ENERGY REGULATION QUARTERLY

VOLUME 14, ISSUE 3 2026

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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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Managing Co-Editors

Karen J. Taylor and Moin A. Yahya

"IT'S DÉJÀ VU ALL OVER AGAIN"[1]

Coined by American baseball icon Yogi Berra, "It's déjà vu all over again" best describes the continued geopolitical instability that is shaping Canadian economic and energy initiatives since the publication of ERQ Issue 2.

Round and round we go

Since the commencement of American and Israeli air-strikes on Iran on February 28, 2026, the United States and Iran have traversed a serpentine path[2] of negotiations, ceasefires, and the short-lived Islamabad Memorandum[3] aimed at ending the war, and the exchange of air-strikes on regional land-based civilian and military targets and marine targets in the Strait of Hormuz, effectively closing one of the world's busiest oil shipping channels. Approximately 20 per cent of the world's oil and liquefied natural gas (LNG) move through the Strait.[4] The on-again off-again conflict has roiled financial markets and the price of crude oil,[5] with the attendant increase in domestic retail gasoline prices.

While there are many observations that could be made about the war between Iran and the United States, two stand out as being most relevant to the Canadian energy file and future actions that could be taken by the Canadian federal and provincial governments.

First, Iran's ability to disrupt commercial maritime traffic through the Strait of Hormuz appears to be a more strategically important deterrent against hostile attack than its nuclear strategy, regional proxies, and ballistic missile capabilities. As if to further illustrate this point, on July 20 the Iran-backed Houthis announced a blockade on Saudi Arabia in the Red Sea.[6] The key takeaway appears to be that the current Iranian regime is likely to remain a factor in whatever new regional order emerges in the Gulf[7] after the present hostilities abate, reinforcing the need in Canada for greater market access, both domestically and internationally, for Canada's oil, gas and LNG production.

Second, the core foreign policy tool of the Trump administration appears to be coercion — economic and/or military. However, as explained by Reid Pauly and

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[1] Yogi Berra Museum & Learning Center, "Yogi-isms", online: Yogi Berra Museum & Learning Center <yogiberramuseum.org/about-yogi/yogisms>.

[2] Cara Anna, "A Timeline of the Iran Conflict and Talks Aimed at Ending It", Associated Press (12 July 2026), online: AP News <apnews.com/article/iran-us-timeline-trump-hormuz-war-ceasefire-04da58cbae991183f8b52ef5bf615963>.

[3] United States & Islamic Republic of Iran, "Islamabad Memorandum of Understanding Between the United States of America and the Islamic Republic of Iran" (17 June 2026), online: The American Presidency Project <presidency.ucsb.edu/documents/islamabad-memorandum-understanding-between-the-united-states-america-and-the-islamic>.

[4] Gavin Butler, Toby Mann & Patrick Jackson, "Why the Strait of Hormuz Matters So Much in the Iran War", BBC News (14 July 2026), online: BBC News <bbc.com/news/articles/c78n6p09pzno>.

[5] Trading Economics, "Crude Oil" (last updated 23 August 2026), online: Trading Economics <tradingeconomics.com/commodity/crude-oil>.

[6] Allison Minor, "The Houthis Just Announced a Blockade on Saudi Arabia. What Does It Mean for the Global Economy?", Atlantic Council (20 July 2026), online: Atlantic Council <atlanticcouncil.org/dispatches/the-houthis-just-announced-a-blockade-on-saudi-arabia-what-does-it-mean-for-the-global-economy>.

[7] Khalid Al-Jaber, "Why the U.S.-Iranian MoU Didn't Last", Middle East Council on Global Affairs (last visited 23 August 2026), online: <mecouncil.org/blog_posts/why-the-u-s-iranian-mou-didnt-last>.

Matthew Cebul in their article "The Lost Art of Coercion: Why Trump's Belligerence Is a Sign of Weakness",[8] the U.S. President's "conflation of coercion — a nuanced foreign policy strategy — with belligerence and raw demonstrations of strength…makes opponents less likely to comply with his demands, both by revealing the limits of U.S. capabilities and resolve and by undermining the credibility of U.S. assurances that targets will be left alone if they acquiesce".[9]

For example, on July 15, U.S. Trade Representative Jamieson Greer acknowledged that Canada had rolled back two major trade irritants — the digital services tax and a separate tax hike on online streaming services — but with the caveat that "they don't really get credit for doing something bad and then undoing it".[10] Similarly, U.S. Ambassador to Canada Pete Hoekstra has previously stated that provincial acquiescence on the ban on U.S. alcohol would not lead to a loosening of Section 232 tariffs on steel and aluminum,[11] despite the former being merely a "trade irritant" and the latter being a direct violation of the Canada-United States-Mexico Agreement (CUSMA).

Finally, following the July 1, 2026 confirmation by the United States that it declined to renew CUSMA, on July 20 the U.S. President invoked the never-before-used Section 338 of the *Tariff Act of 1930*[12] to impose a 50 per cent tariff on a list of Canadian goods representing approximately US$20 billion or 5 per cent of Canada's exports to the United States. The proposed tariffs include items covered regardless of whether a good originates under the CUSMA, but will not apply to energy, potash, products subject to tariffs under Section 232, and certain other goods like fish or critical minerals.[13] It is interesting to note that oil and gas are the main source of the U.S.'s trade deficit with Canada, which Mr. Trump has said he wants to eliminate.[14] The tariffs were scheduled to take effect August 19 and designed to punish Canada for imposing retaliatory tariffs on U.S. automobiles, excluding U.S. alcohol from retail sales by most Canadian provinces, and refusing to abandon supply management in dairy. These tariffs also came at the same time as the U.S. announced tariffs on many other countries, including many that were assured that they would not be subject to such tariffs.[15] As expected, these new tariffs also attracted fresh lawsuits spearheaded by the same legal organization that challenged the last round of Trump tariffs.[16]

These announcements all took place against the backdrop of the drama surrounding the opening of the Gordie Howe International Bridge linking Ontario and Michigan.[17] Although Canada paid the cost of building the bridge, estimated at $6.4 billion, President Trump threatened to block the opening of the bridge until a new revenue sharing deal was

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[8] Reid Pauly & Matthew Cebul, "The Lost Art of Coercion: Why Trump's Belligerence Is a Sign of Weakness", *Foreign Affairs* (16 July 2026), online: <foreignaffairs.com/united-states/lost-art-coercion>.

[9] *Ibid*.

[10] David Cummings, "Canada Doesn't 'Get Credit' for Rolling Back Trade Irritants, U.S. Envoy Says", CBC News (16 July 2026), online: <cbc.ca/news/politics/cusma-trade-negotiations-netflix-tax-dst-9.7273212>.

[11] Laurence Martin, "Trump's Man in Ottawa Doesn't Understand Why Canadians Are So Frustrated Right Now", CBC News (24 May 2026), online: <cbc.ca/news/politics/hoekstra-interview-radio-canada-9.7209252>.

[12] *Tariff Act of 1930*, ch 497, § 338, 46 Stat 590 at 704 (codified as amended at 19 USC § 1338).

[13] US, The White House, "Fact Sheet: President Donald J. Trump Imposes Additional Tariffs on Canada" (20 July 2026), online: The White House <whitehouse.gov/fact-sheets/2026/07/fact-sheet-president-donald-j-trump-imposes-additional-tariffs-on-canada>.

[14] Adrian Morrow, Nathan Vanderklippe & Mark Rendell, "Trump to Impose New Tariffs on Canada", *The Globe and Mail* (21 July 2026), online: <theglobeandmail.com/world/us-politics/article-trump-tariffs-canada-us-executive-order-section-338>.

[15] NPR Staff, "U.S. Allies Hit with New Tariffs Object to Trump's Forced Labor Allegations", NPR (24 July 2026), online: <npr.org/2026/07/24/nx-s1-5906301/us-global-trump-tariffs-reaction>.

[16] Steve Kopack, "Small Businesses Sue Trump Administration to Stop Latest Wave of Tariffs on 60 Trade Partners", NBC News (24 July 2026), online: <nbcnews.com/business/economy/small-businesses-sue-trump-latest-tariffs-rcna589110>.

[17] CBC News, "Canada Celebrates Long-Awaited Opening of Gordie Howe Bridge Without U.S." (updated 24 July 2026), online: CBC News <cbc.ca/news/canada/windsor/livestory/gordie-howe-international-bridge-2026-live-updates-9.7172299>.

worked out despite the existence of an earlier deal between the two countries.[18]

At 12:01 a.m. on August 22, the new Section 338 tariffs took effect, following unsuccessful, last-minute negotiations. Canada has promised to "match those tariffs dollar for dollar to protect our workers and businesses"[19]. What specific actions will be taken are not yet known. The tariffs came after the talks between the two countries broke down over demands made by the United States regarding subsidies for French culture and other bilingual requirements.[20] As well, differential tariff exemption treatment of trucks versus cars with no real clear rationale also broke the talks down. While Prime Minister Carney was the one explaining the breakdown in the talks to the press, the provinces' premiers were most supportive of the decision to end the talks.[21] Only Alberta Premier Danielle Smith urged the federal government to return to the negotiating table and was cautious about retaliation with tariffs.[22] So far, the public seems supportive of the Prime Minister's moves but many are apprehensive about the impact the stalled talks and resulting tariffs will have on their jobs.[23] On August 23, President Trump issued his statement on the matter claiming that Canada wanted the benefit of being a U.S. state without being one while imposing massive tariffs on U.S. agriculture.[24]

This latest salvo of tariffs and other trade impediments highlights the need for Canada's first ministers to complete the long-overdue removal of interprovincial trade barriers, "accelerate approvals for nation-building infrastructure, help businesses diversify export markets and create the conditions for businesses to invest and innovate, to stay here and scale here".[25]

Both observations together highlight the significance of the more than 20 new economic and security partnerships signed[26] by Prime Minister Carney since being sworn into office in March 2025 that are expected to result in "the second-fastest growth in the G7 over the next two years", job growth that is now four times the rate in the United States, doubling of exports to non-U.S. markets over the next decade, and foreign direct investment in Canada that is at its highest level in two decades.[27] There also continues to be the need for a unified front in these next ten weeks prior to the U.S. mid-term elections and the possibility of more dialogue on trade with the Americans, including comprehensive CUSMA negotiations.

[18] Adrian Ghobrial, "Bridge over Troubled Waters: Tensions with U.S. Remain High amid Gordie Howe Ceremony", CTV News (25 July 2026), online: <ctvnews.ca/world/trumps-tariffs/article/bridge-over-troubled-waters-tensions-with-us-remain-high-amid-gordie-howe-ceremony>.

[19] Canada, Prime Minister of Canada, "Statement by Prime Minister Carney on Canada-U.S. Trade Negotiations" (21 August 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/statements/2026/08/21/statement-prime-minister-carney-canada-us-trade-negotiations>.

[20] Peter Zimonjic, "Carney Says Trade Deal Became Untenable When U.S. 'Asked Too Much and Offered Too Little'", CBC News (22 August 2026), online: CBC News <cbc.ca/news/politics/mark-carney-counter-tarrif-response-9.7316934>.

[21] CBC News, "PM Carney Says Canada Intends to Match U.S. Tariffs 'Dollar for Dollar,' After Suspending Trade Negotiations" (22 August 2026), online: CBC News <cbc.ca/news/world/livestory/us-canada-trade-war-new-tariffs-9.7310605>.

[22] Vincent McDermott, "Alberta Premier Urges Return to Trade Talks, Calls U.S. Terms 'Untenable'", CBC News (22 August 2026), online: CBC News <cbc.ca/news/canada/edmonton/alberta-premier-tariffs-reaction-9.7317230>.

[23] Angus Reid Institute, "Resolve & Apprehension: 76% Say Canada Was Right to Ditch Trade Talks, but Two-in-Five Have Fear for Their Jobs" (23 August 2026), online: Angus Reid Institute <angusreid.org/resolve-apprehension-76-say-canada-was-right-to-ditch-trade-talks-but-two-in-five-have-fear-for-their-jobs>.

[24] CBC News, "Trump Says Canada 'Wants the Benefits' of Being a U.S. State 'Without Being One' as Trade Dispute Deepens" (23 August 2026), online: CBC News <cbc.ca/news/canada/trump-canada-trade-dispute-9.7317333>.

[25] Ontario Chamber of Commerce, Media Release, "Ontario Chamber of Commerce Responds to U.S. Tariff Escalation" (20 July 2026), online: Ontario Chamber of Commerce: <occ.ca/mediareleases/ontario-chamber-of-commerce-responds-to-u-s-tariff-escalation>.

[26] Canada, Prime Minister of Canada, "Statement by Prime Minister Carney on the United States Administration's Intention to Impose New Tariffs on Canadian Goods" (20 July 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/statements/2026/07/20/statement-prime-minister-carney-united-states-administrations-intention>.

[27] Canada, Prime Minister of Canada, "Statement by Prime Minister Carney on Canada-U.S. Trade Negotiations" (21 August 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/statements/2026/08/21/statement-prime-minister-carney-canada-us-trade-negotiations>.

Breaking the cycle and moving ahead

The integration of energy and industrial policy as a driver of Canadian economic growth and sovereignty has been embedded in the large number of important announcements and agreements since our last edition of ERQ and is likely to be a continuing trend over the coming months.

A sample of these major announcements includes:

- May 14, 2026 announcement by the government of Canada of the "Powering Canada Strong: A National Strategy for an Electrified Canadian Economy",[28] a plan to expand the electricity system and related infrastructure, make federal financing support available for projects of national interest, strengthen interprovincial interties, enhance regulatory frameworks, advance energy security in Canada's north, support future nuclear development, and continue to support identified projects in the national interest.[29]

- May 15, 2026 announcement by the Governments of Canada and Alberta that they have reached an Implementation Agreement that sets out the framework to implement the November 27, 2025, Memorandum of Understanding, and includes commitments relating to carbon markets, electricity, the Pathways Project, an oil pipeline to global markets, and continuing cooperation.[30]

- July 2, 2026 announcement that Canada, Alberta and the Oil Sands Alliance (comprising Canadian Natural Resources Limited, Cenovus Energy Inc., ConocoPhillips Canada Resources Corp., Imperial Oil Resources Limited, and Suncor Energy Inc.) entered into a Memorandum of Understanding (Pathways MOU) establishing a framework for cooperation on large-scale emissions reduction projects, oil sands production growth and expanded export infrastructure.[31]

- On July 2, 2026, the Government of Canada referred the Government of Alberta's proposal for a west coast pipeline project to the Major Projects Office. The pipeline would transport more than 1 million barrels per day to global markets and the proposed route will largely follow the existing Trans Mountain corridor, fully respecting the *Oil Tanker Moratorium Act*.[32] The new pipeline will be owned by Trans Mountain Corporation (TMC, 100 per cent Government of Canada), Alberta Petroleum Marketing Commission (APMC, 100 per cent Government of Alberta), Pembina Pipeline Corporation (10 per cent economic interest with an option to acquire an additional 10 per cent at commercial in-service), and includes

[28] Canada, Natural Resources Canada, *Powering Canada Strong: A National Strategy for an Electrified Canadian Economy* (May 2026), online: Natural Resources Canada <natural-resources.canada.ca/energy-sources/electricity-infrastructure/powering-canada-strong-national-strategy-electrified-canadian-economy>.

[29] Reena Goyal, Anne-Catherine Boucher & Robeah Saee, "Canada Issues National Strategy for Electrifying the Canadian Economy: 'Powering Canada Strong'", Blakes Bulletin (20 May 2026), online: Blake, Cassels & Graydon LLP <blakes.com/insights/canada-issues-national-strategy-for-electrifying-the-canadian-economy-powering-canada-strong%E2%80%9D>.

[30] Canada, Prime Minister of Canada, Backgrounder, "Implementation Agreement for the Canada-Alberta Memorandum of Understanding of November 27, 2025" (15 May 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/backgrounders/2026/05/15/implementation-agreement-canada-alberta-memorandum-understanding>.

[31] Canada, Major Projects Office, "Memorandum of Understanding" (2 July 2026), online: Major Projects Office <canada.ca/en/privy-council/major-projects-office/projects/other/referred/pathways-plus/memorandum-understanding.html>; Kerri Howard, Alastair MacKinnon, Ashley Urch & Raye Willms, "Trilateral Pathways MOU: An Integrated Energy Development Strategy", Canadian Energy Perspectives (20 July 2026), online: McCarthy Tétrault LLP <mccarthy.ca/en/insights/blogs/canadian-energy-perspectives/trilateral-pathways-mou-an-integrated-energy-development-strategy>.

[32] Canada, Prime Minister of Canada, News Release, "Canada and Alberta Advance West Coast Pipeline Project Proposal and Pathways Project Carbon Capture Initiative – to Build a Stronger, More Resilient Canadian Economy" (2 July 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/news-releases/2026/07/02/canada-and-alberta-advance-west-coast-pipeline-project-proposal>. *Oil Tanker Moratorium Act*, SC 2019, c 26.

a real and meaningful opportunity for Indigenous equity participation.[33]

- July 14, 2026 announcement by LNG Canada that it has reached an agreement with five neighbouring First Nations in northern B.C. that would provide them with an option to invest up to $1 billion in LNG Canada's second phase. MNT Investments LP (development organizations from Gitga'at, Gitxaała, Haisla, Kitselas, and Kitsumkalum) would purchase a majority interest in a special purpose entity that would, in turn, buy a storage tank built in the second phase. The tank would be leased back to LNG Canada for as long as the project in Kitimat operates.[34]

- July 20, 2026 announcement that construction of the Enbridge Sunrise Expansion Program has begun. The Sunrise Expansion is a $4 billion investment that will increase the transportation capacity on the Enbridge Westcoast natural gas pipeline system by up to 300 MMcf/d. The project will maximize Canadian industrial participation and use domestically produced materials, including 100 per cent Canadian melted and poured steel from Saskatchewan. Enbridge has spent more than $52 million on the hiring and procuring of services from Indigenous businesses. The Westcoast natural gas pipeline system is 12.5 per cent owned by 38 Indigenous communities in British Columbia.[35]

- August 17, 2026 announcement by Quebec, Newfoundland and Labrador, and the federal government that the 1969 Churchill Falls Power Contract and the December 2024 Memorandum of Understanding (MOU) between the provinces will be replaced by a new deal.[36] The deal will see that Quebec will have continued access to renewable energy, while Newfoundland and Labrador will have control over its resources. The federal government will also commit to invest $10 billion to upgrade Churchill Falls Generating station, develop the Gull Island hydroelectric project, build more transmission lines, as well as developing onshore and offshore wind power.[37]

The rush of announcements clearly reflects the imperative of the moment, and a wary eye has been cast to October 19, 2026, when Albertans will go to the polls and vote on five questions relating to immigration, four related to various constitutional issues, and a question on separation.[38] The outcome of the Alberta referendum will not be resolved until after the publication of this Issue and will therefore be an ongoing point of discussion.

At the same time across Canada, the question of data centres is becoming more relevant and critical to provincial and federal policy-makers

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[33] Canada, Major Projects Office, "West Coast Oil Pipeline" (last modified 13 July 2026), online: Major Projects Office <canada.ca/en/privy-council/major-projects-office/projects/national/west.html>.

[34] The Canadian Press, "LNG Canada Equity Option Agreement with Five First Nations", CTV News (14 July 2026), online: CTV News <ctvnews.ca/vancouver/article/lng-canada-equity-option-agreement-reached-with-five-first-nations>.

[35] Canada, Natural Resources Canada, News Release, "Construction Begins on the Enbridge Sunrise Expansion Program" (20 July 2026), online: Natural Resources Canada <www.canada.ca/en/natural-resources-canada/news/2026/07/construction-begins-on-the-enbridge-sunrise-expansion-program.html>.

[36] Newfoundland and Labrador, Executive Council, News Release, "Newfoundland and Labrador Reaches Historic Deal with Government of Quebec and Government of Canada to Develop Churchill Falls and Gull Island" (17 August 2026), online: Government of Newfoundland and Labrador <gov.nl.ca/releases/2026/exec/0817n01>; Hydro-Québec, News Release, "Power Generation in Labrador: Hydro-Québec Secures Québec's Energy Future, at a Competitive Cost" (17 August 2026), online: Hydro-Québec <news.hydroquebec.com/news/press-releases/all-quebec/power-generation-labrador-hydro-quebec-secures-quebec-energy-future-competitive-cost.html>.

[37] Canada, Prime Minister of Canada, News Release, "Prime Minister Carney Announces the Largest Clean Energy Investment in North American History" (17 August 2026), online: Prime Minister of Canada <pm.gc.ca/en/news/news-releases/2026/08/17/prime-minister-carney-announces-largest-clean-energy-investment-north>.

[38] Alberta, Government of Alberta, "2026 Alberta Referendum" (last visited 23 August 2026), online: <albertareferendum2026.ca>.

alike.[39] In Alberta, during the Calgary Stampede, Premier Smith announced that Meta had chosen Alberta as the location for its latest data centre with an investment of over $13 billion.[40] The project is a 1 GW data centre that will build its own power through a partnership with various local energy companies.[41] The data centre is paired with the construction of a $4.6 billion, 970 MW natural gas fired electricity generation facility (Project Greenlight) that, according to the Government of Alberta, should lower the transmission portion of Alberta ratepayers' electricity bills by up to 6 per cent.[42] But of course, data centres are controversial on both sides of the border. In the U.S., opposition to data centres is growing,[43] while Manitoba Premier Wab Kinew has announced that he will not allow a proposed data centre to be built south of Winnipeg.[44] The City of Hamilton also discussed and decided against banning data centres from being located in the city.[45] Concerns over energy consumption, water usage, noise, and general social media policies seem to be the driving factors behind much of the opposition. For readers of the *ERQ*, the energy and water issues are the ones to keep an eye on for the next few years, as careful design of grid policies for data centres will become increasingly controversial at the various regulatory hearings.

THIS EDITION

We begin this issue with "*Reliability across the whole energy system: Lessons from CERC's May summit*" by David Morton, former Chair and CEO of the British Columbia Utilities Commission and Advisory Board Member of the Canadian Energy Reliability Council. Morton discusses the four key takeaways from the inaugural Canadian Energy Reliability Summit, namely the need to: address reliability from a "whole energy system" perspective; invest before a crisis occurs; place the appropriate weight on reliability in public policy; and improve public engagement, before concluding with possible next steps to advance the energy system reliability conversation.

In "*Before Alberta can leave: Treaty rights and the separation referendum*", Kyle Paziuk, Student-at-Law at Alberta Counsel and BA – Political Science, MA – Policy Studies and Juris Doctor, University of Alberta, explores how two recent decisions of the Alberta Court of King's Bench, *Athabasca Chipewyan First Nation v Alberta (Chief Electoral Officer)* (*ACFN*),[46] and *Sturgeon Lake Cree Nation v Alberta (Sturgeon Lake)*[47], both establish important parameters for any future separation process by clarifying that any attempt to advance a referendum on Alberta's independence must consider the impact on Treaty Rights from a number of important dimensions. Paziuk identifies three implications for energy counsel to consider when monitoring this ongoing process and concludes that while the two cases may reach different results on different applications, they tell a consistent doctrinal story regarding the legal relationship between the duty to consult and potential Alberta separation.

Following on his remarks at the 2026 *ERQ* Energy Law Forum, Gerard Kennedy, Associate

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[39] Disclosure: Mr. Yahya also works at Alberta Counsel, a law and lobby firm that has Meta as a client. None of the information discussed here regarding Meta is based on any private information.

[40] Alberta, News Release, "Meta Makes Historic Investment in Alberta" (8 July 2026), online: Government of Alberta <alberta.ca/release.cfm?xID=964679A5BC522-A153-A52F-1F8CC3D418C55411>.

[41] Meta, "Breaking Ground on Meta's First Data Center in Canada" (8 July 2026), online: Meta Newsroom <about.fb.com/news/2026/07/breaking-ground-on-metas-first-data-center-in-canada>.

[42] Sturgeon County, News Release, "Meta Makes Historic Investment in Alberta" (8 July 2026), online: Sturgeon County <sturgeoncounty.ca/news-release-meta-makes-historic-investment-in-alberta>.

[43] Valerie Volcovici & Lisa Baertlein, "Data Center Opponents Stage 142 Protests Across 42 US States", Reuters (18 July 2026, updated 19 July 2026), online: Reuters <reuters.com/business/retail-consumer/us-data-center-protests-go-national-backlash-grows-2026-07-18>.

[44] CBC News, "Manitoba Sought U.S. Help to Develop Large AI Data Centre and Find Private Financial Partner on $18B Hydro Dam" (10 June 2026), online: CBC News <cbc.ca/news/canada/manitoba/ai-data-centre-manitoba-9.7223138>.

[45] Saira Peesker & Eva Salinas, "No Ban Against Data Centre Development After Hamilton Council Votes Down Bylaw", CBC News (15 July 2026), online: CBC News <cbc.ca/news/canada/hamilton/data-centre-ban-voted-down-9.7271641>.

[46] *Athabasca Chipewyan First Nation v Alberta (Chief Electoral Officer)*, 2026 ABKB 375 [*ACFN*].

[47] *Sturgeon Lake Cree Nation v Alberta*, 2026 ABKB 373 [*Sturgeon Lake*].

Professor and Associate Dean of Graduate Studies, Faculty of Law at the University of Alberta, contributes the article "*The Act is constitutional, but the application may not be*". Kennedy addresses how the phenomenon of statutes being constitutional, but applications of them being unconstitutional, works in practice by examining the "national concern" branch of the "peace, order and good government" power, considering case law that interprets the statutory term "national interest", and providing a reminder of how all exercises of statutory discretion may be challenged for being unconstitutional, even if the statute itself remains constitutional.

In "*Enbridge v Nessel: Pitfalls of the American judicial system*", Moin Yahya, Professor of Law at the University of Alberta and Managing Co-editor of the ERQ, briefly describes the latest court decision in the long-standing dispute between the State of Michigan and Enbridge,[48] provides a high-level overview of the American state and federal court system, and concludes with a discussion about the need for Canadian companies to pay greater attention to removal deadlines and the venue for litigation in the United States.

Also following on his remarks at the 2026 *ERQ* Energy Law Forum, Thompson Rivers University Faculty of Law Professor Mark Mancini contributes "*Democracy Watch: A post-mortem and the next frontier*", in which he comments on the implications of the very recent Supreme Court of Canada case *Democracy Watch v Canada (Attorney General)*.[49] The case addresses whether Parliament can insulate certain agencies from judicial review. Although the narrow question in the case deals with the *Conflict of Interest Act*[50] and the Conflict of Interest and Ethics Commissioner, the case has broad implications for all administrative agencies, as Professor Mancini explains.

Benjamin Dachis, Vice President, Research and Outreach, and Chloe McElhone, Research Manager, both of Clean Prosperity, with oil sands facility-level operational modelling by Rory Johnston, Founder of Commodity Context, contribute "*How the federal-Alberta grand bargain can increase oil sands profitability*". The article, an abridged version of a longer study published by Clean Prosperity, examines the impact of raising the minimum effective carbon credit price to C$130 per tonne and adding new bitumen pipeline capacity by assessing the effect of higher carbon costs and the future value of increased export capacity on four representative oil sands projects. The article concludes with three key findings that support the trade-offs in the federal-Alberta "grand bargain".

Marc Brouillette, Principal Consultant and Founder of Strategic Policy Economics, in the article "*Canada's clean electricity supply crisis*" explores the apparent discontinuity between federal and provincial policies for an electrified economy and the planning assumptions used by various provincial electricity system planning organizations. Brouillette examines the strategic imperative surrounding electrification and compares the province of Ontario's recent *Energy for Generations* initiative with the electricity planning assumptions used by Ontario's Independent Electricity System Operator, before concluding that a call to action for informed demand forecasting is needed, if aspirational goals relating to electrification are to be met.

Issue 3 concludes with the article "*Tail risks and wholesale electricity prices*" by Michele (Mike) Campolieti, Professor of Economics at the Department of Management, University of Toronto. Campolieti uses extreme value theory and data from seven trading hubs in the United States to estimate the shape of the distribution of wholesale prices in these markets, for the purpose of determining whether the distributions are consistent with fat-tailed Pareto distributions. Campolieti also considers whether the shape of the distributions changes based on the season. The analysis and findings have implications for wholesale electricity risk planning, as extreme pricing is more common in distributions with fat tails. ■

[48] The dispute is between Enbridge Energy, LP, Enbridge Energy Co., Inc., and Enbridge Energy Partners, LP, all American subsidiaries of the Canadian Enbridge Inc. For simplicity, and following the U.S. Supreme Court, they will all be referred to as Enbridge.

[49] *Democracy Watch v Canada (Attorney General)*, 2026 SCC 28.

[50] *Conflict of Interest Act, SC 2006*, c 9, s 2.

RELIABILITY ACROSS THE WHOLE ENERGY SYSTEM: LESSONS FROM CERC'S MAY SUMMIT

Canadian Energy Reliability Council

*David Morton**

INTRODUCTION

On May 28, 2026, the Canadian Energy Reliability Council ("CERC") convened an Energy Reliability Summit in Ottawa to discuss the reliability challenges facing Canada's energy system. The Summit brought together industry leaders, policymakers, reliability experts, and energy-sector representatives at a time when reliability is being tested by environmental change, aging infrastructure, supply-chain constraints, cyber threats, electricity adequacy challenges, geopolitical uncertainty, and the pace of net-zero policy.

Two panels explored energy reliability challenges from various perspectives. The first, which was made up of Bob Larocque, President and CEO of the Canadian Fuels Association; Brad Herald, Senior Special Advisor of the Canadian Association of Petroleum Producers; Paul Cheliak, Chief Operating Officer of the Canadian Gas Association; Shannon Watt, President and CEO of the Canadian Propane Association; and Michael Powell, Vice President of Government Relations of Electricity Canada, provided their insights into energy reliability issues, the risks and challenges industry faces in maintaining that reliability, and how they can best work together to address those challenges. The second consisted of Jim Robb, President and CEO of the North American Electric Reliability Corporation; Robert Johnston, Director of Energy and Natural Resources Policy at the School of Public Policy at the University of Calgary; Tonja Leach, Executive Director of QUEST Canada, a national organization advancing efficient, integrated, community-scale energy systems; and David Marshall, Director of Station Operations and Customer Connections for Enbridge Gas. It further explored how reliable Canada's energy system is and how we can maintain the reliability critical to our economy, our way of life, and our health and safety.

