# Power Perspectives 2023

The **National Energy Group at McCarthy Tétrault LLP** is pleased to present: *Power Perspectives 2023*.

**Message from our Editors-in Chief, Kerri Howard and Jacob Stone:**
This publication is our eighth annual Canadian power industry retrospective. It is intended to provide an overview, at both the regional and national levels, of the most significant developments in the Canadian power sector, and associated emerging energy sectors, in 2022. It has been an exciting year in the power sector, with an increased focus on the energy transition and the procurement of renewable energy. In this publication we will provide updates on Federal and Provincial environmental and other regulatory changes, updates in certain emerging sectors, including carbon capture, storage and utilization, hydrogen and small modular reactors, and provide a discussion around tax incentives fueling the energy transition. We have also highlighted key trends to watch for in 2023. We hope that you will find this publication to be both interesting and informative.

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# BRITISH COLUMBIA REGIONAL OVERVIEW

*Authors: Rachael Carlson, Alexandra Comber, Maureen Gillis, Genevieve Loxley, Sven Milelli, Dave Nikolejsin, Morgan Troke and Robin Sirett.*

## INTRODUCTION

As we noted in last year's publication, several 2021 developments, including the completion of Phase 2 of the province's comprehensive review of BC Hydro, the release of a roadmap to achievement of 2030 emissions targets, and the submission by BC Hydro of its first integrated resource plan (IRP) in almost a decade, were significant milestones in laying the groundwork for BC's energy future.

2022 saw further progress along that path. While BC Hydro's new IRP works its way through regulatory review, the utility continued to advance construction of its Site C hydroelectric facility (Site C) while reaching an important settlement with litigants challenging the project. The provincial government made further investments in its CleanBC inItiative and supported a range of emissions-reducing projects through the CleanBC Industry Fund. Prospects for a number of liquefied natural gas projects in the province, meanwhile, remained promising, but also underlined the potential for significant energy and transmission infrastructure needs to support proposed electrification of their lquefaction processes.

BC Hydro expects to have sufficient energy and capacity until the early 2030s, and accordingly there continues to be no new material procurement opportunities for independent power producers (IPPs) in BC. However, BC Hydro does intend to renew existing electricity purchase agreements (EPAs) for clean or renewable projects set to expire before April 1, 2026 to ensure that these facilities continue to be available if their generation is required to meet domestic needs in the future.

## BC HYDRO INTEGRATED RESOURCE PLAN UPDATE

As we reported in last year's publication, in December 2021 BC Hydro filed an application with the BC Utilities Commission (**BCUC**) requesting acceptance of the IRP. The IRP was informed by the consultation activities that made up BC Hydro's Clean Power 2040 engagement and details BC Hydro's plan to meet the province's projected electricity needs over the next 20 years. In the IRP, BC Hydro emphasized its commitment to:

— continuing the use and implementation of customer-based solutions through demand-side measures (such as energy efficiency and conservation programs);

— ensuring preparedness for future electricity needs—higher electricity demand due to electrification or lower demand resulting from economic downturns; and

— incorporating the United Nations Declaration on the Rights of Indigenous Peoples and the Truth and Reconciliation Calls to Action in its plan.

The IRP currently remains under review by the BCUC, with the review timeline set to continue into mid-2023.

As detailed below, 2022 saw notable advances in the British Columbia liquefied natural gas LNG industry. In the IRP, BC Hydro indicated that new industrial activity by LNG customers is likely to bring about changes in Provincial electricity consumption. Consequently, the IRP outlines a resource plan that takes into consideration potential (LNG) loads that may materialize, particularly on the north coast of the province, based on the premise that several of the LNG facilities in the region will proceed into operation within the next decade. According to Reuters, there are currently 18 proposed LNG projects in Canada, with the majority situated on the west coast. As the new LNG facilities in British Columbia will be powered by hydroelectricity from BC Hydro, an increased need for energy and capacity is likely to be realized. In detailing BC Hydro's preparedness for an increased LNG load, the IRP focuses on the continuation of the Prince George to Terrace Capacitor Project, which has an earliest in-service date of fiscal 2028. However, with companies redirecting their focus to smaller west coast LNG projects that are expected to be completed in quick succession, it is unclear whether the LNG contingency plan contained in the IRP will be sufficient to accommodate the increasing demands for hydroelectricity from the industry. This may be a scenario that BC Hydro will need to revisit in the short term in order to keep pace with the recent revival of the LNG industry in the province.

## SITE C UPDATE

BC Hydro's Site C Clean Energy Project will be the third dam and hydroelectric generating station on the Peace River in Northeastern BC. Once complete, Site C will provide 1,100 MW of capacity and produce approximately 5,100 GW hours of energy per year. Construction of Site C began in July 2015 and, as of June 2022, Site C was more than 65% complete and on track for a 2025 in-service date, with a total budget of $16 billion, nearly double the original $8.775 billion budget approved in 2014. According to the BC government, between $3 billion and $4 billion of the cost overruns are attributable to geotechnical delays and construction slowdowns caused by the COVID-19 pandemic.

Key construction milestones in 2022 included the placement of the final penstock segment, completing the project's six penstock units, ongoing placement of materials at the earthfill dam, approach channel excavations, right bank foundation enhancements, and the realignment of Highway 29. Consistent with this increased activity, the total Site C project workforce reached a new project high of 5,209 workers in June 2022.

According to BC Hydro, key challenges faced by the project as it proceeds toward completion include attracting and retaining sufficient skilled craft labour, inflationary pressures and interest rate increases; potential additional mitigation measures for acid-generating rock, the potential re-emergency of COVID-19 cases on site, commercial negotiations with contractors, possible design changes due to unknown field conditions, and obtaining all of the remaining permits required for project completion.

Perhaps the most significant development in 2022 occurred on June 24, when the BC government and BC Hydro announced a full and final settlement with West Moberly First Nations regarding their treaty infringement claims in relation to Site C. Key elements of the settlement include:

— an impact benefit agreement between BC Hydro and West Moberly;

— two agreements between BC Hydro and West Moberly that provide West Moberly certain contracting opportunities;

— a tripartite land agreement between the BC government, BC Hydro and West Moberly;

— an agreement providing for the release of West Moberly's claims against the Site C project; and

— a separate settlement agreement between the Canadian federal government and West Moberly.

In the remainder of its civil claim, West Moberly has asserted that the existing hydroelectric dams on the Peace River and the cumulative impacts of resource development in their territory are an infringement of their Treaty rights. The parties have agreed to pause the remainder of the civil claim and place it in abeyance, and the BC government and West Moberly have agreed to enter into confidential government-to-government discussions to resolve the remaining matters in the litigation.

## CLEANBC PLAN UPDATE

The BC government continues to advance CleanBC, the climate action plan introduced in 2018 that aims to reduce the province's greenhouse gas (GHG) emissions by 40% below 2007 levels by 2030.

In the 2022 provincial budget, the BC government pledged more than $1.2 billion in further funding for CleanBC, adding to its existing $2.3 billion commitment to CleanBC. Among other investments, the budget allocated $120 million in funding to continue the Climate Action Tax Credit, designed to offset the impact of the province's broad-based carbon taxes on lower- and middle-income households. CleanBC also includes an Industrial Incentive Program that reduces carbon tax costs for facilities that can demonstrate that they are among the lowest emitters in their sector compared to GHG benchmarks. On April 1, 2022, BC's carbon tax rate rose from C$45 to $50 per $tCO_2e$.

The BC government directs some of the carbon tax revenue it collects to the CleanBC Industry Fund, which supports projects that reduce GHG emissions from large industrial operations with emissions of over 10,000 tonnes of $CO_2e$ per year. The size of grants under the Fund is based on the amount of emissions that will be avoided by the funded projects. In its third round, the CleanBC Industry Fund is investing $25 million in carbon tax revenue to support 26 new projects. Some significant projects that received funding include:

— NorthRiver Midstream Inc. received $18.5 million for three projects: electrification of its Dawson Creek natural gas plant, a carbon capture and sequestration project at its McMahon gas processing plant near Fort St. John, and installation of waste heat recovery units. The NorthRiver projects are estimated to reduce GHG emissions by about 1.9 million tonnes of $CO_2$ between now and 2031.

— ARC Resources Ltd. received $13.7 million to electrify its Dawson Creek natural gas plant, which it estimated will reduce emissions by 125,000 tonnes annually.

— Ovintiv Canada ULC (formerly Encana) received $4.23 million for two projects: upgrading compressors and valves at 20 gas processing facilities to reduce energy requirements, and upgrading compressor engines across compression stations in northeast BC to new high-efficiency units.

The BC government also announced that ten BC First Nations will receive funding to develop alternative energy projects and advance energy efficiency in their communities through the British Columbia Indigenous Clean Energy Initiative (BCICEI), supported by CleanBC.

Meanwhile, the province's introduction in the last quarter of 2021 of the CleanBC Roadmap, which purports to set out an accelerated path to achieving the CleanBC 2030 targets, has not gone unchallenged. In March 2022, the Sierra Club BC filed a petition in the Supreme Court of British Columbia alleging that the BC government failed to deliver an annual climate change accountability report that met requirements set out in the Climate Change Accountability Act. The legislation requires this report to be delivered in respect of each calendar year from 2020 onward, setting out, among other things, a description of the actions taken by the BC government in the applicable calendar year to minimize the GHG emissions for which it is responsible, its plans to continue minimizing those emissions, its determination of such GHG emissions for the applicable year, and a statement of the offset units retired by the province in respect of those emissions. A major concern cited in the petition was a lack of detail in the province's reporting as to how it will meet 2025, 2040 and 2050 targets, as well as how it will account for the funding of LNG projects while simultaneously reducing GHG emissions. The Sierra Club petition has parallels with a UK case decided in 2021 that found the UK government had fallen short of its statutory obligations to deliver detailed information illustrating how carbon budgets would be achieved. As of the time of writing, the BC case had not yet been decided.

Other critiques of the CleanBC Roadmap included a report released by the University of British Columbia's Clean Energy Research Centre (CERC), which criticized the CleanBC Roadmap for over-reliance on electrification to meet the province's GHG emission reduction targets. CERC's analysis questioned the prevailing view that BC faces a surplus of renewable energy, projecting a significant shortfall of renewable electricity the province will require to meet its GHG emission reduction targets in light of reliance on electrification to achieve targets, notwithstanding the contributions of the Site C Project to hydroelectricity supply. The report therefore recommended utilizing all available bioenergy and renewable electricity resources and promoting a balanced renewable energy portfolio.

Significant additional electricity demands may be driven by LNG projects, whose electrification plans are frequently cited as significantly reducing GHG emissions

from these large industrial projects. As discussed further below, for example, Woodfibre LNG has reaffirmed its commitment to electrifying the liquefaction process by using an electric train, and LNG Canada is also considering electric-drive technology for its second phase.

The future of one major electrification project, the proposed expansion of transmission by BC Hydro into the North Montney region of Northeastern BC through construction of a 230 kV transmission line from a BC Hydro substation in the vicinity of either the GM Shrum or the Site C Generating Stations, remains undetermined. BC Hydro launched a study to assess requirements to bring transmission infrastructure to the region more than two years ago but continues to describe the project as being in the early study phase, with no timeline for making a decision on the project. If it proceeds, BC Hydro estimates the project could avoid over 1 million tonnes of GHG emissions per year.

## LNG UPDATE

In the past year, certain LNG projects saw notable progress.

In September 2022, LNG Canada – a joint venture between Shell Canada, Petronas, PetroChina, Mitsubishi Corporation and KOGAS – reported that its Phase 1 was 70% complete, with the associated Coastal Gaslink (CGL) pipeline 75% complete, making it two to three years away from its first outgoing LNG shipments. This $40 billion project is located in Kitimat, BC and was the first large-scale LNG export facility to announce a final investment decision in British Columbia. The terminal is being built on the head of the Douglas Channel, on the traditional territory of the Haisla Nation. Phase 1 will use natural gas–powered turbines in its liquefaction process.

A final investment decision has not yet been made for Phase 2 of the project, which would double the exporting capacity of the facility from 14 million to 28 million tonnes per year. However, Phase 2 has not been accounted for in the CleanBC plan and may be subject to significant emissions caps. One potential solution to address emissions caps is to completely electrify the liquefaction process. However, electrification, while technically feasible, will incur significant operating costs. There are also significant concerns regarding capacity and reliability of the BC Hydro system into Kitimat. Powering Phase 2 with electricity would require the construction of new transmission infrastructure.

The proposed Cedar LNG project would neighbour LNG Canada in Kitimat. Cedar LNG is currently undergoing an environmental assessment, having completed the public comment period this year. This $3 billion project would be developed by the Haisla Nation and Pembina Pipeline Corporation, and, if developed, is purported to be the largest Indigenous Nation-owned infrastructure project in Canada. Cedar LNG would produce approximately 3 million tonnes of LNG per year. It would be interconnected with the existing BC Hydro transmission system, minimizing its carbon intensity. The intent to fully electrify the Cedar LNG facility contributes to the BC Hydro system concerns noted above, as both facilities would share the same transmission lines.

In April 2022, Woodfibre LNG announced that it had issued a Notice to Proceed to its prime contractor, McDermott International, in respect of its $US5.1-billion project. This notice instructs McDermott to begin the work required to commence major construction of the Woodfibre LNG project in 2023. Substantial completion is expected to occur by 2027.

Woodfibre LNG will be a 2.1 million-tonne-per-year export facility. This project, located in Squamish, British Columbia, will be powered entirely by renewable hydroelectricity, and purports to be the cleanest LNG facility worldwide. Another notable aspect of Woodfibre LNG is its regulatory oversight by the Squamish Nation, in addition to the BC and Canadian governments. Woodfibre LNG is the first industrial project in Canada to recognize an Indigenous people as a full project regulator in absence of a treaty.

In July 2022, Enbridge Inc. announced that it had reached agreement with Singapore-based Pacific Energy Corp. Ltd. for Enbridge to take a 30% ownership stake in the Woodfibre LNG project, its first investment in an LNG terminal. Enbridge has also green-lit a $3.6 billion expansion of the T-South segment of its BC natural gas pipeline system to meet growing regional demand, including the Woodfibre LNG project. Enbridge is expected to submit a regulatory application for this expansion (the Southern Mainline Expansion Project) in 2024, with operations to start in 2028.

Tilbury LNG is an expansion of an existing FortisBC facility, located on Tilbury Island in Delta, BC. FortisBC is in the early planning stages to complete Phase 1 of the expansion to its liquefaction capacity, which could be in service as early as 2025. In addition, the Tilbury Jetty Limited Partnership, to be jointly owned by Fortis LNG Jetty Limited Partnership and Seaspan, has filed an application for environmental assessment for a marine jetty adjacent to the Tilbury LNG facility. Further, the project description for Phase 2 of the Tilbury LNG expansion project has been submitted to the BC Environmental Assessment Office and the Impact Assessment Agency of Canada. Phase 2 would involve construction of a new 142,400 cubic metre tank and provide new liquefaction capacity of 2.5 million tonnes per year. If approved, Phase 2 construction could begin in 2023 and be completed by 2028.

Nisga'a Nation, Rockies LNG Limited Partnership and Western LNG LLC propose to jointly develop the Ksi Lisims LNG Natural Gas Liquefaction and Marine Terminal project at Wil Milit on the northern end of Pearse Island, British Columbia. This facility would produce 12 million tonnes of LNG per year. It is in the early engagement stages of the BC environmental assessment, having submitted a detailed project description in April. Two natural gas pipelines are being considered for the project, namely, Enbridge's Westcoast Connector Gas Transmission Pipeline and TransCanada's Prince Rupert Gas Transmission Pipeline, each of which could connect gas resources in Northeastern BC to the project site.

## EPA RENEWALS

As proposed in its IRP, BC Hydro is developing an electricity purchase agreement renewal program for IPPs that have EPAs for clean or renewable projects set to expire prior to April 1, 2026. According to BC Hydro's website, there are 19 such IPPs, ranging in size from 0.2 MW to 50 MW in nameplate capacity, with an aggregate of over 200 MW in nameplate capacity and over 900 GWh in annual generation. The projects are comprised of 16 run-of-river projects, one storage hydro project and two biogas projects.

Under the EPA renewal program, these projects will be offered EPA renewals at market-based prices, based on the terms set out in the final draft term sheet published on BC Hydro's website. Key commercial terms set out in the final draft term sheet include the following:

— A term of either five or 20 years.

— In the case of EPAs with a five-year term, an energy price for delivered energy which is based on the applicable Mid-C price at the time of delivery, to a maximum of $80/MWh (USD), adjusted depending on whether net aggregate power flows from both the British Columbia-United States and British Columbia-Alberta interties are in a net export or a net import position.

— In the case of EPAs with a 20-year term, an energy price for delivered energy of $58/MWh, adjusted annually for CPI, subject to a deduction for line losses based on the project's location within BC, and adjusted by a time-of-delivery factor ranging from 50% to 150% depending on the month of delivery and whether the delivery is during on-peak or off-peak hours.

— A seller may choose not to generate during the freshet season if EPA prices are uneconomic.

— All environmental attributes for delivered energy are transferred to BC Hydro.

— No liquidated damages are payable by the seller for non-delivery.

Based on the other terms set out in the final draft term sheet, it appears that the form of the renewal EPA will be similar to the EPA previously utilized by BC Hydro for its discontinued Standing Offer Program (SOP). However, there are certain terms in the final draft term sheet which, if incorporated into the final form of renewal EPA, will be a departure from the last EPA used in the SOP namely:

— BC Hydro may curtail deliveries for safety or system security or reliability issues at any time (i.e., an emergency condition), and the seller must comply with BC Hydro's directions, with no payments being made to the seller during the emergency condition.

- BC Hydro has the right to curtail deliveries for any reason other than an emergency condition, provided BC Hydro will pay for deemed energy that could have been delivered by the seller during a curtailment due to a BC Hydro system constraint after the first 72 continuous hours of the system constraint.  This is similar to the provisions in the last SOP EPA, however, in that case BC Hydro would pay for deemed energy after the first 24 hours of curtailment in the aggregate in any month.
- If the seller is in material default and BC Hydro exercises its termination right, the seller must pay a termination payment equal to the greater of:
  - an amount equal to the positive amount, if any, by which BC Hydro's economic losses and costs exceed the aggregate of BC Hydro's gains from the termination; and
  - $4,000 x plant capacity x years remaining before the EPA expires.
- No payment is owing by BC Hydro if the seller terminates for any reason.

The above provisions will likely be concerning to sellers considering entering into a renewal EPA, particularly those provisions that provide BC Hydro with the discretionary right to suspend delivery and payments to a seller, given the recent experience of some sellers with BC Hydro's unprecedented invocation of force majeure during the early days of the COVID-19 pandemic in May 2020.  However, given the regulatory hurdles and economic challenges that face sellers seeking to sell to a third party other than BC Hydro, we expect that sellers with expiring EPAs will be motivated to enter into a renewal EPA even if the terms are more favourable for BC Hydro than under prior EPAs.

In May 2022, BC Hydro announced that it had entered into a short-term EPA with Capital Power for the Island Generation facility on Vancouver Island to provide back-up electricity support while repairs are made to undersea transmission cables.  This short-term EPA, whose term is 4.5 years, was approved by the BCUC in November 2022.  BC Hydro's long-term EPA with Island Generation expired in April 2022, and BC Hydro indicated in its IRP that a further long-term agreement is not required to meet BC Hydro's system planning requirements.

# Alberta

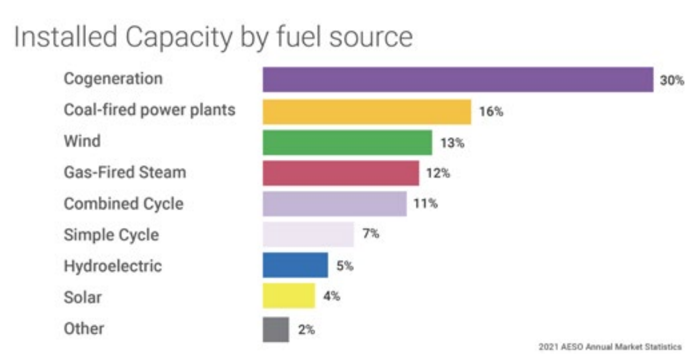
# ALBERTA REGIONAL OVERVIEW

*Authors: Brian Bidyk, Kerri Howard, Kimberly Howard, Connor O'Brien, Ashley Urch and Ashley Wilson[1].*

## INTRODUCTION & MARKET UPDATE

Following the Government of Alberta's (the Province) commitment in its June 2020 Recovery Plan to diversify Alberta's energy industry and as noted in the Alberta System Operator's (AESO) 2022 Long-term Transmission Plan, the Province continues its shift away from coal-fired to gas-fired generation in the electricity market, with continued development and advancement of alternative energy sources.

Alberta's electricity market continued its emphasis on energy efficiency and emission reductions. As plans continue to push for a more decarbonized and decentralized future, Alberta will have to balance such advances with system reliability and affordability for rate payers. To this end and as discussed in detail below, the AESO released its *Net-Zero Emissions Pathways Report* (Net-Zero Report) on the transition of Alberta's electricity system to a net-zero carbon emissions scenario by 2035. The Net-Zero Report analyzed different supply and demand factors and their effects on the electricity market, system reliability and the costs associated with electricity supply and transmission on the road to a net-zero future. The AESO is also engaging stakeholders with respect to its *2023 Reliability Requirements Roadmap,* with a purpose of providing stakeholders with an understanding of the AESO's approach and plans to ensure reliability are sustained as the industry transforms to a more decarbonized and decentralized system.




Source: AESO, "Installed Capacity by fuel source", Understanding Alberta's Electricity Mix (2022), online: https://www.aeso.ca/aeso/understanding-electricity-in-alberta/

[1]Additional Authors: Students-at law: Derek Baker, Jim Christie Brooks, Megan Pryor and Grant Szelewicki.

In 2022, Alberta took a number of steps toward its goals of a transformed generation mix, including awarding 25 carbon capture, utilization and storage (CCUS) hub projects, establishing a framework for geothermal resource development and continuing to evaluate the legislative and regulatory regime governing hydrogen. The AESO and Province are also evaluating and reviewing the legislative scheme governing the electricity market in Alberta, including facilitating self-supply and export of energy and considering the way in which energy storage technologies can be integrated into Alberta's Interconnected Electric System while maintaining a fair, efficient and openly competitive market.

## KEY DEVELOPMENTS IN 2022

### A) REGULATORY UPDATES

#### (i) AESO Net Zero Pathways Report

In June 2022, the AESO released their Net-Zero Emissions Pathways Report (Net-Zero Report) on the transition of Alberta's electricity system to a net-zero carbon emissions scenario by 2035. The Net-Zero Report analyzed different supply and demand factors and their effects on the electricity market, system reliability and the costs associated with electricity supply and transmission on the road to a net-zero future.

#### Key Net-Zero Scenarios

**The Net-Zero Report focused on three key scenarios studied by the AESO:**

1. ***Dispatchable Dominant*** scenario, where Alberta's energy supply continues to include a significant number of thermal units with low carbon emissions (likely resulting from the implementation of carbon capture and sequestration and hydrogen combustion technologies);
2. ***First-Mover Advantage*** scenario, where renewable supply (wind and solar) continues to grow, with the addition of moderate amounts of energy storage, and begins to displace existing thermal units; and
3. ***Renewables and Storage Rush*** scenario, envisioning even faster growth in renewable supply, coupled with high volumes of energy storage to displace an even larger proportion of the low-carbon thermal supply.

Each of these scenarios includes the use of carbon offsets to varying degrees, as the Net-Zero Report found the total physical elimination of carbon emissions was operationally unrealistic.

### 2035 Transition Goal

While the AESO forecasts that a net-zero transition by 2035 is attainable under any of the above three scenarios, these scenarios are still highly uncertain and not without risk. In particular, there is a risk to sufficient electricity supply if legacy unabated gas generation units are retired before sufficient new renewable or low-carbon thermal generation is available to replace them. This becomes a bigger risk in the winter months when Alberta's demand is typically highest. The Net-Zero report also concluded that further study is required on other aspects of system reliability (such as ramping capability, inertia and frequency response) and possible impacts and mitigations in a net-zero scenario.

