Power Perspectives 2022

The **Power Group at McCarthy Tétrault LLP** is pleased to present: *Power Perspectives 2022*.

Message from our Editor-in Chief, Kerri Lui:
This publication is our seventh 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 in 2021, including in the areas of small modular reactors, hydrogen and distributed energy resources, and to highlight key trends to watch for in 2022. We hope that you will find this publication to be both interesting and informative.

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British Columbia Regional Overview

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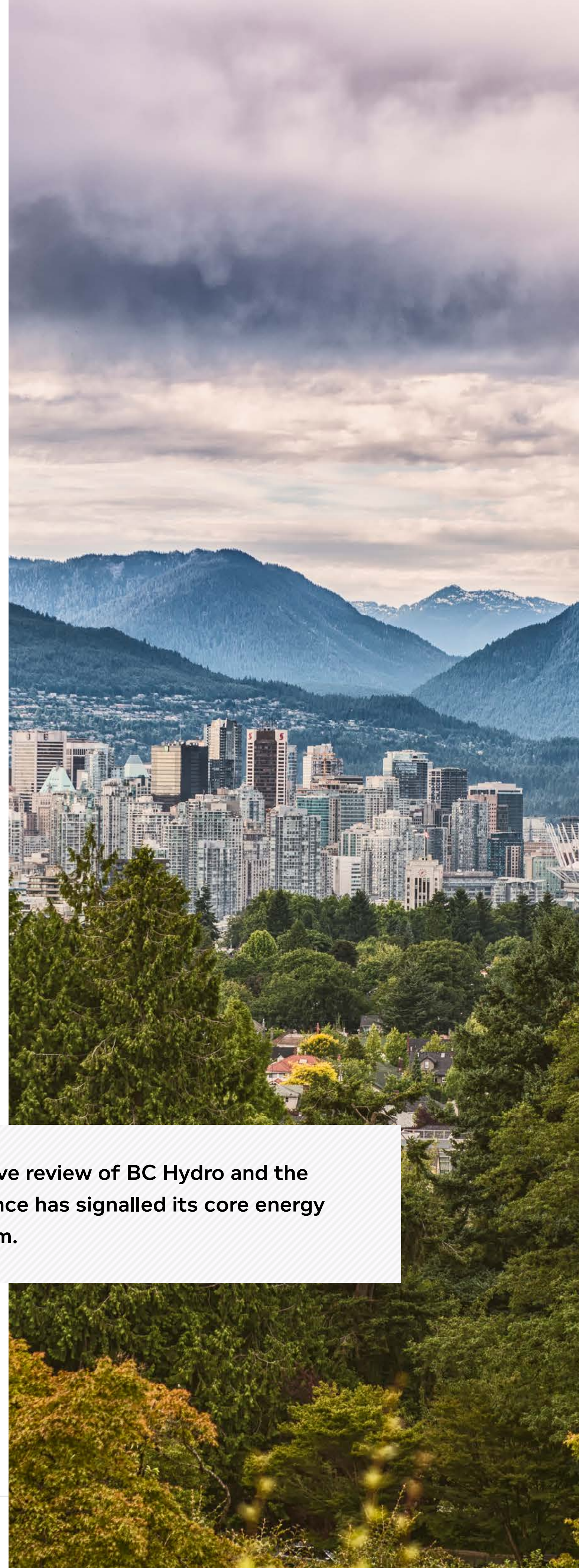


Introduction

In 2021, several long-awaited developments occurred that will lay the groundwork for BC's energy future. With the completion of Phase 2 of its comprehensive review of BC Hydro and the release of its CleanBC Roadmap to 2030, the province has signalled its core energy priorities and outlined key measures to achieve them. Meanwhile, the submission by BC Hydro of a new integrated resources plan—its first in almost a decade—sheds new light on the province's anticipated load-resource profile and implications for market participants, including independent power producers (IPPs).

COMPREHENSIVE REVIEW OF BC HYDRO

The BC government and BC Hydro released recommendations from Phase 2 of the Comprehensive Review of BC Hydro (Phase 2 Review) initiated in 2018. With a mandate to evaluate broad, transformational changes that are likely to impact the energy sector in coming years, and guided by input from a panel of external energy-industry experts, the Phase 2 Review

With the completion of Phase 2 of its comprehensive review of BC Hydro and the release of its CleanBC Roadmap to 2030, the province has signalled its core energy priorities and outlined key measures to achieve them.

focused on providing recommendations for how BC Hydro can accomplish the policy objectives laid out in the CleanBC plan, while taking into account the impact of factors such as emerging technologies, energy market trends, and the changing needs of BC Hydro customers.

Three sets of recommendations from the Phase 2 Review were released in the course of 2021:

Electrification and CleanBC Support

The first release, in July, set out recommendations to advance the electrification of BC's economy (which remains almost 70% powered by fossil fuels) by electrifying industry, supporting clean tech and low-carbon hydrogen, and better integrating BC's grid with neighbouring jurisdictions. These recommendations include, among others:

- developing a 100% clean electricity standard for the integrated grid;
- moving to a flat energy charge for industrial customers instead of the current two-tier rate, and developing a new CleanBC Industry Electrification Rate that offers a discount on BC Hydro's standard industrial rates to new clean industries and industrial customers that transition from fossil fuels to clean electricity;
- applying to the British Columbia Utilities Commission (BCUC) to update the distribution extension portion of the electric tariff to accelerate connections and make their costs more predictable, as well as to repeal the Northwest Transmission Line tariff; and
- considering regulatory changes requiring BC Hydro and the BCUC to use an internal carbon price when evaluating programs and infrastructure investments.

Affordability

In August, the Phase 2 Review released recommendations intended to keep electricity rates affordable, including, among others:

- implementing an optional discounted rate and measures to lower upfront costs to encourage households to switch from natural gas heating to electric heat pumps;
- considering the implementation of a means-tested program to provide support for low-income customers;
- developing a flexible rate option that would offer customers discounts for enabling BC Hydro to manage electricity demand for items such as electric-vehicle charging, hot water and electric baseboards, complemented by demand-side measure programs; and
- developing an optional rate to promote conversion of district energy systems from natural gas to electricity.

Electric Vehicles

In September, the Phase 2 Review released recommendations intended to encourage adoption of electric vehicles, including, among others:

- introducing optional rates that offer residential customers reduced electricity charges in off-peak hours and incentivize employers to offer workplace electric vehicle charging;
- establishing a five-year plan for deployment of DC fast-charging (i.e., Level 3) stations and tasking BC Hydro subsidiary Powertech with exploring innovative technical options to reduce the cost of such stations; and
- developing an electrification/low-carbon fuels strategy for medium-and heavy-duty vehicles.

The recommendations from the Phase 2 Review were intended to inform both the ongoing evolution and implementation of the CleanBC plan and the BC Hydro IRP, as further described below.

In addition, in November 2021, the BC government, working with the First Nations Leadership Council and First Nations Energy and Mining Council, launched the Indigenous Clean Energy Opportunities (ICEO) engagement with First Nations, which will focus on identifying economic opportunities for Indigenous peoples arising from the Phase 2 Review, CleanBC and the BCUC Inquiry on Indigenous Utilities.

BC HYDRO FILES INTEGRATED RESOURCE PLAN

On December 21, 2021, BC Hydro filed its long-awaited 2021 integrated resource plan (IRP) – its first since 2013 – with the BCUC. Informed by government climate action targets, the electrical utility's consultation with Indigenous peoples and the public, and forecasts regarding electricity demand and technological advancements, the IRP describes how BC Hydro intends to meet the electricity needs of the province over the next 20 years. Going forward, BC Hydro expects to complete an integrated resource plan every five years.

The filing of the final IRP followed BC Hydro's extended "Clean Power 2040" engagement, which BC Hydro reports included input from more than 6,000 British Columbians through surveys and virtual engagement sessions and consultation with 85 Indigenous Nations, tribal councils and Indigenous organizations, which culminated in the public release of a draft of the IRP for comment in June 2021 and the subsequent preparation of the final IRP, which addresses some of the feedback received from interest groups and how it helped shape the final version of the IRP.

The IRP consists of three main components:

1. **Base Resource Plan:** BC Hydro's plans to meet the province's projected electricity needs and address BC Hydro generating facilities that are approaching end of life by:
   - increasing existing energy efficiency and conservation programs to achieve system-level capacity savings by:
     - continuing and ramping up energy efficiency programs to achieve system-level capacity savings;
     - pursuing voluntary time-varying rates supported by demand response programs and advancing an industrial load curtailment program to achieve approximately 220 MW and 100 MW of capacity savings, respectively, by fiscal 2030; and
     - pursuing a combination of education and marketing efforts as well as incentives for smart-charging technology for customers;
   - upgrading transmission capacity to the province's South Coast; and
   - renewing certain electricity purchase agreements (EPAs) with IPPs.
2. **Contingency Resource Plans:** Details of alternative sources of electricity supply that BC Hydro could pursue should the province's electricity needs exceed expectations or near-term actions fail to achieve anticipated results.
3. **Near-Term Actions:** An overview of the near-term steps BC Hydro is taking to implement the Base Resource Plan and prepare for contingency scenarios.

Demand for Electricity

Since BC Hydro released its last integrated resource plan in 2013, the electricity needs of British Columbians have changed. The IRP reports that the province is seeing increasing customer demand for electricity driven by continued electrification activities, particularly in the transportation sector. Pointing to an uptick in the sale of electric vehicles coinciding with the passing of the *Zero-Emission Vehicles Act* (British Columbia), BC Hydro states that this increase is most evident in the Lower Mainland and Vancouver Island regions. However, this upward trend is offset by some of BC's resource-based industries, in which economic factors are combining to cause declines in electricity demand.

BC Hydro forecasts that it will have sufficient energy and capacity to meet domestic need in the province until the early 2030s, at which time, with the benefit of up-to-date cost and system information, BC Hydro intends to choose from a variety of types of supply options to provide supplemental electricity, including developing new clean resources, utilizing EPAs with IPPs and expanding BC Hydro's generation assets.

EPA Renewals

The IRP states that as of October 2021, BC Hydro was party to 123 EPAs with IPPs, approximately 70 of which will be expiring over the next 20 years (representing about 9,100 GWh of energy). As discussed further below, the BCUC had previously indicated that it would not be able to determine whether long-term EPA renewals were in the public interest until the IRP was filed, and as such, the IRP will be instrumental in informing EPA renewal decisions.

renewable electricity pursuant to the 19 EPAs expiring within the next five years, which represent roughly 900 GWh of energy. In contrast, the renewal of natural gas EPAs is not assumed in the IRP's Base Resource Plan. In particular, the IRP points to gas-fired IPP facilities McMahon and Island Generation as being two of BC Hydro's biggest sources of greenhouse gas (GHG) emissions within its integrated system and states that BC Hydro does not intend to renew the applicable contracts for those facilities.

Next Steps

On December 23, 2021, the BCUC appointed a four-person panel chaired by Commissioner David Morton that will undertake a public regulatory review process to consider BC Hydro's application for an order approving the IRP.

The IRP states that additional energy from the renewal of EPAs would be surplus to the province's immediate needs but may be required later. Since most of BC's power projects are expected to have a low cost of service, BC Hydro postulates that IPPs will want to continue operating and will be able to do so with market-price-based EPAs. Through such contracts, BC Hydro proposes to keep these facilities available for a time when their generation is necessary to meet electricity demand.

In accordance with the IRP, BC Hydro will offer "market-priced" renewal options to IPPs producing clean or

SITE C UPDATE

In July 2020, BC's energy minister appointed former deputy finance minister Peter Milburn as a special advisor to conduct an independent review of BC Hydro's 1,100-MW Site C Clean Energy Project (Site C) after BC Hydro reported concerns about project risks, construction delays and rising costs. A summary of Millburn's report was made public in February 2021. It focused on four main areas: (i) governance and oversight; (ii) geotechnical issues; (iii) risks; and (iv) construction and claims management. The report contained 17 recommendations for Site C regarding these areas, all of which were accepted by BC Hydro and the BC government.

In February 2021, the BC government also announced its decision to complete construction of Site C, concluding that cancelling the project would impose at least a C$10 billion burden on provincial taxpayers or ratepayers, excluding the cost of replacing the lost energy and capacity Site C would have provided to meet the province's future electricity needs. The BC government confirmed that the capital cost estimate for Site C had increased to C$16 billion from BC Hydro's previous estimate of C$10.7 billion, attributing the increased costs to the COVID-19 pandemic and the foundational enhancements required to address previously identified geological risks. The foundational enhancements are expected to be completed by 2023. In October 2021, BC Hydro completed Site C's roller-compacted-concrete program, a key component of Site C's design. The BC government has extended the expected project completion date by one year, to 2025.

Site C continues to face litigation challenges. In an ongoing civil action, West Moberly First Nations allege the project unjustifiably infringes their Treaty 8 rights. West Moberly are seeking an injunction against operating the Site C dam, an order to remove the dam, and damages, including the payment of all revenues earned on the existing Peace River dams. In April 2021, the BC Supreme Court ordered BC Hydro and the BC government to release undisclosed Site C financial and safety documents to West Moberly First Nations, including the full copy of the final Milburn report, which will nonetheless remain unreleased to the public. The trial is expected to begin in March 2022.

The 2021 decision in *Yahey v. British Columbia* (discussed in more detail in the litigation section of this publication) found that the cumulative effects of a number of different industrial activities authorized by the province in the traditional territories of the Blueberry River First Nations infringed the latter's Treaty 8 rights. The Yahey decision, which the BC government did not appeal, is likely to be referenced prominently in the West Moberly action. BC Hydro has expressed the view that the Yahey decision is unlikely to affect the issuance of provincial permits required for Site C because the project is already approved and under construction, though it has acknowledged that the ruling could affect the timing of permit issuance.

CLEANBC PLAN UPDATE

In 2021, the BC government continued its roll-out of CleanBC, the province's ambitious climate action plan to reduce provincial GHG emissions to a legislated target of 40% below 2007 levels by 2030.

Major developments in 2021 included the launch of the CleanBC Roadmap to 2030 (Roadmap), a plan that accelerates certain measures to transition away from fossil fuels in response to new emissions projections that demonstrated a need to take stronger action, faster, to meet BC's GHG targets.

Citing as a central pillar BC's abundant supply of clean and affordable hydroelectric power, the Roadmap sets out actions across a number of "pathways", including:

- increasing the price of carbon pollution to meet or exceed the federal benchmark beginning in 2023, with financial supports through a climate action tax credit;
- doubling the target for renewable fuels produced in BC to 1.3 billion litres by 2030;
- introducing requirements for new industry projects to have enforceable plans to reach BC's legislated and sectoral targets and net zero by 2050;
- implementing stronger regulations that the BC government states will nearly eliminate industrial methane emissions by 2035;
- completing a comprehensive review of the oil and gas royalty system (the first in 30 years) to ensure it aligns with BC's climate goals and provides a fair return, with outcomes to be released in February 2022;
- introducing new requirements to make all new buildings zero-carbon by 2030;
- accelerating adoption of zero-emission vehicles (ZEVs) to represent 26% of new light-duty vehicles

- by 2026 and 100% by 2035 and developing new ZEV targets for medium- and heavy-duty vehicles in line with California targets;
- completing BC's "Electric Highway" by 2024 and targeting 10,000 public electric vehicle charging stations by 2030;
- accelerating the shift toward active transportation and public transit (30% by 2030; 40% by 2040; 50% by 2050);
- implementing a 100% Clean Electricity Delivery Standard for the BC Hydro grid;
- increasing clean fuel and energy efficiency requirements; and
- supporting innovation in areas such as clean hydrogen, the forest-based bioeconomy and negative emissions technology.

The Roadmap includes rebates for new heat pumps and plans to attract new businesses looking for clean power. It also encourages using low-carbon building materials in construction, such as mass timber. The BC government expects the measures set out in the Roadmap to reduce GHG emissions sufficiently to hit the province's GHG 2030 reduction target and set the course for the province to fulfill its net-zero goal by 2050.

The BC government also announced BC Hydro's C$260-million low-carbon Electrification Plan on September 28, 2021, the implementation of which it projects will result in an additional 3,100 GWh of load and reduce GHG emissions by 930,000 tonnes per year by the end of fiscal 2026. The Plan includes initiatives designed to encourage the transition from the use of fossil fuels to clean electricity to power homes, businesses, industries and vehicles, particularly in three key areas: buildings, transportation and industry. Specific measures include up to C$13 million in "top-up" rebates for residential heat pumps, up to C$3,000 per household, and expanding public charging infrastructure for passenger electric vehicles to 325 charging stations across the province and twinning all single charging stations. In addition to allocating approximately C$190 million for new incentives, energy studies and other programs, BC Hydro plans to spend approximately C$50 million to attract new customers, including new clean tech and hydrogen production facilities, seeking to power their businesses with clean electricity.

BC HYDRO RATE APPLICATION

In August 2021, BC Hydro filed its Fiscal 2023-2025 Revenue Requirements Application with the BCUC, requesting an annual average bill increase of 1.1% for the next three years—consisting of a decrease of 1.4% in 2022, and increases of 2% and 2.7% in the following two years. The BCUC's review of the application is expected to be completed in the first half of 2022.

EPA RENEWALS

In 2021, the BCUC continued to give effect to its position that it could not determine whether most long-term EPAs are in the public interest until BC Hydro filed an updated and approved integrated resource plan.

The BCUC approved two new EPAs in 2021. Consistent with its approach to EPA renewals in 2020, on March 30, 2021, the BCUC approved an EPA with a three-year renewal term effective January 1, 2021, for the Coats hydroelectric generating facility on Gabriola Island. BC Hydro cited the short-term nature of the agreement as a factor in favour of the project's approval in its filing. An EPA with a 20-year term and a further 10-year BC Hydro option for the Hluey Lake hydroelectric facility was also approved by the BCUC in March 2021. Specific factors that made the long-term nature of this project acceptable to the BCUC included the fact that the rural area of Dease Lake covered by the EPA is not connected to the grid and BC Hydro's only other alternative for supplying electricity to the area is diesel generation.

On May 7, 2021, the BCUC also released its final order in respect of the Walden North Hydro project, a 16 MW facility located near Lillooet. BC Hydro had issued a notice of termination for its EPA renewal for Walden North Hydro, relying instead on its original EPA and a related forbearance agreement (Forbearance Agreement). However, in June 2020, the BCUC concluded that the Forbearance Agreement constituted an amendment to the EPA and was required to be filed with the regulator. In its final order, the BCUC determined that while it had the ability to make a declaration on the enforceability of the Forbearance Agreement, the original EPA was outside of its jurisdiction, having been entered into prior to September 2001. Therefore, while the BCUC panel was critical of the EPA as providing "apparently unnecessary" energy, it determined that the EPA, modified by the Forbearance Agreement, is in the public interest, as compared to the original EPA.

As discussed above, BC Hydro filed its final 2021 IRP with the BCUC in December 2021. If approved, the IRP will inform the BCUC's evaluation of renewal applications for existing EPAs, including those with longer renewal terms.

WHAT TO WATCH FOR IN 2022

Site C on Trial: The Final Hurdle?

As noted above, the trial of the West Moberly First Nations' injunction claim against the Site C dam is expected to begin in March 2022, with a view toward ensuring that a decision is rendered prior to the flooding of the dam's reservoir. Site C has to date weathered a number of lawsuits and other challenges—this lawsuit may be the last and most significant, particularly in light of the 2021 decision in *Yahey* and its implications for the development of large projects in British Columbia.

Long-Term EPA Renewals

With the submission by BC Hydro of its IRP late in 2021, the BCUC is expected to have all the information required to make a determination regarding the long-term renewal of a number of EPAs that expired over the last several years. Although context-specific, these renewals will provide important information regarding the economics facing IPPs in connection with expiring EPAs.

Coming Soon: Energy Storage?

While the province's electricity infrastructure has been predicated on the significant storage capacity of BC Hydro's legacy hydroelectric facilities, the province may soon look to alternative sources of storage capacity. British Columbia is already home to three operating electrochemical energy storage projects, as well as a significant planned pump hydro storage project. While BC Hydro notes that utility-scale (over 15 MW) battery technology is still relatively early-stage and expensive, one of the near-term actions proposed in the IRP as part of BC Hydro's contingency resource planning is to integrate and study utility-scale battery resources on a pilot basis, in recognition of the expectation that battery costs will drop and capabilities increase over coming years. BC Hydro cites a preference for utility-scale batteries for storage due to short lead times, small size, high energy efficiency and scalability.

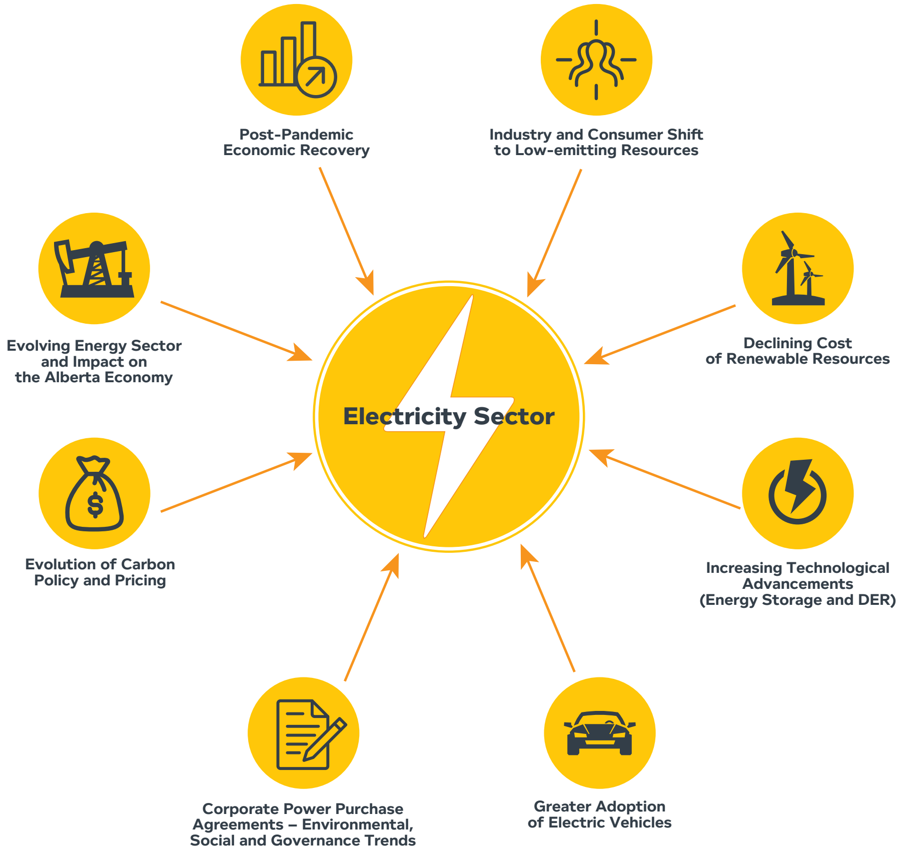
Alberta
Regional Overview

Authors: Brian Bidyk, Jamie Gibb, Kerri Howard, Kimberly Howard and Ashley Wilson[1]

Introduction & Market Update

The Alberta Electric System Operator (AESO) released its 2021 Long-term Outlook on June 29, 2021. According to the report, moderate load growth is expected over the next 20 years but at a lower rate than in the previous 20-year period. Load growth is expected in the near term due to economic recovery as COVID-19 health restrictions ease. It is expected there will be generation growth and natural gas is anticipated to be the primary fuel source to replace coal in the generation mix.

The electricity sector in Alberta is transforming in direct response to the following key drivers:



Source: AESO 2021 Long-term Outlook Report Highlights (July 2021), online: www.aeso.ca/assets/LTO-Report-Highlights_2021.pdf.

1. Additional Authors: Students-at law: Heather Maki, Connor O'Brien and Erinn Wilson.

Key Developments in 2021

A number of key developments occurred in 2021, including the Alberta Utility Commission's (AUC) Distribution System Inquiry Final Report, the phasing out of distribution connected generation (DCG) credits and legislative changes to facilitate new technology and the diversification of Alberta's electricity market.

Distribution System Inquiry Final Report – On February 19, 2021, the AUC released its Distribution System Inquiry Report (Report) summarizing its distribution system inquiry (Inquiry) which was commenced in December 2018. The Inquiry was launched to provide a forum for Alberta's electricity industry to consider a regulatory response to mounting economic and technological pressures affecting Alberta's electric distribution systems. The Inquiry focused on understanding three questions relating to new technologies affecting the grid, how electricity distribution utilities will be expected to respond to alternative approaches and how distribution facility rate structures should be modified to incentivize efficient cost-effective use of the grid. The Inquiry involved participation from 90 parties.

The Inquiry and its findings are a result of a shared responsibility among the Government of Alberta, the AESO, the AUC, transmission and distribution facility owners, generators, technology solution providers and consumer groups to modernize the distribution grid through opportunities to develop a smarter, more flexible distribution system.

The Report identified a number of broad themes to achieve this goal, including:

- driving efficiency and competition across all aspects of the Alberta Interconnected Electric System;
- the need to ensure a level playing field across different types of technology;
- the importance of consumers paying their fair share of costs related to grid usage;
- establishing a consistent and predictable policy framework for market certainty; and
- the ability of grid users to respond to price signals as the system and technologies evolve.

One of the main topics of focus throughout the Report was the integration of distributed energy resources (DERs), which are devices used to automatically manage electricity consumption. Due to decreasing costs in technology, new government policies and a shift in consumer preferences, DERs have become more frequently used in Alberta. However, DERs also allow customers to potentially bypass utility services and the associated tariff charges. Accordingly, avoided costs must be recovered from other customers, amounting to an uneconomic bypass of the grid. In order to avoid the unequal distribution among customers, the industry will need to adapt to market pressures and changing technologies, including the use of DERs.

AUC DECISION 26090-D01-2021 – DCG CREDITS – RELEASED JUNE 2021

In Decision 26090-D01-2021 (DCG Decision), the AUC addressed the uncertainty surrounding the fate of the ISO Tariff DCG credits. The current DCG credit mechanism will be discontinued and all DCG credits will be phased out based on a four year transition period as set out in detail in the DCG Decision.

DCG is a supply-side distributed energy resource. DCG credits are the payments that ATCO Electric, ENMAX and FortisAlberta Inc. (Fortis) provide to DCGs (both without associated load and as part of self-supply and export configurations) connected to their respective distribution systems. These credits are calculated and paid pursuant to provisions within their respective tariffs: Option M for Fortis, Rate D32 for ATCO Electric, and Rate D600 for ENMAX.