A central message emerged from the discussions: reliability is not simply a technical attribute of the electricity grid. It is a public policy matter that affects economic security, affordability, health and safety, emergency preparedness, and public confidence. It must therefore be considered alongside affordability and decarbonization, not treated as an assumed outcome of energy policy.

This article summarizes the Summit's key takeaways and explains how CERC is beginning to develop an action plan in response. The initiatives described below are not presented as a completed workplan, but as the principal areas of follow-up now under

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consideration: public engagement, reliability principles, tabletop exercises, a possible joint industry response to federal energy policy, broader participation in CERC, and greater transparency in energy modelling.

OVERALL SUMMIT TAKEAWAYS

The Summit confirmed that energy reliability is not just a narrow technical issue. It is a national economic, security, affordability, and public-safety issue.

Several core messages have emerged:

First, reliability must be addressed across the whole energy system, not electricity alone. Electricity reliability is critical, but Canadians also depend on reliable natural gas, gasoline, diesel, propane, petroleum products, district energy, and related infrastructure. A reliability discussion that focuses only on the grid risks missing the interdependence of fuels, infrastructure, seasonal demand, emergency response, transportation, food supply, heating, and industrial activity.

Canada's energy system is becoming more interdependent. Electricity reliability increasingly depends on natural gas availability, cyber resilience, supply chains, critical minerals, skilled labour, communications systems, and transmission/distribution infrastructure. Likewise, liquid fuels, propane, and gas networks are essential to backup power, emergency response, logistics, and resilience during extreme events.

Second, reliability requires investment before a crisis occurs. The Summit theme recognized the need for long-term investment, better data, improved regulatory flexibility, and integrated planning across energy sectors. A recurring issue is that reliability is often valued most after it fails, while the investments needed to preserve it must be made years in advance.

Third, the public policy conversation may be underweighting reliability. Policymakers often speak in terms of emissions targets, affordability, and energy transition objectives, but reliability is sometimes treated as an implicit assumption rather than an explicit design consideration. CERC has an important role in making reliability more visible, measurable, and understandable.

Fourth, there is a need for better public engagement. Reliability is not always front and center — until there is an outage, a shortage, a price shock, a fuel disruption, or an emergency. A key CERC opportunity is to communicate reliability in terms that are meaningful to households, businesses, Indigenous communities, municipalities, and public officials.

LESSONS FROM THE SUMMIT

The Summit succeeded in creating a cross-sector conversation rather than a single-fuel or single-technology discussion. The invitation itself included a broad coalition of energy organizations, including gas, fuels, petroleum, propane, electricity, and reliability organizations, which helped reinforce the message that reliability is a whole-system issue.

The second panel brought together expertise in electricity reliability and security, geopolitical and market risk, community-scale integrated energy systems, and operational gas reliability. That combination allowed the Summit to move beyond slogans and into the practical realities of maintaining reliable energy service.

The Ottawa setting was also valuable. Holding the Summit in Ottawa allowed the conversation to be positioned as a national public-policy issue, rather than an industry-only technical discussion.

A key lesson from the Summit is that reliability discussions are most useful when they move from general awareness to specific outputs: reliability principles, policy gaps, public engagement tools, and practical planning exercises. Future events may benefit from a more explicit statement of desired outcomes. For example, the next Summit could ask participants to produce or endorse a short list of reliability principles, identify specific policy gaps, or agree on a public engagement workplan.

There may also be value in more structured participation from policymakers and public servants. A Summit format that includes moderated discussion, tabletop scenarios, or small-group exercises could help move the discussion from "awareness" to "application."

The Summit also pointed toward a broader question for CERC: how should a national reliability-focused organization move from convening discussion to shaping practical public policy tools?

FROM SUMMIT TAKEAWAYS TO AN ACTION PLAN

The Summit was not intended to produce a final action plan. Rather, it was an initial step in identifying the reliability issues that require broader public, policy, regulatory, and industry attention. Together with CERC's newsletter and related outreach, the Summit can be viewed as the first phase of a broader effort to move reliability from a technical concern to a more explicit public policy objective.

The shared commitment of the energy industry to reliability has been demonstrated and key reliability issues have been set out for a broader audience. The Summit also demonstrates that CERC could occupy a valuable middle ground between technical experts, industry associations, regulators, governments, and the public. Its role need not — and should not — be advocacy for one fuel or one technology. Rather, CERC can advocate for the disciplined consideration of reliability in energy policy.

However, an overall strategy within which these initiatives will be executed — if they are executed — is required. The overall themes of the next two phases are:

Phase 2: How is reliability factored into public policy?

This phase would examine the assumptions, modelling, policy drivers, and trade-offs that shape Canadian energy policy. The objective would be to identify where reliability is explicitly considered, where it is assumed, and where it may be underweighted. Issues raised at the Summit — including supply diversity, affordability, community resilience, and the pace of net-zero policy — would form part of this analysis.

Phase 3: What reliability gap needs to be filled, who will fill it, and how?

This phase would focus on practical engagement with policymakers, energy suppliers, regulators, customers, and communities. It would ask what industry is already doing well, where the gaps remain, and what institutional, regulatory, investment, or public engagement tools are needed to strengthen reliability.

To support these next phases, CERC has identified several potential initiatives for further consideration. These are not presented as a final workplan, but as a set of possible activities that could help translate the Summit's takeaways into practical action. CERC will assess these initiatives as part of a broader strategy, including which should be pursued, how they should be prioritized, and whether they are best suited to Phase 2, Phase 3, or a longer-term work program.

PUBLIC-FACING RELIABILITY EXPLAINERS

CERC could develop short, plain-language explainers on topics such as:

- What does "energy reliability" mean?
- Why is reliability different from affordability?
- Why does reliability require redundancy?
- Why does extreme weather change the planning challenge?
- Why do electricity, gas, propane, petroleum products, and transportation fuels need to be considered together?
- What happens when energy systems become more interdependent?

RELIABILITY PRINCIPLES

CERC could develop a short statement of reliability principles for use in policy submissions and public engagement. For example:

- Reliability should be an explicit objective in all major energy policy.
- Reliability must be assessed across all fuels and delivery systems.
- Reliability requires long-term investment, redundancy, and operational flexibility.
- Reliability risks should be transparent to policymakers and the public.
- Reliability, affordability, and decarbonization must be considered together.

MODELLING, TRANSPARENCY, AND RELIABILITY

The modelling issue raised at the Summit is important. Governments increasingly rely on energy modelling to justify policy decisions, infrastructure planning, emissions pathways, and investment choices. However, many models are difficult for non-specialists to scrutinize. It is often unclear how reliability is represented, and what assumptions are made about demand growth, extreme weather, storage, backup fuel, imports, transmission availability, customer behaviour, technology deployment, and emergency conditions.

CERC could pursue this issue in several ways:

- Develop a reliability modelling checklist.
- Commission a paper on how reliability is treated in Canadian energy models.
- Host a technical workshop with modellers, system operators, utilities, regulators, and industry.
- Ask whether models distinguish between annual energy sufficiency and real-time deliverability.
- Examine how models treat low-probability, high-impact events.
- Encourage governments to publish assumptions, sensitivities, and reliability metrics.

A practical goal is to ensure that modelling used for public policy does not merely show that a future energy system balances on average but demonstrates that it can perform in conditions such as summer and winter peaks and under stress and extreme conditions.

EXPANDING CERC MEMBERSHIP AND SUPPORT

The Summit also raised the question of who should be part of the CERC reliability conversation. Possible additional participants include:

- Customer groups, including residential, industrial, agricultural, commercial, and vulnerable-customer representatives.
- Major industry associations, including electricity, gas, fuels, petroleum, propane, renewables, storage, nuclear, mining, transportation, and manufacturing associations.
- Municipal and Indigenous organizations, particularly where community energy resilience and emergency response are major concerns.
- Emergency management organizations.
- Large energy users, including data centres, mines, manufacturers, hospitals, ports, airports, and food-distribution networks.
- Consumer and affordability advocates.
- Academics and modelling experts.

POSSIBLE FOLLOW-UP EVENTS

A. Ottawa Follow-Up Session

A follow-up Ottawa session later in the year could be worthwhile, particularly if it is framed around specific outputs rather than simply a continuation of the May discussion. Possible Ottawa themes include:

- **Reliability as a national policy objective**. How should federal policy explicitly incorporate reliability across electricity, natural gas, petroleum products, propane, transportation fuels, and emergency preparedness?
- **Reliability under stress**. What happens during a multi-day extreme weather event, cyberattack, supply disruption, or electricity adequacy emergency?
- **Reliability and public confidence**. How can governments and industry speak more clearly with Canadians about trade-offs among reliability, affordability, emissions reduction, and infrastructure development?

B. Provincial Summits or Town Halls

Provincial sessions could also be valuable, but they should probably be focused initially on larger provinces where the energy-system issues are particularly consequential: Ontario, Quebec, Alberta, and British Columbia.

Each province could have a tailored focus. For example:

- **Ontario**: electricity adequacy, natural gas-electricity interdependence, nuclear refurbishment/new nuclear, industrial growth, transportation electrification, and distribution system readiness.

- **Quebec**: hydroelectric reliability, export obligations, winter peaks, electrification pressures, transmission constraints, and the interaction between domestic reliability and broader regional markets.

- **Alberta**: resource adequacy, market design, natural gas-fired generation, renewables integration, extreme weather, industrial load, and fuel supply resilience.

- **British Columbia**: hydro variability, load growth from electrification and LNG, transmission constraints, wildfire and extreme-weather resilience, and the relationship between electricity, natural gas, and liquid fuels in emergency response.

A useful format might be a half-day provincial town hall with a short framing presentation, a reliability panel, a scenario exercise, and a concluding discussion on practical actions.

TABLETOP EXERCISES

Tabletop exercises could be especially valuable. They would allow policymakers, industry, regulators, emergency managers, and community representatives to test how the system might respond to specific reliability events.

Possible scenarios include:

- A winter cold snap combined with electricity supply scarcity.

- A prolonged cyberattack affecting electricity and gas operations.

- A major wildfire disrupting electricity transmission, roads, and fuel delivery.

- A multi-day urban energy outage affecting hospitals, telecommunications, heating, water, and transportation.

- A geopolitical fuel supply disruption affecting prices and availability.

- A high-load summer event combined with wildfire smoke, cooling demand, and generation constraints.

These exercises could help reveal where planning assumptions are incomplete, where responsibilities are unclear, and where fuel interdependencies are not fully understood.

CHANGES TO THE CERC WEBSITE AND NEWSLETTER

The CERC website and newsletter should also be reviewed as part of the next phase of work. The current website would benefit from a redesign so that it more clearly communicates CERC's purpose, priorities, membership, and reliability-related resources. Similarly, the newsletter's format and frequency should be assessed to ensure that it is serving a clear strategic purpose. As part of that review, CERC should define the newsletter's goals, identify its intended audiences, and consider practical ways to expand its circulation and impact.

CONCLUSION

The May Summit confirmed that energy reliability deserves a more prominent place in Canadian public policy. Reliability is not automatic, and it is not the responsibility of any one sector. It depends on investment, planning, operational discipline, infrastructure redundancy, transparent modelling, and realistic public discussion about trade-offs.

CERC's opportunity is to become the national forum that keeps reliability visible, practical, and grounded in the real-world functioning of Canada's energy system. The next phase should move from awareness to action: clearer principles, better modelling scrutiny, broader engagement, and a coordinated industry voice on the reliability requirements of Canada's energy future. ■

BEFORE ALBERTA CAN LEAVE: TREATY RIGHTS AND THE SEPARATION REFERENDUM

*Kyle Paziuk**

In the wake of Canada's rapid catalyzation of national unity, spurred entirely by President Donald Trump's threats of a United States takeover, economic or otherwise, one province is seemingly left behind. Talk of secession in Alberta is not new. Besides Quebec, historically Alberta likely boasts the highest number of provincial patriots, with it not being uncommon to hear murmurs of fiscally dubious proposals on what an independent Alberta would resemble. Lately, there exists a marked difference in the sentiment and seriousness behind such wishes for independence. No longer discussed only in backrooms and bars, talk of Alberta separation has progressed to citizen-initiated petitions, and, consequently, Alberta courtrooms. The conclusion of the story on Alberta's future is far from close, with a referendum looming this October.

Whether a miscalculation or purposeful ignorance, separation discussions often ignore a key principle about Alberta's geographical and legal realities: Alberta's energy economy sits, with few exceptions, on Treaty land. Alberta is primarily home to Treaties 6, 7, and 8, with energy projects such as electricity lines and pipeline corridors crossing over the lands of the Numbered Treaties. Energy lawyers in Canada will be intrinsically familiar with the legal duties that stem from projects that infringe on the rights conferred by the Numbered Treaties. For decades, the duty to consult, the honour of the Crown, and the substantive content of Treaty promises have accordingly been working tools of energy law practice.

Two recent Alberta King's Bench decisions authored by Justice Leonard have provided a window into the legal difficulties that Alberta separation could entail, specifically in regard to Indigenous Treaty rights. *Athabasca Chipewyan First Nation v Alberta (Chief Electoral Officer) (ACFN)*[1] and *Sturgeon Lake Cree Nation v Alberta (Sturgeon Lake)*[2] both arise out of Alberta's *Citizen Initiative Act*[3] and the campaign, mounted through that statute, to put a question of Alberta's independence from Canada to a province-wide referendum. To be clear, neither decision was affirmative enough to decide whether or not Alberta will remain in the Dominion of Canada, nor whether it even remains possible for a binding referendum on Alberta's fate to be held. Further, *ACFN* is pending a full hearing in the Alberta Court of Appeal, with a preliminary decision already issued allowing Elections Alberta to begin the verification process for the impugned separatist petition. Nevertheless, the petition cannot advance to a province-wide formal referendum until the appeal in *ACFN* is fully heard and decided.

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[1] *Athabasca Chipewyan First Nation v Alberta (Chief Electoral Officer)*, 2026 ABKB 375 [*ACFN*].

[2] *Sturgeon Lake Cree Nation v Alberta*, 2026 ABKB 373 [*Sturgeon Lake*].

[3] *Citizen Initiative Act*, SA 2021, c C-13.2 [*CIA*].

Despite that procedural uncertainty, the two decisions already establish important parameters for any future separation process. Through different results, both cases clarify that any attempt to advance a referendum on Alberta's independence must consider the impact of such a gravitational shift on Treaty rights.

THE *CITIZEN INITIATIVE ACT*

The *CIA*, passed into law in 2021, was designed to allow electors to trigger referendums on questions of a legislative, policy, or constitutional nature, once a threshold number of signatures was achieved. Petitions with the requisite number of signatures would then be referred to the Chief Electoral Officer (CEO) of Alberta, in preparation for a public vote on the issue. Previously, the *CIA* was not without guardrails. In what the Court in *Sturgeon Lake* called the "*Previous CIA*", no citizen petitions authorized by the CEO were to contain a question that contravened sections 1 to 35.1 of the *Constitution Act, 1982*, under section 2(4) of the *Previous CIA*.[4] Further, the CEO retained the ability to refer questions of a petition's constitutional muster to the Court of King's Bench for further review.[5]

In May 2025, the Legislature passed Bill 54, which lowered the signature threshold and lengthened the collection period for citizen-initiated referendums.[6] The amendments drew immediate opposition from First Nations across Alberta, prompting Premier Danielle Smith to assure the Legislature that "there can be no referendum question that goes forward that violates their section 35 rights,"[7] and prompting Minister of Justice Mickey Amery to confirm, in the same debate, that section 2(4) would continue to guarantee that outcome.[8]

THE *SYLVESTRE* CASE

The precursor to the recent separation litigation was the case of *Chief Electoral Officer of Alberta v Sylvestre*.[9] The premise of the case is simple. Mitch Sylvestre, a proponent of Alberta separatism, sought to bring a citizen-initiated petition for Alberta independence. On July 4, 2025, Sylvestre applied to the CEO for an initiative petition asking whether "the Province of Alberta shall become a sovereign country and cease to be a province in Canada" (the *First Proposal*).[10] As expected, the petition question engaged questions of constitutional validity, and therefore was referred by the CEO to the Alberta courts, under section 2.1 of the *Previous CIA*.[11]

On December 4, 2025, one day prior to the conclusion of oral arguments in *Sylvestre*, the Government of Alberta tabled Bill 14.[12] Whether a convenient coincidence or otherwise, Bill 14 proposed to repeal sections 2(4) and 2.1 of the *Previous CIA*, with the new "*Amended CIA*" containing few of the constitutional guardrails available to the courts.[13] The Court released its decision in *Sylvestre* the next day,[14] holding that the *First Proposal* did not comply with section 2(4) because Alberta independence would contravene the Numbered Treaties as both a legal and a practical matter.[15] The Court also declined to treat the still-pending Bill 14 as having already discontinued the special case, holding that a matter which has been fully

[4] *ACFN*, *supra* note 1 at para 11.

[5] *Sturgeon Lake*, *supra* note 2 at para 13.

[6] Bill 54, *Election Statutes Amendment Act*, 2025, 1st Sess, 31st Leg, Alberta, 2025; *Sturgeon Lake*, *supra* note 2 at para 12.

[7] Alberta, Legislative Assembly, *Alberta Hansard*, 31st Leg, 1st Sess (13 May 2025) at 3390, as cited in *Sturgeon Lake*, *supra* note 2 at para 13.

[8] Alberta, Legislative Assembly, *Alberta Hansard*, 31st Leg, 1st Sess (14 May 2025) at 3494, as cited in *Sturgeon Lake*, *supra* note 2 at para 14.

[9] *Chief Electoral Officer of Alberta v Sylvestre*, 2025 ABKB 712 [*Sylvestre*].

[10] *ACFN*, *supra* note 1 at para 12.

[11] *Sturgeon Lake*, *supra* note 2 at para 83.

[12] Bill 14, *Justice Statutes Amendment Act*, 2025, 2nd Sess, 31st Leg, Alberta, 2025; *ACFN*, *supra* note 1 at para 15.

[13] Bill 14, *Justice Statutes Amendment Act*, 2025, 2nd Sess, 31st Leg, Alberta, 2025.

[14] *Sylvestre*, *supra* note 9.

[15] *Ibid* at paras 214, 231, 245, as cited in *ACFN*, *supra* note 1 at para 160.

argued cannot be legislated out of existence before judgment is rendered.[16]

Three days later, on December 8, 2025, the CEO formally rejected the *First Proposal* under the pre-amendment *CIA*.[17] Mr. Sylvestre subsequently submitted a near-identical question in form to the first, asking "Do you agree that the Province of Alberta should cease to be a part of Canada to become an independent state?" (the *Second Proposal*).[18] The *Amended CIA*, free of the requirement to peruse petition questions for any potential constitutional quandaries, approved the *Second Proposal* quickly, on December 22, 2025.[19]

The approval of the *Second Proposal* sent Alberta barrelling towards an inevitable separation referendum, with all intermittent legal hurdles seemingly cleared. However, separated into two decisions, both decided by Justice Leonard, *ACFN* involved applications for judicial review from the Athabasca Chipewyan First Nation and the Piikani Nation, Siksika Nation, and Blood Tribe (the Blackfoot Nations). The second case, *Sturgeon Lake*, was initiated by the Sturgeon Lake Cree Nation (SLCN), arguing for an injunction against the operation of Bill 14, pending the Court's ruling on its constitutionality. Both cases, despite approaching the constitutional concerns with Bill 14 differently, turned on how the Bill held legal space for Treaty rights, in light of any potential separation.

NUMBERED TREATIES & CONSTITUTIONAL RESTRUCTURING

Despite the fact that the applicant Nations in *ACFN* were successful in their request to, at least temporarily, suspend any binding referendum on Alberta separation, and the applicants in *Sturgeon Lake* were not, both cases demonstrated that Treaty rights in Canada are not merely a roadblock to constitutional restructuring. Neither *ACFN* nor *Sturgeon Lake* was asked to relitigate *Sylvestre*'s substantive Treaty analysis, and neither did so; both simply adopted it as the starting point for the questions actually before the Court.[20] Both *ACFN* and *Sturgeon Lake* focused on what *Sylvestre* concluded regarding the relationship between separation and Treaty rights: that Alberta independence would contravene the Numbered Treaties "both as a matter of law and as a practical matter," because it would remove Canada and substitute an independent Alberta as the entity responsible for fulfilling Treaty obligations without the consent of the Treaties' First Nations parties.[21] Ultimately, whatever protections an independent Alberta might choose to write into its own constitution, Alberta cannot simply step into Canada's shoes as Treaty partner without the consent of the Nations who treated with the Crown in right of Canada, not with a province.[22]

From an energy law perspective, the result in *ACFN* demonstrates the inherited legal architecture that is associated with Alberta's expansive network of energy infrastructure, likely touching on Treaty land. That architecture depends on a legal connection to Canada, not strictly Alberta, and one that is not simply broken by separation. The Blackfoot Nations put the point squarely in *ACFN*, arguing that the CEO Decision would substitute an independent Alberta as the entity responsible for Treaty obligations, contravene the right to move around Treaty tracts, and eliminate the continuity of the constitutional obligations that guarantee Treaty promises are kept.[23] Justice Leonard agreed, finding "a direct causal connection between the CEO Decision and the Treaty rights that are engaged" sufficient to ground both a duty to consult and, ultimately, the quashing of the decision.[24]

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[16] *Sylvestre*, *supra* note 9 at paras 250, 252, as cited in *Sturgeon Lake*, *supra* note 2 at para 20.

[17] *ACFN*, *supra* note 1 at para 17.

[18] *Ibid* at para 18.

[19] *Ibid* at para 20.

[20] *Ibid* at paras 159–64, 216; *Sturgeon Lake*, *supra* note 2 at paras 96–97, 110.

[21] *Sylvestre*, *supra* note 9 at para 214, as cited in *ACFN*, *supra* note 1 at para 160.

[22] *Ibid.*

[23] *ACFN*, *supra* note 1 at para 212.

[24] *Ibid* at para 238.

DUTY TO CONSULT & MULTI-STAGE STATUTORY PROCESSES

Energy law practitioners are constantly alive to the legal realities of navigating multi-stage statutory processes in the development of energy projects. Within Justice Leonard's decisions is commentary on how the duty to consult attaches to such multi-step processes. Alberta's position throughout *ACFN* was that the CEO Decision was nothing more than a non-discretionary step permitting a proponent to gather signatures, involving no governmental policy development or strategic decision-making, and that any duty to consult would only be engaged, if at all, once a referendum had actually produced a result the Government proposed to implement.[25] In performing the *Haida* analysis, to assess the strength of ACFN's claims that the duty to consult was necessary, Justice Leonard rejected the Government's framing at every stage.[26]

On the issue of knowledge, the Court found the Crown had actual, not merely constructive, notice of the Treaty rights being engaged, because the CEO's own statutory obligation to notify the Minister of Justice of the *Second Proposal* supplied that notice, and because the Minister had himself been a party to *Sylvestre*, litigated on the same essential question weeks earlier.[27] On Crown conduct, Alberta and the CEO argued that the CEO, as an independent officer of the Legislature insulated from ministerial direction, could not be equated with "the Crown" for consultation purposes.[28] Justice Leonard accepted that the CEO's institutional independence is real and important, but held, applying the Supreme Court's reasoning in *Clyde River (Hamlet) v Petroleum Geo-Services Inc*,[29] that once a statutory body exercises executive power conferred by the Legislature to make a decision with binding downstream consequences, "any distinction between its actions and Crown action quickly falls away."[30]

As a result of the CEO's decision to allow the petition, a mandatory statutory sequence was triggered, ultimately potentially amounting to a mandatory referendum should the signature threshold be met. Therefore, the end result invoked a determination that Crown conduct was indeed constituted, notwithstanding the arm's-length status of the CEO to the Government.[31] On potential adverse effect, the Court found a direct causal link between the CEO Decision and Treaty rights, reasoning that the entire point of the sequence set in motion by that decision is to place a binding secession question before the electorate, and that a requirement to implement secession without prior First Nations' involvement would self-evidently affect Treaty rights.[32]

Two aspects of this analysis should give energy regulatory counsel pause, even outside the secession context. First, the decision applies the "strategic, higher-level decision" language from *Rio Tinto* to an early, administrative, formally non-discretionary step in a longer regulatory process.[33] Second, the decision confirms that institutional independence from Cabinet, the Government's executive branch, a feature shared by Alberta's energy and utilities regulators, does not remove a decision-maker from "the Crown" for duty-to-consult purposes. What matters is whether the decision-maker is the vehicle through which the Crown brings about a legally consequential outcome, not whether a minister directs its day-to-day operations.[34] Together, these principles provide energy counsel with a recent Alberta authority on the timing of consultation obligations in multi-stage regulatory approvals.

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[25] *Ibid* at paras 199, 225.

[26] Applying *Haida Nation v British Columbia (Minister of Forests)*, 2004 SCC 73 at para 35 [*Haida*], and *Rio Tinto Alcan Inc v Carrier Sekani Tribal Council*, 2010 SCC 43 at para 31 [*Rio Tinto*].

[27] *ACFN*, *supra* note 1 at para 217.

[28] *Ibid* at paras 225, 229–31; *Election Act*, RSA 2000, c E-1, s 2(2); *Anglin v Resler*, 2020 ABCA 184 at para 30.

[29] *Clyde River (Hamlet) v Petroleum Geo-Services Inc*, 2017 SCC 40 at para 28 [*Clyde River*].

[30] *Ibid* at para 29, quoted in *ACFN*, *supra* note 1 at para 233.

[31] *ACFN*, *supra* note 1 at para 234.

[32] *Ibid* at paras 237–38.

[33] *Rio Tinto*, *supra* note 26 at para 44, discussed in *ACFN*, *supra* note 1 at paras 223–24.

[34] *Clyde River*, *supra* note 29 at para 29.

LEGISLATING AROUND LITIGATION

Running through Justice Leonard's decision in *ACFN*, relevant to energy law practice, is the firm declaration that legislation cannot validly substitute a pending litigation decision. Bill 14, modifying the terms of the *CIA*, was tabled one day prior to the conclusion of oral arguments in *Sylvestre*. Alberta's own counsel had told the Court, in a letter dated December 4, 2025, that "once this legislation takes legal effect, this Action will be discontinued."[35] The Court in *Sylvestre* refused to treat the pending amendment as predisposing its conclusions in the case, ultimately ruling that legislating an end to a matter already fully argued would be "the antithesis of the stable, predictable, and ordered society that the rule of law contemplates, and democracy demands."[36]

In pulling from the conclusions of the Court in *Sylvestre*, *ACFN* further commented on the separation between legislation and litigation. Justice Leonard disagreed with the CEO's approval of the *Second Proposal* on the strength of its transitional provisions, following the imposition of Bill 14.[37] Justice Leonard concluded that the CEO's willingness to accept the *Second Proposal*, identical in language to the *First Proposal*, could not be reconciled as a reasonable decision. Ultimately, a proposal rejected three days before the amendments came into force was not, on a plain reading, still "pending" within the meaning of section 71.1(1), and nothing in the record suggested an intention to retroactively revive it.[38] Justice Leonard deemed that no matter the intentions of the Legislature in proposing Bill 14 and reducing the necessary constitutional guardrails in the *CIA*, the legal consequences of the CEO's decision in approving the wording of the *Second Proposal* were still a live issue.

Energy law practitioners should keep this particular element of *ACFN* front of mind. *ACFN* is a useful, recent illustration of just how far Alberta courts will and will not let such legislative responses reach. The Legislature's authority to change the law prospectively, even in direct response to litigation it is losing, is not in doubt.[39] What the Court will resist, on this authority, is any attempt to use that authority to retroactively erase a specific, already-crystallized legal consequence.

SAME VEHICLE, DIFFERENT RESULTS

It is worth pausing on the fact that these two applications, grounded in substantially the same Treaty rights and the same statutory scheme, produced opposite results. *ACFN* and the Blackfoot Nations succeeded. The CEO's Decision was quashed on three independent grounds, and the initiative petition process now stands halted pending a fresh decision that properly grapples with the Transitional Provisions, *Sylvestre*, and the duty to consult.[40] SLCN, despite persuading the Court it had raised serious issues, and despite a balance of convenience the Court found favoured an injunction, was refused relief because it could not establish irreparable harm.[41]

The explanation lies in procedural posture more than in the underlying merits, which the Court treated as substantially aligned across both proceedings. Judicial review targets a decision already made, on a record that is largely complete, and asks whether it was reasonable or correct under the *Vavilov* framework.[42] Where the error is central to the outcome, quashing follows without any need to prove forward-looking injury. An interlocutory injunction is different. It asks a court to intervene before a full record exists and before the merits are tried, and the tripartite test in *RJR-MacDonald Inc v*

[35] *Sylvestre*, *supra* note 9 at para 250, as cited in *ACFN*, *supra* note 1 at para 123.

[36] *Sylvestre*, *supra* note 9 at para 252, as cited in *Sturgeon Lake*, *supra* note 2 at para 20.

[37] *ACFN*, *supra* note 1 at para 94.

[38] *Ibid* at paras 108–16, 151.

[39] *Alberta v Kingsway General Insurance Company*, 2005 ABQB 662 at para 149, discussed in *ACFN*, *supra* note 1 at paras 130–31.

[40] *ACFN*, *supra* note 1 at paras 244–46.

[41] *Sturgeon Lake*, *supra* note 2 at paras 176–80.

[42] *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65 at paras 16–17, 99–101 [*Vavilov*], applied in *ACFN*, *supra* note 1 at paras 86–93.

Canada (Attorney General)[43] exists to guard against exactly that kind of early intervention. Irreparable harm is rarely a formality. It was the outcome-determinative branch for SLCN.

