary, IPCAA and Grande Prairie) were invited to, and attended, every session. Each Party was given a reasonable opportunity to raise and

21 Decision 26617-D02-2022, *ibid* at para 12.
22 AUC Decision 26207-D01-2021, Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement (June 4, 2021) at para 20 [Decision 26207-D01-2021].
23 Refer to, e.g., Decision 26207-D01-2021, *ibid* at para 28; Decision 25726-D01-2021, *supra* note 20 at para 33.

discuss matters related to AET's application, and the negotiations included multiple videoconferencing sessions and the exchange of additional information. All Parties were active in the negotiations and are ultimately signatories to the Settlement Agreement.

49. Further, all parties were well-informed. There was a substantial evidentiary record in Proceeding 27062 before the Parties began negotiation meetings. As detailed above in the Procedural History, AET had provided IR responses and the Intervener Evidence was filed before the start of negotiations. The Parties exchanged information on a without prejudice basis in the course of settlement discussions and, as confirmed in section 8(a) of the Settlement Agreement, no party withheld relevant information. AET submits that Parties to the NSP were therefore reasonably informed and able to meaningfully participate in settlement discussions.

50. The UCA, CCA, and Calgary were represented by legal counsel and had the assistance of expert consultants. In its decision on the 2021 Direct Energy Regulated Services negotiated settlement agreement with respect to its 2020-2022 Default Rate Tariff ("**DRT**") and Regulated Rate Tariff ("**RRT**"), the Commission noted:

> The Commission considers that the CCA and the UCA are sophisticated parties with significant experience in negotiated settlements and proceedings to establish the RRT and DRT. The CCA and the UCA represent the majority of DERS' RRT and DRT customers, with the CCA representing primarily residential customers, and the UCA mandated by the Alberta Government to represent the interests of residential, farm and small business customers.[24]

51. The same considerations apply to the Settlement Agreement. The UCA, CCA, IPCAA and Calgary have historically participated in AET's general tariff application proceedings. In addition, Grande Prairie participated in the NSP, therefore expanding the group of the Interveners beyond those that have historically participated in AET's General Tariff Applications. The UCA, CCA, and IPCAA have all participated in negotiated settlements in the past and have extensive experience participating in Commission

[24] *Ibid* at para 26.

proceedings more generally.[25] The participation of these Parties in the NSP and as signatories to the Settlement Agreement speaks to its fairness.

52. Finally, the NSP did not involve any collusion. The Parties were at arms' length and were adverse of many issues. The Settlement discussions were confidential and without prejudice. However, the process of engaging in negotiations on matters where the Parties are adverse results in a compromise and informs the assessment that the Settlement Agreement is fair and results in just and reasonable rates.

The Settlement Agreement is Not Patently Against the Public Interest or Contrary to Law and Results in Just and Reasonable Rates

53. The Settlement Agreement meets the interests of the Parties and the public interest. As discussed above, the Settlement Agreement represents a unanimous agreement addressing all aspects of AET'S 2023-2025 GTA except the Excluded Matters.

54. As noted above, the Interveners, as Parties to the Settlement Agreement, represent a range of consumers and have also historically participated in the testing of AET's general tariff applications, such that the Commission can be confident that the Settlement Agreement meets the interests of the public.[26]

55. Additionally, both the Commission and the courts have confirmed that there is a public interest in favour of settlements over litigated or contested processes. The Supreme Court of Canada stated in *Sable Offshore Energy Inc v Ameron International Corp* that "[s]ettlements allow parties to reach a mutually acceptable resolution to their dispute without prolonging the personal and public expense and time involved in litigation," and recognized the public interest in favour of settlement.[27] In previous approvals of unanimous negotiated settlements, the Commission has recognized that approval of the settlements would "provide certainty, plus savings in costs, resources and

[25] E.g., Exhibit 23848-X0204, Exhibit 25726-X0196.
[26] Refer to Decision 26207-D01-2021, *supra* note 22 at para 30; Decision 25726-D01-2021, *supra* note 20 at para 42.
[27] 2013 SCC 37 at para 11, citing *Sparling v Southam Inc*, 1988 CanLII 4694 (ON SC), 66 OR (2d) 225 (HCJ) at 230.

time that all parties would have otherwise expended in a fully litigated proceeding,"[28] and would result in "greater regulatory efficiency and cost savings to customers than would a contested process."[29] The same benefits apply here. The Settlement Agreement is unanimous and represents the interests of all Parties and the public interest. Its approval would result in greater efficiency and costs savings for the public by eliminating the need for an extended process before the Commission in Proceeding 27062.

56. As set out in Section 4(v) of the Settlement Agreement, AET has assessed and confirms that the reductions in revenue requirement identified therein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period. The Commission has previously noted such considerations as part of its determination that a negotiated settlement was in the public interest.[30]

57. As such, the Settlement Agreement is not patently against the public interest and it is not contrary to law.

58. Further, the Settlement Agreement addresses all aspects of the Application except for the Excluded Matters. It results in a direct reduction of the transmission tariffs set forth in the 2023-2025 GTA of $113.8 million as described in Table 1 above. This reduced revenue requirement, agreed-upon by AET and all Interveners in Proceeding 27062, results in just and reasonable rates, the details of which have been provided in the Appendices of the Settlement Agreement.

59. The Commission can rely on the fairness of the NSP and the fact that it meets the interests of the Parties and the public interest, as discussed above as evidence that it will result in just and reasonable rates. The Settlement Agreement is a comprehensive, unanimous agreement that is the product of fair and earnest negotiation by well-informed

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28 Decision 26617-D02-2022, *supra* note 20 at para 61.
29 AUC Decision 21149-D01-2016, ENMAX Power Corporation, Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor (August 3, 2016) at para 48.
30 Refer to Decision 26207-D01-2021, *supra* note 22 at para 30.

Parties, the majority of which were represented by legal counsel and supported by expert consultants. As set out in Section 3(c) of the Settlement Agreement, the Interveners have agreed that they will support this application and that the Commission should approve the AET's 2023-2025 GTA with the specific adjustments and modifications identified in the Settlement Agreement.

V. CONCLUSION: THE SETTLEMENT AGREEMENT IS IN THE PUBLIC INTEREST

60. The Settlement Agreement is a unanimous agreement of AET and the Interveners with respect to all elements of AET's 2023-2025 GTA, except the Excluded Matters.

61. The Settlement Agreement results in a reduction of capital and operating costs of $113.8 million over the Test Period, resulting in a fair and reasonable tariff for 2023, 2024 and 2025. As discussed above, AET's Settlement Agreement is in the public interest and not contrary to law. Approval of the Settlement Agreement will bring finality and certainty and will avoid a costly litigated process.

62. For these reasons, AET respectfully requests the Commission to approve the Settlement Agreement in its entirety, together with the resulting adjustments to AET's applied-for revenue requirement.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON this 23rd day of January, 2023~~.~~[1] AS REVISED ON this 3rd day of February, 2023.

NEGOTIATED SETTLEMENT AGREEMENT

ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION

THIS NEGOTIATED SETTLEMENT AGREEMENT for the negotiated settlement of the 2023-2025 General Tariff Application, which is the subject of Alberta Utilities Commission Proceeding No. 27062, is made and entered into as of **January 19, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("**AET**")

- and -

CONSUMERS' COALITION OF ALBERTA (the "**CCA**")

- and -

OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the "**UCA**")

- and -

THE CITY OF CALGARY ("**Calgary**")

- and -

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA ("**IPCAA**")

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

A. AET ("the **Applicant**") submitted its 2023-2025 General Tariff Application ("**Application")** to the Alberta Utilities Commission ("**AUC**" or "**Commission**") on May 19, 2022 for the purpose of

obtaining approval for its revenue requirement for the 2023-2025 Test Period, which is the subject of AUC Proceeding No. 27062;

B. On May 26, 2022, the Commission issued a Notice of Application informing potentially interested parties that it would be considering the Application, and inviting submissions for participation in AUC Proceeding 27062;

C. The CCA, the UCA, Calgary, IPCAA and Grande Prairie (collectively, the "**Interveners**") are participants in Proceeding 27062;

D. On August 5, 2022, the Commission issued an initial process schedule and an issues list for Proceeding 27062 and provided its approval for the Parties to enter into a negotiated settlement process under AUC Rule 018. The Commission directed that:

(i) the following issues be excluded from the negotiated settlement process: (a) removal of the Vegetation Management reserve; and (b) Modifications to the Variable Pay Program reserve; and

(ii) if the Parties negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to.

E. AET filed supplemental information for the Application on July 28, 2022 and an application update on September 6, 2022;

F. AET responded to information requests from the AUC and the Interveners on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022;

G. The Interveners filed evidence on December 2, 2022;

H. The Parties (AET, the CCA, the UCA, Calgary, IPCAA and Grande Prairie) entered into a negotiated settlement process commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022;

I. On December 20, 2022, the Parties reached an agreement in principle for a negotiated settlement on all elements of AET's 2023-2025 GTA, except for specifically excluded matters identified in section 2 below;

J. The term of this settlement is the 2023-2025 Test Years Period ("**Test Period**").

IN CONSIDERATION of the mutual promises made in this negotiated settlement agreement ("**Settlement Agreement**") and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Scope of this Settlement Agreement**

(a) This Settlement Agreement settles all aspects of and relief requested in the Application, except for the Excluded Items identified in section 2 below.

(b) Unless otherwise agreed by the Parties in writing, if the AUC declines to approve this Settlement Agreement in its entirety, the Settlement Agreement will be of no force and effect, in accordance with Section 135 of the *Electric Utilities Act*.

2. **Excluded Matters**

(a) AET and the Interveners agree that the following matters are specifically excluded from this Settlement Agreement:

(i) the removal of the Vegetation Management reserve;

(ii) modifications to the Variable Pay Program reserve; and

(iii) Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant of depreciation related to the Jasper Palisades Isolated Generation Plant;

collectively referred to herein as the "**Excluded Matters**".

3. **Revised Revenue Requirement**

(a) The overall revenue requirement adjustments agreed to in this Settlement Agreement are set out in Schedule 3-1 attached hereto as Appendix "A".

(b) Revised Minimum Filing Requirement ("**MFR**") schedules that reflect the specific adjustments and modifications agreed to herein are attached hereto as Appendix "A". A Summary of Changes to AET's Revenue Requirement is attached as Appendix "B" to this Settlement Agreement.

(c) Except for the Excluded Matters, the Parties agree that the AUC should approve the Application, with the specific adjustments and modifications identified in this Settlement Agreement and in Appendix "A" hereto. The Parties agree to support AET's application to the AUC for approval of this Settlement Agreement.

4. **Specific Adjustments and Modifications**

(a) **Errors and Omissions:** In addition to the adjustments and modifications identified herein, the revenue requirement shall reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130 filed on the record of Proceeding 27062.

(b) **Diesel Fuel Volume Forecast:** The forecast diesel fuel volumes set out in Table 4.2 of the Application, with the corrections identified in response to AET-AUC-2022SEP21-105(d), will be reduced by 5% in each year of the Test Period.

(c) **Fuel Price Deferral Account:** A fuel price deferral account, as proposed in the Application, will be implemented for the Test Period.

(d) **Vacancy Rate:** AET will apply a vacancy rate of 5% in each year of the Test Period. A schedule identifying the impact of the 5% vacancy rate to capital FTEs and O&M FTEs, and to O&M USAs, is attached hereto as Appendix "**C**".

(e) **Inflation Assumptions ("Other"):** Forecast inflation assumptions for "Inflation - Other" will be 4.4% in 2023, 3.0% in 2024, and 2.2% in 2025.

(f) **Information Technology ("IT") Transition Costs:** The Parties agree to the implementation of a temporary deferral account for potential IT transition costs following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025 as described in the Application, with a placeholder amount of $0.00 for such costs in the Test Period. The deferral account will have an opening balance of $0 and the disposition of any non-zero balance in this deferral account will be reviewed as part of AET's next general tariff application, including the prudency and recovery of any such costs incurred in AET's revenue requirement.

(g) **Supervision and Engineering (USA Acct No. 560):** Forecast costs for USA 560 will be $3.3 million in 2023, $3.4 million in 2024, and $3.5 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(h) **Control Centre Operations (USA Acct No. 561):** Forecast costs for USA 561 will be $5.4 million in 2023, $5.6 million in 2024, and $5.8 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(i) **Station Equipment Expenses (USA Acct No. 562):** Forecast costs for USA 562 will be $9.9 million in 2023, $10.0 million in 2024, and $10.1 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.

(j) **Insurance Premiums (USA Acct No. 924):** Forecast costs for insurance premiums included in USA 924 will be $5.3 million for 2023, $5.4 million for 2024, and $5.6 million for 2025.

(k) **Variable Pay Program ("VPP"):** Forecast VPP for the Test Period will be $4.5 million in 2023, $4.6 million in 2024, and $4.7 million in 2025.

(l) **In-scope Salaries:** Forecast in-scope salary inflation will be 1.0% in 2022, 2.5% in 2023, 3.0% in 2024, and 1.8% in 2025.

(m) **Out-of-Scope Salaries:** Out-of-scope salary inflation will be 2.9% in 2022, 2.9% in 2023, 2.5% in 2024, and 2.5% in 2025.

(n) **Income Tax:** AET agrees to expand the scope of its current deferral account for statutory tax rates during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance ("**ACCA**"), including if the ability to claim ACCA is discontinued or enhanced. To clarify, this deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in the direct assigned capital deferral account.

(o) **Shared Services FTEs:** Forecast pre-allocated Shared Services Innovation Function FTEs will be 10.4 FTEs in each year of the Test Period, consistent with 2021 actuals. Forecast pre-allocated Shared Services Indigenous and Government Relations & Sustainability Function FTEs will be 11.0 FTEs in each year of the Test Period, consistent with FTE

levels approved in Proceeding 24964. The impact of these FTE adjustments to capital FTEs and O&M FTEs, and to O&M USAs, is included in Appendix "**C**" attached hereto.

(p) **Additions to Opening 2023 Rate Base for 2022 Forecast IT Capital:** Forecast 2022 additions to GP&E Software opening rate base will be $12.3 million.

(q) **General Reductions in Operating Costs:** AET's applied-for forecast operating costs shall reflect a reduction in the amount of $0.25 million for each year in the Test Period This reduction is not tied to any specific USA account or accounts, but is a holistic reduction that AET may apply to any operating expense, USA account or accounts as it sees fit.. For presentation purposes, AET has included this adjustment within USA 566.

(r) **Project 57259 ("PENVTD"):** The forecast capital addition of $60.1 million associated with PENVTD will be removed from the Test Period.

(s) **Project 58112 ("CETO"):** For the purpose of setting interim rates for the Test Period, AET agrees to remove the financial impact of the forecast $141.1 million addition for the December 2025 energization of CETO Project from the Application. For clarity, AET's deferral application to establish the final revenue requirement related to CETO Project will be based on and include the financial impacts of the actual in-service date of the CETO Project.

(t) **Transmission Capital Maintenance ("TCM") and General Property and Equipment Projects ("GPE"):** AET agrees to an overall reduction of 7.5% to its combined TCM and GPE capital forecast over the Test Period and a one-time reduction of $2 million in 2023 to its combined TCM and GPE capital forecast. These reductions are not tied to any specific project or program, but are holistic reductions that AET may apply as it sees fit. AET shall retain discretion to manage the forecast reduction from projects or programs in assessing the impact on the safety and reliability of its assets.

(u) **Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of Federal FIT as applied-for in the Application, and AET will refund $30 million of previously collected FIT in each year of the Test Period.

(v) AET has assessed and confirms that the reductions in revenue requirement identified herein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period.

5. **Prospective Commitments**

(a) AET will conduct an analysis of property insurance level of deductibles and potential self-insurance and present the findings of this analysis in its next general tariff application.

(b) AET will present a refund strategy in its next general tariff application for refunding the remaining FIT reserve balance.

(c) AET agrees to review its existing risk assessment for Capital Maintenance programs, including enhancements to the numerical quantification of costs and benefits, and to report on this review in its next general tariff application. This review will focus on at least five new or existing sub-programs forecast in the next general tariff application test period.

(d) AET's operations and maintenance forecasts are activity-based. AET agrees to review and examine the level of detail provided to support its activity-based forecasts for USA 560, 561, 562 and 563/9. AET agrees to provide additional detail supporting these activity-based forecasts in its next general tariff application. Such additional details will include activities, activity volumes, time and costs to complete the activities, as applicable.

(e) AET will review and examine the data, the data's integrity, and its current processes supporting the Transmission Line to Ground Clearance Mitigation ("**LGCM**") and the Cross-Arms and Insulator Replacement programs and provide an update on its findings in its next general tariff application. The update will include additional explanation of how such data will be used in the next general tariff application test period to support the strategies chosen to correct LGCM issues and for cross-arm and insulator replacements, or if not used, a full justification as to why not.

(f) AET agrees to develop and maintain a contamination map of its service area depicting zones of contamination and insulation values based on IEC 60815-1-2-3, and to present the findings of such map and the associated potential implications for future transmission capital maintenance and operations and maintenance costs in the next general tariff application. Forecast costs for Project 50020 will be increased by $0.3 million in 2023 to fund the development of the contamination map.

(g) AET agrees to provide additional detail regarding the value engineering (whether different methods can be identified to provide the required function, and an assessment of the tradeoff between cost, risk and performance in evaluating alternatives) applied to LGCM, significant cross-arms and insulator replacements, and line rebuilds in its next general tariff application.

(h) AET agrees that, before undertaking any broad mitigation application to address performance issues of synthetic or polymer insulation effects, where Corona Rings are a potential solution, it will complete a full electrical and mechanical assessment by an independent lab on such suspect insulation according to specific manufacturer and specific insulator type before any installation of Corona Rings on synthetic or polymer insulators. AET agrees to report the results of these activities (if any) in its next general tariff application. The commitment is intended to capture a larger application of corona rings (for instance an entire line that has polymer/ synthetic lines performance issues) as opposed to mitigation of unique or isolated structures.

(i) AET agrees to provide the detailed information on total IT expenditures in one place in its next GTA, as was directed in Decision 26616-D01-2022 paragraph 390, for the ATCO Distribution Utilities. This information will include information on total IT expenditures (including IT O&M (direct, shared services, head office), and IT capital (including additions, indirect and direct capital)), the MFR accounts in which these costs are recorded, an identification of all IT corporate costs, and the method used to allocate IT costs to ATCO distribution and transmission utilities.

(j) AET will review and report on any savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660, in its next general tariff application.

6. **Prudence**

(a) The Parties agree that nothing in this Settlement Agreement, including the reductions to the 2023-2025 GTA revenue requirement, is an admission by AET that those revenue requirement amounts are imprudent. The Parties further agree that no Party may rely on anything in this Settlement Agreement as evidence in any future proceeding that any revenue requirement amounts are either prudent or imprudent.

7. **Confidentiality and Privilege Without Prejudice**

(a) The negotiated settlement reflected in this Settlement Agreement is a compromise and was reached in part as a result of the desire of the Parties to avoid the significant resources associated with a fully litigated process. This Settlement Agreement is for the purpose of AET's 2023-2025 GTA only, unless expressly stated otherwise, and it is without prejudice to the positions that any of the Parties may take in any subsequent negotiations and regulatory proceedings. For greater clarity, the Parties' proposal, which was accepted by the Commission, to not expend resources on advancing the preparation and filing of Information Request responses and rebuttal evidence on the issues included in this Settlement Agreement, does not constitute an admission by any Party that it accepts or agrees with the positions or evidence advanced in intervener evidence or information requests.

(b) All discussions among the Parties during the negotiated settlement process are privileged and confidential, and no matter discussed and no information provided during the negotiated settlement process may be disclosed to any person or to the AUC without the express written consent of all Parties.

8. **General**

(a) Each Party represents that it has not withheld relevant information.

(b) The Parties agree that proper notice of the negotiated settlement process was provided to all interested parties.

(c) The Parties further agree:

(i) The division of this Settlement Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Settlement Agreement.

(ii) This Settlement Agreement sets out the entire understanding and agreement of the Parties and there are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, among the Parties in connection with the subject matter of this Settlement Agreement except as specifically set out herein.

(iii) Any alteration or amendment of this Settlement Agreement must be in writing and signed by the Parties. This Settlement Agreement will be binding upon and inure to the benefit of the Parties and each of their respective successors and permitted assigns. A Party may not assign their rights and/or obligations under this Settlement Agreement without the consent of all other Parties, provided such

consent is not unreasonably withheld. This Settlement Agreement may be executed in any number of counterparts.

(iv) This Settlement Agreement is to be interpreted pursuant to the laws of the Province of Alberta.

(v) If any provision of this Settlement Agreement is found to be invalid by a court of law, this Settlement Agreement will be read and interpreted as if the provision were omitted.

(vi) The failure of any Party to exercise any right, power or option given to it under this Settlement Agreement or to insist upon the strict compliance with any of the terms or conditions in this Settlement Agreement will not constitute a waiver of any provision with respect to any other or subsequent breach.

(vii) Unless otherwise stated, any dollar amounts, prices or amounts stated in this Settlement Agreement are in the lawful currency of Canada.

(viii) Unless otherwise stated, all accounting matters or terms in this Settlement Agreement will be interpreted and construed in accordance with International Financial Reporting Standards.

(ix) References to any statute, legislation or regulation include all subsequent additions, amendments, re-enactments or replacements enacted from time to time during the period covered by this Settlement Agreement.

(d) This Settlement Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: _____
Name: Corinne Severson
Title: Vice President, Regulatory

Per: _____
Name: Melanie Bayley
Title: President ATCO Electric

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per:
Name:
Title:

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Per: _____
Name:
Title:

Per: _____
Name:
Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name: J.A. WACHOWICH
Title: legal counsel to CCA
AET 2023-2025 GTA
I.D. 27062 / Jan 20 2023

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Name:
Title:

CITY OF GRANDE PRAIRIE

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Title:

Per: _____
Name:
Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

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CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name: E. Lynne Davies
Title: Director - Law on behalf of the City Solicitor & General Counsel

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per:
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OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

Richard Penn
Executive Director
IPCAA

CITY OF GRANDE PRAIRIE

Per:
Name:
Title:

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OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per:
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAAG7vm11Qtw0BT5ynoqTio1gacYoU5cX0X

AMENDING AGREEMENT

ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION

THIS AMENDING AGREEMENT is made and entered into as of **January 31, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("**AET**")

- and -

CONSUMERS' COALITION OF ALBERTA (the "**CCA**")

- and -

OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the "**UCA**")

- and -

THE CITY OF CALGARY ("**Calgary**")

- and -

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA ("**IPCAA**")

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

A. The Parties entered into a Negotiated Settlement Agreement made as of January 19, 2023 (the "**Settlement Agreement**") in respect of the negotiated settlement of the Application, which is the subject of AUC Proceeding No. 27062 (the "**Proceeding**");

B. On January 25, 2023, the Commission issued an information request to AET which raised questions regarding provision 4(u) of the Settlement Agreement related to Federal Future Income Taxes ("**FIT**");

C. Having reviewed such information request, AET acknowledges the presentation of the proposed FIT refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund;

D. In order to address this, the Parties have agreed to enter into this Amending Agreement pursuant to the terms and conditions contained herein.

IN CONSIDERATION of the mutual promises made in this Amending Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Definitions**

(a) Unless otherwise specified herein or unless otherwise required by the context hereof, capitalized terms utilized herein, including the recitals hereof will have the meanings given to them in the Settlement Agreement.

2. **Amendments to the Settlement Agreement**

(a) The Settlement Agreement is hereby amended as follows:

(i) Section 4(u) of the Settlement Agreement: Section 4(u) of the Settlement Agreement is amended by deleting the paragraph in its entirety and replacing it with the following:

"(u) Federal Future Income Taxes ("FIT"): AET will discontinue the collection of FIT as applied-for in the Application, and AET will refund previously collected FIT of $22.9 million in 2023, $22.5 million in 2024 and $22.1 million in 2025, and reflect the resulting impacts of such refunds on income tax expense and return on rate base in revenue requirement in each year of the Test Period."

(ii) Appendix "A" to the Settlement Agreement: Appendix "A" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix A – Revised MFRs Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0496.01.

(iii) Appendix "B" to the Settlement Agreement: Appendix "B" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix B – Summary of Changes to Rev Req Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0497.01.

3. **General**

(a) **Continuity**: The provisions of the Settlement Agreement shall, save as amended by this Amending Agreement, continue in full force and effect, and shall be read and construed as one document with this Amending Agreement.

(b) **Governing Law:** Section 8(c)(iv) of the Settlement Agreement shall apply to this Amending Agreement *mutatis mutandis*.

(c) **Counterparts:** This Amending Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if

all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Amending Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: _____
Name: Corinne Severson
Title: Vice President, Regulatory

Per: _____
Name: Melanie Bayley
Title: President, Electric

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

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ATCO ELECTRIC LTD.

Per: _____
Name:
Title:

Per: _____
Name:
Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name: JAMES A. WACHOWICH
Title: Legal Counsel to CCA
27062 Amended NSA-Yeoby
Jan 31/2023

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Per: _____
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CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

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Name:
Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name: Lynne Davies
Title: Director, Law by delegated authority from the City Solicitor & General Counsel

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
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Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name: Richard Penn
Title: Executive Director - IPCAA

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

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Per: _____
Name:
Title:

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAAKFrhWszkt6P8mW1Ju32ms31QTw7QDhqg

ATCO Electric YUKON

September 28, 2023 AEY-UCG-007

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-007

Reference: July 7,2023 Application, page 1-5

AEY states "For non-labour costs, an inflation rate of 2.2% has been applied for 2016 based on the Yukon Economic Outlook issued by the Yukon Economic Development in October 2015. For 2017, no public forecast of Yukon inflation is available, therefore the 2.2 percent inflation rate has also been used for 2017."

Request:

(a) Provide details of the actual monthly inflation rate for the Yukon for 2016 to date and forecast and copies of the related source documents.

(b) Please confirm that Yukon Economic Outlook released in May 2016 indicates that following deflation in 2015, the Whitehorse CPI is expected to grow by 2.0 per cent in 2016 and just under 2.0 per cent in 2017.

(c) Provide non-labour escalation rates are currently used for 2023 and 2024 by FortisBC Utilities. Please provide copies of the reference material relating to these rates.

Response:

(a) Please refer to AEY-UCG-007(a) Attachment 1.

(b) Confirmed. The Whitehorse CPI was expected to grow by 2.0 percent in 2016 and just under 2.0 percent in 2017.[1]

[1] https://emrlibrary.gov.yk.ca/EcDev/Yukon_Economic_Outlook/2016-May.pdf, PDF pp. 3-4.

(c) FortisBC has applied for a blended labour/non-labour rate of 4.517 percent for 2023[2] and 4.080 percent for 2024.[3]

[2] https://docs.bcuc.com/documents/proceedings/2022/doc_67371_b-2-fbc-2023-annualreview-application.pdf, PDF p. 22.

[3] https://docs.bcuc.com/documents/proceedings/2023/doc_72776_b2fbc2024annualreviewratesapplication.pdf, PDF p. 23.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	2016	0.00%	-0.32%	0.40%	0.16%	0.64%	1.12%	-0.16%	0.00%	-0.40%	0.16%	0.00%	0.00%
2	2017	0.63%	0.08%	0.39%	0.08%	0.16%	-0.39%	-0.08%	-0.47%	0.55%	0.00%	1.34%	-0.16%
3	2018	0.08%	0.47%	0.39%	0.31%	0.15%	0.31%	0.69%	-0.23%	-0.84%	0.38%	-0.08%	0.38%
4	2019	-0.38%	0.15%	0.38%	0.46%	0.53%	0.90%	0.75%	-0.22%	-0.96%	0.30%	0.00%	0.67%
5	2020	0.74%	0.07%	-0.59%	-1.11%	-0.37%	0.90%	-0.07%	-0.45%	0.22%	0.45%	0.22%	0.07%
6	2021	0.89%	0.22%	0.15%	0.88%	0.15%	0.36%	0.94%	0.36%	0.14%	0.43%	-0.57%	0.36%
7	2022	0.21%	0.99%	1.68%	0.62%	1.44%	0.88%	0.94%	0.27%	0.00%	0.53%	0.13%	0.13%
8	2023	0.07%	0.13%	0.26%	0.85%	0.45%	0.97%	1.28%					
9													
10	Data source												
11	https://www150.statcan.gc.ca/												
12	Table: 18-10-0004-01												
13	Released 2023-08-15												
14	Monthly CPI for Whitehorse 2016 - 2023												

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

Line No.	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
1																								
2																								
3	124.1	123.7	124.2	124.4	125.2	126.6	126.4	126.4	125.9	126.1	126.1	126.1	126.9	127	127.5	127.6	127.8	127.3	127.2	126.6	127.3	127.3	129	128.8
4																								
5	15-Dec																							
6																								
7	124.1																							

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

Line No.	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
1																								
2																						2002=100		
3	128.9	129.5	130	130.4	130.6	131	131.9	131.6	130.5	131	130.9	131.4	130.9	131.1	131.6	132.2	132.9	134.1	135.1	134.8	133.5	133.9	133.9	134.8
4																								
5																								
6																								
7																								

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

Line No.	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
1																								
2																								
3	135.8	135.9	135.1	133.6	133.1	134.3	134.2	133.6	133.9	134.5	134.8	134.9	136.1	136.4	136.6	137.8	138	138.5	139.8	140.3	140.5	141.1	140.3	140.8
4																								
5																								
6																								
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ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

Line No.	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23
1																			
2																			
3	141.1	142.5	144.9	145.8	147.9	149.2	150.6	151	151	151.8	152	152.2	152.3	152.5	152.9	154.2	154.9	156.4	158.4
4																			
5																			
6																			
7																			

ATCO Electric YUKON

September 28, 2023 AEY-UCG-008

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-008

Reference: July 7, 2023 Application, page 1-5

AEY states: 20. A vacancy rate of 3.65 percent (approximately three FTEs) has been applied to labour expenses for the 2023-2024 Test Period. This is based on a five-year historical average normalized for exogenous events, such as vacancies driven by vaccine policies, 1 Decision 27062- D01-2023, ATCO Electric 2023-2025 GTA and NSA. 2023-2024 General Rate Application (GRA) 1-7 which AEY believes to be reasonable and is consistent with the methodology approved in Board Orders 2014-06 and 2017-01.

Request:

Please provide details of the calculation of the 5-year vacancy rate for ATCO Electric Yukon including details of the positions that were vacant at any time.

Response:

Please refer to the response to AEY-YUB-003(c).

September 28, 2023 AEY-UCG-009

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-009

Reference: July 7,2023 Application, page 1-7 Staff Positions

AEY proposes: 22. The additional positions outlined below are required to manage system growth over the six-year period and continuing into the test period and energy transition. 23. Growth to new extension has grown 4% requiring adequate numbers to accommodate capital program; maintenance requirements in both distribution and production. According to chart 9 additional staff are required.

Request:

(a) Explain how these job responsibilities identified for the new positions are or will be currently fulfilled.

(b) Provide details of the total additional costs included in the 2023 and 2024 revenue requirements for these new positions.

(c) Please provide details on the alternatives that were considered to hiring new staff.

Response:

(a) AEY is unclear on what the IR is asking. AEY is assuming the UCG asked for an explanation of how these job responsibilities are identified. Identifying job responsibilities for new positions typically involves a process that can be broken down into the following key steps:

- Assessment: determine why the new position is necessary and needed, specific goals or problems it aims to address. Identify the job purpose and desired outcomes.
- Job Analysis: perform job analysis for the new position, this involves breaking down the job duties and responsibilities. Analyze the current state

of the organization and the gap that the new positions are required to fill. This analysis process involves:

- Review existing roles and responsibilities to avoid redundancy.
- Gather input from relevant stakeholders, department managers, and executives to identify the needs and pain points.

- Job Description: document detailed job description for the new positions, which outlines the Job titles, purpose of the roles, qualifications, responsibilities, qualifications.
- Internal or External Recruitment: decide whether to fill the new position internally or externally. Evaluate if existing employees have the potential to fulfill the job responsibilities through training and professional development or external hiring.
- Onboarding and Training Plan: develop onboarding and training plan to ensure that new employees will be well-prepared to meet the job responsibilities. This includes orientation, training, and mentoring.
- Regular Review and Update: Job responsibilities should be reviewed and updated periodically to ensure that they remain relevant and aligned with updated needs and goals.

(b) Please refer to the table below for the total additional costs included in the 2023 and 2024 revenue requirement for these new positions.

Table 1: Total Costs for New Positions ($000)

	Capital	O&M
Total Labour costs	577	681

(c) AEY continuously evaluates the most efficient way to manage human capital to ensure optimization. Additional positions were required to manage system growth over the six-year period since AEY's 2016-2017 GRA and remain required into the Test Period. AEY has also reviewed current duties and priorities to assess existing

capacity. There are also several other alternatives considered prior to hiring new employees, as described below:

- Outsourcing: the quality of work or services provided by external vendors can dissuade companies from outsourcing. So that in-house teams are better equipped to maintain and improve quality. Reliability can also be a concern when it comes to outsourcing. Temporary workers or contractors might be a good option for short-term projects, but they typically are not committed to the long-term success of the company. This can lead to a lack of commitment to the company and potential shortfall of labour in the future.

- Specialized Skills: the additional positions require highly specialized skills or expertise that are not readily available within the existing workforce. Hiring new staff with the required qualifications is essential.

- Higher Workload: when the workload increase is expected to be ongoing and permanent, full-time staff are the preferred option. This ensures continuity in operations, lower risk, and lower costs. Short term increases in workload can be managed with overtime and temporary workers, but these alternatives are generally more expensive.

AEY's forecast of additional FTEs considers all of the factors noted above.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-010

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-010

Reference: July 7,2023 Application, page 1-7 Staff Positions

AEY identifies 3 new positions being added in Engineering including Engineering Technologist and Supervisor, Business Support Services.

Request:

(a) Have these positions already been filled? If yes, when?

(b) Was the position for Engineering Technologist and Supervisor not provided for in the 2016 GRA?

Response:

(a) Yes. The three engineering positions were for two electrical engineers and one mechanical engineer. Please refer to the table below for when these positions were filled:

Table 1: Engineering Positions

Position	Year
Electrical Engineer	2019
Mechanical Engineer	2019
Electrical Engineer	2023

(b) No.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-011

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-011

Reference: July 7,2023 Application, page 1-7 Staff Positions

AEY states: The remaining added FTEs address the need of a growing number of customers, vendors and employee expense payment volumes, additional reporting and energy transition planning and communications.

Request:

(a) How many inter-office personnel did you have in your Whitehorse office in 2016? How many of these same positions will you have in your Whitehorse office in 2023?

(b) How much for each of the test year revenue requirements will go to head office support for regulatory work, billing and other? Explain each.

Response:

(a) Please refer to the table below for the FTEs:

Inter-Office Personnel FTEs

Location	2016	2023
Whitehorse office	62.96	69.91

(b) Please note this is an excerpt taken from AEY 2023-2024 AEY General Rate Application, Schedule 5-3, lines 9 and 11.

Head Office Support
($000s)

Head Office Costs	2023	2024
Governance, HR, and Health & Safety	121	112
Financial Reporting and Regulatory Support	697	792

ATCO Electric YUKON

September 28, 2023 AEY-UCG-012

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-012

Reference: July 7,2023 Application, page 1-5 May 11, 2016 Application, page 18-1 Energy Transition.

AEY states: Meeting these targets (i.e., Federal Government 2030 Carbon Emissions and Yukon Government Our Clean Energy Future) is having a dramatic impact on AEYs business responsibility to provide safe and reliable electricity at and affordable cost.

Request:

(a) Give examples of these impacts with forecasted costs associated.

(b) How much of these costs will be covered by Federal or Territorial grants application?

Response:

(a) AEY has undertaken a number of initiatives and programs in response to the Federal and Territorial targets, specifically Grid Modernization, Independent Power Production (IPP), EV Chargers, and Micro-Generation.[1] Not all costs associated with these initiatives are being tracked separately, nor have they been realized as some of these programs are in very early stages. However, some examples of the costs included within the application are the addition of two new positions related to Renewables and Grid Modernization[2] and costs related to IPP projects, specifically the establishment of Electricity Purchase Agreements with IPP's, which are captured in the EPA/IPP Deferral Account.[3]

1 2023-2024 AEY GRA, Section 1B, PDF pp. 22-25.
2 2023-2024 AEY GRA, Section 1.10, PDF p. 16.
3 2023-2024 AEY GRA, Regulatory Schedules, Schedule 8.8, Line No. 54-58.

AEY has included forecast MWh of IPP and Micro Generation in its forecast power supply. These amounts have been excluded from forecast wholesale purchases and diesel generation costs and included in supply at the established electricity purchase rate. Over the long term, with expected reductions in diesel consumption, AEY anticipates longer periods between required maintenance of diesel generators.

(b) IPP projects, and their interconnection to the utility grid, are fully contributed by the proponents. AEY is unable to determine how much Federal or Territorial grants will cover “Our Clean Future” costs; however, AEY is actively investigating the availability to apply for funding. It is important to note that any costs covered by Territorial or Federal funding would be excluded from revenue requirement.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-013

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-013

Reference: July 7, 2023 Application, page 1-5 May 11, 2016 Application, page 18-2

AEY states: The AMI solution will eliminate the need for a person to physically read the meters for billing purposes.

Request:

(a) How much will this save AEY?

(b) Demonstrate how these savings will be adjusted to the revenue requirement.

(c) Will AMI give the consumer options for choice or will AEY control the residential systems, i.e., turn devices within the residences on and off at their whim?

Response:

(a) AEY has not fully forecast savings related to the installation of AMI meters. The AMI program over the Test Period is limited in scope to approximately 1,500 meters located in the Whistle Bend Subdivision. It is anticipated that there will be savings realized from the following: reduced fleet O&M due to fewer truck rolls (situations in which AEY must dispatch a vehicle to physically address a meter issue); lower labour costs as a result of not having to add additional FTE's to the complement to accommodate reading the increase in meter installs due to population growth; and less rework due to weather events. For example, in extreme cold some of the digital displays do not work and AEY has to go out a second time to read, if a read is missed due to deep snow, do not have to go to site to get it as a reading can be pulled from the system.

(b) There are no anticipated adjustments to the revenue requirement with this program with such a small scale of deployment.

(c) AEY is still exploring the options that will be available to consumers as the result of the installation of the AMI network. These may include the option for the customer to participate in future programs where electrical devices behind the meter could be controlled by the utility during peak events or unplanned outage restoration.

September 28, 2023 AEY-UCG-014

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-014

Reference: July 7,2023 Application, page 18-3

AEY states: AEY is requesting deferral on costs associated with the IPPs.

Request:

Give examples of costs that could be associated with IPPs that are to be added to normal business costs.

Response:

Examples of costs that could be included in the deferral account are constraint payments required to be paid to the IPP facility owner in the event that the facility is unable to deliver electricity to the grid as a result of damage to, or a failure of, infrastructure or equipment for which AEY is responsible. Please refer to YUB-002(b)(ii) for other associated costs.

Once the IPP facility is integrated into the grid and has met the Commercial Operation Date, and all requisite conditions for operation, the ongoing operation and maintenance of the Battery Energy Storage System (BESS) and Micro Grid Controller (MGC) are AEY's responsibility similar to other grid electrical infrastructure required to provide electrical service to the community. Examples of maintenance expenses related to the BESS/ MGC can be found in the response to AEY-JM-013(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-015

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-015

Reference: July 7,2023 Application, page 18-4

AEY states: Micro generation may lead to policy changes in MG program that will lead to changes to the electrical grid.

Request:

(a) Give forecast costs associated with these possible changes.

(b) Will these costs be covered by the YG initiative and the AMI program changes?

Response:

(a) AEY is not able to provide a forecast for costs related to unknown policy changes. Due to the uncertainty of these costs, AEY is requesting a zero-balance deferral for Board Orders or Legislative Changes to ensure any savings or costs associated are captured and flow through to customers.

(b) No.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-016

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-016

Reference: July 7,2023 Application, page 18-4

AEY states: Deferral Account for Board Orders and Legislative Changes

Request:

(a) Does AEY expect to oversee this account?

(b) How does AEY propose to handle savings related to this proposal.

Response:

(a) Yes. AEY would oversee this deferral account as it does with all currently approved deferral accounts. Settlement of the proposed deferral account would be subject to review and approval of the Board.

(b) Once approved by the Board, AEY proposes that any savings eligible for treatment under this deferral be treated consistent with other deferral accounts that flow the savings through to customers through a rider.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-017

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-017

Reference: July 7,2023 Application, page 2-1 Table 2.1 Sales by Customer Class

Request:

(a) Please confirm that the electricity sales by customer class shown at the top of page 2-1 are weather normalized.

(b) Has the YUB approved a forecast wholesale sales level for 2023 and 2024 for Yukon Energy Corporation? If yes, what is the amount.

(c) Please provide details on when AEY's current sales forecasts for 2023-2024 were determined for this rates application.

(d) Please identify the impact that demand side management had on sales levels in 2018, 2019, 2020, 2021 and 2022. Explain how this impact has been incorporated into the sales forecast for 2023 and 2024 and provide a revised version of Schedule 2.1 showing the actual and forecast sales for 202302024 with DSM impacts isolated.

(e) Please provide an updated table with the 2023 Forecast reflecting 6 months of actuals and the impact this would have on the 2023 forecast.

Response:

(a) Not confirmed.

(b) No, the YUB has not yet approved YEC's wholesale sales forecast for 2023 and 2024.

(c) AEY's current sales forecast for 2023-2024 was completed in May 2023.

(d) AEY is not able to quantify the precise impact of DSM on the sales forecast as no detailed studies have been completed.

(e) Please refer to the table below for an updated Table 2.1 which incorporates six months of actuals into the 2023 sales forecast:

Table 2.1 AEY Sales by Customer Class (MWh)

	2016	2017	2018	2019	2020	2021	2022	2023[1]	2024
	Actual							Test Period	
Residential	151,351	165,654	167,596	166,455	185,235	188,526	188,388	187,840	195,966
Commercial	157,662	165,924	168,285	168,680	163,933	166,022	168,541	170,146	175,244
Street Lights	3,923	3,942	3,951	3,876	3,889	3,937	3,884	3,878	3,883
Private Lights	496	495	486	480	452	452	456	441	431
Total Retail Primary	**313,432**	**336,016**	**340,318**	**339,491**	**353,508**	**358,936**	**361,269**	**362,304**	**375,523**
Secondary Sales	4,835	8,385	258	1	479	4,430	3,439	1,861	2,931
Wholesale Sales	548	584	636	693	704	487	420	456	451
Total Company	**318,815**	**344,985**	**341,212**	**340,184**	**354,691**	**363,853**	**365,128**	**364,621**	**378,905**

1. 2023 Forecast includes 6 months of actuals for January, February, March, April, May and June.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-018

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-018

Reference: July 7,2023 Application, page 2-1 Sales by Customer Class AEY states; AEY forecasts the total primary retail sales to increase 0.2 per cent in 2023 and to increase 3.7 per cent in 2024. The forecast growth in retail sales for 2023 and 2024 follows year over year growth averaging approximately 1.1 per cent over the period 2020 to 2022.

Request:

(a) Please provide details of the referenced population growth analysis undertaken by AEY and copies of the reference documents.

(b) Please provide specific detail on the impact that DSM and other energy efficient initiatives have had on electricity sales for 2020, 2021 and 2022 including how AEY has determined the impact of these initiatives.

Response:

(a) AEY referenced multiple pieces of information to determine an economic outlook for the Yukon. AEY relied on documents sourced from the Yukon Bureau of Statistics and Yukon Economic Development. Please refer to AEY-UCG-018(a) Attachment 1 for copies of the documents.

(b) Please refer to the response to AEY-UCG-017(d).

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Introduction

The 2023–24 Fiscal and Economic Outlook presents the territory's current fiscal and economic position and expectations for the medium term. The Government of Yukon is moving the territory toward a sustainable and prosperous future while ensuring responsible fiscal management across all government programs and services. The Yukon is recovering from the impacts of the pandemic and the economic outlook is positive.

Despite the recent challenges created by higher rates of inflation, expectations are that the Yukon will build on 2022's robust economic growth, with further real Gross Domestic Product (GDP) gains and an outlook highlighted by a strong labour market and additional population growth. The government remains committed to working closely with partners in the public and private sectors, including First Nations governments, to ensure a strong, diversified and sustainable economy for all Yukoners. Overall, the territory's economy is well-positioned to address the challenges ahead and continue growing in the coming years.

Part 1: The Yukon's finances

In the 2023–24 Budget, the Yukon government is delivering on its longstanding commitment to growing the economy while ensuring strong, sustainable fiscal management. The government projects a surplus of $48.2 million in 2023–24 and projects to remain in a surplus position throughout the duration of this fiscal outlook. A surplus of 2-3 per cent of the total budget is a prudent fiscal management tool and demonstrates the ability of the government to address unforeseen events without going into deficit. Maintaining a surplus position lessens the government's potential need to borrow funds and reduces the net debt position. The expected fiscal position in 2023–24 reflects a focus on strategically allocating resources to the ongoing priorities of Yukoners.

Table 1. Fiscal summary

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Revenue[1,2]	1,460.2	1,504.5	1,575.4	1,663.5	1,719.2
Expense[3]	(1,644.6)	(1,683.8)	(1,642.4)	(1,716.5)	(1,769.1)
Contingency for Anticipated Expenses	(10.0)	(10.0)	(50.0)	(50.0)	(50.0)
Accounting Adjustments[4]	233.9	233.2	165.2	161.7	144.9
Surplus/(Deficit)[5]	39.5	43.9	48.2	58.8	45.1
Net Financial Assets/(Debt), end of year[6]	(207.5)	(298.5)	(374.8)	(453.0)	(528.0)

Source: Department of Finance. Numbers may not add due to rounding.

1. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are included in the Accounting Adjustments in this table.

2. Figures for revenue, contingency for anticipated expenses and surplus (deficit) are found on Pages S-8 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

3. Figures for expense and accounting adjustments are found on Pages S-18 of the 2023–24 Main Estimates and equivalent pages of budget documents for other periods.

4. Accounting Adjustments are the sum of "Tangible Capital Assets (net)," "Investment in Land Development," "Expenditures on Loan Programs," and "Other Adjustments (net)," on Page S-9 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

5. Surplus/(Deficit) is the sum of Revenue, Expense, Contingency for Anticipated Expenses, and Accounting Adjustments.

6. Found on Page S-9 of the 2023–24 Main Estimates.

Net financial debt, or net debt as it is often known, is expected to increase by $76.3 million in 2023–24 to a total of $374.8 million. Recent increases to the government's net financial debt position were incurred to fund ongoing maintenance of the territory's infrastructure and to invest in new projects that will benefit Yukoners now and well into the future. In standard accounting, net financial debt is a measure of how much the government would need to pay if all of its liabilities were due immediately. It does not mean government needs to borrow those funds. Most of the government's net debt position is for long-term liabilities that will not be realized all at once.

Part of the changes to net debt reflect a new accounting standard that came into effect in April 2022. These new rules require the government to record and measure future financial obligations to retire government assets from service, such as buildings or equipment, once they are no longer of productive use. The estimated future costs to retire an asset are then recognized over an asset's productive life. The increase to net debt from 2022–23 includes an additional $54.3 million to reflect accounting changes to align with the new standard. The new standard is also expected to increase net debt by approximately $1.6 million annually.

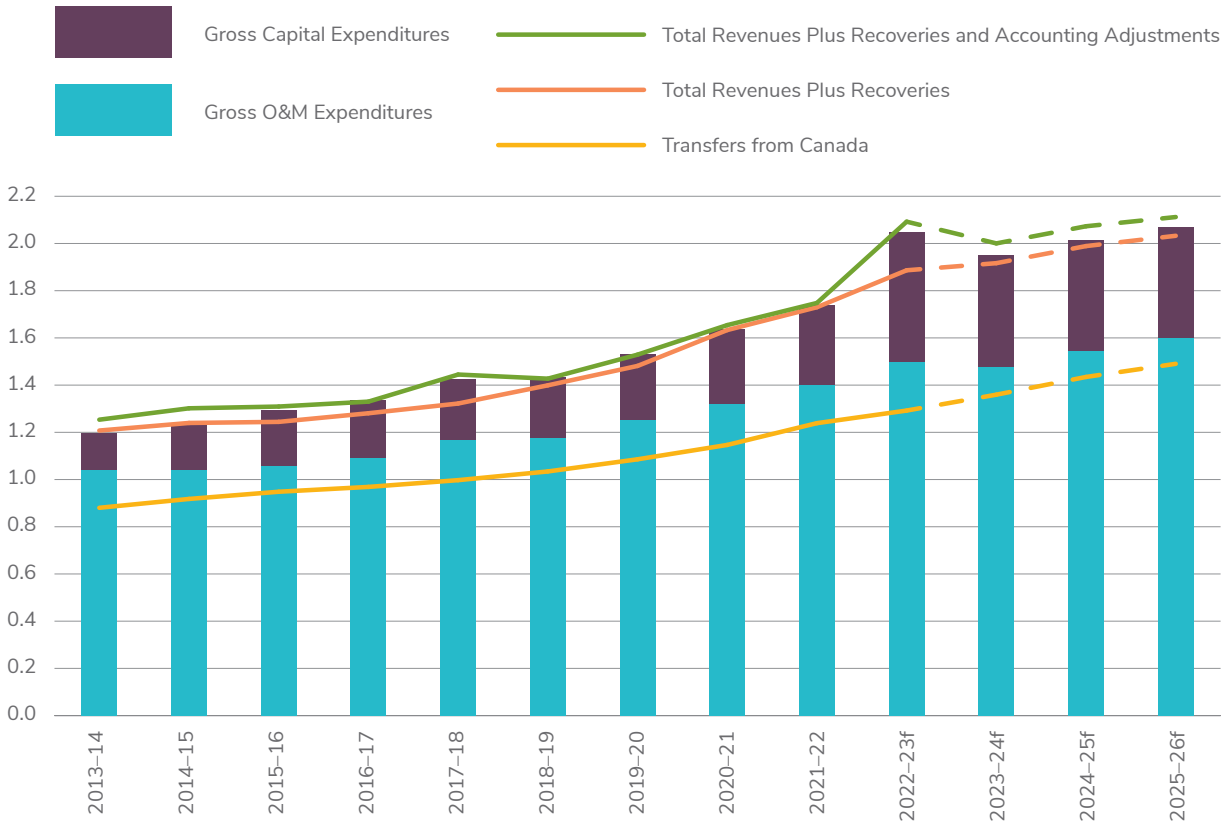
The government is committed to maintaining fiscal sustainability. To achieve this, the government has reviewed spending commitments to ensure expenditures are effectively being used within the framework of expected revenues. These measures will help to ensure that the government is able to meet its spending commitments while maintaining a healthy fiscal position. Capital expenditures are forecast to decrease by $35.2 million or 9.9 per cent, net of recoveries, from the 2022–23 Main Estimates to preserve the government's strong fiscal standing and address increasing inflation while continuing to invest in priority areas. The decrease to capital spending is partially offset by an increase to the forecast for Operations and Maintenance (O&M) expenditures of $33.0 million or 2.6 per cent, net of recoveries, from the 2022–23 Main Estimates.

The government's fiscal summary for 2023–24 also includes a $50 million contingency for areas of expected, but presently undefined, expenditures. The government has benefitted from this realistic approach to budgeting in recent years for COVID-19 spending and we are continuing this approach for expected cost pressures. These costs are not presented in departmental budgets in the coming fiscal year as the expenditures are not yet known. They are included in the overall financial framework so that they will not affect the Yukon's forecast fiscal position, should they be needed. This allows the government to remain transparent about potential pressures and would require legislative authority.

In Chart 1, forecast spending and revenue for the Yukon, including recoveries, from 2022–23 through 2025–26, are compared to historical spending as reported in the Yukon's Public Accounts. In recent fiscal years, growth in government spending has increased in line with revenue growth. For the fiscal years between 2013–14 and 2022–23, O&M expenditures have grown by 5.1 per cent annually and revenues have grown by 5.0 per cent annually, on average. For 2023–24 to 2025–26, expenditures and revenues are expected to change at a similar pace, with expenditures growing by an annual average of 2.3 per cent, while government revenues are expected to grow at an average of 2.5 per cent annually.

Chart 1. Government of Yukon fiscal indicators[7,8]

Expenditures and revenues ($ billions)



Source: Department of Finance *f = forecast*

7. Fiscal years 2013–14 to 2021–22 represent actuals as reported in the Yukon's Public Accounts. For comparability, forecasts for fiscal years 2022–23 to 2025–26 use the same methodology, which differs from the presentation in Table 1 above.

8. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are netted-out of the gross expenditures presented in this chart.

Revenue

Government revenues rely heavily on transfers from the Government of Canada, supplemented by own-source revenues that are mostly driven by economic activity. The Yukon government's revenue is critical to ensuring that the government has the resources needed to meet its spending commitments. As shown in Table 2, total revenue, excluding recoveries, is expected to be $1.58 billion in 2023–24. This represents an increase of $70.9 million, or 4.7 per cent, from the most recent estimates in the 2022–23 Supplementary Estimates #2. This increase is primarily driven by the territory's economic position and a changing fiscal situation across Canada, which affects federal transfers.

Table 2. Revenue by type[9,10]

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Transfers from Canada	**1,244.4**	**1,261.4**	1,327.0	**1,400.3**	**1,454.7**
Tax revenue	**157.7**	**175.0**	170.9	**177.2**	**182.2**
Personal income tax	89.9	100.7	98.4	102.4	105.6
Corporate income tax	24.4	32.0	27.4	27.8	28.4
Property tax	7.0	7.0	7.2	7.6	7.7
Fuel oil tax	9.7	8.7	8.8	8.8	8.9
Tobacco and alcohol taxes	18.6	18.4	20.0	20.7	21.1
Insurance premium tax	8.1	8.2	9.0	9.9	10.6
Other revenue	**58.1**	**68.1**	77.5	**85.9**	**82.3**
Liquor profit	9.4	7.5	8.8	8.8	9.1
Licenses, fees, registrations and permits	17.6	17.1	18.3	18.7	19.2
Sale of land	19.2	20.8	32.3	34.2	31.3
Other revenue	12.0	22.8	18.1	24.2	22.6
Total revenue	**1,460.2**	**1,504.5**	**1,575.4**	**1,663.5**	**1,719.2**

Source: Department of Finance. Numbers may not add due to rounding.

9. All revenue figures are found on Pages S-14 and S-15 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

10. To align with the presentation in the Yukon's Public Accounts, revenues do not include those collected by the Yukon Housing Corporation.

Transfers from Canada

Transfers from Canada, which includes the Territorial Formula Financing grant, represent about 84 per cent of the Yukon's total revenue in 2023–24. Territorial formula financing helps to reduce the gap between the Yukon's ability to raise revenue and its spending needs for core services.

The grant is responsive to changing economic and demographic circumstances in the territory compared to the rest of the country. This includes changes in public spending across the country, which are increasing due to the high inflationary environment and associated inflation relief programs. The growth in spending for other provinces and territories have an upward impact on the Yukon's Territorial Formula Financing grant. However, the improved outlook on the grant is being offset somewhat by growth in resource revenues. Resource revenues in the territory are expected to increase as royalties increase, which would have a downward impact on revenue from the Territorial Formula Financing grant. Under the Devolution Transfer Agreement with Canada, the Yukon's grant is reduced dollar for dollar of resource revenues in excess of $6 million in any given year. Resource revenues subject to offset were $10.2 million in 2021–22, meaning the grant in 2023–24 will be reduced by $4.2 million.

At the time that the 2023–24 Main Estimates were prepared, the Yukon government, along with other provinces and territories, were discussing increases to the Canada Health Transfer that could strengthen the healthcare system for the benefit of all Canadians. The Canada Health Transfer forms part of the overall transfers from Canada. Increases to the Canada Health Transfer have not yet been included in expected revenues for 2023–24.

Taxation revenue

The Yukon's own-source revenue from taxation is forecast to decrease in 2023–24 from the 2022–23 Supplementary Estimates #2. Personal and corporate taxation revenues are expected to be strong in 2023–24, but are forecast to be lower than current estimates for 2022–23 primarily due to a non-recurring adjustment for the 2021 tax year in 2022–23. Adjustments for prior tax years are common due to the timing of final reconciliations of tax assessment information. Corporate income tax projections for 2022–23 have been revised upward from stronger than expected corporate profits but are expected to return to trend in 2023–24.

Personal income tax revenues are expected to continue to be strong due to high inflation and the territory's strong labour market performance, which is increasing individual taxable incomes. Business performance continues to be strong in the territory, but corporate income tax revenue can see large variations from year-to-year. The outlook for corporate taxation, while still expected to increase, has also been reduced from projections in previous years due to a change in federal tax provisions that increases the scope of businesses eligible for the small business tax rate. In the Yukon, the small business tax rate is zero per cent.

The forecast for tax revenue from tobacco products has increased. The *Tobacco Tax Act* links changes to the tax rate to changes in the Consumer Price Index (CPI), so the tax rate increased from 31 cents to 32 cents per cigarette as of January 1, 2023. Under the current outlook for inflation, the tax rate for tobacco products is expected to increase to 37 cents per cigarette by the end of 2027.

Expectations for fuel tax revenue in 2023–24 are lower than in the 2022–23 Main Estimates. Fuel tax revenues have not returned to pre-pandemic levels, which could be partly explained by the tourism industry continuing to operate below levels experienced prior to the start of the pandemic. The ongoing outlook for fuel taxes is expected to be mostly flat as more Yukoners adopt electric vehicles and make other transportation choices that are consistent with the Yukon's *Our Clean Future* strategy.

Aside from changes to the tobacco tax, there are no changes to tax rates proposed as part of the 2023–24 budget.

Other revenue

In addition to transfers from Canada and taxation revenue, the government also generates revenue from other sources. These include liquor profit, licenses, fees, registrations, permits and proceeds from land sales. Revenue from these sources are expected to exceed recent levels, in part due to elevated revenue from land sales.

Operations and maintenance expense

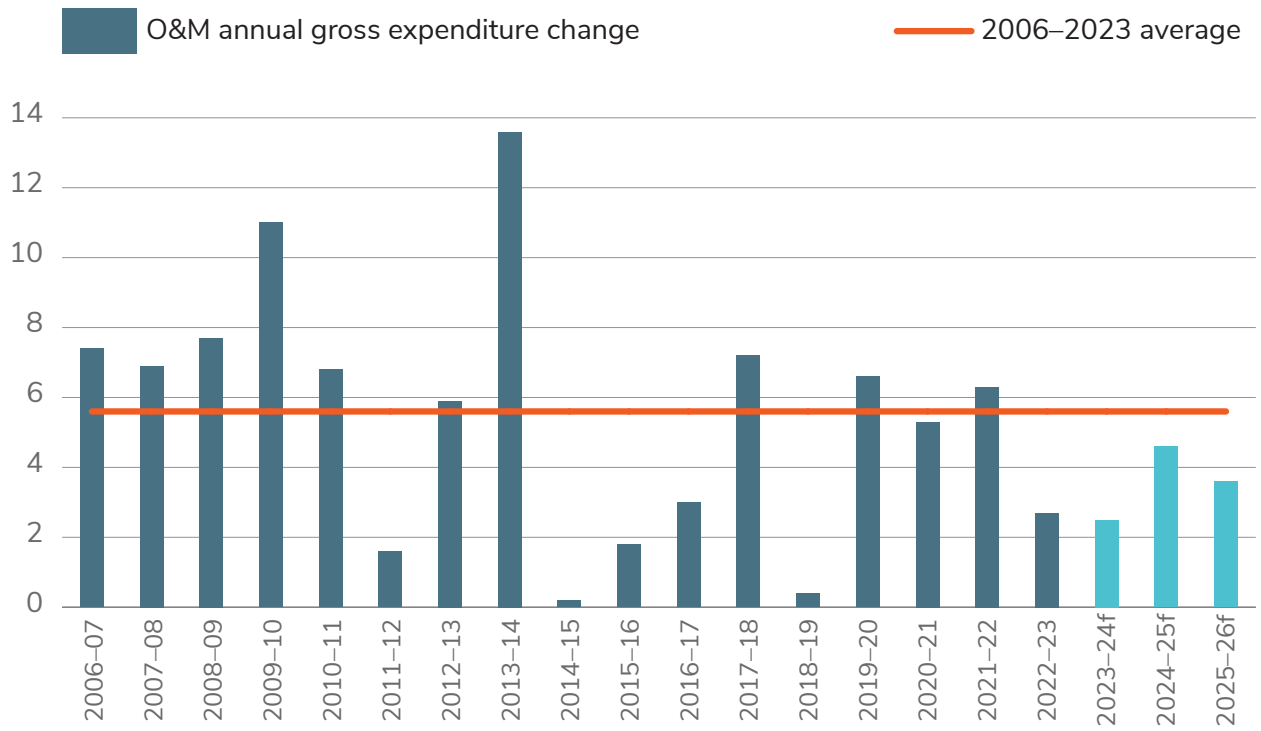
O&M spending for 2023–24 is budgeted at $1.45 billion, which reflects a $35 million, or 2.5 per cent, increase over the previous year's Main Estimates. The increase in spending is primarily for:

- making day-to-day life more affordable for Yukoners;
- investing in the Yukon's health and social system;
- addressing the substance use health emergency;
- improving sustainability and preserving the territory's environment;
- investing in housing and related services, particularly for the most vulnerable; and
- continuing to build relationships and foster reconciliation with Yukon First Nations.

Chart 2 compares forecast gross O&M spending from 2022–23 through 2025–26 to actual historical O&M spending as reported in the Yukon's Public Accounts. The average annual growth in O&M spending between 2006–07 and 2022–23 was 5.6 per cent. Forecast O&M spending growth in 2024–25 and 2025–26 is anticipated to remain below the average at approximately 4.5 per cent and 3.5 per cent, respectively.

Chart 2. Annual growth in O&M budgets

Change in Government of Yukon gross O&M spending (per cent)



Source: Department of Finance *f = forecast*

Higher rates of inflation continue to be the reality for Yukoners, and family budgets are becoming tighter. The government continues to take steps to provide targeted inflationary relief to families, especially the most vulnerable. The government continues to assess how inflation is impacting Yukoners. In 2023–24, the government is extending the Inflation Relief Rebate Program, which provides a $50 per month rebate on ATCO Electric and Yukon Energy utility bills for the April and May billing periods, along with an additional three months later in the year. Other measures in the 2023–24 Budget to help make life more affordable for Yukoners include funding for food in Yukon schools, the timber harvesting incentive to boost fuelwood supply, a quarterly top-up of $150 to eligible recipients of the Yukon Senior Income Supplement and a $100 monthly increase to eligible Social Assistance recipients.

With the COVID-19 State of Emergency coming to an end in March 2022, the Yukon is now adapting to living with the risks from COVID-19 while continuing to support Yukoners' well-being. However, healthcare systems across Canada, including the Yukon, continue to be strained following the pandemic. Healthcare workers are experiencing stress and burnout, and people seeking health services are experiencing long wait times due to staff shortages. The 2023–24 Budget includes funding to improve supports for critical staff, including recruitment and retention bonuses for nurses, negotiated increases with the Yukon Medical Association, a human resources strategy to improve health care worker recruitment and adding nursing positions in rural locations. The government also continues to act on the recommendations from the *Putting People First* report. This includes funding for the territory's dental plan, early learning and childcare.

In 2023–24, the government will continue to support the needs of individuals and communities impacted by the substance use health emergency. This includes additional funding to address the harms of substance use, combat the supply of harmful substances through additional RCMP supports, and help youth with substance use challenges. Together, these initiatives support people who are struggling with addiction and mental health issues and help to reduce the harm caused by substance use in communities.

Many areas across Canada are facing housing shortages and challenges with housing affordability. In 2023–24, the government will continue working to meet the housing needs of Yukoners, including partnering with the private sector on lease costs and supportive services for seniors at the new Normandy Living facility in Whitehorse. The Budget also includes funding to ensure the Yukon Housing Corporation's housing stock remains safe and well maintained.

The government remains fully committed to supporting reconciliation and respectful partnerships with Yukon First Nations governments. The government is working in partnership with Yukon First Nations on key priorities in 2023–24. This includes funding for Community Safety Officers and policing initiatives in communities, and support for the community safety planning priorities of Yukon First Nations governments in their communities.

The government continues to make progress on the implementation of *Our Clean Future* and protect the environment. The Yukon government is working in partnership with the Government of Canada to advance land use planning and species-at-risk protection in the Yukon through the *Bilateral Nature Agreement*. Through this, government will advance work towards the federal government's mandate to conserve and protect 25 per cent of land by 2025, and 30 per cent by 2030.

Five-Year Capital Plan update

With the 2023–24 Main Estimates, the Yukon government is publishing its sixth annual plan for its capital investment priorities over the next five years. The plan helps drive transparency, certainty and coordination with businesses, First Nations governments and municipalities.

Table 3. *Five-Year Capital Plan* gross expenditures by category

($millions)	2023–24	2024–25	2025–26	2026–27	2027–28	Totals
Climate change, energy and green economy	36	43	47	42	29	197
Land development, housing, education and health	133	84	78	81	93	470
Community and First Nations infrastructure	78	75	75	60	65	352
Transportation infrastructure	160	177	197	123	123	779
Real property and asset management	33	46	46	51	35	211
Information technology	45	51	18	17	14	146
Totals	**484**	**475**	**462**	**374**	**359**	**2,155**

Source: Capital Planning Office. Numbers may not add due to rounding.

The 2023–24 *Five-Year Capital Plan* includes approximately $2.15 billion in capital spending over the next five years. These investments will focus on improving access to stable and affordable housing, increasing accessibility to healthcare services, providing modern school facilities and advancing the territory's climate change goals. The government continues to leverage funding from the federal government and other partners to find offsets for over one-third of the capital spending in the plan.

The capital budget for 2023–24 is projected to be $483.8 million, a modest decrease from the 2022–23 Main Estimates. The government remains committed to robust and steady investments in the territory's infrastructure. However, it is prudent for the government to carefully consider how it is investing in capital projects to address increasing inflation by reducing previously planned capital spending in its *Five-Year Capital Plan*. The government has reviewed planned projects in the Plan to ensure it is maintaining its current assets while delivering on the new critical infrastructure that Yukoners need. For certain capital projects, the government is exploring innovative ways to deliver these projects, including partnering with municipalities or First Nations governments in the development of new infrastructure. This approach has resulted in a lower total spend in the next few years compared to earlier projections, while creating a more stable outlook for capital spending.

The government remains committed to robust and steady investments in the territory's infrastructure.

The government is making priority capital investments across six main areas in the *2023–24 Five-Year Capital Plan*:

- $197 million for climate change, energy and green economy projects to continue to advance the *Our Clean Future* strategy and invest in sustainable jobs in the territory. In 2023–24, this includes investing in renewable energy projects, such as solar installations and biomass, through the Green Infrastructure Program; and helping Yukoners increase the energy efficiency of their homes and businesses through the Better Buildings energy retrofit loans program.
- $470 million for land development, housing, education and health projects to ensure the territory can meet the housing, educational and healthcare needs of a growing population and economy. In 2023–24, this includes completing the Old Crow 10-unit mixed-use housing project and work on the Kêts'ádań Kų School in Burwash Landing.
- $352 million for community and First Nations infrastructure to meet infrastructure needs in communities across the territory, including working in partnership with Yukon First Nations and municipal governments on their priorities. In 2023–24, this includes work on a new Fire Hall building in Carmacks; upgrades to the existing Public Works building in Carmacks; and upgrades to the Teslin Tlingit Council community hub.
- $779 million for transportation infrastructure to invest in the territory's transportation system to keep Yukoners and the economy moving and advance the sustainability of supply chains critical to the Yukon. In 2023–24, this includes ongoing work on critical components of the Yukon's transportation infrastructure like the Nisutlin Bay Bridge project, Erik Nielsen Whitehorse International Airport runways and upgrades to the North Klondike Highway.
- $211 million for real property and asset management projects to build and maintain assets that are essential to the delivery of government services. In 2023–24, this includes continuing to retrofit the Old Territorial Administration Building in Dawson City and work on conceptual designs for potential expansions and recreational activities at several campgrounds across the territory.
- $146 million for information technology projects to enhance the territory's vital technological links to Canada and the world. In 2023–24, work will continue on the Dempster Fibre project, which will provide redundancy, increase reliability and reduce the risk of outages in the territory's critical telecommunications infrastructure.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Some important recently-completed projects include:

- $22 million, along with funding from Canada, for the Mayo to McQuesten Transmission Line replacement project, which came online in 2021 and is improving the quality and reliability of electricity infrastructure in the area;
- $22 million, in partnership with Canada, for the Faro Public Works & Fire Hall Building and the Watson Lake Municipal Services Building, which combine public works and fire services into a single shared space, saving money on both construction and long-term operating costs; and
- $21 million for the 47-unit residential housing complex at 401 Jeckell Street, completed in January 2023 in partnership with the Canada Mortgage and Housing Corporation. It is providing affordable homes of various sizes for low-income and vulnerable families, seniors and individuals.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Part 2: Economic overview

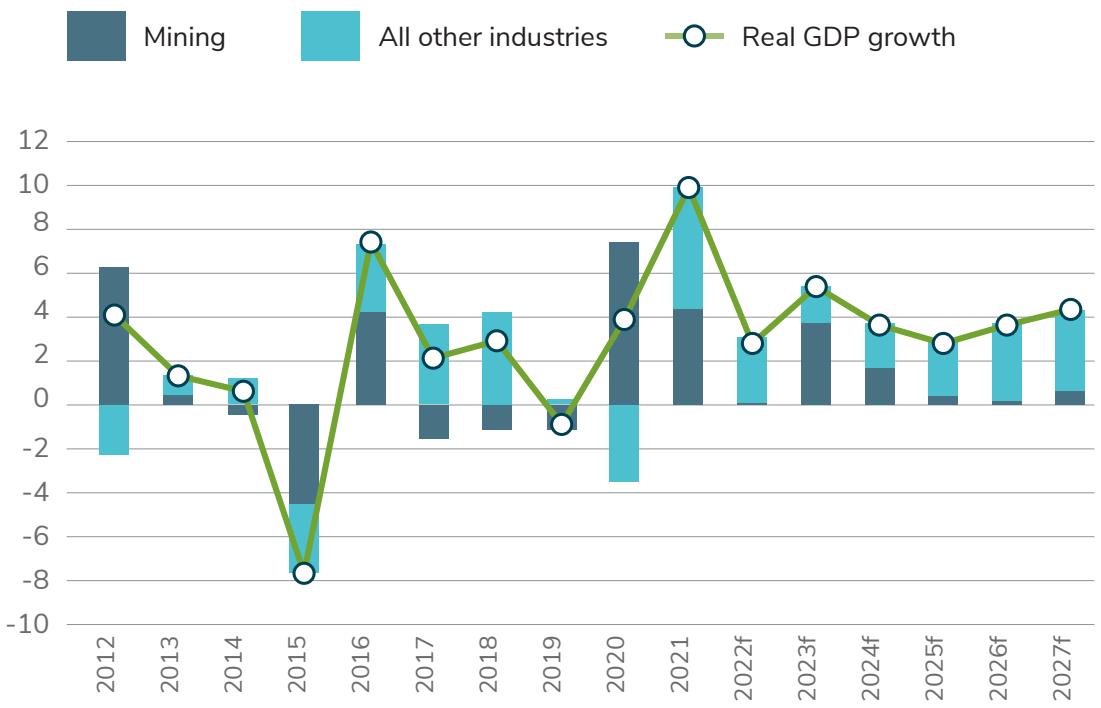
Positive outlook for real GDP growth

The outlook for the Yukon's economy remains positive. A strong labour market is leading to job growth and low unemployment. Tourism is coming back to the territory and the construction sector is busy. Inflation remains higher than anticipated but is expected to moderate with the stabilization of energy prices, improvements to global supply chains and an increase in interest rates that is beginning to absorb excess demand in the Canadian economy.

The Yukon's real GDP is expected to continue to expand. The Yukon led the country in real GDP growth in both 2020 and 2021, with 2021's increase of 10 per cent being the strongest in 13 years. The pace of this expansion returned to more normal levels in 2022 with estimated real GDP growth of 3.1 per cent, close to the Canadian growth estimate of 3.5 per cent. Last year's performance was impacted primarily by the mining sector with disruptions at the Eagle Gold mine and a temporary suspension of operations at the Keno Hill mine.

Chart 3. Further gains in real GDP expected in all years of the forecast

Contribution to real GDP growth (percentage points)



Source: Statistics Canada, Department of Finance *f = forecast*

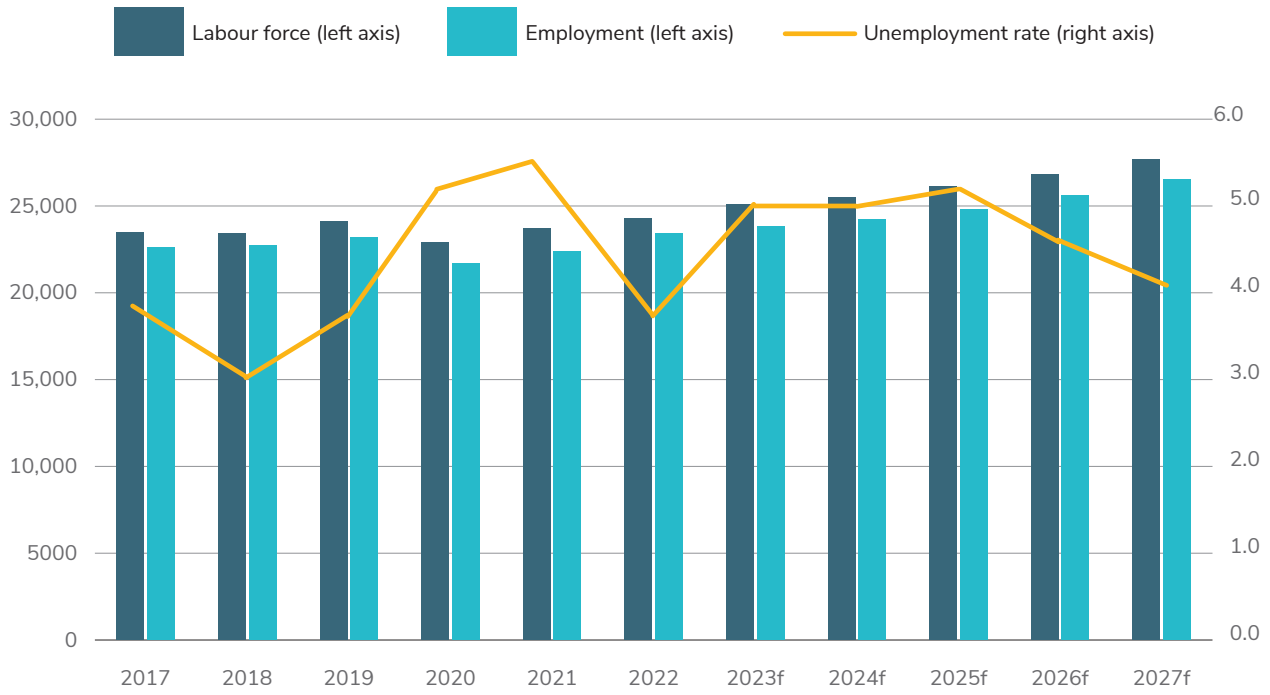
Production at Eagle Gold is expected to ramp up this year and operations at the Keno Hill mine are expected to resume in the third quarter. Higher mineral production and continued recovery of the tourism sector are expected to result in real GDP growth of 5.4 per cent in 2023 followed by 3.7 per cent growth in 2024. Further growth is projected throughout the remainder of the forecast, averaging 3.7 per cent growth through 2025 to 2027.

Further gains in the labour force and employment expected over the medium term

Strong demand for labour and increased economic activity spurred growth in the size of the labour force and employment as both reached record highs in 2022. Employment growth of 4.5 per cent last year outpaced the increase in the labour force and translated into a substantial decline in the territory's unemployment rate. At 3.7 per cent for the year, the Yukon's unemployment rate matched 2019's level and was the lowest in Canada.

Chart 4. Growth in employment and the labour force

Labour force (persons), employment (persons), unemployment rate (per cent)



Source: Statistics Canada, Department of Finance *f = forecast*

Many employers in the Yukon and across the country have had difficulty finding workers. Job vacancies have been elevated in the territory throughout 2022, with the Yukon's job vacancy rate[11] among the top two highest rates in the country for all but one month. Like the experience of many jurisdictions in Canada, the job vacancy rate for the Yukon has recently been higher than the unemployment rate[12], further evidence of a tight labour market (Chart 5).

Chart 5. 2022 has seen tightness in the labour market return

Labour market indicators (per cent)



Source: Statistics Canada

11. The job vacancy rate is the number of job vacancies expressed as a percentage of labour demand, defined as all occupied and vacant jobs.

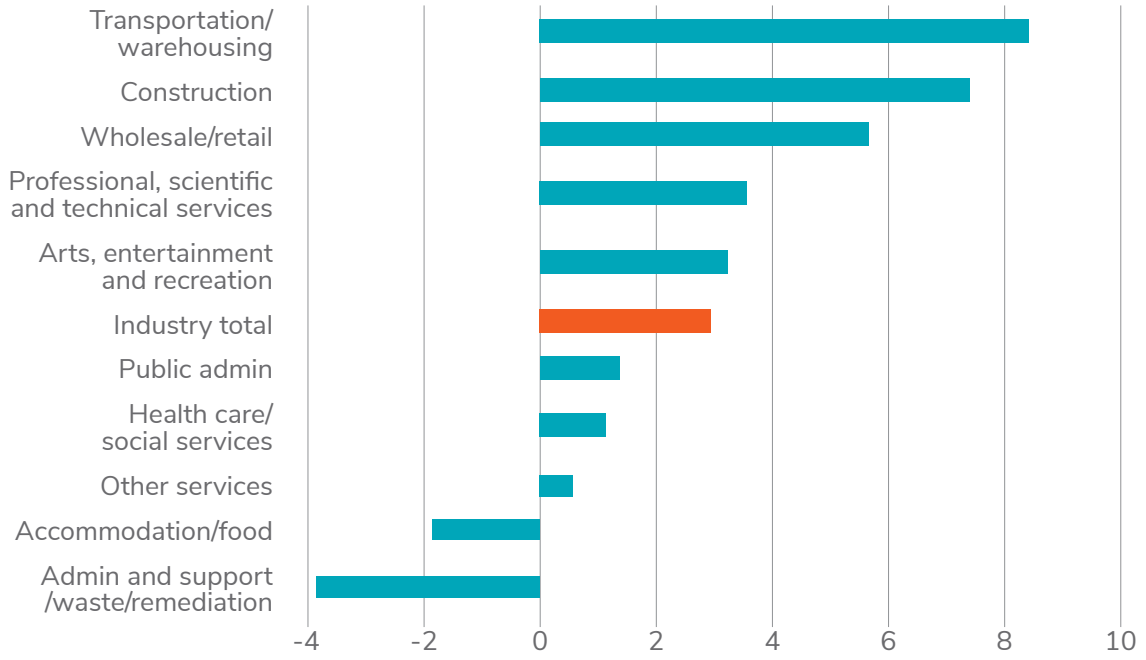
12. When the job vacancy rate exceeds the unemployment rate, this means there are proportionally more jobs seeking workers than workers seeking jobs.

Strong demand for workers at a time when supply is tight is placing upward pressure on wages and earnings. The average offered wage for vacant positions in the Yukon was the third highest in the country at $26.20 per hour in the third quarter of 2022[13], well above the national average of $24.20 per hour and up almost 10 per cent from 2021.

The recent increase in weekly earnings was not as pronounced as the increase in offered wages, but earnings are up across most industries (Chart 6). The average worker in the territory earned $1,334 per week through the first eleven months of 2022, up 2.9 per cent from the same period in 2021. Average weekly earnings for the Yukon ranked third in the country, behind only Nunavut and the Northwest Territories, and were well above the national average of $1,166 per week. While in some cases wages are not keeping pace with inflation, rising incomes have helped to mitigate the inflationary impacts being felt.

Chart 6. Wage pressures reflected in higher earnings across most industries

Average weekly earnings, seasonally adjusted, Jan–Nov 2022 change from Jan–Nov 2021 (per cent)



Source: Statistics Canada

Over the medium term, higher earnings are expected to draw more people into the labour force. The Yukon's labour force is projected to grow slightly faster than employment over the forecast period. This results in a higher projected unemployment rate in the neighbourhood of five per cent. While up from historic lows in recent years, the unemployment rate is projected to remain relatively low, and continue to be one of the lowest in Canada.

13. Average offered wage data is from Statistics Canada table 14-10-0325-01 and is available on a quarterly basis starting with the first quarter of 2015.

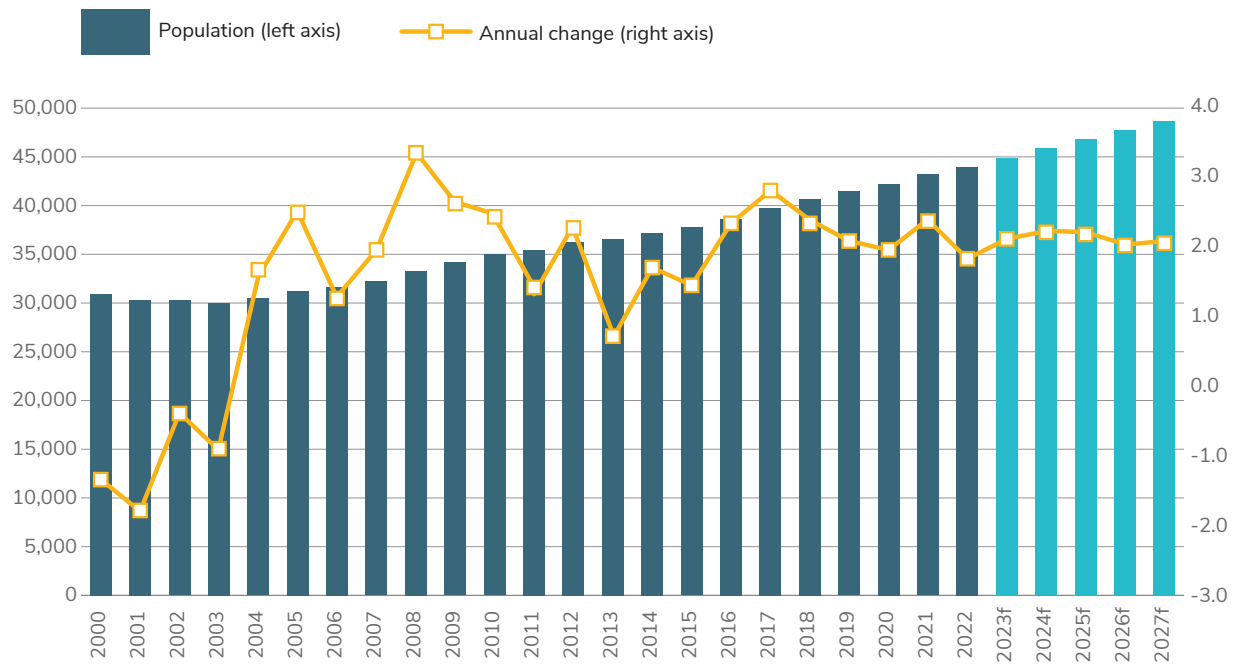
Further population gains anticipated in 2023

At 43,964 on June 30, 2022, the Yukon's population was up 1.8 per cent from 2021.[14] Growth in 2022 was driven primarily by net international migration of 550, which was the highest ever reported.[15] Over the last 20 years, the Yukon's population has grown just over 44 per cent. This growth was second only to Alberta (45.2 per cent) among all provinces and territories and was well ahead of the national growth of 24 per cent. A positive outlook for the territory's economy and labour market is expected to support strong migration into the Yukon and population growth over the medium term.

The federal government is targeting nearly 1.5 million new permanent residents over the 2023 to 2025 period.[16] High levels of immigration should increase the local supply of labour and help alleviate some of the tightness in the labour market. While helping on the labour front, more people moving to the territory has the potential to place further strain on the Yukon housing market, as supply has struggled to keep pace with demand in recent years.

Chart 7. Population is forecast to approach 49,000 by 2027

Population (persons), annual change (per cent)



Source: Yukon Bureau of Statistics *f = forecast*

14. June 30 estimates are considered annual estimates.

15. Statistics Canada's table 17-10-0005-01 reports data for population estimates by age and sex as of July 1.

16. *Government of Canada's Immigration Levels Plan for 2023–2025*. Immigration, Refugees and Citizenship Canada (November 1, 2022).

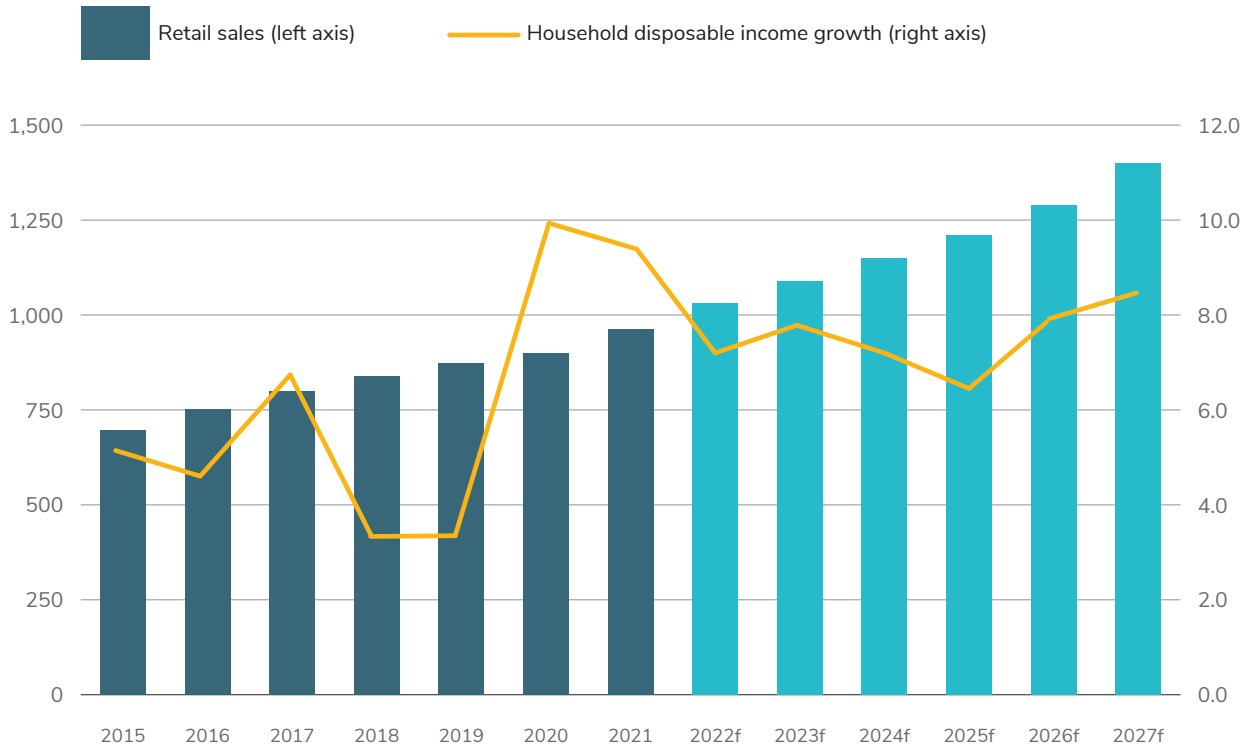
Countering some of the gains in international migration in 2022 was a net outflow of interprovincial migration resulting in 83 fewer residents. This was the first time net interprovincial migration was negative since 2013. Population is projected to increase in every year of the current forecast with growth averaging 2.1 per cent per year. By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Retail sales exceeded $1 billion in 2022

Retail sales exceeded one billion dollars for the first time in 2022. Estimated growth of 6.8 per cent in 2022 is more than double the growth rate from the previous year. Prices were the primary driver of last year's growth in retail sales, with the estimated percentage increase in retail sales equivalent to the 6.8 per cent increase noted in the Whitehorse CPI. The current forecast has retail sales growing every year by an average of 6.3 per cent per year, significantly higher than the projected CPI increases over the same time span.

Chart 8. Income growth a key driver of retail sales growth

Retail sales ($ millions), Household disposable income growth (per cent)



Source: Statistics Canada, Department of Finance *f = forecast*

By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Inflation has increased globally

Global supply chain disruptions and the war in Ukraine contributed to higher food and energy prices in 2022 and added to inflationary pressures noted all over the world. In Canada, domestic factors, including excess demand for labour and other inputs, have also fueled price growth, with the national inflation rate touching levels in 2022 not seen since the early 1980s.

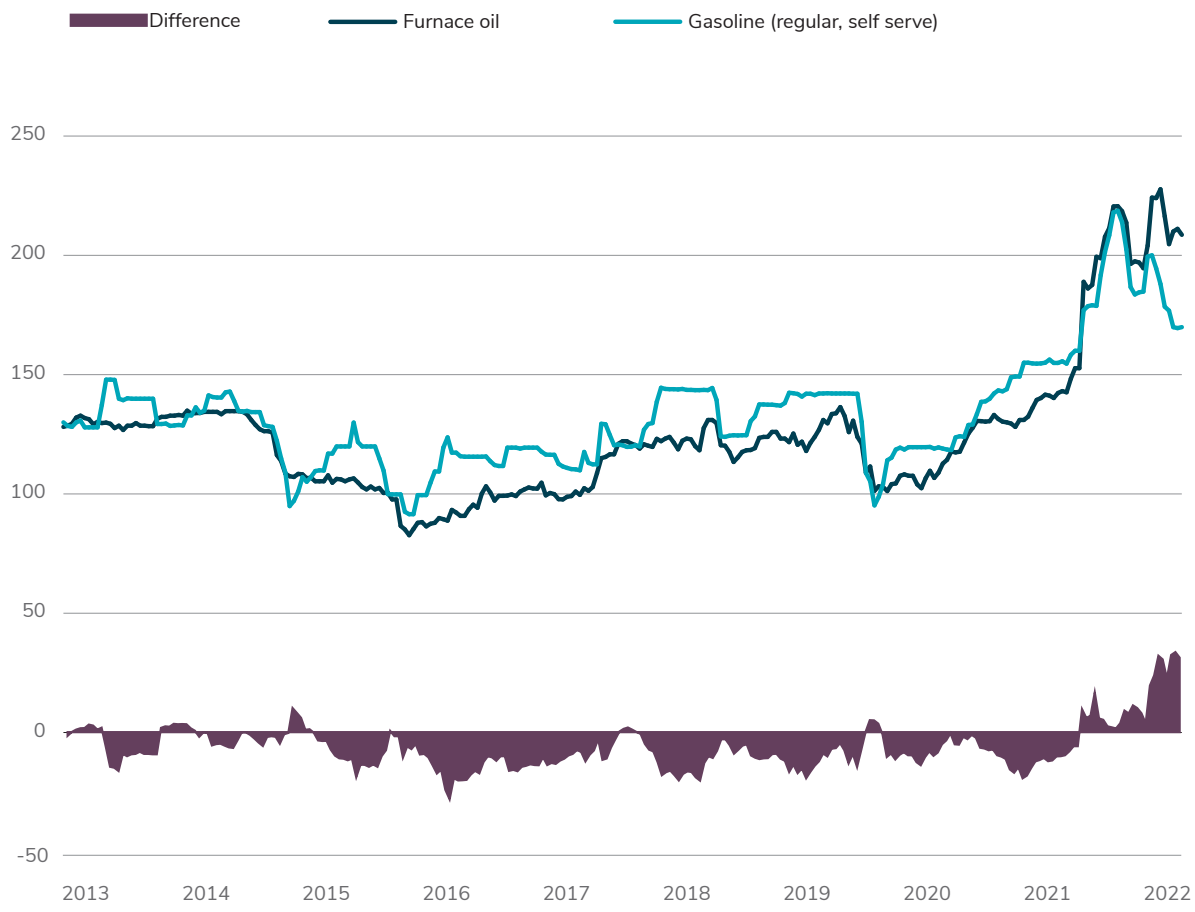
Rapid appreciation of prices for a large variety of consumer goods and services has also been the reality for Yukoners. The inflation rate in Whitehorse[17] averaged 6.8 per cent in 2022, the highest rate for the Whitehorse CPI since records began in 1982. Prices were up across most categories.

Higher fuel prices in 2022 were a prominent driver of overall inflation, with the price of gasoline up 29 per cent, and the price of fuel oil up 47 per cent compared to 2021. While gasoline prices have fallen by over 20 per cent from the peak in June, the price of fuel oil has remained elevated (Chart 9). This reflects global trends. US inventories of distillate fuels, including home heating oil and diesel, are at multi-year lows. Sanctions on Russia have led to Europe shifting towards non-Russian imports. While prices have stabilized, futures prices suggest that diesel and fuel oil prices are likely to remain at a hefty premium to gasoline in the near term.

17. Data are not available for the Yukon, only Whitehorse.

Chart 9. Gap between gasoline and other fuels has widened due to distillate shortage

Whitehorse fuel prices (cents per litre)



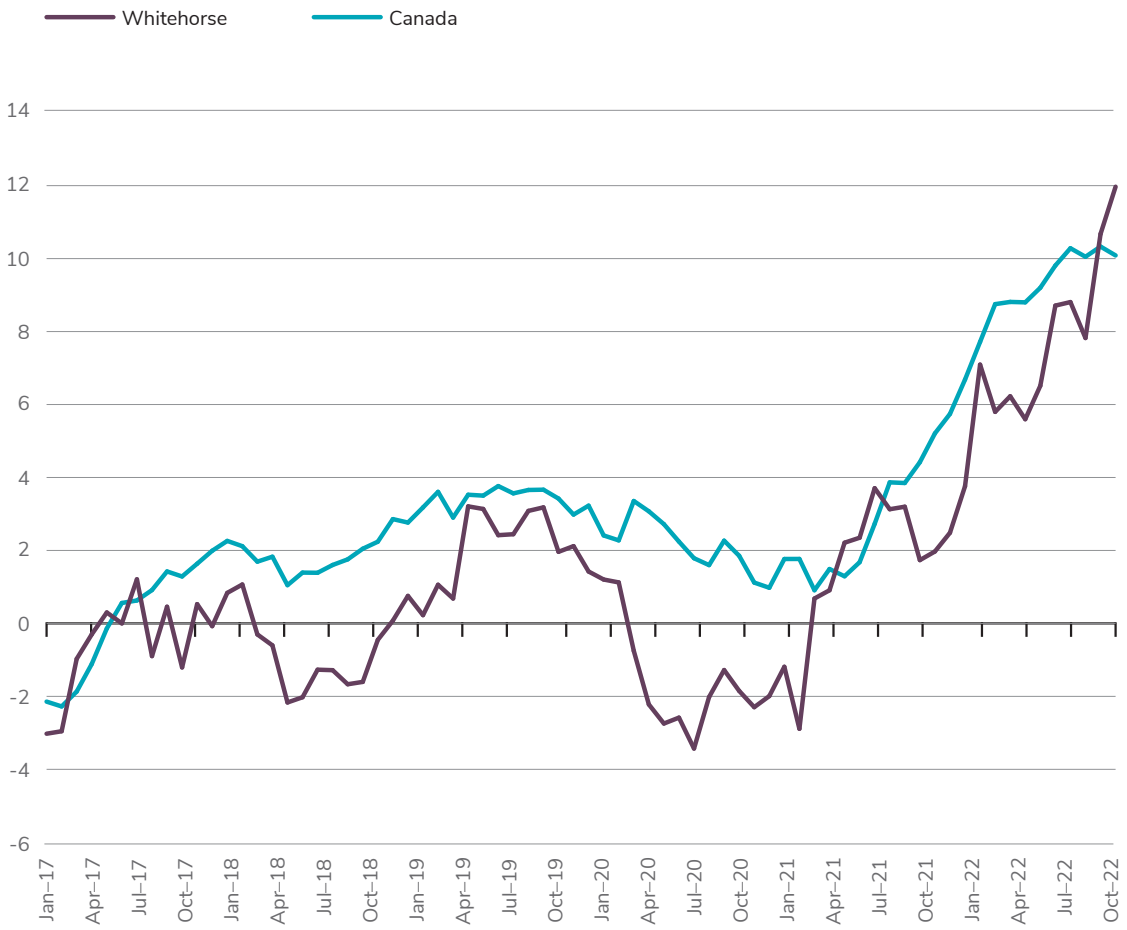
Source: Yukon Bureau of Statistics

Fuel oil is weighted heavier in the Whitehorse CPI than in the national index, because a substantially higher share of Yukoners use fuel oil for heat. This higher weighting is one of the reasons why inflation of 8.1 per cent in Whitehorse as of December was higher than the national rate of 6.3 per cent.

Another factor is that price pressures on food were slower to materialize in the Yukon than in the rest of Canada (Chart 10). Food prices in Canada rose throughout the pandemic, whereas in Whitehorse, they did not start to increase in earnest until later. Ultimately, prices in Whitehorse follow national trends closely and food prices have started to catch up. Inflation in Whitehorse was lower at the beginning of the year and higher at the end, averaging out over the course of the year with annual inflation for both Canada and Whitehorse coming in at 6.8 per cent.

Chart 10. Food price inflation was slower to materialize in Whitehorse

Year-over-year per cent change in the food component of CPI



Source: Statistics Canada

On January 25, 2023, the Bank of Canada increased its policy interest rate to 4.5 per cent to try to reduce the excess demand in the economy. The Bank signaled that it expects to "hold the policy rate at its current level while it assesses the impact of the cumulative interest rate increases."[18] The Bank has increased the policy rate by 4.25 percentage points since last March, the most in such a short span since the Bank began targeting interest rates in the early 1990s.

18. News release – *Bank of Canada increases policy interest rate by 25 basis points, continues quantitative tightening*. Bank of Canada. (January 25, 2023).

Most forecasters expect inflation in Canada will move towards historic norms over the next couple of years as supply chain problems subside and the effect of higher interest rates move through the economy. Canadian inflation is expected to decline from near 7 per cent in 2022, to between 3.5-4.0 per cent in 2023, and many forecasts are calling for inflation in 2024 to approach the midpoint of the Bank of Canada's target range of 1-3 per cent. Similarly, the average annual rate of inflation for Whitehorse is projected to fall from 6.8 per cent in 2022 to 3.8 per cent in 2023 and 2.5 per cent in 2024.

The housing market remains relatively strong but there are signs of cooling

Locally, housing prices have been strong for several years, driven in part by high demand. A generally strong economy has drawn people to the territory. Housing supply has struggled to keep pace with demand, and this has been reflected in upward pressure on housing prices. Prices in Whitehorse across all housing types have seen notable growth in recent years. The average weighted price of single detached homes, duplexes and mobile homes all reached record highs in 2022. Condominium prices in 2022 were down slightly from the 2021 record high.

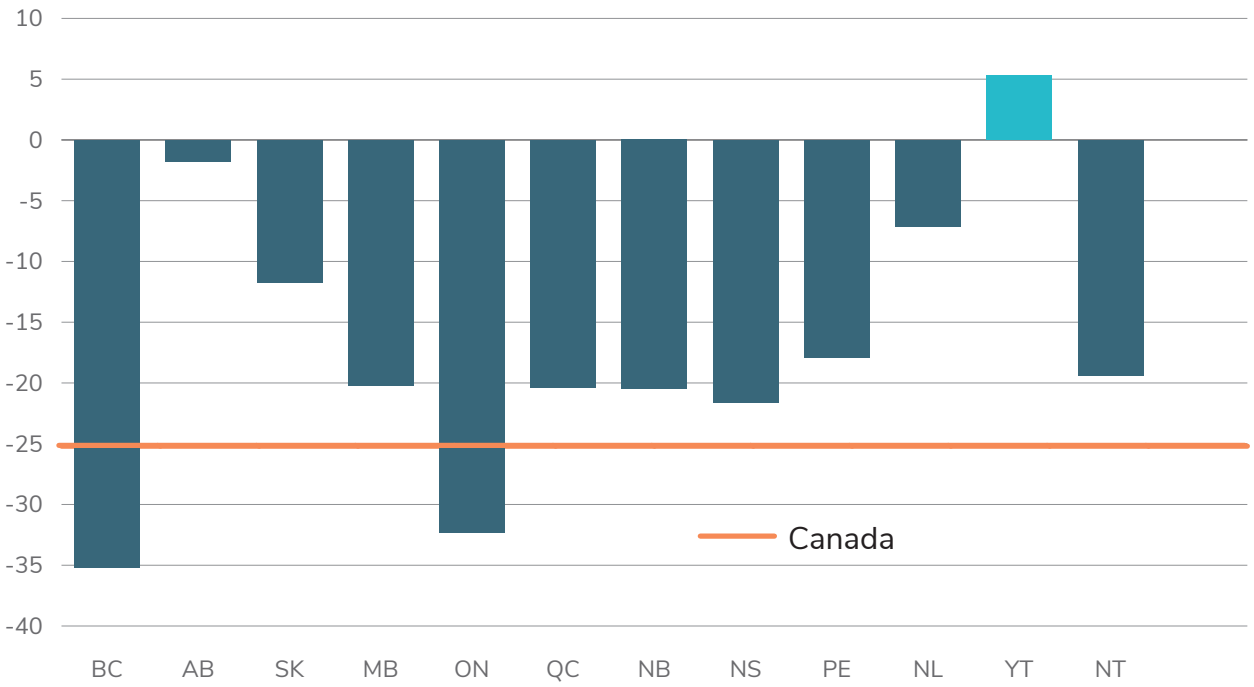
Even during an extended period of very low interest rates and growing household earnings, housing affordability has been eroding due to higher prices. More recently, rapid growth in interest rates has increased borrowing costs for new homebuyers and those on variable rate mortgages. Higher costs will filter through to fixed rate mortgages as they come up for renewal.



Higher interest rates took steam out of housing markets across the country. Average home prices in most Canadian markets fell over the second half of 2022. This effect was slower to materialize in the Yukon, which was the only jurisdiction that saw higher home sales in 2022 than in 2021 (Chart 11). It wasn't until the fourth quarter that signs of cooling showed in the Yukon data.[19] While increasing on average in 2022, average sales prices were down in the fourth quarter of last year across all housing types. Compared to the fourth quarter of 2021, prices were down by 1.2 per cent for single-detached, 3.9 per cent for duplexes, 11.4 per cent for condominiums and 1.6 per cent for mobile homes.

Chart 11. The Yukon experienced growth in the number of residential sales in 2022[20]

Residential sales, 2022 change from 2021 (per cent)



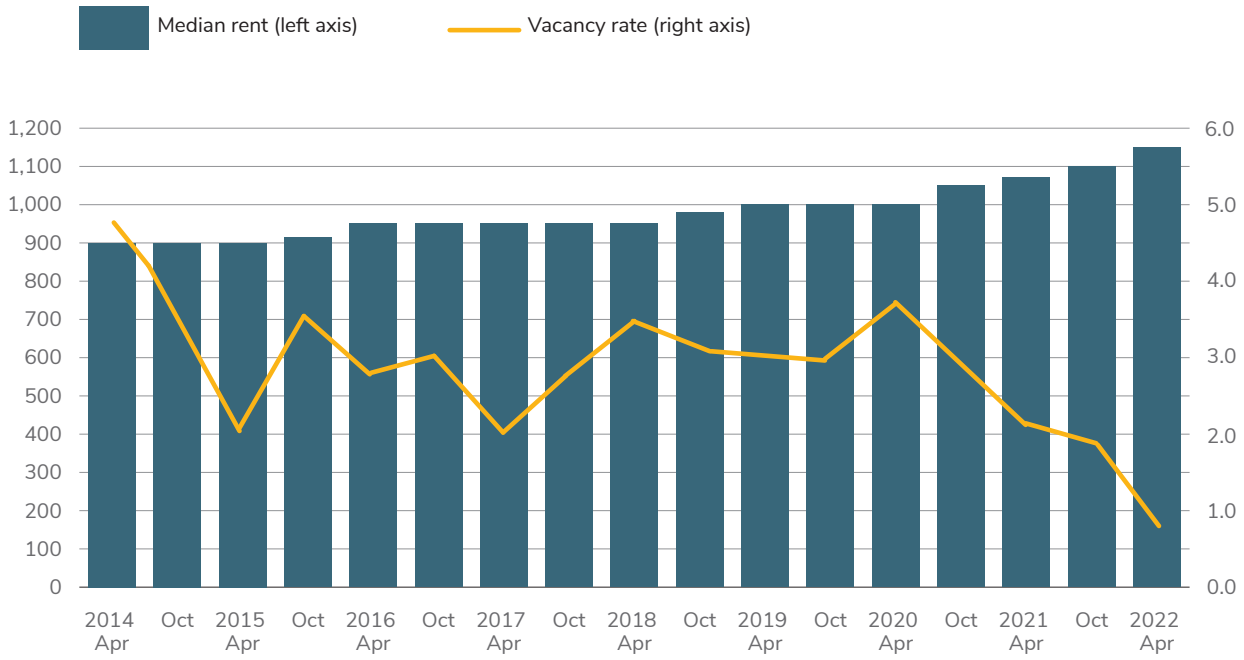
Source: The Canadian Real Estate Association

19. *Yukon Real Estate Report Fourth Quarter, 2022*. Yukon Bureau of Statistics. (February 2023).
20. The Canadian Real Estate Association does not publish data for Nunavut.

On the rental side, the market in recent years has been one of limited supply and increasing rents. The vacancy rate in buildings with three-or-more units fell to 0.8 per cent in April 2022, well below the 1.9 per cent reported in October 2021.[21] High demand and a lack of vacant units has translated into higher rents, with a median rent of $1,150 in April of last year, up 4.5 per cent from the October 2021 figure and 7.4 per cent higher than the April 2021 figure.

Chart 12. Recent history of rental market is one of few vacancies and increasing rents

Whitehorse median rent ($) and vacancy rate (per cent), units in buildings with 3+ rental units



Source: Yukon Bureau of Statistics

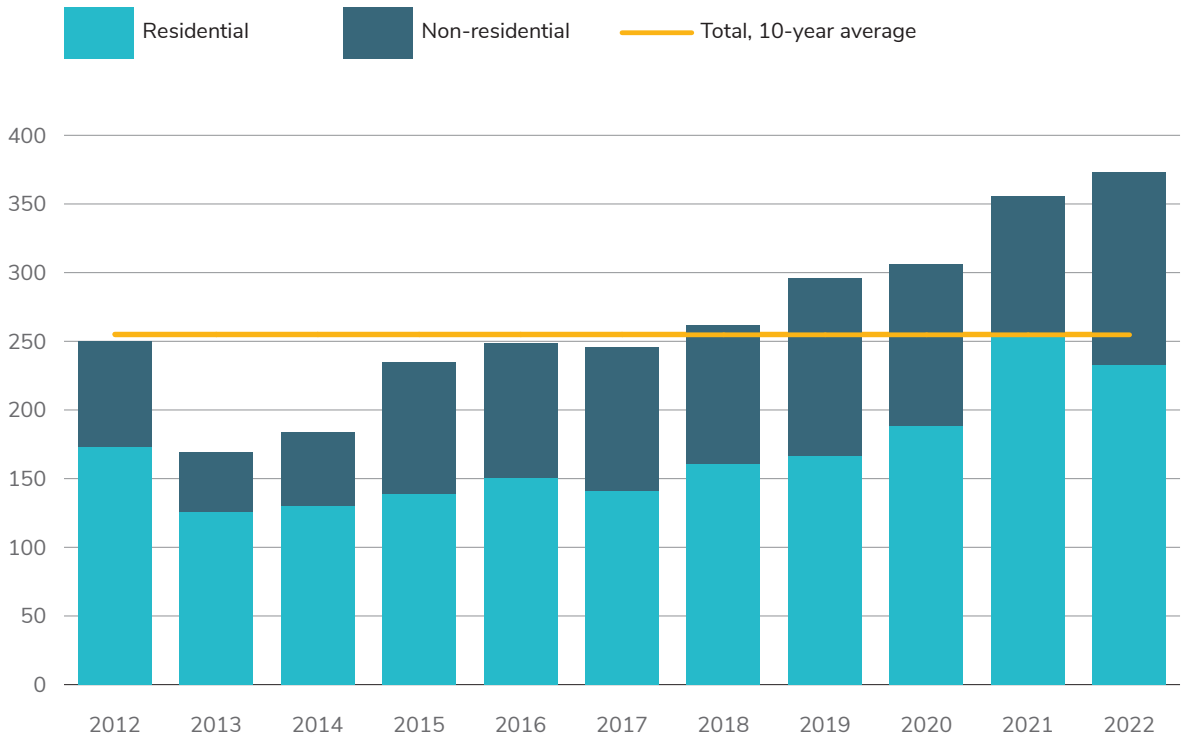
21. *Yukon Rent Survey April 2022*. Yukon Bureau of Statistics. (August 2022).

Residential investment remained strong in 2022

While below 2021's record level, investment in residential construction in 2022 continued to exceed investment on the non-residential side. Residential construction investment totalled $232.6 million in 2022, 62 per cent of the total $373.2 million in building construction reported for the period, and well above the ten-year average of $163 million for residential construction (Chart 13). The recent approval of phases 10 to 13 of the Whistle Bend subdivision will contribute to housing supply going forward.[22]

Chart 13. 2022 was another strong year for building construction

Investment in building construction ($ millions)



Source: Statistics Canada

22. *More phases of Whistle Bend subdivision approved* (January 19, 2023). Whitehorse Star.

Construction sector supported by commercial and government projects

The decline in residential spending from record highs was more than offset by increased non-residential spending. Investment in non-residential building construction totalled $140.6 million in 2022 and was up nearly 39 per cent from 2021 (Chart 13). Similarly, building permits for non-residential work were up substantially in 2022, growing 61 per cent to $150.7 million.

Government-related activities continue to be a primary driver of activity on the non-residential side. Growth was noted in both investment in building construction and building permits associated with institutional and governmental projects, up 83 per cent and 13 per cent, respectively. On the building permits side, construction of a new elementary school in Whitehorse's Whistle Bend subdivision and renovation of the Elijah Smith School were prominent contributors to last year's gains. Commercial permits also showed strong growth in 2022, more than doubling from $44.1 million to $97.0 million. Permit value was supported by construction of a three-storey office building in Whitehorse, renovation of the Old Territorial Administration building in Dawson City and work related to the Whitehorse Battery Energy Storage project.

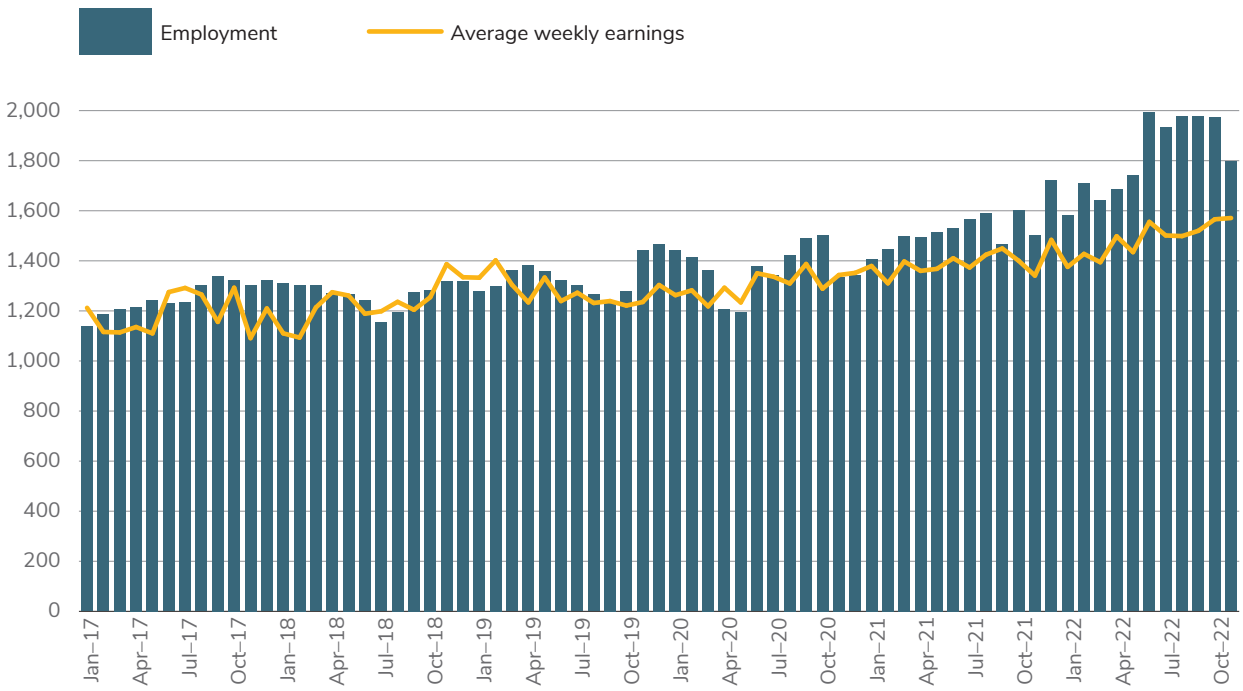
Higher input and labour costs continue to factor into some of the recent gains in building construction investment, due in part to supply chain constraints and stiff competition for tradespeople. Nationally, residential construction costs, on average, were 19 per cent higher and non-residential costs 13 per cent higher in 2022 compared to 2021.[23]

Increased activity created jobs in the construction sector and boosted wages. Construction employment reached an all-time high of 1,993 in June 2022 (Chart 14), up more than 50 per cent versus June 2019. Through the first eleven months of 2022, construction workers earned $1,486 per week on average, an increase of 7.4 per cent from 2021.

23. National figures are based on a composite of 11 census metropolitan areas.

Chart 14. Busy construction sector reflected in growth in construction employment and earnings

Employment (persons), Average weekly earnings ($)



Source: Statistics Canada

The Government of Yukon's *Five-Year Capital Plan* outlines spending to the end of fiscal year 2027–28 of $2.15 billion and includes significant spending in several priority areas such as 'transportation infrastructure', 'land development, housing, education and health' and 'community and First Nations infrastructure'. Projects such as the Nisutlin Bay Bridge, the Dempster Fibre project and the new elementary school in Whistle Bend are examples of investment in critical infrastructure included in the latest Capital Plan. In addition to Government of Yukon projects, the City of Whitehorse also factors into expectations of construction activity with over $130 million in planned spending on capital projects over 2023 to 2026.[24]

24. Spending figure is from the City of Whitehorse's *Capital Expenditure Program 2023–2026* released on November 14, 2022. Figure includes all approved spending, including spending of approximately $75 million that is subject to external funding approval.

Mineral production forecast to be strong over the medium term

The Yukon's mining industry has remained resilient in the face of major headwinds in 2022. High winter precipitation resulted in a heavy spring thaw that hindered mineral production, as both the Eagle Gold and Minto mines lost a month of operations and the sluicing season for placer miners was delayed. The sector has been facing a shortage of workers coming out of the pandemic, hampering some operations. High fuel prices and supply chain issues also presented challenges in 2022.

In addition to disruptions during the spring thaw, operation at Eagle Gold was stalled for three weeks in the third quarter due to the failure of the belt on the overland conveyor. These operational issues caused gold production to fall to 150,182 ounces in 2022, below the previous year's production of 164,222 ounces. With production from Keno Hill underperforming expectations, Alexco Resource Corporation halted operations in June 2022 to focus on mine development. Operations remained suspended following the acquisition of Alexco by Hecla Mining Company in September.

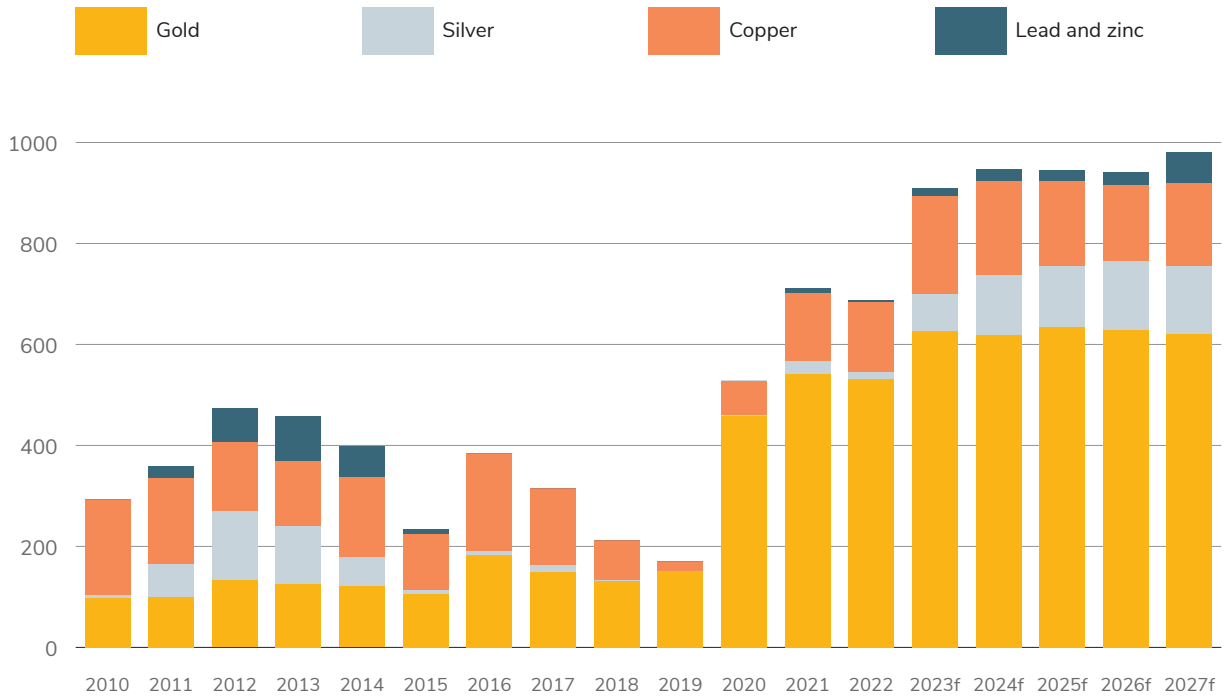
Production for the fourth quarter for the Minto mine was unavailable at the time of writing, but public statements from the President of Minto Metals Corporation in November 2022 noted that the expectation was that annual production would fall within their 2022 production guidance of 28-31 million pounds of copper.[25]

Placer miners also saw higher production. Placer gold production, according to export tax reporting, was 82,420 crude ounces (65,936 fine ounces), up from production of 80,484 crude ounces (64,387 fine ounces) in the previous year. At $154 million, the value of placer gold production accounted for about 22 per cent of 2022's total estimated mineral production.

25. News release – *Minto Metals announces 2022 third quarter results, revenue increased by 17% over the same quarter in previous year*. Minto Metals Corporation (November 17, 2022).

Chart 15. Mineral production value forecast to approach $1 billion[26]

Value of metal production in the Yukon ($ millions)



Source: Natural Resources Canada, Department of Energy, Mines and Resources, Department of Finance *f = forecast*

The Yukon's quartz miners expect to recover from the various setbacks that hindered 2022 production. Victoria Gold expects production at Eagle Gold to rebound in 2023 with production well above 2022's output as the project operator continues to work towards its annual target of 250,000 ounces. Hecla Mining Company announced earlier this year that mine development is ahead of schedule and that they plan to resume operations at Keno Hill in the third quarter of 2023. This, along with anticipated higher production at the Minto mine and sustained placer production, is expected to lead mineral production to rebound to $910 million in 2023 and exceed $900 million in all subsequent years of the forecast (Chart 15).

26. Due to data suppression of Statistic Canada's estimates, data presented for 2019, 2020 and 2021 are based on internal estimates.

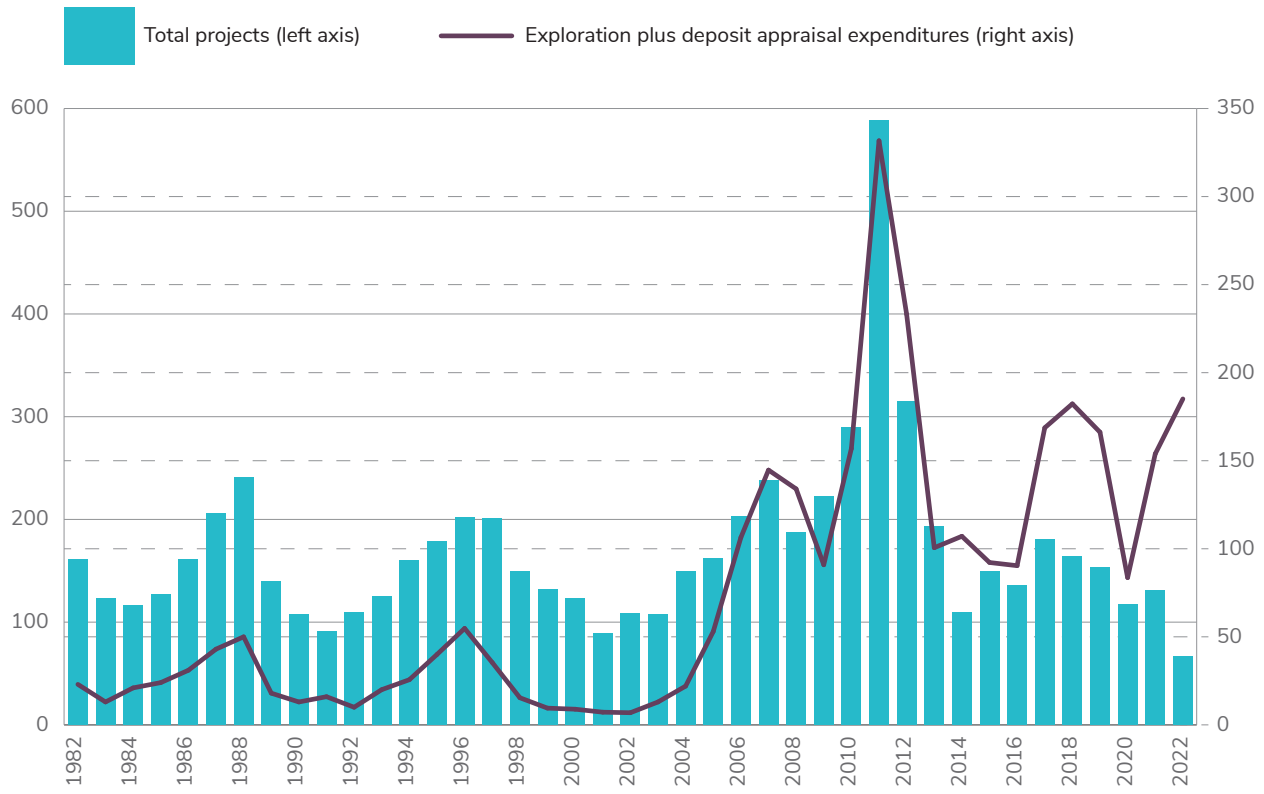
Mineral prices remain supportive of future development

Metals prices rallied to close out 2022 and, though down from earlier highs, remain well above pre-pandemic levels. This could spur development over the medium term for projects such as BMC Minerals Limited's Kudz Ze Kayah mine, Newmont Corporation's Coffee Gold project and Sabre Gold Mine Corporation's Brewery Creek project. Over the longer term, the advancing of the Casino project, a major global copper resource, may attract interest due to the pivotal role copper will play in the green economy and global electrification.

Higher metal prices offer investors the potential of better returns from the discovery of new deposits and exploration activities on current mining plays. Exploration spending has rebounded from pandemic lows. Revised spending intentions from Natural Resources Canada noted exploration spending in 2022 of about $185 million, up 20 per cent from $154 million in 2021 (Chart 16).

Chart 16. Number of active exploration projects trending down even as overall exploration spending has rebounded

Number of active projects, Exploration expenditures ($ millions)



Source: Department of Energy, Mines and Resources, Natural Resources Canada

Recent spending has been increasingly concentrated in a smaller set of mature projects, rather than early-stage projects. The number of exploration projects has fallen over the last several years to a 40-year low in 2022, despite overall spending rebounding.

Spending on exploration for precious metals accounted for 70 per cent of exploration spending in 2022, with the remainder on exploration for base metals. Precious metals are expected to continue to draw most of the interest in exploration activity over the forecast. This mix may eventually be impacted by Canada's critical minerals strategy (see Box 1), which seeks to increase the output of minerals deemed critical to the transition to green energy.

Box 1: Critical minerals a potential opportunity for the local mining industry and for the Yukon's energy goals

The release of *The Canadian Critical Minerals Strategy* in December 2022, along with an almost $4 billion commitment in Budget 2022, is a clear signal of the interest the federal government has in developing the country's critical minerals.

Ultimately, minerals noted as 'critical' reflect societal needs and values at a point in time. Canada's critical minerals strategy notes critical minerals as the building blocks of the green and digital economies, highlighting that "there is no energy transition without critical minerals: no batteries, no electric cars, no wind turbines and no solar panels."

Most of the 31 minerals that the Canadian government has published as being "critical" to Canada have known deposits or documented occurrences in the Yukon. While the territory's current production of critical minerals is quite modest, limited to copper production from the Minto mine and recent production of zinc and indium as a by-product at the Keno Hill mine, there is potential for production from existing identified deposits. Critical minerals are identified as prominent outputs of several potential mines including, Kudz Ze Kayah (zinc, copper); Casino (copper, molybdenum); Nickel Shäw (nickel, cobalt, platinum, palladium, copper) and Mactung (tungsten).

Given commitments by Canada and the Yukon to reduce carbon emissions, as well as the need to ensure future energy security, there is clear motivation to develop a reliable supply of critical minerals. With climate change and economic opportunity acting as strong motivators for development, critical minerals have the potential to be a prominent contributor to the local mining industry and the broader economy over the coming years.

Signs of a solid rebound in tourism activity, but a return to pre-pandemic levels will take time

The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Several key tourism metrics for the territory show significant improvement from the worst of the pandemic. The number of international border crossings into the Yukon totalled just over 168,000 in the first eleven months of 2022, almost five and a half times the number of crossings in the same period of 2021, and well above the 63,657 crossings reported for all of 2020 and 2021 combined when COVID-19 related travel restrictions weighed on visitation.

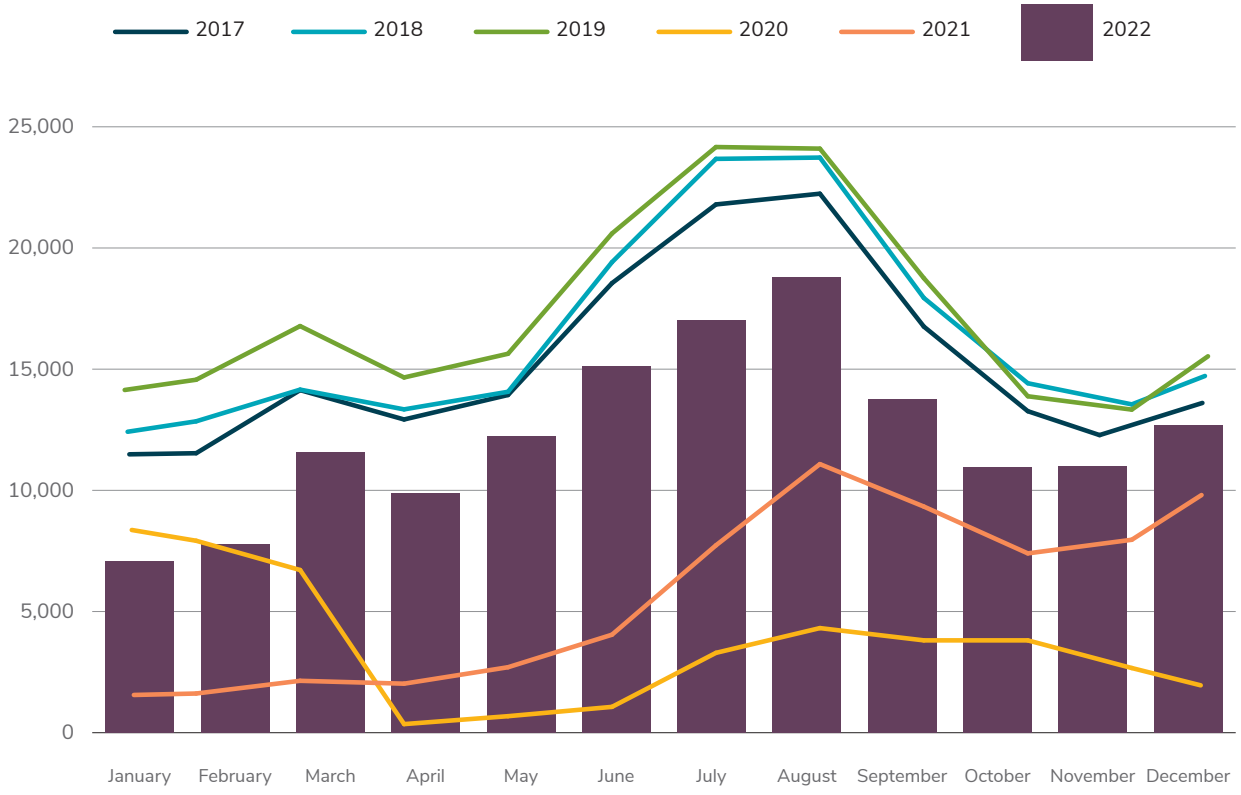
The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Like international border crossings, other indicators of performance are much improved from recent lows but continue to underperform pre-pandemic levels. Data for the first nine months of 2022 show international overnight visitation to be more than double the same period of 2021, but nearly 30 per cent lower than the five-year average.[27] Increased visitation is also reflected in increased hotel occupancy in 2022,[28,29] with data published by CBRE Hotels showing much higher occupancy rates in every month from January to November with the average of 56 per cent over this period, well ahead of the 41 per cent reported for the same period of 2021.[30]

An increased number of air arrivals in 2022 are another sign of the return of travel. Arrivals at Erik Nielsen Whitehorse International Airport were 2.2 times the number of arrivals from 2021 (Chart 17).

Chart 17. Air arrivals much improved from the last two years

Arrivals (deplaning passengers, thousands) at Erik Nielsen Whitehorse International Airport



Source: Statistics Canada

27. *Yukon Tourism Visitation Report, January to September 2022*. Department of Tourism and Culture. (December 22, 2022).
28. Occupancy rate is the percentage of occupied rooms expressed as percentage of the total available rooms at a given time.
29. Figures for the occupancy rate do not capture all hotel rooms in the Yukon, with about 600 rooms captured in this calculation.
30. Data taken from various CBRE Hotels monthly reports: *Trends in the Canadian Hotel Industry – National Market Report*.

Even with strong growth in 2022, air arrivals came in at only 72 per cent of arrivals in 2019, suggesting that there is still more room for recovery from the COVID-19 pandemic.

Tourism activity is increasing, but a variety of headwinds are slowing the recovery. Inflation is running at, or near, many decade highs, and is expected to remain elevated throughout much of 2023. Higher fuel costs have eaten into the bottom-lines of some service providers, particularly those that are fuel intensive such as providers of charter flights and tours.[31] Local tourism-service providers also continue to struggle with finding staff. Labour shortages in the accommodation and food services sector are more severe in the Yukon than they are in the rest of the country. Demand could also be impacted as higher interest rates lead to less discretionary spending.

Further improvement in key tourism metrics is expected. The Conference Board of Canada's latest Travel Markets Outlook supports this improving outlook for tourism, noting an expectation that visitation to the territory will reach pre-pandemic levels by 2024 or 2025, and that overnight visits will recover by 2024.[32] In addition, positive news, like White Pass Railroad's resumption of service to Canada in the summer of 2023, provides further evidence of a return to normalcy for the tourism sector.[33]



31. *Travel Exclusive Winter 2022/23 Travel Intentions Survey*. Canadian Tourism Research Institute. The Conference Board of Canada (December 2022).

32. *Emerging from the Wilderness – Yukon's Travel Markets Outlook to 2026*. The Conference Board of Canada. (January 24, 2023).

33. *White Pass Railroad to resume service to Canada this summer* (January 13, 2023). KHNS FM.

Appendix:
Key economic indicators

	2021	2022	2023f	2024f	2025f	2026f	2027f
Gross Domestic Product (GDP)							
Real GDP by Industry (2012$ millions)	3,045	3,138 (f)	3,308	3,431	3,534	3,666	3,831
Per cent change	10.0	3.1	5.4	3.7	3.0	3.7	4.5
Nominal GDP ($ millions)	3,704	4,049 (f)	4,432	4,795	5,093	5,480	5,948
Per cent change	14.3	9.3	9.4	8.2	6.2	7.6	8.5
Mineral Production *							
Metal production ($ millions)	710	690 (f)	910	950	950	940	980
Labour market							
Labour force *	23,700	24,300	25,100	25,500	26,100	26,800	27,700
Employment *	22,400	23,400	23,800	24,200	24,800	25,600	26,500
Unemployment rate	5.5	3.7	5.0	5.0	5.1	4.5	4.1
Participation rate	72.3	72.8	73.0	72.4	72.1	72.2	72.6
Income							
Household income ($ millions)	2,440	2,664	2,849	3,029	3,210	3,463	3,760
Per cent change	11.4	9.2	6.9	6.3	6.0	7.9	8.6
Consumers							
Consumer price inflation^	3.3	6.8	3.8	2.5	2.0	2.0	2.0
Retail sales ($ millions) *	963	1,030 (f)	1,090	1,150	1,210	1,290	1,400
Population							
Population*	43,190	43,964	44,900	45,900	46,800	47,700	48,700
Per cent change	2.3	1.8	2.1	2.2	2.1	1.9	2.0
Key Assumptions							
Gold (USD/t oz)	1,800	1,809	1,760	1,670	1,650	1,650	1,650
Silver (USD/t oz)	25.15	22.16	21.85	21.68	22.00	22.00	22.00
Copper (USD/lb.)	4.23	3.99	3.48	3.71	3.55	3.55	3.55
Zinc (USD/lb.)	1.36	1.58	1.33	1.25	1.23	1.15	1.15
Lead (USD/lb.)	1.00	0.97	0.91	0.91	0.93	0.93	0.93
Can/US exchange rate	0.80	0.77	0.75	0.77	0.78	0.78	0.78

f = forecast

^ = CPI available only for Whitehorse, annual average.

** = Forecasts are rounded. Annual per cent change based on unrounded figures.*

Source: Statistics Canada, Bank of Canada, Yukon Bureau of Statistics.

Population projections are produced by Yukon Bureau of Statistics. Metal prices forecasts are informed by prominent forecasters. All other forecasts are produced by the Department of Finance's Economic Research branch based on data available as of February 13, 2023.




Yukon

Yukon Bureau of Statistics

Population Projections, 2021-2040
Updated February 2023

Population Projection Methodology

Yukon Bureau of Statistics (YBS) developed new models for population projection in 2016. In the new demographic projection model, various demographic trends (e.g., births, deaths, in-migration and out-migration) are analysed using simple trend analyses and segmented regressions based on best-fit of linear segments of the data. Then three scenarios — Low Growth, Medium Growth, and High Growth — are developed by applying sets of weights to the model parameters.

In addition to the demographic projection model, another projection model — the DemEcon model — is estimated with net migratory growth as a function of economic growth and a projection scenario is developed based on the model parameters.

A fourth projection scenario, the Preferred Projection, is finally derived as a weighted average of the Medium Growth scenario of the demographic projection model and the scenario developed with the results of the DemEcon model. YBS considers this fourth projection scenario to be the most likely scenario.

The demographic projection models are updated every five years when postcensal population estimates (i.e., Census population adjusted for net undercoverage) become available. However, the DemEcon model and the Preferred Projection are updated every year using changed forecasts of economic growth.

Population Projection and Growth Rate by Broad Age Group, Yukon, 2021 to 2040

Year	Projection: Preferred Total	Projected Growth Rate	Projection: Preferred 0 to 14 years	Projected Growth Rate	Projection: Preferred 15 to 64 years	Projected Growth Rate	Projection: Preferred 65 years and over	Projected Growth Rate
2021	**43,190**	**2.4%**	**6,935**	**1.4%**	**30,166**	**1.9%**	**6,089**	**5.5%**
2022	43,964	1.8%	7,040	1.5%	30,546	1.3%	6,378	4.7%
2023f	44,880	2.1%	7,248	3.0%	30,961	1.4%	6,671	4.6%
2024f	45,850	2.2%	7,468	3.0%	31,403	1.4%	6,979	4.6%
2025f	**46,830**	**2.1%**	**7,613**	**1.9%**	**31,927**	**1.7%**	**7,290**	**4.5%**
2026f	47,730	1.9%	7,757	1.9%	32,420	1.5%	7,553	3.6%
2027f	48,680	2.0%	7,896	1.8%	32,900	1.5%	7,884	4.4%
2028f	49,770	2.2%	8,056	2.0%	33,469	1.7%	8,245	4.6%
2029f	50,760	2.0%	8,202	1.8%	33,958	1.5%	8,600	4.3%
2030f	**51,520**	**1.5%**	**8,310**	**1.3%**	**34,291**	**1.0%**	**8,919**	**3.7%**
2031f	52,490	1.9%	8,450	1.7%	34,756	1.4%	9,284	4.1%
2032f	53,520	2.0%	8,601	1.8%	35,252	1.4%	9,667	4.1%
2033f	54,030	1.0%	8,668	0.8%	35,399	0.4%	9,963	3.1%
2034f	54,260	0.4%	8,691	0.3%	35,358	-0.1%	10,211	2.5%
2035f	**54,290**	**0.1%**	**8,680**	**-0.1%**	**35,188**	**-0.5%**	**10,422**	**2.1%**
2036f	54,660	0.7%	8,725	0.5%	35,235	0.1%	10,700	2.7%
2037f	55,530	1.6%	8,849	1.4%	35,598	1.0%	11,083	3.6%
2038f	56,420	1.6%	8,973	1.4%	35,971	1.0%	11,476	3.5%
2039f	57,210	1.4%	9,083	1.2%	36,269	0.8%	11,858	3.3%
2040f	**57,990**	**1.4%**	**9,192**	**1.2%**	**36,558**	**0.8%**	**12,240**	**3.2%**

f = forecast

Population Projection by Age Group, Yukon, 2021 to 2040

Year	1 to 12 months	1 to 4 years	5 to 9 years	10 to 14 years	15 to 19 years	20 to 24 years	25 to 29 years	30 to 34 years	35 to 39 years	40 to 44 years
2021	**391**	**1,842**	**2,412**	**2,290**	**2,155**	**2,489**	**2,978**	**3,702**	**3,810**	**3,129**
2022	415	1,825	2,445	2,355	2,190	2,421	2,961	3,781	4,032	3,247
2023f	452	1,937	2,487	2,372	2,122	2,409	3,049	3,912	3,844	3,178
2024f	491	2,055	2,531	2,391	2,112	2,398	3,117	3,947	3,742	3,184
2025f	**498**	**2,103**	**2,581**	**2,431**	**2,104**	**2,319**	**3,181**	**4,089**	**3,721**	**3,191**
2026f	505	2,149	2,627	2,476	2,100	2,297	3,205	4,202	3,710	3,204
2027f	513	2,188	2,674	2,521	2,099	2,284	3,231	4,267	3,765	3,222
2028f	521	2,233	2,729	2,573	2,098	2,295	3,259	4,347	3,834	3,285
2029f	530	2,274	2,778	2,620	2,106	2,300	3,278	4,415	3,894	3,340
2030f	**536**	**2,304**	**2,815**	**2,655**	**2,104**	**2,294**	**3,301**	**4,457**	**3,927**	**3,379**
2031f	545	2,343	2,863	2,699	2,109	2,295	3,342	4,513	3,974	3,428
2032f	553	2,385	2,916	2,747	2,115	2,297	3,384	4,570	4,020	3,484
2033f	555	2,404	2,939	2,770	2,100	2,276	3,398	4,577	4,024	3,507
2034f	555	2,411	2,948	2,777	2,074	2,244	3,397	4,555	4,003	3,512
2035f	**551**	**2,409**	**2,945**	**2,775**	**2,039**	**2,202**	**3,391**	**4,517**	**3,965**	**3,504**
2036f	553	2,422	2,960	2,790	2,018	2,173	3,412	4,502	3,948	3,517
2037f	559	2,457	3,003	2,830	2,013	2,163	3,451	4,534	3,972	3,563
2038f	565	2,492	3,045	2,871	2,009	2,153	3,495	4,566	3,995	3,608
2039f	570	2,523	3,083	2,907	1,999	2,138	3,534	4,585	4,007	3,647
2040f	**575**	**2,554**	**3,121**	**2,942**	**1,988**	**2,121**	**3,581**	**4,597**	**4,015**	**3,686**

Year	45 to 49 years	50 to 54 years	55 to 59 years	60 to 64 years	65 to 69 years	70 to 74 years	75 to 79 years	80 to 84 years	85 to 89 years	90 to 99+ years
2021	**2,907**	**2,759**	**3,103**	**3,134**	**2,443**	**1,745**	**1,000**	**507**	**253**	**141**
2022	2,962	2,826	2,973	3,153	2,525	1,763	1,127	537	271	155
2023f	3,019	2,897	3,186	3,345	2,644	1,908	1,129	553	285	152
2024f	3,079	2,973	3,377	3,474	2,769	2,056	1,132	570	300	152
2025f	**3,145**	**3,050**	**3,523**	**3,604**	**2,886**	**2,208**	**1,136**	**594**	**313**	**153**
2026f	3,206	3,130	3,662	3,704	2,999	2,316	1,142	618	324	154
2027f	3,267	3,203	3,753	3,809	3,117	2,428	1,198	642	338	161
2028f	3,337	3,251	3,837	3,926	3,247	2,549	1,259	670	352	168
2029f	3,400	3,293	3,895	4,037	3,373	2,669	1,319	697	367	175
2030f	**3,446**	**3,318**	**3,935**	**4,130**	**3,486**	**2,779**	**1,373**	**721**	**379**	**181**
2031f	3,505	3,357	3,991	4,242	3,615	2,903	1,435	750	394	187
2032f	3,572	3,399	4,051	4,360	3,750	3,032	1,500	779	410	196
2033f	3,604	3,406	4,070	4,437	3,851	3,134	1,552	803	422	201
2034f	3,618	3,396	4,069	4,490	3,933	3,221	1,596	823	432	206
2035f	**3,617**	**3,373**	**4,052**	**4,528**	**4,001**	**3,297**	**1,634**	**839**	**441**	**210**
2036f	3,640	3,371	4,060	4,594	4,094	3,393	1,682	862	453	216
2037f	3,695	3,399	4,105	4,703	4,226	3,522	1,748	893	470	224
2038f	3,751	3,428	4,151	4,815	4,362	3,655	1,814	926	487	232
2039f	3,800	3,450	4,190	4,919	4,492	3,785	1,879	958	504	240
2040f	**3,849**	**3,471**	**4,227**	**5,023**	**4,623**	**3,915**	**1,944**	**990**	**520**	**248**

f = forecast

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ATCO Electric YUKON

September 28, 2023 AEY-UCG-019

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-019

Reference: July 7,2023 Application, page 2-4 AEY Residential and Commercial Customers and Sales by Community AEY state: For the 2023-24 sales forecast AEY reviewed its two-step approach for determining weather normalized UPC. AEY has maintained the same 10-year timeframe for UPC regression and normalizing HDD as last Board Compliance Order.

Request:

(a) Provide evidence and statistical analysis that this 10- year average methodology is a superior forecasting tool when compared to the 20-year average methodology.

(b) Confirm or deny that the proposed 10-year average methodology will be more volatile than the longer-term methodology. Explain.

(c) Provide Board Order referenced.

Response:

(a) AEY has created 10-year and 20-year regression models to determine the normalized UPC for the aggregated commercial and residential rate classes. As shown in the table below, the resulting R Square for both residential and commercial rate classes is higher using a 10-year model versus using a 20-year model.

RESIDENTIAL 10YR	
Regression Statistics	
Multiple R	0.879348196
R Square	0.773253249
Adjusted R Square	0.771331667
Standard Error	124.5941627
Observations	120

RESIDENTIAL 20YR	
Regression Statistics	
Multiple R	0.857485186
R Square	0.735280844
Adjusted R Square	0.734168579
Standard Error	118.9895003
Observations	240

COMMERCIAL 10YR	
Regression Statistics	
Multiple R	0.819017185
R Square	0.670789149
Adjusted R Square	0.667999227
Standard Error	389.7395353
Observations	120

COMMERCIAL 20YR	
Regression Statistics	
Multiple R	0.813842541
R Square	0.662339681
Adjusted R Square	0.66092094
Standard Error	356.5270987
Observations	240

(b) AEY is uncertain whether using a 10-year average methodology is more volatile than using a 20-year average methodology. Notwithstanding, AEY considers the 10-year average methodology to be more representative of recent trends in UPC and weather patterns.

(c) Please refer to AEY-UCG-019(c) Attachment 1. The referenced Board Order can be found in paragraph 40.

Yukon Utilities Board

Board Order 2017-01
Appendix A: Reasons for Decision
April 27, 2017

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1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),[1] carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of $53,890,000 for 2016 and $56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:
- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricyukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

[1] Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervener status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervener registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial and lighting customers. This represents an increase in total primary sales of 0.7 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

> In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the "Normal" HDD.[2]

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

	Regression data for UPC (Step 1)	**"Normal" HDD (Step 2)**
Prior Methodology	15 years	20-year average
Current Methodology	3 years	3-year average

Source: Application, page 2-5.

[2] Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

> … over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period.[3]

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base[4] and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was "used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature."[5] The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse's commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

[3] Exhibit BB-1, Application, page 2-5, lines 14-19.
[4] Exhibit B-9, YUB-YECL-7 (a): "For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year."
[5] Exhibit BB-1, Application, page 2-6, lines 11-12.

> ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.[6]

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

(a) the economic slowdown in the Yukon;

(b) a continuous warming trend, starting in 2013; and

(c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.[7]

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.[8]

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

[6] Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)
[7] YECL Final Argument, paragraph 24.
[8] Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.[9]

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.[10] AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.[11]

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."[12] Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.[13] Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

[9] UCG Final Argument, paragraph 76.
[10] Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).
[11] Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.
[12] AEY Final Argument, paragraph 26.
[13] Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology[14] using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	**2014**	**2015**	**2016**	**2017**
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized[15]	(402)	-	(72)	(110)	(86)
Total Purchase Power[16]	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.[17] The drivers of the forecasts for 2016 and 2017 were stated as:

> The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.[18]

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.[19]

[14] The methodology used in its 2013-2015 GRA.
[15] Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."
[16] Rider J has not been included, as these are flow-through amounts to YEC.
[17] Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).
[18] Exhibit B-9, YUB-YECL-9(a).
[19] AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.[20]

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."[21] The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

> The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*[22]

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

[20] UCG Final Argument, paragraph 89.
[21] Board Order 2009-02, Appendix A, Reasons for Decision, page 9.
[22] Board Order 2009-02, Appendix A , Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.[23]

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.[24]

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

> … under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.[25]

54. Further, AEY stated that this account will ensure that there is an additional margin[26] if sales are greater than forecast.[27] Parties were asked to comment on that additional margin in argument[28], but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

[23] UCG Final Argument, paragraph 88.
[24] AEY Reply Argument, paragraph 27.
[25] Exhibit B-9, YUB-YECL-47(b).
[26] By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.
[27] Transcript Vol. 3, page 520, lines 19-23.
[28] Transcript Vol 3., page 518, lines13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 ($000s)**

	Actuals			Forecasts (Test Period)	
	2013	**2014**	**2015**	**2016**	**2017**
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

> The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.[29]

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates. AEY explained that:

> Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent

[29] Exhibit BB-1, Application, page 4-2, lines 20-24.

> for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral. [30]

62. AEY went on to explain that the difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel-deferral amount for the month.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations. [31]

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.[32]

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

[30] Exhibit BB-1, Application, page 4-3, lines 7-12.
[31] Exhibit B-6, UCG-AEY-22
[32] Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling $11.993 million and $12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. **Operations and maintenance expense ($000)**

2013		2014		2015		2016	2017
Approved	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Forecast**	**Forecast**
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. **Key Assumptions**

	2016	2017
Labour inflation	3.25%	3.00%
Other inflation	2.20%	2.20%
Vacancy rate	4.00%	4.00%
Long-term debt rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Interveners did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change[33] in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.[34] This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.[35] Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.[36] To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

[33] Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).
[34] Transcript Vol 2, page 365, lines 1-13.
[35] Exhibit B-9, YUB-YECL-34(a).
[36] Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Interveners did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.[37] For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.[38] It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.[39]

5.3.1 Views of interveners

85. In argument, interveners did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "… it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."[40]

[37] Appendix A to Board Order 2014-06, section 5.2.2, page 23.
[38] AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.
[39] AEY Final Argument, paragraph 68.
[40] UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.[41] John Maissan observed that AEY is able to control overall O&M costs.[42] UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".[43]

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.[44] Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook.*[45] The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

[41] Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.
[42] JM Final Argument, page 4.
[43] UCG Final Argument, paragraph 98.
[44] Transcript Volume 3, pages 400, line 16, to 401, line 8. .
[45] Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:[46]

Table 8. **2013 to 2017 placeholder amounts for pension costs ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.[47]

97. In an update[48] to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be $505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts[49] and also

[46] Exhibit BB-1, Application, page 5-3.
[47] Exhibit BB-1, Application, page 5-3.
[48] Exhibit B-9, YUB-YECL-36(f).
[49] Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.[50]

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.[51]

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.[52] No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of $505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,[53] AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.[54] In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent[55] for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

[50] Exhibit B-4, CW-YECL-15(b).
[51] AEY Final Argument, paragraph 71.
[52] UCG Reply Argument, paragraph 21.
[53] Exhibit BB-1, Application, page 1-5.
[54] Exhibit B-9, YUB-YECL-30(a), Attachment 1.
[55] Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.[56]

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

> When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.[57]

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.[58] CW recommended that production costs be reduced by 15 percent[59] and that distribution and general costs be reduced by $272,000 in 2016 and $369,000 in 2017.[60]

111. UCG argued that "… there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities ($938,000) and overspending on administration and general ($458,000)."[61] UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.[62]

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[56] Exhibit BB-1, Application, page 5-3.
[57] Exhibit C3-3, CW evidence, A5, pages 2-3.
[58] Exhibit C3-3, CW evidence, A6, pages 3-4.
[59] CW equated the 15-percent reduction in production costs to be $314,000 in 2016 and $306,000 in 2017.
[60] Exhibit C3-3, CW evidence, A7, pages 4-5.
[61] UCG Final Argument, paragraph 98.
[62] JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

> … that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.[63]

114. With respect to production costs, CW stated:

> … that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.[64] (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

> Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.[65] (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of $/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.[66]

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.[67]

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.[68]

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

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[63] UCG Reply Argument, paragraph 17.
[64] CW Reply Argument, paragraph 7.
[65] AEY Final Argument, paragraph 54.
[66] AEY Final Argument, paragraphs 58-59.
[67] AEY Reply Argument, paragraph 33.
[68] AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.[69]

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.[70] However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

[69] The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.
[70] Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other[71] costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** "Other" costs were provided in AEY's response to City of Whitehorse's IRs. [72]Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast "Other" costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — "Other" costs ($000s)**

Account 88800				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[73] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other" (Account 88800) is $47,000, and the 2017 balance for "Other" (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

[71] Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).
[72] CW-YECL-14(a), Attachment 1.
[73] Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office)**. "Other" costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual "Other" costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — "Other" costs ($000s)**

Account 88900				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[74] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other", (Account 88900) is $143,000, and the approved 2017 balance for "Other" (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in "Other". Except for an explanation related to $21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** "Other" costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted "Other" costs for this account:

Table 11. **Account 72100 Administrative — "Other" costs ($000s)**

Account 72100				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

[74] Application, page 5-3.

Source: CW-YECL-14(a), Attachment 1, page 3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the "Admin and General" Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for "Other" for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in "Other" costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY's office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY's recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.[75] Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of $0.006 million and $0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

[75] Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of $5.792 million for the year 2016 and $6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of $0.380 million in 2016 and $0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of $0.402 million,[76] [77] which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

[76] This would have the effect of reducing YECL annual depreciation expense by $0.402 million.
[77] YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of $1.1 million[78] over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

[78] UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately $0.100 million over the test years.[79]

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[80] The

[79] Transcript, Volume 1 page 148.
[80] Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of $0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.[81]

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.[82]

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.[83]

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[84]

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

[81] Transcript, Volume 3, page 427.
[82] Board Order 2014-06, Appendix A, page 101..
[83] Exhibit B-6, UCG-AEY-29(a).
[84] Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC[85] and John Maissan[86] accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.[87]

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

> The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.[88]

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

[85] YEC Final Argument, page 3.
[86] JM Final Argument, page 6.
[87] UCG Final Argument, paragraphs 137-150.
[88] YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.[89]

181. The Board, in Board Order 2009-08 stated:

> The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.
>
> The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.
>
> Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.[90]

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.[91]

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.[92]

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.[93]

[89] Board Order 2009-02 Appendix A: Reasons for Decision, page 29.
[90] Board Order 2009-08, paragraphs 280-282.
[91] Exhibit BB-1, Application, page 8-3.
[92] Exhibit BB-1, Application, page 8-4.
[93] Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

> In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;
>
> The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;
>
> The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and
>
> The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.[94]

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.[95]

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to "apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid."[96] However, YEC said that AEY's proposal deviates from the BCUC approach and from past Yukon precedent. AEY's approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.[97]

[94] Exhibit BB-1, Application, Attachment 8.1, page 32.
[95] Exhibit BB-1, Application, page 8-3.
[96] YEC Final Argument, page 3.
[97] YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

> BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.[98]

191. YEC later added that in Board Order 2009-02, the Board stated:

> … that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.[99]

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.[100]

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.[101]

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.[102]

195. Mr. Maissan recommended:

> … that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.[103]

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009…"[104] CW submitted that the request for a risk premium was unwarranted.[105]

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.[106]

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[98] YEC Reply Argument, page 4.
[99] Board Order 2009-02, Appendix A: Reasons for Decision, page 29.
[100] YEC Reply Argument, page 5.
[101] JM Final Argument, page 5.
[102] JM Final Argument, page 6.
[103] JM Final Argument, page 6.
[104] Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".
[105] CW Final Argument, paragraph 26.
[106] UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.[107]

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.[108]

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.[109]

201. For risk due to small size, Concentric stated:

> Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).[110]

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

> *Should a risk premium be applied?*
>
> In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

[107] AEY Reply Argument, paragraphs 57-63.
[108] AEY Reply Argument, paragraphs 64-66.
[109] AEY Reply Argument paragraphs 77 and 80.
[110] Exhibit B-9, YUB-YECL-62(a).

> The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.
>
> *What risk premium should be applied to YECL?*
>
> In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.[111] *(footnotes omitted)*

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.[112] Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.[113]

206. Additionally, AEY testified:

> That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...[114] I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.[115]

[111] Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.
[112] Exhibit BB-1, Application, Attachment 8.1, page 29.
[113] Exhibit BB-1, Application, Attachment 8.1, page 27.
[114] Transcript Volume 1, page 86, lines 2-13.
[115] Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

> The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent…[116] FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.[117]

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.[118]

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

[116] Exhibit BB-1, Application, Attachment 8.1, pages 4-5.
[117] Exhibit BB-1, Application, Attachment 8.1, page 5.
[118] Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.[119] AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.[120] Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.[121]

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,[122] the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding[123] and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

> The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.[124]

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.[125] Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

[119] Exhibit BB-1, Application, Attachment 8.1, page 25.
[120] Exhibit BB-1, Application, Attachment 8.1, page 26.
[121] Exhibit BB-1, Application, Attachment 8.1, pages 26-27.
[122] FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.
[123] Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.
[124] Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bcuc.com)
[125] Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.[126]

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.[127]

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.[128] This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness[129] greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.[130]

[126] Exhibit B-9, YUB-YECL-63(b).
[127] Exhibit BB-1, Application, Attachment 8.1, pages 19-20.
[128] Exhibit B-9, YUB-YECL-62(a).
[129] Equity thickness refers to the ratio of debt to equity of a utility.
[130] JM Final Argument, page 6.

224. UCG submitted:

> … that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.[131]

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

> In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application… Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.[132]

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.[133] AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	2016	**2017**
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%

[131] UCG Final Argument, paragraph 136.
[132] Board Order 2014-06, Appendix A: Reasons for Decision, page 54.
[133] Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.[134]

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.[135]

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.[136]

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.[137]

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.[138]

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

[134] CW Final Argument, paragraph 33.
[135] JM Final Argument, page 4.
[136] UCG Final Argument, paragraphs 152-154.
[137] AEY Final Argument, paragraphs 98-99.
[138] AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November[139] of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

[139] 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — $109,700) and 8.3 (Fish Lake #1 Spillway Failure — $100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than $100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, $500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 ($000s)**

2013-2015 GRA			
	Actual	**Approved**	**Variance (%)**
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
"Controllable" Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,[140] relating to project cost overruns, exceeded the forecast budgets by a total of $4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is $32.048 million. Mr. Maissan stated that AEY underspent by $5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

> … a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by $4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.[141]

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.[142]

[140] Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.
[141] JM Final Argument, page 7.
[142] JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than $50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.[143]

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 ($000s)**

	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	
	2013	2013	2014	2014	2015	2015	2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

[143] AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.[144]

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were $19.736 million, compared to the approved forecast amount of $31.051 million. UCG submitted that ratepayers have paid the costs of $11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.[145]

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions ($31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions ($19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

[144] AEY Reply Argument, paragraph 126.
[145] UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.[146]

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on "historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments … there is no systemic forecast error and … the forecast has no relation to, or correlation with the 2013-2015 forecast."[147]

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.[148]

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney's testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.[149] However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

> With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.[150]

267. Mr. Massie added:

> And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts.[151]

268. The Board accepts AEY's testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW's and UCG's recommendations to reduce AEY's new extension forecast.

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[146] Exhibit B-4, CW-YECL-1.
[147] AEY Final Argument, paragraph 130.
[148] Exhibit C3-3, CW Evidence, A8.
[149] Transcript, Volume 3, page 441, lines 13 to 14.
[150] Transcript, Volume 3, page 442, lines 6 to 9.
[151] Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are $2.116 million, or 98 percent of the 2016 forecast.[152]

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.[153] AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.[154]

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.[155]

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that that the last such report for year 2015 was filed on May 4, 2016.[156]

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of $3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of $4.346 and $4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

> UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

[152] AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.
[153] Exhibit BB-1, Application, Page 9-2.
[154] Exhibit BB-1, Application, Page 9-3,
[155] AEY Final Argument, paragraph 138.
[156] AEY Reply Argument, paragraph 46.

> should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.[157]

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

> … tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.[158]

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."[159] Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

[157] UCG Final Argument, paragraph 231.
[158] AEY Final Argument, paragraph 136.
[159] AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of $708,000 that were well below the approved $1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.[160]

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's direction

> … as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:
>
> (1) A full customer contribution required for all associated capital costs; or
>
> (2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution.[161]

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.[162]

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately $2 million and the project would need to be completed over several years due to resource constraints.

[160] UCG Final Argument, paragraphs 221 to 222.
[161] Exhibit BB-1, Application, page 9-3.
[162] Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.[163] The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.[164]

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

> Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.[165]

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

[163] Exhibit B-9, YUB-YECL-10(b) Attachment 1.
[164] Exhibit B-4, CW-YECL-27 (h).
[165] AEY Reply Argument, paragraph 95.

> … the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.[166]

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and $100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries ($000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

[166] Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of $100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects ($000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by $2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow $1 million of the $2,616 million cost overruns and remove it from rate base.[167] With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed $112,000 over budget.[168]

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, “If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY’s rate base.”[169] UCG stated that additions to AEY’s rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

> AEY’s evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional $728,000 in costs (for a project originally assumed to cost $725,000) and doubling the cost of the project.[170]

[167] JM Final Argument, page 8.
[168] JM Final Argument, page 9.
[169] UCG Final Argument, paragraph 160.
[170] UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board. [171] Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond.[172]

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

> … submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Interveners an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.[173]

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than $100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.[174]

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and interveners with the opportunity to assess the need and prudency of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, al while ensuring the customer and Project needs are addressed."[175]

[171] UCG Final Argument, paragraph 162
[172] UCG Final Argument, paragraph 165
[173] AEY Reply Argument, paragraph 104.
[174] AEY Final Argument, paragraph 106.
[175] AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the "capital projects put forward by AEY are not needed or that they have not been completed prudently."[176] With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.[177]

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

(a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and $100,000 greater than the original forecast; and

(b) business cases for projects where actual costs were greater than $100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the $450,000 forecasted by $184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,[178] accompanied with an explanation for projects with variances of 10 percent and greater than $50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility's expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

[176] AEY Final Argument, paragraph 122.
[177] AEY Reply Argument, paragraph 125.
[178] Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were $500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures[179]

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs ($000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be $20,000 and the current construction costs are forecasted to be $593,000.

[179] Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent $11.429 million in capital and $1.96 million in O&M expenditures, while AEY, over the same period, has recovered $5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over $3 million on the Fish Lake Ditch 3 replacement project and an additional $0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.[180]

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

> As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).[181]

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.[182]

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

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[180] UCG Final Argument, paragraphs 218 to 220.
[181] AEY Reply Argument, paragraph 134.
[182] Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).

- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.[183]

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.[184]

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "… expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."[185]

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.[186]

324. AEY estimated the total cost of this project to be approximately $5 million, albeit at this time, AEY is seeking approval for $3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,[187] excluding the equipment purchased from ATCO Gas. Further:

> ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

[183] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[184] AEY Final Argument, paragraph 150.
[185] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[186] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.
[187] The major elements of the project are described in the Application, Appendix 3, page 3.

> Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[188]

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately $50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.[189]

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

> Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.[190]

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	**2016**	**2017**	**2018**
Study costs	$222,000			
Engineering, design, and permitting	$272,000	$55,000	$152,000	$105,000
LNG vaporizer and LNG storage tank			$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			$1,090,000	
Conversion of remaining units to bi-fuel				$700,000
Tank expansion, piping, cryopump and installation				$905,000
Phase sub-total			$2,985,000	$1,710,000
Total				$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act.* A decision document that supported the project was issued in August 2013.[191]

[188] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.
[189] Exhibit B-9, YUB-YECL-13(e).
[190] Exhibit B-9, YUB-YECL-24(h).
[191] AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is "to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudency determination as part of a future general rate application."[192]

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case[193] and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

> Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below $2 million in NPV. Four scenarios are at $5 million NPV or higher.[194]

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney's acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon's Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.[195]

332. Mr. Maissan noted AEY's submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.[196]

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY's project-related costs to date, approximately $549,000 ($494,000 + $55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

[192] AEY Final Argument, paragraph 154.
[193] Exhibit BB-1, Application, Appendix 3, Table 3, page 8.
[194] JM Final Argument, page 12.
[195] JM Final Argument, page 13.
[196] JM Final Argument, page 14.

Board direct AEY to "… channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."[197]

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.[198]

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."[199]

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

> … the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.[200]

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.[201]

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."[202] Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

[197] JM Final Argument, page 14.
[198] UCG Final Argument, paragraph 172.
[199] YCS Final Argument, page 9.
[200] YCS Final Argument, page 4.
[201] YCS Final Argument, page 5.
[202] AEY Reply Argument, paragraph 141.

model,[203] assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "… there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."[204] Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.[205] However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.[206]

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

> The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."[207] (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

> … to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[208]

[203] The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).
[204] AEY Reply Argument, paragraph 144.
[205] Exhibit BB-1, Application, Appendix 3, Page 5.
[206] AEY Reply Argument, paragraph 146.
[207] Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.
[208] Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV ($M)	Supplier	Simple Payback (years)	20-year NPV ($M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8. Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below $2 million, and four scenarios have NPVs of $5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.[209]

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs[210] for these fuels.

[209] AEY Reply Argument, paragraph 144.
[210] Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."[211]

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.[212] The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

> ATCO Electric Yukon and the Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.[213]

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.[214] Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

[211] Exhibit B-5, JM-AEY-24(d).
[212] Exhibit B-5, JM-AEY-24(a).
[213] Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.
[214] Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are $4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY is proposing to purchase and install a new 600-kW unit to replace the existing undersized 170-kW unit. The new unit will be installed in the new building in Old Crow as it will not be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudency of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."[215] Mr. Maissan pointed out that a 400-kW generator

[215] JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."[216] AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of $612,000, plus $100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.[217]

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.[218]

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application[219] shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions[220] of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

[216] Exhibit B-5, JM-AEY-27 (b).
[217] JM Final Argument, pages 9 and 10.
[218] AEY Reply Argument, paragraphs 107 to 109.
[219] Exhibit BB-1, Application, Appendix 5, pages 1 and 2.
[220] Transcript Volume 3, starting at page 483, line12 and ending page 485, line 23.

is forecasted to be $758,000, compared to the $600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014.The total cost of this project was $634,000, compared to the approved cost of $450,000.[221]

364. AEY explained that the actual costs "were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC upgrade."[222] AEY confirmed that receipt of the unit and installation was "completed, prior to the recent installation of the increased amount of solar PV generation."[223]

9.7.4.2 Views of interveners

365. With respect to AEY's proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

> …providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing…[224]

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

[221] Exhibit BB-1, Application, Appendix 11, page 1.
[222] Exhibit BB-1, Application, Appendix 11, page 1.
[223] Exhibit B-5, JM-AEY-27 (a).
[224] JM Final Argument, page 15.

> … that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.[225]

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

> … it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.[226]

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

> … at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.[227]

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was $184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

[225] JM Final Argument, page 15.
[226] AEY Reply Argument, paragraph 112.
[227] AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.[228]

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile[229] — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time-consuming. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

> The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a

[228] Exhibit BB-1, Application, Appendix 11, page 2.
[229] Exhibit BB-1, Application, Attachment 11.4, page 1.

> Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.[230]

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. **McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs ($000s)**

Year	Actual/Forecast	Streetlights	Total	Scope
2013 (A)	656	-	656	Temporary overhead
2014 (A)	418	-	418	Low voltage pedestals, connected to feeds
2015 (A)	379	-	379	Main underground feed to the subdivision
2016 (F)	565	175	740	Hanna and McCandless
2017 (F)	930	256	1,186	Murphy (partial), O'Brien, and McCrimmon
2018 (F)	500	100	600	McClimon
2019 (F)	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 (F)	300	100	400	McCauly to Hamilton to McIntyre
Total	**4,348**	**781**	**5,129**	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter[231] dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

> Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.[232]

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there… that's what they would like to have when we leave that subdivision at the end of the project."[233] Moreover, the Board

[230] Exhibit BB-1, Application, Attachment 11.4, page 1.
[231] Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.
[232] Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.
[233] Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "… there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."[234]

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."[235] In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than $100,000. AEY also provided business cases for all major capital projects ($500,000 or greater) in Appendix 1 to Appendix 11 of the Application.[236]

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan[237] that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a $1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act.*

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act:*

(a) McIntyre subdivision rebuild;[238]

(b) Watson Lake bi-fuel projects;[239]

(c) Watson Lake Unit #2 replacement;[240]

[234] Transcript, Volume 1, page 152, lines 5 to 8.
[235] Board Order 2009-2, Appendix A: Reasons for Decision, page 37.
[236] Exhibit BB-1, Application, page 9-5.
[237] Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.
[238] UCG Final Argument, paragraph 187.
[239] UCG Final Argument, paragraph 192.
[240] UCG Final Argument, paragraph 197.

(d) Downtown Whitehorse capacity improvement project;[241]

(e) Old Crow Unit #3 replacement;[242]

(f) Whistle Bend Subdivision Stage 3-C project;[243]and

(g) Fish Lake Ditch #3 diversion replacement project.[244]

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act,* the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
Direction 8, Page 51. The Board agrees with the submissions of UCG that no assessment has been provided	*Application, page 11-1,* ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

[241] UCG Final Argument, paragraph 202.
[242] UCG Final Argument, paragraph 207.
[243] UCG Final Argument, paragraph 212.
[244] UCG Final Argument, paragraph 217.

within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear. The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.	analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in section 8 of this Application.	further response is required.
Direction 12, page 62. The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.	*Application, page11-2.* ATCO Electric Yukon contributed funds ($20,000) towards this initiative in 2013 and received a report titled "Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update." ATCO Electric Yukon filed this report in response to Undertaking 17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

Direction 13, page 64. YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100-percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the nine expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL, in future applications, is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.	*Application, page 11-3 to 11-4.* ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and $100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the variance in actual costs to forecast for that project. Business cases have also been provided for completed projects where the actual costs were in excess of $100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included business cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 14, page 70. The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast." Bearing this in mind, in	*Application, page 11-5.* In section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than $20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of $100,000 highlighted in Direction 13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL, in future GRAs, to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.		
Direction 15, page 71. The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.	*Application, page 11-6.* On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the 2013-2015 GRA or in Appendix 1-11 of this Application. Business cases have been provided for all projects that span multiple years where costs were expected to be greater than $500,000.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 20, page 101. As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the utilities benefit, but if participation rates are higher than expected, the utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA. Further, the Board affirms it does not approve the program for the five-year term requested and that the utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance	*Application, page 11-7.* The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.		

12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought the ability to flow through, dollar for dollar, costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.[245]In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)[246] did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.[247]

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.[248]

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.[249]

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.[250]

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

[245] AEY Final Argument, paragraphs 11-12.
[246] Exhibit B-5 — YECL Responses to Maissan Requests
[247] AEY Reply Argument, paragraph 13.
[248] AEY Reply Argument, paragraph 14.
[249] JM Final Argument, page 1.
[250] UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.[251]

406. In Board Order 2014-06, the Board ruled that:

> … on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented… The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.[252]

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

(a) Changes in statutory tax rates can be material;

(b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;

(c) The statutory rates are determined by the Territorial and Federal Governments, and tare [sic] therefore beyond AEY's control; and

[251] Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.
[252] Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

(d) AEY is not typically at risk with respect to items that are beyond its control and that are material.[253]

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.[254] Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."[255]

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.[256]

416. Interveners raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed[257] to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

[253] AEY Final Argument, paragraph 164.
[254] Exhibit BB-1A AEY GRA Schedules, schedule S8.8.
[255] UCG Final Argument, paragraph 30.
[256] UCG Final Argument, paragraphs 166-174.
[257] AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG[258] questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC[259] disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for $494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.[260]

[258] UCG Final Argument, paragraph 228,.
[259] Yukon Energy Reply Argument, pages 9-10.
[260] AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.[261]

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in "Work in Progress" until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in "Work in Progress" until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then $494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.[262]

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG's recommendation is denied.

429. The Board accepts Mr. Maissan's recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of $494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include $300,000 in 2016 and $200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.[263] The $500,000 in costs for the study would be recovered through AEY's deferral account in the amount of $150,000 in 2016 and $350,000 in 2017.

[261] AEY Final Argument, paragraph 108..
[262] JM Final Argument, page 15.
[263] Also referred to in AEY's application as the "Renewables Feasibility Study"; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and "sole-sourcing."[264] The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility's website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.[265]

435. In response to UCG's recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.[266]

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a $500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to $150,000 "to prepare for the significant displacement of diesel generation in Destruction

[264] AEY Final Argument, paragraph 110..
[265] Transcript, Volume 2, page 292.
[266] AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV", and (2) study costs of $50,000 "for a study on how to improve the fuel efficiency of AEY's diesel plants, including the utilization of residual heat, that applies to all of AEY's diesel plants."[267]

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.[268]

441. YEC[269] discounted Mr. Maissan's argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY's next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY's proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

> Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?
>
> A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was $10.6

[267] JM Final Argument, page 12.
[268] YCS Final Argument, page 9.
[269] YEC Reply Argument, pages 7-9.

> million for renewable energy programs. We have been working with the Federal Government to see if we can access that.
>
> To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.
>
> What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.
>
> So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.[270]

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

[270] Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and

- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.[271]

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of $100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.[272]

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the $100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.[273]

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

[271] For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Norther Energy Innovation at Yukon College.
[272] AEY Final Argument, paragraphs 119-122.
[273] JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. ..... Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement. ..... Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. ..... Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 105

6. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. ..... Paragraph 123

7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. ..... Paragraph 124

8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period." However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is $47,000, and the 2017 balance for “Other” (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is $143,000, and the approved 2017 balance for “Other” (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 130

10. The three-year average (2013-2015) for “Other” for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 134

11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. ..... Paragraph 163

12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders. ..... Paragraph 172

14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

..... Paragraph 237

15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 240

16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. ..... Paragraph 278

17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. ..... Paragraph 292

18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. ..... Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. ..... Paragraph 354

20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. ..... Paragraph 384

21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. ..... Paragraph 385

22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 448

23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 456

ATCO Electric YUKON

September 28, 2023 AEY-UCG-020

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-020

Reference: July 7,2023 Application, page 2.1 and 2.6 Secondary Sales

Request:

(a) For the Secondary Sales section of Table 2-1, please expand the table to include data row identifying the costs of providing Secondary Power and a calculation of net revenues.

(b) Explain how secondary power sales income is documented and accounted in revenue requirement.

Response:

(a) Please refer to the table below for AEY's calculation of net revenues, based on Secondary sales revenue and Secondary energy expense information:

Secondary Sales Revenue and Costs
($000)

Line		2016	2017	2018	2019	2020	2021	2022	2023	2024
	Secondary Sales									
(1)	Revenue[1]	296	553	21	0	34	361	401	390	390
	Purchase Power Expense									
(2)	Secondary Energy Expense[2]	243	460	16	0	8	330	276	358	358
(3) = (1) - (2)	**Net Revenue**	53	93	5	0	26	31	124	32	32

1. AEY 2023-2024 GRA, S2.1, Line 36
2. AEY 2023-2024 GRA, S3.1, Line 12.

(b) As shown in the table in part (a) above, Secondary sales are included on Line 36 of Schedule 2.1 and Secondary energy expenses are included on Line 12 of Schedule 3.1 of AEY's 2023-2024 GRA Schedules.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-021

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-021

Reference: July 7,2023 Application, page 3-1

AEY claims Primary and Secondary Purchase Power costs are forecast to remain relatively flat over the Test Period.

Request:

(a) Explain why and how AEY determined population growth no longer drives purchase power sales for each of the two test years.
(b) Explain how possible low balling purchase power costs could result in a surplus for AEY.

(c) What is AEY prepared to do to prevent the surplus cash cow for the utility that occurred for the prior 6 years?

Response:

(a) AEY has neither determined nor stated that population growth no longer drives purchase power sales. AEY is of the view that the purchase power forecast is largely driven by the sales forecast and AEY has maintained the approved methodology for forecasting both purchase power and sales for the Test Years.

(b) The purchase power is driven by the demand for energy, which is not controlled by AEY. The purchase power unit cost is driven by YEC, which is also not controlled by AEY. Therefore, the possibility of lower than reasonable purchase power costs is not applicable.

(c) The premise of the request is argumentative and unfair. Under the regulatory framework, utilities are incentivized to find efficiencies and cost savings on a go-forward basis and are entitled to benefit from any efficiencies achieved until rates

are reset. For example, the efficiencies realized by AEY since its last GRA have been incorporated into the cost forecasts included in the Application and will be passed through to customers in the revenue requirements approved by the Board. Regulated utilities such as AEY are entitled to recover their prudent costs and to earn a fair return on and of capital. Both are widely accepted regulatory principles that the request appears to overlook. In accordance with the above referenced regulatory principles, AEY will continue to look for ways to find efficiencies to the benefit of both customers and its shareholders.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-022

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-022

Reference: July 7,2023 Application, page 3-3

AEY justifies the creation of a deferral account based on the assumption that changes to purchased power costs may produce a loss or gain of substantial magnitude.

Request:

(a) Please provide statistical analysis showing changes to the cost of purchased power for 2017 through 2023.

(b) Please provide details of what AEY would classify as "a loss or gain of substantial magnitude" and why.

Response:

(a) Please refer to the tables below for the summary of AEY's purchased power expenses and year-over-year (YoY) percentage changes over the period 2017 to 2023.

Table 1: Purchase Power Expense
($000)

	Actuals							Test Year
Description	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Primary Energy Expense	25,108	27,069	27,658	27,507	28,817	28,959	28,796	29,015
Secondary Energy Expense	243	460	16	-	8	330	276	358
Shortfall Rider J	5,273	6,487	8,680	8,920	17,028	19,529	21,921	-
Less: Capitalized	(216)	(5)	-	(88)	-	-	-	(49)
Total Purchase Power	**30,409**	**34,011**	**36,354**	**36,339**	**45,853**	**48,818**	**50,993**	**29,323**

Table 2: Purchase Power Expense
YoY Change
(%)

	Actuals							Test Year
Description	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
Primary Energy Expense	6.4	1.7	-0.4	3.6	0.3	-0.3	11.3	0.8
Secondary Energy Expense	0.7	-1.3	0.0	0.0	0.7	-0.1	0.0	29.3
Shortfall Rider J	4.0	6.4	0.7	22.3	5.5	4.9	43.8	0.0
Less: Capitalized	0.7	0.0	-0.2	0.2	0.0	0.0	0.7	0.0
Total Purchase Power	**11.8**	**6.9**	**0.0**	**26.2**	**6.5**	**4.5**	**55.8**	**-42.5**

As noted in the tables above, while overall purchase power increased by approximately 56 percent over the period 2017 to 2022, the majority of the increase, (approximately 44 percent) is related to the flow-thru of YEC's Shortfall Rider J. The remaining 11 percent increase is mainly driven by the increase in AEY's load over that period. For the 2023 test year, the decrease in purchase power of -42.5 percent is mainly due to the removal of YEC's Shortfall Rider J from both purchase power (Schedule 3.1, Line 13) and revenue (Schedule 2.1, Line 51).

(b) There is no defined dollar value for what would classify as a loss or gain of substantial magnitude. AEY is seeking the continuation of a deferral account for power purchase costs on the basis that it continues to meet the previously accepted criteria for establishing a deferral account. The power purchase costs for which AEY is seeking a deferral account are outside the control of the company and are not reasonably forecastable, or a variance in forecasting could produce a loss or gain of a substantial magnitude.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-023

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-023

Reference: July 7,2023 Application, page 3-4

AEY states: Total forecast purchases are determined by applying a forecast line loss percentage to AEYs sales load forecast that was determined in Section 2. Line losses have been determined to be 6.1 percent and are calculated using a five-year historical average.

Request:

(a) Provide 5-year statistics showing calculation of line losses.

(b) Describe specific work AEY has undertaken and when this was done, to reduce the level of line losses since 2017.

(c) Explain why this has not resulted in a reduced line loss since the last GRA.

(d) Under the service contract with related party ATCO, has there been a load and line loss study since the last GRA? If yes, explain the outcome of the study. If not, explain why not.

Response:

(a) Five-Year Historical Line Losses were calculated as follows:

Table 1: Five-Year Historical Line Losses
MWh

		2018	2019	2020	2021	2022
Total Generation & Purchases	(a)	361,811	359,760	376,475	387,440	385,092
Less:						
Total Energy Sale	(b)	341,212	340,184	354,691	363,853	365,128
Losses and Company Used	**(c)**	**20,599**	**19,575**	**21,784**	**23,587**	**19,964**
Losses %	(c)/(b)	6.0%	5.8%	6.1%	6.5%	5.5%
5-Year Average	**6.0%**					

(b) AEY reduces and minimizes line losses on an ongoing basis, through new extensions and system improvement projects that target poor performing lines and infrastructure. All new infrastructure is built to current engineering standards that inherently reduce losses, as AEY installs large ampacity conductors for all new extensions and system improvement distribution lines. This improves line losses when old smaller distribution lines are upgraded with larger conductors. Line losses are also reduced on system loading when the distribution voltages are increased in voltage conversion projects.

(c) The line loss has dropped from 6.2 percent (approved line loss in 2016-2017 GRA) to 6.0 percent.[1]

(d) ATCO Electric has not performed a load and loss research study due to the stability of the system and, on that basis, AEY did not consider that incurring costs on an unnecessary study would be prudent.

[1] In preparing the response to this information request, AEY identified a rounding error within the Application. Line Losses on Line 4 of Sch. 3.2 should reflect 6.0% and will be updated as part of the compliance filing.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-024

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-024

Reference: July 7,2023 Application, page 4-1; Fuel Costs

AEY states: "Fuel is purchased on an ongoing basis for each of the five isolated diesel plants operated by AEY. AEY conducts a diesel fuel tendering process in which a vendor is selected to be the provider of diesel fuel to AEY".

Request:

(a) Explain when the new tender for diesel fuel purchases will be effective and the associated costs.

(b) Confirm that any new diesel fuel prices will be reconciled in fuel costs paid by Yukon ratepayers through the Rider F.

Response:

(a) The diesel supply contract, for road accessed facilities, is effective January 1, 2020 until December 31, 2024. The price is a function of the fluctuating Edmonton rack price (supplier market price) for the product (winter or summer grade) plus a delivery fee (per km) plus an escalation of $0.02/L (effective January 1, 2023) to address operating cost inflation.

(b) Confirmed.

September 28, 2023 AEY-UCG-025

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-025

Reference: July 7,2023 Application, page 4-2

Regarding diesel fuel costs, AEY states "*Price forecasts for each community are based on the 2015 actual prices for diesel fuel*".

Request:

Update Schedule 4.2 with the most recent actual diesel fuel prices for 2023 to date.

Response:

Please refer to AEY-UCG-025 Attachment 1 which reflects August 31, 2023 actual average diesel prices.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Fuel Information

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	Average Cost (in cents per litre)												
2	Watson Lake	Note 1	73.41	83.65	100.05	99.11	74.97	95.71	147.46	124.37	124.37	76.18	76.18
3	Beaver Creek	Note 1	73.61	82.88	100.13	96.12	78.97	94.16	139.16	128.54	128.54	92.40	92.40
4	Destruction Bay	Note 1	71.35	79.98	97.55	93.11	76.93	92.37	137.66	121.98	121.98	91.90	91.90
5	Old Crow	Note 1	179.46	187.36	225.99	229.36	232.31	247.21	308.55	309.49	309.49	201.71	201.71
6	Swift River	Note 1	76.26	89.44	106.69	102.21	84.85	96.77	142.77	133.03	133.03	88.72	88.72
7	Standby Units	Note 1	100.74	98.38	61.85	96.10	94.18	98.95	122.94	124.76	124.76	97.81	97.81
8													
9	Generation (MWh)												
10	Watson Lake		14,992	15,296	15,386	15,171	14,756	15,140	15,116	14,892	15,195	14,690	14,688
11	Beaver Creek		1,792	2,006	1,911	1,837	1,841	1,803	1,745	1,706	1,627	1,820	1,908
12	Destruction Bay		1,556	1,880	1,936	1,966	2,017	1,958	1,923	2,000	2,142	1,782	1,756
13	Old Crow		2,278	2,575	2,522	2,569	2,853	2,567	2,517	2,907	2,365	2,216	2,309
14	Swift River		220	303	269	268	247	231	215	213	221	215	228
15	Standby Units		44	99	110	185	346	103	284	104	208	39	40
16			20,881	22,160	22,135	21,995	22,061	21,801	21,799	21,822	21,758	20,763	20,930
17													
18	Net Heat Rate (kWh/litre)												
19	Watson Lake		3.90	3.90	3.93	3.89	3.87	3.92	3.79	3.88	3.88	3.85	3.85
20	Beaver Creek		3.65	3.59	3.59	3.56	3.44	4.02	3.41	3.59	3.59	3.43	3.43
21	Destruction Bay		3.37	3.42	3.67	3.54	3.71	4.07	3.11	3.60	3.60	3.61	3.61
22	Old Crow		3.40	3.61	3.68	3.84	3.53	3.24	4.44	3.70	3.70	3.40	3.40
23	Swift River		2.76	3.02	2.97	2.33	2.88	2.72	2.43	2.65	2.65	2.68	2.68
24	Standby Units		3.14	3.20	3.03	3.20	3.28	1.85	3.00	2.94	2.94	2.20	2.20
25													
26	Litres Consumed (000)												
27	Watson Lake		3,846	3,922	3,911	3,898	3,810	3,863	3,992	3,838	3,916	3,817	3,816
28	Beaver Creek		491	559	533	517	536	448	512	475	453	531	557
29	Destruction Bay		515	551	528	555	544	481	617	556	596	493	486
30	Old Crow		702	714	685	670	809	793	567	786	640	652	680
31	Swift River		80	100	91	115	86	85	88	81	84	80	85
32	Standby Units		21	31	36	58	106	55	95	35	71	18	18
33			5,655	5,877	5,783	5,812	5,890	5,725	5,872	5,771	5,759	5,592	5,643
34													
35	Note 1 - 2023 and 2024 updated to average diesel fuel cost as of August 31, 2023												

ATCO Electric YUKON

September 28, 2023 AEY-UCG-026

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-026

Reference: July 7,2023 Application, page 4-2; Fuel Costs

AEY states "*Plant efficiencies are based on the average efficiencies of the previous five years adjusted for any changes due to the replacement of units*".

Request:

(a) Expand Table 4.1 to provide details of the diesel fuel efficiencies for the 5 years used to support the 2023 and 2024 forecasts including how they were measured.

(b) Explain all work that AEY has undertaken in the last 5 years to improve diesel fuel efficiencies on its various systems and a statistical analysis showing the results.

Response:

(a) Please refer to AEY-UCG-026(a) Attachment 1.

(b) AEY has carried out projects in the last 5 years to replace end of life diesel gensets due to end-of-life. Any replacement diesel engine must meet emissions regulations and one of the criteria used for tender evaluation is fuel efficiency. AEY has not undertaken individual projects to improve fuel efficiency of existing diesel engines or reduce the heat rate at isolated power plants.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Net Heat Rate (kWh/litre)

Line No.	Description	2018	2019	2020	2021	2022	Average
1	Generation (MWh)						
2	Watson Lake	15,386	15,171	14,756	15,140	15,116	15,114
3	Beaver Creek	1,911	1,837	1,841	1,803	1,745	1,827
4	Destruction Bay	1,936	1,966	2,017	1,958	1,923	1,960
5	Old Crow	2,522	2,569	2,853	2,567	2,517	2,606
6	Swift River	269	268	247	231	215	246
7	Standby Units	110	185	346	103	284	206
8		22,135	21,995	22,061	21,801	21,799	21,958
9							
10	Litres Consumed ($000)						
11	Watson Lake	3,911	3,898	3,810	3,863	3,992	3,895
12	Beaver Creek	533	517	536	448	512	509
13	Destruction Bay	528	555	544	481	617	545
14	Old Crow	685	670	809	793	567	705
15	Swift River	91	115	86	85	88	93
16	Standby Units	36	58	106	55	95	70
17		5,783	5,812	5,890	5,725	5,872	5,816
18							
19	Net Heat Rate (kWh/litre)						
20	Watson Lake	3.93	3.89	3.87	3.92	3.79	3.88
21	Beaver Creek	3.59	3.56	3.44	4.02	3.41	3.59
22	Destruction Bay	3.67	3.54	3.71	4.07	3.11	3.60
23	Old Crow	3.68	3.84	3.53	3.24	4.44	3.70
24	Swift River	2.97	2.33	2.88	2.72	2.43	2.65
25	Standby Units	3.03	3.20	3.28	1.85	3.00	2.94

ATCO Electric YUKON

September 28, 2023 AEY-UCG-027

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-027

Reference: July 7,2023 Application, page 4-2; Diesel Fuel Deferral Account

AEY states: "*The variance between actual and forecast fuel prices as outlined in Schedule 4-2." and "The previously approved methodology for the fuel deferral uses the Board approved calculation.*"

Request:

(a) Why is Schedule 4-2 not included at end of this Section? Cannot find this schedule.

(b) Provide updated Board directed regulatory reporting for Rider F, for 2023 Jan.-Mar. and Feb.-June actuals.

(c) Provide updated Board directed regulatory reporting for Rider F, for remainder of 2023 forecast.

(d) Provide updated Board directed regulatory reporting for Rider F, for 2024 forecast.

(e) What is AEY recommending to Board for fuel price reconciliation in this application?

