The future of Canadian energy: A review of 2023's top energy issues and what to expect in 2024

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In 2023, energy transition policy, carbon pricing uncertainty, evolving technologies, and jurisdictional disputes continued to provoke change in the Canadian energy industry. BLG's Energy lawyers continuously review the policies, issues, cases and developments affecting the Canadian energy industry. The following is our list of the most compelling energy issues of 2023 that will influence trends, business decisions and the future growth of Canada's energy industry in 2024 and beyond.

Key takeaways

The Canadian energy industry continues to encounter structural change, heavily influenced by provincial and federal government policies and regulations. The major themes and energy issues in 2023 that BLG noted include additional clarity, but nevertheless continuing uncertainty, regarding carbon pricing and tax incentives, which are delaying progress on energy transition projects; broad commitments to green energy transition, and carbon reduction goals but with many ideological and practical disputes about how, when and the effect of achieving such goals; and the consolidation and fortification of the traditional oil and gas industry amidst the energy transition. As 2023 ends, the path, pace and direction of the energy industry evolution remains unsettled.

Canada's energy transition: How carbon price uncertainty is delaying key energy projects

Canada's "polluter pay" carbon pricing system is an important tool that the federal government uses to incent investment in energy transition projects. Yes, there are some other tools - the "carrots" - like new investment tax credits on capital investment in things like clean electricity, hydrogen, and carbon capture, utilization, and storage (CCUS) projects, some strategic concessional financing available from federal institutions like the Canada Infrastructure Bank and the new Canada Growth Fund, and a smattering of targeted federal grant-like funding available in specific areas, but it is Canada's carbon pricing system – our "stick" – that underpins it all. If project proponents and their financiers have concerns about the long-term survival of carbon pricing in Canada, they will be hesitant to make final investment decisions to proceed with their projects – the "carrots" are likely not enough on their own to incent investment without our "stick". Unfortunately, that is exactly the position we find ourselves in as 2023 comes to an end.

Canada's carbon pricing system is really a collection of systems. There is the federal output-based pricing system (OBPS). Under any OBPS, like the federal one, large emitters generally pay a federally set price per tonne of emissions that they generate in excess of the emissions thresholds applicable to the facilities that they own. These emitters can also generate carbon credits if they emit less than these emissions thresholds and then sell those carbon credits to other emitters who fail to meet their emissions thresholds. Besides the federal OBPS, there are a number of provincial and territorial (P/T) carbon pricing systems that the federal government has concluded meet the minimum national standards for carbon pricing and can therefore replace the federal OBPS. The result is that we have a hodge podge of carbon pricing systems: 1. some P/Ts with their own OBPS like the federal system, 2. Québec with a unique cap-and-trade system like California, and 3. other P/Ts which use the federal OBPS because those P/Ts do not have one of their own.[1] So, piecing these systems together, we have a price on carbon emissions everywhere in Canada that all businesses need to consider when making production decisions.

This includes a large emitter, like a cement or steel plant or an oil sands facility, which is considering whether to proceed with a decarbonization project that would reduce its carbon emissions. A key factor in that decision is the carbon price savings (operating cost reductions) that would come over time from the resulting reduced emissions from the facility, **plus**, if the proposed decarbonization project is expected to reduce emissions below the applicable emissions threshold, the value of the carbon credits that would be generated and sold in the market over time generating additional revenue.

Carbon pricing is also on the mind of a proponent of a new clean energy project that is looking to build a low-carbon-emitting facility and displace competitor products being produced at existing high-carbon-emitting facilities. The new facility, which will be costly to build and operate, will only be profitable if its products can be priced competitively versus those from the existing facility. This will often only happen if the higher emitting competitor continues to pay a price on carbon and recover it through higher prices. In this regard, think of a new renewable (low-emitting) electricity project that is looking to displace the electricity from an existing gas-fired power plant in the market. Similar reasoning would apply where producers of new clean energy sources are proposing to displace higher carbon energy sources that currently bear a carbon price. In this regard, think of a new project to produce and sell hydrogen that is intended to displace natural gas and other hydrocarbons used in industrial processes in the market.

The net result is that many of these energy transition projects can only be justified if carbon pricing – or some other "stick" – exists to incent the investment. However, broad support does not exist in Canada for carbon pricing, as evidenced by the opposition that has been expressed by several P/Ts. More importantly, the federal Conservative Party of Canada, who are leading today, in many polls, have made "Axe the Tax" a key component of the platform upon which they will campaign in the next election. An election that must be held before Oct. 20, 2025. This all culminates in political/policy uncertainty when it comes to carbon pricing that is preventing proponents from making positive final investment decisions on their energy transition projects as 2023 comes to a close.

