YUKON ENERGY

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October 15, 2014

Mr. Bruce McLennan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. McLennan:

**Re: Application to Revise the Diesel Contingency Fund ("DCF") & Related Amendments to the Energy Reconciliation Adjustment ("ERA") – Rebuttal Evidence**

Pursuant to the process and schedule set out in Order 2014-08, please find attached Yukon Energy's rebuttal evidence regarding the intervenor evidence filed by Utilities Consumers Group on September 3, 2014.

Yours truly,

Ed Mollard CGA
Chief Financial Officer

**Re: UCG Evidence filed regarding Yukon Energy Corporation Application (the "Application") to Revise the Diesel Contingency Fund ("DCF") and Related Amendments to the Energy Reconciliation Adjustment**

## Introduction

On September 3, 2014, the Utilities Consumers' Group (UCG) filed a submission with the Yukon Utilities Board as Intervenor Evidence regarding the above referenced Yukon Energy Application. Yukon Energy as an applicant in this proceeding is submitting rebuttal on this UCG evidence.

In its cover letter, UCG noted that its submission provides "evidence related to rate stabilization mechanisms approved in other jurisdictions which UCG feels should be used to broaden the review of how a mechanism like the proposed Diesel Contingency Fund should be established and used in Yukon." UCG's submission includes a five page summary of mechanisms in Northwest Territories, Manitoba, Newfoundland and Nova Scotia, and over 600 pages of attached Board Orders from the four noted jurisdictions. UCG submits this as "evidence of how other jurisdictions have addressed rate stabilization mechanisms similar to the DCF."

The information and examples from other jurisdictions have been filed on the record of this proceeding by UCG without the necessary context or analysis in order to assist the Board to determine the relevance, if any, of these particular mechanisms to the Yukon integrated system or regulatory environment and the issues related to the DCF in the current proceeding.

In order to assist the Board, the following rebuttal evidence provides context for the other rate stabilization mechanisms included in the UCG submission and assesses the relevance, if any, of these other mechanisms to the current proceeding with specific regard to the DCF. This submission was prepared by Yukon Energy's regulatory consultant (InterGroup Consultants), which (see Attachment 1) has for many years provided expert advice on rate regulation matters to utilities or intervenors in three of the jurisdictions noted (Northwest Territories, Manitoba and Newfoundland).

## Yukon Context for DCF and Review of other Rate Stabilization Mechanisms

The DCF, and the predecessor Low Water Reserve Fund (LWRF), were established in Yukon to provide rate stabilization from variability in generation costs from approved GRA forecasts due only to fluctuations in available water flows and wind. In contrast to the fuel price rate stabilization mechanism in Yukon (i.e., Rider F mechanism), comparatively large minimum and maximum caps were established for the DCF to establish a fund large enough to provide rate stabilization in response to varying water flow availability above and below long-term average conditions.

The DCF rate stabilization mechanism was established, and is proposed to continue operating, in the following Yukon context:

1. **Isolated Hydro Grid -** The Yukon grid operated by Yukon Energy is a hydro-based bulk power system with a very small amount of wind generation and with diesel generation to supply the balance of the power requirement. As such, the Yukon grid is isolated with no interconnection to other jurisdictions (no ability to purchase power from others in the event

of drought and no access to additional revenues from sales of surplus power to other jurisdictions).

2. **Load Variability -** The Yukon grid(s) since the late 1980s have experienced a wide range of load conditions that were reflected in the rate stabilization mechanisms adopted and applied from time to time with regard to water availability:

    a. The Mayo Dawson grid had surplus hydro conditions after the UKHM mine closed in the late 1980s until this grid was connected to the WAF grid in mid-2011; under the conditions from the late 1980s until mid-2011, changes in water flow availability on this grid had no impact on diesel generation and no rate stabilization mechanism similar to the DCF was in operation on this grid.

    b. In contrast, the Whitehorse-Aishihik-Faro (WAF) grid has experienced varying load and hydro generation utilization conditions since the late 1980s:

        i. When the Faro mine was operating in the 1990s, the WAF grid load was sufficient that changes in hydro generation on the Yukon grid due to changes in water flow availability had a direct, opposite and equal impact on diesel generation – and any change in load from GRA forecasts also was 100% reflected in changes in expected diesel generation under long-term average hydro generation water conditions. The LWRF and then the DCF were established as a dedicated fund on WAF during this period to reflect the regulatory premise that ratepayers bear the risk (cost or benefit) for all water-related hydro generation changes that cause changes in diesel generation relative to the last GRA approved forecast hydro generation - and the LWRF-DCF mechanisms were kept entirely separate from the Rider F rate stabilization mechanism addressing fluctuation in diesel fuel prices from GRA forecasts.