The lesson is not that judicial review always wins out. Quashing only ever addresses the decision quashed, and *ACFN* declined to reach the constitutionality of the Impugned Provisions once quashing was available on narrower grounds,[44] leaving Bill 14 available for the Legislature to revisit, as Bill 23, tabled during the *Sturgeon Lake* hearing itself, already suggests it will.[45] Nor is the lesson that interlocutory relief is not worth pursuing. The balance of convenience findings, and the Court's view that SLCN's claim is strong,[46] may matter a great deal at trial. The real lesson is narrower. Where a reviewable decision exists and the objective is to stop it, judicial review is the more direct route. Where none exists, or the real objection is to an entire legislative scheme, an injunction may be the only tool available, but counsel should build the record for irreparable harm from the outset, not as an afterthought.

IMPLICATIONS GOING FORWARD

Three practical points follow for energy counsel monitoring this file. First, nothing about either decision resolves the underlying question of whether, or how, Alberta could ever lawfully put a binding secession question to referendum. *ACFN* quashed a single decision on statutory-interpretation and duty-to-consult grounds without reaching the constitutionality of the *Amended CIA*;[47] SLCN's underlying action, alleging breach of Treaty and of the duty of diligent implementation, remains to be tried on its merits.[48] The Legislature had already tabled further amendments to the *CIA*, Bill 23, before the *Sturgeon Lake* hearing concluded,[49] confirming that this is an evolving statutory target rather than a settled one. Energy clients with long-dated capital committed in Alberta should treat the separatist file as continuing, not closed, litigation, and counsel advising on political and regulatory risk should expect further rounds of legislative amendment, further judicial review applications each time the CEO acts on a revived proposal, and quite possibly appellate review of both decisions discussed here.

Second, and more durably useful regardless of how the secession question resolves, *ACFN*'s extension of the *Clyde River* Crown-conduct reasoning to an independent officer of the Legislature is authority energy counsel should keep on file. Alberta's energy regulatory landscape includes several bodies that are structurally independent of Cabinet in much the same way the CEO is, and that make early-stage, formally non-discretionary decisions which nonetheless set mandatory statutory sequences in motion. *ACFN* supports the proposition that such decisions can constitute Crown conduct for duty-to-consult purposes notwithstanding that independence, wherever the decision-maker can fairly be described as the vehicle through which a statutorily mandated outcome is set in train. Any regulator, or regulated party, assuming that arm's-length status forecloses a duty-to-consult argument at an early approval stage should revisit that assumption in light of this decision.

Third, for all the uncertainty the secession campaign has generated, both decisions offer energy lawyers, and by extension their clients, lenders, and insurers, a measure of reassurance about the legal durability of the Treaty foundation beneath Alberta's energy economy. Two independently argued applications, decided by applying ordinary administrative and equitable principles rather than any special secession-specific doctrine, each concluded that the Numbered Treaties impose real, judicially enforceable constraints on any attempt to restructure Alberta's constitutional relationship with Canada, and that those

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[43] *RJR-MacDonald Inc v Canada (Attorney General)*, [1994] 1 SCR 311 at 332–33 [*RJR-MacDonald*].

[44] *ACFN, supra* note 1 at paras 242–43, 246.

[45] Bill 23, *Justice Statutes Amendment Act*, 2026, 2nd Sess, 31st Leg, Alberta, 2026, referenced in *Sturgeon Lake*, *supra* note 2 at para 153.

[46] *Sturgeon Lake*, *supra* note 2 at para 142.

[47] *ACFN*, *supra* note 1 at paras 242–43, 246.

[48] *Sturgeon Lake*, *supra* note 2 at paras 2, 177–79.

[49] *Ibid* at para 153.

constraints cannot be legislated around, deferred to a post-referendum afterthought, or satisfied by ministerial assurance alone.[50] Whatever one's view of Alberta separatism as a political project, that is a conclusion energy counsel, and the industry more broadly, can reasonably rely on: the Treaty relationships that already underpin consultation frameworks, impact-benefit agreements, and regulatory approvals across the province's resource base are not artifacts a referendum majority can simply vote away.

CONCLUSION

ACFN and *Sturgeon Lake* reach different results on different applications, but tell a consistent doctrinal story regarding the legal relationship between the duty to consult and potential Alberta separation. Ultimately, the decisions demonstrated that the duty to consult attaches earlier in Alberta's secession machinery than the Government assumed, and such a duty is not properly delegated to the CEO. Further, the courts clarified that passing legislation on the barometer of scrutiny required for such a petition does not negate the rule of law's imposition on the real limits of how far the Legislature may reach back to erase the legal consequences of decisions it does not like. None of that turns on any special theory of secession law; each principle is drawn from the ordinary furniture of Crown-Indigenous and administrative law that energy lawyers already carry into every consultation file, regulatory hearing, and impact-benefit negotiation in the province.

The referendum question that gave rise to both decisions may or may not ever reach Alberta voters. However, if it ever does reach a formal vote, both the *ACFN* and *Sturgeon Lake* decisions ensure that due consideration of Treaty rights will need to be explicitly had. ■

[50] *ACFN*, *supra* note 1 at paras 164, 239–41; *Sturgeon Lake*, *supra* note 2 at paras 91, 108, 112.

THE ACT IS CONSTITUTIONAL, BUT THE APPLICATION MAY NOT BE

*Gerard J. Kennedy**

The *Greenhouse Gas Pollution Pricing Act*[1] (*GGPPA*), the constitutionality of which was upheld by a majority of the Supreme Court,[2] expanded federal power at the resistance of most provinces. The revised *Impact Assessment Act*[3] (*IAA*) and the new *Building Canada Act*[4] have raised similar concerns. Even if these laws are upheld as constitutional, however, it must be remembered that, much like the *GGPPA*, particular exercises of discretion under the statutes may well be held to be *ultra vires* as extending beyond legitimate federal authority. By way of illustration, the federal government likely cannot justify regulating the building of a particular residential neighbourhood under the *Building Canada Act* even if declared to be in the "national interest".

This article will address how the phenomenon of statutes being constitutional, but applications of them being unconstitutional, works in practice. First, the "national concern" branch of the "peace, order and good government" power will be discussed. Second, case law that interprets the statutory term "national interest" will be considered. Third, a reminder will be given how all exercises of discretion under these and similar statutes may be challenged for being unconstitutional, even if the statute remains constitutional. While this is quintessentially considered in the *Charter* context, it can apply just as much to the division of powers.

1. "NATIONAL CONCERN"

Section 91 of the *Constitution Act, 1867* gives the federal Parliament power to enact laws for the "peace, order and good government" (POGG) of Canada. Is any law passed by Parliament **not** for the "peace, order and good government" of Canada? One would hope not. To avoid this general power completely overwhelming provincial powers, doctrinal guardrails have had to constrain it.[5] Two "branches" have accordingly emerged in the case law as to when a use of this "POGG" power is appropriate:

a. the "emergency branch"; [6] and

b. the "national concern" branch.

Cases such as *R v Crown Zellerbach Canada Ltd*[7] and the *GGPPA Reference*[8] address the

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[1] *Greenhouse Gas Pollution Pricing Act*, SC 2018, c 12, s 186 [*GGPPA*].

[2] *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11 [*GGPPA Reference*].

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

[4] *Building Canada Act*, SC 2025, c 2, s 4.

[5] Peter Hogg & Wade Wright, *Constitutional Law of Canada*, 5th ed (Toronto: Thomson Reuters Canada, 2020) at s 17:1.

[6] *Re: Anti-Inflation Act*, 1976 CanLII 16 (SCC) [*Anti-Inflation Reference*].

[7] *R v Crown Zellerbach Canada Ltd*, 1988 CanLII 63 (SCC) [*Crown Zellerbach*].

[8] *GGPPA Reference*, *supra* note 2.

latter, which will be the topic of this article. In assessing whether a particular law falls within this power, a court must characterize and then classify the law. It is important to keep these two steps separate. The characterization identifies the matter that the statute addresses. The law can then be classified, based on considering:

1. Whether it addresses a threshold matter of national importance;[9]

2. The matter must be characterized as having a "singleness, distinctiveness, and indivisibility" that is qualitatively different than provincial concern;[10] and

3. There must be provincial inability to regulate the area, as the legislation should be of such a nature that the provinces would be incapable of enacting it, and the failure of a single province to act would jeopardize the national scheme while having "grave" extraprovincial consequences.[11]

There must also be a final evaluation that the federal impact is reconcilable with the division of powers.[12]

Examples of cases where this has been upheld include *Johannesson v Municipality of West St Paul*,[13] *Munro v National Capital Commission*,[14] and *Ontario Hydro v Ontario (Labour Relations Board)*.[15] In these cases, the Supreme Court held that the federal government has exclusive jurisdiction over aeronautics; the establishment and management of the National Capital Region (a defined area consisting of the seat of the federal government and its surroundings); and the production, use, and application of atomic energy. But this has not been upheld in *Re: Anti-Inflation Act*[16] and the *Reference re Impact Assessment Act*.[17] In the former case, a divided majority of the Supreme Court found the containment and reduction of inflation insufficiently specific to be of national concern; in the latter, the Court held that interprovincial environmental effects (*i.e.*, assessing and regulating designated projects to minimize potential adverse effects, and directing how federal authorities assess potential significant adverse effects of federal projects) are too general to be of national concern.

2. NATIONAL INTEREST

Unlike "national concern", "national interest" is not a constitutionally defined term. Rather, it is found in a variety of statutes. Some of these include matters that are clearly in federal jurisdiction, and the term "national interest" is used in the operationalizing statute: the clearest example in this regard may be immigration.[18] At other times, however, the "national interest" may be the reason that the federal government asserts jurisdiction pursuant to the POGG power: the *Building Canada Act* is perhaps the clearest example, though it arguably falls under the trade and commerce and navigation and shipping powers as well.

The term "national interest" will need to be interpreted in the context of each statute in which it appears in accordance with principles of statutory interpretation.[19] While the use of the term across different statutes may indicate a certain commonality between meaning,[20] a statute addressing the "national

[9] *Ibid* at para 142.

[10] *Ibid* at para 145, citing *Crown Zellerbach*, *supra* note 7 at 432.

[11] *GGPPA Reference*, *supra* note 2 at para 160, citing *Crown Zellerbach*, *supra* note 7 at 432.

[12] *GGPPA Reference*, *supra* note 2 at para 165.

[13] *Johannesson v Municipality of West St Paul*, 1951 CanLII 55 (SCC).

[14] *Munro v National Capital Commission*, 1966 CanLII 74 (SCC).

[15] *Ontario Hydro v Ontario (Labour Relations Board)*, 1993 CanLII 72 (SCC).

[16] *Anti-Inflation Reference*, *supra* note 6.

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

[18] *Immigration and Refugee Protection Act*, SC 2001, c 27, ss 42.1(1)-(2); See, *e.g.*, *Mason v Canada (Citizenship and Immigration)*, 2023 SCC 21 at paras 88–89.

[19] See, *e.g.*, Philip Bryden, *et al*, *Public Law: Cases, Commentary, and Analysis*, 5th ed (Toronto: Emond Montgomery, 2025), Chapter Ten.

[20] See, *e.g.*, the link between the *Canadian Security Intelligence Service Act*, RSC, 1985, c C-23 and the *Emergencies Act*, RSC, 1985, c 22 4th Supp, as discussed in *Canada (Attorney General) v Canadian Civil Liberties Association*, 2026 FCA 6.

interest" in railways[21] is quite likely to have a different meaning than a statute concerning the "national interest" in national security.[22] In *Ottawa Police Services v Diafwila*[23], Miller JA noted that the term is likely to be highly contextual in its interpretation. At the same time, a certain threshold level — analogous if not synonymous to the "threshold" in national concern constitutional case law — is likely to be present.

3. THE STATUTES MAY BE CONSTITUTIONAL—BUT THE APPLICATION MAY NOT BE

The Government of Alberta has commenced a fresh constitutional challenge to the revised *Impact Assessment Act*.[24] Irrespective of the outcome of that case, however, it must be remembered that all exercises of discretion under the *IAA*, as well as exercises of discretion under the *GGPPA* and *Building Canada Act*, must also comply with the division of powers. This is because the federal government may not do indirectly, through administrative discretion, what it cannot do directly, through legislation.[25]

This observation — that exercise of administrative discretion may be unconstitutional even if the enabling statute is constitutional — has been made in different contexts in recent years. These have often concentrated on the *Charter*. For instance, there is nothing unconstitutional about a law society bylaw mandating civility in the legal profession. However, once that bylaw affects an individual's freedom of expression, the application becomes constitutionally suspect.[26]

How courts should review instances of the intersection with administrative discretion and the *Charter* has been enormously controversial in administrative law in recent years due to the *Doré* framework,[27] the fate of which was explicitly left open in *Vavilov*.[28] In *Commission scolaire francophone des Territoires du Nord-Ouest v Northwest Territories (Education, Culture and Employment)*,[29] the Supreme Court held that administrative decision-makers always need to consider "*Charter* values" even in cases where a *Charter* right is not affected. However, in *York Region District School Board v Elementary Teachers' Federation of Ontario*, [30] the Court held that whether a Charter right is impacted by an administrative decision must be reviewed by a court on a correctness standard, which appears not to accord with *Doré*. The best, though imperfect, way to reconcile these cases would appear to be that:

a. assessing whether a particular administrative decision limits a *Charter* right is to be reviewed on a correctness standard using orthodox constitutional analysis;

b. assessing whether that limit is reasonably justified by s 1 of the *Charter* requires considering *Doré* rather than *Oakes*; and

c. administrators have a free-standing duty to consider "*Charter* values" and failure to do so risks their decisions being held to be unreasonable.[31]

On federalism grounds, there are similarly cases where courts find administrative decisions and their legislation either *intra vires* (*e.g.*,

[21] See, *e.g.*, *An Act respecting the Saint John and Quebec Railway*, SNB 1918, c 9, s 5.

[22] See, *e.g.*, *Agraira v Canada (Public Safety and Emergency Preparedness)*, 2013 SCC 36 [*Agraira*] at paras 87–88.

[23] *Ottawa Police Services v Diafwila*, 2016 ONCA 627 [*Diafwila*], citing *Agraira*, *supra* note 22.

[24] *IAA Reference*, *supra* note 17; *Reference re Impact Assessment Act (Canada)*, 2025 ABCA 75.

[25] *Baker v Canada (Minister of Citizenship and Immigration) (CA)*, 1996 CanLII 3884 (FCA) at para 20, var'd on other grounds, [1999] 2 SCR 817.

[26] *Doré v Barreau du Québec*, 2012 SCC 12.

[27] See the tension between *Commission scolaire francophone des Territoires du Nord-Ouest v Northwest Territories (Education, Culture and Employment)*, 2023 SCC 31 and *York Region District School Board v Elementary Teachers' Federation of Ontario*, 2024 SCC 22, discussed in, e.g., Gerard J Kennedy, "Charter Values and Canadian Administrative Law: A Doctrinal Journey" (Legal Education Society of Alberta, 2026) [*Kennedy*].

[28] *Canada (Minister of Citizenship and Immigration) v Vavilov,* 2019 SCC 65 [*Vavilov*] at para 57.

[29] *Commission scolaire francophone des Territoires du Nord-Ouest v Northwest Territories (Education, Culture and Employment)*, 2023 SCC 31.

[30] *York Region District School Board v Elementary Teachers' Federation of Ontario*, 2024 SCC 22.

[31] *Kennedy*, *supra* note 27.

Gateway Bible Baptist Church et al v Manitoba et al[32]) or *ultra vires* (*e.g.*, *Director (EAP) v Alberta (Provincial Court)*[33]). In *Gateway Bible Baptist Church*, impugned COVID-19 Public Health Orders could operate pursuant to the provincial *Public Health Act*[34] because they neither conflicted with, nor frustrated the purpose of, the *Criminal Code*.[35] In *Director (EAP)*, however, a Provincial Court justice's mediation order was *ultra vires* because the *Provincial Court Act* and *Alberta Rules of Court* did not grant her inherent authority; only superior courts have inherent authority, and the Provincial Court has not acquired such jurisdiction in any way. Holding otherwise would expand the provincial government's ability to create a superior court, offending the division of powers. This is despite the fact that the creation of the Provincial Court *per se* is clearly constitutional.

Treaty 8 Tribal Association v Barley[36] is especially on point, as the legislation was *intra vires* but the exercise of administrative discretion was not. This was an application for judicial review of a federal adjudicator's decision that the applicant association was a federal undertaking for the purpose of applying the *Canada Labour Code*[37] in the context of an alleged unjust dismissal. Tremblay-Lamer J quashed the adjudicator's decision, concluding that the applicant is a provincial entity and the Code did not apply to the respondent's complaint. She noted that the standard of review must be correctness for constitutional questions involving the division of powers. In this case, the applicant's activities — providing services and advice, facilitating economic projects, and coordinating negotiations for First Nations — were not part of the core of s 91(24) of the *Constitution Act, 1867* concerning "Indians and lands reserved to Indians". While the *Canada Labour Code* is constitutional, it could not apply to the issues raised by the application. The adjudicator would have declined federal jurisdiction if she applied the proper test.

As noted in *Vavilov, Dunsmuir v New Brunswick*, and *Treaty 8 Tribal Association*, no deference is owed to a determination that a particular administrative decision offends the division of powers.[38] This is because a level of government may not do indirectly through administrative action what it cannot do directly through legislation. This is unlike disputes over the compliance of administrative decisions with the *Charter*. In the *Charter* context, a "reasonable limit" on a *Charter*-right is context-specific, and there is accordingly some logic for deference to the administrator.[39]

How do we know that a particular exercise of administrative discretion under the *GGPPA*, *Building Canada Act*, or *IAA* complies with the division of powers? This will obviously need to be addressed in more detail in the future. However, individual housing decisions are extremely unlikely to pass constitutional muster, being quintessentially tied to property and civil rights and not obviously transcending provincial borders. Characteristics from the POGG case law are likely helpful indicia that particular exercises of administrative discretion are constitutionally compliant. However, as Miller JA noted in *Diafwila*,[40] the terms are not synonymous and we should not expect perfect overlap.

CONCLUSION

There is economic and investment uncertainty concerning the ambit of the *Building Canada Act* and the *IAA*. But even assuming both statutes are constitutional, it is clear that individual uses of them must also be *intra vires* of the federal government. Rowe J already noted that this is a requirement for the *GGPPA* in his dissenting reasons in the *GGPPA Reference*. Wagner CJ,

[32] *Gateway Bible Baptist Church et al v Manitoba et al*, 2021 MBQB 219, aff'd 2023 MBCA 56, leave to appeal ref'd, 2024 CanLII 20245 (SCC).

[33] *Director (EAP) v Alberta (Provincial Court)*, 2017 ABQB 3.

[34] *Public Health Act*, CCSM c P210.

[35] *Criminal Code*, RSC 1985, c C-46.

[36] *Treaty 8 Tribal Association v Barley*, 2016 FC 1090 [*Treaty 8 Tribal Association*].

[37] *Canada Labour Code*, RSC 1985, c L-2.

[38] *Dunsmuir v New Brunswick*, 2008 SCC 9 at para 58; *Vavilov*, *supra* note 28 at para 55.

[39] Kennedy, *supra* note 27.

[40] *Diafwila*, *supra* note 23 at para 56.

for the majority, responded by noting that "the underlying premise of my colleague's comments — that regulations made pursuant to an enabling statute must be consistent with the division of powers and further the purpose of the statute — is uncontroversial".[41] In other words, basic principles of administrative and constitutional law still exist to guard against federal overreach in these areas. ■

[41] *Supra* note 2 at para 220.

ENBRIDGE V NESSEL: PITFALLS OF THE AMERICAN JUDICIAL SYSTEM

*Moin A. Yahya**

I. INTRODUCTION

One of Canada's major oil and gas companies, Enbridge Inc., has found itself enmeshed in a dispute with the State of Michigan for over a decade. The latest episode of entanglement ended up in the United States Supreme Court with the issuance of its decision in *Enbridge Energy, LP v. Nessel*.[1] The Supreme Court sided with the state in its dispute against Enbridge,[2] not on the merits of the underlying dispute but rather over a very technical procedural question that the American court system is afflicted with. The goal of this article is to provide the reader with a basic overview of the *Enbridge* case but also with a general overview of how the American federal and state judicial systems interact with each other.

Enbridge and the state of Michigan have had a fraught relationship. Back in 2010, a pipeline operated by Enbridge, Line 6B, ruptured spilling thousands of barrels of oil. The cleanup took years and its impact on state politics lingers. Enbridge owns another pipeline, Line 5, which runs 645 miles (approx. 1,040 km) "from Northwestern Wisconsin through Michigan and into Canada."[3] The pipeline moves "petroleum products to refineries across the Midwestern United States, Ontario, and Quebec."[4] "Between Michigan's Upper and Lower Peninsulas, a 4-mile strip of Line 5 traverses the Straits of Mackinac pursuant to a 1953 easement granted to Enbridge's predecessor by the State of Michigan".[5]

In June 2019, the Attorney General of Michigan filed a lawsuit against Enbridge claiming that the 1953 easement was no longer valid given the risk of oil spills from the pipeline. The lawsuit was brought in a Michigan state court. A year later, in November 2020, the Governor of Michigan purported to revoke the 1953 easement and brought a suit against Enbridge to enforce the revocation of the easement. The lawsuit was similar in nature to the earlier lawsuit by the Attorney General and was also filed in a Michigan state court. It is at this point that a Canadian reader may lose the plot, and for this a basic introduction to the American judicial system is needed. This is the subject of the next section.

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[1] *Enbridge Energy, LP v Nessel*, 608 U.S. ___ (2026), online (pdf): <supremecourt.gov/opinions/25pdf/24-783_bqm2.pdf>.

[2] The dispute is between Enbridge Energy, LP, Enbridge Energy Co., Inc., and Enbridge Energy Partners, L.P., all American subsidiaries of the Canadian Enbridge Inc. For simplicity, and following the U.S. Supreme Court, they will all be referred to as Enbridge.

[3] *Enbridge*, *supra* note 1 at 7.

[4] *Ibid*.

[5] *Ibid*.

II. THE AMERICAN STATE AND FEDERAL COURT SYSTEM

In Canada, each province has a set of trial and appellate courts. Usually, each province has two sets of trial courts, one that adjudicates disputes involving smaller dollar amounts and another that deals with larger more-complicated and higher-dollar-value disputes. Each province also has its own appellate court, from which appeals may be taken up the Supreme Court of Canada. Typically, most disputes including those between private individuals as well as those between private individuals and a provincial or federal government can be brought in these provincial trial courts. Additionally, a federal court system exists that hears appeals or judicial reviews of federal administrative agencies as well as cases in a set of areas that are seen as quintessentially federal in nature such as patents, copyrights, trademarks, immigration, and First Nation matters. Some of these disputes can be brought in either the federal court or the provincial courts, while some must be brought only in one or the other. Canadian lawyers have little trouble figuring out which court to file their cases in, and lawyers spend little time trying to navigate in which court to file their cases.

On the other hand, the United States court system is a bit more complex. Each state has its own state judicial system that has the standard range of courts from trial to intermediate appeal courts to a state supreme court. These courts are considered courts of general jurisdiction and can, in theory, hear almost every type of case regardless of whether the law being adjudicated is state or federal. Then there is a federal court system. These courts include federal trial courts, known as federal district courts, and appellate courts known as the federal circuit courts. The United States Supreme Court is the highest court in the federal system, but it is also the court from which appeals from the state system may be brought if the question being adjudicated is federal in nature.

Where things get interesting is the following interplay between state and federal courts. Federal courts can hear two types of civil cases.[6] The first are cases involving federal law, known as the federal question jurisdiction. A case that is based on a federal law, say the antitrust *Sherman Act* or the 1964 *Civil Rights Act*, is typically filed by the plaintiff in a federal court. Another type of cases that can be heard in a federal court are those known as diversity cases. These are cases based on state law, but where the plaintiff and defendant are from two different states. For example, if the plaintiff is a pedestrian from New York and the defendant is a driver from Illinois who was driving in New York City and had an accident with the plaintiff. The plaintiff's lawsuit, although grounded in New York tort law, could be brought in a federal district court in the state of New York. The idea behind the first type of cases is that federal courts have expertise in federal law, and the idea behind the second type of cases is that an out-of-state defendant might expect unfair treatment in the state court of the local plaintiff (or vice versa). As such, having the case heard in the federal court may provide a more neutral forum for adjudicating the case.

The more interesting question, however, is what happens when a plaintiff files a federal question case or a case where the defendant is from another state in the plaintiff's state court instead of the federal court? The answer is that the defendant has the option to remove the case from the state court and take it to the appropriate federal district court, provided certain conditions are met. These conditions are laid out in legislation found in Chapter 28 of the United States Code, section 1446 titled *Procedure for removal of civil actions*.[7] Section 1446(b)(1) makes it clear that the "notice of removal of a civil action or proceeding shall be filed within 30 days after the receipt by the defendant…of a copy of the initial pleading setting…"[8]

The question in the *Enbridge* case was if the defendant missed the 30 day deadline, could the district court nonetheless hear the case

[6] See Federal Jurisdiction, "Civics Education Project: Courts of the Fifth Circuit", online (pdf): <www.lb5.uscourts.gov/CivicsEducation/FederalJudiciary/Federal%20Judiciary_Maps%20of%20Federal%20Circuits%20and%20District%20Courts.pdf>; See also Federal Judicial Center, "Jurisdiction of Federal Courts", online (pdf): <www.fjc.gov/history/work-courts/jurisdiction-federal-courts>.

[7] 28 USC § 1446.

[8] *Ibid*.

using what is known as equitable tolling, or the ability of a court to exercise its equitable discretion to suspend the time limit for reasons of fairness and equity.[9] How exactly this question ended up being the heart of the dispute between Enbridge and the State of Michigan is explained in the next section.

III. THE ENBRIDGE-MICHIGAN DISPUTE

As mentioned above, two key lawsuits were filed against Enbridge, one by the Governor of Michigan and another one by the State's Attorney General. In June 2019, Michigan's Attorney General sued Enbridge in a Michigan state court to shut down Line 5, claiming the easement was void and operations violated state law. Enbridge litigated in state court for over a year without removing the case to federal court, missing the 30-day removal deadline under §1446(b). Then in November 2020, Michigan's Governor Whitmer separately revoked the easement and filed her own similar lawsuit in a Michigan state court. At this stage, Enbridge and the Attorney General agreed to hold the state case in abeyance pending the outcome of the Governor's lawsuit.

Unlike the Attorney General's case, this time Enbridge removed the Governor's suit to a United States federal district court, arguing that there was federal-question jurisdiction, because the Governor's claims implicated a 1977 U.S.-Canada treaty and the foreign relations of the United States. The Governor opposed the removal of the case to federal court and sought a remand of the case back to state court. The district court denied the remand agreeing that there was a federal question that should be addressed in the federal court. So, the Governor voluntarily dismissed her suit. It was at this point that Enbridge decided to remove the Attorney General's case against it to federal court, and unsurprisingly the Attorney General opposed this move on the grounds that more than 30 days (887 days) had lapsed since the lawsuit was filed. The district court was not bothered by this lapse of time holding that principles of equitable tolling allowed it to assume jurisdiction over the case. The Attorney General sought an interlocutory appeal to the United States Court of Appeals for the Sixth Circuit, which held that the district court could not exercise equitable tolling for the 30 day deadline since the 30 day deadline was mandatory. This decision contrasted with other decisions of some other federal appeal courts. Enbridge sought leave to appeal this decision to the United States Supreme Court, which granted the leave to appeal.

In a short but technical decision the Supreme Court agreed with the Sixth Circuit. In other words, the district court could not have granted Enbridge's attempt to remove the case from state court after the 30 day deadline. As such, the Attorney General's case against Enbridge now returns to a Michigan state court, almost six years after it was first filed.

IV. SO NOW WHAT?

While the reasoning of the Supreme Court may be of interest to those interested in United States federal rules of civil procedure, for most Canadian lawyers, the reasoning is not as important as the result itself. Canadian companies finding themselves embroiled with States or with American companies as litigants should pay careful attention to the necessary deadline for removal, among other deadlines. Enbridge will now have to face the case in a state court. As an aside, there is at least one other case against Enbridge pending at the Michigan Supreme Court as well as other cases pending against it at various court levels.[10]

The question that a Canadian lawyer or company may ask is does it really matter whether the case is in state or federal court? There is a perception that federal courts are more neutral and more fair to defendants who are not from the state in which the plaintiff is located.[11] As such, out-of-state defendants, generally, prefer to have their case heard in

[9] This is a simplified explanation. More technical definitions can be found in Black's Law Dictionary (11th ed, Cengage 2019).

[10] University of Michigan School of Engineering, "Supreme Court's Michigan pipeline case is about Native rights and fossil fuels, not just technical legal procedure" online: <seas.umich.edu/news/supreme-courts-michigan-pipeline-case-about-native-rights-and-fossil-fuels-not-just-technical>.

[11] Orie L. Phillips & A. Sherman Christenson, "The Historical and Legal Background of the Diversity Jurisdiction", 46 A.B.A. J. 959 (1960).

a federal court instead of the corresponding state court. Whether this perception is real or not is a matter of debate,[12] but this issue was danced around during the oral arguments of the *Enbridge* case.[13] Canadian companies have sometimes not fared well in past episodes in American state courts,[14] and the venue for litigation is something that Canadian companies need to pay more attention to in the future. As such, deadlines such as the 30 days for removal from state courts to federal courts are important for Canadian companies to keep in mind, especially when being or potentially being on the receiving end of a lawsuit in the United States. ■

[12] Kevin M. Clermont & Theodore Eisenberg, "Xenophilia in American Courts" 109 Harv L Rev 1120 (1996).

[13] Oral Arguments, *Enbridge Energy, LP v Nessel*, No. 24-783, online: Oyez <oyez.org/cases/2025/24-783>.

