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June 23, 2017

Sent via eFile

FEI 2016 RATE DESIGN
EXHIBIT A2-10

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
gas.regulatory.affairs@fortisbc.com

Re: FortisBC Energy Inc. - 2016 Rate Design Application – Project Number 3698899
Elenchus Rate Design Report

Dear Ms. Roy:

Commission staff submit the following independent consultant report for the record in this proceeding:

> Elenchus Research Associates Inc. – Review of FortisBC Energy Inc. Rate Design Methodology for the 2016 Rate Design Application.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

ES/yl
Enclosure
cc: Registered Interveners

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Review of FortisBC Energy Inc. Rate Design Methodology for the 2016 Rate Design Application

Report prepared by
John Todd and Michael Roger
Elenchus Research Associates, Inc.

Prepared for:
British Columbia Utilities Commission

23 June 2017

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EXECUTIVE SUMMARY

Elenchus Research Associates Inc. (Elenchus) was retained by the British Columbia Utilities Commission (Commission or BCUC) for the review of the FortisBC Energy Inc. (FEI) 2016 Rate Design Application. By letter dated April 26, 2017, the BCUC finalized the scope for the Rate Design Report. Attachment A to the letter itemized eleven topics that are to be addressed in the Elenchus report.

To assist in determining the reasonableness and appropriateness of FEI's rate design methodologies, Elenchus conducted a jurisdictional review of other gas utilities across Canada and in the Pacific Northwest U.S. See Appendix A.

A summary of the key conclusions and observation on the rate design topics are:

1. Rate shock

   - There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock.
   - Whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation.
   - While many utilities and regulatory agencies have no established method for quantifying rate shock, at least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.
   - Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., greater than 10%).

2. FEI rate design for residential customers

   - The percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.
   - There appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge.

- Conceptually, cost allocation principles imply that in order to reflect cost causality the fixed charge should reflect customer-related costs as identified for purposes of the cost allocation model, while the variable charges should reflect energy and demand related costs.

3. FEI rate design for commercial customers

- Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes in its rate design. AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes.

4. FEI rate design for industrial customers

- Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation.
- The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. Applying a minimum load factor requirement to a specific rate class or not depends on utility's specific load profile.
- Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, are provided the option of contracting for interruptible natural gas service. Interruptible gas services are provided at a lower rate than the equivalent firm service. By designing the system to meet only the lower firm design day requirements all utility customers benefit from the reduced capital cost and a more efficient system than if all customers were served on a firm basis.

5. Rate design for Fort Nelson

- All Canadian gas utilities in the review adopt unbundled rates where gas costs, delivery charges, and storage and transport charges are individually visible on consumers' bills.

- AltaGas, ATCO, Centra Gas and Puget Sound Energy have flat rate structures for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista add declining block rates just for industrial customers.
- Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers.
- Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures would need to be applied.

6. FEI's application of revenue to cost ratio range of reasonableness

- The revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated costs. It is also a tool to analyze the degree of cross-subsidization across rate classes.
- Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.
- Elenchus views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise – unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.
- It appears to Elenchus that one ratio must be accepted as the primary, or most relevant, basis for determining whether rate rebalancing is needed. The most important consideration is consistency.

7. Transportation Service review

   - The jurisdictional review indicates that daily balancing provision for transportation service is the industry practice.

8. Bypass customers and rates

   - The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to, consideration of bypass rates may be a moot point.

   - Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

9. Crisis Intervention Funds for residential customers

   - Crisis assistance programs are available in Ontario, Alberta, Manitoba and in the U.S. The programs are designed to help low-income families in a financial crisis pay their utility bills and sometimes also improve household energy efficiency through weatherization, thereby reducing energy costs.

10. Disconnection Policies for residential customers

    - The research indicates that regulators enforce strict rules about energy disconnection during winter to protect vulnerable energy consumers. However, Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated requirements.

1 OVERVIEW

Elenchus Research Associates Inc. (Elenchus) was retained by the British Columbia Utilities Commission (Commission or BCUC) for the review of the FortisBC Energy Inc. (FEI) 2016 Rate Design Application.

On April 26, 2017, the Commission received Elenchus's first report - Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application.

By Order G-30-17, the BCUC established the further regulatory process, which included a procedural conference to seek input from FEI and registered interveners on the key topics to be addressed by Elenchus in the second report – Review of FortisBC Energy Inc. Rate Design for the 2016 Rate Design Application. By letter dated April 26, 2017, the BCUC finalized the scope for the Rate Design Report. Attachment A to the letter itemized eleven topics that are to be addressed in the Elenchus report.

To assist in determining the reasonableness and appropriateness of FEI's rate design methodologies, Elenchus conducted a jurisdictional review of other gas utilities across Canada and in the Pacific Northwest U.S.

The utilities included in the review are:

- AltaGas (Alberta)
- ATCO (Alberta)
- Enbridge Gas Distribution (Ontario)
- Union Gas (Ontario)
- Centra Gas (Manitoba Hydro, Manitoba)
- SaskEnergy (Saskatchewan)
- Gaz Metro (Quebec)[1]

[1] Rate design methodology for Gaz Metro and Gazifere are not reviewed in the report because documents related to their applications on Regie du lodgement website are only available in French. They are listed for the jurisdictional review of rates.

- Gazifere (Quebec)[1]
- Puget Sound Energy (Washington)
- Avista (Washington)

Appendix A summarizes the proceedings reviewed in the report.

This report contains twelve additional sections that correspond to the eleven topics, with a final section that summarizes the report's conclusions and observations. Hence:

- Section 2 reviews the topic of rate shock;
- Section 3 reviews rate design for residential customers;
- Section 4 reviews rate design for commercial customers;
- Section 5 reviews rate design for industrial customers;
- Section 6 reviews rate design for Fort Nelson;
- Section 7 extends the discussion of revenue to cost ratio and range of reasonableness from what was included in Elenchus' first report;
- Section 8 provides an overview of balancing provision for transportation service;
- Section 9 discusses bypass customers and rates;
- Section 10 reviews crisis intervention funds for residential customers;
- Section 11 provides an overview of disconnection policies for residential customers;
- Section 12 addresses other topics with significant impact to customer rates and/or customer classes; and
- Section 13 summarizes the conclusions and observations of the report.

Each section identifies and comments on the individual questions related to each topic that were identified by the BCUC in its April 26, 2017 letter.

Appendices are included at the end of the report providing additional details that may be of interest to some parties.

2 RATE SHOCK

2.1 FEI PROPOSAL

FEI's Application did not include a proposal regarding the mitigation of rate shock. In the Procedural Conference dated April 5, 2017, the company noted that "FEI generally uses a 10 percent increase as a general guideline for rate shock, but believes that each circumstance has to be looked at individually."[2]

2.2 INDUSTRY PRACTICE

There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock. In Elenchus view, the concept is best viewed in the context of the Bonbright principles[3] that are discussed at pages 6-7 of the first Elenchus report (Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application). The principles include:

> 3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

As the previous report observed, "the relevance and weight given to the principles will vary with the particular circumstance and context of a regulatory application" (page 8, lines 2-4). It follows that there can be no absolute definition of rate shock that will apply in all circumstances. Nevertheless, whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation. Elenchus recognizes the following considerations to be relevant to the assessment of whether a mitigation strategy is appropriate to avoid rate shock.

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[2] BCUC, Procedural Conference, Volume 3, page 306.

[3] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

- The determination of a “large” increase may be influenced by the general rate of inflation in other costs (i.e., is the increase large relative to the prevailing inflation rate?), the past trend in rate increases (i.e., is the prospective increase consistent with expectations?), and other factors that bear on the perceived reasonableness of the prospective increase.
- If the “large” rate increase is an across the board increase due to a large increase in costs or significant loss of customers or throughput, mitigation of rate shock for any class may not be practical while allowing the utility to recover its prudently incurred costs in full.
- Mitigation of rate shock for a customer class is normally limited to circumstances in which there are differential rate increases to address COSA results with some classes outside the acceptable range. Rate shock for the customer class(es) facing the largest increases can be mitigated by phasing in the adjustment needed to shift all classes within the acceptable range.
- Mitigation of rate shock for customers within a class due to a design of the rate structure (e.g., a change in the fixed variable split) can also take the form of a phase-in of the change in the rate structure.
- Since mitigation of rate shock will result in rates that may be considered inequitable in terms of the Bonbright principles taken as a whole, since R/C ratios will remain outside the accepted range, mitigation should take the form of a phase-in of the rate changes indicated by the cost allocation study that is completed as expeditiously as possible, while limiting the extent of rate shock. Judgment is required to determine a phase-in period that balances inter-class or inter-customer equity against the potential hardship of a sudden large increase in the bills of some customers.

The preceding list of considerations is not intended to be exhaustive, but is merely an indication of the types of considerations that may influence a regulator’s judgment in determining whether an increase is reasonable or constitutes rate shock that is large enough to warrant some form of mitigation.

- ***What method do utilities and regulatory agencies in other jurisdictions use to quantify rate shock?***

Many utilities and regulatory agencies have no established method for quantifying rate shock. In the absence of an established methodology, regulators are able to make rate decisions that implicitly mitigate the impact of rate adjustments on particular customers or customer classes to the extent they consider appropriate on a case-by-case basis. At least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.

In Ontario, to quantify rate increases, natural gas distributors must provide bill impact information in both percentage and absolute dollar terms for all customer classes calculated at typical customer volumes[4]. For example, Enbridge uses a typical residential heating and water heating customer who consumes 3,064 m^3 (114 GJ[5]) per year and a typical commercial and industrial customer who consumes 22,606 m^3 (843 GJ) per year for the bill impact analysis[6]. The OEB requires natural gas utilities to file a mitigation plan if the total bill increase for any customer class is material[7].

In Alberta, the AUC has generally applied a threshold of 10% of the total bill as the potential indicator of rate shock[8].

- ***In assessing rate shock, is consideration given to the total customer bill, each component (commodity rate, delivery rate, fixed basic charge), or a combination of charges?***
- ***When commodity costs are flow-through to the commodity rate, are commodity costs typically included or excluded from rate shock considerations?***

In Ontario, gas distributors apply for a Quarterly Rate Adjustment Mechanism ("QRAM") every quarter, and the proposed gas supply price is based on the forecast market price

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4 OEB, Filing Requirements For Natural Gas Rate Applications, page 36.

5 1 cubic meters (m^3) natural gas equal to 0.0373 gigajoules (GJ).

6 OEB EB-2014-0039, Final Rate Order.

7 OEB, Filing Requirements For Natural Gas Rate Applications, page 36.

8 AUC, Decision 21987-D01-2016, December 9, 2016, page 21.

for natural gas. The OEB requires natural gas distributors to file evidence that explains in detail the reasons for the large rate increase if a 25% increase is anticipated on the commodity portion of a typical residential customer's bill. Distributors are also required to include a plan for mitigation of the increase in their application[9]. When reviewing delivery rate application proposals, the OEB asks distributors to demonstrate total bill impacts as well as delivery-only components that are within the control of the utility[10]. The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities.