The credits are calculated based on the electrical energy delivered by the DCG to the distribution system, and represent the difference between the AESO transmission charges (Rate Demand Transmission Service and Rate Supply Transmission Service) that the distribution utility must pay with the DCG in operation, and the hypothetical charges that would have been incurred if the DCG had not been in operation. The calculated credits are then allocated to, and recovered from, all load customers of that distribution utility.

The AUC held that DCG credits are not consistent with just and reasonable ratemaking because:

- the credits unnecessarily increase payments made by customers without providing any quantifiable benefits; and
- the credits promote an un-level playing field causing distortionary harm to the wholesale electricity market, which is also a detriment to ratepayers.

Although an application by a number of generators to review and vary the DCG Decision was unsuccessful, the DCG Decision remains the subject of a judicial review application. The applications for leave to appeal the DCG Decision are currently scheduled for the end of Q1 of 2022.

LEGISLATIVE AMENDMENTS

Bill 86: *Electricity Statutes Amendment Act*

Alberta introduced Bill 86, or the *Electricity Statutes Amendment Act*, which if passed, will amend the laws and regulations which currently govern and regulate energy storage, sale and transmission in Alberta, including the *Alberta Utilities Commission Act* (AUC Act), the *Electric Utilities Act* and the *Hydro and Electric Energy Act*. Through this omnibus bill, Alberta is proposing legislative changes to modernize its electricity system in response to new technologies, including the integration of energy storage.

Highlights of the proposed legislative amendments (Proposed Amendments) include:

– **Unlimited Self-Supply and Export:** Under the Proposed Amendments, self-supply with export will be unlimited and would allow market participants to produce electricity for their own use. Under the current regime, market participants can only self-supply and export to the grid in four prescribed scenarios including at designated industrial sites, certain micro-generation facilities, flare gas generators and certain municipality-owned facilities. The Proposed Amendments are responsive to the issue of eligibility to self-supply which has been contentious and most recently considered by the AUC within the context of an Alberta bitcoin mine.

– **Distribution Facility System Planning:** Distribution facility owners will have a duty to prepare distribution system plans and to make decisions about "non-wire services" as part of any decisions regarding amendments to its electric distribution system.

– **Integration of Energy Storage:** The integration of energy storage into the electricity system in both the competitive market and the transmission and distribution system. The Proposed Amendments will create and define a new separate category of energy storage facilities for which AUC approval will be required. In addition, transmission and distribution facility owners will be able to use energy storage facilities to provide utility services and non-wire solutions for the benefit of the transmission and distribution systems. However, based upon the current wording, distribution and transmission facility owners may not be able to sell any electric energy from such energy storage facilities to the power pool.

> **Alberta introduced Bill 86, or the *Electricity Statutes Amendment Act*, which if passed, will amend the laws and regulations which currently govern and regulate energy storage, sale and transmission in Alberta.**

Red Tape Reduction Implementation Act, 2021

On June 21, 2021, Bill 62: the *Red Tape Reduction Implementation Act*, 2021 (Bill) received royal assent. The Bill amends the AUC Act to provide for mandated timelines for AUC decisions about utility rates that will be prescribed in the AUC Rules (Rules). This could potentially speed up the decision-making process for the benefit of operators and distribution companies. As of September 2021, the AUC reported that it had achieved a 48% reduction in regulatory requirements set out in its Rules, exceeding its red tape reduction target as set by the Government of Alberta to reduce mandatory requirements by one third.

Continued Growth in Power Purchase Agreements

In this era of ever greater focus on corporate sustainability, and with the federal government of Canada targeting net-zero emissions by 2050, companies are increasingly pursuing renewable energy alternatives to advance their environmental, social and governance (ESG) initiatives, including through power purchase agreements (PPAs). In addition to the Renewable Electricity Support Agreements entered into between successful proponents through the AESO's Renewable Electricity Program, Alberta has seen a high level of activity in the area of corporate PPAs among developers and purchasers of energy and associated environmental attributes from renewable energy projects.

There are two kinds of PPAs: (1) traditional or physical PPAs; or (2) virtual PPAs (VPPA). With either option, the company agrees to pay a fixed price for every megawatt-hour of clean energy that is generated. Buyers have the option to purchase either bundled or unbundled associated renewable energy certificates (RECs) or offsets and other environmental attributes associated with the generation of power from the project.

Why PPAs are Attractive

Achieve Net-Zero Targets
Purchasing RECs, offsets or other environmental attributes directly from power generators is a cost effective way for companies to reduce emissions without having to invest directly in renewable energy infrastructure.

Capital Investment
ESG issues have become much more important for long-term investors. Access to capital now hinges on the ability of companies to demonstrate that they are reducing their emissions and meeting particular ESG goals.

No Physical Restrictions
With PPAs, depending on the nature of the environmental attribute acquired, such attributes can be used to achieve goals in jurisdictions besides the jurisdiction where the power generation is occurring. This allows for greater investment opportunities and more choice when determining the kind of energy generation projects to invest in, whether it's wind power, solar power, hydro-electric power or otherwise.

Hedge Market Risk
For developers of renewable power projects, PPAs allow for a hedge against fluctuations in market prices (pool prices) over the life of the project, giving more certainty for capital and financing considerations.

Given Alberta's deregulated, energy-only power market, Alberta is an ideal market for PPAs. In the last 3 years, VPPAs in Alberta have become highly attractive. In 2021 alone, the following major companies have invested in VPPAs in Alberta:

- Amazon entered into a VPPA to purchase 400 MW of power from the Travers Solar Project;
- Budweiser entered into a long-term VPPA to purchase 51% of the electricity generated from Capital Power's 75 MW Enchant Solar facility located in Taber, Alberta;
- Cenovus Energy Inc. entered into a VPPA off-take deal with Elemental Energy Inc. from a roughly 150-MW solar project proposed in Alberta by compatriot Elemental Energy Inc.;
- Pembina Pipelines entered into a VPPA with TransAlta Corp. for 100 MW of its 130 MW Garden Plain Wind Power Project;
- Groupo Bimbo Canada entered into two VPPAs with Renewable Energy Systems (RES) to procure renewable electricity that will offset 100% of the company's electricity consumption in Canada; and
- Shell Energy North America (Canada), Inc. entered into a VPPA with BluEarth Renewables for the offtake of 100 MW at its Hand Hills Wind Project.

Noteworthy AUC and ISO Rule Changes

A summary of the noteworthy AUC and ISO Rule changes are outlined below.

Agency	Rule	Summary
AUC	Rule 005: *Annual Reporting Requirements of Financial and Operational Results*	Utilities no longer have to provide the following information on their annual financial and operation reports: (i) general rates application (GRA) and general tariff application (GTA) approved forecast information, and (ii) variance calculations between actual/normalized and approved forecast.
AUC	Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*	Amendments intended to clarify application requirements, including for wind, solar and battery storage applications. They also provide additional guidance with respect to the requirements for consultation with Indigenous communities. Amendments also streamline applications for approval amendments, time extensions and approval transfer applications.
AUC	Rule 016: *Review of Commission Decisions*	In response to the Supreme Court of Canada's decision in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, the AUC amended Rule 016 to: - limit the scope of the AUC's review process by removing errors of law as a ground for review; - change the filing deadline for review and variance applications from 60 to 30 days after the initial decision is issued; and - introduce page limits for applications and reply submissions.
AUC	Rule 019: *Specified Penalties for Contraventions of ISO Rules*	Utilities no longer have to provide the following information on their annual financial and operation reports: (i) general rates application (GRA) and general tariff application (GTA) approved forecast information, and (ii) variance calculations between actual/normalized and approved
AESO	ISO Rules s. 505.2 – Performance Assessment for Refund of Generating Unit Owner's Contribution	Section 505.2 was amended to introduce new performance assessment methodology in response to changes to the ISO tariff. Following the recent approval of the ISO tariff, s. 505.2 requires updates to include the AESO's new method for calculating generating unit owner's contribution (GUOC), the revised GUOC rates, and new terms for payment of the GUOC. The amendments introduce a new binary approach for assessing the performance of a generating unit, which assesses the performance based on the generating unit's metered energy.
AESO	ISO Rules s. 306.7 – Mothball Outage Rule	On November 4, 2021, the AESO released the Mothball Outage Reporting Rule Amendment Options & Recommendations Paper. Consultation remains ongoing in 2022.
AESO	ISO Rule Amendments to facilitate the integration of energy storage	While the AESO does not have a definitive list of ISO Rules that will be amended by the proposed amendments, it anticipates that more than 30 ISO Rules may be impacted in order to address various matters, including: - market participation; - fast frequency response; - technical, qualification and connection requirements; - adjustment to load on the margin; and - opportunities to reduce red tape. AESO anticipates posting draft proposed amendments for stakeholder feedback in Q1 2022.

What's Next for Alberta – New Technology & Diversification

It is anticipated that 2022 will be another growth year for Alberta. With the release of Alberta's Recovery Plan in Q3 2020, the Alberta Hydrogen Roadmap and the release of the 2021 Federal Budget, which earmarks a significant amount of funds for the net-zero transition, the focus on innovation and the push towards clean technology, it is anticipated that Alberta's electricity industry will continue to undergo its transition in 2022 to a greener economy.

In the fall of 2021, Alberta signalled its intention to release a new climate strategy. As discussed within our environmental article, we anticipate Alberta will formulate an updated provincial strategy to tackle its unique emission and industry profile. It will be important to monitor the development of a new climate strategy and the potential impacts to the power industry and participants in Alberta's electricity market.

Highlights for some key growth industries in Alberta are summarized below:

Hydrogen: As a major player in the global energy market and on the heels of following the Federal Hydrogen Strategy released in December 2020 and Alberta's Natural Gas Vision and Strategy released on October 6, 2020, the Province of Alberta released its highly anticipated Alberta Hydrogen Roadmap (Roadmap) on November 5, 2021, setting out the plan for Alberta to become a leader in the emerging hydrogen economy.

The first phase of implementing the Roadmap focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization. For an overview of the hydrogen economy and further details on the Roadmap please refer to the Hydrogen Overview article.

Geothermal: The global geothermal energy market is projected to register a compound annual growth rate of more than 3% between 2021-2026. Alberta has a natural geological advantage to develop geothermal energy in this growing market. Additionally, the Province has a number of other advantages, including opportunities to repurpose inactive oil and gas wells, well sites and infrastructure; leadership in drilling technology; extensive oil and gas expertise; and a well-established service sector tied to energy production.

To date, the development of geothermal resources in Alberta has been limited by the lack of a comprehensive regulatory framework. Geothermal project applications have been assessed on a case-by-case basis; a model that is inefficient for both industry and government. The *Geothermal Resource Development Act* , which received proclamation on December 8, 2021, establishes a regulatory regime for the responsible development of geothermal resources and related wells and facilities in Alberta. This Act applies to geothermal resource development whether commenced before or after the coming into force of the Act. This Act is modelled after the *Oil and Gas Conservation Act* (OGCA) and provides the Alberta Energy Regulator with the authority to regulate the responsible development of Alberta's geothermal resources.

Carbon Capture and Storage: In conjunction with the emphasis on greening the energy industry, carbon capture, utilization and storage (CCUS) is very attractive to Alberta's natural resource based industries and electricity generators. Industry has been quick to act on the booming sub-sector of CCUS. In the summer of 2021, major players such as Shell Canada, Suncor Energy and ATCO, TC Energy and

Pembina Pipeline all announced proposed development of CCUS projects. The industry is also eagerly awaiting the details of the proposed federal tax credit referenced in the 2021 Federal Budget.

In May 2021, Alberta Energy announced, through an information letter, that it intended to move towards a competitive bid process for carbon sequestration tenure, to develop strategically located carbon sequestration hubs, allowing for additional volumes and multiple sources of CO2 to be stored and avoiding stand-alone injection operations. In connection therewith, Alberta Energy suspended the granting of pore space licenses while it developed the proposed hub model for sequestration.

> **The growth of CCUS in Alberta is also evidenced by the C$100 million of provincial funding to seven selected projects through Alberta's Industrial Energy Efficiency and Carbon Capture Utilization and Storage program, with another C$31 million to be provided to other CCUS projects by the end of 2021.**

Following a significant amount of interest received during the May 2021 Request for Expressions of Interest for Carbon Sequestration Hub Proposals (REOI), on December 2, 2021, Alberta Energy released a Request for Full Project Proposals for Carbon Sequestration Hubs (RFPP). The guidelines for submission for this RFPP can be found here. The Province has accepted proposals for Alberta's industrial heartland region in Edmonton and subsequent requests for proposals in additional regions are expected to open in Q2 2022. Only subsurface formations deeper than 1,000 meters with no associated hydrocarbon recovery (i.e. injection into a deep saline aquifer) are eligible. Projects that inject carbon dioxide as part of enhanced oil recovery, or formation acid gas injection, will continue to operate under current mineral rights tenure systems. All required regulatory approvals remain the responsibility of the proponent and will not be granted through the RFPP process.

The growth of CCUS in Alberta is also evidenced by the C$100 million of provincial funding to seven selected projects through Alberta's Industrial Energy Efficiency and Carbon Capture Utilization and Storage program, with another C$31 million to be provided to other CCUS projects by the end of 2021. Details regarding the seven selected projects can be found here.

Small Modular Reactors (SMRs):

Alberta is continuing to work to promote the expanded use of nuclear power. SMRs could potentially provide Alberta's energy sector with competitively-priced, environmentally-acceptable and reliable heat, power and hydrogen for oil sands operations. This could play a critical role in decarbonizing the resource extraction and processing in Alberta's oil sands. Additionally, uranium prospects have been identified in northeast and southern Alberta, which have a potential to contribute to the feedstock needed for SMR development and deployment.

On April 14, 2021, Alberta became a signatory to the SMR Memorandum of Understanding (MOU). In the MOU, the four provinces have agreed to collaborate on the advancement of SMRs as a clean energy option to address climate change and regional energy demands, while supporting economic growth and innovation.

After endorsing Canada's SMR Action Plan in December, 2020, Alberta has taken a number of actions in relation to the SMR Action Plan. Specifically, SMRs are to be connected to the Alberta Innovates Strategic Priorities and included in the Alberta Innovates Clean Technology Program. Initiatives that further low-carbon electricity solutions (e.g. projects that advance SMR deployment for Alberta applications or utilize Alberta's manufacturing operations and industrial services for the advancement of SMR technologies) are welcome to apply for funding through the Clean Technology Program.

As further discussed in our SMR article, Alberta became the fourth signatory to the SMR Memorandum of Understanding (MOU) on April 14, 2021. The next action identified in the MOU is the development of a joint strategic plan to be drafted in collaboration by the governments of Saskatchewan, Ontario, New Brunswick and Alberta. The plan was expected to be completed in the spring of 2021 but has not yet been released.

Ontario Overview

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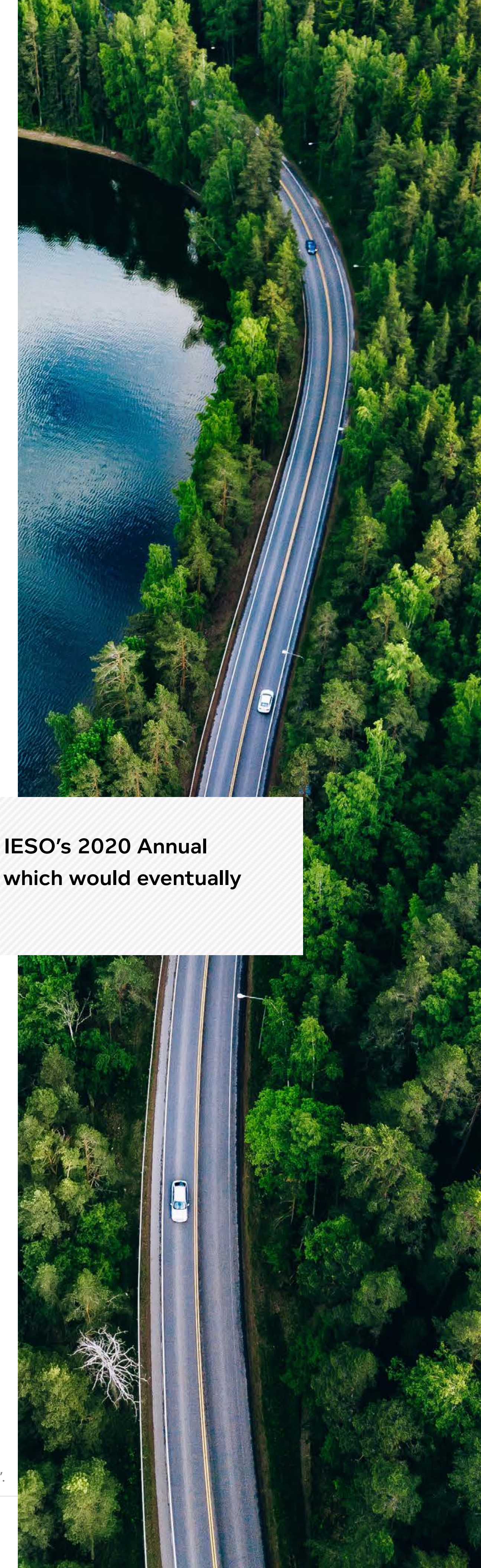

2021 has been a busy year for procurement plan development in Ontario. Readers may recall that in 2020 the IESO released its tripartite Resource Adequacy Framework, identifying short term capacity auctions as the primary procurement method for near-term capacity needs, and competitive contractual (RFP) procurements for medium-term (three years, with a potential two year extension) and long-term (seven to ten years) capacity needs in Ontario.

Assuming existing contracted resources are re-procured, the IESO's 2020 Annual Planning Outlook (2020 APO) forecasted a capacity need arising in 2024, which would eventually become an energy need in the late 2020s and early 2030s. Such needs are driven primarily by expiring contracts, nuclear refurbishments, the retirement of the Pickering Nuclear Generating Station and moderate demand growth (due to projected increases in residential load from COVID-19 related work from home protocols, mining and agriculture sector resiliency and new rail transit electrification projects).

> **Assuming existing contracted resources are re-procured, the IESO's 2020 Annual Planning Outlook forecasted a capacity need arising in 2024, which would eventually become an energy need in the late 2020s and early 2030s.**

In furtherance of its Resource Adequacy Framework and 2020 APO, the IESO released its inaugural Annual Acquisition Report (AAR) in July 2021. The AAR:

- set capacity targets (for the December 2021 Capacity Auction) of 1,000 MW for the 2022 summer obligation period and 500 MW for the 2022-23 winter obligation period;
- established a minimum target threshold of 500 MW for future capacity auctions and, beginning with the 2022 Capacity Auction, using resources qualified on an Unforced Capacity basis;[1]
- confirmed that a medium-term RFP would be issued in late 2021 for up to 750 MW with a three-year commitment period beginning in 2026;
- signaled an intent to issue a long-term RFP in late 2022 for at least 1,000 MWs also beginning in 2026; and
- confirmed that specific bilateral arrangements (for approximately 2,000 MW) would be pursued where reliability needs in specific

1. "Unforced Capacity" is defined as a "consistent capacity service, supporting fair competition amongst all resource types by equalizing the contribution of each megawatt of capacity to the system's resource adequacy".

regions of the province could not be addressed in a timely matter through competitive processes.

Following stakeholder concern that the commitment periods for the medium-term and long-term RFPs were insufficient to warrant the large scale capital spend required to refurbish existing resources (with expiring contracts or otherwise) or to build new resources to compete for these RFPs, the IESO announced in December 2021 that successful resources for the medium-term RFP would be automatically committed for a 5 year term and could commence their contract terms as late as May 1, 2026 (instead of May 1, 2024 or May 1, 2025). Notably, the IESO simultaneously announced that it would be working with the Ministry of Energy to permit automatic extensions of expiring contracts to the nearest subsequent April 30 date.

This was on the heels of the IESO's release of its 2021 Annual Planning Outlook (2021 APO) which reaffirmed expected emerging growth at an average rate of about 1.7% per year, particularly in the industrial, mining and agricultural sectors, as well as major expansion in transportation, manufacturing and industry electrification in Ontario. The 2021 APO did delay Ontario's potential capacity shortfall by forecasting such shortfall to begin in 2025-2026 and to increase significantly closer to 2029 (assuming all existing resources are re-procured). This forecast is now likely bolstered by the provincial COVID-19 related lock down that started in December 2021 and the resulting lag in anticipated growth from commercial sector COVID-19 recovery efforts.

The 2021 APO further asserts that evolving carbon policy, including a possible moratorium on new-build natural gas facilities, could result in lower than predicted availability of gas generation while the number and types of new technologies (e.g. distributed energy resources, storage and demand response) on the system could significantly increase. This may be true for energy storage now that the IESO has made significant efforts to implement energy storage participation at the wholesale level. However, the question of whether demand response resources will contribute to Ontario's evolving capacity and energy needs (and the extent to which such resources will contribute to such capacity and energy needs) remains unanswered; the IESO confirmed in mid-December 2021 that its enabling resources work plan is prioritizing the development and implementation of certain generation and storage hybrid participation models over new demand response participation models at the wholesale level.

Indeed, it is also unclear whether a moratorium on natural gas is likely or possible in the short term. As further discussed on our blog, on November 10, 2021, Ontario's Minister of Energy released a letter (Letter) to the IESO making comments and requests on a number of the IESO's current and planned measures to meet the province's anticipated electricity capacity needs. Key highlights of the Letter include the Minister's request to advance several initiatives beginning in December 2021 and the Minister's notable support for energy storage, the continued operation of small hydro power facilities and the re-contracting of biomass facilities. However, despite the references to decarbonization and zero emissions renewable electricity, what stands out is the absence of a clear goal of aligning electricity procurement in Ontario with achieving zero emissions or clarity on the role of natural gas in the energy transition going forward.

This goal is becoming increasingly important given the outcome of the IESO's natural gas phase out study (Phase Out Study). The study was released on October 7, 2021 and undertaken by the IESO in response to municipal-level resolutions calling for the complete phase out of natural gas generation in Ontario by 2030. The IESO concluded that such a phase out is not possible, primarily for the following reasons:

- new forms of energy supply (e.g. energy storage, small modular nuclear reactors) are either in the development phase or are not ready to operate at the scale needed to compensate for the loss of natural gas generation capacity. The IESO estimates that replacing 11,000 MW of natural gas generation capacity would require 17,000 MW of non-emitting forms of capacity and 1,600 MW of energy conservation;
- new hydro and nuclear capability cannot be constructed within the next 8 years;
- there is insufficient time or resources to build the necessary generation and transmission infrastructure within the next 8 years. The IESO estimates that the cost of such infrastructure would be C$27 billion and that, on average, a single new transmission project currently takes 7 to 10 years to complete under 'optimal' circumstances; and
- a phase out would result in frequent and sustained blackouts.

However, despite the references to decarbonization and zero emissions renewable electricity, what stands out is the absence of a clear goal of aligning electricity procurement in Ontario with achieving zero emissions or clarity on the role of natural gas in the energy transition going forward.

The absence of a clear "net-zero" procurement strategy is also evident in other facets of the IESO's Resource Adequacy Framework. While, as detailed in our blog post, the draft Medium-Term RFP (Draft RFP) released by the IESO on November 2, 2021 provided some clarity on the process and criteria by which the IESO would procure up to 750 MW of capacity from existing generating or storage resources, it notably lacked any mandatory scoring or criteria related to emissions reduction. Arguably, there is an opportunity to further integrate emissions-related criteria in the Medium-Term RFP to address the potential but conceivably imminent increased electricity demand in Ontario resulting from possible future broad based transport electrification and natural gas phase-out.

Sector participants might anticipate further procurement direction from the Ministry following the IESO's responses to the Minister regarding: (a) existing barriers to energy storage (due to the Minister by March 31, 2022); and (b) a moratorium on the procurement of new natural gas generating stations in Ontario and an achievable pathway to phase out natural gas generation and achieve zero emission in the electricity system (due to the Minister by November 2022).

However, in the interim, sector participants should take some comfort in the province's developing procurement strategy, notable progress towards Canada's clean energy goals, and a growing appetite for new projects. Sector participants deciding whether to invest in new generation or storage assets, or to invest in existing facilities, may find some relief in the provincial government's support for the IESO's approach to capacity procurement. Ontario has demonstrated its support for emerging technologies; as described further by our colleagues in the SMR article of this publication. Ontario Power Generation Inc. has chosen a developer to engineer, design and permit Canada's first-of-a-kind commercial, grid-scale small modular reactor.

Somewhat surprisingly, despite several years of industry pessimism due to the dearth of new-build opportunities in the province, 2021 has brought renewed optimism. In addition to the foregoing, additional developments (such as the Ministerial directives from August 27, 2021 and May 20, 2021 relating to the 250 MW Oneida Battery Park Project and the 1,000 MW Lake Erie Connector Project (an underwater transmission intertie between Ontario and Pennsylvania) and the AAR's confirmation that bilateral contracts (for up to 2,000 MW) are contemplated to address the upcoming capacity shortfall) seem to confirm that the IESO is once again poised to enter into new contracts, which will be welcome news for patient industry participants and investors.

Québec Regional Overview

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Introduction

In 2021, the Québec government took major steps towards the implementation of its 2030 Plan for a Green Economy (which was launched in November 2020), including its plans to increase its supply of renewable energy in anticipation of increased electricity demand in the coming years. Heightened activity in the Québec renewable energy sector is therefore anticipated in the years to come.

New Renewable Energy RFP Opportunities

In February 2021, Hydro-Québec announced that it had signed a 30-year 200 megawatt wind power purchase agreement provided through the previously paused Apuiat Wind Project. This project consists of a partnership between Boralex and Innu communities, and is the first important wind energy infrastructure project for Québec's *Côte-Nord* region.

> **At a combined 780 megawatts, these two RFPs represent the Province's largest renewable energy calls for tenders since 2013 and are meant to secure additional electricity supplies by 2026.**

780 MEGAWATTS OF RENEWABLE ENERGY PROJECTS

On July 14, the Québec Government publicly confirmed its intention to launch two renewable energy RFPs by the end of the year. At a combined 780 megawatts, these two RFPs represent the Province's largest renewable energy calls for tenders since 2013 and are meant to secure additional electricity supplies by 2026. As detailed in Decree 906-2021 *Concerning the Economic, Social and Environmental Concerns Reported to the Régie de l'énergie Regarding Hydro-Québec's 2020-2029 Electricity Supply Plan and Relating to a 300 MW Block of Wind Power* and in two related regulations, the calls for tenders are for a 300 megawatt block of wind power (A/O 2021-02) and a 480 megawatt block of renewable energy generally (A/O 2021-01), both to be purchased by Hydro-Québec.