If we are going to unlock these projects in time for them to help Canada meet its climate targets, including our 2030 Paris commitments, and for the country to grow and prosper in tomorrow's low-carbon world, the federal government and P/Ts need to jointly tackle the carbon price uncertainty issue early in 2024. There are some alternatives, including financial mechanisms like the use of carbon contracts for difference and legislative options, but ultimately this is going to take the federal government and P/Ts working together and jointly providing assurance that carbon pricing in some form or, alternatively, that carbon-emission limits or costs will be imposed at a national or provincial level for some time, that justify positive final investment decisions being made now. This will help Canada get on with its clean energy transition in 2024 at the pace and scale that we need to be successful.

[1] Though the focus here is on the carbon pricing system that applies to large emitters, the same political/policy uncertainty applies to other federal carbon reduction pricing and regulatory "sticks", like the Clean Fuel Regulations, the proposed Clean Electricity Regulations, and the proposed federal Oil and Gas Sector Greenhouse Gas Emissions Cap announced by the federal government on Dec. 7, 2023 that will work in tandem with carbon pricing on large emitters to incent emission reductions in most parts of the oil and gas sector.

Hydrogen opportunities in Canada

Introduction

2023 saw a continued focus on advancing the transition to green energy and a low carbon future, with a particular emphasis on hydrogen. In line with their respective, previously announced strategic plans on hydrogen, the Federal and provincial governments introduced several initiatives to support the development of hydrogen production, or the use of hydrogen-powered equipment. This includes a new clean hydrogen investment tax credit and steps to ease the regulatory burden faced by project proponents.

The provinces: Streamlining regulatory review and investing in development

In an effort to spur hydrogen projects and investment, certain provinces took steps in 2023 to either ease the regulatory burden faced by proponents of large-scale hydrogen projects (at least at the provincial level) or increase investment in hydrogen-related innovation.

- **Alberta** - On Aug. 1, 2023, Alberta announced an additional $45 million in funding for new hydrogen technologies, to be distributed pursuant to two parallel competitions administered under its Technology Innovation and Reduction (TIER) fund. A total of $20 million in provincial funding plus an additional $5 million in funding from Natural Resources Canada will be available to successful applicants with early-stage innovations. Similarly, a total of $25 million in provincial funding will be available to successful applicants with later-stage technologies.

This increased funding follows from Alberta's Hydrogen Roadmap and complements other green energy funding initiatives, such as the Alberta Petrochemical's Incentive Program (APIP), which provides for grants worth 12 per cent of a project's eligible capital costs once operational. Notably, Alberta has already provided approximately $161 million in funding through APIP to one major hydrogen-related project – Air Products' natural gas and hydrogen production facility, located in Alberta's Industrial Heartland.

- **British Columbia** – Passed in 2022, the *Energy Statutes Amendment Act, 2022*, introduced changes to the *Oil and Gas Activities Act*, which saw that Act renamed the *Energy Resource Activities Act* to include the regulation of hydrogen, and the British Columbia Oil and Gas Commission renamed to the British Columbia Energy Regulator (BCER). Pursuant to these amendments, as of Sept. 1, 2023, the BCER now acts as a single-window regulator for hydrogen development in British Columbia at the provincial, removing the need to deal with different provincial agencies for various approvals subject to certain exceptions. The hope is that these changes will allow for a reduced regulatory burden (and timelines) to promote more hydrogen projects within the Province.

The assignment of authority for the regulation of hydrogen to the BCER comes after the establishment of a "BC Hydrogen Office" in 2022, which has the sole purpose of advancing hydrogen projects in British Columbia through, among other things, facilitating investment and helping navigate regulatory, permitting and environmental matters. Both initiatives align with BC's Hydrogen Strategy and its short term objectives of providing policy support and "de-risking" the development of hydrogen production infrastructure.

- **Ontario** – Ontario has also laid out its plan for creating a low-carbon hydrogen economy through its Low-Carbon Hydrogen Strategy. In February 2023, Ontario announced the establishment of a Hydrogen Innovation Fund (HIF) that would provide an initial investment of $15 million over three years to promote opportunities for integrating hydrogen into Ontario's electricity system. The HIF will provide support for both existing and new facilities, as well as research studies, with a view to establishing Ontario as a clean manufacturing and transportation hub. In November 2023, Ontario announced $5.9 million in funding through the HIF for nine new projects aimed at integrating hydrogen in the province's electricity grid, including $4.1 million in funding for Atura Power's Niagara Hydrogen Centre project.
- **Nova Scotia** – Although taking place in late 2022, it is notable that Nova Scotia has also amended existing energy-related statutes to apply to hydrogen fuels in an effort to bridge regulatory gaps and remove uncertainty.

