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The Push For Electrification And A Net Zero Grid – Developments, Reactions And Implications

BY: DEIRDRE SHEEHAN, VIVEK WARRIER, JAKE SADIKMAN, LAURA SCOTT*

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* Deirdre Sheehan and Vivek Warrier are partners in the Calgary office of Osler, Hoskin & Harcourt LLP ("Osler") and Jake Sadikman is a partner in the Toronto office of Osler. Laura Scott is an associate in the Calgary office of Osler. The authors would like to extend a special thank you to Stephanie Clark, Cole Tavener, Joey Chan and Tyler Warchola of Osler for their assistance in preparing this paper.

I. Introduction

To achieve its goal of net-zero carbon emissions by 2050, the Federal Government has announced that a critical component of its energy transition plan is the development of additional low- or non-emitting electricity generation. To mandate this development, the Federal Government has proposed and published draft *Clean Electricity Regulations* ("***Draft CERs***"),[1] under the *Canadian Environmental Protection Act, 1999* ("***CEPA***").[2] If adopted as drafted, commencing January 1, 2035, and subject to limited exemptions, the *Draft CERs* would introduce significant restrictions on electricity generation that is not low- or non-emitting.

The Federal Government has indicated that the *Draft CERs* underpin its plan to achieve a net-zero economy by 2050, stating "Canada's electricity systems will be the backbone of Canada's net-zero economy" and that "[b]y fully decarbonizing our electricity grids by 2035, we are enabling the rest of the economy to electrify by 2050."[3] To achieve this shift, the Federal Government has also introduced measures targeted at other sectors, such as the transportation sector, mandating accelerated emission reductions in parallel with requirements to electrify.

The Federal Government's energy transition plan comes at a time when Canadian jurisdictions from coast-to-coast-to-coast are planning for aggressive growth of their electricity supply to meet increased electrification demands and provincial clean energy goals, all the while experiencing transitional impacts arising from changes in generation fleets. The *Draft CER's* proposal to directly regulate the generation of electricity has raised the ire of a number of provincial governments and

[1] *Clean Electricity Regulations*, (2023) C Gaz I, Vol 157, No 3, beginning at 2822, online (pdf): <canadagazette.gc.ca/rp-pr/p1/2023/2023-08-19/pdf/g1-15733.pdf> ["***Draft CERs***"].

[2] SC 1999, c 33 ["***CEPA***"].

[3] Government of Canada, "Powering Canada Forward: Building a Clean, Affordable, and Reliable Electricity System for Every Region of Canada" (31 August 2023) online: <natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/powering-canada-forward-building-clean-affordable-and-reliable-electricity-system-for/25259>.

sharpened the division between competing federal and provincial interests and policies on the necessary pace and technological direction of the transition to low- or non-emitting electricity generation.

This paper provides an overview of some of the policy and legislative trends across Canada arising from this dynamic – including responses to ensure electricity resource adequacy, regulatory response to climate goals, managing electricity and grid access as a scarce resource, tensions regarding imports and exports of electricity, and measures addressing affordability and consumer choice.

II. The Clean Electricity Regulations

Each provincial government has constitutional jurisdiction over electricity generation in their respective province.[4] Consequently, there is a lack of uniformity of electricity market structures and regulatory structures across Canada, which range from vertically integrated utilities in which a single entity holds a monopoly over generation, transmission and distribution, to a fully deregulated generation sector with an open wholesale and retail market. Vertically integrated utilities are common, and the monopoly utility is a Crown corporation in several provinces,[5] a single investor-owned utility in others,[6] or a combination of the two.[7] Ontario has a hybrid electricity market in which the provincial Crown corporation, Ontario Power Generation, is responsible for more than half the electricity generation in Ontario and additional generation is sourced through procurement contracts and a competitive wholesale market. In contrast to the rest

[4] *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11, s 92A(c) ["*Constitution Act, 1982*"].
[5] British Columbia (BC Hydro), Saskatchewan (SaskPower), Manitoba (Manitoba Hydro), Quebec (Hydro-Quebec), New Brunswick (NB Power).
[6] Nova Scotia (Nova Scotia Power Inc.) and Prince Edward Island (Maritime Electric).
[7] In Newfoundland and Labrador generation and distribution of electricity is provided by two utilities, Newfoundland Power is an investor-owned utility, while Newfoundland & Labrador Hydro is a provincial Crown corporation.

of Canada, Alberta has a fully deregulated competitive electricity market in which electricity is generated by a variety of independent power producers and well as regulated investor- or municipally-owned transmission and distribution utilities.[8]

The generation supply mix in each provincial electricity market also varies significantly from province to province based on the availability of natural resources and technology. In Alberta, Nova Scotia, and Saskatchewan more than 50% of electricity is generated from high greenhouse gas ("**GHG**") emitting sources, such as natural gas and coal.[9] In contrast, electricity in British Columbia, Ontario, Manitoba, New Brunswick, Newfoundland and Labrador, Prince Edward Island and Quebec is primarily generated from low GHG emitting sources such as nuclear and hydro.[10] Given the different energy markets and generation supply mix in each province, a one-size-fits-all approach to developing a net-zero grid poses multifaceted challenges in Canada.

Against this backdrop of provincially unique and diverse legacy electricity grid and generation profiles across Canada, the Federal Government introduced the *Draft CERs* to mandate the development of additional low- or non-emitting electricity generation, as a critical component of

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[8] Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Alberta" (22 February 2024), online <cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-alberta.html>.

[9] In 2023, Alberta generated 57% of its electricity was from natural gas: Alberta Electric System Operator, "AESO 2023: Annual Market Statistics" (March 2024) at PDF 17, online: <aeso.ca/assets/Uploads/market-and-system-reporting/Annual-Market-Stats-2023_Final.pdf>. In 2023, Nova Scotia generated 31% of its electricity from coal and 17% from natural gas: Nova Scotia Power Inc., "Powering a Green Nova Scotia, Together: Our Energy Stats" (2024), online: <nspower.ca/cleanandgreen/clean-energy>. As of May 23, 2024, Saskatchewan generated 45% of its electricity from natural gas and 37% from coal: SaskPower, "Where Your Power Comes From" (23 May 2024), online: <saskpower.com/Our-Power-Future/Our-Electricity/Electrical-System/Where-Your-Power-Comes-From>.

[10] In British Columbia, BC Hydro's website reported as of May 25, 2024, that more than 90% of its generation is from hydroelectric sources. In Ontario in 2023, 50.8% of energy production came from nuclear and 24.5% from hydro. Manitoba Hydro reported in 2023 that 97% of all electricity generated in Manitoba was from hydro sources. In New Brunswick, based on 2022 data, 41% of electricity was from nuclear sources, 23% from hydroelectric sources, 8% from wind, tidal and solar. In 2022, Newfoundland and Labrador generated 97% of its electricity from hydroelectricity. In 2022, nearly 100% of Prince Edward Island's energy production was from wind, tidal and solar sources. In Quebec, based on 2022 data, energy production from hydro sources totaled 88% of provincial production.

its energy transition plan. On August 10, 2023, in furtherance of its goal of economy-wide net-zero emissions by 2050 the Federal Government released the *Draft CERs* for public comment. Subject to limited exemptions, the *Draft CERs* would prohibit new electricity generation that is not low- or non-emitting commencing in 2035 in an effort to ultimately eliminate emitting sources of supply connected to public electricity grids in Canada. According to the Federal Government, carbon pricing alone is insufficient to achieve the required emissions reduction from the electricity sector, which accounted for 9.2% of total GHG emissions in Canada in 2020.[11]

The *Draft CERs* were accompanied by a Regulatory Impact Analysis Statement ("**RIAS**") detailing the anticipated impacts and a cost-benefit analysis of implementing the *Draft CERs*. The RIAS highlights that the *Draft CERs* would disproportionately impact certain provincial electricity systems, creating cost savings for some, and imposing substantial costs on others.

After receiving over 18,000 letters and emails in response to the *Draft CERs*, on February 16, 2024, the Federal Government released a public update ("**Update**"). The Update acknowledged that many of the submissions argued that the *Draft CERs* needed to provide more flexibility.[12] However, instead of proposing specific amendments to the *Draft CERs*, the Update outlined conceptual changes being *considered* by the Federal Government, adding further uncertainty regarding the potential impacts of the *Draft CERs*. The Update indicated that the Federal Government's intention is to publish the final *Clean Electricity Regulations* later in 2024.

A. Regulated Generator Emission Prohibition

[11] Clean Electricity Regulations – Regulatory Impact Analysis Statement, (2023) C Gaz I, Vol 157, No 33, beginning at 2709 ["**RIAS**"].

[12] Environment and Climate Change Canada, "Clean Electricity Regulations Public Update: 'What we Heard' during consultations and directions being considered for the final regulations" (16 February 2024) at PDF 4, online (pdf): <canada.ca/content/dam/eccc/documents/pdf/climate-change/clean-fuel/electricity/clean-electricity-regulations-public-update-16022024.pdf> ["**Update**"].

