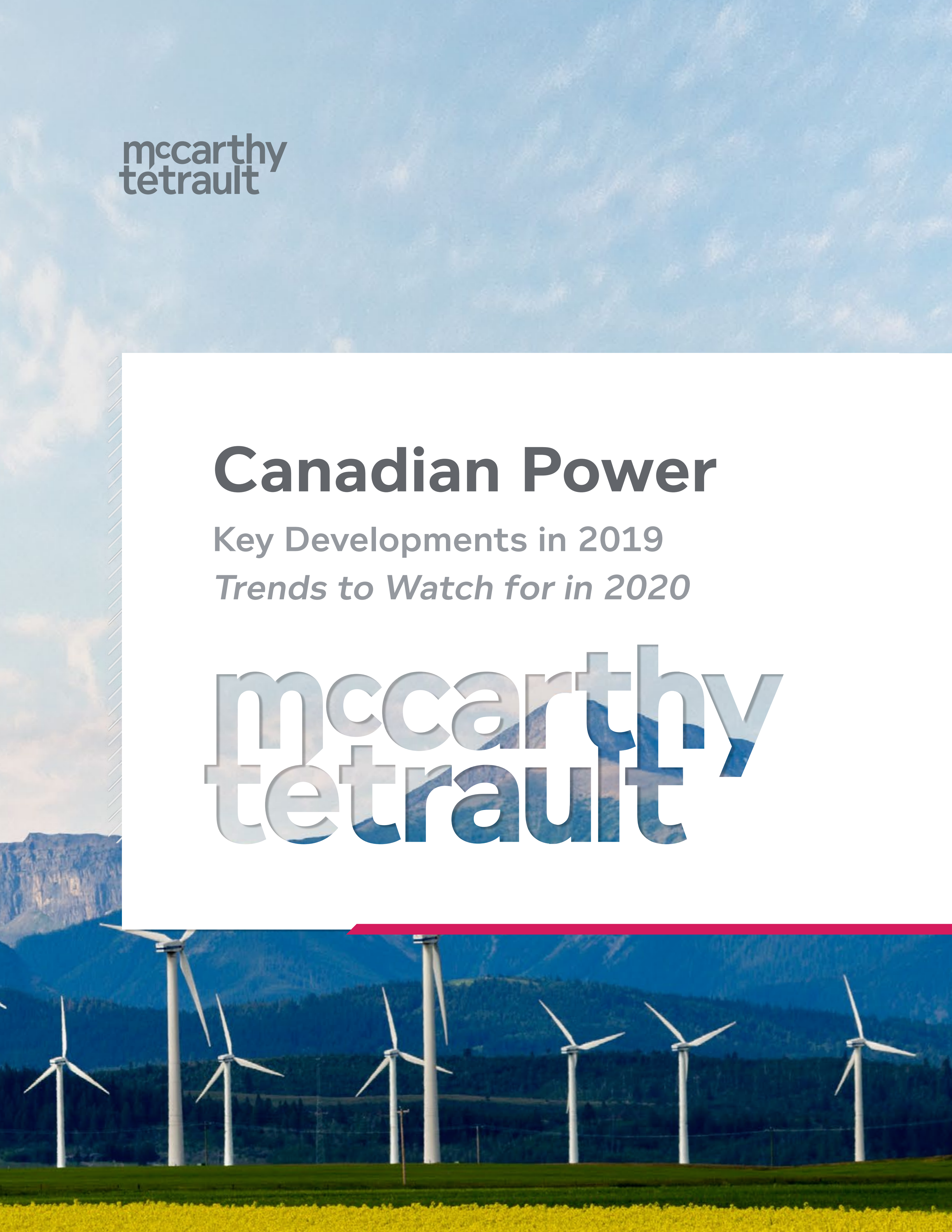

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Canadian Power

Key Developments in 2019

Trends to Watch for in 2020

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The **Power Group at McCarthy Tétrault LLP** is pleased to present:
Canadian Power – Key Developments in 2019 – Trends to Watch for in 2020.

It is our fifth annual Canadian power industry retrospective. This publication is intended to provide an overview, at both the regional and national levels, of the most significant developments in the Canadian power sector in 2019, including in the areas of environmental law, aboriginal law, small modular nuclear reactors, mergers & acquisitions and energy litigation, and to highlight key trends to watch for in 2020. We hope that you will find this publication to be both interesting and informative.

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British Columbia – Overview

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Introduction

2019 proved to be another year of transition for B.C.'s power sector. Following the completion of Phase 1 of its comprehensive review of BC Hydro early in the year, the provincial government embarked on its second stage, which will involve a deeper assessment of the province's energy policy and markets, utility models, and emerging technologies. At the same time, BC Hydro's historical power purchases from independent power producers ("**IPPs**") were the subject of a highly critical government-commissioned report, which further reinforced the continuing moratorium on power procurement opportunities in the province. Meanwhile, development activities for the province's two largest energy projects continued, with construction beginning in earnest for LNG Canada's liquid natural gas project in Kitimat following its final investment decision in October 2018 and key construction milestones being achieved for BC Hydro's 1,100 MW Site C Project as both projects target a 2024 in-service date. In the face of these developments, the provincial government continued to pursue its CleanBC climate strategy, aimed at further electrifying the province's large industrial operations and accelerating the adoption of zero-emission vehicles. Finally, the B.C. government enacted historic legislation committing it to align provincial laws with the *United Nations Declaration on the Rights of Indigenous Peoples* and, further to the achievement of this goal, substantially updated its environmental assessment processes to incorporate Indigenous considerations at all stages.

Government Review of BC Hydro Moves into Second Phase

In February 2019, the B.C. government completed Phase 1 of its comprehensive review of BC Hydro, the province's public electric utility (the "**Review**"). The B.C. government initiated the Review in June 2018 with the objective of developing a plan for BC Hydro to contain electricity rates in the long term and to ensure sound financial and regulatory oversight of the public utility.

A number of significant actions were taken as a result of the Phase 1 report, including the following:

Restored Authority for BCUC

The B.C. government restored or enhanced the regulatory oversight of BC Hydro by the British Columbia Utilities Commission ("**BCUC**") following years of curtailment of this authority under the previous government. The BCUC now has the power to review the scope and amortization of most of BC Hydro's regulatory accounts, which determine BC Hydro's net income for rate-setting purposes (following a two-year transition period), and set electricity rates. The BCUC will also have the authority to review and approve BC Hydro's integrated resource plan ("**IRP**"), the utility's 20-year projection of electricity demand in the province and plan to meet this need, the next of which is due in February 2021.

Reform of Regulatory Accounting

The B.C. government has written off the entire balance of BC Hydro's approximately $1.14 billion Rate Smoothing Regulatory Account, which was established to defer collection of revenues from ratepayers to later fiscal periods, effectively transferring the burden of the account from future ratepayers to current taxpayers. The B.C. government also repealed the Deferral Account Rate Rider ("**DARR**"), a 5% surcharge on ratepayer bills used to pay down BC Hydro's three energy deferral account balances.

Revised Rates Forecast

BC Hydro revised its five-year cumulative electricity rates increase forecast (through fiscal 2024) downward to 8.1% over the next five years, which represents a cumulative decrease of 5.6% for the same period established under the previous electricity rates forecast, to be achieved by a combination of measures, including a $2.7 billion reduction in capital expenditures over ten years, reduction in operating costs, a phase-out of electricity purchase agreements ("**EPAs**") with biomass generating facilities, pursuit of additional revenue streams, and cancellation of new procurement under the utility's Standing Offer Program, which was aimed at renewable energy projects with capacities under 15 MW.

BC Hydro Five Year Rates Forecast
(Fiscal 2020 – Fiscal 2024)[1]

	Fiscal 2020	Fiscal 2021	Fiscal 2022	Fiscal 2023	Fiscal 2024	Cumulative Five Years[i]
Current Rates Forecast – Annual Rate Increase before reducing DARR	6.8%	0.7%	2.2%	0.0%	3.2%	n/a
Current Rates Forecast – Annual Bill Impact – including reduction in DARR[ii]	1.8%	0.7%	2.2%	0.0%	3.2%	8.1%
Previous Government's 10 Year Rates Plan – Annual Bill Impact	2.6%	2.6%	2.6%	2.6%	2.6%	13.7%
Forecast B.C. Inflation	2.3%	2.0%	2.0%	2.0%	2.0%	10.7%

i. *Cumulative rates do not equal the sum of individual rate changes shown for each year due to the effect of compounding.*

ii. *After reducing the DARR from 5% to 0%, beginning in Fiscal 2020. Under the 2013 10 Year Rates Plan, the DARR was set at 5% indefinitely – it was expected to remain at 5% at least through Fiscal 2024. Going forward, the BCUC will now determine how the DARR is set and applied.*

The Review process has now moved into its second phase, which will take more of a long-term, transformation-oriented view, looking at evolving energy markets and trends, new utility models and emerging technologies, as well as opportunities to reduce carbon emissions through electrification, with the goal of developing recommendations for how BC Hydro can accomplish the provincial policy objectives laid out in the CleanBC plan and support the province in meeting its legislated 2030, 2040, and 2050 greenhouse gas reduction targets. Phase 2 will consider potential impacts of North American energy and market trends, current and future customer needs, evolving technologies and utility structures, affordability of electricity, and opportunities to involve Indigenous peoples and communities. Its findings will inform the next provincial IRP.

As part of its efforts to explore new revenue streams, BC Hydro is implementing strategies to grow domestic electricity demand by, for example, attracting energy-intensive customers such as data centres, cryptocurrency mining, and cannabis producers; considering increased sales of low-carbon fuel credits; and exploring the possibility of offering current industrial customers year-round access to real-time, market-based pricing for incremental energy purchases.

Electricity Procurement in 2019: Still on Hold

In the wake of the completion of Phase 1 of the Review, and the concurrent release of a highly critical government-commissioned report on BC Hydro's historical purchases of power from IPPs, a number of measures were announced by the utility aimed at reducing its costs and maintaining low rates. Chief among these was to reduce future energy purchases from IPPs. Indeed, the Phase 1 report took pains to emphasize that future increases to BC Hydro's energy costs are being driven primarily by increasing costs under EPAs, which are set to rise by 5.6% between 2019 and 2021 due to price escalation clauses.

Accordingly, in February 2019, BC Hydro indefinitely suspended its Standing Offer and Micro Standing Offer Programs and stated that it would no longer accept new applications or award any new EPAs under those programs (excluding five First Nations clean energy projects announced in March 2018 and discussed in last year's edition of this publication). In addition, the Review concluded that biomass EPAs set to expire in the coming years would be phased out following a transitional period designed to minimize the impact on the province's forestry sector.

1 Source: BC Hydro

Another key cost-reduction initiative has been the cancellation, deferral or downsizing of existing EPAs. Since 2014, BC Hydro has either terminated or not renewed 19 EPAs, and has negotiated reductions or deferrals to 13 EPAs. Going forward, EPA renewals will be made more selectively, at lower prices, and for shorter periods. Since 2016, BC Hydro has renewed seven hydro EPAs through bilateral negotiations. Rather than adopting Standing Offer Program pricing as some IPPs might have hoped, BC Hydro has been seeking significantly lower pricing based on electricity spot prices and the developer's cost of service, including an acceptable rate of return on incremental invested capital.

BC Hydro's current plan is to renew roughly three-quarters of existing run-of-river EPAs set to expire by 2024. Developers seeking renewals may have leverage where a project is deemed to be "strategic" to BC Hydro, such as where the project is close to a load centre, has an energy profile that matches peak load months, is able to provide standby resources from storage capacity, or serves a remote or off-grid community.

BCUC Review of EPA Renewals

As we noted in our publication last year, in May 2018 BC Hydro applied for BCUC approval of renewed EPAs entered into in respect of three hydroelectric projects – Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro – whose original EPAs date back to the early to mid-1990s.

In October 2018, BC Hydro obtained BCUC approval to suspend the regulatory timetable for the EPA renewal applications until four weeks following the release by the government of the Phase 1 report of the Review. Following the release of the Phase 1 report in early 2019, BC Hydro filed its arguments in July and September 2019, and the BCUC released its decision on November 8, 2019.

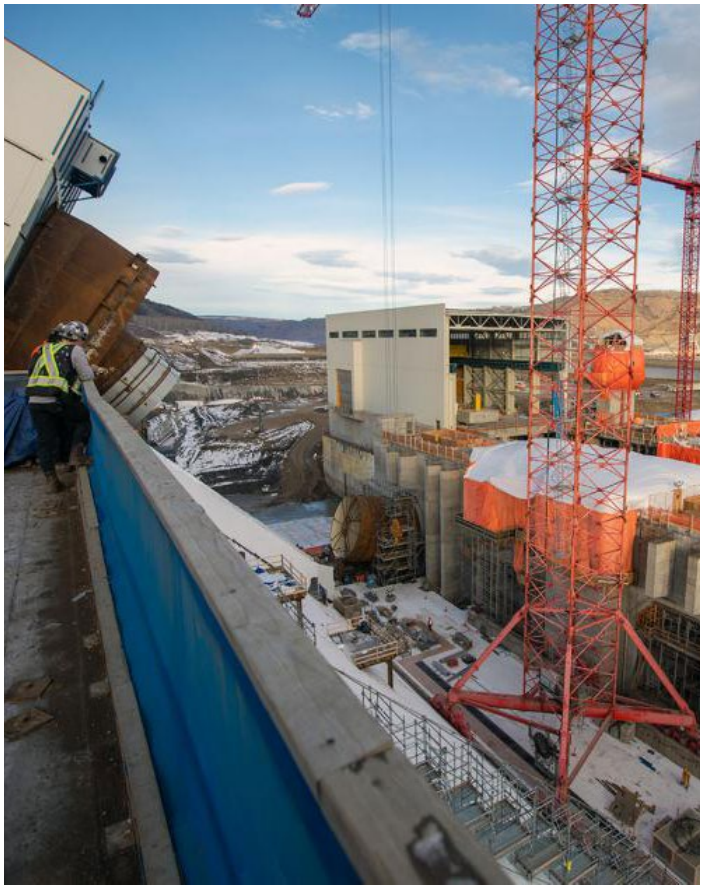
In its decision, the BCUC considered four topics in connection with the EPA renewals: (i) the duty to consult Indigenous groups; (ii) qualitative benefits of the projects; (iii) resource planning and the need for energy; and (iv) cost effectiveness. With respect to the first two topics, the BCUC found that BC Hydro's duty to consult Indigenous groups was not triggered by any of the EPA renewals because there are no anticipated adverse impacts on Indigenous rights or title, and it recognized the importance of the additional benefits provided by each of the EPA renewals to both the local Indigenous and non-Indigenous communities. However, with respect to the third and fourth topics, the BCUC found that there is insufficient evidence to support an approval of the EPA renewals.

In considering resource planning and the need for new energy, the BCUC noted that BC Hydro's most recent IRP from 2013 is outdated, with a new IRP expected from BC Hydro in 2021, and that the Phase 1 report of the Review stated that BC Hydro is currently forecast to be in an energy surplus into the 2030s. Therefore, the BCUC determined that, in the absence of a new IRP, there is insufficient evidence that BC Hydro has a need for the energy from the EPA renewals over their 40-year terms.

In considering cost effectiveness, the BCUC again focused on the 40-year terms of the EPA renewals, and found that ratepayers are exposed to a significant level of risk due to the uncertainty in market prices and potential changes in the energy industry in general over this time period. Therefore, the BCUC determined that there is insufficient evidence that the EPA renewals are cost effective over their 40-year terms.

As a result, while acknowledging the benefits the projects provide to their local and Indigenous communities, the BCUC found that, in the absence of an updated IRP, it was unable to determine that the EPA renewals are in the public interest over their 40-year terms. Importantly, however, the BCUC declined to make a determination that the EPA renewals are not in the public interest, and stated that it is prepared to consider accepting the EPA renewals for periods shorter than 40 years to allow for the conclusion of the next IRP process, at which time there may be further clarity on BC Hydro's long-term energy needs and supply alternatives to meet demand.

Accordingly, the BCUC adjourned the proceeding for 60 days to allow BC Hydro and the counterparties to restructure and resubmit the EPA renewals with a term not to exceed three years, if they so choose. Given the BCUC's decision with respect to these EPA renewals, it appears that any new EPA renewals will need to be for a similarly short term until BC Hydro's new IRP is approved, at which time there may be a basis for longer-term renewals if long-term supply is supported by the new IRP.



source: BC Hydro

Site C Project Update

Construction continues to progress on the $10.7 billion, 1,100 MW Site C project on the Peace River in Northeastern BC, with the project reportedly hitting a concrete placement milestone months ahead of schedule. The most recently released employment figures show that the project employed 4,823 people in October 2019, approximately 75% of whom were workers from B.C.. The project missed a key milestone for timing of diversion of the Peace River due to geotechnical issues that resulted in a one-year delay and increased project costs, but BC Hydro has indicated that Site C is still expected to meet its target in-service date of November 2024. On completion, the project is expected to produce 5,100 GWh of electricity per year for the province.

Site C has faced numerous legal challenges but has prevailed in all 15 court actions so far. In an ongoing civil action, West Moberly First Nations allege that the project unjustifiably infringes their Treaty 8 rights and seek relief including a permanent injunction against completion and operation of the project. In October 2018, the B.C. Supreme Court refused an application by West Moberly for an interlocutory injunction to enjoin certain work on the project pending resolution of their civil claim, but directed that the trial should conclude by no later than mid-2023 such that a judgement could be rendered in advance of reservoir flooding, which is presently scheduled for Fall 2023. Prophet River First Nation is also continuing with its parallel civil action to West Moberly, similarly alleging infringement of its Treaty 8 rights. In February 2019, the B.C. government, BC Hydro, West Moberly and Prophet River agreed to enter into confidential discussions to seek alternatives to litigation, which discussions have apparently been unsuccessful to date.

LNG Update

The province's nascent liquefied natural gas ("**LNG**") export industry received a boost with the announcement in March 2019 of a new tax credit regime whose effect will be to reduce applicable corporate tax rates from 12% to 9%, while replacing the prior LNG tax regime that was seen by many as a barrier to project investment.

source: LNG Canada

Following the announcement of its final investment decision ("**FID**") in October 2018, LNG Canada – a joint venture between Shell Canada, PETRONAS, PetroChina, Mitsubishi Corporation and KOGAS – set to work on the construction of its $40 billion LNG facility in Kitimat, British Columbia. Key activities undertaken in 2019, include dredging in Kitimat harbour to prepare the existing port for larger vessels, environmental offsetting programs (including the creation of salt marshes, a fish ladder, and the diversion of the Kitimat River to offset the environmental impact of construction-related work) and site preparation for Cedar Valley Lodge (the project's long-term workforce accommodation centre and associated facilities), which is targeted to open in the first half of 2020.

Pursuant to an electricity supply agreement entered into with BC Hydro in 2014, the LNG Canada project is expected to draw approximately 2,000 GWh/year of electricity from BC Hydro's grid to power its ancillary (non-liquefaction) activities. With LNG Canada targeting a 2024 completion date, this new load is expected to coincide with Site C's targeted in-service date.

Pacific Oil and Gas Ltd.'s Woodfibre LNG project, which announced a positive FID in November 2018, also continues to achieve milestones in the development of its 2.1 million tonne per annum, $1.6 billion LNG project near Squamish. Having received a key facilities permit in July 2019, the project continues to progress toward construction with a view toward achieving an in-service date in 2023.

The most significant pre-FID LNG project remaining is Kitimat LNG, a 50/50 joint venture between Chevron Canada and Woodside Energy, which comprises the 471 km Pacific Trail Pipeline and a natural gas liquefaction facility at Bish Cove near Kitimat. The Kitimat LNG plant includes up to three LNG trains totalling 18 million tonnes per annum. Significantly, the project has committed to powering its liquefaction and ancillary activities entirely with electricity, which according to its proponents, would enable Kitimat LNG to achieve the lowest emissions intensity of any large-scale LNG facility in the world.

In early December 2019, the Canada Energy Regulator approved Kitimat LNG's application to increase its size to 18 million tonnes per annum and extend its export licence from 20 to 40 years. Shortly thereafter, Chevron Canada announced that it plans to exit its investment in Kitimat LNG and intends to commence soliciting expressions of interest for its 50% interest in the project.