It will be interesting to see if other provinces follow British Columbia and Nova Scotia's lead and attempt to reduce the regulatory burden or existing regulatory uncertainty that is created by the lack of hydrogen-specific legislative provisions in some jurisdictions. In the interim, it is clear that several Canadian provinces remain committed to investing in hydrogen development as part of their respective strategies, which will be a welcome sign to project proponents and market participants alike.

The Federal Government

A. *Impact Assessment Act* in flux?

At the Federal level, the Supreme Court of Canada's recent reference decision in *Reference re Impact Assessment Act*, 2023 SCC 23, may have a significant impact on the regulatory approval process for major hydrogen projects depending on their location.

The true impact of the decision in *Reference re Impact Assessment Act* remains to be seen, as the Federal government has announced its intentions to amend the *Impact Assessment Act*. As noted in our prior bulletin reporting on this decision in the short term (until legislative amendments are made), project proponents and market participants are also likely to experience greater uncertainty.

Increased federal funding and incentives

Readers of BLG's Top 10 energy issues of 2022 article may recall that the 2022 Fall Economic Statement included proposals for certain green energy investment tax credits, including a clean hydrogen investment tax credit (clean hydrogen ITC). Briefly, the clean hydrogen ITC provides refundable tax credits on the cost of purchasing and installing equipment acquired and available for use on or after March 28, 2023, that is used to produce hydrogen from either electrolysis or through natural gas reformation within certain carbon intensity constraints.

In 2023, the Federal government continued to invest heavily in the development of hydrogen projects, including a $125 million loan to EverWind Fuels' green energy hub in Nova Scotia. The Federal government also just recently announced the development of a Green Shipping Corridor Program to help cut pollution in marine shipping and provide funding to support the adoption of clean technology and infrastructure. Furthermore, Canada has signed a memorandum of understanding to pursue the establishment of a green shipping corridor between Canada's West Coast and ports in the United Arab Emirates, Korea and Japan, with a specific focus on green fuels such as ammonia, hydrogen and methanol to be produced in Canada.

Positive outlook for hydrogen opportunities in 2024

Taken together, it is evident that both the Federal and provincial governments remain committed to investing in (or encouraging investment in) hydrogen, resulting in significant opportunities to develop green hydrogen projects in Canada. It is anticipated that these opportunities will continue to grow as both levels of government continue to make good on their strategic plans for hydrogen and a low carbon future.

Jurisdictional disputes and administrative overreach

Impact Assessment Act (IAA): Significance for the energy industry in Canada

On Oct. 13, 2023, the Supreme Court of Canada issued its highly anticipated opinion in Reference re *Impact Assessment Act*, 2023 SCC 23 (the IAA Reference). At issue in the IAA Reference was the constitutionality of the *Impact Assessment Act* (the IAA), which is a significant piece of federal environmental legislation that purports to govern when, and on what basis, certain projects are subject to federal oversight and regulation.

The Court found that the IAA consisted of “two distinct” regulatory schemes: (1) a Designated Projects Regime that subjects certain projects that would otherwise fall outside federal jurisdiction to federal oversight and regulation; and (2) a Federal Projects Regime that applies to federal projects, including projects on federal lands or outside of Canada.

The Majority found that Parliament “plainly overstepped its constitutional competence” in enacting the Designated Projects Regime, which purported to grant the federal government the power to regulate projects based on the mere possibility that they would have “effects within federal jurisdiction”. Likewise, the Majority found that the Designated Projects Regime, which directed the federal agency to consider matters beyond those of federal jurisdiction and regulate the project, was ultra vires. Conversely, the Majority found that the Federal Projects Regime, which it described as “secondary” to the Designated Projects Regime, could be severed from the unconstitutional portions of the IAA and remain in force and effect. In dissent, Justices Karakatsanis and Jamal would have found the IAA constitutional in its entirety.

The IAA Reference is a significant division of powers case and marks an important development in the ongoing saga of constitutional litigation with respect to jurisdiction over environmental matters. Shortly after the SCC released its opinion, the Federal government announced that it intends to amend the IAA as soon as possible, including the scope of its discretionary designation and decision-making provisions. However, the Federal government has yet to introduce such amendments, and it remains to be seen whether same will cure the constitutional defects and regulatory uncertainty present in the original IAA.

Shell Canada Limited v Alberta (Energy)

In *Shell Canada Limited v Alberta (Energy),* 2023 ABCA 230 (CanLII), the Court of Appeal of Alberta upheld a decision of the Court of King’s Bench related to Alberta’s oil sands royalty regime. The Court of Appeal quashed a decision of the Alberta Minister of Energy which disallowed certain costs claimed by Shell. This case is one of a number of recent decisions which have held administrative decision makers accountable for unreasonable or procedurally unfair decisions.

