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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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EDITORIAL

Managing Co-Editors

Karen J. Taylor and Moin A. Yahya[*]

As we enter the Summer of 2025, the hurried pace of change continues, driven by geopolitical events and Canadians' high expectations for the newly elected Carney government. The Prime Minister hosted a First Ministers' Meeting on June 2 in Saskatoon,[1] the focus of which was "to build a stronger, more competitive, and more resilient Canadian economy," including the removal of trade barriers, advance major projects of national interest, and tabling legislation to make Canada stronger at home and abroad.[2]

The need for this unified response to Canada's changed relationship with the United States and the imperative for new trade and security relationships was on full display at the 51st G7 Summit, held on June 15–17 in Kananaskis, Alberta. Despite an objective of "building stronger economies by making communities safer and the world more secure, promoting energy security and accelerating the digital transition, as well as fostering partnerships of the future,"[3] questions relating to "the G7's utility and future in a world where Trump is President of the United States"[4] remained unanswered and the results that were achieved "pale in comparison to what did not happen."[5]

The tabling (June 6, 2025) and Royal Assent (June 26, 2025) of Bill C-5 "*An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act,*"[6] is the first and arguably most significant step taken by the new government to meet the nation's pressing energy and infrastructure challenges and its aspirational goals. Part 1 of Bill C-5 enacts the *Free Trade and Labour Mobility in Canada Act,* which "establishes a statutory framework to remove federal barriers to the interprovincial trade of goods and services and to improve labour mobility within Canada."[7] Part 2 enacts the *Building Canada Act*, the discussion of which features prominently in this edition of *Energy Regulation Quarterly* ("*ERQ*").

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Moin A. Yahya is a professor of law at the University of Alberta. He was a member and acting member of the Alberta Utilities Commission from 2009–2018. He teaches and researches various areas of law.

[1] Prime Minister of Canada, "Monday, June 2, 2025" Media Advisories (2 June 2025), online: <pm.gc.ca/en/news/media-advisories/2025/06/02/monday-june-2-2025>.

[2] Prime Minister of Canada, "First Ministers' statement on building a strong Canadian economy and advancing major projects" Media Statements (2 June 2025), online: <pm.gc.ca/en/news/statements/2025/06/02/first-ministers-statement-building-strong-canadian-economy-and-advancing-major-projects>.

[3] Prime Minsiter' Office, Chair's Summary, (Kananaskis: G7, 2025), online (pdf): <g7.canada.ca/assets/ea689367/Attachments/NewItems/pdf/g7-chairs-summary-en.pdf>.

[4] Murray Brewster, "Where the G7 came from — and where it might go in the era of Trump" (15 June 2025), online: <cbc.ca/news/politics/g7-trump-history-1.7561633>; Aaron Wherry, "In Kananaskis, the G7 held together, but showed signs of strain" (18 June 2025), online: <cbc.ca/news/politics/g7-summit-kananaskis-carney-trump-analysis-1.7564156>.

[5] Madison Minges, "Key Takeaways from the 2025 G7 Summit" (18 June 2025), online: <american.edu/sis/news/20250618-key-takeaways-from-the-g7-summit.cfm>.

[6] Bill C-5 "An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act", June 26, 2025, and as amended in the *One Canadian Economy Act*, 2025, online (pdf): <parl.ca/Content/Bills/451/Government/C-5/C-5_4/C-5_4.PDF>.

[7] *Ibid.*

This edition of *ERQ* begins with a short update to the article written by Daliana Coban, Daniel Gralnick and Ian Thomson, all of Torys, LLP published in the previous issue of ERQ. The Addendum to "Connecting data centres in Ontario: Key considerations and challenges" highlights the key policy and legislative changes energy sector participants should be aware of that relate to data centre connectivity in Ontario.

The articles in this edition of *ERQ* generally reflect two themes. The first theme is the evolving nature of economic regulation — four of the seven articles in this edition discuss and illustrate how the objectives that frame regulatory discretion are changing, even within a traditional rate setting context.

The first of these articles is penned by Ahmad Faruqui, a long-time contributor to energy discussions in the United States, Canada and this journal. Faruqui writes on the ever-challenging topic of "Real time pricing of electricity for households: An international survey." In his article, Faruqui explores the various designs of real time pricing in the United States, Canada, and Europe, discusses consumer uptake of these plans and the associated challenges.

Kenneth Costello, a former regulator with the Illinois Commerce Commission and researcher at the U.S. National Regulatory Research Institute, builds on his past work in the article "Today's ratemaking challenges for utility regulators." Costello discusses how traditional ratemaking has evolved from a focus on the determination of prudent and reasonable costs, cost allocation and rate design, and just and reasonable rates to a new paradigm, where regulators must deal with more objectives brought about by new public policies, technological change, and economic developments. All of which make the setting of just and reasonable rates a harder task for regulators. Costello highlights key challenges and takeaway observations.

John Vellone, Partner and National Leader, Energy, Resources and Renewables and Zoë Thoms, Counsel, of Borden Ladner Gervais LLP discuss the most recent intervention in the mandate and focus of the Ontario Energy Board ("OEB") to introduce new priorities concerned with housing affordability and growth in their article "Connecting growth: Housing policy, energy infrastructure and the evolving role of the OEB." Vellone and Thoms review the policy context for Ontario's "housing push", how the OEB's Phase I decision of Enbridge Gas Inc.'s 2024 rate application became a regulatory turning point, the legislative response, and the resulting regulatory reform and alignment with the policies of the government of Ontario. They conclude with thoughtful commentary of how government direction can redefine the boundaries of regulatory discretion.

The final article dealing with the changing frame of regulatory discretion, is a case comment by Byron Reynolds and Hazel Saffery, both Partners of Dentons Canada LLP. In the article "Alberta Utilities Commission ("AUC") Approves first industrial waste-to-energy facility with carbon capture in Canada", Reynolds and Saffery briefly describe the nature of the facilities subject to AUC approval, the specific approvals sought and decided by the AUC, and explore the significance of the approval of this facility, specifically as it relates to resolving or contributing to the resolution of other societal problems, including management of municipal solid waste, carbon markets, and improving the viability of carbon capture and storage.

The second theme is the regulatory review process for new projects and whether the now proclaimed Bill C-5 can and will result in a more expedited and streamlined review process for major projects of national interest, versus its predecessors — the *Impact Assessment Act*, 2019[8] and the 2012 *Canadian Environmental Assessment Act*, and if so, at what cost. The remaining articles in this edition broadly deal with Part 2, *Building Canada Act* of Bill C-5, including its potential impact on Canada's obligations to First Nations.

In an article comprised of two distinct sections, Rowland Harrison, KC, formerly co-managing editor of *ERQ*, first recasts his keynote address from the 2025 ERQ Energy Law Forum. In "Are things different this time? Reflections on

[8] Bill C-69 "An Act to enact *the Impact Assessment Act and the Canadian Energy Regulatory Act, to amend the Navigation Protection Act and to Make consequential amendments to other Acts*", June 21, 2019 and as amended in the *Budget Implementation Act*, 2024.

a career in energy regulation," Harrison takes his pen over a 50-year career in energy and regulation to examine a number of the seminal regulatory decisions and related energy actions by government to give the reader a historical perspective. The second section is a reply to Mr. Harrison's remarks, provided by Tim Sargent, Director of Domestic Policy of the Macdonald-Laurier Institute. Sargent leans on 28 years of experience in the federal government to explore the arguments and observations put forth by Harrison. Sargent observes that a convincing case can be made that many of the underlying challenges associated with project approvals have not changed in the last two decades and suggests the challenges faced by the Carney government exceed those faced by the Harper government, due to the evolving environment since 2015. Sargent concludes with a pointed discussion of Bill C-5 and makes a number of suggestions how to improve it.

The article "*Building Canada Act*: Move fast and make things, or move fast and break things?" by David V. Wright, Associate Professor, Faculty of Law and Martin Olszynski, Associate Professor and Chair of Energy Resources, and Sustainability, Faculty of Law, both of the University of Calgary, is a comprehensive review of the *Building Canada Act*. Wright and Olszynski review the structure and approach of the *Act*, discuss the amendments made to Bill C-5 as it rapidly progressed through the legislative process, and argue the *Act* is not an impact assessment. Wright and Olszynski raise a number of questions about how the expedited process set out in the *Act* would actually work and at what cost.

This issue concludes with an article by Dwight Newman and Jenna Renwick, Professor of Law and JD student at the University of Saskatchewan College of Law entitled "The uses and abuses of UNDRIP." In their article, they discuss the jurisprudential status of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP). The article canvasses the relevant legislation that has incorporated or referenced the UNDRIP as well as the cases that have invoked the UNDRIP in their judgments. The authors discuss these recent judgments and the methodological flaws in the courts' reasonings, which will create legal uncertainty for those in the energy and mining fields. As such, they conclude, that more clarity from appellate courts, including the Supreme Court, is needed on the status of the UNDRIP and how it fits in with Canadian law.

We hope this issue captures the essence of the moment — rapid and unprecedented geopolitical change and support for the reconsideration and reframing of Canada's administrative law processes. ■

AN ADDENDUM TO "CONNECTING DATA CENTRES IN ONTARIO: KEY CONSIDERATIONS AND CHALLENGES"

*Daliana Coban, Daniel Gralnick and Ian T. D. Thomson**

In the previous issue of *Energy Regulation Quarterly*, our article, "Connecting Data Centres in Ontario: Key Considerations and Challenges" explored the various regulatory requirements and considerations for developing and connecting data centres in Ontario. The article highlighted the importance of parties staying vigilant to regulatory and legislative changes impacting connection processes and cost responsibility and understanding the implications of the Market Renewal Program's ("MRP") changes to the Ontario wholesale electricity market administered by the Independent Electricity System Operator ("IESO"). Since its publication, several announcements have been made which will affect data centre connectivity in Ontario. This addendum highlights the key policy and legislative changes energy sector should be aware of.

On June 3, the government introduced *Protect Ontario by Securing Affordable Energy for Generations Act, 2025* ("Bill 40") which explicitly addresses data centre connectivity.[1] While Ontario's electricity grid is based on the foundational requirement to provide non-discriminatory access (i.e. that any participant may connect regardless of its identity or features), Bill 40 creates an exception to this access right for "specific load facilities" connecting to Ontario's electricity grid.[2] The proposed section 28.1 of the *Electricity Act, 1998* outlines that transmitters

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Ian T. D. Thomson is an incoming associate at Torys LLP with a focus in its energy and infrastructure practice areas. He previously worked as a public policy consultant providing research, analysis and strategic advice to governments, media outlets and research institutes on energy policy matters. The views expressed in this article are those of the authors alone, and do not necessarily reflect that of Torys nor any other person or entity.

[1] Ontario, "Ontario Securing Affordable Energy for Future Generations" (last visited 4 June 2025), online <news.ontario.ca/en/release/1005988/ontario-securing-affordable-energy-for-future-generations>.

[2] Legislative Assembly of Ontario, "Bill 40: An Act to amend various statutes with respect to energy, the electrical sector and public utilities" (last visited 4 June 2025), Schedule 1, s 28.1, online (pdf): <ola.org/sites/default/files/node-files/bill/document/pdf/2025/2025-06/b040_e.pdf>.

or distributors shall not connect (or reconnect) a "specified load facility" onto the electricity system unless connection requirements that are specified in the regulations are met.[3] A "specified load facility" is defined as a facility or class of facilities "that is a data centre" and meets criteria set out in regulation.[4] At time of publication, this bill has only passed first reading and no regulation has set out any specified connection requirements. However, if Bill 40 passes, data centre proponents looking to connect to Ontario's grid could be subject to additional requirements soon.

On June 12, the government published its first Integrated Energy Plan, "*Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*" (the Plan).[5] The Plan, which is statutorily required under the new *Affordable Energy Act, 2024*, articulates several new programs and initiatives to deliver "affordable, secure, reliable and clean" energy. [6] In relation to data centres, the Plan references the forecasted increase in demand from the data centre industry and well as newly introduced Bill 40. Specifically, the Plan highlights the proposed Bill 40 and how it "would allow Ontario to manage electricity connection requests and prioritize data centres that deliver real local, strategic and economic benefits — not just power consumption". [7] This objective aligns with Bill 40's proposal to introduce new purposes of the *Ontario Energy Board Act* and *Electricity Act* to support economic growth, and may offer insight into the policy objectives that future connection requirements under the Regulation may seek to advance. Given these details, and noting that the applicable requirements are not known at this time, data centres proponents should consider ways to demonstrate their economic potential in the region they wish to connect in.

The regulatory landscape for data centre development and connectivity in Ontario continues to evolve. With the introduction of Bill 40, the release of Ontario's first Integrated Energy Plan, and increased market experience following IESO's Market Renewal Program, data centre proponents must remain attentive to emerging requirements and public policy shifts. While the full implications of these changes are still unfolding — particularly as regulations under Bill 40 have yet to be released — available information suggests that it may be important for data centre proponents to demonstrate economic value to secure grid access. Proponents should continue to monitor developments closely and engage early with the OEB and IESO to navigate the emerging framework effectively. ■

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[3] *Ibid.*

[4] *Ibid* at s 28.1(1).

[5] Ontario, "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy the G7" (last visited 30 June 2025), online (pdf): <ontario.ca/files/2025-06/mem-energy-for-generations-en-2025-06-20.pdf>.

[6] *Ibid* at 6.

[7] *Ibid* at 22.

REAL TIME PRICING OF ELECTRICITY FOR HOUSEHOLDS: AN INTERNATIONAL SURVEY

*Ahmad Faruqui, Ph.D.**

ABSTRACT

This paper reviews the international experience with real-time pricing of electricity for households. In the economics literature, real time pricing is regarded as the "best" form of pricing from the vantage point of maximizing economic efficiency. However, from a customer perspective, it has not found much traction in the U.S. or Canada. The widest deployment has been in Europe, where it has been offered by competitive retailers, but even there it is a relatively recent phenomenon. It is being tested by a network in Australia. In the paper, I compare the impact of real time pricing on peak demand with simpler forms of time-varying rates, such as critical-peak pricing and time-of-use rates.

WHAT IS REAL TIME PRICING?

In wholesale markets, electricity prices change from minute to minute in "real time," giving rise to the term: real time pricing ("RTP"). Even where wholesale markets don't exist, RTP can be defined by equating it with variations in the marginal cost of energy, which is sometimes measured by "system lambda" in production costing models. Often, real-time prices ("RTP") or marginal costs also vary locationally, thus giving rise to the term, location-specific, marginal cost pricing. When these wholesale prices are passed through to retail customers, they are also called RTP. Sometimes, they are simply called highly dynamic prices.

WHERE IS RTP BEING OFFERED?

In Canada, RTP was offered in two provinces, Alberta and Ontario. But it was difficult to implement RTP without smart meters, even if the load shape for the entire system or for the residential class was used. Once smart meters were introduced, it was technically possible for consumers to sign onto RTP. But it is hard to find any evidence that they did. In Ontario, the overwhelming majority preferred to buy electricity on the Regulated Price Plan ("RPP"), which was a three-period time-of-use ("TOU") rate. Recently, a fourth period has been introduced which offers a much lower rate than the off-peak period. This is designed to meet the needs of electric vehicle ("EV") drivers and those customers who work during the night shift. About 90 per cent of customers are on the standard TOU rate, 10 per cent are on the inclining block rate (which pre-dates the TOU rate), and less than 1 per cent are on four-period TOU rate.

In Alberta, the Regulated Rate Option ("RRO") used to be the standard rate for residential customers who did not want to switch to a retail energy provider. In January 2025, it was replaced with the Rate of Last Resort ("RoLR").

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The RRO was a flat rate that fluctuated from month to month based on conditions in the wholesale market. RoLR is a fixed rate from January 1, 2025, until December 31, 2026, and it can only go up or down by a maximum of 10 per cent at the end of each 2-year term. It is set every two years to avoid sudden spikes in pricing for customers.[1]

In the U.S., RTP has only been offered to residential customers in one state: Illinois. Two investor-owned utilities are offering it: Commonwealth Edison ("ComEd") and Ameren Illinois. In 2007, Commonwealth Edison began to offer RTP to residential customers and later, it was followed by Ameren Illinois.

The RTP signal only applies to energy sales. Transmission and distribution costs continue to be recovered through a traditional rate design.

In Europe, RTP is being offered in at least five countries: Denmark, Netherlands, Norway, Spain and the United Kingdom. In Denmark, Netherlands, Norway and the United Kingdom, it is offered by retail providers of electricity.[2]

In Spain, it was the default tariff from October 2015 to December 2023. It was discontinued as the default tariff because customers complained.

In France, RTP used to be offered prior to the 2021–22 energy crisis. Currently, it is not being offered. In its place, retailers offer Critical Peak Pricing ("CPP").

In Australia, a form of RTP called Dynamic Operating Envelops[3] is being tested in a pilot called Project Edith.[4] It is operated by Ausgrid[5], a network that serves New South Wales, and Reposit Power. It is only offered to customers that have installed solar panels and applies to imports from and exports to the grid. Prices are set for every five-minute interval and can be positive or negative (rewards).

HOW MANY CUSTOMERS HAVE ADOPTED RTP?

In Illinois, less than 2 per cent of customers have signed up for RTP. That's despite the findings of one study, which found that an overwhelming proportion of customers would have lower bills if they got on the RTP rate as compared to non-time-based rates.[6] Specifically, the study concluded:

"Using 12 months of energy-use data from smart meters, anonymized by zip code, Environmental Defense Fund ("EDF") and Citizens Utility Board ("CUB") calculated what the 2016 electricity bills of 300,000 ComEd residential customers would have been under the Hourly Pricing program. The study found:

- 97 per cent of the households studied would have saved money, comprising total savings of $29.8 million.
- The average ComEd customer would have saved $86.63 for the year, or 13.2 per cent less than they paid under traditional billing.
- The top 5 per cent of savers would have cut their bills by an average of $104 a year, or 31 per cent.
- Of the customers who would have lost money (roughly 3 per cent of the sample), the median increase in bills was an estimated total of $6.23 for the year.

[1] Alberta Utilities Commission, "Electricity rates: The AUC ensures regulated customers receive safe and reliable service at just and reasonable rates" (last visited 14 July 2025), online: <auc.ab.ca/current-electricity-rates-and-terms-and-conditions>.

[2] Nordic Energy Research, "Evaluation of Nordic Electricity Retail Markets" (12 April 2024), online: <nordicenergy.org/publications/evaluation-of-nordic-electricity-retail-markets>.

[3] Enea, "Project Edith: Project Overview Report" (July 2022), online (pdf): <ausgrid.com.au/-/media/Documents/Reports-and-Research/Project-Edith/Project-Edith-2022.pdf?rev=42030a3921274632910a9fbf6ff1e2ac>.

[4] Renew Economy, "Project that calmed network fears about rooftop solar wins innovation award" (26 September 2023), online: <reneweconomy.com.au/project-that-calmed-network-fears-about-rooftop-solar-wins-innovation-award>.

[5] Ausgrid, "Making electricity accessible for all" (last visited 14 July 2025), online: <ausgrid.com.au>.

[6] Environmental Defense Fund, "Data reveals real-time electricity pricing would help nearly all ComEd customers save money" (14 November 2017) online (blog): <blogs.edf.org/energyexchange/2017/11/14/data-reveals-real-time-electricity-pricing-would-help-nearly-all-comed-customers-save-money>.

- There are no significant differences between the effects of real-time pricing on the bills of customers who have low-incomes and other customers.

"In sum, the vast majority of ComEd customers would have financially benefitted in 2016 from participating in the Hourly Pricing program."

Despite this positive finding, why have only 1–2 per cent of customers signed up to receive service on RTP? No one has an answer to this question. Surveys of those customers who are on RTP show that most of them have figured out that there are some hours in the day that are more expensive and other hours are less expensive. They respond to RTP rates as if they were on a time-of-day ("TOD") rate, which defeats the purpose of sending hourly pricing signals. In other words, the same results would have been obtained if the customer had been a much simpler rate design. Interestingly, relatively few customers in Illinois are even on a simple TOD rate.

In Denmark there are approximately 40 retailers of electricity. They provide more than 143 pricing products to customers including flat prices, spot prices, and spot prices with a cap. Some 70 per cent of the customers have chosen some form of RTP. But RTP only applies to the energy portion of the bill. Most distribution utilities offer TOD rates. Distribution costs account for a third of the customer bill while taxes account for a similar percentage.

The typical Danish bill has five elements:

- Cost of electric energy. Most customers get the hourly price defined by the day-ahead spot market, but consumers can also choose to get a fixed price or to get the hourly price with a price cap.

- Cost of distribution. These tariffs typically feature time-of-day variation. Typical tariffs have three levels depending on the season. Winter is the peak season. Here's an example from Radius, which operates the distribution grid in the Copenhagen area.[7]

    - Summer: Off-peak (9pm-6am) 12.15øre/kWh =1.9c/kWh, Normal (6am-7pm) 18.22øre/kWh=2.8c/kWh, Peak (5-9pm) 47.38øre/kWh=7.2c/kWh. The peak to off-peak price ratio is 3.9:1.

    - Winter: Off-peak (9pm-6am) 12.15øre/kWh =1.9c/kWh, Normal (6am-7pm) 36.45øre/kWh=6.5c/kWh, Peak (5-9pm) 109.34øre/kWh=16.8c/kWh. The peak to off-peak price ratio is 9:1.

    - On top of the volumetric charge, Radius has a fixed charge of 537kr=83$ per year.

- Cost of transmission. In 2023, it was a flat rate of 11.2øre/kWh.

- Taxes. There is a fiscal energy tax (69.7øre/kWh=10.7c/kWh in 2023, which is planned to decrease gradually to 56.10øre/kWh=8.6c/kWh by 2030) and a value-added tax (VAT)which amounts to (25% of the total bill including the tax).

- Subscription charge. Distribution companies add a charge for the meter (around $100/year), while retailers may also, in some cases, add a fixed charge depending on the customer's tariff plan (typically around $4–6 /month).

Customers pay the bill to the retail company who then subsequently pays the Distribution System Operator and the Transmission System Operator.

In Norway, about 75 per cent of all customers are on RTP but the prices are not actively communicated to customers. There is no default price for electricity. Distribution utilities set prices for grid services and customers pay a bill for electricity and a bill for the grid, but some retailers combine the two prices into a single price.

In Spain, RTP began to be offered as the default tariff to customers who did not switch to a retailer from October 2015 onwards. Approximately half of the customers were

[7] Radius, "Tariffs and network subscriptions" (14 July 2025), online: <radiuselnet.dk/elnetkunder/tariffer-og-netabonnement>. One Danish Krone equals 0.16 US dollars.

on the default tariff. However, prompted by concerns about price volatility, RTP is no longer the default tariff. In January 1, 2024, RTP was replaced by a three-period TOD rate whose prices change daily, since they are indexed to the wholesale market prices.[8]

In the United Kingdom, Octopus Energy[9] offers RTP. Their product offering is called the Agile Octopus. It is called an "innovative beta smart tariff." According to information on the company's website, it helps "bring cheaper and greener power to all our customers but is directly impacted by wholesale market volatility." Agile features half-hourly prices that can spike up to 100 p/kWh at any time, although on average a typical household in the winter of 2022/23 would have paid around 35 p/kWh average.[10] In US currency, that would represent a peak price of $1.30/kWh, compared to an average tariff of 45.5 cents/kWh. The prices are set between 4 and 8 pm on the previous day and reflect wholesale market prices.

The beta smart tariff is being marketed to customers who are in a position to shift large amounts of their energy away from the peak periods by using smart technologies like solar and batteries, EVs and thermal energy storage. It features a price cap that ensures that prices won't rise above 100 p/kWh, or US $1.38/kWh.

The figure below shows the type of price variation associated with the Agile tariff.[11]

Figure 1: Real-time price variation in the UK[12]

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[8] Red Eléctrica, "Voluntary price for the small consumer (PVPC)" (last visited 14 July 2025), online: <redeia.com/es/actividades/operacion-del-sistema-electrico/precio-voluntario-pequeno-consumidor-pvpc#:~:text=Es%20el%20nuevo%20sistema%20de%20fijación%20del%20precio,a%20la%20anterior%20Tarifa%20de%20Último%20Recurso%20%28TUR%29>.

[9] Octopusenergy, "Join the UK's most popular energy supplier: Enter your postcode to get a quote" (last visited 17 July 2025), online: <octopus.energy>.

[10] Octopusenergy, "The 100% green electricity tariff with Plunge Pricing" (last visited 14 July 2025), online: <octopus.energy/smart/agile>.

[11] Octopusenergy, "Dashboard" (last visited 17 July 2025), online: <agile.octopushome.net/dashboard>.

[12] *Ibid*.

WHAT HAVE BEEN THE RESULTS?

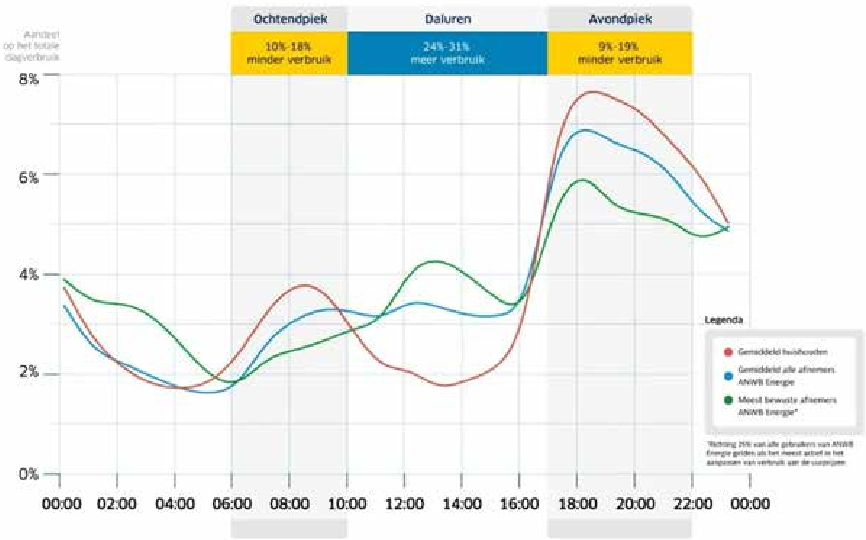
In Illinois, a price elasticity of -0.05 has been estimated for RTP.

In Denmark, no studies have been published that quantify customer response to RTP. It's also unclear how much money customers save through RTP. Many of them defaulted onto RTP when they switched to retail suppliers.

In Holland, according to ANWB Energie, customers on RTP have saved an average of more than 200 euros per year. For households with an EV, the savings have exceeded 1,000 euros per year.[13]

The figure below shows the changes that occur in load shapes with RTP. It shows that consumers shift their power consumption away from the peak hours to the off-peak hours.

Figure 2: Load shifting in response to RTP in Holland[14]



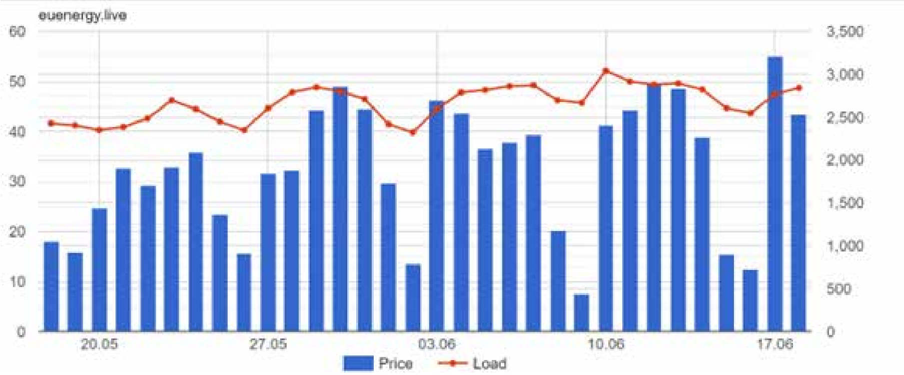
Customer bill savings are relative to what they would pay based on flat rates, not TOD rates. In Norway, which has an abundance of hydro power, there is some variation in hourly prices but not as much as one might see elsewhere, as seen in the figure below.[15] The price variation is in line with variations between peak and off-peak TOD rates that exist in many countries. Thus, it is not surprising that hourly load does not vary much in response to hourly prices.