Three other decrees were published in November 2021 to provide further details and amendments (decrees 1440-2021, 1441-2021 and 1442-2021).

As required under s. 74.1 of the *Act respecting the Régie de l'énergie*, Hydro-Québec submitted the two proposed RFPs and the related power purchase agreements to Québec's energy regulator, the *Régie de l'énergie*, on September 11, 2021 for review and approval. The process continued throughout the fall of 2021, with many interveners taking part in the proceedings and requesting changes to the proposed RFP documents.

On December 13, Hydro-Québec announced the official launch of the two RFPs, despite the ongoing regulatory review at the time. In its announcement, Hydro-Québec noted that the issued RFP documents could be subject to change once the final decision from the *Régie de l'énergie* would be published. Such final decision was released on December 23, 2021, officially ending the planning and preparatory phase of the RFPs.

The two RFPs overlap in many aspects. In both cases, the final and firm bid submission deadline is set for July 21, 2022. Leading up to that date, the RFPs will follow a similar structure, procedure and timeline, and participants are expected to register as the first step of the process.

480 MW block of renewable energy RFP (A/O 2021-01)	300 MW block of wind power RFP (A/O 2021-02)
- Online preparatory conference (optional): January 27, 2022, from 1:00 to 4:00 p.m. - RFP Registration period: January 28 to March 16, 2022, 4 p.m. - Period to submit a question: January 28 to July 7, 2022, 4 p.m. - Deadline for submissions: July 21, 2022, 4:00 p.m. - Bid opening: July 22, 2022, 1:00 p.m..	- Online preparatory conference (optional): January 26, 2022, from 1:00 to 4:00 p.m. - RFP Registration period: January 28 to March 16, 2022, 4:00 p.m. - Period to submit a question: January 28 to July 7, 2022, 4:00 p.m. - Deadline for submissions: July 21, 2022, 4:00 p.m. - Bid opening: July 22, 2022, 10:00 a.m.

Figure 1: Registration and Important Dates of the Québec RFPs

Projects submitted under both RFPs should be capable of delivering energy by no later than November 30, 2026, and any power purchase agreement will need to be approved by the *Régie de l'énergie*. A proposed project's cost of electricity is the predominant selection criteria for both RFPs, 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, although more so for RFP A/0 2021-02 (wind). The RFPs aim to solicit contracts with 30-year terms but there is potential for longer or shorter contracts.

More specifically, RFP A/O 2021-01 (renewables) contemplates that Hydro-Québec will enter into one or more long-term renewable electricity supply contracts for 480 megawatts of energy supply in peak power. The selection and weighting grid is composed of broad criteria, as this RFP is designed to favour renewable energy project submissions with diverse energy delivery profiles, including variable, baseload or cycling, and which may or may not include a power guarantee. Sustainable development requirements are organized into five sub-criteria, which are:

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 worth 11 points in and of itself.[1]

1. The social indicator (translated from "*indicateur à caractère social*") is an umbrella grading criteria used in the RFP A/O 2021-01 documents to cover different sub-criteria. These sub-criteria - which collectively form the social indicator - are: 1) recognition of the project by local authorities; 2) the project's integration plan (within the local community); and 3) economic benefits for the region (where the project will be located).

In contrast, through RFP A/O 2021-02 (wind), Hydro-Québec will eventually enter into one or more long-term contracts for a combined 300 megawatt supply of wind energy generated by new projects. Projects submitted to RFP A/O 2021-02 (wind) will be assessed based on the Régie's approved weighing grid which includes the following three notable requirements:

i. bidders should ensure that the project involves local community participation (including Indigenous participation) at a minimum level of 40% to receive points, with a 50% level of participation receiving maximum points;
ii. bidders must aim for a minimum 60% of the overall expenses to be linked to Québec content (otherwise the proposal may lose points); and
iii. a potential project's regional content should also be maximized, with regional expenses being required to cover at least 35% of the overall expenses.

Developments in Québec's Electricity Export Strategy

Hydro-Québec remained throughout 2021 Canada's largest exporter of electricity. In line with its 2020-2024 strategic plan, Hydro-Québec remains committed to its stated objective of increasing its exports and supporting the decarbonisation of northeastern North America. The Québec utility projects that its net income will reach C$5.2 billion by 2030 through increased exports and the development of other new projects.

> **In line with its 2020- 2024 strategic plan, Hydro-Québec remains committed to its stated objective of increasing its exports and supporting the decarbonisation of northeastern North America.**

The reduced demand for and consumption of energy brought on by the COVID-19 pandemic was less pronounced in 2021 than in 2020. These changes translated into more favourable market conditions for Hydro-Québec's energy exports. Net electricity exports for 2021 grew at an average of approximately 20% during the first three quarters of 2021 compared to 2020 results, with total export volumes reaching 27.8 TWh over these nine months (nearing the 2018 record level of 28.8 TWh). Third quarter export volume growth was 4.5 TWh, an increase from 2020 results.

While average export prices have not yet returned to 2019 levels, there was a significant increase in electricity export volumes. First quarter export prices also rose slightly to 4.5 ¢/kWh, but second quarter export prices decreased to 4.2 ¢/kWh (from 4.4 ¢/kWh for the same quarter in 2020). Prices then reached an average of 4.0 ¢/kWh by the third quarter (from 4.3 ¢/kWh for the same quarter in 2020). Nevertheless, Hydro-Québec's net income from electricity exports grew as of the third quarter, confirming that overall demand for electricity grew throughout the year. These positive results, combined with increasing probability that renewable electricity demand will continue to rise in the coming years, has meant that Hydro-Québec's export plans have not been negatively impacted by the pandemic.

Ongoing infrastructure projects are reflective of this continued export strategy, centred on the utility's ability to provide clean and renewable energy. In addition to the two planned RFPs and operating wind energy projects, the Province has continued its progress on ongoing transmission and production projects.

Work on the 1,500 megawatts Romaine-4 hydroelectric project continued throughout 2021. Due to certain delays in part resulting from the pandemic, the facility is now scheduled to start electricity production as of 2022.

Given the development of other energy projects, the Romaine-4 project may be Hydro-Québec's last major dam venture for some time. Hydro-Québec has also signaled that it considers its existing and developing energy infrastructure to be capable of providing sufficient power reserves to supply both the Province and export contracts for the foreseeable future.

Current projections suggest, however, that an increase in Hydro-Québec's electricity demand should be expected as of 2025 or 2026, leaving room for additional energy infrastructure projects, as exemplified by the recent renewable energy RFPs described above. Given that Hydro-Québec's current export strategy continues to promote the load balancing capacities of its hydroelectric assets to other provinces and to US states, it will be interesting to see how the utility plans to market other sources of renewable energy outside of Québec.

EXPORTS TO THE UNITED STATES

Efforts to export electricity to the United States remain a central feature of Hydro Québec's ongoing export strategy.

After renewed efforts in 2020 to export hydroelectricity to New York, it was announced in September 2021 that Hydro-Québec had been chosen by the State of New York to deliver 1,250 megawatt of electricity (approximately 10.4 TWh) as of 2025, under a 25-year contract with the New York State Public Service Commission. Early estimates suggest that the contract will generate revenues of approximately C$20 billion for Hydro-Québec, but discussions regarding financial terms were ongoing as of the end of 2021. The project will need to obtain regulatory approvals moving forward.

The New York announcement provided further support for the development of an interconnection link between Québec and New York, as existing transmission lines are not sufficient to meet such energy demands.

By November 2021, Hydro-Québec released plans for construction work to begin on the approximately 60-kilometre portion of the Hertel-New York interconnection line project as of spring 2023. This 1,000-megawatt high-voltage transmission line project will link upon completion La Prairie to the Champlain Hudson Power Express line which supplies New York City. In its current form, the line will be buried underground and underwater. In addition to the ongoing collaboration with Transmission Developers Inc. to develop this line construction project in the past ten years, Hydro-Québec indicated this year that the ownership of the line would also be shared with the Mohawk Council of Kahnawà:ke under a 40-year benefit agreement.

The utility also experienced certain unexpected setbacks this past year in its parallel plans to export electricity to Massachusetts pursuant to its 2018 power purchase agreement. Hydro-Québec has been moving forward with a joint venture with Avangrid Inc. to build a 1.2 gigawatt transmission line connecting Québec through Maine to the Massachusetts' power grid, the New England Clean Energy Connect project (NECEC). In February 2021, however, despite having received several of the required regulatory approvals and licences over the years, opponents to the project initiated a referendum procedure in Maine, which resulted in the project being submitted to the popular approval of Maine's residents. The referendum campaign ended on November 2, 2021, when a majority of Maine's voters chose to reject the transmission line project.

Construction of the 233-kilometre transmission line has nonetheless started. Nearly 40% of the NECEC line was complete when Charlie Barker, Maine's Governor, requested further construction work be stopped pending the resolution of various legal proceedings.

The results of the November referendum are currently being contested through a challenge to the procedure's constitutional validity. Requests for preliminary injunctions to resume building have also been tabled. The Québec government has stated that it remains confident that legal solutions will be found to allow the project to move forward.

There also remains strong support for the NECEC south of the border, despite the referendum results. The US Federal Government has remained supportive of the project, while Maine's Governor Charlie Barker and Québec Premier François Legault have indicated that alternatives to the current project's plans are being explored. Independently, Hydro-Québec has indicated that other options are available in order to transmit electricity to Massachusetts, including via alternative routes.

Aboriginal Renewable Energy Projects

In the next few years, the Province may see a growing number of new renewable energy projects that are either sponsored by aboriginal communities or developed in partnership with them. Many communities in Northern Québec are not connected to Hydro-Québec's main grid and are currently supplied with electricity produced from diesel generators. Many mining sites in Northern Québec are also relying on fossil fuel for their electricity needs. Given the current governmental objective of reducing greenhouse gas emissions and replacing fossil fuels, and Hydro-Québec's 2020-2024 Strategic Plan, there are many opportunities to replace diesel with renewable energy sources and we expect that aboriginal communities will continue to participate in such opportunities.

In its 2020-2024 Strategic Plan, Hydro-Québec has targeted using renewable energy sources to supply 70% of the energy for its off-grid systems by 2025. It will also be looking at creating the required infrastructure to convert its off-grid systems to renewable energy. This includes ensuring that diesel generators may be coupled with renewable energy sources to provide necessary backup and deploying energy storage infrastructure.

For mining sites operating in remote areas, the possibility of coupling diesel generators with clean energy could potentially create significant cost savings, in addition to contributing to greenhouse gas emissions reduction targets.

In March 2021, the Canada Infrastructure Bank launched its Indigenous Community Infrastructure Initiative with an investment target of C$1 billion in the financing of indigenous projects across the five priority areas established by the Government of Canada (public transit, green infrastructure, trade and transport, broadband and clean power). To this date, the Canada Infrastructure Bank publicly confirmed its participation in three projects as part of that initiative, including the modernization of the Tshiuetin Railway located in North-Eastern Québec and Labrador which is the first indigenous owned and operated railway in Canada. The Indigenous Community Infrastructure Initiative, as well as other financial assistance programs, could prove a powerful tool for aboriginal communities looking to develop renewable energy projects.

Hydrogen Projects

The 2030 Plan for a Green Economy aims to position the Province as a leader in the production of green hydrogen. New projects and partnerships are currently emerging while the Québec government prepares a more global strategy to develop the hydrogen industry in the Province.

In January 2021, Air Liquide inaugurated a 20 megawatt Proton Exchange Membrane (PEM) electrolyser which produces up to 8.2 tonnes per day of green hydrogen at a site in Bécancour, Québec, and became the world's largest unit of its kind. The operating unit is supplied with renewable energy provided by Hydro-Québec and its production process departs from the traditional hydrogen production process based on fossil fuels.

Hydro-Québec has announced that its Center of Excellence in Transportation Electrification and Energy Storage has signed commercial agreements with the University of South Wales (USW) to transfer USW's patented hydrogen storage technology to Hydro-Québec as part of an effort to commercialize this technology. The technology increases the capacity for hydrogen storage and has numerous applications, including transporting larger quantities of hydrogen safely and holding larger quantities of hydrogen in hydrogen-powered vehicles.

In February 2021, Evolugen and Gazifère Inc., an Enbridge company, announced the construction of a 20 megawatt water electrolysis hydrogen production plant in Gatineau, Québec. The electrolyser will be powered by Evolugen's adjacent hydroelectric facilities, and the green hydrogen will be produced for injection into Gazifère's natural gas distribution network.

Those types of projects will likely grow in numbers in the next few years. As part of its 2030 Plan for a Green Economy, the Québec Government communicated its intent to release and implement Québec's first green hydrogen and bioenergy strategy to enhance the production and use of hydrogen in Québec. A first round of consultations has been held during the Spring of 2021. Further to those consultations, a proposal for a strategic vision and guiding principles has been developed. The Québec government sought additional feedback in light of the proposal by launching a second round of consultations ending in January 2022 with the aim of refining its strategy. The green hydrogen and bioenergy strategy is now expected to be released in April 2022.

Environmental Law

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Key Developments in 2021

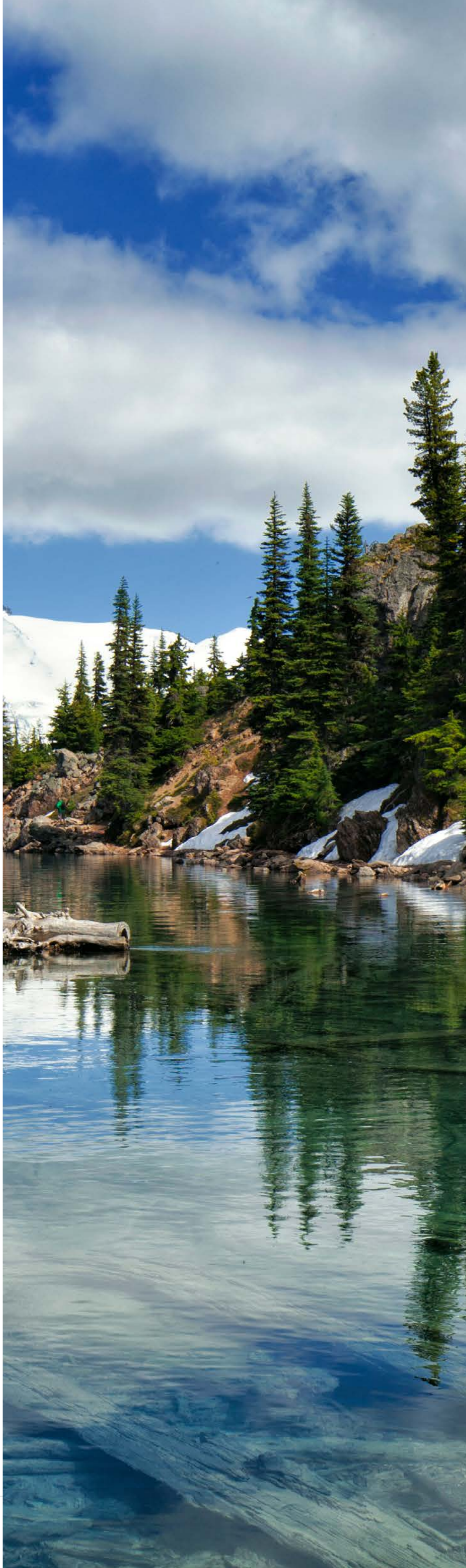
In 2021, there were a number of key environmental law developments across Canada with potential impacts on the power sector. Highlights include the following:

BRITISH COLUMBIA

BC Releases CleanBC Roadmap to 2030: 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 to 2030 includes a series of actions across a number of pathways, including increases to carbon pricing, requirements for new industry projects to have plans to achieve BC's sectoral targets and net zero by 2050, measures to reduce industrial methane emissions, a review of the oil and gas royalty system to ensure it aligns with BC's climate goals, requirements to make all new buildings zero-carbon by 2030, targets for adopting zero-emission vehicles (ZEVs), increased clean fuel and energy efficiency requirements; and support for innovation in areas like clean hydrogen, the forest-based bio-economy and negative emissions technology.

BC Releases Hydrogen Strategy: In July 2021, BC became the first province in Canada to release a comprehensive hydrogen strategy. Part of the CleanBC plan, the BC Hydrogen Strategy includes 63 actions for government, industry and innovators to undertake during the short term (2020-25), medium term (2025-30) and long term (2030 and beyond). Under the BC Hydrogen Strategy, immediate priorities include scaling up production of renewable hydrogen, establishing regional hydrogen hubs, and deploying medium- and heavy-duty fuel-cell vehicles. The Province is supporting the BC Hydrogen Strategy with further investments announced as part of Budget 2021, including C$10 million over three years to develop policy on reducing the carbon intensity of fuel and advancing the hydrogen economy. In addition, BC Hydro recently introduced a discounted electricity rate for renewable hydrogen production to attract new investment in clean industry.

BC Sets Sectoral Greenhouse Gas Emission Reduction Targets for Industry: In March 2021, BC set sectoral GHG targets as part of its CleanBC plan. Sectoral targets for 2030 have been established for the following sectors (expressed as a percentage reduction from 2007 sector emissions): (i) transportation – 27 to 32%; (ii) industry – 38 to



43%; (iii) oil and gas – 33 to 38%; and (iv) buildings and communities – 59 to 64%.

As part of legislated requirements, government will review the targets by 2025, with options to expand the number of sectors included and narrow the percentage ranges. To support emission reductions, the Province launched a new round of applications for emission reduction projects for 2021 through the CleanBC Industry Fund, with temporary changes to increase the provincial share of funding up to 90% of project costs with a cap of C$25 million per project to encourage a greater number of proposals. In addition, a new stream of the CleanBC Industry Fund known as the Innovation Accelerator was announced to support industry projects that use advanced clean tech solutions for tough-to-solve emission problems.

ALBERTA

Amendments to AUC Rule 007: The Alberta Utilities Commission (AUC) amended AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* (AUC Rule 007). AUC approval is required under s. 11 of the *Hydro and Electric Energy Act* to construct or operate a "power plant", which includes facilities for the generation and gathering of electric energy from any source. AUC Rule 007 provides the specific application requirements for a range of facilities including thermal, wind, solar, hydro electric, hydroelectric and geothermal power plants, transmission lines, substations battery storage facilities, grid interconnections, industrial system designations and gas utility pipelines.

Following extensive consultation, including a separate process for the development of Indigenous consultation processes, the revised AUC Rule 007 now includes new or revised requirements addressing: (i) end-of-life management for power plants; (ii) emergency response planning; (iii) time extension applications for power plants; (iv) notification and participant involvement program; (v) solar glint and glare assessment; (vi) shadow flicker; (vii) review of buildable area concept for wind development; (viii) battery storage; and (iv) checklist application for pilot projects.

Highlights of the new and noteworthy environmental requirements include:

– For projects wholly or partially located on federal lands, an environmental impact analysis and annual submission of a post-construction monitoring survey report to Alberta Environment and Parks and the AUC pursuant to AUC Rule 033: *Post approval Monitoring Requirements for Wind and Solar Power Plants*;
– Submission to the AUC of a copy of the initial renewable energy operations conservation and reclamation plan in accordance with the *Conservation and Reclamation Directive for Renewable Energy Operations*; and
– Providing an overview of how project proponents will ensure sufficient funds are available at the project end of life to cover the cost of decommissioning and reclamation.

Extension of Alberta's *Emission Trading Regulation* to November 30, 2030: Alberta has a sulphur dioxide and nitrogen oxides emissions trading program for the electricity sector. It is one part of an overall plan for the electricity sector in Alberta and was established under the *Environmental Protection and Enhancement Act* (EPEA) to adopt the recommendations of An Emissions Management Framework for the Alberta Electricity Sector Report to Stakeholders from the Clean Air Strategic Alliance. The *Emission Trading Regulation* encourages power stations to reduce their nitrogen oxide and sulphur dioxide emissions prior to mandatory improvements required in their EPEA industrial approvals. Alberta extended expiry of this regulation from November 30, 2021 to November 30, 2030.

Alberta establishes Coal Policy Committee: In May 2020, Alberta rescinded the Coal Development Policy for Alberta (1976 Coal Policy). The intention of the 1976 Coal Policy was to ensure that appropriate regulatory and environmental protection measures would be conducted before new coal projects could be formally approved. The 1976 Coal Policy divides land in Alberta into four categories and establishes a framework for where coal leasing, exploration and development can occur and the requirements for those activities within the province.

The revocation of the 1976 Coal Policy was faced with opposition from several interest groups and stakeholders, including an application for judicial review filed with the Alberta Court of Queen's Bench (Blades, *et al v. Her Majesty the Queen in Right of Alberta and the Minister of Energy for the Province of Alberta*, ABQB Action No. 2001-08938). Municipal councils, environmental organizations and Indigenous groups also objected to the revocation of the policy and petitioned for its reinstatement.

In February 2021, Alberta announced that the 1976 Coal Policy would be reinstated, effective February 8, 2021. In addition, Alberta strengthened the reinstated policy by providing the following direction to the Alberta Energy Regulator:

– No mountain-top removal will be permitted and all of the restrictions from the 1976 Coal Policy categories will apply, including the restrictions on surface mining in Category 2 lands; and
– New approvals for coal exploration on Category 2 lands are prohibited until widespread consultation on a new policy is conducted.

In order to continue with their goal of developing a modern coal policy, Alberta also launched a Coal Policy Committee to run a comprehensive engagement with Albertans. The Coal Policy Committee completed its engagement and final reports with recommendations were submitted to the Minister of Energy in December 2021.

New Alberta Energy Regulator (AER) Liability Management Framework: In recent years, liability management for the oil and gas industry has been a growing concern for industry, regulators and landowners. Through ongoing consultation with industry and stakeholders, the Government of Alberta and the AER identified gaps in how ongoing and end of life liability is managed.

On December 1, 2021, Alberta introduced its latest set of amendments to existing AER directives and new directives to implement a new liability management framework (LMF). Specifically, the AER introduced amendments to *Directive 006: Licensee Liability Rating (LLR) Program* and a new *Directive 088: Licensee Life-Cycle Management*.

The LMF replaces the current liability licensee rating (LLR) system and is intended to improve and expedite reclamation efforts, enable industry to better manage the clean-up of oil and gas wells, pipelines and facilities at every stage of development, and provide a holistic and full lifecycle approach to reclamation and remediation obligations.

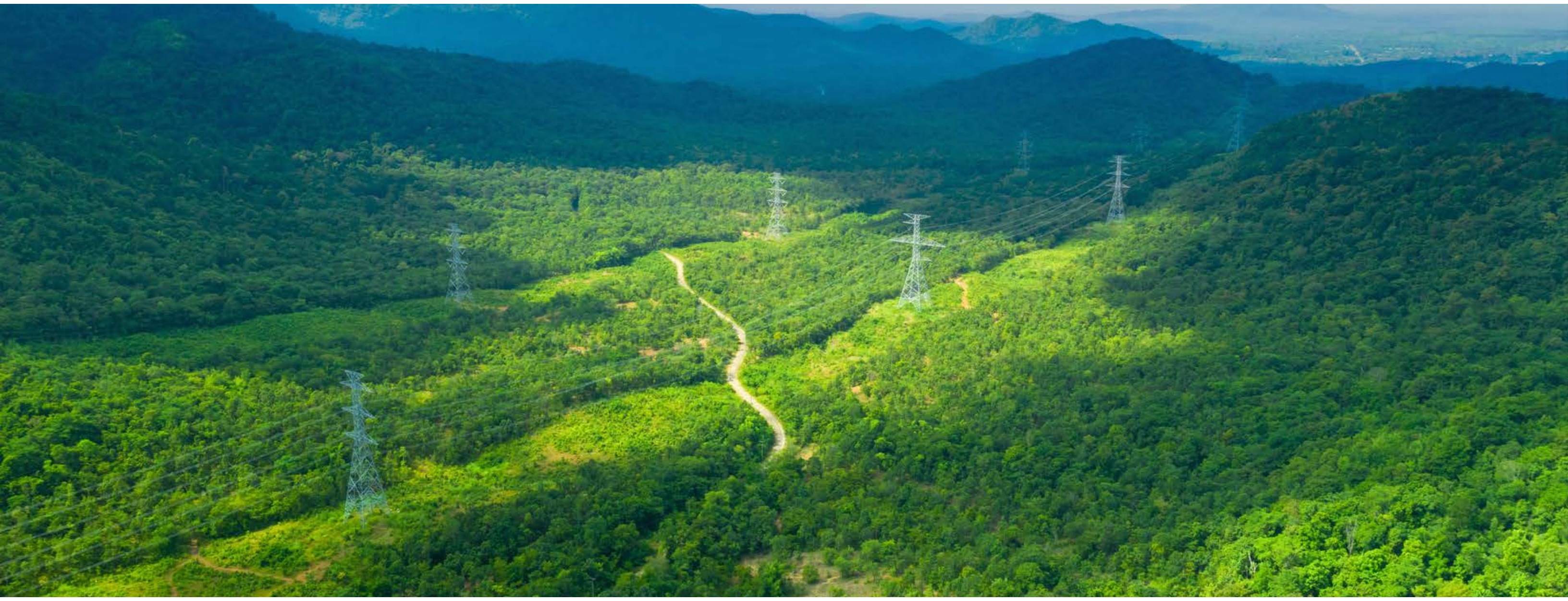
The announcement of the amendments to Directive 006 and new Directive 088 build-on a number of regulatory changes including: (i) the new *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*; (ii) the Site Rehabilitation Program announced in March of 2020; and (iii) the enactment of the *Liabilities Management Statutes Amendment Act*, which received Royal Assent on April 2, 2020.

The requirements within the oil and gas industry regarding end of life obligations and orphan wells influence landowner negotiations for all industries in Alberta including power related projects. As a result, this trend of increased life cycle requirements and monitoring for accountability, impacts stakeholder engagement for other industries including for thermal and renewable electricity generation projects.

ONTARIO

Ontario's Transition to Emissions Performance Standards: The Ontario government created the Ontario Emission Performance Standards (EPS) in 2019 as an alternative to the federal government's output based pricing system (OBPS) for industrial emitters. Both the EPS and OBPS programs regulate emissions from industrial facilities by setting industry-specific emission standards for regulated facilities. Although the administrative requirements of the Ontario EPS program came into effect in 2019, the substantive requirements were dormant as the federal government's OBPS was in force in Ontario. In September 2021, the federal and Ontario governments finalized their agreement to have the EPS apply in Ontario effective January 1, 2022 and to remove the application of the federal OBPS on the same date. 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, and the 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.