Background

Alberta’s oils sands royalty regime provides the mechanism for the Crown to receive a share of the economic revenue, or royalty, generated from the development of the oil sands. The *Oil Sands Allowed Costs (Ministerial) Regulation,* Alta Reg 231/2008 (the Allowed Costs Regulation) sets out the framework for determining if a particular claimed cost is an “allowed cost”. As part of the royalty regime, oil sands project operators are required to submit end of period statements that include information regarding the allowed costs claimed by the operator. The statements are subject to audit by the Alberta Department of Energy (the Department).

In this case, Shell claimed costs which included integrated costs for shared resources used to run operations on Shell's integrated Jackpine and Muskeg River Mines, which are on adjoining lands. The Department determined these costs were not "solely dedicated" to project operations within the meaning of the Allowed Costs Regulation, and they were therefore disallowed.

Despite the request by Shell, the Minister of Energy refused to convene a Dispute Review Committee (Review Committee or DRC) to review the dispute related to the costs claimed by Shell. The Minister of Energy concluded that Shell's position was "without merit". Shell subsequently applied for judicial review of the Minister's decision. The judicial review judge found that the Minister's decision was unreasonable and quashed the decision. The judicial review judge also declared that the Minister was required to convene a Review Committee.

Decision

On appeal, the Court held that the Minister's decisions did not explain the analysis undertaken or test applied to determine that Shell's position was "without merit". The reasons simply repeated the Department's position that Shell's interpretation was "inconsistent with the regulations as written". The reasons did not disclose the reasoning process that led to that conclusion, fail to address the context and purpose of the regulations and, in the result, do not bear the "the hallmarks of reasonableness – justification, transparency and intelligibility".

The Court of Appeal concluded that the Minister's decision was unreasonable. The Court of Appeal also held that it was appropriate for the issue to be referred to a Dispute Review Committee rather than remitting that issue back to the Minister. While it is often appropriate to remit a matter back to an administrative decision maker (in this case the Minister), the Court found that it was appropriate to declare a Review Committee be established.

Takeaways

The decision by the Court of Appeal confirms that the courts will intervene if a decision by an administrative decision maker, such as the Minister of Energy, is unreasonable. A decision by an administrative decision maker must be justified and transparent and disclose the reasoning behind the decision.

The court's decision is important to the energy industry in Alberta. This decision is a number of decisions by the courts in Alberta which have challenged the decisions made by the Minister of Energy. This decision confirms that the judicial review process can be used to challenge decisions by the Minister of Energy related to the oil sands royalty regime.

Taylor Process v Alberta

In *Taylor Processing Inc v Alberta (Minister of Energy),* 2023 ABKB 64, the Court of King's Bench of Alberta quashed three decisions made by the Alberta Minister of Energy (Alberta Energy) related to the payment of Crown royalties pursuant to the *Mines and Minerals Act* and its regulations, including the *Natural Gas Royalty Regulation, 2009*. The Court acknowledged that the threshold for quashing an administrative decision is high, but determined that remitting the issue back to Alberta Energy would be "pointless" given that Alberta Energy had failed to establish any evidentiary basis for its decision in the first instance. As a result of the Court's decision, Alberta Energy was ordered to return over $20 million in royalties to Nova, with interest. Read the full case summary here.

Carbon capture, utilization and storage (CCUS) in Canada

Reducing CO2 as part of Canada's efforts to address climate change and meet climate target commitments (*i.e*. Paris Agreement targets by 2030, net zero by 2050) remains a top policy focus. For certain critical industrial processes, however, such as oil and gas production, cement and steel manufacturing, and thermal generation of electricity, materially reducing or eliminating emissions is technically difficult or prohibitively expensive. Canada, along with other nations, is looking to Carbon Capture and Sequestration (CCS) and Carbon Capture Use and Storage (CCUS) as a primary means of reducing CO2 emissions. CCS/CCUS systems prevent CO2 from entering the atmosphere by capturing it at its source, using the captured CO2 if possible (in the case of CCUS), and then, importantly, permanently injecting and storing the remaining CO2 deep in the underground pore space.

In 2023, CCUS/CCS dominated the headlines in Canada due to significant regulatory, policy and project announcements, and due to the controversy over whether CCUS/CCS is a panacea for reducing CO2 emissions, or a dangerous distraction from achieving global emissions reductions targets.

Regulatory

In some jurisdictions, such as Alberta, the regulatory regimes regarding CCUS/CCS have been long established and have already supported significant CCUS/CCS projects (such as Shell's Quest facility and the Alberta Carbon Trunk Line), and accordingly we witnessed the continued implementation and refinement of those existing regulatory regimes in 2023.