The Net-Zero Report suggests significant investment of capital and operating costs will be required over the AESO's 2021 LTO Reference Case baseline to achieve net-zero by 2035, representing an additional $44 to $52 billion, depending on the scenario. These amounts include capital investments for new generation (including a return on investment), operating costs and transmission revenue requirements. Of the three scenarios examined, the Net-Zero Report suggests the First-Mover Advantage Scenario will have the lowest overall costs.

The Net-Zero Report assumes that the regulatory and political environment would continue to encourage a net-zero transition, and that existing programs (including those implemented pursuant to the Technology Innovation and Emissions Regulation (TIER)) would continue along their current trajectories. Changes in energy policy and regulation at the provincial or federal level, developing technologies as well as the changing economics of low carbon power sources (such as renewables, SMRs, hydrogen and energy storage) may all have an effect on Alberta's road to a net-zero electricity system, which the AESO will continue to monitor.

### (i) Update on Alberta's CCUS Hubs

In May 2021, Alberta Energy announced a new competitive bid process under which it will issue rights for carbon sequestration. The process focuses on the development of strategically located carbon sequestration hubs, allowing for additional volumes and multiple sources of CO2 to be stored and avoiding stand-alone injection operations.

As of the fall of 2022, Alberta approved - through two competitive bid processes - a total of 25 hub proposals. Following a significant amount of interest, the Province closed its first Request for Full Project Proposals for Carbon Sequestration Hubs (RFPP) in Alberta's industrial heartland region on February 1, 2022 and shortly thereafter selected six projects to develop carbon sequestration hubs. All six have entered evaluation agreements with the Province. On October 4, 2022, following the second RFPP, the Province approved 19 additional projects for carbon sequestration hubs across Alberta.

The selected companies will begin exploring how to safely develop their carbon storage hubs and, following a successful evaluation demonstrating the proposed project can provide permanent storage, the selected companies will have the opportunity to apply for the right to inject captured CO2. The Province also announced it will invest $40 million in 11 CCUS projects through Emissions Reduction Alberta. Emissions Reduction Alberta re-deploys funds collected under the TIER through investments aimed at reducing greenhouse gas emissions and growing Alberta's economy by accelerating the development and adoption of innovative technology solutions.

## (B) ALBERTA UTILITIES COMMISSION

### Hydrogen Inquiry Report

The Alberta Utilities Commission (AUC) commenced an inquiry in March 2022 into the viability and impacts of hydrogen blending into natural gas distribution systems in Alberta (Hydrogen Inquiry). The AUC subsequently submitted a report on the Hydrogen Inquiry to the Minister of Energy on June 30, 2022 and on September 6, 2022 released the report to the public (Hydrogen Report).

The Hydrogen Report provides the province with findings, observations and considerations intended to guide the development of legislation for hydrogen blending in Alberta. The Report also identified areas for future study, including, hydrogen distribution systems, renewable natural gas and pure hydrogen pipelines serving customers. It is expected the province will move forward with the development of hydrogen related legislation and future studies in the near future. As outlined in the Hydrogen Report, key findings and challenges facing hydrogen development (based on feedback from stakeholders) include:

— ***Reducing legislative barriers:*** to enable hydrogen blending, the *Gas Utilities Act* and *Gas Distribution Act* should be amended to include "up to 20 percent hydrogen by volume blended within a low-pressure natural gas distribution system".

— ***Agency oversight:*** the current division of responsibilities among the agencies

in Alberta is capable of accommodating hydrogen development and integration and a government-initiated review could be considered to reduce ambiguity.

— ***Rural community blending:*** given hydrogen blending is less practical for rural natural gas consumers, there is likely no need for a regulatory requirement for rural communities or any rural gas co-operatives to blend hydrogen.

— ***Rates payable by consumers:*** it is premature to consider how costs associated with hydrogen blending should be allocated among consumers. Currently, only prudently incurred distribution infrastructure costs to enable hydrogen blending should be recovered from customers.

— ***Credits and tax rebates:*** as the cost burden of hydrogen blending may not outweigh benefits of emission reductions and carbon tax savings offered, the province may want to consider supports for customers in the form of credits, tax rebates or subsidies to reduce the burden on individual customers.

## (C) RECENT AUC DECISIONS

### (i) AUC Decision (27048-D01-2022) – 2023 Generic Cost of Capital Proceeding – released March 31, 2022

The AUC in its Decision 27084-D01-2022 (the 2023 GCOC Decision) approved a return on equity of 8.5% of a deemed equity ratio of 37% for Alberta utility operators in 2023 (the same as was approved in 2021 and 2022). The parameters established in the 2023 GCOC Decision do not apply to EPCOR Energy Alberta GP Inc., Enmax Energy Corporation and Direct Energy Regulated Services as these entities are regulated separately as rate providers.

Recognizing the lingering market uncertainty and continued volatility caused by COVID-19, the AUC indicated its intent to extend the GCOC parameters for 2023. The second stage of the 2023 GCOC Decision will determine the parameters for 2024 and future years.

### (ii) AUC Decision (27047-D01-2022) – Application for Adjusted Metering Practice - released May 31, 2022

In this decision, the AUC denied an application for the approval of the adjusted metering practice (AMP) implementation plan and related amendments to the independent system operator (ISO) tariff and to Section 502.10 of the ISO Rules from the AESO.

The AUC found that the AESO had not provided sufficient information to determine whether the approval was in the public interest or supported the fair, efficient, and openly competitive operation of the electricity market. Specifically, the AESO failed to provide accurate information on costs estimates and information justifying timing differences between substation categories.

The AUC found the ability of the AMP to reduce significant billing determinant erosion was no longer clear and questioned the value of implementing AMP, due to the phase-out of distribution-connected generation credits, which eliminates one of the major causes of billing determinant erosion. As a result, the AUC determined that the AESO was not required to submit a further application to propose an implementation plan for the AMP but provided direction regarding what information would be required, should they wish to do so.

### (iii) AUC Decision (27013-D01-2022) - ATCO Electric Ltd. Administrative Penalty Decision – Released June 29, 2022

The AUC issued an administrative penalty to ATCO Electric Ltd. (ATCO) with respect to the Jasper Interconnection Project (the Jasper Project) and the Trans Mountain Pipeline Expansion Project (the Trans Mountain Pipeline). The issue in question involved a joint venture between ATCO Structure & Logistics Ltd. (ASL) and Simpcw Resources LLP (Simpcw), a commercial entity wholly owned and operated by the Simpcw First Nation, created with a purpose of obtaining contracts for the operation of workforce camps for workers constructing the Trans Mountain Pipeline.

The penalty arose from the award by ATCO of access and matting as well as clearing work around the transmission corridor of the Jasper Project (Matting Work), directly to Blackwoods Contracting Ltd. (Blackwoods), an affiliated entity of Simpcw, after a third party had been selected through an open request for proposal process. The decision to award the Matting Work to Blackwoods was based on the threatened termination of ASL's Joint Venture Agreement with Simpcw, resulting in the potential loss of camp work contracts should Blackwoods not receive the Matting Work.

The AUC held that ATCO improperly took ASL's interests into account when assessing whether to award the Matting Work contract to Blackwoods, knowing Blackwoods rates were above fair-market value, resulting in approximately $10.8 million of overage costs. Knowing that recovering above fair-market value costs from ratepayers was in contravention of the Inter-affiliate Code of Conduct and the ISO Rules, ATCO asked the AUC to approve an addition of $119.1 million to its rate base for recovery of costs in relation to the Jasper Project, which included the full costs incurred under the Blackwoods contract. It was found that no attempts were made by ATCO to transfer the difference between the fair-market value and the Blackwoods rates to a non-regulated account.

In its Decision, the AUC issued an administrative penalty in the amount of $31 million to ATCO, having regard for the seriousness of the contravention and the harm caused, being financial harm to rate-payers and the breach of trust and erosion to the public's confidence in the AUC's regulatory process. ATCO has also committed to amend its deferral account application to exclude from its claim all costs above fair-market value for the Matting Work contract.

### (D) AUC DECISION (26911-D01-2022) – ALBERTA ELECTRIC SYSTEM OPERATOR BULK, REGIONAL AND MODERNIZED DEMAND OPPORTUNITY SERVICE RATE DESIGN APPLICATION – RELEASED NOVEMBER 10, 2022

In this decision, the AUC denied a rate design application from the AESO. The bulk and regional rate design relates to the recovery of wires costs for both the bulk and regional portions of the Alberta transmission system. The AESO's current bulk and regional rate was approved over 15 years ago.

In its application, the AESO deviated from past applications and sought to modernize its demand opportunity service (DOS) rate design, a non-firm rate that allows additional use of available transmission capacity that would not otherwise be used. The AESO argued that the current rate design is no longer valid because it does not recognize that an increasing amount of transmission investment is being driven by investments to accommodate the flow of in-merit energy. Additionally, the AESO raised concerns that some customers are able to avoid charges that were previously thought to be unavoidable, reducing the amount of money recovered from these customers to pay for transmission system costs.

As noted by the AUC in its decision, many stakeholders, representing a range of interests, participated in this proceeding and none supported the AESO's proposed rate design. The primary concerns highlighted by stakeholders were the AESO's approach to the rate design, the relevance of the monthly coincident peak (12 CP) billing determinant, and modernized DOS' application to energy storage resources.

In support of its rejection of the AESO's application, the AUC cited the potential of sending inappropriate price signals to consumers in its decision. The decision highlighted that the focus of cost recovery must shift to a more narrow focus on the efficient use of surplus off-peak transmission capacity as well as fairness in sunk cost recovery. Additionally, the AUC found there to be significant risk that the increased Rate DOS under the proposed modernized approach could "cannibalize" Rate DTS use. While the AUC denied AESO's rate application, it noted that the proceeding provided a solid foundation to reassess core rate design elements moving forward.

### (E) MSA INVESTIGATIONS

The Market Surveillance Administrator (MSA) is a public agency created to protect and promote the fair, efficient and openly competitive operation of the electric and retail natural gas markets in Alberta.

On September 2, 2020, the MSA issued a public notice outlining its decision to initiate an investigation in accordance with the *Alberta Utilities Commission Act*. The investigation was intended to focus on the Balancing Pool's conduct in relation to potential breaches of the *Electric Utilities Act, the Fair, Efficient and Open Competition Regulation* and the Settlement Agreement between the MSA and Balancing Pool that was approved by the AUC in January of 2020.

In its Q4 2021 Quarterly Report issued in February of 2022, the MSA announced that its investigation has been discontinued. The MSA determined that it was not in the public interest to continue the investigation further or proceed with enforcement action because: (i) it has no current or future physical or financial interest in the Alberta electricity market; (ii) the Balancing Pool has no access to funds other than charges levied on electricity consumers through the Balancing Pool Allocation; and (iii) there is limited specific or general deterrence that would result from proceeding with this matter, since the Balancing Pool was a unique market participant that is no longer in the market.

### (F) LEGISLATIVE AMENDMENTS – BILL 22 – ELECTRICITY STATUTES (MODERNIZING ALBERTA'S ELECTRICITY GRID) AMENDMENT ACT, 2022

On April 27, 2022 the Government of Alberta introduced Bill 22, the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act, 2022* (Bill 22). If this sounds familiar, it could be because Bill 22 is a revision of Bill 86 *Electricity Statutes Amendment Act* (Bill 86), introduced in the previous legislative session but never passed. Like its predecessor, Bill 22 seeks to modernize Alberta's electricity system by amending several of its governing statutes and regulations including the *Alberta Utilities Commission Act* (AUC Act), the *Electric Utilities Act* (EUA), and the *Hydro and Electric Energy Act* (HEEA).

Bill 22 introduces some key modernizing changes to Alberta's electricity market, including:

- a formal definition for energy storage in Alberta's legislative and regulatory framework;
- allowing distribution and transmission utilities (DFOs and TFOs, respectively) to own and/or operate energy storage assets under specific conditions set out in HEEA and the EUA;
- allowing competitive models to be used to procure distribution and transmission services from market participants;
- adding a definition of self-supply with export and including exemptions to broadly enable market participants to choose self-supply and export and ensures such facilities pay their fair share of system costs through the AESO's tariff; and
- re-assigning many of the current responsibilities of the Balancing Pool to other entities, allowing the agency to begin to wind down.

### INCORPORATION OF ENERGY STORAGE

Bill 22 implements formal definitions of an "energy storage facility" and an "energy storage resource" into the existing regulatory framework. Generally, the construction and operation of energy storage facilities will be subject to an AUC approvals process under HEEA, like that currently required for hydro developments and power plants. Bill 22 also contains an exception to requirements for an AUC approval for energy storage facilities where a proponent is storing for their own use (unless and until the AUC otherwise directs or sets out in its rules).

#### Self-Supply

Bill 22 introduces a formal definition of "self-supply", being the production of electric energy on a property such that any of that energy is consumed on that property by the owner or tenant. The EUA will not apply to that portion of self-supply which is consumed by the owner or tenant (except in respect of rate setting

and tariffs), meaning parties can produce an unlimited amount of energy for self-supply and may also export excess electric energy to the grid. Previously, the AUC's interpretation of section 2 of the EUA meant that owners who wished to self-supply had to consume the entirety of the energy produced on their property and could not export to the grid, unless they qualified for specific exemptions set out under the EUA or the AUC's rules.

Along with the new definition of self-supply, Bill 22 introduces new cost recovery mechanisms, allowing the AUC to approve tariffs which recover a share of transmission costs from market participants that self-supply or DFOs providing distribution to market participants that self-supply.

### Distribution and Transmission Owners

TFOs and DFOs may incorporate energy storage resources into their systems if approved by the AUC as part of a needs assessment document under Section 34(3) of the EUA. However, Bill 22's amendments to the EUA provide that a TFO may not offer electric energy or ancillary services associated with such energy storage resource to any electricity market, an exception to the general rule that energy entering or leaving the interconnected system be exchanged through the power pool.

The AUC may approve such energy storage facilities where the DFO is not otherwise able to competitively procure non-wires services or under public interest and economic considerations where: (i) there is only 1 non-wires provider available, (ii) competitively securing non-wires services is not economic; or (iii) the proposed use of an energy storage facility would provide superior safety and reliability to the distribution system. Similar to the restrictions on energy resources for TFOs, new Section 105(1.1) of the EUA provides that DFOs may not offer electric energy or ancillary services from approved energy storage resources to any electricity market.

Bill 22 received Royal Assent on May 31, 2022 and the amendments will go into force on proclamation, presumably with some additional regulations to follow.

## NOTEWORTHY AUC AND ISO RULE CHANGES

A summary of the noteworthy AUC and ISO Rule changes are outlined as follows:

| Agency | Rule | Summary |
|---|---|---|
| **AUC** | Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* | Bulletin 2014-11 providing application exemptions for power plants capable of generating 1 megawatt (MW) or greater but less than 10 MW solely for the owner's own use has been replaced by Bulletin 2022-04. Bulletin 2022-04, issued on March 24, 2022 provides that the proposed development of all power plants in the capability range of 1-10 MWs, regardless of intended use, will proceed via a checklist application. Applicants applying for power plants 10 MW or greater must submit a full application meeting the requirements of Rule 007. |
| **AUC** | Rule 023: *Rules Respecting Payment of Interest* | The eligibility for interest payment requirements have been simplified and interest is now calculated using simple interest at the Bank of Canada Policy Interest Rate, plus 1 ¾ percent, unless otherwise directed. |
| **AUC** | Rule 034: *Utility Payment Deferral Program Billing* | Rule 034 expired on June 18, 2022 and is no longer in effect. Rule 034 came into effect on June 30, 2021 and provides that for customers who deferred their utility bill payments under the *Utility Payment Deferral Program Act* service provides must indicate such deferral as separate line items on customer bills. Gas and electric payments not repaid will be recovered in separate gas and electric rate riders. |
| **AESO** | Section 103.5, *Net Settlement Instruction* | Subsections 4(1) and 4(2) of Section 103.5 were updated to require the delivery of financial security before cancelling a net settlement instruction and the condition that the ISO must be satisfied of no adverse effects. |
| **AESO** | Section 501.3, *Abbreviated Needs Approval Process* | Amendments to Section 501.3 simplified eligibility criteria under Section 3. The amendments removed criteria related to facility size, configurations, etc. and instead requires: (i) that a need consistent with the criteria of subsection 34(1) of the *Electric Utilities Act* be identified; (ii) the transmission facility project is identified as an appropriate option to meet that need; and(iii) the ISO reasonably expects the costs of the transmission facility to be less than $25,000,000 with system costs not to exceed $15,000,000.<br>Updates were made to the conditions for approval under Section 4 and confirmation that the transmission facility project is not anticipated to result in significant environmental defects was added. Requirements related to how the ISO conducts assessments of needs and options were also removed.<br>The approval process set out under Section 5 was also updated, removing the requirement to provide an approval letter to the market participant. |
| **AESO** | Section 103.3, *Financial Security Requirements* | Section 103.3 was revised to include a minimum level of financial security, increase unsecured credit limits, remove the process for assigning proxy credit ratings, clarify the forms of financial security, include rights to request financial information and clarify the rights of the ISO in the event of a material adverse change, including the right for ISO to extend deadlines for the delivery of additional or replacement security. |

## ALBERTA ENERGY REGULATOR BULLETIN UPDATES

### (i) Alberta Energy Regulator Directive 089: Requirements for Geothermal Resource Development

The geothermal industry is growing in Alberta and is anticipated to be a key player in the push to achieve federal and provincial net-zero goals. In June 2022, the Alberta Energy Regulator (AER) released the Geothermal Resource Development Rules (GRDR) and subsequently on August 15, 2022, released Directive 089: Geothermal Resource Development (Directive 089). The GRDR provides the regulatory framework for geothermal development in Alberta, and Directive 089 sets out the requirements for several issues related to geothermal developments from inception to closure. Some of the regulatory requirements applicable to geothermal projects overlap with those of oil and gas projects, including the Licensee Management Program. Under the new Licensee Management Program, geothermal developers will be subject to a holistic licensee assessment, security deposit requirements and estimates of liability.

A notable difference from the oil and gas regime is with respect to surface rights. Directive 089 states that the *Surface Rights Act* does not apply to geothermal developments. An applicant for a geothermal development will therefore be required to obtain written consent granting surface access from the appropriate landowner. Additionally, Directive 089 states an applicant must have a geothermal resource tenure lease from the province or documented authorization from the freehold mineral owners.

Directive 089 specifies the different licenses required for geothermal development, which can include a well license, a facility license and a pipeline license. Depending on the type of development, an applicant may require further authorizations under applicable legislation, including the *Environmental Protection and Enhancement Act*, the *Public Lands Act* or the *Water Act*. Finally, Directive 089 also lays out the steps required by applicants who wish to convert an oil and gas well to a geothermal well. Given the interest in conversions of this nature due to potential cost savings and reduction of orphan wells, the process for conversion within Directive 089 is particularly noteworthy.

The release of the GRDR and Directive 089 settled many outstanding questions surrounding Alberta's geothermal development future, and further investment in the industry within Alberta is expected to follow.

### (ii) Alberta Energy Regulator invitation for Feedback on Proposed New Requirements for Brine - Hosted Mineral Resource Development and Directive 056

The introduction of *Bill 82: Mineral Resource Development Act* (Bill 82) by the Government of Alberta in December of 2021, once proclaimed, will provide the AER with the authority to regulate the development of Alberta's mineral resources. To align with the introduction of Bill 82, the AER made changes to Directive 056: Energy Development Applications and Schedules (Directive 056) in order to include geothermal and brine-hosted mineral development requirements.

The revisions to Directive 056 now provide for well, pipeline and facility licensing requirements for both geothermal and brine-hosted mineral developments. The proposed amendments to Directive 056 introduce processes and requirements unique to brine-hosted minerals development and incorporates applicable oil and gas regulatory instruments, where appropriate.

In light of the revisions to Directive 056, the AER sought feedback on the amendments by October 31, 2022, and despite the revisions related to geothermal development, the AER specifically sought feedback on the brine-hosted mineral aspects of the revisions during that period. Following stakeholder feedback, the revised Directive 056 is expected to be released in 2023.

## WHAT'S NEXT?

In 2023, Alberta's final 1200 MW of coal-fired generation capacity is anticipated to be converted to natural gas. In less than 9 years, Alberta transformed its generation mix from over 50% coal-fired generation to none. Alberta's next provincial election is scheduled for May 29, 2023. Regardless of the outcome of that election, in the near-term, we expect Alberta will continue its transformation, which is likely to pair renewables, energy storage and new technologies with natural gas generation for system reliability. This transformation will require a balancing of decarbonisation, reliability and affordability. According to the MSA's Quarterly Report for Q3 2022, the average pool price in Q3 was $221.41/MWh (an increase of 121% over the Q3 2021 pool price) which is also highest quarterly average pool price on record (using data back to Q1 2001). With such high prices and a provincial election on the horizon, we expect considerable debate about the affordability for rate payers and whether market design changes or government back-stops will be required to facilitate the transformation.

The beginning of 2023 is expected to set the foundation for much of the work needed to continue to strive toward net-zero. We hope to see Bill 22 come into force helping to facilitate the incorporation of more energy storage and self-supply to the system. In addition, it is expected that development of the CCUS hubs will continue which will facilitate both the development of hydrogen infrastructure and emission reductions from large emitters across a range of industries. We also anticipate continued progress toward the implementation of Bill 82 in Alberta with two new regulations approved in December, 2022. *The Metallic and Industrial Minerals Tenure Regulations* includes new tenure provisions for brine-hosted minerals and came into force on January 1, 2023, while the *Mineral Resource Development Regulation* will come into force upon proclamation of the *Mineral Resource Development Act*. Following the election, we expect policy announcements influencing the electricity market and will continue to monitor new developments.

# Ontario

# ONTARIO REGIONAL OVERVIEW

*Authors: Reena Goyal, Will Horne, Mitchell Lui, Simon Lusztig, Gordon Nettleton, Seán O'Neill and Chris Zawadzki*

## PROCUREMENT UPDATES

With considerable forecasted increases in electricity demand forecast over the coming years and nuclear plant retirements on the horizon, a capacity gap is expected to arise in Ontario. To that end, 2022 has been an important year for procurement planning. In April 2022, the Independent Electricity System Operator (IESO) released its second Annual Acquisition Report which identified planned actions to address upcoming supply needs. Key takeaways include:

- Capacity needs in the years up to and including 2024 are expected to be met largely through actions identified in the 2021 Annual Acquisition Report;
- While plans in the 2021 Annual Acquisition Report will meet some capacity needs for 2025 and 2026, additional supply is needed for these years, particularly given the planned retirement of the Pickering Nuclear Generating Station in 2026;
- To satisfy the longer term supply needs anticipated to arise in the late 2020s and 2030s, Ontario will need additional capacity, including new resources;
- Accordingly, procurement from long-term RFPs will total approximately 4,000 MW of incremental capacity by 2030; and
- Bilateral arrangements, including the recently signed bilateral contract with Ontario Power Generation for continued operation of the Lennox Generating Station, will be employed where competitive processes cannot satisfy needs in a practical and timely way.

On October 6, 2022, Ontario's Minister of Energy issued a legislative directive furthering these plans. The directive requires the IESO to continue a series of competitive procurements totaling approximately 4,000 MW of additional capacity forecast to begin in 2025/2026 and continue into the 2030s, including:

- an Expedited Long Term I competitive procurement to acquire approximately 1,500 MW of capacity from new build resources and certain same technology expansions of existing capacity resources, with a target commercial operation date of no later than May 2026;
- a Same Technology Upgrades Solicitation intended to procure approximately 300 MW of capacity from existing facility upgrades that can deliver a minimum of 8 hours of energy duration, again with a commercial operation date of no later than May 2026; and
- a Long-Term I (LT I) competitive procurement for up to 2,500 MW of capacity from new build supply and storage resources offering commercial operation by no later than May 1, 2027.

The long-term procurements are in addition to the already closed Medium-Term I competitive procurement, which resulted in six 5-year contracts for a total of 750 MW committed capacity to be available beginning May 1, 2024 and 2026.