In its most recent load forecasts, BC Hydro has estimated the province's prospective LNG load at 2,700 GWh, based solely on the LNG Canada, Woodfibre LNG and Tilbury LNG plants. Should the Kitimat LNG project proceed on a fully-electrified basis, the province's LNG load would significantly exceed this estimate. In its updated project proposal, Kitimat LNG plans for the use of electric motor drives totalling 700 MW, which represents approximately two-thirds of the planned capacity of Site C.

Canada-B.C. Clean Power Planning Committee Established

In August 2019, the governments of Canada and British Columbia entered into a Memorandum of Understanding (the "**MOU**") to establish the Canada–British Columbia Clean Power Planning Committee (the "**Committee**"), whose mandate will be to advance projects that increase electrification and power transmission in British Columbia.

The MOU, which is effective for a five-year term, forms part of a broader effort by both jurisdictions to advance clean power in the province. The Committee will be made up of senior representatives from both jurisdictions as well as BC Hydro. The Committee will also engage with Indigenous groups to help ensure Indigenous views are appropriately reflected in the initiatives set out in the MOU.

The Committee will undertake the following actions in order to achieve its mandate:

- advance natural gas and liquefied natural gas electrification initiatives, including the CleanBC Facilities Electrification Fund, Bear Mountain to Dawson Creek Voltage Conversion project, and North Montney Power Supply project;
- explore other electrification and transmission expansion opportunities, as identified by the participants;
- improve cross-government coordination to connect existing and new funding sources to priorities, and in particular with respect to federal infrastructure funding; and
- develop and consider new and/or alternative financing models to advance priority transmission projects, including potential Indigenous or other private sector ownership and participation by the Canada Infrastructure Bank.

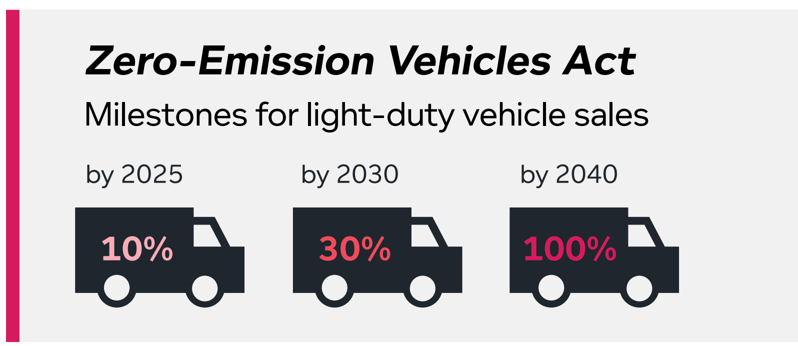
The participants will jointly decide on overall resource levels to devote to the initiatives set out in the MOU. A total of $680 million in near-term electrification projects for joint funding is under consideration.

CleanBC Initiative Creates Opportunities for Electrification

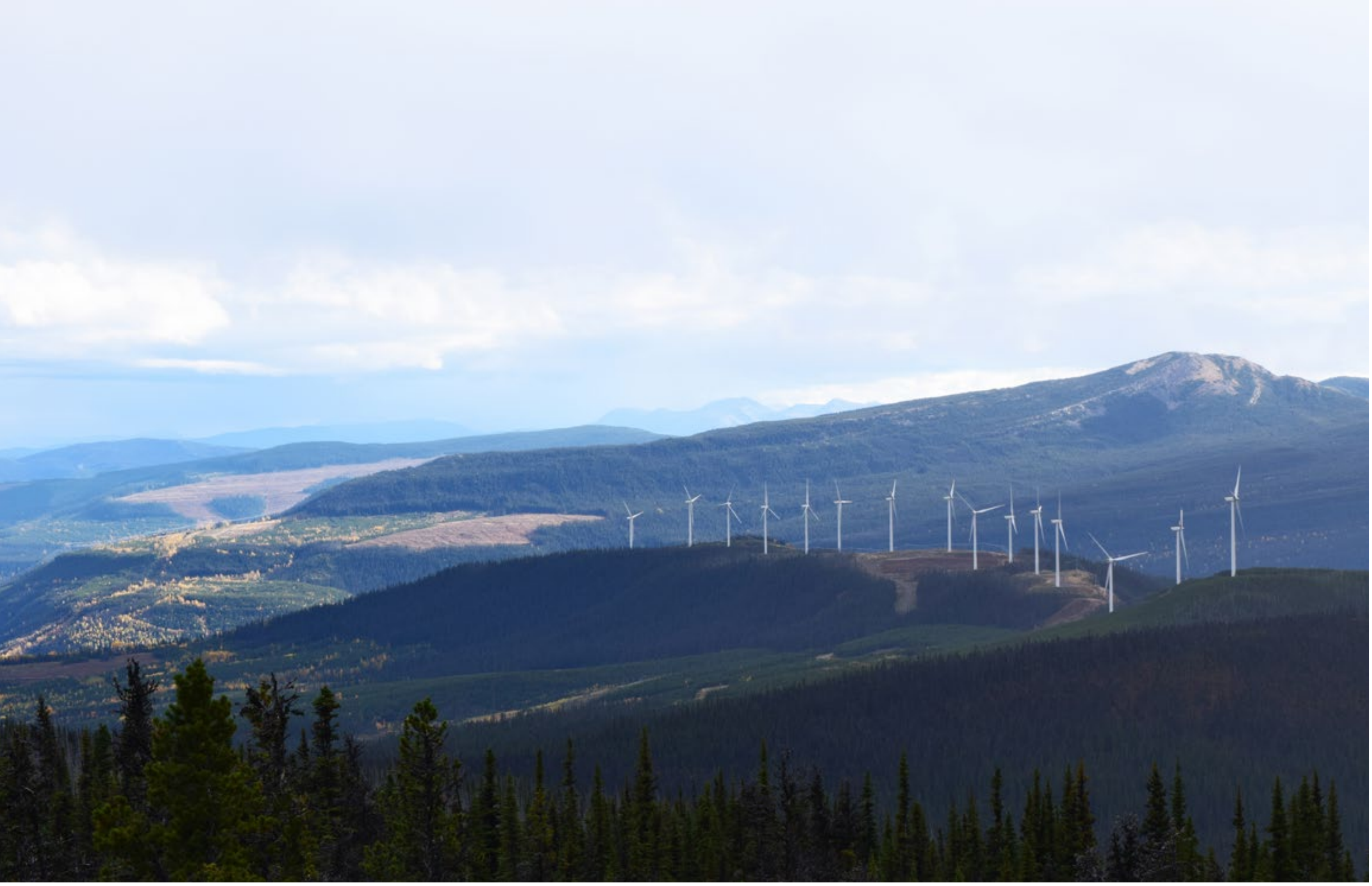
Launched in late 2018, the B.C. government's CleanBC initiative seeks to move British Columbia's energy consumption from fossil fuels to clean energy to help support legislated greenhouse gas ("**GHG**") emissions-reduction targets. Increased electrification of the industrial and transportation sectors in the province are major pillars of the strategy.

The CleanBC plan estimates that by 2030, implementation of the policies in the plan will create an additional 4,000 GWh per year of electricity demand over currently projected load growth in order to meet legislated GHG reduction goals, which require a 40% reduction in GHG below 2007 levels by 2030. The increase is equivalent to increasing BC Hydro's current capacity by approximately 8%.

In May 2019, the B.C. government passed the *Zero-Emission Vehicles Act* ("**ZEV Act**"), which requires automakers to meet an escalating annual percentage of new light-duty ZEV sales and leases, with the following mandated milestones: 10% of light-duty vehicle sales by 2025; 30% by 2030; and 100% by 2040.



In addition to ensuring a greater availability of zero-emission vehicles at more affordable prices in the province, the ZEV Act will provide a regulatory backstop to help ensure that provincial GHG reduction targets are met. With the passage of the ZEV Act, B.C. joined a growing number of jurisdictions with ZEV standards, including Quebec, California, and nine other US states, and became the first jurisdiction in the world to legislate a 100% ZEV target.



Together with potential LNG-related load, these prospective sources of increased electricity demand in B.C. have led many industry observers to speculate that B.C.'s state of electricity surplus, projected by BC Hydro to last until 2032, may in fact end much sooner, creating opportunities for IPPs to help meet the increased demand.

Revitalized B.C. Environmental Assessment Process Incorporates Indigenous Considerations at All Stages

In March 2018, the B.C. government launched the process for revitalizing the province's environmental assessment ("**EA**") process, which was followed by the introduction of Bill 51 – Environmental Assessment Act in November 2018. On December 16, 2019, the new legislation ("**New EAA**") came into force. The New EAA introduces significant changes to the provincial EA process, including the creation of an early engagement process and prescriptive measures to meet the B.C. government's commitment to implement the *United Nations Declaration on the Rights of Indigenous Peoples* ("**UNDRIP**"). Under the revitalized EA process, Indigenous considerations are incorporated at all stages of the EA review process.

Some of the key Indigenous-related changes to the EA process include the following:

- Indigenous participation in EAs will no longer be driven by reference to the strength of their claim; rather, potentially impacted Indigenous nations will identify themselves during the early engagement phase;
- the Minister may enter into agreements with Indigenous nations for the purposes of conducting any aspect of an EA;
- an Indigenous nation can enter into an agreement with the Minister to conduct the entire assessment on behalf of the provincial government (substitution) provided certain conditions are met; and
- Indigenous knowledge must be applied to decision-making in EAs.

Finally, as an affirmation of the principle of "free, prior and informed consent" ("**FPIC**") contained in UNDRIP, participating Indigenous groups will have the opportunity to communicate their consent, or lack of consent, at two decision points in the EA: (1) at the EA readiness phase, to exempt the project from an EA and go straight to permitting, or terminate the process; and (2) whether to issue an EA certificate for the proposed project. In the event consensus cannot be achieved, a dispute resolution mechanism will be available under the *Dispute Resolution Regulation*, expected to be released in mid-2020. Although ministerial discretion is maintained in respect of all final project approvals, the decision must take into account and provide reasons where consent has not been obtained or decisions do not align.

B.C. Embraces Reconciliation with *The Declaration On The Rights Of Indigenous Peoples Act*

On November 28, 2019, B.C.'s *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") received Royal Assent. It is the first legislation to be passed in Canada that directs government to implement UNDRIP into law. DRIPA is intended to form the foundation for B.C.'s work on reconciliation. Its three stated purposes are to (i) affirm the application of UNDRIP to the laws of B.C.; (ii) contribute to the implementation of UNDRIP; and (iii) support the affirmation of, and develop relationships with, Indigenous governing bodies. As a framework piece of legislation, DRIPA provides that the province:

- must, in consultation and cooperation with Indigenous peoples, take all measures necessary to ensure the laws of B.C. are consistent with UNDRIP;
- must prepare and implement an action plan to achieve the objectives of UNDRIP and prepare an annual report outlining its progress in implementing the action plan; and
- may, for the purposes of reconciliation, enter into agreements with Indigenous governing bodies in relation to the exercise of a statutory power of decision.

The B.C. government has stated that DRIPA is not intended to immediately affect or change any existing laws; rather, it is intended to be forward-looking, with a gradual and incremental implementation process as laws are introduced or amended in consultation with Indigenous peoples and stakeholders, including business, industry and local government. Accordingly, DRIPA is not expected to result in any immediate changes to the common-law duty to consult framework or to existing regulatory frameworks.

Despite assurances from the province that DRIPA will support economic development through greater certainty for investment while creating a strong inclusive economy, DRIPA's text and the implementation of UNDRIP into B.C. laws gives rise to numerous questions. Foremost among those is how the principle of FPIC will be interpreted and applied. Several UNDRIP articles address Indigenous land and resource rights, including requirements for states to seek or obtain FPIC from Indigenous groups, including "prior to the approval of any project affecting their lands, territories or resources, particularly in connection with the development, utilization or exploitation of mineral, water or other resources" (Article 32(2)). The B.C. government has repeated its position that it does not view FPIC as equivalent to an unqualified veto right. However, consent could notionally become the standard in certain circumstances, whether through the use of the agreement mechanism under DRIPA, through legislative amendments, or as a condition to granting a project approval. The agreement tool includes express contemplation of a negotiated consent requirement prior to a government decision on matters affecting an Indigenous group. The provincial government's philosophy towards FPIC under the New EAA, as described above, provides a potential model for applying FPIC in other provincial legislative and regulatory regimes. However, the agreement mechanism under DRIPA and the agreement and decision-making processes under the New EAA all remain discretionary approaches on the part of government. Therefore, the manner and extent to which FPIC is applied will largely depend on the B.C. government's willingness to allocate certain responsibilities and authority to Indigenous groups, which could be highly contextual.

Although DRIPA is intended to provide the B.C. government with discretionary and incremental approaches in implementing UNDRIP, DRIPA is significant because it imposes an increased level of accountability on the provincial government to make good on its promises. Expectations will be amplified by the unqualified requirement for the government to "take all measures necessary to ensure the laws of B.C. are consistent with" UNDRIP. Such ambitious requirements could expose the government to scrutiny and legal challenges, setting it up for potential failure with regard to the adequacy of its implementation efforts. The challenge for the provincial government going into 2020 will be to advance its commitments through the development of an action plan and priorities in a way that does not stifle investment or create additional uncertainty. To do so, it must manage the enormous expectations that it has created while striking a balance between competing interests.

What to Expect in 2020

Completion of BC Hydro Review

As noted above, Phase 2 of the Review will focus on ensuring BC Hydro is well positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological changes, and climate action and to help achieve the electrification goals set out in the CleanBC plan. A final report with recommendations is expected to be completed in early 2020.

Integrated Resource Plan Due in Early 2021

BC Hydro is long overdue in updating its IRP – the long-term plan to meet the province's future electricity demand through conservation, generation and transmission, and through upgrades to existing infrastructure. Last prepared in 2013, the IRP has been delayed in order to take into account the Review and the province's emerging energy roadmap, and is now expected to be released in February 2021.

Despite the frozen state of power procurement in B.C. right now, there are a number of forces that could materially reshape the load-resource balance in the province, including:

– the large-scale electrification called for under the CleanBC initiative is projected to require an additional 4,000 GWh of energy by 2030 over and above projected demand growth;

– the potential for another major LNG project whose energy needs will likely need to be powered by electricity to align with CleanBC imperatives; and

– the fact that BC Hydro's forecast of an energy surplus until 2032 is predicated on the achievement of demand-side management savings of over 3,400 GWh of energy, when such targets have historically proven difficult to achieve.

BC Hydro will have to address these contingencies as part of Phase 2 of the Review and the preparation of its IRP.

LNG – Still More to Come?

Despite obtaining regulatory approval for a size increase and extended export license, the all-electric Kitimat LNG project faces uncertainty following the recent announcement by Chevron Canada that it will sell its 50% interest in the project. Stay tuned in 2020 to see who acquires Chevron's stake and whether the project continues to move closer to FID, which its current proponents estimate will occur in 2022 or 2023.

EPA Renewals: On Hold

Given the BCUC's decision that it is unable to determine if long-term EPA renewals are in the public interest until updated information is available on BC Hydro's energy needs and supply alternatives, the fate of long-term EPA renewals will depend heavily on the load-resource forecast being prepared for the IRP due in early 2021.

Alberta – Overview

Authors: Jamie Gibb, Kerri Howard, Kimberly Howard and Gord Nettleton

Introduction

With the newly elected United Conservative Government of Alberta and a new climate strategy, Alberta's electricity industry continues to be in a state of transition. In the AESO 2019 Long-term Outlook, the Alberta Electric System Operator ("**AESO**") predicted that 19% of the province's electricity supply will be sourced from renewables in 2030. This is a 10% increase but significantly less than the 30% by 2030 projection the AESO made in its 2017 forecast under the former New Democratic Party ("**NDP**") governement. The 30% renewables by 2030 target remains enshrined in legislation as part of the *Renewable Electricity Act* ("**REA**"), but it is unclear how the government of Alberta intends to hit this target.

Key Developments in 2019

Election

The Alberta election was held on April 16, 2019. The Jason Kenney-led United Conservative Party ("**UCP**") won 54.88% of the popular vote and 63 seats, reducing then-Premier Notley's NDP to official opposition with 24 seats.

The newly elected Government of Alberta has been quick to implement its platform. Since its election, the Government of Alberta has drastically changed the landscape of the Alberta electricity market. Among other things, the Government of Alberta has cancelled the NDP's planned market overhaul, which would have changed Alberta's energy system from an energy-only market to a capacity market, and cancelled the Alberta Renewable Electricity Program. In addition, after a mere 4 weeks of being sworn-in, the Government of Alberta repealed the Alberta carbon levy and rebate system. It is anticipated that the Government of Alberta will continue to make changes as it continues to implement its platform to balance the provincial budget in 2020.

Cancellation of Capacity Market

On July 24, 2019, the Government of Alberta announced that it would not proceed with the implementation of a capacity electricity market. As highlighted in our 2018 Alberta Regional Overview, *Bill 13: An Act to Secure Alberta's Electricity Future,* was passed to provide the legal framework to support Alberta's transition to a capacity market. The AESO was required to consult with market participants, stakeholders and the Market Surveillance Administrator in the development of proposed changes to the rules to establish a capacity market. The proposed AESO rules would then have required the approval of the Alberta Utilities Commission ("**AUC**" or the "**Commission**") prior to implementation.

However, following a 90-day review period by the new UCP government (a campaign promise to determine which market-based system is best for Alberta), the government determined not to proceed with the implementation of the capacity market and to remain as an energy-only market. The decision to abandon the capacity market came on the eve of a pending AUC decision with respect to the AESO's application for approval of the first set of provisional market rules essential for the implementation and operation of the capacity market. The key goal in the government's decision to abandon a capacity market in Alberta was to restore investor confidence in Alberta's electricity system by returning to a cost-effective, reliable, energy-only market.

In an energy-only market, electricity is generated, sold and bought on the wholesale electricity market. Alberta has been operating an energy-only market for electricity for over 20 years. Coupled with the announcement from the government was direction to the AESO to consider whether changes are needed to the energy-only market, including changes to the price floor/ceiling and shortage pricing, and to provide guidance on market

power mitigation.The AESO delivered an initial report to the Government of Alberta on required market changes; however, the report has yet to be made available publicly.

Cancellation of AESO's Renewable Electricity Program

On June 10, 2019, the Government of Alberta advised the AESO that it will not be continuing with the Renewable Electricity Program ("**REP**"), as it had deemed the program to be a costly subsidy. REP round 4 was intended to procure up to 400 megawatts of renewable electricity. Although the REP was cancelled, the Government of Alberta directed the AESO to continue to honor the awards issued under REP Rounds 1, 2 and 3. Under the REP, successful bidders entered into a Renewable Electricity Support Agreement ("**RESA**") with the AESO, which provides a 20-year indexed renewable energy credit, structured akin to a contract for differences, to cover any difference between the participant's bid for energy generated from a project and the pool price of energy in the market.

The following wind projects were awarded REP Round 1 RESAs and were anticipated to be operational by the end of 2019.

Four wind projects were selected for REP Round 1.[1]

Proponent	Project	MW	Nearest City/Town
EDP Renewables Canada Ltd.	Sharp Hills Wind Farm	248.4	Oyen
Enel Green Power Canada, Inc.	Riverview Wind Farm	115.0	Pincher Creek
Enel Green Power Canada, Inc.	Phase 2 of Castle Rock Ridge Wind Power Plant	30.6	Pincher Creek
Capital Power Corporation	Whitla Wind	201.6	Medicine Hat

The following wind projects were awarded REP Round 2 RESAs and are anticipated to be operational by June 30, 2021.[2]

Proponent	Project	MW	Nearest City/Town
EDF Renewables Canada Inc.	Cypress Wind Power Project	201.6	Medicine Hat
Potentia Renewables Inc.	Stirling Wind Project	113.0	Lethbridge
Capstone Infrastructure Corporation	Buffalo Atlee Wind Farm 1	17.25	Brooks
Capstone Infrastructure Corporation	Buffalo Atlee Wind Farm 2	13.8	Brooks
Capstone Infrastructure Corporation	Buffalo Atlee Wind Farm 3	17.25	Brooks

1 Source: https://www.aeso.ca/market/renewable-electricity-program/rep-results/

2 *Ibid*

The following wind projects were awarded REP Round 3 RESAs and are anticipated to be operational by June 30, 2021.[3]

Proponent	Project	MW	Nearest City/Town
TransAlta Corporation	Windrise Wind	207.0	Pincher Creek
Potentia Renewables Inc.	Jenner Wind Power Project	122.4	Brooks
Potentia Renewables Inc.	Jenner Wind Power Project 2	71.4	Brooks

Alberta Infrastructure Procures 135,000 MWh of Solar-Generated Electricity

In October 2018, Alberta Infrastructure issued a Request for Proposals for the procurement of 135,000 MWh of solar-generated electricity each year for the next 20 years. Before releasing the RFP, Alberta Infrastructure sought input from industry stakeholders through a Request for Information in August 2018. Successful bid participants will enter into Solar Electricity Support Agreements with Alberta Infrastructure.