For example, Alberta's *Mines and Minerals Act* and *Carbon Sequestration Tenure Regulation* have for many years addressed the pore ownership, injection, and long term liability and stewardship issues necessary to support CCS/CCUS projects, including the ability for the minister to enter into agreements to evaluate reservoirs for carbon sequestration, and agreements to grant rights to inject captured CO2 into reservoirs for sequestration, as well as setting out detailed requirements for monitoring, measurement and verification. Unlike many jurisdictions, this regulatory regime provides certainty as to the pore ownership, and post closure liability risks associated with CCUS/CCS projects. In 2023, therefore, we witnessed the Alberta government continue to refine and exercise these regulatory rights (rather than design them from scratch). For example, the Alberta government continued the competitive process that it had commenced prior to 2023, to issue carbon sequestration rights to enable the development of carbon storage hubs, eventually selecting more than 25 proposals for further evaluation. In addition to the exercise and refinement of the regulatory process, we also witnessed the continued development of many proposed projects (there are currently more than a dozen CCUS projects under construction or in the planning stages), perhaps most significantly the $16 Billion Pathways Alliance project. Finally, in early 2023 the Alberta government continued to incentivize CCUS projects in the province by making significant changes to its Technology, Innovation and Emission Reduction (TIER) regulation (its carbon pricing and emissions reduction program) which facilitates participation by proponents and participants of CCS projects. These amendments created new "Sequestration Credits" (credits which can be created by conversion of registered emissions offsets that were created from the geological sequestration of CO_2) which can be used to satisfy compliance obligations under both TIER and federal Clean Fuel Regulations (a dual use of the credits).The amendments also established "Capture Recognition Tonnes" (deductions created by a conversion of Sequestration Credits that can be used to reduce net emissions and thus reduce emission reduction obligations under TIER). These amendments demonstrated Alberta's support of CCUS/CCS projects by creating customized credits and deductions for compliance with TIER. In summary, in 2023 Alberta continued to exercise its established regulatory regime and to develop additional regulatory incentives to facilitate current and proposed CCUS/CCS projects.

In other jurisdictions, such as B.C. and Ontario, the regulatory regimes regarding CCUS/CCS are less developed. Rather than refine an existing regulatory regime, or develop further incentives to facilitate existing CCUS/CCS projects, therefore, these jurisdictions focused on establishing or adapting the regulatory regime to contemplate CCUS/CCS projects. For example, in late 2022 the BC government amended the *Petroleum and Natural Gas Act* to clarify the BC regulatory tenure for storage or disposal of CO_2 and confirmed that storage of CO_2 related to petroleum and natural gas operations can be achieved through a petroleum and natural gas lease, while sequestration of CO_2 from other sources (not solely from related petroleum and natural gas operations) can be achieved through a storage reservoir license. These amendments adapted the existing regulatory regime to allow for CCUS/CCS rather than develop a customized system. Similarly, in April 2023 the Ontario government removed a provision in the *Oil, Gas, and Salt Resources Act* which prohibited injection of CO_2 for purposes of sequestration, and introduced new rules to develop CCS pilot projects, thereby taking the first steps toward establishing a CCUS/CCS regulatory framework. It remains to be seen whether Ontario will establish a customized regulatory regime for CCUS/CCS.

In 2023, therefore, jurisdictions in which the CCUS regulatory framework is more established tended to focus on refining and exercising these regulatory frameworks in order to induce CCUS investment, whereas other jurisdictions took preliminary steps to permit or advance the regulatory framework for CCUS/CCS projects.

Policy

In 2023 we saw the further progression of tax incentives and grants designed to facilitate development of CCUS/CCS projects. However, many remain frustrated by the lack of details and tepid pace of the progress over the course of 2023.

In August of 2023, the federal Department of Finance released its long anticipated revised draft legislation for the CCUS investment tax credit (ITC) (originally released in August 2022), which will provide a refundable investment tax credit of up to 60 per cent on the acquisition of eligible clean technology property used to capture carbon dioxide, and 37.5 per cent of qualified carbon transportation, storage or usage equipment.

At the end of November 2023, the Alberta government also announced its Carbon Capture Incentive Program (CCIP) which builds on the CCUS ITC by providing a grant of up to 12 per cent of eligible capital costs of incorporating CCUS technology into an applicant's operations. The details of the CCIP are still being determined and are subject to the passage of the CCUS ITC and related operating supports. While anxiously anticipated, we expect further details of the CCIP to be announced in Q1 2024 See our additional comments here.