[14] See *e.g.* Tomris Laffly, "The Rousing True Story Behind The Burial", *Time* (6 October 2023), online: <time.com/6321067/the-burial-true-story>.

DEMOCRACY WATCH: A POST-MORTEM AND THE NEXT FRONTIER

*Mark P. Mancini**

It is not often that a case offers an opportunity to clarify the constitutional foundations of the law of judicial review, the ever-present architecture governing review of energy-related decisions. The Supreme Court's decision in *Democracy Watch* provided that opportunity. A unanimous Court (per Wagner CJC) held that legislatures cannot oust judicial review on questions of fact or law.[1] This conclusion is significant not only for the energy sector, but for the very substance of the law of judicial review.

I first review the facts, and then address three issues: (1) the Court's holding in the case that issues of fact must always be left open for curial review; (2) its conclusion that the reasonableness standard is not constitutionalized; and (3) implications for the energy sector.

Facts

Democracy Watch involves sensational facts. The appellant, Democracy Watch, is a non-profit advocacy organization. It applied to the Federal Court of Appeal for judicial review of a report prepared by the Conflict of Interest and Ethics Commissioner. The report concluded that the then-Prime Minister, Justin Trudeau, had not contravened the *Conflict of Interest Act*, when he participated in two Cabinet decisions involving WE Charity.[2] Democracy Watch alleged that, in reaching this conclusion, the Commissioner had committed two errors of law and one error of fact.

The respondent, the Attorney General of Canada, moved to strike the application. The Attorney General advanced two arguments: first, that Democracy Watch lacked standing to bring the application; and second, that the application was barred by s. 66 of the Act. Section 66 provides that the Commissioner's decisions may be reviewed only on grounds limited to jurisdiction, procedural fairness, or acting or failing to act "by reason of fraud or perjured evidence," thereby precluding review on the questions of law and fact that Democracy Watch sought to raise.

Before the Supreme Court of Canada, Democracy Watch contended that, properly interpreted, s. 66 does not preclude judicial review at all; and that if it does, the provision is of no force and effect because it is inconsistent with the *Constitution Act, 1867*, as it would empower the Commissioner to determine the limits of his own jurisdiction and would offend the rule of law.[3]

Underneath Democracy Watch's unique facts is the percolating constitutional question: to what extent can legislatures oust the ability of a party to file an application for judicial review in relation to an administrative decision? The answer to this question was facially answered

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[1] *Democracy Watch v Canada (Attorney General)*, 2026 SCC 28 [*Democracy Watch*].

[2] *Conflict of Interest Act*, SC 2006, c 9, s 2, s 66 [*Conflict of Interest Act*].

[3] *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, ss 96–101, reprinted in RSC 1985, Appendix II, No 5.

by the Supreme Court's decision in Crevier.[4] Crevier held that legislatures must always preserve judicial review over questions of jurisdiction.[5] But the law of judicial review has developed such that the term "jurisdiction" lacks any real meaning.[6] This left the scope of the constitutional guarantee of judicial review unclear.

QUESTIONS OF LAW AND FACT

Democracy Watch holds that all aspects of an administrative decision must be open to review, whether the question is one of law, fact, or fairness. A privative clause barring review on any of these issues will be ineffective.

In reaching this conclusion, Wagner CJC rejects the proposition that I advanced, channeling Near JA in *Canada (Attorney General) v Best Buy Canada Ltd*, that restricting the constitutional guarantee to errors of law meets "any threshold established in *Crevier*."[7] This would include egregious errors of fact that rise to the level of a question of law, like findings based on no evidence, because such errors in the fact-finding process are legal errors.[8] On this much all parties agreed: as Wagner CJC said in *Democracy Watch*, "rationality review has a constitutional aspect."[9] The disagreement lay in which factual errors should be open to correction, with those in the "legislative intentionalist" camp preserving space for legislatures to bar review on many fact issues.[10]

But this is not what the Court accepts. Paragraph 64 of the judgment unlocks the case. Wagner CJC says that, after *CUPE v New Brunswick Liquor Corp*, patently unreasonable findings of fact could not be protected by a privative clause — such a finding would be a jurisdictional error.[11] *Crevier* came next, guaranteeing review for jurisdiction, including such errors.[12] But *Crevier* did not indicate a departure from what Wagner CJC sees as the basis for *CUPE*: the idea that an irrational finding could not be protected by a privative clause. Porting that to the current day, the constitutional guarantee tracks a set of principles requiring review, rather than any particular category of error.[13] An unreasonable error is just as irrational as a patently unreasonable one on this approach. What the Court establishes, then, is that the guarantee tracks a principle rather than a category of this or that error.

Evidence for this comes from Wagner CJC's own analysis. The authorities Wagner CJC relies on speak only to egregious — patently unreasonable — errors, rather than any error of fact, which is where *Democracy Watch* ends up. In *Toronto (City) Board of Education v OSSTF, District 15*, the issue was whether a finding was based on "no evidence."[14] In *Blanchard v Control Data Canada Ltd*, a centrepiece of Wagner CJC's reasons, Lamer J spoke of "unreasonable findings", but did so in applying the patently unreasonable standard.[15]

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[4] *Crevier v AG (Quebec) et al,* [1981] 2 SCR 220 [*Crevier*].

[5] *Ibid* at 236.

[6] See e.g. Mark Mancini, "Foxes, Henhouses, and the Constitutional Guarantee of Judicial Review: Re-Evaluating *Crevier*" (2024) 102:2 Can Bar Rev 315.

[7] *Canada (Attorney General) v Best Buy Canada Ltd*, 2021 FCA 161 at para 60 [*Best Buy 2021*], citing *Crevier*, *supra* note 4; *Democracy Watch*, *supra* note 1 at para 71.

[8] See *Best Buy Canada Ltd v Canada (Border Services Agency)*, 2025 FCA 45 at para 11; *Schuldt v The Queen*, [1985] 2 SCR 592.

[9] *Democracy Watch*, *supra* note 1 at para 69.

[10] See e.g. Paul Daly, "2023 Developments in Administrative Law Relevant to Energy Law and Regulation" (2024) 12:1 Energy Regulation Q, online: <energyregulationquarterly.ca/regular-features/2023-developments-in-administrative-law-relevant-to-energy-law-and-regulation>.

[11] *CUPE v New Brunswick Liquor Corp*, [1979] 2 SCR 227 [*CUPE*]; *Democracy Watch*, *supra* note 1 at para 64.

[12] *Crevier*, *supra* note 4.

[13] Paul Daly, "The Supreme Court of Canada's Decision in the *Democracy Watch* Case: *Democracy Watch v Canada (Attorney General)*, 2026 SCC 28" (30 July 2026), online: *Administrative Law Matters* <administrativelawmatters.com/blog/2026/07/30/the-supreme-court-of-canadas-decision-in-the-democracy-watch-case-democracy-watch-v-canada-attorney-general-2026-scc-28>.

[14] *Toronto (City) Board of Education v OSSTF, District 15*, [1997] 1 SCR 487.

[15] *Blanchard v Control Data Canada Ltd*, [1984] 2 SCR 476 at 499–500.

The distance between these formulations and *Democracy Watch* is by design. It doesn't matter so much that only patently unreasonable errors were reviewable. What matters is that a principle of rationality was guaranteed. That principle of rationality now promises review on all facts.

But this headline won't mean much in day-to-day practice. Courts will continue to review decisions as they have. While some decisions involving facts will now be reviewable, I expect courts to fasten onto a key part of *Vavilov*: "[t]he reasonableness of a decision may be jeopardized where the decision maker has fundamentally misapprehended or failed to account for the evidence before it."[16] In the end, it won't be easier to make out factual errors once in court.

CONSTITUTIONALIZING REASONABLENESS?

The statute in *Democracy Watch* is squarely about availability of review, not intensity. Indeed, the Court said that legislative limits on review are *ultra vires* "not because reasonableness review, per se, is constitutionally entrenched, but because the Constitution guarantees the courts' role in ensuring that all exercises of public power…are sourced in law."[17] However, the issue was not directly in front of the Court.

But Wagner CJC leaves the door open a crack, and the evolution at the heart of *Democracy Watch* will undoubtedly force debate on the scope of the decision. When the time comes, there is good reason to fully decline the invitation to recognize reasonableness review as a constitutional floor. This was raised in *CNR v Alberta Pacific Forest Industries*, where the appellant argued in the alternative — before *Democracy Watch* — that reasonableness review is constitutionalized.[18]

The starting point is that the guarantee is about availability. Intensity should be a constitutional question at one point only: where a legislated standard is so deferential that it is tantamount to no review at all. In principle, I agree with Khullar CJA, dissenting, in *Northback Holdings*: the constitutional guarantee and a particular standard of review, such as reasonableness, "are not a package deal logically speaking."[19] *Vavilov* and *Democracy Watch* both permit legislated standards of review that are consistent with the rule of law—British Columbia has long included, and not changed, the standard of patent unreasonableness in the *Administrative Tribunals Act*.[20]

It would be a remarkable assertion of power under ss.96–101 to hold these legislative efforts to prescribe standards unconstitutional because of a constitutionalized reasonableness standard. Three reasons come to mind.

First, *Democracy Watch* itself counts against a constitutionalized reasonableness standard. Since the constitutional guarantee is about availability, it is not prescriptively tied to reasonableness specifically. Notably, Wagner CJC's statement of the courts' role (to ensure administrative action is sourced in law) and his disclaimer about reasonableness are not merely adjacent, but are side-by-side in the same paragraph.

Second, and as a result, for any argument on intensity to be cognizable, it must present the same problem that *Democracy Watch* deals with — something tantamount to an ouster of review. In other words, legislatures should not be able to do indirectly, via the standard of review, what they cannot do directly by barring review. This principle has considerable vintage as a basic tenet of constitutional law.[21] We can imagine situations where this might be the case — if review is limited only to bad faith, or some other standard but the test should be deliberately strict to match the

[16] *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65 at para 126 [*Vavilov*].

[17] *Democracy Watch*, *supra* note 1 at para 71.

[18] *Canadian National Railway Co v Alberta Pacific Forest Industries Inc*, SCC Docket No 42092 (leave to appeal granted), online: Supreme Court of Canada <scc-csc.ca/cases-dossiers/search-recherche/42092> [*CNR*].

[19] *Northback Holdings Corporation v Alberta Energy Regulator*, 2025 ABCA 186 at para 228, Khullar CJA, dissenting [*Northback Holdings*].

[20] *Administrative Tribunals Act*, SBC 2004, c 45, s 58.

[21] See e.g. *Amax Potash Ltd v The Government of Saskatchewan*, [1977] 2 SCR 576 at 591; *Dominion Stores Ltd v R*, [1980] 1 SCR 844 at 858.

concern in *Democracy Watch*, which was a statute that made review totally unavailable on certain grounds. Something like patent unreasonableness, for example, would pass the test. Though patent unreasonableness is no longer a recognized common law standard of review, it does permit review for legality because it allows for review on all legal issues.

Finally, this strict test is consistent with principles internal to the law of judicial review, and the constitutionalization of reasonableness would run roughshod over them. The power of legislatures to calibrate the relationship between administrative actors and courts — outside of constitutional concerns — is unquestioned. *Vavilov* endorses it in its articulation of the importance of institutional design choices. That principle is embedded in our law of judicial review. It holds a place in the Court's holding on rights of appeal, where a highly deferential standard — palpable and overriding error — can be prescribed by the legislature. It generally permits legislatures, as BC has, to prescribe a standard explicitly. To hold such efforts unconstitutional because of a specific common law standard we happen to adopt in 2026 would be an odd retrofit — and it would be inconsistent with *Democracy Watch's* principle-based approach. Section 96 has a "judicially nourished luxuriance", as Laskin once said, but this would be a new level.[22]

IMPLICATIONS

What are the implications of this decision for the energy sector?

First, the decision clarifies the limits of Parliament's ability to bar review of decisions that might impact the energy sector going forward. In the interests of speed and efficiency, Parliament might have been tempted to limit review of project approvals or technical assessments, especially on issues of fact and evidence. *Democracy Watch* will now prevent this. It does so on the theory that "rationality review has a constitutional aspect."[23] In other words, it is impossible for Parliament to expressly bar judicial examination of the factual and evidentiary basis for administrative decisions.

Another implication pertains to the existing statute book. Several existing statutes limit or tailor judicial remedies for energy-related decisions. Each of these arrangements will have to be carefully reviewed to determine compliance with *Democracy Watch*. Consider several arrangements. In Alberta, s.45(1) of the *Responsible Energy Development Act* provides a right of appeal on questions of jurisdiction or on questions of law, and s.56 of that statute bars all review otherwise.[24] This arrangement will straightforwardly violate Democracy Watch because it expressly bars factual review. The likely fate of *REDA* will be a striking down of the ouster to the extent it bars factual review under the right of appeal.

For its part, the *Canadian Energy Regulator Act*[25] presents a different, more ambiguous situation. Section 72(1) of that statute permits an appeal from a Commission decision to the Federal Court of Appeal on questions of law and jurisdiction, and s.70 otherwise says that all decisions under the statute are final. The clause at issue in the *Canadian Energy Regulator Act* is better understood as a "finality" clause rather than an ouster clause. Since judicial review theoretically remains available, this architecture in the *Canadian Energy Regulator Act* is likely *Democracy Watch* compliant. However, another part of the statute may be constitutionally suspect: s. 170 of the Act, dealing with decisions of the Pipeline Claims Tribunal, forbids judicial review on issues of fact and law.

Additionally, the Supreme Court's upcoming appeal in *CNR v Alberta Pacific Forest Industries* will tell us much about the scope of *Democracy Watch*.[26] One issue there is whether a limited right of appeal can effectively oust judicial review under s.18.5 of the *Federal Courts Act*, which bars judicial review on issues "to the

[22] Bora Laskin, "Municipal Tax Assessment and Section 96 of the British North America Act: The Olympia Bowling Alleys Case" (1955) 33:9 Can Bar Rev 993.

[23] *Democracy Watch*, *supra* note 1 at para 69.

[24] *Responsible Energy Development Act*, SA 2012, c R-17.3, ss 45(1), 56 [*REDA*]; *Northback Holdings*, *supra* note 19.

[25] *Canadian Energy Regulator Act*, SC 2019, c 28, s 10 [*CERA*].

[26] *CNR*, *supra* note 18.

extent that" those issues are "appealable" under a right of appeal.[27] The Federal Court of Appeal has long said that any appeal — whether to a court or to Cabinet — can effectively bar review on issues not covered by the right of appeal.[28] *Democracy Watch* certainly throws doubt on s.18.5: para 73 says that Parliament cannot combine an allocation of jurisdiction to the Federal Courts with a limit on review that would "circumvent the constitutional guarantee of legality."[29]

I think the arrangement in *CNR* channels, rather than directly bars, curial review, leaving it open on issues of fact and law. It permits review on questions of law to the Federal Court of Appeal, while permitting a Cabinet appeal on other issues, including fact and policy, subject to ultimate review in the Federal Courts.[30] As a matter of statutory interpretation, we cannot look at the Cabinet appeal in isolation, but must look at the entire structural arrangement Parliament put together to channel review: this is the principle of institutional design in practice, one on which *Vavilov* hung its hat.[31]

Taking this global look, the arrangement in *CNR* is constitutionally adequate, unlike the arrangement in *Democracy Watch*. What disqualified parliamentary oversight there was not that it was weak, but that it was not a court. The Cabinet appeal in *CNR* ends in curial review. And this read of things falls squarely within language in *Democracy Watch*: "[p]rovided that courts can exercise their supervisory jurisdiction over the legality of all exercises of public power, the rule of law does not preclude meaningful decision-making by other state actors."[32] Because it is constitutionally adequate, the Cabinet appeal becomes one of the remedies a party must exhaust before seeking review. Gleason JA is onto something in saying that s.18.5 merely codifies the idea that parties must exhaust all available remedies.[33]

CONCLUSION

Democracy Watch will not change, in the short term, how judicial review is conducted. However, it does have implications for legislative power in Canada, and the tools that legislators and regulators can use to streamline or make more efficient regulatory processes. In that sense, the story is not yet over — but *Democracy Watch* has set the terms of a new debate. ■

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[27] *Federal Courts Act*, RSC 1985, c F-7, s 18.5.

[28] *Canadian National Railway Company v Scott*, 2018 FCA 148.

[29] *Democracy Watch*, *supra* note 1 at para 73.

[30] See *Canadian National Railway Company v Emerson Milling Inc*, 2017 FCA 79, Stratas JA.

[31] *Vavilov*, *supra* note 16.

[32] *Democracy Watch*, *supra* note 1 at para 69.

[33] See *CNR v Alberta Pacific Forest Industries*, 2025 FCA 160 at para 26.

HOW THE FEDERAL-ALBERTA GRAND BARGAIN CAN INCREASE OIL SANDS PROFITABILITY

Oil sands facility-level operational finance modelling by

Rory Johnston, Commodity Context

*Benjamin Dachis and Chloe McElhone**

INTRODUCTION AND KEY FINDINGS

The May 2026 federal-Alberta implementation agreement commits to industrial decarbonization while boosting Western Canadian energy exports.

This paper examines the impact of two critical provisions in the agreement on Alberta's oil sands industry: raising the minimum effective carbon credit price to C$130 per tonne and adding new bitumen pipeline capacity. We assess the net profitability effect of these increased carbon costs and the future value of increased export capacity for four representative oil sands projects.

Public revenues from the oil sands depend on the price of the Western Canadian Select (WCS) crude blend. Public revenues increase with producer profitability, because mature oil sands facilities pay royalties based on their net profits.

WCS crude trades at a discount to the benchmark West Texas Intermediate (WTI) blend due to its inferior quality and the cost of transporting it to market. Egress capacity from the landlocked Western Canadian Sedimentary Basin is historically the largest and most volatile driver of the WCS-WTI price differential. New pipeline capacity that avoids the need to ship oil sands crude via more expensive rail could reduce the price differential by US$5 per barrel over the long term. This would increase revenues and profitability for oil sands facilities.

The oil sands sector accounts for about a third of Alberta's total greenhouse gas emissions, making it the highest-emitting sector in the province. Like other large emitters, oil sands facilities are regulated under the province's carbon pricing system, the Technology Innovation and Emissions Reduction (TIER) regulation.

This paper looks at the impact of federal-Alberta memorandum of understanding (MOU) implementation agreement on the profitability of four facilities that together account for one-quarter of total oil sands bitumen output. The facilities have a range of emissions

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intensities. Cenovus Energy's Christina Lake facility and Imperial Oil's Kearl mine are best in class, Suncor Energy's Firebag facility has a mid-range emissions intensity, and Imperial's Cold Lake is one of the most emissions-intensive facilities in the province.

This paper, originally published in March 2026, found that **the benefits of increased pipeline capacity outweigh the increase in carbon costs agreed in the MOU**. The modelling done then assumed a carbon credit price of C$130 per tonne by 2035.

Since then, the Government of Canada and Government of Alberta signed their implementation agreement, which aims to meet a credit price of C$130 per tonne by 2040. The resulting costs to these oil sands facilities will therefore actually be lower than we assumed in our models, and their profitability, when additional pipeline capacity comes online, will be even more substantial than is reported here.

Key findings

1. The benefits of increased pipeline capacity outweigh the increase in carbon costs agreed in the MOU. When new pipeline capacity comes online, the resulting sustained reduction in the WCS-WTI differential increases per-barrel profitability for the facilities we analyzed by 30 per cent to 91 per cent, net of carbon costs.

Carbon costs at these facilities would increase from between C$0.53 and C$2.46 per barrel to between C$0.81 and C$3.75 per barrel at the time that new pipeline capacity is likely to come online, relative to a scenario where Alberta kept its industrial carbon price frozen at C$95 per tonne. But these cost increases are far outweighed by an increase in profitability of more than C$10 per barrel at all the facilities we analyzed, resulting from the reduction in the WCS-WTI differential.

2. The increase in profitability from new pipeline capacity will allow most oil sands facilities to quickly recoup all their additional carbon costs. The increase in profitability from a new pipeline is significant: three of the four facilities analyzed recoup all their additional interim TIER costs (between now and the opening of the pipeline) within one year of the pipeline beginning operations. This is driven primarily by the resulting reduction in the WCS-WTI differential.

3. New pipeline capacity significantly increases both net profits for oil sands facilities and provincial royalty revenue. For the four facilities we analyzed, new pipeline capacity increases per-barrel profitability and allows facilities to increase production. **This results in a C$3.16 billion nominal increase in annual profits in the 15 years following the opening of new pipeline capacity that reduces the WCS-WTI differential, and a C$957 million annual increase in provincial royalties.**

SUMMARY OF RESULTS

This analysis asks whether the costs of increased carbon credit prices for oil sands producers in Alberta's carbon market outweigh the benefits of increased pipeline capacity, specifically the avoidance of structurally wider WCS-WTI price differentials. A new pipeline that can transport an additional one million barrels per day will allow Canadian producers to avoid shipping bitumen by more expensive rail transportation. Shipping oil by rail has historically cost US$5 more per barrel than pipeline transport. New pipeline capacity that prevents additional use of rail should result in higher profitability for companies.

We look at four major oil sands projects at different points on the spectrum of emissions costs to evaluate the potential impact of increased credit prices under Alberta's Technology, Innovation and Emissions Reduction (TIER) system on profitability. **We find that for low-emissions facilities, the increase in profit from a lower WCS-WTI differential vastly outweighs the costs from TIER credits increasing to C$130 per tonne.**

New pipeline capacity will likely take another six to 10 years to build, given construction timelines. Nevertheless, we find that once this new capacity comes online it will boost profitability enough to enable low-emitting oil sands facilities to quickly recoup all the additional carbon costs they incur between now and pipeline commissioning.

Even for the oil sands facilities that face the highest costs under TIER — those that are both high-emitting and have seen their emissions increase in recent years — the increase in profitability from a new pipeline still outweighs likely 2035 carbon costs. However, facilities with higher emissions intensities than in the past, or with emissions intensities considerably above best-in-class facilities, face a significantly longer payback period.

Improved facility-level profitability will drive a considerable increase in the royalties collected by Alberta and corporate income taxes paid to the Alberta and federal governments.

We analyze four large oil sands facilities: Cenovus Energy's Christina Lake facility, Imperial Oil's Kearl mine, Imperial's Cold Lake facility, and Suncor Energy's Firebag facility. Together, these facilities account for roughly one-quarter of total oil sands bitumen output. These four projects span a range of emissions intensities, from best-in-class at Christina Lake and Kearl, to mid-range performance at Firebag, to one of the most emissions-intensive facilities in the province at Cold Lake.

None of these projects are forecasted to generate carbon credits in 2035. Our analysis seeks to show the profitability impact of new pipeline capacity and increased TIER carbon costs for facilities that are most likely to bear compliance or decarbonization costs. Many oil sands facilities[1] are credit generators and may remain so over the next decade.[2]

Figure 1 (below) shows the net change in per-barrel profits at each facility in 2035 as a result of realizing the MOU's commitments to build significant new pipeline capacity and achieve a minimum effective TIER credit price of C$130 per tonne. These findings assume that TIER credit prices increase at a rate of C$5 per year beginning in 2026. The findings also assume a WTI price of US$65 per barrel and a reduction in the WCS-WTI differential from US$18 to US$13 per barrel. The findings are discussed in greater detail below.

Figure 1: Profitability growth across four representative oil sands projects

[1] Ross Linden-Fraser & Dale Beugin, "Why Industrial Carbon Pricing Costs the Oil Sands Less Than a Timbit per Barrel" (11 March 2026), online (blog): <440megatonnes.ca/insight/why-industrial-carbon-pricing-costs-oil-sands-less-than-a-timbit-per-barrel>.

[2] Carbon cost estimates are dependent on the future design of the TIER system, including benchmark tightening and carbon price trajectories beyond 2026. Our facility-specific, 2035-horizon findings are consistent with estimates from other organizations (*ibid*), which assume the current federal headline price trajectory and a 2030 timeframe. These carbon cost estimates were modelled prior to the release of the May 2026 Implementation Agreement for the Canada-Alberta Memorandum of Understanding.

KEY CONSIDERATIONS IN OIL INDUSTRY ECONOMICS AND EMISSIONS POLICY

If the Western Canadian oil industry gains access to greater egress capacity, this can help minimize the WCS-WTI price differential. The WCS differential is set by the marginal barrel, meaning the final barrel to clear the market. The price of the marginal barrel sets the price for all barrels produced in the Western Canada Sedimentary Basin (WCSB). Even modest shortfalls of egress capacity can spiral into acute crises in upstream pricing.

At the same time, future pipeline projects — including new pipelines and pipeline expansions — should be carefully structured to ensure that they contribute to reducing the WCS-WTI differential. The Trans Mountain Expansion Project highlighted the risk that runaway pipeline construction costs can lead to high tolls that increase marginal barrel prices.

There are considerations involved in pipeline and upstream capacity expansion that go beyond what we consider here. For example, increased production to fill expanded pipeline capacity may require developing lower-margin projects. A lower WCS-WTI differential affects project economics differently than company-wide profitability; some companies will have hedging or refining strategies that mitigate these concerns. Increased pipeline capacity to the U.S. may reduce the need for additional West Coast egress. Our analysis considers the potential value of a new pipeline that shrinks potential future WCS-WTI price differentials.

There are also global trends that will determine the general appetite for investment in Canada, and our analysis is neutral on the overall competitiveness of Canada's investability relative to competitors. For example, overall cost competitiveness, permitting approval speeds, regulatory costs, additional government policies, and the risk profile of Canada's oil reserves will influence the interest of global capital in Canadian investment. Global oil prices will also influence investment decisions. Our analysis asks how the implementation of the federal-Alberta MOU could impact oil sands profitability.

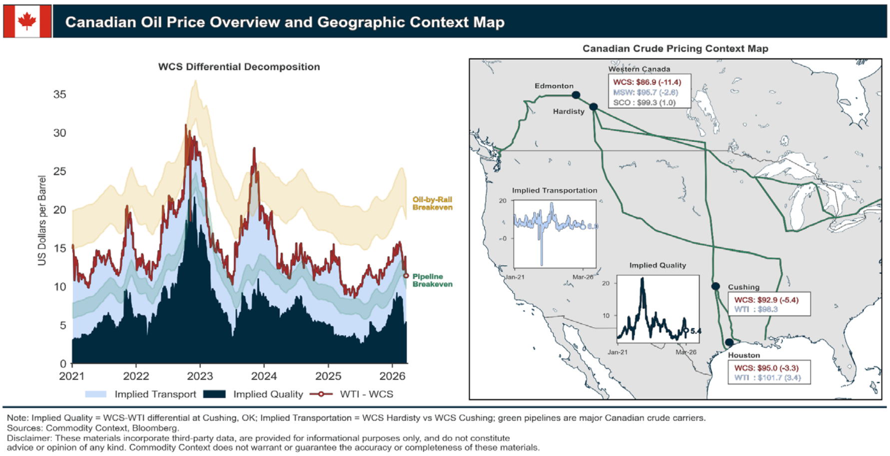
Transportation differentials

If insufficient pipeline capacity shifts the marginal transportation of WCS crude to more expensive rail, the total WCS-WTI price differential in Hardisty, Alberta, can increase to US$18 per barrel.

In cases of extreme oversupply, transport costs can push the differential past US$18 per barrel, until producers are forced to shut in production or the provincial government imposes curtailment. Under current conditions our analysis assumes a stable, if economically sub-optimal, WCS-WTI differential of US$18 per barrel. We project that a new million-barrel-per-day pipeline would allow for expansion of oil sands production without extensive crude-by-rail shipments, thereby reducing the price differential. An analysis[3] of the Trans Mountain Pipeline Expansion found that it reduced the WCS-WTI differential by about US$8/barrel. Although that analysis argues that a new pipeline would not reduce differentials further, additional expansion of oil sands production would likely put renewed pressure on differentials that only new pipeline access would alleviate.

[3] Alberta Central, "Year One of TMX: Increased Export Diversification, Disappearing Oil Discount, and C$13bn in Extra Revenues" (6 August 2025), online: <albertacentral.com/intelligence-centre/economic-news/year-one-of-tmx-increased-export-diversification-disappearing-oil-discount-and-c13bn-in-extra-revenues>.

Figure 2: WCS-WTI differentials and transport break-even points



Tolls

Marginal pipeline tolls are the primary driver of the geographic price differential for WCS and bitumen. Tolls are critical not just for the project economics of a pipeline but for the economics of the entire WCSB upstream oil industry. The Canada Energy Regulator sets tolls on interprovincial pipelines based, typically, on both the cost of construction and operation and as some regulated rate of return. Toll rates have been impacted by the ballooning costs of pipeline construction. Most recently the 590,000 barrel Trans Mountain Expansion Project saw its price tag spiral from an initial cost of C$5.4 billion to approximately C$35 billion by the time it entered service.

The current uncommitted toll to ship a barrel of heavy crude from Edmonton to the Westridge Terminal at the Port of Vancouver via the Trans Mountain pipeline is C$14.40 per barrel, which is more than twice the C$6.60 per barrel cost to ship from Edmonton to Flanagan, Illinois, on the Enbridge Mainline. Once at the Westridge Terminal, Canadian barrels still need to price in tanker transportation to the end destination; transportation to China is an additional US$3 or more per barrel, for example.

Moreover, 80 per cent of the current Trans Mountain system's flow is committed barrels on take-or-pay contracts, which has initially shielded basin-wide pressure on marginal prices. Take-or-pay capacity will be used first, meaning that these higher tolls don't weigh on marginal pricing. However, the economics of shipping on the expanded Trans Mountain system will, undoubtedly, start to put additional widening pressure on the WCS differential once the approximately 180,000-barrel uncommitted portion of the system is required to clear the basin, because it will then be the higher tolls determining marginal egress costs.

The federal-Alberta MOU stipulates that new bitumen pipeline capacity will be privately built and financed. Tolls would need to cover the cost of construction plus a rate of return commensurate with the high risk of pursuing the project, given that similar projects have faced delays, cost overruns, and cancellations. A toll set as high or higher than Trans Mountain's uncommitted rate would likely increase the WCS-WTI differential, thereby devaluing all barrels produced in the basin and eroding the value of incremental takeaway capacity. Our analysis assumes that the tolls charged by a new pipeline would not systematically increase the WCS-WTI differential.