Fossil Fuel Charge in Ontario: As noted below, in May 2021, the Supreme Court of Canada upheld the constitutionality of the federal government's *Greenhouse Gas Pollution Pricing Act*. Although the federal and Ontario governments have agreed that the Ontario EPS program can regulate industrial emitters in Ontario in lieu of the federal OBPS program, the levy on fossil fuel distribution in Ontario—commonly known at the "fossil fuel charge"—that is imposed by the *Greenhouse Gas Pollution Pricing Act*, will, now that the act has been determined to be constitutional, continue to apply in Ontario.



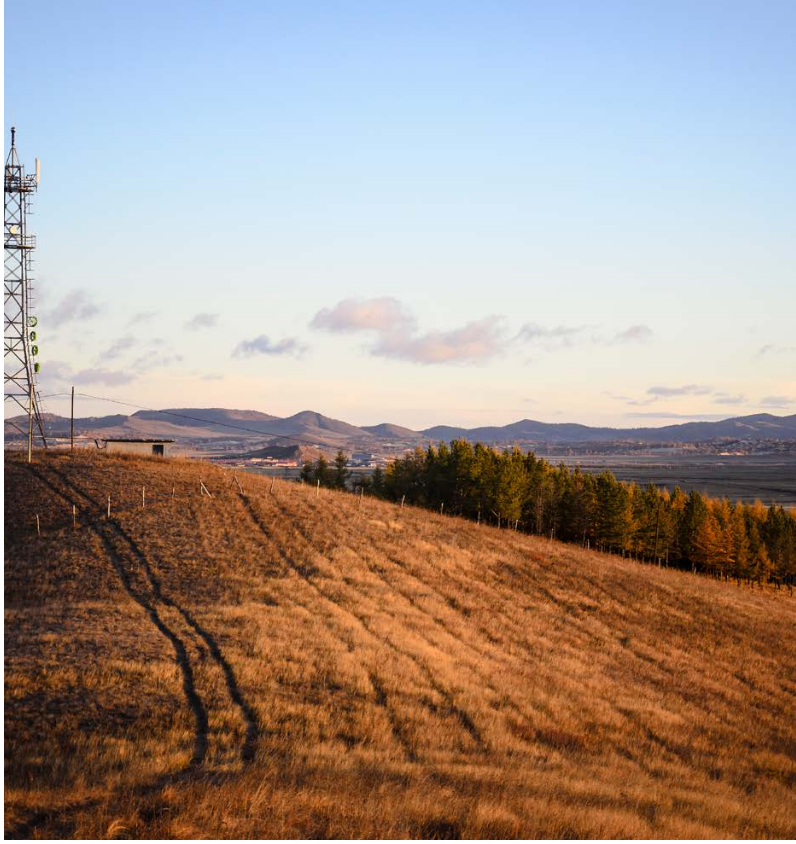
Amendments to Ontario's *Environmental Assessment Act*: Changes made to Ontario's *Environmental Assessment Act* (EAA) in 2020 are starting to come into force in phases. The EAA currently applies to all public sector undertakings (unless exempted) and only to some private sector undertakings that are 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. Companies planning new, large-scale projects in Ontario will want to review the draft comprehensive projects list to determine their potential obligations.

QUÉBEC

Announced Ban on Oil and Gas Upstream Activities: In October 2021, the Government of Québec announced that it intends to ban all oil and gas exploration and production activities in the province, a decision further confirmed by the province joining the Beyond Oil and Gas Alliance in November 2021 at the Glasgow Climate Change Conference (COP 26). A Bill is expected to be tabled by the Government in early January to confirm the ban and related indemnification mechanism in favour of the current holders of exploration and production licences.

Oil and Gas and Surface Water Protection: On November 12, 2021, the Québec Court rendered a long-awaited decision in *Gaspé Énergies inc. v. Ministre de l'Énergie et des Ressources naturelles*, 2021 QCCQ 11747, declaring illegal the decision of the Québec Minister of Energy and Natural Resources to refuse to issue an oil exploration permit to Gaspé Énergie pursuant to the Québec *Petroleum Resources Act*. We refer you to the Energy Litigation article of this publication for an analysis of this decision. While the Court returned the file to the Ministry for a new decision to be made by the Minister, this project is now expected to be captured by the announced ban on oil and gas exploration activities described above.

Bill 102 amending the *Environment Quality Act*: In October 2021, the Government of Québec tabled an 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). Bill 102's main purpose is to improve and standardize the measures enabling the enforcement of the various statutes under the responsibility of the Québec Minister of the Environment, including the *Environment Quality Act* and the *Dam Safety Act*. Among other things, Bill 102 proposes to introduce monetary administrative penalties, increase the amounts of environmental fines and modify the authorization and approval regime under the *Dam Safety Act*.

FEDERAL

Supreme Court of Canada Upholds Constitutionality of Federal Carbon Pricing Backstop: On March 25, 2021, the Supreme Court of Canada (SCC) upheld the constitutionality of the federal *Greenhouse Gas Pollution Pricing Act* (GGPPA). The SCC's review arose from the appeals of three provincial court decisions (Saskatchewan, Ontario and Alberta). The main legal issue in all three cases was whether the federal government has the authority to impose the regime established under the GGPPA. In May 2019, a 3-2 majority at the Saskatchewan Court of Appeal said the Act was a valid use of federal legislative jurisdiction. A 4-1 majority at the Ontario Court of Appeal reached the same conclusion in June 2019. However, in February 2020, four of five Alberta Court of Appeal judges

found the Act to be unconstitutional on the grounds that it exceeded federal jurisdiction. A 6-3 majority of the SCC held that the GGPPA is constitutional and that Parliament has jurisdiction to enact it as a matter of national concern under its constitutional Peace, Order and Good Government power. The SCC decision brings certainty to the carbon pricing regime in Canada, and allows the federal government to continue implementing its climate change strategy.

Continuing Increase to Carbon Price from 2023 to 2030: The federal government has reviewed its approach to carbon pricing and announced in December 2020 that the carbon price will be increased annually at a rate of C$15 per tonne starting in 2023 until it reaches C$170 per tonne of CO_2e in 2030.

Federal Government Releases Updated Climate Plan – *A Healthy Environment and a Health Economy*: On December 11, 2020, the federal government released its Healthy Environment and a Healthy Economy Plan (the Federal Climate Plan), which builds on the Pan-Canadian Framework on Clean Growth and Climate Change and provides a road map forward to meet the country's 2030 emissions reduction target under the Paris Agreement of 40–45% below 2005 levels by 2030. The Federal Climate Plan is also intended to establish initiatives to support efforts to achieve Canada's goal of net-zero emissions by 2050, which has been formalized in the *Canadian Net-Zero Emissions Accountability Act* (passed in June 2021). The Federal Climate Plan outlines actions in five main areas, including: (i) energy efficiency in homes and buildings; (ii) lower emission transportation options; (iii) increasing the price on carbon pollution; (iv) supporting the decarbonization of Canadian industry; and (v) building more resilient communities. As part of Canada's climate change plan, the federal government has committed C$3 billion to establish a Net-Zero Accelerator Fund to help large emitter reduce their emissions.

The SCC decision brings certainty to the carbon pricing regime in Canada, and allows the federal government to continue implementing its climate change strategy

Federal Government Introduces Draft Regulations for Clean Fuel Standard: On December 18, 2020, Environment and Climate Change Canada published the proposed *Clean Fuel Regulations* (CFR), which seek to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The proposed 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 2.4 gCO2e/MJ in 2022, increasing to 12 gCO_2e/MJ in 2030 at a rate of 1.2 gCO2e/MJ per year. Reduction requirements for the years after 2030 would be held constant at 12 gCO2e/MJ, subject to a review of the regulations and future amendments. The proposed CFR would also establish a credit market whereby the annual CI reduction requirement could 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 would be repealed. Final regulations are expected to be released in 2022, with the coming into force of regulatory requirements in early 2023.

The Year Ahead

BRITISH COLUMBIA

Further Actions to Implement CleanBC Roadmap to 2030: In 2022, it is expected that the BC Ministry of Environment will develop and introduce various initiatives to implement the CleanBC Roadmap to 2030. In particular, initiatives will support the actions set out in 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) stronger regulations that will nearly eliminate industrial methane emissions by 2035; (iv) a comprehensive review of the oil and gas royalty system to ensure it aligns with BC's climate goals and provides a fair return for British Columbians, with outcomes released in February 2022; (v) new requirements to make all new buildings zero-carbon by 2030; (vi) adoption of zero-emission vehicles (ZEVs) by 2030 and 100% ZEVs by 2035; (vii) developing new ZEV targets for medium- and heavy-duty vehicles; (viii) an accelerated shift toward active transportation and public transit (30% by 2030; 40% by 2040; 50% by 2050); (ix) increased clean fuel and energy efficiency requirements; and (x) support for innovation in areas like clean hydrogen, the forest-based bioeconomy and negative emissions technology.

ALBERTA

New Alberta 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 the development of a new climate strategy 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* 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.

ONTARIO

Amendments to Ontario's *Environmental Assessment Act*: As noted above, significant changes to the Ontario *Environmental Assessment Act* are coming into force in phases and draft regulations have been released for comment. In 2021, regulations setting out the types of projects, public and private, that will be required to undergo comprehensive environmental assessments and to obtain cabinet approval, will likely be finalized. Further, more clarity will likely be provided for the types of projects that will be exempt from the comprehensive environmental assessment process and those which will be required to complete a streamlined, self-assessment process.

Developments to Watch: As Ontario heads into an election year, 2022 will likely see various announcements regarding initiatives with environmental implications, such as future carbon pricing, clean technology and carbon capture, and further developments towards the government's announced low-carbon hydrogen strategy.

QUÉBEC

New Rules for the Cap-and-Trade System for 2024-2030: In 2022, the Government of Québec is expected to publish its proposed rules for the allocation of carbon emission credits for the 2024-2030 period under the Province's cap-and-trade system for GHG emissions. These new rules are highly anticipated by large industrial operators and are likely to include new measures aimed at encouraging further reductions in the carbon footprint of Québec's main GHG emitters.

Adoption of Bill 102 and Omnibus Regulations: The Government of Québec is expected to adopt Bill 102 in 2022 and Québec Ministry of Environment will likely continue the ongoing modernization of the *Environment Quality Act*, including by tabling omnibus Regulations in spring 2022 to adapt the province's permitting and administrative requirements based on the environmental risk associated with each project.

Ban on Oil and Gas Upstream Activities: A Bill is expected to be tabled by the Government of Québec in early January 2022 to confirm the ban on oil and gas exploration and production activities, and related indemnification mechanism in favour of the current licence holders.

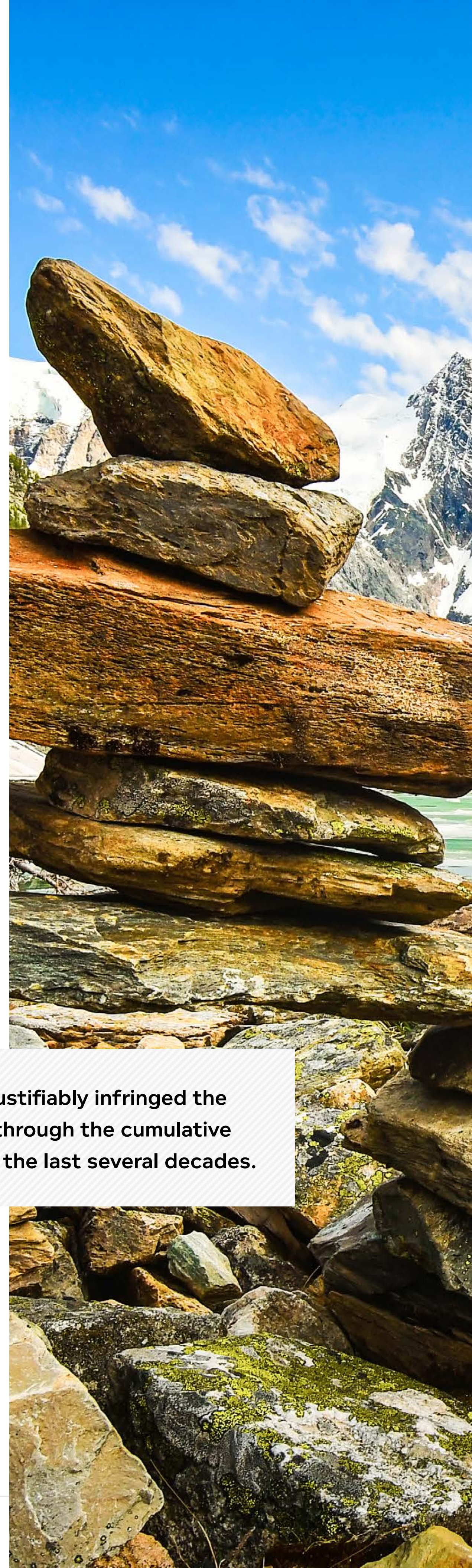
FEDERAL

Federal Government Expected to Launch Net-Zero Challenge for Industry: As part of efforts to achieve Canada's goal of net-zero emissions by 2050, the federal government is expected to launch the Net-Zero Challenge in early 2022. The Net-Zero Challenge is a voluntary initiative to encourage Canadian companies, particularly large industrial emitters, to develop and implement plans to transition their operations to net-zero emissions by 2050.

Final Clean Fuel Standard Regulations to be Released in 2022: As discussed above, the federal government is expected to release the final regulations for its Clean Fuel Standard in 2022, with the coming into force of regulatory requirements in early 2023.

Aboriginal Law

Authors: Bryn Gray and Selina Lee-Andersen



2021 saw a number of significant Aboriginal law and policy developments with implications for the energy sector in Canada. This includes several court decisions that could affect project consultation requirements or provide a new basis to challenge certain projects. It also includes further steps by the BC and federal governments to implement the UN Declaration on the Rights of Indigenous Peoples and continued uncertainty around how this will impact project-decision making by these governments as discussed below.

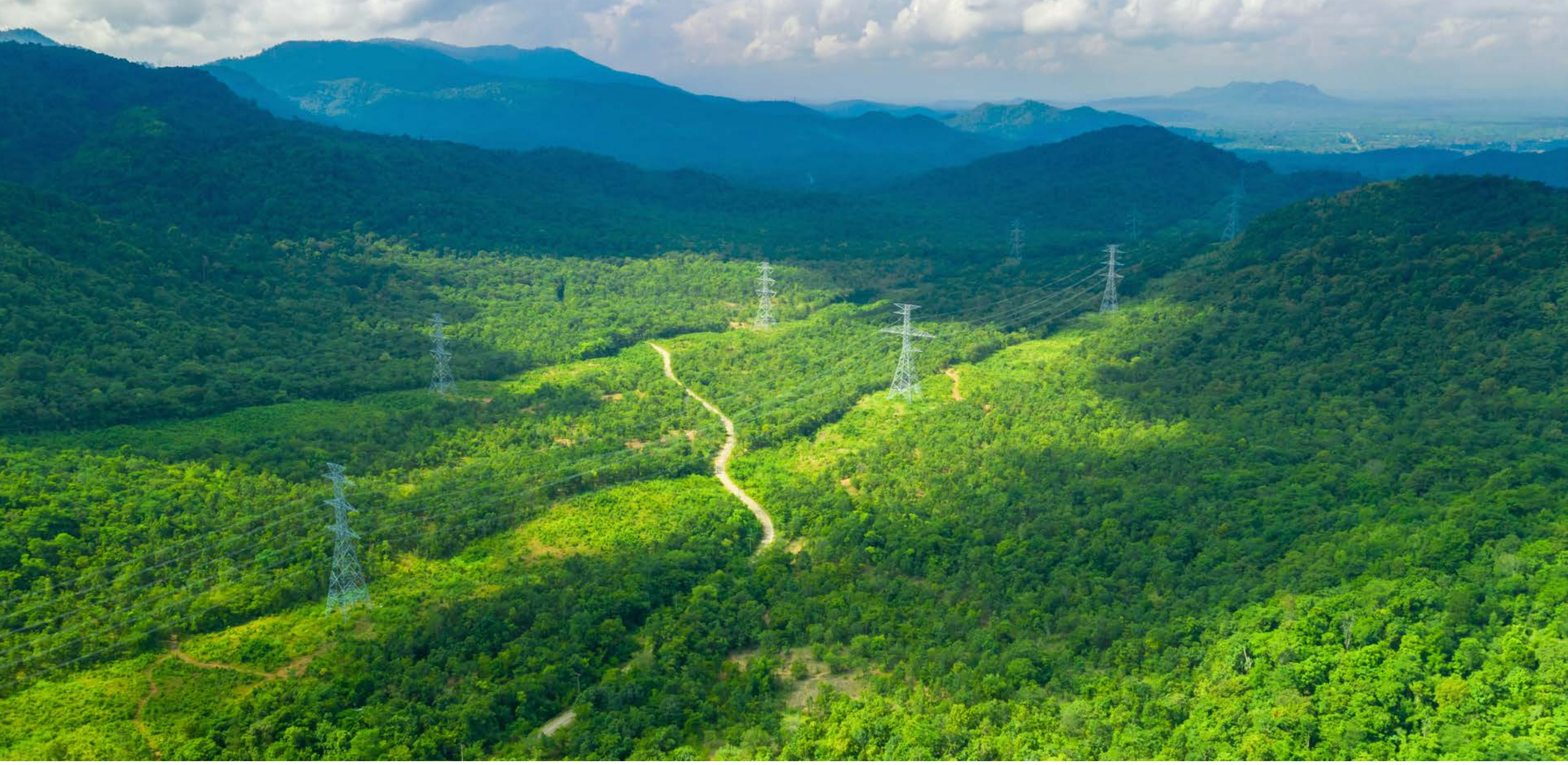
CUMULATIVE IMPACTS HALT DEVELOPMENT IN NORTHEASTERN BC

The most significant Aboriginal law decision for project development in 2021 was *Yahey v. British Columbia*.[1] In this case, the BC Supreme Court ruled that the BC government has unjustifiably infringed the treaty rights of the Blueberry River First Nations (Blueberry) through the cumulative effects of provincially authorized industrial development over the last several decades. The Court declared that the Province may not continue to authorize activities that unjustifiably infringe Blueberry's treaty rights, which has effectively paused permitting for projects throughout the Treaty 8 territory in BC while the provincial government attempts to negotiate a path forward with Blueberry and other Treaty 8 First Nations in BC. The decision is likely to lead to increased scrutiny of cumulative impact concerns in project consultation. It is also likely to result in similar claims by other First Nations in Treaty 8 and other areas of the country with historic treaties, although each case will need to be considered based on its particular facts and treaty context.

The BC Supreme Court ruled that the BC government has unjustifiably infringed the treaty rights of the Blueberry River First Nations (Blueberry) through the cumulative effects of provincially authorized industrial development over the last several decades.

This case required the BC Supreme Court to consider the extent of the Province's authority to take up lands under Treaty 8, an historic treaty negotiated in 1899 that includes portions of northeastern BC, northern Alberta, northwest Saskatchewan, and southern Northwest Territories. Treaty 8 provides the First Nations signatories a right to hunt, trap, and fish throughout the tract surrendered except on lands that are taken up from time to time for settlement, mining, etc. The Province argued

1. *Yahey v. British Columbia*, 2021 BCSC 1287



that Treaty 8 was designed to open up the lands for development and the Blueberry needed to prove that there was no meaningful right to hunt, fish, or trap in their territory to establish an infringement.

Justice Burke of the BC Supreme Court rejected this approach and limited the scope of the land take-up clause. Based on oral assurances provided during treaty negotiations, she found that Treaty 8 guaranteed First Nation signatories and adherents the right to continue their way of life based on hunting, fishing, and trapping and that this way of life would not be forcibly interfered with. She concluded that inherent in this promise is that the Crown would not "significantly affect or destroy basic elements or features needed for that way of life to continue"[2] and that an infringement would arise if Blueberry's treaty rights had been "significantly or meaningfully diminished when viewed within the way of life from which they arise and are grounded."[3]

The Court held that an infringement had arisen in this case based on the extent of development in the territory, impacts on wildlife of importance, and evidence of certain members about the difficulties they were having in exercising their treaty rights. The Court also provided a very critical review of BC's measures to assess cumulative impact concerns and found that the BC government had breached the honour of the Crown and its fiduciary duty by failing to protect Blueberry's treaty rights and adequately respond to and assess cumulative impact concerns.

The BC government decided not to appeal the decision and announced an initial agreement with Blueberry in October 2021 to provide C$65 million in funding to support various restoration activities and measures to support Blueberry's way of life. This funding was in exchange for Blueberry's agreement that 195 forestry and oil and gas projects that were already permitted would be able to proceed. The BC government indicated at that time that 20 currently approved authorizations in areas of high cultural importance would not proceed without further negotiation and agreement from Blueberry. The announcement did not deal with projects that were not yet approved or future ancillary permitting for the 195 approved projects. The path forward for future permitting is currently the subject of larger and longer-term negotiations with Blueberry and other Treaty 8 First Nations.

Beyond the immediate impacts the decision has had on permitting in Treaty 8 territory in BC, the decision will likely lead to similar infringement claims in other areas of Treaty 8 or other areas of the country with historic treaties. The written text of the Historic Numbered Treaties, which cover land from northern Ontario to BC, have similar provisions relating to harvesting rights and land-take up clauses, although each case will be dependent on its specific facts and treaty context. It is important to note that the outcome in this case was largely driven by what was said during treaty negotiations and the Court's interpretation of how that assurance limited the scope of other clauses in the treaty and impacted the threshold at which an infringement arose — as well as the evidence on the extent of development in Blueberry's traditional territory. Other courts may take different approaches in assessing the threshold for infringement based on the treaty context among other things. Future cases may also

2. Yahey, para. 175.
3. Yahey, para. 541.

need to contend with the justification defence which the BC government did not argue at trial.

The decision is also likely to lead to increased scrutiny of cumulative impact concerns in project consultation. There are several prior cases that confirm that cumulative impacts on Aboriginal and treaty rights are relevant to the duty to consult and can serve to deepen the level of consultation and accommodation required in certain circumstances. Where there are valid cumulative impact concerns, it is likely that government decision-makers (particularly in BC and the federal government) will be increasingly concerned about ensuring that any additional impacts are avoided, offset, or minimized and there could be increased scrutiny of efforts to achieve consent. While these issues go beyond individual projects, we expect that the Crown will rely on proponents to assess cumulative impacts on Aboriginal and treaty rights and to ensure measures are in place to avoid, offset, or minimize any additional incremental impacts from the project at issue where there are valid cumulative impact concerns.

US INDIGENOUS GROUPS CAN HOLD ABORIGINAL RIGHTS IN CANADA

In April 2021, the Supreme Court of Canada ruled in *R. v. Desautel* that the Lakes Tribe in Washington State have a constitutionally protected Aboriginal right to hunt in a portion of BC. This appeal of a hunting prosecution in BC required Canada's highest court to interpret the meaning of the words "Aboriginal peoples of Canada" in s. 35 of the *Constitution Act*, 1982. The majority held that Indigenous groups located outside of Canada may be "Aboriginal peoples of Canada" for the purposes of s. 35 if they are a modern-day successor of an Aboriginal society that occupied what is now Canada at the time of European contact. The majority found that it is consistent with the purpose of reconciliation and s. 35(1) to include "Aboriginal peoples who were here when the Europeans arrived and later moved or were forced to move elsewhere, or on whom international boundaries were imposed."[4]

It is likely that this decision will lead to more US Indigenous groups asserting Aboriginal rights in Canada, which could expand the number of groups that need to be consulted and potentially accommodated for project development in certain cases. Where credible cross-border claims are raised, this could impact the distribution of project benefits amongst Indigenous groups including the benefits available to Indigenous groups in Canada, depending on the strength of any such claims and the impacts at issue.

The decision could also impact the interpretation of statutory obligations that have definitions of Aboriginal or Indigenous peoples of Canada that are tied to section 35 of the *Constitution Act*, 1982.

PUBLIC INTEREST TEST MUST CONSIDER BENEFITS TO INDIGENOUS COMMUNITIES

The consideration of Indigenous economic interests in project consultation and decision-making was a matter at issue in two significant decisions this year and another ongoing appeal before the Alberta Court of Appeal.

In *AltaLink Management Ltd. v. Alberta (Utilities Commission)*,[5] the Alberta Court of Appeal held that when the Alberta Utilities Commission (AUC) considers whether a decision is in the public interest, it should take a broad approach that considers the benefits to Indigenous communities and to Indigenous economic activity.

This decision related to whether two First Nations controlled limited partnerships (FN LPs) that had acquired electrical transmission assets on their reserves could pass on their incurred audit and hearing costs to ratepayers. The Piikani Nation and Blood Tribe had previously entered into agreements with Altalink to allow for the construction of transmission lines across their reserves with the option to purchase up to a 51% interest in the transmission line

4. *R. v. Desautel*, 2021 SCC 17 at para. 33.
5. *AltaLink Management Ltd. v. Alberta (Utilities Commission)*, 2021 ABCA 342

assets located on their reserves. The transmission lines became operational in 2010 and transfer applications were filed with the AUC in 2017. The AUC approved the transfer but ordered the FN LPs to absorb their hearing and external auditor costs in order to avoid any impact to ratepayers as part of the "no-harm" test. The AUC specifically refused to take into account the past benefits of siting the line on the shortest route among other things.

On appeal, the Court of Appeal held that the FN LPs should be allowed to include their auditing costs in their respective tariffs and that the AUC had erred in considering only forward-looking benefits as part of the "no-harm test". The Court noted that there were lower maintenance costs for the shorter and more accessible route and highlighted the benefits of education and employment, noting that projects that increase the likelihood of economic activity on reserve are in the public interest and should be encouraged.

In a concurring opinion, Justice Feehan noted that the AUC is obliged to consider the honour of the Crown and act consistently with the honour of the Crown whenever it engages with Indigenous collectives. He also found that the AUC as an administrative tribunal with a broad public interest mandate should have also addressed reconciliation between Indigenous peoples and the Crown — including a consideration of the interests of Indigenous peoples in participating freely in the economy and having sufficient resources to self-govern effectively.