Response:

(a) Schedule 4.2 was included in the Excel workbook as part of AEY's Application filed on July 7, 2023, and is also included in the Excel workbook with the updated Schedules filed on September 11, 2023, with AEY's Depreciation Study. A copy of Schedule 4.2 has also been reattached in AEY-UCG-027(a) Attachment 1.

(b) Please refer to the response to AEY-UCG-005(h).

(c) Please refer to the response to AEY-UCG-005(h-i).

(d) Please refer to the response to AEY-UCG-005(h-i).

(e) Following Board directions on AEY's 2023-2024 GRA following the hearing, AEY will true-up the fuel variance amounts in the Compliance Filing.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Fuel Information

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	Average Cost (in cents per litre)												
2	Watson Lake		73.41	83.65	100.05	99.11	74.97	95.71	147.46	135.21	135.21	76.18	76.18
3	Beaver Creek		73.61	82.88	100.13	96.12	78.97	94.16	139.16	151.39	151.39	92.40	92.40
4	Destruction Bay		71.35	79.98	97.55	93.11	76.93	92.37	137.66	132.65	132.65	91.90	91.90
5	Old Crow		179.46	187.36	225.99	229.36	232.31	247.21	308.55	319.21	319.21	201.71	201.71
6	Swift River		76.26	89.44	106.69	102.21	84.85	96.77	142.77	147.47	147.47	88.72	88.72
7	Standby Units		100.74	98.38	61.85	96.10	94.18	98.95	122.94	122.94	122.94	97.81	97.81
8													
9	Generation (MWh)												
10	Watson Lake		14,992	15,296	15,386	15,171	14,756	15,140	15,116	14,916	15,195	14,690	14,688
11	Beaver Creek		1,792	2,006	1,911	1,837	1,841	1,803	1,745	1,684	1,627	1,820	1,908
12	Destruction Bay		1,556	1,880	1,936	1,966	2,017	1,958	1,923	2,067	2,142	1,782	1,756
13	Old Crow		2,278	2,575	2,522	2,569	2,853	2,567	2,517	2,714	2,365	2,216	2,309
14	Swift River		220	303	269	268	247	231	215	206	221	215	228
15	Standby Units		44	99	110	185	346	103	284	115	208	39	40
16			20,881	22,160	22,135	21,995	22,061	21,801	21,799	21,700	21,758	20,763	20,930
17													
18	Net Heat Rate (kWh/litre)												
19	Watson Lake		3.90	3.90	3.93	3.89	3.87	3.92	3.79	3.88	3.88	3.85	3.85
20	Beaver Creek		3.65	3.59	3.59	3.56	3.44	4.02	3.41	3.59	3.59	3.43	3.43
21	Destruction Bay		3.37	3.42	3.67	3.54	3.71	4.07	3.11	3.60	3.60	3.61	3.61
22	Old Crow		3.40	3.61	3.68	3.84	3.53	3.24	4.44	3.70	3.70	3.40	3.40
23	Swift River		2.76	3.02	2.97	2.33	2.88	2.72	2.43	2.65	2.65	2.68	2.68
24	Standby Units		3.14	3.20	3.03	3.20	3.28	1.85	3.00	2.94	2.94	2.20	2.20
25													
26	Litres Consumed (000)												
27	Watson Lake		3,846	3,922	3,911	3,898	3,810	3,863	3,992	3,844	3,916	3,817	3,816
28	Beaver Creek		491	559	533	517	536	448	512	469	453	531	557
29	Destruction Bay		515	551	528	555	544	481	617	575	596	493	486
30	Old Crow		702	714	685	670	809	793	567	734	640	652	680
31	Swift River		80	100	91	115	86	85	88	78	84	80	85
32	Standby Units		21	31	36	58	106	55	95	39	71	18	18
33			5,655	5,877	5,783	5,812	5,890	5,725	5,872	5,738	5,759	5,592	5,643

ATCO Electric YUKON

September 28, 2023 AEY-UCG-028

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-028

Reference: July 7,2023 Application, page 5-1; Operations and Maintenance Expenses

AEY states "*The forecast labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. These labour costs are then distributed to O&M accounts or capital accounts depending on the nature of work being performed by the staff in that job class.*"

Request:

(a) Identify the number of employees compensated more than $100,000 annually for each of the years from 2016 to 2022 and forecast for 2023 and 2024.

(b) Identify each management position and amount of bonus received for each years 2018- 2022.

(c) Provide a table showing employee complement history by function for each of the years from 2016 to 2022 and forecast for 2023 and 2024.

Response:

(a) Given the small number of personnel employed by AEY, whose positions are well-known to the community, AEY is not able to provide the requested information.

(b) Please refer to the response in part (a) above.

(c) This information is not available and AEY respectfully declines to answer pursuant to Rule 14(4)(b) of the YUB Rules of Practice. AEY does not track employee complement by function. Employees code their timesheets to the activities they have been working on in each time period, which allows AEY to allocate their costs to the appropriate function and/or capital project. Providing the employee complement by function would be a significantly onerous and time-consuming task.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-029

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-029

Reference: July 7,2023 Application, page 5-2; Operations and Maintenance Expense

AEY states: " *The overall increases in O&M expense are mainly attributable to rising labour, contractor, and material costs due to inflation. In addition to incremental labour and non-labour costs driven by higher demands from customer growth and operating a more robust and complex electrical system.*"

Request:

(a) If AEY was not a cost-plus regulated utility, would you not absorb many of these inflationary costs like other smaller Yukon businesses who wish to keep their customers? Explain answer.

(b) Why has customer growth income not covered these perceived incremental costs?

Response:

(a) If AEY were not a regulated utility, it would have to either absorb the inflationary costs or pass the costs on to customers through higher rates. If AEY absorbed the costs, it would need to implement rigorous cost management strategies to mitigate the impact of inflation on its operations, which could negatively impact customers due to service levels being potentially impacted.

Notwithstanding the above, regulated utilities are incentivized to find efficiencies and reduce costs, while maintaining safe and reliable service. These savings are ultimately passed on to customers by minimizing rate increases or even decreasing rates, as AEY has proposed for the 2023 Test Year.

(b) Although AEY has experienced customer growth, inflation is increasing at a higher rate. AEY is expecting an increase in customer growth of 2.5 percent in 2023 and 2.1 percent in 2024.[1] As seen in Table 1.1 of the Application,[2] inflation is expected to increase by 3.8 percent in 2023 and 2.5 percent in 2024, which is higher than the expected rate of customer growth. Furthermore, a portion of AEY's costs are fixed or semi-fixed, such as infrastructure maintenance, capital expenditures, information technology and labour costs. These costs may not decrease or increase in direct proportion to changes in customer numbers. In addition, customer growth alone does not guarantee increased revenue if customers reduce their consumption or become more energy efficient. Therefore, even if AEY experiences customer growth, it may not fully offset the impact of rising inflation on its costs.

[1] 2023-2024 AEY GRA Regulatory Schedules, Schedule 2.1, Line No. 45.
[2] 2023-2024 AEY GRA Application, PDF p. 10, Table 1.1.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-030

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-030

Reference: July 7,2023 Application, page 5-2; Operations and Maintenance Expenses AEY claims an increase in asset base as driver to Test Years.

Request:

(a) Explain what AEY has been doing in each of the years since 2017 to adequately upkeep aging production assets.

Response:

(a) Production operations and maintenance activities include preventative and restorative tasks. Top end overhauls on engines are preventative activities, that are frequency or runtime scheduled, and result in variable costs landing year to year based upon operations. Occasionally, top end overhauls result in additional (i.e., beyond typical) work based on found condition and manufacturer tolerances. Below is a summary of larger cost activities / tasks by year:

Table 1: Production Maintenance

Year	Production & Maintenance Activities
2017	Top end overhauls: WL5, OC2, WL1 Fuel tank cleaning. Failure repairs: FL2
2018	Top end overhauls: BC1, DB3, DB2
2019	Top end overhauls: OC4, WL4, WL5
2020	Delays due to COVID Pandemic
2021	Cylinder packs, cuffed liners: WL4 Fuel tank cleaning.
2022	Top end overhauls: BC2, WL3 API tank inspections. Governor overhaul: FL2.

AEY conducts inspections and predictive tests on equipment and monitors operating performance on local and remote instruments. AEY has found that auxiliary systems (i.e. to the gensets) at generation sites have required additional maintenance, as aging equipment results in more issues being identified and requiring repair.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-031

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-031

Reference: July 7,2023 Application, page 5-3; Operations and Maintenance Expense

The table on page 5-1 shows AEY's actual operations and maintenance expenses for 2016 to 2022 and test period forecast for 2023 and 2024.

Request:

(a) Provide same table showing non-fuel operating and maintenance costs per customer for each of the years above.

(b) Provide details on what expenses are included in each of the above years under Public Information explaining labour and non-labour costs.

Response:

(a) Please refer to AEY-UCG-031(a) Attachment 1.

(b) Please refer to the table below:

Table 1: Public Information costs
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
70100 - Public Information Administration									
Labour	10	10	10	15	16	13	14	15	16
Other	11	22	11	9	15	63	137	15	16
Total	**21**	**32**	**21**	**24**	**31**	**76**	**151**	**30**	**32**
70200 - General Public Information									
Labour	59	103	11	-	-	12	78	79	82
Other	14	56	26	50	53	68	20	70	72
Total	**73**	**159**	**37**	**50**	**53**	**80**	**98**	**149**	**154**

Labour is for a communication advisor and head office marketing costs. Non labour costs are for sponsorship of community events and other marketing and promotional material. Please refer to the responses to AEY-JM-016(b) and AEY-YUB-017 for further details.

ATCO Electric Yukon
2023 - 2024 General Rate Application (GRA)

Operations and Maintenance Expenses per Customer
($ per Customer)

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	Number of Customers	S.2.1 L45	17,863	18,157	18,532	18,926	19,340	19,798	20,308	20,807	21,248	17,854	18,082
2													
3	**Production**												
4	62600 - Hydro Generation	S.5.2 L.5	16	12	15	11	11	17	15	24	16	15	15
5	64000 - Supervision and Engineering Diesel	S.5.2 L.19	3	4	8	9	9	10	12	10	10	4	4
6	64600 - Diesel Generation	S.5.2 L.29	25	20	23	21	24	27	24	27	28	28	28
7	82600 - Hydro Maintenance	S.5.2 L.46	3	11	11	5	6	6	9	11	11	4	4
8	84600 - Diesel Maintenance	S.5.2 L.59	73	81	65	66	46	69	94	90	80	64	59
9			119	128	123	112	97	130	153	162	146	115	109
10	**Distribution**												
11	87000 - Supervision	S.5.2 L.76	15	21	16	18	12	19	19	19	19	18	18
12	87100 - Brushing	S.5.2 L.88	26	38	15	24	24	40	45	29	29	23	23
13	87200 - Vehicle Depreciation	S.5.2 L.104	(15)	(17)	(18)	(17)	(18)	(17)	(18)	(17)	(17)	(12)	(12)
14	87300 - Maintenance	S.5.2 L.109	112	105	113	120	119	116	146	137	138	115	116
15	87310 - Service to Outside Parties	S.5.2 L.128	4	3	3	5	6	32	7	1	1	7	7
16	87400 - Underground Line Maintenance	S.5.2 L.136	10	11	12	7	6	4	8	8	8	8	8
17	87500 - Meter and Meter Testing	S.5.2 L.153	3	8	5	5	9	5	4	7	5	5	5
18	87700 - Transformer Repair and Replacement	S.5.2 L.165	2	1	0	1	1	0	1	1	1	3	3
19	87800 - Street Light Maintenance	S.5.2 L.170	10	7	12	6	9	15	9	14	14	14	14
20			166	177	158	169	168	215	221	198	197	182	183
21	**General**												
22	88400 - Communication	S.5.2 L.185	1	1	2	2	2	2	3	6	6	1	1
23	88800 - Maintenance Company-Owned Houses	S.5.2 L.192	4	6	(2)	1	2	2	1	2	2	3	3
24	88900 - Maintenance Warehouse and Office	S.5.2 L.201	8	9	11	10	11	18	22	10	10	9	9
25			12	17	11	13	15	22	26	18	18	13	13
26	**Public Information**												
27	70100 - Public Information Administration	S.5.2 L.219	1	2	1	1	2	4	7	1	2	1	1
28	70200 - General Public Information	S.5.2 L.226	4	9	2	3	3	4	5	7	7	7	8
29			5	11	3	4	4	8	12	9	9	8	8
30	**Customer Accounting**												
31	71000 - Supervision	S.5.2 L.245	2	2	2	2	1	2	2	2	2	3	3
32	71100 - Customer Applications and Service Orders	S.5.2 L.250	29	23	23	23	22	18	21	22	22	27	28
33	71200 - Meter Reading	S.5.2 L.261	37	39	41	39	36	35	36	38	38	35	35
34	71300 - Customer Billing and Accounting	S.5.2 L.272	25	25	22	28	28	29	29	38	52	35	35
35	71400 - Revenue Collections	S.5.2 L.285	10	9	10	11	11	11	11	11	11	10	10
36	71500 - Collection of Delinquent Accounts	S.5.2 L.292	8	6	8	5	6	6	5	5	5	7	7
37	71800 - Provision for Uncollectible Accounts	S.5.2 L.298	3	4	6	(2)	9	(0)	2	4	4	5	5
38			113	108	111	105	113	99	107	119	134	121	122
39	**Administration and General**												
40	72100 - Administrative	S.5.2 L.312	115	132	118	116	137	140	125	136	140	116	117
41	72200 - Administrative Corporate	S.5.2 L.340	20	15	10	12	13	5	5	5	6	8	8
42	72300 - Insurance	S.5.2 L.349	5	5	5	5	6	7	8	8	8	6	6
43	72400 - Injuries & Damages	S.5.2 L.357	6	6	6	6	6	6	6	(13)	(13)	6	6
44	72500 - Employee Expenses	S.5.2 L.362	22	20	16	6	8	8	9	9	9	19	19
45	72600 - Training and Safety	S.5.2 L.374	23	27	22	24	27	22	36	32	29	28	28
46	72700 - Relocation	S.5.2 L.390	9	1	4	7	9	8	5	7	3	20	20
47	72800 - Miscellaneous General	S.5.2 L.394	-	-	-	-	-	-	-	-	-	0	0
48	72900 - Audit/Legal Fees & Special Studies	S.5.2 L.401	9	9	12	8	17	27	15	13	13	10	10
49			208	215	193	184	222	223	208	196	193	213	214
50													
51	**Total Operations and Maintenance Expenses per customer**		624	655	600	587	619	696	727	702	697	652	650

ATCO Electric YUKON

September 28, 2023 AEY-UCG-032

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-032

Reference: July 7,2023 Application, page 5-4; Table 5.2 Labour Costs by Function

AEY also claims incremental and additional FTEs costs required.

Request:

(a) Break down Public Information labour costs.

(b) Break down Admin and General costs.

(c) Explain savings from far less office staff FTEs who are now no longer needed due to download of office hours and little need for payment in office to balance out much of these incremental and additional FTE costs.

Response:

(a) Please refer to the following table for the breakdown of Public Information labour costs.

Table 1: Public Information Labour Costs
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
70100 -Public Information Administration	10	10	10	15	16	13	14	15	16
70200 - General Public Information	59	103	11	-	-	12	78	79	82
Total	**69**	**113**	**21**	**15**	**16**	**25**	**92**	**94**	**98**

(b) Please refer to the following table for the breakdown of Administrative and General Labour costs:

Table 2: Administrative and General Labour Costs ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
72100 - Administrative	612	684	722	648	678	997	767	867	878
72500 - Employee Expenses	169	187	109	9	20	(22)	-	-	-
72600 - Training and Safety	343	365	330	341	452	380	583	518	524
72900 - Audit/Legal Fees & Special Studies	12	51	71	70	84	77	74	73	74
Total	**1,136**	**1,287**	**1,232**	**1,068**	**1,234**	**1,432**	**1,424**	**1,458**	**1,476**

(c) Office employees are still required to perform all billing functions, which have increased due to the rise in the numbers of customer connections being performed. This includes accepting payments in person and by phone.

September 28, 2023 AEY-UCG-033

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-033

Reference: July 7,2023 Application, page 5-4 and 5-5; Operations and Maintenance costs by function i.e., Production

Request:

(a) Give a cost/benefit analysis of Production from Fish Lake hydro generation plant.

(b) Explain why you need additional labour requirements and a new team lead plant position if you are contracting out the work for incremental maintenance.

(c) If many of your generation assets are nearing end-of-life why have you not invested in alternative renewables since the last GRA?

Response:

(a) The Fish Lake hydro generation plant has allowed AEY to provide renewable energy to its customers for decades. The production of renewable electricity directly aligns with the lower carbon emissions targets set out by the Federal Government and the Our Clean Energy plan set out by the Territorial Government. As the electrical demand of the Yukon Integrated System (YIS) continues to increase, the ongoing production of the Fish Lake Hydro system continues to be important. The renewable electricity produced by the Fish Lake Hydro system offsets purchase power from YEC. This legacy renewable electricity is even more important in the winter months as it offsets incremental thermal generation required to meet the peak winter demand on the YIS.

The benefit of offsetting purchased power outweighs the maintenance costs of running the plant. Refer to the table below.

September 28, 2023 AEY-UCG-033

Purchase Power Offset vs. Maintenance Costs
($000)

Description	Year								
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Primary Energy Charge ($ per MWh)*	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083
Hydro Generation (MWh)	8,051	7,103	5,458	4,973	5,034	9,843	9,597	9,522	10,143
Offset of Purchase Power	668	589	453	413	418	817	796	790	842
62600 - Hydro Generation	277	224	279	209	217	343	297	498	336
82600 - Hydro Maintenance	52	196	210	96	119	127	184	231	237
Total Maintenance Costs	329	420	489	305	336	470	481	729	573
Total Savings/(Overspend)	**339**	**169**	**(36)**	**108**	**82**	**347**	**315**	**61**	**269**

*Note that for 2023 and 2024, AEY is assuming the current purchase power rates, and if the YEC increase in its upcoming application is approved these savings would increase.

(b) The Team Lead, Plant position description is located on page 1-9 of the Application. This position is to address job planning, supervision, reporting, and technical competency assurance focused on the mechanical discipline of generation. This position will offload operational responsibilities from the Team Lead, Electrical as that team is focused on the electrical discipline of generation and has an increasing maintenance and commissioning workload due to additional and upcoming distribution infrastructure (e.g., SCADA devices, IPPs, substations). Contractor resources, i.e., trade technicians, are needed to address incremental maintenance at generating facilities and to assist during vacancies.

(c) AEY has invested in renewable hydro-generation at the Fish Lake facility and is proposing to progress a rebuild of FL#2 to modern standards (refer to Business Case #39), which would increase its production.

All isolated grids operated by AEY have existing diesel infrastructure which provides stable, reliable, and dispatchable power with spinning reserve. Some of these facilities are nearing the end of life and will require investment to continue

providing the same level of utility service. The addition of larger capacity renewables (in proportion to total load) onto isolated grids in the Yukon has been successfully demonstrated by the integration of Old Crow's solar and battery energy storage system with thermal legacy baseload. AEY has been supportive of the establishment of further community owned renewable energy projects within its remote communities, in alignment with the Yukon IPP policy. These new generation sources can decrease thermal demand and therefore reduce noise pollution, air contaminants, and greenhouse gas emissions. However, the need for energy storage systems and micro-grid controllers to address the intermittent and variable nature of renewable sources results in significant capital cost additions that require financial incentive or support to be economic. This support is being provided by various governments as a customer contribution. AEY's role is to ensure these renewable IPP projects integrate safely and reliably into our microgrids. As facilities reach the end of life, options will be evaluated and presented to the Board in future GRAs.

For a Utility to consider a reduction in diesel capacity the renewable generation would need to match the performance and availability of the equipment it is replacing. The diesel generators used in Isolated Gen communities are rated Prime, Prime as defined by the ISO 3046 standard. The maximum power which a generator set can provide a variable electrical load for an unlimited number of hours per year. In addition, the maximum average load factor over a 24-hour period shall not exceed 70 percent of generators prime rating.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-034

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-034

Reference: July 7,2023 Application, page 5-5 and 5-6; Operations and Maintenance costs by function i.e., Distribution

Request:

(a) Explain why there is not carry-over from the surplus of 2016 and 2017 actuals and 2017 approved?

(b) Why has new income from incremental growth not covered incremental growth in costs in new extension projects? Explain.

Response:

(a) There are two main reasons why the surplus from 2016 and 2017 cannot be carried forward: i) increases in inflation; and ii) increases in maintenance costs.

With respect to inflation, the world economy has experienced hyper-inflation and supply chain issues, which AEY has not been immune to. If AEY were to inflate 2017 actual productions and distribution Operations & Maintenance (O&M) costs using actual inflation for the period 2018 to 2022 and forecast inflation for 2023 to 2024, these increases alone account for over $1 million dollars in extra O&M expense for production and distribution annually. Please refer to Table 1 below for the related impacts:

Table 1: Related Inflation Impacts vs 2017 Actual Costs

	Years							
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Inflation Rates	Actuals	2.40%	2.00%	1.00%	3.30%	6.80%	3.80%	2.50%
	Inflated 2017 Actuals ($000)							
Production Costs	2,320	2,376	2,422	2,445	2,522	2,680	2,768	2,826
Distribution Costs	3,217	3,294	3,359	3,391	3,497	3,716	3,838	3,918
Total	5,537	5,670	5,781	5,836	6,019	6,395	6,606	6,744
Inflation Impacts vs 2017		133	244	299	482	858	1,069	1,207

With respect to maintenance costs, these costs have been increasing compared to 2017, above and beyond inflation. This increase is expected with aging infrastructure and increased load demands due to population growth in the area. As equipment ages and gets near the end of life, increased maintenance work is required to keep the system running efficiently.

(b) Incremental revenue growth to incremental costs, from a rapidly increasing population, is not a one-to-one ratio. The rapid population growth is putting a larger strain on the load and on the current infrastructure that must be addressed to provide safe and reliable service. This additional load that is putting strain on the system will require more maintenance and capital costs, over and above what incremental revenue growth provides to fund AEY's operations.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-035

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-035

Reference: July 7,2023 Application, page 5-6 and 5-7; Operations and Maintenance costs by function i.e., General

Request:

(a) Explain the new satellite phone and radio system, i.e., name and program with costs associated.

(b) Explain Maintenance of Warehouse and Office expenses with costs associated for each planned work.

Response:

(a) Please refer to Business Case #14 for a detailed explanation of the new satellite phone and radio system. Subscription is supplied through Roadpost Inc. and uses Iridium hardware with Iridium PTT extended plan service. The annual charge for this plan is $0.06 million for 38 units.

(b) Maintenance of Warehouse and Office expenses addresses deficiencies in the warehouse and yard due to aging. This includes maintenance on HVAC system, maintenance, and reinsulating of service complex. The forecasts for 2023 and 2024 are in line with inflated historical averages from 2016 to 2020. 2021 and 2022 were higher than normal, so this was adjusted out of the Test Period. AEY does not foresee any major building, warehouse, or yard deficiencies in the Test Period.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-036

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-036

Reference: July 7,2023 Application, page 5-7; Operations and Maintenance costs by function i.e., Public Information

Request:

(a) Explain why a communications advisor is needed and at what cost.

Response:

(a) The following are the responsibilities of the AEY Communications Advisor:

- Develop and execute government and public stakeholder plans and community engagement plans that enhance the companies' presence in the communities in which it operates and to address any emerging issue.
- Prepare news releases and backgrounders, respond to all media inquiries as the first point of contact, and act as corporate spokesperson, as required.
- Coordinate and produce materials for external and internal communication including presentations, reports, brochures, web content, advertising, briefings, speeches, memos, etc.
- Appropriately manage AEY's marketing plan and budget. Ensure all external advertising adheres to ATCO brand standards.
- Oversee AEY's community investment plan and budget, including reviewing requests and fulfilling commitments made with community organizations.
- Provide communications support in case of a crisis.
- Be a member of AEY's Employees Participating in Communities (EPIC) and Social Committees and assist with the planning and execution of fundraising events.
- The costs for the communication advisor are $94,000 in 2023 and $98,000 in 2024.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-037

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-037

Reference: July 7, 2023 Application, page 5-8; Operations and Maintenance costs by function i.e., Customer Accounting

Request:

(a) Will AEY still need meter readers when AMI is initiated? If not, what are the predicted savings?

(b) Break down various Customer Billing and Accounting costs.

(c) Break down "Other" with costs associated with each.

Response:

(a) The goal of having AMI is to significantly reduce the need for traditional meter readers. However, the need for meter readers may not be eliminated for following reasons:

- Transition Period: during the transition from traditional meters to AMI, the meter readers are still needed to read older meters.
- Exception Handling: if any issues arise with AMI, the meter reader may still be required to manually collect data in certain situations.
- Customer Requests: customers may request manual readings that are not compatible with AMI; and
- Maintenance and Repair: meter readers may still be needed for meter maintenance or replacement.

Thus, meter readers may still be needed depending on the progress of AMI implementation and new AMI technology reliability. Once AMI is implemented, the

need for traditional meter readers will likely decrease, however it is too early to predict the cost savings now.

(b) Please refer to the following table for breakdown of Customer Billing and Accounting costs:

Table 1: Customer Billing and Accounting Breakdown ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Postage for customer billing	163	169	173	175	164	213	194	200	200
CCS Operating costs	-	-	-	-	-	-	-	180	489
Telephone and Mobility	15	13	13	15	14	13	11	15	15
Financial Services	87	71	35	81	68	49	41	55	56
Total	**265**	**253**	**221**	**271**	**246**	**275**	**246**	**450**	**760**

(c) Please refer to the following table:

Table 2: Other Costs Breakdown ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals				Test Period				
Revenue Collections	2	4	8	8	(2)	2	12	11	12
Collection of Delinquent Accounts	9	6	11	3	8	7	17	11	10
Provision for Uncollectible Accounts	53	67	112	(32)	178	(5)	50	78	78
Total	**64**	**77**	**131**	**(21)**	**184**	**4**	**79**	**100**	**100**

ATCO Electric YUKON

September 28, 2023 AEY-UCG-038

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-038

Reference: July 7,2023 Application, page 5-9 and 5-10; Operations and Maintenance costs by function i.e., Admin & General

Request:

(a) Break down Administrative Services provided by ATCO Electric head office or affiliate companies with associated costs.

(b) Break down Audit/Legal Fees & Special Studies with associated costs.

(c) Break down addition of administrative positions with associated costs.

(d) Explain reasons for large IT Charges increases for each of the test years.

(e) Break down Financial Services with associated costs.

(f) Breakdown Other with associated costs.

Response:

(a) The detailed costs for head office services are shown in table below:

Table 1: Head Office Costs
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Governance, HR, and Health & Safety	31	112	127	127	127	113	118	121	112
Financial Reporting & Regulatory Support[1]	456	494	413	428	410	397	241	697	792
Payroll, Use of Systems and IT	155	115	8	7	7	-	-	-	-
General Marketing	-	-	25	52	52	57	-	-	-
Total Head Office Fees	**642**	**721**	**573**	**614**	**597**	**567**	**359**	**818**	**904**

[1] Including Government Relations & Initiatives

(b) Breakdown for Audit/Legal Fee & Special Studies costs are shown in table below.

Table 2: Audit/Legal Fees & Special Studies ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Audit Fees	107	104	143	78	100	143	125	139	143
Renewable Feasibility Study	-	-	-	-	-	188	-	-	-
Legal Fees	32	2	2	-	145	67	43	-	-
Industrial Research	-	-	-	-	-	50	50	50	50
Other	2	12	14	1	3	5	8	-	10
Total	**142**	**118**[2]	**159**	**79**	**248**	**453**	**226**	**198**	**203**

(c) Please refer to the following table for the breakdown of additional administrative positions with associated costs of $260,000.

Table 3: Addition of Administrative Positions

Position	FTE
Supervisor, Business Support Services	0.75
Head Office Personnel	1.18

(d) IT costs for the test years include additional licenses from Microsoft mainly for cybersecurity as well as an increased user count for AEY. While there is a modest increase from 2022, the test years are lower than both 2020 and 2021.

(e) Please refer to the following table for the breakdown of financial services. Please note this will be renamed to head office support in the Compliance Filing to this Application.

[2] To align Schedule 5.2 of the Application, a reclass of $8K was made between Audit/Legal Fees & Special Studies (Table 2) and Other (Table 5) for 2017, compared to Table 5.8 of the Application Narrative.

Table 4: Details of Financial Services
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Governance, HR, and Health & Safety	31	112	127	127	127	113	118	-	-
Financial Reporting and Regulatory Support	456	494	413	428	410	397	241	697	792
Payroll, Use of Systems and IT	155	115	8	7	7	-	-	-	-
Total	**642**	**721**	**548**	**562**	**544**	**510**	**360**	**697**	**792**

(f) Please refer to the following table for the breakdown of Other.

Table 5: Administrative & General Costs
Breakdown of Other
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Bank fees	358	266	188	226	248	104	108	140	142
Employee Expense	216	182	180	112	130	181	180	177	181
Severance - Due to Covid Vaccine Policy	-	-	-	-	-	-	410	-	-
IT services	160	154	163	165	140	145	162	173	179
Injuries & Damages	112	112	112	112	112	112	112	(279)	(279)
Contract services & Consultants	96	154	166	273	249	274	208	276	278
Telephone	35	54	57	54	58	62	79	86	86
Travel	105	97	78	53	36	43	47	78	79
Office stationery	29	29	30	32	29	29	32	36	39
Printing	16	17	19	23	25	22	23	27	29
Material & Consumables	21	25	30	30	29	26	24	33	38
Courier and Freight	20	19	23	25	28	25	24	29	33
Business Promotion	24	25	34	35	39	29	25	35	44
Total	**1,192**	**1,142**[3]	**1,080**	**1,140**	**1,123**	**1,052**	**1,434**	**811**	**849**

[3] To align Schedule 5.2 of the Application, a reclass of $8K was made between Audit/Legal Fees & Special Studies (Table 2) and Other (Table 5) for 2017, compared to Table 5.8 of the Application Narrative.

ATCO Electric
YUKON

September 28, 2023 AEY-UCG-039

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-039

Reference: July 7,2023 Application, page 5-10; Related Party Costs

AEY states: "*AEY outsources certain major administrative functions to affiliate companies, such as ATCO Electric, to take advantage of the economies associated with the scope and scale of services available from a larger utility. The costs of these services are detailed in Schedule 5.3 and are based on a fully allocated cost methodology that does not contain any element of profit or return. Labour support is purchased from ATCO Electric for various services including financial reporting, regulatory support, governance, human resources, health and safety, payroll, IT services, and customer care & billing support*".

Request:

(a) Are there additional affiliate charges that are capitalized and do not show up on the O&M schedule 5-3? Provide details of these charges for 2017 through 2024.

(b) Are there any outbound affiliate services? If yes, where are they identified?

(c) Please provide copies of service level agreements for all affiliate services provided to and by AEY in 2013-2015 and forecast to be provided to and by AEY over the 2023- 2024 test period.

(d) Please provide evidence demonstrating that it is more cost-effective to procure the services for 2017-2024 from affiliates than from other sources.

September 28, 2023 AEY-UCG-039

Response:

(a) The following table shows capitalized affiliate charges from 2017 to 2024:

Table 1: Capitalized Affiliate Charges
($000)

	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals						Test Period	
Capital Management Services	3	69	89	63	42	49	50	50
THELP Atlin DG Connection	-	-	-	-	39	47	-	-
CIS replacement	-	-	-	-	23	157	210	-
Upgrade 2.5 Element Meters	-	-	-	-	-	16	-	-
Generation Integration Upgrades	-	-	-	-	-	19	-	-
Nthn Energy Cap Haeckel Wind	-	-	-	-	-	31	-	-
Total	**3**	**69**	**89**	**63**	**81**	**552**	**260**	**50**

(b) Yes. AEY employees supported outbound affiliate initiatives in 2021 and a portion in 2022. AEY provided labour support for ATCO's project to rebuild Puerto Rico's Electrical grid (LUMA Energy) in 2021 and 2022. AEY received revenues for all costs including any overhead.

(c) Please refer to AEY-UCG-039(c) Attachment 1.

(d) All services provided by ATCO Electric and ATCO Gas are based on a fully allocated cost methodology. No element of profit or return is included in the costs of the services. If the services were to be procured from a third party, the costs would include an element of profit to the provider, increasing the costs to AEY.

NORTHLAND UTILITIES (NWT) LIMITED, NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED, THE YUKON ELECTRICAL COMPANY LIMITED ("NORTH OF 60 COMPANIES")
and ATCO ELECTRIC LTD. ("ATCO ELECTRIC")

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

Services Agreement # 75

As amended December 1, 2018

Schedule "A" to the Master Services Contract

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

dated December 1, 2011 between

North of 60 Companies and ATCO Electric

As amended December 1, 2018

SCOPE OF SERVICES

ATCO Electric will make available to North of 60 Companies the following functions and activities listed in this agreement. Services included, but not limited to:

1. Finance
2. After Hours Assistance
3. Marketing & Communications
4. Regulatory
5. Human Resources
6. Business Technology Management
7. Customer Care & Billing
8. Supply Chain
9. Project Management
10. Engineering
11. Metering
12. Governance

Schedule "B" to the Master Services Contract

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

dated December 1, 2011 between

North of 60 Companies and ATCO Electric

As amended December 1, 2018

TERMS AND CONDITIONS

1. Term of Contract

This amended agreement shall commence December 1, 2018 and will remain in effect in perpetuity with an annual review.

In the event that amendments are required, an amended agreement will be negotiated one month prior to the new effective date of the agreement. If either party wishes to terminate the agreement, written notice is required at least one month in advance of the termination date.

2. Cost of Service Provided

The cost of services provided by ATCO Electric to North of 60 Companies are to be recovered on a Cost Recovery Basis, as outlined in ATCO Electric Accounting Policy G.5. For services that are reoccurring a fixed fee is provided in Appendix A and will be updated on an as-needed basis.

3. Billing

The Financial Services department of ATCO Electric will be responsible for allocating costs associated with this agreement through the intercompany debit note process and for providing details that support the charges. Settlement of these charges will be consistent with the normal settlement date for intercompany transactions.

Schedule "C" to the Master Services Contract

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

dated December 1, 2011 between

North of 60 Companies and ATCO Electric

As amended October 1, 2018

NORTH OF 60 COMPANIES' REPRESENTATIVE

Doug Tenney
Vice President, Northern Development



Signature

Nov. 23 / 18

Date

Schedule "D" to the Master Services Contract

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

dated December 1, 2011 between

North of 60 Companies and ATCO Electric

As amended December 1, 2018

ATCO ELECTRIC'S REPRESENTATIVES

Karen Probert
Controller

Signature

11/26/18
Date

Paul Goguen
Sr. VP & General Manager, Transmission & Distribution

Signature

Nov 27/18
Date

MASTER SERVICES CONTRACT

THIS MASTER SERVICES CONTRACT DATED effective the 1st day of January, 2003.

BETWEEN:

THE YUKON ELECTRICAL COMPANY LIMITED,
a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

NORTHLAND UTILITIES (NWT) LIMITED,
a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

NORTHLAND UTILTIES (YELLOWKNIFE) LIMITED,
a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "**North of 60 Companies**")

- and -

ATCO GAS, an operating name of
ATCO Gas and Pipelines Limited,
with offices in Edmonton and Calgary, Alberta

(hereinafter referred to as "**ATCO Gas**")

WHEREAS North of 60 Companies desires to engage ATCO Gas to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

WHEREAS ATCO Gas has the expertise and is capable of providing the services to and for North of 60 Companies as described in this Contract, in accordance with the terms and conditions described in this Contract;

THIS CONTRACT WITNESSES that in consideration of the respective covenants and agreements of North of 60 Companies and ATCO Gas (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable

consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. SCHEDULES

1.1 The following Schedules are attached hereto and made a part of this Contract:

(a) Schedule A - Scope of Services - detailing the services to be provided by ATCO Gas to North of 60 Companies pursuant to this Contract (the "Services");

(b) Schedule B - Scope of Terms – detailing, if applicable:

(i) the date, if any, set for commencement of the Services by ATCO Gas (the "Commencement Date");

(ii) the schedule, if any, set for performance of the Services by ATCO Gas;

(iii) the date, if any, set for completion of the Services by ATCO Gas (the "Completion Date");

(iv) the term, if any, of the duration for which the Services will be provided by ATCO Gas (the "Term");

(v) the compensation to be paid by North of 60 Companies to ATCO Gas;

(vi) any categories of out-of-pocket expenses for which reimbursement will be payable from North of 60 Companies to ATCO Gas in accordance with Section 5.1 herein;

(vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and

(viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.

(c) Schedule C - North of 60 Companies' Representative

(d) Schedule D - ATCO Gas' Representative

1.2 In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

2. THE SERVICES

2.1 North of 60 Companies hereby engages ATCO Gas, and ATCO Gas hereby agrees to provide the Services on the terms and conditions set forth herein.

2.2 ATCO Gas shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at ATCO Gas' own expense, subject to Section 5.1 herein providing for reimbursement for certain identified categories of expenses.

2.3 Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.

2.4 ATCO Gas shall periodically, but no more frequently than monthly, furnish to North of 60 Companies written progress reports, when and as requested by North of 60 Companies.

3. TIME OF PERFORMANCE

3.1 ATCO Gas shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. ATCO Gas shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.

3.2 ATCO Gas shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If ATCO Gas determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify North of 60 Companies in writing.

3.3 Should ATCO Gas, with the prior written authorization of North of 60 Companies, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

4. COMPENSATION

4.1 As full consideration for performance of the Services, North of 60 Companies will pay ATCO Gas in accordance with the terms detailed in Schedule B.

4.2 In accordance with Articles 8 and 9 herein, compensation from North of 60 Companies shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of ATCO Gas.

5. EXPENSES

5.1 In accordance with Schedule B, ATCO Gas may also be entitled to be reimbursed by North of 60 Companies for reasonable out-of-pocket expenses incurred by ATCO Gas in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, ATCO Gas is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.

5.2 Any Goods and Services Tax ("G.S.T.") which is applicable to ATCO Gas' reimbursable expenses shall be identified separately as a part of all invoices submitted by ATCO Gas.

6. INVOICING AND PAYMENT

6.1 ATCO Gas shall present on or before the 5th day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by North of 60 Companies for the immediately prior month for Services provided pursuant to this Contract.

6.2 For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in ATCO Gas' statement.

6.3 All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that ATCO Gas does not invoice North of 60 Companies for G.S.T., ATCO Gas shall indicate on the invoice the basis upon which ATCO Gas claims exemption from the statutory obligation to collect G.S.T.

6.4 All invoices shall be provided in accordance with Section 21.2 herein.

6.5 All payments are due and payable by North of 60 Companies **twenty-five (25)** days after receipt in North of 60 Companies' offices of the invoice and any substantiating documentation required by this Contract. If North of 60 Companies has any objection to the invoice or substantiating documentation, it shall notify ATCO Gas within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by North of 60 Companies to ATCO Gas at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. North of 60 Companies shall be entitled to set off any mutually agreed upon amount owed by ATCO Gas to North of 60 Companies against any amount owing

to ATCO Gas. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

7. AUDIT

7.1 This Article 7 shall only apply in the event compensation paid by North of 60 Companies under this Contract is based on ATCO Gas' costs.

7.2 ATCO Gas shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.

7.3 North of 60 Companies, upon providing written notice to ATCO Gas, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. ATCO Gas shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to North of 60 Companies and its authorized representatives, and shall also make available those employees or sub-contractors of ATCO Gas reasonably required to supply desired information during the audit.

7.4 North of 60 Companies will notify ATCO Gas in writing of any erroneous statements made by, or payments made to, ATCO Gas. Subject to ATCO Gas' right to have the matter determined in accordance with Article 27 herein, ATCO Gas will promptly make appropriate adjustments and ATCO Gas shall reimburse North of 60 Companies for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.

7.5 ATCO Gas shall use reasonable efforts to cause any of its sub-contractors to allow North of 60 Companies to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

8. INDEPENDENT CONTRACTOR

8.1 In the performance of the Services, ATCO Gas is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

8.2 All persons employed by ATCO Gas in connection with the Services shall be ATCO Gas' employees and not employees of North of 60 Companies in any respect.

8.3 Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

9.1 ATCO Gas shall promptly pay or cause to be paid, and North of 60 Companies shall not be responsible for, any assessment or contribution required to be paid in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.

9.2 Before commencement of the Services, ATCO Gas will, if requested by North of 60 Companies deliver to North of 60 Companies certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by ATCO Gas and its sub-contractors. Before the final payment owed under this Contract is made by North of 60 Companies, North of 60 Companies may request that ATCO Gas deliver to North of 60 Companies similar certificates with ATCO Gas' application for final payment from North of 60 Companies.

9.3 North of 60 Companies may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to ATCO Gas the amount, if any, of ATCO Gas' required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where North of 60 Companies, in its sole discretion, determines that such amounts may be assessed against North of 60 Companies. Any such withholding or deduction shall not be construed as an admission by North of 60 Companies that ATCO Gas in performing the Services is an employee of North of 60 Companies. North of 60 Companies will assist ATCO Gas in defending any claims against ATCO Gas in the event that ATCO Gas disputes such claims.

9.4 In the event that North of 60 Companies does not deduct and maintain an amount sufficient to provide for ATCO Gas' required assessments or contributions as specified in Section 9.3 herein, ATCO Gas shall indemnify and save harmless North of 60 Companies for any amounts assessed against and paid by North of 60 Companies as a result of failure by ATCO Gas to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.

9.5 ATCO Gas shall pay or cause to be paid, and North of 60 Companies shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding

taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for ATCO Gas' employees and ATCO Gas.

10. LIABILITY AND INDEMNIFICATION

10.1 ATCO Gas shall:

(a) be liable to North of 60 Companies for all losses, costs, damages, and expenses whatsoever which North of 60 Companies and North of 60 Companies' directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and

(b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of ATCO Gas' negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

(c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of ATCO Gas or its employees or sub-contractors; or

(d) ATCO Gas while under the direction of the Indemnified Parties.

10.2 ATCO Gas shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

11. INSURANCE

11.1 Without in any way limiting the liability of ATCO Gas under this Contract, it shall be the responsibility of ATCO Gas while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

(a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, $2,000,000 inclusive, any one accident, or equivalent limits.

(b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability,

owners' and contractors' protective liability, contractual liability assumed by ATCO Gas under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, $5,000,000 inclusive, any one occurrence, or equivalent limits.

(c) Such other insurance as may from time to time be required by law or reasonably required by North of 60 Companies.

11.2 ATCO Gas, or contractors engaged in the provision of the Services, shall provide North of 60 Companies with 30 days prior written notice of any material changes, proposed cancellation or reduction in coverage, or proposed lapse of their respective insurance policies.

11.3 ATCO Gas shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage

11.4 Upon request by North of 60 Companies, ATCO Gas shall, before commencement of the Services, deposit with North of 60 Companies information satisfactory to North of 60 Companies as evidence of the insurance required in Sections 11.1 and 11.2 herein.

12. COMPLIANCE WITH LAW AND POLICY

12.1 The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by ATCO Gas must be in accordance with such laws, ordinances, codes, and regulations.

12.2 ATCO Gas and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of North of 60 Companies from time to time in force which are brought to ATCO Gas' notice and which are not contrary to law or the provisions of this Contract.

12.3 ATCO Gas shall promptly notify North of 60 Companies in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.

12.4 Unless otherwise specified in this Contract and subject to Section 5.1 herein, ATCO Gas shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

13. PUBLICITY RELEASE

13.1 ATCO Gas shall not, without the prior written consent of North of 60 Companies, use North of 60 Companies', name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

14. CONFIDENTIAL INFORMATION

14.1 The term "Confidential Information" shall mean all confidential information of or relating to North of 60 Companies or its business or its customers and shall include without limitation all information which ATCO Gas or its employees or sub-contractors, directly or indirectly, receives or acquires from North of 60 Companies either in writing, orally, or through observation, or which ATCO Gas or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

(a) information which was in the possession of ATCO Gas or its employees or sub-contractors, reasonable proof of which lies on ATCO Gas, prior to receipt or acquisition thereof from North of 60 Companies and which was not acquired by ATCO Gas or its employees or sub-contractors under any obligation of confidentiality;

(b) information which, at the time of the receipt or acquisition thereof by ATCO Gas or its employees or sub-contractors from ATCO Gas was or thereafter became a part of the public domain through no act or failure on the part of ATCO Gas or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and

(c) information which is disclosed to ATCO Gas or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to North of 60 Companies with respect to such information.

14.2 ATCO Gas and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by North of 60 Companies in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in ATCO Gas' performance of the Services) or disclose to any third party

(except as required to be disclosed by operation of law) such Confidential Information, provided that ATCO Gas may disclose such Confidential Information to those of ATCO Gas' employees or sub-contractors to whom disclosure is required for ATCO Gas' performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which ATCO Gas has assumed in this Article 14, and ATCO Gas shall ensure that all employees and sub-contractors at all times comply with such obligations.

14.3 North of 60 Companies shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

14.4 The terms of this Article 14 shall apply, mutatis mutandis, to North of 60 Companies' treatment of Confidential Information of or relating to ATCO Gas.

15. INTELLECTUAL PROPERTY

15.1 For the purposes of this Contract, "Intellectual Property" means

(a) all inventions, whether or not patentable,

(b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,

(c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and

(d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

15.2 All Intellectual Property made or conceived by ATCO Gas, its employees or sub-contractors:

(a) in the course of providing the Services;

(b) during the Term and which relates in any manner to the business of North of 60 Companies;

(c) made with or which arises with the use of the materials, equipment or resources of North of 60 Companies; and

(d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of ATCO Gas.

15.3 ATCO Gas shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

16. ASSIGNMENT

16.1 With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

17. FORCE MAJEURE

17.1 For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.

17.2 Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.

17.3 In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and North of 60 Companies shall either:

(a) terminate this Contract, or

(b) authorize ATCO Gas to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

18. TERMINATION

18.1 In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.

18.2 In the event of termination pursuant to this Article 18, ATCO Gas shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit ATCO Gas to carry out its duties under this Contract. North of 60 Companies shall not be liable for damages or loss of anticipated profits on account of such termination.

19. REMEDIAL WORK

19.1 ATCO Gas shall after receipt of notice from North of 60 Companies, at North of 60 Companies' option and at no cost to North of 60 Companies, without prejudice to any other right that North of 60 Companies might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by ATCO Gas in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. North of 60 Companies reserves the right to complete such remedial work or have such remedial work completed by other parties but at ATCO Gas' expense, in the event ATCO Gas fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from North of 60 Companies.

20. WAIVER

20.1 Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

21. REPRESENTATIVES AND NOTICES

21.1 North of 60 Companies' representative, who has full authority to represent North of 60 Companies in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

ATCO Gas' representative, who has full authority to represent ATCO Gas in

administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

21.2 Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

North of 60 Companies: See Schedule "C"

ATCO Gas: See Schedule "D"

21.3 Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

22. ENTIRETY OF AGREEMENT

22.1 This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.

22.2 There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.

22.3 No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

23. SEVERABILITY

23.1 Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without

affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

24. SURVIVAL OF TERMS

24.1 The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

25. GOVERNING LAW

25.1 The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

25.2 The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

26. INTERPRETATION

26.1 Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

26.2 In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

26.3 Where reference is made in this Contract to "North of 60 Companies' affiliates", such reference shall be meant to include:

(a) an Affiliate, within the meaning of the *Business Corporations Act*, of North of 60 Companies; and

(b) a partnership, joint venture, or person is which North of 60 Companies has a controlling interest or that is otherwise subject to the control of North of 60 Companies.

27. DISPUTE RESOLUTION

27.1 The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of North of 60 Companies and ATCO Gas.

27.2 If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

27.3 In the event that:

(a) such dispute is not resolved pursuant to Section 27.2 above; or

(b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

28. GENERAL PROVISIONS

28.1 The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

28.2 All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

28.3 This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

28.4 Time is of the essence in the performance of every obligation of this Contract.

28.5 This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

IN WITNESS WHEREOF the Parties have duly executed this Contract with effect from the date and year first above written.

North of 60 Companies	**ATCO Gas**
Per:	Per:
Name:	Name:
Per:	Per:
Name:	Name:

ATCO Electric YUKON

September 28, 2023 AEY-UCG-040

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-040

Reference: July 7,2023 Application, page 6-1; Taxes Other Than Income

AEY states "*Property taxes are paid to the communities annually for ATCO Electric Yukon's office building, generation facilities, substation properties and power lines. The increases in the forecast over the test period are due to inflation.*"

Request:

(a) Provide a breakdown of actual property taxes paid in 2016, 2017, 2018, 2019, 2020, 2021, 2022 and forecast for 2023 and 2024 to each entity to which property taxes are paid.

(b) Is there any planned capital work that would result in new taxes? Explain.

Response:

(a) Property tax by entity paid is as noted in Table 1 below:

Table 1: Property Tax by Entity
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
Entity	**Actuals**							**Test Period**	
British Columbia Government	6	6	6	6	7	7	7	7	7
City of Whitehorse	139	135	131	134	141	128	137	142	146
Town of Watson Lake	33	35	48	48	49	49	49	51	52
Village of Carmacks	9	10	10	11	11	11	11	11	12
Village of Haines Junction	5	5	6	6	6	6	5	6	6
Village of Teslin	10	10	10	10	10	10	10	10	10
Yukon Government	51	52	53	62	53	56	56	58	59
Total	**253**	**253**	**264**	**277**	**277**	**267**	**275**	**285**	**292**

(b) No, AEY does not foresee any of the planned capital work in 2023 and 2024 to increase property taxes beyond the proposed inflationary increases.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-041

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-041

Reference: July 7,2023 Application, page 7-1 and 7-2; Depreciation and Negative Net Salvage

AEY states "*The annual increases in depreciation expense from 2018 to 2022 are due to growth in property, plant, and equipment.* Thae increases from 2022 to 2023 and 2024 are mainly driven by the restart of the Net Salvage collection."

Request:

(a) Give the impact on revenue requirement, in a percentage of total increase proposed, for depreciation, deferred costs of amortization, long term debt and ROE.

(b) Provide details of the net negative salvage from 2018 to 2022 (all non-test years) and proposed salvage depreciation for 2023 and 2024. Explain how this affects revenue requirement for each of these test years.

(c) Give reasons why a more balanced approach (i.e., deferring some capital projects to a later date to lower depreciation expense could be used for each test year to provide more stable rates.

(d) Provide specific calculations related to assets being added to rate base that result in an increase in total depreciation expense of $2.047 million in 2023 (2023 forecast vs. 2022 actual) and an additional $1.829 million in 2024 (2023 forecast vs. 2024 forecast).

Response:

(a-b) Please note that the original depreciation expenses included in AEY's 2023-2024 GRA application were placeholder amounts and have been updated per AEY's Depreciation Study, which was filed with the Board on September 11, 2023. As

set out in Board Order 2023-18, information requests related to AEY's updated depreciation expenses can be submitted by October 10, 2023.

(c) AEY does not believe that deferring capital projects to a later date to provide more stable rates is a viable option as these delays could put AEY's ability to provide safe and reliable service at risk. There is increasing strain on the current grid due to load growth from the rapidly increasing population in the Yukon. If these capital projects are not addressed in a timely manner, the reliability of the grid could be compromised.

(d) Please refer to the response to part (a-b) above.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-042

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-042

Reference: July 7,2023 Application, page 8-1 to 8-4

AEY is proposing that the benchmark ROE to be set in a currently incomplete BCUC GCOC proceeding to determine the AEY ROE for the test years which was previously set at 8.75 percent, to be used as a placeholder. and that the add-on risk premium be increased from the current to 0.75 percent.

Request:

(a) Provide AEY's understanding that to accept changes to any element of its revenue requirement after a decision on the test period (i.e., in a compliance filing) has been made by the YUB would violate the prospective nature of rate-setting in the Yukon.

(b) Give current rates of ROE for other jurisdictions in Canada. Reference documentation.

(c) Identify the YUB-allowed ROE and equity ratio currently incorporated in rates charged by Yukon Energy Corporation. Reference documentation.

(d) Since rates for 2018 through 2022 were based in part on a return on rate base that was more than what would have been earned on actual rate base, please provide a calculation of the excess return incorporated in rates for 2018 through 2022.

(e) Confirm that the current benchmark ROE of 8.75% established by the BCUC was for a utility having a 38% equity ratio with no provision for an add-on risk premium.

(f) Confirm that the current benchmark ROE of 8.75% established by the Alberta Utilities Commission does not allow for an add-on risk premium.

(g) Provide a table that reflects the actual annual ROE earned by AEY for 2016 through 2022 (% and $) as compared to the Board set rate of ROE.

(h) What is the difference between rate of return and return on equity.

(i) Explain why AEY has a rate of return amount and not the return of equity amount on yearly reports to YUB.

Response:

(a) AEY does not consider the update of a placeholder to be retroactive rate making, revenue requirement would be set prospectively based on a defined input that is outstanding at the time of the decision. The variance between placeholders can be settled through adjustment riders as done in other jurisdictions similar to adjustments for approved deferrals.

(b) Please refer to the response to AEY-JM-025(a).

(c) Per Board Order 2023-01,[1] the YUB approved a ROE of 8.65 percent after the Application of OIC 1995/90 and 40 percent equity ratio for YEC.

(d) The Yukon Utilities Board approved 9.0 percent ROE in Board Order 2017-01. Please refer to the following table for AEY's actual return on equity for the years 2016-2022:

Table 1: AEYs Actual Return on Equity

	2016	2017	2018	2019	2020	2021	2022
Actual Return on Equity (%)	10.44%	12.72%	12.63%	13.00%	13.19%	12.35%	11.88%
Approved Return on Equity (%)	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Differential (bps)	144	372	363	400	419	335	288
Differential ($000)	566.3	1,543.9	1,554.0	1,732.4	1,806.5	1,450.3	1,318.1

(e) Not confirmed. Please refer to the response to AEY-YUB-022.

(f) Not confirmed. The current ROE established by the Alberta Utilities Commission (AUC) is 8.50 percent, this does not contain a specific ROE adder on account of business risk. This is not because the AUC has prohibited or has a policy against

[1] https://yukonutilitiesboard.yk.ca/pdf/Board_Orders_2020/Board_Order_2023-01.pdf.

business risk premiums, rather that the AUC has not been persuaded that any of the Alberta utilities have greater business risk than comparator Alberta utilities.

(g) Please refer to the response to part (d) above.

(h) The rate of return is the net gain or loss of an investment over a specified period, expressed as a percentage of the investment's initial cost. Return on equity is a measure of financial performance, calculated by dividing net income by shareholders' equity.

(i) AEY provides both the rate of return and the return on equity in its annual reports.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-043

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-043

Reference: July 7,2023 Application, pages 8-4 and 8-5 Forecast Long term Date Rates

Request:

(a) Indicate all cases in the last 5 years where AEY has had to defer or abandon expenditures needed to provide service due to an inability to raise the necessary capital under reasonable terms and conditions. Please provide details.

(b) Is AEY planning to raise any capital to finance investment growth in the 2023 and 2024 test years? Give details.

(c) Detail all AEY Term loans with amounts, dates and to whom from last GRA period.

(d) Explain why AEY is proposing a rate greater than the highest Long Canada Bond Rate?

(e) What is the current YUB direction on determining cost of debt.

Response:

(a) AEY has never had to defer or abandon expenditures needed to provide service due to an inability to raise necessary capital under reasonable T&Cs.

(b) Please refer to the response to AEY-YUB-040(d).

(c) Please refer to the response to AEY-YUB-040(a).

(d) The cost of debt is determined by adding a credit spread on top of Long Canada Bond Rates. Credit ratings determine the credit spread which reflects the entity risk and credit risk. The credit spread forecast is calculated based on CU Inc's

historical credit spread actuals and then added to the underlying rate, which in this case is the Long Canada Bond Rate.

(e) The YUB has relied on market forecasts for the Long Canada Bond rate plus a credit spread based on historical actuals.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-044

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-044

Reference: July 7,2023 Application, page 8-2 Stand-Alone-Principle

Request:

Give AEYs definition of stand-alone-principle and explain why AEY fits into this category.

Response:

AEY's definition of the stand-alone principle is consistent with that outlined in the Concentric Report included in the Application; specifically, that a utility must be regulated as if it were a stand-alone entity, separate and independent from any affiliate or parent companies. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure.[1]

This separation ensures that the rates charged to AEY's customers are determined based on AEY's own financial circumstances and do not reflect the financial situation of affiliate or parent companies. AEY fits into this category because it is a utility that is owned by a parent company (ATCO Electric), which, in turn, is owned by CU Inc. In AEY's view, the financial performance or risk profile of AEY's affiliates and/or parent company should not be factors considered when determining AEY's approved returns.

[1] 2023-2024 AEY GRA, PDF p. 147.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-045

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-045

Reference: July 7,2023 Application, page 8-3

"AEY submits that its ongoing business risks encompass market demand operational risk."

Request:

Explain each of these risks (i.e., business and market demand) with examples.

Response:

Please refer to the response to AEY-JM-022(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-046

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-046

Reference: July 7,2023 Application, page 8-3

AEY claims "AEY sales are more sensitive to weather than other electric utilities due to extreme range of temperatures experienced in northern Canada."

Request:

(a) Give examples of these extreme range of temperatures compared to other jurisdictions.

(b) Would not colder weather present a positive result for AEY (i.e., greater sales, thus greater income)?

Response:

(a) Please refer to the response to AEY-YUB-024(a-c).

(b) The issue from a risk perspective is variability from the forecast, which causes the Company's actual cash flows and earnings to deviate from what is forecast. In addition, weather conditions have become more extreme and less predictable in recent years.

September 28, 2023 AEY-UCG-047

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-047

Reference: July 7,2023 Application, page 8-3

AEY claims transformational change increases risk.

Request:

Compare this concept to other non-regulated Yukon businesses.

Response:

AEY does not consider the risks experienced by other non-regulated Yukon businesses to be relevant to the assessment of its business risk as a regulated utility. Accordingly, AEY declines to provide the requested information pursuant to Rule 14(4)(a) of the YUB *Rules of Practice*.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-048

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-048

Reference: July 7,2023 Application, page 8-3

AEY claims: "Operational cost risks due to potential to under-estimate various cost items including capital expenditures, financing costs and O&M expenses."

Request:

(a) Explain when and if YEC has ever had negative cost recovery (i.e., underestimated various costs).

(b) Explain when and if YEC has had positive cost recovery (i.e., overestimated various costs.

Response:

(a-b) AEY submits that the requested information is beyond the scope of this Proceeding and declines to provide the same pursuant to Rule 14(4)(a) of the YUB *Rules of Practice*.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-049

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-049

Reference: July 7,2023 Application, page 8-4

AEY is seeking continuation of its currently approved common equity ratio of 40 percent for each of 2023 and 2024.

Request:

(a) Give AEYs proxy/benchmark comparison common equity ratio with referenced documents.

Response:

(a) Please refer to the response to AEY-UCG-056(c).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-050

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-050

Reference: July 7,2023 Application, page 8-5; No Cost Capital

AEY claims: The no cost capital included in this Application relates to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans as well as the Reserve for Injuries and Damages. Both the pension plan and OPEB have been accounted for on a cash basis in the test period.

Request:

(a) Explain how no cost capital impacts the revenue requirement for each of the test years.

(b) Break down the no cost capital amounts in Table 8.3 for Pension, OPEB, RID and other for each test year.

(c) Explain what is meant by having a no cost capital for pension and OPEB, yet this has been accounted for on a cash basis for the test period.

(d) What is the status of the ATCO Pension Plan and OPEB in connection with CU Limited affiliates.

(e) Provide copies of the defined benefit pension actuarial evaluation as of December 31, 2018, 2019, 2020, 2021 and 2022 and identify the resulting funding amounts.

(f) Provide details of all credits and debits recorded in existing deferral accounts for 2018,2019, 2020, 2021 and 2022.

(g) What returns or carrying costs have been accrued on the balances in the deferral account since it was approved in the last GRA?

(h) Provide evidence demonstrating that AEY's total compensation costs and compensation strategy are in line with utility sector practice.

(i) Provide a breakdown of total compensation cost and pension cost showing separately the amount attributed to capital expenditures and the amount attributed to operating expenditures.

(j) Does AEY provide enhanced benefits under early retirement or other severance arrangements? If yes, please provide evidence demonstrating the value of the enhancements and impact on ratepayers.

(k) Does AEY incur any pension-related costs directed to special categories of employees such as a supplementary executive retirement plan(s)? If yes, please identify the amounts contributed by employees to any such plan(s) and describe the basis for determining the amount included in rates.

(l) Provide a description of the governance framework AEY employs to govern its pension plans (both DB and DC plans) and OPEB.

(m) Give an accounting for RID since last GRA.

(n) Explain how RID impacts revenue requirement for each of the test years.

Response:

(a) The no cost capital amount reduces the debt and equity financing that AEY has to acquire to finance its utility capital investment, offsetting the cost of capital included in revenue requirement within the Test Period.

(b) Please refer to AEY-UCG-050(b) Attachment 1. AEY notes that the 2023 Actuarial valuation report is now available and, as the pension costs are under deferral treatment, AEY will update revenue requirement accordingly in the Compliance Filing to the Application to minimize the deferred balances requiring future settlement.

(c) The no cost capital for Defined Pension and OPEB is the net pension assets that meet the funding requirements for the Defined Pension and OPEB plan members. This amount is considered no cost capital and proportionately reduces revenue requirement. For example, if AEY invests the funds into a savings account to earn interest, instead of pension, the interest income would reduce revenue

requirement. Therefore, the net pension contributions are included in the no cost capital to reduce the proportional amount of revenue requirement. The pension current service costs and interest costs are accounted for on cash basis, which is not part of the no cost capital.

(d) AEY is a participant of CU Inc's Plan 1. The transfer of pension assets and liabilities in Plan 2 was concluded on September 6, 2016.

(e) Please refer to AEY-UCG-50(e) Attachment 1-4 for the actuarial valuation report for the period 2019-2022. There was no actuarial valuation report completed in 2018 and the resulting funding amounts are per the table below:

Table 1: Net Funding Amounts ($000)

Year	Total costs
2018	240
2019	240
2020	273
2021	249
2022	201

(f) Please refer to AEY-UCG-50(f) Attachment 1 for the determination of the deferred pension costs. In preparation of this response, AEY identified an inadvertent accounting error in the preparation of Schedule 8.8. AEY will correct this in its Compliance Filing along with updating to the most recent pension funding requirements for the Test Period.

(g) The mid-year balance of deferral account balances is included in rate base. Balances owed to customers reduce the net funding requirements and balances due from customers are charged carrying charges through the return on rate base. In 2023 and 2024, the mid-year deferral balances reduce return on rate base by $70,000 and $14,000, respectively.

(h) AEY, with support from ATCO Electric's Human Resources group, establishes an overall compensation strategy, based on a combination of factors, including internal expertise along with consideration and analysis of a variety of available external market compensation reports. External market data is obtained through various compensation survey organizations, government agencies, professional organizations, and applied research organizations. This data is then analyzed and validated by ATCO Electric's compensation specialists and human resource professionals. Based on this experience and data, AEY confirms that its total compensation costs and compensation strategy are in line with utility sector practice.

(i) Please refer to the following table:

Table 2: Compensation
($000)

	2023	**2024**
Compensation (Excl. Pension)	10,481	10,799
Pension Costs	409	418
Total Compensation	**10,890**	**11,217**
Operating Expenditures	7,133	7,295
Capital Expenditures	3,757	3,922

(j) No.

(k) No.

(l) AEY is a participating employer in the Retirement Plan for Employees of Canadian Utilities Limited (CU). CU has a comprehensive pension governance policy and structure in place to fulfill statutory and fiduciary obligations, as the administrator of the Plans. CU also has a pension governance policy that meets the requirements of the Employment Pension Plans Act and sets out the structures

and processes for overseeing, managing and administering the Plans. The administration of each of the Plans is in accordance with its terms and applicable legislation.

(m) AEY had an incident in 2017 (a mechanical failure at Fish Lake) that was fully insurable and recoverable through insurance, less the $100,000 deductible. The $100,000 deductible went through the Reserve for Injuries and Damages (RID) account, which is reflected in the no cost of capital Schedule 8.4, line 29 of the Application. The collection or refund of the accumulated RID balance is included in O&M Schedule 5.1, line 41 of the Application.

(n) The RID provision has accumulated to a refund position as of 2022. In each of the Test Years, AEY plans to refund the credits to customers, which amounts to approximately $279,000 each year. The refund of the accumulated RID balance is incorporated through the O&M costs and is included per Schedule 5.1, Line 41 of the Application.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Revised Continuity Schedule of No Cost Capital
($000)

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	**No Cost Capital**												
2	**Deferred Pension and Regulatory Asset/Liability**												
3													
4	**Mid-Year Balance Summary**												
5	Other Post Employment Benefits (OPEB)		537	537	537	537	537	537	537	537	537	537	537
6	Defined Benefit Pension		133	128	123	119	115	111	106	103	103	140	136
7	Injuries & Damages		33	144	256	367	479	590	701	518	239	(17)	(6)
8	**Total No Cost Capital Mid-Year Balance**		703	809	915	1,023	1,130	1,238	1,344	1,158	880	660	667
9													
10	**Other Post Employment Benefits (OPEB)**												
11	Balance at Beginning of Year		537	537	537	537	537	537	537	537	537	537	537
12	Add: Charges		36	24	29	25	69	141	73	73	73	37	37
13	Less: Cash Payments		(36)	(24)	(29)	(25)	(69)	(141)	(73)	(73)	(73)	(37)	(37)
14	Balance at End of Year		537	537	537	537	537	537	537	537	537	537	537
15													
16	Mid-Year Balance	(L.11+L.14) / 2	537	537	537	537	537	537	537	537	537	537	537
17													
18	**Defined Benefit Pension** [1]												
19	Balance at Beginning of Year		134	132	124	121	116	113	108	103	103	142	138
20	Add: Charges		509	505	244	244	276	252	204	39	39	505	505
21	Less: Cash Payments		(511)	(513)	(247)	(249)	(279)	(257)	(209)	(39)	(39)	(509)	(509)
22	Balance at End of Year		132	124	121	116	113	108	103	103	103	138	134
23													
24	Mid-Year Balance	(L.19+L.22) / 2	133	128	123	119	115	111	106	103	103	140	136
25													
26	**Injuries & Damages**												
27	Balance at Beginning of Year		(23)	89	100	212	323	435	546	658	379	(23)	(12)
28	Add: Write-off		112	112	112	112	112	112	112	(279)	(279)	112	112
29	Less: Costs		-	(100)	-	-	-	-	-	-	-	(100)	(100)
30	Balance at End of Year		89	100	212	323	435	546	658	379	100	(12)	-
31													
32	Mid-Year Balance	(L.26+L.29) / 2	33	94	156	267	379	490	602	518	239	(17)	(6)

1. AEY has updated the forecast of Define Benefit Pension in the test periods as the most recent 2023 Actuarial Valuation Report becomes available during the information response period.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Revised Schedule of Deferred Charges & Credits
($000)

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	**Total Deferred Charges & Credits Summary**												
2													
3	**Write-off Summary**												
4	Rate Case Costs	L. 22	(313)	(313)	(313)	(313)	(313)	(313)	(178)	(156)	(203)	(313)	(313)
5	Watson Lake LNG Study Costs	L. 32	(99)	(99)	(99)	(99)	(99)	(99)	(99)	74	124	(99)	(99)
6	Demand Side Management		-	-	-	-	-	-	-	-	-		
7	Pension Deferral Account	L. 49	77	77	77	77	77	77	77	192	192	77	77
8	ERA/IPP Legal Costs		-	-	-	-	-	-	-	94	94	-	-
9	**Total Write-off**		(334)	(334)	(335)	(335)	(335)	(334)	(200)	204	113	(334)	(335)
10													
11	**Deferred Credits Mid-Year Balance Summary**												
12	Rate Case Reserve	L. 26	1	(45)	(210)	(522)	(835)	(1,147)	(1,393)	(793)	(52)	176	156
13	Watson Lake LNG Study Costs	L. 35	263	345	246	148	49	(50)	(149)	(161)	(62)	263	345
14	Demand Side Management Program Costs	L. 44	199	-	-	-	-	-	-	-	-	199	-
15	Pension Deferral Account	L. 52	(39)	(39)	(38)	(115)	(184)	(252)	(336)	(288)	(96)	(39)	(39)
16	ERA/IPP Legal Costs		-	-	-	-	73	178	198	141	47		
17	**Total Deferred Credits Mid-Year Balance**		424	261	(2)	(490)	(897)	(1,271)	(1,679)	(1,101)	(210)	600	463
18													
19	Rate Case Costs												
20	Balance at Beginning of Year		39	(37)	(54)	(366)	(679)	(991)	(1,304)	(1,481)	(104)	39	313
21	Add: Rate Case Costs		236	296	-	-	-	-	-	301	307	586	-
22	Less: Rate Case (Write-off) Credit		(313)	(313)	(313)	(313)	(313)	(313)	(313)	(156)	(203)	(313)	(313)
23	Less: Adjustment for YUB 2022-13		-	-	-	-	-	-	135	1,232	-	-	-
24	Balance at End of Year		(37)	(54)	(366)	(679)	(991)	(1,304)	(1,481)	(104)	-	313	-
25													
26	Mid-Year Balance	(L.20+L.24)/2	1	(45)	(210)	(522)	(835)	(1,147)	(1,393)	(793)	(52)	176	156
27													
28	Watson Lake LNG Study Costs												
29	Balance at Beginning of Year		131	394	296	197	98	(1)	(99)	(198)	(124)	131	394
30	Add: Costs/AFUDC		-	-	-	-	-	-	-	-	-	-	-
31	Add: Transfers from Plant Additions		362	-	-	-	-	-	-	-	-	362	-
32	Less: Write-off		(99)	(99)	(99)	(99)	(99)	(99)	(99)	74	124	(99)	(99)
33	Balance at End of Year		394	296	197	98	(1)	(99)	(198)	(124)	-	394	296
34													
35	Mid-Year Balance	(L.29+L.33)/2	263	345	246	148	49	(50)	(149)	(161)	(62)	263	345
36													
37	Demand Side Management Program Costs												
38	Balance at Beginning of Year		398	-	-	-	-	-	-	-	-	398	-
39	Add: Costs		136	-	-	-	-	-	-		-	136	-
40	Less: Transfer to Rate Base		(534)	-	-	-	-	-	-	-	-	(534)	
41	Less: Write Off									-	-	-	-
42	Balance at End of Year		-	-	-	-	-	-	-	-	-	-	-
43													
44	Mid-Year Balance	(L.38+L.42)/2	199	-	-	-	-	-	-	-	-	199	-
45													
46	Pension Deferral [1]												
47	Balance at Beginning of Year		-	(77)	-	(77)	(154)	(215)	(289)	(384)	(192)	-	(77)
48	Add: Costs		(154)	-	(154)	(154)	(138)	(150)	(172)	-	-	(154)	-
49	Less: Write-off		77	77	77	77	77	77	77	192	192	77	77
50	Balance at End of Year		(77)	-	(77)	(154)	(215)	(289)	(384)	(192)	-	(77)	-
51													
52	Mid-Year Balance	(L.47+L.50)/2	(39)	(39)	(38)	(115)	(184)	(252)	(336)	(288)	(96)	(39)	(39)
53													
54	EPA/IPP Legal Costs												
55	Balance at Beginning of Year		-	-	-	-	-	146	209	187	94		
56	Add: Costs		-	-	-	-	146	63	(22)	-	-		
57	Less: Write-off		-	-	-	-	-	-	-	(94)	(94)		
58	Balance at End of Year						146	209	187	94	-		
59													
60	Mid-Year Balance	(L.55+L.58)/2	-	-	-	-	73	178	198	141	47	-	-

1. AEY updates the Pension Deferral balance as the most recent 2023 Actuarial Valuation Report becomes available during the information response period.

MERCER

Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies - Plan 1

Report on the Actuarial Valuation for Funding Purposes as at December, 31, 2019

July 10, 2020

Canada Revenue Agency Registration Number: 0343343

welcome to brighter

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the Plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

The valuation results shown in this report also illustrate the sensitivity to three key actuarial assumptions, including the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Should the Plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the Plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound up in the future. In fact, even if the Plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the *Alberta Employment Pension Plans Act*, the Income Tax Act, and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

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1

Summary of Results

	31.12.2019	31.12.2017
Going Concern Financial Status		
Market value of assets	$2,818,113,100	$2,695,205,600
Going concern funding target	$2,710,842,700	$2,603,416,000
Funding excess (shortfall)	$107,270,400	$91,789,600
Funded ratio	104.0%	103.5%
Hypothetical Wind-up Financial Position		
Wind-up assets	$2,816,113,100	$2,693,205,600
Wind-up liability	$3,335,781,100	$3,153,972,700
Wind-up excess (shortfall)	($519,668,000)	($460,767,100)
Solvency Financial Position		
Solvency assets	$2,816,113,100	$2,693,205,600
Solvency liability	$2,770,068,000	$2,691,372,700
Solvency excess (shortfall)	$46,045,100	$1,832,900
Solvency ratio	101.7%	100.1%
Funding Requirements in the Year Following the Valuation[1]		
Total current service cost	$13,412,600	$21,045,400
Estimated members' required contributions	($542,000)	($943,900)
Estimated employer's current service cost	$12,870,600	$20,101,500
Employer's current service cost as a percentage of members' Pensionable earnings	38.90%	35.67%
Minimum special payments	$0	$0
Estimated minimum employer contribution	$12,870,600	$20,101,500
Estimated maximum eligible employer contribution	$12,870,600	$20,101,500
Next required valuation date	31.12.2022	31.12.2020

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To the Management Pension Committee of Canadian Utilities Limited

At your request, we have conducted an actuarial valuation of the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies - Plan 1 (the "Plan"), sponsored by Canadian Utilities Limited (the "Company"), as at the valuation date, December 31, 2019. We are pleased to present the results of the valuation.

The contributions to the defined contribution component of the Plan are determined by the Plan provisions. An estimate of the defined contributions for 2020 is included in this report.

Purpose

The purpose of this valuation is to determine:

- The funded status of the Plan as at December 31, 2019 on going concern, hypothetical wind-up, and solvency bases;
- The minimum required funding contributions from 2020, in accordance with the *Alberta Employment Pension Plans Act* (the "Act"); and
- The maximum permissible funding contributions from 2020, in accordance with the *Income Tax Act*.

The information contained in this report was prepared for the internal use of the Management Pension Committee and the Company, and for filing with the Alberta Treasury Board and Finance and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the Alberta Treasury Board and Finance and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2022, or as at the date of an earlier amendment to the Plan depending on any funding implications.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, the going concern discount rate reflects a margin for adverse deviations of 0.3% per year.

- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations.
  - No benefits were excluded from the solvency liabilities. However, an alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations, to replace future variable inflation protection with a fixed percentage increase.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2017

Pension Plan

There have been no special events since the last valuation date that had a material impact on the funding position.

This valuation reflects the provisions of the Plan as at December 31, 2019. There have been no amendments since the date of the previous valuation that had a material impact on the funding position of the Plan, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	Previous valuation
Discount rate:	3.70%	4.80% to January 1, 2020; 3.90% thereafter

A summary of the going concern methods and assumptions is provided in Appendix C.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

On January 24, 2020, the Canadian Institute of Actuaries released the final standards for pension commuted values ("CIA CV Standard"). The new CIA CV Standard was scheduled to be effective August 1, 2020 with early adoption permitted for target pension arrangements. In April 2020, the

CIA announced that the new CIA CV Standard will be effective no earlier than December 1, 2020. Early adoption remains possible for target pension arrangements.

From the effective date, the new CIA CV Standard will affect the assumptions used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of those changes are not reflected on a solvency and hypothetical wind-up basis but will be considered in a future actuarial valuation, once they are effective.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date that, in our opinion, would have a material impact on the results of the valuation as at December 31, 2019. However, since the valuation date, there have been significant fluctuations in the financial markets, which may have led to a deterioration of the funded position of the Plan after the valuation date. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all claims on the Plan after the valuation date will be in respect of benefits payable to members of the Plan determined in accordance with the Plan terms and that all Plan assets are available to provide for these benefits. It is possible that court and regulatory decisions and changes in legislation could give rise to additional entitlements to benefits under the Plan and cause the results in this report to change. By way of example, we bring your attention to the following decisions:

- The Ontario Court of Appeal's 2003 decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* restricted the use of original plan surplus where two or more pension plans were merged.
- The Supreme Court of Canada's 2004 decision in *Monsanto Canada Inc. versus Superintendent of Financial Services* upheld the requirement, with retroactive effect, to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario).*

Although these decisions dealt with Ontario legislation, it is possible that they could have application to other provinces where the underlying language in the *Pension Benefits Act (Ontario)* is similar to language in the legislation of other provinces.

We are not in a position to assess the impact that such decisions or changes could have on the assumption that all plan assets on the valuation date are available to provide for benefits determined in accordance with the Plan terms. If such a claim arises subsequent to the date of this report, the consequences will be dealt with in a subsequent report. We are making no representation as to likelihood of such a claim.

3

Defined Contribution Component of the Plan

The Plan is made up of defined contribution ("DC") and defined benefit ("DB") components. The DC component is considered in this Section. The remainder of the report relates to the DB component of the Plan, unless otherwise noted.

Current Service Cost

For the DC component of the Plan, Canadian Utilities Ltd.'s funding requirement is the employer DC current service cost. We have estimated the employer DC current service cost based on the projected payroll of participants. Our estimate, compared with the result of the previous valuation, is as follows:

	2020	2018
Estimated DC pensionable earnings that will attract an employer contribution	$423,644,000	$468,728,000
Employer DC current service cost	$25,419,000	$28,124,000

For reference, the Plan terms are summarized in Appendix F.

4

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	31.12.2019	31.12.2017
Assets		
Market value of assets	$2,818,113,100	$2,695,205,600
Going concern funding target		
Active members	$574,233,900	$769,329,100
Pensioners and survivors	$2,105,589,900	$1,815,289,800
Deferred pensioners and pending transfers	$31,018,900	$18,797,100
Total	$2,710,842,700	$2,603,416,000
Funding excess (shortfall)	$107,270,400	$91,789,600

The going concern funding target includes a provision for adverse deviations.

Reconciliation of Financial Status ($Millions)

Funding excess (shortfall) as at previous valuation		$91.8
Interest on funding excess (shortfall) at 4.80% per year		$9.0
Employer's special payments, with interest		$0.0
Expected funding excess (shortfall)		$100.8
Net experience gains (losses)		
• Investment return	$70.5	
• Increases in pensionable earnings	$6.1	
• Indexation	($20.0)	
• Mortality	($0.1)	
• Retirement	$8.9	
• Termination	$8.0	
Total experience gains (losses)		$73.4
Impact of change to discount rate		($70.5)
Net impact of other elements of gains and losses		$3.6
Funding excess (shortfall) as at current valuation		$107.3

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date, compared with the corresponding value determined in the previous valuation, is as follows:

	2020	2018
Total current service cost	$13,412,600	$21,045,400
Estimated members' required contributions	($542,000)	($943,900)
Estimated employer's current service cost	$12,870,600	$20,101,500
Employee's current service cost expressed as a percentage of members' pensionable earnings	1.64%	1.68%
Employer's current service cost expressed as a percentage of members' pensionable earnings	38.90%	35.67%
Total current service cost expressed as a percentage of members' pensionable earnings	40.54%	37.35%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	35.67%
Demographic changes	1.85%
Changes in assumptions	1.38%
Employer's current service cost as at current valuation	38.90%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern liabilities and current service cost shown in this report of using a discount rate that is 1% lower than that used in the valuation.

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Going concern funding liabilities	$2,710,842,700	$3,105,064,600
Current service cost		
• Total current service cost	$13,412,600	$16,093,900
• Estimated members' required contributions	($542,000)	($542,000)
Estimated employer's current service cost	$12,870,600	$15,551,900

Plausible Adverse Scenarios

The financial impact on the going concern results of plausible adverse scenarios that would pose threats to the Plan's future financial condition is presented in Appendix G.

5

Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances consistent with the hypothesized scenario on the valuation date. For this purpose, we have assumed that annuities would be purchased with a fixed rate of increase of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

More details on such scenario are provided in Appendix D.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	31.12.2019	31.12.2017
Assets		
Market value of assets	$2,818,113,100	$2,695,205,600
Termination expense provision	($2,000,000)	($2,000,000)
Wind-up assets	$2,816,113,100	$2,693,205,600
Present value of accrued benefits for:		
• Active members	$609,570,900	$748,317,000
• Pensioners and survivors	$2,691,528,200	$2,378,590,800
• Deferred pensioners	$34,682,000	$27,064,900
Total wind-up liability	$3,335,781,100	$3,153,972,700
Wind-up excess (shortfall)	($519,668,000)	($460,767,100)

6
Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. An alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations, to replace future variable inflation protection with a fixed percentage increase. Specifically, as at December 31, 2019, annuities were assumed to be purchased with a fixed rate of increase of 1.38% per year.

More details on such scenario are provided in Appendix D.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.2019	31.12.2017
Assets		
Market value of assets	$2,818,113,100	$2,695,205,600
Present value of going concern special payments	$0	$0
Termination expense provision	($2,000,000)	($2,000,000)
Net assets	$2,816,113,100	$2,693,205,600
Liabilities		
Total hypothetical wind-up liabilities	$3,335,781,100	$3,153,972,700
Difference in circumstances of assumed wind-up	($565,713,100)	($462,600,000)
Value of excluded benefits	($0)	($0)
Liabilities on a solvency basis	$2,770,068,000	$2,691,372,700
Surplus (shortfall) on a market value basis	$46,045,100	$1,832,900
Solvency ratio	101.7%	100.1%

Solvency Incremental Cost

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period. The solvency incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	31.12.2019	31.12.2017
Number of years covered by report	3 years	3 years
Total solvency liabilities at the valuation date (A)	$2,770,068,000	$2,691,372,700
Present value at the valuation date of projected solvency liability at the next required valuation plus expected benefit payments until the next required valuation (B)	$2,856,452,000	$2,864,680,300
Solvency incremental cost (B – A)	$86,384,000	$173,307,600

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the windup position of the Plan even if actual experience is exactly in accordance with the going concern valuation assumptions. For example, the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the solvency liabilities shown in this report of using a discount rate that is 1% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total solvency liability	$2,770,068,000	$3,184,786,800

7

Minimum Funding Requirements

The Act prescribes the minimum contributions that Canadian Utilities Limited must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions
Period beginning	Monthly current service cost[2]	Minimum monthly deficiency payments	Total minimum monthly contributions
January 1, 2020	38.90%	$0	$1,072,550

The estimated contribution amounts above are based on projected members' pensionable earnings. If current service cost contributions are based on a percentage of members' pensionable earnings, then the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

Alternatively, as the Plan is closed to new employees and therefore the active membership is declining, it would be acceptable under the Act to contribute the above dollar amount of estimated employer's contributions to the Plan.

The estimated 2020 contributions to the defined contribution component of the Plan are set out in Section 3

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

[2] Expressed as a percentage of members' pensionable earnings capped at $172,221 per member.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of Contributions

Funding contributions must be made no less frequently than monthly, and must be made within 30 days following the end of the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 30 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the solvency ratio revealed in an actuarial valuation is less than one. If the solvency ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Specifically, pursuant to the Act, transfers out of the Plan may only be made in full provided an amount equal to the transfer deficiency has been remitted to the pension fund in addition to the minimum special payments.

8

Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan that is underfunded on either a going concern or on a hypothetical wind-up basis, the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan that is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan that is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Notwithstanding the above, any contributions that are required to be made in accordance with pension benefits legislation are eligible contributions in accordance with Section 147.2 of the ITA and can be remitted.

Schedule of Maximum Contributions

Since the surplus does not exceed 25% of the going concern funding target, the Company may make monthly contributions of up to 38.90% of members' pensionable earnings, calculated on a going concern basis, until the next valuation. The monthly amount is estimated at $1,072,550 as shown in Section 7.

The Company could elect to contribute the service cost on a plan termination basis instead of the going concern service cost. For example, based on the scenario in Section 6, the maximum employer contribution for the period to December 31, 2022 is the three year solvency incremental cost of $86,384,000.

The estimated 2020 contributions to the defined contribution component of the plan are set out in Section 3.

9

Actuarial Opinion

In my opinion, for the purposes of the valuations,

- The membership data on which the valuation is based are sufficient and reliable.
- The assumptions are appropriate.
- The methods employed in the valuation are appropriate.

This report has been prepared, and my opinion given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Alberta Employment Pension Plans Act*.



Mark Greenwood
FCIA, FIA

July 10, 2020
Date

Appendix A
Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Going Concern Assets Value	The value of the assets of a plan as of the relevant review date, determined on the basis of a going concern valuation.	$2,818,113,100
Going Concern Liabilities Value	The actuarial present value of a plan's benefits as of the relevant review date, determined on the basis of a going concern valuation.	$2,710,842,700
Unfunded Liability	The amount, if any, by which a plan's going concern liabilities value exceed its going concern assets value.	$0
Going Concern Funded Ratio	The fraction obtained by dividing the Going Concern Assets Value by the Going Concern Liabilities Value	1.0396
Accessible Going Concern Excess	The amount, if any, by which a plan's Going Concern Assets Value exceed 105% of its Going Concern Liabilities Value.	$0
Solvency Asset Value	The value of the plan's assets determined on a plan termination basis including any cash balances and accrued and receivable income and reduced by the actuary's estimate of the expenses that would be incurred in winding-up the plan.	$2,816,113,100
Solvency Liabilities Value	The liabilities of the plan calculated on a plan termination basis.	$2,770,068,000
Solvency Asset Adjustment	The sum of	
	a. the face amount of any prescribed letters of credit.	$0
	b. the present value of special payments sufficient to amortize the unfunded liability due over the next five years, and	$0
		$0

Defined Term	Description	Result
Solvency Ratio	The fraction obtained by dividing:	1.0166
	(a) the Solvency Asset Value, and	$2,816,113,100
	(b) the Solvency Liabilities Value.	$2,770,068,000
Solvency Deficiency	The amount, if any, by which:	$0
	(a) the Solvency Liabilities Value	$2,770,068,000
	exceed the sum of:	
	(a) the Solvency Asset Value, and	$2,816,113,100
	(b) the Solvency Asset Adjustment.	$0
		$0
Accessible Solvency Excess	The amount, if any, by which a plan's Solvency Asset Value exceed 105% of its Solvency Liabilities Value.	$0
Special Payments	A monthly special payment established to amortize an unfunded liability is hereafter referred to as an unfunded liability special payment.	$0
	A monthly special payment established to amortize a solvency deficiency is hereafter referred to as a solvency special payment.	$0

Timing of Next Required Valuation

In accordance with the Act and the Superintendent's Directives, an actuarial report must be prepared at intervals not exceeding three years. The Superintendent also directs that the plan administrator file actuarial reports annually if the going concern funded ratio of the plan is less than 85%. Triennial filings may resume with the filing of a report showing that the going concern funded ratio is at least 85%.

Accordingly, the next valuation of the Plan will be required as of December 31, 2022.

Special Payments

Going Concern Basis

No unfunded liability special payments are required.

Solvency Basis

No solvency special payments are required.

Appendix B
Plan Assets

The pension fund is held by Northern Trust. In preparing this report, we have relied upon fund statements prepared by Northern Trust without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2019	2018
January 1	$2,588,801,409	$2,695,205,550
PLUS		
Members' contributions	$870,144	$982,585
Company's contributions	$19,584,525	$20,101,500
Investment earnings	$100,601,580	$99,793,401
Net Capital gains (losses)	$235,870,706	($91,394,225)
	$356,926,955	$29,483,261
LESS		
Pensions paid	$107,498,5474	$118,681,112
Lump-sums paid	$9,337,408	$8,015,260
Administration and investment fees	$10,779,387	$9,191,030
	$127,615,269	$135,887,402
December 31	$2,818,113,095	$2,588,801,409
Gross rate of return[3]	13.27%	0.32%
Rate of return net of expenses[3]	12.82%	(0.03%)

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[3] Assuming mid-period cash flows.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations, and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy			Actual asset Mix as at 31.12.2019
	Minimum	Target	Maximum	
Canadian Fixed Income	30.0%	47.0%	60.0%	71.1%
Global Fixed Income	15.0%	23.0%	35.0%	
Real Estate	0.0%	9.0%	10.0%	8.2%
Global Equity	0.0%	21.0%	40.0%	19.7%
Cash and Cash Equivalents	-	-	-	1.0%
		100%		100%

Appendix C
Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the Act, a funding shortfall including the provision for adverse deviations must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. As the DB component is closed to new members, the current service cost for DB members, expressed as a percentage of the members' pensionable earnings, can be expected to increase as the average age increases.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	3.70%	4.80% to January 1, 2020; 3.90% thereafter
Inflation:	2.00%	2.00%
ITA limit / YMPE increases:	2.25%	2.25%
Pensionable earnings increases:	2.50% (plus Merit and Promotion)	2.50% (plus Merit and Promotion)
Post-retirement pension increases:	1.85%	1.85%
Retirement rates:	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55
Termination rates:	None	None
Mortality rates:	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality (CPM) Table	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality (CPM) Table
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using CPM Improvement Scale B (CPM-B)
Disability rates:	None	None

Assumption	Current valuation	Previous valuation
Eligible spouse at retirement:	Based on current marital status	Based on current marital status
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age-Related Tables

Sample rates from the age-related tables are summarized in the following table:

Age	Merit and Promotion
20	13.65%
25	6.02%
30	3.08%
35	1.75%
40	1.07%
45	0.70%
50	0.47%
55	0.33%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement or death, we have taken 2019 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees and less a margin for adverse deviations.

The discount rate is comprised of the following:

- An **assumed investment return** based on estimated return for each major asset class that are consistent with market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels, on the expected time horizon over which benefits are expected to be paid, and on the target asset mix specified in the Plan's investment policy. Consistent with market observable and available data, the assumed investment return is a gross return for all asset classes.
- An **assumed passive investment management expense provision** which represents the hypothetical fees for passive investment management of assets based on estimated fees charged by index managers for balanced mandates.
- An **active investment management expense provision** of 28 bps. We have assumed that these fees would be offset by an equivalent **additional return resulting from active management**.
- An **implicit non-investment management expense provision** based on the average rate of non-investment expenses paid from the fund over the last three years. These would include all fees payable from the fund (administration, custodial, audit, consulting, etc.) except those payable to investment managers, to the extent that these fees are not covered in an explicit provision for expenses added to the current service cost
- A **margin for adverse deviations** of 0.30% as per the terms of engagement

The discount rate was developed as follows:

Assumed investment return	4.12%
Additional returns for active investment management	0.28%
Active investment management expense provision	(0.28%)
Assumed passive investment management expense provision	(0.02%)
Implicit non-investment management expense provision	(0.10%)
Margin for adverse deviations	(0.30%)
Net discount rate	3.70%

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on a best estimate of future merit and promotional increases and general wage growth considering current economic and financial market conditions. The assumption takes into account the Company's current outlook for wage growth in the utility sector. Such merit and promotion increases are assumed to be in accordance with the table developed based on an experience study considering increases over the years 1985 to 1992 and which has continued to be reasonably predictive of merit and promotion increases experienced since that time.

Post-Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above, considering that the Plan limits pension increases to 3% in the event that inflation exceeds 3%. We have determined the impact of this cap by performing a stochastic analysis based on trials using a mean of 2.0% and a standard deviation of 1.5%.

Retirement Rates

For this valuation we have continued to assume that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately. This assumption is based on the Plan provisions and the experience of the Plan in recent years.

Retirement earlier than assumed may result in losses to the Plan, while later retirements may result in gains to the Plan. These gains and losses will be revealed in subsequent valuations.

Termination Rates

Use of a different assumption would not have a material impact on the valuation.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014.

The mortality rates selected reflect plan-specific experience over the years 2005 to 2014. However, due to the size of the Plan, this mortality experience is not fully credible. The CPM mortality rates from the private sector have been adjusted after considering the plan-specific experience and characteristics, such as the type of employment, the industry experience, the pension and employment income for the plan members, and data in the CPM study.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. Two mortality improvement scales were recently published by the Canadian Institute of Actuaries (CIA) and may apply to Canadian pension valuations:

- The Canadian Pensioners Mortality (CPM) study published in February 2014 included CPM Improvement Scale B (CPM-B).
- A report released by the Task Force on Mortality Improvement on September 20, 2017 includes an analysis of the rate of mortality improvement for the Canadian population and provides for mortality improvement scale MI-2017 to be considered for the purpose of reflecting future mortality improvement in Canadian actuarial work, while acknowledging that it might be appropriate to use alternative mortality improvement assumptions to reflect the nature of the work.

The CIA Committee on Pension Plan Financial Reporting published a revised version of the Educational Note on the Selection of Mortality Assumptions for Pension Plan Valuations on December 21, 2017.

The Educational Note indicates that given the recent publication of the CPM-B and MI-2017 improvement scales and the similar data sets used in their development, it may be appropriate to use either scale in the absence of credible information to the contrary, such as the publication of a successor scale by the CIA.

For the present valuation, we have continued to use the CPM-B scale which is a reasonable outlook for future mortality improvement.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 22.2 years for males and 24.6 years for females.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on actual membership data, which we believe is the most reliable source.

Spousal Age Difference

The assumption is based on an industry standard showing males are typically 3 years older than their spouse.

Appendix D
Methods and Assumptions – Hypothetical Wind-Up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The Standards of Practice of the Canadian Institute of Actuaries require that the scenario upon which the hypothetical wind-up valuation is based be postulated. However, there are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. No benefits payable on plan wind-up were excluded from our calculations. The plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2019.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2019 and December 30, 2020 (the "Educational Note").*

An alternative settlement method was hypothesized for solvency purposes, whereby plan benefits were modified, as permitted, pursuant to Alberta Treasury Board and Finance's Update 13-01

Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations ("Update 13-01"). Annuities are assumed to be purchased with future variable inflation protection replaced with a fixed percentage increase determined in accordance with Update 13-01.

However, it may not be possible to settle the liabilities through the purchase of annuities due to the size of the Plan and the limited annuity market in Canada. In accordance with the Educational Note, we have assumed that the settlement of such liabilities would be priced on the same basis as the smaller group annuities that are available in the market.

The Educational Note provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated substandard or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan's assumed basis falls outside that range. In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

Interest rate assumptions net of COLA used for lump sum transfers and annuity purchases take into consideration the 3% cap on pension increases provided by the plan provisions. We have carried out a stochastic analysis in order to determine the additional net interest rate as a result of this 3% cap.

We have not included a margin for adverse deviations in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum:	70% of active members under age 55, and 50% of active members over age 55, elect to receive their benefit entitlement in a lump sum
Annuity purchase:	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality (CPM) Table with fully generational improvements using CPM Scale B
Interest rate:	2.40% per year for 10 years, 2.50% per year thereafter
COLA:	1.27% per year for 10 years, 1.33% per year thereafter
Interest rate net of COLA:	1.12% per year for 10 years, 1.15% per year thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality (CPM) Table with fully generational improvements using CPM Scale B
Adjustment to mortality rates:	No adjustment
Interest rate:	2.96% per year based on duration of 12.86 years determined for the liabilities assumed to be settled through the purchase of an annuity
COLA:	1.38% per year[4]
Interest Rate net of COLA:	1.56% per year
Retirement Age	
Maximum value:	Members are assumed to retire at the age that maximizes the value of their entitlement from the Plan, based on the eligibility requirements that have been met at the valuation date
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Termination expenses:	$2,000,000

[4] For the hypothetical wind-up scenario, it is assumed that annuities would be purchased with a fixed rate of increase of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting, and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire, and die consistent with the termination, retirement, and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit, and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.

  Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Appendix E
Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2019, provided by Canadian Utilities Limited.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2019	31.12.2017
Active Members Accruing DB Benefits		
Number	433	645
Total pensionable earnings for prior year	$52,295,763	$76,000,660
Average pensionable earnings for prior year	$120,775	$117,830
Average years of pensionable service	30.1	28.9
Average age	56.7	55.7
Active Members with DB Benefits, but Accruing DC		
Number	31	48
Total pensionable earnings for prior year	$4,371,086	$6,293,849
Average pensionable earnings for prior year	$141,003	$131,122
Average years of pensionable service	7.3	7.9
Average age	54.9	53.3

	31.12.2019	31.12.2017
Active Members with DC Benefits Only		
Number	3,832	4,319
Total pensionable earnings for prior year	$406,069,637	$447,251,193
Average pensionable earnings for prior year	$105,968	$103,554
Average age	41.5	40.7
Deferred Pensioners		
Number	73	79
Total annual pension	$1,549,018	$1,492,401
Average annual pension	$21,219	$18,891
Average age	57.6	57.1
Pensioners and Survivors		
Number	2,687	2,570
Total annual lifetime pension	$123,280,995	$106,279,769
Average annual lifetime pension	$45,881	$41,354
Average age	71.7	71.3

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Active members accruing DB Benefits	Active members with DB benefits but accruing DC benefits	Deferred Pensioners	Pensioners and survivors	Total
Total at 31.12.2017	645	48	79	2,570	3,342
Transfer from ATCO Structures & Logistics	2				2
Terminations:					
• Transfers/lump sums	(18)	(4)	(1)	(1)	(24)
• Pending transfers					
• Deferred pensions	(15)	(2)	17		0
Deaths	(3)			(154)	(157)
Retirements	(178)	(11)	(22)	211	0
Beneficiaries				61	61
Data corrections					
Total at 31.12.2019	433	31	73	2,687	3,224

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

Age	Years of Pensionable Service									
	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40+	Total
45 to 49					8	10	1			19
50 to 54					12	46	45			103
55 to 59		1	1	2	18	93	97	21		233
60 to 64	1				3	34	14	16	10	78
65+										
Total	1	1	1	2	41	183	157	37	10	433

The distribution of the inactive members by age as at the valuation date is summarized as follows:

Age	Deferred Pensioners		Pensioners and Survivors	
	Number	Average Pension	Number	Average Pension
40 – 44			1	*
45 – 49	1	*		
50 – 54	13	$20,026	1	*
55 – 59	39	$21,163	229	$66,618
60 – 64	19	$22,655	642	$60,817
65 – 69	1	*	497	$50,007
70 – 74			421	$39,070
75 – 79			292	$30,695
80 – 84			238	$32,102
85 – 89			232	$30,879
90 – 94			111	$25,647
95+			23	$23,816
Total	73	$21,219	2,687	$45,881

*Information suppressed to preserve member confidentiality.

Appendix F
Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Canadian Utilities Limited. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2019. The Plan has been amended and consolidated since the date of the previous valuation. None of the changes had a material impact on the cost of the benefits provided by the Plan.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2019. This summary is not intended as a complete description of the Plan.

Background	Plan 1 Members: • The Plan became effective January 2, 1962. On December 31, 1986, employees in the Yukon Territory and the Northwest Territories became covered by a separate arrangement. • Effective January 1, 1997, money purchase provisions were introduced into Plan 1, at which time existing Plan members had an option to continue to accrue benefits under the defined benefit component or participate in the new money purchase component. All new employees participate only in the money purchase component. Former Plan 2 Members: • The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC). • Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Service under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets. • Effective December 30, 2003, the Plan was extended to cover employees located in Ontario. Effective January 1, 2015, Plan 2 was merged with Plan 1.

Eligibility for Membership	Plan 1 Members: • The Plan covers salaried employees employed in Canada outside of Ontario, the Yukon and Northwest Territories upon appointment to permanent staff. This typically occurs after 6 months service. In the event that a salaried employee is not appointed to permanent staff earlier, participation in the Plan will commence upon completion of two years' service provided earnings exceed 35% of the YMPE in two consecutive calendar years. • Participation in the Plan is compulsory for all eligible employees who are not participating in another registered pension plan of the employer. Former Plan 2 Members: • The Plan is closed to new entrants. • Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.
Employee Contributions	Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.
Postponed Retirement	A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to his actual retirement.
Normal Retirement Pension	2% of annual final average earnings times years of pensionable service between January 2, 1962 and January 2, 1966; PLUS 1.4% of annual final average earnings up to the YMPE, times years of pensionable service after January 2, 1966; PLUS 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service after January 2, 1966.
Pensionable Earnings	Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.

<table>
<tr><td>Early Retirement Pension</td><td>If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows:
If age and service sum to 90 years or more, no reduction applies;
otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:
<table><tr><th>Age at Retirement</th><th>Percentage</th></tr><tr><td>64</td><td>100</td></tr><tr><td>63</td><td>100</td></tr><tr><td>62</td><td>100</td></tr><tr><td>61</td><td>97</td></tr><tr><td>60</td><td>94</td></tr><tr><td>59</td><td>88</td></tr><tr><td>58</td><td>82</td></tr><tr><td>57</td><td>76</td></tr><tr><td>56</td><td>70</td></tr><tr><td>55</td><td>64</td></tr></table>If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.
In addition, female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable only until age 65. The bridge benefit is equal to the expected Canada pension Plan benefit times the ratio of 36 divided by the number of months from retirement to age 65, provided that the ratio is never more than 1.</td></tr>
<tr><td>Maximum Pension</td><td>The Plan provides that the pension payable at the time of commencement must not exceed the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years).
Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years' service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the Income Tax Act and Regulations.</td></tr>
<tr><td>Cost of Living Adjustments</td><td>The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid. The annual adjustment is granted only to members who retire from active service.</td></tr>
</table>

Death Benefits	Pre-retirement: • If a member dies before becoming eligible for retirement, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. • If a member dies after becoming eligible for retirement, the member's spouse will receive the greater of: • a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value, and • an immediate pension equal to 60% of the pension to which the member would have been entitled had the member retired on their date of death. This pension will also receive future cost of living increases. • If a member dies after becoming eligible for retirement and there is no surviving spouse, the beneficiary will receive the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. Post retirement: • The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date. • For employees with an eligible spouse, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.
Termination Benefits	A deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2019. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan became effective January 1, 1997. Employer and employee contributions are remitted to individual member accounts and are credited with interest.

Eligibility for Membership	An employee must join the Defined Contribution component of the Plan on the date the member is appointed to the permanent staff of Canadian Utilities Limited.
Employee Contributions	The lesser of 4% of member's pensionable earnings and 40% of the maximum contribution limit. Required contributions for Executive Officers and disabled members are made on their behalf by the Employer.
Employer Contributions	The lesser of 10% of member's pensionable earnings and maximum contribution limit reduced by the amount paid by the member.
Benefits	Members receive the balance of their individual employer and employee accounts upon termination, death or retirement.
Maximum Contribution	The employer and employee contributions are limited to the amounts under the Income Tax Act.
Pensionable Earnings	Base salary

Appendix G
Plausible Adverse Scenarios

In this Appendix, the financial impact on the Plan's going concern results (i.e., going concern financial position at the valuation date and current service cost from the valuation date to the next valuation date) of plausible adverse scenarios that would pose threats to the Plan's future financial condition is illustrated for the following risks:

- Interest rate risk, the potential that interest rates will be lower than expected;
- Deterioration of asset values; and
- Longevity risk, the potential that pension plan members will live longer than expected.

The following table summarizes the going concern results, where we assumed for:

- Interest rate risk, an immediate parallel decrease in market interest rates of 90 basis points
- Deterioration of asset values, an immediate decrease of 16% in the market value of non-fixed income assets; and
- Longevity risk, that life expectancy from the valuation date at age 65 for a male and a female would increase by 1.5 years and 1.3 years, respectively.

Scenario	Going Concern Valuation Results as at 31.12.2019	Plausible Adverse Scenario Results as at 31.12.2019		
		Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Going Concern Financial Status				
Market value of assets	$2,818,113,100	$3,099,924,400	$2,677,207,400	$2,818,113,100
Going concern funding target	$2,710,842,700	$3,061,682,400	$2,710,842,700	$2,834,835,700
Funding excess (shortfall)	$107,270,400	$38,242,000	($33,635,300)	($16,722,600)
Estimated Employer's Current Service Cost expressed as a percentage of members' pensionable earnings				
From January 1, 2020	38.90%	46.10%	38.90%	41.06%

The balance of this Appendix provides details of the plausible adverse scenarios selected and the determination of the impact on the going concern results.

Interest Rate Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to the potential that interest rates will be lower than expected. For this purpose, we have assumed an immediate parallel decrease in market interest rates underlying fixed income investments, where fixed income investments include Canadian fixed income and global fixed income as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a parallel decrease in market interest rates of 90 basis points would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For the purpose of this scenario, we have assumed that such a decrease in market interest rates would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions.

Defined Term	Description
Market value of assets	The decrease in market interest rates has been assumed to affect only the market value of the fixed income investments. The decrease is assumed to have occurred immediately on the valuation date.
Discount rate assumption	It was assumed that the decrease in market interest rates affects only the expected return on assets for the fixed income portion of assets. The same margin for adverse deviations was used. The discount rate assumption was therefore decreased from 3.7% to 2.8%.
Other assumptions	Except as mentioned above, all assumptions used were the same as those used for this valuation. In particular, the discount rate used to value benefits assumed to be settled through a lump sum was not changed.

Deterioration of Asset Values

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to a deterioration of asset values. For this purpose, we assumed an immediate reduction in the market value of the Plan's non-fixed income assets, where non-fixed income investments include global equities and real estate as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a decrease of 16% in the market value of non-fixed income assets would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For the purpose of this scenario, we have assumed that such a decrease would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions:

Market value of assets	The decrease in the market value of the non-fixed income portion of assets is assumed to have occurred immediately on the valuation date.
Going concern assumptions	This scenario is assumed to have no impact on the assumptions used for this valuation.

Longevity Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to the potential that pension plan members will live longer than expected. For this purpose, we have determined that a plausible adverse scenario would be to assume that future mortality improvements[5] will be in line with the average improvements experienced by the Canadian population over the most recent 15-year period available, with uniform improvement rates for all future years but varying by age[6] and gender.

The table below summarizes the improvement rates under the plausible adverse scenario compared to those currently assumed under the CPM-B scale and is based on Canadian population experience from the Human Mortality Database (HMD) from 2002 to 2016.

	Males				Females			
	CPM-B			Adverse	CPM-B			Adverse
Age	2020	2025	2030+	Scenario	2020	2025	2030+	Scenario
20	1.59%	1.20%	0.80%	1.68%	0.98%	0.89%	0.80%	1.47%
30	1.88%	1.34%	0.80%	1.68%	0.98%	0.89%	0.80%	1.47%
40	1.80%	1.30%	0.80%	1.68%	1.17%	0.98%	0.80%	1.47%
50	1.17%	0.98%	0.80%	1.76%	0.98%	0.89%	0.80%	1.34%
55	1.47%	1.13%	0.80%	1.67%	1.11%	0.96%	0.80%	1.14%
60	1.77%	1.28%	0.80%	1.75%	1.24%	1.02%	0.80%	1.34%
65	2.06%	1.43%	0.80%	2.11%	1.36%	1.08%	0.80%	1.65%
70	2.06%	1.43%	0.80%	2.48%	1.36%	1.08%	0.80%	1.77%
75	2.01%	1.41%	0.80%	2.66%	1.36%	1.08%	0.80%	1.93%
80	1.96%	1.38%	0.80%	2.63%	1.36%	1.08%	0.80%	2.03%
85	1.38%	1.03%	0.68%	2.32%	1.31%	0.99%	0.68%	1.98%
90	0.75%	0.62%	0.48%	1.68%	0.75%	0.62%	0.48%	1.60%
95	0.16%	0.25%	0.34%	1.04%	0.16%	0.25%	0.34%	1.12%
100	0.14%	0.22%	0.30%	0.64%	0.14%	0.22%	0.30%	0.80%
105	0.14%	0.22%	0.30%	0.38%	0.14%	0.22%	0.30%	0.55%

[5] i.e. starting one year after the valuation in this context

[6] improvement rates below age 45 are set to those at age 45

Appendix H
Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2019 of the Plan, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary described in Section 2 of this report, particularly the requirement to include a margin of 0.3% in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2019 was provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarized in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2019.
- All events subsequent to December 31, 2019 that may have an impact on the Plan have been communicated to the actuary.

July 10, 2020
Date

Carol McCabe
Signed

Carol McCabe
Name

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Mercer

Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 1

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2020

August 11, 2021

Canada Revenue Agency Registration Number: 0343343

welcome to brighter

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the Plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

The valuation results shown in this report also illustrate the sensitivity to the discount rate, and the sensitivity to three adverse scenarios. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Should the Plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the Plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound up in the future. In fact, even if the Plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the *Alberta Employment Pension Plans Act*, the *Income Tax Act*, and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

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1 Summary of Results

	31.12.2020	31.12.2019
Going Concern Financial Status		
Market value of assets	$3,015,005,300	$2,818,113,100
Going concern funding target	$2,981,917,700	$2,710,842,700
Funding excess (shortfall)	$33,087,600	$107,270,400
Funded ratio	101.1%	104.0%
Hypothetical Wind-up Financial Position		
Wind-up assets	$3,013,005,300	$2,816,113,100
Wind-up liability	$3,471,697,200	$3,335,781,100
Wind-up excess (shortfall)	($458,691,900)	($519,668,000)
Wind-up ratio	86.8%	84.4%
Solvency Financial Position		
Solvency assets	$3,013,005,300	$2,816,113,100
Solvency liabilities	$2,896,047,500	$2,770,068,000
Solvency excess (shortfall)	$116,957,800	$46,045,100
Solvency ratio	104.0%	101.7%
Funding Requirements in the Year Following the Valuation[1]		
Total current service cost	$11,331,800	$13,412,600
Estimated members' required contributions	($398,000)	($542,000)
Estimated employer's current service cost	$10,933,800	$12,870,600
Employer's current service cost expressed as a percentage of members' pensionable earnings	44.38%	38.90%
Minimum special payments	$0	$0
Estimated minimum employer contribution	$10,933,800	$12,870,600
Estimated maximum eligible employer contribution	$10,933,800	$12,870,600
Next required valuation date	31.12.2023	31.12.2022

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2
Introduction

To the Management Pension Committee of Canadian Utilities Limited

At your request, we have conducted an actuarial valuation of the Retirement Plan for the Employees of Canadian Utilities Limited and Participating Companies - Plan 1 (the "Plan"), sponsored by Canadian Utilities Limited (the "Company"), as at the valuation date, December 31, 2020. We are pleased to present the results of the valuation.

The contributions to the defined contribution component of the Plan are determined by the Plan provisions. An estimate of the defined contributions for 2021 is included in this report.

Purpose

The purpose of this valuation is to determine:

- The funded status of the Plan as at December 31, 2020 on going concern, hypothetical wind-up, and solvency bases;
- The minimum required funding contributions from 2021, in accordance with the *Alberta Employment Pension Plans Act* (the "Act"); and
- The maximum permissible funding contributions from 2021, in accordance with the *Income Tax Act.*

The information contained in this report was prepared for the internal use of the Management Pension Committee and the Company, and for filing with Alberta Treasury Board and Finance and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with Alberta Treasury Board and Finance and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2023, or as at the date of an earlier amendment to the Plan depending on any funding implications.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, the going concern discount rate reflects a margin for adverse deviations of 0.30% per year.
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - Different plan wind-up scenarios were hypothesized for hypothetical wind-up and solvency valuations.
  - No benefits were excluded from the solvency liabilities. However, an alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's *Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations,* to replace future variable inflation protection with a fixed percentage increase.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2019

Pension Plan

There have been no special events since the last valuation date that had a material impact on the funding position.

This valuation reflects the provisions of the Plan as at December 31, 2020. There have been no amendments since the date of the previous valuation that had a material impact on the funding position of the Plan, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	Previous valuation
Discount rate:	2.80%	3.70%

A summary of the going concern methods and assumptions is provided in Appendix C.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

On June 24, 2020, the Employment Pension Plans Regulation (EPPR) was amended to permit a temporary suspension of unfunded liability and solvency deficiency payments (special payments) until the end of 2020. The impact of this relief must be amortized over a period not exceeding 15 years commenced at the date of the next actuarial valuation report of the plan. The Company did not elect to apply for this suspension.

On July 2, 2020, the Minister of Finance of Canada released draft regulations that would permit sponsors of pension plans to recognize full pensionable service in 2020 for employees who are working reduced hours or who are receiving reduced earnings. The eligible period of reduced pay will be subject to the limit of five years of full-time equivalent compensation. In addition, effective May 5, 2020, the Canada Revenue Agency waived the one percent minimum required employer contributions on defined contribution pension plans for the remainder of 2020.

On July 23, 2020, the CIA published the final version of Section 3500 of the Standards of Practice on Pension Commuted Values and confirmed that the effective date of the new standards is December 1, 2020.

From the effective date, the revised standards affect the assumptions used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of this change is reflected in this actuarial valuation on a solvency and hypothetical wind-up basis.

Subsequent Events

On May 10, 2021, the Bank of Canada revised certain rates for real return bond data (based on the rollover of the 2050 bond) retroactive to June 1, 2020. The previously published rates, based on the 2044 bond, were used for the preparation of the hypothetical wind-up results and solvency results in this report. We note the retroactive nature of this change but have not reflected it in this report given that the actuarial valuation was effectively complete at the time the revised rates were published and using them would not have a material impact on the results.

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date that, in our opinion, would have a material impact on the results of the valuation as at December 31, 2020.

Impact of Case Law

This report has been prepared on the assumption that all claims on the Plan after the valuation date will be in respect of benefits payable to members of the Plan determined in accordance with the Plan terms and that all Plan assets are available to provide for these benefits. It is possible that court and regulatory decisions and changes in legislation could give rise to additional entitlements to benefits under the Plan and cause the results in this report to change. By way of example, we bring your attention to the following decisions:

- The Ontario Court of Appeal's 2003 decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* restricted the use of original plan surplus where two or more pension plans were merged.

- The Supreme Court of Canada's 2004 decision in *Monsanto Canada Inc. versus Superintendent of Financial Services* upheld the requirement, with retroactive effect, to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario).*

Although these decisions dealt with Ontario legislation, it is possible that they could have application to other provinces where the underlying language in the *Pension Benefits Act (Ontario)* is similar to language in the legislation of other provinces.

We are not in a position to assess the impact that such decisions or changes could have on the assumption that all plan assets on the valuation date are available to provide for benefits determined in accordance with the Plan terms. If such a claim arises subsequent to the date of this report, the consequences will be dealt with in a subsequent report. We are making no representation as to the likelihood of such a claim.

3

Defined Contribution Component of the Plan

The Plan is made up of defined contribution ("DC") and defined benefit ("DB") components. The DC component is considered in this Section. The remainder of the report relates to the DB component of the Plan, unless otherwise noted.

Current Service Cost

For the DC component of the Plan, Canadian Utilities Ltd.'s funding requirement is the employer DC current service cost. We have estimated the employer DC current service cost based on the projected payroll of participants. Our estimate, compared with the result of the previous valuation, is as follows:

	2021	2020
Estimated DC pensionable earnings that will attract an employer contribution	$428,410,000	$423,644,000
Employer DC current service cost	$25,705,000	$25,419,000

For reference, the Plan terms are summarized in Appendix F.

4

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	31.12.2020	31.12.2019
Assets		
Market value of assets	$3,015,005,300	$2,818,113,100
Going concern funding target		
Active members	$558,312,900	$574,233,900
Pensioners and survivors	$2,407,498,500	$2,105,589,900
Deferred pensioners and pending transfers	$16,106,300	$31,108,900
Total	$2,981,917,700	$2,710,842,700
Funding excess (shortfall)	$33,087,600	$107,270,400

The going concern funding target includes a provision for adverse deviations.

Reconciliation of Financial Status ($Millions)

Funding excess (shortfall) as at previous valuation		$107.3
Interest on funding excess (shortfall) at 3.70% per year		$4.0
Employer's special payments, with interest		$0.0
Expected funding excess (shortfall)		$111.3
Net experience gains (losses)		
• Investment return	$211.7	
• Increases in pensionable earnings	$1.4	
• Indexation	$38.3	
• Mortality	($0.3)	
• Retirement	$5.9	
• Termination	$0.8	
Total experience gains (losses)		$257.8
Impact of changes in discount rate		($335.7)
Net impact of other elements of gains and losses		($0.3)
Funding excess (shortfall) as at current valuation		$33.1

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date, compared with the corresponding value determined in the previous valuation, is as follows:

	2021	2020
Total current service cost	$11,331,800	$13,412,600
Estimated members' required contributions	($398,000)	($542,000)
Estimated employer's current service cost	$10,933,800	$12,870,600
Employee's current service cost expressed as a percentage of members' pensionable earnings	1.62%	1.64%
Employer's current service cost expressed as a percentage of members' pensionable earnings	44.38%	38.90%
Total current service cost expressed as a percentage of members' pensionable earnings	46.00%	40.54%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	38.90%
Demographic changes	(1.42%)
Changes in assumptions	6.90%
Employer's current service cost as at current valuation	44.38%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern liabilities and current service cost shown in this report of using a discount rate that is 1% lower than that used in the valuation.

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Going concern funding liabilities	$2,981,917,700	$3,440,860,000
Current service cost		
• Total current service cost	$11,331,800	$13,756,400
• Estimated members' required contributions	($398,000)	($398,000)
Estimated employer's current service cost	$10,933,800	$13,358,400

Plausible Adverse Scenarios

The financial impact on the going concern results of plausible adverse scenarios that would pose threats to the Plan's future financial condition is presented in Appendix G.

5
Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances consistent with the hypothesized scenario on the valuation date. For this purpose, we have assumed that annuities would be purchased with a fixed rate of increase of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

More details on such scenario are provided in Appendix D.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	31.12.2020	31.12.2019
Assets		
Market value of assets	$3,015,005,300	$2,818,113,100
Termination expense provision	($2,000,000)	($2,000,000)
Wind-up assets	$3,013,005,300	$2,816,113,100)
Present value of accrued benefits for:		
• Active members	$550,763,800	$609,570,900
• Pensioners and survivors	$2,904,074,700	$2,691,528,200
• Deferred pensioners	$16,858,700	$34,682,000
Total wind-up liability	$3,471,697,200	$3,335,781,100
Wind-up excess (shortfall)	($458,691,900)	($519,668,000)

6
Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. An alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations, to replace future variable inflation protection with a fixed percentage increase. Specifically, as at December 31, 2020, annuities were assumed to be purchased with a fixed rate of increase of 1.48% per year.

More details on such scenario are provided in Appendix D.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.2020	31.12.2019
Assets		
Market value of assets	$3,015,005,300	$2,818,113,100
Present value of going concern special payments	$0	($0)
Termination expense provision	($2,000,000)	($2,000,000)
Net assets	$3,013,005,300	$2,816,113,100
Liabilities		
Total hypothetical wind-up liabilities	$3,471,697,200	$3,335,781,100
Difference in circumstances of assumed wind-up	($575,649,700)	($565,713,100)
Value of excluded benefits	($0)	($0)
Liabilities on a solvency basis	$2,896,047,500	$2,770,068,000
Surplus (shortfall) on a market value basis	$116,957,800	$46,045,100
Solvency ratio	104.0%	101.7%

Solvency Incremental Cost

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period. The solvency incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	31.12.2020	31.12.2019
Number of years covered by report	3 years	3 years
Total solvency liabilities at the valuation date (A)	$2,896,047,500	$2,770,068,000
Present value at the valuation date of projected solvency liability at the next required valuation plus expected benefit payments until the next required valuation (B)	$2,975,018,500	$2,856,452,000
Solvency incremental cost (B – A)	$78,971,000	$86,384,000

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the windup position of the Plan even if actual experience is exactly in accordance with the going concern valuation assumptions. For example, the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the solvency liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the solvency liabilities shown in this report of using a discount rate that is 1% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total solvency liability	$2,896,047,500	$3,337,088,000

7
Minimum Funding Requirements

The Act prescribes the minimum contributions that Canadian Utilities Limited must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

Period beginning	Employer's contribution rule		Estimated employer's contributions
	Monthly current service cost[2]	Minimum monthly deficiency payments	Total minimum monthly contributions
January 1, 2021	44.38%	$0	$911,200

The estimated contribution amounts above are based on projected members' pensionable earnings. If current service cost contributions are based on a percentage of members' pensionable earnings, then the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

Alternatively, as the Plan is closed to new employees and therefore the active membership is declining, it would be acceptable under the Act to contribute the above dollar amount of estimated employer's contributions to the Plan.

The estimated 2021 contributions to the defined contribution component of the Plan are set out in Section 3.

[2] Expressed as a percentage of members' pensionable earnings capped at $180,758 per member.

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of Contributions

Funding contributions must be made no less frequently than monthly, and must be made within 30 days following the end of the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 30 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the solvency ratio revealed in an actuarial valuation is less than one. If the solvency ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Specifically, pursuant to the Act, transfers out of the Plan may only be made in full provided an amount equal to the transfer deficiency has been remitted to the pension fund in addition to the minimum special payments.

8
Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan that is underfunded on either a going concern or on a hypothetical wind-up basis, the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan that is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan that is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Notwithstanding the above, any contributions that are required to be made in accordance with pension benefits legislation are eligible contributions in accordance with Section 147.2 of the ITA and can be remitted.

Schedule of Maximum Contributions

Since the surplus does not exceed 25% of the going concern funding target, the Company may make monthly contributions of up to 44.38% of members' pensionable earnings, calculated on a going concern basis, until the next valuation. The monthly amount is estimated at $911,200 as shown in Section 7.

The Company could elect to contribute the service cost on a plan termination basis instead of the going concern service cost. For example, based on the scenario in Section 6, the maximum employer contribution for the period to December 31, 2023 is the three year solvency incremental cost of $78,971,000.

The estimated 2021 contributions to the defined contribution component of the plan are set out in Section 3.

9

Actuarial Opinion

In my opinion, for the purposes of the valuations,

- The membership data on which the valuation is based are sufficient and reliable;
- The assumptions are appropriate.
- The methods employed in the valuation are appropriate.

This report has been prepared, and my opinion given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Alberta Employment Pension Plans Act.*



Mark Greenwood
FCIA, FIA

August 11, 2021
Date

Appendix A
Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Going Concern Assets Value	The value of the assets of a plan as of the relevant review date, determined on the basis of a going concern valuation.	$3,015,005,300
Going Concern Liabilities Value	The actuarial present value of a plan's benefits as of the relevant review date, determined on the basis of a going concern valuation.	$2,981,917,700
Unfunded Liability	The amount, if any, by which a plan's going concern liabilities value exceed its going concern assets value.	$0
Going Concern Funded Ratio	The fraction obtained by dividing the Going Concern Assets Value by the Going Concern Liabilities Value	1.0111
Accessible Going Concern Excess	The amount, if any, by which a plan's Going Concern Assets Value exceed 105% of its Going Concern Liabilities Value.	$0
Solvency Asset Value	The value of the plan's assets determined on a plan termination basis including any cash balances and accrued and receivable income and reduced by the actuary's estimate of the expenses that would be incurred in winding-up the plan.	$3,013,005,300
Solvency Liabilities Value	The liabilities of the plan calculated on a plan termination basis.	$2,896,047,500
Solvency Asset Adjustment	The sum of	
	(a) the face amount of any prescribed letters of credit.	$0
	(b) the present value of special payments sufficient to amortize the unfunded liability due over the next five years, and	$0
		$0
Solvency Ratio	The fraction obtained by dividing:	1.0404
	(a) the Solvency Asset Value, and	$3,013,005,300
	(b) the Solvency Liabilities Value.	$2,896,047,500
Solvency Deficiency	The amount, if any, by which:	$0
	(a) the Solvency Liabilities Value	$2,896,047,500
	exceed the sum of:	
	(a) the Solvency Asset Value, and	$3,013,005,300
	(b) the Solvency Asset Adjustment.	$0
		$0

Defined Term	Description	Result
Accessible Solvency Excess	The amount, if any, by which a plan's Solvency Asset Value exceed 105% of its Solvency Liabilities Value.	$0
Special Payments	A monthly special payment established to amortize an unfunded liability is hereafter referred to as an unfunded liability special payment.	$0
	A monthly special payment established to amortize a solvency deficiency is hereafter referred to as a solvency special payment.	$0

Timing of Next Required Valuation

In accordance with the Act and the Superintendent's Directives, an actuarial report must be prepared at intervals not exceeding three years. The Superintendent also directs that the plan administrator file actuarial reports annually if the going concern funded ratio of the plan is less than 85%. Triennial filings may resume with the filing of a report showing that the going concern funded ratio is at least 85%.

Accordingly, the next valuation of the Plan will be required as of December 31, 2023.

Special Payments

Going Concern Basis

No unfunded liability special payments are required.

Solvency Basis

No solvency special payments are required.

Appendix B
Plan Assets

The pension fund is held by Northern Trust. In preparing this report, we have relied upon fund statements prepared by Northern Trust without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2020
January 1	$2,818,113,095
PLUS	
Members' contributions	$626,533
Company's contributions	$12,878,200
Investment earnings	$106,164,852
Net capital gains (losses)	$217,687,955
	$337,357,540
LESS	
Pensions paid	$122,466,684
Lump-sums paid	$7,970,815
Administration and investment fees	$10,027,797
	$140,465,296
December 31	$3,015,005,339
Gross rate of return[3]	11.76%
Rate of return net of expenses[3]	11.37%

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[3] Assuming mid-period cash flows.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations, and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy			Actual asset Mix as at 31.12.2020
	Minimum	Target	Maximum	
Canadian Fixed Income	30.0%	50.0%	60.0%	70.0%
Global Fixed Income	15.0%	22.0%	35.0%	
Real Estate	0.0%	9.0%	10.0%	7.3%
Global Equity	0.0%	19.0%	40.0%	21.6%
Cash and cash equivalents	-	-	-	1.1%
		100%		100%

Appendix C
Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions, if any, and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the Act, a funding shortfall including the provision for adverse deviations must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. As the DB component is closed to new members, the current service cost for DB members, expressed as a percentage of the members' pensionable earnings, can be expected to increase as the average age increases.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	2.80%	3.70%
Inflation:	2.00%	2.00%
ITA limit / YMPE increases:	2.25%	2.25%
Pensionable earnings increases:	2.50% (plus Merit and Promotion)	2.50% (plus Merit and Promotion)
Post-retirement pension increases:	1.85%	1.85%
Retirement rates:	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55
Termination rates:	None	None
Mortality rates:	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality (CPM) Table	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality (CPM) Table
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using CPM Improvement Scale B (CPM-B)

Assumption	Current valuation	Previous valuation
Disability rates:	None	None
Eligible spouse at retirement:	Based on current marital status	Based on current marital status
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age-Related Tables

Sample rates from the age-related tables are summarized in the following table:

Age	Merit and Promotion
20	13.65%
25	6.02%
30	3.08%
35	1.75%
40	1.07%
45	0.70%
50	0.47%
55	0.33%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement or death, we have taken 2020 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees and less a margin for adverse deviations.

The discount rate is comprised of the following:

- An **assumed investment return** based on estimated return for each major asset class that are consistent with market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels, on the expected time horizon over which benefits are expected to be paid, and on the target asset mix specified in the Plan's investment policy. Consistent with market observable and available data, the assumed investment return is a gross return for all asset classes except for alternative investments for which it would normally be net of any investment management expense. The assumed investment return includes the diversification and rebalancing effect.
- An **assumed passive investment management expense provision** which represents the hypothetical fees for passive investment management of assets based on estimated fees charged by index managers for balanced mandates.
- An **active investment management expense provision** of 28 bps. We have assumed that these fees would be offset by an equivalent **additional return resulting from active management**.
- An **implicit non-investment management expense provision** determined as the average rate of non-investment expenses paid from the fund over the last three years. These would include all fees payable from the fund (administration, custodial, audit, consulting, etc.) except those payable to investment managers, to the extent that these fees are not covered in an explicit provision for expenses added to the current service cost
- A **margin for adverse deviations** of 0.30% as per the terms of engagement.

The discount rate was developed as follows:

Assumed investment return	3.22%
Additional returns for active investment management	0.28%
Active investment management expense provision	(0.28%)
Assumed passive investment management expense provision	(0.02%)
Implicit non-investment management expense provision	(0.10%)
Margin for adverse deviations	(0.30%)
Net discount rate	2.80%

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on a best estimate of future merit and promotional increases and general wage growth considering current economic and financial market conditions. The assumption takes into account the Company's current outlook for wage growth in the utility sector. Such merit and promotion increases are assumed to be in accordance with the table developed based on an experience study considering increases over the years 1985 to 1992 and which has continued to be reasonably predictive of merit and promotion increases experienced since that time.

Post-Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above, considering that the Plan limits pension increases to 3% in the event that inflation exceeds 3%. We have determined the impact of this cap by performing a stochastic analysis based on trials using a mean of 2.0% and a standard deviation of 1.5%.

Retirement Rates

For this valuation we have continued to assume that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately. This assumption is based on the Plan provisions and the experience of the Plan in recent years.

Retirement earlier than assumed may result in losses to the Plan, while later retirements may result in gains to the Plan. These gains and losses will be revealed in subsequent valuations.

Termination Rates

Use of a different assumption would not have a material impact on the valuation.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014. Considering the characteristics of the group, it was considered appropriate to use the CPM mortality rates from the private sector as a reference table.
The mortality rates selected reflect plan-specific experience over the years 2005 to 2014. However, due to the size of the Plan, this mortality experience is not fully credible. The CPM mortality rates from the private sector have been adjusted after considering the plan-specific experience and characteristics, such as the type of employment, the industry experience, the pension and employment income for the plan members, and data in the CPM study.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. Two mortality improvement scales published by the Canadian Institute of Actuaries (CIA) are generally adopted for Canadian pension valuations:

- The Canadian Pensioners Mortality (CPM) study published in February 2014 included CPM Improvement Scale B (CPM-B).
- A report released by the Task Force on Mortality Improvement on September 20, 2017 included an analysis of the rate of mortality improvement for the Canadian population and provides for mortality improvement scale MI-2017 to be considered for the purpose of reflecting future mortality improvement in Canadian actuarial work, while acknowledging that it might be appropriate to use alternative mortality improvement assumptions to reflect the nature of the work.

The CIA Committee on Pension Plan Financial Reporting published a revised version of the Educational Note on the Selection of Mortality Assumptions for Pension Plan Valuations on December 21, 2017. The Educational Note indicated that given the recent publication of the CPM-B and MI-2017 improvement scales and the similar data sets used in their development, it may be appropriate to use either scale in the absence of credible information to the contrary, such as the publication of a successor scale by the CIA.

COVID-19 has impacted mortality rates globally. Statistics Canada reported excess mortality in 2020 for the general Canadian population and other peer countries globally have also seen excess mortality over the course of the pandemic. Mortality experience for the plan has been reflected up to the date of the valuation. We have not adjusted the expected mortality rates for Plan members after the valuation date. The long-term implications of the pandemic on mortality rates is unclear as at the date of this report. Credible plan specific experience and relevant broader observed mortality trends after the report date will be reflected in future valuations.

For the current valuation, we have continued to use the CPM-B scale, which is a reasonable outlook for future mortality improvement.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 22.3 years for males and 24.6 years for females.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on actual membership data, which we believe is the most reliable source.

Spousal Age Difference

The assumption is based on an industry standard showing males are typically 3 years older than their spouse.

Appendix D

Methods and Assumptions – Hypothetical Wind-Up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The Standards of Practice of the Canadian Institute of Actuaries require that the scenario upon which the hypothetical wind-up valuation is based be postulated. However, there are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. No benefits payable on plan wind-up were excluded from our calculations. The plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2020.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates between December 31, 2020 and no later than December 30, 2021 (the "Educational Note").*

An alternative settlement method was hypothesized for solvency purposes, whereby plan benefits were modified, as permitted, pursuant to Alberta Treasury Board and Finance's Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations ("Update 13-01"). Annuities are assumed to be purchased with future variable inflation protection replaced with a fixed percentage increase determined in accordance with Update 13-01.

However, it may not be possible to settle the liabilities through the purchase of annuities due to the size of the Plan and the limited annuity market in Canada. In accordance with the Educational Note, we have assumed that the settlement of such liabilities would be priced on the same basis as the smaller group annuities that are available in the market.

The Educational Note provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated substandard or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan's assumed basis falls outside that range. In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

Interest rate assumptions net of COLA used for lump sum transfers and annuity purchases take into consideration the 3% cap on pension increases provided by the plan provisions. We have carried out a stochastic analysis in order to determine the additional net interest rate as a result of this 3% cap.

We have not included a margin for adverse deviations in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum:	70% of active members under age 55, and 50% of active members over age 55, elect to receive their benefit entitlement in a lump sum
Annuity purchase:	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.

Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality (CPM) Table with fully generational improvements using CPM Scale B
Interest rate:	1.40% per year for 10 years, 2.90% per year thereafter
COLA:	0.93% per year for 10 years, 1.83% per year thereafter
Interest rate net of COLA:	0.47% per year for 10 years, 1.05% per year thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Scale B
Adjustment to mortality rates:	No adjustment
Interest rate:	2.56% per year based on a duration of 13.15 years determined for the liabilities assumed to be settled through the purchase of an annuity.
COLA:	1.48% per year[4]
Interest rate net of COLA:	1.06% per year
Retirement Age	
Maximum value:	Members are assumed to retire with a 50% probability at the age that maximizes the value of their entitlement from the Plan and a 50% probability at the member's earliest unreduced age in accordance with applicable legislation and based on the eligibility requirements that have been met at the valuation date
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Termination expenses:	$2,000,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting, and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

[4] For the hypothetical wind-up scenario, it is assumed that annuities would be purchased with a fixed rate of interest of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire, and die consistent with the termination, retirement, and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit, and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.

Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Appendix E
Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2020, provided by Canadian Utilities Limited.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2020	31.12.2019
Active Members Accruing DB Benefits		
Number	344	433
Total pensionable earnings for prior year	$43,021,123	$52,295,763
Average pensionable earnings for prior year	$125,061	$120,775
Average years of pensionable service	30.6	30.1
Average age	57.2	56.7
Active Members with DB Benefits, but Accruing DC		
Number	24	31
Total pensionable earnings for prior year	$3,631,384	$4,371,086
Average pensionable earnings for prior year	$151,308	$141,003
Average years of pensionable service	7.2	7.3
Average age	55.1	54.9

	31.12.2020	31.12.2019
Active Members with DC Benefits Only		
Number	3,823	3,832
Total pensionable earnings for prior year	$411,669,259	$406,069,637
Average pensionable earnings for prior year	$107,682	$105,968
Average age	42.1	41.5
Deferred Pensioners		
Number	60	73
Total annual pension	$946,356	$1,549,018
Average annual pension	$15,773	$21,219
Average age	58.3	57.6
Pensioners and Survivors		
Number	2,747	2,687
Total annual lifetime pension	$123,349,289	$123,280,995
Average annual lifetime pension	$44,903	$45,881
Average age	72.0	71.7

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Active members accruing DB Benefits	Active members with DB Benefits accruing DC Benefits	Deferred Pensioners	Pensioners and survivors	Total
Total at 31.12.2019	433	31	73	2,687	3,224
New entrants					
Terminations:					
• Transfers/lump sums	(3)	(1)	(1)		(5)
• Pending Transfers					
• Deferred pensions					
Deaths	(3)			(80)	(83)
Retirements	(84)	(6)	(11)	101	0
Beneficiaries				39	39
Adjustments	1		(1)		0
Total at 31.12.2020	344	24	60	2,747	3,175

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service									
Age	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40+	Total
45 to 49					5	7				12
50 to 54					5	35	37	3		80
55 to 59				3	6	62	93	16	1	181
60 to 64	1	1			1	26	19	10	11	69
65 +						1		1		2
Total	1	1		3	17	131	149	30	12	344

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred Pensioners		Pensioners and Survivors	
Age	Number	Average Pension	Number	Average Pension
40 – 44			1	*
45 – 49	1	*		
50 – 54	10	$10,807	2	$29,000
55 – 59	30	$18,296	193	$63,623
60 – 64	16	$14,270	650	$61,457
65 – 69	3	$10,310	529	$50,286
70 – 74			447	$40,539
75 – 79			304	$29,727
80 – 84			241	$28,242
85 – 89			223	$30,105
90 – 94			120	$24,370
95+			37	$21,950
Total	60	$15,773	2,747	$44,903

*Information supressed to preserve member confidentiality.

Appendix F
Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Canadian Utilities Limited. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2020. The Plan has not been amended since the date of the previous valuation. There were no changes that had a material impact on the cost of the benefits provided by the Plan.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2020. This summary is not intended as a complete description of the Plan.

Background	Plan 1 members: • The Plan became effective January 2, 1962. On December 31, 1986, employees in the Yukon Territory and the Northwest Territories became covered by a separate arrangement. • Effective January 1, 1997, money purchase provisions were introduced into Plan 1, at which time existing Plan members had an option to continue to accrue benefits under the defined benefit component or participate in the new money purchase component. All new employees participate only in the money purchase component. Former Plan 2 members: • The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC). • Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Service under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets. • Effective December 30, 2003, the Plan was extended to cover employees located in Ontario. Effective January 1, 2015, Plan 2 was merged with Plan 1.

Eligibility for Membership	Plan 1 members: • The Plan covers salaried employees employed in Canada outside of Ontario, the Yukon and Northwest Territories upon appointment to permanent staff. This typically occurs after 6 months service. In the event that a salaried employee is not appointed to permanent staff earlier, participation in the Plan will commence upon completion of two years' service provided earnings exceed 35% of the YMPE in two consecutive calendar years. • Participation in the Plan is compulsory for all eligible employees who are not participating in another registered pension plan of the employer. Former Plan 2 members: • The Plan is closed to new entrants. • Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.
Employee Contributions	Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month following the member's 65th birthday. Early Retirement Date • The member may choose to retire as early as age 55
Postponed Retirement	A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to his actual retirement.
Normal Retirement Pension	2% of annual final average earnings times years of pensionable service between January 2, 1962 and January 2, 1966; PLUS 1.4% of annual final average earnings up to the YMPE, times years of pensionable service after January 2, 1966; PLUS 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service after January 2, 1966.
Pensionable Earnings	Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.

Early Retirement Pension

If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows:

- If age and service sum to 90 years or more, no reduction applies;
- otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:

Age at Retirement	Percentage
64	100
63	100
62	100
61	97
60	94
59	88
58	82
57	76
56	70
55	64

If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.

In addition, female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable only until age 65. The bridge benefit is equal to the expected Canada pension Plan benefit times the ratio of 36 divided by the number of months from retirement to age 65, provided that the ratio is never more than 1.

Maximum Pension

The Plan provides that the pension payable at the time of commencement must not exceed the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years).

Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years' service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the Income Tax Act and Regulations.

Cost of Living Adjustments

The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid. The annual adjustment is granted only to members who retire from active service.

Death Benefits	Pre-retirement: • If a member dies before becoming eligible for retirement, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. • If a member dies after becoming eligible for retirement, the member's spouse will receive the greater of: - a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value, and - an immediate pension equal to 60% of the pension to which the member would have been entitled had the member retired on their date of death. This pension will also receive future cost of living increases. • If a member dies after becoming eligible for retirement and there is no surviving spouse, the beneficiary will receive the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. Post retirement: • The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date. • For employees with an eligible spouse, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.
Termination Benefits	A deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2020. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan became effective January 1, 1997. Employer and employee contributions are remitted to individual member accounts and are credited with interest.
Eligibility for Membership	An employee must join the Defined Contribution component of the Plan on the date the member is appointed to the permanent staff of Canadian Utilities Limited.
Employee Contributions	The lesser of 4% of member's pensionable earnings and 40% of the maximum contribution limit. Required contributions for Executive Officers and disabled members are made on their behalf by the Employer.
Employer Contributions	The lesser of 10% of member's pensionable earnings and maximum contribution limit reduced by the amount paid by the member.
Benefits	Members receive the balance of their individual employer and employee accounts upon termination, death or retirement.
Maximum Contribution	The employer and employee contributions are limited to the amounts under the *Income Tax Act.*
Pensionable Earnings	Base salary

Appendix G
Plausible Adverse Scenarios

In this Appendix, the financial impact on the Plan's going concern results (i.e., going concern financial position at the valuation date and current service cost from the valuation date to the next valuation date) of plausible adverse scenarios that would pose threats to the Plan's future financial condition is illustrated for the following risks:

- Interest rate risk, the potential that interest rates will be lower than expected;
- Deterioration of asset values; and
- Longevity risk, the potential that pension plan members will live longer than expected.

The following table summarizes the going concern results, where we assumed for:

- Interest rate risk, an immediate parallel decrease in market interest rates of 125 basis points
- Deterioration of asset values, an immediate decrease of 15% in the market value of non-fixed income assets; and
- Longevity risk, that life expectancy from the valuation date at age 65 for a male and a female would increase by 1.5 years and 1.4 years respectively.

Scenario	Going Concern Valuation Results as at 31.12.2020	Plausible Adverse Scenario Results as at 31.12.2020		
		Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Going Concern Financial Status				
Market value of assets	$3,015,005,300	$3,316,505,800	$2,894,405,100	$3,015,005,300
Going concern funding target	$2,981,917,700	$3,390,191,900	$2,981,917,700	$3,139,374,300
Funding excess (shortfall)	$33,087,600	($73,686,100)	($87,512,600)	($124,369,000)
Estimated Employer's Current Service Cost expressed as a percentage of Members' Pensionable Earnings				
From January 1, 2021	44.38%	53.11%	44.38%	47.28%

The balance of this Appendix provides details of the plausible adverse scenarios selected and the determination of the impact on the going concern results.

Interest Rate Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to the potential that interest rates will be lower than expected. For this purpose, we have assumed an immediate parallel decrease in market interest rates underlying fixed income investments, where fixed income investments include Canadian fixed income and global fixed income as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a parallel decrease in market interest rates of 125 basis points would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease in market interest rates would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions:

Defined Term	Description
Market value of assets	The decrease in market interest rates has been assumed to affect only the market value of the fixed income investments. The decrease is assumed to have occurred immediately on the valuation date.
Discount rate assumption	It was assumed that the decrease in market interest rates affects only the expected return on assets for the fixed income portion of assets. The same margin for adverse deviations was used The discount rate assumption was therefore decreased from 2.8% to 1.9%.
Other assumptions	Except as mentioned above, all assumptions used were the same as those used for this valuation. In particular, the discount rate used to value benefits assumed to be settled through a lump sum was not changed.

Deterioration of Asset Values

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to a deterioration of asset values. For this purpose, we assumed an immediate reduction in the market value of the Plan's non-fixed income assets, where non-fixed income investments include global equities and real estate as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a decrease of 15% in the market value of non-fixed income assets would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions:

Market value of assets	The decrease in the market value of the non-fixed income portion of assets is assumed to have occurred immediately on the valuation date.
Going concern assumptions	This scenario is assumed to have no impact on the assumptions used for this valuation.

Longevity Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's going concern results to the potential that pension plan members will live longer than expected. For this purpose, we have determined that a plausible adverse scenario would be to assume that future mortality improvements[5] will be in line with the average improvements experienced by the Canadian population over the most recent 15-year period available, with uniform improvement rates for all future years but varying by age[6] and gender.

The table below summarizes the improvement rates under the plausible adverse scenario compared to those currently assumed under the CPM-B scale and is based on Canadian population experience from the Human Mortality Database (HMD) from 2002 to 2016.

	Males				Females			
	CPM-B			Adverse Scenario	CPM-B			Adverse Scenario
Age	2020	2025	2030+		2020	2025	2030+	
20	1.59%	1.20%	0.80%	1.68%	0.98%	0.89%	0.80%	1.47%
30	1.88%	1.34%	0.80%	1.68%	0.98%	0.89%	0.80%	1.47%
40	1.80%	1.30%	0.80%	1.68%	1.17%	0.98%	0.80%	1.47%
50	1.17%	0.98%	0.80%	1.76%	0.98%	0.89%	0.80%	1.34%
55	1.47%	1.13%	0.80%	1.67%	1.11%	0.96%	0.80%	1.14%
60	1.77%	1.28%	0.80%	1.75%	1.24%	1.02%	0.80%	1.34%
65	2.06%	1.43%	0.80%	2.11%	1.36%	1.08%	0.80%	1.65%
70	2.06%	1.43%	0.80%	2.48%	1.36%	1.08%	0.80%	1.77%
75	2.01%	1.41%	0.80%	2.66%	1.36%	1.08%	0.80%	1.93%
80	1.96%	1.38%	0.80%	2.63%	1.36%	1.08%	0.80%	2.03%
85	1.38%	1.03%	0.68%	2.32%	1.31%	0.99%	0.68%	1.98%
90	0.75%	0.62%	0.48%	1.68%	0.75%	0.62%	0.48%	1.60%
95	0.16%	0.25%	0.34%	1.04%	0.16%	0.25%	0.34%	1.12%
100	0.14%	0.22%	0.30%	0.64%	0.14%	0.22%	0.30%	0.80%
105	0.14%	0.22%	0.30%	0.38%	0.14%	0.22%	0.30%	0.55%

[5] i.e. starting one year after the valuation in this context
[6] improvement rates below age 45 are set to those at age 45

Appendix H
Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2020 of the Plan, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary described in Section 2 of this report, particularly the requirement to include a margin of 0.30% in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2020 was provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarized in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2020.
- All events subsequent to December 31, 2020 that may have an impact on the Plan have been communicated to the actuary.

August 11, 2021

Date

Brent Perdue

Signed

Manager, Pension & Benefits

Name and Title

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Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 1

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2021

August 8, 2022

Canada Revenue Agency Registration Number: 0343343

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the Plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate, and the sensitivity to three adverse scenarios. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Should the Plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the Plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound up in the future. In fact, even if the Plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the Alberta *Employment Pension Plans Act*, the *Income Tax Act*, and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

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Section 1

Summary of results

	31.12.2021	31.12.2020
Going Concern Financial Status		
Market value of assets	$2,992,864,900	$3,015,005,300
Going concern funding liabilities	$2,973,907,700	$2,981,917,700
Funding excess (shortfall)	$18,957,200	$33,087,600
Funded ratio	100.6%	101.1%
Hypothetical Wind-up Financial Position		
Wind-up assets	$2,990,864,900	$3,013,005,300
Wind-up liability	$3,325,340,900	$3,471,697,200
Wind-up excess (shortfall)	($334,476,000)	($458,691,900)
Wind-up ratio	89.9%	86.8%
Solvency Financial Position		
Solvency assets	$2,990,864,900	$3,013,005,300
Solvency liabilities	$2,852,417,600	$2,896,047,500
Solvency excess (shortfall)	$138,447,300	$116,957,800
Solvency ratio	104.9%	104.0%
Funding Requirements in the year Following the Valuation[1]		
Total current service cost	$8,037,900	$11,331,800
Estimated member's required contributions	($276,000)	($398,000)
Estimated employer's current service cost	$7,761,900	$10,933,800
Employer's current service cost expressed as a percentage of member's pensionable earnings	42.51%	44.38%
Minimum special payments	$0	$0
Estimated minimum employer contribution	$7,761,900	$10,933,800
Estimated maximum eligible employer contribution	$7,761,900	$10,933,800
Next required valuation date	31.12.2024	31.12.2023

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

Section 2
Introduction

To the Management Pension Committee of Canadian Utilities Limited

At your request, we have conducted an actuarial valuation of the Retirement Plan for the Employees of Canadian Utilities Limited and Participating Companies - Plan 1 (the "Plan"), sponsored by Canadian Utilities Limited (the "Company"), as at the valuation date, December 31, 2021. We are pleased to present the results of the valuation.

The contributions to the defined contribution component of the Plan are determined by the Plan provisions. An estimate of the defined contributions for 2022 is included in this report.

Purpose

The purpose of this valuation is to determine:

- The funded status of the Plan as at December 31, 2021 on going concern, hypothetical wind-up, and solvency bases;
- The minimum required funding contributions from 2022, in accordance with the *Alberta Employment Pension Plans Act* (the "Act"); and
- The maximum permissible funding contributions from 2022, in accordance with the *Income Tax Act.*

The information contained in this report was prepared for the internal use of the Management Pension Committee and the Company, and for filing with Alberta Treasury Board and Finance and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with Alberta Treasury Board and Finance and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2024 or as at the date of an earlier amendment to the Plan depending on any funding implications.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, the going concern discount rate reflects a margin for adverse deviations of 0.30% per year.
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - Different plan wind-up scenarios were hypothesized for the hypothetical wind-up and solvency valuations.
  - No benefits were excluded from the solvency liabilities. However, an alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's *Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations,* to replace future variable inflation protection with a fixed percentage increase.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2020

Pension Plan

There have been no special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2021. The Plan has not been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation.

A summary of the going concern methods and assumptions is provided in Appendix C.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

There have been no changes to the Act or the relevant regulations that impact the funding of the Plan.

Subsequent Events

On September 14, 2021, the Actuarial Standards Board published a revised version of Section 3500 of the Standards of Practice on Pension Commuted Values which will be effective February 1, 2022.

The revised standards will affect implied rates of inflation used in the Standard and affirmed that the select and ultimate non-indexed rate cannot be less than zero. From the effective date, the revised standards will affect the assumptions used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of those changes will be reflected in a future actuarial valuation.

After checking with representatives of the Company, to the best of our knowledge there have been no other events subsequent to the valuation date that, in our opinion, would have a material impact on the results of the valuation as at December 31, 2021. However, since the valuation date, there have been significant fluctuations in financial markets including an increase in yields on fixed income investments and an increase in actual and expected short-term inflation, which may have led to a variation in the funded position of the Plan after the valuation date. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any subsequent experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all claims on the Plan after the valuation date will be in respect of benefits payable to members of the Plan determined in accordance with the Plan terms and that all Plan assets are available to provide for these benefits. It is possible that court and regulatory decisions and changes in legislation could give rise to additional entitlements to benefits under the Plan and cause the results in this report to change. By way of example, we bring your attention to the following decisions:

- The Ontario Court of Appeal's 2003 decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* restricted the use of original plan surplus where two or more pension plans were merged.
- The Supreme Court of Canada's 2004 decision in *Monsanto Canada Inc. versus Superintendent of Financial Services* upheld the requirement, with retroactive effect, to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario)*.

Although these decisions dealt with Ontario legislation, it is possible that they could have application to other provinces where the underlying language in the *Pension Benefits Act (Ontario)* is similar to language in the legislation of other provinces.

We are not in a position to assess the impact that such decisions or changes could have on the assumption that all plan assets on the valuation date are available to provide for benefits determined in accordance with the Plan terms. If such a claim arises subsequent to the date of this report, the consequences will be dealt with in a subsequent report. We are making no representation as to the likelihood of such a claim.

Section 3

Defined contribution component of the plan

The Plan is made up of defined contribution ("DC") and defined benefit ("DB") components. The DC component is considered in this Section. The remainder of the report relates to the DB component of the Plan, unless otherwise noted.

Current Service Cost

For the DC component of the Plan, Canadian Utilities Ltd.'s funding requirement is the employer DC current service cost. We have estimated the employer DC current service cost based on the projected payroll of participants. Our estimate, compared with the result of the previous valuation, is as follows:

	2022	2021
Estimated DC pensionable earnings that will attract an employer contribution	$458,035,000	$428,410,000
Employer DC current service cost	$27,482,000	$25,705,000

For reference, the Plan terms are summarized in Appendix F.

Section 4

Valuation results – Going concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	31.12.2021	31.12.2020
Assets		
Market value of assets	$2,992,864,900	$3,015,005,300
Going concern funding target		
Active members	$469,932,400	$558,312,900
Pensioners and survivors	$2,486,561,100	$2,407,498,500
Deferred pensioners and pending transfers	$17,414,200	$16,106,300
Total	$2,973,907,700	$2,981,917,700
Funding excess (shortfall)	$18,957,200	$33,087,600

The going concern funding target includes a provision for adverse deviations.

Reconciliation of Financial Status ($Millions)

Funding excess (shortfall) as at previous valuation		$33.1
Interest on funding excess (shortfall) at 2.80% per year		$0.9
Employer's special payments, with interest		$0.0
Expected funding excess (shortfall)		$34.0
Net experience gains (losses)		
• Investment return	$10.0	
• Increases in pensionable earnings	$4.0	
• Increase in YMPE	$0.6	
• Increase in maximum pension	($1.7)	
• Indexation	($23.9)	
• Mortality	($0.9)	
• Retirement	($1.1)	
• Termination	($0.0)	
Total experience gains (losses)		($13.0)
Net impact of other elements of gains and losses		($2.0)
Funding excess (shortfall) as at current valuation		$19.0

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date, compared with the corresponding values determined in the previous valuation, is as follows:

	2022	2021
Total current service cost	$8,037,900	$11,331,800
Estimated members' required contributions	($276,000)	($398,000)
Estimated employer's current service cost	$7,761,900	$10,933,800
Employees' current service cost expressed as a percentage of members' pensionable earnings	1.51%	1.62%
Employer's current service cost expressed as a percentage of members' pensionable earnings	42.51%	44.38%
Total current service cost expressed as a percentage of members' pensionable earnings	44.02%	46.00%

The key factors that have caused a change in the employer's current service cost, since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	44.38%
Demographic changes	(1.87)%
Employer's current service cost as at current valuation	42.51%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern liabilities and current service cost shown in this report of using a discount rate that is 1% lower than that used in the valuation.

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Going concern funding target	$2,973,907,700	$3,419,315,100
Current service cost		
• Total current service cost	$8,037,900	$9,755,000
• Estimated members' required contributions	($276,000)	($276,000)
Estimated employer's current service cost	$7,761,900	$9,479,000

Plausible Adverse Scenarios

The financial impact on the going concern results of plausible adverse scenarios that would pose threats to the Plan's future financial condition is presented in Appendix G.

Section 5

Valuation results – Hypothetical wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances consistent with the hypothesized scenario on the valuation date. For this purpose, we have assumed that annuities would be purchased with a fixed rate of increase of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

More details on such scenario are provided in Appendix D.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	31.12.201	31.12.2020
Assets		
Market value of assets	$2,992,864,900	$3,015,005,300
Termination expense provision	($2,000,000)	($2,000,000)
Wind-up assets	$2,990,864,900	$3,013,005,300
Present value of accrued benefits for:		
• Active members	$436,347,800	$550,763,800
• Pensioners and survivors	$2,871,645,800	$2,904,074,700
• Deferred pensioners	$17,347,300	$16,858,700
Total wind-up liability	$3,325,340,900	$3,471,697,200
Wind-up excess (shortfall)	($334,476,000)	($458,691,900)

Section 6
Valuation results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. An alternative settlement method for solvency funding purposes was hypothesized, whereby plan benefits were modified as permitted, pursuant to Alberta Treasury Board and Finance's *Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations*, to replace future variable inflation protection with a fixed percentage increase. Specifically, as at December 31, 2021, annuities were assumed to be purchased with a fixed rate of increase of 1.70% per year.

More details on such scenario are provided in Appendix D.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.2021	31.12.2020
Assets		
Market value of assets	$2,992,864,900	$3,015,005,300
Present value of going concern special payment	$0	$0
Termination expense provision	($2,000,000)	($2,000,000)
Net assets	$2,990,864,900	$3,013,005,300
Liabilities		
Total hypothetical wind-up liabilities	$3,325,340,900	$3,471,697,200
Difference in circumstances of assumed wind-up	($472,923,300)	($575,649,700)
Liabilities on a solvency basis	$2,852,417,600	$2,896,047,500
Surplus (shortfall) on a market value basis	$138,447,300	$116,957,800
Solvency ratio	104.9%	104.0%

Solvency Incremental Cost

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period. The solvency incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	31.12.2021	31.12.2020
Number of years covered by report	3 years	3 years
Total solvency liabilities at the valuation date (A)	$2,852,417,600	$2,896,047,500
Present value at the valuation date of projected solvency liability at the next required valuation plus expected benefit payments until the next required valuation (B)	$2,914,448,400	$2,975,018,500
Solvency incremental cost (B – A)	$62,030,800	$78,971,000

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the windup position of the Plan even if actual experience is exactly in accordance with the going concern valuation assumptions. For example, the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the solvency liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the solvency liabilities shown in this report of using a discount rate that is 1% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total solvency liability	$2,852,417,600	$3,269,938,500

Section 7
Minimum funding requirements

The Act prescribes the minimum contributions that Canadian Utilities Limited must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions
Period beginning	Monthly current service cost[2]	Minimum monthly deficiency payments	Total minimum monthly contributions
January 1, 2022	42.51%	$0	$646,800

The estimated contribution amounts above are based on projected members' pensionable earnings. If current service cost contributions are based on a percentage of members' pensionable earnings, then the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

Alternatively, as the Plan is closed to new employees and therefore the active membership is declining, it would be acceptable under the Act to contribute the above dollar amount of estimated employer's contributions to the Plan.

The estimated 2022 contributions to the defined contribution component of the Plan are set out in Section 3.

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater.

[2] Expressed as a percentage of members' pensionable earnings capped at $190,470 per member.

Timing of Contributions

Funding contributions must be made within 30 days following the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 30 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the solvency ratio revealed in an actuarial valuation is less than one. If the solvency ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Specifically, pursuant to the Act, transfers out of the Plan may only be made in full provided an amount equal to the transfer deficiency has been remitted to the pension fund in addition to the minimum special payments.

Section 8

Maximum eligible contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan that is underfunded on either a going concern or on a hypothetical wind-up basis, the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan that is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan that is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Notwithstanding the above, any contributions that are required to be made in accordance with pension benefits legislation are eligible contributions in accordance with Section 147.2 of the ITA and can be remitted.

Schedule of Maximum Contributions

Since the surplus does not exceed 25% of the going concern funding target, the Company may make monthly contributions of up to 42.51% of members' pensionable earnings, calculated on a going concern basis, until the next valuation. The monthly amount is estimated at $646,800 as shown in Section 7.

The Company could elect to contribute the service cost on a plan termination basis instead of the going concern service cost. For example, based on the scenario in Section 6, the maximum employer contribution for the period to December 31, 2024 is the three year solvency incremental cost of $62,030,800.

The estimated 2022 contributions to the defined contribution component of the plan are set out in Section 3.

Section 9

Actuarial opinion

In my opinion, for the purposes of the valuations,

- The membership data on which the valuation is based are sufficient and reliable;
- The assumptions are appropriate.
- The methods employed in the valuation are appropriate.

This report has been prepared, and my opinion given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the Alberta *Employment Pension Plans Act.*



Mark Greenwood
FCIA, FIA

August 8, 2022
Date

Appendix A
Prescribed disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Going Concern Assets Value	The value of the assets of a plan as of the relevant review date, determined on the basis of a going concern valuation.	$2,992,864,900
Going Concern Liabilities Value	The actuarial present value of a plan's benefits as of the relevant review date, determined on the basis of a going concern valuation.	$2,973,907,700
Unfunded Liability	The amount, if any, by which a plan's going concern liabilities value exceed its going concern assets value.	$0
Going Concern Funded Ratio	The fraction obtained by dividing the Going Concern Assets Value by the Going Concern Liabilities Value	1.0064
Accessible Going Concern Excess	The amount, if any, by which a plan's Going Concern Assets Value exceed 105% of its Going Concern Liabilities Value.	$0
Solvency Asset Value	The value of the plan's assets determined on a plan termination basis including any cash balances and accrued and receivable income and reduced by the actuary's estimate of the expenses that would be incurred in winding-up the plan.	$2,990,864,900
Solvency Liabilities Value	The liabilities of the plan calculated on a plan termination basis.	$2,852,417,600
Solvency Asset Adjustment	The sum of	
	i. the face amount of any prescribed letters of credit.	$0
	ii. the present value of special payments sufficient to amortize the unfunded liability due over the next five years, and	$0
		$0
Solvency Ratio	The fraction obtained by dividing:	1.0485
	(a) the Solvency Asset Value, and	$2,990,864,900
	(b) the Solvency Liabilities Value.	$2,852,417,600
Solvency Deficiency	The amount, if any, by which:	
	(a) the Solvency Liabilities Value	$2,852,417,600
	exceed the sum of:	
	(a) the Solvency Asset Value, and	$2,990,864,900
	(b) the Solvency Asset Adjustment.	$0
		$0

Defined Term	Description	Result
Accessible Solvency Excess	The amount, if any, by which a plan's Solvency Asset Value exceed 105% of its Solvency Liabilities Value.	$0
Special Payments	A monthly special payment established to amortize an unfunded liability is hereafter referred to as an unfunded liability special payment.	$0
	A monthly special payment established to amortize a solvency deficiency is hereafter referred to as a solvency special payment.	$0

Timing of Next Required Valuation

In accordance with the Act and the Superintendent's Directives, an actuarial report must be prepared at intervals not exceeding three years. The Superintendent also directs that the plan administrator file actuarial reports annually if the going concern funded ratio of the plan is less than 85%. Triennial filings may resume with the filing of a report showing that the going concern funded ratio is at least 85%.

Accordingly, the next valuation of the Plan will be required as of December 31, 2024.

Special Payments

Going Concern Basis

No unfunded liability special payments are required.

Solvency Basis

No solvency special payments are required.

Appendix B
Plan assets

The pension fund is held by Northern Trust. In preparing this report, we have relied upon the fund statements prepared by Northern Trust without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2021
January 1	$3,015,005,339
PLUS	
Members' contributions	$578,586
Company's contributions	$10,958,750
Investment earnings	$86,406,797
Net capital gain (loss)	$18,104,588
	$116,048,720
LESS	
Pensions paid	$125,429,006
Lump-sums paid	$1,066,310
Administration and investment fees	$11,693,843
	$138,189,159
December 31	$2,992,864,900
Gross rate of return[3]	3.48%
Rate of return net of expenses[3]	3.08%

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

[3] Assuming mid-period cash flows.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations, and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy			Actual asset Mix as at 31.12.2021
	Minimum	Target	Maximum	
Canadian Fixed Income	40.0%	61.0%	80.0%	83.2%
Global Fixed Income	10.0%	19.0%	35.0%	
Real Estate	0.0%	9.0%	10.0%	7.7%
Global Equity	0.0%	11.0%	40.0%	7.8%
Cash and cash equivalents	-	-	-	1.3%
		100%		100%

Appendix C
Methods and assumptions – Going concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions, if any, and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the Act, a funding shortfall including the provision for adverse deviations must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. As the DB component is closed to new members, the current service cost for DB members, expressed as a percentage of the members' pensionable earnings, can be expected to increase as the average age increases.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	2.80%	2.80%
Inflation:	2.00%	2.00%
ITA limit / YMPE increases:	2.25%	2.25%
Pensionable earnings increases:	2.50% (plus Merit and promotion)	2.50% (plus Merit and promotion)
Post-retirement pension increases:	1.85%	1.85%
Retirement rates:	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55	Retirement occurs when age and service sum to 90 years, but not after age 65 or before 55
Termination rates:	None	None
Mortality rates:	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using CPM Improvement Scale B (CPM-B)
Disability rates:	None	None
Eligible spouse at retirement:	Based on current marital status	Based on current marital status
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age-Related Tables

Sample rates from the age-related tables are summarized in the following table:

Age	Merit and promotion
20	13.65%
25	6.02%
30	3.08%
35	1.75%
40	1.07%
45	0.70%
50	0.47%
55	0.33%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement or death, we have taken 2021 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees and less a margin for adverse deviations.

The discount rate is comprised of the following:

- An **assumed investment return** based on estimated returns for each major asset class that are consistent with market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels, on the expected time horizon over which benefits are expected to be paid, and on the target asset mix specified in the Plan's investment policy. Consistent with market observable and available data, the assumed investment return is a gross return for all asset classes except for alternative investments for which it would normally be net of any investment management expense. The assumed investment return includes the diversification and rebalancing effect.
- An **assumed passive investment management expense provision** which represents the hypothetical fees for passive investment management of assets based on estimated fees charged by index managers for balanced mandates.

- An **active investment management expense provision** of 28 bps. We have assumed that these fees would be offset by an equivalent **additional return resulting from active investment management**.
- An **implicit non-investment management expense provision** determined as the average rate of non-investment expenses paid from the fund over the last three years. These would include all fees payable from the fund (administration, custodial, audit, consulting, etc.) except those payable to investment managers, to the extent that these fees are not covered in an explicit provision for expenses added to the current service cost.
- A **margin for adverse deviations** of 0.30% as per the terms of engagement.

The discount rate was developed as follows:

Assumed investment return	3.15%
Additional returns for active investment management	0.28%
Active investment management expense provision	(0.28%)
Assumed passive investment management expense provision	(0.02%)
Implicit non-investment management expense provision	(0.08%)
Margin for adverse deviations	(0.30%)
Net discount rate (rounded up to nearest 0.1%)	2.80%

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on a best estimate of future merit and promotional increases and general wage growth considering current economic and financial market conditions. The assumption takes into account the Company's current outlook for wage growth in the utility sector. Such merit and promotion increases are assumed to be in accordance with the table developed based on an experience study considering increases over the years 1985 to 1992 and which has continued to be reasonably predictive of merit and promotion increases experienced since that time.

Post-Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above, considering that the Plan limits pension increases to 3% in the event that inflation exceeds 3%. We have determined the impact of this cap by performing a stochastic analysis based on trials using a mean of 2.0% and a standard deviation of 1.5%.

Retirement Rates

For this valuation we have continued to assume that active members will retire when their age and service sum to 90 years, provided that retirement does not occur after 65 or before 55. Individuals who have already attained this condition are assumed to retire immediately. This assumption is based on the Plan provisions and the experience of the Plan in recent years.

Retirement earlier than assumed may result in losses to the Plan, while later retirements may result in gains to the Plan. These gains and losses will be revealed in subsequent valuations.

Termination Rates

Use of a different assumption would not have a material impact on the valuation.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014. Considering the characteristics of the group, it was considered appropriate to use the CPM mortality rates from the private sector as a reference table.

The mortality rates selected reflect plan-specific experience over the years 2005 to 2014. However, due to the size of the Plan, this mortality experience is not fully credible. The CPM mortality rates from the private sector have been adjusted after considering the plan-specific experience and characteristics, such as the type of employment, the industry experience, the pension and employment income for the plan members, and data in the CPM study.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. Two mortality improvement scales published by the Canadian Institute of Actuaries (CIA) are generally adopted for Canadian pension valuations:

- The Canadian Pensioners Mortality (CPM) study published in February 2014 included CPM Improvement Scale B (CPM-B).
- A report released by the Task Force on Mortality Improvement on September 20, 2017 included an analysis of the rate of mortality improvement for the Canadian population and provides for mortality improvement scale MI-2017 to be considered for the purpose of reflecting future mortality improvement in Canadian actuarial work, while acknowledging that it might be appropriate to use alternative mortality improvement assumptions to reflect the nature of the work.

The CIA Committee on Pension Plan Financial Reporting published a revised version of the Educational Note on the Selection of Mortality Assumptions for Pension Plan Valuations on December 21, 2017. The Educational Note indicated that given the recent publication of the CPM-B and MI-2017 improvement scales and the similar data sets used in their development, it may be appropriate to use either scale in the absence of credible information to the contrary, such as the publication of a successor scale by the CIA.

COVID-19 has impacted mortality rates globally. Statistics Canada reported excess mortality in 2020 and 2021 for the general Canadian population and other peer countries globally have also seen excess mortality over the course of the pandemic. Mortality experience for the plan has been reflected up to the date of the valuation. We have not adjusted the expected mortality rates for Plan members after the valuation date. The long-term implications of the pandemic on mortality rates is unclear as at the date of this report. Credible plan specific experience and relevant broader observed mortality trends after the report date will be reflected in future valuations.

For the current valuation, we have continued to use the CPM-B scale, which is a reasonable outlook for future mortality improvement.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 22.3 years for males and 24.7 years for females.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on actual membership data, which we believe is the most reliable source.

Spousal Age Difference

The assumption is based on an industry standard showing males are typically 3 years older than their spouse.

Appendix D
Methods and assumptions – Hypothetical wind-up and solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The Standards of Practice of the Canadian Institute of Actuaries require that the scenario upon which the hypothetical wind-up valuation is based be postulated. However, there are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. No benefits payable on plan wind-up were excluded from our calculations. The plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2021.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates on and after December 31, 2021 and no later than December 30, 2022 (the "Educational Note").*

An alternative settlement method was hypothesized for solvency purposes, whereby plan benefits were modified, as permitted, pursuant to Alberta Treasury Board and Finance's *Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations* ("Update 13-01"). Annuities are assumed to be purchased with future variable inflation protection replaced with a fixed percentage increase determined in accordance with Update 13-01.

However, it may not be possible to settle the liabilities through the purchase of annuities due to the size of the Plan and the limited annuity market in Canada. In accordance with the Educational Note, we have assumed that the settlement of such liabilities would be priced on the same basis as the smaller group annuities that are available in the market.

The Educational Note provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated substandard or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan's assumed basis falls outside that range. In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

Interest rate assumptions net of COLA used for lump sum transfers and annuity purchases take into consideration the 3% cap on pension increases provided by the plan provisions. We have carried out a stochastic analysis in order to determine the additional net interest rate as a result of this 3% cap.

We have not included a margin for adverse deviations in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum:	70% of active members under age 55, and 50% of active members over age 55, elect to receive their benefit entitlement in a lump sum
Annuity purchase:	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Scale B
Interest rate:	2.30% per year for 10 years, 3.40% per year thereafter.
COLA	1.48% per year for 10 years, 1.96% per year thereafter
Interest rate net of COLA	0.81% per year for 10 years, 1.41% per year thereafter

Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Scale B
Adjustment to mortality rates:	No adjustment
Interest rate:	2.86% per year based on a duration of 12.65 years determined for the liabilities assumed to be settled through the purchase of an annuity.
COLA	1.70% per year[4]
Interest rate net of COLA	1.14% per year
Retirement Age	
Benefits assumed to be payable through a lump sum:	Members are assumed to retire with a 50% probability at the age that maximizes the value of their entitlement from the Plan and a 50% probability at the member's earliest unreduced age in accordance with applicable legislation and based on the eligibility requirements that have been met at the valuation date
Benefits assumed to be settled through the purchase of an annuity:	Members are assumed to retire at the age that maximizes the value of their entitlement from the Plan, based on the eligibility requirements that have been met at the valuation date
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Termination expenses:	$2,000,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting, and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

[4] For the hypothetical wind-up scenario, it is assumed that annuities would be purchased with a fixed rate of interest of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire, and die consistent with the termination, retirement, and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit, and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.
- Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Appendix E
Membership data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2021, provided by Canadian Utilities Limited.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2021	31.12.2020
Active Members Accruing DB Benefits		
Number	280	344
Total pensionable earnings for prior year	$35,236,851	$43,021,123
Average pensionable earnings for prior year	$125,846	$125,061
Average years of pensionable service	31.4	30.6
Average age	57.5	57.2
Active Members with DB Benefits, but Accruing DC		
Number	23	24
Total pensionable earnings for prior year	$3,560,189	$3,631,384
Average pensionable earnings for prior year	$154,791	$151,308
Average years of pensionable service	7.3	7.2
Average age	55.8	55.1
Active Members with DC Benefits Only		
Number	4,059	3,823
Total pensionable earnings for prior year	$440,504,595	$411,669,259
Average pensionable earnings for prior year	$108,525	$107,682
Average age	42.3	42.1

	31.12.2021	31.12.2020
Deferred Pensioners		
Number	55	60
Total annual pension	$904,231	$946,356
Average annual pension	$16,441	$15,773
Average age	58.8	58.3
Pensioners and Survivors		
Number	2,761	2,747
Total annual lifetime pension	$129,695,423	$123,349,289
Average annual lifetime pension	$46,974	$44,903
Average age	72.3	72.0

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Active members accruing DB Benefits	Active members with DB Benefits accruing DC Benefits	Deferred Pensioners	Pensioners and survivors	Total
Total at 31.12.2020	344	24	60	2,747	3,175
New entrants					
Terminations:					
• Transfers/lump sums			(1)		(1)
• Pending transfers					
• Deferred pensions	(1)		1		
Deaths	(4)			(82)	(86)
Retirements	(59)	(1)	(5)	65	
Beneficiaries				29	29
Adjustments				2	2
Total at 31.12.2021	280	23	55	2,761	3,119

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service									
Age	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40+	Total
45 to 49					1	5				6
50 to 54					2	25	37	3		67
55 to 59				1		47	73	24		145
60 to 64		1			1	14	23	11	11	61
65 +						1				1
Total		1		1	4	92	133	38	11	280

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred Pensioners		Pensioners and Survivors	
Age	Number	Average Pension	Number	Average Pension
40 – 44			1	*
45 – 49	1	*		
50 – 54	7	$10,489	5	$42,891
55 – 59	27	$17,314	146	$65,314
60 – 64	19	$16,459	593	$65,451
65 – 69	1	*	609	$52,930
70 – 74			467	$42,948
75 – 79			320	$33,035
80 – 84			236	$29,661
85 – 89			228	$31,038
90 – 94			126	$28,308
95+			30	$19,190
Total	55	$16,441	2,761	$46,974

*Information supressed to preserve member confidentiality.

Appendix F
Summary of plan provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Canadian Utilities Limited. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2021. The Plan has not been amended since the date of previous valuation. There were no changes that had a material impact on the cost of the benefits provided by the Plan.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2021. This summary is not intended as a complete description of the Plan.

Background	Plan 1 members: • The Plan became effective January 2, 1962. On December 31, 1986, employees in the Yukon Territory and the Northwest Territories became covered by a separate arrangement. • Effective January 1, 1997, money purchase provisions were introduced into Plan 1, at which time existing Plan members had an option to continue to accrue benefits under the defined benefit component or participate in the new money purchase component. All new employees participate only in the money purchase component. Former Plan 2 members: • The Predecessor Plan was effective January 2, 1962. On December 31, 1986 the Predecessor Plan was split into three parts, covering employees in the Yukon (Plan 2), the Northwest Territories (Plan 3) and elsewhere (Plan 1). Plan 2A was established effective April 1, 1987 to cover Yukon based employees who had previously been employed by the Northern Canada Power Commission (NCPC). • Effective January 1, 1994, Plan 2 was amended to extend coverage to all current and former members of Plan 2A and Plan 3. Service under Plan 2A and Plan 3 were assumed by Plan 2 in exchange for a transfer of assets. • Effective December 30, 2003, the Plan was extended to cover employees located in Ontario. Effective January 1, 2015, Plan 2 was merged with Plan 1.

Eligibility for Membership	Plan 1 members: • The Plan covers salaried employees employed in Canada outside of Ontario, the Yukon and Northwest Territories upon appointment to permanent staff. This typically occurs after 6 months service. In the event that a salaried employee is not appointed to permanent staff earlier, participation in the Plan will commence upon completion of two years' service provided earnings exceed 35% of the YMPE in two consecutive calendar years. • Participation in the Plan is compulsory for all eligible employees who are not participating in another registered pension plan of the employer. Former Plan 2 members: • The Plan is closed to new entrants. • Some individuals who were employed by NCPC immediately prior to April 1, 1987 elected to have their pension benefit entitlements under the PSSA transferred to the Plan. For these members, pensionable service under the Plan includes service that was pensionable under the PSSA. Service with NCPC counts for determination of vested rights whether or not the individual member elected to transfer his PSSA benefit entitlements to the Plan.
Employee Contributions	Members contribute 2.8% of earnings up to the YMPE and 4.0% of earnings over the YMPE, up to an annual maximum contribution of $2,000. Disabled members and certain executive members are not required to contribute.
Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month following the member's 65th birthday. Early Retirement Date • The member may choose to retire as early as age 55
Postponed Retirement	A member who remains employed with the company after age 65 may elect to commence receipt of pension or continue to accrue benefits under the Plan up to his actual retirement.
Normal Retirement Pension	2% of annual final average earnings times years of pensionable service between January 2, 1962 and January 2, 1966; PLUS 1.4% of annual final average earnings up to the YMPE, times years of pensionable service after January 2, 1966; PLUS 2.0% of annual final average earnings in excess of the YMPE, times years of pensionable service after January 2, 1966.
Pensionable Earnings	Annual final average earnings are calculated over the 60 consecutive months for which earnings are highest. The YMPE is calculated over the same period.

Early Retirement Pension

If a member retires from active service with the consent of the Company, a reduced early retirement benefit is payable, as follows:

- If age and service sum to 90 years or more, no reduction applies;
- otherwise, the pension payable is equal to the normal retirement pension times a percentage from the following table:

Age at Retirement	Percentage
64	100
63	100
62	100
61	97
60	94
59	88
58	82
57	76
56	70
55	64

If retirement is not from active service, or if Company consent is not obtained, an actuarial reduction applies.

In addition, female participants employed prior to June 1, 1972 are entitled to a bridge benefit payable only until age 65. The bridge benefit is equal to the expected Canada pension Plan benefit times the ratio of 36 divided by the number of months from retirement to age 65, provided that the ratio is never more than 1.

Maximum Pension

The Plan provides that the pension payable at the time of commencement must not exceed the defined benefit limit prescribed under the Income Tax Act, multiplied by years of pensionable service (with service rendered prior to January 1, 1992 limited to 35 years).

Reductions to this maximum apply if retirement occurs before age 60, before completion of 30 years' service, and before attainment of age and service summing to 80. The maximum provision automatically reflects any increases to the defined benefit limit that occur in the Income Tax Act and Regulations.

Cost of Living Adjustments

The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid. The annual adjustment is granted only to members who retire from active service.

Death Benefits	Pre-retirement: • If a member dies before becoming eligible for retirement, the member's spouse, or the member's beneficiary if there is no surviving spouse, will receive a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. • If a member dies after becoming eligible for retirement, the member's spouse will receive the greater of: - a benefit equal in value to the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value, and - an immediate pension equal to 60% of the pension to which the member would have been entitled had the member retired on their date of death. This pension will also receive future cost of living increases. • If a member dies after becoming eligible for retirement and there is no surviving spouse, the beneficiary will receive the commuted value of the benefit to which the member would have been entitled had he terminated employment immediately prior to his death, plus any excess of the member's contributions over 50% of that commuted value. Post retirement: • The normal form of pension for single employees guarantees a return of the member's own contributions with interest up to retirement date. • For employees with an eligible spouse, the normal form of pension provides a continuing survivorship pension to the member's spouse. If retirement occurs prior to July 1, 1987, the spouse's benefit is 50% of the member's benefit. If retirement occurs after July 1, 1987 the spouse's benefit is 60%.
Termination Benefits	A deferred pension commencing at normal retirement date, or alternatively the commuted value thereof may be transferred to the member's locked-in RRSP. If the member's own contributions exceed 50% of the commuted value of the deferred pension, the excess is available as an additional benefit.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2021. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan became effective January 1, 1997. Employer and employee contributions are remitted to individual member accounts and are credited with interest.
Eligibility for Membership	An employee must join the Defined Contribution component of the Plan on the date the member is appointed to the permanent staff of Canadian Utilities Limited.
Employee Contributions	The lesser of 4% of member's pensionable earnings and 40% of the maximum contribution limit. Required contributions for Executive Officers and disabled members are made on their behalf by the Employer.
Employer Contributions	The lesser of 10% of member's pensionable earnings and maximum contribution limit reduced by the amount paid by the member.
Benefits	Members receive the balance of their individual employer and employee accounts upon termination, death or retirement.
Maximum Contribution	The employer and employee contributions are limited to the amounts under the *Income Tax Act.*
Pensionable Earnings	Base salary.

Appendix G
Plausible adverse scenarios

In this Appendix, the financial impact on the Plan's going concern results (i.e., going concern financial position at the valuation date and current service cost from the valuation date to the next valuation date) of plausible adverse scenarios that would pose threats to the Plan's future financial condition is summarized in the following tables for the following risks:

- Interest rate risk - an immediate parallel decrease in market interest rates of 110 basis points;
- Deterioration of asset values - an immediate decrease of 15% in the market value of non-fixed income assets; and
- Longevity risk - that life expectancy from the valuation date at age 65 for a male and a female would increase by 1.6 years and 1.4 years, respectively.

Scenario	Going Concern Valuation Results as at December 31, 2021	Plausible Adverse Scenario Results as at December 31, 2021		
		Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Going Concern Financial Status				
Market value of assets	$2,992,864,900	$3,322,080,000	$2,903,079,000	$2,992,864,900
Going concern funding target	$2,973,907,700	$3,370,237,300	$2,973,907,700	$3,130,949,800
Funding excess (shortfall)	$18,957,200	($48,157,300)	($70,828,700)	($138,084,900)
Estimated Employer's Current Service Cost expressed as a percentage of Members' Pensionable Earnings				
From January 1, 2022	42.51%	50.86%	42.51%	45.30%

The balance of this Appendix provides details of the plausible adverse scenarios selected and the determination of their impact on valuation results.

Interest Rate Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to the potential that interest rates will be lower than expected. For this purpose, we have assumed an immediate parallel decrease in market interest rates underlying fixed income investments, where fixed income investments include Canadian and Global Fixed Income, as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a parallel decrease in market interest rates of 110 basis points would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease in market interest rates would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions:

Defined Term	Description
Market value of assets	The decrease in market interest rates has been assumed to affect only the market value of the fixed income investments. The decrease is assumed to have occurred immediately on the valuation date.
Discount rate assumption	It was assumed that the decrease in market interest rates affects only the expected return on assets for the fixed income portion of assets. The same margin for adverse deviations was used. The discount rate assumption was therefore decreased from 2.80% to 1.90%.
Other assumptions	Except as mentioned above, all assumptions used were the same as those used for this valuation. In particular, the discount rate used to value benefits assumed to be settled through a lump sum was not changed.

Deterioration of Asset Values

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to a deterioration of asset values. For this purpose, we assumed an immediate reduction in the market value of the Plan's non-fixed income assets, where non-fixed income investments include Real Estate and Global Equity, as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a decrease of 15% in the market value of non-fixed income assets would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease would occur immediately on the valuation date and would have the following impact on the value of assets and valuation assumptions:

Market value of assets	The decrease in the market value of the non-fixed income portion of assets is assumed to have occurred immediately on the valuation date.
Going concern assumptions	This scenario is assumed to have no impact on the assumptions used for this valuation.

Longevity Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to the potential that pension plan members will live longer than expected. For this purpose, we have determined that a plausible adverse scenario would be to assume that future mortality improvements[5] will be in line with the average improvements experienced by the Canadian population[6] over the most recent 15-year period available, with uniform improvement rates for all future years but varying by age[7] and gender.

[5] i.e. starting one year after the valuation in this context

[6] Based on Canadian population experience from the Hum Mortality Database from 2002 to 2016

[7] improvement rates below age 45 are set to those at age 45

Appendix H
Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2021 of the Plan, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary described in Section 2 of this report, particularly the decision to include a margin of 0.30% in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2021 was provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarized in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2021.
- All events subsequent to December 31, 2021 that may have an impact on the Plan have been communicated to the actuary.

August 8, 2022
Date

Brent Perdue
Signed

Brent Perdue, Sr Manager, Pension & Benefits
Name



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Mercer

Funding Valuation Results as at December 31, 2022

Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 1

09 June 2023

welcome to brighter

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1

Introduction

We have conducted an actuarial valuation of the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies – Plan 1 (the Plan) as of December 31, 2022. We are pleased to present the preliminary results of the valuation.

Mercer has prepared this report exclusively for CU to present preliminary results for the December 31, 2022 funding valuation for the Plan.

The valuation results herein are for discussion purposes. Should CU choose to file this valuation with the pension regulators, the required contributions would change as described. There is no requirement to file this valuation as of December 31, 2022.

2

Development of Funding Discount Rate and Margins

Proposed Basis

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy;
- Provision for investment and administrative expenses (currently 0.38%); and
- A margin for adverse deviations of 0.25%.

The defined benefit program is closed to new entrants and the Plan provides incentives for employees to remain employed until they attain eligibility for early retirement. Therefore, in time, solvency considerations including annuity purchase rates will become a more dominant feature of the Plan's funding requirements.

Development of Discount Rate

	12/31/2022 (Proposed)	12/31/2021 (Filed)	12/31/2020 (Filed)
Assumed investment return	5.00%	3.10%	3.10%
Margin for adverse deviations	(0.25%)	(0.30%)	(0.30%)
Net discount rate	**4.75%**	**2.80%**	**2.80%**

3

Going Concern Funding Valuation

Results (Millions)

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Assets			
• Market value of assets	**$2,364.8**	**$2,992.9**	**$3,015.0**
Funding Target			
• Active members	$283.4	$469.9	$558.3
• Pensioners and survivors	$2,061.8	$2,486.6	$2,407.5
• Deferred pensioners and pending transfers	$12.4	$17.4	$16.1
	$2,357.6	**$2,973.9**	**$2,981.9**
Surplus (deficiency)	**$7.2**	**$19.0**	**$33.1**
Funded ratio	**100.3%**	**100.6%**	**101.1%**

Key Economic and Demographic Assumptions

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Discount rate	4.75%	2.80%	2.80%
Indexing rate	3.0% on Jan 1, 2024, 2.2% on Jan 1, 2025, 1.85% thereafter	No change	1.85% per year
Salary scale	No change	No change	2.50% plus merit & promotion
Mortality	No change	No change. Confirmed by mortality experience study.	Canadian Pensioners Mortality (CPM) Private Sector Table with 95% adjustment and generational projection using Scale CPM-B

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Retirement Rates	No change	No change	Retirement occurs when age and service sum to 90 years, but not after age 65 or before age 55

4

Reconciliation of Going Concern Position

(Millions)

	2022
Funding excess (shortfall) at Beginning of Period	**$19.0**
Interest on funding excess (shortfall)	0.5
Asset returns different than expected	(584.2)
Pensionable earnings less (greater) than assumed	1.8
Pension increases less (greater) than assumed	(30.0)
Termination experience	1.2
Retirement experience	2.2
Mortality experience	4.8
Impact of change to indexing rate	(38.2)
Impact of change in discount rate	629.7
All other sources combined	0.4
Funding excess (shortfall) at End of Period	**$7.2**

5

Defined Benefit Service Cost

(Millions)

	2023 Proposed Basis	2022 (Filed)	2021 (Filed)
Total current service cost	$4.0	$8.1	$11.3
Members' required contributions	($0.2)	($0.3)	($0.4)
Company current service cost	**$3.8**	**$7.8**	**$10.9**
Assumed members' pensionable earnings	$12.7	$18.3	$24.6
As a percentage of pay			
Members' required contributions	1.50%	1.51%	1.62%
Company current service cost	30.16%	42.51%	44.38%
Total	**31.66%**	**44.02%**	**46.00%**

6

Solvency Valuation – Alternative Settlement Method

An alternative settlement method for solvency funding purposes is permitted by Alberta Treasury Board and Finance's Update 13-01 Alternative Settlement Methods for Hypothetical Wind-Up and Solvency Valuations. By applying this method, future variable inflation protection is assumed to be replaced with a fixed percentage increase. For this purpose, we have assumed that annuities would be purchased with a fixed rate of increase of 1.88% per year.

Results (Millions)

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Assets			
• Market value of assets	$2,364.8	$2,992.9	$3,015.0
• Termination expenses	($2.0)	($2.0)	($2.0)
	$2,362.8	**$2,990.9**	**$3,013.0**
Funding Target			
• Active members	$255.4	$396.8	$493.2
• Pensioners and survivors	$2,017.2	$2,438.4	$2,386.0
• Deferred pensioners	$12.3	$17.3	$16.8
	$2,284.9	**$2,852.5**	**$2,896.0**
Surplus (deficiency)	**$77.9**	**$138.4**	**$117.0**
Funded ratio	**103.4%**	**104.9%**	**104.0%**

Key Economic and Demographic Assumptions

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Annuity purchase discount rate	4.91%	2.86%	2.56%
Annuity purchase COLA	1.88%	1.70%	1.48%
Annuity purchase discount rate net of COLA	2.97%	1.14%	1.06%
Commuted value discount rate net of COLA	2.32% for 10 years, 2.71% thereafter	0.81% for 10 years, 1.41% thereafter	0.47% for 10 years, 1.05% thereafter
Percentage of members electing commuted values	No change	No change	Actives under 55 – 70% Actives over 55 – 50% Inactives – 0%
Mortality	No change	No change	CPM 2014 Table with generational projection using scale CPM-B

Key factors that impacted the solvency position since the previous valuation as of December 31, 2021 were as follows:

- Asset returns less than expected (-17.1% net of expenses compared with average rate of 2.8% assumed in 2022).
- Impact of January 1, 2023 COLA of 3.0%.