Royalties

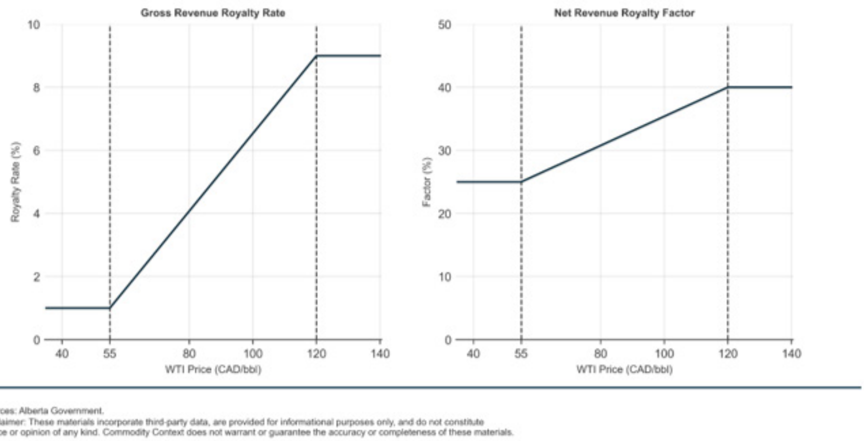
Royalties are the most direct financial stake that Albertans have in the value received for bitumen produced from the oil sands. Over the past half-decade, royalties have ballooned due to a combination of higher oil prices, healthier WCS differentials thanks to increases in pipeline capacity, and projects being required to pay higher royalty rates as they recoup their capital costs. Oil sands royalties have soared to more than C$17 billion in 2025 from C$950 million in 2006.

Oil sands projects that haven't recovered their capital costs are said to be "pre-payout," and pay royalties at a rate of 1per cent of gross revenues at WTI prices up to C$55 per barrel. Their royalties increase to a maximum of 9 per cent of gross revenue as WTI prices rise to C$120 per barrel. A "post-payout" project has recovered its capital costs and pays the greater of either the pre-payout royalty calculation, or between 25 per cent and 40 per cent of net revenues, again increasing as the price of WTI crude increases from C$55 per barrel to C$120 per barrel (see Figure 3).

A long-established and highly profitable facility such as Cenovus Energy's Christina Lake is now in the post-payout royalty period, while the more recent Imperial Oil Kearl oil sands mine, which incurred a very large upfront capital cost, is still recouping its initial investment and is in the pre-payout period.

In recent years many oil sands projects have shifted to post-payout status, driving the Alberta royalty windfall that began in 2022. As a result, Alberta's fiscal sensitivity to changes in crude prices and WCS differentials is much higher today than during the egress crisis of 2018. Albertans benefit relatively more from price increases for post-payout projects and, on the flip side, face larger declines in public revenues as oil prices fall or WCS-WTI differentials widen. The impact of an increase in the WCS-WTI differential on the royalties paid by a profitable post-payout project is much larger in absolute terms than the impact would have been on the same project during its pre-payout period, when it paid a much lower royalty rate.[4]

Figure 3: Alberta oil sands royalty rates



[4] Emissions are determined through rearranging the formula specified in the Government of Alberta's oilsands database (*ibid*) of Cogen Adjusted Emissions = Emissions - Cogen Emissions + Cogen Heat x 0.06299 tonnes per GJ heat.

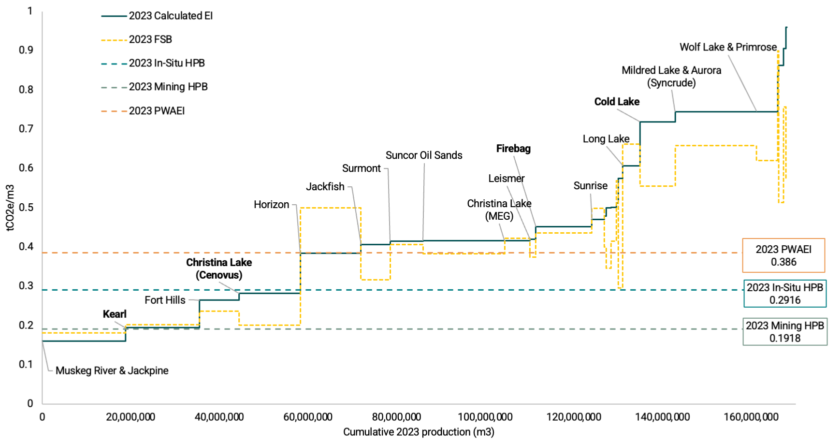
Emissions from Alberta's oil sands

The oil sands sector accounted for just less than 33 per cent of Alberta's total emissions[5] in 2023, making it the highest-emitting sector in the province. In Alberta, emissions from the oil sands and other large industrial sources are regulated through a combination of provincial carbon pricing and emissions-management policies, such as methane regulations. This analysis focuses on the impact of the TIER regulation, which applies to high-emitting facilities. Under TIER, regulated companies must meet emissions benchmarks. They can reduce emissions directly, use approved credits for reductions, or pay into a provincial fund if they exceed their targets.

Under TIER, large industrial facilities — including many in the oil sands — are given an annual emissions target based on a benchmark. The benchmark defines how much a facility is allowed to emit per unit of production. Oil sands producers can choose between two benchmarks. The first option is a facility-specific benchmark (FSB), based on that facility's own historical performance. This benchmark requires the facility to emit less per unit of production compared with its own past performance. The second option is the high-performance benchmark (HPB), based on the average emissions intensity of the top-performing 10 per cent of facilities in a given sector for a particular product. This flexibility prevents facilities with low emissions intensity from being penalized by TIER's standard facility-specific benchmarking method.

Figure 4 (below) compares the estimated facility-specific benchmarks and 2023 emissions intensities across oil sands facilities using 2023 data, illustrating the impact of this approach and the differences in emissions intensity across projects. Notably, FSBs are substantially higher for facilities with greater emissions intensity.

Figure 4: Estimated 2023 emissions intensity and facility-specific benchmarks for oil sands facilities under TIER[6]



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[5] See Government of Alberta, "Alberta's Greenhouse Gas Emissions Reduction Performance" (9 January 2026), online: <alberta.ca/albertas-greenhouse-gas-emissions-reduction-performance> (33 per cent of Alberta's total emissions).

1. We estimate two additional data points for 2013 to 2015 necessary for development of facility-specific benchmarks. 1) We determine emissions from the heat used in cogeneration through the multiplication of the heat generated by the cogeneration unit in GJ by the heat intensity value of 0.06299 tCO_2e/GJ. Imported and exported heat are additional variables, assumed as zero in the absence of data. The forecast for cogen-adjusted emissions is calculated based on each year's forecasted cogen-adjusted emissions intensity and production, and the forecast for total site emissions is calculated based on each year's forecasted cogen data.
2. We also accommodate emissions from the electricity used through the multiplication of the electricity generated on-site by the electricity high-performance benchmark for the baseline year (0.37 tCO_2e/MWh in 2022 and earlier). Imported and exported electricity are additional variables, assumed as zero in the absence of data.

See section 8.2.4 of the Standard for Developing Benchmarks v2.5 (*ibid*) for more information.

Estimating emissions from oil sands facilities

The four oil sands facilities we analyze represent a range of emissions intensities. Other facilities with similar emissions intensities should see similar impacts on their profitability from the implementation of the MOU. We analyze two projects with relatively low emissions intensities (Christina Lake and Kearl), one with an average emissions intensity (Firebag), and one that is on the higher end (Cold Lake) and faces high compliance costs in relation to its facility-specific benchmark. A metric called production weighted average emissions intensity (PWAEI) in Figure 6 puts the projects' emissions performance in perspective by weighting each facility according to output.

These project-specific emissions intensity differences necessitate project-specific analysis of carbon costs. We sourced historical oil sands data from the Government of Alberta's Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis.[7] The dataset includes the following data for in-situ oil sands and mined oil sands projects from 2011 to 2023: monthly and annual production volumes, emissions, cogeneration emissions, heat and electricity generation (as applicable), cogeneration adjusted emissions, and cogeneration adjusted emissions intensity.

We compiled historical data from 2013 to 2023 for Cenovus Energy's Christina Lake facility, Suncor's Firebag facility, Imperial Oil's Kearl mine, and Imperial's Cold Lake facility.[8] We forecast facility data for the years 2024 to 2035. We assume production increases by 2.7 per cent annually and produce forecasts for cogen adjusted emissions intensity, cogen heat, and cogen electricity.[9] We assume that emissions intensities decline at a conservative rate of 0.5 per cent annually.[10]

To estimate costs under TIER for each project, we compare the costs under an FSB and the HPB.[11]

We chose the lesser of the two costs for each facility. We also assume that companies maximize the credit usage limit at the forecasted credit price. Finally, companies can deduct their TIER costs from post-payout net-revenue royalties. We assume an estimated average post-payout royalty rate of 33 per cent.

These are conservative estimates of carbon costs. Costs could be lower as projects make low-carbon investments over the next decade. We also do not account for credit generation that could result from significant emissions reduction projects in the sector, such as the Oil Sands Alliance's Pathways carbon capture project.

These estimates also do not incorporate the potential impact of the Pathways project on emission reductions. Companies that are not participating in the project would have unchanged costs, continuing to comply with carbon pricing at market credit prices. Participating companies would likely face lower carbon costs, optimizing carbon credit use across their portfolios. See Box 1 below for more details on how the Pathways project could impact the profitability of participating companies.

[7] Alberta, Environment and Protected Areas, "Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis" (last modified 10 January 2024), online: <open.alberta.ca/opendata/alberta-oil-sands-greenhouse-gas-emission-intensity-analysis>.

[8] See the appendix in the original paper for more information on how this assumption affects results: (*ibid*).

[9] We calculate FSBs based on formulas prescribed in the Standard for Developing Benchmarks v2.5 (*supra* note 6) using baseline years 2013 to 2015 (if available) or alternate years to calibrate against reported true-up obligation data for the 2023 compliance period. Actual FSBs may vary based on confidential project-level data or director-authorized departures from standard baseline years.

[10] Find details about the assumptions used in our financial model: Benjamin Dachis & Chloe McElhone, *Net Gains: How the Federal-Alberta Grand Bargain Can Increase Oil Sands Profitability* (Clean Prosperity, March 2026) at 22, online (pdf): <cleanprosperity.ca/wp-content/uploads/2026/03/Net-Gains-March-2026.pdf>.

[11] Totals in this and subsequent figures may not sum due to rounding.

RESULTS: PROFITABILITY GROWTH FROM A PIPELINE OUTWEIGHS CARBON COSTS

Project-specific analysis [12]

Using Commodity Context's financial model of Alberta oil sands operations, which includes facility-level royalty data, we estimate the future gross revenue, production, costs, royalties, and net operating cost of our four oil sands facilities. We assume that each facility sees annual production growth of 2.7 per cent. Such growth is consistent with the MOU's commitment to build additional pipeline capacity of at least one million barrels per day to Canada's West Coast. To ascertain the increase in profitability, we assume that a new pipeline reduces the WCS-WTI differential from US$18 per barrel to US$13 per barrel.

In our figures below, "without-MOU profit" represents profitability in 2035 under a status quo scenario — Alberta carbon pricing still frozen at its current rate of C$95 per tonne, no major new pipeline capacity, and therefore a WCS-WTI differential of US$18 per barrel. In contrast, "with-MOU profit" represents a scenario where implementation of the MOU provisions leads to the construction of new pipeline capacity, and the price of TIER carbon credits rises to C$130 per tonne by 2035.

This paper was originally published in March 2026, before the Government of Canada and Government of Alberta signed the implementation agreement. The agreement signed in May 2026 has TIER carbon credits rising to C$130 by 2040.

The resulting costs to these oil sands facilities will therefore actually be lower than we assumed in our models, and their profitability, when additional pipeline capacity comes online, will be even more substantial than is reported here.

A US$1 per barrel change in the WCS differential has a magnified effect on underlying bitumen values. A barrel of WCS is about two-thirds bitumen and one-third diluent, which oil sands producers must purchase or produce elsewhere. If diluent prices remain constant while WCS prices change, the bitumen component of a WCS barrel must absorb 100 per cent of that price fluctuation. The value of bitumen increases or decreases by about US$1.50 per barrel for every US$1 per barrel change in the WCS-WTI differential.

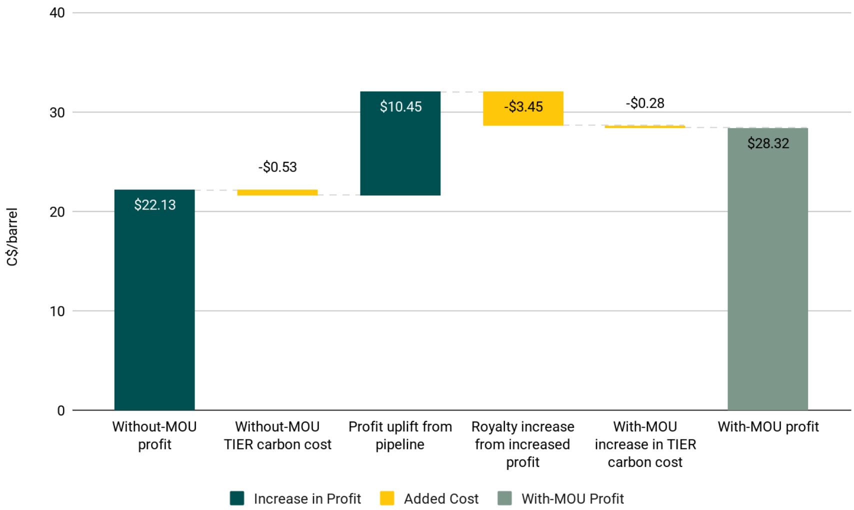
Christina Lake

The addition of new pipeline capacity envisaged in the MOU results in a meaningful improvement in profitability for Christina Lake by 2035, even after accounting for higher royalties and carbon compliance costs. Without the MOU, profit is C$21.60 per barrel, including TIER carbon costs of C$0.53 per barrel. Following implementation of the MOU, improved pipeline access delivers a large impact, increasing profitability by 31 per cent (C$6.72 per barrel) as tighter WCS-WTI price differentials strengthen realized bitumen pricing. This upside is partially offset by a C$3.45 per barrel increase in royalties as higher WCS prices and net revenues increase the project's royalty rate, along with a C$0.28 per barrel increase in TIER carbon costs at a C$130 per tonne carbon credit price. Overall, profit rises to C$28.32 per barrel, demonstrating that improved market access more than compensates for increased carbon costs.

Additional pipeline capacity not only increases per-barrel profits but also increases total profits and royalties. Net profit increases by about C$473 million in 2035 alone, relative to a scenario with no new pipeline capacity.

[12] Unlike the other projects we analyze here that are in the post-payout royalty phase, and can deduct TIER credit costs as an allowable cost, we assume that TIER credit costs are not deductible for Kearl during its pre-payout royalty period.

Figure 5: Increased profitability of Cenovus Energy's Christina Lake facility in 2035 following implementation of federal-Alberta MOU[13]



Kearl

New pipeline capacity that holds the WCS-WTI differential at C$13 per barrel in 2035 also delivers a substantial uplift in profitability for a project like the Kearl mine. Without the MOU, profit is C$10.51 per barrel, including TIER carbon costs of C$0.65 per barrel.[14] Under the MOU, additional pipeline capacity adds a significant C$9.56 per barrel, nearly doubling baseline margins, inclusive of a C$0.55 per barrel increase in royalties and a C$0.34 per barrel increase in TIER carbon costs.

We project that Kearl will still be in its pre-payout period in 2035, meaning that revenue increases will have a more muted effect on the increase in royalties until the project recoups its investment. Additionally, as a mine it has lower operating margins. As a result, any increase in revenue from reductions in WCS-WTI differentials has a disproportionately higher impact on its profit growth, compared to older, post-payout facilities with higher margins. Although outside the scope of this analysis, it's also worth noting that higher profits will accelerate Kearl's transition to a post-payout royalty regime, resulting in higher fiscal returns for the province.

Overall, implementation of the MOU increases profitability to C$20.08 per barrel, roughly a 91 per cent improvement versus the without-MOU scenario of widening WCS-WTI price differentials. This highlights how enhanced market access is particularly transformative for lower-margin projects like Kearl.

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[13] Based on Clean Prosperity modelling (*supra* note 10). Cost estimates are inclusive of the federal carbon capture, utilization, and storage investment tax credit, the Alberta Carbon Capture Incentive Program, and the deduction of TIER costs when calculating post-payout royalties. Costs reflect the low end of the modelled range, on the basis that the project would only participate in Pathways if the per-tonne cost of carbon capture is below the price of carbon credits. Applying the median cost value instead would also yield total profits materially equivalent to those earned without participation in Pathways. We assume that Firebag captures 24 per cent of its annual emissions (equivalent to 1.88 $MtCO_2$ in 2035), based on its emissions-weighted share of total projected Pathways capture volume, and that all carbon credits generated are retired and/or sold in the year they are generated (not banked).

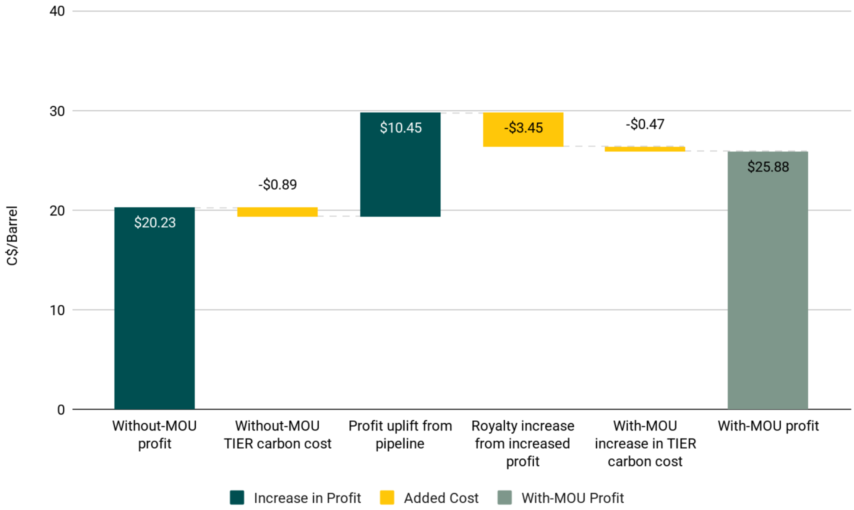
[14] Cold Lake began as a cyclic steam stimulation project that began commercial operations in the 1980s. As reservoirs age, oil-to-steam ratios typically decline, requiring more steam per barrel to maintain production. New developments use SA-SAGD to improve efficiency.

Figure 6: Increased profitability of Imperial Oil's Kearl mine in 2035 following implementation of federal-Alberta MOU

Firebag

For Suncor's Firebag facility in 2035, additional pipeline capacity added under the terms of the MOU produces a solid improvement in profitability, with gains clearly outweighing incremental carbon costs, albeit not as much as for Cenovus' Christina Lake or Imperial's Kearl mine. Without-MOU profit starts at C$19.34 per barrel, partially reduced by C$0.89 per barrel in TIER carbon costs. Improved pipeline access delivers a 34 per cent increase in profitability (C$6.54 per barrel), reflecting stronger revenues from tighter WCS-WTI differentials. This upside is partially offset by a C$3.45 per barrel increase in royalties due to higher WCS prices and higher profits, along with a C$0.47 per barrel increase in TIER carbon costs. Overall, profitability rises to C$25.88 per barrel, demonstrating that for facilities with stable historical emissions intensities that can achieve reductions relative to their facility-specific benchmarks, improved market access remains a meaningful driver of long-term margin expansion, despite rising carbon costs.

Figure 7: Increased profitability of Suncor's Firebag facility in 2035 following implementation of federal-Alberta MOU



Box 1: Impact of the Pathways project on profitability

The Oil Sands Alliance's Pathways project[15] is a large-scale carbon capture, transport, and storage project in Alberta's oil sands. Phase 1 is a C$20-billion system proposed to capture up to 12 $MtCO_2$ per year from oil sands facilities.

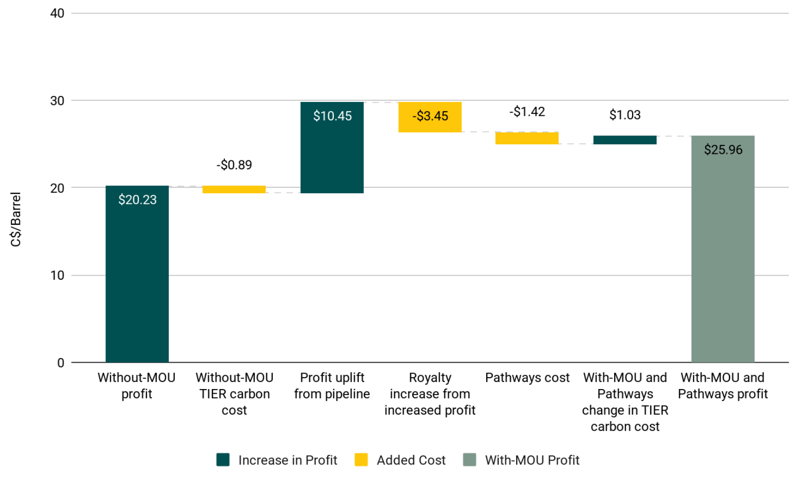
Our analysis elsewhere in the report does not consider the potential impact of participation in the Pathways project on the profitability of our four oil sands facilities, as the exact cost of the project will differ for each facility. All four facilities are planned to participate in Pathways. Construction of the Pathways project is a commitment in the federal-Alberta implementation agreement.

We repeated our analysis of Suncor's Firebag facility, this time incorporating the additional costs and carbon-credit generation that would result from Pathways.[16]

Under an MOU scenario with a minimum effective carbon credit price of C$130 per tonne and additional pipeline capacity, we estimate that also joining the Pathways project would reduce Firebag's TIER carbon costs. Even with the cost of building and operating carbon capture infrastructure, the facility would still be more profitable in 2035, thanks to the implementation of the MOU, than it would be without it.

In our estimates, the Firebag project is also slightly more profitable by taking on the Pathways costs instead of paying the full TIER costs we estimate, but the exact results would be highly dependent on the Pathway project costs. Not all oil sands facilities would be impacted in the same way by participation in Pathways. The impact on a facility's profitability will depend on current and future emissions relative to the facility's benchmark.

Figure: Increased profitability of Suncor's Firebag facility in 2035 following implementation of federal-Alberta MOU and Pathways Phase 1



[15] Oil Sands Alliance, "Pathways Project" (last modified 15 June 2026), online: <oilsandsalliance.ca/pathways-project>

[16] Royalties are calculated net of TIER costs for post-payout projects. We deduct the net present value of foregone royalties between 2027 and 2035, as a result of higher TIER costs under the MOU, in our calculation of the total increase in royalties between 2035 and 2050.

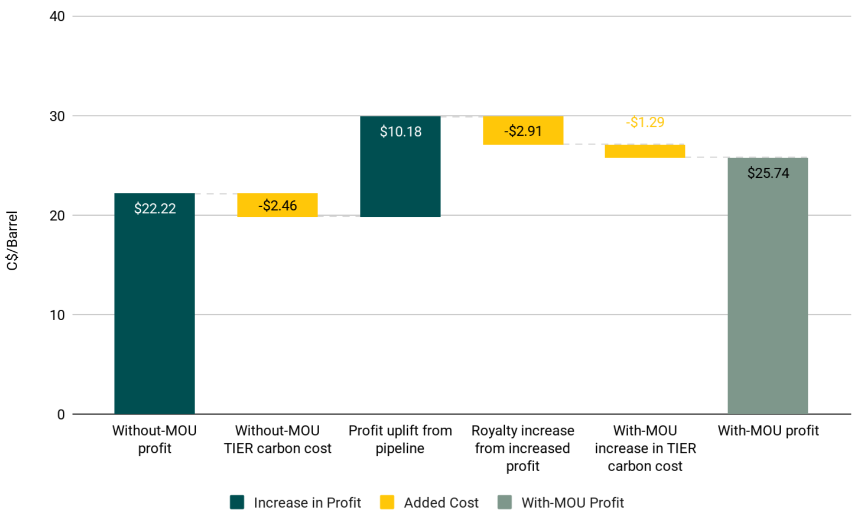
Cold Lake

Imperial's Cold Lake has increased its emissions intensity since its benchmark years.[17] As a result, we project that the facility will incur higher TIER costs in 2035 compared to sites that have decreased their emissions since their facility benchmark was set. This is a typical dynamic under TIER, in which sites compete against their own previous performance.

For Cold Lake in 2035, implementation of the MOU delivers a slightly more modest net improvement in profitability. Without the MOU, profit is C$19.76 per barrel, net of C$2.46 in TIER carbon costs. Tighter WCS-WTI differentials due to increased pipeline access increase profitability by 30 per cent (C$5.98 per barrel). This pricing uplift is partially eroded by a C$2.91 per barrel increase in royalties due to higher profits. Under the MOU, Cold Lake incurs the highest increase in carbon costs in our analysis — C$1.29 per barrel at a C$130 per tonne carbon credit price. This reflects the fact that Cold Lake's emissions intensity increased since its benchmark years.

Overall, Cold Lake's profit rises to C$25.74 per barrel, highlighting how facilities with a history of deteriorating emissions performance are still likely to be financially better off, net of a C$5 reduction in the WCS-WTI differential and higher TIER prices.

Figure 8: Increased profitability of Imperial Oil's Cold Lake facility in 2035 following implementation of federal-Alberta MOU



[17] Kearl is likely to enter its post-payout royalty period in the mid-2030s. This would increase the net present value of the province's 2035-2050 royalties by about C$1.4 billion (and reduce Imperial Oil's profits from the project).

Future value analysis

The above analysis shows that in 2035, the profitability uplift from improved egress more than offsets the higher cost of carbon pricing for four representative oil sands projects with varying emissions intensities and royalty periods.

The profitability benefits of new pipeline capacity are a decade away, but the costs of higher carbon pricing will be borne in the near term. Do those future benefits and present costs present a compelling investment case now?

One way to address this question is to calculate the present value of carbon costs and compare that to the present value of the reduced WCS-WTI price differentials from new pipeline capacity. We determined the total per-barrel cost of the TIER program between 2027 and our assumed 2035 in-service date of a new one-million-barrel-per-day pipeline, discounted to present.

We show two versions of the cost of TIER. The first is the total cost of the full TIER program at the carbon price outlined in the MOU. A second version shows just the incremental cost of increasing carbon prices from the current level of C$95 per tonne. We then divided that cost by the discounted future increases in per-barrel profit once the pipeline is in operation in 2035. That creates a measure of how many years of pipeline operation each project needs to recover the higher TIER costs it incurred before the pipeline entered service. This measure of how many years of higher profits are required from any new pipeline reflects the inherent uncertainty that a new pipeline may not ever result in a lower WCS-WTI differential. If it does, how long it provides that higher return is a measure of its value. The total net profit with the MOU in place (the last column of Table 1) is the net present value of the increased annual profits from 2035 to 2050 if the pipeline provides continuous improvement in pricing over this period, minus the net present value of the incremental TIER costs above C$95 per tonne between 2027 and 2035.

We used the same assumptions about TIER costs as in the analysis above. We also calculated the discounted total net additional profit after 15 years, assuming the WCS-WTI differential remains at US$13 instead of US$18, and that production and prices remain flat between 2035 and 2050. We used a 10 per cent discount rate and the same assumptions about the TIER cost trajectory outlined above through to 2035. We assumed that emissions intensities remained flat after 2035, and that headline TIER prices remained frozen at C$145 after that date. Importantly, for these calculations of the net present value of total profit, we assume no increase in oil prices until a new pipeline becomes operational in 2035.

For projects like Christina Lake, Kearl or Firebag, the increased long-term profitability that results from new pipeline capacity pays off the increased near-term costs of a C$130 per tonne TIER credit price in approximately one year or less, and total TIER costs in one to two years. Each of these projects also sees a significant overall increase in profit assuming that WCS-WTI price differentials remain constrained for 15 years. We also assume that the Kearl facility stays in the pre-payout royalty regime for this analysis. However, it will likely move to a post-payout regime over this period, reducing the project profitability but improving the fiscal returns for Alberta (as we discuss further below).

This one-year payback could materialize in a number of ways. Even if an increase in pipeline capacity to the U.S. lowers transport costs, a new pipeline to the West Coast offers egress diversification that could support producer profits in the event that exports to the U.S. are in any way constrained. The optionality value of a new pipeline to the Pacific Ocean underpins the economic return potential of the MOU framework.

Unlike the other three projects, Imperial's Cold Lake facility faces substantial TIER costs between now and 2035, assuming it only slightly reduces emissions. That project only recovers its total 2027–2035 TIER costs after about eight years of higher profits from a new pipeline, and incremental TIER costs from the MOU in about two years.

Looking at the last column of Table 1, all projects see a substantial increase in net profits from the MOU. The net present value of their increased profits, assuming 15 years of lower WCS-WTI differentials, is substantially larger than the net present value of increased TIER costs under the MOU. The Christina Lake and Firebag projects both see an increase of around C$2.6 billion in the net present value of their profits. Kearl's profits, assuming it stayed under the pre-payout royalty framework, would increase by a net present value of C$4.6 billion. For Cold Lake, the net present value of increased profits is C$1.3 billion.