In February of 2019, Alberta Infrastructure awarded Canadian Solar Solutions Inc. a 20-year contract at an average price of 4.8 cents per kilowatt-hour. Canadian Solar Solutions Inc. along with Conklin Metis Local 193 (which has a 50% equity stake in the projects) will build three new solar farms near the communities of Hays, Tilly and Jenner in southeast Alberta. These three facilities will have a combined capacity of approximately 100 MW and are expected to be completed in 2021.

Cancellation of Energy Efficiency Alberta Programs

On November 7, 2019, numerous programs offered by Energy Efficiency Alberta (an organization established by the NDP government in 2017) were cancelled by the newly elected UCP government. The following incentive programs were eliminated:

i. the Residential and Commercial Solar Program, which provided incentives to businesses and homeowners to install solar panels on their rooftops;

ii. the Community Generation Program, a partnership between Energy Efficiency Alberta and the Municipal Climate Change Action Centre to support the installation of locally generated renewable energy projects;

iii. the Home Improvement Program, which offered rebates for new windows, insulation, tankless water heaters and more; and

iv. the Online Rebate Program, through which Albertans could receive rebates for new appliances, smart thermostats and other purchases that improve energy efficiency.

3 *Ibid*

Market Rule Developments

AUC Rule Amendments

The following are new or amended AUC requirements or processes established in 2019:

Rule 012: Noise Control

In December 2017, the AUC initiated a consultation process on changes to certain provisions of Rule 012: Noise Control. The AUC stated that a number of issues with respect to predicted sound level and compliance determination have arisen when construction is delayed, and when multiple facilities exist or are proposed in proximity to one another. These issues include the following:

i. post-construction sound level surveys submitted by facility owners frequently identify challenges in collecting sufficient representative data required to meet the requirements of Rule 012. Many of these post-construction surveys have had to be redone;

ii. members of the public have filed noise-related complaints regarding constructed facilities;

iii. delays between approval and construction dates for facilities/power plants can add complexity to adjacent facility proposals or construction of dwellings in proximity to approved facilities; and

iv. lengthy construction delays after a project has been approved can result in alterations to the selected wind turbine model, thereby potentially affecting noise impact assessments of the proponent, as well as adjacent facilities.

The AUC approved amendments to Rule 012 on April 16, 2019. The final results of the consultation process were a revised Rule 012 and a revised Rule 007, which were issued and published on the AUC website. The amendments to the rules were effective August 1, 2019. The amended Rule 012 includes but is not limited to: (i) a new definition of baseline sound level which now includes noise contribution from existing energy-related facilities, (ii) conditions for when a new noise impact assessment must be filed as part of a time extension request; and (iii) a new definition of ambient sound.

Rule 024: Rules Respecting Micro-Generation

The AUC worked with stakeholders and the AESO to update the AUC's Micro-Generation Notice Submission Guideline. The revised guideline was published in May 2019, and summarizes the current processes required to obtain approval for micro-generation connection to the grid. As a result, Rule 024: Rules Respecting Micro-Generation also underwent minor amendments.

Rule 030: Compliance with the Code of Conduct Regulation

The AUC approved an amended Rule 030: Compliance with the Code of Conduct Regulation, effective April 1, 2019. Section 40(4) of the Code of Conduct Regulation permits the Commission to make exemptions from audits for a period not exceeding 36 months. The table in Section 6 of Rule 030 has been amended to reflect audits completed in 2018-2019, the revised timing due to updated compliance plans, and has been reorganized for ease of reference. The amendments were considered to be minor and were made without stakeholder consultation.

Rule 033: Post-Approval Monitoring Requirements for Wind and Solar Power Plants

On June 12, 2019, the Commission approved Rule 033: Standardized Post-approval Monitoring Requirements for Wind and Solar Power Plants. This Rule was effective July 1, 2019. The intent of post-construction monitoring standards is to ensure that approved wind and solar power plant owners and operators implement effective, consistent operational mitigation measures to minimize the potential for negative effects on Alberta's wildlife and wildlife habitat. The Commission believes that the establishment of standardized post-approval monitoring requirements will improve the consistency of monitoring obligations for owners and operators of approved wind and solar power plants, and will add certainty to the regulatory process.

ISO Rule Amendments

Minimal amendments to the ISO Rules occurred in 2019. The only substantive amendment was to Section 501.10 (Transmission Loss Factors). The amendments were made for the following reasons: (i) to ensure that loss factors reasonably recover the cost of losses on the transmission system; and (ii) to provide transparency to market participants on how loss factors are calculated.

Market Surveillance Administrator

MSA Consultation on Offer Behaviour Enforcement Guidelines

As previously discussed, on July 24, 2019, the Government of Alberta announced that a capacity market will not be implemented in Alberta and the energy-only market will be maintained. Following such announcement, the Alberta Department of Energy was directed to examine whether any changes to the existing energy-only market are needed for it to remain successful, including a policy review related to market power and market power mitigation. The subject matter of this examination, according to the Market Surveillance Administrator ("**MSA**"), is indistinguishable from participant offer behaviour. As a result, the MSA is not continuing its own consultation related to the Offer Behaviour Enforcement Guidelines.

Section 5 of the Fair, Efficient and Open Competition Regulation ("**FEOC**") requires that the MSA publish the percentage of offer control held by electricity market participants at least annually. An electricity market participant's total offer control is measured as the ratio of megawatts under its control to the sum of maximum capability of generating units in Alberta.

	2019-01-31[4]	
Company	Control (MW)	%
TransAlta	3,270	21.0%
Balancing Pool	2,284	14.7%
ATCO	1,977	12.7%
ENMAX	1,446	9.3%
Suncor	1,158	7.4%
Capital Power	1,118	7.2%
Other	4,002	25.7%
Total Dispatchable	15,254	98.0%
Total Non-Dispatchable	316	2.0%
Grand Total	**15,570**	**100.0%**

Alberta's total capacity decreased 318 MW since the last market share offer control assessment on April 22, 2018. This was primarily due to the retirement of TransAlta's Sundance Unit 2.

Advisory Opinion Program

Following requests received from market participants in October 2018, the MSA initiated a stakeholder consultation to consider whether a voluntary advisory opinion program would be helpful to market participants. On October 23, 2019, the MSA created an Advisory Opinion Program ("**AOP**") that will provide advisory opinions with respect to whether proposed business conduct and practices of Alberta electricity market participants comply with their obligations under the Electric Utilities Act, including regulations created thereunder.

4 Source: Market Surveillance Administrator, 2019 Market Share Offer Control Report (September 24, 2019)

Alberta electricity market participants who wish to obtain a non-binding Advisory Opinion from the MSA (the "**Applicant**") must submit a written request that contains all of the following information:

- details of the Applicant's proposed business practice;
- relevant data and analysis available to the Applicant;
- relevant third-party data and analysis; and
- the Applicant's contact information.

There is no fee to be paid by an Applicant who requests an advisory opinion. In the interest of facilitating greater understanding and transparency of the MSA's views to the broader market, the MSA will publish a version of any advisory opinion it issues that maintains the confidentiality of the Applicant and any commercially sensitive information.

The Future of Distribution Connected Generator Credits

AUC Decision 22942-D02-2019 issued on September 22, 2019 approved the AESO's 2018-2020 tariff. One of the key changes proposed in this application concerned the metering of flows used to calculate demand transmission services and which may affect distribution connected generators ("**DCG**"). Generation technologies used in DCG include photovoltaics, microturbines, internal combustion reciprocating engines, combustion turbines, wind generators and fuel cells that may be situated at residential, commercial and industrial sites. DCG can be used to generate a customer's entire electrical energy supply, to reduce peak demand (commonly referred to as "peak shaving") for standby or emergency generation, as a green power source or for increased reliability of the distribution system.

As at the end of 2017, ATCO Electric, ENMAX and FortisAlberta tariffs all included a provision that provides transmission-based credit to large-scale DCG providers. Micro-generators (less than 5 MW) are not eligible to receive transmission tariff-based credits. FortisAlberta's credit is referred to as Option M, ATCO Electrics's credit is D32 and ENMAX's credit is known as rate D600. The credits are calculated based on the electrical energy delivered by the DCG to the distribution system, and are the difference between the AESO system access service charges to the distribution wire owner (with the generator in operation), and the charges that would have been incurred if the generator had not been in operation. The amounts are calculated manually for each DCG using actual hourly metering data.

In a prior report, the AUC observed that because the AESO does not provide a credit to the distribution wire owners for reduced transmission system costs due to DCG, the distribution wire owners that must provide this credit must recover the cost of the credit from all of its distribution customers. In this decision, the AUC formally considered the continuation of this practice.

The AESO's position was that no economic advantage should be provided to a generator that connects via the distribution system over the transmission system and DCGs should not receive distribution derived transmission credits. In response, the AUC held that the continuation of DCG credits was a matter to be determined in distribution tariff-setting processes, and not the present AESO tariff matter. Therefore, the fate of the DCG credits remains uncertain pending the outcome of future distribution tariff-setting processes.

AUC Decisions re Cogen and Self-Supply

On February 20, 2019, the AUC released AUC Decision 23418-D01-2019, El Smith Solar Power Plant (the "**Smith Decision**") contemplating the issue of cogeneration and self-supply. Additional commentary regarding the Smith Decision can be found in our litigation review on page 56 of this publication.

The Smith Decision raises important issues regarding self-generation where a generator seeks to export surplus generation not used for self-supply to the grid. The AUC concluded that a self-generator could only avoid the general must-offer, and must-exchange obligations as set out in the *Electric Utilities Act* ("**EUA**") and the *Hydro and Electric Energy Act* ("**HEEA**"), if it fell within one of the prescribed exceptions in the legislative scheme.

	Nature of exemption[5]	Trigger for exemption	Maximum size
EUA s. 2(1)(b)	Exemption from the entire EUA	Entire generation self-consumed. Fuel neutral.	No maximum
EUA s. 99 (Industrial System Designation)	Energy produced is exempted from the EUA	An Industrial System Designation by AUC	No maximum
Flare Gas Regulation	Exempt from must-exchange (18(2)) & financial settlement (17(d)) & by implication, must-offer.	Generating unit must run on solution gas; solely used by operator.	No maximum but must connect to distribution.
Small Micro-Generation	Exempt from must-exchange (18(2)) & by implication, must-offer. Service provider acts as market participant	Renewable or alternative energy	< 150 kW
Large Micro-Generation	Service provider acts a market participant and must-exchange	Renewable or alternative energy	< 5MW
Small Scale Generation	No exemption from must-exchange; deemed $ zero offer and balancing pool ("**BP**") acts as the market participant	Renewable or alternative energy & a community benefits agreement or statement	Must not exceed distribution system's hosting capacity

The AUC concluded that the broad exemption offered under section 2(1) of the EUA is only available to a self-generator who does not export any surplus generation to the grid. If any surplus generation is exported, no matter how small, this exemption is forfeited and the generator must then comply with the must-offer, must-exchange rules for the entire output of the facility unless another exemption can be applied. The Smith Decision has been subsequently affirmed by AUC Decision 23756-D01-2019 and AUC Decision 24393-D01-2019. Read together, the AUC concluded that a project would not be approved for self-supply and export unless it fell within the 5 MW limit of the *Microgeneration Regulation* or the project had an industrial system designation ("**ISD**") under section 4 of the *Hydro and Electric Energy Act*.

Prior to the Smith Decision, many co-generation facilities were relying on prior AUC decisions which contemplated such facilities supplying both to the grid and for their own use without reference to the must-offer, must-exchange obligations under the *Fair, Efficient and Open Competition Regulation* ("**FEOC Regulation**") enacted pursuant to the EUA. On September 13, 2019, the Commission issued Bulletin 2019-16 launching consultation on the issue of power plant self-supply and export and sought stakeholder input on the following options for addressing the self-supply and export issue in the future:

Option 1: Status quo – no change to the statutory scheme is required.

Option 2: Allow limited self-supply and export – this requires a change to the statutory scheme. This exemption could be similar to the micro-generation exemption where operators are required to size their plant to meet internal need on an annual basis, but will be allowed to export excess energy to the grid to a certain percentage of annual production. Comments on the concept and an appropriate export threshold will be helpful.

Option 3: Unlimited self-supply and export – this requires a change to the statutory scheme and

5 Source: Nigel Bankes, 'Opening a Can of Worms: What are the applicable market rules for generation where the generator fails to use the entire output?', Ablawg.ca, March 5, 2019.

may require changes to existing transmission and distribution tariff structures.

The outcome of these consultations, future AUC decisions and any resulting legislative changes could have impacts on co-generation and industrial systems across the province. The change in the AUC's interpretation of its governing legislation has created significant regulatory uncertainty. It is anticipated that relief in the form of statutory amendments or new AUC rules may be on the horizon in 2020.

Energy Storage in Alberta

Alberta is in the process of phasing out coal-fired power and has a legislated target of 30% renewable electricity generation by 2030. In late 2017 and early 2018, as part of its plan to achieve these goals, the AESO assessed the potential need for dispatchable renewables and energy storage to maintain system reliability, flexibility and ramping capability. The AESO concluded that there was no emerging need to specifically procure additional flexibility on the system. This conclusion was based upon the Energy+ Environmental Economics Inc. (E3) study commissioned by the AESO. E3 assessed two common types of energy storage to determine its cost effectiveness: (1) lithium-ion batteries (short-term duration); and (2) pumped hydro storage (long-term duration).

E3's key findings regarding the potential cost effectiveness of energy storage on the Alberta system included:

– Alberta's current transmission tariff makes it difficult for storage to be cost-effective;

– large-scale storage projects (> 50 MW) are unlikely to be cost effective in Alberta due to: (1) early reserve market saturation (AESO's operating reserve market may provide high revenues per MW but the market is small); and (2) insufficient daily pool price spreads (even with 12 hours of daily "energy arbitrage" (charging 12 hours at low prices and discharging 12 hours at high prices), storage would need more than a $60/MWh daily price spread to cover a $2500/kW capital cost. AESO projected daily spreads instead range from $15-30/MWh); and

– smaller storage projects (< 50 MW) may provide market positive revenues in Alberta from operating reserve and the future capacity market if: (1) Alberta's transmission tariff is revised for charging costs; and (2) price saturation in the operating reserve markets can be avoided.

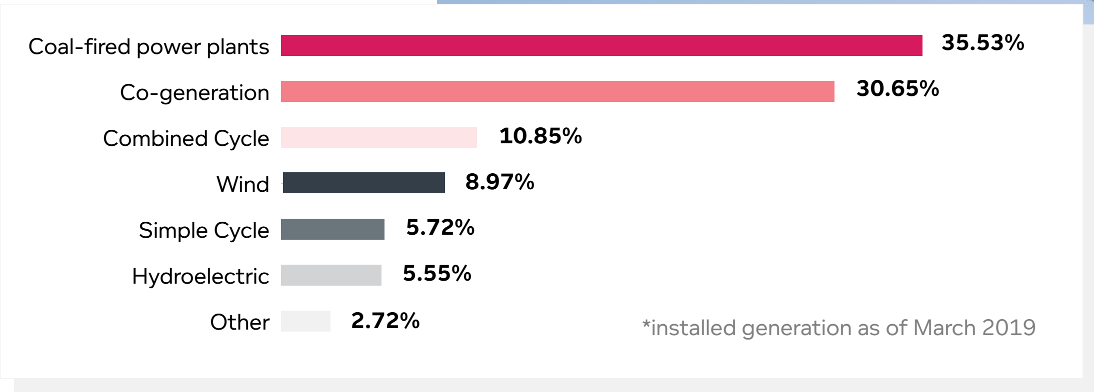
Although the AESO concluded that there was no requirement to procure storage capacity, it nonetheless developed an Energy Storage Roadmap for Alberta's system. In August 2019, the AESO released its Energy Storage Roadmap. The AESO solicited stakeholder input on the roadmap and a summary of the feedback can be found on the AESO's website[6]. A key theme arising from the stakeholder feedback includes the need to clarify tariff design for energy storage and whether it will be considered generation, load, both, or an ancillary service.

6 https://www.aeso.ca/assets/Uploads/Energy-Storage-Roadmap-update-to-stakeholders-final.pdf

What to Expect in 2020

Alberta continues with its energy-only market and a legislatively enshrined target of 30% renewable electricity by 2030. As of March 2019, the installed generation capacity still relies heavily on coal-fired power plants, co-generation and combined and simple cycle natural gas generation.

Electricity in Alberta[7]



Notwithstanding the federal government's grant of equivalency to Alberta's greenhouse gas emissions policy (the "Technology Innovation and Emissions Reduction System" or "**TIER**"), the federal consumer carbon levy will take effect in Alberta effective January 1, 2020. With the cancellation of most, if not all, of the NDP's program incentives for renewable generation, it remains uncertain how Alberta will meet its legislative "30 by 30" target. Whether the Government of Alberta will create its own regime and policies to achieve this target or seek legislative amendment, will have a direct impact on the generation supply mix and investment in Alberta. This, combined with the rapid pace of technological advancements, will no doubt spur change in Alberta's electricity market.

We expect that Alberta will continue to see growth in the number of smaller market participants as more industrial facilities and consumers install their own generation (e.g. co-generation or even small-scale roof-top solar) and more distribution system-connected renewable energy is developed. Interest in private or non-government backed power purchase agreements will continue to be a focus for future investment in the province.

7 Source: https://www.aeso.ca/aeso/electricity-in-alberta/

Ontario – Overview

Authors: Karen Luu, Zachary Masoud, Seán O'Neill and George Vegh

Introduction

Ontario's power sector continues to be in a state of transition. With the provincial government continuing a wide-ranging review and changes on multiple fronts (including energy regulator governance, renewable projects, climate change and generation contracts), uncertainty and anticipation continue to impact market activity in Ontario. However, progressive changes and initiatives in governance and a growing emphasis on collaboration and innovation is welcome progress that could bring new opportunities in 2020.

Sovereign Risk and Political Uncertainty – Keeping Ontario Interesting

Generation Contract Review Directive

As we saw in 2018, the change in government has led to uncertainty and anticipation across the power sector in Ontario. Since the Progressive Conservative Party of Ontario has come into power, we have witnessed the dismantling of existing renewable energy programs and projects that unwind, at least in part, 15 years of policies enacted by the Ontario Liberal Party. The government's approach in 2019 was no exception.

As part of its election mandate, the Ontario government has pledged to reduce electricity bills by 12%. To achieve this goal, the government has targeted the cost of generation, which industrial stakeholders have recently identified as a "central theme" in the discussion of electricity costs.[1]

In November 2019, the Ontario government released the 2019 Fall Statement which contained two directives aimed at addressing concerns around "improvements to cost transparency and certainty, and rate stability": (i) the Billing Practice Directive; and (ii) the Generation Contract Review Directive (the "**GCR Directive**"). Per the GCR Directive, the Independent Electricity System Operator (the "**IESO**") will retain an independent third party expert to undertake a targeted review of existing generation contracts for opportunities to reduce electricity system costs. The stated focus of the review is on large gas, wind and solar contracts that expire in the next 10 years, as well as any other areas with potential for cost savings. The review is also intended to consider system reliability and potential impacts on Indigenous, municipal

1 For more information, please see a summary of the consultation: https://files.ontario.ca/endm-industrial-consultations-what-we-heard-en-2019-11.pdf. Participants noted that "[global adjustment] charges comprise most of their electricity bill" and that renegotiating generation contracts is one option to reduce system-wide annual GA costs. (page 8-9) See also "Background" section of the GCR Directive.

and local partnerships. It expressly excludes the Bruce Power Refurbishment Agreement and conservation and demand-management initiatives from the scope of the review. The IESO is required to deliver its findings and its assessment of those findings by February 28, 2020.

Based on what we have seen, it is currently unclear what the GCR Directive means for the IESO's contractual counterparties. Some observers have speculated that the particular focus of the review (i.e. larger contracts in the last 10 years of their term) suggest that the Ontario government is pursuing a strategy of having contract holders offer contractual modifications or concessions that would reduce the overall purchase price of energy in Ontario. The so-called "blend and extend" amendment (whereby a supplier would agree to a lower contract price in consideration for a term extension) has been bandied about for some time, even before the GCR Directive was issued as a possible option, as such an amendment could meet the government's rate reduction objective while being a palatable concession to some contract holders, particularly those with balance sheet financing.

