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MISSION STATEMENT

The mission of Energy Regulation Quarterly (ERQ) is to provide a forum for debate and discussion on issues surrounding the regulated energy industries in Canada, including decisions of regulatory tribunals, related legislative and policy actions and initiatives and actions by regulated companies and stakeholders. The role of the ERQ is to provide analysis and context that go beyond day-to-day developments. It strives to be balanced in its treatment of issues.

Authors are drawn from a roster of individuals with diverse backgrounds who are acknowledged leaders in the field of energy regulation. Other authors are invited by the managing editors to submit contributions from time to time.

EDITORIAL POLICY

The ERQ is published online by the Canadian Gas Association (CGA) to create a better understanding of energy regulatory issues and trends in Canada.

The managing editors will work with CGA in the identification of themes and topics for each issue. They will author editorial opinions, select contributors, and edit contributions to ensure consistency of style and quality. The managing editors have exclusive responsibility for selecting items for publication.

The ERQ will maintain a "roster" of contributors and supporters who have been invited by the managing editors to lend their names and their contributions to the publication. Individuals on the roster may be invited by the managing editors to author articles on particular topics or they may propose contributions at their own initiative. Other individuals may also be invited by the managing editors to author articles on particular topics.

The substantive content of individual articles is the sole responsibility of the respective contributors. Where contributors have represented or otherwise been associated with parties to a case that is the subject of their contribution to ERQ, notification to that effect will be included in a footnote.

In addition to the regular quarterly publication of Issues of ERQ, comments or links to current developments may be posted to the website from time to time, particularly where timeliness is a consideration.

The ERQ invites readers to offer commentary on published articles and invites contributors to offer rebuttals where appropriate. Commentaries and rebuttals will be posted on the ERQ website (www.energyregulationquarterly.ca).

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Rowland Harrison K.C.

The challenges raised by the relentless pursuit of "net-zero" and "electrification" are both immense and pervasive. It is becoming increasingly apparent that meeting those challenges, in many spheres, will likely necessitate innovative approaches, rather than mere incremental modifications to established practices. This is certainly apparent with respect to the challenges emerging in energy regulation — the energy regulatory forum will be the crucible in which solutions to those challenges will be implemented.

The extent of the changes that may be required in the regulatory framework itself is seen in the restructuring being implemented under Nova Scotia's *Energy Reform (2024) Act,*[1] ushering in transformational changes for the province's electricity system. The changes include carving out the responsibilities of the existing Nova Scotia Utilities and Review Board with respect to energy matters and assigning them to a new Energy Board established by the *Energy and Regulatory Boards Act.*[2] Interestingly, the two boards will have a common Chair, while each will have its own Vice-Chair. This new regulatory framework is reviewed by David MacDougall and colleagues in "The Nova Scotia *Energy Reform (2024) Act*: A New Paradigm for Energy Regulation in Nova Scotia."

The pursuit of electrification also presents challenges to identify and ameliorate potential impediments to wider adoption. In "Accelerating Electrification by Lowering its Operating Costs Through Technology — Specific Marginal Cost Pricing," Ahmad Faruqui observes that in some North American states and provinces, "[t]he biggest barrier facing electrification is the high cost of electricity…" He argues that, under the existing paradigm, "rate design should not be technology-specific." He proposes a new paradigm under which "marginal cost pricing would only be applied at the margin for *incremental* consumption associated with the installation of heat pumps for HVAC and water heating, EV chargers and other electrification technologies such as induction stoves." This approach, he argues, could lower the cost of electrification "without triggering a redistribution of wealth among customers…"

Several articles in *ERQ* have discussed the challenges faced by regulators in the context of the energy transition, most recently in reviewing two significant decisions of the Ontario Energy Board and the British Columbia Utilities Commission.[3] Those decisions raised fundamental questions about the implications of the transition for planning for the future of energy markets and the role of regulators in overseeing the transition. The discussion is ongoing. David Morton, former Chair of the British Columbia Utilities Commission, brings a further perspective in "The Energy Transition and Natural Gas: Two Regulators Speak Out."

While much of the focus of energy regulation and the role of regulators is on the energy transition, meanwhile many of the core issues that have concerned regulators and utilities continue to arise. The role of Performance Based Regulation (PBR) is one such issue. In "AUC Decision 28300-D01-2024: What will

[1] *Energy Reform (2024) Act*, SNS 2024, c 2.

[2] *Ibid* at schedule A.

[3] See, for example: Gordon E. Kaiser, "The Energy Transition, Stranded Assets, and Agile Regulation" (2024) 12:1 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/the-energy-transition-stranded-assets-and-agile-regulation>; Mark Kolesar, "Regulatory Decision-Making in Evaluating Electrification Initiatives" (2024) 12:3 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/regulatory-decision-making-in-evaluating-electrification-initiatives>.

it Mean for the Future of PBR in Alberta?," Mark Kolesar, former Chair of the Alberta Utilities Commission, analyzes a recent decision resulting from a decision by the AUC to reopen the PBR from 2018 to 2022 of two ATCO Utilities, in accordance with a reopener provision that had originally been approved by the AUC as part of an earlier PBR. It appeared from regulatory filings that the ATCO Utilities' achieved return on equity (ROE) in two years had exceeded the threshold specified in the reopener provision. Kolesar concludes that the decision has implications for the future of the Commission, the companies it regulates and consumers: "...it may serve to blunt the intended management efficiency incentives of PBR and sour utilities on continuing PBR regulation."

Discourse on achieving "net-zero" — especially by 2050 — frequently lacks any real understanding of the enormity of the challenge. In the words of a White Paper published at the end of 2023 by Positive Energy at the University of Ottawa, "[it] is a daunting task, bigger and faster than any that has ever been undertaken through deliberate policy — with the exception of wartime — in Canadian history."[4] In "Energy Projects and Net Zero by 2050: Can we Build Enough Fast Enough?," Michael Cleland and Monica Gattinger focus on the regulatory dimension of the broader study reported in the White Paper. Papers on specific aspects of the challenge, such as energy system planning, will follow and will be reported in *ERQ* as appropriate.

This issue of *ERQ* closes with two Case Comments. Reena Goyal comments on the Ontario Energy Board's 2023 decision approving a Settlement Proposal filed by the Independent Electricity System Operator (IESO), including proposed revenue requirements for the years 2023, 2024 and 2025. Until recently, applications for approval of IESO's revenue requirement was made on a single-year basis.

Nigel Bankes comments on a recent decision of the Supreme Court of Canada, confirming the Crown has a duty of diligent implementation of treaty promises that is informed not by fiduciary principles, but by the honour of the Crown.[5] The Crown had breached that duty since (in words that Bankes suggests "will ring down through the decades"):

> For well over a century, the Crown has shown itself to be a patently unreliable and untrustworthy treaty partner in relation to the augmentation promise. It has lost the moral authority to simply say 'trust us.'[6] ■

[4] University of Ottawa, "Energy Projects and Net Zero by 2050: Can we build enough fast enough?" (last visited 11 November 2024), online: <www.uottawa.ca/research-innovation/positive-energy/blog>.

[5] *Ontario (Attorney General) v Restoule*, 2024 SCC 27.

[6] *Ibid* at para 262.

THE NOVA SCOTIA *ENERGY REFORM (2024) ACT*: A NEW PARADIGM FOR ENERGY REGULATION IN NOVA SCOTIA

*David MacDougall, Lucia Westin-Eastaugh, and Alexandra Gosse**

INTRODUCTION

In early April 2024, Nova Scotia's *Energy Reform Act*[1] (originally known as Bill 404) passed, marking the beginning of a new direction for Nova Scotia's energy system. At the time of writing only a small portion of the Act was in force, but the balance of its robust changes are expected to come into force in the near future, ushering in significant changes for Nova Scotia's electricity sector — including both "traditional" electricity generators and existing and new renewable energy and energy storage proponents, including onshore and offshore wind and green hydrogen.

BACKGROUND

Nova Scotia's electricity sector is dominated by the vertically integrated incumbent electricity utility, Nova Scotia Power Inc. ("NS Power"). With the substantial changes occurring in the Nova Scotia electricity sector driven by federal and provincial environmental goals, including a phase out of NS Power's still substantial coal fleet by 2030 and a provincial 80 per cent renewable electricity grid target for the same year.

The provincial government announced the creation of a Clean Electricity Solutions Task Force ("Task Force") on April 20, 2023. The Task Force was charged with exploring ways to modernize Nova Scotia's electricity infrastructure and regulatory environment through, in part:

1. Examining the then current transmission grid capacity and determining the level of increased grid capacity required to ensure Nova Scotia's energy targets are met;
2. Reviewing the extent of the regulator's (the Nova Scotia Utility and Review Board) jurisdiction, its powers and its enforcement capacity; and
3. Engaging with Nova Scotians, including subject matter specialists, on the best path forward for the electricity sector.

The Task Force released its report on January 31, 2024, entitled Modernizing Energy from Transition to Transformation: A Report of

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[1] *Energy Reform (2024) Act*, SNS 2024, c 2 [*Energy Reform (2024) Act* or *Act*].

the Clean Electricity Solutions Task Force.[2] The Task Force made 12 specific recommendations, four of which will be noted here. The Task Force's first recommendation was the enactment of an *Energy Modernization Act* that would in part establish defined purposes for energy regulation in Nova Scotia, create a Nova Scotia Independent Energy System Operator ("NSIESO"), enable transparent competition for new generation, and create a standalone energy regulator.[3]

Recommendations #2 and #3 were to provide an expanded budget and adjusted compensation framework for the new Nova Scotia Energy Board to hire and retain the appropriate expertise in staffing to fulfill the new Board's expanded scope of responsibilities, and recommendation #7 was for the new NSIESO to oversee open competition for new infrastructure, with NS Power not being excluded from the bidding in any competitive process overseen by the NSIESO.

NOVA SCOTIA *ENERGY REFORM (2024) ACT*[4]

The provincial government took the recommendations of the Task Force under consideration and accepted the majority of the substantive changes, and in early April 2024, *Nova Scotia's Energy Reform (2024) Act* (originally, Bill 404) was passed by the Nova Scotia legislative assembly.

The creation of an independent system operator which is mandated by the new *Act* will be the first time that Nova Scotia will have a system operator function separate from the incumbent electric utility, and is a substantive change to the electricity regime in the province. In the words of the Task Force,

> To enable the successful transition of our energy system, The Task Force believes it is necessary to eliminate the tension created by the competing interests NSPSO [the internal NS Power system operator function] must balance: the interests of shareholders and the interests of customers.[5]

The creation of a new Energy Board which is also required by the new *Act*, focused solely on the energy sector as opposed to the much broader mandate of the current Nova Scotia Utility and Review Board, will allow for a greater focus of the energy regulator on the significant changes occurring during the fast moving energy transition occurring in Nova Scotia at present and anticipated to accelerate towards 2030.

Some of the key items arising from the new legislation are as follows.

1. Statutory Amendments and New Acts

The *Act* establishes 2 new statutes:

- The *Energy and Regulatory Boards Act.*[6]
- The *More Access to Energy Act.*[7]

These new *Acts* focus on specialization, competition, environmental and reliability considerations. In line with these changes, the *Energy Reform (2024) Act* also makes substantive amendments to, in part, the:

- Nova Scotia *Electricity Act.*[8]
- Nova Scotia *Gas Distribution Act.*[9]
- Nova Scotia *Public Utilities Act.*[10]
- *Nova Scotia Power Privatization Act.*[11]

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[2] Alison Scott & John Macisaac, *Nova Scotia Clean Electricity Solutions Task Force: Modernizing Energy From Transition to Transformation A Report of the Clean Electricity Solutions Task Force* (2024), online (pdf): <cetaskforce.ca/wp-content/uploads/2024/02/FInal-Report-February-23.pdf>.

[3] See *ibid* at 4–6.

[4] *Act*, *supra* note 1.

[5] *Supra* note 2 at 24.

[6] *Energy Reform (2024) Act*, SNS 2024, c 2, schedule A [*Energy and Regulatory Boards Act*].

[7] *Ibid* art 3.

[8] *Electricity Act*, SNS 2004, c 25 [*Electricity Act*].

[9] *Gas Distribution Act*, SNS 1997, c 4 [*Gas Distribution Act*].

[10] *Public Utilities Act*, RSNS 1989, c 380 [*Public Utilities Act*].

[11] *Nova Scotia Power Privatization Act*, SNS 1992, c 8 [*Nova Scotia Power Privatization Act*].

2. Specialized Energy Board

Over the past few years, the provincial government has put special emphasis on developing the province's energy potential (both for environmental and economic reasons), improving services and reducing energy costs for Nova Scotian residents and businesses. With the *Energy Reform (2024) Act*, the province takes further steps toward this goal by creating a board with specialization in energy regulatory matters.

Two Boards instead of one

The new *Energy and Regulatory Boards Act*[12] will effectively split the current Utility and Review Board ("UARB") into two entities:

- One to deal with energy matters (the Energy Board).
- One to deal with all other matters that previously fell within the UARBs' jurisdiction (the Regulatory and Appeals Board).

The two boards will have one common Chair, and each will have its own Vice-Chair. The chair of the current UARB will take on the role of Chair of the new Boards, while the vice-chair of the current UARB will take on the role of vice-chair of the Energy Board. The Regulations created under the UARB statute remain in force under the new *Energy and Regulatory Boards Act,*[13] suggesting the procedural rules for matters before the Boards will likely remain the same as for the UARB.

Board Recommendations

The *Energy and Regulatory Boards Act* allows the Minister of Natural Resources and Renewables, when considering changes in legal or political direction related to public utilities or the integrated electricity system as a whole, to submit the proposed change to the Energy Board for its recommendations, to protect the interests of the public and the applicable public utility. This will allow the Minister, in collaboration with the energy regulator, to make informed changes for the further development of Nova Scotia's energy systems.

Board Direction

The *Energy and Regulatory Boards Act* also provides the Energy Board with additional direction in carrying out its mandate. For example, it requires that, in determining matters over which it has authority, the Energy Board must consider the extent to which the matter:

- Supports competition and innovation in the provision of energy resources in the province.
- Supports the development of a competitive electricity market.
- Ensures the provision of safe, secure, reliable and economical energy supply in the province.
- Supports sustainable development and sustainable prosperity.

The government retains the ability to provide further direction by allowing the Governor in Council (ie. Cabinet) to add to these considerations through regulation. Further, the Energy Board's decisions must be consistent with the purpose of the *Energy and Regulatory Boards Act*, the *More Access to Energy Act* and their regulations. Contextual analysis will be required in this regard.

The thrust of these changes is to create an independent regulator with a specific focus on the energy sector, while still making effective and efficient use of the existing resources of the current UARB. The new Energy Board is intended to have the expertise and regulatory powers necessary to regulate the rapidly evolving energy landscape in Nova Scotia. In this regard it will be interesting to see in due course the qualifications of the other members of the Energy Board yet to be appointed, and whether the province adopts the Task Force's recommendations #2 and #3 noted above to provide the Energy Board with an expanded budget and adjusted compensation framework to hire and retain the appropriate expertise to fulfill the new Board's expanded scope of responsibilities.

[12] *Energy and Regulatory Boards Act*, *supra* note 6.

[13] *Ibid*.

3. Promotion of Competition

Two of the stated purposes of the *More Access to Energy Act*[14] relate to increased competition:

- Seeking to "increase competition and innovation in the Province's energy sector"[15].
- "[P]rovide for competitive procurement practices for new energy-system resources."[16]

The *More Access to Energy Act* largely sets out to achieve these (and its other) goals by establishing a new Nova Scotia Independent Energy System Operator ("IESO"). The IESO will direct operations of transmission systems pursuant to agreements with owners and operators of transmission systems in the province (the "IESO-controlled grid"), a role currently filled by the Nova Scotia Power System Operator. Amongst many other responsibilities, the new IESO will also be tasked with:

- Responsibility for the development of transmission tariffs (for approval by the Energy Board).
- Establishing market rules governing the IESO-controlled grid and actors on it.
- Facilitating the operation of a competitive electricity market.
- Conducting procurement for energy resources.

One element worthy of note here is the provincial government's acceptance of the Task Force's recommendation #7 noted above for the new IESO to oversee open competition for new electric infrastructure. In this regard the energy resources for which the IESO is mandated to conduct procurements include, electricity supply, electricity capacity, energy storage, ancillary services and hybrid peaking resources. Hybrid peaking resources in this context are defined as "electricity resources and non-electricity resources used in combination to satisfy the integrated electricity system demand." The IESO is also mandated to work with the Nova Scotia demand-side management ("DSM") franchise holder to supply NS Power with reasonably available, cost-effective DSM. As such, together with the traditional roles of an independent system operator to manage the grid, the NSIESO is given broad powers with respect to the procurement of energy resources required to fulfill the results of the integrated planning exercises also mandated to be carried out by the IESO.

4. Environmental Focus

The *Energy Reform (2024) Act* also aims to integrate environmental considerations into Nova Scotia's energy regulatory system through various mechanisms.

Sustainability

One of the stated purposes of the new *More Access to Energy Act* is to "support the sustainable development, sustainable prosperity, energy efficiency and greenhouse gas emissions reduction goals of the Province articulated in the *Environmental goals and Climate Change Reduction Act.*" This is particularly relevant since the Energy Board will be required to make decisions consistent with the purposes of this Act. The *Energy Reform (2024) Act* specifically incorporates the ideas of "sustainable development" (as defined in the *Environment Act*) and "sustainable prosperity"[17] (as defined in the *Environmental Goals and Climate Change Reduction Act*):

- "[S]ustainable development" means development that meets the needs of the present generation without compromising the ability of future generations to meet their own needs.
- "[S]ustainable prosperity" means prosperity where economic growth, environmental stewardship and social responsibility are integrated and recognized as being interconnected.

The Energy Board, when approving rates, tolls, charges, tariffs and capital applications or any other matter over which it has authority, must consider the extent to which they support sustainable development and sustainable prosperity.

[14] *Energy Reform (2024) Act*, SNS 2024, c 2, schedule B [*More Access to Energy Act*].

[15] *Ibid*, s 2(a).

[16] *Ibid*, s 2(d).

[17] *Ibid*.

Curtailment

The *Act* makes changes to improve clarity around, and financial compensation for, curtailment for generation facilities that have received a power-purchase agreement ("PPA") under a procurement initiated under section 4B of the *Electricity Act* (which addresses the procurement of renewable low-impact electricity or energy storage). These statutory clarifications, to be set out in a new section 4E of the *Electricity Act*, directly affect renewable electricity generators and energy storage in the province, both of which are needed for the province to reach its renewable energy goals. For this new Section 4E, "curtailment" will be defined as "based on instruction sent to a generation facility from the system operator, the decrease or cessation of the generation facility's generation output."[18] Pursuant to that section, generally:

- The purchaser of the facility's generation output will compensate the facility at the rate set out in the power purchase agreement between them where curtailment exceeds 5% of a generation facility's total energy bid.
- There will be no compensation for (i) any curtailment below 5% of the total energy bid, (ii) where the facility is not generating electricity when the system operator instructed the generator to stop/decrease output or (iii) where the system operator's request was due to "an unforeseeable emergency or *force majeure* event."[19]

Further regulatory certainty is provided on the curtailment issue by making the system operator responsible for determination of what constitutes an emergency or *force majeure* event and allowing curtailment disputes to be appealed to the Energy Board.