Table 1: Net present value (NPV) of near-term TIER costs and long-term increased profitability

Project	Total TIER cost, 2027 to 2035, NPV (C$ million)	Total TIER cost in 2035 (C$/barrel)	MOU TIER cost increase, NPV (C$ million)	Post-MOU increased profit per barrel	Annual production in 2035 (million barrels)	Annual profit increase, 2035 through 2050 (C$ million)	Net profit, 2027 to 2050, NPV (C$ million)
Christina Lake	$240	$0.83	$63	$6.72	111	$747	$2,662
Kearl	$349	$1.01	$92	$9.56	133	$1,274	$4,559
Firebag	$481	$1.39	$120	$6.54	112	$730	$2,546
Cold Lake	$989	$3.84	$232	$5.98	69	$411	$1,268
Four project total	**$2,060**	**$1.52**	**$507**	**$7.44**	**425**	**$3,162**	**$11,034**

Note: Per barrel amounts are production weighted-totals.

An additional consideration for the province of Alberta is the increased future value of royalties. Table 2 (below) shows the increase in per-barrel royalties as a result of the implementation of the MOU, and the increase in total royalties paid between 2035 and 2050. We assume that 2035 production levels remain flat through 2050.

All projects see a significant increase in total royalties paid to the province. Given their current royalty status, these four projects combined would pay roughly C$950 million more in royalties to the province if the WCS-WTI differential is reduced by US$5 per barrel. The net present value of the increase in royalties from these four projects from 2035 to 2050 is approximately C$3.2 billion to C$4.6 billion. The companies that own the projects would likely also pay more in provincial and federal corporate income taxes, though this is outside the scope of our project-level analysis.

Table 2: Royalty increase from increased profitability, 2027–2050

Project	Total royalty increase, 2035–2050 (C$/barrel)	Increased annual royalties, 2035–2050 (C$ million)	Royalty increase, 2035–2050, NPV (C$ million)
Christina Lake	$3.31	$368	$1,312
Kearl	$0.55	$73	$233
Firebag	$3.22	$360	$1,254
Cold Lake	$2.27	$156	$456
Four project total	**$2.25**	**$957**	**$3,254**

Note: Per barrel amounts are production-weighted totals.

CONCLUSION

Analysis shows that the profitability gains from securing new pipeline capacity — which significantly reduces the WCS-WTI price differential — outweigh the increased compliance costs associated with strengthening Alberta's TIER carbon market to achieve a market price of C$130 per tonne by 2035. Even for high-emission oil sands facilities, increased market access is the dominant factor, translating into a potential net profit increase that strongly supports the grand bargain articulated in the federal-Alberta MOU. An aggressive path to decarbonization can be paired with, and financially supported by, strategic growth in market access for the oil sands sector. ■

CANADA'S CLEAN ELECTRICITY SUPPLY CRISIS

*Marc Brouillette**

OVERVIEW

As the nation embarks on the national strategy for an electrified economy recently announced by the Federal government,[1] provinces across Canada are becoming exposed to the risks of supply shortfalls. The objectives of the national strategy include doubling Canada's electricity grid to support economic growth and accelerate electrification across the economy. The doubling of demand for electricity has become widely accepted by policy makers, such as with the Ontario-led National Energy Corridor Agreement that is underpinned by assumptions of unprecedented, rapid, and sustained growth in electricity demand across Canada.[2] Policy makers recognize that the expansion of a reliable electricity system must be charted in an affordable manner. Analyses suggest that the growth in electricity demand arising from the combination of electrification and economic growth will more than double and potentially more than triple current electricity demand, in some provinces as Canada strives to decarbonize its economy. Unfortunately, despite policy statements about the need to address this heightened growth, the provincial electricity system planning organizations that are responsible for charting infrastructure development are generally planning for only a quarter of this demand growth. Using Ontario as a case study, as a result of conservative electricity demand growth assumptions, electricity supply shortfall risks are likely to arrive before clean energy infrastructure can be fully developed. The consequence is that supply shortfall risks may persist for decades and drive an increasing dependence on additional natural gas-fired generation, with the associated emissions. These circumstances raise several questions for policy makers on how much electricity demand growth should be planned for given their economic growth, electrification, and emission reduction policy objectives and how that may drive the associated need to prioritize infrastructure development to support those objectives.

1. Context: Building Canada strong means more power to electrify and grow the economy

The Federal government's recently released *National Strategy For An Electrified Economy* recognizes that available affordable and reliable electricity is a strategic imperative for Canadian federal government ambitions. [3] The strategy recognizes that the "[t]he world is changing rapidly" and that "[m]ajor economies are moving decisively to strengthen their electricity systems".[4] It argues that "[a]ccess to abundant, affordable, and reliable electricity is — more than ever — fundamental to competitiveness, energy security, and economic sovereignty"

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[1] Natural Resources Canada, *Powering Canada Strong: A National Strategy for an Electrified Canadian Economy* (May 2026), online: <natural-resources.canada.ca/energy-sources/electricity-infrastructure/powering-canada-strong-national-strategy-electrified-canadian-economy>.

[2] Ontario, Ministry of Energy and Mines, News Release, "Ontario Secures Groundbreaking National Energy Corridor Agreement" (4 March 2026), online: *Ontario Newsroom* <news.ontario.ca/en/release/1007115/ontario-secures-groundbreaking-national-energy-corridor-agreement>.

[3] *Supra* note 1.

[4] *Ibid*.

and that electrification "drives critical progress towards climate goals".[5] These imperatives are also recognized by the provinces. [6] Ontario's recent *Energy for Generations* integrated energy plan seeks to advance Ontario as the strongest economy in the G7: "[e]nergy keeps Ontario's economy growing and people working. … The choices we make about energy policy today will determine our success for generations…"[7] Furthermore, the Ontario-led *National Energy Corridor Agreement*[8] is underpinned by assumptions of unprecedented, rapid, and sustained growth in electricity demand across Canada.[9] The federal strategy refers to estimates that the "emerging electricity demand **will require at least a doubling** — if not more — of electricity system infrastructure between now and 2050."[10]

The anticipated growth in electricity demand is significant, well understood, and being witnessed the world over as new sources of demand emerge: electrification of the economy, industrial expansion, data centre proliferation, and developing critical minerals.[11] Yet electricity systems are already becoming strained. The North American Electric Reliability Corporation (NERC) is highlighting critical reliability shortfalls across the northeast, including Canada.[12] Vulnerable utilities across North America are aggressively investing to expand grids. To mitigate supply risk and cost-to-rate-payer risks, policy makers are intervening. Environmentalists are concerned about the large amount of new natural gas-fired generation being proposed.[13] In Canada, Quebec has run out of hydro-electric export capacity and, along with British Columbia, is turning away large domestic loads.[14]

Understanding how economic growth ambitions relate to a reliable electricity system requires consideration of emergent demand growth and how the electricity system is being planned in response.

2. Implications of electrifying the economy

Electrification is one of three approaches for decarbonizing the economy, driven by the primary objective to reduce carbon emissions arising from the consumption of fossil fuels, as illustrated in Figure 1.

[5] *Ibid*.

[6] Colin Anderson, "Ontario's economic future hinges on energy investment", *iPolitics* (17 March 2026), online: <ipolitics.ca/2026/03/17/ontarios-economic-future-hinges-on-energy-investment>.

[7] Ontario, Ministry of Energy and Mines, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7* (Toronto: King's Printer for Ontario, 2025) at 4, online (pdf): <ontario.ca/files/2025-07/mem-energy-for-generations-en-2025-07-18.pdf>.

[8] *Supra* note 2.

[9] *Ibid*.

[10] *Supra* note 1 [emphasis in original].

[11] Strategic Policy Economics, *Outlook for Nuclear Energy in Canada 2025* (Ottawa: Canadian Nuclear Association, 16 September 2025), online: <cna.ca/publication/outlook-for-nuclear-energy-in-canada-2025/outlook-for-nuclear-energy-in-canada-report-september-16>.

[12] Alessia Simona Maratta, "Canada's power grid is under pressure amid rising demand, watchdog warns", *Global News* (7 February 2026), online: <globalnews.ca/news/11657048/canada-power-grid-under-pressure-rising-demand-watchdog-warns>; Robert Walton, "NERC forecasts peak demand to rise 24% on new data center loads", *Utility Dive* (30 January 2026), online: <utilitydive.com/news/nerc-10-year-peak-demand-forecast-jumps-24-on-new-data-center-loads/810955>.

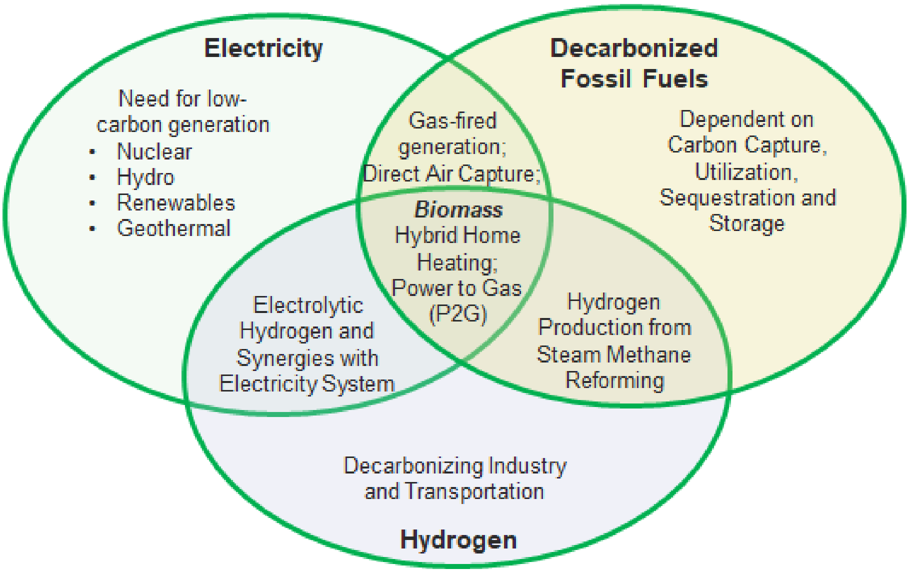
[13] See Meris Lutz, "Utilities' spending spree continues, according to their Q4 2025 reports", *Utility Dive* (4 March 2026), online: <utilitydive.com/news/q4-2025-earnings-roundup-utilities-tout-load-growth/813742>; see also Brandon Owens & Morgan Bazilian, "As data centers go off-grid, utilities face new cost and planning risks", *Utility Dive* (17 March 2026), online: <utilitydive.com/news/as-data-centers-go-off-grid-utilities-face-new-cost-and-planning-risks/811944>.

[14] See Chris Bonasia, "Cold Snap Exposed Limits of Quebec-New England Power Deal", *The Energy Mix* (11 February 2026), online: <theenergymix.com/cold-snap-exposed-limits-of-quebec-new-england-power-deal>; Tristin Hopper, "FIRST READING: How Canada squandered its most valuable national asset", *National Post* (9 February 2026), online: <ca.news.yahoo.com/first-reading-canada-squandered-most-123725662.html>; Nelson Bennett, "Why B.C. is rewriting energy rules to decide who gets power and who doesn't", *Business in Vancouver* (21 November 2025), online: <www.biv.com/news/resources-agriculture/why-bc-is-rewriting-energy-rules-to-decide-who-gets-power-and-who-doesnt-11508107>.

2.1. Approaches to decarbonizing the economy

Carbon emissions are produced across the Canadian economy: Transportation from light and heavy-duty (HD) vehicles (22 per cent), Buildings (12 per cent), Industry (Oil & Gas 30 per cent, Heavy Industry 11 per cent), other (Agriculture 10 per cent, Electricity 7.2 per cent, Waste and the remaining miscellaneous other sources, 6.9 per cent).[15] The mix differs by province. For example, Oil and Gas emissions are primarily in Alberta and Saskatchewan. Carbon emissions from electricity are primarily in Alberta, Saskatchewan and Nova Scotia. Ontario contributes the most emissions from heating buildings due to the sheer size of the province, while Quebec and New Brunswick have already electrified much of their building heating. As a result, decarbonization options vary across provinces but include three main approaches [Figure 1]:

Figure 1: The future energy trifecta[16]



[15] Environment and Climate Change Canada, "Executive Summary of the Report: Greenhouse Gas Sources and Sinks in Canada: 2026" (14 April 2026), online: <canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary-2026.html>.

[16] Toward a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future, CCRE Commentary 2021, M. Brouillette; Strapolec Analysis; Marc Brouillette, *Toward a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future*, CCRE Commentary (Toronto: Council for Clean & Reliable Energy, December 2021), online: <thinkingenergy.ca/commentaries/ccre-commentary-toward-a-national-energy-vision-canadas-low-carbon-energy-infrastructure-opportunity-in-a-global-net-zero-future>.

Decarbonizing fossil fuels involves the capture or elimination of emissions as well as the use of bio-based or other synthetic fuels. Indeed, two carbon-abatement approaches may enable the continuing use of fossil fuels in a net-zero world. The first, carbon capture, utilization and storage (CCUS) extracts carbon at the point it is emitted from large-scale facilities, such as gas-fired generation, and then either incorporates it into a static product (utilization) or else sequesters it (storage), often in geological formations.

The second carbon-abatement approach, direct air capture, absorbs carbon dioxide from ambient air to address ubiquitous emitters such as home heating. Direct air capture technologies are in early development, have not yet been demonstrated at scale, and rely on the same utilization and storage capabilities.[17] Given the regional diversity of energy resources and storage capacity, the potential role of CCUS can be expected to vary across Canada.

Meanwhile, renewable biomass from forestry, agriculture and waste streams can be used to generate electricity, support combined heat and power applications, for hydrogen production, and bio-fuels.

Hydrogen can be used for many power applications in buildings, transportation and industry.[18] Hydrogen is generally produced by water electrolysis, through the steam methane reforming of natural gas, or from biomass. However, for hydrogen to contribute to lower carbon emissions, it must be produced from low-emitting sources, which means the deployment of CCUS for fossil based or biomass-based hydrogen production.

Electrification involves switching from fossil fuels and is a pathway to achieve significant reductions in carbon emissions in buildings, transportation and industry.[19] Electric heat pumps can efficiently heat buildings and water. Industrial applications are being electrified and/or are shifting to hydrogen use.[20] This places the generation of electricity at the centre of the energy debate. Electricity is not an energy source — it must be manufactured using other primary energies: wind, energy from the sun, power of falling or moving water, fossil fuels, uranium, and the combustion of biomaterials or waste.

The future energy potential of each trifecta element is influenced by regional choices, local cost competitiveness and export objectives.

2.2. Broadly understood electrification implications entails much more electricity

Electrification has the potential to reduce emissions, through:

a. **Buildings**: Primarily residential and commercial heat pumps for space and water heating to displace the use of natural gas but also fuel oil and propane;

b. **Transportation**: Primarily electric vehicles (EVs) to displace gasoline powered light/passenger vehicles and EV and hydrogen options to displace diesel use in land-based freight and HD vehicles; and,

c. **Industry**: Primarily via electrification of industrial processes and process heating, as well as electrification of process cooling, machine drives, and mobile equipment. These displace the use of natural gas as well as gasoline and diesel use. Hydrogen may be one of few viable

[17] International Energy Agency, *Direct Air Capture 2022: A key technology for net zero* (Paris: IEA, 2022), online: <iea.org/reports/direct-air-capture-2022>.

[18] Marc Brouillette, *Toward a National Energy Vision: Canada's Low-Carbon Energy Infrastructure Opportunity in a Global Net Zero Future*, CCRE Commentary (Council for Clean & Reliable Energy, 2021), online: <thinkingenergy.ca>. See Green Ribbon Panel, *Clean Air, Climate Change and Practical, Innovative Solutions: Policy Enabled Competitive Advantages Tuned for Growth* (2020), online: <greenribbonpanel.com/reports-and-publications>.

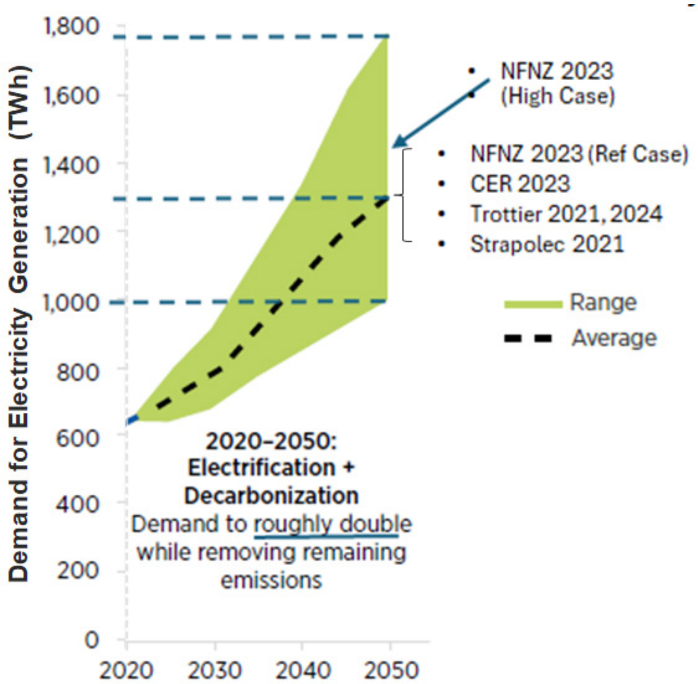
[19] The largest emissions sources in Canada are in buildings, transportation and industry: see Canadian Institute for Climate Choices, *Canada's Net Zero Future: Finding our way in the global transition* (2021), online: <climateinstitute.ca/reports/canadas-net-zero-future>.

[20] See Algoma Steel, News Release, "Government of Canada Endorses Algoma Steel's Transformation Plan for Green Steel: Commitment of up to $420 Million" (5 July 2021), online: <algoma.com/news/government-of-canada-endorses-algoma-steels-transformation-plan-for-green-steel-commitment-of-up-to-420-million>; ArcelorMittal, News Release, "ArcelorMittal and the Government of Canada announce investment of CAD$1.765 billion in decarbonisation technologies in Canada" (30 July 2021), online: <corporate.arcelormittal.com/media/news/regulatory-news/arcelormittal-and-the-government-of-canada-announce-investment-of-cad-1765-billion-in-decarbonisation-technologies-in-canada>; S Julio Friedmann, Zhiyuan Fan & Ke Tang, *Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today* (New York: Center on Global Energy Policy, Columbia University, 2019), online: <energypolicy.columbia.edu/publications/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today>.

options in some hard to decarbonize high heat requirement areas.

The impacts of the role of electrification in achieving a Net Zero (NZ) economy have been known for a decade[21] — with recurring third party estimates of total Canadian long-term electricity demand remaining relatively stable. The doubling of Canadian electricity demand just from electrification has been identified by both Natural Resources Canada (NRCan) and Environment and Climate Change Canada (ECCC).[22] The 2024 Canada Electricity Advisory Council (CEAC) report for NRCan informed these expectations and presented a range of available demand estimates for electrifying the economy — pointing to a doubling of demand, as illustrated in Figure 2.

Figure 2: CEAC and CNA evaluated electrification demand forecast for NZ economy[23]



[21] Independent Electricity System Operator, *Ontario Planning Outlook: A Technical Report on the Electricity System Prepared by the IESO* (Toronto: IESO, 1 September 2016), online (pdf): <www.rds.oeb.ca/CMWebDrawer/Record/544592/File/document>; Council of the Great Lakes Region, *Ontario's Long-Term Energy Plan: Understanding Carbon Emissions, the Role of Nuclear, and Electricity Trade with Quebec* (December 2016), online (pdf): <councilgreatlakesregion.org/wp-content/uploads/2016/12/Ontarios-long-term-energy-plan.pdf>.

[22] Environment and Climate Change Canada, News Release, "Accelerating Canada's clean power advantage" (9 November 2025), online: <canada.ca/en/environment-climate-change/news/2025/11/accelerating-canadas-clean-power-advantage.html>; Natural Resources Canada, *Powering Canada's Future: A Clean Electricity Strategy* (2024), online: <natural-resources.canada.ca/energy-sources/powering-canada-s-future-clean-electricity-strategy>.

[23] Canada Electricity Advisory Council, *Powering Canada: A Blueprint for Success: Final Report* (Ottawa: Natural Resources Canada, May 2024), online (pdf): <natural-resources.canada.ca/sites/nrcan/files/energy/electricity/Canada-Electricity-Advisory-Council-Final-Report-2024.pdf>.

A 2025 Canadian Nuclear Association (CNA) report assessed the sources referenced by the CEAC report, as well as other available or more recent sources, observing a remarkably tight alignment of electricity demand of between 1250 TWh and 1400 TWh.[24] This range is consistent with an independent 2021 Ontario forecast[25] and the recent Canada Energy Regulator forecast of 1323 TWh.[26] The mid-range of this alignment is referred to in the remainder of this article as the *Consensus Opinion* on electrification implications.

The alignment of these forecasts of total Canadian electricity demand growth is notable because these reports each have substantially different assumptions on the role of the various options for decarbonizing the economy: electrolytic hydrogen, biofuels, carbon capture and sequestration. However, they also all consider a significant reduction in oil sands production by 2050, which may now appear to be a questionable assumption.

Importantly, this doubling of total long-term Canadian electricity demand forecast by the foregoing studies does not contemplate provincial and federal economic development ambitions, such as "Build Canada Strong".[27]

3. Powering Canada's economic growth

Governments across Canada are pursuing ambitious economic development objectives. These are distinct from the implications of electrification to achieve a NZ economy and include:

- Critical minerals development and refining;
- Auto sector retooling towards electric vehicles (EVs);
- Data centre proliferation and Canada's Artificial Intelligence strategy;
- Electricity exports, including hydrogen production for export; and
- Population growth and immigration.

In addition to the aforementioned assessment of electrification studies, the CNA study also examined provincial electricity demand growth forecasts arising from the above economic development factors and compiled a forecast for Canada. The results are provided in Figure 3 that presents a *Minimum* demand case that could arise from electrification only or some combination of reduced electrification and reduced economic development, a High demand that encompasses higher electrification case pathways and economic development, and a New Reference case that is put forward as the recommended demand case upon which to base electricity system planning. Most of the forecast demand is expected to come in the form of baseload. Demand from industrial growth may potentially drive over 50 per cent more demand for baseload capacity than identified for electrification alone. Figure 3 indicates that demand for generation capacity could grow by a factor of 2.4 to 3 times, not just the doubling referred to by policy makers. Consideration of the combined effects of industrial growth and electrification is a necessity for system planning.

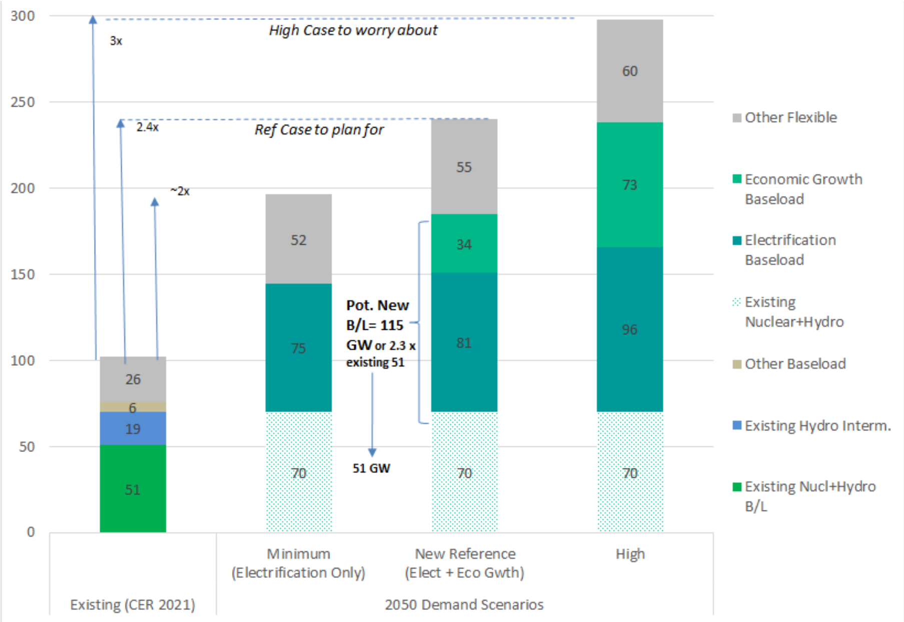
[24] *Supra* note 11.

[25] Green Ribbon Panel, *Submission for the Ministry of Energy, Northern Development and Mines Review of Ontario's Long-Term Energy Planning Framework* (27 April 2021), online (pdf): <ero.ontario.ca/public/public_uploads/2021-04/Green%20Ribbon%20Panel%20Submission.pdf>; Marc Brouillette, Toward a National Energy Vision: Case Study: Electricity System Implications for Ontario and Quebec, CCRE Commentary (Council for Clean & Reliable Energy, 30 June 2022), online: <thinkingenergy.ca/commentaries/toward-a-national-energy-vision-case-study-electricity-system-implications-for-ontario-and-quebec>.

[26] Canada Energy Regulator, *Canada's Energy Future 2026: Energy Supply and Demand Projections to 2050* (Calgary: Canada Energy Regulator, 2026), DOI: <10.35002/57gd-q723>.

[27] Canada, Department of Finance, *Budget 2025: Canada Strong — Our Plan: Building Canada Strong* (4 November 2025), online: <budget.canada.ca/2025/report-rapport/intro-en.html>.

Figure 3: Canada's clean economy 2025 electricity demand scenarios[28]
(GW capacity, derated at peak)



4. Misalignment of provincial plans with emerging growth

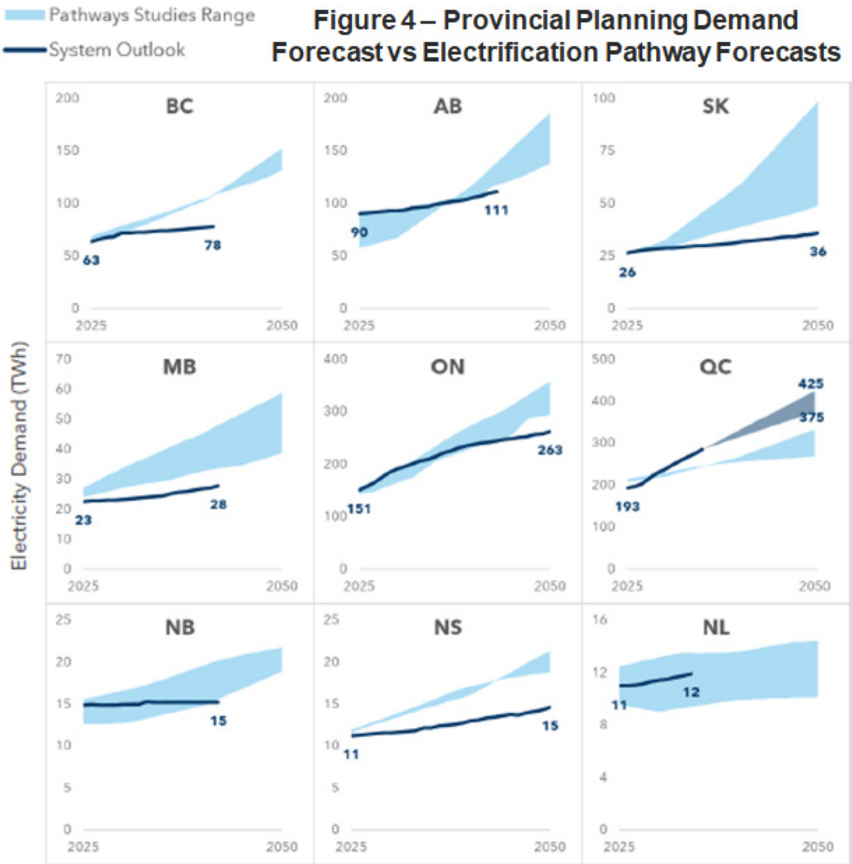
In general, most Canadian provinces are not yet planning for the combined effects of electrification and industrial/economic growth on their respective electric systems. A recent report titled *Forecasting Canada's Electricity Future Demand Growth, Key Drivers, and Implications for Provincial Planning* examined provincial electricity demand forecasts being used for planning.[29] The results are reproduced in Figure 4 which contrasts the provincial planning forecasts (dark lines) with the range of potential electricity demand forecasts that could result from pathways for electrification in each province according to various published reports (shaded areas). The pathways represent various approaches to implementing the trifecta of decarbonization strategies identified earlier. Provincial planning forecasts tend to exclude significant electrification, while the sources used to characterize the electrification pathways tend to exclude industrial development, and in some cases, such as for Ontario, may not reflect the full impacts of achieving net zero economies that are reflected in Figure 2.

With the exception of the province of Quebec, Figure 4 illustrates that provincial planning agencies across Canada are not yet preparing for the growth in electricity demand arising from both industrial growth and electrification. Quebec is planning for demand growth that exceeds the electrification assumptions, recognizing that power system planning must reflect electricity demand arising from both electrification and economic and industrial growth aspirations. Newfoundland and Labrador is tracking the mid-range, primarily due to the assumptions made regarding the export of green hydrogen.

[28] Demand in Figure 3 has been segregated into two main types: (1) *Baseload demand* that is present 24x7, 365 days/year and well suited to being supplied by baseload nuclear and hydro; (2) *Variable demand* that reflects demand variations on a daily, weekly and seasonal basis, as well as the need for peaking supplies and reserve capacity - this demand requires dispatchable/flexible supply solutions such as hydro, natural gas-fired generation or some aggregated solution formed from a combination of renewables, storage, hydro and gas, etc. Strategic Policy Economics, *Outlook for Nuclear Energy in Canada 2025* (Ottawa: Canadian Nuclear Association, 16 September 2025), online: Canadian Nuclear Association; Strapolec Analysis.

[29] The Transition Accelerator, *Forecasting Canada's Electricity Future: Demand Growth, Key Drivers, and Implications for Provincial Planning*, by Dunsky Energy + Climate Advisors (November 2025), online (pdf): <transitionaccelerator.ca/wp-content/uploads/2025/11/Forecasting-Canadas-Electricity-Future-Report-Final-November-2025.pdf>.