In another case involving the consideration of Indigenous economic interests, the Federal Court held in *Ermineskin Cree Nation v. Canada*[6] that a Crown decision that had the potential to adversely impact a First Nation's economic benefits under an IBA triggered the duty to consult. This case involved an application by the Ermineskin Cree (Ermineskin) to quash an order designating the Vista Coal Mine expansion project in Alberta as a reviewable project under the federal *Impact Assessment Act*. The project was designated under the IAA at the request of two First Nations after the Minister had declined six months earlier to designate the project. Ermineskin was consulted on the initial designation decision but not notified or consulted on the second designation request and the Designation Order was contrary to the recommendation of the Impact Assessment Agency. Ermineskin argued that the Minister breached the duty to consult as the Designation Order would delay or eliminate the economic interests they negotiated in an IBA with the proponent. The Federal Court agreed and found the IBA was an economic interest that was closely related to and derivative of Aboriginal and treaty rights (in this case harvesting rights) and capable of triggering the duty to consult. The Court held the duty was breached in this case as there was no consultation whatsoever, although the decision is currently under appeal to the Federal Court of Appeal.

It is surprising that the federal government did not consult Ermineskin from a policy and relationship perspective but the underlying reasoning of this decision is questionable and it may be set aside or varied on appeal. The duty to consult is focused on avoiding or minimizing impacts to Aboriginal and treaty rights. This can include impacts to economic components of rights like commercial harvesting rights but its extension to adverse impacts to contractual benefits in third-party contracts is questionable, particularly when these benefits are not derivative

6. *Ermineskin Cree Nation v. Canada*, 2021 FC 758

components of Aboriginal or treaty rights and there would be no impact to Aboriginal or treaty rights from the Crown decision at issue.

If this decision is upheld on appeal by the Federal Court of Appeal, it could expand the circumstances in which the duty to consult is triggered and the issues that need to be considered in project consultation. There are also similar challenges by two other Alberta First Nations currently before the Federal Court and the Alberta Court of Appeal relating to decisions by the federal government and the Alberta Energy Regulator to decline approvals relating to the Grassy Mountain coal project. The First Nations — one of whom requested the designation order for the Vista Mine expansion project — are alleging breaches of the duty to consult by the federal government and the joint review panel acting for the Alberta Energy Regulator for failing to consider their economic interests in declining the approval of the project.

COMPENSATION FOR FLOODING OF RESERVE LAND MUST INCLUDE VALUE OF LAND TO HYDRO PROJECT

In *Southwind v. Canada*,[7] the Supreme Court of Canada (SCC) set aside a damages award for the use of reserve land for a hydroelectric project because the award did not take into account the value of the land to hydroelectricity generation. This decision provides guidance on the principles of equitable compensation and the fiduciary obligations of the Crown with respect to the management of reserve land.

This decision related to the permanent flooding of 11,304 acres of Lac Seul First Nation (Lac Seul) reserve land following the construction of a hydroelectric dam in 1929. The flooding of reserve land proceeded without Lac Seul's authorization and the First Nation did not receive any compensation until 14 years after the flooding began and the amount was inadequate. The trial judge found that Canada had breached its fiduciary duty and ordered C$30 million in damages, which was based on expropriation principles and excluded the value of the land for hydroelectricity generation.

Lac Seul appealed the judge's valuation to the Federal Court of Appeal, and then to the SCC. The SCC allowed Lac Seul's appeal, holding that the fiduciary duty requires more than compensation based on expropriation principles. The Court found that the ability to expropriate or take land under the *Indian Act* or the need to use the land for a public work did not define, negate or limit Canada's fiduciary obligations relating to reserve land and that the principles of expropriation law are entirely inappropriate within the context of valuing the underlying Indigenous interest in land and Canada's breach of its historic obligations. The SCC held that that Crown has a duty to consider the nature of the interest and the impact on the First Nation in assessing appropriate compensation and has a "duty to preserve the First Nation's quasi-proprietary interest in the land as much as possible and to ensure fair compensation reflecting the *sui generis interest*."[8] In light of the significant impact of the expropriation on the First Nation interest and Canada's knowledge that "the impact would be catastrophic", the Court held that Canada was required to capture the full potential value of the land for the First Nation which would reflect the land's use as water storage for hydroelectricity generation.[9]

UNDRIP IMPLEMENTATION UPDATES

BC Proposes Extensive Changes in Draft Action Plan to Implement UNDRIP: In June 2021, the BC government released a Draft Action Plan for consultation, with a view to supporting the implementation of the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) in the province. The action plan, which was developed pursuant to BC's *Declaration on the Rights of Indigenous Peoples Act* (DRIPA), identifies 79 proposed actions that the BC government will take to achieve the objectives of UNDRIP in cooperation with Indigenous peoples over the next five years. The Draft Action Plan proposes a number of potentially significant new measures, although these initiatives are only described at a high-level at this time and the precise magnitude of the potential changes remains to be seen. Some of the measures include: (i) a new framework for resource revenue sharing and other fiscal mechanisms to support Indigenous peoples; (ii) 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; (iii) reviews of various policies and programs relating to the stewardship of the environment, land and resources; (iv) establishing economic metrics to help evaluate progress as reconciliation is advanced; and (v) establishing a dedicated secretariat to coordinate the Province's reconciliation and UNDRIP compliance efforts and a new institution to provide support to First Nations in their work of nation and governance rebuilding and resolution of overlapping claims.

7. *Southwind v. Canada*, 2021 SCC 28
8. Southwind, para. 104
9. Southwind, para. 107

Public consultation on the Draft Action Plan has been completed. Once finalized, BC ministries will continue to work with Indigenous peoples on implementing the Action Plan and reporting on progress. It is expected that the Action Plan will be reviewed within five years and a new plan adopted at that time.

BC Amends Interpretation Act: On November 25, 2021, the BC government amended the *Interpretation Act* to require that provincial laws and laws must be construed in a manner that is consistent with UNDRIP and that does not abrogate or derogate from the rights recognized and affirmed in s. 35 of the *Constitution Act, 1982*. In discussing the intent of the legislation, the BC Attorney General clarified that the intention of the amendment is to provide "direction and assistance for the interpretation of laws when the meaning is not clear." He noted that the amendment does not incorporate UNDRIP into BC law and "if a court considers a provincial law to be inconsistent with the UN declaration, this amendment does not allow the court to read in, read down or find that law to be of no force or effect," noting that the substantive work of amending provincial laws and regulations was to be done in consultation with Indigenous groups.

Gitxaala Takes Legal Action to Bring BC *Mineral Tenure Act* into Compliance with DRIPA: In October 2021, the Gitxaala First Nation launched a judicial review in the BC Supreme Court, seeking to overturn seven mineral claims granted for exploration on Banks Island, which is located in Gitxaala traditional territory. The Gitxaala's position is that the granting of mineral claims without the consent, or even knowledge, of the Gitxaala in their traditional territory is a violation of DRIPA. The Gitxaala is seeking, among other things, an amendment of the provincial *Mineral Tenure Act* to bring it into compliance with DRIPA. In addition, the Gitxaala are seeking a declaration that DRIPA legally requires the BC government to consult and cooperate with Gitxaala (as well as other Indigenous peoples) about measures necessary to bring the *Mineral Tenure Act* regime into compliance with UNDRIP.

Federal Government Passes UNDRIP Legislation: 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. affirm UNDRIP as a universal international human rights instrument with application in Canadian law; and

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

The Act sets out a framework for how these two objectives will be achieved, namely by making Canada's laws consistent with UNDRIP and by preparing and implementing an action plan to achieve UNDRIP's objectives. The federal government has until June 21, 2023 to prepare the federal action plan. The government has established an UNDRIP implementation secretariat and will be engaging initially with Indigenous groups and then industry about measures to align federal laws with UNDRIP. Federal officials have repeatedly stated that the principle of free, prior, and informed consent (FPIC) in UNDRIP does not provide Indigenous groups with a veto but the federal government has not been clear about how specifically requirements relating to project consultation may change as a result. Instead, the federal government has made statements that are open to multiple interpretations and create continued uncertainty and varying expectations, such as the following:

> **"FPIC is a manifestation of Indigenous peoples' right to self-determination and is about the effective and meaningful participation of Indigenous peoples in decisions that affect them, their communities, and territories. FPIC is contextual in that there is no "one size fits all" for all Indigenous peoples in terms of what it means or how it is implemented on the ground. Operationalizing FPIC may require different processes or new creative ways of working together to ensure meaningful and effective participation in decision-making."[10]**

The one area where the federal government has provided some direction is the *Impact Assessment Act*. The government has indicated that legislation already aligns with the Declaration and does not need to be changed as a result of the federal UNDRIP legislation,[11] although the federal government's commitment to implement UNDRIP could still impact their interpretation and application of the *Impact Assessment Act*.

10. Government of Canada, Backgrounder – Natural Resources Sector, online: www.justice.gc.ca/eng/declaration/bgnrcan-bgrncan.html
11. Government of Canada, Implementing the United Nations Declaration on the Rights of Indigenous Peoples, online: www.canada.ca/en/impact-assessment-agency/programs/participation-indigenous-peoples/implementing-united-nations-declaration-rights-indigenous-peoples.html

Energy Litigation

Authors: Kyle McMillan, Reena Goyal, Samuel LePage, Sam Rogers

ALBERTA

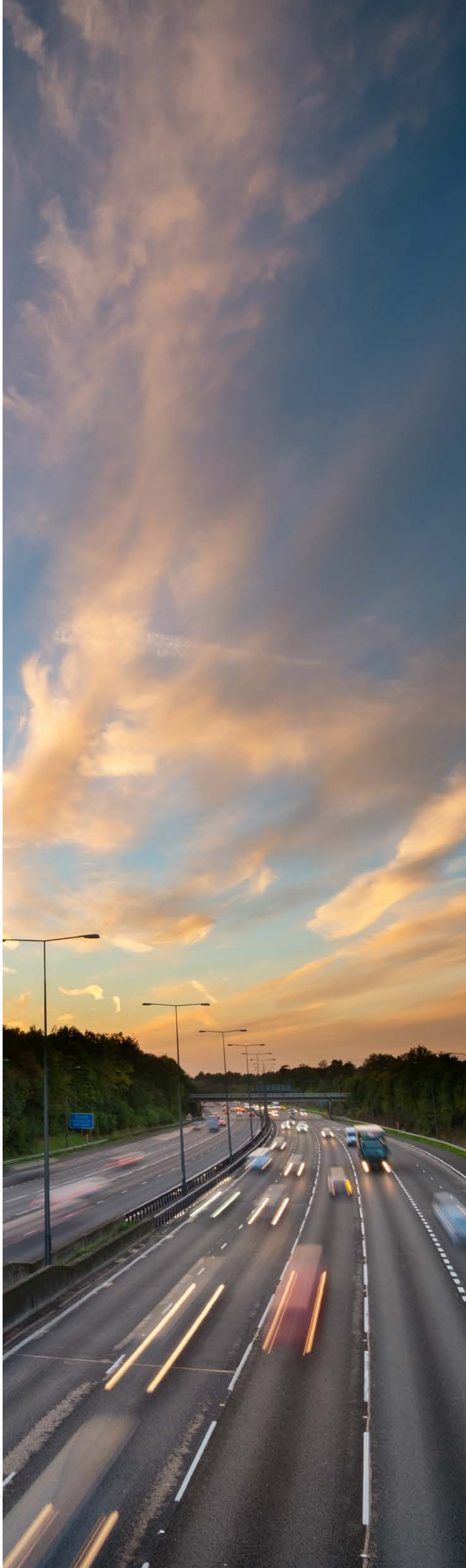
AltaLink Management Ltd. v. Alberta (Utilities Commission), 2021 ABCA 342

As discussed in more detail in our Aboriginal Law article, the Alberta Court of Appeal further clarified the nature of the public interest as it relates to decisions affecting First Nations in *AltaLink Management Ltd. v. Alberta (Utilities Commission)*. In November 2018, the Alberta Utilities Commission (AUC) conditionally approved transfers of electrical transmission assets between AltaLink Management Ltd. and limited partnerships controlled by two Alberta First Nations. The AUC applied a "no harm" test and determined that transfers were in the public interest, though it did not accept arguments to justify passing on the anticipated increased costs (about C$60,000 annually) to ratepayers. The appellants had argued before the AUC that savings arose from the lines having been optimally routed through First Nations lands (i.e. when they were initially constructed) and that intangible benefits arising from the partnership with the First Nations provided further justification.

The Court varied the decision of the AUC, and allowed the incremental costs to be recovered from ratepayers. The majority declined to address the constitutional questions presented, but Feehan, JA in his concurring opinion gave guidance to the Commission that "the Commission must take all relevant factors into account in determining the public interest" (para 126), including the honour of the Crown and the objective of reconciliation.

The Office of the Utilities Consumer Advocate v. Alberta Utilities Commission, 2021 ABCA 336

COVID-19 has changed the nature of proceedings in many ways, most commonly by necessitating remote hearings, but in also in less obvious (and perhaps more important) ways, one of which was at issue in *The Office of the Utilities Consumer Advocate v. Alberta Utilities Commission*. In March of 2020, an intensive proceeding to set the fair return for electrical rates for 2021 was underway when it was temporarily suspended because of the rapidly evolving market conditions at that time, brought about by COVID-19. That proceeding was intensive, involving extensive evidence, including expert evidence. The intensive process was not resumed, and in October 2020, the AUC extended the status quo for a fair return into 2021. In December 2020, the AUC initiated the proceeding to determine the fair return for 2022, and invited comments on substantive and procedural issues for that proceeding from interested parties, including the Office of the Utilities Consumer Advocate (Applicant). Ultimately, in March 2021, the AUC decided to set the fair return for 2022 at the same level as for 2021 because of the unusually high flux and uncertainty in the markets.



The applicant requested the AUC review and vary the March 2021 decision, but that application was dismissed. The applicant then sought leave to appeal from the Court of Appeal on the questions of: (i) whether the AUC erred in law or jurisdiction by failing to undertake its statutory obligation to set a fair return for 2022; and (ii) whether the AUC erred in law by breaching its duty of procedural fairness in setting a fair return for 2022. The Court considered the test for permission to appeal, and concluded that although the points on appeal were significant to the practice and the proceeding itself, they could ultimately not succeed. On the first question, the Court concluded that "[t]he Commission had discretion to employ an appropriate method and procedure given the COVID-19 pandemic. It was not required to utilize the intensive process it had used at times past; it could adopt an alternative approach, particularly in light of the COVID-19 pandemic" (at para 17), and that using that alternative approach could not amount to an error of law. On the procedural fairness question, the Court likewise noted the unprecedented conditions presented by COVID-19, and held that "the [Applicant] was not denied any procedural rights nor was it treated any differently than other parties in the proceedings" (at para 31). Leave to appeal was thus denied.

Alberta (Attorney General) v. British Columbia (Attorney General), 2021 FCA 84

Alberta (Attorney General) v. British Columbia (Attorney General) is another chapter in the years-long dispute between the governments of Alberta and British Columbia (BC) arising from a 2018 Alberta law, which BC asserts to be political retaliation for its lack of support for the Trans Mountain pipeline expansion project. That law, the *Preserving Canada's Economic Prosperity Act*, SA 2018, c P-21.5 (Act), colloquially known as the 'turn off the taps legislation', received royal assent on May 18, 2018 and was proclaimed into force on April 30, 2019. The Act authorizes Alberta's Minister of Energy (Minister) to create a licencing regime for the export of natural gas, crude oil, and refined fuels and for the Lieutenant Governor in Council to make regulations. Importantly, at all material times, no such licencing regime, nor any regulations, had been enacted under the Act.

As noted above, this case has a long procedural history, which includes actions before the Court of Queen's Bench of Alberta and the Federal Court. Before the Federal Court, BC sought a declaration that the Act was unconstitutional, and applied for an interlocutory injunction to prohibit the Minister from exercising her powers under the Act until the action had been finally resolved. BC's constitutionality arguments focused on sections 92A(2) and 121 of the Constitution Act, 1867. Alberta brought a motion to strike the federal action on the ground that it disclosed no reasonable cause of action. On September 24, 2019, the Federal Court granted BC's injunction and dismissed Alberta's motion to strike in *British Columbia (Attorney General) v. Alberta (Attorney General)*, 2019 FC 1195. The present case is an appeal of that Federal Court decision.

The Federal Court of Appeal allowed Alberta's appeal, dismissing BC's action and quashing the injunction. The Court considered the jurisdiction of the Federal Court under section 19 of the Federal Courts Act (RSC 1985, c F-7, s 19), a point on which Nadon, JA and the majority disagreed (though Nadon, JA's decision otherwise concurred with the majority). The majority held that the "controversies" that may be considered by the Federal Court under section 19 can include challenges to the validity of legislation, even including provincial legislation. The majority decided the appeal on the basis that declaratory relief was not appropriate, given that no Ministerial action had been taken under the Act, nor had regulations been enacted. In other words, BC's claim was premature, as the constitutional disputes that may arise as a result of the law "[have] yet to arise and may not arise" (paras 181 and 188). Interestingly, the government of Alberta allowed the Act to lapse under its own terms in 2021, though it enacted a new and similar (though not identical) act retroactively a short time later under the same name as the previous Act (SA 2021, c P-21.51). It seems that the constitutional uncertainty surrounding the new act, as well as the tension between the litigants, is likely to remain for the foreseeable future.

Ecojustice Canada Society v. Alberta, 2021 ABQB 397

In July 2019, the government of Alberta initiated an inquiry into anti-Alberta energy campaigns (Inquiry), under the *Public Inquiries Act* (RSA 2000, c P–39). Ecojustice Canada Society (Applicant) applied for judicial review in November 2019, alleging that the Inquiry is unlawful, and seeking to halt the Inquiry, or to restrict the publication of the report and other information. After delays in the hearing caused by COVID-19, and some interlocutory applications (which we discussed in this publication last year), the matter was heard and decided in this case.

The Applicant argued its application on three grounds. Firstly, that the Inquiry was brought for an improper purpose and was therefore outside the Lieutenant Governor in Council's legal authority under section 2 of the *Public Inquiries Act*; secondly, on the constitutional ground that certain matters identified in the order initiating the Inquiry (including the terms of reference appended thereto) are matters of exclusive federal jurisdiction; and thirdly that the political context of the Inquiry, certain terms of the order initiating the Inquiry and certain political donations made by the Inquiry commissioner give a reasonable apprehension of bias.

The Court rejected the first point, finding that the order initiating the Inquiry was "a reasonable exercise of Cabinet discretion" (para 45). On the second point, the Court considered the pith and substance of the order initiating the Inquiry, and concluded that it was "to discover and report on the existence of a perceived threat to Alberta's energy industry and explore ways of addressing that threat if considered necessary" (para 76). As such, the Court considered the appropriate head of power under the *Constitution Act*, 1867 to be s. 92(13) ("Property and Civil

Rights in the Province"), noting that it also concerned the province's legislative and proprietary powers over natural resources under s. 92A and s. 109. The Court reviewed certain federal heads of power, but was not convinced that the order could be brought within any of them. The constitutional ground of the application was dismissed. On the reasonable apprehension of bias question, the Court found the application to be premature, but would have held that no reasonable apprehension of bias existed in any event. As such, the application for judicial review was dismissed in its entirety. The final report of the Inquiry was released on July 30, 2021.

ONTARIO

Trillium Power Wind Corp. v. Ontario, 2021 ONSC 6731

The long running litigation arising from the 2011 offshore wind moratorium announcement is nearing its conclusion. Trillium Power Wind Corporation, a proponent of an offshore wind project in Lake Ontario, had originally commenced a broad claim against the Province in 2011 attacking the merits and the motives of the Province's moratorium. That claim was substantially narrowed by the Court of Appeal in 2013, and Trillium's only surviving claim was that Trillium had been specifically targeted by the Province when it stopped all off-shore wind development in the Province on the day Trillium's financing was

scheduled to close.

In the course of the litigation, a second claim was added for "spoliation" — destruction of evidence — based on the practice of the Premier's office (during Dalton McGuinty's tenure) of deleting emails and destroying handheld devices when personnel left the office. Given that the moratorium was a highly political decision, Trillium alleged that relevant documents had likely been destroyed when key decision makers left the Premier's office.

Both claims were dismissed in November 2021. Fundamentally Trillium was unable to make out its claims because there was no evidence that the Province knew about the closing date of Trillium's financing so it could not have been targeting Trillium when it announced the moratorium. In a similar vein, it was clear that the deletion of emails and other potentially relevant documents was done in the normal course of business and not done in contemplation of any litigation — a necessary element for any claim of spoliation according to the motions judge.

It is noteworthy that throughout his somewhat entertaining decision, the motions judge makes a number of sweeping conclusions about government power policy. Most notably, in reference to the *Green Energy Act*, asserting that that the "McGuinty government's policy accomplished none of its stated goals." Certainly some commentators may share his views, but it is unusual to see such commentary in a judicial decision.

Rayonier A.M. Canada Enterprises Inc. v. Independent Electricity System Operator

An interesting challenge to the Independent Electricity System Operator's ability to create market rules was launched in June 2020 by Rayonier A.M. Canada Enterprises Inc. (RYAM).

The IESO is the entity mandated under the *Ontario Electricity Act*, 1998 to, among other things, operate and administer the wholesale electricity markets in Ontario. At the time of the application, RYAM had a pulp and paper manufacturing company with facilities in Ontario, registered to withdraw electricity required for its operations from the IESO-controlled electricity grid.

Fundamentally Trillium was unable to make out its claims because there was no evidence that the Province knew about the closing date of Trillium's financing so it could not have been targeting Trillium when it announced the moratorium.

As a registered entity participating in the IESO-administered markets, RYAM was required to comply with the IESO's market rules — a collection of over 10,000 rules, manuals and procedures governing market participation. A subset of the IESO, namely its market assessment and compliance division (MACD), conducts investigations of market participants like RYAM to ensure participation is compliant with the IESO market rules.

In conducting its investigations, MACD relies on certain market rules[1] that purportedly permit it to compel the production of documents and information and to make non-compliance determinations. MACD's investigation findings can result in orders imposing financial penalties of up to C$1 million per occurrence; additional or more stringent record-keeping or reporting requirements; requirements to do or cease from doing such things MACD deems to be required; and/or suspension or termination of any future participation in the IESO-administered markets.

In its application for judicial review, RYAM challenged

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

the IESO's authority to create these market rules. RYAM argued in its application that although the IESO has the statutory authority to make market rules "governing the making of orders" as prescribed under subsection 32(2)(e) of the *Electricity Act*, that authority does not extend to establishing an investigatory regime, including one that requires mandatory preparation of evidence and documentary production.

Following the determination of certain procedural motions in September 2020 (2020 ONSC 5460), the application was dismissed earlier this year on consent without a final determination.

Notwithstanding the dismissal, the application raises important and unresolved issues regarding the IESO's purported authority to conduct and enforce market rules compliance investigations of its market participants. Time will tell if these issues are resurrected following the issuance of future investigation orders by the IESO/MACD against other market participants.

QUÉBEC

Gaspé Énergies inc. c. Ministre de l'Énergie et des Ressources naturelles, 2021 QCCQ 11747

In this groundbreaking decision, the Court declared illegal a regulatory provision adopted under the *Petroleum Resources Act* (PTA), a provincial Act, and declared illegal the decision of the Minister to refuse to issue a drilling permit to Gaspé Énergies Inc. (Gaspé). This case represented the first opportunity for a court to rule on the process followed by the Ministry of Energy and Natural Resources (MENR) in implementing the PTA. More broadly, this decision is of interest for any organization dealing with an administrative decision maker in a context where there are changes in government and public policy. Indeed, the contested decision was rendered a few months prior to the announcement by the Québec government that it was considering the option of permanently ending oil and gas exploration and production in Québec.

The decision pertains to the Galt Project, a light oil production project located approximately 20 kilometers west of the town of Gaspé. In July 2008, an exploration permit was issued by the Minister to Junex Inc. In 2018, a new regulatory regime for the hydrocarbon industry in Québec was introduced. In 2020, the permit was transferred from Junex to Gaspé and Gaspé filed an application for authorization to perform onshore exploratory drilling. This was, incidentally, the very first such application under the new regime. In support of its application, Gaspé filed an environmental study presenting the potential environmental impacts of the drilling, as well as detailing the proposed mitigation measures. It was not disputed that this study met all the MENR's requirements. Despite this, the Minister decided in October 2020 not to grant authorization to Gaspé based on s. 23 of the Regulation respecting petroleum exploration, production and storage on land (Regulation), which provided the Minister with a broad discretion to refuse an application.

Gaspé filed an application for judicial review of the Minister's decision. Before the Court, Gaspé argued that s. 23 of the Regulations was not pre-published in contravention of the government's and the Minister's duty to consult under the requirements of the *Regulations Act*. The Court agreed and overturned the Minister's decision because the Regulation was not enacted in accordance with the requirements of

the *Regulations Act*, which rendered it inoperative and unenforceable. Thus, the Minister's decision was invalid because it was based on an inoperative section. Given this conclusion, the Court wrote that it was not necessary to rule specifically on Gaspé argument that the Minister relied exclusively on political considerations.

Gaspé also argued that the Minister's decision was not sufficiently justified. The Court concluded that the Minister was required to give reasons in support of his decision, notably given the important impacts this decision had on Gaspé. In the presence of a duty to give reasons, the Court concluded that the Minister could not limit himself to indicating to Gaspé that he had not been convinced. He had to explain why. Therefore, the Court referred the case back to the Minister for a new decision on Gaspé's application for authorization for exploratory drilling.

Conseil des Innus Pessamit c. Hydro-Québec, 2020 QCCS 4345

In this decision rendered at the very end of 2020, the Superior Court of Québec granted in part an injunction sought by the Innu Council of Pessamit to stop Hydro-Québec from raising to its maximum limit the level of the reservoir supplying the Daniel-Johnson Dam and Manic-5 Generating Station, a major hydroelectricity facility with a capacity of 2,660 MW located on the Manicouagan River in northern Québec. The Court concluded that under the very specific circumstances of the case, Hydro-Québec needed to obtain new governmental authorizations before raising the reservoir level up to the maximum height previously authorized. However, the Court only imposed a limit already accepted by Hydro-Québec at trial.

Hydro-Québec occupies the site under validly issued leases or permits of occupation since the 1960s. The dam was designed for a maximum use level of 359.66 meters but the level has never exceeded 354 meters since 1985. Starting in 2016, Hydro-Québec began raising the level and wanted to reach the dam's maximum operating level of 359.66 metres "as early as 2019."

Notified of Hydro-Québec's intention to raise its reservoir, the Innu Council of Pessamit presented an application for an permanent injunction to limit the retention level. They invoked the breach of various environmental laws, both federal and provincial, as well as the Charter of Human Rights and Freedoms. The Innu Nation argued that its members often visit, hunt and fish at the reservoir, and are thus affected by the proposed raising. It sought an order that the maximum elevation not exceed 353 meters until the impacts have been examined. Hydro-Québec retorted that it had the right to use the reservoir up to the maximum height previously authorized, i.e. 359.66 metres, hence its challenge. A few days before the start of the trial, Hydro-Québec announced that it has agreed not to exceed the level of 355.95 meters (which is still 2 meters more than the level sought by the Innu Nation) until the governmental authorities decide on applications for approval that it will initiate.