For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers[11].

The AUC considers the overall change in total customer bills when applying the 10% threshold as the potential rate shock indicator[12].

- ***Does the assessment of rate shock differ for different types of customers?***

In Ontario, the bill impacts and mitigation requirement apply to all customer classes and in Alberta, the AUC uses the 10% bill increase threshold for all rate classes.

Other utilities included in the jurisdictional review did not specify their methods of quantifying and assessing rate shock in the proceedings listed in Appendix A. Elenchus notes, however, that since the mitigation of rate shock is essentially a public policy issue, each regulator's enabling legislation or other policy direction may provide important guidance on how the issue should be addressed in a specific jurisdiction. Elenchus also conducted a jurisdictional review on government legislations that provide a general guideline with respect to energy price. Please refer to Appendix B for the across Canada legislation review.

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[9] OEB, EB-2014-0199, Decision and Order, August 14, 2014, page 5.

[10] OEB, Handbook to Utility Rate Application, October 13, 2016, page 20.

[11] Ibid, page v.

[12] AUC, Decision 21981-D01-2016, December 21, 2016, page 17.

2.3 ELENCHUS ANALYSIS

Rate shock is an important concept that constrains the pace at which the rates for specific classes, or specific customers within a class, are increasing in a single year. The definition of rate shock is a matter of judgment since it requires the balancing of two concepts of fairness:

- The first concept of fairness relates to the absolute level of rates. The rates implied by a regulator's analytic findings with respect to a utility's revenue requirement, cost allocation and rate design, taking into account all considerations other than rate shock will, by definition, be rates that are fair and equitable in terms of the share of costs recovered from each class and from individual customers within each class.
- The second concept of fairness relates to the rate of change in rates, or more importantly the change in a customer's average monthly bill[13], as a result of the justified rate changes. In many circumstances, a significant increase in customer bills can result in real or perceived hardship for customers that are sufficiently severe that the increase is considered inequitable. This inequity may justify moderating the impact on customers by reducing the increase that would otherwise be implemented, although the necessary consequence is that some other customers will have higher rates than would have been required in the absence of the mitigation of rate shock for the customers with the largest increases.

Due to these equity concerns, it is a common practice for regulators to require mitigation of rate changes in two circumstances, whether or not there is an explicit methodology for measuring rate shock:

1. When a cost allocation study indicates the need to rebalance between classes through differential rate increases, the full impact of the rebalancing may be spread over two or more years. Any class that would experience an unacceptably large rate/bill

[13] The average monthly bill is typically calculated as the average monthly volume (annual volume/12) multiplied by the old and new rates. The result is equal to the change in the average customer's annual cost at the new rate versus the old rate.

increase (rate shock) will receive a reduced rate increase in the first year and possible in subsequent years as well. Consequently, to allow the utility to recover its full revenue requirement, the rates for one or more other rate classes will be higher than they would otherwise have been.

2. When a cost allocation study, or other considerations, implies the need for changes in the rate structure (e.g., a change in the fixed variable split), the impact on the bills of different customers within a class will vary. For example, if the fixed charge is increased relative to the variable charge, lower volume customers within the class will experience larger percentage rate increases. This rate design change may be phased in so that the impact on customer bills will be mitigated. As a result, customer within a class that would otherwise have experienced very large increases, will have that impact reduced, while those that would have experienced smaller increases, or decreases, will instead have their rates adjusted slightly upwards.

   As an example, if the monthly fixed charge is proposed to be increased by 50% from $10 to $15 and the variable charge is proposed to be maintained at current levels, (0% change). Customers with minimal usage may experience an increase in their bills close to 50%. To mitigate the impact on low volume customers, the change in the fixed charge could be spread over two years resulting in the first-year fixed charge being $12.50. The target of $15 would not be reached until the second year. In order to recover the approved revenue requirement in the first year, the variable charge will need to be increased to recover the foregone $2.50 per month fixed charge not implemented in the first year.

Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., 10% or more). This view of rate shock appears to be more reflective of perceived societal values than any analytic basis for defining undue hardship resulting from a rate increase. Indeed, the hardship resulting from a rate increase is more closely correlated to income than the rate increase itself. Further, since customers tend to focus on the change in their total bills, rather than changes in individual components of the bill, it is typical, and in the view of Elenchus more appropriate, to define rate shock in terms of the increase in the total bill.

FEI's proposed rates for all rate classes are within the 10% rate increase threshold. Furthermore, FEI's approach as indicated in the Procedural Conference dated April 5, 2017, appears to be consistent with the approach that has been accepted in other jurisdictions.

3 FEI RATE DESIGN FOR RESIDENTIAL CUSTOMERS

3.1 FEI PROPOSAL

FEI is proposing to continue with its existing rate structure[14] for its residential customers which consists of a fixed daily basic charge[15] and a flat volumetric delivery charge. FEI states that the flat rate structure is preferred considering that residential customers are already familiar with this rate structure and it provides simplicity in administration and stability in revenues forecast.

FEI is proposing a one-time 5% increase to fixed daily basic charge and corresponding decrease in the volumetric delivery charge. This type of changes is typically referred to as a change in the fixed-variable split. As indicated in the delivery cost COSA model, about 98.6%[16] of the costs allocated to the residential rate schedule are fixed costs within the time frame of the test year (i.e., both customer and demand-related costs cannot be avoided in response to declining customer counts or volume). Furthermore, FEI calculates that the current basic charge of $11.84 per month recovers about 44% of the customer costs and about 27% of the total fixed costs allocated to the residential class[17]. Therefore, the proposed 5% increase in daily basic charge and corresponding decrease in the delivery charge will improve the alignment between fixed costs allocated to the residential class and the fixed charges applicable to residential customers.

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[14] FEI defines the flat rate structure as the straight-line meter rate structure, where the volumetric charge is flat and does not vary with the customer's consumption. (Exhibit B-1, Section 7, page 7-11, line 2)

[15] Note that although the basic charge is referred to as a fixed daily basic charge, the quantum is the amount charged on a monthly basis.

[16] Exhibit B-1, Appendix 6-4, Schedule 7.

[17] Exhibit B-1, Section 7, page 7-17, line 5-9.

The proposed rate design has essentially no impact on customers with annual consumption within the 80 to 85 GJ range. The mean annual residential consumption based on 2015 data was estimated to be 81 GJ[18]. Customers with consumption above the 80 to 85 GJ range will experience reductions in their bills while customers with consumption below this range will experience increases in their bills. Lower volume customers with annual consumption less than 45 GJ will experience increases in their bills ranging from approximately $4 to $7 (approximate 0.7% to 5% of the annual bill) depending on the consumption level[19].

3.2 INDUSTRY PRACTICE

- ***A review of the different tools (example: basic charge, variable charge, demand charge) used in natural gas tariffs to recover fixed costs and variable costs and how these tools are used in the industry.***
  - ***What are acceptable practices for the recovery of fixed costs using the tools identified?***
- ***Is it acceptable practice to set the basic charge based on recovering a specific percentage or range of percentages of fixed costs?***

It is extremely rare for residential natural gas customers to have meters that record their daily demand due to the high cost of this type of meter. As a result, it is not practical to implement the conceptually optimal three-part tariff structure (fixed basic connection charge, variable volumetric charge and variable demand charge). Consistent with the perception that monthly volumetric consumption is a reasonable proxy for demand, it follows that it is reasonable to recover demand-related costs through the volumetric charge. It is common for utilities to also recover some portion of customer-related costs through the volumetric charge, presumably with the rationale that the volumetric charge is a proxy for the value of service to customers. Maintaining a low fixed basic monthly charge also serves to maintain customer connections even for customers with low

[18] Exhibit B-1, Section 7, page 7-5, lines 6 to 8

[19] Exhibit B-1, Section 7, page 7-25, Table 7-9.

demand. This approach is consistent with the marginal cost of serving connected customers (i.e., it is financially beneficial for a utility to encourage connected customers to continue to take service, even if their volume is minimal, and avoid having them discontinue natural gas service). Nevertheless, there appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge, which improves equity as measured by fully allocated costs.

In its 2003-2004 and 2005-2007 General Rate Application Phase II Review, ATCO Gas suggested that the fixed charge for the Low Use rate group[20] should be moved from the existing level which recovers 73% of the customer classified costs allocated to the rate group to recovering 100% of such costs. ATCO Gas indicated that such treatment is required to ensure that higher-volume customers within the rate group are not cross subsidizing lower-volume customers within the same rate group. ATCO Gas also argued that a utility's ability to earn its approved revenue requirement should not be subject to weather related risk and recovering fixed costs in the variable charge leads to the potential of under or over recovering of those costs. The Alberta Energy and Utilities Board (EUB, now AUC) decided to limit the Low Use fixed charge to 90% of the customer classified costs in the COSS results. The EUB recognized the arguments for moving fixed charge more in line with the costs, including fairness within and between rate classes and predictability and stability in revenue requirement recovery. However, the decision was made in recognition of the affordability for the lowest use customers and fixed income customers, and the concern of potential rate shock[21].

Similarly, AltaGas proposed a directional move towards recovery of a greater proportion of fixed costs through fixed charges from the existing 66%[22] in its rate design proposal for small general service customers in 2013-2017 Performance Based Regulation Application Phase II.

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[20] Low Use Delivery Service is applicable to all customers using 1,200 GJ per year or less. ATCO Gas 2011-2012 GRA Phase II Application, Tab D, page 9 of 13.

[21] EUB Decision 2007-026 (April 26, 2007), page 94-96.

[22] AltaGas 2013-2017 Performance Based Regulation Application Phase II, page 20.

For SaskEnergy, its long-term objective is to recover at least 75% of its customer care related costs through the Basic Monthly Charge[23].

In its 2015 General Rate Case, Avista applied to increase the customer charge for residential customers from $9.00 to $12.00 per month. It claims that the total customer allocated costs to residential customers are $27.07 per customer per month and $12.17 of the $27.07 total costs are related to the cost of the meter and service, billing, and providing customer service. It was stated that ideally the fixed costs for providing service would be recovered through a fixed monthly charge because a utility's facilities and support functions are made available to its customers irrespective of how much energy they use[24]. However, the Washington Utilities and Transportation Commission (UTC) directed Avista to retain the customer charge for residential natural gas customers at $9.00 per month[25]. The decision stated that this approach is consistent with the UTC's preference for basic charges to reflect only "direct customer costs"[26].

For other proceedings in the review, the percentage of recovery of fixed costs in the fixed charges was not specified.

3.3 ELENCHUS ANALYSIS

3.3.1 PERCENTAGE RECOVERY OF FIXED COSTS

As the Elenchus survey indicates, the percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.