Figure 4: Provincial planning demand forecast vs electrification pathway forecasts[30]

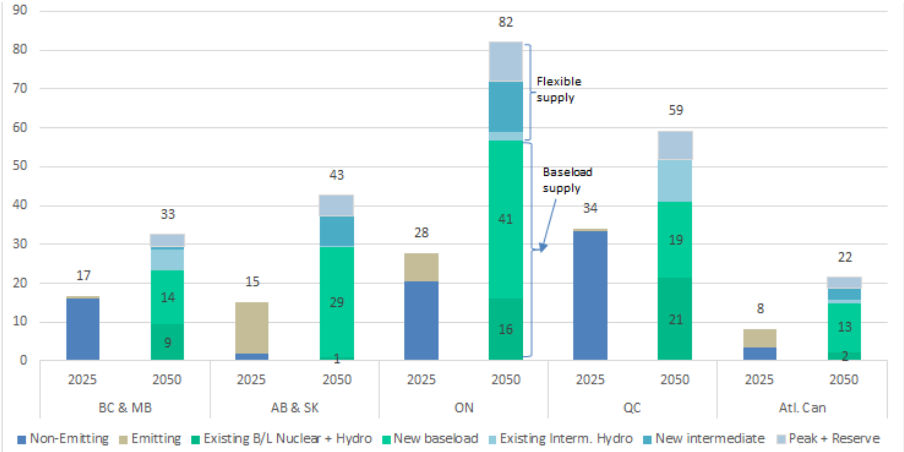


The implications of combined electrification and industrial growth on needed electricity system capacity at peak in each province is provided in Figure 5. This chart contrasts the existing capacity across Canada to the need for capacity at peak for the *New Reference* demand forecast described earlier in Figure 3. Colors reflect types of demand: demand for baseload capacity in shades of green, the largest area of growth; demand for flexible supply in shades of blue for intermediate, peak, and reserve. Growth in the need for flexible electricity generation stems primarily from the seasonal nature of electrifying building heating.[31]

[30] The Transition Accelerator, Forecasting Canada's Electricity Future: Demand Growth, Key Drivers, and Implications for Provincial Planning, by Dunsky Energy + Climate Advisors (November 2025), Figure 8: "Electricity Demand by Province, 2025–2050, system outlooks and pathway studies".

[31] Marc Brouillette, *Electrification Pathways for Ontario to Reduce Emissions: Procuring Ontario's Energy Future* (Strategic Policy Economics, August 2021), online: <strapolec.ca/publications>.

Figure 5: Illustrative clean capacity demand forecast[32]
(GW derated at peak, reference scenario, flexible vs baseload by provinces)



Demand growth varies materially by province. This variation stems from industrial composition, existing electrical home heating, and existing non-emitting assets in each province. The degree of variation highlights that aggregated national level demand growth observations are not useful for informing planning decisions. The more than doubling of national demand discussed previously implies a tripling of demand in Ontario and Alberta, less so in hydro rich provinces such as Quebec, British Columbia and Manitoba.

Canada's dispatchable, low-emitting generation options are limited. Nuclear and hydro, offer viable solutions, though each face the hurdle of extended development timelines. Non-dispatchable renewables like wind and solar will require firming technologies, such as storage and/or backup natural gas-fired generation, to ensure reliability.

5. Case study Ontario: Demand will be much higher than the annual planning outlooks suggest

A deeper dive into Ontario's electricity system planning assumptions illustrates the implications of these planning mismatches.

As with the other provinces, Ontario's planners have been slow to respond to the emerging demand expectations. The Ontario government's *Energy for Generations* (E4G) integrated energy plan offers "to ensure Ontario's energy system remains affordable, reliable, secure, and clean — not just today, but for decades to come." [33] Ontario's Independent Electricity System Operator (IESO) is charged with developing the demand forecasts for guiding development of Ontario's electricity system. The IESO produces an Annual Planning Outlook (APO) to capture the reference case demand forecast and the system development activities that the IESO will undertake to supply that demand. Yet relying on the APO reference case is creating significant supply risk given the magnitude of emerging needs, the development timelines involved, and the limited electricity supply options available. Contingency planning for the larger baseload and flexible supply capacity development could mitigate the evident shortfalls and costs that will otherwise hamper Ontario's economy for generations.

[32] Strategic Policy Economics, *Outlook for Nuclear Energy in Canada 2025* (Canadian Nuclear Association, 16 September 2025); Strapolec Analysis.

[33] *Supra* note 7 at 150.

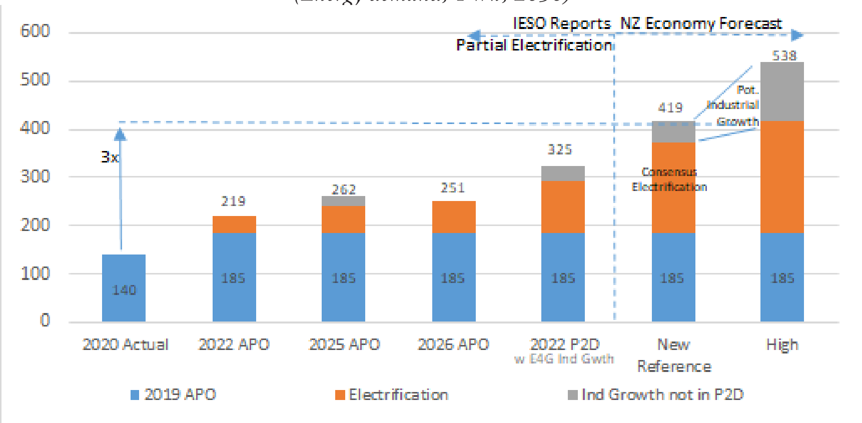
5.1. Ontario's IESO slow response to emerging demand growth

The 2026 IESO APO forecasts demand growth of 65 per cent by 2050.[34] This forecast underpins the IESO's planning and procurement activities. Yet, the aforementioned analyses suggest that almost three times greater demand growth would better reflect the *Energy for Generations* ambitions. This gap is an example of the risk that demand growth might outpace supply development.

This planning gap does not arise because the IESO does not understand decarbonization technology options. They issued the *Pathways to Decarbonization* (P2D) report in 2022[35] to illustrate the implications of electrification-driven decarbonization. Rather, the IESO has transparently excluded many electrification assumptions from all of its APOs. The IESO has purposefully made these planning choices, as is their remit, given their interpretation of the energy and electricity policies of the government of Ontario.

It is notable that in each successive APO since 2019, the IESO has incrementally added elements of electrification demand, as illustrated in Figure 6. However, in the latest 2026 APO reference case, electrification assumptions are lower than contained in the 2025 APO and remain below the *Consensus Opinion* of Canadian studies discussed in Figure 2, and as captured by the *New Reference* in Figure 6. The IESO's APOs continue to mostly exclude electrification of building heating, industry, and heavy-duty transportation. Even the 2022 P2D excludes electrification of industry and heavy-duty transportation.

Figure 6: IESO vs net zero growth economy forecast[36]
(Energy demand, TWh, 2050)



[34] Independent Electricity System Operator, *2026 Annual Planning Outlook* (Toronto: IESO, March 2026), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2026/2026-Annual-Planning-Outlook.pdf>.

[35] Independent Electricity System Operator, *Pathways to Decarbonization* (Toronto: IESO, 15 December 2022), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Pathways-to-Decarbonization.pdf>.

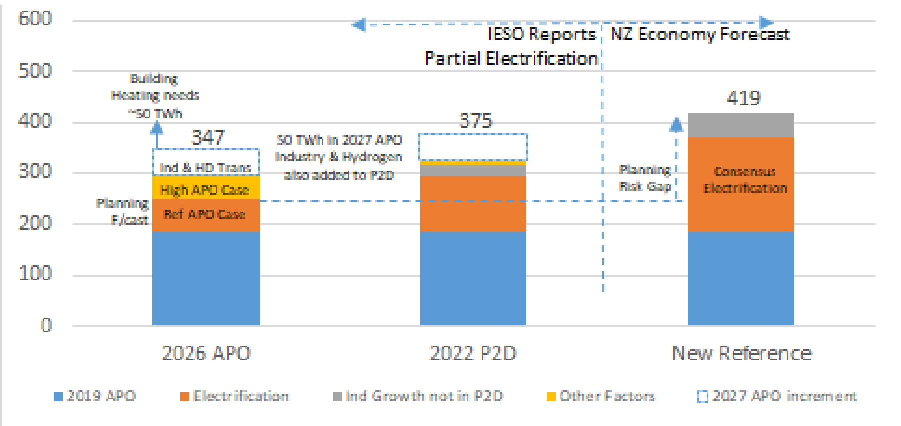
[36] The 2019 and 2022 APO series are extrapolated to 2050 using the compound annual growth rate over the terminal years of the respective IESO forecasts; the published IESO forecast horizons end in 2040 and 2043, respectively. APO values represent the IESO's reference forecast used for system planning. The 2026 APO Reference Scenario incorporates known industrial and economic-development loads but forecasts lower overall demand growth than the 2025 APO (65% versus 75% through 2050). *Energy for Generations* presents both the IESO APO and P2D Pathways demand outlooks and incorporates broader economic-development considerations. Any extension or adjustment of these published forecasts, including estimates concerning the timing of full-economy electrification beyond 2050, constitutes Strategic Policy Economics (Strapolec Analysis). Independent Electricity System Operator, *Annual Planning Outlooks* (2019–2026) and *Pathways to Decarbonization* (15 December 2022); Ontario, Ministry of Energy and Mines, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7* (12 June 2025); Strategic Policy Economics (Strapolec Analysis).

Examining the underlying assumptions embedded in the IESO's APOs and P2D forecasts of demand to 2050 shows greater alignment of the electrification implications between the IESO's assumptions and the *New Reference*, as illustrated in Figure 7. The most recent 2026 APO also provided an illustrative high case to capture some contingencies, as requested by the government.[37] It is this *High* case that the Ontario government references in support of the *National Energy Corridor Agreement*.[38] The IESO has further suggested next year's 2027 APO might include additional partial industry and hydrogen electrification assumptions.[39] There is no indication as to when the IESO may consider electrification of building heating in its forecasts. Adding these additional partial industry and hydrogen electrification assumptions to the P2D forecast, which does include building heating, yields total new demand that is beginning to approximate the *New Reference* for a Net Zero (NZ) economy illustrated in Figure 7.

But it remains that the IESO's current procurement planning activities and statements of system supply adequacy rely in the 2026 APO reference demand case. The APO reference case only captures 25 per cent of the *Consensus Opinion* on electrification and other growth factors.

The low growth forecast of the Annual Planning Outlook assumes much electrification will occur beyond a 25-year horizon — including full EV adoption and most electrification of industry, Heavy Duty (HD) transport, and building heating. The IESO has adopted a conservative approach to demand forecasting in order to minimize the risks of overbuilding. However, with substantial potential demand growth from electrification and industrial/economic expansion, focal points of both provincial and federal government policies, the question of what under-building risks these choices might present to Ontario's supply adequacy as the economy evolves over the next 25 years becomes ripe for consideration.

Figure 7: Comparative 2050 energy demand forecast drivers[40]
(TWh, 2026 APO vs P2D vs new reference)



[37] *Supra* note 34.

[38] *Supra* note 2.

[39] Independent Electricity System Operator, *Annual Planning Outlook (APO): 2026 Demand Forecasts & 2027 Demand Scenario* (Toronto: IESO, 18 November 2025), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/engage/apo/apo-20251118-presentation.pdf>.

[40] Independent Electricity System Operator, *2025 Annual Planning Outlook* (April 2025), *2026 Annual Planning Outlook* (March 2026), and *Pathways to Decarbonization* (15 December 2022); Ontario, Ministry of Energy and Mines, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7* (12 June 2025); Strapolec Analysis.

5.2. Supply shortfalls are emerging and putting Government ambitions at risk despite its initiatives

Ontario's overarching economic development plan, outlined in the *2026 Ontario Budget: A Plan to Protect Ontario*, focuses on building a competitive, resilient and self-reliant G7 economy.[41] It lays out several core initiatives including automotive and EV expansion and critical minerals. These are long term objectives. The Ontario Budget reflects the *Energy for Generations* plan and was released concurrently with the *National Energy Corridor Agreement* initiated by the Ontario Government.

In contrast, analysis of APO assumptions reveals a focus on near-term economic growth, with limited industrial growth assumed beyond 2030. While the 2026 APO's expectation of a 65 per cent increase in demand reflects increased electricity demand for data centres,[42] the IESO has reduced the 2025 APO's economic development provisions for most other areas, such as the auto sector.

The Ontario Government's recent strategy statements assume the 90 per cent growth implied by the 2026 APO High demand scenario. Yet the IESO is not using this APO High demand scenario for resource planning purposes, and, furthermore, the High demand scenario does not include any provisions for critical minerals/Ring-of-Fire development, higher population growth that would accompany Ontario becoming the G7's fastest growing economy, or the proposed high-speed rail to Montreal.[43]

Ontario has unveiled a bold nuclear development program

Notably, independent of the IESO, the Ontario government has created a plan and is moving ahead with a long-term nuclear program. Ontario currently has three nuclear sites, with two operated by Ontario Power Generation (OPG) and one operated by Bruce Power, with many current and future initiatives being pursued as summarized in Table 1. The *Energy for Generations* plan supports Small Modular Reactors (SMRs), Pickering refurbishment, Bruce C and Wesleyville, largely predicated on the 17 GW of new nuclear identified by the 2022 P2D. The government is also sponsoring the evaluation of OPG's Nanticoke and Lambton sites for further nuclear opportunities.

Yet these planned resources are not enough. As the *New Reference* demand forecasts begin to emerge, it will become increasingly evident that extended development timelines will result in electricity supply shortfalls. Figure 8 illustrates a timeline of possible demand growth and the identified nuclear generation capacity initiatives from Table 1 (shown in green). The reddish line is the IESO 2026 APO reference case for baseload. The top of the grey is the 2026 APO high case demand for baseload. The blue dashed line is the *New Reference* demand, reflecting near term industrial demand from the 2025 APO and electrification growth straight-lined from the 2025 APO demand for 2035. The dotted light grey line is the total derated capacity at peak that may be needed, reflecting the need for flexible supply.

[41] Ontario, Ministry of Finance, *2026 Ontario Budget: A Plan to Protect Ontario* (Toronto: King's Printer for Ontario, 26 March 2026), online (pdf): <budget.ontario.ca/2026/pdf/2026-ontario-budget-en.pdf>.

[42] MaRS Staff, "Sharing the Load: How Collaborative Data Centre Expansion Could Lead to a Better Grid" (10 March 2026), online: *MaRS Discovery District* <marsdd.com/research-and-insights/data-centres-sharing-the-load>.

[43] The Globe and Mail, "Ontario Advances National Partnership and Energy Expansion Strategy" (22 April 2026), online: <theglobeandmail.com/business/adv/article-ontario-advances-national-partnership-and-energy-expansion-strategy>.

Table 1: Nuclear initiatives identified in *Energy for Generations* plan[44]

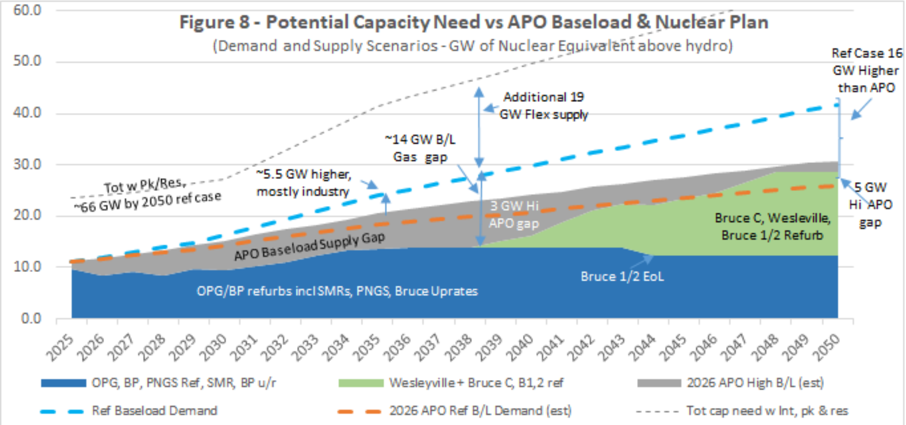
Facility	Operator/ location	Initiative	Description/capacity	Status & timeline
Darlington Nuclear Generating Station	OPG Clarington	Darlington refurbishment	Refurbishment of 4 large CANDU reactors – 3,500 MW	Completed, to extend station operation to the end of 2055.
Bruce Nuclear Generating Station	Bruce Power Kincardine	Bruce refurbishment	Refurbishment of 6 large CANDU reactors (Units 3-8) – 7,000 MW	Ongoing to complete by 2033; ensures generation into the 2060s.
Pickering Nuclear Generating Station	OPG Pickering	Pickering refurbishment	Refurbishment of 4 CANDU reactors – 2,200 MW	Planning phase underway to extend operating life by 30 years.
Darlington New Nuclear Project	OPG Clarington	Darlington SMR Project	G7's first grid-connected Small Modular Reactor (GE Vernova Hitachi BWRX-300). Government directive includes 3 additional unites – 1,200 MW	Construction underway. First SMR to be fully constructed by 2030. Total Darlington SMR capacity to be 1,200 MW
Bruce Nuclear Generating Station	Bruce Power Kincardine	Bruce C (new build)	New large-scale nuclear reactor build – up to 4,800 MW	Federal Impact Assessment in progress. First new large-scale nuclear build in Ontario since 1993.
Wesleyville	OPG Port Hope/ Clarington	New nuclear	OPG assessing new large-scale reactors – up to 10,000 MW	Planning phase for impact assessment
Nanticoke	OPG Nanticoke	New nuclear	TBD	Under consideration
Lambton	OPG Sarnia	New nuclear	TBD	Under consideration

The *New Reference* baseload demand shows how it may exceed APO planning by material amounts, not only in a long-term electrified economy, but also for industrial growth within the next 10 years.

Projected long-term demand for baseload supplies could be 15 to 20 GW beyond identified additional nuclear capacity. Furthermore, the timelines of advancing nuclear development leave under-supply risks in the medium-term that will be difficult to address and could be sustained for many decades. The grey shows how much baseload capacity to meet the 2026 APO high case demand would likely be needed to come from baseload natural gas-fired generation, potentially with mix of renewables and storage. The gap between the grey and the dashed blue line is the additional natural-gas-fired generation that may be needed to address the *New Reference* demand.

[44] Ontario, Ministry of Energy and Mines, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7* (Toronto: King's Printer for Ontario, 12 June 2025), online: <ontario.ca/page/energy-generations> ; Strapolec Analysis.

Figure 8: Potential capacity need vs APO baseload & nuclear plan[45]
(Demand and supply scenarios – GW of nuclear equivalent above hydro)



The gap between near-term baseload demand and the identified new nuclear capacity initiatives is large, and the long-term gap is larger, reflecting multiples of today's grid capacity. With all of Ontario's non-nuclear and hydro generation capacity set to contractually expire in the 2030s, Ontario could need to source an additional 14 GW of baseload supply for 2038 as well as 19 GW of flexible supply or 60 per cent of the needed total system supply capacity in the next decade.

Conservatively low demand forecast of the APO presents risks to policy makers

A. Mitigating demand growth may not be desired or possible

The identified supply shortfall risks reflect an assumed pace of demand growth. The government of Ontario may be unwilling to abandon its near-term *Energy for Generations* economic objectives, as it favours the more aggressive economic growth. In contrast, discouraging electrification in the medium- to long-term could mitigate some supply shortfalls, as the APO assumes — but could create political risks around Ontarians' sentiment on global climate imperatives. Furthermore, demand arising from electrification may increase regardless of policy, as innovation-induced organic electrification adoption may advance even without policy — as EV and heat pump innovations accelerate globally. The war in Iran is also widely referred to as a tipping point in the global clean energy transition, impacting innovation adoption for energy security reasons.[46]

B. The nuclear program could get challenged

Figure 8 illustrates that the *Energy for Generations* nuclear initiatives exceed the 2026 APO baseload demand. If the 2026 APO reference case is to be relied upon as the formal basis for planning, then the Government's nuclear program could be viewed as being too aggressive — by almost 5 GW in 2050 (e.g. Bruce C or part of Wesleyville would not be needed) and the nuclear program could be challenged.

C. More natural gas, and its emissions, may be inevitable

The gap between demand and confirmed supply presented in Figure 8 illustrates how demand growth could arrive before planned new nuclear or hydro electric capacity could be built,

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[45] IESO data from the *2025 Annual Planning Outlook* (April 2025) and *2026 Annual Planning Outlook* (March 2026); Ontario, Ministry of Energy and Mines, *Energy for Generations* (12 June 2025); Strapolec Analysis.

[46] Kathryn Krawczyk, "The Iran war sparked a shift toward clean energy. Will it last?", *Canary Media* (18 June 2026), online: <canarymedia.com/articles/clean-energy/iran-war-clean-energy>.

resulting in a substantial increase in Ontario's gas-fired generating fleet over the next 10–15 years. Assuming ongoing demand growth from electrification, Ontario will then likely rely on energy from new natural gas-fired generating supply for decades as demand continues to outpace the availability of comparable electricity supply. The associated growth in emissions may create additional political risk.

5.3. Contingency plans are needed to address time-sensitive development challenges

Relying solely on the APO reference case for new generation procurement is creating significant development risk given the potential magnitude of the need for additional electricity supply, the lengthy development timelines involved, and the limited supply options available. The 2026 APO offers no contingency plans to address even the additional 2-3 GW of baseload that would be necessary to meet the APO high case demand for 2035, let alone the *New Reference* demand which is the recommended planning scenario presented in this article.

Contingency planning is warranted to identify how higher demand might be addressed, for both baseload supplies and flexible supply solutions whose output can match hourly, daily, weekly, and seasonal variations in demand.

The infrastructure development challenge is a doubling of all planned supplies

The baseload supply capacity in 2035 is 10 GW short of the needs to meet the *Energy for Generations* economic development objective, as illustrated in Figure 9. This gap of unserved baseload grows to 14 GW by 2050, and could potentially grow to 19 GW under the high demand scenario. Post 2050, this gap could be 33 GW beyond the currently contemplated 21 GW nuclear and hydro programs.

As set out in Figure 10, ensuring adequate flexible supply is equally challenging, with a projected 5 GW shortfall by 2035. If flexible supplies must address unserved baseload, the 2035 flexible supply shortfall could be 13 GW, an amount not currently reflected in the IESO's procurement strategy. Even if long-term baseload supply is satisfactorily addressed, Ontario could need an additional 12 GW of flexible supply over that which the APO contemplates.

Figure 9: Baseload capacity needs[47]
(GW nuclear equivalent capacity)

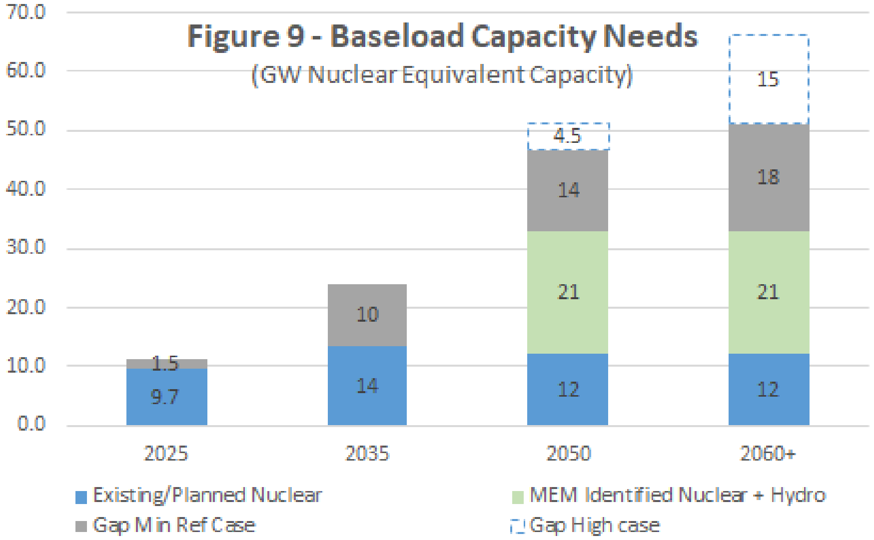
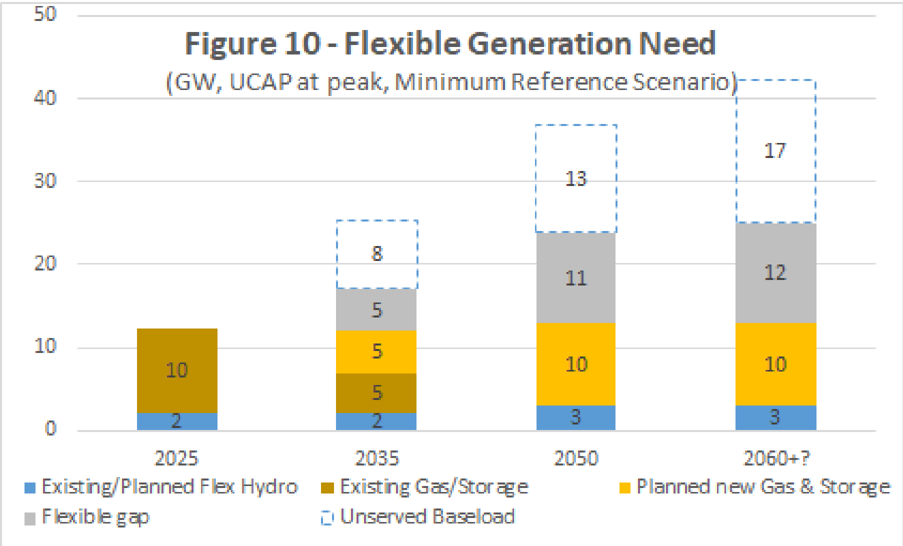


Figure 10: Flexible generation needs[48]
(GW, UCAP at peak, minimum reference scenario)



[47] Figure 9 reflects nuclear equivalent name plate capacity; Illustrated existing Gas/Storage in 2025 includes all other resources; Independent Electricity System Operator, *2025 Annual Planning Outlook: Capacity Expansion Scenario, Costs, and Emissions* (April 2025); Strapolec Analysis.

[48] Figure 10 represents UCAP, derated capacity available at peak demand times; *ibid*.

Building natural gas is no longer the easy path to choose

Relying on natural gas as the fuel of choice to mitigate short-term reliability risks may be at an end:

a) *Canada's Clean Electricity Regulation (CER) prohibits the significant operation of new unabated natural gas fired-generation post 2035.* The recent federal national electricity strategy suggests that the CER will retain the long-term goal of a net-zero grid by 2050, but be modified to introduce more compliance flexibility to prevent stranded assets and ensure grid reliability. However, important details are not yet clear for new generation that will need to come into operation in the late 2030s and 2040s. Despite this, until the details are resolved for all provinces, the CER's implied operational risks may inhibit new investments in natural gas-fired generation. Ontario may not have cost effective flexible generation solutions — even with significant rollouts of renewables and carbon capture, which are also currently unplanned. Furthermore, while not endorsing the CER, the IESO stated that the 2025 APO provides a pathway to a zero emissions grid by 2050.[49] However, under the identified *New Reference* demand growth neither the CER nor the IESO 2025 APO procurement approaches provide viable pathways to a net zero grid by 2050.[50]

b) *Emerging supply chain bottlenecks may handcuff Energy for Generations ambitions*. The world has recognized the implications of significant electricity demand growth, including the presence of non-traditional players, such as AI data centers, who are competing to build gas-fired generation.[51] The U.S. is embracing the need for significant new generation. Commercial interests are securing turbine supplier contracts but are facing 5-7 year wait times.[52] Despite turbine vendors investing in manufacturing capacity upgrades, order backlogs remain extended and some costs could triple.[53]

c) *The ability to otherwise mitigate Ontario's 2035 need for flexible capacity is low*. New renewables and storage may sporadically reduce emissions but cannot materially reduce needed gas-fired generation capacity. Even 24-hour storage only modestly reduces gas capacity needs.[54]

d) *Turbine supply chain constraints will spill onto nuclear projects*. While different in design, steam turbines for nuclear are manufactured by the same global supply chains: Siemens, Mitsubishi, GE Vernova, and Hitachi. Many countries are advancing nuclear plans — for example, the U.S. has announced US$80 Billion of investments for new Westinghouse reactors and almost $18 Billion to build up the US nuclear supply chain.[55]

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[49] Independent Electricity System Operator, *2025 Annual Planning Outlook* (Toronto: IESO, April 2025), online (pdf): <ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf>.

[50] Marc Brouillette, *Patchworking Canada's Energy Transition: Accelerating through Evidence-based Decision Making* (backgrounder presented at the CCRE Energy Leaders Roundtable, Orangeville, Ontario, 26 October 2023), online (pdf): <thinkingenergy.ca/wp-content/uploads/2023/10/Patchworking-Canadas-Energy-Transition-Marc-Brouillette-Strategic-Policy-Economics-October-26-2023.pdf>.

[51] Daniel Raimi et al, *Global Energy Outlook 2026: How the World Lost the Goal of 1.5°C* (Washington, DC: Resources for the Future, 7 April 2026), online: <rff.org/publications/reports/global-energy-outlook-2026>.

[52] Gavin Maguire, "US-driven gas turbine crunch may speed global clean power uptake", *Reuters* (3 February 2026), online: <reuters.com/markets/commodities/us-driven-gas-turbine-crunch-may-speed-global-clean-power-uptake-2026-02-03>; Bobby Noble, "5-year waits and rising costs: How demand is redefining the gas turbine market", *Utility Dive* (23 March 2026), online: <utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385>; Jared Anderson, "US gas-fired turbine wait times as much as seven years; costs up sharply", *S&P Global Commodity Insights* (20 May 2025), online: <spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

[53] Wood Mackenzie, Press Release, "Gas Turbine Prices Soar 195% as Market Faces Supply-Demand Crisis" (1 April 2026), online: <woodmac.com/press-releases/gas-turbine-prices-soar-195-as-market-faces-supply-demand-crisis>.

[54] *Supra* note 50.