The *Draft CERs* are proposed to apply to electricity generating units that, on or after January 1, 2025:

- have a generating capacity of 25 megawatts (MW) or more;
- generate electricity using fossil fuel; and
- are connected to an electricity system subject to the NERC[13] standards, which includes systems in Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Québec, and Saskatchewan.[14]

The rationale provided for the 25 MW threshold is to avoid regulating units that are not expected to be a major source of GHG emissions and are too inefficient to be a viable option for broad deployment of baseload power.[15] The NERC connection requirement is intended to avoid regulation of own-use generation and generation supplying northern and remote locations with few options for electricity generation.[16]

The *Draft CERs* would essentially prohibit regulated generating units from emitting more than 30 tonnes of carbon dioxide ("**CO_2**") per gigawatt hour ("**30t/GWh**") of electricity generated on average in a calendar year ("**Emission Prohibition**"), commencing on January 1, 2035.[17] The 30t/GWh value is ostensibly designed to align with the emissions intensity of natural gas

[13] The North American Electric Reliability Corporation ("**NERC**") is a non-profit international regulator that monitors the grid across the US, Canada, and northern Mexico. NERC develops and enforces reliability standards to ensure the reliability and security of the grid. NERC and the regional entities (such as WECC, MRO, and NPCC) operate pursuant to joint agreements with the governments of Canada and Mexico. These entities operate either through the provincial regulatory framework or through Memoranda of Understanding with each Canadian province. See North American Electric Reliability Corporation, "About NERC", online: <nerc.com/AboutNERC/Pages/default.aspx>.
[14] *Draft CERs*, *supra* note 1, s 3 at 2826.
[15] RIAS, *supra* note 11 at 2816.
[16] *Ibid*.
[17] *Draft CERs*, *supra* note 1, s 6(1) at 2828 and 6(4) at 2829.

generation with carbon capture and storage ("**CCS**") achieving a 95% capture rate.[18]

To demonstrate compliance with the Emission Prohibition, the *Draft CERs* require the emissions intensity of a unit to be determined by dividing the quantity of CO_2 emissions attributed to a unit (in tonnes) by the quantity of electricity generated by the unit (in GWh), during a calendar year.[19] A unit's total CO_2 emissions are calculated based on the quantity of CO_2 emitted (including CO_2 emitted from the production of hydrogen fuel or steam used to produce electricity) less emissions attributed to the production of useful thermal energy, captured by CCS, or emitted during a declared emergency.[20]

Including emissions from hydrogen or steam used to generate electricity is intended to ensure that all emissions associated with electricity generated by a unit are included in the calculation of the unit's emissions intensity, regardless of the location of the supplier of the hydrogen fuel or thermal energy used in that unit for electricity generation.[21] For emissions captured by a CCS system to be excluded from a generating unit's total emissions for the purposes of the Emission Prohibition,[22] the *Draft CERs* require the CO_2 be permanently stored in a prescribed type of geological site – either a deep saline aquifer used exclusively for CO_2 storage or a depleted oil reservoir for the purpose of enhanced oil recovery.[23] However, the *Draft CERs* also provide a transition period for regulated units that include a CCS system, acknowledging that some flexibility is needed for CCS

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[18] RIAS, *supra* note 11 at 2817.

[19] *Draft CERs*, *supra* note 1, s 7(1) at 2829-2830.

[20] The formula used to calculated the emissions under the *Draft CERs* is: **Eu – Eth – Eccs + Eext – Eec**. Where **Eu** = a unit's CO2 emissions from the combustion of fossil fuels; **Eu** = a unit's CO2 emissions from the combustion of fossil fuels; **Ecss** = the quantity of CO2 emissions captured and stored from a unit by a CCS system; **Eext** = the quantity of CO2 emissions emitted from the production of hydrogen fuel or purchased or transferred steam used by the unit to generate electricity; **Eec** = a unit's CO2 emissions during any period for which the Minister has issued an emergency circumstance exemption. See *Draft CERs*, *supra* note 1, ss 6-8 & 18 at 2828-2831 & 2842-2843.

[21] RIAS, *supra* note 11 at 2727.

[22] *Draft CERs*, *supra* note 1, s 8(1) and s 16 at 2830 & 2841.

[23] *Draft CERs*, *supra* note 1, s 8(4) at 2831.

technology to ultimately to meet the ambitious 95% carbon capture rate.[24] Until December 31, 2039, these units may emit a calendar year average of 40 tonnes of CO_2 emissions per GWh of electricity generated.[25]

The January 1, 2035 date for compliance with the Emission Prohibition applies to units that combust coal and units commissioned after, or that increase their capacity by 10% or more after January 1, 2025. [26] For all other units, the Emissions Prohibition applies on January 1 of the year following the unit's *end of prescribed life* (the latter of December 31 of the calendar year 20 years after the commissioning date and December 31, 2034).[27]

However, generating assets can have varying expected useful lifespans with many thermal generating technologies expected to last 45 years.[28] During consultations, various utilities, generation owners and electric system operators raised the concerns that the truncated 20-year prescribed life gave rise to a profound risk of stranded assets and a disincentive to invest in new generation infrastructure, as the prescribed terms would not be sufficient to recoup investment costs and would create reliability risks.[29]

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[24] RIAS, *supra* note 11 at 2817.

[25] Provided that: the unit's CCS system began operating within the last seven calendar years; and the unit has operated at or below 30 tonnes of CO^2 emissions per GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in a calendar year: *Draft CERs*, *supra* note 1, s 6(2) at 2828.

[26] Note that for boiler units converted from coal to natural gas, the Emission Prohibition under the *CER* applies on the latter of January 1, 2035 or January 1 of the calendar year that the emissions limits under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* begins to apply to that unit. These are units that are considered "significantly boiler modified units" under that regulation, which provides that the emissions intensity limit under that regulation apply at the latest (depending on the units' achieved emissions intensity) in the 11th year after the unit's end of useful life (ss 3(4) and 4(2)). The end of useful life of such units is established by the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulation*, which establishes the "useful life" of such units to be at the latest December 31, 2019 (s 2(1)). Therefore, the Emission Prohibit applies to boiler units converted from coal to natural gas starting in 2040 at the latest.

[27] *Draft CERs*, *supra* note 1, ss 6(4)(c) & (5) at 2829.

[28] RIAS, *supra* note 11 at 2721.

[29] Government of Canada, "Canada Gazette, Part 1, Volume 157, Number 33: Clean Electricity Regulations", (19 August 2023) online: <gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html>, under "View comments for General Comment section" ["***Draft CERs* General Comment Section**"].

For Alberta, the RIAS models that compliance with the *Draft CERs* would come from significant new investment in CCS.[30] If investments in CCS are not economical or technically feasible, the *Draft CERs* truncated lifespan for generating units can be expected to result in a risk of significant stranded costs, limiting the ability of utility generators to optimize such sources of generation over the coming decades of energy transition planning horizons. Furthermore, multiple submissions in the *Draft CERs* consultation identified that the 30t/GWh performance standard (equivalent to a 95% capture rate), even with the transition period, is extremely stringent. For example, SaskPower's submission stated that the standard cannot be met by any current thermal generating unit, and has not been met on an annual basis by any thermal unit fitted with CCS at the utility scale, calling the standard "theoretical and not yet commercially proven."[31] Given the stringency of the standard, multiple commentators expressed concern that the standard is achievable only under ideal conditions, which would serve as a deterrent to investment in CCS as a compliance mechanism.[32]

In response to the consultation, the Update reports that the Federal Government is *considering* several changes to the *Draft CERs*.

The 25 MW threshold: The Update notes feedback that the proposed minimum capacity threshold of 25 MW for a unit to be required to comply with the *Draft CERs* could create an incentive to commission new facilities with multiple units smaller than 25 MW. In response, the Update states that the Federal Government is considering making all new units at the same facility whose capacities collectively amount to 25 MW or greater, as well as single units 25 MW or greater,

[30] RIAS, *supra* note 11, at 2767, Table 17.
[31] SaskPower, "SaskPower Response: Federal Clean Electricity Regulations, Canada Gazette, Part I" (2 November 2023) at PDF 10, online (pdf): <saskatchewan.ca/government/news-and-media/2023/november/21/saskatchewan-responds-to-unaffordable-unconstitutional-and-unattainable-proposed-federal-clean-elect> ["**SaskPower Response Appendix**"].
[32] See *Draft CERs* General Comment Section, *supra* note 29.

subject to the *Draft CERs*. However, the Update lacks clarity regarding how a "facility" would be defined in the regulation.

Emissions Prohibition: In addition to the concerns noted above, the Update notes that many provinces and utilities commented that the Emissions Prohibition would be difficult to achieve for "load following"[33] natural gas fired units equipped with CCS because when "load following", a unit is likely operating at a higher emissions intensity (ramping up and ramping down to meet demand) than if the same unit were operated at a continuous steady-state.[34] In response, the principal change to the *Draft CERs* being considered is the replacement of the 30t/GWh Emissions Prohibition with a capacity-based, unit-specific annual emissions limit (in tonnes/yr) linked to an adjusted emissions performance standard as follows:

$$\underset{(t/year)}{\textit{Unit Emission limit}} = \underset{\text{(t/GWh)}}{\textit{Performance standard}} \times \underset{\textit{(capacity of unit)}}{\textit{MW}} \times \underset{\textit{(total hours in a year)}}{\textit{8760 hours}} \times \underset{\textit{(unit conversion)}}{\left(\frac{1\,GW}{1000\,MW}\right)}$$

The Update does not specify the applicable performance standard, indicating that it is "TBD" and noting that it is being considered to increase above 30 t/GWh. Unlike the Emissions Prohibition, the annual emissions limit being considered would permit units unable to achieve the emissions performance standard to continue to be operated, but the hours such units operate would be limited compared to the hours more emissions efficient units are able to operate, since such units would reach their annual emissions limit after fewer hours of operation. The Update also indicates that under consideration is allowing an owner of multiple units operating in the same jurisdiction to pool the annual emissions limits of such units, which would enable the operation of more efficient

[33] When load-following, the unit ramps up and down to fill in when renewables are not producing or when demand is very high.
[34] Update, *supra* note 12 at PDF 5.

units above each individual unit's limit, offset by fewer hours of operation of less efficient units.