The issue the Court had to decide was whether Hydro-Québec needed to obtain new governmental authorizations before raising the reservoir level up to the maximum height previously authorized. The Court concluded that Hydro-Québec's decision to undergo the governmental authorization process made it clear that that the environmental acceptability of the raising should be left to the governmental authorities. This non-interference by the Court was all the more important given that some of the laws invoked are under federal jurisdiction. As for the limit imposed, the Court concluded that the Innu Nation failed to present a convincing justification for the limit it sought, and that it was inappropriate to go below the limit accepted by Hydro-Québec, i.e. 355.95 metres.

SMRs: Renewed Support for Nuclear Power in Canada

Authors: Audrey Bouffard-Nesbitt, Stephen Furlan, Emma Holmes, Heather Maki and Seán O'Neill

Introduction

Nuclear power is increasingly being accepted as one of the clean energy technologies required to achieve emissions reduction targets in Canada and to meet global climate goals. According to the International Energy Agency, climate change initiatives will fall short without nuclear power as part of the electricity supply mix. Unsurprisingly, 2021 witnessed expanding interest and support for small modular reactors (SMRs) both globally and across Canada. SMRs are nuclear reactors that produce 300 megawatts of electricity or less and are designed to be constructed on a modular basis to achieve economies of scale and reduce overall costs. A single SMR of about 300 megawatts can prevent between 0.3 – 2 megatonnes of carbon dioxide emissions per year. Given that Canada is one of over 120 countries committed to achieving net-zero emissions by 2050, SMRs may be the key to making nuclear power a viable part of Canada's clean energy future.

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SMR ACTION PLAN AND CANADIAN UPDATES

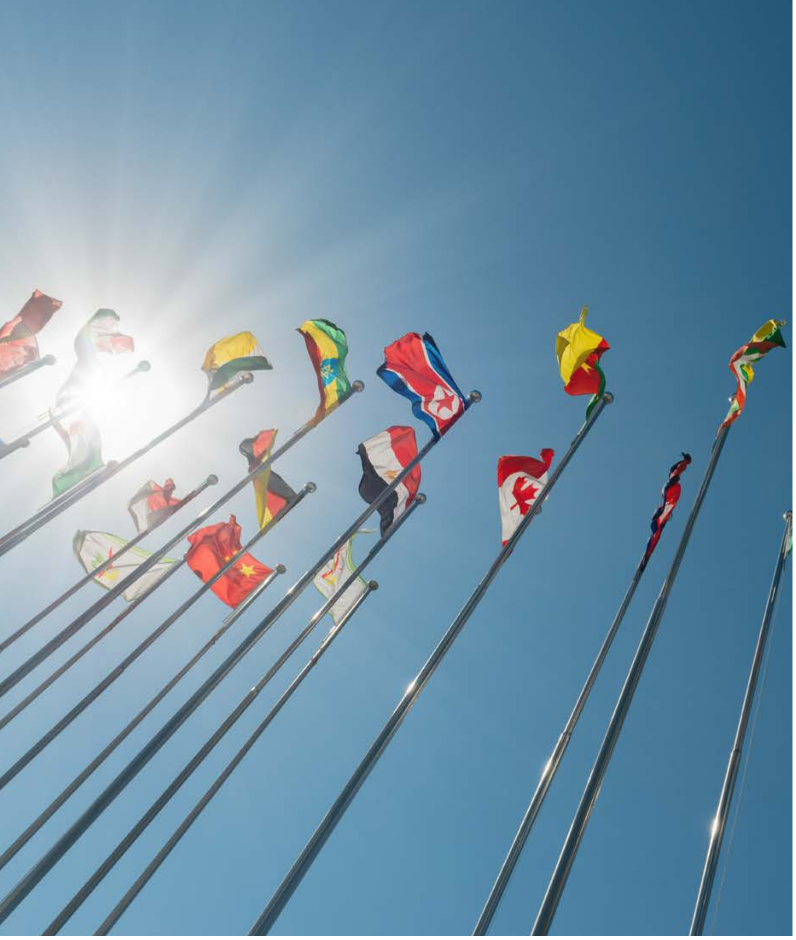
Since Canada's release of the Small Modular Reactor Action Plan (SMR Action Plan) in December 2020 (discussed further here), Canada has seen the progression of many actions to advance the safe and responsible development and deployment of SMRs. Completed actions include investments in technology, provincial governments and territories undertaking feasibility studies, engagement with the public and Indigenous communities, international partnerships and market engagement, and Alberta becoming the fourth province to sign the inter-provincial memorandum of understanding (Inter-Provincial MOU) on SMR development. In last year's publication, we indicated that sustained government support, patient venture capital and public acceptance would be required to make Canada competitive on the world stage. We are pleased to note that, since the release of the SMR Action Plan, steps have been taken to begin to address some of these issues.

One important initiative in public engagement is the December 15, 2021 announcement that the federal government will invest C$800,000 in the First Nations Power Authority to create a national Indigenous Advisory Council. This investment is part of the SMR Action Plan and its purpose is to support Indigenous communities in exploring the potential of SMRs to provide emissions-free energy for a wide range of applications, including electricity generation in remote communities. The advisory council, composed of individual First Nations, Métis and Inuit members from Saskatchewan, New Brunswick, Ontario, Alberta and the territories, will enable Indigenous communities to be more informed about the role SMRs could play in addressing energy challenges and potential opportunities from development and deployment.

Other funding updates from 2021 include the following:

- In February 2021, the Premier of New Brunswick, Blaine Higgs, announced an additional C$20 million in funding towards SMR development, specifically for the advancement of ARC Nuclear Canada Inc.'s (ARC Canada) ARC-100 sodium-cooled fast reactor, one of the two designs being studied as part of the SMR vendor cluster established by New Brunswick Power (NB Power), Moltex Energy Canada Inc. (Moltex Energy) and Advanced Reactor Concepts, the parent company of ARC Canada, at the Point Lepreau nuclear site in New Brunswick. The funding is conditional on ARC Canada providing C$30 million of matching funds. According to ARC Canada's chairman, Donald Wolf, the funding will play an integral role in the development of SMRs in the late 2020s. ARC Canada is beginning the second phase of the Canadian Nuclear Safety Commission's (CNSC) Vendor Design Review Process of the ARC-100, which is expected to be operational by 2029.
- In March 2021, the federal government announced C$50.5 million in funding through the Strategic Innovation Fund and the Regional Economic Growth through Innovation program to advance the design of Moltex Energy's 300-megawatt Stable Salt Reactor – Wasteburner (SSR-W) and WAste To Stable Salt facility. The SSR-W is the second design being developed at the Point Lepreau nuclear site and is expected to be operational by the early 2030s.
- The federal government also announced the following investments through the Atlantic Canada Opportunities Agency:
  - Almost C$5 million to help NB Power prepare the Point Lepreau site for SMR deployment and demonstration; and
  - C$561,750 to help the University of New Brunswick expand its capacity to support SMR technology development in New Brunswick.
- The 2021 Canadian Federal Budget (Budget), released on April 19, 2021, contained green policy tools that could support and enable the development of the nuclear industry and SMRs. Particularly, the Budget provided a tax break for manufacturers of zero-emission technologies; further funding to the Strategic Innovation Fund's "Net Zero Accelerator"; C$5 billion in funding to a "Green Bond Framework" which would allow investors to invest in "Green Bonds"; and C$1 billion in funding over five years to increase funding to "Clean Tech Projects".

Significant developments by Canadian companies have reduced the expected timelines for operational SMRs in Canada. On May 19, 2021, Global First Power Ltd.'s (Global First Power) Micro Modular Reactor (MMR™) Project achieved a licensing milestone, bringing it closer to constructing and operating Canada's first SMR. The project will use the MMR® technology designed by Ultra



Safe Nuclear Corporation and will be capable of producing 15 megawatts of thermal output, which can be converted to 5 megawatts of electrical power. MMR® technology is an economically competitive alternative to greenhouse gas-emitting diesel power and heat generation with a smaller footprint, which according to Global First Power's CEO, Robby Sohi, can help meet Canada's energy needs, specifically for heavy industry (such as mining) and remote communities. Global First Power fulfilled the requirements under its Licence to Prepare Site, enabling it to proceed to the formal phase of the CNSC's licensing process. The MMR™ is scheduled for first power in 2026.

Most significantly, Ontario Power Generation Inc. (OPG) reached its stated milestone of down-selecting a developer to deploy an SMR at the Darlington New Nuclear site, choosing GE Hitachi Nuclear Energy (GE Hitachi) as its developer. As part of "Stream 1" of the SMR project proposals described in the SMR Feasibility Study (described below), OPG and GE Hitachi will work together on all aspects of the SMR engineering, design and permitting with a goal to complete construction of Canada's first-of-a-kind commercial, grid-scale SMR as early as 2028 and to subsequently achieve the "fleet approach" to pan-Canadian SMR deployment.

At the 2021 United Nations Climate Change Conference (COP26), Prime Minister Justin Trudeau expressed support for nuclear power, stating that Canada will need every alternative pursued and explored fully as it tries to achieve its clean energy goals, including exploring nuclear power. He indicated that a number of provinces are working hard on developing SMRs and he is certain that those efforts will continue to evolve, pointing to Canada's strong history in nuclear energy.

> **The SMR Feasibility Study concluded that the development of SMRs would support domestic energy needs, curb greenhouse gas emissions and position Canada as a global leader in the industry.**

One such example of provincial commitment to developing SMRs is the addition of Alberta as the fourth signatory to the Inter-Provincial MOU on April 14, 2021. In the Inter-Provincial MOU, the provinces of Alberta, New Brunswick, Ontario and Saskatchewan agreed to collaborate on the advancement of SMRs as a clean energy option to address climate change and regional energy demands, while supporting economic growth and innovation. On the same day, the provinces released the report, *Feasibility of SMR Development and Deployment in Canada* (SMR Feasibility Study), completed by power utilities in New Brunswick, Ontario and Saskatchewan. The SMR Feasibility Study was formally requested when the Inter-Provincial MOU was first signed in December 2019. The SMR Feasibility Study concluded that the development of SMRs would support domestic energy needs, curb greenhouse gas emissions and position Canada as a global leader in the industry. The SMR Feasibility Study anticipates that 4th generation advanced SMRs designed in New Brunswick can begin to be deployed in support of industrial needs in Alberta and Saskatchewan as early as 2030. The next action identified in the Inter-Provincial MOU is the development of a joint strategic plan to be drafted in collaboration by the four governments.

HOW DOES CANADA MEASURE UP AGAINST THE INTERNATIONAL COMMUNITY?

US updates

On June 24, 2021, Canada and the US entered into a revised memorandum of understanding (Revised MOU) (discussed further here) to create a framework for cooperation on energy between the Department of Natural Resources of Canada and the US Department of Energy (DOE). Under the

Revised MOU, the parties committed to sharing knowledge and exploring options for enhancing cooperation in areas of mutual interest, such as those related to nuclear energy policies, technologies and fuel cycles.

While Canada increased its funding to nuclear and SMR projects in 2021, it still lags behind the US. For example, on October 13, 2020, the DOE announced that, as part of its Advanced Reactor Development Program (ARDP), it had selected two US-based teams, TerraPower LLC and X-energy, LLC to receive a total of USD$160 million in initial funding to build two advanced nuclear reactors that can be operational within seven years. The DOE plans to invest a total of USD$3.2 billion in the two projects over those seven years, subject to availability of future appropriations by Congress. As highlighted above, the Canadian federal government invested approximately C$52.3 million to private companies, universities, and the First Nations Power Authority. On top of this, C$20 million was invested to Terrestrial Energy in 2020, totalling approximately C$72.3 million in comparison.

Since the DOE announcement, the US has taken further funding initiatives that illustrate its commitment to energy innovation and nuclear technology as a significant component to achieving climate change goals. On April 27, 2021, the US Department of State committed an initial USD$5.3 million investment to the *Foundational Infrastructure for Responsible Use of Small Modular Reactor Technology*. The program promotes the responsible development and deployment of SMRs and provides capacity-building support to partner countries as they develop their nuclear energy programs.

The DOE plans to invest a total of USD$3.2 billion in the two projects over those seven years, subject to availability of future appropriations by Congress. As highlighted above, the Canadian federal government invested approximately C$52.3 million to private companies, universities, and the First Nations Power Authority. On top of this, C$20 million was invested to Terrestrial Energy in 2020, totalling approximately C$72.3 million in comparison.

Subsequently, on November 3, 2021, the US announced at COP26 that it will provide USD$25 million in support towards expanding access to clean nuclear energy as part of the program, the "Nuclear Futures Package." As part of this initiative, the US is partnering with Poland, Kenya,

Ukraine, Brazil, Romania and Indonesia, among others, to support progress on meeting their nuclear energy goals. Passage of the *Infrastructure Investment and Jobs Act* by Congress on November 15, 2021 earmarked an additional USD$2.5 billion for the ARDP.

Other international updates

Following a number of recent developments in the UK, Argentina and China, the UK published its "Net Zero Strategy: Build Back Greener" on October 19, 2021. Alongside Canada, the UK is pursuing net zero carbon emissions by 2050 and net decarbonization specifically with respect to its electricity system by 2035. The UK aims to use nuclear power as a significant part of its strategy to achieve this goal. The goal is that SMR designs will complete regulatory approval for UK deployment by 2025 and the first SMR and advanced modular reactor demonstrators will be deployed by 2030. As part of the UK's consideration of large scale and advanced nuclear technologies, the UK government announced a new £120 million Future Nuclear Enabling Fund to provide specific support in relation to barriers to entry. The UK government is also providing funding for SMR design through their £385 million Advanced Nuclear Fund.

British companies have been pursuing the deployment and commercialization of SMR technology with government assistance. For example, prior to announcing its new business named Rolls-Royce SMR Limited, Rolls-Royce secured £210 million in funding from the UK government, matched by more than £250 million in private investment including from the Qatar Investment Authority. Rolls-Royce is leading a UK SMR consortium to build 16 SMRs with an intention to complete its first unit in the early 2030s and to build up to 10 units by 2035.

France recently announced a five-year investment plan, "France 2030", aimed at placing the country as a world leader in green hydrogen by 2030 and building new SMRs. Additionally, the French government pledged €1 billion to invest in SMRs and other technologies, placing Électricité de France SA, the state-controlled utility company, in the race to develop SMRs.

HOW CAN SMRS BECOME A VIABLE PART OF CANADA'S CLEAN ENERGY FUTURE?

The future viability of SMRs in Canada will depend on, among other things, their cost-effectiveness, the regulatory framework for their development, and public perception and acceptance. With respect to cost-effectiveness, SMRs have the potential to be more cost effective than conventional nuclear. To ensure that SMRs are cost-competitive, a fleet approach is envisioned. SMRs are designed to be mass produced, lowering overall unit costs to realize economic benefits. However, this will require the market for a single design to be relatively large, which emphasizes the need for a market beyond the Canadian domestic market.

Generally, there are no major impediments to the licensing of SMRs for deployment in Canada. However, regulating SMRs in the same manner as the few, large, centralized nuclear generating stations that only three Canadian provinces have ever sited could result in increased timelines and uneconomic cost escalation for SMR project approval. SMRs are designed with enhanced safety features, more modular construction approaches for ease of installation, operation and removal and potentially decentralized, load-following deployment. Such features should inform the licensing requirements and regulatory framework without compromising the safety case.

With respect to public perception and acceptance, historically, opposition to nuclear power has stemmed from the potential harm that can be caused by a nuclear accident despite the strong safety records of most nuclear plants. SMRs, with their smaller size, passive safety, and reliance on passive circulation, are designed to offer a more inherently safe design than traditional reactors. Further, SMRs are adaptable to different applications, ranging from generating electricity to burning nuclear waste. To enable the viability of SMRs, governments and proponents will need to cultivate public trust. A critical step will be demonstrating the inherent safety features presented by SMR designs. Additionally, proponents must pay close attention to the preferences of host communities and ensure there are opportunities for local and regional job creation such that SMRs are attractive to local communities. As noted above, Indigenous consultation and acceptance will be an integral aspect of such a trust building exercise. Highlighting the generally high support and satisfaction of communities that host existing Canadian nuclear generating stations may assist as well.

CONCLUSION

Alongside many global players, Canada is working to promote and support the expanded use of nuclear power and SMRs through funding initiatives and partnerships. This action will be beneficial in decarbonizing and helping Canada achieve its net-zero emissions target by 2050. Canadian companies are favourably situated to become one of the first to develop commercially viable SMR technology with projected timelines analogous to their leading international counterparts. Conservative estimates place the potential value for SMRs in Canada at C$5.3 billion between 2025 and 2040. The global market, estimated at C$150 billion between 2025 and 2040, shows a potential export market for Canada.

DERs / Storage Overview

Authors: Reena Goyal, Will Horne, Kerri Lui and Jason Phelan

Canada's Evolving Electricity Grids: Recent Developments in Distributed Energy Resources

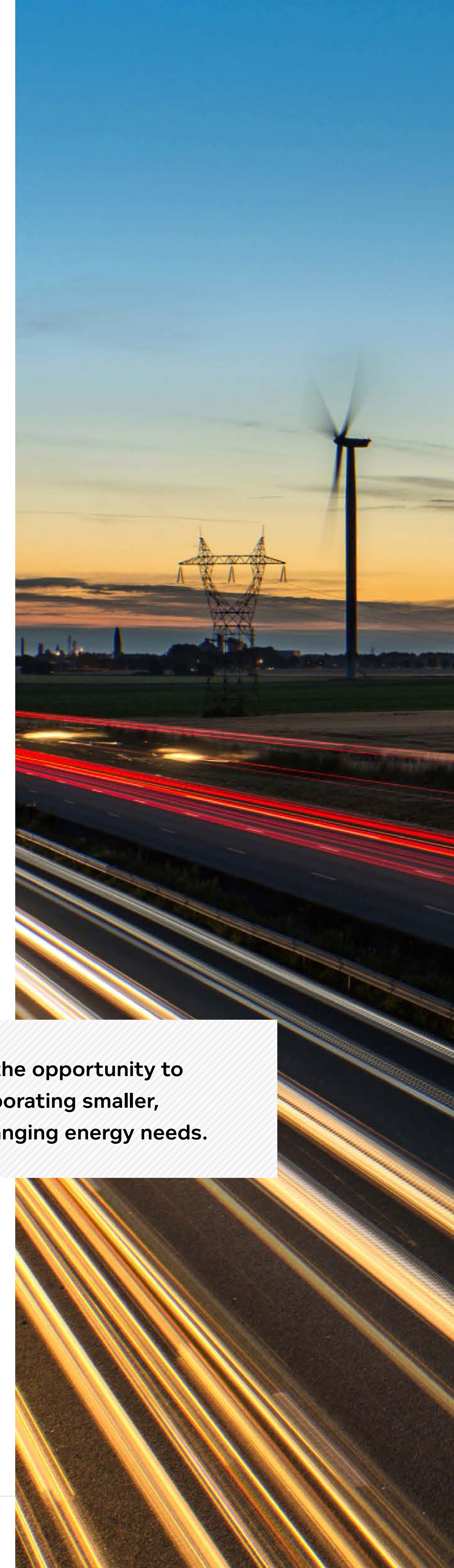
THE EXPANDING SCOPE AND CHALLENGES ARISING FROM DERS

Distributed Energy Resources (DERs) are increasingly offering the opportunity to create a more efficient and sustainable electricity grid by incorporating smaller, decentralized resources that are dynamic and responsive to changing energy needs.

These resources (which encompass distributed energy storage) are leading to increasing expectations for Canada's electricity grids, and the regulatory regimes that govern them, to be receptive and adaptable. DERs, and storage in particular, are hailed for the myriad of benefits they already offer (or could in theory offer) to energy stakeholders, from grid balancing, to peak shaving, to reducing the need for expensive infrastructure, to overall reliability — the list goes on.

Not only are the potential benefits substantial in their own right, but virtually every electricity stakeholder — including generators, transmitters, industrial loads, and ratepayers — stand to benefit from the deployment of DERs in one way or another.

> **Distributed Energy Resources (DERs) are increasingly offering the opportunity to create a more efficient and sustainable electricity grid by incorporating smaller, decentralized resources that are dynamic and responsive to changing energy needs.**



While DERs representing a significant amount of capacity are already online (including, for example, in Ontario), there is a long way to go before the traditional centralized grids that continue to dominate Canadian electricity grids can claim to be fully leveraging DER potential, from both a regulatory and market perspective.

Whether Canadian regulators and system operators will go to the hassle of maximizing DER integration is an open question. Notwithstanding this continuing uncertainty, the following is an overview of some recent developments in the space, particularly as they relate to the

increasing deployment of energy storage across Canadian provinces and the regulatory conditions that are enabling or impeding development.

OVERVIEW OF DEVELOPMENTS IN CANADA

Québec

Hydro-Québec continuing to make moves in DER development

EVLO Energy Storage Inc. (EVLO), Hydro-Québec's subsidiary launched in 2020, designs, sells and operates sustainable energy storage systems, and has developed lithium iron phosphate batteries used in energy storage systems. In 2021, EVLO announced its most advanced storage system to date: a 1-MWh battery storage designed for large-scale projects mainly aimed at power producers, transmission providers and distributors. During the same period, EVLO entered into a reseller agreement with Nuvation Energy, a provider of battery management systems and energy storage engineering services to battery manufacturers and power producers. Such agreement will allow Nuvation to resell the energy storage system developed by EVLO, which would then be built using Nuvation's battery management systems.

The technology developed by EVLO has been implemented in some of Hydro-Québec's projects and has seen its range of applications grow, including:

- Deployment of a 20-MWh battery energy storage system during work being carried out on a transmission line in the municipality of Parent, Québec, a remote community which is supplied by a single transmission line. The storage system, which will be recharged overnight, will supply the residential and commercial customers of Hydro-Québec with electricity during the day while the line is de-energized for work to be performed on the transmission line. The system will remain in place once the work is completed to act as an auxiliary source of energy in the event of a power outage. It is a solution to replace generators running on fossil fuels that would have otherwise been used during the transmission line work.
- The energy microgrid project located in Lac-Mégantic's new downtown area was inaugurated in 2021 and is an example of the implementation of DERs. The microgrid is equipped with solar panels and energy storage units, and can operate independently from Hydro-Québec's main grid. Energy surpluses generated by the microgrid can be fed back to the main grid. Hydro-Québec hopes to use the technology and expertise developed as part of the Lac-Mégantic project to decarbonize its off-grid

systems, which are located in remote areas that mostly remain fossil-fuel dependent.

– A behind-the-meter application of EVLO's technology in an office building in Blainville, Québec, to help manage peak energy consumption.

Furthermore, in its recent requests for proposals launched in December 2021 in respect of a 480 MW block of renewable energy and a 300 MW block of wind power, with expectations that energy delivery would begin no later than November 30, 2026 (as further described in our Quebec Regional Overview), Hydro-Québec has specified that the proposed projects can be combined with energy storage projects.

It is noteworthy that the energy storage component of a proposal will be considered by Hydro-Québec on a number of levels. The following project details must be included in a proposal: (i) the daily profile of the power available through the energy storage system for the winter period, with certain minimum requirements to be met in respect of guaranteed and fixed power availability (a minimum of 100 hours for the winter period and a minimum of three hours per day during peak winter periods), (ii) the installed capacity of the energy storage component, and (iii) such component's contribution in the determination of the cost of electricity for the project.

Ontario

The OEB and DERs – background

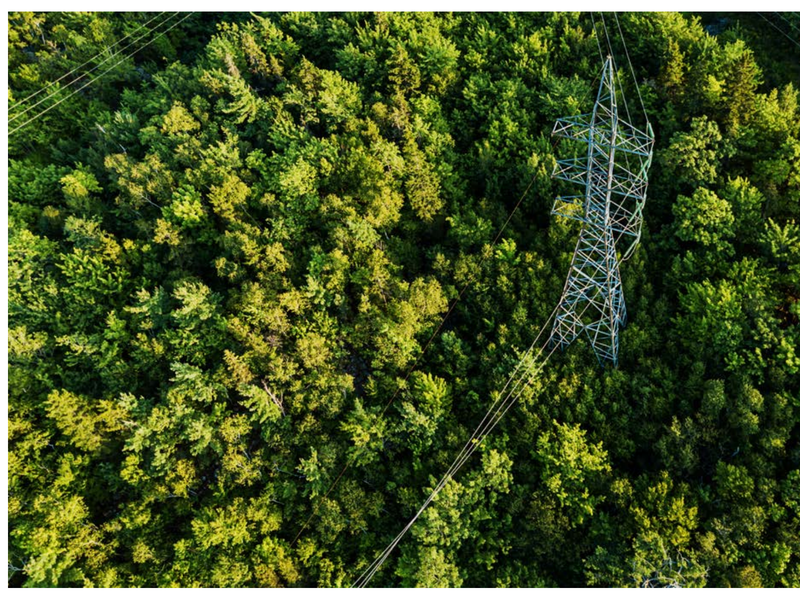
In 2017, the Ontario Energy Board (OEB) issued its *Strategic Blueprint: Keeping Pace with an Evolving Energy Sector* (Strategic Blueprint) which set out its commitment to modernize its approach to regulation in order to keep pace with an evolving energy sector. The Strategic Blueprint reflects the OEB's recognition of significant changes underway and sets out four strategic goals:

– Utilities are delivering value to consumers in a changing environment;
– Utilities and other market participants are embracing innovation in their operations and the products they offer consumers;
– Consumers have confidence in the oversight of the sector and in their ability to make choices about products and services; and
– The OEB has the resources and processes appropriate for the changing environment.

In 2018, the OEB established an Advisory Committee on Innovation to help determine whether and how to adapt its regulatory framework to meet the above listed goals. In January 2019, the OEB held a public Stakeholder Forum to receive feedback on how it should proceed with initiatives to support the evolution of the sector. In response to the feedback received, the OEB initiated two integrated consultation processes: *Utility Remuneration* (EB-2018-0287) and *Responding to Distributed Energy Resources (DERs)* (EB-2018-0288). The OEB then held two further stakeholder meetings in September 2019 and February 2020, the latter at which the OEB facilitated the presentation of expert studies it commissioned to assist in confirming the scope and next steps for the Utility Remuneration and Responding to DERs initiatives.