While the initial progress on the CCUS ITCs and the CCIP in 2023 provided welcomed financial support to CCUS/CCS project proponents, there remains a lack of long-term certainty on the cost of carbon emissions which continues to impact CCUS/CCS investments. In essence, CCUS/CCS project proponents remain concerned that the value of avoided carbon price payments and/or the value of earned carbon credit revenues may plunge due to market or government actions, thereby reducing the expected financial return of the CCUS/CCS investment. In its 2022 Fall Economic Statement, the federal government had announced its intention to introduce "carbon contracts for difference" to backstop the future federal carbon prices, and to de-risk an important variable for CCUS/CCS projects, amongst other clean growth projects. It reiterated that plan in its 2023 Fall Economic Statement. The 2023 Fall Economic Statement announced that the Canada Growth Fund would be the principal federal entity issuing "carbon contracts for difference" and that the fund would allocate up to $7 billion of its current $15 billion in capital to such contracts and offtake agreements, although it remains unclear how much of this capital would be available for carbon contracts for difference or with respect to CCUS/CCS projects specifically. Accordingly, while the concept of a carbon price support scheme remained in consideration in 2023, the level of commitment, implications, and application to CCUS/CCS projects specifically, remains uncertain.

Projects

Significant CCUS project announcements dominated the headlines in 2023. Perhaps most prominently, the Pathways Alliance, a $16 Billion CCS project promoted by Canada's six largest oilsands producers, which includes a massive pipeline to transport carbon from approximately 20 carbon capture facilities at oilsands sites to an underground storage hub near Cold Lake, Alberta, continued to advance the feasibility, engineering and design, subsurface evaluation, and regulatory approvals preparation work. In addition, Enbridge continued to advance its Wabamun Carbon Hub which would support CCS projects by Capital Power and by Lehigh Cement, and Heidelberg Materials continued to advance its CCS project on a cement plant in Edmonton. In addition, at the commencement of 2023, Air Liquide approved its Hydrogen Production facility near Edmonton, which includes the capture of three million tonnes of CO_2 per year, and near the end of 2023, Dow Chemicals approved its $6.5 Billion ethylene cracker facility with associated CCS facilities. We anticipate further announcements on the advancement of the Alberta carbon hub projects and various other CCS/CCUS proposals in 2024.

Canada's new clean economy investment tax credits

Over the past 18 months, the Canadian government has announced five investment tax credits (ITCs) to incentivize businesses to make capital investments that support Canada's transition to a cleaner and greener economy. These new "Clean Economy ITCs," along with over $20 billion of related public sector financing commitments from the Canada Infrastructure Bank, constitute Canada's response to the massive U.S. subsidies for clean energy included in the *Inflation Reduction Act* in the U.S.

These new ITCs are expressed as a percentage of eligible expenditures on qualifying property to be used in Canada in eligible activities. They are refundable, meaning that the government will pay them to qualifying taxpayers even if they do not have Canadian income tax owing. Each of these new ITCs is directed at specific clean economy segments:

Clean Technology: the Clean Technology ITC is available for various forms of clean energy generation, including from wind, solar, water and geothermal sources, as well as small modular nuclear reactors and stationary electricity storage equipment.

Carbon Capture, Utilization & Storage (CCUS): The CCUS ITC is directed at equipment used exclusively to capture, transport or store carbon dioxide in an eligible project (dual-use heat and/or power equipment may also qualify). Unlike most of the other ITCs that are limited to new property, refurbishment costs may also be eligible for the CCUS ITC.

Clean Hydrogen: the Clean Hydrogen ITC is applicable to equipment that produces hydrogen from either electrolysis or natural gas and has been extended to support equipment converting hydrogen into ammonia in some cases. There are three levels of ITC offered, depending on how clean (*i.e*., carbon-intensive) the hydrogen being produced is (no ITC applies if 4 kg or more of CO2/H kg is produced).

Clean Technology Manufacturing: The Clean Technology Manufacturing ITC is directed further up the supply chain, at Canadian companies that are manufacturing or processing clean technologies and their precursors. It applies to machinery and equipment used to manufacture or process key clean technologies, and extract, process, or recycle key critical minerals, including machinery and equipment used in manufacturing (and related activities) of:

- grid-scale electrical energy storage equipment;
- renewable or nuclear) energy equipment;
- zero-emission vehicles, and
- various upstream components and materials for such above-noted activities.

Machinery and equipment used in the extraction, processing, or recycling of lithium, cobalt, nickel, graphite, copper, and rare earth elements also qualifies.

Clean Electricity: The Clean Electricity ITC will apply to eligible investments (including refurbishments) in the following types of property:

- non-emitting electricity generation systems, *i.e.*, wind, solar, hydro, wave, tidal, and both large and small-scale nuclear;
- abated natural gas fired electricity generation meeting an emissions threshold;
- stationary electricity storage systems; and
- inter-provincial electricity transmission equipment.

Various technical details apply to these Clean Economy ITCs, including the way they are computed, how they apply when claimed through a partnership rather than a directly by an eligible taxpayer, and additional requirements applicable to some or all of them. A number of these are summarized in the table below. Particular care must be exercised regarding the impact of any government assistance received or expected to be received as part of the project (late in 2023 the government announced that low/no-interest loans with reasonable repayment terms would not be considered as "government assistance" for this purpose).