Policy Guidelines

The amendments to the *Public Utilities Act*[20] also provide the Minister with the authority to issue policy guidelines concerning objectives set out in its regulations. The Energy Board is charged with implementing these policy guidelines. These guidelines will provide flexibility in the Minister's ability to influence regulation of public utilities.

Nuclear Power

The *Energy Reform (2024) Act*[21] also removes the long-standing legislative prohibition in Nova Scotia against NS Power's construction of a nuclear power plant.

5. Increased System Reliability

The *Energy Reform (2024) Act*[22] increases the Energy Board's ability to address energy reliability concerns within the Nova Scotia electricity context. One of the express purposes of the new *More Access to Energy Act* is to "ensure the provision of a safe, secure, reliable and economical energy supply in the Province."[23]

Energy Board Powers

Reliability is addressed through expanding powers of the new Energy Board. First, the Energy Board is required to make decisions consistent with the purposes of the *More Access to Energy Act*, which includes the reliability consideration. The Energy Board is also outright required to give appropriate consideration to ensuring the provision of "safe, secure, reliable and economical energy supply in the Province"[24] when approving rates, tolls, charges, tariffs, capital applications or any other matter over which it has authority. Upon application to it, the Energy Board will be authorized to approve, modify or retire reliability standards. The Energy Board will also be authorized to monitor, assess, enforce compliance with, and make orders with respect

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[18] *Act*, *supra* note 1, s 21(1)(a).

[19] *Ibid*, s 21(4)(b).

[20] *Public Utilities Act*, *supra* note 10.

[21] *Act*, *supra* note 1.

[22] *Ibid*.

[23] *Ibid*, s 6(2)(c).

[24] *Ibid*.

to, approved reliability standards, and have the power to issue certain interim licences with respect to the operation of the Provincial transmission system where required "to ensure the reliable supply of electricity."[25]

IESO

The *More Access to Energy Act* also gives the IESO direction with respect to reliability. Some of the objects of the new IESO relating directly to reliability, include:

- Establish and enforce reliability standards for the province's integrated electricity system.
- Maintain the reliability of the bulk electricity system.
- Participate in the development of standards relating to the reliability of the transmission system.
- Undertake power system planning responsibilities to ensure the reliability of the bulk electricity system for present and future needs, as well as for the efficient operation of a competitive market.
- Forecast reliability of electricity resources for the province.
- Collect and make public information relating to the reliability of the integrated electricity system to meet the province's electricity needs.

The IESO will also have authority to give directions for the purpose of maintaining the reliability of electricity service or the IESO-controlled grid.

Transmitters

At the same time, transmitters are required to participate in the development of reliability standards for the transmission system and to comply with procedures, directions and orders of the IESO to ensure such reliability.

Regulations

As well, under the *More Access to Energy Act*, the Governor in Council will be granted authority to make regulations respecting reliability standards.

CONCLUSION

As can be seen from the foregoing, the changes to be implemented by the *Energy Reform (2024) Act* are broad in scope, and designed to create a more competitive landscape for the provision of electricity and related energy resources in the Province as it transitions off coal and to a more renewable energy based system.

The new legislation is expansive, and the foregoing is just a sample of many of the key changes to be brought about by the legislation. Anyone operating in the electricity sector in Nova Scotia is recommended to review the legislation in its totality.

As noted at the outset, the changes outlined in the legislation are anticipated to be brought in to force over the coming months, anticipated to be in phases. Many practical issues will need to be dealt with, including the establishment of the new NSIESO and the new Energy Board, and transfers of relevant assets and staff from NS Power to the new IESO which although not described above is also a key element of the legislation.

At the time of writing the province had recently commenced recruitment for the inaugural Board and Chair of the NSIESO. The recruitment notice indicated that the NSIESO will have about 80 employees and an estimated budget of $20M, and that the IESO would assume the system operator functions currently embedded in NS Power in two phases, with the first involving transferring the responsibilities for system planning and generator interconnection processes and charging the IESO with responsibility for procurement of new energy resources, and the second transferring control of the dispatch of generation and transmission facilities.

As this all roles out, it will be important that the transition be as seamless as possible so as not to disrupt the electricity system, especially considering the significant energy transition that is occurring in Nova Scotia at the same time. ■

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[25] *Ibid*, s 96(1).

ACCELERATING ELECTRIFICATION BY LOWERING ITS OPERATING COSTS THROUGH TECHNOLOGY-SPECIFIC MARGINAL COST PRICING

*Ahmad Faruqui**

Electrification is a top priority for just about every state and province in North America and for many countries around the globe. The urgency comes from the need to mitigate climate change.[1]

The biggest barrier facing electrification is the high cost of electricity in states[2] such as California and New York, and in the New England states.[3] Similar barriers exist in the Canadian province of Alberta.

While rebates from utilities and income tax credits from governments provide substantial financial incentives that lower the capital and installation cost of electrification technologies, such as heat pumps for HVAC[4] and water heating and electric vehicles (EVs), those financial incentives don't lower their operating costs. Thus, heat pumps are not being adopted by customers as fast as policy makers had hoped they would.[5]

EV sales continue to grow despite high electric rates in certain regions because gasoline prices are equally high. In my case, during the past 12 months, I spent US$1,095 to charge my Model 3 Tesla and saved US$578 by not

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[1] Masahiro Sugiyama, "Climate change mitigation and electrification" (2012) 44 Energy Pol'y 464, online: <www.sciencedirect.com/science/article/abs/pii/S030.142.151200033X>.

[2] U.S. Energy Information Administration, "Rankings: Average Retail Price of Electricity to Residential Sector, July 2024 (cents/kWh)", online (pdf): <www.eia.gov/state/rankings/?sid=US#/series/31>.

[3] Hawaii has the highest electric rates in North America but since natural gas is not widespread there.

[4] See, for example, Consolidated Edison Company of New York, "Get Thousands Off an Air-Source Heat Pump", online (pdf): <www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-residential-customers/electric-heating-and-cooling-technology-for-renters-homeowners/save-on-a-central-air-source-heat-pump>. Financial incentives in the $10,000 range are being offered in New York. Even then, the all-in installed costs of a heat pump HVAC system in states such as California can exceed $25,000.

[5] Another option being considered by policy makers in a few states is to ban natural gas in new buildings or to put a tax on the consumption of natural gas. The experience of the City of Berkeley in California is discussed in this blog by Professor Severin Borenstein. See Sanem Sergici et al, « Heat Pump–Friendly Cost-Based Rate Designs" (January 2023), online (pdf): <www.esig.energy/wp-content/uploads/2023/10/Heat-Pump–Friendly-Cost-Based-Rate-Designs.pdf>.

driving a comparable gasoline car.[6] However, as electric rates continue to climb, the driving cost advantages of an EV over conventional, internal combustion vehicles will diminish, slowing the rate of adoption of EVs.

At the same time, we are seeing the accelerated deployment of time-varying rates in many regions of North America, enabled in part by the widespread installation of advanced metering infrastructure (AMI) and in part by the encouraging results that several rate design pilots have yielded. But time-varying rates by themselves cannot lower the rate level, which is the primary barrier to electrification.

There is no easy way to lower the rate level overnight, because that will erode utility revenues and create financial turbulence. We need a new rate design paradigm that satisfies three conditions:

1. Makes electrification affordable
2. Recovers the utility's revenue requirement
3. Does not unleash a public outcry

It's a time-honoured principle in public utility economics to price energy services at marginal costs.[7] In theory, electrification can be encouraged by setting the energy charge equal to the marginal cost of energy in cases where marginal cost is lower than average cost. But that will create a significant deficiency in revenues for public utilities. Thus, some have suggested recovering the revenue deficiency through a fixed charge. However, in states and provinces with high electric rates, this will yield really high values for the fixed charge when the energy charge is dropped to the marginal cost of energy, which will be a lot lower than the average cost.

To deal with that adverse effect, some have suggested that the fixed charge should vary based on income, being lower for low-income customers and higher for all other customers. That was the genesis of California's income graduated fixed charge (IGFC). In the original conception, written by three academics at U.C. Berkeley, energy prices would be set equal to marginal costs. The revenue shortfall of some US$4 billion would be recovered through a fixed charge.[8] In the case of PG&E, the fixed charge would end up being US$74.02, much higher than anywhere else in the country and infinitely higher than the existing fixed charge of US$0.

Thus, the paper proposed to divide customers into five income tiers, and graduate the fixed charge across the income tiers, with customers in the lowest tier paying the lowest charge and customers in the highest tier paying the highest fixed charge. For customers in the highest income tier, the fixed charge would be US$186.

Even PG&E realized that such a high fixed charge would not be approved by the California Public Utilities Commission (CPUC). Thus, it proposed four income tiers with customers in the highest income tier paying US$92 a month. The average fixed charge would be US$53.

Even that proposal elicited a public outcry. It was criticized by several state legislators and members of California's Congressional delegation, and in several major newspapers, not only in the state, but nationally. It also came in for severe criticism from the public on social media.

When the CPUC ultimately ruled on the matter, the number of income tiers had been reduced to three with those in the highest income tier paying US$24.15 a month. The average fixed charge computes to roughly US$18. Energy prices are going to be lowered only by 5-7 cents/kWh across the three investor-owned utilities.[9]

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[6] This is based on information from the Tesla app under Charge Stats. It assumes that an equivalent gasoline vehicle would have 30 mpg and gasoline would be priced slightly above $5 a gallon.

[7] Paul L. Joskow, "Contributions to the Theory of Marginal Cost Pricing" (1976) 7:1 The Bell J of Econs 197, online (pdf): <www.jstor.org/stable/3003196>.

[8] Leo Borenstein, Severin, Meredith Fowlie and James Sallee, *Designing Electricity Rates for An Equitable Energy Transition*, Next10 (2021), online (pdf): <www.next10.org/publications/electricity-rates>.

[9] Stephanie Wang, "California approves restructure to income-based electric bills, cut to residential electricity prices" (22 May 2024), online: <www.dailycal.org/news/state/california-approves-restructure-to-income-based-electric-bills-cut-to-residential-electricity-prices/article_664622d2-181e-11ef-ba29-4fb356af5997.html>.

However, even the CPUC's approved IGFC rate design suffers from several limitations.[10]

- It will raise bills for energy consumers who are frugal, efficient or green, without any fault of theirs. Several of them have spent thousands of dollars to lower their electric bills. Their investments will be laid waste.
- It will lower bills for consumers who use large amounts of electricity, regardless of whether they have electrified their homes and their vehicles. Many of them live in large homes that use a lot of electricity.
- There is no empirical evidence it will promote electrification, because whatever customers save on their energy charges they will lose through their fixed charge. All it will do is to create winners and losers among customers and stir public anger.
- It may even be challenged in court for being an income tax in disguise.

Clearly, the IGFC is not a Pareto optimal rate design. It's simply an income redistribution program being carried outside the tax code.

A NEW RATE DESIGN PARADIGM

Under the existing paradigm, rate design should not be technology-specific. However, the new circumstances require us to change that paradigm, since mitigating climate change via electrification is the new reality.

Under the new paradigm being proposed in this paper, marginal cost pricing would only be applied at the margin for *incremental* consumption associated with the installation of heat pumps for HVAC and water heating, EV chargers and other electrification technologies such as induction stoves.

This approach is not without precedent in the world of tariff design. Today, a few utilities allow customers with EVs to be charged a rate that is specific to that vehicle if they install a separate meter. But that can be expensive. Other utilities are examining the use of telematics to bill EV customers for charging their vehicles at home, which would eliminate the need for separate metering.

As for HVAC heat pumps, under the traditional metering and pricing paradigm, this would have required end-use metering, which can be very expensive. That's no longer necessary. Artificial Intelligence (AI) may act as a perfectly acceptable alternative.[11] AI can infer the incremental load associated with electrification to which marginal cost pricing would be applied.

If there is some hesitation in using AI, an alternative would be to initially apply marginal cost pricing to all incremental changes in load shape. The notion of applying marginal cost pricing for incremental load shapes is not as radical as it sounds. It is not without precedent.

Georgia Power has implemented marginal cost pricing in this fashion since the 1990s for commercial and industrial customers. The pricing design they offer is real-time pricing (RTP). Both day-ahead and hour-ahead versions are provided, depending on the size of the load.[12] The logic behind the rate is discussed in a paper by Michael T. O'Sheasy that was published in 1998 in *The Electricity Journal*.

O'Sheasy concludes the paper by saying:

> In summary, two-part RTP affords the customer the luxury of buying above the CBL [customer baseline load] when the price is low and selling back effectively below the CBL when the price is too high. RTP customers have demonstrated an uncanny ability to do just this resulting in remarkable reductions in their cents/kWh [effective average rate]. Since these changes are performed at a price reflecting the utility's marginal cost, the utility benefits likewise. Imagine

[10] Ahmad Faruqui, Jim Lazar & Richard McCann, "New electricity rate reform in California: A rejoinder to Meredith Fowlie" (2023) 11:4 Energy Regulation Q, online: <energyregulationquarterly.ca/articles/new-electricity-rate-reform-in-california-a-rejoinder-to-meredith-fowlie>.

[11] For EVs, there is another option, which is to use the telematics in the car for metering their usage.

[12] See Georgia Power, *Electric Service Tariff: Real Time Pricing – Day Ahead*, online (pdf): <www.georgiapower.com/content/dam/georgia-power/pdfs/business-pdfs/rates-schedules/RTP-DA-5.pdf>. See also Georgia Power, *Electric Service Tariff: Real Time Pricing – Day Ahead*, online (pdf): <www.georgiapower.com/content/dam/georgia-power/pdfs/electric-service-tariff-pdfs/RTP-HA-6.pdf>.

> a classic win-win whereby the seller and the buyer are in perfect accord to buy low and sell high.[13]

This paper applies that idea to residential customers with one modification. It proposes that marginal cost pricing be only applied for incremental loads, as in Georgia Power's case, but limits the new rate design to those households who have either already *electrified their homes or their cars or are considering electrifying* their homes or their cars. Households would have to furnish proof that they have acquired either heat pumps or EVs or both. They could do that by providing a copy of their utility rate application or copy of their income tax credit application. Of course, the household would need to have a smart meter in place for this to work but 80 per cent of US households today do have that capability in the US.

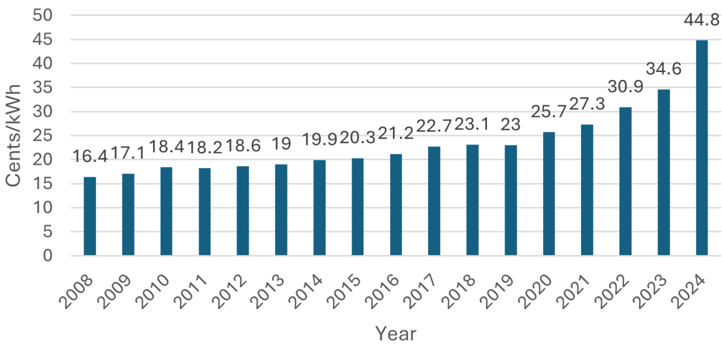
Marginal cost pricing does not have to be full-blown hourly pricing. That idea will have to wait until technology advances enable prices to be sent directly to devices with the customer's consent and foreknowledge.[14] Marginal cost pricing could take the form of any time-varying rate, including time-of-use rates, critical-peak pricing rates, peak time rebates or real time pricing.

It could also include a capacity cost element if electrification in certain zones bumps into distribution capacity constraints.

A CASE STUDY

Consider the case of Pacific Gas & Electric Company, which serves more than 5 million customers in northern California. The average residential rate currently stands at 42 cents/kWh.[15] Using the E-1 tiered rate as a point of reference, the price of electricity has doubled over the past seven years, far exceeding the rate of inflation. In the seven years prior to 2017, it had only grown by 23 per cent. As a point of reference, in 2008 the rate stood at 16.4 cents/kWh.[16] More increases are expected to occur at year end, with the average rate possibly reaching 50 cents/kWh.

History of the average residential rate (cents/kWh)[17]



[13] Michael O'Sheasy, "How to buy low and sell high" (1998) 11:1 The Electricity J, online: <www.sciencedirect.com/science/article/abs/pii/S1040619098800201>.

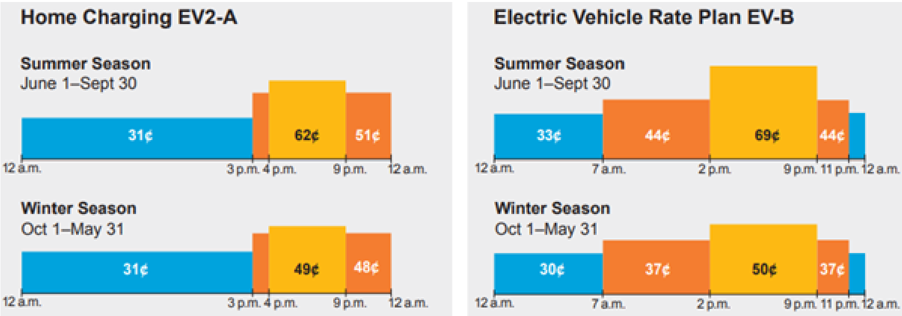
[14] OGE in Oklahoma has been doing that for almost a decade. It sends four-tiered critical-peak pricing rates directly to smart thermostats of the roughly ten percent its customers who have enrolled in such rates. The critical-peak pricing rates have four tiers, depending on the nature of the power-supply balance. OGE does not control the thermostats but merely sends the signal to them. It is up to the customer to program their thermostats to respond to the price signal. Similar ideas have been expressed for charging EVs. The key is gaining the driver's assent and communicating successfully with the EV charger. Of course, the drivers have to keep their EV plugged in for "managed charging" to work.

[15] The rate has been discounted temporarily during the summer months. Earlier, it had reached 46 cents/kWh.

[16] See Pacific Gas and Electric Company, "Electric rates: Current historic electric rates" (last visited 23 October 2024), online: <www.pge.com/tariffs/en/rate-information/electric-rates.html#accordion-a84c67dc1e-item-e10eec0cc5>.

[17] Based on annual data for the E-1 tariff provided by PG&E. Pacific Gas and Electric Compagny, "Electric rates: Current and historic electric rates" (last visited 29 October 2024), online: <www.pge.com/tariffs/en/rate-information/electric-rates.html>.