Nation Rise

Further to the cancellation of over 750 renewable energy contracts and the White Pines Wind Project in 2018, Ontario's Minister of the Environment, Conservation and Parks, Jeff Yurek, revoked the Nation Rise Wind Farm's renewable energy approval on December 4,

2019. Please refer to our environmental law overview on page 39 of this publication for further commentary.

Shelving the IESO's Incremental Capacity Auction

As part of the Market Renewal Program, the IESO launched the Incremental Capacity Auction ("**ICA**") engagement in April 2017, in order to collaborate and coordinate with stakeholders to develop a long-term, market-based mechanism to secure incremental capacity and provide a cost-effective mechanism to ensure Ontario's needs. The IESO hosted multiple stakeholder engagement meetings and education sessions on the ICA design and released a draft High-Level Design ("**HLD**") for the ICA for stakeholder feedback on March 22, 2019.

However, in July 2019, the IESO announced that it was stopping work on the HLD. The IESO subsequently launched a new Resource Adequacy Engagement in November 2019, and announced its plans to meet and engage with stakeholders in discussions on what tools the IESO needs to achieve resource adequacy to complement capacity auctions. The first meeting with stakeholders is scheduled to occur on January 27, 2020.

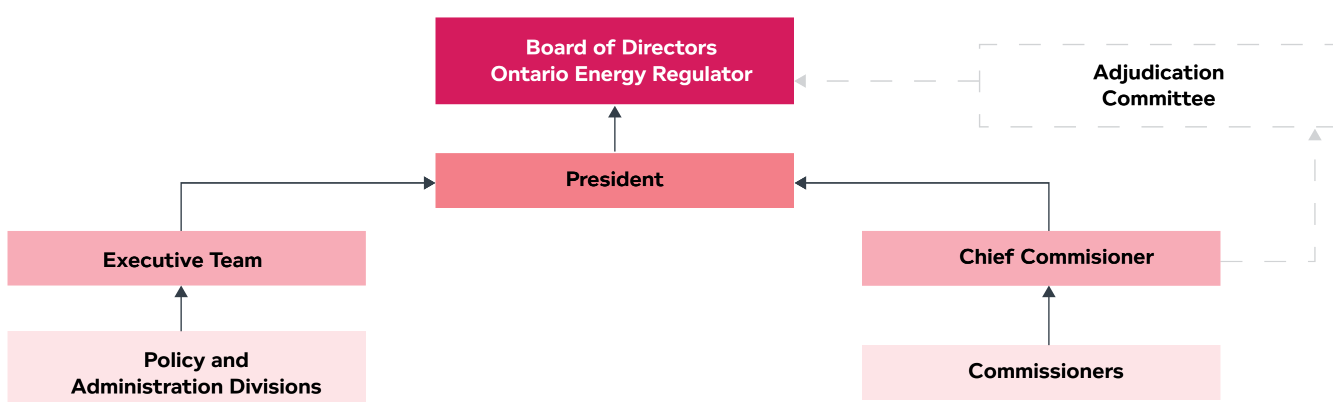
One issue related to the consultation on Resource Adequacy Engagement is whether a broader policy review by the Ontario government may be in order, as the consultation only relates to procurements by the IESO with respect to IESO-administered markets and does not consider alternative procurement models (e.g. OEB regulation of procurement by local distribution companies, OEB regulated generation or government-run initiatives through, for example, Infrastructure Ontario).

A Continual Reshaping of Energy Governance in Ontario – OEB Reform

In December 2017, the previous Ontario government launched a year-long review of the Ontario Energy Board (the "**OEB**") to consider the appropriate mandate, role and structure of a modern energy regulator. The OEB Modernization Review Panel, which was constituted to engage with the public and procure expert input and feedback, provided its final report in October 2018 (the "**Report**").

On May 9, 2019, the Ontario government passed Bill 87, *Fixing the Hydro Mess Act, 2019* (the "**Bill**"), which amends the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998* and the *Ontario Fair Hydro Plan Act, 2017*, as part of its comprehensive reform of, among other things, the structure of the OEB. In accordance with the recommendations of the Report, the changes included the creation and appointment of a board of directors with a non-executive Chair as well as a Chief Commissioner who would be responsible for adjudication (as shown below).[2]

2 Source: https://files.ontario.ca/endm-oeb-report-en-2018-10-31.pdf



However, the most important issues raised by the Report have not been sufficiently addressed.

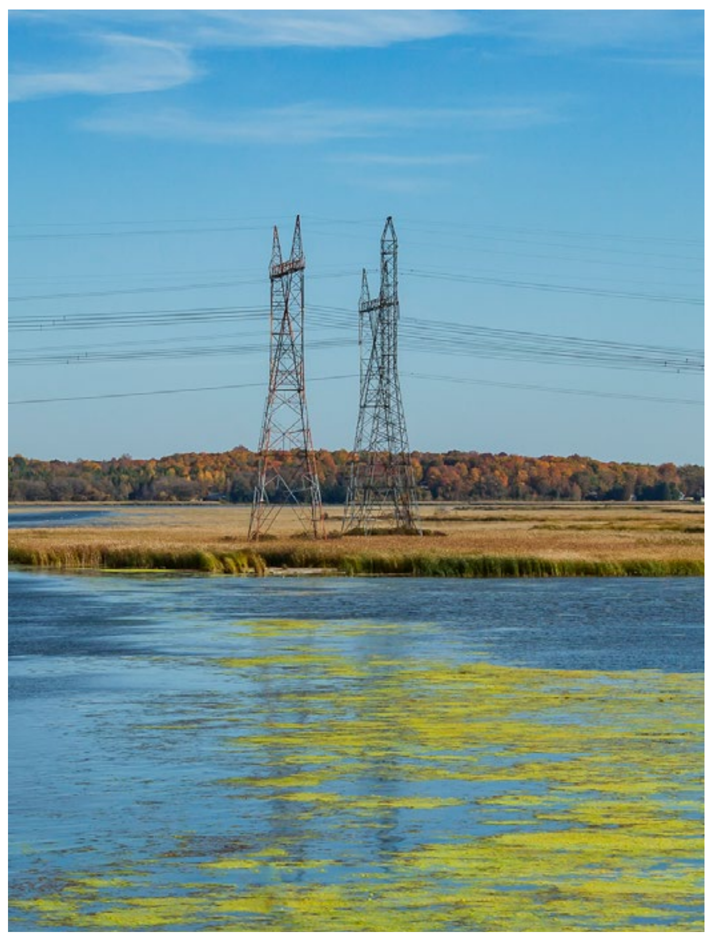
First, neither the Bill nor the Report properly address the implications of the proposed structural reform of the OEB. Although stated to have been "informed by the recommendations of the OEB Modernization Review Panel, stakeholders, and regulatory experts" which "reflect best practices and support independent decision-making", the concern is that the Board of Directors will ultimately be answerable to the government of the day. While regulatory accountability is important, independent regulatory decision-making is also critical and it remains unclear as to how the proposed structure will foster that. As such, without more structural reform focused on independent regulatory decision-making, the current structure may result in a less independent regulator than its predecessor.

Second, the Report refers to the commissioners exercising adjudicative authority to make decisions in specific cases but neither the Report nor the Bill address the fact that the OEB has many other processes and policy instruments for which independence is also required. Some of the most important regulatory issues are addressed in either OEB guidelines (e.g. incentive-based regulation cost of capital, LDC merger policies) or codes and rules (e.g. connection requirements, affiliate relationships, and codes of conduct).

Third, neither the Report nor the Bill address perhaps the largest issue in the electricity sector, which is the lack of regulatory oversight of procurement of capacity. This issue and its financial consequences have been noted by the Auditor General. Yet the Report does not address how the OEB's mandate should be changed to provide that oversight. Ontario is one of the few jurisdictions in the Western world without regulatory oversight over procurement and the cost consequences have been significant. Unless this changes, the OEB reform will be of limited impact to Ontario ratepayers.

Ontario's Environment Plan

In late 2018, the Ontario government released the "Environment Plan: Preserving and Protecting our Environment for Future Generations" (the "**Plan**"). The Plan outlined the government's intended actions and policies for addressing many environment-related issues in Ontario, including the pollution of air, land, and water,



the reduction of litter and waste, and the emission of greenhouse gases ("**GHGs**"), including the following:

i. establishing a new advisory panel on climate change to provide the Minister with advice on the "implementation and development of actions in the province's climate change plan" and "how Ontarians can prepare for the costs and impacts of climate change";

ii. finalizing Ontario's emissions performance standards for large, industrial emitters; and

iii. releasing a request for bids for a third-party expert to undertake a multi-sector provincial climate change impact assessment.

Please refer to our environmental law overview on page 38 of this publication for further commentary on other environmental law developments across Ontario.

A Renewed Focus on Innovation

Energy Storage and Storage Solutions

On a more positive note, we have continued to see progress on the innovation front. One key example is the development of technologies and regulation related to energy storage and storage solutions. Some recent examples of Ontario energy storage projects include:

– the joint venture between Convergent Energy + Power and Royal Dutch Shell PLC to equip two Shell Canada Products facilities with energy storage systems; and

– the collaboration between Ontario Power Generation and Stem Inc. to provide a battery-based system to reduce electricity costs for industrial customers in Ontario.

However, while the promise and presence of these technologies are progressing rapidly, the legal and regulatory landscape in Ontario has not developed at a corresponding pace.[3] Some recent developments to close the gap and prepare for future investment and integration of energy storage technologies in the electricity grid include:

i. the formation of the IESO's Energy Storage Advisory Group, which has been tasked with obtaining feedback and involving industry stakeholders in the development of procurement processes, technical standards, metering and permitting for energy storage;

ii. the development by the OEB of a special licence and related exemption for energy storage projects in the province;

iii. the launch of an initiative titled "Responding to Distributed Energy Resources (DERs)" by the OEB that is intended to support the integration, expansion and operation of distributed energy resources ("**DERs**") in Ontario by encouraging service providers to embrace innovation and sector transformation and by facilitating stakeholder engagement for consultation processes related to DERs; and

iv. the launch of an initiative titled "Utility Remuneration" by the OEB that is intended to identify how to better remunerate utilities in ways that make them indifferent to traditional or innovative solutions, better assists them in their pursuit of cost effective solutions, strengthens their focus on long-term value and requires them to better consider the impact of sector evolution in their system planning and operations.

OEB Sandbox

The power sector is also embracing innovation in other ways. Building upon the Advisory Committee on Innovation Report (the "**ACI Report**") delivered in 2018, the OEB announced the opening of its Innovation Sandbox initiative on January 16, 2019. According to this initiative – the first one coming out of the ACI Report – innovators will be able to exchange information and feedback informally with OEB staff. The objective is to encourage innovators to test projects on a trial basis while obtaining temporary relief from a regulatory requirement or customized guidance from OEB staff. By providing a forum for collaboration, it is expected that this initiative will reduce regulatory uncertainty and risk in ways that encourage innovation and provide the OEB with "enhanced insight into … sector challenges and solutions to inform its longer-term work supporting innovation".

Optimism for Nuclear Generation

There should also be a cause for optimism for the role of nuclear generation as part of Ontario's power sector. This is evidenced by: (i) the fact that the GCR Directive specifically carves out the Bruce Power Refurbishment Agreement; and (ii) the announcement by the Premier of Ontario, together with the Premiers of Saskatchewan and New Brunswick, of the entering into of a memorandum of understanding to document their commitment to the development and deployment of small modular nuclear reactors or 'SMRs' in order to address climate change, regional energy demand and economic development. Please refer to our article on SMRs on page 31 of this publication for further commentary.[4]

3 For more information, please see: https://www.mccarthy.ca/en/insights/blogs/canadian-energy-perspectives/storage-storage-renewable-energy-projects-canadian-opportunity

4 For more information, please also see: https://www.mccarthy.ca/en/insights/blogs/canadian-energy-perspectives/small-modular-reactors-big-interprovincial-deal

Québec – Overview

Authors: Louis-Nicolas Boulanger, Mathieu LeBlanc, Matthieu Rheault, Alexandre Saulnier-Marceau and Jacob Stone

While Québec's electricity industry made the headlines a few times in 2019, both within the province and in its main export markets, Hydro-Québec remains in a transition period following the objectives set last year by the new Government of Québec: no new hydroelectric projects after the completion of the 245 MW Romaine-4 plant in 2021, no significant private renewable energy procurement programs, a focus on exporting Québec's current energy surplus and contributing to energy transition and the fight against climate change.

Hydro-Québec issued its 2020-2024 Strategic Plan, announcing experimental solar projects and confirming its support of transport electrification within Québec. It innovated by launching an RFP for potential clients wishing to benefit from a new tariff specifically aimed at the blockchain industry. Hydro-Québec's efforts to build the Northern Pass transmission line through New Hampshire met a dead end, but an alternative route reaching Massachusetts through Maine made progress, in addition to discussions with New York City's municipal government.

Among notable developments, in June 2019, the Québec Court of Appeal sided with Hydro-Québec in another round of the ongoing dispute with Newfoundland over the power generated at Churchill Falls. This particular dispute was about Hydro-Québec's right to purchase additional power from the second-largest power station in Canada in addition to its basic monthly allocation, thus ensuring Québec's flexible and continuous supply until 2041.

On the consumer side, after significant debate in the course of 2019 over Hydro-Québec's tariffs and alleged overcharges in past years, the National Assembly of Québec passed a bill setting electricity prices for consumers for the next five years in line with inflation and limiting the Régie de l'énergie's oversight powers.

Hydro-Québec's Strategic Plan

Hydro-Québec's 2020-2024 Strategic Plan brands Québec as the "battery of North America." After spending the last decade investing in additional generating capacity with wind power projects, small hydro plants and the 1,550 MW Romaine complex (whose fourth plant will be commissioned in 2021), the public utility is now looking at ways to make the most of its generating capacity.

For the next years, Hydro-Québec wants to make better use of its surpluses by increasing exports and increasing electricity's share of Québec's energy mix above the current level of 35% in order to decarbonize Québec's economy. This includes electric mass transportation, starting with Montréal's Réseau électrique métropolitain and Québec City's upcoming tram network, but also expanding Québec's charging stations circuit for electric vehicles, and continuing to invest in its Dana TM4 venture to develop electric power trains. Hydro-Québec is also looking at the development of greenhouses and at ways to produce hydrogen as an alternative green fuel source. It also intends to take advantage of synergies between Québec's cold climate and cheap electricity to develop data centres and cryptocurrency mining.

Hydro-Québec also intends to improve the integration of remote communities to its TransÉnergie power grid. The two wind turbines under construction in the Îles-de-la-Madeleine as part of the Dune-du-Nord project will eventually be complemented by an undersea cable linking the islands with the mainland network. The northern village of Inukjuak will be supplied with hydroelectric power by 2025, advancing Hydro-Québec's goal of phasing out the remaining thermal generation facilities in remote communities.

Solar Energy in Québec

Hydro-Québec announced in February 2019, that it will build two solar pilot plants on the Montreal south shore, in an attempt to familiarize itself with the solar sector. The 36,000 panels and 10 MW capacity plants are expected to be commissioned in 2020, with investments reaching $40 million. Both projects will be developed by Hydro-Québec Production, the generation arm of Hydro-Québec, and will be built within Hydro-Québec's Research Centre in Varennes and on the site of a former thermal plant in La Prairie. This is not Hydro-Québec's first foray in the solar sector, as it previously installed a solar power demonstration system in the northern village of Quaqtaq in 2017.

This announcement is in line with the 2030 Québec Energy Policy, which provided that Hydro-Québec would develop expertise in solar electricity centralised production through a pilot plant. Under the plan, Hydro-Québec is also to assess the capacity of decentralized photovoltaic panels technology to improve the operation of the electricity network.

Québec's Electricity Export Strategy

As Québec's power generation capacity continues to significantly exceed its consumption needs, 2018 saw record exports of 36.1 TWh to neighbouring provinces and U.S. states, and both Hydro-Québec and Premier François Legault renewed their efforts to convince Ontario, New England and New York to increase the share of Québec's green power in their supply.

After winning a bid to supply Massachusetts with 9.45 TWh of electricity each year, Hydro-Québec considered various options to increase Québec's transmission capacity to export electricity to New England. The Northern Pass project was abandoned in 2019, after being blocked in New Hampshire.

Hydro-Québec is now focusing its efforts on the New England Clean Energy Connect ("**NECEC**") 142-mile transmission line, a joint project with Central Maine Power. NECEC achieved significant milestones in 2019, including approval from Maine's Public Utilities Commission, while Hydro-Québec's agreements with Massachusetts distributors received approval from the state's Department of Public Utilities. If construction proceeds according to schedule, NECEC will be commissioned in 2022, in time for increased deliveries to Massachusetts to begin.

New York City's mayor Bill De Blasio also announced a plan to import "zero-emission Canadian hydroelectricity" and Hydro-Québec is in discussions with U.S. partners to build a new transmission line along the Hudson River.

On the domestic front, following repeated initiatives by the Government of Québec, Ontario Premier Doug Ford indicated in December that Ontario also has electricity surpluses and therefore, has no intention to increase its supply from Hydro-Québec (which amounted to 6.8 TWh in 2018), preferring instead to explore the use of small modular nuclear reactors with New Brunswick and Saskatchewan.

Hydro-Québec's Strategic Plan does not provide for any clear indication as to Hydro-Québec's intentions

regarding future energy projects or procurement programs. It merely states that, over the next few years, Hydro-Québec will decide on future energy projects to meet long-term needs for clean electricity and indicates that several variables will influence Hydro-Québec's choice, including the costs associated with each generating option, future capacity and energy needs, the expiry of Hydro-Québec's contracts with the Churchill Falls (Labrador) Corporation in 2041, the storage capacity of Hydro-Québec's reservoirs, market adoption of home automation, self-generation and energy efficiency measures, as well as the impact of climate change.

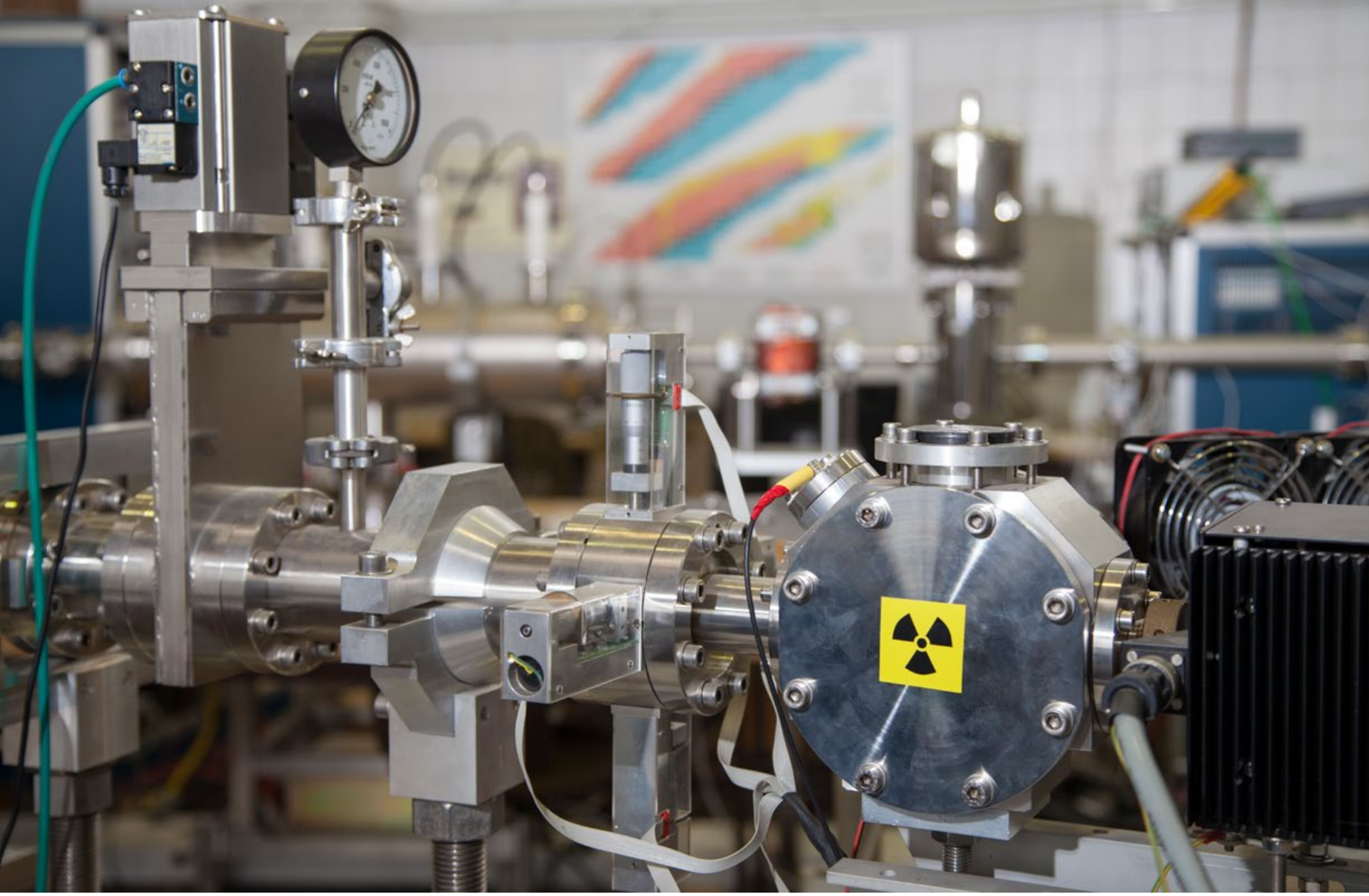
Hydro-Québec RFP for Blockchain Projects

On June 5, 2019, Hydro-Québec launched a RFP intended at supporting blockchain projects in the Province of Québec. A 300 MW block of power was allocated based on new tariffs approved by the Régie de l'énergie specifically for cryptographic use applied to blockchains. Of that block, at least 50 MW will be reserved for projects of 5 MW or less of power and all admissible projects must require at least 50 kW of power. This RFP is the most recent step taken by Hydro-Québec to address the increasing demand for power by the blockchain industry. In 2018, Hydro-Québec had put a hold on the processing of new power supply demands from that category of customers and adopted a temporary dissuasive tariff for those already serviced, until complete terms of service were approved by the Régie de l'énergie.

