# ENERGY REGULATION QUARTERLY

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## MISSION STATEMENT

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

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

## EDITORIAL POLICY

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

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

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

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

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

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

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# EDITORIAL

Managing Editors

*Rowland Harrison K.C. and Gordon E. Kaiser*

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The first section in this issue of the *Energy Regulation Quarterly* (*ERQ*) starts with a snapshot of pipeline developments, the benchmark of Canadian energy markets. The Enbridge Line 3 has been completed. The others are still moving forward but are behind schedule with significant cost overruns. The government of Canada has announced it will not provide any further public funding for the Trans Mountain Expansion because the cost has increased 70 per cent to $ 21.4 billion. At the same time TC Energy Corporation announced that the Coastal GasLink pipeline cost has increased from $ 6.6 billion to $ 11.2 billion.

The next section of the annual review covers the key regulatory decisions. It starts with Canadas first decision on EV charging rates. The British Columbia Utility Commission turned down the rates proposed by BC Hydro because the rates did not include all the relevant costs and would likely contribute to an un-even playing field.[1]

Next came the first decision by a Canadian energy regulator started by a whistleblower claim[2]. There the Alberta Commission found that ATCO Electric had charged ratepayers for the costs of a contract it had entered into at $10 million above fair market price to benefit the utilities' unregulated affiliate. To make matters worse the utility took steps to conceal the facts from the Commission. The Commission charged that the utility had breached its duty to disclose all relevant information to the regulator. This is another first in Canadian energy regulation. After a lengthy investigation the company agreed to pay a fine of $31 million, the highest fine awarded by a Canadian energy regulator to date.

The next decision reported on was another first. The Nova Scotia Commission approved an investment by a utility in a new technology called the tidal generation. It turned out not to be successful. The utility then asked the Commission to allow it to write off the costs. The Commission refused because there was insufficient evidence to determine whether the investment was still useful.[3] This will become the next challenge for Canadian energy regulators. We have seen a number of decisions where regulators struggle with investments in new technology. This is the first one dealing with technology write offs. It will not be the last.

Another significant and unique decision from the Alberta is the decision in *Calgary District Heating*[4] (CDH) that reinforced the concept of complaint-based regulation. Here the Alberta Commission decided not to regulate the rates of CDH because district energy services in the City of Calgary were competitive. In complaint-based regulation the utility has the right to set rates without the regulator's approval but in the event of a complaint the regulator can consider if the rates are just and reasonable and set new rates on a retroactive basis if necessary. To date this form of regulation is rare but other jurisdiction may follow particularly in district energy applications.

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[1] *Re British Columbia Hydro and Power Authority Public Electric Vehicle (EV) Fast Charging Rate Application Decision and Final Order* (26 January 2022), G-18-2022, online: British Columbia Utilities Commission <www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/520273/index.do>.

[2] *Re Allegations against ATCO Electric Ltd.* (29 June 2022), 27013-D01-2022, online: Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/719764>.

[3] *Nova Scotia Power Incorporated (Re)*, 2022 NSUARB 2, online: Nova Scotia Utility and Review Board <www.canlii.org/en/ns/nsuarb/doc/2022/2022nsuarb2/2022nsuarb2.html?autocompleteStr=2022%20NSUARB%202&autocompletePos=1>.

[4] *Re Calgary District Heating Inc.* (2 March 2022), 26717-D01-2022, online: Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/713215>.

Next came the decision of the Alberta Commission to substantially amend its Rules of Practice.[5] It started with the Commission appointing an independent panel composed of Kem Yates, David Mullan and Rowland Harrison all of whom have very substantial experience in Canadian energy regulation.

That panel issued a report containing 30 recommendations of which 29 were accepted. The Alberta Commission recently reported that the recommendations have substantially improved its processing of complicated rate cases.

The AUC is now averaging 7.4 months between the application date and the date of the decision, an improvement of 41 per cent. Other Canadian energy regulators will no doubt review the amended Rules of Practice with some care

The last section of the annual review deals with regulatory decisions in the courts. It starts out with the Alberta Court of Appeal decision regarding the constitutionality of the Federal *Impact Assessment Act*.[6] That decision has been reported on in these pages earlier and does not require further analysis except to say that the majority found the legislation not constitutional. The Alberta government called it the "no pipelines Act" and the federal government promised to appeal it to the Supreme Court of Canada.

Many of the Court decisions in the annual review relate to questions of jurisdiction. There were six decisions that fell within that category. This was the same number of decisions that fell within that category the previous year. *Waterloo Hotel*[7] raised a rare but important issue — did the Ontario Energy Board have exclusive jurisdiction of the question before it? The court found that it did. Not all provinces have this provision in their statute but it is certainly an important one in Ontario.

The next jurisdiction case was a decision of the Ontario Superior Court of Justice in *West Whitby Landowners*[8] where the court held that the Board does not need to hold a hearing every time someone requests it. The Ontario Energy Board also made an important decision in *Waterfront Toronto*[9] where Enbridge asked the Board to order Waterfront Toronto to pay $70 million to cover the cost of a new pipeline. Waterfront Toronto claimed that the Board had no jurisdiction to order Waterfront to pay anything because it was not a gas customer. The Board agreed.

There were a number of decisions last year regarding aboriginal property rights. The decision of the BC Supreme Court in *Blueberry River First Nation*[10] (BRFN) found that new construction projects should be put on hold where the province had authorized a number of industrial developments that the BRFN had opposed over many decades. This was the first Canadian decision to consider whether the cumulative effects of previous development can amount to an unjustified infringement of treaty rights.

The next decision of note is the Alberta Court of Appeal decision in *AltaLink Management*[11] where the court emphasized that in determining whether or not a project is in the public interest, the regulator must consider the opportunities and benefits the project offers First Nations.

The next section of this issue of the *ERQ* is an article by Monica Gattinger and David Morton. Morton is the Chair and CEO of the British Columbia Utilities Commission. Gattinger is the Director of the Institute for Science, Society and Policy at the School of Political Studies and Chair of Positive Energy at the University of Ottawa. This is an important article because it

[5] C. Kemm Yates, David J. Mullan & Rowland J. Harrison, "Report of the AUC Procedures and Processes Review Committee" (14 August 2020), online (pdf): <media.www.auc.ab.ca/prd-wp-uploads/2021/12/2020-10-22-AUCReviewCommitteeReport-1.pdf>.

[6] SC 2019, c 28, s 1.

[7] *Vista Waterloo Hotel Inc. v 1426398 Ontario Inc., & Ontario Energy Board*, 2021 ONSC 2724.

[8] *West Whitby Landowners v Elixicon Energy*, 2022 ONSC 1035.

[9] *Re Enbridge Gas Inc.* (7 July 2022), EB-2022-0003, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/750562/File/document>.

[10] *Yahey v British Columbia*, 2021 BCSC 1287.

[11] *AltaLink Management Ltd v Alberta (Utilities Commission)*, 2021 ABCA 342.

lays out the challenges that energy regulators in Canada will face over the next five years. The authors refer to it as a massive disruption.

The issue is how will Canadian regulators handle massive investment that we are about to see as governments attempt to decarbonize the electricity grid across Canada. The authors note that they will face great uncertainty. The main issue to put it simply is who is going to call the shots. Will the regulators have a passive role and take instruction from the government or will they lead the charge. The answer the authors suggest is a bit of both.

The authors explain that the challenge comes from two factors. The first is the money. The second is the technology. Money matters because of the amount. Trillions of dollars. To a regulator that is called rate base expansion. That raises another question that always troubles regulators-who pays? In the case of the technology the problem is simple. The big question on everyone's mind is will the technology succeed? And how do you write it off when it fails?

The article is quick to point out that there is another new important social goal on the regulatory scene That is the concept of reconciliation. This issue of the *ERQ* surveys those decisions. The recent decisions have clearly broadened the scope of issues that regulators must now consider. It is no longer simply a question of making sure that there was adequate consultation. The concept of reconciliation goes well beyond that. The courts have been very clear. In making decisions with respect to what is in the public interest, regulators must now consider the impact on aboriginal parties. In fact, it is now at the top of the list.

This article does not come up with any easy answers, but it does a very good job of laying out the questions. That is a good place to start.

Another addition to this issue of the *ERQ* is a book review of a recent book by Scott Hempling. Hempling has written a number of articles for this journal and more than once we have reviewed one of his books. This latest book is an important contribution to the literature on energy regulation. It is a detailed study of mergers and acquisitions in the United States. Hempling is very critical of the policy of the Federal Energy Regulatory Commission over many years with respect to the approval of mergers and acquisition within the United States electric utility industry. He is of the view that the Commission has been more than generous. He claims than they should not have relied on a strange reverse onus test called the no harm test.

That benchmark test was that mergers should be approved if the applicant can show that they would result in no harm. This no harm test was adopted in Canada where it has been used for many years. For that reason, Canadian lawyers and regulators will have more than a passing interest in this book. It is highly recommended.

One of the things that the editors of the *ERQ* do from time to time is that we republish reports that analyse important areas of regulatory practice. The general practice is to provide an editor's introduction. We include two such reports in this issue. The first report was prepared by a consulting company called Guidehouse that was retained by both the American Gas Association and the Canadian Gas Association.

The report addresses a very important question facing gas utilities in North America today. That question is simply this. What is the future of natural gas utilities from an investor's viewpoint given the very substantial investments taking place in both Canada and the United States to reduce carbon emissions? This report does a good job of surveying the investment community particularly the United States. Not surprisingly one of the major findings is that gas utilities should pay attention to ways in which they can decarbonize their product. At least in Canada there is strong evidence that companies are doing just that. Recent initiatives by Enbridge in Ontario and Fortis in British Columbia are good evidence. The report is worth reading.

A final report appears in this issue of the *ERQ*. It's a report by Michael Cleland and Monica Gattinger called Next Zero an International Review of Energy Delivery System Policy and Regulation for Canadian Energy Decision Makers. ■

# CANADIAN ENERGY REGULATION: THE ANNUAL REVIEW

*Gordon E. Kaiser*

## THE PIPELINES

In the last five years investors have walked from four major pipeline projects in Canada. The four projects were the TransCanada Energy East pipeline, the Enbridge Northern Gateway pipeline, the Kinder Morgan Trans Mountain Expansion and Keystone XL. In total, they accounted for over $60 billion in investment. Three projects are still moving forward. They are the Trans Mountain Expansion project (TMX), Coastal GasLink, and Enbridge Line 5. Enbridge Line 3 has been completed.

### The Trans Mountain Expansion

In 2018, the federal government purchased the Trans Mountain Expansion from Kinder Morgan for $4.5 billion.[1] On February 22, 2019, the NEB released its reconsideration report on the project, recommending again that it proceed.[2] The federal cabinet accepted that recommendation and approved the project.[3] Construction of the project officially began on December 3, 2019.[4] Shortly thereafter, on January 16, 2020, the Supreme Court of Canada unanimously dismissed the attempt by British Columbia to claim jurisdiction over this project[5] upholding an earlier decision by the British Columbia Court of Appeal.[6]

On February 4, 2020, a unanimous Federal Court of Appeal dismissed a serious legal challenge to the project.[7] Six Indigenous communities challenged whether the Government of Canada had adequately fulfilled its duty to consult with Indigenous peoples in approving the TMX. The court made it clear that the government's duty to consult Indigenous peoples did not provide them with a veto over projects such as this one[8] and that courts should defer to the governments that make the initial decision on whether the duty to consult has been met.[9] Three Indigenous groups appealed the Federal Court of Appeal's decision.

In May 2020, the Province of British Columbia issued an amended EAC in response to the

[1] Canada Energy Regulator, "Trans Mountain Pipeline System Purchase Agreement FAQs" (last modified 29 September 2020), online: <www.cer-rec.gc.ca/en/applications-hearings/view-applications-projects/trans-mountain-expansion/trans-mountain-pipeline-system-purchase-agreement-faqs.html>.

[2] Canada Energy Regulator, News Release, "NEB releases Reconsideration report for Trans Mountain Expansion Project" (22 February 2019), online: <www.cer-rec.gc.ca/en/about/news-room/news-releases/2019/neb-releases-reconsideration-report-trans-mountain-expansion-project.html>.

[3] *Certificate of Public Convenience and Necessity OC-65 to Trans Mountain Pipeline ULC in respect of the Trans Mountain Expansion Project Pipeline*, PC 2019-820, (2019) C Gaz I, Supplement.

[4] Trans Mountain, "Trans Mountain Marks the Start of Pipeline Construction" (3 December 2019), online: <www.transmountain.com/news/2019/trans-mountain-marks-the-start-of-pipeline-construction>.

[5] Reference re *Environmental Management Act*, 2020 SCC 1.

[6] *Reference re Environmental Management Act (British Columbia)*, 2019 BCCA 181.

[7] *Coldwater First Nation v Canada (Attorney General)*, 2020 FCA 34 [*Coldwater*].

[8] *Ibid* at para 55.

[9] *Ibid* at para 83.

British Columbia Court of Appeal's decision in September 2019.[10] In July 2020, the Supreme Court of Canada denied leave to the three First Nations seeking to appeal the Federal Court of Appeal's February 2020 decision.[11] The most recent decision by the Supreme Court of Canada to deny leave to appeal to the three indigenous groups means there are no more outstanding legal challenges to the project.[12]

In February 2022 the government of Canada announced that it will not provide any further public funding for the Trans Mountain Expansion because the cost has increased 70 per centto $ 21.4 billion.[13] In 2018 when the Canadian government bought the pipeline for $ 4.5 billion the cost was estimated at $ 4.5 billion. On completion the Trans Mountain Expansion will nearly triple the capacity of the pipeline shipping 890,000 barrels per day to the Pacific Coast for export

**Coastal GasLink**

The Coastal GasLink pipeline project is owned and operated by TC Energy. The $6.6 billion project starts near Dawson Creek and will run 420 miles southwest to a liquefaction plant near Kitimat. The pipeline goes through the traditional territories of several First Nations. It has long been opposed by multiple hereditary chiefs, although a number of First Nations groups support the project and have an ownership interest. In December 2018, the Supreme Court of British Columbia granted an injunction preventing blockades of the pipeline.[14]

In July 2019, the NEB released its decision that the pipeline — including the export terminal in Kitimat — was under provincial, and not federal, jurisdiction.[15] The NEB concluded that the pipeline would transport natural gas within British Columbia, although it would also facilitate international exports, providing some clarity to the earlier Supreme Court of Canada decision in *West Coast Energy*[16] on provinces' rights to control works and undertakings within their boundaries.

In December 2019, the Alberta Investment Management Corp., the Alberta public pension manager, teamed up with one of the largest American investment companies to acquire a majority stake in the Coastal GasLink project.

In February 2022 TC Energy Corp. announced that the Coastal GasLink pipeline will go significantly over budget and will not meet the expected completion date.[17] In July 2022 the company reported that the price tag had increased from $6.6 billion to $11.2 billion.[18] The pipeline is currently 70 per cent complete. When completed the project will move 2.1 billion cubic feet per day (bcf/d) of natural gas to LNG's Canada's terminal at Kitimat BC where it will be converted into a liquefied state for export to global markets

TC Energy Corp. did say however that it expects the pipeline to be finished ahead of

[10] British Columbia, Ministry of Environment, "Trans Mountain Expansion project granted environmental assessment approval" (11 January 2017), online: <news.gov.bc.ca/releases/2017ENV0001-000047>.

[11] *Coldwater*, *supra* note 7, leave to appeal to SCC refused, 39111 (2 July 2020).

[12] *Ibid*.

[13] Department of Finance Canada, News Release, "Government Announces Next Steps on Trans Mountain Expansion Project" (18 February 2022), online: <www.canada.ca/en/department-finance/news/2022/02/government-announces-next-steps-on-trans-mountain-expansion-project.html>; See also TransMountain, "Trans Mountain Corporation Updates Expansion Project Cost and Schedule" (18 February 2022), online: <www.transmountain.com/news/2022/trans-mountain-corporation-updates-expansion-project-cost-and-schedule>.

[14] *Coastal GasLink Pipeline Ltd. v Huson*, 2018 BCSC 2343.

[15] *Re Jurisdiction over Coastal GasLink Pipeline Project* (26 July 2019), MH-053-2018, online: National Energy Board <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90550/90715/3615343/3715570/3809973/C00715-1_NEB_%E2%80%93_Letter_Decision_%E2%80%93_Coastal_GasLink_%E2%80%93_MH-053-2018_-_A6W4A5.pdf?nodeid=3809655&vernum=-2>.

[16] *Westcoast Energy Inc. v Canada (National Energy Board)*, [1998] 1 SCR 322, 156 DLR (4th) 456.

[17] TC Energy, "TC Energy generates strong results in 2021 while progressing energy transition initiatives" (15 February 2022), online: <www.tcenergy.com/announcements/2022-02-15-tc-energy-generates-strong-results-in-2021-while-progressing-energy-transition-initiatives/>.

[18] TC Energy, "TC Energy reports solid second quarter 2022 results" (28 July 2022), online: <www.tcenergy.com/announcements/2022-07-28-tc-energy-reports-solid-second-quarter-2022-results/>.

the LNG Canada's export terminal currently under construction. TC Energy has agreed to provide $ 3.3 billion in additional temporary bridge financing to cover the cost overruns. The $40 billion LNG Canada export terminal at Kitimat is now more than 50 per cent fully complete. LNG Canada is a joint venture of the subsidiaries of Royal Dutch Shell, Petronas, PetroChina Co. Mitsubishi Corporation and Korea Gas Corporation.

**Enbridge Line 3**

The Enbridge Line 3 which runs from Hardisty, Alberta to Superior, Wisconsin, has been operating since 1968. Over the years it became clear that parts of the pipeline had to be replaced if Enbridge wished to restore it to its historical capacity and move 800,000 barrels per day. The necessary authorization was obtained from regulatory bodies in Canada,[19] North Dakota, and Wisconsin. However, the $3 billion project ran into problems in Minnesota where environmentalists and native groups opposed the project.

In June 2018 the Minnesota Public Utilities Commission (Minnesota Commission) approved the route and granted the necessary permits.[20] However, a year later that decision was overturned by the Minnesota Court of Appeals, when it found that the environmental impact statement placed before the Minnesota Commission was inadequate.[21] In February 2020 the Minnesota regulators approved a revised environmental review, thus removing the last regulatory hurdle for the project.

The US portion of the Line 3 project involved replacing 364 miles of pipeline. Most of the work was in Minnesota with 27 miles located in North Dakota and Wisconsin. The replacement project is connected to an existing 1097-mile crude oil pipeline installed in the 1960s that runs from central Canada to Wisconsin.

The capital cost of the Line 3 replacement project, including the Canadian segment already in service, has cost $9.3 billion compared to the original estimate of $8.2 billion. The Enbridge Line 3 is one of the few successful projects in recent years. When it came into service in October 2021 the project added 370,000 additional barrels per day of crude oil export capacity from Western Canada to refineries in the US Midwest.

**Enbridge Line 5**

Enbridge is also replacing Line 5 which runs from Superior, Wisconsin to Sarnia, Ontario. The state of Michigan is opposing the underwater segment which runs under the Straits of Mackinac in the Great Lakes. The concern relates to environmental damage that could result from a leak in the pipe that currently sits on the lakebed. The project was approved by the former governor of Michigan but his successor, Gov. Whitmer, challenged the constitutional validity of the project in 2018.

The Michigan District Court ruled the legislation constitutional in October 2019 and that decision was upheld by the Michigan Court of Appeals in January 2020. In January 2021 the Governor of Michigan ordered Enbridge to cease operating the segment the pipeline under the Straits of Mackinac by May 2021. Enbridge argues that the 645-mile pipeline has been operating safely for 65 years. However, to address the concerns, Enbridge is now proposing to place the pipe in a tunnel underneath the lake bed at a cost of $500 million.

Line 5 part is part of the Enbridge mainline system that transports crude from Alberta and Saskatchewan to refineries in Michigan, Ohio, Pennsylvania, Ontario, and Québec. Enbridge has argued that those refineries will see their capacity drop by 45 per cent if Line 5 it is not maintained. On. January 29, 2021, the Michigan Department of Environment Great Lakes and Energy (EDLE) approved the Enbridge application for the permits required to build the utility tunnel under the Straits of Mackinac.

The November 2020 decision by Governor Whitmer of Michigan to revoke the 1953 easement has led to lengthy litigation, first in

[19] Canada Energy Regulator, "Project Information" (last modified 29 September 2020), online: < www.cer-rec.gc.ca/en/applications-hearings/view-applications-projects/line-3-replacement/project-information.html>.

[20] Minnesota Public Utilities Commission, "Line 3 Review Process", online: <web.archive.org/web/20220215000909/https://mn.gov/puc/line3/process/>.

[21] *In re Applications of Enbridge Energy, LP*, 930 NW 2d 12 (Ct App Minn 2019).

the state courts and more recently in the federal courts. All of that led to a decision by Canada on 4 October 2021 to invoke a 1977 pipeline treaty[22] with the US. That treaty contains a mandatory negotiation process pursuant to Article 9 of the 1977 treaty before formal binding arbitration proceedings can take place. Canada has intervened in supporting Enbridge, as have the states of Louisiana and Ohio. The court proceedings have been put on hold pending the negotiations, which are still underway.

### Enbridge Main Line Contracting

In late November 2021 the Canadian Energy Regulator released its decision[23] denying an application by Enbridge pipelines to contract up to 90 per cent of its transportation capacity on the Canadian mainline oil pipeline for firm transportation service. The Commission found that the proposal was contrary to Enbridge's common carrier responsibilities and was unjustly discriminatory and would result in unjust and unreasonable rates.

The Enbridge mainline pipeline is the largest crude oil pipeline Canada accounting for approximately 70 per cent of the total transportation capacity in the country. The application proposed largely fixed tolls with long-term contracts that would lock-in volumes for up to 20 years. The Commission found that the application was not consistent with Enbridge's common carrier obligations under section 239 of the *CER Act*[24] and was likely unjust discrimination contrary to section 235.

As result the existing tolls on the Enbridge mainline continue to remain in place as interim rates. Enbridge is continuing to consult with the stakeholders to establish new rates and terms for the Canadian mainline service. Enbridge hopes to file a new application in the fall of 2022 and have new rates approved by the Commission in early 2023.

## KEY REGULATORY DECISIONS

Over the past year energy regulators across Canada faced a number of new challenges. The first was EV charging. There is a concern that Canadian charging networks are failing to keep up with the demand given the number of new EVs.