Electric vehicle (EV) rate plans[18]



One of the popular rates being used by its EV customers is EV2-A.[19] The rate features three pricing periods. During the summer, the off-peak rate is 31 cents/kWh.[20] If EV load is priced at the marginal cost of electricity, the price may drop to 10 cents/kWh. A typical household whose EV load is 3,000 kWh a year would see their annual EV driving costs drop substantially from US$930 to US$300. This would substantially enhance the appeal of EVs to drivers who are in the market for a new car, and probably accelerate the EV adoption rate.

In the areas that lie east or south of San Francisco, or in the Central Valley, summers are hot and winters are cold. A heat pump for heating, ventilating and air conditioning (HVAC) may consume 3,500 kWh a year. In the summer, a heat pump in the cooling and ventilation mode is likely to run for several hours a day, spanning the off-peak, mid-peak and peak periods. It is likely to run most intensely in the late afternoon and early evening periods. In the winter, in the heating and ventilation mode, it is likely to run mostly in the mid-peak and off-peak periods.

If the year-round peak period price averages 55 cents/kWh, the mid-peak averages 49 cents/kWh and the off-peak price averages 31 cents/kWh, then a weighted average price of 45 cents/kWh may be used to get a rough estimate of the annual operating cost of a heat pump.

With the existing rate, that would amount to roughly US$1,575. If a marginal price of 15 cents/kWh is used, the cost would drop to US$525, making it a substantially more attractive investment for customers, and probably accelerating the adoption rate. In both cases, operating costs fall by two-thirds, as brought out in the figure below.

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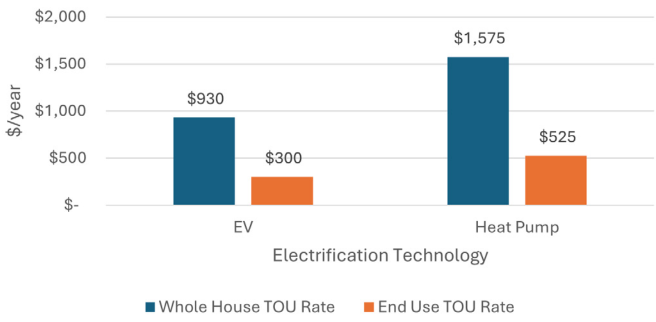
[18] Pacific Gas and Electric Compagny, "Electric Vehicle (EV) rate plans" (last visited 29 October 2024), online: <www.pge.com/evrates>.

[19] Allen Meredith, *Electric Schedule EV2: Residential Time-of-use: Service for Plug-in Electric Vehicle Customers*, Pacific Gas and Electric Company (2023), online (pdf): <www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV2%20(Sch).pdf>.

[20] It was 17 cents/kWh in 2019, just five years ago.

Reduction in operating costs of electrification: Whole house v end use TOU rates[21]



It should be noted that operating costs with whole house TOU are likely to already be lower than with a flat rate, by 5–10 per cent. These savings are dwarfed by the savings shown above. A recent paper by ESIG examined the reduction in operating costs of heat pumps associated with three different whole house rate designs: TOU, higher fixed charges, and demand charges. In all three cases, the reduction in operating costs was less than 20 per cent.[22]

Similar calculations can be performed for other electrification technologies, such as heat pump water heaters and induction stoves.

In some areas, electrification might run into distribution capacity constraints, requiring capacity expansion. In such cases, estimates of marginal capacity costs would be added to marginal energy costs. In addition, electrification-focused marginal cost pricing should feature time variation in energy rates to avoid creating new peaks and to facilitate load flexibility.

PILOTING THE NEW RATE DESIGN

As with any new rate design, it would be good to test the empirical effectiveness of electrification-specific marginal cost pricing through carefully designed pilots before proceeding with full scale implementation.

Lessons learned from designing and evaluating pilots with time-varying rates could be harnessed to assist in pilot design.[23] At a high level, pilots should seek to imitate the best features of medical clinical trials that are used to test the efficacy of new drugs. These clinical trials feature randomized selection of treatment and control groups, where treatment refers to the new rate design paradigm. Such designs are called Randomized Control Trials (RCT). A good example is the rate design pilot that was carried out by SMUD, the municipal utility that serves half a million customers in the Sacramento area.[24]

If the RCT design is not possible, for budgetary or ethical reasons, pilot designs should seek to approximate such designs to the best extent possible. Examples include Randomized

[21] Author's computations.

[22] *Supra* note 6.

[23] See Ahmad Faruqui & Sanem Sergici, "Household response to dynamic pricing of electricity–a survey of 15 experiments" (2010) 38 J of Regulatory Econs 193. See also Sanem Sergici, Ahmad Faruqui & Sylvia Tang, "Do Customers Respond to Time-varying Rates: A Preview of Arcturus 3.0" (2023) Brattle, Working Paper, online (pdf): <www.brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf>.

[24] Meredith Fowlie & al, "Default Effects and Follow-On Behavior: Evidence From An Electricity Pricing Program" (2020) Energy Inst At HAAS, online (pdf): <haas.berkeley.edu/wp-content/uploads/WP280.pdf>.

Encouragement Design and Random Sampling with Matching Controls.

In all designs, a sufficient number of participants have to be selected so that the statistical test of differences have sufficient power.[25]

The pilots should be designed to measure the impact of the new rate on three variables: customer adoption rates for electrification technologies, changes in customer load shapes and changes in customer bills.

To get an accurate idea of the effectiveness of the new rate design, all three variables should be measured before and after the treatments are offered. When all is said and done, the impact of the treatment will be measured as a difference-in-differences. In other words, any pre-existing differences between the treatment and control groups will be netted out of the measured difference between the two groups after the treatment has been offered. Pilots should run for more than a year.

CONCLUSION

High electric rates in many regions of North America pose a major barrier to electrification, which is viewed by many policy makers as an important enabler of reaching climate mitigation roles. While marginal cost pricing at the whole house level can lower operating costs of electrification equation to some extent, the reduction is not sufficient to accelerate customer adoption of these technologies.

It's imperative to change the existing rate design paradigm, which argues that rates should only be applied at the whole house level and extend the rate design paradigm to allow marginal cost pricing to be applied at the technology level.

Technology-based marginal cost pricing can lower the operating cost of electrification without triggering a redistribution of wealth among customers, which would precipitate a public backlash. Rates for existing load shapes would remain unchanged. Utilities will still recover their revenue.

Society as a whole will benefit through the reduction of carbon emissions that will accompany electrification. Climate change will be mitigated. Customers who electrify will see lower bills compared to what they would be paying with gas furnaces and internal combustion engine vehicles. There will be no losers. No one will see higher bills, unlike the situation in California with the IGFC.

In other words, such a rate design will yield a Pareto-optimal outcome. ■

[25] Eduardo Hariton & Joseph J Locascio, "Randomised controlled trials — the gold standard for effectiveness research" (2018) 125:13 An Intl J of Obstetrics & Gynaecology 1716.

THE ENERGY TRANSITION AND NATURAL GAS: TWO REGULATORS SPEAK OUT

*David Morton**

INTRODUCTION

Near the end of 2023, two strikingly similar decisions were issued almost simultaneously, one by the British Columbia Utilities Commission (BCUC), the other by the Ontario Energy Board (OEB). Both raised significant concerns about investments in natural gas infrastructure, yet both fell short of considering the broader questions raised by the changing energy context in Canada.

These broader questions include:

- What is the role of the natural gas distribution system?
- Where will the electricity come from?
- Is there a holistic plan for the transition?

This article reviews further those broader questions and highlights the difficulties that can arise when examining them.

OEB AND ENBRIDGE

On December 21,2023, the OEB issued its Decision and Order on the remaining Phase 1 issues in Enbridge Gas Inc.'s (Enbridge) application seeking approval for changes to the rates it charges for the sale, distribution, transmission, and storage of natural gas starting January 1, 2024.

In the decision the OEB Panel determined by majority decision that for small volume customer connections, the revenue horizon that Enbridge uses to determine the economic feasibility of new connections is to be reduced from 40 years to zero, in a move to reduce stranded asset risk to zero, effective January 1, 2025. This methodology effectively precludes connecting any new customers as the costs will far exceed the costs of electric alternatives.

The Panel also reduced Enbridge's overall proposed capital budget of approximately $1.4 billion for 2024 by $250 million, stating that

> [t]he energy transition poses a risk that assets used to serve existing and new Enbridge customers will become stranded because of the energy transition. Enbridge has not provided an adequate assessment of this risk to demonstrate that its capital spending plan is prudent. The stranded asset risk affects all aspects of Enbridge's system and its proposals for capital spending on system expansion and system renewal.[1]

The Panel further stated that the

> assets Enbridge Gas proposes to add to rate base in 2024 would be depreciated over the next 40 years or more, based on the physical asset life. The same would apply to the assets that Enbridge Gas plans to add in each of the following four years, as proposed in its application, and over the next ten years, as proposed in its Asset

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[1] *Phase 1 Enbridge Gas Inc: 2024-2028 Rates Proceeding* (21 December 2023), EB-2022-0200, at 2, online: OEB <www.rds.oeb.ca/CMWebDrawer/Record/827754/File/document>.

> Management Plan. It is the 40-year horizon against which the stranded asset risk must be examined, not the five-year horizon of the requested rate term that Enbridge Gas urges the Panel to use. When looked at through the 40-year lens, what Enbridge Gas proposes looks very much like business as usual and it is not sustainable.[2]

The Panel's concern about sustainability was also evident in its directives to Enbridge to mitigate stranded asset risk, including:

- put more emphasis on monitoring, repairing and life extension of its system so that replacement projects are only implemented where absolutely necessary
- carry out a risk assessment and to consider a range of risk mitigation measures, including:[3]
    - How Enbridge Gas would prune its existing system to avoid the replacement of assets.
    - What role Enbridge Gas's depreciation policy should play in reducing the stranded asset risk.
    - How Enbridge Gas will identify maintenance, repair and life extension alternatives to extend the life of existing assets instead of long-lived replacements that increase the stranded asset risk.

One of the three Panel members, Commissioner Allison Duff, dissented on the zero-year revenue horizon for assessing the economics of small volume gas expansion customers, saying the evidence doesn't support pushing the connection costs completely up front. In particular, she considers the rationale is conjecture as no developers intervened or filed evidence in this proceeding. Commissioner Duff instead finds that a 20-year revenue horizon is appropriate.[4]

Commissioner Duff went on to say: "[t]o me, the risk of unintended consequences to Enbridge Gas, its customers and other stakeholders increases given the magnitude of this conclusive change."[5]

Commissioner Duff also expressed concern about the feasibility of replacing new gas connections with electricity, writing: "would electricity generators, transmitters, distributors and the IESO be able to meet Ontario's energy demands in 2025? I don't know."[6]

THE REACTION AND ENBRIDGE'S VIEW

Reaction to the decision was swift. On the very next day, Ontario's Energy Minister stated that he was "extremely disappointed" in the split decision and vowed to "use all of my authorities as Minister to pause the Ontario Energy Board's decision…[w]e will not stand for this]."[7]

The opposition to the decision was focussed on affordability. Minister Todd explained it could lead to tens of thousands of dollars added to the cost of building new homes, which would slow or halt the construction of new homes, including affordable housing.[8]

Not surprisingly, Enbridge said it is disappointed with the decision and it is "reviewing all of its potential options for challenging the order, including going to court."[9]

Enbridge also commented on affordability issues, stating: "[a]t a time when affordability is the number one concern for Ontarians, this decision means that new customers will have to pay for their connection to natural gas immediately rather than over several years, adding unnecessary costs to residents."[10]

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[2] *Ibid* at 21.

[3] *Ibid*.

[4] *Ibid*.

[5] *Ibid* at 2.

[6] *Ibid*.

[7] Government of Ontario, "Ontario Government Standing Up for Families and Businesses" (22 December 2023), online: <news.ontario.ca/en/statement/1004010/ontario-government-standing-up-for-families-and-businesses>.

[8] *Ibid*.

[9] The Canadian Press, "Minister to overrule Ontario Energy Board, says decision will raise cost of new homes" (22 December 2023), online: <www.toronto.ctvnews.ca/minister-to-overrule-ontario-energy-board-says-decision-will-raise-cost-of-new-homes-1.6699449>.

[10] *Ibid*.

BCUC AND FORTISBC

On December 22, 2023, the BCUC issued its decision denying FortisBC Energy Inc.'s ("Fortis") application for a Certificate of Convenience and Necessity (CPCN) for its proposed Okanagan Capacity Upgrade Project (OCU), which included the construction, installation, and operation of approximately 30 kilometers of new natural gas pipeline. The denial of the application was a unanimous decision of the two person Panel. The Panel determined that the project was not necessary for public convenience or in the public interest.[11]

In its application, Fortis stated that the pipeline expansion project is needed to meet its forecast increase in demand for natural gas in the Okanagan region of BC due to population growth. Fortis indicated that it expects to be unable to meet the growing demand with its existing pipeline infrastructure, as early as the winter of 2026/2027.[12]

The Panel found that Fortis application did not consider the possibility that demand for natural gas in the Okanagan region could flatten or decrease over the next 20 years, due, in part, to BC's CleanBC Roadmap commitments, BC Building and BC Energy Step Codes impacts, and other planning guidelines or zoning bylaws.[13]

As stated in the decision, and with the numbers that the determination was based on, the most recent estimate of the project cost was $327.4 million with a delivery rate impact of 2.37 per cent. However, the evidence suggests that this rate impact may be overstated, as the levelized rate impact is 1.78 per cent.[14]

One focus of the proceeding was the examination of alternatives to the pipeline, trucking CNG to meet peak loads being probably the most examined. Fortis' position was that this was impractical, but the Panel disagreed. While it accepted that "this is not appropriate for a long-term solution as it has numerous drawbacks" it endorsed it as a short-term solution, stating that "it might be able to cost effectively fill the gap in the meantime."

The Panel also suggested that other short term mitigation strategies could be targeted to address those parts of their gas transmission system, which Fortis identifies would be the first to experience capacity shortfalls. The first communities to experience capacity shortfalls are identified by Fortis as West Kelowna, Lumby and Lavington, having a combined population of about 40,000.

The only other potential short-term solution (other than trucking) suggested by the Panel was the Peak Shaving CNG Unit outlined in Fortis's Gibsons Capacity Upgrade Project. The approved but not yet completed Peak Shaving CNG Unit referred to will serve a town of approximately 5,000 on the "Sunshine Coast," an area that enjoys somewhat warmer winters than the Okanagan.

This peak shaving unit replaces a scheme of barging in CNG on trucks to supplement the capacity of the existing distribution pipeline. It consists of a slow filling peak shaving facility and associated tie-ins to the existing distribution main. The facility draws gas from the existing distribution system during periods of low system demand, compress it, and store it in two high-pressure storage vessels. During periods of high gas demand, the stored gas will be depressurized, heated, and injected back into the distribution system to supplement the supply. Its cost of approximately $12 million is less than that of a pipeline upgrade.[15]

The Panel directed Fortis to file an alternative plan by July 2024.

THE REACTION TO THE BCUC DECISION

The reaction to the BCUC decision was muted, at least compared to the reaction in Ontario

[11] British Columbia Utilities Commission, News Release, "BCUC Rejects FortisBC Energy Inc. Okanagan Capacity Upgrade Project" (22 December 2023), online (pdf): <docs.bcuc.com/documents/NewsRelease/2023/2023-12-22-NEWS-RELEASE-BCUC-Rejects-FortisBC-Okanagan-Upgrade-Project.pdf>.

[12] *Ibid*.

[13] *Ibid*.

[14] FortisBC Energy Inc: Application for a Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project (14 August 2023) Final Submission, at para 134, online (pdf): <docs.bcuc.com/documents/arguments/2023/doc_72977_20230814feifinalargument.pdf>.

[15] *FortisBC Energy Inc: Annual Review for 2023 Delivery Rates* (5 December 2022), BCUC G-352-22, online: BCUC <www.ordersdecisions.bcuc.com/bcuc/orders/en/521395/1/document.do>.

to the OEB decision. Fortis official statement expressed "disappointment" and went on to emphasize:

> The Okanagan Capacity Upgrade project is required to meet peak energy demand in the Okanagan region, which occurs during colder winter months when customers rely on gas to heat their homes and businesses… Fortis' infrastructure is vital to the delivery of renewable and low-carbon gases, which are critical to the Province's ability to meet its CleanBC targets.[16]

Although both these decisions speak volumes about their respective regulators' views on the future of the natural gas system, they are silent on a number of critical questions, such as: What is the role of the natural gas distribution system? Is there a holistic plan for the transition? In the absence of natural gas, where will the electricity come from? Is there a joint plan for the transition?

WHAT IS ROLE OF THE NATURAL GAS DISTRIBUTION SYSTEM?

Both decisions operate from a premise that the need for the natural gas distribution system will be reduced as the demand for conventional natural gas diminishes. Combining that assumption with findings that the demand for conventional natural gas may be reduced or eliminated over the next 40 or so years leads to the conclusion that investments in gas infrastructure must be reduced in order to prudently manage the risk of stranded assets.

However, in both decisions, these assumptions appear to be based on the effective implementation of a particular assumed pathway to decarbonization, specifically the replacement of conventional natural gas with electricity.

Neither decision addresses the difference between the demand for a gas pipeline delivery system as opposed to the demand for conventional natural gas.

Currently, both Enbridge and Fortis sell a limited amount of what they call "renewable natural gas" (RNG) through the same pipeline delivery system. Although RNG is currently not an approved compliance pathway in BC, the BCUC Panel did acknowledge that should it become one, "there may well be little variance in the trajectory of FEI's longer-term peak demand forecast."[17] However, due to that uncertainty and also because there has been no decision to date on the Revised Renewable Gas Comprehensive Review proceeding the Panel declined to take into account the possibility that Fortis' load forecast may be reasonable.

The BCUC recently issued a report on renewable natural gas in which it considered the issue of abated gas, which it defined as conventional natural gas combined with environmental attributes (EA) derived from any source other than the production of biomethane.[18]

The report included a recommendation that the provincial government

> consider legislative changes to recognize abated gas. The abated gas should be derived from EAs that arise from processes that clearly fulfil the objectives of the *CEA* [*Clean Energy Act*], the CleanBC Roadmap to 2030 and British Columbia's broader GHG reduction commitments, and are therefore an acceptable and achievable pathway to emission reductions for the Province.[19]

Is there a possibility that the existing natural gas pipeline system could be used to transport other gasses to provide home heating, such as hydrogen, conventional natural gas combined with carbon capture and storage schemes or other abated gasses?

[16] FortisBC, "Statement regarding BCUC decision on the Okanagan Capacity Upgrade Project" (22 December 2022), online: <www.fortisbc.com/news-events/media-centre-details/2023/12/22/statement-regarding-bcuc-decision-on-the-okanagan-capacity-upgrade-project>.

[17] *Supra* note 15 at 24.

[18] British Columbia Utilities Commission, *Inquiry into the Acquisition of Renezable Naturel Gas by Public Utilities in British Columbia*, Phase 2 Report (Vancouver: British Columbia Utilities Commission, 2023) at 24.