In Ontario, the OEB has mandated that electricity distributors transition to fully fixed rates for residential customers by 2019 to recover distribution costs. Commercial and industrial (C&I) customers continue to be billed on a combination of fixed and variable charges. The

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[23] SaskEnergy 2016 Commodity and Delivery Service Rate Application, page 27.

[24] The Washington Utilities and Transportation Commission, Docket No. UE-150204/UG-150205, Direct Testimony of Patrick D. Ehrbar, page 26.

[25] The Washington Utilities and Transportation Commission, Docket No. UE-150204/UG-150205, Order 05, page 9.

[26] Ibid, page 10.

current split between fixed and variable charges differs dramatically across Ontario distributors, reflecting their historical billing practices. The split also varies significantly among customers within the C&I classed due to the wide range of volumetric consumption that is a characteristic of these classes.

The OEB's reasoning for the move to fully fixed residential distribution rates is that it helps ensure that electric distributors will recover their approved revenue requirement through a fixed charge and it will eliminate the disincentive to conservation program success since success inherently results in lower customer consumption and revenue under a variable distribution rate. Also, the OEB suggested that utilities will be able to do better long-term asset management planning knowing that there is more certainty in recovering their future capital and operating expenses.

Previously, the costs of Ontario electricity distributors were recovered from residential customers based on a combination of fixed and variable distribution charges and each utility determined the proportion of fixed costs recovered through the basic charge taking into consideration their previously approved fixed basic distribution charge and the results of the cost allocation study methodology. This has been the standard approach in other jurisdictions for distributors of both natural gas and electricity.

Conceptually, cost allocation principles imply that to reflect cost causality the fixed charge should mirror customer-related costs as identified in the cost allocation model, while variable energy and demand charges should reflect energy and demand-related costs. Nevertheless, rate-setting is also often influenced by value of service considerations that result in a lower fixed charge which keeps bills down for customers with below average demand. This approach can encourage increased penetration in terms of the number of customers connected although this is arguably accomplished by embedding a cross-subsidy of low-volume users by the higher volume users in the same rate class.

3.3.2 ALTERNATIVE TO FEI'S PROPOSAL OF ONE TIME 5% INCREASE

- ***A review of acceptable alternatives to FEI's proposal for a one-time 5% increase in the residential fixed charge in order to improve the alignment between the***

fixed costs allocated to the residential rate schedule and the fixed charges recovered from residential customers as explained by FEI.

Elenchus' opinion is that rates to customers should reflect the costs customers impose on the utility based on the cost causality principle. To the extent feasible and taking into consideration customers' bill impacts, fixed charges should recover the fixed costs imposed by customers on the utility and variable charges should recover variable costs.

There appears to be two primary reasons for utilities not recovering their fixed costs through fixed charges:

1. Doing so may result in rate shock to customers' bills.
2. This approach may run counter to a Government policy objective of encouraging conservation.

Alternatives to FEI's one time 5% increase proposals could include:

- No one-time increase
- One time 5% increase and subsequent annual adjustments to the fixed charge(s)
- One time increase greater than 5%

These are commented on in the following subsections.

3.3.2.1 NO ONE- TIME INCREASE

The benefits of no one-time increase are that it would eliminate potential bill impacts for low-use customers and it would be consistent with Government policy of encouraging customers to reduce their consumption of natural gas.

When a customer undertakes conservation and reduces consumption, the customer expects that its bill will be lower reflecting lower consumption. The fixed charge in the bill is unaffected by consumption changes, therefore, the larger the proportion of fixed charge in a bill, the less benefit that the customer will see as a result of conservation.

The disadvantages of no one-time increase are that fixed charges billed to customers will deviate further from the fixed costs imposed by customers on the utility and a larger proportion of fixed costs would be recovered through the variable charge resulting in more

uncertainty to the utility of recovering its approved revenue requirement. In addition, keeping a higher variable charge is a disincentive for the utility to maximize the effectiveness of its conservation programs.

3.3.2.2 ONE TIME 5% INCREASE AND SUBSEQUENT ANNUAL ADJUSTMENTS

The benefits of FEI's proposal of a one time 5% increase to better align fixed charges with recovering fixed costs would start to dissipate if in subsequent years approved revenue requirement increases are recovered only by way of the variable charge. Depending on the level of increases, over time FEI may be recovering the same percentage of fixed costs through the fixed charge as it currently recovers and it could even deteriorate further and FEI may eventually recover a lower percentage of fixed costs through the fixed charge. In this case a future one-time adjustment would be necessary to again better align fixed charges with recovering fixed costs.

An alternative to FEI's proposal is to apply the one time 5% increase, but in subsequent years increase both the fixed and variable charges by the same proportion as the approved revenue requirement increase. This approach would better align rates with cost imposed by customers on the utility and maintain the alignment between the proportion of fixed costs recovered through the fixed charge.

The benefit of this alternative is that fixed charges would continue to recover a similar proportion of fixed costs in subsequent years and there would be limited future deviation in the proportion of fixed costs recovered though the fixed charges.

The disadvantage of this alternative is that it runs counter to the Government objective of encouraging conservation by continuously increasing the fixed charge in subsequent years in the same proportion as the approved revenue requirement for the utility increases. Continuously increasing fixed charges would tend to discourage reducing energy consumption from the customers' perspective.

3.3.2.3 MORE THAN 5% ONE TIME INCREASE

Taking into consideration potential rate shock to customers, especially low use customers, another alternative to FEI's one time 5% increase is to increase the fixed

charge by more than 5% based on what is considered to be the maximum tolerable bill impact for low use customers. Low use customer could be a customer that used natural gas only for cooking, for example. A 5% increase in the fixed distribution charge will result in a smaller percentage increase in total customer bills after commodity and transportation charges are taking into consideration.

The benefit of this alternative is that it will allow the utility to recover a larger proportion of its fixed costs from the fixed charge and better align fixed charges with fixed costs.

The disadvantage of this alternative is that it runs counter to Government objective of encouraging conservation by increasing fixed charges and reducing variable charges sending the opposite price signal to customers that reduced energy consumption results in lower customer bills.

Elenchus notes that increases in the fixed monthly charge in excess of 5% have been common in the Ontario electricity sector; however, these increases have been the direct result of the OEB's policy decision to require all distributors to transition to a fully fixed distribution charge. In addition, large percentage increases in fixed charges are common in cases where utilities have a relatively low basic monthly charge and increase the charge by a relatively small dollar amount, especially in cases where the utility maintains a rounded amount (for example, an increase from $20 to $25 would constitute a 25% increase but would typically not be considered to result in rate shock).

- ***A jurisdictional review of how low-volume residential customers are treated with regards to tariff charges or customer segmentation.***

Elenchus' survey did not identify any natural gas utilities with low-volume residential customer rates. Low volume residential customers pay the same rates as larger volume residential customers. Some utilities such AltaGas and ATCO have general service rates that apply not only to residential customers but also to commercial customers with demand below a specified volumetric threshold.

The rationale for this approach is that the causal costs (essentially the costs associated with connecting a customer) below an identified modest volume are the same for most residential customer, whether small volume or larger volume, and for small commercial

customers; hence, it is appropriate to group them together as small general service customers for rate design purposes.

Table 1 provides the jurisdictional review of the treatment of residential customers with regards to tariff charges and customer segmentation.

Table 1: Jurisdictional Review of Residential Customers Tariff and Customer Segmentation

Utility	Tariff for Residential Customers	Customer Segmentation
AltaGas Utilities[27]	Fixed charge: $37.83/Month Variable charge: $2.084/GJ	For residences and small businesses who consume up to 7,226 gigajoules (GJ)/year.
ATCO Gas[28]	North Fixed charge: $29.19/Month Variable charge: $1.830/GJ South Fixed charge: $24.69/Month Variable charge: $1.731/GJ	For customers that use less than 1,200 GJs annually, including residential, small apartment, small commercial and small industrial customers.
Centra Gas[29]	Fixed charge: $14.00/Month Variable charge: $2.489/GJ	For residential customers.
SaskEnergy[30]	Fixed charge: $22.45/Month Fixed charge: $3.65/GJ	For residential customers.
Enbridge Gas Distribution[31]	Fixed charge: $20/Month Variable charge: First 30 m³ (1.137 GJ): $2.673/GJ Next 55 m³ (2.084 GJ): $2.528/GJ Next 85 m³ (3.221 GJ): $2.415/GJ Over 170 m³ (6.441 GJ): $2.33/GJ	For residential customers.

27 AltaGas, Rates & Rules, Accessible online: http://www.altagasutilities.com/general-services

28 ATCO Gas, Current Rates, Accessible online: http://www.atcogas.com/Rates/Current_Rates/

29 Manitoba Hydro, Current Natural Gas Rates, Accessible online: https://www.hydro.mb.ca/regulatory_affairs/energy_rates/natural_gas/current_rates.shtml

30 SaskEnergy, Residential Rates Effective November 1, 2016, Accessible online: http://www.saskenergy.com/residential/resrates_curr.asp

31 Enbridge Gas, Residential Customers – Rate 1, Accessible online: https://www.enbridgegas.com/homes/accounts-billing/residential-gas-rates/purchasing-gas-from-enbridge.aspx

Utility	Tariff for Residential Customers	Customer Segmentation
Union Gas[32]	North East and North West Fixed charge: $21.00/Month Variable charge: First 100 m³ (3.789 GJ): $3.309/GJ Next 200 m³ (7.578 GJ): $3.247/GJ Next 200 m³ (7.578 GJ): $3.15/GJ Next 500 m³ (18.945 GJ): $3.061/GJ All Over 1,000 m³ (37.89 GJ): $2.987/GJ	For residential customers.
Gazifere[33]	Fixed charge: $10.05/Month Variable charge: First 50 m^3 (1.895 GJ): $7.068/GJ Next 50 m^3 (1.895 GJ): $6.865/GJ Next 220 m^3 (8.336 GJ): $6.667/GJ Next 680 m^3 (25.765 GJ): $6.471/GJ Excess of 1,000 m^3 (37.89 GJ): $6.268	For residential service.
Puget Sound Energy[34]	Fixed charge: $10.34/Month (USD) Variable charge: $3.45/GJ (USD)[35]	For residential customers.
Avista (Washington)[36]	Fixed charge: $9/Month (USD) Variable charge: First 70 Therms (7.3 GJ): $7.5/GJ (USD) Over 70 Therms: $8.6/GJ (USD)	For general service (Firm).

[32] Union Gas, Current Natural Gas Rates, Accessible online: https://www.uniongas.com/residential/rates/current-rates

[33] Gazifere, Conditions of Service and Tariff, Effective April 1st 2017.

[34] Puget Sound Energy, Inc., Natural Gas Shedule NO. 23 Residential General Service (https://pse.com/aboutpse/Rates/Documents/gas_sch_023.pdf)

[35] Converted from therms to gigajoule using 1 thm=0.105587 GJ.