Following further stakeholder feedback on these expert studies, the OEB announced in March 2021 that it would be effectively amalgamating the two initiatives into a single consultation entitled *Framework for Energy Innovation: Distributed Resources and Utility Incentives* (EB-2021-0118).

During this 2017-2021 period of lengthy public consultation conducted by the OEB, the Independent Electricity System Operator (IESO) has been steadfastly developing a framework for DERs integration at the wholesale level. The IESO's work began with a series of white papers including conceptual models for DER participation (released October 2019), non-wire alternatives using energy and capacity markets (released June 2020), and exploring expanded DER participation in the IESO-administered markets (draft released in November 2020). In addition, the IESO commissioned its own report from third party



consultant ICF on the development of possible transmission-distribution frameworks that facilitate DER market participation at both the wholesale or distribution levels and/or a hybrid participation model.

Current status

The recommendations and conclusions from these papers and report ultimately formed the framework for the IESO's DER Roadmap launched in June 2021, establishing objectives, initiatives and timing for DER integration. The final version of the DER Roadmap objectives and proposed timelines was presented at an IESO stakeholder engagement webinar on October 20, 2021.

The DER Roadmap is in turn being used to inform the IESO's contemporaneous Enabling Resources Program (ERP) engagement, which will purportedly produce a five to ten year plan to enable, among other resource types, distributed resources to provide services that they currently are not. Most recently the IESO announced its draft ERP work plan which will ultimately inform and be incorporated as part of the IESO's broader DER Market Vision and Design Project for the integration of competitive DER market participation.

The DER Market Vision Project phase will explore new, "foundational" participation models for DER integration into wholesale markets and will identify the criteria for more sophisticated models that will form the basis of future DER integration efforts. The second Market Design Project phase will design and implement the foundational participation models from the first phase.

Passing the DER buck?

Notably, the first phase of the project includes a recently-issued joint IESO/OEB call for DER innovation pilot projects or research to be funded through the merged OEB Innovation Sandbox and IESO Grid Innovation Fund (~C$9.5 million annual budget). It seems, then, that the OEB has effectively jumped on the IESO bandwagon rather than continuing to independently pursue its own policy mandate for DER integration even though DERs are primarily connected at the distribution level and not the wholesale level.

After all, DER integration falls outside the legislative mandate of the IESO, and should arguably instead continue to remain within the scope of policy development and regulatory oversight of the OEB. Indeed, the closest IESO legislative object found under the *Electricity Act,* 1998 is subsection 6(1)(n) which provides that the IESO is required "to engage in activities *in support of* system-wide goals for the amount of electricity to be produced from different energy sources" (italics added). This language suggests that, at best, the IESO is only mandated to provide a supporting or facilitating role with respect to DER integration and not to usurp the lead role in "[facilitating] innovation in the electricity sector" which properly belongs to the OEB under subsection 1(1)4 of the *Ontario Energy Board Act,* 1998.

Furthermore, and despite the IESO continuing to (at least co-) lead the charge on DERs, new demand response DERs are being effectively left behind in terms of participation in near-term contract procurement opportunities. Most recently, the IESO confirmed at its December 16, 2021 stakeholder engagement sessions that its ERP work plan — and therefore ultimately the DER Market Vision and Design Project — will be more immediately geared toward the integration of storage and proposed hybrid generation-energy storage models (namely, (i) Interim Storage Model + Generator Resource (ISM+G), and (ii) the Integrated Hybrid Model) over the integration of other new potential load side

or demand response DER participation models.

This information has been met with frustration by the demand response community — aggregators and otherwise — as it effectively means that new DER participation models will be unable to compete for IESO contract procurement opportunities before the 2026-2029 time frame. DER developers and aggregators claim there to be ~5,000 MWs of potential capacity currently available to be deployed at the wholesale level in Ontario but for regulatory lag; the IESO estimates this amount to only be ~200 MWs. Irrespective, time will tell if the IESO will evolve its ERP work plan to allow for new demand side participation models to compete alongside existing DER models in the current medium-term RFP and anticipated long-term RFQ and RFP to be released in 2022/2023.

Alberta

Energy storage projects in Alberta have been accelerating throughout 2021. Following completion of Alberta's first transmission connected energy storage project in September 2020, three more energy storage projects have been completed and are participating in Alberta's electricity market. As of the date of publication, there are over 17 energy storage projects listed within the AESO's connection queue.

On November 4, 2021, the Government of Alberta announced C$25 million in financial support for solar-plus-storage and pumped hydro energy storage as part of a C$176 million package that will also give funding to the oil and gas industry.

In continuing to implement the Energy Storage Roadmap, the Alberta Electric System Operator (AESO) and the Government of Alberta implemented the following key developments for the integration of energy storage:

- **AESO's Long-term Energy Storage Market Participation Draft Recommendation Paper:** In February 2021, the AESO released this paper examining four identified areas requiring clarification, consideration or amended or new ISO rules to integrate energy storage into Alberta electricity market. As discussed in detail within the report, the AESO made the following recommendations in the four areas identified:
  - ISO rules to allow for hybrid asset configurations; however, include the variable energy resource block mechanism to determine the allowable dispatch variance for those assets.
  - Optional full-range participation of energy storage using the linked-assets submission mechanism for those participants that choose to submit the full operational range of the resource; and a must-communicate charging levels requirement for participants that choose not to participate with their full-range.
  - "State of charge" to be defined in the ISO Rules as an aggregate measurement from the site as a percent charge ranging from zero to one hundred percent that will be provided to the AESO and updated in real-time via supervisory control and data acquisition (SCADA) systems; however, this information would not be reported publicly.
  - Sites with controllable inflows or outflows to be required to submit two offer blocks during commissioning and that those offer blocks include an offer with a price of zero dollars and an offer at the price cap.
- **Bill 86:** On November 17, 2021, as part of Alberta's Recovery Plan, Alberta introduced Bill 86: the *Electricity Statutes Amendment Act*, 2021 (Bill 86). If passed, this Act will amend the laws and regulations regarding energy storage, electricity sale and transmission in Alberta, including the *Alberta Utilities Commission Act* (AUCA), the *Electric Utilities Act* (EUA) and the *Hydro and Electric Energy Act* (HEAA). If passed, the amendments are expected to be finalized in 2022. Highlights of the proposed amendments include:
  - The integration of energy storage into Alberta's interconnected electricity system (grid) in both the competitive electricity market and the transmission and distribution system.
  - A statutory definition for energy storage. The definition proposed is any "facility that uses any technology or process that is capable of using electric energy as an input, storing the energy for a period of time and then discharging electric energy as an output."
  - Amendments to the AUCA create a separate category for energy storage facilities, for which approval by the Alberta Utilities Commission (AUC) is required.
  - Allowing distribution and transmission companies to use energy storage facilities to provide utility service under certain circumstances.
  - Allowing unlimited self-supply with export to the grid (i.e. on site generation with ability to sell excess power to the market).

- Building on the AUC Distribution System Inquiry by (i) requiring distribution transmission owners (DFOs) to prepare electric distribution system plans; and (ii) allowing competitive forces to develop distributed energy resources.
- Distribution owners will be required to prepare electric distribution system plans in accordance with future regulations.

– **Amendments to the ISO Rules:** As part of Phase 2 of the AESO's Energy Storage Roadmap Integration Activities (set out in the AESO's Energy Storage Roadmap), the AESO is expected to commence the Energy Storage Rule Amendment process in 2022. The AESO intends to develop draft proposed amendments to the ISO Rules. These amendments are anticipated to impact more than 30 ISO rules, including those addressing: market participation, fast frequency response, technical, qualification and connection requirements, technology agnostic application of requirements, adjustment to load on the margin and opportunities to reduce red tape. Draft ISO Rule amendments are anticipated to be ready for stakeholder feedback in Q1 2022.

– **Bulk and Regional Tariff Design:** In October 2021, the AESO completed 19 months of engagement for the Bulk and Regional Tariff Design, intending to redesign the ISO tariff to ensure rates appropriately recover sunk costs of the current transmission system and send efficient price signals to guide investment and consumption decisions. The AESO submitted its Bulk and Regional Rate Design and Modernized DOS Rate Design Application (Application) to the AUC on October 15, 2021.

In response to an increased number of System Access Service Requests submitted by energy storage resources, the AESO examined the appropriate treatment of energy storage resources under the ISO tariff. The AESO did not propose a separate rate for energy storage resources or other special relief for energy storage resources under the ISO tariff. In the Application, the AESO maintained that energy storage resources should continue to pay for the costs of the transmission system based on the flows of electricity and the associated benefits by charging the owner of an energy storage resource Rate STS when electricity is injected onto the transmission system and Rate DTS when electricity is withdrawn from the transmission system.

Given the flexible nature of energy storage resources when withdrawing electricity from the transmission system, the AESO's Application recognizes that energy storage resources may qualify for the same opportunity services under the ISO tariff as other Rate DTS market participants, specifically, Rate DOS. Rate DOS is an existing non-firm rate that allows additional use of available transmission capacity that would not otherwise be used. The AESO is seeking to modernize Rate DOS (Modernized DOS) by removing barriers to entry to Rate DOS to enable owners of energy storage resources to utilize spare transmission system capacity not otherwise used. If approved, this would be a partial shift from the AESO's view in its 2018 general tariff application.

12-Month Rolling Timeline for Energy Storage Roadmap Integration Activities

Classification	ES Roadmap Integration Activities	2021 Q2			2021 Q3			2021 Q4			2022 Q1		
		A	M	J	J	A	S	O	N	D	J	F	M
Education and Awareness	**ES Progress Updates – UPDATED** Share progress on the Energy Storage (ES) Roadmap integration activities, interrelated initiatives and provide a forum to address stakeholder questions.		E			E			E			E	
	ES Industry Learnings Forum (ESILF) – UPDATED Organize forum to provide expertise and key learnings to the AESO on targeted matters related to the integration of energy storage in Alberta.								E				E
Phase 2 Long-term Implementation	**ISO Tariff Design – RESUMED** Work in concert with ISO tariff design to ensure ES is considered.	**Progress will align with Bulk and Regional Tariff Design**											
	Forecasting, Planning and Market Reports* Develop and implement forecasting and planning models to support Long-term Outlook (LTO) and Long-term Transmission Plan (LTP).	C		I, E (only pertaining to AESO internal changes) *These work streams provided input on potential ISO rule changes to enable storage adn will continue to provide support to the single ISO rule changes process as required.*									
	Configurations, Qualification and Connection Requirements* Develop appropriate functional specification documents; identify market participation options, permissible configurations, and metering requirements for ES.	C											
	Market Participation* Evaluate long-term options for energy storage participation in the Energy and Ancillary Service markets.	C											
	Operations* Perform technical studies for the review of the operating parameters and requirements for the different types and configurations of ES; identify the impact to thge connection processes and system applications to enable full range of ES operation.	C											
	ISO Rule Changes Based on the work performed by the different cross-functional teams, the AESO will conduct a single consultation process under AUC rule 017 to develop and file the proposed.	**Progress and information will be provided as part of the Energy Storage Rule Amendments process**											

ES integration process phases: Analysis (A), Conception (C), Development (D), Regulatory (R), Implementation (I), Engagement (E)

Source: AESO online

British Columbia

Further to its Clean Power 2040 consultations which were completed in 2021, BC Hydro has made available to the public its 2021 Integrated Resource Plan which articulates BC Hydro's strategy to meet the electricity needs of the province on a 20-year horizon.

The plan is now under review by the BC Utilities Commission. BC Hydro anticipates that following the implementation of certain demand-side measures, including energy efficiency programs, voluntary time-varying rates and implementation of smart-charging technology for electric vehicles, no new energy needs will be expected to occur before 2030 and no new capacity needs will be expected to occur before 2037.

In light of such findings, the plan does not put forward a short or medium-term strategy to provide additional capacity through energy storage technologies such as utility-scale batteries and pumped hydro storage. For now, the potential and characteristics of such new sources of electricity are monitored by BC Hydro.

It is noted that BC Hydro expects cost declines in respect of utility-scale batteries over the next 10 years, which would make this technology more attractive at such time.

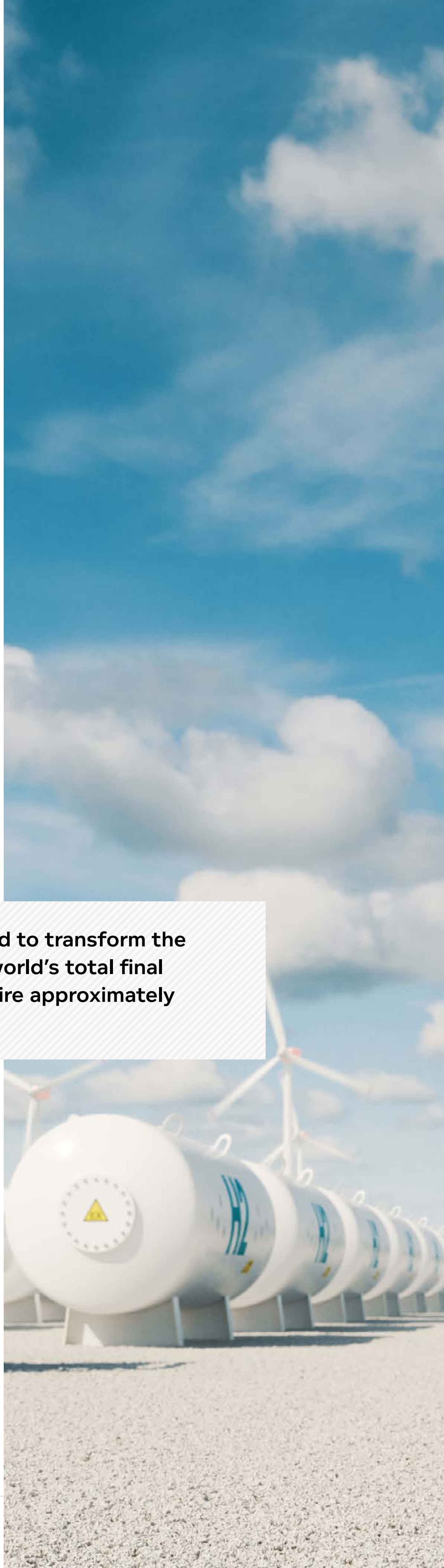
CONCLUSION

Notwithstanding persistent barriers stemming from the legacy of centralized grids, DERs continue to make inroads in a number of Canadian jurisdictions. Especially when it comes to storage, there is wide acknowledgement that scaling up distributed resources is a key aspect of decarbonization and achieving net zero emissions. All stakeholders, particularly regulators, system operators, and project proponents, will need to step up their collaborative efforts in order to realize DER potential in the coming years.

Hydrogen Overview

Authors: Jamie Gibb, Will Horne, Christopher Langdon, Kerri Lui, Dave Nikolijsin and Connor O'Brien

Unlocking the Potential of Hydrogen: Canadian Developments in the Drive to Net Zero



GROWING AMBITIONS — GLOBALLY AND DOMESTICALLY

The potential for hydrogen to play an essential role in transitioning to a net zero economy continues to generate enthusiasm amongst key stakeholders, including governments, investors, and project proponents. 2021 saw steadily increasing investment commitments aimed at realizing that potential.

The International Energy Agency (IEA) reports that, globally, countries that have adopted hydrogen strategies have committed at least USD$37 billion, while the private sector has announced an additional investment of USD$300 billion. Such commitments are driven not only by the policy imperative embodied in such multilateral summits as COP 26 in Glasgow, but also by the scale of the economic opportunity. Indeed, the IEA has identified hydrogen as being amongst the "biggest innovation opportunities" in the push toward net zero.

> **While investment commitments are increasing, far more is needed to transform the hydrogen economy, which could supply upwards of 10% of the world's total final energy consumption by 2050. The IEA estimates this would require approximately USD$1.2 trillion.**

This figure reflects an anticipated dramatic increase in demand beyond the existing market (consisting of refining and industrial feedstock). Such demand is expected to come from numerous additional sectors including transport, heating, and difficult-to-decarbonize industrial applications like steel production.

From an industrial policy perspective, there are now 17 governments worldwide (Canada included) that have established hydrogen strategies, compared with only three in 2019. There are now also numerous subnational strategies, including those of Alberta and British Columbia. While the pace of change will need to accelerate if the hydrogen sector's ambitions are to be realized, the incremental developments we discuss below are nevertheless steps in the right direction.

NEW DEVELOPMENTS

Following the late 2020 release of the *Federal Hydrogen Strategy* (Federal Strategy), there has been momentum growing across Canada whereby provinces have begun setting the course for the future of the hydrogen economy in their own backyards. Since the release of the Federal Strategy in 2020, two of the provinces that are expected to become major players in the national hydrogen economy — from production to export and everything in between — have released their own plans. British Columbia released its B.C. Hydrogen Strategy (BC Strategy) on July 6, 2021 and Alberta released its *Alberta Hydrogen Roadmap* (Roadmap) on November 5, 2021.

Federal

When it was released, the Federal Strategy was notably lacking in new investment measures. As a result, industry stakeholders looked to the 2021 federal budget (Budget) with great anticipation. While there were a number of hydrogen-specific aspects of the Budget, the greatest support for the sector will come from measures earmarked for the net zero transition generally, including the Net Zero Accelerator, and an expansion of tax incentives targeted at clean technologies. Some of the these direct spending and incentives that will impact the hydrogen industry include:

Additional C$5 billion for Net Zero Accelerator. The Strategic Innovation Fund's Net Zero Accelerator will receive this investment over the next seven years on top of the initial C$3 billion dollars in funding that was allocated at its launch, for a total of C$8 billion dollars.

A Tax Reduction for Zero-Emission Technology. To support the growth of clean technology manufacturing in Canada, the Budget proposes to reduce by 50% the general corporate and small business income tax rates for businesses that manufacture zero-emission technologies. Production of green hydrogen has been expressly highlighted by the Budget as a zero-emission technology.

C$319 million to Advance CCUS Technologies. Starting in 2021-22, this funding will come from Natural Resources Canada (NRCAN) to support research, development, and demonstrations that would improve the commercial viability of CCUS technologies.

C$1 billion Investment for Clean Tech Projects. Given that transformative clean technology projects often require investment at a scale and time horizon outside of the scope of traditional project financing, the Budget proposes to make up to C$1 billion available on a cash basis, over five years, starting in 2021-22, to help attract private sector investment for clean tech projects.

British Columbia

With more than half of the country's active companies in the hydrogen industry located in British Columbia, the province is expected to play a major role in the future of the Canadian hydrogen industry.

The BC Strategy is anchored against the province's CleanBC strategy which sets out the province's commitments to achieving net-zero emissions by

2050. Although the BC Strategy does not single out specific initiatives related to hydrogen, it does set out 63 policy actions to be undertaken over the short (2020-2025), medium (2025-2030), and long term (2030-beyond). The immediate priorities are a focus on scaling up green hydrogen production in the province and establishing a regulatory framework for carbon capture, utilization and storage (CCUS) to enable low or zero emission blue hydrogen production.

Clean BC also creates numerous market supply options for hydrogen in BC. For example, hydrogen should be able to play a role in compliance, and potentially credits under the soon to be revamped BC Low Carbon Fuel Standard. Clean BC also supports hydrogen in the ZEV transportation space and hydrogen will also likely play a role in helping BC utilities to meet Clean BC requirements to decarbonize the natural gas grid.

> **BC announced a C$10 million investment over three years to develop a policy on reducing the carbon intensity of fuel and advancing the hydrogen economy.**

In addition to the BC Strategy, the province's 2021 budget contains measures to support hydrogen development and, in particular, to address the significant barrier created by high electricity costs with respect to large scale hydrogen production. BC announced a C$10 million investment over three years to develop a policy on reducing the carbon intensity of fuel and advancing the hydrogen economy. The province also launched the "Clean Industry and Innovation Rate" in January 2021 to help support innovative industries by lowering the cost for such industries to connect to BC Hydro's grid. The initiative provides a 20% discount from BC Hydro's standard industrial rate for the first five years, 13% for year six and 7% for year seven. The initiative is available to plants that produce low-carbon fuel or use a process to remove greenhouse gases from the atmosphere.

Alberta

Alberta boasts industrial infrastructure and geological advantages that stand to give the province an important edge, particularly when it comes to blue hydrogen. The Alberta Roadmap was developed with this in mind. Based on advice and input from municipalities, industry, academia, indigenous organizations, and non-governmental organizations, the Roadmap outlines seven key policy pillars to achieve its plans:

(i) Build new market demand;
(ii) Enable Carbon Capture, Utilization and Storage;
(iii) De-risk investment and improve access to capital;
(iv) Activate technology and innovation;
(v) Ensure regulatory efficiency, codes, and standards to drive safety;
(vii) Lead the way and build alliances; and
(viii) Pursue hydrogen exports.

The first phase of implementing the Roadmap focuses on establishing policy, investing in technology to reduce the carbon intensity of hydrogen production and accelerating commercialization across the supply chain. The second phase will focus on growth and achieving scale through improved technologies and commercialization.

The Roadmap outlines several short and long term actions in furtherance of each of the seven key policy pillars. These include:

- Supporting hydrogen blending in the utility market by amending the *Gas Utilities Act* and *Gas Distribution Act*;
- Advancing CCUS hubs and improving the economics of CCUS;
- Supporting clean hydrogen production through the Alberta Petrochemicals Incentive Program;
- Support hydrogen technology and innovation throughout the value chain by establishing a Clean Hydrogen Centre of Excellence and hydrogen feasibility studies;
- Support the development of national and provincial codes and standards;
- Coordinate the development of hydrogen hubs and partnerships across the province; and
- Pursue international market access by establishing a clean energy corridor with connections through British Columbia and other jurisdictions.

The release of the Roadmap makes it quite clear that Alberta is committed to moving forward — sooner rather than later — in order to capture its share of the hydrogen economy in Canada.

Target Markets

In addition to the Roadmap's key policy pillars, it also identifies five major markets for hydrogen which represent opportunities for Alberta:

Heating (residential and commercial)

Power generation and storage

Transportation

Industrial processes

International export

Each of these markets represent significant opportunity, and several of them have already begun transitioning to zero-carbon fuel.

Why Alberta has a Competitive Advantage

Alberta holds significant competitive advantages that will help support the growth of Canada's hydrogen economy and thereby support the global transition to clean energy. Alberta currently produces the most hydrogen of any province in Canada, approximately 2.4 million tonnes per year — primarily used in industrial applications. This experience will help enable Alberta to scale hydrogen production quickly and efficiently.

Currently, hydrogen is predominantly produced from fossil fuels such as natural gas, which is in abundant supply. With more than 60% of Canada's natural gas production and well-established extractive capabilities, Alberta has the potential to be one of the world's lowest cost producers of blue hydrogen. This is assuming CCUS is an integral piece of the development of clean hydrogen. Due to its geology and focus on emissions reduction in the oil and gas industry, Alberta also has a robust and established regulatory and risk management framework in place for large-scale CCUS which has already supported the development of two world-scale commercial CCUS projects for large industrial emitters in the Province.

As the focal point of Canada's energy industry, Alberta has the opportunity to leverage existing infrastructure, natural gas reserves, and expertise to play a leading role as Canada enters the global hydrogen economy. In an effort to attract investment to Alberta, the government has implemented the following measures:

- Job Creation Tax Cut — reduction of the general corporate income tax rate on July 1, 2020;
- Alberta Petrochemicals Incentive Program — financial incentives for investment in hydrogen facilities using CCUS;
- Alberta Indigenous Opportunities Corporation — provides indigenous communities with access to up to C$1 billion in financial support and loan guarantees for participation in equity ownership of natural resource projects;
- Creation of Invest Alberta; and
- Technology Innovation and Emissions Reduction (TIER) Fund - a commitment of up to C$750 million over three years for innovative projects that reduce emissions.

The Alberta Hydrogen Roadmap models two potential scenarios which are helpful to understand what the hydrogen economy could look like in Alberta by 2030 and what it takes to ensure that the hydrogen economy is successful. The two models are:

- **An Incremental Future** where clean hydrogen has a slow uptake into the provincial economy. This scenario assumes industry continues on with business as usual with incremental demand for hydrogen under the existing policies and regulations.
- **A Transformative Future** where clean hydrogen is integrated into provincial energy systems on a large scale. This scenario assumes favorable policies that create demand growth and technological development. This would lead to large-scale domestic hydrogen deployment and exports by 2030.

Sector	Incremental Future	Transformative Future
Industrial Processes	CCUS is added to existing bitumen upgrading and/or oil refining sites. It should be noted that the pending federal tax credit regime related to CCUS and its applicability to production of blue hydrogen will affect the near term risk appetite for blue hydrogen projects in Alberta, and elsewhere in Canada.	CCUS is added to existing bitumen upgrading and/or oil refining sites, and at ammonia and methanol facilities to reduce emissions.
Residential and Commercial Heating	Pilot projects are blending hydrogen at 5% by volume with natural gas into municipal distribution infrastructure.	Blending hydrogen at 15% by volume in municipal distribution infrastructure across the province. Using pure hydrogen networks in contained areas.
Power Generation and Storage	Small scale public-private partnership support for pilot projects for hydrogen energy storage in underground salt caverns or depleted oil and gas reservoirs.	1200 MW of Alberta's power generation is using 15 % volume of blended clean hydrogen with natural gas in regional clusters. Power generation projects using hydrogen powered turbines. Hydrogen is being used as a seasonal storage system from surplus renewable power through power-to-gas.
Transportation	1% of gasoline vehicles and 5% of diesel vehicles have transitioned to FCEV.	5% of gasoline vehicles and 10% of diesel vehicles have transitioned to FCEVs.
Exports	Alberta is exporting clean hydrogen carriers (for example, ammonia) by rail to the United States and across Canada.	Alberta exports 1 million tonnes of gaseous hydrogen, noting this would require a fully permitted and constructed pipeline to the west coast, liquefaction, and export infrastructure. In addition, Alberta also exports 1 million tonnes of hydrogen carriers (such as ammonia) to global markets by 2030.

MAKING MOVES: CANADIAN HYDROGEN DEALS AND PROJECTS IN 2021

Although the drive to harness low and zero emissions hydrogen remains nascent in Canada, 2021 nevertheless saw a noteworthy range of hydrogen-related transactions and announcements involving Canadian entities and their assets. Publicly announced deals spanned a number of energy-related sectors and applications, including clean tech, transportation, blue hydrogen production & export, and industrial/heating. Canadian entities active in the hydrogen space are frequently transacting internationally as purchasers, targeting acquisitions, or forming project development partnerships.