        ii. When the Faro mine was not operating in the 1990s, and after it was closed in early 1998, the reduced load resulted in surplus hydro generation on the WAF grid under long term average hydro generation water conditions. Accordingly, DCF operation was suspended under these load conditions except when severe drought conditions in 1999 briefly caused a need to operate diesel generation. During these conditions GRA approved rates only included diesel generation costs related to winter peaking and maintenance operation requirements, i.e., rates did not include any diesel generation costs that reflected sensitivity to hydro generation water flow availability.

    c. By 2012, interconnection of the WAF and Mayo-Dawson grids combined with load growth resulted in conditions where diesel generation costs were once again sensitive to hydro generation water flow availability. Board Order 2013-01 directed that 2012-2013 test year GRA rates reflect 100% of diesel generation forecast to be required on the integrated grid under long-term average hydro generation conditions – and Yukon Energy filed for approval to resume operation of the DCF with modifications to reflect current integrated grid conditions (including recognition that, unlike the 1990s when the Faro mine was operating, expected diesel generation under long-term average generation would currently account for less than 100% of any changes in grid loads from the GRA forecast).

3. **Rate Policy -** Rate policy requirements in Yukon established by the Public Utilities Act and rate policy OICs such as OIC 1995/90 (and its predecessors) required rate base regulation of Yukon Energy rates as well as equalization of first block retail rates and Major Industrial customer rates throughout Yukon for both public utilities, with specific directions regarding YEC wholesale rates charged to YECL/AEY and provisions to address fuel price changes from approved GRA forecasts.

### Other Rate Stabilization Mechanisms - Context and Relevance Assessment

The UCG evidence copies, and purports to summarize, Board Orders dealing with rate stabilization mechanisms in four other jurisdictions (Northwest Territories, Manitoba, Newfoundland and Nova Scotia). The context of each referenced mechanism in each jurisdiction, and its relevance to the current proceeding on Yukon Energy's DCF mechanism, are assessed below.

1. **Northwest Territories (NWT Power Corporation)** – UCG's evidence addresses at length a variety of Board Orders and filings in Northwest Territories since the 1990s regarding rate stabilization mechanisms. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

   The context for NWT Power Corporation has notable similarities with the context for Yukon Energy. For example, NWT Power Corporation has two isolated hydro grids, each with diesel generation to supply the balance of the power requirement, and each very sensitive to changes in industrial loads. It also has dedicated rate stabilization funds to address changes from GRA forecast for hydro generation water availability (variance from long term average) and fossil fuel prices, recognizing that the risks for each such change are ultimately born by ratepayers rather than by the utility. Further, NWT Power Corporation has rate base regulation of rates.

   The context for NWT Power Corporation also has notable differences from the context for Yukon Energy. For example, the following are noted:

   - Until very recently, NWT Power Corporation's rates were set separately for each individual community (e.g., different rates for customers in each community), rather than equalized in the manner established in Yukon in the late 1980s. Some of the Orders and filings referenced by UCG address measures adopted to facilitate a transition to rate zones in the Northwest Territories and do not have any relevance to the DCF mechanism in Yukon.
   - NWT Power Corporation has experienced over time various changes to its rate stabilization fund organization, including recent measures to implement a policy directive in 2010 from the Territorial government to consolidate the previously

separate stabilization funds into a single fund (RSF) that addresses a variety of rate stabilization measures (including fuel price stabilization as well as diesel generation stabilization as it is affected by hydro generation variations due to water availability). Beyond addressing specifically how water variability impacts are addressed, the details related to these various changes do not have any relevance to the current proceeding on the DCF mechanism in Yukon. Further, the new consolidated fund and its potential future operation does not offer any information relevant to the current DCF proceeding in Yukon[1].