Offset by:

- Changes in annuity purchase and commuted value discount rates (significant increase in annuity purchase rate net of COLA, as well as increase in commuted value rates net of COLA).

7

Hypothetical Wind-up Valuation – Annuity Purchase Cost

The hypothetical wind-up financial position in the absence of the alternative settlement method is as follows. For this purpose, we have assumed that annuities would be purchased with a fixed rate of increase of 3.0% per year, which is the maximum rate of increase under the Plan provisions.

Results (Millions)

	12/31/2022 Proposed Basis	12/31/2021 (Filed)	12/31/2020 (Filed)
Assets			
• Market value of assets	$2,364.8	$2,992.9	$3,015.0
• Termination expenses	($2.0)	($2.0)	($2.0)
	$2,362.8	**$2,990.9**	**$3,013.0**
Funding Target	**$2,564.5**	**$3,325.4**	**$3,471.7**
Surplus (deficiency)	**($201.7)**	**($334.5)**	**($458.7)**
Funded ratio	**92.1%**	**89.9%**	**86.8%**

8

Defined Benefit Contribution Requirements

(Millions)

	2023 Proposed	2022 (Filed)	2021 (Filed)
Minimum employer funding requirements			
• Company service cost	$3.8	$7.8	$10.9
• Going concern special payments (over 15 years)	$0.0	$0.0	$0.0
• Solvency special payments (over 5 years)	$0.0	$0.0	$0.0
Total	**$3.8**	**$7.8**	**$10.9**
Maximum funding requirements			
• Company service cost	$3.8	$7.8	$10.9
• Special payments	$0.0	$0.0	$0.0
Total	**$3.8**	**$7.8**	**$10.9**

9

COLA Disallowance for Utilities

As requested, we have estimated the impact of the disallowance of cost of living increases (COLA) in excess of 50% of CPI for the regulated utilities (ATCO Gas, ATCO Electric, ATCO Pipelines, ATCO Corporate, CU Inc., YECL, and Northland Utilities). This is as directed by the 2011 decision of the Alberta Utilities Commission ("AUC"). To determine the effect of this disallowance, a duplicate valuation is performed at December 31, 2022 using the proposed basis previously described in this report. This duplicate valuation considers the following:

- The market value of assets at December 31, 2022 is adjusted to exclude disallowed current service contributions remitted in 2012 as well as disallowed current service contributions and special payments remitted in 2013 to 2022, as required by the AUC's decision. We have also adjusted the asset value to exclude an estimated value of pension payments made as a result of COLA being granted at 100% of CPI rather than 50% of CPI.

- Liabilities and service costs are adjusted to allow future COLA based on 50% of CPI for the regulated utilities and ATCO Corporate, rather than 100% of CPI. An additional adjustment is made to exclude 50% of the actual COLA granted previously.

Estimated Impact on Funding Requirements (Millions)

These results are for illustration only, assuming that a new valuation is filed as at December 31, 2022.

	2023 Proposed Basis	Utilities Disallowance
Minimum employer funding		
• Company service cost	$3.8	$0.4
• Special payments	$0.0	$0.0
Total	**$3.8**	**$0.4**

The above utilities disallowance compares with $0.9 million calculated based on the December 31, 2021 valuation, and with $1.3 million calculated based on the December 31, 2020 valuation.

10

Important Notices

Mercer has prepared this report exclusively for CU to present preliminary results for the December 31, 2022 funding valuation. This report is intended to facilitate CU's decision making relating to the December 31, 2022 funding valuation. This report may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any such other use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

The results presented herein are preliminary and subject to change. This report is not a substitute for a formal valuation report.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this preliminary valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

CU is responsible for selecting the plan's funding policy (including margins, if any, for adverse deviations in the going concern valuation), the actuarial and asset valuation methods in the going concern valuation, and other methodologies permitted by legislation for the solvency valuation.

The actuarial assumptions used in the going concern valuation reflect the actuary's best estimate, except for the margin for adverse deviations which has been selected by CU. CU is responsible for reviewing the going concern valuation assumptions referenced and advising Mercer as to any information it deems worthy of consideration in the determination of such assumptions.

To prepare the results in this report, actuarial assumptions are used to model certain scenarios from a range of possibilities for each valuation basis. The results based on those scenarios are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors. The key assumptions used for the valuation are described in Sections 3 and 6 of this report.

Mercer has used and relied on the membership data as supplied by CU. If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided. Statistics on the membership data are provided in Appendix A.

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions, supplied by CU. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary. There were no changes made to the plan provisions since the previous valuation that had a material impact on the liabilities of the plan.

We used financial data submitted by Northern Trust as of the valuation date without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and general reasonableness.

Funding calculations reflect our understanding of the requirements of Alberta legislation, the Income Tax Act and related regulations that are effective as of the valuation date. Mercer is not a law firm, and this analysis is not intended to be a legal opinion. CU should consider securing the advice of legal counsel with respect to any legal matters related to this document.

The plan administrator is solely responsible for selecting the plan's investment policies, asset allocations and individual investments.

Appendix A
Membership Data

	31/12/2022	31/12/2021	31/12/2020
Active Members Accruing DB Benefits			
Number	226	280	344
Total pensionable earnings for prior year	$27,634,371	$35,236,851	$43,021,123
Average pensionable earnings for prior year	$122,276	$125,846	$125,061
Average years of pensionable service	32.0	31.4	30.6
Average age	58.2	57.5	57.2
Active Members with DB Benefits, but Accruing MP Benefits			
Number	21	23	24
Total pensionable earnings for prior year	$3,361,297	$3,560,189	$3,631,384
Average pensionable earnings for prior year	$160,062	$154,791	$151,308
Average years of pensionable service	7.2	7.3	7.2
Average age	56.9	55.8	55.1
Deferred Pensioners			
Number	50	55	60
Total annual pension	$813,210	$904,231	$946,356
Average annual pension	$16,264	$16,441	$15,773
Average age	59.6	58.8	58.3
Pensioners and Survivors			
Number	2,749	2,761	2,747
Total annual lifetime pension	$134,602,689	$129,695,423	$123,349,289
Average annual lifetime pension	$48,964	$46,974	$44,903
Average age	72.7	72.3	72.0

Distribution of Active Members by Age and Pensionable Service:

	< 10	10-14	15-19	20-24	25-29	30-34	35-39	40+	Total
45-49					1				1
50-54				1	19	31	2		53
55-59			1		25	58	15	1	100
60-64	1				11	36	12	7	67
65-69					1	2	1	1	5
Total	**1**	**0**	**1**	**1**	**57**	**127**	**30**	**9**	**226**

Distribution of Inactive Members by Age:

Age	Deferred Pensioners	Pensioners and Survivors
< 45		1
45-49	1	
50-54	5	3
55-59	21	124
60-64	21	520
65-69	2	675
70-74		448
75-79		350
80-84		250
85-89		203
91-94		138
95+		37
Total	**50**	**2,749**

Appendix B

Plan Assets

(Millions)

	2022
January 1	**$2,992.9**
PLUS	
Members' contributions	$0.4
Company's contributions	$7.8
Investment income	$64.7
Net capital gains (losses)	($556.5)
LESS	
Pensions paid	$131.2
Lump-sum refunds	$2.9
Administration and investment expenses	$10.3
December 31	**$2,364.8**
Gross rate of return[1]	-16.8%
Rate of return net of expenses[1]	-17.1%

[1] Assuming mid-period cash flows.

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A business of Marsh McLennan

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Pension Balances and Deferral Balances

Line No.	Description	Cross Reference	2018	2019	2020	2021	2022	2023	2024
			Actual					Test Period	
1	Pension Costs								
2	Defined Benefit		240	240	273	249	201	39	39
3	Exclude COLA		(30)	(30)	(34)	(33)	(27)		-
4	Defined Benefit Pension	S.8.4, Line 20	210	210	239	216	174	39	39
7	Approved/Applied Defined Benefit Costs		505	505	505	505	505	39	39
8	Difference	L.4 - L.7	(295)	(295)	(266)	(289)	(331)	-	-
9	O&M portion of Difference	(L.8 x 65.0%)	(192)	(192)	(173)	(188)	(215)		
10	Impact of lower income tax deductions	(L.8 x 27.0%)	80	80	72	78	89		
11	Net of Income Tax	L.9 + L.10	(112)	(112)	(101)	(110)	(126)		
12	Total (refund to) / collection from customers	L.11 / (1 - 27.0%)	**(154)**	**(154)**	**(138)**	**(150)**	**(172)**	**-**	**-**
13	Pension Deferral write-off	S.8.4, Line 49	77	77	77	77	77	192	192
13	Cumulative Pension Deferral Balance[1]	S.8.8, Line 85	**(77)**	**(153)**	**(215)**	**(288)**	**(383)**	**(192)**	**-**

1. AEY updates the defined pension costs forecast in the test periods as the most recent 2023 actuarial valuation report becomes available during the information response period. A revised S8.8 showing the Cumulative Pension Deferral is attached on the AEY-UCG-050(b) Attachment 1. AEY has proposed transferring the deferral balance to deferred charges to be refunded to customers over the 2023-24 Test Period.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-051

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-051

Reference: July 7,2023 Application, page 8-6; Rate Base and Table 8.4

AEY states: These additions are primarily driven by a requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their life cycle as well as meet system needs due to growth.

Request:

(a) Add a column in Table 8.4 showing rate base amounts for each of the years shown.

(b) Explain fully the need to more than double the capital expenditures from 2022 to each of the test years.

(c) Explain why AEY has not developed a more gradual approach to enhancing and replacing distribution and generation systems.

(d) Break down the Capital Additions chart 8.4 for AEY distribution and generation systems.

(e) Explain with examples why load growth will not result in a balance of costs versus new income produced.

September 28, 2023 AEY-UCG-051

Response:

(a) Please refer to the following table:

Table 1: Capital Additions & Rate Base
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Expenditures	14,784	10,476	9,491	13,529	13,001	15,147	18,914	31,234	25,073
Capital Additions	12,079	8,393	11,159	9,982	11,893	11,014	15,857	34,734	31,780
Net Rate Base[1]	**98,470**	**102,558**	**105,033**	**106,149**	**107,099**	**109,110**	**114,468**	**129,288**	**142,869**

(b-c) Please refer to responses AEY-YUB-042 and AEY-JM-027.

(d) Please refer to Table 2 below. The categories of GP&E & Software and CCS have been added to tie the total to Table 8.4 from the Application.

Table 2: Capital Additions
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Distribution	5,471	5,667	7,693	8,676	7,349	5,094	11,940	20,494	14,400
Generation	5,277	1,847	3,079	400	3,642	5,591	3,020	3,993	15,043
GP&E & Software	1,332	880	387	907	902	329	897	2,157	1,837
CCS	-	-	-	-	-	-	-	8,090	500
Total	**12,079**	**8,393**	**11,159**	**9,982**	**11,893**	**11,014**	**15,857**	**34,734**	**31,780**

(e) While the rapidly expanding customer base does lead to increased revenues, it also increases the load strain on the current electrical infrastructure. This increase in load could lead to issues with reliability and potential increase in outage length as system restoration is more difficult due to cold load pickup. To ensure continued safe and reliable service, load capacity needs to increase. As such, the current infrastructure needs to be upgraded and the capital costs of these improvements are not completely offset by the increased customer base.

[1] Rate Base for the Test Period has been updated for Depreciation Parameters filed September 11, 2023.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-052

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-052

Reference: July 7,2023 Application, page 8-7; Contributions

Request:

(a) Explain how contribution in aid of construction is accounted for in the rate base.

(b) Explain why AEYs company investment policy has not been reviewed since 2010.

Response:

(a) When the assets are put into service and added to rate base, so is the corresponding contribution. This results in a net zero impact on the net rate base if the asset is fully contributed. The contribution added to the rate base is then depreciated in the same manner as the depreciation of the corresponding assets. Please refer to Schedule 1.1, line 12, for how this is recorded in the Application.

(b) The investment policy is reviewed when AEY's Terms and Conditions of Service (T&Cs) are reviewed and updated. As outlined in the Application,[1] because the T&Cs are also those of Yukon Energy Corporation (YEC), AEY reached out to YEC on this matter. Both parties consider that, given the number of changes and proposals included in AEY's GRA (and YEC's anticipated upcoming GRA), as well as simultaneous staffing resources required to properly review and address any required changes to T&Cs, undertaking such a review is not feasible at this time. Notwithstanding the above, both parties also agree that there are multiple sections in the T&Cs that require review (for example: maximum investment levels). As

[1] 2023-2024 AEY GRA Application, Cover Letter, PDF pp. 2-3.

such, both parties proposed to address any required changes and/or updates to the T&Cs sometime in mid to late 2024, as a standalone limited scope filing, rather than including any changes as part of a GRA.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-053

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-053

Reference: July 7, 2023 Application, page 8-5; Deferred Charges and Credits

Request:

(a) Explain how deferred charges and credits are accounted for in rate base.

(b) Give forecast costs for this GRA. Is the Rate Case Reserve adequate to cover these costs?

(c) Does AEY foresee the need to continue with a Rate Case Reserve. Why or why not?

(d) Explain why AEY over collected in 2014 and 2015 in the benefit pension account.

(e) Where is Schedule 8.8?

Response:

(a) Deferred charges and credits are balances held for deferral accounts and reserve accounts that are due to or from customers. These amounts are settled through either the rate adjustment rider throughout the Test Period or through a separate rider and the mid-year balance of amounts held are included in rate base. Net balances due to customers reduce the capital funding requirements and net balances due from customers are funded at the approved debt to equity ratio.

(b) Forecast costs for rate case expense are $608,000. The previous balance of the rate case reserve has been returned to customers through the 2022 Rate Relief. The expected cost of this Proceeding is forecast to be recovered over the Test

Period. Consistent with historical precedent,[1] any differentials between the estimate and forecast costs will be accounted for in the reserve account for true up in a future application.

(c) AEY requires the Rate Case Reserve account. This is the mechanism to record and settle costs approved by the Board related to the participation in regulatory proceedings for all parties, including the Board, interveners and applicants.

(d) The Pension Deferral Account was approved due to uncertainty surrounding the forecast and potentially material impact of the costs associated with AEY's Defined Benefit Plan. For the years 2014 and 2015, the forecast costs included in revenue requirement were higher than the actual costs incurred, and the differential was returned to customers through the 2016-2017 GRA.

(e) Schedule 8.8 was included in the Excel workbook as part of AEY's Application filed on July 7, 2023, and is also included in the Excel workbook with the updated schedules filed on September 11, 2023, with AEY's Depreciation Study. A copy of Schedule 8.8 has also been re-attached in AEY-UCG-053(e) Attachment 1.

[1] Board Order 2017-01.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity Schedule of Deferred Charges & Credits
($000)

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	**Total Deferred Charges & Credits Summary**												
2													
3	**Write-off Summary**												
4	Rate Case Costs	L. 22	(313)	(313)	(313)	(313)	(313)	(313)	(178)	(156)	(203)	(313)	(313)
5	Watson Lake LNG Study Costs	L. 32	(99)	(99)	(99)	(99)	(99)	(99)	(99)	74	124	(99)	(99)
6	Demand Side Management		-	-	-	-	-	-	-	-	-		
7	Pension Deferral Account	L. 49	77	77	77	77	77	77	77	223	223	77	77
8	ERA/IPP Legal Costs		-	-	-	-	-	-	-	94	94	-	-
9	**Total Write-off**		(334)	(334)	(335)	(335)	(335)	(334)	(200)	234	143	(334)	(335)
10													
11	**Deferred Credits Mid-Year Balance Summary**												
12	Rate Case Reserve	L. 26	1	(45)	(210)	(522)	(835)	(1,147)	(1,393)	(793)	(52)	176	156
13	Watson Lake LNG Study Costs	L. 35	263	345	246	148	49	(50)	(149)	(161)	(62)	263	345
14	Demand Side Management Program Costs	L. 44	199	-	-	-	-	-	-	-	-	199	-
15	Pension Deferral Account	L. 52	(39)	(39)	(35)	(112)	(188)	(244)	(308)	(287)	(111)	(39)	(39)
16	ERA/IPP Legal Costs		-	-	-	-	73	178	198	141	47		
17	**Total Deferred Credits Mid-Year Balance**		424	261	1	(487)	(901)	(1,263)	(1,651)	(1,100)	(225)	600	463
18													
19	Rate Case Costs												
20	Balance at Beginning of Year		39	(37)	(54)	(366)	(679)	(991)	(1,304)	(1,481)	(104)	39	313
21	Add: Rate Case Costs		236	296	-	-	-	-	-	301	307	586	-
22	Less: Rate Case (Write-off) Credit		(313)	(313)	(313)	(313)	(313)	(313)	(313)	(156)	(203)	(313)	(313)
23	Less: Adjustment for YUB 2022-13		-	-	-	-	-	-	135	1,232	-	-	-
24	Balance at End of Year		(37)	(54)	(366)	(679)	(991)	(1,304)	(1,481)	(104)	-	313	-
25													
26	Mid-Year Balance	(L.20+L.24)/2	1	(45)	(210)	(522)	(835)	(1,147)	(1,393)	(793)	(52)	176	156
27													
28	Watson Lake LNG Study Costs												
29	Balance at Beginning of Year		131	394	296	197	98	(1)	(99)	(198)	(124)	131	394
30	Add: Costs/AFUDC		-	-	-	-	-	-	-	-	-	-	-
31	Add: Transfers from Plant Additions		362	-	-	-	-	-	-	-	-	362	-
32	Less: Write-off		(99)	(99)	(99)	(99)	(99)	(99)	(99)	74	124	(99)	(99)
33	Balance at End of Year		394	296	197	98	(1)	(99)	(198)	(124)	-	394	296
34													
35	Mid-Year Balance	(L.29+L.33)/2	263	345	246	148	49	(50)	(149)	(161)	(62)	263	345
36													
37	Demand Side Management Program Costs												
38	Balance at Beginning of Year		398	-	-	-	-	-	-	-	-	398	-
39	Add: Costs		136	-	-	-	-	-	-		-	136	-
40	Less: Transfer to Rate Base		(534)	-	-	-	-	-	-	-	-	(534)	
41	Less: Write Off									-	-	-	-
42	Balance at End of Year		-	-	-	-	-	-	-	-	-	-	-
43													
44	Mid-Year Balance	(L.38+L.42)/2	199	-	-	-	-	-	-	-	-	199	-
45													
46	Pension Deferral												
47	Balance at Beginning of Year		-	(77)	-	(71)	(154)	(223)	(265)	(351)	(223)	-	(77)
48	Add: Costs		(154)	-	(148)	(160)	(146)	(119)	(163)	(94)	-	(154)	-
49	Less: Write-off		77	77	77	77	77	77	77	223	223	77	77
50	Balance at End of Year		(77)	-	(71)	(154)	(223)	(265)	(351)	(223)	-	(77)	-
51													
52	Mid-Year Balance	(L.47+L.50)/2	(39)	(39)	(35)	(112)	(188)	(244)	(308)	(287)	(111)	(39)	(39)
53													
54	EPA/IPP Legal Costs												
55	Balance at Beginning of Year		-	-	-	-	-	146	209	187	94		
56	Add: Costs		-	-	-	-	146	63	(22)	-	-		
57	Less: Write-off		-	-	-	-	-	-	-	(94)	(94)		
58	Balance at End of Year						146	209	187	94	-		
59													
60	Mid-Year Balance	(L.55+L.58)/2	-	-	-	-	73	178	198	141	47	-	-

ATCO Electric YUKON

September 28, 2023 AEY-UCG-054

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-054

Reference: July 7,2023 Application, page 8-8 and 8-9; Working Capital

Request:

(a) Explain how working capital impacts rate base and revenue requirement for each of the test years.

(b) Explain the concepts of Common Equity (retained earnings component) and Common Equity (dividend component).

(c) Provide and explain the components of dividend common equity for AEY. How have these have been instructed by earlier Board decisions?

(d) Break down the working capital costs of test years from table 8.7 for each component listed on page 8-8.

Response:

(a) Working capital is the average short term capital requirements to fund AEY's short term assets (Accounts Receivable and Inventories) net of short term liabilities (Accounts Payable). Typically, the payment of expenses occurs in advance of the receipt of revenues and this balance is a component of the company's total rate base and is included in AEY's cost of capital.

(b) The retained earnings component of Common Equity is the undistributed utility earnings (or deficit) accumulated from operations. Retained earnings increases when there are positive utility earnings and decreases when dividend is declared or there are negative earnings. The dividend component of Common Equity is the return distributed to shareholders.

(c) AEY's last approved common equity ratio is 40 percent in the 2016-2017 GRA. AEY's dividend distribution has followed and maintained the Board-approved 40 percent structure in common equity.

(d) The working capital breakdown was included in the Excel workbook as part of AEY's Application filed on July 7, 2023, and is also included in the Excel workbook with the updated schedules filed on September 11, 2023, with AEY's Depreciation Study. A copy of Schedule 8.10 has also been reattached in AEY-UCG-054(d) Attachment 1.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Computation of Allowance for Working Capital
($000)

Line No.	Description	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	Operations and Maintenance	S.1.1 L.9	11,141	11,884	11,114	11,104	11,966	13,814	14,794	14,609	14,863	11,630	11,754
2	Purchase Power		25,135	27,524	27,674	27,419	28,825	29,432	29,498	29,778	30,961	25,229	26,404
3	Diesel Fuel	S.1.1 L.8	5,363	5,571	5,403	5,432	5,709	5,353	5,766	9,181	9,023	5,257	5,334
4	Property Taxes	S.1.1 L.10	253	253	264	277	277	267	275	285	292	262	267
5	Net O&M		41,892	45,232	44,455	44,231	46,776	48,866	50,334	53,853	55,139	42,377	43,759
6	O&M Lag Days		4	4	4	4	4	4	4	4	4	4	4
7	Operating Expenses Working Capital		477	515	506	504	533	557	573	614	628	483	499
8													
9	Tax Installments		0	0	0	0	(257)	(1,877)	(764)	(218)	(1,134)	0	0
10	Income Tax Installment Lag Days		22	22	22	22	22	22	22	22	22	22	22
11	Tax Installments Working Capital		0	0	0	0	(15)	(113)	(46)	(13)	(68)	0	0
12													
13	Income Taxes Receivable (Payable)		0	0	0	(268)	(776)	65	722	2,045	0	0	0
14	Tax Receivable Lag Days		204	204	204	204	204	204	204	204	204	204	204
15	Taxes Payable Working Capital		0	0	0	(150)	(434)	36	404	1,143	0	0	0
16													
17	Inventory (Three-Year Average)		2,175	2,215	2,386	2,458	2,565	2,584	3,102	2,750	2,812	2,123	2,123
18													
19	GST Impact on Working Capital	S.8.11 L.36	151	130	124	130	159	170	182	147	183	134	129
20													
21	Return - Long Term Debt		3,182	3,191	3,200	3,132	3,002	2,999	3,136	3,455	3,693	3,235	3,319
22	Combined Long Term Debt Lag Days		(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
23	Long Term Debt Working Capital		(453)	(455)	(456)	(446)	(428)	(427)	(447)	(492)	(526)	(461)	(473)
24													
25	Return - 50% of Common Equity		2,049	2,609	2,645	2,757	2,791	2,615	2,652	2,423	2,704	1,776	1,886
26	Dividend Lag Days		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
27	Common Equity (Dividend) Working Capital		(22)	(29)	(29)	(30)	(31)	(29)	(29)	(27)	(30)	(19)	(21)
28													
29	Return - 50% of Common Equity		2,049	2,609	2,645	2,757	2,791	2,615	2,652	2,423	2,704	1,776	1,886
30	Depreciation Lag Days		42	42	42	42	42	42	42	42	42	42	42
31	Common Equity (Retained Earnings) Working Capital		236	300	304	317	321	301	305	279	311	204	217
32													
33	Net Depreciation		4,336	4,590	4,755	4,747	4,953	5,073	5,310	7,231	8,691	4,342	4,661
34	Depreciation Lag Days		42	42	42	42	42	42	42	42	42	42	42
35	Depreciation Working Capital		499	528	547	546	570	584	611	832	1,000	500	536
36													
37	Working Capital		3,062	3,206	3,383	3,330	3,240	3,662	4,655	5,235	4,315	2,964	3,010

ATCO Electric YUKON

September 28, 2023 AEY-UCG-055(1)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-055(1)

Reference: July 7,2023 Application, page 8-8 #35; Working Capital

AEY states: "*To determine the working capital for the test periods, AEY completed a review of the components of each of the items in necessary working capital to ensure that the nature of the revenue/expenses included in each category had not changed materially since the previous lead/lag study. Based on this review, AEY has not identified any material updates required to the lead/lag days as previously determined and approved in Board Order 2017-01.*

Request:

(a) Provide all details of the lead lag analysis conducted by AEY for this application as well as the referenced previous lead lag study.

Response:

(a) Please refer to AEY-UCG-055(1) Attachment 1 for the lead-lag study conducted for AEY's 2016-2017 GRA, approved in Board Order 2017-01. Regarding AEY's 2023-2024 GRA, AEY determined that there were no material changes in the types of revenues and expenses or in payment terms. As a result, AEY did not conduct a full lead-lag study for the purpose of this Application, as it was determined to be unnecessary.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Lead/Lag Study

Line No.		Days
1	Average lag in revenue collection:	41.87
2	Less: average lag in payment of operating expense:	37.71
3	Net O&M lag days	4.16
4		

Lead/Lag on Revenues

Line No.	Revenue Type	2015 Revenue ($000)	Lag Days	Weighted Revenue ($000)
5				
6				
7				
8				
9	Residential	22,404	42.83	959,669
10	Commercial	27,121	41.12	1,115,229
11	Street & Sentinel Lighting	1,242	40.84	50,724
12	Secondary	890	41.89	37,284
13	Revenues included in Lead/Lag Study	51,657	41.87	2,162,906
14				
15				

Lead/Lag on Operating Expenses

Line No.		2015 Operating Expenses ($000)	(Lead)/Lag Days	Weighted Revenue ($000)
16				
17				
18				
19				
20	Salary and wages	5,710	31.60	180,409
21				
22	Fuel	6,621	47.94	317,427
23				
24	Purchased Power	30,373	37.68	1,144,397
25				
26	Property taxes	256	2.90	743
27				
28	Other Operating Expenses			
29	Insurance	90	(135.90)	(12,231)
30	Intercompany	961	31.86	30,618
31	IT Services	481	41.40	19,913
32	Employee travel and expenses	206	36.77	7,574
33	Other	4,168	36.93	153,918
34		5,906	33.83	199,793
35				
36	Operating Expenses included in the Lead Lag Study	48,866	37.71	1,842,769

ATCO Electric YUKON

September 28, 2023 AEY-UCG-055(2)

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-055(2)

Reference: July 7,2023 Application; Working Capital

Request:

(a) Has there been deferred costs incurred with any studies? Give details.

(b) Please explain why there are no DSM-related costs forecast for 2023 and 2024.

(c) Is AEY still practicing DSM? Explain.

Response:

(a) There have not been any deferred costs incurred with respect to studies in this Application.

(b-c) Please refer to the response to AEY-JM-020(a) and AEY-JM-020(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-056

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-056

Reference: July 7,2023 Application, section 8 Attachment 8.1

AEY has submitted an assessment by Concentric Energy Advisors of the business and financial risk of AEY to FortisBC Energy as well as other regulated electricity and gas distribution utilities in Canada and the business and financial risk of AEY compared to AEY's risk profile at the time of its 2008 GRA filing.

Request:

(a) Provide details and documentation related to the RFP process followed by AEY before hiring Concentric to undertake the business and financial risk study.

(b) Confirm that in its Board Order 2014-06 (dated April 23, 2014), the YUB determined that AEY did not qualify for a risk premium over the BCUC benchmark utility. Please explain where this is discussed in the Concentric report.

(c) Explain how each of the utilities mentioned on page 3 of the report are regulated (i.e., cost of service, performance based, etc.)

(d) Explain why AEY claim they are at risk when they have exceeded the prescribed rate of return sanctioned by the YUB since the last GRA.

Response:

(a) Pursuant to YUB Rule 14(4)(a), AEY declines to provide the requested information on the basis that it is not relevant to this Proceeding. AEY will only seek recovery of costs in accordance with the scale of costs as prescribed by the Board.

(b) Confirmed, with regard to Board Order 2014-06; please refer to page 2 of Concentric's report. Also as discussed on that page, in the more recent Board

Order 2017-01, the YUB found that AEY had provided sufficient evidence to support a risk premium of 25 basis points over the BCUC benchmark.

(c) Concentric has added a column to Figure 1 of its report which provides the requested information. The information for FortisBC Energy and FortisBC Electric has also been updated to reflect the BCUC's recent decision in the GCOC (Stage 1) Proceeding.

Comparators Type of Regulation

	Awarded ROE	Equity Ratio	Business Risk Compared to AEY	Type of Regulation
ATCO Electric Yukon (current)	9.00%	40.0%	N/A	COS
Canadian Electric & Gas Utilities				
FortisBC Energy	9.65%	45.0%	Lower	PBR
FortisBC Electric	9.65%	41.0%	Lower	PBR
Ontario Electric Distributors	9.36%	40.0%	Lower	PBR
Newfoundland Power	8.50%	45.0%	Lower	COS
Maritime Electric Company Ltd	9.35%	40.0%	Similar	COS
ATCO Electric Distribution[1]	8.50%	37.0%	Lower	PBR
Pacific Northern Gas-West	9.50%	46.5%	Higher	COS
2022-2023 U.S. Electric Utilities				
Electric T&D Utilities	9.56%	51.6%	Lower	Various

(d) The cost of capital is a forward-looking concept, and the evaluation of business risk is generally a qualitative analysis. The fact that a company has generally been able to earn its authorized ROE in the past does not necessarily indicate whether it will be able to do so in the future, as operating conditions and risks change over time. Further, a utility that earns its authorized ROE does not necessarily have low business risk. The authorized ROE provides a utility the opportunity to earn that return, not a guarantee that it will do so. Concentric has provided evidence that

[1] Alberta 2023 Generic Cost of Capital Decision is expected October 2023.

AEY's very small size magnifies other business risks for the Company and that investors require a higher return to compensate for the risks associated with that small size.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-057

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-057

Reference: July 7,2023 Application, page 9-1; Capital Additions

AEY states; *"AEY is seeking Board approval of the 2016-2022 actuals on a final basis and approval of its forecasts for 2023 and 2024."*

Request:

(a) Explain how AEY has already claimed these capital expenditures and additions for the non-test years since last GRA and now ask for approval? Is this not retroactive rate making?

Response:

(a) To clarify, AEY has not claimed these capital expenditures and additions for non-Test Years. Since there has not been an application, since the 2016-2017 AEY GRA, AEY has included actuals from 2016 to 2022 in the AEY 2023-2024 GRA for Board approval. As stated in AEY-UCG-065(b), consistent with generally accepted utility practices, AEY has included all utility capital that is in service within its opening rate base, net of accumulated depreciation expenses. AEY has continued to operate and manage its capital program within the funding included in rates approved in the 2016-2017 GRA and has reported the annual changes to rate base through the Annual Filings, which are filed with the Board each year. AEY notes that the net cost of capital has been included in the 2023-2024 Revenue Requirement, on a prospective basis, and AEY is not seeking retroactive recovery of returns or depreciation expenses incurred for the period since its last GRA. Opening rate base continues to be within scope for the Board's review and approval as part of this Application.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-058

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-058

Reference: July 7,2023 Application, page 9-1; Capital Additions

AEY in #3 and 4 rationalizes the need for extreme capital expenditures and additions are caused by growth in the Yukon because of rapidly increasing population.

Request:

(a) Provide documented evidence of this population growth.

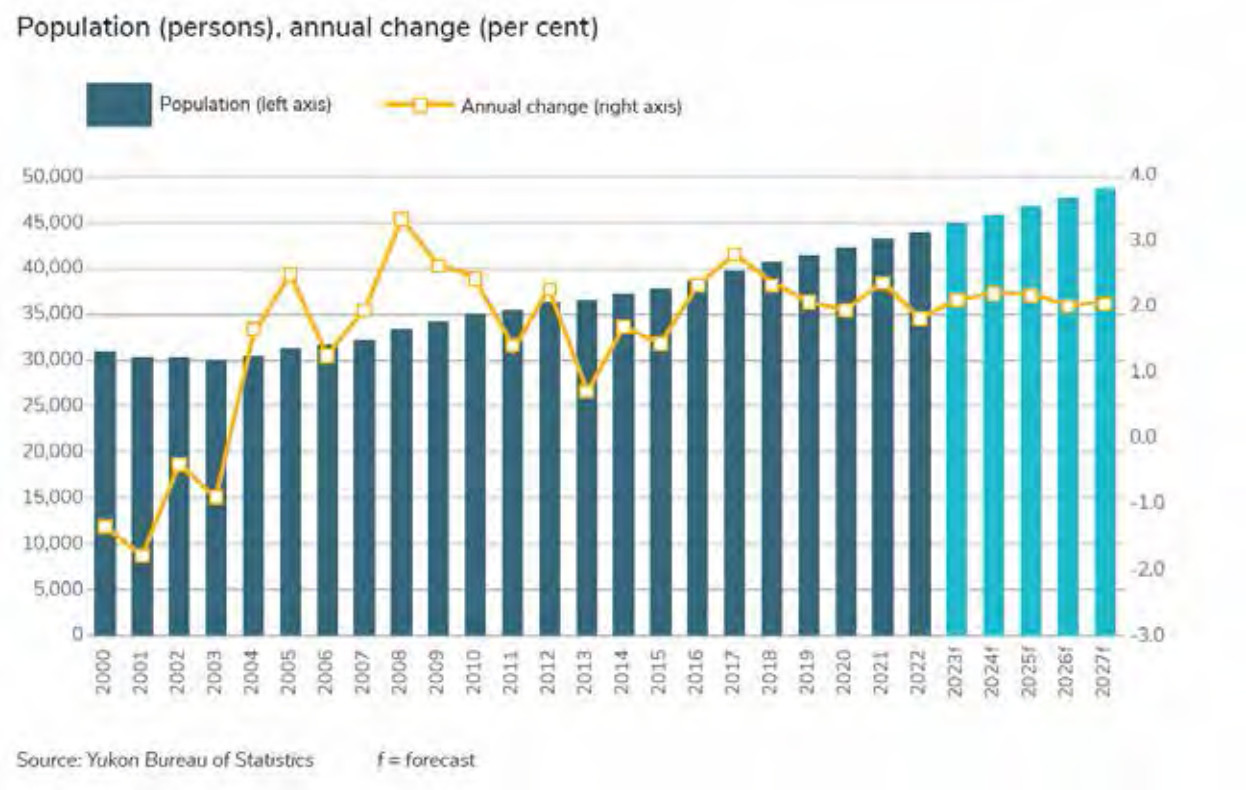
(b) Explain if this population growth has not been relevant for each of the non-test years from 2018 to 2022. Explain why AEY has not progressively rectified the need to upgrade during this time frame.

Response:

(a) The chart below, obtained from the 2023-2024 Fiscal and Economic Outlook,[1] shows the increase in population from 2000 until 2027 (forecast) compared with the annual change. According to the report, the Yukon's population has grown just over 44 percent over the past 20-years. This growth was second only to Alberta (45.2 percent) among all provinces and territories and was well ahead of the national average growth of 24 percent. The population is projected to continue to increase by an average of 2.1 percent per year and by 2027, the Yukon's population is expected to be near 49,000.

[1] https://yukon.ca/en/2023-24-fiscal-and-economic-outlook, PDF p. 17.

Chart 1: Yukon Population Growth



(b) Population growth is a relevant consideration for all years as AEY has a mandate to provide safe and reliable service and has undertaken capital projects to ensure this is met. The growth in population has also led to increased work in New Extensions as can be seen in Schedule 9.1, Line17, which has costs for all years in 2018 – 2022 greater than the 2016-2017 Test Period. With the recent rapid growing population, there is additional load causing strain on the distribution network. This additional load on the current infrastructure has increased the risk to the network's reliability, and capital distribution improvements are required to address system concerns in a planned manner. AEY's capital plans focus on system performance, reliability, and safety. Assets that are shown to have vulnerability are prioritized to be replaced or rebuilt. AEY completes proactive planning for system improvement and does not proceed with the work until required by system conditions. Furthermore, there are factors that are outside of

AEY's control that can impact projects, such as weather, supply chain and global events. These factors can lead to either the advancement or delay of capital projects, causing the actual capital expenditures to fluctuate from year to year. For example, the restrictions imposed under the pandemic greatly impacted capital projects, as many could not proceed in 2020 and 2021, which resulted in a large uptick in capital additions in 2022.[2]

[2] 2023-2024 AEY GRA, Section 9.1, PDF p. 173.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-059

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-059

Reference: July 7,2023 Application, pages 9-1 and 9-2; Capital Additions

AEY states: "*To support the capital spend, AEY provided Business Cases related to capital expenditures as follows: Business Cases are provided for 2016-2017 where variances from actual to approved were both greater than 100 percent and greater than $100,000; Business Cases are provided for capital expenditures for 2018-2022 that exceeded $100,000; Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period*."

Board Order 2014-06, Reasons for Decision, page 64

"However, YECL needs to provide information in relation to project cost overruns in its application. ***Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns.*** *For clarity, for project costs overruns that are (collectively) 100 percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the expenditure was not foreseen and the actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL in future applications is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project."*

Board Order 2009-2, page 37

> *"The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests.* ***Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures.****"*

Request:

(a) Has AEY given reasons for all cost overruns? Explain using various Business Cases.

(b) Provide business case type information in relation to projects forecast to be added to rate base in 2023 and 2024 where actual total project costs are forecast to be $100,000 greater than originally estimated.

(c) Has AEY provided the Board with an annual update on its capital plans and expenditure? Explain with references.

(d) Explain why AEY considers "major capital projects" to only be those projects costing $500,000 or greater. Page 9-8, #21

(e) Has the Board ever given a defined threshold to what it considers AEY Capital Expenditures and Additions spending should follow? Explain giving references.

(f) Does AEY believe that a utility with a $100 million rate base (such as AEY) should have the same expenditures threshold to define a major project as a utility with a $226 million rate base (such as YEC)? Explain

Response:

(a) Please refer to Business Cases #01, 02, and 03 for the projects in 2016-2017 that have cost overruns that are greater than $100,000 and 100 percent of the approved costs.

(b) AEY has complied with Board Order 2009-02 for Business Cases in the Test Period. AEY was directed in Board Order 2009-02 direction #19 to provide Business Cases for major capital projects in the next GRA. AEY did so using

$500,000 as the threshold for major capital projects. In Board Order 2014-06 Section 14.1, the Board stated that this direction #19 has been complied with.

(c) Yes, AEY includes the current year additions in the Property, Plant and Equipment section of the Annual Filing and the following year's capital forecast is provided in paragraph 6 of the Statutory Declaration included in the annual filing.

(d) Please refer to the response to part (b) above.

(e) Please refer to the response to part (b) above.

(f) AEY considers the $500,000 threshold for major capital projects established in Board Order 2009-02 to remain appropriate.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-060

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-060

Reference: July 7,2023 Application, pages 9-1 to 9-7; Capital Additions

Request:

(a) Provide an itemized list of miscellaneous capital expenditures greater than $100,000 for Generation Improvements Table 9-2, Distribution Improvements Table 9-4, New Extensions Table 9-3, Street and Sentinel Lights Table 9-5 , Meters Table 9-6, and General Property&Equipment Table 9-7as per Board Order Board Order 2009-8, page 37

> *"Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:*
>
> - *descriptions of the project*
> - *economic analysis including preliminary engineering estimates*
> - *discussion of alternatives and how the chosen option was determined*
> - *discussion of the risks of proceeding with the chosen alternative*
> - *discussion of risks of not proceeding with the chosen alternative; and*
> - *discussion of assumptions included in the business case including escalation*
> - *factors, loading, financial measures, term of project and associated ancillary costs."*

(b) For any of the itemized list above show which projects have a business case presented and which not.

(c) For any of the itemized list not demonstrating a business plan, then we now request this information.

(d) Provide a detailed description and detailed breakdown of the total costs incurred in all the generation plant projects where actual expenditures are over $100,000, when these costs were incurred and when these projects are proposed to be added to rate base. Provide supporting analysis in Excel spreadsheet.

(e) What were the average annual capital expenditures on generation plant projects for the period 2017 -2022?

(f) Provide a detailed description and detailed breakdown of the total costs incurred in all new extension projects where actual expenditures are over $100,000, when these costs incurred and when these projects are proposed to be added to the rate base. Please provide the supporting analyses in an Excel spreadsheet.

(g) What were the average annual capital expenditures on new extensions projects for the period 2017-2022?

(h) Provide a detailed description and detailed breakdown of the total costs incurred in all the distribution improvements projects where actual expenditures are over $100,000, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(i) What were the average annual capital expenditures on distribution improvements projects for the period 2017-2022?

(j) provide a detailed description and detailed breakdown of the total costs incurred in all street and sentinel lights projects where actual expenditures are over $100,000, when these costs were incurred and when these projects are proposed to be added to the rate base. Please provide the supporting analyses in an Excel spreadsheet.

(k) What were the average annual capital expenditures on new street and sentinel lights projects for the period 2017-2022?

(l) provide a detailed description and detailed breakdown of the total costs incurred in all the meter's projects where actual expenditures are over $100,000, when these costs were incurred and when these projects are proposed to be added to the rate base. Please provide the supporting analyses in an Excel spreadsheet.

(m) What were the average annual capital expenditures meters projects for the period 2017-2022?

(n) Provide a detailed description and detailed breakdown of the total costs incurred in all the generation plant and equipment projects where actual expenditures are over $100,000, when these costs were incurred and when these projects are proposed to be added to rate base. Please provide the supporting analyses in an Excel spreadsheet.

(o) What were the average annual capital expenditures on generation plant and equipment projects for the period 2017-2022?

Response:

(a) All capital expenditures summarized in Tables 9-2 through 9-7 of the Application can be found in the 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2. For example, on Table 9-2, the total generation matches the total on Schedule 9.2, line 131, with all the projects that make up that total listed from lines 2 through 129.

(b) Please refer to AEY-YUB-046(a) Attachment 1 for an itemized list showing which projects have a Business Case and which do not.

(c) As outlined in the Application,[1] AEY has provided Business Cases related to capital expenditures as follows:

a. Business Cases are provided for 2016-2017 where variances from actual to approved were both greater than 100 percent and greater than $100,000;[2]

b. Business Cases are provided for capital expenditures in 2018-2022 that exceeded $100,000;[3]

c. Business Cases are provided for projects planned to be undertaken in 2023-2024 where capital expenditures are forecast to be $500,000 or greater;[4] and

1 2023-2024 AEY GRA, Section 9.1, Para. 5, PDF p. 174.
2 Board Order 2014-06.
3 Board Order 2014-06.
4 Board Order 2009-02.

d. Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period, but capitalized expenditures are forecast subsequent to the Test Period.

AEY has complied with the Board's prior direction on the threshold for providing Business Cases and is not prepared to provide additional Business Cases.

(d) Please refer to Schedule 9.2, lines 1 through 131, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(e) The average annual Generation capital expenditures for 2017-2022 is $2,261,511.[5]

(f) Please refer to Schedule 9.2, lines 141 through 171, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(g) The average annual New Extension capital expenditures for 2017-2022 is $4,156,818.[6]

(h) Please refer to Schedule 9.2, lines 181 through 307, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(i) The average annual Distribution Improvement capital expenditures for 2017-2022 is $2,623,224.[7]

[5] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 131, average of 2017 through 2022.
[6] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 171, average of 2017 through 2022.
[7] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 307, average of 2017 through 2022.

(j) Please refer to Schedule 9.2, lines 309 through 336, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(k) The average annual Street and Sentinel Lighting capital expenditures for 2017-2022 is $994,193.[8]

(l) Please refer to Schedule 9.2, lines 338 through 339, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(m) The average annual Meters capital expenditures for 2017-2022 is $81,197.[9]

(n) Please refer to Schedule 9.2, lines 351 through 428, for a description and breakdown of the total costs incurred and when these costs were incurred. These projects will be added to rate base when they go into service.

(o) The average annual General Plant and Equipment capital expenditures for 2017-2022 is $1,611,991.[10]

[8] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 336, average of 2017 through 2022.
[9] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 341, average of 2017 through 2022.
[10] 2023-2024 AEY GRA Regulatory Schedules, Schedule 9.2, Line 428, average of 2017 through 2022.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-061

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-061

Reference: July 7,2023 Application, pages 9-4; Distribution Improvements

AEY states: "*In addition to the above, AEY tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.*"

Request:

(a) Does this statement mean the same as AEY Key Performance Indicators? If yes, explain where in these documents does it contains distribution system performance.

Response:

(a) Yes. The referenced statement is referring to the KPI's where the SAIFI and SAIDI scores are being considered when developing with the Distribution System capital forecast. Please refer to Section 11 – Attachment 11.2 of the Application for further details on how the KPI are used in Corrective System Performance.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-062

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-062

Reference: July 7,2023 Application, pages10-1 Income Tax

AEY states: "*The increase in income tax expense between 2023 and 2024 are mainly due to lower CCA deductions as a result of CIS preplacement cost fully deducted in 2023*."

Request:

(a) Since the ATCO CIS system replacement to Oracle CCS, is an ongoing project from 2021 and will/has cost some $8.403 million, why was some of these costs not deferred for the 2024 test year taxation CCA deductions?

Response:

(a) AEY has applied the full CCA tax deduction for the ATCO CIS Replacement in a single year to ensure customers receive the full benefit immediately.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-063

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-063

Reference: As per Board Order Board Order 2009-8, page 37

"Further, in future GRA applications, the Board directs YEC to include business cases for major capital items, including electronic models. Business cases will include:

- *descriptions of the project*
- *economic analysis including preliminary engineering estimates*
- *discussion of alternatives and how the chosen option was determined*
- *discussion of the risks of proceeding with the chosen alternative*
- *discussion of risks of not proceeding with the chosen alternative; and*
- *discussion of assumptions included in the business case including escalation factors, loading, financial measures, term of project and associated ancillary costs."*

UCG will be referencing these conditions for all the IRs on AEY Business Cases (BCs) #s 1-41.

Reference: *McIntyre Subdivision Replacement Project Update 2016-2017 BC #01Cost $7.314 million.*

Request:

(a) Since this project started in 2013, provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Explain how the scope of this project has changed since 2013 and why this was not foreseen in the detailed engineers report on risks on this project. Provide preliminary engineers report with risks and cost risks identified.

(c) Give details of how the updated cost performance of $7.314 million compared with the original engineers' scope, report, and estimated costs. Provide all the details.

Response:

(a) The Business Case provided by AEY was drafted with direct input from qualified engineers who were involved with the project. The Business Case includes the drivers and need for the work as well as the actual costs of the work completed. The original forecast for this project was approved by the Board in the 2016-2-017 GRA and can also be found in Schedule 9.2 from that GRA. Refer to Appendix #8 2016--2017 GRA for details from previous Application.

(b) Please refer to Business Case #1 for an explanation of changes to project scope. Please also refer to Attachment 11.4 of AEY's 2016-2017 GRA for further explanation on the reasons for the previous scope changes. The project scope and estimate were developed from knowledge of work in and around this area. Until the civil construction started, AEY was not certain of the exact soil conditions. As the stages were completed AEY applied this experience for estimating further work.

(c) Appendix #8 of AEY's 2016-2017 GRA estimates a total completed cost of $5.129 million. The new estimate is $7.314 million in Business Case #1. The scope changes are explained in Business Case #1, Appendix #8 of AEY's 2016-2017 GRA, and Attachment 11.4 of AEY's, 2016-2017 GRA.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-064

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-064

Reference: Replace Ditch #1 Spillway BC #02 The project took 12 weeks to complete and a cost of $262,000 net of the insurance proceeds.

Request:

(a) Is this job complete?

(b) How will the above referenced costs be handled by AEY?

(c) Is AEY asking for a rate base addition for these costs after suggesting all costs would be borne by AEY? Explain.

Response:

(a) The project was completed in 2016.

(b) The $100,000 deductible is included in the Reserve for Injuries and Damages. The like for like replacement costs are offset by insurance proceeds. For the treatment of the current net book value of betterment costs, please refer to the response to AEY-UCG-065(b).

(c) In the Business Case where AEY stated that "The upgraded structure (betterment) costs will be borne by AEY, while like-for-like costs will be borne by insurance less a $100,000 deductible", AEY was referring to the Utility itself and would be applying for these costs in this Application. These are costs to improve the spillway and extend its useful life and should be included in rates whereas the insurance claim portion to return the spillway to its original state is covered by proceeds from the insurance claim.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-065

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-065

Reference: 400 Amp Regulators at Logan Substation BC #03 Cost $174,000.

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Please refer to the response to AEY-UCG-063(a).

(b) Consistent with generally accepted utility practices, AEY has included all utility capital that is in service within its opening rate base, net of accumulated depreciation expenses. AEY has continued to operate and manage its capital program within the funding included in rates approved in the 2016-2017 GRA and has reported the annual changes to rate base through the Annual Filings, which are filed with the Board each year. AEY notes the net cost of capital has been included in the 2023-2024 Revenue Requirement on a prospective basis and AEY is not seeking retroactive recovery of returns or depreciation costs incurred for the period since its last GRA. The opening rate base continues to be within scope for the Board's review and approval as part of the Application.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-066

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-066

Reference: S17 HLC Breaker Replacement BC #04 Cost $130,000.

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) The Business Case provided by AEY was drafted with direct input from qualified engineers who were involved with the project. The Business Case includes the drivers and need for the work as well as the actual costs of the work completed.

As this project was completed outside of the Test Period, there is no Board approved forecast.

(b) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-067

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-067

Reference: Extend Three-Phase Line on Hot Springs Road BC #05 12. The total Cost of this project is $393,935 and was completed in 2019.

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Please refer to the response to AEY-UCG-066(a).

(b) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-068

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-068

Reference: Partial Reconductor Mayo Road, BC #06. Cost $426,000 target completion 2022.

Request:

(a) Is this project now complete and at what final cost?

(b) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(c) Was this cost already added to the rate base? If yes, when and under what authority?

Response

(a) This project was completed in 2022, and the final cost per the business case is $426,000.

(b) Please refer to the response to AEY-UCG-066(a).

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-069

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-069

Reference: Replace Watson Lake Generating Unit. BC #07 Total Cost $5.585 million completion date January 2021.

Request:

(a) Is this project now complete and at what final cost?

(b) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(c) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Yes. The actual costs of $5.585 million are shown in Table 2 of the Business Case.

(b) Please refer to response to AEY-UCG-66(a).

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-070

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-070

Reference: Installation of Remote Electronic Modular Control Panel Watson Lake Unit 4, BC #08. The project went into service Q3 2021 and cost $151,000.

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.
(b) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Please refer to the response to AEY-UCG-066(a).

(b) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-071

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-071

Reference: Upgrade Regulators at Laberge Substation, BC 09. "19.Alternative 1 is the recommended solution: however, with uncertainty on when new 25kV can be built given lead times and land procurement. "

Request:

(a) Is this project now complete and at what was the total final cost?

(b) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(c) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) The project is complete with a total final cost of $129,000.

(b) Please refer to the response to AEY-UCG-066(a). Please also refer to AEY-UCG-071(b) Attachment 1.

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric
YUKON

Whitehorse North 25kV System Improvement

Technical Appendix

	Name	Signature	Date
Prepared by:	Ryan Grams		2019-10-01
Reviewed by:	John Williams		
Reviewed by:			
Reviewed by:			

Revision History

Revision	Date	Editor	Comments
R1.0		Ryan Grams	Document Created

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1. Problem Statement

The Whitehorse North 25kV system has significant load growth expected over the next 5 years. At present, there is a contingency scenario that cannot be adequately addressed. As the load grows, substation regulator capacities will be exceeded, rural customer voltages will drop below acceptable levels and the number of failed contingency scenarios will increase. The projected load growth must be planned for and accommodations implemented to ensure continued safe and reliable operation of the Whitehorse power system.

2. Background

Load growth continuously pushes a power system closer to its capacity limits. This leads to electrical equipment being operated past its capacity, which compromises the safety and reliability of the network.

To understand the problem statement in more detail we can consider how the North 25kV System is configured, how the load has grown in the past, how we expect it to grow in the future, and at what point the load is higher than the system's capacity.

2.1 System Configuration

During normal operation the North 25kV System is supplied power from a single transmission substation source (S164), through two sub-transmission substations (Laberge Substation and Whistlebend Substation), and out to both urban and rural customers in the northern Whitehorse area and along the North Klondike and Alaska highways. At each voltage level, there are interconnection points between parallel feeds, allowing for a variety of potential system configurations.

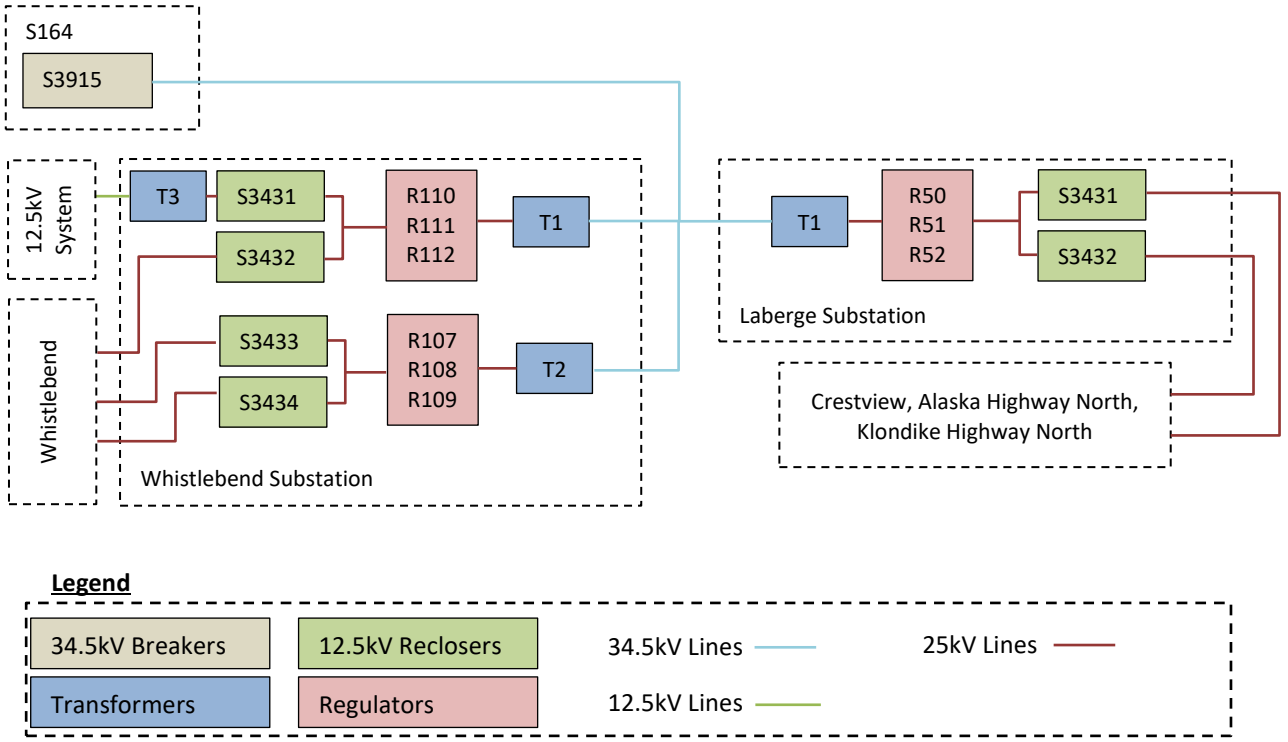


Figure 1 - Whitehorse North 25kV System During Normal Operation

2.2 Historical Load Growth

Between 2016 and 2018, the total peak loads measured at the transmission substations in the Whitehorse area (S150, S164, S170) increased at an average of 2.99% per year. Therefore, unless they are associated with known projects/load additions, the average load growth across the system will be assumed at 3% per year. A 6-year planning period was selected as Whistlebend subdivision is expected to grow at a rate of 1MW/year as stages 4 to 7 are constructed and commissioned leading up to the end of 2025. Additionally, a load addition of at least 1MW is planned along Takhini Hot Springs Road as part of an upcoming expansion at the hot spring's facility in 2021.

2.3 Forecasted Load Growth

Currently the Whistlebend subdivision is undergoing extensive construction and is expected to complete Stage 7 by the end of 2025. This growth will dramatically increase the loading on the Whistlebend substation, therefore the loading on Whistlebend's feeders has been forecast independent of the 3%/year calculated for the rest of the city. The Whistlebend subdivision loading for the planning period was developed based on peak Stage 1-3 loading, forecast customer count and the estimated construction schedule up to the end of Stage 7. The complete forecast for each of the feeders in Laberge and Whistlebend is shown in the figure below.

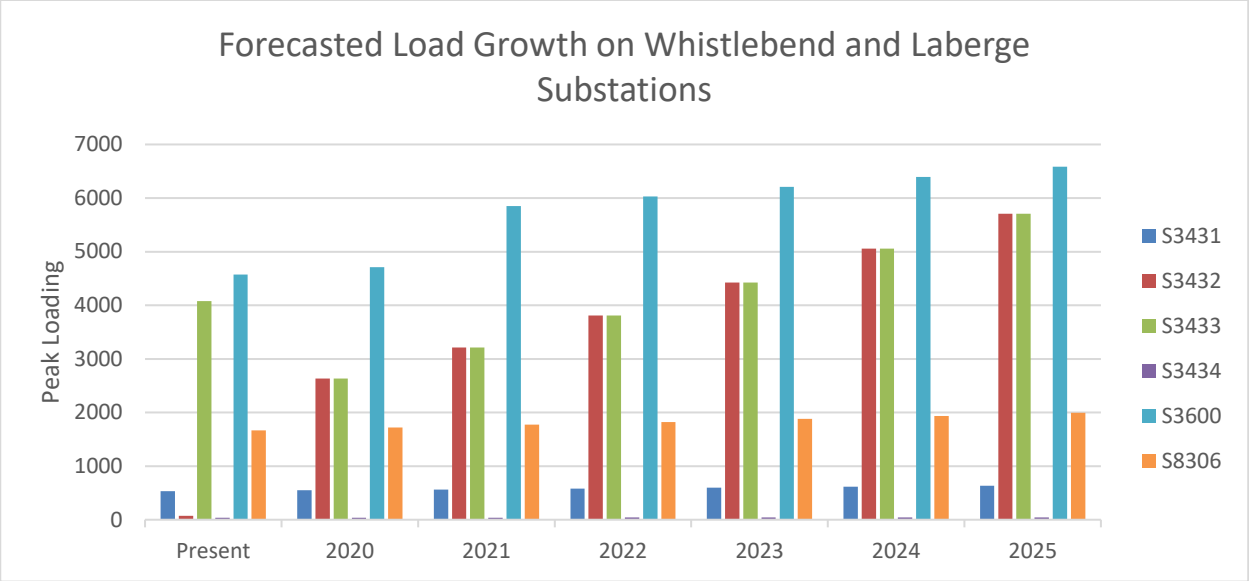


Figure 2 - Forecast Load Growth for Whistlebend and Laberge Substations until the completion of Whistlebend Stage 7.

* Load growth for Whistlebend Subdivision is forecast to be redistributed evenly over reclosers S3432 and S3433 in future years, instead of only loading S3433 as is the present arrangement.
**The 1MW addition to S3600 in year 2020-2021 is due to a planned load addition at Takhini Hot Springs

3. Evaluation Criteria

3.1 Regular Operation

No components of the system should have load in excess of their nameplate rating during peak load conditions.

To ensure safe operation and maintain the expected lifespan of the electrical system, it is important to operate equipment within nameplate ratings at all times. Power transformers are an exception to this rule, as they can be operated above their nameplate apparent power ratings depending on ambient temperature and duration of overload. This overloading will be evaluated further in Section 5.4.

Specific to the Whitehorse North 25kV system, the major system limitations that require adequate planning are as follows:

- Whistlebend Substation max loading of 10MVA on each of the 34.5/25kV transformers
- Laberge Substation max loading of 10MVA on 34.5/25kV transformer
- S164 Substation max loading of 25MVA on 138/34.5kV transformer
- 266 MCM sub-transmission line (6L16, 6L17) max loading of 38 MVA

During normal operation:

- *Maximum 25kV bus voltage at transmission POD substations -> 1.04 p.u.*
- *Minimum primary voltage at urban residential customers with multiple customer secondaries -> 0.97 p.u.*
- *Minimum voltage at all other points on distribution feeders -> 0.95 p.u.*

To provide safe and reliable power to ATCO Electric Yukon's (AEY) customers and to prevent unnecessary damage to customer electrical equipment, the system per-unit voltage must remain within the limits defined in AEY's standards.

3.2 Load Addition

Substations and main feeders should have sufficient reserve capacity.

Reserve capacity allows routine load additions/growth and provides lead time for system upgrade projects to take place before critical thresholds are exceeded. Sufficient reserve capacity is assed by looking at the peak loading and forecasted load growth for each feeder within the planning period planning window.

The Whitehorse North 25kV System has significant load growth planned in the next 6 years largely due to the development of the Whistlebend subdivision. Based on expected customer additions and planned projects within that area, the Whistlebend subdivision growth will be forecast independently of the overall Whitehorse load growth average of 3% per year.

3.3 Contingency

The peak load on major equipment (e.g. transformers, regulators, reclosers) in systems that warrant loop connections should be able to be transferred to another power source.

Contingency planning is required to maintain service to customers during planned or unplanned outages resulting from maintenance work, system faults, or equipment failures. When a portion of the system needs to be removed from service, any downstream load will lose power unless the removed section can be isolated and downstream customers transferred to an alternate source.

For this to be a viable tool for maintaining system reliability, the alternate source must be able to handle the load addition in a worst-case scenario. This would typically be the loss of major equipment such as transformers, regulators, or reclosers during peak load. For low customer-density areas or in rural areas, the system is typically composed of radial feeds. Radial networks do not have a loop connection with a normally-open point, therefore the outage scenario is managed through alternative methods including portable generation or quick repair times.

In the Whitehorse North 25kV system, contingency situations are mainly addressed through interconnection points between parallel sources on both the 34.5kV subtransmission lines and the 25kV distribution lines. The following contingency situations require additional attention as

they address scenarios that if not properly planned, could result in an outage to a large group of customers:

- Loss of 34.5kV source to Laberge and Whistlebend substations (sub-transmission line 6L17)
- Loss of a single 34.5/25kV transformer in North 25kV System
- Loss of 34.5kV primary bus at Whistlebend substation
- Loss of a single 25kV breaker at Whistlebend substation

3.4 Power Restoration

Critical loads should be restored as quickly as possible (includes residential and commercial customers). All loads should be restored within 24 hours.

The responsibility of an electrical utility is to operate a safe and reliable electrical system. Following outages, safe power restoration is a priority.

When planning for system restoration, Cold Load Pick-Up (CLPU), a phenomenon that occurs during restoration from extended outages, must also be considered. When restoring from prolonged outages, the system diversity factor drops to nearly 1 and the system can experience 2-5 times the regular load for a period of minutes to hours. Based on historical data, typically 200% of regular load for several minutes is assumed.

4. Technical Review

Using the evaluation criteria listed above, for the Whitehorse North 25kV system we have the following:

4.1 Regular Operation

- *No system components are currently overloaded*
- *Whistlebend Substation 34.5/25kV transformers are not expected to be overloaded in the next 6 years*
- *Laberge Substation 34.5/25kV transformer is not expected to be overloaded in the next 6 years. Regulators R50, R51 and R52 are expected to overload in 2024.*
- *S164 Substation 138/34.5kV transformer is not expected to be overloaded in the next 6 years*
- *The subtransmission line 6L17 sourcing both Laberge and Whistlebend substations is not expected to be overloaded in the next 6 years*
- *Customer voltage is currently within the acceptable band for all customers on the North 25kV System. Rural customers up the Alaska Highway and Klondike Highway North are expected to be outside of acceptable voltage as early as 2021. Voltage levels are not the focus of this study and other system upgrades/reconfiguration will occur as necessary to maintain mandatory voltage levels.*

Currently no system components are overloaded, but the Laberge Substation Regulators are expected to overload in the next 6 years. Below are modelled forecasts for system loading for the 6-year planning period.

	Equipment / System Area	Critical Ratings	Present Status (2019)	Future Status (2025)
Whistlebend Substation	Transformer T1	34.5/25kV 10MVA	6% Loaded	63% Loaded*
	Transformer T2	34.5/25kV 10MVA	41% Loaded	58% Loaded*
	Transformer T3	25/12.5kV 5MVA	12% Loaded	13% Loaded
	Reclosers: S3431, S3432, S3433, S3434	27kV 630A each	2%, 0%, 15%, 0% Loaded	2%, 21%, 21%, 0% Loaded*
	Regulators: R110, R111, R112	400A each	4%, 4%, 4% Loaded	38%, 37%, 36% Loaded
	Regulators: R107, R108, R109	400A each	24%, 24%, 24% Loaded	33%, 34%, 33% Loaded
Laberge Substation	Transformer T1	34.5/25kV 10MVA	62% Loaded	86% Loaded
	Reclosers: S3600, S8306	38kV 630A, 400A (per phase)	17%, 10% Loaded	24%, 12% Loaded
	Regulators: R50, R51, R52	200A each	62%, 78%, 77% Loaded	86%, 107%, 106%
S164	Transformer T1	138/34.5kV 25MVA**	43% Loaded	72% Loaded

Table 1 - Whitehorse North 25kV System Peak Loading

*Future 25kV load on Whistlebend Substation redistributed evenly across S3432, S3433
**Assuming that S164 is operating in OFAF mode. If Transformer T1 is unable to operate at the nameplate rating of 25MVA, the transformer will require upgrades and/or replacement in coming years. This asset is owned by YEC, therefore any upgrades required are outside of the scope of this study.

Note: Additional substation apparatus (Gang Switches, Buses, etc.) were not included in Table 1 as their rating greatly exceeds that of the other equipment and will not be the limiting factor for substation capacity.

4.2 Load Addition

As shown in section 4.1, the majority of the equipment in the Whitehorse North 25kV system is lightly loaded and has the available capacity to grow at expected rates

4.3 Contingency

- *There currently is a significant contingency scenario that cannot be adequately addressed:*
    - *Loss of the 34.5kV primary overhead (O/H) bus at Whistlebend substation will result in a contingency situation where peak loading on all of the Whitehorse North 25kV System cannot be picked up by Laberge alone.*
- *Laberge regulators (R50, R51, R52) will become overloaded in 2023 during normal system configuration. Any outages resulting in additional load being shifted to Laberge Substation will intensify this problem. Additionally, starting in 2025 the loss of a single 34.5/25kV transformer on the North 25kV system will cause an overload on the remaining 2 transformers.*

For the loss of any major equipment within the electrical distribution system, AEY requires that there be a plan in place on how to restore power to as many customers as possible. Ideally, this means the peak load of any piece of equipment can be transferred to an alternative feeder/breaker/source in order to re-energize the customers without the failed equipment.

For the North 25kV System, the following cases are being considered as potential issues both presently and within the 6-year planning window:

Contingency Scenario	Description	Present Status (2019)	Future Status
Loss of 6L17	6L17 is the normal source of 34.5kV to both Whistlebend and Laberge substations from S164. A loss of this line will require both distribution substations to be transferred to 6L16 (loading limit of 38MVA) and source from T1 at S170 (loading limit of 47MVA).	OK – Current peak loading of 11MVA on North 25kV System. S170 alone has capacity to receive this transfer.	OK – Expected peak loading of 21MVA on North 25kV System. S170 alone does not have capacity for transfer. A possible solution is for S150 to take Logan Sub from S170 and then S170 alone would have capacity to pick-up the North 25kV.

Loss of single 34.5/25kV transformer	Between Whistlebend and Laberge Substations, there are 3 x 10MVA transformers for 34.5/25kV. Assuming adequate switching to distribute load among remaining 2 transformers, overall load cannot exceed 20MVA.	OK – Current peak loading of 11MVA.	Overload - Capacity reached in 2025. Expected peak loading of 21MVA on North 25kV System.
Loss of 34.5kV primary bus at Whistlebend	The loss of the primary bus at Whistlebend will prevent any 25kV sourcing from this substation. All load will have to be transferred to T1 at Laberge Substation (10MVA rating).	Overload – Currently at peak load, the North 25kV system requires more capacity than T1 at Laberge can supply. Additionally, Laberge regulator will be overloaded prior to the T1.	
Loss of 25kV breaker at Whistlebend	The loss of a single 25kV breaker at Whistlebend or Laberge would require all load to be transferred to the remaining breakers on the North 25kV system.	Ok	Ok

Table 2 - North 25kV System Contingency Analysis

OK – All equipment will be within manufacturer recommended equipment ratings if this contingency scenario occurs at a time when all feeders are exhibiting peak loading.

4.4 Power Restoration

Within the Whitehorse North 25kV system, there are rural, urban and critical customers (e.g. Whistlebend Place). To restore the system within a short time for these customer types, both Whistlebend and Crestview subdivisions have been designed with loop connections. This allows for switching operations to isolate the faulted section of line and alternative feeds to energize the remaining portion of the loop while the faulted section is repaired.

The system has been designed with discrete sections of large load (e.g. subdivisions) to have independent feeders. This minimizes the system strain of Cold-Load Pick-Up, by allowing separate feeders to be placed back on-line individually and therefore control the system diversity factor.

5. Potential Solutions

5.1 Solutions Considered

As identified above the main issues facing the North 25kV System over the upcoming 6-year period are:

- Capacity: Overload on Regulators (R50, R51, R52) at Laberge Substation
- Contingency Scenario 1: Loss of a single 34.5/25kV transformer
- Contingency Scenario 2: Loss of the 34.5kV primary bus at Whistlebend Substation

To address these issues, the following potential solutions have been considered:

1) New 25kV Substation & System Reconfiguration
2) Laberge Substation Upgrades
3) Status Quo

As part of system maintenance and compliance with voltage regulations, the AEY system will require voltage regulators or system upgrades on both the Alaska Highway North and Klondike Highway North in the upcoming years to counteract the unacceptable voltage levels expected to begin in 2021. The following 3 options assume these upgrades will be conducted independently of the solution selected and are not the focus of this study.

5.2 - OPTION 1: New 25kV Substation & System Reconfiguration

Building a new substation for the 25kV North System would directly resolve Contingency Scenarios 1 and 2, by providing additional reserve capacity to assist with system reconfiguration during outages. In 2025, the total peak loading on S164 is estimated to be 20.7MVA. In Contingency Scenario 2, the only remaining transformer is T1 at Laberge, with a rating of 10MVA. This results in 10.7MVA of power that needs to be alternatively sourced by a new substation. At minimum the new substation should be designed to continuously provide at least 10.7MVA without overloading any equipment.

To address the capacity issue on the regulators at Laberge Substation, during normal operation it is recommended that the load currently serviced by Laberge T1 is split among Laberge and the new substation. The simplest and most cost-effective method of dividing the load is to service Crestview area by the existing Laberge Substation and service Alaska Highway North and the Klondike Highway by the new substation. This is not an equal division of load (only ~25% of estimated Laberge load is in Crestview area), however it does shorten the average distance between a substation and load-centres, without requiring any additional distribution line to be constructed. This will contribute to minimizing line losses and lessen the voltage drop between the substations and end-of-line customers. The recommended method to achieve this would be to create a dedicated feeder at the new substation to feed the existing 5L645 (servicing Alaska Highway North and Klondike Highway North). This would effectively allocate all of Laberge's capacity to the Crestview area during normal operation. Additionally, with the majority of the future load growth expected in the Whistlebend area, it is recommended that the new

substation also includes a dedicated feeder that connects to the north-west region of Whistlebend.

This option covers Contingency Scenario 1 and 2, and resolves the forecast Laberge regulator capacity issue.

5.3 - OPTION 2: Laberge Substation Upgrades

As mentioned in Option 1, in order to cover all contingency scenarios that are forecast for 2025, at least 10.7MVA of additional transformer capacity is required on the North 25kV system. This option meets this requirement by adding an additional transformer to the Laberge substation that is rated for at least 10.7MVA. The additional transformer capacity would cover both identified contingency scenarios and during normal operation, this transformer would be a dedicated feed for line 5L645 (servicing Alaska Highway North and Klondike Highway North), along with the ability to tie in to 5L648 and support future expansions of Whistlebend along the north west side of the subdivision. By alleviating the strain on the existing Transformer T1 at Laberge Substation, the capacity issue on the existing regulators R50, R51 and R52 will be resolved.

This option covers Contingency Scenario 1 and 2, and resolves the forecast Laberge regulator capacity issue.

5.4 - OPTION 3: Status Quo

Without making any changes to the North 25kV system and with load growth continuing at the expected rates, equipment will be overloaded in the near future. Assuming that peak loading only occurs in winter months (with temperatures at or below 0˚C), power transformers can be steadily overloaded at 1.22 p.u. of their nameplate rating and can be emergency overloaded up to 1.31 p.u. for less than 8 hours before the loading must drop below 0.90 p.u.

Utilizing these seasonal equipment ratings and assuming that the Laberge regulators are upgraded to no longer be the limiting factor at that substation, the North 25kV System will be able to handle Contingency Scenario 2 up until 2021. In 2021, the peak loading on the North 25kV System is anticipated to be ~14.7MVA. This load cannot be carried by Laberge T1 alone.

Additionally, anytime equipment operates outside of nameplate rating, there is the potential for decreased lifespan and increased maintenance requirements on these assets. Deferring system improvements, may result in increased service and asset replacement costs going forward.

This option covers Contingency Scenario 1 in its entirety and covers Contingency Scenario 2 up until 2021. This does not address the forecast Laberge regulator capacity issue.

6. Recommendation

In typical electrical design, it is advantageous to source power as close as possible to the load-centre it will serve as this method minimizes voltage drop and resistive losses. Therefore, it is recommended that AEY proceeds with Option 1: New 25kV Substation and System Reconfiguration. As most of the future load growth is expected to be located in Whistlebend and up the Klondike Highway North, it would be beneficial to construct a new substation in the area between these locations, with independent feeders and dedicated 10MVA transformers for each area. This in turn will not only solve capacity and contingency issues, it will also alleviate some of the low-voltage concerns and minimize the number of regulator additions/upgrades required in the coming years.

As the load continues to grow in the future, the division of 25kV sources among a greater number of substations, mitigates contingency issues related to primary bus outages and therefore strengthens the system as a whole. When directly compared against Option 2, the construction of a new substation would result in a more robust electrical system and shorten the distance between the 25kV sources and their customer load-centres.

As it does not address all of the Contingency Scenarios presented and has the potential to shorten the lifespan of existing equipment, it is not recommended to proceed with Option 3.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-072

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-072

Reference: Service Complex Boiler Replacement, BC #10 Project cost $107,443 including YG rebate of $31, 736. Constructed 2020.

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Was this cost already added to the rate base? If yes, when and under what authority.

Response:

(a) Please refer to response to AEY-UCG-066(a).

(b) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-073

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-073

Reference: McIntyre Subdivision Contingency Loop, BC #11 "19.The cost of this option is preliminary at $410,000. This assumes that all poles along the double circuit path will need to be replaced."

Request:

(a) Is this project now complete? If yes, when and at what final cost?

(b) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(c) Was any of this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Yes. The overhead double circuit section was completed on July 3, 2018 and the underground portion was completed on December 17, 2019. As stated in the business case it cost $295,000.

(b) Please refer to the response to AEY-UCG-066(a) and AEY-UCG-073(b) Attachment 1.

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric

DISTRIBUTION PLANNING SPECIFICATION
PART 1 - SUMMARY

Project #: Y14334
ISD: Q2 2018
Customer: 25kV Tie from Hamilton to Alaska Highway
Location: Whitehorse
Substation: Arkell
Line: 5L630

Planning Completed By: John Williams
Date: January 9, 2018
Revision: R0

Project Description

McIntyre subdivision is currently fed as a radial network. While the current rebuild project (to be completed in 2020) was designed with looping within the subdivision, there is no alternate feed for the subdivision as a whole.
In order to create an alternate feed 25kV infrastructure will be expanded northward along the Alaska Highway and into Valleyview. New underground cable would connect this infrastructure to the north end of McIntyre Drive.

Scope of Work

Three parts:

1. Convert approximately 1500m of 12.5kV line to 25kV from Burns Road to Klondike Motors. 11 transformers will also need to be converted to 25kV primaries.
2. Build approximately 800m of double circuit from the Alaska Highway to Hamilton Blvd on the south side of Valleyview subdivision. The new double circuit will be 25kV 1/0 ACSR and 12.5kV along the existing 12.5kV alignment.
3. Build approximately 500m of 25kV 350 MCM underground from the west end of the new double circuit to the north entrance to McIntyre subdivision, and add one switchcube to tie into the McIntyre system. The switchcube should have at least two ganged bays, one for the tie to Arkell, and one ganged bay feeding McIntyre.

Revision Control

- R0 – (JW) – Initial Issue

ATCO Electric

DISTRIBUTION PLANNING SPECIFICATION
PART 3 – SINGLE LINE DIAGRAM

A. Conductor Selection

Conductor	25kV Thermal Limit (Summer/Winter)	Expected Loading*	Max Present Loading**	Max Future Loading***	Max Loading Scenario
350 MCM	16 MVA	5.1MVA	6.7MVA	9.7MVA	All load from Logan 5L632, Logan 5L633, Arkell 5L629, plus 3MVA of tank farm load
1/0 ACSR	10MVA / 14MVA				
750 MCM	25MVA				
266 ACSR	21MVA / 27MVA				

*Expected Loading is McIntyre, 3MVA for Tank Farm and Logan 5L633.

**Max Present loading is McIntyre, Ingram, Copper Ridge subdivisions only. This represents the maximum load we can expect without future developments. Logan sub was considered out of service and Arkell feeds all this load through the new tie. The #4 ACSR through McIntyre is at its absolute limit for loading in this scenario and may need to be upgraded.

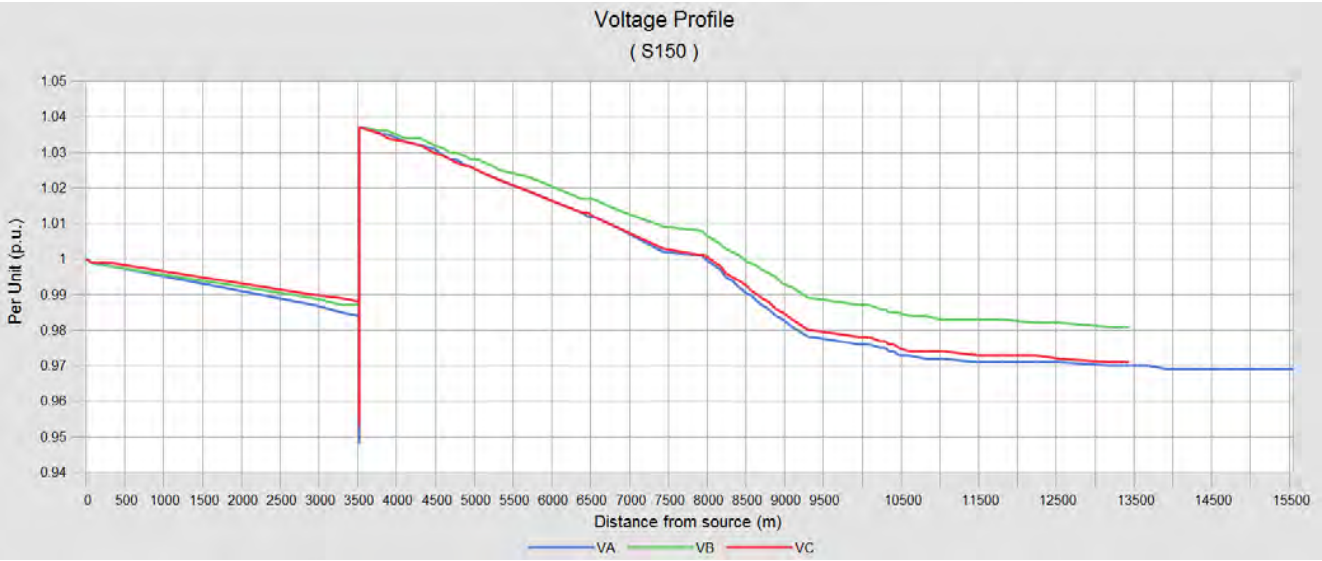
*** Max Loading represents the total expected load, plus significant development at the Tank Farm. The tank farm is assumed to be at a similar load density to Whistle Bend. Tank Farm is ~70 hectares. WB stage 1 (based around Aksala Drive) is 13 hectares. The modeled load for this area is 500kVA. This gives 38 kVA/hectare. Using 40kVA/hectare the tank farm load could be 2.8MVA.

To reach either “Max Loading Scenario” several system improvements need to be made:

1. **Increase pick-up of breaker S8619 from 200A**
2. **Reconductor the #4 ACSR in McIntyre to larger conductor**
3. **Build a mainline tie between McIntyre and Ingram (remove S3710) or build a mainline tie between new McIntyre Switch Cube and Ingram**
4. **Ensure all 25kV double circuit along the Alaska Highway from Arkell Substation to this project is 1/0 or larger**
5. **Pay special attention to feeding through fuses and not tripping on load**

ATCO Electric

DISTRIBUTION PLANNING SPECIFICATION
PART 3 – SINGLE LINE DIAGRAM



Voltage profile at at S2359 near Hmailton and south Access under Max Future Loading Case

ATCO Electric

DISTRIBUTION PLANNING SPECIFICATION
PART 3 – SINGLE LINE DIAGRAM

B. Protection

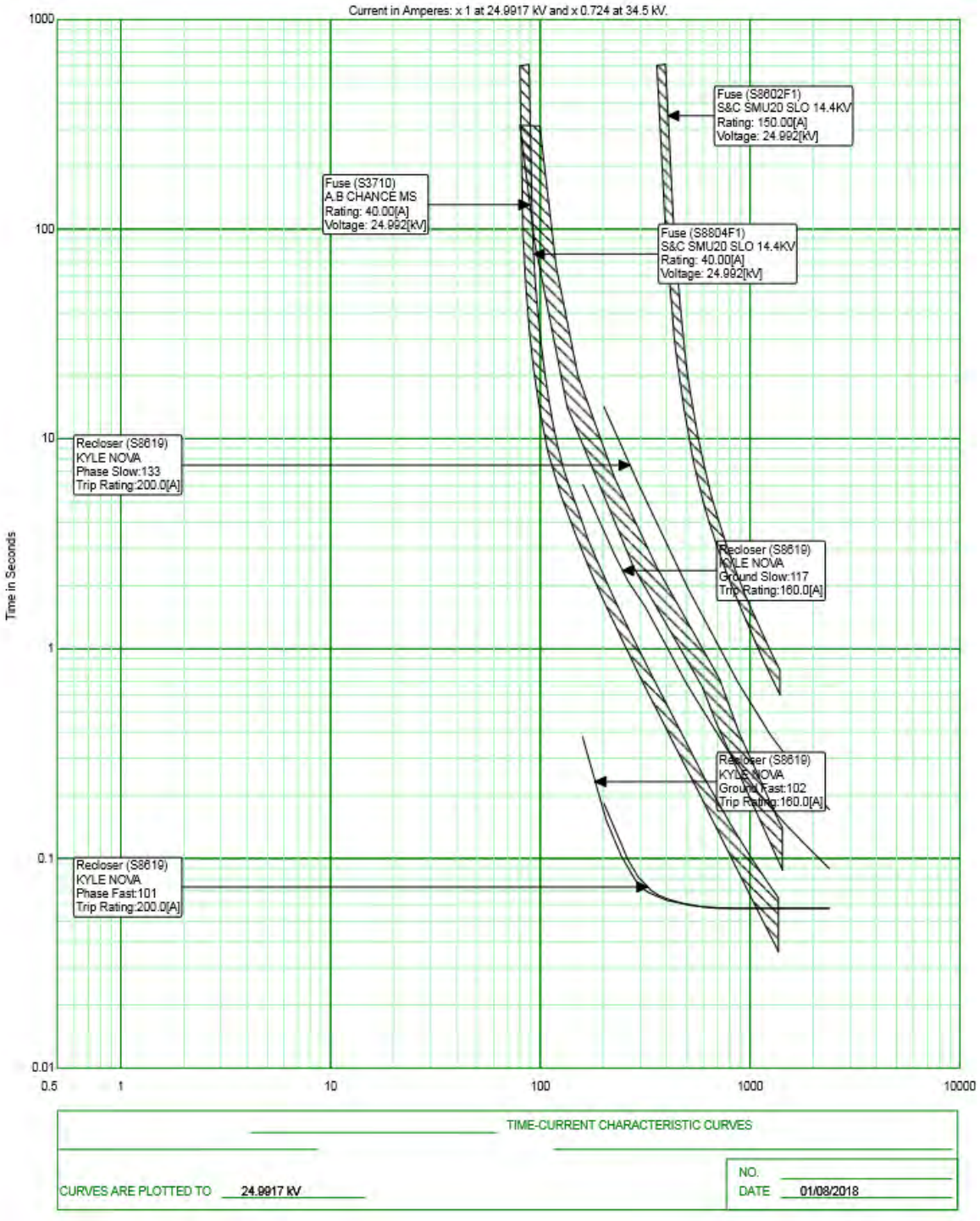
Location	LLL	LL	LG	LG(Z)	Expected Loading*	Max Present Loading**	Max Future Loading***
Arkell S8619	2141	1855	2481	670	189A	233A	303A
New McIntyre Switch Cube (Gang)	1644	1425	1591	591	124A	167A	237A
New McIntyre Switch Cube (Fused to McIntyre)	1644	1425	1591	591	57A	167A	170A
Tie from McIntyre to Ingram (S3710)	1419	1229	1303	537	41A	144A	146A
Logan (via new feed)	1392	1206	1252	528	0A	53A	53A
S8804 (40A SMU)	1373	1190	1228	522	21A	21A	21A
End of the line (S2350 on Hamilton)	1271	1101	1092	495	7A	7A	7A

Table 2: Short Circuit Levels (A) when fed from Arkell

To feed through Logan sub's 25kV breakers, both S9877 and S9878 need to be bypassed. All of the load will be on Arkell's S8619.

ATCO Electric

DISTRIBUTION PLANNING SPECIFICATION
PART 3 – SINGLE LINE DIAGRAM



ATCO Electric YUKON

September 28, 2023 AEY-UCG-074

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-074

Reference: Annual Right of Way Widening-Brushing, BC #12. "2. AEY has an ongoing capital brushing plan."

Request:

(a) Has the YUB given prior approval to this plan? Give reference details

(b) Have all these costs for Appendix A, B, C, D and E all been completed?

(c) Are these all the final costs of these brushing jobs? If not, explain giving cost overruns.

(d) Were any of these costs already added to the rate base? If yes, when how much and under what authority?

Response:

(a) No.

(b) Yes.

(c) Yes.

(d) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-075

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-075

Reference: Fleet Replacement, BC #13

Request:

(a) Give Atco Fleet and 3rd party vendor tenders with purchase costs from each.

(b) Did AEY sell the four used trucks? How and how much? Was this deducted anywhere in this accounting? Explain.

(c) Was this cost already added to the rate base? If yes, how much, when and under what authority?

Response:

(a) Vehicle purchases are completed through contracted vendors that have been awarded through a competitive RFP process lead by ATCO Fleet Services and ATCO Strategic Sourcing Teams. These vendors are typically awarded tenders for a period of three years. If vehicles can be sourced locally, bids are requested from vendors. Please refer to AEY-UCG-075(a) Attachment 1 for quotes and purchase costs.

(b) Units YT091 and YT886 were sold by public bid action in 2022. When a vehicle is sold, the historical costs are retired and removed from rate base, which includes the credit from the net proceeds received from the sale. Units YT092 and YT429 are still in AEY possession and will be sold by public bid auction.

Table 1: Fleet Replaced

Unit	Description	Year Purchased	Kilometers	Sale Proceeds	Retirements
YT091	Technologist Truck	2010	245,537	23,000	(85,482)
YT092	Crew Flat Deck	2008	237,000		
YT886	Technologist Truck	2009	248,748	6,000	(40,050)
YT429	Bucket Truck	1994	81,471		

(c) Please refer to the response to AEY-UCG-065(b).

TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

Delivered to ATCO Gas HERD 5623 - 82 Ave. Edmonton

Company Name: METRO CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2018

Qty Required:

	Mfg Code	Price
Model	DP0L94	59570
Engine 6.7L Cummins	29G	11895
Payload Upgrade Package	AH5	500
Max Tow Package	AHQ	325
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	200
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	650
Heated Mirrors	GPG	~~0~~
Color: Fleet white	PW7	~~0~~
Black/Grey seat cloth	X8	~~0~~
Front: 40/20/40 split with Lumbar support	*M9	700
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	350
Radio	RA2	600
Interior rubber flooring	CKW	~~0~~
Option Group 1	AHD	525
Option Group 2	LBN	795
Require 3 keys per vehicle	?	257
	Subtotal Per Unit	78262
	AC/Tire Tax	100
	AMVIC Fee	~~0~~
	Freight & Handling	1895
	Fleet Discount	16500
	Net Price Per Unit	63757

Submitted by:
Contact name: KEN SCHNICK
Date: March 13/18

Contact phone number: 867 667 2525
Signature:

Delivery Date:

```
CNGP530                    VEHICLE ORDER CONFIRMATION              05/08/18 13:09:07
==> _________ ____________________________________________                Dealer: CB6248
                                2019 F-SERIES SD                          Page: 1 of 2
Order No: 0100    Priority: 20                    Order Type: 2  Price Level: 915
Ord PEP:  663A Cust/Flt Name:                       PO Number:
                        RETAIL   DLR INV                                  RETAIL   DLR INV
W5H  F550 4X4 CHAS/C $62749 $56189.00   TFB  .225 BSW AS 19.5
     203" WHEELBASE                     X4N  4.10 LTD SLIP                 NC        NC
     FED EXCISE TAX     100    100.00   17V  XLT VALUE PKG              450    405.00
     2019 MODEL YEAR                    62M  .ADJ GAS/BRK PDL
Z1   OXFORD WHITE                       90D  .8 WAY PWR DRV
3    40/20/40 CLOTH                     18A  UPFIT INTER MOD            400    360.00
S    MEDIUM EARTH GR                    18B  PLAT RUNNING BD            490    441.00
663A PREF EQUIP PKG                          LESS TPMS
     .XLT TRIM
39S  .SIRIUSXM SAT                      TOTAL BASE AND OPTIONS 81209  73041.00
559  .FRT/SIDE AIRBGS                   TOTAL                  81209  73041.00
     .AM/FM/CLOCK                       *THIS IS NOT AN INVOICE*
     .TRANS PTO PROV
99T  6.7L V8 DIESEL    9450   8505.00  * MORE ORDER INFO NEXT PAGE *
44W  6-SPD AUTOMATIC     NC        NC              F8=Next
F1=Help               F2=Return to Order          F3/F12=Veh Ord Menu
F4=Submit             F5=Add to Library
S006 - MORE DATA IS AVAILABLE.                                          CGB6248
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CNGP530                    VEHICLE ORDER CONFIRMATION          05/08/18 13:08:56
==> _________ ____________________________________                Dealer: CB6248
                              2019 F-SERIES SD                     Page: 2 of 2
Order No: 0100     Priority: 20                  Order Type: 2  Price Level: 915
Ord PEP:  663A Cust/Flt Name:                      PO Number:
                          RETAIL   DLR INV                          RETAIL   DLR INV
207  18000# GVWR PKG        NC        NC   86S  LOW DEFLEC PKG      $100     $90.00
213  ELECTRONIC SOF         200    180.00   872  RR CAM & PREP K      550     495.00
     PTC SUPP HTR                          91S  4-CORNER STROBE      800     720.00
41P  SKID PLATES            200    180.00   913  SYNC 3               500     450.00
43C  110V/400W OUTLT         NC        NC    10  U.S. GAL GAS                  48.00
512  SPARE TIRE/WHL2        410    369.00        DEST AND DELIV      1800    1800.00
54F  PWRSCOPE TT MIR         800    720.00
61J  JACK                    NC        NC  TOTAL BASE AND OPTIONS  81209   73041.00
63A  UTLTY LIGHT SYS         NC        NC  TOTAL                   81209   73041.00
64D  POL ALNM WHLS          820    738.00  *THIS IS NOT AN INVOICE*
65C  DUAL FUEL TANKS        890    801.00
67B  DUAL XTR HD ALT         NC        NC
693  PARTIAL GAS FIL
76C  REVERSE ALARM          150    135.00
76S  REMOTE START           350    315.00              F7=Prev
F1=Help                F2=Return to Order             F3/F12=Veh Ord Menu
F4=Submit              F5=Add to Library
S099 - PRESS F4 TO SUBMIT                                              CGB6248
```

QUOTATION # AME190318

Date: March 19, 2018

Prepared For: Atco Electric Yukon
Bill Cullen
205 Tungsten Rd
Whitehorse, YT Y1A 0G4
Edmonton, AB T5J 2V6
Phone: 867.633.7057
Cell: 867.336.4017

Prepared By:
General Body & Equipment Ltd.
c/o Mark Edel
8124 Davies Road
Edmonton, AB T6E 4N2
Phone: 780-468-5359
Email: medel@generalbody.ca

General Body & Equipment Ltd. is pleased to present the following for your consideration:

Supply and install one (1) Custom Built Aluminum Service Body
onto customer supplied chassis

Material Specifications For Aluminum Service Bodies:
- Compartment sizes and layout as per customer supplied drawing
- Compartments fabricated from 1/8 in aluminum, stitch welded inside and out
- 3 x 2" aluminum channel cross sills on 16" centers
- 3 x 3" aluminum tubing long sills
- 3/16" aluminum checkerplate floor inside body center

Standard Body Features:
- Heavy duty rolled edge shelving with safety hem
- Extruded aluminum wheel well edge moldings
- 1/8" aluminum checkerplate stone guards installed on both front corners of body
- Heavy duty rear bumper mounted dependent of body
- Fuel spouts are recessed as per Federal safety laws
- One (1) set of rear mud flaps
- All welds and edges are dressed to remove weld spatter, sharp edges and mill scale
- All bolts used are cadmium plated or stainless steel, all nuts are nylock style

Compartment Doors:
- 1/8" aluminum single panel compartment doors fabricated from 5052 aluminum alloy
- Extruded aluminum frames
- Hollow bulb, automotive style, snap-in rubber door seals
- All doors to have gas strut holdback
- Stainless steel hinges on all compartment doors
- Black 3-point "Whale Tail" handle door locks with lock cylinders and rattle proof locks
- All doors are keyed alike
- Integral full length drip moldings above compartment doors

Lighting:
- Tail, stop, signal, back-up, and license lights complete with reflectors to comply with Federal/Canada Motor Vehicle Safety Standard 108
- Clearance lights on separate circuit
- Tail lights are to be LED
- Clearance lights are to be LED
- Backup lights are to be LED
- All electrical connections are soldered and enclosed in heat shrink
- All wiring is concealed and enclosed in split loom
- Luma Bar LED lighting installed in each compartment (not in oxy/acet compartments) with cab mounted on/off switch
- Two (2) LED work lights mounted on top of compartments at front of service body
- Two (2) LED work lights mounted on top of compartments at rear of service body

Paint:
- Complete body is treated for dissimilar metals
- Complete body is phosphatized (metal etching and phosphate coating process)
- Compartment interiors of aluminum service body texture coated grey

- Wheel wells are undercoated
- All seams are caulked

Installation:

- Complete installation in Edmonton on customer supplied suitable cab & chassis
- One (1) year warranty on materials and workmanship
- Five (5) year warranty on rust through of body panels
- CMVSS safety sticker installed on driver's side door jamb

Compartment Configuration:

- Designed and fabricated utilizing computer-aided-design (CAD) methodology
- Overall length: 138" + 7" Bumper
    - Overall width: 96"
    - Overall height: 50"
    - Compartment depth: 24"
- Drivers side front compartment
    - Four (4) 4" drawers on rollout slides
    - Three (3) 7" drawers on rollout slides
- Drivers side second compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) 6" drawers on rollout slides
    - One (1) 8" drawers on rollout slides
- Drivers side horizontal compartment
    - One (1) fixed shelf
    - One (1) 3" drawers on rollout slides
    - One (1) large drawer to fit space below existing top drawer
    - Split door with double lined door to use as work surface
- Drivers side rear compartment
    - Three (3) adjustable shelves
    - One (1) full width bar (1/2") to fit in adjustable shelf holder
- Passengers side front compartment
    - Vented for carrying bottled gasses per Alberta regulations
    - Two (2) J-hooks
    - Two rows of E-Tracking on all walls
    - Hose wrap on door
- Passengers side second compartment
    - Three (3) adjustable shelves
- Passengers side horizontal compartment
    - One (1) fixed shelf
    - One (1) heavy duty divided bolt bin on roll out slides
    - Split door with double lined door to use as work surface
- Passengers side rear compartment
    - Four j-hooks (1-2-1)
    - One (1) Fixed shelf at floor height
    - Reinforced for Crane
- Cargo area
    - Three (3) piece aluminum sliding roof covering cargo area
    - 26" high rear tailgate, formed from one (1) piece with dual check chains to hold tailgate in open or closed position
    - Stainless steel master lock system
    - E-Track on cargo wall 12" from floor from rear to front tool holders (street side)
    - Four tube tool holder attached to passenger side wall at front under fixed portion of sliding roof
    - Supply and Install water pack holder for customer supplied water pack

Other features included

- Manual in/out, up/down outrigger bumper
- 2" square hitch receiver tube mounted under bumper at rear
- Spare tire mounted above cargo area front
- Seven prong RV style trailer plug
- Four (4) LED Work lights as noted above in electrical section
- Two (2) Aluminum rubber grip grab handles at rear to access cargo area
- Supply and Install 6" Vise with two vise receivers on top of bumper each side, storage receiver in cargo floor on street side

- GBE grip strut running boards
- Two (2) Jetco 126-67089A-8 LED Strobes Location front of body with pedestal, viewable from all sides
- LED boom light for crane, switch in rear curb side compartment
- 20lb ABC Fire extinguisher
- LED 20" Light bar combo spot/flood mounted in center of front bumper with cover connected to high beam
- Roda Deaco - Fully automatic for Chassis
- Espar Coolant heater
- Zone Defense Backup Camera Monitor with rear bullet cam

Chassis:

- Dodge 5500 (as per customer specification)
  - DRW
  - 84" cab-to-axle
  - diesel engine
  - Automatic transmission
  - Paint: white

Supply One (1) Maxilift Cobra Model 5500 RSE Service Crane

Specifications:

- Hydraulic planetary gear winch, high speed and efficiency
- Unlimited continuous slewing system
- Two fully hydraulically telescoping boom sections
- 100 ft of 5/16” 13,300 lbs. breaking strength cable, non twisting type.
- Radio Remote control with handheld ergonomic and light control box
- Fully digital proportional controls enable fast smooth precise operation.
- Easy upgrading from wired to radio remote
- Digital processor, LED display, water proof casing.
- Solenoid operated valves with emergency manual override
- Painted Cobra white with epoxy primer and fade resistant polyurethane enamel

Technical data:

- Crane rating: 25,000 ft lbs.
- Horizontal reach: 20'
- Slewing angle: continuous unlimited
- Boom elevation angle: -5 to +72 degrees
- Winch capacity single line: 2640 lbs.
- Winch line speed: 33 ft/minute
- Crane weight: 1140 Lbs.

Crane Lifting Capacities:

Feet	Pounds
3'	5100
9' 8"	2700
15'	1650
20'	1200

Installation:

- Install crane and do all necessary electrical hook ups
- Supply and install boom rest
- Manual in/out crane side, manual up/down stabilizers included with body
- Test crane for stability and proper operation of all functions

Complete Aluminum Service Body Package Price: **$82,600.00**

Terms and Conditions

Customer Supplied Equipment and Information:

- Complete Chassis Specification to be provided by Customer at time of Order.
- Truck/Chassis to be supplied to GBE with a minimum 1/4 tank of fuel.
    - Fuel charges will be added to invoice if chassis arrives below 1/4 tank
- Relocation of exhaust, Air Tanks, Battery Boxes, Fuel or Urea Tanks will be an additional charge.
- Quote valid for 30 Days. Acceptance of quote after this period will require a review of proposed pricing.

Payment Terms:

- FOB GBE Edmonton
- 30% Down Payment required at time of order.
    - Balance due upon completion of unit at Production facility
    - Unit will be held at GBE Edmonton until payment arrangements have been
- Taxes Extra
- GBE Supplied Products affected by monetary exchange rates may require price build when rates have changed by a differential of 5% from the date was officially
- Third Party Financing Options available on request.

Warranty Terms:

- All Warranty work to be completed by GBE. If geography prevents the unit from being warranty repairs, prior to any work being completed by a third party, third party provided in writting and approved by GBE,
- 1-year Defects in Material and Workmanship.
- 1-year on all parts, materials and equipment (Some third party equipment warranties ask salesman for details)
- 2-years on de-lamination (Rock Chips excluded).
- 5-years No Rust-through guarantee.
- In accordance with GBE's Continuous Improvement program, specifications are subject to without notice or obligation

Change Order Policies:

- Minimum Change order costs after Specifications and Drawings are approved by customer
    - Change order at less than 25% project completion = Minimum $500 charge + delivery delay
    - Change order at greater than 25% project completion = Minimum $1,000 charge + delivery delay
    - If Customer Supplied Chassis does not match Chassis specification used in associated modification cost + minimum 1-week delivery delay

Cancellation Policy:

- Cancellation must be communicated to General Body and Equipment in writing
- Resulting Cancellation Costs are the responsibility of the customer as follows:
    - Cancellation prior to start of Purchasing/Fabrication process = No Charge
    - Cancellation after start of Purchasing/Fabrication process = All labour and material up to and including date of written notice plus any re-stocking charges associated with return of materials to vendors.

Acceptance by customer:_____ **Date:** _____

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69360

PAGE 1 OF 4

TO (SUPPLIER)	METRO CHRYSLER LTD 5 TWO MILE HILL ROAD WHITEHORSE, YT Y1A 0A4 CANADA
ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
FREIGHT TERMS	PAID
TRADE TERMS	DESTINATION
SHIP VIA	VENDOR'S MODE
DATE REQUIRED	15-DEC-2018
SHIP TO	ATCO Electric Yukon **MULTIPLE LOCATIONS - SEE BELOW**
BILL TO (PURCHASER)	ATCO Electric Yukon Whitehorse Office Accounts Payable 100-1100 Front St. Whitehorse, YT Y1A 3T4 Phone 867-633-7029 Fax 867-668-6692 EMAIL **apaey@atco.com**

AS PER QUOTE PROVIDED BY KEN SCHICK

ATCO ELECTRIC TERMS & CONDITIONS APPLY

FOR INVOICING, REFERENCE PO ELD69360 AND SUBMIT INDIVIDUAL ELECTRONIC COPIES TO APAEY@ATCO.COM; AND COPY AMY.MILLER@ATCO.COM ON ALL SUBMISSIONS.

LINE	ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1		Y14460 A - New Mechanic's Truck - Metro Chrysler - supply 1 new RAM 5500 Crew Cab Chassis				$63,757.00

SHIP TO
The Yukon Electrical Company Limited
Whitehorse Office
205 Tungsten Road
Whitehorse, YT Y1A 3T4
Canada

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX	
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856	**TOTAL** **$63,757.00**

To report inappropriate commercial or purchasing practices, please call the following:

Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69360

TO (SUPPLIER)	METRO CHRYSLER LTD 5 TWO MILE HILL ROAD WHITEHORSE, YT Y1A 0A4 CANADA
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STANDARD PURCHASE ORDER
TERMS AND CONDITIONS

P01 Acceptance Any work, shipment or acknowledgement by the Vendor, Seller, Contractor or Supplier (collectively "Supplier") in response to this Purchase Order shall constitute complete acceptance by said Supplier of the entire Purchase Order including all Terms and Conditions contained or referenced herein. No other terms and conditions shall apply.

P02 Scope of Work The Supplier shall perform the work or supply goods as outlined in the Purchase Order (the "Work") and shall, at its expense unless otherwise provided in the Purchase Order, supply all labour, goods, transport, travel, and supporting facilities and services necessary for the proper execution of the Work in accordance with the Purchase Order, requirements of the law and generally accepted industry or professional standards, as applicable.

P03 Independence of Supplier The Supplier is and shall be an independent contractor and nothing herein shall be construed as creating an agency, partnership, joint venture or employment relationship between ATCO Electric Ltd. (the "Owner") and the Supplier.

P04 Changes The Owner reserves the right to change any and all quantities and description of the Work on this Purchase Order upon written notice provided that the Supplier is entitled to an equitable adjustment in compensation and schedule as a result of such change.

P05 Delivery Time shall be of the essence in all matters that are material to the Purchase Order except for the time of payment. All Work shall be provided to the Owner upon the specified delivery date.

P06 Assignment The Supplier shall not assign any obligation or benefit arising from this Purchase Order or in respect of the performance of the Work without the written consent of the Owner. This Contract shall enure to the benefit of and bind the parties and their respective successors and permitted assigns.

P07 Governing Laws The Purchase Order shall be governed by and construed under the laws in force in the Province of Alberta, without reference to conflict of laws rules, and the Parties shall submit all disputes arising out of or in connection with this Purchase Order to the exclusive jurisdiction of the Courts of Alberta.

P08 Confidentiality & Publicity All information acquired through any means from the Owner by the Supplier as a consequence of the performance, non-performance, or purported performance of the Work by the Supplier or its subcontractors, shall be deemed confidential and shall not be disclosed by the Supplier to others unless in support of the Work and with the same requirement for confidentiality. The Supplier shall not use Owner's name in any form of promotion or advertising without specific prior written consent of the Owner.

P09 Intellectual Property If the Supplier or any of its subcontractors, manufacturers, agents, employees, officers, or directors, incorporate into the Work any intellectual property which shall include without limitation all inventions, designs, ideas, discoveries, artistic works, creations, patents, copyrights and trade-marks (Intellectual Property) that existed prior to the execution of the Purchase Order and is owned by the Supplier or a third party, said Intellectual Property remains the sole property of the Supplier or the third party, as applicable. Notwithstanding the foregoing, upon request of the Owner, the Supplier shall provide copies, drawings, data sheets and other documents in respect of the Work. The Owner is hereby granted and shall have a non-exclusive, fully paid, royalty free, irrevocable, perpetual, worldwide right and licence to make, modify, adapt, or use said Intellectual Property provided it is used to operate, maintain, reconstruct, refurbish, repair, replace or expand the Owner's facilities.

P10 Risk of Loss Unless otherwise stated in this Purchase Order, risk of loss or damage in respect of any goods to be supplied by the Supplier shall remain with the Supplier until such goods are delivered and accepted by the Owner, provided that if the Work involves the construction, erection or installation of goods, the risk of loss or damage to such Work, including the goods, shall remain with the Contractor until the Owner accepts the Work as complete.

P11 No Licence Other than as may be required for the provision of the Work hereunder, nothing in this Purchase Order shall grant the Supplier any licence to use any intellectual or other property that the Owner may now or hereafter own or possess.

P12 Liability and Indemnity The Supplier shall be liable for, indemnify and hold harmless the Owner from all liabilities, losses, damages, demands, causes of action, claims, costs, expenses, judgments of any nature or kind, including legal disbursements and fees on a solicitor and his own client basis, and all costs of whatever nature which may be brought against the Owner that are attributable to or arises out of any one or more, or any combination of, the following which are caused by the Supplier or anyone for whose acts or omissions the Supplier may be liable:
(a) any breach of the Purchase Order;

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

TOTAL
$63,757.00

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Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69360

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SHIP VIA	VENDOR'S MODE
DATE REQUIRED	15-DEC-2018
SHIP TO	ATCO Electric Yukon **MULTIPLE LOCATIONS - SEE BELOW**
BILL TO (PURCHASER)	ATCO Electric Yukon Whitehorse Office Accounts Payable 100-1100 Front St. Whitehorse, YT Y1A 3T4 Phone 867-633-7029 Fax 867-668-6692 EMAIL **apaey@atco.com**

(b) any fault or negligent act or omission;
(c) any damage to property or injury to any person;
(d) any environmental deficiencies or contaminations;
(e) any noncompliance with any laws or regulations, including in relation to HSE requirements at the Work; and
(f) any breach of intellectual property rights pertaining to the Work by the Supplier.

P13 Limitation of Liability Except as hereinafter provided in this Section, in no event shall the liability of the Supplier to the Owner pursuant to this Purchase Order, whether arising in contract, indemnity or in tort, or any other legal theory, be more than 100% of the aggregate total compensation payable to the Supplier under the Purchase Order ("Maximum Liability Limit"), provided that such Maximum Liability Limit shall not apply to any legal or third party costs incurred by the Owner in pursuing or defending any claim against the Supplier or liabilities and obligations arising from:
(a) the Supplier's fraud, bad faith, gross negligence, or wilful default;
(b) any third party claims against the Owner which are attributable to the wrongful acts or negligence of the Supplier;
(c) the Supplier's failure to procure and maintain insurance pursuant to section P14 Insurance; and
(d) the Contractor's breach of section P08 Confidentiality and Publicity.
Notwithstanding anything to the contrary contained herein, neither party shall be liable to the other for any indirect, consequential damages or lost profits, arising under the Purchase Order, whether such liability arises in contract, tort, or otherwise and whether or not either party had notice thereof, provided that nothing in this section shall limit the Supplier's liabilities for those matters specified in section P.13 (a) to (d).

P14 Insurance The Supplier, and any subcontractors involved in carrying out the Work, or any portion thereof, shall carry insurance adequate to cover the obligations incurred under this Purchase Order or to any minimum amount specified herein.

P15 Payment & Billing All payments due the Supplier from the Owner, and not in dispute, shall be made within thirty (30) calendar days from satisfactory receipt and acceptance by the Owner of the Work or receipt of a satisfactory invoice from the Supplier, whichever shall be the later. All such payments due shall not be unreasonably withheld. Invoices shall include a breakdown of all items according to category, rate and date supplied. Invoices shall also be marked with the Purchase Order number and submitted to the address specified.

P16 Right to Audit For this Purchase Order, the Owner reserves the right to audit the supporting records and documents of the Supplier and its subcontractors, relating to any and all amounts invoiced by the Supplier. All such records shall be maintained in accordance with International Financial Reporting Standards. Notwithstanding the foregoing, in no event shall the Owner be entitled to audit the composition of any fixed fee or rate, unit rate, lump sum or multiplier.

P17 Severability & Waiver If any provision or a part thereof of these Terms and Conditions are found to be void, voidable or unenforceable then it shall be deemed severable and all remaining provisions remain in full force and effect. Failure by either party to insist on any one or more instances upon the strict performance of any one of the covenants contained herein shall not be construed as a waiver or relinquishment of such covenants.

P18 Disputes If any dispute arises between the Owner and the Supplier with respect to the performance of the Work, or the interpretation, application or administration of the Purchase Order, the Supplier shall nevertheless continue to perform the Work as directed by the Owner in accordance with the Purchase Order. Both during and after the performance of the Work, the parties each shall:
(a) make bona fide efforts to resolve any disputes arising between them by amicable negotiations; and
(b) provide frank, candid and timely disclosure of all relevant facts, information and documents to facilitate those negotiations.
If the dispute is not resolved within thirty (30) days from the date the dispute arose then the dispute may, at the request of either Owner or the Supplier, exclusively be referred to and finally settled by arbitration pursuant to the National Arbitration Rules of the ADR Institute of Canada, Inc.

P19 Force Majeure If either party is unable to perform any of its obligations under this Purchase Order by reason of fire or other casualty, strike, order of public authority, Act of God, or other cause beyond the reasonable control of such party, then such party shall be excused from its performance of the Purchase Order for the duration of such cause. In the event such inability to perform shall continue longer than thirty (30) days, either party may terminate or cancel the Purchase Order without further liability by giving written notice to the other party.

P20 Warranties the Supplier warrants to the Owner that the Work and Goods shall, as applicable:

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

TOTAL
$63,757.00

To report inappropriate commercial or purchasing practices, please call the following:

Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69360

TO (SUPPLIER)	METRO CHRYSLER LTD 5 TWO MILE HILL ROAD WHITEHORSE, YT Y1A 0A4 CANADA
ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
FREIGHT TERMS	PAID
TRADE TERMS	DESTINATION
SHIP VIA	VENDOR'S MODE
DATE REQUIRED	15-DEC-2018
SHIP TO	ATCO Electric Yukon **MULTIPLE LOCATIONS - SEE BELOW**
BILL TO (PURCHASER)	ATCO Electric Yukon Whitehorse Office Accounts Payable 100-1100 Front St. Whitehorse, YT Y1A 3T4 Phone 867-633-7029 Fax 867-668-6692 EMAIL **apaey@atco.com**

(a) be free from any encumbrance, lien, security interest or other defect in title as the Supplier warrants and guarantees to be the absolute owner of goods specified herein;
(b) not constitute an infringement or contributory infringement of any patent or any copyright or trademark, or violation of any trade secret when sold or used for their ordinary intended purpose or any special purpose specified in this Purchase Order;
(c) be in strict conformance with this Purchase Order and any specification, drawing or other description supplied or advised by the Owner to the Supplier and attached to this Purchase Order;
(d) to the extent design and engineering is included in this Purchase Order, be designed, and engineered, in accordance with industry standards;
(e) be manufactured, fabricated, assembled, delivered and sold in accordance with industry standards;
(f) be without fault, defect or deficiency;
(g) be of good design, materials and workmanship;
(h) be new, unless specified otherwise in a Purchase Order; and
(i) be fit for use for their ordinary intended purpose as well as any special purpose specified in this Purchase Order.
The warranties and guarantees contained in P.20 (c) through (i) shall commence on the date the goods are delivered or Work is completed and continue for a period of twelve (12) months (the "Warranty Period"). The warranties outlined in P.20 (a) and (b) shall have no expiry.

P21 Warranty Remedy Following the discovery of a breach of warranty, the Owner shall notify the Contractor who shall, at its expense, promptly remedy any defects or non-conformity. Any part of the Work which is remedied under terms of warranty shall be further warranted for a period of twelve (12) months from the date of completion of the remedy provided that in no event shall any Warranty Period extend beyond twenty-four (24) months from the original delivery of goods or completion of Work. The Contractor shall take whatever steps are necessary to remedy any defect in title, at its expense, to conform with this warranty including the defence of the Owner's title to the Work.

P22 Inter-Affiliate Code of Conduct In accepting the Purchase Order, the Supplier agrees to abide by the requirements contained in the ATCO Inter-Affiliate Code of Conduct which can be viewed: http://www.atcoelectric.com/Rates/regulatory/Inter-Affiliate-Code-of-Conduct.

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

TOTAL
$63,757.00

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Vice President , Internal Audit (403) 292-7737

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69361

PAGE 1 OF 4

TO (SUPPLIER)	GENERAL BODY & EQUIPMENT LTD 8124 DAVIES RD EDMONTON, AB T6E 4N2 CANADA Fax: (403) 250-1925
ATTN	EDEL, MARK
PHONE	780 4685331 EXT 157
SHIP TO	ATCO Electric Yukon **MULTIPLE LOCATIONS - SEE BELOW**

ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
FREIGHT TERMS	PAID
TRADE TERMS	DESTINATION
SHIP VIA	VENDOR'S MODE
DATE REQUIRED	30-NOV-2018
BILL TO (PURCHASER)	ATCO Electric Yukon Whitehorse Office Accounts Payable 100-1100 Front St. Whitehorse, YT Y1A 3T4 Phone 867-633-7029 Fax 867-668-6692 EMAIL **apaey@atco.com**

AS PER QUOTE NO. AME190318

ATCO ELECTRIC TERMS & CONDITIONS APPLY

FOR INVOICING, REFERENCE PO YE69361 AND SUBMIT ELECTRONIC COPIES INDIVIDUALLY TO APAEY@ATCO.COM; AND COPY AMY.MILLER@ATCO.COM ON ALL SUBMISSIONS.

LINE	ITEM	DESCRIPTION	QUANTITY	UNIT	UNIT PRICE	AMOUNT
1		Y14460 A - New Mechanic's Truck - General Body & Equipment - supply and install 1 custom built deck as per Quote AME190318				$72,765.00

SHIP TO
The Yukon Electrical Company Limited
Whitehorse Office
205 Tungsten Road
Whitehorse, YT Y1A 3T4
Canada

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

TOTAL
$72,765.00

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ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69361

TO (SUPPLIER)	GENERAL BODY & EQUIPMENT LTD 8124 DAVIES RD EDMONTON, AB T6E 4N2 CANADA Fax: (403) 250-1925
ATTN	EDEL, MARK
PHONE	780 4685331 EXT 157

ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
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SHIP VIA	VENDOR'S MODE
DATE REQUIRED	30-NOV-2018

SHIP TO ATCO Electric Yukon
MULTIPLE LOCATIONS - SEE BELOW

BILL TO (PURCHASER)
ATCO Electric Yukon
Whitehorse Office
Accounts Payable
100-1100 Front St.
Whitehorse, YT Y1A 3T4
Phone 867-633-7029 Fax 867-668-6692
EMAIL **apaey@atco.com**

STANDARD PURCHASE ORDER
TERMS AND CONDITIONS

P01 Acceptance Any work, shipment or acknowledgement by the Vendor, Seller, Contractor or Supplier (collectively "Supplier") in response to this Purchase Order shall constitute complete acceptance by said Supplier of the entire Purchase Order including all Terms and Conditions contained or referenced herein. No other terms and conditions shall apply.

P02 Scope of Work The Supplier shall perform the work or supply goods as outlined in the Purchase Order (the "Work") and shall, at its expense unless otherwise provided in the Purchase Order, supply all labour, goods, transport, travel, and supporting facilities and services necessary for the proper execution of the Work in accordance with the Purchase Order, requirements of the law and generally accepted industry or professional standards, as applicable.

P03 Independence of Supplier The Supplier is and shall be an independent contractor and nothing herein shall be construed as creating an agency, partnership, joint venture or employment relationship between ATCO Electric Ltd. (the "Owner") and the Supplier.

P04 Changes The Owner reserves the right to change any and all quantities and description of the Work on this Purchase Order upon written notice provided that the Supplier is entitled to an equitable adjustment in compensation and schedule as a result of such change.

P05 Delivery Time shall be of the essence in all matters that are material to the Purchase Order except for the time of payment. All Work shall be provided to the Owner upon the specified delivery date.

P06 Assignment The Supplier shall not assign any obligation or benefit arising from this Purchase Order or in respect of the performance of the Work without the written consent of the Owner. This Contract shall enure to the benefit of and bind the parties and their respective successors and permitted assigns.

P07 Governing Laws The Purchase Order shall be governed by and construed under the laws in force in the Province of Alberta, without reference to conflict of laws rules, and the Parties shall submit all disputes arising out of or in connection with this Purchase Order to the exclusive jurisdiction of the Courts of Alberta.

P08 Confidentiality & Publicity All information acquired through any means from the Owner by the Supplier as a consequence of the performance, non-performance, or purported performance of the Work by the Supplier or its subcontractors, shall be deemed confidential and shall not be disclosed by the Supplier to others unless in support of the Work and with the same requirement for confidentiality. The Supplier shall not use Owner's name in any form of promotion or advertising without specific prior written consent of the Owner.

P09 Intellectual Property If the Supplier or any of its subcontractors, manufacturers, agents, employees, officers, or directors, incorporate into the Work any intellectual property which shall include without limitation all inventions, designs, ideas, discoveries, artistic works, creations, patents, copyrights and trade-marks (Intellectual Property) that existed prior to the execution of the Purchase Order and is owned by the Supplier or a third party, said Intellectual Property remains the sole property of the Supplier or the third party, as applicable. Notwithstanding the foregoing, upon request of the Owner, the Supplier shall provide copies, drawings, data sheets and other documents in respect of the Work. The Owner is hereby granted and shall have a non-exclusive, fully paid, royalty free, irrevocable, perpetual, worldwide right and licence to make, modify, adapt, or use said Intellectual Property provided it is used to operate, maintain, reconstruct, refurbish, repair, replace or expand the Owner's facilities.

P10 Risk of Loss Unless otherwise stated in this Purchase Order, risk of loss or damage in respect of any goods to be supplied by the Supplier shall remain with the Supplier until such goods are delivered and accepted by the Owner, provided that if the Work involves the construction, erection or installation of goods, the risk of loss or damage to such Work, including the goods, shall remain with the Contractor until the Owner accepts the Work as complete.

P11 No Licence Other than as may be required for the provision of the Work hereunder, nothing in this Purchase Order shall grant the Supplier any licence to use any intellectual or other property that the Owner may now or hereafter own or possess.

P12 Liability and Indemnity The Supplier shall be liable for, indemnify and hold harmless the Owner from all liabilities, losses, damages, demands, causes of action, claims, costs, expenses, judgments of any nature or kind, including legal disbursements and fees on a solicitor and his own client basis, and all costs of whatever nature which may be brought against the Owner that are attributable to or arises out of any one or more, or any combination of, the following which are caused by the Supplier or anyone for whose acts or omissions the Supplier may be liable:
(a) any breach of the Purchase Order;

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

TOTAL
$72,765.00

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Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69361

TO (SUPPLIER)	GENERAL BODY & EQUIPMENT LTD 8124 DAVIES RD EDMONTON, AB T6E 4N2 CANADA Fax: (403) 250-1925
ATTN	EDEL, MARK
PHONE	780 4685331 EXT 157

ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
FREIGHT TERMS	PAID
TRADE TERMS	DESTINATION
SHIP VIA	VENDOR'S MODE
DATE REQUIRED	30-NOV-2018

SHIP TO ATCO Electric Yukon
MULTIPLE LOCATIONS - SEE BELOW

BILL TO (PURCHASER)
ATCO Electric Yukon
Whitehorse Office
Accounts Payable
100-1100 Front St.
Whitehorse, YT Y1A 3T4
Phone 867-633-7029 Fax 867-668-6692
EMAIL **apaey@atco.com**

(b) any fault or negligent act or omission;
(c) any damage to property or injury to any person;
(d) any environmental deficiencies or contaminations;
(e) any noncompliance with any laws or regulations, including in relation to HSE requirements at the Work; and
(f) any breach of intellectual property rights pertaining to the Work by the Supplier.

P13 Limitation of Liability Except as hereinafter provided in this Section, in no event shall the liability of the Supplier to the Owner pursuant to this Purchase Order, whether arising in contract, indemnity or in tort, or any other legal theory, be more than 100% of the aggregate total compensation payable to the Supplier under the Purchase Order ("Maximum Liability Limit"), provided that such Maximum Liability Limit shall not apply to any legal or third party costs incurred by the Owner in pursuing or defending any claim against the Supplier or liabilities and obligations arising from:
(a) the Supplier's fraud, bad faith, gross negligence, or wilful default;
(b) any third party claims against the Owner which are attributable to the wrongful acts or negligence of the Supplier;
(c) the Supplier's failure to procure and maintain insurance pursuant to section P14 Insurance; and
(d) the Contractor's breach of section P08 Confidentiality and Publicity.
Notwithstanding anything to the contrary contained herein, neither party shall be liable to the other for any indirect, consequential damages or lost profits, arising under the Purchase Order, whether such liability arises in contract, tort, or otherwise and whether or not either party had notice thereof, provided that nothing in this section shall limit the Supplier's liabilities for those matters specified in section P.13 (a) to (d).

P14 Insurance The Supplier, and any subcontractors involved in carrying out the Work, or any portion thereof, shall carry insurance adequate to cover the obligations incurred under this Purchase Order or to any minimum amount specified herein.

P15 Payment & Billing All payments due the Supplier from the Owner, and not in dispute, shall be made within thirty (30) calendar days from satisfactory receipt and acceptance by the Owner of the Work or receipt of a satisfactory invoice from the Supplier, whichever shall be the later. All such payments due shall not be unreasonably withheld. Invoices shall include a breakdown of all items according to category, rate and date supplied. Invoices shall also be marked with the Purchase Order number and submitted to the address specified.

P16 Right to Audit For this Purchase Order, the Owner reserves the right to audit the supporting records and documents of the Supplier and its subcontractors, relating to any and all amounts invoiced by the Supplier. All such records shall be maintained in accordance with International Financial Reporting Standards. Notwithstanding the foregoing, in no event shall the Owner be entitled to audit the composition of any fixed fee or rate, unit rate, lump sum or multiplier.

P17 Severability & Waiver If any provision or a part thereof of these Terms and Conditions are found to be void, voidable or unenforceable then it shall be deemed severable and all remaining provisions remain in full force and effect. Failure by either party to insist on any one or more instances upon the strict performance of any one of the covenants contained herein shall not be construed as a waiver or relinquishment of such covenants.

P18 Disputes If any dispute arises between the Owner and the Supplier with respect to the performance of the Work, or the interpretation, application or administration of the Purchase Order, the Supplier shall nevertheless continue to perform the Work as directed by the Owner in accordance with the Purchase Order. Both during and after the performance of the Work, the parties each shall:
(a) make bona fide efforts to resolve any disputes arising between them by amicable negotiations; and
(b) provide frank, candid and timely disclosure of all relevant facts, information and documents to facilitate those negotiations.
If the dispute is not resolved within thirty (30) days from the date the dispute arose then the dispute may, at the request of either Owner or the Supplier, exclusively be referred to and finally settled by arbitration pursuant to the National Arbitration Rules of the ADR Institute of Canada, Inc.

P19 Force Majeure If either party is unable to perform any of its obligations under this Purchase Order by reason of fire or other casualty, strike, order of public authority, Act of God, or other cause beyond the reasonable control of such party, then such party shall be excused from its performance of the Purchase Order for the duration of such cause. In the event such inability to perform shall continue longer than thirty (30) days, either party may terminate or cancel the Purchase Order without further liability by giving written notice to the other party.

P20 Warranties the Supplier warrants to the Owner that the Work and Goods shall, as applicable:

Prices Exclude Canadian Goods and Services Tax

BUYER CONTACT	PHONE	FAX
MacLeod, Ms. Molly A Molly.MacLeod@atco.com	780-508-4768	780-420-3856

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Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

TOTAL
$72,765.00

ATCO Electric YUKON

PURCHASE ORDER

ORDER NUMBER YE69361

TO (SUPPLIER)	GENERAL BODY & EQUIPMENT LTD 8124 DAVIES RD EDMONTON, AB T6E 4N2 CANADA Fax: (403) 250-1925
ATTN	EDEL, MARK
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ORDER DATE	15-JUN-2018
PAYMENT TERMS	NET 30
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SHIP VIA	VENDOR'S MODE
DATE REQUIRED	30-NOV-2018

SHIP TO	ATCO Electric Yukon **MULTIPLE LOCATIONS - SEE BELOW**
BILL TO (PURCHASER)	ATCO Electric Yukon Whitehorse Office Accounts Payable 100-1100 Front St. Whitehorse, YT Y1A 3T4 Phone 867-633-7029 Fax 867-668-6692 EMAIL **apaey@atco.com**

(a) be free from any encumbrance, lien, security interest or other defect in title as the Supplier warrants and guarantees to be the absolute owner of goods specified herein;
(b) not constitute an infringement or contributory infringement of any patent or any copyright or trademark, or violation of any trade secret when sold or used for their ordinary intended purpose or any special purpose specified in this Purchase Order;
(c) be in strict conformance with this Purchase Order and any specification, drawing or other description supplied or advised by the Owner to the Supplier and attached to this Purchase Order;
(d) to the extent design and engineering is included in this Purchase Order, be designed, and engineered, in accordance with industry standards;
(e) be manufactured, fabricated, assembled, delivered and sold in accordance with industry standards;
(f) be without fault, defect or deficiency;
(g) be of good design, materials and workmanship;
(h) be new, unless specified otherwise in a Purchase Order; and
(i) be fit for use for their ordinary intended purpose as well as any special purpose specified in this Purchase Order.
The warranties and guarantees contained in P.20 (c) through (i) shall commence on the date the goods are delivered or Work is completed and continue for a period of twelve (12) months (the "Warranty Period"). The warranties outlined in P.20 (a) and (b) shall have no expiry.

P21 Warranty Remedy Following the discovery of a breach of warranty, the Owner shall notify the Contractor who shall, at its expense, promptly remedy any defects or non-conformity. Any part of the Work which is remedied under terms of warranty shall be further warranted for a period of twelve (12) months from the date of completion of the remedy provided that in no event shall any Warranty Period extend beyond twenty-four (24) months from the original delivery of goods or completion of Work. The Contractor shall take whatever steps are necessary to remedy any defect in title, at its expense, to conform with this warranty including the defence of the Owner's title to the Work.

P22 Inter-Affiliate Code of Conduct In accepting the Purchase Order, the Supplier agrees to abide by the requirements contained in the ATCO Inter-Affiliate Code of Conduct which can be viewed: http://www.atcoelectric.com/Rates/regulatory/Inter-Affiliate-Code-of-Conduct.

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Director , Corporate Security (403) 245-7285
Vice President , Internal Audit (403) 292-7737

TOTAL
$72,765.00

MM

RECEIVED
MAY 29 2018

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Amy Miller

Department: North 60

VP / GM: Doug Tenney

Ph. / Email: 867-633-7062 amy.miller@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact): Bill Cullen

Owner Representative: Bill Cullen

Project Name: Y14460 New Mechanic's Trcuck

Requisition Number: *no longer required by SCM

Project Location: Whitehorse

CEAR: Approved ☐ NOT Required ☑

Region: Yukon

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☐ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: _____ / Completion: _____

- or -

Delivery / Installation required by: 2018-12-15

Total Estimated Value: $63,757.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years): _____

Maximum Release Value: _____

Minimum Release Value: _____

Estimated # of Releases / year: _____

Estimated Annual Value: _____

2. Scope of Work Document name: Quote Date of issue: 13-Mar-2018 Number of pages: 1

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

Metro Chrysler to supply 1 New Ram 5500 Crew Cab Chassis.

Requisition # 257994
Release #
P.O. #
Received
Date

BC
JH

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

Vehicle to be delivered to Whitehorse Yukon via GENERAL body in Edmonton.

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☑ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

Goods and Services Request

This document is an uncontrolled printed copy. Please see Supply Chain Management for a controlled copy.
TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 - 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☑	to FOLLOW	☐
b) Drawings and / or blueprints	attached	☐	NOT required	☑	to FOLLOW	☐
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐

d) HSE Hazard Requirements — LOW ☐ attached ☐ to FOLLOW; MEDIUM ☐ attached ☐ to FOLLOW; HIGH ☐ attached ☐ to FOLLOW

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments: This is a goods purchase, parts b, c, d and e do not apply

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Single Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Field Bid ☑
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☑ Unit Rate ☐
Hourly Rate ☐ Combined ☐
a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

freight - Edm to Whitehorse.

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** Metro Chrysler Ltd.	Attn: Ken Schick	**HSE Pre-Assessed**
Address: 5 Two Mile Hill Road, Whitehorse YT	Tel: 867-667-2525	Yes ☐ No ☑
Email: ken@metrochrysler.ca	Fax:	
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**
Address:	Tel:	Yes ☐ No ☐
Email:	Fax:	
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**
Address:	Tel:	Yes ☐ No ☐
Email:	Fax:	

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

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d) **Full Legal Name:** _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.

0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal	
Safety Record	
Proposed Schedule	
Availability of Resources	
Depth of Experience	
Reputation / Qualifications	
Creative Solutions	
Accuracy / Conciseness of Bid	
Other:	Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

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ATCO Electric

Goods and Services Request (GSR Form)

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Part F. Single or Sole Source Justification

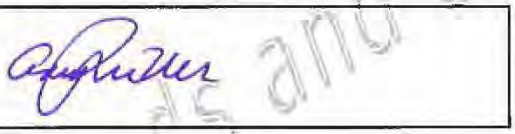
Supply Chain Management G93 Purchase Process Control states:

Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Vehicle was ordered from Metro Chrysler as it was the lowest quote.

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
	Amy Miller 29-May-18
Manager Signature	Print name and date MM-DD-YY
	Jay Massie 05.29.18
Additional Signature (as required)	Print name and date MM-DD-YY
	Bill Cullen 18-05-29

End of **GOODS AND SERVICES REQUEST FORM**

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

~~**Delivered to ATCO Gas HERD 5623 - 82 Ave. Edmonton**~~

Company Name: METRO CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2018

Qty Required:

	Mfg Code	Price
Model	DP0L94	59570
Engine 6.7L Cummins	29G	11895
Payload Upgrade Package	AH5	500
Max Tow Package	AHQ	325
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	200
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	650
Heated Mirrors	GPG	~~0~~
Color: Fleet white	PW7	~~0~~
Black/Grey seat cloth	X8	~~0~~
Front: 40/20/40 split with Lumbar support	*M9	700
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	350
Radio	RA2	600
Interior rubber flooring	CKW	~~0~~
Option Group 1	AHD	525
Option Group 2	LBN	795
Require 3 keys per vehicle	?	257
	Subtotal Per Unit	78262
	AC/Tire Tax	100
	AMVIC Fee	~~0~~
	Freight & Handling	1895
	Fleet Discount	16500
	Net Price Per Unit	63757

Submitted by:
Contact name: KEN SCHUK
Date: March 13/18

Contact phone number: 867 667 2525
Signature:

Delivery Date:

FORD QUOTE

CNGP530 VEHICLE ORDER CONFIRMATION 05/08/18 13:09:07
==> _____ _____ Dealer: CB6248
2019 F-SERIES SD Page: 1 of 2
Order No: 0100 Priority: 20 Order Type: 2 Price Level: 915
Ord PEP: 663A Cust/Flt Name: PO Number:

		RETAIL	DLR INV			RETAIL	DLR INV
W5H	F550 4X4 CHAS/C	$62749	$56189.00	TFB	.225 BSW AS 19.5		
	203" WHEELBASE			X4N	4.10 LTD SLIP	NC	NC
	FED EXCISE TAX	100	100.00	17V	XLT VALUE PKG	450	405.00
	2019 MODEL YEAR			62M	.ADJ GAS/BRK PDL		
Z1	OXFORD WHITE			90D	.8 WAY PWR DRV		
3	40/20/40 CLOTH			18A	UPFIT INTER MOD	400	360.00
S	MEDIUM EARTH GR			18B	PLAT RUNNING BD	490	441.00
663A	PREF EQUIP PKG				LESS TPMS		
	.XLT TRIM						
39S	.SIRIUSXM SAT			TOTAL BASE AND OPTIONS		81209	73041.00
559	.FRT/SIDE AIRBGS			TOTAL		81209	73041.00
	.AM/FM/CLOCK			*THIS IS NOT AN INVOICE*			
	.TRANS PTO PROV						
99T	6.7L V8 DIESEL	9450	8505.00	* MORE ORDER INFO NEXT PAGE *			
44W	6-SPD AUTOMATIC	NC	NC				

F8=Next
F1=Help F2=Return to Order F3/F12=Veh Ord Menu
F4=Submit F5=Add to Library
S006 - MORE DATA IS AVAILABLE. CGB6248

CNGP530 VEHICLE ORDER CONFIRMATION 05/08/18 13:08:56
==> Dealer: CB6248
2019 F-SERIES SD Page: 2 of 2
Order No: 0100 Priority: 20 Order Type: 2 Price Level: 915
Ord PEP: 663A Cust/Flt Name: PO Number:

		RETAIL	DLR INV			RETAIL	DLR INV
207	18000# GVWR PKG	NC	NC	86S	LOW DEFLEC PKG	$100	$90.00
213	ELECTRONIC SOF	200	180.00	872	RR CAM & PREP K	550	495.00
	PTC SUPP HTR			91S	4-CORNER STROBE	800	720.00
41P	SKID PLATES	200	180.00	913	SYNC 3	500	450.00
43C	110V/400W OUTLT	NC	NC	10	U.S. GAL GAS		48.00
512	SPARE TIRE/WHL2	410	369.00		DEST AND DELIV	1800	1800.00
54F	PWRSCOPE TT MIR	800	720.00				
61J	JACK	NC	NC	TOTAL	BASE AND OPTIONS	81209	73041.00
63A	UTLTY LIGHT SYS	NC	NC	TOTAL		81209	73041.00
64D	POL ALNM WHLS	820	738.00	*THIS	IS NOT AN INVOICE*		
65C	DUAL FUEL TANKS	890	801.00				
67B	DUAL XTR HD ALT	NC	NC				
693	PARTIAL GAS FIL						
76C	REVERSE ALARM	150	135.00				
76S	REMOTE START	350	315.00				

F1=Help F2=Return to Order F7=Prev F3/F12=Veh Ord Menu
F4=Submit F5=Add to Library
S099 - PRESS F4 TO SUBMIT CGB6248

MM RECEIVED MAY 29 2018

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Amy Miller

Department: North 60

VP / GM: Doug Tenney

Ph. / Email: 867-633-7062 amy.miller@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact): Bill Cullen

Owner Representative: Bill Cullen

Project Name: Y14460 New Mechanic's Truck

Requisition Number: *no longer required by SCM

Project Location: Whitehorse

CEAR: Approved ☐ NOT Required ☑

Region: Yukon

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☑ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: _____ / Completion: _____

- or -

Delivery / Installation required by: 2017-11-30

Total Estimated Value: 72,765.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years): _____

Maximum Release Value: _____

Minimum Release Value: _____

Estimated # of Releases / year: _____

Estimated Annual Value: _____

2. Scope of Work Document name: Quote AME190318 Date of issue: 19-Mar-18 Number of pages: 4

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

General Body and Equipment to supply and install 1 Custom Built deck as per Quote AME190318

Requisition # 257995 BC
Release #
E.S. #
Received
Date

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

OWNER to supply Cab/Chassis for deck to be installed on.

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☐ Contractor as Prime ☑ Dependent on the Work (per Work Release) ☐

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

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3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☑	to FOLLOW	☐
b) Drawings and / or blueprints	attached	☐	NOT required	☐	to FOLLOW	☑
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐

d) HSE Hazard Requirements — LOW ☐ attached ☐ to FOLLOW; MEDIUM ☐ attached ☐ to FOLLOW; HIGH ☐ attached ☐ to FOLLOW

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments: This is a goods purchase, parts b, c, d and e do not apply

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Single Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Field Bid ☑
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☑ Unit Rate ☐
Hourly Rate ☐ Combined ☐
a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name**: General Body and Equipment	Attn: Mark Edel	**HSE Pre-Assessed**	
Address: 8124 Davies Rd Edmonton, AB T6E 4N2	Tel: 780-468-5359	Yes ☐	No ☑
Email: medel@generalbody.ca	Fax:		
b) **Full Legal Name**:	Attn:	**HSE Pre-Assessed**	
Address:	Tel:	Yes ☐	No ☐
Email:	Fax:		
c) **Full Legal Name**:	Attn:	**HSE Pre-Assessed**	
Address:	Tel:	Yes ☐	No ☐
Email:	Fax:		

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d) **Full Legal Name:** _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.
0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal
Safety Record
Proposed Schedule
Availability of Resources
Depth of Experience
Reputation / Qualifications
Creative Solutions
Accuracy / Conciseness of Bid
Other: Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

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ATCO Electric

Goods and Services Request (GSR Form)

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Part F. Single or Sole Source Justification

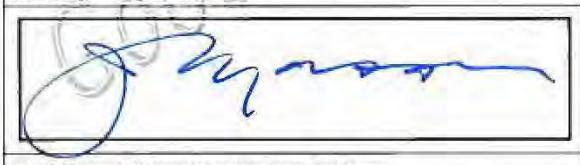
Supply Chain Management G93 Purchase Process Control states:

Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Custom deck was ordered from General Body as they had lowest comparative bid.

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
	Amy Miller 29-May-2018
Manager Signature	Print name and date MM-DD-YY
	Jay Massie 05.29.18
Additional Signature (as required)	Print name and date MM-DD-YY
	Bill Cullen 18-05-29

End of **GOODS AND SERVICES REQUEST FORM**

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

QUOTATION # AME190318

Date: March 19, 2018

Prepared For: Atco Electric Yukon
Bill Cullen
205 Tungsten Rd
Whitehorse, YT Y1A 0G4
Edmonton, AB T5J 2V6
Phone: 867.633.7057
Cell: 867.336.4017

Prepared By:
General Body & Equipment Ltd.
c/o Mark Edel
8124 Davies Road
Edmonton, AB T6E 4N2
Phone: 780-468-5359
Email: medel@generalbody.ca

General Body & Equipment Ltd. is pleased to present the following for your consideration:

Supply and install one (1) Custom Built Aluminum Service Body
onto customer supplied chassis

Material Specifications For Aluminum Service Bodies:
- Compartment sizes and layout as per customer supplied drawing
- Compartments fabricated from 1/8 in aluminum, stitch welded inside and out
- 3 x 2" aluminum channel cross sills on 16" centers
- 3 x 3" aluminum tubing long sills
- 3/16" aluminum checkerplate floor inside body center

Standard Body Features:
- Heavy duty rolled edge shelving with safety hem
- Extruded aluminum wheel well edge moldings
- 1/8" aluminum checkerplate stone guards installed on both front corners of body
- Heavy duty rear bumper mounted dependent of body
- Fuel spouts are recessed as per Federal safety laws
- One (1) set of rear mud flaps
- All welds and edges are dressed to remove weld spatter, sharp edges and mill scale
- All bolts used are cadmium plated or stainless steel, all nuts are nylock style

Compartment Doors:
- 1/8" aluminum single panel compartment doors fabricated from 5052 aluminum alloy
- Extruded aluminum frames
- Hollow bulb, automotive style, snap-in rubber door seals
- All doors to have gas strut holdback
- Stainless steel hinges on all compartment doors
- Black 3-point "Whale Tail" handle door locks with lock cylinders and rattle proof locks
- All doors are keyed alike
- Integral full length drip moldings above compartment doors

Lighting:
- Tail, stop, signal, back-up, and license lights complete with reflectors to comply with Federal/Canada Motor Vehicle Safety Standard 108
- Clearance lights on separate circuit
- Tail lights are to be LED
- Clearance lights are to be LED
- Backup lights are to be LED
- All electrical connections are soldered and enclosed in heat shrink
- All wiring is concealed and enclosed in split loom
- Luma Bar LED lighting installed in each compartment (not in oxy/acet compartments) with cab mounted on/off switch
- Two (2) LED work lights mounted on top of compartments at front of service body
- Two (2) LED work lights mounted on top of compartments at rear of service body

Paint:
- Complete body is treated for dissimilar metals
- Complete body is phosphatized (metal etching and phosphate coating process)
- Compartment interiors of aluminum service body texture coated grey

- Wheel wells are undercoated
- All seams are caulked

Installation:

- Complete installation in Edmonton on customer supplied suitable cab & chassis
- One (1) year warranty on materials and workmanship
- Five (5) year warranty on rust through of body panels
- CMVSS safety sticker installed on driver's side door jamb

Compartment Configuration:

- Designed and fabricated utilizing computer-aided-design (CAD) methodology
- Overall length: 138" + 7" Bumper
    - Overall width: 96"
    - Overall height: 56"
    - Compartment depth: 24"
- Drivers side front compartment
    - Four (4) 4" drawers on rollout slides
    - Three (3) 7" drawers on rollout slides
- Drivers side second compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) 6" drawers on rollout slides
    - One (1) 8" drawers on rollout slides
- Drivers side horizontal compartment
    - One (1) fixed shelf
    - One (1) 3" drawers on rollout slides
    - One (1) large drawer to fit space below existing top drawer
    - Split door with double lined door to use as work surface
- Drivers side rear compartment
    - Three (3) adjustable shelves
    - One (1) full width bar (1/2") to fit in adjustable shelf holder
- Passengers side front compartment
    - Vented for carrying bottled gasses per Alberta regulations
    - Two (2) J-hooks
    - Two rows of E-Tracking on all walls
    - Hose wrap on door
- Passengers side second compartment
    - Three (3) adjustable shelves
- Passengers side horizontal compartment
    - One (1) fixed shelf
    - One (1) heavy duty divided bolt bin on roll out slides
    - Split door with double lined door to use as work surface
- Passengers side rear compartment
    - Four j-hooks (1-2-1)
    - One (1) Fixed shelf at floor height
    - Reinforced for Crane
- Cargo area
    - Three (3) piece aluminum sliding roof covering cargo area
    - 26" high rear tailgate, formed from one (1) piece with dual check chains to hold tailgate in open or closed position
    - Stainless steel master lock system
    - E-Track on cargo wall 12" from floor from rear to front tool holders (street side)
    - Four tube tool holder attached to passenger side wall at front under fixed portion of sliding roof
    - Supply and Install water pack holder for customer supplied water pack

Other features included

- Manual in/out, up/down outrigger bumper
- 2" square hitch receiver tube mounted under bumper at rear
- Spare tire mounted above cargo area front
- Seven prong RV style trailer plug
- Four (4) LED Work lights as noted above in electrical section
- Two (2) Aluminum rubber grip grab handles at rear to access cargo area
- Supply and Install 6" Vise with two vise receivers on top of bumper each side, storage receiver in cargo floor on street side

- GBE grip strut running boards
- Two (2) Jetco 126-67089A-8 LED Strobes Location front of body with pedestal, viewable from all sides
- LED boom light for crane, switch in rear curb side compartment
- 20lb ABC Fire extinguisher
- LED 20" Light bar combo spot/flood mounted in center of front bumper with cover connected to high beam
- Roda Deaco - Fully automatic for Chassis
- Espar Coolant heater (Deleted)
- Zone Defense Backup Camera Monitor with rear bullet cam

Chassis:

- Dodge 5500 (as per customer specification customer supplied)
  - DRW
  - 84" cab-to-axle
  - diesel engine
  - Automatic transmission
  - Paint: white

Supply One (1) Maxilift Cobra Model 3300 NWE Service Crane

Specifications:

- Hydraulic planetary gear winch, high speed and efficiency
- 400 degree slewing system
- One fully hydraulically one manual telescoping boom sections
- 82 ft of 1/4" cable, non twisting type.
- Tethered handheld ergonomic and light control box
- Digital processor, LED display, water proof casing.
- Solenoid operated valves with emergency manual override
- Painted Cobra white with epoxy primer and fade resistant polyurethane enamel

Technical data:

- Crane rating: 11,500 ft lbs.
- Horizontal reach: 15'
- Slewing angle: 400 degree
- Boom elevation angle: -5 to +72 degrees
- Crane weight: 550 Lbs.

Crane Lifting Capacities:

Feet	Pounds
6"10"	1650
11'1"	1050
15'	750

Installation:

- Install crane and do all necessary electrical hook ups
- Supply and install boom rest
- Manual in/out crane side, manual up/down stabilizers included with body
- Test crane for stability and proper operation of all functions

Complete Aluminum Service Body Package Price: $72,765.00

Terms and Conditions

Customer Supplied Equipment and Information:

- Complete Chassis Specification to be provided by Customer at time of Order.
- Truck/Chassis to be supplied to GBE with a minimum 1/4 tank of fuel.
  - Fuel charges will be added to invoice if chassis arrives below 1/4 tank

- Relocation of exhaust, Air Tanks, Battery Boxes, Fuel or Urea Tanks will be an additional charge.
- Quote valid for 30 Days. Acceptance of quote after this period will require a review of proposed pricing.

Payment Terms:

- FOB GBE Edmonton
- 30% Down Payment required at time of order.
    - Balance due upon completion of unit at Production facility
    - Unit will be held at GBE Edmonton until payment arrangements have been
- Taxes Extra
- GBE Supplied Products affected by monetary exchange rates may require price build when rates have changed by a differential of 5% from the date was officially
- Third Party Financing Options available on request.

Warranty Terms:

- All Warranty work to be completed by GBE. If geography prevents the unit from being warranty repairs, prior to any work being completed by a third party, third party provided in writting and approved by GBE,
- 1-year Defects in Material and Workmanship.
- 1-year on all parts, materials and equipment (Some third party equipment warranties ask salesman for details)
- 2-years on de-lamination (Rock Chips excluded).
- 5-years No Rust-through guarantee.
- In accordance with GBE's Continuous Improvement program, specifications are subject to without notice or obligation

Change Order Policies:

- Minimum Change order costs after Specifications and Drawings are approved by customer
    - Change order at less than 25% project completion = Minimum $500 charge + delivery delay
    - Change order at greater than 25% project completion = Minimum $1,000 charge + delivery delay
    - If Customer Supplied Chassis does not match Chassis specification used in associated modification cost + minimum 1-week delivery delay

Cancellation Policy:

- Cancellation must be communicated to General Body and Equipment in writing
- Resulting Cancellation Costs are the responsibility of the customer as follows:
    - Cancellation prior to start of Purchasing/Fabrication process = No Charge
    - Cancellation after start of Purchasing/Fabrication process = All labour and material up to and including date of written notice plus any re-stocking charges associated with return of materials to vendors.

Acceptance by customer:_____ **Date:** _____

Additional quote.

INTERCONTINENTAL TRUCK BODY LTD.
PO Box 1300, 1806 11St Coaldale AB T1M 1N1
Ph: (403)345-4427 Fax: (403)345-6078
E-mail: matt.vandyk@itb.ca Web address: www.itb.ca

***** QUOTATION *****

ATCO Electric Yukon
205 Tungsten Rd
Whitehorse, YT Y1A 0G4
Contact: Bill Cullen
E-mail: bill.cullen@atco.com
Phone: 867.633.7057

March 29, 2018
Quotation #QMVD18.ATCO.134

134"L x 96"W x 60"H Custom ITB Service Body:

Frame and Body Construction:

- HSS 2"x2" Steel tubing sub-frame
- 1/8" Aluminium body, ends, sides, and compartment dividers
  - 1/8" Aluminium checker plate on front, top, and rear of side packs
- 8 – Aluminium side pack compartments with full centre compartment
  - Double panel aluminum doors with
    - 1/8" Aluminum exterior skin
    - ITB extruded aluminum door edge and frame
    - 14 Gauge aluminum interior lining
    - Ridged board insulation
    - Stainless steel stamped hinges
    - Recessed stainless steel two point "D" handles keyed alike
    - Automotive style rubber door seals
    - Gas strut hold-back
  - Full length aluminum drip mouldings above all compartment doors
  - Aluminum checker plate rear skirt
  - Aluminum wheel well mouldings
  - Above-wheel well compartments to be clam-shell style
    - Upper door with gas shock door retainer
    - Bottom door with check chains for horizontal work surface
- Manual central locking system with camlock handle in center compartment
- 14 Gauge galvanized steel rock guard in wheel well with extruded aluminum trim
- Aluminum HD double line reinforced tailgate with checkerplate interior lining
  - Dual 90 degree cable checks
- Three piece sliding 1/8" aluminum roof with fixed front section and flip over rear door
- Spare tire carrier mounted above fixed roof section
- 10" HD steel bumper with aluminum treadplate top
  - HD receiver tube and 7-pin plug
  - 2 - Vertical 2" ID vise receivers with 6" vise and vise receiver in center deck floor
  - 2 - Manually adjustable reinforced removable outriggers - one on each side of bumper
- All drawers with heavy duty locking drawer slides and rubber matting
- All shelves with rubber matting and 1" lip with edge rubber
- Adjustable shelves with Cantruss rail system with sliding bolt

Road Side Doors and Compartments:

- Double-door front compartment A:
  - 3 - 7"H Full W Drawers at bottom
  - 4 - 4"H Full W Drawers above
- Single-door second compartment B:
  - 8"H Full W Drawer at bottom
  - 6"H Full W Drawer above bottom drawer
  - 4"H Full W Drawer above 6" drawer
  - Fixed shelf above drawers
- Clamshell Door Above Wheel Well compartment C:
  - Full W shelf at 15 1/2" from compartment ceiling
  - 3"H Full W Drawer below shelf
  - Full H Full W Drawer below 3" drawer
- Rear compartment D:
  - 3 - Adjustable shelves
  - Full W bar to fit in adjustable shelf holder

Curb Side Doors and Compartments:

- Double-door front compartment E:
  - Oxy-Acetylene compartment with
    - Louvered door
    - 2 - J-hooks
    - 2 - Rows of full W E-tracking on all walls
- Single-door second compartment F:
  - 3 - Adjustable shelves
- Clamshell Door Above Wheel Well compartment G:
  - Full W shelf at 15 1/2" from compartment ceiling
  - 3"H Full W Drawer below shelf with fixed dividers
- Single-door rear compartment H:
  - 4 - J-hooks
  - Reinforced for Crane installation

Center Deck:

- ITB Heavy duty extruded aluminum flooring with welded outer seam on center deck
- E-track on roadside wall at 12" above floor from rear to front tool holders
- Four tube tool holder attached to passenger side wall at front under fixed portion of sliding roof
  - Tool holder designs to be confirmed with customer at time of order
- Water pack holder for customer supplied water pack
  - Water pack dimensions to be provided at time of order
- 2 - Rescue style grabhandles mounted at rear - one on each side

Exterior Finishing and Mechanical

- Body installed on customer supplied Dodge 5500 DRW diesel chassis with 84" CA
  - Undercoating in wheel wells
  - ITB Mud flaps with anti-swing brackets
  - Checkerplate running boards

- Automatic Roda Deaco installed on chassis
- Paint exterior white to match cab - PPG premium polyurethane paint process
    - The following components are to be painted:
        - Compartment doors (including vent)
        - Tailgate
        - Sliding roof
        - Side packs and drip mouldings
        - Bumper and outriggers
    - Interior of all compartments to be painted in white speckled Zolatone paint
- Recessed fuel fill to suit
- 20lb ABC Fire extinguisher

Electrical:

- All wiring must be concealed in automotive split loom
    - All connections soldered and enclosed in shrink tube
    - Switch lights at factory upfitter switches or Compartment A if unavailable
- Grote LED DOT sealed lighting
    - 2 - 4" red and 1 - 4" back up lights
    - High and low mount on each side at rear
    - Microdot center lights in rear skirt and sides of bumper
- 10 - Anodized aluminum Lumabar LED compartment strip lights with switch in cab
    - One vertical in each tall compartment except the Oxy-Acetylene compartment
        - One extra in front roadside vertical compartment - two total
    - Two vertical in each above wheel well compartment
- 4 - Grote 63611 Mini Trilliant LED work lights - one on roof at each corner
    - Switched in cab
- 2 - 5" HD LED Amber Warning Beacon Strobes at front of body viewable from all sides
- Rigid 20" Light bar combo spot/flood mounted in center of front bumper with cover
- Engine driven glycol heater in center deck at front with Carling switch in cab
- Zone Defense Z350 Rear View Mirror Backup Camera Monitor with rear bullet cam

Crane:

- Maxilift Cobra Model 5500 RPKE Service Crane
    - Boom light for crane, switch in rear curb side compartment
    - Hydraulic planetary gear winch, high speed and efficiency
    - Unlimited continuous slewing system
    - Two fully hydraulically telescoping boom sections
    - 100' of 5/16" 13,300 lbs. breaking strength cable, non twisting type
    - Radio Remote control with handheld ergonomic and light control box
    - Fully digital proportional controls enable fast smooth precise operation
    - Digital processor, LED display, water proof casing
    - Solenoid operated valves with emergency manual override

Drawing Requirements:

- 3D Proposal Drawings provided

BODY SUB-TOTAL:---------- $67,995.00
CRANE: ---------- $23,655.00
TOTAL: ---------- $91,650.00

TERMS:	25% deposit with balance on delivery OAC
TAXES:	Not Included
DELIVERY:	TBD at time of order
FOB:	Coaldale, AB - Delivery to customer location available with pricing on request

Thank you,

Matthew Van Dyk
Technical Sales

TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

Delivered to AEY 205 Tungsten Rd. Whitehorse YT

Company Name: MEYAU CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2019

Qty Required:

	Mfg Code	Price
Model	DP0L94	60,770
Engine 6.7L Cummins	29G	12,250
Payload Upgrade Package	AH5	NOT AVAILABLE
Max Tow Package	AHQ	325
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	395
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	500
Heated Mirrors	GPG	included
Color: Fleet white	PW7	N/C
Black/Grey seat cloth	X8	725
Front: 40/20/40 split with Lumbar support	*M9	included
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	375
Radio	RA2	included
Interior rubber flooring	CKW	N/C
Option Group 1	AHD	525
Option Group 2	LBN	300
Require 3 keys per vehicle	?	275
Luxury group 795	**Subtotal Per Unit**	79,130
	AC/Tire Tax	240
	AMVIC Fee	N/A
	Freight & Handling	5400
	Fleet Discount	16,000
	Net Price Per Unit	68,770

Submitted by:
Contact name: KEN SCHICK Date: March 25/19

Contact phone number: 867-667-3525 Signature:

Delivery Date:

METRO CHRYSLER LTD.
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Configuration Preview

Date Printed:	2019-03-25 6:44 PM	**VIN:**		**Quantity:**	1
Estimated Ship Date:		**VON:**		**Status:**	BA - Pending order

Sold to:	**Ship to:**
METRO CHRYSLER LTD. (C8523)	METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD	5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4	WHITEHORSE, YT Y1A0A4

Vehicle: **2019 5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN) (DP0L94)**

	Sales Code	Description	MSRP(CAD)
Model:	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	60,770
Package:	2YG	Customer Preferred Package 2YG	2,800
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500
Paint/Seat/Trim:	PW7	Bright White	0
	APA	Monotone paint	0
	*M9	Premium cloth front 40/20/40 bench	725
	-X8	Black w/ Diesel Grey seats	0
Options:	LNJ	Fog lamps	250
	XAC	ParkView(R) Rear Back-Up Camera	475
	XAA	Park-Sense(R) Rear Park Assist System	425
	XBM	Remote start system	395
	AH2	Ambulance Prep Group	500
	AHQ	Max Tow Package	325
	DK3	Elec shift-on-the-fly transfer case	200
	LBN	Power take-off prep - right side	300
	TBB	Full-size spare tire	395
	AHD	Heavy-Duty Snowplow Prep Group	525
	TUZ	225/70R19.5G All-Traction tires	150
	CKW	Add Black vinyl floor covering	0
	ADA	Luxury Group	795
	XHC	Electronic Trailer Brake Controller	375
	5N6	Easy Order	0
	125	Zone 25-Canada-Alberta	0
	4EX		0
Destination Fees:			1,895

extra Key **Total Price:** 80,750 + 275 = 81025

Order Type: Retail
Scheduling Priority: 4-Dealer Order
Salesperson:
Customer Name:
Customer Address:

Instructions:

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

Luxury Group (ADA)

Details:

- Premium overhead console (CUS)
- Locking lower glove box (JKA)
- Power adjustable pedals (XAP)
- Rear power sliding window (GFE)
- Leather-wrapped steering wheel (SCV)
- Rear dome lamp with on/off switch (LHE)
- Steering wheel-mounted audio ctrls (RDZ)
- Dual glove boxes (JKN)
- Glove box lamp (LBC)
- Courtesy lamps (LBB)
- 115-volt aux power outlet - rear (JJN)
- Dual remote USB charging ports (RS4)
- 7-inch colour in-cluster display (JAL)
- 115-volt aux power outlet - IP (JKV)
- Universal garage door opener (XGD)
- Door trim panel foam bottle insert (CWL)
- Sun visors w/ illum vanity mirrors (GNC)

VIP DETAILS

Dealer Code: C8523 **Date: 3/25/2019**

FAN Number:A0391
Account Name:ATCO LTD

VIP#	Model Year	Body Model	Body Model Desc	CPOS	Date Approved	VIP Amount (CAD)	VIP Status
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27A	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27G	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27H	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27M	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YA	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YG	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YH	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YM	02/14/2019	12000	Approved

Uconnect® 3 with 5-inch display (RA2)

Details:

- Overhead console (CUN)
- Temperature and compass gauge (JFJ)
- GPS antenna input (JLP)
- 5-inch touchscreen (RFU)
- Remote USB charging port (RS3)
- Media hub w/ USB & aux input jack (RS6)
- SiriusXM satellite radio (RSD)
- For SiriusXM info call 888-539-7474 (X9A)
- 1-year SiriusXM subscription (X9B)
- Bluetooth® integrated voice command (XRB)

Package Details - 2YG	
Package Contents	**MSRP (CAD)**
6.7L Cummins® I-6 turbo diesel eng	6950
6-speed AISIN® heavy-duty automatic	2500
1-year SiriusXM subscription	0
2-way rear headrests	0
3.5-inch colour in-cluster display	0
4-way front headrests	0
5-inch touchscreen	0
Active noise control system	0
Black exterior mirrors	0
Black wheel flares	0
Black-out tape	0
Blk pwr man fold trailer tow mirror	0
Body insulation	0
Body-colour and bright door handles	0
Bright front bumper	0
Bright grille surround	0
Carpet floor covering	0
Centre stack storage drawer	0
Cloth front 40/20/40 bench seat	0
Daytime running lights - high beam	0
Door sill scuff pads	0
Dual glove boxes	0
Exterior mirrors w/ courtesy lamps	0
Exterior mirrors with turn signals	0
For SiriusXM info call 888-539-7474	0
Front 40/20/40 split bench seat	0
Front and rear floor mats	0
Front armrest with cup holders	0
Front door acoustic glass	0
GPS antenna input	0
Glove box	0
Heated exterior mirrors	0
LED fog lamps	0
Locking lower glove box	0
Manual 4-way adjustable driver seat	0
Manual 4-way adjustable pass seat	0
Map/courtesy lamp	0
Mirror running lights	0
Overhead console	0
Overhead cup holder lamp	0
Painted IP bezels w/ hydrographics	0
Prem vinyl door trim w/ map pocket	0

Quad-lens halogen headlamps	0
Rear dome lamp	0
Rear folding seat	0
Remote keyless entry	0
SLT badge	0
Satin Chrome key fob	0
SiriusXM satellite radio	0
Temperature and compass gauge	0
Tinted acoustic windshield	0
Tire pressure information system	0
Trailer tow mirrors	0
Traveller/mini trip computer	0
Uconnect® 3 with 5-inch display	0
Vinyl shift knob	0
Package Value Price	2800
NET PACKAGE PRICE	**12250**

QUOTATION # AME150419

Date: April 15, 2019

Prepared For: Atco Electric Yukon
Bill Cullen
205 Tungsten Rd
Whitehorse, YT Y1A 0G4
Edmonton, AB T5J 2V6
Phone: 867.633.7057
Cell: 867.336.4017

Prepared By:
General Body & Equipment Ltd.
c/o Mark Edel
8124 Davies Road
Edmonton, AB T6E 4N2
Phone: 780-468-5359
Email: medel@generalbody.ca

General Body & Equipment Ltd. is pleased to present the following for your consideration:

Supply and install one (1) Custom Built Aluminum Service Body
onto customer supplied chassis

Material Specifications For Aluminum Service Bodies:
- Compartment sizes and layout as per customer supplied drawing
- Compartments fabricated from 1/8 in aluminum, stitch welded inside and out
- 3 x 2" aluminum channel cross sills on 16" centers
- 3 x 3" aluminum tubing long sills
- 3/16" aluminum checkerplate floor inside body center

Standard Body Features:
- Heavy duty rolled edge shelving with safety hem
- Extruded aluminum wheel well edge moldings
- 1/8" aluminum checkerplate stone guards installed on both front corners of body
- Heavy duty rear bumper mounted dependent of body
- Fuel spouts are recessed as per Federal safety laws
- One (1) set of rear mud flaps
- All welds and edges are dressed to remove weld spatter, sharp edges and mill scale
- All bolts used are cadmium plated or stainless steel, all nuts are nylock style

Compartment Doors:
- 1/8" aluminum single panel compartment doors fabricated from 5052 aluminum alloy
- Extruded aluminum frames
- Hollow bulb, automotive style, snap-in rubber door seals
- All doors to have gas strut holdback
- Stainless steel hinges on all compartment doors
- Black 3-point "Whale Tail" handle door locks with lock cylinders and rattle proof locks
- All doors are keyed alike
- Integral full length drip moldings above compartment doors

Lighting:
- Tail, stop, signal, back-up, and license lights complete with reflectors to comply with Federal/Canada Motor Vehicle Safety Standard 108
- Clearance lights on separate circuit
- Tail lights are to be LED
- Clearance lights are to be LED
- Backup lights are to be LED
- All electrical connections are soldered and enclosed in heat shrink
- All wiring is concealed and enclosed in split loom
- Luma Bar LED lighting installed in each compartment (not in oxy/acet compartments) with cab mounted on/off switch
- Two (2) LED work lights mounted on top of compartments at front of service body
- Two (2) LED work lights mounted on top of compartments at rear of service body

Paint:
- Complete body is treated for dissimilar metals
- Complete body is phosphatized (metal etching and phosphate coating process)
- Compartment interiors of aluminum service body texture coated grey

- Wheel wells are undercoated
- All seams are caulked

Installation:

- Complete installation in Edmonton on customer supplied suitable cab & chassis
- One (1) year warranty on materials and workmanship
- Five (5) year warranty on rust through of body panels
- CMVSS safety sticker installed on driver's side door jamb

Compartment Configuration:

- Designed and fabricated utilizing computer-aided-design (CAD) methodology
- Overall length: 138" + 7" Bumper
    - Overall width: 96"
    - Overall height: 56"
    - Compartment depth: 24"
- Drivers side front compartment
    - Four (4) 4" drawers on rollout slides
    - Three (3) 8" drawers on rollout slides
- Drivers side second compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) 6" drawers on rollout slides
    - One (1) 8" drawers on rollout slides
- Drivers side horizontal compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) large drawer to fit space below existing top drawer
    - Split door with double lined door to use as work surface
- Drivers side rear compartment
    - Three (3) adjustable shelves
- Passengers side front compartment
    - Vented for carrying bottled gasses per Alberta regulations
    - Two (2) J-hooks
    - Two rows of E-Tracking on all walls
    - Hose wrap on door
- Passengers side second compartment
    - Three (3) adjustable shelves
- Passengers side horizontal compartment
    - One (1) fixed shelf
    - Two (2) 4" drawer on roller slides with adjustable dividers front to back and left to right
    - Split door with double lined door to use as work surface
- Passengers side rear compartment
    - Four j-hooks (1-2-1)
    - One (1) Fixed shelf at floor height
    - Reinforced for Crane
- Cargo area
    - Three (3) piece aluminum sliding roof covering cargo area
    - 26" high rear tailgate, formed from one (1) piece with dual check chains to hold tailgate in open or closed position
    - Stainless steel master lock system
    - Add two (2) Rows of E-Track on driver's side of cargo wall instead of just 1
    - Add two (2) rows of E Track on passenger side cargo wall
    - Four tube tool holder attached to passenger side wall at front under fixed portion of sliding roof Delete
    - Add 6 D rings in cargo floor
    - Add Shovel Bin to the top of the driver’s side pack. Approx. 72” long X 16” deep X 22” Wide

Other features included

- Manual in/out, up/down outrigger bumper
- 2" square hitch receiver tube mounted under bumper at rear
- Spare tire mounted above cargo area front
- Seven prong RV style trailer plug
- Four (4) LED Work lights as noted above in electrical section
- Two (2) Aluminum rubber grip grab handles at rear to access cargo area
- Supply and Install 6" Vise with two vise receivers on top of bumper each side, storage receiver in cargo floor on street side

- GBE grip strut running boards
- Two (2) Jetco 126-67089A-8 LED Strobes Location front of body with pedestal, viewable from all sides
- LED boom light for crane, switch in rear curb side compartment
- 20lb ABC Fire extinguisher
- LED 20" Light bar combo spot/flood mounted in center of front bumper with cover connected to high beam
- Roda Deaco - Fully automatic for Chassis
- Zone Defense Backup Camera Monitor with rear bullet cam

Chassis:

- Dodge 5500 (as per customer specification customer suppied)
  - DRW
  - 84" cab-to-axle
  - diesel engine
  - Automatic transmission
  - Paint: white

Supply One (1) Maxilift Cobra Model 3300 NWE Service Crane

Specifications:

- Hydraulic planetary gear winch, high speed and efficiency
- 400 degree slewing system
- One fully hydraulically one manual telescoping boom sections
- 82 ft of 1/4" cable, non twisting type.
- Tethered handheld ergonomic and light control box
- Digital processor, LED display, water proof casing.
- Solenoid operated valves with emergency manual override
- Painted Cobra white with epoxy primer and fade resistant polyurethane enamel

Technical data:

- Crane rating: 11,500 ft lbs.
- Horizontal reach: 15'
- Slewing angle: 400 degree
- Boom elevation angle: -5 to +72 degrees
- Crane weight: 550 Lbs.

Crane Lifting Capacities:

Feet	Pounds
6"10"	1650
11'1"	1050
15'	750

Installation:

- Install crane and do all necessary electrical hook ups
- Supply and install boom rest
- Manual in/out crane side, manual up/down stabilizers included with body
- Test crane for stability and proper operation of all functions

Complete Aluminum Service Body Package Price: **$75,990.00**

Terms and Conditions

Customer Supplied Equipment and Information:

- Complete Chassis Specification to be provided by Customer at time of Order.
- Truck/Chassis to be supplied to GBE with a minimum 1/4 tank of fuel.

- Fuel charges will be added to invoice if chassis arrives below 1/4 tank
- Relocation of exhaust, Air Tanks, Battery Boxes, Fuel or Urea Tanks will be an additional charge.
- Additional chassis programming required upon chassis arrival at General Body and Equipment will be an additional charge.
- Quote valid for 30 Days. Acceptance of quote after this period will require a review of proposed pricing.

Payment Terms:

- FOB GBE Edmonton
- 30% Down Payment required at time of order.
  - Balance due upon completion of unit at Production facility
  - Unit will be held at GBE Edmonton until payment arrangements have been
- Taxes Extra
- GBE Supplied Products affected by monetary exchange rates may require price build when rates have changed by a differential of 5% from the date was officially
- Third Party Financing Options available on request.

Warranty Terms:

- All Warranty work to be completed by GBE. If geography prevents the unit from being warranty repairs, prior to any work being completed by a third party, third party provided in writting and approved by GBE,
- 1-year Defects in Material and Workmanship.
- 1-year on all parts, materials and equipment (Some third party equipment warranties ask salesman for details)
- 2-years on de-lamination (Rock Chips excluded).
- 5-years No Rust-through guarantee.
- In accordance with GBE's Continuous Improvement program, specifications are subject to without notice or obligation

Change Order Policies:

- Minimum Change order costs after Specifications and Drawings are approved by customer
  - Change order at less than 25% project completion = Minimum $500 charge + delivery delay
  - Change order at greater than 25% project completion = Minimum $1,000 charge + delivery delay
  - If Customer Supplied Chassis does not match Chassis specification used in associated modification cost + minimum 1-week delivery delay

Cancellation Policy:

- Cancellation must be communicated to General Body and Equipment in writing
- Resulting Cancellation Costs are the responsibility of the customer as follows:
  - Cancellation prior to start of Purchasing/Fabrication process = No Charge
  - Cancellation after start of Purchasing/Fabrication process = All labour and material up to and including date of written notice plus any re-stocking charges associated with return of materials to vendors.

Delivery:

18000004 75 Metro Chrysler

ATCO Electric

Goods and Services Request (GSR Form)

RECEIVED APR 18 2019

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Bill Cullen

Department: AEY Oprerations

VP / GM: Doug Tenney

Ph. / Email: bill.cullen@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact):

Owner Representative: Amy Miller

Project Name: 1012337 Replace Unit 091 C-05.000

Requisition Number: *no longer required by SCM

Project Location: Whitehorse

CEAR: Approved ☐ NOT Required ☑

Region: Yukon

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☐ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: / Completion:

- or -

Delivery / Installation required by: 2019-12-31

Total Estimated Value: 68,770.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years):

Maximum Release Value:

Minimum Release Value:

Estimated # of Releases / year:

Estimated Annual Value:

Goods and Services Request

2. Scope of Work Document name: Replace Unit 091 Date of issue: 25-Mar-19 Number of pages: 7

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

Metro Chrysler to supply 1 New Ram 5500 Crew Cab Chassis.

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

Vehicle to be delivered to Whitehorse Yukon

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☐ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

This document is an uncontrolled printed copy. Please see Supply Chain Management for a controlled copy.
TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☑	to FOLLOW	☐
b) Drawings and / or blueprints	attached	☐	NOT required	☐	to FOLLOW	☐
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐
d) HSE Hazard Requirements	LOW ☐ attached ☐ to FOLLOW		MEDIUM ☐ attached ☐ to FOLLOW		HIGH ☐ attached ☐ to FOLLOW	
e) Forest Fire Fighting Expense Insurance Waiver:	Waived ☐		Insurance Required ☐		NOT Required (Goods) ☑	

Comments:

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Single Sourced ☑
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source. (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Field Bid ☐
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☑ Unit Rate ☐
Hourly Rate ☐ Combined ☐ a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** Metro Chrysler Ltd.	Attn: Ken Schick	**HSE Pre-Assessed**
Address: 5 Two Mile Hill Road, Whitehorse YT	Tel: 867-667-2525	Yes ☐ No ☐
Email: ken@metrochrysler.ca	Fax:	
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**
Address:	Tel:	Yes ☐ No ☐
Email:	Fax:	
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**
Address:	Tel:	Yes ☐ No ☐
Email:	Fax:	

Suggested Service Request

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

d) **Full Legal Name:** _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.

0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal	
Safety Record	
Proposed Schedule	
Availability of Resources	
Depth of Experience	
Reputation / Qualifications	
Creative Solutions	
Accuracy / Conciseness of Bid	
Other:	Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

Goods and Services Request

This document is an uncontrolled printed copy. Please see Supply Chain Management for a controlled copy.
TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part F. Single or Sole Source Justification

Supply Chain Management G93 Purchase Process Control states:

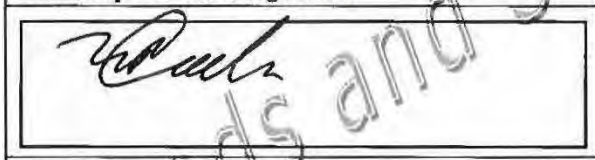
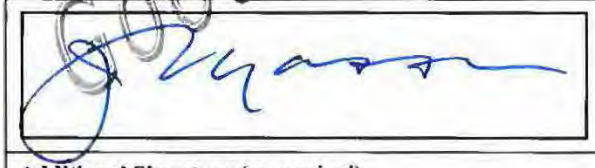
Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Vehicle was ordered from Metro Chrysler as it was the lowest quote as well as being a preferred ATCO supplier.

Goods and Services Request

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
	Bill Cullen 16-April-19
Manager Signature	Print name and date MM-DD-YY
	Jay Massie April 17/19
Additional Signature (as required)	Print name and date MM-DD-YY

End of **GOODS AND SERVICES REQUEST FORM**

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TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

Delivered to AEY 205 Tungsten Rd. Whitehorse YT

Company Name: METRO CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2019.

Qty Required:

	Mfg Code	Price
Model	DP0L94	60,770
Engine 6.7L Cummins	29G	12,250
Payload Upgrade Package	AH5	NOT AVAILABLE
Max Tow Package	AHQ	375
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	395
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	500
Heated Mirrors	GPG	included
Color: Fleet white	PW7	NC
Black/Grey seat cloth	X8	725
Front: 40/20/40 split with Lumbar support	*M9	included
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	375
Radio	RA2	included
Interior rubber flooring	CKW	NC
Option Group 1	AHD	525
Option Group 2	LBN	300
Require 3 keys per vehicle	?	275
Luxury group 795	**Subtotal Per Unit**	79,130
	AC/Tire Tax	240
	AMVIC Fee	N/A
	Freight & Handling	5400
	Fleet Discount	16,000
	Net Price Per Unit	68,770

Submitted by:
Contact name: KEN SCHICK
Date: March 25/19
Contact phone number: 867-667-2525
Signature:
Delivery Date:

METRO CHRYSLER LTD.
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Configuration Preview

Date Printed:	2019-03-25 6:44 PM	**VIN:**		**Quantity:**	1
Estimated Ship Date:		**VON:**		**Status:**	BA - Pending order

Sold to:
METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Ship to:
METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Vehicle: **2019 5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN) (DP0L94)**

	Sales Code	Description	MSRP(CAD)
Model:	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	60,770
Package:	2YG	Customer Preferred Package 2YG	2,800
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500
Paint/Seat/Trim:	PW7	Bright White	0
	APA	Monotone paint	0
	*M9	Premium cloth front 40/20/40 bench	725
	-X8	Black w/ Diesel Grey seats	0
Options:	LNJ	Fog lamps	250
	XAC	ParkView(R) Rear Back-Up Camera	475
	XAA	Park-Sense(R) Rear Park Assist System	425
	XBM	Remote start system	395
	AH2	Ambulance Prep Group	500
	AHQ	Max Tow Package	325
	DK3	Elec shift-on-the-fly transfer case	200
	LBN	Power take-off prep - right side	300
	TBB	Full-size spare tire	395
	AHD	Heavy-Duty Snowplow Prep Group	525
	TUZ	225/70R19.5G All-Traction tires	150
	CKW	Add Black vinyl floor covering	0
	ADA	Luxury Group	795
	XHC	Electronic Trailer Brake Controller	375
	5N6	Easy Order	0
	125	Zone 25-Canada-Alberta	0
	4EX		0
Destination Fees:			1,895

Total Price: 80,750
extra key 275
81025

Order Type: Retail
Scheduling Priority: 4-Dealer Order
Salesperson:
Customer Name:
Customer Address:

Instructions:

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

Luxury Group (ADA)

Details:

- Premium overhead console (CUS)
- Locking lower glove box (JKA)
- Power adjustable pedals (XAP)
- Rear power sliding window (GFE)
- Leather-wrapped steering wheel (SCV)
- Rear dome lamp with on/off switch (LHE)
- Steering wheel-mounted audio ctrls (RDZ)
- Dual glove boxes (JKN)
- Glove box lamp (LBC)
- Courtesy lamps (LBB)
- 115-volt aux power outlet - rear (JJN)
- Dual remote USB charging ports (RS4)
- 7-inch colour in-cluster display (JAL)
- 115-volt aux power outlet - IP (JKV)
- Universal garage door opener (XGD)
- Door trim panel foam bottle insert (CWL)
- Sun visors w/ illum vanity mirrors (GNC)

VIP DETAILS

Dealer Code: C8523 **Date: 3/25/2019**

FAN Number:A0391
Account Name:ATCO LTD

VIP#	Model Year	Body Model	Body Model Desc	CPOS	Date Approved	VIP Amount (CAD)	VIP Status
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27A	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27G	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27H	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27M	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YA	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YG	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YH	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YM	02/14/2019	12000	Approved

Uconnect® 3 with 5-inch display (RA2)

Details:

- Overhead console (CUN)
- Temperature and compass gauge (JFJ)
- GPS antenna input (JLP)
- 5-inch touchscreen (RFU)
- Remote USB charging port (RS3)
- Media hub w/ USB & aux input jack (RS6)
- SiriusXM satellite radio (RSD)
- For SiriusXM info call 888-539-7474 (X9A)
- 1-year SiriusXM subscription (X9B)
- Bluetooth® integrated voice command (XRB)

Package Details - 2YG	
Package Contents	MSRP (CAD)
6.7L Cummins® I-6 turbo diesel eng	6950
6-speed AISIN® heavy-duty automatic	2500
1-year SiriusXM subscription	0
2-way rear headrests	0
3.5-inch colour in-cluster display	0
4-way front headrests	0
5-inch touchscreen	0
Active noise control system	0
Black exterior mirrors	0
Black wheel flares	0
Black-out tape	0
Blk pwr man fold trailer tow mirror	0
Body insulation	0
Body-colour and bright door handles	0
Bright front bumper	0
Bright grille surround	0
Carpet floor covering	0
Centre stack storage drawer	0
Cloth front 40/20/40 bench seat	0
Daytime running lights - high beam	0
Door sill scuff pads	0
Dual glove boxes	0
Exterior mirrors w/ courtesy lamps	0
Exterior mirrors with turn signals	0
For SiriusXM info call 888-539-7474	0
Front 40/20/40 split bench seat	0
Front and rear floor mats	0
Front armrest with cup holders	0
Front door acoustic glass	0
GPS antenna input	0
Glove box	0
Heated exterior mirrors	0
LED fog lamps	0
Locking lower glove box	0
Manual 4-way adjustable driver seat	0
Manual 4-way adjustable pass seat	0
Map/courtesy lamp	0
Mirror running lights	0
Overhead console	0
Overhead cup holder lamp	0
Painted IP bezels w/ hydrographics	0
Prem vinyl door trim w/ map pocket	0

Quad-lens halogen headlamps	0
Rear dome lamp	0
Rear folding seat	0
Remote keyless entry	0
SLT badge	0
Satin Chrome key fob	0
SiriusXM satellite radio	0
Temperature and compass gauge	0
Tinted acoustic windshield	0
Tire pressure information system	0
Trailer tow mirrors	0
Traveller/mini trip computer	0
Uconnect® 3 with 5-inch display	0
Vinyl shift knob	0
Package Value Price	2800
NET PACKAGE PRICE	**12250**

FORD
81,969.—

Whitehorse Motors Ltd. Tel: (867) 667-7866 Fax: (867) 667-6246

4178 4th Avenue, Whitehorse, YT, Y1A 1J6 Dealer #: B7190 GST/HST#: **105669923**

Offer to Purchase prepared for: Bill Cullen **4/3/2019**

Prepared By: Ricky Campbell Home: Mobile: (867) 336-4017 Quote #: **20511874**

2019 Ford F550 4x4 - Chassis Crew Cab XLT - 203" WB **Designed**

Ext. Colour:	Z123 - Oxford White
Int. Colour:	3S23 - Cloth - Medium Eart
Total KMs:	90 (anticipated)
Warranty:	
In-Serv. Date:	
VIN:	
Status:	New
Sp. Status:	NA

Body Style
Pick up

Transmission
Automatic

MSRP OPTIONS

W5H - F550 4x4 - Chassis Crew Cab XLT - 203" WB	$63,049.00
166 - Delete Carpet	$0.00
17V - XLT Value Package	$450.00
18A - Upfitter Interface Module	$400.00
18B - Platform Running Boards	$490.00
213 - Electronic-Shift-On-The-Fly	$200.00
3S23 - Cloth - Medium Earth Grey	$0.00
41P - Transfer Case Skid Plates	$200.00
435 - Power-sliding with Privacy Glass and Defrost	$550.00
43C - 110v/400w Outlet	$250.00
44W-02 - 6 Speed Automatic (44w) - Automatic	$0.00
47A-F - Ambulance Prep Package (Fleet Only)	$1,250.00
52B - Trailer Brake Controller	$350.00
Other MSRP Options	$14,780.00
TOTAL MSRP	**$81,969.00**
SALE PRICE	**$81,969.00**

DEALER OPTIONS AND CHARGES

Tire Levy	$35.00

ATCO Electric

Reg 1800000476 General Body

Goods and Services Request (GSR Form)

RECEIVED
APR 18 2019

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Bill Cullen

Department: AEY Oprerations

VP / GM: Doug Tenney

Ph. / Email: bill.cullen@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact):

Owner Representative: Amy Miller

Project Name: 1012337 Replace Unit 091 - SBody

Requisition Number: *no longer required by SCM

Project Location: Whitehorse C-05-000

CEAR: Approved ☐ NOT Required ☐

Region: Yukon

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☐ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: _____ / Completion: _____

- or -

Delivery / Installation required by: 2019-11-30

Total Estimated Value: 75,990.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years):

Maximum Release Value:

Minimum Release Value:

Estimated # of Releases / year:

Estimated Annual Value:

Goods and Services Request

2. Scope of Work Document name: PQuot # AME150419 Date of issue: 15-Apr-19 Number of pages: 4

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

General Body and Equipment to supply and install 1 Custom Built deck as per Quote AME150419

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

OWNER to supply Cab/Chassis for deck to be installed on.

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☐ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

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ATCO Electric

Goods and Services Request (GSR Form)

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3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☐	to FOLLOW	☐
b) Drawings and / or blueprints	attached	☐	NOT required	☐	to FOLLOW	☐
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐

d) HSE Hazard Requirements — LOW ☐ attached ☐ to FOLLOW; MEDIUM ☐ attached ☐ to FOLLOW; HIGH ☐ attached ☐ to FOLLOW

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments:

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Single Sourced ☑
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Field Bid ☐
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☑ Unit Rate ☐
Hourly Rate ☐ Combined ☐ a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** General Body and Equipment	Attn: Mark Edel	**HSE Pre-Assessed**		
Address: 8124 Davies Rd Edmonton, AB T6E 4N2	Tel: 780-468-5359	Yes ☐	No ☑	
Email: medel@generalbody.ca	Fax:			
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			

Goods and Services Request

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d) **Full Legal Name**: _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.

0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal	
Safety Record	
Proposed Schedule	
Availability of Resources	
Depth of Experience	
Reputation / Qualifications	
Creative Solutions	
Accuracy / Conciseness of Bid	
Other:	Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

Goods and Services Request

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ATCO Electric

Goods and Services Request (GSR Form)

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Part F. Single or Sole Source Justification

Supply Chain Management G93 Purchase Process Control states:

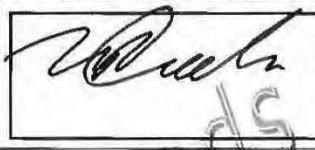
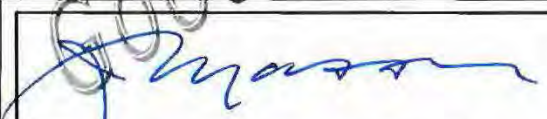
Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Custom deck was ordered from General Body as they designed and manufactured the previous deck and were the lowest quote at the time. Price this year remains unchanged.