In addition to representing a major commitment to procuring new resources, the directive also requires the IESO to procure a varied resource mix. In particular, the Minister's direction is a boon for battery storage resources in the province. Consistent with the IESO's prior announcement that it would carve out a special long-term procurement target specifically for battery storage resources, it directs the IESO to procure a minimum of 1,500 MW of capacity from standalone storage projects. This direction marks a significant shift in a wholesale electricity market which historically has not had regulations amenable to storage resources.

LT I contacts are expected to employ a fixed price contract structure that pays for capacity based on a "pay-as-bid" approach, but subject to a capacity payment adjustment mechanism (CPAM). The IESO has acknowledged that because battery storage resources primarily operate by leveraging arbitrage opportunities in withdrawing electricity when market prices are low and injecting electricity when market prices are high, a different CPAM is appropriate for these resources. The form of mechanism is still under development as of the date of this writing. Accordingly, the IESO has bifurcated the LT I procurement target for battery storage on the one hand and for all other resources on the other hand. Additionally, participating storage facilities will be reimbursed in the form of a "regulatory charge credit" for all regulatory energy charges, including global adjustment, incurred in respect of electricity withdrawn. These are significant advances toward greater integration of energy storage participation at the wholesale level in Ontario.

The directive's approach to natural gas procurement is more measured but equally noteworthy. In late 2021, following a report considering the future phasing-out of

natural gas resources in Ontario, the Minister had asked the IESO to evaluate a moratorium on the procurement of new natural gas generating systems. While this was viewed by some as a harbinger of the demise of fossil fuel generation in Ontario, instead the directive permits the IESO to procure up to, but no more than, 1,500 MW of new natural gas resources. It also mandates keeping existing natural gas fired generation in-service to continue to provide system flexibility, at least until storage generation resource participation is developed and implemented at the grid-wide scale needed to address potential reliability gaps. Newly procured projects that are unable to comply with future greenhouse gas emissions laws and regulations – which will largely be natural gas-fired generation facilities – will be permitted "to suspend operations for the balance of the contract term" while still retaining contract payments, effectively providing insurance to producers against regulatory risk and incentivizing bids. This approach appears to reflect that the continued use of natural gas-fired generation in Ontario will need to take heed of federal government net-zero policy and direction. We expect that this measured approach toward natural gas-fired generation, and the procurement of these resources, will continue moving forward.

## TRANSMISSION: EQUITY PARTICIPATION BY INDIGENOUS GROUPS

Hydro One launched a new equity partnership model with First Nations groups in 2021. The model provides First Nations groups with an opportunity to invest and gain an ownership stake of up to 50% in future Hydro One capital transmission line projects exceeding $100 million in value. Earlier in the year, eight First Nations represented by Gwayakocchigewin Limited Partnership invested in the Waasigan Transmission Line project in northwest Ontario using the model. Hydro One has advised that the model will also be applied to five transmission line projects being developed by it in southwest Ontario as well.

The model represents a significant structural shift in the allocation of ownership for new transmissions projects in Ontario. It also reflects a growing focus of the power sector on increasing Indigenous participation. Prior to the implementation of this arrangement, Hydro One negotiated equity stakes with First Nations groups on a case-by-case basis. Hydro One has stated that using a standard starting offer of 50 per cent opens the door for millions of dollars' worth of economic benefits for participating First Nations communities and reduces the potential for project delays.

## THE RISE OF EV CHARGING: A NEW SOURCE OF DEMAND (AND OPPORTUNITY) FOR ONTARIO'S GRID

As recently as 2021, research suggested that Ontario was lagging behind other jurisdictions in the transition to electric vehicles (EVs). While the province may yet have a long way to go, the past year has seen a number of significant developments alongside stronger growth, not only in demand for EVs themselves, but in the publicly accessible charging infrastructure needed to power the transition.

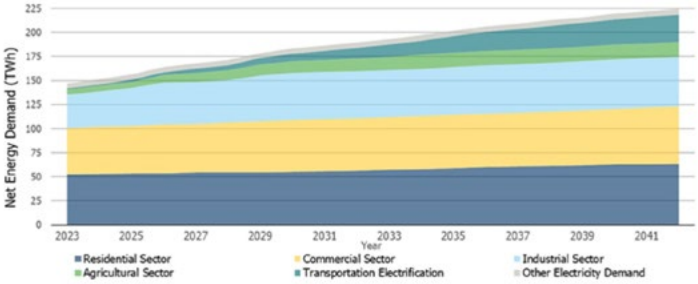
If the federal government's target of 100% EV sales by 2035 is to achieved (and the benefits that come with it), there are a lot of chargers to be built. Although Ontario

is now home to more than 1,700 EV chargers, it may be necessary to have over 1 million chargers running by 2050. Therein lies a critical opportunity for developers of EV charging infrastructure, one which an increasingly varied field of providers is seizing upon.

EV charging is a case in point for certain trends in the development of Ontario's electricity grid. On the one hand, demand is set to increase substantially over the coming decade and beyond.  On the other, the grid will be increasingly characterized by distributed energy resources (DERs), which offer a range of advantages, including increased reliability and opportunity for a broader spectrum of stakeholders to become market participants.

Both of these trends are embodied in EV charging. According to the IESO, electrification of transportation is forecasted to grow an average of 20 per cent a year over the next two decades. The IESO expects the impact of EVs to be felt "particularly strongly" beginning in 2030, as demonstrated in the below table:

Ontario Electricity Demand Forecast 2023 - 2042

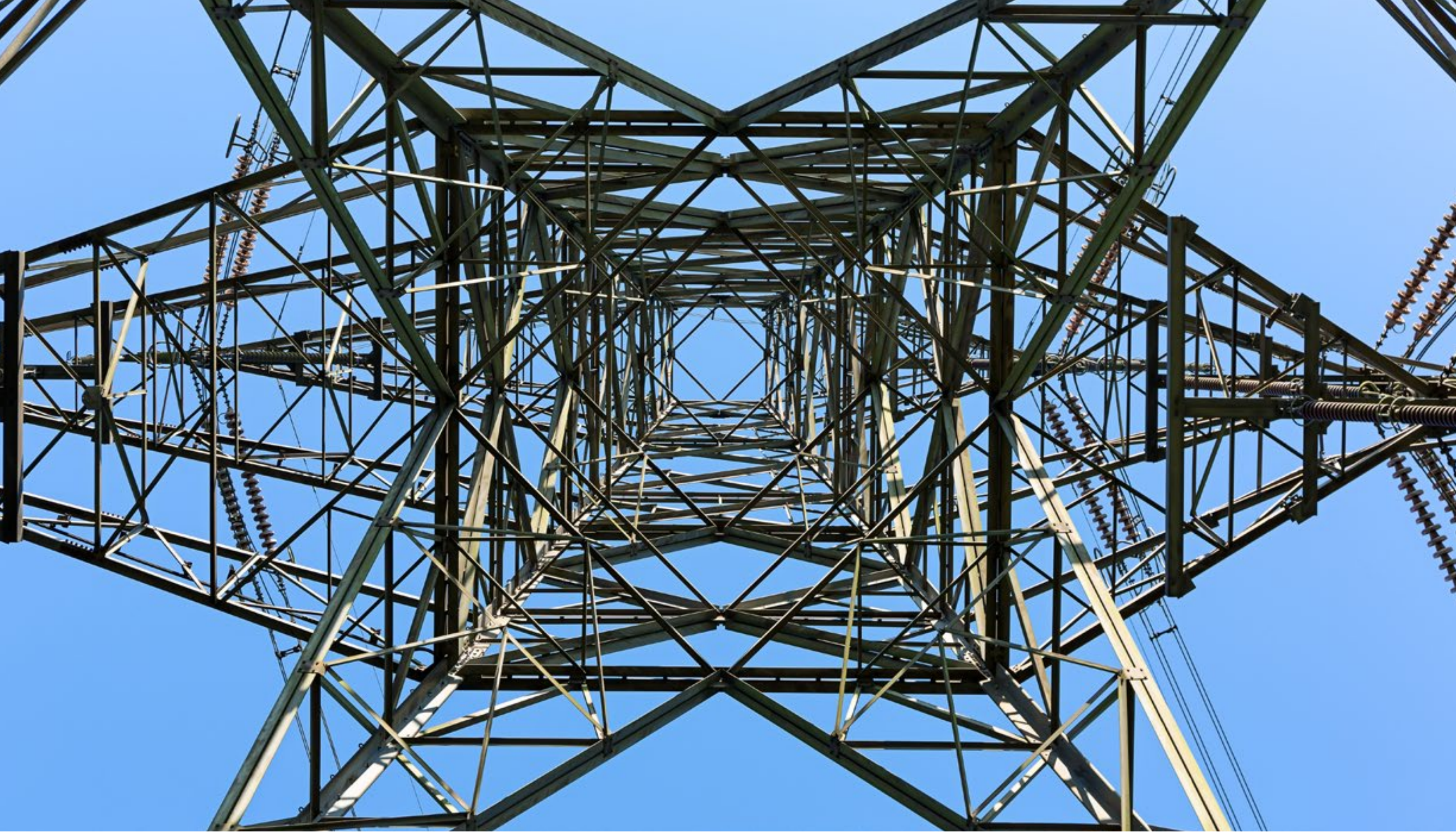



As DERs, EV chargers have the potential to act as a vast network of backup power sources and sophisticated demand-side management participants, among other potential uses. The IESO currently supports several such pilot projects through its Grid Innovation Fund.

However, pilot projects alone will not provide the necessary incentives to industry. To support the build-out of charging infrastructure, and to take advantage of the opportunities it offers, both provincial and federal governments have begun stepping up their respective funding and regulatory initiatives.

On the federal level, commitments include the $680 million Zero Emission Vehicle Infrastructure Program (ZEVIP), which is specifically targeted at the "lack of charging stations in Canada",  while the Canada Infrastructure Bank recently announced $500 million aimed at tripling the number of EV charging stations. From the province, commitments include a $91 million funding package for the installation of DC fast chargers and Level 2 chargers along Ontario's highways, as well as the continued growth and development of the Ivy Charging Network, a joint venture of Hydro One and OPG that is building chargers across Ontario.

This is only a snapshot of the enormous effort required to support the electrification of Ontario's transportation sector. The scale of the challenge will not be lost on industry stakeholders, who, with the right incentives and regulatory certainty, can be key drivers of this critical aspect of the energy transition.



## ONTARIO'S LOW-CARBON HYDROGEN STRATEGY

Following the release of British Columbia's Hydrogen Strategy in July 2021 and Alberta's Hydrogen Roadmap in November 2021, Ontario released its Low-Carbon Hydrogen Strategy in April 2022. Ontario's hydrogen strategy sets out eight concrete and immediate action items that are expected to lead to an eight-fold increase in the province's production capacity of low-carbon hydrogen. This strategy aims to support the rise of the hydrogen sector in the context of transitioning to a net-zero future, specifically by:

- Generating economic development and jobs in the low-carbon hydrogen economy;
- Reducing greenhouse gas emissions;
- Promoting energy diversity and strengthen reliability through electricity storage and clean fuel supply;
- Promoting innovation and investment; and
- Strengthening collaboration, including with the federal government, Indigenous communities, and other stakeholders.

In addition to investment in and support for specific hydrogen production projects, the Ontario government appears to be committed to exploring policy changes and other regulatory approaches. Ontario's hydrogen strategy is centered on the following eight action items:

1. Producing hydrogen using electricity from the Sir Adam Beck Generating Station in Niagara Falls, a project proposed to be built, owned and operated by Atura Power;
2. Identifying Ontario's hydrogen "hubs" (i.e., where demand for low-carbon hydrogen can match production that leverages existing electricity infrastructure), which may include Niagara, Sarnia-Lambton, Halton Hills, Nanticoke, and Brighton Beach;
3. Determining whether excess energy from the Bruce Nuclear Generating Station can be used for hydrogen production;
4. Introducing an Interruptible Rate pilot to offer consumers reduced electricity rates in exchange for reduced consumption during system or local reliability events, in order to support low-carbon hydrogen production;
5. Directing the IESO to explore options for hydrogen storage and grid integration pilot projects;
6. Phasing out the use of coal by transitioning industry to low-carbon processes and hydrogen-ready equipment, such as the $1.8 billion project by ArcelorMittal Dofasco to replace its coal-fed furnaces with a hydrogen-ready electric arc furnace;

7. Consulting with the public on a regulatory framework for carbon sequestration and storage on Crown land; and with the right incentives and regulatory certainty, can be key drivers of this critical aspect of the energy transition; and
8. Supporting ongoing hydrogen research along with Natural Resources Canada.

Ontario had already committed to reducing greenhouse gas emissions to 30% below 2005 levels by 2030. Along with the province's investments in EVs and clean steel, this low-carbon hydrogen strategy is a cornerstone of Ontario's plan to reach its stated target.

## ONTARIO SUPERIOR COURT DISMISSES NATIONAL STEEL CAR'S CHALLENGES TO THE "GLOBAL ADJUSTMENT"

A recent decision by the Ontario Superior Court of Justice in National Steel Car Limited v. Independent Electricity System Operator *suggests* the Global Adjustment (GA) is not an unlawful tax.

National Steel Car Limited (National Steel Car) challenged the constitutionality of the GA by arguing:

(i) the feed-in-tariff (FIT) first introduced in 2009 was an indirect attempt by the Ontario government to tax ratepayers in order to fund public policy objectives and stimulus goals unrelated to Ontario's electricity scheme; and

(ii) GA is a tax not enacted by statute.

More precisely, National Steel argued that the government's purported purposes of the FIT programs to enhance Ontario's electricity system were lies. Rather, the "real" purposes of the FIT programs were to provide general economic stimulus as well as specific economic assistance to rural municipalities, co-operatives, and Indigenous communities that had been adversely affected by the 2008 economic financial crisis (the Stimulus Goals).

National Steel argued that the Stimulus Goals funded by the GA (as it existed following the introduction of the FIT programs in 2009) were unrelated to the regulation of electricity and that the GA is therefore a tax in disguise, i.e. colourable attempt to tax or "colourable taxation", contrary to the Canadian *Constitution Act, 1867*.

In the alternative, National Steel argued that the GA is unlawful because it is contrary to sections 53 and 54 of the *Constitution Act, 1867*, which require provincial taxes to be authorized by statute and not merely by regulation.

The Court held that National Steel Car's arguments failed and that the GA is in fact constitutional because:

(i) the pith and substance of the FIT programs is indeed related to Ontario's electricity scheme; and

(ii) the GA is not a tax but is rather a regulatory charge, which can lawfully be implemented by provincial regulation.

### GA IS NOT A COLOURABLE TAX

In deciding that the GA is not a colourable tax, the Court made note of the seriousness of National Steel's allegations that the Ontario government lied in its characterization of the FIT programs as being about environmental concerns associated with fossil fuels, energy conservation and procuring renewable electricity.

The Court found that the evidence demonstrated that the Ontario government was making efforts toward a regulatory purpose of increasing and incentivizing renewable electricity generation in Ontario. In so doing, the Court wrote:

> *"That the FIT Programs may have been bad policy or a good policy implemented badly is relevant only insofar as it sheds light on what is the pith and substance of the enabling legislation. That the Provincial Government's electricity procurement policy meant that some of the procured energy may have been wasted because it was not needed or it was not taken up or it was taken up and exported at a loss and that this resulted in higher prices for consumers, however, is not necessarily evidence of colourability under the Constitution Act, 1867."*

Also harmful to National Steel's arguments was the fact that it did not challenge the constitutionality of the GA as it was implemented in connection with earlier renewable energy procurement programs, e.g. RES I, RES II, RES III and RESOP programs.

The Court ultimately found that the professed purposes of the FIT programs were in fact integral to Ontario's electricity regulatory system. This included (a) eliminating coal-fired generation of electricity; (b) improving air quality and reducing healthcare costs; (c) planning for an impending supply shortage; (d) increasing renewable energy sources; and (e) encouraging Indigenous communities to participate in Ontario's electrical system.

The Court also confirmed that given "that the procurement of energy is a vital component of any economy and any business", the pursuit of economic stimulus can be lawfully related to a regulatory scheme about energy. The Court found that the evidence showed that the economic stimulus of the FIT programs was objectively and reasonably related to Ontario's electricity regulation.

### GA IS NOT A DIRECT OR INDIRECT TAX

In determining that the GA is a regulatory charge (rather than a tax), the Court applied the requisite legal test and held that the GA is (a) in relation to rights and privileges associated with a regulatory scheme established under the *Ontario Energy Board Act, 1998* and the *Electricity Act, 1998;* (b) used to finance that regulatory scheme (is not a colourable tax); and (c) used to alter individual behavior in relation to that regulatory scheme by promoting cleaner energy sources and technologies and by ensuring the adequacy, safety, sustainability and reliability of electricity supply for the benefit of Ontario consumers.

While the Ontario government and stakeholders grapple with the design and implementation of net zero mandates and electrification protocols, the court has provided certainty that the anticipated resulting cost increases to ratepayers are likely constitutionally valid and lawful.


Québec

# QUÉBEC REGIONAL OVERVIEW

*Authors: Louis-Nicolas Boulanger, Danielle Drolet, Elena Sophie Drouin, Amelia Fong, Mathieu LeBlanc, Ariane Monjauze, Jean-Charles Panzini, Jason Phelan, Matthieu Rheault, Alexandra Simard and Jacob Stone*

## INTRODUCTION

2022 saw the Government of Québec continue taking steps towards the implementation of its 2030 Plan for a Green Economy, including clarifying plans to increase its supply of renewable energy in anticipation of increased electricity demand. This was reflected in heightened activity in the Québec renewable energy sector, as anticipated, a trend which is expected to continue in the years to come. Fall elections in Québec resulted in the re-election of Québec Premier François Legault and the Coalition Avenir Québec (CAQ) party, whose campaign included talks of renewed plans for sizeable hydroelectric developments.

New electricity supply for the Province is highly anticipated amid continued decreases in electricity surpluses. Hydro-Québec has communicated to developers of large industrial projects in the Province that it may not be possible to provide electricity to all projects seeking supply, due to the potential impact of such large-scale projects on supply and demand during winter peaks. In selecting industrial projects, the Government of Québec is expected to favour those who fit within its current policies and guidelines on energy and economic development. For example, projects in the bioenergy and green hydrogen spaces will be prioritized based on criteria which include the project's contribution towards electrification of the Province, the energy transition from fossil fuel energy and reduction of greenhouse gas emissions, economic spinoffs (particularly outside of major cities), impacts on the value chain, as well as the development of Québec-based expertise and innovation. Consequently, developers of industrial projects which require large supplies of electricity should consider such criteria when structuring and developing their projects, in order to maximize chances that an electricity supply will be available in order to meet the needs of their project.

## NEW RENEWABLE ENERGY RFP OPPORTUNITIES

In March 2022, Hydro-Québec released its Strategic Plan 2022–2026: For an Efficient Energy Transition. The plan outlines Hydro-Québec's vision of the path forward for Québec's ambitious transition towards a low-carbon economy and demonstrates the utility's awareness of its growing energy demand and the need to develop new power supply infrastructure and projects. In particular, it anticipates a need for 20 TWh of energy by 2029. The plan implies that development could come both in the form of upgrades to existing grid infrastructure and the addition of new power facilities and infrastructure in the coming years, with the goal of sourcing an additional 100 TWh of clean energy by 2050 (which represents over 50% of Hydro-Québec's current 165 TWh capacity).

### (a) Ongoing RFP Process and New Project Announcements

In April 2022, Hydro-Québec announced that it had entered into a partnership with Boralex and Énergir to jointly develop three wind projects totalling 1,200 MW on the Seigneurie de Beaupré territory in the Charlevoix region of Québec. The two RFPs for 300 MW of wind energy and 480 MW of renewable energy announced and published in December 2021 are also nearing completion. Hydro-Québec received project submissions in late July 2022 and issued two lists of submissions received as a result of this process. Hydro-Québec has yet to announce which projects have been selected under these RFPs.

### (b) Upcoming 2,300 MW of Renewable Energy Projects

The Government of Québec and Hydro-Québec announced on April 20, 2022, as part of the *2030 Plan for a Green Economy,* the launch of two new RFPs for a total block of 2,300 MW of renewable energy. This announcement effectively launched the largest renewable energy procurement project in the Province's history and adds to the two ongoing RFPs totalling 780 MW. This announcement was a means for the Government of Québec to reaffirm its commitment to making such RFPs a tool for regional economic development, promoting community participation, collaboration with Indigenous peoples, and other similar measures.

Hydro-Québec and the province have implied that the new RFPs will have a structure similar to that of the current 300 MW (wind) and 480 MW (renewable energy) RFPs, with one 1,000 MW block (A/O 2022-02) being reserved

for wind energy projects, and the other larger block of 1,300 MW (A/O 2022-01) would be open to all forms of renewable energy projects, such as solar, biomass, hydroelectric, and wind.

Pursuant to the Act respecting the Régie de l'énergie (Québec), the Government of Québec officially enacted regulations formalizing these RFP projects on August 3, 2022, as Orders in Council 1451-2022 and 1452-2022 (together, the Regulations). Under the Regulations, both RFPs were initiated by Hydro-Québec at the latest by December 31, 2022. Of particular note, the Regulation respecting a 1,000-megawatt block of wind energy sets out plans for the 1,000 MW block of wind energy RFP to be segmented into three distinct transmission connection deadlines:

1. 400 MW to be available and connected by December 1, 2027;
2. 300 MW to be available and connected by December 1, 2028; and
3. 300 MW to be available and connected by December 1, 2029.

There are no similar provisions in the Regulation respecting a 1,300-megawatt block of renewable energy for A/O 2022-01, the general renewable energy 1,300 MW RFP, as all projects are expected to be available and connected by December 1, 2027.

In keeping with previous Québec RFPs, the projects submitted are required to meet certain guidelines relating to social, economic and environmental concerns. These objectives, and others stemming from Hydro-Québec Distribution's Electricity Supply Plan for 2020-2029, were previously integrated into the 2021 RFPs. A new decree No. 1189-2022 Economic, social and environmental concerns reported to the Régie de l'énergie regarding a 1,000 megawatt block of wind power (Préoccupations économiques, sociales et environnementales indiquées à la Régie de l'énergie à l'égard d'un bloc de 1 000 mégawatts d'énergie éolienne) provides updated conditions for local community benefit requirements for energy projects submitted to the 1,000 MW RFP. A "buy-local" component is included to encourage local spending, divided into three notable requirements, which are as follows:

1. bidders should ensure that the project involves local community participation (including Indigenous participation) at around 50%;
2. bidders must aim for project expenses in the Province of Québec to be maximized so as to reach around 60% of the overall project expenses; and
3. a potential project is expected to have regional content in the Gaspésie, Magdalen Islands and the Matanie regions of Québec, with regional expenses expected to equal around 35% of the global amount.

As required under section 74.1 of the *Act respecting the Régie de l'énergie* (Québec), Hydro-Québec submitted the two proposed RFPs's evaluation criteria and their weighting to the Régie de l'énergie, Québec's energy regulator, for review and approval on October 21, 2022. These submissions provide insight into what criteria may be expected for the upcoming RFP processes. The regulatory review that is to take place following submission was expected to last throughout the balance of 2022 with interveners taking part in the consultation proceedings.

For these RFPs, projects tendered could reasonably be expected to meet the same minimum requirements as in the 2021 RFPs, with small adjustments. The cost of a proposed project's electricity remains the predominant selection criterion, being worth 60 points out of a possible

100. The local content of proposals, including any local support or participation and regional economic benefits, will also be important considerations in both RFPs. A new objective, the development and maintenance of harmonious relations with First Nation communities, is expected to be reflected by new points-based criteria for economic benefits for First Nation communities. The RFPs aim to solicit power purchase agreements with 30-year terms, but there is potential for longer or shorter contracts (with a minimum of 20 years). As required by Québec regulation, any power purchase agreement entered as part of the RFPs will need to be approved by the Régie de l'énergie.