The Update opines that the potential to pool emissions limits, the use of offsets as a compliance option (discussed below), and the annual emissions limit approach would enable the owner of a generating unit subject to the *Draft CERs* to install CCS without the concern that the technology might not achieve the 30t/GWh performance standard and enable the continued operation of the generating unit.

End of Prescribed Life: The Update also indicates that Federal Government is considering "slightly extending" the 20-year end-of-prescribed life to reduce stranded asset costs[35] and allowing units that have substantial investment and work underway, but are unable to achieve commissioning by January 1, 2025, to make use of the end-of-prescribed life provisions of the *Draft CERs*, provided such units achieve commissioning by a set date (TBD) as opposed to compliance as at January 1, 2035. The Update contemplates that the end-of-prescribed life for such units would be shortened to ensure the units are subject to the CERs no later than a unit commissioned by January 1, 2025.[36]

The *Draft CERs* do provide limited exemptions from the application of the Emissions Prohibition, for example in respect of Behind-the-Fence generating units with no net exports or generating units granted an exemption by the Minister due to an emergency circumstance.[37] A further exemption for peaking units[38] would allow such units to operate for a total emissions threshold of 150 kt/yr and maximum hour threshold of 450h/yr (or 18.75 days) to address peak or back-up generating

[35] Update, *supra* note 12 at PDF 8.
[36] *Ibid.*
[37] *Draft CERs*, *supra* note 1, ss 5, 19-20 at 2827-2828 & 2843-2842
[38] Peaking power plants, or peaker plants, are power plants that generally run only when to meet high or peak demand for electricity.

capacity.[39] The Update indicates the Federal Government is *evaluating* changes to the scope of the exempted categories to allow for more flexibility and contemplating allowing system operator declarations of emergencies. The Update also opines that the potential for "pooling" of units owned by single entity may avoid the need to prescribe a time limit for peaker units. However, the unconstructive result is that these amendments remain in flux.

In light of the changes under consideration, there remains considerable uncertainty regarding the application and restrictions to be imposed in the final regulations.

B. Enforcement

The *Draft CERs* would make non-compliance with the Emission Prohibition an offence under the CEPA punishable by fines from $100,000 to $12 million and potentially criminal penalties resulting even in incarceration.[40] As part of the consultation process for the *Draft CERs*, stakeholders expressed significant concern regarding the potential for criminal liability for non-compliance, particularly in light of the stringency and complexity of the *Draft CERs*.[41] Many stakeholders identified the need for the ability to use emission offsets to achieve compliance. The Update identified that consideration is being given to allow a unit to emit over its emissions limit by a prescribed amount, provided it remits GHG offsets to account for such excess emissions. However, the Update did not identify the extent of the prescribed amount or the criteria for

[39] *Draft CERs*, *supra* note 1, s 6(3) at 2828.

[40] *Ibid*, s. 31 at 2851 states that the schedule to the *Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act,1999)*, SOR/2012-134 [*CEPA Regs*] is amended by adding subsections 6(1)-(3) of the *Draft CERs* as item 42. Subsections 6(1)-(3) of the *Draft CERs* set out the Emission Prohibition and exceptions regarding CCS and hours of operation. The provisions in the schedule of the *CEPA* are designated as offences under the paragraph 272(1)(h) of the *CEPA* (per s 286.1). Subsection 272(3) establishes significant penalties for persons other than individuals and subsection 272.2(1) provides for the potential incarceration of individuals who commit offences.

[41] Electricity Canada, "Clean Electricity Regulations – Electricity Canada Response" (2 November 2023) at PDFs 3-4, online (pdf): <electricity.ca/files/reports/Final-Electricity-Canada-CER-Response.pdf> ["**Electricity Canada Response**"].

acceptable offsets.

C. Constitutional Questions

Not surprisingly, the *Draft CERs* prompted vociferous backlash from provincial governments with electricity systems most reliant on emitting sources of generation – including claims of unconstitutionality. Under the *Constitution Act, 1867*, provinces have exclusive jurisdiction over the development, conservation and management of sites for the generation and production of electricity, and shared jurisdiction with the Federal Government over the export of electrical energy.[42]

Alberta Premier Danielle Smith introduced a motion in Alberta's legislative assembly for a resolution under the as-yet untested *Alberta Sovereignty within a United Canada Act (Sovereignty Act)* to bar enforcement of the regulation's restrictions. Among other things, the resolution requested that Alberta's cabinet order all provincial entities to not recognize the constitutional validity of the proposed *Draft CERs* and to not enforce them or cooperate in their implementation in any manner "to the extent legally permissible", indicating that Alberta should also use all legal means necessary to oppose the *Draft CERs*, including legal challenges. The resolutions also suggest the government establish a provincial Crown corporation to ensure reliable and affordable electricity supply – by either building new generation or purchasing and de-risking existing generation assets held by private industry that would be subject to the *Draft CERs*.

In his response to the *Draft CERs*, Saskatchewan's Minister of Crown Investments Corporation likewise called the regulations a contravention of 92A(1) of the *Constitution*, a concerning example of federal jurisdictional overreach, and an impermissible intrusion on the governance of

[42] *Constitution Act, 1982, supra* note 4, ss 92(A)(1)(C), 92(A)(2), 92(A)(3).

it provincial Crown-owned utilities.[43] In the fall of 2023, Saskatchewan passed the *Saskatchewan First Act*[44], with an objective to "protect Saskatchewan from constitutional overreach" by the Federal Government. The act amends the *Constitution of Saskatchewan* to "clearly confirm Saskatchewan's autonomy and assert Saskatchewan's exclusive legislative jurisdiction under Section 92 (A) of the Constitution of Canada."[45] Among other things, under section 3(d) of *The Saskatchewan First Act*, Saskatchewan asserts exclusive jurisdiction over the operation of sites and facilities in Saskatchewan for the generation and production of electrical energy, including the source of fuel for electrical generation. Part 3 of *The Saskatchewan First Act* establishes an independent Economic Impact Assessment Tribunal for the purposes of defining, quantifying, and reporting on the economic effects of federal initiatives of provincial investments and Saskatchewan projects, businesses, and people.[46] On November 28, 2023, Saskatchewan announced that the *Draft CERs* as the first matter to be referred to this tribunal.[47]

The constitutionality of the *Draft CERs* was also raised in other stakeholder comments, including a recommendation that the regulations should be referred to the Supreme Court of Canada to determine its constitutionality prior to implementation in light of the Supreme Court of Canada's ruling regarding the *Impact Assessment Act*.[48]

While the Update indicates that the final *CERs* may introduce additional flexibility, it remains

[43] Letter from Dustin Duncan to Honorable Steve Guilbeault (2 November 2023) in Government of Saskatchewan News and Media online: <saskatchewan.ca/government/news-and-media/2023/november/21/saskatchewan-responds-to-unaffordable-unconstitutional-and-unattainable-proposed-federal-clean-elect>

[44] SS 2023, c 9 ["*The Saskatchewan First Act*"].

[45] Government of Saskatchewan, "Province Passes Saskatchewan First Act" (16 March 2023), online: <saskatchewan.ca/government/news-and-media/2023/march/16/province-passes-saskatchewan-first-act-adds-house-amendments>.

[46] *The Saskatchewan First Act*, *supra* note 44, ss 6-12. See *ibid*.

[47] Government of Saskatchewan, News Release, "Government of Saskatchewan Announces Membership of Economic Assessment Tribunal" (28 November 2023), online: <saskatchewan.ca/government/news-and-media/2023/november/28/government-announces-first-impact-assessment-tribunal>.

[48] See *Draft CERs* General Comment Section, *supra* note 29.

apparent that significant restrictions on unabated emitting generation will still be legislated in the *CERs*, whatever their final form. The Federal Government has provided no indication in the Update, or otherwise, that it is considering walking back the prescribed restrictions in the *Draft CERs*. It would not be unexpected if Alberta or other significantly impacted provinces such as Saskatchewan seek to challenge the final *CERs* regardless of the nature or scope of the remaining restrictions on emitting electricity generation.