[13] Solar Storage Mazazine, "ANWB: more conscious use of energy through dynamic contracts with hourly prices" (26 October 2023), online: <solarmagazine.nl/nieuws-zonne-energie/i35666/anwb-bewuster-gebruik-energie-door-dynamische-contracten-met-uurprijzen?trk=article-ssr-frontend-pulse_publishing-image-block>.

[14] *Ibid*.

[15] Euenergy, "Electricity prices NO Norway" (last visited 17 July 2025), online: <euenergy.live/country.php?a2=NO1> .

Figure 3: Price variation ($/MWh) and load (MW) in Norway[16]



The chart above shows how load varies with prices, the left vertical axis represents price in $/MWh, the right vertical axis load in MW and the horizontal axis shows time across months.

Econometric studies have found really low-price elasticities with RTP in the -0.01 to -0.07 range. However, on the coldest days, there has been no price elasticity. Research has shown that the average household does not respond to RTP. But certain segments in the general population do respond to RTP, including those who check the hourly prices frequently on apps or those with electric vehicles.

A field experiment with peak-time rebates[17] was carried out in Norway to measure customer response to the rebates, which were provided to customers on RTP.[18] There were two sets of results, one for the 2-hour peak period and one for the 13-hour peak period, as shown below. The figure below shows the reduction in peak demand that took place as the ratio of peak to off-peak prices was dialed up.

Figure 4: The arc of price response in Norway (2 and 13 hours)[19]

[16] *Ibid.*

[17] Peak-time rebates (PTR) have been successfully deployed in Maryland by BGE, Delmarva Power and Pepco. All customers are defaulted onto PTR. More than 80 per cent of the customers actively engage with PTR and reduce their demand during critical system hours and are compensated at $1.25/kWh.

[18] Matthias Hofmann & Karen Byskov Lindberg, *Evidence of households' demand flexibility in response to variable electricity prices – Results from a comprehensive field experiment in Norway*, Energy Policy, 2024.

[19] Ahmad Faruqui, "Flexible Demand in Norway: A conversation with Matthias Hofmann" (last visited 26 July 2025), online: <energycentral.com/energy-management/post/flexible-demand-norway-conversation-matthias-hofmann-ucF8AEYtaQpYfVS>.

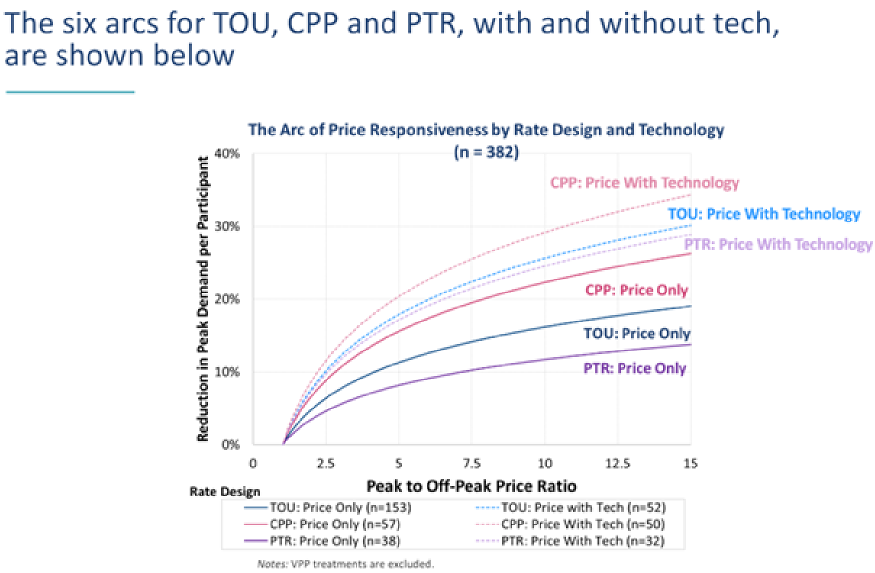
It's useful to benchmark these results against those from other experiments and full-scale deployment. As of the time of writing, some 400 time-varying rates have been implemented across the globe and their impacts on peak demand have been reported. A meta-analysis of this data is contained in *Arcturus*.[20] The meta-analysis yields six "arcs of price response" that (a) plot the percent reduction in peak demand against the ratio of peak to off-peak rates and (b) that differ based on whether (i) the relationship being measured is based only on the price signal or (ii) is paired with an enabling technology and (iii) whether it pertains to TOU, critical-peak pricing ("CPP")or Peak Time Rebate ("PTR").[21]

In general, the higher the ratio between peak and off-peak prices, the higher the price response. However, the relationship between price response and the price ratio is not linear, it's curvilinear. Price response rises with the price ratio but at a diminishing rate.

Enabling technology such as a smart thermostat boosts price response. Finally, price response also depends on the type of price signal being conveyed to the customer — i.e., it varies by TOU, CPP and PTR.

When compared with the meta-analysis in *Arcturus* shown above, the impacts from Norway are a lot lower, as shown in the figure below. The green dots come from analyzing the data from 400 deployments of time-varying rates ("TVRs") across the globe in Figure 5.

Figure 5: The arcs of price response for various time-varying rates[22]

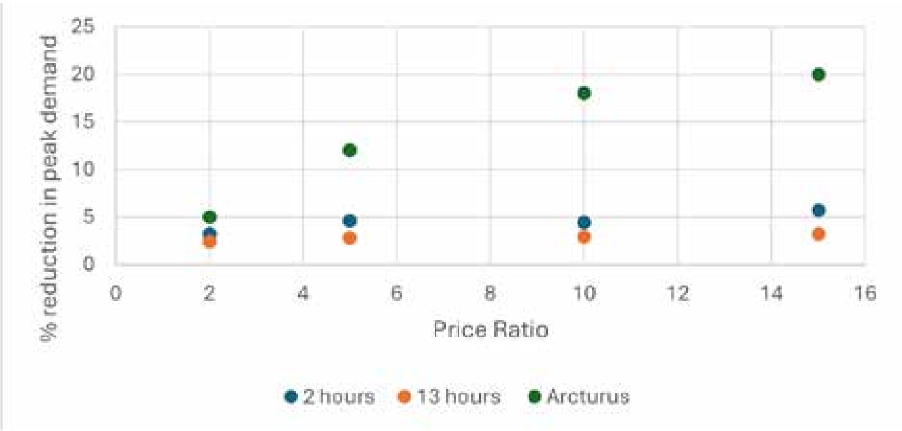


[20] Sanem Sergici et al, "DO Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0" (2023) Brattle, online (pdf): <brattle.com/wp-content/uploads/2023/02/Do-Customers-Respond-to-Time-Varying-Rates-A-Preview-of-Arcturus-3.0.pdf>.

[21] Customers who reduce their load during critical time periods are offered a rebate under a PTR program, as opposed to being exposed to a higher price under a CPP rate.

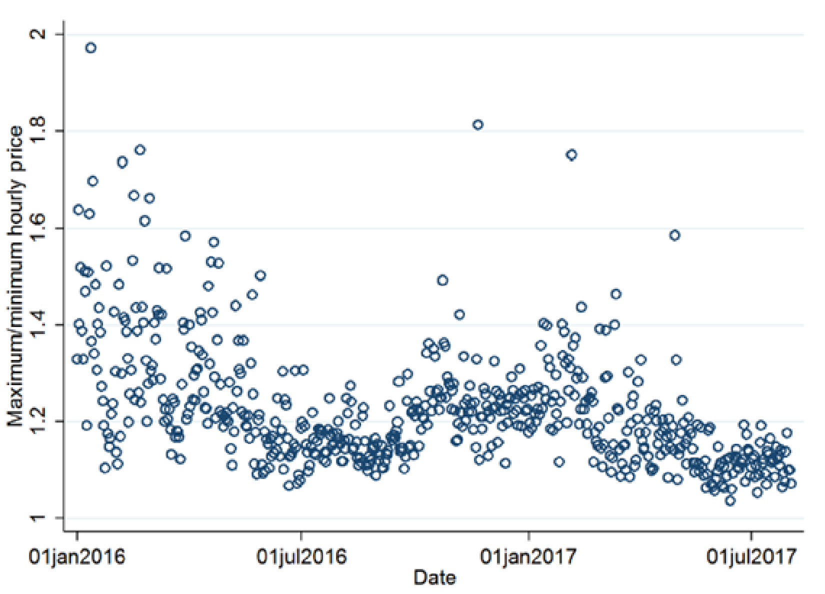
[22] *Supra* note 20 at 9.

Figure 6: The arc of price response Norway (2 and 13 hours) and Arcturus[23]



In Spain, between 2015 and 2023, RTP was the default rate, as noted earlier. Roughly half of the households are on it but 77 per cent of them were not even aware of being on RTP. Most RTP customers didn't know what price they were paying. The ratio of the highest to the lowest prices during the day is shown in the figure below. It does not exceed 2:1. Price variation across the sample period is shown in Figure 8.

Figure 7: Ratio between the highest and lowest price each day in Spain[24]



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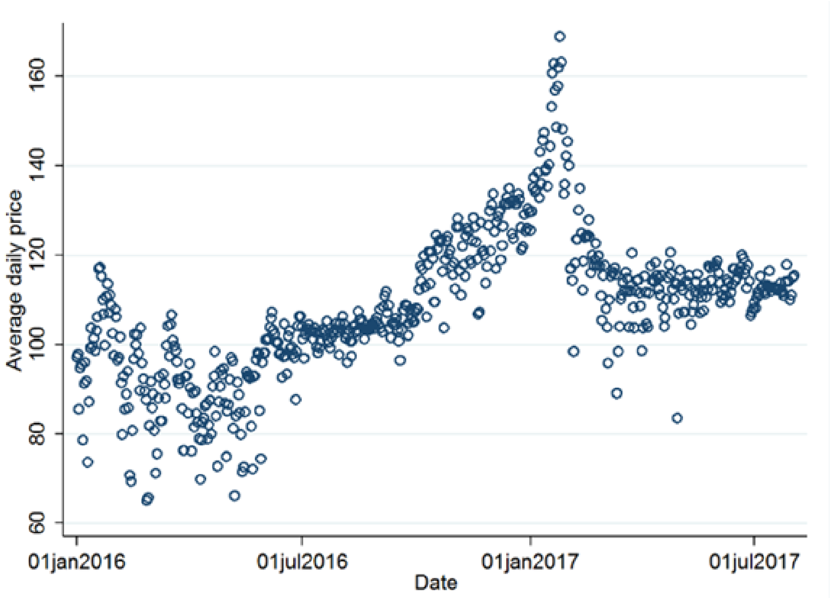
[23] *Supra* note 21.

[24] Natalia Fabra et al, "Estimating the Elasticity to Real Time Pricing: Evidence from the Spanish Electricity Market" (2021) 111:1 AEA Papers and Proceedings 425; Natalia Fabra, "Real Time Pricing for Everyone: Evidence from the Spanish Electricity Market" (2019), online (pdf): <mreguant.github.io/em-course/materials/day4/slides_rtp.pdf>.

Figure 8: Average daily prices over the same period in Spain (Euro/MWh)[25]



Econometric analysis of load shape and price data for 4 million households has failed to measure any statistically significant value for the price elasticity of demand.[26]

HOW MUCH ADDITIONAL PEAK LOAD REDUCTION STEMS FROM RTP VERSUS TOD PRICING?

The answer depends on how much RTP varies across the hours of the year and whether, during the peak hours, RTP values are higher than TOU and CPP prices. It's likely RTP prices will be higher than TOU peak period prices since the latter are averaged over 600–1,000 hours during the peaking season. However, RTP prices and CPP prices might be quite similar in magnitude since CPP prices focus on the top 50–100 hours of the peaking season. Thus, one should not expect to get much incremental load response from RTP over and above a cost-based CPP rate.

To get the highest response from RTP, three things need to occur.

1. Customers need to be fully informed about the hourly prices, preferably via an app on their phone and on a web portal.

2. They must be educated about the benefits of RTP and be internally motivated to spend time checking the app.

3. They must learn to program their end use loads to automatically respond to prices, a process referred to as "getting prices-to-devices". This can be done with smart thermostats and EV chargers but just because something can be done does not mean that it will be done. The same concepts apply to the CPP rate.

[25] *Ibid.*

[26] Natalia Fabra et al, "Estimating the Elasticity to Real Time Pricing: Evidence from the Spanish Electricity Market" (2021) 111:1 AEA Papers and Proceedings 425; Natalia Fabra, "Real_Time Pricing for Everyone: Evidence from the Spanish Electricity Market" (2019), online (pdf): <mreguant.github.io/em-course/materials/day4/slides_rtp.pdf>.

It is worth mentioning that Oklahoma Gas & Electric ("OGE") in Oklahoma has implemented a more advanced concept of CPP known as variable-peak pricing or VPP. VPP should not be confused with virtual power plants.[27] VPP features four levels of CPP, based on system conditions. OGE sends the prices directly to the customer's thermostat, thereby implementing the variable prices-to-devices concept but much simpler than RTP. The customer can, if they wish, program the thermostat such that its temperature settings vary with the prices but it is not required to do so. In addition, it is worth noting that OGE does not control the customer's thermostat.

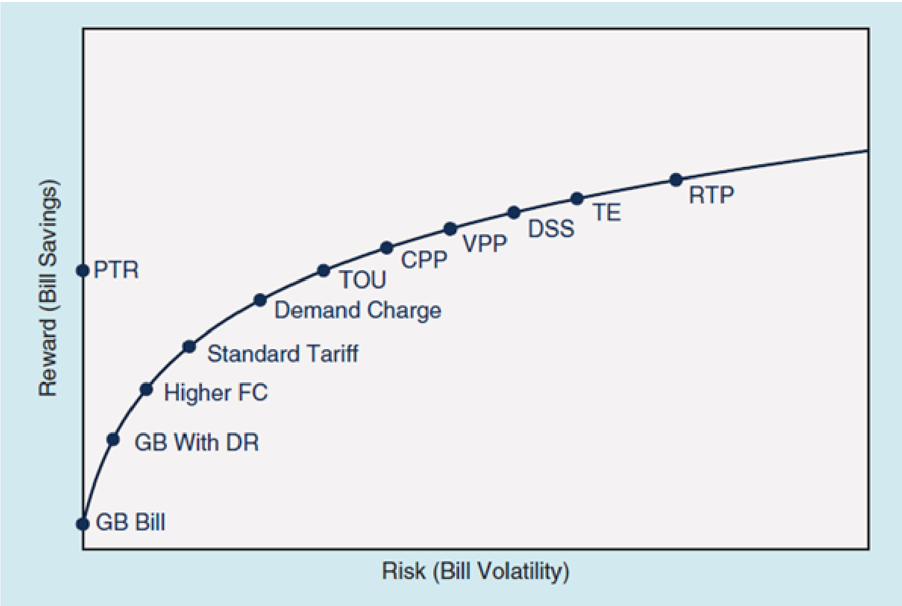
The program is opt-in. It has signed up 10 per cent of the household population. Bill savings are substantial and so are the reductions in peak demand.

CPP sign-up rates are much lower. In California, estimated take-up rates are approximately 2% of household customers.[28]

SHOULD UTILITIES OFFER CUSTOMERS A CHOICE OF RATE DESIGNS?

In general, it is a good idea to offer a choice of rates to customers.[29] No two customers are alike. There are demographic and psychographic reasons for why some are happy with flat rates, some with time-of-day rates and some with dynamic pricing rates. Each rate being offered should be cost-based. When these rates are plotted in the risk-reward space, they create an efficient pricing frontier, as shown in Figure 9.

Figure 9: Risk-reward trade-offs along the efficient pricing frontier[30]



[27] OGE Energy Corp., "Pricing Options" (2025) online: <oge.com/wps/portal/ord/residential/pricing-options/smart-hours>.

[28] Based on conversations with staff at one of the three investor-owned utilities.

[29] Ahmad Faruqui & Cecile Bourbonnais, "The Tariffs of Tomorrow: Innovations in Rate Designs" Institute of Electrical and Electronics Engineers, online: <ieeexplore.ieee.org/document/9069846>.

[30] Author's conceptualization.

The terms are defined in Table 1 below.

Table 1: Rate design options[31]

Rate Design	Definition
GB	Customers pay the same bill every month, regardless of usage.
Fate rate	A uniform US$/kWh rate is applied to all usage.
Demand charge	Customers are charged based on peak electricity consumption, typically over a span of 15, 30, or 60 min.
TOU	The day is divided into time periods, which define peak and off-peak hours. Prices are higher during the peak-period hours to reflect the higher cost of supplying energy during that period.
CPP	Customers pay higher prices during critical events when system costs are highest or the power grid is severely stressed.
IBR	Customers are charged a higher rate for each incremental block of consumption.
PTR	Customers are paid for load reductions on critical days, estimated relative to a forecast of what they would have otherwise consumed (their baseline)
VPP	During predefined peak periods, customers pay a rate that varies by utility to reflect the actual cost of electricity
DSS	Customers subscribe to a kilowatt demand level based on the size of their connected load. If they exceed their subscribed level, they must reduce their demand to restore electrical service.
TE	Customers subscribe to a baseline load shape based on their typical usage patterns and then buy or sell deviations from their baseline.
RTP	Customers pay prices that vary by the hour to reflect the actual cost of electricity.
GB: guaranteed bill; IBR: inclining block rate; PTR: peak-time rebates; DSS: demand subscription service; TE: transactive energy	

CONCLUSIONS

RTP deployment has not made much progress in the US even though simpler forms of time-varying rates are gaining traction in much of the globe, primarily static time-of-use rates but also dynamic rate designs such as critical-peak pricing rates and peak-time rebates.

RTP deployment is proceeding at a much more rapid pace in Europe, primarily due to the presence of retail competition. However, at the time of writing, there is no empirical evidence to suggest that RTP is generating greater reductions in peak demand or in the amount of load shifted from peak to off-peak periods than much simpler forms of time-varying rates or that it is bringing about greater bill savings for customers. ■

[31] Author's conceptualization.

TODAY'S RATEMAKING CHALLENGES FOR UTILITY REGULATORS

*Kenneth W. Costello**

INTRODUCTION

Ratemaking consists of three distinct components: revenue requirements, cost allocation, and rate design. Ratemaking therefore determines how much revenue that utilities should collect from customers, from whom, and how. All of these parts have undergone scrutiny in recent years. For example, more jurisdictions in North America have switched from historical test years to future test years[1] in setting new utility rates and have integrated some form of performance-based regulation ("PBR") into their ratemaking portfolio.[2]

Ratemaking is a primary regulatory function that touches all aspects of utility operations. It also has wide-ranging consequences for the different objectives that utility regulators pursue either because of legislative statutes or self-imposed directives. In pursuing these objectives, regulators (at least in theory) strive to promote the public interest.[3] Good ratemaking is tough to achieve, requiring both sound analytics and judgment by regulators.

Throughout most of its history, utility regulation placed primary emphasis on ratemaking to assure the financial viability of utilities and achieve

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[1] Future test years rely on forecasts that are susceptible to error and contain certain costs and sales components inherently difficult to predict. Another problem is that utilities would have incentives to present biased forecasts that are not always easy for regulatory staff and interveners to uncover. A regulator would be therefore presumptuous to assume that forecasted costs and sales are more accurate than modified historical test year data accounting for "known and measurable" changes. In fact, several US regulators have taken this view, rationalizing that an historical test year is more in line with their mandate to set "just and reasonable" rates. See Maryluz Hoyos E., "Future Test Year: MOST Policy Initiative Science Note", March 19, 2025; Ken Costello, "Future Test Years: Challenges Posed for State Utility Commissioners" Briefing Paper No. 13-08, July 2013.

[2] New public policy goals and objectives as well as new technologies have triggered much of the recent interest in PBR. Some observers have expressed concern that prevailing incentives steer utilities toward specific actions that clash with those goals and objectives. For example, utilities may be incentivized to make excessive capital expenditures when lower-cost alternatives (e.g., purchased power) are available. Utilities may also have inadequate incentives or even disincentives to advance new technologies, such as clean energy, that would benefit customers and society. See Advanced Energy Economy, "Performance-Based Regulation: Aligning Utility Incentives with Policy Objectives and Customer Benefits," (5 June 2018), online (pdf): <evtransportationalliance.org/wp-content/uploads/2021/11/2018-Performance-Based-Regulation-by-staff-of-Advanced-Energy-Economy-AEE.pdf>; Cara Goldenberg and Kaja Rebane, "Building a Brighter Future by Changing Utility Incentives," (12 July 2024), online: <rmi.org/building-a-brighter-future-by-changing-utility-incentives>.

[3] Long-term customer welfare, arguably, is one of the least represented interests in the regulatory and political arena. Utilities look out for their financial interests, and consumer advocates tend to take a short-term view. A gap in adequate representation for the long-term interests of customers becomes evident. One may then be able to assert that the main job of regulators is to fill that void by protecting customers from the monopoly position of utilities. Thus, according to this premise, the public interest is aligned with long-term customer welfare. This has become more difficult as regulators have faced heightened pressure in recent years to appease other stakeholders entering the regulatory arena and to comply with political mandates and self-imposed directives. The above perception of the public interest is only one of many; others include the common good, environmental sustainability, utility-service affordability to all customers, due process available to all stakeholders in the regulatory process, fairness in outcomes.

fairness for customers.[4] Good ratemaking therefore protects customers from incompetent utility management and utility shareholders from capricious denial of cost recovery. Financial viability typically requires that a utility has a reasonable opportunity to earn a fair return.[5]

A mantra often heard in regulation is "just and reasonable" rates, which translates into an opportunity for a utility to recover the reasonable and prudent costs incurred to provide public utility service. But, as discussed below, ratemaking has had to satisfy additional objectives recently brought on by new public policies, technological changes, and economic developments, making setting "just and reasonable" rates yet a harder task for regulators.[6] Setting such rates requires regulators to reexamine all three parts of ratemaking: revenue requirements, cost allocation and rate design.

One widely accepted definition of the public interest relates to the common well-being or general welfare. It is central to policy debates, politics, democracy, and the purpose of government itself.[7]

This definition of the public interest for utility ratemaking measures the composite indicator of the public well-being that combines the individual effects of an action on direct stakeholders, like utility customers and shareholders, and other societal interests (e.g., the environment).[8] Another definition relates the public interest to the stakeholders' collective consent to a regulatory action. For each definition, the aggregate interest of society matters most.[9]

While few would dispute that advancing the public interest is an admirable goal, there is little consensus on how to define and achieve it. Many utility regulators associate the public interest with meeting minimum fairness requirements. For example, fair treatment of utility investors and protection of core customers.[10] Even though fairness is a subjective term, regulators must establish bounds and

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[4] Economists sometimes lose sight of the fact that the main goal of regulation is not merely to promote *economic efficiency*: regulation originated and developed prior to the ideas of economic efficiency and the principles of welfare economics. Most enabling legislation mandates just and reasonable rates, not efficient rates per se. Throughout the history of US utility regulation, for example, "fairness" has been a major consideration in ratemaking. Reasons for why regulators would not maximize economic welfare (i.e., take the most efficient actions to correct market failures), which, incidentally, some economists associate with the public interest, include: (1) individuals have, besides economic objectives, non-economic objectives (e.g., due process) affected by regulation but not accounted for by welfare economics; and (2) political institutions and administrative processes influence regulatory actions. These two reasons can explain why a rational regulator would be unlikely to seek to maximize conventional measures of economic welfare (i.e., the sum of consumer and producer surplus).

[5] Legally, utility regulators in the U.S. must set reasonable rates that allow a prudent utility to operate successfully, maintain its financial integrity, attract capital, and compensate its investors in line with actual risks. [The US Supreme Court outlined these conditions in its order for *Federal Power Commission v Hope Natural Gas Co.* (1944), 320 US 591, 605 (US SC)]. The emphasis is on the results reached rather than the methods used or means of getting to those results. Another constraint is regulators setting rates based on cost of service, which is the second side to "just and reasonable rates"; regulators also face constrains from legislatures in setting rates; for example, in some states regulators must set rates that conform with utility incentives to promote energy efficiency and clean energy. See *Supra* note 2.

[6] Regulators have had to revisit their interpretation of "just and reasonable" rates and redefine the public interest. They have grappled with advancing additional objectives, either mandated by the outside or self-imposed.

[7] Paul M. Hogan, "Utilities, the State, and the Public Interest," (1958) 10:2 UC LJ 176 online (pdf): <repository.uclawsf.edu/cgi/viewcontent.cgi?article=1579&context=hastings_law_journal>; Eric Filipink, "Serving the "Public Interest"– Traditional vs Expansive Utility Regulation." (2009) Harrison Institute for Public Law Georgetown Law, NRRI 10-02; and Johny Ghasemi, "Importance of Public Interest in Developing Policies and Governing Institutions," (2023) 11:2 J of Political Sciences & Pub Affairs, online (pdf): <longdom.org/open-access/importance-of-public-interest-in-developing-policies-and-governing-institutions.pdf>.

[8] The fall 2007 issue of *Daedalus* (Journal of the American Academy of Arts & Sciences).

[9] *Supra* note 7 and *ibid*. Defining the collective interest of society or what some analysts call the common good is to some extent a value judgment. Each individual or group has unique preferences, available information and position in society. Even if everyone can agree on objectives, they are likely to disagree on the relative importance of those objectives.

[10] The rationale is that utility markets exhibit what economists call "market failure" that requires regulators to protect customers (especially vulnerable customers like households) from the monopoly power of utilities. Regulators also know that utilities need to be financially viable in attracting capital and maintaining their system to provide reliable service to their customers.

rules to distinguish between fair and unfair actions.[11]

When ratemaking goes sour, bad outcomes are inevitable. Faulty ratemaking[12] can lead to undesirable consequences like undue discrimination, inequity, poor incentives for innovation, uneconomic bypass,[13] and financially stressed utilities. As competition increases, for example, faulty ratemaking can lead to consumers choosing providers that have lower prices but have higher costs. A regulated utility with an unregulated affiliate might have an incentive to subsidize the affiliate by shifting some of the affiliate's costs to its core customers (e.g., residential electricity customers). As stated by one late prominent economist: "Cross-subsidy becomes a pertinent possibility when a multiproduct firm sells some products for which there are competing suppliers but enjoys effective monopoly in the sale of other(s) of the outputs it sells."[14]

The following sections argue that changes in the electric industry will require regulators to reexamine their current and sometimes long-held ratemaking practices. This is especially pertinent in view of the new objectives that regulators must address. These objectives, in addition to the old objectives of utility financial viability and reliable/resilient utility service, include service affordability, the accommodation and even the subsidization of new technologies that compete with utilities' core business, decarbonization of utilities' generation portfolio, and the subsidization of utilities' customers to use less electricity. No other private business comes to mind in which society forces firms to tackle such a wide range of social issues. While regulators in the past have adapted their ratemaking decisions to new economic, political and technological realities, they have taken a cautious position that lies within one of Bonbright's principles for ratemaking, *gradualism*.[15]

TRADITIONAL RATEMAKING

The transformation of the electric industry calls into question whether traditional ratemaking[16] can accommodate the public interest by establishing just and reasonable rates.[17] Back in

[11] Because fairness is elusive and enters the domain of philosophy, it becomes difficult to know what is fair and to assert that one policy is fairer than another is. Since stakeholders' perceptions of fairness differ, regulators face the difficult task of balancing them to decide what is in the public interest. In the end, it is regulators that define fairness. Instead of evaluating actions and policies based on fairness, regulators might find it easier to eliminate those policies that are clearly unfair before determining whether a particular policy passes a "fairness" test.

[12] One example of faulty ratemaking is political expediency where the regulator attempts to appease influential industrial groups by requiring utilities to offer them subsidized rates paid for by the other utility customers.

[13] Bypass is uneconomic because a customer turns to a non-utility provider for one or more services when the alternative provider (e.g., retail marketer) has higher total costs but lower prices. Society incurs higher costs in meeting the demands of a customer. Probably the major cause of uneconomic bypass is the inability of the utility to lower its rates below fully-allocated embedded costs, which under certain circumstances (e.g., a utility has a high level of surplus capacity) could far exceed its marginal cost. Another cause of uneconomic bypass is faulty rate design, specifically an excessive usage or volumetric charge, where certain customers within a group (e.g., high-usage customers within the industrial class) pay more than the utility's cost of serving them, and perhaps at a higher rate than the price of competitive providers.