In contrast with the previous 2021 300 MW wind energy RFP, the 1,000 MW A/O 2022-02 RFP would not only require local community participation in the tendered project, but would also require support of the community located in the project's immediate surrounding areas. Additionally, bids are expected to include a minimum commitment to pay to local communities for a given territory an annual sum of $5,850 per MW installed in that territory, indexed annually. Most other criteria applicable to the 1,000 MW RFP remain the same as the previous 2021 300 MW wind RFP. The proposed weighting evaluation grid is also substantially similar, although the point value of local content has been reduced in favour of an increase in the points attributable to sustainable development goals (worth 18 points as opposed to 9).

Likewise, the general 1,300 MW renewable energy RFP's contemplated selection and weighting grid is expected to retain the same broad criteria used in the previous RFP, although points for sustainable development goals have been similarly increased. The 1,300 MW RFP (A/O 2022-01) still favours renewable energy project submissions with diverse energy delivery profiles, including variable, baseload or cycling. Projects submitted may or may not include a power guarantee, the only limit being a requirement that the project can ensure energy availability for a minimum of 100 hours during the winter season. Sustainable development requirements may be expected to once again be organized into five sub-criteria: (i) the proposal's greenhouse gas emissions (if any); (ii) the source of any supply of renewable natural gas (if any); (iii) the proposal's capability to recover thermal waste; (iv) the existence of an environmental certification system; and (v) a social indicator slated to be worth the most points within the sub-criteria.

In a surprising twist just prior to press time for this publication, Hydro-Québec and the Government of Québec announced that both the 1,000 MW RFP (A/O 2022-02) and the 1,300 MW RFP (A/O 2022-01) in their originally proposed form have been tabled and will be officially reissued at a later date. According to Hydro-Québec, a new procurement strategy will be implemented in order to "make it possible to respond efficiently and at the least possible cost to the need to significantly increase renewable energy supplies by 2030." We note, however, that any RFP documents issued following press time may also change further as they will be subject to review and approval by the Régie de l'énergie.

### (c) Future Considerations for Renewable Project Developments: Changes to Land Rights and Use

In September 2021, Hydro-Québec updated its Terms of Reference for the Siting of Wind Farms on Farmland and in Woodlands (Terms of Reference), the document which provides non-binding guidelines with respect to: (i) the siting of wind farm structures; (ii) mitigation of the impacts related to construction and dismantlement or any similar work such as major repairs, renovation and reconstruction; (iii) mitigation of the impacts related to wind farm maintenance; and (iv) compensation for landowners. The guidelines are applicable to agricultural or forestry type land, whether or not they are located in an agricultural zone (under the Act respecting the preservation of agricultural land and agricultural activities).

Although the updated Terms of Reference have included additional compensation for surface rights, we note that they do not appear to reflect market trends. For example, the 2021 and 2022 RFPs call for an allocation of financial compensation to be provided to Québec municipalities. In practice, this compensation of municipalities often serves as a point of reference for comparison of, and has had an upward pressure on, compensation paid by promoters to individual landowners.

Renewable energy technology has also greatly evolved since the last major RFPs in Québec, and the use of new technology will have an important impact on the development of new wind farm projects in Québec. Notably, the industry is moving to bigger and more powerful wind turbines. Although the use of these turbines will result in a more efficient use of space - because a smaller number of wind turbines will be able to generate the same amount of power as existing wind farms - they also introduce new challenges. In particular, wind turbine blades will be bigger than previous iterations, and we anticipate this will have a significant impact on the occupation of the land, access roads and infrastructure, setbacks from the wind turbines, and general potential additional nuisances.

## DEVELOPMENTS IN QUÉBEC'S ELECTRICITY EXPORT STRATEGY & AND INDUSTRY PLANS

### (a) Hydro-Québec Financial Results

Hydro-Québec continued throughout 2022 to be one of Canada's largest exporters of electricity. In line with its previous and newly released strategic plans (i.e. the *Strategic Plan 2022–2026*, and the Sustainable Development Plan 2020-2024), Hydro-Québec has continued on the path of increasing its exports and supporting the decarbonisation of northeastern North

America.

The impact of reduced demand for and consumption of energy brought on by the COVID-19 pandemic, already in decline in 2021, was no longer felt in 2022. Rather, this past year saw increasingly favourable market conditions for Hydro-Québec's energy exports. Net electricity exports grew at an average of approximately 15% during the third quarter of 2022 compared to 2021 results, with total export volumes reaching 28 TWh over the first nine months (in comparison with the results of 2021). These results translated into sales of $2,128 million, an increase of 83% from the 2021 reference period, confirming that overall demand for electricity grew again throughout the year.

### (b) Hydro-Québec Strategies and Plans for Industrial Development

Hydro-Québec has indicated in the past that it considered its existing energy infrastructure and infrastructure under development to be capable of providing sufficient power reserves to supply both the Province and export contracts for the foreseeable future. 2022 saw a shift in Hydro-Québec's discourse on this matter, largely due to increasing interest in industrial development in Québec, which is being drawn to Québec's reliable and reasonably priced renewable energy supply.

This increased interest has resulted in Hydro-Québec adopting throughout 2022 a more cautions approach to authorizing new interconnection requests from industrial clients. In March 2022, Hydro-Québec's CEO, Sophie Brochu, announced that the utility would cease to supply cryptocurrency projects with electricity, in order to favour the best industrial and commercial projects submitted to it.

In practice, Hydro-Québec has been requesting detailed submissions and proposals for any projects involving interconnection requests for power equal to 50 MW or greater. This practice is in accordance with article 11.7 of Hydro-Québec's Electricity Rates, whereby the utility is under no obligation to contract for energy over 50 MW or to grant any request to supply additional loads totalling more than 50 MW. Hydro-Québec has been using qualitative factors to evaluate requests, notably the ability for a project to demonstrate economic benefits for Québec, including commitments to supplying the province with "priority access" to certain products produced as a result of this interconnection. The interest in industrial projects has lent further weight to ongoing interest in promoting additional energy infrastructure projects, and Hydro-Québec is working to increase its production capacity by 5,000 MW in the next years as a result.

These developments were reflected and further detailed in Hydro-Québec's release of its new Electricity Supply Plan 2023-2032 in early November 2022, which was filed with the Régie de l'énergie for its approval. The new Electricity Supply Plan 2023-2032 projects a five-fold increase in energy sold to data centers in the next 10 years, potentially reaching 5.1 TWh (an amount equal to that of 300,000 households). The data processing and storage sector's projected energy demand in the next decade is only surpassed by that of transportation electrification and building heating. Despite the projected increase in demand, Hydro-Québec has indicated that it is not working to attract new projects or proponents in the data sector. Due to the increase in demand, the cryptocurrency sector, once highly touted in Quebec, has seen opportunities for growth in the province diminish. In November 2022, the Government of Québec indicated that it had asked the Régie de l'énergie by order-in-council to consider withdrawing a 270 MW block of energy previously reserved for consumption by blockchain projects.

Ongoing infrastructure projects are also reflective of Hydro-Québec's continued export strategy, centred on the utility's ability to provide clean and renewable energy. In addition to the two RFPs planned for 2022, the ongoing 2021 RFPs, recent project acquisitions by Hydro-Québec, and renewable energy project announcements, the Province progressed on ongoing transmission and production plans, with investments in assets increasing 20% this past year. The utility is also considering refurbishing its own power production facilities and updating its transmission lines.

Work on the 1,550 MW Romaine-4 hydroelectric project was completed in July 2022 and electricity production started in September 2022. Given the development of other energy projects, the Romaine-4 project was considered by some to be Hydro-Québec's last major dam venture for some time. Fall 2022 electoral announcements by the governing political party, CAQ, however, have led to revised expectations, with Québec Premier François Legault stating during the campaign that new hydroelectric projects are back on the table for future development.

### (c) Electricity Export Strategy

Electricity exports are a central component of Hydro-Québec's *Strategic Plan 2022–2026*. During 2022, Hydro-Québec's export strategy has continued to promote the load balancing capacities of its hydroelectric assets to other provinces and to American states. Its activities in this respect have been demonstrative of Hydro-Québec's cross-border ambition, and efforts to export electricity to the United States have remained a central feature of Hydro-Québec's ongoing export strategy. In October 2022, Hydro-Québec announced its subsidiary, HQI US Holding LLC, had acquired 13 hydropower generating stations in New England through the purchase of Great River Hydro, LLC, adding 589 MW to its power capacities south of the border, and branching out its activities in Vermont, New Hampshire and Massachusetts.

Following the September 2021 announcement that Hydro-Québec had been chosen by the State of New York to deliver 1,250 MW of electricity (approximately 10.4 TWh) as of 2025, under a 25-year contract with the New York State Public Service Commission, regulatory approval was obtained in April 2022 from the New York State Public Service Commission. On the Canadian side, an application was filed on July 8, 2022, with the Canada Energy Regulator for its approval, and the file remains ongoing.

Approved by the Regie D'énergie in mid-November, this export project aims to deliver power to New York City by way of the Champlain Hudson Power Express line. Early estimates suggest that the contract could generate revenues of approximately $20 billion for Hydro-Québec. Hydro-Québec partnered with Transmission Developers Inc. to begin construction on the line, including 339 miles of buried lines, this past summer in order to meet the scheduled 2025 commissioning. In Québec, the Mohawk Council of Kahnawà:ke and Hydro-Québec announced they would be joint owners of the Hertel–New York line. Work on this line was kicked off in New York in late-November and work in Quebec is expected to start as begin in fall of 2023. Upon completion it will link the Hertel substation in La Prairie to the American portion of the transmission line by connecting to a point located at the Richelieu River.

After experiencing certain setbacks in 2021, Hydro-Québec's project to export electricity to Massachusetts pursuant to a 2018 power purchase agreement saw new developments in 2022. In November 2021, a referendum in Maine unexpectedly brought the project, Hydro-Québec's joint venture with Avangrid Inc. to build a 1.2 GW transmission line that would connect Québec through Maine to the Massachusetts's power grid called the New England Clean Energy Connect (NECEC), to a halt. These results were challenged in court, where the referendum's constitutional validity was contested. This eventually resulted in a 5-0 finding in August of 2022 by the Supreme Court of Maine that the referendum infringed on due process rights. The case has since been remanded back to trial, but requests for preliminary injunctions to resume building have so far been unsuccessful. The trial judgment on the NECEC project is expected to be rendered in 2023. In 2022, the Supreme Court of Maine also ruled in favour of Maine, finding that the lease it obtained from the Bureau of Parks and Lands was valid.

While international exports of Hydro-Québec electricity have received significant attention, Hydro-Québec's strategy also includes exports to neighbouring provinces. On October 11, 2022, the Ontario government stated that it did not plan to renew past 2023 the *Ontario-Québec Electricity Trade Agreement*, a power purchase agreement for 2.3 TWh of electricity annually (approximately 7% of Hydro-Québec's annual exports). Discussions between the provinces and Hydro-Québec are ongoing regarding this matter and new developments can be expected in the future. Our team will continue to monitor the situation.

## THE YEAR AHEAD: GREEN ENERGY AND HYDROGEN

As part of its commitment to achieve carbon neutrality by 2050 and in line with its 2026 Québec Energy Transition, Innovation and Efficiency Master Plan, the Government of Québec introduced in May 2022 the Québec Green Hydrogen and Bioenergy Strategy (the Strategy). The Strategy follows the announcement in 2020 of the 2030 Plan for a Green Economy to tackle climate change and to reduce greenhouse gas emission by 37.5% below the 1990 levels by 2030 (the 2030 Plan).

The Strategy aims at creating and coordinating the framework to accelerate the development of the green hydrogen and bioenergy sectors in Québec as means to achieve its target of reducing Québec's consumption of petroleum products by 40% below 2013 levels by 2030. Conceived around five guiding principles, the Strategy aims to: (i) contribute to the decarbonization of the Province by increasing efficiency of energy consumption and direct electrification; (ii) develop natural resources and promote residual material sustainability; (iii) foster collaboration between and participation of all stakeholders; (iv) contribute to Québec's energy autonomy by using renewable energy produced in the province; and (v) attract investments in and export its knowledge of renewable energy.

It is estimated that green hydrogen and bioenergy could potentially reduce consumption of petroleum products by 1 billion litres per year by 2030, equivalent to removing 1.2 million gasoline vehicles from the road.

### (a) Green Energy: 2022-2026 Strategy Roadmap

The Strategy sets out, among other things, various initiatives in order to lay the groundwork for accelerating Québec's energy transition:

- the development of production and distribution infrastructure by providing financial assistance programs for biogas and renewable natural gas production and offering tax credits for production of biofuels and pyrolytic oil;
- the increase of green hydrogen and bioenergy use by adapting the regulatory framework to include minimum renewable content in fossil fuels, adopting a hydrogen installation and safety code to ensure the safe and sustainable deployment of these renewable energies, pursuing funding programs which target the conversion of fossil fuel consumption to renewable electricity, green hydrogen and bioenergy;
- the development of innovative solutions and processes, which include the funding of demonstration projects via Technoclimate (Technoclimat) and Wood Innovation (Innovation Bois) programs; and
- the increased commitment from the public and private sectors for the development of green hydrogen and bioenergy by attracting investment and capital financing in local projects and creating business opportunities internationally.

In support of the Strategy and the 2030 Plan, the Government of Québec renewed in 2021 its *Bioenergy* (Bioénergies) program financed by the *Electrification and Climate Change Fund* (Fonds d'électrification de changements climatiques) and offers to enterprises, institutions and cities funding to develop infrastructure and bioenergy distribution networks in Québec.

### (b) Ongoing Hydrogen Projects

In June 2022, Charbone Corporation, a company listed on the TSX Venture Exchange, announced it had started phase 1 construction of its hydrogen plant project located in Sorel-Tracy. Charbone Corporation is authorized by the Government of Québec to produce up to 5.5 MW of hydrogen once the three projected phases of the project have been completed. The project is exclusively funded through private funds.

In August 2022, the Government of Québec announced an investment, through Investissement Québec, of approximately $284 million in the form of loans and preferred shares in Varennes Carbon Recycling, which now combines a green hydrogen plant project and an adjacent bio-refinery plant project in Varennes. This investment replaces the investment that Hydro-Québec had previously made in the green hydrogen plant, after Hydro-Québec exited the project due to a shift in strategic priorities. These projects continue to be developed among the initial strategic partners Enerkem, Shell, Suncor and Proman.

### (c) What to Expect in 2023 for Hydrogen Market

Looking forward to 2023, we can expect further advances towards the production, storage, transportation and use of hydrogen. Following the creation of Hydrogen Alliance, which concluded in August 2022 between Canada and Germany as discussed further in our Atlantic Provinces Regional Overview Chapter, additional agreements relating to hydrogen supply between countries may be concluded by Canada with European countries attempting to move away from Russian imports in the context of the Ukrainian war. This may create opportunities for the burgeoning Québec hydrogen sector, which is be expected to grow given the favorable environment being created by the Government of Québec through the implementation of its Strategy.

# Atlantic Provinces

# ATLANTIC PROVINCES REGIONAL OVERVIEW

*Authors: Elena Sophie Drouin, Stephen Furlan, Jacob Stone, Gaëtan Thomas, and Paul Zed*

2022 was again a year of continued growth and activity for Atlantic Canada's power sector. The region's provinces (Nova Scotia, Newfoundland & Labrador, New Brunswick and Prince Edward Island) all made headway on their plans to transition to renewable and new energy sources. This shift has led to further opportunities for public and private projects aimed at increasing the regional supply of wind, solar and tidal energy, and new interest in regional hydrogen development.

All Atlantic provinces clarified their plans for the energy sector which assisted businesses interested in project work in the region. In the case of Nova Scotia and Newfoundland & Labrador, while an interest in offshore oil and gas exploration was renewed this past year, the main development was these provinces' intentions to become leaders in green hydrogen production.

While there was much activity at the provincial level, other key 2022 developments occurred at the interprovincial and federal levels. Regional strategic initiatives on renewable energy were advanced by regional groups such as the Offshore Energy Research Association, the Atlantic Hydrogen Alliance and the Maritimes Energy Association. Three areas of activity–the Atlantic Loop project, small modular nuclear reactors, and hydrogen fuel production–continue to present particular opportunities for growth given their potential for further innovation.

## ATLANTIC PROVINCES GOVERNMENTAL UPDATES

In 2022, the Atlantic provinces were actively enacting new energy legislation to facilitate the energy transition to reduce carbon intensity.

At the Federal level, the government announced that it had decided to proceed with a regional assessment of offshore wind development in the Atlantic region (Newfoundland and Labrador and Nova Scotia) using the *Impact Assessment Act*. Draft *Terms of Reference* for the regional assessment were released on June 30, 2022. By October 12, 2022, draft agreements with Nova Scotia and Newfoundland and Labrador were published, and public consultation has started.

Complementary changes were also made in 2022 to the Canada-Newfoundland & Labrador Offshore Petroleum Board and the Canada-Nova Scotia Offshore Petroleum Board. Originally created through the Atlantic Accord and the Canada - Nova Scotia Offshore Petroleum Resources Accord respectively to oversee petroleum activities and the offshore oil industry, these joint provincial-federal bodies will have an expanded role to support the clean energy transition, and oversee renewable energy projects. Upcoming regulatory changes related to this new mandate are pending and will be important to clarify the regulatory framework applicable to offshore renewable energy project development.

The Atlantic Trade and Investment Growth Strategy, first launched in 2017, was also updated this past year. This strategy is a federal-provincial collaboration and new funding was provided for ocean technologies and energy innovation (including oil and gas, clean technologies and renewable energy) for a further five years. The aim of the strategy is to increase exports from the region, and the renewed funding should support the region's aspirations to export hydrogen.

### (A) NOVA SCOTIA GOVERNMENTAL UPDATES

2022 saw a series of legislative changes made in Nova Scotia to adapt to the 2030 national climate goals set out by the federal government in the Canadian Net-Zero Emissions Accountability Act. The Environmental Goals and Climate Change Reduction Act (Nova Scotia), passed in late 2021, sets out 28 new goals, including an important commitment to entirely phase out coal energy by 2030. This is a significant milestone given Nova Scotia's reliance on coal generation.

As the supply of renewable energy continued to be insufficient to meet Nova Scotia's legislated targets, multiple new legislative changes occurred in 2022 as Nova Scotia law makers worked towards creating opportunities for independent power producers to develop renewable energy projects with the Nova Scotia Government's support.

Changes were first made through amendments to the Public Utilities Act (Bill 147), which changed the performance standards, requirements and minimums for Nova Scotia Power Incorporated (**NSPI**) for green energy production and procurement. These changes should stimulate future renewable energy RFPs in Nova Scotia. Other changes to the Marine Renewable-energy Act (Bill 101) followed, clarifying licencing and eligibility requirements for marine energy projects.

Two amendments were proposed to the *Electricity Act,* first on April 22, 2022 (Bill 145) and later on October 18, 2022 (Bill 207). Important components of these amendments aim to alleviate regulatory impediments to the development of hydrogen projects, put in place hydrogen innovation programs, and change the definition of "wholesale customer" to include any business developing a hydrogen project (previously, only Nova Scotia Power and municipal utilities were deemed to be wholesale customers).

Bill 207 also proposes changing the Underground Hydrocarbons Storage Act, the Pipeline Act and the Gas Distribution Act, as part of developing a new provincial regulatory framework applicable to hydrogen, in particular by introducing provisions for transport, storage and sale of hydrogen.

The proposed bill also contemplates placing a cap on NSPI's rates, and would limit the powers of the province's energy regulator, the Utility and Review Board (UARB), to approve any request made by NSPI to increase in its rate of return on equity any higher than 9.25%. NSPI had applied to the UARB for an approximately 14% rate increase over two years. This proposed change has led to some controversy as to how Nova Scotia plans to fund its ambitious expansion agenda and further clarifications are expected in 2023.

As of November 2022, the Nova Scotia Government was studying changes to the *Environment Act* (Nova Scotia) contained in Bill 208, which modify measures on cap and trade programs and the output-based pricing system for carbon emissions, with a focus on industry and electricity sectors. The changes would replace the existing cap and trade system applicable to greenhouse gas emitters and make NSPI's participation in the system mandatory. The proposed legislation also includes plans to create a Nova Scotia Climate Change Fund, which would provide funding for new climate change-related projects (such as renewable energy initiatives).

Activity in Nova Scotia's offshore oil and gas sector increased with increasing oil prices sparking renewed interest. In September 2022, the Nova Scotia Government and the Canada-Nova Scotia Offshore Petroleum Board issued Call for Bids NS22-1 to explore eight different parcels of land offshore. Bids are expected before September 19, 2023.

### (B) NEWFOUNDLAND & LABRADOR GOVERNMENTAL UPDATES

In Newfoundland & Labrador, expected growth of energy demand has translated into government action to encourage new energy projects. The Province's Renewable Energy Plan was launched in December 2021, laying out a five-year plan organized into four specific areas of work: (i) Energy Uses and Markets; (ii) Regulatory Framework; (iii) Partnerships, Innovation and Industry Support; and (iv) Training and Jobs.

In April 2022, following a review, the provincial government announced it would lift the ban that had been in place for moratorium on development, and accept proposals for potential wind projects.

The combined effect of government interest in creating a more favourable economic environment for renewable energy projects, the end of the Muskrat Falls project's construction, and the government's limited financial resources appear to have provided room for independent private producer initiatives.

The province's growing interest in renewable energy did not alter in 2022 its ongoing interest in oil and gas development. While fossil-fuel sourced energy plant projects, such as a proposed diesel plant in Port Hope-Simpson, have been put on hold or set for decommissioning, the province remains committed to the oil and gas industry and hopes to double offshore oil production by 2030. The province opened calls for exploration bids on 28 parcels in its eastern region and 10 parcels in the southeast coastal area. In April 2022, the province's oil sector's lifespan was extended by the important federal approval of the proposed Bay du Nord project, allowing Canada's first deepwater oil site to move forward on its goal to start pumping oil by 2028.

### (C) NEW BRUNSWICK GOVERNMENTAL UPDATES

In September 2022, the New Brunswick Government released its climate change framework outlining how it plans to reach its commitments to source 100% of its power from non-greenhouse-gas-emitting sources by 2050. The Climate Change Action Plan 2022-2027 and the Climate Change Action Plan Progress Report 2022, prepared in connection with New Brunswick's Climate Change Act, outline actions taken by New Brunswick to reach its goals by setting out 30 planned steps for future action. The province notably committed to lowering emissions 46 per cent below 2005 levels by 2030.

Like the other Atlantic Provinces, New Brunswick enacted

new legislation to reflect its climate change ambitions, passing the Act to Amend the Electricity Act on June 10, 2022. The amendments to the Electricity Act, and the subsequent Energy Efficiency Regulation (NB Reg 2022-74) create an Energy Efficiency Fund for transition away from nonelectric energy sources and the creation of energy efficiency programs. For now, this fund is oriented towards consumers and households.

### (D) PEI GOVERNMENTAL UPDATES

The PEI Government continued this past year to move forward on its pledge to reduce provincial carbon emissions and reach net-zero energy consumption by 2030 by enacting the Net Zero Carbon Act (PEI).

In Fall 2022, storms caused significant damage to PEI's electrical infrastructure, and recent activity has involved repair and reconstruction efforts. The Building Resilience: Climate Adaptation Plan roadmap issued in October 2022, notably considers the benefits of building improved energy distribution in the province and burying power lines underground. Further energy infrastructure projects are anticipated for 2023, continuing repair, reconstruction and climate change resilience efforts.

## GENERAL DEVELOPMENTS IN 2022

2022 saw growing room in the energy market for independent power producers, a rise in new energy technologies and the implementation of multiple pilot projects in the region.

### (A) ACHIEVING OFFSHORE, MARINE AND TIDAL POWER AMBITIONS

Marine and tidal power development continued in the Atlantic region, particularly in Nova Scotia. A tidal energy system operated by Sustainable Marine started producing power and delivering electricity to the Nova Scotia grid in June 2022, a first in Canada. The project draws on the tidal energy potential of the Bay of Fundy which is estimated to be able to generate up to 2,500 MW. The project received $28.5 million in federal government support. The technology is also slated to be deployed in a different location at later phases. Once operational, energy production at both locations is estimated to reach a total of 1.26 MW.