	Clean Technology	**Carbon Capture, Utilization and Storage**	**Clean Hydrogen**	**Clean Technology Manufacturing**	**Clean Electricity**
Maximum Rate	30% *	60% /50% /37.5%*	40% /25% /15%*	30%	15%*
Eligible Taxpayers	Taxable Canadian corporations** & REITs**	Taxable Canadian corporations**	Taxable Canadian corporations**	Taxable Canadian corporations**	Canadian tax-exempts and taxable entities**
Phase-out Starts	January 1, 2034	January 1, 2031	January 1, 2034	January 1, 2032	N/A
End Date	December 31, 2034	December 31, 2040	December 31, 2034	December 31, 2034	December 31 , 2033
Recapture Period* **	10 years	20 years	20 years	10 years	Unclear
Status: January 2023	Legislation before Parliament (Bill C-59)	Legislation before Parliament (Bill C-59)	Draft legislation released for comment December 20, 2023; input due by February 5, 2024	Draft legislation released for comment December 20, 2023; input due by February 5, 2024	Draft legislation scheduled to be released during 2024

* Labour requirements must be met to attain highest ITC %

** Directly or through as a member of a partnership

*** Period during which certain actions can cause ITCs claimed to be reversed

Status of Alberta's renewable energy pause and the impact on the future of Alberta energy

As noted in a previous post, the significant recent growth of Alberta's renewable energy sector and the resultant historically high volume of facilities applications to the Alberta Utilities Commission (the AUC) prompted the Government of Alberta to order the AUC to pause approvals of renewable energy projects larger than 1 MW until Feb. 29, 2024. Heeding to concerns raised by the AUC, landowners, and municipalities regarding responsible land use and the rapid pace of development, the government initiated a related public inquiry led by the AUC itself. This inquiry will culminate with recommendations submitted to the Minister of Affordability and Utilities (the Minister) by March 29, 2024.

While approvals for isolated generating units, micro-generation, and amendments to prior approvals remain unaffected, the approval pause implicates all other renewable projects involving electricity sources such as solar, wind, hydro power, biomass, and geothermal. The AUC will continue processing these projects, but no new approvals will be granted until the pause ends. During this period, power plant applicants should refer to the AUC's supplemented Rule 007, which outlines additional, notably more stringent, interim information requirements related to agricultural land, viewscapes and reclamation security that current applicants must adhere to. Alternatively, applicants can request that the AUC suspend their application(s) until the pause period ends in late February 2024.

As part of its inquiry, the AUC has been reviewing submissions from interested parties based on the Minister's terms of reference, quoted as follows:

- Considerations on development of power plants on specific types or classes of agricultural or environmental land;
- Considerations of the impact of power plant development on Alberta's pristine viewscapes;
- Considerations of implementing mandatory reclamation security requirements for power plants;
- Considerations for development of power plants on lands held by the Crown in Right of Alberta;
- Considerations of the impact the increasing growth of renewables has to both generation supply mix and electricity system reliability.

More recent indications from Alberta underscore that the issue of affordability - stemming from the province's lack of renewable baseload power and increased transmission costs for ratepayers - is also a central concern of the government. The government's position suggests that the cost-benefit analysis of intermittent renewable electricity generation requires scrutiny. Building transmission for these projects results in less utilization of lines compared to more reliable power sources like natural gas, which can operate continuously.

The public consultation of the AUC's inquiry is divided into two "modules." As part of Module A, in November and December, the AUC commissioned four expert reports and received oral and written submissions from various stakeholders on the land use and reclamation issues related to the first four terms of reference. The final issue concerning generation supply and reliability will be addressed in Module B in February 2024. The AUC has already commissioned two expert reports on this subject, slated for publication on February 7, 2024, followed by a period for public commentary.

The pause in renewables inconveniences numerous stakeholders and injects uncertainty into the future regulatory landscape. However, it also presents an opportunity for interested parties to contemplate and offer their perspectives on the future of renewables developments in Alberta. During the preliminary information-gathering stage, the AUC received over 600 stakeholder submissions.

The AUC has also now announced its intention to deliver the report for Module A to the Minister ahead of the March deadline. Presently, the full implications of this inquiry on Alberta's power grid remain largely unknown. Stakeholders will have to eagerly await the Minister's guidance once the AUC submits its reports on both modules.

Canada's net zero commitments and the impact on the Alberta energy industry

Introduction

Canada has committed to achieving net-zero emissions. As part of this, Canada is putting in place a system to cap and cut oil and gas sector emissions to meet Canada's 2030 climate goals and achieve net-zero emissions by 2050. Canada's path to net-zero has had a significant impact on the Alberta energy industry and it will continue to do so going forward.