The new blockchain tariff is based on the existing M and LG tariffs which provide for electricity rates (as of 2019) ranging between 3.46 and 9.90 ¢/kWh. The blockchain tariff will be a non-firm supply service which may be curtailed by Hydro-Québec for a maximum of 300 hours per year at any time between April 1st and March 31st of each year. Selected bidders will bear the costs of connection of the project to Hydro-Québec's grid.

As part of their bid, proponents will be required to make commitments with respect to economic benefits and the environmental performance of their projects. For the economic benefits component, Hydro-Québec will look at the number and payroll of direct jobs created in Québec as well as capital investments in the province. For the environmental component, proponents will be required to commit to recover and reroute a portion of the thermal energy produced by their project. In each case, the commitments must be maintained for a period of five years from the commencement of service and failure to comply with those commitments will result in the application of a penalty intended to recoup in whole or, in part, the difference between the blockchain tariff and Hydro-Québec's dissuasive tariff (which is equal to 15¢/kWh).

At the initial stage of the selection process, bids will be analyzed to confirm that they meet the applicable minimum requirements. They will thereafter be ranked based on the economic benefits and environmental criteria. Hydro-Québec will then determine the optimum combination of projects in order to meet the quantity offered, with the aim of maximizing sales of electricity for the period from January 1, 2020 to December 31, 2024. Proponents were required to submit their bids by October 31, 2019 and the results are expected to be announced in January 2020.



SMRs – The Link to a Bright Future?

Authors: Joshua Hollenberg, Kerri Lui, Seán O'Neill, Suzanne Murphy and Lynn Parsons

Small modular nuclear reactors or 'SMRs' have grabbed the nation's attention with the announcement on December 1, 2019 by Ontario Premier Doug Ford, Saskatchewan Premier Scott Moe and New Brunswick Premier Blaine Higgs that Ontario, Saskatchewan and New Brunswick have entered into a memorandum of understanding (the "**SMR MOU**"). The SMR MOU documents these provinces' commitment to collaborate on the development and deployment of SMRs in an effort to advance the needs of such provinces in connection with climate change, regional energy demand, economic development and research and innovation technologies. SMR technology, however, has been on the radar of many stakeholders working in the Canadian energy sector for some time. For example, the SMR MOU was preceded by the publication in November 2018 by Natural Resources Canada of 'A Call to Action: A Canadian Roadmap for Small Modular Reactors' (the "**Roadmap**")[1].

Prepared by a steering committee constituted by provincial and territorial governments, power utilities, Natural Resources Canada and Atomic Energy of Canada Limited, the Roadmap articulates the following collective vision statement by participating stakeholders for implementing SMR technology in Canada: "Small Modular Reactors as a source of safe, clean affordable energy, opening opportunities for a resilient, low-carbon future and capturing benefits for Canada and Canadians." With this Roadmap, Canada has declared its intention to be at the forefront of SMR technology and industry not only domestically, but internationally, and has set forth a guide for actions to be taken by Canadian stakeholders to achieve that goal.

The current buzz around SMR technology shouldn't really come as a surprise. With the world focused on

1 https://smrroadmap.ca/

pursuing low-carbon and clean energy technologies to address the climate crisis and reduce greenhouse gas emissions, innovators looking for solutions have zeroed in on nuclear energy, which is effectively a zero-emission source of electricity. In particular, such innovators have focused on SMRs as a means of harnessing the benefits of nuclear power while mitigating some of the industry's current perceived disadvantages. While gaining recent attention, SMRs – nuclear fusion reactors designed to be built on a smaller scale than traditional nuclear power facilities – are hardly novel and have been used in certain sectors, such as in university research reactors and the propulsion of marine vessels, for decades. The International Atomic Energy Agency, the UN organization for nuclear cooperation, considers a nuclear reactor to be small if it has a capacity of less than 300 MW. To put that in perspective, current "Generation 3" nuclear reactors are designed to produce between 1,100 MW and 1,750 MW of electricity depending on the manufacturer and model.

> **!** The re-scaling and repurposing of nuclear technology in the form of SMRs makes nuclear technology cheaper and more flexible in terms of locations, site transportation and use.

Since SMRs are 'modular', these reactors can be used to expand already existing nuclear power plants or to work as single standalone reactors. New proposed designs for SMRs incorporate features such as, a passive safety system (i.e. an automatic shutdown mechanism for systems that are not actively managed), safety features to prevent harmful emissions, a design that enables a relatively simple manufacturing process and a long period of operation on a single load of fuel. In order to address a long-standing concern about nuclear power, some innovative designs can also use spent fuel from existing reactors as fuel.

The Roadmap envisions three major areas of application for SMRs in Canada: (i) on-grid power generation given the regulatory requirement to phase out coal electricity generation by 2030, (ii) on-grid and off-grid heat and power for heavy industry; and (iii) off-grid power, heating and water desalination in remote communities that currently rely on diesel fuel. To get there, the Roadmap sets forth four thematic pillars to guide the actions needed to be taken by stakeholders to ensure that Canada is at the forefront of SMR technology: (A) demonstration and deployment of SMR projects; (B) policy, legislation and regulation; (C) capacity, engagement and public confidence; and (D) international partnerships and markets.

While the Roadmap has generated widespread interest in SMRs, and has served as a call to action by stakeholders for the development and implementation of SMRs in Canada's energy infrastructure, the Roadmap is not the only part of Canada's SMR story. For example, in an effort to encourage SMR technology in Canada, the Canadian Nuclear Safety Commission (the "**CNSC**") has established an optional pre-licensing vendor design review. Such review permits a vendor seeking to build and operate a new nuclear facility in Canada to submit its project design to the CNSC prior to the submission of the much more involved nuclear reactor license application. Pre-licensing requires the CNSC to verify, at a high level, the acceptability of a proposed design with respect to Canadian nuclear regulatory requirements, codes and standards. This review consists of three phases but does not certify a design or result in the issuance of a license to proceed with a project. If the results of the pre-licensing verification are positive, a proponent of a particular SMR technology could then decide to proceed to a full licensing application to certify its design. This process is separate from the much more stringent licence application and hearing process required to prepare, construct, and operate a nuclear facility in Canada.

While at least eight vendors have applied to the CNSC pre-licensing review program for an SMR design, only one vendor to date, Global First Power, who is supported by Ontario Power Generation and Ultra Safe Nuclear Corporation, has submitted an application for a "License to Prepare Site" for an SMR project. The proposed location of this demonstration project is on the property of Chalk River Laboratories, the birthplace of Canada's nuclear sector, located in the pre-Upper Ottawa Valley, Ontario. Media sources have indicated that the facility proposed by Global First Power is not expected to be operational until 2026.

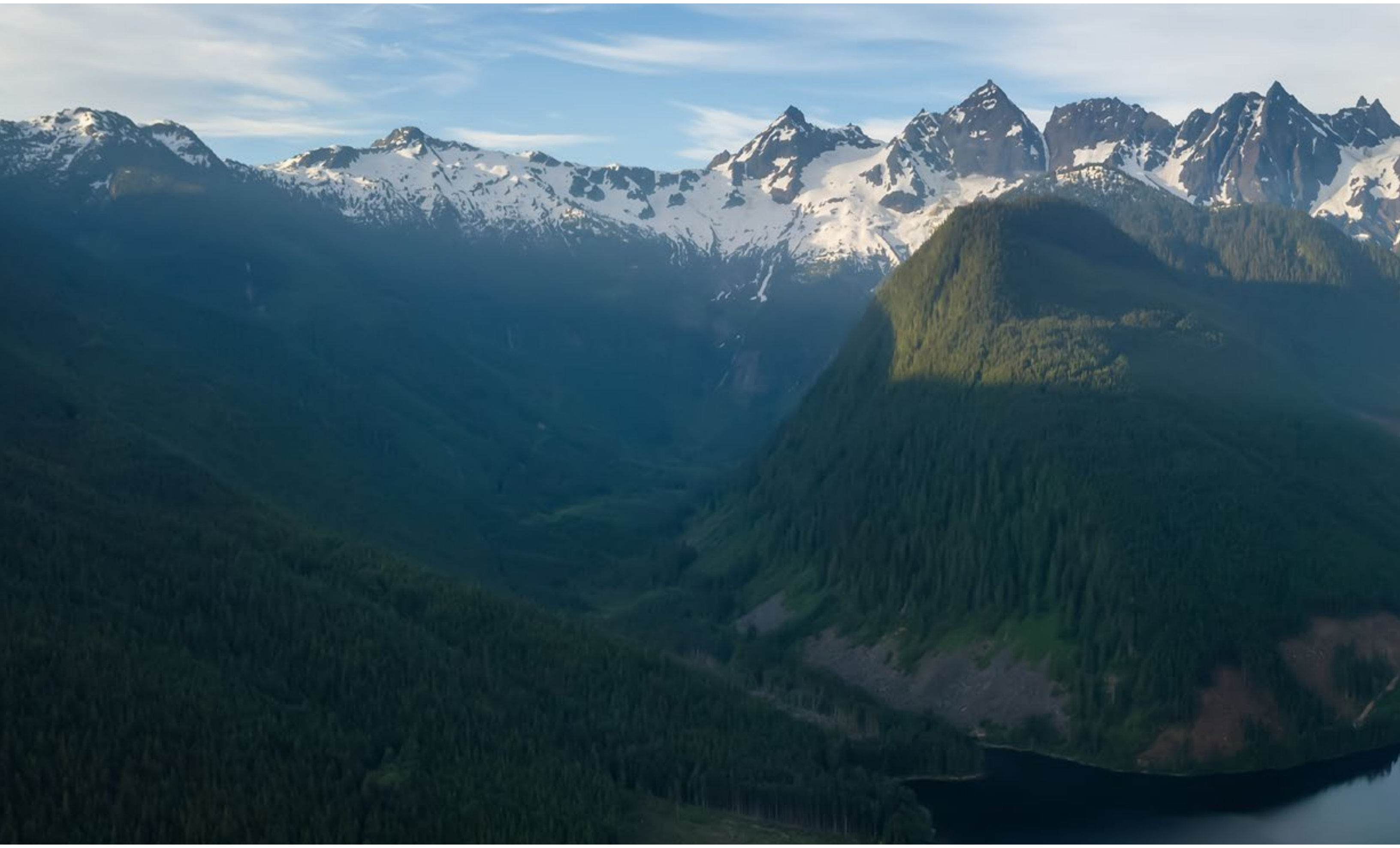
Two other vendors that have applied to the CNSC pre-licensing review program are Advanced Reactor Concepts LLC and ARC Nuclear Canada Inc. (collectively, "**ARC**") and Moltex Energy. Both of these companies were invited to open offices in New Brunswick by

New Brunswick Power and have agreed to collaborate with New Brunswick Power on the fostering of SMR research and development through a nuclear research cluster. New Brunswick Energy Solutions Corporation, a provincial Crown corporation, committed $10 million and each of ARC and Moltex committed $5 million to this project. Currently, New Brunswick Power operates Point Lepreau Nuclear Generating Station, the only operating nuclear reactor in Atlantic Canada.

Canada is not alone in its commitment to be a leader in SMR technology and shares that ambition with several other countries. The United States, China, Russia and Argentina, among others, are investing in research and construction of SMRs and challenging Canada's ambitions of dominance. The World Nuclear Association identifies China as having "the most advanced small modular reactor project". Russia has multiple small reactor designs with advanced development and with some under construction. Such reactors include the *Akademik Lomonosov* – the world's most advanced floating nuclear power plant built on a non-self-propelling barge – which arrived in Russia's remote north-eastern region earlier this year. Argentina is also in the process of building an SMR prototype, with completion scheduled for 2020. Other nations at the same stage as Canada – advanced design development with construction not yet started – include the United States and South Korea. India, Japan, the United Kingdom, and South Africa have also entered the SMR race but are at earlier stages of development.

Are Canadians ready to embrace SMR technology? While the benefits of SMRs are numerous, the technology is not without its downsides and detractors. Some of the biggest concerns are not environmental, but economic. Current nuclear generation stations rely on economies of scale to compete with cheaper hydrocarbon alternatives and increasingly affordable renewable alternatives. SMRs sacrifice scale to reduce capital costs, meaning they would need multi-reactor facilities for scale in order to compete on a cost basis with existing alternatives. Beyond economics, SMRs share many of the same environmental concerns as conventional reactors, including the consumption of nuclear material and the production of nuclear waste, both of which will need to be transported and stored. This is a particularly difficult issue for some of the proposed uses of SMRs, such as deployment in remote communities or industrial applications which may require the transportation of spent fuel over greater distances. Some First Nations communities in Canada have pre-emptively stated that they will never permit nuclear waste to be stored on or transported through their lands, citing unacceptably high contamination risk. The proliferation of nuclear facilities also creates more opportunities for incidents due to natural disasters, human error, or terrorist attacks. These concerns are heightened by the arguments by many SMR developers that the nature of the technology does not require as stringent regulations for fail-safes and back up systems, or setbacks from urban populations, as do traditional nuclear facilities. Proponents argue that rethinking such regulations is necessary for SMRs to be feasible and that the risks are substantially lower than for conventional nuclear reactors; opponents point to the high cost of nuclear disasters and the increased risks created by proliferation. Beyond the technical and economic challenges faced by the SMR industry, the public relations battle may be the most important – and most difficult – one it faces.

The Roadmap has sent out a call for action to stakeholders on the development and deployment of SMR technology but does note that there is much work to be done before SMR technology can be applied in Canada in any meaningful way. **The future of SMRs in Canada remains to be seen.** What is certain, however, is that the stakeholders who charted the Roadmap believe that the opportunity for an SMR market is a real one and that the dialogue and efforts to carve out a place for SMR technology in the Canadian energy sector will continue.



Environmental Law

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

Key Developments in 2019

In 2019, there were a number of key environmental law developments across Canada with potential impacts on the energy sector. Highlights include the following:

British Columbia

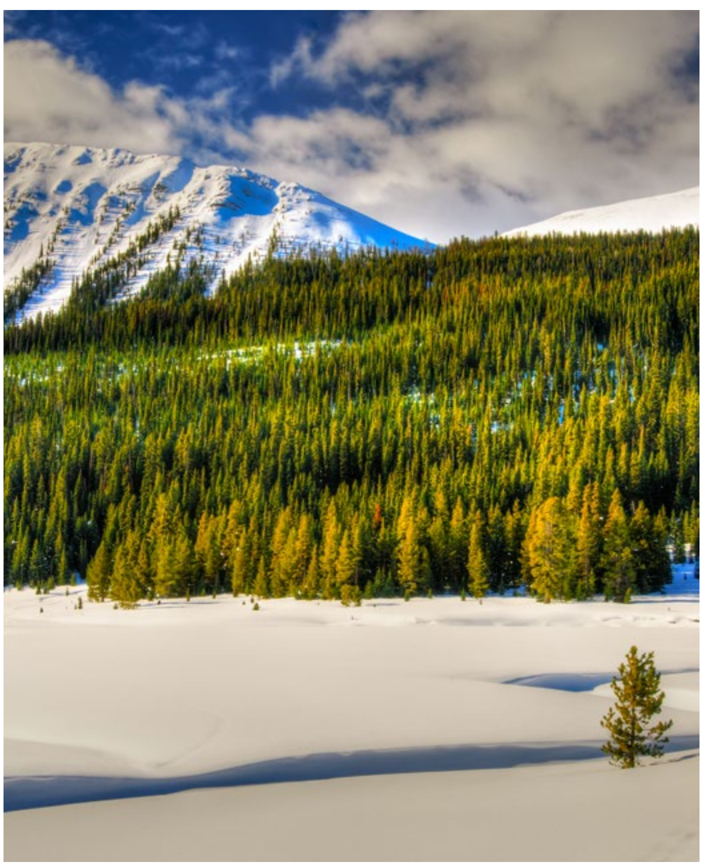
Revitalized B.C. Environmental Assessment Act now in force

In November 2018, the B.C. government introduced *Bill 51 – Environmental Assessment Act* ("**Bill 51**") as part of the province's efforts to revitalize the environmental assessment ("**EA**") process. The revitalized *Environmental Assessment Act* ("**New EAA**") and the majority of regulations came into force on December 16, 2019. The key regulations include the *Reviewable Projects Regulation*, *Protected Areas Regulation*, and *Proponent Fee Regulation* (in addition, consequential amendments have been made to administrative, compliance and enforcement regulations). Additional regulations to support the revitalized EA process are expected in 2020. The New EAA introduces significant changes to the provincial EA process, including the creation of an early engagement process and prescriptive measures to meet the B.C. government's commitment to implement the *United Nations Declaration on the Rights of Indigenous Peoples*.

Projects with an environmental assessment already underway will continue under the old Act (2002) process, while any new projects after December 16, 2019, will undergo an environmental assessment under the New EAA process. If a project does not yet have a Section 11 Order (establishing the formal scope, procedures and methods for the EA) as of December 16, 2019, the project will be considered under the new EAA in the Early Engagement phase, as set out in the *Environmental Assessment Transition Regulation*. If a Section 11 Order has been issued as of December 16, 2019, the proponent has six months from the date the New EAA is brought into force to file notice with the Project Lead at the Environmental Assessment Office ("**EAO**") that it wishes to continue under the current Act. If this option is selected, the EA process must be completed within three years. Otherwise, the EA process must be completed under the New EAA.

Revised Electricity Project Thresholds under New EAA

Under the previous *Environmental Assessment Act*, the EA threshold for all power projects was 50 megawatts ("**MW**") rated nameplate capacity. In order to take into account the range of project effects produced by different technologies, the single 50 MW threshold has been replaced by the following thresholds under the updated *Reviewable Projects Regulation* ("**RPR**"): (i) > 50 MW rated nameplate capacity for hydroelectric, thermal electric or other power plant (not including wind and tidal plants); (ii) ≥ 15 turbines for a land-based wind generating facility; (iii) ≥ 10 turbines for a marine or freshwater wind generating facility; (iv) any new tidal (excluding in-stream tidal) power generating facility; and (v) > 15 MW rated nameplate capacity for an in-stream tidal power facility. In addition, the New EAA and RPR require that if a project within a prescribed category does not meet the threshold for that particular project category, it may still be required to notify the EAO if its meets one or more of the notification thresholds under the Regulation, including (among others): (i) if the project is subject to federal EA review, but is not wholly located on federal lands; (ii) if the project is within 15% of RPR thresholds; (iii) if the project has a maximum annual direct employment number of ≥ 250 persons; (iv) projects that emit 125,000 tonnes or more per year of one or more greenhouse gases directly from project facilities, measured in carbon dioxide equivalents; (v) transmission lines that are greater than 230 kV and greater than 40 km in length; or (vi) if an existing project was not subject to the provincial EA process, but a modification to the project is being proposed that would exceed the threshold for new projects in that category.