In parallel, the Fundy Ocean Research Centre for Energy has been allocated 30 MW of capacity by the Nova Scotia Government. This capacity will be used to issue demonstration permits to allow for developers to test costs, impact and technology for tidal energy generation, and facilitate the formation of a regulatory framework.

On the offshore wind front, the Nova Scotia Government announced on September 21, 2022 its target to offer 5 GW in offshore wind energy leases by 2030, intending these leases to support the province's green hydrogen industry. The offshore wind potential in the Atlantic region is thought to be stronger than that of the more developed region of Northern Europe, and offers greater wind speeds than those available in the northeast coast of the United States.

### (B) NOVA SCOTIA RFP AND POWER PURCHASE AGREEMENT MADE PUBLIC

Nova Scotia's 350 MW wind and solar energy RFP, announced in the summer of 2021, was completed in 2022. On August 17, 2022, the winning projects were announced (see table below).

| Proponent Name | Location (Counties) | Technology | Developers |
|---|---|---|---|
| **Benjamins Mill Wind LP** | (Falmouth) Hants County | Wind | Natural Forces Development and Wskijnu'k Mtmo'taqnuow Agency Ltd which represents all 13 Mi'kmaw bands |
| **Ellershouse 3 Wind LP** | Hants County | Wind | Potentia Renewables and Annapolis Valley First Nation |
| **Higgins Mountain Wind Farm LP** | (Wentworth) Cumberland County + Colchester County | Wind | Elemental Energy and Sipekne'katik First Nation |
| **WEB Weavers Mountain Wind LP** | (Marshy Hope) Pictou County + Antigonish County | Wind | SWEB Development and Glooscap First Nation |
| **Wedgeport Wind Farm LP** | Yarmouth County | Wind | Elemental Energy and Sipekne'katik First Nation |

Collectively, the projects total 372 MW (1,373 GWh per year) of renewable electricity production. Average rates for electricity for these projects under the 25-year Power Purchase Agreements provided by NSPI are $53.17 per MWh. The projects are all expected to be operational by the end of 2025, and all projects are majority owned by one or more Nova Scotia First Nations communities. This RFP is expected to serve as a blueprint for further renewable energy procurement in Nova Scotia.

### (C) "NUCLEAR" BRUNSWICK?

In New Brunswick, nuclear power was top of the energy agenda again this year. On March 31, 2022, the New Brunswick Government announced it had entered into a joint strategic plan with its Ontario, Saskatchewan and Alberta counterparts in order to expand the use of nuclear power using small modular reactors. The plan aims to support three different development streams for SMRs across Canada, including two fourth-generation, advanced SMRs in New Brunswick. The provinces of Ontario, Saskatchewan and Alberta also intend to jointly develop a regulatory framework with the federal government and develop a waste management plan, while also providing opportunities for Indigenous participation and public engagement.

Other projects are also being considered. For instance, $13 million in federal and provincial infrastructure funding was announced on July 26, 2022, to support solar energy generation at the Jean-Daigle Centre solar energy generation in Edmundston. NB Power has also continued progress on the planned upgrade to the Mactaquac dam and generating station, located near Fredericton, which would allow the plant to continue operations until 2068. The 42 MW 10 turbine Burchill Wind Project led by Saint John Energy is also moving ahead.

### (D) WIND POWER PROJECTS IN NEWFOUNDLAND & LABRADOR

Wind energy was an active sector in Newfoundland & Labrador during 2022. A process was initiated by the provincial government on July 26, 2022, opening crown lands to projects, with no limit on the number of submissions or the size of the projects. By the closing of the process on October 1, 2022, 31 applications had been received. A competitive land rights bid process is expected to be launched as a result.

One of the proposals was for a large-scale wind power project led by North Atlantic Refining Ltd, an independent power producer based in Nova Scotia, in partnership with local First Nation communities. Expectations are for this project to displace between 35% and 50% of regional diesel consumption, and produce between 200 MW and 600 MW of wind energy capacity. The project would also involve production facilities for hydrogen and ammonia (targeting 160,000 metric tonnes of ammonia per year).

Another wind farm/hydrogen project has also been proposed by World Energy GH2. This project entails plans to build 164 wind turbines to produce approximately 500 MW of energy and is currently undergoing environment assessment. Part of the project would involve building an ammonia plant in Stephenville by 2024 to generate green hydrogen. A community fund was announced by World Energy GH2 in October 2022, to solidify local support in Port au Port Peninsula for the project, and two memorandums of understanding have been executed by World Energy GH2 with the Qalipu First Nation and the Town of Stephenville in this regard.

Pattern Energy, a wind energy producer owned by the Canada Pension Plan, indicated on June 2, 2022, that it had signed an option to lease up to 4,000 acres of undeveloped land, indicating it had plans for a green hydrogen project in Newfoundland & Labrador. The project would be multidimensional in nature, with the initial phase involving 200 MW of installed wind power and a hydrogen electrolysis plant with a storage facility and other fuel infrastructure.

Other energy projects have also been active in 2022. In October 2022, N.L. Hydro proposed expansions to the 604 MW Bay d'Espoir hydroelectric plant to meet electricity load growth and provide a backup to the Holyrood diesel plant currently in operation. The proposed project would involve investment of $522 million to be used towards construction of a new and eighth turbine at the plant, adding capacity of 154 MW. An application for this upgrade is planned to be filed in 2023 before the Province's energy regulator, the Public Utilities Board, and if approved, the project could be in service within five to eight years.

## HYDROGEN TRENDS

There was significant interest throughout 2022 in developing a budding hydrogen sector in the Atlantic region. The industry-led Atlantic Hydrogen Alliance, founded in late 2021 by a group of around 60 Atlantic Canadian companies, has been advancing a roadmap to regional hydrogen development.

In late August 2022, German Chancellor Olaf Scholz


visited Stephenville, Newfoundland & Labrador as part of a series of meetings in Canada with Canadian government officials and business representatives to discuss, among other things, the safeguarding of energy security and the acceleration of the global transition to clean energy. During the visit, a Joint declaration of intent between the Government of Canada and the Government of the Federal Republic of Germany on establishing a Canada-Germany Hydrogen Alliance was signed. The non-binding declaration of intent called for shipments of hydrogen to start as of 2025, with further plans to develop a trans-Atlantic hydrogen supply chain by 2030. While there were expectations of talks between Canada and Germany to cover liquefied natural gas, these did not materialize. A subsequent Declaration of Intent was signed on September 27, 2022 between the Newfoundland & Labrador Government and the City of Hamburg, Germany to further hydrogen-related cooperation.

In addition to the series of hydrogen projects in Newfoundland & Labrador announced over 2022 mentioned above, on August 18, 2022, Port of Belledune, New Brunswick, announced it had entered into an agreement in principle with Cross River Infrastructure Partners LLC to develop a green hydrogen production facility. Collaborations with the Pabineau First Nation and the federal government are also planned. As announced, the project would produce green ammonia using 200 MW of clean energy, which could then be exported. Feasibility studies and regulatory approvals for the project are pending.

The Nova Scotia Government is also proposing new policies and legislation to facilitate hydrogen production, including a new "hydrogen innovation program". Certain hydrogen developers have indicated that they are working on hydrogen export projects (for example, Bear Head Energy, Fortescue Metals Group, and Northland Power), and two (Eastward Energy and Port Hawkesbury Paper) have expressed interest in domestic production and use projects.

In addition, a green hydrogen and ammonia production and storage project has been proposed by New York-based company EverWind Fuels in Point Tupper, Nova Scotia. The project would involve two phases and would start producing 200,000 tonnes of green ammonia in 2025, with production expanding to a million tonnes of green ammonia by 2026. All production would be exported to Europe and EverWind Fuels has entered into MOUs with local First Nation groups in connection with the project. EverWind Fuels purchased a 7.8-million-barrel oil storage terminal in Nova Scotia for $60 million in February 2022 for use as the principal site of the project.

## MUSKRAT FALLS - UPDATES

In 2022, the Muskrat Falls Generating Station and related high-voltage transmission line linking Muskrat Falls to the Churchill Falls generating station achieved commercial operation. Testing of the Labrador-Island Link, a 1,100 km-long high-voltage and direct-current transmission line from the project's location in Labrador to Newfoundland across the Strait of Belle Isle connecting the Lower Churchill Project, is ongoing.

On March 31, 2022, Newfoundland & Labrador Hydro announced that it had finalized $1 billion loan guarantee and capital restructuring for Muskrat Falls and the related transmission line projects. Part of this financing has closed through the issuance of a series of bonds underwritten by CIBC and guaranteed by the Federal Government. A follow on financing by Canada of the Labrador-Island Link will occur once this transmission line achieves commercial operation.

## ATLANTIC LOOP

The Atlantic Loop, a project to provide significant transmission upgrades to the Atlantic provinces' power grids, aims to increase the load and balancing capacity in the Atlantic provinces in order to facilitate the use by the Atlantic provinces (particularly Nova Scotia) of potential larger volumes of electricity produced in Québec. The Atlantic Loop is part of the Clean Power Roadmap for Atlantic Canada, which was released in March 2022 by the Government of Canada and the Atlantic provincial governments and includes input from the Government of Quebec.

In response to the legislative changes proposed by the Nova Scotia Government this fall (noted above) capping NSPI's regulated return on equity, NSPI indicated on October 21, 2022, it would need to pause its involvement in the Atlantic Loop project for two years. NSPI's parent company, Emera, specified that the proposed legislation would impede planned phasing out of coal power by 2030, and implied the cap would limit NSPI's ability to fund new renewable energy projects. NSPI and Emera's announcements do not appear to have terminated the project, with the Nova Scotia Government signalling it was a temporary setback. The UARB's decision on rate changes is expected in December 2022 but had not yet been released at the date of writing..

# Environmental Law

# ENVIRONMENTAL LAW UPDATES

*Authors: Dominique Amyot-Bilodeau, Amelia Fong, Kimberly Howard, Selina Lee-Andersen, Joanna Rosengarten*

## KEY DEVELOPMENTS IN 2022

In 2022, there were a number of key environmental law developments across Canada with potential impacts on the power sector. Highlights include the following:

### BRITISH COLUMBIA

— **BC Signs Climate Statement of Cooperation with Pacific Coast States:** On October 6, 2022, British Columbia, Washington, Oregon and California signed a new partnership recommitting the region to climate action. The Pacific Coast Collaborative's Statement of Cooperation (SOC) promotes collaboration among the four regional governments on accelerating the transition to a low-carbon economy, investing in climate infrastructure (such as electric vehicle (EV) charging stations, green ports and a clean-electricity grid), and protecting communities from climate impacts such as drought, wildfire, heat waves and sea-level changes. The SOC includes a major focus on equity to ensure that no communities are left behind in the transition to a low-carbon future.

— **Further Actions to Implement CleanBC Roadmap to 2030:** As noted in the British Columbia Regional Overview Chapter, the The BC government released its updated climate change plan in October 2021. The CleanBC Roadmap to 2030 builds on the CleanBC plan released in 2018, and sets out policy plans to help BC achieve the province's emission reduction target for 2030 and to reach net-zero by 2050. The CleanBC Roadmap includes a range of actions to reduce emissions, including: (i) adoption of zero-emission vehicles (ZEV) (90% by 2030 of new light-duty sales) and 100% ZEVs by 2035; (ii) a commitment to develop new ZEV targets for medium- and heavy-duty vehicles in line with California; (iii) completing BC's Electric Highway by 2024 with a target of having 10,000 public EV charging stations by 2030; (iv) new requirements to ensure all new buildings emit zero carbon by 2030 and the highest energy-efficiency standards for new space- and water-heating equipment; (v) increasing clean fuel requirements and doubling the target for renewable fuels produced in BC; (vi) introducing a new oil and gas royalty system that will end the biggest fossil fuel subsidy in the province; and (vii) reducing methane emissions from the oil and gas sector by 75% by 2030, and nearly eliminating them from oil and gas, mining, forestry and industrial wood waste by 2035.

— **Funding for Clean BC Initiatives:** BC's 2022 provincial budget provided more than $1.2 billion in new funding for the CleanBC Roadmap to 2030, including, among other things: (i) investing in the Low Carbon Economy with $9 million over the fiscal plan to expand the Low Carbon Fuel Standard and to develop a new emissions cap on natural gas utilities; (ii) financial incentives to support cleaner transportation over the fiscal plan: (iii) supporting industry to decarbonize with $310 million to maintain competitiveness while reducing emissions and preparing for requirements to be net zero by 2050; (iv) promoting emissions reductions in BC's forests with $22 million over three years to improve the province's forests' ability to sequester carbon, and to expand the Indigenous Forest Bioeconomy Program; and (v) investing $83 million to begin implementation of a new Climate Preparedness and Adaptation Strategy.

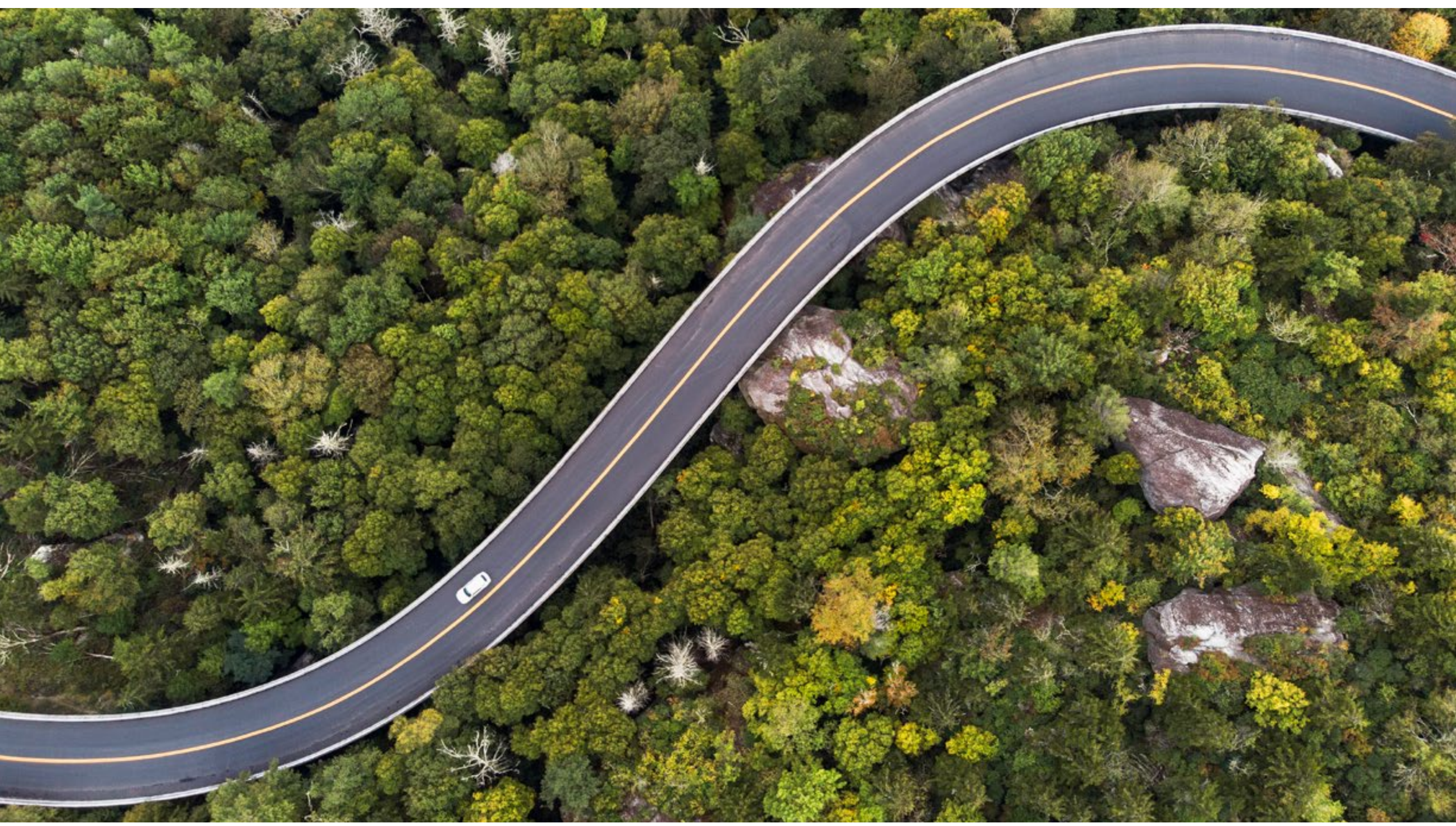
### ALBERTA

— **Amendments to the TIER Regulation:** The Technology Innovation and Emission Reduction Regulation (TIER Regulation), enacted under Alberta's Emissions Management and Climate Resilience Act, governs Alberta's industrial greenhouse gas emissions pricing regime and emissions trading system. Facilities regulated under the TIER Regulation must reduce emissions to meet facility benchmarks. Facilities regulated by or those which opt in, are exempt from paying the federal fuel charge. The TIER Regulation also establishes the Alberta Emission Offset System. The Government of Alberta completed its review in December of 2022 and released the Technology Innovation and Emissions Reduction Amendment

Regulation and the Administrative Penalty Amendment Regulation. Highlights of the amendments, which come into force on January 1, 2023, include:

- Opt-in threshold for emissions-intensive and trade-exposed industry is reduced from 10,000 tonnes $CO_2e$ per year to 2,000 tonnes $CO_2e$ per year.
- A 2% annual tightening rate will apply to facility-specific benchmarks and high performance benchmarks. For oil sands mining, in situ and upgrading, the annual tightening rate is 4% in 2029 and 2030.
- The credit usage limit is set at 60% in 2023, 70% in 2024, 80% in 2025, and 90% in 2026 forward.
- Emission performance credit and emission offset credit expiry is 5 years.
- The establishment of "sequestration credits" and "capture recognition tonnes". The sequestration credits are intended to enable recognition under the federal Clean Fuel Regulations. Capture recognition tonnes are intended to enable large emitters and opt-in facilities to reduce sequestered emissions from total regulated emissions at carbon capture sites.
- The TIER Regulation will be in effect through 2030 and the next review must be completed by December 31, 2026.
- A Ministerial Order will set the TIER Fund Price for 2023 to 2030. The price will increase annually (by $15 increments) starting at $65 in 2023 to $170 in 2030.

- **Alberta's new division between the Ministry of Environment and Protected Areas and Ministry of Forestry, Parks and Tourism:** Late in October 2022, the Government of Alberta announced it would split Alberta Environment and Parks into two: Environment and Protected Areas and Forestry, Parks and Tourism. As part of this shift, Alberta approved Order in Council 362/2022 transferring responsibility for administration of the acts that manage and protect the province's wildland provincial parks, provincial parks and provincial recreational



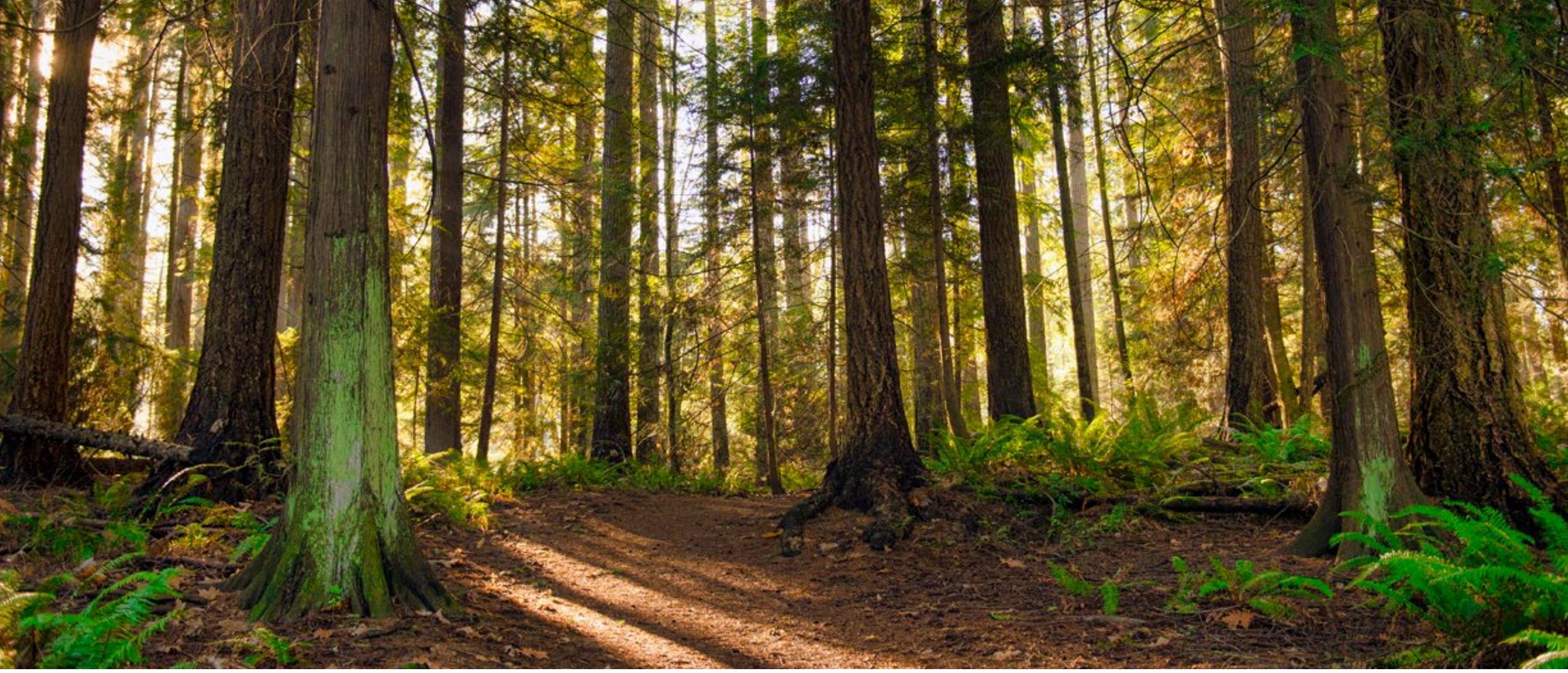
areas, including the *Provincial Parks Act* from the Minister of Environment to the new Minister of Forestry, Parks and Tourism Ministry.

**ONTARIO**

— **Amendments to Ontario's *Environmental Assessment Act*:** Changes made to Ontario's *Environmental Assessment Act* (EAA) in 2020 are starting to come into force in phases. The EAA currently applies to all public sector undertakings (unless exempted) and only to some private sector undertakings that are designed by regulations or by order, such as electricity undertakings and waste management projects. However, the provincial government is transitioning the EAA to a "project list" framework and released draft regulations in November, 2021 that set out: a proposed "projects list" for projects requiring a comprehensive environmental assessment and ultimate cabinet approval, the types of transit projects that will be exempt from the requirement to undergo a comprehensive environmental assessment if they follow a streamlined process, the types of projects that will be exempt from the EAA, and a transitional process for projects currently under assessment. The draft regulations were open for comment until January 25, 2022 and we await final regulations. Companies planning new, large-scale projects in Ontario will want to review the draft comprehensive projects list to determine their potential obligations, and will want to keep an eye out for the final projects list regulations.

— **Ontario's Transition to Emissions Performance Standards:** Ontario's transition from the federal Output Based Pricing System (OBPS) for industry-specific emissions to the Ontario Emission Performance Standards (EPS) for industry-specific emissions began on January 1, 2022. The EPS program requires regulated facilities to meet an annual baseline amount of greenhouse gas emissions that is calculated using an industry-specific performance standard. If a regulated facility exceeds this baseline emissions limit, it will have to pay a carbon price for the portion of the emissions output that is in excess. The emissions performance standards, and thus the emissions limits for regulated facilities, are expected to become mores stringent over time, as the federally-stipulated price on carbon is expected to rise annually. Most industrial emitters in Ontario will have strong economic incentive to develop strategies and technologies to reduce their greenhouse gas emissions. The generation of electricity using fossil fuels is an industrial activity that was regulated under the OBPS and will continue to be regulated under the EPS program.