[36] Avista, Washington – Natural Gas Resources, 101 General Service – Firm – Washington (https://www.myavista.com/about-us/our-rates-and-tariffs/washington-natural-gas-resources)

4 FEI RATE DESIGN FOR COMMERCIAL CUSTOMERS

4.1 FEI PROPOSAL

FEI's rate design proposal for commercial customers includes two issues as follows:

- FEI proposed to maintain the threshold between small (RS 2) and large (RS 3 and RS 23) commercial customers at the existing level of 2,000 GJ per year.
- FEI proposed to increase the Basic Charge for RS 2, RS 3 and RS 23 and adjust the Delivery Charge to ensure that the economic crossover point for small and large commercial customers occurs at the threshold of 2,000 GJ per year.

FEI reviewed the relationship between commercial customer annual consumption and load factor and concluded that the existing threshold remains reasonable because the load factor flattens out after the 2,000 GJ/year consumption level.

It is calculated that the economic crossover between RS 2 and RS 3 at the current rates is at an annual consumption level of 1,457 GJ, which means that a customer who consumes more than 1,457 GJ and less than 2,000 GJ is better off financially as a RS 3 customer. Three options were evaluated to address this misalignment, including moving the threshold to 1,000 GJ, moving the threshold to 1,400 GJ, and adjusting the basic and delivery charges. Of these three options, FEI chose the third option on the basis that this option would cause the least disruption or impact on customers[37].

4.2 INDUSTRY PRACTICE

- ***When commodity costs are flow-through to the commodity rate, does the calculation of an economic crossover volume between two rate classes typically include the commodity rate?***

Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes in its rate design.

[37] Exhibit B-1, Section 8, page 8-21, lines 16-22.

Specifically, AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes[38], which is different from the method used by FEI.

4.3 ELENCHUS ANALYSIS

It is noted that the gas cost recovery charge is collected through a rider at the same rate for small and large general service customers served by AltaGas, which means that the economic crossover volume is the same whether the commodity cost is included in or excluded from the calculation. However, this is not the case for FEI where different commodity costs exist for small and large commercial customers. The difference is due to the different method of regulating gas costs. For AltaGas, gas costs are excluded from the cost of service study and are recovered by a monthly rider applied to all sales service rates unless otherwise specified to ensure that customers pay neither more nor less than the actual costs[39]. For FEI, the commodity component of the gas cost is allocated to customers based on throughput while storage and transport components are allocated using the load factor adjusted volumetric basis.

It is common practice to recover commodity costs in a separate commodity rate; hence, commodity costs will not have an impact on the cross-over volume. Excluding commodity costs therefore simplifies the calculation with no loss of information.

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[38] AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, Appendix 3, Schedule 2.0.

[39] AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, Appendix 4, Rate Rider “D”.

5 FEI RATE DESIGN FOR INDUSTRIAL CUSTOMERS

5.1 FEI PROPOSAL

FEI is proposing to maintain the current customer segmentation for industrial customers where rates are segmented into different rate groups based on service type (i.e., sales and transportation service with further segmentation into firm or interruptible services).

With respect to interruptible rates, FEI is proposing to maintain the existing methodology for setting interruptible service at a discount to firm service. Specifically, the delivery charge for interruptible service is based on the demand charge[40] and the delivery charge for firm service[41].

5.2 INDUSTRY PRACTICE

- ***A review of the benefits/disadvantages of requiring a minimum load factor to qualify for a specific rate for industrial rate classes***
  - ***What is a typical minimum load factor used in other jurisdictions, if any?***
  - ***An explanation of the benefits/disadvantages of different load factor levels.***

FEI does not have a minimum load factor requirement for the industrial rate classes and it is not proposing to introduce a minimum load factor although many other natural gas distributors do have a minimum load factor.

There are four utilities in the jurisdictional review that require a minimum load factor to qualify for specified industrial rate, which is one method that can be used to provide high load factor customers with lower rates that are reflective of their lower causal costs relative to volume. Table 2 below summaries the load factors requirements.

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[40] General Firm Service RS 5/RS 25 Demand Charge based on 90.9% adjusted load factor as proposed in this current proceeding due to the proposed decrease in the multiplier in Daily Demand formula for firm service.

[41] Exhibit B-1, Section 9, page 9-32, Table 9-20.

Table 2: Minimum Load Factor Requirement

Utility	Rate Class	Minimum Load Factor Requirement
Enbridge Gas[42]	Large Volume Load Factor Large Volume High Load Factor	40% 80%
Union Gas[43]	Large Volume High Load Factor Firm	70%
Gaz Metro[44]	Stable Load Service	60%
Gazifere[45]	Moderate Volume Firm Large Volume Firm Very Large Volume Firm	50% 50% 50%

Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation for a given volume of natural gas. Consequently, lower rates are justified for higher load factor customers unless the rate structure consists of customer, demand and energy rates that correspond closely to the corresponding costs drivers.

- ***A jurisdictional review of how the rates for interruptible customers are typically determined, considering things such as cost causation, the risk of interruption, the benefits/disadvantages of having interruptible customers, and the benefits/disadvantages of having only firm customers.***

Interruptible rates are generally set at a lower rate than the equivalent firm service as interruptible customers cause lower costs that firm customers. In Ontario, the OEB approved interruptible rates for large contract customers who have the capacity to maintain operations during gas service curtailments using traditional cost allocation methods. Union and Enbridge use cost causality principle to establish interruptible rates. For example, no capacity related costs for peak transportation and storage deliverability

[42] OEB EB-2016-0215, Rates Effective July 1st 2016.

[43] OEB EB-2016-0245, Rates Effective January 1st 2017.

[44] Gaz Metro, Conditions of Service and Tariff, Effective March 31st 2017.

[45] Gazifere, Conditions of Service and Tariff, Effective April 1st 2017.

are allocated to Enbridge's Interruptible Rates 145 and 170. The bulk of the allocated costs are related to gas commodity and upstream transportation[46]. Table 3 present as comparison of the Enbridge and Union Interruptible Rates.

Table 3. Comparison of Firm and Interruptible Rates

Utility	Firm and Interruptible Rates	Average Unit Price (cents/m^3)	Interruptible Discount from Firm Rate (%)
Enbridge[47]	Rate 100 Average Commercial Firm	18.39	
	Rate 145 Average Commercial Interruptible	8.47	53.9
	Rate 110 Average Industrial Firm	7.72	
	Rate 170 Average Industrial Interruptible	5.44	29.5
Union[48]	**Union South**		
	Firm Contract Commercial / Industrial M5 (F)	2.7592	
	Interruptible Contract Commercial / Industrial M5 (I)	1.6298	40.9
	Firm Special Large Volume Contract M7 (F)	2.7417	
	Interruptible Special Large Volume Contract M7 (I)	0.9551	65.2
	Union North and East		
	Large Volume Firm Rate 10	5.2606	
	Large Volume Interruptible 25	1.8052	65.7

For Manitoba Hydro[49], interruptible customers are billed using a three-component rate structure, including a basic monthly charge, a monthly demand charge and a volumetric (commodity) charge. The basic monthly charge recovers 100% of the customer related costs determined in the cost allocation study. The monthly demand charge recovers 65% of the capacity/demand related costs from the COSA and the remaining 35% of the demand related costs are recovered through volumetric charge.

[46] OEB EB-2016-0215, Exhibit G2, Tab 5, Schedule 3, page 1 of 2.

[47] OEB EB-2016-0215, Exhibit H2, Tab 7, Schedule 1, page 5-8 of 8.

[48] OEB EB-2011-0210, Exhibit H3, Tab 1, Schedule 3, Page 1 & 2 of 2.

[49] Centra Gas Manitoba Inc. 2013/14 General Rate Application, Tab 11, page 16 of 17.

5.3 ELENCHUS ANALYSIS

5.3.1 MINIMUM LOAD FACTOR

The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. The appropriateness of applying a minimum load factor requirement to a specific rate class depends on utility's load profile and the structure of its rates. Providing lower rates for high load factor customers serves as an incentive (price signal) for customers in that rate class to improve their load factor. In cases where the improved load profile will reduce the utility's cost, the incentive is reasonable. In cases where the rate structure closely aligns with causal costs, the rate structure will normally provide the appropriate incentive for customers to optimize their load factor.

However, Elenchus notes that the effects of a minimum load factor can be quite complex. For example, Enbridge proposed to lower the load factor requirement from 50% to 40% under Large Volume Load Factor in proceeding EB-2012-0459[50]. It was stated that the reason for lowering the load factor requirement was based on two concerns:

- To facilitate continuity of service under this rate for customers who implement energy efficiency measures; and
- To provide a choice for general service customers with load factors greater than 40% to take service under this rate.

It was explained that when implementing energy efficiency measures, customer's annual consumption declines proportionally more than their peak consumption, thereby, resulting in a decline in load factor. Lowering the load factor requirement keeps those customers under this rate class. For those customers who have the choice to change from general service rate to this rate class, Enbridge evaluated the rate option with customers based on their specific needs and consumption characteristics. The OEB accepted Enbridge's proposed changes in Decision with Reasons for proceeding EB-2012-0459.

[50] OEB EB-2012-0459, Exhibit H1, Tab 2, Schedule 3.

It is noted that EES Consulting supported FEI's current segmentation of industrial rates because these rates include a demand charge[51] that already takes into account differing load factors by rate group and as a result, load factor is not necessary to segment customers even further in the industrial rate groups.

5.3.2 Interruptible Service

Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, may be provided the option of contracting for interruptible natural gas service. Interruptible gas services are provided at a lower rate than the equivalent firm service. This service allows for the gas system to be designed to meet a lower peak day capacity thereby avoiding capital costs associated with a system that would be designed to meet the full peak day design had all customers' peak requirements been firm. This higher peak day firm design is typically only required a few days each year, even under extreme weather conditions. By designing the system to meet only the lower firm design day requirements, all utility customers benefit from lower capital costs and a more efficient distribution system.

Conceptually, it is reasonable to provide a discount for interruptible service that results in the total annual lost revenue being no more than the annualized costs avoided as a result of the ability to curtail the interruptible customers. At the same time, it benefits other customer classes to charge the highest rate for interruptible service that results in the optimal volumes being contracted as interruptible service. The value of interruptible service for both the utility and the customer depends on the detailed terms and conditions.

Interruptible service can also permit interruptions for economic reasons: the customer's service may be interrupted if the value of the resources that are made available to the utility due to the interruption (possible including diverted gas supply) are more valuable

[51] Utilities listed in Table 1 that require a minimum load factor do not include a demand charge in their rate schedules.

than the revenue that would be received for the interruptible service. For example, service curtailments may enable the utility to engage in spot transactions at a high market price.