[19] *Ibid* at iii.

These are difficult issues for the regulator to address. No legislative framework exists in either province that includes clear policy on these schemes. Further, they involve new and evolving technologies with uncertain outcomes and largely unknown cost implications.

WHERE WILL THE ELECTRICITY COME FROM?

Largely unaddressed in both decisions was the question of where the electricity would come from if the demand for natural gas is partially or completely replaced by electrification of home heating.

In Ontario, while the IESO has been optimistic about the ability of the electric system to fully eliminate natural gas generation in its own electricity system by 2050. Starting with a moratorium on new natural gas fired generation in 2027, in a report issued in late 2022 it stated that to do so will require about $400 billion in capital spending and new, large-scale nuclear plants.

Further, in an assessment of resource adequacy in the 2025-2027 period, the IESO reports that "Ontario will require an additional 4,000 MW of electricity between 2025 and 2027 — the equivalent of adding a city the size of Toronto to the power grid". IESO further recommends that the province step-up natural gas use to help avoid an energy shortage, stating there is no "like-for-like" replacement for natural gas.

As a result, the provincial government approved the IESO's plan to add up to an additional 1,500 MW of new natural gas capacity between 2025 and 2027, and 2,500 MW of non-natural gas generation — directing that at least 1,500 MW of which should be storage, while the rest should be other clean sources such as hybrid solar-battery technology or new hydroelectric power.[20]

It appears that all else equal in the short-term, incremental electricity load requires additional gas-powered electricity generation. If that is the case, in the short-term at least, replacing natural gas with electricity means replacing natural gas with electricity that may be generated using natural gas.

However, it is not clear whether the OEB Panel considered any of these factors. If its decision results in a switch from natural gas to electricity in the short-term. Will that increase the electric load needed in the 2025 to 2027 period beyond that considered in the 2022 IESO study? The Panel majority did not appear to consider the impact of its decision on electricity demand — and where any additional incremental electricity would come from to provide for building heating needs that would otherwise have been supplied by natural gas — although the dissenting Commissioner did.

In BC, on February 24, 2023, Fortis filed, in its long-term resource plan proceeding, its "Kelowna Electrification Case Study." The study concludes that

> at 100 percent electrification of gas load and a mean daily temperature of -26 Celsius (C), peak demand in 2040 would more than triple, from 472 megawatts (MW) to 1,429 MW, resulting in a high-level estimate of between approximately $2.6 and $3.4 billion in capital expenditures on the electric distribution and transmission system which would be needed in less than 20 years. Even at 25 percent electrification of gas load, peak demand would increase to 711 MW and result in an estimated range of $1.3 to $1.7 billion in capital expenditures over this same timeframe.[21]

However, the BCUC Panel does not appear to have considered this evidence in the OCU proceeding, even though the *Utilities Commission Act* requires it to consider a utility's most recently filed long-term resource plan when considering an application for new infrastructure such as this new pipeline.[22]

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[20] Independent Electricity System Operator, *Evaluating Procurement Options for Supply Adequacy: A Resource Adequacy Update to the Minister of Energy*, Resource Adequacy Update (Toronto: Independent Electricity System Operator, 2023).

[21] FortisBC Energy Inc & FortisBC Inc, *Kelowna Electrification Case Study — Electrification and the Impacts of Cold Temperature on Peak Demand and System Upgrade Costs*, (Vancouver, FortisBC, 2023), at 1, online (pdf): <docs.bcuc.com/documents/proceedings/2023/doc_70278_b-20-fei-evidentiary-update.pdf>.

[22] *Utilities Commission Act*, RSBC 1996 c 473, s 46(3)(1).

Electricity is supplied to the Okanagan are by a sister corporation, Fortis Electric. Fortis Electric filed its most recent Long Term Resource Plan in 2021. That plan did not identify any increased heating load from the reduction of natural gas demand.

Further, according to its 2020 Annual Report, approximately 18 per cent of Fortis Electric's electricity is acquired through a Power Purchase Agreement from BC Hydro, which supplies electricity to most of the province.[23] BC Hydro filed its Integrated Resource Plan in late 2022. It did not identify any increase in demand to replace natural gas as a home heating fuel. Although it has since revised its load forecast, and its Integrated Resource Plan hearing is ongoing, it is not clear whether this provides any additional capacity for the Okanagan or whether it has sufficient infrastructure to deliver that additional capacity.

Recent events underline the amount of electrification required to serve heating load on peak days. On January 12,2024, cold temperatures broke numerous temperature records in BC. According to a Fortis press release, its gas system provided 21,763 MW, which by comparison, is almost double the 11,300 MW provided by BC Hydro.[24] Clearly, replacing natural gas as a heating fuel with electricity will require considerable thought and planning.

IS THERE A HOLISTIC PLAN FOR THE TRANSITION?

In the Enbridge decision, the Panel stated,

> In the face of the energy transition, Enbridge Gas bears the onus to demonstrate that its proposed capital spending plan, reflected in its Asset Management Plan, is prudent, having accounted appropriately for the risk arising from the energy transition. The record is clear that Enbridge Gas has failed to do so. Enbridge Gas has taken the position that there is no stranded asset risk for the purposes of setting rates for 2024. This is not logical.[25]

Indeed, it isn't logical if one assumes that the demand for conventional natural gas will drop significantly in the near to medium term. However, as Commissioner Duff highlighted in her dissent, where will the electricity to replace the demand for natural gas come from? Until regulators can get some visibility on where, and at what cost, is it indeed prudent for them to assume we don't need conventional natural gas?

In the BC decision, the regulator directed Fortis to find a short-term fix while the future of the gas distribution system in BC becomes clearer. It found:

> a significant risk that the forecast growth flattens or potentially begins to decline due to Fortis' inability to serve new customers' space and water heating needs resulting from the province's commitments in the CleanBC Roadmap, the changes to the BC Energy Step Code and the ZCSC.[26]

Again, a not unreasonable conclusion on its face. However, as with the OEB decision, it assumes that natural gas — or any other product transported by the pipeline — will be unable to meet government's decarbonization goals and that natural gas can be replaced by zero emitting electricity at a reasonable cost and within the required timeframe.

Is this the most prudent approach? Does denying an application for capacity that is demonstrably needed in the short term in an attempt to save the ratepayer cost actually increase the risk to the utility's customers?

[23] FortisBC Inc, *Annual Information From: Fort the Year Ended December 31, 2020*, (FortisBC, 2021), online (pdf): <www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fbc-aif-2020-final-mar-26-2021-sedar.pdf?sfvrsn=c8b7cc8e_2>.

[24] Colin Dacre, "During peak demand, FortisBC's natural gas system delivered double the energy of BC Hydro" (15 January 2024), online: <www.castanet.net/news/BC/467369/During-peak-demand-FortisBC-s-natural-gas-system-delivered-double-the-energy-of-BC-Hydro>.

[25] *Supra* note 1 at 21.

[26] *FortisBC Energy Inc: Application for Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project* (22 December 2023), G-361-23, online: BCUC <www.ordersdecisions.bcuc.com/bcuc/decisions/en/522057/1/document.do>.

They are at the forefront when risks materialize, such as increased energy costs or brownouts or blackouts when there is insufficient energy on cold winter days.

To make these determinations requires a much more holistic view than was taken in either of the decisions. That said though, it is difficult for regulators to obtain a holistic view of the energy transition. In many cases, legislation is not in place to support the transition and technology is developing rapidly. Further, regulators have always viewed specific applications on their own merit, often with different Panels examining different applications. This can lead to unavoidable siloing of issues.

The Kelowna Study concludes that there are opportunities for solutions to managing the energy transition through the operation of an integrated gas and electric system.

Additionally, the BCUC recently led an exercise to develop joint load forecasts for both BC Hydro and Fortis. This resulted in each company providing responses to various scenarios put forward by the other. This evidence was filed in both the Fortis and BC Hydro recently filed Resource Plan proceedings.

Regulators need the holistic view that these exercises can provide. The Electrification and Energy Transition Panel convened by the Ontario government, seems to agree. In its recent report, issued after both of these decisions, one of the 7 principles and next steps it sets out for "Ontario to navigate and succeed in the transition towards a clean energy economy in the long term" is: "Ensuring effective collaboration and integration in energy planning across fuels, especially electricity and natural gas, across end use sectors and across levels of government, to ensure investments and innovation can be deployed in a way that unlocks their full value."[27]

CONCLUSION

Neither of these decisions involved significant sums of money — several hundred million in each case — relative to rate bases that are measured in the billions. It is also not unusual for a regulator to deny a spending application of that magnitude. Further, both decisions were well reasoned, at least in the arguably narrow framework the decision makers set for themselves. Why are they important?

Their importance lays in what they didn't say as opposed to what they did say. Neither decision fully examined the broader context of the energy system. As a result, they may have unintended consequences. However, as outlined in this article, the broader context can be difficult to discern, with much uncertainty arising from policy and changing technology.

While issues arising from technology change can be largely intractable, policy can be clarified. For regulators to make informed decisions requires a holistic view of an energy transition that is not always amenable to such views. It also requires policy makers to provide clear policy direction when at all possible and when not possible to ensure that they encourage and support the regulator to take steps to consider all the aspects of the energy system when making decisions about the energy transition. ■

[27] Electrification and Energy Transition Panel, *Ontario's Clean Energy Opportunity: Report of the Electrification and Energy Transition Panel*, (Electrification and Energy Transition Panel: 2023), at 2, online: <www.ontario.ca/files/2024-02/energy-eetp-ontarios-clean-energy-opportunity-en-2024-02-02.pdf>.

AUC DECISION 28300-D01-2024: WHAT WILL IT MEAN FOR THE FUTURE OF PBR IN ALBERTA?[1]

*Mark Kolesar**

> ATCO Electric Ltd. (ATCO Electric) and ATCO Gas and Pipelines Ltd (ATCO Gas), collectively the ATCO Utilities, were regulated under the Alberta Utilities Commission (AUC) second Performance-Based Regulation (PBR) plan from 2018 to 2022 (PBR2). The plan, which was approved in Decision 20414-D01-2016 (Errata), included the reopener provision initially approved in the AUC's first PBR plan.[2] The reopener provision was intended…to identify, assess and potentially address design or operational problems within the plan. Reopener provisions are triggered by positive or negative financial results that were unanticipated at the commencement of the plan, material and which cannot be addressed by other features of the plan.[3]

Under the reopener provision, an achieved return on equity (ROE) that is 500 basis points above or below the approved ROE in a single year, or 300 basis points above or below the approved ROE for two consecutive years, may result in a reopening of the PBR plan, on application from the regulated company or an interested party, or on the Commission's own motion.

ATCO Electric's regulatory filings for 2021 and 2022 included financial results that exceeded its approved ROE by 435 and 635 basis points respectively. The ROE for ATCO Gas in the same years exceeded the approved ROE by 331 and 635 basis points. Given these results, the Commission reopened the PBR plans for the ATCO Utilities for 2021 and 2022. On May 22, 2024 the Commission issued Decision 20414-D01-2016 *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas.*

The proceeding set out to determine the factors that contributed to the ATCO Utilities' achieved ROEs in excess of the approved ROE.

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[1] At the time of writing, the decision has not been appealed.

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As a former Chair of the Alberta Utilities Commission, I read Decision 28300-D01-2024 with great interest. My objective in this article is to point out issues that, from my perspective as a former regulator, arise in this decision. I do not offer any legal opinions on the decision as I am not a lawyer.

[2] *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas* (22 May 2024), AUC 28300-2024, online (pdf): Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/806783>.

[3] *2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities* (6 February 2017), AUC 20414-2016, at para 261.

The Commission determined that for ATCO Electric, the main factors were its capital cost savings in 2021 and 2022. For ATCO Gas, the main factors were its capital cost savings in 2021 and 2022 and its operating and maintenance savings in 2022.

The Commission's approach in the proceeding was to determine what portion of the total cost savings achieved over the PBR Term, and specifically in 2021 and 2022, were quantifiable and explainable with reference to specific programs or initiatives undertaken by the ATCO Utilities during the PBR2 term. The assumption was that any savings that were not attributable to specific programs or initiatives of the ATCO Utilities were not the result of efficiency gains, and therefore the "spending envelope" provided by the PBR2 formula in 2021 and 2022 exceeded the amount required to provide utility service by the relevant unattributed amounts.[4]

Over the PBR2 term ATCO Electric had total capital savings of $569.9 million. The Commission determined that approximately $183 million was explained and quantified by ATCO. That left approximately $387 million in unquantified and unexplained capital savings.[5] The Commission also determined, on the same basis, that approximately $28.5 million of ATCO Gas's total capital savings of $281 million over the PBR2 term were the result of capital-related efficiencies and measurable cost-savings.[6] ATCO Gas also had operating and maintenance (O&M) savings of $29.6 million in 2022, of which the Commission determined that ATCO had reasonably supported approximately $8.72 million, leaving about $21.1 million of savings unexplained.[7] Finally, the ATCO Utilities reported approximately $81.5 million in cost savings resulting from full time equivalent (FTE) labour reductions over the PBR2 term.[8] ATCO Electric explained that it had a 13 per cent reduction in FTEs resulting in cost savings of approximately $21.2 million annually over the PBR2 term, while ATCO Gas had achieved a seven per cent reduction in FTEs, resulting in cost savings of approximately $16.3 million annually.[9]

Given these results, the Commission questioned whether there was a problem with the design or operation of the ATCO Utilities' PBR2 plans.[10] Although the actual capital spend by the ATCO Utilities was significantly below the amount of capital-related funding provided by the I-X and K-Bar mechanisms, the Commission concluded that there were no problems with the design of the K-Bar mechanism. The Commission recognized that the K-Bar mechanism was "meant to allow the utilities to manage costs on a holistic basis to arrive at the optimal mix of O&M and capital expenditures required to fulfill their obligation to provide safe and reliable distribution service."[11] The Commission went on to conclude that there were no problems with the design of the other elements of the PBR2 plans and that the evidence in the proceeding did not support a conclusion that there was a flaw in the design of the ATCO Utilities' PBR2 plans.[12]

Turning to whether there was a problem with the operation of the ATCO Utilities' PBR2 plans, the Commission focused on "the lack of quantification and explanation of savings by the ATCO Utilities attributable at any level (i.e., specific amounts, ranges, estimates) to specific programs, projects or initiatives such as those enumerated by the ATCO Utilities." The Commission noted that "[t]he gap between the amount of cost savings realized by each of ATCO Electric and ATCO Gas over the PBR2 term and the amount that the utilities quantified as being attributable to achieved efficiencies throughout the PBR2 term is inordinate."[13]

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[4] The term "spending envelope" does not appear in the decision.

[5] *Supra* note 2 at para 73.

[6] *Ibid* at para 76.

[7] *Ibid*.

[8] *Ibid* at para 74.

[9] *Ibid* at para 69.

[10] *Ibid* at para 78.

[11] *Ibid* at para 87.

[12] *Ibid* at para 90.

[13] *Ibid* at para 95.

The Commission stated that it:

> …does not expect every dollar of cost savings to be perfectly quantified and apportioned precisely to the specific driver of that dollar of savings. However, it does expect distribution utilities to be aware of the factors, both within and outside of their control, that contribute to the cost savings achieved during a PBR term. The Commission also expects that utilities will be able to adequately explain the difference between revenues provided by the PBR formula and the actual costs incurred with reference to the associated quantified cost savings attributable to those factors or, in instances where such quantification and explanation is not feasible, with a reasonably robust description of the utility's choices and actions (supported by evidence such as business cases or corporate directives) that led to the related reduction in costs.[14]

The Commission went on to adopt the following basis for its decision:

> While the Commission is not bound by the rules of evidence, in this Commission initiated proceeding and considering the information asymmetry that is inherent in the regulation of utilities, it finds that it is appropriate to adopt principles related to negative inferences; in particular, that a decision maker can draw a negative inference from the absence of relevant information on the record and may conclude that the matter that was not recorded did not occur or exist.[15]

The Commission concluded that:

> The magnitude of the savings that were neither quantified nor attributed to particular projects, programs or initiatives by the ATCO Utilities has led the Commission to conclude that the savings cannot be attributed to utility-driven efficiency gains resulting from the incentives intended under PBR. The Commission's view is that much of the ATCO Utilities' unquantified and unexplained savings were the result of factors other than efficiencies, including those asserted by the interveners, such as the ATCO Utilities opting to not pursue certain capital projects (what the UCA and the CCA referred to as "lower workloads"), and realizing cost savings as a result of COVID-related externalities including supply chain disruptions that prevented the ATCO Utilities from executing certain required projects. These decisions are made by each of the ATCO Utilities in response to their PBR2 plans and are therefore operational, rather than structural in nature.
>
> The Commission therefore finds that the PBR2 plans of ATCO Electric and ATCO Gas did not operate as intended in each of 2021 and 2022. The result is rates that were not just and reasonable in those years because customers were required to pay rates (including the rates of return achieved by the ATCO Utilities that exceeded the approved return and the threshold for the reopener) without receiving the benefit of more efficient utility service. In other words, the operation of the plans was inconsistent with the bargain that is inherent in PBR, and customers paid more than what was reasonably required for the provision of safe and reliable utility service. The Commission finds that this constitutes a problem with the operation of each of ATCO Electric's and ATCO Gas's PBR2 plans.[16]

Having determined that there was a problem with the operation of the ATCO Utilities' PBR2 plans that cannot be resolved without reopening and reviewing the plans, the

[14] *Ibid* at para 96.

[15] *Ibid* at para 110 [emphasis added].

[16] *Ibid* at paras 111–12 [emphasis added].

Commission turned to the matter of a remedy and the applicable time period over which the remedy should be applied. The Commission set out the scope and preliminary process steps for a Phase 2 proceeding to deal with this matter, noting that "[b]ecause the PBR2 plans are complete, an adjustment to the PBR2 plans on a go-forward basis is not a possible remedy."[17] The Commission concluded that:

> …an appropriate remedy may be in the nature of refunds to the ATCO Utilities' customers that relate to the quantum of savings that were not supported through evidence of quantified efficiencies and explanations of the drivers and sources of those efficiencies, which resulted in savings.[18]

Perhaps recognizing the challenges in determining an appropriate remedy, the Commission authorized and encouraged the parties to commence a negotiated settlement process.[19]

A SHIFT IN FOCUS

The approach undertaken by the Commission in Decision 28300-D01-2024[20] is very different from the approach adopted by the Commission in a previous re-opener proceeding resulting in Decision 23604-D01-2019[21], which is discussed below. The Commission's approach signals a noteworthy shift in the focus and attitude of the Commission between 2019 and 2024. This shift is likely attributable to two significant events.

Affordability

The Alberta Government established a new Affordability and Utilities Ministry. The minister's mandate letter includes objectives relevant to the AUC.