III. Supply Adequacy: Restructuring and Risk Allocation

Canadian jurisdictions from coast-to-coast-to-coast are planning for aggressive growth of their electricity supply to meet increased electrification demands in support of economy-wide carbon reduction targets and are experiencing transitional impacts arising from changes in generation supply mix. Many Canadian provinces, regardless of their electricity frameworks, are experiencing reliability and affordability challenges that are becoming more significant as the pace of change increases. Further complicating this transition are the restrictions proposed in the *Draft CERs*. According to the RIAS, if the *Draft CERs* are implemented, electricity systems in Alberta, Saskatchewan, Ontario, Nova Scotia and New Brunswick would be mandated to implement an estimated 98% of incremental emission reductions from 2024 to 2050[49] - these are the five provinces with electricity systems most reliant on electricity generated using fossil fuels.[50]

In response to the *Draft CERs*, and other market forces, jurisdictions across Canada are introducing new measures and means of meeting resource adequacy in the medium and longer term. These measures include market restructuring initiatives, competitive procurements as well as more direct government assumption of risk for compliance.

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[49] RIAS, *supra* note 11 at 2758-2759.
[50] *Ibid* at 2791.

In Alberta, the imposition of restrictions on investment in emitting sources of electricity generation, significant investment in renewable generation, and the entrance of new market participants are causing the government to review all aspects of electricity generation and transmission policy.

A Grid Alert[51] issued by the Alberta Electric System Operator ("**AESO**") on April 5, 2024 illustrates the complexity of reliability and resource adequacy in Alberta, even absent the *Draft CERs*. The Grid Alert was issued due to tight generation supply.[52] According to the AESO, the available solar and wind generation was 900 MW below forecast at a time when several thermal generating units were on planned outages. During this same period, another thermal natural-gas fired generating unit tripped, experiencing an unplanned outage, resulting in the loss of an additional 400 MW of generation.[53] Other thermal generating units were taking time to ramp up and return to service, and the AESO had dispatched available Operating Reserve, calling on all available generation as well as contracted load shed services.[54] Electricity was also imported to address the supply deficit.[55] However, rolling outages were still required throughout the province until normal operations resumed several hours later.[56] This Grid Alert demonstrates the

[51] Grid Alerts are issued when the Alberta power system is under stress, and the AESO is preparing to use emergency reserves to meet demand and maintain system reliability. See Alberta Electricity System Operator ["**AESO**"], "Grid Alert Notifications", online: <aeso.ca/aeso/understanding-electricity-in-alberta/electricity-conservation-and-grid-alerts/grid-alert-notifications/> ["**Grid Alert Notification**"].

[52] *Ibid*.

[53] AESO, "Media Briefing: Overview of the Grid Alerts" (5 April 2024), online (video): <aeso.ca/assets/video/media/media-briefing-april-5-2024.mp4> ["**AESO Media Briefing**"].

[54] The AESO procures Operating Reserve from generators or loads to maintain system reliability when there is an unexpected imbalance between supply and demand. Operating Reserves are categorized as regulating, spinning or supplement reserves. The AESO procures active and standby volumes of each type of Operating Reserve from a competitive market. See AESO, "Guide to understanding Alberta's electricity market", online: <aeso.ca/aeso/understanding-electricity-in-alberta/continuing-education/guide-to-understanding-albertas-electricity-market/>. See AESO, "Operating Reserve", online: <aeso.ca/market/market-participation/ancillary-services/operating-reserve/>

[55] AESO Media Briefing, *supra* note 53.

[56] The Grid Alert was issued at 6:49 am and ended at 11 am on April 5, 2024: see Grid Alert Notification, *supra* note 52. According to the AESO 250 MW of load was taken offline for 20 to 30 minutes at a time by working with the distribution utilities: AESO Media Briefing, *supra* note 56.

complexities of balancing Alberta's generation supply mix even absent the *Draft CERs*.

Alberta government policy is currently directed at a net-zero economy, including a net-zero grid, by 2050,[57] not 2035. Nonetheless, in its recently released 2024 Long-Term Outlook ("**AESO 2024 LTO**"), the AESO included a "Decarbonization by 2035" scenario that would align with the *Draft CERs* restrictions. This scenario would require approximately 25,000 MW of generation capacity additions and retrofits between 2024 and 2041, which is similar to forecast capacity additions under the AESO's reference case (which aligns with the provincial government's target to achieve decarbonization by 2050). However, the AESO models that the Decarbonization by 2035 scenario has a much higher risk of supply shortfall and unserved energy and the development of alternative generation technologies that have higher costs and lesser technological maturity.[58]

As has been the subject of much reporting, on August 3, 2023, one week in advance of the release of the *Draft CERs,* the Government of Alberta enacted the *Generation Approvals Pause Regulation*, requiring the Alberta Utilities Commission ("**AUC**") to immediately pause approvals of new renewable electricity generation projects over one megawatt until February 29, 2024. Concurrently, the Alberta Minister of Utilities and Affordability directed the AESO and the Market Surveillance Administrator ("**MSA**") to study the current energy market framework in Alberta.

The AESO's recommendation report titled "Alberta's Restructured Energy Market: AESO Recommendation Report" (the "**REM Report**")[59] identifies, among other things, that structural

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[57] Alberta Government, "Alberta emissions reduction and energy development plan" (2024) online (pdf): < open.alberta.ca/dataset/7483e660-cd1a-4ded-a09d-82112c2fc6e7/resource/75eec73f-8ba9-40cc-b7f4-cdf335a1bd30/download/epa-emissions-reduction-and-energy-development-plan.pdf> at 6.

[58] AESO, "2024 Long-Term Outlook" (15 May 2024) at PDF 15, online (pdf): <aeso.ca/assets/Uploads/grid/lto/2024/2024-LTO-Report-Final.pdf> ["**AESO 2024 LTO**"].

[59] AESO, "Alberta's Restructured Energy Market: AESO Recommendation to the Minister of Affordability and Utilities" (31 January 2024), online (pdf): <aesoengage.aeso.ca/42253/widgets/176297/documents/125528> ["**REM Report**"].

change to the Alberta market design and provincial electricity policy is needed and being driven by a combination of: technological shift; generation investment driven by environmental attributes; and uncertainty for gas-fired controllable[60] generation due to the proposed *Draft CERs*.[61] In terms of resource adequacy, the current Alberta Energy Only Market ("**EOM**") relies on private investment in new generation to ensure long-term supply adequacy, by attracting needed investments primarily through wholesale energy prices.[62] The REM Report describes that Alberta, like other jurisdictions, is experiencing a significant shift from carbon-emitting controllable generation sources to variable renewable generation resources (i.e., wind and solar) and that although renewables support a carbon-neutral future, they must be supported with controllable resources.[63] Among other recommendations, the REM Report proposes several changes to the EOM – calling it the Restructured Energy Market, or "**REM.**" According to the REM Report, the two mechanisms most relevant to strengthening incentives for investments in dispatchable technologies are:

- the implementation of scarcity-based administrative pricing mechanism and a day-ahead forward energy market, which are proposed to be implemented in the medium term (2-5 years); and

- the option to directly contract for controllable supply if needed in the long-term to ensure reliability, only to be used if REM changes are ineffective in incenting the required investment.

[60] See *ibid* at PDF 6, footnote 1, when referring to different types of supply, the terms dispatchable and controllable are used interchangeably to represent technologies that can be dispatched and controlled in real time.
[61] *Ibid* at PDF 19.
[62] *Ibid* at PDF 17.
[63] *Ibid* at PDF 20. Low-carbon emission controllable resources include abated natural gas generation, hydrogen-fueled generation, full-scale nuclear, small modular reactors, hydroelectric power, and energy storage resources.

The introduction of a day-ahead market represents a significant change to the Alberta EOM, under which suppliers are currently able to change volumes at any time with an acceptable operational reason and can change their offer price up to **two hours** before the settlement interval.[64] The REM Report proposed centrally cleared day-ahead market would commit generation to meet forecasted load. All generation types would offer their expected available generation in the day-ahead market. According to the REM Report, generators that clear in the day-ahead market would be guaranteed a price for producing to their schedule, providing sellers with certainty that daily revenues can cover their short-term costs regardless of real-time price conditions. Generators that clear in the day-ahead market but are not available in real time may be obligated to pay for the shortfall in their delivered volumes at the real-time energy price. According to the REM Report, this will create incentives for dispatchable technologies to operate by providing a more certain revenue stream and production schedule, and for non-controllable resources (i.e., wind and solar) to become more dispatchable and better at forecasting production.[65]

As an optional measure, the REM Report also proposes direct contracts for controllable supply if needed in the long-term to ensure reliability. The REM Report is clear that this is onlyfor targeted procurements on an as-needed basis, and only in the event of inadequate market investment in controllable supply.[66] Further, in keeping with comments of Alberta Premiere Danielle Smith, the REM Report notes that decarbonization policies, such as the *Draft CERs'* strict requirements,

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[64] Using the price-quantity offers, a merit order is created by sorting offers from the lowest-priced to the highest-priced for each hour of the day. The AESO dispatches the lowest-priced offers from the bottom of the merit order first, and move up towards the higher-priced offers until all electricity required to meet demand has been dispatched. The last offer dispatched to meet demand sets the system marginal price ("**SMP**") for electricity. For example, if offers in the merit order are priced from $0 to $100 and the last offer dispatched to meet demand is priced at $40, the SMP is $40. The SMP is set on a minute-to-minute basis and is used in the calculation of the hourly settlement price, also known as the pool price. The pool price is calculated as the average of all 60 one-minute SMPs in each hour and is posted at the end of the hour.

[65] REM Report, *supra* note 59 at PDF 34.