Goods and Services Request

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
	Bill Cullen 16-Apr-2019
Manager Signature	Print name and date MM-DD-YY
	Jay Massie April 17/19
Additional Signature (as required)	Print name and date MM-DD-YY

End of **GOODS AND SERVICES REQUEST FORM**

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GENERAL BODY AND EQUIPMENT

QUOTATION # AME150419

Date: April 15, 2019

Prepared For: Atco Electric Yukon
Bill Cullen
205 Tungsten Rd
Whitehorse, YT Y1A 0G4
Edmonton, AB T5J 2V6
Phone: 867.633.7057
Cell: 867.336.4017

Prepared By:
General Body & Equipment Ltd.
c/o Mark Edel
8124 Davies Road
Edmonton, AB T6E 4N2
Phone: 780-468-5359
Email: medel@generalbody.ca

General Body & Equipment Ltd. is pleased to present the following for your consideration:

Supply and Install one (1) Custom Built Aluminum Service Body
onto customer supplied chassis

Material Specifications For Aluminum Service Bodies:
- Compartment sizes and layout as per customer supplied drawing
- Compartments fabricated from 1/8 in aluminum, stitch welded inside and out
- 3 x 2" aluminum channel cross sills on 16" centers
- 3 x 3" aluminum tubing long sills
- 3/16" aluminum checkerplate floor inside body center

Standard Body Features:
- Heavy duty rolled edge shelving with safety hem
- Extruded aluminum wheel well edge moldings
- 1/8" aluminum checkerplate stone guards installed on both front corners of body
- Heavy duty rear bumper mounted dependent of body
- Fuel spouts are recessed as per Federal safety laws
- One (1) set of rear mud flaps
- All welds and edges are dressed to remove weld spatter, sharp edges and mill scale
- All bolts used are cadmium plated or stainless steel, all nuts are nylock style

Compartment Doors:
- 1/8" aluminum single panel compartment doors fabricated from 5052 aluminum alloy
- Extruded aluminum frames
- Hollow bulb, automotive style, snap-in rubber door seals
- All doors to have gas strut holdback
- Stainless steel hinges on all compartment doors
- Black 3-point "Whale Tail" handle door locks with lock cylinders and rattle proof locks
- All doors are keyed alike
- Integral full length drip moldings above compartment doors

Lighting:
- Tail, stop, signal, back-up, and license lights complete with reflectors to comply with Federal/Canada Motor Vehicle Safety Standard 108
- Clearance lights on separate circuit
- Tail lights are to be LED
- Clearance lights are to be LED
- Backup lights are to be LED
- All electrical connections are soldered and enclosed in heat shrink
- All wiring is concealed and enclosed in split loom
- Luma Bar LED lighting installed in each compartment (not in oxy/acet compartments) with cab mounted on/off switch
- Two (2) LED work lights mounted on top of compartments at front of service body
- Two (2) LED work lights mounted on top of compartments at rear of service body

Paint:
- Complete body is treated for dissimilar metals
- Complete body is phosphatized (metal etching and phosphate coating process)
- Compartment interiors of aluminum service body texture coated grey

- Wheel wells are undercoated
- All seams are caulked

Installation:

- Complete installation in Edmonton on customer supplied suitable cab & chassis
- One (1) year warranty on materials and workmanship
- Five (5) year warranty on rust through of body panels
- CMVSS safety sticker installed on driver's side door jamb

Compartment Configuration:

- Designed and fabricated utilizing computer-aided-design (CAD) methodology
- Overall length: 138" + 7" Bumper
    - Overall width: 96"
    - Overall height: 56"
    - Compartment depth: 24"
- Drivers side front compartment
    - Four (4) 4" drawers on rollout slides
    - Three (3) 8" drawers on rollout slides
- Drivers side second compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) 6" drawers on rollout slides
    - One (1) 8" drawers on rollout slides
- Drivers side horizontal compartment
    - One (1) fixed shelf
    - One (1) 4" drawers on rollout slides
    - One (1) large drawer to fit space below existing top drawer
    - Split door with double lined door to use as work surface
- Drivers side rear compartment
    - Three (3) adjustable shelves
- Passengers side front compartment
    - Vented for carrying bottled gasses per Alberta regulations
    - Two (2) J-hooks
    - Two rows of E-Tracking on all walls
    - Hose wrap on door
- Passengers side second compartment
    - Three (3) adjustable shelves
- Passengers side horizontal compartment
    - One (1) fixed shelf
    - One (1) 4" heavy duty divided bolt bin on roll out slides
    - One (1) 4" drawer on roller slides with adjustable dividers front to back and left to right
    - Split door with double lined door to use as work surface
- Passengers side rear compartment
    - Four j-hooks (1-2-1)
    - One (1) Fixed shelf at floor height
    - Reinforced for Crane
- Cargo area
    - Three (3) piece aluminum sliding roof covering cargo area
    - 26" high rear tailgate, formed from one (1) piece with dual check chains to hold tailgate in open or closed position
    - Stainless steel master lock system
    - Add two (2) Rows of E-Track on driver's side of cargo wall instead of just 1
    - Add two (2) rows of E Track on passenger side cargo wall
    - Four tube tool holder attached to passenger side wall at front under fixed portion of sliding roof Delete
    - Add 6 D rings in cargo floor
    - Add Shovel Bin to the top of the driver's side pack. Approx. 72" long X 16" deep X 22" Wide

Other features included

- Manual in/out, up/down outrigger bumper
- 2" square hitch receiver tube mounted under bumper at rear
- Spare tire mounted above cargo area front
- Seven prong RV style trailer plug
- Four (4) LED Work lights as noted above in electrical section
- Two (2) Aluminum rubber grip grab handles at rear to access cargo area

- Supply and Install 6" Vise with two vise receivers on top of bumper each side, storage receiver in cargo floor on street side
- GBE grip strut running boards
- Two (2) Jetco 126-67089A-8 LED Strobes Location front of body with pedestal, viewable from all sides
- LED boom light for crane, switch in rear curb side compartment
- 20lb ABC Fire extinguisher
- LED 20" Light bar combo spot/flood mounted in center of front bumper with cover connected to high beam
- Roda Deaco - Fully automatic for Chassis
- Zone Defense Backup Camera Monitor with rear bullet cam

Chassis:

- Dodge 5500 (as per customer specification customer suppied)
  - DRW
  - 84" cab-to-axle
  - diesel engine
  - Automatic transmission
  - Paint: white

Supply One (1) Maxilift Cobra Model 3300 NWE Service Crane

Specifications:

- Hydraulic planetary gear winch, high speed and efficiency
- 400 degree slewing system
- One fully hydraulically one manual telescoping boom sections
- 82 ft of 1/4" cable, non twisting type.
- Tethered handheld ergonomic and light control box
- Digital processor, LED display, water proof casing.
- Solenoid operated valves with emergency manual override
- Painted Cobra white with epoxy primer and fade resistant polyurethane enamel

Technical data:

- Crane rating: 11,500 ft lbs.
- Horizontal reach: 15'
- Slewing angle: 400 degree
- Boom elevation angle: -5 to +72 degrees
- Crane weight: 550 Lbs.

Crane Lifting Capacities:

Feet	Pounds
6"10"	1650
11'1"	1050
15'	750

Installation:

- Install crane and do all necessary electrical hook ups
- Supply and install boom rest
- Manual in/out crane side, manual up/down stabilizers included with body
- Test crane for stability and proper operation of all functions

Complete Aluminum Service Body Package Price: $75,990.00

Terms and Conditions

Customer Supplied Equipment and Information:

- Complete Chassis Specification to be provided by Customer at time of Order.

- Truck/Chassis to be supplied to GBE with a minimum 1/4 tank of fuel.
    - Fuel charges will be added to invoice if chassis arrives below 1/4 tank
- Relocation of exhaust, Air Tanks, Battery Boxes, Fuel or Urea Tanks will be an additional charge.
- Quote valid for 30 Days. Acceptance of quote after this period will require a review of proposed pricing.

Payment Terms:

- FOB GBE Edmonton
- 30% Down Payment required at time of order.
    - Balance due upon completion of unit at Production facility
    - Unit will be held at GBE Edmonton until payment arrangements have been
- Taxes Extra
- GBE Supplied Products affected by monetary exchange rates may require price build when rates have changed by a differential of 5% from the date was officially
- Third Party Financing Options available on request.

Warranty Terms:

- All Warranty work to be completed by GBE. If geography prevents the unit from being warranty repairs, prior to any work being completed by a third party, third party provided in writting and approved by GBE,
- 1-year Defects in Material and Workmanship.
- 1-year on all parts, materials and equipment (Some third party equipment warranties ask salesman for details)
- 2-years on de-lamination (Rock Chips excluded).
- 5-years No Rust-through guarantee.
- In accordance with GBE's Continuous Improvement program, specifications are subject to without notice or obligation

Change Order Policies:

- Minimum Change order costs after Specifications and Drawings are approved by customer
    - Change order at less than 25% project completion = Minimum $500 charge + delivery delay
    - Change order at greater than 25% project completion = Minimum $1,000 charge + delivery delay
    - If Customer Supplied Chassis does not match Chassis specification used in associated modification cost + minimum 1-week delivery delay

Cancellation Policy:

- Cancellation must be communicated to General Body and Equipment in writing
- Resulting Cancellation Costs are the responsibility of the customer as follows:
    - Cancellation prior to start of Purchasing/Fabrication process = No Charge
    - Cancellation after start of Purchasing/Fabrication process = All labour and material up to and including date of written notice plus any re-stocking charges associated with return of materials to vendors.

Acceptance by customer:_____ **Date:** _____

TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

Delivered to AEY 205 Tungsten Rd. Whitehorse YT

Company Name: MEYAU CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2019

Qty Required:

	Mfg Code	Price
Model	DP0L94	60,770
Engine 6.7L Cummins	29G	12,250
Payload Upgrade Package	AH5	NOT AVAILABLE
Max Tow Package	AHQ	325
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	395
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	500
Heated Mirrors	GPG	included
Color: Fleet white	PW7	N/C
Black/Grey seat cloth	X8	725
Front: 40/20/40 split with Lumbar support	*M9	included
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	375
Radio	RA2	included
Interior rubber flooring	CKW	N/C
Option Group 1	AHD	525
Option Group 2	LBN	300
Require 3 keys per vehicle	?	275
Luxury group 795	**Subtotal Per Unit**	79,130
	AC/Tire Tax	240
	AMVIC Fee	N/A
	Freight & Handling	5400
	Fleet Discount	16,000
	Net Price Per Unit	68,770

Submitted by:
Contact name: KEN SCHICK Date: March 25/19

Contact phone number: 867-667-3525 Signature:

Delivery Date:

METRO CHRYSLER LTD.
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Configuration Preview

Date Printed:	2019-03-25 6:44 PM	**VIN:**		**Quantity:**	1
Estimated Ship Date:		**VON:**		**Status:**	BA - Pending order

Sold to:
METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Ship to:
METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Vehicle: **2019 5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN) (DP0L94)**

	Sales Code	Description	MSRP(CAD)
Model:	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	60,770
Package:	2YG	Customer Preferred Package 2YG	2,800
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500
Paint/Seat/Trim:	PW7	Bright White	0
	APA	Monotone paint	0
	*M9	Premium cloth front 40/20/40 bench	725
	-X8	Black w/ Diesel Grey seats	0
Options:	LNJ	Fog lamps	250
	XAC	ParkView(R) Rear Back-Up Camera	475
	XAA	Park-Sense(R) Rear Park Assist System	425
	XBM	Remote start system	395
	AH2	Ambulance Prep Group	500
	AHQ	Max Tow Package	325
	DK3	Elec shift-on-the-fly transfer case	200
	LBN	Power take-off prep - right side	300
	TBB	Full-size spare tire	395
	AHD	Heavy-Duty Snowplow Prep Group	525
	TUZ	225/70R19.5G All-Traction tires	150
	CKW	Add Black vinyl floor covering	0
	ADA	Luxury Group	795
	XHC	Electronic Trailer Brake Controller	375
	5N6	Easy Order	0
	125	Zone 25-Canada-Alberta	0
	4EX		0
Destination Fees:			1,895

Total Price: 80,750

extra key 275

81025

Order Type: Retail
Scheduling Priority: 4-Dealer Order
Salesperson:
Customer Name:
Customer Address:

Instructions:

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

Luxury Group (ADA)

Details:

- Premium overhead console (CUS)
- Locking lower glove box (JKA)
- Power adjustable pedals (XAP)
- Rear power sliding window (GFE)
- Leather-wrapped steering wheel (SCV)
- Rear dome lamp with on/off switch (LHE)
- Steering wheel-mounted audio ctrls (RDZ)
- Dual glove boxes (JKN)
- Glove box lamp (LBC)
- Courtesy lamps (LBB)
- 115-volt aux power outlet - rear (JJN)
- Dual remote USB charging ports (RS4)
- 7-inch colour in-cluster display (JAL)
- 115-volt aux power outlet - IP (JKV)
- Universal garage door opener (XGD)
- Door trim panel foam bottle insert (CWL)
- Sun visors w/ illum vanity mirrors (GNC)

VIP DETAILS

Dealer Code: C8523 **Date: 3/25/2019**

FAN Number:A0391
Account Name:ATCO LTD

VIP#	Model Year	Body Model	Body Model Desc	CPOS	Date Approved	VIP Amount (CAD)	VIP Status
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27A	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27G	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27H	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27M	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YA	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YG	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YH	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YM	02/14/2019	12000	Approved

Uconnect® 3 with 5-inch display (RA2)

Details:

- Overhead console (CUN)
- Temperature and compass gauge (JFJ)
- GPS antenna input (JLP)
- 5-inch touchscreen (RFU)
- Remote USB charging port (RS3)
- Media hub w/ USB & aux input jack (RS6)
- SiriusXM satellite radio (RSD)
- For SiriusXM info call 888-539-7474 (X9A)
- 1-year SiriusXM subscription (X9B)
- Bluetooth® integrated voice command (XRB)

Package Details - 2YG	
Package Contents	**MSRP (CAD)**
6.7L Cummins® I-6 turbo diesel eng	6950
6-speed AISIN® heavy-duty automatic	2500
1-year SiriusXM subscription	0
2-way rear headrests	0
3.5-inch colour in-cluster display	0
4-way front headrests	0
5-inch touchscreen	0
Active noise control system	0
Black exterior mirrors	0
Black wheel flares	0
Black-out tape	0
Blk pwr man fold trailer tow mirror	0
Body insulation	0
Body-colour and bright door handles	0
Bright front bumper	0
Bright grille surround	0
Carpet floor covering	0
Centre stack storage drawer	0
Cloth front 40/20/40 bench seat	0
Daytime running lights - high beam	0
Door sill scuff pads	0
Dual glove boxes	0
Exterior mirrors w/ courtesy lamps	0
Exterior mirrors with turn signals	0
For SiriusXM info call 888-539-7474	0
Front 40/20/40 split bench seat	0
Front and rear floor mats	0
Front armrest with cup holders	0
Front door acoustic glass	0
GPS antenna input	0
Glove box	0
Heated exterior mirrors	0
LED fog lamps	0
Locking lower glove box	0
Manual 4-way adjustable driver seat	0
Manual 4-way adjustable pass seat	0
Map/courtesy lamp	0
Mirror running lights	0
Overhead console	0
Overhead cup holder lamp	0
Painted IP bezels w/ hydrographics	0
Prem vinyl door trim w/ map pocket	0

Quad-lens halogen headlamps	0
Rear dome lamp	0
Rear folding seat	0
Remote keyless entry	0
SLT badge	0
Satin Chrome key fob	0
SiriusXM satellite radio	0
Temperature and compass gauge	0
Tinted acoustic windshield	0
Tire pressure information system	0
Trailer tow mirrors	0
Traveller/mini trip computer	0
Uconnect® 3 with 5-inch display	0
Vinyl shift knob	0
Package Value Price	2800
NET PACKAGE PRICE	**12250**

Production Number:

FalCan Industries Ltd.
Box 1178
Fort Macleod, Alberta
T0L 0Z0

FALCAN INDUSTRIES LTD.

Tel: (403) 553-2114
Fax: (403) 553-2527

Salesperson:

Bill To:
ATCO YUKON

Ship To:

Invoice:
Invoice Date:
PO:
Quote Date: 7/8/2019
Ship Date:
Terms:

Pending

INSTRUCTIONS:

Phone: (867) 633-7007 Cell: (867) 633-7007 Fax: (867) 668-6692

Qty	Description	Price	Disc	Ext Price
	DODGE 5500 2019 84" CA 6.7 DIESEL			
1	2019 STEEL FLOOR DECK-134"- SERIAL:	$6,891.00		$6,891.00
1	COLOR: WHITE	$675.00		$675.00
2	CUSTOM CABINET WITH TAPERED TOP	$2,693.81		$5,387.62
1	DRAWER SYSTEM 4-2.5" & 1-5.5" WITH TOP SHELF	$1,250.00		$1,250.00
1	TOP THROUGH CABINET (SEE PICTURES)	$531.00		$531.00
2	HOOKS AROUND TOP OF CABINET	$113.30		$226.60
6	LIGHTS IN CABINETS (SIDES) (THROUGH) (TOP)(LOWER)	$200.85		$1,205.10
2	FRONT TOOL BOX WG-24"	$595.00		$1,190.00
1	MUD FLAPS AT REAR OF DECK	$135.00		$135.00
1	4 POST REEL STAND CAN BE TURNED / DECK RECEIVERS	$2,184.00		$2,184.00
1	RV 7 POLE AT REAR OF DECK	$103.00		$103.00
1	REAR PULL OUT 6 FT STORAGE BOX ON 5 FT SLIDERS	$1,530.00		$1,530.00
1	CABINET LIGHTS (BRAKE,TAIL,MARKER)	$370.00		$370.00
1	REMOVABLE SIDES FOLD DOWN REAR GATE	$1,464.00		$1,464.00
2	LED LOW PRO STROBES LIGHTS FRONT	$381.00		$762.00
1	FRONT WINCH BUMPER INSTALLED (BP PRE RUNNER)INSTALLED	$3,300.00		$3,300.00
1	WARN WINCH 12,500 LB INSTALLED	$2,849.00		$2,849.00
1	HYDRAULIC POWER WINDER FOR REEL STAND	$3,868.00		$3,868.00
1	POWERED BY HYDRAULIC PTO & PUMP INSTALLED	$5,104.00		$5,104.00
1	MH-C2 SLIM LINE COOLER(FOR HYDRAULIC OIL) INSTALLED	$4,280.00		$4,280.00
1	QUICK COUPLERS AND VAVLE BANK, FLOW CONTROL HOSING, ETC	$2,200.00		$2,200.00

Notes:
THANK YOU - WE APPRECIATE YOUR BUSINESS. **PLEASE NOTE - STEEL IS SOLD BY FULL FOOT.

Subtotal	$58,429.16
Tax @ 5.0%	$2,921.46
Less Deposit	-$
Total	**$61,350.62**

Please Print Name, Sign and Date

1-BP ALL PRICES ARE F.O.B OUR PLANT. INVOICE DUE UPON RECEIPT. G.S.T. # R126180561

Production Number:

FalCan Industries Ltd.
Box 1178
Fort Macleod, Alberta
T0L 0Z0

FALCAN INDUSTRIES LTD.

Tel: (403) 553-2114
Fax: (403) 553-2527

Salesperson:

Bill To:
ATCO YUKON

Ship To:

Invoice:
Invoice Date:
PO:
Quote Date: 7/8/2019
Ship Date:
Terms:

Pending

INSTRUCTIONS:

Phone: (867) 633-7007 Cell: (867) 633-7007 Fax: (867) 668-6692

Qty	Description	Price	Disc	Ext Price
1	ESPAR HEATER FOR CABINET INSTALLED	$3,700.00		$3,700.00
1	GO LIGHT LED (20074)	$984.00		$984.00
1	INSTALLED ON MOUNT CENTER FRONT CABINET	$320.00		$320.00
1	TOP OPEN BOX ON TOP OF CABINET (12" DEEP)	$850.00		$850.00
1	FLOOD LIGHTS 3" CUBES FLUSH MOUNT FACING REAR	$396.00		$396.00
1	FLOOD LIGHTS 3" CUBES FLUSH MOUNT FACING SIDES	$701.00		$701.00
6	FALCAN SURFACE MOUNT STROBES 12 WATT	$132.14		$792.84
6	INSTALL SURFACE MOUNT STROBES	$110.00		$660.00
1	DEFENDER CAMERA (HEATED)	$1,188.00		$1,188.00
	ZONE DEFENSE 5" RUGGED ZD-322-1-R-CH			
3	INSTALL OF CAMERA	$110.00		$330.00
1	ANTI SLIP COATING ON DECK TOP (BLACK)	$1,450.00		$1,450.00
6	SWIVEL FLUSH MOUNT D-RING IN DECK (3 PER SIDE)	$78.00		$468.00
1	CUSTOM STEEL TOP DECK INSTALLED	$1,884.00		$1,884.00

Notes:
THANK YOU - WE APPRECIATE YOUR BUSINESS. **PLEASE NOTE - STEEL IS SOLD BY FULL FOOT.

Subtotal	$58,429.16
Tax @ 5.0%	$2,921.46
Less Deposit	-$
Total	**$61,350.62**

Please Print Name, Sign and Date

1-BP ALL PRICES ARE F.O.B OUR PLANT. INVOICE DUE UPON RECEIPT. G.S.T. # R126180561

Req 1800000738

RECEIVED
JUL 30 2019

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Bill Cullen

Department: AEY Oprerations

VP / GM: Doug Tenney

Ph. / Email: bill.cullen@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact): ?

Owner Representative: Bill Cullen

Project Name: Replace Unit 092 1019147

Requisition Number: *no longer required by SCM

Project Location: Whitehorse

CEAR: Approved ☐ NOT Required ☐

Region: Yukon

Anticipated Approval Date: _____

Part B. The Work

1. Recurrence

☐ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: 2019-07-16 / Completion: _____

- or -

Delivery / Installation required by: 2019-12-31

Total Estimated Value: $68,770.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years): _____

Maximum Release Value: _____

Minimum Release Value: _____

Estimated # of Releases / year: _____

Estimated Annual Value: _____

Goods and Services Request

2. Scope of Work Document name: Replace Unit 092 Date of issue: _____ Number of pages: ____

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

Metro Chrysler to supply 1 New Ram 5500 Crew Cab Chassis.

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

Vehicle to be delivered to Whitehorse Yukon

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☑ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

This document is an uncontrolled printed copy. Please see Supply Chain Management for a controlled copy.
TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 - 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☐	to FOLLOW	☐	
b) Drawings and / or blueprints	attached	☐	NOT required	☑	to FOLLOW	☐	
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐	
d) HSE Hazard Requirements	LOW ☐ attached ☐ to FOLLOW		MEDIUM ☐ attached ☐ to FOLLOW		HIGH ☐ attached ☐ to FOLLOW		

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments: This is a goods purchase, parts b, c, d and e do not apply

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Single Sourced ☑
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source. (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Field Bid ☐
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☐ Unit Rate ☐
Hourly Rate ☐ Combined ☐
a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** Metro Chrysler Ltd.	Attn: Ken Schick	**HSE Pre-Assessed**		
Address: 5 Two Mile Hill Road, Whitehorse YT	Tel: 867-667-2525	Yes ☐	No ☑	
Email: ken@metrochrysler.ca	Fax:			
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

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d) **Full Legal Name:** _____	Attn: _____	**HSE Pre-Assessed**
Address: _____	Tel: _____	Yes ☐ No ☐
Email: _____	Fax: _____	

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.
0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal
Safety Record
Proposed Schedule
Availability of Resources
Depth of Experience
Reputation / Qualifications
Creative Solutions
Accuracy / Conciseness of Bid
Other: Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

Goods and Services Request

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part F. Single or Sole Source Justification

Supply Chain Management G93 Purchase Process Control states:

Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Vehicle was ordered from Metro Chrysler as it was the lowest quote.

Goods and Services Request

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
Manager Signature	Print name and date MM-DD-YY
Additional Signature (as required)	Print name and date MM-DD-YY

End of **GOODS AND SERVICES REQUEST FORM**

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TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

TRUCK - 2 TON - 4X4 - Diesel Engine 84" CA
Crew Cab - DUAL REAR WHEELS - AUTOMATIC TRANSMISSION

Delivered to AEY 205 Tungsten Rd. Whitehorse YT

Company Name: METRO CHRYSLER

Model: RAM 5500 CREW CAB 4X4 84"CA

Year: 2019

Qty Required:

	Mfg Code	Price
Model	DP0L94	60,770
Engine 6.7L Cummins	29G	12,250
Payload Upgrade Package	AH5	NOT AVAILABLE
Max Tow Package	AHQ	325
All Traction Tires	TUZ	150
Full Size Spare Tire	TBB	395
Electric Shift Transfer Case	DK3	200
Ambulance Prep Group	AH2	500
Heated Mirrors	GPG	included
Color: Fleet white	PW7	NIC
Black/Grey seat cloth	X8	725
Front: 40/20/40 split with Lumbar support	*M9	included
Remote Start	XBM	395
Rear Park Assist	XAA	425
Rear Backup Camera	XAC	475
Fog Lights	LNJ	250
OEM brake controller	XHC	375
Radio	RA2	included
Interior rubber flooring	CKW	NIC
Option Group 1	AHD	525
Option Group 2	LBN	300
Require 3 keys per vehicle	?	275
Luxury group. 795	**Subtotal Per Unit**	79,130
	AC/Tire Tax	240
	AMVIC Fee	N/A
	Freight & Handling	5400
	Fleet Discount	16,000
	Net Price Per Unit	68,770

Submitted by:
Contact name: KEN SNICK Date: March 25/19

Contact phone number: 867-667-2525 Signature:

Delivery Date

METRO CHRYSLER LTD.
5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4

Configuration Preview

Date Printed:	2019-03-25 6:44 PM	**VIN:**		**Quantity:**	1
Estimated Ship Date:		**VON:**		**Status:**	BA - Pending order

Sold to:	**Ship to:**
METRO CHRYSLER LTD. (C8523)	METRO CHRYSLER LTD. (C8523)
5 TWO MILE HILL ROAD	5 TWO MILE HILL ROAD
WHITEHORSE, YT Y1A0A4	WHITEHORSE, YT Y1A0A4

Vehicle: **2019 5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN) (DP0L94)**

	Sales Code	Description	MSRP(CAD)
Model:	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	60,770
Package:	2YG	Customer Preferred Package 2YG	2,800
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500
Paint/Seat/Trim:	PW7	Bright White	0
	APA	Monotone paint	0
	*M9	Premium cloth front 40/20/40 bench	725
	-X8	Black w/ Diesel Grey seats	0
Options:	LNJ	Fog lamps	250
	XAC	ParkView(R) Rear Back-Up Camera	475
	XAA	Park-Sense(R) Rear Park Assist System	425
	XBM	Remote start system	395
	AH2	Ambulance Prep Group	500
	AHQ	Max Tow Package	325
	DK3	Elec shift-on-the-fly transfer case	200
	LBN	Power take-off prep - right side	300
	TBB	Full-size spare tire	395
	AHD	Heavy-Duty Snowplow Prep Group	525
	TUZ	225/70R19.5G All-Traction tires	150
	CKW	Add Black vinyl floor covering	0
	ADA	Luxury Group	795
	XHC	Electronic Trailer Brake Controller	375
	5N6	Easy Order	0
	125	Zone 25-Canada-Alberta	0
	4EX		0
Destination Fees:			1,895

Total Price: 80,750

extra key 275

81025

Order Type: Retail
Scheduling Priority: 4-Dealer Order
Salesperson:
Customer Name:
Customer Address:

Instructions:

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

Luxury Group (ADA)

Details:

- Premium overhead console (CUS)
- Locking lower glove box (JKA)
- Power adjustable pedals (XAP)
- Rear power sliding window (GFE)
- Leather-wrapped steering wheel (SCV)
- Rear dome lamp with on/off switch (LHE)
- Steering wheel-mounted audio ctrls (RDZ)
- Dual glove boxes (JKN)
- Glove box lamp (LBC)
- Courtesy lamps (LBB)
- 115-volt aux power outlet - rear (JJN)
- Dual remote USB charging ports (RS4)
- ✳ 7-inch colour in-cluster display (JAL)
- 115-volt aux power outlet - IP (JKV)
- Universal garage door opener (XGD)
- Door trim panel foam bottle insert (CWL)
- Sun visors w/ illum vanity mirrors (GNC)

VIP DETAILS

Dealer Code: C8523 **Date: 3/25/2019**

FAN Number:A0391
Account Name:ATCO LTD

VIP#	Model Year	Body Model	Body Model Desc	CPOS	Date Approved	VIP Amount (CAD)	VIP Status
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27A	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27G	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27H	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	27M	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YA	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YG	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YH	02/14/2019	12000	Approved
396787	2019	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	2YM	02/14/2019	12000	Approved

Uconnect® 3 with 5-inch display (RA2)

Details:

- Overhead console (CUN)
- Temperature and compass gauge (JFJ)
- GPS antenna input (JLP)
- 5-inch touchscreen (RFU)
- Remote USB charging port (RS3)
- Media hub w/ USB & aux input jack (RS6)
- SiriusXM satellite radio (RSD)
- For SiriusXM info call 888-539-7474 (X9A)
- 1-year SiriusXM subscription (X9B)
- Bluetooth® integrated voice command (XRB)

Package Details - 2YG	
Package Contents	MSRP (CAD)
6.7L Cummins® I-6 turbo diesel eng	6950
6-speed AISIN® heavy-duty automatic	2500
1-year SiriusXM subscription	0
2-way rear headrests	0
3.5-inch colour in-cluster display	0
4-way front headrests	0
5-inch touchscreen	0
Active noise control system	0
Black exterior mirrors	0
Black wheel flares	0
Black-out tape	0
Blk pwr man fold trailer tow mirror	0
Body insulation	0
Body-colour and bright door handles	0
Bright front bumper	0
Bright grille surround	0
Carpet floor covering	0
Centre stack storage drawer	0
Cloth front 40/20/40 bench seat	0
Daytime running lights - high beam	0
Door sill scuff pads	0
Dual glove boxes	0
Exterior mirrors w/ courtesy lamps	0
Exterior mirrors with turn signals	0
For SiriusXM info call 888-539-7474	0
Front 40/20/40 split bench seat	0
Front and rear floor mats	0
Front armrest with cup holders	0
Front door acoustic glass	0
GPS antenna input	0
Glove box	0
Heated exterior mirrors	0
LED fog lamps	0
Locking lower glove box	0
Manual 4-way adjustable driver seat	0
Manual 4-way adjustable pass seat	0
Map/courtesy lamp	0
Mirror running lights	0
Overhead console	0
Overhead cup holder lamp	0
Painted IP bezels w/ hydrographics	0
Prem vinyl door trim w/ map pocket	0

Quad-lens halogen headlamps	0
Rear dome lamp	0
Rear folding seat	0
Remote keyless entry	0
SLT badge	0
Satin Chrome key fob	0
SiriusXM satellite radio	0
Temperature and compass gauge	0
Tinted acoustic windshield	0
Tire pressure information system	0
Trailer tow mirrors	0
Traveller/mini trip computer	0
Uconnect® 3 with 5-inch display	0
Vinyl shift knob	0
Package Value Price	2800
NET PACKAGE PRICE	**12250**

Req 1800000786

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Bill Cullen

Department: AEY Oprerations

VP / GM: Doug Tenney

Ph. / Email: bill.cullen@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact): ?

Owner Representative: Bill Cullen

Project Name: ~~Purchase New Desk~~ Purchase Unit YT148 to replace unit 092

Requisition Number: *no longer required by SCM

Project Location: Whitehorse

CEAR: Approved ☐ NOT Required ☐

Region: Yukon

1019147

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☑ One time purchase / individual project (Goods and Services Contract, Purchase Order)

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Start Date: 2019-08-22 / Completion: 2019-11-30

- or -

Delivery / Installation required by: 2019-11-30

Agreement Duration (years):

Total Estimated Value: $58,429.16

Maximum Release Value:

Minimum Release Value:

Estimated # of Releases / year:

Estimated Annual Value:

2. Scope of Work Document name: Purchase Unit XXX Date of issue: Number of pages:

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

Falcon Industries to supply and install 1 Custom Built deck as per Quote ATCO-YUKON-011

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

OWNER to supply Cab/Chassis for deck to be installed on.

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☑ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

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DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☐	to FOLLOW	☐
b) Drawings and / or blueprints	attached	☑	NOT required	☑	to FOLLOW	☐
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐

d) HSE Hazard Requirements — LOW ☐ attached ☐ to FOLLOW — MEDIUM ☐ attached ☐ to FOLLOW — HIGH ☐ attached ☐ to FOLLOW

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments: This is a goods purchase, parts b, c, d and e do not apply

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Single Sourced ☑
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Field Bid ☐
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☐ Unit Rate ☐
Hourly Rate ☐ Combined ☐
a combination of the pricing formats.

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** Falcan Industries Ltd.	Attn: Kevin Sutherland	**HSE Pre-Assessed**		
Address: Box 1178 Fort McLeod, AB T0L 0Z0	Tel: 867-667-2525	Yes ☐	No ☑	
Email: kevin@falcan.com	Fax: 403-553-2527			
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			

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ATCO Electric

Goods and Services Request (GSR Form)

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d) **Full Legal Name:** _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.

0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal	
Safety Record	
Proposed Schedule	
Availability of Resources	
Depth of Experience	
Reputation / Qualifications	
Creative Solutions	
Accuracy / Conciseness of Bid	
Other:	Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

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ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part F. Single or Sole Source Justification

Supply Chain Management G93 Purchase Process Control states:

Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Custom deck was ordered from Falcan Industries LTD. because they have the options available for the design required.

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
WPCullen	William Cullen 08-22-19
Manager Signature	Print name and date MM-DD-YY
Additional Signature (as required)	Print name and date MM-DD-YY

End of **GOODS AND SERVICES REQUEST FORM**

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TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

Production Number:

FalCan Industries Ltd.
Box 1178
Fort Macleod, Alberta
T0L 0Z0

FALCAN INDUSTRIES LTD.

Tel: (403) 553-2114
Fax: (403) 553-2527

Salesperson:

Bill To:
ATCO YUKON

Ship To:

Kevin@falcan.com

Invoice:
Invoice Date:
PO:
Quote Date: 7/8/2019
Ship Date:
Terms:

INSTRUCTIONS:

Pending

Phone: (867) 633-7007 Cell: (867) 633-7007 Fax: (867) 668-6692

Qty	Description	Price	Disc	Ext Price
	DODGE 5500 2019 84" CA 6.7 DIESEL			
1	2019 STEEL FLOOR DECK-134"- SERIAL:	$6,891.00		$6,891.00
1	COLOR: WHITE	$675.00		$675.00
2	CUSTOM CABINET WITH TAPERED TOP	$2,693.81		$5,387.62
1	DRAWER SYSTEM 4-2.5" & 1-5.5" WITH TOP SHELF	$1,250.00		$1,250.00
1	TOP THROUGH CABINET (SEE PICTURES)	$531.00		$531.00
2	HOOKS AROUND TOP OF CABINET	$113.30		$226.60
6	LIGHTS IN CABINETS (SIDES) (THROUGH) (TOP)(LOWER)	$200.85		$1,205.10
2	FRONT TOOL BOX WG-24"	$595.00		$1,190.00
1	MUD FLAPS AT REAR OF DECK	$135.00		$135.00
1	4 POST REEL STAND CAN BE TURNED / DECK RECEIVERS	$2,184.00		$2,184.00
1	RV 7 POLE AT REAR OF DECK	$103.00		$103.00
1	REAR PULL OUT 6 FT STORAGE BOX ON 5 FT SLIDERS	$1,530.00		$1,530.00
1	CABINET LIGHTS (BRAKE,TAIL,MARKER)	$370.00		$370.00
1	REMOVABLE SIDES FOLD DOWN REAR GATE	$1,464.00		$1,464.00
2	LED LOW PRO STROBES LIGHTS FRONT	$381.00		$762.00
1	FRONT WINCH BUMPER INSTALLED (BP PRE RUNNER)INSTALLED	$3,300.00		$3,300.00
1	WARN WINCH 12,500 LB INSTALLED	$2,849.00		$2,849.00
1	HYDRAULIC POWER WINDER FOR REEL STAND	$3,868.00		$3,868.00
1	POWERED BY HYDRAULIC PTO & PUMP INSTALLED	$5,104.00		$5,104.00
1	MH-C2 SLIM LINE COOLER(FOR HYDRAULIC OIL) INSTALLED	$4,280.00		$4,280.00
1	QUICK COUPLERS AND VAVLE BANK, FLOW CONTROL HOSING, ETC	$2,200.00		$2,200.00

Notes:
THANK YOU - WE APPRECIATE YOUR BUSINESS. **PLEASE NOTE - STEEL IS SOLD BY FULL FOOT.

Subtotal	$58,429.16
Tax @ 5.0%	$2,921.46
Less Deposit	-$
Total	**$61,350.62**

Please Print Name, Sign and Date

1-BP ALL PRICES ARE F.O.B OUR PLANT. INVOICE DUE UPON RECEIPT. G.S.T. # R126180561

Production Number:

FalCan Industries Ltd.
Box 1178
Fort Macleod, Alberta
T0L 0Z0

FALCAN INDUSTRIES LTD.

Tel: (403) 553-2114
Fax: (403) 553-2527

Salesperson:

Bill To:
ATCO YUKON

Ship To:

Invoice:
Invoice Date:
PO:
Quote Date: 7/8/2019
Ship Date:
Terms:

Pending

INSTRUCTIONS:

Phone: (867) 633-7007 Cell: (867) 633-7007 Fax: (867) 668-6692

Qty	Description	Price	Disc	Ext Price
1	ESPAR HEATER FOR CABINET INSTALLED	$3,700.00		$3,700.00
1	GO LIGHT LED (20074)	$984.00		$984.00
1	INSTALLED ON MOUNT CENTER FRONT CABINET	$320.00		$320.00
1	TOP OPEN BOX ON TOP OF CABINET (12" DEEP)	$850.00		$850.00
1	FLOOD LIGHTS 3" CUBES FLUSH MOUNT FACING REAR	$396.00		$396.00
1	FLOOD LIGHTS 3" CUBES FLUSH MOUNT FACING SIDES	$701.00		$701.00
6	FALCAN SURFACE MOUNT STROBES 12 WATT	$132.14		$792.84
6	INSTALL SURFACE MOUNT STROBES	$110.00		$660.00
1	DEFENDER CAMERA (HEATED)	$1,188.00		$1,188.00
	ZONE DEFENSE 5" RUGGED ZD-322-1-R-CH			
3	INSTALL OF CAMERA	$110.00		$330.00
1	ANTI SLIP COATING ON DECK TOP (BLACK)	$1,450.00		$1,450.00
6	SWIVEL FLUSH MOUNT D-RING IN DECK (3 PER SIDE)	$78.00		$468.00
1	CUSTOM STEEL TOP DECK INSTALLED	$1,884.00		$1,884.00

Notes:
THANK YOU - WE APPRECIATE YOUR BUSINESS. **PLEASE NOTE - STEEL IS SOLD BY FULL FOOT.

Subtotal	$58,429.16
Tax @ 5.0%	$2,921.46
Less Deposit	-$
Total	**$61,350.62**

Please Print Name, Sign and Date

1-BP ALL PRICES ARE F.O.B OUR PLANT. INVOICE DUE UPON RECEIPT. G.S.T. # R126180561

180000 1118

ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part A. General Information

Client Representative / Contract Administration Name: Bill Cullen

Department: AEY Oprerations

VP / GM: Doug Tenney

Ph. / Email: bill.cullen@atco.com

Manager / Director: Jay Massie

Project Rep. (field contact): ?

Owner Representative: Bill Cullen

Project Name: Replace Unit 429 103089

Requisition Number: *no longer required by SCM

Project Location: Whitehorse C05.000

CEAR: Approved ☐ NOT Required ☐

Region: Yukon

Anticipated Approval Date:

Part B. The Work

1. Recurrence

☐ One time purchase / individual project (Goods and Services Contract, Purchase Order)

Start Date: 2020-01-15 / Completion:

- or -

Delivery / Installation required by: 2020-12-31

Total Estimated Value: $294,577.00

☐ Multiple work / material releases (Master Services / Supply Agreement) (CPO/BPO)

Agreement Duration (years):

Maximum Release Value:

Minimum Release Value:

Estimated # of Releases / year:

Estimated Annual Value:

2. Scope of Work Document name: Replace Unit 429 Date of issue: Number of pages:

a) General description of the Work (include **Contractor / Supplier** provided materials / Goods, if any):

Drive Products to supply 1 Hercules Digger Derrick 5042/45 as per Quote #EDWQTE091661

Owner provided materials / Special Delivery / Shipping / Packaging Instructions, if any:

Vehicle to be delivered to Whitehorse Yukon

b) Prime Contractor Designation: the *Occupational Health and Safety Act* (Alberta) requires a prime contractor whenever two or more employers engage in work at a work site. AE will be Prime Contractor unless the Contractor agrees to assume those responsibilities.

AE to retain Prime ☑ Contractor as Prime ☐ Dependent on the Work (per Work Release) ☐

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ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

3. Work Specification Details

a) Specifications, procedures and regulations	attached	☐	NOT required	☐	to FOLLOW	☐	
b) Drawings and / or blueprints	attached	☐	NOT required	☑	to FOLLOW	☐	
c) Maps	attached	☐	NOT required	☑	to FOLLOW	☐	
d) HSE Hazard Requirements	LOW	☐ attached ☐ to FOLLOW	MEDIUM	☐ attached ☐ to FOLLOW	HIGH	☐ attached ☐ to FOLLOW	

e) Forest Fire Fighting Expense Insurance Waiver: Waived ☐ Insurance Required ☐ NOT Required (Goods) ☑

Comments: This is a goods purchase, parts b, c, d and e do not apply

Part C. Procurement Method and Pricing

Competitive Bid ☐
Complete this GSR in its entirety. DO NOT complete Part F.

Single Sourced ☑
Complete sections D (a) and Part F only. These purchases may occur where the competitive bid process has not been undertaken for documented safety, business, timing or technical reasons.

Sole Sourced ☐
Complete sections D (a) and Part F only. These purchases may occur where materials or services ONLY exist from ONE source (Original Equipment Manufacturer, Software Developer / Owner, Exclusive Authorized Distributor)

Field Bid ☐
Provide any and all documents used to acquire bid(s)
Provide ONLY the successful bidder(s) name(s) in Section D (a). DO NOT complete Part F UNLESS deviating from G93.

Lump Sum ☐ Unit Rate ☐

Hourly Rate ☐ Combined ☐
a combination of the pricing formats

Allowable Expenses are potential additional costs to the Work such as third party pass through or force account. They are contingent and excluded from Contract Price. Identify any specific, permitted Allowable Expenses below:

Part D. Suggested Contractors / Suppliers

a) **Full Legal Name:** Drive Products	Attn: Blaine Bilyk	**HSE Pre-Assessed**		
Address: 11465-259 St. Acheson, AB T7X 6C4	Tel: 780-960-6101	Yes ☐	No ☑	
Email: bbilyk@driveproducts.com	Fax:			
b) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			
c) **Full Legal Name:**	Attn:	**HSE Pre-Assessed**		
Address:	Tel:	Yes ☐	No ☐	
Email:	Fax:			

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ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

d) **Full Legal Name:** _____ Attn: _____

Address: _____ Tel: _____

Email: _____ Fax: _____

HSE Pre-Assessed

Yes ☐ No ☐

Comments:

Part E. Evaluation Criteria & Competitive Bidding

1. Commercial Evaluation – Rank the following evaluation criteria for importance.

0 (n/a) 1 (low) 2 (medium) 3 (high) 4 (critical)

Financial Proposal

Safety Record

Proposed Schedule

Availability of Resources

Depth of Experience

Reputation / Qualifications

Creative Solutions

Accuracy / Conciseness of Bid

Other: Other:

2. Technical Evaluation – Briefly outline any technical specification(s) / requirement(s) that may carry greater weight / importance than others as this must be identified in the Bid Package.

3. Price Validity - the standard RFP requests the bidder to hold its prices for 90 days. However, you may choose to change this to 30, 60, 120 etc. If the box below is blank the offer will remain 90.

3. Pre-Bid Meeting

	Date	Location	Time	Administrator / Chair
Mandatory ☐				
Optional ☐				
NOT Required ☐				

4. RFP / ITT Schedules Indicate which of the following information you require the Bidder to submit:

List of Subcontractors /Manufactures used: Required ☐ Key Personnel for the Work ☐ NOT Required ☐

5. Performance Bond / Irrevocable Letter of Credit Indicate which of the following you require the Bidder to submit:

Performance Bond ☐ Letter of Credit ☐ NOT Required ☐

Special Instructions

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ATCO Electric

Goods and Services Request (GSR Form)

This Form is ATCO Electric's internal document used to procure goods and / or services.

Part F. Single or Sole Source Justification

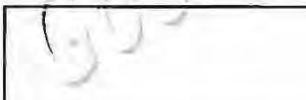
Supply Chain Management G93 Purchase Process Control states:

Purchase Value	Minimum Bids Sought	Bid Request Method	Bid Response Method
Up to $50,000	1	Informal Written	Informal Written
>$50,000 to $100,000	2	Informal Written	Informal Written
>$100,000 to $250,000	3	Informal Written	Informal Written
>$250,000	3	Formal Written	Formal Written

Justification:

Vehicle was ordered from Drive Products as it is a specialized piece of equipment, no other vendors able to supply.

Part G. Approvals

Client Representative Signature:	Print name and date MM-DD-YY
	William Cullen 02-13-20
Manager Signature	Print name and date MM-DD-YY
	
Additional Signature (as required)	Print name and date MM-DD-YY

End of **GOODS AND SERVICES REQUEST FORM**

This document is an uncontrolled printed copy. Please see Supply Chain Management for a controlled copy.
TO REPORT INAPPROPIATE COMMERCIAL OR PURCHASING PRACTICES, PLEASE CALL THE FOLLOWING:
DIRECTOR, CORPORATE SECURITY (403) 245 – 7285 VICE PRESIDENT, INTERNAL AUDIT (403) 292 - 7737

DRIVE PRODUCTS INC.
11465-259 St.
Acheson, AB T7X 6C4
Phone: (780) 960-6826
Toll Free: (800) 661-7335
Fax: (780) 960-6138

QUOTATION - SOUMISSION

Quotation / Soumission	EDWQTE091661
Date	2/11/2020
Page	1

Expiry Date / Date d'expiration	3/12/2020

Sold To - Vendu À

Yukon Electrical Company Ltd (The)
Box 4190
Whitehorse YT Y1A 3T4

Ship To - Expédié À

Yukon Electrical Company Ltd (The)
#100 1100 1st Ave
Whitehorse YT Y1A 3T4

Customer No. N° du Client	Customer PO Bon commande	Salesperson Vendeur	Customer Service Représentant	Shipping Method Méthode d'expédition	Ship Date Date d'expédition (mm/dd/yy)
YUKON	ERCULES DIGGE	RBILYK	BBILYK		
VIN : NIV		Odometer : Odomètre	Unit# : Numéro d'unité	Job Scope : Description de tâche	

Qty	Item Number Numéro d'article	Description	U of M	Unit Price Prix Unitaire	Net Amount Montant Net
1	*	Attn: Bill Cullen 867-633-7057	each	$0.00	$0.00
1	*	Comment *Complete install of a Hercules Digger Derrick 5042/45 c/w 4 radial outriggers, insulated boom, bucket liner/cover. To order this unit we require a 30% deposit*	each	$0.00	$0.00
1	PACKAGE-SHO	Kit	each	$206,677.00	$206,677.00
1	*	Comment *Note: we are quoting a new F-650 Ford c/w Diesel engine 2x4, delivery is 12-14 weeks and will require 30% deposit to order.*	each	$0.00	$0.00
1	VEHICLE-TRUCK-TRU	Ford F650 2x4 Diesel engine	each	$87,900.00	$87,900.00
1	*	Comment *Note: Pricing of the F650 is only good for 30 days and is subject to change when order is placed, delivery is approx 3 months from order date and deposit.*	each	$0.00	$0.00

Attn: Bill Cullen
thanks

DPI GST# 85240 0316 RT0001
DPI QST# 1217408993 TQ0001

Subtotal / Sous-total	$294,577.00
Freight / Transport	$0.00
GST	$14,728.85
PST	
Total	$309,305.85

Signature _____ Date _____

1- 5500 CREW CAB. DIESEL 60" CA.

LONDONDERRY DODGE CHRYSLER JEEP LTD.
13333 FORT ROAD NW
EDMONTON, AB T5A1C3

Configuration Preview

1047665
new unit
YT159

Date Printed:	2021-01-20 5:07 PM	**VIN:**	
Estimated Ship Date:		**VON:**	
		Quantity:	
		Status:	BA - Pending order
		FAN 1:	A0391 ATCO LTD
		FAN 2:	
		Bid Number:	

RECEIVED
JAN 25 2021

Sold to:	**Ship to:**
LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)	LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)
13333 FORT ROAD NW	13333 FORT ROAD NW
EDMONTON, AB T5A1C3	EDMONTON, AB T5A1C3

PO Number:

replace unit 886

Vehicle: **2021 5500 CREW CAB CHASSIS (173.4 IN WB - CA of 60 IN) (DP0L93)**

	Sales Code	Description	MSRP(CAD)	FWP(CAD)
Model:	DP0L93	5500 CREW CAB CHASSIS (173.4 IN WB - CA of 60 IN)	61,970	56,139
Package:	2YG	Customer Preferred Package 2YG	2,800	2,464
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950	6,116
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500	2,200
Paint/Seat/Trim:	PW7	Bright White	0	0
	APA	Monotone paint	0	0
	*M9	Premium cloth front 40/20/40 bench	725	638
	-X8	Black/Diesel Gray	0	0
Options:	LSA	Security alarm	225	198
	XNR	Manual DPF regeneration	250	220
	XF6	Voltage monitoring auto idle-up sys	300	264
	CKW	Add Black vinyl floor covering	0	0
	XHC	Trailer brake control	375	330
	LBN	Power take off prep	395	348
	LAY	LED taillamps	100	88
	AD6	Premium Lighting Group	700	616
	AHD	Heavy-Duty Snowplow Prep Group	525	462
	XBM	Remote start system	395	348
	ADA	Luxury Group	795	700
	XAC	ParkView(R) Rear Back-Up Camera	475	418
	XAG	Park-Sense(R) Front & Rear Park Assist	550	484
	GFA	Rear window defroster	225	198
	DK3	Elec shift-on-the-fly transfer case	295	260
	5N6	Easy Order	0	0
	4FM	Fleet Option Editor	0	0
	4FT	Fleet Sales Order	0	0
	125	Zone 25-Canada-Alberta	0	0
	4EA	Sold Vehicle	0	0
Non Equipment:	4FN	Fleet Commercial Sale	0	0
Discounts:	4CP	Federal A/C Excise Tax	100	100
Destination Fees:			1,895	1,895
		Total Price:	82,545	74,486

$74,486.00
$ 100 Fuel
$ 245- levy
$ 300. MISC.
- 11,800.00 >
$63,331.00
+ TAP.

Order Type:	Fleet	**PSP Month/Week:**	
Scheduling Priority:	1-Sold Order	**Build Priority:**	99

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

ATCO

Request for Goods / Services Form (RGS)

This form is to request goods and/or services where the annual spend or individual project spend is over $50K and/or of medium or high complexity/visibility. Quotes for goods/services or Request for Information (RFI) for less than $50k can be obtained by the originator.

1047665 Replace Unit 886 New unit YT 159

RECEIVED FEB 24 2021

Submitted 24 Feb. 21

Form submission and inquiries to be directed as follows:

- Non-work releases to EGBUProcurement@atco.com.
- Work releases to AEContractAdmin@atco.com.

ORIGINATOR TO COMPLETE				
1. Project Information: Project Name & Location.	Replacement service bodies. Replacement for unit 886. Operations - Whitehorse, YT		# 18 0000 1717	
	Project #: 1047665		Task Code: ~~212005~~ C.05.000	
2. CEAR:	Not Required	3. Contract Administrator (CA)	Required	
4. Business Division:	North of 60 (N60)	5. Estimated total or annual value ($CAD):	$ 83,805.00	
6. Project Type:	Non-Direct Assigned	7. Pricing Schedule(s):	☑ Attached; or ☐ To be provided later	
8. Work Recurrence:	One time purchase / individual proje	9. Pricing Method:	Lump Sum	
10. Services / Delivery Date(s):	Start Date: March 22, 2021 Completion / Delivery Date(s): June 7, 2021	11. Allowable Expenses: List items & budget identified by ATCO for the Project.	None	
12. Work Specification Details:	12.1 Work package (specifications, drawings, maps, etc) Other (as below) Quote attached 12.2 Permits required by contractor/supplier Yes ☐ No ☑ 12.3 Site specific orientation requirements Yes ☐ No ☑ 12.4 Forest Fire Fighting Expense Insurance Waiver Yes ☐ No ☑			
13. HSE Document(s):	Prime Contractor: Contractor If contractor is identified as prime, a prime contractor agreement is required			
14. Pre-Bid Meeting:	Yes ☐ No ☑	15. Site Visit:	Yes ☐ No ☑	

ATCO

Request for Goods / Services Form (RGS)

16. Recommended Supplier(s) or Contractor(s) and contact information (contact name, email, phone number, address) to be provided. For MSAs, only Contractor names to be provided. Contractors are required to be Avetta approved prior to award.

General Body and Equipment Ltd
8124 Davies Road
Edmonton, AB
T6E 4N2
www.generalbody.ca
780 468-5359

17. Evaluation Criteria: Yes ☑ No ☐

General Body is ATCO's supplier for 2 ton service bodies - as per ATCO Fleet

18. Single or Sole Source Justification: this section is to be used when company bidding standards are not followed for Non-AESO Transmission Direct Assigned Projects (REF form to be completed for AESO Transmission Direct Assigned Projects that do not follow the procurement guideline). Select the applicable reason(s) for the supplier/contractor selection in 18.1. Provide supporting information in 18.2.

Company Bidding Standards	
Bid Value	Minimum Number of Bids (Written Response)
UP TO AND INCLUDING $50,000	1 Bid
OVER $50,000 AND UP TO AND INCLUDING $100,000	2 Bids
OVER $100,000	3 Bids

18.1 Select the applicable reason(s) for the supplier/contractor selection.

Standard (Standardized equipment to minimize spare parts inventory - explain why ATCO has standardized on product or line)

18.2 Provide supporting information.

ATCO Fleet has a contract with General Body to fabricate 2- ton service bodies.

ATCO

Request for Goods / Services Form (RGS)

19. Submitted by:

Signature:_____
Name:_____
Date:_____

Reviewed by Project Manager (if applicable):

Signature: Tony Badry Digitally signed by Tony Badry Date: 2021.02.23 10:23:05 -07'00'
Name: Tony Badry
Date: Feb 23 2021

Approved by:

Signature:_____
Name:_____
Date:_____

Approved by:

Signature:_____
Name:_____
Date:_____

The form is to be approved by Supervisor/Manager. When using Single source, Signatures on this form tc follow Delegation of Authority (DOA)

GENERAL BODY & EQUIPMENT

QUOTATION #ME022421

Date: February 24, 2021

Prepared For: Atco Electric Yukon

Attention: Tony Badry/Jason Allan

Prepared By:
General Body & Equipment Ltd.
c/o Mark Edel
8124 Davies Road
Edmonton, AB T6E 4N2
Phone: 780-468-5359
medel@generalbody.ca

General Body & Equipment Ltd. are pleased to present the following for your consideration:

Custom Built Service Body as per GBE Drawing 3996TS00
- See drawings in separate file

$83,805.00

Terms and Conditions

Customer Supplied Equipment and Information:
- Complete Chassis Specification to be provided by Customer at time of Order.
- Truck/Chassis to be supplied to GBE with a minimum 1/4 tank of fuel.
  - Fuel charges will be added to invoice if chassis arrives below 1/4 tank
- Relocation of exhaust, Air Tanks, Battery Boxes, Fuel or Urea Tanks will be an additional charge.
- Additional chassis programming required upon chassis arrival at General Body and Equipment will be an additional charge.
- Quote valid for 30 Days. Acceptance of quote after this period will require a review of proposed pricing.

Payment Terms:
- FOB GBE Edmonton
- 30% Down Payment required at time of order.
  - Balance due upon completion of unit at Production facility
  - Unit will be held at GBE Edmonton until payment arrangements have been confirmed
- Taxes Extra
- GBE Supplied Products affected by monetary exchange rates may require price adjustment at build when rates have changed by a differential of 5% from the date was officially awarded
- Third Party Financing Options available on request.

Warranty Terms:
- All Warranty work to be completed by GBE. If geography prevents the unit from being returned to warranty repairs, prior to any work being completed by a third party, third party estimate provided in writting and approved by GBE,
- 1-year Defects in Material and Workmanship.
- 1-year on all parts, materials and equipment (Some third party equipment warranties exceed this ask salesman for details)
- 2-years on de-lamination (Rock Chips excluded).
- 5-years No Rust-through guarantee.
- In accordance with GBE's Continuous Improvement program, specifications are subject to change without notice or obligation

Change Order Policies:
- Minimum Change order costs after Specifications and Drawings are approved by customer are as f
  - Change order at less than 25% project completion = Minimum $500 charge + minimum 1-delivery delay
  - Change order at greater than 25% project completion = Minimum $1,000 charge + delivery delay
  - If Customer Supplied Chassis does not match Chassis specification used in quoting associated modification cost + minimum 1-week delivery delay

Cancellation Policy:
- Cancellation must be communicated to General Body and Equipment in writing
- Resulting Cancellation Costs are the responsibility of the customer as follows:
  - Cancellation prior to start of Purchasing/Fabrication process = No Charge
  - Cancellation after start of Purchasing/Fabrication process = All labour and material costs up to and including date of written notice plus any re-stocking charges associated with return of materials to vendors.

Delivery:

GENERAL
BODY & EQUIPMENT
EDMONTON, CALGARY, SASKATOON

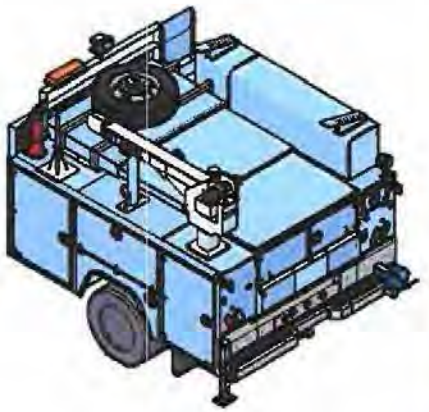
APPROVED FOR PRODUCTION

OCT. 07, 2020 - N.M.

CUSTOMER: ATCO	
BODY DESCRIPTION: 112" SERVICE BODY W/	
LIFTMOORE 206REL CRANE	
BODY MATERIAL: ALUMINIUM	
CHASSIS: 2020 RAM 5500, CREW CAB, 60" C.A. DRW, DIESEL	
UNIT #	
SALES: M. EDEL	
PROJECT MANAGER: M. EDEL	
WORK ORDER # PR43542	
ASSEMBLED IN: EDMONTON	
ISSUED FOR: PRODUCTION	
DRAWN BY: S. LIU	DATE: SEPT. 23, 2020
CHECKED BY: N. MACDONALD	DATE: SEPT. 28, 2020
APPROVED BY: M. EDEL	DATE: SEPT. 30, 2020
MFG. CHK. BY:	DATE:
CAD FILE #: 3996TS00	REVISION: 0

DWG NO.	DESCRIPTION	REV.	DATE REVISED
3996TS00	112" SERVICE BODY W/CRANE		
3996-A1	SERVICE BODY		
3996-A3	REAR BARN DOOR		
3996-A4	TAILGATE		
3996-A5	BUMPER ASSEMBLY		
3996-A6	TOP BIN		
3996-A8	BATTERY BOX		
3996-A9	SPARE TIRE W/CARRIER		
3996-A11	TOOL HOLDER		
3996-A12	LADDER MOUNTING BRACKET		
3996-A13	HEADACHE RACK		
3996-A30~A34	DOORS		
3996-D1~D3	DS COMP. CONTNETS		
3996-P1~P3	PS COMP. CPNTENTS		





THIRD ANGLE PROJECTION

DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED: TOLERANCES ANGLES ±1.00°

.X [X/X] ±0.1 (1/16)
.X [X/XX] ±0.01 (1/32)
.X [X/XXX] ±0.001 (1/64)

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GENERAL NOTES

1. CHASSIS: 2020 RAM 5500, CREW CAB, 60" C.A. DRW, DIESEL
2. 3" X 2" X 1/4" ALUMINUM CHANNEL CROSS SILLS.
3. 3" X 3" X 1/4" SQUARE ALUMINUM TUBING CROSS SILLS.
4. 3" X 3" X 1/4" SQUARE ALUMINUM TUBING LONG SILLS.
5. 3/4" UHMW SPACER.
6. COMPARTMENTS FABRICATED FROM 1/8" ALUMINUM, STITCH WELDED INSIDE AND OUT.
7. ALUMINIUM EXTRUSION DOORS, KEYED ALIKE
8. CARGO FLOOR TO BE 3/16" ALUMINIUM CHECKPLATE
9. PAINT: SEE SPEC

STANDARD EQUIPMENT

1. ROCK GUARDS, DRIP RAILS, AND REAR MUD FLAPS.
2. CMVSS LIGHTING GBE STANDARD LED.
3. MASTER ROD LOCK.
4. ALL DOORS DOUBLE WALLED.
5. ALL DOORS HAVE GAS STRUTT HOLDBACK
6. REINFORCED TAILGATE
7. GRAB HANDLES
8. STAINLESS STEEL HINGES
9. BLACK 3-POINT WHALE TAIL HANDLES
10. 20" LUMABAR LED STRIP LIGHTING IN ALL COMPARTMENTS
11. ALL COMPARTMENT SHELVES AND DRAWERS TO HAVE RUBBER MATTING
12. COMPLETE UNDERBODY UNDERCOATED
13. S&I ESPAR HEATER FOR CHASSIS
14. S&I HAVIS C-3010 CENTER CONSOLE IN CAB AND SWITCH PANEL AND INSERTS FOR ESPAR CONTROLS AND CUSTOMER RADIO (TAIT TM9155)
15. REMOVE 60% OFREAR SEATS, 40% LEFT ON THE PASSENGER SIDE. STORAGE CABINET AS PER CUSTOMER PROVIDED SKETCH
16. TEXTURE COATING ON BOTTOM 8" OF CHASSIS AND BODY
17. SAUBER VENTS FOR ALL COMPARMENTS
18. RAM FACTORY BACKUP CAMERA SYSTEM

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.X [X/X] ±0.1 (1/16)
.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

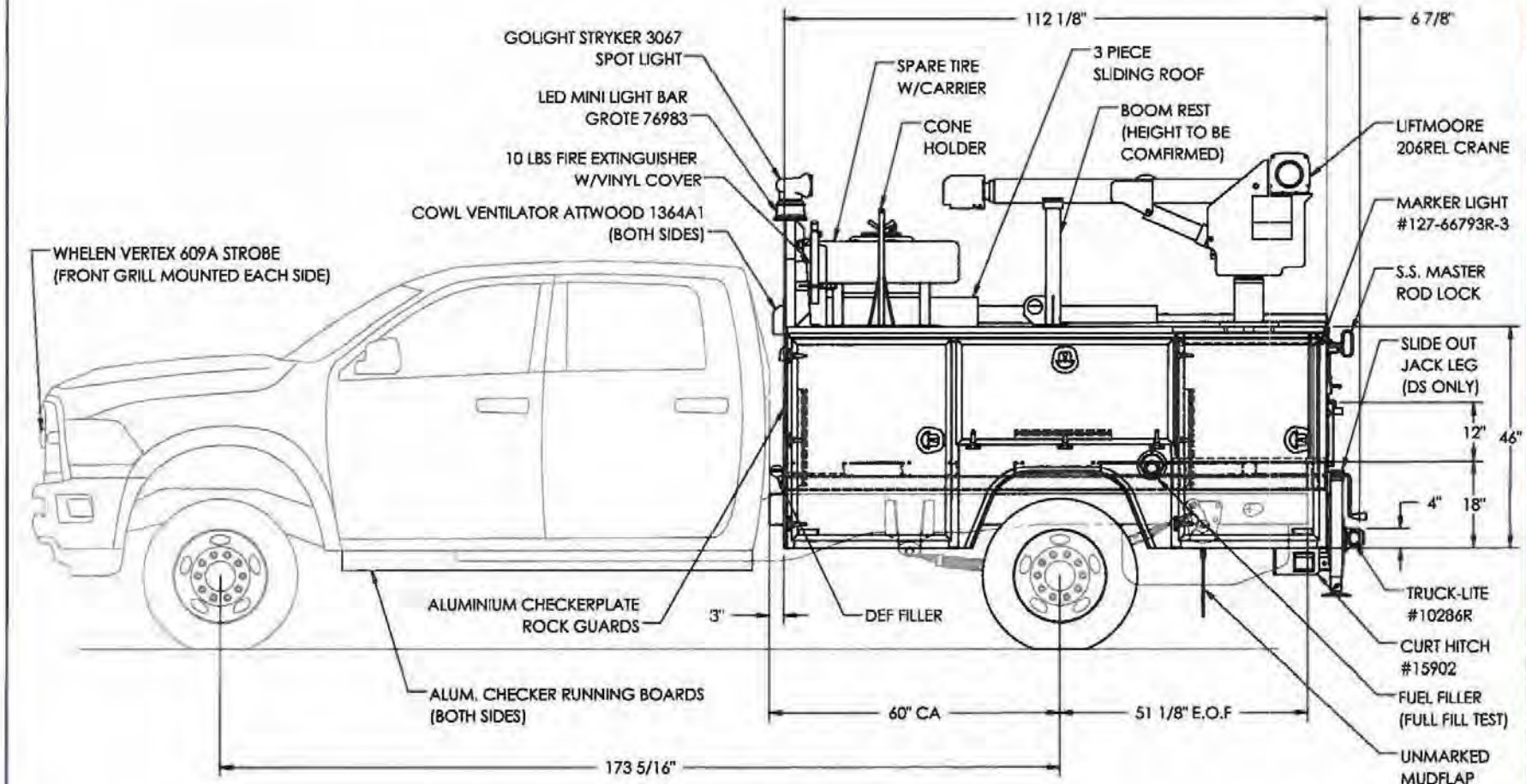
THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER: ATCO		WO#: PR43542
DWN. BY: SL	DATE: SEPT. 23, 2020	
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:
APP. BY: ME	DATE: SEPT. 30, 2020	SCALE: N.T.S.
MFG. CHK. BY:	DATE:	SHEET: 2 OF 12
		PROJECT MANAGER: M. EDEL
		CAD FILE: 3996TS00

GENERAL BODY & EQUIPMENT

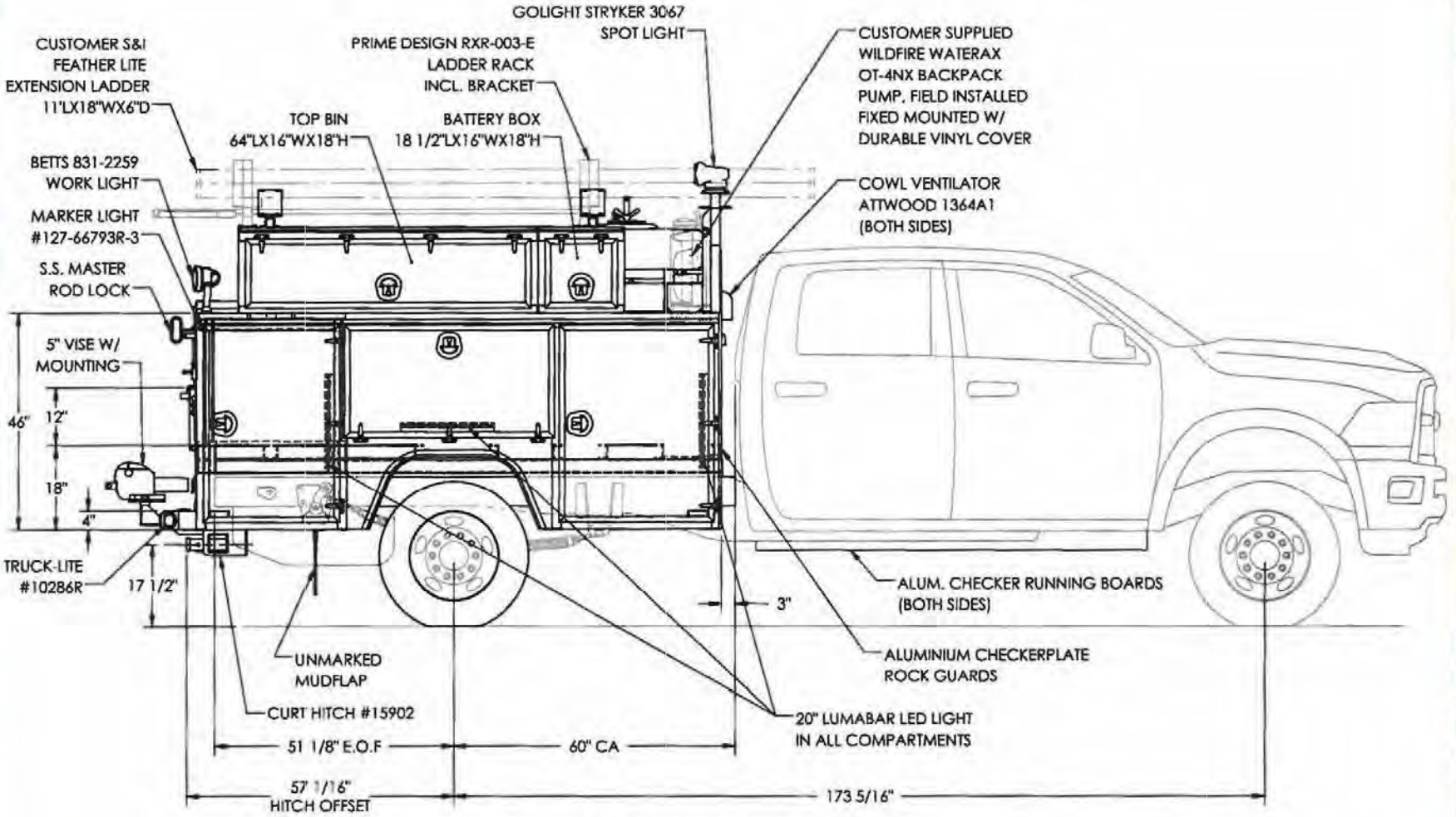
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DRIVE SIDE VIEW
(PS TOP BOXES, LADDER, VISE
& WORK LIGHT HIDDEN)

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		DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	
		CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 3 OF 12
	THIRD ANGLE PROJECTION / WEIGHT (LBS): XXX	APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00
		MFG. CHK. BY:	DATE:		

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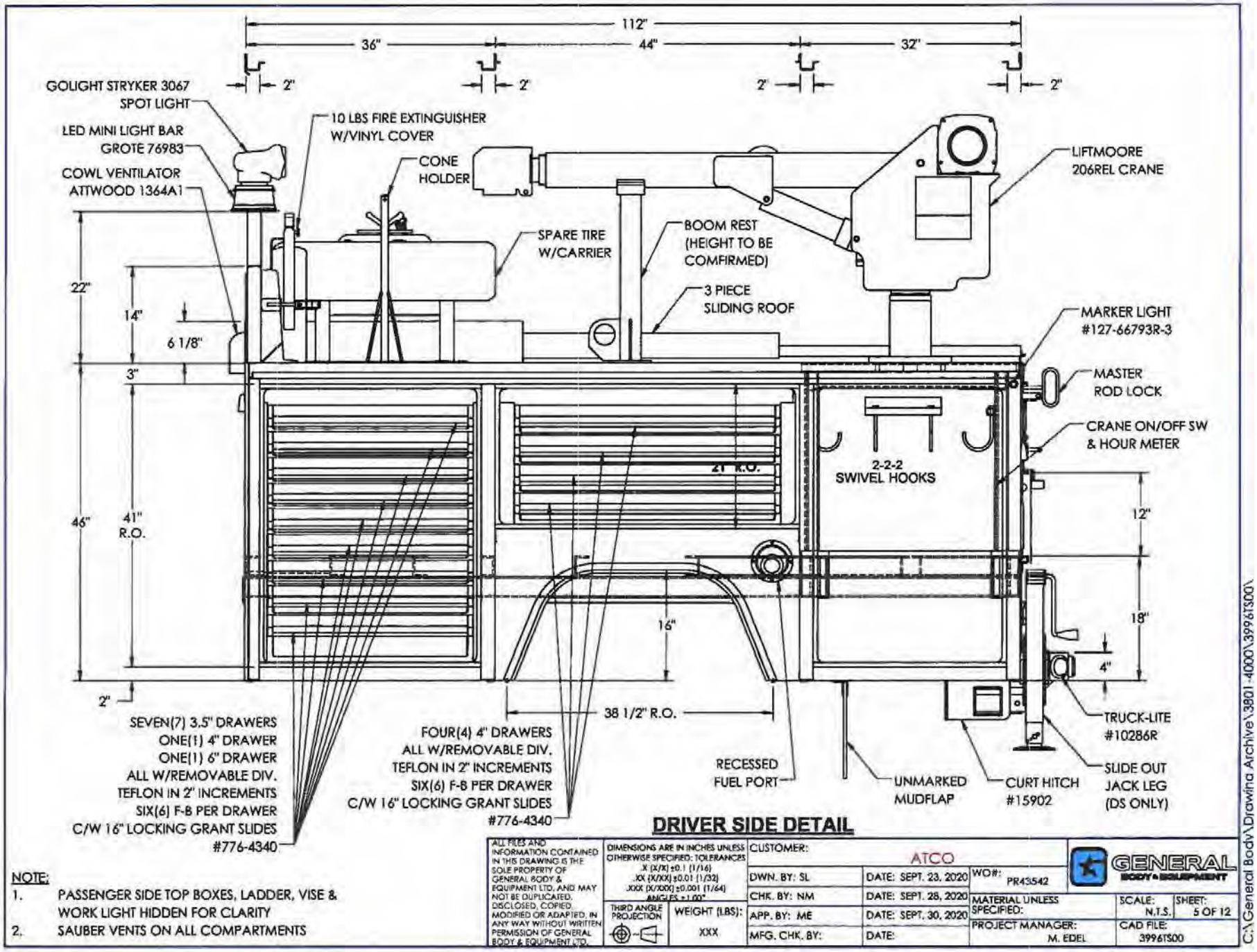


PASSENGER SIDE VIEW

(DS CRANE, JACK LEG, CONE HOLDER,
FIRE EXTINGUISHER HIDDEN)

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		DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	
		CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 4 OF 12
	THIRD ANGLE PROJECTION / WEIGHT (LBS): XXX	APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 39961S00
		MFG. CHK. BY:	DATE:		

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DRIVER SIDE DETAIL

NOTE:
1. PASSENGER SIDE TOP BOXES, LADDER, VISE & WORK LIGHT HIDDEN FOR CLARITY
2. SAUBER VENTS ON ALL COMPARTMENTS

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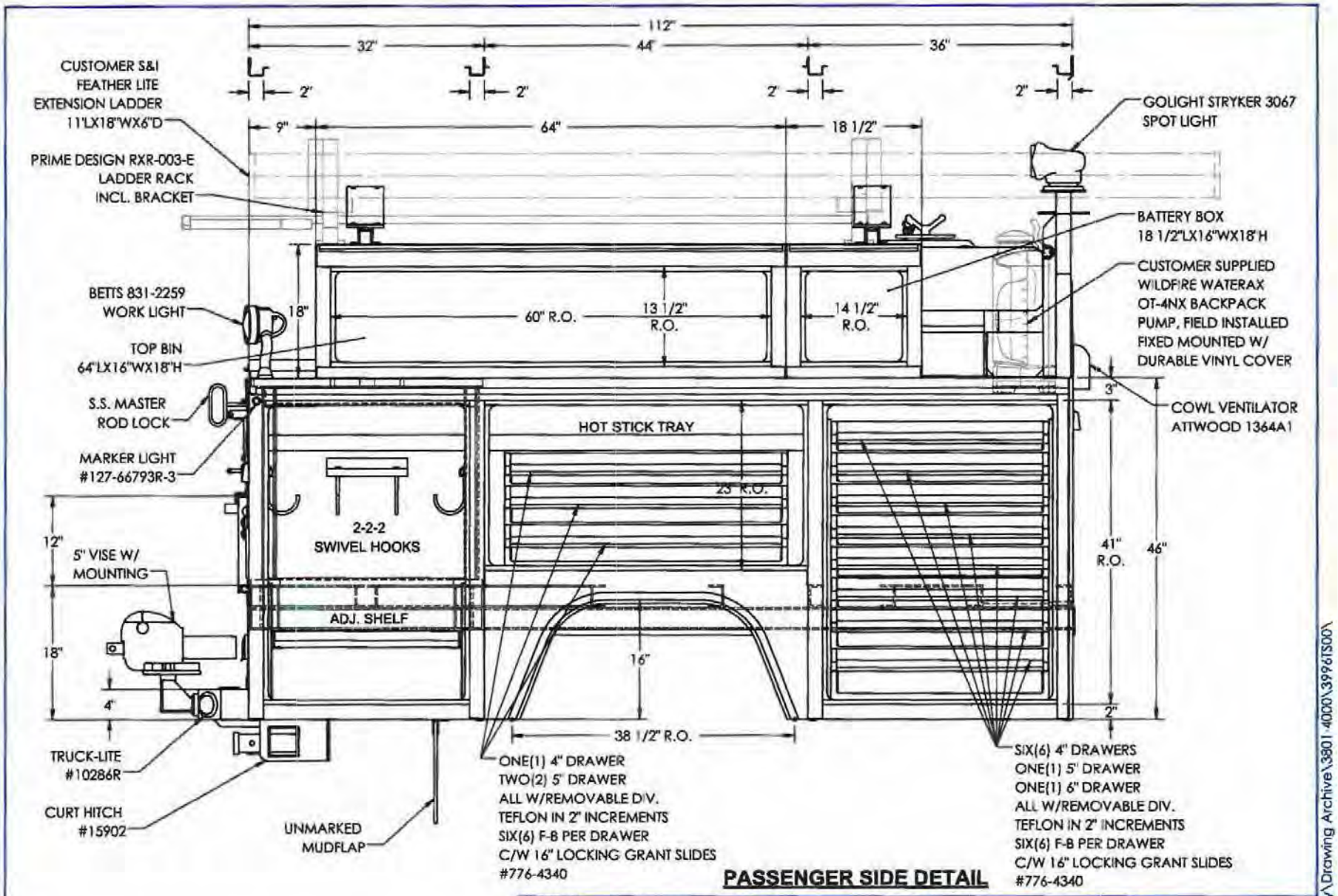
DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED: TOLERANCES
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.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER: ATCO			
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	GENERAL BODY & EQUIPMENT
CHK. BY: NM	DATE: SEPT. 28, 2020		
APP. BY: ME	DATE: SEPT. 30, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 5 OF 12
MFG. CHK. BY:	DATE:	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00

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PASSENGER SIDE DETAIL

NOTE:
1. DRIVER SIDE CRANE, JAVK LEG, CONE HOLDER & FIRE EXTIGUISHER HIDDEN FOR CLARITY
2. SAUBER VENTS ON ALL COMPARTMENTS

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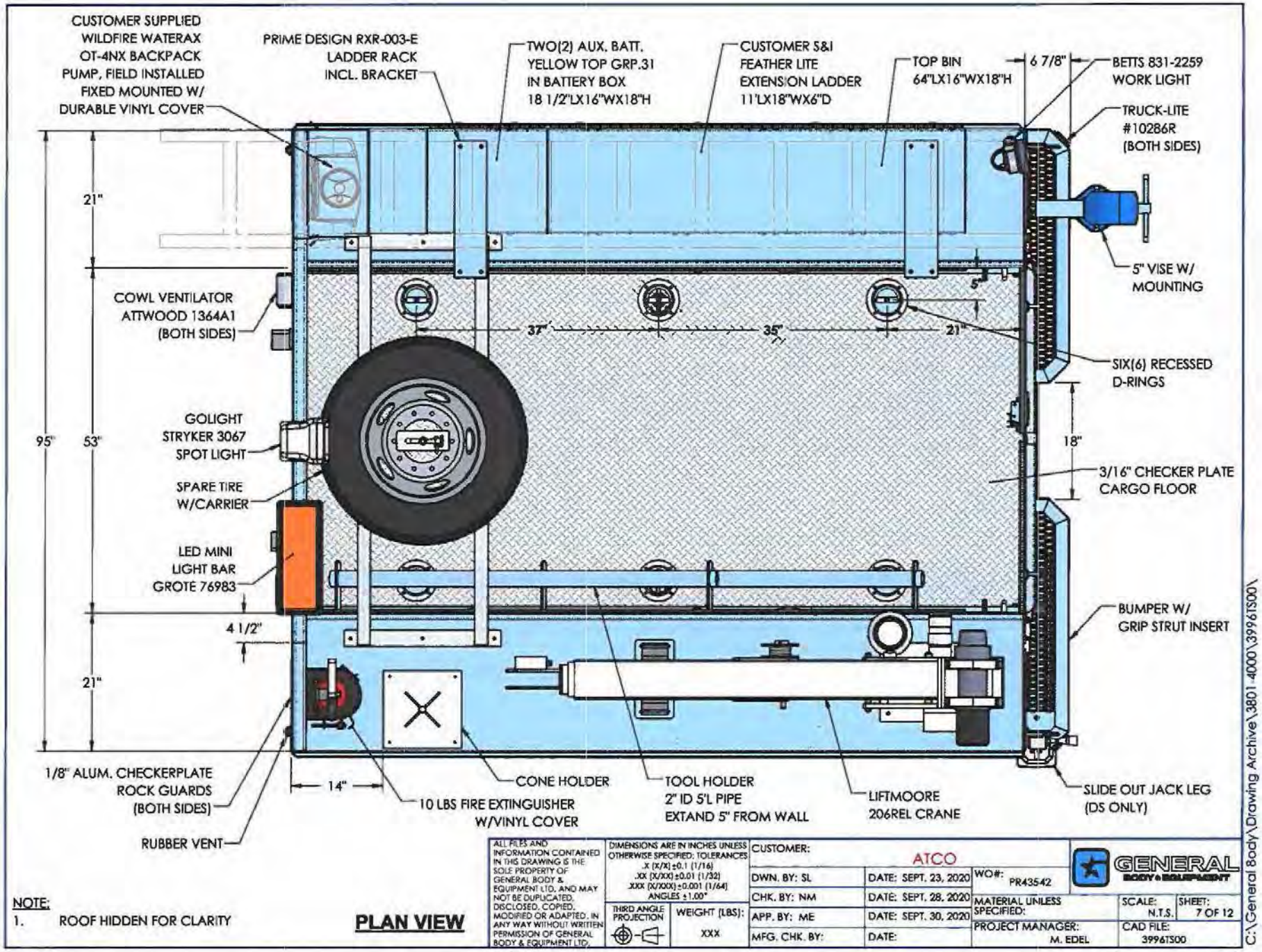
DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED: TOLERANCES
.X (X/X) ±0.1 (1/16)
.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER:	ATCO		
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	GENERAL BODY & EQUIPMENT
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 6 OF 12
APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00
MFG. CHK. BY:	DATE:		

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NOTE:
1. ROOF HIDDEN FOR CLARITY

PLAN VIEW

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DIMENSIONS ARE IN INCHES UNLESS OTHERWISE SPECIFIED; TOLERANCES
X (X/X) ±0.1 (1/16)
.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

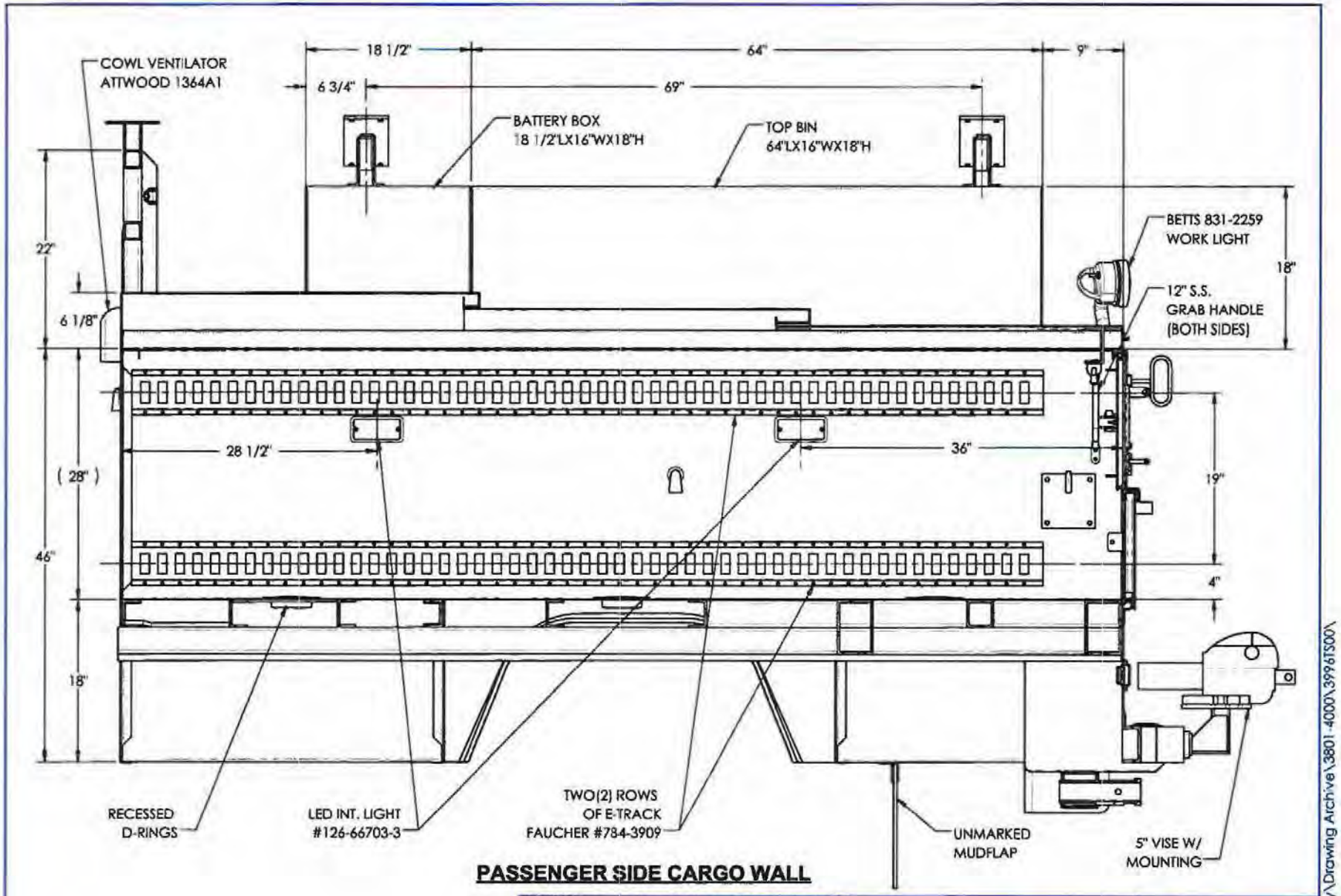
THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER:	ATCO		
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 7 OF 12
APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 39961S00
MFG. CHK. BY:	DATE:		

GENERAL BODY & EQUIPMENT

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PASSENGER SIDE CARGO WALL

NOTE:
1. SPARE TIRE W/CARRIER & GOLIGHT HIDDEN FOR CLARITY

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.X (X/X) ±0.1 (1/16)
.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

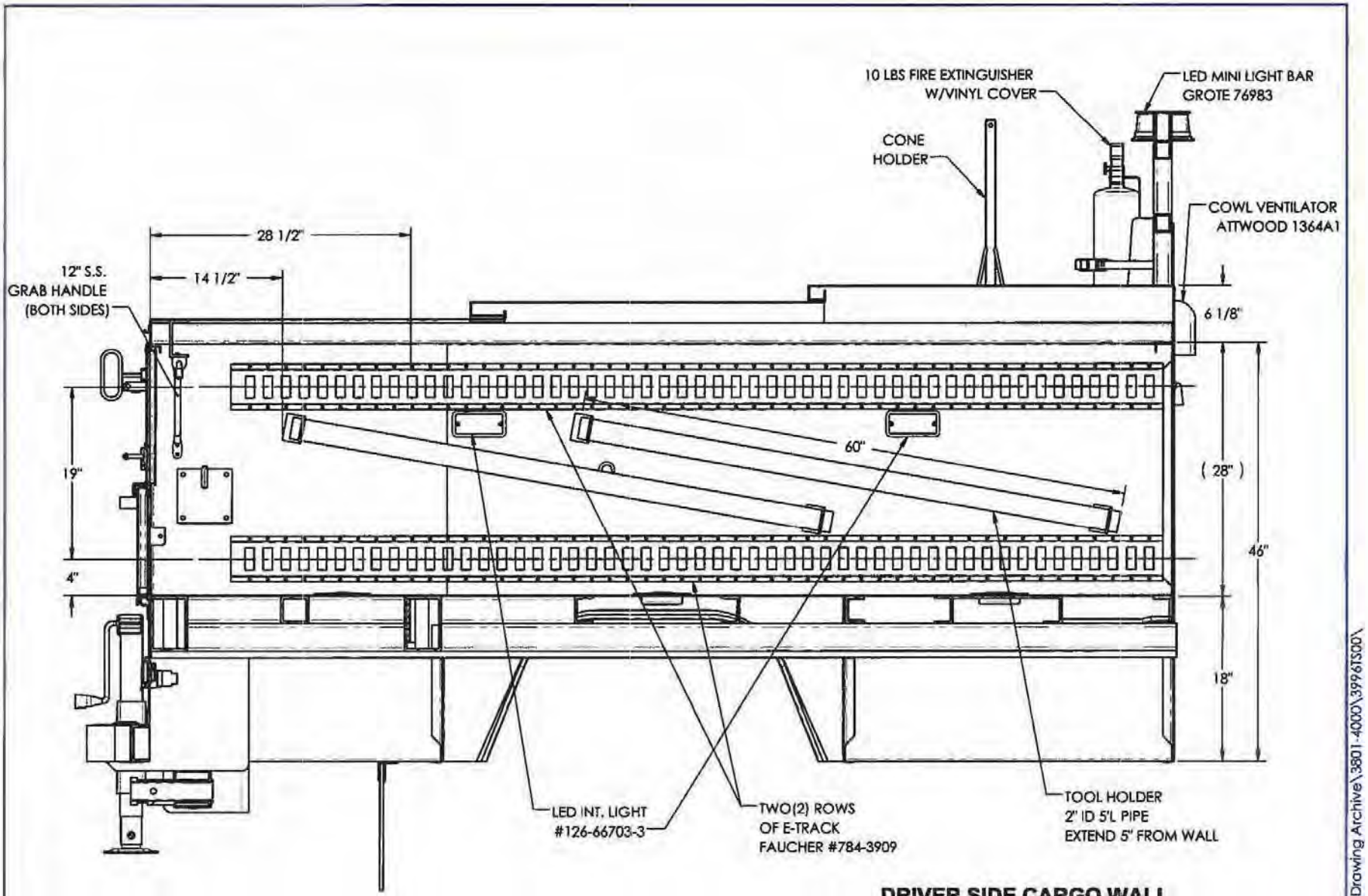
THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER: ATCO		
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:
APP. BY: ME	DATE: SEPT. 30, 2020	SCALE: N.T.S. / SHEET: 8 OF 12
MFG. CHK. BY:	DATE:	PROJECT MANAGER: M. EDEL / CAD FILE: 3996TS00

GENERAL BODY & EQUIPMENT

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DRIVER SIDE CARGO WALL

NOTE:
1. SPARE TIRE W/CARRIER, GOLIGHT, CRANE & BOOM REST HIDDEN FOR CLARITY

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ANGLES ±1.00°

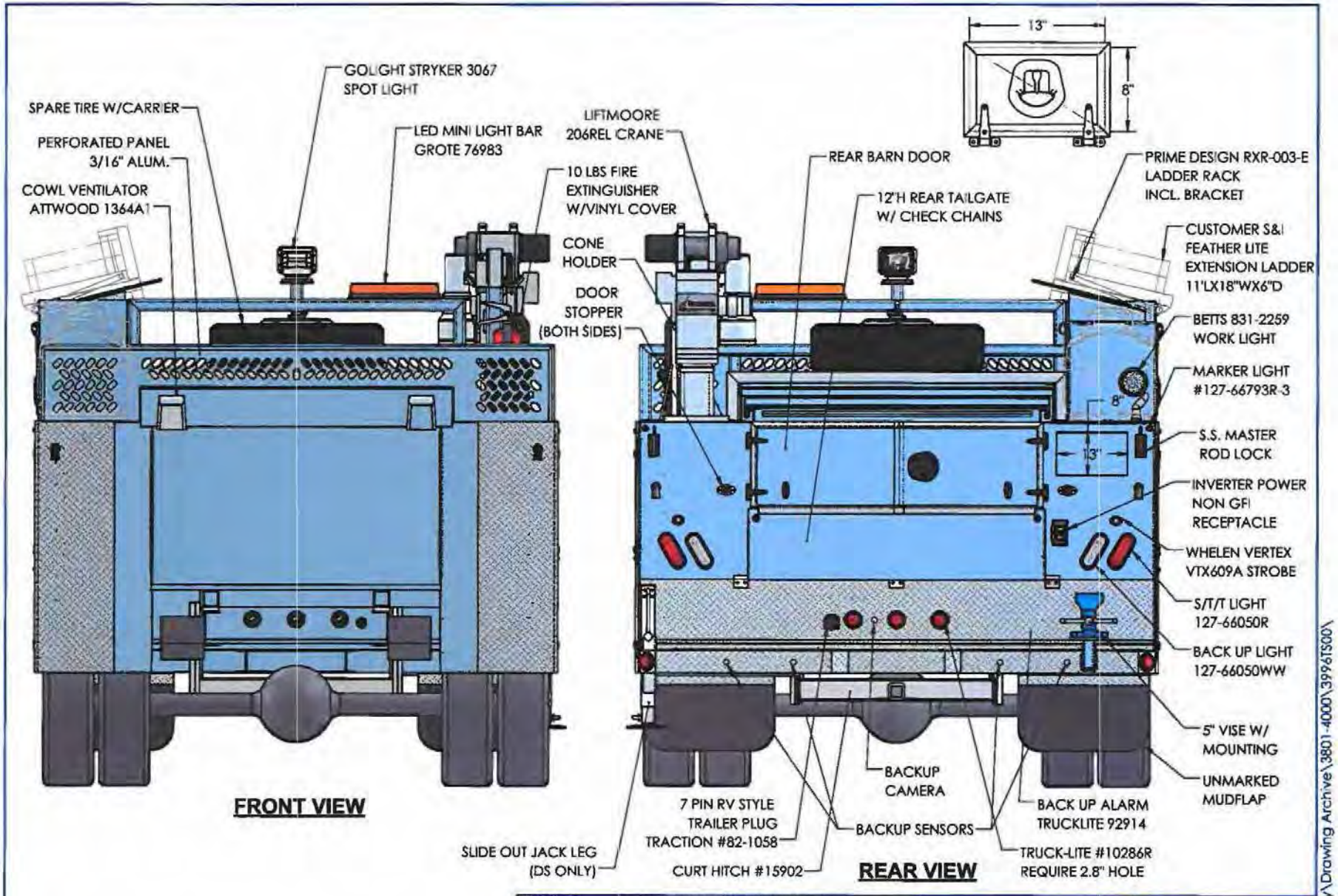
THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER: ATCO		WO#: PR43542	
DWN. BY: SL	DATE: SEPT. 23, 2020		
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 9 OF 12
APP. BY: ME	DATE: SEPT. 30, 2020		
MFG. CHK. BY:	DATE:	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00

GENERAL BODY & EQUIPMENT

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NOTES:
1. INSTALL FACTORY BACKUP SENSORS & CAMERA
2. TWO(2) WHELEN VERTEX MINI STROBE MOUNT AT REAR OF BODY

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.XX [X/XX] ±0.01 [1/32]
.XXX [X/XXX] ±0.001 [1/64]
ANGLES ±1.00°

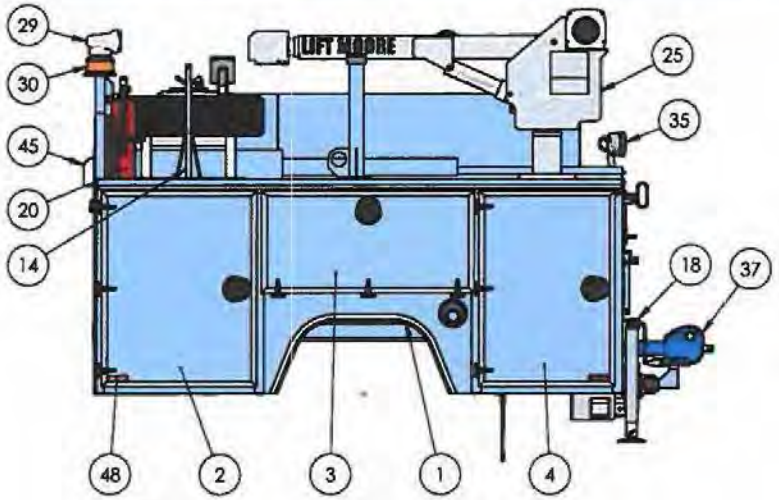
THIRD ANGLE PROJECTION

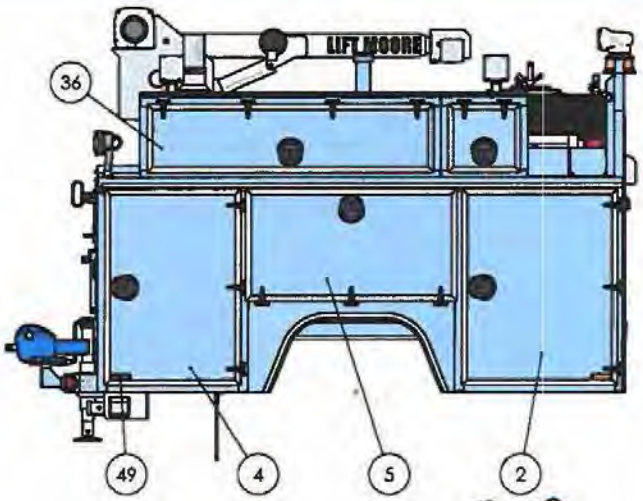
WEIGHT (LBS): XXX

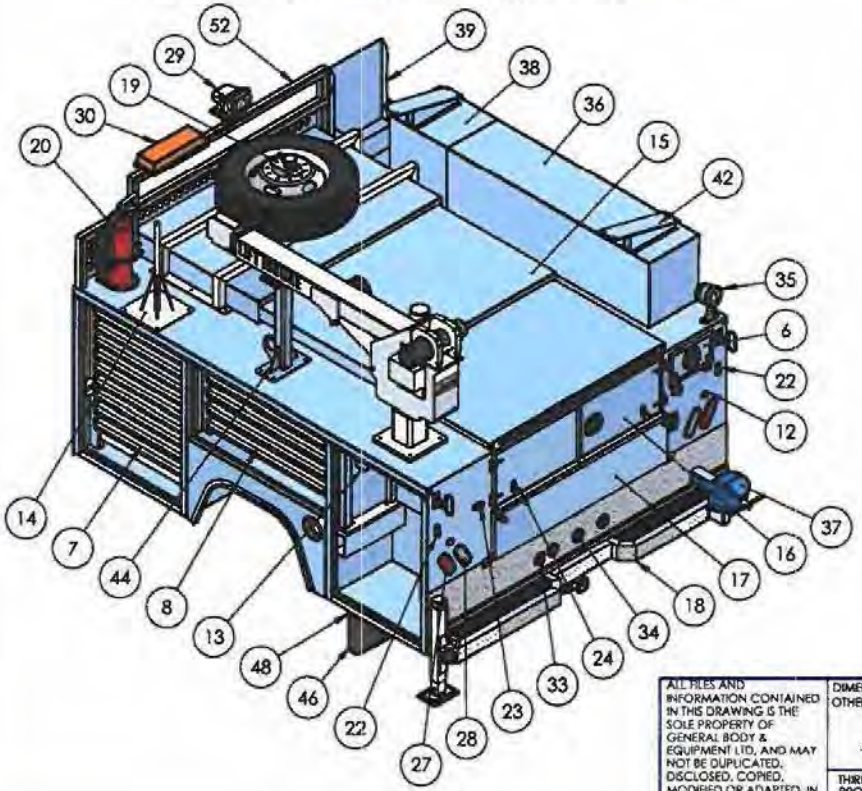
CUSTOMER:	ATCO	
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:
APP. BY: ME	DATE: SEPT. 30, 2020	SCALE: N.T.S. / SHEET: 10 OF 12
MFG. CHK. BY:	DATE:	PROJECT MANAGER: M. EDEL / CAD FILE: 3996TS00

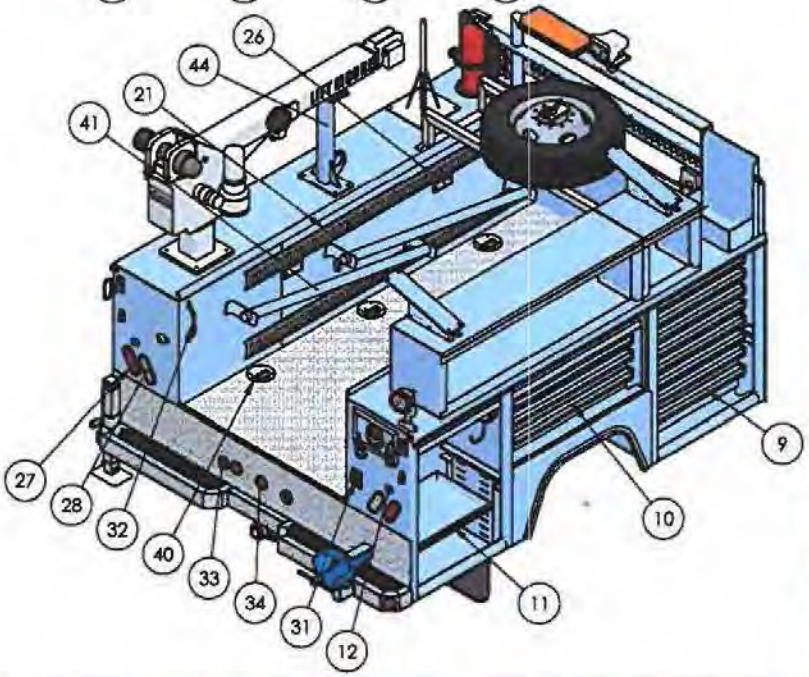
GENERAL BODY & EQUIPMENT

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.XXX (X/XXX) ±0.001 [1/64]
ANGLES ±1.00°

THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER: ATCO		WO#: PR43542	GENERAL BODY & EQUIPMENT
DWN. BY: SL	DATE: SEPT. 23, 2020		
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 11 OF 12
APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00
MFG. CHK. BY:	DATE:		

C:\General Body\Drawing Archive\3801-4000\3996TS00\

ITEM NO.	PART NUMBER	DESCRIPTION	QTY.
1	3996-A1	9' SERVICE BODY - 3 COMPARTMENTS	1
2	3996-A30	DS1/PS1 DOOR	2
3	3996-A31	DS2 DOOR	1
4	3996-A32	DS3/PS3 DOOR	2
5	3996-A33	PS2 DOOR	1
6	3996-A34	HOT STICK ACCESS DOOR	1
7	3996-D1	DS1 COMP. CONTENTS	1
8	3996-D2	DS2 COMP. CONTENTS	1
9	3996-P1	PS1 COMP. CONTENTS	1
10	3996-P2	PS2 COMP. CONTENTS	1
11	3996-P3	PS3 COMP. CONTENTS	1
12	VTXFC	VERTEX SUPER-LED LIGHT	2
13	3996-D3	DS3 COMP. CONTENTS	1
14	3996-A0-001	TRAFFIC CONE HOLDER	1
15	3996-A2	3 PIECE SLIDING ROOF	1
16	3996-A3	REAR BARN DOORS	1
17	3996-A4	ALUMINUM TAILGATE ASSY	1
18	3996-A5	ALUMINIUM BUMPER ASSLY	1
19	3996-A9	SPARE TIRE/CARRIER ASSEMBLY	1
20	Fire Extinguisher - 10 lb	Fire Extinguisher	1
21	102 IN	HORIZONTAL E-TRACK	4
22	7400856	FIBER BODY 90 DEG RUBBER VENT	6
23	771-5008	KEEPER FOR PLUNGER TYPE DOOR HOLDER	2
24	771-5047	PLUNGER TYPE DOOR HOLDER	2
25	206 REL	LIFTMOORE 206REL CRANE	1
26	127-66703-3	JETCO LED LIGHT #127-66703-3	4

ITEM NO.	PART NUMBER	DESCRIPTION	QTY.
27	127-66050R		2
28	127-66050W	6" X 2" OVAL WHITE LED BACK-UP LIGHT	2
29	3000	PERMANENT MOUNT SEARCHLIGHT, Go-Light	1
30	76983	GROTE LOW-PROFILE LED MINI LIGHTBAR	1
31	GFI Electrical Box	GFI Electrical Box With 2 Door Cover	1
32	682-1980	11.5" GRAB HANDLE	2
33	82-1058	7-PIN RV STYLE TRAILER PLUG	1
34	10286R	2-1/2" LED MARKER W/GROMMET (CUTOUT: 3")	5
35	1492125	FLOOD LIGHT	1
36	3996-A6	TOP BIN ASSEMBLY	1
37	3996-A7	5" VISE W/STAND	1
38	3996-A8	BATTERY BOX	1
39	3996-A10	BACKPACK HOLDER	1
40	783-2008	HEAVY DUTY ROPE RING	6
41	3996-A11	TOOL HOLDER	2
42	3996-A12	LADDER MOUNTING BRACKET	2
43	3996-A0-002	3" X 3/4" UHMW FRAME SPACER	2
44	3996-BOOM REST	BOOM REST	1
45	ATTWOOD 1364A1	COWL VENTILATOR	2
46	3996-MUDFLAP	24" WIDE MUDFLAP	2
47	3996-A0-003	MUDFLAP BRACKET	2
48	98003Y	REFL YELLOW 1-1/1/4" WIDE	2
49	98003R	REFL RED 1-1/1/4" WIDE	2
50	127-66793R-3	LED MARKER LIGHT, 3/4" DIA.	4
51	127-66320	LUMABAR 20"	6
52	3996-A13	HEADACHE RACK	1

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.XX (X/XX) ±0.01 (1/32)
.XXX (X/XXX) ±0.001 (1/64)
ANGLES ±1.00°

THIRD ANGLE PROJECTION

WEIGHT (LBS): XXX

CUSTOMER:	ATCO		
DWN. BY: SL	DATE: SEPT. 23, 2020	WO#: PR43542	GENERAL BODY & EQUIPMENT
CHK. BY: NM	DATE: SEPT. 28, 2020	MATERIAL UNLESS SPECIFIED:	SCALE: N.T.S. / SHEET: 12 OF 12
APP. BY: ME	DATE: SEPT. 30, 2020	PROJECT MANAGER: M. EDEL	CAD FILE: 3996TS00
MFG. CHK. BY:	DATE:		

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Simcoe, Dennis

From: Simcoe, Dennis <dennis.simcoe@atco.com>
Sent: Wednesday, June 29, 2022 9:12 AM
To: Badry, Tony
Subject: FW: Altec AT41M - ATCO unit E20138
Attachments: Stock AT41M one sheet spec.PDF

Good morning,

Here is the quote for the AT41M that is currently being built. There may be a small adjustment when the unit arrives, but it should be minimal overall.

Regards,

Dennis Simcoe P. Eng
Supervisor, Fleet Services
Common Groups

C. 780 203 6128



Fleet Services Sharepoint

From: Braddon D'Hulster <braddon.dhulster@altec.com>
Sent: Monday, June 27, 2022 2:21 PM
To: Simcoe, Dennis <dennis.simcoe@atco.com>
Subject: Altec AT41M - ATCO unit E20138

Caution – This email is from an external source. If you are concerned about this message, please forward it to spam@atco.com for analysis.

Here's the quote for the Stock AT41M's with upfits (to be requoted at delivery)

Current estimated delivery is September 2022

_____
Braddon D'Hulster
Account Manager
Altec Industries Ltd.
Cell: 587-830-5932
braddon.dhulster@altec.com



June 27, 2022
Customer: ATCO
Contact: Dennis Simcoe

Unit / Body Specifications

- Altec model AT41M telescopic articulating aerial device with continuous rotation and ISO-Grip insulating system at boom tip
  working height: 45.8 ft
  side reach: 30.1 ft
- Single one man platform, 180 degree rotation
- Round material handling jib/winch, hydraulically articulating, top mounted
- Two (2) platform steps
- Platform cover
- Platform liner
- One set of hydraulic tool outlets at the boom tip
- Engine start/stop with secondary stowage system
- Jib stick, 36 in L, non-extension dependent, non-certified
- Modified A-frame primary outriggers with fixed shoes and safety interlock system
- Lifting eye - lifting eye on underside of boom.
- Unit manufactured to Canadian standards per CSA C225
- Temperature sight gauge
- Hydraulic oil heater, 120 vac
- Fiberglass body
- Low-side general service line body with step
- Fiberglass hotstick shelf
- Fiberglass hotstick shelf, drop down door
- Aluminum tailshelf
- Manual boom stow securing system installed on boom rest
- Wood outrigger pads
- Rope lights (LED)
- FMVSS 108 lighting package. (LED with incandescent reverse lights)
- Amber LED strobe light
- 4-Corner strobes, amber LED
- Remote spot light, LED
- 6-Way trailer receptacle, pin type
- Mounting bracket for inverter mounted at bottom of body compartment or storage box
- Inverter, 1200 watt, pure sine wave, 120 VAC
- Power distribution module (PDM-6)
- No upper boom out of stow indicator
- Standard altec warranty: one (1) year parts, one (1) year labor, ninety (90) days travel and limited lifetime structural
- Canadian order

Chassis Specifications

- Ford F550
- 4x4 drive train
- 84 inch CA
- Ford 6.7L Power Stroke diesel
- 19,500 lb GVWR
- 7,500 lb FAWR
- 14,706 lb RAWR

www.altec.com for additional models and information. Quote valid for 45 days; Price does not reflect any local, state, or Federal Excise Taxes (F.E.T.). For additional accessories or details contact your Altec Account Manager.

NEW EQUIPMENT SALES | 800.958.2555 | SALES@ALTEC.COM | ALTEC.COM

February 3, 2022

Options

1. Four (4) swivel LED work lights (2 at the front of the body – 1/side, 2 rear facing at the rear of the body – 1/side)
2. Two (2) Go-lights (1 forward facing at the front of the vehicle, 1 rear facing high mount on the main boom near turret)
3. 2000W inverter and 3 remote outlets
4. Fold down cone holder on the rear corner of the deck
5. 24” x 24” x 1” yellow composite outrigger pads
6. Replace hydraulic oil with hydrex extreme
7. Install e-track system both top and bottom of the body.

Price:	$	240,224
Options:	$	24,098
Delivery:	$	Includes delivery to Edmonton, AB
Total: (Excluding Taxes)	$	$264,322

**Options to be re-estimated at time of delivery

www.altec.com for additional models and information. Quote valid for 45 days; Price does not reflect any local, state, or Federal Excise Taxes (F.E.T.). For additional accessories or details contact your Altec Account Manager.

NEW EQUIPMENT SALES | 800.958.2555 | SALES@ALTEC.COM | ALTEC.COM

Request for Goods / Services Form (RGS)

This form is to request goods and/or services where the annual spend or individual project spend is over $50K and/or of medium or high complexity/visibility. Quotes for goods/services or Request for Information (RFI) for less than $50k can be obtained by the originator.

Form submission and inquiries to be directed as follows:

- Non-work releases to EGBUProcurement@atco.com.
- Work releases to AEContractAdmin@atco.com.

ORIGINATOR TO COMPLETE			
1. Project Information: Project Name & Location.	Watson Lake Service Bucket Watson Lake		
	Project #: 1068871	Task Code:	C.07.002
2. CEAR:	Not Required	3. Contract Administrator (CA)	Not Required
4. Business Division:	North of 60 (N60)	5. Estimated total or annual value ($CAD):	$ 264,322.00
6. Project Type:	Non-Direct Assigned	7. Pricing Schedule(s):	☑ Attached; or ☐ To be provided later
8. Work Recurrence:	One time purchase / individual pr	9. Pricing Method:	Lump Sum
10. Services / Delivery Date(s):	Start Date: July 4, 2022 Completion / Delivery Date(s): October 15, 2022	11. Allowable Expenses: List items & budget identified by ATCO for the Project.	N/A
12. Work Specification Details:	12.1 Work package (specifications, drawings, maps, etc) Other (as below) 12.2 Permits required by contractor/supplier Yes ☐ No ☑ 12.3 Site specific orientation requirements Yes ☐ No ☑ 12.4 Forest Fire Fighting Expense Insurance Waiver Yes ☐ No ☑		
13. HSE Document(s):	Prime Contractor: Contractor If contractor is identified as prime, a prime contractor agreement is required		
14. Pre-Bid Meeting:	Yes ☐ No ☑	15. Site Visit:	Yes ☐ No ☑

Request for Goods / Services Form (RGS)

16. Recommended Supplier(s) or Contractor(s) and contact information (contact name, email, phone number, address) to be provided. For MSAs, only Contractor names to be provided. Contractors are required to be Avetta approved prior to award.

_____
Braddon D'Hulster
Account Manager
Altec Industries Ltd.
Cell: 587-830-5932
braddon.dhulster@altec.com

17. Evaluation Criteria: Yes ☐ No ☑

N/A

18. Single or Sole Source Justification: this section is to be used when company bidding standards are not followed for Non-AESO Transmission Direct Assigned Projects (REF form to be completed for AESO Transmission Direct Assigned Projects that do not follow the procurement guideline). Select the applicable reason(s) for the supplier/contractor selection in 18.1. Provide supporting information in 18.2.

Company Bidding Standards	
Bid Value	Minimum Number of Bids (Written Response)
UP TO AND INCLUDING $50,000	1 Bid
OVER $50,000 AND UP TO AND INCLUDING $100,000	2 Bids
OVER $100,000	3 Bids

18.1 Select the applicable reason(s) for the supplier/contractor selection.

Purchases <$50K for non-AESO and <$10K for AESO can be perfomed (no SSJ required)

18.2 Provide supporting information.

Truck sourced by ATCO Fleet Services

Request for Goods / Services Form (RGS)

19. Submitted by:

Signature:_____
Name:_____
Date:_____

Reviewed by Project Manager (if applicable):

Signature: Tony Badry Digitally signed by Tony Badry Date: 2022.06.30 14:27:01 -07'00'
Name:_____
Date:_____

Approved by:

Signature: Digitally signed by William Cullen DN: cn=William Cullen, o=ATCO Electric Yukon, ou=Manager, email=bill.cullen@atco.com, c=CA Date: 2022.07.01 05:32:30 -07'00'
Name:_____
Date:_____

Approved by:

Signature:_____
Name:_____
Date:_____

The form is to be approved by Supervisor/Manager. When using Single source, Signatures on this form to follow Delegation of Authority (DOA)

ATCO Electric YUKON

September 28, 2023 AEY-UCG-076

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-076

Reference: Satellite Radios Purchase, BC#14 Cost $157,000

Request:

(a) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-077

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-077

Reference: Line Moves in Highway ROW, BC#15 Cost $121,000 &$118,000 &$184,000

Request:

(a) Are all these jobs now complete and were there any additional costs associated?

(b) Did this work consider that further work will be required on securing ROW for Alaska Highway widening and construction? If not, why not?

(c) Were these costs already added to the rate base? If yes, when and under what authority?

Response:

(a) All three projects are completed, and cost details are included in the Business Case.

(b) Yes, AEY coordinates annually with the Yukon Government on ROW widening projects.

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-078

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-078

Reference: Dual Rated Transformer Upgrade, BC#16 Cost $292,761

Request:

(a) Since the project initiated in 2013, revisited 2016-17 GRA, was there any prior activity in the accounting? Explain.

(b) Did this delay increase costs? Explain.

(c) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(d) Was any of this cost already added to the rate base? If yes, when and under what author

(e) Did this result in less line loss? Explain.

Response:

(a) The need for switchable padmount transformers was established before 2013. Whenever a transformer replacement or new install is required, a switchable transformer is installed.

(b) It is not estimated that project costs increased beyond inflation.

(c) Please refer to the response to AEY-UCG-066(a). Please also refer to the technical report in 2016-2017 GRA included in IR response YUB-YECL-017(b).

(d) Please refer to the response to AEY-UCG-065(b).

(e) As losses are proportional to line voltage, line loss improvements will not be realized until voltage conversion has been fully completed.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-079

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-079

Reference: Install 35 kV Regulators on Carcross Road, BC#17; Cost $196,387

Request:

(a) Provide original engineering qualifications of what work was to be done and what were the economic analyses including preliminary engineering estimate of costs. Provide engineers report.

(b) Was any of this cost already added to the rate base? If yes, when and under what authority?

(c) Did this result in less line loss? Explain.

Response:

(a) Please refer to the response to AEY-UCG-066(a).

(b) Please refer to the response to AEY-UCG-065(b).

(c) Line loss would see an extremely marginal improvement. As losses are proportional to line voltage, the voltage adjustment provided by the regulators would improve losses at times when load is high and system voltage is being suppressed due to this load.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-080

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-080

Reference: New Services Overhead and Underground, BC#18; Cost $126,000 & $145,000

Request:

(a) Explain why these costs were not borne by the customer.

(b) Were these costs already added to the rate base? If yes, when and under what authority?

Response:

(a) These are annual costs incurred by AEY to connect new customers to the distribution system where the cost of each connection is less than the Board approved investment amount(s). As a result, individual capital projects are not opened for each customer connection as no contribution is being made by the customer.

(b) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-081

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-081

Reference: My Account for Online Customer Access, BC#19; Cost $265,622 & On-Going forecasted O&M Fees of $5,458.

Request:

(a) Provide tenders for this contract and explain why it was awarded to Global IT group.

(b) Are the Forecasted O&M fees $5.458 thousand or $5.558 million? Explain

(c) Produce cost/benefit analysis demonstrating costs for online customer portal vs. in-person manual services.

(d) Were these costs already added to the rate base? If yes, when and under what authority?

Response:

(a) The contract was not awarded to Global IT, it was awarded to WIPRO. The project was awarded to WIPRO as it was AEY's IT service provider at the time and this project was an extension of a current functionality and not a new software purchase.

(b) The costs are $5,458. These are the monthly O&M fees for the system. A breakdown of the costs is provided in the Business Case and included in Table 1 below.

Table 1: Forecast Monthly O&M Fees
($)

Ongoing Fees	**Cost**
AMS Projected Monthly Cost (Silver)	2,320
DR Service (Annual Cost of $2,137)	178
Oracle Cloud Hosting Fees	2,960
Total Ongoing Fees Estimate	**5,458**

(c) A formal cost/ benefit analysis was not completed as cost was not the main driver of the project. The main driver was allowing customers to access their account and pay bills online, a feature that is considered a necessity in a digital society. In addition, the project allows AEY staff to spend less time processing manual payment transactions and focus instead on more value-added tasks.

(d) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-082

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-082

Reference: Streetlights Hart Crescent, BC#20; Cost $180,176 completed 2021

Request:

(a) Has the long-term streetlight rebuild plan been okayed by YUB? Give references.

(b) Was this project tendered or done in-house? Provide details of tender is such.

(c) Was this cost already added to the rate base? If yes, when and under what authority?

Response:

(a) The long-term streetlight rebuild plan is not submitted for approval as an overall plan but is broken into smaller projects, each of which are submitted to the Board for prudency review as required through a GRA.

(b) Both the electrical ($17,000) and civil construction labour ($109,000) were completed by AEY sub-contractors under Master Service Agreements that are signed annually by AEY's approved contractors.

(c) Please refer to the response to AEY-UCG-065(b).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-083

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-083

Reference: Swift River Unit 2 Replacement (CUL 544), BC21; Cost $226,589 Completed 2022

Request:

(a) Provide tenders for this unit.

(b) Was this cost already added to the rate base? If yes, when and under what authority?

(c) Provide who salvaged the replaced unit and what ATCO was paid for this.

Response:

(a) The genset was supplied by Frontier Power Solutions, as a match to the existing Swift River Unit 2 manufacturer and model. The rationale for this sole source purchase (<$50,000) was to ensure consistency of parts, familiarity of operation, and simplicity of integration with existing control and monitoring equipment.

Due to changes in Off Road Compression Ignition Engine Emissions Regulations, this unit required EPA Tier 3 compliance. This necessitated additional infrastructure including a charge air cooler, piping, ducting, and radiator along with circulation pump and additional motor wiring and control. The installation of this unit was completed by contractors; the tender for the mechanical portion of the scope was unsuccessful in attracting competitive bids and the electrical/instrumentation portion of the scope was done under the Master Services Agreement.

Prior replacements in Swift River were solely genset replacements, that repurposed the existing piping and cooling systems. The cost breakdown of actuals on this project is as follows:

Table 1: Swift River Unit 2 Replacement Project ($000)

Project Management and Design and Construction Supervision (internal)	21
Material Supply (genset, bulk)	52
Mechanical Installation	79
Electrical Installation	62
Commissioning	12
Total	**226**

(b) Please refer to the response to AEY-UCG-065(b).

(c) AEY is still in possession of CUL 544.

September 28, 2023 AEY-UCG-084

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-084

Reference: ATCO CIS Replacement, BC#22; Cost $8.403 million plus additional O&M cost of $235,000 for 2023 and $415,000 for 2024.

Request:

(a) Does not the main office of ATCO Utilities handle billing? At what cost?

(b) Provide business risk report identified in #5 p. 1 and 2.

(c) Provide original engineering qualifications of what work was to be done and what were the economic analyses identifying the business drivers and cost/benefits, including the preliminary engineering estimate of costs. Provide engineers report.

(d) Provide tender procurement process with tenders and amounts.

(e) Provide a cost/benefit analysis of the costs of this replacement with efficiencies generated.

Response:

(a) No, the main office of ATCO Utilities does not handle billing. Customer billing services are provided at AEY's main office in the Yukon.

(b) Please refer to AEY-UCG-084(b) Attachment 1. For context, ATCO CIS is an ATCO-owned, in-house developed, custom built, application that handles utility Customer Care and Billing processes for both the Alberta and North of 60 distribution utilities. The report identifies the business risks and assessment of the legacy CIS system for the Alberta utilities; however, it extends to the North of 60 as it is the same system. Furthermore, AEY notes that the Alberta Utilities Commission approved the replacement of CIS in Decision 26616-D01-2022,

specifically para. 254: “The Commission is satisfied that, given the risk of the continued use and operation of the existing ATCO Distribution Utilities’ CIS, the need for replacement is warranted.”

(c-e) Please refer to AEY-UCG-084(c-e) Attachment 1 for a scorecard summary of various tenders and evaluation categories. Please refer to AEY-YUB-067(f) Attachment 1 for the annual revenue requirement and cumulative revenue requirement for each of the explored scenarios over 20-years.

Efficiencies generated by the implementation of Oracle CCS include leveraging economies of scale across ATCO’s Alberta based Distribution Utilities through the application of a common business support team for Oracle CCS. Further, the Oracle CCS product benefited from technical compatibility and ease of integration to the existing North of 60 technical environment.

ATCO always there. anywhere.

TMG's Assessment of ATCO's Current CIS

Presentation of Results

December 9, 2019





TMG Consulting
Where Business and Technology Intersect

Introduction and Presentation Outline

- This assessment was conducted for the ATCO Group by TMG Consulting, Inc. as part of our Strategic Application Roadmap offering. The objective of this assessment was:
  - For TMG to evaluate the current ATCO legacy CIS from both a Gas and Electric perspective and determine if the application should be retained or replaced.
  - If the decision was to replace, TMG conducted a second exercise to identify and analyze alternative replacement scenarios in order to identify an optimum scenario for ATCO to consider.
- This presentation has been structured in the following sections to facilitate your review.
  1. Interview Results
  2. Current CIS Assessment
  3. Alternative Scenarios
  4. Evaluation Criteria
  5. Detailed Evaluation Results
  6. Summary Scoring
  7. Recommendations
  8. Closing

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Your Experienced TMG Team

- An experienced team of TMG consultants with extensive experience in the evaluation of CIS solutions was assigned to this project.



PAM GLANVILLE
PRESIDENT

Pam is the President and an owner of TMG. She joined TMG after a long and successful career guiding and implementing mission critical applications. She has worked in the IT industry in South Africa and the United States for thirty years, specifically focusing on the utility and revenue verticals for the last eighteen years. Among other various positions within SPL World Group and Oracle, she was the VP of Delivery, responsible for leading and growing the CC&B product as well as the implementation services. She then became the President of Origin Consulting in 2011 and was responsible for growing that company into a successful consulting firm. At TMG, Pam is responsible for our Client-Side Delivery Support services. Her role included overall responsibility for the project. Contact Pam at pam.Glanville@tmgconsulting.com or 973-727-8732.



GREG GALLUZZI
EXECUTIVE VP

Greg founded TMG in 1992 and is considered to be an expert in the CIS area with experience working on over 200 CIS utility industry projects at over 130 client sites. Today, he remains an owner and is an Executive Vice President. Greg has 39 years of CIS/Utility experience, and has participated in the majority of TMG's 400-plus projects, (CIS planning (40), studies (15), assessments (20), procurements (90), implementations (50), and expert witness testimony (5)). Recent projects include: EPCOR contracting, ATCO alternative assessment, default supply provider outsourcing assessment, and system integrator procurement, National Grid planning and procurement, AES requirements, financial model and procurement, SFPUC application plan, NWN application plan, and SWG application plan. Greg is responsible for maintaining TMG's project metric and pricing database, he is responsible for TMG's strategic application roadmap methodology and templates/ accelerators. He also provides assistance to consultants working on many other TMG projects regarding adherence to project methodology/accelerators, pricing, contracting, etc.. Contact Greg at: greg.galluzzi@tmgconsulting.com or 512-757-1156.

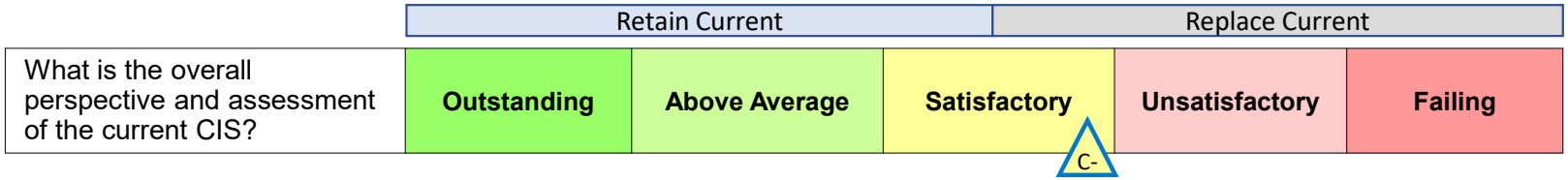
1. Interview Results



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Interview Assessment

- As a part of the information gathering process, individuals from ATCO who are involved with the current CIS were interviewed. TMG reviewed these interview results and based on our experience a grade of "C" or Low Satisfactory, was assigned.



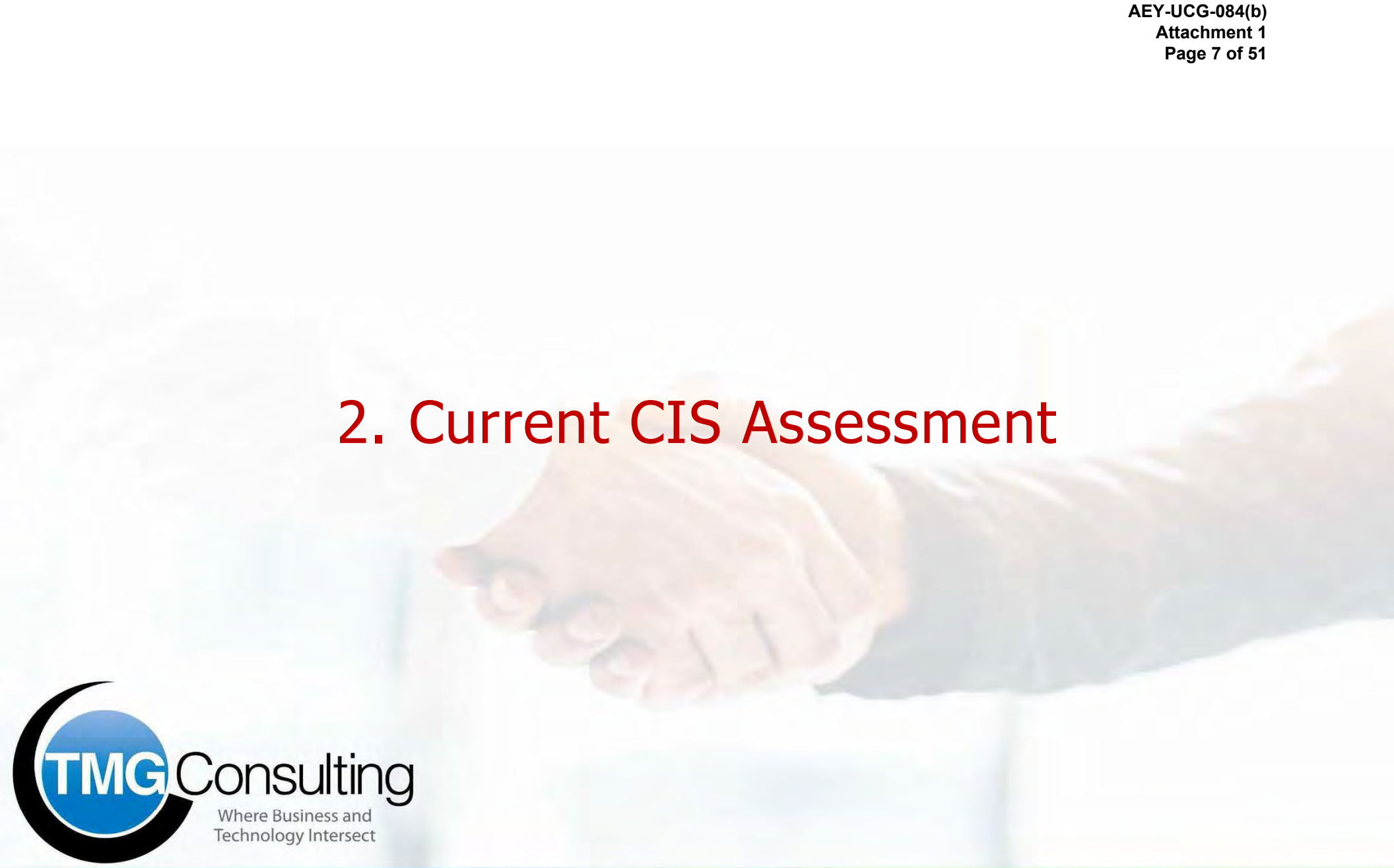
- This grade indicates that the people who manage, use, and support the current system on a daily basis, believe it should be REPLACED.
- Several main themes were observed, including:

1. There is a support issue as there are only five application support personnel that understand the system and can code, they are close to retirement or have other opportunities to go to. We estimate it takes 6 years to train a new support person.
2. It is an old system written in COBOL with a DB2 database, this makes it difficult to recruit, hire, and train new support personnel (colleges no longer teach this language).
3. Changes to the system are time consuming, costly, and risky. It takes time for a change to be made, the change is very costly (could be $100k to $1m), and sometimes when it is delivered it breaks other things in the system which introduces a level of risk to the business.
4. The code is old and poorly structured, integration work through API's and extensions are difficult, this all makes any changes to the system complicated.
5. The business no longer asks for new enhancements because they cost to much and take to much time.

Interview Assessment

6. Changes requested by our regulator are getting more difficult and costly to implement, the last one took 8 months and cost over $1m.
7. Anything new is typically implemented in another system (edge system), and then attempted to be integrated to the current CIS.
8. Any changes to existing reports or requests for new reports have to be developed by that same small group of developers (a report change can cost $30k and take 6 wks). There is no analytics engine to assist all aspects of the business in serving customers, regulators, managers, and executives.
9. It is primarily a billing engine with a focus on the meter and account, and it does a good job of supporting the core business functions.
10. It does not focus on the customer and providing exceptional levels of service to that customer. This will inhibit future customer driven initiatives regarding movement toward becoming a digital utility and customer transformation utilizing newer technologies and communication channels.
11. It does not support the company's growth strategy through acquisition. It would be difficult to use the current system to onboard new customers and provide service and support.
12. It does not easily support future company revenue streams through new complex rates, or offering of new products, programs, or services.
13. The current system has a poor user interface and is difficult to navigate and understand and has limited documentation and no help. It takes time to teach new users how the system works and make them proficient in their job. This is important as the business is losing people and they are taking this application knowledge with them.
14. The current system is an aging platform and has a declining resource pool for support. Changes are timely, costly, and risky. If the company stays with the current system these issues will only grow worse and can jeopardize our revenue stream (accounts for 90% of the revenue stream) and service to our customers.

2. Current CIS Assessment



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TMG Assessment of ATCO Gas from a Business Perspective

- The current CIS was evaluated by TMG n terms of how it supports the ATCO Gas business across 15 primary business considerations and 115 secondary business considerations. The following tables summarize this analysis, and TMG assigned an overall business grade of "D" or unsatisfactory.

Business Consideration	Grade
Strategy ▪ Meets corporate business and customer strategy	D
Objectives ▪ Meets customer based service objectives	D
Scope of Services ▪ Accommodates services e.g. gas, electric, water	C
Scope of Products ▪ Accommodates various product offerings	F
Scope of Programs ▪ Accommodates various programs e.g. budget billing	C
Organization and Staffing ▪ Addresses organizational and staffing issues	D
Configuration ▪ It is configurable, and users have control	F
Business Processes ▪ Aligned with business process and industry practices	D

Business Consideration	Grade
Data ▪ Data integrity, quality, reporting, analytics	D
Customer Life-Cycle ▪ Support customer services e.g. contact, metering	C
Product Functionality ▪ Provides CIS functional components	C
Product Usability ▪ Nice user interface, easy to navigate and learn	D
Product Workflow ▪ Utilizes a workflow engine, scripts, work queues	D
Product Mechanics ▪ Provides documentation, help, security, audit	C
Product Viewpoint ▪ Viewed by users, tech, exec, board, customers	D
OVERALL BUSINESS GRADE	D

TMG Assessment of ATCO Gas from a Technology Perspective

- The current CIS was evaluated by TMG in terms of how it supports the ATCO Gas business across 10 primary technology considerations and 75 secondary technology considerations. The following tables summarize this analysis, and TMG assigned an overall technology grade of "D" or unsatisfactory.

Business Consideration	Grade
Strategy ▪ Meets corporate technology strategy	D
Infrastructure/Platform ▪ Meets preferred infrastructure components	D
Operational Services ▪ Provides services to operate the CIS platform	C
Security ▪ Provides platform, data, application security	D
Programming Considerations ▪ The language, structured code, documentation	F
Support Services ▪ Help desk, investigation, responsiveness	C

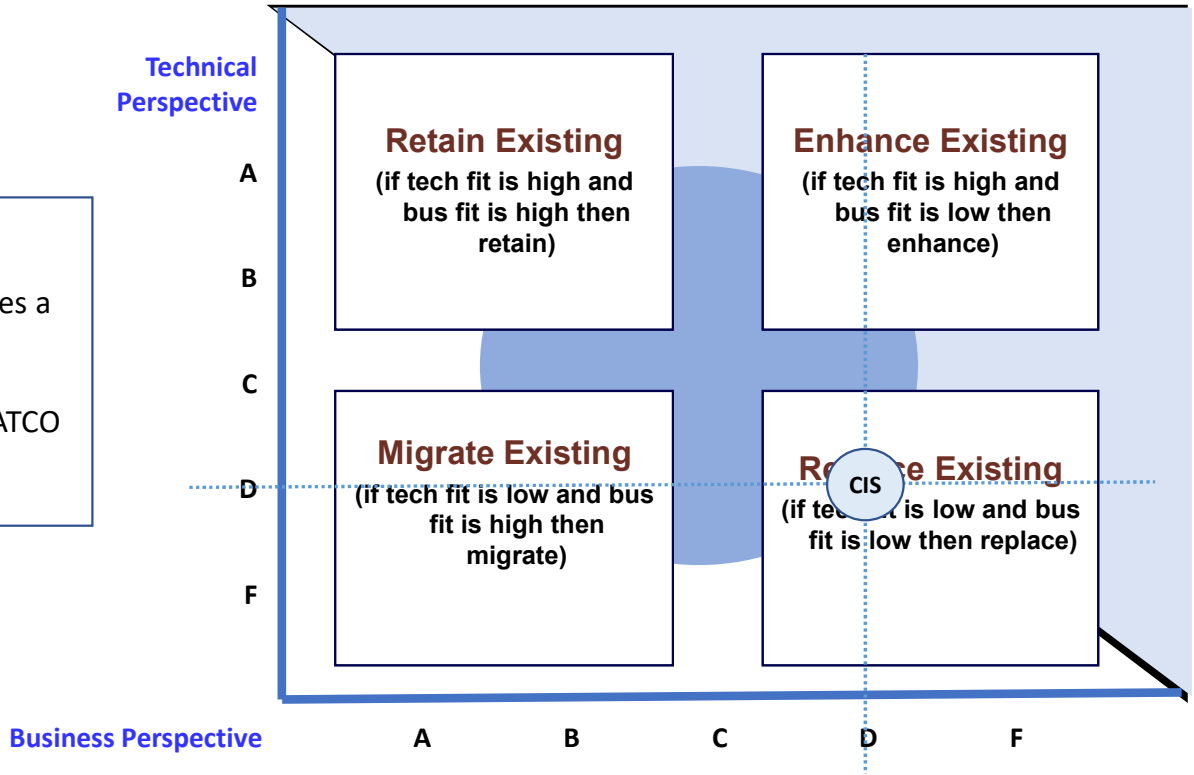
Business Consideration	Grade
Maintenance Services ▪ Corrective, preventive, and emergency work	C
Development Services ▪ Development of small and large projects	C
Product Data Design ▪ Solid data design, retention, integrity, normalized	D
Product Scalability, Availability, Performance ▪ It scales, is available, and performs	C
OVERALL TECHNCIAL GRADE	D

TMG Summary Assessment of ATCO Gas

- The following TMG model examines the assessment of the current CIS from an ATCO Gas business and technical perspective to indicate if the system should be retained, enhanced, migrated, or replaced. TMG has used this model extensively to provide direction in terms of retaining or replacing an existing CIS system.

TMG's analysis indicates the current CIS scores a "D" or Unsatisfactory from a Technical Perspective, and it scores a "D" or Unsatisfactory from a Business Perspective.

Using these two grades the TMG model indicates that ATCO Gas should move toward a strategy of **REPLACE.**



TMG Assessment of ATCO Electric from a Business Perspective

- The current CIS was evaluated by TMG in terms of how it supports the ATCO Electric business across 15 primary business considerations and 115 secondary business considerations. The following tables summarize this analysis, and TMG assigned an overall business grade of "D" or unsatisfactory.

Business Consideration	Grade
Strategy ▪ Meets corporate business and customer strategy	D
Objectives ▪ Meets customer based service objectives	D
Scope of Services ▪ Accommodates services e.g. gas, electric, water	C
Scope of Products ▪ Accommodates various product offerings	F
Scope of Programs ▪ Accommodates various programs e.g. budget billing	C
Organization and Staffing ▪ Addresses organizational and staffing issues	D
Configuration ▪ It is configurable, and users have control	F
Business Processes ▪ Aligned with business process and industry practices	D

Business Consideration	Grade
Data ▪ Data integrity, quality, reporting, analytics	D
Customer Life-Cycle ▪ Support customer services e.g. contact, metering	B
Product Functionality ▪ Provides CIS functional components	C
Product Usability ▪ Nice user interface, easy to navigate and learn	D
Product Workflow ▪ Utilizes a workflow engine, scripts, work queues	D
Product Mechanics ▪ Provides documentation, help, security, audit	C
Product Viewpoint ▪ Viewed by users, tech, exec, board, customers	D
OVERALL BUSINESS GRADE	D

TMG Assessment of ATCO Electric from a Technology Perspective

- The current CIS was evaluated by TMG in terms of how it supports the ATCO Electric business across 10 primary technology considerations and 75 secondary technology considerations. The following tables summarize this analysis, and TMG assigned an overall technology grade of "D" or unsatisfactory.

Business Consideration	Grade
Strategy ▪ Meets corporate technology strategy	D
Infrastructure/Platform ▪ Meets preferred infrastructure components	D
Operational Services ▪ Provides services to operate the CIS platform	C
Security ▪ Provides platform, data, application security	D
Programming Considerations ▪ The language, structured code, documentation	F
Support Services ▪ Help desk, investigation, responsiveness	C

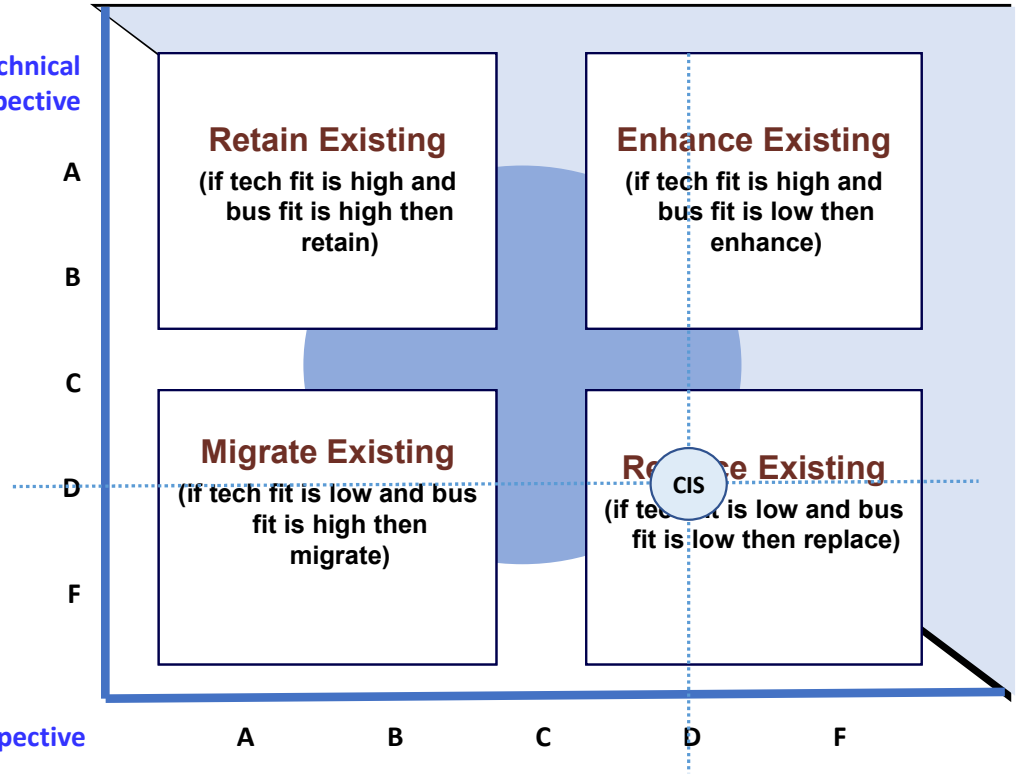
Business Consideration	Grade
Maintenance Services ▪ Corrective, preventive, and emergency work	C
Development Services ▪ Development of small and large projects	C
Product Data Design ▪ Solid data design, retention, integrity, normalized	D
Product Scalability, Availability, Performance ▪ It scales, is available, and performs	C
OVERALL TECHNCIAL GRADE	D

TMG Summary Assessment of ATCO Electric

- The following TMG model examines the assessment of the current CIS from an ATCO Electric business and technical perspective to indicate if the system should be retained, enhanced, migrated, or replaced. TMG has used this model extensively to provide direction in terms of retaining or replacing an existing CIS system.

TMG's analysis indicates the current CIS scores a "D" or Unsatisfactory from a Technical Perspective, and it scores a "D" or Unsatisfactory from a Business Perspective.

Using these two grades the TMG model indicates that ATCO Electric should move toward a strategy of **REPLACE.**



TMG Indicates - Should ATCO Retain or Replace the Current CIS?

Based on this analysis TMG recommends that the current CIS be **REPLACED**. TMG's analysis of the interviews indicated the current system should be replaced, and TMG's assessment of both the business considerations and the technical considerations indicate the current system should be replaced. Based upon TMG's experience and our review of the current CIS, the following items should be viewed as primary drivers for replacement and are inline with what TMG has experienced with similar utilities who have decided to replace their legacy CIS.

1. A strategic and essential foundational initiative in support of company business, technical, and customer based strategies and initiatives.
2. Implementation of newer application technologies and a platform which resolves issues associated with an older legacy billing system e.g. loss of expertise, better integration, improved security, improved reporting and analytics, scalability, etc..
3. Addresses the need for cybersecurity to accommodate operating in a digital environment, and digital customer communication channels with the need to protect critical and important customer information.
4. Replacement of a technical foundation which may adversely impact the company's current and future revenue stream in support of both business operations, and impacts to the customer life-cycle and level of service.
5. A solution which supports staff in providing customers with exceptional levels of service, customer transformation, and applying new technologies and multiple channels of communication and interaction.
6. Provide users with a new and efficient browser based user interface, with new capabilities, documentation, and help. This will enable new users to learn the system quicker and be more effective in meeting job responsibilities and serving customers.
7. The ability to apply regular product releases to provide new customer capabilities in a timely fashion – following a close to zero modification approach. No need for enhancements that take to much time, cost to much, and are risky – those days are over.

3. Alternative Scenarios



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TMG Alternative Scenarios

The following alternative scenarios have been identified by TMG.

- **Scenario 1: Status Quo**

Continue to utilize the existing ATCO CIS solution operated in the existing hosted environment.

- **Scenario 2: Replace and Re-Engineer**

Utilize the existing ATCO CIS solution as the functional baseline for the development of a new system. The logical data/process design is loaded into design software. It is updated and generated into a new coding and technical environment. It will be operated in the current hosted environment.

- **Scenario 3: Replace and Custom Develop**

Purchase a CIS product or design guide or template and develop a custom CIS solution. It will be operated in the current hosted environment.

- **Scenario 4: Replace and Work With Another Utility**

Work with another utility to select and implement a new CIS product solution. It will be operated in a Platform as a Service or PaaS environment with the other utility.

- **Scenario 5: Replace New Product Solution in PaaS Environment**

Select and implement a new CIS product solution, with a perpetual license operating in a Platform as a Service or PaaS environment.

- **Scenario 6: Replace New Product Solution in SaaS Environment**

Select and implement a new CIS product solution, with a subscription license operating in a Software as a Service or SaaS environment.

TMG Option 1 Profile – Status Quo

Scenario 1: Status Quo. Continue to utilize the existing ATCO CIS solution operated in the existing hosted environment.

Positive Considerations	Negative Considerations
1. Since there is no project, there are no implementation dollars, no timeframe, no internal resources required to staff, and no project risk. 2. The solution can scale to accommodate a larger customer base. 3. The current legacy CIS satisfies the basic needs of business users, regulators, customers, etc..	1. This retains the aging legacy CIS solution, this may be viable in the short-term, but at some point it will have to be replaced as it has a cracked technical foundation. 2. Retaining status quo does not usually support corporate strategies, business strategies or technical strategies. 3. This is not a cloud solution, it is a hosted solution which has already been replatformed, and does not adhere to the technical strategy. 4. Does not address issues with technical skilled labor to support the current legacy CIS. 5. Does not address costly and time consuming changes that are required anytime a user wants to make a change or enhance the system. 6. Does not result in any new functionality or capabilities. 7. The current investment in the Oracle CIS could not be used. 8. Operating costs will remain the same while other alternatives typically see costs go down. 9. There are no updates or impacts to the business which would address any existing issues, or provide for an improved levels of customer experience, interaction, or digital communications. 10. The current and future revenue streams remain at risk. Difficult to offer new products, programs and services. 11. The current system is not made to quickly onboard new customers, or add new products, programs, or services. 12. There is no product roadmap, this is an inhouse developed application which started out with a consortium. There are no regular releases.

TMG Option 2 Profile – Replace and Re-Engineer

Scenario 2: Replace and Re-Engineer. Utilize the existing ATCO CIS solution as the functional baseline for the development of a new system. The logical data/process design is loaded into design software. It is updated and generated into a new coding and technical environment. It will be operated in the current hosted environment.

Positive Considerations	Negative Considerations
1. The cost to implement is usually on the low end compared to other alternatives. 2. Usually a shorter time and less resources required to plan, select, implement and stabilize the solution. 3. Changing the application code, may allow for faster and less costly development to accommodate onboarding, or add new products, programs, or services, or implement new functionality. 4. The solution can scale to accommodate a larger customer base.	1. This scenario retains the current aging CIS, it simply is re-engineering it from an application written in Cobol, to one written in a more modern language. So, it may address some of the application and technology issues, but it retains the current data, process, user interface, etc.. 2. Not sure if any true re-engineering software is still available in the market, e.g. knowledgeware, however assume there is software available to just convert code without re-engineering the application. Unaware of utilities that are doing this. 3. There are no updates or impacts to the business which would address any existing issues, or provide for an improved customer experience. However, with a new language enhancements may be conducted quicker and at a lower cost. 4. No significant changes to operational costs 5. While this is a minimal project, there are not a lot of utilities that can be pointed to where large scale legacy CIS applications have been re-engineered (they have been replatformed). 6. The solution does not do anything to support onboarding new customers. 7. The current and future revenue stream remain at risk. 8. It does not do anything to enhance the customer experience, interaction, or digital experience. 9. There is no product roadmap, this is an inhouse developed application which started out with a consortium. There are no regular releases. This is simply re-engineering the same functionality developed with Cobol to a more modern current language. 10. This is not a cloud solution and will continue to be hosted.

TMG Option 3 Profile – Replace and Custom Develop

Scenario 3: Replace and Custom Develop. Purchase a CIS product or design guide or template and develop a custom CIS solution. It will be operated in the current hosted environment.

Positive Considerations	Negative Considerations
1. This scenario will replace the legacy application and provide ATCO with a solution that is specific to the business needs of the organization and the customers. 2. This will enable the system and the business to collect current revenue streams and bill and collect for new revenue streams associated with new products, programs, and services. 3. This will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications. 4. Complete design authority to implement new business operations and automation. 5. The solution can scale to accommodate a larger customer base through organic growth and acquisition. 6. A new technical and application solution, with many resources available in the market to work on the application.	1. This replaces the aging legacy CIS solution, however, it is a "one-off" solution and it is up to ATCO to enhance and maintain it. Regular releases would probably occur every 3 -5 years. 2. This is a tremendous risk, and there have been many failures. However, a utility may buy a CIS design guide, or may purchase a CIS product and then possibly discontinue maintenance. In any event, this is a very high risk scenario and not very viable for a number of reasons. 3. Implementation costs can be the most expensive compared to other alternatives. 4. Operational costs can be more expensive that what the utility is currently paying. 5. It results in ATCO continuing to support, develop, maintain, and operate the application. (assume custom development of a new CIS solution will continue to use the existing hosted environment). 6. Why get back into the custom CIS solution like SinglePoint?

TMG Option 4 Profile – Replace and Work With Another Utility

Scenario 4: Replace and Work With Another Utility. Work with another utility to select and implement a new CIS product solution. It may be operated in a Platform as a Service or PaaS environment with the other utility.

Positive Considerations	Negative Considerations
1. Operational costs are usually lower then current legacy application costs. 2. Implementation costs my be slightly lower then other alternatives. 3. This replaces the legacy CIS with a modern CIS product solution which may operate in a PaaS cloud environment. 4. It provides a new technical and application solution, with many resources available in the market to work on the application. 5. Will enable the system and the business to collect current revenue streams and bill and collect for new revenue streams associated with new products, programs, and services. 6. Will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications. 7. This replaces the aging legacy CIS solution. ATCO will have to work with the other utility(s) to do upgrades, which may not be according to the ATCO schedule or plan. 8. The solution can scale to accommodate a larger customer base through organic growth or acquisitions.	1. Over the past 40 years there have been may consortiums where utilities have gotten together to design and implement a new CIS, e.g. ATCO SinglePoint. There have also been a number of attempts for utilities to work together to procure and implement a common CIS. The majority of these have failed. This is a very high risk project, which ends up requiring much more time and money and ends up in failure or the utilities go there own way. 2. May not be able to utilize the current Oracle perpetual licenses that were paid for. 3. Business operations may be hindered in some areas as ATCO will have to align with what the other utility(s) want to do, or how they want to adhere to the product roadmap. 4. There my be some issues to consider in working with the consortium to implement new products, programs, and services. Also, to just do enhancements the utility may have to compete with consortium resources.

TMG Option 5 Profile – Replace New Product Solution PaaS

Scenario 5: Replace New Product Solution in PaaS Environment. Select and implement a new CIS product solution, with a perpetual license operating in a Platform as a Service or PaaS environment.

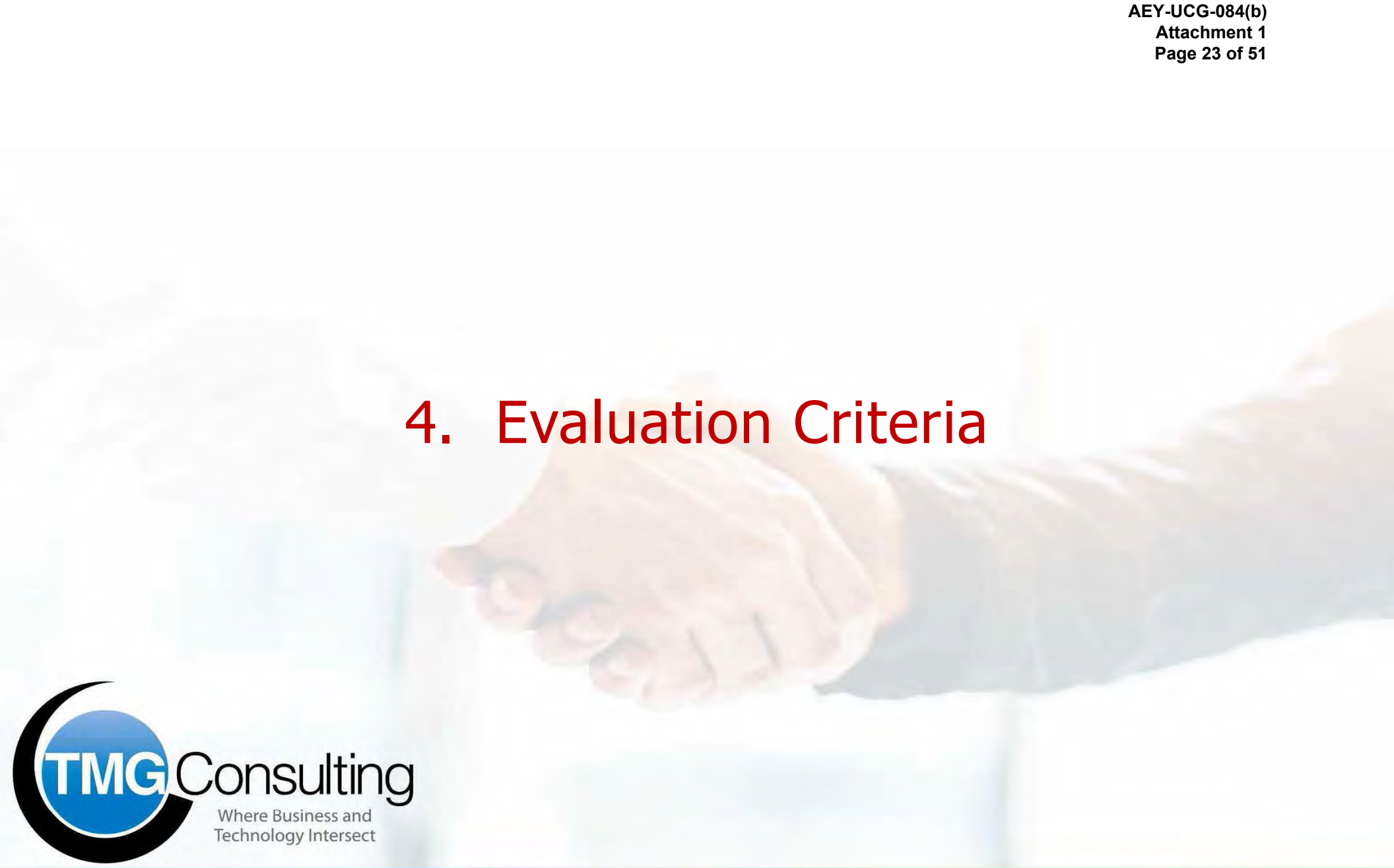
Positive Considerations	Negative Considerations
1. Operational costs are usually less then the costs of the legacy system. 2. This replaces the current legacy CIS with a modern CIS cloud based product. 3. In a PaaS perpetual environment the utility is free to do what it wants to modify and enhance the system to meet specific business and regulatory requirements. 4. The PaaS solution is much like hosting, which many utilities are familiar with. There have been many successful PaaS/Hosted solution that have been implemented . 5. Most large IOUs like ATCO are going with this PaaS model or something they are calling MPaaS, which is Managed Platform as a Service. Both have proven to be successful. 6. A new system will be very flexible to quickly add new products, programs, and services. As a result, both the current and new revenue streams will be recognized. 7. It will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications. 8. It can utilize existing Oracle licenses. 9. Onboarding tools can be developed as part of a new CIS. This is a perpetual license, with ATCO able to implement and stay on the CIS Product Roadmap for a CIS product solution. It is up to ATCO if they pursue a SaaS-like solution or do something more specific to ATCO operations. 10. This replaces an aging legacy CIS solution by a industry leading CIS product which alleviates the technology headache and the ability to find resources who can work on the CIS. 11. The solution can scale to accommodate a larger customer base associated with organic growth and acquisitions.	1. Although this is a cloud based PaaS perpetual model it does not meet the technical vision of a true public SaaS subscription solution. 2. This solution comes with a higher price tag compared to other alternatives. 3. Implementation costs are usually middle of the road, PaaS is not the cheapest to implement but also not the most expensive. 4. De[ending on what is negotiated, there may be limited service levels, lack of termination for cause, and the identification of termination services. 5. Release strategies run anywhere from about once a year to once every 3 to 5 years. 6. Ultimately, utilities may move past this model and go with a true SaaS offering. 7. True PaaS does not alleviate the entire technology headache, that is why utilities are also engage managed service firms to provide that technical and application knowledge.

TMG Option 6 Profile – Replace New Product Solution SaaS

Scenario 6: Replace New Product Solution in SaaS Environment. Select and implement a new CIS product solution, with a subscription license operating in a Software as a Service or SaaS environment.

Positive Considerations	Negative Considerations
1. Operational costs are usually lower then the current legacy system. 2. Utilities are slow to adapt, but they will be moving to a SaaS environment in the future like ATCO. 3. This will replace the legacy CIS and will focus on providing new products, programs, and services. There will be no negative impacts to either the existing revenue stream or future revenue streams. 4. Improvements in customer service, self-service, digital communications, etc. can be realized with SaaS. 5. Will utilize existing Oracle perpetual licenses as they become subscription licenses and are built into the subscription fee. 6. New releases with SaaS come on a regular based, e.g. every 2 months, every 3 to 4 months. 7. The SaaS solution can be easily scaled up to accommodate larger customer either through organic growth, or through acquisition. 8. SaaS provides for the technical architecture which surrounds the application, the utility no longer needs to provide this technical staff, and with a new popular CIS architecture there will be many resources available in the market.	1. The public SaaS subscription model has not yet been implemented for a CIS in North America. ATCO will be the first large scale IOU, and other utilities are looking to this project to see how successful it is, both from an implementation and an operation perspective. 2. In SaaS users are asked to conform to how the product has been designed with exceptions for regulatory requirements and a few key business requirements. This may be difficult to implement what is known as a “zero” mod approach. 3. With frequent releases (every 3 months) resources may be strained in planning and implementing these releases. Vendors usually indicate you can Apply a release but you don’t have to activate it. This would still entail some amount of work. 4. Compared to history with off premise solutions, SaaS solutions have limited service level. Usually, convenience for cause, and termination services are not well negotiated. 5. Implementation costs are usually middle of the road, SaaS is not the cheapest to implement but also not the most expensive.

4. Evaluation Criteria



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TMG Primary Evaluation Criteria and Weights

- The following are the primary evaluation categories and the weights that were used by TMG to evaluate the alternative scenarios.

Evaluation Matrix - C. Evaluation Catégories

Item #	Evaluation Category	Weight	Description
1	Implementation Costs	15%	The total cost to implement the scenario.
2	Operational Costs	10%	The total annual cost to operate the scenario.
3	Implementation Timeframe	5%	The time to implement and stabilize the scenario.
4	Solution Risk & Viability	10%	The risk associated with installing and operating the scenario.
5	Resource Utilization	15%	The staffing and resources to implement and operate the scenario.
6	Business Considerations	20%	The scenario meets various business constructs and considerations.
7	Technology Considerations	10%	The scenario meets various technical constructs and considerations.
8	Benefits & Improvements	15%	The scenario delivers benefits and improvements to various stakeholders.
	Total	**100%**	

TMG Subcategory Evaluation Criteria

The following are the subcategories that were used by TMG to evaluate the alternative scenarios.

Evaluation Matrix - D. Evaluation Subcategories

ITEM #	Evaluation Category	Subcategory 1	Subcategory 2	Subcategory 3	Subcategory 4	Subcategory 5
1	Implementation Costs	$50M or Less	$50M to $65M	$65M to $85M	$85m to $105M	Over $105M
2	Operational Costs	$10M or Less	$10M to $15M	$15M to $20M	$20M to $25M	Over $25M
3	Implementation Timeframe	24 Months or Less	24 to 30 Months	30 to 35 Months	35 to 40 Months	Over 40 Months
4	Solution Risk & Viability	Application Risk	Platform Risk	Business Risk	Project Risk	Viability
5	Resource Utilization	$1M or Less	$1M to $10M	$10M to $20M	$20m to $40M	Over $40M
6	Business Considerations	Revenue Stream	Utility & Customer Transformation	Cost Recovery & Investment	Automation & Efficient Business Operations	Growth Strategies
7	Technology Considerations	CIS Roadmap	Aging CIS	Cloud Solution & Services	Scalability & Performance	Efficient Technical Operations
8	Benefits & Improvements	Regulatory Bodies	Executives / Board	Technical Personnel	Business Users	Customers

5. Detailed Evaluation Results



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TMG Evaluation Matrix – Grading Scale

- The following are the grades which were used by TMG to evaluate each of the alternative scenarios across all evaluation categories and subcategories. The results are presented on the following pages.

Evaluation Matrix - B. Grade Scale

Rating Value	Short Description	Long Description
2	Meets	The Alternative Scenario demonstrates the capability to meet the evaluation criteria or it meets defined metrics for this rating.
1	Meets Most	The Alternative Scenario demonstrates the capability to meet most of the evaluation criteria or it meets defined metrics for this rating.
0	Somewhat Meets	The Alternative Scenario demonstrates the capability to somewhat meet the evaluation criteria or it meets defined metrics for this rating.
-1	Only Meets a Few	The Alternative Scenario demonstrates the capability to only meet a few of the evaluation criteria or it meets defined metrics for this rating.
-2	Does Not Meet	The Alternative Scenario demonstrates that it does not meet the evaluation criteria or it meets defined metrics for this rating.

TMG Analysis - 1. Installation Costs

- The following summarizes TMG's analysis of installation costs for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	2 Meets	1 Meets Most	-2 Does Not Meet	-1 Meets Few	-2 Does Not Meet	-2 Does Not Meet
Install Value:	$0m to $0m	$62m to $82m	$168m to $216m	$103m to $127m	$126m to $154m	$115m to $145m

Note: minus ES&G and IDC plus contingency.

TMG Analysis - 2. Operational Costs

- The following summarizes TMG's analysis of operational costs for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	-1 Meets Few	0 Somewhat Meets	-2 Does Not Meet	2 Meets	2 Meets	2 Meets
Annual Value:	$18m to $22m	$17m to $21m	$27m to $33m	$8m to $10m	$8m to $10m	$8m to $10m

TMG Analysis - 3. Implementation Timeframe

- The following summarizes TMG's analysis of implementation timeframe for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	2 Meets	2 Meets	-2 Does Not Meet	-1 Meets Few	-1 Meets Few	-1 Meets Few
Value:	0 mo	21 mo	72 mo	39 mo	36 mo	36 mo

Note: involves plan/select, implementation, stabilization.

TMG Analysis - 4. Solution Risk & Viability

- The following summarizes TMG's analysis of solution risk and viability for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	-1 Meets Few	-1 Meets Few	-1 Meets Few	0 Somewhat Meets	2 Meets	1 Meets Most
Application Risk:	-2 Does Not Meet	-2 Does Not Meet	-1 Meets Few	1 Meets Most	2 Meets	2 Meets
Platform Risk:	-2 Does Not Meet	-2 Does Not Meet	-1 Meets Few	1 Meets Most	1 Meets Most	2 Meets
Business Risk:	-2 Does Not Meet	-1 Meets Few	2 Meets	0 Somewhat Meets	2 Meets	1 Meets Most
Project Risk:	2 Meets	0 Somewhat Meets	-2 Does Not Meet	-2 Does Not Meet	2 Meets	0 Somewhat Meets
Viability:	-1 Meets Few	1 Meets Most	-2 Does Not Meet	-2 Does Not Meet	2 Meets	1 Meets Most

TMG Analysis - 5. Resource Utilization

- The following summarizes TMG's analysis of internal resource utilization for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	2 Meets	0 Somewhat Meets	-2 Does Not Meet	0 Somewhat Meets	-1 Meets Few	-1 Meets Few
Value:	$0m to $0m	$13m to $19m	$49m to $61m	$18m to $22m	$25m to $31m	$25m to $31m

TMG Analysis - 6. Business Considerations

- The following summarizes TMG's analysis of business considerations for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	-1 Meets Few	-1 Meets Few	2 Meets	1 Meets Most	2 Meets	2 Meets
Revenue Stream:	-2 Does Not Meet	-2 Does Not Meet	2 Meets	2 Meets	2 Meets	2 Meets
Utility Transformation:	-2 Does Not Meet	-2 Does Not Meet	1 Meets Most	1 Meets Most	1 Meets Most	2 Meets
Cost Recovery & Investment:	2 Meets	1 Meets Most	1 Meets Most	1 Meets Most	2 Meets	2 Meets
Automation and Efficient Ops:	-2 Does Not Meet	-2 Does Not Meet	2 Meets	1 Meets Most	2 Meets	2 Meets
Supports Growth Strategies:	-2 Does Not Meet	1 Meets Most	2 Meets	1 Meets Most	1 Meets Most	2 Meets

TMG Analysis - 7. Technology Considerations

- The following summarizes TMG's analysis of technology considerations for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	-2 Does Not Meet	-1 Meets Few	0 Somewhat Meets	1 Meets Most	1 Meets Most	2 Meets
CIS Product Roadmap:	-2 Does Not Meet	-2 Does Not Meet	-2 Does Not Meet	1 Meets Most	1 Meets Most	2 Meets
Aging CIS:	-2 Does Not Meet	-2 Does Not Meet	1 Meets Most	1 Meets Most	2 Meets	2 Meets
Cloud Solution:	-2 Does Not Meet	-2 Does Not Meet	1 Meets Most	1 Meets Most	1 Meets Most	2 Meets
Scalability & Performance:	1 Meets Most	1 Meets Most	1 Meets Most	1 Meets Most	1 Meets Most	2 Meets
Efficient Technical Ops:	-2 Does Not Meet	-1 Meets Few	1 Meets Most	1 Meets Most	1 Meets Most	2 Meets

TMG Analysis - 8. Benefits & Improvements

- The following summarizes TMG's analysis of benefits and improvements for each scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
Assigned Score:	0 Somewhat Meets	0 Somewhat Meets	0 Somewhat Meets	0 Somewhat Meets	1 Meets Most	2 Meets
Regulatory Bodies:	0 Somewhat Meets	0 Somewhat Meets	-2 Does Not Meet	0 Somewhat Meets	0 Somewhat Meets	1 Meets Most
Executives/ Board:	-2 Does Not Meet	-2 Does Not Meet	-2 Does Not Meet	0 Somewhat Meets	0 Somewhat Meets	2 Meets
Technical Personnel:	-2 Does Not Meet	0 Somewhat Meets	-2 Does Not Meet	0 Somewhat Meets	0 Somewhat Meets	2 Meets
Business Users:	1 Meets Most	1 Meets Most	2 Meets	0 Somewhat Meets	2 Meets	2 Meets
Customers:	1 Meets Most	-2 Does Not Meet	2 Meets	1 Meets Most	2 Meets	2 Meets

6. Summary Scoring



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TMG Summary Scoring

- The following summarizes TMG's scores for all of the evaluation categories for each alternative scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
TOTAL OVERALL:	0 Somewhat Meets	-1 Meets Few	-1 Meets Few	1 Meets Most	1 Meets Most	1 Meets Most
1. Installation Costs:	2 Meets	1 Meets Most	-2 Does Not Meet	-1 Meets Few	-2 Does Not Meet	-2 Does Not Meet
2. Operational Costs:	-1 Meets Few	0 Somewhat Meets	-2 Does Not Meet	2 Meets	2 Meets	2 Meets
3. Installation Timeframe:	2 Meets	2 Meets	-2 Does Not Meet	-1 Meets Few	-1 Meets Few	-1 Meets Few
4. Solution Risk & Viability:	-1 Meets Few	-1 Meets Few	-1 Meets Few	0 Somewhat Meets	2 Meets	1 Meets Most
5. Resource Utilization:	2 Meets	0 Somewhat Meets	-2 Does Not Meet	0 Somewhat Meets	-1 Meets Few	-1 Meets Few
6. Business Considerations:	-1 Meets Few	-1 Meets Few	2 Meets	1 Meets Most	2 Meets	2 Meets
7. Technology Considerations:	-2 Does Not Meet	-1 Meets Few	0 Somewhat Meets	1 Meets Most	1 Meets Most	2 Meets
8. Benefits & Improvements:	0 Somewhat Meets	0 Somewhat Meets	0 Somewhat Meets	0 Somewhat Meets	1 Meets Most	2 Meets

TMG Summary Ranking

- The following summarizes TMG's ranking of first to sixth place for all of the evaluation categories for each alternative scenario.

Scenario:	1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
TOTAL OVERALL:	4th Place	5th Place	6th Place	3rd Place	2nd Place	1st Place
1. Installation Costs:	1st Place	2nd Place	6th Place	3rd Place	5th Place	4th Place
2. Operational Costs:	5th Place	4th Place	6th Place	2nd Place	3rd Place	1st Place
3. Installation Timeframe:	1st Place	2nd Place	6th Place	5th Place	4th Place	3rd Place
4. Solution Risk & Viability:	6th Place	4th Place	5th Place	3rd Place	1st Place	2nd Place
5. Resource Utilization:	1st Place	2nd Place	6th Place	3rd Place	5th Place	4th Place
6. Business Considerations:	6th Place	5th Place	3rd Place	4th Place	2nd Place	1st Place
7. Technology Considerations:	6th Place	5th Place	4th Place	3rd Place	2nd Place	1st Place
8. Benefits & Improvements:	5th Place	6th Place	3rd Place	4th Place	1st Place	2nd Place

TMG Summary Award Points

- The following provides TMG's assigned award points by evaluation category for each alternative scenario.

			Awarded Points					
			1. Status Quo	2. Re-engineer CIS	3. Custom Develop CIS	4. Another Utility CIS	5. New PaaS CIS	6. New SaaS CIS
	100.00%	1,000	139	(110)	(585)	319	508	701
Evaluation Category	Assigned Weight	Assigned Points	Points	Points	Points	Points	Points	Points
Implementation Costs	15%	150	300	150	(300)	(150)	(300)	(300)
Operational Costs	10%	100	(100)	0	(200)	200	200	200
Implementation Timeframe	5%	50	100	100	(100)	(50)	(50)	(50)
Solution Risk & Viability	10%	100	(100)	(80)	(80)	(40)	180	120
Resource Utilization	15%	150	300	0	(300)	0	(150)	(150)
Business Considerations	20%	200	(240)	(160)	320	240	320	400
Technology Considerations	10%	100	(140)	(120)	0	100	120	200
Benefits & Improvements	15%	150	19	0	75	19	188	281

- The following TMG table presents a ranking of alternative scenarios by total award points, the items in green should be considered.

TMG recommends pursuing these alternatives which do the best job of meeting overall criteria.	**701**	**6. New SaaS CIS**	**Positive Return.** Generally solutions with the highest scores should be pursued as they provide a positive return and acceptable risk.
	508	**5. New PaaS CIS**	
	319	**4. Another Utility CIS**	
TMG recommends not pursuing these alternatives as they do not result in any net benefit.	**139**	**1. Status Quo**	**Ground Zero.** Alternatives whose scores are near zero.
TMG recommends not pursuing these alternative as they do not adequately address evaluation criteria.	**-110**	**2. Re-engineer CIS**	**Negative Return.** Generally solutions with a score less than zero should not be pursued as they provide a negative return or unacceptable risk.
	-585	**3. Custom Develop CIS**	

TMG Recap – 1st Place – New SaaS CIS

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
-2 Does Not Meet	2 Meets	-1 Meets Few	1 Meets Most	-1 Meets Few	2 Meets	2 Meets	2 Meets

Outstanding Points (2 and 1)

- Operational costs are significantly decreased over current spending.
- Application risk - This replaces the current legacy CIS with a modern CIS product to be supported by the vendor, and third parties.
- Platform risk - This will utilize a true public SaaS subscription solution, in keeping with the corporate vision and technical strategy.
- Business risk - In a SaaS environment, ATCO will be conforming to a template or model office which will drive design, and be able to accept and apply quarterly releases.
- Viability - This is the future direction of the industry. But ATCO is the first large utility who has decided to implement this solution. The industry is watching to see if it is successful.
- Will enable the system and the business to bill and collect current revenue streams and bill and collect for new revenue streams.
- Will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications
- Can utilize existing Oracle licenses. Subscription fees during implementation years can be capitalized.
- Complete design authority. Indicated that while ATCO has to apply the quarterly release, they don't have to activate this.
- Supports growth strategies as onboarding tools could be developed as part of this customer effort. The new system will be very flexible to quickly add new products, programs, and services.
- This is a subscription license, with ATCO able to implement and stay on the CIS Product Roadmap for a CIS product solution. This scenario forces conformance to the product roadmap, while perpetual does not.
- This replaces the aging legacy CIS solution by a industry leading CIS product.
- This is on a cloud platform - public SaaS subscription, which fits the corporate vision and strategy.
- The solution can scale to accommodate a larger customer base to accommodate growth.
- Promotes efficient technical operations, it is a new technical and application solution, with many resources available in the market.
- Executive/Board - Very interested in moving to a cloud solution with a new product vendor. This fits the overall technical vision of a public SaaS platform.
- Technical personnel - alleviates many of the technical issues regarding support, development, operations, etc..
- Business users - can have a new product solution with regular releases, as they conform to the product and the future product roadmap.
- Customers – they will see a lot of benefits in service and availability of new products and programs.
- Regulatory bodies - with this solution they may be interested in the customer transformation and service. Reduction in operating costs is a benefit. This is the direction of the industry.

Satisfactory Points (0)

- Approximately 36 months to plan, select, implement, and stabilize the solution.
- Project risk - The SaaS model is new. It has some similarity to outsourced deals. But it brings with it newer technology, and an approach to design which makes the utility adhere to the product and its roadmap. Today, as of this analysis there are no active and successful implementations of a public SaaS CIS subscription solution. However, this is the direction of the industry.
- Significant internal resource expenditures are required to implement this solution.

Unsatisfactory Points (-1 and -2)

- High implementation costs.

TMG Recap – 2nd Place – New PaaS CIS

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
-2 Does Not Meet	2 Meets	-1 Meets Few	2 Meets	-1 Meets Few	2 Meets	1 Meets Most	1 Meets Most

Outstanding Points (2 and 1)

- Operational costs are significantly decreased over current expenditures.
- This replaces the current legacy CIS with a modern CIS product to be supported by the vendor, and third parties.
- This will utilize a PaaS cloud platform. Although it is cloud based it does not meet the vision of a true public SaaS subscription solution.
- In a PaaS perpetual environment the utility is free to do what it wants to modify and enhance the system to meet specific business and regulatory requirements. It is very flexible to accommodate the needs of the business.
- The PaaS solution is much like hosting, which many utilities are familiar with. There have been many successful PaaS/Hosted solution that have been implemented on time, and on budget, with the expected functionality.
- Most large IOUs like ATCO are going with this or something they are calling MPaaS, which is Managed Platform as a Service. This is very viable.
- Will enable the system and the business to bill and collect current revenue streams and bill and collect for new revenue streams.
- Will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications.
- Can utilize existing Oracle licenses. 85% of implementation fees are usually capx dollars.
- Complete design authority to implement new business operations and automation.
- Onboarding tools could be developed as part of this customer effort. The new system will be very flexible to quickly add new products, programs, and services.
- This is a perpetual license, with ATCO able to implement and stay on the CIS Product Roadmap for a CIS product solution. It is up to ATCO if they pursue a SaaS-like solution or do something more specific to ATCO operations.
- This replaces the aging legacy CIS solution by a industry leading CIS product.
- This Is on a cloud platform - private PaaS perpetual license, however, it is not inline with the corporate vision or strategy.
- The solution can scale to accommodate a larger customer base associated with acquisitions.
- Provides a new technical and application solution, with many resources available in the market.
- Technical personnel - A great solution, but it still requires more internal technical support then the SaaS solution.
- Business users - can have a new product solution with regular releases, and can still do enhancements as necessary. They should see significant improvements.
- Customers – will see a lot of benefits in new products, programs, and services.

Satisfactory Points (0)

- Regulatory bodies - with this solution they may be interested in the customer transformation and service. But still a high price tag. Reduction in operating costs is a benefit. Still like a hosted environment and does not meet some of the technology objectives.

Unsatisfactory Points (-1 and -2)

- Implementation costs are high.
- Implementation timeframe is 36 months to plan, select, implement, and stabilize the solution.
- Significant internal resource expenditures are required to implement this solution.

TMG Recap – 3rd Place – Another Utility CIS

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
-1 Meets Few	2 Meets	-1 Meets Few	0 Somewhat	0 Somewhat	1 Meets Most	1 Meets Most	0 Somewhat

Outstanding Points (2 and 1)

- A significant reduction in current operating costs
- This replaces the current legacy CIS with a modern CIS product solution. However, there are issues which have to be addressed as the application is shared with another utility.
- This will utilize a PaaS cloud platform. Which does not meet the vision of a true public SaaS subscription solution.
- Will enable the system and the business to bill and collect current revenue streams and bill and collect for new revenue streams.
- Will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications.
- Costs would be from scratch with another utility. 85% of implementation fees are usually capx dollars.
- Business operations may be hindered in some areas as ATCO will have to align with what the other utility(s) want to do.
- A new system will be very flexible to quickly add new products, programs, and services. There my be some issues to consider in working with the consortium to quickly onboard new customers.
- Assume this will involve the purchase and implementation of a CIS product solution with a product roadmap, however, ATCO may have issues maintaining a base product with the other utility(s) and stay on the product roadmap.
- This replaces the aging legacy CIS solution. ATCO will have to work with the other utility(s) to do upgrades, which may not be according to the ATCO schedule or plan.
- Assume would be on a cloud platform
- The solution can scale to accommodate a larger customer base.
- Provides a new technical and application solution, with many resources available in the market.
- Customers - there may be some restrictions by other utility(s) in terms of service and communication channels. It may not be the preferred choice for a customer.

Satisfactory Points (0)

- This is a design and implementation consortium where ATCO will have to work in conjunction with another utility, and may have to compromise on various design decisions.
- Executives/Board - It would be nice to share cost with another utility, but this also means sharing design. Not sure they would have much interest for the price tag and the risk.
- The utility will require a significant amount of internal resources to staff the project.
- Regulatory bodies - they would be interested in having Alberta utilities share in the cost of a new CIS. But still a large price tag, and they seem to be happy with what they have.
- Technical personnel - this has many positive and negative considerations. But from a technical perspective, ATCO would need to support the application with limited resources.
- Business users - would have to adapt to how other an other utility wants to do business. Could be a problem for them.

Unsatisfactory Points (-1 and -2)

- A high implementation price tag.
- A long period to plan, select, implement, and stabilize the solution.
- Over the past 40 years there have been may consortiums where utilities have gotten together to design and implement a new CIS, e.g. ATCO SinglePoint. There have also been a number of attempts for utilities to work together to procure and implement a common CIS. The majority of these have failed. This is a very high risk project, it usually takes much more time and money and ends up in failure or the utilities go there own way.
- The success of doing a combined selection, design, and implementation of a CIS with more then 1 utility has been very limited. These have been known to be runaway projects, where the involved utilities end up leaving the consortium and doing their own thing.

TMG Recap – 4th Place – Status Quo

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
2 Meets	-1 Meets Few	2 Meets	-1 Meets Few	2 Meets	-1 Meets Few	-2 Does Not	0 Somewhat

Outstanding Points (2 and 1)

- There are no implementation dollars.
- There is no project so zero months.
- There is no implementation project, therefore no project risk.
- There is no implementation project, therefore no internal resources required.
- Regarding current investment, there are no implementation dollars.
- The solution can scale to accommodate a larger customer base.
- Business Users - they like the system and they have simply learned to live with it and its deficiencies and workarounds.
- Customers - It seem customers have no significant issues with the current system.

Satisfactory Points (0)

- Regulatory Bodies - seems satisfied with what they are getting out of the current CIS, and no cost to replace. But may become an issue for them.

Unsatisfactory Points (-1 and -2)

- Operational costs remain at current levels.
- This scenario retains the current aging CIS.
- This is a hosted environment which has already been replatformed. It does not adhere to a cloud platform.
- There are no updates or impacts to the business which would address any existing issues, or provide for an improved customer experience.
- Maintaining status quo is viable in the short term but not the long term.
- The current and future revenue stream remains in jeopardy.
- Does not do anything to enable the customer experience, interaction, or digital experience.
- No changes to business operations or automation.
- The current system is not made to quickly onboard new customers, or add new products, programs, or services.
- There is no product roadmap, this is an inhouse developed application which started out with a consortium. There are no regular releases.
- This retains the aging legacy CIS solution.
- No cloud solution, this is a hosted solution.
- Does not address issues with technical skilled labor to support the current legacy CIS.
- Executives/Board - They understand the need to replace from both a business and technical perspective. So it needs to be replaced.
- Technical Personnel - They do not want to continue to support this legacy CIS. Key assets are retiring. It is risky, time consuming and costly to maintain.

TMG Recap – 5th Place – Re-engineer CIS

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
1 Meets Most	0 Somewhat	2 Meets	-1 Meets Few	0 Somewhat	-1 Meets Few	-1 Meets Few	0 Somewhat

Outstanding Points (2 and 1)

- The cost to implement is moderate.
- A shorter timeframe to plan, select, implement and stabilize the solution.
- From a viability perspective, very few have done this successfully. Not sure if any true re-engineering software is still available in the market, however assume there is software available to just convert code without re-engineering the application.
- There are no current investment dollars, however, 85% of implementation fees are usually capx dollars.
- Changing the application code, may allow for faster and less costly development to accommodate onboarding, or add new products, programs, or services.
- Yes, the solution can scale to accommodate a larger customer base. No tools to facilitate onboarding of new customers.
- Business Users - this has minimal impact on the business user, but they may see improvements on the cost and the turnaround timeframes on enhancements.

Satisfactory Points (0)

- Annual operational costs are slightly less then current expenditures.
- This is a minimal project, however, there are not a lot of other projects that can be pointed to where large scale legacy CIS applications have been re-engineered. As a result, this project risk is a little higher. Plus, it does not do a lot for mitigating future project risk associated with onboarding new customers.
- Regulatory Bodies they wont really understand why they need to spend money on a technical upgrade on the existing system if they are already getting what they need.
- Technical Personnel - they do not want to continue to support this legacy CIS. Key assets are retiring. It is risky, time consuming and costly to maintain. This scenario provides some relief, but does not go far enough
- Internal resources to staff the implementation project are moderate.

Unsatisfactory Points (-1 and -2)

- This scenario retains the current aging CIS, it simply is re-engineering it from an application written in Cobol, to one written in a more modern language. So, it may address some of the application and technology issues, but it retains the current data, process, user interface, etc..
- Assume only converting the code, the application will continue to run in the existing hosted environment and not a cloud platform.
- There are no updates or impacts to the business which would address any existing issues, or provide for an improved customer experience. However, with a new language enhancements may be conducted quicker and at a lower cost.
- The current and future revenue stream remains in jeopardy.
- Does not do anything to enable the customer experience, interaction, or digital experience.
- There are no changes to business operations or automation.
- There is no product roadmap, this is an inhouse developed application which started out with a consortium. There are no regular releases. This is simply re-engineering the same functionality developed with Cobol to another Current Language.
- This retains the aging legacy CIS solution.
- This is not a cloud solution and will continue to be hosted by Wipro.
- Does not address issues with technical skilled labor to support the legacy CIS. However, does provide some relief with new code and perhaps quicker time to market and less cost.
- Executive /Board - this is just a bandage with a price tag, does not get them a lot.
- Customers - would not really benefit from this scenario, this is more of a technical upgrade.

TMG Recap – 6th Place – Custom Develop CIS

Implementation Costs	Operational Costs	Implementation Timeframe	Solution Risk & Viability	Resource Utilization	Business Considerations	Technology Considerations	Benefits & Improvements
-2 Does Not	-2 Does Not	-2 Does Not	-1 Meets Few	-2 Does Not	2 Meets	0 Somewhat	0 Somewhat

Outstanding Points (2 and 1)

- This scenario will provide ATCO with a solution that is specific to the business needs of the organization and the customers.
- Will enable the system and the business to collect current revenue streams and bill and collect for new revenue streams.
- Will enable an emphasis on the customer life-cycle, with a focus on the customer journey, self-service, and digital communications.
- Costs would be from scratch. 85% of implementation fees are usually capx dollars.
- Complete design authority to implement new business operations and automation.
- Onboarding tools could be developed as part of this customer effort. The new system will be very flexible to quickly add new products, programs, and services.
- This replaces the aging legacy CIS solution, however, it is a "one-off" and it is up to ATCO to enhance the solution.
- The solution can scale to accommodate a larger customer base.
- A new technical and application solution, with many resources available in the market.
- Business users - Users would have a system completely tailored to their needs in order to perform their jobs and serve customers.
- Customers - The new solution would provide for all customer requirements, and interactions.

Satisfactory Points (0)

- none

Unsatisfactory Points (-1 and -2)

- Implementation costs are the most expensive.
- Annual operation costs significantly increase over current expenditures.
- A long timeframe to plan, select, implement and stabilize, more then any other solution.
- This scenario replaces the current aging CIS, with a brand new solution. However, it will take time compared to other scenarios. It results in ATCO continuing to have support, develop, maintain, and operate the application.
- Assume custom development of a new CIS solution will continue to use the existing hosted environment. However, there is a possibility it may be moved to a PaaS platform.
- This is a tremendous risk, and there have been many failures. However, now a utility will buy a CIS design guide, or may purchase a CIS product and then discontinue maintenance. In any event, this is a very high risk scenario.
- The days of custom development are over, and it is recommended that for a number of reasons this is not a viable solution.
- The highest level of internal resource utilization.
- There is no product roadmap. This is a custom developed solution specifically for ATCO. It is assumed that regular releases are delivered every several years.
- Planned for the current hosted environment. But could be placed on any platform.
- Regulatory bodies - Large price tab, and risk, makes this an issue for the regulators.
- Executives/Board - Why get back into the custom CIS world like they were with SinglePoint?
- Technical Personnel - This would place significant emphasis on ATCO to support a large custom developed CIS, like SinglePoint. Not attractive to them.

7. Recommendations



TMG Consulting
Where Business and Technology Intersect

TMG's Recommendation

- What is the answer to the question posed to TMG: "Should the current ATCO legacy CIS from both a Gas and Electric perspective be retained or replaced?".

TMG's recommendation is to REPLACE the current CIS from both a Gas and Electric perspective. TMG is making this recommendation based on our analysis of the interviews, the assessment of business considerations, and technical considerations, our replacement model, along with our vast experience assessing legacy CIS solutions for similar utilities over the past 28 years.

- If the decision was to replace, a second question was asked of TMG: "Based upon an analysis of alternative replacement scenarios, which is the optimum scenario for ATCO to consider?".

TMG conducted an analysis of 6 replacement scenarios. Based on this analysis TMG recommends that ATCO Gas and Electric consider replacement of the current CIS with a new SaaS CIS product solution as the first place or optimum solution. TMG's analysis utilized data from TMG's extensive industry project database, as well as, the direct experience of our consultants who have worked on various CIS projects for over 30 years.

TMG Replacement Considerations

Based upon TMG's experience and our review of the current CIS, the following items should be viewed as primary drivers for replacement and are inline with what TMG has experienced with similar utilities who have decided to replace their legacy CIS.