[14] William J. Baumol, *Superfairness: Applications and Theory* (Cambridge: The MIT Press, 1988), 112.

[15] James C. Bonbright et al., *Principles of Public Utility Rates*, 2nd Edition, Public Utilities Reports, Inc., (Columbia University Press, 1988), the first edition, authored solely by Bonbright, was published in 1961.

[16] Traditional ratemaking, sometimes called rate-of-return ("ROR") regulation, refers to the application of cost-of-service principles for setting rates that determine the utility's authorized rate of return. Features include: (a) new rates remains fixed until the regulator approves new rates after a comprehensive rate case; (b) the utility has a reasonable opportunity (but no guarantee) to earn its authorized rate of return; (c) the balancing of utility customer and shareholder interests is an overriding goal; (d) the selected test year matches revenues with costs over the first year of new rates; (e) the utility's actual rate of return between rate cases deviates from the authorized return when actual sales and costs differ from their test-year levels; and (f) regulatory lag can either benefit or harm utilities, depending on whether average cost is decreasing or increasing. [Alfred E. Kahn, "The Economics of Regulation" (1971) 2:2 The Bell J of Econ and Management Science 678 [*Kahn*]. Added features aligned with real-world applications are limited use of cost trackers or riders for utilities to recover specific costs outside of a general rate case and a rate design that incorporates most of a utility's fixed costs into the volumetric or usage charge. See Ken Costello, "How Should Regulators View Cost Trackers?" (2009) 22:10 The Electricity J 20 [*Costello*]; and Scott P. Burger et al., "The Efficiency and Distributional Effects of Alternative Residential Rate Design" (2020) 44:1 The Energy J 199 [*Burger et al.*].

[17] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, (Edison Electric Institute, 2013), online (pdf): <ourenergypolicy.org/wp-content/uploads/2013/09/disruptivechallenges-1.pdf>.

the 1990s when the electric industry underwent major restructuring, many experts believed that traditional ratemaking would gradually end its long history.[18] These experts thought that price caps (a form of multi-year rate plans) or other more "innovative" ratemaking mechanisms would replace it, but that did not happen. One reason was that most state utility regulators were unwilling to renounce traditional ratemaking, although they did modify it around the edges.[19] From their history, regulators tend to favor a gradualist approach to ratemaking, rather than a radical one that unravels a long-held rate mechanism.

Four factors explain the popularity of traditional ratemaking in the US over time: (1) its perceived fairness to all parties under normal market and business conditions; (2) its ease of understanding; (3) the public's general acceptance of average-cost approaches that relate rates to costs, even if not the correct costs from an economic-efficiency perspective; (4) fairness in due process for the different stakeholders; and (5) its attempt to achieve a balanced outcome that avoids, in most circumstances, extreme discontent by individual stakeholders. Regulators attempt to balance the rights of utilities and their customers by considering three major factors: (1) *legal controls* — for example, utilities have the constitutional right to be given a reasonable opportunity to be financially viable, and customers have a right to just and reasonable prices; (2) *the regulator's perception of fairness*; and (3) *compatibility with a broader interest*. Regulators strive to reach balanced decisions with the ultimate objective of promoting the general good; at least, that is the premise behind the public-interest theory of regulation.[20]

RECENT CONCERNS WITH TRADITIONAL RATEMAKING

Sources of discontent with traditional ratemaking through the years have come from different quarters: economic theory, real-world experiences, recent market and other developments triggering a revisit of "old" ratemaking practices. Many critics consider traditional ratemaking as old-fashion and out of touch with today's environment.

Some stakeholders have expressed frustration with the rigid features of traditional ratemaking. As an example, it offers utilities inadequate incentives to invest in new technologies that are cost-beneficial (e.g., provide customers with new services, address new environmental regulations at least cost). Specifically, it may remove many of the economic benefits that induce unregulated firms to make

[18] Severin Borenstein & James Bushnell, "The US Electricity Industry after 20 Years of Restructuring" (2015) 7 Annual Rev of Econ 437, online : <doi.org/10.1146/annurev-economics-080614-115630>.

[19] Regulators' rejection or non-consideration of variants of traditional ratemaking, like price caps and multiyear rate plans ("MRPs"), may be more of a rational response than inertia (David E. M. Sappington & Dennis L. Weisman, "The Disparate Adoption of Price Cap Regulation in the U.S. Telecommunications and Electricity Sectors" (2016) 49:2J of Regulatory Econ, at 250–64.) Inertia implies a rigid regulatory position toward these rate mechanisms, irrespective of the circumstance or what the evidence shows; namely, a status-quo bias in which regulators adhere to traditional ratemaking no matter the environment under which a utility operates or the expected outcome. It seems plausible that the lack of wide acceptance of price caps and MRPs in the US electric industry reflects the reluctance of risk-averse regulators to accept a mechanism with uncertain outcomes that could make matters worse, which is conceivable with a poorly structured and executed plan.

[20] *Kahn*, *supra* note 16.

technological improvements.[21] On the other hand, traditional ratemaking also limits utility risk for unsuccessful new technologies, which at least partially, if not perfectly, compensates for the absence of potentially high profit. Overall, traditional ratemaking tends to socialize both the benefits and the risks of new technologies, which is contrary to how well-functioning markets normally operate.[22]

A summary of the major arguments against traditional ratemaking over the years is as follows:

- Traditional ratemaking does not update rates for changes in costs beyond what regulatory practitioners call the "test period," especially when historical in nature; this means in a dynamic cost environment, utilities would tend to file frequent rate cases.[23]

- It gives utilities weak incentive to innovate.[24]

- It creates excessive delay in cost recovery for capital projects.

- With frequent rate cases lessening regulatory lag, utilities have weak incentives to control their costs.[25]

- It prices utility service based on average cost rather than the more theoretically correct marginal cost.[26]

- It can create rate shock under inflationary and other conditions (leading to political difficulties for regulators and a disruptive effect on customers).

- Its standard rate design (i.e., volumetric rates) magnifies efficiency and equity problems with the availability of distributed and other non-utility generation.

- It places high demands on regulator's staff and utility resources.

[21] Regulatory policies can discourage or stimulate utility investments in innovations, thereby affecting the amount that utilities spend on innovation, the speed at which they innovate, and the nature of the innovations. The regulatory tools that affect innovation are ratemaking, mandates, and performance standards. By placing bounds on utility profits and risk, regulation can either constrain or stimulate innovation. Regulated utilities face more severe profit constraints than their unregulated counterparts, which by itself diminishes their willingness to innovate. Analysts have criticized traditional ROR ratemaking for providing utilities with weak incentives to innovate. See, GE Digital Energy and Analysis Group, "Results-Based Regulation: A Modern Approach to Modernize the Grid," (2013) UN environment programme, Working Paper. For discussion of regulatory options to encourage distributed energy resources, see Ontario Energy Board, *Framework for Energy Innovation: Setting a Path Forward for DER Integration*, (2023), online (pdf): <oeb.ca/sites/default/files/FEI-Report-20230130.pdf>.

On the other hand, regulatory policies can also encourage innovation, sometimes with poor results. Electric utilities, for example, historically invested aggressively in new technologies when their economic incentives were strong (i.e., the expected return was high relative to the risk). In the past, some of those new technologies have performed poorly, burdening utility customers with recovery of excessive costs. See, for example, H. Stuart Burness, W. David Montgomery, & James P. Quirk, "Capital Contracting and the Regulated Firm" (1980) 70:3 Am Econ Rev, at pp 342–54. During the 1960s to the mid-1970s, for example, utilities found nuclear power attractive because of the potential to earn high rates of return and the low risks involved during this period of rare retrospective review. See also Paul Joskow, "Productivity Growth and Technical Change in the Generation of Electricity" (1987) 8:1 The Energy J at 17–38.

[22] See Ken Costello, "New Technologies: Challenges for State Utility Regulators and What They Should Ask" (2012) 12:1 NRRI.

[23] As a rule, regulators frown upon frequent rate cases: They expose regulators to public scrutiny and confront them with the difficult task of balancing the interests of politically active stakeholders. Rate cases are also time consuming and expensive, leaving the regulators with fewer resources to pursue other activities integral to their duties.

[24] Traditional ratemaking can also motivate utilities to overinvest in innovation when the expected return is high relative to the risk (see *supra* note 21).

[25] "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates.

[26] Regulators have been hesitant to move from average-cost to marginal-cost pricing thanks in part to higher rates for some customers or much higher rates for all customers over specific periods (e.g., summer peak periods for electricity service). For other problems with marginal cost pricing, see Ronald H. Coase, "The Marginal Cost Controversy: Some Further Comments" (1946) 13:51 Economica, at 169.

- It motivates utilities to increase both sales and rate base.[27]

- It allows utilities to decide the timing of rate cases.[28]

The following section illustrates the potential problems caused by utility regulators retaining a rate design long held but now debatable in the new electric industry. Influential stakeholders like consumer and clean-air advocates have opposed changes in the rate design.[29]

PROBLEMS WITH THE STANDARD RATE DESIGN

The heightened interest in fixed and demand charges for residential electricity customers has sprung largely from the flaws in the prevailing rate design for residential electric service, namely, volumetric rates.[30] This is especially true as those shortcomings have magnified with recent developments in electricity markets and public policy.

The following expression represents the typical two-part tariff for base rates set by utilities:

$$B_i = C + p \cdot q_i$$

The base rate for customer i, B_i, equals the sum of the customer charge (C)[31] applicable to all customers, and the volumetric charge (p) times the quantity of utility service consumed by customer i (q_i).[32] It excludes fuel, specific capital expenditures and other costs recovered by a utility through a tracker or other rate mechanism outside of a general rate case.

The base rate recovers those costs related to investment in, and operation of, a utility system. The customer charge typically includes the direct cost of serving a customer, including the cost for meters, meter reading, billing and collection, servicing an account, call centers, and other costs independent of usage.[33] The volumetric charge recovers the remaining costs of a utility. It includes both operating costs and capital costs not recovered in the customer charge.[34]

[27] One prominent criticism originates with the Averch-Johnson (A-J) effect, which says that a utility would use excessive capital input relative to other inputs such as labor, fuel, and materials. This outcome assumes that a utility faces a binding rate-of-return constraint on its rate base and its allowed rate of return exceeds its actual cost of capital. [Harvey Averch & Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint" (1962) 52:5 Am Eco R, 1052].

[28] When the utility initiates rate reviews, it can manipulate the regulatory process to its advantage. Yet if reviews occur at fixed intervals, such as under a price-cap regime, the utility would have an incentive to inflate costs just prior to a review so as to receive higher rates in the following period, defined by analysts as the "ratchet effect".

[29] Severin Borenstein, "Energy Hogs and Energy Angels: What Does Residential Electricity Usage Really Tell Us About Profligate Consumption?" (2024) National Bureau of Economic Research, Working Paper No 32023, online (pdf): <nber.org/system/files/working_papers/w32023/w32023.pdf>; and Kayla Carroway et al., "Costs, Benefits, And Methods Of Implementing Alternative Rate Mechanisms For Utility Ratemaking," (2022) Kentucky Legislative Research Commission, Research Memorandum No 531, online (pdf): <legislature.ky.gov/LRC/Publications/Research%20Memoranda/RM531.PDF>.

[30] Non-linear pricing (with two-part tariff) has been used in the pricing of utility services since early in the 20th century. Early proponents such as Samuel Insull viewed this rate design as a way to expand demand and lower average costs while satisfying a break-even constraint (i.e., a financially viable utilty). Prior to that time, an unmetered rate was the earliest type of rate used by utilities: a customer is billed a fixed sum for service during a specified period regardless of usage; this billing practice was used prior to the introduction of meters; this rate structure was simple and easy to administer, but was both highly uneconomical and inequitable, since two customers with much different levels of electricity consumption would have the same monthly bill. Flat rates (i.e., one-part volumetric tariff) were the next rate structure, where the utility bills a customer based on a constant price per electricity consumed and registered by a meter; this is simplest of all metered rate methods; it posed serious problems as well, including revenue instability, poor price signals, and subsidization of low-usage customers by high-usage ones.

[31] Some utilities label this rate element the monthly service charge or some other name that represents the minimum charge to customers when they consume no utility service.

[32] The formula above assumes a uniform volumetric distribution charge. Many utilities have block pricing where the volumetric distribution charge varies between blocks of consumption. These rate designs include increasing and declining block structures.

[33] The monthly customer charge equals the allocated annual customer costs divided by the number of customer months.

[34] The volumetric charge equals the total costs (minus the costs recovered in the customer charge) divided by the annual sales as determined at the last rate case.

Major reasons for this longstanding rate structure include: (1) the ease in understanding by customers (which is one of Bonbright's ratemaking criteria); (2) the perception that alternative rate designs like fixed charges are unfavorable to vulnerable customers, like low-income households, and discourage energy efficiency as well as roof-top solar;[35] and (3) less-than-definitive rules for allocating fixed or common costs to different customers and services.

Volumetric rates present a number of social problems related to economic efficiency and equity. These problems have become more acute with new developments in the electric power industry. They include:

- *A significant mismatch exists between a utility's costs and its rate structure*, with excessive fixed or network costs recovered in the volumetric charge; the consequence of that has become more damaging with the growth of self-generation like distributed generation; a more rational rate design that features the cost-causation principle of rate setting can prevent cost-shifting and uneconomic switching of customers to self-generation.

- *Time- and location-invariant volumetric rates* assume that each kWh consumed — irrespective or the time or the location — imposes the same cost on a utility; the reality is that both energy and capacity costs in the real world are higher during system-peak periods. The marginal cost to generate and distribute electricity varies significantly from hour to hour, season to season, and from different locations on a power grid.[36]

- *Self-generating customers avoid their fair share of fixed costs*; when they self-generate, the utility recovers less fixed costs even though they were previously approved as prudent by the regulator and the self-generating customer still relies on the grid for both importing power from the grid and exporting power to the grid, and for other grid services (connection to the power grid, whether the customer self-generates or not, is akin to purchasing a 24/7 call option); the upshot is that the utility usually continues to recover its fixed costs but from non-self-generating customers (who on average are less wealthy than self-generators[37]), which has the tendency to lead to a spiral where the higher rates accelerate self-generation that yet loads more fixed costs on a declining number of customers.

- *Cross-subsidies occur as customers whose demand is relatively constant across hours are subsidizing customers whose demand is "peakier."* For those customers with relatively high kWh consumption but a relatively small contribution to system peak demand, their bills will likely decrease with a fixed or demand charge. For those customers with low consumption but a relatively high contribution to system peak demand, their bills will likely increase. Under volumetric rates, two residential customers with the same monthly electricity usage but differing peak demands on the grid would have almost identical bills, even though one of the customers would require more capacity (and thus higher fixed costs) from the utility.

- *When a customer cuts back on kWh consumption she can avoid paying its fair share of grid service*; that is, she is not paying for what she uses or is available for her to use.

- *Customers receive wrong price signals from an excessive volumetric charge that causes customers to under-consume electricity.* Setting volumetric rates greater than short-run marginal cost creates what economists call a deadweight loss by impeding welfare-enhancing electricity consumption.

[35] *Burger et al., supra* note 16.

[36] Ahmad Faruqui, "Rate Design 3.0," (May 2018) Public Utilities Fortnightly, online: <fortnightly.com/fortnightly/2018/05/rate-design-30>.

[37] *Burger et al., supra* note 16.

- *There is an added incentive for uneconomic bypass aggravated by opportunities for self-generation.* Uneconomic bypass not only diminishes economic efficiency but it also causes cost shifting, likely from wealthier customers to low-income customers.

Notwithstanding these problems with volumetric pricing, most US regulators have done little to replace it. Opponents of change have successfully sway regulators that alternatives would disfavour low-income customers and efforts to advance "green energy."

DO REGULATORS ADAPT?

History has shown that utility regulators do adapt, although gradually, to a changed economic, technological and political environment by throwing their support to new rate designs and ratemaking mechanisms. Changes follow when the political equilibrium has been disrupted (i.e., stakeholders are so unsatisfied with the current situation that they expend substantial resources to change the status quo).[38] But experience has shown the reluctance of regulators to take drastic action without first having a good idea of the effects. Regulators usually prefer a gradualist approach to ratemaking. After all, the legacy of utility ratemaking is average-cost pricing or rates based on historical embedded cost.[39]

As on example, we have seen in the past how a changing landscape for utilities have compelled regulators to modify their ratemaking. Joskow discussed how the combination of inflation, oil price shocks, technological changes and stricter environmental standards caused steep increases in U.S. electricity generating costs in the late 1960s and early 1970s.[40] Utilities could not incorporate these cost (to a large extent beyond their control) into rates fast enough to keep their earnings from falling to a critical level. Eventually regulators allowed fuel adjustment clauses (and, to a lesser extent, future test years) to reduce regulatory lag and avert more serious financial difficulties. Regulators also revisited existing rate structures (e.g., declining block rates) to evaluate whether they satisfied new objectives, like those relating to energy efficiency and clean air, and were still in the public interest. In general, Joskow discussed how the changed political, technological and economic background pressured regulators to adapt their rate mechanisms to this new environment.

CHALLENGES FOR REGULATORS IN BALANCING OBJECTIVES

In today's world balancing the interest of stakeholders involves the recognition of (1) utility competitors wanting a "level playing field," (2) many customers no longer wanting just plain vanilla service (e.g., lower prices and reliable service) but wanting such things as more control over their utility bill, the ability to self-generate and real-time information from their utility, (3) utilities wanting rates that allow them to be financially healthy, and (4) environmentalists wanting clean energy and energy efficiency. Engaged customers tend to better exploit increased competitive conditions and have access to more information and new technologies, and is more aware of market conditions. They place greater demands on utilities to provide (1) a wider array of products and services, and (2) greater opportunities to

[38] One instance is the restructuring of the US electric industry, starting in the 1970s, triggered by the discontent of consumer groups (for example, industrial customers) from continuous rising electricity rates along with the problems experienced by utilities in getting the regulators to approve pass-throughs of costs, even those prudently incurred but second-guessed because of unexpected circumstances. See Paul L. Joskow, "Regulatory Failure, Regulatory Reform and Structural Change In The Electric Power Industry" (1989) Brookings Papers on Economic Activity: Microeconomic, Working Paper No 02139 at 125–99. Joskow remarked that "After 1973 utilities requested much larger rate increases because of large, unanticipated, and mostly uncontrollable increases in costs. These requests further intensified political resistance to rate increases and created pressures for regulatory changes that would deal with the problems caused by rapidly rising electricity costs. Regulatory resistance to price increases caused utilities' financial performance to decline precipitously. By the late 1970s the system that had appeared to work so smoothly for so long was near collapse, plagued by controversies that had not been associated with the industry since the early1930s (at 126–27)."

[39] *Supra* note 15.

[40] Paul L. Joskow, "Inflation and Environmental Concern: Structural Changes in the Process of Public Utility Regulation," (1974) J of L and Econ, 17:2 at 291.

control their electricity usage and the price they pay for electricity.[41] All of these new "balancing" demands have made ratemaking more difficult for regulators.

A big challenge for regulators is to weigh or prioritize those objectives underlying ratemaking and measure (if possible) the effect of a rate mechanism on each one, as well as on the overall public interest. Assigning weights requires judgment by regulators, while examining the effect demands data and other unbiased information derived from sound analytical methods. If a regulator assigns a top priority to economic efficiency, for example, it would tend to favor mechanisms that set prices compatible with marginal-cost principles and provide utilities with strong incentives for technological advances and productivity.

To wit, all rate mechanisms have mixed effects on the public interest. The presumption is that when a rate mechanism impedes some regulatory objective it diminishes the public interest, while improving the public interest when it advances an objective. One example is cost trackers or riders in which a tradeoff exists between timely utility recovery of costs and robust incentives: Trackers and riders allow utilities to recover their costs more quickly and with more certainty, but they also can create incentive problems when (1) regulators fail to adequately scrutinize those costs and (2) cost recovery methods differ across different utility functional areas.[42]

Another example with conflicting outcomes for the public interest comes from utilities offering discounted rates and other special treatment to low-income households.[43] Specific energy-assistance alternatives offered by utilities include a change in rate design, a rate discount, a bill cap based on income, a lump-sum payment, a cost waiver, and subsidized weatherization and other forms of energy efficiency.[44] These options have unique effects on low-income households, other customers, and the utility. Regulators need to ask the following questions: Which of these initiatives would provide "most bang for the buck"?[45] What should be the dollar amount of assistance? Regulators should review whether a utility's energy-assistance initiatives are achieving the regulatory goal of utility-service affordability (1) most effectively and (2) with minimal adverse effects on other regulatory objectives. For example, many economists consider inverted ("lifeline") rates an inefficient and wasteful approach for assisting poor households.[46]

A major problem with energy assistance is that they can cause rates charged to low-income households to fall below cost and rates charged to other customers to increase above cost. Economic efficiency diminishes, and low-income households would tend to consume more energy.[47] The latter effect by itself runs counter to lessening the energy burden of low-income households, as well as advancing energy efficiency.

[41] See Darrell Proctor, "The POWER Interview: What Energy Consumers Want from Utilities" (25 December 2022), online: <powermag.com/the-power-interview-what-energy-consumers-want-from-utilities>; and Bill LeBlanc, "What market research is telling utilities about consumers and solar, Part 1" (11 June 2015) Smart Electric Power Alliance, online: <sepapower.org/knowledge/what-market-research-is-telling-utilities-about-consumers-and-solar-part-1>.

[42] Direct Testimony of Kenneth W. Costello, (2022), Case No. 21-637-GA-AIR et al., online: The Public Utilities Commission of Ohio <dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A22E13B22252A02162>; and *Costello*, *supra* note 16.

[43] Jeffrey A. Adams et al., "Utility Assistance and Pricing Structures for Energy Impoverished Households: A Review of the Literature" (2024) 37:2 The Electricity J, online (pdf): <sciencedirect.com/science/article/pii/S1040619024000034/pdfft?md5=934017cfde71a5662e9ae232749fcf69&pid=1-s2.0-S1040619024000034-main.pdf>; and Kenneth W. Costello, "The Features of Good Utility-Initiated Energy Assistance" (2020) 139 Energy Pol'y, online: <sciencedirect.com/science/article/abs/pii/S0301421520301026#:~:text=This%20paper%20identifies%20criteria%20that%20public> [*The Features of Good Utility-Initiated Energy Assistance*]. The last article remarked that "Utility programs are common in the US. Public utility regulators are on the front lines in evaluating these initiatives and approving them, conditioned on legal, economic and other constraints, that best serve the public interest."

[44] *Ibid*.

[45] For example, which initiatives offer the highest benefit-to-cost ratio?

[46] Kenneth W. Costello, "A Welfare Measure of a New Type of Energy Assistance Program," *The Energy J*, 9:3 (1988) at 129–42.

[47] If these households face below-cost rates, they would tend to consume more energy. Some observers would contend that even if they do, that is desirable since presumably they were under-consuming energy previously when utility service was less affordable.

Energy assistance is a form of discriminatory ratemaking that some regulators might consider undue or excessive.[48] Its rationale is that customers with a low ability to pay for utility services should receive favorable rate treatment. Discriminatory ratemaking almost always raises a question of fairness, especially when a subsidized rate falls outside a "zone of reasonableness." When a rate falls short of a utility's short-run marginal cost or lies above the price that an unregulated monopolist would charge, a regulator would likely find the rate impermissible.

TAKEAWAYS

These are my major observations on the evolution of utility ratemaking in today's environment:

- Ratemaking can address many of the challenges facing the "new" electric utility industry; as some economists would say, "Set the prices right and good things will happen." Faulty utility ratemaking can create serious problems that are contrary to the regulator's duty to set "just and reasonable" rates.

- Ratemaking is tougher than choosing a car or a health care plan[49]; changing rate design, for example, would benefit some customers but hurt others, and the information presented to regulators is fraught with biasness and devoid of reasonably accurate measurement.

- Ratemaking has become harder over time because of expanded public policy objectives and more stakeholders in the regulatory process. Some of these objectives harm utility customers by imposing costs on them without compensatory benefits. As with other things, trade-offs are inevitable, making the regulator's job more difficult for evaluating different rate mechanisms. There is no one rate mechanism that comes to mind advancing all regulatory objectives.

- Regulators do adapt to a changed environment, although cautiously, when the political pressures heighten. Gradualism aligns with one of Bonbright's principles for good ratemaking and is often a rational response to uncertainty over the effects of a major change in ratemaking.

- Ratemaking comes down to the relative importance that regulators and stakeholders place on different objectives. The weighting of each objective by a regulator requires a combination of subjective judgment and compliance with statutory and constitutional mandates. State or provincial statutes may require regulators to consider certain objectives and even mandate that they prioritize others.

- Reaching agreement on rate issues requires a balancing of interests, where each stakeholder may have to give up its preferred choice for the public good; stakeholders in some jurisdictions have not agreed on things like (1) compensation by the utility for surplus rooftop solar PV power, (2) compensation to the utility for grid services provided to DG customers, and (3) the optimal use of smart meters for ratemaking.

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[48] Many economists have identified inadequate income as the real culprit of unaffordable utility service. They contend that state and federal legislatures, or other governmental entities, are best able to address poverty by (a) supplementing the income of poor households (e.g., via cash subsidies with no strings attached), (b) in-kind assistance funded through general revenues (e.g., "energy stamps") or (c) offering them financial support for energy-efficiency improvements. Specifically, they argue that these actions are more effective and efficient than subsidized utility rates. Political pressures and legislative mandates, however, have led to energy utilities' offering of programs to insulate low-income households from unaffordable utility bills. These initiatives, described by some economists as "taxation by regulation," require higher rates to the majority of customers to pay for energy subsidies targeted at a smaller group of customers. The "tariff effect" that makes funding customers minimally worse off in return for making low-income recipients better off has political appeal. See *The Features of Good Utility-Initiated Energy Assistance*, *supra* note 43.

[49] At least in choosing a car, a consumer has objective and definitive information on the features of different cars. One knows the miles per gallon, the color, the power, the safety features, the maintenance and operating history of different car models, and so forth. Like ratemaking, car buyers have to make trade-offs. But at least they have access to objective information. Regulators have no such luxury. They must judge which witnesses have presented the most unbiased and well-founded information. For example, stakeholders would tend to differ over the extent to which a straight fixed-variable rate design would have a negative effect on energy efficiency or low-income households.

To conclude, ratemaking requires that regulators comply with statutes and legal rules, economic principles, precedent, public acceptability, and the tradeoffs among different objectives initiated by legislatures and the regulators themselves, among other things. An essential part of the regulator's job is to exercise judgment on (1) what objectives ratemaking should achieve, (2) the relative significance of each objective, and (3) the willingness to impede certain objectives to advance others; for example, rates that diminish economic efficiency (e.g., cost-based rates) but make electricity more affordable to low-income households. This task has become progressively challenging in recent years as society expects utilities to tackle additional social problems. ■

CONNECTING GROWTH: HOUSING POLICY, ENERGY INFRASTRUCTURE AND THE EVOLVING ROLE OF THE OEB

*John Vellone and Zoë Thoms**

INTRODUCTION

For many years, the Ontario Energy Board ("OEB") has grounded its oversight of energy infrastructure and regulation in a set of core principles which include consumer protection, affordability, safety, reliability, and the fair return standard for utilities. These principles, reflected in the *Ontario Energy Board Act, 1998* (the "*OEB Act*"), have long served as the foundation of the OEB's regulatory mandate. When operating independently, the OEB has historically adhered to this framework, focusing on economic regulation and the public interest.

However, at key moments, government policy has intervened to expand the Board's focus and introduce new priorities. One such moment was the introduction of the *Green Energy and Green Economy Act, 2009* (the "*GEA*"), which shifted the OEB's attention toward conservation and the enablement of renewable energy.[1] The *GEA* amended the *OEB Act* to include the promotion of renewable energy and conservation within the Board's objectives, requiring it to integrate environmental considerations into its decisions, a departure from its traditional economic lens. The OEB was tasked with facilitating renewable energy connections, overseeing cost recovery for the Feed-in Tariff program, and adjusting its regulatory codes to support the government's green energy agenda. Although the *Green Energy and Green Economy Act* was repealed, effective in 2019, many of its conservation and renewable energy objectives remain embedded in the OEB's regulatory codes and processes, continuing to shape how the Board evaluates infrastructure, system planning, and demand-side initiatives.[2]

Today, Ontario is experiencing a similarly significant moment of policy intervention, this time driven by the government's focus on housing affordability and growth. In response to a province-wide housing crisis, the Ontario government has introduced a suite of legislative and policy measures aimed at accelerating

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[1] *Green Energy and Green Economy Act*, 2009, SO 2009, c 12, Schedule A; *Ontario Energy Board Act*, 1998, SO 1998, c 15, Schedule B, as amended by the *GEA*.