[66] *Ibid* at PDF 35.

introduce significant uncertainty for investment in some controllable technologies such as CCS.[67] The REM Report notes that more direct government support or ownership may be appropriate to financially underpin the investment or assign a liability to the province.[68]

The Alberta Minister of Affordability and Utilities and has directed the AESO to develop a draft technical design of the proposed REM on an expedited timeframe by the fall of 2024.[69] At the time of writing, the REM measures are still subject to further refinement and modification. For the time being, Alberta intends to rely on private investment in new generation to ensure long-term supply adequacy, albeit with a restructured market intended to provide additional incentives. Should the *Draft CERs* be passed, more direct government intervention is anticipated.

Alberta is not alone in examining and implementing new measures to ensure that resource adequacy requirements are met in the lead up to 2035 and beyond. Differing approaches to addressing the implications of the *Draft CER* are evident, particularly in those jurisdictions most impacted.

Ontario provides an example of a provincial jurisdiction with a large fleet of non-emitting generation (nuclear, hydroelectric and significant wind and solar facilities) that is nonetheless also grappling with resource adequacy in the near term. In its submission on the *Draft CERs,* the Ontario Independent Electricity System Operator (the "**OIESO**") [70] has stated that the *Draft CERs* are unachievable in Ontario by 2035 without putting at risk the reliability of the electricity system,

[67] *Ibid* at PDF 37.
[68] *Ibid*.
[69] Minister of Affordability and Utilities, Direction Letter to the AESO (11 March 11, 2024), online (pdf): < aesoengage.aeso.ca/42905/widgets/179261/documents/128106>.
[70] The OIESO is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario.

electrification of the broader economy and economic growth.[71] Ontario's decarbonization plan includes the procurement of energy storage capacity; refurbishments its existing nuclear fleet; small modular reactors, with the first underway at the Darlington Nuclear Generating Station; hydroelectric generation; additional renewable generation (wind, solar and bioenergy); energy efficient enhancements and distributed generation; and natural gas generation until nuclear refurbishments are complete and new non-emitting technologies such as storage mature.[72] The OEISO's planning scenario for a decarbonized grid identifies forecasts that 8,000 MW of natural gas generation (17% of Ontario's installed capacity), will need to remain available in 2035 to ensure system reliability until other generation alternatives are identified and in service.[73]

Approximately 31% of Ontario's connected capacity is nuclear but it accounts for almost half of the total electricity output annually.[74] While the refurbishments aim to secure long term supply, a significant portion of Ontario's nuclear supply will be taken offline in the short term for refurbishment. At its peak, four nuclear units will be down at one time, representing about 9% of Ontario's generating capacity, during which time, electricity demand will be met significantly by natural gas generation and by energy storage battery projects.[75] Unlike Alberta (presently), Ontario has Long-Term Contracts underpinning its electricity industry, with generation developed by both private entities and a crown corporation. Nearly all electricity generation is utility-owned (rate-regulated) or secured via long-term contracts.[76] In 2022, the Ontario government issued a direction

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[71] Ontario Independent Electricity System Operator, News Release, "The IESO's Response to draft Clean Electricity Regulations" (16 November 2023), online: <ieso.ca/en/Sector-Participants/IESO-News/2023/11/The-IESOs-Response-to-draft-Clean-Electricity-Regulations> ["**OIESO Response**"].
[72] Government of Ontario, "Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future" (10 July 2023) at PDF 44, online (pdf): <ontario.ca/files/2023-07/energy-powering-ontarios-growth-report-en-2023-07-07.pdf> ["**Powering Ontario's Growth**"].
[73] OIESO Response, *supra* note 71.
[74] Powering Ontario's Growth, *supra* note 72 at PDF 14-15.
[75] *Ibid* at PDF 44.
[76] REM Report, *supra* note 59 at PDF 36.

to the OIESO under the *Electricity Act*,[77] to undertake procurement of electricity resources to ensure the reliability, including natural gas-fired electricity resources. To address the anticipated impact of future regulation of and restrictions on natural gas-fired generation, the direction included the requirement that associated procurement contracts:

> … include provisions … that, where laws or regulations are introduced and passed restricting GHG emissions from a project:
>
> i. Require such projects to submit GHG emissions abatement plans, showing how the project will bring its operations into compliance with the laws or regulations, prior to the new emissions standards coming into force; and
>
> ii. If a project is unable to comply with such laws or regulations in order to continue meeting its obligations under the Contract, despite commercially reasonable efforts, allow such project to suspend operations for the balance of the contract term while retaining payments under the Contract.[78]

In 2023, the OIESO announced that it had awarded contracts for new natural-gas fired generating facilities at existing locations within Ontario, capacity upgrades at existing facilities, and contract extensions to existing natural-gas fired facilities. In compliance with the direction, the form of contract includes obligation on the OIESO to continue payments to the natural gas generation facility owner in the event that the facility operation is restricted or it is decommissioned early due to the *Draft CERs* or similar legislation.[79] What is clear from the OIESO procurement is that the Ontario Government is willing to have the OIESO, or customers, assume the risk of *Draft CERs* compliance and stranded costs, in its pursuit of near term resource adequacy.

Saskatchewan, like Ontario, has also signaled an intention to continue to rely on natural gas generation in the medium term. Saskatchewan has announced its plans to reach net-zero generation

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[77] *Electricity Act*, SO 1998, c 15, s 25.3(2) and 25.4; *Directive – Order in Council*, OC 1348/2022, online: <ontario.ca/page/directive-order-council-13482022> ["**OC 1348/2022**"].
[78] *Ibid*.
[79] OIESO, "LT1 Contract" (29 September 2023), s 2.15, online: <ieso.ca/Sector-Participants/Resource-Acquisition-and-Contracts/Long-Term-RFP-and-Expedited-Process>.

by 2050, calling the *Draft CERs* and net-zero by 2035 unaffordable and unrealistic.[80] SaskPower[81] has indicated that its decarbonization pathway between 2023 and 2025 includes adding additional renewables generation, battery energy storage, expanding imports, developing nuclear SMR generation, and adding approximately 1,500 MW of natural gas-fired generation to replace retiring coal assets.[82] To comply with the *Draft CERs*, SaskPower has stated that it would need to expand, replace and rebuild the majority of its current power generating capacity of more than 5,400 megawatts in just 11 years while also significantly expanding its transmission infrastructure – which it states is "is not possible from technological, financial and logistical perspectives."[83] SaskPower is further developing a long-term plan to meet Saskatchewan's greenhouse gas emission targets of net zero emissions by 2050 and a 2030 emissions reduction target of 50% below 2005, which is expected to be released in June 2024.[84]

Like Saskatchewan, Nova Scotia is currently also heavily reliant on coal-fired generation. The Nova Scotia provincial government has mandated the closure of coal-fired generation by 2030 and will require 80% of electricity to be produced from renewable sources by 2030.[85] On April 20, 2023, Nova Scotia Premier Tim Houston and Natural Resources and Renewables Minister Tory Rushton announced the establishment of the Clean Electricity Solutions Task Force ("**CESTF**"). The CESTF was directed to, amongst other things, examine electricity infrastructure needs to ensure reliability, capacity, and storage to meet Nova Scotia's emission reduction targets, and on

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[80] Government of Saskatchewan, "Premier Outlines Plans For Affordable, Reliable Power Production" (16 May 2023), online: <saskatchewan.ca/government/news-and-media/2023/may/16/premier-outlines-plans-for-affordable-reliable-power-production>.

[81] SaskPower is a vertically integrated Crown corporation, responsible for generation, transmission and distribution of electricity in Saskatchewan.

[82] SaskPower Response Appendix, *supra* note 31 at PDF 8.

[83] Letter from Rupen Pandya to Honorable Steve Guilbeault (2 November 2023) in Government of Saskatchewan Media online: <saskatchewan.ca/-/media/news-release-backgrounders/2023/nov/saskpower-cer-response-letter-november-2-2023.pdf>.

[84] SaskPower Response Appendix, *supra* note 31 at PDF 7.

[85] Nova Scotia Department of Natural Resources and Renewables, "Nova Scotia's 2030 Clean Power Plan" (14 October 2023), online (pdf): <novascotia.ca/cleanpowerplan> ["**Nova Scotia's 2030 Clean Power Plan**"].

February 23, 2024, released a final report ("**NS Task Force Report**"). The CESTF concluded that the electricity generation from coal to renewables will require very significant investments in new energy generation in Nova Scotia and that competitive processes conducted by an independent system operator (a role currently undertaken by Nova Scotia Power Inc. ("**NS Power**")[86] are required to ensure that competitive investment is attracted.[87] Among other recommendations, the NS Task Force Report recommended the creation of a new Nova Scotia Independent Energy System Operator ("**NSIESO"**) to oversee open competition for procurement of all new infrastructure, including for generation, transmission, distribution, and storage, in which NS Power would not be excluded from participating.[88]

On April 5, 2024, the Nova Scotia Legislature passed Bill No. 404, the *Energy Reform (2024) Act* ("***NS ERA 2024***") to implement the recommendations of the NS Task Force Report.[89] The *NS ERA 2024* introduces significant changes to energy regulation and governance in Nova Scotia to support the shift to renewable energy generation and electrification. The *NS ERA 2024* creates two new acts (the *Energy and Regulatory Boards Act* and the *More Access to Energy Act*), establishes two new regulators (the Nova Scotia Energy Board and the Utility and Review Board), and creates the NSIESO to manage the operations formally performed by NS Power. The *ERA* also removes obstacles to NS Power's ownership of nuclear generating stations and mandates public procurements for energy resources for all large-scale utilities. The legislation and amendments enacted by the *NS ERA 2024,* including the shift to an independent system operator, are a significant change to the electricity regulation framework in Nova Scotia and will take time to

[86] Nova Scotia Power Inc. ("**NS Power**") is an investor owned vertically integrated utility, owning 79% of the provincial generation capacity, all transmission assets and a significant portion of the distribution system.
[87] Nova Scotia Clean Electricity Solutions Task Force, "Final Report: Modernizing Energy from Transition to Transformation" (23 February 2024) at PDF 34, online (pdf): <cetaskforce.ca/wp-content/uploads/2024/02/Report-February-23-2024-Final-Signed.pdf> ["**NS Task Force Report**"].
[88] *Ibid* at PDF 34-35.
[89] NSA 2024, c 2.

operationalize.