There is a continuing debate in different Canadian jurisdictions whether charging network should be regulated or not. Most jurisdictions have elected not to regulate. British Columbia is the exception. In a recent decision an application by BC Hydro to set new EV charging rates was turned down.

The second case is from Alberta. It resulted in the highest fine ever issued by a Canadian energy regulator. It was also the first time a case was bought to an energy regulator by whistleblower.

The next case deals with a technology write off in Nova Scotia. In the last annual review we pointed to the difficulties that regulators in Nova Scotia, Ontario, and British Columbia were having with the adoption of new technology.[25] It turns out there is an even bigger problem when regulators discover that technology will not work and is write off is necessary.

Another Alberta case discussed below suggests that new technology may require more deregulation particularly in areas such as district energy. The last case we review also comes from Alberta. It relates to a very substantial overhaul of the Alberta Commission's rules of practice and procedure that was conducted at the request of the Alberta government under

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[22] *Agreement between the governments of United States Canada and the government of Canada Concerning Transit Pipelines*, E101884 - CTS 1977 No. 29 (signed on 28 January 1977), online: <www.treaty-accord.gc.ca/text-texte.aspx?id=101884>.

[23] *Re Enbridge Pipelines Inc. Application dated 19 December 2019 for Canadian Mainline Contracting*, RH-001-2020 (November 2021), online: Canada Energy Regulator <docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/155829/3773831/3890507/4038614/4167013/C16317-1_Commission_-_Canada_Energy_Regulator_Reasons_for_Decision_RH-001-2020_%E2%80%93_Enbridge_Pipelines_Inc._%E2%80%93_Canadian_Mainline_Contracting_-_A7Y9R1.pdf?nodeid=4166515&vernum=-2>.

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

[25] Gordon Kaiser, "Canadian Energy Regulators and New Technology: The Transition to a Low Carbon Economy" (2021) 9:2 Energy Regulation Q 7; Christopher Bystrom & Madison Grist, "The Future of Gas Utilities in a Low Carbon World: Canada's First Public Utility Administered Green Innovation Fund" (2020) 8:3 Energy Regulation Q 8.

the new *Red Tape Reduction Act*.[26] Alberta has completely revamped its rules of practice and procedure. They appear to have resulted in some impressive efficiency gains.

**EV Charging Networks**

The introduction of electric vehicles in Canada has exceeded the expectations of most people. There is however a serious concern whether the charging networks will be sufficient to meet the demand.

As of May 2022, Canadian EV drivers had access to 16,000 chargers at over 6000 locations. Of these only 1200 are for DC fast charging according to Ernst & Young Canada who claim Canada has an insufficient charging infrastructure. Canada ranks eighth in the ten leading car markets when it comes to charging infrastructure.

The regulatory structure for charging networks vary from province to province. In Ontario it is deregulated. In British Columbia it is regulated as far as the regulated utilities are concerned. Recently the British Columbia Utilities Commission (BCUC) turned down an application by BC Hydro with respect to its proposed rates for public electric vehicle (EV) fast charging service across British Columbia.[27] BC Hydro was directed to file a new application for permanent rates no later than December 31, 2022. In the meantime, the current interim rates will remain in place.

The BCUC found that BC Hydro's proposed rates were designed to only recover electricity costs and ignore other incremental cost including operating, maintenance and capital costs. Accordingly, the BCUC found that the proposed rates were not just and reasonable. The BCUC found that the subsidized rates proposed by BC Hydro would contribute to an uneven playing field which may have a detrimental impact on achieving the provincial government's objectives of increasing EV adoption across British Columbia.

The BCUC noted that in a new application filed for permanent rates the BCUC would consider rates based on a levelized recovery of all costs which must reflect all the cost required to provide the service to be just and reasonable. In the alternative, the Commission would consider approving wholesale rates BC Hydro would charge exempt EV charging service providers that would mirror the costs used to calculate BC Hydro's own levelized EV charging rate.

It should be noted the BCUC determined that time-based rate rather than energy based great are currently the only option for EV charging service because there are currently no approved Measurement Canada standards to measure how much electricity is consumed at fast charging stations. As a result, BC Hydro was directed to apply for an exemption from the *Electricity and Gas Inspection Act* to obtain the ability to charge energy based rates in the future. BC Hydro has since advised that Measurement Canada has declined to grant the requested exemption. As a result, the interim time based EV charging rate remains in place for BC Hydro.

On March 23, 2021, the BCUC approved interim rates for BC Hydro's public EV fast charging service as follows: $0.12 per minute for EV charging service at 25 kWh stations, $0.21 per minute for EV charging service at 50 kW stations, and $0.27 per minute for EV fast charging service at 1 00 kW stations.

The BCUC has also been active in approving EV charging services and rates proposed by Fortis. In the fall of 2020, the BCUC resumed its hearings in the Fortis Application. The rates Fortis applied for were $0.26 per minute for its 50 kW charging stations, $0.54 per is 100 kW charging stations. Fortis claimed that these prices would fully recover the cost of the services on a levelized basis over 13 and 10 years respectively. The BCUC approved this proposed pricing by final order on November 24, 2021.[28]

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[26] *Red Tape Reduction Act*, SA 2019, c R-8.2.

[27] *Re British Columbia Hydro and Power Authority Public Electric Vehicle (EV) Fast Charging Rate Application Decision and Final Order* (26 January 2022), G-18-2022, online: British Columbia Utilities Commission <www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/520273/index.do>.

[28] *Re FortisBC Inc. Application for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Decision*, (25 November 2021) G-341-21, online: British Columbia Utilities Commission <www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/516736/index.do?q=BC+hydro+charging>.

As indicated, Ontario does not regulate the rates for EV charging. It has however taken steps to reduce the cost of EV charging, In March 2022 the OEB released a report proposing low cost overnight rates.[29] The proposed overnight rate is 2.5 cents per kWh for the low overnight period (11PM – 7 AM) compared to 11.3 cents per kWh for mid-peak period ( 7 AM – 4 PM and 9 PM –11 PM) and 25.3 cents per kWh for on-peak period (4 PM – 9 PM). The rationale of this initiative is based on the belief that 80 per cent of EV drivers will charge their cars at home at night. It is expected that the new rates will be in place by April 2023.

**The Duty to Disclose**

A recent decision of the Alberta Commission reinforces an often forgotten principal of public utility law — regulated companies have a responsibility and a duty to disclose all relevant information to the regulator. In Canada this principle was first set out in a decision of the Ontario Energy Board in *West Coast Energy*[30] in 2008 where the Board set out the standard of disclosure required of utilities and sanctioned a utility with a cost penalty for failure to comply stating as follows:

> Public utility in Ontario with the a monopoly franchise is not a garden-variety corporation. It has special responsibilities which form part of what the courts have described as the "regulatory compact". One aspect of that regulatory compact is an obligation to disclose material facts on a timely basis.
>
> Failure to disclose can lead to unfortunate consequences. First it can only result in less than optimal Board decisions. Second it adds to the time and cost of proceedings. Neither of these are in the public interest.
>
> A publicly regulated corporation is under a general duty to disclose all relevant information relating to the Board proceedings it is engaged in unless the information is privileged or not under its control. In doing so utilities should err on the side of inclusion. Furthermore, the utility bears the burden of establishing that there is no reasonable possibility that withholding the information would impair a fair outcome in the proceeding. This onus would not apply where the nondisclosure is justified by the law of privilege but no privilege is claimed here.[31]

The Alberta case was much more complicated than the Ontario case. On November 29, 2021, the AUC Enforcement Staff filed an Application before the Commission asking the Commission to commence a proceeding pursuant to sections 8 and 63 of the *Alberta Utilities Commission Act* to determine whether ATCO Electric had acted unlawfully in a rate setting case and should pay an administrative penalty.

It was alleged that ATCO Electric had transferred to ratepayers the cost of a contract it had entered into at above fair market rates to benefit its nonregulated affiliate. The Report of the Enforcement Branch claimed that ATCO Electric had documented the scheme in such a way that concealed the relevant facts and other important information from the Alberta Commission. The Enforcement staff argued that ATCO Electric had breached its fundamental duty of honesty and candour to its regulator. A good summary of this decision is set out by Vice-Chair Larder KC, the sole panel member, in the first three paragraphs of the decision:[32]

> 1. This proceeding is the result of a pattern of self-dealing and deception perpetrated by ATCO Electric Ltd. to benefit its shareholders as well as

[29] Ontario Energy Board, "Report to the Minister of Energy – Design of an Optional Enhanced Time-of-use Price" (March 2022), EB-2022-0074, online (pdf): <www.oeb.ca/sites/default/files/Report-Design-of-an-Optional-Enhanced-Time-of-Use-Price-20220331.pdf>.

[30] *Re Westcoast Energy Inc. and Union Gas Limited leave for the transfer of a controlling interest in Union Gas Limited to a limited partnership* (19 November 2008), EB-2008-0304, online (pdf): Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/93155/File/document>.

[31] *Ibid* at 10.

[32] *Re Allegations against ATCO Electric Ltd.* (29 June 2022), 27013-D01-2022, online: Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/719764>.

the shareholders of an ATCO affiliate at the cost of Alberta ratepayers.

2. In the course of building a regulated transmission line, ATCO Electric took advantage of its position as a regulated utility to benefit its unregulated affiliate, ATCO Structures & Logistics Ltd. (ASL). ATCO Electric knowingly sole-sourced a major contract for the Jasper Interconnection Project transmission line at rates above fair market value, to secure a contract and a financial benefit for ASL. ATCO Electric then sought recovery of millions of dollars in above fair market costs from ratepayers for that sole-source contract. Further, ATCO Electric created a misleading paper trail justifying its decision and concealing critical information about why it sole-sourced the contract — namely, to benefit its unregulated affiliate ASL — in an attempt to avoid Commission detection of its actions and improperly recover those above fair market costs from Alberta ratepayers.

3. Prompted by a whistleblower complaint, Alberta Utilities Commission Enforcement staff investigated ATCO Electric's dealings over the last five years. Enforcement staff then requested the Commission commence a proceeding to consider whether ATCO Electric contravened its legal obligations. Enforcement staff and ATCO Electric subsequently requested the opportunity to attempt to settle the issues in this proceeding, which the Commission allowed. Ultimately the parties reached a settlement agreement, which was objected to by the Consumers' Coalition of Alberta (CCA). In this decision, the Commission considers whether approval of the settlement agreement is in the public interest, in accordance with the standards for considering settlement agreements set out in Section 3.2 of this decision.

**Background**

ATCO Electric is the owner of a electric utility regulated by the Alberta Commission. The Jasper Interconnection Project was a transmission project assigned to ATCO Electric by the Alberta System Operator (AESO) that was approved by the Commission in 2018 and completed by ATCO Electric using in 2019. The Jasper Project required ATCO Electric to conduct access and matting work.[33] The conduct complained of is set out at paragraph 11 and 12 of the Commission decision:

> 11. ATCO Electric originally estimated the costs of its portion of the Jasper project at approximately $84 million, $6.6 million of which was estimated for access matting costs. When ATCO Electric returned to the Commission to ask for recovery from ratepayers of the actual costs of the project in 2021, it claimed the project cost $119 million, $31 million of which was for access matting services. ATCO Electric attributed the cost increase to scope changes.
>
> 12. As eventually came to light, a significant portion of the overage (estimated by ATCO Electric to be $10.8 million) was the result of ATCO Electric improperly sole-sourcing a contract for matting services for the Jasper project to benefit ASL in relation to the operation of work camps for the pipeline project. That is, ATCO Electric sole-sourced the matting services contract because to do otherwise would have jeopardized ASL's joint venture with Simpcw Resources LLP. ATCO Electric then attempted to improperly over-recover millions of dollars from ratepayers that it had incurred purely to benefit its affiliate. What occurred here was ultimately the result of placing the demands of Simpcw and ASL above ATCO Electric's regulatory obligations.

[33] Matting is a service involving the placement of large mats that can support heavy equipment in work areas, required to mitigate potential environmental impacts while a transmission line is built.

Further details are set out in the following paragraphs of the decision:

> 48. In its initial deferral account application, ATCO Electric indicated that the Backwoods contract was sole-sourced but did not provide the real reasons for that decision, omitting material information. When directly asked about matting costs for the Jasper project (by both the CCA and the Commission through information requests), ATCO Electric stated that rates under the Backwoods contract were market competitive and that matting work was directly awarded to the only entity capable of completing the work. Neither of those statements were true, and ATCO Electric knew it.
>
> …
>
> 50. ATCO Electric provided none of that information in its responses to the information requests, choosing instead to falsely assert that rates under the Backwoods contract were market competitive.
>
> …
>
> 52. ATCO Electric provided none of that information in its responses to the information requests, choosing instead to falsely assert that matting work was directly awarded to the only entity capable of completing the work. ATCO Electric made no effort to disclose its wrongdoing; the only reason these events came to light was through the actions of a whistleblower
>
> 53. Section 7.6 of the Code of Conduct requires ATCO Electric to prepare regular compliance reports, which should include a comprehensive description of instances of material non-compliance with the code and any steps taken to correct such non-compliance.
>
> 54. ATCO Electric filed its compliance reports for 2018, 2019 and 2020 stating that it had complied with the Code of Conduct during that year, with no mention of any of the information set out above. ATCO Electric did not file an exception report until November 29, 2021, after it had been contacted by Enforcement staff.
>
> 55. The AESO conducted a compliance audit of the Jasper project, and did not identify any suspected contraventions of Section 9.1.5 of the ISO Rules, which required ATCO Electric to have solicited bids from at least three arm's-length bidders for the project. However, the AESO was not provided with critical information, such as the reasons for the sole-sourcing of the Backwoods contract or any other facts set out at paragraph 44 of this decision.
>
> 56. No ATCO Electric employee or management personnel reported any concerns regarding the contraventions discussed in this decision to senior regulatory personnel responsible for preparing the deferral account application.
>
> 57. Instead, the events forming the basis for the contraventions were only brought to Enforcement staff's attention through a whistleblower who was an employee of ATCO Electric with direct knowledge of the events surrounding the Backwoods contract. The Commission acknowledges the integrity and courage required for the whistleblower to bring these events to the Commission's attention; the Commission is grateful to this individual on its own behalf and on behalf of Alberta ratepayers.

**The Legal Principles for Acceptance of a Settlement Agreement**

This decision contains a detailed and important analysis of the standard a Commission should apply when accepting a settlement agreement particularly where there is an agreement between the prosecutor and the party charged. The main elements are in paragraph 65, 66, 70, and 73:

> 65. The Saskatchewan Court of Appeal and many Canadian tribunals that administer disciplinary schemes adopted the approach to joint sentencing submissions described

in *R v GWC*. The Commission then stated in Decision 3110-D03-2015:

> 20. Taking guidance from the foregoing, the Commission must not ask itself if the proposed consent order is the order that it would have issued. Rather, **the Commission must decide if the consent order is fit and reasonable and falls within a range of acceptable outcomes given the circumstances.** When making this assessment, the Commission is guided by the factors set out in Rule 013: *Rules on Criteria Relating to the Imposition of Administrative Penalties* (Rule 13) and other applicable sanctioning principles. [emphasis added]

66. Since the decision in *R v GWC* and the Commission's application of its principles in Decision 3110-D03-2015, the Supreme Court of Canada has addressed the legal test trial judges should apply in deciding whether it is appropriate in a particular case to depart from a joint submission on sentence. This test has since been adopted by a number of regulatory and disciplinary tribunals in Canada. In *R v Anthony-Cook*, the Supreme Court of Canada concluded that the proper test for trial judges assessing whether to depart from joint submissions on sentencing is "whether the proposed sentence would bring the administration of justice into disrepute or is otherwise contrary to the public interest." This "public interest test" (notably similar to that articulated in *R v GWC* and adopted by the Commission in Decision 3110-D03- 2015) sets an "undeniably high threshold" for rejecting a joint submission on penalty. As explained in Anthony-Cook:

> [33] … [A] joint submission will bring the administration of justice into disrepute or be contrary to the public interest if, despite the public interest considerations that support imposing it, it is so "markedly out of line with the expectations of reasonable persons aware of the circumstances of the case that they would view it as a break down in the proper functioning of the criminal justice system"…
>
> [34] [A] joint submission should not be rejected lightly … **Rejection denotes a submission so unhinged from the circumstances of the offence and the offender that its acceptance would lead reasonable and informed persons, aware of all the relevant circumstances, including the importance of promoting certainty in resolution discussions, to believe that the proper functioning of the justice system had broken down.** [emphasis added]

…

70. In the settlement agreement, ATCO Electric admits that it contravened the ISO Rules, the Code of Conduct, and the Electric Utilities Act. ATCO Electric admits that it sole-sourced the matting, brushing and hydrovac work for the Jasper project (violating the ISO Rules respecting competitive procurement), at above fair market rates to the benefit of its unregulated affiliate (violating the spirit, intent and letter of the Code of Conduct), and deliberately concealed those actions from the Commission in an attempt to recover those above fair market rates from Alberta ratepayers (violating its fundamental duty of honesty and candour under the *Electric Utilities Act*).

…

> 73. Having regard for the seriousness of the contravention and the harm caused, and taking into account that the purpose of the Commission's sanctioning authority is protective and preventative, not punitive, the Commission considers that the $31 million penalty and associated terms and conditions in the settlement fall within a range of acceptable outcomes, and it is in the public interest to approve the settlement agreement.
>
> *The $31 million administrative monetary penalty falls within a range of acceptable outcomes and is proportionate to the severity of the contraventions*

The concern that the Alberta Commission had with the conduct of ATCO Electric turned on the length of time that the deception took place, the number of people involved, and the contravention of a well-established Code of Conduct designed to prevent precisely this activity:

> 79. The issue is not whether a particular ATCO Electric employee preparing an information response in the deferral account proceeding was actively intending to deceive the Commission at the time. Rather, the issue is that multiple employees had previously created and shared a set of records underlying the project (the REFs and backgrounders) in a manner inconsistent with ATCO Electric's normal practices, to ensure that those records were not discoverable by the Commission in its regulatory process. These employees did so with the knowledge and/or prompting of senior management, or in many cases **were** senior management. Further, as it fully admitted in the settlement agreement, ATCO Electric is responsible for the conduct of its employees.
>
> 80. The Commission considers this contravention of the Electric Utilities Act to be deeply serious and finds that it has caused significant harm in the form of a breach of trust, both of the public and the Commission.
>
> 81. Second, the Code of Conduct is designed precisely to avoid this type of behaviour, where benefits are sought for unregulated affiliates at the expense of ratepayers. The Code of Conduct governs relationships and transactions between regulated and non-regulated affiliates within the ATCO Group of companies, to anticipate and adjust for the potential misalignment of interest between shareholders and utility customers, and avoid uncompetitive practices between utilities and their affiliates, which may be detrimental to the interests of utility customers.
>
> 82. The Code of Conduct stresses "the need to respect the spirit and intent behind the Code.
>
> …
>
> 84. Fourth, Section 9.1.5.2 of the ISO Rules required ATCO Electric to "solicit written bids from not less than three arm's length suppliers," as the Jasper project fell into the category of acquisitions where the cost of a specific item exceeds $50,000. This was a clear contravention; there were concerns from the outset within ATCO Electric that the direct-award to Backwoods would violate the ISO Rules, and ATCO Electric decided to do it anyway, in pursuit of a "larger pot of gold" for its unregulated affiliate, ASL.

The Commission faced a difficult decision in determining whether a $31 million penalty was the correct amount. It concluded it was for the reasons set out below:

> 91. The second aspect of the harm to ratepayers is difficult to quantify, but very serious. There is a broader harm to ratepayers and all other participants in the regulatory system resulting from ATCO Electric's actions. In making its decisions, the Commission must be able to rely on the information presented by the utility as full, fair and accurate. This is a fundamental premise of the *Electric Utilities Act* and our regulatory system more generally, as set out above. ATCO Electric's

> contraventions represent an egregious breach of trust, which has eroded the public's trust and confidence in the Commission's regulatory process, and the Commission's trust of ATCO Electric. Regardless of the financial harm suffered, this harm is in and of itself material and significant.
>
> …
>
> 93. The Commission finds that the $31 million penalty is significant. The parties indicated that as far as they are aware, the high watermark for similar sanctions (administrative monetary penalties) in Canada is $33 million; in that case the misconduct was deemed to be "at the highest end of the scale of seriousness." In Decision 3110-D03-2015, the administrative penalty portion of the final sanction approved by the Commission was $25 million. The Supreme Court of Canada has commented that in determining the magnitude of monetary penalties, the amount "should reflect the objective of deterring non-compliance with the administrative or regulatory scheme," and must be large enough that it is not merely a "cost of doing business," or, as the Alberta Court of Appeal put it, a "licencing fee."
>
> 94. The Commission considers that the $31 million penalty does not reflect merely a cost of doing business for ATCO Electric in this case. The Commission notes that the $80-100 million "larger pot of gold" in camp contracts that ATCO Electric attempted to gain on behalf of ASL through its misconduct represents capital costs, not profit, and also that the $31 million penalty is imposed alongside ATCO Electric's obligation to amend its deferral account application to exclude all costs above fair market value for the Jasper project (a currently estimated reduction of $10.8 million). This means that the Commission can be reasonably assured that the benefit gained by ATCO Electric through this contravention does not outweigh the proposed penalty, nor render the $31 million penalty a mere licencing fee. Instead, the magnitude of the penalty encourages both general and specific deterrence — the penalty sends a message to all utilities operating under the Commission's jurisdiction that this type of conduct will not be taken lightly and carries significant repercussions.

In the Report on its investigation the Commission relied on precedents in Law Society disciplinary proceedings.[34] The Report also referenced the *Report of the AUC Procedures and Processes Review Committee*.[35] The recommendations in that Report were aimed at reducing regulatory burden to create a more efficient regulatory process The process was initiated because Alberta utilities complained that the process had become unduly long. Accordingly, Board staff argued that it was even more important that information provided by regulated utilities be fair and accurate in a new regulatory environment where the Board would limit discovery and oral evidence as request by the utilities. Enforcement staff argues that the benefits of a more efficient regulatory proceeding could only be achieved if regulated utilities were prepared to be transparent, honest, and candid in their regulatory filings.