6 RATE DESIGN FOR FORT NELSON

6.1 FEI PROPOSAL

6.1.1 UNBUNDLED RATES

FEI is proposing to unbundle Fort Nelson's rates. That is, Fort Nelson's customers would see a separate volumetric Commodity Cost Recovery Charge per GJ, Storage and Transport Charge per GJ, Basic charge per day and Delivery charge per GJ[52]. Currently Fort Nelson's customers are billed based on bundled charges.

The benefits of moving Fort Nelson's customers to unbundled charges, as stated by FEI in its evidence in Section 13.5.2, are that the unbundled rate structure would be consistent with the rate structure in the rest of British Columbia, it would provide customers with transparency into the different components of customers' bills and eventually it would allow customers to participate in other services that require unbundled rates, such as the Renewable Natural Gas program.

The disadvantage of unbundling rates is that some customers may prefer bundled rates and may find unbundled bills to be complicated to understand.

6.1.2 FLAT RATE STRUCTURE

FEI is proposing to change the current declining block structure used in Fort Nelson to a flat rate structure. For Fort Nelson's residential customers, rates decline for consumption in excess of 30 GJ per month. For commercial customers, rates decline for consumption in excess of 300 GJ per month[53].

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[52] Exhibit B-1-1, Section 13, page 13-20, lines 25 to 27.

[53] Exhibit B-1-1, Section 13.5.3, page 13-22, lines 17 to 20

FEI states that the benefits of moving to a flat rate structure are that it is a common rate structure used in Canada, it would be more consistent with Government policy of encouraging conservation, and based on the residential customer research survey conducted by FEI the flat rate structure, it would be preferred by most Fort Nelson customers. Furthermore, most Fort Nelson's customers do not reach the declining consumption block. Moving to a flat rate structure would also eliminate the fluctuation in the minimum charge that is currently used with the declining block rate structure[54].

The disadvantage of changing from a declining block rate structure to a flat rate structure is that there may be customers that would have adverse bill impacts from the rate structure change given their own consumption characteristics.

FEI's evidence is that the bill impact for residential customers of moving from a bundled declining block rate structure with a minimum charge to an unbundled flat rate structure with a daily Basic charge is favourable to customers with the most number of months of consumption of less than 2 GJ and no monthly consumption in excess of 30 GJ. Residential customers with monthly consumption above 2 GJ and the highest number of months of consumption above 30 GJ would have less favourable bill impacts[55].

6.2 INDUSTRY PRACTICE

- ***A jurisdictional review of the use of bundled and unbundled rates in natural gas utilities***

6.2.1 BUNDLED AND UNBUNDLED RATES

All Canadian gas utilities in the Elenchus review have unbundled rates where gas costs, delivery charges, and storage and transport charges are shown on consumers' bills. This approach provides greater transparency of the cost drivers since the line items are consistent with the costs of the various services provided by the utility to their customers.

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[54] Exhibit B-1-1, Section 13.5.3, pages13-22 line 29 to page 13-24 line14

[55] Exhibit B-1-1, Section 13.5.4.4, page 13-22, lines 17 to 23

6.2.2 Flat Rate and Declining Block Rate

AltaGas, ATCO, Centra Gas (Manitoba Hydro), and Puget Sound Energy utilize flat rates for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista have declining block rates only for their industrial customers[56].

6.3 Elenchus Analysis

- ***A review of the benefits/disadvantages of FEI's proposal to move to unbundled rates***
- ***A discussion of the considerations that are typically made when changing rate structure for different rate classes in the context of FEI's rate design proposals for Fort Nelson***
- ***A review of the benefits/disadvantages of FEI's proposal for removing a declining block rate structure and adopting a flat rate structure***

Elenchus agrees with the advantages and disadvantages that are identified by FEI that are summarized in the preceding sections. An approach that is more consistent with standard practice will align the billing of Fort Nelson customers more closely with contemporary customer expectations which include a bill that provides more information on the factors that drive their energy costs and in doing so provide better price signals for customers that wish to manage their natural gas bills more effectively by investing in more efficient appliances and managing their use more prudently.

Customers whose energy consumption never exceeds the first block would be indifferent to a flat rate structure since they already have what amounts to a flat rate structure. Larger volume customers, who may have the greatest opportunity to reduce their consumption through improved conservation, will have increased information on the financial value to them of reducing their consumption.

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[56] Exhibit B-1, Appendix 6-1, page 28.

On the other hand, customers may be accustomed to the situation that more consumption results in lower unit costs and would not easily accept giving up this benefit. They may perceive that their higher consumption, which may reflect higher need, is being unfairly penalized. Appropriate customer education, however, can focus on the reality that unbundled rates result in a more equitable sharing of costs.

Depending on the rate design of the flat rate structure, based on consumption levels, some customers may end up paying more and some customers may end up paying less than under a declining block rate structure. Change always results in resistance among some of the customers that pay more, especially if customer communications about the reasons for the change are not communicated effectively.

Abandoning the declining block rate structure in favour of a flat rate structure would align the Fort Nelson rates with standard practice and all customers in FEI's service territory would be under the same rate structure. Consistency across FEI's service areas should enhance the ability of FEI to educate its customers about the drivers of their energy costs and to manage their natural gas bills by adopting better conservation practices and investing in more efficiency appliances.

In addition, from the FEI perspective, given that most distribution expenses are fixed, having a fixed rate structure would better align with the nature of their operating costs. Also, in promoting conservation consistent with Government objectives, a flat rate structure sends a better price signal for conservation than a declining block rate structure.

On the downside, there will be changes to billing procedures that the utility will have to introduce to implement the flat rate structure and customer service will have to be enhanced to deal with the expected increase in customer enquiries once customers start receiving bills based on the new rate structure. The transition to a flat rate structure may result in significant bill increases for some customers.

Any change in a utility's rate structure results in some degree of customer confusion until customers understand and accept the new rate structure. The utility will have to make an extra effort in communicating the change and reasoning behind the change to customers. FEI may also want to equip its staff to respond to complaints with information on ways that customers can reduce their consumption and bills most effectively.

6.3.1 FEI'S METHODOLOGY FOR MOVING TO A FLAT RATE STRUCTURE

- ***A review of FEI's methodology used to calculate fixed (basic) and variable charges in a flat rate structure when moving from a declining block structure***

FEI states that the Basic charge and volumetric Delivery charge were developed in a way that achieves the lowest maximum dollar amount bill increase for any individual residential customer[57].

Alternatives to develop the Basic charge and volumetric charge when changing rate structure from declining block to flat rate structure are approaches that would result in:

1. the Basic charge being set equal to the current Minimum bill excluding non-distribution components currently included in the Minimum bill,
2. no bill impact for customers consuming the average monthly class consumption,
3. setting the Basic charge similar to the Basic charge used by FEI for its Residential customers in other service territories, or
4. setting the Basic charge based on the results of the COSA study for Fort Nelson.

The approach that is most consistent with the principle of designing rates so that they correspond to the relevant costs drivers is the fourth option. The rationales supporting the first three options are various pragmatic considerations that may be relevant to the degree of initial customer acceptance that is achieved.

Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers. Customers have different levels of monthly consumption and will be impacted differently when implementing rate structure changes.

Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures can be used to minimize negative reactions.

Nevertheless, the transition to a more equitable and more transparent rate design is a progressive step. The inevitable resistance to change by customers that are negatively impact should not be viewed as a justification for not proceeding with charges that

[57] Exhibit B-1-1, Section 13.5.4.3, page 13-31 lines 12 to 14

improve equity, provide greater transparency, and in doing so should reinforce public policy objectives such as encouraging conservation. Rather than avoiding change it makes more sense to complement progressive changes with effective communications and appropriate conservation programs, as well as giving due consideration of programs that provide financial assistance to customers that may face the greatest hardship as a result of the changes.

7 FEI's Application of Revenue to Cost Ratio Range of Reasonableness

7.1 FEI Proposal

FEI applied a range of reasonableness of 90% to 110% for the revenue to cost ratios for all rate schedules to evaluate the appropriateness of R:C ratios. The R:C ratios include gas and transportation costs.

7.2 Industry Practice

- ***A discussion of how the concept of range of reasonableness is dealt with in other jurisdictions in relation to revenue to cost ratios and their application to rate design and rebalancing.***

The calculation of revenue to cost ratios by customer class is a primary purpose of cost allocation studies and the use of a range of reasonable is the most common approach to relating proposed rates to the allocated costs.

Revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated allocated costs by customer class. They are also a tool for analyzing the degree of cross-subsidization across rate classes. While also taking other rate design principles into consideration, utilities use revenue to cost ratios as a tool to show whether the rates charged to each rate class adequately recover the costs they cause as determined by the utility's cost allocation study.

Union Gas noted that revenue to cost ratios are the outcome of the rate design application and acceptable ratios must satisfy rate design principles as well as bear a reasonable relationship to previously approved revenue to cost ratios. In Union's 2011 Cost of Service review, the OEB found that the proposed revenue to cost ratios were further away from unity than previous approved ones for some rate classes and concluded that the proposed ratios were not appropriate[58].

AltaGas stated that revenue to cost ratios are designed to mitigate the rate impacts and maintain reasonable continuity of rates for all classes[59]. In one of ATCO's Application, the EUB noted that rates that vary from the target revenue to cost ratios after a consideration of other rate design criteria may be approved in order to take into account non-cost issues[60].

Table 4 summarizes the R:C ratio range of reasonableness accepted by other regulators.

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[58] OEB EB-2011-0210, Decision and Order, page 85.

[59] AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, page 20.

[60] EUB (now AUC) Decision 2006-062 (June 27, 2006), page 3.

Table 4: R:C Ratio Range of Reasonableness

Utility	Range of Reasonableness
AltaGas[61]	95% to 105%
ATCO[62]	95% to 105%
Union Gas[63]	Close to unity[64]
Enbridge[65]	Close to unity
Centra Gas[66]	100%
SaskEnergy[67]	95% to 105%

7.3 ELENCHUS ANALYSIS

- ***A discussion regarding the use of FEI's margin to cost ratio, instead of the revenue to cost ratio, to assess transportation customers' rate design, since these customers do not incur gas costs.***

Transportation customers arrange their own commodity, storage and transport resources; hence delivery is the only service they buy from FEI. As such, the R:C ratio and M:C ratio are almost the same for this class. Commodity, storage and transport costs are excluded from both the numerator and denominator when calculating the M:C ratios[68].

Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.

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61 AUC Decision 2014-139 (May 23, 2014), page 17.

62 EUB Decision 2006-062 (June 27, 2006), page 3.

63 OEB EB-2011-0210, Decision and Order, page 81.

64 Elenchus interprets "Close to unity" as a smaller range than 95% to 105%.

65 OEB Order EB-2012-0459, page 6 of 63.

66 Centra Gas Manitoba Inc. 2013/14 General Rate Application, Appendix 15.2, page 2 of 5.

67 SaskEnergy Incorporated Rate Application - 2016, slide 19.

68 Exhibit B-1. Section 6, page 6.34, lines 22 to 23

Elenchus nevertheless views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise. Hence, unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.