Regardless of whether the goal is for a net zero grid by 2050 or by 2035, with increased electrification demands, adherence to the *status quo* is unlikely to support the required investments needed. It is anticipated that different mechanisms to support investment – including marketing restructure and framework reforms, government intervention and public assumption of regulatory risk to facilitate electrification and energy transition – is a trend that will continue.

IV. Managing the Tension Between Policies for Increased Electrification and Scarcity of Supply

The *Draft CERs* restrictions on electricity generation that is not low- or non-emitting also have the potential to conflict with various policy directives intensifying demands for electrification. The RIAS cost-benefit-analysis models that electricity demand increases by 40% over the analytical period (2024-2050), while acknowledging that other studies had previously estimated that electricity demand could triple by 2050. The 2023 federal budget indicated that Canada's demand is expected to double by 2050 and overall installed capacity would have increase by 2.2 to 3.4 times compared to current levels to meet demand by 2050.[90]

In Alberta, electrification and new industrial load are expected to drive energy consumption increases. On June 27, 2022, the AESO published a detailed analysis of the opportunities and challenges involved in eliminating greenhouse gas emissions from Alberta's power system – the *AESO Net Zero Emissions Pathways Report* ("**AESO Net Zero Report**"). The AESO Net Zero Report notes that the impact of net-zero policies on electricity load in Alberta is uncertain and difficult to forecast, acknowledging that there are differing views on petroleum production, which

[90] Government of Canada, "Budget 2023" at PDF 89, online (pdf): <budget.canada.ca/2023/pdf/budget-2023-en.pdf>.

have historically been significant drivers of industrial electricity demand.[91] However, among other findings, the AESO Net Zero Report concludes that electrification of industrial processes, heating and transportation will drive electricity demand growth in Alberta over the next two decades. Even considering the potential for lower electricity demand from the petroleum sector, and the increased adoption of distributed energy resources (such as roof-top solar) that offset Alberta internal load ("**AIL**"), compared to 2021, load is expected to increase by 15% by 2035 and 25% by 2041.[92] The AESO 2024 LTO predicts that AIL average hourly load will increase by approximately 26% from 2024 to 2043 in the reference scenario and by 43% in a high electrification scenario (reflecting increased electric vehicle adoption, building heating and cooling electrification, hydrogen production, and electrification of heavy industry).[93]

Indeed, multiple jurisdictions, including the Federal Government, have deployed various policy levers to encourage higher use of electricity, in place of other emitting fuel or energy sources. As noted in the AESO Net Zero Report, a significant driver of electricity demand is expected to be the conversion to electric vehicles. For example, Canada has also amended the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* ("***Automobile Regulations***"),[94] which will mandate that a specified portion of new light-duty vehicles sold by manufacturers and importers in Canada be zero-emissions vehicles ("**ZEV**"), with the required percentage increasing over time. Furthermore, the Federal Government, British Columbia, New Brunswick, Newfoundland and Labrador, Nova Scotia, Prince Edward Island, Quebec and the

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[91] AESO, "AESO Net-Zero Emissions Pathways Report" (June 2022) at PDF 18, online (pdf): <aeso.ca/assets/Uploads/net-zero/AESO-Net-Zero-Emissions-Pathways-Report.pdf> ["**AESO Net Zero Report**"].
[92] *Ibid* at PDF 26.
[93] AESO 2024 LTO, *supra* note 58 at PDF 3-4.
[94] SOR/2023-275.

Yukon currently offer rebates and incentives related to electric vehicles.[95]

The AESO Net Zero Report identifies another driver of electrical demand will be the electrification of heating systems via "fuel-switching" from natural gas to electric heat pumps. While the AESO report acknowledges that in Alberta the implementation of building net-zero solutions is challenged by the lack of regulatory direction and limited incentives,[96] other Canadian jurisdictions have taken more concrete steps to encourage fuel-switching and building decarbonization. For example, British Columbia and Quebec are taking steps to increase energy-efficiency requirements in buildings[97] and several jurisdictions have introduced rebates available for heat pumps.[98]

The International Energy Agency has highlighted that electricity consumption by data centres, artificial intelligence ("**AI**"), and the cryptocurrency sector is a significant driver of increasing electricity demand and projected to double globally by 2026.[99] This corresponds roughly to the equivalent of adding the 2022 demand of Germany by 2026. Data centres are significant drivers of electricity demand, but the AI industry is expected to grow exponentially and consume at least 10 times its 2023 demand by 2026.[100] While much of this growth has been in other jurisdictions,

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[95] Government of Canada, "Zero-emission vehicles incentives" (22 February 2024), online: <canada.ca/en/services/transport/zero-emission-vehicles/zero-emission-vehicles-incentives.html>.

[96] AESO Net Zero Report, *supra* note 91 at PDF 22.

[97] Government of British Columbia, "Energy Efficiency" (24 April 2024), online: <gov.bc.ca/gov/content/industry/construction-industry/building-codes-standards/energy-efficiency>. See Quebec's Bill 41, which has targets of reducing greenhouse gas emissions in the buildings sector: Bill 41, *An Act to enact the Act respecting the environmental performance of buildings and to amend various provisions regarding energy transition*, 1st Sess, 43rd Leg, Quebec, 2023.

[98] See e.g., Government of British Columbia and CleanBC, "Enjoy year-round comfort with a $6,000 heat pump rebate", online: <betterhomesbc.ca/heatpumps/>. The Federal Government has introduced an oil-to-heat-pump affordability program for homeowners to transition from oil heating to new, energy-efficient heat pumps: Government of Canada, "Oil to Heat Pump Affordability Program" (20 March 2024), online: <natural-resources.canada.ca/energy-efficiency/homes/canada-greener-homes-initiative/oil-heat-pump-affordability-program/24775>.

[99] International Energy Agency, "Electricity 2024 Analysis and forecast to 2026" (7 May 2024) at 8, online (pdf): <iea.blob.core.windows.net/assets/18f3ed24-4b26-4c83-a3d2-8a1be51c8cc8/Electricity2024-Analysisandforecastto2026.pdf>

[100] *Ibid.*

several Canadian provinces have already implemented restrictions on or suspended the connection of new cryptocurrency developments to electricity grids, to prioritize electrification of other loads that align with policy objectives.[101]

The restrictions on cryptocurrency load may be a harbinger of a broader trend. In Québec, like Alberta, the guiding principle in electricity supply has been that Hydro-Québec is required to distribute electric power to every person who requests service within its territory, per the *Act respecting the Régie de l'énergie.*[102] However, *An Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity* ("**Bill 2**"),[103] modified the *Act respecting the Régie de l'énergie*[104] by amending the guiding principle of mandatory electricity supply upon request and granting the Minister of Economy, Innovation and Energy[105] the discretionary power to select the industrial projects that require supply by Hydro-Québec of electricity in excess of 5 MW. Bill 2 provides that such selection must be made by the Minister considering Hydro-Québec's technical capabilities as well as the economic benefits and social and environmental impacts of the use of the electric power requested.[106] The measure stems from the incapacity of Hydro-Québec to match the electricity demand from ever more energy-intensive industrial projects[107] and the Québec's government

[101] See for example, Manitoba's *The Crown Corporations Governance and Accountability Act*, CCSM c C336, s 13; British Columbia's *Bill 24 – 2024, Energy Statutes Amendment Act, 2024*, 5th Sess, 42nd Parl, British Columbia, 2024; New Brunswick's *An Act to Amend the Electricity Act*, SNB 2023, c 37, modifying the *Electricity Act*, SNB 2013, c 7, s 91(3).

[102] CQLR c R-6.01, s. 76 ["***Act respecting the Régie de l'énergie***"].

[103] SQ 2023, c 1 ["**Bill 2**"].

[104] *Act respecting the Régie de l'énergie, supra* note 102.

[105] The Minister of Natural Resources and Wildlife's functions are currently exercised by the Minister of Economy, Innovation and Energy.

[106] Bill 2, *supra* note 103, s 10.