[2] Ontario Newsroom, "Ontario Repeals the *Green Energy Act*" (7 December 2018), online: <news.ontario.ca/en/backgrounder/50683/ontario-repeals-the-green-energy-act>.

development, including the *More Homes, More Choice Act, 2019*, the *More Homes for Everyone Act, 2022*, and the *More Homes Built Faster Act, 2022*.[3] These initiatives have been accompanied by strong mayor powers, housing targets, and financial incentives, all of which signal a clear policy direction: to remove barriers to housing construction, including those related to energy infrastructure.

The OEB has been called upon to respond. Ministerial Letters of Direction issued in 2023 and 2024 instructed the Board to align its regulatory processes with the government's housing objectives, including by reviewing connection cost policies, extending revenue and connection horizons, and streamlining approvals for system expansions.[4] These letters of direction have already resulted in substantive changes to the Distribution System Code ("DSC"), the development of a new Capacity Allocation Model ("CAM"), and the introduction of new cost allocation rules for electricity system expansions.[5]

This shift is not merely rhetorical, it is being codified through legislative amendments, regulatory code changes, and appointments to the OEB's Board of Directors. The *Keeping Energy Costs Down Act, 2024*, for example, reversed a major OEB (EB-2022-0200) that had reduced the revenue horizon for natural gas infrastructure to zero, and instead restored the 40-year horizon through ministerial authority.[6] The Act also introduced new powers for the Minister of Energy to direct the OEB to hold hearings on matters of public interest and to set revenue horizons by regulation.[7]

This article explores how the government's housing priorities have come to shape the OEB's regulatory approach. It examines the Enbridge Phase 1 decision, the legislative response through the *Keeping Energy Costs Down Act*, and the resulting evolution in the OEB's role and regulatory tools.

1. POLICY CONTEXT: ONTARIO'S HOUSING PUSH

The Ontario government's housing policy agenda has evolved rapidly over the past decade in response to mounting affordability challenges, population growth, and infrastructure constraints. Between 2019 and 2025, the province introduced a suite of legislative initiatives to address housing supply and affordability.

The *More Homes, More Choice Act, 2019* aimed to streamline development approvals by reforming the *Planning Act* and *Development Charges Act* to expedite housing construction. It emphasized building "the right homes in the right places" as part of a multi-year strategy to alleviate the housing crisis.[8]

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[3] *More Homes, More Choice Act*, 2019, SO 2019, c 9 [*More Homes, More Choice Act*]; *More Homes for Everyone Act*, 2022, SO 2022, c 12 [*More Homes for Everyone Act*]; *More Homes Built Faster Act*, 2022, SO 2022, c 21 [*More Homes Built Faster Act*].

[4] Ontario Energy Board, "Ministerial Letter of Direction" (29 November 2023), online (pdf): <oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20231129.pdf> [*November Ministerial Letter*]; Letter from the Minister of Energy to the Ontario Energy Board (19 December 2024), online (pdf): <oeb.ca/sites/default/files/Letter%20from%20the%20Minister%20of%20Energy%20and%20Electrification%20-%202024-1074.pdf> [*December Ministerial Letter*]. Ministerial letters of direction are non-binding expressions of the government's strategic priorities and expectations for the OEB over a specific period. They are distinct from ministerial directives which are issued pursuant to statutory authority, generally require approval by Cabinet and are legally binding (see *OEB Act* s 27 to s 28.8). While both tools are used to guide the OEB, directives have a stronger legal basis and are binding, whereas letters of direction provide strategic guidance and outline expectations.

[5] Ontario Energy Board, "System Expansion For Housing Developments Consultation – Final Notice of Amendments to the Distribution System Code" (16 June 2025), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/final-notice-of-amendments-to-the-dsc>; Ontario Energy Board, "System Expansion For Housing Developments Consultation – Consultation Launched – Capacity Allocation Model" (21 November 2024), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/consultation-on-a-capacity-allocation-model>; Ontario Energy Board, *Report Back To The Minister On System Expansion For Housing Developments* (Ontario: Ontario Energy Board, 2024) [*Report*].

[6] Enbridge Gas Inc. Application for 2024 Rates – Phase 1 (21 December 2023), EB-2022-0200, online (pdf): <oeb.ca/node/4501> [*Enbridge Gas Inc. Phase 1 Decision*]; *Keeping Energy Costs Down Act*, 2024, SO 2024, c 10 [*Keeping Energy Costs Down Act*].

[7] *Ibid* at ss 28.8, 36.0.1, 96.2.

[8] Ontario.ca, "Archives – More Homes More Choice: Ontario's Housing Supply Action Plan" (4 April 2024), online: <ontario.ca/page/more-homes-more-choice-ontarios-housing-supply-action-plan>.

In December of 2021, the Ontario government announced the creation of a Housing Affordability Task Force to "explore measures to address housing affordability, including increasing the supply of market housing, reducing red tape and accelerating timelines, and supporting economic recovery and job creation."[9] The Task Force released its report in February 2022 concluding that average home prices in the province had increased by 180% over the past decade, while incomes had grown by only 38 per cent.[10] The report stated that the root cause of the housing crisis was a lack of supply and recommended reforms, including:

- Setting a provincial target of 1.5 million new homes over 10 years.
- Increasing density in urban areas and near transit.
- Removing exclusionary zoning rules.
- Limiting public consultations and appeals that delay projects.
- Creating an Ontario Housing Delivery Fund to reward municipalities that meet housing targets.[11]

The Ontario government introduced legislation in response to the Task Force's recommendations:

- ***More Homes for Everyone Act, 2022***: Building on the reforms from the *More Homes, More Choice Act, 2019*, this Act introduced further amendments to housing and development statutes. It established a Housing Supply Working Group to coordinate efforts across federal, provincial, and municipal levels as well as industry and associations. The Act also introduced penalties for municipalities that failed to meet housing targets and sought to make the development process more transparent and predictable.[12]
- ***More Homes Built Faster Act, 2022***: This legislation implemented the Task Force's target of building 1.5 million homes over 10 years. It proposed sweeping changes to zoning, development charges, and environmental approvals.[13] The Act promoted intensification near transit, reduced bureaucratic delays, and encouraged public-private partnerships between municipalities, the private sector, not-for-profits and the federal government to accelerate construction.[14] It also targeted streamlining development approvals, including infrastructure such as water and electricity connections.[15]
- ***Strong Mayors, Building Homes Act, 2022***: This Act gave Toronto and Ottawa mayors the power to veto council decisions that conflicted with provincial priorities. These priorities include the target of 1.5 million new residential units by 2031 and supporting infrastructure like transit, roads, utilities, and services.[16] In 2025, these powers were extended to 169 more municipalities to expedite housing and infrastructure projects.[17]

The Ontario government's housing policy priority during this time was reflected in the

[9] Ontario Newsroom, "Ontario Names Chair and Members of Housing Affordability Task Force" (6 December 2021), online: <news.ontario.ca/en/backgrounder/1001286/ontario-names-chair-and-members-of-housing-affordability-task-force>.

[10] Housing Affordability Task Force, *Report of the Ontario Housing Affordability Task Force* (Ontario: Housing Affordability Task Force, 2022).

[11] *Ibid*.

[12] *More Homes for Everyone Act*, *supra* note 3.

[13] Ontario.ca, "Archived – More Homes Built Faster" (4 April 2024), online: <ontario.ca/page/more-homes-built-faster>.

[14] *Ibid*.

[15] *Ibid*.

[16] O Reg 580/22, s 1, Provincial Priorities, section 1, made under the Municipal Act, 2001, SO 2001, c 25.

[17] Ontario Newsroom, "Ontario Proposing to Expand Strong Mayor Powers to 169 Additional Municipalities" (9 April 2025), online: <news.ontario.ca/en/release/1005752/ontario-proposing-to-expand-strong-mayor-powers-to-169-additional-municipalities>.

Minister of Energy's direction to the OEB. While the 2022 Letter of Direction to the OEB emphasized broader considerations of electrification, energy transition and enhancing resiliency and preparing for the adoption of EVs, by 2023 the Minister of Energy specifically noted the OEB's role in achieving the government's new housing target.[18] In the November 2023 Letter of Direction, the Minister of Energy emphasized the importance of ensuring that Ontario's electricity and gas transmission and distribution systems support the government's housing goals. The Minister highlighted the need for timely decision-making, scrutinized costs, and a regulatory environment with certainty for proponents. The letter encouraged the OEB to review infrastructure unit costs and potential models for cost recovery to keep costs low and avoid barriers to growth. Additionally, the Minister requested a review of the connection and revenue horizon to balance growth and ratepayer costs appropriately.[19]

A. Comparative Horizons: Electricity vs. Natural Gas Connections

At the time the OEB initiated its review, a key regulatory distinction that had influenced infrastructure investment and cost allocation in Ontario was the different treatment of connection and revenue horizons across utility sectors. These parameters, used in economic feasibility tests, determine how long utilities expect to recover capital costs from new customers and how much risk is borne by ratepayers versus developers.

Electricity distributors, governed by the DSC, have historically applied a five-year customer connection horizon and a 25-year revenue horizon.[20] These relatively short timeframes result in higher upfront capital contributions from developers, particularly for early movers, and are designed to minimize risk to existing ratepayers. Developers have raised concerns that this approach disproportionately burdens initial customers while allowing later entrants to benefit from infrastructure without equivalent contributions.[21]

In contrast, natural gas distributors have historically operated under the E.B.O. 188 framework, which allows for a 10-year connection horizon and a 40-year revenue horizon.[22] Moreover, gas distributors can assess economic feasibility on a portfolio basis, blending profitable and less profitable projects to maintain an overall profitability index (PI) of 1.0.[23] Individual projects may proceed with a PI as low as 0.8, provided the portfolio remains viable. This flexibility enables cross-subsidization and reduces the need for upfront contributions, facilitating broader system expansion.[24]

[18] *November Ministerial Letter*, *supra* note 4; Ontario Energy Board, "Ministerial Letter of Direction" (21 October 2022), online (pdf): <oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf>.

[19] *November Ministerial Letter*, *supra* note 4.

[20] Ontario Energy Board, Distribution System Code, Appendix B – Methodology and Assumptions for An Economic Evaluation (last revised October 21, 2009), online (pdf): <oeb.ca/oeb/_Documents/Regulatory/Distribution_System_Code_AppB.pdf>.

[21] *Report*, *supra* note 5 at 3–4.

[22] Distribution System Expansion Report (January 30, 1998), E.B.O 188, online (pdf): <oeb.ca/oeb/_Documents/Decisions/EBO%20188%20Decision.pdf>.

[23] OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (January 30, 1998), online (pdf): <oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/EBO-188-AppB-Guidelines-Gas-Expansion-19980130.pdf> [*EBO 188*]. The profitability index ("PI") measures the ratio of the present value of future cash flows to the initial investment of a project. A PI of 1.0 signifies that the project's expected returns exactly equal its initial cost, indicating a break-even point.

[24] Electricity transmitters, regulated under the Transmission System Code ("TSC"), do not apply a fixed connection horizon. Instead, they use a risk-based approach to determine true-up periods, ranging from five to fifteen years depending on customer classification. Revenue horizons vary from five to 25 years, with 40 years used as an industry standard for low-risk or large-volume customers. The TSC also allows for cost-sharing of network upgrades when broader system benefits are demonstrated. Natural gas transmitters follow the E.B.O. 134 framework, which includes a three-stage economic feasibility test. While there is no prescribed connection horizon, the revenue horizon is typically assumed to be 40 years. The OEB has affirmed that economic feasibility should not be the sole determinant of project approval. Projects with a PI below 1.0 may still proceed if they serve the public interest and do not impose undue burdens on existing customers.

In response to the Minister's Letter of Direction, in April 2024 the OEB launched a consultation to engage stakeholders on the connection and revenue horizon issue.[25]

2. ENBRIDGE PHASE 1 DECISION: A REGULATORY TURNING POINT

In December 2023, the OEB issued a decision in phase 1 of Enbridge Gas Inc.'s ("Enbridge") 2024 rate application. This was Enbridge's first rebasing since the 2019 amalgamation of Enbridge Gas Distribution Inc. and Union Gas. In its decision, the majority of the Board reduced the revenue horizon for new natural gas connections from the standard 40 years to zero, effective January 1, 2025.[26] At 40 years, it allowed developers to connect homes with little or no upfront cost, while the long-term infrastructure costs were gradually recovered from ratepayers through rates. The Board found that the traditional 40-year horizon was no longer appropriate given the accelerating energy transition and the increasing likelihood that customers may leave the gas system before the end of that period.[27]

The majority of the Board held that the 40-year revenue horizon created a "split incentive" problem.[28] Developers were not exposed to the long-term risks or costs of gas infrastructure, while future homeowners and ratepayers would bear the burden. By requiring full cost recovery upfront, the Board's stated aim was to ensure that developers make more informed decisions, potentially opting for all-electric developments that align with decarbonization goals and reduce long-term system costs.[29]

The Board was not unanimous in its decision. One commissioner dissented from the majority's decision to adopt a zero-year revenue horizon, arguing that the evidentiary record did not support such a drastic change and that a 20-year horizon would better balance risk mitigation with regulatory continuity.[30] The dissent emphasized that zero is not a "horizon" in any meaningful sense and is inconsistent with the principles of the OEB's own guidelines for assessing natural gas expansion in Ontario, which envisioned a contribution model and not a full upfront payment.[31] The dissent also noted the absence of developer input in the proceeding and warned of unintended consequences, including feasibility concerns for all-electric developments and potential strain on electricity infrastructure.[32] The dissent advocated for a more incremental approach, suggesting that a 20-year horizon would still significantly reduce stranded asset risk while preserving flexibility for future adjustments.[33]

The decision marked a significant departure from past practice and signaled a more assertive role for the OEB in managing the energy transition. It also raised broader questions about the regulator's mandate. Should the OEB prioritize long-term decarbonization, or should it focus on affordability and access in the short term? The Enbridge decision forced a reckoning with these competing imperatives and set the stage for a political response.

3. LEGISLATIVE RESPONSE: *KEEPING ENERGY COSTS DOWN ACT*

The provincial government responded swiftly to the OEB's decision. The Minister of Energy issued a response condemning the OEB's decision to reduce the revenue horizon to zero the day after the decision was released, citing concerns that it would increase the price of new

[25] Ontario Energy Board, "System Expansion For Housing Developments Consultation – Consultation Launched" (13 March 2024), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/updates>.

[26] *Enbridge Gas Inc. Phase 1 Decision*, *supra* note 6 at 2.

[27] *Ibid* at 23.

[28] *Ibid* at 34–35.

[29] *Ibid* at 40–41.

[30] *Ibid* at 143–44.

[31] *Ibid* at 143 referencing EBO 188.

[32] *Ibid* at 143.

[33] *Ibid* at 144.

homes and limit customer heating choices.[34] The Minister vowed to reverse the OEB's decision.[35]

In early 2024, the provincial government introduced the *Keeping Energy Costs Down Act*, a legislative package designed to reverse the Board's Enbridge ruling and reassert political control over energy infrastructure policy.[36] The Act restored the 40-year revenue horizon for natural gas connections and granted the Minister of Energy new powers to direct the OEB's activities.

The government framed the legislation as a necessary intervention to protect housing affordability and consumer choice. The Minster of Energy argued that the OEB's decision would increase the cost of new homes by tens of thousands of dollars, undermining the province's goal of building 1.5 million homes over the next decade.[37]

The Keeping Energy Costs Down Act introduced several key changes:

- It amended the *Ontario Energy Board Act, 1998* to allow the government to set revenue horizons by regulation.
- It granted the Minister of Energy authority to issue directives requiring the OEB to hold generic hearings on matters of public interest.
- It temporarily shifted jurisdiction over revenue horizon decisions from the OEB to the government, with the expectation that authority would revert to the Board by no later than January 1, 2029.[38]

The Act also included provisions to ensure that the OEB considers a broader range of public interest factors in its decisions, including housing affordability, economic development, and energy access.[39] The legislation was designed to align regulatory decisions with the government's broader policy objectives and to prevent future rulings that could derail housing or infrastructure priorities.[40]

The Enbridge Phase 1 decision represented a notable shift in regulatory approach, prompting a swift legislative response that highlighted the evolving relationship between energy regulation and the government's housing policy objectives.

4. REGULATORY REFORM AND POLICY ALIGNMENT: DSC AMENDMENTS AND THE CAPACITY ALLOCATION MODEL

In response to the Minister's previous letters of direction and legislative developments , the OEB launched a series of consultations and policy reforms aimed at modernizing the regulatory framework for electricity distribution. These efforts culminated in a set of amendments to the DSC and the development of a new Capacity Allocation Model ("CAM").

A. DSC Amendments

In June 2024, the OEB reported to the Minister of Energy from its consultations that there was general stakeholder support for extensions to connection and revenue horizons to reduce burden on first mover developers and ensure cost distribution is fair.[41] However, distributors seemed to highlight potential challenges that

[34] Ontario Newsroom, "The Keeping Energy Costs Down Act" (22 February 2024), online: <news.ontario.ca/en/backgrounder/1004216/the-keeping-energy-costs-down-act>; Toronto Star, "Minister to overrule Ontario Energy Board, says decision will raise cost of new homes" (22 December 2023), online: <thestar.com/politics/minister-to-overrule-ontario-energy-board-says-decision-will-raise-cost-of-new-homes/article_bc7d3811-4656-5eb3-8a10-9c5f75e61f58.html>.

[35] *Ibid*.

[36] *Keeping Energy Costs Down Act*, *supra* note 6.

[37] *Supra* note 34.

[38] *Keeping Energy Costs Down Act*, *supra* note 6, ss 28.8, 36.0.1.

[39] Ontario Newsroom, "The Keeping Energy Costs Down Act" (22 February 2024), online: <news.ontario.ca/en/backgrounder/1004216/the-keeping-energy-costs-down-act>.

[40] *Ibid*.

[41] *Report*, *supra* note 5 at 4.

may arise in terms of financial implications of extending the horizons.[42] The OEB proposed:

- New provisions for the DSC to clarify for distributors and customers how extended connection horizons beyond the standard five years should be employed.

- Extending the revenue horizon used in the evaluation of expansion projects to recognize the life of assets used in connecting and serving residential customers.

- To develop new DSC provisions for a capacity allocation model that specifically addresses multi-year, multi-party developments and ensures a fair allocation of costs between connecting parties.[43]

The Minister of Energy endorsed the OEBs recommendations and agreed to extend the maximum revenue horizon in the DSC for residential developments from 25 to 40 years.[44] The Minister stated that the amendments should reduce the expansion costs for homebuilders and make housing more affordable, while ensuring that burdens are not placed on ratepayers. The Minister also recommended that the OEB consider extending the connection horizon for housing developments from five to 15 years.

In November 2024, the OEB issued a proposal to amend the DSC to:

- Extend the connection horizon for qualifying housing developments to a maximum of 15 years.

- Extend the revenue horizon for all residential customers to 40 years.[45]

These changes were finalized in December 2024 and came into force in March 2025.[46]

B. 2024 Minister of Energy's Letter of Direction

In December 2024, the Minister of Energy's Letter of Direction to the OEB reinforced the government's housing and affordability priorities.[47] Whereas the 2023 Letter of Direction letter emphasized the need for Ontario's electricity and gas transmission and distribution systems to support the province's goal of building 1.5 million new homes, the December 2024 letter went further. It referenced the *Keeping Energy Costs Down Act* and called on the OEB to implement regulatory and process changes that would support housing development, economic growth, and energy affordability. Specifically, the Minister directed the OEB to:

- Amend the Distribution System Code ("DSC") to extend the connection horizon for new electricity distribution lines to a maximum of 15 years.

- Establish a capacity allocation model ("CAM") for multi-phased housing development projects by March 2025.

- Provide specific guidance to local distribution companies ("LDCs") on implementing these changes. [48]

The letter also emphasized the importance of reducing the cost burden on first-mover developers and ensuring that infrastructure investments are aligned with Ontario's growth

[42] *Ibid*.

[43] *Ibid* at 5–6.

[44] Ontario Energy Board, "Letter from the Minister of Energy and Electrification" (20 October 2024), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/report-published-2https://engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/report-published-2>.

[45] Ontario Energy Board, "System Expansion For Housing Developments Consultation – Notice of Proposal to Amend the Distribution System Code" (18 November 2024), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/notice-of-proposal-to-amend-the-distribution-system-code>.

[46] Ontario Energy Board, "System Expansion For Housing Developments Consultation – Final Notice of Amendments to the Distribution System Code" (23 December 2024), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/final-notice-of-amendment-to-the-distribution-system-code>.

[47] *December Ministerial Letter*, *supra* note 4.

[48] *Ibid*.

objectives. It called on the OEB to maintain practices of innovation, sustainability, and accountability while supporting the province's housing and energy goals.[49]

C. Capacity Allocation Model

The OEB developed the CAM to address issues related to system expansions for large and multi-developer residential projects.[50] This CAM ensures that developers who connect first pay a fair share of the costs, while those who connect later will contribute based on their allocated share of the new facilities. The current DSC mandates that a distributor allocate the costs of distribution facilities among multiple customers based on the apportioned benefit. However, what is not addressed is how such an allocation would function in scenarios where there is an extended connection horizon and potentially several years between connections by different customers/developers.[51]

The CAM was designed to:

- Provide a fair and sustainable model for allocating infrastructure costs among developers, ratepayers, and distributors.
- Facilitate expansion planning and ensure that capacity is allocated efficiently.
- Align cost allocation with the benefits received by different stakeholders.[52]

The CAM was developed through a stakeholder advisory group and was informed by feedback from developers, distributors, and municipalities. It was finalized in June 2025 and is scheduled to come into force in September 2025.[53]

The DSC amendments and the CAM represent a significant evolution in the OEB's approach to system expansion, incorporating more integrated planning practices intended to support housing development while addressing cost allocation and affordability considerations.

5. OEB: CHANGING PERSPECTIVES AND EVOLVING ROLE

In May 2025, the OEB appointed Frederic Waks, President and CEO of Trinity Development Group and former President and COO of RioCan, to its Board of Directors.[54] This appointment introduced a development-sector perspective to a body traditionally composed of individuals with backgrounds in utilities, law, and public policy. The addition of Waks aligns with the government's emphasis on the need for interdependence between housing and infrastructure development.

The continued evolution of the Board of Director's composition, particularly the inclusion of sector-specific expertise, intersects with the OEB's dual mandate of regulatory independence and policy responsiveness. While the Board of Directors does not participate in adjudicative decisions, it is responsible for appointing adjudicators and shaping strategic direction. This ongoing evolution invites further reflection on how governance structures can balance the benefits of sectoral insight with the imperative to preserve adjudicative independence.

CONCLUSION

Ontario's housing policy agenda is reshaping the regulatory landscape in ways that echo earlier moments of legislative intervention, such as the *Green Energy and Green Economy Act*. Just as the *GEA* expanded the Ontario Energy Board's ("OEB") mandate to incorporate environmental and conservation objectives, the current focus on housing affordability and growth is prompting a recalibration of the Board's regulatory tools and priorities.

[49] *Ibid*.

[50] Ontario Energy Board, "System Expansion for Housing Development Consultation – Final Notice of Amendments to the Distribution System Code" (16 June 2025), online: <engagewithus.oeb.ca/system-expansion-for-housing-developments-consultation/news_feed/final-notice-of-amendments-to-the-dsc>.

[51] *Report*, *supra* note 5 at 37.

[52] *Supra* note 54.

[53] *Ibid*.

[54] Ontario Energy Board, "About the OEB – Who We Are – Board of Directors" (2025), online: <oeb.ca/about-oeb/who-we-are/board-directors>.

The Enbridge Phase 1 decision and its legislative reversal through the *Keeping Energy Costs Down Act, 2024*, illustrate how government direction can redefine the boundaries of the OEB's discretion. Subsequent amendments to the Distribution System Code, the introduction of the Capacity Allocation Model, and the extension of connection and revenue horizons reflect a regulatory framework increasingly oriented toward enabling infrastructure to support housing development.

These developments suggest a broader evolution in the OEB's role, from a regulator primarily focused on economic oversight and consumer protection to one that is also expected to facilitate provincial policy objectives related to land use, growth, and affordability. The inclusion of development-sector expertise on the Board signals this changing orientation, introducing perspectives more closely aligned with infrastructure and housing policy. The implications of this shift for the OEB's regulatory approach are likely to be shaped by how government, regulators, industry, and communities continue to interact and respond to emerging policy objectives. ■

ALBERTA UTILITIES COMMISSION APPROVES FIRST INDUSTRIAL WASTE-TO-ENERGY FACILITY WITH CARBON CAPTURE IN CANADA

*Byron Reynolds and Hazel Saffery**

The Alberta Utilities Commission (the "Commission") recently approved the construction and operation of the Heartland Waste-to-Energy Facility (the "Facility") pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*.[1] The Facility is a powerplant that utilizes waste-to-energy technology combined with carbon capture and storage technology. The Commission found that the approval of the Facility is "in the public interest having regard to its social, economic, environmental and other effects" in accordance with Section 17 of the *Alberta Utilities Commission Act*.[2] The approval by the Commission is solely for the electrical components that comprise the power plant equipment.[3]

1. DECISION SUMMARY

A. Facts

The total generating capability of the Facility is 19.6 MW and the Facility will be fuelled by approximately 205,000 tonnes per year of municipal solid waste obtained from the City of Edmonton.[4] The Facility's generator terminals will export 5.8 MW to the Alberta Interconnected Electric System and the remaining 10.4 MW will be supplied to the Facility's carbon capture package.[5] Varme Energy Inc. ("Varme"), which was granted the approval, expects to commence construction in Q3 of 2025 and to have an in-service date in Q2 of 2028. The Facility will be located the Alberta Industrial Heartland Industrial Area.[6]

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With thanks to Dentons 2025 Summer Student, Sara Mah.

[1] *Varme Energy Inc. Heartland Waste-to-Energy Facility* (2 May 2025), 29820-D01-2025, online: Alberta Utilities Commission <prd-api-efiling20.auc.ab.ca/Anonymous/DownloadPublicDocumentAsync/834802> [*Decision*].

[2] *Ibid* at para 8.

[3] *Ibid* at para 20.

[4] *Ibid* at para 3.

[5] *Ibid*.

[6] *Ibid* at paras 5, 11.

B. Issues & Findings

a. Is the Facility compliant with The Commission's Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines?

The Commission ruled that the requirements for Rule 007 were met, specifically because of Varme's participant involvement program. That program included notification and consultation with directly and/or adversely affected stakeholders such as landowners, occupants, and residents.[7]

b. Is the Facility compliant with The Commission's Rule 012: Noise Control, Section 2.7?

The Facility was found to be compliant with Rule 012 or to meet the Northeast Capital Industrial Association (NCIA) specific no net increase requirement.[8] In the NCIA region, the generally accepted method for noise impact assessments is to consider noise levels from the proposed Facility alone, without assessing the noise levels in combination with existing facilities in the NCIA region.[9] Cumulative sound levels are the sum of baseline sound levels and noise levels from the Facility.[10] Baseline sound levels are the sum of ambient sound levels and noise levels from existing facilities in the NCIA region.[11] Some receptors in the region already exceed permissible sound levels ("PSLs").[12]

The Commission accepted the noise impact assessment's prediction that the noise levels from the proposed Facility alone in combination with ambient sound levels will be compliant with the PSLs at all receptors.[13] However, based on predictive results, the cumulative sound levels were compliant with Rule 012 at all receptors except R01.