Subsequently the AUC Enforcement staff and counsel for ATCO Electric reached a settlement agreement and asked the Commission to approve that settlement agreement. Under that Settlement Agreement and an Agreed Statement of Fact ATCO Electric agreed to pay an administrative penalty of $31 million. In the Agreed Statement of Fact ATCO admitted it had contravened the *Electric Utilities Act* and breached a regulated utilities duty to be honest and not misleading in their submission to the regulator.

[34] *Kumar v The Law Society of Saskatchewan*, 2015 SKCA 132 at para 7; *Law Society of Alberta v Ihensekhien-Eraga*, 2019 ABLS 16.

[35] C. Kemm Yates, David J. Mullan & Rowland J. Harrison, "Report of the AUC Procedures and Processes Review Committee" (14 August 2020), online (pdf): <media.www.auc.ab.ca/prd-wp-uploads/2021/12/2020-10-22-AUCReviewCommitteeReport-1.pdf>.

In paragraphs 32 to 34 of the Joint Submission the parties reiterate much of what was in the earlier Application by Enforcement staff. The regulator is entitled to assume that the information submitted by a utility is full, fair, and accurate. ATCO Electric admitted it took steps to omit relevant information in filings with the AUC in its deferral account proceeding and acknowledged a lack of transparency and the impact this had on the Commission and the public in the deferral account proceeding.

The Joint Submission also outlined at length whether the Commission in approving the Settlement Agreement should follow the principles developed by courts with respect to joint submissions on sentencing in a criminal law context. This principle generally is that where the Crown prosecutor and the accused have come to an agreement the court or the regulator should accept it unless it clearly is contrary to the public interest.

On June 29, 2022 the Commission issued a decision approving the Settlement Agreement ordering that the negotiated settlement agreement between Enforcement staff and ATCO Electric attached as Appendix to the decision would be approved without variation. ATCO Electric was ordered to the pay an administrative penalty of $31 million pursuant to section 63 of the *Alberta Utilities Commission Act*. ATCO was also required to pay the cost of the Commission's external legal counsel for both the investigation and the hearing.

We should remember that this case came to the Commission as a result of a whistleblower complaint. Alberta has legislation that allows for whistleblower claims with respect to conduct relating to the public service sector. The AUC also has a document entitled *AUC Policy for Third Party Complaints* which sets out the practice and procedure with respect to whistleblower complaints. Whistleblower complaints are increasingly common in Securities Commissions proceedings across Canada. This case represents the first time an enforcement application before an energy regulator has been based on a whistleblower complaint. It will not likely be the last.

**New Developments**

Alberta is not the only energy regulator interested in the concept of the duty to disclose or the duty of candour. Recently the FERC in Washington created a Notice of Proposed Rulemaking[36] that addressed this issue. A Staff Presentation[37] noted that the Commission intended to amend its existing rule in a manner that would significantly increase the scope of the situations that were covered stating:

> This existing patchwork of requirements is insufficient to encompass all of the situations in which the Commission must be assured that it is receiving accurate communications that are necessary for it to adequately conduct its regulatory oversight and fulfill its statutory obligations.
>
> The proposed rule is a broad duty of candor intended to capture many communications that have not been explicitly included in these existing requirements, but nonetheless are important to the effective execution of the Commission's statutory obligations. The proposed rule is based on 18 C.F.R. § 35.41(b), which governs communications by Sellers of electricity with market-based rate authority to: the Commission, regional transmission organizations, independent system operators, and their market monitors, and jurisdictional transmission providers. That regulation has been in force, in different forms, for nearly 20 years.
>
> The proposed rule broadens the application of the requirement of accurate and truthful communications by providing that all entities communicating with the Commission or other specified organizations related to a matter subject to the jurisdiction of the Commission submit accurate and factual information and not submit false or misleading information or omit material information. As with section 35.41(b), an entity is shielded from violation of the proposed regulation

[36] FERC, "Duty of Candor" (28 July 2022), M-1-RM22-20-00, online (pdf): <www.ferc.gov/media/m-1-rm22-20-000>.

[37] FERC, "Staff Presentation | Duty of Candor NOPR" (28 July 2022), online: <www.ferc.gov/news-events/news/staff-presentation-duty-candor-nopr>.

> if it exercises due diligence to prevent such occurrences.
>
> Communications to the following organizations would be covered by the proposed rule: the Commission (including Commission staff), Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, jurisdictional transmission or transportation providers, and the Electric Reliability Organization and its associated Regional Entities.[38]

The Commission proposed that the following rule would be added to 18 CFR part 1d

> **1d.1 Accuracy of communications.**
>
> Any entity must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, jurisdictional transmission or transportation providers, or the Electric Reliability Organization and its associated Regional Entities, where such communication relates to a matter subject to the jurisdiction of the Commission, unless the entity exercises due diligence to prevent such occurrences.[39]

The proposed rule imposes a duty of candour on communications between market participants such as pipelines and shippers on matters subject to further jurisdiction. It also allows for an affirmative defence where an entity is accused of providing false information or communications but nonetheless exercised due diligence to ensure that the communication was accuracy.[40]

The existing rule has been challenged from time to time but has been upheld (4) The Commission notice also provided interpretive guidance for the proposed rule. For example, the term "entity" is defined as including individuals and businesses and the duty applies both to the entity making the communication as well as the entity responsible for the communication.

The communications will include informal or formal communications, verbal or written communication and any method of transmission. Comments on the proposed rule are due 60 days from the date the Notice is published in the Federal Register.

Given the experience of the Alberta Commission in the ATCO Electric case described above, Canadian energy regulators will no doubt be considering similar rules to provide greater clarity on this important issue.

**Technology Write Offs**

Energy regulators today live in a new world. Worldwide energy regulators face a $131 trillion investment in new technologies designed to reduce the amount of carbon in the production, distribution and use of electricity.[41] Picking winners and losers in new technology is not easy. It is always a challenge.

Approving a technology pilot is just the first problem. The second problem is what do the regulators do when the technology fails. The first decision addressing this problem surfaced in Nova Scotia recently.[42] There the energy regulator faced an application by Nova Scotia Power to write off significant costs related to a new technology pilot that after many years not to be commercially viable.

[38] *Ibid*.

[39] FERC, *supra* note 36 at 29.

[40] *Ibid* at para 43.

[41] International Renewable Energy Agency, *World Energy Transition Outlook* (Masdar City: International Renewable Energy Agency, 2021) at 28, online (pdf): <irena.org/publications/2021/Jun/World-Energy-Transitions-Outlook>

[42] *Nova Scotia Power Incorporated (Re)*, 2022 NSUARB 2, online: Nova Scotia Utility and Review Board <www.canlii.org/en/ns/nsuarb/doc/2022/2022nsuarb2/2022nsuarb2.html?autocompleteStr=2022%20NSUARB%202&autocompletePos=1>.

The project in question is known as the Annapolis Tidal Generation Station. At the time of its commissioning in the mid-1980s the Station was intended to be a short-term research initiative to test the viability of tidal barrage technology in the Bay of Fundy. In recent years the utility that was operating the project, Nova Scotia Power, experienced significant operational and maintenance costs with the Generating Station. Capital costs were increasing significantly while at the same time the amount of power generated was declining

The application by Nova Scotia Power asked the Commission to approve the amortization of the undepreciated value and the remaining construction work in progress over ten year period. Nova Scotia Power did not apply for decommissioning at the same time.

The Board's decision and the reasoning shows how complicated these cases can become. Nova Scotia Power asked the Board to find that the project was no longer used and useful. It turns out that is not a simple question to answer.

There is no question that at the time of the application the generating station was not being used. The question was whether the technology could be useful in the future. The Commission pointed to the arguments of the intervenor groups at paragraph 32.

> [32] The closing submissions of the Small Business Advocate, the Industrial Group, the Consumer Advocate, and the Town of Annapolis Royal all expressed concerns relating to NS Power's assertion that the retirement of the Generating Station is the lowest cost option to customers. All four stakeholders noted that they do not agree that NS Power has put forth a sufficiently comprehensive analysis to convince them that there is no viable future use of the assets in question for public utility purposes.

The analysis by the Commission is best set out in the following paragraphs:

> [89] In this case, given the significant amount of the undepreciated cost remaining in rate base, NS Power proposed a 10-year amortization period. No party challenged the proposed length of the amortization period. It was supported by both Mr. Reed and Grant Thornton. The Board agrees that, if decommissioning is established as the least cost option, a 10-year amortization period appears to create a reasonable balance between negative impacts to current ratepayers and intergenerational equity considerations.
>
> [90] The substantive issue in dispute in this case is whether NS Power has shown that decommissioning of the Generating Station is the least cost option for ratepayers. The Board recognizes that in preparing its case NS Power took several steps in this application which are appropriate. The use of external consultants to supplement in-house expertise follows Board guidance. The Board acknowledges these consultants support the approach set out in the application. As well, the use of probabilistic modelling was appropriate in this case, given the number of uncertainties which could impact cost estimates. That said, the Board has determined it does not have enough information to find that decommissioning is, in fact, the least cost option. The Board therefore finds NS Power has not met the burden of proof to obtain the accounting treatment relief sought in this matter.
>
> [91] The Board is in general agreement with the Intervenors, based on the evidence filed by Midgard and MS Consulting, that there are too many cost variables which have not been sufficiently addressed, or have been addressed in an inconsistent manner across the various options. The Board acknowledges there is contention between NS Power and MS Consulting as to the actual impact of certain inputs on the modelling results, including certain inputs used by MS Consulting. The Board also recognizes that Midgard's ultimate recommendation was that the LEM option be kept alive. This could theoretically be done by approving the current application and revisiting the issue, if necessary, when a decommissioning application is filed.
>
> [92] That said, given the magnitude and scope of the unaddressed issues,

> the Board concludes approval of the accounting treatment at this point is premature. The evidence indicates there are varying levels of class estimates for the different options. In particular, the spread in NPVRR values between the LEM option and the decommissioning option are not that wide. In certain scenarios, the LEM option might actually be more cost-effective, although with greater risk.
>
> [93] It is therefore important that, as far as it is possible, there be an apples-to apples comparison between the LEM option and the decommissioning option. The Board is concerned that if the accounting treatment is approved now, there may be a tendency to focus on having the decommissioning option approved. This may create less incentive to continue robustly assessing the LEM option.

In the end the Commission concluded that it did not have sufficient information to make a decision. The complexity of the issues that face regulators in this type of case is evident in the Commission's direction to Nova Scotia Power regarding the additional information that is required to properly address the issue:

> [99] While it will not direct NS Power to undertake any specific studies, it would seem to the Board that the following information would be of assistance in determining the least cost option in this matter:
>
> 1. A more fulsome assessment of LEM costs;
>
> 2. A more fulsome assessment of the new technology option, including: a. A more thorough assessment of options and costs to change station capacity under the new technology option; and b. Solicitation of pricing from multiple manufacturers for the new technology option;
>
> 3. A more fulsome assessment of sedimentation issues and costs associated with the decommissioning option;
>
> 4. Completion of environmental studies needed to assess environmental risks and costs associated with each alternative;
>
> 5. A more fulsome assessment of station asset disposal options;
>
> 6. A detailed explanation of why capital cost estimates for the decommissioning option have decreased so dramatically from the estimates included in NS Power's 2018 Hydro Asset Study;
>
> 7. Engagement with DFO personnel on if NS Power can satisfactorily present alternative studies or data on fish migratory periods and fish mortality for the site, short of returning the Generating Station into operation, including potentially modifying its operation to reduce or mitigate the potential impacts on fish so as to avoid the requirement for a DFO Authorization;
>
> 8. Engagement with DFO personnel on whether it would consider any compliance plan with an accompanying request for authorization. If DFO will entertain such a request, NS Power could estimate the cost of preparing and implementing a compliance plan in its Decision Analysis;
>
> 9. Engagement with DFO personnel and the Province on any *Fisheries Act* or environmental compliance issues under the Decommissioning

> option with respect to restoring the area to its original condition (i.e., with no water flow through the causeway at the location of the Generating Station and any resulting decommissioning compliance costs related to the sluice gates, causeway, and fish passages). The results of these discussions could be incorporated into the Decommissioning option in the Decision Analysis; and
>
> 10. With respect to the above initiatives, engagement with Indigenous communities respecting the various options (including LEM, New Technology and Decommissioning), to better inform the potential costs to be incorporated into the Decision Analysis.

The Board concluded that until it received this information in a new application it was unable to make a decision stating at paragraph 118.

> [118] The Board has determined that it has insufficient evidence at this time to find that decommissioning of the Generating Station is the least cost option for ratepayers. It therefore is not able to find that the asset is not used and not useful in accordance with Accounting Policy 6350. Therefore, the Board will not approve the application at this time. The Board believes the best way of proceeding is to reconsider the application for accounting treatment approval along with a decommissioning application. That said, NS Power is at liberty to reopen the matter if it is in a position to address the Board's concerns.

The introduction of new technology creates two problems for energy regulators. The first is defining the terms and conditions on which regulators accept and approve investment in new technology. The second as outlined in this Nova Scotia case is the terms and conditions on which regulators remove the technology from rate base when it turns out not to be useful.

The term "used and useful" has a long history in both Canadian[43] and American[44] public utility law. A recent decision by the Ontario Energy Board turned on the debate of whether the proper test was "used and useful" or "used or useful" in that jurisdiction.[45]

As far as Canadians are concerned regulators face the Supreme Court of Canada decision in ATCO[46] which make it clear that assets that are no longer required to meet a utility service needs cannot be included as regulatory assets and considered part of rate base.

The ATCO rule may end up being modified by the courts in the future. The regulatory landscape is changing. Regulators such as the Ontario Energy Board now face recent legislation that adds an important new responsibility to their jurisdiction — the requirement to promote innovation.

However time-honoured the "used and useful" rule is in public utility law, it was clearly not designed to meet the technology challenge facing regulators in a world dominated by climate change demands.

**Deregulation**

Decisions involving deregulation are not that common. The leading decision is likely the Ontario decision in 2006 in the *NGEIR*

[43] *Re London Hydro Inc.* (20 March 2009), EB-2008-0235, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/111240/File/document>; *Re PowerStream Inc.* (27 July 2009), EB-2008-0244, online: Ontario Energy Board <www.oeb.ca/oeb/_Documents/2009EDR/Dec_PowerStream_20090727.pdf>; *Re Toronto Hydro Electric System* (2 April 2013), online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/410473/File/document>.

[44] James J. Hoecker, "'Used and Useful': Autopsy of a Ratemaking Policy" (1987) 8:2 Energy LJ 303.

[45] *Re Ontario Power Generation Inc.* (15 November 2021), EB-2020-0290, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/732079/File/document>.

[46] *ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4.

proceeding.[47] That turned out to be a two-year inquiry on the interpretation of section 29 of the *Ontario Energy Board Act* which reads as follows:

> In an application or in a proceeding the Board shall make a determination to refrain in whole or part from exercising any power or performing any duty under this Act if it finds as a question of fact that the licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest.

In *NGEIR* the Board found that the energy storage market was workably competitive and that neither Union nor Enbridge had market power in the storage market. The Board determined that it would cease regulating the price charged for certain storage services. The exception was the rates for storage services provided to Union and Enbridge distribution customers which continue to be regulated.

This issue has risen recently in Alberta with respect to a class of service known is a district energy. The Alberta decision may have implications for decisions in other jurisdictions dealing with this class of service.

In March 2022 the Alberta Utilities Commission issued a decision[48] exempting Calgary District Energy Inc. (CDHI) and the Downtown District Energy Center (DDEC) from certain provisions of the *Public Utilities Act* including the regulation of its rates and certain reporting requirements. DDEC was originally constructed and operated by Enmax Corporation which was wholly owned by the City of Calgary.

DDEC provides thermal energy in the form of central heating and hot water services to commercial and residential buildings in downtown Calgary. DDEC was statutorily exempt from a large portion of the *Public Utilities Act* in Alberta and for this reason was not subject to AUC oversight and regulation. For some time the AUC did not have any direct role in regulating the operations of DDEC or in setting rates charged to DDEC customer.

In April 2021 the AUC approved the sale of DDEC to CDHI. Following the sale of the DDEC, CDHI brought an application requesting an order pursuant to sections 8 and 9 of the *Alberta Utilities Commission Act* and section 79 of *Public Utilities Act* declaring that certain provisions of the Public Utilities Act would not apply to either CDHI or DDEC. CDHI argued that requested exemptions were in the public interest and represented a flexible and proportionate form of light-handed regulation that was responsive to the unique nature of district energy services. The parties agreed that the AUC would retain oversight of the services provided by CDHI and DDEC on complaint basis.

The most important aspect of that argument was that district energy services were highly competitive in the City of Calgary. The same is true in many Canadian markets.

In the hearing the Commission had to deal with the objection of ATCO, the only intervenor that opposed the status that CDHI was seeking. ATCO in fact provided competing services in the City of Calgary. The Commission responded to the ATCO arguments as follows in paragraph 25 of the decision:

> 25. The Commission disagrees that a departure from prospective economic regulation would necessarily frustrate the purpose of the Public Utilities Act or undermine the intent of legislature. The Commission finds that the overarching purpose of the legislative scheme is to safeguard the public interest in a service environment that is susceptible to abuses of monopoly power. The legislature has equipped the Commission with the tools required to fulfil this purpose, including the ability to fix rates and to exercise general oversight of the operation of public utilities. Given the nature of public utilities (which tend to be highly capital intensive,

[47] *Re Natural Gas Electricity Interface Review* (7 November 2006), EB-2005-0551, online: Ontario Energy Board <www.oeb.ca/documents/cases/EB-2005-0551/Decision_Orders/dec_reasons_071106.pdf>.

[48] *Re Calgary District Heating Inc.* (2 March 2022), online: Alberta Utilities Commission <efiling-webapi.auc.ab.ca/Document/Get/713215>.

> such that duplication of services by different providers is inefficient), they are often natural monopolies. In these circumstances, prospective economic regulation serves important functions, including the protection of customers. The Commission does not accept, however, that protecting the public interest, or upholding the legislative scheme, necessitates that any public utility must be subject to prospective economic regulation, regardless of its particular characteristics or the context in which it operates.

The AUC went on to observe that it would not benefit the public interest to require prospective economic regulation of any entity meeting the definition of a public utility where the facts established, as they do in this case, that such regulation is not necessary to protect sophisticated customers in a competitive environment in the light of other available regulatory mechanisms.

The alternative regulatory mechanisms that the Commission referenced were that the rates of CDHI Calgary in the new environment would only come under review if a customer complained about the rates. CDHI agreed that if the customers did complain regarding rates they would submit to the Commission's jurisdiction to regulate their rates.

In approving this light-handed regulation proposed by CDHI the Commission concluded at paragraph 39 as follows:

> 39. The Commission finds that CDHI operates in an environment that is sufficiently competitive that its customers have a degree of choice about their service provider that is not present in a traditional monopolistic industry. Specifically, customers of CDHI can elect to take service from the DDEC or acquire a boiler (powered by either gas or electricity) from a variety of providers to meet their thermal energy needs. In the future, given that CDHI has no exclusive franchise, its customers may elect to take service from new entrants to the district energy market. The services agreements executed between CDHI and its customers for the provision of district energy are based on mutually acceptable terms negotiated between sophisticated commercial parties. Further, in the event that they are dissatisfied with the rates they pay, or service they receive, CDHI customers retain the ability to raise a complaint with the Commission. Taken together, the Commission considers that these factors are sufficient to ensure that the rates paid by CDHI customers will be just and reasonable, in the sense that they are fair to both customers and the utility, as intended by the legislative scheme.

In fact, the Commission concluded that district energy projects were public utilities within the meaning of the PUA but at the same time they should be able to take advantage of flexible and proportionate forms of light-handed regulation to accommodate the particular needs of district energy markets. This is an important development. The concept of light-handed case-by-case regulation will be increasingly important in new energy markets and services like district energy. While the original rationale for deregulation in this market was municipal ownership it now becomes a question whether there is sufficient competition to protect the public interest. This is essentially the test that the Ontario Energy Board applied in the in *NGEIR* case.

To be fair to the AUC, the CDHI decision is not really deregulation. It is regulation by complaint. The AUC retains complete discretion to regulate rates at any time. This is different from the Ontario procedure under section 29 of the *Ontario Energy Board Act*, as explained by the following sections in the *Union Gas LNG* decision[49]:

> As several parties observed, the use of the word "shall" in section 29(1) means that the OEB has a positive obligation to forbear from regulation where it finds that there is or will be competition sufficient

[49] *Re Union Gas Limited LNG Application* (9 April 2015), EB-2014-0012 at 5-7, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/473354/File/document>.

> to protect the public interest. If the factual record indicates that there is sufficient competition, the OEB has no discretion and must refrain (in whole or in part) from regulating the activity.
>
> In considering section 29, the OEB is further guided by its statutory objectives. Of particular note is the OEB's first objective with respect to natural gas: "to facilitate competition in the sale of gas to users."
>
> There does not appear to be any serious dispute between the parties that the LNG service Union proposes is or will be competitive. Most of the elements of the section 29 are not actively contested. It is agreed by Northeast and Union that the relevant product market is the market for motor vehicle transportation fuel. Currently the chief competitor for LNG as a motor vehicle transportation fuel is diesel fuel, which is widely available. It is also generally agreed that the relevant geographic market is Ontario, Quebec, and portions of the Northeast and Midwest United States … Section 29 is clear that where the OEB finds that there is, or will be, competition sufficient to protect the public interest; it will refrain (in whole or in part) from regulation. The OEB has found that the new service is subject to competition sufficient to protect the public interest. It therefore has little choice but to refrain from regulation, whatever the difficulties.

Complaint-based regulation is very different. Under complaint-based regulation a utility has a right to set rates without prior approval of the regulator but in the event of a complaint the regulator may consider whether the rate is just and reasonable and set new rates on a retroactive basis.[50] This type of light-handed regulation has enjoyed some success in telecommunications.[51] It will likely be used more often in the energy sector as energy regulators introduce new technology to decarbonize the production and distribution of electricity.

**New Rules of Practice and Procedures**

In May 3, 2021 the Alberta Utilities Commission (AUC) approved very substantial amendments to its rules of practice. They came into effect on May 17, 2021. These amendments have an interesting history. When the new Conservative government came into power in 2019 one of their first steps was to enact the *Red Tape Reduction Act* which was applicable to all regulatory agencies in the province. It turns out that the AUC was the most aggressive agency in reacting to it.