- Focusing on rate stabilization mechanisms related specifically to water variability impacts on diesel generation, NWT Power Corporation (NTPC) does not currently have any grid system where diesel generation has recently been impacted by limits on hydro generation under long-term average water conditions (i.e., in Yukon terms, diesel has not recently been "on the margin" under long-term average water conditions on either of the two NTPC hydro grids):
  - The Taltson grid water fund in NTPC is currently inactive due to very low loads on that system relative to available hydro generation - the only relevance to the Yukon DCF is the full recognition by the utility and its regulator that the Taltson water fund may need to be reactivated in future when loads grow to the point where there is potential for diesel generation to be on the margin again under long-term average water conditions. Specific issues between NTPC and Northland utilities on the Taltson grid reflect specific conditions and history for that grid, and have no relevance to current Yukon DCF proceeding.
  - The Snare-Yellowknife grid loads are also not at a level where diesel is on the margin under long-term average water conditions, e.g., total generation requirements in the most recent test year approximated 200 GW.h/year, and remained below long-term average hydro generation at 220 GW.h/year. Forecast diesel requirements for GRA rates are limited to about 1.2 GW.h/year, and are related only to winter peaking and/or maintenance requirements. Under these conditions, water stabilization funds are only charged when hydro availability falls below 200 GW.h/year due a reasonably significant drought - and there is no upside potential to replenish the fund in years when hydro availability is higher than long-term average (because loads are inadequate to make use of such added hydro generation).

Overall, the evidence confirms that the Snare-Yellowknife grid is the only NTPC grid relevant to the current DCF proceeding, and (to the extent that any relevance is available to the DCF

[1] There is limited operating experience to date in NWT with the new consolidated RSF. Calculation of balances in the water portion of the consolidated fund have not changed from previous rules; however, riders are generally implemented when the consolidated fund reaches a balance of +/- $2.5 million (no longer any separate triggers for individual portions of the consolidated fund) and riders are calculated to target a zero balance within 18 months (i.e. no longer distinction between targets for fuel and targets for water portions of funds, there is only one target balance for the consolidated fund that includes all components).

proceeding) that experience on this grid is reasonably consistent with Yukon DCF experience and principles during similar periods when diesel was not on the margin on the WAF grid. Further, the water-related rate stabilization mechanisms that would apply on the Yellowknife-Snare grid when diesel is on the margin [which is the case being addressed for the DCF in the current proceeding] are also reasonably consistent with the DCF rate stabilization mechanism under similar conditions (subject to the material differences related to rider operation that were introduced with the new consolidated RSF).

The UCG evidence does not note impacts of the severe drought that was suddenly experienced in 2014 on the Snare-Yellowknife system, resulting in the September 3, 2014 NTPC application for a two-year stabilization fund rate rider to collect a forecast $20 million added cost resulting from over 60 GW.h of additional diesel generation forecast to be needed over two years due to record low water conditions[2]. Circumstances for this Northwest Territories system and reservoir reflect a variety of NTPC specific conditions and severe drought impacts that remain well below what could occur for Yukon's hydro grid[3] - but this recent experience highlights the continued vulnerability of isolated hydro grids to very major diesel cost increases when severe drought conditions occur (as they eventually will), and the continued relevance of water rate stabilization funds such as the DCF to help stabilize rate impact risks for ratepayers.

In summary, the NTPC experience indicates rate stabilization principles related to water variability that fully support the DCF as proposed in the current proceeding. The NTPC mechanisms specifically related solely to water variability are premised on the same principles as the DCF when diesel is on the margin under long term average water conditions, including;

- that ratepayers rather than the utility are at risk for hydro generation availability due to water, and
- that prior to the consolidation of the Snare-Yellowknife fund with NTPC's other stabilization funds as a matter of Territorial government policy, the Snare-Yellowknife water rate stabilization fund provided for fund amounts above or below zero that were well in excess of fuel price related rate stabilization funds and also provided for

[2] Due to a sudden drought, NTPC went from a balance of zero in the water rate stabilization fund in April 2014 to a balance owing from ratepayers of $3.4 million at the end of September 2014 with reservoir levels near record lows and recent 2014 inflows below all previous records - and with the expectation that by September 2016 ongoing drought conditions will increase the balance owing from ratepayers to $20 million. NTPC subsequently withdrew its application when the territorial government agreed to fund the additional $20 million fuel costs.