At R01, the Commission acknowledged that the cumulative sound level exceeds the nighttime PSL because the corresponding baseline sound level already exceeds the acceptable PSL and that the sound level increase resulting from the proposed Facility is no greater than 0.4 decibels.[14] In this case, the Commission found that the requirement by the Commission in its endorsement of the NCIA's regional noise management plan could apply.[15] The requirement was developed in response to the NCIA's concerns that development in areas on the fringe of the regional noise model area would not be allowed if proposed facilities result in an increase over the background noise levels in the region.[16] The Commission responded in a letter dated October 16, 2023 that in circumstances where meeting the Rule 012 PSLs is not effective, there should be no net sound increase at nearby receptors above the baseline case.[17]

Given this, the Commission found that the noise from the Facility is expected to comply with the Rule 012 PSLs or to meet the no net increase requirement for the NCIA's regional noise management plan.[18]

c. Is the Facility compliant with the *Alberta Wetland Mitigation Directive?*

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[7] *Ibid* at para 10.

[8] *Ibid* at para 14.

[9] *Ibid* at para 11.

[10] *Ibid* at para 12.

[11] *Ibid*.

[12] *Ibid*.

[13] *Ibid*.

[14] *Ibid*.

[15] *Ibid* at para 14.

[16] Letter from Douglas A. Larder, QC, General Counsel for the Alberta Utilities Commission to Dr. Laurie J. Danielson, Executive Director of the Northeast Capital Industrial Association (16 October 2013), online: <ncia.ca/public/download/files/103831>.

[17] *Ibid*.

[18] *Decision*, *supra* note 1 at para 14.

The Facility was found to be compliant with the *Alberta Wetland Mitigation Directive*.[19] The Commission accepted Varme's submissions that the Facility was designed to be as small as possible to minimize the impact to wetlands, that siting the Facility within the Industrial Heartland Designated Industrial Zone necessarily limits the impacts on wetlands, and that wetland compensation offsets would be paid.[20]

Further, the Commission imposed the condition that approval of the project under the Alberta Environment and Protected Areas' ("AEPA") *Water Act* must be filed with the Commission when available and will include the Wetland Assessment Impact Report submitted to the AEPA.[21]

d. What are the impacts to Air Quality in the Region?

The Commission recognized that site-specific emissions limits are subject to AEPA's approval under the *Environmental Protection and Enhancement Act* ("*EPEA*") because the Facility uses municipal waste as the source of its fuel.[22] The use of municipal waste renders some routine air emissions standards inapplicable.[23] In particular, the *Multi-Sector Air Pollutants Regulation* limits on NO_x emissions is only applicable for boilers fueled by gaseous fossil fuels.[24] For the same reason, the emission requirements for NO_x in the *Air Emissions Requirement Policy for the Industrial Heartland Designated Industrial Zone* do not apply.[25] The triggering of the EPEA approval process is discussed below.

The air quality report submitted by Varme predicted the expected impact of the Facility and was accepted by the Commission.[26] The report indicates that the *Alberta Ambient Air Quality Objectives* are met within the modelled area based on the predicted maximum emissions for a day (accounting for all nearby sources), notwithstanding two exceptions.[27] Those exceptions are fine particulate matter (PM2.5) and sulphur dioxides (SO_2), as the ground-level concentrations of both substances exceed the maximum emissions.

However, the Commission accepted that these exceedances are due to the fact that the Facility is located in an area of concentrated emissions sources. It worked in the Facility's favour that the locations of the maximum ground level concentrations for PM2.5 and sulphur dioxides SO_2 are distant from the Facility stack, and that this siting is desirable compared to alternative locations outside the industrial zone.[28]

The Commission once again approved the impacts to air quality on the condition of approval by Alberta Environment and Protected Areas.[29] Industrial application approval under the *EPEA* must be filed with the Commission for the Facility to be approved by the Commission.[30]

Similarly, the carbon capture, process water recycling, waste management and flue gas treatment system components of the Facility were held to be under the purview of the *EPEA*.[31]

e. Does Varme have a suitable reclamation security program?

[19] *Ibid* at para 18.

[20] *Ibid* at para 17.

[21] *Ibid* at para 19.

[22] *Ibid* at para 21.

[23] *Varme Energy Inc. Heartland Waste-to-Energy Facility* (2 May 2025), 29820-D01-2025 (Alberta Utilities Commission Application for a Power Plant) [*Application*] at para TP16.

[24] *Ibid*.

[25] *Ibid*.

[26] *Decision*, *supra* note 1 at para 21.

[27] *Ibid* at para 22.

[28] *Ibid*.

[29] *Ibid* at para 23.

[30] *Ibid*.

[31] *Ibid* at para 24.

Varme's approach to reclamation was found sufficient to satisfy the Commission that the Facility's approval is in the public interest.[32] The Commission accepted Varme's submission that the Facility reclamation security is to be provided to the AEPA in accordance with the *Waste Control Regulation* under the *EPEA*.[33] The conditions of the *EPEA* approval will incorporate Varme's legal obligation to carry out reclamation of all Facility components.[34]

The security to be provided to AEPA is estimated at $889,455.03. The Commission accepted that this amount would be sufficient to reclaim all the power plant components of the Facility because Varme submitted that the salvage value would cover a significant portion of the estimated reclamation costs.[35]

f. The Commission's Conclusion

The Commission approved the application for the electrical components that comprise the power plant equipment.[36] It made no approvals over the carbon capture and process water recycling components of the Facility.[37]

2. THE *EPEA* APPROVAL PROCESS IS TRIGGERED BY THE FACILITY'S ACTIVITIES

The Facility is still subject to AEPA approval.[38] Despite the small size of the Facility, the Facility is governed by the *EPEA* as a waste-to-energy facility requiring and *EPEA* approval.

By combusting municipal solid waste, the powerplant will emit NO_x. NO_x emissions are regulated by the *EPEA* through the Alberta Ambient Air Quality Objectives ("AAAQOs") which set specific limits for NO_x concentrations in the air. The AAAQOs are developed under Section 14 of the *EPEA*.[39]

The development of the Facility involves potential impact to wetlands meaning that *EPEA* is also triggered because of the use of the land. However, the Commission found that approval was conditional on approval under the *Water Act* by the AEPA, including the Wetland Assessment Impact Report.

3. THE HEARTLAND WASTE-TO-ENERGY FACILITY IS A FIRST OF ITS KIND FACILITY IN CANADA

This decision is significant for several reasons, one of which is that the Heartland Waste-to-Energy Facility will be the first industrial-scale waste-to-energy Facility with carbon capture in Canada.[40] Waste-to-energy facilities are also not new to Alberta.[41] Currently, there are 7 projects which fall under the Government of Alberta's *Energy Generation from the Combustion of Biomass Waste Protocol.*[42] However, none of these projects capture and sequester the associated carbon dioxide emissions.[43] The addition of carbon capture and storage infrastructure enables the Facility to secure financial incentives from the federal government and the Province of Alberta and to

[32] *Ibid* at para 28.

[33] *Ibid* at para 25.

[34] *Ibid*.

[35] *Ibid* at para 27.

[36] *Ibid* at para 29.

[37] *Ibid*.

[38] *Decision*, *supra* note 1.

[39] Government of Alberta, "Alberta Ambient Air Quality Objectives and Guidelines" (19 July 2024), online (pdf): <open.alberta.ca/dataset/09a63fe8-11ae-420e-9008-82aa4db4824a/resource/094dae9e-b6f9-4de9-86c7-a651019f3aab/download/epa-ambient-air-quality-objectives-and-guidelines-2024.pdf>.

[40] Michele Bertone, Luca Stabile & Giorgio Buonanno, "An Overview of Waste-to-Energy Incineration Integrated with Carbon Capture Utilization or Storage Retrofit Application" (2024), 16:10 Sustainability 4117; online: <doi.org/10.3390/su16104117>.

[41] Government of Alberta, *Energy Generation from the Combustion of Biomass Waste* (Quantification Protocol) (2018), online (pdf): <open.alberta.ca/dataset/882aa4e1-9358-4a98-a633-9435b2a49830/resource/501c00bd-4385-4c45-94bd-bc4a0efa0ee0/download/energygenerationbiomass-jun18-2018.pdf>.

[42] CSA Group, "Alberta Carbon Registries, Alberta Emission Offset Registry Listing", database: *Alberta Emission Offset Registry*, online: <alberta.csaregistries.ca/GHGR_Listing/AEOR_Listing.aspx>.

[43] *Ibid*.

generate carbon emission offsets that may be sold to third parties on compliance or voluntary carbon markets.

The development of carbon capture and storage projects in Alberta is incentivized by federal and provincial government support.

The federal government has implemented a refundable tax credit aimed at incentivizing carbon capture, utilization, and storage ("CCUS") through the CCUS investment tax credit ("CCUS ITC") regime under the *Income Tax Act* (Canada).[44] The CCUS ITC is initially set at 50% for qualified capital expenditures incurred to capture carbon dioxide and 37.5% for qualified capital expenditures incurred to transport and store carbon dioxide up to December 31, 2030 and is reduced by 50% for 2031–2040.[45]

Around the same time, the Province of Alberta announced its CCUS incentive program: Alberta's Carbon Capture Incentive Program ("ACCIP"). Through ACCIP, the Province expects to commit an estimated CA$3.2 to CA$5.3 billion of support between 2024 and 2035 to the development of new CCUS infrastructure. ACCIP will provide a 12% grant for new CCUS capital costs for qualifying projects physically located in Alberta.[46] Alberta has a strong track record of supporting CCUS. The Province has invested over CA$1.8 billion in projects to capture carbon dioxide.[47]

Governments in Alberta have also supported the Facility itself, with the City of Edmonton awarding the contract to Varme in January 2024.[48] Additionally, the Facility is the culmination of a front-end engineering and design study led by Varme and funded in part by the Government of Alberta, which provided $2.8 million through Emissions Reduction Alberta.[49]

Government incentive programs like CCUS ITC and ACCIP are crucial to the development of CCUS in Alberta. The industries which are expected to benefit from this support are industries such as the Alberta oil sands, petrochemicals, manufacturing, cement and power generation.[50] These industries could make significant emissions reductions by using CCUS technology.

4. THE FACILITY SIGNALS THE POSITIVE IMPACT OF CARBON MARKETS

The development of the Facility is one indicator that carbon markets and government supports are achieving their common goal of driving innovation and the use of carbon reduction technologies.

The Facility is expected to be eligible to generate carbon emission offsets for both the waste-to-energy process and the carbon capture and storage process on compliance or voluntary markets.

Under Alberta's *Technology Innovation and Emissions Reduction Regulation* ("TIER"),[51] waste-to-energy projects are eligible to generate carbon emission offsets pursuant to the *Energy Generation from the Combustion of Biomass Waste*[52] protocol. By diverting feedstock from landfills and avoiding greenhouse gas ("GHG") emissions, projects can realize on emission

[44] Dentons Canada LLP, "Boosting carbon capture: Federal and provincial incentives propel CCUS Facility development in Alberta" (29 November 2023), online: <dentons.com/en/insights/articles/2023/november/29/boosting-carbon-capture-federal-and-provincial-incentives-propel>.

[45] *Ibid.*

[46] Dentons Canada LLP, "The Alberta Carbon Capture Incentive Program" (23 April 2024), online: <dentons.com/en/insights/alerts/2024/april/23/the-alberta-carbon-capture-incentive-program> [*ACCIP*].

[47] *Ibid.*

[48] Alberta Major Projects, *Heartland Waste-to-Power Project*, online: <majorprojects.alberta.ca/details/Heartland-Waste-to-Power-Project/11042>.

[49] Emissions Reduction Alberta, "Heartland Waste to Energy With Carbon Capture Feed Study", online: <eralberta.ca/projects/details/heartland-waste-to-energy-with-carbon-capture-pre-fid-completion>.

[50] *ACCIP*, *supra* note 44.

[51] Alta Reg 133/2019.

[52] Government of Alberta, "Energy Generation from the Combustion of Biomass Waste" (18 June 2018), online (pdf): <open.alberta.ca/dataset/882aa4e1-9358-4a98-a633-9435b2a49830/resource/501c00bd-4385-4c45-94bd-bc4a0efa0ee0/download/energygenerationbiomass-jun18-2018.pdf>.

offsets opportunities.[53] In addition, carbon emission offsets can be generated from the capture and storage of carbon dioxide emissions pursuant to the *Quantification Protocol for CO_2 Capture and Permanent Geologic Sequestration*[54] issued under TIER. Accordingly, the Facility could generate valuable emission offsets from two carbon reduction activities under TIER which can be sold on the Alberta Emissions Offset Registry to support project economics.

Alternatively, emission offsets generated through the production of bioenergy with carbon capture and storage are highly sought after in the voluntary carbon offsets market. Businesses looking to voluntarily reduce their GHG emissions and meet their sustainability or net-zero targets may pay a premium to purchase these credits in these voluntary markets.

5. GOVERNMENTAL INCENTIVES AND CARBON MARKETS LEAD TO NEW PROJECTS AND INNOVATIONS

The Facility is one of several examples of how governmental incentives and carbon markets can lead to innovation and technological developments in the Province. CCUS ITCs and the ACCIP program provide strong incentives to encourage investment in CCUS in Alberta. By incentivizing the development of carbon emission reduction technologies, programs like CCUS ITCs, ACCIP and carbon emission offsets generated under TIER drive Alberta forward along its Emissions Reduction and Energy Development Plan to achieve a carbon neutral economy by 2050.[55] ■

[53] Government of Alberta, "Quantification Protocol for CO_2 Capture and Permanent Geologic Sequestration" (7 January 2025), online (pdf): <open.alberta.ca/dataset/687c7368-0b41-435e-9e17-7bb7322a95bf/resource/17cdbee0-bba3-4c64-aa7a-e7159253278f/download/epa-quantification-protocol-co2-capture-and-permanent-geologic-sequestration-2025-01.pdf>.

[54] *Ibid*.

[55] *ACCIP*, *supra* note 44.

ARE THINGS DIFFERENT THIS TIME? REFLECTIONS ON A CAREER IN ENERGY REGULATION

*Rowland J. Harrison, K.C.**

It is a singular honor to be the recipient of the inaugural ERQ Energy Bison, especially as the Kaiser Award has been established in memory of such a legendary pioneer in promoting Canadian energy regulation.[1]

It is particularly fitting to be receiving the award here in Halifax where my career in Canadian energy regulation really began, more than 50 years ago, when I was retained as a consultant by the Office of the then Premier in the wake of Mobil Oil Canada's announcement in 1971 that it had encountered oil in a well drilled on the western tip of Sable Island. The excitement generated by that discovery was short-lived — but, happily, my career was not!

The theme for this Forum — a **new** focus on Canadian energy sovereignty — is particularly judicious as it is certainly not the first time that energy sovereignty has preoccupied the national agenda. In the mid-1950s, the "Great Pipeline Debate", surrounding the routing of what would become the TransCanada Mainline, precipitated the defeat of the federal government of the day. Canadian sovereignty was at the core of that debate. The Royal Commission that ensued emphasized the need for independent regulation of pipelines under federal jurisdiction and led directly to the enactment in 1959 of the *National Energy Board Act* ("*NEB Act*")[2] and the establishment of the National Energy Board ("NEB" or "Board").

Is today's energy sovereignty debate different? I suggest that it is — and it isn't!

The energy challenge now facing Canada is widely described as a crisis and it is trite to say that crises present opportunity.[3] In the present context, opportunity may be found in the widespread recognition that indeed Canada does face a serious challenge that must be met head on — something must be done. Evolving public opinion on the importance of energy development to Canada's economic prosperity also appears to recognize the seriousness of the challenge and, by providing political support for appropriate responses, may contribute to identifying and implementing effective responses.

Responses to crises, however, also come with risks, perhaps the most serious of which is the risk of "responding" for the sake of being seen to be doing something. The real challenge of

* Formerly Co-Managing Editor, *Energy Regulation Quarterly*. This paper is based on remarks by the author on being presented with the inaugural Energy Bison Award, the Kaiser Award, at the 2025 ERQ Energy Law Forum, in Halifax on May 7, 2025.

[1] The Kaiser Award is named in honour of Gordon Kaiser, whose unwavering dedication as Co-Managing Editor of *Energy Regulation Quarterly* for over a decade and passing in 2024 left a profound impact on the publication and all who had the privilege of working with him.

[2] National Energy Board Act, RSC, 1985, c N-7, repealed, 2019, c. 28, s44 [*NEB Act*]. The *NEB Act* remained essentially unchanged for more than 50 years, from 1959 to 2012.

[3] Churchill is often quoted as having said: "Never let a crisis go to waste!", although there appears to be no record of him actually having said that.

course is not to simply do "something"; rather, the challenge is to identify, and implement, solutions that address the real, not merely perceived, challenges at hand. And that is not an easy task, particularly in the field of energy policy and regulation where there are persistent, underlying realities that must be recognized and accommodated.

An overarching call for measures to address today's challenges is to "simplify regulation." Past experience with attempts to do just that, however, exposes the persistence of certain fundamental dynamics. Three specific examples illustrate that designing robust solutions to at least some of today's challenges has dogged policy-makers repeatedly, in some cases for decades.

The first example relates to the widespread calls to simplify the review process for proposed energy projects by eliminating overlap and duplication — encapsulated in catchphrases such as "one project, one review" or the "single (regulatory review) window." The concept of the "single window" is almost universally embraced; it is, however, neither new, nor as simple to implement as might at first appear.

In the early 1980s, I was a senior official with an administrative agency, the Canada Oil and Gas Lands Administration ("COGLA"), established under the National Energy Program to manage federal responsibilities with respect to oil and gas exploration and development in offshore and northern areas. COGLA was to be a "single window" for industry to deal with the federal government. In reality, however, industry had to continue to comply separately with a variety of other federal requirements. The failure was captured in the witty pun by a senior industry executive that "COGLA might be a single window, but the window has many panes!"

The reality is that major infrastructure projects, particularly energy projects, trigger multiple, diverse public interests that must be recognized and accommodated. That reality is reflected in the fact that calls to better coordinate — to "simplify" — the review process are still widespread, nearly 20 years after the establishment of the Major Projects Management Office ("MPMO") in 2007 "to improve the performance of the review process for major natural resource projects…"[4], as mandated by a federal Cabinet Directive on Improving the Performance of the Regulatory System for Major Resource Projects. The wide variety of government interests that are engaged is reflected in the fact that no fewer than 12 federal departments participate directly in the "horizontal initiative." That reality is not going away!

Further, it is reported that legislation expected to be tabled by the new federal government in June to promote the "One Canadian Economy" will include measures aimed at providing faster regulatory approval for projects through a **new** "Major Projects Office."

My second example illustrates the potential in undertaking any regulatory reform initiative of "unintended consequences."

For more than 50 years, Canada in fact had a "single window" regulatory authority with responsibility for reviewing and certifying oil and gas pipelines under federal jurisdiction, namely, the National Energy Board. From its establishment in 1959, the NEB was mandated, in the broadest possible terms, to consider, among other specific matters, "**any** public interest that in the Board's opinion may be affected…"[5] While this formulation did not confer on the Board exclusive authority, it at least provided project proponents with a single point of entry into the federal regulatory maze.

The independence of the NEB was entrenched in the *NEB Act*. The tenure of Board members was secured by a formula for their removal through a process borrowed directly from the *Supreme Court of Canada Act*.[6]

Most importantly, the Board was responsible for actually issuing certificates of public convenience and necessity, not merely for making a recommendation to Cabinet. While a Board decision to issue a certificate was subject

[4] Nature Resources Canada, "Major Projects Management Office Initiative (MPMOI)" (last modified 29 January 2025), online : <natural-resources.canada.ca/corporate/planning-reporting/departmental-results-reports/departmental-results-reports-2017–18/major-projects-management-office-initiative-mpmoi>.

[5] *NEB Act*, *supra* note 2 s 52.

[6] *Supreme Court Act*, RSC, 1985, c S-26.

to Cabinet approval, Cabinet could not amend or vary a Board decision; Cabinet could only approve or refuse to approve the decision of the Board. More significantly, Cabinet had no role where the Board decided to **reject** an application for a certificate. A refusal by the Board to issue a certificate did not even find its way to the Cabinet table.[7] It was this feature of the formula established by the *NEB Act* that may have led the government in 2012 to introduce amendments that fundamentally changed the role of the Board.

In 2010, Enbridge filed an application with the NEB for approval of the Northern Gateway Project. Apparently, there was concern that, were the NEB to reject Enbridge's application, the government would have no mechanism for reversing or amending the decision, should the government decide that the project was indeed in the national interest and should proceed, despite a decision by the Board to the contrary.

Whatever the motivation, the *NEB Act* was amended in 2012 to change the role of the NEB from that of decision-maker to that of making a mere recommendation to Cabinet, which in future could accept, reject or vary a Board recommendation.

In the event, the NEB in fact recommended approval of the Northern Gateway Project, Cabinet accepted the recommendation and a certificate was of public convenience and necessity for the Project was issued.[8] The change in the role of the Board, resulting in for approving or rejecting pipeline applications being assumed by the Cabinet, proved to have been unnecessary.

It was, however, the government's role in the initial approval of the Northern Gateway Project and the widespread controversy surrounding the Project that triggered the subsequent drive to "modernize" the NEB. That debate in turn contributed to the enactment of the *Impact Assessment Act* ("Bill C-69"),[9] the abolition of the NEB and the establishment of the Canadian Energy Regulator.

The lesson relevant to the current debate about simplifying the regulatory process might be captured in the familiar adage "be careful what you wish for"!

My third example of challenges faced by efforts to simplify the regulatory review process relates to widespread calls to mandate fixed timelines for project approvals. Mandatory timelines for NEB reviews were included among the 2012 amendments of the *NEB Act* and thus were in place in December 2013 when Trans Mountain filed its application the proposed system expansion, the TMX Project. Final approval of TMX, however, was not forthcoming until February 2019, more than five years later. The Project finally came into service in 2024, nearly 10 years after the original application was filed.

Two observations about mandatory time limits. Firstly, such limits cannot be unconditional and must be accompanied by off ramps in order to anticipate the possibility, if not likelihood, of unforeseen circumstances requiring adjustments in project schedules, sometimes at the request of project proponents.

Secondly, mandatory timelines can directly challenge principles of procedural fairness. Indeed, the 2012 amendments to the *NEB Act* openly recognized this potential and stated bluntly that "considerations of fairness" must yield to the prescribed time limits.[10]

Mandated timelines for approvals may have a role to play in improving the efficiency of the regulatory review process. However, their effectiveness ultimately rests on the commitment of each participant in the overall process, including project proponents, to fulfill its individual role in an effective, efficient and **timely** manner.

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[7] See Rowland J Harrison, "The Elusive Goal of Regulatory Independence and the National Energy Board: Is Regulatory Independence Achievable? What Does Regulatory "Independence" Mean? Should We Pursue It?" (2013) 50:4 Alta L Rev 757.

[8] The issuance of this certificate was subsequently set aside by a decision of the Federal Court of Appeal, on the ground that the federal government (not the NEB) had not met its obligations with respect to consultation relating to Indigenous rights. The federal government decided not to appeal that FCA decision, thereby in effect cancelling the Project.

[9] *Impact Assessment Act*, SC 2019, c 28 s 1.

[10] *NEB Act*, *supra* note 2 s 11(4).

None of these three examples is intended to suggest that the challenges in simplifying the regulatory process for reviewing major infrastructure projects are insurmountable; obviously those challenges must be addressed. The point is that "simplification" is not so simple, certainly not as simple as many critics suggest — and as some politicians would have people believe.

Let's hope that all interested parties will contribute constructively to addressing the challenges in Canada's current regulatory process for reviewing major infrastructure projects, while recognizing and accommodating the multiple legitimate interests that are impacted by such projects. Let's hope that the opportunity — or "crisis," as many insist — does not go to waste and that down the road we do not look back and conclude, regretfully:

Plus ça change, plus c'est la même chose

Thank you. ■

REPLY TO "ARE THINGS DIFFERENT THIS TIME? REFLECTIONS ON A CAREER IN ENERGY REGULATION"

*Tim Sargent Ph.D.**

It is a great pleasure to have the opportunity to comment on Rowland Harrison K.C.'s thoughtful reflection on his career as a regulator. I do so from a different vantage point: I am an economist, not a lawyer, and most of my career has been spent not as a regulator, but in the policy world, both at the Privy Council Office, where I was involved in the changes to the *Canadian Environmental Assessment Act*[1] ("*CEAA*") in 2012, and as Deputy Minister of Fisheries and Oceans, where I was around for the 2019 changes to the *Fisheries Act*[2] and the new *Impact Assessment Act*[3] ("*IAA*").

In his article, Mr. Harrison concludes that the recent calls to "simplify regulation"— reflected in the Carney government's Bill C-5, the *One Canadian Economy Act*[4] (which enacts the *Free Trade and Labour Mobility in Canada Act* and the *Building Canada Act*) — are nothing new, and in many ways the Carney government is taking a similar approach to the Harper government and will face many of the same challenges. He gives three examples of where this is likely to be true.

The first is the idea of a single federal window for proponents. As Mr. Harrison notes, the Harper government set up the Major Projects Management Office ("MPMO") in 2007 precisely to provide that single window. However, the establishment of this office (which was ultimately eliminated when the *IAA* came in to being) did not obviate the regulatory role of the Department of Fisheries and Oceans ("DFO"), Environment and Climate Change Canada ("ECCC"), Transport Canada ("TC") and several other agencies and departments. At the end of the day, companies still had to deal with the relevant Departments for permitting, often a lengthy process.

Bill C-5 attempts to deal with this multiplicity of decision makers by subordinating all federal decision making for projects that are deemed in the national interest to Cabinet, which would then make an early decision on a project.

This provides Mr. Harrison with his second example. Centralizing all decision-making power to Cabinet has a parallel to the decision of the Harper government to take away the National Energy Board's ("NEB") power to not approve a project. He notes that this decision ultimately did nothing to hasten the

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[1] *Canadian Environmental Assessment Act*, SC 2012, c 19 s 52.

[2] *Fisheries Act*, RSC 1985, c F-14.

[3] *Impact Assessment Act*, SC 2019, c 28 s 1.

[4] Bill C-5, An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act, *One Canadian Economy Act*, 1st Sess, 44th Parl, 2025.

Northern Gateway project, which, as it turned out, the NEB would have approved anyway. Instead, the erosion of the NEB's independent decision-making power made it easier for the it made it easier for the Trudeau government to do away with the NEB altogether and replace it with the Canadian Energy Regulator which, unlike the NEB, was not responsible for environmental assessments.

The third example is the attempt to establish deadlines for project decisions, so that proponents can be assured that the process will not drag on, costing them time and money. While not made explicit in Bill C-5, Prime Minister Carney has committed to a two-year timeline for project approvals. However, deadlines for project approval are nothing new: the 2012 changes to the NEB Act prescribed a timeline of 18 months, which did not prevent the Trans Mountain Pipeline Expansion ("TMX") from taking more than five years to be approved. Indeed, the Trudeau government's *IAA* also had statutory deadlines. The reality is that statutory deadlines do not deal with one of the main sources of delay, which is legal challenges to projects on environmental or indigenous rights grounds. Furthermore, proponents themselves may end up needing more time and so ask for the process to be paused.

Thus a convincing case can be made that many of the underlying problems have not changed in the last two decades. Indeed, I would argue that in many ways the challenges that the Carney government faces are greater than those faced by Prime Minister Harper, given the evolving environment since the election of the Trudeau government in 2015.

- The Trudeau government's emphasis on reconciliation, and in particular the incorporation of the *United Nations Declaration on the Rights of Indigenous Peoples*[5] ("UNDRIP") into law, means that many Indigenous communities now expect to have an overall veto over development.
- Many environmental non-government organizations ("ENGOs") now oppose projects based not only on the direct environmental impacts of a project, but also on the impact on green house gases ("GHGs"). The Trudeau government's *IAA* reflected this approach by including GHGs as a criterion for project approval.
- Two provinces, B.C. and Quebec, vociferously opposed pipelines crossing their jurisdictions, with B.C. launching a legal challenge to TMX, and Quebec seeking to subject the EnergyEast pipeline to its own environmental assessment process, despite the federal government having clear federal jurisdiction over interprovincial transportation infrastructure. The Carney government has gone further than the Trudeau government in this regard, with the Prime Minister stating that provinces would need to agree to any pipeline crossing into "their" territory[6].
- Other changes, including the ban on tanker traffic on the West coast north of Vancouver Island and regulatory initiatives to curtail fossil fuel production, such as the oil and gas emissions cap, all make it more difficult to fill new oil and gas pipelines even if they were to be approved and built.

Given these obstacles, as well as the challenges faced by the Harper government, will Bill C-5 provide a firm basis for moving forward on major energy projects in Canada, particularly pipelines?