[107] Chouinard, Tommy, La Presse, "Demandes d'alimentation faites à Hydro-Québec: 1000 mégawatts pour 11 entreprises, annonce Pierre Fitzgibbon" (31 August 2023), online : <lapresse.ca/affaires/entreprises/2023-08-31/demandes-d-alimentation-faites-a-hydro-quebec/1000-megawatts-pour-11-entreprises-annonce-pierre-fitzgibbon.php>.

objective to attain net-zero emissions by 2050.[108]

In the first of such allocations, Hydro-Québec was awarded the authorization to provide electricity service to eleven industrial projects, five of which are directly related to the electric vehicle battery industry, which has been an economic priority of the current Québec government.[109] It was reported unofficially in February 2024 that at least 150 industrial projects were submitted to the Minister for review and approval for the next allocation[110] but it is anticipated that only a select few projects will be greenlighted.[111] This approach has raised questions within Québec as to the appropriate balance between electricity exports and the connection of industrial projects in the province.[112]

Measures restricting new load connections are an extension of more traditional methods of managing demand, such as efficiency improvements, time-of-use rates, and other demand-side management measures. All of these measures will likely see increasing adoption as a means to manage electricity demand in the face of potential supply inadequacy, even absent the imposition of the *Draft CERs*. If the *Draft CERs* are implemented and enforced by 2035, and needed investment for replacement abated or non-emitting generation lags, then impacted jurisdictions

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[108] Politique-Cadre d'électrification et de lute contre les changements climatiques, Bibliothèque et Archives nationales du Québec, 2020, ISBN 978-2-550-86279-6 (PDF).

[109] Cabinet du ministre de l'Économie, de l'Innovation et de l'Énergie et ministre responsable du Développement économique régional, "Attribution responsable et durable de notre électricité - Québec dévoile la liste des onze projets sélectionnés pour un raccordement d'une puissance de 5 MW et plus", News Release (10 November 2023), online: <www.newswire.ca/fr/news-releases/attribution-responsable-et-durable-de-notre-electricite-quebec-devoile-la-liste-des-onze-projets-selectionnes-pour-un-raccordement-d-une-puissance-de-5-mw-et-plus-895481275.html>.

[110] Talbot, Dominique, "Les entreprises se bousculent pour les mégawatts d'Hydro-Québec" (4 February 2024), online: *Les Affaires* <lesaffaires.com/secteurs/ressources-naturelles/les-entreprises-se-bousculent-pour-les-megawatts-dhydro-quebec/648659>.

[111] Tommy Chouinard, "1000 mégawatts pour 11 entreprises, annonce Pierre Fitzgibbon" (31 August 2023), online : *La Presse* <lapresse.ca/affaires/entreprises/2023-08-31/demandes-d-alimentation-faites-a-hydro-quebec/1000-megawatts-pour-11-entreprises-annonce-pierre-fitzgibbon.php>.

[112] Bloomberg News, "Quebec faces big electricity shortfall after wooing U.S. to buy cheap hydro power" (27 April 2023), online: *Financial Post* <financialpost.com/commodities/energy/renewables/quebec-faces-power-shortfall-hydro-electricity-exports>.

may be forced to adopt increasing stringent measures to allocate electricity if faced with inadequate supply.

V. Interties, Imports, Exports and Regional Cooperation

According to the RIAS, the *Draft CERs* are expected to result in a significant increase to domestic electricity trade activity, facilitated by new provincial interties to minimize the system-wide compliance costs.[113] The RIAS models that domestic trade would increase by $43 billion in economic value from 2024 to 2050, which is a 17% increase compared to baseline assumptions.[114] Alberta is projected to see an estimated net import expenditure of $16.3 billion over that time period, whereas British Columbia is projected to see estimated cost savings of $21.7 billion, while other provinces can expect to see cost impacts or savings falling somewhere in between.[115] The RIAS estimates that that the proposed *Draft CERs* would result in a total of $6.7 billion of incremental capital costs for new-interprovincial transmission lines to 2050,[116] with the majority of these costs being incurred by Ontario, Manitoba, Alberta, and British Columbia.

The federally appointed Clean Electricity Advisory Council[117] has also identified that wider regional integration, combined with multi-jurisdictional planning and coordination, has the potential to support reliability and resilience goals at lower overall costs than other available solutions.[118] However, provincial grids have historically evolved with limited consideration for

[113] RIAS, *supra* note 11 at 2781.
[114] *Ibid*.
[115] *Ibid* at 2782.
[116] *Ibid* at 2769.
[117] The federal Minister of Energy and Natural Resources created the Canada Electricity Advisory Council in May 2023 as an independent, electricity-sector focussed, expert advisory body to provide advice to the Minister of Energy and Natural Resources to accelerate investment, and promote sustainable, affordable, and reliable electricity systems: Government of Canada, "The Canada Electricity Advisory Council" (22 May 2024), online: <natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/25297>.
[118] Clean Electricity Advisory Council, "Interim Report" (December 2023) at PDF 8, online (pdf): <natural-resources.canada.ca/sites/nrcan/files/pdf/CEAC%20Interim%20Report%202023-12-13.pdf> ["**CEAC Interim Report**"].

inter-regional cooperation within Canada. Canadian interties (transmission lines that connect separate electric grids and enable the trade of electricity between jurisdictions) generally have greater capacity going north-south – i.e., between the United States and Canada – than east-west.[119]

Alberta's comments on the *Draft CERs* indicate that the RIAS has overly optimistic assumptions about capacity and timelines for increased interties with British Columbia, given that "current ties are constrained and increasing intertie capability by significant volumes to balance intermittent generation across regions will take significant time and coordination between jurisdictions, beyond the 2035 horizon."[120] The Alberta Ministry of Affordability and Utilities has initiated a consultation through a green paper "Transmission Policy Review: Delivering the Electricity of Tomorrow" ("**Green Paper**"), which among other things considers the treatment of interties in Alberta. The Green Paper acknowledges that with intermittent generation increasing, interties can play a crucial role in achieving affordability, reliability, and decarbonization by allowing low-priced imports to put downward pressure on pool prices; providing grid balancing, load management and reserve capacity services; and allowing surplus clean electricity to imported to and exported from Alberta to address supply surplus.[121] The Green Paper indicates that several measures are under consideration to amend the *Transmission Regulation* to provide clarity for interties – including changes to more clearly indicate when restoration of interties to their path rating must be completed, including the Alberta-B.C. intertie[122] and amendments to outline

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[119] House of Commons, *Strategic Electricity Interties: Report of the Standing Committee on Natural Resources* (December 2017) (Chair: James Maloney).

[120] See Alberta Environment and Protected Areas, "Federal Draft Clean Electricity Regulations – Government of Alberta Technical Submission" (3 November 2023) at PDF 18, online (pdf): <alberta.ca/system/files/epa-government-of-alberta-submission-on-draft-federal-electricity-regulations.pdf> ["**GoA Technical Submissions**"], which notes that the in the RIAS, the model had 1,000 to 1,900 MW with BC in 2034 and then to 2,700 MW in 2044.

[121] Government of Alberta, "Transmission Policy Review: Delivering the Electricity of Tomorrow" (October 2023) at PDF 21, online (pdf): <ablawg.ca/wp-content/uploads/2023/11/Transmission-Policy-Green-Paper-2023.pdf> ["**Green Paper**"].

[122] Section 16 currently requires the AESO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

Alberta's "intent to develop additional interties with its neighboring provincial and state jurisdictions and clarify how these developments may fit into the broader planning of the Alberta interconnect electricity system."[123] Despite the longstanding requirement in the *Transmission Regulation* to restore the Alberta-British Columbia intertie to its path rating, it is currently operating far below this level. In its response to the Green Paper, the AESO has concurred that clarification regarding the volumes and timing targets for restoring existing intertie capacity will "enhance the AESO's ability to move more quickly towards solutions."[124]

In the *Draft CERs* consultation, Saskatchewan also stated that the RIAS modelling inaccurately assumed a barrier-free exchange of electricity between provinces, and that Manitoba would be a key partner in Saskatchewan's transition. Saskatchewan called these assumptions flawed due to differing provincial electricity market structures; differing domestic priorities and export commitments; and inadequate interprovincial transmission capacity.[125] Nonetheless, Saskatchewan has identified that its decarbonization pathway includes adding at least 1,000 MW of low or non-emitting imports and expanded regional transmission interconnections to facilitate imports.[126] However, Saskatchewan is not planning to rely solely on domestic trade. The province is planning a new international line to increase interconnection capacity between Saskatchewan and the Southwest Power Pool[127] and in the fall of 2023 issued a request for supply proposals for

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[123] Green Paper, *supra* note 121 at PDF 22.

[124] Alberta Electric System Operator, "AESO Comments on Transmission Policy Review" (November 30, 2023) at PDF 4, online (pdf): <aesoengage.aeso.ca/37884/widgets/156642/documents/125519#:~:text=The%20AESO's%20Recommendation&text=A%20move%20away%20from%20a,transforming%20nature%20of%20Alberta's%20grid.>.

[125] Crown Investments Corporation of Saskatchewan, "SK Technical Appendix Clean Electricity Regulations" (2 November 2023) at PDF 16, online (pdf): <saskatchewan.ca/government/news-and-media/2023/november/21/saskatchewan-responds-to-unaffordable-unconstitutional-and-unattainable-proposed-federal-clean-elect> ["**SK Technical Appendix**"].

[126] SaskPower Response Appendix, *supra* note 31 at PDF 8.