— **Expansion of Administrative Monetary Penalties:** On January 27, 2022 the Ministry of the Environment, Conservation and Parks (MECP) posted for comment a proposal to expand the use of administrative monetary penalties (AMPs) for environmental contraventions. The MECP proposes to replace the current limited Environmental Penalty regime with a new AMP regime that would introduce AMPs for contraventions under the *Environmental Protection Act,* the *Ontario Water Resources Act*, the *Nutrient Management Act*, the *Pesticides Act* and the *Safe Drinking Water Act.* AMPs allow regulatory authorities to quickly and inexpensively



address compliance with environmental laws by issuing penalties that are akin to "tickets", as an alternative to charges laid for non-compliance with environmental laws. There are reduced procedural and legal requirements for issuing an AMP and, unlike for regulatory offences, a defence of due diligence is not available i.e. liability is absolute. As a potential benefit to industry, AMPs are issued without the stigma of prosecution and generally involve fines that are much lower than those imposed by a court when charges are laid for regulatory offences. The government's proposal includes a detailed overview of how AMPs would be calculated and the process for their issuance and review.

**QUÉBEC**

- **Adoption of Bill 102:** In May 2022, the *Act mainly to reinforce the enforcement of environmental and dam safety legislation, to ensure the responsible management of pesticides and to implement certain measures of the 2030 Plan for a Green Economy concerning zero emission vehicles* (Bill 102) came into force. Bill 102 enacted the Act respecting certain measures enabling the enforcement of environmental and dam safety legislation which main purpose is to expand and standardize the enforcement measures applicable to various provincial environmental statutes, including the *Environment Quality Act* and the *Dam Safety Act*.
- **Omnibus Regulations:** In August 2022, the Government of Québec published several omnibus regulations in support of the modernization of the *Environment Quality Act*, including amendments to the Regulation respecting the regulatory scheme applying to activities on the basis of their environmental impact and Regulation respecting activities in wetlands, bodies of water and sensitive areas in order to ensure a better alignment between the applicable regulatory framework and the level of environmental risk of certain activities. Certain amendments have already come into effect and others will gradually come into force in early 2023.
- **Ban on Oil and Gas Upstream Activities:** In April 2022, the Government of Québec published *An Act mainly to end petroleum exploration and production and the public financing of those activities* (Bill 21). Amongst other things, Bill 21 enacted the Act ending exploration for petroleum and underground reservoirs and production of petroleum and brine (Act) which came into force on August 23, 2022. This Act bans the exploration for petroleum and brine on the Quebec territory, revokes all petroleum exploration and production licences and authorizations to produce brine under the former Petroleum Resources Act and requires all holders of the revoked licences to permanently close all wells and restore the sites, unless they are being used under a storage licence for natural gas storage. The Act also establishes a limited compensation program for holders of revoke licences.
- **New Rules for the Cap-and-Trade System for 2024-2030:** In August 2022, the Government of Québec introduced its amendments to the *Regulation to amend the Regulation respecting a cap-and-trade system for greenhouse gas*



1. IESO Market Rules at Chapter 3, section 6.2.

*emission allowances* providing the rules for the allocation of carbon emission units free of charge for the 2024-2030 period under the Province's cap-and-trade system for GHG emissions. These new rules, which were highly anticipated by large industrial operators, provide for a gradual average of a 2.7% yearly decrease in the overall level of allocation of emission units without charge granted to emitters which will result in an overall increase of the compliance costs. The Government of Québec will also consign, on behalf of several emitters, a portion of the emission units for auctioning and the revenues generated will be set aside for the emitter to finance projects related to the reduction of GHG emissions.

**FEDERAL**

— **Federal Government Releases 2030 Emissions Reduction Plan:** In March 2022, the Government of Canada introduced the Canada's 2030 Emissions Reduction Plan, which provides a roadmap to achieve Canada's emissions reduction target of 40-45% below 2005 levels by 2030. The Plan builds upon the actions outlined in Canada's previous climate plans, A Healthy Environment and a Healthy Economy (December 2020) and the Pan-Canadian Framework on Clean Growth and Climate Change (2016). The *2030 Emissions Reduction Plan* includes $9.1 billion in new investments in the following areas: (i) electric vehicle charging infrastructure and consumer incentives for zero-emission vehicles; (ii) development of a national net-zero by 2050 buildings plan; (iii) industry incentives for clean technologies, including carbon capture, utilization and storage; (iv) development of a clean electricity standard to help move Canada's electricity grid to net-zero emissions by 2035; (v) initiatives to enable the oil and gas sector to achieve net-zero emissions by 2050; (vi) program support for farmers and the agricultural sector; (vii) community projects under the Low Carbon Economy Fund; (viii) programs to help Canada's oceans, wetlands, peatlands, grasslands, and agricultural lands capture and store carbon, and to explore the potential for negative emission technologies in the forest sector.

— **Development of Clean Electricity Regulations:** The federal government is currently developing the Clean Electricity Regulations (CER) that will help drive progress towards a net-zero electricity grid by 2035. The CER are being developed around three core principles: (i) maximize greenhouse gas reductions to achieve net-zero emissions from the electricity grid by 2035; (ii) ensure grid reliability to support a strong economy and ensure Canadians are safe by having energy to support their cooling needs in the summer and warmth in the winter; and (iii) maintain electricity affordability for homeowners and businesses. The CER is part of a suite of measures by the Government of Canada from

the 2030 Emissions Reduction Plan to move the country's electricity sector to net-zero. Proposed regulations are expected to be published in the *Canada Gazette, Part I* by the end of 2022.

- **Final *Clean Fuel Regulations Published:*** In July 2022, Environment & Climate Change Canada published the final *Clean Fuel Regulations* (CFR), which are expected to come into force on July 1, 2023. Efforts to develop a clean fuel standard started in 2016, the objective of which is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFR will require liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity (CI) of the liquid fossil fuels they produce in, and import into, Canada from 2016 CI levels by 3.5 $gCO_2e/MJ$. It will increase by 1.5 $gCO_2e/MJ$ each year, reaching 14 $gCO_2e/MJ$ in 2030. The CFR will also establish a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its lifecycle, (ii) supplying low-carbon fuels, and (iii) specified end-use fuel switching in transportation. Parties that are not fossil fuel primary suppliers (e.g. low-carbon fuel producers and importers) will be able to participate in the credit market as voluntary credit creators by completing certain actions. In addition, the proposed CFR would retain the minimum volumetric requirements (at least 5% low CI fuel content in gasoline and 2% low CI fuel content in diesel fuel and light fuel oil) currently set out in the federal *Renewable Fuels Regulations* (RFR) and the RFR will be repealed.
- ***Canadian Greenhouse Gas Offset Credit System Regulations* Published**: The Canadian Greenhouse Gas Offset Credit System Regulations (GHG Offset Regulations), established under Part 2 of the Greenhouse Gas Pollution Pricing Act (GGPPA), were published in the Canada Gazette, Part II on June 8, 2022. The Greenhouse Gas (GHG) Offset Credit System enables project proponents to generate federal offset credits if they register and implement projects that reduce GHG emissions using a published federal GHG offset protocol.  Offset credits can be sold

and used for compliance by facilities covered in the federal Output Based Pricing System, or sold and used by others who are looking to meet voluntary climate commitments. The GHG Offset Credit System is now accepting applications for project registration under the Landfill Methane Recovery and Destruction protocol. In addition, Carbon Pollution Pricing: Considerations for facilitating Indigenous participation in the Federal Greenhouse Gas Offset System was published in May 2022, which provides information on proposed measures to facilitate the participation of Indigenous peoples in the GHG Offset Credit System.

— **Proposed Amendments to OBPS Regulations:** The Output-Based Pricing System Regulations (OBPS Regulations), under the GGPPA apply in the backstop jurisdictions listed on Part 2 of Schedule 1 to the GGPPA. On October 26, 2022, the Order Amending Schedule 3 to the Greenhouse Gas Pollution Pricing Act (Order Amending Schedule 3) and the Order Amending Schedule 4 to the Greenhouse Gas Pollution Pricing Act (Order Amending Schedule 4) were published in the *Canada Gazette,* Part II. The Order Amending Schedule 3 updates the global warming potential values for greenhouse gases listed on Schedule 3 to the Act as of January 1, 2023, in accordance with the Intergovernmental Panel on Climate Change's Fifth Assessment Report. The Order Amending Schedule 4 updates the excess emissions charge for calendar years 2023 to 2030. The excess emissions charge increases to $65 per tonne of $CO_2e$ in 2023 and will increase by $15 per calendar year until 2030, resulting in an excess emissions charge of $170 per tonne of $CO_2e$ in 2030. As part of the federal government's commitment to review the OPBS Regulations in 2022, a Notice of Intent was published on October 28, 2022, setting out the Minister of Environment and Climate Change's intent to amend the OBPS Regulations. The amendments would implement certain proposed measures set out in the Review of the OBPS Regulations: Consultation Paper, published in December 2021.

— **Federal Government Launches Net-Zero Challenge for Industry:** As part of efforts to achieve Canada's goal of net-zero emissions by 2050, the federal government launched the Net-Zero Challenge in 2022. The Net-Zero Challenge is a voluntary initiative to encourage Canadian companies to develop and implement plans to transition their operations to net-zero emissions by 2050. The Net-Zero Challenge has three streams of participation: (i) Stream 1: Large emitters in industrial sectors;

(ii) Stream 2: Financial institutions; and (iii) Stream 3: All other companies, including small- and medium-size enterprises. Any business or organization operating in Canada can join the Net-Zero Challenge at any time. A list of the founding participant companies of the Net-Zero Challenge is available online.

- **Proposed Amendments to CEPA under Bill S-5:** In June 2022, the Senate passed Bill S-5 *(Strengthening Environmental Protection for a Healthier Canada Act)*, which seeks to amend the Canadian Environmental Protection Act (CEPA). The preamble of CEPA would be amended to recognize that every individual in Canada has a right to a healthy environment. Section 2 of CEPA would require that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under the CEPA. Other proposed amendments include creating a risk assessment Plan of Chemical Management Priorities (which will set out a multi-year assessment of substances and activities), and a commitment to consider the cumulative effects of these assessments on vulnerable populations.

## THE YEAR AHEAD

### BRITISH COLUMBIA

- **Further Actions to Implement CleanBC Roadmap to 2030:** In 2023, it is expected that the BC Ministry of Environment will continue to develop and introduce various initiatives to implement the CleanBC Roadmap to 2030, including: (i) a commitment to increase the price on carbon pollution to meet or exceed the federal benchmark; (ii) requirements for new industry projects to have enforceable plans to reach BC's legislated and sectoral targets and net zero by 2050; (iii) regulations that will nearly eliminate industrial methane emissions by 2035; (iv) requirements to make all new buildings zero-carbon by 2030; (v) increased clean fuel and energy efficiency requirements; and (vi) support for innovation in areas like clean hydrogen, the forest-based bioeconomy and negative emissions technology.

### ALBERTA

- **Provincial Climate Strategy:** Leading up to the 2021 United Nations Climate Change Conference, the Government of Alberta signalled its intention to release a new provincial climate strategy. We anticipate Alberta will create an updated provincial strategy to tackle its unique emission and industry profile. It will be important to monitor any new climate strategies and the potential impacts to the power industry and participants in Alberta's electricity market. Key to the power industry will be Alberta's approach to the regulation of emissions and carbon pricing, including how it approaches its long-standing carbon market for large emitters under the Technology Innovation and Emission Reduction Regulation (TIER Regulation) and whether it re-implements a province-wide carbon levy to replace the federal fuel charge currently applicable in Alberta pursuant to the federal GGPPA.

- **Looming Election:** Alberta's next provincial election is scheduled for May 29, 2023. Although different political leadership in Alberta could certainly depart from the existing UCP (or the NDP prior to that) government's policies, how changes may be implemented remains uncertain. Further, with any election it will be important to monitor the potential impacts to the power industry including how parties will tackle the inherent tension between achieving net zero targets and ensuring reliability of the Alberta electric system and affordability for ratepayers.

**ONTARIO**

- **Regulations Implementing Amendments to Ontario's *Environmental Assessment Act:*** As noted above, changes made to Ontario's *Environmental Assessment Act* (EAA) in 2020 are starting to come into force in phases. We are likely to see final projects list regulations in 2023, which will provide clarity on the types of projects that are required to undergo streamlined or full environmental assessments under Ontario's legislation.
- **Expansion of Administrative Monetary Penalties:** As noted above, the Ontario government introduced a proposal to expand the use of administrative monetary penalties (AMPs) for environmental contraventions. We will likely see regulations implementing this proposal some time in 2023.
- **Further Amendments to Ontario's Emission Performance Standards (EPS) program.** Ontario may introduce further amendments to the EPS program to implement the federally-stipulated price on carbon emissions.

**QUÉBEC**

- **Economy and Energy Transition as a Priority:** Following its re-election in October 2022, the Québec Premier, François Legault, announced that he would chair a newly created *Economy and Energy Transition Committee,* signaling that he intends to place energy transition amongst its government's priorities.

**FEDERAL**

- **Continuing Increase to Carbon Price from 2023 to 2030:** The federal government announced in December 2020 that the carbon price will be increased annually at a rate of $15 per tonne starting in 2023 until it reaches $170 per tonne of $CO_2e$ in 2030.
- **Federal Government Finalizes Regulations for Clean Fuel Standard:** The *Clean Fuel Regulations* are expected to come into force on July 1, 2023.
- **Supreme Court of Canada to Hear Appeal on Constitutional Challenge to IAA:** On May 10, 2022, the Alberta Court of Appeal (the Court) released its opinion on the constitutionality of the federal *Impact Assessment Act* (IAA) and *Physical Activities Regulations.* The government of Alberta initiated a constitutional challenge of the IAA in September 2019, arguing that when applied to intra-provincial projects, the IAA permitted the federal government to conduct far-ranging inquiries into, and ultimately regulate, matters within provincial jurisdiction. The federal government asserted that the IAA does not regulate intra-provincial projects, but rather provides an impact assessment mechanism whereby "adverse federal effects" from such projects can be regulated. A majority of the Court agreed with the government of Alberta's position that the IAA was beyond the constitutional authority of federal Parliament. In essence, the Court was concerned that the IAA encroached too deeply into areas of exclusive provincial authority. Subsequently, the federal government announced that it would appeal the Court's decision to the Supreme Court of Canada. The appeal hearing has been tentatively scheduled for the week of March 20, 2023. If the Court's decision is upheld, it will likely have significant impacts on the regulatory review process for designated projects and the constitutional division of powers with respect to environmental assessments.

# Aboriginal Law

# ABORIGINAL LAW UPDATES

*Authors: Bryan Gray, Heather Maki and Selina-Lee Andersen*

## INTRODUCTION

2022 saw a number of Aboriginal law and policy developments with implications for the energy sector in Canada as highlighted below. This includes court decisions that could affect claims in tort brought by Aboriginal rights holders against proponents and remedies for challenges to projects on the basis of the duty to consult. It also includes further steps by the BC and federal governments to implement the UN Declaration on the Rights of Indigenous Peoples and steps by the federal government to provide guidance on the use of Indigenous Knowledge in federal project reviews and regulatory decisions.

## PROPONENTS CAN BE LIABLE IN NUISANCE FOR UNREASONABLE INTERFERENCE WITH ABORIGINAL RIGHTS IF IMPACTS ARE NOT AUTHORIZED BY GOVERNMENTS

Earlier this year, the BC Supreme Court dismissed a claim by two BC First Nations against the owner/operator of a hydroelectric dam for nuisance and breach of riparian rights. The BC Court recognized that tort claims could be brought against a non-government entity for interference with established Aboriginal rights but dismissed the claim after finding that the company had complied with all applicable regulatory requirements in constructing and operating the dam and therefore had established the defence of statutory authorization. The Court found that any legal remedy for the First Nations must be pursued against the BC and federal governments. This decision is currently under appeal to the BC Court of Appeal.

By way of background, in the 1950s, the government of British Columbia authorized the construction of the Kenney Dam to produce hydropower for the smelting of aluminum. The Saik'uz and Stellat'en First Nations (the **First Nations**) alleged that the Dam and the alteration of the water flowing to the Nechako River had significantly impacted their Aboriginal rights, title, and fisheries which had resulted in a nuisance and a breach of their riparian rights. The First Nations sought injunctive relief to restore a more natural water flow to the Nechako River as well as damages, although they did not pursue damages at trial.

The decision of Justice Nigel Kent in *Thomas and Saik'uz First Nation v. Rio Tinto Alcan Inc.* was released following a 189 day trial that considered multiple complex issues, including whether the First Nations had proven the Aboriginal rights and title they were asserting.

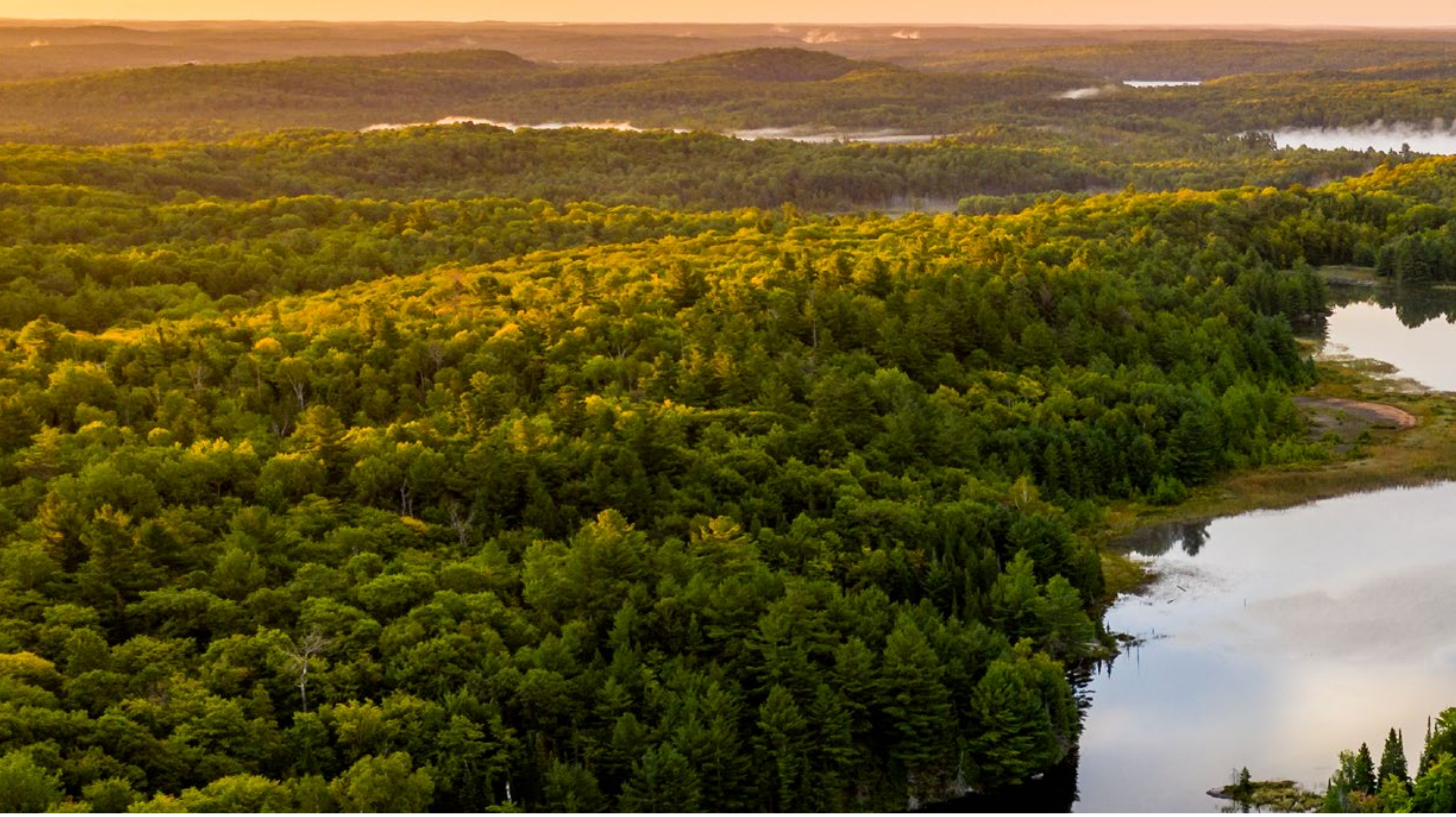
Justice Kent recognized that the First Nations held an Aboriginal right to fish for food, social and ceremonial purposes but declined to recognize Aboriginal title to two reserves (due to the absence of evidence from First Nations with overlapping claims) and the riverbed of the Nechako River (due to the failure to establish the requirements for title, including exclusivity). He held that interference with Aboriginal interests, including Aboriginal rights and reserve land interests, can serve as a basis for a common law tort action against non-government entities, subject to the defence of statutory authority. While nuisance claims normally relate to land, he found that the Aboriginal right to fish could be sufficient basis for an action in private nuisance because the right is closely related to a particular piece of land[1].

Justice Kent found that the construction and operation of the Kenney Dam had negative effects on the abundance and health of certain fish populations in the watershed which had negatively impacted the First Nations' Aboriginal rights to fish and met the requirements of the tort of nuisance (a non-trivial and unreasonable interference). However, the proponent was not liable because its operation of the Dam was authorized by the government and was in compliance with all regulatory requirements. He also dismissed the claim of breach of riparian rights as there was no evidence that showed the First Nations possessed ownership or control of the water before the assertion of Crown sovereignty.

The defence of statutory authority applies if the nuisance, or commission of another tort, is the inevitable result of exercising power authorized by Parliament or the Legislature. In this case, the design, construction and entire operation of the Kenney Dam was approved by all levels of government and the Court found that the proponent has always operated within the parameters of its authorization and complied with the water flow directions. As a result, it was concluded that the defense clearly and appropriately applied in the circumstances of this case.

It is a significant development that a Canadian court has confirmed that Aboriginal rights can be the foundation for actions in tort law against private companies. This case shows that private entities may be open to liability if they partake in non-compliance or unauthorized activity that interferes with Aboriginal rights and interests. However, this case also confirms that, if private entities follow and rely on government authorizations, the claim then rests

[1] Thomas and Saik'uz First Nation v Rio Tinto Alcan Inc, 2022 BCSC 15 at para 377.



between the Indigenous claimant and the government. The Court suggested that the Crown might have liability to the First Nations for damages related to the government's past and perhaps ongoing involvement in the construction and operation of the Kenney Dam, but no claim for damages was being pursued against the Crown in this case.

This is also notably the second Canadian court decision to consider claims to Aboriginal title to submerged lands. Both decisions (which are both currently under appeal) have either dismissed or declined to make findings of Aboriginal title to submerged lands due to the Aboriginal title test not being met and issues relating to the public right of navigation. In this case, Justice Kent noted that the public right of navigation would appear to be a barrier for any Aboriginal title claim to the bed of a navigable waterway. However, the court left open the possibility that Aboriginal title could be found to non-navigable waters such as a land-locked lake that is fully bounded by land to which Aboriginal title has been found.