I tend to agree with Mr. Harrison that centralizing authorities and decision making, and imposing timetables, are unlikely to be a successful as the government would wish, as they do not really grapple with the fundamental causes of the Canada's slow, cumbersome and

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

[6] Carson Jerema, "Carson Jerema: Carney ignores his own constitutional power to approve pipelines" (last modified 9 Jun 2025), online: <nationalpost.com/opinion/carson-jerema-carney-ignores-his-own-constitutional-power-to-approve-pipelines>.

unpredictable project approval process, which includes the following:

Lack of a transparent and timely Indigenous consultation process

- While the Bill makes numerous references to the rights of Indigenous people, it does not lay out a clear consultation process that will provide a fair hearing to Indigenous communities, which makes it likely that aggrieved communities will be able to successfully challenge decisions, as happened with the Trans Mountain pipeline[7].

Onerous federal environmental requirements

- Bill C-5 attempts to circumvent numerous pieces of federal legislation, such as the *Species at Risk Act*[8] ("*SARA*"), the *Fisheries Act*[9] ("*FA*") and the *Migratory Birds Act*[10] ("*MBA*"). The provisions of these laws have been blamed for lengthening timelines for approval and construction, both because they require extensive study of project impacts, but also because they can lead to onerous requirements on proponents (the Northern Gateway pipeline had 209 conditions and TMX had 159). Bill C-5 essentially has Cabinet make the project approval upfront, based on "any factor that the Governor in Council considers relevant," (section. 5(6)), and that approval supersedes the requirements of other relevant legislation.

- However, the Cabinet decision will still be reviewable by the courts on a reasonableness standard, and it is an open question as to whether the courts will insist on the same kind of information about environmental impacts to be placed before decision makers as would be required under *SARA, FA, MBA* etc.

- Furthermore, Bill C-5 is clear (section. 6(2)) that proponents must still meet any conditions that are set by the government. These conditions would also be subject to a judicial review on a reasonableness test, and without specific criteria laid out in the legislation, the courts may well look to existing legislation to assess the reasonableness of the conditions. The risk is that the government would be obligated to impose dozens of conditions that proponents might find expensive to meet.

Confusion about Federal and Provincial roles

- As noted above, several provinces have challenged the federal government's right to approve interprovincial projects, and the Carney government now seems to have given provinces a veto over projects that pass their boundaries. In fairness to the provinces, the federal government has not hesitated to interfere in areas of provincial responsibility, most notably through the *IAA*, where the Supreme Court of Canada[11] struck down provisions that were judged to be entirely within the competence of the provinces. Another example is *SARA*, which numerous provincial governments have criticized for intruding on provincial jurisdiction when applied outside of federal lands, and to species other than fish or migratory birds for which the federal government has clear responsibility.

Confusion about government and business roles

- Ideally, governments should do what they do best, which is to regulate in the national interest, with clear rules of the road that provide certainty and predictability for businesses to do what they do best, which is to choose, design and execute projects that make economic sense.

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[7] *Tsleil-Waututh Nation v Canada (Attorney General)*, 2018 CanLII 153.

[8] *Species at Risk Act*, SC 2002, c 29.

[9] *Fisheries Act*, RCS 1985, c F-14.

[10] *Migratory Birds Convention Act*, SC 1994, c 22.

[11] *Reference re Impact Assessment Act*, 2023 SCC 23.

- However, Bill C-5 blurs these lines: while it provides maximum discretion for the government to label a project as being in the national interest, it does not guarantee that outcome, no matter what criteria a project might meet, and so potential proponents are left in the dark about what will actually qualify.

What then is the way forward? In his closing paragraph, Mr. Harrison concludes by hoping that "all interested parties will contribute constructively to addressing the challenges in Canada's current regulatory process." I am not sure that this will happen to the extent necessary to make a significant change to the regulatory environment for major energy projects in Canada. As we saw with TMX, many ENGOs, Indigenous nations and even provinces can remain implacably opposed to a project despite attempts to accommodate legitimate concerns.

Rather, I would argue that the government needs to address the fundamental problems with our environmental assessment system that are outlined above. Achieving this will require:

1. A clear protocol on Indigenous consultation that lays out a clear process and reasonable timelines. This protocol should of course be consulted on with Indigenous nations, following which the government should refer the protocol to the SCC so that proponents can be confident that they can meet their consultation obligations with fear of a successful lawsuit;

2. Root and branch reform of Federal environment legislation, particularly the *IAA* and SARA, to eliminate intrusion by the federal government in provincial areas of competence;

3. Explicit assertion of the federal government's paramountcy in areas of clear federal competence, particularly interprovincial pipelines;

4. Clear criteria for proponents as to what kinds of projects that the federal government would find acceptable.

While Bill C-5 is clearly ambitious and well-intentioned, I suspect that the more fundamental reforms described above will be required if Canada is indeed to see the investment in its energy infrastructure that will be so necessary to our economic success as a nation in the coming years. ■

BUILDING CANADA ACT: MOVE FAST AND MAKE THINGS, OR MOVE FAST AND BREAK THINGS?

*David V. Wright and Martin Z. Olszynski**

INTRODUCTION

On Friday, June 6th, the new Carney government tabled Bill C-5, Part II of which consists of the *Building Canada Act*.[1] Following an extremely expedited legislative process that was virtually unprecedented, the new law received Royal Assent less than three weeks later, on June 26, 2025.[2] The new legislation is intended to follow through on a promise to speed up resource development and streamline federal project approvals.[3] Tabling of the Bill followed the June 2025 First Ministers' meeting,[4] where there was discussion of potential major projects such as "highways, railways, ports, airports, oil pipelines, critical minerals, mines, nuclear facilities, and electricity transmission systems."[5] The Bill entered today's broader context of threats to Canada's economic security and sovereignty due to developments south of the border such as tariffs and expressed imperialist ambitions,[6] and the associated shockwaves rumbling through global economic and political orders.

Part I of this article sets out the basic structure and approach of the *Building Canada Act* as it was first tabled, offering initial reflections and commentary. Part II describes some of the more important amendments that were introduced by the House Transportation Committee and adopted at third reading by the House of Commons.[7] Part III sets out some further

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[1] Bill C-5, *An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act*, 1st Sess, 45th Parl, 2025 (first reading June 6, 2025) [*Bill C-5, Building Canada Act*].

[2] Bill C-5, *An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act*, 1st Sess, 45th Parl, 2025 (assented to June 26, 2025).

[3] Mark Ramzy, "Mark Carney's promise to 'build, baby, build' has some Canadians fearing the worst", *The Toronto Star* (24 May 2025), online: <thestar.com> [perma.cc/HUE7-EA9A]. See also see also the recent Speech from the Throne: Canada, Privy Council, *Speech from the Throne*, 1st Sess, 45th Parl (May 27, 2025) online: <canada.ca/en/privy-council> [perma.cc/JB69-W8T3].

[4] Prime Minister of Canada, Statement, "First Ministers' statement on building a strong Canadian economy and advancing major projects" (2 June 2025), online: <pm.gc.ca/en/news/statements> [perma.cc/G7Y4-9CF2].

[5] Canada, Intergovernmental Affairs, *One Canadian Economy: An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act*, (Ottawa: Intergovernmental Affairs, 6 June 2025), online: <canada.ca/en/intergovernmental-affairs> [perma.cc/3QHD-D8FY].

[6] Allan Smith & Peter Nicholas, "Trump's quest to conquer Canada is confusing everyone", *NBC News* (14 March 2025), online: <nbcnews.com> [perma.cc/YY3L-Q4HS].

[7] Canada, House of Commons, *Bill C-5, An Act to enact the Free Trade and Labour Mobility in Canada Act and the Building Canada Act*, Standing Committee on Transport, Infrastructure and Communities, 1st Sess, 45th Parl, 2025 (Chair: Peter Schiefke), online: <ourcommons.ca> [perma.cc/TS5N-2RH7]. The Senate ultimately chose not to propose any amendments of its own, but it should be noted that the House rose before the Senate was even able to debate potential amendments, meaning that the Senate was not in a position to propose and push for amendments without requiring the House to reconvene.

commentary on the broader trendlines and implications of the *Building Canada Act*.

Overall, while there are several concerning features in the proposed law (in addition to, and likely because of, the rushed drafting and parliamentary processes), much will come down to how the Act is implemented. It may be the case that this new law does not change very much in a practical sense. Projects will still be proposed, reviewed, and built in compliance with binding federal regulatory authorizations and associated approval conditions.

However, the *Building Canada Act* does provide new, broad legislative authority that creates a new legal pathway for at least a small number of projects to proceed more swiftly — and some might say recklessly — than before. Whether such an approach unfolds as 'move fast and make things' or 'move fast and break things' remains to be seen. Cautionary tales in the Canadian context suggest that rushing and narrowing review processes for major resource and infrastructure projects can lead to backlash (e.g. Idle No More),[8] cost overruns, lengthy legal battles, and, in worst case scenarios, devastating impacts to human and ecosystem health.

PART I: THE GENERAL PROCESS AND MECHANICS OF THE *BUILDING CANADA ACT*

Notwithstanding preambular attention to environmental protection and the rights of Indigenous peoples, the proposed legislation is laser focused on "an accelerated process that enhances regulatory certainty and investor confidence."[9] The primary way of achieving this is, to adopt the government's phrasing, shifting the process from "whether" a project should be build to "how".[10] The linear structure of the proposed process is relatively simple, premised primarily on providing project proponents with an early green light from the federal government and limiting — although not eliminating — the chance of a late-stage red light (see discussion below regarding s.5(4) and 5(5)).

First, based on five explicit but non-exhaustive factors, a project is identified and included on the Schedule 1 as one of national interest ("project of national interest" or PONI hereafter).[11] Second, all federal determinations and findings that have to be made with respect to the listed PONI (e.g. the decision to issue a *Fisheries Act* authorization for impacts to fish habitat) are deemed to have been made in favour of the project being carried out.[12] Third, the PONI proponent must take all measures necessary to satisfy those same federal authorizations, and potentially affected Indigenous communities must be consulted (the timing and duration of this third step is unclear and will most certainly vary between projects).[13] Fourth, the Minister must subsequently issue to the PONI proponent an all-authorizations-in-one document that is deemed to be all required authorizations — and deemed to meet the requirements of all the enactments under which those authorizations would normally be sought. This document must include conditions with respect to the applicable federal authorizations.[14]

The following elaborates on these four steps and then considers the remaining provisions in the Bill related to federal life-cycle regulators, an exceedingly broad executive law making and amending power, and a reporting requirement.

1. IDENTIFYING AND LISTING PROJECTS OF NATIONAL INTEREST (PONIS)

At the heart of the proposed law is the creation of a PONI list. Under s 5(1) the Governor in Council (i.e. federal Cabinet) may, on recommendation from the Minister, add a

[8] Laura Beaulne-Stuebing, "How Idle No More transformed Canada", *CBC Radio* (26 November 2022), online: <cbc.ca/radio> [perma.cc/8M2F-87MC].

[9] *Bill C-5, Building Canada Act*, *supra* note 1 s 4.

[10] Rachel Aiello, "Carney gov't tables bill to reduce interprovincial trade barriers, build national projects", *CTV News* (6 June 2025), online: <ctvnews.ca> [perma.cc/4LNQ-35YD].

[11] *Bill C-5, Building Canada Act*, *supra* note 1 schedule 1 & s 5(5).

[12] *Ibid* s 6(1); see e.g., *Fisheries Act*, RSC 1985, c F-14.

[13] *Bill C-5, Building Canada Act*, *supra* note 1 s 6(2), 7(2)(c).

[14] *Ibid* s 7(1).

PONI to Schedule 1, which is essentially the master PONI list.[15] A PONI's name and description can be continually amended and, as alluded to above, a PONI can even be deleted from the list right until the moment that it has received its s 7 decision document,[16] which of course would mean it no longer benefits from the exalted status that listed PONIs receive, including priority treatment within the federal system. Depending on how the government uses (or doesn't use) this PONI deletion power, the potential of being deleted from the PONI list could constrain proponents from being too cavalier in terms of demanding exemptions from current federal regulatory requirements (e.g. authorizations under the *Fisheries Act*), as further discussed below.

The basis for identifying PONIs is set out in s 5(6), which includes the following non-exhaustive list of factors that may be considered:

> (a) strengthen Canada's autonomy, resilience and security;
>
> (b) provide economic or other benefits to Canada;
>
> (c) have a high likelihood of successful execution;
>
> (d) advance the interests of Indigenous peoples; and
>
> (e) contribute to clean growth and to meeting Canada's objectives with respect to climate change.[17]

Additionally, s 5(7) requires that before recommending a PONI be added to the list, the Minister "must consult with any other federal minister and any provincial or territorial government that the Minister considers appropriate and with Indigenous peoples whose rights recognized and affirmed by section 35 of the *Constitution Act, 1982* may be adversely affected by the carrying out of the project to which the order relates."[18]

It is notable that there are no timelines or other prescriptive procedural obligations imposed on the listing process, although the amendments discussed in Part II will bring considerably more transparency to the exercise. This leaves much latitude for government and proponents, and presumably this will vary on a case-by-case basis. One key aspect to watch is the extent to which the present rush to identify and list projects compromises meaningful consultation with Indigenous peoples. Indigenous governments and leaders have already expressed concerns.[19] How can the Crown fulfill its consultation obligations (let alone obtain consent) with respect to a large-scale nation-building project within the short timelines that seem to be envisioned by government and proponents? The answer is not entirely clear. Perhaps the only way is for the first string of PONIs to only include projects that are already entirely supported by Indigenous peoples who may be adversely affected by the project.

2. DEEMINGS AND APPROVALS

By virtue of a PONI being added to the list, it receives an early green light for any federal regulatory approvals that may be required. Section 6(1) provides that all federal "determinations and findings" that have to be made in order for an authorization to be granted with respect to the listed PONI are deemed to have been made in favour of the project being carried out.[20] However, that deeming "does not exempt the proponent of a project from the requirement to take all measures that they are required to take…in respect of an authorization."[21]

[15] *Ibid* schedule 1, s 5(1).

[16] *Ibid* s 5(3), s 7, ss 5(4)–(5).

[17] *Ibid* s 5(6).

[18] *Ibid* s 7(2)(c).

[19] Emily Haws & Laura Stone, "AFN calls emergency meeting to discuss Bill C-5" *The Globe and Mail* (June 6, 2025), online: <theglobeandmail.com> [perma.cc/CZ3F-HQ7B]. See also Mark Blackburn, "9 First Nations challenge federal and provincial project laws in court" *APTN News*, online: <aptnnews.ca/national-news/9-first-nations-challenge-federal-and-provincial-project-laws-in-court>.

[20] *Bill C-5, Building Canada Act*, *supra* note 1 s 6(1).

[21] *Ibid* s 6(2).

Again, this shifts the process from a "whether" to a "how" by effectively guaranteeing that an authorization will be provided while still requiring that the proponent actually do what is required to obtain that authorization (subject to potential future regulations that may remove such requirements, as further discussed below). For example, a PONI proponent may be assured that they will obtain the necessary *Fisheries Act* s 35 authorization to cause the harmful alteration, disruption, or destruction of fish habitat (HADD), but they still have to apply for said authorization in accordance with the relevant regulations.[22]

Before recommending a PONI for listing, the Minister must consult with any other federal minister and any provincial or territorial government that the Minister considers appropriate, and further to the above point, must consult with "with Indigenous peoples whose rights recognized and affirmed by section 35 of the *Constitution Act, 1982* may be adversely affected by the carrying out of the project to which the order relates".[23] How meaningful consultation with Indigenous communities can happen at this stage is a mystery given that consultation is very fact and context specific, yet at this early stage many of the facts and details about the project would still be unknown. Again, the only fathomable shortcut is a context where the Indigenous community is prepared to provide full, free, prior, informed, and explicit consent and deem Crown consultation to be fulfilled at this early stage.

3. ALL-IN-ONE AUTHORIZATIONS AND CONDITIONS DOCUMENT

Once all relevant authorizations are sought pursuant to s 6, the Minister is required to provide the PONI proponent with a document that is "deemed to be each authorization that is specified in the document in respect of the project."[24] This all-authorizations-in-one document can only be issued after three conditions are met: proponent has taken all measures in respect of each otherwise applicable federal authorization; the Minister has consulted on approval conditions with the minister responsible for each of the federal authorizations; and Indigenous peoples have been consulted regarding potential adverse effects.[25] The document must also set out conditions that apply with respect to each federal authorization.[26] Those conditions are linked to their respective specific federal authorization to ensure sound jurisdictional and constitutional footing.[27] Conditions and authorizations can be amended, provided the minister fulfills any further consultation requirements.[28] Schedule 2 of the proposed Act sets out the relevant federal statutes and regulations pursuant to which authorizations may be required, such as the *Fisheries Act*, the *Canadian Navigable Waters Act*,[29] and the *Species at Risk Act*.[30]

While this new process would be moving very quickly up to the point of adding a PONI to Schedule 1, it would then presumably slow down as it will unavoidably take time for the proponent to gather information, make submissions for regulatory approvals, and work with regulators throughout these specific federal regulatory processes. Such a slowing down at this multi-faceted stage would, however, be tempered by the creation of a new "Major Projects Office" (MPO), which will serve as a single point of contact.[31]Through this approach, the Minister ultimately issues a single all-in-one document rather than multiple ministers issuing individual regulatory decisions.

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[22] *Fisheries Act*, RSC 1985, c F-14 s 35 [*Fisheries Act*]. See also, *Authorizations Concerning Fish and Fish Habitat Protection Regulations*, SOR/2019-286 s 2.

[23] *Bill C-5, Building Canada Act*, *supra* note [1] s 5(7).

[24] *Ibid* s 7(1).

[25] *Ibid* s 7(2).

[26] *Ibid* s 7(5).

[27] *Ibid* ss 7(5)–(6).

[28] *Ibid* ss 8(1)–(3).

[29] *Canadian Navigable Waters Act*, RSC 1985 c N-22.

[30] *Species at Risk Act*, SC 2002 c 29.

[31] *Supra* note 5; *Bill C-5, Building Canada Act*, *supra* note 1 s 20.

To be clear, there is no harm, and indeed some utility, in consolidating the necessary authorizations and permits in one place. But the *Building Canada Act* goes further: subsection 7(3) "deems" that the master authorization meets the requirements of all the enactments that would govern relevant authorizations in the normal course.[32] The use of the term "deem" is critical here. As explained by the federal Department of Justice, "deeming" is used to create a *legal fiction*.[33] To understand why such a fiction is problematic, it is useful to recall that modern environmental laws are both outward and inward facing: they constrain individuals and corporations but those constraints are rarely absolute — they're an opening bid. At that point, recognizing governments' prior poor track record of taking environmental concerns into account in decision making, environmental laws seek to constrain the executive branch too.

For example, if a PONI is going to impact fish habitat, then section 34.1 of *Fisheries Act* would normally require DFO to consider several factors, including the potential for cumulative effects, before issuing an authorization.[34] If a PONI triggers the *Impact Assessment Act*, the Agency and the Minister are normally bound by section 6 to apply the precautionary principle and adhere to the principle of scientific integrity.[35] These constraints are guideposts: they do not dictate a particular outcome but help to guide decision-making — to varying degrees — towards sustainable development.[36]

Subsection 7(3) essentially amputates this part of the federal environmental regime for PONIs. It creates the 'legal fiction' that the designated Minister has complied with all these guideposts — even if they do not.[37] Further, because it is a legal fiction explicitly created by statute, the Canadian judiciary's supervisory role also appears to have been circumscribed or even negated — a role that has proven critical in securing at least some semblance of implementation of Canada's environmental laws. It remains to be tested in court, but a section 7 authorization may be effectively immune from legal challenges except those that have a constitutional dimension, such as a failure of the federal Crown to fulfill its consultation and accommodation duties with respect to potentially adversely affected Indigenous peoples.[38]

4. RELATION TO OTHER FEDERAL REVIEW PROCESSES

Sections 9–18 of the Bill set out how the proposed PONI regime would interface with other existing federal regulators that engage in project review processes.[39] This is because some PONIs may fall under the authority of these other regulators, including the Nova Scotia and Newfoundland offshore regulatory boards, the Canadian Nuclear Safety Commission, and the Canada Energy Regulator. The basic approach under the Bill is to require the Minister designated under the *Building Canada Act* to consult with those regulators prior to issuing a section 7 document, to consult with them again prior to amending any conditions in a section 7 document, and in all cases to only issue a section 7 document for such projects if certain conditions are met (these vary from regulator to regulator but generally include human safety and regard for relevant international obligations).[40] Beyond that, the PONI regime leaves undisturbed the processes administered by these federal bodies, with the overriding difference being that all determinations and findings are all deemed to favour project approval.

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[32] *Ibid* s 7(3).

[33] Canada, Department of Justice, *Legistics*, (2024) online:<justice.gc.ca> [perma.cc/9DBR-TYVY].

[34] *Fisheries Act*, *supra* note 21 s 34.1.

[35] *Impact Assessment Act*, SC 2019 c 28; *Bill C-5, Building Canada Act*, *supra* note 1 s 6.

[36] A. Dan Tarlock, "Is There a There There in Environmental Law?" (2004) 19 J Land Use & Envtl L 213.

[37] *Bill C-5, Building Canada Act*, *supra* note 1 s 7(3).

[38] Of course, such challenges have been fairly common in the past two decades, including with respect to the Northern Gateway pipeline project, the Trans Mountain pipeline expansion project, and both the Site C and Muskrat Falls hydro-electric projects, to name just a few.

[39] *Bill C-5, Building Canada Act, supra* note 1 s 9–18.

[40] *Ibid* s 7.

The Bill also recognizes that some (perhaps most) PONIs may also be designated projects under the federal *Impact Assessment Act* ("*IAA*"). The *IAA* process would still apply, but with one significant modification — elimination of the 180-day planning phase.[41] For those with an interest in robust public participation and belief in the logic of the planning phase providing the time and space to build relationships and social license, this is a significant step backward. The government could temper this regression by targeting PONIs that are already well advanced, including significant past engagement and involvement with members of the public and Indigenous communities.

Finally, it is implicit based on the text of the Bill that processes established under modern treaties and self-government agreements do not change. For example, a project that triggers application of the *Yukon Environmental and Socio-economic Assessment Act*, the *Mackenzie Valley Resource Management Act*, or the *Nunavut Planning and Project Assessment Act* would still have to be assessed under those statutes.[42] However, it is possible that the location of a PONI is within the geographical area covered by those statutes and associated modern treaties. In such a case, the *Building Canada Act* could still apply as a way for the federal government to centralize and expedite the federal authorizations aspect of the project (e.g. a *Fisheries Act* authorization). One such example would be the Grays Bay port and road.[43] To be clear, however, the *Building Canada Act* would not — and constitutionally could not — oust the applicable northern assessment regime. Rather, one way to conceptualize the proposed new landscape is that the northern assessment regimes that are rooted in constitutionally protected modern treaties actually oust much of the approached envisioned in the *Building Canada Act*.

5. HENRY VIII CLAUSES

As initially drafted and tabled, sections 21, 22 and 23 gave Cabinet unrestricted authority to make regulations not merely to flesh out the provisions of the Act, as is the normal course, but to modify and even exempt the application of *any law* in the federal statute book (this power was somewhat tempered by the amendments discussed in Part II, below).[44]

Such executive law-making powers are referred to as Henry VIII clauses, as Olszynski and Bankes explained when Premier Danielle Smith initially sought such powers for herself under Alberta's sovereignty legislation: "A Henry VIII clause is a provision in a statute that delegates to a subordinate body the authority not simply to pass regulations or the like under the statute, but to amend the statute itself."[45] As was the case there, Bill C-5 initially contained an extraordinarily broad version of a Henry VIII clause insofar as it authorized regulations to modify and even exempt the application of the federal statutes listed in Schedule 2, which schedule already includes many of Canada's most important environmental laws but can also be further amended, without limitation, pursuant to section 21.

This would be a staggering power — even by today's standards. Comparing the Henry VIII clauses in all such recent legislation — Alberta's Bill 1 (*Alberta Sovereignty within a United Canada Act*), British Columbia's Bill 7 (*Economic Stabilization Act*) and Bill 15 (*Infrastructure Projects Act*), and Ontario's own Bill 5 (*Special Economic Zones Act*), the initial *Building Canada Act* was only matched by Premier Ford's legislation for its breadth.[46] As further discussed in Part II, it has been tempered by including a list of laws that Cabinet may not amend or exempt by regulation.

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[41] *Ibid* s 19; *Supra* note [30] ss 9–17, 18(3)–(6).

[42] See e.g., *Yukon Environmental and Socio-economic Assessment Act* SC 2003, c 7; Mackenzie *Valley Resource Management Act* SC 1998, c 25 and *Nunavut Planning and Project Assessment Act* SC 2013, c 14, s 2.

[43] See David Thurton, "Here's a look at some major projects Canada's leaders hope to fast-track", *CBC News* (June 4, 2025), online: <cbc.ca/major-projects-carney-fast-track> [perma.cc/ARE9-D8HB].

[44] *Bill C-5, Building Canada Act*, *supra* note 1 s 21–23.

[45] Martin Olszynski and Nigel Bankes, "Running Afoul the Separation, Division, and Delegation of Powers: The Alberta Sovereignty Within a United Canada Act" (6 December 2022), online (blog): ABLawg <ablawg.ca> [perma.cc/4H4C-FZBJ]; Nigel Bankes and Martin Olszynski, "The Amendments to Bill 1" (12 December 2022), online (blog): ABLawg <ablawg.ca/amendments-to-bill-1>[perma.cc/5P8G-BE4H].

[46] Bill 1, *Alberta Sovereignty Within a United Canada* Act, 4th Sess, 30th Leg, Alberta, 2022 (assented to December 15, 2022); Bill 7, *Economic Stabilization (Tariff Response) Act*, 1st Sess, 43rd Parl, British Columbia, 2025 (first reading May 7, 2025); Bill 15, *Infrastructure Projects Act*, 1st Sess, 43rd Parl, British Columbia 2025 (third reading May 28, 2025) and Bill 5, *Special Economic Zones Act*, 1st Sess, 44th Parl, Ontario (assented to June 5, 2025).

6. SUNSET AND REPORTING

Pursuant to section 5(2), the PONIS regime expires 5 years after the coming into force of the legislation.[47] Within that time, section 24 requires the designated Minister to complete "a review of the provisions and operation of this Act…and of the efficacy of the federal regulatory system in relation to projects that are in the national interest," and to present it to Parliament.[48] This is a laudable requirement — the whole debate about the merits of impact assessment is currently transpiring in what might be described as a 'fact-free zone' — but this provision would benefit from greater specificity — and indeed has (as discussed in Part II, below).

PART II: AMENDMENTS ADOPTED AT THIRD READING

Using similar structure and headings as above in Part I, this part briefly describes and discuses some of the more important amendments to the *Building Canada Act* adopted at third reading.[49] Overall, the thrust of the amendments is to increase transparency and accountability requirements and mechanisms that will allow for at least some public scrutiny and oversight by courts and civil society.

1. IDENTIFYING AND LISTING PROJECTS OF NATIONAL INTEREST (PONIS)

Added with the amendments that were integrated at third reading was section 4.1(1), which authorizes Cabinet to define the "national interest" for the purposes of PONI listing, including setting out specific criteria that must be met. If Cabinet does not exercise this authority within 15 days of the coming in force of the Act, the Minister must table a report explaining the reasons for the delay and the expected timeline for defining "national interest."[50]

Section 5 was also amended to require a detailed — not short — description of the PONI, while a new subsection 5(1.1) requires 30 days notice in the *Canada Gazette* and the written consent of the province or territory in which the PONI will be carried out if it also falls within areas of exclusive provincial or territorial jurisdiction (bearing in mind that the *Constitution Act, 1867* generally grants exclusive authority *to make laws* in relation to matters falling within sections 91 or 92, not exclusive authority over projects *per se*). It was conspicuous, during the hasty legislative process, that amendments included attention to explicit consent of provinces and territories but not Indigenous peoples.

Several amendments will also result in the creation of a public registry[51] that is accessible to the public through the internet and will contain:

> (a) a detailed description of the project and the reasons why it is in the national interest;
>
> (b) the extent to which the project is expected to meet the outcomes set out in paragraphs 5(6)(a) to (d);
>
> (c) detailed cost estimates that do not include private sector commercially sensitive financial information; and
>
> (d) the estimated timelines for completion of the project.