[3] Based on available water records and 2016 forecast Base Case loads without Alexco (with long-term average diesel generation requirements at 22.9 GW.h/year), diesel generation would exceed 175 GW.h in total over the two worst consecutive water years. [For the most recent such forecast, see Table C-3, Attachment C: Yukon Energy Application for an Energy Project Certificate and an Energy Operation Certificate re; Whitehorse Diesel-Natural Gas Conversion Project; December 2013. An earlier Base Case 2016 forecast filed in November 2012 during the YEC 2012/13 GRA proceeding indicates slightly larger impacts for the two consecutive worst drought years (a copy is provided in current proceeding in YUB-YEC-1-1(b) and (c) Attachment 1).]

any rider to remain in effect only until the fund balance was brought back to its upper or lower range limit, not to a zero balance[4].

2. **Manitoba (Manitoba Hydro)**– UCG's evidence addresses Board Orders and filings related to Manitoba Hydro over the period 2003 to 2009 that UCG states relate to rate stabilization. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

   Beyond dominant reliance on hydro generation, the context for Manitoba Hydro has few similarities with the context for Yukon Energy. Material differences include the following:

   - Unlike Yukon, Manitoba Hydro has extensive connections to several neighbouring jurisdictions, including interconnection with the US grid - with resulting ability to secure power from other jurisdictions during periods of drought and to sell surplus hydro generation to other jurisdictions when water supplies are well above long term average and/or domestic loads are inadequate to fully utilize long term average hydro generation.
   - Unlike Yukon Energy, Manitoba Hydro has no formal rate stabilization fund(s) for water change impacts or fuel price changes from GRA forecasts - and does not do any formal accounting to track such variances.
   - Unlike Yukon Energy, Manitoba Hydro uses rate revenues as approved by its regulator to build up equity/retained earnings to fund all of its major risks (including drought).
   - Unlike Yukon Energy, Manitoba Hydro is not rate base regulated - in contrast, under the overall ratemaking context for Manitoba Hydro, ratemaking requires consideration of long-term financial targets and projections of 10 to as much as 20 years[5].

   Notwithstanding all of the relevant differences in context for Manitoba Hydro and Yukon Energy, the following underlying similarities are noted with regard to rate stabilization mechanisms related to water variability:

   - Drought is a major risk for both utilities, and planning for drought events is a major consideration for Manitoba Hydro and its rate regulator (the Manitoba Public Utilities Board or "PUB").

[4] The earlier NTPC water stabilization funds, like the DCF, attempted to provide for fund "caps" i.e., (fund amounts above and below zero at which point a rate rider is to be established) within which the fund may normally absorb swings in water flow availability impacts without needing to introduce any new rate impacts. This approach in each case reflects the expectation that, under a wide range of conditions, when diesel is on the margin under long-term average water conditions impacts on the fund will tend to balance out over time and thereby provide the desired rate stabilization related to water variability impacts.

[5] For example, PUB Order 25/92 addressed the financial impacts of Limestone Generating Station coming into service. In that application, Manitoba Hydro sought a 3.5% rate increase, which would have yielded a net loss of $17.3 million for 1992/93, but still permit the achievement of an 85:15 debt: equity ratio by the end of the then relevant Integrated Financial Forecast (IFF) horizon (2002). Hydro indicated the proposal was acceptable as the most important financial forecasts were those looking at the longer-term. Notwithstanding the forecast immediate net loss, the Board's Report had a 2.65% rate increase (also focused on the long-term requirement for reserve).