1. A strategic and essential foundational initiative in support of company business, technical, and customer based strategies and initiatives.
2. Implementation of newer application technologies and a platform which resolves issues associated with an older legacy billing system e.g. loss of expertise, better integration, improved security, improved reporting and analytics, scalability, etc..
3. Addresses the need for cybersecurity to accommodate operating in a digital environment, and digital customer communication channels with the need to protect critical and important customer information.
4. Replacement of a technical foundation which may adversely impact the company's current and future revenue stream in support of both business operations, and impacts to the customer life-cycle and level of service.
5. A solution which supports staff in providing customers with exceptional levels of service, customer transformation, and applying new technologies and multiple channels of communication and interaction.
6. Provide users with a new and efficient browser based user interface, with new capabilities, documentation, and help. This will enable new users to learn the system quicker and be more effective in meeting job responsibilities and serving customers.
7. The ability to apply regular product releases to provide new customer capabilities in a timely fashion – following a close to zero modification approach. No need for enhancements that take to much time, cost to much, and are risky – those days are over.

TMG Optimum Solution Considerations

Why proceed with the optimum or first place solution which is a new SaaS CIS product solution? TMG believes the following are primary considerations for pursuing this solution and are very much inline with other utilities who are pursuing this same solution.

1. Annual operating costs decrease significantly.
2. Mitigation of risks associated with the application, the platform, and the business.
3. It will enable customer transformation, improved services, and digital communication channels.
4. Utilizes the existing investment in the Oracle CIS/MDM licenses with the ability to capitalize the subscription fees during implementation months.
5. Support for the current revenue stream and future revenue streams associated with new offerings for products, programs, and services.
6. Will adhere to a product roadmap to take advantage of new releases from hundreds of other utilities on a regular basis.
7. Provides cybersecurity to protect critical and important customer information.
8. Supports the vision and strategy of a public SaaS subscription platform and integration to other primary applications.
9. The solution would seem favorable to Regulators, Executives/Board Members, Technical Personnel, Business Users and Customers.

TMG Proposed Next Steps

- The following are the recommended next steps.
  1. Review and update this analysis as required.
  2. Confirm the decision to replace.
  3. Confirm the decision to replace with a new SaaS product solution.
  4. Socialize the results with stakeholders.
  5. Incorporate results into the business case.


Thank you
ctrl
end

Scorecard Summary - N60 CIS Implementation

				Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
				2.99	**3.23**	**3.17**	**2.60**	**3.53**
Evaluation Category		**Assigned Weight**	**Category Weight**					
Commercial Criteria			**45.00%**	**2.78**	**3.25**	**3.66**	**3.16**	**3.72**
	Agreement with Contract Terms	**5.00%**		3.00	2.00	2.00	2.00	3.00
	Pricing	**40.00%**		2.75	3.41	3.87	3.31	3.81
Technical Criteria			**55.00%**	**3.16**	**3.21**	**2.76**	**2.14**	**3.38**
	Proponent Qualifications	**10%**		3.13	2.73	2.53	2.17	3.17
	Business Requirements	**15%**		3.78	4.84	4.24	3.80	3.78
	Implemention Environment	**10%**		3.18	2.73	1.45	0.91	3.34
	Timeline & Staffing	**10%**		2.31	2.31	2.50	1.19	3.00
	Implementation Services	**10%**		3.10	2.60	2.35	1.80	3.41

ATCO Electric YUKON

September 28, 2023 AEY-UCG-085

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-085

Reference: Genset Major Overhauls, BC#23; Costs from 2017-2022 $3.5 million plus Test Year costs of $375,000 in 2023 and $515,000 in 2024.

Request:

(a) Why the extreme differences in cost to overhaul gensets, for example Old Crow-2, 71K and Old Crow 1, $465K).

(b) Provide procurement tenders with bids included.

(c) Provide who salvaged each genset replaced and how much did ATCO get for each of these units?

Response:

(a) The differences in cost to overhaul gensets can be due to the scope of work and the location of the genset, among other factors. For example, Old Crow 2 was a long block replacement because of a failure; please refer to AEY-YUB-046(b) Attachment 1 for a project description. Old Crow 1 is a larger engine than Old Crow 2 and required multiple flights for people and parts, due to the size/weight of materials and the COVID restrictions at the time in the community. Generally, Old Crow overhauls are more expensive than elsewhere due to its remote location. Overhauls costs can also be higher (i.e., variable) due to found work on inspection and disassembly.

(b) There is no tender information because AEY has a Master Services Agreement with a large distributor and service company for provision of parts and qualified technicians on overhauls. This distributor has warranty and inventory and quality assurance facilities, in addition to a large resource pool.

(c) For the overhauls described in Business Case #23, there is no salvage since this work is maintenance of existing equipment. AEY receives some credit from the supplier, based upon their capacity to remanufacture and resell certain parts that are replaced due to age or condition. This cost is included in the project invoicing.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-086

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-086

Reference: Asset Management Program, BC#24; Cost 2023-$305K, 2024-$901K, Total $1.206 million.

Request:

(a) Provide procurement tenders for AMA Assessment with the amounts of bids included.

(b) Provide examples of operational efficiencies/cost effectiveness of this new program.

Response:

(a) Four bids were received for the Asset Management Program development scope:

Table 1: Bids Received for Asset Management Program Development RFP

Bidder 1	Bidder 2	Bidder 3	Bidder 4
$49,910	$135,168	$48,950	$48,600

The evaluation was scored in five categories: 1) project requirements & understanding; 2) key personnel & roles; 3) previous experience on similar projects; 4) project execution methodology and ability to meet schedule; and 5) manhour and cost estimate.

(b) The program benefits are extensively articulated within the report by METSCO (Table 2-1 of the appendix in Business Case #24). Please refer to the response to AEY-YUB-068(a).

ATCO Electric YUKON

September 28, 2023 AEY-UCG-087

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-087

Reference: New Substations-Mayo Road and Whistle Bend, BC #25; Costs: Mayo Rd.- $2.554million and Whistle Bend- $2.781 million.

Request:

(a) Provide engineering qualifications of what work was to be done for each project and what were the economic analyses identifying the business drivers and cost/benefits, including the preliminary engineering estimate of costs. Provide engineers report.

Response:

(a) Please refer to the response to AEY-UCG-066(a). Please also refer to AEY-UCG-087(a) Attachment 1 - Whitehorse North 25 kV System Study Rev 2.0.

ATCO Electric
YUKON

Whitehorse North 25kV System Improvement

Technical Appendix

	Name	Signature	Date
Prepared by:	Ryan Grams		2019-10-01
Reviewed by:	John Williams		
Reviewed by:			
Reviewed by:			

Revision History

Revision	Date	Editor	Comments
R1.0		Ryan Grams	Document Created
R2.0	2023-02-06	Alex Deans	Updated numbers with most recent load forecast. Removed options for Laberge reg upgrades as they are now 400A. Typo fixes.

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1. Problem Statement

The Whitehorse North 25kV system has significant load growth expected over the next 5 years. At present, there is a contingency scenario that cannot be adequately addressed. As the load grows, substation regulator capacities will be exceeded, rural customer voltages will drop below acceptable levels and the number of failed contingency scenarios will increase. The projected load growth must be planned for and accommodations implemented to ensure continued safe and reliable operation of the Whitehorse power system.

2. Background

Load growth continuously pushes a power system closer to its capacity limits. This leads to electrical equipment being operated past its capacity, which compromises the safety and reliability of the network.

To understand the problem statement in more detail we can consider how the North 25kV System is configured, how the load has grown in the past, how we expect it to grow in the future, and at what point the load is higher than the system's capacity.

2.1 System Configuration

During normal operation the North 25kV System is supplied power from a single transmission substation source (S164), through two sub-transmission substations (Laberge Substation and Whistlebend Substation), and out to both urban and rural customers in the northern Whitehorse area and along the North Klondike and Alaska highways. At each voltage level, there are interconnection points between parallel feeds, allowing for a variety of potential system configurations.

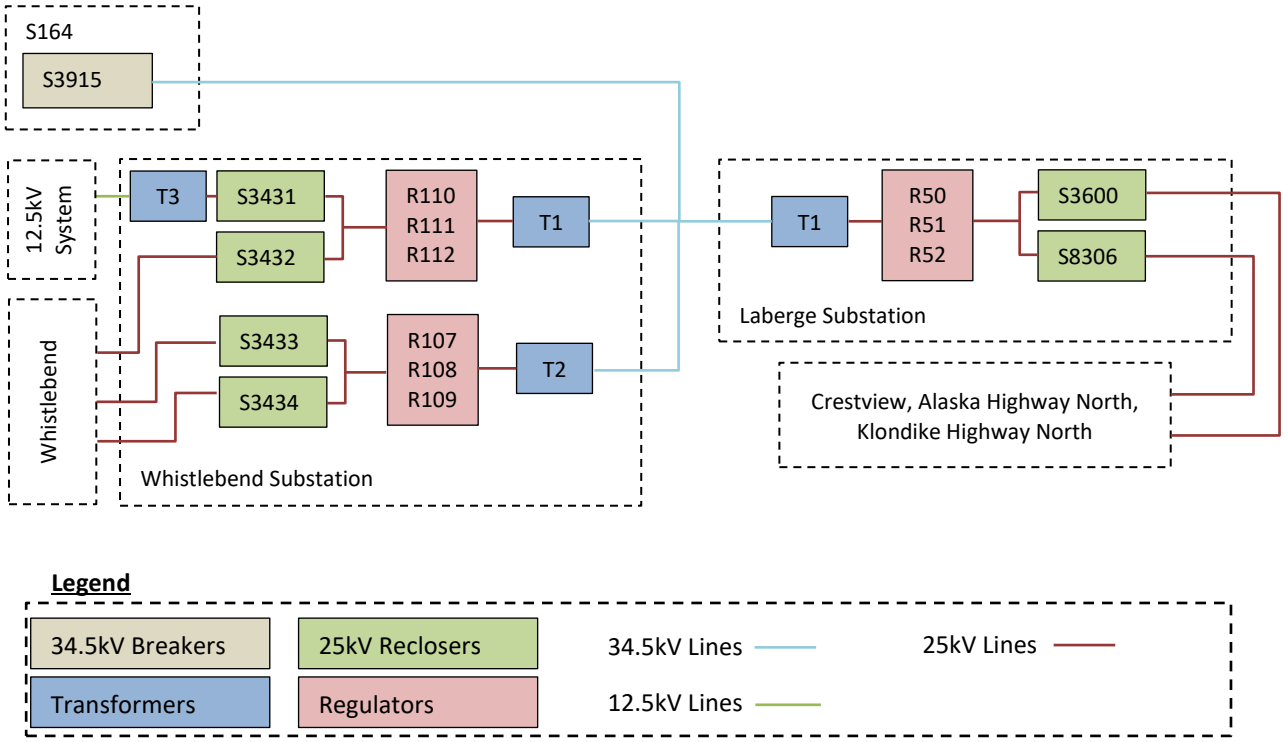


Figure 1 - Whitehorse North 25kV System During Normal Operation

2.2 Forecasted Load Growth

Currently the Whistlebend subdivision is undergoing extensive construction and is expected to complete Stage 7 by the end of 2025. Using historical SCADA data from Whistlebend substation, year-over-year load increase was modeled at 11.26%. Historical Laberge substation SCADA data proved a 2.06% year-over-year load increase along the North Alaska Highway, North Klondike Highway and Crestview.

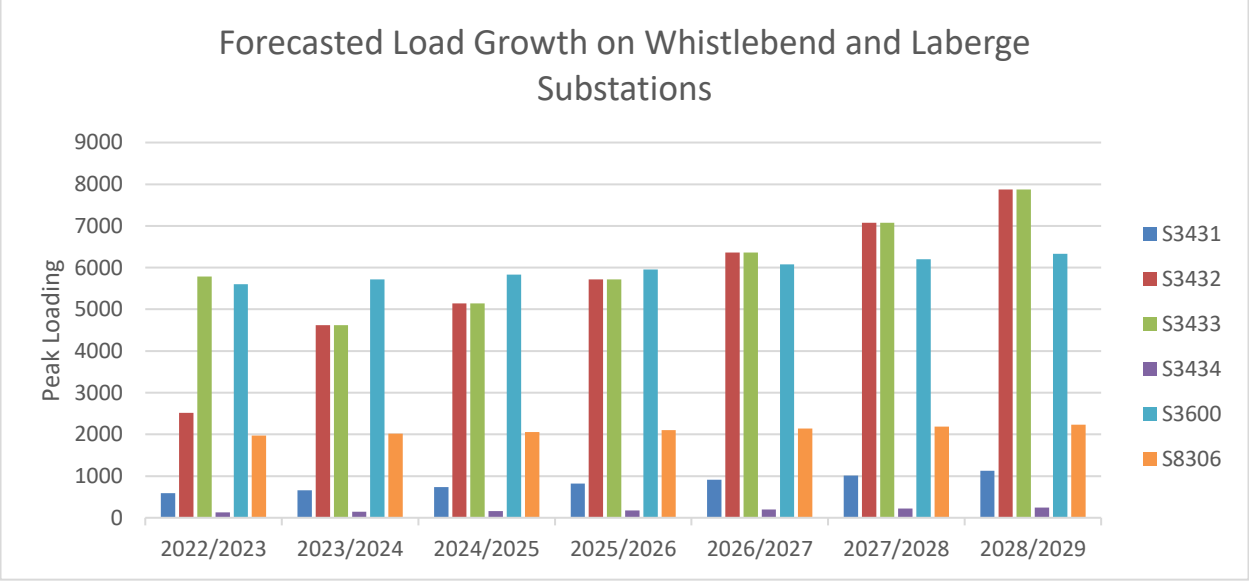


Figure 2 - Forecast Load Growth for Whistlebend and Laberge Substations until the 2028/2029 winter.

* Load growth for Whistlebend Subdivision is forecast to be redistributed evenly over reclosers S3432 and S3433 in future years, instead of only loading S3433 as is the present arrangement.

3. Evaluation Criteria

3.1 Regular Operation

No components of the system should have load exceeding their nameplate rating during peak load conditions.

To ensure safe operation and maintain the expected lifespan of the electrical system, it is important to operate equipment within nameplate ratings at all times. Power transformers are an exception to this rule, as they can be operated above their nameplate apparent power ratings depending on ambient temperature and duration of overload. This overloading will be evaluated further in Section 5.4.

Specific to the Whitehorse North 25kV system, the major system limitations that require adequate planning are as follows:

- Whistlebend Substation max loading of 10MVA on each of the 34.5/25kV transformers
- Laberge Substation max loading of 10MVA on 34.5/25kV transformer
- S164 Substation max loading of 28MVA on 138/34.5kV transformer
- 266 MCM sub-transmission line (6L16, 6L17) max loading of 38 MVA at 0^{o}C (28MVA at 40^{o}C)

During normal operation:

- *Maximum 25kV bus voltage at transmission POD substations -> 1.04 p.u.*
- *Minimum primary voltage at urban residential customers with multiple customer secondaries -> 0.97 p.u.*
- *Minimum voltage at all other points on distribution feeders -> 0.95 p.u.*

To provide safe and reliable power to ATCO Electric Yukon's (AEY) customers and to prevent unnecessary damage to customer electrical equipment, the system per-unit voltage must remain within the limits defined in AEY's standards.

3.2 Load Addition

Substations and main feeders should have sufficient reserve capacity.

Reserve capacity allows routine load additions/growth and provides lead time for system upgrade projects to take place before critical thresholds are exceeded. Sufficient reserve capacity is assessed by looking at the peak loading and forecasted load growth for each feeder within the planning period window.

The Whitehorse North 25kV System has significant load growth planned in the next 6 years largely due to the development of the Whistlebend subdivision. Based on historical SCADA data within that area, the Whistlebend subdivision growth will be forecast at 11.26% growth per year, while Laberge's load growth averages 2.06% per year.

3.3 Contingency

The peak load on major equipment (e.g. transformers, regulators, reclosers) in systems that warrant loop connections should be able to be transferred to another power source.

Contingency planning is required to maintain service to customers during planned or unplanned outages resulting from maintenance work, system faults, or equipment failures. When a portion of the system needs to be removed from service, any downstream load will lose power unless the removed section can be isolated and downstream customers transferred to an alternate source.

For this to be a viable tool for maintaining system reliability, the alternate source must be able to handle the load addition in a worst-case scenario. This would typically be the loss of major equipment such as transformers, regulators, or reclosers during peak load. For low customer-density areas or in rural areas, the system is typically composed of radial feeds. Radial networks do not have a loop connection with a normally-open point, therefore the outage scenario is managed through alternative methods including generation or quick repair times.

In the Whitehorse North 25kV system, contingency situations are mainly addressed through interconnection points between parallel sources on both the 34.5kV subtransmission lines and the 25kV distribution lines. The following contingency situations require additional attention as they address scenarios that if not properly planned, could result in an outage to a large group of customers:

- Loss of 34.5kV source to Laberge and Whistlebend substations (sub-transmission line 6L17)
- Loss of a single 34.5/25kV transformer in North 25kV System
- Loss of 34.5kV primary bus at Whistlebend substation
- Loss of a single 25kV breaker at Whistlebend substation

3.4 Power Restoration

Critical loads should be restored as quickly as possible (includes residential and commercial customers). All loads should be restored within 24 hours.

The responsibility of an electrical utility is to operate a safe and reliable electrical system. Following outages, safe power restoration is a priority.

When planning for system restoration, Cold Load Pick-Up (CLPU), a phenomenon that occurs during restoration from extended outages, must also be considered. When restoring from prolonged outages, the system diversity factor drops to nearly 1 and the system can experience

2-5 times the regular load for a period of minutes to hours. Based on historical data, typically 200% of regular load for several minutes is assumed.

4. Technical Review

Using the evaluation criteria listed above, for the Whitehorse North 25kV system we have the following:

4.1 Regular Operation

- *No system components are currently overloaded*
- *Whistlebend Substation 34.5/25kV transformers are not expected to be overloaded in the next 6 years*
- *Laberge Substation 34.5/25kV transformer is not expected to be overloaded in the next 6 years. Regulators R50, R51 and R52 are expected to overload in 2024.*
- *S164 Substation 138/34.5kV transformer is not expected to be overloaded in the next 6 years*
- *The subtransmission line 6L17 sourcing both Laberge and Whistlebend substations is not expected to be overloaded in the next 6 years*
- *Customer voltage is currently within the acceptable band for all customers on the North 25kV System. Rural customers up the Alaska Highway and Klondike Highway North are expected to be outside of acceptable voltage as early as 2021. Voltage levels are not the focus of this study and other system upgrades/reconfiguration will occur as necessary to maintain mandatory voltage levels.*

Currently no system components are overloaded, but the Laberge Substation Regulators are expected to overload in the next 6 years. Below are modelled forecasts for system loading for the 6-year planning period.

	Equipment / System Area	Critical Ratings	Present Status (2023)	Future Status (2029)
Whistlebend Substation	Transformer T1	34.5/25kV 10MVA	31% Loaded	90% Loaded*
	Transformer T2	34.5/25kV 10MVA	59% Loaded	81% Loaded*
	Transformer T3	25/12.5kV 5MVA	12% Loaded	23% Loaded
	Reclosers: S3431, S3432, S3433, S3434	27kV 630A each	4%, 16%, 37%, 1% Loaded	7%, 50%, 50%, 2% Loaded*
	Regulators: R110, R111, R112	400A each	18%, 18%, 18% Loaded	53%, 52%, 51% Loaded

	Regulators: R107, R108, R109	400A each	34%, 35%, 34% Loaded	46%, 48%, 47% Loaded
Laberge Substation	Transformer T1	34.5/25kV 10MVA	76% Loaded	86% Loaded
	Reclosers: S3600, S8306	38kV 630A, 400A (per phase)	36%, 20% Loaded	40%, 22% Loaded
	Regulators: R50, R51, R52	400A each	38%, 47%, 47% Loaded	43%, 53%, 53%
S164	Transformer T1	138/34.5kV 28MVA**	59% Loaded	92% Loaded

Table 1 - Whitehorse North 25kV System Peak Loading

*Future 25kV load on Whistlebend Substation redistributed evenly across S3432, S3433
**Assuming that S164 is operating in OFAF mode. If Transformer T1 is unable to operate at the nameplate rating of 28MVA, the transformer will require upgrades and/or replacement in coming years. This asset is owned by YEC, therefore any upgrades required are outside of the scope of this study.

Note: Additional substation apparatus (Gang Switches, Buses, etc.) were not included in Table 1 as their rating greatly exceeds that of the other equipment and will not be the limiting factor for substation capacity.

4.2 Load Addition

As shown in section 4.1, the majority of the equipment in the Whitehorse North 25kV system is lightly loaded and has the available capacity to grow at expected rates

4.3 Contingency

- *There currently is a significant contingency scenario that cannot be adequately addressed:*
    - *Loss of the 34.5kV primary overhead (O/H) bus at Whistlebend substation will result in a contingency situation where peak loading on all of the Whitehorse North 25kV System cannot be picked up by Laberge alone.*

For the loss of any major equipment within the electrical distribution system, AEY requires that there be a plan in place on how to restore power to as many customers as possible. Ideally, this means the peak load of any piece of equipment can be transferred to an alternative feeder/breaker/source in order to re-energize the customers without the failed equipment.

For the North 25kV System, the following cases are being considered as potential issues both presently and within the 6-year planning window:

Contingency Scenario	Description	Present Status (2023)	Future Status
Loss of 6L17	6L17 is the normal source of 34.5kV to both Whistlebend and Laberge substations from S164. A loss of this line will require both distribution substations to be transferred to 6L16 (loading limit of 38MVA) and source from T1 at S170 (loading limit of 47MVA).	Overload – Current peak loading of 16.6MVA on North 25kV System. S170 and S150 do not have the capacity to receive this transfer.	Overload – Current peak loading of 16.6MVA on North 25kV System. S170 and S150 do not have the capacity to receive this transfer.
Loss of single 34.5/25kV transformer	Between Whistlebend and Laberge Substations, there are 3 x 10MVA transformers for 34.5/25kV. Assuming adequate switching to distribute load among remaining 2 transformers, overall load cannot exceed 20MVA.	OK – Current peak loading of 16.6MVA.	Overload - Capacity reached in 2029. Expected peak loading of 25.7MVA on North 25kV System.
Loss of 34.5kV primary bus at Whistlebend	The loss of the primary bus at Whistlebend will prevent any 25kV sourcing from this substation. All load will have to be transferred to T1 at Laberge Substation (10MVA rating).	Overload – Currently at peak load, the North 25kV system requires more capacity than T1 at Laberge can supply.	
Loss of 25kV breaker at Whistlebend	The loss of a single 25kV breaker at Whistlebend or Laberge would require all load to be transferred to the remaining breakers on the North 25kV system.	Ok	Ok

Table 2 - North 25kV System Contingency Analysis

OK – All equipment will be within manufacturer recommended equipment ratings if this contingency scenario occurs at a time when all feeders are exhibiting peak loading.

4.4 Power Restoration

Within the Whitehorse North 25kV system, there are rural, urban and critical customers (e.g. Whistlebend Place). To restore the system within the 4-hour goal associated with these customer types, both Whistlebend and Crestview subdivisions have been designed with loop connections. This allows for switching operations to isolate the faulted section of line and alternative feeds to energize the remaining portion of the loop while the faulted section is repaired.

The system has been designed with discrete sections of large load (e.g. subdivisions) to have independent feeders. This minimizes the system strain of Cold-Load Pick-Up, by allowing separate feeders to be placed back on-line individually and therefore control the system diversity factor.

5. Potential Solutions

5.1 Solutions Considered

As identified above the main issues facing the North 25kV System over the upcoming 6-year period are:

- Contingency Scenario 1: Loss of a single 34.5/25kV transformer
- Contingency Scenario 2: Loss of the 34.5kV primary bus at Whistlebend Substation

To address these issues, the following potential solutions have been considered:

1) New 25kV Substation & System Reconfiguration
2) Status Quo

As part of system maintenance and compliance with voltage regulations, the AEY system will require voltage regulators or system upgrades on both the Alaska Highway North and Klondike Highway North in the upcoming years to counteract the unacceptable voltage levels expected to begin in 2021. The following 3 options assume these upgrades will be conducted independently of the solution selected and are not the focus of this study.

5.2 - OPTION 1: New 25kV Substation & System Reconfiguration

Building a new substation for the 25kV North System would directly resolve Contingency Scenarios 1 and 2, by providing additional reserve capacity to assist with system reconfiguration during outages. In 2029, the total peak loading on S164 is estimated to be 25.7MVA. In Contingency Scenario 2, the only remaining transformer is T1 at Laberge, with a rating of 10MVA. This results in 15.7MVA of power that needs to be alternatively sourced by a new substation. At minimum the new substation should be designed to continuously provide at least 15.7MVA without overloading any equipment.

5.4 - OPTION 2: Status Quo

Without making any changes to the North 25kV system and with load growth continuing at the expected rates, equipment will be overloaded in the near future. Assuming that peak loading only occurs in winter months (with temperatures at or below 0˚C), power transformers can be steadily overloaded at 1.22 p.u. of their nameplate rating and can be emergency overloaded up to 1.31 p.u. for less than 8 hours before the loading must drop below 0.90 p.u.

Utilizing these seasonal equipment ratings, the North 25kV System will be able to handle Contingency Scenario 1 up until 2027. In 2027, the peak loading on the North 25kV System is anticipated to be ~23.8MVA. This load cannot be carried by two operational transformers.

Additionally, anytime equipment operates outside of nameplate rating, there is the potential for decreased lifespan and increased maintenance requirements on these assets. Deferring system improvements, may result in increased service and asset replacement costs going forward.

This option covers Contingency Scenario 1 up until 2027 and does not cover Contingency Scenario 2.

6. Recommendation

In typical electrical design, it is advantageous to source power as close as possible to the load-centre it will serve as this method minimizes voltage drop and resistive losses. Therefore, it is recommended that AEY proceeds with Option 1: New 25kV Substation and System Reconfiguration. As most of the future load growth is expected to be located in Whistlebend and up the Klondike Highway North, it would be beneficial to construct a new substation in the area between these locations, with independent feeders and dedicated 10MVA transformers for each area. This in turn will not only solve capacity and contingency issues, it will also alleviate some of the low-voltage concerns and minimize the number of regulator additions/upgrades required in the coming years.

As it does not address all of the Contingency Scenarios presented and has the potential to shorten the lifespan of existing equipment, it is not recommended to proceed with Option 2.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-088

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-088

Reference: Annual Right-0f-Way (ROW) Widening, BC#26; Costs 2023- $520,000 and 2024- $528,000.

Request:

(a) Provide 5year capital brushing plan with YUB permissions/ orders.

(b) Provide AEYs brushing coordinator and vegetation management consultant and at what cost per year.

(c) Provide report from this consultant giving economic analysis identifying business drivers and cost/benefit analysis including preliminary estimate of cost for each year.

Response:

(a) Please refer to AEY-UCG-088(a) Attachment 1 for the AEY five-year brushing plan. YUB permissions were not required for this project.

(b) The AEY brushing coordinator has annual costs, as this function is performed by an AEY employee from March to November. The costs for this employee include capital bushing costs as well as Operations and Maintenance (O&M). The costs listed below for 2022 represent the seasonal average costs per year. The vegetation management consultant is contracted through ATCO Electric Forestry. This consultant was the successful vendor from the competitive Patrol / Consent tender. This consultant was utilized to create a brushing inventory of the AEY overhead power system, suggest work plans by year and area, as well as obtain brushing permissions from customers. These services were obtained in 2019 and 2022 and were an O&M cost.

Table 1: Brushing Coordination and Vegetation Management Costs

Costs	2019	2022	Total
Contract Services – Vegetation Management	87,581	93,597	181,17
AEY – Brushing Coordinator		40,692	

(c) The consultant was coordinated through ATCO Electric Forestry to leverage their existing contract. The vegetation management consultant provided AEY with the following reports:

- Patrol Reports.
- Work Plans; and
- Landowner Notification of Vegetation Control.

These reports identify areas of the system, what brushing activities are required, when activities should be conducted, and customer permissions needed.

Business Drivers

These reports supplement the five-year brushing plan. This plan improves the reliability and safety of the power system.

Cost Benefit

Completion of these reports aids the direction of the five-year plan. Ensuring that costs are distributed in the correct areas of the power system at the proper intervals.

The brushing inventory is complete for the Whitehorse area. There are no plans to contract the vegetation management consultant during the 2023-2024 Test Period.

ATCO Electric
YUKON

Vegetation Management 2023-2027 Forecast

The Following is our tentative Brushing plan for 2023-2027 seasons.

Dates: Weather Dependent our brushing program will start in March and Finish up November.

Summary: Brush/Mow/Slash and widen where required for license of occupation and easement requirements. Cut and stack all merchantable wood in 4ft lengths along the ROW/Easement for public consumption. Chip and spray non-merchantable wood products back on ROW/Easements. Burn non salvageable wood when permitted or conditions allow in the following areas:

AEY Vegetation Management Plan 2023

1. Haines Junction
2. Alaska Highway North/Alaska Highway North 5L645
3. Watson Lake – HWY #5 Km 0 to Km 22.1
4. Carcross/6L18 South Klondike Highway – Support YTG Highway Brushing Contracts/HROW Widening KM 115 to 157.8
5. Ross River – Town Site and Tower Line to Jackfish Lake
6. Whitehorse (Riverdale, Porter Creek, Hillcrest) – Customer Lots
7. Carmack's – Mainline and Customer Taps

AEY Vegetation Management Plan 2024

1. Tagish – (Reid Rd and Sub roads off Reid Rd)
2. Whitehorse – (Crestview, Downtown) – Customer Lots, Mainline

3. Marsh Lake – Customer Lots
4. Watson Lake - Townsite
5. Alaska Highway South – (Mary Lake, Wolf Creek)
6. South Klondike Highway – HROW Widening KM 115 to KM 157
7. Teslin – Cottage Lots

100 – 1100 Front Street, Whitehorse, YT Y1A 3T4 • tel: 867-633-7000 or 1-800-661-0513 • fax: 867-668-6692

ATCO Electric
YUKON

Dates: Weather Dependent our brushing program will start in March and Finish up November.

Summary: Brush/Mow/Slash and widen where required for license of occupation and easement requirements. Cut and stack all merchantable wood in 4ft lengths along the ROW/Easement for public consumption. Chip and spray non-merchantable wood products back on ROW/Easements. Burn non salvageable wood when permitted or conditions allow in the following areas:

AEY Vegetation Management Plan 2025

1. Destruction Bay – Town Site to Burwash
2. Beaver Creek – Town Site
3. Watson Lake – Robert Cambell Cottage Lots
4. Whitehorse – COW Feeders, Riverdale, Crestview, Mt Sima, MT McIntyre, Fish Lake.
5. South Klondike Highway – Customer Taps
6. Alaska Highway South – HROW Widening KM1249 To KM1277
7. Minto – Tower Line

AEY Vegetation Management Plan 2026

1. Pelly/Stewart – Town Sites
2. Old Crow – Ongoing Hot spotting
3. Watson Lake – Upper Liard
4. #1 Alaska Highway South - HROW Widening KM 1296 To KM 1341
5. Whitehorse - (Takhini Hot Spring Rd Customer Taps)
6. South Klondike Highway - Robinson Subdivision – Main Line and Customer Taps

AEY Vegetation Management Plan 2027

1. Watson Lake – Lower Post
2. Whitehorse – (Riverdale, McCrae)
3. North Klondike Highway – Grizzly Valley, Customer Taps off Main line
4. #1 Alaska Highway South – Customer Taps off Mainline Whitehorse to Jakes Corner
5. Haines Junction – (Pine Lake, Town Site)
6. Teslin – (Town Site, Morley Bay 5L16)

ATCO Electric YUKON

September 28, 2023 AEY-UCG-089

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-089

Reference: Fleet Replacement 2023, BC#27; Costs $697,000

Request:

(a) Give Atco Fleet and 3rd party vendor tenders with purchase costs from each.

(b) Will AEY sell the six used trucks? How will these tendered and how much is estimated to be recouped? How will this be deducted in this accounting process? Explain.

Response:

(a) Vehicle purchases and upfitting are completed through contracted vendors that have been awarded through a competitive RFP process lead by ATCO Fleet Services and ATCO Strategic Sourcing Teams. These vendors are typically awarded tenders for a period of three years. If vehicles can be sourced locally, bids are requested from vendors. Due to availability, only two of the 2023 units for fleet replacements have purchase orders. Note: Unit numbers in red in Table 1: Purchased Fleet 2023 represent the updated unit numbers in AEY Fleet spreadsheet. Units YT180 and YT177 have chassis on order and will require upfitting at a later date. Please refer to AEY-UCG-089(a) Attachments 1-4 for copies of purchase documents.

Table 1: Purchased Fleet 2023

Unit	Description	Year Purchased	Purchase Cost ($)	PO – Chassis only ($)
YT160-YT175 (Replaces YT116)	LD Service Body	2023	110,000	
YT161-YT178 (Fleet Add)	Technologist Truck	2023	160,000	
YT162-YT180 (Fleet Add)	Generation Truck	2023	160,000	82,771
YT163-YT176 (Replaces YT117)	LD Service Body	2023	110,000	
YT164-YT177 (Replaces YT099)	LD Service Body	2023	110,000	74,645
Units under $100,000	Various[1]	2023	47,000	
Total			**697,000**	

(b) Unit YT099 was sold by public bid action in 2022. Units 116 and 117 are still in AEY's possession and will be sold by public bid. When a vehicle is sold, the historical costs are retired and removed from rate base, which includes the credit from the net proceeds received from the sale. Note: The km for units YT116, YT117 and YT099 were incorrectly entered into BC # 27. The actual kms are noted – Table 2: Retired/Sold Fleet Vehicles below in red.

Table 2: Retired/Sold Fleet Vehicles

Unit	Description	Year Purchased	Kilometers	Sale Proceeds	Retirements
YT116	LD Service Body	2013	245,537 (170,705)		
YT117	LD Service Body	2013	237,000 (230,840)		
YT099	LD Service Body	2010	248,748 (246,478)	9,850	(53,875)

[1] Category includes items such as trailers, snowmobiles, and all-terrain vehicles. These units are evaluated for replacement using the lifecycle criteria evaluation after seven-years of service or 200,000 km.

Request for Goods / Services Form (RGS)

This form is to request goods and/or services where the annual spend or individual project spend is over $50K and/or of medium or high complexity/visibility. Quotes for goods/services or Request for Information (RFI) for less than $50k can be obtained by the originator.

Form submission and inquiries to be directed as follows:

- Non-work releases to EGBUProcurement@atco.com.
- Work releases to AEContractAdmin@atco.com.

ORIGINATOR TO COMPLETE			
1. Project Information: Project Name & Location.	Purchase of 2023 3500 Crew Cab Long Box Fleet Truck - Fleet replacement for 099 1088202 Unit 099 Replacement – 1 ton Service body - 2023 Dodge 3500 Big Horn crew cab 4x4 120k – Unit 177		
	Project #: 1088202	Task Code:	
2. CEAR:	Not Required	3. Contract Administrator (CA)	Not Required
4. Business Division:	North of 60 (N60)	5. Estimated total or annual value ($CAD):	$ 74,645.00
6. Project Type:	Non-Direct Assigned	7. Pricing Schedule(s):	☑ Attached; or ☐ To be provided later
8. Work Recurrence:	One time purchase / individual proje	9. Pricing Method:	Lump Sum
10. Services / Delivery Date(s):	Start Date: June 28, 2023 Completion / Delivery Date(s): December 15, 2023	11. Allowable Expenses: List items & budget identified by ATCO for the Project.	N/A
12. Work Specification Details:	12.1 Work package (specifications, drawings, maps, etc) — Select from drop down As per Londonderry Dodge quote provided 12.2 Permits required by contractor/supplier — Yes ☐ No ☐ 12.3 Site specific orientation requirements — Yes ☐ No ☐ 12.4 Forest Fire Fighting Expense Insurance Waiver — Yes ☐ No ☐		
13. HSE Document(s):	Prime Contractor: Contractor If contractor is identified as prime, a prime contractor agreement is required		
14. Pre-Bid Meeting:	Yes ☐ No ☑	15. Site Visit:	Yes ☐ No ☑

Request for Goods / Services Form (RGS)

16. Recommended Supplier(s) or Contractor(s) and contact information (contact name, email, phone number, address) to be provided. For MSAs, only Contractor names to be provided. Contractors are required to be Avetta approved prior to award.

PETER SMALL SR
LONDONDERRY DODGE CHRYSLER JEEP LTD.
13333 FORT ROAD NW
EDMONTON, AB T5A 1C3

Lowest cost

17. Evaluation Criteria: Yes ☑ No ☐

Dodge is standard for ATCO Fleet purchase. AEY RECIEVES FLEET PRICING

18. Single or Sole Source Justification: this section is to be used when company bidding standards are not followed for Non-AESO Transmission Direct Assigned Projects (REF form to be completed for AESO Transmission Direct Assigned Projects that do not follow the procurement guideline). Select the applicable reason(s) for the supplier/contractor selection in 18.1. Provide supporting information in 18.2.

Company Bidding Standards	
Bid Value	Minimum Number of Bids (Written Response)
UP TO AND INCLUDING $50,000	1 Bid
OVER $50,000 AND UP TO AND INCLUDING $100,000	2 Bids
OVER $100,000	3 Bids

18.1 Select the applicable reason(s) for the supplier/contractor selection.

Purchases <$50K for non-AESO and <$10K for AESO can be perfomed (no SSJ required)

18.2 Provide supporting information.

QUOTE PROVIDED THROUGH FLEET COMMON SERVICES

Request for Goods / Services Form (RGS)

19. Submitted by:

Signature: Matthew Gibson Digitally signed by Matthew Gibson DN: cn=Matthew Gibson, o=ATCO ELectric Yukon, ou=Construction, email=Matthew.Gibson@atco.com, c=CA Date: 2023.06.29 12:10:52 -07'00'

Name: Matthew Gibson

Date: June 28, 2023

Reviewed by Project Manager (if applicable):

Signature:_____

Name:_____

Date:_____

Approved by:

Signature:_____

Name:_____

Date:_____

Approved by:

Signature:_____

Name:_____

Date:_____

The form is to be approved by Supervisor/Manager. When using Single source, Signatures on this form to follow Delegation of Authority (DOA)

LONDONDERRY DODGE CHRYSLER JEEP LTD.
13333 FORT ROAD NW
EDMONTON, AB T5A1C3

Priced Order Confirmation (POC)

Date Printed:	2023-02-13 12:58 PM	**VIN:**		**Quantity:**	3
Estimated Ship Date:		**VON:**	58354801	**Status:**	BA - Pending order
Date Ordered:	2023-02-13 12:58 PM	**Ordered By:**	S14342F	**FAN 1:**	A0391 ATCO LTD
				FAN 2:	
				Bid Number:	
Sold to:		**Ship to:**		**PO Number:**	

2023 - 3500 CREW L/Box (GAS)

LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)
13333 FORT ROAD NW
EDMONTON, AB T5A1C3

LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)
13333 FORT ROAD NW
EDMONTON, AB T5A1C3

Vehicle: **2023 3500 BIG HORN CREW CAB 4X4 (169 IN WB 8 FT 0 IN Box) (D28H92)**

	Sales Code	Description	MSRP(CAD)	FWP(CAD)
Model:	D28H92	3500 BIG HORN CREW CAB 4X4 (169 IN WB 8 FT 0 IN Box)	69,745	63,773
Package:	2GZ	Customer Preferred Package 2GZ	0	0
	ESB	6.4L HEMI(R) V8 engine w/ FuelSaver	0	0
	DFX	8-speed automatic transmission	0	0
Paint/Seat/Trim:	PW7	Bright White	0	0
	APA	Monotone paint	0	0
	*M9	Premium cloth front 40/20/40 bench	0	0
	-X8	Black w/ Diesel Grey seats	0	0
Options:	AHD	Heavy-Duty Snowplow Prep Group	325	286
	XCH	2 additional key fobs	200	176
	A73	Level B Equipment Group	6,195	5,452
	XXS	Upfitter electronic module (VSIM)	200	176
	CKJ	Black vinyl floor covering	0	0
	DMF	4.10 rear axle ratio	195	172
	ADB	Protection Group	0	0
	LHL	IP-mounted auxiliary switches	200	176
	NFC	189-litre (50-gallon) fuel tank	740	651
	LNC	Clearance lamps	100	88
	AD6	Premium Lighting Group	800	704
	MWH	Rear wheelhouse liners	0	0
	RC3	9 Alpine(R) speakers with subwoofer	450	396
	4FT		0	0
	5N6	Easy Order	0	0
	4EA	Sold Vehicle	0	0
	125	Zone 25-Canada-Alberta	0	0
Non Equipment:	4FN	Fleet Commercial Sale	0	0
Discounts:	YGE	5 Additional Gallons of Gas	0	0
Destination Fees:			2,095	2,095
		Total Price:	81,245	74,145

+200 Fuel
+300. mil up.
$74,645.00

Order Type:	Fleet	**PSP Month/Week:**	
Scheduling Priority:	1-Sold Order	**Build Priority:**	99

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

Request for Goods / Services Form (RGS)

This form is to request goods and/or services where the annual spend or individual project spend is over $50K and/or of medium or high complexity/visibility. Quotes for goods/services or Request for Information (RFI) for less than $50k can be obtained by the originator.

Form submission and inquiries to be directed as follows:

- Non-work releases to EGBUProcurement@atco.com.
- Work releases to AEContractAdmin@atco.com.

ORIGINATOR TO COMPLETE			
1. Project Information: Project Name & Location.	Purchase of 2023 5500 Crew Cab Fleet Truck - Fleet addition 1088204 2 ton 2023 Dodge 5500 crew cab and chassis Tech Truck – Unit 180		
	Project #: 1088204	Task Code:	
2. CEAR:	Not Required	3. Contract Administrator (CA)	Not Required
4. Business Division:	North of 60 (N60)	5. Estimated total or annual value ($CAD):	$ 82,771.00
6. Project Type:	Non-Direct Assigned	7. Pricing Schedule(s):	☑ Attached; or ☐ To be provided later
8. Work Recurrence:	One time purchase / individual proje	9. Pricing Method:	Lump Sum
10. Services / Delivery Date(s):	Start Date: June 28, 2023 Completion / Delivery Date(s): December 15, 2023	11. Allowable Expenses: List items & budget identified by ATCO for the Project.	N/A
12. Work Specification Details:	12.1 Work package (specifications, drawings, maps, etc) — Select from drop down As per Londonderry Dodge quote provided 12.2 Permits required by contractor/supplier — Yes ☐ No ☐ 12.3 Site specific orientation requirements — Yes ☐ No ☐ 12.4 Forest Fire Fighting Expense Insurance Waiver — Yes ☐ No ☐		
13. HSE Document(s):	Prime Contractor: Contractor If contractor is identified as prime, a prime contractor agreement is required		
14. Pre-Bid Meeting:	Yes ☐ No ☑	15. Site Visit:	Yes ☐ No ☑

Request for Goods / Services Form (RGS)

16. Recommended Supplier(s) or Contractor(s) and contact information (contact name, email, phone number, address) to be provided. For MSAs, only Contractor names to be provided. Contractors are required to be Avetta approved prior to award.

PETER SMALL SR
LONDONDERRY DODGE CHRYSLER JEEP LTD.
13333 FORT ROAD NW
EDMONTON, AB T5A 1C3

Lowest cost

17. Evaluation Criteria: Yes ☑ No ☐

Dodge is standard for ATCO Fleet purchase. AEY RECIEVES FLEET PRICING

18. Single or Sole Source Justification: this section is to be used when company bidding standards are not followed for Non-AESO Transmission Direct Assigned Projects (REF form to be completed for AESO Transmission Direct Assigned Projects that do not follow the procurement guideline). Select the applicable reason(s) for the supplier/contractor selection in 18.1. Provide supporting information in 18.2.

Company Bidding Standards	
Bid Value	Minimum Number of Bids (Written Response)
UP TO AND INCLUDING $50,000	1 Bid
OVER $50,000 AND UP TO AND INCLUDING $100,000	2 Bids
OVER $100,000	3 Bids

18.1 Select the applicable reason(s) for the supplier/contractor selection.

Purchases <$50K for non-AESO and <$10K for AESO can be perfomed (no SSJ required)

18.2 Provide supporting information.

QUOTE PROVIDED THROUGH FLEET COMMON SERVICES

Request for Goods / Services Form (RGS)

19. Submitted by:

Signature: Matthew Gibson
Digitally signed by Matthew Gibson
DN: cn=Matthew Gibson, o=ATCO ELectric Yukon, ou=Construction, email=Matthew.Gibson@atco.com, c=CA
Date: 2023.06.29 12:13:47 -07'00'

Name: Matthew Gibson

Date: June 28, 2023

Reviewed by Project Manager (if applicable):

Signature:_____

Name:_____

Date:_____

Approved by:

Signature:_____

Name:_____

Date:_____

Approved by:

Signature:_____

Name:_____

Date:_____

The form is to be approved by Supervisor/Manager. When using Single source, Signatures on this form to follow Delegation of Authority (DOA)

LONDONDERRY DODGE CHRYSLER JEEP LTD.
13333 FORT ROAD NW
EDMONTON, AB T5A1C3

Priced Order Confirmation (POC)

Date Printed:	2023-02-13 12:55 PM	**VIN:**		**Quantity:**	2
Estimated Ship Date:		**VON:**	58354601	**Status:**	BA - Pending order
Date Ordered:	2023-02-13 12:55 PM	**Ordered By:**	S14342F	**FAN 1:**	A0391 ATCO LTD
				FAN 2:	

2023 - 5500 Crew. D

Bid Number:

Sold to:	**Ship to:**	**PO Number:**
LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)	LONDONDERRY DODGE CHRYSLER JEEP LTD. (C8150)	
13333 FORT ROAD NW	13333 FORT ROAD NW	
EDMONTON, AB T5A1C3	EDMONTON, AB T5A1C3	

Vehicle: **2023 5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN) (DP0L94)**

	Sales Code	Description	MSRP(CAD)	FWP(CAD)
Model:	DP0L94	5500 CREW CAB CHASSIS (197.4 IN WB - CA of 84 IN)	68,295	62,488
Package:	2YG	Customer Preferred Package 2YG	2,845	2,504
	ETN	6.7L Cummins(R) I-6 turbo diesel eng	6,950	6,116
	DF2	6-speed AISIN(R) heavy-duty automatic	2,500	2,200
Paint/Seat/Trim:	PW7	Bright White	0	0
	APA	Monotone paint	0	0
	*M9	Premium cloth front 40/20/40 bench	725	638
	-X8	Black w/ Diesel Grey seats	0	0
Options:	AD6	Premium Lighting Group	700	616
	AHD	Heavy-Duty Snowplow Prep Group	525	462
	AHQ	Max Tow Package	895	788
	A62	Big Horn(R) Level 1 Equipment Group	1,495	1,316
	CKW	Add Black vinyl floor covering	0	0
	DK3	Elec shift-on-the-fly transfer case	295	260
	GFA	Rear window defroster	225	198
	LAY	LED taillamps	100	88
	LBN	Power take off prep	395	348
	LSA	Security alarm	225	198
	UED	Uconnect(R) 5 with 8.4-in display	700	616
	XAC	ParkView(R) Rear Back-Up Camera	475	418
	XAG	Park-Sense(R) Front & Rear Park Assist	550	484
	XBM	Remote start system	395	348
	XCH	2 additional key fobs	200	176
	XF6	Voltage monitoring auto idle-up sys	300	264
	XHC	Trailer brake control	375	330
	XNR	Manual DPF regeneration	250	220
	4FT		0	0
	5N6	Easy Order	0	0
	4EA	Sold Vehicle	0	0
	125	Zone 25-Canada-Alberta	0	0
Non Equipment:	4FN	Fleet Commercial Sale	0	0
Destination Fees:			2,095	2,095
		Total Price:	91,510	83,171

$82,771.00 + TAX.

+300 mkup
+200 fuel
$83,671.00
-900.00

Note: This is not an invoice. The prices and equipment shown on this priced order confirmation are tentative and subject to change or correction without prior notice. No claims against the content listed or prices quoted will be accepted. Refer to the vehicle invoice for final vehicle content and pricing. Orders are accepted only when the vehicle is shipped by the factory.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-090

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-090

Reference: Fleet Replacement 2024, BC#28; Costs $766,000

Request:

(a) Give Atco Fleet and 3rd party vendor tenders with purchase costs from each.

(b) Will AEY sell the six used trucks? How will these tendered and how much is estimated to be recouped? How will this be deducted from costs in this accounting process? Explain.

Response:

(a) The fleet to be purchased in 2024 has not yet been sent to ATCO fleet for tender.

(b) The fleet listed below in Table 1: Fleet Replaced will be sold by public bid auction. When a vehicle is sold, the historical costs are retired and removed from rate base, which includes the credit from the net proceeds received from the sale.

Table 1: Fleet Replaced

Unit	Description	Year Purchased	Kilometers
YT109	MD Ram 3500 Flat	2012	206,620
YT125	Teletruck Forklift	2014	1,838 hrs
YT129	MD Ram 3500 Flat	2014	114,800
YT133	MD Ram 2500 SB	2015	145,687
YT135	MD ram 2500 Flat	2015	174,972

ATCO Electric YUKON

September 28, 2023 AEY-UCG-091

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-091

Reference: Old Crow Voltage Improvement, BC#29; Costs $1,174 million

Request:

(a) Provide engineering qualifications of what work was to be done for this project and what were the economic analyses identifying the business drivers and cost/benefits, including the preliminary engineering estimate of costs. Provide engineers report.

Response:

(a) Please refer to the response to AEY-UCG-066(a) and AEY-YUB-060 Attachment 2.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-092

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-092

Reference: 6L19 Voltage Improvement, BC#30; Costs $949,000

Request:

(a) Provide engineering qualifications of what work was to be done for each project and what were the economic analyses identifying the business drivers and cost/benefits, including the preliminary engineering estimate of costs. Provide engineers report.

(b) Is this expected to decrease line loss. Explain, giving examples of savings from this project.

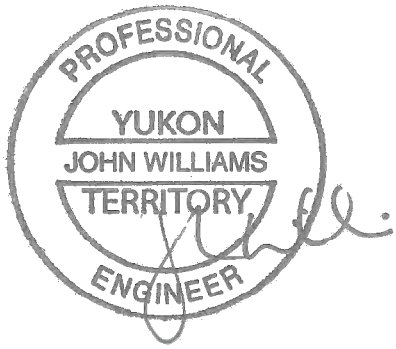
Response:

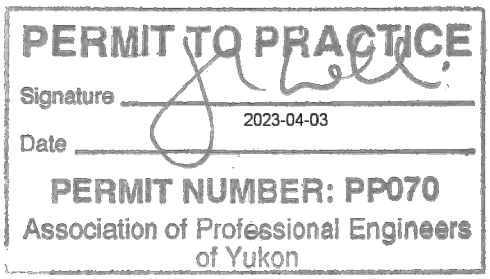
(a) Please refer to the response to AEY-UCG-066(a) and AEY-UCG-092(a) Attachment 1.

(b) This is not expected to decrease line loss as there is no change in conducting material.

6L11 and 6L19 Low Voltage

Technical Study





Revision History

Revision	Date	Editor	Comments
R1	2023-03-20	Alex Deans	First Draft

Executive Summary

Voltages below ATCO standard have been measured on the 35kV system south of Whitehorse. This study is to identify possible solutions that alleviate the low voltage conditions on 6L11 and 6L19.

Problem Definition

Issues along the 35kV system south of Whitehorse include low voltage conditions at Teslin; Robinson; and customers fed off the 35kV system and the Lewes River regulators being tapped to their maximum limit for extended periods of time.

Low voltage conditions on a typical transmission line would not be an issue since the voltage can be stepped up at the distribution sub-stations, but, since the sub-transmission system feeds customers as well, the voltage on the sub transmission system will need to adhere to ATCO distribution voltage standards.

As can be seen in Figure 1, low voltage issues on the sub-transmission line are passing through to the distribution networks along 6L19. South McLintock, New Constabulary, Teslin Lake, and Teslin distribution networks. Refer to Table 1 for a summary of the voltages along 6L19 and the distribution networks fed off this line.

It should be noted that the issues on 6L18, seen in Figure 1, will be addressed in a future study. This is because, since the issues on 6L19 are worse and more widespread, the solution to the issues on 6L19 will likely affect, and lessen, the voltage issues on 6L18.

Model Validation

Voltage data and load data is available for December 2022 at the load side of the Teslin Substation regulator and at S150 respectively. This time frame was chosen as the peak load at S150 occurred on Dec 20, 2022. This data was used to validate the CYME models used in this study and was done so following this method:

1. Adjust the CYME loading percentage until the load at S150 matches the SCADA data at S150
2. Set S150 source voltage in CYME to SCADA's voltage at that given time
3. Compare CYME voltages against SCADA voltages retrieved from the load side of the Teslin substation regulator

Table 1 - CYME Model Validation Table

Timestamp	CYME Load Percentage	Teslin Field Voltage (kV)	Teslin CYME Voltage (kV)	Percent Error
12/20/2022 12:15:00 AM	88.0%	25.179	24.892	1.14%
12/20/2022 1:00:00 AM	87.2%	25.154	24.946	0.83%
12/20/2022 1:15:00 AM	89.0%	25.012	24.669	1.37%
12/20/2022 4:15:00 AM	91.0%	24.886	24.415	1.90%
12/20/2022 4:30:00 AM	92.3%	24.901	24.319	2.34%
12/20/2022 4:45:00 AM	92.9%	24.892	24.261	2.53%
12/20/2022 5:45:00 AM	94.5%	24.739	23.940	3.23%
12/20/2022 6:15:00 AM	98.1%	24.838	23.412	5.74%
12/20/2022 6:30:00 AM	99.0%	24.774	23.263	6.10%
12/20/2022 7:15:00 AM	97.0%	25.209	23.453	6.96%
12/20/2022 10:15:00 AM	103.7%	24.708	22.432	9.21%
12/20/2022 11:15:00 AM	102.0%	24.963	22.658	9.23%
12/20/2022 12:00:00 PM	100.0%	25.095	22.893	8.77%

As seen in Table 1 and Figure 1, the CYME model voltages align within 3.23% of the field data until the CYME model is loaded more than 94.5%. Once the model is more heavily loaded, the error increases substantially and is believed to be attributed to CYME's inability to model extreme voltage drop conditions (<0.9pu) accurately. For the remainder of the study, we cannot fully confirm if the CYME voltages that fall below 0.90pu are completely accurate; however, we do know that the voltages do not meet ATCO standards and must be addressed.

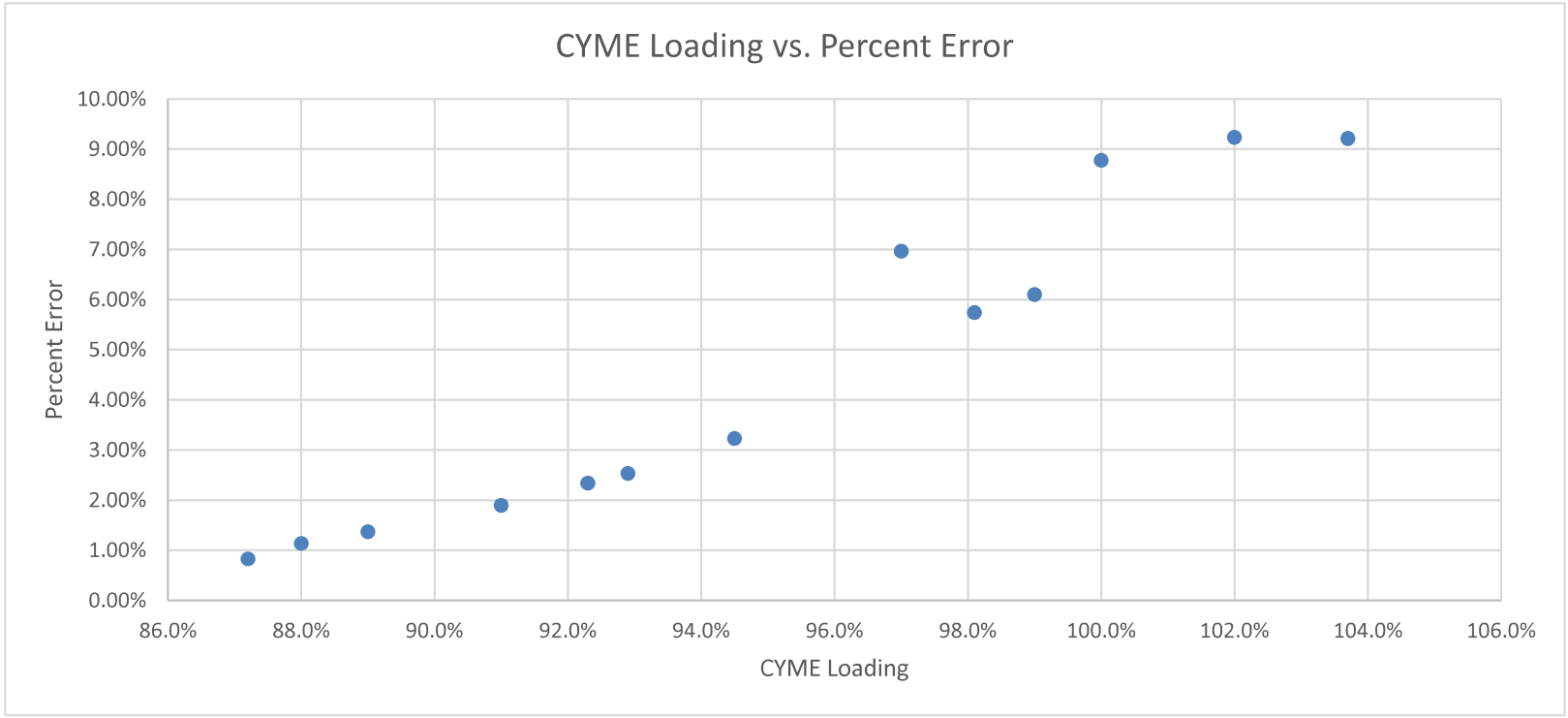


Figure 1 - Voltage Validation Scatter Plot

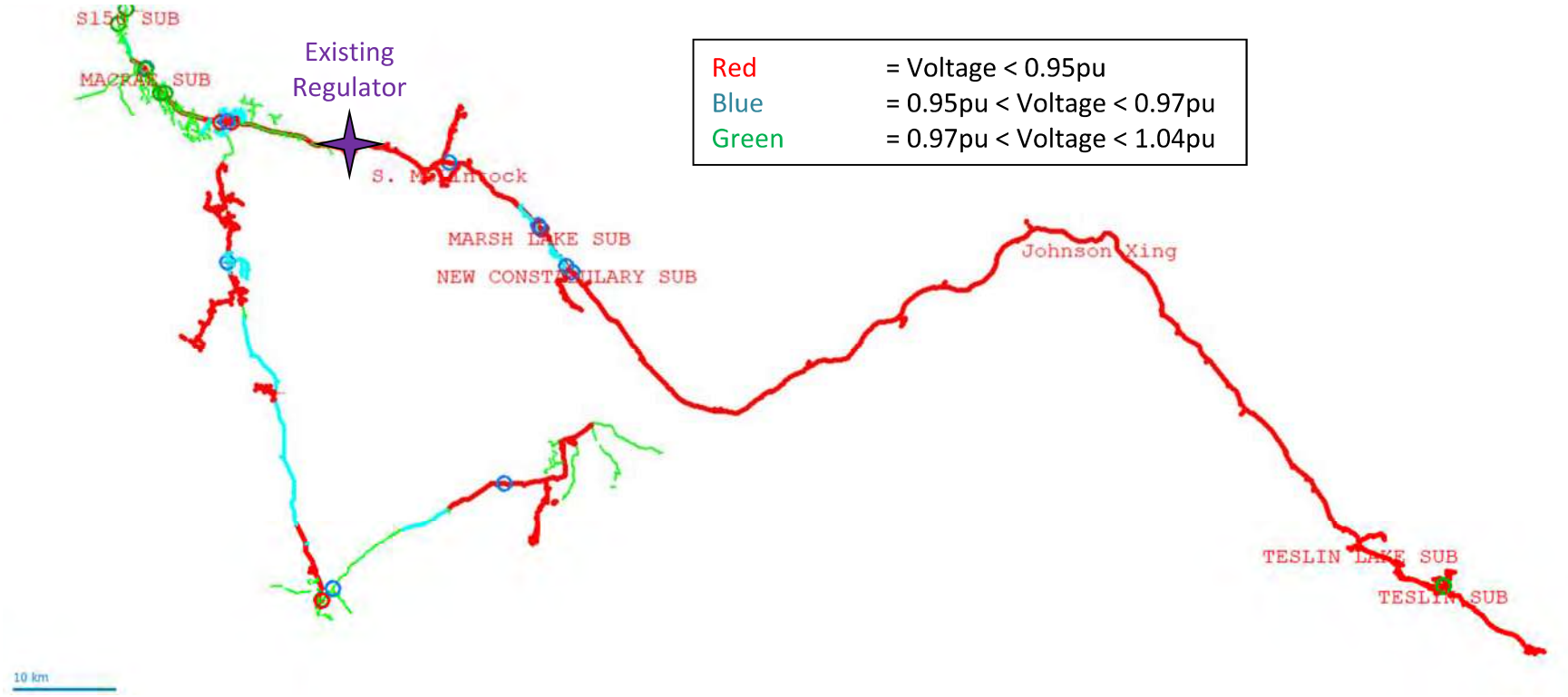


Figure 2 - Existing Voltages on 6L11 and 6L19

Table 2 - Existing 6L19 Voltage and Current Summary

Location	Va (pu)	Vb (pu)	Vc (pu)	Ia (A)	Ib (A)	Ic (A)
McRae Sub (35kV)	0.945	0.946	0.944	220.3	219.5	225.5
5L649 EOL	1.019	1.019	1.018	-	-	-
5L631 EOL	-	-	0.949	-	-	-
South McLintock Sub (35kV)	0.932	0.946	0.934	54.7	45.0	64.0
5L611 EOL	-	-	0.926	-	-	-
Marsh Lake Sub (35kV)	0.909	0.927	0.917	53.3	33.1	53.6
5L612 EOL	0.958	-	-	-	-	-
New Constabulary Sub (35kV)	0.902	0.919	0.912	40.5	33.2	40.3
5L615 EOL	0.855	-	-	-	-	-
Johnson Crossing Sub (35kV)	0.851	0.843	0.861	23.0	31.8	23.0
Teslin Lake Sub (35kV)	0.819	0.796	0.828	22.4	29.6	22.5
4L301 EOL	-	0.802	-	-	-	-
Teslin Sub (35kV)	0.812	0.787	0.821	20.7	24.4	19.2
5L613 EOL	0.879	-	-	-	-	-
5L614 EOL	-	0.868	-	-	-	-
Worst Voltage on 6L19	0.815	0.791	0.824	-	-	-
Carcross Cutoff	-	-	-	121.2	108.2	118.0

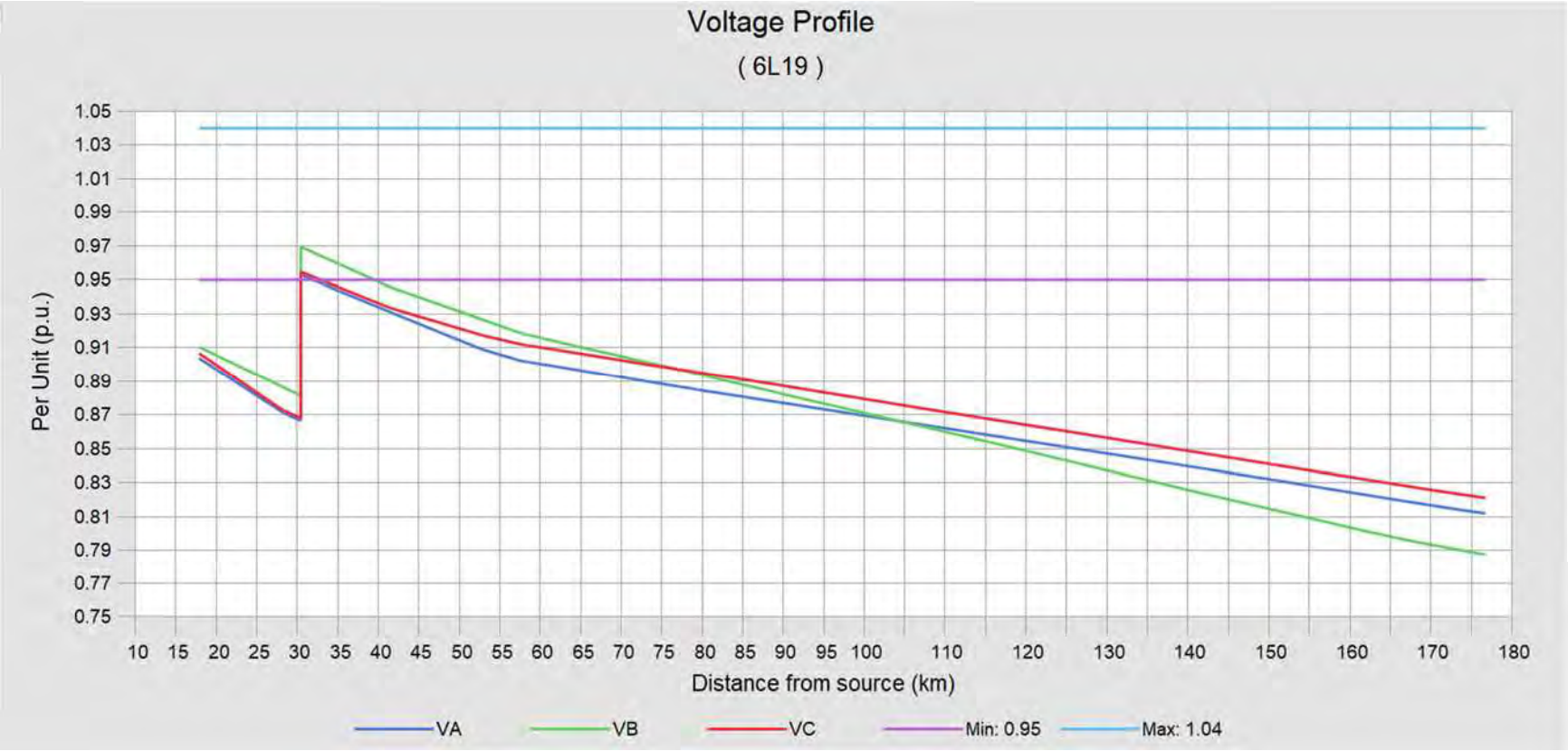


Figure 3 - Existing 6L19 Voltage Profile

Alternatives Considered

The ways to address low voltages on 6L19 include reconductoring, installing regulators, and adjusting the source voltage at S150. Many combinations of these choices are possible and were investigated; however, in the interest of being concise only the following cases were considered:

1. Install Two New Regulators on 6L11 and 6L19
2. Reconductor 6L11 and 6L19
3. Reconductor 6L11 and Install a New Regulator on 6L19
4. Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19
5. Boost S150 Voltage, Relocate Two Reg Banks, and Install Regulator on 6L11
6. Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19

Loading Assumptions
Load within the CYME models was adjusted to be equivalent to the most recent Winter 2022/2023 YEC S150 (52-22 feeder) SCADA data (~12.7MW). Load growth is calculated to be 4.62% per year, therefore the load on the system was increased by $(1.0462)^5 = 25.3\%$ to simulate a 5-year future load. This 25.3% increase equates to ~16.0MW

- Existing CYME Model Loading = 108%
- 2028 CYME Model Loading = 128.4%

Alternative 1- Install Two New Regulators on 6L11 and 6L19

This alternative explores installing two new 3-phase regulator banks, one 400A bank on 6L11 and one 100A bank on 6L19. The additions of two regulator banks will mean there are four inline regulators between S150 and any distribution substation with a regulator along 6L19. This could pose the risk of overvoltage conditions during a load shedding event.

The location for the first regulator will be on 6L11 upstream of Macrae where voltage begins to dip below 0.95pu (between Miles Canyon Rd and Mt. Sima Rd). Once this regulator is installed, the model will be run, and the second regulator will be placed where the voltage drops below 0.97 on 6L19 (Squan Lake).

The two load shed events that have the risk for the highest voltage are the loss of Teslin sub and the opening of the Judas Creek recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.164pu. This is below the long line rural maximum voltage of 1.167pu. During the opening of the Judas Creek recloser, the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.099pu. This is also within the acceptable range for over voltage.

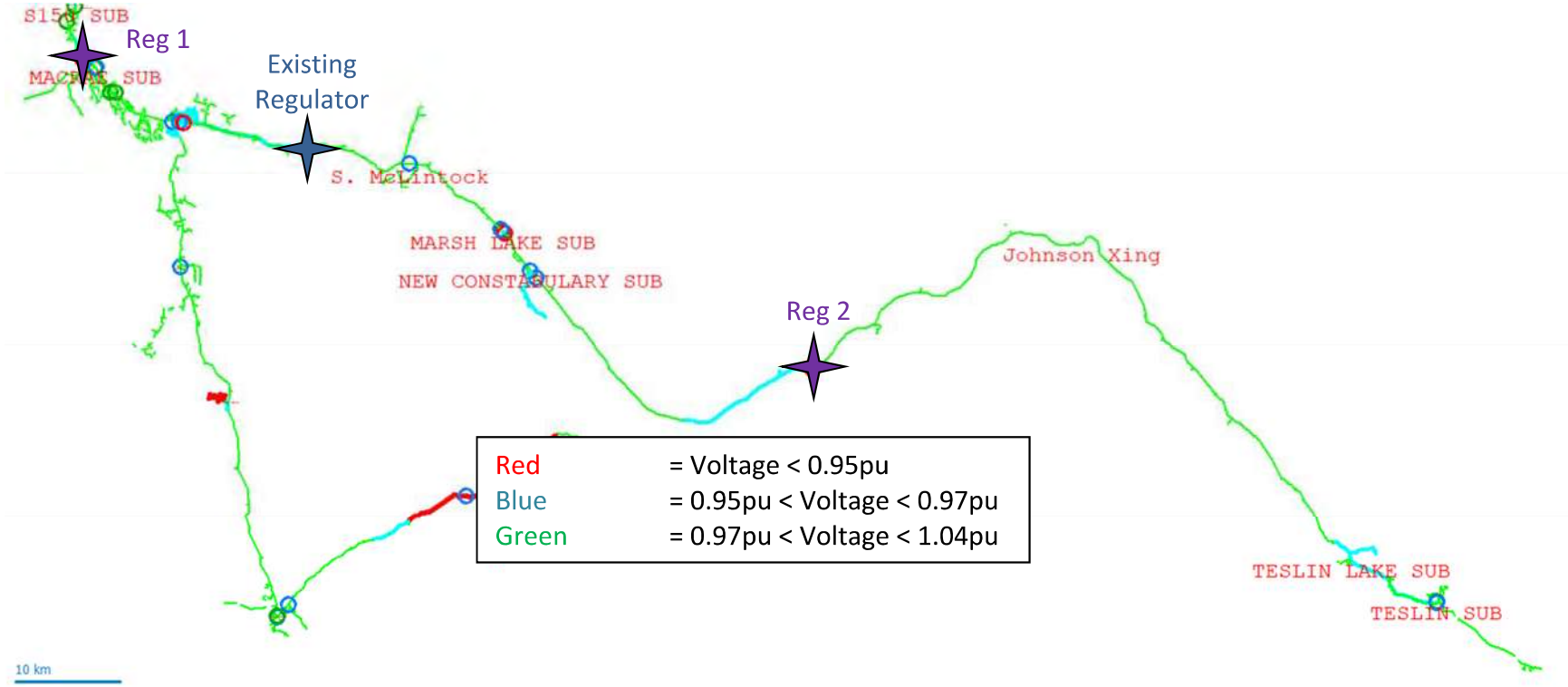


Figure 4 - Alternative 1 Voltage Conditions

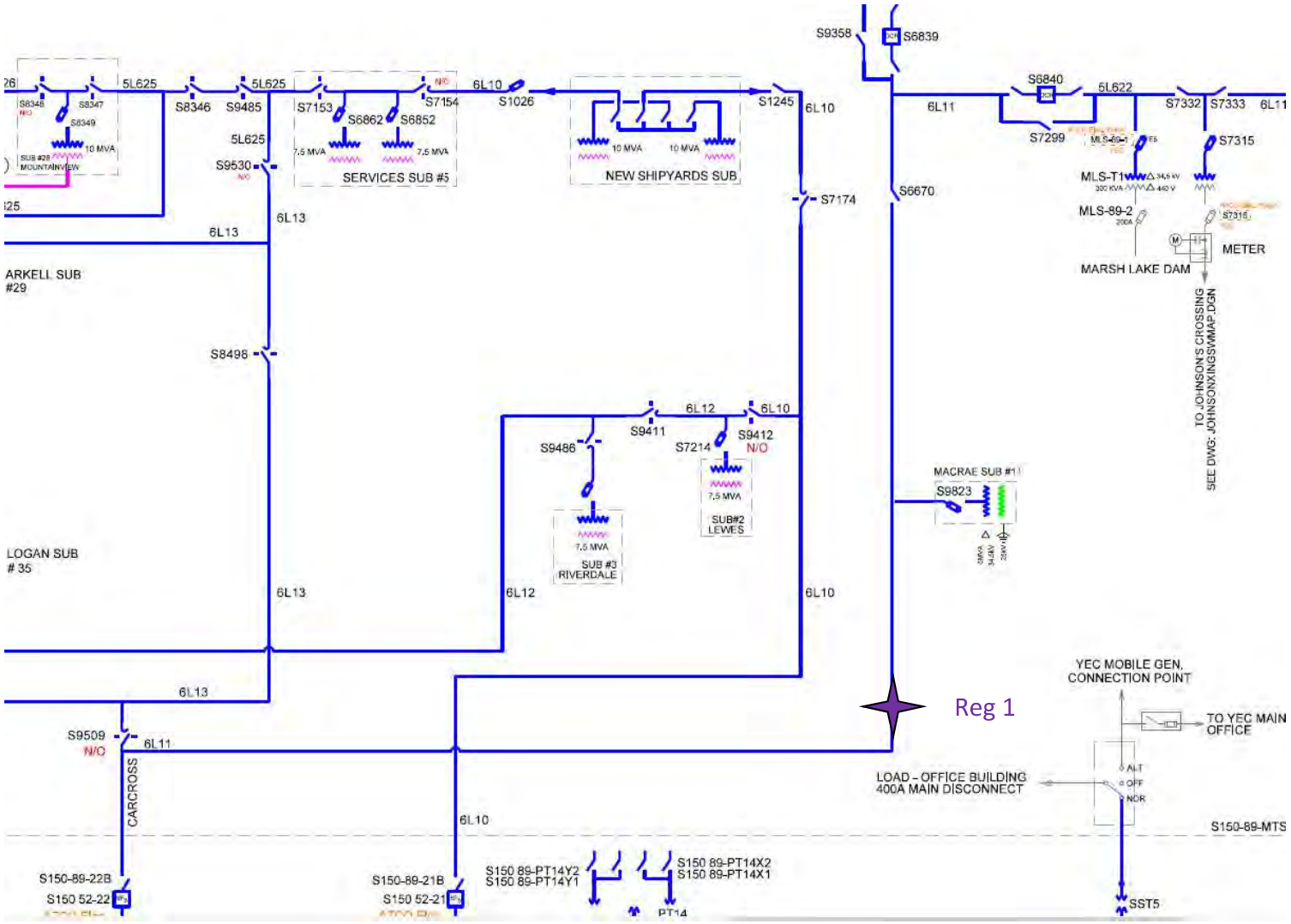


Figure 5 – Alternative 1 Regulator 1 Location SLD

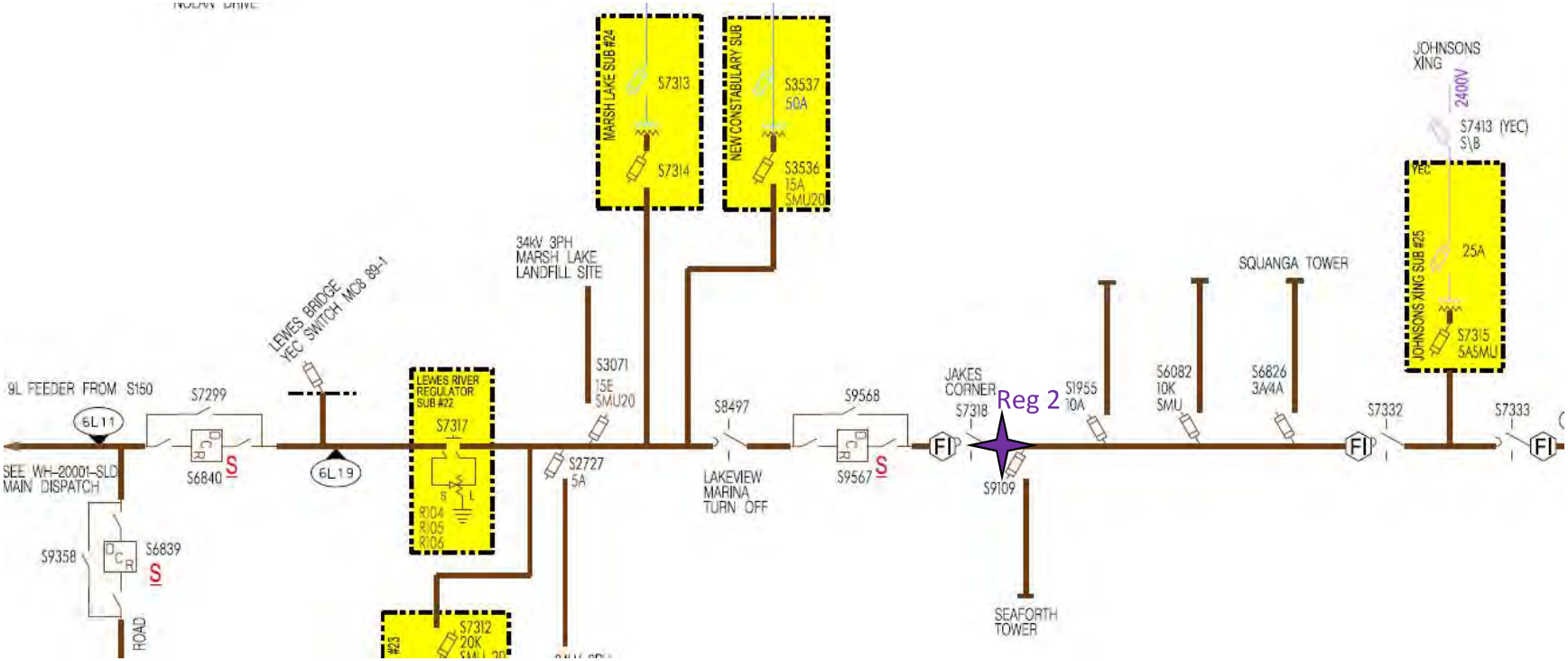


Figure 6 - Alternative 1 Regulator 2 Location SLD

Table 3 - Alternative 1 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	1.025	1.027	1.025
5L649 EOL	1.033	1.027	1.032
5L631 EOL	-	-	0.964
South McLintock Sub (35kV)	1.017	1.013	1.020
5L611 EOL	-	-	1.003
Marsh Lake Sub (35kV)	0.998	0.996	1.007
5L612 EOL	0.995	-	-
New Constabulary Sub (35kV)	0.995	0.990	1.003
5L615 EOL	0.952	-	-
Johnson Crossing Sub (35kV)	1.019	1.006	1.018
Teslin Lake Sub (35kV)	0.994	0.969	0.993
4L301 EOL	-	0.972	-
Teslin Sub (35kV)	0.988	0.962	0.987
5L613 EOL	1.027	-	-
5L614 EOL	-	1.021	-
Worst Customer Voltage on 6L19	0.958	0.973	0.960

Table 4 - Alternative 1 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	1.023	1.025	1.022
5L649 EOL	1.026	1.026	1.031
5L631 EOL	-	-	0.949
South McLintock Sub (35kV)	1.007	1.007	1.009
5L611 EOL	-	-	0.992
Marsh Lake Sub (35kV)	0.983	0.986	0.992
5L612 EOL	0.994	-	-
New Constabulary Sub (35kV)	0.976	0.977	0.986
5L615 EOL	0.924	-	-
Johnson Crossing Sub (35kV)	1.013	0.993	1.013
Teslin Lake Sub (35kV)	0.981	0.947	0.981
4L301 EOL	-	0.954	-
Teslin Sub (35kV)	0.974	0.938	0.974
5L613 EOL	1.026	-	-
5L614 EOL	-	1.017	-
Worst Customer Voltage on 6L19	0.938	0.955	0.939

Alternative 2 - Reconductor 6L11 and 6L19

This alternative explores reconductoring the entirety of 6L11 and 6L19 with 477 ACSR (158km in total). Anything less than this results in voltage below 0.95pu on 6L19 close to Teslin during existing conditions which impacts 35kV customers.

This amount of reconductoring will be very expensive, so the following alternatives explore a combination of reconductoring and installing voltage supporting equipment.

This alternative allows for future a regulator addition along the lines of other alternatives in this study which would greatly increase system capacity and further improve voltages in the Teslin area.

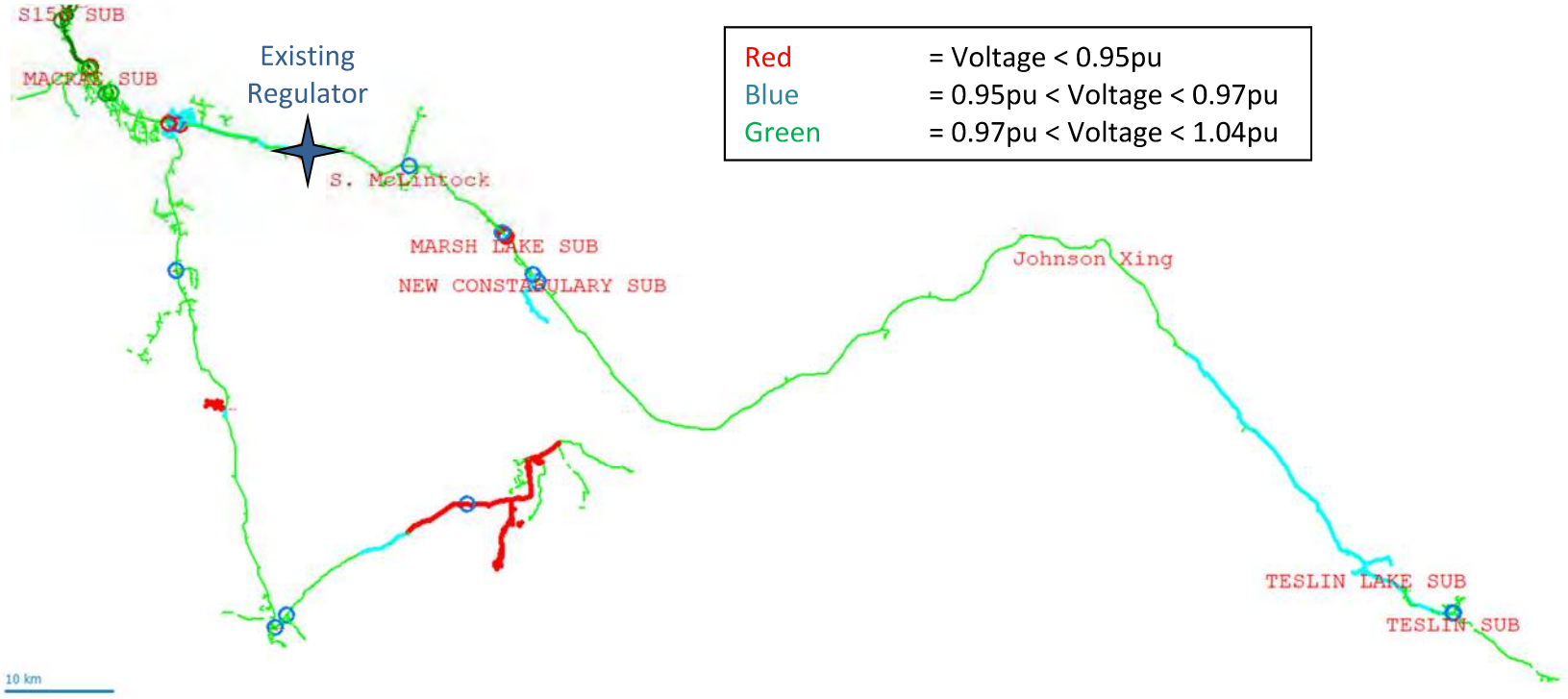


Figure 7 – Alternative 2 Voltage Conditions

Table 5 - Alternative 2 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	0.984	0.985	0.984
5L649 EOL	1.033	1.032	1.032
5L631 EOL	-	-	0.964
South McLintock Sub (35kV)	1.016	1.016	1.015
5L611 EOL	-	-	1.001
Marsh Lake Sub (35kV)	0.994	1.000	1.001
5L612 EOL	0.993	-	-
New Constabulary Sub (35kV)	0.989	0.993	0.997
5L615 EOL	0.949	-	-
Johnson Crossing Sub (35kV)	0.979	0.972	0.986
Teslin Lake Sub (35kV)	0.970	0.957	0.978
4L301 EOL	-	0.958	-
Teslin Sub (35kV)	0.968	0.954	0.975
5L613 EOL	1.027	-	-
5L614 EOL	-	1.025	-
Worst Customer Voltage on 6L19	0.968	0.954	0.975

Table 6 - Alternative 2 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	0.978	0.980	0.979
5L649 EOL	1.029	1.027	1.027
5L631 EOL	-	-	0.946
South McLintock Sub (35kV)	1.015	1.013	1.012
5L611 EOL	-	-	0.995
Marsh Lake Sub (35kV)	0.991	0.993	0.994
5L612 EOL	0.992	-	-
New Constabulary Sub (35kV)	0.985	0.986	0.989
5L615 EOL	0.934	-	-
Johnson Crossing Sub (35kV)	0.971	0.958	0.974
Teslin Lake Sub (35kV)	0.959	0.939	0.963
4L301 EOL	-	0.940	-
Teslin Sub (35kV)	0.957	0.935	0.960
5L613 EOL	1.027	-	-
5L614 EOL	-	1.025	-
Worst Customer Voltage on 6L19	0.957	0.935	0.960

Alternative 3 - Reconductor 6L11 and install a new regulator on 6L19

This alternative explores reconductoring all of 6L11 with 296 ACSR and installing a new regulator on 6L19 to boost the end of line voltage.

The location for the regulator was chosen to be where the voltage is below 0.97 but is still above 0.95 after the reconductor.

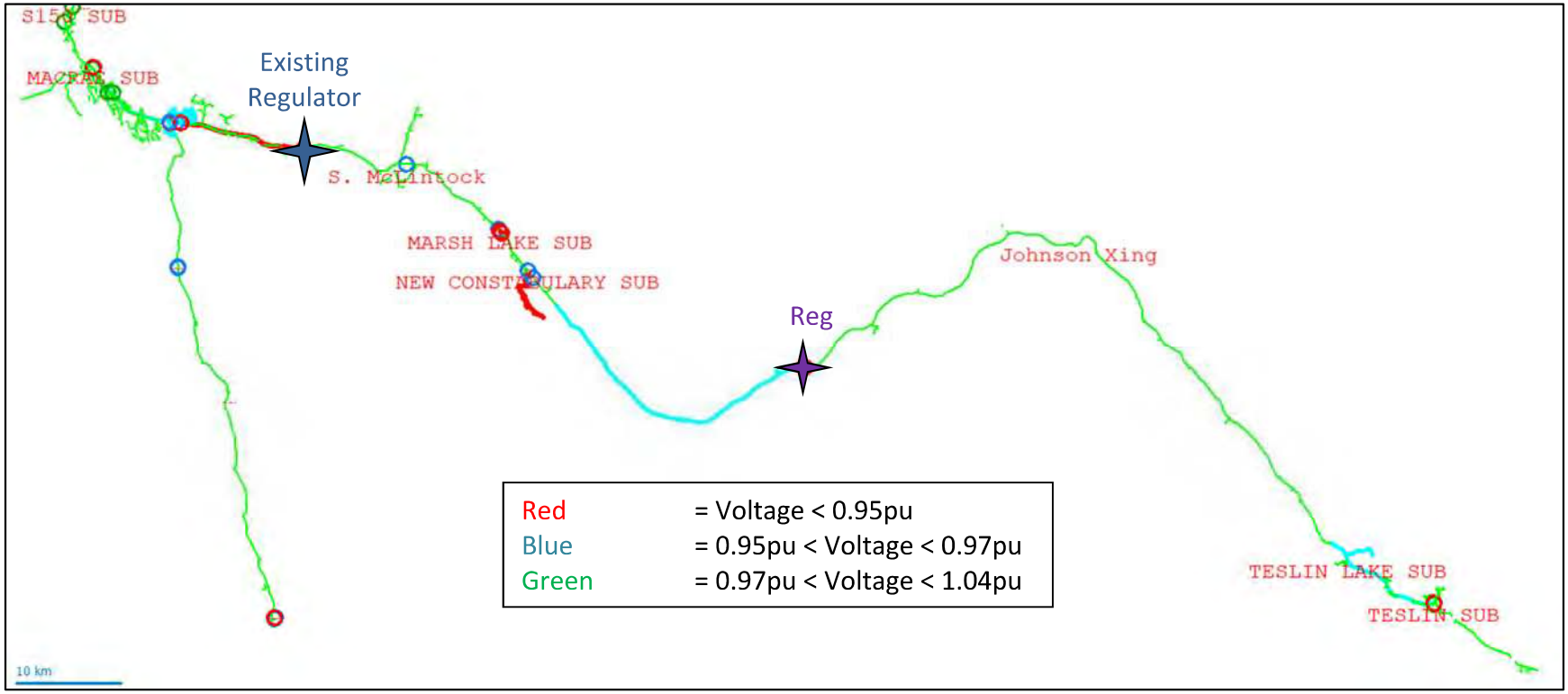


Figure 8 - Alternative 3 Voltage Conditions

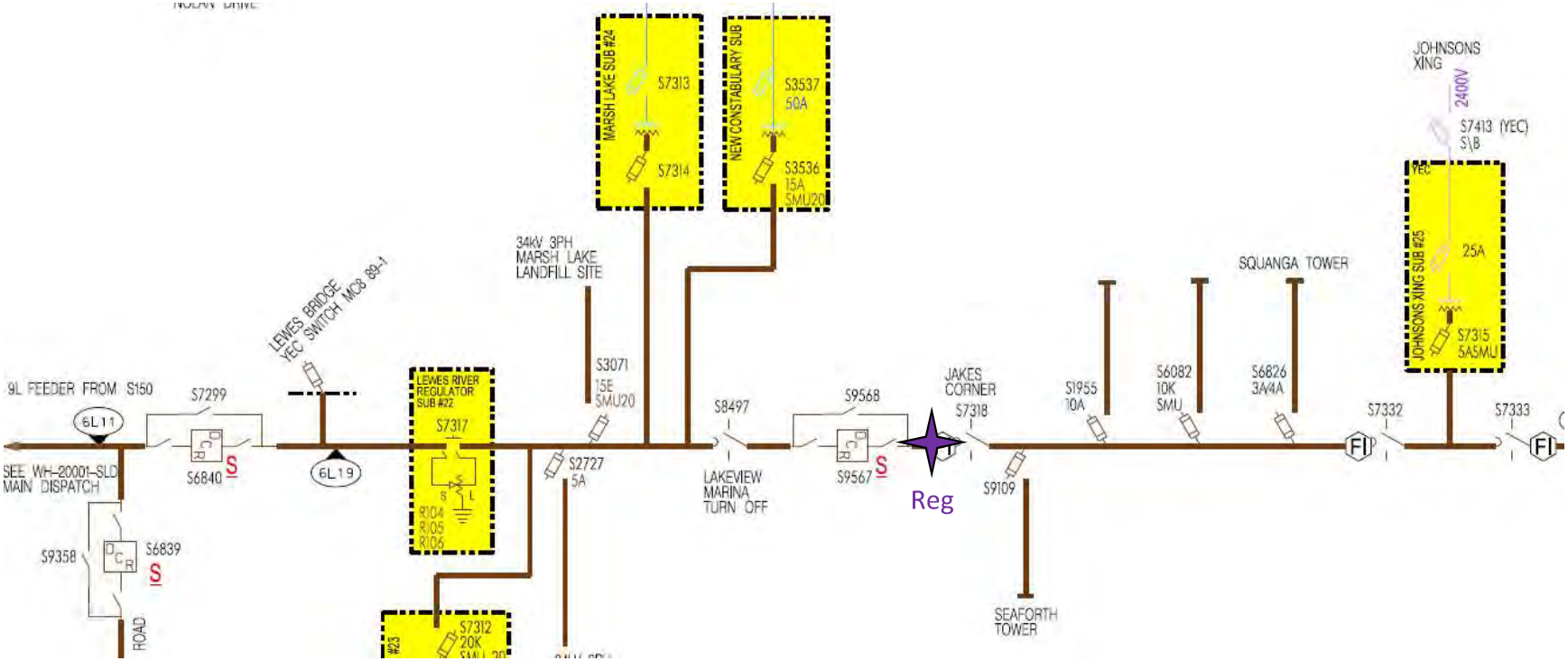


Figure 9 - Alternative 3 Regulator Location SLD

Table 7 - Alternative 3 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	0.977	0.978	0.977
5L649 EOL	1.031	1.030	1.029
5L631 EOL	-	-	0.959
South McLintock Sub (35kV)	0.999	1.011	1.024
5L611 EOL	-	-	0.993
Marsh Lake Sub (35kV)	0.979	0.994	0.988
5L612 EOL	0.992	-	-
New Constabulary Sub (35kV)	0.973	0.987	0.983
5L615 EOL	0.931	-	-
Johnson Crossing Sub (35kV)	1.020	1.007	1.019
Teslin Lake Sub (35kV)	0.994	0.968	0.993
4L301 EOL	-	0.972	-
Teslin Sub (35kV)	0.988	0.961	0.987
5L613 EOL	1.033	-	-
5L614 EOL	-	1.026	-
Worst Customer Voltage on 6L19	0.927	0.939	0.929

Table 8 - Alternative 3 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	0.971	0.972	0.971
5L649 EOL	1.029	1.025	1.030
5L631 EOL	-	-	0.946
South McLintock Sub (35kV)	0.972	0.986	0.975
5L611 EOL	-	-	0.963
Marsh Lake Sub (35kV)	0.946	0.963	0.955
5L612 EOL	0.992	-	-
New Constabulary Sub (35kV)	0.938	0.954	0.949
5L615 EOL	0.884	-	-
Johnson Crossing Sub (35kV)	0.974	0.963	0.986
Teslin Lake Sub (35kV)	0.940	0.914	0.952
4L301 EOL	-	0.923	-
Teslin Sub (35kV)	0.933	0.905	0.945
5L613 EOL	1.011	-	-
5L614 EOL	-	0.998	-
Worst Customer Voltage on 6L19	0.907	0.921	0.909

Alternative 4 - Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19

This alternative explores increasing the S150 voltage to 1.04pu, reconductoring 6L11 using 477 ACSR and installing a new regulator along 6L19. This is a similar approach to Alternative 1, but instead of using a regulator to increase 6L11 voltage, the voltage will be increased at substation S150. The regulator was placed in the same methodology as in Alternative 1.

This alternative would immediately address the voltage issue all along 6L11 and 6L19 with issues arising at McRae and New Constabulary after 5 years. The issue after 5 years at MacRae can easily be addressed by relocating the single-phase regulator further upstream, and the issues at New Constabulary can be fixed by installing a single-phase regulator at the substation.

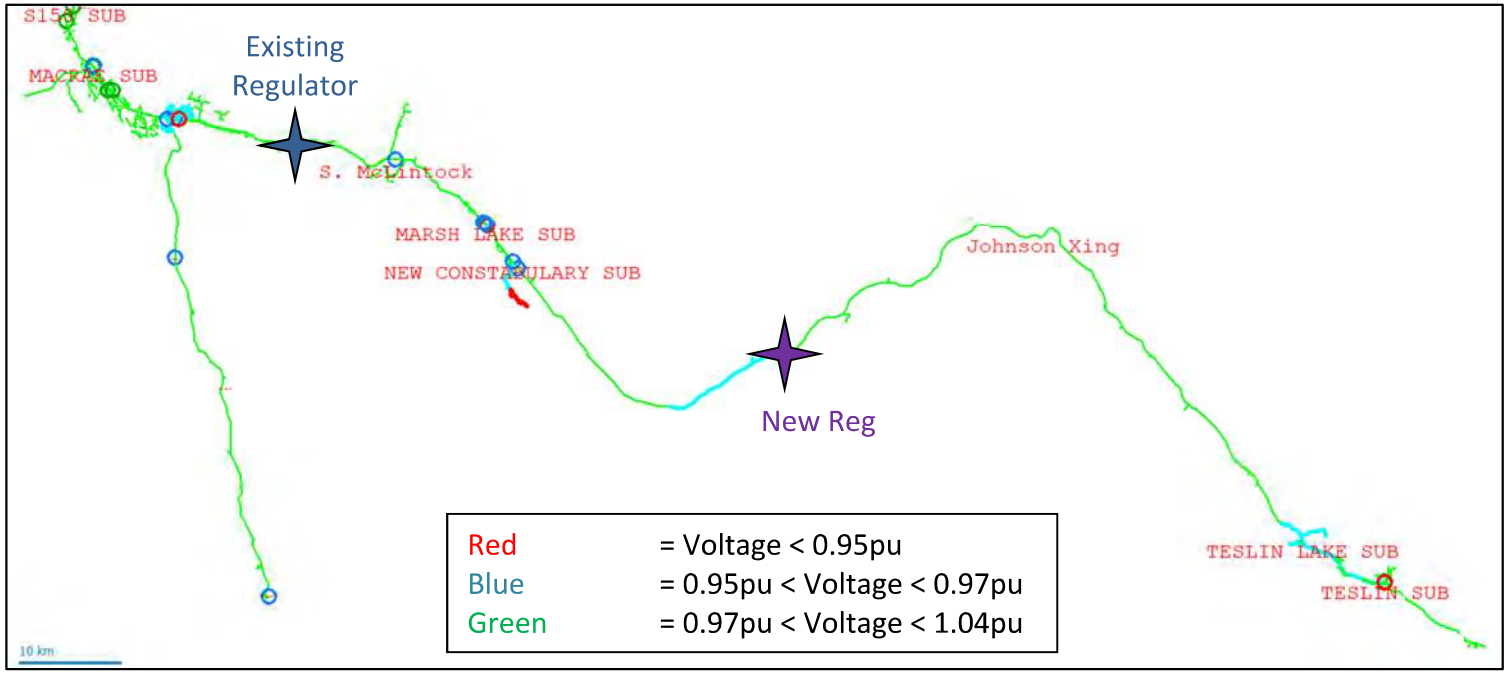


Figure 10 - Alternative 4 Voltage Conditions

Table 9 - Alternative 4 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	1.018	1.019	1.019
5L649 EOL	1.032	1.031	1.031
5L631 EOL	-	-	0.961
South McLintock Sub (35kV)	1.018	1.016	1.015
5L611 EOL	-	-	1.002
Marsh Lake Sub (35kV)	0.998	0.999	1.001
5L612 EOL	0.992	-	-
New Constabulary Sub (35kV)	0.992	0.992	0.997
5L615 EOL	0.948	-	-
Johnson Crossing Sub (35kV)	1.017	1.007	1.016
Teslin Lake Sub (35kV)	0.991	0.968	0.990
4L301 EOL	-	0.969	-
Teslin Sub (35kV)	0.985	0.960	0.984
5L613 EOL	1.030	-	-
5L614 EOL	-	1.024	-
Worst Customer Voltage on 6L19	0.988	0.963	0.986

Table 10 - Alternative 4 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	1.013	1.014	1.013
5L649 EOL	1.029	1.027	1.027
5L631 EOL	-	-	0.943
South McLintock Sub (35kV)	1.012	1.007	1.009
5L611 EOL	-	-	1.002
Marsh Lake Sub (35kV)	0.987	0.985	0.992
5L612 EOL	0.991	-	-
New Constabulary Sub (35kV)	0.980	0.976	0.986
5L615 EOL	0.927	-	-
Johnson Crossing Sub (35kV)	1.011	0.991	1.011
Teslin Lake Sub (35kV)	0.979	0.943	0.979
4L301 EOL	-	0.950	-
Teslin Sub (35kV)	0.972	0.934	0.972
5L613 EOL	1.031	-	-
5L614 EOL	-	1.019	-
Worst Customer Voltage on 6L19	0.954	0.937	0.961

Alternative 5 - Boost S150, Relocate Two Reg Banks, and Install Regulator on 6L11

This alternative relocates existing regulators on the system to better align with system demand, while lowering costs by reusing assets versus buying new ones. Two regs banks will be relocated to within the 6L19 line, while a new 200A reg bank will be installed on 6L11.

The location for the new 200A regulator will be on 6L11 upstream of Macrae where voltage begins to dip below 0.95pu (between Fireweed Dr and Salmon Tr). The 100A Lewes River regulator bank will be relocated approximately 11km downstream, just before South McLintock substation. Lastly, the 6L18 Carcross Cutoff 100A reg bank will be relocated to the Summit Lake area (approx. 5km West of Squanga Lake Campground).

The three load shed events that have the risk for the highest voltage are the loss of Teslin sub, the opening of the Judas Creek recloser, and the opening of the 6L18 Carcross Cutoff recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.152pu. This is below the long line rural maximum voltage of 1.167pu. During the opening of the Judas Creek recloser and the Carcross Cutoff recloser the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.095pu and 1.094pu respectively. This is also within the acceptable range for over voltage.

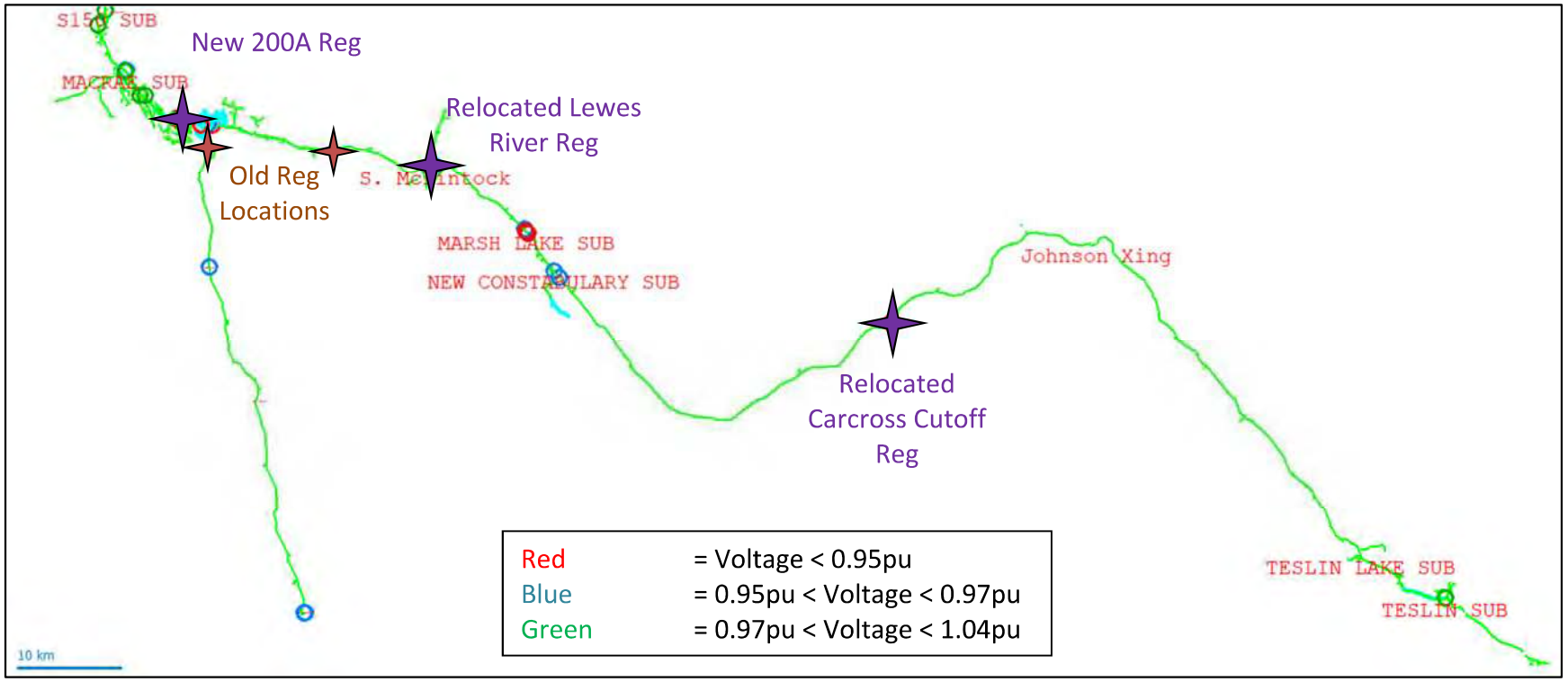
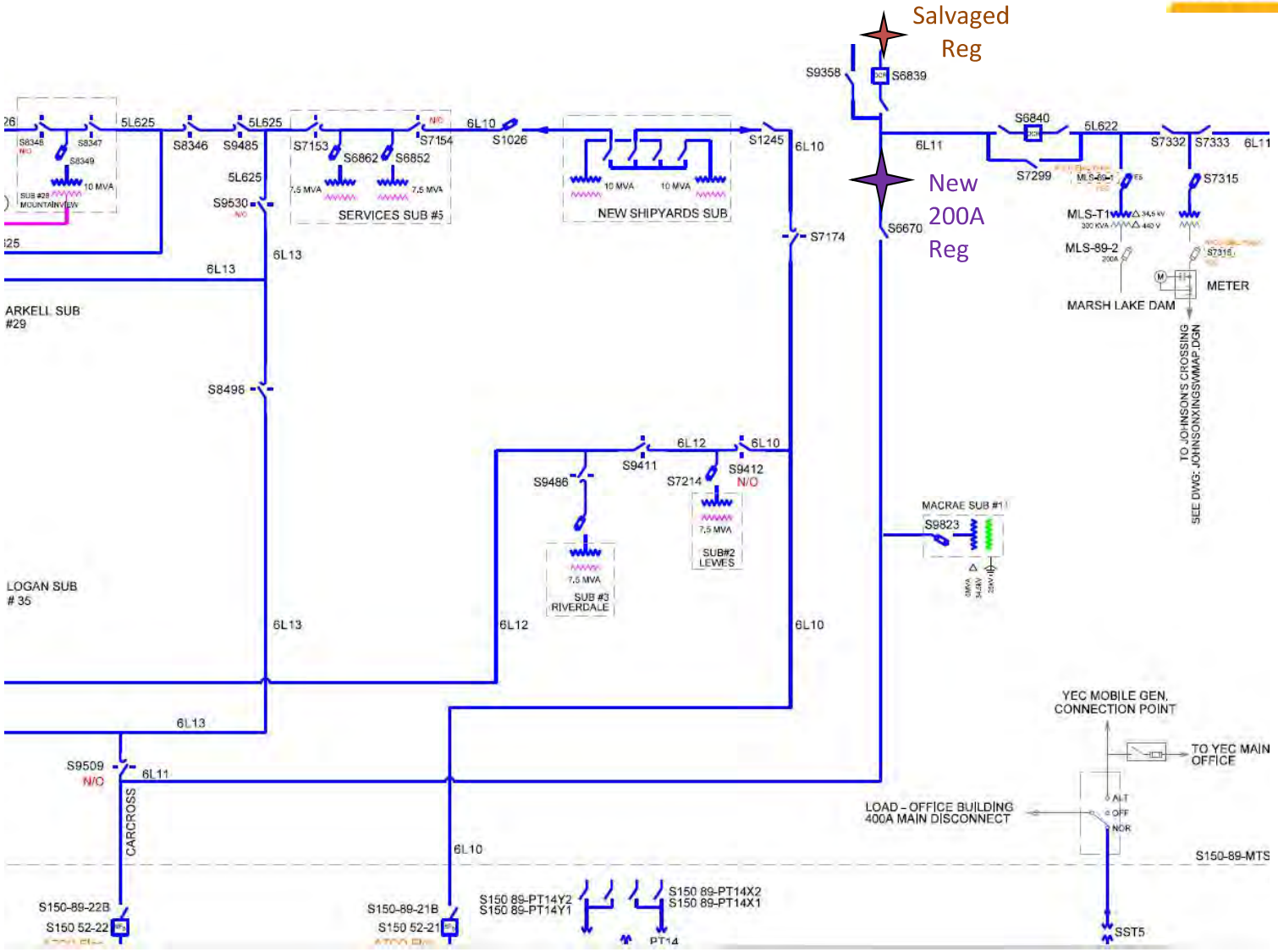


Figure 11 - Alternative 5 Voltage Conditions


Salvaged
Reg
New
200A
Reg
S9358
S6839
S6840
S6670
5L625
S8346
S9485
S7153
S6862
S6852
S7154
6L10
S1026
S1245
SERVICES SUB #5
NEW SHIPYARDS SUB
10 MVA
7.5 MVA
S9530
6L13
S7174
5L622
S7332
S7333
6L11
S7299
S7315
MLS-T1
MLS-89-2
METER
MARSH LAKE DAM
TO JOHNSON'S CROSSING
SEE DWG: JOHNSONXINGSWMAP.DGN
ARKELL SUB
#29
S8498
6L12
S9411
S9412
N/O
S9486
S7214
SUB#2
LEWES
SUB #3
RIVERDALE
MACRAE SUB #1
S9823
LOGAN SUB
35
S9509
N/O
CARCROSS
YEC MOBILE GEN.
CONNECTION POINT
TO YEC MAIN
OFFICE
LOAD - OFFICE BUILDING
400A MAIN DISCONNECT
S150-89-MTS
S150-89-22B
S150 52-22
S150-89-21B
S150 52-21
S150 89-PT14Y2
S150 89-PT14Y1
S150 89-PT14X2
S150 89-PT14X1
PT14
SST5

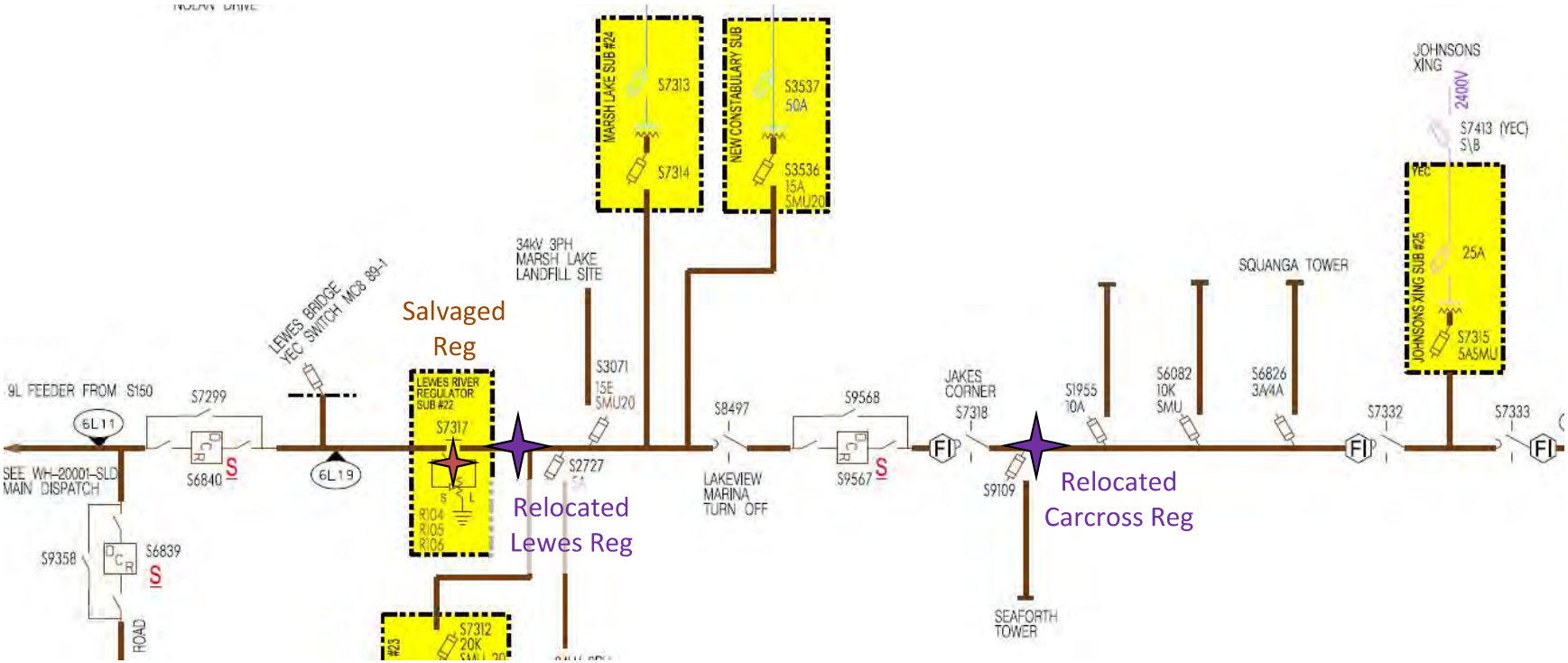

MARSH LAKE SUB #24
S7313
S7314
NEW CONSTABULARY SUB
S3537
50A
S3536
15A
SMU20
JOHNSONS XING
2400V
S7413 (YEC)
S1B
YEC
25A
S7315
5ASMU
JOHNSONS XING SUB #25
34kV 3PH
MARSH LAKE
LANDFILL SITE
S3071
15E
SMU20
LEWES BRIDGE
YEC SWITCH MC8 89-1
Salvaged
Reg
LEWES RIVER
REGULATOR
SUB #22
S7317
R104
R105
R106
9L FEEDER FROM S150
6L11
S7299
SEE WH-20001-SLD
MAIN DISPATCH
S6840
6L19
S2727
Relocated
Lewes Reg
S8497
LAKEVIEW
MARINA
TURN OFF
S9568
S9567
JAKES
CORNER
S7318
S9109
Relocated
Carcross Reg
SEAFORTH
TOWER
S1955
10A
S6082
10K
SMU
SQUANGA TOWER
S6826
3A4A
S7332
S7333
S9358
S6839
ROAD
S7312
20K

Table 11 - Alternative 5 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	0.987	0.989	0.987
5L649 EOL	1.030	1.029	1.029
5L631 EOL	-	-	0.958
South McLintock Sub (35kV)	1.038	1.039	1.035
5L611 EOL	-	-	1.024
Marsh Lake Sub (35kV)	1.018	1.022	1.021
5L612 EOL	0.994	-	-
New Constabulary Sub (35kV)	1.012	1.015	1.017
5L615 EOL	0.968	-	-
Johnson Crossing Sub (35kV)	1.020	1.013	1.019
Teslin Lake Sub (35kV)	0.994	0.974	0.993
4L301 EOL	-	0.975	-
Teslin Sub (35kV)	0.988	0.967	0.987
5L613 EOL	1.033	-	-
5L614 EOL	-	1.030	-
Worst Customer Voltage on 6L19	0.991	0.970	0.989

Table 12 - Alternative 5 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	0.975	0.976	0.974
5L649 EOL	1.030	1.030	1.028
5L631 EOL	-	-	0.944
South McLintock Sub (35kV)	1.036	1.034	1.035
5L611 EOL	-	-	1.019
Marsh Lake Sub (35kV)	1.013	1.022	1.017
5L612 EOL	0.993	-	-
New Constabulary Sub (35kV)	1.005	1.005	1.012
5L615 EOL	0.952	-	-
Johnson Crossing Sub (35kV)	1.020	1.011	1.016
Teslin Lake Sub (35kV)	0.988	0.964	0.984
4L301 EOL	-	0.963	-
Teslin Sub (35kV)	0.981	0.955	0.977
5L613 EOL	1.032	-	-
5L614 EOL	-	1.031	-
Worst Customer Voltage on 6L19	0.984	0.959	0.980

Alternative 6 - Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19

This alternative is the exact same as Alternative 1; however, the regulators will be installed at the locations specified by the THELP project.

The two load shed events that have the risk for the highest voltage are the loss of Teslin sub and the opening of the Judas Creek recloser. During the loss of Teslin sub, the maximum voltage at the new 6L19 regulator is 1.121pu. This is below the long line rural maximum voltage of 1.167pu. During the opening of the Judas Creek recloser, the worst-case voltage will occur on 5L613 in Teslin with a voltage of 1.091pu. This is also within the acceptable range for over voltage.

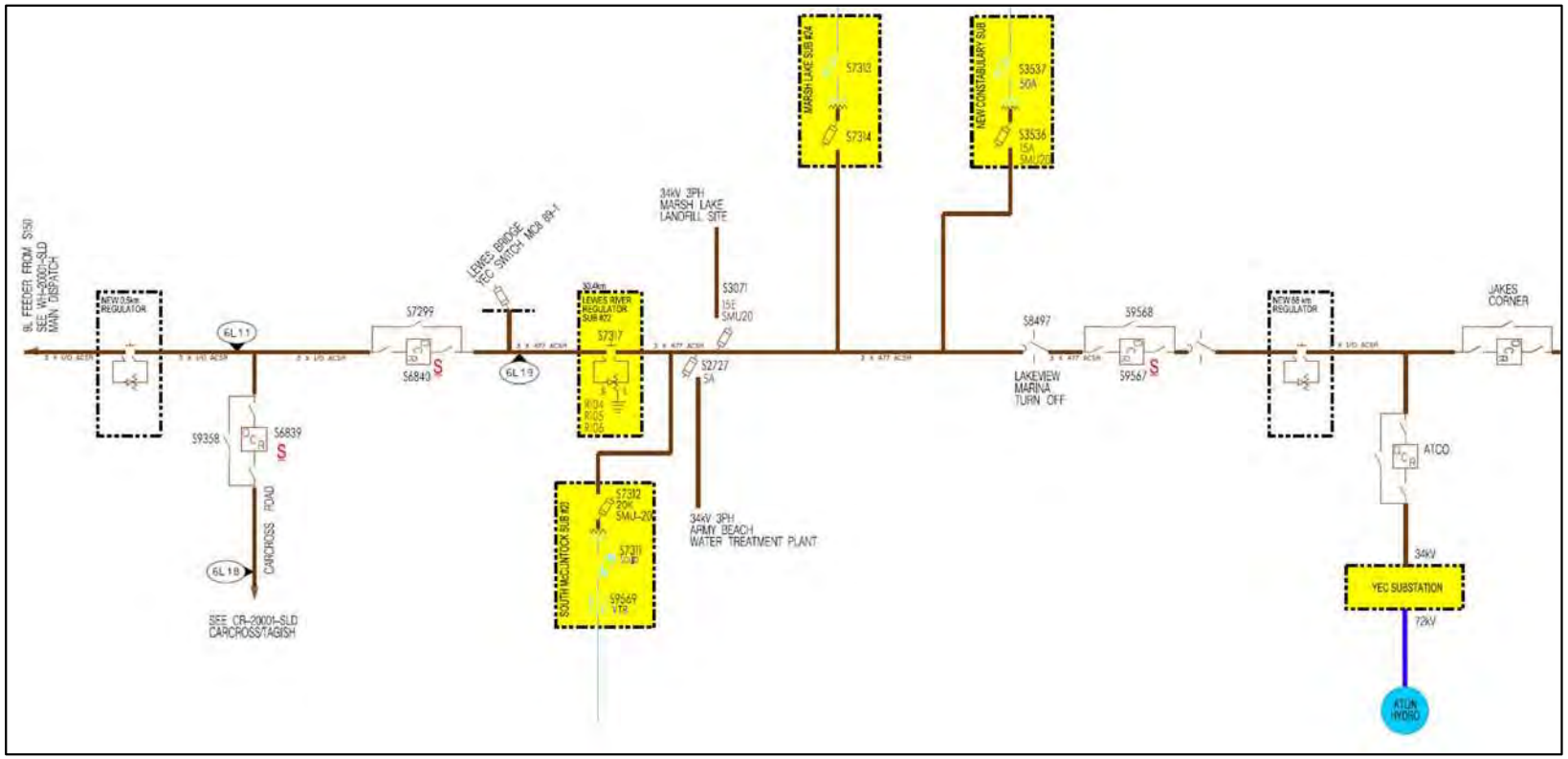


Figure 12 - THELP Regulator Placement SLD

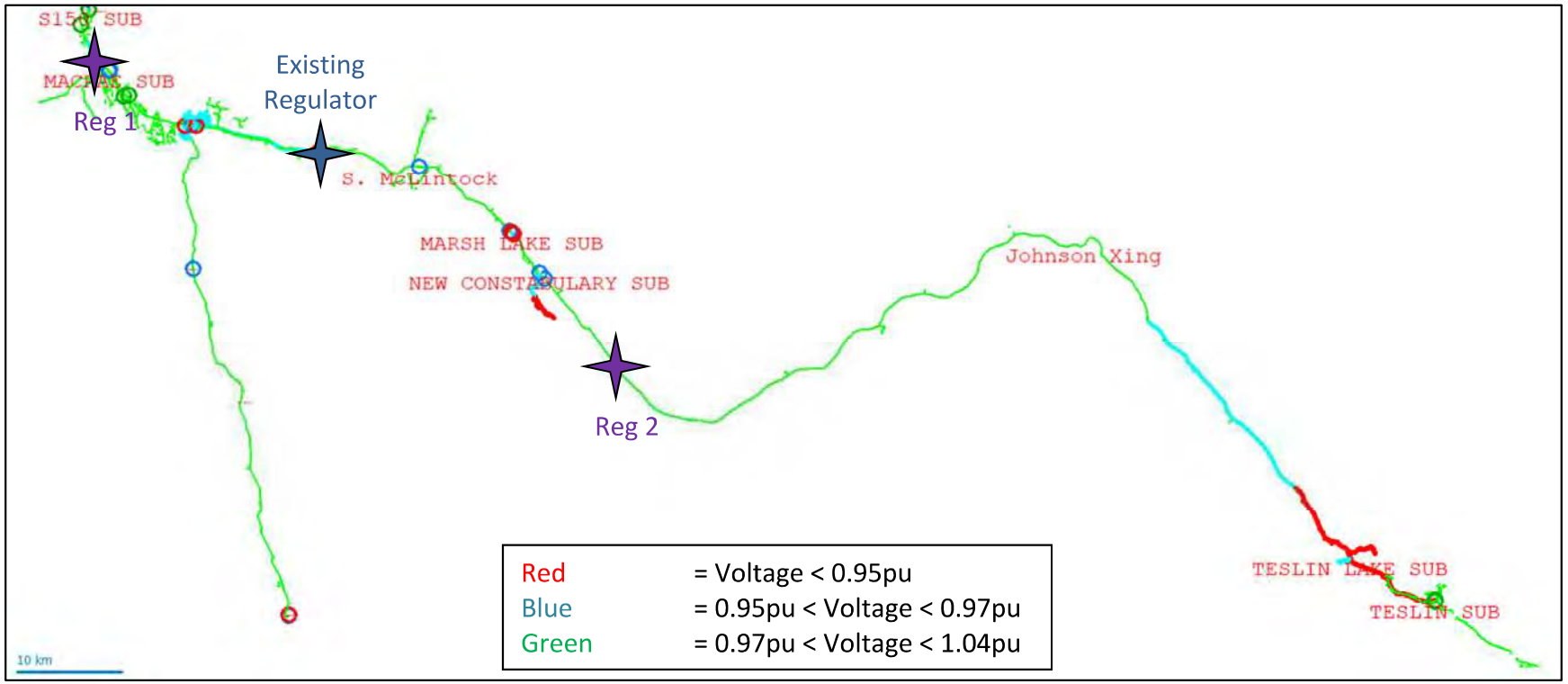


Figure 13 - Alternative 6 Voltage Conditions

Table 13 - Alternative 6 Voltage Summary

Location	Va	Vb	Vc
McRae Sub (35kV)	1.023	1.025	1.028
5L649 EOL	1.033	1.030	1.033
5L631 EOL	-	-	0.963
South McLintock Sub (35kV)	1.017	1.014	1.015
5L611 EOL	-	-	1.001
Marsh Lake Sub (35kV)	0.997	0.997	1.000
5L612 EOL	0.990	-	-
New Constabulary Sub (35kV)	0.991	0.990	0.996
5L615 EOL	0.946	-	-
Johnson Crossing Sub (35kV)	1.005	0.982	1.004
Teslin Lake Sub (35kV)	0.979	0.942	0.977
4L301 EOL	-	0.951	-
Teslin Sub (35kV)	0.973	0.935	0.971
5L613 EOL	1.028	-	-
5L614 EOL	-	1.016	-
Worst Customer Voltage on 6L19	0.975	0.944	0.973

Table 14 - Alternative 6 Voltage Summary 2028

Location	Va	Vb	Vc
McRae Sub (35kV)	1.022	1.023	1.021
5L649 EOL	1.031	1.025	1.029
5L631 EOL	-	-	0.946
South McLintock Sub (35kV)	1.004	1.010	1.006
5L611 EOL	-	-	0.992
Marsh Lake Sub (35kV)	0.979	0.988	0.988
5L612 EOL	0.994	-	-
New Constabulary Sub (35kV)	0.972	0.980	0.982
5L615 EOL	0.919	-	-
Johnson Crossing Sub (35kV)	0.992	0.975	0.997
Teslin Lake Sub (35kV)	0.960	0.926	0.964
4L301 EOL	-	0.935	-
Teslin Sub (35kV)	0.952	0.917	0.957
5L613 EOL	1.028	-	-
5L614 EOL	-	1.017	-
Worst Customer Voltage on 6L19	0.955	0.921	0.960

Conclusions

Reconductoring costs for Alternatives 2, 3, and 4 are all substantially greater in cost than to install regulators or boost S150 output voltage; therefore, the previously listed alternatives weren't as heavily considered as the remaining alternatives.

Alternative 5 is the recommended alternative as it immediately solves the 35kV low voltage issues for the entire 6L11 and 6L19 line without any need for reconductoring and can benefit from cost savings through relocating two 100A regulators versus buying new ones. This alternative also performs the best in the year 2028 and is the only alternative that addresses the low voltage conditions on the 25kV New Constabulary distribution system.

- New 200A regulator on 6L11 upstream of Macrae (between Fireweed Dr and Salmon Tr)
- Relocate 100A Lewes River regulator bank approximately 11km downstream, just before South McLintock substation
- Relocate 6L18 Carcross Cutoff 100A regulator bank to the Summit Lake area (approx. 5km West of Squanga Lake Campground)

Appendix (Overview of Voltage Conditions per Alternative)

Existing			
Location	**Va**	**Vb**	**Vc**
McRae Sub (35kV)	0.945	0.946	0.944
5L649 EOL	1.019	1.019	1.018
5L631 EOL	-	-	0.949
South McLintock Sub (35kV)	0.932	0.946	0.934
5L611 EOL	-	-	0.926
Marsh Lake Sub (35kV)	0.909	0.927	0.917
5L612 EOL	0.958	-	-
New Constabulary Sub (35kV)	0.902	0.919	0.912
5L615 EOL	0.855	-	-
Johnson Crossing Sub (35kV)	0.851	0.843	0.861
Teslin Lake Sub (35kV)	0.819	0.796	0.828
4L301 EOL	-	0.802	-
Teslin Sub (35kV)	0.812	0.787	0.821
5L613 EOL	0.879	-	-
5L614 EOL	-	0.868	-
Worst Voltage on 6L19	0.815	0.791	0.824

Alternative 1			Alternative 2			Alternative 3			Alternative 4			Alternative 5			Alternative 6		
Va	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**
1.025	1.027	1.025	0.984	0.985	0.984	0.977	0.978	0.977	1.018	1.019	1.019	0.987	0.989	0.987	1.023	1.025	1.028
1.033	1.027	1.032	1.033	1.032	1.032	1.031	1.030	1.029	1.032	1.031	1.031	1.030	1.029	1.029	1.033	1.030	1.033
-	-	0.964	-	-	0.964	-	-	0.959	-	-	0.961	-	-	0.958	-	-	0.963
1.017	1.013	1.020	1.016	1.016	1.015	0.999	1.011	1.024	1.018	1.016	1.015	1.038	1.039	1.035	1.017	1.014	1.015
-	-	1.003	-	-	1.001	-	-	0.993	-	-	1.002	-	-	1.024	-	-	1.001
0.998	0.996	1.007	0.994	1.000	1.001	0.979	0.994	0.988	0.998	0.999	1.001	1.018	1.022	1.021	0.997	0.997	1.000
0.995	-	-	0.993	-	-	0.992	-	-	0.992	-	-	0.994	-	-	0.990	-	-
0.995	0.990	1.003	0.989	0.993	0.997	0.973	0.987	0.983	0.992	0.992	0.997	1.012	1.015	1.017	0.991	0.990	0.996
0.952	-	-	0.949	-	-	0.931	-	-	0.948	-	-	0.968	-	-	0.946	-	-
1.019	1.006	1.018	0.979	0.972	0.986	1.020	1.007	1.019	1.017	1.007	1.016	1.020	1.013	1.019	1.005	0.982	1.004
0.994	0.969	0.993	0.970	0.957	0.978	0.994	0.968	0.993	0.991	0.968	0.990	0.994	0.974	0.993	0.979	0.942	0.977
-	0.972	-	-	0.958	-	-	0.972	-	-	0.969	-	-	0.975	-	-	0.951	-
0.988	0.962	0.987	0.968	0.954	0.975	0.988	0.961	0.987	0.985	0.960	0.984	0.988	0.967	0.987	0.973	0.935	0.971
1.027	-	-	1.027	-	-	1.033	-	-	1.030	-	-	1.033	-	-	1.028	-	-
-	1.021	-	-	1.025	-	-	1.026	-	-	1.024	-	-	1.030	-	-	1.016	-
0.958	0.973	0.960	0.968	0.954	0.975	0.927	0.939	0.929	0.988	0.963	0.986	0.991	0.970	0.989	0.975	0.944	0.973

ATCO Electric YUKON

September 28, 2023 AEY-UCG-093

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-093

Reference: Whistle Bend Subdivision, BC#31; Costs ? million

Request:

(a) Are all the costs for the distribution system paid for by YG?

(b) Provide engineering qualifications streetlight work and the economic analyses identifying the business drivers and cost/benefits, including the preliminary engineering estimate of costs. Provide engineers report.

Response:

(a) All costs less the Board approved street light investment were paid for by YG.

(b) Please refer to the response to AEY-UCG-066(a). There was no engineering report done to identify needs and drivers for the project. The developer identified the need and area of development for streetlighting and electrical infrastructure.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-094

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-094

Reference: Fish Lake 1 Roof Replacement, BC#32; Cost $511,000

Request:

(a) Provide all the $amounts with work completed that AEY spent on Fish Lake improvements/infrastructure in last 10 years or since the start of replacements.

(b) Provide a cost/benefit analysis demonstrating this was viable. Give alternatives.

Response:

(a) Please refer to the response to AEY-UCG-101(a).

(b) Cost benefit was not a driver. Numerous repair attempts were made without success, leaving no alternatives to the replacement.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-095

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-095

Reference: Louise Lake Auxiliary Structure Replacement, BC #33; Cost $826,000

Request:

(a) Provide all the $amounts with work completed that AEY spent on Fish Lake hydro system improvements/infrastructure in last 10 years or since the start of replacements.

(b) Provide a cost/benefit analysis demonstrating this was viable. Give alternatives.

Response:

(a) Please refer to the response to AEY-UCG-101(a).

(b) Cost-benefit was not a driver. The structure is required to manage flood events. It was recommended to be replaced in 2015 by Northland Earth and Water and in 2019 by Morrison Hershfield. No alternatives are available.

September 28, 2023 AEY-UCG-096

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-096

Reference: YG Robert Campbell Highway Streetlights, BC #34; Cost $67,000

Request:

(a) Is the above the amount AEY is proposing to recoup from ratepayers?

(b) What are these costs for?

Response:

(a) Correct. In accordance with Section 1(c) in Schedule B to AEY's Terms and Conditions of Service (T&Cs),[1] the maximum company investment is $1,240 per light.

(b) This is the approved portion of the cost of installing new municipal lighting for which AEY is responsible under the T&Cs.

[1] https://www.atcoelectricyukon.com/content/dam/web/electric-yukon/yecl-yec-terms-of-service-july-2011.pdf, p. 33.

September 28, 2023 AEY-UCG-097

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-097

Reference: Artic -Pharm IPP Site, BC #35; Cost $543,000

Request:

(a) Why is this infrastructure requirement not paid for by the IPP or YG and not the ratepayer?

Response:

(a) Please refer to paragraph 3 in Business Base #35, which states that the project is fully contributed by the customer.

September 28, 2023 AEY-UCG-098

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-098

Reference: Haeckel Hill Customer Connection, BC #36; Cost $1.454million

Request:

(a) Why is this infrastructure requirement not paid for by the IPP or YG and not the ratepayer?

Response:

(a) Please refer to paragraph 3 in Business Case #36, which states that the project is fully contributed by the customer.

September 28, 2023 AEY-UCG-099

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-099

Reference: Artic -Pharm IPP Site, BC #37; Cost $4.204million

AEY states:

> 3. This is a fully contributed customer-driven interconnection project/

Request:

(a) Is all this infrastructure paid for by the IPP without any costs to the ratepayer?

Response:

(a) Please refer to paragraph 3 in Business Case #37, which states that the project is fully contributed by the customer.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-100

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-100

Reference: Beaver Creek Photovoltaic Project, BC38; Cost $8.017million

AEY states:

> 3. This is a fully contributed customer-driven interconnection project/

Request:

(a) Is all this infrastructure paid for by the IPP without any costs to the ratepayer?

Response:

(a) Confirmed.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-101

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-101

Reference: Fish Lake 2 Power Station Design, BC#39; Cost $912,000

Request:

(a) Provide all the $amounts with work completed that AEY spent on Fish Lake improvements/infrastructure in last 10 years or since the start of replacements.
(b) Provide a cost/benefit analysis demonstrating this was/is viable. Give alternatives.

Response:

(a) Refer to AEY-UCG-101(a) Attachment 1, and the summary below of expenses attributed to Generation or Waterway category assets at Fish Lake. AEY notes that projects and costs in 2013-2017 were reviewed and approved by the Board in Board Orders 2014-06 and 2017-01. In the below breakdown, Waterway is defined as infrastructure hypothetically required for water management, irrespective of the existence of Generation equipment.

Table 1: Generation or Waterway Category Assets - Fish Lake ($000)

Category	2013-2017	2018-2022	2023-2024	Total
	Actuals		Test Period	
Waterway	6,419	1,474	1,351	9,394
Generation	2,238	231	1,752	4,221

(b) It is important to understand that water control structures, spillways, ditches, dams and associated infrastructure used to direct, control and monitor water are, and will continue to be in perpetuity, required to safely convey water throughout the Fish Lake drainage system, regardless of whether electricity is made through

hydro-generating plants. This is a hydro system with an accompanying Type A Water Licence (HY12-065 expires 2038) that directs “all works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices”. Fish Lake 1 plant failed in 2010, at its end of life (i.e., 50+ years) and Fish Lake 2 plant is nearing 70-years of age. These generating facilities, and the associated waterway infrastructure, are legacy assets that require capital investment due to the deterioration of condition, modernization and change in technical and occupational standards, and evolving risk management practices reflected in regulation (e.g., Canadian Dam Safety Guidelines).

A large proportion of the capital work completed in 2018-2022, and proposed for the Test Years, is directly attributable to compliance with Yukon Water Board (YWB) directives or licence conditions. Costs attributed to the Generation category are related to maintenance of the hydro-generator facilities and equipment to produce electricity. The proposed Test Period expenditures of $912,000 to proceed with design and estimating for a replacement FL2 power station progresses the lowest risk alternative identified in the business case (Table 2 of Business Case #39). This will result in increased reliability, greater capacity, and extension of its lifespan. Fish Lake is a permitted and operational renewable source of power and AEY sees the value in continued production due to YIS capacity constraints and Yukon government emissions objectives, with due consideration of YWB obligations.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Generation and Waterway Expenditures for Fish Lake
($000)

Line No.	GRA	S9.2 Line No.	Project Name	Category (Waterway / Generation)	2013 Actual	2013 Approved	2014 Actual	2014 Approved	2015 Actual	2015 Approved	2016 Actual	2016 Approved	2017 Actual	2017 Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Test	2024 Test
1	2016-17	2	Fish Lake Unit 1 Turbine and Building Replacement	Generation	1,409	1,798	426		15												
2	2016-17	3	Fish Lake Dyke Upgrade	Waterway	326	300	2,226	1,420													
3	2016-17	4	Fish Lake Unit 2 Siding Replacement	Generation	51	35															
4	2016-17	5	Louise Lake Control Structure	Waterway	49	-															
5	2016-17	6	Fish Lake Unit 1 Fiber Communication	Generation	45	20															
6	2016-17	7	Fish Lake Unit 2 SCADA	Generation	44	50															
7	2016-17	8	Fish Lake Unit 2 Penstock Improvements	Generation	43	40															
8	2016-17	9	Fish Lake Unit 1 Spillway Diversion Structure	Waterway	22	20		100					30	413	0	220	527	-5			
9	2016-17	10	Fish Lake Unit 2 Building Improvements	Generation	20	20															
10	2016-17	11	Fish Lake Unit 2 Vibration Monitoring	Generation	19	20															
11	2016-17	12	Fish Lake Ditch 3 Diversion Replacement	Waterway	16	-	51	1,640	67			2,915									
12	2016-17	13	Fish Lake Unit 2 Head Pond Low Level Outlet Pipe	Waterway				30													
13	2016-17	14	Fish Lake Unit 1 Needle Detach Failure	Generation					21												
14	2016-17	15	Fish Lake Unit 2 Assessment	Generation							98	100	11		-112					35	
15	2016-17	16	Fish Lake Water Monitoring Upgrades	Waterway								25		26							
16	2016-17	17	Fish Lake #2 Head Pond Spillway Replacement	Waterway	30	30					286	20	166	593	540	-17					
17	2016-17	18	Louise Lake Containment Dyke Seismic Analysis	Waterway								40									
18	2016-17	19	Fish Lake Ditch 1 Intake Building - Design	Waterway							2	-	1	31	115	-26	11				
19	2023-24	2	Fish Lake Unit 2 - Replace Power Station - Detailed Design	Generation																	527
20	2023-24	3	Fish Lake 1 Roof Replacement	Generation																452	
21	2023-24	4	Fish Lake 2 Replace Power Station FEED	Generation																385	
22	2023-24	5	Fish Lake 2 Head pond Intake Building Replacement	Waterway																153	
23	2023-24	7	Fish Lake Ditch 1 Failure	Waterway							412		-150								
24	2023-24	11	Fish Lake Unit 2 Condition Assessment and Options Analysis	Generation															66		
25	2023-24	12	Fish Lake 2 TIV actuator and wicket gates	Generation																37	
26	2023-24	13	Fish Lake Unit 1 Roof Design	Generation														43	16		
27	2023-24	14	Fish Lake Unit 2 Bearing and Shaft Repair	Generation												48	6				
28	2023-24	15	Fish Lake Unit 2 TIV Replace	Generation											48	-1					
29	2023-24	16	Fish Lake 1 Add TIV Actuator	Generation																	53
30	2023-24	17	Fish Lake 1 TIV replacement	Generation															24	89	
31	2023-24	18	Fish Lake 2 Add bypass valve actuator and automation	Generation																35	
32	2023-24	19	Fish Lake 2 PLC Replacement	Generation																	39
33	2023-24	20	Fish Lake Unit 2 DC TIV Actuator & Wicket Gate Replacem	Generation															138		
34	2023-24	21	Fish Lake Water Monitoring Upgrades	Waterway							10	25	106	25	1	24	0	0		26	81
35	2023-24	22	Fish Lake Unit 1 Turbine and Building Replacement	Generation							20		16		16	3	4	3	-71		
36	2023-24	23	Fish Lake Ditch 3 Diversion Replacement	Waterway							2,601	2,908	168		30	0		29	-27		
37	2023-24	24	Louise Lake Containment Dyke Seismic Analysis	Waterway								40									
38	2023-25	110	Louise Lake Auxiliary Structure Replacement	Waterway												11	31	8	2	1	773
39	2023-26	123	Add transfer trip scheme	Generation																100	
40	2023-24	124	Fish Creek Diversion	Waterway																	317

Category	2013 Actual	2013 Approved	2014 Actual	2014 Approved	2015 Actual	2015 Approved	2016 Actual	2016 Approved	2017 Actual	2017 Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Test	2024 Test
Waterway	443	350	2277	3190	67	0	3311	5973	321	1088	686	212	569	32	-25	180	1171
Generation	1631	1983	426	0	36	0	118	100	27	0	-48	50	10	46	173	1133	619

Category	2013-2017 Actual	2018-2022 Actual	2023-2024 Test	Total
Waterway	6419	1474	1351	9244
Generation	2238	231	1752	4221

ATCO Electric
YUKON

September 28, 2023 AEY-UCG-102

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-102

Reference: Condition Assessment and Options Program for Beaver Ck. Destruction Bay and Stewart Crossing Generating Plants, BC #40; Cost $627,000

Request:

(a) Why wasn't a qualified engineer first tendered to evaluate each site instead of spending over half a million dollars mostly on ATCO Electric, a related company, to evaluate the same thing?

Response:

(a) ATCO Electric conducted condition assessments for multiple AEY sites in 2012. These condition reports used the corporate asset health framework that was in use at the time. AEY has not fully implemented ATCO's asset management systems or programs for continued condition or health monitoring, so these reports were a snapshot in time that aided in short-term decisions and job definitions.

AEY is recommending using third-party consultants to provide comprehensive expert evaluation of three generating sites, known to be in poor operational condition and nearing end of life, due to a lack of internal asset management systems and technical resources. AEY would like to do so in coordination with AEY's development of asset health indicators and lifecycle decision guidelines, so long range plans and recapitalization decisions can be integrated, data-driven, and systematic going forward. The third-party consultants will also identify options for continued reliable utility service at each location, such as rebuilds or alternatives, based upon performance and reliability values and objectives that AEY identifies

in its strategic asset management plans. AEY expects this work will define large capital investments in future years.

ATCO Electric YUKON

September 28, 2023 AEY-UCG-103

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023

AEY-UCG-103

Reference: Old Crow Plant Design, BC #41.

Request:

(a) Why would AEY tender all the design and preliminary work at a cost of $444,000 before you received an okay from the YUB that this plan was acceptable and viable?

(b) Why did not AEY conduct a multidisciplinary review before and not after the new construction of a facility in 2014?

(c) Why would AEY not build for a capacity expansion, i.e., larger units, when you constructed a new facility in 2015?

(d) Has there ever been flooding in the current facilities?

(e) How much is AEY requesting to go to rate base on this project in 2023? Explain.

(f) How much is AEY requesting to go to rate base on this project in 2024? Explain.

(g) Is AEY requesting the YUB to accept the estimated construction costs of $10.55 million in this GRA?

(h) Was the Old Crow #3 generator replaced during the last GRA? If yes, what capacity and what cost?

Response:

(a) The design and preliminary work is required to be performed ahead of time in order to determine a proper scope of work and to estimate the cost of replacement.

(b) Due to the limitations of transporting a temporary mobile generator into Old Crow in an emergency, the new plant built in Old Crow was designed to be a stand alone structure to provide redundancy for the community that placing all the generation

in one structure could not provide. Once the new plant was operational, AEY could then evaluate the old plant to decide what the best course of action was for it, renovate or replace.

(c) The design maximum for the new facility was two units rated at ~700 kW. At the time of design based on current and forecasted load growth, this was determined to be sufficient capacity at that time.

(d) The existing power plant was impacted during the flood of 1991 where water levels were at plant floor levels.

(e) AEY is requesting $0 to go into rate base in 2023.

(f) AEY is requesting $0 to go into rate base in 2024.

(g) No. As indicated on page 9-9 of the Application, AEY filed the Business Case with the Application in an effort to be transparent and to notify the Board and other stakeholders regarding larger upcoming capital expenditures. While AEY is seeking Board approval of the uncapitalized costs for this Project forecast during the Test Period, AEY will seek approval of capital costs forecast to be incurred subsequent to the Test Period in a future GRA.

(h) Yes, this unit was replaced. The new unit is rated at 680 kW and purchased and installed at a cost of $1,306,136.

ATCO Electric YUKON

September 28, 2023 AEY-NY-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-001

Topic: Billing and Riders:

Preamble: In the 2023 AEY and YEC Rate Rebasing proceeding, the Utilities proposed rolling Rider R into base rates on billing statements. Now that Rider R will be changing,

Requests:

(a) Is rolling Rider R into base rates still the intention?

(b) When is this change expected to happen?

(c) Will further and future changes to Rider R be reflected in changes in base rates on billing statements, or broken out separately?

Response:

(a) Yes. As proposed and approved in the "AEY and YEC Rate Rebasing" proceeding and subsequent Board Order 2023-08, Riders R and J are considered "Base rate adjustment riders" and will be incorporated into base rates on the billing statement.

(b) As proposed and approved in the "AEY and YEC Rate Rebasing" proceeding, the bill adjustment would be implemented following a three-to-six-month stabilization period after the new billing system is in place. Accordingly, the change is expected to occur in Q1 of 2024.

(c) AEY expects that future changes to Rider R will be rolled into base rates on the billing statements.

ATCO Electric YUKON

September 28, 2023 AEY-NY-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-002

Topic: Billing and Riders

Requests:

Concerning Rider R, as this is an AEY issue and an AEY GRA, why are customers who deal exclusively with YEC subject to this and other AEY riders? As a YEC customer, why am I paying AEY rate increases? (Riders R and S)

Response:

Please refer to the response to AEY-UCG-003(c).

ATCO Electric YUKON

September 28, 2023 AEY-NY-003

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-003

Topic: Billing and Riders

Preamble: In the 2023 Rebasing proceeding, the Utilities claimed that removing Riders R & J from the billing statement would improve readability, reduce customer confusion, etc.

Requests:

(a) Given that AEY is now adding riders (Rider S), does AEY expect increased customer confusion, increased billing statement complexity and reduced readability?

(b) What steps will AEY be taking to mitigate this?

Response:

(a-b) As proposed and approved in the "AEY and YEC Rate Rebasing" proceeding and subsequent Board Order 2023-08, Rider S is considered a "Stabilizing mechanism", as it is temporary in nature and infrequent. As such, this rider will not be incorporated into base rates on the billing statement. In Appendix A to Board Order 2023-08, the Board stated that the proposed option of rolling only Riders R and J into the base rates on the statement "is a step toward reducing confusion of customers' bills and increasing customers' understanding of their bills".

ATCO Electric YUKON

September 28, 2023 AEY-NY-004

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-004

Topic: Billing and Riders

Reference: Please provide a mock up or sample billing statement that includes a summary with the actual cost per kwh and fixed monthly charge inclusive of all of the riders. An example is provided below, which I hope can be improved on by AEY.

My idea is to show the effect of the individual Riders as currently shown on billing statements (the status quo), and a more understandable summary in parallel. In my example I have simply added the summary to the left of the current billing statement. The best of both worlds?

My first take:

Adding this readable summary to the left of…. the current billing statement here:

Current Charges Inclusive of Riders	
Monthly Customer Charge Including Riders	21.37
Energy Charge Including Riders	42.36
(248 kwh @ .1708 per kwh)	
(0 kwh @ .1825 per kwh)	
(0 kwh @ .1992 per kwh)	
Sub-Total	63.73
GST	3.19
Current Billing	66.92
Amount Due	66.92

CURRENT CHARGES DETAILS	
CUSTOMER CHARGE	14.65
ENERGY CHARGE	30.10
AEY TEMPORARY RATE ADJUSTMENT	0.12CR
FUEL ADJUSTMENT RIDER	4.06
YEC TEMPORARY RATE TRUE UP	1.35
YECL RATE ADJUSTMENT RIDER	3.71
YUKON ENERGY REVENUE SHORTFALL RIDER	15.59
YUKON INTERIM ELECTRICAL REBATE	5.61CR
SUB-TOTAL	63.73
GST	3.19
CURRENT BILLING	66.92
AMOUNT DUE	66.92

Request:

For this IR, we can assume that AEY has been directed to provide this information to customers. Is this the best way to do it? If not, please show what you would change and what would improve or replace the above example.

Response:

As proposed and approved in the "AEY and YEC Rate Rebasing" proceeding and Board Order 2023-08,[1] a sample summary was provided in Section 3.4, Table 2 of the AEY/YEC submission, as shown below.

Table 2: The Rates and Riders for the Residential Customer Class under Option 4

	Residential	Option 1 - Status Quo	Option 4	Units
Base Rates				
A	Customer Charge	14.65	20.86	$/month
B	Energy Block 1 (kWh)	12.14	17.28	cents/kWh
C	Energy Block 2 (kWh)	12.82	18.25	cents/kWh
D	Energy Block 3 (kWh)	13.99	19.92	cents/kWh
Base Rate Adjustment Riders				
Applies to A-D	YEC Rider J	34.08%	N/A	% of Base Bill
Applies to A-D	AEY Rider R	8.30%	N/A	% of Base Bill
Stabilization mechanisms				
Applies to energy	YEC & AEY Rider F	1.6350	1.6350	cents/kWh
Applies to energy	AEY Purchase Power Adjustment Rider (Rider S)	0.0000	0.0000	cents/kWh
Applies to energy	YEC LWRF Rider (Rider E)	0.0000	0.0000	cents/kWh
Temporary Riders				
Applies to A-D	YEC Rider J1 - true-up	1.85%	1.85%	% of Base Bill
Applies to A-D	AEY Rate Relief Rider R1	-4.57%	-4.57%	% of Base Bill

In the Proceeding, the idea of a summarized charge per kWh was thoroughly discussed, evaluated and, ultimately, was not accepted by the Board. As approved in Board Order 2023-08, the more stable riders, Rider J and R, will be rolled into base rates on the statement, while other, more variable riders will continue to be displayed separately on the statement for greater transparency.

[1] Board Order 2023-08.

ATCO Electric YUKON

September 28, 2023 AEY-NY-005

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-005

Topic: Billing and Riders

Request:

What are the advantages to the customer of being informed what they are actually paying for electricity – that is being told how much they are being charged per kwh and how much is a fixed monthly charge? Would this help customers make decisions about energy usage?

Response:

In the "AEY and YEC Rate Rebasing" proceeding, the idea of a summarized charge per kWh was thoroughly discussed, evaluated and, ultimately, was not accepted by the Board in Board Order 2023-08. As stated during the proceeding, given the complexity of variable and fixed components of utility rates, providing a total cost per kWh does not help customers make decisions about energy usage since this information misleads customers that all utility costs vary linearly with kWh. Furthermore, the total cost per kWh will vary between different customers, which could lead to greater confusion and an increase in customer service concerns.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-006

Topic: Billing and Riders

Request:

Would it be useful for TOU billing and/or DSM for customers to know and understand how much they are paying per kwh?

Response:

Please refer to the response to AEY-NY-005.

ATCO Electric YUKON

September 28, 2023 AEY-NY-007

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-007

Topic: Billing and Riders

Request:

From a customer perspective, what are the advantages of NOT knowing the cost of electricity per kwh? (the status quo) How does it help the customer NOT to have this information on billing statements?

Response:

Please refer to the response to AEY-NY-005.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-008

Topic: Billing and Riders

Request:

Does obscuring the fixed charge and cost per kwh from the customer serve the interest of general energy literacy?

Response:

Please refer to the response to AEY-NY-005.

ATCO Electric YUKON

September 28, 2023 AEY-NY-009

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-009

Topic: Billing and Riders

Request:

What ideas does AEY have concerning making the Riders more understandable on billing statements? Please provide alternate or enhanced descriptions for all riders on the billing statement.

For example:

"FUEL ADJUSTMENT RIDER"	could become	"FUEL ADJUSTMENT RIDER (1.635 cents/kWh)"
and "YEC TEMPORARY RATE TRUE UP"	becomes	"YEC TEMPORARY RATE TRUE UP 1.85% of Base Bill"

Does AEY have better ideas for these? Please suggest improved text for each of the Riders shown on billing statements. This IR does not ask feasibility, but seeks new ideas to improve the customer experience. Some inspiration could be taken from the AEY online "Bill Calculator" in terms of showing the numbers.

Response:

AEY respectfully submits that changes to billing information and presentation have been fully addressed by the YUB in Board Order 2023-08 and that further discussion on such changes is beyond the scope of this Proceeding. AEY notes that it periodically reviews how bill statements are displayed and will consider making changes, as required and in collaboration with YEC, following a stabilization period of the new billing system.

September 28, 2023 AEY-NY-010

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-010

Topic: Billing and Riders

Request:

While a readable billing statement is preferred, the AEY online Bill Calculator is useful and does help in understanding how the Riders work. What are AEY's thoughts on including a summary that shows the actual monthly customer charge and actual energy charge inclusive of the Riders on the Bill Calculator? Additionally, the names of the riders on the Bill Calculator could link to the actual riders? Any further thoughts on how this could be improved while we wait for billing/statement improvements?

Response:

AEY respectfully submits that changes to AEY's online Bill Calculator are beyond the scope of this Proceeding and, pursuant to Rule 14(4)(a) of the YUB Rules of Practice, declines to provide the requested information. AEY notes that it periodically reviews the online Bill Calculator and will consider any required changes and improvements at the next reasonable opportunity.

September 28, 2023 AEY-NY-011

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-011

Topic: Billing and Riders

Request:

Estimated meter readings and billing statements: In the course of looking at billing and rates I noticed that varying energy rates combined with estimated meter readings can lead to unintended effects on customer charges. As an example, if the customer has used more power than is in on estimated bill, the eventual charges for this energy will reflect the rate in effect at the time the meter is read rather than when the energy was actually used. This is a problem that occurs with the combination of varying rates and estimated meter readings. How does AEY propose to fix this issue?

Response:

In most circumstances, AEY strives to manually read meters on a monthly basis. When AEY cannot manually read a meter, AEY uses estimated meter reads, in accordance with its approved Terms and Conditions of Service (T&Cs). Estimates are based on a site's specific annual usage data, pro-rated by the number of days in the billing period. Estimates are an accepted utility practice to help prevent large swings in customer bills, if a manual read cannot be undertaken in a specific month. If a customer has concerns about their estimated meter reads, they may contact AEY's customer service team. AEY's staff are committed to working quickly with customers to address any issues to the customer's satisfaction. AEY also provides customers with the opportunity to submit their meter reading via our website.

ATCO Electric YUKON

September 28, 2023 AEY-NY-012

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-012

Topic: IPP, Micro-Generation, DSM

Request:

Are IPP and MG program incentives similar for power produced in summer and in winter?

Response:

AEY's interpretation of incentive is that there is a preferred price per kWh or increased company contribution for the program. There are no incentives provided by AEY for the MG program because this is a Government of Yukon supported program. The IPPs in our AEY's isolated generation communities do not receive any incentives from AEY, because these projects are fully contributed by the IPP. As AEY's isolated communities are supplied by diesel generation at all times, the price per kWh for IPP's does not seasonally change.

ATCO Electric YUKON

September 28, 2023 AEY-NY-013

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-013

Topic: IPP, Micro-Generation, DSM

Request:

Given that there is a surplus of hydro power on the YIS in the summer months, is there any benefit to IPP and MG programs that produce only in warmer and sunnier months?

Response:

There is limited benefit for intermittent renewable energy to displace surplus hydro generation that is available at a low cost of production in summer months. YEC is the main generator on the YIS and, as such, is better positioned to define the benefits of displacing surplus hydro generation. AEY notes that as the YIS peak demand continues to grow alignment with electrical heating in the winter months, when a majority of the currently installed micro-generation is not available, the benefits of intermittent renewable energy are diminished further.

AEY notes that IPP and MG installations are able to produce energy year-round (*i.e.,* not only in warmer and sunnier months), dependent on the type of renewable technology. As discussed in the response to AEY-JM-009(d), all forecast micro-generation offsets AEY's power purchases, which lowers AEY's revenue requirement. At the same time, unused hydro energy decreases YEC's sales, which can decrease YEC's revenue requirement.

Overall, currently, it is difficult for AEY to identify an obvious, material, and tangible benefit for lower hydro sales which are displaced by IPP and MG generation in the summer months.

ATCO Electric YUKON

September 28, 2023 AEY-NY-014

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-014

Topic: IPP, Micro-Generation, DSM

Request:

What projects are on the horizon for energy storage? (batteries, pumped storage, etc.?)

Response:

AEY is not forecasting any stand-alone energy storage projects in the Test Period. AEY has worked in partnership with three Yukon First Nations that are implementing IPP projects, which include battery storage, for the communities of Beaver Creek, Destruction Bay/Burwash Landing and Watson Lake. The BESS is required as each of these projects is designed to supply 100 percent of community electrical load for periods of time from intermittent renewable electricity. The BESS ensures the transition and coordination with AEY's diesel power does not affect grid reliability. These IPP projects are designed to significantly reduce diesel emissions for electricity production.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-015

Topic: IPP, Micro-Generation, DSM

Request:

What projects are in the works or on the horizon for DSM?

Response:

AEY is not forecasting any specific projects for DSM in the Test Period. As part of the Grid Modernization initiative, AEY is exploring options to use the AMI communication network to manage various devices on the grid (including loads) during power quality and outage events. AEY will continue to work with the DSM working group on a coordinated approach to DSM.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-016

Topic: IPP, Micro-Generation, DSM

Request:

Has there been any consideration of SSM? Voltage optimization? Other technologies?

Response:

AEY is unclear on what the term "SSM" is intended to refer to, or what "other technologies" the request may be contemplating. Voltage optimization is standard practice within utilities and AEY continues to implement this practice.

As noted in section 1B of the Application. AEY is undertaking steps towards Grid Modernization. These steps are required to maintain service quality including the reliable, safe and economic operation of AEY's distribution system in light of the evolution of customer behaviors, and the challenges presented as a result of the distribution system's increasing size, changing utilization and complexity. Grid Modernization is increasingly recognized within the utility industry as a necessary response to changing Government policies, technologies, and customer behaviors since they will fundamentally alter the future operation of the distribution grid. These changes are driving new challenges for utilities such as bidirectional flow of power and a significant potential for localized demand spikes that cannot be ignored. One example is the AMI program. Please refer to the response to AEY-YUB-065 for further details.

ATCO Electric YUKON

September 28, 2023 AEY-NY-017

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-017

Topic: IPP, Micro-Generation, DSM

Request:

Are administration and implementation of IPP and MG programs similar on and off the YIS? What are the differences?

Response:

The administration of IPP and MG programs are similar on and off the YIS as they all adhere to the Yukon Government's IPP Policy and MG program. Notable differences include YEC as the Buyer on the YIS, AEY as the Buyer in the isolated communities, lack of payment for reduction in capital and maintenance on the YIS, and the annual CPI adjustment to the price of electricity. For MG, overall capacity limits for each remote system are established.

ATCO Electric YUKON

September 28, 2023 AEY-NY-018

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
Nathaniel Yee (NY)
Received: September 6, 2023

AEY-NY-018

Topic: IPP, Micro-Generation, DSM

Request:

What issues has AEY experienced with the IPP and MG programs, and what could be changed or improved to make it better or more efficient towards displacing thermal and non-renewable generation?

Response:

It is important to note that the IPP and MG programs were established as Yukon Government initiatives. As they were designed for non-utility participation in power generation, they do not precisely align with regulated utility responsibilities to provide a safe and reliable power supply or principles of ratemaking. It is also important to recognize the success of the MG and IPP programs in the Yukon. The uptake has been remarkable, and the Yukon is approaching its 2030 goal in Our Clean Future (OCF) of 7 MW of installed renewable capacity from the micro-generation program.

However, these programs create several challenges for the utilities and Yukon ratepayers, namely:

1. The MG program can drive rate increases, relative to a base case without the program, due to reduced sales by the utilities. Utility costs are collected on prospective ratemaking principles and the inclusion of non-utility generation makes forecasting more difficult.

2. The timing of most MG production occurs in warmer months of the year that mainly coincide with low grid loads and surplus availability of hydro generation. By contrast, MG production is lowest in the winter, where the marginal cost of energy is higher due to thermal generation. As the majority

of export energy from MG is available when excess hydro energy is available on the YIS for a low marginal cost, program participants are mainly drawing from the grid during periods when electricity is at a higher cost and contribute to system peak requirements. MG surplus export energy offers decreased grid value in summer months. This might lead to customer inequity between participating and non-participating.

3. The rapid expansion of intermittent renewable sources on the YIS is also creating reliability concerns. Generally, Distributed Energy Resources (DER) generation lacks the ancillary benefits, which are key to power quality and are standard with conventional forms of generation like hydro and thermal. In particular, intermittent renewable devices lack inertia and can contribute to, and compound, system disturbances, which could lead to additional outages. As these devices become more prevalent, solutions like those offered by the Grid Modernization program will become increasingly important to ensure the ongoing safety and reliability of the system.

AEY is collaborating with Yukon Government and Yukon Energy Corporation to further study and address the above issues to ensure that the YIS will be safe and reliable while still allowing intermittent renewable generation onto the grid to achieve the goals in Our Clean Future.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-001

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-001

Reference: 2023-24 GRA, Section 1.4, Changes in Accounting Practices and Procedures, PDF pages 11-12

Issue: Practices and procedures

Quote: 1.4 Changes in Accounting Practices and Procedures

> 6. Changes in Accounting Practices and Procedures since the 2016-17 GRA are due to (1) implementation of Oracle Financials changed accounting procedures for charging labour; (2) on-going transition to cloud-based IT applications which have different accounting treatment as compared to previous on-premises applications and (3) updated accounting practices related to contributions work in progress to smooth out fluctuations in rate base.
>
> 7. In 2018, AEY began utilization of Oracle Financials, which is a cloud-based financial system. As part of that system implementation AEY and its affiliates adopted leading practices utilizing standard labour rates to account for labour costs. Standard labour rates are a fully loaded labour expense inclusive of fringe benefits and based on average cost by job class. As such AEY no longer records and tracks fringe costs separate and distinct from overall labour expenses.
>
> 8. AEY previously utilized on-premises business applications for which AEY purchased capitalizable licenses. These licenses were capitalized and amortized over a period of time. As technology advances, more and more systems are cloud-based and AEY and its affiliates are making a concerted effort to transition away from on-premises applications. Cloud based technology is licensed on a subscription basis, which is not capitalizable under IFRS accounting standards. AEY's current and future subscription costs for cloud-based applications are accounted for in operating and administrative expenses.

> 9. Finally, AEY is proposing removal of contributions related to work in progress from the computation of rate base, consistent with the exclusion of the corresponding construction work in progress. Historically, AEY has included contribution work in progress within rate base computations, which has resulted in a temporary reduction to rate base balances due to the exclusion of the corresponding capital spend lowering revenue requirements. An offsetting amount of AFUDC would be accumulated within the projects to be later added to rate base and collected over the life of the asset in service.
>
> 10. Overall, the implications of contributions have historically been negligible to rate base on ordinary course new extension balances; however, with the recent and projected installation of renewables and the related infrastructure both construction and contribution work in progress balances are expected to be significantly larger than what AEY has previously experienced. This results in high fluctuations in rate base balances and corresponding revenue requirements. Excluding contribution work in progress from rate base smooths out the rate base and revenue requirement trends over the long term, reduces AFUDC accumulated on related projects and more accurately represents AEY's annual returns and rate base balances.

Request:

(a) Please provide copies of all currently approved policies and procedures (for example, policies or procedures for recognizing capital asset additions, retirements, depreciation expense, income tax, reserve for injuries and damages and similar policies and procedures).

(b) For any policy or procedure document to which revisions are proposed in this GRA, please provide a blackline copy of the document.

(c) In reference to paragraph 7 quoted above, please explain the checks and balances that AEY and its affiliates undertake to ensure that fringe benefit costs (now as part of "fully loaded labour expense") are reflected accurately in AEY's actual and forecast labour rates which inform labour expense calculations, regardless of whether the costs are expensed or capitalized.

(d) Has the use of "fully loaded labour expense" had any negative or positive impact on AEY's ability to forecast labour expense calculations, regardless of whether the costs are expensed or capitalized? Please explain.

(e) In reference to paragraph 8 quoted above, please provide a reference to any other authority (accounting or otherwise) supporting AEY's proposal to account for its cloud-based technology subscription costs within operating and administrative expenses.

(f) Please revise **GRA Schedule S8.12** - Continuity Schedule of Contributions in Aid of Construction to breakdown Line No. 3 - **Additions to Property by project** (including a reference to the applicable business case number) such that the total costs for all projects, as shown on Line No. 3, are accounted for in full.

(g) Please explain AEY's current practice for recording contributions in aid of construction specific to when the contributions are received from the customer and the subsequent accounting entries upon project completion. Please ensure that the response addresses contributions as they pertain to both contribution work in progress and contributions that have been capitalized. Please reconcile this explanation with the amounts noted in response to part (f).

(h) Under AEY's proposal respecting contribution work in progress, would the practice where "An offsetting amount of AFUDC [Allowance for Funds Used During Construction] to be accumulated within the projects to be later added to rate base and collected over the life of the asset in service" be eliminated or changed in any way? If so, please clarify how AFUDC would be recorded and at what point during the construction of an asset.

(i) Please prepare a table showing the **revenue requirement** impact due to AEY's proposal with respect to contribution work in progress. Please include detail for AEY's 2023 and 2024 revenue requirement at the status quo (AFUDC) and compare this amount to AEY's 2023 and 2024 revenue requirement reflecting AEY's proposal to exclude contribution work in progress from rate base calculations. Please state all assumptions used.

Response:

(a) In general, AEY follows International Financial Reporting Standards as well as US Generally Accepted Accounting Principles for regulatory accounting practices for Adjusted Earnings. Income taxes are in accordance with legislation under the Income Tax Act. Please refer to AEY-YUB-001(a) Attachment 1 for internal accounting policies.

(b) Please refer to AEY-YUB-001(b) Attachment 1.

(c) This is a change in mechanics for accumulating and allocating fringe benefit costs. It does not change how such costs are managed and reviewed, nor does it affect the accounting outcome. In prior practices, fringe benefit costs were accumulated in a Fringe Benefit Pool and allocated to capital and O&M, based on the determined fringe rates.

AEY continues to accumulate fringe costs and allocates these costs to O&M and Capital, based on pre-determined fully loaded labour cost rates. The fringe costs continue to be approved and reviewed through accounts payable controls and processes and are reviewed annually to ensure these costs have been appropriately allocated. The fully loaded labour rates are also reviewed annually, and any required rate changes administered to the system, are reviewed and approved by the appropriate levels in the organization.

(d) The shift to Standard Labour Rates enables AEY to forecast labor costs at a less granular level with reasonable accuracy and has streamlined the review process, since the rates are applied across job classes, as opposed to at the individual employee level. Standard Labour Rates also improves the overall efficiency of the forecasting process and aligns with AEY's strategy to minimize burdensome customization of its IT systems.

Standard Labour Rates are reflective of the total cost of an employee and enable better project estimates, as components of labour costs are not missed when looking at fully loaded costs. In addition, this process protects the privacy of AEY's employees and enables broader access to labour information across the organization as it is not employee specific. AEY has not been negatively impacted by tracking these costs in a single account, as opposed to the old practice of tracking labour costs across various accounts.

(e) AEY and its affiliates have worked closely with their external auditors in determining the appropriate accounting treatments as more software applications are shifting towards cloud-based platforms as opposed to older on-premises applications. AEY accounts for these costs under the guidelines of IFRS accounting standards, specifically under IAS 38 (Intangible Assets) paragraph 68 which stipulates:

> Expenditure on an intangible item shall be recognized as an expense when it is incurred[1]

The accounting guideline goes on to provide further clarification:

> In the case of the supply of good, the entity recognizes such expenditure as an expense when it has a right to access those goods. In the case of the supply of service, the entity recognizes the expenditure as an expense when it receives the services.[2]

Ongoing license costs for cloud-based applications are akin to subscription costs and allow the licensee access to the platforms owned by providers, such as Oracle or IBM. AEY and its audit firm have interpreted the expensing of these costs in the year they are incurred to be the appropriate accounting treatment.

(f) Please refer to AEY-YUB-001(f) Attachment 1.

(g) The process for recording contributions in aid of construction initially involves recognizing contributions received during the project as part of work in progress. Upon project completion, these contributions are capitalized and then removed from contribution work in progress and added to net property, plant, and equipment, once capitalized contributions are depreciable.

1 IAS 38, para.68.
2 IAS 38, para.69.

(h-i) AFUDC is accumulated in projects that are in work in progress (WIP) based on the weighted average cost of capital (WACC) applied to balances in WIP.

Under the previous methodology for determining rate base and the funds used during construction, the customer contributions received for projects not yet in service were applied to rate base, reducing the balance required for short term debt and equity financing until the related capital was in service. The related capital costs included in WIP accumulate funds used during construction, as the customer contribution received is funding rate base, not the related capital work in progress.

The proposed methodology, which is consistent with the methodology approved by the Alberta Utilities Commission, removes customer contributions included in WIP from rate base and instead applies the funding directly to the related capital work during construction. Under this methodology, customer contributed capital would not accumulate funds used during construction.

Please refer to AEY-YUB-001(h) Attachment 1 for an illustrative example of both methodologies assuming a $1.0 million fully contributed project that is 75 percent complete in Year 1 and in-service in Year 2.

Due to the volume of customer contributed work within the Test Period, AEY's proposal increases revenue requirement for the Test Period, but decreases cumulative revenue requirement over the life of the contributed capital assets. Please refer to the table below:

Table 1: Impact of Excluding Contribution Work In Progress from Rate Base ($000)

	Per 2023-2024 GRA		**Previous Methodology**	
	2023	2024	2023	2024
Capital Revenue Requirement	14,820	17,174	14,420	16,297
Cumulative Incremental AFUDC	-	-	600	1,103

This policy is intended to describe the accounting treatment involved in the capitalization of fixed assets.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

1) Fixed Asset

A unit of property which can be physically identified and has a useful life in excess of one year. The value of the assets should include any non-recurring costs which are relative to its creation. Included in the cost of a fixed asset would be materials, direct and indirect labour, expenses, fringe benefits and an appropriate proportion of administrative overhead. For IFRS reporting purposes, the value of the asset will include interest capitalized during construction; whereas for Regulatory purposes the value of the asset will include an allowance for funds used during construction. The total cost of the asset is significant, relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed $300.

2) Capital versus O&M Expenditures

3) Capital

An expenditure is capital in nature if it involves: constructing or purchasing a new asset or upgrading it, rehabilitating or replacing an existing asset.

a. Constructing or purchasing a new asset

i. Outright purchase of fixed assets, such as land, a building, a vehicle, machinery, standby equipment, office furniture, etc.

ii. The entire cost of constructing new additions to physical assets such as transmission lines, substations, etc.

iii. All startup and commissioning costs

b. Upgrade existing assets

i. An enlargement of existing structures or facilities

ii. To increase the capacity of an existing asset

iii. A substantial improvement in the facility affecting quality of output or reduces operating costs

c. Rehabilitate existing assets

ii. To ensure achievement of life of an asset

iii. To extend the life of an asset beyond its normal service life

d. Replace existing assets

i. The substitution of new for existing facilities that are worn out, irreparably damaged, or have become inadequate in service.

ii. The substitution having substantially no greater capacity than the facility for which it is substituted.

4) Operation and Maintenance

a. Operational Expense

i. The cost of labour, expense and consumable materials used to start up or turn on a system and monitor its operations.

b. Maintenance Expense
   i. The cost of labour, materials and expense to keep all parts of the system in a safe operating condition.

This policy is intended to describe the accounting treatment involved in the retirement of the Company's fixed assets when they have been replaced and/or removed from service, sold, decommissioned or destroyed due to accident.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

Topics and Definitions

1) Fixed Asset

A unit of property which can be identified and has a useful life in excess of one year. The value of the assets should include all costs necessary to bring the asset to work condition for its intended use.

2) Cost of Retirement

The cost incurred to retire facilities from service and is comprised of the expenditures involved to disassemble and transport the assets.

IFRS – Amounts collected from customers in rates are recorded as revenue in the period these amounts are billed. Actual costs of retirement incurred are recorded as O&M in the period incurred.
Regulatory – An allowance is built into the monthly depreciation expense to allow for the cost of retiring an asset. Therefore, these costs do not constitute a capital expenditure but rather should be charged to the accumulated depreciation – net salvage pool.

3) Gross Salvage

Gross salvage represents the value of material recovered from the asset retired or sale proceeds if sold.

IFRS – Gross salvage is recorded as an offset to cost of retirement expense in the period received/receivable.

Regulatory – Gross salvage is applied to accumulated depreciation – net salvage.

4) Normal Retirements

In the normal course of business and under the mass/group property accounting process, assets are deemed to be fully consumed for utility services and therefore fully depreciated upon retirement. Gains or losses are not recorded on ordinary course retirements. 100% of the original cost value of the asset being retired is removed from the fixed assets cost and accumulated depreciation – life.

5) Gains or Losses on Sales

For disposal of assets outside of normal course of business, land and non-regulated assets, the difference between the net book value (original cost less accumulated depreciation - life) plus cost of disposal and the disposal proceeds is accounted for as gain or loss in the statement of earnings.

6) Retirement Methods

a) Deflation Values
For some assets, the original cost is not readily available. In those cases, the current value of the replacement part will be deflated back using tables formulated on the Utility Handy Whitman tables and Consumer Price Indexes.

b) Original Costs

Where the historical records lend themselves to determining accurate original asset values, these will be used for retirements. This is obviously the most accurate method and is preferred if the information is available.

DEPRECIATION OBJECTIVE

ATCO Electric Yukon's depreciation objective is to allocate 100%, no more no less, of the depreciable portion of each fixed asset's capital cost to operating expense as evenly as possible; that is, on a straight line basis over the expected useful life of each fixed asset. The depreciation portion of the capitalized cost is the capitalized cost less gross salvage plus cost of retirement.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

DEPRECIATION STUDIES

ATCO Electric Yukon conducts depreciation studies periodically to review and determine the appropriate depreciation parameters (service life and net salvage) to use in calculating depreciation rates, expense and accumulated depreciation. The recommended depreciation rates along with the supporting depreciation study are generally submitted to the Yukon Utilities Board as a component of general rate applications.

DEPRECIATION RATES

ATCO Electric Yukon's annual depreciation rates are developed using YUB approved service lives (average service life and IOWA curves) and net salvage percentages. The approved depreciation parameters are applied to account vintage surviving dollars as at the previous year-end. The depreciation rates are calculated in accordance with the Straight-Line method, the Equal Life Group procedure and applied using the Whole Life technique.

DEPRECIATION EXPENSE

Depreciation expense for an account is calculated on a monthly basis by multiplying the previous month closing account plant balance by the depreciation rate. Depreciation expense is calculated in two components: life and net salvage.

IFRS – only the life component of depreciation is booked as depreciation expense. Costs of retirement are expensed as incurred which can result in large O&M fluctuations from year to year.

Regulatory – both the life and any net salvage components, as approved by the YUB, are booked to depreciation expense. In this manner the impact of costs of retirement to the customer are smoothed. Per Board Orders 2009-2 and 2014-06, the YUB suspended collection of depreciation net salvage and currently only life depreciation is being recorded in the regulatory ledger. AEY has applied for reinstatement of collection of depreciation net salvage in this application.

AMORTIZATION OF DIFFERENCES

In each depreciation study, the book accumulated depreciation is measured against the calculated accumulated depreciation using YUB approved depreciation parameters for the study accounts by life and net salvage separately. The difference between the book accumulated depreciation and the calculated accumulated depreciation is called reserve difference. If the reserve difference for an account exceeds +/- 5% tolerance level, the difference is amortized over the composite remaining life of that account. The amortization of reserve difference is part of the annual depreciation expense and amount remains unchanged between depreciation studies.

ACCUMULATED DEPRECIATION

IFRS - Accumulated Depreciation Life is determined by adding monthly account depreciation expense – life to the previous month closing balance, subtracting account retirements and adding any adjustments recorded during the month.

Regulatory - Accumulated Depreciation Life is calculated as above for IFRS. Accumulated Depreciation – Net Salvage is similarly determined by adding monthly account depreciation – net salvage to the previous month account closing balance, adding account gross salvage, subtracting account cost of retirement and adding any adjustments recorded during the month.

CONTRIBUTION IN AID OF CONSTRUCTION

Contributions are amortized using the composite Distribution life depreciation rate.

When property, plant and equipment is retired at a location a pro rata share of any contributions at the location are also retired. That is the proportion of dollars of plant retired to dollars surviving at the location results in the same proportion of contributions retired.

IFRS – amortization of contributions is recorded as revenue and contributions in aid of construction are classified as deferred revenue.

Regulatory – amortization of contributions is recorded as a credit to depreciation expense and contributions in aid of construction are shown as part of the net book value of property, plant and equipment.

ATCO ELECTRIC YUKON ACCOUNTING POLICY MANUAL	*Reserve for Injuries and Damages*
	Date: December 1994 **Number:** E.5
PREPARED BY: **B. Packianayagam**	**APPROVED BY:** K. Trunzo
	UPDATED: September 2023

INTRODUCTION

The charges made against the Reserve for Injuries and Damages fall into two main categories. The first category is insured losses and the second is uninsured or uninsurable losses.

Insured Losses:

With respect to insured losses, the item in question must be covered by insurance. Charges against the reserve include the deductible portion of insured losses as well as any portion of the claim not paid by the insurance company.

Uninsured or Uninsurable Losses:

An uninsured loss is one where insurance coverage could have been obtained except that the exposure risk was minimal or the cost of the insurance was prohibitively high.

An uninsurable loss is one where insurance coverage was not available as a result of very high-risk exposure.

PURPOSE OF THE RESERVE

The reserve serves as a protection against uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve will mitigate rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of such a reserve provides financial advantages over paying significantly higher insurance premiums in order to reduce deductibles or to insure items which carry prohibitively high premiums.

The reserve is established for the payment of:

1. The deductible portion of insured losses including any portion of a claim not paid by the insurance company.

2. Uninsured and uninsurable losses resulting from but not limited to design error, failure to supply (blackout, brownout), professional liability and pollution liability.

ATCO ELECTRIC LIMITED **ACCOUNTING POLICY MANUAL**	***Capitalization***
	Date: December 2010 **Number:** D.1.a
PREPARED BY: K. Trunzo	**APPROVED BY:** D. Freedman

This policy is intended to describe the accounting treatment involved in the capitalization of fixed assets. Immediately following this policy, additional policies can be found which cover more specific topics.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its publicly released financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

1) Fixed Asset

A unit of property which can be physically identified and has a useful life in excess of one year. The value of the assets should include any non-recurring costs which are relative to its creation. Included in the cost of a fixed asset would be materials, direct and indirect labour, expenses, fringe benefits and an appropriate proportion of administrative overhead. For IFRS reporting purposes, the value of the asset will include interest capitalized during construction; whereas for Regulatory purposes the value of the asset will include an allowance for funds used during construction. The total cost of the asset is significant, relative to the total capital cost of the particular asset. In the case of new assets, the cost must exceed $300. There are numerous items (e.g. office furniture, loose tools, etc.) that are too small to capture in individual projects therefore blanket projects are utilized to capture these costs.

2) Capital versus O&M Expenditures

3) Capital

An expenditure is capital in nature if it involves: constructing or purchasing a new asset or upgrading it, rehabilitating or replacing an existing asset.

a. a. Constructing or purchasing a new asset

i. Outright purchase of fixed assets, such as land, a building, a vehicle, machinery, standby equipment, office furniture, etc.

ii. The entire cost of constructing new additions to physical assets such as transmission lines, distribution facilities, substations, etc.

iii. All startup and commissioning costs

b. Upgrade existing assets

i. An enlargement of existing structures or facilities

ii. To increase the capacity of an existing asset

iii. A substantial improvement in the facility affecting quality of output or reduces operating costs

c. Rehabilitate existing assets

i. As a general guideline, to determine if a cost falls into this category, one must consider if the expenditures were planned to be incurred at the time if purchasing the asset.

~~If the expenditures were planned at the time of purchase to occur in the future, they will be expensed to O&M when they are incurred.~~ii.

~~1. When extraordinary, material unplanned items are incurred in the future, they will be considered capital.~~

To ~~insure~~ensure achievement of life of an asset

iii. To extend the life of an asset beyond its normal service life

d. Replace existing assets

i. The substitution of new for existing facilities that are worn out, irreparably damaged, or have become inadequate in service.

ii. The substitution having substantially no greater capacity than the facility for which it is substituted.

4) Operation and Maintenance

a. Operational Expense
   i. The cost of labour, expense and consumable materials used to start up or turn on a system and monitor its operations.
b. Maintenance Expense
   i. The cost of labour, materials and expense to keep all parts of the system in a safe operating condition.

~~I. **Specific Accounting Treatment**~~

~~Following is~~

This policy is intended to describe the accounting treatment ~~of some of the more common capitalization questions which are encountered.~~

~~1) **Transformers – Capital/O&M**~~
~~All transformers 50 KVA and under will be purchased under inventory and charged to~~ involved in the retirement of the Company's fixed assets when ~~installed and if~~ they have been replaced~~, returned to inventory and credited to fixed assets. Transformers greater than 50 KVA are charged directly to fixed assets. For policy on burnouts, planned and unplanned increases and shop repairs see D.1.a.10 in this manual.~~

~~2) **Refurbishing & Installing Vehicle Service Bodies – Capital**~~
~~This expenditure is eligible because it extends the~~ and/or removed from service ~~life of an asset.~~

~~3) **First Time Painting of Street Lights – Capital**~~
~~Considered a cost of installing a street light.~~

~~4) **Switch Number Plates & Installation – Capital**~~
~~Required for the safe operation of transmission facilities.~~

~~5) **5 kV Underground Replacement – Capital**~~
~~Considered as a distribution rebuild.~~

~~6) **Brushing – Capital**~~
~~Capitalize if brushing at time of construction, first time spraying to kill remaining root system, line widening (i.e. the removal of entire trees) along right of ways for trees not previously cleared at time of construction or hazard tree removal for trees either on an existing right of way which has not been previously cleared~~, sold, decommissioned or ~~those trees outside the existing right of way~~destroyed due to accident.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

Topics and Definitions

1) Fixed Asset
A unit of property which can be identified and has a useful life in excess of one year. The value of the assets should include all costs necessary to bring the asset to work condition for its intended use.

2) Cost of Retirement
The cost incurred to retire facilities from service and is comprised of the expenditures involved to disassemble and transport the assets.

IFRS – Amounts collected from customers in rates are recorded as revenue in the period these amounts are billed. Actual costs of retirement incurred are recorded as O&M in the period incurred.
Regulatory – An allowance is built into the monthly depreciation expense to allow for the cost of retiring an asset. Therefore, these costs do not constitute a capital expenditure but rather should be charged to the accumulated depreciation – net salvage pool.

3) Gross Salvage

Gross salvage represents the value of material recovered from the asset retired or sale proceeds if sold.

IFRS – Gross salvage is recorded as an offset to cost of retirement expense in the period received/receivable.

Regulatory – Gross salvage is applied to accumulated depreciation – net salvage.

4) Normal Retirements

In the normal course of business and under the mass/group property accounting process, assets are deemed to be fully consumed for utility services and therefore fully depreciated upon retirement. Gains or losses are not recorded on ordinary course retirements. 100% of the original cost value of the asset being retired is removed from the fixed assets cost and accumulated depreciation – life.

5) Gains or Losses on Sales

For disposal of assets outside of normal course of business, land and non-regulated assets, the difference between the net book value (original cost less accumulated depreciation - life) plus cost of disposal and the disposal proceeds is accounted for as gain or loss in the statement of earnings.

6) Retirement Methods

a) Deflation Values

For some assets, the original cost is not readily available. In those cases, the current value of the replacement part will be deflated back using tables formulated on the Utility Handy Whitman tables and Consumer Price Indexes.

b) Original Costs

Where the historical records lend themselves to determining accurate original asset values, these will be used for retirements. This is obviously the most accurate method and is preferred if the information is available.

DEPRECIATION OBJECTIVE

ATCO Electric Yukon's depreciation objective is to allocate 100%, no more no less, of the depreciable portion of each fixed asset's capital cost to operating expense as evenly as possible; that is, on a straight line basis over the expected useful life of each fixed asset. The depreciation portion of the capitalized cost is the capitalized cost less gross salvage plus cost of retirement.

Note that transition to International Reporting Standards (IFRS) on January 1, 2010 resulted in significant changes to revenue recognition and treatment of rate-regulated assets and liabilities. As a result, ATCO Electric Yukon now applies certain accounting policies to its financial statements for IFRS reporting and in some cases another policy for regulatory reporting and rate-making purposes. Where accounting treatment differs between the two measures, these are identified below.

DEPRECIATION STUDIES

ATCO Electric Yukon conducts depreciation studies periodically to review and determine the appropriate depreciation parameters (service life and net salvage) to use in calculating depreciation rates, expense and accumulated depreciation. The recommended depreciation rates along with the supporting depreciation study are generally submitted to the Yukon Utilities Board as a component of general rate applications.

DEPRECIATION RATES

ATCO Electric Yukon's annual depreciation rates are developed using YUB approved service lives (average service life and IOWA curves) and net salvage percentages. The approved depreciation parameters are applied to account vintage surviving dollars as at the previous year-end. The depreciation rates are calculated in accordance with the Straight-Line method, the Equal Life Group procedure and applied using the Whole Life technique.

DEPRECIATION EXPENSE

Depreciation expense for an account is calculated on a monthly basis by multiplying the previous month closing account plant balance by the depreciation rate. Depreciation expense is calculated in two components: life and net salvage.

IFRS – only the life component of depreciation is booked as depreciation expense. Costs of retirement are expensed as incurred which can result in large O&M fluctuations from year to year.

Regulatory – both the life and any net salvage components, as approved by the YUB, are booked to depreciation expense. In this manner the impact of costs of retirement to the customer are smoothed. Per Board Orders 2009-2 and 2014-06, the YUB suspended collection of depreciation net salvage and currently only life depreciation is being recorded in the regulatory ledger. AEY has applied for reinstatement of collection of depreciation net salvage in this application.

AMORTIZATION OF DIFFERENCES

In each depreciation study, the book accumulated depreciation is measured against the calculated accumulated depreciation using YUB approved depreciation parameters for the study accounts by life and net salvage separately. The difference between the book accumulated depreciation and the calculated accumulated depreciation is called reserve difference. If the reserve difference for an account exceeds +/- 5% tolerance level, the difference is amortized over the composite remaining life of that account. The amortization of reserve difference is part of the annual depreciation expense and amount remains unchanged between depreciation studies.

ACCUMULATED DEPRECIATION

IFRS - Accumulated Depreciation Life is determined by adding monthly account depreciation expense – life to the previous month closing balance, subtracting account retirements and adding any adjustments recorded during the month.

Regulatory - Accumulated Depreciation Life is calculated as above for IFRS. Accumulated Depreciation – Net Salvage is similarly determined by adding monthly account depreciation – net salvage to the previous month account closing balance, adding account gross salvage, subtracting account cost of retirement and adding any adjustments recorded during the month.

CONTRIBUTION IN AID OF CONSTRUCTION

Contributions are amortized using the composite Distribution life depreciation rate.

~~7)~~ **When ~~Brushing – O&M~~**
~~Mowing the regrowth of trees which were previously cleared and also the second and subsequent sprayings are O&M.~~

~~8) Moving Expense – Capital/O&M~~
~~The individual's moving expenses should be allocated to capital or O&M, or a combination of both, based on the type of work the individual is doing.~~

~~9) Underground Splice Replacements – O&M~~
~~There is no increase in capacity or life extension of the primary asset.~~

~~10) Loose Tools and Office Furniture – Capital/O&M~~

The key determinant is the $300 minimum cost which will decide if an item should be capitalized or expensed.

11) Ground Rod Testing and Replacement – Capital / O&M

Testing would be charged to O&M unless it leads to immediate major site specific replacement which would qualify the costs as a major capital item. Replacement costs would be capitalized if the work order is for a major replacement done at a specific site.

12) Pole Inspection or Testing – O&M

The work involved in inspecting or testing a pole to see if treatment is required.