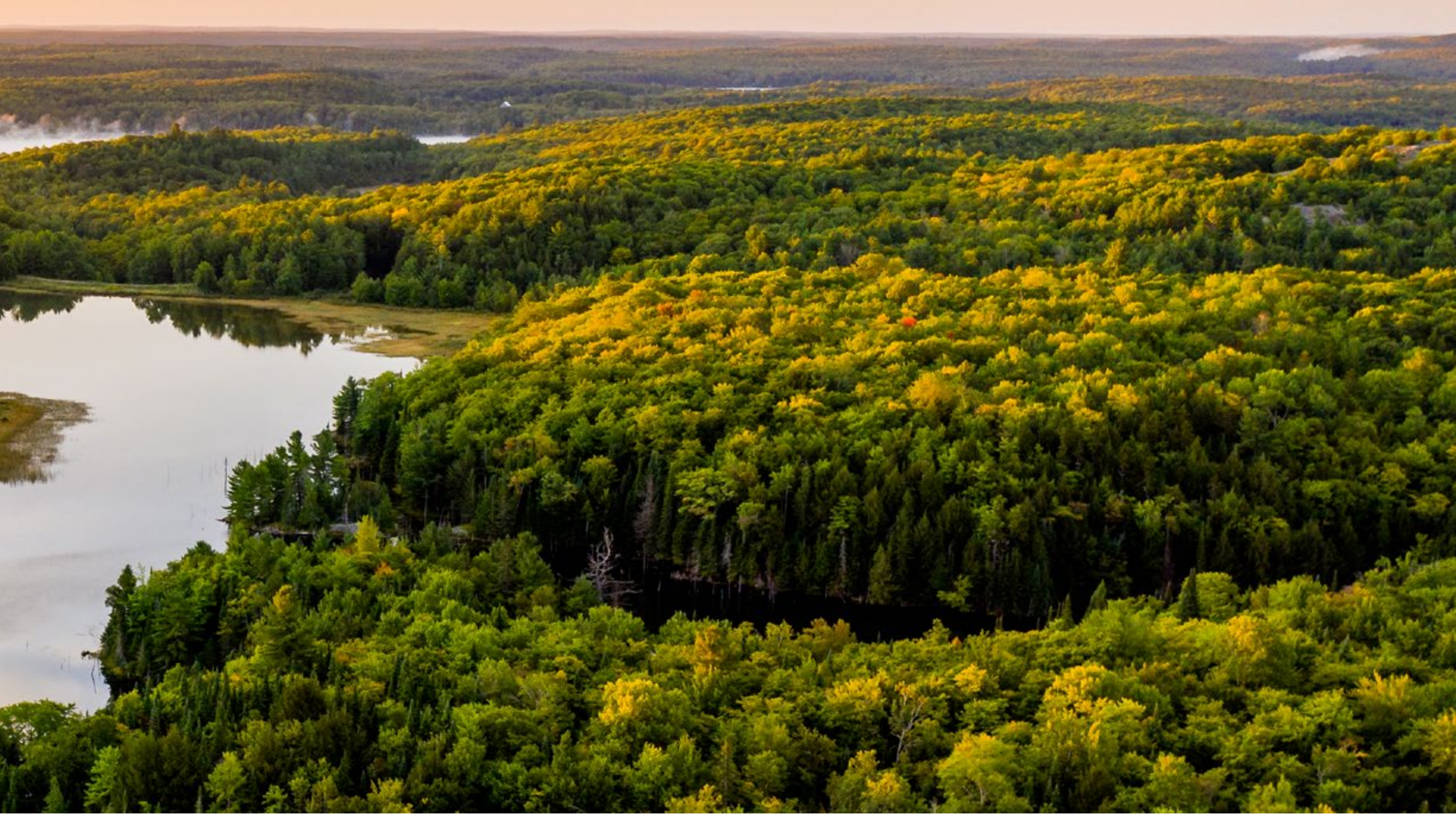
## ONTARIO COURT DECLINES TO QUASH PERMITS AFTER FINDING CROWN BREACHED DUTY TO CONSULT

In *Attawapiskat First Nation v Ontario*, Attawapiskat First Nation (Attawapiskat) sought an order quashing two mineral exploration permits issued by the Ontario Director of Exploration to Juno Corp. on the basis that Ontario did not adequately fulfil the duty to consult and accommodate. The Ontario Divisional Court granted the application but declined to set aside the permits on the basis that the breach was minor and that it would be unreasonable to require further consultation and accommodation given the record before the Court.

In this case, the proponent applied for two early mineral exploration permits on lands covered by Treaty 9. Like many numbered treaties, Treaty 9 provides Attawapiskat with treaty rights to continue to hunt, trap and fish on treaty lands that are not taken up for various purposes.

Attawapiskat asserted that the proposed projects would disrupt traditional harvesting activities as an Attawapiskat family had trap lines in the area of the projects. Attawapiskat argued that the Crown failed to fulfill its duty to consult for several reasons including that Ontario had refused to provide them with funding to obtain targeted archeological assessment and a traditional land use and occupancy study.

The Court determined that the Ministry correctly assessed the scope of duty at the low end of the spectrum given the limited nature, geographic scope and duration of the proposed activities. The Court found that it was reasonable for Ontario to decline to fund a traditional land use study as there was no information to suggest that Attawapiskat was making current use of the lands in a way that would be impacted by the proposed mineral



exploration activities.  There was a family that had been known to lay trap lines in the general area of the proposed activities but no information about current use and the court found that Ontario had no reason to believe that there would be a material cost involved in Attawapiskat communicating with the family to obtain further information.

The ultimate breach of the duty to consult arose from the fact that there had been a breakdown in communication and there were two outstanding issues that had not been addressed when the permits were issued.  The breakdown in communication arose because Attawapiskat had assumed that it was dealing with the proponent on consultation based on initial communication from the proponent and the proponent had not responded to Attawapiskat's communications.  The Court found that the Crown did not adequately deal with this issue when it came to its attention several months later and set an unreasonable deadline for Attawapiskat to provide further information. It was also found that the Crown failed to engage in further discussions with Attawapiskat about two outstanding points: (i) Attawapiskat's statement that it was unable to complete sufficient site-specific consultation with members, particularly with the one family with history of trap lines in the area (ii) Attawapiskat's general territorial interest and sovereignty over the area where the activities were to be undertaken.

With respect to the first point, the Court found that the Crown should have asked Attawapiskat to be more specific about what was required for the consultation and then considered the request reasonably.  However, the Court noted that no further site-specific information had been provided that would bear on the issuance of the permits despite having plenty of time to obtain and provide this information. With respect to the second point, the Court found the First Nation's territorial interest in the project lands was accommodated through an undertaking that the proponent had provided subsequent to the issuance of the permits that it would give Attawapiskat notice before going out on the land and drilling.

Although it found that Ontario failed to fulfil its constitutional duty to consult and accommodate, the Court exercised its discretion and declined to quash the permits.  The Court concluded that the breach was minor and was something that could have been addressed through conditions and did not go to whether permits should be issued at all.  The Court found that it would be unreasonable to require the parties to engage in further consultation given the record before it, including the undertaking to provide notice of drilling activities.  The Court seemed to be influenced by the fact that the proposed activities were on undeveloped lands that were remote to Attawapiskat settlements and there was no information provided that traditional activities would be affected by the Project despite numerous opportunities to

provide this information both before and after the permits were issued.

## NEW CUMULATIVE IMPACTS CLAIMS COMMENCED IN ALBERTA AND ONTARIO

As discussed in last year's Power Perspectives, in 2021, the BC Supreme Court ruled that the BC government unjustifiably infringed the treaty harvesting rights of Blueberry River First Nation (**Blueberry**) through the cumulative effects of provincially authorized industrial development· and that the BC government could not continue to authorized activities that gave rise to further infringements of Blueberry's treaty rights. This case has effectively halted provincial permitting in northeastern BC while the BC government negotiates a path forward with Blueberry and other Treaty 8 First Nations in BC. This year, similar claims have been filed by First Nations in Alberta and Ontario.

On July 18, 2022, Duncan's First Nation (**DFN**) filed a statement of claim alleging that the Province of Alberta has breached its obligations to DFN under Treaty 8 by authorizing uses of DFN's traditional territory in a way that "significantly diminishes" the Nation's right to hunt, fish, trap and gather as part of their way of life. The claim, which relates to the same Treaty that was at issue in the Blueberry case, advances many of the same grounds and seeks similar relief, including that Alberta's mechanisms for assessing cumulative impacts are lacking and have contributed to the breach of its obligations under Treaty 8; directing the province to establish new mechanisms to assess and manage cumulative impacts of development in consultation with DFN; and prohibiting Alberta from permitting any activities that further infringe DFN's treaty rights and breach Alberta's fiduciary obligations to DFN.

On September 30, 2022, the Missanabie Cree First Nation, Brunswick House First Nation, and Chapleau Cree First Nation filed a legal action against the Ontario government claiming that its management of the province's boreal forests violates James Bay Treaty 9. The claim asserts that the cumulative impacts from various provincially authorized activities (i.e. forestry, mining, energy and agriculture) in their traditional territories have had significant adverse impacts on the health of the boreal forest and Aboriginal and treaty rights. The plaintiff First Nations assert that they no longer have access to sufficient undisturbed lands in their respective traditional territories to carry on their way of life and livelihoods and that their treaty rights have been infringed.

These new cumulative impacts claims are in addition to similar claims previously commenced by Beaver Lake Cree Nation (**Beaver Lake**) and Carry the Kettle First Nation (**CTK**). In 2008, Beaver Lake filed a lawsuit against the Alberta and federal government, claiming that the cumulative impacts of industrial development within their

territory amounted to a breach of Treaty 6. The trial is scheduled for January 2024. In December of 2017, CTK filed an action against the Saskatchewan and federal government, alleging that the authorization of development has prevented CTK members from exercising their rights pursuant to Treaty 4. CTK seeks an injunction preventing Saskatchewan and Canada from authorizing more development on their traditional territory and a declaration that will require the governments to consult CTK prior to authorizing any new development on their territory.

If any of these claims are successful, there will be implications for future permitting in the respective territories.

## CANADA RELEASES INDIGENOUS KNOWLEDGE POLICY FRAMEWORK

On September 26, 2022, the federal government issued an Indigenous Knowledge Policy Framework for Project Reviews and Regulatory Decisions (the Framework) to provide guidance for federal officials implementing the Indigenous Knowledge provisions under the *Impact Assessment Act, Canada Energy Regulator Act, the Fisheries Act, and Canadian Navigable Waters Act*. These statutes require the consideration of Indigenous Knowledge, when provided, alongside other factors, in project reviews and regulatory decisions. These provisions were introduced in light of long-standing concerns raised by Indigenous groups that Indigenous knowledge was not being given sufficient weight and consideration in project reviews.

The Framework states that there is "no universally accepted definition of Indigenous Knowledge" and that the term describes "complex knowledge systems embedded in the unique cultures, languages, values, and worldviews of Indigenous People". This can include but is not limited to traditional ecological or environmental knowledge and this knowledge is "evolving in the context of contemporary society" and not "relegated to the past".

The Framework articulates five overarching principles to guide federal officials in the consistent and respectful consideration of Indigenous Knowledge: (i) respect Indigenous peoples and their knowledge (ii) establish and maintain collaborative relationships with Indigenous peoples (iii) meaningfully consider Indigenous knowledge (iv) respect the confidentiality of Indigenous knowledge and (v) support capacity building relating to Indigenous knowledge. Within each of these principles, the Framework provides further guidelines illustrating how the principles are to be applied which include direction to:

— respect governance, guidance, protocols, ceremonies and processes relating to Indigenous knowledge and decisions on whether to share Indigenous knowledge;

— engage early with Indigenous peoples about opportunities to share Indigenous knowledge for project reviews and regulatory decisions and about any conditions for the consideration of Indigenous knowledge;

— consider and not disregard Indigenous knowledge when it is provided for project reviews and regulatory decisions and equally value Indigenous knowledge and western scientific knowledge systems;

— clarify how Indigenous knowledge is to be understood when shared in order to promote an accurate and respectful consideration of Indigenous knowledge;

— communicate how Indigenous knowledge was considered in the outcome of project review or regulatory decisions;

— not use Indigenous knowledge for future decisions without the permission and guidance of knowledge holders; and

— provide capacity support to the extent possible where Indigenous peoples identify capacity needs relating to the sharing of Indigenous knowledge.

While the Framework directs federal officials to equally value Indigenous Knowledge and western scientific knowledge, the Framework does not provide further guidance on resolving any potential conflicts between these knowledge systems or how Indigenous Knowledge is best incorporated within the decision-making process. However, this requirement along with requirements to clarify how Indigenous Knowledge is to be understood and to communicate how it was used will result in greater weight and consideration being given to Indigenous Knowledge. Each federal department will still need to develop their own policies that are consistent with the overarching principles of the Framework.

The issues around confidentiality do raise procedural fairness issues for proponents. The Framework indicates that procedural fairness means that proponents "*may* have a right….to know what information the decision-maker is relying on when making the decision" and "*may* be given a chance to respond to that information" (emphasis added). While provisions can be put in place to preserve confidentiality, it is unclear what, if any, circumstances this information would not be shared with proponents as it would be a breach of procedural fairness for the federal government to rely on Indigenous Knowledge in making a decision and not give the proponent the opportunity to review and respond to the information.

The Framework applies only to the consideration of Indigenous Knowledge in federal decision-making relating to projects but similar provincial policies have been released or are being developed. In April 2020, the BC Environmental Assessment Office released the Guide to Indigenous Knowledge in Environmental Assessments to provide guidance on supporting the inclusion of Indigenous Knowledge in the Environmental Assessment process. Similarly, the Alberta government is developing an Indigenous Knowledge Policy to help guide how government and Alberta Energy Regulator staff can respectfully consider and include Indigenous Knowledge in land and natural resource planning and decision-making.

## UNDRIP IMPLEMENTATION UPDATES

**BC Unveils Action Plan to Implement UNDRIP:** In March 2022, the BC government unveiled the Declaration on the Rights of Indigenous Peoples Act Action Plan (Action Plan) to support the implementation of the *United Nations Declaration on the Rights of Indigenous Peoples* (UNDRIP). The Action Plan, which was developed pursuant to BC's *Declaration on the Rights of Indigenous Peoples Act* (DRIPA), details 89 actions to advance the rights of Indigenous peoples in the province from 2022 to 2027. The actions are focused on four themes: (i) self-determination and inherent right of self-government; (ii) title and rights of Indigenous peoples; (iii) ending Indigenous-specific racism and discrimination; and (iv) social, cultural and economic well-being. The Action Plan includes a number of potentially significant new measures that could have implications for project developing including (i) the negotiation of joint-decision making agreements and agreements in which consent from Indigenous governing bodies will be required before the BC government exercises a statutory decision-making power; (ii) a new framework for resource revenue sharing and other fiscal mechanisms to support Indigenous peoples; and (iii) reviews of various policies and programs relating to the stewardship of the environment, land and resources. While the themes and goals of the Action Plan are effectively the same as the Draft Action Plan released in June 2021, certain changes were made to the desired outcomes and specific actions. Some of the most notable new action items added include, but are not limited to: (i) co-developing policies, programs and initiatives that address cumulative effects; (ii) identifying policy or legislative reforms supporting Indigenous water stewardship, including shared decision-making and;

(iii) modernizing the Mineral Tenure Act in consultation and cooperation with First Nations. The province will report annually on its work to implement the Action Plan, and reports will be publicly available by June 30 of each year. In addition, the Action Plan will be updated within five years.

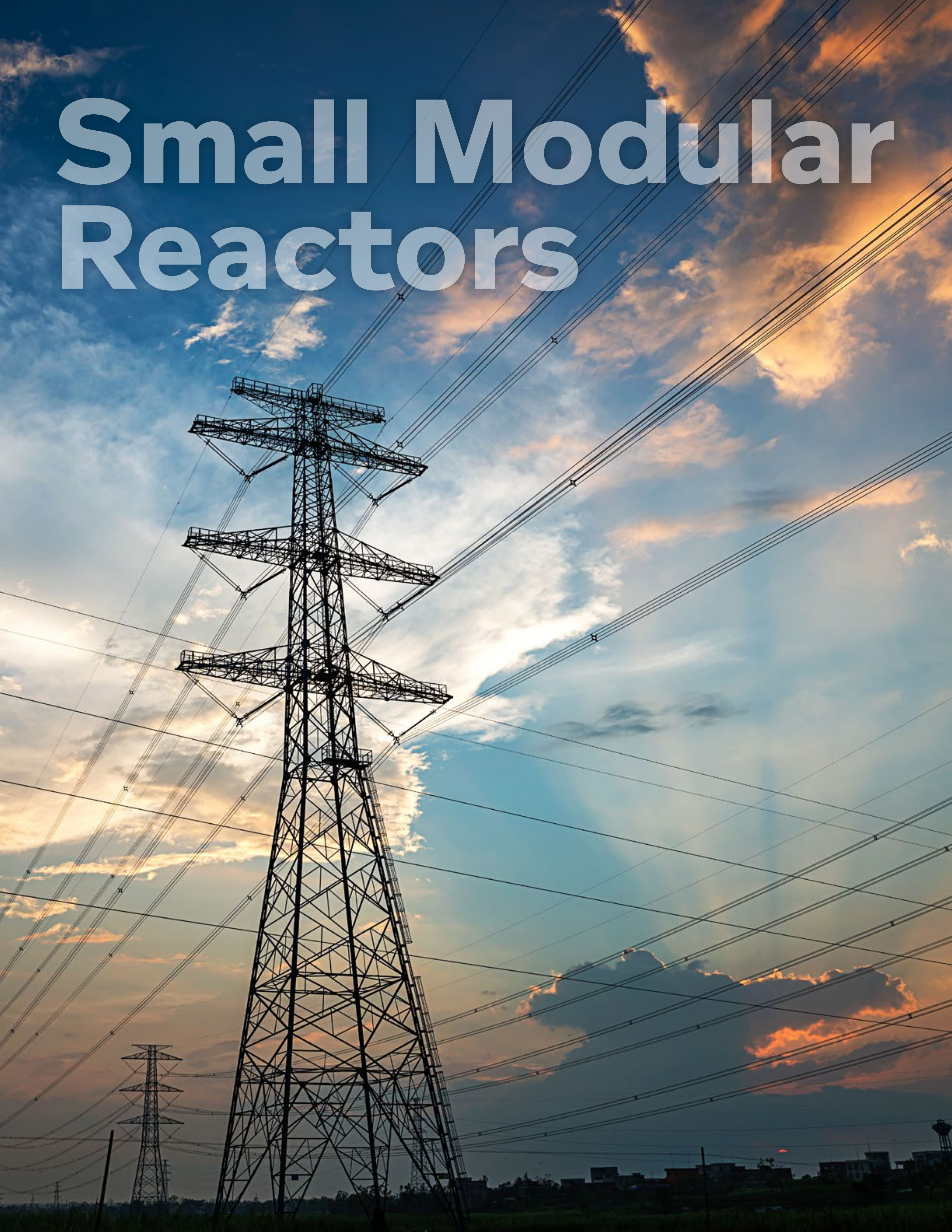
**Federal UNDRIP Action Plan under Development:** On June 21, 2021, the federal *United Nations Declaration on the Rights of Indigenous Peoples Act* (the Act) received Royal Assent. The Act contains two key objectives:

i. to affirm UNDRIP as a universal international human rights instrument with application in Canadian law; and

ii. to provide a framework for the government of Canada to implement UNDRIP.

Similar to the BC legislation, the Act does not give immediate legal effect to UNDRIP but provides a framework to align federal laws with UNDRIP over time in consultation and cooperation with Indigenous peoples. This includes the development of an action plan by June 21, 2023 to achieve the objectives of UNDRIP. The development of the federal action plan is proceeding in two phases, the first of which is underway and is focused on working with Indigenous peoples to better understand their priorities to help shape the initial draft of an action plan and to begin to identify potential measures for aligning federal laws with UNDRIP. The second phase will focus on continued engagement with Indigenous peoples to validate the draft action plan and will include opportunities for broader engagement with industry and the provinces and territories. It is currently anticipated that Canada will publicly release a draft of the action plan for public comment in February 2023.

# Small Modular Reactors



# SMALL MODULAR REACTORS

*Authors: Audrey Bouffard-Nesbitt, Steve Furlan and Gaëtan Thomas*

## INTRODUCTION

As countries around the world race to decarbonize their energy consumption, nuclear power is increasingly cited as a necessary component in achieving net-zero. While climate-related concerns continue to drive the development and adoption of nuclear technologies, the geopolitical and economic events of 2022 have added a new dimension to the need for nuclear energy. In particular, the Russian invasion of Ukraine in February 2022 pushed nuclear energy to the forefront of global conversations surrounding energy security and sovereignty. As many leading economies continue to radically re-examine their energy supply, Canada stands to position itself as a global leader in the advancement of nuclear technologies.

## CANADIAN UPDATES

In 2022, Canada continued to progress the development and deployment of Small Modular Reactors (SMRs). Government and industry stakeholders have increasingly collaborated to implement many of the actions outlined in Canada's Small Modular Reactor Plan (SMR Action Plan). While this progress follows years of industry advocacy, the geopolitical events of 2022 and their subsequent effect on the global energy economy have drawn increased attention and enthusiasm towards the advancement of SMR technologies across the country.

The Federal Government continues to be a key driver in Canada's emerging SMR industry. However, 2022 saw Provincial governments take further steps to embrace and expedite SMR technologies. In December of 2019, the governments of Ontario, Saskatchewan and New Brunswick (subsequently joined by Alberta) (the Provinces) entered into a Memorandum of Understanding respecting SMR development (the MOU). The key deliverable under the MOU, the release of a joint strategic plan (the Strategic Plan), was achieved when the Strategic Plan was released on March 28, 2022. The Strategic Plan outlines the path forward for SMRs in their respective jurisdictions and sets forth five key priority areas for SMR development and deployment: (1) technology readiness, (2) regulatory framework, (3) economic and financing, (4) Indigenous and public engagement, and (5) nuclear waste management, discussed in detail in this blog post.

## SMR TECHNOLOGY AS AN ENERGY REALITY

The concerted collaboration of industry and government stakeholders continues to propel the safe and responsible development and deployment of SMRs in Canada.

A notable announcement from the Canada Infrastructure Bank (**CIB**) demonstrates this growing trend. On October 25, 2022, the CIB announced that it finalized an agreement with Ontario Power Generation (**OPG**) to fund the development and construction of a 300-megawatt SMR next to OPG's existing 3,500-megawatt Darlington Nuclear Generating Station.

Once constructed, the Darlington Project will be Canada's first operational grid-scale SMR. CIB and other stakeholders expect the Darlington SMR to prompt similar projects in other provinces, as domestic and international investors increasingly eye Canada as a global SMR technology hub. CIB's announcement is a leading example of government and private sector collaboration in the SMR space and represents a key important milestone for the industry.

While the CIB's funding commitment represents the most concrete step towards the deployment of SMR technology in Canada to date, 2022 saw several other notable funding and development announcements. For example:

- On March 17, 2022, the Minister of Innovation, Science and Industry, Francois-Philippe Champagne, announced $27.2 million dollars in federal funding for Westinghouse Electric Canada Life's next-generation SMR, the eVinci micro-reactor. The funding will support Westinghouse's existing $57 million investment into the project. The announcement follows the Federal government's existing $220 million commitment to SMR technologies through the Strategic Innovation Fund's Net Zero Accelerator Initiative.
- As noted in the Environmental Law Updates Chapter, on March 29, 2022, the Federal Government announced $9.1 billion in new investments as part of its Emissions Reduction Plan. The Emissions Reduction Plan identifies nuclear energy, including SMRs, as playing a role in Canada's emissions reduction targets. The federal government highlighted SMRs as one of several emerging technologies that will benefit from over $850 million in development and deployment support.


— Announced on April 7, 2022, Canada's Federal Budget outlined further commitment to supporting SMR technology. Specifically, the 2022 budget allocated $69.9 million to Natural Resources Canada to fund research into nuclear-waste mitigation, support the creation of an SMR fuel supply chain, strengthen international nuclear cooperation agreements and enhance domestic safety and security policies and practices. The budget further outlined $50.7 million in funding for the Canadian Nuclear Safety Commission to increase the agency's SMR regulatory capacity.

— On October 12, 2022, the Saskatchewan-based mining company, Cameco, announced that it finalized the purchase of a 49 per cent stake in the nuclear service provider Westinghouse Electric Co. for $2.2 billion in equity consideration. Cameco, the world's largest publicly-traded uranium company, cited Westinghouse Electric's expertise in servicing nuclear reactors, including SMR technologies, as a key factor motivating the acquisition.

— On November 3, 2022 the Government of Canada released a fiscal update and introduced an investment tax credit of up to 30% for clean technologies, importantly including SMRs.