[55] Mark Shenk, "Westinghouse Megadeal Set to Revitalize Nuclear Supply Chain", *Reuters* (26 January 2026), online: <reuters.com/business/energy/westinghouse-megadeal-set-revitalize-nuclear-supply-chain--reeii-2026-01-26>; "US Federal Loan to Jumpstart AP1000 Reactor Supply Chain", *World Nuclear News* (24 June 2026), online: <world-nuclear-news.org/articles/us-federal-loan-to-jumpstart-ap1000-reactor-supply-chain>.

Contingency planning will highlight the risk implications for policy makers

Sustaining the IESO's inclination towards conservative demand forecasts will likely defer decisions on new projects and technology choices, pushing Ontario farther behind in the supply chain order book, increasing future costs, and undermining the ability to secure the electricity supply options needed to sustain or achieve the province's growth objectives. Possible higher demand scenarios should be transparently developed and matched with possible supply solution scenarios with clear depiction of schedule risks and cost implications.

6. Closing – Implications for Canada's national electricity strategy

The drivers of electricity demand in Canada, from electrification to reduce emissions and from policy maker economic growth ambitions, are evident and emerging quickly. Yet the full implications of this significant demand growth are not being reflected in federal or provincial electricity system planning and initiatives. This is creating supply shortfall risks across this country as development awaits policy direction. The deferment of policy direction is delaying planning and procurement decisions beyond the timelines necessary to develop the infrastructure needed to meet anticipated demand. These risks have been illustrated through the case study on Ontario, the implications of which extend to most provinces in Canada. Quebec may stand out as an example of policies that are facing these challenges head on, reducing their risks, and may provide lessons to others.

The world is recognizing that countries with affordable reliable clean electricity will attract investment and win the economic development race.[56] Timely electricity system development is essential to the availability of the affordable and reliable electricity essential to powering Canada's economic growth. In an increasingly clean energy world, affordable and reliable clean electricity will define the country's international competitiveness.

6.1. A call to action for informed demand forecasting

To respond to these challenges, both provincial and federal governments must understand demand and supply risks to develop policies around strategic procurement alternatives and move Canadian provinces closer to the front of global supply chain queues. Given current policy makers' economic priorities, the electricity system should be planned to get ahead of demand and enable economic growth. For this, the greater demand potential such as illustrated by the *New Reference* and *High* demand scenarios identified in this article must be clearly and appropriately put forward. Overlapping federal and provincial roles in such areas as nuclear strategies and national electricity corridor agreements would benefit from policy alignment.

The lack of alignment between provincial planning and electrification and economic development objectives must be resolved. The question comes down to timing: Should electricity system planners be building the infrastructure to accommodate demand before or after it arrives? The electricity system should be used as an enabler of economic growth, not a cautionary response to events that unfold. For electricity to be an enabler, infrastructure development must accelerate to get ahead of demand and do so promptly to ensure favourable positions in supply chain order books. It is clear that the electricity system cannot grow fast enough to meet anticipated increases in electricity demand arising from electrification and industrial/economic growth aspirations. As a result, there is merit to aggressively pursuing reliable and affordable solutions now. Alternatively, conservative electricity supply planning will lead to future urgent needs to secure supply that can be built quickly, like natural gas-fired generation — which, even if possible, will come with cost, environmental, and public opinion consequences.

In order to stay ahead of demand, both federal and provincial policy makers need validated risk-informed demand scenarios with associated resource portfolio alternatives. A consensus

[56] Kamen Kraev, "Access To Electricity Will Determine Economic Success Or Failure, Says Magwood", *NucNet* (20 March 2026), online: <www.nucnet.org/news/access-to-electricity-will-determine-economic-success-or-failure-says-magwood-3-5-2026>.

around these forecasts will help identify procurement strategies to align federal roles in a national electricity strategy with provincial electricity system development priorities. A well communicated consensus will send the signals to developers and markets that will enable them to propose the medium- and long-term solutions that are needed. Such a consensus will thus enable the urgent policy decisions to accelerate site selections, project identification and investment strategies to secure Canada's energy future. ■

TAIL RISKS AND WHOLESALE ELECTRICITY PRICES

*Michele Campolieti**

ABSTRACT

I use extreme value theory and estimate a Generalized Pareto distribution for wholesale electricity prices using data from seven trading hubs in the United States. My estimates of the shape parameter indicate that the distribution of wholesale electricity prices is fat-tailed. I also explore whether the shape parameter for this distribution changes during the summer months, which are the peak months for electricity usage in the United States. My estimates suggest that for most trading hubs the shape parameter does not vary during the summer months. I also present return levels for prices, which can be viewed as the waiting time for worst-case scenarios for prices, and compare realizations of prices with them.

Keywords and Phrases: Extreme Value Theory; Generalized Pareto Distribution; Fat-tails; Electricity Prices; Return Levels.

1. INTRODUCTION

Tail risk is a term that is being used more commonly these days, with references in areas as diverse as financial markets, environmental and climatic disasters as well as public health.[1] These tail risks represent low probability events that are in the tails of a distribution. However, even though these events have a low probability of occurring they can have outsized effects and serious consequences when they do occur, e.g., large financial losses, devastating storm damage or huge mortality during a pandemic.

In financial and commodity markets these tail risks can manifest as price spikes, which represent sudden price swings. In electricity markets, storage is difficult, which means that it can be difficult to balance the market for electricity at different parts of the cycle. For example, the demand for electricity can exceed generating capacity and as there is so little electricity in storage to act as a buffer, this can lead to large price swings. Consequently, modelling the probability of these sorts of price swings is important from a risk management perspective.

Extreme value theory is one tool that can be used to assess the probability of these extreme price movements or tail risks. As noted by Cirillo and Taleb, extreme value theory emphasizes that the tails of the distribution contain more information than the values that are observed more frequently.[2] Consequently,

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[1] Nassim Nicholas Taleb, *Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications* (STEM Academic Press, 2020); Saralees Nadarajah, "Extremes of Daily Rainfall in West Central Florida"(2005) 69 Climatic Change 325; VF Pisarenko & Didier Sornette, "Characterization of the Frequency of Extreme Earthquake Events by the Generalized Pareto Distribution" (2003) 160 Pure & Applied Geophysics 2343; Pasquale Cirillo & Nassim Nicholas Taleb, "Tail Risk of Contagious Diseases" (2020) 16 Nature Physics 606; Michele Campolieti, "Tail Risks and Infectious Disease: Influenza Mortality in the U.S., 1900–2018" (2021) 6 Infectious Disease Modelling 1135.

[2] Cirillo & Taleb, *supra* note 1.

extreme value theory is a viable tool for managing the risks associated with these extreme price swings. Moreover, extreme value theory can be useful even in cases with a small number of observations.[3] This has certainly been recognized in the banking industry for risk management.[4]

I study wholesale electricity prices from several trading hubs in the United States. I apply extreme value theory to these data and estimate the distribution of wholesale electricity prices. While some earlier work using extreme value theory has considered European and Canadian electricity markets,[5] the electricity prices from the United States have not been studied using this perspective. My approach focuses on price data that exceeds a threshold to estimate a Generalized Pareto distribution with a maximum likelihood estimator.[6] Maximum likelihood proceeds by assuming a distribution for the data and creating a likelihood function that provides a complete probabilistic description of the data and then picking the parameters of the distribution to maximize the likelihood function.

In order to examine whether there is a good chance of an extreme event, in this case, wholesale electricity prices, I will consider the estimate of the "shape parameter" of the distribution of prices. The shape parameter of the distribution is quite informative as it indicates how fat the tails of the distribution are. "Fat tails" is a statistical term indicating how likely outliers, e.g., extreme events, are to occur. With a normal distribution, a thin tailed distribution, extreme events are quite rare and have a low probability of occurring. Generally speaking, extreme prices are more common in a distribution with fatter tails.

My estimates of the shape parameter are all consistent with a fat-tailed Pareto distribution.[7] Moreover, I can rule out alternative distributions that have thinner tails such as the Beta and exponential distributions.[8] I use the estimates of the distribution from each of the hubs I consider to compute the return levels, which present the likelihood that an "extreme" value is observed in the future. These return levels can be viewed as the time before observing an extreme price event for the wholesale prices to return to normal. As such, return levels are also known as the waiting time for worst-case scenarios for wholesale electricity prices in each of the trading hubs that I consider. The return levels are thus a way to quantify the tail risks in electricity prices.

Finally, I also consider how the distribution of electricity prices could differ across seasons (i.e., summer months, which are the peak months for electricity consumption in the United States, versus the other months of the year), by estimating a specification that makes the shape parameter a function of this seasonal dummy.

In the next section of the paper, I discuss the data used and provide some background on extreme value theory as well as my estimation approach. The empirical results are presented and discussed in Section 3. I present a summary

[3] *Ibid*.

[4] Basel Committee on Banking Supervision, *Enhancements to the Basel II framework* (Basel: Bank for International Settlements, 2009).

[5] WD Walls & Wei Zhang, "Using Extreme Value Theory to Model Electricity Price Risk with an Application to the Alberta Power Market" (2005) 23:5 Energy Exploration & Exploitation 375; Hans NE Byström, "Extreme Value Theory and Extremely Large Electricity Price Changes" (2005) 14:1 Intl Rev Econs & Finance 41; Kam Fong Chan & Philip Gray, «Using Extreme Value Theory to Measure Value-at-Risk for Daily Electricity Spot Prices» (2006) 22:2 Intl J Forecasting 283; F Paraschiv, R Hadzi-Mishev & D Keles, "Extreme Value Theory for Heavy Tails in Electricity Prices" (2016) 9 J Energy Markets 21; Efthymios Stathakis, Theophilos Papadimitriou & Periklis Gogas, "Forecasting Price Spikes in Electricity Markets" (2021) 13:1 Rev Econ Analysis 65.

[6] Stuart Coles, *An Introduction to Statistical Modeling of Extreme Values* (London, UK: Springer-Verlag, 2001); Samuel Kotz & Saralees Nadarajah, *Extreme Value Distributions: Theory and Applications* (London, UK: Imperial College Press, 2000).

[7] Pareto (power law) distributions are continuous distributions known for being skewed and concentrated. For example, Pareto's rule where 20 percent of households own 80 per cent of wealth can be described by a Pareto distribution. There are many applications of Pareto distributions (capturing this sort of concentration) in economics, finance and science.

[8] Beta distributions are continuous distributions for data that takes values between 0 and 1 and are often used to describe the distributions of percentages and proportions. An exponential distribution is for positive variables and is sometimes used in statistics and engineering to model waiting times.

of my estimates and their implications in Section 4.

2. DATA AND EMPIRICAL METHODS

The wholesale electricity price data used were obtained from the U.S. Energy Information Administration (EIA).[9] I focus on the daily high price for electricity contracts (price per megawatt hour (MWh)) traded for seven major trading hubs (over the counter markets) in the United States. Electricity trading on these hubs reflects purchases and sales by power stations, utilities, chemical and transportation companies, financial institutions, hedge funds, as well as other energy market participants. The trading hubs, as well as their respective regions, considered are: the MASS hub (the New England region); the PJM hub (Pennsylvania, New Jersey, Maryland, Ohio and parts of Tennessee); the INDIANA hub (Midwestern states); the MID-COLUMBIA hub (states in the Pacific Northwest); the PALO VERDE hub (the southwestern states); the NP15 hub (Northern California); and, the SP15 hub (Southern California).[10] The availability of the data varies by hub, with some hubs having data as far back as 2001 (e.g., MASS and PJM) and others beginning later (e.g., 2006 for the INDIANA and 2009 for NP15 hubs).

I present some descriptive statistics for the price data in Table 1. As can be seen in Table 1 the mean price is greater than the median price, which suggests that the distribution of maximum daily prices is skewed to the right in all the hubs I consider. The skewness coefficients indicate that the skewness in the price data varies a great deal across hubs. There is also a great deal of dispersion in the electricity price data, as indicated by the standard deviation of the price, and this also varies a great deal by hub. Finally, the kurtosis measures for the price data are quite large. Recall that a normal distribution has a kurtosis measure of 3, which suggests that the price data from these trading hubs have quite thick tails and therefore may be prone to extreme, low probability events.

Let $x_1, \ldots, x_N$ be independently and randomly distributed random variables from an unknown distribution function F(x). As shown in Coles,[11] and elsewhere, the distribution of the values of x that exceed a threshold u is defined by

$$F_u\left(\epsilon\right) \;=\; Prob\left[x > u + \epsilon | x > u\right] = F\frac{(\epsilon + u - F(u)}{1 - F(u)}, \quad (1)$$

If the threshold level $F_u(\epsilon)$ is sufficiently large then the distribution can be approximated by a Generalized Pareto distribution, which has cumulative distribution function

$$G\left(x\right) = 1 - \left[1 + \xi\left(\frac{x-u}{\sigma_u}\right)\right]^{-\frac{1}{\xi}}, \quad (2)$$

where u is a threshold, $x > u$, σ_u is a scale parameter, which depends on the threshold u and determines the dispersion or spread in the distribution, and is such that $\sigma_u > 0$ and ξ is a shape parameter. In addition, the Generalized Pareto distribution has an infinite mean if $\xi > 1$ and infinite variance if $\xi > ½$. The shape parameter, ξ, is also key for determining the nature of the tails of the distribution. In particular, when $\xi > 0$ the distribution is fat-tailed (i.e., a Pareto). In contrast, the thinner tailed Beta and exponential distribution result when $\xi < 0$ and $\xi \to 0$, respectively. I obtain my estimates using a maximum likelihood estimator.

The estimates of the parameters of the Generalized Pareto distribution can also be used to compute the return level x_m, i.e., a level that is exceeded once every m^{th} year,

$$x_m = u + \frac{\sigma_u}{\xi}\left[(m \times Prob[x > u])^{\xi} - 1\right], \quad (3)$$

where m is large enough so that $x_m > u$ and the notation is as defined earlier. The return levels provide some indication of the likelihood of spikes in the price of electricity that exceed the threshold level in the future. The return levels are thus useful and important from a risk management perspective, as they provide an indication of the sorts of price spikes in wholesale electricity prices we could observe in the future.

[9] The data are available from the U.S. Energy Information Administration (EIA) and are provided to the EIA by the Intercontinental Exchange (ICE). See US Energy Information Administration, "Wholesale Electricity and Natural Gas Market Data" (last modified 28 August 2026), online: <eia.gov/electricity/wholesale>.

[10] I exclude data from the ERCOT hub, which covers Texas, as the data have not been updated since 2019 (the last year of data recorded in this hub).

[11] Coles, *supra* note 6.

I also explored whether the shape parameter might vary by season. In particular, I estimated a model that makes the shape parameter a function of an intercept and an indicator variable that takes the value 1 for a summer month (which I defined as June, July and August) and 0 otherwise. This alternative specification means that the shape parameter of the distribution for electricity will vary by season instead of being constant across all seasons. In the United States, the summer tends to be the peak season for electricity usage. Consequently, this specification sheds light on whether the distribution varies by the peak season. For example, do distributions of electricity prices have heavier tails during the summer months or is the distribution constant across seasons? If the coefficient estimate on the indicator for a summer month is not statistically different from zero, this suggests that the shape parameter of the distribution for electricity prices does not vary across seasons.

The value of the threshold in equations (1) and (2) is not known and must be determined based on the data. As with most things in statistics, there is a bit of a trade-off when selecting the threshold. One needs to pick a threshold that is large enough to satisfy the theory underlying equation (1), but doing so can result in small samples that can create imprecise estimates and suffer from small sample biases. There are a few approaches for selecting the value of the threshold. On the one hand, "the eyeball method" where one examines plots of the residuals (mean residual life plot)[12] to determine where the plot exhibits linearity, with the threshold being the point at which linearity appears in the plot. On the other hand, the Hill approach where the threshold is estimated using the Hill estimator.[13] I focus on using the Hill estimator to select the threshold, but my selections for the threshold using the eyeball method tend to be similar to those picked by the Hill estimator for most of the hubs I consider. I present these threshold values in Table 2. Table 2 also presents the number of observations that exceed the threshold value selected by the Hill estimator. As can be seen in Table 2, the number of observations above the thresholds selected by the Hill estimator tends to vary across hubs with the largest samples of observations above the thresholds in the MASS (Massachusetts), Mid-Columbia and Palo Verde hubs.

I obtain my maximum likelihood estimates of the Generalized Pareto distribution using the R package extRemes.[14]

3. EMPIRICAL RESULTS

I present estimates of the scale and shape parameters of the Generalized Pareto distribution for wholesale electricity price for each trading hub and use these estimates to compute the return levels. I divide my data on prices into a training and a test sample, where the test sample contains the last year of data available for each of the trading hubs. I fit the models with the training data and use these estimates to compute the return levels. I compare the return levels with the test data to assess how frequently realizations of prices appear in the confidence intervals of the return levels.

The estimates of the parameters of the Generalized Pareto distribution by trading hub are presented in Table 3. The estimates in Table 3 show that the shape parameter estimates for each of the trading hubs are all positive and have confidence intervals that do not cross zero. This indicates that the distributions of electricity prices are all consistent with the Pareto distribution. In addition, I can also rule out thinner tailed alternatives like the exponential and Beta distributions. The shape parameter estimates indicate that the distribution for electricity prices would have finite mean and variance in all but one of the hubs I consider. The shape parameter estimate for the SP15 hub is greater than 0.5, which indicates that the variance for the distribution of electricity prices from this hub is infinite. An infinite variance suggests that extreme price movements are much more likely to be observed.

[12] Coles, *supra* note 6; Eric Gilleland & Richard W Katz, «extRemes 2.0: An Extreme Value Analysis Package in R" (2016) 72:8 J Statistical Software 1, DOI: <10.18637/jss.v072.i08>.

[13] The Hill estimator can be computed as $\left(\frac{1}{k(n)}\sum_{i=n-k(n)+1}^{n}(ln(X_{i,n}) - ln(X_{n-k(n)+1,n}))\right)^{-1}$, where $X_{i,n}$ is the i-th order statistic of $X_1, \ldots, X_n$, $k(n)\epsilon\{1, \ldots, n-1\}$.

[14] Gilleland & Katz, *supra* note 12.

The return levels for each of the hubs, which are based on the estimates in Table 3 for the training data, are presented in Figure 1 with 95 per cent confidence intervals. As discussed earlier, I also took the last year of data available and saved it as "test" data, and determined how the maximum price in the test data compares with the return levels computed using the training data. This is a validation exercise where I examine how well the return levels coincide with extreme prices out-of-sample. In the Mid-Columbia and Palo Verde hubs the maximum price in the test data exceeded all the return levels plotted in Figure 1 for these hubs. The maximum high price during the test period for the MASS, NP15 and SP15 hubs ($290, $367.95 and $395/MWh) are all contained within the confidence intervals at various horizons presented for the return levels. For the remaining hubs (Indiana and Mid-Columbia), the maximum price during the test period is not contained in the confidence intervals for any of the return levels plotted in Figure 1. This suggests that the out-of-sample validation in some of the hubs is not as strong as in some of the others.

Finally, I present the estimates of the Generalized Pareto distribution where the shape parameter is specified as a function of an intercept and an indicator for the summer months. These estimates are presented in Table 4. Overall, most of the estimates in Table 4 indicate that the summer dummy does not have statistically significant estimates, which suggests that the distribution of electricity prices does not vary across seasons for the trading hubs. However, I did find statistically significant estimates on the summer dummy in two hubs. First, the summer dummy has a negative estimate that is statistically significant at the 5 percent level of significance for the Massachusetts hub.[15] While the estimate is negative, the estimates of the slope and intercept for the Massachusetts hub indicate that the distribution of electricity prices would still be a fat-tailed Pareto distribution, although the shape parameter would be smaller during the summer. Second, the Palo Verde hub, which covers the hot and arid U.S. southwest, has a positive estimate on the summer dummy that is statistically significant at the 10 per cent level of significance. This suggests that the distribution of electricity prices in this hub has a bigger shape parameter during the summer months. As discussed earlier, the shape parameter presented in Table 3 for the Palo Verde hub exceeds 0.5, so the distribution of electricity prices during the summer months is still consistent with a distribution with infinite variance.

The relative homogeneity of the distribution for electricity prices in most of the trading hubs is noteworthy, as the demand for electricity tends to be greatest during the summer in the United States. While the demand for electricity does peak during the summer, this seasonal change does not affect the tails of the distribution for electricity prices in most of the trading hubs. This differs somewhat from the findings in Walls and Zhang for electricity prices in the Canadian province of Alberta.[16] Walls and Zhang divided their data into summer and winter months and estimated generalized Pareto distributions for these two periods.[17] While the distribution for both the summer and winter months are fat-tailed, the estimated shape parameter of the distribution during the summer months differs a great deal from the estimates for the winter months. While I use U.S. data in my analysis there are some implications for Canada. The energy-wholesale market in Alberta may increase the possibility of extreme price events if demand spikes during peak periods. Consequently, one would expect larger estimates of the shape parameter for the Generalized Pareto distribution. For example, Walls and Zhang do obtain larger shape parameter estimates for Alberta than those I present, which is consistent with a distribution of wholesale electricity prices that may be more prone to extreme price movements.[18] In other provinces, without organized wholesale markets, the implications are more difficult to ascertain via price movements, but the consequences of spikes in demand will manifest via other means.

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[15] The Massachusetts differs from the other U.S. hubs in that peak use is in the winter months. This is consistent with the negative estimate on the indicator for summer months I obtain.

[16] Walls & Zhang, *supra* note 5.

[17] *Ibid*. Walls and Zhang defined the winter months as October to May and the summer months as June to September.

[18] *Ibid*.

4. DISCUSSION AND CONCLUDING REMARKS

I apply extreme value theory to wholesale electricity prices from several trading hubs in the United States. I use electricity prices that exceed a threshold to estimate a Generalized Pareto distribution with maximum likelihood. I find that the distribution is fat-tailed and I can rule out thinner tailed alternatives, such as the exponential and Beta distributions. Moreover, I also find that the shape parameter of the distribution does not vary during the summer months in most of the trading hubs, which suggests that the thickness of the tails of the distribution of wholesale electricity prices is not likely to change during the summer months of peak electricity usage. This is a somewhat surprising result as demand for electricity tends to increase during the summer. If the shape parameter did become larger during the summer months, that would suggest that the distribution would be fatter-tailed during the summer and extreme price movements are more likely relative to the other seasons. Finally, I also present the return levels for electricity prices in each of these hubs. Not surprisingly, the return levels vary considerably across hubs, which suggests that risk management for price surges should be based on data for a particular hub.

Table 1: Descriptive Statistics for Daily High Price of Electricity (MWh)[19]

Hub	Total number of observations	Sample Period	Mean	Median	Standard Deviation	Skewness	Kurtosis
INDIANA	2937	2006–2023	46.6	39.5	20.19	3.5	24.77
MASS	5487	2001–2023	56.86	48.25	34.56	3.39	22.11
MID-COLUMBIA	5581	2001–2023	46.59	38	46.14	10.27	183.78
NP15	1894	2009–2023	47.74	40	32.35	5.64	43.59
PALO VERDE	5609	2001–2023	51.04	40.5	61.15	16.19	394
PJM WEST	5801	2001–2023	51.69	44	30.14	4.89	50.22
SP15	3409	2009–2023	47.78	39	39.38	6.46	59.15

Notes: price reported is for megawatt hour (MWh) for maximum daily price. Total number of observations is for all observations during the sample period listed.

Table 2: Threshold Values

Trading Hub	Hill Estimator threshold	Number of observations above Hill threshold	Eyeball method threshold
INDIANA	62	463	60
MASS	63	1704	60
MID-COLUMBIA	53.75	1407	50
NP15	54.55	308	50
PALO VERDE	48	2023	50
PJM WEST	80	661	50
SP15	55.25	582	45

Notes: Threshold value is price per megawatt hour (MWh); Number of observations above the threshold selected by the Hill estimator is presented above. To implement the eyeball method, I examine the mean residual life plot and pick the threshold level to be the point (vicinity) where the plot begins to exhibit linearity.

[19] Descriptive Statistics for Daily High Price of Electricity (MWh), by Trading Hub. Author's calculations based on US Energy Information Administration, *supra* note 9.

Table 3: Estimates of the Generalized Pareto Distribution for Wholesale Electricity Price by Trading Hub, using the training data

Trading Hub (training data sample period)	Scale Parameter (σ_u)	Shape Parameter (ξ)	Log-likelihood	Number of observations above threshold
INDIANA (2006–2022)	14.80*** (1.008)	0.241*** (0.056)	-1778.21	463
MASS (2001–2022)	22.36*** (0.886)	0.272*** (0.032)	-7222.47	1704
MID-COLUMBIA (2001–2022)	17.40*** (0.818)	0.465*** (0.040)	-5219.86	1407
NP15 (2009–2022)	22.873*** (2.815)	0.472*** (0.103)	-1119.39	308
PALO VERDE (2001–2022)	18.13*** (0.666)	0.430*** (0.030)	-7897.94	2023
PJM WEST (2001–2022)	24.294*** (1.429)	0.254*** (0.045)	-2849.05	661
SP15 (2009–2022)	22.832*** (1.799)	0.532*** (0.069)	-2246.18	582

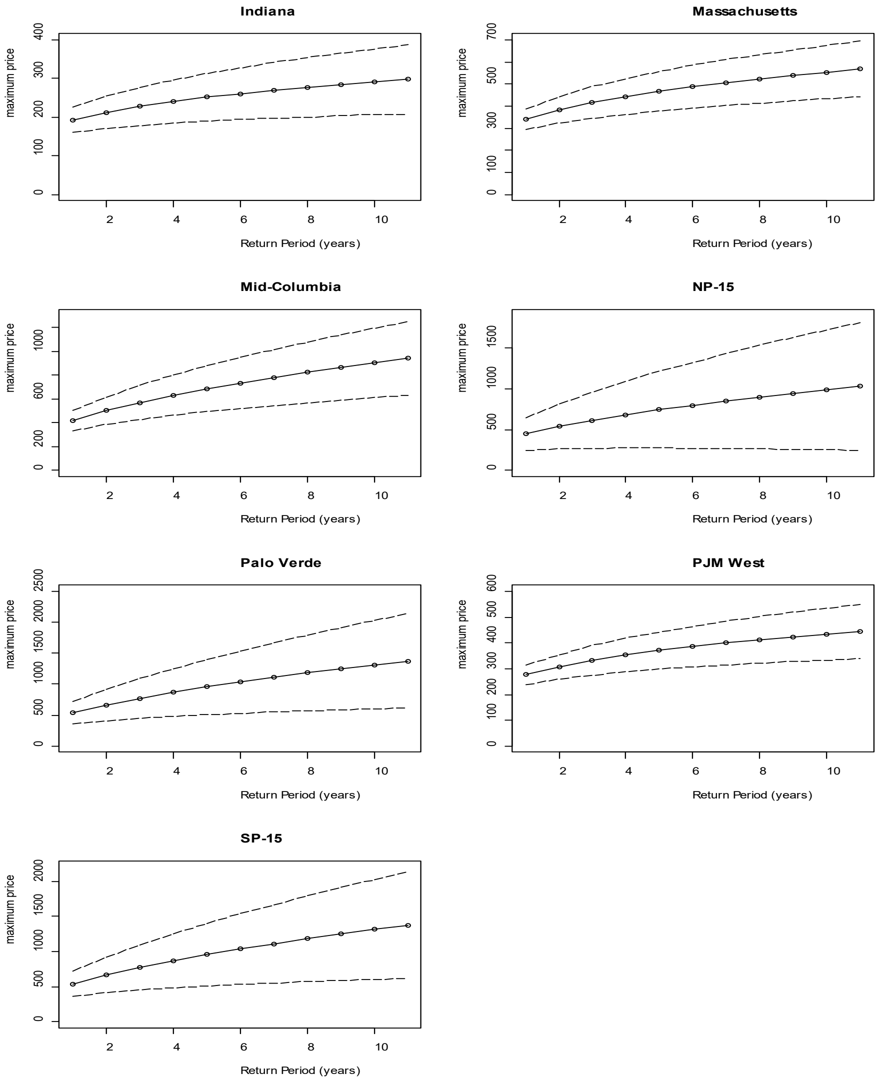
Notes: Standard errors in parentheses. *** denotes statistical significance at the 1 percent level; ** denotes statistical significance at the 5 percent level. The estimates are based on the training data, which excludes the last year of data I have available, and are indicated in parentheses in the first column of the table.

Table 4: Estimates of the Generalized Pareto Distribution for Wholesale Electricity Price by Trading Hub, shape parameter a function of a summer dummy, using the training data

		Shape Parameter (ξ)			
Hub (training data sample period)	**Scale Parameter (σ_u)**	**Intercept**	**Summer Dummy**	**Log-likelihood**	**Number of observations above threshold**
INDIANA (2006–2022)	14.675*** (1.080)	0.213*** (0.059)	0.097 (0.098)	-1777.69	463
MASS (2001–2022)	22.60*** (0.888)	0.296*** (0.035)	-0.135** (0.053)	-6220.82	1704
MID-COLUMBIA (2001–2022)	20.12*** (0.885)	0.408*** (0.041)	0.087 (0.068)	-6220.82	1407
NP15 (2009–2022)	25.144*** (2.524)	0.376*** (0.092)	0.080 (0.140)	-1423.16	308
PALO VERDE (2001–2022)	19.42*** (0.734)	0.400*** (0.035)	0.102* (0.055)	-7903.11	2023
PJM WEST (2001–2022)	24.344*** (1.484)	0.257*** (0.050)	-0.010 (0.078)	-2849.04	661
SP15 (2009–2022)	24.743*** (1.801)	0.462*** (0.071)	0.067 (0.106)	-2725.59	582

Notes: Standard errors in parentheses. *** denotes statistical significance at the 1 percent level; ** denotes statistical significance at the 5 percent level; * denotes statistical significance at the 10 percent level. The estimates are based on the training data, which excludes the last year of data I have available, and are indicated in parentheses in the first column of the table.

Figure 1: Return Level Plots by Trading Hub for Wholesale Electricity Price



Notes: Dashed line denotes 95 percent confidence bounds.