13) Pole Treating – Capital/O&M

Any major pole treating program involving 50 poles or more would be considered capital. Programs of less than 50 poles will be charged to O&M.

14) Temporary Generation – Capital/O&M

The cost of renting a temporary generating station to supply load in an isolated fashion to allow a line to be rebuilt would be expensed for IFRS reporting purposes. For Regulatory purposes this cost would be capitalized.

15) Gang Switch Maintenance – O&M

Since the refurbishing of gang switches involves only the replacement of insulators in the gang switch assembly, this item should be charged to O&M. The intent is to keep the switch in operating condition.

16) Substation Regravelling – O&M

The costs should be charged to O&M as the substation life is not extended, nor is the asset value increased.

17) URD Elbow & Insert Replacement – O&M

Costs should go to O&M as essentially the underground system is being maintained in operating condition.

18) Pedestal Replacement – Capital

The associated costs should be capitalized and the pedestal being replaced, retired.

19) Accreditation Manuals – Capital/O&M

The costs to initially set up the manuals should be capitalized. However a revision to the manual should be expensed.

20) Panel Upgrades – Capital

Due to capacity increases, these costs would be eligible for capital.

21) Pole Replacement – Capital/O&M

All poles replaced on a pre-planned basis due to decay should be charged to capital and the old pole and labour to install them should be retired. Poles replaced on an emergency basis due to mechanical damage by vehicles or during storms should be expensed whether or not there is some evidence of wood decay.

~~22) Pole Stubbing – Capital/O&M~~

~~Stubbing of transmission lines on a pre-planned basis should be charged to capital as the intent to increase the service life of the poles. Unplanned pole stubbing would be expensed.~~

~~23) Conductor Replacement – Capital/O&M~~

~~Replacement of a conductor on a transmission or sub transmission line would be charged to capital if the length of the line is one mile or greater (three miles for a 3 phase line) regardless of the size of the conductor being replaced. Replacement of conductors on distribution lines will be charged to capital if the new conductor is of a larger size or insulation rating compared to the one being replaced. This applies to underground, aerial spaced and overhead conductors.~~

~~24) System Spares – Capital/Inventory~~

~~The cost of spares that are designated to support specific fixed assets are initially capitalized and depreciated. If the spare part turns over on a regular basis, consideration would be given to setting it up in inventory.~~

~~25) Leasehold Improvements – Capital~~

~~Leasehold improvements are capitalized where a lease agreement is in place. It is amortized using the straight-line method over the life of the lease plus one renewal period.~~

~~26) Postponed Projects – WIP~~

~~Costs incurred to date would remain in work-in-progress and reviewed periodically for appropriateness.~~

~~27) Properties Removed From Service (i.e. not disposed of)~~

~~Original cost would remain with assets in service and depreciated until disposed of.~~

~~28) Leases – Capital~~

~~Will be capitalized depending on the terms and conditions of the lease, particularly the issue of transfer of ownership at the conclusion of the lease. The lease obligation is included with long-term debt and the original cost is included in fixed assets.~~

property, plant and equipment is retired at a location a pro rata share of any contributions at the location are also retired. That is the proportion of dollars of plant retired to dollars surviving at the location results in the same proportion of contributions retired.

IFRS – amortization of contributions is recorded as revenue and contributions in aid of construction are classified as deferred revenue.

Regulatory – amortization of contributions is recorded as a credit to depreciation expense and contributions in aid of construction are shown as part of the net book value of property, plant and equipment.

~~THE~~ATCO ELECTRIC YUKON ~~ELECTRICAL COMPANY LIMITED~~ ACCOUNTING POLICY MANUAL	*Reserve for Injuries and Damages*
	Date: ~~94-12-08~~December 1994 **Number:** E.5
PREPARED BY: ~~K. Trunzo~~**B. Packianayagam**	**APPROVED BY:** ~~David Freedman~~K. Trunzo
	UPDATED: ~~December 15, 2010~~September 2023

INTRODUCTION

The charges made against the Reserve for Injuries and Damages fall into two main categories. The first category is insured losses and the second is uninsured or uninsurable losses.

Insured Losses:

With respect to ~~incurred~~insured losses, the item in question must be covered by insurance. Charges against the reserve include the deductible portion of insured losses as well as any portion of the claim not paid by the insurance company.

Uninsured or Uninsurable Losses:

An uninsured loss is one where insurance coverage could have been obtained except that the exposure risk was minimal or the cost of the insurance was prohibitively high.

An uninsurable loss is one where insurance coverage was not available as a result of very high-risk exposure.

PURPOSE OF THE RESERVE

The reserve serves as a protection against uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve will mitigate rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of such a reserve provides financial advantages over paying significantly higher insurance premiums in order to reduce deductibles or to insure items which carry prohibitively high premiums.

The reserve is established for the payment of:

1. The deductible portion of insured losses including any portion of a claim not paid by the insurance company.

2. Uninsured and uninsurable losses resulting from but not limited to design error, failure to supply (blackout, brownout), professional liability and pollution liability.

~~Also, effective with events charging to the reserve after January 1, 1999, only those that are significant and of low probability shall be charged to the reserve.~~

~~All events will be considered on a case by case basis and will be reviewed and approved by the Manager, Insurance and by a representative from the company's insurance adjusters.~~

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Contribution in Aid of Construction
($000)

Line No.	Project Name	Cross Ref.	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024
1	**Renewables**										
2	Renewables - Old Crow		-	-	-	2,045	418	1,002	-	-	-
3	Kluane Wind Project	Business Case No. 37	-	-	-	-	-	-	1,952	2,056	-
4	Beaver Creek PV Project	Business Case No. 38	-	-	-	-	-	75	205	5,794	1,686
5	**Renewables Total**		**-**	**-**	**-**	**2,045**	**418**	**1,077**	**2,157**	**7,850**	**1,686**
6											
7											
8	**Generation**										
9	WL - Waste Heat Cathodic Protection		-	-	-	-	-	-	-	150	-
10	WL – Replace HRS pumps/motors		-	-	-	-	-	-	-	75	-
11	**Generation Total**		**-**	**-**	**-**	**-**	**-**	**-**	**-**	**225**	**-**
12											
13											
14	**New Extensions**										
15	New Services Overhead and Underground	Business Case No. 18	275	709	749	724	789	1,206	3,284	4,101	3,243
16	Mt Sima Pumphouse		-	-	-	-	-	175	-	-	-
17	Brookside Phase 2B		-	143	27	-	(67)	-	-	-	-
18	Schmidt, Harold & Savanah		-	-	-	115	-	-	-	-	-
19	TSL/Ketza Old Crow Health & Housing		-	-	-	-	-	210	-	-	-
20	VGFN Houses on North Rd		247	-	-	-	-	-	-	-	-
21	VoT Connector Road Subdivision		-	-	-	143	-	-	-	-	-
22	Loft 2240 2nd Avenue		-	-	-	-	-	105	-	-	-
23	Whistle Bend Stage 3	Business Case No. 31	226	337	530	223	(2)	-	-	-	-
24	Whistle Bend Stage 4	Business Case No. 31	-	455	706	805	-	-	-	-	-
25	Whistle Bend Stage 5	Business Case No. 31	-	-	-	582	360	-	-	-	-
26	Whistle Bend Stage 9	Business Case No. 31	-	-	-	-	-	-	-	870	458
27	Whistle Bend Stage 8	Business Case No. 31	-	-	-	-	-	-	-	-	-
28	Whistle Bend Stage 6	Business Case No. 31	-	-	-	-	-	-	-	-	-
29	Whistle Bend Stage 7	Business Case No. 31	-	-	-	-	-	140	-	-	-
30	Whistle Bend - Future Stages	Business Case No. 31								727	309
31	Yukon Lot 503		-	-	-	102	-	-	-	-	-
32	YG Airport Hangar		-	-	-	-	-	-	-	235	-
33	CAFN Marshall Creek Rd Subdivision, HJunction		-	-	-	-	-	-	-	-	-
34	Hammerstone Lots off Tlingit Street		-	-	-	-	24	162	-	-	-
35	New Extensions< -$20,000		304	349	442	744	740	829	462		-
36	**New Extensions Total**		**1,051**	**1,994**	**2,454**	**3,438**	**1,844**	**2,828**	**3,746**	**5,933**	**4,011**
37											
38	**New Extensions-IPP**										
39	Arctic Pharm IPP	Business Case No. 35	-	-	-	-	-	-	117	523	-
40	Sunergy YEC HJ IPP		-	-	-	-	-	-	237	340	-
41	Haeckel Hill	Business Case No. 36	-	-	-	-	-	710	1,576	-	-
42	YEC Mayo Road IPP Interconnection		-	-	-	-	-	135	9	-	-
43	Other New Ext IPP		-	-	-	-	-	-	-	-	-
44	THELP		-	-	-	-	-	233	55	-	-
45	**New Extensions - IPP Total**		**-**	**-**	**-**	**-**	**-**	**1,078**	**1,993**	**863**	**-**
46											
47	**Distribution Improvements**										
48	AEY YG Nares River Bridge		-	31	-	-	-	-	-	-	-
49	YG Toyota Access, Intersection & Frontage Road Upgrades		-	-	-	4	302	-	-	-	-
50	McIntyre Subdivision Rebuild	Business Case No. 01	-	-	-	-	-	-	-	-	155
51	Distribution Improvements< -$20,000		-	-	15	9	7	-	1	4	-
52	**Distribution Improvements Total**		**-**	**31**	**15**	**13**	**309**	**-**	**1**	**4**	**155**
53											
54	**Street and Sentinel Lighting**									-	-
55	New Customer Streetlight Installations	Business Case No. 34	167	157	162	14	874	183	295	1,285	346
56	General Streetlight Replacements		-	-	32	-	-	-	-	-	-
57	Alaska Highway North Klondike Highway Intersection		-	-	-	-	321	-	-	-	-
58	Car Cross Streetlights		-	-	316	-	81	-	-	-	-
59	Street Lights Burns Road to Range Road Intersection		-	-	-	-	-	-	142	-	-
60	YG Nisutlin Bridge Streetlights		-	-	-	-	-	-	-	83	88
61	Whistle Bend Street Lights - Stage 3		-	-	161	18	-	-	-	-	-
62	Whistle Bend Street Lights - Stage 4	Business Case No. 31	-	-	51	376	148	-	-	-	-
63	Whistle Bend Street Lights - Stage 5	Business Case No. 31	-	-	-	42	186	-	-	-	-
64	Whistle Bend Street Lights - Stage 8	Business Case No. 31	-	-	-	-	-	-	-	136	-
65	Whistle Bend Street Lights - Stage 6	Business Case No. 31	-	-	-	-	-	-	-	-	-
66	Whistle Bend Street Lights - Stage 7	Business Case No. 31	-	-	-	-	-	62	-	-	-
67	Whistle Bend Street Lights - Stage 9	Business Case No. 31	-	-	-	-	-	-	-	159	119
68	YG Lighting Stewart Crossing		-	-	-	-	-	-	-	-	-
69	Village of Carmacks Street Lights		-	-	-	-	-	-	-	-	-
70	C of W Cook St Street Lights		-	-	-	-	-	-	-	-	-
71	YG Street Lights Lodestar to Philmars Phase 1		-	-	-	-	-	-	-	-	-
72	Street and Sentinel Lights< -$20,000		23	22	21	23	39	22	28	-	-
73	**Street and Sentinel Lighting Total**		**190**	**179**	**742**	**473**	**1,649**	**267**	**465**	**1,662**	**554**
74											
75	**Grand Total**		**1,241**	**2,204**	**3,212**	**5,969**	**4,220**	**5,250**	**8,362**	**16,538**	**6,405**
76											
77	Opening Contribution Work in Progress	Note 1	**-**	**-**	**-**	**-**	-	-	-	5,833	12,252
78	Ending Contribution Working in Progress	Note 1	306	1,354	2,727	3,615	3,898	4,278	5,833	12,252	2,226
79											
80	**Contribution Additions**	Note 2	**1,241**	**2,204**	**3,212**	**5,969**	**4,220**	**5,250**	**2,529**	**10,119**	**16,431**

Note 1: Amounts from 2016 to 2021 are there for illustrative purposes, they were included in the additions each year until 2022. In 2022 , per the proposed methodology, contributions included in work in progress (WIP) were removed. 2023 and 2024 continue with this proposed methodology and a continuity of contributions in WIP is shown.

Note 2: ATCO Electric Yukon (AEY) 2023-2024 General Rate Application, Schedule 8.12, Line 3

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Illustrative Example - Contribution Funding Relative Capital

Line No.	Assumptions:		
1	Depreciation Rate	3.00%	
2	WACC	6.50%	

Line No.		Original Cost	Accumulated Depreciation	Net Book	Mid Year	Contributions	Accumulated Depreciation	Net Book	Mid Year	Net Rate Base	Return	Depreciation	Revenue Requirement
5	Year 1	-	-	-	-	-	-	-	-	-	-	-	-
6	Year 2	1,000,000.00	15,000.00	985,000.00	492,500.00	(1,000,000.00)	(15,000.00)	(985,000.00)	(492,500.00)	-	-	-	-
7	Year 3	1,000,000.00	45,000.00	955,000.00	970,000.00	(1,000,000.00)	(45,000.00)	(955,000.00)	(970,000.00)	-	-	-	-
8	Year 4	1,000,000.00	75,000.00	925,000.00	940,000.00	(1,000,000.00)	(75,000.00)	(925,000.00)	(940,000.00)	-	-	-	-
9	Year 5	1,000,000.00	105,000.00	895,000.00	910,000.00	(1,000,000.00)	(105,000.00)	(895,000.00)	(910,000.00)	-	-	-	-
10	Year 6	1,000,000.00	135,000.00	865,000.00	880,000.00	(1,000,000.00)	(135,000.00)	(865,000.00)	(880,000.00)	-	-	-	-
11	Year 7	1,000,000.00	165,000.00	835,000.00	850,000.00	(1,000,000.00)	(165,000.00)	(835,000.00)	(850,000.00)	-	-	-	-
12	Year 8	1,000,000.00	195,000.00	805,000.00	820,000.00	(1,000,000.00)	(195,000.00)	(805,000.00)	(820,000.00)	-	-	-	-
13	Year 9	1,000,000.00	225,000.00	775,000.00	790,000.00	(1,000,000.00)	(225,000.00)	(775,000.00)	(790,000.00)	-	-	-	-
14	Year 10	1,000,000.00	255,000.00	745,000.00	760,000.00	(1,000,000.00)	(255,000.00)	(745,000.00)	(760,000.00)	-	-	-	-
15	Year 11	1,000,000.00	285,000.00	715,000.00	730,000.00	(1,000,000.00)	(285,000.00)	(715,000.00)	(730,000.00)	-	-	-	-
16	Year 12	1,000,000.00	315,000.00	685,000.00	700,000.00	(1,000,000.00)	(315,000.00)	(685,000.00)	(700,000.00)	-	-	-	-
17	Year 13	1,000,000.00	345,000.00	655,000.00	670,000.00	(1,000,000.00)	(345,000.00)	(655,000.00)	(670,000.00)	-	-	-	-
18	Year 14	1,000,000.00	375,000.00	625,000.00	640,000.00	(1,000,000.00)	(375,000.00)	(625,000.00)	(640,000.00)	-	-	-	-
19	Year 15	1,000,000.00	405,000.00	595,000.00	610,000.00	(1,000,000.00)	(405,000.00)	(595,000.00)	(610,000.00)	-	-	-	-
20	Year 16	1,000,000.00	435,000.00	565,000.00	580,000.00	(1,000,000.00)	(435,000.00)	(565,000.00)	(580,000.00)	-	-	-	-
21	Year 17	1,000,000.00	465,000.00	535,000.00	550,000.00	(1,000,000.00)	(465,000.00)	(535,000.00)	(550,000.00)	-	-	-	-
22	Year 18	1,000,000.00	495,000.00	505,000.00	520,000.00	(1,000,000.00)	(495,000.00)	(505,000.00)	(520,000.00)	-	-	-	-
23	Year 19	1,000,000.00	525,000.00	475,000.00	490,000.00	(1,000,000.00)	(525,000.00)	(475,000.00)	(490,000.00)	-	-	-	-
24	Year 20	1,000,000.00	555,000.00	445,000.00	460,000.00	(1,000,000.00)	(555,000.00)	(445,000.00)	(460,000.00)	-	-	-	-

Under this scenario - Contributions for Capital that is work in progress is used to fund the capital work in progress. The relative capital does not accumulate AFUDC.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Illustrative Example - Contribution Funding Existing Rate Base

Line No.														
1	Assumptions:													
2	Depreciation Rate	3.00%												
3	WACC	6.50%												
4		Original Cost	Allowance for Funds During Construction	Accumulated Depreciation	Net Book	Mid Year	Contributions	Accumulated Depreciation	Net Book	Mid Year	Net Rate Base	Return	Depreciation	Revenue Requirement
5	Year 1	-	-	-	-	-	(1,000,000.00)	-	(900,000.00)	(450,000.00)	(450,000.00)	(29,250.00)	-	(29,250.00)
6	Year 2	1,000,000.00	48,750.00	15,731.25	1,033,018.75	516,509.38	(1,000,000.00)	(15,000.00)	(985,000.00)	(942,500.00)	(425,990.63)	(27,689.39)	731.25	(26,958.14)
7	Year 3	1,000,000.00	48,750.00	47,193.75	1,001,556.25	1,017,287.50	(1,000,000.00)	(45,000.00)	(955,000.00)	(970,000.00)	47,287.50	3,073.69	1,462.50	4,536.19
8	Year 4	1,000,000.00	48,750.00	78,656.25	970,093.75	985,825.00	(1,000,000.00)	(75,000.00)	(925,000.00)	(940,000.00)	45,825.00	2,978.63	1,462.50	4,441.13
9	Year 5	1,000,000.00	48,750.00	110,118.75	938,631.25	954,362.50	(1,000,000.00)	(105,000.00)	(895,000.00)	(910,000.00)	44,362.50	2,883.56	1,462.50	4,346.06
10	Year 6	1,000,000.00	48,750.00	141,581.25	907,168.75	922,900.00	(1,000,000.00)	(135,000.00)	(865,000.00)	(880,000.00)	42,900.00	2,788.50	1,462.50	4,251.00
11	Year 7	1,000,000.00	48,750.00	173,043.75	875,706.25	891,437.50	(1,000,000.00)	(165,000.00)	(835,000.00)	(850,000.00)	41,437.50	2,693.44	1,462.50	4,155.94
12	Year 8	1,000,000.00	48,750.00	204,506.25	844,243.75	859,975.00	(1,000,000.00)	(195,000.00)	(805,000.00)	(820,000.00)	39,975.00	2,598.38	1,462.50	4,060.88
13	Year 9	1,000,000.00	48,750.00	235,968.75	812,781.25	828,512.50	(1,000,000.00)	(225,000.00)	(775,000.00)	(790,000.00)	38,512.50	2,503.31	1,462.50	3,965.81
14	Year 10	1,000,000.00	48,750.00	267,431.25	781,318.75	797,050.00	(1,000,000.00)	(255,000.00)	(745,000.00)	(760,000.00)	37,050.00	2,408.25	1,462.50	3,870.75
15	Year 11	1,000,000.00	48,750.00	298,893.75	749,856.25	765,587.50	(1,000,000.00)	(285,000.00)	(715,000.00)	(730,000.00)	35,587.50	2,313.19	1,462.50	3,775.69
16	Year 12	1,000,000.00	48,750.00	330,356.25	718,393.75	734,125.00	(1,000,000.00)	(315,000.00)	(685,000.00)	(700,000.00)	34,125.00	2,218.13	1,462.50	3,680.63
17	Year 13	1,000,000.00	48,750.00	361,818.75	686,931.25	702,662.50	(1,000,000.00)	(345,000.00)	(655,000.00)	(670,000.00)	32,662.50	2,123.06	1,462.50	3,585.56
18	Year 14	1,000,000.00	48,750.00	393,281.25	655,468.75	671,200.00	(1,000,000.00)	(375,000.00)	(625,000.00)	(640,000.00)	31,200.00	2,028.00	1,462.50	3,490.50
19	Year 15	1,000,000.00	48,750.00	424,743.75	624,006.25	639,737.50	(1,000,000.00)	(405,000.00)	(595,000.00)	(610,000.00)	29,737.50	1,932.94	1,462.50	3,395.44
20	Year 16	1,000,000.00	48,750.00	456,206.25	592,543.75	608,275.00	(1,000,000.00)	(435,000.00)	(565,000.00)	(580,000.00)	28,275.00	1,837.88	1,462.50	3,300.38
21	Year 17	1,000,000.00	48,750.00	487,668.75	561,081.25	576,812.50	(1,000,000.00)	(465,000.00)	(535,000.00)	(550,000.00)	26,812.50	1,742.81	1,462.50	3,205.31
22	Year 18	1,000,000.00	48,750.00	519,131.25	529,618.75	545,350.00	(1,000,000.00)	(495,000.00)	(505,000.00)	(520,000.00)	25,350.00	1,647.75	1,462.50	3,110.25
23	Year 19	1,000,000.00	48,750.00	550,593.75	498,156.25	513,887.50	(1,000,000.00)	(525,000.00)	(475,000.00)	(490,000.00)	23,887.50	1,552.69	1,462.50	3,015.19
24	Year 20	1,000,000.00	48,750.00	582,056.25	466,693.75	482,425.00	(1,000,000.00)	(555,000.00)	(445,000.00)	(460,000.00)	22,425.00	1,457.63	1,462.50	2,920.13
25														
26	*Under this scenario - Contributions for Capital that is work in progress is applied against rate base, reducing the required debt and equity financing for a short term. The capital work in progress accumulates AFUDC as*													
27	*the relative contributions are funding existing rate base.*													

ATCO Electric YUKON

September 28, 2023 AEY-YUB-002

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-002

Reference: 2023-24 GRA, Section 1.8, Deferral Accounts, PDF pages 13-14 and 20; 2023-24 GRA Schedules, S8.4, Continuity Schedule of No Cost Capital and S 8.8, Continuity Schedule of Deferred Charges & Credits

Issue: Deferral and reserve accounts

Quote: GRA, PDF pages 13-14:

> 17. AEY is seeking approval to use the following deferral accounts during the Test Period:

Table 1.3: Deferral Accounts

Board Orders or Legislative Changes	Section 1B
Industrial Rider R Flow Through	Section 2
Purchased Power Flow Through	Section 3
Independent Power Producers (IPP) Flow Through	Section 3
Diesel Fuel Deferral Account	Section 4

GRA, PDF page 20 (excerpt of first two rows of Attachment 1.2:

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Issues List

Issue	Section	Request
Board Orders or Legislative Provisions Deferral	Section 1B	AEY seeks the ability to flow-through (dollar for dollar) costs and savings related to Board Orders or legislative provisions resulting in changes to the rules or parameters under which AEY operates, or that bear on the nature and extent of AEY's obligations as a regulated utility, and which impact its 2023-2024 revenues or revenue requirement.
Independent Power Producers (IPP) Deferral	Section 03	AEY is requesting deferral treatment on both Constraint Payments as well as maintenance costs related to the IPP projects.

GRA Schedule, S8.4, Continuity Schedule of No Cost Capital (excerpt Line Nos. 4-8):

Deferred Credits Mid-Year Balance Summary
Rate Case Reserve
Watson Lake LNG Study Costs
Demand Side Management Program Costs
Pension Deferral Account
ERA/IPP Legal Costs
Total Deferred Credits Mid-Year Balance

Preamble: The Board requires further information respecting AEY's approved and proposed deferral and reserve accounts.

Request:

(a) Please confirm that the reserve accounts shown on GRA Schedule S8.4 are currently approved and that AEY is not proposing to establish any further reserve accounts during the test period. If not confirmed, please explain fully.

(b) Please reconcile the deferral accounts identified in Table 1.3: Deferral Accounts (PDF page 14) and Attachment 1.2 (PDF page 20) of AEY's GRA with the deferral accounts identified on GRA Schedule S8.8.

In the response, please confirm that the deferral accounts referred to in this IR are currently approved and that AEY is not proposing to establish any further deferral accounts during the test period. If not confirmed, please explain fully.

(c) For each of the deferral and reserve accounts identified in requests (a) and (b), please provide the Operations & Maintenance (O&M) account in which the expense is being recorded or is proposed to be recorded.

(d) Please describe how the Board Orders or legislative provisions deferral account would work. Specifically address whether AEY would come before the Board for permission to address certain shortfalls which may arise in future because of Board Orders or legislative provisions.

(e) Have Board Orders impacted AEY's revenue requirement set for a test year without a new subsequent proceeding? If so, please indicate which order(s) and describe how AEY was impacted.

(f) Have any legislative provisions impacted AEY's revenue requirement set for a test year without a new subsequent proceeding? If so, please indicate which legislative provision(s) and describe how AEY was impacted.

(g) Does an alternative to a deferral account exist in which AEY can mitigate the effect of these types of issues?

Response:

(a) Confirmed. AEY notes that not all accounts included in No Cost Capital (Schedule 8.4) are reserve accounts; they are differentials between accrual and cash-based accounting which are net with AEY's equity and debt financing.

(b) (i) Please refer to AEY-YUB-002(b) Attachment 1 for a reconciliation between deferral accounts identified in Table 1.3: Deferral Accounts, Attachment 1.2 and Schedule 8.8.

- Table 1.3 was intended to summarize where information on certain deferral accounts is located in the Application narrative and is not a comprehensive listing of all deferrals. Previously approved deferrals that have no incremental cost within this Application were not included in Table 1.3.
- Attachment 1.2 was intended to identify the material changes, including new deferral accounts requested since the 2016-2017 GRA for ease of review.
- Schedule 8.8 includes all deferrals and reserve accounts, which are settled through the amortization of deferred charges.

(ii) Not all deferrals have been approved. AEY is seeking approval for the Board Orders or Legislative Changes and the Independent Power Producers (IPP) Flow Through Deferrals, which are outlined further below.

Board Orders or Legislative Changes: AEY seeks the ability to flow-through (dollar for dollar) incremental costs and/or savings related to Board Orders or legislative provisions resulting in changes to the rules or parameters under which AEY operates, or that impact the nature and extent of AEY's obligations as a regulated utility, and which impact its 2023-2024 revenues or revenue requirement. Please refer to the response to parts (e)

and (f) below for the impact that these changes can have on AEY's revenue requirement.

Independent Power Producers (IPP) Flow Through: The IPP deferral account is necessary as it is intended to capture cost variances associated with the significant uncertainty related to the startup phases of IPPs, including the costs recoverable under OIC 2019/25, legal and contracting expenses, costs of system constraint, and maintenance expenses. AEY incurs these costs to support the Yukon Government's Our Clean Future strategy.[1] In AEY's experience, IPP projects in off-grid communities involve considerable technical, commercial, legal, and operational complexity, which makes the associated costs difficult to forecast and material, necessitating deferral treatment. Please refer to AEY-YUB-002(b) Attachment 1, column I, for the Operations & Maintenance (O&M) activity in which the expense is being recorded or is proposed to be recorded for deferral and reserve accounts identified in requests (a) and (b). As outlined in the attachment, not all reserve or deferral expenses are recorded in O&M.

(c) AEY is not requesting that this deferral account provide blanket ability to flow through costs without seeking Board approval. Any balance(s) as a result of a Board order or legislative change would be put in the deferral account and brought forward by AEY for consideration in AEY's next GRA or in a limited scope Deferral Application. Within those proceedings, the Board would have the opportunity to test and review the proposed deferral for prudency and eligibility for recovery or refund. Amounts approved by the Board would be included in AEY's revenue requirement for recovery from or refund to customers and balances disallowed would be removed from revenue requirements.

[1] From Page 48 of Our Clean Future: "Our target is to have an operating independent power production project in all off grid communities by 2030 in order to reduce diesel use for electricity generation by 30 percent by 2030."

(d) Board Orders have typically not impacted AEY's revenue requirement in the past. However, as programs related to Our Clean Future and the overarching energy transition mature, there is potential that Board Orders may be issued which impose requirements on utilities regarding the Yukon's EV charging network, IPPs and Micro-generation. In addition, Board Orders may be issued as grid modernization efforts are realized, and technology allows more complex demand side management practices. Accordingly, having a deferral account in place would provide AEY with the opportunity to seek recovery in an unprecedented time of change and transformation across the entire industry. This deferral would support business decisions and enable quicker response time as transformational changes occur.

(e) The Yukon Government has been introducing policies geared towards transitioning the energy industry through increased electrification and reducing carbon emissions, as seen with the "Our Clean Future" initiative. The impact of these changes, as outlined in Section 1B of the Application and the Concentric Report included in the Application, include impacts related to Grid Modernization, Independent Power Production (IPP) legislation, the expansion of the Electric Vehicle (EV) Charger Network and Micro-Generation, which are outlined further below.

Not all costs associated with these initiatives are being tracked separately, nor have they been realized as some of these programs are in the very early stages. Therefore, the impact they will have on AEY's revenue requirement is not completely known. AEY notes that legislative or policy changes can result both in higher costs as well as relief from rising costs, such as the legislated carbon tax credits.

Programs such as those identified above can impact AEY through a variance related to either sales or costs. Furthermore, AEY is unsure if Federal or Territorial

grants will cover any of these costs. AEY generally has no control over these policies or programs, has no way to forecast with certainty the impact related to these programs and, therefore, considers it appropriate to seek deferral account treatment for these items.

Grid Modernization: Grid Modernization is increasingly recognized within the utility industry as a necessary response to changing Government policies, technologies, and customer behaviors, since these factors will fundamentally alter the future operation of the distribution grid. As outlined in the Application, one of the Grid Modernization programs that AEY is initiating in this Test Period is the Advanced Metering Infrastructure (AMI) program in Whitehorse, which AEY has estimated will cost approximately $0.4 million. For additional information on AMI, please refer to AEY-YUB-065.

Independent Power Production (IPP) Policy The IPP Policy was adopted by the Yukon Government in October 2015 and provides opportunities for non-utility entities to generate new power that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy. Costs related to IPP projects, specifically the establishment of Electricity Purchase Agreements with IPPs, which are captured in the EPA/IPP Deferral Account on Schedule 8.8, lines 54 through 60. Costs related to constraint payments are captured in Schedule 3.1, line 23. As outlined in Section 3.4 of the Application, in addition to constraint payments, AEY is responsible for the maintenance of the Battery Energy Storage System (BESS), Microgrid Controller (MGC) and distribution and generation interconnections of the IPP projects. As this is a new area, there is a degree of uncertainty regarding the quantum of work and effort required to maintain the BESS, MGC and other system integration components required for the IPP projects to successfully operate.

Electric Vehicle (EV) Charger Network: Demand for electricity is expected to increase for electric vehicles, making it more challenging for AEY to accurately forecast demand growth and the timing of when these changes will occur.[2] In "Our Clean Future", the Yukon Government has outlined a goal of expanding the EV Charger Network.[3] The proposed expansion of the EV network is expected to result in a number of new connection points to the grid in AEY's service area. In addition, the Federal Emissions Reduction Plan has set a mandatory target that 100 percent of new light-duty vehicles and passenger trucks are zero-emission by 2035. This will have a significant impact on remote grids and utilities, and regulators and governments will be required to respond accordingly. Due to the uncertainty of this program and the grants that may be available, AEY is unable to quantify the expected impact on revenue requirement.

Micro-Generation (MG): In "Our Clean Future", the Yukon Government has outlined a goal of reducing diesel use for electricity generation by 30 percent in Off-Grid communities by 2030[4] by establishing community-based renewable electricity projects in order to reduce diesel use for electricity generation by 30 percent. As outlined in the Application, AEY's isolated communities are at peak capacity for MG based on the reliability restrictions of the program. Though the community MG peak capacity is reached, and as the energy transition continues, there is consistent demand to review or expand the reliability restrictions for MG in the isolated communities. There is concern that this increased demand may lead to policy changes in the MG program that will lead to changes to the electrical grid. Due to the uncertainty of this program and the grants that may be available, AEY is unable to quantify the impact on revenue requirement.

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2 2023-2024 AEY GRA, Section 8, Attachment 8.1, PDF p.169.

3 "Our Clean Future", p. 35. https://yukon.ca/en/our-clean-future-yukon-strategy-climate-change-energy-and-green-economy.

4 "Our Clean Future", p. 20. https://yukon.ca/en/our-clean-future-yukon-strategy-climate-change-energy-and-green-economy.

(g) The proposed deferral accounts were considered as part of the recommended risk premium in AEY's proposed ROE. In the absence of these deferrals, it would be appropriate to apply a risk premium on the higher end of the range (40-100 basis points), identified on page 33 of the Concentric Report.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Deferral and Reserve Accounts

Line No.		Reserve / Deferral Account	Table 1.3[1]	Attachment 1.2[2]	Schedule 8.8	Regulatory Schedule	O&M Activity Name & Number	Approved
2	**Reserve Accounts**	Injuries & Damages	Not Included	Not Included	Not Included	Schedule 8.4 Line No 26-32	72400 - Injuries & Damages Schedule 5.1, Line No. 41	Yes
3		Rate Case Costs	Not Included	Not Included	Included	Schedule 8.8 Line No. 19-26	72100 – Administrative	Yes
4	**Deferral Accounts**	Industrial Rider R Flow Through	Included	Not Included	Not Included	Schedule 13.1	Not included in O&M	Yes
5		Purchased Power Flow Through	Included	Not Included	Not Included	Schedule 3.1	Not included in O&M	Yes
6		Diesel Fuel Deferral Account	Included	Not Included	Not Included	Schedule 4.1	Not included in O&M	Yes
7		Watson Lake LNG Study Costs	Not Included	Not Included	Included	Schedule 8.8 Line No. 28-35	Not included in O&M. No costs have been or will be incurred, once all balances have been settled this account can be discontinued.	Yes
8		Demand Side Management (DSM)	Not Included	Not Included	Included	Schedule 8.8 Line No. 37-44	Not included in O&M	Yes
9		Pension Deferral Account	Not Included	Not Included	Included	Schedule 8.8 Line No. 46-52	Embedded in labour costs within multiple activities in Schedule 5.1	Yes
10		Board Orders or Legislative Changes	Included	Included	Not Included	Not included	Will depend on the nature of the costs	No
11		Independent Power Producers (IPP) Flow Through	Included	Included	Included	Schedule 8.8 Line No. 54-60	Will depend on the nature of the costs	No

12
13
14 (1) 2023-2024 AEY GRA, Section 1.9, PDF p. 14.
15 (2) 2023-2024 AEY GRA, Section 1.11, PDF p. 20.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-003

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-003

Reference: 2023-24 GRA, Section 1.9, Key Assumptions, PDF pages 14-17

Issue: Key assumptions – labour and inflation

Quote: GRA, Table 1.4, PDF page 14:

Table 1.4: Key Assumptions
(%)

	2023	2024
In-scope Labour Inflation	2.00	2.50
Out-of-scope Labour Inflation	2.90	2.50
Other Inflation	3.80	2.50
Vacancy Rate	3.65	3.65
Long Term Debt Rate	4.56	4.56

GRA, Table 1.4, PDF page 16:

Table 1.4: FTEs

	FTEs
2017 Approved Ending Complement	**68.13**
Program Manager, Renewables & Grid Modernization	1.0
Engineering Technologist, Renewables & Grid Modernization	1.0
Engineers	3.0
Team Lead, Plant	1.0
Field Services Representative	1.0
Supervisor, Business Support Services	0.75
VP and VP Support Services	-0.8
Head Office Personnel	1.18
2024 Forecast Ending Complement	**76.26**

Request:

(a) Please provide details respecting inflation rates either applied for or approved in B.C. or the Northwest Territories for either in-scope or out-of-scope utility labour costs.

(b) Please provide a copy of the referenced Yukon Economic Outlook issued by Yukon Economic Development (March 2023).

(c) Please provide AEY's calculation for determining the vacancy rate of 3.65 percent based on "a five-year historical average normalized for exogenous events." Please ensure that detail addressing the normalization of exogenous events has been provided.

(d) What was AEY's actual 2017 FTE complement? Please explain any variance between the 2017 Approved Ending Complement (68.13 FTEs) and the 2017 Actual Ending Complement.

(e) Referring to Table 1.4: FTEs above, please clarify if the Engineering Technologist, Renewables & Grid Modernization (2016) 1.0 FTE was approved in 2016-17. Please also clarify if any of the other FTEs that make up the difference between 68.13 and 76.26 FTEs were approved in 2016-17.

(f) For any proposed 2023-24 FTE addition that is the result of an allocation, please provide detail that supports the percentage allocation to AEY for that FTE. How does this allocation percentage affect labour costs related to AEY's 2017 approved FTE complement as they pertain to labour costs in its 2023-24 GRA?

Response:

(a) FortisBC has applied for a blended labour/non-labour rate of 4.517 percent for 2023[1] and 4.080 percent for 2024.[2] For Northwest Territories, the in-scope rate applied for is 3.5 percent, and the out-of-scope rate is 4.0 percent.[3]

(b) Please refer to AEY-YUB-003(b) Attachment 1.

1 https://docs.bcuc.com/documents/proceedings/2022/doc_67371_b-2-fbc-2023-annualreview-application.pdf, PDF p. 22.
2 https://docs.bcuc.com/documents/proceedings/2023/doc_72776_b2fbc2024annualreviewratesapplication.pdf, PDF p. 23.
3 https://www.nwtpublicutilitiesboard.ca/sites/nwtpub/files/supporting/2023%2003%2007%20Northland%20Utilities%20%28NWT%29%20Limited%202023%20Amended%20General%20Rate%20Application.pdf pp. 1-6, para.18.

(c) Please refer to Table 1 below. Please note that the actual FTE excludes exogenous events, such as vacancies driven by vaccine policies. These exogenous events have been normalized for in the vacancy rate calculation below.

Table 1: Vacancy Rate

	FTE				
Year	**Actual**	**Forecast**	**+/-**	**Vacancies**	**%**
2018	63.80	68.17	(4.37)	4.37	6.4
2019	65.21	67.17	(1.96)	1.96	2.9
2020	65.80	67.67	(1.87)	1.87	2.8
2021	66.30	68.67	(2.37)	2.37	3.5
2022	68.80	70.67	(1.87)	1.87	2.7
5 Year Average				**2.49**	**3.65**

(d) AEY's actual FTE complement in 2017 was 64.13, it was below the approved 68.13 due to unplanned vacancies.

(e) No, the Engineering Technologist, Renewables & Grid Modernization was not approved in 2016-2017. All of the FTEs noted in Table 1.4 are changes from what was approved in 2016-2017.

(f) AEY confirms that there are no proposed 2023-2024 FTE additions resulting from allocations. All FTE are direct charged to AEY.

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Introduction

The 2023–24 Fiscal and Economic Outlook presents the territory's current fiscal and economic position and expectations for the medium term. The Government of Yukon is moving the territory toward a sustainable and prosperous future while ensuring responsible fiscal management across all government programs and services. The Yukon is recovering from the impacts of the pandemic and the economic outlook is positive.

Despite the recent challenges created by higher rates of inflation, expectations are that the Yukon will build on 2022's robust economic growth, with further real Gross Domestic Product (GDP) gains and an outlook highlighted by a strong labour market and additional population growth. The government remains committed to working closely with partners in the public and private sectors, including First Nations governments, to ensure a strong, diversified and sustainable economy for all Yukoners. Overall, the territory's economy is well-positioned to address the challenges ahead and continue growing in the coming years.

Part 1: The Yukon's finances

In the 2023–24 Budget, the Yukon government is delivering on its longstanding commitment to growing the economy while ensuring strong, sustainable fiscal management. The government projects a surplus of $48.2 million in 2023–24 and projects to remain in a surplus position throughout the duration of this fiscal outlook. A surplus of 2-3 per cent of the total budget is a prudent fiscal management tool and demonstrates the ability of the government to address unforeseen events without going into deficit. Maintaining a surplus position lessens the government's potential need to borrow funds and reduces the net debt position. The expected fiscal position in 2023–24 reflects a focus on strategically allocating resources to the ongoing priorities of Yukoners.

Table 1. Fiscal summary

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Revenue[1,2]	1,460.2	1,504.5	1,575.4	1,663.5	1,719.2
Expense[3]	(1,644.6)	(1,683.8)	(1,642.4)	(1,716.5)	(1,769.1)
Contingency for Anticipated Expenses	(10.0)	(10.0)	(50.0)	(50.0)	(50.0)
Accounting Adjustments[4]	233.9	233.2	165.2	161.7	144.9
Surplus/(Deficit)[5]	39.5	43.9	48.2	58.8	45.1
Net Financial Assets/(Debt), end of year[6]	(207.5)	(298.5)	(374.8)	(453.0)	(528.0)

Source: Department of Finance. Numbers may not add due to rounding.

1. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are included in the Accounting Adjustments in this table.

2. Figures for revenue, contingency for anticipated expenses and surplus (deficit) are found on Pages S-8 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

3. Figures for expense and accounting adjustments are found on Pages S-18 of the 2023–24 Main Estimates and equivalent pages of budget documents for other periods.

4. Accounting Adjustments are the sum of "Tangible Capital Assets (net)," "Investment in Land Development," "Expenditures on Loan Programs," and "Other Adjustments (net)," on Page S-9 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

5. Surplus/(Deficit) is the sum of Revenue, Expense, Contingency for Anticipated Expenses, and Accounting Adjustments.

6. Found on Page S-9 of the 2023–24 Main Estimates.

Net financial debt, or net debt as it is often known, is expected to increase by $76.3 million in 2023–24 to a total of $374.8 million. Recent increases to the government's net financial debt position were incurred to fund ongoing maintenance of the territory's infrastructure and to invest in new projects that will benefit Yukoners now and well into the future. In standard accounting, net financial debt is a measure of how much the government would need to pay if all of its liabilities were due immediately. It does not mean government needs to borrow those funds. Most of the government's net debt position is for long-term liabilities that will not be realized all at once.

Part of the changes to net debt reflect a new accounting standard that came into effect in April 2022. These new rules require the government to record and measure future financial obligations to retire government assets from service, such as buildings or equipment, once they are no longer of productive use. The estimated future costs to retire an asset are then recognized over an asset's productive life. The increase to net debt from 2022–23 includes an additional $54.3 million to reflect accounting changes to align with the new standard. The new standard is also expected to increase net debt by approximately $1.6 million annually.

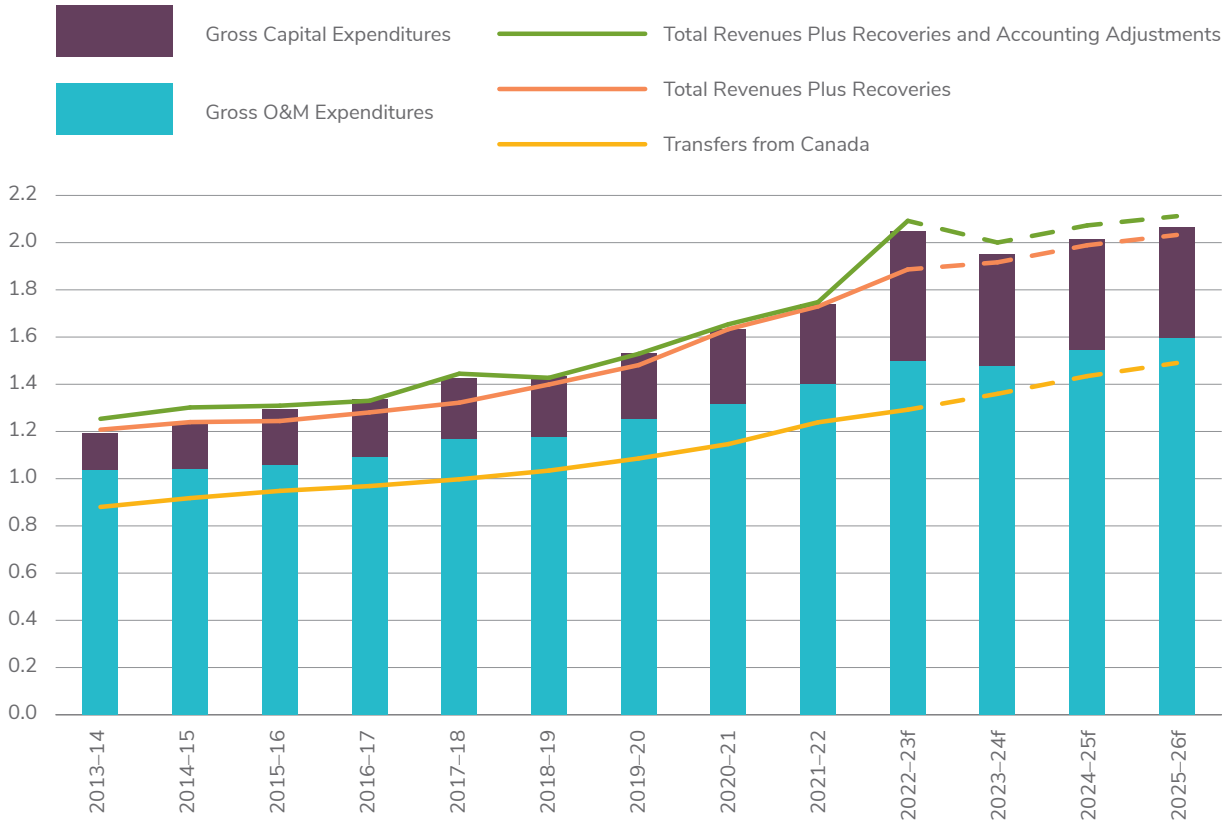
The government is committed to maintaining fiscal sustainability. To achieve this, the government has reviewed spending commitments to ensure expenditures are effectively being used within the framework of expected revenues. These measures will help to ensure that the government is able to meet its spending commitments while maintaining a healthy fiscal position. Capital expenditures are forecast to decrease by $35.2 million or 9.9 per cent, net of recoveries, from the 2022–23 Main Estimates to preserve the government's strong fiscal standing and address increasing inflation while continuing to invest in priority areas. The decrease to capital spending is partially offset by an increase to the forecast for Operations and Maintenance (O&M) expenditures of $33.0 million or 2.6 per cent, net of recoveries, from the 2022–23 Main Estimates.

The government's fiscal summary for 2023–24 also includes a $50 million contingency for areas of expected, but presently undefined, expenditures. The government has benefitted from this realistic approach to budgeting in recent years for COVID-19 spending and we are continuing this approach for expected cost pressures. These costs are not presented in departmental budgets in the coming fiscal year as the expenditures are not yet known. They are included in the overall financial framework so that they will not affect the Yukon's forecast fiscal position, should they be needed. This allows the government to remain transparent about potential pressures and would require legislative authority.

In Chart 1, forecast spending and revenue for the Yukon, including recoveries, from 2022–23 through 2025–26, are compared to historical spending as reported in the Yukon's Public Accounts. In recent fiscal years, growth in government spending has increased in line with revenue growth. For the fiscal years between 2013–14 and 2022–23, O&M expenditures have grown by 5.1 per cent annually and revenues have grown by 5.0 per cent annually, on average. For 2023–24 to 2025–26, expenditures and revenues are expected to change at a similar pace, with expenditures growing by an annual average of 2.3 per cent, while government revenues are expected to grow at an average of 2.5 per cent annually.

Chart 1. Government of Yukon fiscal indicators[7,8]

Expenditures and revenues ($ billions)



Source: Department of Finance *f = forecast*

7. Fiscal years 2013–14 to 2021–22 represent actuals as reported in the Yukon's Public Accounts. For comparability, forecasts for fiscal years 2022–23 to 2025–26 use the same methodology, which differs from the presentation in Table 1 above.

8. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are netted-out of the gross expenditures presented in this chart.

Revenue

Government revenues rely heavily on transfers from the Government of Canada, supplemented by own-source revenues that are mostly driven by economic activity. The Yukon government's revenue is critical to ensuring that the government has the resources needed to meet its spending commitments. As shown in Table 2, total revenue, excluding recoveries, is expected to be $1.58 billion in 2023–24. This represents an increase of $70.9 million, or 4.7 per cent, from the most recent estimates in the 2022–23 Supplementary Estimates #2. This increase is primarily driven by the territory's economic position and a changing fiscal situation across Canada, which affects federal transfers.

Table 2. Revenue by type[9,10]

($ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Transfers from Canada	**1,244.4**	**1,261.4**	**1,327.0**	**1,400.3**	**1,454.7**
Tax revenue	**157.7**	**175.0**	**170.9**	**177.2**	**182.2**
Personal income tax	89.9	100.7	98.4	102.4	105.6
Corporate income tax	24.4	32.0	27.4	27.8	28.4
Property tax	7.0	7.0	7.2	7.6	7.7
Fuel oil tax	9.7	8.7	8.8	8.8	8.9
Tobacco and alcohol taxes	18.6	18.4	20.0	20.7	21.1
Insurance premium tax	8.1	8.2	9.0	9.9	10.6
Other revenue	**58.1**	**68.1**	**77.5**	**85.9**	**82.3**
Liquor profit	9.4	7.5	8.8	8.8	9.1
Licenses, fees, registrations and permits	17.6	17.1	18.3	18.7	19.2
Sale of land	19.2	20.8	32.3	34.2	31.3
Other revenue	12.0	22.8	18.1	24.2	22.6
Total revenue	**1,460.2**	**1,504.5**	**1,575.4**	**1,663.5**	**1,719.2**

Source: Department of Finance. Numbers may not add due to rounding.

9. All revenue figures are found on Pages S-14 and S-15 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

10. To align with the presentation in the Yukon's Public Accounts, revenues do not include those collected by the Yukon Housing Corporation.

Transfers from Canada

Transfers from Canada, which includes the Territorial Formula Financing grant, represent about 84 per cent of the Yukon's total revenue in 2023–24. Territorial formula financing helps to reduce the gap between the Yukon's ability to raise revenue and its spending needs for core services.

The grant is responsive to changing economic and demographic circumstances in the territory compared to the rest of the country. This includes changes in public spending across the country, which are increasing due to the high inflationary environment and associated inflation relief programs. The growth in spending for other provinces and territories have an upward impact on the Yukon's Territorial Formula Financing grant. However, the improved outlook on the grant is being offset somewhat by growth in resource revenues. Resource revenues in the territory are expected to increase as royalties increase, which would have a downward impact on revenue from the Territorial Formula Financing grant. Under the Devolution Transfer Agreement with Canada, the Yukon's grant is reduced dollar for dollar of resource revenues in excess of $6 million in any given year. Resource revenues subject to offset were $10.2 million in 2021–22, meaning the grant in 2023–24 will be reduced by $4.2 million.

At the time that the 2023–24 Main Estimates were prepared, the Yukon government, along with other provinces and territories, were discussing increases to the Canada Health Transfer that could strengthen the healthcare system for the benefit of all Canadians. The Canada Health Transfer forms part of the overall transfers from Canada. Increases to the Canada Health Transfer have not yet been included in expected revenues for 2023–24.

Taxation revenue

The Yukon's own-source revenue from taxation is forecast to decrease in 2023–24 from the 2022–23 Supplementary Estimates #2. Personal and corporate taxation revenues are expected to be strong in 2023–24, but are forecast to be lower than current estimates for 2022–23 primarily due to a non-recurring adjustment for the 2021 tax year in 2022–23. Adjustments for prior tax years are common due to the timing of final reconciliations of tax assessment information. Corporate income tax projections for 2022–23 have been revised upward from stronger than expected corporate profits but are expected to return to trend in 2023–24.

Personal income tax revenues are expected to continue to be strong due to high inflation and the territory's strong labour market performance, which is increasing individual taxable incomes. Business performance continues to be strong in the territory, but corporate income tax revenue can see large variations from year-to-year. The outlook for corporate taxation, while still expected to increase, has also been reduced from projections in previous years due to a change in federal tax provisions that increases the scope of businesses eligible for the small business tax rate. In the Yukon, the small business tax rate is zero per cent.

The forecast for tax revenue from tobacco products has increased. The *Tobacco Tax Act* links changes to the tax rate to changes in the Consumer Price Index (CPI), so the tax rate increased from 31 cents to 32 cents per cigarette as of January 1, 2023. Under the current outlook for inflation, the tax rate for tobacco products is expected to increase to 37 cents per cigarette by the end of 2027.

Expectations for fuel tax revenue in 2023–24 are lower than in the 2022–23 Main Estimates. Fuel tax revenues have not returned to pre-pandemic levels, which could be partly explained by the tourism industry continuing to operate below levels experienced prior to the start of the pandemic. The ongoing outlook for fuel taxes is expected to be mostly flat as more Yukoners adopt electric vehicles and make other transportation choices that are consistent with the Yukon's *Our Clean Future* strategy.

Aside from changes to the tobacco tax, there are no changes to tax rates proposed as part of the 2023–24 budget.

Other revenue

In addition to transfers from Canada and taxation revenue, the government also generates revenue from other sources. These include liquor profit, licenses, fees, registrations, permits and proceeds from land sales. Revenue from these sources are expected to exceed recent levels, in part due to elevated revenue from land sales.

Operations and maintenance expense

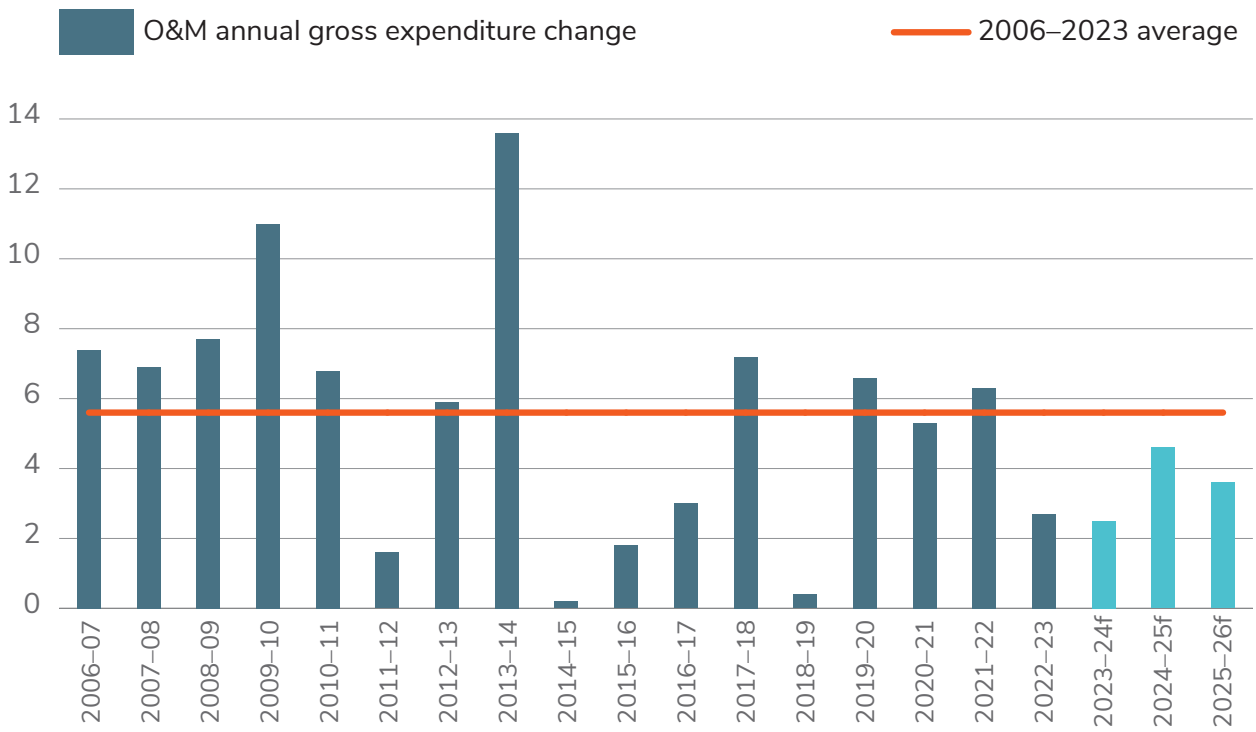
O&M spending for 2023–24 is budgeted at $1.45 billion, which reflects a $35 million, or 2.5 per cent, increase over the previous year's Main Estimates. The increase in spending is primarily for:

- making day-to-day life more affordable for Yukoners;
- investing in the Yukon's health and social system;
- addressing the substance use health emergency;
- improving sustainability and preserving the territory's environment;
- investing in housing and related services, particularly for the most vulnerable; and
- continuing to build relationships and foster reconciliation with Yukon First Nations.

Chart 2 compares forecast gross O&M spending from 2022–23 through 2025–26 to actual historical O&M spending as reported in the Yukon's Public Accounts. The average annual growth in O&M spending between 2006–07 and 2022–23 was 5.6 per cent. Forecast O&M spending growth in 2024–25 and 2025–26 is anticipated to remain below the average at approximately 4.5 per cent and 3.5 per cent, respectively.

Chart 2. Annual growth in O&M budgets

Change in Government of Yukon gross O&M spending (per cent)



Source: Department of Finance *f = forecast*

Higher rates of inflation continue to be the reality for Yukoners, and family budgets are becoming tighter. The government continues to take steps to provide targeted inflationary relief to families, especially the most vulnerable. The government continues to assess how inflation is impacting Yukoners. In 2023–24, the government is extending the Inflation Relief Rebate Program, which provides a $50 per month rebate on ATCO Electric and Yukon Energy utility bills for the April and May billing periods, along with an additional three months later in the year. Other measures in the 2023–24 Budget to help make life more affordable for Yukoners include funding for food in Yukon schools, the timber harvesting incentive to boost fuelwood supply, a quarterly top-up of $150 to eligible recipients of the Yukon Senior Income Supplement and a $100 monthly increase to eligible Social Assistance recipients.

With the COVID-19 State of Emergency coming to an end in March 2022, the Yukon is now adapting to living with the risks from COVID-19 while continuing to support Yukoners' well-being. However, healthcare systems across Canada, including the Yukon, continue to be strained following the pandemic. Healthcare workers are experiencing stress and burnout, and people seeking health services are experiencing long wait times due to staff shortages. The 2023–24 Budget includes funding to improve supports for critical staff, including recruitment and retention bonuses for nurses, negotiated increases with the Yukon Medical Association, a human resources strategy to improve health care worker recruitment and adding nursing positions in rural locations. The government also continues to act on the recommendations from the *Putting People First* report. This includes funding for the territory's dental plan, early learning and childcare.

In 2023–24, the government will continue to support the needs of individuals and communities impacted by the substance use health emergency. This includes additional funding to address the harms of substance use, combat the supply of harmful substances through additional RCMP supports, and help youth with substance use challenges. Together, these initiatives support people who are struggling with addiction and mental health issues and help to reduce the harm caused by substance use in communities.

Many areas across Canada are facing housing shortages and challenges with housing affordability. In 2023–24, the government will continue working to meet the housing needs of Yukoners, including partnering with the private sector on lease costs and supportive services for seniors at the new Normandy Living facility in Whitehorse. The Budget also includes funding to ensure the Yukon Housing Corporation's housing stock remains safe and well maintained.

The government remains fully committed to supporting reconciliation and respectful partnerships with Yukon First Nations governments. The government is working in partnership with Yukon First Nations on key priorities in 2023–24. This includes funding for Community Safety Officers and policing initiatives in communities, and support for the community safety planning priorities of Yukon First Nations governments in their communities.

The government continues to make progress on the implementation of *Our Clean Future* and protect the environment. The Yukon government is working in partnership with the Government of Canada to advance land use planning and species-at-risk protection in the Yukon through the *Bilateral Nature Agreement*. Through this, government will advance work towards the federal government's mandate to conserve and protect 25 per cent of land by 2025, and 30 per cent by 2030.

Five-Year Capital Plan update

With the 2023–24 Main Estimates, the Yukon government is publishing its sixth annual plan for its capital investment priorities over the next five years. The plan helps drive transparency, certainty and coordination with businesses, First Nations governments and municipalities.

Table 3. *Five-Year Capital Plan* gross expenditures by category

($millions)	2023–24	2024–25	2025–26	2026–27	2027–28	Totals
Climate change, energy and green economy	36	43	47	42	29	197
Land development, housing, education and health	133	84	78	81	93	470
Community and First Nations infrastructure	78	75	75	60	65	352
Transportation infrastructure	160	177	197	123	123	779
Real property and asset management	33	46	46	51	35	211
Information technology	45	51	18	17	14	146
Totals	**484**	**475**	**462**	**374**	**359**	**2,155**

Source: Capital Planning Office. Numbers may not add due to rounding.

The 2023–24 *Five-Year Capital Plan* includes approximately $2.15 billion in capital spending over the next five years. These investments will focus on improving access to stable and affordable housing, increasing accessibility to healthcare services, providing modern school facilities and advancing the territory's climate change goals. The government continues to leverage funding from the federal government and other partners to find offsets for over one-third of the capital spending in the plan.

The capital budget for 2023–24 is projected to be $483.8 million, a modest decrease from the 2022–23 Main Estimates. The government remains committed to robust and steady investments in the territory's infrastructure. However, it is prudent for the government to carefully consider how it is investing in capital projects to address increasing inflation by reducing previously planned capital spending in its *Five-Year Capital Plan*. The government has reviewed planned projects in the Plan to ensure it is maintaining its current assets while delivering on the new critical infrastructure that Yukoners need. For certain capital projects, the government is exploring innovative ways to deliver these projects, including partnering with municipalities or First Nations governments in the development of new infrastructure. This approach has resulted in a lower total spend in the next few years compared to earlier projections, while creating a more stable outlook for capital spending.

The government remains committed to robust and steady investments in the territory's infrastructure.

The government is making priority capital investments across six main areas in the 2023–24 *Five-Year Capital Plan*:

- $197 million for climate change, energy and green economy projects to continue to advance the *Our Clean Future* strategy and invest in sustainable jobs in the territory. In 2023–24, this includes investing in renewable energy projects, such as solar installations and biomass, through the Green Infrastructure Program; and helping Yukoners increase the energy efficiency of their homes and businesses through the Better Buildings energy retrofit loans program.
- $470 million for land development, housing, education and health projects to ensure the territory can meet the housing, educational and healthcare needs of a growing population and economy. In 2023–24, this includes completing the Old Crow 10-unit mixed-use housing project and work on the Kêts'ádań Kų School in Burwash Landing.
- $352 million for community and First Nations infrastructure to meet infrastructure needs in communities across the territory, including working in partnership with Yukon First Nations and municipal governments on their priorities. In 2023–24, this includes work on a new Fire Hall building in Carmacks; upgrades to the existing Public Works building in Carmacks; and upgrades to the Teslin Tlingit Council community hub.
- $779 million for transportation infrastructure to invest in the territory's transportation system to keep Yukoners and the economy moving and advance the sustainability of supply chains critical to the Yukon. In 2023–24, this includes ongoing work on critical components of the Yukon's transportation infrastructure like the Nisutlin Bay Bridge project, Erik Nielsen Whitehorse International Airport runways and upgrades to the North Klondike Highway.
- $211 million for real property and asset management projects to build and maintain assets that are essential to the delivery of government services. In 2023–24, this includes continuing to retrofit the Old Territorial Administration Building in Dawson City and work on conceptual designs for potential expansions and recreational activities at several campgrounds across the territory.
- $146 million for information technology projects to enhance the territory's vital technological links to Canada and the world. In 2023–24, work will continue on the Dempster Fibre project, which will provide redundancy, increase reliability and reduce the risk of outages in the territory's critical telecommunications infrastructure.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Some important recently-completed projects include:

- $22 million, along with funding from Canada, for the Mayo to McQuesten Transmission Line replacement project, which came online in 2021 and is improving the quality and reliability of electricity infrastructure in the area;
- $22 million, in partnership with Canada, for the Faro Public Works & Fire Hall Building and the Watson Lake Municipal Services Building, which combine public works and fire services into a single shared space, saving money on both construction and long-term operating costs; and
- $21 million for the 47-unit residential housing complex at 401 Jeckell Street, completed in January 2023 in partnership with the Canada Mortgage and Housing Corporation. It is providing affordable homes of various sizes for low-income and vulnerable families, seniors and individuals.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Part 2: Economic overview

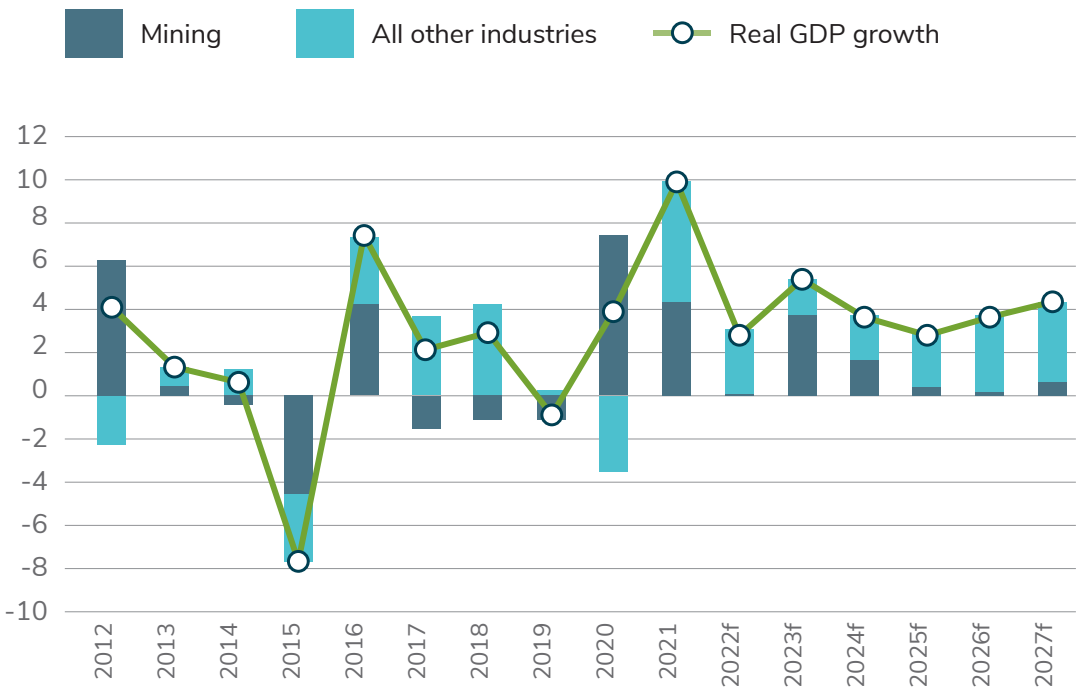
Positive outlook for real GDP growth

The outlook for the Yukon's economy remains positive. A strong labour market is leading to job growth and low unemployment. Tourism is coming back to the territory and the construction sector is busy. Inflation remains higher than anticipated but is expected to moderate with the stabilization of energy prices, improvements to global supply chains and an increase in interest rates that is beginning to absorb excess demand in the Canadian economy.

The Yukon's real GDP is expected to continue to expand. The Yukon led the country in real GDP growth in both 2020 and 2021, with 2021's increase of 10 per cent being the strongest in 13 years. The pace of this expansion returned to more normal levels in 2022 with estimated real GDP growth of 3.1 per cent, close to the Canadian growth estimate of 3.5 per cent. Last year's performance was impacted primarily by the mining sector with disruptions at the Eagle Gold mine and a temporary suspension of operations at the Keno Hill mine.

Chart 3. Further gains in real GDP expected in all years of the forecast

Contribution to real GDP growth (percentage points)



Source: Statistics Canada, Department of Finance *f = forecast*

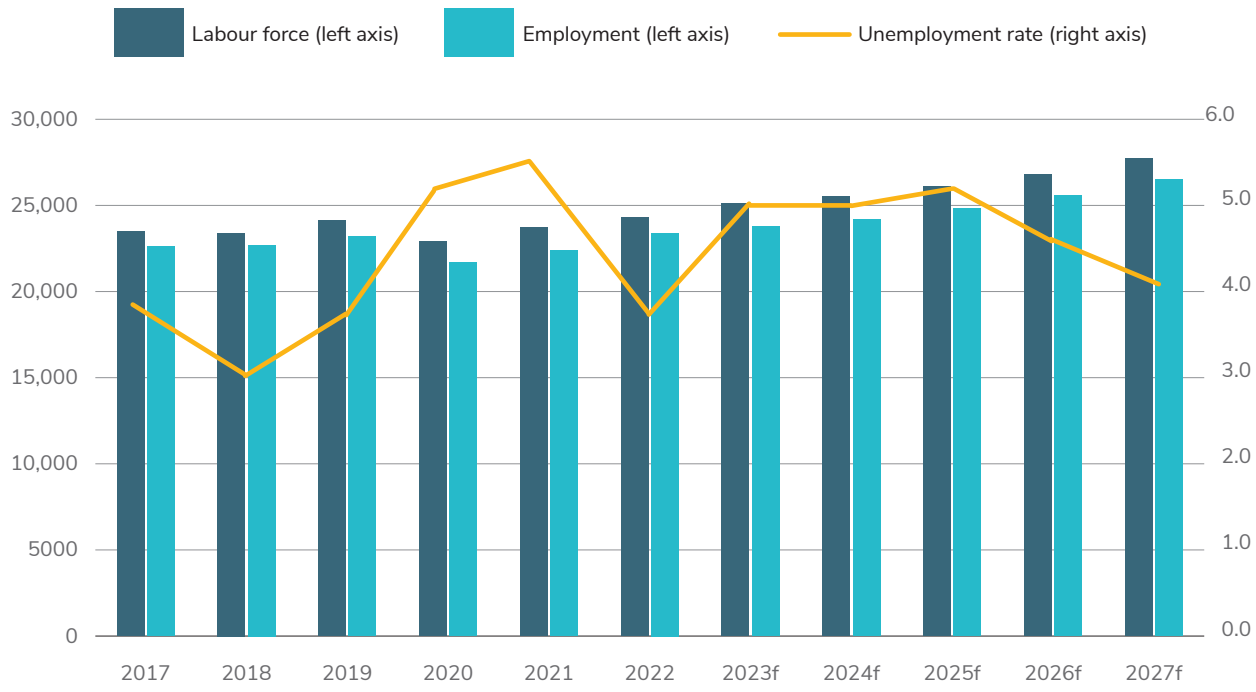
Production at Eagle Gold is expected to ramp up this year and operations at the Keno Hill mine are expected to resume in the third quarter. Higher mineral production and continued recovery of the tourism sector are expected to result in real GDP growth of 5.4 per cent in 2023 followed by 3.7 per cent growth in 2024. Further growth is projected throughout the remainder of the forecast, averaging 3.7 per cent growth through 2025 to 2027.

Further gains in the labour force and employment expected over the medium term

Strong demand for labour and increased economic activity spurred growth in the size of the labour force and employment as both reached record highs in 2022. Employment growth of 4.5 per cent last year outpaced the increase in the labour force and translated into a substantial decline in the territory's unemployment rate. At 3.7 per cent for the year, the Yukon's unemployment rate matched 2019's level and was the lowest in Canada.

Chart 4. Growth in employment and the labour force

Labour force (persons), employment (persons), unemployment rate (per cent)



Source: Statistics Canada, Department of Finance *f = forecast*

Many employers in the Yukon and across the country have had difficulty finding workers. Job vacancies have been elevated in the territory throughout 2022, with the Yukon's job vacancy rate[11] among the top two highest rates in the country for all but one month. Like the experience of many jurisdictions in Canada, the job vacancy rate for the Yukon has recently been higher than the unemployment rate[12], further evidence of a tight labour market (Chart 5).

Chart 5. 2022 has seen tightness in the labour market return

Labour market indicators (per cent)



Source: Statistics Canada

11. The job vacancy rate is the number of job vacancies expressed as a percentage of labour demand, defined as all occupied and vacant jobs.

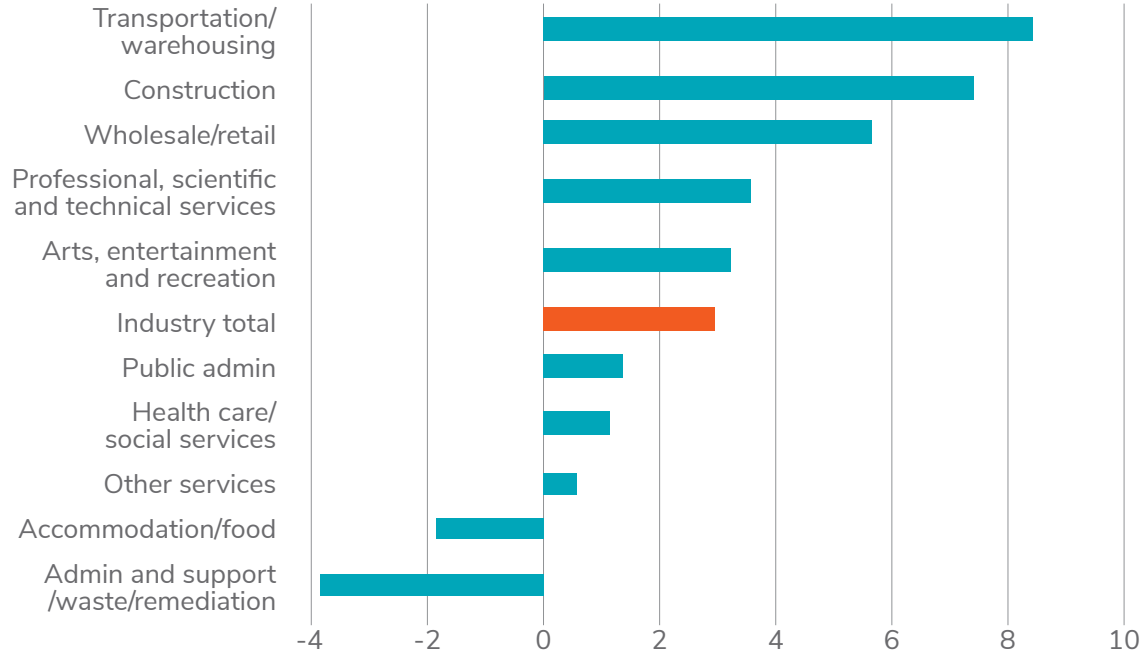
12. When the job vacancy rate exceeds the unemployment rate, this means there are proportionally more jobs seeking workers than workers seeking jobs.

Strong demand for workers at a time when supply is tight is placing upward pressure on wages and earnings. The average offered wage for vacant positions in the Yukon was the third highest in the country at $26.20 per hour in the third quarter of 2022[13], well above the national average of $24.20 per hour and up almost 10 per cent from 2021.

The recent increase in weekly earnings was not as pronounced as the increase in offered wages, but earnings are up across most industries (Chart 6). The average worker in the territory earned $1,334 per week through the first eleven months of 2022, up 2.9 per cent from the same period in 2021. Average weekly earnings for the Yukon ranked third in the country, behind only Nunavut and the Northwest Territories, and were well above the national average of $1,166 per week. While in some cases wages are not keeping pace with inflation, rising incomes have helped to mitigate the inflationary impacts being felt.

Chart 6. Wage pressures reflected in higher earnings across most industries

Average weekly earnings, seasonally adjusted, Jan–Nov 2022 change from Jan–Nov 2021 (per cent)



Source: Statistics Canada

Over the medium term, higher earnings are expected to draw more people into the labour force. The Yukon's labour force is projected to grow slightly faster than employment over the forecast period. This results in a higher projected unemployment rate in the neighbourhood of five per cent. While up from historic lows in recent years, the unemployment rate is projected to remain relatively low, and continue to be one of the lowest in Canada.

13. Average offered wage data is from Statistics Canada table 14-10-0325-01 and is available on a quarterly basis starting with the first quarter of 2015.

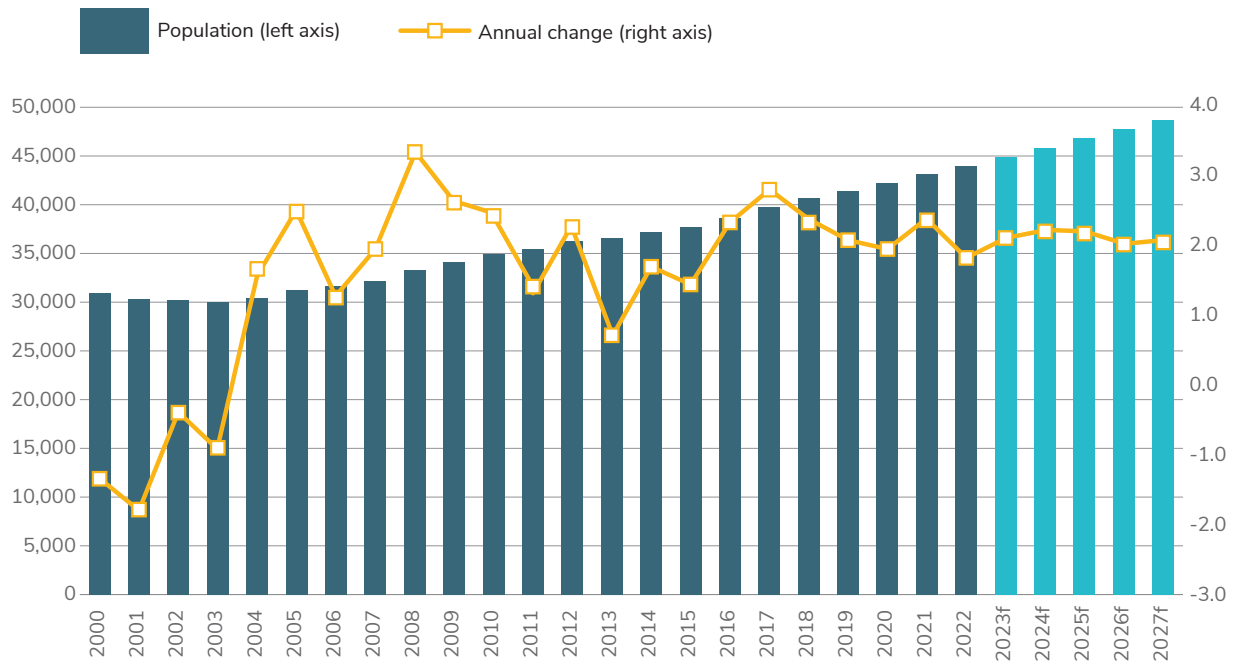
Further population gains anticipated in 2023

At 43,964 on June 30, 2022, the Yukon's population was up 1.8 per cent from 2021.[14] Growth in 2022 was driven primarily by net international migration of 550, which was the highest ever reported.[15] Over the last 20 years, the Yukon's population has grown just over 44 per cent. This growth was second only to Alberta (45.2 per cent) among all provinces and territories and was well ahead of the national growth of 24 per cent. A positive outlook for the territory's economy and labour market is expected to support strong migration into the Yukon and population growth over the medium term.

The federal government is targeting nearly 1.5 million new permanent residents over the 2023 to 2025 period.[16] High levels of immigration should increase the local supply of labour and help alleviate some of the tightness in the labour market. While helping on the labour front, more people moving to the territory has the potential to place further strain on the Yukon housing market, as supply has struggled to keep pace with demand in recent years.

Chart 7. Population is forecast to approach 49,000 by 2027

Population (persons), annual change (per cent)



Source: Yukon Bureau of Statistics *f = forecast*

14. June 30 estimates are considered annual estimates.

15. Statistics Canada's table 17-10-0005-01 reports data for population estimates by age and sex as of July 1.

16. *Government of Canada's Immigration Levels Plan for 2023–2025*. Immigration, Refugees and Citizenship Canada (November 1, 2022).

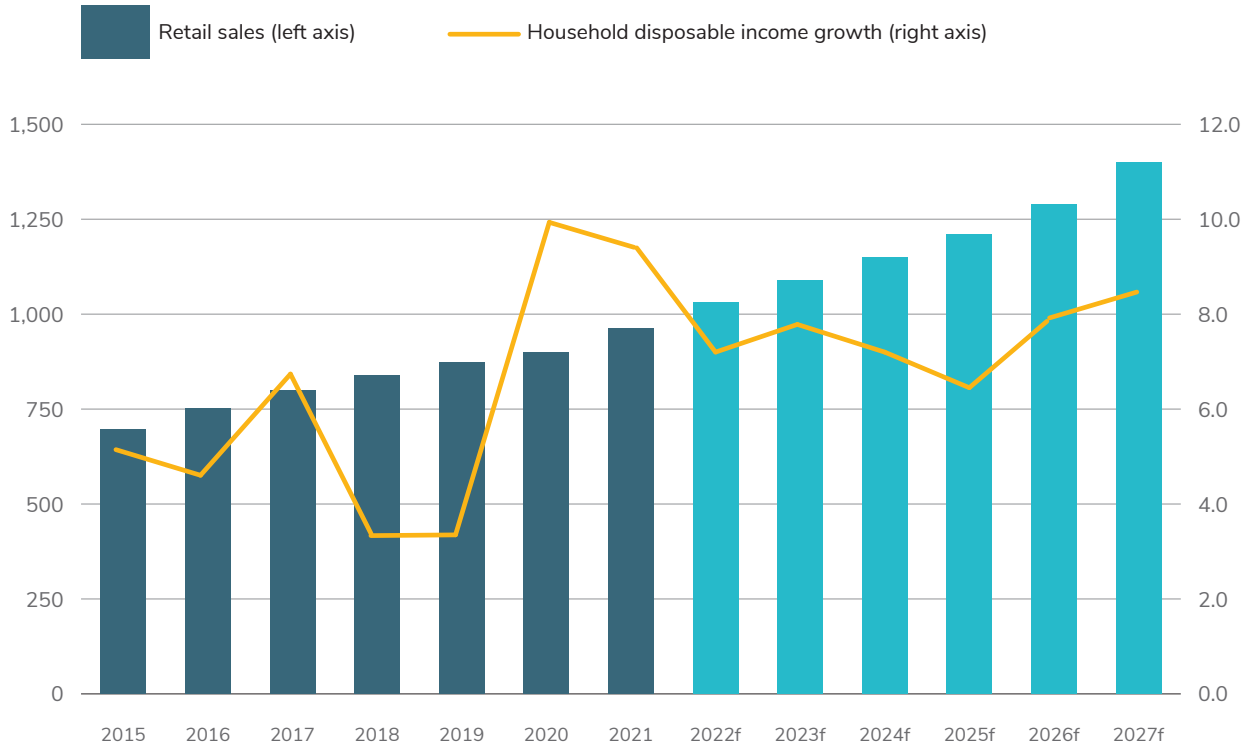
Countering some of the gains in international migration in 2022 was a net outflow of interprovincial migration resulting in 83 fewer residents. This was the first time net interprovincial migration was negative since 2013. Population is projected to increase in every year of the current forecast with growth averaging 2.1 per cent per year. By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Retail sales exceeded $1 billion in 2022

Retail sales exceeded one billion dollars for the first time in 2022. Estimated growth of 6.8 per cent in 2022 is more than double the growth rate from the previous year. Prices were the primary driver of last year's growth in retail sales, with the estimated percentage increase in retail sales equivalent to the 6.8 per cent increase noted in the Whitehorse CPI. The current forecast has retail sales growing every year by an average of 6.3 per cent per year, significantly higher than the projected CPI increases over the same time span.

Chart 8. Income growth a key driver of retail sales growth

Retail sales ($ millions), Household disposable income growth (per cent)



Source: Statistics Canada, Department of Finance *f = forecast*

By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Inflation has increased globally

Global supply chain disruptions and the war in Ukraine contributed to higher food and energy prices in 2022 and added to inflationary pressures noted all over the world. In Canada, domestic factors, including excess demand for labour and other inputs, have also fueled price growth, with the national inflation rate touching levels in 2022 not seen since the early 1980s.

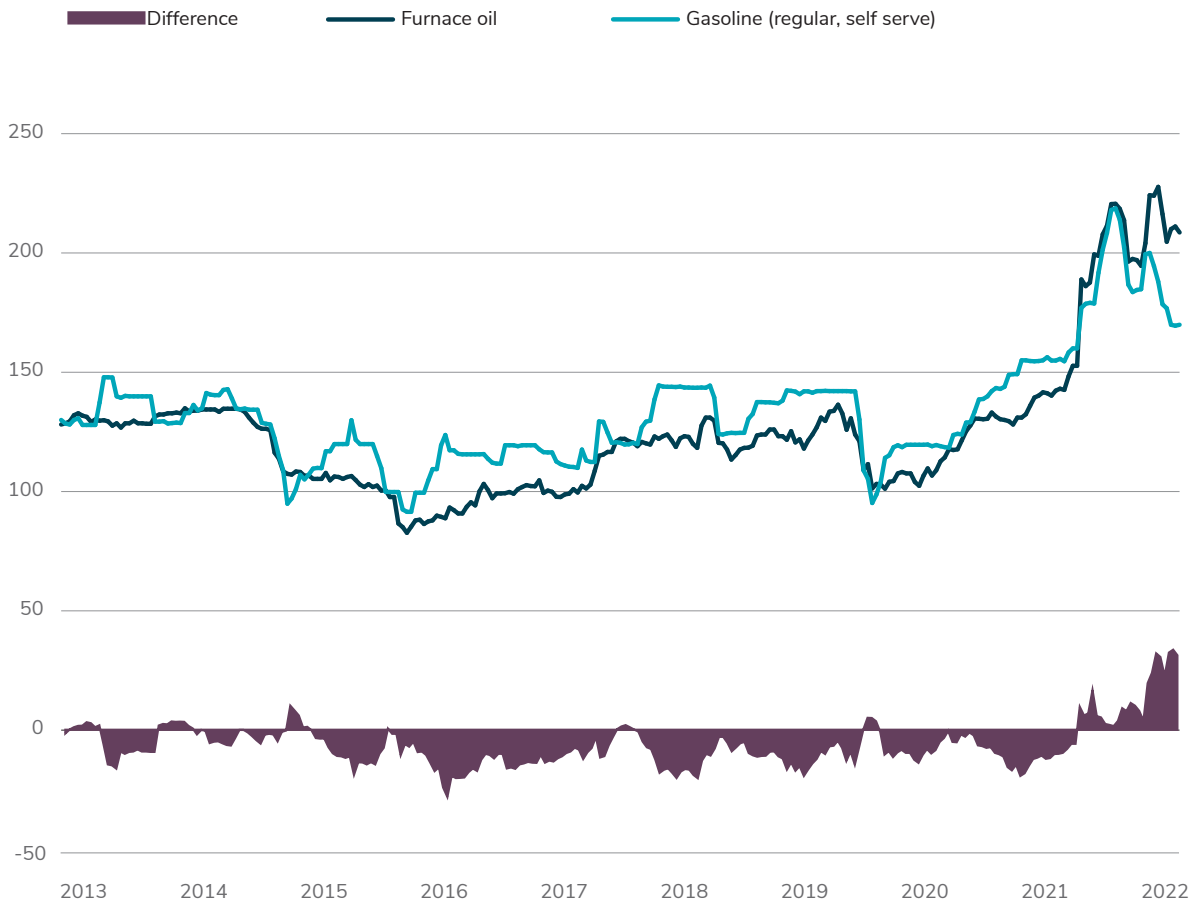
Rapid appreciation of prices for a large variety of consumer goods and services has also been the reality for Yukoners. The inflation rate in Whitehorse[17] averaged 6.8 per cent in 2022, the highest rate for the Whitehorse CPI since records began in 1982. Prices were up across most categories.

Higher fuel prices in 2022 were a prominent driver of overall inflation, with the price of gasoline up 29 per cent, and the price of fuel oil up 47 per cent compared to 2021. While gasoline prices have fallen by over 20 per cent from the peak in June, the price of fuel oil has remained elevated (Chart 9). This reflects global trends. US inventories of distillate fuels, including home heating oil and diesel, are at multi-year lows. Sanctions on Russia have led to Europe shifting towards non-Russian imports. While prices have stabilized, futures prices suggest that diesel and fuel oil prices are likely to remain at a hefty premium to gasoline in the near term.

17. Data are not available for the Yukon, only Whitehorse.

Chart 9. Gap between gasoline and other fuels has widened due to distillate shortage

Whitehorse fuel prices (cents per litre)



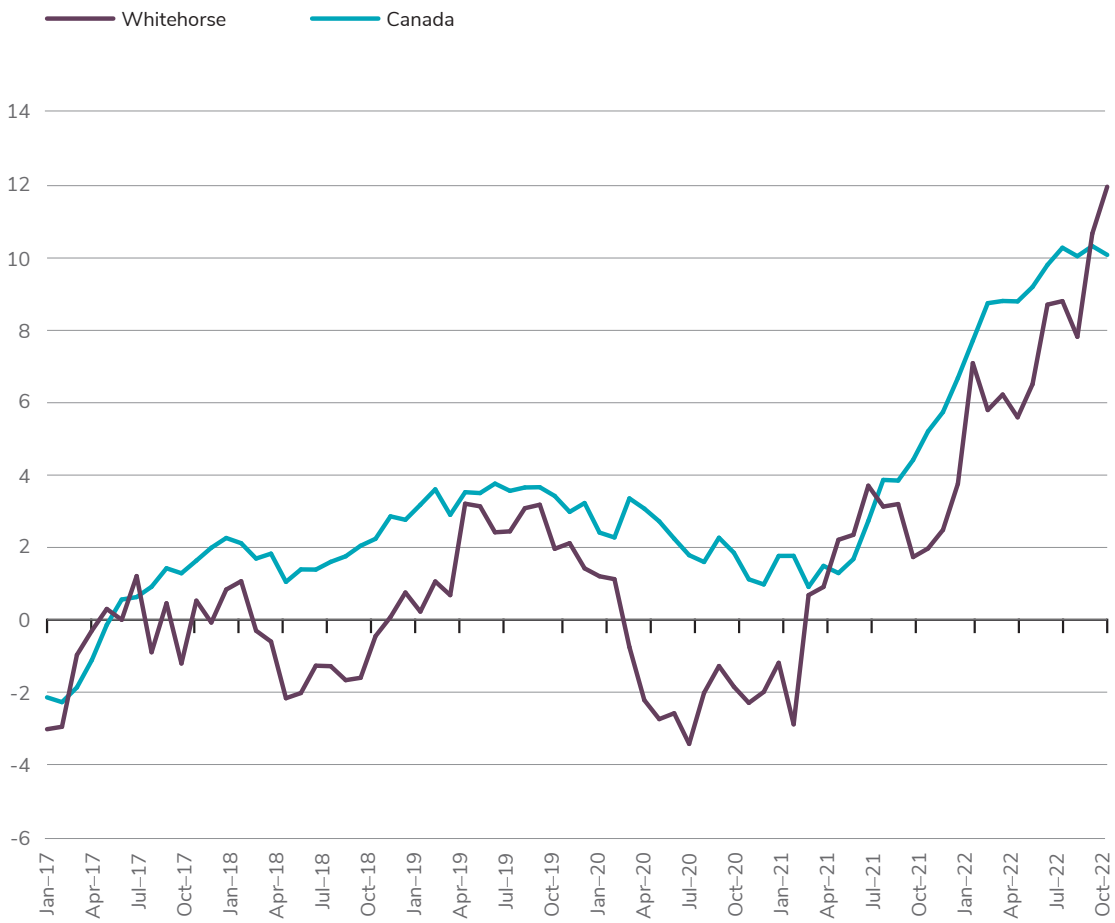
Source: Yukon Bureau of Statistics

Fuel oil is weighted heavier in the Whitehorse CPI than in the national index, because a substantially higher share of Yukoners use fuel oil for heat. This higher weighting is one of the reasons why inflation of 8.1 per cent in Whitehorse as of December was higher than the national rate of 6.3 per cent.

Another factor is that price pressures on food were slower to materialize in the Yukon than in the rest of Canada (Chart 10). Food prices in Canada rose throughout the pandemic, whereas in Whitehorse, they did not start to increase in earnest until later. Ultimately, prices in Whitehorse follow national trends closely and food prices have started to catch up. Inflation in Whitehorse was lower at the beginning of the year and higher at the end, averaging out over the course of the year with annual inflation for both Canada and Whitehorse coming in at 6.8 per cent.

Chart 10. Food price inflation was slower to materialize in Whitehorse

Year-over-year per cent change in the food component of CPI



Source: Statistics Canada

On January 25, 2023, the Bank of Canada increased its policy interest rate to 4.5 per cent to try to reduce the excess demand in the economy. The Bank signaled that it expects to "hold the policy rate at its current level while it assesses the impact of the cumulative interest rate increases."[18] The Bank has increased the policy rate by 4.25 percentage points since last March, the most in such a short span since the Bank began targeting interest rates in the early 1990s.

18. News release – *Bank of Canada increases policy interest rate by 25 basis points, continues quantitative tightening*. Bank of Canada. (January 25, 2023).

Most forecasters expect inflation in Canada will move towards historic norms over the next couple of years as supply chain problems subside and the effect of higher interest rates move through the economy. Canadian inflation is expected to decline from near 7 per cent in 2022, to between 3.5-4.0 per cent in 2023, and many forecasts are calling for inflation in 2024 to approach the midpoint of the Bank of Canada's target range of 1-3 per cent. Similarly, the average annual rate of inflation for Whitehorse is projected to fall from 6.8 per cent in 2022 to 3.8 per cent in 2023 and 2.5 per cent in 2024.

The housing market remains relatively strong but there are signs of cooling

Locally, housing prices have been strong for several years, driven in part by high demand. A generally strong economy has drawn people to the territory. Housing supply has struggled to keep pace with demand, and this has been reflected in upward pressure on housing prices. Prices in Whitehorse across all housing types have seen notable growth in recent years. The average weighted price of single detached homes, duplexes and mobile homes all reached record highs in 2022. Condominium prices in 2022 were down slightly from the 2021 record high.

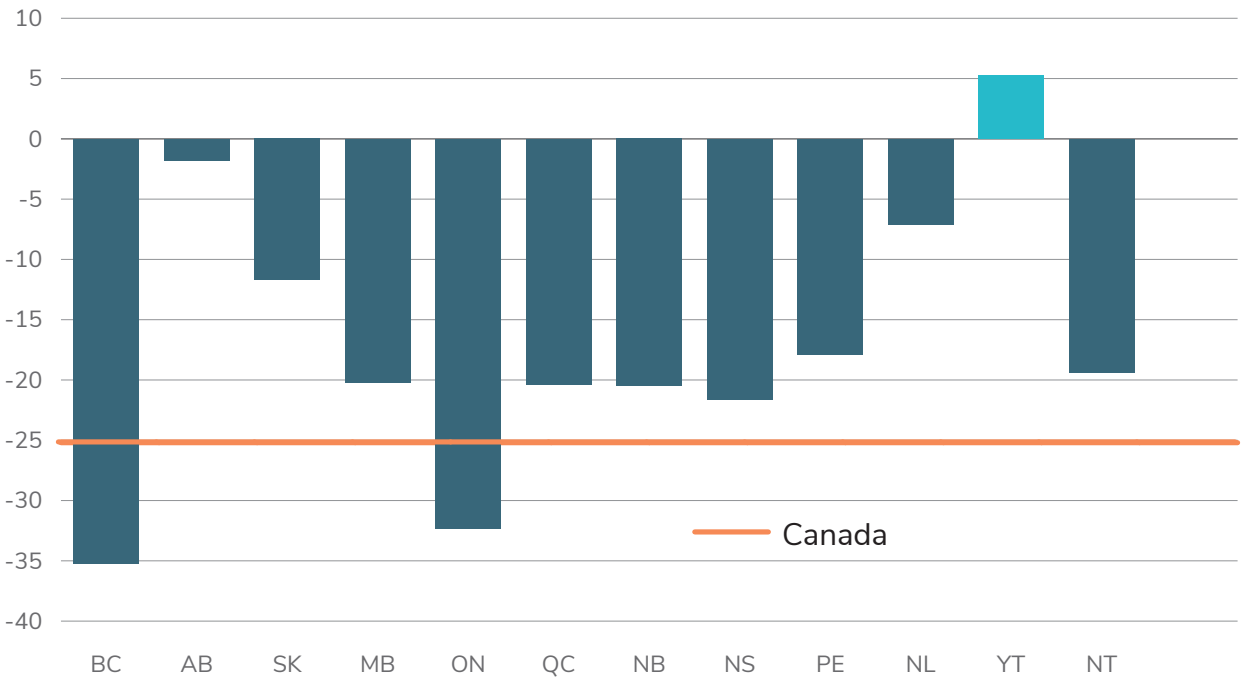
Even during an extended period of very low interest rates and growing household earnings, housing affordability has been eroding due to higher prices. More recently, rapid growth in interest rates has increased borrowing costs for new homebuyers and those on variable rate mortgages. Higher costs will filter through to fixed rate mortgages as they come up for renewal.



Higher interest rates took steam out of housing markets across the country. Average home prices in most Canadian markets fell over the second half of 2022. This effect was slower to materialize in the Yukon, which was the only jurisdiction that saw higher home sales in 2022 than in 2021 (Chart 11). It wasn't until the fourth quarter that signs of cooling showed in the Yukon data.[19] While increasing on average in 2022, average sales prices were down in the fourth quarter of last year across all housing types. Compared to the fourth quarter of 2021, prices were down by 1.2 per cent for single-detached, 3.9 per cent for duplexes, 11.4 per cent for condominiums and 1.6 per cent for mobile homes.

Chart 11. The Yukon experienced growth in the number of residential sales in 2022[20]

Residential sales, 2022 change from 2021 (per cent)



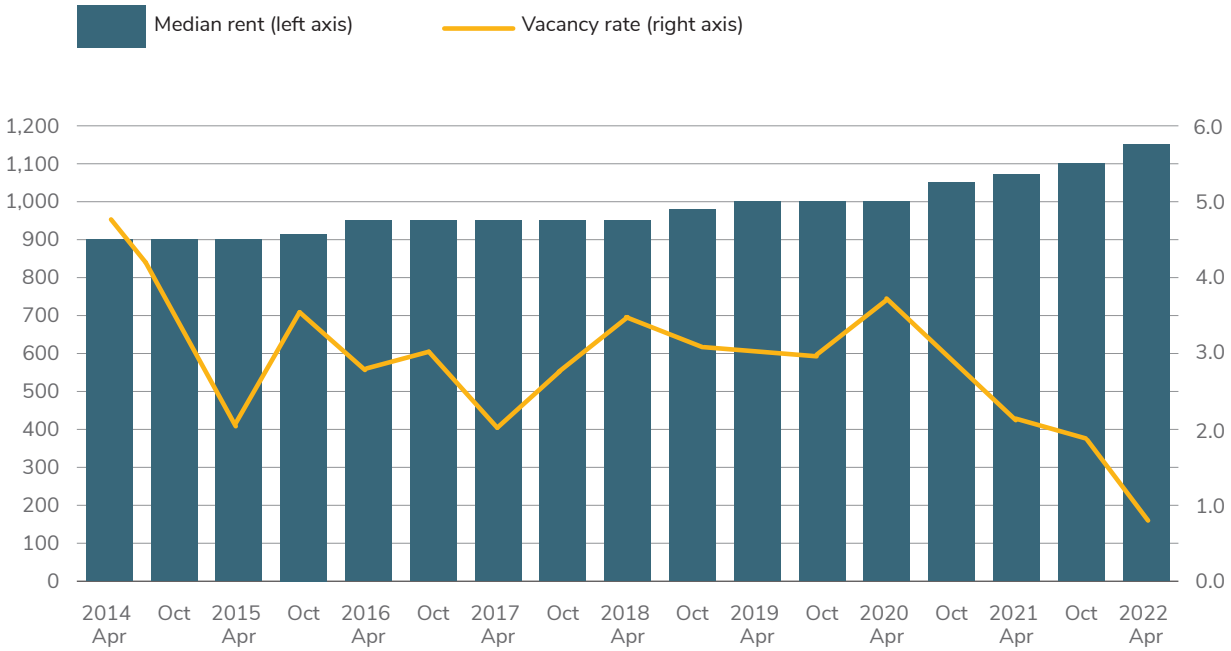
Source: The Canadian Real Estate Association

19. *Yukon Real Estate Report Fourth Quarter, 2022*. Yukon Bureau of Statistics. (February 2023).
20. The Canadian Real Estate Association does not publish data for Nunavut.

On the rental side, the market in recent years has been one of limited supply and increasing rents. The vacancy rate in buildings with three-or-more units fell to 0.8 per cent in April 2022, well below the 1.9 per cent reported in October 2021.[21] High demand and a lack of vacant units has translated into higher rents, with a median rent of $1,150 in April of last year, up 4.5 per cent from the October 2021 figure and 7.4 per cent higher than the April 2021 figure.

Chart 12. Recent history of rental market is one of few vacancies and increasing rents

Whitehorse median rent ($) and vacancy rate (per cent), units in buildings with 3+ rental units



Source: Yukon Bureau of Statistics

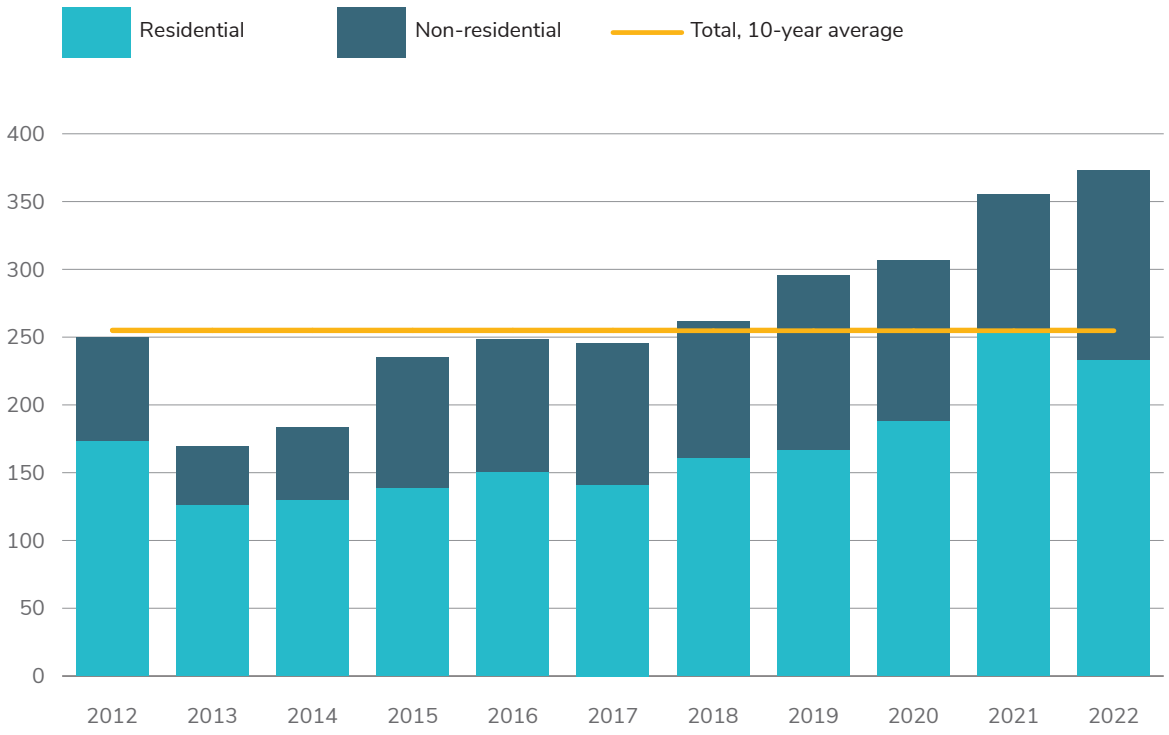
21. *Yukon Rent Survey April 2022*. Yukon Bureau of Statistics. (August 2022).

Residential investment remained strong in 2022

While below 2021's record level, investment in residential construction in 2022 continued to exceed investment on the non-residential side. Residential construction investment totalled $232.6 million in 2022, 62 per cent of the total $373.2 million in building construction reported for the period, and well above the ten-year average of $163 million for residential construction (Chart 13). The recent approval of phases 10 to 13 of the Whistle Bend subdivision will contribute to housing supply going forward.[22]

Chart 13. 2022 was another strong year for building construction

Investment in building construction ($ millions)



Source: Statistics Canada

22. *More phases of Whistle Bend subdivision approved* (January 19, 2023). Whitehorse Star.

Construction sector supported by commercial and government projects

The decline in residential spending from record highs was more than offset by increased non-residential spending. Investment in non-residential building construction totalled $140.6 million in 2022 and was up nearly 39 per cent from 2021 (Chart 13). Similarly, building permits for non-residential work were up substantially in 2022, growing 61 per cent to $150.7 million.

Government-related activities continue to be a primary driver of activity on the non-residential side. Growth was noted in both investment in building construction and building permits associated with institutional and governmental projects, up 83 per cent and 13 per cent, respectively. On the building permits side, construction of a new elementary school in Whitehorse's Whistle Bend subdivision and renovation of the Elijah Smith School were prominent contributors to last year's gains. Commercial permits also showed strong growth in 2022, more than doubling from $44.1 million to $97.0 million. Permit value was supported by construction of a three-storey office building in Whitehorse, renovation of the Old Territorial Administration building in Dawson City and work related to the Whitehorse Battery Energy Storage project.

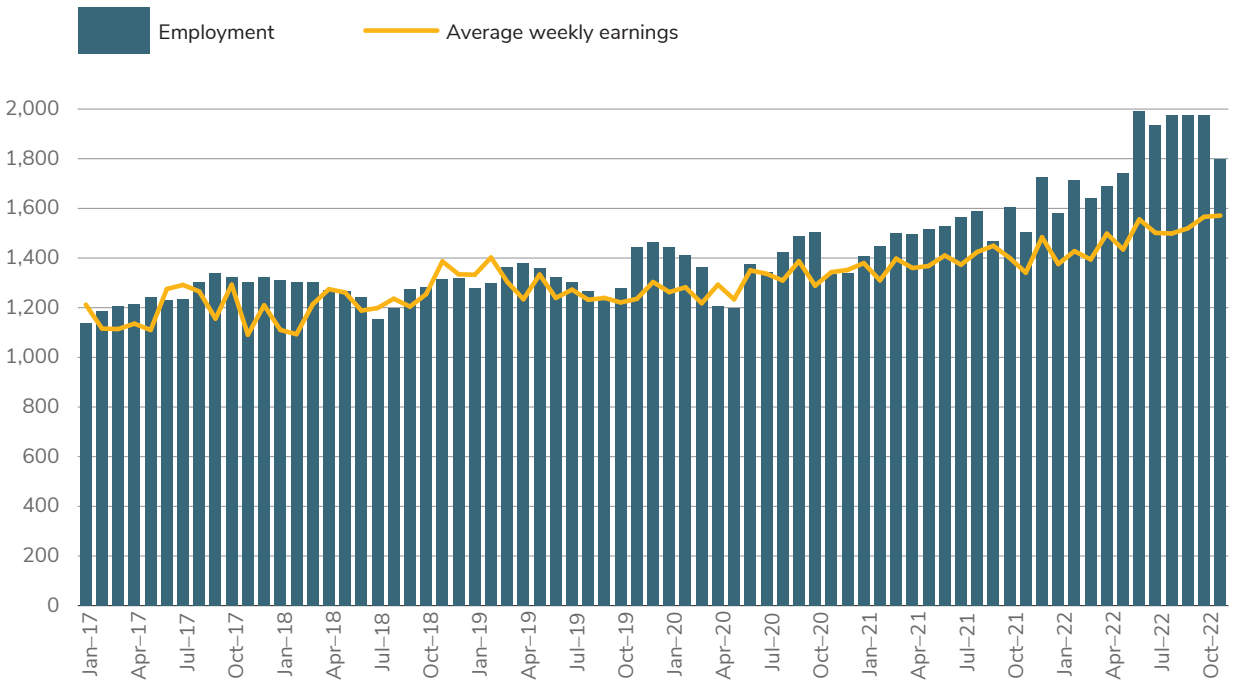
Higher input and labour costs continue to factor into some of the recent gains in building construction investment, due in part to supply chain constraints and stiff competition for tradespeople. Nationally, residential construction costs, on average, were 19 per cent higher and non-residential costs 13 per cent higher in 2022 compared to 2021.[23]

Increased activity created jobs in the construction sector and boosted wages. Construction employment reached an all-time high of 1,993 in June 2022 (Chart 14), up more than 50 per cent versus June 2019. Through the first eleven months of 2022, construction workers earned $1,486 per week on average, an increase of 7.4 per cent from 2021.

23. National figures are based on a composite of 11 census metropolitan areas.

Chart 14. Busy construction sector reflected in growth in construction employment and earnings

Employment (persons), Average weekly earnings ($)



Source: Statistics Canada

The Government of Yukon's *Five-Year Capital Plan* outlines spending to the end of fiscal year 2027–28 of $2.15 billion and includes significant spending in several priority areas such as 'transportation infrastructure', 'land development, housing, education and health' and 'community and First Nations infrastructure'. Projects such as the Nisutlin Bay Bridge, the Dempster Fibre project and the new elementary school in Whistle Bend are examples of investment in critical infrastructure included in the latest Capital Plan. In addition to Government of Yukon projects, the City of Whitehorse also factors into expectations of construction activity with over $130 million in planned spending on capital projects over 2023 to 2026.[24]

24. Spending figure is from the City of Whitehorse's *Capital Expenditure Program 2023–2026* released on November 14, 2022. Figure includes all approved spending, including spending of approximately $75 million that is subject to external funding approval.

Mineral production forecast to be strong over the medium term

The Yukon's mining industry has remained resilient in the face of major headwinds in 2022. High winter precipitation resulted in a heavy spring thaw that hindered mineral production, as both the Eagle Gold and Minto mines lost a month of operations and the sluicing season for placer miners was delayed. The sector has been facing a shortage of workers coming out of the pandemic, hampering some operations. High fuel prices and supply chain issues also presented challenges in 2022.

In addition to disruptions during the spring thaw, operation at Eagle Gold was stalled for three weeks in the third quarter due to the failure of the belt on the overland conveyor. These operational issues caused gold production to fall to 150,182 ounces in 2022, below the previous year's production of 164,222 ounces. With production from Keno Hill underperforming expectations, Alexco Resource Corporation halted operations in June 2022 to focus on mine development. Operations remained suspended following the acquisition of Alexco by Hecla Mining Company in September.

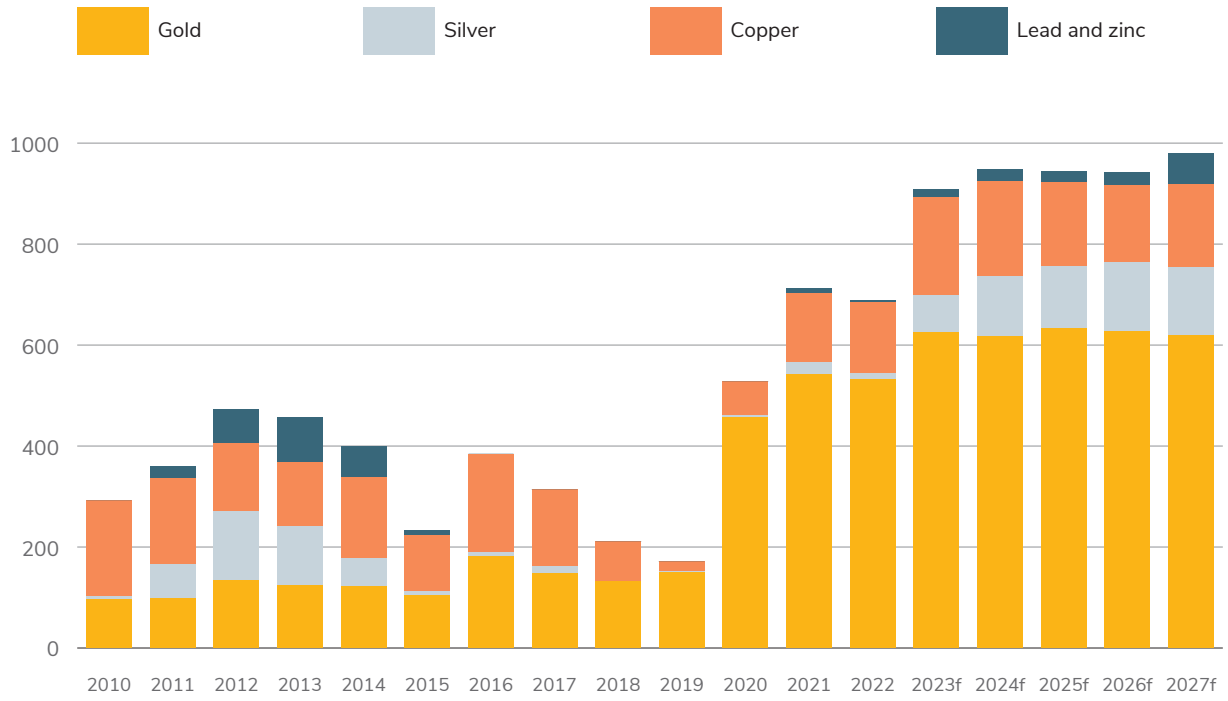
Production for the fourth quarter for the Minto mine was unavailable at the time of writing, but public statements from the President of Minto Metals Corporation in November 2022 noted that the expectation was that annual production would fall within their 2022 production guidance of 28-31 million pounds of copper.[25]

Placer miners also saw higher production. Placer gold production, according to export tax reporting, was 82,420 crude ounces (65,936 fine ounces), up from production of 80,484 crude ounces (64,387 fine ounces) in the previous year. At $154 million, the value of placer gold production accounted for about 22 per cent of 2022's total estimated mineral production.

25. News release – *Minto Metals announces 2022 third quarter results, revenue increased by 17% over the same quarter in previous year.* Minto Metals Corporation (November 17, 2022).

Chart 15. Mineral production value forecast to approach $1 billion[26]

Value of metal production in the Yukon ($ millions)



Source: Natural Resources Canada, Department of Energy, Mines and Resources, Department of Finance *f = forecast*

The Yukon's quartz miners expect to recover from the various setbacks that hindered 2022 production. Victoria Gold expects production at Eagle Gold to rebound in 2023 with production well above 2022's output as the project operator continues to work towards its annual target of 250,000 ounces. Hecla Mining Company announced earlier this year that mine development is ahead of schedule and that they plan to resume operations at Keno Hill in the third quarter of 2023. This, along with anticipated higher production at the Minto mine and sustained placer production, is expected to lead mineral production to rebound to $910 million in 2023 and exceed $900 million in all subsequent years of the forecast (Chart 15).

26. Due to data suppression of Statistic Canada's estimates, data presented for 2019, 2020 and 2021 are based on internal estimates.

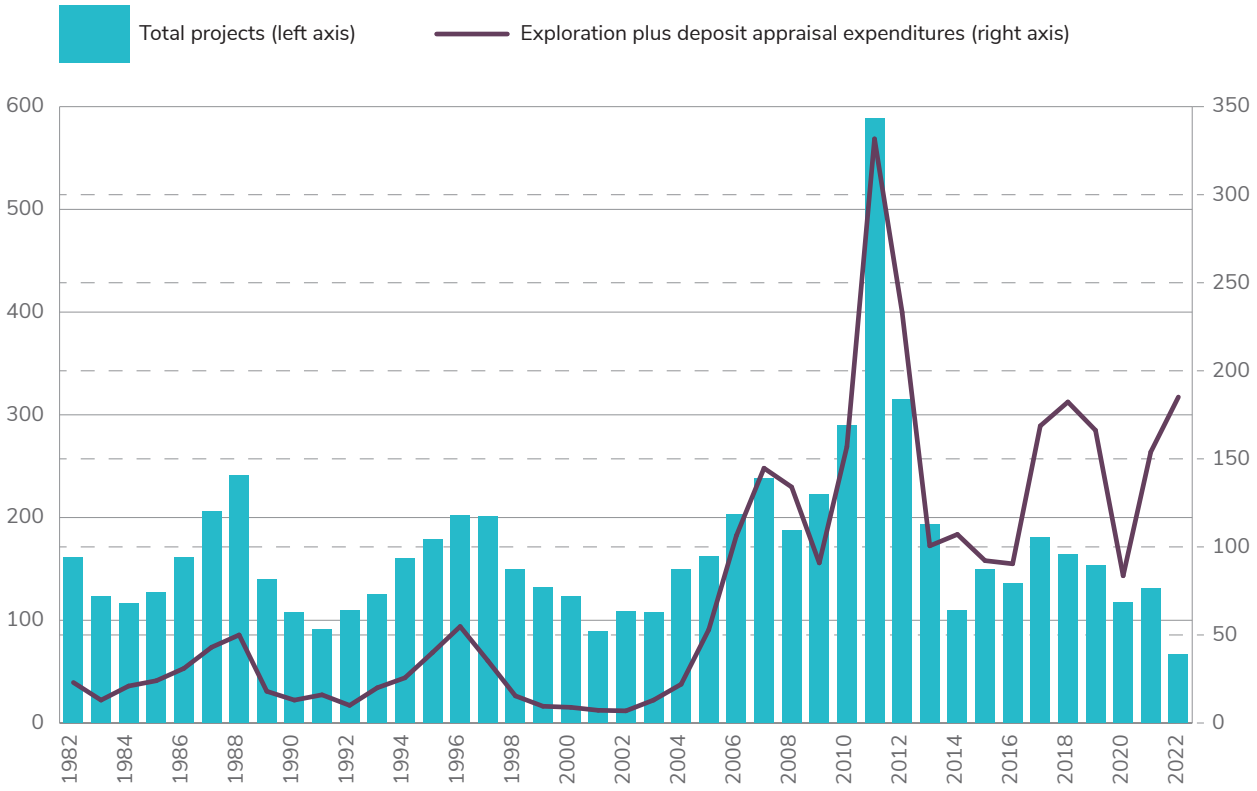
Mineral prices remain supportive of future development

Metals prices rallied to close out 2022 and, though down from earlier highs, remain well above pre-pandemic levels. This could spur development over the medium term for projects such as BMC Minerals Limited's Kudz Ze Kayah mine, Newmont Corporation's Coffee Gold project and Sabre Gold Mine Corporation's Brewery Creek project. Over the longer term, the advancing of the Casino project, a major global copper resource, may attract interest due to the pivotal role copper will play in the green economy and global electrification.

Higher metal prices offer investors the potential of better returns from the discovery of new deposits and exploration activities on current mining plays. Exploration spending has rebounded from pandemic lows. Revised spending intentions from Natural Resources Canada noted exploration spending in 2022 of about $185 million, up 20 per cent from $154 million in 2021 (Chart 16).

Chart 16. Number of active exploration projects trending down even as overall exploration spending has rebounded

Number of active projects, Exploration expenditures ($ millions)



Source: Department of Energy, Mines and Resources, Natural Resources Canada

Recent spending has been increasingly concentrated in a smaller set of mature projects, rather than early-stage projects. The number of exploration projects has fallen over the last several years to a 40-year low in 2022, despite overall spending rebounding.

Spending on exploration for precious metals accounted for 70 per cent of exploration spending in 2022, with the remainder on exploration for base metals. Precious metals are expected to continue to draw most of the interest in exploration activity over the forecast. This mix may eventually be impacted by Canada's critical minerals strategy (see Box 1), which seeks to increase the output of minerals deemed critical to the transition to green energy.

Box 1: Critical minerals a potential opportunity for the local mining industry and for the Yukon's energy goals

The release of *The Canadian Critical Minerals Strategy* in December 2022, along with an almost $4 billion commitment in Budget 2022, is a clear signal of the interest the federal government has in developing the country's critical minerals.

Ultimately, minerals noted as 'critical' reflect societal needs and values at a point in time. Canada's critical minerals strategy notes critical minerals as the building blocks of the green and digital economies, highlighting that "there is no energy transition without critical minerals: no batteries, no electric cars, no wind turbines and no solar panels."

Most of the 31 minerals that the Canadian government has published as being "critical" to Canada have known deposits or documented occurrences in the Yukon. While the territory's current production of critical minerals is quite modest, limited to copper production from the Minto mine and recent production of zinc and indium as a by-product at the Keno Hill mine, there is potential for production from existing identified deposits. Critical minerals are identified as prominent outputs of several potential mines including, Kudz Ze Kayah (zinc, copper); Casino (copper, molybdenum); Nickel Shäw (nickel, cobalt, platinum, palladium, copper) and Mactung (tungsten).

Given commitments by Canada and the Yukon to reduce carbon emissions, as well as the need to ensure future energy security, there is clear motivation to develop a reliable supply of critical minerals. With climate change and economic opportunity acting as strong motivators for development, critical minerals have the potential to be a prominent contributor to the local mining industry and the broader economy over the coming years.

Signs of a solid rebound in tourism activity, but a return to pre-pandemic levels will take time

The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Several key tourism metrics for the territory show significant improvement from the worst of the pandemic. The number of international border crossings into the Yukon totalled just over 168,000 in the first eleven months of 2022, almost five and a half times the number of crossings in the same period of 2021, and well above the 63,657 crossings reported for all of 2020 and 2021 combined when COVID-19 related travel restrictions weighed on visitation.

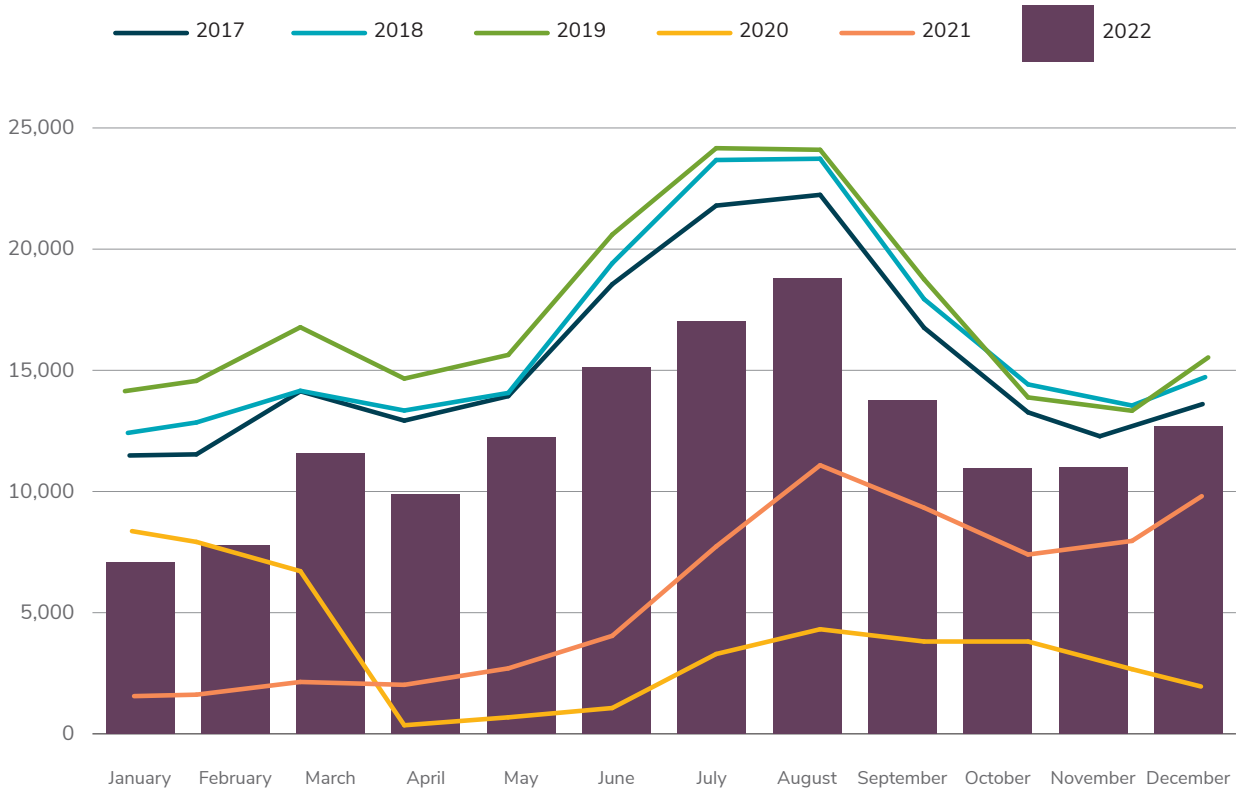
The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Like international border crossings, other indicators of performance are much improved from recent lows but continue to underperform pre-pandemic levels. Data for the first nine months of 2022 show international overnight visitation to be more than double the same period of 2021, but nearly 30 per cent lower than the five-year average.[27] Increased visitation is also reflected in increased hotel occupancy in 2022,[28,29] with data published by CBRE Hotels showing much higher occupancy rates in every month from January to November with the average of 56 per cent over this period, well ahead of the 41 per cent reported for the same period of 2021.[30]

An increased number of air arrivals in 2022 are another sign of the return of travel. Arrivals at Erik Nielsen Whitehorse International Airport were 2.2 times the number of arrivals from 2021 (Chart 17).

Chart 17. Air arrivals much improved from the last two years

Arrivals (deplaning passengers, thousands) at Erik Nielsen Whitehorse International Airport



Source: Statistics Canada

27. *Yukon Tourism Visitation Report, January to September 2022*. Department of Tourism and Culture. (December 22, 2022).
28. Occupancy rate is the percentage of occupied rooms expressed as percentage of the total available rooms at a given time.
29. Figures for the occupancy rate do not capture all hotel rooms in the Yukon, with about 600 rooms captured in this calculation.
30. Data taken from various CBRE Hotels monthly reports: *Trends in the Canadian Hotel Industry – National Market Report*.

Even with strong growth in 2022, air arrivals came in at only 72 per cent of arrivals in 2019, suggesting that there is still more room for recovery from the COVID-19 pandemic.

Tourism activity is increasing, but a variety of headwinds are slowing the recovery. Inflation is running at, or near, many decade highs, and is expected to remain elevated throughout much of 2023. Higher fuel costs have eaten into the bottom-lines of some service providers, particularly those that are fuel intensive such as providers of charter flights and tours.[31] Local tourism-service providers also continue to struggle with finding staff. Labour shortages in the accommodation and food services sector are more severe in the Yukon than they are in the rest of the country. Demand could also be impacted as higher interest rates lead to less discretionary spending.

Further improvement in key tourism metrics is expected. The Conference Board of Canada's latest Travel Markets Outlook supports this improving outlook for tourism, noting an expectation that visitation to the territory will reach pre-pandemic levels by 2024 or 2025, and that overnight visits will recover by 2024.[32] In addition, positive news, like White Pass Railroad's resumption of service to Canada in the summer of 2023, provides further evidence of a return to normalcy for the tourism sector.[33]



31. *Travel Exclusive Winter* 2022/23 Travel Intentions Survey. Canadian Tourism Research Institute. The Conference Board of Canada (December 2022).

32. *Emerging from the Wilderness – Yukon's Travel Markets* Outlook to 2026. The Conference Board of Canada. (January 24, 2023).

33. *White Pass Railroad to resume service to Canada this summer* (January 13, 2023). KHNS FM.

Appendix:
Key economic indicators

	2021	2022	2023f	2024f	2025f	2026f	2027f
Gross Domestic Product (GDP)							
Real GDP by Industry (2012$ millions)	3,045	3,138 (f)	3,308	3,431	3,534	3,666	3,831
Per cent change	10.0	3.1	5.4	3.7	3.0	3.7	4.5
Nominal GDP ($ millions)	3,704	4,049 (f)	4,432	4,795	5,093	5,480	5,948
Per cent change	14.3	9.3	9.4	8.2	6.2	7.6	8.5
Mineral Production *							
Metal production ($ millions)	710	690 (f)	910	950	950	940	980
Labour market							
Labour force *	23,700	24,300	25,100	25,500	26,100	26,800	27,700
Employment *	22,400	23,400	23,800	24,200	24,800	25,600	26,500
Unemployment rate	5.5	3.7	5.0	5.0	5.1	4.5	4.1
Participation rate	72.3	72.8	73.0	72.4	72.1	72.2	72.6
Income							
Household income ($ millions)	2,440	2,664	2,849	3,029	3,210	3,463	3,760
Per cent change	11.4	9.2	6.9	6.3	6.0	7.9	8.6
Consumers							
Consumer price inflation^	3.3	6.8	3.8	2.5	2.0	2.0	2.0
Retail sales ($ millions) *	963	1,030 (f)	1,090	1,150	1,210	1,290	1,400
Population							
Population*	43,190	43,964	44,900	45,900	46,800	47,700	48,700
Per cent change	2.3	1.8	2.1	2.2	2.1	1.9	2.0
Key Assumptions							
Gold (USD/t oz)	1,800	1,809	1,760	1,670	1,650	1,650	1,650
Silver (USD/t oz)	25.15	22.16	21.85	21.68	22.00	22.00	22.00
Copper (USD/lb.)	4.23	3.99	3.48	3.71	3.55	3.55	3.55
Zinc (USD/lb.)	1.36	1.58	1.33	1.25	1.23	1.15	1.15
Lead (USD/lb.)	1.00	0.97	0.91	0.91	0.93	0.93	0.93
Can/US exchange rate	0.80	0.77	0.75	0.77	0.78	0.78	0.78

f = forecast

^ = CPI available only for Whitehorse, annual average.

** = Forecasts are rounded. Annual per cent change based on unrounded figures.*

Source: Statistics Canada, Bank of Canada, Yukon Bureau of Statistics.

Population projections are produced by Yukon Bureau of Statistics. Metal prices forecasts are informed by prominent forecasters. All other forecasts are produced by the Department of Finance's Economic Research branch based on data available as of February 13, 2023.




Yukon

ATCO Electric YUKON

September 28, 2023 AEY-YUB-004

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-004

Reference: 2023-24 GRA, Section 2, Schedule S2.1, Street Lights and Private Lights

Issue: Number of street and private lights

Preamble: Similar to how the average number of residential customers is determined, the Board would like to know how many street lights and private lights are in AEY's service territory.

Request:

For each of the years in Schedule S2.1, please provide the average (during the year) number of street lights and private lights.

Response:

Please refer to the table below for the annual average site counts for Street Lights and Private Lights.

Table 1: AEY Average Annual Lights

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Street Lights	5,443	5,511	5,609	5,635	5,783	6,143	6,240	6,306	6,411
Private Lights	810	806	803	794	773	767	785	772	751

ATCO Electric YUKON

September 28, 2023 AEY-YUB-005

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-005

Reference: 2023-24 GRA, Section 2, PDF pages 26-27; Schedule S2.1

Issue: Residential customer UPC

Quote: After experiencing a few years of moderate growth, the Yukon economy was disrupted by the pandemic starting in 2020. The COVID-19 global pandemic impacted Residential and Commercial Usage Per Customer (UPC) in 2020, 2021 and 2022. In 2020, Residential UPC increased significantly as more people were working from home and Commercial UPC decreased as businesses were impacted by COVID-19 restrictions as well as the decrease in employees working in offices. As pandemic restrictions have been lifted, policies and procedures are beginning to normalize, such that the 2023 forecast anticipates UPCs returning to pre-pandemic levels for both Residential and Commercial customers.

Preamble: From Schedule S2.1, the MWh sales per customer has been above 10.73 for five of the seven years preceding the test years.

Request:

(a) AEY has explained increases in MWh sales per residential customer for the pandemic years; however, as many businesses have gone to a hybrid model of allowing people to work from home part of the time, please justify the drop to 10.73 MWh for residential customers in 2023 and the reason for the increase to 10.96 MWh per residential customer for 2024.

(b) AEY has explained decreases in MWh sales per commercial customer for the pandemic years; however, as restrictions have been lifted, there has been growth in the forecast number of residential customers and tourism has returned to pre-pandemic levels, please justify why the 2023 forecast of MWh sales per commercial customer is below that for each of the preceding pandemic years.

(c) Given that AEY has forecast 51.14 MWh per commercial customer for 2023, please explain why the MWh sales per commercial customer increases to 52.09 for 2024.

Response:

(a) AEY is using the Board-approved methodology to forecast Usage Per Customer (UPC), which has two main drivers:

- Compound Annual Growth Rate (CAGR); and
- Monthly actual/normalized UPC from the previous year.

For 2023, the decrease in residential UPC is attributable to two factors:

- Three months (January to March) of actual UPC included in the 2023 forecast being 2.3 percent lower than the same first three months in 2022; and
- The 2022 normalized residential UPC for the period April to December being lower than actual usage.

For 2024, the overall year over year impact of the CAGR for residential is an increase of 0.4 percent, explaining the increase in 2024.

(b) AEY anticipates the commercial UPC to continue trending towards pre-pandemic levels and, while UPC for 2023 is down, it is still above the UPC for 2020 and 2021, when normalized for weather.

(c) AEY has included the addition of seven new large commercial customers in its sales forecast during the Test Period. AEY has included three large commercial customers in December 2023, three in June 2024 and one in September 2024. The addition of these new large commercial customers, layered on top of the approved methodology, results in increased commercial UPC in 2024.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-006

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-006

Reference: 2023-24 GRA, Section 2, PDF page 31

Issue: Industrial sales

Quote: While AEY does not forecast serving any industrial customers over the Test Period, AEY plans to continue its approved Industrial Rider R Deferral, respecting YEC's industrial sales forecast for purposes of calculating AEY's Rider R rate adjustment. AEY proposes to true-up any differences between YEC's actual and approved industrial sales forecast in future rider adjustments. (Footnote omitted)

Request:

(a) Please explain how the Industrial Rider R Deferral will operate and provide a detailed example.

(b) What is the impact to AEY and its customers if industrial load changes from YEC's last approved forecast? (Explain in terms of a new industrial load coming onto the system or an existing mine line leaving the system.)

(c) Please describe the steps AEY took to verify the veracity of the industrial sales forecast.

Response:

(a) YEC provided AEY with a forecast of industrial sales and revenue. Once a Board Order is received on AEY's 2023-2024 GRA, AEY will calculate the approved expected Rate Adjustment Rider R revenue for industrial customers and track expected and actual Rider R revenue. The difference between expected and actual Rider R revenue will be included in the deferral balance.

A hypothetical example of how the Industrial Rider R Deferral will operate is provided below:

January 2024
Forecast: $56,000
Actual: $60,000
Difference: +$4,000 (refund to customers) will be included in the deferral

February 2024
Forecast: $56,000
Actual: $55,000
Difference: -$1,000 (collection from customers) will be included in the deferral

As per Board Order 2022-13, the YUB directed AEY as follows: "Once the balance in the deferral account accumulates to $0.25 million, AEY will make an application to the Board to dispense with the balance in that deferral account…the balance in the deferral account may apply solely to residential and commercial non-government customers".

(b) If Rider R revenue is higher than forecast, as may be the case if additional industrial load unexpectedly comes onto the system, this will cause the deferral balance to increase. Alternatively, if an existing mine unexpectedly leaves the system, this will cause the deferral balance to decrease. Once the deferral balance reaches plus or minus $0.25 million, AEY will apply to the YUB to refund/collect the balance to/from AEY residential and commercial non-government customers using the Rate Relief Rider.

(c) AEY received an industrial sales forecast from YEC staff on April 20, 2023. AEY followed up with YEC after it was announced that the Minto Mine was ceasing operations and received an updated industrial sales forecast from YEC on May 25, 2023. Accordingly, AEY considers that it has included YEC's most current and representative sales forecast while preparing its GRA.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-007

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-007

Reference: 2023-24 GRA, Section 2, PDF page 30; Schedule S2.1

Issue: New commercial customers

Quote: Additionally, six new large commercial customers are anticipated to be added during the Test Period in Whitehorse as well as one new large customer in Carcross.

Request:

(a) Please provide when each of the new large commercial customers is to be added.

(b) Does AEY expect the addition of the large commercial customers to increase the average MWh per commercial customer for each of the test years?

Response:

(a-b) Please refer to the response to AEY-YUB-005(c). AEY has included three large commercial customers in December 2023, three in June 2024 and one in September 2024. AEY expects that the addition of the new large commercial customers will increase the average MWh per commercial customer for the 2024 forecast year.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-008

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-008

Reference: 2023-24 GRA, Section 2, Schedule S2.2, Miscellaneous Revenue

Issue: Carbon Tax Rebate; Other

Preamble: Schedule S2.2 shows "Carbon Tax Rebate" and "Other" as line items under Miscellaneous Revenue.

Request:

(a) Given a 2022 carbon tax rebate of $832,000 for 2022, please explain how the 2023 and 2024 amounts were forecast for this line item.

(b) For the line item "Other", please provide details on how YEC is charged for billing services.

Response:

(a) Note that the 2022 carbon tax rebate of $832,000 included the 2019-2021 carbon tax rebate amount which was previously unclaimed. Please refer to table below for the breakdown of the $832,000:

Table 1: Carbon Tax Rebate
($000)

Year	Carbon Tax Rebate
2019	33
2020	115
2021	123
2022	561
Total	**832**

The prior year carbon tax rebate calculation was based on the Schedule 444 - Yukon Business Carbon Price Rebate on the Canada Revenue Agency website.[1] The forecast Carbon Tax Rebate is based on AEY's forecast Eligible Undepreciated Capital Costs (UCC). Please refer to the table below for the calculation of AEY's forecast Carbon Tax Credit at the rates prescribed in Schedule 444.

Table 2: Forecast Carbon Tax Credit

	2023	2024
	Test Year	
Forecast Eligible UCC ($000)	15,273	13,561
Rebate Factor (per $1000)	21.89	21.89
Carbon Tax Rebate ($000)	334	297

(b) The charges are based on the estimated proportionate operational, administrative, and capital costs of providing billing services for YEC customers. The terms are agreed upon through a Customer Billing Services Agreement between AEY and YEC.

[1] https://www.canada.ca/content/dam/cra-arc/formspubs/pbg/t2sch444/t2sch444-23e.pdf.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-009

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-009

Reference: 2023-24 GRA, Section 11, Attachment 11.1, PDF page 191

Issue: Summary of Customers, Energy Sales and Revenue

Request:

(a) Referring to PDF page 191 and AEY's Summary of Customers, Energy Sales and Revenue 2013-2022, please provide reasons for the year-over-year changes in Secondary Sales in MWh that can be observed on Line No. 28.

26	**Secondary Sales**										
27	Customers (average during year)	1	2	3	3	5	5	5	5	10	9
28	Sales in MWh	3,959	5,415	7,030	4,835	8,385	258	1	479	4,430	3,439
29	MWh sales per customer	1,979.5	2,707.5	2,812.0	1,511.0	1,705.4	51.6	0.1	97.5	458	382
30	Revenue ($000s)	336	474	532	296	553	21	0	34	361	401
31	Cents per KWh	8.49	8.75	7.57	6.13	6.59	7.99	8.37	7.07	8.15	11.65

Response:

(a) Secondary energy is available at certain times, as determined by YEC based on the availability of surplus energy. This surplus has historically only been available in summer months and only if surplus hydro is available. There have been long periods in which surplus hydro was not available (e.g., years of low water levels).

ATCO Electric YUKON

September 28, 2023 AEY-YUB-010

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-010

Reference: 2023-24 GRA Section 3, PDF page 108

Issue: Fish Lake Hydro

Quote: The forecast Fish Lake Hydro Generation in the Test Period outlined in Schedule 3.21 is based on the recent 2021-22 output, planned maintenance, water availability, and is adjusted for any planned decreases in generation due to capital rebuilds. (Footnote omitted)

Request:

(a) What capital rebuilds is the quote referring to and when are they expected to occur?

(b) Does AEY foresee any water availability issues in the test period? Please explain.

Response:

(a) The capital rebuild referred to is for the Fish Lake Unit 2 wickets replacement and bypass automation, which commenced on August 4, 2023 and is expected to be complete in mid-October 2023.

(b) AEY does not foresee any water availability issues in the Test Period.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-011

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-011

Reference: 2023-24 GRA Section 3, PDF page 108; AEY 2016-17 GRA Proceeding, YUB-YECL-47(b); Appendix A to Board Order 2017-01, PDF page 17

Issue: Purchase Power Flow Through Deferral Account (PPFTDA)

Quote: GRA, PDF page 108:

> AEY is of the view that the changes to the wholesale rates (including any ERA charges) continue to meet the criteria for the establishment of a deferral account, and any variance should continue to be included in the Purchase Power Flow Through Deferral Account.

YUB-YECL-47(b):

> Consistent with historical practice, under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate.

Appendix A to Board Order 2017-01:

> The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

ATCO Electric
YUKON

September 28, 2023 AEY-YUB-011

Request:

(a) Is the PPFTDA requested by AEY in this application identical to the PPFTDA approved in Board Order 2017-01?

(b) Please confirm whether AEY continues to assume the risk associated with sales volumes as set out in the statement above. Please explain.

Response:

(a) Yes.

(b) Confirmed. AEY would still assume the risk associated with sales volume, but AEY would not assume the risk associated with changes to the Wholesale purchase rate.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-012

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-012

Reference: 2023-24 GRA Section 3, PDF pages 109-110

Issue: Constraint Payments and Independent Power Producers (IPP) Deferral

Quote: To ensure the IPPs are not unduly put at risk of poor system availability, Constraint Payments were required. Constraint Payments occur when the IPP is producing power and, due to circumstances outside the IPP's control, an incident occurs that results in the inability of the IPP to access AEY's grid and sell power to AEY. Examples include distribution line outages or a constraint of the Battery Energy Storage System (BESS). In addition, there are legal costs and contracting costs associated with setting up these EPAs.

…

Under the IPP program, the risks and impacts of unplanned events are amplified. If an unplanned event results in an IPP's inability to provide the expected energy to the grid, then the reduced generation is normally made up through the running of diesel plants. This requirement to run diesel plants results in increased fuel usage during the constraint period and AEY must pay for both the increase in fuel costs and the minimum energy purchase.

Request:

(a) Please explain how the BESS can cause a constraint.

(b) Is the BESS referred to in the quote a YEC asset? If the answer is affirmative, why would AEY be responsible for the maintenance of this asset? If the BESS is not a YEC asset, which BESS is AEY referring to?

(c) Please explain the purpose and operation of a microgrid controller. Why is AEY responsible for the microgrid controller and not the IPP?

(d) Are the IPPs referred to or expected in the test period located in the hydro zone? If the answer is yes, then why is diesel generation the assumed replacement for the constrained IPP energy?

(e) Has AEY ever commissioned a new asset and asked for a deferral account because it did not have certainty around maintenance costs? Please explain.

(f) Given AEY's system reliability, what is the probability of a system constraint for reasons other than the BESS or the microgrid controller?

(g) In what year(s) did AEY initially receive energy from IPPs and micro generators?

(h) Generally, is system reliability under the control of management? Please explain.

Response:

(a) Any event or protection which limits or stops the operation of the BESS will impact the IPP's ability to generate energy onto the grid. For example, this could be a component failure or internal temperature alarms both high and low. The operation of the BESS, due to the limitation of isolated systems, is essential to allow for safe and reliable delivery of the IPP's energy generation onto the distribution system. The BESS can fail or be disconnected like any other electrical infrastructure on a power system.

(b) No, the referenced BESS is not a YEC asset. The referenced BESS are those fully contributed by the IPP and owned and operated by AEY in the isolated communities. The role of the BESS for intermittent renewables is to ensure proper grid operation which is solely the responsibility of the utility.

(c) The microgrid control is responsible for the overall operation of the remote electrical system comprised of both AEY's and the IPP's generation, distribution feeders, and the BESS. As this device controls the overall electrical system, which is the responsibility of the utility, it is owned and operated by AEY.

(d) No, these IPPs are not located in the hydro zone. The referenced IPPs are in AEY's isolated communities.

(e) A deferral account is needed for the maintenance costs of the BESS and Microgrid Controller (MGC) required for the IPP projects as well as for the constraint payments. It is not typical, and there is no precedent, for a particular AEY asset, to have a deferral account for electrical infrastructure in a power system. This is not typical utility infrastructure as the Old Crow Solar Project is the first of its kind in northern Canada. AEY has worked with the community as well as territorial and federal governments to integrate this renewable energy system into AEY's isolated grid to the best of its abilities. AEY does not have extensive experience with this new technology, nor experience at integrating an intermittent source of power that can displace 100% of community diesel generation for periods of time. AEY believes these maintenance costs meet the criteria for deferral as previously accepted in AEY's 2016-2017 Phase I GRA. The criteria are as follows:

- Costs are not under the control of the company and are not reasonably forecastable; or
- A variance in forecasting could produce a loss or gain of a substantial magnitude.

(f) The probability of a system constraint, for reasons other than a BESS or microgrid controller, is low for those circumstances under AEY control. The system reliability, if the new BESS and IPP facility are isolated on the electrical grid, would remain comparable to recent reliability reports absent events such as wildfires.

(g) In isolated generation communities, AEY began receiving electrical energy from the IPP facility in Old Crow in 2021 and from micro-generation in Burwash Landing in 2013. On AEY's distribution system attached to the Yukon Integrated System, the first micro-generation received was in the Annie Lake area in 2014.

(h) Yes, system reliability is generally under control of management. This is managed through AEY's ongoing preventative maintenance work throughout the system, capital improvements and regular inspections. However, there are events outside

the utility's control that cause outages such as third-party contacts, extreme weather events, and animal contacts.

September 28, 2023 AEY-YUB-013

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-013

Reference: 2023-24 GRA, Section 5, Operations and Maintenance (O&M) expenses, PDF pages 113-115

Issue: O&M forecasting

Request:

(a) Please clarify whether AEY has changed any aspect of its methodology for forecasting O&M expenses. Please explain fully.

Response:

(a) AEY has not changed any aspect of its methodology for forecasting O&M expenses.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-014

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-014

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other

Issue: Production O&M

Request:

(a) Referring to S5.2, Line Nos. 16, 17, 21 and 23 (Production: 64000 – Supervision and Engineering Diesel), please provide the quantity of FTEs representing the additional engineering resources in each of 2018 ($0.084 million) and 2022 ($0.040 million).

(b) Referring to S5.2, Line Nos. 26, 27, 31, 33, 34 and 38 (Production: 64600 – Diesel Generation), please explain if the vacancies referred to on lines 31 and 34 were filled by the "additional plant maintenance resource" noted on Line No. 38. What is the quantity of FTEs representing the additional plant maintenance resource noted on Line No. 38 in 2023 ($0.070 million)?

(c) Referring to S5.2, Line Nos. 42, 43, 47, 48, 53 and 54 (Production: 82600 – Hydro Maintenance), please provide the quantity of FTEs representing the additional resources in each of 2017 ($0.065 million due to filling vacant positions) and 2023 (approximately $0.050 million due to an additional plant maintenance resource).

(d) Referring to S5.2, Line Nos. 56, 57, 65 and 67 (Production: 84600 – Diesel Maintenance), please provide the quantity of FTEs representing the additional plant maintenance resource noted on Line No. 67 ($0.086 million).

Response:

(a) The quantity of FTEs representing the additional engineering resources in 2018 is 0.4 and the quantity of FTEs representing the additional engineering resources in 2022 is 0.18.

(b) Yes. The quantity of FTEs representing the additional plant maintenance resource noted on line No. 38 in 2023 is 0.38.

(c) The quantity of FTEs representing the additional resources in 2017 ($0.065 million due to filling vacant positions) is 0.4.

The quantity of FTEs representing the additional resources in 2023 (approximately $0.050 million due to an additional plant maintenance resource) is 0.3.

(d) The quantity of FTEs representing the additional plant maintenance resource noted on line No. 67 ($0.086 million) is 0.5.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-015

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-015

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other;

2023-24 GRA, Section 1B.2 – Grid Modernization, PDF pages 22-23

Issue: Distribution O&M

Request:

(a) Referring to S5.2, Line Nos. 73, 74 and 81 (Distribution: 87000 – Supervision), please provide the quantity of FTEs representing the 2020 vacancy ($0.060 million). Has this vacancy been filled at the time of submitting the response to this IR?

(b) Referring to S5.2, Line Nos. 106, 107, 111, 113, 115 and 124 (Distribution: 87300 – Maintenance - Labour), please provide the quantity of FTEs representing the 2017 vacancy ($0.190 million), the reduction in 2020 vacancy ($0.120 million), the impact in 2019 of the vacancy filled in 2018 ($0.091 million) and the additional resource added in 2023 (0.070 million). Please confirm that the additional resource in 2023 has been added on an actual basis at the time of submitting the response to this IR.

(c) Referring to S5.2, Line Nos. 106, 108 and 121 (Distribution: 87300 – Maintenance - Other), please provide further detail in respect of the 2022 "write off of cancelled projects" in the amount of $0.127 million. Other than the inflationary and cancelled project amounts noted by AEY on Line No. 121 ($0.179 million $0.127 million respectively) as explanations for the total $0.598 million[1] increase in "Other" expenses between 2021 and 2022, please provide an explanation for the remaining increase of approximately $0.292 million in 2022 "Other" expenses.[2]

[1] $0.598 million total "Other" variance was calculated as the difference between $1.310 million (2022) and $0.712 million (2021).

[2] $0.292 million unexplained "Other" variance was calculated as $0.598 million total "Other" variance less the$0.179 million variance due to inflation and $0.127 million variance due to cancelled projects.

(d) Referring to S5.2, Line Nos. 126, 127, 130 and 131 (Distribution: 87310 – Service to Outside Parties), please provide details in respect of the most common services AEY provides to outside parties. Please also provide reasons for the increase in these services between 2020 and 2021 in the amount of approximately $0.509 million (calculated as the difference between total costs of $0.120 million in 2020 and $0.629 million in 2021).

(e) Referring to S5.2, Line Nos. 133, 134, 138, 140, 142, 145 and 148 (Distribution: 87400 – Underground Line Maintenance), AEY provides general variance explanations as pertaining to reduced vacancies or filling vacancies. Please provide further details, including quantities of FTEs and the related costs.

(f) Referring to S5.2, Line Nos. 150, 152 and 160 (Distribution: 87500 – Meter and Meter Testing) and the increase of approximately $0.050 million in 2023 in maintenance related to Advanced Metering Infrastructure (AMI) metering functions, please explain why this incremental cost is forecast only for the year 2023. Please also explain in general where it can be observed on S5.2 that AEY's proposed Grid Modernization and AMI program will provide a benefit in terms of reduced costs within Distribution: 87500 – Meter and Meter Testing.

(g) Referring to S5.2, Line Nos. 167, 169, 174 and 177 (Distribution: 87800 – Street Light Maintenance), please provide further information respecting AEY's costs related to street light testing. Is AEY's street light testing the result of an organized and scheduled maintenance program? In addition, please also explain why it is reasonable that forecast street light testing costs for 2023 and 2024 ($0.155 million and $0.159 million respectively) are more than double the amount incurred in 2022 ($0.071 million).

Response:

(a) The quantity of FTEs representing 'Distribution: 87000 – Supervision' vacancy in 2020 is 0.3. The vacancy has been filled at the time of submitting this response.

(b) The quantity of FTEs representing the 2017 vacancy ($0.190 million) is 1.0. The quantity of FTEs representing the reduction in 2020 vacancy ($0.120 million) is 0.64. The quantity of FTEs representing the impact in 2019 of the vacancy filled in 2018 ($0.091 million) is 0.5 and the quantity of FTEs representing additional resources added in 2023 (0.070 million) is 0.4 FTEs. AEY confirms, that the additional resource in 2023 has been added at the time of submitting this response.

(c) The expenditures for "write off of cancelled projects" relate to, contract services to be provided by vendors for the customers' projects. However, the customers decided not to proceed with the projects and the cancelled projects were deemed to not meet the capitalization criteria. The contract services cost and customer contributions had both been moved to O&M expense and the expenditures for "write off of cancelled projects" represents the net amount of write-offs in this Activity group.

Other than the inflationary and cancelled project amounts noted by AEY on Line No. 121 ($0.179 million and $0.127 million, respectively) as explanations for the total $0.598 million[3] increase in "Other" expenses between 2021 and 2022, there is a remaining increase of approximately $0.292 million in 2022 "Other" expenses. This increase is due to catch up on maintenance work deferred due to the pandemic and the breakdown is outline in Table 1 below.[4]

Table 1: Incremental Costs in 2022 ($000)

Incremental Cost	Total
Vehicle Charges	120
Business Travel	75
Freight	32
Equipment Rentals	15
Materials	3
Safety Expense	2
Other	45
Total	**292**

[3] $0.598 million total "Other" variance was calculated as the difference between $1.310 million (2022) and $0.712 million (2021).

[4] $0.292 million unexplained "Other" variance was calculated as $0.598 million total "Other" variance less the $0.179 million variance due to inflation and $0.127 million variance due to cancelled projects.

(d) The increase in services to outside parties between 2020 and 2021 is due to labour support provided to ATCO's project to rebuild Puerto Rico's Electrical grid (LUMA Energy). Incremental costs within the service to outside parties and affiliate services are fully recoverable (no element of profit is received), therefore, there is no impact on revenue requirement.

(e) Please refer to the table below for further details respecting labor cost year-over-year variances (Distribution: 87400 – Underground Line Maintenance), including quantities of FTEs and related costs.

Table 2: 87400 – Underground Line Maintenance FTEs

2016 vs. 2017	Labour cost decreased by $0.03 million in 2017 (0.15 FTE)
2017 vs. 2018	Labour cost increased by $0.066 million in 2018 (0.3 FTE)
2018 vs. 2019	Labour cost decreased by $0.039 million in 2019 (0.19 FTE)
2019 vs. 2020	Labour cost decreased by $0.03 million in 2020 (0.15 FTE)
2020 vs. 2021	Labour cost decrease by $ 0.015 million in 2021 (0.08 FTE)
2021 vs. 2022	Labour cost increased by $0.058 million in 2022 (0.28 FTE)
2022 vs. 2023	Labour cost decreased by $0.012 million in 2023 (0.06 FTE)

(f) The incremental costs were forecast for AMI testing during the transition period. Once AMI is implemented, the need for traditional meter readers will likely decrease, however it is too early to predict the cost savings now. Therefore, savings in terms of reduced costs have not been incorporated into the test period.

(g) AEY has an ongoing street light testing program. This program was implemented in 2021 and will follow an eight-year testing schedule. AEY will complete the testing within the test period which is included in the forecast. This forecast is based on the scheduled number of streetlights and their estimated costs. This forecast also includes streetlights in relation to system growth as newer streetlights still require monitoring and inspection to prevent failure.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-016

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-016

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other

Issue: General O&M

Request:

(a) Referring to S5.2, Line Nos. 182, 184 and 187 (General: 88400 – Communication), please explain if the "new radio system" was described in Business Case #14 – Satellite Radios. If not confirmed, please identify the business case to which the "new radio system" relates.

(b) Assuming AEY's response to part (a) is confirmed, please confirm that the annual subscription fee for the 38 satellite radios (which appears to have a total capital cost of $0.157 million as noted in Business Case #14) is in the amount of $0.060 million as noted on S5.2, Line No. 187. What was the annual subscription fee for AEY's previous radio system?

(c) Referring to S5.2, Line Nos. 189, 191 and 196 (General: 88800 – Maintenance Company-Owned Houses), please clarify if the approximate $0.028 million increase in costs noted in 2023-24 to "assess and address deficiencies" includes all repair costs resulting from the assessment. If not confirmed, please identify the account to which the repair costs were recorded.

(d) Referring to S5.2, Line Nos. 198, 200, 204 and 207 (General: 88900 – Maintenance Warehouse and Office), please clarify if the increases in costs in 2021 ($0.094 million to "address drainage issues") and 2022 ($0.102 million to "address deficiencies") includes all assessment and repair or maintenance costs resulting from the assessment. If not confirmed, please identify the account to which the costs not related to an assessment were recorded.

Response:

(a) Confirmed.

(b) Confirmed, the annual subscription fee for 38 satellite radios is $0.06 million. The annual subscription fee for the original radio system was $4,000, which AEY will discontinue in 2024.

(c) Confirmed.

(d) Confirmed.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-017

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-017

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other

Issue: Public Information O&M

Request:

(a) Referring to S5.2, Line Nos. 216, 218 and 221 (Public Information: 70100 – Public Information Administration), AEY indicates that increases of approximately $0.050 million and $0.063 million in "Other" costs for the years 2021 and 2022 respectively were "mainly due to sponsorships of community events." Please clarify if the Board has historically approved the recovery of costs of this nature through AEY's revenue requirement.

(b) Referring to S5.2, Line Nos. 223, 224, 229, 232 and 234 (Public Information: 70200 – General Public Information), AEY provides general variance explanations as pertaining to reduced vacancies or filling vacancies. Please provide further details, including quantities of FTEs and the related costs.

Response:

(a) Yes.

(b) AEY had a vacancy position for Senior Corporate Communication advisor (0.6 FTE) during the period 2018-2021. Head office Marketing had been providing affiliate services to support AEY when that position was vacant. The position was filled in November 2021, shared between AEY, Northland Utilities (Yellowknife) and Northland Utilities (NWT). The labour cost forecast in 2023 and 2024 is $0.079 million in 2023 and $0.082 million in 2024.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-018

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-018

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other; 2023-24 GRA, Section 5.3, Operations and Maintenance (O&M) Costs by Function, PDF page 122

Issue: Customer Accounting O&M

Quote: Effective July 2021 AEY switched its IT service provider to Kyndryl, a subsidiary of IBM and terminated its contract with its previous provider, Wipro. The change in IT service provider was necessary given the fast-paced requirements to modernize, progression from on-premises to cloud-based services, and transformation of user services to address remote working and in-field solutions. One-time costs associated with the termination of the previous contract and transition to the new service provider were incurred in 2020 and 2021 and were excluded in all determinations of the 2023 and 2024 revenue requirements.

Request:

(a) Referring to S5.2, Line Nos. 247, 249 and 254 (Customer Accounting: 71100 – Customer Applications and Service Orders), please provide further information respecting the 2022 increase in "contractor services to integrate weather stations into Old Crow Control systems" in the amount of $0.070 million. Why do these costs not appear to have continued in either 2023 or 2024?

(b) Please also explain in general where it can be observed on S5.2 within the Customer Accounting function that AEY's proposed Grid Modernization and AMI program will provide a benefit in terms of reduced costs for meter reading. For example, will there be cost savings that can be observed within the Customer Accounting: 71200 – Meter Reading function on S5.2, Line Nos. 259 and 260?

(c) Referring to S5.2, Line Nos. 269, 270 and 271 (Customer Accounting: 71300 – Customer Billing and Accounting), please clarify if any portion of the one-time costs

(incurred in 2020 and 2021) associated with the termination of the previous contract and the transition to the new service provider (as quoted above) are reflected in either of the referenced line nos. and, if so, in what amount.

(d) Referring to S5.2, Line Nos. 269, 270, 271, 278 and 280 (Customer Accounting: 71300 – Customer Billing and Accounting), please clarify if the costs at issue (being a full year of CCS billing system subscription fees in the amount of $0.300 million) have been determined as the result of a direct bill to AEY or if are they an allocated amount. If they are an allocated amount, how was AEY's percentage allocation calculated?

(e) Referring to S5.2, Line Nos. 269, 270, 271, 274 and 276 (Customer Accounting: 71300 – Customer Billing and Accounting), AEY provides general variance explanations as pertaining to reduced vacancies or fluctuating vacancies. Please provide further details, including quantities of FTEs and the related costs.

Response:

(a) The incremental cost in 2022 was one time contract services for integrating weather stations into Old Crow Control systems, so this was not forecast in 2023.

(b) Reduced costs for meter reading are not reflected in this test period as the AMI program is just being initiated. Please also refer to the response to AEY-YUB-015(f).

(c) There are no one-time costs included in these referenced line numbers.

(d) The CCS billing system is shared between AEY, Northland Utilities (Yellowknife) and Northland Utilities (NWT). These CCS subscription fees are allocated between these three entities and AEY's allocation is based on its number of customers as a percentage of the total customers of all three entities.

(e) Please refer to following table for detailed Year-over-year quantities of FTEs and the related costs for Customer Accounting: 71300 – Customer Billing and Accounting:

Table 1: Customer Billing and Accounting Labour Costs
($000)

	Actuals						
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
FTEs	1.8	2.0	2.0	2.5	2.7	2.8	3.3
Labour Costs	178	193	189	251	295	290	334

ATCO Electric YUKON

September 28, 2023 AEY-YUB-019

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-019

Reference: 2023-24 GRA Schedules, S5.2 – Breakdown of Operations & Maintenance Expenses – Labour, Other

Issue: Administration & General

Request:

(a) Referring to S5.2, Line Nos. 309-334 (Administration & General: 72100 – Administrative), for each of the years 2016 to 2023, please provide a table to reflect a year-over-year breakdown of the O&M costs into the five largest cost categories for each of "Labour" and "Other". Please ensure that, irrespective of whether the following fall into the five largest cost categories, all costs related to each of travel, severance payments due to "ATCO's COVID Vaccination Policy," employee incentives and benefits, transition costs related to a new IT service provider and costs for the early termination of the Master Services Agreement with Wipro are identified as stand-alone cost categories under either labour costs or other costs.

(b) Referring to S5.2, Line Nos. 309-334 (Administration & General: 72100 – Administrative), AEY provides general variance explanations as pertaining to reduced vacancies or higher vacancies. Please provide further details, including quantities of FTEs and the related costs.

(c) Referring to S5.2, Line Nos. 347, 348 and 351 (Administration & General: 72300 – Insurance) and the evident year-over-year increase in insurance costs, please explain AEY's process for examining insurance premiums for the purpose of confirming that a competitive price for the insurance coverage has been negotiated at the time of each renewal period. How has the practice described assisted in the forecast in the current GRA?

(d) Referring to S5.2, Line No. 355 and 356 (Administration & General: 72400 – Injuries & Damages), these amounts can also be observed on S8.4, Line No. 28, identified as negative "Write-off" amounts for the same years in AEY's Continuity Schedule of No Cost Capital for Injuries & Damages. Please provide reasons for the two negative $0.279 million amounts forecast for 2023 and 2024 respectively.

(e) Referring to S5.2, Line Nos. 359, 360, 364 and 366 (Administration & General: 72500 – Employee Expenses), please clarify if the reason the labour costs after 2020 are negative or zero is the result of vacancies or due to transitioning to standard labour rates.

(f) Referring to S5.2, Line Nos. 371, 373, 380 and 382 (Administration & General: 72600 – Training and Safety), please clarify what "PLT training" is.

Response:

(a) Please refer to the following table for the breakdown of the O&M costs for 72100 – Administrative.

Table 1: Breakdown of 72100 – Administration & General ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Employee Labour & Benefits	612	684	722	648	678	997	767	867	878
Total Labour Cost	**612**	**684**	**722**	**648**	**678**	**997**	**767**	**867**	**878**
Head Office Services	642	721	573	614	597	567	359	818	904
IT Charge	290	393	325	294	325	354	419	472	472
IT Services	160	162	163	165	140	145	162	173	179
Contract Services & Consultants	96	162	166	272	249	274	208	276	278
Telephone	35	54	57	54	58	62	79	86	89
Travel	105	97	78	53	36	43	47	78	79
IT Termination	-	-	-	-	467	-	-	-	-
IT Transition Costs	-	-	-	-	-	294	-	-	-
Severance – Covid Vaccine Policy	-	-	-	-	-	-	410	-	-
Other	109	115	111	93	98	75	129	67	89
Total Non-Labour	**1,437**	**1,704**	**1,473**	**1,546**	**1,969**	**1,814**	**1,813**	**1,970**	**2,090**
Total	**2,049**	**2,388**	**2,195**	**2,194**	**2,647**	**2,811**	**2,580**	**2,837**	**2,968**

(b) Regarding the variances mentioned in S5.2, Line Nos. 309-334 (Administration & General: 72100 – Administrative), please refer to the detailed changes including quantities of FTEs and the related costs.

- Costs increase in 2017 mainly due to reduced administrative and head office vacancies ($174 thousand) which was for 1.4 FTEs.
- Costs decrease in 2018 mainly due to higher head office vacancies ($112,000) which was for 0.8 FTEs.
- Costs decrease in 2019 mainly due to vacancies for 0.6 FTEs ($74,000).
- Cost decreased in 2022 due to lower head office costs due to high vacancy ($295,000) for 2 FTEs.
- Cost increased in 2023 mainly due to filling head office vacancies ($327,000) for 2 FTEs.

(c) During each renewal period, ATCO's Risk & Insurance team prepares updated insurance underwriting information and circulates this submission to Aon (ATCO's insurance broker). Aon's experienced brokers and account executives then leverage their industry expertise to present this information to the insurance marketplace and obtain competitive quotes.

We select the most competitive quotes based on a thorough evaluation of pricing and favorable Terms and Conditions, ensuring that we negotiate the best possible insurance coverage.

ATCO also participates on the Canadian Electrical Risk Managers (CERM) committee. The CERM is comprised of risk and insurance professionals representing power and utility companies from across Canada. We convene on an annual basis to benchmark the outcomes of our respective renewals (to ensure competitive pricing) and to discuss and ensure that our limits and deductibles are in line with those of our peers'. AEY utilizes the benchmarks established through this process as a foundation for forecasting insurance costs in the upcoming years. This includes factoring in inflation rates to provide an accurate estimate of insurance expenses in the GRA. By following this process and benchmarking against industry peers through CERM, AEY ensures that competitive prices are

negotiated for insurance coverage during each renewal period. The benchmarking data and inflation adjustments derived from this practice significantly contribute to the accuracy of AEY's forecasts, helping AEY plan for and manage insurance costs effectively.

(d) The RID provision has accumulated to a refund position as of 2022. In each of the Test Years, AEY plans to refund the credits to the consumers which is $0.279 million each year. The refund of the accumulated RID balance is through the O&M Schedule 5.1, line 41.

(e) The labour cost was negative in 2021 due to a correction of a miscode in 2020 and zero after 2021 due to the transition to standard labour rates. These costs are now included in the standard labour rates and are charged as part of the employee's labour costs to the O&M activities or Capital projects in which the employees perform work.

(f) PLT is Power Line Technician training.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-020

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-020

Reference: 2023-24 GRA Schedules, S5.3 – Affiliate Charges included in Operations and Maintenance Expenses

Issue: Head Office Costs – Administrative Expenses, Financial Reporting and Regulatory Support

Request:

(a) Referring to S5.3, Line No. 11 (Details of Head Office Costs: 72100 – Administrative Expenses, Financial Reporting and Regulatory Support), please clarify the reasons for the Financial Reporting and Regulatory Support cost increases for the years 2023 and 2024 ($0.697 million and $0.792 million respectively) compared to the historical costs for the years 2016 to 2022 which ranged between $0.241 million and $0.494 million.

(b) Please provide general explanations for the costs incurred for each of the years 2016 to 2022.

Response:

(a-b) The Financial Reporting and Regulatory support costs are related to labour and costs for staff that support AEY's regulatory and finance functions, as well as travel costs, excluding the time-period when travel restrictions were in place. Increased workload is the main driver for the increase in costs, in addition to filling previously vacant positions. AEY also notes that the Corporate Accountant position that was previously based in Whitehorse was back-filled in Head Office when that position became vacant. Specific tasks for each function and the driver for increase in costs for the years 2023 and 2024 are mainly as follows:

- The Financial Reporting group is responsible for preparing monthly, quarterly, and annual financial information, for both internal reporting

purposes and for supporting external reporting requirements, as well as providing financial support for the regulatory team. This group's responsibilities include: completing business plans and forecasts, corporate planning, filing tax information, implementing new reporting standards preparing Financial Statements and Management reports, supporting audit and assurance functions, and improving processes and procedures. The Financial Reporting group has experienced a high level of turnover due to the increase in workload. Additional resources are required to ensure that there is enough manpower to prevent overburdening existing staff and to ensure that business objectives are achieved.

- Additional Regulatory Support is required due to increased workload and complexity associated with regulatory filings and commercial matters including, but not limited to, rates and riders administration, rate applications, calculations for the terms of Electricity Purchase Agreements, managing customer complaints and ad hoc matters. AEY has experienced increasing volumes of workload and complexity with IPP and microgrid programs and, therefore, requires resources to meet these growing demands. Without an increase in manpower in the Regulatory functional group, legal and consulting costs will increase and there will be inefficiencies in the regulatory process as additional extensions would be required in order to complete the current workload. Due to the increase in regulatory requirements, capacity building, grid modernization initiatives, aging infrastructure and regulatory implications of changes in Government policies and legislation, AEY does not anticipate a decrease in the level of support needed from the Regulatory group.

- Government Relations & Initiatives support is required for building relationships with government representatives, participating and prioritizing cross-functional policy discussions, and providing support for businesses, as required. Coordinated government relations activities are important in ensuring impacts to AEY and its customers are broadly considered and understood by policymakers, as various levels of government develop policies and regulations that affect the reliability, affordability, and sustainability of electricity. This position ensures that AEY is aware of government initiatives that can directly impact AEY and its customers and so that AEY can proactively participate in the development of these initiatives.

- A portion of the cost increase in 2023, compared to 2022, is due to the filling of vacancies.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-021

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-021

Reference: 2023-24 GRA, Section 6, Taxes other than income, PDF page 123

Issue: Taxes other than income (Property Taxes)

Quote:

Table 6.1: Taxes Other than Income
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Property Taxes	253	253	264	277	277	267	275	285	292

6.2 Property Taxes

2. Property taxes are paid to the communities annually for AEY's office building, generation facilities, substation properties and power lines. The forecast increases over the Test Period are due to inflation.

Request:

Please clarify if the year-over-year increases and decreases for the years 2017-22, as shown in Table 6.1 above, are due to inflation or are the result of capital projects. If neither, please explain further.

Response:

Actual property tax increases from 2016-2022 were due to inflation.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-022

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-022

Reference: 2023-24 GRA, Section 8, PDF pages 128 and 130

Issue: Return on equity

Quote: PDF page 128:

> The BCUC is currently undertaking a GCOC proceeding (Stage 1 proceeding) to determine the appropriate benchmark ROE which was previously set at 8.75 percent. A decision is expected to be released either in the third or fourth quarter of this year. (Footnote omitted)
>
> …

PDF page 130:

> In accordance with prior Board direction, AEY is requesting to link its ROE for the 2023-24 Test Period to the soon to be determined BCUC GCOC benchmark rate plus a risk premium of 0.75 percent.
>
> In this Application, AEY has utilized the existing 8.75 percent as a placeholder and is proposing to true-up to the benchmark approved by the BCUC in its upcoming GCOC decision as part of AEY's Compliance Filing to this Application. (Footnote omitted)

Request:

(a) If the BCUC GCOC proceeding does not release its decision before the close of the evidentiary record (conclusion of the oral hearing) of this proceeding, what does YECL propose for its ROE?

(b) Should the Board apply the latest BCUC GCOC proceeding decision released at the time the evidentiary record closes for this proceeding as the appropriate

benchmark to determine an ROE for AEY for the test years of AEY's 2023-24 GRA?

Response:

(a) The BCUC GCOC released its Stage 1 GCOC Decision (Decision and Order G-236-23) on September 5, 2023. For FBC (Electric), a deemed equity component of 41.0 percent (up from 40.0 percent) and an ROE of 9.65 percent (up from 9.15 percent) have been determined. For FEI, the previous benchmark utility, a deemed equity component of 45.0 percent (up from 41.0 percent) and an ROE of 9.65 percent (up from 8.75 percent) have been determined. The BCUC has not determined which (or if both) of these utilities will serve as the benchmark as part of its Stage 1 determination; however, for the purpose of this Proceeding the outcome is the same for AEY's proposed ROE.

(b) Yes. AEY submits that the Board should use the latest benchmark established in BCUC Decision and Order G-236-23, as detailed in part (a).

ATCO Electric YUKON

September 28, 2023 AEY-YUB-023

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-023

Reference: 2023-24 GRA, Section 8, PDF page 128

Issue: Return on equity

Quote: AEY submits that the determination of whether a ROE premium is appropriate with respect to AEY should address the relative business risks of AEY compared to the BCUC benchmark utility and other similar utilities across Canada, taking into account the stand-alone principle.

Request:

(a) Should YEC be considered as one of the comparable utilities?

(b) In terms of relative comparability, would YEC be the utility most comparable to AEY?

(c) How has the stand-alone principle been applied in Yukon?

(d) In determining an appropriate ROE for a Yukon utility, is the stand-alone principle the preeminent criteria, or are other criteria considered? Please explain.

Response:

(a-b) Concentric does not believe that YEC should be considered a comparable utility because it is primarily a generation and transmission utility and serves a few commercial customers. AEY is mainly a distribution utility and owns limited generation. Additionally, YEC is a crown corporation rather than being owned by a publicly-traded holding company that raises debt and equity capital in public markets. Lastly, YEC's ROE is also set by this Board and would not provide an independent comparator. As discussed in the Concentric Report, Concentrics view

is that smaller, publicly-traded electric and gas utilities in Canada are the most appropriate comparators to AEY for the purposes of determining whether a risk premium above the benchmark utility is justified.

(c) Concentric is aware that the YUB has not recognized the stand-alone principle. However, this principle is consistently recognized by other utility regulators across Canada, including the Alberta Utilities Commission (AUC), Ontario Energy Board and the British Columbia Utilities Commission. The standalone principle is well accepted in developing a fair return, as outlined by the AUC in Decision 22570-D01-2018 (2018 Generic Cost of Capital), paragraphs 217 and 218:

> 217. The stand-alone principle has been applied by the Commission to treat a regulated utility as a distinct entity for the purposes of determining the costs to be borne by ratepayers for the service of the regulated utility. As noted by the Alberta Court of Appeal in ATCO Electric Ltd. v Alberta (Energy and Utilities Board), "The purpose of the stand-alone principle is to notionally isolate and categorize – for accounting and rate-making purposes – the costs incurred in the operation of a discrete business function of a utility. "The principle has been applied to allocate costs between regulated and non-regulated activities of an integrated utility, with the theory being that regulated utility customers should only pay for the costs of the regulated service. It has also been applied to allocate costs incurred by an integrated utility amongst its various business functions, so that just and reasonable rates can be set for each business function. In the context of a GCOC proceeding, the stand-alone principle has been applied to determine an ROE and deemed equity structure for each regulated utility as if it were a stand-alone entity.
>
> 218. The stand-alone principle arises with respect to municipal utilities when the Commission considers what regard, if any, should be had for the fact that the utility is ultimately owned by a municipality. A municipality possesses certain unique traits that distinguish it from a nonmunicipal corporation. For example, a municipality has access to low cost ACFA financing and the ability to use an equity funding rider, which it may pass on to the regulated utility. Additionally, a municipally owned utility is exempt from paying income taxes.

Because AEY's parent company is regulated subject to the standalone principle, incremental risk associated with owning a small-sized utility in a northern

jurisdiction is not contemplated in its fair returns. In AEY's view that risk should be accounted for within the fair returns of AEY.

(d) As discussed in the Concentric Report, the most important criterion is the Fair Return Standard as established by the Supreme Court of Canada in Northwestern Utilities v. City of Edmonton where the Supreme Court found as follows:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

The stand-alone principle, however, is also important because the YUB should consider the company-specific business and financial risks of AEY and not those of its parent company, Canadian Utilities Ltd., when determining the aforementioned fair return.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-024

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-024

Reference: 2023-24 GRA, Section 8, PDF page 129

Issue: Return on equity

Quote: Market demand risks relate to the volatility of sales and their impact on ROE.

Realization of sales forecasts in AEY's service territory is subject to many variables including the weather and the economic health of the community. AEY's sales are more sensitive to weather than other electric utilities due to the extreme range of temperatures experienced in northern Canada.

Request:

(a) Please explain why AEY's sales are more sensitive to weather than other electric utilities.

(b) Please provide the analysis of other utilities that led to the conclusion that AEY's sales are more sensitive to weather than other electric utilities' due to the extreme range of temperatures experienced in northern Canada.

(c) Please provide examples where other utilities are not affected by extreme weather conditions such as heat, wind, ice, etc.

(d) Please provide an example of any electric utilities which are not impacted by the economic health of the community.

(e) If AEY is concerned about the volatility from its sales forecast, could AEY request deferral account treatment to cover this risk? Please explain.

Response:

(a-c) Neither Concentric nor AEY have completed extensive analyses on a large sample of other utilities, and Concentric Report does not state that other utilities are also

not affected by extreme weather conditions. The distinguishing factor for AEY is that the Company's service territory is characterized by extreme weather conditions to a greater degree than most other electric and gas utilities in Canada. As a result, the Company's sales are more sensitive than most utilities to weather conditions, while at the same time AEY is smaller, meaning that the Company has fewer resources to respond to weather-related service disruptions and outages that may occur in the remote locations served by AEY.

AEY has reviewed the weather sensitivity of AEY's residential sales compared to its affiliate electric companies. AEY's regression of UPC and weather shows that AEY has a significantly higher HDD coefficient than ATCO Electric Distribution (AED), Northland Utilities Yellowknife Limited (NUY) and Northland Utilities (NWT) Limited (NWT). These findings are also consistent with the fact that AEY has higher residential average use and a higher proportion of customers using electric heat.

Table 1: Select HDD and UPC data

	HDD Coefficient	2022 Actual Annual UPC (kWh)
AEY (Whitehorse)[1]	0.7376	11,065
AED[2]	0.2769	6,969
NUY[3]	0.2612	7,071
NWT (Hay River)[4]	0.2242	5,955

1. AEY 2023-2023 GRA, Section 02 – Attachment 2.1.
2. ATCO Electric 2023 COS Compliance Filing.
3. NUY 2011-2013 GRA.
4. NWT 2023 GRA, Section 02 - Attachment 1.

(d) While every electric and gas utility is impacted by the economic health of the community to some degree, as discussed on pages 20-21 of the Concentric Report, the distinguishing factor for very small utilities like AEY is that adverse economic conditions have a more significant effect on the utility's sales and the

Company's ability to recover its revenue requirement and earn its authorized return. This is because reduced demand for electricity due to economic conditions or the loss of a large customer have a much greater effect on a company such as AEY than on a larger utility that has a more diversified customer base.

(e) While there are risks to AEY's sales, due to the impacts from weather (as discussed in parts (a) to (c) above), changes in the economy, and customer behavior, AEY does not consider that a deferral on sales is required, at this time. AEY does have an approved deferral respecting YEC's Industrial sales forecast. However, this deferral account is strictly for purposes of calculating AEY's Rider R adjustment.

In AEY's view, a deferral account related to its sales forecast would not meet the criterion related to risk. As supported by the Concentric Report, AEY's capital structure is the appropriate mechanism to compensate for these risks. AEY notes that, currently, it is uncommon for electric utilities to have sales deferrals as this process adds additional complexity and administrative and regulatory burden respecting further regulatory submissions to true-up deferrals.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-025

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-025

Reference: 2023-24 GRA, Section 8, PDF page 129

Issue: Return on equity

Quote: AEY also serves a relatively small market with considerably less economic strength and diversity than the service areas of other utilities. Its residential and commercial sales are primarily affected by the general economic activity within the communities served.

Request:

Would the above statement similarly apply to any other electric utility with a rural base? If not, please explain why.

Response:

Most electric utilities primarily serve large urban areas, while also serving customers in rural areas that are more remote and sparsely populated. While other utilities may face similar risk, the distinguishing factor is the extent to which this operating risk applies to AEY's service territory. While the risk associated with serving a rural base may apply to other electric utilities, this risk is higher for AEY because the Company serves a larger percentage of customers in very remote communities and locations. In addition, AEY has greater than average operating risk due to severe weather conditions because the Company serves customers within these very remote areas.

The costs associated with addressing issues, outages and/or implications of inclement weather are higher in remote, rural communities as opposed to urban centers. As such, AEY has a higher risk of a higher negative impact to its returns due to the higher proportion of rural and remote customers that it serves.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-026

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-026

Reference: 2023-24 GRA, Section 8, PDF page 129

Issue: Return on equity

Quote: Since AEY's last GRA, transformational change has started to occur in the electric utility industry with emphasis on decarbonization, increased focus on Environmental, Social and Governance (ESG), the need for grid modernization, and general changes to the way in which customers receive utility service (e.g., self-supply). These changes increase risk and uncertainty for utilities to a level never experienced before, and particularly affect AEY because of the small customer base over which costs can be shared.

Request:

(a) What evidence has AEY reviewed/considered in making its statements noted in the quote?

(b) Are these changes being considered in the BCUC GCOC proceeding to determine the benchmark ROE?

(c) Were such factors considered in YEC's 2021 GRA proceeding?

Response:

(a) The Federal government and many Canadian provinces and territories have passed legislation in the past two years regarding decarbonization of the economy by 2050 with interim targets in 2030. Government policy has only intensified influencing customer behaviors, which includes rebates on new technology such as solar panels and Electric Vehicles, government grants for renewable generation, and mandates on the auto industry by 2035. While this provides opportunity, this transition also introduces risk and challenges to electric utilities,

in particular small electric utilities providing service in remote locations. Electric utilities must respond to these influences as the way the system is used is changing, creating new challenges such as technical issues with intermittent generation from renewables, new peak loads and higher demand loads. It is clear that the traditional and technical operations of the system, especially in remote locations, will not withstand the changes in customer behaviors. The utility must modernize the grid, while navigating challenges such as predicting customer behaviors, modernizing regulations and policy, supply chain and resourcing issues as this transition occurs across the globe. These challenges and the transition creates risk for investors not seen in the past.

The credit rating agencies have taken notice of these changes and starting in or about 2018, S&P Global Ratings, Moody's Investors Service, and DBRS added ESG criteria to their rating methodologies for regulated electric and gas utilities. Many pension funds and institutional investors are also prevented from investing in companies that do not meet certain ESG criteria. However, Concentric's recommended risk premium for AEY does not depend on a finding from the YUB that AEY's risk related to these industry trends has increased since 2017.

(b) The BCUC considered how the energy transition (specifically the effect of decarbonization on the gas distribution business) is affecting the risk of the gas LDC, FortisBC Energy, Inc. (FEI). In September 2023, the BCUC issued an Order in which they determined that FEI's overall business risk had increased since 2016, particularly with regard to the energy transition. As a result, the BCUC raised the common equity ratio of FEI from 38.5 percent to 45.0 percent to reflect that higher risk. In addition, FEI's authorized ROE was increased from 8.75 percent to 9.65 percent. FEI serves over 1 million gas distribution customers in British Columbia, compared to AEY's much smaller customer base.

(c) The YUB's findings on the return on equity included in revenue requirement in Appendix A to Board Order 2022-03, issued in March 2022, and Appendix A to Board Order 2023-01, issued in January 2023, do not address the effects of ESG, decarbonization, the energy transition, customer self-supply, or grid modernization on the risk profile of YEC, and rather focused on water-related risk, small size, and generation-related risk. Further, YEC did not present any evidence in that proceeding that its business risk had changed.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-027

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-027

Reference: 2023-24 GRA, Section 8, PDF pages 129-130

Issue: Return on equity

Quote: Operational cost risks exist due to the potential to under-estimate various cost items including: capital expenditures, financing costs and O&M expenses. The remote locations served by AEY can result in higher than anticipated repair costs for unplanned maintenance of facilities. Also, due to the severe weather conditions that can occur in northern Canada, repair costs can deviate substantially from those forecast in operating budgets which are based on normalized weather conditions. The length of the winter period increases the probability that these severe weather conditions may be experienced.

Based on the above, and as supported by the expert evidence of Concentric, AEY faces greater business risk than the average Canadian or British Columbia benchmark utility and such that a risk premium is appropriate. As such, Concentric has determined an appropriate risk premium to be 75 basis points.

Request:

Can AEY's Yukon experience mitigate some of those operational risks? Please explain.

Response:

Yes, AEY's experience and expertise is undoubtedly valuable in helping the Company plan for and manage these operational risks as they arise. However, that does not change the fact that the operational cost risks are greater in such a service territory where winters are long, weather conditions are severe, and wildfires have become more frequent in summer. AEY operates multiple, isolated, remote grids in communities that do not support

or accommodate the need for full time employees. In the event of an unplanned outage, our employees are dispatched at all hours to drive or fly into the community to diagnose and repair and restore power to the community or customer. Travel to these isolated communities in severe weather conditions can be slow, delayed or all together impossible, which makes an unplanned event take longer than normal to respond to. The experience of our employees mitigates the amount of time it takes to repair infrastructure, but it does not mitigate the risk of an unplanned event occurring.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-028

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-028

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), Figure 1, PDF page 141

Issue: Comparables

Preamble: Figure 1 lists utilities compared to AEY.

Request:

(a) Please cite the criteria used, the weightings given and any assumptions made when selecting the utilities compared to AEY.

(b) Why is PNG-West included in the list of comparables?

(c) Would other electric utilities be a stronger comparator to AEY? Please explain.

(d) Why was YEC not included in the list of comparators?

(e) For the column "Risk Compared to AEY", how were those ratings made? Were those relative risk assessments determined by Concentric? If not, please provide the source of those relative risk assessments. Please provide any quantitative evidence used to assess those ratings.

(f) For each of the utilities cited, please provide the year the ROE was determined, the corresponding decision reference from the governing regulatory authority and whether the ROE was an adjudicated result versus the product of a negotiated settlement.

(g) What has this Board previously said regarding the comparators used by Concentric for ROE determinations?

Response:

(a) The companies in the comparison group meet the following criteria: i) smaller operating utilities that provide distribution service in British Columbia (in the case

of FortisBC Electric and PNG West); ii) smaller operating utilities that provide electric distribution service and own limited generation assets (in the case of Newfoundland Power and Maritime Electric); and iii) smaller electric distribution utility of ATCO Electric (in the case of ATCO Electric Distribution). No particular weighting was assigned to any specific criteria. In totality, these companies represent smaller investor-owned distribution utilities in Canada that have similar business and financial risks as AEY.

(b) PNG-West was chosen as a comparator utility because it is very similar in size to AEY, both on a customer count and rate base basis. PNG-West had approximately 21,000 customers at the end of 2021, compared to 20,000 for AEY, and a regulated rate base of $172 million at the end of 2021, compared to $109 million for AEY, both of which represent the closest metrics to AEY, proportionally speaking, of all Canadian utilities considered. PNG-West's authorized ROE includes a risk premium of 75 basis points over the benchmark utility in British Columbia.

(c) Concentric believes that from a business risk perspective, electric utilities are generally an appropriate comparator for AEY. However, AEY is smaller than any of the other investor-owned electric distribution utilities in the comparator group. AEY has higher investment risk than those other electric utilities due to its extremely small size . In addition, the small size of AEY magnifies risks associated with other factors such as adverse economic conditions and severe weather conditions. Lastly, the small size of AEY limits its financial flexibility in terms of raising capital. For all of these reasons, it is appropriate to reflect this additional risk for AEY through a risk premium above the benchmark utility.

(d) Please refer to the response to AEY-YUB-023(a).

(e) These were qualitative comparisons made by Concentric based on the evidence in its report and its knowledge and experience in the industry. These relative

rankings reflect how Concentric believes investors would perceive the risk of AEY compared to each utility in the peer group.

(f) Please refer to the table below for Comparator Utilities' ROE and Decision references.

Table 1: Comparator Utilities ROEs and Decision References

Comparator Utility	Authorized ROE	Year ROE Determined	Decision Reference	Adjudicated or Settlement?
FortisBC Energy	9.65%	2023	BCUC 2021 Generic Cost of Capital Stage 1 Decision, issued Sept. 2023	Adjudicated
FortisBC Electric	9.65%	2023	BCUC 2021 Generic Cost of Capital Stage 1 Decision, issued Sept. 2023	Adjudicated
Ontario Electric Distributors	9.36%	2022	OEB 2023 Cost of Capital Parameters Update, issued 10-20-22	Formula-based
Newfoundland Power	8.50%	2022	NL BCPU Decision & Order No. P.U. 3 (2022), issues 2-16-22	Settlement
Maritime Electric Company Ltd	9.35%	2023	IRAC Docket UE20946, Order UE23-04, issued 4-24-23	Settlement
ATCO Electric Distribution	8.50%	2022	AUC Decision 27084-D01-2022, issued 3-31-22	Adjudicated
Pacific Northern Gas-West	9.50%	2014	BCUC 2014 Generic Cost of Capital Stage 2 Decision, issued 3-25-14	Adjudicated

(g) In the prior Board Order 2017-01, the YUB reviewed the similarities and differences between AEY and the prior comparable utilities group without opining on the makeup of the comparable utilities group. In addition, although the YUB concluded that AEY was not "directly comparable" to FortisBC Electric, Maritime Electric, or PNG-West, due to certain differentiating factors, including generation asset

ownership, power procurement, and other market factors,[1] Concentric believes that it is still necessary and appropriate to compare AEY to these other distribution utilities to determine if a risk premium is justified.

[1] Board Order 2017-01, Appendix A: Reasons, for Decision pp. 43-44.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-029

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-029

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), Figure 1, PDF page 141; PDF page 143

Issue: Generation risk

Quote: As discussed later in the report, companies that generate a larger percentage of their power supply from company-owned facilities are viewed by investors and credit rating agencies as being a higher risk.