This registry will be especially important for PONIs that do not trigger an impact assessment under the IAA (for which a public registry already exists),[52] although the requirements in 5.1(2) (b)–(d) also differ from what is explicitly required in the IAA registry.

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[47] *Bill C-5, Building Canada Act*, *supra* note 1 s 5(2).

[48] *Ibid* s 24.

[49] The amendments flow from the amendments produced by the review and report of the Standing Committee on Transport, Infrastructure and Communities (TRAN) (see Canada, House of Commons, "Standing Committee on Transport, Infrastructure and Communities" (last visited 10 August 2025), online: <ourcommons.ca/Committees/en/TRAN?parl=45&session=1>, *supra* note 7.

[50] *Bill C-5, Building Canada Act*, *supra* note 1 s 4.1(3).

[51] *Ibid*, see esp s 5.1.

[52] See Impact Assessment Agency of Canada, *Canadian Impact Assessment Registry*, (6 June 2026) online: <iaac-aeic.gc.ca/evaluations> [perma.cc/J34H-ZPVH]

It should also be noted that the requirement to substantiate why a project is in the national interest (section 5.1 (a)) currently excludes the "clean growth and climate change" criterion (section 5(6)(e)). It is reasonable to expect that this glaring omission will be rectified in the near future or that the current government will treat all criteria equally under s. 5.1(a).

2. ALL-IN-ONE AUTHORIZATIONS AND CONDITIONS DOCUMENT

Prior to issuing a PONI's master authorization, the Minister will now have to undertake a national security review with a view towards foreign investment in particular.[53] (s 7(b.1)). This part has also been amended to more explicitly dictate the matter in which the Minister consults with affected Indigenous peoples.[54]

Perhaps the most important amendment to this part of the *Building Canada Act* regime is a new s. 8.1., which will require the Minister to publish a document that essentially explains the difference, in terms of substance (i.e., conditions) and process, between the "normal regulatory process" to which a PONI would have been subject to in the absence of the *Building Canada Act*, and the conditions and processes that it has been subjected to.[55] This Minister must, *before* the s.7 authorization is issued, make public the information set out in 8.1(1),[56] and the Minister is also is required under 8.1(4) to table a report that contains those informational requirements.

Combined with the section 7(3) deeming provisions, the Act effective transfers accountability for PONI conditions from the judicial branch, which until now has exercised its supervisory authority to ensure some semblance of implementation of Canada's environmental laws, to Parliament. That said, the potential for democratic accountability has always played an important role in Canada's environmental law regimes, which are still largely procedural in nature.[57]

3. HENRY VIII CLAUSES

The amendments modestly constrained the Act's exceedingly broad Henry VIII powers in that seventeen (17) statutes have been explicitly exempted from being able to be listed to Schedule 2, including the *Access to Information Act*, the *Conflicts of Interest Act,* the *Criminal Code*, the *Official Languages Act*, and the *Indian Act*, to name but a few (see s 21(2)).

Surprisingly, the project-specific assessment regimes established under modern treaties are not included in this list of laws. Presumably this omission is due to a recognition that, as noted above, these regimes are constitutionally rooted by virtual of the constitutionally protect modern treaty provisions that underpin them. As such, it would be fair to say that as a constitutional matter the *Mackenzie Valley Resource Management Act*, the *Yukon Environmental and Socio-Economic Assessment Act*, and the *Nunavut Planning and Project Assessment Act* cannot be added to Schedule 2.[58]

4. SUNSET AND REPORTING

Finally, the amendments enhanced the Act's reporting requirements. The Minister has an obligation to ensure an independent review of the status of each PONI is conducted annually, and to table a report of that review within 15 days on which the House is sitting once the review is completed, which review also has to be made publicly available (s 23.1).

The Parliamentary Review Committee that is part of the federal *Emergencies Act*[59] regime has now also been given a role in review, reporting every 6 months (180 days) on Cabinet's and the Minister's exercise of their powers and performance of their duties and functions under the Act (amended s 24). The

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[53] *Bill C-5, Building Canada Act*, *supra* note 1 s 7(b.1).

[54] *Ibid*, s 7(2.1).

[55] *Ibid*, see esp s 8.1(1)(e), 8.1(2). See also 8.1(3).

[56] *Ibid*, s 8.1(3).

[57] Martin Z. Olszynski, "Environmental Assessment as Planning and Disclosure Tool: G*reenpeace Canada v Canada (Attorney General)*" (2015) 38(1) Dalhousie L J 207 at 221–25.

[58] *Supra* note [42].

[59] *Emergencies Act*, RSC, 1985 c 22.

Parliamentary Review Committee will also play a role in the 5 year review of the Act, which review is to be based on the "common good of Canada": "assured in part by the pursuit of the objectives set out in section 4 relating to shared jurisdiction, public safety, national and international security, the quality of the environment, public health, transparency, public participation and the protection of the rights of Indigenous peoples and linguistic communities."[60]

It should also be noted that there is a series of amendments to prevent Cabinet or the Minister from exercising their various powers while Parliament is prorogued or dissolved (see e.g., amended sections 5(2), 21(3), 22(2) and 23(2)).

PART III: COMMENTARY

Impact assessment is the logical starting point for bringing into focus the changes brought in through Bill C-5. As described in *Oldman*, impact assessment is "a planning tool that is…an integral component of sound decision-making."[61] The basic idea of environmental assessment is that "certain proposed activities should be scrutinized in advance from the perspective of their possible environmental consequences."[62] Colloquially, this is often called a "look before you leap" approach.[63]

The new regime under the *Building Canada Act* is not impact assessment. Far from it. The new expedited approach turns the system on its head for PONIs. Depending on the specific project, this could be fairly characterized as a 'leap before you look' approach. Instead of a precautionary, comprehensive assessment process for careful, informed, and calculated decision-making about major projects, the new process sets a fast-track for an initial affirmative decision that is not necessarily underpinned by robust informational basis, along with a cluster of siloed and expedited regulatory decisions, all done without sufficient statutory space to see the big picture. The only cross-issue and cross-department integration that seems to be achieved under the new process is bundling all the specific regulatory authorizations into the final all-in-one authorizations and conditions document. Minimal substantive coherence or collaboration between federal departments is required en route to that final point (though perhaps the new MPO will be striving to facilitate such). As such, on one hand it is important to simply recognize that C-5 is not at all about impact assessment, even though impact assessment is a useful benchmark. The *Building Canada Act* is about what it says it is about: an accelerated process aiming to provide project proponents and investors with early and ongoing certainty that a project will receive federal approval.

But the key question to ask is: at what cost? Obviously, it is too early to tell. Trade-offs and downsides will hinge entirely on what projects are added to the list initially and into the future. In a smooth case scenario, a PONI would be listed in a context where there has already been meaningful public and Indigenous engagement, there is consent from potentially affected Indigenous communities (and perhaps ownership), the project triggers the *IAA* such that there will still be a federal impact assessment within prescribed timelines, and any applicable provincial or territorial assessment processes proceeds in parallel and fills in any gaps. With some hesitation and many blind spots, we acknowledge that the enormous offshore wind project touted by Nova Scotia Premier Tim Houston may be in this range.[64]

There ought to be concern, however, because it is rare for so many stars to align when it comes to infrastructure and resource extraction projects of this magnitude. A more difficult (and foreseeable) scenario would be one where a PONI is not a designated project under the *IAA*, there are very few opportunities for meaningful public engagement, Crown

[60] *Bill C-5, Building Canada Act*, *supra* note 1 at s 24(3).

[61] *Friends of the Oldman River Society v Canada (Minister of Transport)*, [1992] 1 SCR 3, at para 71.

[62] Reference re *Impact Assessment Act*, 2023 SCC 23 at para 10, citing J. Benidickson, *Environmental Law* (5th ed. 2019), at 257.

[63] Deborah A Sivas, "Is the National Environmental Policy Act About to be Dramatically Transformed?" (1 December 2024), online (blog): SLS <law.stanford.edu> [perma.cc/C3VV-TUW6].

[64] Michael MacDonald, "Houston Pitches ambitious 'Wind West' offshore wind energy project" *CBC News*, (5 June 2025), online: <cbc.ca/offshore-wind-energy-project> [perma.cc/7YHH-99ZR].

consultation efforts are approached with a narrow interpretation of Indigenous rights and interests, federal departments work in isolated lanes, and applicable provincial assessments are expedited or superficial. The fact that the *Building Canada Act* creates legislative space for such a scenario could lead to major legal problems (e.g. legal challenges brought by affected rights-holders), not to mention poor outcomes if a project actually proceeds. One need only look at projects like Northern Gateway, Site C, Muskrat Falls and Energy East for cautionary tales.[65]

CONCLUSION

It is certainly precarious times for Canada. On that, most would agree. And many would probably also agree that present conditions are right for concerted major infrastructure building across the country. The question is not so much whether to embark on this path, but how. Given the features and concerns outlined above, it is not clear that this effort aimed at shifting from 'whether' to 'how' is actually the 'how' that should be pursued. Time will tell if the *Building Canada Act* leads to moving fast and making things or just moving fast and breaking things. The stakes could hardly be higher. ■

[65] See discussion here Mark Winfield, "Why the federal government must act cautiously on fast-tracking project approvals" *The Conversation*, (3 June 2025), online: <theconversation.com> [perma.cc/EZ44-B8TV].

USES AND ABUSES OF UNDRIP IN CANADIAN COURTROOMS

*Dwight Newman, K.C. and Jenna Renwick**

I. INTRODUCTION

In this article, we seek to overview current uses and abuses of the *United Nations Declaration on the Rights of Indigenous Peoples* ("*UNDRIP*")[1] in Canadian courtrooms, particularly in so far as these developments have implications in generating additional uncertainties for the Canadian energy sector. After setting out some basic background on *UNDRIP* and on *UNDRIP*-related legislation, we will turn to the rather underdeveloped approaches of the Supreme Court of Canada and then to three lower court cases pressing the issues forward: the *Gitxaala v British Columbia (Chief Gold Commissioner)* case,[2] the sweeping decision of Justice Bourque in her last judgment in the Québec Superior Court in the *Montour and White* case,[3] and the early decision of Justice Blackhawk in her judgment in the *Kebaowek First Nation v Canadian Nuclear Laboratories Inc* case.[4] All three decisions are under appeal, but we will show how citations between cases ahead of the appellate level magnify the impact even of decisions that may be overturned. More generally, we will argue that some of these cases manifest highly surprising dimensions and risk generating very significant legal uncertainties.

To develop our argument, Part II sets out basic background on *UNDRIP*, and Part III sets out background on the *UNDRIP* legislation in British Columbia and at the federal level. In Part IV, we survey a number of attempted invocations of this *UNDRIP* legislation in courtrooms, showing that there have been surprisingly rapid attempts to extend the implications of this legislation in courtrooms. In Part V we trace the Supreme Court of Canada's references to *UNDRIP*, showing that they began very modestly but have started to be shaped by this legislation to some degree. In Part VI, we discuss briefly the *Gitxaala v British Columbia (Chief Gold Commissioner)* case, showing how the trial judge stuck more closely to the legislative history of British Columbia's *UNDRIP* legislation. In Part VII, we discuss *Montour and White* and its use of the federal *UNDRIP* legislation to more substantially reshape major precedents. In Part VIII, we discuss *Kebaowek* and a number of challenging features within its reasoning on *UNDRIP*. In Part IX, we draw some very brief conclusions.

II. *UNDRIP* BACKGROUND

In thinking about how *UNDRIP* is being used today and how it should be used, it is helpful

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[1] [United Nations] *Declaration on the Rights of Indigenous Peoples* (*UNDRIP*), GA Res 61/295, UN Doc A/RES/47/1 (2007).

[2] *Gitxaala v British Columbia (Chief Gold Commissioner)*, 2023 BCSC 1680.

[3] *R v Montour and White*, 2023 QCCS 4154.

[4] *Kebaowek First Nation v Canadian Nuclear Laboratories Inc*, 2025 FC 319.

to set out some basic *UNDRIP* background. *UNDRIP* was adopted by a resolution of the United Nations General Assembly in 2007, meaning that it is already almost two decades old. That adoption followed on a multi-decade process that started with Indigenous drafting of a *Draft Declaration*, put forth in 1994,[5] and then was followed by a period of negotiation with states, which led to a very different document than the *Draft Declaration* would have been.

In the end, *UNDRIP* was adopted as a resolution of the United Nations General Assembly. The General Assembly is not a legislative body. Indeed, there is there no international legislative body. However, some resolutions of the General Assembly can be very significant as it can express the view of the world community on different issues. The Universal Declaration of Human Rights ("UDHR") emerged as a United Nations General Assembly resolution.[6] It led to the adoption of international treaties in the form of the two international covenants that created legally binding treaties. UNDRIP has not had similar effect (at least as yet), but it arguably has significance in other ways as an important normative instrument expressing an agreed view amongst those affected by it, both states and Indigenous peoples.[7]

In 2007, Canada voted against *UNDRIP*. However, it offered subsequent endorsements in 2010 and in 2016.[8] We could argue about the different qualifications on those two endorsements and how different they actually were — the significance of the 2016 endorsement may sometimes be overstated — but Canada's subsequent endorsement is in any event of significance.

Given that *UNDRIP* is not a treaty and not legislation, one could ask how it has legal effects in Canada. There are several ways in which it could conceivably do so. In terms of direct legal effects, parts may express norms of customary international law that may then be brought into Canadian law, parts may help to develop customary law that is still crystallizing, and/or *UNDRIP* may help to identify how international treaties are interpreted in the specific circumstances of Indigenous peoples.[9] It could have these sorts of direct legal effects and/or it could simply affect states and encourage them on paths towards domestic implementation of *UNDRIP*-style norms. The latter aspect has perhaps become the most significant dimension in Canada in so far as *UNDRIP* has encouraged the adoption of implementing legislation federally as well as in one province and one territory.

III. UNDRIP-RELATED LEGISLATION

Canada and its subnational units have taken several legislative steps regarding *UNDRIP* since it was endorsed by the federal government in 2016. Despite some efforts at the federal level in a private member's bill introduced over a number of years by former NDP Member of Parliament Romeo Saganash,[10] the province of British Columbia was the first mover on the legislative front. In 2019, British Columbia adopted the *British Columbia Declaration on the Rights of Indigenous Peoples Act* ("*BCDRIPA*").[11]

[5] *Draft United Nations Declaration on the Rights of Indigenous Peoples*, UN Doc E/CN.4/Sub.2/RES/1994/45 (26 August 1994).

[6] *UNDRIP*, *supra* note 1.

[7] See Dwight Newman, "Interpreting FPIC in UNDRIP" (2019) 27 International Journal on Minority and Group Rights 233 at 234.

[8] See Government of Canada, "Canada Endorses the United Nations Declaration on the Rights of Indigenous Peoples" News Release, (12 November 2010), online: <canada.ca/en/news/archive/2010/11/canada-endorses-united-nations-declaration-rights-indigenous-peoples.html> ; See Government of Canada, "Canada Becomes a Full Supporter of the United Nations Declaration on the Rights of Indigenous Peoples" News Release, (10 May 2016), online: <canada.ca/en/indigenous-northern-affairs/news/2016/05/canada-becomes-a-full-supporter-of-the-united-nations-declaration-on-the-rights-of-indigenous-peoples.html>.

[9] If we might have nuanced differences from him elsewhere, here we align well with Gib van Ert, *Using International Law in Canadian Courts*, 3rd ed (Toronto: Irwin Law, 2024) at 626–28. These possible routes to a legal status for *UNDRIP* are clear enough and it is also clear that some of them require rigorous proof of, for instance, state practice and *opinio juris*.

[10] Bill C-262 ("United Nations Declaration on the Rights of Indigenous Peoples Act"), 2nd sess, 42nd parliament, 2018 (failed to pass third reading in the Senate in advance of 2019 election).

[11] *British Columbia Declaration on the Rights of Indigenous Peoples Act*, SBC 2019, c 44 [*BCDRIPA*].

Subsequently, an amendment was made to section 8.1(3) of British Columbia's *Interpretation Act*,[12] stating "Every Act and regulation must be construed as being consistent with the Declaration." The amendment, while adopted after *BCDRIPA*, has received surprisingly limited attention. One would expect Indigenous parties — or even non-Indigenous parties, since the law is about interpretation generally, and some might prefer different interpretations than presently exist — might have taken up the amendment and argued for different interpretations of British Columbia legislation and regulatory provisions. However, at this time, the amendment has only been cited four times and not given an overly thorough treatment.[13] The most comprehensive judicial guidance comes from the *Gitxaala* decision, where Ross J. clarifies that s. 8.1, which anchors s. 8.1(3) "acts as an interpretive aid during the entirety of the interpretive process, and not a mere 'confirmatory' role at the end."[14] Understood this way, s.8.1(3) requires BC enactments to be interpreted in a manner consistent with *UNDRIP* at each step of the statutory interpretation process but with little detail developed in the courts on what that might ultimately mean.

The next legislative move came in 2021, following the federal government's adoption of the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("*UNDRIPA*").[15] The federal statute was adopted as government legislation. More recently, the Legislative Assembly of the Northwest Territories adopted the *United Nations Declaration on the Rights of Indigenous Peoples Implementation Act*,[16] which has its own approaches warranting separate attention.

For purposes of this article, it is most important to focus on the federal *UNDRIPA* and British Columbia's *BCDRIPA*. The operative provisions found in each statute are closely analogous in several respects. These are: (1) a commitment to seek to harmonize the laws of the jurisdiction with *UNDRIP*; and (2) a commitment to ongoing action plans to pursue the objects of the *UNDRIP*.[17] The operative provisions do not extend beyond these two fundamental commitments, both of which are significant but are to take place over a period of time.

At the time *BCDRIPA* was adopted, British Columbia Premier John Horgan spoke about it being "the start of a process".[18] As matters moved forward with the federal *UNDRIPA*, federal Minister of Justice David Lametti said, "Implementing the United Nations Declaration on the Rights of Indigenous Peoples is generational work."[19] These and similar statements have made clear the nature of both statutes as launching processes and further detailed work. In light of the statutory commitments at the federal level and in British Columbia, there is extensive work to do with the various detailed provisions of *UNDRIP* that cut across all areas of law. With these two statutes, those working in any area of law need to be thinking about *UNDRIP*, not because of any prospect of taking it into court immediately, but because there will be ongoing legislative and policy reforms underway that affect every area of practice.

[12] *Interpretation Act*, RSBC 1996, c 238, s.81(c).

[13] *Gixtaala*, *supra* note 2 at paras 416–17, 469; *Skii km Lax Ha v British Columbia (Chief Executive Assessment Officer)*, 2024 BCSC 1687 at paras 90–92; *Kits Point Residents Association v Vancouver (City), 2023 BCSC 1706* at para 170; *L.L. v A.I.*, 2023 BCSC 1503 at para 36.

[14] *Gitxaala*, *ibid* at para 413.

[15] *United Nations Declaration on the Rights of Indigenous Peoples Act*, SC 2021, c 14 [*UNDRIPA*].

[16] *United Nations Declaration on the Rights of Indigenous Peoples Implementation Act*, SNWT 2023 c 36 [*NWT DRIPA*].

[17] These key commitments from the legislation are found in *UNDRIPA*, *supra* note 14, s 5 (statutory alignment) and s. 6 (action plan); *BCDRIPA*, *supra* note 10, ss. 3 (statutory alignment) and 4 (action plan). Notably, *BCDRIPA* also has extra provisions on consent agreements with Indigenous governments (ss 6 and 7), but those need to be the subject of more extended discussion elsewhere.

[18] Andrew Macleod, "Celebrations as BC Government Moves to Adopt UN Declaration on Indigenous Rights", *The Tyee* (24 October 2019).

[19] See Government of Canada, "Implementing United Nations Declaration on the Rights of Indigenous Peoples Act: Next phase of co-development" News Release, (20 March 2023) online: <canada.ca/en/department-justice/news/2023/03/implementing-united-nations-declaration-on-the-rights-of-indigenous-peoples-act-next-phase-of-co-development.html>.

The purposes of the two statutes, those sections which normally shape the interpretation, the section that specifies what the purpose of the statute is, in both the *BCDRIPA* and the *UNDRIPA*, do not have the operative provision that the federal private member's bill C-262 was going to have, which was an operative provision stating that *UNDRIP* "is hereby affirmed as a universal international human rights instrument with application in Canadian law."[20] That language does not exist in other Canadian statutes and could have had highly unpredictable effects.[21] In the versions actually adopted, that language ended up not being part of the operative provisions in the statutes but in purpose clauses that may simply help to shape the interpretation of the statutes.

IV. ATTEMPTED INVOCATIONS OF THE UNDRIP-RELATED LEGISLATION IN CANADIAN COURTROOMS

While both the federal *UNDRIPA* and the provincial *BCDRIPA* were enacted on the basis that they set the stage for gradual change and were not to be invoked immediately into courtrooms, the attempted invocation of these statutes into court is precisely what has happened — and quickly.

In 2021, there were attempts by two intervenor parties to invoke *BCDRIPA* in the Supreme Court of Canada in *R v Desautel*,[22] with the attempted invocations being put to argue for tangible results. One intervener, the Lummi Nation, advanced the argument that "[British Columbia's] *DRIPA* explicitly requires that all provincial laws are consistent with UNDRIP. As a result, UNDRIP is no longer a non-binding international instrument but has the status and force of domestic legislation. As such, it is the text of UNDRIP that is a primary source of meaning or interpretation."[23] Another intervener, the Nuchatlaht First Nation, took the position that "… a Crown pleading in a s.35 rights case is a government 'measure' within the meaning of the Act. The Appellant is therefore statute-barred from advancing any argument in this court which would be inconsistent with UNDRIP."[24] While it is laudable that government lawyers act in a manner consistent with the overall obligations and policy of the government, a specific rule statute-barring particular lines of advocacy would be highly constraining of legal discussion and undermine the ability of the courts to receive the full range of submissions that might bear on a matter. The Court ultimately did not reference these interventions in its decision, leaving them as what we would consider implicitly rejected attempts to shift the nature of the statute.[25]

These attempts were not an isolated incident, and there were intervenor efforts in a series of cases decided in 2024 to get the Supreme Court of Canada to ascribe more immediate substantive significance to *UNDRIPA*. For example, in the *Indigenous Child Welfare* case,[26] the Union of British Columbia Indian Chiefs ("UBCIC") argued that even though the statute did not make *UNDRIP* binding *per se*,

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[20] Supreme Court of Canada File No 40153 (*R v Shot Both Sides*), Factum of *Intervener Innu Takuaikan Uashat Mak Mani-Utenam*, at paras 41–43.

[21] One of us (Dwight Newman) made submissions to this effect in the parliamentary committee hearings on the legislation, suggesting that it is proper to consider considerations on statutory drafting when enacting a statute. Such submissions were surprisingly rare in a process that arguably featured many good intentions but could have used additional rigour all the way along. Even in the context of well-intentioned legislation intended to advance rights, it is important to consider statutory drafting considerations, unintended effects, and other similar considerations, and the implicit pressures on people not to raise such issues in good faith for fear of being seen as opposed to the legislative objectives were highly unfortunate and something of a discredit to a process that should have always been aimed at bringing everyone together in developing good, sustainable paths forward on Indigenous rights.

[22] *R v Desautel*, 2021 SCC 17 [*Desautel*].

[23] *R v Desautel*, 2021 SCC 17 (Factum of the Intervener Lummi Nation at para 32).

[24] *R v Desautel*, 2021 SCC 17 (Factum of the Intervener Nuchatlaht First Nation at para 37).

[25] We do not say that the statutes could never be invoked in seeking a judicial remedy. Notably, in the event of a governmental failure to meet the two key commitments in the statute, such as if a government made no efforts at statutory alignment or failed to prepare an action plan, there would be ways of seeking a remedy for such failures to comply with a statutory obligation. But the operative commitments in the statute must be the basis for any judicial action, rather than any excessively generalized reading of the statute as giving force to *UNDRIP*.

[26] *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families* ("*Indigenous Child Welfare*"), 2024 SCC 5.

it was meant to give it significant weight in Canadian law.[27] In *Dickson v Vuntut Gwitchin First Nation*,[28] the "Pan-Canadian Forum on Indigenous Rights and the Constitution" sought to develop an extended principled approach to using *UNDRIPA* in judicially altering Canadian law.[29] In *Shot Both Sides*,[30] the intervenor Innu Takuaikan Uashat Mak Mani-Utenam argued that *UNDRIPA* had changed the Canadian legal landscape and implied substantive legal effect to UNDRIP.[31] In *Restoule*,[32] the Assembly of First Nations ("AFN") argued for giving weight to *UNDRIPA*'s preamble and argued for a province to be under a presumed obligation to conform to Canada's federally adopted commitments on *UNDRIP*.[33] Obviously, some of the submissions go beyond the scope of legitimate approaches to statutory interpretation and violate principles of federalism, but those realities have not stopped them from being made. Moreover, even while no judgment has specifically mentioned any of these submissions, the gradual accumulation of such submissions may have influenced the Supreme Court of Canada into some statements ascribing legal significance to *UNDRIPA*, albeit still relatively ambiguous statements at the present time, the matter to which we now turn.

V. SUPREME COURT OF CANADA CITATIONS TO *UNDRIP*

The Supreme Court of Canada was resistant to citing *UNDRIP* for many years. Aside from a surprising earlier citation to the 1994 *Draft Declaration in Mitchell v MNR*,[34] the Court for a long time said nothing about *UNDRIP*, despite numerous opportunities and, indeed, invitations to do so. Various cases saw intervenor groups attempt to argue that *UNDRIP* should influence how the case was decided. For example, in *Tsilhqot'in Nation v British Columbia*, there were submissions on how the *UNDRIP* provisions on land rights should help to shape Canada's law of Aboriginal title, but these were ignored by the Court. In *Ktunaxa Nation v British Columbia (Forests, Lands and Natural Resource Operations)*,[35] a highly critiqued case involving religious freedoms, several intervenors argued for the significance of UNDRIP as a source to be considered. Notably, in that case, the Court opted to engage with other international human rights law instruments on religious freedom but without reference to *UNDRIP*, awkwardly showing a direct distinction between different international soft law instruments to the disadvantage of Indigenous peoples.

In *Mikisew Cree First Nation v Canada (Governor General in Council)*,[36] when considering whether the duty to consult applies to legislative action, the Supreme Court of Canada's decision did not feature references to *UNDRIP*. This was the case even in the context of an UNDRIP article that could be seen as directly on point, with article 19 explicitly requiring consultation and cooperation prior to the adoption of legislative or administrative measures that affect Indigenous peoples.[37] Some law professors wrote critically of the decision and argued that the Court was wrong not to recognize *UNDRIP*.[38] However, given that *UNDRIP* was not mentioned in oral argument and barely mentioned in factums — with one

[27] Supreme Court of Canada File No 40061 (*Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*), Factum of intervenor Union of British Columbia Indian Chiefs (UBCIC), paras 24–25.

[28] *Dickson v Vuntut Gwitchin First Nation*, 2024 SCC 10.

[29] Supreme Court of Canada File No 39856 (*Dickson v Vuntut Gwitchin First Nation*), Factum of intervenor Pan-Canadian Forum on Indigenous Rights and the Constitution.

[30] *Shot Both Sides v Canada*, 2024 SCC 12.

[31] Supreme Court of Canada File No 40153 (*Shot Both Sides v Canada*), Factum of intervenor Innu Takuaikan Uashat Mak Mani-Utenam, paras 41–43.

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

[33] Supreme Court of Canada File No 40024 (*Ontario (Attorney General) v Restoule*), Factum of intervenor Assembly of First Nations (AFN), paras 28, 33.

[34] *Mitchell v MNR*, 2001 SCC 33 at para 81 [Mitchell].

[35] *Ktunaxa Nation v British Columbia (Forests, Lands and Natural Resource Operations)*, 2017 SCC 54 [*Ktunaxa*].

[36] *Mikisew Cree First Nation v Canada (Governor General in Council)*, 2018 SCC 40 [*Mikisew*].

[37] *UNDRIP*, *supra* note 1, art 19.