- Rate regulation for Manitoba Hydro recognizes the ultimate need for the utility to recover drought related cost impacts from ratepayers and notes the related objective of gradualism and sensitivity to customer impacts (as opposed to seeking rapid recovery of added costs from drought, or rapid rebate of surpluses earned under favourable water conditions).
- In order to provide for drought and other major risks, Manitoba Hydro's rate revenue has been approved to build up its equity and reduce its debt to equity ratio (from about 90/10 in the late 1980s to a current target of 75/25) in order that its equity can be sufficient, as a fund, to address drought and other risk events - on the premise that, after such events, rates will be again be increased as required to replenish this equity as needed to achieve the target debt/equity ratio. Over the past decade, the PUB has granted rate increases in excess of Manitoba Hydro requested rate increases in order to build retained earnings and manage risks that the PUB considers the utility may be not adequately considering.
- The following examples are noted to highlight concerns about drought and adequate equity funds being built up through rates - and as well to demonstrate that regulator concerns about risk as reflected in Orders go beyond only drought-related impacts:
  - PUB Order 7/03 reflected Board concern about the impact of a "five-year drought" being the greatest threat to Manitoba Hydro's financial position, which could cost the Corporation approximately $1.3 billion at the time through lost export revenues and/or added generation costs (for fossil fuel generation on Manitoba's grid or purchased from other jurisdictions)[6]. The five-year drought reflected a five year period that occurred in the water record (80+ years) where low water flows occurred for five consecutive years (and the repeat of which would constitute the biggest "drought risk" to the Corporation). [In the case of Yukon Energy, a similar multi-year drought risk is demonstrated by water records in the late 1990s - closure of the Faro mine was the sole reason why this drought's impacts on Yukon Energy and ratepayers were muted at that time.[7]]
  - In the 2004 GRA proceeding for Manitoba Hydro, a severe drought (and consequent reduced power generation and export potential) from 2002-2004 resulted in losses to Manitoba Hydro in excess of $400 million[8] – the highest loss ever experienced by Manitoba Hydro at the time. These losses were recovered in their entirety from ratepayers through a series of rate increases as directed by the PUB in Order 101/04[9] and Order 143/04. The Board in Order 101/04 noted “the drought’s impact on the Corporation’s retained

[6] See page 88 of PUB Order 07/2003.
[7] See YUB-YEC-1-1(b) and (c) Attachment 1).
[8] PUB Order 101/04 at page 2.
[9] The Board notes in PUB Order 101/04, “The drought’s impact on the Corporation’s retained earnings, and a related and increased realization by The Public Utilities Board (the Board) of the financial and operating risks faced by MH, were the primary factors contributing to the Board’s decision to grant MH rate increases, as outlined in this Order.”

earnings", and "a related and increased realization [by the PUB] of the financial and operating risks faced by MH[10]", underlined the decision to provide Hydro with a 5% rate increase [effective August 1, 2004 for all customer classes], followed by two conditional rate increases of 2.25% (for each of 2004/05 and 2005/06 upon application of Manitoba Hydro).[11]

- At the time of the drought addressed in PUB Order 101/04, Manitoba Hydro had also paid a large dividend to the Province [such dividends had not been typical in prior years]- and losses were pushing back the date of realizing the 75:25 debt:equity ratio target by several years. In this context, discussion and argument addressed options to preserve secure funds to protect ratepayers against major risk impacts - aside from regulatory concern to have adequate "funds" to address such risks, the specifics of this discussion were very much tied to the Manitoba Hydro context and have no useful relevance to the current Yukon Energy DCF proceeding.
- The Manitoba PUB awarded a 5% rate increase in Order 90/08 when Manitoba Hydro had only requested 2.9% for 2008/09 in Order 90/08, noting that the Board "is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks". In this context, the Board was addressing concerns about capital plan cost risks as well as other risks - and the discussion has limited if any useful relevance to the current Yukon Energy DCF proceeding.

In summary, beyond highlighting utility and regulator concern to set aside adequate funds to address drought related risks (which risks ultimately are to be borne by ratepayers), the Manitoba Hydro experience and Orders have no material relevance to the current DCF proceeding.

3. **Newfoundland (Newfoundland Hydro) -** UCG's evidence addresses Board Orders and filings by Newfoundland Hydro related to 2002/03 and 2013/14, as well as references to earlier history based on these sources, regarding the Rate Stabilization Plan (RSP). However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding.

   Newfoundland Hydro's RSP is a complex rate stabilization mechanism with separate funds to manage changes from GRA forecasts as regards fuel price; changes in fuel volumes compared to forecast, i.e., addresses changes in load compared to forecast; water variability; and rural rates[12]. In addition to other complexities, fund payments/ withdrawals are assigned according to rate class - and load variation provisions (i.e., changes in load relative to

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[10] PUB Order 101/04 at page 2.

[11] The Application sought: Approval of electricity rate increases to be effective as of April 1, 2004 and 2005. The proposed rates were projected to result in an annual aggregate revenue increase of approximately $28 million (3.0%) for the fiscal year April 1, 2004 to March 31, 2005, and an additional revenue increase of $24 million or 2.5% for the fiscal year April 1, 2005 to March 31, 2006.

[12] Newfoundland and Labrador Hydro Rate Stabilization Plan Report, July 2014, page 1.

forecast) affecting each rate class add a wide range of issues that have no relevance at all to the current DCF proceeding in Yukon.