The first thing that the AUC did was to hold a hearing. It invited all of the companies they regulate as well as other regulatory agencies in the energy sector. The utilities were the parties with the loudest voices in the room. Their main complaint was "scope creep" and the resulting delays in the decisions of the Commission.

The Commission's first response was to establish an independent panel to write a report and make recommendations. It was a first-class panel consisting of a retired senior counsel who had represented major utilities before both the National Energy Board and the AUC for many years, a former member of the National Energy Board, and Canada's leading administrative law professor. Their Report made 30 recommendations.[52] The Commission adopted 29 of them. They are considered below.

*The Application*

An application to the Alberta Utilities Commission can be commenced by any person if it complies with section 6 of the rules, by the Market Surveillance Administrator by filing a notice under Act, or by the Commission on its own initiative, or at the direction of the Government of Alberta.

The new Rules provide that if an application is not complete when filed the Commission

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[50] *Nova, An Alberta Corporation v Amoco Canada Petroleum Company Ltd.*, [1981] 2 SCR 437, 128 DLR (3d) 1.

[51] *Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 SCR 1722, 60 DLR (4th) 682.

[52] Yates, *supra* note 35.

may submit information requests to the applicant and direct the applicant to provide the additional information the Commission requires to accept the application. This is a novel but important amendment. Rather than turning the matter over to the interveners and starting the traditional IR mud fight, the AUC decided to assume responsibility of clarifying the evidence upfront.

Where the Commission identifies a material deficiency in the application the Commission can dismiss the application with an explanation of the deficiency and close the proceeding (s 6.3). If an applicant does not take any steps with respect to an application within the time specified by the Commission, the Commission may declare the application be withdrawn unless acceptable reasons are provided (s 12.3). The new rules also provide that the Commission at any time during the proceedings may suspend an application or determine that it cannot process the application and close the proceeding (s 17.1).

*The Hearing*

Unless otherwise directed by the Commission the development of the evidentiary record in rate cases must be conducted through written process (s 36.1). Any party that wants to establish an oral hearing in a rate case must make this request as early as possible and convince the Commission that an oral hearing is necessary. It should be noted when the Commission holds a written hearing it may dispose of the proceedings on the basis of the documents filed by the parties.

When the Commission holds an oral hearing in a rates case no party may question a witness unless the party obtains approval from the Commission in advance (s 36.7). The request to question a witness in a rates case must be made as soon as possible and be supported by a description of the witness to be questioned, the time required for questioning, the issues that the questions will address, and an explanation of how the question will assist the Commission (s 36.8).

*The Argument*

Unless otherwise ordered by the Commission argument shall be delivered orally unless it can be demonstrated that written argument would be more efficient. No argument may be received by the Commission unless it complies with the directions issued by the Commission with respect to the scope, format, or content of the argument including directions on page limits for written arguments or time limits for oral arguments (s 48).

*The Decision*

The Commission is required to issue decisions in accordance with its performance standards. If the Commission is unable to issue a decision within that standard it is required to notify all registered parties in advance. Alberta is not the only Canadian jurisdiction to feature immediate notification of a failure to meet established deadlines for the delivery of final decisions. Every decision of the Nova Scotia Board features on its first page a table that identifies when the hearing started, when the hearing finished, and when the decision was issued.

If there is one thing the AUC should borrow from another jurisdiction it is the Nova Scotia Notice. It reminds everyone involved in the regulatory process how important efficiency is to the credibility of energy regulation. Regulators cannot complain about interveners and applicants if they themselves are not meeting their decision deadlines. Alberta has bought into the notice concept but a front page notice on every decision is a good idea.

The Commission may without notice, correct typographical, spelling and calculation errors and other similar types of errors made in any of its rulings, orders, decisions or directions (s 51.1).

The Commission may, no later than 60 days from the date that the Commission issued a decision or order and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision or order on its website and the eFiling System (s 51.2).

There is another feature under the new Alberta rules that is unique. The Commission now has authority to issue a corrigenda decision. The corrigenda decision corrects substantive errors that are not a typographical, spelling, or a calculation error. Under this section the Commission can also correct errors detected more than 60 days after the date of issuance of the decision. The corrigenda decision will indicate the changes required and attach an amended form of the original decision (s 51.3).

*The Issues List*

The new Rules provide that when the Commission serves a notice of hearing in a rate proceeding the Commission shall also issue directions on procedure which may include the establishment of a preliminary list of issues for the hearing. An Issues list under the Ontario rules has for over 10 years been instrumental in reducing what is called "scope creep". In Ontario it becomes part of a Procedural Order very early in the proceeding and is strictly enforced throughout the hearing. The new Alberta Rules adopts a similar procedure.

*Information Requests*

A party in a hearing is entitled to make an information request in order to clarify documentary evidence filed by the applicant. In rate cases the rules provide that these questions must be directly related to the issues set out in the issues list. In addition the questions must be directed to a party adverse in interest from the requesting party. This is an attempt to eliminate what are known as sweetheart IRs which apparently is a problem in Alberta hearings. Certainly it is a common objection to cross examination in those hearings.

In the new Rules Information requests (or IRs) are limited in rate cases to questions that relate directly to the issues identified in the Issues List (s 26.2d). When a party refuses to answer the information request the requesting party must attempt to resolve the matter with the other party before bringing a motion (s 28.2). If the parties are unable to settle the matter the motion must be brought no later than 5 business days after the date on which the information request was made (s 28.3). The motion can be no greater than 10 pages in length (s 29.2).

The party responding to a motion must file a response no later than 3 business days from the date that the motion was filed (s 29.5). The response to a motion must be no greater than 10 pages in length (s 29.6). The Commission is required to issue its ruling on a motion no later than 10 business days after the date on which the time limit for filing a reply lapsed (s 29.9). Detailed rules also exist where motions relate to confidential information (s 30).

Information Request have become a fundamental and time-consuming part of all Canadian rate cases The new Alberta Rules seek to remove some of the delay. As indicated the new Rules provide that the Commission may impose limits on the number of information requests each party may ask.

*Pre Hearing Motions*

The new AUC rules set out specific provisions with respect to prehearing motions. Prehearing motions can be critical to clearing up important legal issues like jurisdiction up front. Prehearing motions must be brought in writing and be no greater than 10 pages in length. They must describe the decision and order sought, the grounds for the motion and interestingly any relevant prior rulings of the Commission dealing with the issue raised or relief requested. The motion must also contain any evidence and documents that support the motion (s 29.3).

An interesting new feature is the requirement in section 29.4 that the party bringing the motion must identify any inconsistent prior rulings of the Commission on the same issue and has the onus of demonstrating why the commission should depart from the prior ruling.

If a party to whom a written motion is directed wishes to respond they have 3 business days from the date on which the motion was filed (s 29.5). The response must provide any evidence and documents in support of the response. If the party who brought the motion wishes to reply to the response it has 30 days to do so.

As is common in many of the new rules time limits are also established regarding the date of the Commission decision. The Commission is required to issue its ruling no later than 10 business days after the date of the reply (s 29.9).

Under the new rules the Commission reserves the right to proceed directly to ruling on a motion if it determines that is required (s 29.10).

*Participation*

Any party wishing to participate in a hearing must file an intent to participate statement with the Commission. The Commission will allow the party to attend if it determines that the party has demonstrated that the Commission's decision in the proceeding will directly and adversely affect that party's rights (s 11.2). It should be noted that the Commission may on its own initiative or at the request of a party issue a notice to a person requiring that person to either produce documents or attend an oral hearing as a witness (s 38.1).

If the Commission believes it is necessary the Commission can call as a witness a member of staff or an independent witness to participate in the hearing to present evidence, question a witness, or submit argument (s 46.1). The crown may also participate in a proceeding and may file a written statement in evidence in the proceeding which is not subject to questioning (s 47).

*Expert Evidence*

The new Rules provide the parties may call independent experts That evidence however must include the instructions that were provided to the independent witness, an acknowledgement of the witnesses duty to provide evidence that is fair, objective and nonpartisan and a list of all documents on which the evidence is based.

In the case of evidence that is provided in response to another expert witness the evidence must include a summary of the points of agreement and disagreement with the other expert witness. In addition, the Commission may require independent witnesses from different parties to confer with each other in advance of a hearing to narrow the issues identified points on which the views differ or agree and prepare joint written statements to be admissible as evidence (s 21).

*Confidential Evidence*

Claims of confidentiality are likely the most common objection to the production of documents in hearings. Under the new Alberta rules a party may file a motion objecting to production of documents based on confidentiality in writing in which they must describe the specific harm that would result if the confidential information was placed on the public record. The Commission may grant a motion for confidential treatment of information on any terms that it considers necessary if it finds that

> granting the request is necessary to prevent a serious risk to an important public interest including a commercial interest because reasonable alternative measures will not prevent the risk and the benefits of granting the request outweigh its harmful effects including the effects on the public interest in open and accessible proceedings (s 30.7)

It should be noted that where the Commission grants a motion for confidentiality the confidential ruling will extend to any review or appeal in which the Commission's decision on the confidential ruling is being considered.

The new rules set out a new procedure in which the Commission may adopt in dealing with confidential information. If the Commission grants a motion for confidentiality, it can under the rules adopt any process or procedure that it considers reasonable or necessary in the public interest for considering the confidential information including

a. receiving and considering the confidential information in confidence to the exclusion of any party to the proceeding on terns the Commission considers to be in the public interest, and

b. issuing a decision in which the confidential information is redacted and providing an unredacted copy of the decision only to the disclosing party and any person who has been permitted access to the confidential information (s 30.9).

This is a new and important procedure may help solve some difficult situations.

*Constitutional Issues*

Notice must be provided with respect to constitutional issues. A party who intends to raise a question constitutional law before the Commission in an oral argument must give written notice of the party's intention at least 14 days before the oral hearing starts. A party who intends to raise the question of constitutional law in the written hearing must also give 14 days not days notice there are also serious penalties for late filing of evidence (s 31).

*Documentary Evidence*

Documentary evidence in a proceeding must be directly relevant to the proceeding and must be filed in accordance with Commission's directions. In addition documentary evidence filed in a proceeding must be accompanied with a statement setting out the qualifications of the person who prepared the document in evidence, the qualification of the purpose of the person under who direction or control the evidence was prepared, and an explanation of how such qualifications are directly relevant to the issues addressed in the evidence. This is a new requirement in Canadian energy regulations (s 20.2).

The Commission may on any terms it determines — allow the revision or removal of all or any part of the document, order the revision or removal of all or any part of the document that in the opinion of the Commission is not relevant to the proceedings or necessary for the purpose of the hearing (s 24.1).

The Commission may on its own initiative, or at the request of a party, issue a notice requiring a person to produce certain documents or attend an oral hearing as a witness (s 38.1).

Where a party intends to use a document that has not been filed in the proceeding as an aid to question a witness an oral hearing that party must provide a copy of that document to the witness at least 24 hours before the witness is questioned (s 40.1).

The use of surprise documents has long been a problem in energy regulation hearings.

*Cross Examination*

Cross-examination is also tightly controlled under the new rules. Where a party intends to use a document to cross-examine the witness and that document has not been previously filed that witness or his representative must be provided with a copy of that document no less than 24 hours before the witness appears. This addresses a long-abused practice by counsel (s 40.1). Any witness that intends to provide an opening statement as part of his evidence in an oral hearing must file a copy of the opening statements at least 24 hours in advance (s 43.3).

*Review and Variance*

The rule amendments discussed to this point have all been amendments to Rule 001 approved by the Commission on April 27, 2021. The most important amendment may be the amendment to Rule 016 approved a short time later on May 6, 2021.

For many years parties appearing before the AUC had the opportunity to apply to the Commission if they didn't like the Commission decision. It was called an application for Review & Variance or R&V. If the parties did not like the Commission's R&V decision, they then had an opportunity to go to the Alberta Court of Appeal or at least apply for leave. There have been close to 30 such applications over the last 10 years.

The new rule eliminates errors of law or jurisdictions as grounds for a R&V application. A R&V application continues to exist, but the amendments accelerate the deadline for such an application from 60 days to 30 days.

The elimination of errors of law and jurisdiction as grounds for an R&V application requires the parties that question the legality of a AUC decision to apply directly to the Court of Appeal under section 29 of the *AUC Act*.This appears to be consistent with the Supreme Court of Canada decision in *Vavilov*[53] which interprets provisions such as section 29 as intending that the court not the administrative tribunal is required to decide the correct interpretation of the law. There was also an efficiency argument. The Commission states that this reform is designed to minimize overlap with the Court of Appeal with respect to questions under review or appeal.

This is a controversial step. Some have argued that removing the ability to request the AUC to review and correct its own errors of law will result in weaker oversight of the legal or jurisdictional aspects of AUC decisions. We should also remember that there was a reason why the concept of a R&V decision by a energy regulator was introduced in Canada. Twenty years ago it did not exist. It was an attempt to increase efficiency. It meant parties did not have to rush off to court which usually involved much greater time and cost for all involved.

Others have argued that this change will lead to practical difficulties. Under the new rule a person that considers the AUC to have made an error of law may not apply to the AUC for a R&V but must apply to the court for permission to appeal. But if the court of appeal decides that it is not an issue of law that person will be out of time to apply for an R&V because under the new rules the time limits for R&V application and court appeals is now the same- namely 30 days after the date of the decision. In addition, if a person applies for an

[53] *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65.

R&V and the AUC determines the issue of law the party may have missed the time window to apply for permission to appeal. In the end parties may apply for both a R&V before the Commission and seek leave to appeal before the court.

The amended rule 016 applies to all R&V applications filed after June 15, 2021. It is not clear whether eliminating errors of law and jurisdiction as grounds for an R&V application will lead to greater efficiency.

One thing is a clear. It will lead to more appeals and that is unlikely to increase efficiency. It remains to be seen if the Court of Appeal will continue to expect appellants to exhaust all remedies before pursuing an appeal. It also means that in those cases where applicants are seeking to review a decision based on fact or changed circumstances and a question of law or jurisdiction they will be required to file both a R&V application with the Commission and seek permission to appeal from the court within 30 days of the challenged decision.

**Conclusion**

The new AUC rules represent a significant milestone in Canadian energy regulation. They are unique in a number of respects. First, as indicated below, the discretion granted to the regulator as outlined in the rules exceeds the discretion enjoyed by most energy regulators in North America.

Second, the new rules have been developed through an extensive and exhaustive process administered by an independent panel with wide participation from the industry.

Third, the new rules are being subjected to a unparalleled review process with monthly reporting on their effectiveness to the Minister of Energy. The annual reports which will no doubt develop and hopefully become public will become required reading for all energy regulators in Canada.

Below we consider four issues. First, how wide is that discretion? Second, are these new rules effective? Third, what rule changes re next? Fourth, what lessons can other regulators learn from the Alberta regulatory reform effort?

*Wide Discretion*

The new Rule 001 grants the Alberta Utilities Commission wide discretion when it comes to administering the practice and procedures relating to hearings under its jurisdiction. The following 12 sections detail that discretion.

> 2.3 The Commission may, at any time before making a decision on a proceeding, issue any directions it considers necessary for the fair, expeditious and efficient determination of an issue.
>
> 2.4 The Commission may dispense with, vary, or supplement all or any part of these rules if it is satisfied that the circumstances of any proceeding, or the fair, expeditious and efficient resolution of any issue, require it.
>
> 2.5 The Commission may set time limits for doing anything provided for in these rules and may extend or abridge a time limit set out in these rules or by the Commission, on any terms that it considers reasonable, before or after the expiration of the time limit.
>
> 6.3 If an application is not complete when filed, the Commission may
>
> > (a) make an information request to the applicant;
> >
> > (b) direct the applicant to provide any additional information the Commission requires in order to accept the application; or
> >
> > (c) in the case where the Commission identifies a material deficiency, dismiss the application with an explanation of the deficiency in the application and close the proceeding
>
> 12.3 If an applicant does not take any steps with respect to an application within a time specified by the Commission, the Commission may declare the application to be withdrawn by a certain date, unless the applicant shows cause before that date why the application should not be declared to be withdrawn.

14.5 The Commission may issue whatever directions on procedure it considers necessary, including restricting the scope of a hearing and imposing limits on the number of information requests each party may ask.

17.1 The Commission may, at any time during a proceeding,

(a) place an application into abeyance and suspend the proceeding; or

(b) in the case where the Commission determines that it cannot continue to process an application, dismiss the application with an explanation of the dismissal and close the proceeding.

23.1 The Commission may direct a party to file such further information, documents or material as the Commission considers necessary to permit a full and satisfactory understanding of an issue in a proceeding

24.1 Despite any other provision in these rules, the Commission may, on any terms it determines, (b) order the revision or removal of all or any part of a document that in the opinion of the Commission, is

(i) not relevant or may tend to prejudice or delay a proceeding on the merits, or

(ii) necessary for the purpose of hearing and determining the pertinent questions at issue in the proceeding;

36.4 When the Commission holds a written hearing, it may

(a) dispose of the proceeding on the basis of the documents filed by the parties;

(b) require additional information and material from the parties; or

(c) decide, at any time during the written hearing, to hold an oral hearing

36.7 When the Commission holds an oral hearing for a rates proceeding, no party may question a witness unless the party obtains approval from the Commission in advance.

36.9 Questioning of witnesses in a rates proceeding shall be restricted to the specific witnesses, issues and time limits approved by the Commission in advance.

38.1 The Commission may, on its own initiative or at the request of a party, issue a notice requiring a person to

(a) produce the documents and material out in the notice; or

(b) attend an oral hearing as a witness

The revised Rule 016 adds the following:

2(1) Notwithstanding sections 3 to 5 of these rules, the Commission may review a decision, in whole or in part, on its own motion at any time for any reason.

*Are the Rules Working?*

Pursuant to the *Red Tape Reduction Act*, the AUC is responsible for tracking, reporting and monitoring its progress to the Department of Energy. Direction to the AUC regarding its responsibilities was received by the AUC by way of Ministerial Order 181/2020. The order states as follows:

RED TAPE
REDUCTION DIRECTION

The Alberta Utilities Commission (AUC) shall

1. Establish a red tape reduction task force within the AUC, instructed specifically to:

a) Create a Red Tape Reduction Work Plan outlining how the AUC will achieve a one-third reduction in regulatory requirements by 2023;

b) Review AUC regulations, directives, rules, policies and forms to find efficiencies and duplications;

c) Work with the Department of Energy to assess and implement red tape recommendations; and

d) Assist the Department of Energy with any ad hoc red tape reduction information and reporting requests relating to the AUC.

2. Report on the progress the AUC has made on red tape reduction to the Minister during the first week of each month.[54]

The AUC retained an independent consultant to benchmark the performance of the AUC against other comparable North American regulators.

As of the end of fiscal year 2021-22 the AUC was able to considerably improve its processing timelines across all application types. For example, specific improvements resulting from the *Regulation Review Report* recommendations have resulted in the AUC averaging about 7.4 months from the filing of a complex rates application to the issuance of a final decision. This represents a 41 per cent improvement in the time it takes to review complex rate cases. The AUC now ranks among the top two quartiles of peer North American regulators when comparing the time it takes to review an application. This is in relation to the benchmarking study undertaken in 2020.

Improvements have also been realized over all other application types. Assertive case management has been applied to 738 proceeding improving the average full cycle time by approximately 33 per cent.

In addition to adopting assertive case management, the AUC has introduced other application streamlining initiatives, including checklist applications, expedited processes for compliance filing and other strategies that have been applied to 387 proceedings, improving average full cycle time by 49.9 per cent.

In terms of red tape reduction, the AUC has achieved a 48.2 per cent reduction in red tape since the benchmark regulatory count was established in 2019. This is far ahead of schedule and well above the target of reducing red tape by one-third by 2023.

Lastly, while many of the resulting benefits of regulatory efficiency improvements are not easily expressed in dollar amounts, the AUC has, where possible, attempted to identify direct cost savings related to its work. As of March 31, 2022, the cumulative internal and industry red tape reduction and efficiency cost savings are an estimated $9.2 million.

*Future Amendments*

The Alberta rule reform process is not finished. Three developments are expected in the next year. First, the AUC advised that in coming months it will release practice notes with respect to the rules.[55] This is an important but new concept for energy regulators. Energy regulation has become a lot more complicated in recent years. The issuance of practice notes on an annual basis would be a welcome addition. The process has long been used in the court system.

There is another report which has yet to be addressed by the Commission. As indicated the Commission is required to advise the Minister of Energy on a monthly basis with respect to the efficiency gains resulting from the rule amendments. The Alberta Commission without too much trouble could consolidate the monthly report into an annual report. That would be a big help not just to the Alberta community but Canadian energy regulators

[54] *Red Tape Reduction Direction* Ministerial Order 181-2020, April 24, 2020.

[55] Alberta Utilities Commission, "Bulletin 2021-10 – Amendments to AUC Rule 001" (3 May 2021), online (pdf): <media.www.auc.ab.ca/prd-wp-uploads/News/2021/Bulletin%202021-10.pdf>.

across the country. This is the first time in the history of Canadian energy regulation that any regulator has been required to provide monthly reports on the efficiency of its hearing process.

There is another regulatory reform in Alberta that is likely to unfold over the next year. Alberta like many Canadian regulators does not have a very robust settlement process. The exception is Ontario that has a long-standing panel of mediators. There are settlement hearings in almost all cases and close to 40 per cent of the cases are settled. Settlements and mediations are now commonplace in all court proceedings across the country. There is no reason why it cannot happen in energy hearings. As part of the red tape regulation reform, the AUC has received an expert report on settlements.[56] That report recommended seven amendments to the current Rule 018, rules on negotiated settlements.[57] The Commission is in the process of developing new rules in this area. This will also become an important milestone.

The final development we can expect over the next year is a review of the cost rules in rate cases. There is a link between the cost initiative and new settlement procedures. Bulletin 2022-10[58] deals with the draft amendments to Rule 0022 and points out that parties appearing before the Commission should be encouraged to participate in cost-effective programs such as negotiated settlements. The AUC received comments on the draft rules on August 10, 2022. A decision is expected shortly.