> Reviewing the operations, policies, and mission of your agencies, including the Alberta Utilities Commission and the Alberta Electric System Operator, and recommending ways to improve their operations and align its mission with the government's goal of a carbon neutral, reliable, and affordable power grid by 2050.
>
> Reviewing Alberta's electricity pricing system with the goal of reducing transmission and distribution costs for Albertans.[22]

The focus of the AUC is now more aligned with issues of affordability than was the predecessor Commission. This is apparent in recent decisions of this Commission. For example, in Decision 26356-D01-2021: *Evaluation of Performance-Based Regulation on Alberta,*[23] the Commission concluded that the sharing of benefits among customers and the utilities was not adequate during the two previous PBR terms, noting that:

> Although the evidence suggests that customers experienced lower rates under PBR than would be expected under COS regulation and some sharing of savings occurred during rebasing for the 2018-2022 PBR plans, rates continued to increase during an economic downturn in Alberta and utility earnings during this same period were characterized by the interveners as excessive.[24]

[17] *Ibid* at para 177.

[18] *Ibid*.

[19] *Ibid* at para 178.

[20] *Ibid*.

[21] *AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities*, AUC 23604-D01-2019.

[22] Letter from Premier of Alberta Danielle Smith to the Minister of Affordability and Utilities Nathan Neudorf (19 July 2023), online (pdf): <open.alberta.ca/dataset/bf7f9a42-a807-49b3-8ba3-451ae3bc2d2f/resource/9ebd0656-8e60-45f4-ad06-41f06a3177eb/download/au-mandate-letter-affordability-and-utilities-2023.pdf>.

[23] Evaluation of Performance-Based Regulation in Alberta (30 June 2021), AUC 26356-D01-2021, online (pdf): <efiling-webapi.auc.ab.ca/Document/Get/701629>.

[24] *Supra* note 2 at para 79.

In Decision 27388-D01-2023: *2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities,*[25] the Commission sought to "secure better sharing of total benefits of PBR between utilities and their customers"[26] by introducing into the PBR3 plans an asymmetric, two-tiered earnings sharing mechanism and an X factor premium of 0.3 per cent.

The focus of the Commission now appears to more sharply consider the goal of reducing transmission and distribution costs for Albertans in alignment with Government of Alberta policy objectives. This is not to say that the prior Commission was blind to issues of affordability, however, the focus of the PBR1 and PBR2 plans was arguably on maximizing efficiency incentives, recognizing that consumers benefited from the caps on rates and revenues in the plans and from the recognition of achieved efficiency gains when rebasing was undertaken at the end of the PBR regimes.

It is not a criticism that the Commission is attuned to Government policy objectives with respect to issues of affordability. Indeed, regulators often adopt public policy objectives related to affordability or decarbonization goals, for example, with or without governing legislation that compels them to do so. For example, PBR plans in Massachusetts and Hawaii include elements such as earnings sharing, consumer dividends, scorecards and metrics, and other performance incentive mechanisms designed to encourage the achievement of public policy objectives. Nor should the Commission be criticized for adopting what it sees as a more equitable sharing of the benefits of PBR in its PBR3 regime. The question is whether its current public policy lens should be applied to the PBR2 outcomes; outcomes that may well align with the objectives of the Commission panel that approved those plans.

A loss of trust

In 2022, ATCO Electric agreed to pay a $31 million administrative penalty after an AUC investigation found it deliberately overpaid a First Nations group for work on a new transmission line, and then failed to disclose it when it applied to include the extra cost in its application for approval of the Jasper Transmission Interconnection Project.[27] In July 2024, ATCO again agreed to pay $3 million in fines and to refund $4 million to customers for two additional contraventions of the *Electric Utilities Act* with respect to proceedings before the AUC.[28] These missteps likely coloured the Commission's perspectives on ATCO. There is pointed language in Decision 28300-D01-2024 that suggests the Commission simply did not believe the ATCO evidence.

> In the oral hearing, D. McHugh stated that the ATCO Utilities do not have the information required to reconcile their cost savings any further than what has already been provided on the record of this proceeding. <u>The Commission finds this statement to be inconsistent with other statements the ATCO Utilities made in this proceeding related to their sophisticated and superior business management</u>… The ATCO Utilities' evidence of their ability to set performance targets and to measure performance at such a granular level is not consistent with their professed inability to determine the source of organization-level cost savings.[29]
>
> Again, there is an inconsistency between the ATCO Utilities' evidence of their ongoing monthly processes to manage their capital and O&M programs and their evidence that they do not have a record of what programs resulted in

[25] *2024–2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities* (4 October 2023), AUC 27388-D01-2023, online (pdf): Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/794425>.

[26] *Ibid* at para 327.

[27] Rob Drinkwater, "ATCO Electric agrees to $31 million penalty following regulator's investigation" (18 April 2022), online: <www.cbc.ca/news/canada/edmonton/atco-electric-penalty-investigator-transmission-line-1.6422427>.

[28] Bob Weber, "ATCO Electric fined $3 million for unearned rate increases, overstating its costs" (9 July 2024), online: <calgary.citynews.ca/2024/07/09/atco-contraventions-fines>.

[29] *Supra* note 22 at para 107 [emphasis added].

> a significant majority of capital, and in the case of ATCO Gas, O&M cost savings… It strains credulity for the Commission to accept that entities as sophisticated as the ATCO Utilities, with professed business practices as described in their evidence, would not have documented or tracked the source of hundreds of millions of dollars in savings.[30]

It seems evident that the Commission did not believe that the ATCO Utilities were unable to provide the information the Commission requested to further demonstrate that the achieved cost savings were attributable to achieved efficiencies. There is a maxim in public utility regulation that a regulated company is loathe to lose the trust and unbiased goodwill of the regulator. That maxim may well have been proven in the proceeding leading to Decision 28300-D01-2024.

ISSUES ARISING

Was it reasonable to expect ATCO to demonstrate that its earnings resulted from utility-driven efficiency gains?

Referencing Decision 28300-D01-2024[31], the Commission noted that "the ATCO Utilities themselves were in a similar proceeding previously and were able to quantify and attribute their costs savings."[32] However, a review of the record of that proceeding and Decision 23604-D01-2019 would argue that ATCO was unable to fully quantify and attribute their cost savings to utility-driven efficiency gains resulting from the incentives intended under PBR.

In that proceeding, the Commission requested that the ATCO companies provide:

> an analysis of items that contributed to the achieved ROEs exceeding the approved ROE in each of 2016 and 2017, for capital and operating and maintenance costs (e.g., productivity improvements implemented by the utility, externally driven factors affecting costs). In addition, identification of any attributes of the PBR features that affect revenues that may have contributed to the achieved ROEs exceeding the allowed ROE in each of 2016 and 2017 (e.g., going-in rates, I-X adjustments, customer growth, Y factors, Z factors, K factors).[33]

In response, the companies provided financial results showing variances across revenue and cost categories and evidence of a number of factors that contributed to the achieved ROEs, but did not provide a full accounting of the efficiency gains resulting from the incentives intended under PBR. In response to a Commission information request that asked ATCO to complete tables detailing the cost reductions and their associated effect on earned ROE from 2015 to 2016 and 2016 to 2017, the ATCO Utilities argued that they were unable to provide the level of detailed reporting requested by the Commission. ATCO stated:

> ATCO is unable to calculate the effect on earned ROE for each productivity improvement as ATCO has not tracked revenue, O&M costs and capital costs associated with every activity. Under PBR, there is no direct link between costs and revenue… It is not possible to re-establish a link between revenue and costs, after the fact, in an attempt to explain the overall results of the utilities. This is exacerbated by the fact that the utilities did not track this kind of information, and in fact took deliberate steps to eliminate all unnecessary reporting and tracking as a key aspect of the culture change required to drive out efficiencies. Had detailed tracking of costs with a linkage to revenues been undertaken over the first term, the incentives would not have been

[30] *Ibid* at para 108 [emphasis added].

[31] The author was on the AUC panel that issued Decision 23604-D01-2019.

[32] *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas*, (22 May 2024), AUC 28300-D01-2024, at para 100, online (pdf): <efiling-webapi.auc.ab.ca/Document/Get/806783>.

[33] *Supra* note 21 at para 16.

> as strong and the effort required to administer such tracking would have resulted in fewer efficiencies found.[34]

The Commission accepted the evidence of the ATCO utilities with respect to the factors that contributed to the achieved results in 2016 and 2017 as evidence that the companies responded to the incentives intended under the PBR plan. The bulk of the decision, however assessed a number of alleged faults with the PBR plan to determine whether there was sufficient evidence to conclude that the earnings achieved by the ATCO Utilities above the Commission's generically approved ROE were the result of a problem with the design or operation of the ATCO Utilities' 2013–2017 PBR plans. The Commission found that there was no evidentiary basis to conclude that the earnings achieved by the ATCO Utilities above the Commission's generically approved ROE were the result of a problem with the design or operation of the ATCO Utilities' 2013–2017 PBR plans.

Given this precedent, could the ATCO Utilities have reasonably understood that they would be required to have the information necessary to reconcile all of their cost savings to achieved efficiency gains?

Is it reasonable to require utilities under PBR to demonstrate that their earnings resulted from utility-driven efficiency gains?

Productivity is generally measured as the ratio of total outputs to total inputs in the production process of the firm. Total factor productivity (TFP) growth, which Is the measure of industry productivity used to establish the productivity offset (X Factor) in PBR plans such as those approved by the AUC, is the difference between the growth in outputs and the growth in inputs over time, based on a year-over-year index of output and input growth. The firm's own input and output data can theoretically be used to derive a company-specific productivity growth estimate and, alternatively, the Kahn Method can be used to calculate a productivity growth estimate based on financial data as opposed to the outputs measured in TFP growth studies. Given how productivity is calculated in a PBR plan, it is difficult to relate achieved productivity growth results to specific activities of the firm.

PBR incentivizes three types of efficiencies:

- **Productive efficiency:** Taking customer demand as given, the utility satisfies that demand at the least cost possible and operates as close as possible to the frontier of the "production possibility set", which characterizes a firm operating at the most efficient level possible.
- **Allocative efficiency:** Considering that customer demand for outputs and services can change based on their price, the utility provides the highest value range of outputs and services, given the least-cost mix of current inputs and future cost structure and technology.
- **Dynamic efficiency:** The utility finds the optimal rate of innovation and investment to improve production processes, satisfy evolving consumer demand and reduce long-run average cost. To the extent that it provides more flexibility to introduce new services and/or more attractive rate plans, PBR can increase dynamic efficiencies.

Even though a company may undertake specific programs aimed at achieving identifiable efficiencies, in practice efficiencies are achieved through a myriad of activities throughout an organization at every level. In a given year, there are an almost infinite number of decisions made by utility managers that impact costs. Allocating cost savings into those due to the plan and those that would have happened in any event is a challenge and almost certainly unquantifiable. Is it reasonable to keep track of all of them and then say which are due to efficiency decisions and which would have happened anyway with or without a PBR regime? On an accounting basis, budgets are set to achieve cost and revenue targets under the price or revenue cap. Some targets are achieved, others are not. And, although companies are capable of providing financial results showing variances across revenue and cost categories that align with their system of accounts, relating many of these variances to a measure of productivity growth is a different exercise. Likewise attributing any earnings beyond the allowed ROE to productivity growth resulting from specific utility activities is likely not fully achievable, and likely beyond the objectives of the Commission when it approved the PBR2 plans.

[34] *Ibid*, exhibit 33.

PBR allowed the Commission to set just and reasonable rates and to incentivize the companies to minimize their costs without having to obtain or consider cost information from the companies beyond the initial information required to set going-in rates. The reduced need for the Commission to obtain information on the companies' costs and avoid the problem of informational asymmetry was one of the objectives of the Commission when it initially adopted PBR. Among the reasons for adopting PBR, the Commission included:

> ...rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings… These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing.[35]

When the Commission approved PBR2, it did not contemplate that the companies would, or should, be required to attribute any earnings beyond the allowed ROE to efficiency gains resulting from specific activities. In addition, there is no such requirement in Decision 27388-D01-2023 which approved the PBR3 plans. If the Commission now intends to adopt a PBR regime that requires companies to undertake such an accounting, then perhaps the current PBR regime will need to be reconsidered.

Did the PBR2 plans operate as intended?

The PBR2 plans may have operated as the Commission intended when the plans were approved. It is noteworthy that the Commission, in Decision 28300-D01-2024, determined that that there were no problems with the design of the PBR2 plans, but determined that there was a problem with the operation of the plans in 2021 and 2022. A corollary of the latter determination is that the design of the PBR2 plans was such that it was unworkable under the conditions that prevailed in 2021 and 2022; the COVID and post-COVID era that resulted in lower workloads, delayed capital investments and cost savings resulting from COVID-related externalities. If that is not the case, then arguably the plans worked as designed.

The productivity offset in the PBR2 plans was based on TFP studies that measured long-run industry productivity, recognizing that productivity fluctuates over time. The level of achieved productivity is not uniform, and it may be periodically positive or negative from one year to the next. However, over the long run, an average level of productivity, whether positive or negative, is realized. Had the PBR2 term played out beyond 2022, the gains achieved, and the resulting positive ROEs, may have been negated in subsequent years when the lower workloads and delayed but necessary capital investments experienced in 2021 and 2022 were potentially reversed. On an accounting basis, the increase in retained earnings arising from the ROE results in 2021 and 2022 might have been re-invested in the operations and capital investment requirements beyond 2022 to catch up after the lingering effects of COVID ended.

Alternatively, was there the potential that the effects of COVID on the lower workloads and delayed capital investments experienced in 2021 and 2022 could have been the result of exogenous events that were rightfully dealt with as a Z Factor event under the PBR2 plans? In Decision 20414-D01-2016 (Errata) the following criteria were to be applied when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

> (i) The impact must be attributable to some event outside management's control.
>
> (ii) The impact of the event must be material. It must have a significant influence on the operation of the distribution utility; otherwise the

[35] *Rate Regulation Initiative, Distribution Performance-Based Regulation*, (12 September 2012), AUC 2012-237, at para 14.

> impact should be expensed or recognized as income, in the normal course of business.
>
> (iii) The impact of the event should not have a significant influence on the inflation factor in the PBR formula.
>
> (iv) All costs claimed as an exogenous adjustment must be prudently incurred.
>
> (v) The impact of the event was unforeseen.[36]

Might the cost savings have been considered as exogenous and remedied as a Z Factor adjustment under the plans? However, the criteria for a Z factor adjustment appear to contemplate that only costs can be claimed as an exogenous adjustment. They do not mention savings resulting from exogenous events qualifying for Z Factor treatment.

The plans came to an end, and the going-in rates were rebased, which accounted for at least a portion of the gains in 2021 and 2022 being recognized in the subsequent PBR term, as the revenue requirements of ATCO Gas and ATCO Electric decreased by $51 million and $41 million, respectively.[37] All of which may be as intended in the decision approving the PBR2 plans. In any event, it would seem that the revenue requirement reductions at rebasing should be considered when calculating the Commission's remedy to avoid double counting.

What constitutes just and reasonable rates in a PBR plan?

The upshot of Decision 28300-D01-2024[38] is that rates are just and reasonable under PBR only when any earnings beyond the allowed ROE can be attributed to utility-driven efficiency gains resulting from the incentives intended under PBR. This may prove to be problematic. The earnings sharing mechanism adopted in PBR3 requires that achieved earnings in excess of 100 basis points be shared with consumers. There is now the potential that parties will argue that any portion of the shared earnings accruing to the utility should rightfully accrue to consumers, unless the utility can demonstrate that the earnings resulted from utility-driven efficiency gains.

Under Cost of Service Regulation (COSR) if the approved rates allowed the company to recover its prudently incurred costs including a reasonable opportunity to earn a fair return, as determined by the regulator, then the rates are just and reasonable. Until they aren't at which time the company would apply for, or the regulator would initiate, a proceeding to reset rates on a going forward basis.

PBR, by contrast, results in just and reasonable rates by directly regulating the rates the utility can charge by setting of rates and then governing them over the PBR term through the I-X formula and other mechanism of the PBR plan, irrespective of the utility's actual costs or the profits the utility earns. Revenues and costs are de-linked for the duration of the plan. Under PBR, rates are considered just and reasonable if the going-in rates at the outset of the PBR term are just and reasonable, on the same basis as under COSR. They are assumed to remain just and reasonable until the PBR term ends and going-in rates are re-set for the next PBR term.

Decision 28300-D01-2024[39] appears to have redefined what constitutes just and reasonable rates under PBR.

Does Decision 28300-D01-2024 constitute retroactive ratemaking?

One of the issues in this decision is whether it constitutes retroactive rate making. It is not clear in the wording of the Commission's PBR decisions going back to Decision 2009-035 that the Commission intended that any necessary remedy resulting from a re-opening of a PBR plan should be applied retroactively. And the question now is whether it can be.

Under COSR, rates were set on a going forward basis and remained unchanged until

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[36] *Supra* note 2 at 91.

[37] *Supra* note 32 at para 114.

[38] *Ibid*.

[39] *Ibid*.

the company returned with an application to update its revenue requirement and set new rates, or the Commission commenced a proceeding to do so. If the company was able to provide service at costs that were less than forecasted, or if billing units were greater than forecasted, the company was permitted to keep any ROE above the allowed ROE established when rates were set. The Commission was prohibited from adjusting rates to claw back the earnings achieved by the company in excess of the allowed ROE because doing so constituted retroactive ratemaking. And likewise, if the company was unable to earn its allowed return in the prior period, the rates in the subsequent period would not include recovery of the prior period shortall. Any earnings attrition remained to the account of the company.

Under PBR, rates and costs are de-linked. The going-in rates are set in a fashion similar to COSR, but rates are adjusted annually according to the PBR formula so that the company is afforded an opportunity to stay out longer between rate setting proceedings. At rebasing, as with COSR, the revenue requirement to set going-in rates for the next PBR period considers the actual results from the previous period so that customers receive the benefit of the company's improved productivity (lower costs and/or higher billing units) in the rates for the next period. And, as with COSR, the earnings of the company in the prior period are not clawed back, largely because doing so would blunt the intended efficiency incentives of PBR, and because doing so would likely be deemed retroactive ratemaking. Likewise, if the utility experiences earnings attrition under the PBR plan, the company does not recoup its losses in the subsequent PBR term. However, Decision 28300-D01-2024 has modified the landscape.