[38] See eg Sarah Morales, "Supreme Court of Canada Should Have Recognized UNDRIP in Mikisew Cree Nation v Canada", *Canadian Lawyer* (29 October 2018) (criticizing the Court *inter alia* for "fail[ing] to consider any legal principles recognized by the United Nations Declaration on the Rights of Indigenous Peoples").

factum having a very brief mention but citing to the wrong article of *UNDRIP*[39] — it is frankly difficult to see the case as one where the Court ought on its own initiative to have engaged in an extensive discussion of *UNDRIP*. By this point, advocates had practically abandoned the idea of putting *UNDRIP* before the Court.

In that sense, the federal *UNDRIPA* arguably led to new initiatives to argue *UNDRIP*, and *UNDRIPA* appears to have encouraged the Court to reference both the legislation and *UNDRIP* itself. In *Reference re an Act respecting First Nations, Inuit, and Metis children, youth and families*,[40] the Court says that "the Declaration has been incorporated into the country's positive law by the [*UNDRIPA*], s.4(a)."[41] In doing so, the Court does not outright draw anything from *UNDRIP* but rather reads the legislation as part of implementation and mentions that it has been incorporated into Canada's positive law. However, that brief, factual statement that could be read as simply stating that *UNDRIP* had been cited in a statute lent itself to further-extended readings that now make *UNDRIP* much more significant within the Court's jurisprudence.

In *Dickson v Vuntut Gwitchin First Nation*,[42] a case concerning the application of the *Canadian Charter of Rights and Freedoms* to Indigenous governments, the majority notes the "consonance" of its positions with *UNDRIP*.[43] The idea of looking for "consonance" now attributes a form of persuasive authority to *UNDRIP*, marking a significant step. The separate opinion of Martin and O'Bonsawin JJ goes even further, appearing to take *UNDRIP* and *UNDRIPA* as authority for recognizing a right to self-government.[44] The brief paragraph suggests that self-government is a way of preserving the collective and individual rights of Indigenous peoples. While Martin and O'Bonswain JJ astutely highlight that both collective and individual rights are contained in *UNDRIP*, there is little reasoning from that generality to the very specific conclusion that self-government must now be recognized in Canadian constitutional law in a general form (contrary to the Court's own past precedent, it bears noting). Interestingly, while the effect of his separate opinion is actually most inclined to suggest that the sovereignty of Indigenous governments exempts them from application of the *Charter*, something arguably fitting well with *UNDRIP*'s emphasis on self-determination, Rowe J's opinion reaches that conclusion without citing to *UNDRIP*.

These two decisions may simply be testing the waters in some respects. After many years of not offering any clarity on *UNDRIP* when asked to do so, the Supreme Court of Canada managed to discourage further argument based on *UNDRIP*. Then, when the new legislation seemed to open new possibilities, the Court seemed to respond to new advocacy on *UNDRIP* in these two cases, while ignoring the intervenor arguments on *UNDRIP* in other cases the same year. The Court has been unfortunately inconsistent and undertheorized in its approaches. Much work remains for the lower courts, although in now turning to three recent decisions, we will see that principles are also emerging there in an inconsistent manner.

VI. *GITXAALA V BRITISH COLUMBIA (CHIEF GOLD COMMISSIONER)*

In *Gitxaala*,[45] a judge of the British Columbia Supreme Court rejected the argument that courts could, in effect, invoke *BCDRIPA* to unilaterally strike down BC laws inconsistent with *UNDRIP*. In doing so, the Court clarified that the legislative intention of *BCDRIPA* does not have the effect of inviting judicial intervention. Rather, it contemplates ongoing cooperation between the government and Indigenous peoples to align existing laws and future legislation with the principles of *UNDRIP*.

[39] See Supreme Court of Canada File No 37441 (*Mikisew Cree v Canada (Governor General in Council)*), Factum of Intervenor Assembly of First Nations (AFN), para 21 (incorrectly citing art. 32 for a point on which the cite should have been to art. 19).

[40] *Reference re an Act respecting First Nations, Inuit, and Metis children, youth and families*, 2025 SCC 5 [*Indigenous Child Welfare Reference*].

[41] *Ibid* at para 4.

[42] *Dickson v Vuntut Gwitchin First Nation*, 2024 SCC 10.

[43] *Ibid* at paras 47, 110.

[44] *Ibid* at para 283.

[45] *Gitxaala*, *supra* note 2.

In April 2023, two British Columbia First Nations argued that the Court could use *BCDRIPA* to essentially strike down provisions of the province's mineral tenure system. The *Mineral Tenure Act*[46] ("*MTA*") permits free miners to register a "mineral claim" on unclaimed Crown land and grants claim holders various exploration and search rights, not including the right to extract minerals for commercial purposes, which requires approvals governed by the *Mines Act*.[47] Consultation with potentially affected First Nations occurs at the later permitting stage, not prior to granting the mineral claim, which raised pertinent questions about the Crown's duty to consult upon the operation of the *MTA*. Given the adverse physical impacts resulting from granting mineral rights, the Court held that British Columbia would need to fundamentally amend parts of the existing legislation to comply with the duty to consult doctrine.[48]

In terms of the effect of *UNDRIP* and *BCDRIPA*, the Court decided two issues:

1. Did *DRIPA* implement *UNDRIP* into the domestic law of British Columbia?[49]

2. Does s.3 of *DRIPA* raise justiciable questions of law? If so, what are they?[50]

The Court answered both questions in the negative, justifying its decision to use *BCDRIPA* as "an interpretive aid in addressing the proper reading of the *MTA*."[51] First, finding that section 2 of *BCDRIPA*, the "purposes" provision, should be read as statements of purpose that can bear on interpretation and help give meaning to the substantive provisions found in the legislation.[52] Justice Ross relied on Hansard and legislative context to conclude *DRIPA* did not implement *UNDRIP* into BC law. *BCDRIPA* in effect calls for a process of cooperation and consultation to "prepare, and then carry out, an action plan to address the objectives of UNDRIP."[53] Accordingly, on the question of justiciability, section 3 of *BCDRIPA*, which provides "the government must take all measures necessary to ensure consistency" should not be understood as a rights-creating provision that grants courts the authority to immediately invalidate legislation. Justice Ross recognized that courts possess both the institutional capacity and legitimacy to assess whether laws align with the rights outlined in *UNDRIP*.[54] However, section 3 does not impose a requirement of consistency, requiring courts to unilaterally adjudicate every instance where a law may be inconsistent with *UNDRIP*.[55] Instead, section 3 envisions an ongoing cooperative process involving Indigenous peoples in British Columbia, rather than giving the courts the unilateral right to strike down legislation immediately.

While some scholars who generally argue for the expansion of Indigenous rights have candidly admitted that the Court is right on the limited scope of *BCDRIPA*,[56] there has nonetheless been a sort of chorus of criticism of the Court for not making more of the legislation.[57] For example, British Columbia Human Rights

[46] *Mineral Tenure Act*, RSBC 1996, c 292, ss.6.3, 7–14.

[47] *Mines Act*, RSBC 1996, c 293.

[48] *Gixtaala*, *supra* note 2 at paras 396–98.

[49] *Ibid* at para 442.

[50] *Ibid*.

[51] *Ibid* at para 14.

[52] *Ibid* at para 461.

[53] *Ibid* at paras 466–67.

[54] *Ibid* at para 485.

[55] *Ibid* at para 488.

[56] See e.g. Nigel Bankes, "The Legal Status of UNDRIP in British Columbia: Gitxaala v British Columbia (Chief Gold Commissioner)" (5 October 2023), online (blog): *ABlawg*, <ablawg.ca/2023/10/05/the-legal-status-of-undrip-in-british-columbia-gitxaala-v-british-columbia-chief-gold-commissioner>.

[57] Consider elements of David Wright, "British Columbia Free Entry Mining System Triggers Duty to Consult and Must Change: Gitxaala v British Columbia (Chief Gold Commissioner)"(18 October 2023) , online (blog): *ABlawg*, <ablawg.ca/2023/10/18/british-columbia-free-entry-mining-system-triggers-duty-to-consult-and-must-change-gitxaala-v-british-columbia-chief-gold-commissioner>; Jeffrey Warnock, "So, I Guess We're Going with Vacuous Political Bromide: A Commentary on Gitxaala v British Columbia (Chief Gold Commissioner), 2023 BCSC 1680", (2024) 57:3 *UBC Law Review*;

Commissioner Kasari Govenderissued a press release with a title referring to being "dismayed" by the Court and rhetorically stating that "[t]he *Declaration Act* should not be merely symbolic — yet, today's decision indicates that the *UN Declaration on the Rights of Indigenous People* still does not have the force of law in B.C.".[58] This sort of harsh criticism of the Court for interpreting a statute according to its text and intentions illustrates the heated environment around these cases.

We take the view that the decision is consistent with the legislative history and the legislation. The legislative history indicates *BCDRIPA* was designed to foster a process over time, in which the government would work on the consistency of its legislation via an action plan reviewed every few years. British Columbia's Minister of Indigenous Relations and Reconciliation, Scott Fraser, said during debate, "With the passage of this bill, this will still be an interpretive tool. Bill 41 brings no legal force and effect to the UN declaration. What our intention is and our commitment is, clearly and publicly, is to work with Indigenous peoples in this province to bring our laws — if they're existing ones, future ones — into alignment over time with the UN declaration."[59] The introduction of the bill received unanimous support based on assurances that it would not immediately strike down existing laws. Therefore, the legislative history supports interpreting *BCDRIPA* as an instrument for generational change through ongoing processes.

An appeal has been heard, with a decision expected this year. The appellate guidance is worth paying attention to, given the similarity of *BCDRIPA* to the federal *UNDRIPA* legislation.

VII. *R V MONTOUR AND WHITE*

In *R v Montour and White*,[60] Justice Sophie Bourque of the Québec Superior Court released the final judgment of her judicial career in a highly novel judgment on a broad range of Aboriginal and treaty rights questions. Using a novel legal test in place of the *Van der Peet* test, Bourque J held that the right to freely determine and pursue economic development is a generic right shared by all Indigenous peoples, as established by *UNDRIP* and protected by the traditional legal system of the Mohawks of Kahnawà:ke.[61] On a separate issue, the judgment also determined that the Crown unjustifiably infringed its obligation under the Covenant Chain, a treaty between the Haudenosaunee and the British as recognized by s. 35(1), by limiting the right to trade tobacco through the imposition of excise duties and criminal charges under the *Excise Act*.[62]

As a part of a lengthy 1696 paragraph decision, Bourque J. used the federal government's adoption of *UNDRIPA* as evidence of a change in circumstances meeting the *Bedford/Carter* standard for lower courts to overrule SCC decisions, to hold in relation to *UNDRIP* that the *Van der Peet* test must be overturned, and to create a replacement test, all in the course of a fairly small number of paragraphs.[63] Unsurprisingly, the Attorney General of Québec has appealed the judgment. Nevertheless, there has been widespread comment against Québec seeking further judicial guidance on the groundbreaking ruling.[64]

[58] See British Columbia's Office of the Human Rights Commissioner, "B.C. Human Rights Commissioner dismayed as court decision undermines impact of Declaration on the Rights of Indigenous Peoples Act" (26 September 2023), online: <bchumanrights.ca/news-and-events/news/b-c-human-rights-commissioner-dismayed-as-court-decision-undermines-impact-of-declaration-on-the-rights-of-indigenous-peoples-act>.

[59] British Columbia, *Official Reports of Debates of the Legislative Assembly (Hansard)*, 41st Parl, 4th Sess, No 292 (19 November 2019) at 10569 (Hon. S. Fraser).

[60] *Montour*, *supra* note 3.

[61] *Ibid* at para 1375.

[62] *Excise Act*, SC 2002, c 22, s 42(1).

[63] *Montour*, *supra* note 3 at paras 1171–1204 present the main reasoning on the point (there could be arguments for including more paragraphs, but one could also argue for including fewer), with this reasoning on such a crucial issue thus making up about two percent of the judgment.

[64] Laura Koerner-Yeo & Brendan Schatti, "Update Part II: Attorney General of Quebec Appeals trailblazing R v Montour and White decision", *JFK Law* (19 March 2024), online: <jfklaw.ca/update-attorney-general-of-quebec-appeals-quebec-superior-courts-trailblazing-r-v-montour-and-white-decision-part-ii/#_ftn4>; Ka'nhehsí:io Deer, "Quebec appeals 'landmark' decision recognizing Kanien'kehá:ka treaty right to trade tobacco", *CBC News* (11 January 2024), online: <cbc.ca/news/indigenous/quebec-appeals-treaty-right-tobacco-trade-1.7080655>.

Justice Bourque cites to the *Bedford/Carter* standard at some length in considering the possibility of using *UNDRIPA* to overturn past precedent.[65] In *Canada (Attorney General) v Bedford66and Carter v Canada (Attorney General)*,[67] the Supreme Court defined the limits of vertical *stare decisis* on lower courts. The Court held that lower courts could depart from precedent set by higher courts in two circumstances: (1) where a new legal issue is raised and (2) where there is a change in circumstances that "fundamentally shifts the parameters of the debate."[68] In what she framed as her application of this standard, Justice Bourque held that presumption of conformity with UNDRIP, the endorsement of UNDRIP "without qualification,"[69] and the adoption of the *UNDRIPA* constitute new legal issues not raised before the SCC in Van der Peet. Further, the entire social landscape underpinning the decision has changed.[70] As such, Bourque J held that exceptional circumstances exist to overturn *Van der Peet* and develop a new framework for s.35(1) claims.

Academics have extensively critiqued the *Van der Peet* "integral to a distinctive culture" test over the years. In addition to arguments about the potential culture-freezing effects of the test, some critiques include that subsequent applications of the *Van der Peet* test have seen the court have to make *ad hoc* adjustments to parts of the test to make it fit other s.35 contexts, leading to peculiar cultural limits on the scope of property rights and other rights.[71] The Court in *Montour* found *Van der Peet* inconsistent with *UNDRIP* because recognition of rights is limited to specific practices.[72] Accordingly, the Court posited that the current test is unable to capture modern rights with economic impacts, which hampers rights articulated in *UNDRIP* that depend on the right to develop an autonomous economy because "without independent financial leverage, most collective rights are just empty shells."[73]

The replacement test created by Justice Bourque departs from the *Van der Peet* test, which is oriented towards customs, practices, and traditions, to a framework that contemplates whether the right under consideration "is a right protected by the traditional legal system of the Indigenous peoples claiming the right."[74] Thus, the Court must determine which rights are protected by Indigenous legal systems as opposed to the frozen "integral idea."

The reformed s.35(1) test devised in *Montour* imposes three burdens on applicants to determine whether a right invoked is protected by the traditional legal system of Indigenous peoples claiming the right:

1. It will require first to <u>identify</u> the collective right that an Applicant invokes;

2. Then, an Applicant will have to prove that such a right is <u>protected by his or her traditional legal system</u>; and

3. Finally, an Applicant will have to show that the litigious practice or activity in question is <u>an exercise of that right</u>.[75]

This represents a notable shift, as it may have the potential to influence the outcomes of various Aboriginal rights questions across the country (and, in the meantime, also

[65] *Montour*, *supra* note 3 at paras 1145ff. At paras 1154–56, Bourque J also references the notes of caution in the application of the *Bedford/Carter* standard indicated by the Supreme Court of Canada in *R v Comeau*, 2018 SCC 15, but her view was that the case at bar surmounted even a cautious application of the *Bedford/Carter* standard.

[66] *Carter v Canada (Attorney General)*, 2015 SCC 5 [*Carter*].

[67] *Ibid* at para 44.

[68] *Ibid*.

[69] *Montour*, *supra* note 3 at para 1204.

[70] *Ibid* at para 1205.

[71] Dwight Newman, "Day Six: Dwight Newman" (30 December 2018), online (blog): <doubleaspect.blog/2018/12/30/day-six-dwight-newman>.

[72] *Montour*, *supra* note 3 at para 1295.

[73] *Ibid*.

[74] *Ibid* at 18.

[75] *Ibid* at para 1297.

potentially alters the duty to consult analysis in every consultation situation involving an asserted Aboriginal right, with the *prima facie* strength of the claim now to be analyzed under a different test). While this amendment could be viewed as a positive and constructive change, it also has the effect of creating an evidentiary barrier for some Indigenous communities, if they are then put in a position of having to prove "sufficient continuity" of a right within an Indigenous legal system rather than proven customs, practices, and traditions.[76] So, there could be unintended consequences, and the highly limited analysis of the alteration of the test within a very lengthy judgment does not show the sort of careful attention that would be appropriate on a change of this magnitude.

A final concern regarding *UNDRIP* pertains to a significant conclusion on constitutional interpretation. Justice Bourque concluded that UNDRIP "despite being a declaration of the General Assembly, should be given the same weight as a binding international instrument in the constitutional interpretation of s. 35(1)."[77] An argument could then be advanced that *UNDRIP* could appropriately change the interpretation of the constitution. In principle, if *Nevsun Resources Ltd. v Araya*,[78] is correct and will be applied, that might also mean parts of *UNDRIP* become part of Canadian common law outside of the statutory process. Nevertheless, there are some complexities concerning how the decision will work. The question remains: How does the adoption of a federal statute change the interpretation of the Constitution? On a principled level, the adoption of a federal statute cannot legitimately change the interpretation of the Constitution, or one has created an unprincipled new amending formula within the sole power of the federal government.

VIII. *KEBAOWEK FIRST NATION V CANADIAN NUCLEAR LABORATORIES*

On February 19, 2025, the Federal Court in *Kebaowek First Nation v Canadian Nuclear Laboratories*[79] purported to adopt the *UNDRIP* free, prior, and informed ("FPIC") standard in lieu of the duty to consult, with this adoption being as a result of Canada's implementation of *UNDRIP* into domestic law via *UNDRIPA*. On that basis, the Court found that the Canadian Nuclear Safety Commission's consultation process for approving a license amendment for Canadian Nuclear Laboratories to construct a Near Surface Disposal Facility at Chalk River Laboratories was inadequate.[80] However, Blackhawk J. also interprets FPIC as mandating a process rather than an obligation to obtain consent.[81] The case is currently under appeal. Some may argue that of the three cases, this one stands out as the most remarkable. Thus, a few key elements require further attention.

First, it is worth noting the impact of the existing authorities. The chosen authorities are significant, particularly the citation to another lower court decision that is not definitive, and it itself is currently under appeal. Blackhawk J. begins by citing *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*,[82] along with *Montour*,[83] to stand for the idea that *UNDRIP* has been implemented into Canada's domestic positive law and can be required to inform the interpretation of Canadian law.[84] *UNDRIP* is described as "an interpretive lens to be applied to determine if the Crown has fulfilled its obligations."[85] Following this, it is asserted that the Supreme Court of Canada has indicated that the rights articulated in *UNDRIP* exist, suggesting that what has been legislated in *UNDRIPA* codifies pre-existing rights.[86]

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[76] *Ibid* at para 1327.

[77] *Ibid* at para 1201.

[78] *Nevsun Resources Ltd. v Araya*, 2020 SCC 5.

[79] *Kebaowek*, *supra* note 4.

[80] *Ibid* at para 183.

[81] *Ibid* at para 131.

[82] *Montour*, *supra* note 3 at para 1287.

[83] *Kebaowek*, *supra* note 4 at para 76.

[84] *Ibid* at para 76.

[85] *Ibid*.

[86] *Ibid*.

Interestingly, *Gixtaala*, which considers the consistency of the provincial mineral tenure system with *UNDRIP* and *BCDRIPA*, is referenced only much later in the decision.[87] Here, Blackhawk J. briefly finds that the *Gixtaala* decision is unpersuasive and distinguishable from *Kebaowek*, noting that, unlike the former, the issue being contemplated is "not conformity of laws… Rather, the question is whether UNDRIP has been incorporated into Canadian law such that it may inform the interpretation of the duty to consult and accommodate."[88] A more thorough treatment of the questions raised in *Gixtaala* would surely have been warranted, given that it considers highly parallel legislation that predates the federal legislation.

These points on sources highlight that ambiguous statements in the Supreme Court of Canada are apt to be read in unexpected ways. They also show that some judges may pick amongst other lower court decisions during this interim phase in which appellate guidance is lacking, thus amplifying the effects of decisions that may ultimately be overturned. This period of legal development gives rise to some significant uncertainties on what might happen in any given case affecting clients.

Second, the general statement in the case that the adoption of *UNDRIP* via *UNDRIPA* "…means more than a status quo application of the section 35 framework"[89] is significant. Once again, we observe a lower court taking the view that the adoption of a federal statute changes constitutional interpretation, again adopting that new constitutional amendment process that lets the federal government effect unilateral changes to the constitution that affect the provinces.

Third, operating on the basis that *UNDRIP* is to be used to interpret the Crown's analysis of the duty to consult and accommodate, the Court takes an interesting approach of beginning by trying to identify a specific article of *UNDRIP* into which the case fits. The Court concludes that the proposed Near Surface Disposal Facility project clearly falls within the scope of Article 29(2) of *UNDRIP*, thereby triggering the *UNDRIP* FPIC standard. Article 29(2) states that "no storage or disposal of hazardous materials shall take place in the lands or territories of indigenous peoples without their free, prior and informed consent."[90] As a result, based on this rather distinctive methodology, Blackhawk J suggests that an FPIC standard applies in reshaping the duty to consult.

However, Justice Blackhawk then interprets FPIC as "a right to a robust process…not a veto or a right to a particular outcome."[91] This interpretation actually corresponds with the mainstream view in international law scholarship, which contends that FPIC in general mandates a right to a process aimed at consent but not necessarily requiring the obtaining of consent on every decision.[92] A divergent stream of thought in international law scholarship contends that FPIC requires a consultation process to obtain consent, sometimes portrayed as a "veto," which implies an absolute power to override all other considerations.[93]

However, here is where the methodology of fitting matters into article 29 becomes peculiar. As stated, on FPIC generally, Blackhawk J's approach of saying that FPIC processes do not always require obtaining consent is within mainstream views. However, those holding this mainstream often arrive at it by considering the text of *UNDRIP* and the distinction between articles that textually require consent and articles that do not textually require consent but simply consultation and cooperation "in order to obtain" consent. Article 29(2) of *UNDRIP*, which governs the storage of nuclear waste, is one of the rare articles that contains language

[87] *Ibid* at paras 101–02.

[88] *Ibid* at para 102.

[89] *Ibid* at para 128.

[90] *UNDRIP*, *supra* note 1, art. 29.

[91] *Kebaowek*, *supra* note 4 at para 130.

[92] See Newman, "Interpreting FPIC in UNDRIP", *supra* note 7; Mauro Barelli, "Free, Prior and Informed Consent in the United Nations Declaration on the Rights of Indigenous Peoples - Articles 10, 19, 29(2) and 32(2)", in Jessie Hohmann & Marc Weller, eds, *The UN Declaration on the Rights of Indigenous Peoples: A Commentary* (Oxford: Oxford University Press, 2018).

[93] See discussion of this view in Newman, "Interpreting FPIC in UNDRIP", *ibid* at 238.

stating that obtaining consent is mandatory. The only other article with such language is Article 10, which contains a mandatory consent requirement for the relocation of a population. Thus, to say that the methodology of a right to a process is to fit in Article 29(2) is a highly peculiar feature of the decision, raising some broader questions about the cohesiveness of the judgment's methodology.

The judgment also contains an interesting citation to Article 46(2), the limitations clause of the *UNDRIP*, which states that *UNDRIP* rights are not absolute and that States may infringe on *UNDRIP* rights in limited circumstances.[94] This article is seldom cited, as many scholars and judges alike proceed as if *UNDRIP* contained no limitations clause, thereby interpreting *UNDRIP* solely as a rights-affirming instrument in every circumstance. Thus, the Court's reference is notable, as it suggests possible limits on the effects of the articles of *UNDRIP* that the Court chose to engage with and suggests that *UNDRIP* can be interpreted in balanced ways. If courts are going to follow this methodology, using *UNDRIP* as an interpretive framework, proper engagement with Article 46(2) to interpret the substantive provisions within the Declaration and how they interact with Canadian law is imperative for a more balanced approach.

Finally, it is worth noting the Court's extensive use of decisions from the Inter-American Court of Human Rights ("IACHR") to assist with the interpretation of FPIC.[95] The IACHR is the judicial body, based in San José, Costa Rica, established to interpret and apply the *American Convention on Human Rights* ("*ACHR*"),[96] a regional human rights treaty in the Americas. Two key aspects should be considered. First, the IACHR decisions referenced were not cited by the parties or raised by the parties for comment. Thus, the Court appears to have engaged with IACHR jurisprudence without first seeking submissions from the parties regarding what these cases should mean in the context of the case before the court. While this practice is not unprecedented, it does not seem like the ideal process in an adversarial system of advocacy. Parties should have a chance to consider the legal arguments included in cases and not be rendered unable to challenge influential arguments advanced by the Court on its own initiative. Second, the IACHR decisions are arguably not applicable in the ways presented by Blackhawk J. In our view, significant methodological issues exist with the Court's engagement with international law materials. For the most part, the IACHR cases in question interpret the *ACHR*., As noted, that is a regional human rights treaty in the Americas. It is a treaty ratified by many member states of the Organization of American States ("OAS") — but not by Canada, thus raising profound questions about the appropriateness of relying upon these cases in interpreting Canadian obligations.[97] In referencing these cases, Blackhawk J. is arguably doing something other than interpreting FPIC in UNDRIP and almost certainly doing something other than interpreting international law materials applying to Canada in the ordinary ways.

Kebaowek represents an ambitious attempt to implement UNDRIP into Canadian law via *UNDRIPA*, but it is fraught with methodological incoherence. The Court based its analysis on an unsettled legal question as to whether *UNDRIPA*, a federal statute, alters constitutional interpretation and proceeded on this basis to interpret FPIC as a right to process. This was arguably correct in relation to FPIC in general terms but did not fit well with the language in Article 29(2), the provision which the Court claimed triggered the FPIC standard. Moreover, the Court's reliance on arguably inapplicable jurisprudence from the IACHR and unsettled legal questions under appeal from *Montour* raises additional concerns. The decision is under appeal, and those seeking to rely upon it in the meantime should be highly cautious in doing so. However, those who could be affected by its citation by other courts again face significant risks during this interim period.

[94] *Kebaowek*, *supra* note 32 at para 131.

[95] *Ibid* at paras 107–11.

[96] *American Convention on Human Rights*, San José, Costa Rica, 22 November 1969, 1144 UNTS 123 (entered into force 27 August 1979) [*American Convention*].

[97] The cases also involve some reference to ILO Convention 169 (*Convention concerning Indigenous and Tribal Peoples in Independent Countries* (ILO No 169), 72 ILO Official Bulletin 59, *entered into force* Sept. 5, 1991), which has similarly not been ratified by Canada.

IX. PRACTICAL IMPLICATIONS AND CONCLUSIONS

We are currently experiencing a period of significant instability regarding the impact of *UNDRIP* and *UNDRIPA* legislation on various issues. As a result, we observe a phenomenon in which courts cite each other faster than matters are being resolved at the appellate level, with cases of uncertain authority being cited by other cases of uncertain authority in rendering major decisions. Ultimately, we need a resolution from an appellate court, and ultimately something principled and rigorous from the Supreme Court of Canada.

We also see a phenomenon in which *UNDRIP* legislation may be invoked in various ways that were assumed against in agreements to pass legislation. Problematic interpretations that deviate from the original legislative intention upon adoption risk rendering positively viewed aspects of the legislation politically contentious and may ultimately lead to the revocation of such legislation in the future. When *BCDRIPA* was enacted in 2019, it had unanimous support in the BC legislature. Five years later, it was saved from a promised revocation by the new main opposition party in BC only by a knife-edge election result. If legislation is interpreted in ways going beyond the assurances offered at the time of its adoption, we are likely to see an unfortunate heightening of politicization and less sustainable support for Indigenous rights.

For those working in the energy law space, there is also quite possibly now a need to consider *UNDRIP*-related uncertainties in nearly every case. This even includes considering how to deal with arguments that the other side does not raise but that the judge may rely upon or develop, potentially incorrectly, on the judge's own initiative. An additional need has arisen for natural resources-related organizations to consider engaging more rigorously on these matters to ensure careful, balanced consideration of these issues in commentary and scholarship. Canadians can be simultaneously proud of their efforts to respond to past wrongs against Indigenous peoples and to advance Indigenous rights while also working to do so in ways that follow proper process, that do not generate economically harmful uncertainties, and that bring people together rather than driving them apart. ■