Those that have been following the Alberta rule reform process will notice ten fundamental rules:

1. Focus on rate cases. That is where the real problem is.

2. Establish an issues list on day one and enforced it every day.

3. Cleanup the application on day one. Do not leave it for a intervener mud fight.

4. Control Information Requests. Use timelines and the Issue List.

5. Control cross-examination with clear rules.

6. Use a written process but require oral argument.

7. Clearly outline the discretion the Commission has in controlling hearings.

8. The Commission must meet its decision deadlines.

9. Make rule reform a continuous process. Issue annual Practice Notes.

10. Publish an Annual Report on efficiency gains.

## IN THE COURTS

### Constitutional Issues

A major constitutional decision relating to the energy sector was issued recently. That was the decision of the Alberta Court of Appeal[59] in a reference case regarding the Federal *Impact Assessment Act*[60] (*IAA*). As in the *Greenhouse Gas Pollution* case last year,[61] the Alberta Court of Appeal declared this legislation unconstitutional. And as in the case of *Greenhouse Gas Pollution* pricing the federal government has signalled that they will appeal the decision to the Supreme Court of Canada.

The *IAA* as Bill C-69 received Royal Assent in June 2019 and was quickly labelled "the no more pipelines act" by the Alberta Premier. The legislation established various types of federal assessments for projects depending on whether or not the project meets the criteria of a designated project. If federal assessment is required, the impact assessment agency or a joint review panel established by the legislation will conduct an assessment to determine the environmental effects of the project. Where it

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[56] John J. Marshall, Bill Kenny et Doug Crowther, "Report of the Committee on Mediated Settlements to the Alberta Utilities Commission" (13 November 2020).

[57] *Ibid*, Appendix D.

[58] Alberta Utilities Commission, "Bulletin 2022-10 – Request for comments on draft amendments to Rule 022" (30 June 2022), online (pdf): <media.www.auc.ab.ca/prd-wp-uploads/News/2022/Bulletin%202022-10.pdf>.

[59] *Reference re Impact Assessment Act*, 2022 ABCA 165.

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

[61] *Reference re Greenhouse Gas Pollution Pricing Act*, 2020 ABCA 74.

is determined that the project is likely to result in a significant adverse environmental impact, the government may decide if the emissions are justified.

The Alberta government argued in the reference case before the Court of Appeal that this was an overreach of federal jurisdiction that threatened to eliminate any provincial authority over resource development. The *Constitution Act* does not assign the environment to either Parliament or the provincial legislatures. The federal government can pass environmental legislation in the area of federal jurisdiction. The federal government argues that the *IAA* relates to areas within federal jurisdiction. Alberta on the other hand argues that the *IAA* provides a complete federal veto over the development of natural resources which is an area of provincial jurisdiction.

The Court of Appeal held that the main purpose of the *IAA* was to regulate any program subject to federal jurisdiction and oversight noting that the *IAA* targets activities that generate greenhouse gas emissions which is an extremely broad category. Like the *Greenhouse Gas Pollution Pricing Act* this legislation is headed to the Supreme Court Canada. There the arguments will likely be similar to those raised in the *Greenhouse Gas Pollution* case.

The decision of the majority starts with a lengthy history of the complaints that Alberta has had over the years with federal jurisdiction with respect to natural resources. The tenor of the debate can be best be seen through the following paragraphs:

> [1] Sustainable economic development cannot be achieved without a sustainable healthy environment and society. Since we all want a healthy biosphere in which to live, we expect our governments to make informed decisions about proposed larger scale projects in this country in a careful and precautionary manner. The utility therefore of environmental impact assessments of such projects to determine their environmental, social, economic and health impacts is undisputed. That has been unanimously recognized by the four governments and all intervenors who participated in this Reference. Indeed, without exception, every government in this country has, in aid of responsible stewardship of the environment, enacted comprehensive environmental assessment processes to evaluate the benefits and burdens of significant proposed infrastructure and resource activities.
>
> [2] Times of great change often lead to pressures to centralize power. Popular thinking may consider a central government best suited to manage whatever change dominates public discourse. Today, that discourse most certainly includes climate change. The increasing frequency of weather events related to climate change and their detrimental effects are evident; the need to act with urgency on this front undeniable. But this should not be confused with the issue at stake here.
>
> [3] This Reference is not about the legitimate concerns all governments and citizens have today about climate change nor how best to address them. Nor is it about the anxiety many rightly feel about this subject. Rather, the issue before this Court is whether Parliament has overstepped the limits of its constitutional mandate under Canada's Constitution.
>
> …
>
> [5] For reasons explained in this Opinion, the *Act* and *Regulations* are unconstitutional.
>
> [6] Climate change constitutes an existential threat to Canada. But climate change is not the only existential threat facing this country. The *IAA* involves another existential threat — one also pressing and consequential — and that is the clear and present danger this legislative scheme presents to the division of powers guaranteed by our Constitution and thus, to Canada itself. This Reference shines a spotlight on the crucial feature of federalism built into our constitutional framework. History teaches that government by central command rarely works in a geographically large country with a diverse population and divergent

regional priorities. In most major democratic countries in the world, federalism and its associated principle, subsidiarity, have been insisted upon by the governed. That includes Canada which, by deliberate choice, is a federation not a unitary state.

…

[10] There is a long history here. The *IAA* is a classic example of legislative creep. The federal government appears to have taken the Supreme Court decision in *Oldman River* upholding the federal government's *Environmental Assessment and Review Process Guidelines Order*, SOR/84- 467 [*Guidelines Order*] as a license to systematically expand federal powers under the environmental umbrella. The *IAA*, with its intrusions into provincial jurisdiction, is far removed from the federal environmental assessment legislation that the Supreme Court found constitutional in *Oldman River*. The assessment process under the *Guidelines Order* did not include the usurpations of provincial jurisdiction embedded in the *IAA*. It was also procedural only, a planning tool and integral component of sound decision-making. Its purpose was to provide the federal decision maker with an objective basis for granting or denying permits or approvals required for a proposed development under federal legislation. But the *IAA* extends well beyond this.

…

[14] Through this legislative scheme, Parliament has also imposed a regulatory regime on all intra-provincial designated projects on provincially owned as well as provincially controlled lands. That has been accomplished through a number of means including a public interest determination by the federal executive and related decision statement. In the result, the *IAA* regulates matters within provincial competence as well as federal competence.

…

[31] Parliament has the authority to legislate to protect the environment. However, it must do so in accordance with the Constitution. For reasons explained in detail in this Opinion, we have concluded that the subject matter of the *IAA* is properly characterized as "the establishment of a federal impact assessment and regulatory regime that subjects all activities designated by the federal executive to an assessment of all their effects and federal oversight and approval". When applied to intra-provincial designated projects, this subject matter does not fall under any heads of power assigned to Parliament but rather intrudes impermissibly into heads of power assigned to provincial Legislatures by the *Constitution Act, 1867*.

[32] Accordingly, the *IAA* is *ultra vires* Parliament. Intra-provincial activities requiring a federal permit under other valid and applicable federal laws remain subject to those laws but in accordance with the terms of such laws, not this legislative scheme.

[33] In summary, the federal government's invocation of concerns about the environment and climate change that all provincial governments and Canadians share is not a basis on which to tear apart the constitutional division of powers.

…

[424] Where natural resources are involved, it is each province that is concerned with the sustainable development of its natural resources, not the federal government. It is the province that owns those natural resources, not the federal government. And it is the province and its people who lose if those natural resources cannot be developed, not the federal government. The federal government does not have the constitutional right to veto an intra-provincial designated project based on its view of the public interest. Nor does the federal

> government have the constitutional right to appropriate the birthright and economic future of the citizens of a province.
>
> Conclusion on Validity of the *IAA* and Severance
>
> [425] For these reasons, we have concluded that the *IAA* is *ultra vires* Parliament
>
> …
>
> [434] We ought never lose sight of the great genius of our constitutional structure which has produced a free and secure democracy, one that has served Canadians well for 155 years. Our ancestors chose a federal, not unitary, structure for a purpose — to unify separate colonies and create a country. The negotiated division of powers lies at the heart of what makes this country what it is, and why, despite significant tensions from time to time, Canada has been able to survive and prosper since Confederation. It remains one of this country's greatest strengths. It will continue to benefit present and future generations as we face the environmental, economic and security challenges ahead providing that we respect the principles on which Canada has been founded: federalism, responsible government and the Rule of Law.

There is however a very powerful dissent by Justice Greckol which concludes as follows:

> [760] It is my opinion that the *IAA*, establishing a federal environmental impact assessment regime, is a valid exercise of federal constitutional authority. The answers to the questions are:
>
>> Is Part 1 of *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, S.C. 2019, c. 28, unconstitutional in whole or in part, as being beyond the legislative authority of the Parliament of Canada under the Constitution of Canada? **No**.
>>
>> Is the *Physical Activities Regulations*, SOR/2019-285, unconstitutional in whole or in part by virtue of purporting to apply to certain activities listed in Schedule 2 thereof that relate to matters entirely within the legislative authority of the Provinces under the Constitution of Canada? **No**.
>
> [761] The federal environmental assessment regime in the *IAA* and *Regulation* prohibits projects on the Project List that may have *effects in federal jurisdiction* — on fish and fish habitat, aquatic species, migratory birds, on federal lands or federally funded projects, between provinces, outside Canada, and with respect to Indigenous peoples — from proceeding unless and until the proponents engage the process and a decision is made that an assessment in unnecessary or that it is in the public interest for the project to proceed.
>
> …
>
> [763] In a thought-provoking *cri de coeur* written prior to promulgation of the *IAA* and *Regulation*, environmental academics envisioned a future where sustainability assessments are responsive to the interests of both the economy and the citizenry, calling for harmonization of environmental assessment regimes among multiple jurisdictional actors, including the federal government, provinces, territories, municipalities, Indigenous peoples, NGOs, academia, project proponents and industry groups, as well as the Canadian public. This approach is anticipated to have "the potential not only to resolve intensifying multijurisdictional disputes over the direction of energy and economic development in Canada in a manner that is effective, efficient,

> and socially inclusive, but also to develop widely-shared commitments about Canada's future".
>
> [764] All this to say, the complexities and urgency of the climate crisis call for co-operative, interlocking environmental protection regimes among multiple jurisdictions, each functioning at its highest and best within their constitutional jurisdiction.
>
> [765] In my opinion, in enacting the *IAA* and *Regulation*, Parliament has established a federal environmental assessment regime designed to regulate *effects within federal jurisdiction* caused by physical activities or designated projects; and to authorize such projects when it is in the public interest to do so, in cooperation with other jurisdictions that bear responsibility for the environment, especially the provinces and First Nations. The *IAA* confines its reach to protection of the environment and the health, social and economic conditions within Parliament's legislative authority from the adverse environmental effects of select activities that in its view, have the greatest potential for adverse effects on areas of federal jurisdiction. Having done so, the legislative regime prescribed in the *IAA* and *Regulation* is a valid exercise of Parliament's authority and compliant with the *Constitution Act, 1867*, as amended.

This is a difficult and gut wrenching case. It will be just as contentious as the case dealing with the carbon tax. If anything the argument has become more heated. In conclusion it is useful to look at a commentary by two well-known experts Nigel Banks and Andrew Leach of the University of Calgary[62] they state as follows:

> In this post, we consider in more detail the majority's lengthy discussion of the historical evolution of the resource rights of the prairie provinces from the creation of Alberta and Saskatchewan as provinces in 1905, through to the Natural Resources Transfer Agreements (NRTAs) of 1930, culminating with the adoption of s 92A (the Resources Amendment) in 1982.
>
> The majority's historical account provides useful context, but it also seems designed to perform two more rhetorical purposes. First, the majority seeks to characterize the federal *IAA* as interference with provincial property rights. Second, the majority builds an implied immunity argument to protect a supposed provincial "right to development" from federal interference. In our view, both rhetorical claims seriously overstate provincial authority and, in particular, overstate the effect of both the Resources Amendment and Crown ownership of public lands and resources within a province, and also conflate the two in unhelpful ways.
>
> …
>
> **The Alberta Natural Resources Transfer Agreement**
>
> The purpose of the Alberta NRTA of 1930 was to vary s 21 of the *Alberta Act* and to put Alberta in a position of *equality* with the other Provinces of Confederation "with respect to the administration and control of its natural resources" (Preamble, at para 2).
>
> This was achieved by stipulating that all Crown lands within the province shall henceforward "belong" to the province subject to the same conditions as are contained in s 109 (trusts and interests other than those of the Crown), plus the obligation to observe the terms and condition of interests (e.g. leases)

[62] Nigel Banks & Andrew Leach, "The Rhetoric and Immunity in the Majority Opinion in the Impact Assessment Reference" (8 June 2022), online (blog): ABLawg <ablawg.ca/2022/06/08/the-rhetoric-of-property-and-immunity-in-the-majority-opinion-in-the-impact-assessment-reference/>.

that the Dominion had created. Certain lands were also excluded from the transfer including Indian reserves and national parks as listed in a schedule to the Agreement. In addition, ss 20 – 22 of the NRTA provided some financial terms including compensation to be paid to Alberta as decided by a joint commission of inquiry: see Report of the Royal Commission on the Natural Resources of Alberta (1935). This compensation (albeit a rough and ready calculation) was intended to represent the "net revenue which the province would probably have obtained from those portions of its resources alienated or otherwise disposed of by the Dominion during the course of its twenty-five year administration" (Report at para 89).

The NRTA did not amend s 92 of the *Constitution Act*, 1867 since, as observed above, Alberta already had all the legislative powers of the original provinces of Confederation.

What did the majority opinion say about the Alberta NRTA?

Again, the majority's opinion generally tracks this account, although the majority again suggests that the province "gained a number of significant new powers" (at para 56), which we would argue is not the case. The province did not obtain new legislative powers via the NRTA, although the transfer did place the now-provincial public lands and resources within the legislative ambit of s 92(5). Furthermore, the majority makes no reference to the financial terms of the Agreement as part of putting Alberta in a position of equality with the original provinces of Confederation.

…

**Section 92A: The Resources Amendment**

Section 92A, the focus of much of the rhetoric in the majority opinion, reads as follows.

92A (1) In each province, the legislature may exclusively make laws in relation to

> (a) exploration for non-renewable natural resources in the province;
>
> (b) development, conservation and management of non-renewable natural resources and forestry resources in the province, including laws in relation to the rate of primary production therefrom; and
>
> (c) development, conservation and management of sites and facilities in the province for the generation and production of electrical energy.

(2) In each province, the legislature may make laws in relation to the export from the province to another part of Canada of the primary production from non-renewable natural resources and forestry resources in the province and the production from facilities in the province for the generation of electrical energy, but such laws may not authorize or provide for discrimination in prices or in supplies exported to another part of Canada.

(3) Nothing in subsection (2) derogates from the authority of Parliament to enact laws in relation to the matters referred to in that subsection and, where such a law of Parliament and a law of a province conflict, the law of Parliament prevails to the extent of the conflict.

(4) In each province, the legislature may make laws in relation to the raising of money by any mode or system of taxation in respect of

> (a) non-renewable natural resources and forestry resources in the

> province and the primary production therefrom, and
>
> (b) sites and facilities in the province for the generation of electrical energy and the production therefrom, whether or not such production is exported in whole or in part from the province, but such laws may not authorize or provide for taxation that differentiates between production exported to another part of Canada and production not exported from the province.

*Primary production*

(5) The expression primary production has the meaning assigned by the Sixth Schedule.

(6) Nothing in subsections (1) – (5) derogates from any power or rights that a legislature or government of a province had immediately before the coming into force of this section.

Section 92A was added to the *Constitution Act, 1867* in 1982 at the time that the constitution was patriated from the United Kingdom, the *Charter of Rights and Freedoms* was adopted, constitutional recognition was afforded to Aboriginal and treaty rights, and a constitutional amending formula was added.

Subsection (1) of s 92A provides that the provinces have the exclusive power to make laws with respect to the exploration for non-renewable natural resources (s 92A(1)(a)), the "development" (a word the significance of which the majority emphasizes at para 415), conservation, and management of non-renewable and forest resources including "the rate of primary production therefrom" (s 92A(1)(b)), and in relation to sites for the generation and production of electrical energy (s 92A(1)(c)).

…

Section 92A adds nothing to provincial proprietary rights. While s 92A(6) makes it clear (see para 413 & n 204) that the section does not derogate from provincial proprietary rights, there is nothing in s 92A that affords additional protection to provincial property rights. At the risk of stating the obvious, s 92A — like all other legislative heads of powers — is about assigning the authority to *make laws* in relation to certain classes of subjects. Laws that are in "pith and substance" about managing natural resources in the province fall within s 92A's legislative authority. Those that are not, do not.

…

Section 92A does not provide for exclusive provincial jurisdiction over resource projects. The majority decision in *Westcoast Energy Inc v Canada* [*National Energy Board*], 1998 CanLII 813 (SCC), [1998] 1 SCR 322, states that the language of s 92A(1)(b) "does not refer to jurisdiction over 'sites and facilities', but more generally to jurisdiction over 'development, conservation and management of non-renewable resources'" (at para 84). The exclusivity in s 92A refers to the subject matter of legislation. Laws affecting resource projects may be validly enacted by the federal government (*Quebec (Attorney General) v Moses*, 2010 SCC 17 (CanLII), [*Moses*] at para 36). In fact, the majority contradicts its own assertion that the provinces have exclusive jurisdiction with respect to major projects in note 109, when it quotes the opinion of Justice Ian Binnie in *Moses*, which held that federal fisheries legislation could validly restrict the development of an intra-provincial project because "the mining of non-renewable mineral resources aspect falls within provincial jurisdiction, but the fisheries aspect is federal." The fact that a federal law affects a resource project in a province offer no grounds upon which to judge the validity of that federal law. On the

> contrary, as Chief Justice Beverley McLachlin wrote in *Canada (Attorney General) v PHS Community Services Society*, 2011 SCC 44 (CanLII), [*Insite*] it is "untenable to argue that a valid federal law becomes invalid if it affects a provincial subject" (at para 51).
>
> …
>
> In our view, the majority's Opinion that the *IAA* represents unacceptable federal overreach is based upon an inflated interpretation of the NRTAs, s 109 and provincial property rights, and the implications of s 92A.
>
> Much of the majority's analysis relies on the claim that s 92A, read together with s 109, affords provinces an express right to development and an implied monopoly over project approvals. The jurisprudence does not support those claims. Instead, it supports the view that federal laws can prevent the development of intra-provincial resource projects (*Moses* at para 36) and may impose terms and conditions that are necessary conditions for such projects to be allowed to proceed. Furthermore, while the majority opinion toys with the availability of IJI for intra-provincial resource projects, any such reliance is inconsistent with the "dominant tide" of current constitutional doctrine.

**Jurisdiction Decisions**

The most important category of court decisions for energy regulators are jurisdiction decisions. They are fairly common. Last year in this section of the Review there were six of them. This year there are also six.

The first was a decision of the Ontario Superior Court of Justice in *Waterloo Hotel*.[63] It raised a simple but important issue. Did the Ontario Energy Board have exclusive jurisdiction over the dispute in question. Waterloo Hotel had applied for electricity rebates that were available to electricity customers under an new Ontario government program. The rebate program was being administered by the electricity distributor in each market which in this case was Kitchener Wilmont Hydro (KWH).

KWH refused to grant Waterloo Hotel the requested discount. Waterloo Hotel then brought a motion before the Superior Court. KWH requested a stay of the proceedings on the basis that the Superior Court of Justice did not have jurisdiction to hear the matter. The Ontario Energy Board agreed with the KWH position because the dispute at issue was within the exclusive jurisdiction of the Ontario Energy Board.

KWH determined that the applicant was not eligible for rebate under the program the consumers living in the hotel did not meet the definition of a consumer living in a residential complex. They were living in the hotel on a long-term basis and had no other residential address. When the hotel was refused it applied to the Court for a declaration that it was included in the definition of an eligible customer in the legislation.

The court rejected the applicant's claim because it found that the OEB had exclusive jurisdiction in this matter and the court application should be stayed. The court relied on section 19 of the *OEB Act* that grants the Board exclusive jurisdiction in respect of all matters in which jurisdiction is conferred by its legislation. The Board referenced a long line of authorities on this point as set out below.

The *Ontario Energy Board Act*, Section 19 sets out the basic provision concerning exclusive jurisdiction:

> (1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and of fact.
>
> …
>
> (6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act.

[63] *Vista Waterloo Hotel Inc. v 1426398 Ontario Inc., & Ontario Energy Board*, 2021 ONSC 2724.

At s. 112.3, the *OEB Act* states,

> If the Board is satisfied that a person has contravened or is likely to contravene an enforceable provision, the Board may make an order requiring the person to comply with the enforceable provision and to take such action as the Board may specify to,
>
> > (a) remedy a contravention that has occurred; or
> >
> > (b) prevent a contravention or further contravention of the enforceable provision.

In *Garland v Consumers' Gas Company Ltd*, the Court of Appeal for Ontario expressly accepted that, given the exclusive nature of the OEB's jurisdiction as confirmed by s. 19(6) of the *Act*, 'there can be no issue of concurrent jurisdiction in the courts and the Board'. This position was confirmed in *Snopko v Union Gas*, where the court held that the Board maintained exclusive jurisdiction even though there were properly pleaded, common law claims of breach of contract, negligence, unjust enrichment and nuisance that were otherwise within the jurisdiction of the court. As the court noted, 'if the substance of the claim falls within the ambit of s. 38 the Board has jurisdiction, whatever legal label the claimant chooses to describe it.'

Canadian courts have consistently held that where the subject matter involves a complex regulatory scheme and there is a body created by statute for, amongst other matters, the adjudication of disputes involving the interpretation of the provisions of that scheme, the courts should defer to the administrative body.

In *Mahar v Rogers Cablesystems Ltd*, the court outlined three situations where the courts are reluctant to permit jurisdiction to be divided between the regulatory body or tribunal and the courts:

> 1. Where there is a regulatory framework with the legislature choosing a specific public body to supervise that regulatory framework;
>
> 2. Where the courts have granted the administrative body at issue a curial deference with respect to their decisions; and
>
> 3. Where Parliament or the legislature has created a statutory regime, which includes both rights and a procedure for their resolution.

The next jurisdiction case is the decision of the Ontario Superior Court of Justice in *West Whitby Landowners*.[64] Like the last decision this case limits the court review of an energy regulator. West Whitby was a property developer. It ran into a dispute with the local energy distributor, Elexicon Energy, and the Ontario Energy Board.

It was a common problem — the property developer needed electricity for a new property being developed and sought an electricity connection. The cost of suppling electricity to the new property by Elexicon depended on whether the project was classified as an "enhancement" or an "expansion". There was a big difference in the cost.