Request:

(a) Does the above quote apply to any generation level contained in a utility or significant levels of generation?

(b) Would a utility whose self-supply of load requirements consists of eight-percent generation be considered a lower risk than a utility whose self-supply of load requirements consists of 45-percent generation? Please explain.

Response:

(a) As a general premise, Concentric's view is that companies that derive a higher percentage of their electricity supply from company-owned generation have higher generation risk than those companies that derive a lower percentage. In addition, this risk pertains to companies with significant ownership of generation assets, rather than companies which own generation as backup supply but purchase most power from another source, such as Maritime Electric or Newfoundland Power.

(b) All else being equal, Concentric agrees that a utility that derives eight percent of its load requirements from company-owned generation would have less generation risk than a utility that derives 45 percent of its load requirements from company-owned generation. That is but one of many factors; however, that determine utility business risk, and financial risk must also be considered.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-030

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-030

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), Figure 1, PDF page 141; PDF pages 143-144

Issue: Recommended risk premium

Quote: PDF Page 143:

> The majority of Newfoundland Power's residential customers use electricity for space heating purposes, which increases variability in usage per customer depending on weather conditions, and the company has a weather normalization adjustment clause to account for volumetric risk due to abnormal weather conditions. Newfoundland Power's currently authorized ROE is 8.50 percent, with a deemed equity ratio of 45 percent, as compared to 40 percent for AEY.
>
> …
>
> Maritime Electric has an authorized ROE of 9.35 percent and a deemed equity ratio of 40 percent. Maritime Electric was allowed to implement a weather normalization variance account in its 2018 rate application, while AEY has no protection against volumetric risk.

PDF page 144:

> At a minimum, the risk premium for AEY should be set no lower than 40 basis points, which is what the BCUC has established for FortisBC Electric, an electric utility company which is much larger than AEY in terms of retail customers served and rate base, has more deferral and variance accounts and full revenue decoupling, and operates in a service territory with a stronger and more diversified economy.

September 28, 2023 AEY-YUB-030

Request:

(a) Is there a generally accepted trade-off between risk premium and equity thickness? If applicable, provide any quantitative analysis and cite any authoritative decisions to support your response.

(b) When a utility prepares its sales forecast, does it use normalization procedures to adjust its forecast? If so, does the use of normalization procedures reduce the variability and any related risk in the forecast?

(c) Has AEY ever requested any deferral account to mitigate volumetric risk from sales? If AEY has not made such a request, can it be interpreted as a risk AEY is willing to accept?

(d) In Appendix A to Board Order 2017-01, if the Board made its risk premium determinations for AEY relative to FortisBC (the benchmark utility) and FortisBC Electric and if AEY's relative size to the two utilities has not materially changed since Board Order 2017-01, then on what basis should the Board now give more weight to a risk premium for AEY based on size?

Response:

(a) Yes, there is a relationship between the authorized ROE and the deemed equity thickness. Specifically, as financial leverage increases, investors require a higher ROE to compensate for the higher financial risk. Many Canadian regulators adjust for differences in business risk through the equity ratio rather than the authorized ROE. As discussed in the Concentric Report, AEY's deemed equity ratio is 40 percent. Several utilities shown in Figure 1 of the Concentric Report have deemed equity ratios greater than 40 percent. For example, FortisBC Energy, Inc. (the benchmark utility) now has an approved equity ratio of 45 percent, FortisBC, Inc. (the electric utility) has an equity ratio of 41 percent, and Newfoundland Power has a deemed equity ratio of 45 percent. Both the authorized ROE and the deemed equity ratio must meet the Fair Return Standard.

(b) Yes, most utilities provide a weather normalized sales forecast. However, there is an important distinction between a utility that weather normalizes its sales forecast and a utility that is allowed to recover revenues that were lost due to abnormal

weather. In the former case, it depends on the ability of the utility to accurately forecast the effect of weather on sales. In the latter case, the utility is allowed to recover revenues if actual sales are different than forecast sales due to the effect of abnormal weather. Weather normalizing the sales forecast does not protect the utility's earnings and cash flows in the event of abnormal weather.

(c) AEY had sought deferral treatment on sales volumes respecting industrial load as part of its 2013-2015 GRA which was denied in Board Order 2014-06. In 2022, as part of AEY's Rate Relief Application, AEY sought deferral treatment on revenues related to industrial load which was approved in Board Order 2022-13. AEY is seeking continuation of that deferral as part of this Application.

(d) Concentric is not suggesting that the YUB should give more weight to the size premium for AEY than in 2017, when the Board determined that the small size of AEY was an important factor supporting a risk premium for the Company. In this proceeding, Concentric has provided additional evidence from Kroll to quantify the risk premium that investors require for smaller companies including utilities. This evidence shows that the risk premium for companies with market capitalizations similar to AEY is approximately 400 basis points. This is substantially higher than the risk premium determined by the YUB for AEY in 2017, and well above the risk premium of 75 basis points that Concentric is recommending for AEY in this GRA.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-031

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-031

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence); PDF page 158

Issue: Risk premium for size

Quote: Size is an important consideration for investors in setting their return requirements. According to Morningstar, investors in smaller companies typically require a higher return because returns for smaller companies are more unpredictable.

Request:

(a) Is it standard when choosing comparators to utilities to use size as the dominant criteria for assessing a risk premium for business risk? Please explain.

(b) Please file any information that shows that the returns (ROE) for small regulated electric utilities are more unpredictable.

(c) Please provide examples showing that AEY's returns (ROE) have been unpredictable. Provide AEY's returns for the last seven years.

(d) The BCUC determined and AEY previously noted from the last Stage 2 GCOC decision that an adder of 25 basis points for a risk premium recognized small size. This applied to FortisBC Whistler and PNG Tumbler Ridge. Has the BCUC released a decision that changed that recognition for small size? Why didn't Concentric use either FortisBC Whistler or PNG Tumbler Ridge as a comparator?

Response:

(a) Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and

gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).

(b) As support for the premise that investors require higher returns for small regulated utilities, Concentric relied on a 1995 article published in Public Utilities Fortnightly by Michael Annin, an analyst for Ibbotson and Associates, the firm which publishes historical market return data. A copy of that article is provided as AEY-YUB-031(b) Attachment 1. That article demonstrates that the small size effect also pertains to regulated utility companies such as AEY.

(c) Please refer to the table below for the requested information.

Table 1: AEYs Actual Return on Equity (%)

2016	2017	2018	2019	2020	2021	2022
10.44	12.72	12.63	13.00	13.19	12.35	11.88

The fact that AEY has generally been able to earn at least the Board determined ROE since 2016 does not guarantee that the Company will be able to do so in the future as operating risks and business conditions change.

In AEY's view the ROE's earned are reflective of unpredictability, AEY did not anticipate the incremental industrial load in the Yukon, nor did it have insight into

reductions in statutory tax rates and carbon relief added to tax legislation, which were significant factors that contributed to AEY's returns since 2016.

(d) Confirmed, with regard to the risk premium of 40 basis points for FortisBC Electric and the risk premium of 25 basis points for FortisBC Whistler and PNG-Tumber Ridge in the BCUC's Stage 2 GCOC 2014 decision. FortisBC Whistler was not included as a comparator to AEY because the company was amalgamated into FortisBC Energy, Inc. in 2014 and has not had its own authorized ROE or capital structure since 2014.

PNG-Tumbler Ridge was not included as a comparator to AEY because Concentric did not believe it was necessary to include each PNG affiliate in its risk analysis. Further, at the time of the BCUC's 2014 GCOC decision, the deemed equity ratio for FortisBC Whistler was 41.5 percent. The deemed equity ratio for PNG-Tumbler Ridge has been 46.5 percent every year since 2013. Both are higher than the deemed equity ratio for AEY of 40.0 percent. The BCUC generally accounts for greater business risk through the deemed equity ratio rather than the authorized ROE.

Equity and the small-stock effect
Annin, Michael
Public Utilities Fortnightly; Oct 15, 1995; 133, 19; ABI/INFORM Global
pg. 42

Financial News

By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \times RP] + R_f$$

where:

- R_s = expected return or cost of equity on the stock of company "s"
- β = the *beta* of the stock of company "s"
- RP = the expected equity risk premium
- R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	–0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

*Betas are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

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Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$R_s = [\beta_s \times RP] + R_f + SP$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

Michael Annin, CFA, is a senior consultant with Ibbotson Associates, specializing in business valuation and cost of capital analysis. He oversees the Cost of Capital Quarterly, *a reference work on using cost of capital for company valuations.*

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ATCO Electric YUKON

September 28, 2023 AEY-YUB-032

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-032

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 158

Issue: Risk premium for size

Quote: In addition to contributing to higher investment risk, the small size of AEY magnifies the risk associated with other factors. For example, adverse economic conditions in the territory could result in the loss of a large customer or reduced demand for electricity. Under those circumstances, the small size of AEY means that the Company's fixed costs are spread across a very small customer and revenue base, making it more likely that AEY would be unable to earn its authorized ROE.

Request:

(a) The above example describes a volumetric risk. Can this risk be compensated by frequent regulatory filings or by special applications such as the YEC/YECL application when the Faro mine closed?

(b) Relatively, has size risk materially changed since AEY's last GRA? Please explain.

Response:

(a) While more frequent regulatory filings might be useful in terms of adjusting the sales forecast in future years, they do not provide the utility with a better opportunity to earn its awarded ROE in a previous year. If adverse economic conditions occur during a year in which there is no rate case, the utility has no way to go back and recover any lost revenues or earning shortfall after the fact. In addition, more frequent regulatory filings and special applications also can result

in less regulatory efficiency and higher costs for both the customer and the regulatory agency.

(b) The risk associated with small size has not materially changed since the prior GRA, when the YUB found that it was an important risk factor for AEY that supported a risk premium above the BCUC benchmark utility. In its report, Concentric has provided additional evidence from Kroll to quantify how small size affects the return that investors require. Please also refer to the response to AEY-YUB-030(d).

ATCO Electric YUKON

September 28, 2023 AEY-YUB-033

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
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AEY-YUB-033

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 159

Issue: Risk premium for size

Quote: To estimate the magnitude of the size premium, I used data from Kroll (formerly Duff and Phelps) that divides companies into deciles based on market capitalization.

Request:

(a) Does the data from Kroll only look at market capitalization?

(b) What other factors can affect the size premium for a company?

(c) What other factors affect market capitalization?

Response:

(a) Yes, the data that Concentric used from Kroll that divides companies into deciles and assigns a size premium to each decile solely relies on market capitalization to determine the decile cut-offs. To estimate the magnitude of each decile's assigned size premium, Kroll uses historical return data; specifically, the actual historical excess return, which is the annual average return of the decile less the annual average risk-free rate, and the excess return predicted by the CAPM, which is the beta of the decile multiplied by the equity risk premium.

(b) Please refer to the response to subpart (a). Kroll defines the "size premium" as "the difference between the actual historical excess return and the excess return predicted by beta that is attributed to the risk implied by the size of the subject

company."[1] Size, as used in this context by Kroll, is solely measured by market capitalization. In general, size usually refers to market capitalization, although Kroll has also used other measures of size in other contexts, including in its Risk Premium report study,[2] e.g., book value of equity, five-year average net income, market value of invested capital, total assets, five-year average EBITDA, sales, and number of employees.

(c) Market capitalization is the number of shares outstanding times the share price and represents the total market value of a company's shares of stock. Certain factors, including changes to the stock price, driven by supply and demand of the stock as well as public sentiment of future growth potential, and company issues or repurchases, may affect market capitalization.

1 Source: Kroll Cost of Capital Navigator: Glossary
2 Source: Kroll U.S. Cost of Capital – Size Premium Methodology

ATCO Electric YUKON

September 28, 2023 AEY-YUB-034

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-034

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141, PDF page 160

Issue: Generation risk

Quote: FBC purchases approximately 55 percent of its electricity supply and generates the other 45 percent of its supply requirements through company-owned hydro facilities.

Request:

(a) FortisBC Electric generates 45 percent of its supply requirements. Does Concentric consider this a significant increase in generation relative to AEY?

(b) Please comment on whether FortisBC Electric would be considered to have higher generation risk than AEY.

Response:

(a-b) Concentric agrees that FortisBC Electric (FBC) has greater generation risk than AEY. That higher risk; however, is offset by FBC's larger size compared to AEY in terms of both customers and rate base and by FBC's fuel and purchased power adjustment clause which eliminates FBC's risk related to fuel cost recovery. In September 2023, the British Columbia Utilities Commission issued an Order in the 2021 Generic Cost of Capital (Stage 1) proceeding in which FBC's authorized ROE was raised to 9.65 percent from 9.15 percent and its common equity ratio was increased to 41 percent from 40 percent. Please also refer to the response to AEY-YUB-029(b) for further discussion on generation risk.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-035

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

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AEY-YUB-035

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 160

Issue: Fuel and purchased power cost risk

Preamble: AEY has fuel price and purchase power flow through deferral accounts, including the ability to pass on ERA charges to customers.

Request:

(a) In terms of overall business risk assessment, does fuel and purchase power cost risk have a lower weighting than size and generation risk? Please explain.

(b) Regarding fuel and purchase power cost risk, what risk is AEY exposed to?

(c) If the response to part (b) is volumetric risk, please explain and demonstrate through a numeric example how this is a risk to AEY.

(d) Relatively, has this risk materially changed since AEY's last GRA? Please explain.

Response:

(a) While fuel and purchase power cost risk is important, most utilities are able to pass through those costs directly to customers and, therefore, are not at risk for cost recovery if actual costs are higher/lower than forecast. Risk differences occur when the utility is not allowed to pass through 100 percent of these costs, or when the variance accounts expire. As a general premise, Concentric agrees that fuel and purchase power cost risk is not as important as small size and generation risk.

(b) Consistent with historical practice, AEY is proposing continuation of its existing purchase power and fuel deferral accounts where costs related to price variances

are flowed through to customers. AEY continues to assume risk for costs related to forecast volumes.

(c) AEY has forecast fuel and purchase power assuming 2.5 percent of its supply is self-generated through Fish Lake Hydro Generation and 0.03 percent of supply is self-generated through standby diesel generation. AEY has also forecast 0.2 percent of supply from Independent Purchases.

Since 2016, AEY's Fish Lake Hydro generation has been as low as 1.3 percent of supply. If AEY were to experience the same low levels of generation due to low water or mechanical issues, AEY would incur incremental costs of approximately $360,000 (or, approximately a 70 basis point reduction in returns) due to the higher volume of wholesale purchases required.

Also, since 2016, AEY has required as high as 0.09 percent of its supply being sourced through its standby generation. Similarly, load constraints or outages that require running standby diesel for as much as 0.10 percent of total supply, would result in AEY incurring net costs of approximately $80,000 (or, approximately a 10 basis point reduction in returns) due to higher consumption of diesel fuel, partially offset by lower wholesale purchases.

The IPP program is relatively new. As such, AEY does not have enough historical supply data to analyze. If supply from renewables, owned by independent power producers in Old Crow, is 50 percent lower than what AEY has forecast, this reduction would result in incremental net costs of approximately $121,000 (or, approximately a 25 basis point reduction in returns). If AEY's requested IPP deferral is not approved and renewables supply is constrained due to outages on the utilities infrastructure, this reduction in supply would result in an increase in AEY's costs of approximately $345,000 (or, approximately a 68 basis point reduction in returns) for incremental supply and constraint payments.

(d) No, this risk has not materially changed since AEY's last GRA, assuming that the continuation of AEY's deferral accounts for purchase power and fuel prices are approved by the YUB. If the IPP deferral account requested in this Application is not approved, however, AEY's risk would be materially higher than in 2016.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-036

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
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AEY-YUB-036

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 161

Issue: Volumetric/demand risk

Quote: AEY does not have regulatory protection against changes in volume/demand due to weather conditions or DSM and energy efficiency programs.

Request:

(a) In terms of determining overall business risk, please provide the relative weighting of the above-noted risk versus the risks of size, generation, fuel and purchased power risk and the other business risks evaluated in the report.

(b) Relatively, has the risk due to weather conditions materially changed since AEY's last GRA? Please explain.

Response:

(a) Concentric has not assigned relative weights to the risk factors that are discussed in the report. Risk assessments are generally more qualitative than quantitative. The most important considerations are whether the utility faces the specific risk, the magnitude of the risk on earnings and cash flows, and whether the utility has some form of regulatory protection that mitigates the effect of the risk. In summary, Concentric takes a holistic approach to evaluating risk. No specific risk factor is more important than another from the perspective of investors.

(b) Risk due to weather conditions has not materially changed since 2016. However, the frequency of severe weather events has generally increased in the past

decade, and credit rating agencies such as S&P have commented that climate change is challenging the utility industry's traditional risk management assumptions.[1] For this reason, it is very important that AEY has the financial flexibility to respond to these events as they arise.

[1] S&P Global Ratings, "Can U.S. Utilities Weather the Storm," November 8, 2018.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-037

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-037

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 162

Issue: Volumetric/demand risk

Quote: The Company believes that the increased variability in residential use per customer is due in part to customers responding to changes in prices for alternative fuels. For example, when heating oil and propane prices are high, customers are more likely to switch to electricity for space heating. When heating oil and propane prices are lower, customers are less likely to switch to electricity for space heating. Figure 10 below shows that residential use per customer has increased since 2016 as heating oil prices have approximately doubled.

Request:

(a) Has the company filed any studies to support its determination that customers are responding to changes in prices for alternative fuels. If so, please provide those studies. If not, what is the basis for the statement?

(b) In terms of alternative fuel sources, does this mean that most homes will have duplicate sources for heat such as an oil-burning furnaces and electric space heating? Please comment.

(c) In reference to: "… when heating oil and propane prices are high, customers are more likely to switch to electricity for space heating", is this referring to new customers entering the system or existing customers retrofitting their homes? Please explain.

(d) Relatively, has the risk due to prices for alternative fuels materially changed since AEY's last GRA? Please explain.

Response:

(a) Concentric is not aware of any studies performed by AEY in this regard. The statement is based on anecdotal evidence from AEY employees and individuals in the communities served by AEY that confirms "fuel switching" between heating sources is common.

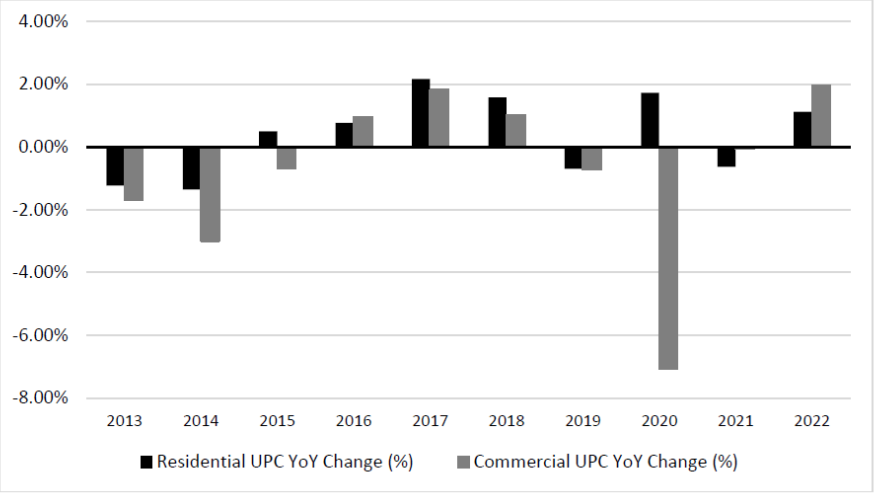
(b) The statement recognizes customers have a choice with regard to fuel, and that to the extent they prefer one fuel source over another, it affects the risk profile of AEY. Some houses may have both primary (e.g., oil, propane) and secondary (e.g., wood stoves, portable electric heaters) heating sources.

(c) The statement refers to houses with primary and secondary heating sources, new customers signing up for electric service, and existing customers converting space or water heating equipment to electric from another fuel source.

(d) As shown in Figure 9 from the Concentric Report (also provided below), the year-over-year changes in AEY's residential and commercial weather-normalized Use per Customer (UPC) has seen a slight uptick since AEY's last GRA in 2016.

Figure 9: Variability in Use Per Customer

Residential and Commercial: Year to Year Percent Change



The average absolute magnitude of YoY changes from 2013-2016 was 1.0 percent for residential and 1.6 percent for commercial, whereas the average YoY change from 2017-2022 was 1.3 percent for residential and 2.1 percent for commercial. Increases in fuel switching could be a cause for these increases in UPC variability, thereby increasing the probability that sales differ from forecasts and that AEY may not fully recover its costs.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-038

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

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The Yukon Utilities Board (YUB)
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AEY-YUB-038

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF page 164

Issue: Risk from alternative fuels

Quote: In summary, AEY's residential customers respond to price signals as the relative cost of heating with electricity changes. However, this risk is difficult to quantify and likely does not have a material effect on the risk profile of AEY. It does, however, make it more difficult for AEY to accurately forecast sales, which in turn increases the variability in AEY's cash flows and earnings.

Request:

If the risk of alternative fuels is not material, why is this risk considered?

Response:

Concentric has considered the principal business risks relevant to a regulated utility from an investor's perspective. As part of assessing this risk, Concentric determined: (i) if the utility has this risk; (ii) if the risk is material to the stability and predictability of the earnings and cash flows of the company; and (iii) if the utility has a way to mitigate the risk through regulatory protections. In the case of competition from alternative fuels, Concentric determined that this risk exists but is not material for AEY, at this time.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-039

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

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The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-039

Reference: 2023-24 GRA, Section 8, Attachment 8.1 (Concentric Energy Advisors, Inc. – Evidence), PDF page 141; PDF pages 165-171

Issue: Changes in business risk

Preamble: The writeup for Section B. Changes in business risk since the last GRA in the Application is surprisingly similar to that in Section B of the Concentric report in the application for AEY's 2016-17 GRA.

Request:

(a) Part 1 of Section B (weather-related risk) states that this risk has not materially changed since 2016 but adds that S&P has commented that climate change is challenging the utility industry's traditional risk management assumptions. Is this something that affects all utilities? If so, is this likely something that is considered in setting the ROE for the benchmark utility, or is this unique to AEY?

(b) Part 2 of Section B discusses power supply risk. Concentric states that this item has not materially changed since the last GRA. The fuel price deferral account has been set by an OIC. Does Concentric agree that the only way the fuel price protection for the utilities can change is by a change in legislation? Is AEY or Concentric aware of whether or not the government intends to make such a change? Please explain.

(c) Part 3 of Section B discusses competition from alternative fuels. Has this risk changed materially since the last GRA? Is this risk unique to AEY, or does it generally apply to all utilities? Please explain.

(d) Part 4 of Section B discusses government policies. Does the growth of the IPP present capacity opportunities for AEY? Please explain. Is this risk unique to AEY, or does it generally apply to all utilities? Please explain.

(e) Although IPPs may remove some generation opportunities for AEY, does the investment in batteries, storage and interconnection facilities somewhat mitigate that effect?

Response:

(a) Concentric agrees that climate change is an operating risk that affects all utilities, including FortisBC, Inc. (FBC), the benchmark utility, to some degree. However, the magnitude of climate change risk varies depending on the location of the utility's service territory and the number and type of customers served. This is another area where the size of the utility is an important risk factor. Smaller companies have less ability to respond to climate change related events such as service disruptions and outages, as discussed on page 27 of the Concentric Report, because they have fewer financial and human resources. In recent years, credit rating agencies and investors have become more aware of climate change risk for regulated utilities and are factoring it into their assessment of the utility's operating risk profile.

(b) Confirmed. The fuel price deferral mechanism is legislated through OIC 1995/90, Rate Policy Directive (1995). Neither AEY nor Concentric are aware of any upcoming or intended changes to this legislation.

(c) This risk only applies to jurisdictions where consumers have access to alternative heating fuels (heating oil, propane, wood pellets etc.), such as AEY's residential consumers. The risk to AEY's forecast has not materially changed since 2016. While there has been significant growth in the proportion of dwellings fit for electric heat over the last several years, there is uncertainty for whether this trend will continue at this rate. As such, there is increased risk as penetration rises that the growth trends will level off or decline, resulting in variability in AEY's sales volume assumptions, which could have a material impact.

(d) No, the growth of IPPs does not present capacity opportunities in the short term. In AEY's experience, IPP generation has been limited to intermittent sources which require full thermal generation redundancy as well as a battery and microgrid controller, which are fully-contributed at the time of connection. Following the

connection, AEY's costs to maintain or replace equipment or infrastructure necessary to accommodate the IPP are recoverable, per OIC 2019/25. In other words, in the short term, AEY has limited opportunity to invest in new capacity (like batteries). Presumably, AEY will have the opportunity to invest in battery replacement at the end of the life-cycle. In the interim period; however, AEY is presented with increased risk associated with operating the grid, due to the technical complexity of integrating the battery.

This risk is not unique to AEY; however, the risk is exacerbated and intensified for AEY due to:

1) the number of small, off-grid communities it serves, each with its own load profiles, generation capabilities, and staffing capacity; and

2) the proportion of rate base and revenue AEY receives from these communities relative to its overall operations.

Please refer to the response to AEY-YUB-035 for further discussion around the risks associated with increased intermittent generation.

(e) As discussed in response to part (d) above:

1) The investment in batteries, storage, and interconnection facilities is not directly correlated with IPP growth, as these items are typically fully-contributed in the short term.

2) Because IPPs have typically been intermittent generation sources, AEY must still maintain full thermal generation redundancy in the off-grid communities to ensure ongoing safe and reliable service.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-040

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

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The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-040

Reference: 2023-24 GRA, Section 8, PDF pages 130-131

Issue: Long-term debt

Quote: AEY used an average Long Canada Bond Rate and applied a spread to determine the forecast debenture rate. The forecast for Long Canada Bonds and credit spreads were based on discussions with ATCO's Treasury Department at the time of the filing.

Request:

(a) Please provide a table showing the forecast issues and spreads (long-term Canada bond rates and spreads) and then the actual issues and spreads for the years 2016 to 2022 inclusive. Include in that table the amounts, dates and final rates for the acquired long-term debt.

(b) Please provide the sources for the Long Canada Bond Rate and spreads.

(c) Please provide any updates to the forecast Long Canada Bond Rates and spreads and the date of that update.

(d) Please provide details of the amounts of long-term debt AEY intends to issue during each of the years 2023 and 2024.

Response:

(a) Please refer to the following table of actual debt rates for 2016-2022 and approved debt rates for 2016-2017. AEY did not have new debt issued in 2021.

Table 1: Issues and Spreads for 2016 to 2022

	2016 Approved	2016 Actual	2017 Approved	2017 Actual
Issue Date	2016-11-17	2016-11-17	2017-11-01	2017-11-22
Maturity Date	2046-11-17	2046-11-17	2057-11-01	2047-11-22
Long Canada Bond	2.04%	2.04%	2.18%	2.18%
Issue Spread	1.72%	1.72%	1.37%	1.37%
Debenture Rate	3.75%	3.76%	3.77%	3.55%
Debenture Amount	5,400,000	7,400,000	6,900,000	6,400,000

	2018 Actual	2019 Actual	2020 Actual	2022 Actual
Issue Date	2018-11-21	2019-09-07	2020-09-28	2022-09-14
Maturity Date	2048-11-21	2049-09-07	2050-09-28	2052-09-14
Long Canada Bond	2.41%	1.48%	0.98%	3.14%
Issue Spread	1.54%	1.48%	1.63%	1.63%
Debenture Rate	3.95%	2.96%	2.61%	4.77%
Debenture Amount	2,600,000	4,600,000	4,200,000	3,000,000

(b) The Long Canada Bond Rate and spreads information was obtained from the Bank of Canada website. Please refer to AEY-YUB-040(b) Attachment 1.

(c) As per the September 11, 2023, Consensus Forecast (provided in AEY-YUB-040(c) Attachment 1) forecast debt rates for 2023 and 2024 are as follows:

Table 2: Forecast Debt Rates for 2023 and 2024

	2023	2024
Long Canada Bond Rate	3.40%	3.10%
Credit Spread	1.55%	1.55%
Debenture Rate	4.95%	4.65%
Issue Costs	0.05%	0.05%
Recommended All-In Rate	**5.00%**	**4.70%**

(d) Details of the debt included in the Application are as follows:[1]

Table 3: Long-term Debt Forecast Issuance for 2023 and 2024

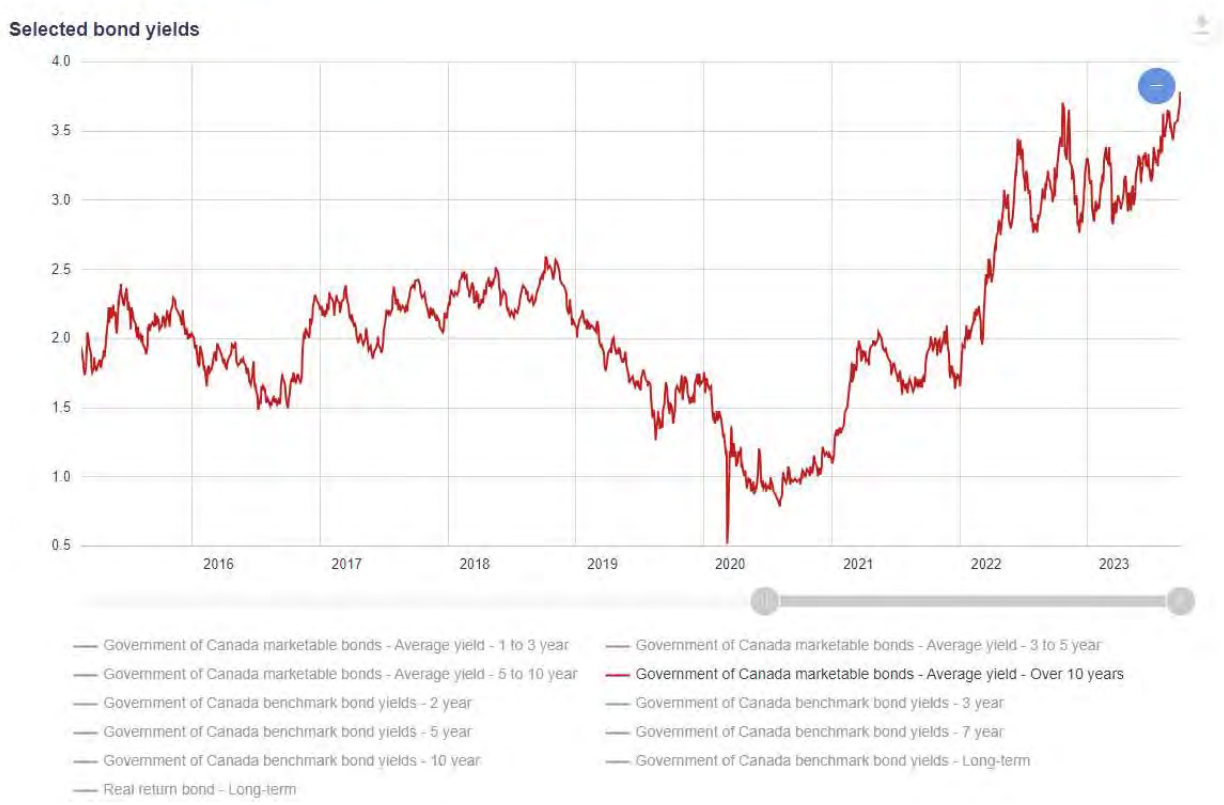
	2023	2024
Long Canada Bond	2.50% - 3.00%	2.50% - 3.00%
Issue Spread	1.55%	1.55%
Debenture Rate	4.56%	4.56%
Debenture Amount	$7,000,000	$9,000,000

[1] 2023-2024 AEY GRA, Section 8, PDF p. 131, Table 8.2.

Source of interest rates on Canadian Bonds

https://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/

Data available as: **CSV**, **JSON** and **XML**



	CDN.AVG.OVER.10.AVG	Over 10 ye	Government of Canada marketable bonds - Average yield		
	OBSERVATIONS				
	date	CDN.AVG.	CDN.AVG.	CDN.AVG.	CDN.AVG.OVER.10.AVG
98	2016-11-17	0.67	0.88	1.31	2.04
51	2017-11-22	1.43	1.59	1.79	2.18
00	2018-11-21	2.2	2.28	2.33	2.41
98	2019-09-06	1.5	1.36	1.29	1.48
53	2020-09-28	0.23	0.31	0.47	0.98
52	2022-09-14	3.72	3.39	3.19	3.14
06					

SEPTEMBER 2023 CANADA

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 5.0%		3.7%	
Unemploy-ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2023	2024	2023	2024	FY 23-24	FY 24-25	End Dec.'23	End Sep.'24	End Dec.'23	End Sep.'24
5.3	5.9	-21.3	-63.5	-34.9	-27.8	5.0	4.0	3.2	3.1
5.5	6.2	-17.1	-23.9	na	na	na	na	na	na
5.3	6.3	-25.0	-32.0	na	na	5.0	3.8	3.3	3.0
5.4	6.4	-22.0	-34.7	-39.9	-35.0	5.0	4.0	3.3	3.2
5.4	5.7	na	na	na	na	na	na	na	na
5.4	5.9	na	na	na	na	na	na	na	na
5.5	5.8	na	na	na	na	5.1	4.1	3.7	3.2
5.2	5.7	-7.7	-6.7	na	na	4.5	3.5	3.5	3.2
5.5	6.5	-25.0	-28.9	na	na	5.0	4.4	3.0	2.8
5.4	6.0	-25.3	-23.3	na	na	na	na	na	na
5.4	6.1	na	na	na	na	5.1	3.9	3.5	3.1
5.4	6.0	-30.0	-42.0	-39.8	-35.0	5.1	4.6	3.5	3.1
5.4	6.0	-27.5	-40.0	-40.0	-45.0	5.1	4.6	3.7	3.2
5.5	7.1	-30.5	-59.6	-41.5	-40.6	4.9	2.9	3.6	2.8
5.5	5.9	na	na	na	na	na	na	na	na
5.4	6.3	-31.6	-51.2	na	na	5.0	3.8	3.6	3.7
5.4	6.4	-35.0	-37.0	na	na	5.0	4.2	3.5	3.3
5.6	7.1	-29.6	-45.6	na	na	4.7	4.7	3.5	3.4
5.4	6.2	-25.2	-37.6	-39.2	-36.7	4.9	4.0	3.4	3.1
5.4	6.1	-31.2	-45.5	-40.8	-35.2				
5.4	6.0	-29.4	-36.1	-38.9	-33.2				
5.6	7.1	-7.7	-6.7	-34.9	-27.8	5.1	4.7	3.7	3.7
5.2	5.7	-35.0	-63.5	-41.5	-45.0	4.5	2.9	3.0	2.8
0.1	0.4	7.1	15.5	2.5	6.5	0.2	0.5	0.2	0.2
5.2	5.7								

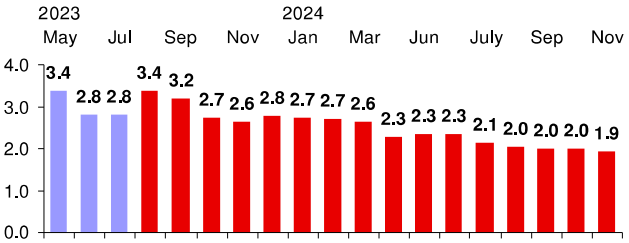
Bank of Canada Pauses and Assesses Landscape

The Bank of Canada (BoC) kept its overnight rate at 5.00% on September 6 but suggested hawkishness with regards to underlying inflation. The headline CPI moderated during the H1 2023, from +5.1% (y-o-y) in Q1 to +3.5% in Q2. However, the July outturn ticked up to 3.3% (y-o-y) from 2.8% in June, as the base-year effect from a big fall in gasoline prices in July 2022 dropped out of the index. Summer demand for electricity, especially in Alberta, alongside the phasing out of energy caps and rebates earlier in the year, boosted the electricity component. Meanwhile, core price pressures are currently around 3.5%, above the BoC's 2% inflation target. Monthly CPI forecasts (below) point to stickiness in the y-o-y numbers over 2023 and early 2024. The central bank is wrestling with bringing inflation down but is also mindful of the impact of higher interest rates on the economy. The expenditure-based GDP release for Q2, for example, cited a fifth straight contraction in housing investment and sharp curtailment in new construction across many provinces (both are particularly sensitive to interest rates and mortgage approvals). The lagged impact of previous rate hikes also has further to run.

GDP growth ground to a halt in Q2, following an upbeat 0.6% (q-o-q) outturn in Q1. As mentioned, interest rates impacted the housing sector, while slower inventory build-up and reduced export growth were also a factor. After a +1.2% (q-o-q) surge in Q1, household expenditure slowed to +0.1% in Q2. On an output-based monthly basis, GDP in June dropped by -0.2% (m-o-m) following a +0.2% rise in May. Both goods production and services output fell. Wildfires dented activity in several sectors, specifically mining in Quebec, which led to mining & quarrying contracting by -5.7% (m-o-m), their largest monthly decline since November 2021. Energy, however, rebounded following Alberta wildfires in May.

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



Canada Overnight Lending Rate – Sep. 11, 2023 = 5.00%

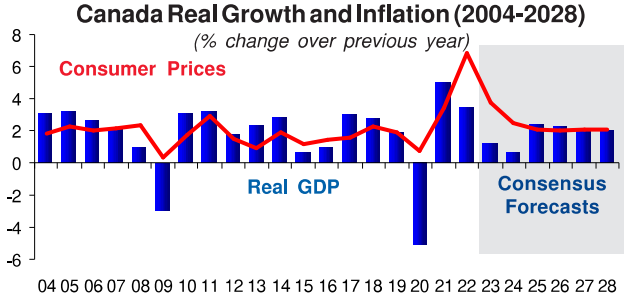
Average probabilities of a change in the Lending Rate on **October 25:**

Increase = 17.3% **No change =** 71.6% **Decrease =** 0.1%

Consensus Forecasts	End Sep '23	End Dec'23	End Mar '24	End Jun '24	End Sep '24	End Dec '24	End Mar '25
Mean Average:	5.03 %	5.03 %	4.95 %	4.63 %	4.25 %	3.88 %	3.50 %
Mode (most frequent):	5.00 %	5.00 %	5.00 %	4.75 %	4.50 %	4.00 %	4.00 %

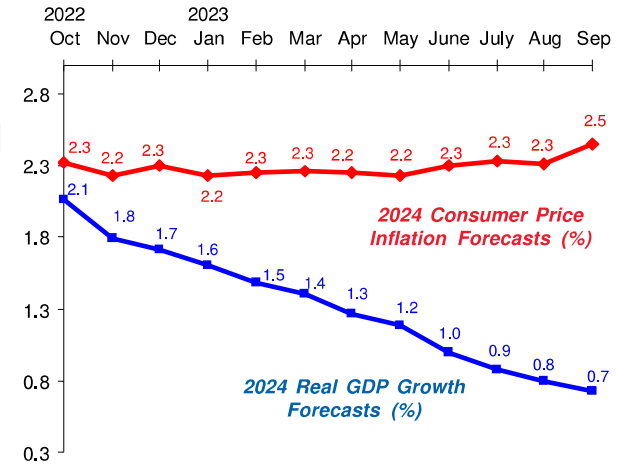
Canada Real Growth and Inflation (2004-2028)

(% change over previous year)



2024 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



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ATCO Electric YUKON

September 28, 2023 AEY-YUB-041

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-041

Reference: 2023-24 GRA Schedules, S9.2 – Continuity of Capital Expenditures

Issue: Capital expenditures

Preamble: The Board has been unable to fully cross reference certain capital cost information between the business cases that have been provided and the information in 2023-24 GRA Schedules, S9.2 – Continuity of Capital Expenditures.

Request:

(a) For the following line no. references from S9.2, please provide a reference to the applicable business case where details supporting the capital expenditure have been provided. If no business case had been prepared for the costs at issue, please provide detail supporting the capital expenditures on the noted line no. To the extent that the information requested in this IR has been provided in response to another Board IR, please cross-reference that IR response.

(i) Line No. 134 – Renewables – Old Crow (2019, $1.034 million; 2020, $1.147 million; 2021, $1.406 million; and 2022, $0.034 million);

(ii) Line No. 161 – Mt. Sima Hill Service (2022, $0.413 million);

(iii) Line No. 167 – YG Airport Hangar (2022, $0.562 million; 2023, $-0.030 million);

(iv) Line No. 279 – AEY DWCI – New 12.5kV substation (2023, $0.025 million; 2024, $0.792 million);

(v) Line No. 282 – AEY Nisutlin Bridge Pole Relocation (2023, $0.380 million; 2024, $0.165 million)

(vi) Line No. 315 – Carcross Streetlights (2017, $0.429 million; 2018, $-0.024 million; 2019, $0.111 million);

(vii) Line No. 322 – McIntyre Subdivision Streetlight Rebuild (2023, $0.412 million; 2024, $0.155 million);

For Line No. 322, please also explain why AEY had approved 2016-17 costs for this project ($0.175 million and $0.254 million, respectively), but no capital expenditures appear to have been incurred.

(viii) Line No. 419 – Unit 136 to Replace Unit 643 Bucket Truck (2017 $0.614 million)

(b) For the following line no. references from S9.2, please provide the requested information

(i) Line No. 183 – General Pole Replacements. Please explain why historical actuals for 2016-2022 (ranging from $0.029 million to $0.112 million each year) are significantly less than approved 2016-17 yearly capital expenditures ($0.297 million and $0.284 million respectively).

Please also justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 ($0.254 million, $0.211 million, respectively) given the lower actual costs incurred in 2016-2022.

(ii) Line No. 186 – General Clearance Upgrades/Fixes. Please explain why historical actuals for 2016-2022 (ranging from $0.00 million to $0.037 million per year) are significantly less than approved 2016-17 capital expenditures ($0.050 million and $0.051 million respectively).

Please also justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 ($0.084 million and $0.108 million respectively) given the lower actual costs incurred in 2016-2022.

(iii) Line No. 189 – T&B Switch Change Out. Given that historical actuals for 2016-2022 range from $0.002 million to $0.036 million per year, please justify AEY's proposed increases in capital expenditure forecasts for the years 2023-24 ($0.119 million and $0.064 million respectively).

(iv) Line No. 196 – McCrae Substation Second Feeder Breaker. Please provide a variance explanation for the $0.327 million difference between the actual 2016-17 costs incurred (the total of $0.608 million and $0.133 million) compared to the 2016 approved costs of $0.414 million.

(v) Line No. 340 – Replacement of Meters and New Installations. Please explain why the actual capital expenditures for the years 2016-17 ($0.105 million and $0.088 million respectively) were less than the approved capital

forecast for this project for the years 2016-17 ($0.199 million and $0.203 million respectively).

Please also address the Board's observation that actual capital expenses for this project continued during 2018-2022 (ranging from $0.032 million to $0.127 million) at amounts significantly less than being recovered through approved 2017 revenue requirement.

(vi) Line No. 344 – General Capitalizable Transformers. Please explain why the approved 2016-17 capital expense forecast ($0.090 million and $0.091 million respectively) does not appear to have been incurred.

Please also address the Board's observation that AEY proposes capital expenditures for 2023-24 ($0.218 million and $0.275 million respectively) notwithstanding that, between the years 2016 and 2022, a total of only $0.297 million has been incurred on an actual basis for this project.

(vii) Line No. 345 – Spare 10 MVA Transformer. Please explain why the approved 2016 capital expense forecast ($0.219 million) does not appear to have been incurred.

(viii) Line No. 346 Spare Padmount Regulator for Shipyards Substation. Please explain why the approved 2016 capital expense forecast ($0.058 million) does not appear to have been incurred.

Response:

(a) (i) A Business Case was not prepared. This is a customer driven fully contributed project. The scope of the project included the purchase of BESS/Micro Grid Controller, new transformer for the PV site, new recloser for the IPP site, foundation design and construction for BESS and various distribution and generation upgrades to accommodate the connection of the IPP to the Old Crow system.

(ii) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in load based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project included extending underground primary power

comprised of cable in conduit up the Mt. Sima Ski hill to a new padmount transformer.

(iii) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in load based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project includes extending underground primary power comprised of cable in conduit around the Whitehorse Airport runway to a new padmount transformer.

(iv) A Business Case was not prepared. Applied for expenditures include: design, land acquisition and long lead materials. This project will not be energized or capitalized during the 2023-2024 Test Period.

(v) A Business Case was not prepared. This project is a highway right of way move requested by the Yukon Government to facilitate the replacement of the Nisutlin Bridge. Our Highways right of way permits state:

> Yukon may at any time require the Utility to modify, relocate or remove a portion or all of its physical infrastructure in order for Yukon to facilitate work being done on the highway, to install new or modify existing points of access or intersection, to permit Yukon to use the land, or for any other purpose which Yukon considers to be in Yukon's or the public's interests.

This project includes relocating the existing line along the Nisutlin bridge, as well as distribution infrastructure at 2 intersections being upgraded along the Alaska Highway on the bridge approaches.

(vi) A Business Case was not prepared. This is a customer driven fully contributed project, apart from investment in new streetlights based on YUB approved amounts. The total investment was below the business case threshold. The scope of the project includes installation of new streetlights

on wood poles from the Carcross Bridge to the intersection of the Klondike Highway and Tagish Road.

(vii) Business Case #01 was split into two different line items per S9.2 of the GRA schedules. This split was done to differentiate between asset classes within the project. Table 1 reflects the sum of the 2016 and 2017 approved values included on line 191 and line 322 per schedule S9.2.

Streetlights were unable to be installed while there were still overhead powerlines along the roads. AEY needed to wait until all civil and electrical work was complete and overhead lines were removed before installing streetlights.

(viii) While preparing responses to IRs, a presentation error in Schedule 9.2 was identified where several items that should have been included in line 417 – Transportation equipment were included in line 419 - Unit 136 to Replace Unit 643 Bucket Truck for the 2017 year. This error only impacts how the information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application. A summary of the items to be moved is shown below. AEY notes that this project is below the major projects business case threshold of $500,000. However, in an effort to be helpful, AEY has prepared a Business Case for this project. Please refer to AEY-YUB-041(a)(viii) Attachment 1.

Table 1: Transportation Equipment Reconciliation

Project Description	Cost ($)	Original line on Schedule 9.2	Corrected line on Schedule 9.2
2017 H&H Topline Cargo	28,500	419	417
Replace Unit 096	47,482	419	417
Replace Unit 990	48,570	419	417
Replace Unit 776	58,361	419	417
Unit 139 - 2017 Dodge R	24,142	419	417
Unit 138 - 2017 Dodge R	43,610	419	417
Unit 137 - 2017 Dodge R	43,728	419	417
Unit 136- Replace # 643 Bucket Truck	370,883	419	419

(b) (i) Project scope was reduced in 2016 and 2017, as new extension projects required additional power line technician resources to complete. This impacted AEY's ability to complete the full scope of this project within the prior test period. AEY was able to complete the pole replacement work in subsequent years once resources were available. AEY has created plans to address the backlog of this capital work which is further described in AEY-YUB-042.

(ii) Project scope was reduced in 2016 and 2017 as new extension projects required additional power line technician resources to complete. This impacted AEY's ability to complete the full scope of this project within the prior test period. AEY was able to complete the pole replacement work in subsequent years once resources were available. AEY has created plans to address the backlog of this capital work which is further described in AEY-YUB-042.

(iii) Increase to budget due to increased material costs for the switches, as a result of inflation and supply chain issues.

(iv) Line No. 196 scope was expanded to include the addition of a 10 MVA Padmount Transformer upgrade in the McRae Substation, which was not

identified in the original project plan. The final cost for the Seconder Feeder Breaker Project was $0.431 million.

(v) There are two types of meters charged to Line No. 340. Meters for new extension customers and meters that require to be replaced. Meters for new extensions, where there is a general service meter or more than one residential meter required, were charged directly to the capital project, instead of to the line-item account for Line 340. The forecast for 2016 to 2017 was based off the 2013 to 2015 time-period average of $0.236 million per year. There were fewer meters required to be changed and fewer meters for new connections charged to this line item account than expected.

The forecast for the test period is $0.103 million and $0.106 million for 2023 and 2024, respectively. This forecast is more in line with the 2016 to 2022 timeframe that average of $0.85 million for this line item than the previous forecast.

(vi) Project scope is driven by load growth on distribution transformers in residential neighborhoods. During the years of 2016-17 the load growth impacting existing transformers was not as significant as had been predicted. As the push to electrify residential homes increases, AEY expects that there will be increased requirements to replace transformers in these neighborhoods.

(vii) While preparing these IR responses, a presentation error in Schedule 9.2 was identified. The spare transformer ($251,000) was misclassified in Line No. 197 – McCrae Substation Transformer Upgrade to 10 MVA rather than Line No. 345 – Spare 10 MVA Transformer. In addition, the transformer for Line No. 197 – McCrae Substation Transformer Upgrade to 10 MVA ($300,000) was grouped in Line 196 – McCrae Substation Second Feeder

Breaker. These errors only impact how information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application.

(viii) While preparing these IR responses, a presentation error in Schedule 9.2 was identified. The Shipyards Spare 25kV beaker was misclassified as Line No. 304 Shipyards Spare breaker ($55,000), instead of Line No. 346 Spare Padmount Regulator for Shipyards Substation. This error only impacts how the information is presented on Schedule 9.2. AEY will update this Schedule in the Compliance Filing to the Application.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Replace Unit 643 – Bucket Truck

2023-2024 Business Case #AEY-YUB-041(a)(viii)

Executive Summary

1. AEY currently operates and maintains 78 vehicles and trailers. It is an important management decision on when to replace this equipment. Given the large service area and cold climate, fleet reliability is essential to system operations.

Background

2. Unit 643 – Bucket Truck is 20 years old; its reliability has been decreasing and maintenance required on it is increasing.

Project Description

3. Replace Unit 643 with a Terex TL50 Hi Ranger Articulating Boom and Freightliner Chassis. Procurement of this vehicle will be through ATCO Fleet.

Project Schedule and Cost

Table 1: Purchased Fleet

Unit	Description	Year Purchased	Purchase Cost ($)
Unit 136 (Replaces Unit 643)	Freightliner with Ranger Boom	2016	370,883

Business Drivers and Benefits

4. Bucket trucks are required on a regular basis to perform maintenance on overhead and low voltage systems. This unit is required for routine and emergency work as well as assisting with live line procedures when required. AEY's overall overhead assets continue to increase requiring more hours of bucket truck time for maintenance.

5. This vehicle will be available for line crews when their bucket truck is out of service resulting in decreased downtime and increased customer satisfaction. The Operations Department will have the ability to complete small work orders when required, increasing efficiency. The bucket will have a maximum working height of 54.5 ft, giving workers the ability to park off roadway and away from traffic more often, specifically when maintaining 14m streetlights.

Evaluation of Viable Alternatives

Alternative 1

6. Continue to use Unit 643 – the vehicle is over 20 years old, and maintenance required to maintain adequate performance has increased.

Alternative 2

7. Renting or leasing the equipment to support these permanent positions, which is subject to equipment availability. AEY's experience with renting machinery to temporarily fill in for machinery requiring unexpected repairs is that the costs are not economical, and availability is limited.

Recommendation

8. Replacement of Unit 643 with new bucket truck as proposed above.

ATCO Electric
YUKON

September 28, 2023 AEY-YUB-042

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-042

Reference: 2023-24 GRA, Section 9.1, Capital Additions, PDF page 173, Table 9.1 and paragraphs 2 and 3

Issue: Capital expenditures and additions

Table 9.1: Capital Expenditures and Additions
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Capital Expenditures	14,784	10,527	9,491	13,529	13,001	15,147	18,914	31,234	25,073
Capital Additions to Rate Base	12,079	8,393	11,159	9,982	11,893	11,014	15,857	34,734	31,780
Contributions	(1,241)	(2,204)	(3,212)	(5,969)	(4,220)	(5,250)	(2,529)	(10,119)	(16,431)
Net additions	10,838	6,189	7,947	4,013	7,673	5,764	13,328	24,615	15,349

Table 9.1: Capital Expenditures and Additions
($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Capital Expenditures	14,784	10,527	9,491	13,529	13,001	15,147	18,914	31,234	25,073
Capital Additions to Rate Base	12,079	8,393	11,159	9,982	11,893	11,014	15,857	34,734	31,780
Contributions	(1,241)	(2,204)	(3,212)	(5,969)	(4,220)	(5,250)	(2,529)	(10,119)	(16,431)
Net additions	10,838	6,189	7,947	4,013	7,673	5,764	13,328	24,615	15,349

3. Since the last GRA there has been significant load growth in the Yukon (approximately 40 percent increase since 2014), as a result of the rapidly increasing population. This growth has led to the need for AEY's capital program to keep up with the demand, as can be seen in the steadily increasing capital expenditures. This increase was not only required to maintain safe and reliable service but also to strengthen and grow the power system as the demand continues to rise.

Preamble: In paragraph 2, AEY explains that its actual capital additions for the years 2016-17 ($12.079 million and $8.393 million, respectively) were overall less than the approved amounts ($13.823 million and $12.059 million[1] respectively) "due to the timing of a number of

[1] AEY 2016-2017 GRA Schedules – Compliance Filing, Schedule 8.6.

projects which were completed in subsequent years." Further, the Board notes in Table 9.1 that for all years 2018 to 2021, AEY continued to have capital additions that were lower than approved for 2016, notwithstanding its assertion, as quoted above, of a need to strengthen and grow the power system.

Request:

(a) Given that AEY's actual capital additions in each of the years 2016 to 2021 have been lower than its approved 2016-17 capital additions, please explain in detail the basis for AEY's claim that it actively managed its capital program to keep up with the significant load growth since 2014.

(b) Given the large increases in capital expenditures and capital additions forecast for 2023-24, can AEY explain in detail how it will be able to complete all the capital work it has set out for itself given the significantly lower amount of capital work completed in the previous seven years?

Response:

(a) AEY manages a four-year business plan that incorporates all capital expenditures as follows:

Table 1: Capital Management

Appropriation	Driver	Schedule
Distribution New Extensions	Customer driven – Yukon Government, City of Whitehorse, Northwestel	Annual
Distribution Improvements	SAIDI / SAIFI, Line Patrols, Inspections, load studies	Quarterly / Annual / Monthly
Distribution Street and Sentinel Lights	Testing, Inspections	Annual
Distribution Meters	New connects, due for test groups, sample groups	Annual
Distribution Transformers and Regulators	Equipment testing, Inspections	Annual
Tools, Instruments and Equipment	End of life, Reliability, Changes in equipment / technology	Annual / Monthly / Daily
Office Furniture and Equipment	End of life, Inspections	Annual
Office Computer Equipment	End of life, Reliability, Changes in equipment / technology	Annual

Appropriation	Driver	Schedule
Communications	End of life, Reliability, Changes in equipment / technology	Annual
Transportation Equipment	End of life, Reliability, Inspections	Annual
Land, Building, Leasehold Improvements	Inspections, Assessments	Annual
Generation	End of life, Inspections, Assessment, Reliability	Monthly

AEY's capital plans focus on system performance, reliability, and safety. Assets that are shown to have vulnerability are prioritized to be replaced or rebuilt. AEY has replaced, rebuilt, and upgraded many areas of the distribution and generation power systems, as shown in S. 9.2 L.6-129 and L.182-318, that collectively contribute to a robust power system. These projects included:

- Transformer replacements;
- Regulator replacements / upgrades;
- Reconductoring to larger capacity conductor;
- Streetlight / davit replacements;
- Generator / engine replacements and rebuilds;
- Switch replacements;
- Breaker replacements / additions; and
- Pole replacements.

AEY frequently assesses the electrical system for deficiencies and needed improvements to maintain service. Electrical planning is ongoing and shows the need for these improvements during the test years, as described in the supplied business cases.

Reasons some projects will be completed in 2023-2024 and not earlier include:

- Uncertainty in resources and material during the pandemic;
- Timing implementation of improvements to when they are needed; and
- Increased pole and streetlight testing programs since 2021 resulting in more assets requiring replacement.

Please refer to the following responses as examples to highlight the planning process AEY uses to determine areas of poor performance, reliability, and safety:

- AEY-YUB-060(a), AEY-YUB-060(a) Attachment 2;
- AEY-YUB-070(a), AEY-YUB-070(a) Attachment 1;
- AEY-UCG-071(b), AEY-UCG-071(b) Attachment 1;
- AEY-UCG-073(b), AEY-UCG-073(b) Attachment 1;
- AEY-UCG-087(a), AEY-UCG-087(a) Attachment 1; and
- AEY-UCG-092(a), AEY-UCG-092(a) Attachment 1.

(b) AEY plans for all identified system work to be completed to maintain service to customers. AEY is procuring or has procured contractor support to accomplish the significant capital plan in the test years. Where appropriate, contractors will be used for engineering, project management, and construction more than in previous years to supplement internal resources. AEY's proposed organizational chart includes additional key resources to execute proposed projects.

Many large projects in the test years require costly pieces of equipment. The material costs of these projects account for a large portion of the budget. Examples include Kluane First Nation Wind Turbine Upgrades, Beaver Creek PV Generation, the substation projects, and regulator projects.

Below AEY has provided the status of a number of large projects as of September 2023 to demonstrate how this capital work is already underway:

- New Substation Mayo Road (S9.2 lines 266 and 272)
    - Project schedule provided in AEY-YUB-059(a);
    - Large equipment procured, some delivered; and
    - Significant cost in large equipment, refer to AEY-YUB-59 Table 3.
- AEY New Substation Whistle Bend – Leota (S9.2 line 281)
    - Project schedule provided in AEY-YUB-059(a);
    - Transformer out to tender, other large equipment ordered;
    - Lands application submitted to YG, YESAB application prepared;

  - Project management, engineering, construction to be tendered to contractors; and
  - Significant cost in large equipment, refer to AEY-YUB-59 Table 4.

- AEY 6L19 voltage improvement (S9.2 line 296)

  - Regulators ordered and in queue for production and delivery in 2024; and
  - Project cost is mostly material.

- AEY Old Crow Regulators (S9.2 line 348)

  - Regulators on site in Whitehorse for testing before shipping to site for installation;
  - Engineering completed; and
  - Project cost is mostly material and shipping equipment to Old Crow.

- AEY Whitehorse Escarpment line reroutes - 5th avenue (S9.2 line 300)

  - Engineering and project management contractor hired;
  - Engineering started;
  - Discussion with the City of Whitehorse on new alignment ongoing; and
  - Site visit completed.

- AEY Nisultlin Bridge Pole Relocation (S9.2 line 282)

  - Engineering complete to IFR stage; and
  - Project timing depends on bridge construction schedule.

- AEY Voltage Improvement Destruction Bay (S9.2 line 286)

  - Regulators on site in Whitehorse for testing before shipping to site for installation;
  - Engineering completed; and
  - Project cost is mostly material.

- AEY DWCI - New 12.5kV substation

  - Planning underway for location; and
  - Listing long lead equipment to be ordered in 2024.

- McIntyre Subdivision Rebuild (S9.2 line 191)

  - Preliminary engineering done; and

  - Preparing construction package and tender to be issued in Q1 2024 to secure contractor.

- General Pole Replacements (S9.2 line 183)

  - Engineering underway for 2024 projects; and
  - Preparing construction package and tender to be issued in Q1 2024 to secure contractor.

- Whistle Bend 6 (S9.2 line 149)

  - Under construction now.

- Whistle Bend 7 (S9.2 line 150)

  - Under construction now.

- Whistle Bend 9 (S9.2 line 152)

  - Stage 9A under construction now; and
  - Stage 9B material ordered for 2024.

- Old Crow Bunkhouse replacement (S9.2 line 370)

  - Planning and pre-lim engineering underway; and
  - Project cost is mostly material and shipping.

- Watson Lake plant upgrades and modifications, and WL unit 2 overhaul (S9.2 line 26-34, 36)

  - These projects are near complete.

- Fish Lake upgrades and modifications (S9.2 line 5, 17-19)

  - These projects are near complete.

- Yukon Government Robert Campbell Highway Streetlights (included in S9.2 line 311)

  - Construction underway.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-043

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-043

Reference: 2023-24 GRA, Section 9.1, Capital Additions, PDF pages 173, paragraph 2, PDF page 174, paragraph 5 and PDF page 181, paragraph 22

Issue: Capital additions

Quote:

2. In this Section, AEY is seeking Board approval of the 2016-2022 actuals on a final basis and approval of its forecasts for 2023 and 2024 additions. Overall, the 2016 and 2017 actuals were below the approved additions mainly due to the timing of a number of projects which were completed in subsequent years.

…

5. … and Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period.

…

22. AEY is providing an additional set of Business Cases for capital projects which will not result in capitalized costs during the Test Period, but which are forecast to result in certain un-capitalized costs during the Test Period [or in the years 2016 to 2022] as well as large capital expenditures subsequent to the Test Period. AEY has included these Business Cases in the Application even though costs incurred during the Test Period will not be capitalized, in an effort to be transparent and to notify the Board and other stakeholders regarding larger upcoming capital expenditures. For the purposes of this Application, AEY is seeking Board approval for the un-capitalized costs forecast during the Test Period that are associated with these projects. Any capital expenditures forecast to occur

subsequent to the Test Period will remain subject to the Board's review and oversight in a future GRA proceeding.

Preamble: It is not clear to the Board what type of expenditures are being referred to in the above quote.

Request:

(a) Referring to paragraph 5 quoted above, please clarify if AEY's reference to "significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period" is intended to describe capital expenditures to be accumulated in construction work in progress for projects that will not be recorded as a capital addition until after 2024. If not confirmed, please explain fully.

(b) Referring to paragraph 22 quoted above, please confirm that AEY is requesting that the Board approve capital cost expenditures that do not yet qualify as a used and useful asset. Please explain whether it/this? conforms with the Board's mandated requirement to test the prudence of AEY's capital asset additions.

Response:

(a) Confirmed.

(b) AEY included these project Business Cases in this Application to ensure transparency and to inform the Board and other stakeholders of the anticipated large upcoming capital spend that will be required in order to address aging infrastructure needs and ensure AEY can sustain the provision of safe reliable service for the growing population and resulting load growth. As there is currently no mechanism in the Yukon (for example, compared to a Facility Application in Alberta) to apply for large capital projects. AEY is signaling capital requirements and providing parties opportunity to review the capital requirements. AEY is not seeking approval for the capital expenditures that do not yet qualify as used and useful assets that are to be included in rate base in a future application.

September 28, 2023 AEY-YUB-044

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-044

Reference: 2016-17 Business Case #02 – Fish Lake Ditch 1 Failure, PDF page 10, paragraphs 5 and 8

Issue: Capital expenditures (Generation)

Quote: 5. A new structure has been designed with additional loading constraints and non-frost susceptible fill will be used surrounding the spillway. The upgraded structure (betterment) costs will be borne by AEY, while like-for-like costs will be borne by insurance less a $100,000 deductible.

…

8. The project took 12 weeks to complete and cost $262,000, net of the insurance proceeds.

Preamble: In the referenced business case, AEY explains that betterment costs will be borne by AEY, while like-for-like costs will be borne by insurance. AEY further states that the cost of the Fish Lake Ditch 1 Failure was $0.262 million net of insurance but provides no further information respecting the insurance claim and the costs at issue.

Request:

Please provide further detail identifying the project costs "borne by AEY" and those recovered through an insurance claim. In the response, please clarify whether the betterment costs are for AEY shareholders or ratepayers. Please also confirm that this business case and the betterment costs are specific to the Fish Lake Ditch 1 Failure project alone. If not confirmed, please explain fully.

Response:

Costs covered by the insurance claim include temporary repairs, failure assessments, and like-for-like inflation adjusted rebuild costs. The insurance claim is intended, per the underwritten policy, to replace the loss back to the original condition.

As the spillway structure failed in part due to a deficient design, it would not be prudent to rebuild a spillway structure to the same standard that had failed. Costs to upgrade and improve the spillway structure, over and above the like-for-like replacement costs, are considered a system improvement project and are treated the same as other similar capital projects.

AEY confirms that the Business Case and the betterment costs are specific to Fish Lake Ditch 1 Failure.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-045

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-045

Reference: 2023-24 GRA, Section 9, PDF page 174; AEY 2016-17 GRA Compliance Filing, Schedule 9.2, PDF page 54

Issue: Capital Expenditures – Generation

Preamble: In AEY's 2016-17 GRA compliance filing, AEY submitted forecast generation plant expenditures of $2,529,000 for 2017. Actual capital expenditures for generation were $963,000 in 2017.

Request:

(a) Please explain the variance of this item for both 2016 and 2017.

(b) What work was undertaken in 2017?

(c) Please list all projects included in the 2017 forecast for generation capital expenditures.

(d) Please explain what happened to the forecast but incomplete generation projects for 2017.

Response:

(a) Please refer to AEY-YUB-045(a) Attachment 1 for explanations for 2016 and 2017 projects with variances of 10% and greater than $50,000.

(b) Please refer to AEY-YUB-045(a) Attachment 1, column F, for a list of projects from 2017.

(c) Please refer to AEY-YUB-045(a) Attachment 1, column I, for a list of forecast projects for 2017.

(d) Although 2017 actuals were lower than approved, the spend related to the approved but incomplete 2017 projects was incurred in prior and subsequent years. As outlined in the table below and in AEY-YUB-045(a) Attachment 1, 2017 Actuals were lower than 2017 Approved by $1.566 million mainly due to the following:

- Line 2 - Fish Lake 2 Head Pond Spillway Replacement delayed to 2018 ($0.423 million), due to the unexpected Fish Lake Ditch 1 Failure;
- Line 5 - Fish Lake Unit 1 Spillway Diversion Structure delayed to 2019 and 2020 ($0.381 million), due to the unexpected Fish Lake Ditch 1 Failure;
- Line 17 - Old Crow Original Plant Rebuild delayed to 2018 due to unexpected floor reinforcement in 2016 ($0.199 million) and;
- Write-off of cancelled projects ($0.582 million). It is important to note the cancelled projects were not included in revenue requirement.

Table 1: 2017 Actuals vs Approved
($000)

	2017			2016-2022
	Actuals	**Approved**	**Variance**	**Total Project Spend**
Fish Lake 2 Head Pond Spillway Replacement	166	589	423	974
Fish Lake Unit 1 Spillway Diversion Structure	30	411	381	772
Old Crow Original Plant Rebuild	50	249	199	714
Generation < $20,000	(553)	29	582	
All Other Projects	1,270	1,251	(19)	
Total	**963**	**2,529**	**1,566**	

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
($000)

Line No.	Project Name	Business Case	Actuals 2016	Actuals 2017	Approved 2016	Approved 2017	Variance $ 2016-2017	Variance % 2016-2017	
1	**Generation**								
2	Fish Lake 2 Head Pond Spillway Replacement		286	166	20	589	157	35%	Delayed to 2018 due to Fish Lake Ditch 1 Failure as well as digging and water level conditions.
3	Fish Lake Ditch 1 Failure	#02	412	(150)	-	-	(262)	-100%	Unanticipated event that required immediate remediation. 2017 includes $150K credit for insurance proceeds. Please see Business Case #02 for further details.
4	Fish Lake Ditch 1 Intake Building - Design		2	1	-	30	27	930%	
5	Fish Lake Unit 1 Spillway Diversion Structure		-	30	-	411	381	1262%	Delayed to 2019 and 2020 due to Fish Lake Ditch 1 Failure as well as digging and water level conditions.
6	Fish Lake Unit 2 Assessment		98	11	100	-	(9)	-8%	
7	Fish Lake Water Monitoring Upgrades		10	106	25	25	(66)	-57%	Higher than approved due to Fish Lake Ditch 1 Failure and changes in requirements.
8	Fish Lake Unit 1 Turbine and Building Replacement		20	16	-	-	(35)	-100%	
9	Fish Lake Ditch 3 Diversion Replacement		2,601	168	2,908	-	139	5%	
10	Louise Lake Containment Dyke Seismic Analysis		-	-	40	-	40	100%	
11	Watson Lake Plant Fire Alarm System - Design		-	-	-	102	102	100%	The costs related to the project design were captured in the Watson Lake Plant Fire alarm project in line 12 below and were lower than expected.
12	Watson Lake Plant Fire Alarm System		-	62	-	-	(62)	-100%	Higher than approved due to costs related to project design being included in this line item ($7K) as well as project work being advanced from future years.
13	Watson Lake Plant PLC		-	28	-	-	(28)	-100%	
14	Watson Lake Unit 5 PLC		-	22	-	-	(22)	-100%	
15	Watson Lake Unit 2 Replacement		1,054	270	1,387	-	63	5%	
16	Old Crow Unit 2 Generator Refurbishment		39	-	75	-	36	92%	
17	Old Crow Original Plant Rebuild	#41	369	50	-	249	(170)	-41%	Higher than approved due to unexpected costs required to reinforce the floor of the facility. 2018 includes a $118K credit for settlement costs from the Engineering firm hired to design the new plant due to the failure of the floor system design. Costs related to the original plant rebuild were incurred from 2018 through 2022.
18	Old Crow Unit 3 Replacement		1,085	8	1,046	-	(47)	-4%	
19	Old Crow Unit 2 - External Equipment		-	-	-	51	51	100%	Lower than approved due to work on project being halted based on plant conditions. Awaiting new plant construction.
20	Destruction Bay Unit 1 Major Overhaul	#23	133	7	-	-	(140)	-100%	Units require an overhaul after 24,000 hours of runtime, which occurred earlier than anticipated for Destruction Bay Unit 1. Please see Business Case #23 for further details.
21	Destruction Bay Unit 3 Replacement		5	28	-	-	(34)	-100%	
22	Destruction Bay Programmable Logic Controller Upgrade		15	252	-	305	38	14%	
23	Destruction Bay Unit 2 Replacement		538	9	620	-	74	13%	Lower than approved due to shared savings of other work being completed on site PLC replacement line 22.
24	Destruction Bay Fuel Line Upgrade		55	-	106	-	51	94%	Lower than approved due to forecast including costs for potential Utilidor and plant modifications which where not required during construction.
25	Pelly Crossing Fuel System Upgrade		-	143	-	152	9	6%	
26	Pelly Crossing Ventilation System Upgrade		-	-	-	25	25	100%	
27	Pelly Crossing Unit 2 Silencer		-	-	-	20	20	100%	
28	Ross River Replace ABB 5HK Breakers		71	-	95	-	24	33%	
29	Ross River Electrical Service Panel Upgrade		-	-	25	-	25	100%	
30	Swift River Unit 1 Replacement		36	82	80	61	22	19%	
31	Teslin Plant Assessment		-	13	-	102	89	710%	Lower than approved due to project scope being reduced to only assess pad and foundation.
32	Teslin PLC Replacement - Design		-	41	-	105	64	155%	Lower than approved due to project scope being increased to include long lead equipment purchase.
33	Haines Junction Fuel Containment Upgrade		-	-	-	30	30	100%	
34	PLC Replacement Stage 1		-	76	-	103	27	36%	
35	2017 Gen Failed Hardware Contingency		-	27	-	-	(27)	-100%	
36	Mobile Generator 250kW Voltage and Frequency Protection		7	0	35	-	28	382%	
37	Mobile Generator 225 kW Refurbishment		6	10	20	-	4	26%	
38	Mobile Generator 350 kW Refurbish Enclosure		-	38	-	19	(19)	-50%	
39	Fuel System Assessment		-	-	-	99	99	100%	Work was complete in 2017, but due to the scope of work, it was determined that the expenses should be classified as O&M instead of capital.
40	IRC Chargers		-	-	-	22	22	100%	
41	Generation < $20,000		102	(553)	20	29	500	-111%	Lower than approved due to cancelled project write-offs, including a $443K write-off of for Watson Lake LNG per Board Order 2017-03 in 2017.
42									
43	**Generation Total**		**6,944**	**963**	**6,602**	**2,529**	**(1,224)**		

ATCO Electric YUKON

September 28, 2023 AEY-YUB-046

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-046

Reference: 2023-24 GRA, Section 9, PDF page 174; Schedule 9.2

Issue: Capital Expenditures – Generation

Quote: To support this capital spend, AEY has provided Business Cases related to capital expenditures as follows: Business Cases are provided for 2016-17 where variances from actual to approved were both greater than 100 percent and greater than $100,000; Business Cases are provided for capital expenditures in 2018-2022 that exceeded $100,000; Business Cases are provided for projects planned to be undertaken in 2023-24 where capital expenditures are forecast to be $500,000 or greater; and Business Cases are provided for significant upcoming projects where certain un-capitalized costs are forecast in the Test Period but capitalized expenditures are forecast subsequent to the Test Period.

Preamble: The Board requires a cross-reference between the projects listed in Schedule 9.2 and the business cases provided by AEY.

Request:

(a) Please insert an additional column in Schedule 9.2 providing the business case reference to each of the line items in that schedule.

(b) Please provide a business case regarding all Old Crow plant work (Schedule 9.2 lines 56-69), the Louise Lake Auxiliary Structure Replacement (Schedule 9.2 line 110) and Fish Lake projects (Schedule 9.2 - lines 2-24).

Response:

(a) Please refer to AEY-YUB-046(a) Attachment 1.

(b) AEY notes that not all the Old Crow and Fish Lake generation project line items on Schedule 9.2 lend themselves to a single overarching business case, as there are

many different drivers for the expenditures such as load growth, end of life equipment and emergency repairs. AEY has provided a detailed project description of all of the line items on Schedule 9.2 that are not included in the Business Cases and has included the references to the Business Cases where applicable.

- Old Crow plant work please refer to AEY-YUB-046(b) Attachment 1.
- Fish Lake projects please refer to AEY-YUB-046(b) Attachment 2.

For the Louise Lake Auxiliary Structure Replacement, please refer to Business Case #33.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
($000)

Line No.	Project Name	Business Case	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
1	**Generation**												
2	Fish Lake Unit 2 - Replace Power Station - Detailed D	Business Case No. 39	-	-	-	-	-	-	-	-	527	-	-
3	Fish Lake 1 Roof Replacement	Business Case No. 32	-	-	-	-	-	-	-	452	-	-	-
4	Fish Lake 2 Replace Power Station FEED	Business Case No. 39	-	-	-	-	-	-	-	385	-	-	-
5	Fish Lake 2 Head pond Intake Building Replacement		-	-	-	-	-	-	-	153	-	-	-
6	Fish Lake 2 Head Pond Spillway Replacement		286	166	540	(17)	-	-	-	-	-	20	589
7	Fish Lake Ditch 1 Failure	Business Case No. 02	412	(150)	-	-	-	-	-	-	-	-	-
8	Fish Lake Ditch 1 Intake Building - Design		2	1	115	(26)	11	-	-	-	-	-	30
9	Fish Lake Unit 1 Spillway Diversion Structure		-	30	0	220	527	(5)	-	-	-	-	411
10	Fish Lake Unit 2 Assessment		98	11	(112)	-	-	-	-	35	-	100	-
11	Fish Lake Unit 2 Condition Assessment and Options Analysis		-	-	-	-	-	-	66	-	-	-	-
12	Fish Lake 2 TIV actuator and wicket gates		-	-	-	-	-	-	-	37	-	-	-
13	Fish Lake Unit 1 Roof Design	Business Case No. 32	-	-	-	-	-	43	16	-	-	-	-
14	Fish Lake Unit 2 Bearing and Shaft Repair		-	-	-	48	6	-	-	-	-	-	-
15	Fish Lake Unit 2 TIV Replace		-	-	48	(1)	-	-	-	-	-	-	-
16	Fish Lake 1 Add TIV Actuator		-	-	-	-	-	-	-	-	53	-	-
17	Fish Lake 1 TIV replacement		-	-	-	-	-	-	24	89	-	-	-
18	Fish Lake 2 Add bypass valve actuator and automation		-	-	-	-	-	-	-	35	-	-	-
19	Fish Lake 2 PLC Replacement		-	-	-	-	-	-	-	-	39	-	-
20	Fish Lake Unit 2 DC TIV Actuator & Wicket Gate Replacement		-	-	-	-	-	-	138	-	-	-	-
21	Fish Lake Water Monitoring Upgrades		10	106	1	24	(0)	(0)	-	26	81	25	25
22	Fish Lake Unit 1 Turbine and Building Replacement		20	16	16	3	4	3	(71)	-	-	-	-
23	Fish Lake Ditch 3 Diversion Replacement		2,601	168	30	0	-	29	(27)	-	-	2,908	-
24	Louise Lake Containment Dyke Seismic Analysis		-	-	-	-	-	-	-	-	-	40	-
25													
26	Watson Lake - Replace Air Start Piping		-	-	-	-	-	-	-	103	-	-	-
27	Watson Lake Add Building Concrete Apron		-	-	-	-	-	-	-	25	-	-	-
28	Watson Lake block heater pumps		-	-	-	-	-	-	-	50	-	-	-
29	Watson Lake Expansion Tank and Access Replacement Design		-	-	-	-	-	-	25	152	-	-	-
30	Watson Lake Fuel Piping Upgrade		-	-	-	-	-	-	-	231	-	-	-
31	Watson Lake Fuel System Control Replacement		-	-	-	-	-	-	-	136	-	-	-
32	Watson Lake Install Diverter Actuator, with limit switches, for #1/6 boilers		-	-	-	-	-	-	-	25	-	-	-
33	Watson Lake Replace HRS pumps/motors		-	-	-	-	-	-	-	100	-	-	-
34	Watson Lake Replace Non-Code Exchangers for #2/4		-	-	-	-	-	-	-	100	-	-	-
35	Watson Lake Unit 1 Replacement	Business Case No. 07	-	-	-	418	1,278	130	-	-	-	-	-
36	Watson Lake Unit 2 - Major Overhaul	Business Case No. 23	-	-	-	-	-	-	-	375	-	-	-
37	Watson Lake Unit 3 Replacement	Business Case No. 07	-	-	436	1,213	241	-	-	-	-	-	-
38	Watson Lake Unit 4 - Major Overhaul	Business Case No. 23	-	-	371	(2)	-	-	-	-	515	-	-
39	Watson Lake Unit 4 EMCP Replacement	Business Case No. 08	-	-	-	-	-	177	(26)	-	-	-	-
40	Watson Lake Unit 5 Major Overhaul	Business Case No. 23	-	-	-	-	-	-	438	41	-	-	-
41	Watson Lake Unit 6 Replacement	Business Case No. 07	-	-	-	-	828	901	140	-	-	-	-
42	Watson Lake Waste Heat Cathodic Protection		-	-	-	-	-	-	-	150	-	-	-
43	Watson Lake 125VDC Battery and Charger Replacement		-	-	-	23	-	-	-	-	-	-	-
44	Watson Lake Fuel Tank Access		-	-	17	128	-	-	-	-	-	-	-
45	Watson Lake Inverter Replacement		-	-	-	51	-	-	-	-	-	-	-
46	Watson Lake Plant Fire Alarm System - Design		-	-	-	-	-	-	-	-	-	-	102
47	Watson Lake Plant Fire Alarm System		-	62	106	(2)	-	-	-	-	-	-	-
48	Watson Lake Plant Fuel Sys Control Replace		-	-	-	-	-	1	147	-	-	-	-
49	Watson Lake Plant Overhead Door Replacement		-	-	-	-	-	-	24	-	-	-	-
50	Watson Lake Plant Phone System Replacement		-	-	-	34	(1)	-	-	-	-	-	-
51	Watson Lake Plant PLC		-	28	1	-	-	-	-	-	-	-	-
52	Watson Lake Unit 5 PLC		-	22	1	-	-	-	-	-	-	-	-
53	Watson Lake Utilidor Split/Fuel Sys		-	-	42	6	4	2	3	-	-	-	-
54	Watson Lake Unit 2 Replacement		1,054	270	-	-	-	-	-	-	-	1,387	-
55													
56	Old Crow Add Day Tank and Fuel Transfer Pump		-	-	-	-	-	-	-	25	103	-	-
57	Old Crow Boiler Metering and Control		-	-	-	-	-	-	-	25	-	-	-
58	Old Crow Plant Tank Access		-	-	-	-	-	-	-	-	232	-	-
59	Old Crow Unit 1 Major Overhaul YTCU414	Business Case No. 23	-	-	-	-	475	(10)	-	-	-	-	-
60	Old Crow Unit 2 Replacement		-	-	-	192	(17)	-	-	-	-	-	-
61	Old Crow Unit 3 Failure - Major Overhaul		-	-	-	-	-	270	(190)	-	-	-	-
62	Old Crow Unit 4 Major Overhaul	Business Case No. 23	-	-	-	-	-	-	252	-	-	-	-
63	Old Crow # 2 Long Block Replacement	Business Case No. 23	-	-	-	-	-	-	71	-	-	-	-
64	Old Crow Unit 2 Generator Refurbishment		39	-	-	-	-	-	-	-	-	75	-
65	Old Crow Old Plant Gantry Accessories		-	-	-	-	23	(2)	-	-	-	-	-

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
($000)

Line No.	Project Name	Business Case	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
66	Old Crow Plant (old) Gantry Crane		-	-	-	-	22	-	-	-	-	-	-
67	Old Crow Original Plant Rebuild	Business Case No. 41	369	50	(118)	2	6	489	(85)	150	-	-	249
68	Old Crow Unit 3 Replacement		1,085	8	-	-	-	-	-	-	-	1,046	-
69	Old Crow Unit 2 - External Equipment		-	-	-	-	-	-	-	-	-	-	51
70													
71	Beaver Creek Unit 3 Major Overhaul	Business Case No. 23	-	-	-	-	-	323	(6)	-	-	-	-
72	Beaver Creek Replace JW and CAC cooler		-	-	-	-	-	-	-	100	-	-	-
73	Beaver Creek Station Service Transformer		-	-	-	-	-	-	-	100	-	-	-
74	Beaver Creek Unit 1 Major Overhaul	Business Case No. 23	-	-	-	-	-	307	(132)	-	-	-	-
75	Beaver Creek Unit 2 Major	Business Case No. 23	-	-	127	(1)	-	-	-	-	-	-	-
76	Beaver Creek Utilidor Upgrades		-	-	-	-	-	-	-	20	-	-	-
77	Destruction Bay/ Stewart/ Beaver Creek Plant Conditic	Business Case No. 40	-	-	-	-	-	-	-	318	-	-	-
78													
79	Destruction Bay Unit 2 Major Overhaul	Business Case No. 23		-	-	-	-	181	(7)	-	-	-	-
80	Destruction Bay Unit 1 Major Overhaul	Business Case No. 23	133	7	-	-	-	-	-	-	-	-	-
81	Destruction Bay Unit 3 Replacement		5	28	-	-	-	-	-	-	-	-	-
82	Destruction Bay Programmable Logic Controller Upgrade		15	252	13	-	-	-	-	-	-	-	305
83	Destruction Bay Unit 2 Replacement		538	9	-	-	-	-	-	-	-	620	-
84	Destruction Bay Fuel Line Upgrade		55	-	-	-	-	-	-	-	-	106	-
85	Destruction Bay Unit 3 Major Overhaul	Business Case No. 23	-	-	-	-	-	112	(16)	-	-	-	-
86	Destruction Bay Replace POW	Business Case No. 40		-	-	-	-	-	-	-	309	-	-
87													
88	Pelly Crossing Fuel System Upgrade		-	143	119	(4)	-	-	-	-	-	-	152
89	Pelly Crossing Ventilation System Upgrade		-	-	-	-	-	-	-	-	-	-	25
90	Pelly Crossing Unit 2 Silencer		-	-	-	-	-	-	-	-	-	-	20
91													
92	Ross River Replace ABB 5HK Breakers		71	-	-	-	-	-	-	-	-	95	-
93	Ross River Electrical Service Panel Upgrade		-	-	-	-	-	-	-	-	-	25	-
94													
95	Swift River Unit 2 Replacement	Business Case No. 21	-	-	-	-	-	-	225	2	-	-	-
96	Swift River Unit 1 Replacement		36	82	4	-	-	-	-	-	-	80	61
97	Swift River Fuel System Upgrade		-	-	-	38	-	-	-	-	-	-	-
98	Swift River Unit 1 PLC Replacement		-	-	-	23	-	-	-	-	-	-	-
99	Swift River Unit 2 Replace		-	-	-	-	52	8	-	-	-	-	-
100													
101	Teslin Plant Assessment		-	13	(14)	1	-	-	-	-	-	-	102
102	Teslin PLC Replacement - Design		-	41	387	(1)	-	-	-	-	-	-	105
103	Teslin Plant Platform Replacement		-	-	-	34	(0)	-	-	-	-	-	-
104	Teslin Rad Core Replacement		-	-	-	-	22	-	-	-	-	-	-
105													
106	Haines Junction Fuel Containment Upgrade		-	-	-	-	-	-	-	-	-	-	30
107	Haines Junction Plant Positive Air Shutoff for YTCU416		-	-	-	-	-	20	3	-	-	-	-
108	Haines Junction Regulator Pad Replacement		-	-	-	-	-	4	36	-	-	-	-
109													
110	Louise Lake Auxiliary Structure Replacement	Business Case No. 33	-	-	-	11	31	8	2	1	773	-	-
111													
112	IPP Remote monitoring		-	-	-	-	-	-	-	100	-	-	-
113	Carmacks Plant Foundation Repair		-	-	-	14	16	-	-	-	-	-	-
114	Mobile CUL-341 PLC replacement		-	-	-	-	-	-	-	-	94	-	-
115	Pelly Unit 3 Block Replacement	Business Case No. 23	-	-	-	111	(1)	-	-	-	-	-	-
116	PLC Replacement Stage 1		-	76	(3)	(1)	-	-	-	-	-	-	103
117	Replace fuel ESD valve within utilidor (x10)		-	-	-	-	-	-	-	-	52	-	-
118	2017 Gen Failed Hardware Contingency		-	27	(1)	(2)	-	-	-	-	-	-	-
119	Mobile Generator 250kW Voltage and Frequency Protection		7	0	-	-	-	-	-	-	-	35	-
120	Mobile Generator 225 kW Refurbishment		6	10	-	-	-	-	-	-	-	20	-
121	Mobile Generator 350 kW Refurbish Enclosure		-	38	2	-	-	-	-	-	-	-	19
122	Standby plant equipment and building heat		-	-	-	-	-	-	-	-	52	-	-
123	Add transfer trip scheme		-	-	-	-	-	-	-	100	-	-	-
124	Fish Creek Diversion		-	-	-	-	-	-	-	-	317	-	-
125	General Plant Improvements		-	-	-	-	-	-	-	-	155	-	-
126	Fuel System Assessment											-	99
127	IRC Chargers											-	22
128													
129	Generation < $20,000		102	(553)	19	96	70	59	127	82	52	20	29
130													
131	**Generation Total**		**6,944**	**963**	**2,147**	**2,635**	**3,597**	**3,050**	**1,178**	**3,723**	**3,352**	**6,602**	**2,529**

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Line No.	Project Name	Business Case	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
132													
133	Kluane First Nation Wind Turbine Upgrades	Business Case No. 37	-	-	-	-	12	17	1,210	2,215	750	-	-
134	Renewables - Old Crow		-	-	-	1,034	1,147	1,406	34	-	-	-	-
135	Watson Lk IPP - Integration to Plant		-	-	-	-	-	18	6	75	-	-	-
136	Beaver Creek PV Generation	Business Case No. 38	-	-	-	-	-	64	2,500	3,767	1,686	-	-
137	Study Costs			208	80	(27)	(72)	(175)	(1)	(13)			
138	**Renewables Total**		**-**	**208**	**80**	**1,007**	**1,087**	**1,330**	**3,749**	**6,044**	**2,436**	**-**	**-**
139													
140													
141	**New Extensions**												
142	New Services Overhead and Underground	Business Case No. 18	1,747	1,600	2,555	2,701	2,446	3,846	2,777	4,219	4,324	1,995	2,032
143	Annual Land Rights		116	84	66	89	81	69	67	102	82	120	122
144	General Drafting and Mapping		37	35	53	42	52	49	45	46	41	40	41
145													
146	Whistle Bend Stage 3	Business Case No. 31	215	690	545	479	(20)	-	-	-	-	-	1,173
147	Whistle Bend Stage 4	Business Case No. 31	-	476	729	717	(12)	-	-	-	-	-	-
148	Whistle Bend Stage 5	Business Case No. 31	-	-	(17)	745	216	-	-	-	-	-	-
149	Whistle Bend Stage 6	Business Case No. 31	-	-	-	-	433	-	-	285	-	-	-
150	Whistle Bend Stage 7	Business Case No. 31	-	-	-	-	9	0	351	460	-	-	-
151	Whistle Bend Stage 8	Business Case No. 31	-	-	-	-	-	-	140	18	-	-	-
152	Whistle Bend Stage 9	Business Case No. 31	-	-	-	-	-	-	-	683	458	-	-
153	Whistle Bend future stages - place holder	Business Case No. 31	-	-	-	-	-	-	-	-	309	-	-
154	Whistle Bend New Services		-	-	-	-	136	-	234	-	-	-	-
155													
156	Mt Sima Pumphouse		-	-	-	-	123	141	-	-	-	-	-
157	Brookside Phase 2B		-	112	59	25	-	-	-	-	-	-	-
158	Challenge Development 704 Main Street		-	-	-	-	135	0	-	-	-	-	-
159	Hammerstone Lots off Tlingit Street		-	-	-	-	37	27	125	-	-	-	-
160	Loft 2240 2nd Avenue		-	-	-	-	-	133	-	-	-	-	-
161	Mt Sima Hill Service		-	-	-	-	-	-	413	-	-	-	-
162	Schmidt, Harold & Savanah		-	-	-	119	(0)	-	-	-	-	-	-
163	TSL/Ketza Old Crow Health & Housing		-	-	-	-	-	163	-	-	-	-	-
164	VGFN Houses on North Rd		250	-	-	-	-	-	-	-	-	-	-
165	VoT Connector Road Subdivision		-	-	-	145	(1)	-	-	-	-	-	-
166													
167	YG Airport Hangar		-	-	-	-	-	-	562	(30)	-	-	-
168	Yukon Lot 503		-	-	-	113	-	-	-	-	-	-	-
169													
170	New Extension < $20,000		-	-	-	-	-	-	-	102	-	-	(1)
171	**New Extensions Total**		**2,365**	**2,997**	**3,990**	**5,176**	**3,636**	**4,428**	**4,714**	**5,885**	**5,215**	**2,155**	**3,367**
172													
173													
174	**New Extensions-IPP**												
175	Arctic Pharm IPP	Business Case No. 35	-	-	-	-	-	-	-	543	-	-	-
176	Sunergy YEC HJ IPP		-	-	-	-	-	-	-	343	-	-	-
177	Haeckel Hill	Business Case No. 36	-	-	-	-	-	-	1,219	235	-	-	-
178	THELP		-	-	-	-	-	185	175	(7)	-	-	-
179	**New Extensions - IPP Total**		**-**	**-**	**-**	**-**	**-**	**185**	**1,394**	**1,115**	**-**	**-**	**-**
180													
181	**Distribution Improvements**												
182	Annual Right of Way Widening	Business Case No. 12&26	494	581	292	489	434	481	555	520	528	439	447
183	General Pole Replacements		40	35	39	29	112	97	98	254	211	297	284
184	PCB Identification and Transformer Change Outs		137	14	-	-	-	-	-	-	-	150	51
185	Vault Replacements		27	44	0	117	(15)	(4)	10	51	-	40	102
186	General Clearance Upgrades/Fixes		11	-	5	3	9	33	37	84	108	50	51
187	Test and Treat Pole Program		-	-	-	45	25	70	117	21	22	-	-
188	Gang Switch Replacement		53	29	11	36	19	1	20	-	-	-	-
189	T&B Switch Change Out		17	2	20	36	32	34	16	119	64	-	-
190													
191	McIntyre Subdivision Rebuild	Business Case No. 01	748	1,035	405	141	(91)	1,368	285	109	1,244	564	924
192	Downtown Whitehorse Capacity Upgrade		1,299	507	-	-	-	-	-	-	-	1,451	366
193	Hillcrest Subdivision Conversion		(5)	41	-	-	-	-	-	-	-	-	152
194													
195	Upgrade Underground Line Into Services and Shipyard Sub		-	-	-	-	-	-	-	-	-	102	-
196	McCrae Substation Second Feeder Breaker		608	133	-	-	-	-	-	-	-	414	-
197	McCrae Substation Transformer Upgrade to 10 MVA		251	-	-	-	-	-	-	-	-	297	-

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($000)

Line		Business	Actuals							Test Period		Approved	
No.	Project Name	Case	2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
198	Whistle Bend Way Underground Crossing		230	94	-	-	-	-	-	-	-	60	-
199	Upper Liard – Replace Liard River Crossing		27	-	-	-	-	-	-	-	-	-	-
200	AEY 34.5kV Cable Replacement		152	0	-	-	-	-	-	-	-	-	-
201	Fault Indicators in Padmount Equipment		49	1	-	-	-	-	-	-	-	50	-
202	AEY Maintenance Work Request 241-2016 HJ Reg		23	-	-	-	-	-	-	-	-	-	-
203	AEY 2016 Safety Audit F		22	-	-	-	-	-	-	-	-	-	-
204	AEY Cable Testing 2016		20	-	-	-	-	-	-	-	-	-	-
205	AEY Maintenance Work Request M97-2013 Pole Change		2	26	0	-	-	-	-	-	-	-	-
206	AEY 102 Lambert Encroachment		2	3	2	18	1	2	1	-	-	-	-
207	AEY Trespass L1131 Car		1	67	-	-	-	-	-	-	-	-	-
208	5L622 - Lewes River Bridge Crossing Replacement		1	87	-	-	-	-	-	-	-	140	-
209	Paint Mountain Conductor Replacement		(4)	144	72	306	37	177	(34)	-	-	-	559
210	Range Road Rebuild		108	-	-	-	-	-	-	-	-	110	-
211	Carcross Nares Bridge Relocation		-	-	-	-	-	-	-	-	-	90	-
212										-	-	-	-
213	Replace Watson Lake Substation Transformer T2		-	175	67	(7)	0	-	-	-	-	-	356
214	400 Amp Regulators in Logan Substation	Business Case No. 03	-	168	6	-	-	-	-	-	-	-	122
215	AEY Carcross Corner Pol		-	41	1	-	-	-	-	-	-	-	-
216	AEY Maintenance Work Order M255-2016 3rd a		-	28	-	-	-	-	-	-	-	-	-
217	AEY CCC Rd Rebuild		-	9	174	0	-	-	-	-	-	-	-
218	3 Phase Hotsprings Rd	Business Case No. 05	-	-	-	386	11	(4)	-	-	-	-	-
219	Haines Junction OSS Replacement		-	47	21	(16)	-	-	-	-	-	-	51
220	Single Regulator 5L631		-	25	-	-	-	-	-	-	-	-	30
221	Steward Crossing Ferry Hill Line Rebuild - Design		0	16	2	1	1	(21)	-	-	-	-	30
222	McRae Substation Regulator Upgrade		-	-	-	-	-	-	-	-	-	-	20
223	Rebuild Line Behind City Municipal Services Building		-	-	-	-	-	-	-	-	-	-	81
224													
225													
226	**Distribution Improvements Continued**												
227	AEY Old Crow Volt Issues-Loop		-	-	356	6	-	-	-	-	-	-	-
228	AEY 25kV A.Hwy Hamilton Tie		-	-	218	(12)	(14)	-	-	-	-	-	-
229	McIntyre Subdivision Contingency Loop	Business Case No. 11	-	-	116	189	(0)	(10)	-	-	-	-	-
230	Teslin Substn Metering		-	-	61	(1)	-	-	-	-	-	-	-
231	Teslin OSS Replacement		-	-	47	(0)	-	-	-	-	-	-	-
232	AEY 3rd Ave Burial Dwntwn		-	-	42	3	6	2	2	-	-	-	-
233	AEY Wtsn Lk Vertical Strcts		-	-	28	0	-	-	-	-	-	-	-
234	AEY Teslin Sub Gnd Grid		-	-	18	7	6	0	-	-	-	-	-
235	AEY Lower Post Fire 2018		-	-	16	24	-	-	-	-	-	-	-
236	AEY Cowley Rd Rebuild SKH		-	-	7	85	18	-	-	-	-	-	-
237	AEY 2nd Ave Trespass		-	-	3	2	18	-	-	-	-	-	-
238	AEY SCADA Swtch at Pinerdg		-	-	1	42	2	25	6	-	-	-	-
239	YG Toyota Access, Intersection & Frontage Road Upgrades		-	-	0	341	2	-	-	-	-	-	-
240	AEY YG Nares River Bridge		4	82	(13)	(7)	-	-	-	-	-	-	-
241	Whitehorse Airport Hanger D Area Rebuild		0	12	1	160	(9)	-	-	-	-	-	142
242													
243	AEY Reroute Mountain View		-	-	-	53	0	-	-	-	-	-	-
244	AEY Aerial Trespass Lot 9 Blk 16 Adela Trail Watson Lake		-	-	-	0	1	116	37	-	-	-	-
245	Rogers Street 25kV Conversion		-	-	-	24	16	-	-	-	-	-	-
246	AEY Trespass Primary Line Reroute, Lot 1499 Hotsprings Road		-	-	-	1	21	24	-	-	-	-	-
247	Install 35kV Regulators on Carcross Road	Business Case No. 17	-	-	-	-	199	(3)	-	-	-	-	-
248	HLC Breaker Replacement	Business Case No. 04	-	-	-	-	136	-	-	-	-	-	-
249	Upgrade Regulators at Laberge Substation	Business Case No. 09	-	-	-	-	129	-	-	-	-	-	-
250	Powerline Relocation Hillcrest YG Highway Realignme	Business Case No. 15	-	-	-	-	119	5	(3)	-	-	-	-
251	Reconductor Mayo Rd Mainline	Business Case No. 06	-	-	-	-	111	-	-	-	-	-	-
252	Shipyards Sub Replace Relays		-	-	-	-	94	-	-	-	-	-	-
253	266 ACSR Upgrade Sumanik Drive		-	-	-	-	73	-	-	-	-	-	-
254	AEY Aerial Trespass Lots 14A & 14B Pilot Mtn Sub'd		-	-	-	-	37	-	-	-	-	-	-
255	AEY D/C Powerline Reroute Cousins to Mayo Cutoff		-	-	-	-	35	(7)	-	-	-	-	-
256	Riverdale Load Sectionalizing		-	-	-	-	25	-	-	-	-	-	-
257	DWCI -Downtown South Voltage Conversion- prep		-	-	-	-	17	18	2	-	-	-	-
258	AEY Reconductor Mayo Road Mainline - Stage 2	Business Case No. 06	-	-	-	-	15	138	-	-	-	-	-
259	AEY Powerline Relocation YG Alaska Hwy Crestview I	Business Case No. 15	-	-	-	-	0	225	(41)	-	-	-	-
260													
261	Powerline Relocation Burns Road to Range Road Inte	Business Case No. 15	-	-	-	-	-	136	(18)	-	-	-	-
262	AEY Hamilton to Alaska Highway 25kV Tie		-	-	-	-	-	73	(4)	-	-	-	-
263	AEY Powerline Relocation Lot 2 Salvation Army		-	-	-	-	-	62	2	-	-	-	-

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Line		Business	Actuals							Test Period		Approved	
No.	Project Name	Case	2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
264	Upgrade Recloser at Carx Substn		-	-	-	-	-	44	-	-	-	-	-
265	AIS 9 Switch Cube Replacement - S2350 Hamilton Blvd		-	-	-	-	-	37	0	-	-	-	-
266	AEY New Subst Mayo Rd		-	-	-	-	-	29	-	-	-	-	-
267	AEY Voltage Issues Gold Road		-	-	-	-	-	3	28	-	-	-	-
268													
269	AEY Aerial Trespass Lot 23, Blk 25 or 102 Teslin Crescent, (Thomas Slager), Watson La		-	-	-	-	-	-	47	-	-	-	-
270	Ross River Substn Voltage Regulator Control		-	-	-	-	-	-	36	-	-	-	-
271	Upgrade Recloser Mountainview Substn		-	-	-	-	-	-	54	-	-	-	-
272	New Substation Mayo Road	Business Case No. 25	-	-	-	-	-	-	400	2,400	-	-	-
273	Reconductor Mayo Rd Mainline - Stage 3	Business Case No. 06	-	-	-	-	-	0	162	-	-	-	-
274	Watson Lake Substation Feeder & Feeder Protection Replacement		-	-	-	-	-	-	146	66	-	-	-
275													
276	Downtown south voltage conversion		-	-	-	-	-	-	-	-	-	-	-
277	AEY Choutla Long Span Rebuild		-	-	-	-	-	-	-	40	-	-	-
278	AEY Dogwood voltage improvement		-	-	-	-	-	-	-	40	-	-	-
279	AEY DWCI - New 12.5kV substation		-	-	-	-	-	-	-	25	792	-	-
280	AEY Haines Junction Regulator Stand Replacement		-	-	-	-	-	-	-	20	-	-	-
281	AEY New Substation Whistle Bend - Leota	Business Case No. 25	-	-	-	-	-	-	-	154	2,781	-	-
282	AEY Nisultlin Bridge Pole Relocation		-	-	-	-	-	-	-	380	165	-	-
283	AEY SCADA Pineridge Switch		-	-	-	-	-	-	-	47	-	-	-
284	AEY Upgrade 6L11 conductor S150 to Carcross Corner		-	-	-	-	-	-	-	50	52	-	-
285	AEY Upgrade recloser		-	-	-	-	-	-	-	87	90	-	-
286	AEY Voltage Improvement Destruction Bay		-	-	-	-	-	-	-	225	-	-	-
287	AEY Whitehorse Escarpment line reroutes - Hoge		-	-	-	-	-	-	-	110	-	-	-
288	Robinson sub capacity		-	-	-	-	-	-	-	-	165	-	-
289	AEY Hillcrest Voltage Improvement		-	-	-	-	-	-	-	100	-	-	-
290	AEY Pelly Crossing Voltage Improvement		-	-	-	-	-	-	-	-	361	-	-
291	Watson Lake 5L621 Upgrade		-	-	-	-	-	-	-	-	103	-	-
292	Power System Assessment - YEC and AEY		-	-	-	-	-	-	-	150	206	-	-
293	Whitehorse CKES UG conversion		-	-	-	-	-	-	-	-	155	-	-
294	Encroachment 3rd and Black Encroachment		-	-	-	-	-	-	-	-	124	-	-
295													
296	AEY 6L19 voltage improvement	Business Case No. 30	-	-	-	-	-	-	-	-	593	-	-
297	Relocate 100 A Carcross Cutoff Regulator	Business Case No. 30									178		
298	Relocate 100 A Lewes River Regulator	Business Case No. 30									178		
299	AEY Carcross PQ monitoring		-	-	-	-	-	-	-	-	77	-	-
300	AEY Whitehorse Escarpment line reroutes - 5th avenue		-	-	-	-	-	-	-	-	412	-	-
301	Old Crow voltage improvement - reconductor	Business Case No. 29	-	-	-	-	-	-	-	-	464	-	-
302													
303	400 Amp Regulators in Arkell Substation		-	161	5	-	-	-	-	-	-	-	122
304	Shipyards Spare 25kV Breaker		-	55	146	2	-	-	-	-	-	-	102
305	Replace Underground Cables at Whitehorse Airport		0	1	1	0	(0)	0	(1)	-	-	-	84
306	Distribution Improvements < $20,000		197	260	146	130	27	28	66	143	10	81	77
307	**Distribution Improvements Total**		**4,516**	**3,921**	**2,318**	**2,634**	**1,658**	**3,180**	**2,028**	**5,195**	**9,081**	**4,335**	**4,153**
308													
309	**Street and Sentinel Lighting**												
310	General Streetlight Replacements		237	211	85	166	48	105	121	342	186	199	254
311	New Customer Streetlight Installations	Business Case No. 34	170	112	230	84	850	555	180	1,060	448	199	203
312	Whistle Bend Streetlights		-	-	-	-	-	-	-	-	-	-	348
313	Watson Lake Street Light Replacement		-	-	-	-	-	-	-	-	-	-	41
314	St Lt Replacements Hart Cr.	Business Case No. 20	-	-	-	-	-	180	-	-	-	-	-
315	Car Cross Streetlights		-	429	(24)	111	(0)	-	-	-	-	-	-
316													
317	Alaska Highway North Klondike Highway Intersection		-	-	-	-	359	0	-	-	-	-	-
318	Street Lights Burns Road to Range Road Intersection		-	-	-	-	-	184	-	-	-	-	-
319	Street Lights Lodestar to Philmars Phase 1		-	-	-	-	-	-	509	-	-	-	-
320	Pelly Crossing Community Lights		-	-	-	-	-	-	145	-	-	-	-
321												-	-
322	McIntyre Subdivision Streetlight Rebuild		-	-	-	-	-	-	-	412	155	175	254
323	YG Nisutlin Bridge Streetlights		-	-	-	-	-	-	-	110	106	-	-
324													
325	Whistle Bend 3C Street Lights		-	185	-	-	-	-	-	-	-	-	-
326	Whistle Bend Lights 4D	Business Case No. 31	-	-	-	-	159	-	-	-	-	-	-
327	Whistle Bend Street Lights - Stage 4	Business Case No. 31	-	0	261	291	-	-	-	-	-	-	-
328	Whistle Bend Street Lights - Stage 5	Business Case No. 31	-	-	-	133	211	-	-	-	-	-	-
329	Whistle Bend Street Lights - Stage 6	Business Case No. 31	-	-	-	-	-	-	-	50	-	-	-

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
($000)

Line No.	Project Name	Business Case	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
330	Whistle Bend Street Lights - Stage 7	Business Case No. 31	-	-	-	-	-	31	55	301	-	-	-
331	Whistle Bend Street Lights - Stage 8	Business Case No. 31	-	-	-	-	-	-	-	103	-	-	-
332	Whistle Bend Street Lights - Stage 9A	Business Case No. 31	-	-	-	-	-	-	-	186	-	-	-
333	Whistle Bend Street Lights - Stage 9B	Business Case No. 31	-	-	-	-	-	-	-	-	147	-	-
334													
335	Street and Sentinel Lighting < $20,000		-	-	-	-	-	-	-	-	-	11	25
336	**Street and Sentinel Lighting Total**		**407**	**936**	**553**	**785**	**1,627**	**1,055**	**1,009**	**2,563**	**1,042**	**584**	**1,125**
337													
338	**Meters**												
339	AMI Project New Meters		-	-	-	-	-	-	-	132	304	-	-
340	Replacement of Meters and New Installations		105	88	32	67	127	75	98	103	106	199	203
341	**Meters Total**		**105**	**88**	**32**	**67**	**127**	**75**	**98**	**235**	**410**	**199**	**203**
342													
343	**Transformers & Regulators**												
344	General Capitalizable Transformers	Business Case No. 16	-	-	-	-	268	49	(19)	218	275	90	91
345	Spare 10 MVA Transformer		-	-	-	-	-	-	-	-	-	219	-
346	Spare Padmount Regulator for Shipyards Substation		-	-	-	-	-	-	-	-	-	58	-
347	Transformers and Regulators		73	213	70	262	118	173	10	-	-	-	-
348	AEY Old Crow Regulators	Business Case No. 29	-	-	-	-	-	-	-	710	-	-	-
349	**Transformers & Regulators Total**		**73**	**213**	**70**	**262**	**385**	**222**	**(8)**	**928**	**275**	**367**	**91**
350													
351	**GP&E**												
352	**Computer**												
353	My Account- Technology Project	Business Case No. 19	-	-	22	247	(4)	-	-	-	-	-	-
354	**Computer Total**		**-**	**-**	**22**	**247**	**(4)**	**-**	**-**	**-**	**-**	**-**	**-**
355													
356	**Land & Building**												
357	Service Complex Heating System		4	17	6	-	-	-	-	-	-	40	25
358	Annual Building Upgrades		-	-	-	-	-	-	-	75	73	-	-
359	Downtown Office Interior Renovations		-	-	-	-	-	-	-	51	-	-	-
360	Whitehorse Service Complex RTU'S Construction		-	-	-	-	-	-	-	100	-	-	-
361	Whitehorse Service Complex Rooftop Unit Design		-	-	-	-	-	-	-	5	-	-	-
362	Service Complex Boiler Replacement	Business Case No. 10	-	-	-	-	132	(27)	-	-	-	-	71
363	Kilowatt - Misc. Imp		24	-	-	-	-	-	-	-	-	-	-
364	102 Kilowatt Ln Refurbish		-	14	32	-	-	-	-	-	-	-	-
365	101 Kilowatt Ln Refurbish		-	19	32	-	-	-	-	-	-	-	-

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Continuity of Capital Expenditures
($000)

Line No.	Project Name	Business Case	Actuals 2016	2017	2018	2019	2020	2021	2022	Test Period 2023	2024	Approved 2016	2017
366	Warehouse Mezzanine Upg		-	22	-	-	-	-	-	-	-	-	-
367	DT Office Renos & Improvements		-	-	-	27	-	-	-	-	-	-	-
368	Service Complex Yard Extension		-	-	-	36	0	-	-	-	-	-	-
369	Fencing for Marwell Yard		-	-	-	-	-	-	45	-	-	-	-
370	Old Crow Bunkhouse replacement	Business Case No. 41	-	-	-	-	-	-	-	-	515	-	-
371	Fish Lake 1 Storage building roof replacements		-	-	-	-	-	-	-	-	77	-	-
372	Downtown Office Security and Fire Suppression		-	-	-	-	-	-	-	-	103	-	-
373	Warehousing Seacan		-	-	-	-	-	-	-	-	26	-	-
374	Furnace Replacements - Watson Lake		-	-	-	-	-	-	-	-	-	25	-
375	Watson Lake Septic Upgrade		-	-	-	-	-	-	-	-	-	-	51
376	Watson Lake Storage Solutions		-	-	-	-	-	-	-	-	-	-	92
377	Land & Buildings - Corporate < $20,000		61	32	21	9	15	5	50	-	-	-	-
378	**Total Land & Buildings**		**89**	**105**	**91**	**72**	**147**	**(22)**	**95**	**232**	**794**	**65**	**239**
379													
380													
381	**Communication Equipment**												
382	Communication Equipment		36	23	2	(0)	19	48	(46)	-	-	18	13
383	AEY SCADA Upgrades		26	116	30	20	10	5	20	47	141	49	66
384	Satellite Radios	Business Case No. 14	-	-	-	-	-	-	157	-	-	-	-
385	Windows XP Conversion for Operations Dispatch		-	-	-	-	-	-	-	-	-	30	-
386	Form 6 Substation Controls		-	-	-	-	-	-	-	-	-	20	-
387	Whitehorse SCADA Dispatch UHF Repeater		-	-	-	-	-	-	-	-	-	-	36
388													
389	**Total Communication Equipment**		**63**	**138**	**32**	**20**	**29**	**53**	**131**	**47**	**141**	**117**	**115**
390													
391	**Tools, Instruments & Equip.**												
392	FRC Replacement		19	24	9	18	13	10	8	22	25	-	-
393	Power Quality Meter		-	-	-	-	-	-	14	20	-	-	-
394	Primary current monitors		-	-	-	-	-	-	-	26	27	-	-
395	Miscellaneous Tools and Instruments		132	138	64	180	95	150	65	242	76	149	165
396	**Total Tools, Instruments & Equip.**		**151**	**162**	**73**	**197**	**108**	**160**	**87**	**310**	**128**	**149**	**165**
397													
398	**Office Computer Equipment**												
399	Office Furniture & Equipment		20	11	2	5	5	12	14	62	20	20	20
400	2021 Surface Pro Purchases		-	-	-	-	-	21	-	-	-	-	-
401	Replace XP Operating Systems - iFix PCs		31	0	-	-	-	-	-	-	-	-	46
402													
403	**GP&E Continued**												
404	CIS Replacement	Business Case No. 22	-	-	-	-	-	680	3,712	3,666	345	-	-
405	Asset Management - Evaluation & Program Roadmap		-	-	-	-	-	-	59	13	-	-	-
406	Asset Management - Phase 1	Business Case No. 24	-	-	-	-	-	-	-	305	901	-	-
407	Sales force		-	-	-	-	-	-	-	172	155	-	-
408	My Account Enhancements - AEY		-	-	-	-	-	37	16	-	-	-	-
409	Enterprise Batch Printing		-	-	-	-	-	-	49	-	-	-	-
410	Fleet Maximo - AEY		-	-	24	29	7	-	-	-	-	-	-
411	Oracle R12 Replacement		-	51	51	-	-	-	-	-	-	-	-
412													
413	Office Computer Equipment < $20,000		2	16	3	10	21	4	(71)	43	13	-	-
414	**Total Office Computer Equipment**		**54**	**79**	**79**	**44**	**32**	**755**	**3,780**	**4,261**	**1,434**	**20**	**66**
415													
416	**Transportation Equipment**												
417	Transportation Equipment	Business Case No. 27&28	18	51	6	88	117	507	397	697	766	369	315
418	Purchase New Unit YT169 - Small Bucket Truck	Business Case No. 13							264				
419	Unit 136 to Replace Unit 643 Bucket Truck			614									
420	Unit YT144 New Mechanic's Truck	Business Case No. 13	-	-	-	145	-	-	-	-	-	-	-
421	Purchase Unit YT145 to Replace Unit 091	Business Case No. 13	-	-	-	149	-	-	-	-	-	-	-
422	Unit 151 Digger to Replace Unit 429 - WLk Bucket	Business Case No. 13	-	-	-	-	324	11	-	-	-	-	-
423	Purchase Unit YT148 - Replace Unit 092 - Ram 5500 (	Business Case No. 13	-	-	-	-	129	-	-	-	-	-	-
424	Purchase YT159 - Replace Unit 886 - 1 Ton Service B	Business Case No. 13	-	-	-	-	-	158	-	-	-	-	-
425	**Total Transpiration Equipment**		**18**	**665**	**6**	**382**	**570**	**675**	**661**	**697**	**766**	**369**	**315**
426			-	-	-	-	-	-	-	-	-	-	-
427	Other Projects Less Than $20,000											37	102
428	**GP&E Total**		**374**	**1,150**	**303**	**962**	**883**	**1,621**	**4,753**	**5,547**	**3,263**	**757**	**1,002**
429	**Grand Total**		**14,784**	**10,476**	**9,491**	**13,529**	**13,001**	**15,147**	**18,914**	**31,234**	**25,073**	**14,999**	**12,470**

ATCO Electric YUKON

2023-2024 General Rate Application

Old Crow Generation

Capital Expenditure Information

OLD CROW GENERATION **$3,517,000**

- Old Crow Add Day Tank and Fuel Transfer Pump $128,000

  Old Crow #3 and #4 and the boiler suffer from fuel starvation / priming issues, due to the elevation of the new plant and the existing fuel storage tanks. A day tank and pump, designed to meet National Fire Code requirements, will be installed to alleviate these operational problems.

- Old Crow Boiler Metering and Control $25,000

  A hydronic heating system is used in Old Crow to provide heat to the buildings and engine blocks. The diesel boiler is used to satisfy heat demand when engine waste heat is not available. A meter will be installed to quantify the volume of fuel used.

- Old Crow Plant Tank Access $232,000

  Old Crow has four 50,000 L diesel tanks to supply the power plants. These are horizontal double-walled tanks on individual skids, with a shared catwalk to access connections on top. The ground has shifted, pulling these tanks apart and stressing the catwalk welds to the tank. A new catwalk will be installed to provide access to all instruments and be supported independently.

- Old Crow Unit 1 Major Overhaul $465,000

  Please refer to Business Case #23.

- Old Crow Unit 2 Replacement $175,000

  Old Crow Unit 2 suffered a catastrophic engine failure in Q3 2019. The long block was replaced, rather than complete genset replacement, due to cost and schedule.

- Old Crow Unit 3 Failure – Major Overhaul $80,000

  Old Crow Unit 3 had a bearing failure in Q1 2021 that damaged the generator. The generator was repaired at factory, rather than on-site, due to cost, quality, and warranty.

- Old Crow Unit 4 Major Overhaul $252,000

  Please refer to Business Case #23.

- Old Crow #2 Long Block Replacement $71,000

Please refer to Business Case #23. In Q4 2020, AEY observed a coolant leak. Troubleshooting determined the long block (received 2019) was deficient and required replacement. This was conducted in Q2 2021 but costs captured in 2022; manufacturer warranty and distributor goodwill credit covered the majority of costs.

- Old Crow Unit 2 Generator Refurbishment $39,000

  In 2015, Old Crow Unit 2 had a long block replacement: refer to AEY-YUB-46(b) Attachment 1 Appendix 3. This project was to complete a generator major overhaul, due to this piece of equipment reaching its service interval.

- Old Crow Old Plant Gantry Accessories $21,000

  The new gantry crane required low-profile trolley and hoist, to fit within the existing building clearance.

- Old Crow Plant (old) Gantry Crane $22,000

  Old Crow required a new certified gantry crane, for removal and maintenance of gensets, as the existing failed inspection and was not rated for Unit 1.

- Old Crow Original Plant Rebuild $863,000

  Please refer to Business Case 41 and AEY-YUB-46(b) Attachment 1 Appendix 1

- Old Crow Unit 3 replacement $1,093,000

  Please refer to AEY-YUB-46(b) Attachment 1 Appendix 2

- Old Crow Unit 2 – External Equipment $51,000

  The radiator and silencer were installed in 1993 for CUL# 371, prior to CUL #355 being installed in 2012. This project was to replace them with appropriately sized equipment for the current engine capacity, and due to end-of-life. Funds were not spent, and this risk has been managed by regular inspection.

Old Crow Plant Expansion

Project Summary and Description

The original generating plant in Old Crow did not have the physical capacity to house newer engines of the same or higher kW rating as the existing units reach end of life. It also did not have the space for additional units which are required as the community continues to experience load growth. Aside from the unit housing issues, the existing plant also did not have adequate floor or wall space to facilitate the installation of new control equipment. In order to address these issues and ensure contingencies are in place to minimize outages in the community, ATCO Electric Yukon installed a second 1,350 square foot generating building adjacent to the existing Old Crow plant.

Both the original and additional building have sufficient space to house two diesel generators and the associated equipment as well as provide sufficient working space for regular work to be performed safely.

Project Cost Update

Original estimates for this project were $1,950,000 but, despite ATCO Electric Yukon's best efforts to minimize the costs while meeting the requirements of a safe reliable system, increased scope and unforeseen circumstances caused actual costs to be significantly higher than previously approved.

Actual and approved costs for this project were as follows:

	Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
Labour	60	238	178	297%
Contract Services	1,890	3,417	1,527	81%
Materials	-	336	336	-
Other	-	575	575	-
	1,950	**4,566**	**2,616**	**134%**

Building & Electrical Design (approx. $1,300,000 additional costs)

A portion of the cost overrun is due to the updated design of the building structure. Original engineering and design provided to ATCO Electric Yukon at the time of the preparation of the 2013-2015 General Rate Application were preliminary. Additional detailed engineering and design work to integrate the updated building design with the existing system resulted in increased work scope and materials required.

The original forecast also did not include the electrical equipment required for the switchgear component for the additional building.

2013-2015 Project Post Completion Summary — Attachment 11.2

Construction, Installation & Commissioning Costs (approx. $900,000 additional costs)

Conditions in the community significantly impacted the cost of this project. During construction, two other projects were being carried out in the community, which reduced availability of accommodations resulting in large increase of pricing. As a result contract workers, materials and resources within Old Crow were limited.

The existing store in the community closing prior to opening of the new store, due to construction delays of the new store. As a result food was either flown in or local catering services were utilized at an additional cost. Furthermore in part due to the new fuel depot construction, the community experienced occasional fuel shortages which resulted in additional delays or time onsite.

Whenever possible, ATCO Electric Yukon was diligent to use the lowest cost option. However, due to the size of the community and the limited resources available there was often only a single option to continue with construction of the project.

The quotes provided to ATCO Electric Yukon for the original design also did not compensate for the poor working conditions of the existing plant. More time was required to complete the work to integrate the two plants due to the space constraints and overall poor condition of the existing facility.

There was also additional unplanned site drainage work required in 2015, due in part to seasonal movement of disturbed permafrost from the excavation of the foundation in 2013.

Unforeseen situations such as weather conditions, flight availability, community events and aircraft mechanical issues, also resulted in delays which impacted work schedules resulting in additional labor and project management costs.

Freight (approx. $100,000)

Old Crow is a fly in community with only one dedicated supplier of regular passenger and freight air service. A combination of other community projects and regular community demands limited the availability of transporting equipment and workers in and out of the community. As a result, additional costs for transporting equipment to site were encountered to ensure a timely delivery.

The charter of one Hercules aircraft was required in fall of 2015 to bring in the electrical switchgear plus construction material. Unfortunately, the only Canadian supplier of this service ceased operation in the spring of 2015. As a result Lynden transport out of Alaska was the only source available. In order to accommodate the delivery by Lynden all material had to be imported into the US (Alaska) to be exported back into Canada. Additional project management time was required to document and provide all the required information for the brokerage of this material.

Other (approx. $100,000 additional cost)

Due to the large nature of the project various other incidental items increased the costs and additional timelines resulted in additional supervision and project management costs.

Economic conditions also impacted that cost of this project. At the time of the application the Canadian dollar was near par with the US dollar. The Canadian dollar steadily declined through the entire scheduled project timeline. Materials and the cost to fly in the switchgear were higher than ATCO Electric Yukon had anticipated partially due to the disparity between the Canadian and US dollar at the time of construction.

Other Considerations

Throughout the project, scope and costs were reviewed and revisited to ensure that ATCO Electric Yukon could address the load growth and provide adequate contingency to the community of Old Crow at a prudent cost.

As project scope and costs related to the building increased, modular options were explored. Quotes for this option came back between $400,000-$500,000 higher than the site built option and did not meet ATCO Electric Yukon's operational and maintenance requirements. There were significant costs related to transporting prefabricated structures to a community as remote as Old Crow. This modular unit did not have room for growth; it had space for one unit. The modular option would require an addition in the future in order to house additional or larger units as the community grows.

As there was still a need for a new building and Old Crow has been experiencing load growth over the last few years, ATCO Electric Yukon proceeded with the updated design. The building construction was tendered and the lowest bid was awarded the contract.

ATCO Electric
YUKON

2016-2017 General Rate Application
Appendix #5

Old Crow Unit #3 Replacement

ATCO Electric YUKON

Executive Summary

Load growth and load duration of the Old Crow community have steadily diminished the utilization of the existing 170 kW unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, ATCO Electric Yukon is proposing to purchase and install a new 600 kW unit to replace the existing undersized 170 kW unit. The new unit will be installed in the new building in Old Crow, as it will not physically fit in the existing building.

Business Case #15 "Old Crow Unit #3 Replacement" was submitted in the 2013-2015 General Rate Application and approved in Decision 2014-06. The unit tender and selection occurred in 2015; the unit will be received and installed in 2016.

Background

Based on the 2012 loading data (as submitted in the 2013-2015 General Rate Application), a project was identified that required a purchase of a 250 kW unit to replace the currently undersized 170kW unit in operation in the existing plant.

In preparation for tender of the new unit in 2015, a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was identified as being required.

Project Description

Multi-year project to replace the existing 170 kW unit, housed in the original Old Crow generating facility, with a larger 600 kW unit to be house in adjacent new building.

Manufacturer will also be responsible for disassembly and reassembly of unit to allow for transportation into the community via aircraft.

Unit will be installed within the new facility with structural, mechanical, and seismic engineering completed on the installation project to meet the applicable standards for a post disaster rated facility.

ATCO Electric YUKON

Project Schedule & Cost

This is a multi-year project. The tender and unit selection process occurred in 2015 with the unit scheduled to be installed in 2016. Total cost for this project is forecast to be $1,262,000.

The original budget for this project as per the 2013-2015 GRA was $500,000. The primary drivers for this cost increase are:

- Realization of actual costs based on previous projects in regards to construction and logistics of work completed within the isolated, fly-in only community;
- Understanding of construction and engineering requirements of installations carried out within the new facility; and
- Increase in physical size of unit, and associated costs in respect to transportation and installation as unit has to be disassemble for transport and reassembled on site.

Overall the first two items were the most significant causes of the increased forecast. The cost differential between a typical 285kW (based on a bids received for the Beaver Creek #2 Replacement) and 600kW unit is approximately $60,000.

Business Drivers and Benefits

Load Growth

Load in Old Crow has been increasing over the last few years. Notable developments include the Water Treatment Center, Co-op Store, Fuel Depot, and new housing. Based on these developments and other factors within the community, a significant increase in peak load has occurred. With further potential development this peak is expected to rise. On average the peak has grown 4.023% based on 2008 – 2015 recorded values. The peak load has increased almost 21% since the original replacement unit was determined in 2012.

Old Crow Peak Loading 2008 – 2015

Year	Peak Load (kW)
2008	407
2009	460
2010	439
2011	478
2012	462
2013	481
2014	491
2015	558

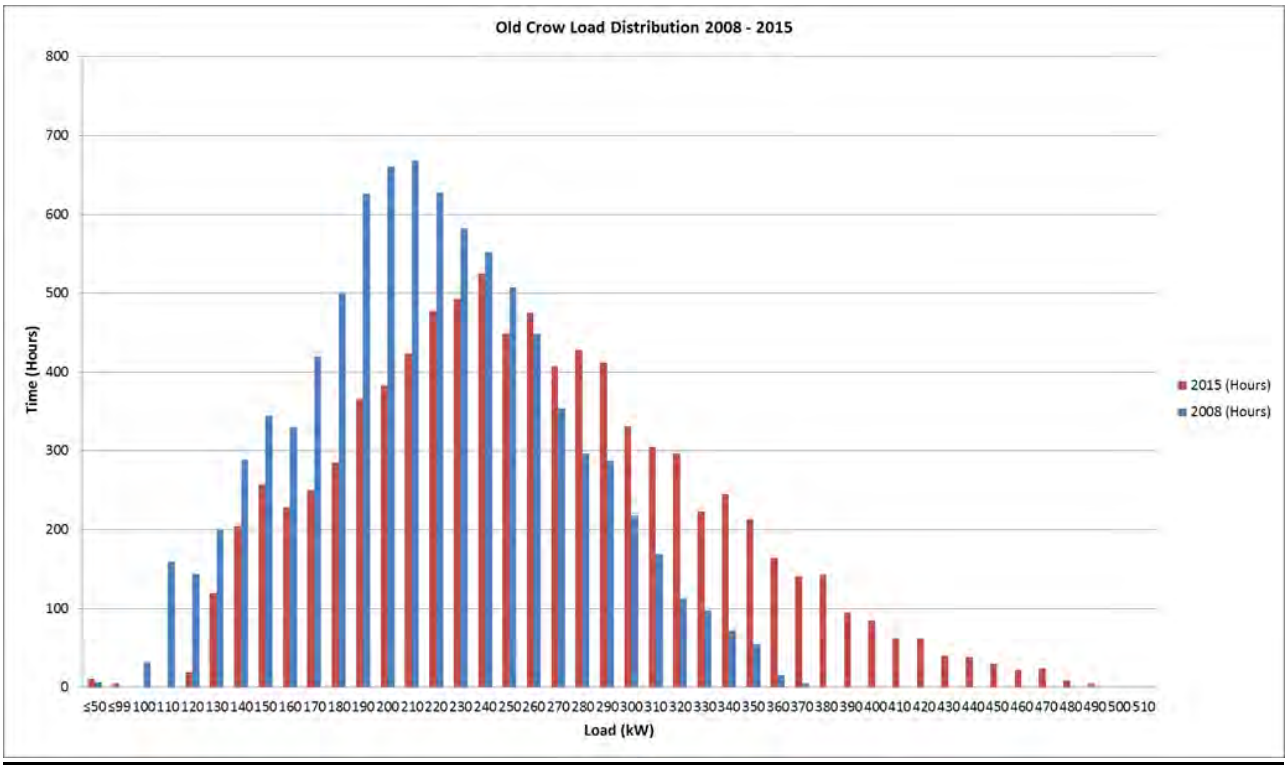
ATCO Electric YUKON

Plant Efficiency

Sustained load growth within the community has impacted the overall load profile. As a result, the base load levels within the community have risen. Based on this trend, it is expected that the operational hours on a 250kW unit if installed would continuously decrease with load increase. This could result in the unit not operating under normal dispatch similar to the operation of the original 170kW unit.

Additionally this increase would reduce the possibility of the unit providing 100% community load under normal dispatch operation.

Old Crow Load Distribution 2008 / 2015



Contingency

The larger unit will not physically fit in the original facility where CUL 384 is currently housed. This new unit will be installed in the new plant adjacent to the original facility and provide additional contingency and mitigate the risk of long term outages within the community due to the loss of the original power plant for any reason.

Evaluation of Viable Alternatives

Alternative # 1: Leave existing 170kW unit in service. With continued load growth the unit will not run to provide 100% community supply under normal dispatch. The annual operating hours of the unit will continue to decrease.

Alternative # 2: Purchase and install 250kW unit as originally planned. Due to actual load growth, this alternative is not recommended, as it only provides short term solution. With continued load growth it is expected that this unit would see a continued decrease in hours of operation. Furthermore, the majority of project costs are related to logistics and installation, only a small differential in cost ($60,000) is related to the price of a 250kW vs 600kW unit.

Alternative # 3: Replace the existing unit with a 600kW unit. Unit will be able to meet supply requirements of present load and provide capacity for future load growth.

Recommendation

It is recommended to replace Old Crow Unit #3 with a 600kW unit in the new plant adjacent to the original facility. This will address the load growth issue and improve contingencies in Old Crow.

Business Case for Actual Expenditures over $100,000 **Attachment 11.7**
2013-2015 Completed Projects

Old Crow Unit #2 Replacement

Project Summary and Description

The replacement of Old Crow Unit #2 was originally forecasted to occur in 2016, as outlined in the 2013-2015 GRA response to information request YEC-YECL-19(a). The original forecasted 2016 replacement was based on the unit being due for a major overhaul at approximately 75,000 hours. ATCO Electric Yukon's current practice is to replace high speed machines near 80,000 hours or the closest life extension to 80,000 hours.

The scope of this project was to cover the supply, shipping, and installation of one 3421 long block for Old Crow Unit 2. Also included in the scope was disconnection, reconnection, new fluids, start up, commissioning, and return of existing block. Existing generator and skid were reused, with the generator to be serviced at a later date.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual ($000s)
Old Crow Unit 2 Replacement	161
Total	**161**

Business and Technical Drivers

The original replacement date of 2016 was based on the 5 year average of the unit's operational hours. In 2013 the 5 year average was 5,881 hours, as of January 2016 the 5 year average increased to 6,093. The primary driver for the increase in operational hours is community load growth.

Throughout the 3rd quarter of 2015 the operation of Unit 2 continued to deteriorate with increased oil consumption, smoking, and valve wear. Due to the condition of the unit, there was a high probability that required replacement could not be delayed until the original forecast of 2016.

Alternatives

Alternative #1 - Purchase long block and replace existing engine - This option ensures the work will be completed before winter and the unit will physically fit in the power plant. The cost is comparable to a major overhaul with a higher probability of increased operational life.

Alternative #2 - Life extension on existing unit (major overhaul)- Perform major life extension on Unit 2 and operate in Old Crow for an additional 20,000 hours until replacement. While this

option would have delayed the purchase of a new unit, concerns around the downtime for the work were considered.

Alternative #3 - Replace unit with similar unit from Pelly Crossing - Pelly Crossing Unit 2 is a newer machine rated for 600kW and is the best match for the existing control system. However, the compatibility of the unit with existing mechanical equipment (exhaust silencer, radiator, and primary cable) would not allow it to handle 100% of the 600kW rated load.

Alternative #4 - Perform top end service, operate until April 2016 - A top end service is a minor over haul that is part of a regular maintenance schedule. It was determined that this maintenance service may not address the mechanical issues that are currently affecting the unit.

Alternative #5 - Accelerate the whole replacement of the unit to 2015 - Unable to procure a replacement unit and install before the winter season.

Recommendation

ATCO Electric Yukon determined that the best solution was the purchase of a refurbished long block and replacement of the existing engine of Old Crow Unit #2 and completed this work in 2015.

2023-2024 General Rate Application

Fish Lake Generation

Capital Expenditure Information

FISH LAKE GENERATION **$7,436,000**

- The driver for most of the following projects is to comply with Water License HY12-065 that expires in 2038. Additionally, the expenditures related to the generating plants themselves are driven by the fact that they are nearing end of life. i

- Fish Lake Unit 2 – Replace Power Station – Detailed Design $527,000

  Please refer to Business Case #39.

- Fish Lake 1 Roof Replacement $452,000

  Please refer to Business Case #32.

- Fish Lake 2 Replace Power Station FEED $385,000

  Please refer to Business Case #39

- Fish Lake 2 Head Pond Intake Building Replacement $153,000

  The building will be replaced due to end-of-life; there are personnel hazards, failed structural components, and building envelope leaks. The substructure, containing trash racks and penstock intake, will be reused.

- Fish Lake 2 Head Pond Spillway Replacement $975,000

  Please refer to AEY-YUB-046(b) Attachment 2 Appendix 1

- Fish Lake Ditch 1 Failure $262,000

  Please refer to Business Case #02

- Fish Lake Ditch 1 Intake Building - Design $103,000

  The building shell was replaced due to end-of-life; new cantilevered structural elements were added for support.

- Fish Lake Unit 1 Spillway Diversion Structure $772,000

  This Spillway Diversion Structure is located at the northwest corner of the Unit #1 plant yard. It is required to divert and control all water from Ditch #1 Spillway to separate channels forming the entrances of West McIntyre Creek and Porter Creek. The existing structure is built of plywood and dimensional lumber that are at the end of their useful life. A new and adequately engineered structure is required.

- Fish Lake Unit 2 Assessment $32,000

  Fish Lake 2 had a failure because of a grid outage. Experts (Maven and ONEC Engineering) were retained to evaluate causes and required actions. The costs from 2016/17 were moved from capital to production operations in 2018. The test year cost of $35,000 should have been captured in "Fish Lake Unit 2 Condition Assessment and Options Analysis" since the invoicing carried into 2023.

- Fish Lake Unit 2 Condition Assessment and Options Analysis $66,000

  These are the costs for the BBA Engineering report appended to Business Case #39. See above; the total cost was $101,000.

- Fish Lake 2 TIV actuator and wicket gates $37,000

  These costs should be allocated to line 20; this is a duplicate.

- Fish Lake Unit 1 Roof Design $59,000

  Please refer to Business Case #32

- Fish Lake Unit 2 Bearing and Shaft Repair $54,000

  Following the failure in 2016, the thrust bearing and shaft required machining and resurfacing.

- Fish Lake Unit 2 TIV Replace $47,000

  During extended downtime on Fish Lake 2, the TIV froze and cracked and required replacement.

- Fish Lake 1 add TIV Actuator $53,000

  The TIV actuator and bypass valve actuator will be controlled from the PLC, to provide automated headpond level control and isolation in case of trip, reducing impact to waterway users and fish habitat.

- Fish Lake 1 TIV Replacement $113,000

  The manual ball valve originally installed was not functional (inoperable gear train, failed seals) and did not provide isolation. The TIV was replaced with a triple offset butterfly valve with motorized actuator.

- Fish Lake 2 add bypass valve actuator and automation $35,000

  The bypass valve will be replaced and will have a motorized actuator added, controlled from PLC, to provide headpond level control and

reduce impact to waterway users and fish habitat.

- Fish Lake 2 PLC replacement $39,000

  Fish Lake 2 PLC is obsolete and requires replacement. This is the last remaining PLC in the multi-year replacement program (lines 51, 52, 98, 102, 116 AEY-YUB-046(a) Attachment 1) for generating sites and this deficiency was identified in the BBA Engineering report.

- Fish Lake Unit 2 DC TIV Actuator & Wicket Gate Replacement $138,000

  Fish Lake 2 TIV has a motorized actuator (VAC) that is not functional on grid loss. A UPS battery bank and inverter will be installed to provide emergency closure of the TIV and bypass valves. The project title is because the original solution was to change the TIV actuator motor to VDC – however this option proved more costly than the one selected. In addition, the wicket gates and wear rings are end-of-life and require replacement to provide adequate turbine control and isolation. These risks were identified by Maven and BBA Engineering.

- Fish Lake Water Monitoring Upgrades $248,000

  Water monitoring upgrades in the Fish Lake Hydro system include instrumentation to gather flow and level data, telecommunications and solar/batteries for data historizing and reporting, and public safety signage – all of which are required to comply with water license conditions. These costs have been treated as an annual program. .

- Fish Lake Unit 1 Turbine and Building Replacement $-9,000

  The costs in S9.2 were removed since this project was closed in 2015.

- Fish Lake Ditch 3 Diversion Replacement $2,801,000

  Please refer to AEY-YUB-046(b) Attachment 2 Appendix 2.

- Louise Lake Containment Dyke Seismic Analysis $40,000

  An in-situ testing and seismic analysis is required to meet Canadian Dam Association guidelines pursuant to this infrastructure's assessed safety factor.

ATCO Electric YUKON

2016-2017 General Rate Application
Appendix #2

Fish Lake #2 Head Pond Spillway Replacement

ATCO Electric YUKON

Executive Summary

The Fish Lake Hydro system was built around 1950 and has aging infrastructure that is coming to the end of useful life. Investigative repairs of Fish Lake #2 Head Pond Spillway structure identified that the structure was in need of replacement. ATCO Electric Yukon will replace the existing spillway structure to adequately handle IDF flows while maintaining safe access to ATCO Electric Yukon generation facilities.

Background

In 2013 the existing structure was scheduled to undergo investigative repairs due to obvious signs of aging. These repairs were expedited when a sink hole was noted in the dam immediately adjacent to the structure in the summer of 2013.

During the investigative repair work it was apparent the structure had come to the end of its lifespan and needed significant repairs. The 2014 Dam Safety Report (recommendation #2014-09) identified the structure required replacement by the end of 2017.

Project Description

The scope of the project is to design and replace the existing concrete and wood structure with a new structure, capable of handling the IDF flows of 8.5m3/s.

Project Costs & Schedule

The project is scheduled to be designed in 2016 with construction completed in 2017. Design and engineering is estimated to be $20,000 and the current construction costs is forecast to be $593,000.

Project Schedule

The design of this project is scheduled to be completed in 2016 and construction is scheduled for 2017.

Business Drivers and Benefits

The main driver for this project is aging infrastructure. This project will ensure ATCO Electric Yukon complies with recommendation #2014-09 of the 2014 Dam Safety Report and item 42 of water license HY12-065.

Evaluation of Viable Alternatives

Alternative 1: Replace the aging structure. This alternative ensures ATCO Electric Yukon is compliant with the terms of the water license and ensures safe and reliable operation of the Fish Lake Hydro system.

Alternative 2: Replace after the structure fails. Failure of this structure inhibits ATCO Electric Yukon's ability to manage a flood event and poses significant risk to the remaining structures within the system.

Recommendation

ATCO Electric Yukon recommends replacing the existing spillway structure as recommended in the 2014 Dam Safety Report. This alternative mitigates the risks associated with a failure of the structure and aligns with ATCO Electric Yukon's commitment to provide safe, reliable service.

ATCO Electric YUKON

2016-2017 General Rate Application
Appendix #1

Fish Lake Ditch 3 Diversion Replacement

ATCO Electric YUKON

Executive Summary

Fish Lake Ditch 3 is not able to adequately handle a 100-Year Inflow Design Flood (IDF) event, as required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and ATCO Electric Yukon's current water licence HY12-065. In the event of an IDF event, the Ditch 3 infrastructure, including the Drop Box, would be at risk of catastrophic failure and risks impacting all remaining downstream infrastructure. As a result, ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Background

On May 31, 2013, ATCO Electric Yukon was granted a 25 year extension to water use licence HY12-065. During the application process it was identified that Ditch 3 Diversion structure and spillway were not adequately built to withstand a 100 year flood event (Inflow Design Flood). ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the Inflow Design Flood rates and complies with the terms outlined in the water licence. Please refer to Attachment 1 of this business case for a map of the Fish Lake facilities.

Project Description

Reestablishment of the Fish Lake Ditch 3 Diversion will allow water to escape the Fish Lake hydro system through a control structure and ditch to Franklin Lake. This project will construct a diversion structure and spillway ditch capable of diverting all water flows in excess of 4.4 m3/s (maximum capability of the Drop Box) out of Ditch 3 and into Franklin Lake prior to entering Ditch 3.

Project Schedule & Cost

This is a multi-year project. The draft design and spillway channel brushing occurred in 2014. Spillway channel surveying occurred in 2015, allowing ATCO Electric Yukon to update the design model and adjust the design accordingly. Rough grading, general fill, rip rap and filter rock supply and placement, and new discharge structure construction are scheduled to occur in 2016.

This project that was approved in ATCO Electric Yukon's 2013-2015 GRA for $1,640,000. The updated cost forecast of $3,049,000 is as follows:

Year	Actual ($000s)	Forecast ($000s)	Total ($000s)
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	**134**	**2,915**	**3,049**

The primary drivers for the cost increase between the previous forecast submitted in the 2013-2015 GRA are as follows:

Spillway Structure

The draft design consisted of a rock lined soil berm as a fixed crest overflow and included a single 600mm diameter culvert complete with slide gate/headwall. The final spillway design changed from the original concept of a simple fixed crest weir to the current 4 gated box culvert design and resulted in a $480,000 increase to the forecast.

Operationally, the fixed crest weir would not have functioned well as a control point for regulating Franklin Levels as required within ATCO Electric Yukon's water licence HY12-065. Flow within the single culvert would have required very high levels in the ditch with minimal freeboard. Secondly, the Ditch would have had to reach near full capacity prior to the spillway becoming active (reactive control to an event). The new design allows controlled flow to Franklin Lake for regulating levels all while Ditch 3 levels are normal. Further, the spillway can be utilized pro-actively in the case of an event that can be reasonably forecasted.

Rock Quantity within Spillway Channel

The required rock quantity within the spillway channel increased as a result of detailed survey information that was not possible at the time of the conceptual design. This resulted in a $530,000 increase to the forecast.

The channel had to be extended 50 meters at the Franklin Lake end to ensure the still basin would discharge at or near operational levels in Franklin Lake. Approximately 20 meters of additional channel was realized due to modifications to the spillway pilot channel and overall channel alignment. Overall, the channel saw approximately 10% increase in length. The lineal channel greater than 5.5% slope increased by 7%. The steeper channel requires additional rock armor protection.

Business Drivers and Benefits

Water Licence Compliance

ATCO Electric Yukon is required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and current water licence HY12-065. ATCO Electric Yukon is required to be able to adequately and safely manage a flood event. ATCO Electric Yukon also seeks to minimize the use of the Louise Lake Auxiliary Spillway and provide controlled inflows into Franklin Lake.

Protection of Existing Infrastructure

With the current inability to release water from the Fish Lake Hydro system upstream of Ditch 3, the Drop Box and Ditch 3 infrastructure poses a risk of catastrophic failure and risks of impact to all remaining downstream infrastructure during an IDF event.

Evaluation of Viable Alternatives

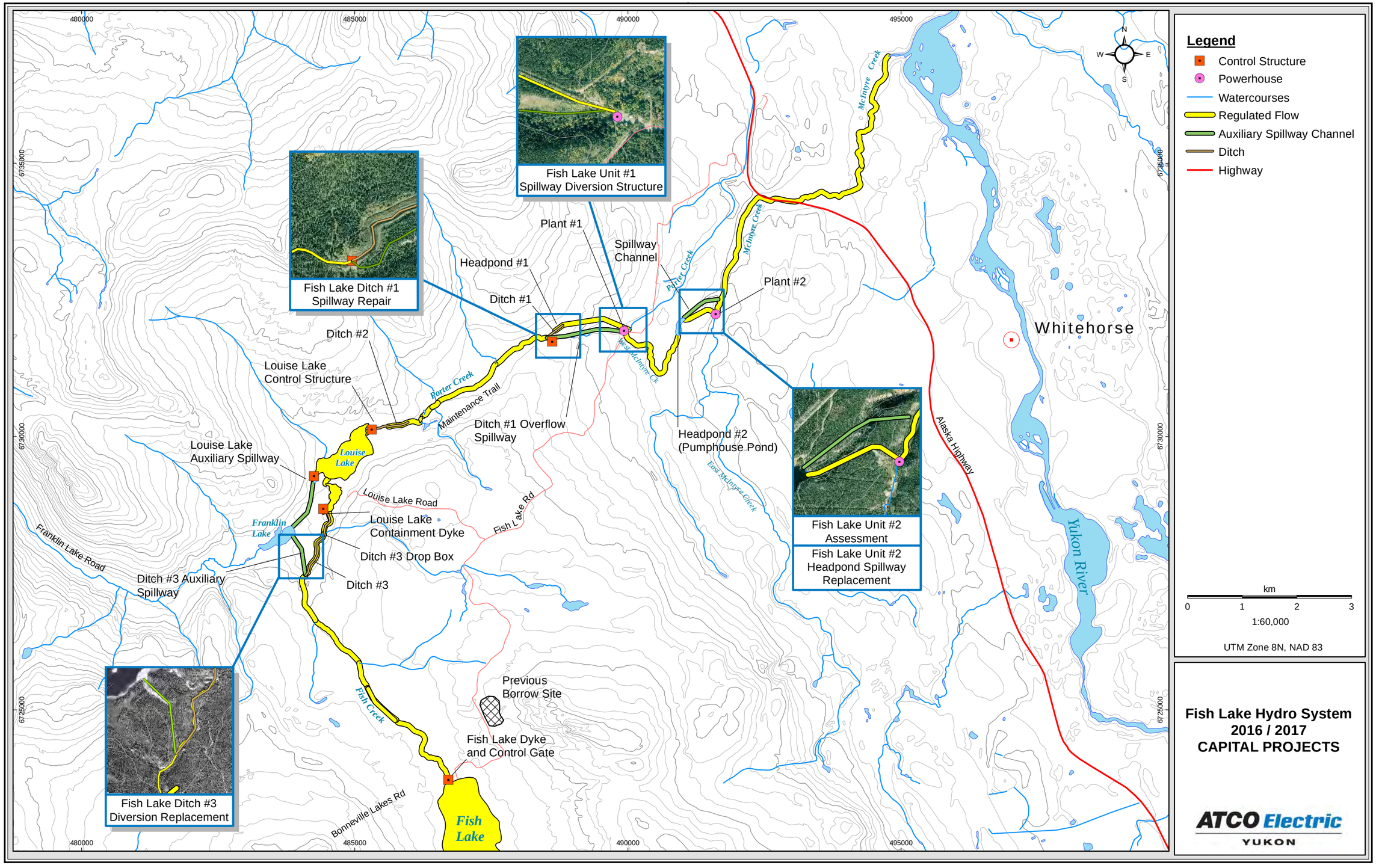
Alternative #1: Status Quo. This alternative could lead to future compliance issues with ATCO Electric Yukon's current water licence HY12-065. It also risks Fish Lake Ditch 3 infrastructure during an IDF event.

Alternative #2: Build a bypass structure at the Drop Box on Ditch 3. The bypass alternative was designed and studied; however the structure could still not adequately bypass 15.2m3/s of water flow which is the Inflow Design for Ditch 3. Ditch 3 infrastructure would still be at risk.

Alternative #3: Replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Recommendation

Replace and upgrade the Ditch 3 Diversion structure and spillway.


480000
485000
490000
495000
6735000
6730000
6725000
Fish Lake Unit #1
Spillway Diversion Structure
Fish Lake Ditch #1
Spillway Repair
Plant #1
Spillway
Channel
Headpond #1
Ditch #1
Plant #2
Ditch #2
Louise Lake
Control Structure
Porter Creek
Maintenance Trail
Ditch #1 Overflow
Spillway
McIntyre Creek
West McIntyre Ck
Whitehorse
Louise Lake
Auxiliary Spillway
Louise
Lake
Louise Lake Road
Louise Lake
Containment Dyke
Franklin
Lake
Franklin Lake Road
Ditch #3 Drop Box
Ditch #3 Auxiliary
Spillway
Ditch #3
Fish Lake Rd
Headpond #2
(Pumphouse Pond)
East McIntyre Creek
Fish Lake Unit #2
Assessment
Fish Lake Unit #2
Headpond Spillway
Replacement
Alaska Highway
Yukon River
Previous
Borrow Site
Fish Creek
Fish Lake Dyke
and Control Gate
Fish Lake Ditch #3
Diversion Replacement
Bonneville Lakes Rd
Fish
Lake
N
W
E
S
Legend
Control Structure
Powerhouse
Watercourses
Regulated Flow
Auxiliary Spillway Channel
Ditch
Highway
km
0
1
2
3
1:60,000
UTM Zone 8N, NAD 83
Fish Lake Hydro System
2016 / 2017
CAPITAL PROJECTS
ATCO Electric
YUKON

ATCO Electric YUKON

September 28, 2023 AEY-YUB-047

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-047

Reference: 2023-24 GRA, Business Case #07 – Replace Watson Lake Generating Units, PDF pages 17-24

Issue: N-1-1

Quote: AEY employs a risk management principle that generating facilities on isolated community grids must have sufficient capacity to meet their peak load despite the loss of one operating unit while another unit is undergoing maintenance (N-1-1 criteria). The capacity that can be met under this N-1-1 criterion is known as the facility's Firm Capacity.

…

Based on this recommendation along with operational experience, AEY believes it is more cost effective and secure to replace these three units rather than overhaul the units with a significant risk that the life extension provided will not last long enough for operations to recover the investment nor provide sufficient reliability for continuing operations.

…

AEY has observed marginal improvements after a major overhaul in operation and reliability of 1200 RPM generating units operating passed the 100,000-hour mark.

Request:

(a) How long has the stated criteria/risk management principle (N-1-1) been in place?

(b) Has the Board previously approved this principle? If so, please provide the reference citing the Board Order and reasons showing this was accepted by the Board.

(c) Please provide a copy of the policy (N-1-1) to which this principle applies.

(d) Please provide the economic analysis regarding the decision to overhaul or replace the Watson Lake generation units.

(e) For each of the Watson Lake units replaced in Business Case #07, provide the availability of each unit for each of the three years prior to replacement and the percentage of that availability that was utilized.

(f) Would other units that operate at a different RPM level be more efficient? Please explain.

(g) Please explain why Watson Lake #5 underwent a major overhaul in 2022 and not a replacement. Please provide your economic analysis.

(h) Since 2018, has AEY put out for tender all work related to either replacement or major overhauls of generation units? Please explain.

Response:

(a) AEY employs a qualitative approach to this risk management, with subjective experience used to define consequence and likelihood of events. As mentioned in the Asset Management gap assessment, AEY's enterprise risk management system is still evolving.

In practice, the application of this criterion considers several specific conditions in Watson Lake and to AEY's operation. For example, this site has larger generators than other sites. This means that a major overhaul can make a unit unavailable for 4-12 weeks, depending on scope and other factors observed recently. In addition, AEY does not own a mobile genset of comparable size to those installed in Watson Lake so a rental would need to be sourced immediately if a spare was needed. Watson Lake is 5 hrs from Whitehorse service center where technicians are based, and remote from any service contractor or supplier inventory. Watson Lake's peak load is seasonal and generally increasing, but fluctuating and therefore difficult to predict.

Therefore, it is possible for the largest unit to be out of service for maintenance (or due to a failure) for an extended period, which may include winter peak. Based upon AEY's ongoing operational experience, it is likely that within a 4-12 week period another unit would have an unanticipated trip - due to fault or protection or equipment failure. The result could be an outage in winter weather. The extent of the outage would be ~1000 customers in three communities, and its duration would depend on the cause of the trip. In a likely case, a critical part needs replacement and/or a tradesperson is required to repair – coming out of Whitehorse. In a worst case, parts are not available locally or more extensive repair is necessary.

Due to the foregoing, AEY has decided the risk of N-1 to be too great and N-1-1 is more appropriate to avoid the consequence of an outage in the Watson Lake Plant. This was reflected in the write-up for Business Case 3 and 13 in AEY GRA 2013-15.

(b) Although the N-1-1 criterion has not been specifically discussed in past Board Orders, the principle of risk management as applied to unit sizing and capacity of a generating plant was discussed extensively in the 2016-17 GRA, as shown in Volume 3, page 479 onwards of the transcript.[1][2] The Board has also approved prior replacements of units 4 and 2 at the Watson Lake generating plant in the 2013-2015 and 2016-2017 AEY GRA's respectively.

(c) AEY is proposing to develop an asset management program, which would include creation of strategic and specific asset management plans and progress on an enterprise risk management program (refer to METSCO report in BC #24) that is aligned with organizational goals. This would help articulate reliability objectives, operational risk mitigations, and maintenance practices for groups or classes of

[1] https://yukonutilitiesboard.yk.ca/pdf/YECL_GRA_2016-2017/YUB-YECL_2016-2017_GRA__Vol_3__November_3__2016_(unsecured)_.pdf PDF p. 94.

[2] https://yukonutilitiesboard.yk.ca/pdf/Board_Orders_2010/Board_Order_2017-01_Appendix_A_-_Reasons.pdf PDF p. 72.

assets under a framework of defined business values and asset performance principles. Furthermore, contingency and critical spares procedures would be developed and documented as equipment risks are identified, evaluated and mitigated.

(d) Beyond the identified lifespan, a genset's availability and utilization decrease and the cost to repair it increases, thereby increasing risk to the grid and to the ratepayer. AEY did not complete an economic analysis in the form of a lifecycle quantification of this risk, and comparison to specific alternatives, for the Watson Lake generation units. AEY has based its lifespan estimate for the generation unit, or replacement planning criteria, on industry practice and prior operating experience, having observed increased downtime and regular component failures as 1200 RPM units age beyond 100,000 hrs.

(e) Below is a summary of Key Performance Indicators (KPIs) published to the YUB, for three-years prior to each unit's commissioned replacement:

Table 1: Key Performance Indicators (KPIs)

Unit	Metric	2017	2018	2019	2020	2021
WL#1	Availability			99.36%	82.9%	72.1%
	Capacity			84.54%	94.5%	63.3%
	Operating			40.21%	47.7%	46.7%
WL#3	Availability	95.9%	99.81%	68.76%		
	Capacity	80.55%	81.15%	82.36%		
	Operating	16.62%	23.73%	34.76%		
WL#6	Availability		99.7%	99.5%	83.4%	
	Capacity		78.82%	80.91%	92.4%	
	Operating		37.43%	31.13%	29.2%	

(f) No. The referenced statement is intended convey that the lifespan for 1200 RPM units is 100,000 hrs. 1800 RPM units have a shorter expected lifespan and shorter recommended interval between overhauls such that they are less efficient in that respect.

(g) WL5 underwent a major overhaul at 37,276 hrs., or at an interval of approximately 22,500 hrs. since its last major overhaul. A replacement would be considered closer to its end of life at 80,000 hrs, since this is a 1800 RPM unit. end of life.

(h) AEY has conducted tendering or RFP processes for the referenced replacement projects including for equipment supply, engineering consultants, and installation contractors pursuant to ATCO's purchasing policy and sourcing and procurement guidelines. As described in Business Case #23 and AEY-UCG-085(b), AEY outsources major overhauls to qualified contractors. Since 2014, this has been conducted by a contractor on a Master Services Agreement with AEY.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-048

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-048

Reference: 2023-24 GRA, Business Case #35 – ArcticPharm Yukon's Independent Power Production (IPP) Site, PDF pages 135-137

Issue: Customer contribution

Quote: This is a fully contributed Customer-Driven Interconnection Project. AEY has an obligation to serve customers in (sic) with electrical supply.

Request:

(a) Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, then please explain any impact.

(b) Who is responsible for costs that exceed budget/forecast for the IPP projects? Please explain.

Response:

(a) There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

(b) The Independent Power Producer (IPP) customer is responsible for the costs of connecting the IPP project to the grid. The forecasts are used by the IPP to evaluate the feasibility of the overall project in the planning stage and to choose between options where applicable.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-049

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-049

Reference: 2023-24 GRA, Business Case #35 – ArcticPharm Yukon's Independent Power Production (IPP) Site, PDF pages 135-138; 2023-24 GRA, Business Case #36 – Haeckel Hill Customer Connection, PDF pages 139-143

Issue: Capital expenditures (New Extensions-IPP)

Quote: PDF page 136:

> 2. ArcticPharm has signed an Electricity Purchase Agreement (EPA) with Yukon Energy Company (YEC), and YEC has directed AEY to complete the required upgrades. AEY's customer for this project is YEC.

PDF page 140:

> 2. EHLP has signed an Electricity Purchase Agreement (EPA) with YEC, and YEC has directed AEY to complete the required upgrades. AEY's customer for this project is YEC.

Request:

(a) For each of the referenced business cases, please explain the nature of YEC's direction to AEY to complete the required upgrades?

(b) For each of the referenced business cases, please explain if AEY has completed the project in July 2023 as forecast. If not, please summarize the work completed to date and the revised date of completion of each project.

Response:

(a) For each of the referenced Business Cases, YEC provides direction to AEY through its review and approval of the design, cost estimate and schedule provided by AEY to YEC for IPP projects that connect to the Yukon Integrated System (YIS)

through AEY's distribution system. The reason for this process is that YEC has the "commercial" relationship with the IPP in the form of an EPA between YEC and the IPP. The EPA states how the financial terms of the agreement will be handled. Generally, the IPP is required to pay YEC up front for all new and upgraded infrastructure required to connect the IPP to the YIS. As YEC is required by the EPA to collect funds for construction of facilities to connect the IPP to the YIS whether directly from their system or through AEY's distribution system, YEC is responsible to ensure AEY is paid for the work completed as these projects are fully contributed by the IPP. This means that YEC becomes the "customer" for this project and is responsible to approve the work. This is no different than any other new customer extension attaching to AEY's distribution system.

(b) EHLP - As of September 15, 2023, all work on AEY's distribution system has been completed for this project to connect to the YIS.

ArcticPharm – As of September 15, 2023, AEY has completed the upgrades and new infrastructure to connect this project to the YIS. The outstanding work to be completed is programming protection settings into the new and existing devices on the portion of distribution system to which the IPP connects.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-050

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-050

Reference: 2023-24 GRA, Business Case #36 - Haeckel Hill Customer Connection, PDF pages 140-142

Issue: Customer contribution

Quote: This is a customer-driven interconnection project. AEY has an obligation to serve customers in the City of Whitehorse with electrical supply. This (sic) a fully customer contributed project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-051

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-051

Reference: 2023-24 GRA, Business Case #37 – Kluane Wind Turbine Integration, PDF pages 145-146

Issue: Customer contribution

Quote: This is a fully contributed customer-driven interconnection project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-052

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-052

Reference: 2023-24 GRA, Business Case #38 – Beaver Creek Photovoltaic Project, PDF pages 148-149

Issue: Customer contribution

Quote: This is a fully contributed customer-driven interconnection project.

Request:

Please confirm that this project will have no net impact on AEY rate base or revenue requirement. If not confirmed, please explain any impact.

Response:

There will be no net impact on AEY rate base assuming the contribution is applied to the relative capital project and not utilized to fund existing rate base. There will be a net impact on revenue requirement because the assets themselves are AEY assets and, as such, any operating and maintenance costs required for safe and reliable operation would be included in revenue requirement going forward.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-053

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-053

Reference: 2023-24 GRA, 2018-2022 Business Case #18 – New Services Overhead and Underground, PDF page 77, Table 1 and paragraph 4

Issue: Capital expenditures (New extensions)

Quote:

Project Schedule and Cost

Table 1: New Services Overhead and Underground ($000)

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
New Services Overhead and Underground	1,747	1,600	2,555	2,701	2,483	3,873	2,777	4,219	4,324

4. Customer driven services that are undertaken to meet customer needs. Most of these projects are fully funded. Further explanation is provided below for projects that are not fully funded where the net amount capitalized exceeds $100,000.

Preamble: It is not clear whether the amounts shown in Table 1 are net of contributions.

Request:

(a) Please clarify if the amounts shown in Table 1 are net of contributions. If confirmed, please breakdown Table 1 into rows which will show the total costs, the contribution amount received and the net amount. If not confirmed, please insert a row below Table 1 to provide the total contributions received for AEY's New Services Overhead and Underground.

(b) Referring to Table 1, given the significant increases in capital expenditures forecast for 2023-24 in comparison to the work completed in the prior years, please explain how AEY plans to complete the work associated with this project. Please

include an explanation addressing how AEY will prioritize the work associated with this project if faced with competing deadlines from other projects it has asserted are equally or more critical.

Response:

(a) Not confirmed. The amounts shown in Table 1 are only capital expenditures. Refer to the Table 1 below for contributions received for New Services Overhead and Underground.

Table 1: New Services Overhead and Underground Capital and Contribution Expenditure ($000)

	Actuals							Test Period	
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Capital Expenditures	1,747	1,600	2,555	2,701	2,446	3,846	2,777	4,219	4,324
Contribution	(870)	(477)	(994)	(2,218)	(1,525)	(2,574)	(2,895)	(3,634)	(3,243)
Net Total	877	1,124	1,561	483	921	1,272	(118)	585	1,081

(b) Please refer to the response to AEY-YUB-042(b). The new extension work will be bundled by service areas, be made shelf ready and contracted out as much as possible. This will allow company crews to focus on projects with more critical timelines.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-054

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-054

Reference: 2023-24 GRA, 2016-17 Business Case #01 – McIntyre Subdivision Rebuild Capital, PDF pages 1-7; 2023-24 GRA Schedules, S9.2, Line No. 191

Issue: Capital expenditures (Distribution Improvement)

Request:

(a) Please explain why the approved 2016-17 forecast capital expenditures shown on S9.2, Line No. 191 ($0.564 million and $0.924 million respectively) do not match approved 2016-17 forecast capital expenditures shown in BC#01, Table 1, for the same years ($0.740 million and $1.186 million respectively).

(b) Please prepare an actual-to-approved variance analysis for the years 2016-17 using the approved 2016-17 forecast capital expenditures shown on S9.2.

(c) Please explain why the 2023-24 forecast capital expenditures shown on S9.2 ($0.109 million and $1.244 million respectively) do not match the capital expenditures shown in BC#01, Table 3, for the same years ($0.521 million and $1.399 million respectively).

(d) Please prepare a life-to-date summary table (2013-2025) for the project and provide the actual capital expenditures incurred each year and the applicable forecast. Please confirm that all costs identified in the summary table remain in "construction work in progress". If not confirmed, please explain. Where applicable for a given year, please identify any costs that were the result of project scope changes.

Response:

(a) Business Case #01 was split into two different line items within Schedule S9.2 to differentiate between asset classes within the project.

Table 1 reflects the sum of the 2016 and 2017 approved values in line 191 and line 322 of S9.2.

(b) As noted in the response to part (a), Table 1 in Business Case #01 reflects the sum of the 2016 and 2017 approved values in line 191 and line 322 of S9.2. 2016 has a variance of 1 percent, which is an insignificant and reasonable amount. 2017 has a variance of -13 percent and, as mentioned in paragraph 8, “All the planned civil work was completed but the electrical installation and overhead powerline salvage was delayed to Q1 2018, which resulted in underspending in 2017.”

(c) Business Case #01 was split into two different line items within Schedule S9.2 to differentiate between asset classes within the project.

Table 3 reflects the sum of the 2023 and 2024 Test Period values in line 191 and line 322 of S9.2.

(d) Please refer to the table below for a summary by year of the McIntyre Subdivision Rebuild (including streetlights). Note that for the years 2016 to 2022 the costs of the streetlights were included in the overall rebuild cost on Schedule 9.2, AEY will update this presentation in the Compliance Filing to the Application.

McIntyre is a phased project and, as phases go into service, AEY has removed them out of work in progress and capitalized the costs. AEY has included these costs, net of accumulated depreciation expenses. AEY notes the net cost of capital has been included in the 2023-2024 Revenue Requirement on a prospective basis and AEY is not seeking retroactive recovery of returns or depreciation costs incurred for the period since its last GRA. The expenditures from 2013 to 2020 listed in the table below have been capitalized.

Table 1: Actual/Forecast vs Approved Costs
($000)

	Actual/Forecast				Approved		
Year	**Rebuild**	**Streetlight**	**Total**	**Year**	**Rebuild**	**Streetlight**	**Total**
2013	656	-	656	2013	475		475
2014	418	-	418	2014	250		250
2015	379	-	379	2015	-		-
2016	617	131	748	2016	564	175	739
2017	890	145	1,035	2017	924	254	1,178
2018	362	43	405	2018			-
2019	116	25	141	2019			-
2020	(81)	(10)	(91)	2020			-
2021	1,201	167	1,368	2021			-
2022	277	8	285	2022			-
2023	521	412	933	2023			-
2024	1,244	155	1,399	2024			-
2025	50	-	50	2025			-
Total	**7,159**	**567**	**7,726**	**Total**	**2,213**	**429**	**2,642**

Table 2: Costs Related to Scope Changes Since 2016-2017 GRA
($000)

Year	Cost due to Scope Change	Description of Scope Change
2013	50	Added pullbox as existing cables were deeper than expected.
2014	40	Added streetlights to wood poles to bring lighting to similar levels as previous underground fed lights. Added one overhead transformer to convert a service to overhead line.
2015	-	
2016	30	Added risers to keep mainline overhead along McIntyre drive instead of converting McIntyre to underground in stages as originally planned. These risers were for feeding local residential streets. Added streetlights to wood poles to improve lighting.
2017	115	Added 5 risers to feed local residential streets from McIntyre overhead mainline, extra trenching, an additional switch modular for operational need, and additional low voltage pedestals to serve residential lots. Added streetlights to wood poles to improve lighting.

Year	Cost due to Scope Change	Description of Scope Change
2018	100	Added 6 risers to feed local residential streets from McIntyre overhead mainline, added one switch modular for operational need, one additional transformer and one pedestal to serve residential lots.
2019	100	Additional conduit and trenching to account for system changes, new customers since McIntyre project started, and potential future development.
2020	-	
2021	-	
2022	-	
2023	120	Added a switch modular for operational need, 2 pull boxes, and one riser to keep mainline electrically connected.
Total	**555**	

September 28, 2023 AEY-YUB-055

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-055

Reference: 2023-24 GRA, 2016-17 Business Case #03 – 400 Amp Regulators in Logan Substation; 2023-24 GRA Schedules, S9.2, Line No. 214

Issue: Capital expenditures (Distribution Improvements)

Request:

Please provide a variance explanation for the increase in costs from those approved ($0.122 million) and the actual costs ($0.174 million) incurred.

Response:

The initial cost estimate developed for this project in January 2017 was $122,000. The estimate based on 2016 values equaled $141,000. The final build price came out to $174,000 due to increased cost of materials at the time the work was completed in [2017] compared to the cost of materials in [2016] used in the estimate.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-056

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-056

Reference: 2023-24 GRA, 2018-2022 Business Case #12 – Annual right of Way Widening, PDF page 52, paragraph 5; 2023-24 Business Case #26 - Annual Right-of-Way (ROW) Widening, PDF page 83, paragraph 5

Issue: Capital expenditures (Distribution Improvements)

Quote: Currently, AEY does not use any herbicide applications.

Request:

Please explain whether AEY has explored the use of herbicides for its required brushing work. If so, please provide any qualitative and quantitative cost-benefit analysis that was conducted during AEY's research respecting the use of herbicides. If not, please explain why.

Response:

To date, AEY has not explored the use of herbicides for annual ROW widening brushing work. This work involves removing older growth that had not previously been cleared to AEY standards or hazard trees outside the existing ROW. This vegetation is to be removed at the time of brushing activities.

The brushing method of mowing ROW has proven to be effective in areas that have either been cleared of larger growth or have smaller species growth (willows etc.). Mowing provides a clear safe ROW for the public as it involves mulching of the vegetation as it is dispersed back to the ROW.

Herbicides are currently used at AEY substation sites. These locations are secured and gated to the public. These locations also contain critical electrical equipment which must

remain clear of vegetation for safe and reliable operation. These applications of herbicide are conducted annually.

ATCO Electric
YUKON

September 28, 2023 AEY-YUB-057

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

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The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-057

Reference: 2023-24 GRA, 2018-2022 Business Case #15 – Line Moves in Highway ROW, PDF page 67, paragraph 4

Issue: Capital expenditures (Distribution Improvements)

Quote: YK 1045669 AEY Powerline Relocation YG Alaska Hwy Crestview Phase 1 of 2;

- 25 kV relocate in Phase 1.
    - Phase 2 was deferred due to YG roadwork delay.

Request:

Please clarify if Phase 2 has been completed and, if so, provide a reference to where all relevant information respecting this project has been provided in AEY's GRA.

Response:

Phase 2 has not yet been started. AEY is awaiting confirmation from the Yukon Government regarding when this work will be required.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-058

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
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AEY-YUB-058

Reference: 2023-24 GRA, 2018-2022 Business Case #16 – Dual Rated Transformer Upgrade, PDF pages 69-72, paragraph 2; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Distribution Improvements)

Quote: This is a part of a larger long-term plan to modernize the electrical supply and increase capacity of the system in downtown Whitehorse. This project was initially contemplated in 2013 but due to slower than anticipated load growth it was deferred. It was revisited within the 2016-17 GRA and is an action item identified in appendix 9 to that filing.

Preamble: The Board is unable to confirm costs associated with this business case in AEY's 2023-24 GRA Schedules, S9.2.

Request:

(a) Please provide line number references to where the costs (2016-17 approved, 2016-2022 actual and 2023-24 forecast) for this project are reflected between the years 2016-2024 within GRA Schedules, S9.2.

(b) Please clarify if AEY received approval for the costs for this project as a part of the revenue requirement in a GRA, when it was "initially contemplated in 2013".

Response:

(a) These costs are reflected in lines 344 and 347 of AEY's 2023-24 GRA Schedules, S9.2. General Capitalizable Transformers and Transformers and Regulators.

(b) Yes. Board Order 2014-06 - ERRATA approved YECL's 2013-2015 revenue requirement. Business Case 24 in YECL's 2013 GRA submission speaks to changing out equipment to 25 kV rated equivalents, in pursuit of AEY's long term

Downtown voltage conversion plan. Downtown Whitehorse voltage conversion remains a key item in AEY's long term system plan as electrical load continues to grow in the area.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-059

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
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AEY-YUB-059

Reference: 2023-24 GRA 2023-24, Business Case #25 – New Substations - Mayo Road and Whistle Bend, PDF pages 67-81, paragraph 5

Issue: Capital expenditures (Distribution Improvements)

Quote: Two new substations will be built to support the North 25 kV system. The first – Mayo Road substation – will be near the intersection of Klondike Highway North and Takhini Hot Springs Road. The second – Whistle Bend 2 Substation – will be in the Northwest corner of the Whistle Bend community.

Preamble: The Board requires further detail for Business Case #25.

Request:

(a) AEY's business case forecasts the construction of two substations within a period of less than three years. Please provide a detailed construction timeline noting all approvals required by any person(s) or governmental body(ies) aside from the Yukon Utilities Board in order to proceed with the project at a given stage of the timeline.

(b) Please provide the comparative cost-benefit analysis prepared for each alternative, including the analysis of "previously completed substation projects and the main expected costs for each design."

(c) Please explain AEY's plans for material sourcing and availability with respect to these two substation projects. Please include in the response any unit and unit cost detail currently available by major material component (e.g., transformers, regulators, switches, land, etc.).

(d) Please provide a historical timeline (both forecast and actual timelines achieved) for the construction of AEY's last substation project build.

Response:

(a) Please refer to the following table for the detailed project schedule:

Table 1: Detailed Project Schedule

Task	2022	2023	2024	2025
Order long lead items (Tx, Reg)	Q1	Q3		
YG – Land Application	Q4	Q3		
Start Detailed Engineering		Q1, Q4		
Submit YESAB Application		Q1, Q3		
Order Major Equipment (Reclosers, Switch Cubes, Communication Bldg)		Q2, Q4		
HazCOM Design Review		Q3	Q2	
Receive YESAB Decision Document		Q3	Q3	
YG – Land Lease		Q3	Q3	
YG – Work in ROW Permit		Q3	Q3	
City – Development Permit			Q3	
Receive long lead items and major equipment		Q4	Q3	
Construction – Clearing, Grubbing, Geotechnical		Q4	Q3	
Construction – Undergrounds, Grading, Access Road			Q2, Q3	
Construction – Equipment, Concrete, and Cable			Q3	Q2
YG – Building Permit			Q3	
City – Building Permit			Q4	
Construction – Overhead, Communications, Interconnection			Q3	Q2

Blue = Mayo Road, Red = Whistle Bend

(b) Please refer to the following cost-benefit analysis prepared for each of the three alternatives, included as Table 6 in the Business Case. Please refer to AEY-YUB-059(b) Attachment 1 for the complete cost analysis table in Appendix B. It is important to note that the costs shown in the Attachment 1 do not represent the total project costs, only a comparative cost between Alternatives. A description of the method is written in section 3.4 of Attachment 1. Equipment and labour costs have also increased significantly above the base costs shown in Appendix B of Attachment 1 since Selkirk substation was built in 2017.

Table 2: Cost Benefit Analysis

				Alternative 1		Alternative 2		Alternative 3	
Criterion type	**Criterion**	**Criterion Weight**	**Threshold Value**	**Rating**	**Score**	**Rating**	**Score**	**Rating**	**Score**
Eliminatory	Additional Transformer Capacity	4	3	5	**20**	5	**20**	5	**20**
Eliminatory	Resolve Laberge Regulator Overload	4	3	4	**16**	4	**16**	4	**16**
Ranking-only	Improve System Voltage	2	3	2	**4**	4	**8**	4	**8**
Ranking-only	Ease of Switching/Operation	2	N/A	4	**8**	4	**8**	4	**8**
Ranking-only	Utilization of New Apparatus	3	N/A	4	**12**	2	**6**	4	**12**
Ranking-only	Project Cost	5	N/A	3	**15**	2	**15**	3	**10**
			Totals:	75		68		79	

(c) Delivery timelines for major materials are longer than in prior years, due to global supply chain and logistics constraints. ATCO does provide AEY with greater purchasing power and inventory access. Longest lead equipment (transformers,

regulators) is ordered in advance of the completion of detailed engineering, based on ATCO standards and consistent sizing and specifications.

Table 3: Mayo Road Substation
($000)

Major Equipment	Qty	2022	2023	2024
Transformer	1	400		-
Regulators	3	-	325	-
Switch Cubicles	2	-	50	-
Reclosers	2	-	150	-
Communication Bldg	1	-	40	-

Table 4: Whistle Bend Substation
($000)

Major Equipment	Qty	2024
Transformer	1	400
Regulators	3	110
Switch Cubicles	4	112
Reclosers	4	220
Communication Bldg	1	40

(d) The Selkirk substation timeline is outlined in the table below.

Table 5: Selkirk Substation Timeline

	Forecast Timeline	Actual Timeline
Start of land procurement/permitting	Sept 2013	Sept 2013
Substation design finalized	Mar 2015	Mar 2015
Land procurement/permitting is completed	Oct 2015	Oct 2015
Project Kick-off	Feb 2016	Feb 2016
Substation brushing complete	May 2016	May 2016
Civil construction starts	May 2016	May 2016
Electrical construction starts	May 2016	Sept 2016
Civil construction completed	Nov 2016	Nov 2016
Electrical construction completed	Nov 2016	Oct 2017[1]
Substation In Service Date	Dec 2016	Dec 2017

[1] Delay due to damaged material and winter weather conditions.

ATCO Electric
YUKON

Whitehorse North 25kV New Substation Analysis

Technical Appendix

Revision History

Revision	Date	Editor	Comments
R0.2		Ryan Grams	Document Created

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1. Problem Statement

The Whitehorse North 25kV system is expecting significant load growth over the next 5 years that cannot be adequately supported by the existing system. As identified in the Whitehorse North 25kV System Study conducted in October 2019, system upgrades will be required in order to handle both normal peak power levels and all N-1 contingency scenarios. To correctly address these issues, a combination of upgrades to existing infrastructure and the construction of new substations were considered, resulting in the development of 3 distinct solutions: a new Whistlebend Substation (WB2), a Takhini Hot Springs Road Substation (TK1) with upgrades to Laberge, and a combination of a new Takhini Hot Springs Road Substation and a new Whistlebend Substation.

2. Background

A study of the North 25kV system was completed in order to analyze the system's ability to support new load growth over the next 5 years (up until 2025). The study found 3 key system deficiencies: the Laberge regulators are expected to over-current at peak loads in 2025, the North 25kV system peak load will not be able to support a single 25/34.5kV transformer outage in 2025, and presently the North 25kV system cannot support a primary 34.5kV bus outage at Whistlebend. These deficiencies are based on expected system peak loads that were created through a combination of historical loading and planned upcoming developments. Based on 2016-2018 data, Whitehorse peak loading increased at a rate of 3% per year and it is assumed that typical loads will grow at this rate for the 5-year planning period. Additionally, large new load additions in the form of Whistlebend stages 4 through 7 and new construction on Takhini Hot Springs road have been forecast on top of the 3% as they are expected to add a combined 7MW of load by 2025. Altogether peak loading on the North 25kV system is forecast to increase from its current level of ~11MW up to ~21MW by 2025. For the following models analyzed in this study, all loading levels are based on expected peak customer loads in 2025 assuming unity coincidence factor among feeders (all feeders experience their peak at the same time, but not all customers necessarily peak simultaneously).

3. Evaluation Criteria

3.1 Equipment Capacity

As identified in the previous North 25 System planning study, over the next 5 years, expected load growth will result in new system requirements. Specifically, to maintain a robust system that can operate in any N-1 contingency without large system failure, additional 34.5/25kV transformer capacity is required. This is mainly due to the potential scenario where the primary bus to Whistlebend undergoes an outage, taking both T1 and T2 offline. In order to maintain service to the Whistlebend subdivision in this scenario, at a bare minimum 10.7MVA of additional transformer capacity is required (assuming switching allowed all other transformers to divide load evenly). In reality, additional transformer capacity of 15-20MVA is required depending on where it is located in the system.

Additionally, based on current expected loading levels, it is expected that Laberge Regulators (R50, R51, R52) will be overloaded by 2025. Therefore, any potential solution must address this problem by either off-loading from Laberge to another source, or by upgrading these regulators.

3.2 Contingency Scenarios

After analyzing all of the possible N-1 contingency scenarios that could face the North 25kV system, the following 2 scenarios were identified as requiring system upgrades at or before 2025:

Contingency 1: The loss of a single 10MVA 34.5/25kV transformer in the North 25kV system. At present configuration, a loss of any of the 3 sub-transmission transformers would create a system overloading issue with 2025 expected loading levels, however it was determined that a loss of Laberge would be the worst-case of the 3. This is mainly due to the increased voltage-drop issues when Crestview and the highways are supplied by Whistlebend.

Contingency 2: The loss of the primary 34.5kV bus at Whistlebend Substation, resulting in an outage to both Whistlebend transformers. This scenario results in all of the load currently serviced by Whistlebend transformers requiring an alternative source. Present-day loading levels in this scenario would already exceed the capacity of Laberge's single transformer and 2025 loading levels are expected to intensify this problem.

3.3 Voltage Improvement

As feeder loading grows to the expected 2025 levels, the North 25kV system will experience wide-spread under-voltage (below 0.95 p.u.) along both the Alaska and Klondike Highways North. These problems can be addressed by the addition of regulators, however to minimize the risk of load rejection, it is preferred that system additions improve voltage levels by decreasing the resistance between a source and load (e.g. shortening the length of line from substation to customer transformer). For equal comparison of all options, all new substation voltage regulators proposed have been modelled with a setpoint of 124V.

3.4 Cost Analysis

As a regulated utility, it is important that all costs are necessary and justifiable. Intrinsic to this, is the requirement to choose the most cost-effective option when comparing equivalent options. Within Section 4: Proposed Solutions, the 3 solutions presented all aim to solve the same goals, however they do so in different ways and therefore cannot be solely analyzed based on cost alone. To compare these options, a decision matrix was developed to provide a clear grading scheme for evaluating the 3 proposed solutions (see Section 5).

The cost section of the decision matrix has been assigned the largest relative weighting and will therefore have a significant impact on each solution's final score. To determine estimate costs for these solutions, a relative-costing strategy was utilized. Instead of comprehensively listing every item that is expected to be required, items of insignificant cost or items that are common to all solutions were ignored and the costs for unique or large items in each proposed solution

were totaled. This provides a relative difference in estimated costs among the 3 alternatives without requiring a comprehensive estimating process.

3.5 Protection Settings and System Re-Configuration

All of the 3 proposed solutions will require new protection settings for the north 25kV feeders and some system reconfiguration/redistribution of the existing reclosers and other protective devices. As these requirements will be common to all solutions, they have not been included as part of this study and will be considered outside of the analysis scope.

4. Proposed Solutions

Using the evaluation criteria listed above, the following solutions have been developed:

4.1 Option A: Whistlebend Substation 2 (WB2)

4.1.1 Overview

The first proposed solution focuses around the construction of a new substation situated west of Whistlebend Stage 7 along existing 25kV line 5L648. This substation would primarily service two load centres: Whistlebend stages 4-7 and line 5L645 serving the Alaska and Klondike Highways north of Whitehorse. By servicing these areas, WB2 will offload approximately 6MW from Laberge Substation and 6.5MW from Whistlebend.

4.1.2 Equipment/Apparatus Requirements

In order to meet the 2025 system requirements detailed in section 3.1, WB2 needs to provide at least 10.7MVA of 34.5/25kV transformer capacity to the North 25kV system. To meet this target, as well as to provide opportunity for future growth along the North 25kV system, WB2 would include 2 separate 10MVA transformers, 6 matching 400A 25kV regulators, and 3 SCADA-controlled 630A substation reclosers. During regular operation, these breakers would service the Alaska and Klondike Highways north of Whitehorse, Whistlebend stages 4-7, and a N/O hot-spare to supply Whistlebend stages 1-3 through S3434 in the event of an outage on Whistlebend T1 or T2 (see section 4.1.4). A single-line diagram (SLD) for Whistlebend Substation 2 is included in Figure 1 below. A summary of the large apparatus required for this proposal is listed below:

- 2 x 10MVA 34.5/25kV Transformers
- 6 x 400A 25kV Regulators
- 3 x 630A 25kV Reclosers

Additionally, the regulators installed at Laberge Substation (R50, R51, R52) are still anticipated to be overloaded during a Contingency Scenario 2, therefore this apparatus will also require an upgrade. The next standard size of regulator AEY utilizes is rated for 400A and will adequately meet the expected loading on this device.

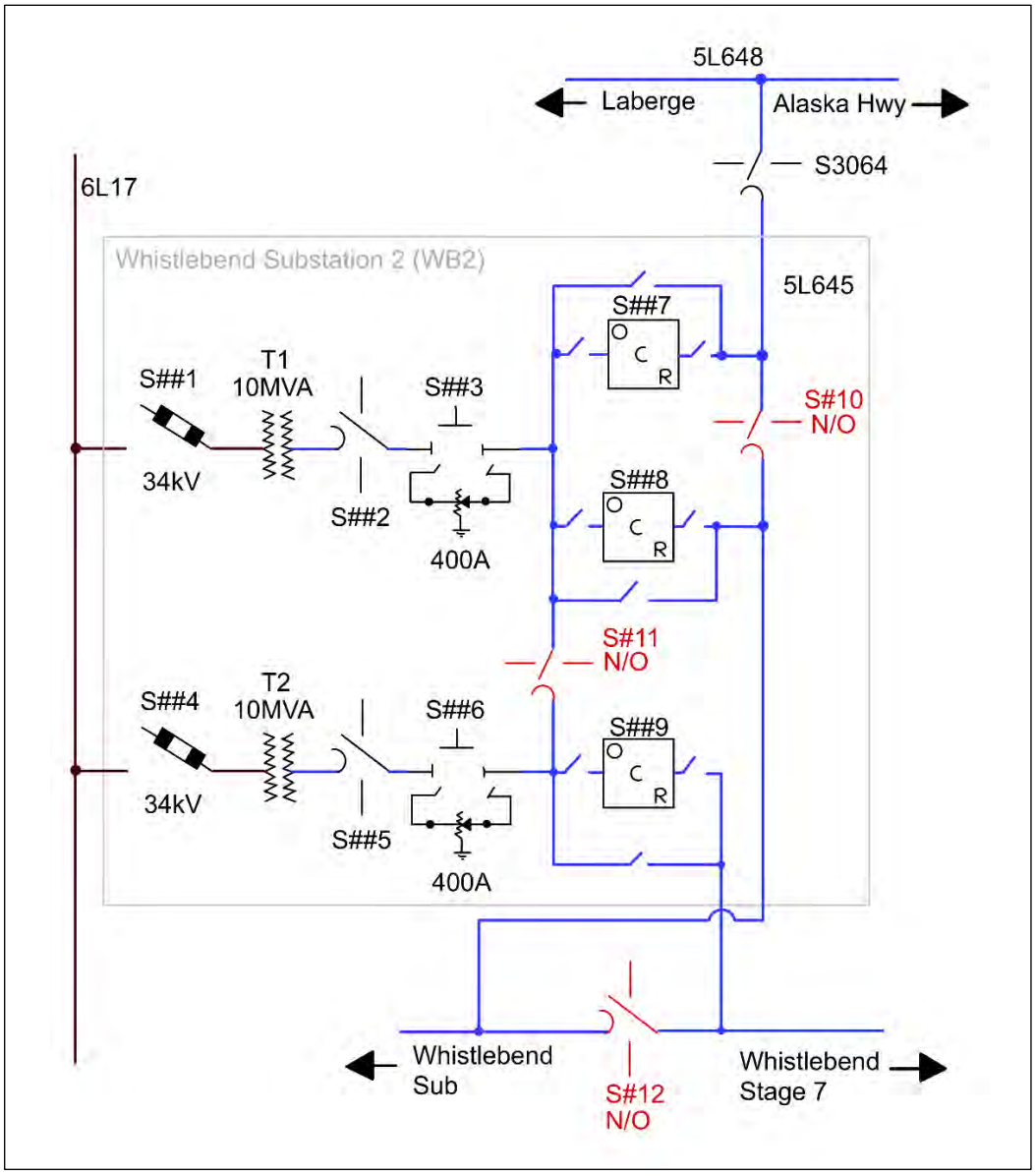


Figure 1: Whistlebend Substation 2 (WB2)

4.1.3 Additional System Improvement Requirements

In order to connect Whistlebend Substation 2 to the existing North 25kV system, the following switch points would be utilized:

- A recloser connecting WB2 Feeder 1 to 5L648 towards the highways (labelled as “S##7” in Figure 1)
- A recloser connecting WB2 Feeder 2 to Whistlebend Stage 7 (labelled as “S##9” in Figure 1)
- A recloser connecting WB2 Feeder 3 to serve as hot spare for Whistlebend Substation (labelled as “S##8” in Figure 1).

A comprehensive set of the switching devices required is displayed in Figure 1.

4.1.4 Contingency Operation

The proposed Whistlebend Substation 2 fully addresses the 2025 loading requirements for both of the contingency scenarios identified in Section 3. In Contingency scenario 1 (where the North 25kV system loses Laberge T1), WB2 will pick-up Laberge's load on its transformer T1 via new S##7 and back-feeding through Laberge's feeder breaker S3600 on 5L648. A possible switching program to achieve this is as follows: Isolate Laberge T1 using gang-switch S8302 and close-in the N/O breaker S3600.

In Contingency scenario 2 (where the North 25kV system loses Whistlebend T1 and T2 due to a primary bus outage), WB2 will pick up Whistlebend's load via Feeder 3. A possible switching program to achieve this is as follows: Isolate Whistlebend T1 and T2 using the transformer disconnects, close-in N/O switch S3434, and feed Whistlebend Substation from S##8 at WB2.