Paris Agreement and COP26

On Dec. 12, 2015, Canada and 194 other countries reached the Paris Agreement. Under the Paris Agreement, countries committed to developing national plans to reduce their emissions, known as Nationally Determined Contributions, or 'NDCs'. As part of the Paris Agreement, countries are required to update their NDC target and each NDC target must be more ambitious than the one before.

In 2021, COP26 was held in Glasgow, Scotland, which marked the first 5-year period since the Paris Agreement was signed. The signatories to the Paris Agreement gathered to increase climate action, including through more ambitious emissions reduction targets and plans to accelerate the global shift to clean energy, clean technology, and clean growth.

Canada's path to net-zero

Prior to COP26, Canada announced a new target of reducing emissions to 40-45 per cent below 2005 levels by 2030. The Government of Canada also created legislation that formalized Canada's commitment to achieve net-zero emissions by 2050 and will legally bind the Government to a process toward that objective, which is called the *Canadian Net-Zero Emissions Accountability Act*.

The Canadian *Net-Zero Emissions Accountability Act*, which came into force on June 29, 2021, legislates the Government of Canada's commitment to achieve net-zero greenhouse gas emissions by 2050. The *Canadian Net-Zero Emissions Accountability Act* establishes a legally binding process to set five-year national emissions-reduction targets as well as develop credible, science-based emissions-reduction plans to achieve each target. It also establishes the 2030 emissions target as well as a requirement to set national emissions reduction targets for 2035, 2040 and 2045.

As part of the Canadian *Net-Zero Emissions Accountability Act*, in March 2022, the Government of Canada published the 2030 Emissions Reduction Plan. The 2030 Emissions Reduction Plan describes how Canada expects to meet its obligations under the Paris Agreement and COP26 to reduce emissions to 40-45 per cent below 2005 levels by 2030. Part of the 2030 Emissions Reduction Plan is to reduce oil and gas sector emissions and transitioning to net-zero.

Energy sector regulations and programs

The path to net-zero and the 2030 Emissions Reduction Plan has resulted in various regulations and programs that impact the oil and gas / energy sector, including the following:

- **Methane regulations** : Federal regulations require the oil and gas sector to reduce methane emissions by 40-45 per cent below 2012 levels by 2025. This includes stringent regulations related to reducing and leaking non-emergency flaring of methane from upstream oil and gas production.
- **Clean Fuel Regulations** : The Clean Fuel Regulations increase incentives for the development and adoption of clean fuels, technologies, and processes. The Clean Fuel Regulations also require liquid fossil fuel (gasoline and diesel) suppliers to gradually reduce the carbon intensity – or the amount of pollution – from the fuels they produce and sell for use in Canada over time, leading to a decrease of approximately 15 per cent (below 2016 levels) in the carbon intensity of gasoline and diesel used in Canada by 2030.
- **Emissions Reduction Fund** : The Emissions Reduction Fund (ERF) – Onshore Program assists companies invest in green solutions and infrastructure to continue progress towards reducing methane emissions in the context of the COVID-19 pandemic.
- **Clean Growth Program** : The Clean Growth Program (CGP) was an investment in clean technology research, development, and demonstration projects in three Canadian sectors: energy (including oil and gas), mining, and forestry.
- **Energy Innovation Program** : The Energy Innovation Program (EIP) advances clean energy technologies that will help Canada meet its climate change targets, while supporting the transition to a low-carbon economy. It funds research, development and demonstration projects, and other related scientific activities.

- **CCUS Investment Tax Credit** : The Government is developing an investment tax credit for capital invested in CCUS projects to encourage the development and deployment of CCUS technologies.

Impact on energy companies

Canada's path to net-zero will have a significant impact on the energy industry going forward, in Alberta.

Alberta has traditionally relied on coal-fired electricity generation, which is on track to be eliminated as a fuel source for electricity by the end of 2023. Emissions from Alberta's power sector has declined more than 40 per cent since 2005, in part, as a result of the shift away from coal.

In addition, Alberta has been a leader in energy projects in Canada. Alberta's experience in the energy industry has allowed corporations to capitalize on the push towards renewable energy projects. Further, Alberta's 'open market' electricity sector (at least until recently) provided the most opportunity for renewable energy projects and energy storage.

Similarly, Alberta's experience in the energy industry has led to growing interest in carbon capture. The Oil Sands Pathways to Net Zero Coalition is such an example of leadership commitments from energy corporations to achieve net zero targets using carbon capture.

While the Alberta energy industry has made significant investments in renewables and carbon capture, further steps are required in order to meet net-zero and the targets in the 2030 Emissions Reduction Plan.

Canada's electrical distribution system was largely designed around centralized, carbon-emitting energy sources. In most cases, it's not possible to merely change the source of power. Switching to renewable sources will require upgrading or replacing legacy systems to include distributed resources and a two-way flow of power. This process may compromise reliability over the short term and impact Canadians' ability to access electricity when they need it.

By

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