More importantly, it raises the issue of whether the Commission can retroactively remedy a finding that there is a problem with a PBR plan. Or can the remedy only be applied on a going forward basis, by adjusting the parameters of the next PBR plan. As with COSR, is the Commission prohibited from applying its remedy in such a way that any over-earning or under-earning in a prior period is paid to or recovered from customers in a subsequent period? And it is certainly not clear that the re-opener provision was intended to retroactively remedy any design or operational problems in a PBR plan. Does doing so constitute retractive ratemaking?[40]

CONCLUDING REMARKS

This decision will likely have implications into the future for the Commission, the companies it regulates and consumers, some of which may not yet have come to light. Among others, it may serve to blunt the intended management efficiency incentives of PBR and sour utilities on continuing PBR regulation. Some of the issues this decision raises may result in changes to the design of PBR plans in Alberta, and potentially in other jurisdictions. In addition, some issues will certainly find their way into the Alberta Court of Appeal. Some may manifest themselves in the responses of the regulated utilities to PBR, while others may affect consumers in the years ahead. It will be insightful to follow the aftermath of this decision. ■

[40] The Commission previously allowed a company to recover a significant shortfall resulting from a formula based regulation plan that was approved for a transmission company; however, the decision was unchallenged and settled by way of a negotiated settlement.

ENERGY PROJECTS AND NET ZERO BY 2050: CAN WE BUILD ENOUGH FAST ENOUGH?

*Michael Cleland and Monica Gattinger**

Can Canada build enough fast enough to meet its net zero targets? Beneath this seemingly straight-forward question lie multiple sub-questions:

- can Canada build enough fast enough while sustaining the integrity of its energy systems?
- does the country have the policy and regulatory frameworks needed to attract sufficient investment and to enable the vast range and number of projects needed to transform its energy system and broader economy in line with net zero?
- will its approach strengthen the country's competitiveness and prosperity in the years ahead?
- will there be adequate public and investor confidence in decision systems to build at scale and maintain a sustainable pace of change?

This article addresses this crucial set of questions. It is based on a research study undertaken by the University of Ottawa's Positive Energy program.[1] Given the profile of *Energy Regulation Quarterly* readers, we focus more of our attention on the regulatory dimension of the study. We refer interested readers to the final report,[2] which provides a fulsome analysis of findings and a more comprehensive discussion of recommendations.

In this article, we begin by underscoring the scale and pace of change implied by a net zero transformation and key aspects of the Canadian context relevant to the challenge. We then describe the study's research approach and methodology. The following two sections share the key findings and recommendations emerging from the research. We conclude with a call to action and preview of forthcoming Positive Energy research and engagement to advance action.

Scale and pace of the net zero transformation and the Canadian context

Transforming Canada's energy system and broader economy over the next two plus decades entails some combination of the following: replacing or retrofitting roughly 20 per cent of the electric power system that is greenhouse gas (GHG) emitting; doubling or tripling the power system as a whole; replacing, decarbonizing or retrofitting three-quarters

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[1] University of Ottawa, "Positive Energy" (last visited 11 November 2024), online: <www.uottawa.ca/research-innovation/positive-energy>.

[2] Michael Cleland et al, *Energy Projects and Net Zero by 2050: Can we build enough fast enough?* (Positive Energy, 2025), online (pdf): <www.uottawa.ca/research-innovation/sites/g/files/bhrskd326/files/2024-12/241213-pe-fast-enough-proof04-share%20%281%29.pdf>.

of the energy end use that fuels transport or provides heat to industry and communities; developing new energy infrastructure and markets for new energy sources like hydrogen; and decarbonizing the country's oil and gas industries. And all of this before 2050. This is a daunting task, bigger and faster than any that has ever been undertaken through deliberate policy — with the exception of wartime — in Canadian history. It raises many questions about pacing, notably what a sustainable pace of change looks like for markets, for governments and for civil society.

Various aspects of Canadian reality compound the task. Canada's federal system is notorious for making economic projects more challenging than might be the case in a unitary system. This is especially the case for energy. First, most aspects of electric power are explicitly matters of provincial jurisdiction. Second, Canada's geography and resource wealth are considerable benefits, but variability in provincial economies, power generation, GHG emissions profiles and resources, generate diverse provincial and territorial interests and inequities in getting every place to net zero emissions. Third, the variety of needed projects involves numerous and different decision-making processes managed by various regulatory authorities, some federal, many provincial or territorial, some municipal, and, emerging, some Indigenous.

Study description and approach

Against this backdrop, Positive Energy undertook a research study on public confidence in government decision-making systems for energy projects. By "public" we mean a broad and overlapping spectrum of citizens, consumers, communities and investors. Without their confidence, Canada will not be able to transform its energy system and broader economy in line with net zero. The research approached the question from two directions — *looking back* at what has happened in the past two decades and *looking forward* over the next two decades at what's to come.

In our look back, we undertook a review of literature in Canada and abroad on government decision-making for energy projects, with a view to identifying Canada's performance, how to address performance challenges, and international best practice.

We also undertook "project profiles" examining 18 energy projects undertaken since the beginning of this century, some of which are now in service, some under construction, and some of which were abandoned by proponents or rejected by governments. In selecting the projects to review, we aimed for representativeness across project types, sizes, successes/failures, regions and jurisdictional approval processes (federal, provincial, Indigenous, or combinations thereof). The projects included pipelines, power lines, oil and gas exploration and processing, hydropower, wind, solar, electrical storage and nuclear waste management. Collectively, they are reasonably representative of experience in Canada over the past two decades. Our aim was to identify the length of time from project inception to in-service (or abandonment), the proportion of that time accounted for by the regulatory process and key areas of challenge/tension or success/innovation moving a project to completion.

In our look forward, we undertook confidential interviews on the current and future investment environment with over thirty leaders. We asked our interlocutors to speak to Canada's attractiveness as a place to invest, the challenges the country faces on government decision-making processes for projects, and what actions might be taken to make the system work better. Our objective was to gain a range of perspectives, primarily from those in the private sector directly involved in project development (individual companies, industry associations, the financial and investment sector, and Indigenous leaders involved in projects), but also former regulators or policy advisors, and environmental advocates.

Key findings

The most important finding is that the challenge of rebuilding the energy system over the next two and a half decades is much bigger than a question of regulatory reform respecting federal impact assessment, an area that has received much attention in recent years. It is also about more than just timeliness of decision-making: it involves clarity and predictability of current and future policy and regulatory frameworks and processes. There was broad consensus among interviewees that Canada currently lacks the investment environment needed to build enough fast enough.

Key findings span four broad areas:

- ***Activities outside of government decision-making processes for projects***

take time and involve uncertainties. The time it takes to move a project from inception to in-service involves far more than just regulatory decision-making. Project design and engineering, relationship-building with communities, project financing and construction, all take time. Market factors — pace of consumer uptake, uncertain future demand, labour and materials availability, and evolving financial and capital markets — also shape the pace of new projects. Reforming regulatory systems for projects can only shave off so much time. Regulatory reform efforts need to be accompanied by both a sense of urgency and a sense of realism about how much reforms will deliver in time savings, on the one hand, and how long it will take to frame up and successfully implement reforms, on the other.

- ***The entire public policy system matters.*** Many interviewees pointed to the absence of a shared national vision, lack of alignment between federal and provincial governments, lack of public understanding of the scale of the transformation before us, and lack of planning processes for key areas of the energy future, as major stumbling blocks for the country. Lack of clarity and future policy uncertainty over key instruments like carbon pricing, tax credits and sectoral regulations, challenge the calculation of project economics. This finding underscores that the challenge is about more than just timeliness of decision-making — it is about clarity and predictability of government frameworks just as much if not more.

- ***Challenges within regulatory systems are many and complex — but tractable.*** Again, the challenge is about more than just timeliness. Political involvement at various stages of project decision-making is a major source of uncertainty, as are multiple requests for information and lack of clear guidelines from regulators. These challenges apply in particular to federal impact assessment, but this is not only a federal problem. It also dogs regulatory processes carried out by provinces, territories, municipal governments and Indigenous governments. In addition, lack of clear delineation, coordination and streamlining between federal, provincial and territorial roles, conflicting mandates among regulatory and permitting agencies, and lack of intragovernmental coordination reduce the attractiveness of Canada for investors. This is a broad set of large and complex challenges, but with political will and management skill, they are tractable. Success will depend on developing a comprehensive understanding of the issues at hand, and then, most importantly, identifying an action and implementation plan that drives real change and meaningful improvements on an ongoing basis.

- ***Relationships with Indigenous nations and communities are a very big part of the solution.*** There has been a transformation in the relationship between project proponents and Indigenous communities in recent years. Indigenous nations are increasingly taking equity stakes in projects, leading projects of their own, undertaking Indigenous-led impact assessments and leading project monitoring. Much work remains to be done to support and scale up this progress, including building Indigenous governments' experience with balancing community buy-in, timeliness and risk. Time invested now will pay dividends in the years ahead. Alongside efforts to build relationships with Indigenous nations and communities, proponents and governments also need to invest time and effort to build and maintain the support of other communities as well (municipalities, local communities, rural communities, etc.). Community support is essential for projects of all types. Presuming that projects that help reduce emissions will be supported by local communities is a dangerous assumption. Communities are often seized more with local social, economic and environmental impacts than they are with global climate change.

Recommendations: address multiple packages of reform within and beyond the regulatory system

Given the scope of the challenge and its possible solutions, there is danger in trying to fix everything all at once and ending up losing coherence and focus. The problem needs to be parsed and different parts approached in different ways. With that in mind, we have organized our recommendations for reform as a series of what we call 'packages.' Each can be approached on its own, will often require a different set of actors to come together, and will involve different timelines, although the urgency of the problem argues for action starting as soon as possible across the board. Given the breadth of coverage of our recommendations they are necessarily framed in general terms — although in most cases the detailed possible directions are easily discernible and we have provided a number of potential options for action within each package.

The packages sit within and beyond the regulatory system. Of note, the diverse roles of Indigenous communities and the variety of issues to be addressed are woven throughout all of the packages.

Recommendations respecting three packages lie primarily beyond the regulatory system:

- ***Provide more predictability and clarity of policy, strategy and vision:*** governments at all levels need to do a better job of collaborating and aligning their efforts. Lack of clarity and uncertainty over future policy and the country's vision for its energy future shape investor confidence just as much — if not more — than the regulatory system for projects. Whether carbon pricing, investment tax credits, or emissions regulations for electricity, oil and gas, uncertainty over foundational policy measures inhibits the ability of investors to calculate project economics and make the investments necessary to pursue Canada's net zero aspirations. Likewise, while there is a widespread national consensus around the need for emissions reductions, if we look much deeper than that, the consensus comes apart. These challenges have been with us since climate policy emerged over thirty years ago and they won't ever be 'solved.' Unfortunately, the direction of current politics doesn't bode well for addressing these issues. Instead, it suggests we are in for less predictability and clarity, not more.

  Regardless of political context, however, it is unlikely that a detailed shared national vision can be developed and sustained in a country as diverse as Canada. But federal, provincial and territorial governments need to regain the instinct to collaborate. Collaboration sends a crucial message to investors and citizens: Canada is serious about net zero and governments can set aside their differences to chart a constructive path forward. Much of this is likely to happen through bilateral or multilateral processes, and it needs to be scaled up significantly. Crucially, federal efforts to collaborate must speak to core regional or provincial priorities and take into consideration existing provincial and territorial initiatives.

- ***Establish planning processes:*** governments need to take action on a number of areas where planning is essential (energy delivery, electric power systems, supporting the roles of Indigenous communities, and costs), but they must do so without overturning a largely market-based system. Far too little attention has been given to the future of energy delivery to the end user. This will involve not just technologies but consumer behaviour, decarbonization strategies across a wide variety of industry sectors, community, regional and provincial energy planning and infrastructure systems. Electrification and electric power systems will likely be the centrepiece of emissions reductions efforts, but planning for electric power systems cannot be done in isolation. It must include thoughtful coordination across energy sources (notably natural gas) and energy uses (transportation, building heat, industrial processes, etc.). One of the biggest questions is about cost: who pays for what, when and how? There is an urgent need to develop a realistic consensus about cost allocation among ratepayers, taxpayers, and investors over the medium to long terms. Positive Energy is turning its attention to this package with a forthcoming set of discussion papers.

- ***Build machinery and capacity in policy and regulatory systems:*** all actors need to cooperate and resolve to invest in building policy, regulatory and decision-making systems in the public, private, Indigenous and broader civil society sectors that are up to the challenge of net zero. Labour, skills and supply chain challenges need priority attention, as does capacity building within regulatory agencies. This package lies both within and beyond the regulatory system. Governments need to evaluate whether their policy and regulatory systems are up to the scale of the challenge when it comes to their institutional systems, skills and capabilities. In virtually all instances, capacity building will be needed. Organizational attention will generally turn first to the need for more staff, but fiscal realities will likely put a cap on how much new hiring can be done. Importantly, while more people will surely be needed if the volume of projects envisioned materializes, but there is much that needs to be done that doesn't involve adding more people. This includes restructuring basic approaches to decision-making (breaking down silos, cross-departmental coordination, public-private-civic collaboration) and ensuring staff have the right capabilities (the right skills and competencies). Success will also turn in large part on whether policy and regulatory leaders and those at the working level have the culture and mindset to drive change, as discussed further below.

Recommendations respecting four packages lie within the regulatory system:

- ***Clarify who provides policy direction for projects and who regulates them:*** governments should focus their attention on policy, planning and structuring regulatory systems, and refrain from intervening in individual project decisions. Regulators should focus on assessing project applications and making decisions/recommendations to government. Governments at all levels have, over the years, reformed many of the country's regulatory systems in ways that see a much larger role for politicians (ministers, cabinets) in individual applications, including final approval and conditions on projects. If this continues, the systems will grind to a halt. Not only is cabinet ministers' time limited, but regulatory frameworks that involve political decision-making at various stages will undoubtedly see ministers pressured to use it. Investors, if always faced with the uncertainty and unpredictability of late-stage political interventions — or worse, political interventions at multiple stages — will tend to shy away.

  Looking forward, the default should be to let the regulators regulate again. The regulators' job should be to colour within the lines drawn by governments. If the lines are specified through their enabling legislation, regulation and appropriately framed government directives of general application, regulators have scope to be innovative without violating principles of democratic accountability. Governments should only modify or overturn regulatory decisions under very limited circumstances — ministerial and cabinet roles should be narrowly circumscribed, transparent and clear. Limiting the role of ministers or cabinets in final approvals to accepting, rejecting or, in rare instances, sending a project back to agencies to reconsider specific issues — rather than adding conditions — would convey a much-needed message of predictability to investors and communities. This is another area where Positive Energy is pursuing further research and engagement, as discussed further below.

- ***Establish collaborative intergovernmental relations and decide which governments are best placed to get the job done:*** these should be treated as practical questions in the spirit of cooperative federalism and should include using substitution or other agreements that ensure government responsibilities — federal, provincial, territorial, Indigenous, municipal — are met without unnecessary overlap or duplication. All levels of government need to approach this question constructively. Noting the capacity issue raised above (package 3), one obvious solution is to avoid duplication of effort. Importantly, intergovernmental relations include relations with Indigenous governments, which will increasingly take on lead roles in regulation, whether as knowledge holders, partners in impact assessment, contributors to ultimate decisions, ongoing monitors or regulators who lead their own impact assessment and regulatory processes. Each project and each community will require their own approach. Governments and proponents need to be open to this and develop their capacity to work constructively with Indigenous governments in a variety of ways.

- ***Distinguish between changing mandates and changing mindsets:*** reforming regulatory mandates will only get us so far. Mindsets will often need to change towards greater innovation and risk-taking within public agencies, whether departments or stand alone agencies such as regulators. Governments are increasingly alive to this challenge, including the federal government through its recently issued Cabinet Directive on Regulation. Fundamental culture change within governments needs to be approached deliberately and seriously, and with the recognition that culture change is difficult and takes time.

  The regulator's job is to question, to be skeptical, to demand evidence, to carry out due process and to be prepared to say no when warranted. Different regulators will inevitably approach this with different mandates and different mindsets. There is danger in assuming all regulators are the same. Context, history, culture, prevailing practices and experience matter.

  Given the unique challenge and urgency of net zero, there will be a growing need for regulators to say yes to the adverse impacts created by new projects and to streamline processes to arrive more rapidly at decisions. This will likely be more difficult for some than others and will definitely be more difficult for some risks than others. What's required is a risk-based approach to regulation. Most regulators have already moved in this direction. They are building on years of experience and knowledge without constantly reinventing the wheel. They are avoiding full reviews for routine projects, brownfield sites or for risks that are well understood and for which well-established risk mitigation measures exist. They are avoiding the temptation to request ever more information from proponents. But more can definitely be done to reduce timelines and maximize learning within and across organizations. Creating a national forum for regulatory and permitting excellence would help accelerate innovation, learning and best practice sharing. So would establishing an independent advisory body to provide advice from outside parties (industry, Indigenous organizations, academia, etc.) about what's working, and, importantly, what's not.

- ***Build a functioning whole of government machine:*** governments need to develop intragovernmental coordination mechanisms to help projects move through the variety of policy, regulatory and permitting processes for an individual project application in a timely and predictable way that minimizes regulatory burden. Various approaches have emerged to attempt to address these challenges. Generally, they involve creating a single window for projects to navigate the web of policy, program, regulatory and permitting frameworks (e.g., British Columbia's Clean Energy and Major Projects Office, the former federal Major Projects Management Office, the new federal Regulatory Efficiency Action Council and Clean Growth Office). The aim is to provide focus, leadership and the necessary degrees of coordination consistent with timeliness, minimizing regulatory burden and predictability. These bodies aim to ensure the system keeps driving towards a decision on a project, whatever it might be.

  Crucial to supporting these efforts is ongoing assessment and evaluation of regulatory reforms and their impact: are they achieving their intended aims? Establishing a body to evaluate the effectiveness (or not) of reforms and seeking input from people with experience in regulatory processes would be a good place to start.

Next steps: develop a process and action/implementation plan for each package of reform.

We urge governments and other organizations to collaborate on a process to convene the key players needed to advance solution-seeking in each area of reform. Some of this work is already well underway through various federal, provincial, territorial and intergovernmental processes, but much remains to be done. The aim should be to develop a detailed action and implementation plan so that Canada can achieve meaningful and durable progress on the goal of net zero.

Positive Energy is using its convening power and research expertise to help develop paths forward for priority areas. As noted above, we are pursuing work on planning as well as the respective roles of policymakers and regulators in energy project decisions (some of this work will be profiled in future articles for *ERQ*). We are developing discussion papers, undertaking detailed empirical work, and convening policy and regulatory leaders to advance thinking and action on these crucial topics.