Clean Tech

- On June 25, 2021, BioHEP Technologies Ltd. (Vancouver) and Next Hydrogen (Toronto) completed an amalgamation. The resulting issuer, Next Hydrogen Solutions Inc., is engaged in development of water electrolysis technology and providing green hydrogen solutions.
- On September 8, 2021, HTEC Hydrogen Technology & Energy Corporation (Vancouver), a designer, builder and operator of hydrogen fuel supply solutions, announced the completion of a C$217 million investment by Chart Industries, Inc. (USA) and I Squared Capital (ISQ) (USA). Chart is a manufacturer of liquefaction and cryogenic equipment serving multiple applications in the energy and industrial gas end markets, including hydrogen.
- On September 20, 2021, Xebec Adsorption Inc. (Montreal) announced the execution of its first steel metal treatment contract to supply two Hy.GEN® 150 units to a Turkey-based flat steel manufacturer. The two units will have a capacity of approximately 600 kg of hydrogen per day (220 tons per year).

Fuel Cells & Transportation

- On May 11, 2021, Matthews International Corporation (USA) announced the acquisition of the assets of Terrella Energy Systems, Ltd. (Vancouver), a supplier of technology solutions to the global hydrogen fuel cell industry.
- On August 18, 2021, Tidewater Renewables Ltd. announced the completion of its initial public offering (IPO) and announced a positive final investment decision (FID) on a Renewable Diesel and Renewable Hydrogen Complex.

- On October 7, 2021, Nikola Corporation and TC Energy Corporation announced their agreement to collaborate on co-developing, constructing, operating and owning large-scale hydrogen production facilities (hubs) in the United States and Canada. Nikola and TC Energy desire to accelerate the adoption of heavy-duty zero-emission fuel cell electric vehicles (FCEVs) and hydrogen across industrial sectors.
- On November 10, 2021, Hyzon Motors Inc. (USA), a supplier of hydrogen-powered fuel cell electric vehicles, and TC Energy Corporation (Canada) announced an agreement to collaborate on development, construction, operation, and ownership of hydrogen production facilities (hubs) across North America. The facilities will be used to meet FCEV demand.
- On November 11, 2021, Ballard Power Systems (British Columbia), a designer and manufacturer of PEM fuel cell engines for medium- and heavy-duty vehicles, announced the acquisition of Arcola Energy (UK), a systems engineering company specializing in hydrogen fuel cell powertrain and vehicle systems integration.

Blue Hydrogen Production & Export

- On August 3, 2021, Itochu (Japan) announced a partnership with Petronas (Malaysia) to explore and plan for a natural gas-based ammonia facility with CCUS in Alberta, to export ammonia as a hydrogen carrier to Asian markets.
- On September 8, 2021, Mitsubishi Corporation (Japan) and Shell Canada announced a MOU regarding the production of low-carbon blue hydrogen to support Japan's push for clean energy. Mitsubishi plans to build and start up the low-carbon hydrogen facility near Shell's Scotford facility in Alberta. The companies aim to produce about 165,000 tons per annum of hydrogen in the first phase of the project, which would be converted to low-carbon ammonia for export to Asian markets.

Industrial & Natural Gas Blending

- On May 11, 2021, ATCO Ltd. (Alberta) and Suncor Energy Inc. (Alberta) announced a collaboration on early stage design and engineering for a potential clean hydrogen project near Fort Saskatchewan, attempting to blend hydrogen into a subsection of its natural gas distribution system with a concentration of 5% by volume.
- On June 3, 2021, Ontario Power Generation subsidiary Artura Power and Hatch Ltd. (Toronto) announced a partnership exploring the feasibility of the creation of regional hubs in Ontario with potential end-uses in natural gas blending, industrial applications (e.g. steel production), and fuel cells.

WHAT'S NEXT?

As demonstrated by the 2021 Federal Budget, the development of both federal and provincial strategies, as well as an increasingly active transactional landscape, there is little doubt that Canada intends to compete in the developing global hydrogen economy — yet certain obstacles persist.

Remaining Challenges

Despite Canada's natural resource and infrastructure advantages, several challenges still need to be tackled in order to achieve the long-term success of a hydrogen market in Canada.

- **Supporting Policy and Regulations:** In addition to the adoption of hydrogen strategies at both the provincial and federal levels, long-term policies are required to provide for a regulatory framework that includes hydrogen. Given the large upfront capital costs associated with developing these new technologies, without clear policies that recognize hydrogen's essential role in Canada's net zero greenhouse gas future, uncertainty remains for investors. Some good examples are the pending federal tax credits for CCUS, the pending federal regulations for the Canadian Clean Fuel Standard, and the revisions underway to the British Columbia Low Carbon Fuel Standard.
- **Codes and Standards:** Gaps in existing codes and standards (e.g. hydrogen blending limits in natural gas pipelines) need to be addressed to enable greater adoption of hydrogen and hydrogen technologies.
- **Availability of Low-Carbon Intensity Hydrogen:** Access to domestic low-carbon intensity hydrogen in many parts of Canada is preventing both pilot and commercial development. In provinces with low-cost natural gas and the geology suitable for permanently sequestering the byproduct CO2, blue hydrogen can be produced at a price of $1.50 to $2.0/kg H2 ($10 to $14/GJhhv H2). The cost of producing green hydrogen remains significantly higher, however, some anticipate that by 2030, green hydrogen will be cost-competitive as a result of the declining cost of renewables and the scaling up of electrolyzer technology (although such estimates are based on assumptions which are arguably speculative at best).
- **Investment:** A lack of sustained investment in innovation is impeding the advancement in technology that is needed to support the production and use of hydrogen. Without stable support, costs will not decrease, performance will not improve and Canada will not be able to maintain a leadership role at the cutting edge of clean technology.
- **Exports:** In order for Canada to become a large exporter of hydrogen, there needs to be a fully permitted and constructed pipeline to the west coast, as well as liquefaction and export infrastructure. Support from Canada, British Columbia, and Indigenous and local communities will be critical to establish hydrogen export supply chains.

A Promising — But Uncertain — Outlook for Canada

It is an open question as to whether Canada will rise to meet these challenges and fulfill its potential as a global hydrogen leader in the drive to net zero. As discussed above, recent movements in the sector are encouraging, but are arguably insufficient to accelerate the industry in the context of an increasingly active global market. As Canada seeks to secure its future in a rapidly transforming energy system, it will remain essential for government and industry leaders to keep pace with international competitors in the hydrogen industry.

Atlantic Provinces Regional Overview

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

Introduction and Market Update

Last year was one of continued growth and activity for the Atlantic power sector. The region continued to pursue its transition towards renewable and new energy sources. All four provinces — Nova Scotia, Newfoundland & Labrador, New Brunswick and Prince Edward Island — took initiatives to make good on their ongoing climate change action commitments and to address Canadian federal energy regulations which now require that coal-fired electricity be phased-out by 2030 by putting forward, to varying degrees, plans of shifting the structure of their energy markets and moving towards a greener economy.

The movement towards renewable energy sources has led to opportunities for public and private projects aimed at increasing the regional supply of wind, solar and potentially even tidal energy. Recent provincial elections have not changed trends in this direction.

> **Three areas of regional activity — the Atlantic Loop project, small modular nuclear reactors, and hydrogen fuel production — present particular opportunities for growth given their novelty and potential for further innovation.**

Key 2021 developments occurred at the Atlantic interprovincial level as well, with the completion of regional projects and the emergence of regional strategic initiatives on renewable energy being put forward by regional groups such as the Offshore Energy Research Association, the Atlantic Hydrogen Alliance and the Maritimes Energy Association. Three areas of regional activity — the Atlantic Loop project, small modular nuclear reactors, and hydrogen fuel production — present particular opportunities for growth given their novelty and potential for further innovation.

Atlantic Provinces Governmental Updates

While each province's renewable energy commitments vary in terms of ambition and scope, 2021 revealed the pressure felt by the governments of the Atlantic provinces to reach their short and long-term climate change

goals and they are responding by putting forward or supporting new renewable energy projects and strategies.

Attracting and obtaining funding for such initiatives remain a regional challenge. Ensuring that the renewable energy transition does not lead to significant increases in energy costs for consumers is also a concern. In November 2021, the Council of Atlantic Premiers sent the Federal Government a letter requesting C$5 billion in assistance to support the regional renewable energy transition (including mainly the Atlantic Loop project) and to minimize the financial burden on ratepayers.

NOVA SCOTIA GOVERNMENTAL UPDATES

In Nova Scotia, the Nova Scotia Progressive Conservatives Party, led by Tim Houston, was elected to majority government as of August 2021, defeating the previous Liberal Party government. Despite the change, the new provincial government maintained the ambitious plan announced in February 2021 to reduce the province's greenhouse gas emissions to 40% below 2007 levels by 2030 and to source 80% of the province's energy from renewable energy sources by 2030. According to Nova Scotia Power forecasts, this plan will have to result in 60% of Nova Scotia's energy use being sourced from renewable energy by the end of 2022. On October 27, 2021, the *Environmental Goals and Climate Change Reduction Act* was introduced, setting out 28 new goals, including a commitment to entirely phase out coal energy by 2030.

With current provincial supply of renewable energy being insufficient to meet legislated targets, the Nova Scotia government has been creating opportunities for independent power producers to develop renewable energy projects. A new renewable energy procurement round (discussed in further detail below), and special funding programs such as the Nova Scotia Green Fund have been announced.

The new provincial government maintained the ambitious plan announced in February 2021 to reduce the province's greenhouse gas emissions to 40% below 2007 levels by 2030 and to source 80% of the province's energy from renewable energy sources by 2030.

It should also be noted that activity in Nova Scotia's offshore oil and gas reserves continues to dwindle. For the fourth year in a row, no new licences were issued to explore the offshore region, leaving Nova Scotia's petroleum future uncertain.

NEWFOUNDLAND & LABRADOR GOVERNMENTAL UPDATES

On January 15, 2021, Newfoundland & Labrador Premier Andrew Furey called a provincial election that resulted in his Liberal Party winning a House of Assembly majority on March 27, 2021. As in Nova Scotia, the newly elected government announced its new renewable energy strategy in late 2021.

The government's plan provides little in terms of financial information, but highlighted an interest in maximizing renewable energy opportunities, prioritizing hydro, wind, biomass, solar and tidal power. Industry development is at the centre of the plan. Preliminary initiatives such as legislative and regulatory reviews, assembling an inventory of the province's potential energy assets and reviewing the current moratorium on wind development are steps in this direction.

This could lead to renewed activity for existing, but on hold, renewable energy projects such as the experimental Ramea wind turbine and hydrogen-diesel project (under development by Nalcor Energy since 2011) which would provide electricity to communities not connected to the larger provincial grid.

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 is still committed to the oil and gas industry, hoping to double production by 2030 and supporting the province's fossil fuel sales abroad.

The absence of budgetary commitments for renewable energy projects in the newly released plan is not surprising given Newfoundland and Labrador's current level of debt and budget deficit problems. The plan's announcement coincided with efforts by the government to review and evaluate the province's assets in response to the May 6, 2021 Greene report on economic recovery.

It is unclear how the Greene report's recommendations will affect the province's new energy plan. One recommendation proposed the wind up of Nalcor, a key provincial energy corporation involved in the Muskrat Falls hydroelectric plant project, which led to a June 2021 announcement that Nalcor would be integrated into NL Hydro.

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 could potentially result in greater room for independent private producer initiatives.

NEW BRUNSWICK GOVERNMENTAL UPDATES

New Brunswick's government has yet to provide a clear framework on how it plans to reach its commitments to source 100% of its power from non-greenhouse-gas-emitting sources by 2050. The province was under an obligation, stemming from the New Brunswick *Climate Change Act*, to provide an update to its Climate Change Action Plan by the end of 2021. The government's plan was initially to publish new power supply targets by fall 2021, but it seems more likely that such targets will be made public early in 2022.

Lack of guidance on this front may be tied to the New Brunswick government's financial concerns regarding the energy transition. The federal plan to end the activities of Belledune Coal Plant by 2030 is creating challenges for NB Power, the provincial power utility, which is currently struggling with debt issues. Given the unsuccessful attempts to delay the closure timeline, it is possible that the New Brunswick government is working on plans to build new power generation projects while trying to avoid significant energy rate increases.

PEI GOVERNMENTAL UPDATES

The PEI government continued over the past year to move forward on a pledge to reduce provincial carbon emissions and reach net-zero energy consumption, with specific goals for 2030 and 2040, but this pledge has yet to materialize into a clearly defined plan or steps. The province nevertheless remains a favourable environment for potential renewable energy initiatives.

Muskrat Falls

The construction in Labrador of the 824 megawatt Muskrat Falls energy plant, a portion of the Lower Churchill Project which began in 2013, was set to be completed in November 2021. Energy produced at the combined Muskrat Falls and at the Gull Island (still to be completed) sites would eventually provide an energy capacity of 3,000 megawatts or higher, with part of the electricity generated being transmitted through the Maritime Link Project to Nova Scotia.

The Muskrat Falls project's financing issues have been significant and a source of public concern in the past. Despite increases in capital costs, the four Muskrat Falls power generating stations were completed and active by fall 2021. The project's overall completion date, however, was pushed back to spring 2022, in part due to issues with the software designed to operate 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.

Maritime Link

The Maritime Link project connects Granite Canal, Newfoundland and Labrador to Woodbine, Cape Breton (Nova Scotia) via a 170 km undersea cable across the Cabot Strait, and enables Nova Scotia to access part of the hydroelectric energy supply generated by the Muskrat Falls Project, in addition to providing the provinces with more stable prices.

Construction (led by Emera) was completed in 2018. Investments for the estimated C$1.7 billion project costs are spread out over 35 years, and also involve Nalcor (now Hydro NL), and Nova Scotia Power. The Maritime Link will allow the island of Newfoundland to connect to the North American grid for the first time. This alternative electrical-transmission route makes the abundance of energy in Newfoundland and Labrador available for export to Nova Scotia and beyond, and improves the feasibility and profitability of future energy projects in the region.

The Maritime Link has a planned capacity to transport 500 megawatts HVdc between provinces, with Emera being responsible for the operation of the transmission line. Agreements between Emera and proponents of the Muskrat Falls project have led to a 35-year guarantee that Nova Scotia will benefit from 20% of the energy generated at the Muskrat Falls generating station in exchange for investments of 20% of the total cost of Phase I of the Lower Churchill Project, among others. Nova Scotia could purchase further electricity at market rates.

With delays in the completion of the Muskrat Falls project, no date has been set as to when the full expected volume of electricity would start to consistently flow through the Link towards Nova Scotia. Between the months of August and November 2021, only 19% of the promised electricity was flowing towards the province. Emera representatives have indicated, however, that this amount had risen to between 70 to 100% by mid-January 2022.

Nova Scotia energy regulators were assessing in December 2021 a request by Nova Scotia Power's Maritime Link affiliate to recover part of its expenses by collecting C$169 million from ratepayers in 2022, by rolling the amounts into rates. A decision should be published in 2022.

Atlantic Loop

The Atlantic Loop is a project to provide significant transmission upgrades to the Atlantic provinces' power grids, connecting their grids with Québec's grid. It is part of the Clean Power Roadmap for Atlantic Canada, whose interim report was released in 2020, and was due to be released in 2021. The project is in its early stages and its estimated project costs are of at least C$5 billion.

Plans are for the Atlantic Loop to increase overall transmission capacity, which would enable the region to source renewable energy from Québec and Labrador, and ease the transition away from coal energy production in the region. The project would also enable the provinces to be in a position to supply electricity to the US on a long-term basis.

Following the announcement that the request to run the Belledune coal plant past 2030 was denied, New Brunswick indicated that it needed the Atlantic Loop to materialize soon for it to be able to realistically meet its renewable energy goals.

The Federal Government indicated back in 2020 that the Atlantic Loop was a top priority project for the region. Despite strong ongoing support from the Atlantic provinces' premiers, consensus around the project, and involvement from Hydro-Québec, the Atlantic Loop idea is still on the drawing board, despite the need for the region to achieve its renewable energy goals before 2030.

No definitive financial commitment has yet been made, but C$25 million has previously been set aside to help proponents complete engineering assessments, community engagement, and environmental and regulatory studies for the Atlantic Loop.

Pressure to move the project forward was increasing by the end of 2021. Following the announcement that the request to run the Belledune coal plant past 2030 was denied, New Brunswick indicated that it needed the Atlantic Loop to materialize soon for it to be able to realistically meet its renewable energy goals. Nova Scotia Premier Tim Houston has raised the project in late-fall talks with Prime Minister Justin Trudeau.

General Developments in 2021

Despite heavy financial investments in the Muskrat Falls project and the Maritime Link, renewable energy procurement initiatives were also on the rise across the Atlantic region. The last year saw growing room in the energy market for independent power producers and other industry participants to contribute.

NOVA SCOTIA POWER ANNOUNCES PLANS TO SHARPLY REDUCE CARBON FOOTPRINT

Nova Scotia Power (an affiliate of Halifax-based Emera) announced in February 2021 its plans to reduce its carbon footprint and its goal of achieving net-zero greenhouse gas emissions by 2050 across its North American operations. Details of the utility's plans included targets of an 80% reduction in coal energy within 2 years, and closure of all coal-fired plants by 2040. The ability of the utility to meet is objectives will depend on the creation of the interconnected Atlantic Canadian electric grid, the Atlantic Loop.

Plans indicated that only one of Nova Scotia's currently active coal power plants would be slated to close this decade, but this could change with the impact of federal coal legislation.

By the end of 2021, the utility appeared to be in a good position to make good on its plans. News releases were issued by Emera when 25% of the province's electricity was officially being generated from wind power. Nova Scotia Power will also receive part of the hydroelectric energy from Muskrat Falls.

RIDING THE WAVES: CONTINUED INTEREST IN MARINE AND TIDAL POWER

Interest in marine and tidal power continues to grow in the Atlantic region, particularly in Nova Scotia. The past year notably saw floating tidal energy turbines trialled near Digby Neck, Nova Scotia by Sustainable Marine Energy, a UK company. Trials in the Bay of Fundy were promising and plans are for the recently installed PLAT-I tidal turbine platform to connect to the Nova Scotia grid in 2022.

Japanese firms — Chubu Electric Power and Kawasaki Kisen Kaisha—have joined this past year with DP Energy, a private Irish developer, to support new tidal energy projects, which are to be located at the Fundy Ocean Research Centre for Energy. This is a first for Japanese investment in tidal power outside of Japan.

NOVA SCOTIA RFP AND POWER PURCHASE AGREEMENT MADE PUBLIC

Last year saw an increase in regional RFP opportunities, particularly in Nova Scotia. During the summer, Nova Scotia publicly announced plans for further RFPs in the coming years, starting with a 350-megawatt project RFP, in order to reach its goal of using 80% renewable energy by 2030.

This RFP, administered by CustomerFirst Renewables, is for a low-impact renewable electricity project which would supply 10% of the province's electricity. Proposals must either be for solar or wind energy, with details still to come. The procedure and administration of this new RFP may also serve as a blueprint for further RFPs in Nova Scotia.

During the summer, Nova Scotia publicly announced plans for further RFPs in the coming years, starting with a 350-megawatt project RFP, in order to reach its goal of using 80% renewable energy by 2030.

The RFP is still in its preliminary regulatory phase, despite plans to open submissions by December 2021. In fall 2021, interested parties were invited to provide comments on the draft RFP, to prepare interconnection requests, and file notices with Nova Scotia regulators for increased capacity, while the procurement administrator made available important information concerning environmental and First Nations consultation expectations. Interested proponents should expect to submit their notices of intent to bid by March 2022, with the proposal submission deadline currently scheduled for June 2022, and the related power purchase agreements to be executed in October 2022.

In parallel, the RFP's draft Power Purchase Agreement was submitted in December to the Utility and Review

Board of Nova Scotia, opening a hearing and consultation process. Interested parties are invited to comment on the application until January 7, 2022, with the RFP Administrator's reply expected by January 21, 2022.

NEW BRUNSWICK LOOKS TO NUCLEAR SOLUTIONS

In New Brunswick, nuclear power was the main energy development of the year. A C$50.5 million Federal Government investment was announced to assist Moltex Energy in developing small modular nuclear reactors for the province. Other federal funds were allocated for improvements to the Point Lepreau Nuclear Generating Station and to set up a nuclear power research center. In parallel, New Brunswick agreed to provide ARC Clean Energy with C$20 million in funds to support its small modular nuclear reactors venture.

Another significant development is an energy storage benefits agreement between NB Power and Malta Inc. The project is to build a long-term energy storage facility by 2024 with capacity for 1,000 MWh. Smaller scale developments include solar panel farms in Shediac, and upgrades to the hydroelectric power Nepisiguit Galls Generating Station.

SUN OF PLENTY FOR PEI?

PEI's renewable energy transition has been progressing. As of 2021, wind energy provides 24% of the province's electricity. PEI is also ranked second in Canada for solar power installations. This past year highlighted, however, limitations caused by existing PEI laws and regulation for renewable energy projects. Despite sizeable interest and incentives for solar based energy projects in the province, Maritime Electric — PEI's private utility — announced it had to limit access to its grid to solar power generated by individuals, likely affecting planned projects for installations of up to 100 kilowatts.

In September 2021, it was announced that the town of Summerside's Sunbank project's C$55 million contract was awarded to Aspin Kemp & Associates. This contract concerns the second part of a three-phase agreement between Summerside and Samsung Renewable Energy, for a new 10-megawatt lithium-ion battery storage system to be installed, allowing renewable power sources in Summerside's grid to reach 62%, and a new 21-megawatt solar power plant. The project involves a consortium of different PEI companies, and construction is expected to last from October 2021 until December 2022.

Meanwhile, PEI Energy Corporation's proposal for more wind turbines in Eastern Kings, near Souris, was denied during fall 2021. The decision is being appealed. Plans were to add another 30 megawatts to the existing 10 turbines' 30-megawatt capacity.

WIND POWER PROJECT PROPOSED FOR NAIN, LABRADOR

A large-scale wind power project was proposed in Nain, Labrador, with expectations that this project could likely displace anywhere between 35 and 50% of annual diesel consumption in the area. The project contemplates the installation of wind turbines, which could produce 1.8 to 2.3 megawatts of wind energy capacity. The project is a partnership between the Nunatsiavut Government and Natural Forces, an independent power producer based in Nova Scotia. The plan is for the project to be running by the summer of 2022.

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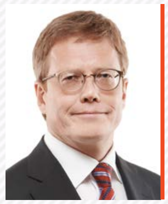

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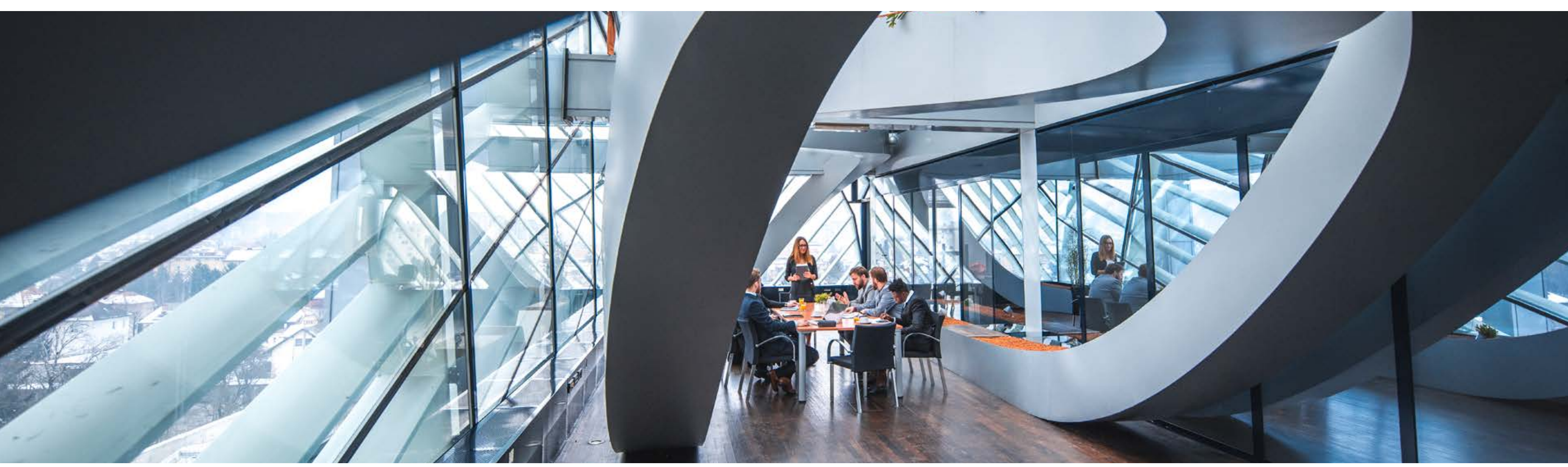

Our Power Group consists of more than 40 lawyers nationally, including the most experienced energy lawyers in Canada. Our principal areas of practice include project development, project finance, mergers and acquisitions, utility restructuring, privatizations and procurement. We also have extensive expertise in advising and representing clients in the area of energy regulation and litigation.

Drawing on our breadth of expertise and experience in the power and energy sectors, we provide practical and timely advice to our clients, and take a hands-on approach to resolving issues. We understand the complexities associated with developing, structuring, financing, approving and operating a variety of different types of power projects.

Our retainers on North American electricity matters include acting for Canada's major public and private electric generators, transmission and distribution utilities, major equity investors and developers of power projects, lenders to power projects and fuel and equipment suppliers to the power industry.

About McCarthy Tétrault

McCarthy Tétrault LLP provides a broad range of legal services, providing strategic and industry-focused advice and solutions for Canadian and international interests. The firm has substantial presence in Canada's major commercial centres as well as in New York City and London.

Built on an integrated approach to the practice of law and delivery of innovative client services, the firm brings its legal talent, industry insight and practice experience to help clients achieve the results that are important to them.

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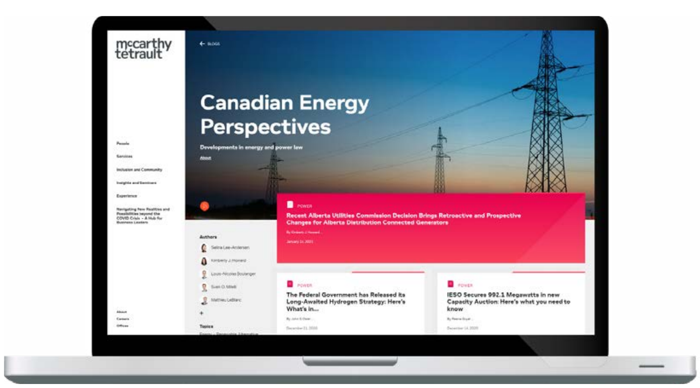

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