West Whitby decided to get an opinion from the Ontario Energy Board. The interesting point was this -the parties entered into an Offer to Connect Agreement in which they agreed to refer any dispute about whether the work was an extension or enhancement under the Code to the OEB and that decision would be final and binding. They also agreed that if the project was an "expansion", West Whitby would pay . If it was an "enhancement", Elexicon would pay.

The staff issued two opinions. Both opinions agreed with Elexicon position. West Whitby was not happy. West Whitby then asked the Ontario Superior Court to order the OEB to hold a hearing. The Court after careful analysis rejected the request. The decision warrants a close review. The reasons are set out below:

> [4] For the reasons below, the application for judicial review is dismissed. I agree with the respondents' preliminary arguments. In my view, this Court does not have jurisdiction over the OEB's opinion that the project is primarily

[64] *West Whitby Landowners v Elixicon Energy*, 2022 ONSC 1035.

an expansion because this was not the exercise of a statutory power of decision. In addition, WWLG does not have standing to compel the OEB to hold a hearing or to challenge the OEB's assessment of its complaint. At most, WWLG would have standing to compel the OEB to deal with its complaint, which the OEB did.

…

[25] The respondents argue that the Divisional Court does not have jurisdiction over the application because the Board did not exercise a statutory power of decision. They approach this issue from two different perspectives. First, they argue that the Board did not make a decision because it only provided an opinion for the purpose of helping the parties resolve their differences. Second, they argue that, even if the Board made a decision, the only decision it made was not to refer the matter for a hearing. WWLG does not have standing to challenge such a decision.

…

[27] One of the challenges in this case is to tease out the role of the agreement between the parties from the OEB's statutory functions. While the parties can agree to be bound by an OEB opinion or determination, they have no power to require the OEB to do anything or follow any process that is not provided for by statute or regulation. Accordingly, the agreement is irrelevant to the issue of what the OEB should have done and how it should have handled the communications from the parties, and, therefore, ultimately irrelevant to the issue of whether WWLG can challenge the OEB's opinion and decision not to refer the issue to a hearing.

…

[29] As reviewed above, section 105(a) of the *Ontario Energy Board Act* gives the OEB the power to receive complaints and section 105(b) gives the OEB the power to "make inquiries, gather information and attempt to mediate or resolve complaints". Therefore, the starting point for assessing this Court's jurisdiction over the application for judicial review is whether this Court has jurisdiction to consider an application for judicial review of a decision made by the OEB over how to deal with a complaint under section 105 of the Act.

…

[31] On the first issue, in my view, WWLG has no standing to ask this Court to compel the OEB to hold a hearing. Looking at section 105 in combination with the provisions in Part VII.1, it is evident that, while WWLG can make a complaint, it has no standing to require that the Board hold a hearing if it is not satisfied with the manner in which the Board has handled the complaint. As reviewed above, the *Ontario Energy Board Act* sets out a clear process leading to a hearing. That process provides that the OEB can conduct an investigation and make an order against an electricity provider, after which the provider can request a hearing to challenge the order. There is nothing in this process that gives a complainant status to request or compel a hearing. The wording of section 112.2(1) of the *Ontario Energy Board Act* is clear; it provides that an "order under section 112.3, 112.4 or 112.5 may only be made on the Board's own motion" [emphasis added]. As held in *Ocean Port Hotel Ltd. v British Columbia*, 2001 SCC 52, at para. 22, the principles of natural justice can be ousted by clear and unambiguous language. Here, the legislature has made it clear that only the OEB can trigger the process leading to a hearing into a concern that an electricity provider is not complying with the law, including the Code. In *Graywood Investments Ltd. v. OEB*, 2005 CanLII 2763 (Div Ct.), at para. 22, Molloy J. reached a

similar conclusion when dealing with predecessor legislation, holding that:

> There is no requirement that the Board hold a hearing every time a complaint is referred to it. Rather, the right to a hearing arises only where, after its initial investigation, the Board is inclined to issue a notice of non-compliance. Even then,it is the licensee rather than the complainant who is entitled to request a hearing. Apart from that, it is entirely within the discretion of the Board whether to hold a hearing in this type of situation...

[32] Accordingly, in my view, WWLG has no standing to ask this Court to compel the OEB to hold a hearing. The OEB opinion is not the exercise of a statutory power of decision

[33] On the second issue, in my view, this Court does not have the jurisdiction to review the OEB's opinion and how it arrived at that opinion.

…

[37] In my view, the OEB's opinion regarding whether the MS16 is an expansion or an enhancement is not a decision giving rise to the public law remedy of *certiorari*. While the OEB is a public body that makes many decisions of a public character, in this case, the first factor, namely the character of the matter, weighs heavily against the availability of public law remedies. The parties sought the opinion for the purpose of resolving their private dispute. The fact that they agreed to be bound by the OEB's opinion does not turn the *opinion* into a *decision* of a public character. Ultimately, the only decision made by the OEB was not to refer the matter for further investigation or not to make an order against Elexicon which, as reviewed above, is a decision that WWLG does not have standing to challenge.

…

[39] The OEB and Elexicon argue that the OEB did not exercise a statutory power of decision and the Court therefore cannot review the decision. They point to a distinction in the case law between different complaint regimes and submit that the OEB complaint process falls into the category of cases where courts have found that a decision not to take further steps in relation to a complaint is not the exercise of a statutory power of decision.

…

[44] From the perspective of the statutory scheme, WWLG is in no different position than any member of the public who makes a complaint against an electricity supplier. Pursuant to section 105 of the *Ontario Energy Board Act*, the OEB is given broad discretion over how it will handle the complaint. This includes the ability to help the parties resolve the complaint, which is what the OEB did here by providing its opinion. However, this does not mean that a complainant can seek to judicially review the OEB's opinion. The only statutory decision the OEB makes when receiving a complaint is whether to conduct an investigation and, ultimately, whether to make an order against a regulated entity. The Act makes clear that only the OEB has the power to make such an order and members of the public have no right to compel an investigation or an order against a regulated entitled [*sic*].

[45] Accordingly, in my view, the OEB's opinion on whether the MS16 is an enhancement or an expansion is not subject to judicial review. This was not the exercise of a statutory power. The OEB provided this opinion to the parties because they requested that it do so as part of their dispute resolution process. In addition, WWLG has no standing to challenge the decision of the OEB

> not to conduct an investigation and not to make an order against Elexicon. At most, if the OEB had not processed the complaint, Elexicon could have challenged its failure to do so. But there is no legal basis on which WWLG can seek to judicial review the process the OEB followed in handling the complaint or the opinion given by the OEB on the nature of the MS16.
>
> [46] For the reasons above, the application for judicial review is dismissed.

The next decision involving jurisdiction is a decision of the Alberta Court of Appeal in September 2021 in *Utility Consumer Advocate*.[65] It involved a decision by the Alberta Utilities Commission to extend the period in time that the Board's decision on the approved rate of return would apply. That rate of return had initially been approved in 2019 and the board decided that given the difficulties created by COBIT the decision would extended for a number of months beyond the date originally set for its review the office of the utilities consumer advocate should been established by the government to represent the interests of Alberta residential farmers and small business consumers of electricity and natural gas objected to the extension while the utilities that were affected generally approved the Board's decision. The question before the court was whether the board had exceeded its jurisdiction in failing to renew the rate of return that utilities are entitled to earn in accordance with the previously set schedule

The Board and ultimately the court decided had the authority the board had the authority to make that decision. The Court of Appeal upheld the commission's decision on March 4, 2021 to delay setting of the return on equity because the economic and market data that would normally be used remain in a state of flux and any evidence would be clouded by an unusual degree of uncertainty. The court ruled that when the commission said a fair rate of return same level of proof for 2021 it was probably exercising its discretion stating as set out below:

> **Test for Permission to Appeal**
>
> [11] Pursuant to section 29(1) of the *AUCA*, an appeal lies from a decision or order of the Commission to the Court of Appeal on a question of jurisdiction or on a question of law. In order to succeed, the applicant must demonstrate that the question of law or jurisdiction raises a "serious, arguable point": *TransAlta Corporation v Alberta (Utilities Commission)*, 2021 ABCA 232 at para 16; *Remington Development Corporation v ENMAX Power Corporation*, 2016 ABCA 6 at para 10.
>
> …
>
> [15] There is no question that the application of the Fair Return Standard is an issue that is of significance to the practice and of significance to the proceeding itself as setting a fair return is an important component in setting the tariff that utilities are allowed to charge their customers and involves hundreds of millions of dollars annually.
>
> ***Merits of the proposed ground of appeal, the standard of review and delay***
>
> [16] Nowhere in the *Northwestern Utilities* decision is a specific method for the Commission mandated. The majority in *Northwestern Utilities* emphasized that the then Alberta Public Utilities Board had statutory discretion in a given case to select the method, procedure and evidence it considered appropriate to determine a fair return. The Commission in this case enjoys a similar broad discretion as noted by this Court in *AltaGas Utilities Inc v Alberta Utilities Commission*, 2020 ABCA 375 at para 21, and in legislative provisions such as section 37 of the *Gas Utilities Act* that provides the Commission may determine the matters that

[65] *The Office of the Utilities Consumer Advocate v Alberta Utilities Commission*, 2021 ABCA 336.

"in its opinion are relevant" for determination of a fair return…

[17] The Commission had discretion to employ an appropriate method and procedure given the COVID-19 pandemic. It was not required to utilize the intensive process it had used at times past; it could adopt an alternative approach, particularly in light of the COVID-19 pandemic. The applicant acknowledged those unusual circumstances when it initially moved to suspend Proceeding 24110 in the first place.

…

[20] The Commission is given a wide discretion to consider all the facts it finds relevant in exercising its statutory mandate. These decisions involve questions of mixed fact and law: *Alta Gas Utilities Inc v Alberta Utilities Commission* at para 21, citing *TransCanada Pipeline Ventures Ltd. v Alberta (Utilities Commission)*, 2009 ABCA 281 at para 37.

…

[23] The applicant's argument that the Commission made an error in law by applying the incorrect test and considering irrelevant factors does not raise a question of law permitting this Court to intervene. In settling a utilities' fair return, the Commission is empowered to weigh the evidence and exercise its judgment, which it did in this case.

[24] Accordingly, there is no basis to allow this Court to grant permission to appeal on this proposed ground of appeal.

…

[31] The applicant would have difficulty showing any unfairness arising from the Commission's decision to depart from its past procedures given the unprecedented circumstances that existed. The applicant was not denied any procedural rights nor was it treated any differently than other parties in the proceedings.

[32] As with the Fair Return Issue, delay is not a concern. However, this ground of appeal does not raise a question of law permitting this Court to grant permission to appeal.

The next decision was the decision of the Ontario Divisional Court in *Rogers Communication*.[66] There the Ontario Divisional court issued a decision dismissing an appeal with respect to a charge approved by the Ontario Energy Board for wireline attachments to electricity distribution poles. To arrive at a provincewide rate for pole attachment the OEB had conducted review of charges for wireline attachments and issued a final report in March 2018 setting a provincewide rate of $43.63 with annual adjustments based on a OEB inflation factor.

A group of carriers appealed to the Divisional Court and asked the court to set aside the report arguing that the OEB had failed to follow the provisions of the *Ontario Energy Board Act* requiring the OEB to hold the hearing. Their position was that the Board's attachment charges were a rate for transmitting electricity or retailing electricity which required the OEB to hold a hearing. The Divisional Court responded that the use of rental space on a pole by a telecommunication company had nothing to do with retailing or distribute electricity. The court further noted that previously these rates had been adjusted by amending the license of electricity distributors which contained a requirement that distributors must allow access to the poles at a specified rate which was approved by the OEB and included in the distribution license. The court concluded that the change to the attachment charge was a lawful exercise of the OEB's jurisdiction and did not require OEB hearing. The court also concluded that the process followed by the OEB was procedurally fair.

The next decision with respect to Board jurisdiction was the decision of the Ontario

[66] *Rogers Communications Canada Inc. v Ontario Energy Board*, 2020 ONSC 6549.

Energy Board in *Waterfront Toronto*[67] relating to a request by Enbridge that the Board order Waterfront Toronto to pay $70 million to cover the cost of new pipeline.

Waterfront Toronto, a consortium of three governments: the City of Toronto, the Province of Ontario, and the government of Canada, argued that it was not requesting the pipeline and in any event the Board has no authority to order Waterfront Toronto to pay any or all of the cost of a pipeline because Waterfront Toronto was not a consumer of gas. Waterfront Toronto relied on earlier decisions that found that the Board's authority to allocate costs for pipeline construction was within the Board's jurisdiction only where the Board was exercising its ratemaking authority.[68] However, in this case Waterfront Toronto was not a gas customer and no ratemaking authority was involved. Accordingly the Board ruled that it had no jurisdiction to order Waterfront Toronto to pay any of the cost of the pipeline.

The Board ordered the parties to engage in mediation. When that failed Enbridge withdrew the application. A new application was filed in February 2022, to construct two new gas pipelines in the City of Toronto. One pipeline was a temporary 190-meter 20-inch diameter bypass pipeline. The other was a permanent 160-meter pipeline. The temporary pipeline would be located on the existing Lakeshore Bridge and maintain service levels to downtown Toronto while the permanent pipeline was being constructed. The permanent pipeline will be constructed on a newly designed utility corridor that to be located on the Keating Railway bridge after that bridge is upgraded and extended in length as a necessary part of the Waterfront Toronto Flood Protection Project.

The negotiations between Waterfront Toronto, the City of Toronto, and Enbridge reduced the cost of the project from $70 million to $25 million. Waterfront Toronto agreed to contribute $5 million to the project on a voluntary basis resulting in net cost to the Enbridge Gas customers of the $18.5 million. The second application was approved by the Board.[69]

**Aboriginal Property Rights**

Last year we saw two decisions which will have a significant effect on the development of the Canadian energy projects. The first of these decisions is the decision of the British Columbia Supreme Court in *Yahey*.[70] In that case the BC Supreme Court ruled that the BC government had unjustifiably infringed the treaty rights of the Blueberry River First Nations (BRFN) through the cumulative effects of provincially authorized industrial development over a number of decades. The Court issued a declaration that the province could not continue to authorize further activities until it had reached a satisfactory agreement with the BRFN and the other Treaty 8 First Nations.

This decision is the first decision that has considered whether the cumulative effects of provincial development on treaty lands can amount to an unjustified infringement of treaty rights. The Court found that despite promises made to the BRFN extensive development of oil and gas, hydroelectric, mining, and agriculture had taken place during the last hundred years. This decision was a response to a motion brought before the Court by the BRFN to stop further development.

The Court rejected the argument that a treaty was only infringed if the BRFN had no meaningful land rights left. In other words, the BRFM did not need to show that they had no ability to exercise any rights, but only that their rights had been significantly diminished.

The British Columbia government elected not to appeal the decision. Instead, they began negotiations with the BRFN as suggested by the Court. On October 7, 2020, the province announced that they had reached an agreement

[67] *Re Enbridge Gas Inc.* (22 January 2021), EB-2020-0198, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/700885/File/document>.

[68] *Re Natural Resource Gas Limited* (7 February 2013), EB-2012-0396, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/382636/File/document>.

[69] *Re Enbridge Gas Inc.* (7 July 2022), EB-2022-0003, online: Ontario Energy Board <www.rds.oeb.ca/CMWebDrawer/Record/750562/File/document>.

[70] *Yahey v British Columbia*, 2021 BCSC 1287.

that would help provide stability and certainty for oil and gas permit holders in the BRFN traditional territory in the immediate term.

The Restoration Agreement granted $35 million to the BRFN to address past conduct including land, water, and infrastructure restoration. In addition $30 million was allocated to support the BRFN activities to protect its indigenous way of life. As part of the agreement 195 forestry and oil and gas projects which had been authorized prior to the Court decision will proceed. However 20 currently approved authorizations related to development activities in five areas of cultural importance will not proceed without agreement by the BRFN.

The next case expanding indigenous rights is the decision of the Alberta Court of Appeal in *AltaLink Management*.[71] There were two issues in that decision. The first was whether the Alberta Utilities Commission in approving the sale of transmission facilities to aboriginal groups had applied the no harm test correctly.

The second and most important issue concerned constitutional issues that involved the concept of reconciliation and whether that concept applied to decision-making by the Commission. Two of the three judges limited their decision to the definition of the no harm test and did not address the constitutional issues. One justice on the other hand offered a lengthy concurrence. Justice Feehan agreed with the majority decision but considered it appropriate to carefully explore whether the Commission's decision-making must consider the concept of reconciliation. In doing so he started with section 17 of the *Alberta Utilities Commission Act* that clearly stated that when the Commission is conducting a hearing with respect to an application to construct a transmission line it must determine if the transmission line is in the public interest.

At paragraph 113 Justice Feehan stated that reconciliation is "a work in progress of rebuilding the relationship between indigenous people and the Crown following historical and continuing injustice by the Crown against indigenous people". He further stated at paragraph 114 that "while reconciliation underlies the honour of the Crown in section 35 rights it is a distinct concept that exist separately from the honour of the Crown and includes both legal and social dimensions". The following statements in the concurrence deal precisely with the concept of reconciliation.

> [115] Reconciliation is a primary consideration where constitutionally protected interests are potentially at stake. The fundamental purpose of s 35 of the *Constitution Act, 1982* is to rebuild the relationship between the Crown and Indigenous peoples through reconciliation; legally, morally and socially. The fundamental objective of the modern law of Aboriginal and treaty rights is the reconciliation of Indigenous peoples and non-Indigenous peoples and their respective claims, interests, and ambitions: *Mikisew Cree*, paras 1, 63. Section 35 supports reconciliation of the assertion of Crown sovereignty over Canadian territory and prior occupation by distinctive Indigenous societies by "bridging Aboriginal and non-Aboriginal cultures": *R v Van der Peet*, [1996] 2 SCR 507, paras 42–45, 49–50, 137 DLR (4th) 289. The controlling question in all situations is what is required to effect reconciliation with respect to the interests at stake in an attempt to harmonize conflicting interests, and achieve balance and compromise: *Taku River*, para 2.
>
> [116] The concept of reconciliation is illustrated in *Tsilhqot'in Nation v British Columbia*, 2014 SCC 44, [2014] 2 SCR 257, para 23:
>
>> What is at stake is nothing less than justice for the Aboriginal group and its descendants, and the reconciliation between the group and broader society.... It is in the broader public interest that land claims and rights issues be resolved in a way that reflects the substance of the matter. Only thus can the project

[71] *AltaLink Management Ltd v Alberta (Utilities Commission)*, 2021 ABCA 342.

> of reconciliation this Court spoke of in *Delgamuukw* be achieved.
>
> …
>
> [118] Any consideration of public goals or public interest must "further the goal of reconciliation, having regard to both the Aboriginal interest and the broader public objective": *Tsilhqot'in Nation*, para 82. Reconciliation requires justification of any infringement on or denial of Aboriginal rights, paras 119, 125, 139, and meaningful consideration of the rights of Indigenous collectives as part of the public interest.

The most important paragraphs in Justice Feehan's concurrence may be at paragraphs 119 and 120 as follows:

> [119] As this Court said in *Fort McKay*, the direction to all authorized government entities to foster reconciliation particularly requires that they consider this constitutional principle whenever they consider the public interest, para 68, and requires the Crown to act honourably in promoting reconciliation, such as by "encouraging negotiation and just settlements" with Indigenous peoples: *Mikisew Cree*, para 26; *Fort McKay*, para 81.
>
> [120] Aiming to achieve reconciliation is a continuing obligation, existing separately from honour of the Crown. An important aspect of reconciliation is the attempt to achieve balance and compromise, essential to the consideration of the public good. Reconciliation must be a consideration whenever the Crown or a government entity exercising delegated authority contemplates a decision that will impact the rights of Indigenous peoples.

Justice Feehan concludes his concurrence with the following two paragraphs

> [125] The Commission is an authorized governmental entity empowered to decide questions of law and constitutional issues and make decisions that are in the public interest. As a result, it has special obligations to consider the honour of the Crown and reconciliation whenever these are raised by the parties and relevant to determining the public interest, and to provide in its decisions an analysis of the impact of such principles upon the orders made. Where one or more of the parties appearing before the Commission is an Indigenous collective which raises the honour of the Crown or reconciliation in its submissions, the Commission should consider whether those constitutional principles are applicable to its decision.
>
> [126] The Commission must take all relevant factors into account in determining the public interest. In exercising its authority, it is required to consider the social and legal impact of its decisions on Indigenous peoples, including doing what is necessary to uphold the honour of the Crown and achieve reconciliation between the Crown and Indigenous peoples.

The important aspect of the decision is this. No one disputes that a Canadian energy regulator in approving the construction of a major energy facility must make a determination whether the construction of that facility in the public interest. The definition of the public interest has always been very broad and allows the regulator considerable discretion.[72] The Feehan concurrence, if followed, would add a very significant element to that public interest test — namely that the regulator must ensure that the agreement with respect to any use of aboriginal land in a project must display "significant accommodation" (para 109),

[72] *ATCO Ltd. v Calgary Power Ltd.*, [1982] 2 SCR 557, 140 DLR (3d) 193; *Union Gas Ltd. v Township of Dawn*, 76 DLR (3d) 613, 15 OR (2d) 722; *Enbridge Gas Distribution Inc. v Ontario Energy Board*, [2005] OJ No 756 (QL), 75 OR (3d) 72.

"constructive action" (para 114), "balance and compromise" (para 115), "justice for the aboriginal group" (para 116), and "a just settlement" (para 119).

Canadian energy regulators spend most of their time on two things. The first is setting rates and making sure those rates are just and reasonable. The second is approving the construction of new energy facilities and making sure that they are in the public interest. In the case of the latter most projects now involve aboriginal land.

The Feehan concurrence strongly suggests that a regulator, in determining if the new project is in the public interest, must make sure that any aboriginal landowners have received a fair deal.[73] This will create a new challenge for Canadian energy regulators. However, the Feehan decision is a concurrence not a majority decision. We will have to wait and see how much traction it gets in the future. The writing may be on the wall. The Supreme Court of Canada in the recently released decision in *Anderson v Alberta*[74] considered the principles of reconciliation in making a determination whether to award an aboriginal group an advanced cost award.

A third decision last year also speaks to the expansion of aboriginal rights in Canada and the concept of reconciliation. That is the decision of the Supreme Court of Canada on April 23, 2021 in *R v Desautel*.[75]

Mr. Desautel was a member of the Lakes tribe in Washington State. He was charged with hunting without a license in British Columbia. He admitted he had shot an elk but argued that as a member of the Lakes tribe he had aboriginal rights protected by section 35 of the *Constitution Act*.