But this needs a lot of hands on deck. Even where there is agreement on “the what” of reforms and even when commitments are made to take action, success will hinge on maintaining momentum and effective implementation. We urge all those with a stake in moving Canada to a truly sustainable future to keep a sharp focus on creating a clear, timely and predictable investment environment to ensure the country can build enough fast enough in the years ahead. ■

IESO APPLICATION TO THE ONTARIO ENERGY BOARD FOR 2024 AND 2025 INCREMENTAL REVENUE REQUIREMENT, EXPENDITURES, AND USAGE FEES[1]

*Reena Goyal**

Ontario's Independent Electricity System Operator (IESO) is required under subsection 25(1) of the Ontario *Electricity Act*[2] to periodically apply to the Ontario Energy Board (OEB) for approval of its revenue requirements, expenditures and usage fees. Until recently this application was made on a single-year basis, following the Ontario Ministry of Energy's annual approval of the IESO's business plan. In its most recent revenue requirement application to the OEB, however, the IESO for the first time sought approval from the OEB on a multi-year (2023–2025) basis (the "**Original Fees Application**").[3]

The Original Fees Application was filed on March 29, 2023. A settlement conference was held between the IESO, OEB staff and various registered interveners on June 26-29, 2023, during which a tentative settlement proposal encompassing all disputed issues was reached — including acceptance of the IESO's proposed 2023, 2024 and 2025 revenue requirements of $208.4 million, $218.4 million and $229.7 million, respectively ("**Settlement Proposal**"). The IESO subsequently filed the Settlement Proposal with the OEB on July 21, 2023, which the OEB approved in its entirety by Decision and Order dated August 29, 2023.

[1] Application for 2024 and 2025 Incremental Revenue Requirement, Expenditures, and Usage Fees (1 August 2024), EB-2024-0004, online (pdf): Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/860710/File/document>.

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[2] *Electricity Act*, SO 1998, c 15, Schedule A, s 25(1) : "The IESO shall, at least 60 days before the beginning of each fiscal year, submit its proposed expenditure and revenue requirements for the fiscal year and the fees it proposed to charge during the fiscal year to the Board for review, but shall not do so until after the Minister approves the IESO's proposed business plan for the fiscal year under section 24."

[3] Application for Approval of 2023, 2024, and 2025 Expenditures, Revenue Requirement, and Fees (29 August 2023), EB-2022-0318, online (pdf): Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/813433/File/document>.

The OEB-approved Settlement Proposal ("**Settlement Agreement**") provided that if unforeseen expenses or changes in revenues caused the IESO's Forecast Variance Deferral Account (FVDA) balance to fall below zero for the first year of the three-year cycle, i.e. fiscal 2023, then the IESO could reapply to the OEB to have its fees adjusted for the last year of the three-year cycle, i.e. 2025 (the "**Adjustment Mechanism**").[4] In short, the Adjustment Mechanism provided the IESO could return to the OEB to seek adjustment of its 2025 fees if there were unforeseen expenditures for the 2023 fiscal year.

Notwithstanding the Adjustment Mechanism, the IESO filed another application with the OEB less than 6 months later on January 12, 2024 requesting approval for incremental increases of $4.5 million and $5.4 million to its revenue requirements for 2024 and 2025 respectively[5] ("**Incremental Fees Application**"). The IESO claimed its incremental funding request was directly attributable to specific initiatives outlined in a July 10, 2024 letter from the Minister of Energy to the IESO furthering the Ministry of Energy's "*Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future"* (the "**POG Plan**") released the same day. Following receipt of the July 10, 2024 letter, the IESO submitted an amended 2023–2025 business plan to the Ontario Minister of Energy, which was approved by the Minister on or about November 28, 2023 ("**Amended Business Plan**"). Unsurprisingly, various interveners challenged the IESO's Incremental Fees Application on the basis that it was contrary to the Adjustment Mechanism which required fiscal 2023 increases to be dealt with for year three of the three-year cycle. Interveners and OEB staff argued the Incremental Fees Application was inconsistent with the parties' intentions for including the Adjustment Mechanism in the Settlement Agreement, namely to limit the circumstances under which the IESO could seek approval to adjust its fees.[6]

Moreover, the IESO received the Ministerial letter on July 10, 2023, approximately two weeks after the June 26–29 settlement conference and more than ten days before it filed the Settlement Proposal with the OEB for approval on July 21, 2023. This was more than six weeks before the OEB issued its August 29, 2023 decision mandating the Settlement Agreement. OEB staff and interveners accordingly submitted in the Incremental Fees Application "that the IESO was aware of the situation that there would be work associated with the POG Plan before filing the Settlement Proposal, and it is likely the IESO could have anticipated the potential financial impact of the POG work at least prior to the OEB's decision."[7] Interveners argued the IESO should have brought the potential financial implications of the POG Plan to their attention before filing the Settlement Proposal on July 21, if not during the June 26–29 settlement conference.

In response, the IESO submitted it was not relying on the Adjustment Mechanism in support of its Incremental Fees Application. Rather, the IESO argued (as described by the OEB Panel):

> the Adjustment Mechanism was designed as a guardrail that identified specific triggers that would require the IESO to consider and assess an adjustment to its fees, and the inclusion of the Adjustment Mechanism in the Settlement

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[4] *Ibid*. ("In the case that the FVDA balance reaches below zero in year 1 of the three-year cycle the IESO proposes that a revised submission during interim years would adhere to the following process:

- IESO Annual Report completed in Q1 Year 2 confirms that the balance in the FVDA in Year 1 has reached below zero;
- IESO Business Plan is revised and re-submitted to Minister;
- After Minister approval received, revised application is filed with OEB;
- Revised application would request:
    - Approval to amend usage fees in Year 3 to recover some or all of the amounts that impacted the IESO's FVDA to reduce below zero. IESO will notify the OEB and parties when a revised business plan has been approved by the Minister", at 18).

[5] As well as the resulting updated usage fees.

[6] *Supra* note 1.

[7] *Ibid* at 7.

> Proposal in no way precluded the IESO from applying to adjust its usage fees in response to unplanned material operating or capital budget [*sic.*] arising from changes in government policy.[8]

The IESO also took the position that "the terms of the Settlement Proposal do not and, as matter of law, could not restrict the IESO's statutory right [under subsection 25(1) of the Electricity Act] to request approval of increased usage fees for 2024 and 2025 following the Minister's approval of the… Amended Business Plan"[9].

Relying on subsection 25(4) of the *Electricity Act*[10], the OEB held it did in fact have the authority to approve the Incremental Fees Application notwithstanding the Adjustment Mechanism. Primarily because "[t]he OEB has an ongoing responsibility to ensure that the IESO's expenditures, revenue requirements and fees are reasonable and consistent with the purposes of the *Electricity Act* and the OEB's objectives under the *Ontario Energy Board Act*, 1998."[11]

Nevertheless, the OEB did describe the IESO's approach to bringing the Incremental Fees Application as "highly questionable":

> The OEB's concern is that a timely disclosure of the Minister's Letter to the OEB and the parties to the Settlement Proposal might have obviated the necessity of this section 25(1) application and the resultant ill will that it appears to have generated reflected in the submissions received. Such a disclosure would likely have provoked efforts to provide for the letter's recognition by way of a delay in the OEB's approval of any Settlement Proposal until the new information with its potential for unanticipated costs was available and addressed by the settlement conference. The OEB further notes that a Settlement Proposal emanating from such a conference could well have provided for an "off-ramp" enabling consideration of the financial impact of the Minister's Letter when the appropriate cost assessments were complete and ministerial approval of the Business Plan was received. Such a course of action would have been consistent with a principal goal of a settlement conference to arrive at a resolution that was in keeping with the public interest and the agreement of all the participating parties.
>
> …there was no prohibition on the IESO notifying parties to the Settlement Proposal that the Minister's Letter was likely to require additional expenditures, and it is clear that this was known prior to the OEB issuing its decision on the EB-2022-0318 proceeding.
>
> …
>
> A successful result of settlement conferences that are convened by the OEB depends on full disclosure of all relevant information, a frank discussion of issues (a discussion that cannot be referenced in the proceeding outside of the conference) and a shared understanding of the results by the parties. In this case, the process chosen by the IESO to carry out the initiatives set out in the Minister's Letter may have significant serious consequences for future settlement conferences if parties have lost trust in the transparency and timeliness of information being provided.[12]

The issues canvassed in the Incremental Fees Application dealt primarily with statutory and contractual interpretation of the Adjustment Mechanism. But, a fundamental question that

[8] *Ibid* at 4.

[9] *Ibid* at 3–4 [footnotes omitted].

[10] *Ibid*. ("[The Board] may approve the proposed expenditure and revenue requirements and the proposed fees or may refer them back to the IESO for further consideration with the Board's recommendations", at 8).

[11] *Ibid*.

[12] *Ibid* at 10–11 [footnotes omitted].

was not raised was whether the IESO acted contrary to its duty to perform its contractual obligations under the Settlement Agreement in good faith.

The preamble to the Settlement Agreement explicitly stated that "this document is intended to be a legal agreement, creating mutual obligations, and binding and enforceable in accordance with its terms."[13] And we know from the Supreme Court of Canada's decision in *Bhasin v Hrynew*,[14] that parties to an existing agreement are required to "perform their contractual duties honestly and reasonably"[15]. The duty of honest performance "requires that contractual parties be honest with each other in relation to the performance of their contractual obligations"[16] — "it is a simple requirement not to lie or mislead the other party about one's contractual performance."[17] Each party must have an appropriate regard to the legitimate contractual interests of the other party, and the party cannot "seek to undermine those interests in bad faith."[18]

In the case of the Settlement Agreement, it is reasonable to conclude the intervenors had a legitimate interest in limiting the ability of the IESO to return to the OEB for a fees adjustment solely to the circumstances set out in the Adjustment Mechanism.[19] Did the IESO fail to have appropriate regard to that interest in bringing the Incremental Fees Application. Did such conduct amount to "active dishonesty"[20]?

The IESO might respond that the *Bhasin* principles of contractual interpretation do not or should not apply to the Incremental Fees Application because it is a publicly-regulated entity[21] and therefore distinct from a private commercial contracting party. But the duty of honest performance applies to all contracts, operates irrespective of the intention of the parties and cannot be contracted out of.[22] Indeed, a further argument could be made that an elevated duty or obligation of good faith performance existed as between the IESO as a public sector entity that has discretionary authority over the ratepayers represented by the interveners. This power imbalance or information asymmetry was perpetuated by the fact that it is more likely than not that the IESO had some awareness of the POG Plan before receiving the Minister's letter on July 10.

The IESO may rebut the immediate publication of the Minister's letter as a news item on the IESO's public website provided sufficient disclosure to intervenors and that therefore no information asymmetry or imbalance existed. However, the OEB correctly noted that "one of the practical purposes of regulatory proceedings is to consolidate available information touching upon the merits of an application. The assumption that relevant information may also be obtained by ongoing scrutiny of items on applicant websites is a proposition of doubtful validity."[23] This is consistent with the *Bhasin* decision which recognizes the duty of good faith may extend to pre-contractual negotiations.

It is unfortunate that the duty of honest performance was not more carefully considered in the Incremental Fees Application. Perhaps it will be if and when future similar circumstances arise — a very real possibility given the accelerated pace at which provincial government policy is evolving to meet increasing demand forecasts and the broader energy transition. ■

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[13] *Supra* note 4 at 18.

[14] *Bhasin v Hrynew*, 2014 SCC 71 [*Bhasin*].

[15] *Ibid* at para 63.

[16] *Ibid* at para 93.

[17] *Ibid* at para 73.

[18] *Ibid* at para 65.

[19] *Supra* note 1 at 4.

[20] *Bhasin*, *supra* note 14 at para 86.

[21] *Supra* note 1 at 4.

[22] *Bhasin*, *supra* note 14 at para 74.

[23] *Supra* note 1 at 10–11.

RESTOULE: TUGGING ON THE ROPE AND THE DUTY OF DILIGENT IMPLEMENTATION OF TREATY PROMISES

*Nigel Bankes**

Case Commented On: *Ontario (Attorney General) v Restoule.*[1]

> [T]he trial judge found that the Robinson Treaties were motivated largely by the principles of kinship and mutual interdependence, as reflected in the Covenant Chain. This enduring alliance has been depicted using the metaphor of a ship tied to a tree with a metal chain: "The metaphor associated with the chain was that if one party was in need, they only had to 'tug on the rope' to give the signal that something was amiss, and 'all would be restored'"... The Anishinaabe treaty partners have been tugging on the rope for some 150 years now, but the Crown has ignored their calls. The Crown has severely undermined both the spirit and substance of the Robinson Treaties.[2]

In a unanimous judgment authored by Justice Jamal, the Supreme Court of Canada in *Ontario (Attorney General) v Restoule,*[3] has confirmed that the Crown has a duty of diligent implementation of treaty promises informed not by fiduciary principles, but by the honour of the Crown. And in this case, the Crown was clearly in breach of that duty since, as Justice Jamal noted in words that will ring down through the decades:

> For well over a century, the Crown has shown itself to be a patently unreliable and untrustworthy treaty partner in relation to the augmentation promise. It has lost the moral authority to simply say 'trust us.'[4]

The Augmentation Promise of the Robinson Treaties

In 1850, William Benjamin Robinson on behalf of Her Majesty, and the Anishinaabe (Ojibewa) Indians of Lake Huron and of Lake Superior, negotiated and entered into two land cession treaties. The treaties provide for an initial payment of 2,000 pounds and a

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[1] *Ontario (Attorney General) v Restoule*, 2024 SCC 27 [*Restoule*].

[2] *Ibid* per Justice Jamal at para 286.

[3] *Ibid*.

[4] *Ibid* at para 262.

perpetual annuity of 500 pounds. Both treaties also contained an "augmentation clause" in materially identical terms. The text of the clause in the Robinson-Huron Treaty reads as follows:

> ….The said William Benjamin Robinson, on behalf of Her Majesty, Who desires to deal liberally and justly with all Her subjects, further promises and agrees that should the territory hereby ceded by the parties of the second part at any future period produce such an amount as will enable the Government of this Province, without incurring loss, to increase the annuity hereby secured to them, then and in that case the same shall be augmented from time to time, provided that the amount paid to each individual shall not exceed the sum of one pound Provincial currency in any one year, *or such further sum as Her Majesty may be graciously pleased to order…*[5]

In 1850, the annuity on a per capita basis amounted to about $1.60 or $1.70 per person (the judgement uses a conversion rate of $4 to a pound). The annuity was increased once in 1875 to $4.00 per person, "the first and only increase to the annuities ever made."[6] As the Court notes in the opening paragraphs of its judgment, the question of liability for the annuities as between Canada and Ontario had previously been before the courts in *Attorney-General for the Dominion of Canada v Attorney-General for Ontario,*[7] *("In re Indian Claims")*. In that decision the Privy Council concluded that the annuities, whether as originally stipulated or as augmented, did not constitute a trust or interest other than that of the province within the meaning of section 109 of the *Constitution Act,* 1867 [8] and thus liability for the annuities lay with Canada and not with the province.

The Litigation

The Superior plaintiffs commenced an action against Canada and Ontario in 2001 and the Huron plaintiffs followed with their own action in 2014. The actions were tried together in three stages. Stage 1 dealt with interpretation.[9] Stage 2 dealt with Ontario's defences based on Crown immunity and limitations.[10] Stage 3 deals with the plaintiffs' claim for damages and allocation of any award as between Canada and Ontario. Prior to the hearing of Stage 3, Canada, Ontario, and the Huron plaintiffs reached a settlement which has now been finalized and approved.[11] The Stage 3 proceedings in relation to the Superior plaintiffs alone concluded in September 2023 but judgment has been stayed by order of Chief Justice Wagner.[12]

It is convenient to note at the outset that Justice Jamal concluded that the plaintiffs' treaty actions were not time barred by Ontario's *Limitations Act*,[13] largely it seems on the basis that a breach of treaty claim did not fall within any of the specific causes of action listed in the Ontario statute.[14]

Interpretation of the Augmentation Promise

Justice Jamal proceeded (after significant discussion) on the basis that the standard of review for the interpretation of historic treaties is correctness. Factual findings, including findings of historical fact that may inform the interpretation, attract deference.[15] The

[5] *Restoule*, *supra* note 1 at para 43 [emphasis added].

[6] *Ibid* at para 44.

[7] *Attorney-General for the Dominion of Canada v Attorney-General for Ontario*, [1896] UKPC 51 [*In re Indian Claims*].

[8] *Constitution Act*, 1867 (UK), 30 & 31 Vic, c 3, s 91, reprinted in RSC 1985, Appendix II, No 5.

[9] *Restoule v Canada (Attorney General)*, 2018 CanLII 7701 (ONSC); *Restoule v Canada (Attorney General)*, 2021 CanLII 779 (ONCA).

[10] *Restoule v Canada (Attorney General)*, 2020 CanLII 3932 (ONSC); *Restoule v Canada (Attorney General)*, 2021 CanLII 779 (ONCA).

[11] *Mike Restoule v The Attorney General of Canada*, 2024 CanLII 1127 (ONSC).

[12] *Restoule*, *supra* note 1 at para 62.

[13] *Limitations Act*, SO 2002, c 24, Schedule B.

[14] *Restoule*, *supra* note 1 at paras 198–217.

[15] *Ibid* 1 at paras 67–119.

court followed the two-step approach to treaty interpretation adopted by Justice McLachlin in *R v Marshall*,[16] a framework that as Justice Jamal notes "reflects the current state of the law" and has been cited with approval in many decisions.[17] The first step focuses on the words of the treaty and identifies the range of possible interpretations. At the second step "the court considers those interpretations against the treaty's historical and cultural backdrop."[18] Justice McLachlin's well known nine principles[19] inform both steps in the process.

At the first step Justice Jamal identified four possible interpretations of the augmentation clause: (1) any legal duty to augment was capped at $4 per person, any augmentation beyond that was at the Crown's unfettered discretion; (2) the Crown was obliged to augment per person allocations when economic circumstances permitted, (3) the Crown was obliged to augment individual payments to the ceiling of $4 per person (after which some discretion), plus a duty to augment payments to the collective when economic circumstances permitted, and (4) a single obligatory payment to the collective up to a "soft cap" calculated by reference to $4 per person, and in addition, if the economic condition is met, (i.e., "without incurring loss") an ongoing power ("or such further sum as Her Majesty may be graciously pleased to order") to make additional payments to the collective.[20] Both the trial judge and the majority of the Court of Appeal favoured the third option[21] while the minority of the Court of Appeal favoured the fourth option.[22]

In the second step Justice Jamal proceeded to analyze each of these possible interpretations "against the treaty's historical and cultural backdrop."[23] The first interpretation was, according to Justice Jamal, "a legal impossibility"[24] because "[a]n interpretation based on unfettered discretion does not fit within Canadian notions of legality and cannot reflect the common intention of the parties to the Robinson Treaties."[25] I note that this is a very "public law"[26] reading of the treaty: all the cases that Justice Jamal relies upon for this proposition are public law cases including, most famously, *Roncarelli v Duplessis*.[27]

Justice Jamal dealt with the second, third, and fourth options together on the basis that the second option (a duty to augment when the economic condition was met) was a necessary component of both the third and fourth options. Justice Jamal ultimately preferred the fourth option. In doing so, he rejected the proposition, as had the Court of Appeal, that the treaties required that the Anishinaabe receive a "fair share" of net Crown revenues from the ceded territories. Instead, Justice Jamal considered that any sharing should be

> …effected by an exercise of Crown discretion that reflects the honour of the Crown and abides by the Crown's promise to the Anishinaabe "to deal liberally and justly with all Her subjects", having regard to the relative wealth and needs of all the Crown's subjects, signatories and non-signatories alike.[28]

The Anishinaabe's acceptance of the Crown's discretionary power in relation to the augmentation clause

> …was entirely consistent with the Anishinaabe's conceptions of a good leader, and reflected the principles

[16] *R v Marshall*, [1999] 3 SCR 456, 1999 CanLII 665 (SCC) [*Marshall*].