B.C. Bolsters Climate Action with New Climate Change Accountability Act

Provincial climate action was bolstered with the passage of the new *Climate Change Accountability Act* in November 2019. Under the Act, the B.C. government is required to set an interim emissions target on the path to the legislated 2030 target (i.e. a 40% in greenhouse gas reductions below 2007 levels – total emissions in B.C. in 2017 were 64.5 million tonnes of carbon dioxide equivalent, which is 2% lower than 2007 levels). Separate 2030 sectoral targets will also be established following stakeholder engagement. Interim emissions targets will be established by ministerial order by no later than Dec. 31, 2020, while sectoral targets will be established no later than March 31, 2021. The Act also requires the B.C. government to report annually on its progress towards the province's legislated emission reduction targets. Every fifth year, the climate change accountability report will include an updated provincial climate risk assessment, which will build on B.C.'s Preliminary Strategic Risk Assessment and work done in the interim to assess risks from climate change.

Alberta

Alberta Revamps Greenhouse Gas Emissions Policy

On October 29, 2019, Alberta introduced Bill 19, the *Technology Innovation and Emissions Reduction Implementation Act, 2019* and the *Technology Innovation and Emission Reduction Regulation* ("**TIER Regulations**"). Bill 19 rebrands the *Climate Change and Emissions Management Act* as the *Emissions Management and Climate Resilience Act*, and revamps the province's greenhouse gas emissions policy into the Technology Innovation and Emissions Reduction ("**TIER**") system. Bill 19 received royal assent on November 22, 2019, and will come into force on January 1, 2020. In December 2019, the federal government granted Alberta's TIER system equivalency with the federal industrial carbon tax. However, the federal consumer carbon tax will still take effect in Alberta as of January 1, 2020.

The TIER Regulations are intended to meet the federally mandated carbon standards of the federal *Greenhouse Gas Pollution Pricing Act* for large emitters (as opposed to the consumer fuel charge, or "carbon tax," which is applied in parallel). Under the CCIR, emissions targets for an individual facility were based on industry-wide benchmarks, whereby each facility in a specific industry shared a common emission target, with limited exceptions. Under the TIER framework, emitters other than electricity generators, will be able to apply for a facility-specific benchmark. If approved, each facility's allowable emissions threshold will be based on the average past performance of that facility between 2016-2018, a move back to the historical performance standard employed by the *Specified Gas Emitters Regulation* ("**SGER**"). The TIER framework also employs an industry-wide benchmark for certain products; however, the regulations stipulate that if both a facility-specific benchmark and an industry benchmark exist for a given facility, the less onerous of the two will apply.

Electricity facilities with more than 100,000 tonnes of CO_2e per year will be required to comply with a "good-as-best-gas" benchmark set at 0.37 tonnes of CO_2e per megawatt hour. This benchmark is equal to the performance of the best combined-cycle natural gas powered electricity generator in Alberta.

Regulated facilities can achieve compliance by:

- reducing their emissions;
- using credits from facilities that have met and exceeded their emissions targets;
- using emission offsets from projects that are not regulated by TIER, but have voluntarily reduced their emissions; and/or
- paying into the TIER Fund.

The first $100 million in annual revenue and 50% of the remaining revenue paid into the TIER Fund will be used for emissions reduction technologies, such as new and improved technologies for oil sands extraction, research and investment in carbon capture, utilization and storage, or other areas of opportunity for industrial emission reductions. The Alberta government is also considering solutions under the TIER system to protect 26 facilities (including smaller conventional oil and gas facilities) emitting less than 100,000 tonnes of CO_2e per year from the federal fuel levy.

Under the TIER system, it is proposed that a facility may opt-in to the system if it competes directly against a facility that is covered by the regulation, or if the facility has greater than 10,000 tonnes CO_2e of annual emissions and belongs to a high Emissions Intensive and Trade Exposed ("**EITE**") sector.

> **Eligible facilities that opted-in to the CCIR would be automatically opted-in to TIER to facilitate exemption from the federal fuel charge, but may opt-out if desired. If the person responsible for an opted-in facility decides that they do not want to remain regulated under the TIER system, the facility may apply to opt-out of the TIER system. Facilities that have sequestered CO_2 on site will not be eligible to opt-out.**

Renewable electricity facilities are eligible to opt-in, unless any of the following criteria applies to the facility:

- the facility has a total nominal capacity of less than 5 megawatts;
- the facility has entered into a renewable electricity support agreement under section 7(4) of the *Renewable Electricity Act*; or
- an economic benefit is being provided under a program or other scheme that is attributable to the electricity produced at the facility having been produced from a renewable energy resource.

Constitutional Challenge to the Federal Government's Consumer Carbon Tax

In June 2019, Alberta launched a constitutional challenge of the federal government's *Greenhouse Gas Pollution Pricing Act*, which imposes a fuel levy or an output-based pricing system for greenhouse gas emissions in Alberta. From December 16 to 19, 2019, the Alberta Court of Appeal heard arguments for and against the federal carbon tax. Alberta argued that the federal carbon tax represents a "radical extension of federal powers that violates the Constitution". Similar challenges by Saskatchewan and Ontario have been unsuccessful. The five-judge panel of the Alberta Court of Appeal is expected to deliver its decision in the first quarter of 2020.

*Alberta Utilities Commission ("**AUC**") Consulting with Utility Industry to Gather Input on the Implementation of the Federal Carbon Tax*

The provincial carbon levy was repealed in May 2019, when the new provincial conservative party was elected. In response, the federal government announced that federal fuel charge, known as the federal carbon tax, will be implemented in Alberta starting January 1, 2020. In response to a request from the utility industry, the AUC has scheduled a teleconference meeting with industry representatives to discuss a number of topics in preparation of the implementation of the federal carbon tax in January 2020. Topics discussed include:

- distributor's learnings from other jurisdictions;
- customer communication plan;
- GST on the carbon tax; and
- pricing for January and April 2020.

Ontario

Constitutional Challenge to the Federal Government's Pollution Pricing Regime for Greenhouse Gases

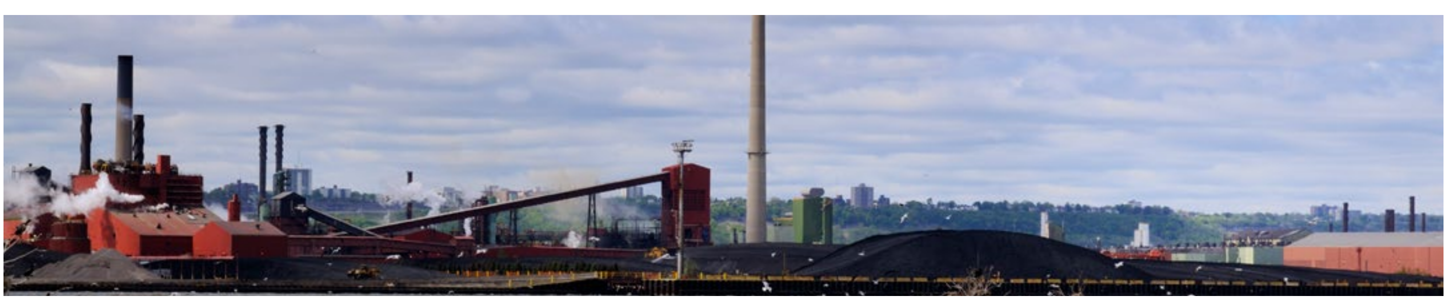
In September 2018, the Ontario government launched a constitutional challenge to the federal government's *Greenhouse Gas Pollution Pricing Act*, which imposes a fuel levy or an output-based pricing system for greenhouse gas emissions in Ontario. Ontario argued that the federal government did not have the jurisdiction to impose a carbon price on the province. The Ontario Court of Appeal heard the reference in April 2019, and released its advisory opinion regarding the constitutional validity of federal legislation on June 28, 2019. The majority held that the federal *Greenhouse Gas Pollution Pricing Act* is constitutional. The Ontario government has appealed and the Supreme Court of Canada will hear the case in March 2020. Please refer to our litigation review on page 53 of this publication for additional commentary.

Pending Provincial Emissions Performance Standards

In July 2019, the Ontario released the *Greenhouse Gas Emissions Performance Standards* regulations under the *Environmental Protection Act,* establishing its own provincial program to address greenhouse gas emissions in the province. The provincial program is similar to the federal output-based pricing system as it is premised on industry greenhouse gas emission performance standards. The first compliance period for the provincial system is intended to begin on January 1 in the year in which Ontario is removed from the list of provinces to which the federal system applies.

Expansion of Administrative Monetary Penalties

The Ontario government introduced an omnibus bill in late 2019, the *Better for People, Smarter for Business Act*, that made various changes to environmental legislation. One of the changes is the introduction of a framework that will allow administrative monetary penalties to be applied to a broader range of environmental violations. There is an environmental penalty regime currently in effect under Ontario's two main environmental statutes, the *Environmental Protection Act* and the *Ontario Water Resources Act*. The current regime applies only to prescribed large industrial facilities and the government has signaled an intent for broader application. The details of the new administrative



monetary penalty regime will be spelled out in regulations. Administrative monetary penalties are controversial as they are absolute penalties that do not provide the possibility of a due diligence defence. It will be interesting to see the details of the new penalty regime and, also, to see if it is widely and frequently applied.

Revocation of the Renewable Energy Approval for the Nation Rise Wind Farm Project

On December 4, 2019, the Ontario Minister of the Environment, Conservation and Parks granted an appeal made by the Concerned Citizens of North Stormont of the Renewable Energy Approval ("**REA**") issued for the operation of the Nation Rise Wind Farm. The Minister revoked the REA, citing reasons related to irreversible harm to bats in the local area. The REA for the Nation Rise Wind Farm had been issued in May 2018, and the project was already under construction. The Minister's decision was surprising, as the REA had already been the subject of an appeal hearing before the Environmental Review Tribunal (the "**ERT**"). The ERT specifically considered the issue of harm to bats and found that the appellants had not met the onus of proving that the project would cause serious and irreversible harm to bats. The *Environmental Protection Act* provides the Minister with the power to confirm, alter or revoke the decision of the ERT "as to the matter in appeal as the Minister considers in the public interest." The project developer has filed a judicial review application in respect of the Minister's decision.

Québec

Québec Consults the Public to Develop its Electrification and Climate Change Plan

In order to develop its Electrification and Climate Change Plan ("**ECCP**"), the Québec government conducted public consultation in 2019 among multiple stakeholders, including municipalities and aboriginal groups, in order to identify priorities and initiatives to reduce greenhouse gas emissions. The ECCP will identify the intended policies and establish the main actions that Québec intends to implement in order to meet its targets and objectives for 2030 regarding climate change. The draft ECCP is expected to be published in early 2020.

Federal

New Impact Assessment Regime Comes Into Force

On August 28, 2019, the *Impact Assessment Act* (the "**IAA**") came into force, replacing the *Canadian Environmental Assessment Act, 2012* ("**CEAA 2012**"). The IAA establishes a new Canadian Impact Assessment Agency, and projects and activities that are subject to the IAA are set out in the *Physical Activities Regulations under the IAA*, commonly referred to as the "Projects List". While the Projects List under the IAA is very similar to the categories of projects that are subject to environmental assessments under CEAA 2012, some changes have been made to the list, including certain new thresholds and the introduction of certain project categories.

Canada Energy Regulator replaces National Energy Board

Along with changes to the federal EA process, Bill C-69 introduced changes to federal energy regulatory review processes. Changes to the National Energy Board ("**NEB**") regime came into force on August 28, 2019, pursuant to which the *National Energy Board Act* was replaced with the *Canadian Energy Regulator Act* ("**CER Act**") and the NEB was replaced by the Canada Energy Regulator ("**CER**"). The CER Act introduces a number of changes to federal processes for project review and decisions, which are focused on providing a modern governance structure, timely and predictable decisions, strengthened safety and environmental protection, greater Indigenous participation, and more inclusive public participation.

Changes to Fisheries Act Regime Receive Royal Assent

Bill C-68 was introduced by the federal government on February 6, 2018, which proposed amendments to restore lost protections and incorporate modern safeguards into the *Fisheries Act*. On June 21, 2019, the new *Fisheries Act* received royal assent. The new fish and fish habitat protection provisions under the *Fisheries Act* came into force on August 28, 2019. The fisheries protection and pollution prevention provisions of the *Fisheries Act* remain in force until the new Fish and Fish Habitat Protection and Pollution Prevention

Provisions set out in *An Act to amend the Fisheries Act and other Acts in consequence* are brought into force. The Department of Fisheries and Oceans is developing a public registry for authorizations under the *Fisheries Act*, which is expected to be in place in 2020.

Development of Federal Clean Fuel Standard Continues

In late 2016, the federal government announced that it would develop a Clean Fuel Standard ("**CFS**") to reduce Canada's greenhouse gas emissions through the increased use of lower carbon fuels, energy sources and technologies. The objective of the CFS is to achieve 30 million tonnes of annual reductions in greenhouse gas emissions by 2030. The CFS will be a performance-based approach designed to incent the innovation and adoption of clean technologies in the oil and gas sector and the development and use of low-carbon fuels throughout the economy. The CFS regulations will cover all fossil fuels used in Canada, but will set separate requirements for liquid, gaseous and solid fossil fuels. It is being developed in a phased approach, with liquid fuel class regulations being developed first followed by gaseous and solid fuel class regulations. On June 28, 2019, Environment and Climate Change Canada ("**ECCC**") released the *Proposed Regulatory Approach for the Clean Fuel Standard*, which sets out the proposed regulatory design for the liquid fossil fuel regulations of the Clean Fuel Standard, including credit creation opportunities that will be included in the liquid class regulations. It builds upon the *Regulatory Design Paper* published in December 2018, as well as the *Clean Fuel Standard Regulatory Framework* published in December 2017.

Saskatchewan and Ontario Courts of Appeal Uphold Constitutionality of Federal Carbon Pricing Backstop

The federal government's *Greenhouse Gas Pollution Pricing Act* includes a two-pronged approach to carbon pricing: (i) a charge on fossil fuels that are consumed within a province; and (ii) an output-based pricing system that applies to emission-intensive industrial facilities. Both the Saskatchewan government and, as mentioned earlier in this article, Ontario government launched a constitutional challenge to the *Greenhouse Gas Pollution Pricing Act*, each asserting that the federal government did not have the jurisdiction to impose a carbon price on the provinces. A majority of both the Saskatchewan Court of Appeal (opinion released in May 2019) and the Ontario Court of Appeal upheld the constitutionality of the *Greenhouse Gas Pollution Pricing Act*. Both decisions have been appealed and the Supreme Court of Canada will hear the case in March 2020. Please refer to our litigation review on page 53 of this publication for additional commentary.

The Year Ahead

British Columbia

Additional Environmental Assessment Regulations

As noted above, additional regulations to support the revitalized EA process are expected in 2020. The regulations in development include the *Administrative Monetary Penalties Regulation* (expected mid-2020), *Indigenous Capacity Funding Regulation* (expected mid-2020), *Dispute Resolution Regulation* (expected mid-2020), *Regional Assessment Regulation* (expected late 2020), and *Strategic Assessment Regulation* (expected late 2020). Further, guidance documents for each EA process phase are being developed for project proponents, which are expected to be available in early 2020.

Alberta

*Alberta Energy Regulator ("**AER**") Directive 060 Aimed at Reducing Methane Comes into Force in January 2020*

In 2015, the Government of Alberta directed the AER to develop requirements to reduce methane emissions from upstream oil and gas operations by 45 per cent (relative to 2014 levels) by 2025. To meet the goal set out by the Government of Alberta, the AER developed regulatory requirements within *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (Directive 060) and *Directive 017: Measurement Requirements for Oil and Gas Operations* (Directive 017). A new edition of Directive 060 comes into effect on January 1, 2020, including the methane reduction requirements. The new edition of Directive 017 is effective immediately following its release.

The requirements address the primary sources of methane emissions from Alberta's upstream oil and gas industry: fugitive emissions and venting, which includes emissions from compressors, pneumatic devices, and glycol dehydrators. The requirements also focus on improved measurement, monitoring, and reporting of methane emissions. Companies may request to use an alternative program ("**Alt-FEMP**") to deviate from the technologies and processes outlined in Directive 060. The AER has developed an Alt-FEMP checklist to provide guidance to industry on these types of requests.

Ontario

Judicial Review Regarding the Revocation of the REA for the Nation Rise Wind Farm Project

The application for judicial review of the Minister's decision to revoke the REA for the Nation Rise Wind Farm project, as described above, will be heard in 2020. It will be watched with interest and may provide valuable guidance on when a decision made by the Minister is within the scope of the "public interest".

Québec

New Regulations to Support Bill 102

Most of the provisions of Bill 102 that targeted the modernization of the environmental authorization scheme under the Québec *Environment Quality Act,* came into force on March 23, 2018. Advisory groups were formed in early 2019, in order to continue working on draft regulations to support such modernization. The main supporting regulation is expected to be published in draft form in the second quarter of 2020.

Federal

Further Development of Federal Clean Fuel Standard

As noted above, the federal government is in the process of developing a CFS. ECCC has indicated that proposed regulations for the liquid fuel class of the CFS will be published in early 2020, in the *Canada Gazette,* Part I, followed by consultations on the proposal. Final regulations planned for early 2021. On January 1, 2022, liquid fuel class regulations are expected to come into force. As it relates to the gaseous and solid fuel classes of the CFS, ECCC has indicated that regulations for these classes will be published in mid-2021, in the *Canada Gazette*, Part I, followed by consultations on proposal. Final gaseous and solid fuel regulations are planned for 2022, with a coming into force date of January 1, 2023, for these regulations.

Supreme Court of Canada to Determine Constitutionality of GGPPA

As noted above, the Supreme Court of Canada will hear the Saskatchewan and Ontario governments' appeal of the opinion by each of those province's Courts of Appeal that the federal *Greenhouse Gas Pollution Pricing Act* is constitutional. This will be the final determination of the validity of this legislation and, more generally, on federal vs. provincial jurisdiction to regulate and impose a price on greenhouse gas emissions. In the meantime, the federal fuel levy and output-based pricing system established by the federal *Greenhouse Gas Pollution Pricing Act* will continue to apply in Saskatchewan and Ontario.

Aboriginal Law

*Authors: Stephanie Axmann,
Bryn Gray and Selina Lee-Andersen*

Aboriginal law is a continually evolving area in the context of Canadian energy and resource development. This trend continued in 2019, with numerous notable decisions from lower and appeal courts concerning the Crown's duty to consult. There were also significant steps taken by the federal and B.C. governments to increase Indigenous participation in environmental assessment and regulatory regimes and enhance the consideration of Aboriginal rights and interests in these processes. This trend is expected to continue in 2020, as several significant cases on a range of Aboriginal law issues are currently proceeding through the courts.

Developments In The Duty To Consult

No change to consultation obligations in the context of asserted Aboriginal title claims

In 2019, two notable cases addressed the required scope and standard of consultation in the context of asserted but unproven Aboriginal title claims. In May, the Supreme Court of Yukon considered the distinction in consultation obligations between asserted title versus established title in *Ross River Dena Council v. Yukon*[1]. This case arose from Yukon's issuance of hunting licenses and seals and the Court considered whether Ross River Dena Council ("**RRDC**"), by virtue of its asserted claim for Aboriginal title, was entitled to consultation that addressed the suite of ownership rights of established Aboriginal title as set out by the Supreme Court of Canada ("**SCC**") in *Tsilhqot'in Nation*. This suite of ownership rights includes the right to use, possess, and manage the land, the right to the economic benefits of the land, and the right to decide how the land will be used.

The Court found that the ownership rights only apply to established Aboriginal title and that RRDC was at the claim stage of asserting Aboriginal title, not at the final resolution or shortly before a finding of Aboriginal title. The Court concluded that deep consultation (and accommodation) was owed and had occurred and there was no requirement for the Yukon to literally apply and assess the *Tsilhqot'in Nation* incidents of established Aboriginal title in its deep consultation with RRDC on wildlife matters. This case is important in clarifying the scope of consultation for asserted Aboriginal title claims and how this differs from established Aboriginal title. The Court also notably reiterated that the duty to consult does not grant the RRDC a veto over any development nor was there an obligation to obtain the RRDC's consent for any developments in this area due to their asserted Aboriginal title claim.