The Court heard evidence that at one time the Lake tribe ancestral territory was on both sides of the border of what is now British Columbia and Washington state. The Court ruled that Mr. Desautel was a modern day successor of a aboriginal society that occupied Canadian territory at the time of European contact, and the principle of reconciliation required that their aboriginal status should be recognized even if tribe members had been displaced as a result of colonization.

**The No Harm Test**

In a decision handed down in May 2022 the Alberta Court of Appeal in *AltaLink Management*[76] clarified the meaning of the no context as it applies to transactions in Alberta. At the same time the court made it clear that in determining whether a transaction is the public interest the regulator should consider the impact on aboriginal interests where aboriginal property rights are at issue.

The concept of the no harm test was first used in United States by FERC in merger transactions. It was a reverse onus test stating that the merger would be approved where it would create no harm. That concept was picked up by the Ontario Energy Board nine years later in what was know as the Joint MAADs case[77] where the Ontario Energy Board set down the basic rules with respect to mergers and acquisitions when it heard a number of merger applications at the same time.

*AltaLink Management* concerned the activities of AltaLink, a major Alberta electricity transmission company. AltaLink had purchased a transmission system and expanded it across two first Nations reserves. There were alternatives to using the first Nations land but that was the lowest cost route. The First Nations affected agreed to the construction of transmission line on their land in exchange for an opportunity to obtain an ownership interest in the transmission line.

A few years after the transmission line became operational the first Nations exercised their option to acquire the interest in transmission business. AltaLink then filed an application with the Alberta Utilities Commission for approval of the transfer of the financial interest to the first Nations group as well as approval for the transmission rates.

[73] Gordon E. Kaiser, "Reconciliation: The Public Interest in a Fair Deal" (2021) 9:4 Energy Regulation Q 38.

[74] *Anderson v Alberta*, 2022 SCC 6.

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

[76] *AltaLink Management Ltd v Alberta (Utilities Commission)*, 2022 ABCA 18.

[77] *Re Greater Sudbury Hydro Inc., PowerStream Inc. & Gravenhurst Hydro Electric Inc.* (31 August 2005), EB-2005-0234, EB-2005-0254, EB-2005-0257, online: Ontario Energy Board <www.oeb.ca/documents/cases/RP-2005-0018/decision_310805.pdf>.

The Commission approved the transfers on the condition that the partnership agreed not to recover from ratepayers $60,000 in incremental auditor costs and the cost of the hearing. The Commission applied the no harm test to measure the positive and negative impacts of the transaction on ratepayers. The Commission rejected the argument that routing the transmission line through First Nations land would save $32 million and would create benefits for First Nation communities. Instead the Commission stated that the no harm test is a forward-looking exercise and the Commission can not consider the alleged savings because AltaLink failed to provide sufficient evidence of the those benefits.

AltaLink then sought and obtained leave to appeal to the Court of Appeal. A majority of Court of Appeal found that the Commission erred in considering only forward-looking benefits stating that there was no legislative basis for that approach. The majority also found that the projects would increase the economic advantages on reserves which are in the public interest and should be encouraged. The Court of Appeal varied the Commission's decision and allowed the partnership to recover the disputed regulatory costs from ratepayers.

The decision also had a concurrence by Justice Feehan. His concurrence addressed the aspect of the application that the majority determined was not necessary to address. The majority concluded its decision as follows:

> [1] We allow this appeal and direct the Alberta Utilities Commission to allow two limited partnerships ultimately controlled by the Piikani Nation and the Blood Tribe to pass on audit and hearing costs they incur as utility owners to ratepayers. The Commission had ordered the appellants to absorb these costs. This is the first and only time that the Commission has issued such an order.
>
> II. Questions Presented
>
> [2] The Commission determined that its approval of the electrical transmission asset transfers from AltaLink Management Ltd. to the limited partnership controlled by the Piikani Nation and the Blood Tribe would result in incremental costs to the ratepayers — the consumers of electricity. The transferees would each incur additional annual audit fees payable to external auditors and Commission hearing costs, estimated to be $60,000. The Commission refused to allow the transferees to pass these costs on to the ratepayers.
>
> …
>
> [4] The appellant argued that the Commission, when discharging its authority under the Alberta Utilities Act, must take into account the honour of the Crown principle and the reconciliation concept.
>
> [5] These arguments presented five questions.
>
> [6] First, does the honour of the Crown principle apply to the decision-making authority of the Commission?
>
> [7] Second, if so, what is the impact of the honour-of-the-Crown principle on its decision making authority?
>
> [8] Third, what are the legal benchmarks of "reconciliation"?
>
> [9] Fourth, does the reconciliation concept apply to the decision-making authority of the Commission?
>
> [10] Fifth, if so, what is the impact of the reconciliation concept on its decision-making authority?
>
> III. Brief Answers
>
> [11] The Commission committed a legal error by failing to take into account all relevant factors that determine whether a sale is in the public interest. Its decision to ignore the cost savings arising from the routing of the transmission lines across the reserves of the Piikani Nation and the Blood Tribe is an error of law.
>
> [12] We vary the Commission's Decision 22612-D01-2018 by ordering that the transferees be allowed to include the incremental audit and hearing costs in their respective tariff applications and

> recover them from ratepayers in the usual course.
>
> **[13] Given our answer to the first question, we need not answer the other queries. Only one declaration of error is needed to strip the contested order of its legal effect.**
>
> [Emphasis added]

The Feehan concurrence focused on the concept of reconciliation and what obligation that concept placed on energy regulators. AltaLink in its argument before the Court of Appeal had emphasized the benefit that aboriginal groups would gain from the transaction as well as the benefits that Altalink and ultimately the ratepayers obtained by building the transmission line in the lowest-cost manner by using aboriginal lands.

In addition to correcting the error the Alberta regulator made in its definition of the no harm test the decision emphasized the importance of considering the impact of a transaction on aboriginal groups in making a determination whether the transaction was in the public interest,

There is nothing new about the public interest test. That test and the use of the no harm test in determining if the public interest has been met is a long-accepted standard. The impact of the transaction on aboriginal interests is however a new and important addition. The scope of that inquiry will become more challenging in the future. ■

# REGULATORS: DISRUPTED BY CHANGE OR DISRUPTORS BRINGING CHANGE?[1]

*Monica Gattinger and David Morton**

The annual CAMPUT 2022 conference explored an essential issue facing regulators across the world — disruption.

When energy sector regulators, industry, and other stakeholders gather, conversations quickly turn to change. Energy sector regulation is rarely discussed without someone or several someones bringing up "massive disruption." And as these conversations unfold, a key debate emerges: Are regulators predominantly disrupted by a rapidly changing environment? Or are regulators themselves the disruptors? There is rarely consensus. Some encourage regulators to be change-makers, noting that the urgency of addressing issues like climate change requires proactive attention. Others push back on this idea.

The 2022 conference of Canada's Energy and Utility Regulators (CAMPUT), titled "Deep dive into disruption," took place May 1–4 in Vancouver, British Columbia, and featured these types of conversations. Attended in person by close to 300 regulatory and industry leaders, along with almost 200 people attending virtually, the event explored decision-making, regulation, and regulators in the context of disruption. Sessions focused on rates and utilities in a decarbonizing world, the future of gas, relationships with Indigenous peoples, energy equity and affordability, the growing role of consumers and distributed energy resources, and digitalization. The role of the regulator underpinned most conference discussions.

Here, we aim to unpack the debate and propose an answer to the question.

## REGULATORS AND RAPID CHANGE

Start with the context. There's no question regulators are operating within a rapidly changing environment. Much of the urgent change is driven by global efforts to reduce the effects of climate change. Meeting Canada's climate targets of reducing emissions 40 to 45 per cent from 2005 levels by 2030 — and becoming net zero by 2050 — requires Canada's energy systems to change dramatically in a very short timeframe. Enormous costs lie ahead, and regulators will play an important role in climate change mitigation and adaptation. At the same time, technological change, innovation, and

[1] The following article is a reprint with permission of the original that appeared in the ICER Chronicle, Edition 12 (Summer 2022), online (pdf): <intranet.icer-regulators.net/public/uploads/files/events/20220715191238_ICER_Chronicle_Edition_12_FINAL.pdf>.

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energy sector digitalization are occurring at a growing pace and scale, further disrupting the regulatory environment.

The emergence of new technologies and energy sources is impossible to predict. No one knows with certainty how long it will take for batteries, hydrogen, or small modular nuclear reactors to operate in the system at scale. But regulators will nonetheless be called upon to make decisions, many of which will shape the technological landscape and have significant impacts on the cost of energy. All the while, the use of distributed energy resources continues to grow, and shifting consumer expectations create the potential for "prosumers" to take on more prominence in the years ahead.

Alongside these environmental and technological disruptions, major social changes are transforming the regulatory landscape. In Canada, chief among them is reconciliation with Indigenous peoples. The need for reconciliation between Indigenous and non-Indigenous Canadians is fundamentally reshaping energy projects. Given the constitutional, legal, and historic context in the country, Indigenous consent for projects is crucial. Without it, project approvals can face lengthy — and often successful — court challenges. Many Indigenous communities have become willing partners with other proponents on energy projects (notably partners with equity stakes). This is fast becoming the path in Canada to Indigenous consent for projects. Regulators are increasingly working alongside Indigenous advisory committees that provide ongoing advice on regulatory issues that affect their communities. Regulators are also establishing joint monitoring programs through which Indigenous communities conduct safety and environmental monitoring activities on energy infrastructure like pipelines.

Regulators are also faced with the rise of affordability and social equity imperatives, including questions of equity and affordability in rate design, tensions between price signals and affordability in emissions reductions, and how to allocate capital costs of projects when governments don't want to defray those costs using the tax base.

All of these issues amplify uncertainty, risk, and disruption for regulators and challenge their capacity to plan, make decisions, and create appropriate regulatory frameworks. A crucial question emerges — What is the role of the regulator? — and this question begs many more.

## REGULATORS: DISRUPTED OR DISRUPTORS?

Should regulators be proactive and become disruptors? Or is their role about reacting to disruptive change? At the CAMPUT 2022 conference, some speakers advocated for regulators to "choose change" and drive it by creating regulations based on desired end states, whether those end states are emissions reductions, social equity, reconciliation, or all three. Other speakers encouraged regulators, as administrative tribunals, to "stick to their knitting" and operate within the purview of their legislative mandates. This debate has both legal and democratic dimensions. Regulatory decisions are subject to various forms of judicial review, and, at the end of the day, elected officials should be the ones deciding on broader matters of public policy.

Many of these discussions were framed, on the one hand, by the urgency of addressing climate change, and, on the other hand, by questions and concerns about how to allocate the enormous costs of decarbonization in ways that are fair and equitable. What is the precise role of regulators in this con text? Should regulators be the ones deciding who pays which costs for emissions reductions, when they pay them, and how they pay them? Or should regulators play a supporting role and provide evidence and data to governments to help inform policy choices on these questions?

Similarly, should regulators be making decisions about the role of gas in future energy systems? Or should regulators instead provide evidence to inform choices by governments and consumers? Speakers and attendees at the CAMPUT conference often said regulators should be proactive change-makers because of the urgency of reducing emissions: There are costs to society if regulators wait for governments to reform regulators' enabling legislation. But there may also be costs to society if regulators "lean out over their skis" and make mistakes or make decisions for which there is no democratic foundation.

At their heart, many of these discussions hinge on whether a regulator's stance on environmental, economic, or social imperatives represents a failure of legislative frameworks and mandates, or whether it's instead a failure of imagination on the part of regulators. Our view is that this bifurcated way of framing the issues misses the mark.

## A MORE CONSTRUCTIVE FRAMING

There is a more constructive approach to discussing these important topics. Instead of pointing fingers at legislation or at regulators, why not ask whether regulators can work within the broader decision systems of which they are a part to effectively navigate and respond to disruption?

Regulators are one part of a broader decision-making system for energy that includes, importantly, policymakers and legislatures. Responding effectively to climate change, technological change, social equity imperatives, and Indigenous reconciliation requires a system-level approach. First, regulators should innovate within their existing mandates. This could include working with utilities and other market participants to find innovative solutions for emissions reductions planning (or other imperatives) in an uncertain environment.

The British Columbia Utilities Commission, for example, has required regulated companies BC Hydro, the largest supplier of electricity in British Columbia, and Fortis Energy, the largest supplier of natural gas, to exchange their energy forecasts for electricity and gas. This enables each of the utilities to provide their own forecast in response to the other's and helps to foster alignment on future resource plans. Regulators could also develop scenarios for emissions reductions or electrification to inform government decision-making. There are multiple scenarios published by a variety of sources, with greater or lesser levels of rigour and credibility. With their deep expertise and access to data, regulators could play a crucial role on this front.

But to take this third route in the disruption discussion depends on policymakers trusting regulators to "do the right thing." Effectively navigating and responding to disruption requires a whole of system approach in which everyone is open to taking on new roles. Governments will have to decide how much authority they want to give regulators to be part of the solution for issues like decarbonization, Indigenous reconciliation, and social equity. They will then need to provide the necessary authority, resources, and personnel for them to take on new roles.

For urgent issues, such as reaching ambitious decarbonization targets, increasing the speed of change while minimizing mistakes requires improved dialogue among all actors in decision-making systems. It also requires mutual learning in meaningful and thoughtful ways in order to help foster alignment on problems and solutions, and in particular how problems can be addressed by policy, regulation, industry, and civil society. Effectively responding to climate change will also involve integrated system planning and clear communication of pathways and options. Integrated planning across sectors can help to optimize existing systems and assets for emissions reductions and, crucially, for affordability, resilience, and reliability. Regulators can play pivotal roles in all of these changes, but there needs to be shared understanding among energy sector decision-makers of their roles and responsibilities to avoid conflict, overlap, and working at cross-purposes.

Finding ways of moving faster will also require rethinking the risk tolerance of regulators and paying careful attention to the costs of failure. A culture change towards better acceptance of failure may be needed within regulatory agencies and among politicians and policymakers. Learning from mistakes — rather than punishing them — would be a good place to start.

The questions threaded through CAMPUT's 2022 conference will emerge ever more frequently in the years ahead. Regulators will need to think through their answers rapidly, thoughtfully, and proactively. So will policymakers. None of this will be easy. But it is essential for energy decision systems to navigate and respond effectively to disruption. ■

# REGULATING MERGERS AND ACQUISITIONS OF U.S. ELECTRICAL UTILITIES: INDUSTRY CONCENTRATION AND CORPORATE COMPLICATION[1] BY SCOTT HEMPLING

*Gordon E. Kaiser*

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**R***egulating Mergers and Acquisitions* of US Electrical Utilities provides a unique analysis of the approval of mergers and acquisitions by energy regulators in the United States over the last forty years. There are hundreds of books dealing with the approval of mergers in competitive markets in over 100 years of competition law and anti trust law in Canada and the United States. In that sector the analysis is less complicated. There, mergers mean increased concentration which usually means less competition and higher prices. In regulated markets however the price is regulated, and price is not the concern.

Scott Hempling makes two fundamental points in this book. The first is that the expansion of a monopoly rate base often creates a greater consistent flow of revenue and that, Hempling claims, can help subsidize business activities in unregulated markets. The second, he argues, is that the "no harm" test which is used in both Canada and the United States in merger analysis is next to meaningless. By way of background, Hempling observes that since the 1980s in the United States a stream of mergers and acquisition has cut the number of local independent electric retail utilities in the US by more than half. This, he states, is not in the public interest.

Before we go further, we should outline the substantial experience this author brings to this book. Hempling is the author of three books[2] which energy regulators and counsel consider to be required reading. Scott Hempling has acted as counsel, arbitrator, and expert witness in various regulatory proceedings throughout the United States. For many years he has been a very popular professor at the Georgetown University Law Centre. He has lectured widely at energy conferences in Canada, the United States, and Europe.

He is no stranger to Canada. He has spoken three times at the Canadian Energy Law Forum.

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[1] Scott Hempling, *Regulating Mergers and Acquisitions of U.S. Electric Utilities: Industry Concentration and Corporate Complication* (Chelthenham: Edward Elgar Publishing, Inc., 2020).

[2] Scott Hempling, *Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction* (Chicago: ABA Book Publishing, 2021); Hempling, *supra* note 1; Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Washington: Scott Hempling, Attorney at Law LLC, 2013).

First at Salt Spring Island, British Columbia in 2011; then at Malbaie, Quebec in 2012, and Fox Harbour, Nova Scotia in 2014. Hempling has also authored nine articles in this journal. We should add that within a few months the *Energy Regulation Quarterly* will be 10 years old. Scott Hempling will be one of the few authors that has averaged one article a year over the decade.

There is a reason why Hempling has such a wide following. As we noted when we reviewed one of his earlier books Hempling is the Will Rogers of the energy regulation lecture circuit. He takes after his mentor, Alfred Kahn, the former chairman of the Economics Department at Cornell University. Kahn became best known when he was Chair of the Civil Aeronautics Board in Washington, DC. While in that job Kahn made the famous statement that he did not know one plane from another but it did not matter because they were only marginal cost with wings. Scott Hempling enjoys a similar turn of phrase and in his lectures sophisticated economic and legal concepts become long remembered catchy phrases.

This book is unique in that it carefully reviews over seventy merger transactions reviewed and approved by the Federal Energy Regulatory Commission (FERC). Scott Hempling's concerns with the FERC record in merger cases can be best summarized by three paragraphs on the subject in a recent ERQ article.[3] His position in this book can be traced to that article and that article can be traced to a significantly larger article on the same subject in the Energy Law Journal one year earlier.[4]

> Since the mid-1980s, mergers and acquisitions approved by the *Federal Energy Regulatory Commission* (FERC) have cut the number of independent retail electric utilities by more than half. These transactions have taken every possible form: horizontal, vertical, convergence, and conglomerate; operationally integrated and remote; domestic and international; publicly traded and going-private; debt-financed and stock-for-stock.
>
> Accompanying this consolidation has been a complication. The conventional pre-1980s utility — local, pure play, conservatively financed — is being replaced by multistate and multinational holding company systems: corporate structures housing multiple, and sometimes conflicting, business ventures — structures that owe their finance ability and viability to their utility affiliates' monthly cash flow.
>
> Under Section 203 of the *Federal Power Act*,[5] the FERC must find these consolidating and complicating transactions "consistent with the public interest".[6] Despite multiple policy statements, rules, and 70-plus transaction approvals, the FERC has never defined a "public interest" in terms of the industry's performance. Though the 1996 *Merger Policy Statement*[7] states a purpose of "encouraging greater wholesale competition", that purpose rarely appears in the FERC's actual merger orders. These orders require only "no harm", and no harm only to pre-merger competition — regardless of whether that pre-merger competition is effective or ineffective. Effective competition exists when a market's structure, and its sellers' conduct, pressure all rivals to perform at their best. By requiring only "no harm", and by applying that standard only to pre-merger competition, the FERC has invited and approved transactions whose contributions to performance are

[3] Scott Hempling, "Inconsistent with Public Interest: FERC's Three Decades of Deference to Electricity Consolidation" (2019) 7:2 Energy Regulation Q 33.

[4] Scott Hempling, "Inconsistent with Public Interest: FERC's Three Decades of Deference to Electricity Consolidation" (2018) 39:2 Energy LJ 233.

[5] *Federal Power Act*, 16 USC § 824b.

[6] *Ibid*, § 203(a)(4).

[7] See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 61 Fed Reg 68595 (1996).

> necessarily suboptimal. For 30 years, the Commission's merger decisions have disconnected the "public interest" from performance.
>
> The Commission's deference to applicants' strategies is logical, and lawful, when the relevant markets giving birth to these transactions are effectively competitive markets. But when mergers involve retail monopolies, the relevant markets are not effectively competitive. Deference to transactions undisciplined by effective competition cannot be consistent with the public interest.

Scott Hempling's concern is really with the no harm test. Since 2005 Canada has used the no harm test in merger cases. More recently Alberta has used this test when it comes to approving construction of new transmission facilities. In that case the Court of Appeal had to determine whether the benefits of the new construction in the determination of whether the no harm test had been met was limited to past benefits and could not include future benefits.

In both Canada and the United States, the no harm test is part and parcel of the public interest test. Hempling points out that the FERC has never offered an adequate definition of that test. Nor have the Canadian courts. Both Canadian courts and American courts concede that it is very broad test and considerable discretion is granted to the regulator in both countries in determining if the public interest test has been met.

In conclusion we note that the regulator's role in approving mergers and acquisition is an important one. It certainly could be improved, as Hempling argues. This book is required reading for any serious energy regulator. The merger issue will become more important going forward. Today regulated utilities are being asked to adopt a number of new technologies in an effort to help decarbonize the electricity grid. Some of those new technologies will lead regulated utilities into competitive markets. A good example is EV charging where many policymakers believe the market should be competitive but at the same time they want the utilities to be involved to ensure that the EV charging networks expand fast enough to meet the dramatic increase in EV vehicles.

Scott Hempling's recent appointment as an Administrative Law Judge at FERC in June 2021 may mean that we will see fewer books and articles by him questioning regulatory conduct. However, no doubt his quick mind will be put to work in writing some very important decisions. ■

# INVESTOR EXPECTATIONS ON NORTH AMERICAN NATURAL GAS UTILITIES

*Guidehouse*

From time to time the *Energy Regulation Quarterly* publishes reports prepared by other organizations on different aspects of regulatory practice. Our usual practice is to introduce the Report with an Editor's Introduction that summarizes the highlights.

**EDITORS INTRODUCTION**

This Report, which was published on July 12, 2022, was prepared by the consulting firm, Guidehouse.[1] It was sponsored by the Canadian Gas Association and the American Gas Association. The study starts by answering three key questions:

1. How do energy regulators set the allowed return on equity or ROE for gas utilities?
2. Do the ROE's in Canada and the United States meet investor expectations?
3. What future business opportunities should utilities pursue to maintain investor attractiveness?

The study points to some concern about declining levels in the average ROE between 2010 and 2021. It was also significant that the Canadian returns were below the American returns. At the end of the day, it was apparent that the decline was largely related to declining interest rates generally during the period. Generally speaking gas utilities were seen as an attractive investment provided that:

1. There was positive year-over-year growth in rate base and customer numbers
2. The rate setting process established by regulators was transparent and consistent
3. Utilities had plans to diversify and introduce clean fuel with hydrogen blending.