[17] *Restoule*, *supra* note 1 at para 81.

[18] *Ibid*.

[19] See *ibid* at para 79

[20] *Ibid* at paras 139–50.

[21] *Ibid* at para 157.

[22] *Ibid* at para 158.

[23] *Ibid* at para 80.

[24] *Ibid* at para 152.

[25] *Ibid*.

[26] *Ibid* at para 210.

[27] *Roncarelli v Duplessis*, [1959] SCR 121, 1959 CanLII 50 (SCC).

[28] *Restoule*, *supra* note 1 at para 181.

> of respect, responsibility, reciprocity, and renewal. The Robinson Treaties recognized the Anishinaabe's authority to conclude agreements to share their territory and their responsibility to their people, embodied the idea of reciprocity and mutual dependence, and cemented a longstanding nation-to-nation relationship that would be renewed in perpetuity.[29]

But the Crown's discretionary power "is not unfettered; it is justiciable and reviewable by the courts"[30] both as to timing and substance and must be exercised "diligently, honourably, liberally, and justly, while engaging in an ongoing relationship with the Anishinaabe based on the values of respect, responsibility, reciprocity and renewal."[31]

Is the Crown's Discretionary Power Fiduciary in Nature?

Once Justice Jamal had settled on the correct interpretation of the augmentation promise, it was necessary to consider what principles might inform and constrain the Crown in the exercise of this discretionary power, specifically, whether the power might be subject to an *ad hoc* or *sui generis* fiduciary duty. In the end, Justice Jamal concluded that the treaty power could not be characterized in either way, although both the court and the parties agreed that "the honour of the Crown", albeit not a cause of action, "must guide the interpretation and implementation of the Augmentation Clause and the appropriate remedies for the Crown's past breach…"[32]

For Justice Jamal, the treaty power could not be subject to an *ad hoc* fiduciary duty since the plaintiffs could not fit the power within the three-fold test for an *ad hoc* duty:

> (1) an undertaking by the alleged fiduciary to act in the best interests of the alleged beneficiaries; (2) a defined class of beneficiaries vulnerable to the fiduciary's control; and (3) a legal or substantial practical interest of the beneficiaries that stands to be adversely affected by the alleged fiduciary's exercise of discretion or control…[33]

More specifically, the plaintiffs could not get past the first branch of the test since "[t]here is no evidence that the Crown undertook to act in the best interests of the Huron and Superior plaintiffs in relation to the treaty promise."[34] Instead, the treaty text expressed the Crown's "desire to deal liberally and justly *with all Her subjects*"[35] which effectively contradicted the signature duty of undivided loyalty of a fiduciary.

Neither was it possible to bring the treaty power within the Court's jurisprudence on *sui generis* fiduciary duties. That jurisprudence, notably *Wewaykum Indian Band v Canada*,[36] and *Manitoba Metis Federation Inc v Canada (Attorney General)*[37] requires "(1) a specific or cognizable Aboriginal interest; and (2) a Crown undertaking of discretionary control over that interest."[38] In this case, Justice Jamal seems to have qualified the first part of the test still further by suggesting a "general principle that specific or cognizable Aboriginal interests cannot be established by treaty or legislation."[39] Justice Jamal's conclusion that the augmentation obligation of the Robinson treaties may not be a sufficiently specific cognizable interest relating to particular lands (such as surrendered reserve lands) may be correct, but it is far from obvious why there should be a "general principle that specific or cognizable Aboriginal interests cannot be

[29] *Ibid* at para 195.
[30] *Ibid* at para 196.
[31] *Ibid* at para 197.
[32] *Ibid* at para 218.
[33] *Ibid* at para 228.
[34] *Ibid* at para 229.
[35] *Ibid* at para 232 [emphasis added].
[36] *Wewaykum Indian Band v Canada*, 2002 SCR 79.
[37] *Manitoba Metis Federation Inc v Canada (Attorney General)*, 2013 SCC 14 [*Manitoba Metis*].
[38] *Restoule*, *supra* note 1 at para 234.
[39] *Ibid* at para 238.

established by treaty or legislation."[40] After all, in *Guerin v The Queen,*[41] Justice Wilson was of the view that while "s. 18 [of the *Indian Act*[42]] does not *per se* create a fiduciary obligation in the Crown with respect to Indian reserves, I believe that it recognizes the existence of such an obligation…"[43] Similarly, in his leading judgment in the same case (and preferring a fiduciary analysis rather than Justice Wilson's trust analysis), Justice Dickson also relies in part on the language of section 18 of the *Indian Act*.[44]

The Honour of the Crown and the Duty of Diligent Implementation of Treaty Promises

But even if the Crown was not under a fiduciary obligation in implementing the augmentation promise, all parties before the Court agreed that the honour of the Crown required it "to diligently fulfill or implement"[45] that promise. The duty of diligent implementation was first articulated in a statutory and constitutional context in *Manitoba Metis* but has since been carried over into treaties, most notably in *Yahey v British Columbia*,[46] a treaty 8 case,[47] but also into modern treaties (Justice Jamal references *First Nation of Nacho Nyak Dun v Yukon*,[48] [*Peel River Case*] at para 52 but a far more pertinent reference is the more recent *First Nation of Na-Cho Nyäk Dun v Yukon (Government of).*[49]

But what did the duty of diligent implementation mean in this case? A principal issue at the outset was whether the duty is purely procedural or also substantive.[50] Justice Jamal had little hesitation in concluding that the duty attracted both procedural and substantive elements and that judicial supervision would apply to both elements.[51] Furthermore, the Crown was clearly in breach of both its procedural and substantive obligations:

> I cannot accept Ontario's submission that a purely procedural duty — by which the Crown is simply required to "consider" or "turn its mind" to discretionary increases to the annuities from time to time — would maintain the honour of the Crown or effect reconciliation between the parties. Since 1875, when the first and only increase to the annuities was made, the Crown has failed to consider whether it can increase the annuities without incurring loss and, if so, to exercise its discretion to determine whether and by how much to increase them. For well over a century, the Crown has shown itself to be a patently unreliable and untrustworthy treaty partner in relation to the augmentation promise. It has lost the moral authority to simply say "trust us."[52]

As an aside, I note that while Justice Jamal concludes that there is little domestic jurisprudence on the duty of diligent implementation of treaties,[53] there is a considerable jurisprudence on due diligence

[40] *Ibid*.

[41] *Guerin v The Queen*, [1984] 2 SCR 335.

[42] *Indian Act*, RSC 1985, c I-5 [*Indian Act*].

[43] *Supra* note 41 at 348–49; See also *supra* note 41 at 352, 354–55.

[44] See *ibid* at 383–84, 387.

[45] *Restoule*, *supra* note 1 at para 248.

[46] *Yahey v British Columbia*, 2021 CanLII 1287 (BCSC) at paras 1779–87 [*Yahey*].

[47] See Robert Hamilton & Nick Ettinger, "Blueberry River First Nation and the Piecemeal Infringement of Treaty 8" (20 July 2021), online: <www.ablawg.ca/2021/07/20/blueberry-river-first-nation-and-the-piecemeal-infringement-of-treaty-8/#more-12264>. See also Robert Hamilton & Nick Ettinger, "*Yahey v British Columbia* and the Clarification of the Standard for a Treaty Infringement" (24 September 2021), online: <www.ablawg.ca/2021/09/24/yahey-v-british-columbia-and-the-clarification-of-the-standard-for-a-treaty-infringement>.

[48] *First Nation of Nacho Nyak Dun v Yukon*, 2017 SCC 58.

[49] *First Nation of Na-Cho Nyäk Dun v Yukon (Government of)*, 2024 CanLII 5 (YKCA) [*Majestic Mines Case*].

[50] See *Restoule*, *supra* note 1 at para 260.

[51] See *ibid* at paras 261–64.

[52] See *ibid* at para 262.

[53] See *ibid* at para 259.

obligations (both treaty and customary) in international law.[54]

Remedies

The next step was to consider what might be an appropriate remedy for the Crown's failure to diligently implement the augmentation promise. Reasoning from *Haida Nation v British Columbia (Minister of Forests)*[55],

> [t]he controlling question…is what is required to maintain the honour of the Crown and to effect reconciliation between the Crown and the Aboriginal peoples with respect to the interests at stake," Justice Jamal concluded that it was appropriate to provide the plaintiffs with both declaratory relief as well as "further direction."[56]

Justice Jamal made the following six declarations:

1. Under the Augmentation Clause of the Robinson Treaties, the Crown has a duty to consider, from time to time, whether it can increase the annuities without incurring loss.
2. If the Crown can increase the annuities without incurring loss, it must exercise its discretion as to whether to increase the annuities and, if so, by how much.
3. In carrying out these duties and in exercising its discretion, the Crown must act in a manner consistent with the honour of the Crown, including the duty of diligent implementation.
4. The Crown's discretion must be exercised diligently, honourably, liberally, and justly. Its discretion is not unfettered and is subject to review by the courts.
5. The Crown dishonourably breached the Robinson Treaties by failing to diligently fulfill the Augmentation Clause.
6. The Crown is obliged to determine an amount of honourable compensation to the Superior plaintiffs for amounts owed under the annuities for the period between 1875 and the present.[57]

But declaratory relief on its own was

> …insufficient given the egregious and longstanding nature of the breaches at issue in these appeals. In these circumstances, a simple declaration would not adequately repair the treaty relationship or restore the honour of the Crown. It would not sufficiently vindicate the treaty rights or meaningfully advance reconciliation.[58]

As for the further direction that would be required, Justice Jamal was concerned that such direction should be sensitive to the nature of the treaty promise, be respectful of the proper role of the judicial branch and recognize, as per *Haida* above, the importance of renewing the treaty relationship.

The treaty promise was not a promise to pay a certain sum of money; it was instead "a promise to consider whether the economic conditions allow the Crown to increase the annuities without incurring loss and, if they do, to *exercise its discretion* and determine whether to increase the annuities and, if so, by how much."[59] Accordingly, the Crown, even after all these years, should be accorded the opportunity "through honourable engagement with its treaty partners"[60] to propose a settlement. Absent an agreed settlement,

> …the Crown will be required to explain to the Superior plaintiffs and the court how it reached its determination and why. This would permit the court to pay careful attention to the manner in which

[54] See for example and most recently, the *Climate Change Advisory Opinion* of the International Tribunal of the Law of the Sea (21 May 2024), online (pdf): <www.itlos.org/fileadmin/itlos/documents/cases/31/Advisory_Opinion/C31_Adv_Op_21.05.2024_orig.pdf>.

[55] *Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73 [*Haida*].

[56] *Ibid* at para 45.

[57] See *Restoule*, *supra* note 1 at para 304.

[58] *Ibid* at para 283.

[59] *Ibid* at para 290 [emphasis in original].

[60] *Ibid*.

> the Crown exercised its discretion, having regard to both the amount determined and the process by which it arrived at that amount, when assessing whether the Crown's determination is honourable.[61]

This approach was also consistent with the judicial role. The exercise of discretion in fixing the amount that the Crown should pay is a polycentric exercise in which the Crown must have regard to the responsibility "to deal liberally and justly <u>with all Her Subjects</u>."[62] This responsibility "is well within the expertise of the executive branch, but is much less within the expertise of the courts."[63] On the other hand,

> …it is very much the business of the courts to review exercises of Crown discretion for constitutional compliance — to ensure that the Crown exercises its discretion in accordance with its treaty obligations and the constitutional principle of the honour of the Crown.[64]

And finally, the direction to the Crown to engage with its treaty partners was also consistent with the idea of the treaties as honouring a relationship rather than as transactional instruments.[65] While

> …the augmentation promise does not expressly require the parties to negotiate and agree on an annuity increase, it is undeniable that negotiation and agreement outside the courts have better potential to renew the treaty relationship, advance reconciliation, and restore the honour of the Crown.[66]

In light of these three considerations, and in addition to the six declarations listed above, Justice Jamal, "[w]ith a view to respecting the nature of the treaty promise, repairing the treaty relationship, restoring the honour of the Crown, and advancing reconciliation"[67] directed the Crown

> …to engage *meaningfully* and *honourably* with the Superior plaintiffs in an attempt to arrive at a just settlement regarding past breaches. If such a settlement cannot be mutually agreed upon, the Crown will be obliged, within six months of the release of these reasons, to exercise its discretion and determine an amount to compensate for past breaches.[68]

It also followed from this that the Stage 3 proceedings should be stayed for the same period and while the Superior plaintiffs would have leave to seek a further extension the Crown could not.[69] If the parties cannot reach a negotiated settlement, then "the Superior plaintiffs may seek review before the courts of both the process the Crown has undertaken and the substantive amount it has determined as compensation."[70] That presumably would take the form of the Stage 3 proceedings "modified in accordance with these reasons."[71] Finally, Justice Jamal offered guidance in the form of a non-exhaustive list of factors that the Crown should consider in any proposed settlement:

> (a) the nature and severity of the Crown's past breaches, including the Crown's neglect of its duties for close to a century and a half; (b) the number of Superior Anishinaabe and their needs; (c) the benefits the Crown has received from the

[61] *Ibid*.

[62] *Ibid* at para 296 [emphasis in original].

[63] *Ibid* at para 297.

[64] *Ibid* at para 299.

[65] See *ibid* at 300.

[66] *Ibid* at para 303.

[67] *Ibid* at para 305.

[68] *Ibid* at para 305 [emphasis in original].

[69] See *ibid* at para 307.

[70] *Ibid*.

[71] *Ibid*.

> ceded territories and its expenses over time; (d) the wider needs of other Indigenous populations and the non-Indigenous populations of Ontario and Canada; and (e) principles and requirements flowing from the honour of the Crown, including its duty to diligently implement its sacred promise under the treaty to share in the wealth of the land if it proved profitable.[72]

Conclusions

I think that *Restoule* will come to be recognized as one of the Court's most significant treaty cases — certainly its most significant treaty case since *Marshall* — and it is all the more significant because it is a unanimous judgment. I say this for two principal reasons.

First, the decision is based on a deeply contextual reading of the 1850 treaties, which begins pre-contact with a consideration of the Anishinaabe's system of law and governance based on the values of *respect, responsibility, reciprocity,* and *renewal*[73] and continues with a discussion of the Covenant Chain.[74] These are not mere recitations. Justice Jamal uses these references throughout his judgment to justify his preferred interpretation of the augmentation promise, to inform the meaning of the honour of the Crown in this particular context, to emphasize the relational rather than transactional nature of historic treaties, and, perhaps most significantly, to inform his discussion of remedies.

Second, the Court has fully endorsed the proposition that the honour of the Crown supports a duty of diligent implementation of treaty promises. While the decision is specific to the Robinson treaties, and indeed to a specific clause in the Robinson treaties, there is nothing to suggest that the Court's reasons should be so confined. Indeed, by referring to the *Yahey* decision and *Chippewas of Nawash Unceded First Nation v Canada (Attorney General)*,[75] with apparent approval, the Court has endorsed the application of the duty of diligent implementation of promises to other historic treaties, including the numbered treaties. Given this endorsement, the Crown would do well to remember Justice Greckol's observation in her separate concurring opinion in *Fort McKay First Nation v Prosper Petroleum Ltd*,[76] in the context of the 'lands taken up' clause of the numbered treaties, that a treaty promise may be "easy to fulfill initially" but become increasingly "difficult to *keep* as time goes on and development increases."[77]

I think that the decision also offers important guidance on the application of fiduciary law in the context of Crown-Indigenous relations. I suspect that some will be disappointed by what may be seen as a backing away from some of the Court's more general statements as to fiduciary obligations and relationships (e.g., *R v Sparrow*[78]) but in my view it is more convincing to view the honour of the Crown rather than a fiduciary relationship as the general organizing principle while recognizing that in some cases the court should impose a fiduciary duty.

There are of course some puzzles in the case. I have already referred in the body of the comment to one aspect of Justice Jamal's treatment of *sui generis* fiduciary duties that seems problematic. Another puzzle is why, just as in the Court's other recent historic treaty case *Canada v Jim Shot Both Sides*,[79] the Court in this case makes no reference to the *United Nations Declaration on the Rights of Indigenous Peoples*[80]

[72] *Ibid* at para 309. See also *ibid* at para 271.

[73] See *ibid* at paras 17–18.

[74] See *ibid* at paras 19–20.

[75] *Chippewas of Nawash Unceded First Nation v Canada (Attorney General)*, 2023 CanLII 565 (ONCA).

[76] *Fort McKay First Nation v Prosper Petroleum Ltd*, 2020 CanLII 163 (ABCA). See also Nigel Bankes, "The AER Must Consider the Honour of the Crown" (28 April 2020), online: <www.ablawg.ca/2020/04/28/the-aer-must-consider-the-honour-of-the-crown>.

[77] *Ibid* at para 80, [emphasis in original].

[78] *R v Sparrow*, [1990] 1 SCR 1075 at 1108.

[79] *Shot Both Sides v Canada*, 2024 SCC 12. See the postscript in the ABlawg post on the *Dickson* decision discussing this point: Nigel Bankes and Jennifer Koshan, "The *Dickson Decision*, UNDRIP, and the Federal *UNDRIP Act*" (18 April 2024), online: <www.ablawg.ca/2024/04/18/the-dickson-decision-undrip-and-the-federal-undrip-act>.

[80] *UN Declaration on the Rights of Indigenous Peoples*, OHCHR, 33rd Sess, UN Doc A/RES/61/295 (2007).

notwithstanding its decision in *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*,[81] to the effect that the Declaration has been incorporated into the country's positive law.

And Justice Jamal does not weigh-in on the allocation of responsibility for treaty implementation as between Canada and Ontario. But that of course is understandable. This is one of the issues that is before the trial court in the adjourned Stage 3 proceeding and is an issue that the parties will have to resolve either in settlement discussions (as was the case with Huron plaintiffs) or in the resumed Stage 3 proceedings. In the meantime, it is the Crown writ large that continues to bear the shame of the continuing breach of its treaty obligations. ■

[81] *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*, 2024 SCC 5. See ABlawg post: Nigel Bankes & Robert Hamilton, "What Did the Court Mean When It Said that UNDRIP "has been incorporated into the country's positive law"? Appellate Guidance or Rhetorical Flourish?" (28 February 2024), online: <www.ablawg.ca/2024/02/28/what-did-the-court-mean-when-it-said-that-undrip-has-been-incorporated-into-the-countrys-positive-law-appellate-guidance-or-rhetorical-flourish>.