For example, if the range of acceptable R:C ratios in a jurisdiction is between 0.90 and 1.10 and customer class A has a ratio of 0.91 and customer class B has a ratio of 1.11, rebalancing in order to bring the ratios to within the acceptable range would require that the R:C ratio for customer class B be reduced to 1.10 and customer class A would have to have its rates increased to absorb the reduction in revenues from customer class B, probably resulting in a ratio for customer class A that would be higher than 0.91. There is no requirement to bring the R:C ratios for either customer class to be equal to 1.00.

Rebalancing is done to bring all customer classes within the accepted range of R:C ratios. Any resulting shortfall in revenue requirement resulting from reducing rates to customer classes that have R:C ratios that are above the upper end of the accepted range, would be recovered from customer classes that have R:C ratios below 1.00 and/or that have the lowest R:C ratios. The exact steps used to rebalance rates vary across jurisdictions with no approach being analytically superior to any other. The preferred methodology is a matter of judgment.

The reverse scenario also applies. If a customer class has a R:C ratio below the lower end of the accepted range, its rates would be increased to bring the R:C ratio within the range. The additional revenue requirement received from this increase is offset by rate reductions for customer classes that have R:C ratios above 1.00 and/or have the highest R:C ratios.

The M:C ratio is a reasonable alternative to the R:C ratio because the uncertainty that is being addressed through the adoption of a range of reasonableness for the R:C (or M:C) ratio corresponds to the inherent imprecision in using cost allocation as a measure of

causal costs is associated primarily with the allocation of common costs to rate classes. The commodity, storage and transport costs that are not included in the M:C ratio, are directly assignable to classes, although the rates may be based on the allocation of common costs in the cost allocation studies of the external suppliers.

While providing two sets of ratios has the benefit of providing more information to the Commission and stakeholders, it appears to Elenchus that as a practical consideration one ratio must be used as the primary basis for determining whether rate rebalancing is appropriate. The most important consideration in choosing an approach is consistency. That is, the same ratio and the same range should be used as the primary reference point on an on-going basis. Furthermore, the range that is used for a ratio should be consistent with the confidence that can reasonably be placed in the COSA results. This confidence is a matter of judgment, since there is no methodology, analogous to that used for some types of statistical analysis, for quantifying a confidence interval.

Elenchus sees merit in using the M:C ratio as the primary reference frame for determining whether rate rebalancing is appropriate since it excludes pass through costs. However, the R/C is so widely accepted that it would not be inappropriate as the primary reference.

8 TRANSPORTATION SERVICE REVIEW

8.1 FEI PROPOSAL

FEI proposed to eliminate monthly balancing and to require all transportation customers in all service areas to balance daily.

FEI also proposed to amend the balancing tolerance from 20% to 10%, coupled with a tiered charge approach under which charges increase as tolerance ranges are exceeded[69].

[69] Exhibit B-1, Section 10, page 10-1.

8.2 INDUSTRY PRACTICE

- ***A discussion of the use of daily balancing versus monthly balancing for transportation service.***
  - ***A discussion of the range of balancing tolerances used within the industry.***

Table 5 provides a review by jurisdiction of the balancing requirements for transportation service.

Table 5: Balancing Provisions for Transportation Service

Utility	Daily or Monthly Balancing	Range of Balancing Tolerance
AltaGas[70]	Daily	4%
ATCO[71]	Daily	5%
Union Gas[72]	Daily	Maximum daily requirement for firm service is 100,000 m^3 (3,730 GJ) or more
Enbridge[73]	Daily	Maximum daily volume not less than 10,000 m^3 (373 GJ) and not more than 150,000 m^3 (5,595 GJ).
Avista[74]	Daily	3% (Aug-Feb); 5% (Mar-Jul)
Puget Sound[75] Energy	Daily	5%

[70] AUC Decision 2014-139 (May 23, 2014), Appendix 3, page 218 of 266.

[71] ATCO Gas 2011/2012 General Rate Application Phase II, Tab E, page 74 of 75.

[72] OEB EB-2011-0210, Decision and Rate Order, January 17, 2013.

[73] OEB EB-2016-0215, Draft Rate Order, Exhibit H2, Tab 6, Schedule 1.

[74] Exhibit B-1, Appendix 10-1, page 4 of 20.

[75] Exhibit B-1, Appendix 10-1, page 4 of 20.

8.3 ELENCHUS ANALYSIS

The jurisdictional review indicates that daily balancing provision for transportation service is the standard industry practice.

Daily balancing is consistent with the normal operating parameters of natural gas distribution systems. Natural gas distribution systems are capable of managing typical demand variances within a day through variances in pressure without requiring significant storage. In essence, natural gas storage is not required to accommodate the typical intra-day variances in customer consumption rates. Day-to-day variances on the other hand typically require storage, including variances within the permitted tolerance level.

Transportation customers arrange for their own supply of natural gas. To do so they must either be sophisticated customers or utilize external gas supply experts. As a result, it is reasonable to include relatively stringent balancing requirements (i.e., daily balancing); however, it will also be appropriate for the utility to make available to these customers the other services that may be required to meet those requirements in a cost-effective way unless alternatives for those services are readily available in the service area. For example, transportation customers may have access to market-based storage services from the utility on a competitive basis. More flexible load balancing requirement will inevitably facilitate gaming of the system by sophisticated customers so as to maximize their access to “free” storage and minimize their total commodity costs.

9 BYPASS CUSTOMERS AND RATES

9.1 FEI PROPOSAL

Bypass customers are on a negotiated rate which is not set as part of the rate design application process. Those customers are typically within close proximity to connect directly to the upstream pipeline system if they so choose. Bypass rates are derived from a discounted cash flow analysis based on the estimated cost of constructing and operating a hypothetical pipeline to bypass FEI’s system. Agreements are reviewed and approved by the BCUC with a typical initial term of 10 years. Extension of the contracts

is subject to the BCUC approval[76]. Bypass customers are not allocated any costs in the COSA model and revenues from these customers are credited back to all other customers. A negotiated inflation rate is applied to the bypass rate each year to account for changes in operating costs over time[77]. FEI is not proposing any changes to the existing bypass agreements.

9.2 INDUSTRY PRACTICE

- ***A discussion of how bypass rates are determined in other jurisdictions.***
- ***A review of how other jurisdictions review bypass rates in an ongoing way.***

The treatment of bypass varies across jurisdictions in part due to differing policies with respect to whether bypass is permitted and whether bypass opportunities are available (i.e., if bypass is not permitted or available, bypass rates may not be necessary).

In New Brunswick, bypass is only available to major natural gas users that have been granted single end use franchises (SEUFs), by the Province. No other bypass is permitted.

In Ontario, gas distributors offer a form of bypass competitive rates to avoid potential bypass applications. For example, Rate 125 – Extra Large Volume Firm Distribution Service in Enbridge's rate schedule was designed to introduce a rate that would be robust against bypass[78]. In proceeding EB-2005-0551, Enbridge developed rates for Rate 125 based on its fully allocated cost study. It was stated that the costs associated with providing the service have been identified as the cost of providing incremental assets to serve new customers, the cost for system implementation, and the cost of providing load balancing service. The proposed rate structure includes a monthly customer charge, a delivery demand charge and a load balancing charge[79]. The OEB approved Enbridge's proposed rates for Rate 125 with the adjustments of lowering the monthly customer

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[76] Exhibit B-1, Stakeholder Consultation, Information Session #2, May 19, 2016, page 110.

[77] Exhibit B-1, Section 6, page 6-9.

[78] OEB EB-2005-0551, Technical Conference Transcript, April 27, 2006, page 113.

[79] OEB EB-2005-0551, Exhibit C, Tab 2, Schedule 4, page 2-4.

charge from $550 to $500 and ensuring that "the only aspect of Rate 125 that will be restricted to new customers is the billing contract demand feature"[80]. The OEB reviews rates for Rate 125 in each cost of service application in an ongoing way and the OEB found that Rate 125 customers should not be allocated the costs of transmission pressure pipelines less than 6" in diameter in the Decision to EB-2012-0459.

9.3 ELENCHUS ANALYSIS

The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to legally, consideration of bypass rates may be a moot point.

Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

Bypass rates are typically designed in a manner that is consistent with the principle that a bypass rate should be granted when the rate recovers the utility's costs in full, preferably with a contribution to fixed costs, while being less than the utility's standard rates for the class of customer receiving the bypass rate. When this test is met, uneconomic bypass is avoided. Uneconomic bypass may occur if bypass is permitted and the utility is required to charge a rate based on average fully allocated costs rather than serving customers that have the opportunity to bypass at a rate that reflects marginal cost.

[80] OEB EB-2005-0551, Rate Order for Enbridge Gas Distribution, December 20, 2006, page 3.

10 CRISIS INTERVENTION FUNDS FOR RESIDENTIAL CUSTOMERS

In the Application FEI states that it "has developed and implemented a number of low income programs that are of no cost or low cost to low income participants. These programs are part of FEI's annual natural gas DSM program. In 2015, FEI's DSM program included three major low-income programs with a total expenditure of $1.55 million" (p. 7-28) It goes on to note that "FEI's view is that the Commission does not have the jurisdiction to set rates based on the financial circumstances of FEI's customers. FEI has, therefore, not addressed this matter further in this Application." (p. 7-29)

Elenchus cannot comment on the legal issues related to the jurisdiction of the Commission; however, Elenchus is aware that public policy mandates generally do derive from government legislation, regulations or specific directives. The issue of the OEB's jurisdiction to establish programs that assist low-income households with the cost borne by ratepayers (as opposed to taxpayer funded programs) was addressed by a court case which found that the OEB did have the jurisdiction to order utilities to undertake this type of program, although it was not obliged to do so. It is Elenchus understanding that the jurisdictional issue is determined by the specific legislation in each jurisdiction.

10.1 CRISIS ASSISTANCE PROGRAMS IN BC

The Ministry of Social Development and Social Innovations (the Ministry) runs crisis assistance programs that are designed to help low income customers. Under the Essential Utilities Supplement Program, a crisis supplement for essential utilities may be provided if recipients have reached their monthly or annual limit for crisis supplements, exhausted all resources, and do not have the ability to maintain essential utilities for their home when served with a disconnection notice or faced with the inability to re-establish essential utilities. The essential utilities supplement counts towards a recipient's cumulative annual limit for crisis supplements. Another program administered under the Ministry's supervision is the Utility Security Deposit program under which a supplement

may be provided to assist recipients of income, hardship, and disability assistance with the cost of securing service for electricity or natural gas[81].