In summary, beyond noting that ratepayers in each of these jurisdictions bear the risks related to hydro variations from forecast water conditions, there is no apparent relevance for the current DCF proceeding of examining further the Orders and filings related to the Newfoundland Hydro RSF.

4. **Nova Scotia (Nova Scotia Power)** – UCG's evidence addresses Board Orders and filings related to Nova Scotia Power related to 2011 to 2014 regarding a specific Rate Stabilization Plan that was recently approved for Nova Scotia Power. However, no assessment is provided by UCG of the context or relevance of these Orders or filings with regard to the current DCF proceeding

   Unlike Yukon Energy, Nova Scotia Hydro is not a hydro-based jurisdiction and examples of rate stabilization mechanisms from this jurisdiction are consequently of no apparent relevance for the Yukon context related to the need to provide rate stability in event of material swings in water availability. Accordingly, evidence provided regarding Nova Scotia Power has no apparent relevance to the current Yukon DCF proceeding.

## Conclusions

Review of the context for the Orders or filings referenced in four other jurisdictions by the UCG evidence indicates very limited relevance of this information to the current DCF proceeding.

A large portion of the UCG evidence for each jurisdiction references rate stabilization mechanisms other than those related specifically to water variability, (e.g., the Nova Scotia, and most of the Newfoundland and Manitoba references, demonstrate this point as well as the new consolidated RSF for NTPC).

In the cases where fund operation for rate stabilization is actually related specifically to water variability, the evidence shows that mechanisms are context dependent and vary across jurisdictions and over time within jurisdictions in response to specific changes in, and requirements of, the operating environment (e.g. in NWT the Taltson fund has been inactive since the Pine Point mine closure, as there is not enough load on the system to make water availability an issue, and even the Snare-Yellowknife portion of the RSF related to water operates in a context today where diesel is not "on the margin" at long term average water flows).

In conclusion, it can be noted that each of the above noted jurisdictions has adapted specific mechanics for funds or other mechanisms to address water variability where it is a material risk. The specific mechanics vary among the above jurisdictions, and the details of these variations are of limited (if any) relevance to the Board in the current DCF proceeding. What is relevant to the current DCF proceeding, as shown by the above review, is that the following core principles are common to all of the above-noted jurisdictions addressing risks related to water variability:

1. Ratepayers (not the utility or its shareholder) are ultimately at risk for cost impacts caused by variations in water availability.

2. All of the approaches to water stabilization mechanisms recognize that water availability can be self-correcting over time and that some form of fund might help to stabilize rates in this regard if it has sufficiently large "caps".

## ATTACHMENT 1 – INTERGROUP EXPERIENCE IN OTHER JURISDICTIONS

InterGroup Consultants Ltd. experience providing expert advice on rate regulation matters to utilities or intervenor groups in Northwest Territories, Manitoba and Newfoundland is as follows:

- **Northwest Territories (Northwest Territories Power Corporation) –** Since 2000, InterGroup has provided support to Northwest Territories Power Corporation (NTPC) with preparing the Corporation's Rate Applications for 2001/03, 2006/08, and 2012/14 fiscal years. InterGroup's responsibilities have included preparation of the Corporation's revenue requirements, cost-of-service and rate design studies. InterGroup also provided rate hearing support including expert witness testimony before the Northwest Territories Public Utilities Board.

- **Manitoba (Manitoba Industrial Power Users Group) –**InterGroup has provided ongoing advice to the Manitoba Industrial Power Users Group (MIPUG) in their role as intervenors in each of the Public Utilities Board's reviews of electricity rates since December 1988 when the Board was first given the jurisdiction to approve electricity rates. MIPUG played a role in the Board's review of Manitoba Hydro's Major Capital Projects in 1990, the Centra Gas acquisition in 1999, and Manitoba Hydro's Needs for and Alternatives To capital projects hearing in 2014. InterGroup assists MIPUG in electricity rate design matters with Manitoba Hydro, and has provided rate hearing support including expert witness testimony before the Manitoba Public Utilities Board in each of the above referenced proceedings.

- **Newfoundland (Island Industrial Customers)** – Since 2001, InterGroup has provided rate hearing support to the Island Industrial Customers including expert witness testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities on areas such as revenue requirement, rate design and long-term system planning. InterGroup has assisted the Island Industrial Customers with ongoing rate design matters including the Rate Stabilization Plan.