The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 1. As shown, during 2025 peak system loading and the N-1 contingencies, all equipment will be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	10MVA	2.109MVA	0MVA	8.907MVA
LB Regs (R50, R51, R52)	**400A**	48A	0A	206A
LB Reclosers S3600	630A	2A	48A	158A
LB Reclosers S8306	400A	47A	48A	48A
WB Transformer T1 (458)	10MVA	3.861MVA	3.864MVA	0MVA
WB Transformer T2 (456)	10MVA	5.873MVA	5.875MVA	0MVA
WB Regs (R107, R108, R109)	400A	137A	138A	0A
WB Regs (R110, R111, R112)	400A	90A	90A	0A
WB Recloser S3431	630A	15A	15A	12A
WB Recloser S3432	630A	75A	75A	77A
WB Recloser S3433	630A	137A	138A	139A
WB Recloser S3434	630A	0A	0A	231A
WB2 Transformer T1	**10MVA**	6.571MVA	8.922MVA	8.926MVA
WB2 Transformer T2	**10MVA**	2.535MVA	2.536MVA	3.565MVA
WB2 Regs (on T1)	**400A**	156A	208A	207A
WB2 Regs (on T2)	**400A**	59A	59A	82A
WB2 Recloser 1	**630A**	0A	0A	207A
WB2 Recloser 2	**630A**	156A	208A	0A
WB2 Recloser 3	**630A**	59A	59A	82A

Table 1: Modelled system loading if the proposed WB2 substation is constructed (new equipment in bold)

4.1.5 System Voltage Improvement

Voltage levels at various locations throughout the system, including substation equipment and end-of-line customers are present in Appendix A. Overall, the system would experience a 7.22% voltage improvement across the North 25kV substations and a 0.5% voltage improvement for End-of-Line (EOL) customers compared to how the current system configuration would perform with 2025 peak loading levels.

4.1.6 Estimated Costs

Estimated relative costing for this option totaled to $1,753,772. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

4.2 Option B: Laberge Upgrade & Takhini Hot Springs Road Substation (TK1)

4.2.1 Overview

This solution involves a 2-part approach to meeting the desired system capabilities: upgrading Laberge Substation and constructing a new 10MVA substation near the intersection of Takhini Hot Springs Road and Klondike Highway North. The new substation will service all of the 25kV System on Alaska Highway and Klondike Highway north of Whitehorse. This area was previously serviced by Laberge Substation and will offload approximately 6MW of loading from Laberge, while improving the voltage levels along the highway and lowering the conductor resistive losses along 6L17. Upgrades to the Laberge substation will focus around a new 20MVA transformer to replace the existing 10MVA.

4.2.2 Equipment/Apparatus Requirements

To fully meet the expected 2025 system requirements, this solution proposes the addition of a new substation TK1 and upgrades to the existing Laberge Substation. At TK1, there would be a single 10MVA transformer, paired with a set of 400A regulators. This regulator would then feed a single 630A SCADA-controlled recloser that would feed both the North Alaska Highway and the North Klondike Highway. An SLD of TK1 is shown below in Figure 2.

The scope of the upgrades to Laberge Substation include replacing the existing T1 with a 20MVA transformer, replacing the existing regulators with 578A rated models, and upgrading bus-bars and gang-switches as required to facilitate the output of 20MVA from this site. During regular operation, Laberge is only anticipated to be loaded at ~2MVA and mainly servicing the Crestview area, as there would be more system loss if this substation was to feed any of the Whistlebend subdivision. This new transformer would therefore be lightly loaded, except during contingency situations. A summary of the large apparatus required for this proposal is listed below:

For TK1:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 1 x 630A 25kV Reclosers

For Laberge:

- 2 x 20MVA 34.5/25kV Transformer (1 for Laberge, 1 spare)
- 3 x 578A 25kV Regulators

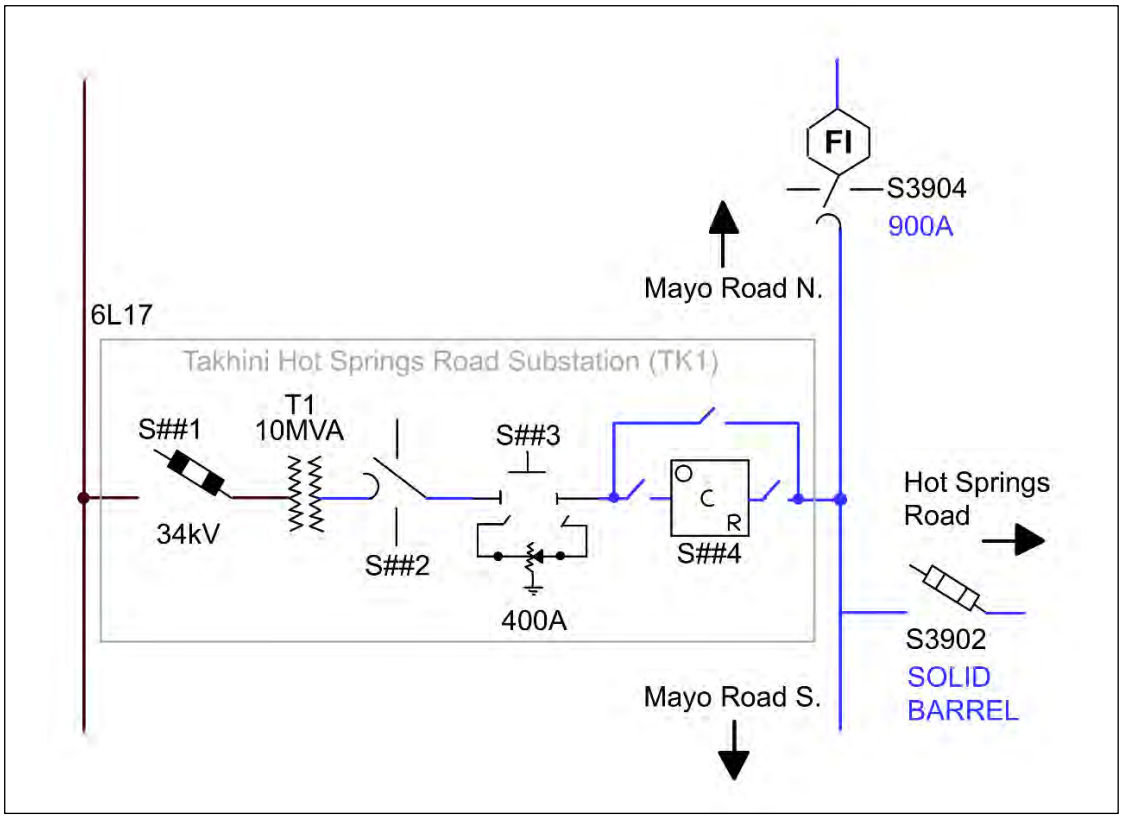


Figure 2: Takhini Hot Springs Road Substation (TK1)

4.2.3 Additional System Improvement Requirements

As this proposal already includes upgrades to resolve the expected overloading on the Laberge regulators, the only other system improvements will be the following additional switching points:

- A recloser connecting TK1 to the 5L648 along Klondike Highway North (labelled as "S##4" in Figure 2.)
- An inline N/O switch on 5L645 just north of the junction with 5L648. This will keep the hot-spare tie-in between Laberge and Whistlebend, while isolating the highways that will be supplied by TK1.

4.2.4 Contingency Operation

The proposed combination of a new Takhini Hot Springs Road Substation and upgrades to Laberge Substation would fully meet the expected loading requirements for N-1 contingency coverage in 2025. During Contingency Scenario 1 (loss of 34.5/25kV transformer at Laberge), the regular load serviced by Laberge would be transferred to Whistlebend Substation via recloser S3434. One possible switching operation to achieve this, would be to isolate Laberge T1 and then back-feed Laberge substation from Whistlebend's S3434 and feed through S3600 and continue to supply the Crestview area through S8306.

In the event of Contingency 2 (loss of primary bus at Whistlebend), the reverse of the Contingency 1 restoration will occur. Laberge will source the power for Whistlebend subdivision and feed through S3600 and feed into Whistlebend Substation through S3434 and the tie-in point at the edge of Stage 7. A possible switching program to achieve this would be: Isolate T1 and T2 at Whistlebend, close-in N/O S3434 to connect all 4 reclosers at Whistlebend, close-in stage-7 tie-in, close-in S3064 to tie 5L645 and 5L648 together, and close-in recloser S3600 at Laberge. The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 2. As shown, during 2025 peak system loading and the N-1 contingencies, all equipment will be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	**20MVA**	2.108MVA	0MVA	14.788MVA
LB Regs (R50, R51, R52)	**578A**	48A	0A	335A
LB Reclosers S3600	630A	2A	47A	291A
LB Reclosers S8306	400A	47A	47A	49A
WB Transformer T1 (458)	10MVA	6.456MVA	6.458MVA	0MVA
WB Transformer T2 (456)	10MVA	5.914MVA	8.104MVA	0MVA
WB Regs (R107, R108, R109)	400A	134A	185A	0A
WB Regs (R110, R111, R112)	400A	146A	147A	0A
WB Recloser S3431	630A	15A	15A	15A
WB Recloser S3432	630A	132A	132A	51A
WB Recloser S3433	630A	133A	135A	137A
WB Recloser S3434	630A	1A	50A	203A
TK1 Transformer T1	**10MVA**	6.650MVA	6.648MVA	6.648MVA
TK1 Regs (on T1)	**400A**	148A	148A	148A
TK1 Recloser 1	**630A**	108A	108A	108A

Table 2: Modelled system loading if the proposed TK1 substation is constructed and Laberge is upgraded (new equipment in bold)

4.2.5 System Voltage Improvement

Overall, the North 25kV system would experience a 9.35% voltage improvement across the 3 34.5/25kV substations if compared against how the current system configuration would perform with 2025 peak loading. End-of-Line customers are expected to have 1.9% voltage improvement as well.

4.2.6 Estimated Costs

Estimated relative costs for this option totaled to $2,005,650. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

4.3 Option C: Whistlebend Substation 2 (WB2) & Takhini Hot Springs Road Substation (TK1)

4.3.1 Overview

Similar to Option B, this option also takes a 2-part approach to meet the desired system capabilities, however this option involves the construction of 2 new substations: Takhini Hot Springs Road Substation (TK1) and Whistlebend Substation 2 (WB2). Identical to Option B, TK1 would be a 10MVA substation at the intersection of the Alaska Highway and Takhini Hot Springs Road. This substation would service the Alaska Highway and Klondike Highway sections of the North 25kV system, therefore offloading approximately 6MW from Laberge Substation. If selected, this option would involve the construction of WB2 with only a single 10MVA transformer and would be located near stage 7 of the Whistlebend Subdivision (same location as WB2 in Option A). This substation would service stages 4-7 of the Whistlebend subdivision during regular operation. This option places both substations close to the load-centres they would serve and would decrease electrical system losses as a whole.

4.3.2 Equipment/Apparatus Requirements

To be able to provide adequate power with 2025 peak loading levels and expected system expansions, this option proposes the construction of two new substations: TK1 and WB2. At TK1 (the same as proposed in Option B), there would be a single 10MVA transformer, paired with a set of 400A regulators and a single 630 SCADA-controlled recloser. A simplified model of TK1 is shown above in Figure 2.

The scope of equipment required for WB2 would be similar to TK1 with the addition of a second recloser. This substation would require a 10MVA transformer, 400A regulators for each phase and 2 separate 630A SCADA-controlled reclosers. One of the reclosers would feed directly into the Whistlebend subdivision through stage 7, while the other breaker would connect to 5L648 and would be a hot-spare to support either Laberge or Whistlebend in the event of an outage. A summary of the large apparatus required for this proposal is listed below:

For TK1:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 1 x 630A 25kV Reclosers

For WB2:

- 1 x 10MVA 34.5/25kV Transformer
- 3 x 400A 25kV Regulators
- 2 x 630A 25kV Reclosers

Additionally, the regulators installed at Laberge Substation (R50, R51, R52) are still anticipated to be overloaded during Contingency Scenario 2, therefore this apparatus will require an upgrade. The next standard size of regulator AEY utilizes is rated for 400A and will adequately meet the expected loading on this device.

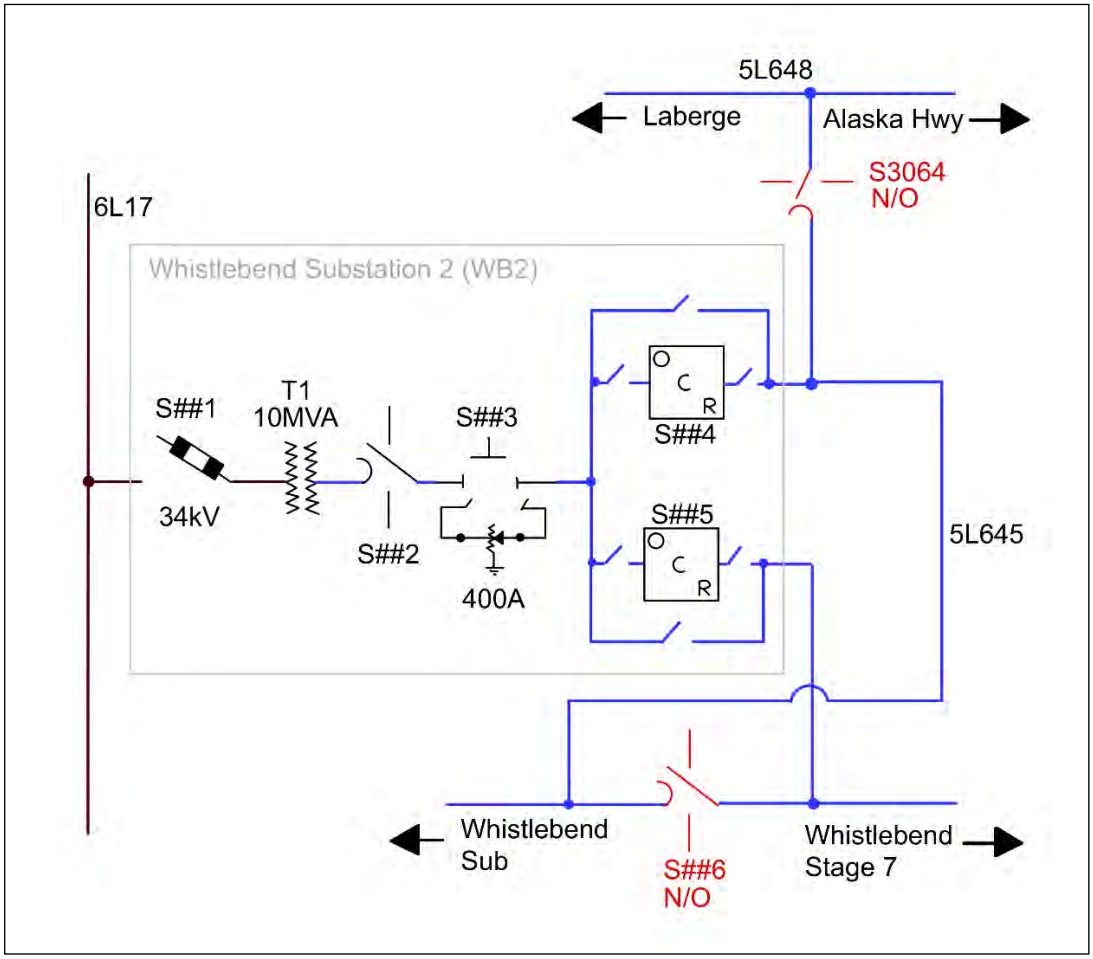


Figure 3: Whistlebend Substation 2 - 10MVA Option (WB2)

4.3.3 Additional System Improvement Requirements

This proposal includes the addition of 2 new substations, therefore it does require a few more switching points to be added than the other options provided:

- A recloser connecting TK1 to the 5L648 along Klondike Highway North (labelled as "S##4" in Figure 2.)
- Inline N/O switch on 5L645 just north of the junction with 5L648. This will keep the hot-spare tie-in between Laberge and Whistlebend, while isolating the highways that will be supplied by TK1.

- A recloser connecting WB2 to 5L648 (labelled as "S##4" in Figure 3.)
- A recloser connecting WB2 to Whistlebend Stage 7 (labelled as "S##5" in Figure 3.)

A comprehensive set of the switching devices required at WB2 is displayed in Figure 3.

4.3.4 Contingency Operation

The proposed combination of constructing a Takhini Hot Springs Road Substation and a new Whistlebend Substation 2 would fully meet the system requirements for 2025. In Contingency Scenario 1 (loss of 34.5/25kV transformer at Laberge), the load typically served by Laberge (~2MW in the Crestview area) would be picked-up by WB2. This would only require Laberge transformer to be isolated and then close-in S3064 to tie 5L648 and 5L645 together.

If the system was in Contingency Scenario 2, all of the typical Whistlebend load would need to be off-loaded to other substations. This could be most easily accomplished by using a combination of Laberge and WB2 to pick-up the stranded load. Laberge could feed into the Whistlebend Substation through S3434, while WB2 would continue to feed into stage 7 and could take on more of the Whistlebend load by moving the open point further downstream. The loading on all major substation equipment during normal system configuration and during both contingencies is presented below in Table 3. During 2025 peak system loading and the N-1 contingencies, all equipment would be operating within manufacturer recommended limits.

Asset Description	Loading Limit	Loading during Regular Operation	Loading during Contingency 1	Loading during Contingency 2
LB Transformer T1 (3516)	10MVA	2.213MVA	0MVA	9.043MVA
LB Regs (R50, R51, R52)	**400A**	50A	0A	204A
LB Reclosers S3600	630A	2A	49A	155A
LB Reclosers S8306	400A	48A	49A	49A
WB Transformer T1 (458)	10MVA	2.827MVA	2.827MVA	0MVA
WB Transformer T2 (456)	10MVA	5.930MVA	5.931MVA	0MVA
WB Regs (R107, R108, R109)	400A	134A	135A	0A
WB Regs (R110, R111, R112)	400A	64A	64A	0A
WB Recloser S3431	630A	14A	15A	15A
WB Recloser S3432	630A	49A	50A	0A
WB Recloser S3433	630A	134A	135A	137A
WB Recloser S3434	630A	0A	0A	152A
TK1 Transformer T1	**10MVA**	7.153MVA	7.153MVA	7.153MVA
TK1 Regs (on T1)	**400A**	159A	159A	159A
TK1 Recloser 1	**630A**	159A	159A	159A
WB2 Transformer T1	**10MVA**	3.563MVA	5.867MVA	5.787MVA
WB2 Regs (on T1)	**400A**	80A	132A	130A
WB2 Recloser 1	**630A**	80A	80A	130A
WB2 Recloser 2	**630A**	0A	52A	0A

Table 3: Modelled system loading if the proposed substations TK1 and WB2 are both constructed (new equipment in bold)

4.3.5 System Voltage Improvement

Overall, the North 25kV system would experience a 10.28% voltage improvement at the 3 34.5/25kV substations and a 2.0% voltage improvement for EOL customers if compared against how the current system configuration would perform with 2025 peak loading.

4.3.6 Estimated Costs

Estimated relative costs for this option totaled to $1,831,086. The cost breakdown is included in Appendix B.

NOTE: Costs for the construction of this substation were calculated relatively to the other options (as described in Section 3.4) and are used for comparison, not as a comprehensive total cost for construction of this solution.

5. Decision Matrix

To facilitate a comparison of the 3 proposed solutions, a decision matrix was developed based on the expected system requirements and key criteria for the planning window. The key criteria that resulted from the previous study of the North 25kV system are eliminatory elements on the decision matrix. Therefore, if any solution does not at least fully address these criteria, the solution would be removed from the running. The remaining non-key criteria are ranking-only and therefore do not have a minimum required score for a solution to pass. A summary of the decision matrix as well as the legend explaining the ranking process are included below in Table 4 and Table 5.

				Solution A		Solution B		Solution C	
Criterion type	**Criterion**	**Criterion Weight**	**Threshold Value**	**Rating**	**Score**	**Rating**	**Score**	**Rating**	**Score**
Eliminatory	Additional Transformer Capacity	4	3	5	**20**	5	**20**	5	**20**
Eliminatory	Resolve Laberge Regulator Overload	4	3	4	**16**	4	**16**	4	**16**
Ranking-only	Improve System Voltage	2	3	2	**4**	4	**8**	4	**8**
Ranking-only	Ease of Switching/Operation	2	N/A	4	**8**	4	**8**	4	**8**
Ranking-only	Utilization of New Apparatus	3	N/A	4	**12**	2	**6**	4	**12**
Ranking-only	Project Cost	5	N/A	3	**15**	2	**10**	3	**15**
			Totals:	75		68		79	

Table 4: Decision Matrix

Legend	
1	Does not address criterion (<50% of criteria)
2	Does not fully address criterion (>75% of criteria)
3	Fully addresses criterion (>95% of criteria)
4	Exceeds criterion (>125% of criteria)
5	Greatly exceeds criterion (>150% of criteria)

Table 5: Legend for Decision Matrix

6. Recommendation

Each proposed solution was individually evaluated against equipment loading limits, system voltage requirements, and restoration-switching guidelines. Additionally, among all of the proposed solutions, a comparative cost analysis was performed based on previous completed substation projects and the main expected costs for each design. After inputting the results into a decision matrix and totaling the data, it was determined that Solution C is the recommended solution to meet the North 25kV system requirements. Solution B will include the construction of a new 10MVA substation on the north-west side of Whistlebend Subdivision, as well as the construction of a new 10MVA substation near the junction of Takhini Hot Springs Road and Klondike Highway North. This solution will meet all the key requirements and will well-position the North 25kV for future expansions beyond the 6-year planning window.

Appendix A: CYME Modelling Data

				Expected Loading							
		Loading Limit		Status Quo		Solution A (WB2)		Solution B (TK1 & Laberge Upgrade)		Solution C (TK2 & WB2)	
	Asset Description	kVA	Amps	kVA	Volts (p.u.)	kVA	Volts (p.u.)	kVA	Volts (p.u.)	kVA	Volts (p.u.)
Regular Operation	LB Transformer T1 (3516)	10000	N/A	8847	0.89	2109	0.911	2108	0.936	2213	0.935
	LB Regulators (R50, R51, R52)	N/A	200	8651	0.9657	2098	1.002	2098	1.006	2202	1.028
	LB Recloser S3600	N/A	630	6636	0.957	84	1.002	84	1.006	84	1.028
	LB Recloser S8306	N/A	400	2016	0.957	2014	1.002	2014	1.006	2118	1.028
	WB Transformer T1 (458)	10000	N/A	6467	0.888	3861	0.888	6456	0.914	2827	0.925
	WB Transformer T2 (456)	10000	N/A	5920	0.888	5873	0.888	5914	0.914	5930	0.917
	WB Regulators (T2)	N/A	400	5833	0.0976	5786	0.977	5831	1.006	5848	1.009
	WB Regulators (T1)	N/A	400	6360	0.977	3825	0.983	6356	1.006	2808	1.017
	WB Recloser S3431	N/A	630	638	0.977	637	0.983	637	1.006	637	1.017
	WB Recloser S3432	N/A	630	5723	0.977	3187	0.983	5719	1.006	2171	1.017
	WB Recloser S3433	N/A	630	5788	0.976	5786	0.977	5786	1.006	5848	1.009
	WB Recloser S3434	N/A	630	45	0.976	0	0.977	45	1.006	0	1.009
	New Sub T1	10000	N/A	0	N/A	6571	0.894	6650	0.97	3563	0.929
	New Sub T2	10000	N/A	0	N/A	2535	0.903	0	N/A	7153	0.97
	New Sub Reg 1	N/A	400	0	N/A	6652	0.984	6564	1.026	3534	1.022
	New Sub Reg 2	N/A	400	0	N/A	2520	0.993	0	N/A	7058	1.028
	New Sub Recloser 1	N/A	630	0	N/A	0	0.984	6564	1.025	3507	1.028
	New Sub Recloser 2	N/A	630	0	N/A	6652	0.984	0	N/A	0	1.028
	New Sub Recloser 3	N/A	630	0	N/A	2520	0.993	0	N/A	7058	1.022
Contingency 1*	LB Transformer T1 (3516)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	LB Regulators	N/A	200	0	N/A	0	N/A	0	N/A	0	N/A
	LB Recloser S3600	N/A	630	2016	0.92	2016	0.964	2014	0.995	2119	1.008
	LB Recloser S8306	N/A	400	2345	0.938	2016	0.964	2014	0.995	2119	1.008
	WB Transformer T1 (458)	10000	N/A	10128	0.853	3864	0.884	6458	0.909	2827	0.922
	WB Transformer T2 (456)	10000	N/A	11057	0.859	5875	0.89	8104	0.902	5931	0.915
	WB Regulators (T2)	N/A	400	10709	0.938	5788	0.973	7942	0.992	5848	1.006
	WB Regulators (T1)	N/A	400	9846	0.944	3826	0.979	6357	1	2808	1.015
	WB Recloser S3431	N/A	630	638	0.944	637	0.979	637	1	637	1.015
	WB Recloser S3432	N/A	630	9208	0.944	3189	0.979	5719	1	2171	1.015
	WB Recloser S3433	N/A	630	2345	0.938	5788	0.973	5786	0.992	5848	1.006
	WB Recloser S3434	N/A	630	8364	0.938	0	0.973	2155	0.992	0	1.006
	New Sub T1	10000	N/A	0	N/A	8922	0.883	6648	0.97	5867	0.92
	New Sub T2	10000	N/A	0	N/A	2536	0.899	0	N/A	7153	0.97
	New Sub Reg 1	N/A	400	0	N/A	8719	0.971	6564	1.026	5845	1.012
	New Sub Reg 2	N/A	400	0	N/A	2520	0.989	0	N/A	7058	1.027
	New Sub Recloser 1	N/A	630	0	N/A	0	0.971	6564	1.025	3507	1.012
	New Sub Recloser 2	N/A	630	0	N/A	8719	0.971	0	N/A	2311	1.027
	New Sub Recloser 3	N/A	630	0	N/A	2520	0.989	0	N/A	7059	1.027

Contingency 2	LB Transformer T1 (3516)	10000	N/A	21707	0.826	8907	0.889	14788	0.916	9043	0.912
	LB Regulators	N/A	200	20186	0.888	8709	0.978	14584	1.007	8840	1.003
	LB Recloser S3600	N/A	630	18170	0.888	6693	0.978	12570	1.001	6722	1.003
	LB Recloser S38306	N/A	400	2017	0.888	2015	0.978	2015	1.007	2119	1.003
	WB Transformer T1 (458)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	WB Transformer T2 (456)	10000	N/A	0	N/A	0	N/A	0	N/A	0	N/A
	WB Regulators (T2)	N/A	400	0	N/A	0	N/A	0	N/A	0	N/A
	WB Regulators (T1)	N/A	400	0	N/A	0	N/A	0	N/A	0	N/A
	WB Recloser S3431	N/A	630	521	0.851	638	0.962	637	0.979	637	0.986
	WB Recloser S3432	N/A	630	3189	0.851	3190	0.962	2172	0.979	0	0.986
	WB Recloser S3433	N/A	630	5790	0.851	5789	0.962	5787	0.979	5849	0.986
	WB Recloser S3434	N/A	630	9500	0.851	9617	0.962	8596	0.979	6486	0.986
	New Sub T1	10000	N/A	0	N/A	8926	0.888	6648	0.97	5787	0.925
	New Sub T2	10000	N/A	0	N/A	3565	0.902	0	N/A	7153	0.972
	New Sub Reg 1	N/A	400	0	N/A	8717	0.976	6564	1.025	5709	1.017
	New Sub Reg 2	N/A	400	0	N/A	3534	0.992	0	N/A	7058	1.027
	New Sub Recloser 1	N/A	630	0	N/A	8717	0.976	6564	1.025	5709	1.017
	New Sub Recloser 2	N/A	630	0	N/A	0	0.976	0	N/A	0	1.027
	New Sub Recloser 3	N/A	630	0	N/A	3534	0.992	0	N/A	7059	1.027

End of Line Voltage:	93.2%	93.7%	95.1%	95.2%

Appendix B: Cost Estimates

Categories:	Selkirk (Inflated) Cost:	Option A		Option B		Option C	
		Multiplier	Cost	Multiplier	Cost	Multiplier	Cost
Contractor/Non-Stock							
Surveying	$13,728	1.5	$20,592	1	$13,728	2	$27,456
Overhead (Stock) Material							
Regulator (400A)	$29,326	9	$263,933	3	$87,978	9	$263,933
Regulator (578A)*	$40,292	0	$0	3	$120,876	0	$0
Overhead (Non-Stock) Material							
Timbers	$9,360	2.5	$23,400	1	$9,360	2	$18,720
Undergorund (Non-Stock) Material							
38kV Reclosers	$24,750	3	$74,250	1	$24,750	3	$74,250
10MVA 34.5/25kV Transformer	$189,357	2	$378,714	1	$189,357	2	$378,714
20MVA 34.5/25kV Transformer*	$500,000	0	$0	2	$1,000,000	0	$0
Contractor Work							
Oil Containment	$39,624	2	$79,248	1	$39,624	2	$79,248
Resistivity Testing	$7,097	1	$7,097	1	$7,097	2	$14,194
Contractor	$86,522	1.5	$129,783	1	$86,522	2	$173,044
Engineering Consultant							
Land Developing and Permits	$5,778	1	$5,778	1	$5,778	2	$11,556
AEY Overhead Construction							
Crew Overhead Construction	$75,966	2	$151,932	1.5	$113,949	2	$151,932
AEY Underground Construction							
Crew Underground Work	$12,839	2	$25,678	1.5	$19,258	2	$25,678
Contractor Civil Work							
Supply 3/4" Crush	$53,026	2	$106,053	1	$53,026	2	$106,053
Supply 6" Minus	$10,997	2	$21,994	1	$10,997	2	$21,994
Ducts and Trench	$16,680	2	$33,359	1	$16,680	2	$33,359
Concrete Cast in Place	$23,706	2	$47,412	1	$23,706	2	$47,412
Pre-Cast Vaults	$16,068	2	$32,136	1	$16,068	2	$32,136
Grounding Grid	$13,284	2	$26,568	1	$13,284	2	$26,568
Equipment Commissioning							
Techs	$33,977	2	$67,954	1	$33,977	2	$67,954
Project Lead							
EA	$13,358	1.5	$20,037	1.5	$20,037	2	$26,716
Project Engineering							
Engineering	$18,118	1.5	$27,177	1.5	$27,177	2	$36,236
Contractor Lead							
Contractor Lead	$12,955	2	$25,911	2	$25,911	2	$25,911
AEY Drafting							
Drafting	$6,512	1.5	$9,769	1	$6,512	2	$13,025
Substation Connection Costs							
Connection Costs*	N/A	N/A	$175,000	N/A	$40,000	N/A	$175,000
		Totals:	$1,753,772		$2,005,650		$1,831,086

*Equipment included in the scope of any of these options that was not included Selkirk's has been estimated using manufacturer quotes and current AEY Engineering estimating tools

ATCO Electric
YUKON

September 28, 2023 AEY-YUB-060

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-060

Reference: 2023-24 GRA, Business Case #29 – Old Crow Voltage Improvement, PDF pages 91-97, paragraph 2

Issue: Capital expenditures (Distribution Improvements)

Quote: During a 2021 system study for the addition of a new health center and 10 plex in Old Crow, it was noted that, after the addition, the voltage would drop below acceptable levels (0.95 p.u.).

Table 1: Voltage Level Analysis

Existing Worst Case Voltage Levels	Va	Vb	Vc
(p.u.)	0.914	0.921	0.933

Preamble: In tables 3 and 7 of this business case, AEY provides existing conditions and worst voltage A, B and C under various alternative solutions. Only Table 7 indicates an existing voltage that is below the acceptable level (0.95 p.u.).

Request:

(a) Please substantiate AEY's claim that the Old Crow Voltage Improvement project will resolve any existing voltage below the acceptable level (0.95 p.u.) by providing further information addressing the Board's observation.

(b) Please provide the comparative cost-benefit analysis prepared for each of the seven alternatives examined.

Response:

(a) Business Case #29 has been re-evaluated to help clarify the data used and the decisions arrived at. Please refer to AEY-YUB-60(a) Attachment 1. Some of the

voltage values and evaluated alternatives may differ; however, the recommended solutions remain the same. Differences in voltage values are due to model updates and load growth. The original Business Case #29 has been completed with 2021 data, whereas the re-evaluated Business Case utilizes 2022 and 2023 data. Please refer to AEY-YUB-060(a) Attachment 2 for the updated data. The recommendations from the original Business Case and the re-evaluated Business Case remain the same.

(b) Costs have been added to alternatives listed in AEY-YUB-60(a) Attachment 1. The recommended alternatives best meet the driver needs at the least cost.

ATCO Electric
YUKON

2023-2024 General Rate Application (GRA)

Old Crow Voltage Improvement

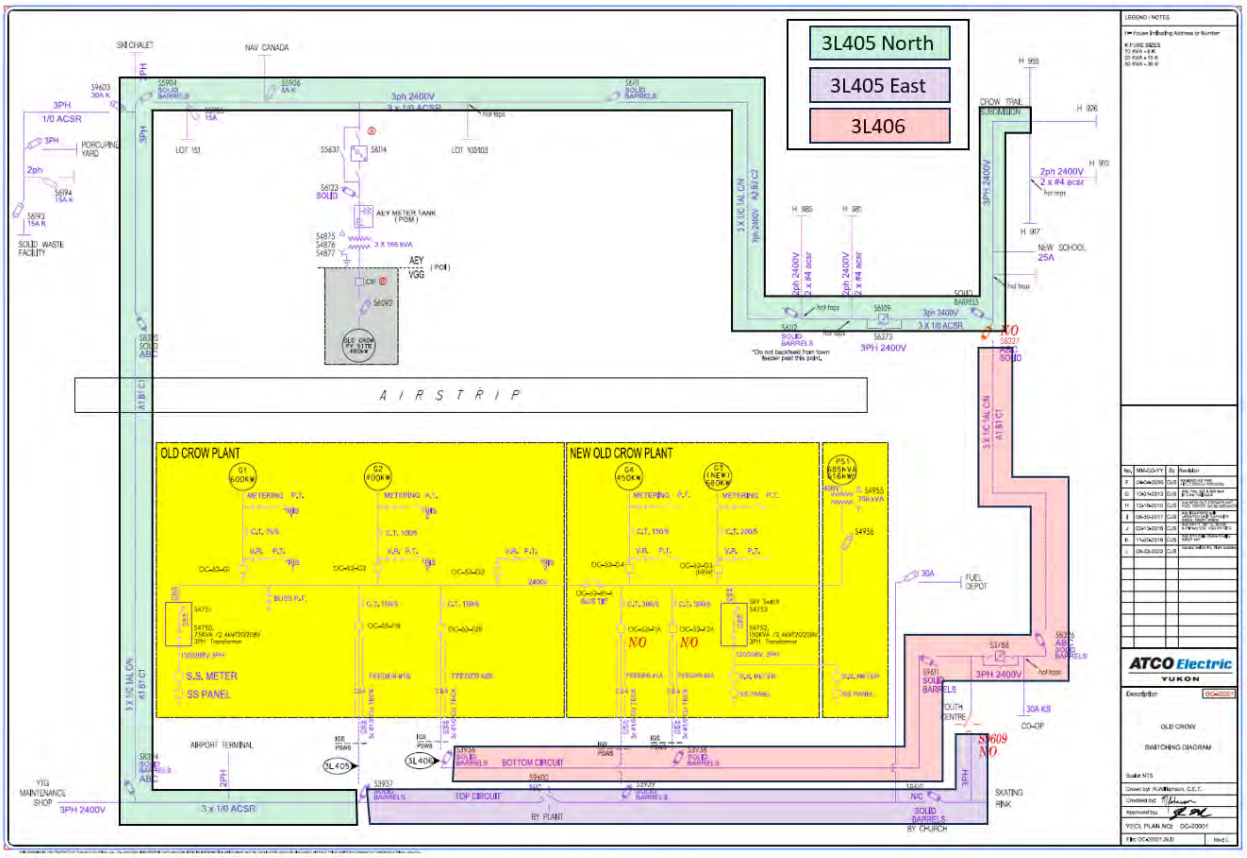
2023-2024 Business Case #29 (Updated)

Executive Summary

1. Old Crow has continued to see an increase in load growth year after year. New peak loads are straining the Old Crow system to a point where AEY cannot reliably provide electricity that is within voltage standards greater than 0.95 Vpu. This deficiency is caused by long distances between generation and customers, size of primary conductors, and the overall primary system voltage.

Background

Figure 1: Old Crow SLD


3L405 North
3L405 East
3L406
A I R S T R I P
OLD CROW PLANT
NEW OLD CROW PLANT
S.S. METER
SS PANEL
AEY METER TANK (PSM)
AEY YGG (POI)
FUEL DEPOT
SKATING RINK
ABORIGINAL CENTRE
ABORIGINAL CHURCH
ABORIGINAL CEMETERY
ABORIGINAL CEMETERY
ABORIGINAL CEMETERY

generation with BESS charging. These dates were chosen so that the Old Crow system would be diesel-off (i.e., the Old Crow system is solely powered by the PV array and battery).

Scenario 1: BESS-only generation

Historical data shows a peak in BESS generation on July 3, 2023, at 10:20 pm equaling 241 kW. Since the BESS is connected at the plant, and the modelling goal is confirming voltage levels and not fault current, this scenario was modeled in CYME with all generators connected with voltage set at 1.01 Vpu (BESS set point), and the model loaded at 33 percent (to match measured BESS output).

Note - The BESS has the capability to generate up to 685 kW of power which is why all generators were left active in the model.

Scenario 2: PV generation with BESS charging

The peak load on the system – less BESS charging – was found on July 3, 2023, and equaled 322 kW. To model this scenario a generator was placed at the PV array site, all diesel generators at the main plant were disconnected, the BESS was set to charge at 95 kW, and the model was loaded at 44 percent. The voltage setpoint for the PV site was set to 1.05 Vpu, resulting in a 1.01Vpu measurement at the plant bus (BESS setpoint voltage).

No low voltage issues were found when analyzing the Old Crow system during summer conditions.

Winter

The CYME model is run at 100 percent which is equal to peak winter loading.

Table 1: Old Crow Voltages

Study Area	Summer Loading – Scenario 1 (Worst Vpu)	Summer Loading – Scenario 2 (Worst Vpu)	Winter Loading – No PV (Worst Vpu)
3L406	A – 0.977 B – 0.970 C – 0.976	A – 0.968 B – 0.957 C – 0.961	A – 0.928 B – 0.904 C – 0.923
3L405 North	A – 0.974 B – 0.976 C – 0.977	A – 0.984 B – 0.985 C – 0.986	A – 0.918 B – 0.923 C – 0.927
3L405 East	A – 0.995 B – 0.996 C – 0.993	A – 1.002 B – 1.001 C – 0.995	A – 0.984 B – 0.986 C – 0.978

Voltages that fall below AEY standards were found on 3L406 and 3L405 North. Upgrades must be completed to fix the low voltages issues.

Project Description

This project includes reconductoring two main feeders in Old Crow: 3L406 and 3L405 East. Existing conductor sizes on 3L406 range from #4 ACSR to #6 ACSR and will be reconductored between the Old Crow diesel plant and recloser S3788 with 1/0 ACSR. The 3L405 East feeder that services customers on the East side of the Old Crow Diesel Plant is also a combination of #4 ACSR and #6 ACSR that will be reconductored to 1/0 ACSR between S3937 and S9609. This also includes reconductoring the tap to the Old Crow skating rink to 1/0 ACSR. Furthermore, a new regulator will be installed near the Old Crow PV Site as seen in Alternative 1.1.

Project Schedule and Cost

Table 2: Project Schedule and Cost ($000)

Date		Cost
2023	Regulator Addition	$710
2024	Reconductor 3L406 and 3L405 East	$464
Total		**$1,174**

Business Drivers and Benefits

The main driver behind the regulator addition and reconductoring is to raise the voltage at customer's service points to a level that is at or above AEY's minimum supply voltage standards. Not only will the voltage levels be within standard after the completion of the upgrades, but system capacity will also be increased due to the infrastructures capabilities to provide energy at adequate voltage levels. This will ensure that growth in Old Crow can continue, and electricity demand can be met.

Evaluation of Viable Alternatives

There are three problems within the Old Crow system that are addressed in the alternatives below:

1. Low voltage on 3L405 North during Winter loading,
2. Low voltage on 3L406 during Winter loading, and
3. Capacity on 3L405 East.

For modelling each alternative, the modification specified in each option was added, with no changes to system loading. The new worst EOL voltage was recorded.

To determine an approximate load growth capacity, load was added until the worst end-of-line voltage hit 0.95 Vpu.

1. Alternatives for Low Voltage on 3L405 North

Alternative 1.1 - Regulator Bank on 3L405 North

Project Scope: $710,000

- 100A 2.4kV Regulator Bank

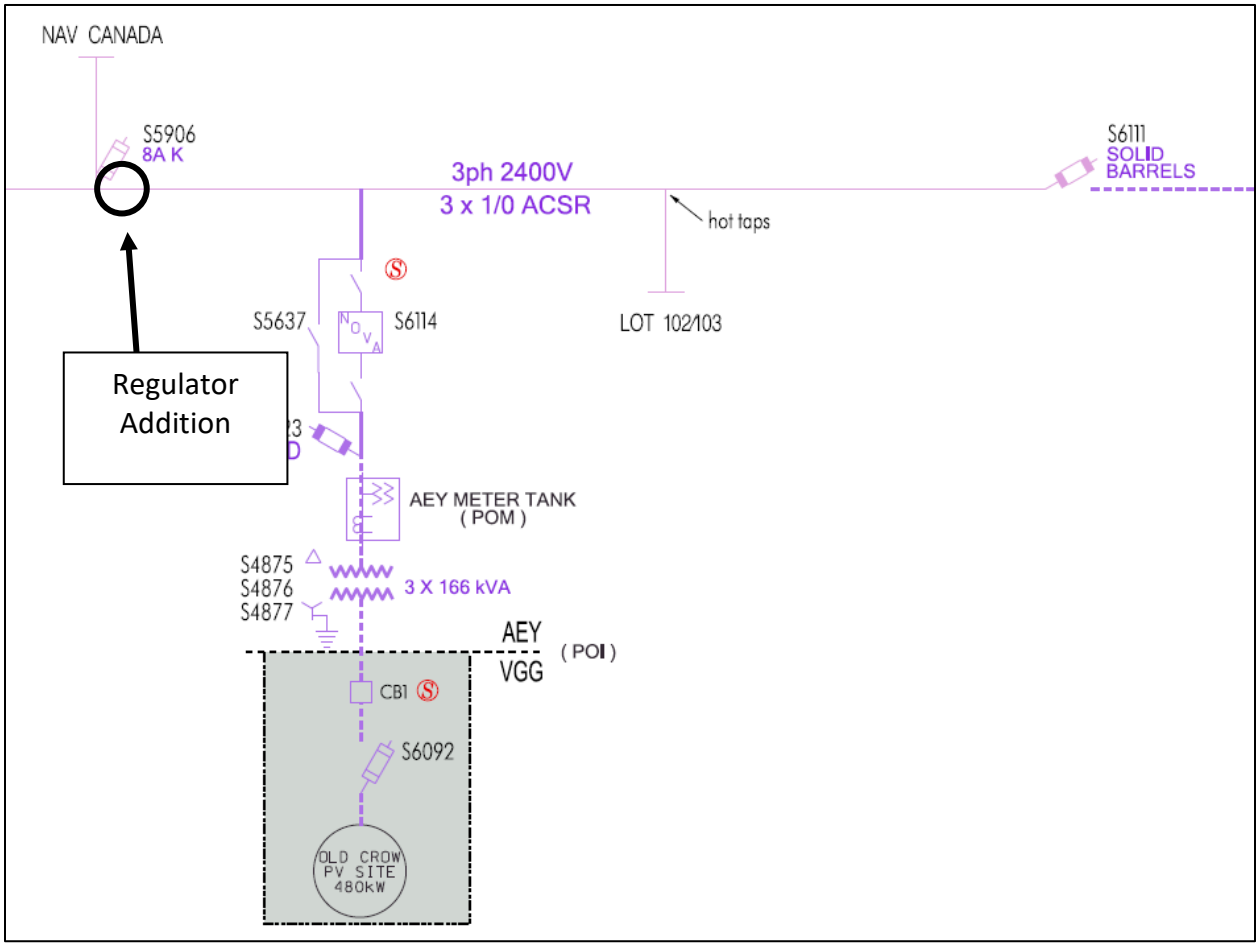
Regulator location was determined using two criteria:

1. Locating a point near where voltages on 3L405 North begin to fall below AEY standard during peak Winter loading, and
2. Allows for the largest increase in end-of-line load growth.

Table 3: Alternative 1.1 Voltages

	Existing (V pu)	Alternative 1.1 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000
End of Line Load Growth Capacity	0 kW	80 kW

Figure 2: Alternative 1.1 SLD



Alternative 1.2 - Reconductor with Regulator Bank on 3L405 North

Project Scope: $787,000

- 100A 2.4kV Regulator Bank ($710,000)
- ~310m of 4/0 UG AL ($77,000)

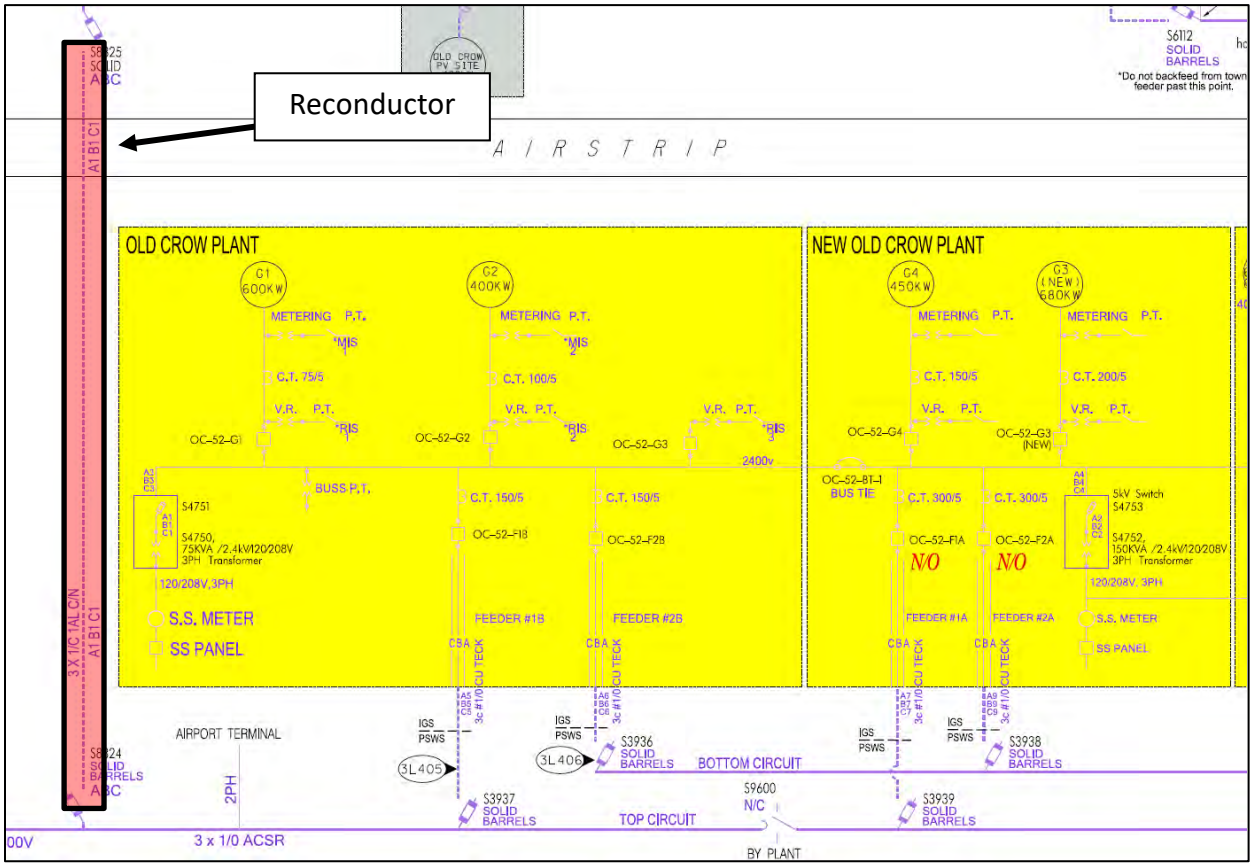
Regulator location is the same as in Alternative 1.1. The existing 1C1 AL underground cable between S8324 and S8325 is a bottle neck for voltage drop. By upgrading the cable size to 4/0 AL, capacity on 3L405 can be further increased.

Reconductoring this section of line alone is not sufficient to address the low voltage issues on 3L405 North.

Table 4: Alternative 1.2 Voltages

	Existing (V pu)	Alternative 1.1 (V pu)	Alternative 1.2 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000	A – 0.992 B – 0.996 C – 1.000
End of Line Load Growth Capacity	0kW	80kW	100kW

Figure 3: Alternative 1.2 SLD



2. Alternatives for Low Voltage on 3L406

Alternative 2.1 - Regulator Bank on 3L406

Project Scope: $710,000

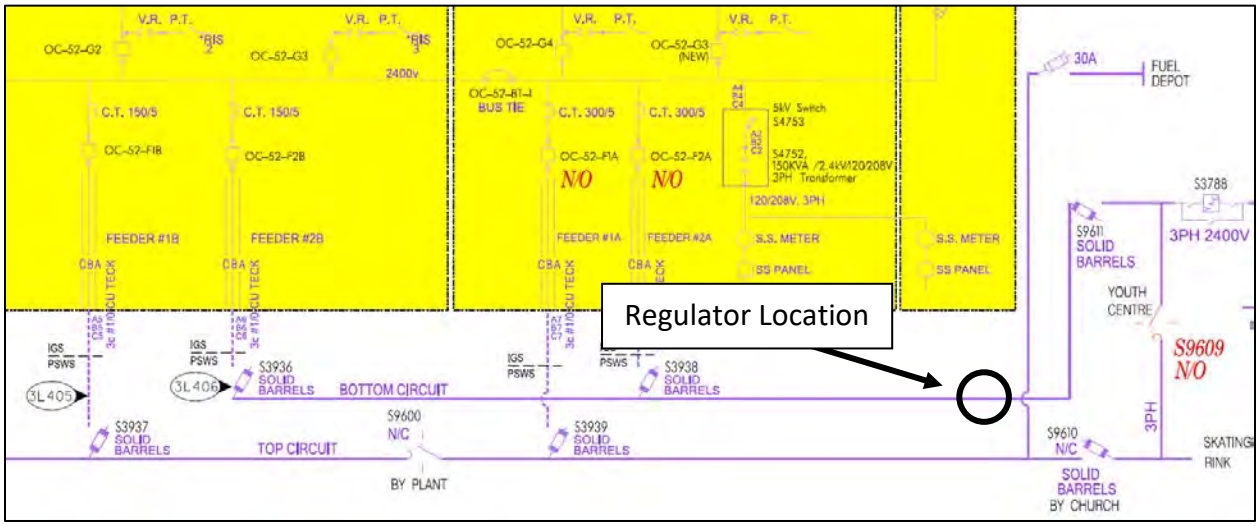
- 100A 2.4kV Regulator Bank

Regulator location was determined in the same manner as in Alternative 1.1.

Table 5: Alternative 2.1 Voltages

	Existing (V pu)	Alternative 2.1 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 1.004 B – 0.987 C – 1.002
End of Line Load Growth Capacity	0 kW	75 kW

Figure 4: Alternative 2.1 SLD



Alternative 2.2 - Reconductor 3L406

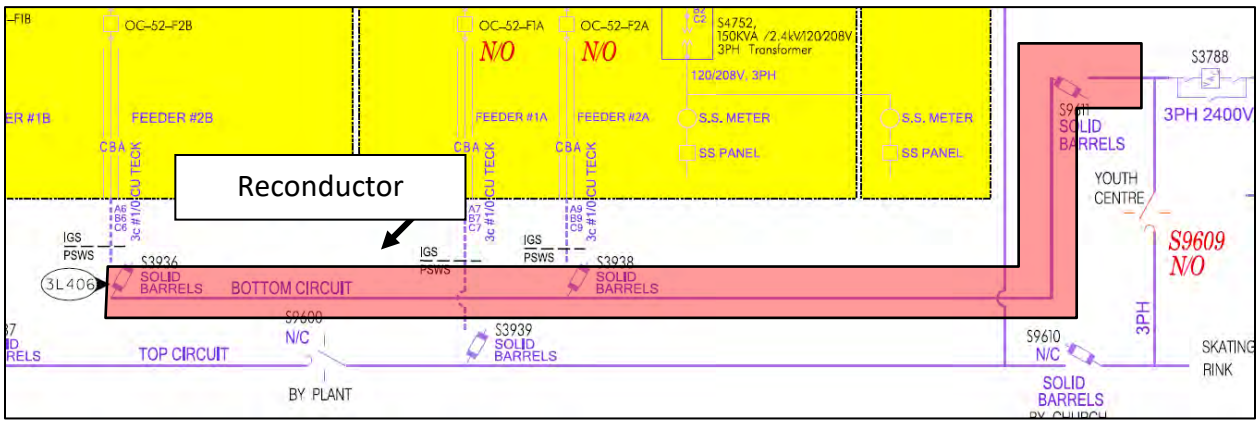
Project Scope: $232,000

- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Table 6: Alternative 2.2 Voltages

	Existing (V pu)	Alternative 2.2 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962
End of Line Load Growth Capacity	0 kW	35 kW

Figure 5: Alternative 2.2 SLD



Alternative 2.3 - New System Configuration and Reconductor 3L405

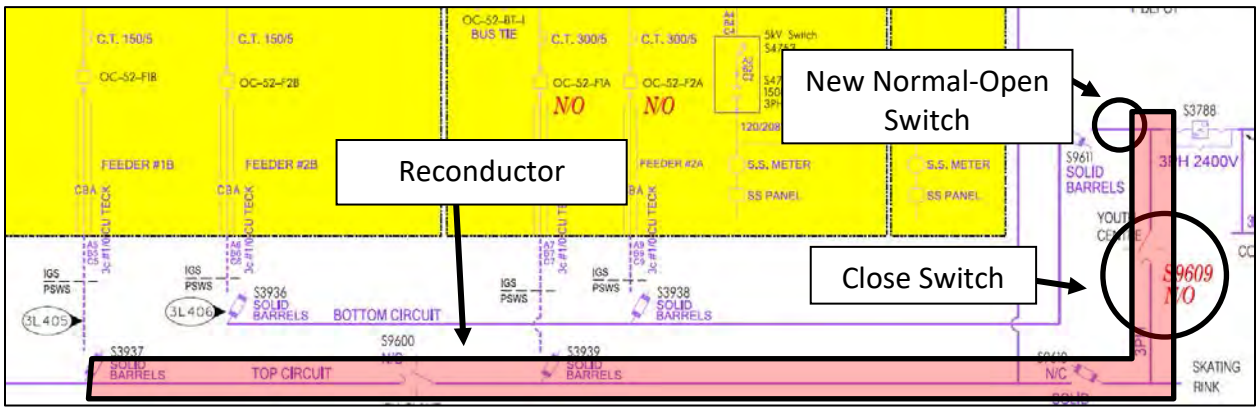
Project Scope: $249,000

- ~940m of 1/0 ACSR ($232,000)
- Overhead gang switch ($17,000)

Table 7: Alternative 2.3 Voltages

	Existing (V pu)	Alternative 2.2 (V pu)	Alternative 2.3 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962	A – 0.971 B – 0.958 C – 0.961
End of Line Load Growth Capacity	0 kW	35 kW	20 kW

Figure 6: Alternative 2.3 SLD



Alternative 2.4 - Reconductor with Regulator Bank on 3L406

Project Scope: $942,000

- 100A 2.4kV Regulator Bank ($710,000)
- ~940m of 1/0 ACSR ($232,000)

This alternative was not assessed as both Alternative 2.1 and Alternative 2.2 adequately address the low voltage issues on 3L406 individually. Combining both alternatives would be an unjustified increase in cost at this time; however, given that both alternatives are independent of each other, these alternatives could be combined in the future if a further increase in capacity is needed.

3. Capacity on 3L405 East

Alternative 3.1 - Reconductor 3L405 East

Project Scope: $232,000

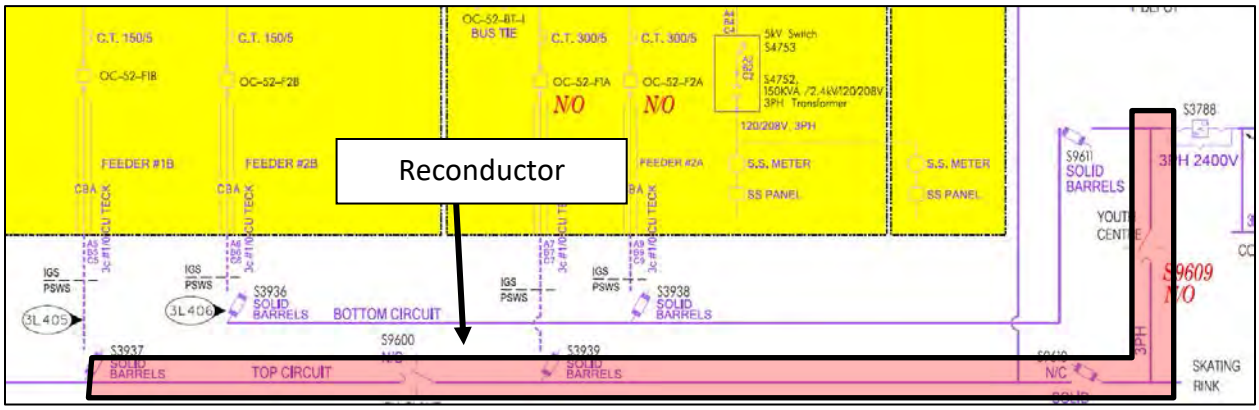
- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Although there are no existing low voltage issues on 3L405 East, capacity on the feeder is limited. A maximum load of 85 kW can be installed at the end of 3L405 East before voltage falls below 0.95 Vpu. This alternative allows for 230 kW of increased system capacity to account for continued load growth in Old Crow.

Table 8: Alternative 3.1 Voltages

	Existing (V pu)	Alternative 3.1 (V pu)
Worst Voltage on 3L405 East	A – 0.984 B – 0.986 C – 0.978	A – 0.988 B – 0.991 C – 0.986
End of Line Load Growth Capacity	85 kW	230 kW

Figure 7: Alternative 3.1 SLD



4. Alternatives for Low Voltage System Wide

Alternative 4.1 – Old Crow Voltage Conversion

Project Scope: >$1,000,000

- Convert Old Crow system to 4160 V
  - Change system to Wye
    - Rebuild over 6km of primary system to include a neutral conductor
    - System and generation wiring changes
  - Replace distribution transformers that cannot be reconfigured to 4160 V
  - Protection changes
    - Line-to-ground faults due to Wye system (Old Crow has poor grounding)

This alternative was not assessed further due to project cost and extended lead-times.

Recommendation

It is recommended that Alternatives 1.1, 2.2 and 3.1 are undertaken to both fix existing voltage issues and increase system capacity for future load growth.

Alternative 1.1 is the only alternative that addresses the low voltages on 3L405 North.

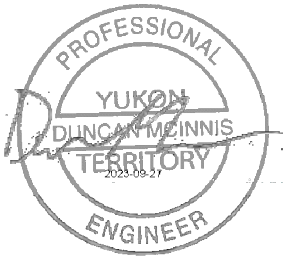
Alternatives 2.1, 2.2, and 2.3 all address low voltages on 3L406; however, Alternative 2.2 is the least-cost alternative. Alternative 3.1 allows for increased capacity on 3L405 East to accommodate load growth.

In total, the work that will be completed is:

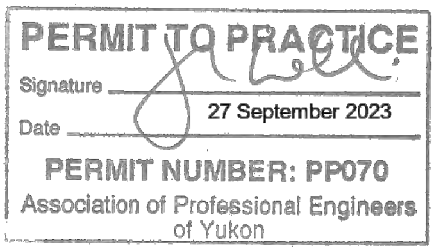
- Regulator addition on 3L405 North;
- Reconductor 3L406, and
- Reconductor 3L405 East.

Old Crow Undervoltage (2023 Update)

Technical Study



2023-09-27



Revision History

Revision	Date	Editor	Comments
R0	2023-09-26	Alex Deans	First version

Issue Summary

Old Crow has continued to see an increase in load growth year after year. New peak loads are straining the Old Crow system to a point where AEY cannot reliably provide electricity that is within voltage standards. This deficiency is caused by long distances between generation and customers, size of primary conductors, and the overall primary system voltage.

System Overview

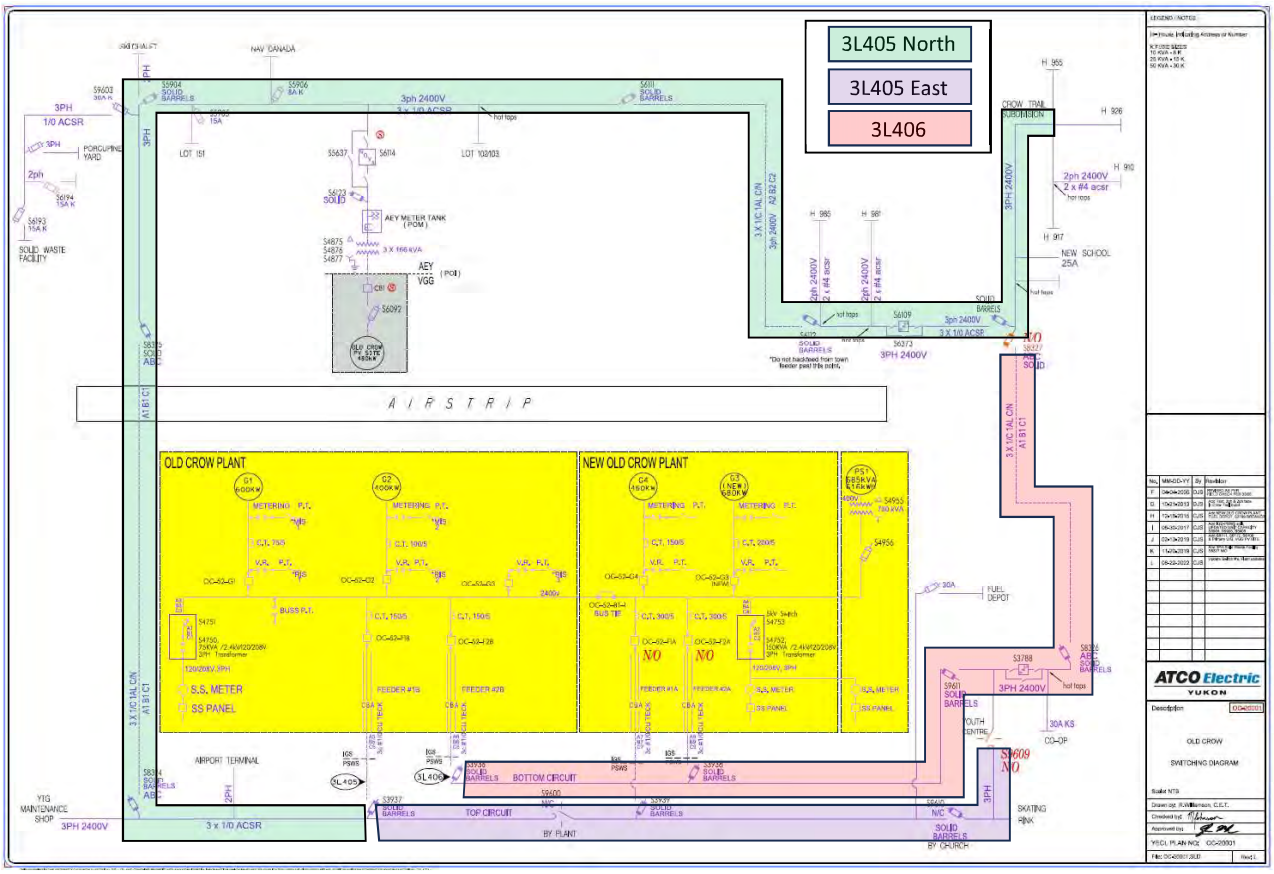


Figure 1 - Old Crow SLD

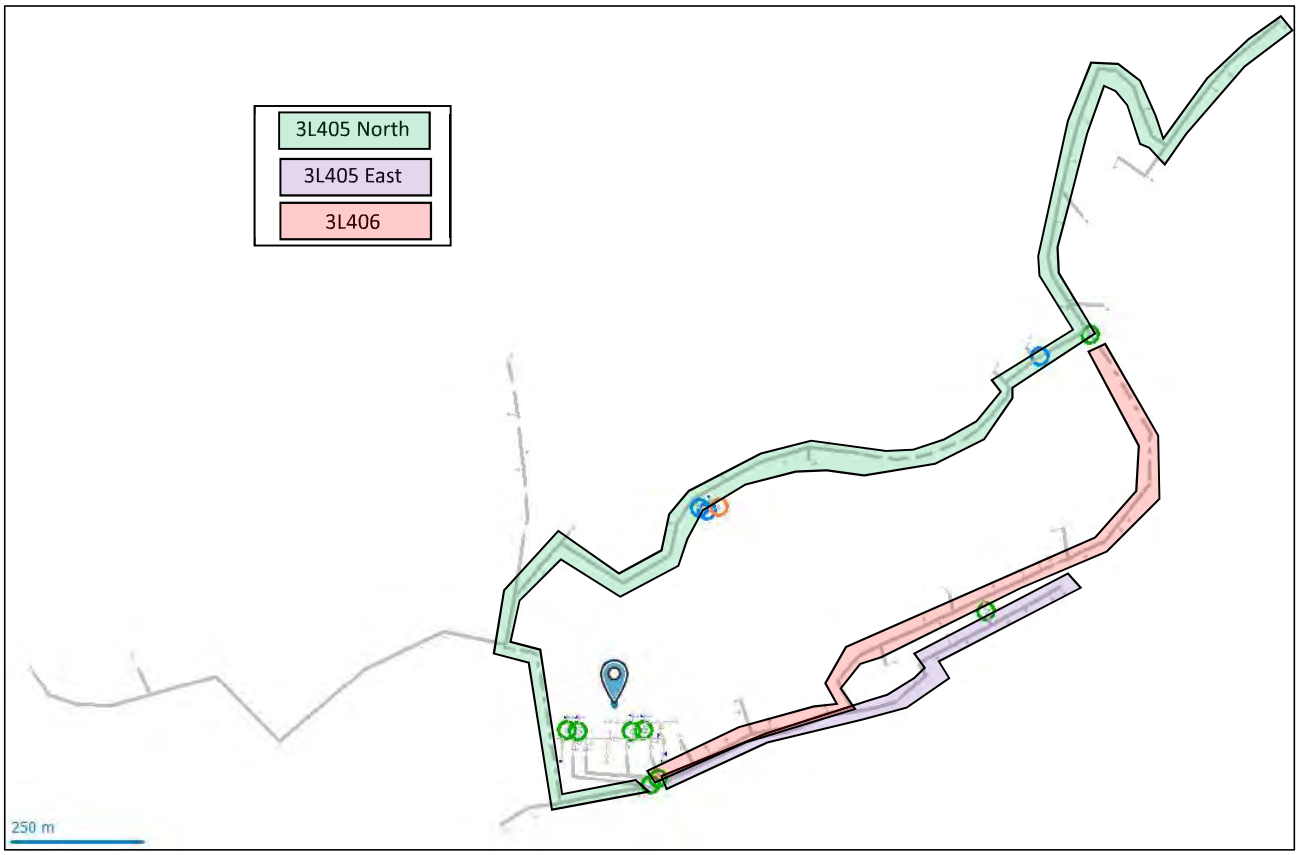


Figure 2 - Old Crow CYME Map

Seasonal Loading

Summer

Two scenarios were analyzed in CYME during summer loading using historical data between July 1, 2023, and July 6, 2023; Scenario 1 represents Battery Energy Storage System (BESS)-only generation and Scenario 2 represents Photo Voltaic (PV) array generation with BESS charging. These dates were chosen so that the Old Crow system would be diesel-off (i.e., the Old Crow system is solely powered by the PV array and battery).

Scenario 1: BESS-only generation

Historical data shows a peak in BESS generation on July 3, 2023, at 10:20pm equaling 241 kW. Since the BESS is connected at the plant, and the modelling goal is confirming voltage levels and not fault current, this scenario was modeled in CYME with all generators connected with voltage set at 1.01Vpu (BESS set point), and the model loaded at 33% (to match measured BESS output).

Table 1 – Scenario 1 PV and BESS Historical Data

Date	Total System Load (kW)	CYME Load %	PV Output (kW)	BESS Output (kW)	Diesel Output (kW)
03-Jul-23 (10:20pm)	241	33	0	241	0

Note - The BESS has the capability to generate up to 685 kW of power which is why all generators were left active in the model.

Table 2 – Scenario 1 Old Crow Voltages

Study Area	Summer Loading – Scenario 1 (Worst Vpu)
3L406	A – 0.977 B – 0.970 C – 0.976
3L405 North	A – 0.974 B – 0.976 C – 0.977
3L405 East	A – 0.995 B – 0.996 C – 0.993

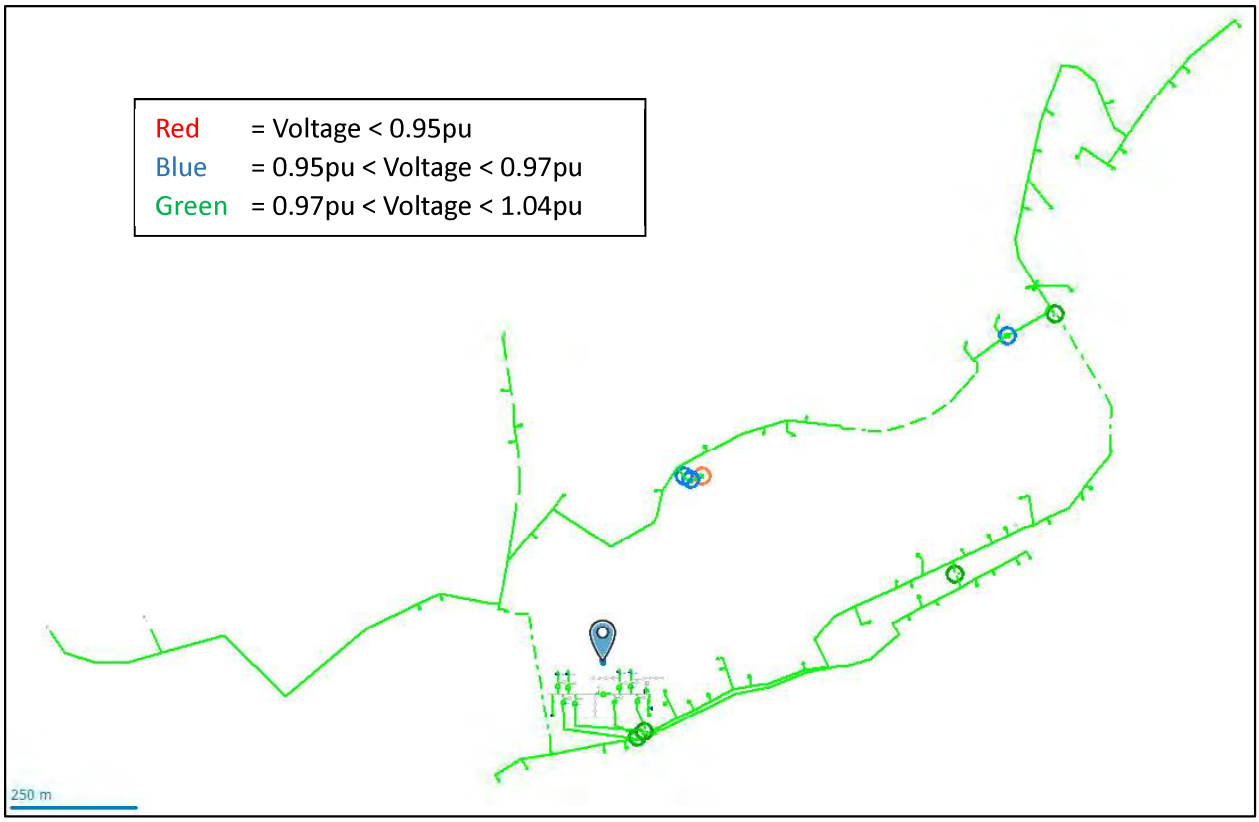


Figure 3 - Old Crow Scenario 1 CYME Map

Scenario 2: PV generation with BESS charging

The peak load on the system – less BESS charging – was found on July 3, 2023, and equaled 322 kW. To model this scenario a generator was placed at the PV array site, all diesel generators at the main plant were disconnected, the BESS was set to charge at 95 kW, and the model was loaded at 44%. The voltage setpoint for the PV site was set to 1.05Vpu, resulting in a 1.01Vpu measurement at the plant bus (BESS setpoint voltage).

Table 3 - Scenario 2 PV and BESS Historical Data

Date	Total System Load (kW)	CYME Load %	PV Output (kW)	BESS Output (kW)	Diesel Output (kW)
03-Jul-23 (2:25pm)	322	44	417	-95	0

Assumptions:

The historical data shows the line-to-line voltage on the generator bus for AB, BC, and CA which equal 2.40 kV, 2.38 kV, and 2.41kV respectively. To achieve a similar bus voltage in CYME, the generator at the PV site needs to be set to 2.5kV. We can then assume that all voltages downstream of the diesel plant on 3L406 and 3L405 East will represent real-world voltages.

Table 4 - Scenario 2 Old Crow Voltages

Study Area	Summer Loading – Scenario 2 (Worst Vpu)
3L406	A – 0.968 B – 0.957 C – 0.961
3L405 North	A – 0.984 B – 0.985 C – 0.986
3L405 East	A – 1.002 B – 1.001 C – 0.995

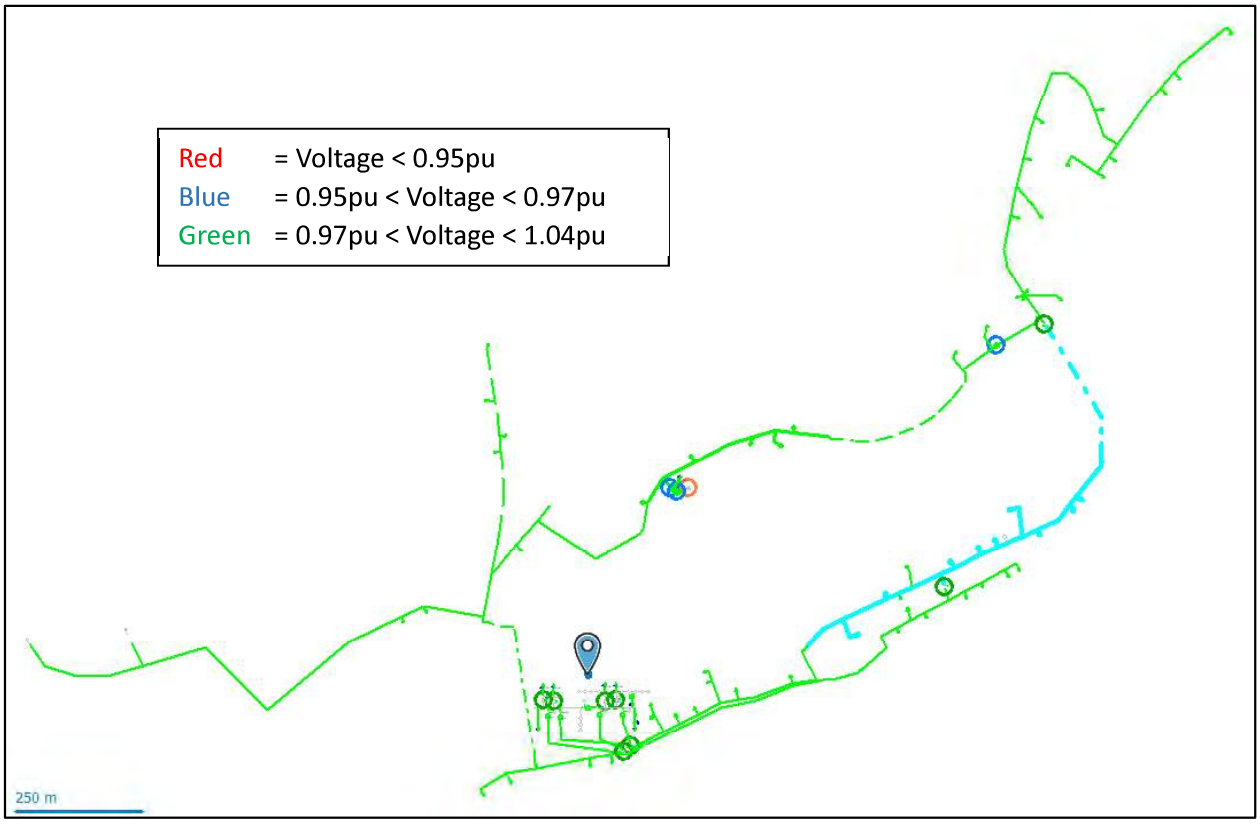


Figure 4 - Old Crow Scenario 2 CYME Map

Winter

The CYME model is run at 100% and includes the assumed loads of the new 10-plex and health center that was built on 3L405 North (see attached pdf).

DPS Old Crow Health Center and 1

Table 5 – Old Crow Winter Loading Voltages

Study Area	Winter Loading – No PV (Worst Vpu)
3L406	A – 0.928 B – 0.904 C – 0.923
3L405 North	A – 0.918 B – 0.923 C – 0.927
3L405 East	A – 0.984 B – 0.986 C – 0.978

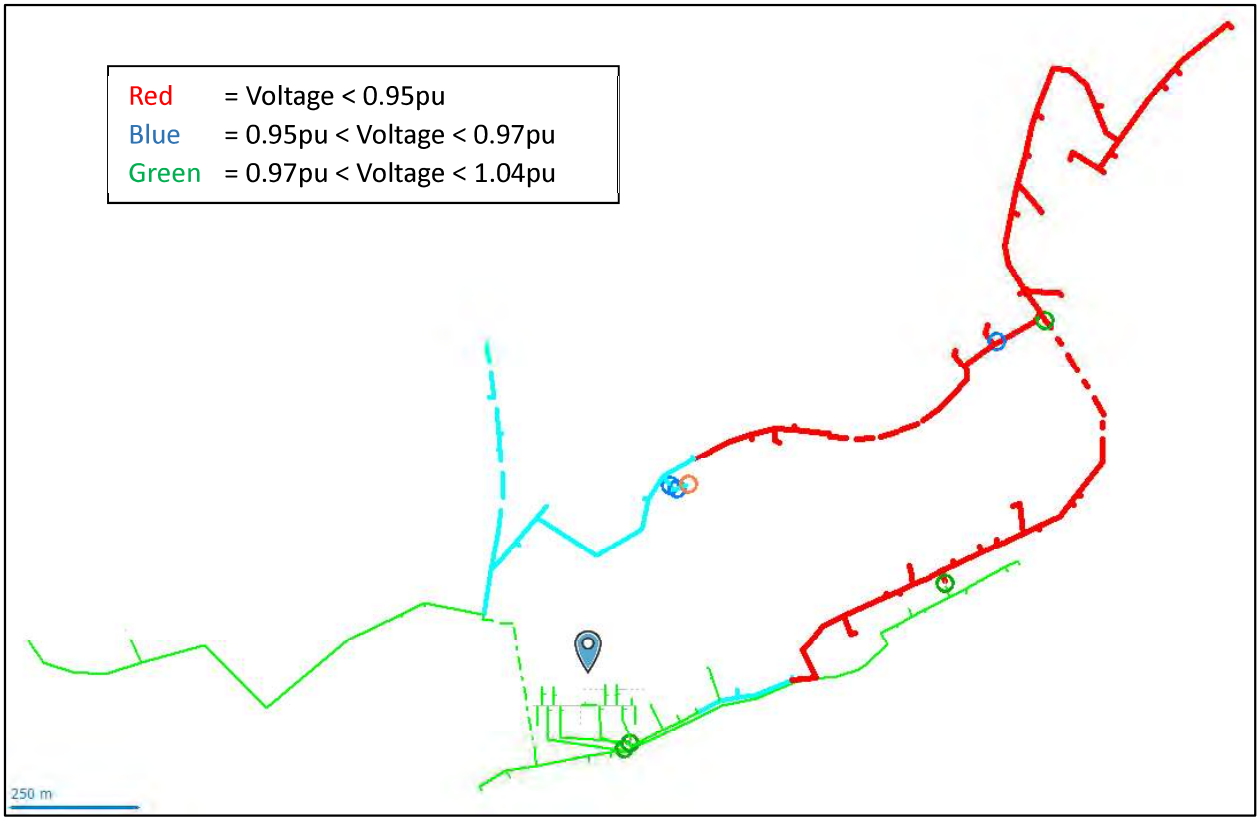


Figure 5 – Winter Loading CYME Map

Alternatives

There are two problems within the Old Crow system that are addressed in the alternatives below; they are the following:

- Low voltage on 3L405 North during Winter loading,
- Low voltage on 3L406 during Winter loading,

For modelling each alternative, the modification specified in each option was added, with no changes to system loading. The new worst EOL voltage was recorded.

To determine an approximate load growth capacity, load was added until the worst end-of-line voltage hit 0.95 Vpu.

Alternatives for Low Voltage on 3L405 North

Alternative 1 - Regulator Bank on 3L405 North

Project Scope: $710,000

- 100A 2.4kV Regulator Bank

Regulator location was determined using two criteria:

1. Locating a point near where voltages on 3L405 North begin to fall below AEY standard during peak Winter loading,
2. And allows for the largest increase in end-of-line load growth.

Table 6 - Alternative 1 Voltages

	Existing (V pu)	Alternative 1 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000
End of Line Load Growth Capacity	0kW	80kW

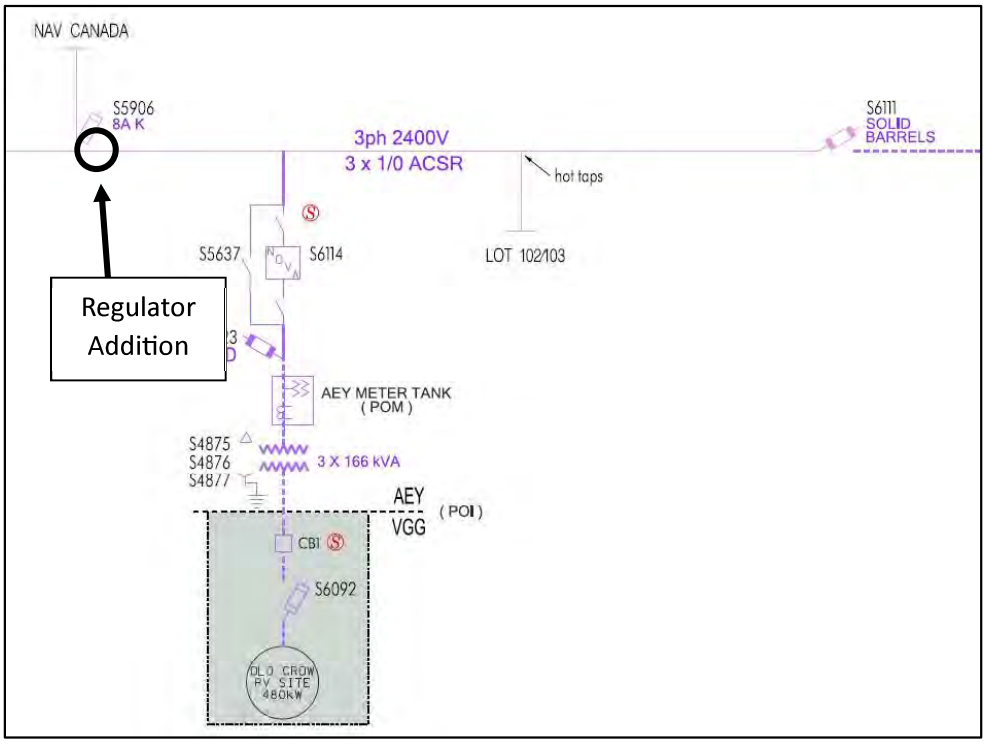


Figure 6 - Alternative 1 SLD

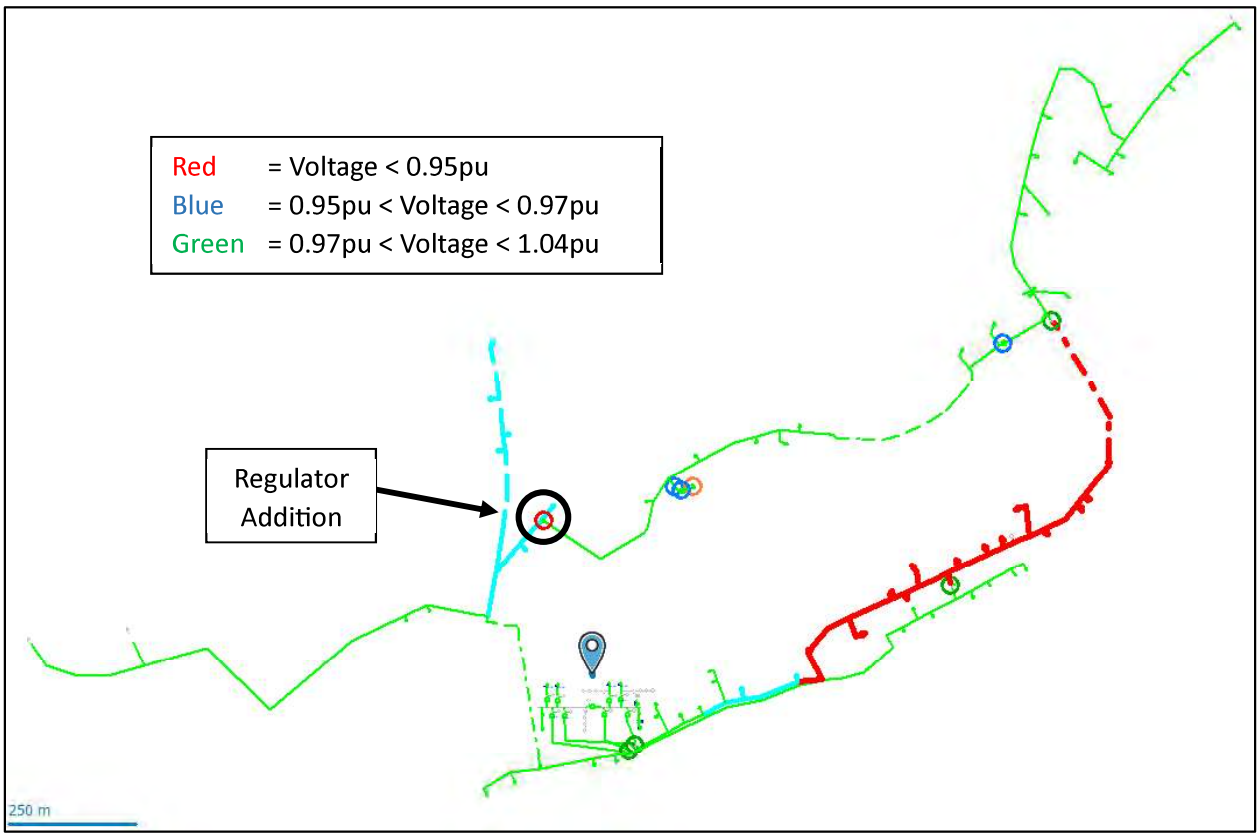


Figure 7 - Alternative 1 CYME Map

Alternative 2 - Reconductor with Regulator Bank on 3L405 North

Project Scope: $787,000

- 100A 2.4kV Regulator Bank ($710,000)
- ~310m of 4/0 UG AL ($77,000)

Regulator location is the same as in Alternative 1. The existing 1C1 AL underground cable between S8324 and S8325 is a bottle neck for voltage drop. By upgrading the cable size to 4/0 AL, capacity on 3L405 can be further increased.

Reconductoring this section of line alone is not enough to address the low voltage issues on 3L405 North.

Table 7 - Alternative 2 Voltages

	Existing (V pu)	Alternative 1 (V pu)	Alternative 2 (V pu)
Worst Voltage on 3L405 North	A – 0.918 B – 0.923 C – 0.927	A – 0.994 B – 0.994 C – 1.000	A – 0.992 B – 0.996 C – 1.000
End of Line Load Growth Capacity	0kW	80kW	100kW

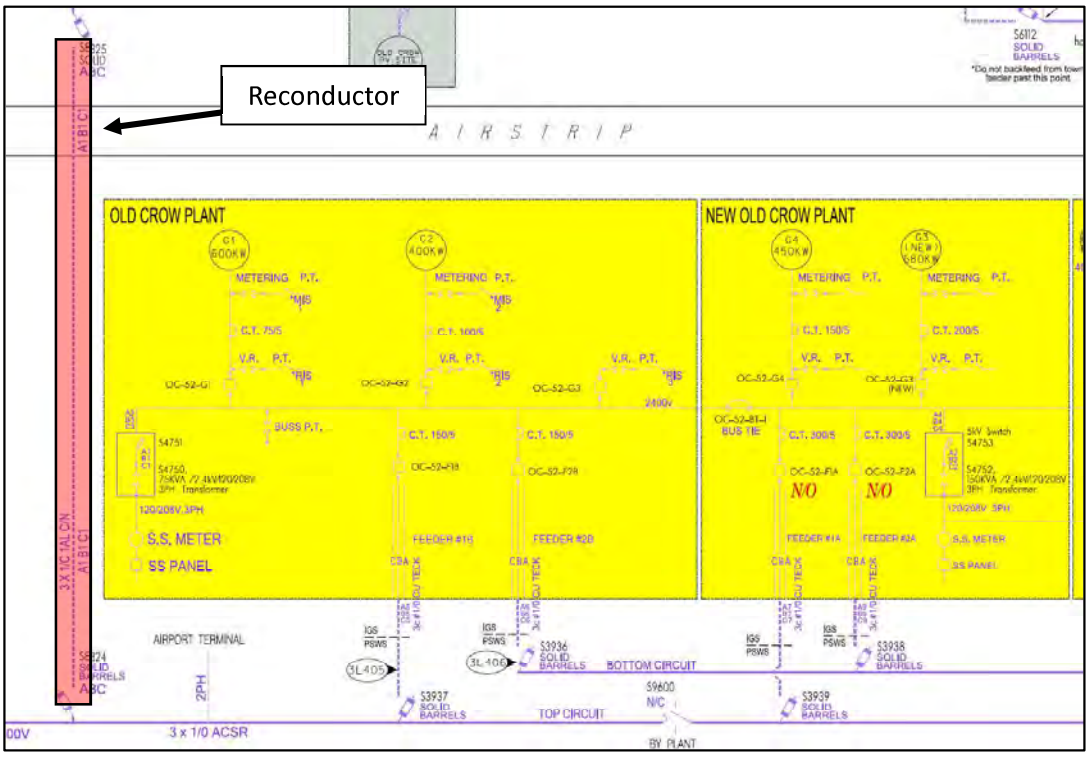


Figure 8 - Alternative 2 SLD

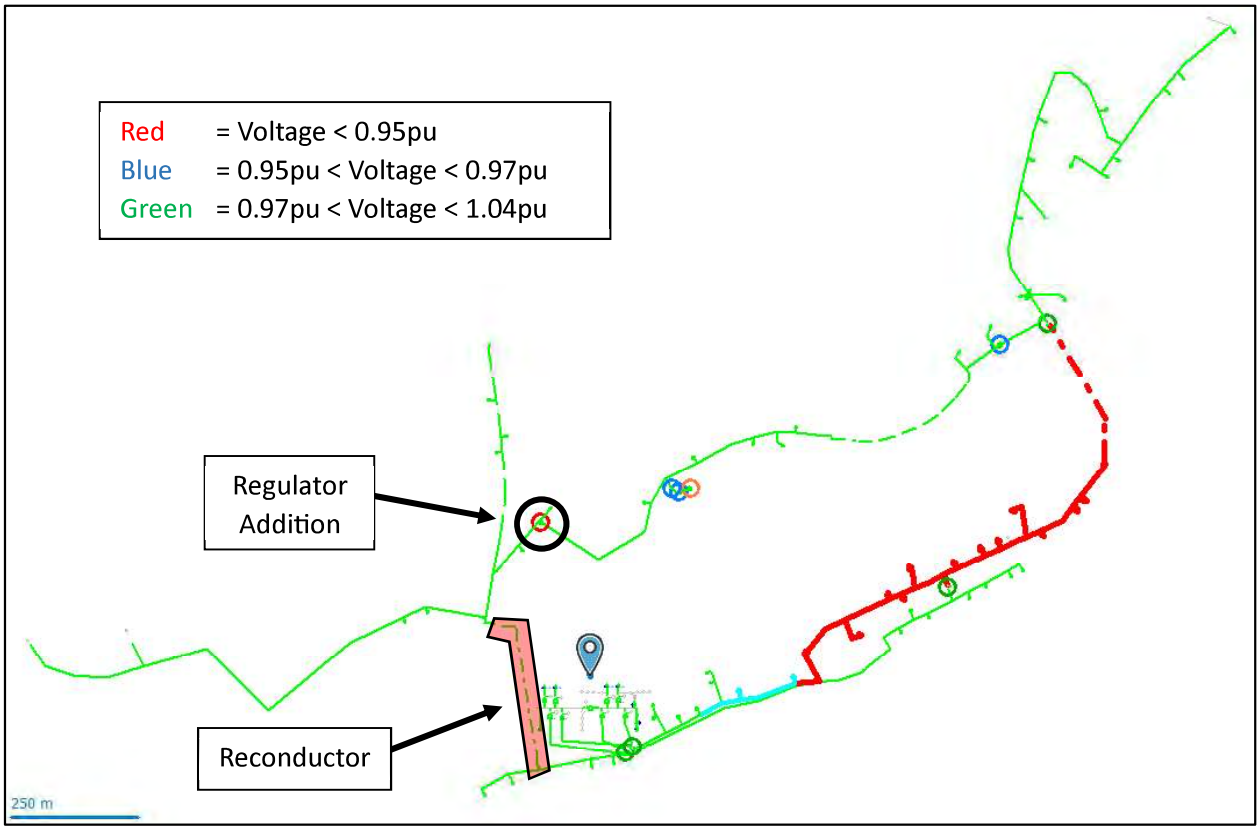


Figure 9 - Alternative 2 CYME Map

Alternatives for Low Voltage on 3L406

Alternative 3 - Regulator Bank on 3L406

Project Scope: $710,000

- 100A 2.4kV Regulator Bank

Regulator location was determined in the same manner as in Alternative 1.

Table 8 - Alternative 3 Voltages

	Existing (V pu)	Alternative 3 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 1.004 B – 0.987 C – 1.002
End of Line Load Growth Capacity	0kW	75kW

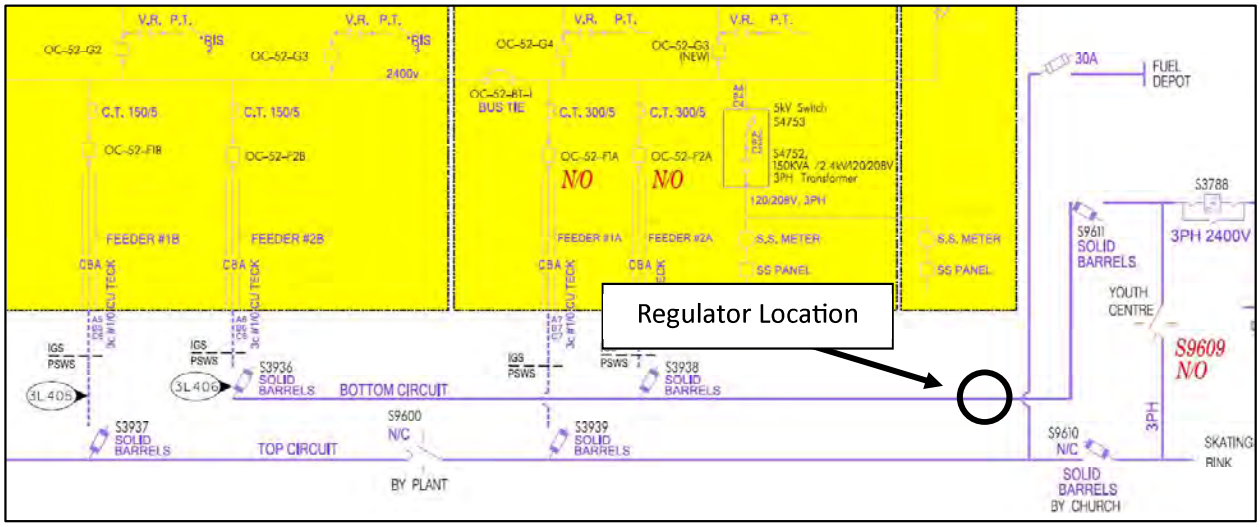


Figure 10 - Alternative 3 SLD

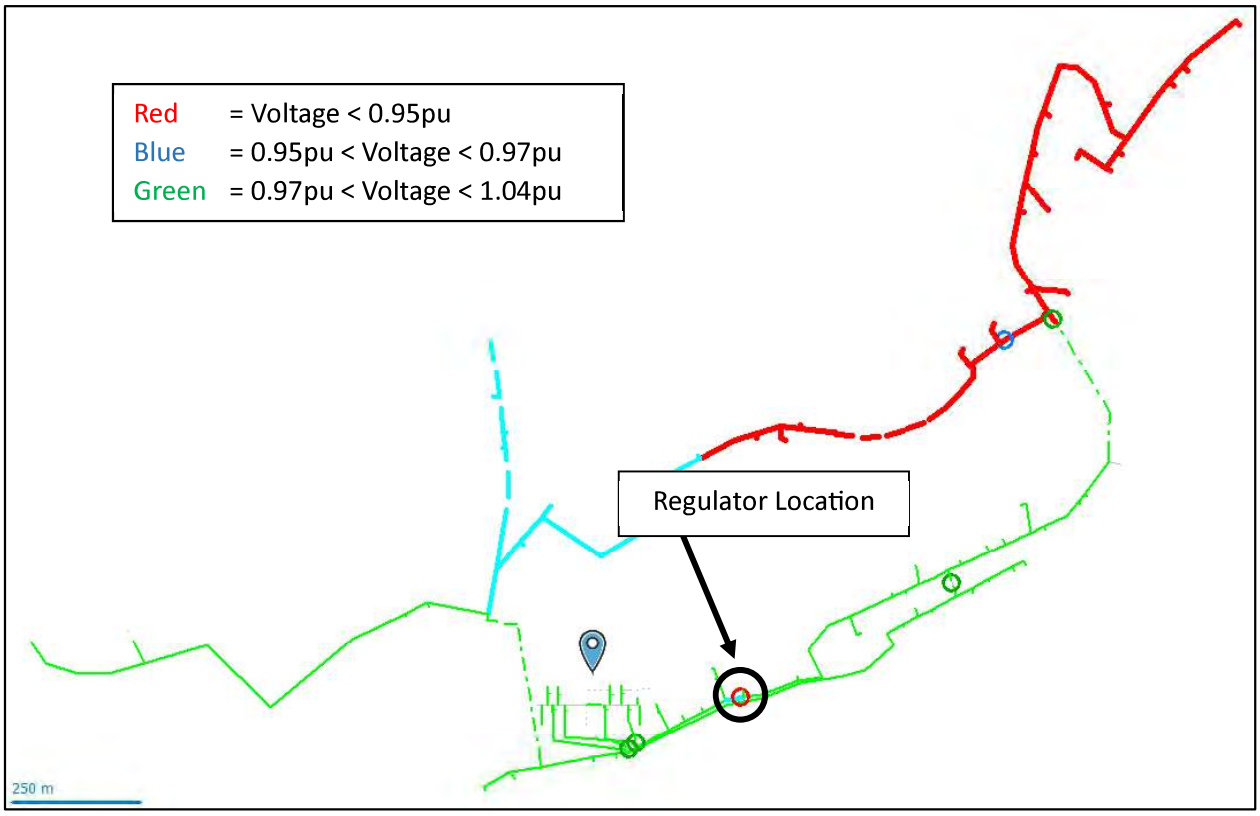


Figure 11 - Alternative 3 CYME Map

Alternative 4 - Reconductor 3L406

Project Scope: $232,000

- ~940m of 1/0 ACSR, replacing a mixture of #4 and #6 ACSR

Table 9 - Alternative 4 Voltages

	Existing (V pu)	Alternative 4 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962
End of Line Load Growth Capacity	0kW	35kW

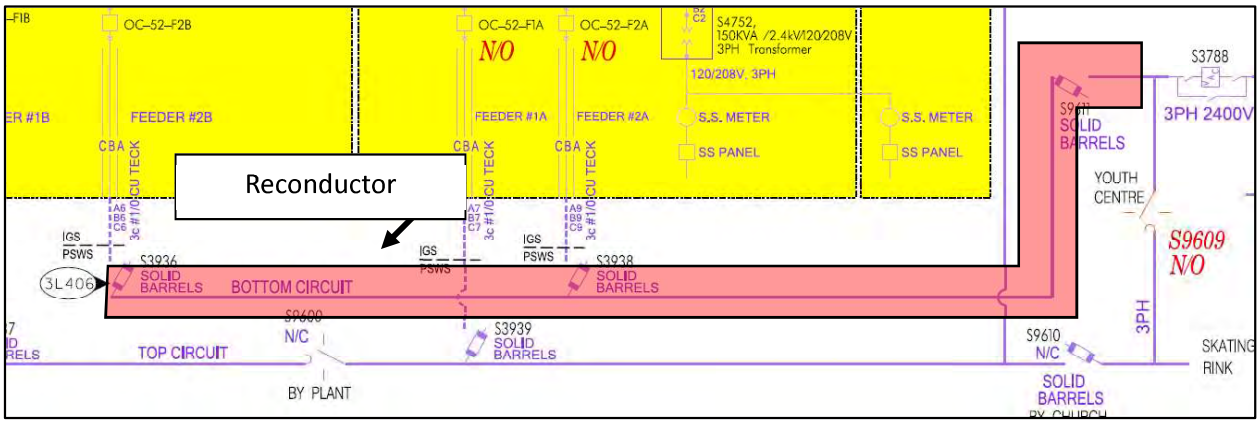


Figure 12 - Alternative 4 SLD

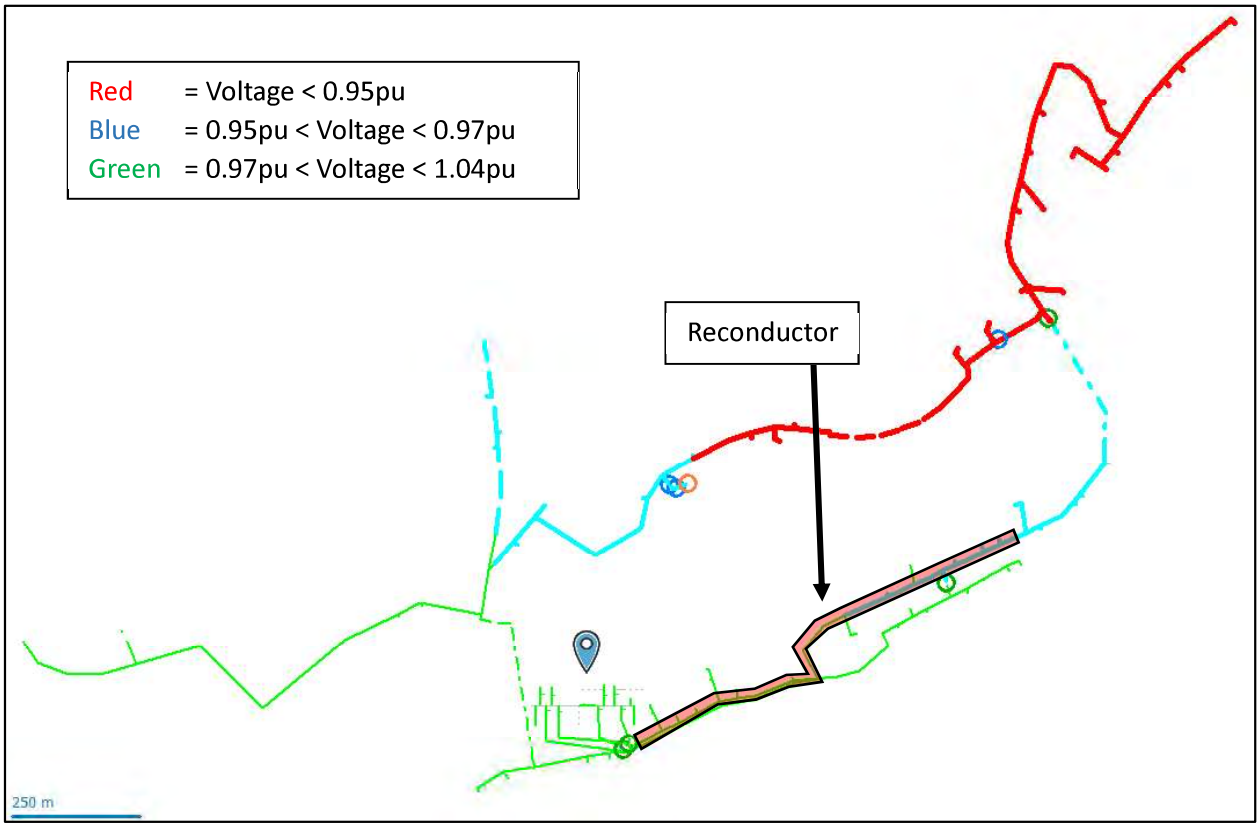


Figure 13 - Alternative 4 CYME Map

Alternative 5 - New System Configuration and Reconductor 3L405

Project Scope: $249,000

- ~940m of 1/0 ACSR ($232,000)
- Overhead gang switch ($17,000)

Table 10 - Alternative 5 Voltages

	Existing (V pu)	Alternative 4 (V pu)	Alternative 5 (V pu)
Worst Voltage on 3L406	A – 0.928 B – 0.904 C – 0.923	A – 0.968 B – 0.961 C – 0.962	A – 0.971 B – 0.958 C – 0.961
End of Line Load Growth Capacity	0kW	35kW	20kW

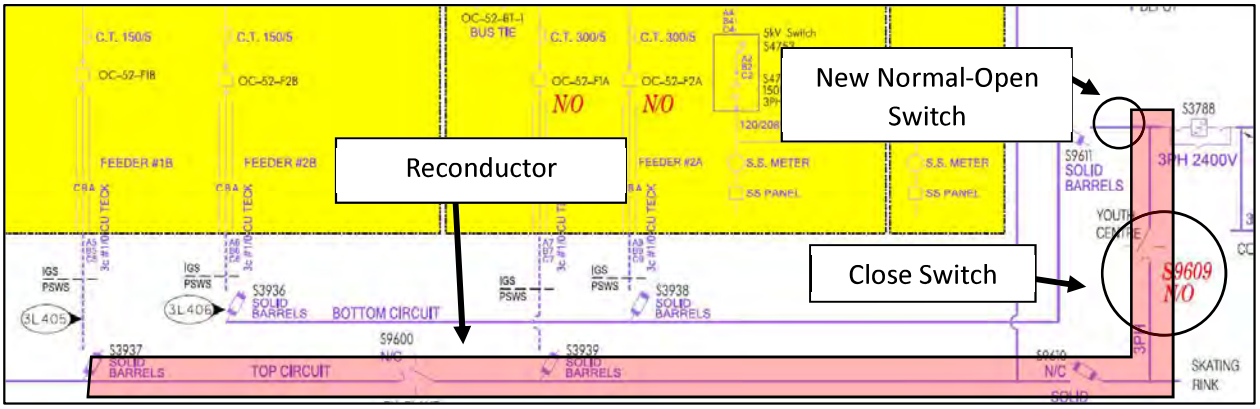


Figure 14 - Alternative 5 SLD

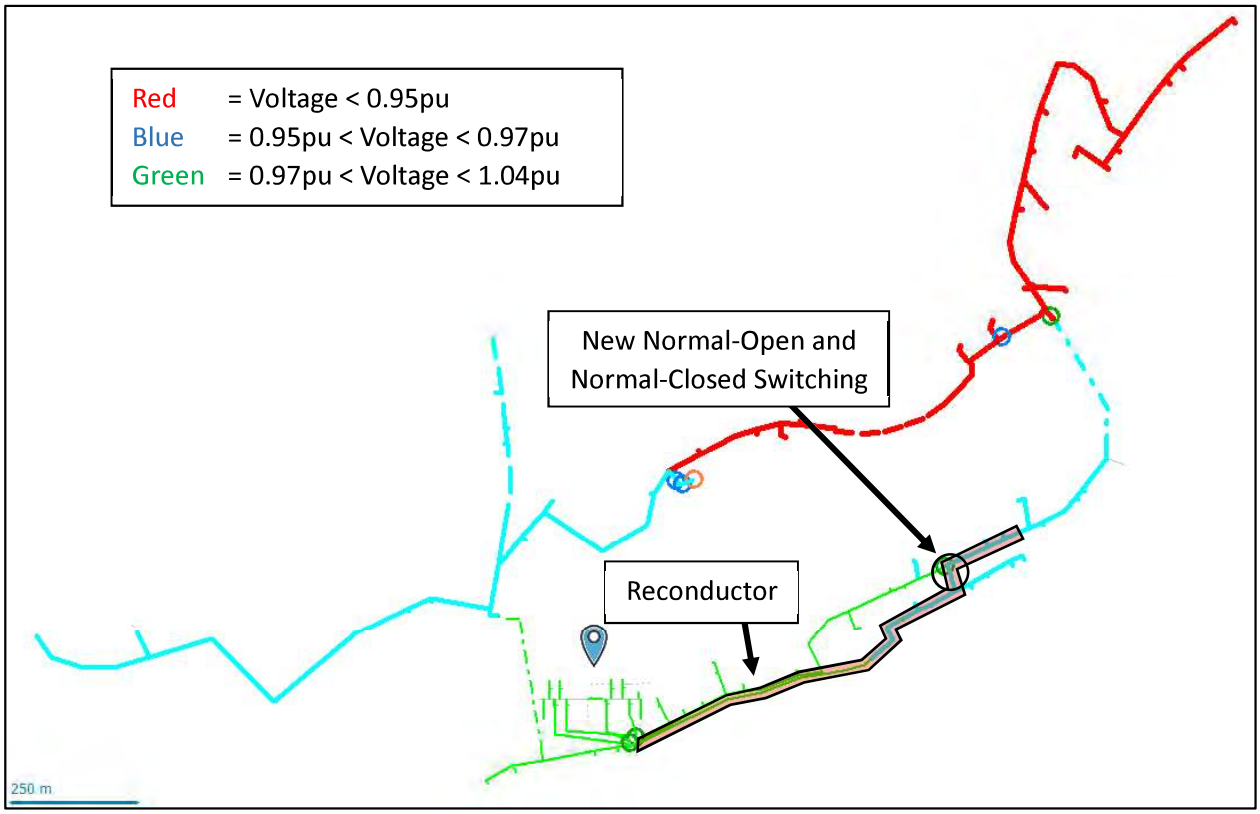


Figure 15 - Alternative 5 CYME Map

Alternative 6 - Reconductor with Regulator Bank on 3L406

Project Scope: $942,000

- 100A 2.4kV Regulator Bank ($710,000)
- ~940m of 1/0 ACSR ($232,000)

This alternative was not assessed as both Alternative 3 and Alternative 4 adequately address the low voltage issues on 3L406 individually. Combining both alternatives would be an unjustified increase in cost at this time; however, given that both alternatives are independent of each other, these alternatives could be combined in the future if a further increase in capacity is needed.

Alternatives for Low Voltage System Wide

Alternative 7 – Old Crow Voltage Conversion

Project Scope: >$1,000,000

- Convert Old Crow system to 4160 V
  - Change system to Wye
    - Rebuild over 6km of primary system to include a neutral conductor
    - System and generation wiring changes
  - Replace all distribution transformers with 4160 V transformers
    - ~65 transformers
  - Protection changes
    - Line-to-ground faults due to Wye system (Old Crow has poor grounding)

This alternative was not assessed due to project cost and extended lead-times.

Recommend Alternative

The recommended solutions for 3L405 North and 3L406 are Alternative 1 and Alternative 4 respectively.

Alternative 1 is the only alternative that addresses the low voltages on 3L405 North. Alternatives 3, 4, and 5 all address low voltages on 3L406; however, Alternative 4 is the least-cost alternative.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-061

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-061

Reference: 2023-24 GRA, Business Case #30 – 6L19 Voltage Improvement, PDF pages 98-118

Issue: Capital expenditures (Distribution Improvements)

Request:

Please provide the comparative cost-benefit analysis prepared for each of the seven alternatives examined.

Response:

Please refer to the comparative cost-benefit analysis prepared in the table below.

Table 1: Comparative Cost-Benefit Analysis ($Millions)

Alternatives	Estimate
1. Install Two New Regulators on 6L11 and 6L19	$1.19
2. Reconductor 6L11 and 6L19 *Does not fix New Constab. voltage issues*	$50+
3. Reconductor 6L11 and Install a New Regulator on 6L19 *Does not fix New Constab. And Teslin voltage issues*	$7.2
4. Boost S150 Voltage, Reconductor 6L11, Install Regulator on 6L19 *Does not fix New Constab. voltage issues*	$7.2
5. Boost S150 Voltage, Relocate Two Reg Banks, and Install Regulator on 6L11	$0.95 *Recommended Alternative*
6. Scenario 4 THELP: Install Regulator on 6L11, Install Regulator on 6L19 *Does not fix New Constab. And Teslin voltage issues*	$1.19

Figure 1: Comparison of Alternative Performance

Existing			
Location	**Va**	**Vb**	**Vc**
McRae Sub (35kV)	0.945	0.946	0.944
5L649 EOL	1.019	1.019	1.018
5L631 EOL	-	-	0.949
South McLintock Sub (35kV)	0.932	0.946	0.934
5L611 EOL	-	-	0.926
Marsh Lake Sub (35kV)	0.909	0.927	0.917
5L612 EOL	0.958	-	-
New Constabulary Sub (35kV)	0.902	0.919	0.912
5L615 EOL	0.855	-	-
Johnson Crossing Sub (35kV)	0.851	0.843	0.861
Teslin Lake Sub (35kV)	0.819	0.796	0.828
4L301 EOL	-	0.802	-
Teslin Sub (35kV)	0.812	0.787	0.821
5L613 EOL	0.879	-	-
5L614 EOL	-	0.868	-
Worst Voltage on 6L19	0.815	0.791	0.824

Alternative 1			Alternative 2			Alternative 3			Alternative 4			Alternative 5			Alternative 6		
Va	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**
1.025	1.027	1.025	0.984	0.985	0.984	0.977	0.978	0.977	1.018	1.019	1.019	0.987	0.989	0.987	1.023	1.025	1.028
1.033	1.027	1.032	1.033	1.032	1.032	1.031	1.030	1.029	1.032	1.031	1.031	1.030	1.029	1.029	1.033	1.030	1.033
-	-	0.964	-	-	0.964	-	-	0.959	-	-	0.961	-	-	0.958	-	-	0.963
1.017	1.013	1.020	1.016	1.016	1.015	0.999	1.011	1.024	1.018	1.016	1.015	1.038	1.039	1.035	1.017	1.014	1.015
-	-	1.003	-	-	1.001	-	-	0.993	-	-	1.002	-	-	1.024	-	-	1.001
0.998	0.996	1.007	0.994	1.000	1.001	0.979	0.994	0.988	0.998	0.999	1.001	1.018	1.022	1.021	0.997	0.997	1.000
0.995	-	-	0.993	-	-	0.992	-	-	0.992	-	-	0.994	-	-	0.990	-	-
0.995	0.990	1.003	0.989	0.993	0.997	0.973	0.987	0.983	0.992	0.992	0.997	1.012	1.015	1.017	0.991	0.990	0.996
0.952	-	-	0.949	-	-	0.931	-	-	0.948	-	-	0.968	-	-	0.946	-	-
1.019	1.006	1.018	0.979	0.972	0.986	1.020	1.007	1.019	1.017	1.007	1.016	1.020	1.013	1.019	1.005	0.982	1.004
0.994	0.969	0.993	0.970	0.957	0.978	0.994	0.968	0.993	0.991	0.968	0.990	0.994	0.974	0.993	0.979	0.942	0.977
-	0.972	-	-	0.958	-	-	0.972	-	-	0.969	-	-	0.975	-	-	0.951	-
0.988	0.962	0.987	0.968	0.954	0.975	0.988	0.961	0.987	0.985	0.960	0.984	0.988	0.967	0.987	0.973	0.935	0.971
1.027	-	-	1.027	-	-	1.033	-	-	1.030	-	-	1.033	-	-	1.028	-	-
-	1.021	-	-	1.025	-	-	1.026	-	-	1.024	-	-	1.030	-	-	1.016	-
0.958	0.973	0.960	0.968	0.954	0.975	0.927	0.939	0.929	0.988	0.963	0.986	0.991	0.970	0.989	0.975	0.944	0.973

ATCO Electric
YUKON

September 28, 2023 AEY-YUB-062

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-062

Reference: 2023-24 GRA, Business Case #31 – Whistle Bend Subdivision, PDF pages 119-122, paragraph 2; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Street and Sentinel Lighting)

Quote: This is new construction and is fully contributed other than the Board approved $1,240 per street light.

…

Project Schedule and Cost

Table 1: Project Costs and Schedules ($000)

Description	Completion	Distribution Cost	Streetlight Cost
Stage 3D + 3E	2019	567	214
Stage 4	2019	1,910	551
Stage 4D	2020	N/A	159
Stage 5	2020	944	344
Stage 6	2023	718	50
Stage 7A	2023	352	86
Stage 8	2022	140	103
Stage 7B	2023	460	301
Stage 9A	2024	683	186
Stage 9B	2025	456	147

Preamble: The Board requires further detail respecting the "Distribution Cost" and the contribution amounts.

Request:

(a) Referring to Business Case #31, Table 1 (PDF page 121), please reference where the 2019 Street light Cost of $0.214 million for Stage 3D and 3E can be found on 2023-24 GRA Schedules, S9.2. If the response to part (a) indicates Line No. 310 under the years 2019 and 2020 ($0.166 million and $.048 million respectively), please identify the business case associated with all other amounts on Line No. 314.

(i) If the response to part (a) refers to some other line no. on S9.2, please explain any variance between the amount shown on the line no. identified in part (a) and the amount of $0.214 million.

(ii) Referring to Table 1 as quoted above, please explain where the amounts shown under the column "Distribution Cost" can be found on AEY's 2023-24 GRA Schedules, S9.2.

(b) Referring to Table 1 as quoted above, please explain where the amounts shown under the column "Distribution Cost" can be found on AEY's 2023-24 GRA Schedules, S9.2.

(c) Please revise Table 1 to include columns indicating the quantum of units and the total contributed amounts for each of the lines that indicate each of the 10 stages.

(d) Please provide a citation to the "Board approved $1,240 per streetlight" referenced by AEY in the quote above.

Response:

(a) The streetlights for stage 3D and 3E were inadvertently included in line 146 Whistle Bend Stage 3 in the presentation of Schedule 9.2. AEY will break these costs out in the updated Schedule to be filed in the Compliance Filing to the Application.

(i) $0.214 million is what was included in line 146.

(ii) Please refer to the table Distribution Cost Line Reference in the response to part (b) below.

(b) The amounts shown under the column "Distribution Cost" are found on lines 146 through 153 of Schedule 9.2. Table 1 as quoted above shows the amounts on a per stage basis whereas Schedule 9.2 shows the amounts on an as expended basis. Please refer to the table below for a breakdown:

Table 1: Distribution cost Line reference

Description	Completion	Distribution Cost ($000)	Schedule 9.2 Line Reference
Stage 3D + 3E	2019	567	146
Stage 4	2019	1910	147
Stage 4D	2020	n/a	n/a
Stage 5	2020	944	148
Stage 6	2023	718	149
Stage 7A	2023	352	150
Stage 8	2022	140	151
Stage 7B	2023	460	150
Stage 9A	2024	683	152
Stage 9B	2025	458	152

(c) Project Schedule and Cost

Table 2: Project Costs and Schedules

Description	Completion	Distribution Cost ($000)	Streetlight Cost ($000)	Contributed Amount Aug. 2023 ($000)	Number of Streetlights
Stage 3D + 3E	2019	567	214	847	46
Stage 4	2019	1910	551	2393	106
Stage 4D	2020	n/a	159	148	15
Stage 5	2020	944	344	1169	89
Stage 6	2023	718	50	996	67
Stage 7A	2023	352	86	201	42
Stage 8	2022	140	103	219	9
Stage 7B	2023	460	301	185	30
Stage 9A	2024	683	186	186	29
Stage 9B	2025	458	147	0	22

(d) Yukon Energy Corporation & The Yukon Electrical Company Ltd. Terms and Conditions of Service, Schedule B Maximum Company Investment 1 C) Municipal Street Lighting: $1,240.00 per light. These T&Cs were approved by the YUB in Board Decision 2011-05

September 28, 2023 AEY-YUB-063

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-063

Reference: 2023-24 GRA, Business Case #34 – Yukon Government Robert Campbell Highway Streetlights, PDF pages 131-134; 2023-24 GRA Schedules, S9.2

Issue: Capital expenditures (Street and Sentinel Lighting)

Request:

Referring to the Business Case #34, Table 1 (PDF page 132), please reference where the street light project costs of $0.907 million ($0.350 million – Material; $0.557 million - Labour) can be found on 2023-24 GRA Schedules, S9.2.

Response:

These capital expenditures are included on Schedule 9.2, line 311. Please refer to AEY-YUB-046(a) Attachment 1.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-064

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-064

Reference: 2023-24 GRA, Section 9.5, Streetlights, PDF pages 177; Schedule 9.2

Issue: Street lights

Preamble: The Board requires further information concerning street lights.

Request:

(a) Please provide the capital spend to date (2023) on the new customer, McIntyre, and Whistle Bend Streetlight installation projects.

(b) For New Customer Streetlight Installations (Schedule 9.2 line 311), please explain the material increase in forecast expenditures for 2023 over 2022.

(c) Are there offsetting customer contributions for any of the street light installations? If so, please provide the amount of customer contributions.

Response:

(a) Summary of Streetlight Costs Year-To-Date August 2023.

Table 1: Streetlight Costs
($)

	Capital	Contribution	Net Cost of Capital
New Customer Streetlights	513,386	(933,511)	(420,125)
Whistle Bend Street Lights - Stage 6	596	-	596
Whistle Bend Street Lights - Stage 7	153,532	-	153,532
Whistle Bend Street Lights - Stage 8	1,210	(43,795)	(42,584)
McIntyre Subdivision Streetlight Rebuild	5,152	5,153	10,305
Total	**673,876**	**(972,152)**	**(298,276)**

(b) The increased cost from 2022 to 2023 on line 311 of Schedule 9.2 is due mainly to the streetlighting and underground supply cables to be installed from km 1 to km 4 on the Robert Campbell Highway near Watson Lake. This is a customer driven project request by the Yukon Government.

(c) Please refer to the response to part (a) above for 2023. New Customer Streetlights installation contributions in 2022 total $462,488.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-067

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-067

Reference: 2023-24 GRA, Sections 9.7 and 9.9, General Property Plant and Equipment, PDF pages 178 and 179-180; Schedule 9.2.; Business Case #22, PDF pages 2-6

Issue: ATCO CIS Replacement

Preamble: The Board requires further information.

Request:

(a) What is the expected life of the replacement system?

(b) Is the replacement system a licensed product?

(c) If the replacement system is a licensed product, what do the capital costs represent?

(d) Will AEY have ownership for those capital costs attributed to it? Please explain.

(e) Please explain how increasing demands of electrification and renewable technologies affect the complexity of the billing system.

(f) Please provide the economic analysis that demonstrates that this ATCO CIS Replacement is the lowest cost option.

(g) AEY's parent company is transitioning away from the use of CIS; how were charges to AEY (both capital and operating) determined?

Response:

(a) Oracle's Customer Cloud Service (CCS) product is a cloud-based application which receives monthly security based patches, and tri-annual software based improvements/enhancements that are mandatory to be deployed through the Oracle subscription. The exact life expectancy is unknown at this point in time, but

it would be similar to that of ATCO Oracle ERP system, which follows a similar process of keeping the cloud-based software up-to-date and current.

(b) Yes, the replacement product is a subscription-based Oracle product called Oracle Customer Cloud Service (CCS).

(c) The licensed Oracle CCS product includes out-of-box functionality, requiring some configuration in order to meet ATCO's technical and business requirements. The capital costs represent the costs associated with labour, computing (which includes software subscription costs, software licensing costs, IT environment costs, and IT storage costs), costs associated with designing, building, testing, and implementing a reliable and robust billing system while meeting ATCO's specific business and technical requirements and ensuring the transition from ATCO's legacy CIS to Oracle CCS is as seamless as possible for AEY's customers.

(d) Yes, AEY will be attributed 62 percent of total project cost. The percentage allocation has been determined based on number of customers being served by AEY.

(e) The replacement of ATCO's end of life CIS will provide customers with a modern CIS that is flexible to new and growing customer requirements as a modern CIS will facilitate advancements in electrification and renewable technologies. The implementation of Oracle CCS for AEY followed the principle of replacing existing functionality that existed in ATCO's legacy CIS. That said, the Oracle CCS Software as a Services (SaaS) product lends itself well to out-of-the-box configurations to meet future demands of customer and industry needs. This includes, but is not limited to, customer growth and allows for management of large volumes of meter data. It also integrates with AMI to enable the management of enhanced automated services including on-demand time-of-use meter readings and remote connect and disconnects.

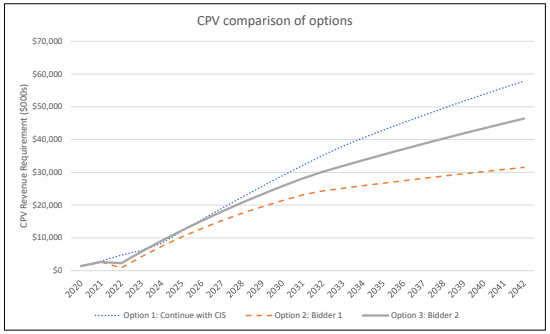
(f) Please refer to AEY-YUB-067(f) Attachment 1 for the annual revenue requirement and cumulative revenue requirement for each of the explored scenarios over 20-years. Oracle CCS was chosen as the lowest cost option.

(g) AEY is utilizing a separate and distinct instance of Oracle CCS from that of ATCO Electric and ATCO Gas Distribution Utilities (different utility requirements). Therefore, all capital and operating costs allocated to AEY are those for the separate North of 60 implementation.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

CIS Project Cumulative Present Value Analysis

Line No.				{0}	{1}	{2}	{3}	{4}	{5}	{6}	{7}	{8}	{9}	{10}	{11}	{12}	{13}	{14}	{15}	{16}	{17}	{18}	{19}	{20}	{21}	{22}	{23}	{24}	{25}
1	**CIS Update Project**																												
2	Discount Rate 7.93%		yr	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
3																													
4	x	**1) Undiscounted Revenue Requirement ($000s)** - *link to option*																											
5		Option 1: Continue with CIS		1,407	1,624	2,132	1,776	3,050	5,321	5,611	5,938	6,247	6,566	6,907	7,246	7,644	7,654	7,330	7,361	7,746	8,204	8,660	9,125	9,612	10,123	10,740	3,369	3,002	2,640
6		Option 2: Bidder 1		1,407	1,342	(2,087)	4,303	4,243	4,186	4,144	4,114	4,067	4,024	3,996	3,962	3,065	2,183	2,284	2,407	2,515	2,660	2,816	2,944	3,079	3,247	3,451	101	91	80
7		Option 3: Bidder 2		1,407	1,342	(441)	4,425	4,505	4,593	4,703	4,858	4,974	5,101	5,251	5,401	5,116	4,813	5,067	5,392	5,671	5,967	6,365	6,699	7,054	7,508	7,923	439	393	348
8																													
9	x	**2) Cumulative Present Value Revenue Requirement ($000s)**																											
10		Option 1: Continue with CIS		$1,407	$2,912	$4,743	$6,155	$8,402	$12,036	$15,585	$19,065	$22,458	$25,762	$28,982	$32,112	$35,171	$38,009	$40,527	$42,870	$45,155	$47,397	$49,589	$51,730	$53,819	$55,857	$57,861	$58,443	$58,924	$59,316
11		Option 2: Bidder 1		$1,407	$2,651	$859	$4,282	$7,408	$10,266	$12,887	$15,298	$17,507	$19,532	$21,395	$23,106	$24,333	$25,143	$25,927	$26,694	$27,435	$28,162	$28,875	$29,566	$30,235	$30,889	$31,532	$31,550	$31,564	$31,576
12		Option 3: Bidder 2		$1,407	$2,651	$2,272	$5,792	$9,112	$12,249	$15,224	$18,071	$20,772	$23,339	$25,787	$28,120	$30,167	$31,952	$33,693	$35,409	$37,082	$38,712	$40,324	$41,895	$43,428	$44,940	$46,418	$46,494	$46,557	$46,609
13																													
14	x	**3) Summary chart**																											
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ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

CIS Project Cumulative Present Value Analysis

Option 1: Continue with CIS

Line No.																															
							{0}	{1}	{2}	{3}	{4}	{5}	{6}	{7}	{8}	{9}	{10}	{11}	{12}	{13}	{14}	{15}	{16}	{17}	{18}	{19}	{20}	{21}	{22}	{23}	{24}	{25}	
						yr	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
x	**Capital structure**																															
		Rate	Ratio	B.T. Cost	A.T. Cost																											
	Debt	5.09%	59.57%	3.03%	3.03%																											
	Preferred	0.00%	0.69%	0.00%	0.00%																											
	Common	9.00%	39.73%	4.90%	3.58%																											
	TOTALS		**100.0%**	**7.93%**	**6.61%**																											
	Income Tax	27.0%																														
x	**Escalation**																															
	Capital	2.00%																														
	O & M	2.00%																														
x	**Capital spending ($000s)**																															
	Description	**ISD (Year)**	**Deprc'n (yrs)**	**CCA (%)**																												
	Installation costs	2022	10	100%			4	4	4	5,299	5,373	977	991	1,065	1,080	1,096	1,112	1,128	1,222	1,240	1,258	1,276	1,295	1,403	1,423	1,444	1,465	1,486	1,610	0	0	0	
	(escalated at 2%)						*4*	*4*	*4*	*5,623*	*5,815*	*1,078*	*1,116*	*1,223*	*1,266*	*1,310*	*1,355*	*1,402*	*1,550*	*1,604*	*1,660*	*1,717*	*1,777*	*1,964*	*2,032*	*2,103*	*2,177*	*2,253*	*2,489*	*0*	*0*	*0*	
x	**Incremental O&M spending ($000s)**																															
	Description																															
	Annual Operating Costs						1,407	1,592	2,053	3,068	3,149	2,957	3,046	3,179	3,265	3,356	3,461	3,560	3,722	3,832	3,959	4,087	4,220	4,424	4,577	4,728	4,884	5,047	5,299	0	0	0	
	(escalated at 2%)						*1,407*	*1,624*	*2,136*	*3,256*	*3,409*	*3,264*	*3,430*	*3,652*	*3,826*	*4,011*	*4,219*	*4,426*	*4,721*	*4,957*	*5,224*	*5,501*	*5,793*	*6,194*	*6,538*	*6,887*	*7,257*	*7,649*	*8,193*	*0*	*0*	*0*	
x	**Installation costs detail (Expand with '+')**																															
	Description	Installation costs			**Capital Expenditures**																												
	ISD	2022			Escalated Cap Ex		4	4	4	5,623	5,815	1,078	1,116	1,223	1,266	1,310	1,355	1,402	1,550	1,604	1,660	1,717	1,777	1,964	2,032	2,103	2,177	2,253	2,489	-	-	-	
	Depreciation	10.00%																														
	CCA Rate	100%			**AFUDC**																											
					Opening		-	4	9	13	5,636	11,452	12,530	13,646	14,870	16,135	17,445	18,800	20,203	21,753	23,357	25,016	26,733	28,511	30,475	32,507	34,610	36,787	39,039	41,529	41,529	41,529	
	Tax	27.0%			Cap Ex		4	4	4	5,623	5,815	1,078	1,116	1,223	1,266	1,310	1,355	1,402	1,550	1,604	1,660	1,717	1,777	1,964	2,032	2,103	2,177	2,253	2,489	-	-	-	
	AT WACC	6.61%			AFUDC		0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BT WACC	7.93%			**Rate Base Add.**		-	-	**13**	**5,623**	**5,815**	**1,078**	**1,116**	**1,223**	**1,266**	**1,310**	**1,355**	**1,402**	**1,550**	**1,604**	**1,660**	**1,717**	**1,777**	**1,964**	**2,032**	**2,103**	**2,177**	**2,253**	**2,489**	-	-	-	41,529
	Equity	3.58%			Mid-year		-	-	7	2,818	5,719	3,447	1,097	1,170	1,245	1,288	1,333	1,379	1,476	1,577	1,632	1,688	1,747	1,871	1,998	2,068	2,140	2,215	2,371	1,245	-	-	
	Debt	3.03%																														
	Preferred	0.00%			**Rate Base**																											
					Opening		-	-	-	13	5,353	10,314	10,193	10,001	9,798	9,514	9,145	8,688	8,140	7,593	7,224	7,319	7,648	7,972	8,412	8,846	9,272	9,691	10,103	10,661	8,764	7,029	
					Closing		-	-	13	5,353	10,314	10,193	10,001	9,798	9,514	9,145	8,688	8,140	7,593	7,224	7,319	7,648	7,972	8,412	8,846	9,272	9,691	10,103	10,661	8,764	7,029	5,464	
					Rate Base		**-**	**-**	**6**	**2,683**	**7,834**	**10,254**	**10,097**	**9,900**	**9,656**	**9,329**	**8,916**	**8,414**	**7,866**	**7,408**	**7,271**	**7,483**	**7,810**	**8,192**	**8,629**	**9,059**	**9,482**	**9,897**	**10,382**	**9,712**	**7,896**	**6,247**	
					Tax Treatment																											
					Depreciation		-	-	1	282	854	1,199	1,309	1,426	1,550	1,679	1,812	1,950	2,097	1,973	1,564	1,388	1,453	1,523	1,599	1,677	1,758	1,841	1,931	1,897	1,734	1,565	
					Equity & Preferred		-	-	0	96	280	367	361	354	345	334	319	301	281	265	260	268	279	293	309	324	339	354	371	347	282	223	
					CCA		-	-	(13)	(5,623)	(5,815)	(1,078)	(1,116)	(1,223)	(1,266)	(1,310)	(1,355)	(1,402)	(1,550)	(1,604)	(1,660)	(1,717)	(1,777)	(1,964)	(2,032)	(2,103)	(2,177)	(2,253)	(2,489)	-	-	-	
					Earnings for Tax		**-**	**-**	**(12)**	**(5,245)**	**(4,681)**	**487**	**554**	**556**	**630**	**703**	**776**	**849**	**828**	**634**	**165**	**(61)**	**(45)**	**(148)**	**(125)**	**(102)**	**(80)**	**(58)**	**(187)**	**2,245**	**2,017**	**1,789**	
					Revenue Requirement																											
					Depreciation		-	-	1	282	854	1,199	1,309	1,426	1,550	1,679	1,812	1,950	2,097	1,973	1,564	1,388	1,453	1,523	1,599	1,677	1,758	1,841	1,931	1,897	1,734	1,565	
					Debt		-	-	0	81	238	311	306	300	293	283	270	255	239	225	220	227	237	248	262	275	287	300	315	294	239	189	
					Equity		-	-	0	96	280	367	361	354	345	334	319	301	281	265	260	268	279	293	309	324	339	354	371	347	282	223	
					Tax		-	-	(5)	(1,940)	(1,731)	180	205	206	233	260	287	314	306	235	61	(23)	(16)	(55)	(46)	(38)	(30)	(21)	(69)	830	746	662	
					Asset 1 Revenue Requirement		**-**	**-**	**(3)**	**(1,480)**	**(359)**	**2,057**	**2,181**	**2,286**	**2,421**	**2,555**	**2,688**	**2,820**	**2,923**	**2,697**	**2,106**	**1,860**	**1,953**	**2,010**	**2,123**	**2,238**	**2,355**	**2,474**	**2,547**	**3,369**	**3,002**	**2,640**	49,462
					Depreciation Matrix																											
						{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{2}	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1
						{3}	-	-	1	282	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	282
						{4}	-	-	1	282	572	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	854
						{5}	-	-	1	282	572	345	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,199
						{6}	-	-	1	282	572	345	110	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,309
						{7}	-	-	1	282	572	345	110	117	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,426
						{8}	-	-	1	282	572	345	110	117	124	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,550
						{9}	-	-	1	282	572	345	110	117	124	129	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,679
						{10}	-	-	1	282	572	345	110	117	124	129	133	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,812
						{11}	-	-	1	282	572	345	110	117	124	129	133	138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,950
						{12}	-	-	-	282	572	345	110	117	124	129	133	138	148	-	-	-	-	-	-	-	-	-	-	-	-	-	2,097
						{13}	-	-	-	-	572	345	110	117	124	129	133	138	148	158	-	-	-	-	-	-	-	-	-	-	-	-	1,973
						{14}	-	-	-	-	-	345	110	117	124	129	133	138	148	158	163	-	-	-	-	-	-	-	-	-	-	-	1,564
						{15}	-	-	-	-	-	-	110	117	124	129	133	138	148	158	163	169	-	-	-	-	-	-	-	-	-	-	1,388
						{16}	-	-	-	-	-	-	-	117	124	129	133	138	148	158	163	169	175	-	-	-	-	-	-	-	-	-	1,453
						{17}	-	-	-	-	-	-	-	-	124	129	133	138	148	158	163	169	175	187	-	-	-	-	-	-	-	-	1,523
						{18}	-	-	-	-	-	-	-	-	-	129	133	138	148	158	163	169	175	187	200	-	-	-	-	-	-	-	1,599
						{19}	-	-	-	-	-	-	-	-	-	-	133	138	148	158	163	169	175	187	200	207	-	-	-	-	-	-	1,677
						{20}	-	-	-	-	-	-	-	-	-	-	-	138	148	158	163	169	175	187	200	207	214	-	-	-	-	-	1,758
						{21}	-	-	-	-	-	-	-	-	-	-	-	-	148	158	163	169	175	187	200	207	214	221	-	-	-	-	1,841
						{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	158	163	169	175	187	200	207	214	221	237	-	-	-	1,931
						{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	163	169	175	187	200	207	214	221	237	124	-	-	1,897
						{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	169	175	187	200	207	214	221	237	124	-	-	1,734
						{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	175	187	200	207	214	221	237	124	-	-	1,565
					Capital Cost Allowance Matrix																											
						{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{2}	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13
						{3}	-	-	-	5,623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,623
						{4}	-	-	-	-	5,815	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,815
						{5}	-	-	-	-	-	1,078	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,078
						{6}	-	-	-	-	-	-	1,116	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,116
						{7}	-	-	-	-	-	-	-	1,223	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,223
						{8}	-	-	-	-	-	-	-	-	1,266	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,266
						{9}	-	-	-	-	-	-	-	-	-	1,310	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,310
						{10}	-	-	-	-	-	-	-	-	-	-	1,355	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,355
						{11}	-	-	-	-	-	-	-	-	-	-	-	1,402	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,402
						{12}	-	-	-	-	-	-	-	-	-	-	-	-	1,550	-	-	-	-	-	-	-	-	-	-	-	-	-	1,550
						{13}	-	-	-	-	-	-	-	-	-	-	-	-	-	1,604	-	-	-	-	-	-	-	-	-	-	-	-	1,604
						{14}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,660	-	-	-	-	-	-	-	-	-	-	-	1,660
						{15}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,717	-	-	-	-	-	-	-	-	-	-	1,717
						{16}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,777	-	-	-	-	-	-	-	-	-	1,777
						{17}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,964	-	-	-	-	-	-	-	-	1,964
						{18}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,032	-	-	-	-	-	-	-	2,032
						{19}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,103	-	-	-	-	-	-	2,103
						{20}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,177	-	-	-	-	-	2,177
						{21}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,253	-	-	-	-	2,253
						{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,489	-	-	-	2,489
						{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
x	**Total Revenue Requirement ($000s)**																															
	Capital subtotal						0	0	(3)	(1,480)	(359)	2,057	2,181	2,286	2,421	2,555	2,688	2,820	2,923	2,697	2,106	1,860	1,953	2,010	2,123	2,238	2,355	2,474	2,547	3,369	3,002	2,640	
	O&M subtotal						1,407	1,624	2,136	3,256	3,409	3,264	3,430	3,652	3,826	4,011	4,219	4,426	4,721	4,957	5,224	5,501	5,793	6,194	6,538	6,887	7,257	7,649	8,193	0	0	0	
	Total Revenue Requirement						**$1,407**	**$1,624**	**$2,132**	**$1,776**	**$3,050**	**$5,321**	**$5,611**	**$5,938**	**$6,247**	**$6,566**	**$6,907**	**$7,246**	**$7,644**	**$7,654**	**$7,330**	**$7,361**	**$7,746**	**$8,204**	**$8,660**	**$9,125**	**$9,612**	**$10,123**	**$10,740**	**$3,369**	**$3,002**	**$2,640**	

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

CIS Project Cumulative Present Value Analysis

Line No.																															
1	**Option 2: Bidder 1**					{0}	{1}	{2}	{3}	{4}	{5}	{6}	{7}	{8}	{9}	{10}	{11}	{12}	{13}	{14}	{15}	{16}	{17}	{18}	{19}	{20}	{21}	{22}	{23}	{24}	{25}	
2					**yr**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
3																															
4	x **Capital structure**																														
5		Rate	Ratio	B.T. Cost	A.T. Cost																										
6	Debt	5.09%	59.57%	3.03%	3.03%																										
7	Preferred	0.00%	0.69%	0.00%	0.00%																										
8	Common	9.00%	39.73%	4.90%	3.58%																										
9	**TOTALS**		**100.0%**	**7.93%**	**6.61%**																										
10	**Income Tax**	27.0%																													
11																															
12	x **Escalation**																														
13	**Capital**	2.00%																													
14	**O & M**	2.00%																													
15																															
16	x **Capital spending ($000s)**																														
17	**Description**	**ISD (Year)**	**Deprc'n (yrs)**	**CCA (%)**																											
18	Installation costs	2022	10	100%		4	1,363	11,732	22	23	24	25	26	27	28	30	31	32	34	35	37	38	40	42	44	46	48	50	0	0	0	
19	*(escalated at 2%)*					*4*	*1,390*	*12,206*	*23*	*25*	*26*	*28*	*30*	*32*	*34*	*36*	*39*	*41*	*44*	*47*	*50*	*53*	*56*	*60*	*64*	*68*	*72*	*77*	*0*	*0*	*0*	
20																															
21	x **Incremental O&M spending ($000s)**																														
22	**Description**																														
23	Annual operating costs					1,407	1,316	1,465	1,372	1,385	1,401	1,428	1,465	1,485	1,507	1,539	1,564	1,626	1,655	1,697	1,753	1,794	1,861	1,931	1,978	2,027	2,096	2,184	0	0	0	
24	*(escalated at 2%)*					*1,407*	*1,342*	*1,524*	*1,456*	*1,500*	*1,547*	*1,608*	*1,682*	*1,740*	*1,800*	*1,876*	*1,944*	*2,062*	*2,140*	*2,239*	*2,359*	*2,463*	*2,606*	*2,758*	*2,882*	*3,013*	*3,177*	*3,376*	*0*	*0*	*0*	
25																															
26	x **Installation costs detail (Expand with '+')**																														
27	Description	installation costs			**Capital Expenditures**																										
28	ISD	2022			Escalated Cap Ex	4.1	1,390.2	12,205.9	23.3	24.8	26.4	28.1	29.9	31.9	34.0	36.2	38.5	41.0	43.7	46.5	49.5	52.7	56.2	59.8	63.7	67.9	72.3	77.0	-	-	-	
29	Depreciation	10.00%																													
30	CCA Rate	100%			**AFUDC**																										
31					Opening	-	4	1,441	13,694	13,717	13,742	13,769	13,797	13,827	13,859	13,893	13,929	13,967	14,008	14,052	14,098	14,148	14,201	14,257	14,317	14,380	14,448	14,520	14,597	14,597	14,597		
32	Tax	27.0%			Cap Add	4	1,390	12,206	23	25	26	28	30	32	34	36	39	41	44	47	50	53	56	60	64	68	72	77	-	-	-	
33	AT WACC	6.61%			AFUDC	0	46	48	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
34	BT WACC	7.93%			**Rate Base Add.**	-	-	**13,694**	**23**	**25**	**26**	**28**	**30**	**32**	**34**	**36**	**39**	**41**	**44**	**47**	**50**	**53**	**56**	**60**	**64**	**68**	**72**	**77**	-	-	-		14,597
35	Equity	3.58%			Mid-year	-	-	6,847	6,859	24	26	27	29	31	33	35	37	40	42	45	48	51	54	58	62	66	70	75	38	-	-		
36	Debt	3.03%																													
37	Preferred	0.00%			**Rate Base**																										
38					Opening	-	-	-	13,009	11,662	10,314	8,965	7,615	6,263	4,911	3,557	2,203	846	173	184	196	209	223	237	253	269	287	305	325	268	216		
39					Closing	-	-	13,009	11,662	10,314	8,965	7,615	6,263	4,911	3,557	2,203	846	173	184	196	209	223	237	253	269	287	305	325	268	216	169	
40					**Rate Base**	-	-	**6,505**	**12,336**	**10,988**	**9,639**	**8,290**	**6,939**	**5,587**	**4,234**	**2,880**	**1,524**	**510**	**179**	**190**	**203**	**216**	**230**	**245**	**261**	**278**	**296**	**315**	**297**	**242**	**192**		
41																															
42					**Tax Treatment**																										
43					Depreciation	-	-	685	1,371	1,373	1,376	1,378	1,381	1,384	1,388	1,391	1,395	714	32	35	37	39	42	44	47	50	54	57	57	52	47		
44					Equity & Preferred	-	-	233	441	393	345	296	248	200	151	103	55	18	6	7	7	8	8	9	9	10	11	11	11	9	7		
45					CCA	-	-	(13,694)	(23)	(25)	(26)	(28)	(30)	(32)	(34)	(36)	(39)	(41)	(44)	(47)	(50)	(53)	(56)	(60)	(64)	(68)	(72)	(77)	-	-	-		
46					**Earnings for Tax**	-	-	**(12,777)**	**1,788**	**1,741**	**1,694**	**1,647**	**1,599**	**1,552**	**1,505**	**1,458**	**1,411**	**691**	**(5)**	**(5)**	**(6)**	**(6)**	**(6)**	**(7)**	**(7)**	**(8)**	**(8)**	**(9)**	**67**	**61**	**54**		
47																															
48					**Revenue Requirement**																										
49					Depreciation	-	-	685	1,371	1,373	1,376	1,378	1,381	1,384	1,388	1,391	1,395	714	32	35	37	39	42	44	47	50	54	57	57	52	47		
50					Debt	-	-	197	374	333	292	251	210	169	128	87	46	15	5	6	6	7	7	7	7	8	8	9	10	9	7	6	
51					Equity	-	-	233	441	393	345	296	248	200	151	103	55	18	6	7	7	8	8	9	9	10	11	11	11	9	7		
52					Tax	-	-	(4,726)	661	644	626	609	592	574	557	539	522	256	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	25	23	20	
53					**Asset 1 Revenue Requirement**	-	-	**(3,611)**	**2,847**	**2,743**	**2,639**	**2,535**	**2,431**	**2,328**	**2,224**	**2,121**	**2,017**	**1,003**	**42**	**45**	**48**	**51**	**55**	**58**	**62**	**66**	**70**	**75**	**101**	**91**	**80**		20,122
54																															
55					**Depreciation Matrix**																										
56					{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57					{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58					{2}	-	-	685	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	685
59					{3}	-	-	685	686	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,371
60					{4}	-	-	685	686	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,373
61					{5}	-	-	685	686	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,376
62					{6}	-	-	685	686	2	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,378
63					{7}	-	-	685	686	2	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,381
64					{8}	-	-	685	686	2	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,384
65					{9}	-	-	685	686	2	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,388
66					{10}	-	-	685	686	2	3	3	3	3	3	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,391
67					{11}	-	-	685	686	2	3	3	3	3	3	4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,395
68					{12}	-	-	-	686	2	3	3	3	3	3	4	4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	714
69					{13}	-	-	-	-	2	3	3	3	3	3	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-	-	32
70					{14}	-	-	-	-	-	3	3	3	3	3	4	4	4	4	5	-	-	-	-	-	-	-	-	-	-	-	35
71					{15}	-	-	-	-	-	-	3	3	3	3	4	4	4	4	5	5	-	-	-	-	-	-	-	-	-	-	37
72					{16}	-	-	-	-	-	-	-	3	3	3	4	4	4	4	5	5	5	-	-	-	-	-	-	-	-	-	39
73					{17}	-	-	-	-	-	-	-	-	3	3	4	4	4	4	5	5	5	5	-	-	-	-	-	-	-	-	42
74					{18}	-	-	-	-	-	-	-	-	-	3	4	4	4	4	5	5	5	5	6	-	-	-	-	-	-	-	44
75					{19}	-	-	-	-	-	-	-	-	-	-	4	4	4	4	5	5	5	5	6	6	-	-	-	-	-	-	47
76					{20}	-	-	-	-	-	-	-	-	-	-	-	4	4	4	5	5	5	5	6	6	7	-	-	-	-	-	50
77					{21}	-	-	-	-	-	-	-	-	-	-	-	-	4	4	5	5	5	5	6	6	7	7	-	-	-	-	54
78					{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	4	5	5	5	5	6	6	7	7	7	-	-	-	57
79					{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	5	6	6	7	7	7	4	-	-	57
80					{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	5	6	6	7	7	7	4	-	-	52
81					{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	5	6	6	7	7	7	4	-	-	47
82																															
83					**Capital Cost Allowance Matrix**																										
84					{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85					{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86					{2}	-	-	13,694	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13,694
87					{3}	-	-	-	23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23
88					{4}	-	-	-	-	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25
89					{5}	-	-	-	-	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
90					{6}	-	-	-	-	-	-	28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	28
91					{7}	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30
92					{8}	-	-	-	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32
93					{9}	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	34
94					{10}	-	-	-	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	36
95					{11}	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39
96					{12}	-	-	-	-	-	-	-	-	-	-	-	-	41	-	-	-	-	-	-	-	-	-	-	-	-	-	41
97					{13}	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	-	-	-	-	-	-	-	-	-	-	44
98					{14}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-	-	-	-	-	47
99					{15}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	50
100					{16}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	53	-	-	-	-	-	-	-	-	-	53
101					{17}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	56	-	-	-	-	-	-	-	-	56
102					{18}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
103					{19}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64	-	-	-	-	-	-	64
104					{20}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	-	-	68
105					{21}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	72
106					{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	-	-	-	77
107					{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
108					{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
109					{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110																															
111	x **Total Revenue Requirement ($000s)**																														
112	Capital subtotal					0	0	(3,611)	2,847	2,743	2,639	2,535	2,431	2,328	2,224	2,121	2,017	1,003	42	45	48	51	55	58	62	66	70	75	101	91	80	
113	O&M subtotal					1,407	1,342	1,524	1,456	1,500	1,547	1,608	1,682	1,740	1,800	1,876	1,944	2,062	2,140	2,239	2,359	2,463	2,606	2,758	2,882	3,013	3,177	3,376	0	0	0	
114	**Total Revenue Requirement**					**$1,407**	**$1,342**	**($2,087)**	**$4,303**	**$4,243**	**$4,186**	**$4,144**	**$4,114**	**$4,067**	**$4,024**	**$3,996**	**$3,962**	**$3,065**	**$2,183**	**$2,284**	**$2,407**	**$2,515**	**$2,660**	**$2,816**	**$2,944**	**$3,079**	**$3,247**	**$3,451**	**$101**	**$91**	**$80**	

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

CIS Project Cumulative Present Value Analysis

Option 3: Bidder 2

Line No.																															
							{0}	{1}	{2}	{3}	{4}	{5}	{6}	{7}	{8}	{9}	{10}	{11}	{12}	{13}	{14}	{15}	{16}	{17}	{18}	{19}	{20}	{21}	{22}	{23}	{24}	{25}	
						yr	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
	x **Capital structure**																															
		Rate	Ratio	B.T. Cost	A.T. Cost																											
	Debt	5.09%	59.57%	3.03%	3.03%																											
	Preferred	0.00%	0.69%	0.00%	0.00%																											
	Common	9.00%	39.73%	4.90%	3.58%																											
	TOTALS		**100.0%**	**7.93%**	**6.61%**																											
	Income Tax	27.0%																														
	x **Escalation**																															
	Capital	2.00%																														
	O & M	2.00%																														
	x **Capital spending ($000s)**																															
	Description	**ISD (Year)**	**Deprc'n (yrs)**	**CCA (%)**																												
	Installation costs	2022	10	100%			4	1,528	5,662	95	99	104	108	113	118	123	129	134	140	146	153	159	167	174	182	190	198	207	216	0	0	0	
	(escalated at 2%)						*4*	*1,559*	*5,891*	*101*	*107*	*114*	*122*	*130*	*138*	*147*	*157*	*167*	*178*	*189*	*202*	*215*	*229*	*243*	*259*	*276*	*294*	*313*	*333*	*0*	*0*	*0*	
	x **Incremental O&M spending ($000s)**																															
	Description																															
	Annual operating costs						1,407	1,316	1,492	2,711	2,769	2,831	2,908	3,020	3,093	3,171	3,262	3,348	3,483	3,578	3,692	3,851	3,969	4,093	4,280	4,414	4,555	4,753	4,915	0	0	0	
	(escalated at 2%)						*1,407*	*1,342*	*1,552*	*2,877*	*2,997*	*3,126*	*3,275*	*3,469*	*3,624*	*3,789*	*3,977*	*4,163*	*4,418*	*4,629*	*4,871*	*5,184*	*5,449*	*5,731*	*6,113*	*6,431*	*6,768*	*7,203*	*7,599*	*0*	*0*	*0*	
	x **Installation costs detail (Expand with '+')**																															
	Description	installation costs			**Capital Expenditures**																												
	ISD	2022			Escalated Cap Ex		4.1	1,559.1	5,891.1	100.9	107.4	114.4	121.8	129.7	138.2	147.1	156.7	166.9	177.7	189.2	201.5	214.6	228.6	243.4	259.2	276.1	294.0	313.1	333.5	-	-	-	
	Depreciation	10.00%																														
	CCA Rate	100%			**AFUDC**																											
					Opening		-	4	1,615	7,560	7,660	7,768	7,882	8,004	8,134	8,272	8,419	8,576	8,743	8,920	9,109	9,311	9,526	9,754	9,998	10,257	10,533	10,827	11,140	11,474	11,474	11,474	
	Tax	27.0%			Cap Add		4	1,559	5,891	101	107	114	122	130	138	147	157	167	178	189	202	215	229	243	259	276	294	313	333	-	-	-	
	AT WACC	6.61%			AFUDC		0	52	53	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	BT WACC	7.93%			**Rate Base Add.**		-	-	**7,560**	**101**	**107**	**114**	**122**	**130**	**138**	**147**	**157**	**167**	**178**	**189**	**202**	**215**	**229**	**243**	**259**	**276**	**294**	**313**	**333**	-	-	-	11,474
	Equity	3.58%			Mid-year		-	-	3,780	3,830	104	111	118	126	134	143	152	162	172	183	195	208	222	236	251	268	285	304	323	167	-	-	
	Debt	3.03%																														
	Preferred	0.00%			**Rate Base**																											
					Opening		-	-	-	7,182	6,521	5,857	5,189	4,517	3,840	3,158	2,470	1,777	1,078	751	799	851	907	965	1,028	1,095	1,166	1,242	1,322	1,408	1,163	936	
					Closing		-	-	7,182	6,521	5,857	5,189	4,517	3,840	3,158	2,470	1,777	1,078	751	799	851	907	965	1,028	1,095	1,166	1,242	1,322	1,408	1,163	936	731	
					Rate Base		-	-	**3,591**	**6,851**	**6,189**	**5,523**	**4,853**	**4,178**	**3,499**	**2,814**	**2,124**	**1,428**	**914**	**775**	**825**	**879**	**936**	**997**	**1,062**	**1,130**	**1,204**	**1,282**	**1,365**	**1,285**	**1,049**	**833**	
					Tax Treatment																											
					Depreciation		-	-	378	761	771	782	794	807	820	835	850	866	505	140	150	159	170	181	192	205	218	232	248	246	226	206	
					Equity & Preferred		-	-	128	245	221	197	174	149	125	101	76	51	33	28	30	31	33	36	38	40	43	46	49	46	38	30	
					CCA		-	-	(7,560)	(101)	(107)	(114)	(122)	(130)	(138)	(147)	(157)	(167)	(178)	(189)	(202)	(215)	(229)	(243)	(259)	(276)	(294)	(313)	(333)	-	-	-	
					Earnings for Tax		-	-	**(7,053)**	**905**	**885**	**866**	**846**	**827**	**807**	**788**	**769**	**750**	**360**	**(21)**	**(22)**	**(24)**	**(25)**	**(27)**	**(29)**	**(31)**	**(33)**	**(35)**	**(37)**	**292**	**264**	**235**		
					Revenue Requirement																											
					Depreciation		-	-	378	761	771	782	794	807	820	835	850	866	505	140	150	159	170	181	192	205	218	232	248	246	226	206	
					Debt		-	-	109	208	188	167	147	127	106	85	64	43	28	23	25	27	28	30	32	34	37	39	41	39	32	25	
					Equity		-	-	128	245	221	197	174	149	125	101	76	51	33	28	30	31	33	36	38	40	43	46	49	46	38	30	
					Tax		-	-	(2,609)	335	327	320	313	306	299	291	284	277	133	(8)	(8)	(9)	(9)	(10)	(11)	(11)	(12)	(13)	(14)	108	98	87	
					Asset 1 Revenue Requirement		-	-	**(1,993)**	**1,549**	**1,508**	**1,468**	**1,428**	**1,389**	**1,350**	**1,312**	**1,274**	**1,238**	**699**	**184**	**196**	**209**	**222**	**237**	**252**	**268**	**286**	**304**	**324**	**439**	**393**	**348**		14,881
					Depreciation Matrix																											
						{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
						{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
						{2}	-	-	378	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	378
						{3}	-	-	378	383	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	761
						{4}	-	-	378	383	10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	771
						{5}	-	-	378	383	10	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	782
						{6}	-	-	378	383	10	11	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	794
						{7}	-	-	378	383	10	11	12	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	807
						{8}	-	-	378	383	10	11	12	13	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	820
						{9}	-	-	378	383	10	11	12	13	13	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	835
						{10}	-	-	378	383	10	11	12	13	13	14	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	850
						{11}	-	-	378	383	10	11	12	13	13	14	15	16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	866
						{12}	-	-	-	383	10	11	12	13	13	14	15	16	17	-	-	-	-	-	-	-	-	-	-	-	-	-	505
						{13}	-	-	-	-	10	11	12	13	13	14	15	16	17	18	-	-	-	-	-	-	-	-	-	-	-	-	140
						{14}	-	-	-	-	-	11	12	13	13	14	15	16	17	18	20	-	-	-	-	-	-	-	-	-	-	-	150
						{15}	-	-	-	-	-	-	12	13	13	14	15	16	17	18	20	21	-	-	-	-	-	-	-	-	-	-	159
						{16}	-	-	-	-	-	-	-	13	13	14	15	16	17	18	20	21	22	-	-	-	-	-	-	-	-	-	170
						{17}	-	-	-	-	-	-	-	-	13	14	15	16	17	18	20	21	22	24	-	-	-	-	-	-	-	-	181
						{18}	-	-	-	-	-	-	-	-	-	14	15	16	17	18	20	21	22	24	25	-	-	-	-	-	-	-	192
						{19}	-	-	-	-	-	-	-	-	-	-	15	16	17	18	20	21	22	24	25	27	-	-	-	-	-	-	205
						{20}	-	-	-	-	-	-	-	-	-	-	-	16	17	18	20	21	22	24	25	27	29	-	-	-	-	-	218
						{21}	-	-	-	-	-	-	-	-	-	-	-	-	17	18	20	21	22	24	25	27	29	30	-	-	-	-	232
						{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	18	20	21	22	24	25	27	29	30	32	-	-	-	248
						{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	21	22	24	25	27	29	30	32	17	-	-	246
						{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21	22	24	25	27	29	30	32	17	-	-	226
						{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	22	24	25	27	29	30	32	17	-	-	206
					Capital Cost Allowance Matrix																												
						{0}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{1}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{2}	-	-	7,560	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,560
						{3}	-	-	-	101	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	101
						{4}	-	-	-	-	107	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	107
						{5}	-	-	-	-	-	114	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	114
						{6}	-	-	-	-	-	-	122	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	122
						{7}	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130
						{8}	-	-	-	-	-	-	-	-	138	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	138
						{9}	-	-	-	-	-	-	-	-	-	147	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	147
						{10}	-	-	-	-	-	-	-	-	-	-	157	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	157
						{11}	-	-	-	-	-	-	-	-	-	-	-	167	-	-	-	-	-	-	-	-	-	-	-	-	-	-	167
						{12}	-	-	-	-	-	-	-	-	-	-	-	-	178	-	-	-	-	-	-	-	-	-	-	-	-	-	178
						{13}	-	-	-	-	-	-	-	-	-	-	-	-	-	189	-	-	-	-	-	-	-	-	-	-	-	-	189
						{14}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	202	-	-	-	-	-	-	-	-	-	-	-	202
						{15}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	-	-	-	-	-	-	-	-	-	215
						{16}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	229	-	-	-	-	-	-	-	-	-	229
						{17}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	243	-	-	-	-	-	-	-	-	243
						{18}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	259	-	-	-	-	-	-	-	259
						{19}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	276	-	-	-	-	-	-	276
						{20}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	-	-	-	-	-	294
						{21}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	313	-	-	-	-	313
						{22}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	333	-	-	-	333
						{23}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{24}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						{25}	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	x **Total Revenue Requirement ($000s)**																															
	Capital subtotal						0	0	(1,993)	1,549	1,508	1,468	1,428	1,389	1,350	1,312	1,274	1,238	699	184	196	209	222	237	252	268	286	304	324	439	393	348	
	O&M subtotal						1,407	1,342	1,552	2,877	2,997	3,126	3,275	3,469	3,624	3,789	3,977	4,163	4,418	4,629	4,871	5,184	5,449	5,731	6,113	6,431	6,768	7,203	7,599	0	0	0	
	Total Revenue Requirement						**$1,407**	**$1,342**	**($441)**	**$4,425**	**$4,505**	**$4,593**	**$4,703**	**$4,858**	**$4,974**	**$5,101**	**$5,251**	**$5,401**	**$5,116**	**$4,813**	**$5,067**	**$5,392**	**$5,671**	**$5,967**	**$6,365**	**$6,699**	**$7,054**	**$7,508**	**$7,923**	**$439**	**$393**	**$348**	

ATCO Electric YUKON

September 28, 2023 AEY-YUB-068

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-068

Reference: 2023-24 GRA, Sections 9.7 and 9.9, General Property Plant and Equipment, PDF pages 178 and 179-180; Schedule 9.2.; Business Case #24, PDF pages 13-16

Issue: Asset Management

Preamble: The Board requires further information.

Request:

(a) Table 1 from the BC#24 (PDF page 14) lists five categories where AEY is compared to a peer group. For each of the categories, please describe how AEY has failed to meet any reliability measures, where customer service has been negatively impacted or where AEY has incurred additional costs because it did not implement this Asset Management Program.

(b) The Evaluation of Viable Alternatives (PDF page 15) states: "The Alternative is Status Quo, which will not address any of the issues identified in the METSCO report and will lead to AEY falling further and further behind its peers." Is the appropriate measure where AEY ranks relative to other utilities or is it the level of service AEY provides to its customers? Please explain.

Response:

(a) METSCO Energy Solutions Inc. provided a comprehensive evaluation of AEY for each of these categories and documented missed opportunities, or gaps, relative to peers. These gaps correspond to improvement opportunities in the roadmap. See below table, for each category and a reference in the Appendix of the business case that describes the benefits of short-term step-wise improvement in asset management maturity.

Table 1: METSCO Report Categories

Category of Asset Management	METSCO Energy Solutions Inc. Report Heading
Capital Planning	3.2.1.3
Maintenance & Operations	3.2.2.3
Records Management	3.2.3.3
Finance and Corporate Reporting	None
Enterprise Risk Management	3.2.5.3

Furthermore, benefits of medium- and long-term actions in the roadmap are described specifically in Table 4-3.

This structured improvement program would help articulate and align reliability objectives, customer service expectations, cost performance, and other important business and strategic goals under a framework of defined organizational values and asset management principles. The purpose of asset management for physical infrastructure is to coordinate the right asset investments to achieve strategic objectives while balancing costs, opportunities, and risks. AEY is recommending this initiative to face upcoming challenges of aging infrastructure, loss of knowledge (i.e., demographics), grid automation and modernization, and changing customer profiles with a methodical and sequenced approach to improvements in the way we work. AEY believes implementing the asset management roadmap will also help Yukon ratepayers understand how AEY is delivering on its broad mandate in more specific terms.

(b) When benchmarked against its peers, AEY ranks below in broad categories of capital planning, maintenance & operations, records management, finance & corporate reporting, and enterprise risk management. This is indicative of adoption and progress of the asset management principles within similar sized utilities in order to meet the challenges and expectations these businesses face. The measure of where AEY ranks in these categories to its peers, with similar customer profiles and infrastructure challenges, and the level of service that AEY provides

to its customers are not mutually exclusive. AEY would expect that reliability, affordability, and customer experience are level of service standards shared amongst its peers and it is reasonable to infer a direct correlation between peer performance in these respects to the maturity of their asset management program, based upon the benefits that METSCO Energy Solutions Inc. described within the report (Table 2-1 and footnote 2).

ATCO Electric YUKON

September 28, 2023 AEY-YUB-069

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-069

Reference: 2023-24 GRA, Section 10, Schedule S10.1, Line No. 30

Issue: Income taxes

Request:

(a) Are the deductible items and amounts for income tax purposes largely up to the discretion of management? Please explain.

(b) What is "ES&G & Other Deductible Costs"?

(c) How are actual ES&G & Other Deductible Costs determined?

(d) How are ES&G & Other Deductible Costs forecast?

(e) Does the "ES&G" portion of "ES&G & Other Deductible Costs" follow capital expenditures? That is, as capital expenditures increase, so would ES&G costs increase?

(f) If the "ES&G" portion of "ES&G & Other Deductible Costs" follow capital expenditures, should the they increase with the projected capital expenditures for each of the test years 2023 and 2024? Please explain.

(g) For the years 2016 and 2017, please explain why the actual deductible amounts for ES&G & Other Deductible Costs are higher than the approved amounts for that line item.

(h) If actual income tax expense is lower than forecast, is that a benefit to the shareholder?

Response:

(a) While management has some discretion respecting income tax deductions, AEY follows Canada Revenue Agency tax rules and guidelines with respect to deductible items and amounts for income tax purposes.

(b) Similar to AEY's previous GRAs, ES&G and Other Deductible Costs have been deducted from Utility Earnings before Tax for purposes of calculating Taxable Income.

ES&G (Engineering, Supervision and General) costs are general in nature and not attributable to specific projects. These costs are allocated to the construction of capital projects as an overhead charge, such as telephone, printing and stationery, travel and accommodations, equipment hours, clerical support, drawings, and other project document management as well as the development and maintenance of engineering standards. These expenditures are analogous to overhead costs that would normally be charged by a contractor to engineer, procure, and construct similar projects.

Other Deductible Costs include one-time adjustments such as mid-term incentives and short-term incentive program payouts in relation to ES&G charged as capital support.

(c) As outlined in part (b) above, actual ES&G costs are costs that relate to the construction of capital projects. These costs are captured in ES&G accounts in AEY's general ledger and are allocated to capital projects, on a monthly basis, as capital overhead. Other Deductible Costs are not recurring and are determined when payments are incurred.

(d) ES&G and Other Deductible Costs are forecast by reviewing historical actuals, as explained in part (b) and (c) above, and applying trending analysis and using the best information available at the time of developing the forecast. For example,

additional review and analysis could include the addition of a capital project that is not typical compared to the norm, or a new initiative that has not previously been contemplated. Similarly, AEY's forecast has been adjusted for large customer projects, in the test period, which differs from the historical trend.

(e) The relationship between ES&G and capital expenditures is not linear. The estimated capital expenditures, to construct a capital asset, are comprised of different types of costs such as internal labor, materials, and contractors which do not have an impact on capital support (ES&G). The capital expenditures, in a given period, may increase (or decrease) due to higher (or lower) material costs or due to delays of project execution, which do not directly relate to the increased need for capital support (ES&G).

(f) Forecast ES&G costs are determined by reviewing the anticipated allocation of labour related costs to capital, less the portion directly allocated to large projects plus a historical average of other non-labour costs. Actual ES&G and Other Deductible Costs came in higher than the approved amounts mainly due to increased needs for capital support for Generation and Construction Projects in 2016 and 2017. This increase also included more support for AEY's renewables capital portfolio along with increased system investment for customer connections. The costs, previously anticipated to be charged to general capital overhead, were directly charged to the respective programs and are included in the undepreciated capital costs eligible for CCA deductions.

(g) While lower actual income tax amounts (versus forecast) may be to the benefit of shareholders, customers also benefit over the longer term, as trends in actual income tax expenses are reviewed and help form the basis for forecasting future income tax expenses included in revenue requirement and rate setting in AEY's GRAs.

ATCO Electric YUKON

September 28, 2023 AEY-YUB-070

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Information Responses Round 1 to:
The Yukon Utilities Board (YUB)
Received: September 6, 2023

AEY-YUB-070

Reference: 2023-24 GRA, Section 11, Prior Board Directions, PDF pages 11-12, 184-185 and 191

Issue: AEY response to Board Order 2017-01, Appendix A, dated April 27, 2017, Direction No. 16, paragraph 278

Quote: GRA, PDF page 184-185:

Direction No. 16, Reference: Paragraph 278

> Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. (Emphasis added)

Request:

(a) For the five most costly improvement project business cases submitted by AEY in its GRA, please provide references for each project to where AEY has included "the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs."

(b) For each project (Preventative System Performance, Note 1, and Corrective System Performance, Note 2) identified in Section 11 – Attachment 11.2, Direction No. 16, Reference: Paragraph 278, please provide a reference to the applicable

business case number from those submitted by AEY in its 2023-24 GRA and also the corresponding line no. on GRA Schedule S9.2 for that project.

Response:

(a) The five most costly distribution improvement project business cases with references to the performance deficiency are:

a. BC#12,26 Annual ROW Widening para 6. The selection of areas uses feeder specific statistics as an input.

b. BC#25 New Substations Mayo Road and Whistle Bend paras 2&4. This project addresses the capacity issue.

c. BC#30 6L19 Voltage Improvement paras 2-4,6 This project addresses the low voltage issues.

d. BC#29 Old Crow Voltage Improvement paras 2-3,5. This project addresses the low voltage issues.

e. BC#05 3 Phase Hotsprings Road para 5. This project addresses the system balance issue.

As the projects identified above are preventative rather than corrective, AEY has provided its load growth KPI report used to help determine the need for the distribution improvements in the area. Please refer to AEY-YUB-070(a) Attachment 1.

(b) Please refer to AEY-YUB-070(b) Attachment 1.

Summary

Less than 20% capacity remaining
Less than 10% capacity remaining

* All Values are in kVA

Arkell							
	Actual	Forecasted					
Percent Increase 2.72%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S8615 Normalized Load	3428	4380	4500	4622	4748		
S8619 Normalized Load	3068	3017	3099	3184	3270		
Transformer 1 Normalized Load	6266	7398	7599	7806	8018		
Regulator 1 Remaining Capacity	11055	9923	9721	9515	9302	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	3734	2602	2401	2194	1982	Transformer Rating	10000

Laberge							
	Actual	Forecasted					
Percent Increase 2.06%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S3600 Normalized Load	5600	5715	5833	5953	6075		
S8306 Normalized Load	1975	2016	2057	2099	2143		
Transformer 1 Normalized Load	7287	7730	7890	8052	8218		
Regulator 1 Remaining Capacity	10034	9590	9431	9268	9102	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	2713	2270	2110	1948	1782	Transformer Rating	10000

Lewes							
	Actual	Forecasted					
Percent Increase 0.58%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S6817 Normalized Load	2830	2807	2823	2839	2856		
S6822 Normalized Load	2139	2250	2263	2276	2289		
Transformer 1 Normalized Load	4851	5056	5086	5115	5145		
Regulator 1 Remaining Capacity	3809	3604	3575	3545	3515	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2649	2444	2414	2385	2355	Transformer Rating	7500

Logan							
	Actual	Forecasted					
Percent Increase 2.69%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9877 Normalized Load	1950	2122	2179	2237	2297		
S9878 Normalized Load	2677	2789	2864	2941	3020		
Transformer 1 Normalized Load	4447	4911	5043	5178	5318		
Regulator 1 Remaining Capacity	12874	12410	12278	12142	12003	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	5553	5089	4957	4822	4682	Transformer Rating	10000

Macrae							
	Actual	Forecasted					
Percent Increase 1.76%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S5953 Normalized Load	1861	1893	1927	1961	1995		
S9833 Normalized Load	4416	4494	4573	4654	4736		
Transformer 1 Normalized Load	6082	6387	6500	6614	6731		
Regulator 1 Remaining Capacity	2578	2273	2160	2046	1930	Regulator Rating (200A)	8660
Transformer 1 Remaining Capacity	3918	3613	3500	3386	3269	Transformer Rating	10000

Mountain View							
	Actual	Forecasted					
Percent Increase 2.52%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S8354 Normalized Load	1091	1118	1147	1176	1205		
S8358 Normalized Load	5630	5771	5917	6066	6219		
S8471 Normalized Load	1059	1086	1113	1141	1170		
Transformer 1 Normalized Load	7780	7976	8177	8383	8594		
Regulator 1 Remaining Capacity	1091	685	484	278	66	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	2431	2024	1823	1617	1406	Transformer Rating	10000

Porter Creek							
	Actual	Forecasted					
Percent Increase 2.12%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9402 Normalized Load	2867	3101	3166	3233	3302		
S9403 Normalized Load	4189	4278	4369	4461	4556		
Transformer 1 Normalized Load	6772	7379	7535	7695	7858		
Regulator 1 Remaining Capacity	1888	1282	1125	966	802	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3228	2621	2465	2305	2142	Transformer Rating	10000

Riverdale							
	Actual	Forecasted					
Percent Increase 1.9%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9400 Normalized Load	2197	2386	2431	2477	2524		
S9401 Normalized Load	933	962	980	999	1018		
Transformer 1 Normalized Load	2985	3348	3412	3476	3543		
Regulator 1 Remaining Capacity	5675	5312	5249	5184	5118	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	4515	4152	4088	4024	3957	Transformer Rating	7500

Selkirk							
	Actual	Forecasted					
Percent Increase 2.72%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S9977 Normalized Load	4675	4803	4934	5068	5207		
Transformer 1 Normalized Load	4675	4803	4934	5068	5207		
Regulator 1 Remaining Capacity	3985	3858	3727	3592	3454	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	5325	5197	5066	4932	4793	Transformer Rating	10000

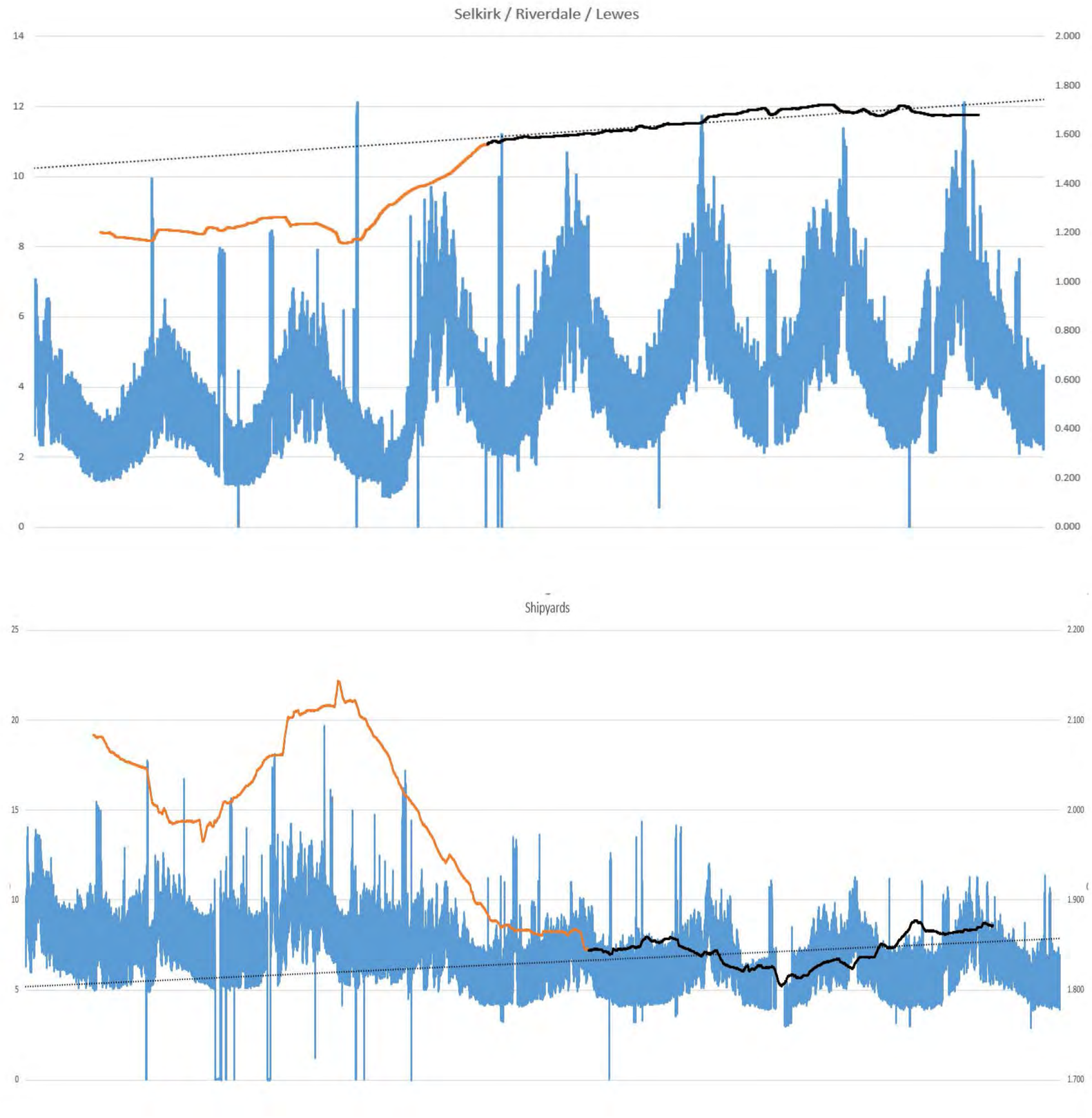
Services							
	Actual	Forecasted					
Percent Increase 0%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S7191 Normalized Load	3676	3676	3676	3676	3676		
Transformer 1 Normalized Load	3676	3676	3676	3676	5207		
Regulator 1 Remaining Capacity	5144	4984	4984	4984	4984	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3984	3824	3824	3824	3824	Transformer Rating	7500
S7192 Normalized Load	3268	3268	3268	3268	3268		
S7193 Normalized Load	1374	1374	1374	1374	1374		
Transformer 2 Normalized Load	4520	4642	4642	4642	4642		
Regulator 2 Remaining Capacity	4140	4019	4019	4019	4019	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	2980	2859	2859	2859	2859	Transformer Rating	7500

Shipyards							
	Actual	Forecasted					
Percent Increase 0.99%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S1020 Normalized Load	3720	3757	3794	3832	3870		
S1023 Normalized Load	3607	3643	3679	3715	3752		
Transformer 1 Normalized Load	6879	7400	7473	7547	7622		
Regulator 1 Remaining Capacity	1781	1260	1187	1113	1038	Regulator Rating (400A)	8660
Transformer 1 Remaining Capacity	3121	2600	2527	2453	2378	Transformer Rating	10000
S1011 Normalized Load	3550	3585	3620	3656	3692		
S1016 Normalized Load	1731	1748	1765	1782	1800		
Transformer 2 Normalized Load	4863	5333	5385	5439	5493		
Regulator 2 Remaining Capacity	3797	3328	3275	3222	3168	Regulator Rating (400A)	8660
Transformer 2 Remaining Capacity	5137	4667	4615	4561	4507	Transformer Rating	10000

Whistlebend							
	Actual	Forecasted					
Percent Increase 11.26%	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**	**2026/2027**		
S3431 Normalized Load	593	660	735	817	909		
S3432 Normalized Load	2518	2802	3117	3468	3858		
Transformer 1 Normalized Load	3088	3462	3852	4285	4768		
Regulator 1 Remaining Capacity	14233	13859	13469	13035	12553	Regulator Rating (400A)	17321
Transformer 1 Remaining Capacity	6912	6538	6148	5715	5232	Transformer Rating	10000
S3433 Normalized Load	5785	6436	7161	7967	8864		
S3434 Normalized Load	127	142	158	175	195		
Transformer 2 Normalized Load	5674	6578	7318	8142	9059		
Regulator 2 Remaining Capacity	11647	10743	10002	9178	8261	Regulator Rating (400A)	17321
Transformer 2 Remaining Capacity	4326	3422	2682	1858	941	Transformer Rating	10000

Substation	1yr moving avg	1yr moving avg with peak factor	Notes
Arkell	1.94%	2.72%	S150 SCADA (2015-2022) for the Arkell feeder supllied by YEC. This substation is servicing a mature residential subdivision, as well as some commercial along Range Road. No major development so moderate growth is expected
Laberge	1.47%	2.06%	This substation is servicing a large mature residential and industiral area that includes Hot Springs Road, the Alaska Hwy, and Kulan industrial. Therefore, a moderate yearly growth is to be expected. YEC SCADA data used
Lewes	0.42%	0.58%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Logan	1.92%	2.69%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Macrae	1.25%	1.76%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Mountain View	1.80%	2.52%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Porter Creek	1.52%	2.12%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Riverdale	1.35%	1.90%	This substation is servicing a mature residential subdivision. Therefore, low to moderate yearly growth is to be expected. Substation SCADA data used
Selkirk	1.95%	2.73%	Load from Services and Shipyards was shifted to Selkirk, this can be seen in the graph below. Data provided by YEC for S150 was used for the feeder that supplies Selkirk, Lewes, and Riverdale. The growth rate for Selkirk was calculated by taking the slope of the S150 feeder regression, minus the slope of the Riverdale regression, minus the slope of the Lewes regression. The remaining value is the slope of what would be the Selkirk regression.
Services	0.00%	0.00%	Both ATCO and YEC SCADA data show a steady decrease in load over the last four years (-5.19% and -3.56% respectively). There's uncertainty around why the decrease is occuring. Temporary load shifting within the data between Services, Arkell, Mountain View, and Porter Creek can all be accounted for.
Shipyards	0.71%	0.99%	Load from Shipyards was shifted to Selkirk. As seen in the graph below, the trendline was taken for the period of time after the load shift and once the 1 year moving average had stabalized.
Whistlebend	8.04%	11.26%	Growth at this substation is rapid due to on going development. Since ATCO has first hand knowledge of expected growth from the number of houses that are built each year, one of two approaches can be taken: Use the yearly growth percentage found from the moving average or apply a set load increase based on total number of homes built in a given year multiplied by average load per home. YEC SCADA data was used.

*Note regarding Laberge and Whistlebend - The growth percentage found from ATCO SCADA data subjectly high, whereas the growth seen from the YEC SCADA data for the feeder supllying Laberge and Whistlebend looked to be closer to what would be expected. To break up the YEC feeder data into its respective substations, the weight of growth percentages for each substation from ATCO SCADA was applied to the YEC data.


Selkirk / Riverdale / Lewes
14
12
10
8
6
4
2
0
2.000
1.800
1.600
1.400
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Shipyards
25
20
15
10
5
0
2.200
2.100
2.000
1.900
1.800
1.700

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Direction No. 16, Reference: Paragraph 278

Line No.	System Improvement Projects	2018	2019	2020	2021	2022	2023	2024	Annual Program
2	System Performance - Preventative[1]	1	2	3	1	2	3	10	2
3	System Performance - Corrective[2]	2	-	1	-	-	1	1	-
4	Life Extension	3	-	6	2	4	2	3	1
5	System Replacement	2	1	1	-	2	-	1	4
6	Customer Driven and/or Assigned	1	3	3	4	5	1	4	-

1. Preventative System Performance

Preventative system performance projects are determined based on operational drivers and address potential system imbalance, voltage or capacity issues before degradation of system or outages occur.

Project Name	I/S Year	Driver	Business Case	Line on 9.2	Note
Annual Right of Way Widening	Annual	Feeder-specific stats are used for ROW selection	#12, #26	182	
General Clearance Upgrades/Fixes	Annual	Conductor clearance concerns, trespass issues		186	
AEY 102 Lambert Encroachment	2024	Clearance issue		206	
3 Phase Hotsprings Rd	2020	System balance	#05	218	
AEY Old Crow Volt Issues-Loop	2019	System voltage		227	
AEY 25kV A.Hwy Hamilton Tie	2018	System alternative feed	#11	228	
Alaska Highway to Mcintyre Tie Stage 2	2019	System alternative feed	#11	229	
Teslin Substn Metering	2018	System power quality		230	
AEY SCADA Swtch at Pinerdg	2023	Operational capability		238	1
Carcross Road Voltage Improvements	2020	System voltage	#17	247	
Riverdale Load Sectionalizing	2020	Operational capability		256	
AEY Hamilton to Alaska Highway 25kV Tie	2021	System alternative feed		262	
AEY New Subst Mayo Rd	2024	Capacity	#25	266	2
AEY Voltage Issues Gold Road	2022	System voltage		267	
New Substation Mayo Road	2024	Capacity	#25	272	2
Reconductor Mayo Rd Mainline - Stage 3	2022	Protection and capacity	#06	273	
AEY Dogwood voltage improvement	2024	Voltage		278	
AEY DWCI - New 12.5kV substation	2026	Capacity		279	
AEY New Substation Whistle Bend - Leota	2025	Capacity	#25	281	
AEY SCADA Pineridge Switch	2023	Operational capability		283	1
AEY Voltage Improvement Destruction Bay	2023	Voltage		286	
AEY Hillcrest Voltage Improvement	2024	Voltage		289	
AEY Pelly Crossing Voltage Improvement	2024	Voltage		290	
Power System Assessment - YEC and AEY	2024	Capacity		292	
AEY 6L19 voltage improvement	2024	Voltage	#30	296	
AEY Carcross PQ monitoring	2024	System power quality		299	
Old Crow voltage improvement - reconductor	2024	Voltage	#29	301	

Note 1 - Line 21 is the actual costs for the SCADA Switch at Pineridge expended prior to the test years and line 32 is the forecast cost in the test year
Note 2 - Line 25 is the actual planning expenditure for the Mayo Road Substation while line 27 is the forecast cost for the Mayo Road Substation.

2. Corrective System Performance

Corrective system performance projects address system performance issues.

Project Name	I/S Year	KPI	Post Improvement KPI	Business Case	Line on 9.2
AEY CCC Rd Rebuild	2018	Outage count S6709 (2015-2018): 8	Outage Count S6709 (2019-2022): 0		217
AEY Wtsn Lk Vertical Strcts	2018	SAIFI (Watson Lake - 2017 System Wide): 5.25	SAIFI (Watson Lake - 2019 System Wide): 8.9		233
AEY Cowley Rd Rebuild SKH	2020	Outage count S6711 (2015-2018): 5	Outage Count S6711 (2019-2022): 0		236
AEY Choutla Long Span Rebuild	2023	SAIFI (5L600, all outages, 2021): 0.19	Project not completed yet		277
Watson Lake 5L621 Upgrade	2024	SAIFI (Watson Lake - 2017 System Wide): 5.25	Project not completed yet		291