10.2 JURISDICTIONAL REVIEW

- ***A review of other jurisdictions that have a crisis intervention fund or similar program to assist ratepayers who are unable to pay their bills and are facing disconnection.***
  - ***A discussion of how the program is funded, designed, and administered.***

In Ontario, low income customers can apply for the Low-income Energy Assistance Program (LEAP) which provides a maximum $500 one-time assistance for their natural gas bills. The program is available to customers who are behind in their bill payments or may face having their service disconnected[82]. It is designed to provide emergency relief to eligible low-income consumers and is not intended to provide regular or ongoing bill payment assistance. The LEAP is funded by all ratepayers through each distributor's rates and the funds must be used only for that distributor's customers. OEB developed the program and one agency or a network of agencies (i.e. intake agency, distributors, lead agency, unit sub-meter provider) are responsible for the delivery of the program[83].

In Alberta, an one-time financial assistance to low income individuals or families facing utility disconnection is provided by Alberta Works/Alberta Supports or Canadian Red Cross[84]. For Manitobans, the Employment and Income Assistance Program (EIA) provide low-income consumers help with their utility costs[85].

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81 Exhibit B-1, Section 7, page 7-28.

82 OEB, Low-income Energy Assistance Program, Accessible online: https://www.oeb.ca/rates-and-your-bill/help-low-income-consumers/low-income-energy-assistance-program

83 OEB OESP & LEAP Program Manual, Effective October 2015, Accessible online: https://www.oeb.ca/oeb/_Documents/Documents/OESP_LEAP_Program_Manual.pdf

84 Utilities Consumer Advocate, Financial Assistance, Accessible online: https://ucahelps.alberta.ca/financial-assistance.aspx

85 Government of Manitoba, Employment and Income Assistance (EIA), Accessible online: http://www.gov.mb.ca/fs/eia/

Crisis assistance programs have been available in U.S. for many years. For example, the federally-funded Low-Income Home Energy Assistance Program (LIHEAP) is designed to help low-income families in a financial crisis pay their utility bills and improve household energy efficiency through weatherization, thereby reducing energy costs. In California, the LIHEAP is administered by the department of Community Service & Development[86]. Since the U.S. programs are federally funded they are offered widely, but they are not ratepayer funded.

11 DISCONNECTION POLICIES FOR RESIDENTIAL CUSTOMERS

11.1 FEI PROPOSAL

FEI's current disconnection policies are set out in section 23, Discontinuance od Service and Refusal of Service in its General Terms and Conditions. The current online version had an effective date of January 1, 2015. It was approved by Order No. G-21-14, with the original being signed by the BCUC Secretary (Erica Hamilton).

Section 23.1 states that "FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons." The reasons include the standard reasons that appear in most utilities terms and conditions such as non-payment of the customer's account.

These General Terms and Conditions do not mention any standard practice for dealing with arrears in a manner that avoids disconnection. Many natural gas and electric utilities have processes for negotiating a payment schedule that addresses arrears in a manner that is financial manageable for the customer and is sufficient to avoid disconnection. Some utilities also assist customers faced with disconnection due to financial hardship by

[86] California Department of Community Service & Development, LIHEAP, Accessible online: http://www.csd.ca.gov/services/helppayingutilitybills.aspx

connecting them with government or non-profit organizations that provide financial assistance, or ratepayer programs that assist customers that cannot pay their utility bills.

The Application does not discuss provisions for mitigating the harm to customers associated with disconnections in FEI's Application policy other than the Provincially funded Crisis Assistance Program discussed above in section 10.1.

11.2 INDUSTRY PRACTICE

- ***A review of natural gas utility disconnection policies that are designed to mitigate any harm associated with disconnections, including winter shut-off restrictions and special circumstances with associated with medical issues.***

In Alberta, natural gas providers are compelled to include in their terms and conditions agreements the condition that they may not disconnect natural gas service between the dates of November 1st and April 14th, or at any time when the forecast for the next 24 hours indicates temperatures below 0 degrees. After April 14th, natural gas providers may disconnect gas service at their own discretion[87].

The OEB has also issued a Decision and Order[88] amending the licences of all Ontario electricity and natural gas distributors to ban the disconnection of residential consumers for the period commencing February 24, 2017 and ending April 30, 2017[89], and to require that disconnected homes be reconnected as soon as possible at no charge.

11.3 ELENCHUS ANALYSIS

The research indicates that some regulators enforce strict rules about disconnection during winter to protect vulnerable energy consumers. Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated

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[87] Utilities Consumer Advocate, Utilities Disconnection, Accessible online: https://ucahelps.alberta.ca/utilities-disconnection-and-load-limiters.aspx

[88] OEB EB-2017-0101, Decision and Order, February 23, 2017, Attachment A.

[89] The ban applies to the specified winter period. The OEB is launching a comprehensive review of the customer service rules that apply to all distributors and customer service rules relating to disconnection will be a key part of that review.

requirements. Social policy guidance is required since limitations on disconnections can result in higher costs for the utility due to increased bad debt, which are ultimately borne by other customers. The actual loss to the utility resulting from a restriction on disconnection will only equal the lost revenue in cases where the threat of disconnection would result in full payment. In cases where a customer would not be able to pay the arrears to maintain the connection or be reconnected, the loss to the utility will be only the costs that would be avoided due to the disconnection, which normally will be limited to the cost of the commodity being supplied to the customer since other costs are fixed.

Disconnection can result in increased charges to the customers since the amount owning can escalate significantly, especially if there are late payment charges that accumulate and compound. For this reason, there is merit in integrating policies that limit disconnection with programs that provide financial assistance to customers that fail to pay their bills due to low income problems.

12 OTHER TOPICS WITH SIGNIFICANT IMPACT TO CUSTOMER RATES AND/OR CUSTOMER CLASSES

Elenchus did not find any additional rate design topics with significant impact on customer rates or customer classes to include in this report.

13 SUMMARY OF KEY CONCLUSIONS AND OBSERVATIONS

A summary of the key conclusions and observation on the rate topics discussed above are:

1. Rate shock
   - There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock.
   - Whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation.

- Many utilities and regulatory agencies have no established method for quantifying rate shock. In the absence of an established methodology, regulators are able to make rate decisions that implicitly mitigate the impact of rate adjustments on particular customers or customer classes as they consider appropriate on a case-by-case basis. At least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.
- In Ontario, to quantify rate increases, natural gas distributors must provide bill impact information in both percentage and absolute dollar terms for all customer classes at the rate class level calculated at typical customer volumes. Natural gas utilities must file a mitigation plan if the total bill increase for any customer class is material.
- In Alberta, the AUC has generally applied a threshold of 10% of the total bill as the potential indicator of rate shock.
- Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., greater than 10%).

2. FEI rate design for residential customers

- The percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.
- There appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge, which typically improves equity as measured by fully allocated costs.
- Conceptually, cost allocation principles imply that in order to reflect cost causality the fixed charge should reflect customer-related costs as identified for purposes of the cost allocation model, while the variable charges should reflect energy and demand related costs.

3. FEI rate design for commercial customers

- Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes

in its rate design. AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes.

- Gas cost recovery charge is collected through a rider at the same rate for small and large general service customers served by AltaGas, which means that the economic crossover volume is the same whether the commodity cost is included in or excluded from the calculation.
- The treatment of commodity costs in a cost of service study in AltaGas and FEI is different and is due to the different method of regulating gas costs. For AltaGas, gas costs are excluded from the cost of service study and are recovered by a monthly rider applied to all sales service rates unless otherwise specified to ensure that customers pay neither more nor less than the actual costs. For FEI, the commodity component of the gas cost is allocated to customers based on throughput while storage and transport components are allocated using the load factor adjusted volumetric basis.

4. FEI rate design for industrial customers

- Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation. Consequently, lower rates are justified for higher load factor customers unless the rate structure consists of customer, demand and energy rates that correspond very closely to the corresponding costs drivers.
- The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. Applying a minimum load factor requirement to a specific rate class or not depends on utility's specific load profile.
- Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, are provided the option of contracting for interruptible natural gas service. Interruptible gas services

are provided at a lower rate than the equivalent firm service. This service allows for the gas system to be designed to meet a lower peak day capacity thereby avoiding capital costs associated with a system that would be designed to meet the full peak day design had all customers' peak requirements been firm. This higher peak day firm design are typically only required a few days each year, even under extreme weather conditions. By designing the system to meet only the lower firm design day requirements all utility customers benefit from the reduced capital cost and a more efficient system than if all customers were served on a firm basis.

5. Rate design for Fort Nelson

- All Canadian gas utilities in the review adopt unbundled rates where gas costs, delivery charges, and storage and transport charges are individually visible on consumers' bills.
- AltaGas, ATCO, Centra Gas and Puget Sound Energy have flat rate structures for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista add declining block rates just for industrial customers.
- Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers. Customers have different levels of monthly consumption and will be impacted differently when implementing rate structure changes.
- Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures would need to be applied.

6. FEI's application of revenue to cost ratio range of reasonableness

- The revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated costs. It is also a tool to analyze the degree of cross-subsidization across rate classes.

- Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.
- Elenchus views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise – unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.
- While providing two sets of ratios has the benefit of providing more information to the Commission and stakeholders, it appears to Elenchus that one ratio must be accepted as the primary, or most relevant, basis for determining whether rate rebalancing is needed. The most important consideration is consistency.
- Elenchus sees merit in using the M:C ratio as the primary reference frame for determining whether rate rebalancing is appropriate, since it excludes pass through costs. Nevertheless, the R/C is so widely accepted that it cannot be deemed inappropriate as the primary reference.

7. Transportation Service review

- The jurisdictional review indicates that daily balancing provision for transportation service is the industry practice.

8. Bypass customers and rates

- The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to, consideration of bypass rates may be a moot point.
- Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be

incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

9. Crisis Intervention Funds for residential customers

- Crisis assistance programs are available in Ontario, Alberta, Manitoba and in the U.S. The programs are designed to help low-income families in a financial crisis pay their utility bills and sometimes also improve household energy efficiency through weatherization, thereby reducing energy costs.
- In Ontario, low income customers can apply for the Low-income Energy Assistance Program (LEAP) which provides a maximum $500 one-time assistance for their natural gas bills. The program is available to customers who are behind in their bill payments or may face having their service disconnected. It is designed to provide emergency relief to eligible low-income consumers and is not intended to provide regular or ongoing bill payment assistance. The LEAP is funded by all ratepayers through each distributor's rates and the funds must be used only for that distributor's customers.
- In Alberta, a one-time financial assistance to low income individuals or families facing utility disconnection is provided by Alberta Works/Alberta Supports or Canadian Red Cross.
- For Manitobans, the Employment and Income Assistance Program (EIA) provide low-income consumers help with their utility costs.

10. Disconnection Policies for residential customers

- The research indicates that regulators enforce strict rules about energy disconnection during winter to protect vulnerable energy consumers. However, Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated requirements.