In November 2019, the Prince Edward Island Court of Appeal issued its first judicial review decision concerning the duty to consult in *Mi'kmaq of P.E.I. v. Province of P.E.I. et al.*[2] This case confirms that mere assertions

1 2019 YKSC 26

2 2019 PECA 26

of Aboriginal rights, including title, are insufficient to trigger a duty to consult if there is no evidence that the Crown decision will have an adverse impact on the asserted rights. The decision also demonstrates the need for Indigenous groups to provide information to support their assertions of Aboriginal title when contested, to show how the Crown decision will adversely affect their rights, and the risks of not doing so.

In this case, the Province of P.E.I. intended to sell a Crown owned golf course and resort to a private party. Prior to completing the sale, the Province consulted with the P.E.I. Mi'kmaq, who claim Aboriginal title to all of P.E.I. The Mi'kmaq sought judicial review on the basis that the Province did not satisfy its duty to consult. Despite the fact that Aboriginal title is the strongest form of Aboriginal right, the Court held that the duty to consult was not triggered as there was no evidence of a causal connection between the transfer of ownership of the property from the Crown to the private sector and a potential adverse impact on the Mi'kmaq's claim for Aboriginal title. The land at issue had been used as a golf course since 1983, and the purchaser intended to continue to use the property in the same way. While the conveyance could result in a change in use in the future, the Court found that this was a speculative concern. The Court also found that the claim to Aboriginal title was weak as there was no evidence beyond assertions to establish sufficiency of occupation at the time of the Crown sovereignty and no use of the property, either historic or present day, to be protected pending proof of the Mi'kmaq claim. The land was not shown to be unique and there was no historic association, structures or sites or present use that needed to be protected. There was also no evidence of a shortage of Crown land that could be used in the event of a future settlement of the claim and it was concluded that

this would result in a *de minimus* reduction in provincial Crown land. The Court concluded that even if the duty to consult had been triggered, it would have been at the low end of the spectrum and had been satisfied.

This decision also underscores the reciprocal obligations of Indigenous groups in consultation and the potential consequences when they are not fulfilled. The P.E.I. CA noted several instances where the P.E.I. Mi'kmaq did not meet their reciprocal obligations which likely impacted the outcome in this case:

"Various positions taken by the P.E.I. Mi'kmaq had the effect of limiting the consultation. They stated their claims in very general terms that left ambiguity as to the precise rights claimed. They declined to participate in accordance with the protocols established by the Supreme Court of Canada. They provided little information about any historic connection with the property, and did not respond substantively to requests as to how the conveyance would affect the rights and interests they claimed."

Taking Up of Land in a Treaty Area Doesn't Automatically Trigger the Duty to Consult

In October 2019, the Alberta Court of Appeal dismissed an appeal in which the Athabasca Chipewyan First Nation ("**ACFN**") asserted that there was a duty to consult all Treaty 8 First Nations any time land is taken up for a project in the Treaty 8 area. In *Athabasca Chipewyan First Nation v. Alberta*, the Court of Appeal held that it cannot be presumed that a First Nation suffers an adverse effect by the taking up of any land in a treaty territory[3]. A contextual analysis must be undertaken to determine if there is the potential for an adverse impact on Aboriginal or treaty rights from the Crown decision at issue. The duty to consult is only engaged if this question is answered in the affirmative and it is limited to the specific groups whose rights may be adversely affected.

The case related to a proposed pipeline project and the determination by the Alberta Aboriginal Consultation Office ("**ACO**") that the ACFN was not one of the Indigenous groups that needed to be consulted. The proponent still consulted the ACFN and they had an opportunity to make submissions to the Alberta Energy Regulator. While the ACFN did not challenge the Alberta Energy Regulator's approval, they instead sought judicial review of the ACO's determination about who needed to be consulted. They argued the ACO lacked the authority to make this decision and that they needed to be consulted whenever there is a project anywhere in the 840,000 square km area encompassed by Treaty 8. Both the Court of Queen's Bench and the Alberta Court of Appeal rejected these arguments. The Court of Appeal held that the ACO had the jurisdiction to determine who needs to be consulted for a particular project and that there was no at-large duty to consult for developments within the Treaty 8 area. While this arose in the context of Treaty 8, this case is relevant for consultation in other historic treaty areas across the country particularly the Numbered Treaties. It underscores that consultation is not determined on a treaty-wide basis in historic treaty areas. It is focused on the Indigenous groups who are exercising Aboriginal and treaty rights in the vicinity of the project and engaged only if these rights may be adversely affected by the Crown approval at issue.

Crown Funding Decisions May Trigger the Duty to Consult

The Nova Scotia Court of Appeal released an important duty to consult decision in September 2019, for proponents that are seeking government funding to develop their projects. In *Nova Scotia (Aboriginal Affairs) v. Pictou Landing First Nation*, the Nova Scotia Court of Appeal held that the Province of Nova Scotia needed to consult the Pictou Landing First Nation ("**PLFN**") before making a decision to provide funding to a new effluent treatment facility[4]. The effluent treatment facility would extend the life of a pulp mill that the PLFN had longstanding concerns about.

3 2019 ABCA 401

4 2019 NSCA 75

The Province was already consulting the PLFN on the environmental approvals for the effluent treatment facility, but refused the PLFN's request to consult them before providing any funding to the project. The Nova Scotia Supreme Court and Court of Appeal rejected the Province's position that there was no duty to consult because any funding decision would not itself have an adverse impact on Aboriginal or treaty rights. The Court of Appeal found that there was a potential adverse impact and thus the duty to consult was triggered for two reasons. First, a decision to provide partial funding would reduce the likelihood of the pulp mill closing and there was no evidence that the effluent facility would be built without the provincial funding. Second, the Court found that a decision to provide funding would increase the likelihood of ministerial approvals for the pulp mill's continued operation. The Court concluded, among other things, that the provision of funding could influence the Minister's exercise of discretion given that some provincial funds had already been paid with more to come and these funds would be wasted without the ministerial approvals.

While the Court engages in speculative reasoning to arrive at its conclusion, this decision highlights the risk that funding decisions for projects that have the potential to adversely impact asserted or established Aboriginal or treaty rights could be found to engage the duty to consult. This will be most important where a funding decision is the only Crown decision relating to the project for a particular government. There are some jurisdictions (such as the federal government) that are already consulting on government funding decisions where the project at issue would not proceed but for the funding. It is likely that consultation by governments in this area will increase and we anticipate further disputes and court decisions on this topic.

Cases To Watch

In addition to the Federal Court of Appeal's anticipated decision in 2020 concerning the Trans Mountain pipeline and the adequacy of further consultation carried out by the federal government with certain Indigenous groups, there are several upcoming Aboriginal law cases to watch for in 2020 (and beyond).

Saik'uz and Stellat'en First Nations' water rights nuisance claim – In this proceeding, Saik'uz and Stellat'en First Nations allege that Rio Tinto Alcan's operation of the Kenney Dam since 1952 has diverted and altered the water flowing to the Nechako River, resulting in significant adverse impacts to the Nechako's waters, and their fisheries resources. In 2015, the B.C. Court of Appeal allowed the First Nations to proceed with a tort claim in private and public nuisance and for breach of riparian rights against Rio Tinto Alcan, on the basis of asserted but unproven rights and title. In 2016, the B.C. Supreme Court granted Rio Tinto Alcan's application to add the federal and provincial governments as defendants, finding that it is a "major and complex case" in which the intersection between Aboriginal rights and common law tort stand to be defined, and that the Crown parties are necessary parties to the determination of issues respecting Aboriginal title. The case will address whether there are valid causes of action in property law against proponents based on adverse impacts to asserted Aboriginal rights and title and specifically, where the activities at issue are undertaken pursuant to valid government approvals. The 200-day trial commenced in October 2019.

Treaty Rights Infringement Claims – Several Indigenous groups have commenced treaty rights infringement claims against governments on the basis of cumulative impacts.

These include actions by Blueberry River First Nation in B.C., Beaver Lake Cree First Nation in Alberta, and Carry the Kettle First Nation in Saskatchewan. These ongoing infringement cases are based on the premise that the cumulative impacts of projects and industrial development in the Indigenous groups' traditional territories, have deprived them of their ability to meaningfully exercise their treaty rights, to the point of infringement. These cases differ from duty to consult claims, in which inadequate consultation and accommodation for impacts to rights are the focus. Whereas it is legally permissible for the Crown to make decisions that impact or limit Aboriginal and treaty rights (subject to the constitutional principles of reasonable consultation and accommodation), in contrast, a potential action for infringement will arise where the impacts on rights by the 'taking up' of lands leaves the Aboriginal group without the ability to meaningfully exercise a right. The SCC has held that this type of treaty infringement claim is viable and could succeed if an Indigenous group is left without the ability to meaningfully exercise its treaty rights and such infringement cannot be justified by the Crown. Regardless of outcome, these cases indicate a trend of increasing focus on cumulative impacts resulting from project development and will contribute substantially to the law of treaty rights infringement.

The Blueberry River First Nation's claim in B.C. is the most advanced of the three proceedings. The 120-day trial began in May 2019, after negotiations between the First Nation and the Province broke down (although the government reportedly still hopes to reach a settlement). New details were presented at trial that approximately 91% of Blueberry River's Treaty 8 traditional territory, located in the Peace Region of northeastern B.C., is within 500 metres of an industrial disturbance (including hydroelectric dams, oil and gas wells and pipelines, roadways, transmission lines and forestry activities).

Saugeen Ojibway Nation's Water Title Claim (Water title) – A trial is currently underway, in which two Ontario First Nations are seeking a declaration of Aboriginal title to a large portion of the lakebed of Lake Huron and Georgian Bay. This is a novel claim that will require the Court to determine whether title can be established to a lake or river bed and, if so, what rights does this afford and how are those rights reconciled with existing third-party interests. It is an interesting case to watch that could impact future consultation on projects depending on the outcome. There are numerous Indigenous groups with water title claims in Canada, such as the Haida Nation, the Mississaugas of the New Credit, the Chippewas of the Thames, and the Mohawks of Awkwasane.

First Nations move forward with challenge to Site C – In August 2019, West Moberly First Nation and Prophet River First Nations decided to move forward with their legal challenge to the Site C hydroelectric project in B.C. following unsuccessful negotiations with the province. A 120-day trial is scheduled for March 2022. The First Nations claim that the project unjustifiably infringes their Treaty 8 rights. Construction of the Site C project continues, following unsuccessful applications by the First Nations for injunctive relief in 2018. However, the case will be heard before the scheduled filling of the reservoir in 2023, and the outcome of that decision (and related appeals) could have significant bearing on the final outcome of the project.

SCC to hear appeal of *R. v. Desautel* concerning transboundary hunting rights[5] – In 2020, the SCC will hear an appeal of a B.C. hunting rights case which will consider whether s. 35 Aboriginal rights can extend to Indigenous groups that do not reside in Canada but, whose traditional territories include parts of present day Canada. The defendant is a member of the Lakes Tribe in Washington State whose northern part of their traditional territory includes part of southern B.C. The B.C. Provincial Court found that the Lakes Tribe was capable of holding Aboriginal rights in Canada and the B.C. Supreme Court and B.C. Court of Appeal dismissed the appeals. This case will impact project consultation in areas near the Canada-US border if the SCC dismisses the appeal and could clarify other important issues relating to Aboriginal rights.

SCC to decide jurisdictional case in *Newfoundland and Labrador v. Uashaunnuat et al.*[6] – In 2020, the SCC will issue a decision in a jurisdictional challenge relating to a transboundary claim by two Quebec Innu First Nations. The First Nations are seeking $900M in damages and injunctive relief against two corporations and declarations of Aboriginal rights and title in Quebec and Newfoundland. The SCC will decide Newfoundland and Labrador's appeal of its unsuccessful motions to strike portions of the claim relating to lands and resources in Newfoundland. Newfoundland and Labrador argued that the Quebec court did not have jurisdiction to grant relief regarding real property in Newfoundland and against the Newfoundland Crown. Both the Quebec Superior Court and Court of Appeal dismissed this motion and the SCC's decision will have implications for other transboundary claims.

5 2019 BCCA 151

6 2017 QCCA 1791

Developments In Federal Legislation And Policy

New federal environmental legislation enhances Indigenous participation and decision-making opportunities

On August 28, 2019, Canada's new federal environmental legislation under Bill C-69 (including the *Impact Assessment Act* ("**IAA**"), *Canadian Energy Regulator Act* ("**CERA**"), and *Canadian Navigable Waters Act* ("**CNWA**")) and Bill C-68 (amendments to the *Fisheries Act* and other Acts in consequence) came into force. These new statutes and legislative amendments introduce enhanced Indigenous consultation requirements for projects that require federal impact assessments and certain federal regulatory approvals and permits. In broad strokes, the new Indigenous-related aspects of the IAA and other Acts generally focus on new measures designed to: (a) increase opportunities for Indigenous participation, cooperation and partnership with government in impact assessment processes and decision-making; (b) enhance recognition and consideration of Indigenous rights and interests; and (c) enhance consultation and engagement opportunities for Indigenous groups.

In respect of impacts to Aboriginal rights and interests, the IAA and CERA expand the scope of what must be considered vis-à-vis Indigenous interests in decisions or recommendations under these statutes. The decision-maker will be required to consider any impacts on Indigenous peoples and their asserted and established Aboriginal or treaty rights. This goes beyond the common law requirements of the duty to consult, which is limited to the consideration of impacts on s. 35 rights and does not consider impacts on Indigenous peoples more generally.

The new Acts seem to reflect the federal government's intentions for how to implement the principles of the *United Nations Declaration on the Rights of Indigenous Peoples* ("**UNDRIP**") and specifically the concept of free, prior and informed consent ("**FPIC**") of Indigenous groups in decision-making. The federal government is doing so by increasing opportunities for Indigenous participation in decision-making ("aiming to secure consent") rather than by implementing a stricter standard of consent in respect of all decisions affecting Indigenous peoples or rights. The federal government's approach aims to strike a balance between competing interests, including where certain affected Indigenous groups support a project and others oppose it. However, there continues to be heightened expectations of consent and confusion in this area. This is due in part to earlier statements by the federal government about its "unqualified support" for UNDRIP, which it has in fact qualified through further statements and actions.

The various agreement, arrangement, substitution and delegation approaches set out in the IAA do, however, give rise to the potential for Indigenous groups to negotiate consent principles into decision-making processes. These types of agreements and arrangements are discretionary on the part of either the Minister or the Impact Assessment Agency. If exercised, they give rise to potential opportunities that would significantly shift assessment and decision-making authority from government to Indigenous groups whose rights may be affected by a project. In our view, the true extent to which such measures will have any meaningful impact on the impact assessment regime will largely depend on the government's willingness to implement them in practice, and particularly the degree to which they are willing to enter into such agreements with Indigenous groups that are not parties to modern treaties, and whether government will offer up authority beyond projects on modern treaty or reserve lands.

Federal government commits to table new UNDRIP implementation legislation in 2020

In June 2019, federal Bill C-262, *An Act to ensure that the laws of Canada are in harmony with UNDRIP*, failed to pass the final stage of the legislative process in the Senate and died on the order paper. Under Bill C-262, UNDRIP would have been affirmed as a "universal international human rights instrument with application in Canadian law."

The federal government would have been required to "take all measures necessary to ensure that the laws of Canada are consistent with" UNDRIP, to implement a national action to achieve the objectives of UNDRIP, and to provide an annual report to Parliament until 2030. The Bill failed to pass the Senate largely due to concerns with respect to the lack of clarity surrounding interpretation of the Bill (including how FPIC would be interpreted and applied) and potential unintended consequences if passed, rather than due to a lack of support for the aspirations of UNDRIP.

However, the federal government has committed to reintroduce and pass similar legislation by the end of 2020 to implement UNDRIP, as set forth in the Liberals' fall election platform and Speech from the Throne. The Prime Minister's December 13, 2019, Mandate Letter to the Minister of Crown-Indigenous Relations, the Honourable Carolyn Bennett, directs the Minister to "[s] upport the Minister of Justice and Attorney General of Canada in work to introduce co-developed legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples by the end of 2020." It will be interesting to see how the new legislation will differ from Bill C-262, and whether the federal government will follow B.C.'s lead with the successful passing of its new UNDRIP legislation, as discussed in the British Columbia regional section on page 8 of this publication. Notably, some of the language in B.C.'s new Act was borrowed directly from Bill C-262, with B.C.'s Act passing unanimously in the legislature in just over the span of one month.

Mergers & Acquisitions

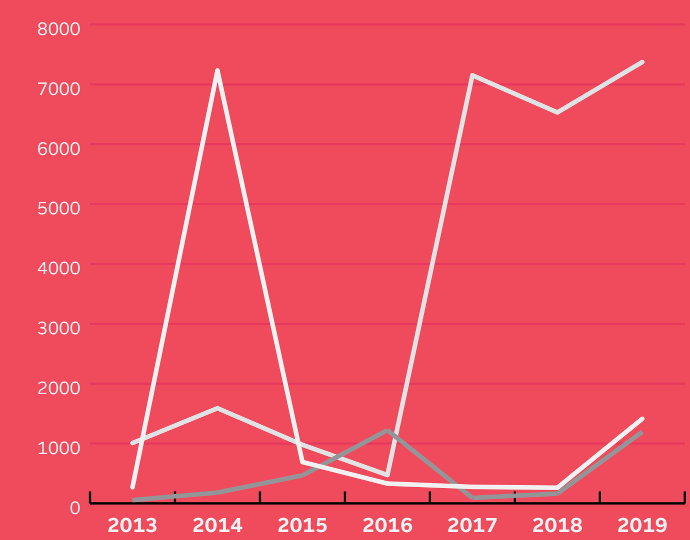
Authors: Scott Bergen, Maureen Gillis, Kerri Lui, Suzanne Murphy and Xinya Wang

Introduction

2019 saw the continued growth of domestic M&A activity in the Canadian power sector, with an aggregate domestic deal value of US$7.4 billion. Notably, domestic investments in the power sector in 2019, exceeded the peak aggregate US inbound deal value from 2014, of US$7.2 billion.

By contrast, US and non-US inbound investments in the Canadian power sector remained stable in 2019, with an uptick from 2017 and 2018 figures. Aggregate domestic deal values for US and non-US inbound investments in 2019, were US$1.4 billion and US$1.2 billion, respectively, compared with US$262 million and US$163 million in 2018.

Canada M&A Deal Value in the Electricity, Power & Utilities Sectors
($US mm)



US Inbound	470	7,232	691	331	276	262	1,414
Non-US Inbound	55	181	468	1,228	92	163	1,196
Canada Domestic	1,008	1,590	979	474	7,152	6,531	7,374

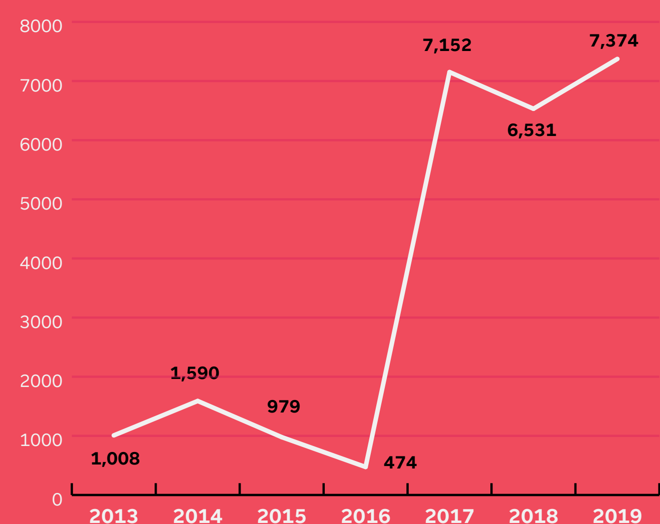
Source: MergerMarket

Foreign investments in the power sector by Canadian companies declined significantly in 2019, with an aggregate deal value of US$13.4 billion, compared with US$28.2 billion in 2018. The most significant region for outbound investment by Canadian companies continues to be the United States, followed by Latin America, Mexico, and the Caribbean; Europe; and Asia.

Domestic Investments by Canadians

Domestic investments in the power sector continued to grow in 2019, maintaining momentum from the surge in investment seen in 2017 and 2018.