## SMRs IN CANADA'S OIL AND GAS SECTOR

Alberta, home to Canada's oil and gas industry, is increasingly eyeing SMR technology as a viable option to decarbonize the province's vital energy sector. In August, 2022, Invest Alberta, a crown-corporation promoting high value investments in the province, signed a memorandum of understanding (MOU) with Ontario-based Terrestrial Energy to support the "commercialization of Terrestrial Energy's Integral Molten Salt Reactor (ISMR) Generation IV" SMR plant in western Canada. Terrestrial Energy's SMR has the "unique potential" to supply the heat and power needs of many industrial activities, including notably "those in the Alberta oil and gas, and petrochemical sectors". Terrestrial promotes the technology as "ideally suited for natural resource, low-carbon hydrogen and ammonia production" as well as additional energy-intensive industrial activities.

The Terrestrial MOU is a further step towards the integration of SMR technology in Canada's oil sands. As oil sands producers commit to reducing the carbon intensity of their operations, SMR technology is increasingly being identified as a viable option in the industry's climate-action toolkit. The Terrestrial MOU follows in the wake of the Canadian Oil Sands Innovation Alliance's (COSIA) inclusion in Canada's SMR Action Plan. 2022 saw the completion of COSIA's preliminary evaluation of SMRs in the oil sands context. The subsequent public report is expected to be released in the near future. The carbon-intensive industrial operations of Canada's oil sands producers are an ideal market for SMR adoption and we believe there will be a number of positive applications of SMR technologies in this sector.

## THE VIABILITY OF SMRS IN CANADA – A GREENER FUTURE

### SAFETY, ECONOMY, & OTHER BENEFITS

Full-scale nuclear plants are generally very safe. SMRs are even safer. SMRs are also cheaper and cleaner than full-scale plants.

Because SMRs engage passive safety features and use less fuel than traditional reactors, they are inherently safer. Passive safety measures engage without human intervention. SMRs are smaller and simpler than full-scale reactors, which allows them to be mass-produced and transported more easily. Repeatable processes foster higher and more consistent construction quality. Smaller size also contributes to safety because safety radii around SMRs are smaller and SMRs require less heat removal than larger models. Further, SMRs can be built primarily underground, making them resilient to severe weather events. SMRs also create less fuel waste than large reactors.

Economies of scale allow for inexpensive construction and reduced financial risk for players in the nuclear industry. Notably, a larger market would be required in order to realize the greatest economic benefits of SMRs. SMRs can also provide power to isolated regions where it would be impractical to build a full-scale plant. As noted above, oil sands plants are a prime example because they require a source of non-emitting and reliable off-grid power.

**CHALLENGES**

Although there are generally no major obstacles to the licensing of SMRs in Canada, there are some areas where action is needed to push SMRs to the mainstream level. First, the Canadian Nuclear Safety Commission (CNSC) requires applicants to go through an approximately 10-year approval process, a concern in light of Canada's ambitious federal emissions targets in 2035 and 2050. The industry believes this should be reduced to 5-6 years without compromising safety. Other countries have already begun reducing red-tape in nuclear plant approval. For example, as of September 2022, France has begun legislative change intended to reduce the approval process for nuclear plants to a maximum of 5 years.

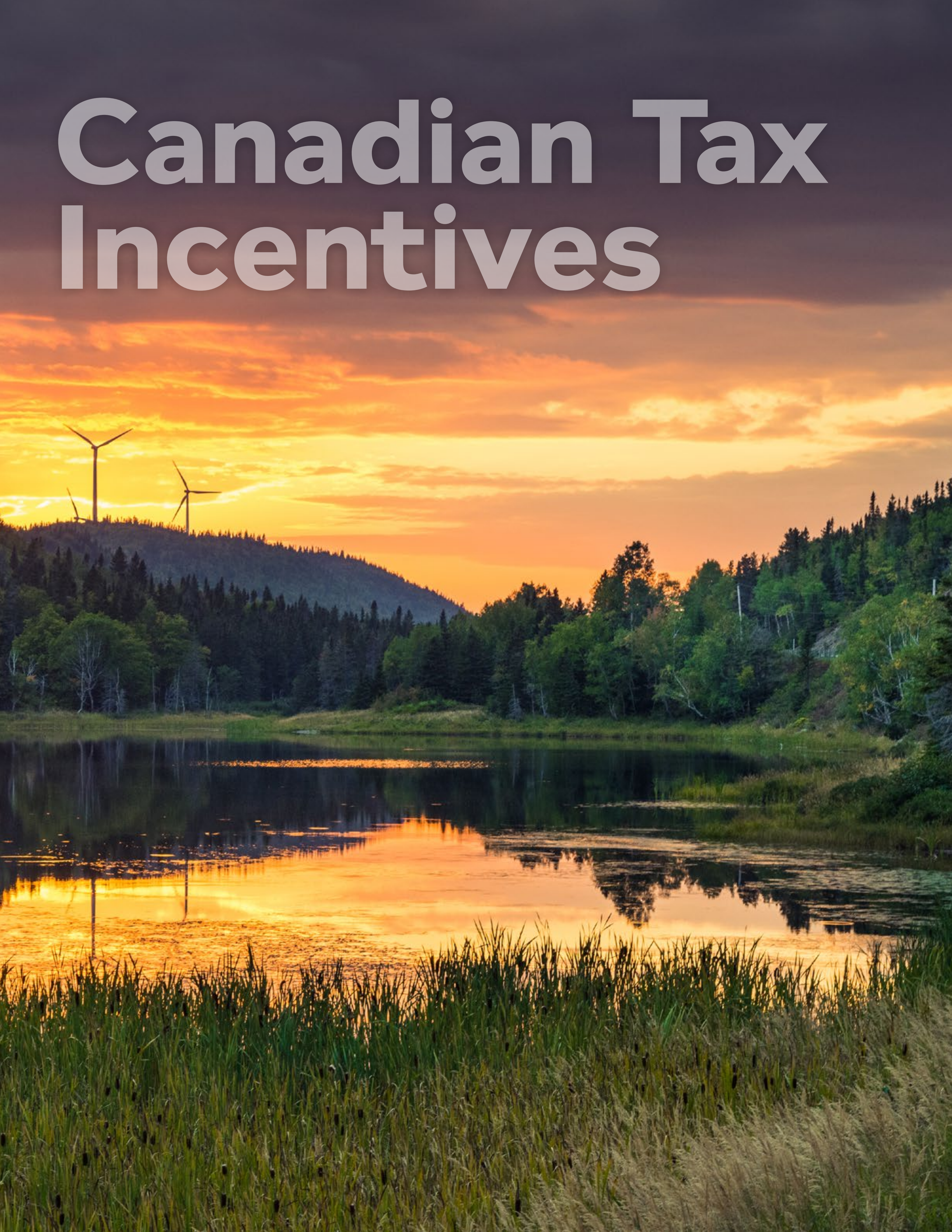
Because SMRs are a new technology, another concern is the large investment gap expected. This means that continued and substantial government support will be required. Government funding will also be necessary to allow nuclear power to compete on a level playing field with renewable energy and gas. Further, Canada will need to mobilize a new supply chain to foster SMR development, although risk is greatly mitigated because 70-80% of the supply chain is Canadian. Finally, public acceptance and Indigenous consultation and approval is essential for SMR success in Canada.

**CONCLUSION**

As time progresses, the need for alternatives to carbon intensive sources of energy becomes increasingly clear. Because of its lower cost, increased safety, and incredible adaptability, the time is now for SMR technology in Canada and the rest of the world. This is particularly true in light of the Russia-Ukraine War which has led numerous countries to plan for SMRs to reduce their dependence on oil and gas. SMRs also represent a potentially lucrative opportunity for Canadian industry. At minimum, the value of SMRs is expected to rise to $5.3 billion between 2025 and 2040, with the global figure climbing to $150 billion.

With unmatched experience in the nuclear energy industry and a consistently top-tier ranked Project Development practice, McCarthy Tétrault is uniquely positioned to develop and implement sophisticated strategic and legal solutions to implement SMR projects. For further insights into the development and deployment of SMR technologies in Canada, please contact our National Power Group.

# Canadian Tax Incentives



# RECENT CANADIAN TAX INCENTIVES FOR CLEAN ENERGY

*Authors: Jeremy Ho and Matthew Kraemer*

## INTRODUCTION

Within the past year, the Canadian federal government has proposed a number of tax incentives to encourage investment in clean energy in furtherance of achieving its commitments under the Paris Agreement and goal of net-zero emissions by 2050. The following summary describes certain of these recent Canadian tax incentive measures relating to carbon capture, utilization and storage (CCUS), clean technologies and hydrogen production.

## INVESTMENT TAX CREDIT FOR CCUS

In the federal government's 2022 budget (Budget 2022), a new refundable investment tax credit (CCUS ITC) was proposed to encourage investment in CCUS project development. The CCUS ITC is proposed to apply to eligible expenses incurred after 2021 through 2040. The Department of Finance subsequently released draft legislation in respect of the CCUS ITC on August 9, 2022, as well as an accompanying backgrounder outlining additional design features of the CCUS ITC. Legislation to implement the CCUS ITC has yet to be introduced in Parliament and, as such, details of the CCUS ITC may undergo further revision. A brief summary of the new proposed CCUS ITC regime, as proposed at the time of writing, is set out below.

### ELIGIBLE EXPENSES

Expenses eligible for the CCUS ITC will need to fall within one of four categories of qualified CCUS expenditures: (i) qualified carbon capture expenditures; (ii) qualified carbon transportation expenditures; (iii) qualified carbon storage expenditures; and (iv) qualified carbon use expenditures. Very generally, such expenses will need to be incurred in the taxation year to acquire or install eligible equipment (Eligible Equipment) that will be used in a qualified CCUS project that results in $CO_2$ being used for an eligible use (Eligible Use). Each of these concepts is discussed below. Expenses incurred in the development of a CCUS project that do not relate to the acquisition or installation of equipment do not qualify for the CCUS ITC (such as feasibility studies, front end engineering design studies, operating expenses, and exploration and development expenses).

### ELIGIBLE EQUIPMENT

Eligible Equipment is generally equipment the sole use of which is to capture, transport, store or use $CO_2$ as part of a qualified CCUS project that is situated in Canada. Equipment that captures $CO_2$ in Canada, compresses it and transports it to another jurisdiction to be stored will be considered to be used in Canada.

Expenditures on equipment that does not support CCUS, as well as equipment required for hydrogen production, natural gas processing and acid gas injection is not eligible equipment.

### ELIGIBLE USE

An Eligible Use is the storage of $CO_2$ in (i) underground geological formations or (ii) the storage of $CO_2$ in concrete. For geological $CO_2$ storage, the storage requirement is that the geological formation be capable of permanently storing captured carbon within Canada, in an offshore area of Canada or in a jurisdiction outside of Canada that has sufficient environmental laws and enforcement to ensure that captured carbon is permanently stored, as prescribed by the regulations at the time a relevant expenditure is incurred. For concrete storage projects, the storage requirement is that the process demonstrates, in a prescribed manner, that at least 60% of the $CO_2$ injected into the concrete is successfully mineralized and permanently stored in the concrete. The use of $CO_2$ to enhance oil and gas recovery is not an Eligible Use. If a portion of the eligible expense will not be utilized for an Eligible Use, such expenditure is not included as a qualified CCUS expenditure and the CCUS ITC is reduced by the percentage of $CO_2$ that will be put to the ineligible use.

### QUALIFIED CCUS PROJECT

A qualified CCUS project is a project that is intended to support a CCUS process by capturing $CO_2$ that would otherwise be released into the atmosphere or directly from ambient air, transporting captured carbon or storing or using captured carbon and that meets the following conditions:

- the project is expected to support the capture of $CO_2$ in Canada;
- an initial project evaluation has been issued by the Minister of National Resources in respect of the project following the filing

of the most recent project plan that meets certain enumerated requirements;

- at least 10% of the quantity of captured carbon the project is expected to support for storage or use in an Eligible Use in each of the project's first 20 years;
- the project complies with all federal, provincial and municipal environmental laws, by-laws and regulations applicable in respect of the project; and
- it is not a project that is operated to service a facility that existed prior to April 7, 2022 and undertaken for the purposes of complying with emissions standards regulations under the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations and the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity.

The Department of Finance provided the following examples of CCUS projects that are "expected to support the capture of $CO_2$ in Canada" where such activities are undertaken in Canada:

- capturing $CO_2$ from a single site and transporting it up to the point where it connects to a transportation hub;
- transporting carbon captured from multiple sites (i.e. a transportation hub);
- storing or using captured carbon;
- capturing $CO_2$ from a single site, transporting the captured carbon and storing or using the captured carbon; and
- transporting and storing or using carbon captured from multiple sites (i.e., a transportation and storage hub).

**ITC RATES**

The rate of the CCUS ITC depends on the type of expense incurred and the period of time in which the expense is incurred.

Between January 1, 2022, and December 31, 2030, the following rates apply:

| | |
|---|---|
| **60%** | Qualified carbon capture expenditures in respect of equipment used to capture carbon directly from ambient air |
| **50%** | Qualified carbon capture expenditures in respect of equipment used to capture carbon other than directly from ambient air |
| **37.5%** | All other types of qualified CCUS expenditures (i.e., qualified carbon transportation expenditures, qualified carbon storage expenditures and qualified carbon use expenditures) |

Between January 1, 2031 and December 31, 2040 the rates are one-half of those rates described above.

### NEW CAPITAL COST ALLOWANCE (CCA) CLASSES

New depreciable property classes have been proposed for certain expenses incurred in respect of a CCUS project:

- new CCA Class 57 with a CCA rate of 8% includes $CO_2$ capture equipment, $CO_2$ transportation equipment and $CO_2$ storage equipment, and is eligible for enhanced first year depreciation under the Accelerated Investment Incentive;
- new CCA Class 58 with a CCA rate of 20% includes equipment required for using $CO_2$ in an industrial production is eligible for enhanced first year depreciation under the Accelerated Investment Incentive; and
- new CCA Classes 59 and 60 with CCA rates of 100% and 30% for intangible exploration expenses and development expenses, respectively, associated with storing $CO_2$.

Depreciable property acquired that qualifies for the CCUS ITC will have its capital cost reduced by the amount of the CCUS ITC claimed.

### COMPLIANCE MATTERS

Claiming the CCUS ITC will bring about significant compliance obligations for taxpayers. Certain of the compliance matters are relevant to the claim of the CCUS ITC are as follows:

- CCUS projects are subject to a validation and verification process:
- CCUS projects that expect to have eligible expenses of $100 million or greater are generally required to undergo an initial project tax assessment; and
- eligible expenses must be verified by Natural Resources Canada, which occurs after the end of the taxpayer's tax year in which the expenses are incurred.
- CCUS projects will be assessed every five years (up to a maximum of 20 years) to determine if there should be a repayment by the taxpayer of the CCUS ITC based on the amount of $CO_2$ that ultimately is used for an ineligible use.
- CCUS projects that expect to have eligible expenses of $250 million or greater are required to contribute to public knowledge sharing in Canada.

— Taxpayers are required to prepare an annual climate risk (CRD) disclosure report in each of the first 20 years of the project which details the project's governance, strategy, risk management, metrics and targets and the taxpayer's plan to contribute to the federal government's commitment under the Paris Agreement and to achieve net-zero emissions by 2050.

— Taxpayers are required to track the amount of $CO_2$ being captured by the CCUS project. Taxpayers must track the portion of $CO_2$ that is used for an Eligible Use and the portion of $CO_2$ that is used for an ineligible use. Where the portion of $CO_2$ being used for an ineligible use exceeds the amount set out in the initial project plan, a taxpayer may be required to repay CCUS ITC amounts.

## INVESTMENT TAX CREDITS FOR CLEAN TECHNOLOGIES AND CLEAN HYDROGEN PRODUCTION

In its 2022 Fall Economic Statement delivered on November 3, 2022 (FES 2022), the federal government announced new investment tax credits for clean technology (Clean Technology ITC) and hydrogen production (Hydrogen ITC) in response the recent passage of the Inflation Reduction Act (United States) (US IRA), which introduced significant tax incentives for clean technology and hydrogen production in the US. Legislation for the Clean Technology ITC and the Hydrogen ITC is not yet available. A brief summary of the proposed measures, as announced by the federal government, is set out below.

### CLEAN TECHNOLOGY ITC

The Clean Technology ITC is proposed to be a refundable tax credit of up to 30% of the capital cost of investments in certain eligible equipment, including:

— Electricity Generation Systems, including solar photovoltaic, small modular nuclear reactors, concentrated solar, wind, and water (small hydro, run-of-river, wave, and tidal);

— Stationary Electricity Storage Systems that do not use fossil fuels in their operation, including but not limited to: batteries, flywheels, supercapacitors, magnetic energy storage, compressed air storage, pumped hydro storage, gravity energy storage, and thermal energy storage;

— Low-Carbon Heat Equipment, including active solar heating, air-source heat pumps, and ground-source heat pumps; and

— Industrial zero-emission vehicles and related charging or refueling equipment,


such as hydrogen or electric heavy duty equipment used in mining or construction.

The Clean Technology ITC is proposed to be available for eligible investments made on the day of the release of the federal government's budget in 2023 (i.e., possibly sometime in the first quarter of 2023) until the end of 2034 (with a phase out starting in 2032).

### CLEAN HYDROGEN ITC

The Clean Hydrogen ITC is proposed to be a refundable tax credit of at least 40% of eligible investments in clean hydrogen projects. The FES 2022 contained few details as to the design of the Clean Hydrogen ITC. Rather, the Department of Finance said it would launch a public consultation to determine how to implement the Clean Hydrogen ITC based on the lifecycle carbon intensity of hydrogen and would seek input on (i) an appropriate carbon intensity-based system within the Canadian context, and (ii) the level of support needed for different production pathways in Canada. The FES 2022 referred to the US IRA's metric of providing support to projects where emissions from clean hydrogen production are 4.0kg of $CO_2e$ or less per kg of hydrogen, with the highest level of support provided where emissions are 0.45kg of $CO_2e$ or less per kg of hydrogen, but it remains to be seen as to whether the eligibility thresholds for the Clean Hydrogen ITC will be at similar or more or less favourable thresholds than the US IRA incentives. The Clean Hydrogen ITC is proposed to be available for eligible investments made as of the day of the release of the federal government's budget in 2023 and phased out after 2030.

### LABOUR CONDITIONS FOR THE CLEAN TECHNOLOGY ITC AND CLEAN HYDROGEN ITC

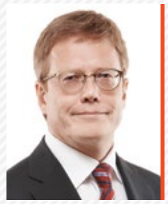
Of additional note, both the Clean Technology ITC and Clean Hydrogen ITC will be subject to labour conditions to ensure, according to the government, "wages paid are at the prevailing level in the local labour market, and that apprenticeship training opportunities are being created". The Department of Finance noted that it would consult with unions, among other stakeholders, regarding such labour condition requirements. Projects that do not add adhere to such labour conditions to be determined will only be eligible for a 20% Clean Technology ITC and, in the case of the Clean Hydrogen ITC, the maximum tax credit rate will be reduced by 10%.

## CONCLUSION

All of the foregoing tax measures – the CCUS ITC, the Clean Technology ITC and the Clean Hydrogen ITC - have yet to been enacted by Parliament. It will be interesting to see if the federal government will make changes to these measures following feedback from stakeholders and in response to similar incentives being enacted in other countries, such as the United States.

## FOR MORE INFORMATION, PLEASE CONTACT:

**Sven Milelli**
smilelli@mccarthy.ca
604-643-7125
BRITISH COLUMBIA



**Robin Sirett**
rsirett@mccarthy.ca
604-643-7911
BRITISH COLUMBIA

**Kerri Howard**
kerrihoward@mccarthy.ca
403-260-3720
ALBERTA

**Kimberly Howard**
khoward@mccarthy.ca
403-260-3575
ALBERTA

**Brian Bidyk**
bbidyk@mccarthy.ca
403-260-3610
ALBERTA

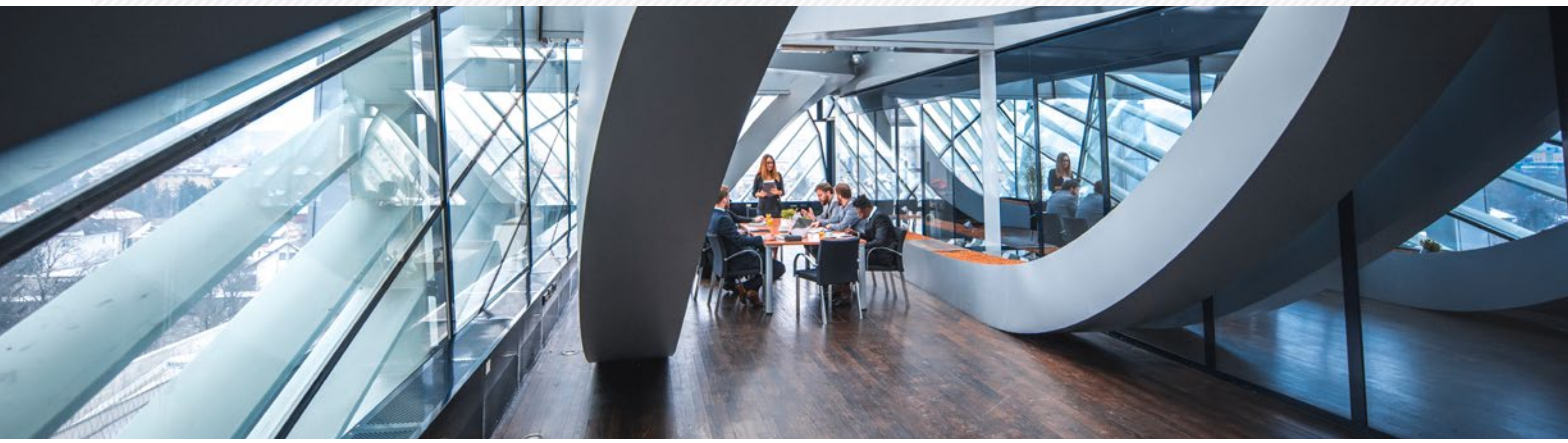
**Suzanne Murphy**
smurphy@mccarthy.ca
416-601-8278
ONTARIO

**Seán C. O'Neill**
soneill@mccarthy.ca
416-601-7699
ONTARIO

**Mathieu Leblanc**
maleblanc@mccarthy.ca
418-521-3046
QUÉBEC

**Louis-Nicolas Boulanger**
lnboulanger@mccarthy.ca
514-397-5679
QUÉBEC

**Jacob Stone**
jstone@mccarthy.ca
418-521-3056
QUÉBEC



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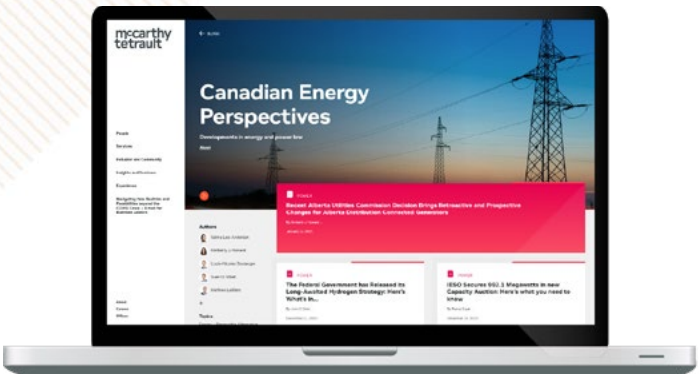


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**VANCOUVER**
Suite 2400, 745 Thurlow Street
Vancouver BC  V6E 0C5

**CALGARY**
Suite 4000, 421 7th Avenue SW
Calgary AB  T2P 4K9

**TORONTO**
Suite 5300, TD Bank Tower
Box 48, 66 Wellington Street West
Toronto ON  M5K 1E6

**MONTRÉAL**
Suite MZ400
1000 De La Gauchetière Street West
Montréal QC  H3B 0A2

**QUÉBEC CITY**
500, Grande Allée Est, 9e étage
Québec QC  G1R 2J7

**NEW YORK**
55 West 46th Street, Suite 2804
New York, New York 10036
United States

**LONDON**
1 Angel Court, 18th Floor
London  EC2R 7HJ
United Kingdom