APPENDIX A: UTILITIES REVIEWED

Utility	Proceeding	Decision
AltaGas[90] Number of Customers: 570,000 Annual Throughput: 730 Bcf Annual Revenue: $1,049.9 Million	2013-2017 Performance Based Regulation Application Phase II	AUC Decision 2014-139 (May 23, 2014)
ATCO[91] [92] Number of Customers: 1.1 million Annual Throughput: 237,734,785 GJ[93] (225.3 Bcf) Annual Revenue: $1,496 Million[94]	ATCO Gas 2011/2012 General Rate Application Phase II	AUC Decision 2013-035 (February 14, 2013)
Enbridge Gas Distribution Number of Customers: 2,158,000 Annual Throughput: 559.18 Bcf Annual Revenue: $2,486 Million (via Gas distribution sales) $34,560 Million (via Commodity sales, Gas distribution sales, and transportation and other services)	Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application	EB-2012-0459 (August 22, 2014)
Union Gas[95] Number of Customers: 1,400,000 Annual Throughput: 1,205 Bcf (Distribution volume – 472 Bcf; Storage and Transmission activity – 733 Bcf) Annual Revenue: $1.8 Billion	Union Gas Limited 2013 Rebasing Application	EB-2011-0210 (October 24, 2012)

[90] AltaGas, 2016 Annual Report, 2016, pp. 1, 66, Accessible Online: https://www.altagas.ca/sites/default/files/quarterly_reports/2016%20Anual%20Report%20web_0.pdf

[91] ATCO Gas, Corporate Profile, Accessible Online: http://www.atcogas.com/About_Us/About_ATCO_Gas/Corporate-Profile

[92] ATCO, Annual Report, 2016, pp. 123, Accessible Online: https://www.atco.com/Investors/Documents/Annual-Reports/ATCO_2016_YE_AR.pdf

[93] AUC Decision 21981-D01-2016 (December 21, 2016), page 16.

Utility	Proceeding	Decision
Centra Gas[96] Number of Customers: 276,858 Annual Throughput: 1,846 million m^3 (65.19 Bcf) Annual Revenue: $356 Million	Centra Gas 2013/2014 General Rate Application	PUB Order No. 85/13 (July 26, 2013)
SaskEnergy[97] Number of Customers: 387,019 Annual Throughput: 6,382 million m^3 (225.38 Bcf) Annual Revenue: $586 Million	2016 Commodity and Delivery Service Rate Application effective November 1, 2016	Saskatchewan Rate Review Panel Report submitted September 14, 2016
Puget Sound Energy[98] Number of Customers: 807,586 Annual Throughput: 1,058,398 Therms Annual Revenue: $1.181 Million[99]	2011 PSE General Rate Case	Docket UE-111048/UG-111049 Order 08 (May 7, 2012)
Avista[100] Number of Customers: 340,131 Annual Throughput: 1,173,257 Therms Annual Revenue: $1,913 Million $628,192 in Natural Gas Revenue[101]	General rate increase for natural gas services, effective March 12, 2015.	Docket No. UG-150205 Order 05 (January 6, 2016)

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[94] This number includes ATCO Gas, ATCO Pipelines, ATCO Gas Australia, ATCO Energy Solutions and ATCO Pipelines Mexico.

[95] Union Gas, Union Gas at a Glance, 2016, Accessible Online: https://www.uniongas.com/about-us/at-a-glance

[96] Manitoba Hydro, Manitoba Hydro-Electric Board 65th Annual Report, 2016, pp. 4, 21, 113, Accessible Online: https://www.hydro.mb.ca/corporate/ar/pdf/annual_report_2015_16.pdf

[97] SaskEnergy, 2015-16 Annual Report, 2016, pp. 13-14, Accessible Online: http://www.saskenergy.com/about_saskenergy/annual_report/documents/2015-16/2015-16_Annual%20Report-web.pdf

[98] United States Securities and Exchange Commission, Puget Sound Energy Annual Report, December 31, 2016, p. 19, Accessible Online: http://phx.corporate-ir.net/phoenix.zhtml%3Fc%3D63643%26p%3Dirol-sec

[99] Converted with currency rate of USD $1 = CAD $1.32669

[100] Avista, 2016 Annual Report, 2016, p. 13/160

[101] Converted with currency rate of USD $1 = CAD $1.32669

APPENDIX B JURISDICTIONAL REVIEW OF GOVERNMENT LEGISLATIONS

Jurisdiction	Government Legislation	Description/Relevant Content
Ontario	*Electricity Act, 1998*[102]	The purposes of this Act include the following: (f) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
	Ontario Energy Board Act, 1998[103]	Board objectives, gas The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives: 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
	Fair Hydro Act, 2017 (Bill 132)[104]	The Fair Hydro Act, 2017 would lower electricity bills by 25 per cent on average for all residential consumers and hold increases to the rate of inflation for four years.
Alberta	*An Act to Cap Regulated Electricity Rates (Bill 16)*[105]	Bill 16 will impose a maximum rate of 6.8 cents per kilowatt hour (kWh) for electricity consumers on the regulated rate option or RRO (a government-regulated rate that fluctuates monthly).

[102] Accessible online: https://www.ontario.ca/laws/statute/98e15

[103] Accessible online: https://www.ontario.ca/laws/statute/98o15

[104] Accessible online: http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&Intranet=&BillID=4875

[105] Accessible online: http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_3/20170302_bill-016.pdf

Jurisdiction	Government Legislation	Description/Relevant Content
Manitoba	*The Affordable Utility Rate Accountability Act (Bill 18)*[106]	The act required the province to enlist an independent accounting firm to prepare a report each year[107] comparing the cost in each province of a bundle including home electricity, home heating and car insurance. Under the act, if the report shows the cost of the utility bundle in any province to be lower than in Manitoba, the finance minister must prepare a plan to return the province to the lowest-cost position.
New Brunswick	*Electricity Act*[108]	The act requires that rates charged for sales of electricity within the province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year.
British Columbia	*Utilities Commission Act*[109]	The act requires the Commission to set a rate that is not unjust or unreasonable.

[106] Accessible online: http://web2.gov.mb.ca/bills/40-1/b018e.php

[107] The 2017 Manitoba budget report indicated that the act will be repealed and no report will be prepared in 2017-18.

[108] Accessible online: http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf

[109] Accessible online: https://web.archive.org/web/20060209000159/http://www.qp.gov.bc.ca:80/statreg/stat/U/96473_01.htm#section60

APPENDIX C: CVS

JOHN D. TODD

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PRESIDENT

John Todd has specialized in government regulation for 40 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 250 regulatory proceedings and provided expert evidence in over 125 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) 2003

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) 2002

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc. (ECS) 1980

- ECS was divested as a separate company in 2003
- There are presently four ECS consultants: Bill Harper, Mark Garner, Shelley Grice, and James Wightman. Web address: www.econalysis.ca

EDUCATION

1975 Masters in Business Administration in Economics and Management Service, University of Toronto

1972 Bachelors of Science in Electrical Engineering, University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) 1978 - 1980

Research Assistant, Univ. of Toronto, Faculty of Management Studies 1973 - 1978

Bell Canada, Western Area Engineering 1972 – 1973

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant:

Before the Ontario Energy Board

John Todd has provided expert assistance in a total of 62 proceedings before the Ontario Energy Board from 1991 to 2016. He has presented evidence in 25 of these cases. The most recent case he participated in was the *Independent Electricity System Operator, 2016 Usage Fee*. Evidence: Cost Allocation and Rate Design for the 2016 IESO Usage Fee.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 46 proceedings before the Public Utilities Board of Manitoba from 1990 to 2015. He has presented evidence in 23 of these cases. The most recent case he participated in was the *City of Winnipeg: Manitoba Hydro 2015/16 GRA and Manitoba Hydro COSS Review.*

Before the British Columbia Utilities Commission

John has provided expert assistance in a total of 33 proceedings before the British Columbia Utilities Commission from 1993 to 2006. He has presented evidence in eight of these cases. The most recent case he participated in was the *British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement.*

Before the Régie de l'énergie

John has provided expert assistance in a total of ten proceedings before the Régie de l'énergie from 1998 to 2014. He has presented evidence in nine of these cases. The most recent case he participated in was the *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.*

Before the Alberta Energy and Utilities Board

John has provided expert assistance in of two proceedings before the Alberta Energy and Utilities Board in 2001. He has presented evidence in one case. The second case of 2001 was in regards to the case of *Generic, Gas Rate Unbundling (2001-093)*. Evidence: Canadian Experience and Approaches.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2015. He has presented evidence in three cases. The most recent proceeding he participated in was the *Newfoundland Power, 2016 Deferred Cost Recovery Application* case.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of nine proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2016. He has presented evidence in three cases. The most recent proceeding he participated in was the *2015 New Brunswick Power Customer Cost Allocation Student Review.* Evidence: Cost Allocation Study Review.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of nine proceedings before the Nova Scotia Utility and Review Board from 2008 to 2016. He has presented evidence in four cases. The most recent proceeding he participated in was *Efficiency One, Updated Cost Allocation Methodology.*

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2016. He has presented evidence in 13 of these cases. The most recent proceeding he participated in was a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134.*

Before the Ontario Telephone Services Commission (OTSC)

John has provided expert assistance in one proceeding before the Ontario Telephone Services Commission in 1992. The case was in regards to a *Review of Rate-of-Return Regulation for Public Utility Telephone Companies.* Evidence used: The need for OTSC regulation of municipal utility telcos.

Before the Ontario Securities Commission

John has provided expert assistance in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case. The most recent proceeding he participated in was a *Securities Industry Review.* Evidence: Industry structure and the form of regulation.

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy.

Non-Hearing Processes

John has provided expert assistance in 17 non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in 6 commercial arbitrations and lawsuits between 2004 and 2015.

Facilitation Activities

- 5 Strategic Planning sessions with Executive and/or Board of Directors of regulated companies between 2000 and 2015
- 6 stakeholder processes for regulators and utilities from 2000 through 2016

Other Regulatory Issues Researched

- Over 20 studies completed for regulators, utilities and others outside of hearing processes

SELECTED PRESENTATIONS

- Productivity Benchmarking Panel at Canadian Electrical Association RITG CAMPUT Workshop (May 2016)
- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Committee and Regulatory Innovations Task Group (June 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (2016)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2016
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How to Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Assoc.
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over 70 private sector companies, including utilities

15 industry and other associations

Over 30 consumers' associations and legal clinics

Government

- 5 Regulatory Tribunals
- 6 Federal departments
- 14 Provincial departments, commissions and agencies
- 13 municipal and other departments/entities

For John Todd's complete curriculum vitae, please visit: www.elenchus.ca

MICHAEL J. ROGER

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ASSOCIATE, RATES AND REGULATION

Michael has over 38 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario

Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.