Canada Domestic M&A Deal Value in the Electricity, Power & Utilities Sectors
($US mm)



Source: MergerMarket

Based on deal value, the major players in the 2019 Canadian power M&A market were Ontario Power Generation Inc., the Public Sector Pension Investment Board ("**PSP Investments**"), and the Alberta Teachers' Retirement Fund Board (the "**ATRF**").

The two largest transactions by value in the Canadian power sector followed the trend of high domestic

investment activity in large energy infrastructure. The largest deal by value was Ontario Power Generation Inc.'s agreement to acquire a portfolio of combined-cycle natural gas–fired plants in Ontario from TransCanada Energy Ltd. for US$2.2 billion. TransCanada Energy is a publicly listed Canadian energy company focused on natural gas transmission and power services, headquartered in Calgary. The portfolio of acquired plants includes 100% of Halton Hills Generating Station and Napanee Generating Station, along with 50% of the Portlands Energy Centre.

The next major transaction in 2019, was the acquisition of AltaGas Canada Inc. by a consortium of investors comprised of PSP Investments and the ATRF. The consortium agreed to acquire all of the shares of AltaGas Canada Inc. for approximately US$1.3 billion. AltaGas Canada Inc. is a publicly listed Canadian company with natural gas distribution utilities and renewable power generation assets, headquartered in Calgary.

Other significant domestic transactions included the following:

TD Greystone Infrastructure Fund, a fund managed by TD Asset Management ("TD Greystone"), and IST Investmentstiftung ("IST"), a Swiss non-profit organization, agreed to acquire Alberta PowerLine Limited ("**APL**"), a Canadian transmission line developer, from Canadian Utilities Limited and Quanta Services, Inc. for US$1.2 billion. As part of the transaction, the Athabasca Chipewyan First Nation, Bigstone Cree Nation, Gunn Métis Local 55, Mikisew Cree First Nation, Paul First Nation, Sucker Creek First Nation, and Sawridge First Nation exercised an option to acquire a 40% stake in APL for US$90 million. McCarthy Tétrault acted as counsel to TD Greystone and IST.

Canadian Utilities Limited sold its Canadian fossil fuel–based electricity generation portfolio for approximately CAD$835 million, including the sale of the interest of ATCO Power Canada Ltd. ("**ATCO Power**") in the Cory facility and related Saskatchewan assets to SaskPower International Inc., the sale of the equity interests of ATCO Power in Brighton Beach Power L.P. and Brighton Beach Power Ltd. to Ontario Power Generation Inc., and the sale of ATCO Power (2010) Ltd.'s direct equity interest in ATCO Power (and indirect interest in Alberta Power (2000) Ltd.) to Heartland Generation Ltd., an affiliate of Energy Capital Partners. McCarthy Tétrault acted as counsel to the lenders to Energy Capital Partners.

Noverco Inc. ("Noverco") agreed to acquire all of the shares of Valener Inc., a publicly listed Canadian natural gas company headquartered in Montréal, for US$824 million. McCarthy Tétrault acted as counsel to Noverco.

Capital Power Corporation acquired the Goreway Power Station, a combined-cycle natural gas-fired plant located in Brampton, Ontario, from Toyota Tsusho Corporation ("**Toyota**") and JERA Co. Inc. ("**JERA**") for US$726 million. McCarthy Tétrault acted as Canadian counsel to Toyota and JERA.

Connor, Clark & Lunn Infrastructure and Desjardins acquired all of the shares of Regional Power Inc., a Canadian developer of hydroelectric and wind projects, from Manulife. McCarthy Tétrault acted as counsel to Manulife.

Columbia Basin Trust and Columbia Power Corporation acquired a 51% stake in the Waneta Expansion Hydro-electric Project from Fortis Inc. for US$1 billion. Following the transaction, FortisBC continues to operate the Waneta Expansion facilities and purchase its surplus capacity.

Whitby Hydro Electric Corporation ("Whitby") and Veridian Corporation merged to form Elexicon Corporation, which is the single shareholder of the subsidiaries: Elexicon Energy Inc. and Elexicon

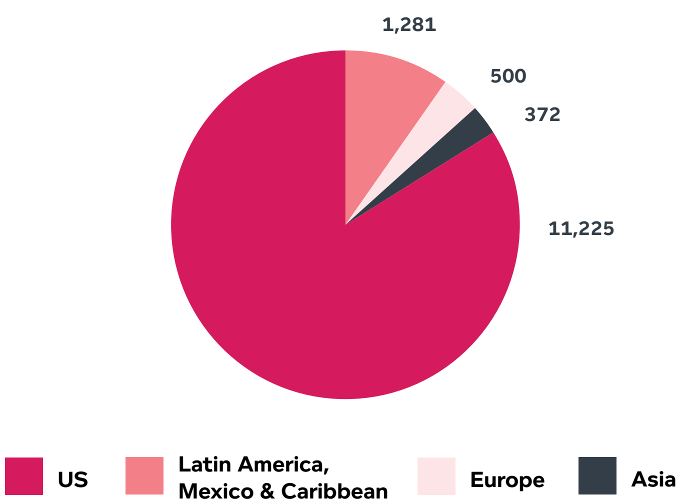
Group Inc. Elexicon Energy Inc. serves over 162,000 residential and business customers with a combined rate base of approximately CAD$313.9 million. McCarthy Tétrault acted as counsel to Whitby.

Foreign Investments by Canadians

Aggregate foreign investment by Canadian companies in the power sector in 2019 fell by more than 50% from 2018 foreign investment figures. In 2019, the aggregate Canadian outbound deal value was US$13.4 billion, compared with US$28.2 billion in 2018.

As in previous years, the majority of foreign investment by Canadian companies in the power sector in 2019 was in the United States, with an aggregate deal value of US$11.2 billion. Investment in the United States was followed by investment in Latin America, Mexico, and the Caribbean (US$1.3 billion), Europe (US$500 million), and Asia (US$372 million). This activity remained proportionately consistent with previous years; however, as in 2018, 2019, also saw no investments by Canadian companies in Oceania and Africa.

Canadian Outbound Investment in Electricity, Power & Utilities in 2019
($US mm)



Source: MergerMarket

The leading transactions by value for Canadian companies investing in the power sector in foreign jurisdictions in 2019 included the following:

Canada Pension Plan Investment Board agreed to acquire all of the shares of Pattern Energy Group Inc., a publicly listed US-based owner and operator of wind and solar facilities, for approximately US$6.1 billion.

Canada Pension Plan Investment Board acquired a 35% stake in Williams Ohio Valley Midstream LLC ("**OVM**") and Utica East Ohio Midstream LLC ("**UEO**") from Williams Companies, Inc. for US$1.3 billion. Both OVM and UEO are US-based companies; OVM is a distributor of natural gas and is engaged in the processing and fractionation of natural gas and natural gas liquids.

John Hancock Infrastructure Fund, GP and John Hancock Life Insurance Company, Inc. acquired a minority interest in a portion of a commercial renewable energy portfolio from Duke Energy Renewables for US$1.3 billion. John Hancock Infrastructure Fund, GP, is the Canada-based fund of Manulife Capital, the private equity arm of Manulife Financial Corporation. The acquired portion of the portfolio includes 49% of 37 operating wind, solar, and battery storage assets and 33% of 11 operating solar assets across the US.

ENMAX Corporation agreed to acquire Emera Maine, a US-based provider of electric delivery services to residential and business clients, from Emera Inc. for US$1.3 billion.

Ontario Power Generation Inc. acquired Cube Hydro Partners, LLC, a US-based operator of small and medium-sized hydropower facilities, from I Squared Capital for US$1.1 billion.

Northland Power Inc., a Canada-based electricity generation company, agreed to acquire a 99.2% stake in Empresa De Energia De Boyaca S.A. E.S.P., a Colombia-based generator and distributor of electricity, from Brookfield Infrastructure Partners Limited for US$795 million.

Wataynikaneyap Power Transmission Project

Authors: Lynn Parsons, Alexandre Saulnier-Marceau and Jacob Stone

2019 saw the financial close of what has been billed as the largest First-Nations-led infrastructure project in Canadian history: the Wataynikaneyap Power Transmission Project (the "**Project**"). Officially closed on October 29, 2019, the construction and project financing will fund a total project cost of up to $1.9 billion. The Project is being led by Wataynikaneyap Power, a partnership between FortisOntario Inc. and First Nations LP ("**FNLP**"), which is in turn a partnership wholly owned by 24 First Nations. Through FNLP, these First Nations will maintain majority ownership and control of the Project.

The Project

The Project will see the construction of approximately 1,800 kilometres of transmission lines throughout a large swath of northwestern Ontario that will connect 17 First Nations communities to the Ontario power grid. Once completed, the Project will supply reliable energy to thousands of residents across northwestern Ontario who currently rely on diesel generation for electricity. In doing so, the Project will avoid an estimated 6.6 million tonnes of CO_2 equivalent greenhouse gas emissions over 40 years. The Project is also expected to create an estimated 769 jobs during construction and close to $900 million in socio-economic value.

Valard was engaged as the engineering, procurement and construction contractor for the Project in September 2019. The Pikangikum First Nation community was the first to be connected and the remaining communities are projected to be connected upon completion of the Project by the end of 2023. The notice to proceed for construction immediately followed the financial close for the Project.

The Financing

The financing of the Project was very complex and consisted of a multi-layer debt financing, all of which needed to be synchronized on many fronts and required all involved parties to work jointly with the common goal of achieving financial close. In addition to the financing, the Project required extensive commercial, regulatory and strategic considerations at all levels of involvement in the Project.

At the Project level, there was a construction financing comprised of a $1.34 billion loan from the Ontario government and a $680 million loan from a syndicate of five Canadian Schedule I banks. At the FNLP ownership level, there was a complex equity financing comprised of a $220 million loan from a syndicate of two Canadian life insurance companies (represented by McCarthy Tétrault) that is supported by a guarantee provided by the Ontario Ministry of Finance under the Aboriginal Loan Guarantee Program. The Project had also previously secured financial support from the Canadian government in July 2019.

Going Forward

The Project presents a compelling model for partnerships between First Nations and the private and public sectors. In addition, it presents a unique and sustainable solution to the challenge of connecting northern communities to Ontario's southern grid. As the push continues to reduce the isolation of northern communities while maintaining a limited environmental impact, we may not have seen the last of ambitious projects of this nature.

Energy Litigation

Authors: Will Horne, Julie Parla and Sam Rogers

Reference re *Greenhouse Gas Pollution Pricing Act* [1,2]

What are the limits of the federal government's authority to regulate greenhouse gas emissions? The answer to this question – soon to be decided by Supreme Court of Canada (the "**SCC**") – will determine how governments in Canada approach climate change policy for the foreseeable future.

At issue is the federal government's *Greenhouse Gas Pollution Pricing Act* (the "**Act**"), which sets national standards for carbon pricing, commonly known as the "carbon tax". Part 1 of the Act applies a levy to fossil fuels, and Part 2 sets a cap-and-trade system for output-based greenhouse gas ("**GHG**") emissions for large industrial facilities to maintain competitiveness. All revenues raised are returned to the provinces in which they are levied.

Ontario and Saskatchewan challenged the constitutionality of this legislation. The courts of appeal in both provinces upheld the constitutionality of the Act in 2019.

Both courts said that the federal government has authority to set minimum GHG standards under the "peace, order, and good governance" ("**POGG**") power in the Constitution, which is often viewed as a residual "catch-all" for matters not specifically defined under other sections. The courts held that regulating GHG emissions falls under the "national concern" branch of POGG, meaning it concerns the country as a whole and not just any one province. In other words, GHG reduction cannot be accomplished in a piecemeal fashion absent a national benchmark to ensure overall competition and effectiveness.

Interestingly, both courts also said that the carbon tax is not actually a tax, but a regulatory charge. This is because it does not raise general revenue, but imposes a charge for a regulatory purpose, which, in this case, is to promote and reward behaviour modification. The implication is that the Act does not create a constitutionally impermissible tax, as argued by the provinces.

One notable difference between the Ontario and Saskatchewan decisions is the way in which the respective courts defined the federal power. The Saskatchewan Court of Appeal took a narrower approach, stating that the federal government can establish *minimum national standards of price stringency for GHG emissions*. The Ontario approach was more general, stating that the federal government can establish *minimum national standards to reduce GHG emissions*. The latter version would appear to give the federal government broader scope to legislate in this space, which could theoretically support a greater variety of policy measures in the future.

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Either way, using a "minimum national standards" approach under the POGG power appears to be a novel development in Canadian law.

As such, we do not yet know how it might impact the balance between federal and provincial powers, and the subsequent impacts on industry.

It is now up to the SCC to determine whether the Act interferes with provincial jurisdiction, or whether the courts of appeal in Ontario and Saskatchewan were correct in finding a valid exercise of federal jurisdiction. The matters are scheduled to be heard on March 24 and 25, 2020.

It should also be noted that the Alberta Court of Appeal heard its own version of this reference question during the week of December 16, 2019. It is unclear when the court will make its ruling. It remains to be seen how the Alberta decision may impact or inform the Supreme Court proceedings in March.

For now, businesses across Canada are still required to comply with current pricing regime under the Act, or equivalent provincial statute.

1 2019 ONCA 544

2 2019 SKCA 40

National Steel Car Limited v. Independent Electricity System Operator [3]

The Ontario Court of Appeal has decided that the ongoing constitutional challenge to the "Global Adjustment" brought by National Steel Car Limited deserves a full hearing.

The Global Adjustment is a charge paid by all Ontario electricity consumers to cover the difference between the hourly electricity price and the price guaranteed to generators pursuant to their IESO procurement contracts. It is also intended to cover various infrastructure improvements and conservation programs. The amount paid by consumers, including National Steel Car (a heavy industrial user), has increased substantially since 2008, due to a number of factors including the *Green Energy Act*.

National Steel Car is challenging the Global Adjustment by arguing that it is actually a tax in disguise, and is therefore unconstitutional because Ontario cannot levy indirect taxes.

Last year we reported on the decision of the lower court, in which the motions judge struck National Steel Car's applications on the basis that it was "plain and obvious" that the applications had no chance of success because the Global Adjustment was a regulatory charge and not a tax.

National Steel Car successfully appealed that decision this year. The company's argument focuses particularly on the existing FIT contracts, which it states are not actually part of a closed regulatory system designed to promote cleaner energy sources, but instead are being used to accomplish broader policy goals unrelated to electricity generation, such as rural development.

The Court of Appeal ruled on November 29, 2019, that National Steel Car's claim is sufficiently plausible that the lower court should not have dismissed it without a full hearing on all of the evidence. The Court of Appeal did not make any findings on the merits of National Steel Car's arguments. The matter has been sent back to the lower court to be considered on a full evidentiary record.

3 2019 ONCA 929

It remains to be seen whether the provincial government will appeal to the SCC within the 60 day limit, but the 2018 change in government may shape the ultimate outcome. In particular, counsel for Ontario advised the Court of Appeal that the current government "does not agree with the former government's electricity procurement policy (since-repealed)" and it feels that "[t]he solution does not lie with the courts, but instead in the political arena with political actors." For the time being, the Global Adjustment remains in place.

Reference re Environmental Management Act (British Columbia) [4]

Can B.C. pass a law to unilaterally stop the Trans Mountain Pipeline expansion ("**TMX**")? It would seem unlikely following this year's Court of Appeal ruling in Reference *re Environmental Management Act (British Columbia)*, 2019 BCCA 181.

The unanimous panel of five judges held that the B.C. government's attempt to defeat TMX by restricting possession of "heavy oil" was unconstitutional. The provincial law was found to interfere with the federal government's exclusive jurisdiction over federal undertakings, which includes interprovincial pipelines. The result is a clear victory for pipeline proponents, and a positive affirmation of Parliamentary authority in this area.

In 2018, the B.C. government introduced amendments to the *Environmental Management Act* ("**EMA**") prohibiting anyone from possessing heavy oil in quantities greater than that possessed between 2013 and 2017, unless they obtained a hazardous substance permit. Commonly known as the "turn off the taps bill", the amendments were clearly and specifically targeted at TMX, a project which involves twinning an existing pipeline and increasing the quantities of oil flowing through B.C.

The B.C. government asked the Court of Appeal to weigh in on the amendments in a constitutional reference which pitted B.C. against Ottawa and Alberta. No fewer than nineteen intervenors submitted arguments.

In support of its legislation, the B.C. government argued that the purpose of its amendment was not to regulate an interprovincial pipeline, but to regulate the release of

4 2019 BCCA 181

hazardous substances into the environment. It stated that the effect on TMX is merely incidental. They also underscored the importance of environmental stewardship to both levels of government, the "disproportionate" impacts of TMX to B.C., and that law-making is often best achieved by the level of government closest to those affected (a principle known as subsidiarity).

The Court of Appeal nevertheless found the EMA amendments to be unconstitutional. It held that the "pith and substance" (or dominant characteristic) of the law was "to place conditions on, and if necessary, prohibit, the carriage of heavy oil thorough an interprovincial undertaking", which is beyond B.C.'s jurisdiction. The Court found that the amendments would "*actually apply* only to Trans Mountain's heavy oil", thus confirming Canada's assertion that the law was designed to frustrate the pipeline.

Having found that the law related in substance to a federal head of power, this was "the end of the matter". Accordingly, the Court noted that unless an undertaking is contained entirely within a province, "federal jurisdiction is the only way in which it may be regulated".

The Court was quick to add that its decision does not reflect a "sea change" (or decisive shift) in the law away from cooperative federalism. Rather it reflects the constitutional allocation of certain powers exclusively to only one level of government.

The B.C. government has exercised its automatic right of appeal on constitutional reference questions – the matter is scheduled to be heard by the SCC on January 16, 2020.

Also of note are the ongoing proceedings in the Federal Court of Appeal challenging the federal government's decision in June 2019 to re-approve the TMX expansion (after its previous approval was quashed by the Court in August 2018). Several First Nations are arguing that Canada has again failed in meeting its duty to consult with Indigenous Peoples.

While the TMX project continues to make headway, uncertainty resulting from ongoing legal proceedings persists.

EPCOR Water Services Inc., EL Smith Solar Power Plant [5]

Alberta self-generators who export their surplus power to the grid are coping with regulatory uncertainty following a decision of the Alberta Utilities Commission (the "**AUC**") early in 2019. At issue was whether EPCOR Water Services Inc. could benefit from an exemption in *Alberta's Electric Utilities Act* ("**EUA**") that would allow it to consume a portion of self-generated power on site, while exporting the rest.

In a departure from its earlier practice, the AUC determined that such an arrangement was, in EPCOR's circumstances, inconsistent with the EUA and that the exemption did not apply.

In AUC Decision 23418-D01-2019 ("**Smith**"), EPCOR Water filed applications with the AUC to build a 12 MW solar installation at its water treatment facility in Edmonton. EPCOR planned to use about 70% of the electricity to power its water treatment systems and to export the remaining 30% to the grid to be sold on the wholesale market. This aligned with EPCOR's commitment to replace a portion of conventional power consumption with locally-produced renewable energy.

The EUA requires that all electric energy entering or leaving the grid must be exchanged through the power pool. In other words, unless EPCOR could access an exemption, it would be required to offer 100% of the electricity from its solar installation for sale on the wholesale market (not just the 30% it intended to offer).

In EPCOR's view (which aligned with previous AUC approvals), the EUA exemption for electric energy produced and consumed solely by the generator on their own property was applicable. The AUC disagreed. After conducting an analysis of the broader legislative scheme and attempting to reconcile the wording of the exemption with the intent of the legislature, the AUC determined that the exemption was intended to apply in "very limited" circumstances, which were not met in this case.

It is important to note that, while the legislation provides numerous exemptions to the offer/exchange requirement, none were held to apply to EPCOR.

5 February 20, 2019, Decision 23418-D01-2019

In concluding, the AUC acknowledged that its change of direction "may have ramifications for existing approval holders and future applicants".

This was borne out in two subsequent AUC decisions: *Advantage Oil and Gas Ltd., Glacier Power Plant Alteration*, Decision 23756-D01-2019, and *International Paper Canada Pulp Holdings ULC, Request for Permanent Connection for 48-Megawatt Power Plant*, Decision 24393-D01-2019.

The upshot of all three cases is that unless self-generators can access another specific exemption (e.g. an industrial system designation), they must either consume 100% of the energy on site, or exchange 100% of the energy through the power pool. As a result, existing self-generators will need to carefully assess their positions going forward.

Please refer to our Alberta regional overview on page 18 of this publication for additional commentary on these cases, the existing exemptions and subsequent developments.

About Us

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.

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