There is no doubt that in Canada both Fortis in British Columbia and Enbridge in Ontario have established a solid track record in terms of hydrogen blending. More recently Enbridge has taken a major investment position in LNG which is generally seen as a positive step with attractive long-term markets.

The study indicates that investors generally agree that there is no low cost alternative to replace natural gas in the short term but gas utilities must still be proactive in addressing decarbonization. Utilities are expected to invest in new fuel supply streams including hydrogen and work towards introducing new technology solutions to the market.

One point should be made about this study- virtually all of the analysis took place before Russia invaded Ukraine. That war has created a dramatic change in the North American gas utility business from an investor perspective. Europe, which is one of the largest energy markets in the world, is dependent on Russia for more than 40 per cent of its gas. All of a sudden there is a demand to replace the Russian gas with gas from other sources.

In particular the focus is on LNG coming from Canada and the United States as well as Australia and Qatar. The recent Enbridge

[1] Greenhouse, "Investor Expectations on North American Natural Gas Utilities" (12 July 2022), online (pdf): <www.cga.ca/wp-content/uploads/2022/07/Study-Investors_View_Natural_Gas_Utilities_as_Desirable_Investments.pdf>.

investment in LNG Canada in Kitimat is a good example. That project will be operational within a year. Other projects are in the planning stage including two projects in Atlantic Canada.

The study provides a useful perspective because it is based on interviews with the relevant investor groups. There is no doubt however that the perspective of those investor groups may well be more positive today than at the time the research for this study took place.

The full Report is available here. ■

# THE FORGOTTEN FACTOR IN CLIMATE POLICY: ENERGY DELIVERY

*Michael Cleland and Monica Gattinger**

## INTRODUCTION

Throughout over thirty years of climate policy a great deal of thinking — and considerable action — has been devoted to upstream energy systems. And there has been some success, especially decarbonizing power production and reducing upstream oil and gas emissions intensity. But as we bear down on the challenge of net zero by 2050 and the potential electrification of much of the energy system, policymakers will increasingly need to confront the forgotten factor of energy delivery.

In our view, this is where the rubber will most visibly meet the road on climate policy. If emissions reductions efforts don't sustain energy fundamentals — the safety, security, reliability, resilience and, crucially, affordability, of energy — they will fail. The political, social and economic consequences of a world without energy fundamentals will stand in the way of climate progress. Simply put, durable emissions reductions hinge on maintaining public support and that requires maintaining energy fundamentals.

So how to secure both emissions reductions and energy fundamentals in energy delivery systems? In recent research, we looked at the political, regulatory, economic, social and technical challenges facing energy delivery systems in Canada and internationally on the road to net zero. We examined New York State, Western Australia and Great Britain.[1] We reviewed what delivery system emissions reductions might involve in terms of capital investment, operational issues for power and gas distribution, the implications for piped energy systems, reliability and affordability, the responses of energy consumers, and the successes and failures of various policy and regulatory approaches being tried.

The answer? No one knows much with certainty. There is lots of work on technological solutions and lots of modeling and analysis, but there remain yawning gaps between the assumptions baked into models and the 'real worlds' of energy delivery and energy fundamentals. Similarly, there are lots of climate policy and regulatory approaches being implemented, but for the most part it is too early to assess their ultimate outcomes and success in reducing emissions — although our research points to the risk of ambitious climate policies running off the rails on cost, affordability, supply or reliability of end use power and natural gas.

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Dr. Monica Gattinger is Founding Chair of Positive Energy, Director of the Institute for Science, Society and Policy, and Full Professor in the School of Political Studies at the University of Ottawa.

[1] Michael Cleland & Monica Gattinger, "Net Zero: an International Review of Energy Delivery System Policy and Regulation for Canadian Energy Decision Makers" (4 April 2022), online (pdf): <www.electricity.ca/files/reports/english/Net-Zero-Intl-Regulation-and-Policymaking-Report_Gattinger-Assoc_April-2022.pdf> (This research study was undertaken for the Canadian Gas Association and Electricity Canada, with support from Natural Resources Canada. In separate work, we reviewed the state of knowledge across North America and Europe respecting the cost and operational implications of rapid large-scale electrification of transport and heat).

All told, we have very little to go on respecting the most constructive path forward on emissions reductions in energy delivery.

So what should be done? Our research underscores that the time is now for Canadian jurisdictions to move with alacrity to better understand how the forgotten factor of energy delivery can be better understood and acted upon in ways that are consistent with both climate aspirations and how the system actually works. With that in mind we have proposed a Canada-wide effort to fill this gap.

Before sketching that out, below we dive deeper into the challenges, contexts, tensions and attention to costs that our research reveals will need to inform current and future policies for energy delivery systems.

## CITIZENS, CUSTOMERS, COMMUNITIES AND COMPANIES: CHALLENGES, CONTEXTS, TENSIONS AND COSTS

In the course of decades of climate policy we have encountered a few "oops" moments. We have seen consumer anger over escalating power prices in Ontario driven at least in part by climate policy decisions. Most notorious of course is consumer reaction to skyrocketing energy prices and inflation as countries lift COVID-19 restrictions and as the war in Ukraine carries on. What these experiences show is that when put to it, energy fundamentals like security of supply, affordability and reliability, tend to trump all other considerations for citizens — and by extension policymakers.

But what may turn out to be the biggest oops concerns what happens when the aspirations for energy delivery system transformation meet the real worlds of consumers, citizens and communities in their day to day lives, the real worlds of investors and companies who need sufficient incentives to bring capital and new business models to bear on emissions reductions, and the real world of cost, where decisions about who pays what, when and how for emissions reductions will need to be decided upon in a transparent and thoughtful manner.

The challenge of net zero is unprecedented — in scale, in complexity, in speed. Unlike previous energy transformations, it must be brought about primarily by public policy makers. Individual economic actors such as investors, utilities or technology developers — and in some cases consumers — have become active participants in responding to the challenge. But companies' ability to act and their confidence to invest depends in large measure on policy and regulation. Decisions to invest in innovation and in large long-lived energy projects hinge on policy and regulatory clarity, certainty and predictability. Policy reversals, politicized decision-making and unclear rules and regulations can all be barriers to unlocking the large-scale investment needed to transform energy delivery systems.

Citizens have expressed support in principle for the goal of net zero but they have little understanding of what that means for them personally in practice. Experience to date suggests that when push comes to shove, in their personas as customers they will give priority to energy fundamentals (security of supply, affordability, reliability, safety, resilience). At the same time, citizens and customers generally live in long established communities. Communities can be facilitators of change or impediments depending on how they are engaged and brought along, and the sorts of leadership roles they aspire to take on.

If policy and regulation fail to recognize the realities of citizens, customers, communities, companies and costs, no emission reduction plan can survive nor, in all likelihood, will the democratic government that tries to implement it.

Therefore, the central question for this article and the research behind it concerns the delivery of energy in end use markets in a way that responds to climate goals (net zero) while adhering to all of the energy fundamentals and — ultimately — political sustainability of emissions reductions policies.

Every jurisdiction has its unique characteristics as does every community, but comparisons can be useful. Roughly speaking, we might describe the challenges in terms of the physical and organizational changes that need to be made to energy systems, often referred to as "pathways". Jurisdictions in Canada and in our case studies of Western Australia, New York State and Great Britain are confronting some mix of the following challenges:

- How to accommodate massive growth in electric system load and changes in load profiles entailed by electrification.

Flowing from that, how to manage all the issues surrounding new infrastructure and system management.

- How to integrate new local sources into power systems including renewables, storage, distributed energy and demand side response in ways that sustain the integrity of the systems.
- How to support emissions reductions in natural gas systems, including the ongoing greening of gas delivery through energy efficiency and demand side management and the introduction of low GHG alternatives from RNG to hydrogen.
- How to address natural gas systems potentially becoming obsolete if they are replaced by an all-electric system — and all that implies for system integrity, stranded assets, stranded customers and cost allocation.
- How to integrate power, fuel and heat systems (combining gas, hydrogen, electricity, heat and local renewables in integrated systems).
- How to transform the respective roles and business models for utilities, energy service providers and technology providers and create investment conditions that make the new systems work.
- How to account for inevitable supply constraints respecting critical materials, skills and workers in the economy writ large and within public agencies.
- How to reconcile the local character of the challenge with the realities of distant energy sources and interconnected systems at a regional scale.
- And, crucially, how to do all of the above in a way that sustains energy fundamentals.

Different contexts can aggravate the challenges or facilitate solutions:

- The most obvious is physical. Decision-makers have to ask: What energy sources are available? Do they come from within the jurisdiction, and if not, what implications does that raise for cross jurisdiction cooperation or conflict? What are the available delivery routes?
- What are the drivers of load on the system (e.g., space heat or cooling, seasonal variability, industrial, resource sector or commercial demand)?
- Constitutional and legal factors can facilitate or constrain — most notably for Canada the realities of federalism and the imperative of accounting for the rights and roles of Indigenous peoples.
- Political cultures differ, among them the extent to which jurisdictions might be amenable to central economic direction, along with expectations of the populace to directly shape policy and for policy and regulatory processes to be open and inclusive.
- Governmental machinery and associated practices can vary regarding the respective roles of legislative bodies and the political executive and the degree to which authority is devolved to independent bodies, from planning commissions to regulators.
- Public ownership in the energy delivery space and the influence of Crown corporations on policy development is also a crucial element of context.

Regardless of context, for any jurisdiction, responding to the various challenges will inevitably generate tensions that have ongoing political ramifications. Ignoring any of these fast endangers climate policy success:

- The drive to net zero delivers very little direct or immediate energy benefit to citizens but must be undertaken in a way that sustains citizen support for climate action.
- As outlined earlier, the most critical threat to citizen support is common across all jurisdictions: how to reduce emissions while sustaining the energy fundamentals of security, reliability, affordability, safety and resilience.
- Clarifying the respective roles of policymakers and regulators, and identifying how governments can

best pursue environmental objectives alongside economic regulation.

- How to secure community and investor support for new energy infrastructure. As discussed above, local acceptability and the investment environment are intertwined unavoidable factors that govern whether new facilities can be financed, approved and built and that shape the speed and costs of doing so.

- Net zero requires speed, predictability for investors and supportable costs. Citizen support requires openness, engagement and due process, all of which add time, reduce predictability and almost always add cost. How can governments best navigate these tensions?

- Finally, and crucially, is cost. Who will pay what, when and how for emissions reductions? Transforming energy delivery systems requires clear, thoughtful and informed approaches to the costs to be borne by governments (taxpayers), by industry and by consumers.

## WHAT HAS BEEN LEARNED TO DATE?

As noted earlier we draw here on experience in Canada and other jurisdictions — notably three case studies in the US, Great Britain and Australia, along with a broader literature review covering US and European experience. Again, to underscore, the most striking observation is that very little is known at the level of practical application.

Market based systems have become the norm in most jurisdictions over the past 20 to 30 years, starting with natural gas and later encompassing electricity. Although power distribution in most Canadian jurisdictions is largely owned by provincial or municipal governments, commodity prices are generally market generated. The overarching question for our purposes concerns how market participants (suppliers, pipes and wires, users) respond to market or regulatory signals and how that affects emissions strategies and durability of reforms.

Two of the case studies in particular (Great Britain and New York) underscore how unbundling of energy service delivery, privatization of energy delivery and market pricing, may be hard to reconcile with effective and rapid decarbonization. With multiple players in complex systems, behaviour and outcomes are hard to predict, far less control — all the more so in the face of a policy driven transformation of unprecedented scale, nature and speed. What remains far from clear, however, is whether more centralized and dirigiste methods working in a democratic context can possibly cope with the demands of the transformation before us.

One important question concerns whether what was learned from the market transformations of the past several decades has relevance for the net zero transformation. On its face the answer would appear to be very little since policy is now being driven by a new non-economic imperative (climate) that pulls decision-makers in the direction of more government intervention, not less. On the other hand, much has been learned about consumers, including their general preference for being relatively passive players concerned mainly with knowing that their systems work and being intolerant of price shocks.

In this context, achieving the desired net zero outcome depends fundamentally on the system and its participants being creative, innovative, nimble and adaptable. Much of the technology that needs to be deployed is at best untried, at worst, unknown. New market structures, corporate structures and business models, and new approaches to policy and regulation will need to emerge and evolve. It is impossible to know conclusively what factors will bear on all of this and how they will interact.

Several issues illustrate the complexity and the political, economic and social perils. Precipitate action by policymakers applying the technologies and business models we know today (and in the Great Britain case, a highly complex mix of regulations and incentive systems) risks locking in sub-optimal approaches with legacies that could take decades to resolve.

Cost effects will impinge on consumers whose willingness or ability to absorb costs have been consistently demonstrated to be very limited — and when limits are reached the political blowback is almost always impossible for policymakers to escape. The costs of change inevitably bear disproportionately on disadvantaged consumers, a societal outcome widely regarded as unacceptable in twenty-first century democracies.

Effects on energy fundamentals are often unpredictable and subject to both internal and external factors. To date, fundamentals have generally been maintained, in all probability for three reasons: because the systems were designed with energy fundamentals as the first priority (including being built with some head room for change); because the physical systems themselves have long been generally stable and well understood; and because recent changes (electrification, distributed resources, integration of renewables, etc.) have taken place mostly at the margins (and been accommodated by head room). None of those conditions appears to apply as we look to the coming transformation to net zero.

The inherent inertia of large complex systems built on long lived capital, readily available but in some instances carbon intensive resources and long-established human skills and management systems are mismatched with the speed of change envisioned by net zero. Correspondingly, the potential responsiveness at the demand end varies depending on industrial profiles, local climate, the nature and age of energy using assets and the potential for distributed energy to be practically deployed.

The basic physics of energy systems impinge unavoidably on the potential for change. Heat requirements — especially for certain industries — affect what is practical in choice of supply. The requirements for real time load balancing in power systems is a physical fact and as intermittent renewable resources become more dominant the practical consequences for system design and real time management become ever more challenging. The materials and land intensity of renewable systems raise whole new perspectives on security of supply, resilience and social acceptability.

Local renewable sources may in and of themselves be more economic than distant sources due to reduced transmission requirements, but that may be in tension with more cost effective, reliable and resilient large scale renewable sources if looked at from an overall system perspective.

The economics and operational practicality of existing systems are vulnerable to the effects of rapid change. Power systems from upstream to down are called on to accommodate growth of two (or more) times existing capacities, will need to put in place new system management tools and will need to accommodate changing seasonal load profiles. Declining utilization of existing hydrocarbon (natural gas) systems potentially leaves stranded assets whose costs must be accounted for. It also leaves potentially stranded users for whom new systems may be impractical or too costly. And the advent of electric mobility adds load and system management complexities. Even with a whole system perspective on needed energy services — heat, cooling, mobility, drive power, lighting, electronics — there is no way from today's perspective to know what will actually work. But without aspiring to whole of system thinking we are flying blind in the wind.

Finally, the effects of climate change itself are a physical fact whose consequences are unknown. But such effects are going to grow and will dominate investment choices and thinking about supply, particularly requirements for resilience like the hardening of systems and the development of ever more robust recovery strategies.

All told, energy delivery system reform is an intricate and complex puzzle with multiple pieces forever in motion.

## AN OVERARCHING QUESTION: WHO IS IN CHARGE?

As noted earlier, an overriding theme arising notably in Great Britain and New York is the question of whether markets and market actors can be sufficiently responsive to meet the compressed time frame of 2050 and sufficiently predictable to act in ways that make hard legislated mandates achievable. Against that, of course, is the mystery of whether central planning by governments can meet the multiple imperatives of nimbleness, adaptability and openness in the face of social, economic and technological unknowns that greatly outweigh what *is* known — and the inevitable limitations of modeling and forecasting in the face of so many unknowns.

The traditional machinery governing energy delivery systems — essentially public or private monopoly utilities for wires and pipes overseen by independent expert economic regulators — is slow to move and risk averse. As such, aside from the conundrum around central planning versus markets, the actors who normally operationalize policy direction in the system have deep knowledge of it but are not particularly nimble (at least sometimes that is for good reason given the need to sustain energy fundamentals and ensure fairness and openness to input from multiple sources).

In contrast, policymakers driven by the net zero imperative may be faster to move but often lack sufficient expert capacity to make choices that will sustain energy fundamentals, and, by extension political support for emissions reductions. Policymakers may also be inclined to create new legislation, policies, public entities and programs as new issues and problems arise, leading to an increasingly complex system that defies comprehension and clarity as has been the case in particular in Great Britain.

All of this raises the question of what role regulators should play in an increasingly crowded energy and climate decision-making system. If their energy expertise and capacity to ensure due process remain important, how best can policymakers provide them with the scope and direction to take into account imperatives — notably emissions reductions — beyond the traditional economic imperative of fair and reasonable rates?

Should policymakers assume roles as de facto regulators or can they stand back, provide policy direction and allow regulators to act? If policy makers are unable to provide clarity of direction, to what degree should regulators be creative in interpreting their mandates or explicit in how they will manage trade-offs? And if regulators get creative with their mandates, how are such actions squared with political accountability? In short, it is crucial to carefully think through the transformation of economic regulators into economic/environmental regulators.

Who needs to be in charge or at least influential in policy choices is a question founded mainly on the issue of expertise. One thing that seems clear is the very large need for technical, economic, environmental, financial and legal expertise. Whether there should be a large role for economic ministries and in particular energy and finance rests on this issue. So does the role of provincial Crown corporations that often embody the bulk of available expertise and have the potential to exert an outsized influence on provincial policy choices. But perhaps a bigger question that emerges strongly from our research is the limited energy expertise in policy systems as a whole. Taking it back to the question of central planning, the expertise gap may be one of the most daunting challenges that will need to be overcome.

## CONCLUSIONS: WHAT IS TO BE DONE?

It is clear that there is much to be done, the need is urgent and there is little base of experience anywhere from which to draw. What is emerging, on the other hand, is a growing appetite to reform energy delivery systems and a growing body of early experience in Canadian and international jurisdictions, albeit so far only at modest scale.

Several critical policy principles emerge from our research:

***Policy should take an integrated approach to energy and climate.*** While the foundational approach of legislating specific targets has helped to concentrate minds on the problem of achieving net zero, it has fallen well short of reconciling the overriding emissions priority with the energy fundamentals that delivery systems must fulfill. Reducing energy fundamentals to second order considerations will not lead to durable emissions reductions.

***Policy should incorporate inclusive, rigorous and adaptable planning that corresponds with market-based systems.*** There is growing recognition of the vital role of planning but it will be crucial to identify how to ensure it corresponds to market systems where a great number of essential technological solutions remain far from tried and true. Technology neutrality is a good place to start.

***Policy should be grounded in whole of system thinking — both in energy system and machinery of government terms.*** Whole system thinking remains an elusive but crucial goal. While adding more perspectives should bring greater wisdom it also adds complexity and ambiguity and inhibits speed. And, of course, what constitutes the "whole system" varies. For some, the debate centers entirely on the electric power system but the "system" necessarily extends to heat systems and mobility systems and, given the vital role of energy in society, the boundaries get pushed steadily outward to encompass broader economic questions such as competitiveness, social questions such as equity and questions of fiscal management. In the end it comes down to the political judgment of leaders. This is good for democratic accountability but it is filled with the perils of what may well turn out to be bad judgments based on narrow and short-term considerations.

***Policy should recognize the strengths and limitations of both incremental and comprehensive processes of reform.*** The Western Australia case suggests there is merit in incremental approaches, in effect learning by doing. The Great Britain case, on the other hand, shows how incremental approaches can lead to such accretion of measures that the whole approach becomes incomprehensible. None of the experiences we reviewed provides us with a sure model of how best to allocate responsibility and accountability among various actors but in all circumstances there is a need for comprehensive thinking and large scale policy at the system level within which numerous close to the ground actors can undertake incremental approaches in various parts of the system.

***Policy approaches should include environmental organizations, communities, citizens and other parts of civil society at the right time and on the right questions.*** All of the case studies and experience in Canada have varying degrees of citizen engagement — largely through advocacy groups — and varying degrees of success. Where the focus is on relatively simple challenges such as designing small local systems or driving particular technologies, citizens may become engaged and become sufficiently knowledgeable as to be constructive contributors. But at the big system level and for highly technical questions that concern power system physics or complex business or regulatory models, citizens may be little more than bystanders. When they react negatively to price increases or oppose new infrastructure, they may also be inhibitors of change. What is crucial is identifying the appropriate level, nature and timing of public involvement.

Operationalizing these principles is a tall order. Distinctive conditions in individual jurisdictions will inevitably dictate distinctive solutions. Nonetheless, given the shared challenges and tensions, there is ample opportunity for mutual learning across Canadian jurisdictions on an ongoing basis.

With this in mind, we propose the creation of a time-limited task force mandated to develop concrete and actionable recommendations for energy delivery system reform. Such a process would convene federal, provincial and territorial policymakers and regulators alongside Indigenous and municipal governments, industry, civil society and academic leaders to identify needed policy, legislative and regulatory changes. Crucially, this process would not supplant existing efforts towards emissions reductions (including the recently announced regional strategy tables undertaken by the Minister of Natural Resources), but rather, serve to accelerate, inform and better coordinate them.

Key to the approach is respect for constitutional divisions of authority — energy delivery is largely under provincial jurisdiction — and the diversity of energy profiles and market systems across the country, and that it be and be seen to be collaborative, credible, influential and representative of the expertise required to effectively execute its mandate. If done well, such a process would provide policymakers with many of the means by which to make the above noted principles operational.

This will be pivotal as attention turns increasingly from the what to the how of emissions reductions. The idea of net zero emissions by mid-century has, over the few years, become firmly embedded in the public discourse. In many jurisdictions, including Canada, that goal is now expressed in legislation, thereby creating an imperative for action that has been absent from most climate policy worldwide for the past several decades. Legislation can always be changed of course but politically the idea of net zero appears increasingly to be set in stone.

Not surprisingly but strikingly, experience to date reveals the extent to which countervailing realities, even if not set in legislative stone, remain economic and political bedrock that cannot be avoided. The most important of these are energy fundamentals, and the place where their absence will be most visibly felt is in the energy delivery system. As policymakers turn their attention to energy delivery — the forgotten factor of climate policy — it will be crucial to sustain energy fundamentals. Ongoing support for emissions reductions from citizens, communities, customers and companies depends on it. ■