[127] Southwest Power Pool is a regional transmission organization ("**RTO**") regulated by the Federal Energy Regulatory Commission (FERC) and is responsible for coordinating the reliability of the transmission system and balancing electric supply and demand in its area of the Eastern Interconnection in the United States. It has members in 14

up to 500 MW of power through the Southwest Power Pool. [128]

The conflict between differing provincial domestic priorities and export commitments is also apparent in a complaint brought by NorthPoint Energy Solutions Inc. ("**NorthPoint**"), a wholly owned subsidiary of SaskPower, currently before the Canada Energy Regulator.[129] The complaint alleges that Manitoba Hydro-Electric Board ("**Manitoba Hydro**") has not granted fair market access to electricity available for export ("**FMA**") as required by a 2015 electricity export permit, which includes a condition essentially requiring Manitoba Hydro to inform Canadian purchasers of the quantities and classes of electricity available for sale and an opportunity to purchase electricity on terms and conditions as favourable as the terms and conditions which apply to the proposed exports. [130] The Complaint alleges that Manitoba Hydro has not allowed North Point to purchase power on terms equivalent to its exports and, as a result, SaskPower must run its fossil fuel generation or purchase, through NorthPoint, surplus fossil fuel-generated energy from Alberta or the United States.[131] In its complaint, NorthPoint requests that the Canada Energy Regulator direct Manitoba Hydro to provide FMA to NorthPoint or suspend or revoke Permit EPE-404.[132] This proceeding is currently ongoing but nonetheless demonstrates the interprovincial tensions that may arise regarding domestic electricity trade.

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states: Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming.

[128] SaskPower, "Southwest Power Pool Project", online: <saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Planning-and-Construction-Projects/Southwest-Power-Pool-Project>.

[129] See *Canadian Energy Regulator Act,* SC 2019, c 28, s 10 ["***CER Act***"] where, Part 7 states that the Canada Energy Regulator regulates the export of electricity outside of Canada. Further under section 355 of the *CER Act*, it is prohibited to export electricity except in accordance with a permit or license from the Canada Energy Regulator.

[130] National Energy Board, "Permit EPE-404" (30 July 2015) (Filing ID: A4R8S4) at PDF 3-4, online (pdf): <apps.cer-rec.gc.ca/REGDOCS/File/Download/2809333>.

[131] Affidavit of Dean Jones in Support of NorthPoint Complaint (2 November 2023) (Filing ID: C27205-3) at PDF 3, online: <apps.cer-rec.gc.ca/REGDOCS/File/Download/4416868> ["***Jones Affidavit***"].

[132] NorthPoint Energy Solutions, "NorthPoint Complaint against Manitoba Hydro Denial of FMA EPE-404" (10 November 2023) (Filing ID: C2705-2) at PDF 6, online (pdf): <apps.cer-rec.gc.ca/REGDOCS/File/Download/4416867>.

Recent policy decisions by Nova Scotia provides another example of canceled or deferred regional cooperation on electricity supply. In the fall of 2023, Nova Scotia abandoned the Atlantic Loop – referred to as the Eastern Clean Energy Initiative – which would have run more than 1,000 kilometres of transmission line from Quebec into New Brunswick and on to Nova Scotia to supply hydro electric energy from Quebec. However, in its fall 2023 Clean Energy Plan, the Nova Scotia Government indicated that the project was no longer viable in light of ballooning costs, Quebec confirming that it does not have firm energy available for sale to meet Nova Scotia's winter peak needs, supply chain challenges and because "investing in our energy resources avoids Nova Scotian's having to spend billions on infrastructure in Quebec and New Brunswick."[133]

The RIAS's hopes of encouraging more sharing of electricity among provinces to decarbonize power grids is far from certain. Infrastructure needed for increased domestic trade is lacking, and projects to build new or increase intertie capacity are expensive and may compete with other provincial policy objectives. Further, with the prospect of jurisdictions with largely non-emitting generation supply also facing shortages, firm commitments to interprovincial trade may not align with domestic policy objectives. However, where surplus electricity is exported to the United States, the added pressure of the *Draft CERs* may subject exports to additional scrutiny and potentially objections.

VI. The Need for Alignment Between Government Climate Policy and Regulators

The *Draft CERs* and the RIAS do not address changes that may be required for provincial regulatory regimes to achieve its 2035 net-zero objectives. In its Interim Report, the Canada Electricity Advisory Council[134] identified that while several provinces and territories have set

[133] Nova Scotia's 2030 Clean Power Plan, *supra* note 85 at PDF 6.

[134] The Canada Electricity Advisory Council is an independent, electricity-sector focussed, expert advisory body that provides advice to the Minister of Energy and Natural Resources to accelerate investment, and promote sustainable, affordable, and reliable electricity systems: Government of Canada, "The Canada Electricity

emissions reduction goals, these have not yet been consistently translated as a specific objective to utility and regulator mandates. The Interim report states that aligning regulator and Crown mandates, and providing clearer policy direction, is essential for providing greater certainty to markets; enabling clear, optimized long-term planning; attracting sufficient and competitive capital; and ensuring a reasonably predictable and timely approvals process. [135] The Interim Report identifies "the need to add a vital pillar – the attainment of climate goals – to the existing pillars of reliability and affordability (just and reasonable rates) that currently govern the mandates of utility regulators, system operators, and Crown utilities across Canada."[136] The tension between emission reductions and regulation has been playing out in several jurisdictions in Canada, with varying results.

A recent Ontario Energy Board ("**OEB**") decision is another example of misalignment between government policy and utility regulation. In 2022, Enbridge Gas Inc. ("**Enbridge**") filed an application with the OEB seeking approval of proposed changes to the rates Enbridge charges for natural gas distribution, transportation and storage as of January 1, 2024. The OEB raised concerns regarding energy transition in its decision,[137] despite Enbridge's submission of an Energy Transition Plan, on the basis that Enbridge had not met the onus to demonstrate that its proposed capital spending plan was prudent "and that it has accounted appropriately for the risk arising from the energy transition."[138] The OEB found Enbridge's Energy Transition Plan to be unreasonable because it assumed that new housing developments would include gas connections that would

Advisory Council" (22 May 2024) online: <natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/electricity-infrastructure/the-canada-electricity-advisory-council/25297>.

[135] CEAC Interim Report, *supra* note 118 at PDF 8.

[136] *Ibid*.

[137] Ontario Energy Board, "Decision and Order – EB-2022-0200 – Enbridge Gas Inc. Application for 2024 Rates – Phase 1" (21 December 2023) at PDF 21-25, online: < rds.oeb.ca/CMWebDrawer/Record/827754/File/document>.

[138] *Ibid* at PDF 22.

remain in service for 40 years.[139] Therefore, the OEB determined that for new connections for natural gas service, rather than a 40-year revenue horizon to calculate the upfront capital costs, as historically had been the case, the recovery horizon should be 0 years, effectively directing that 100% of the connection costs would be paid upfront. In rendering its decision, the OEB concluded that energy transition poses a risk that assets used to serve existing and new gas customers would become stranded (i.e., retired before the end of their useful life and before all capital costs could be recovered).[140] Enbridge has appealed and sought review of the OEB's determination, arguing among other things that the OEB erred in the decision by not implementing and conflicting with Ontario energy policy, contrary to its statutory objectives.[141]

Additionally, in response to the OEB decision, the Government of Ontario stepped in and recently passed legislation essentially over-turning the OEB's decision. The *Keeping Energy Costs Down Act, 2024*, amends the *Ontario Energy Board Act, 1988* to permit revenue horizons to be set by regulations made under the Act. "Revenue horizon" is proposed to be defined as the number of years of presumed revenue that is used in determining the economic feasibly of a new consumer connection to a natural gas distribution system and the corresponding contribution in aid of construction collected from the consumer.[142] The amendments also provide authority for regulations to be made that require the OEB to hold a hearing to determine revenue horizons.[143] The government has stated it intends to immediately introduce regulations to reset the revenue

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[139] *Ibid* at PDF 37.
[140] *Ibid* at PDF 52.
[141] Enbridge Gas Inc., "Notice of Motion" (29 January 2024) (EB-2024-0078), online: <rds.oeb.ca/CMWebDrawer/Record/833980/File/document>.
[142] Bill 165, *Keeping Energy Costs Down Act, 2024,* 1st Session, 43rd Legislature, Ontario, 2 Charles III, 2024, online (pdf): <ola.org/sites/default/files/node-files/bill/document/pdf/2024/2024-05/b165ra_e.pdf> ["**Bill 165**"]. Note that Bill 165 received Royal Ascent on May 16, 2024.
[143] *Ibid.*

horizon for natural gas connection costs to 40 years.[144]

On the other hand, a recent decision by the Ontario Court of Appeal highlights that Courts are willing to recognize policy goals as valid regulatory objectives. In *National Steel Car Limited v IESO*,[145] National Steel Car Limited ("**NSCL**") challenged the constitutionality of the electricity charges attributable to the Ontario Government's feed-in-tariff renewable electricity procurement program ("**FIT Program**") under which suppliers of renewable energy were paid under long-term, fixed price contracts to "feed in" energy into Ontario's electricity grid.[146] As a result of the FIT program, the cost of electricity (in the form of Ontario's "Global Adjustment" charge established by regulation) increased substantially for large industrial users of electricity such as NSCL.[147] NSCL challenged the FIT Program on the basis that it was a tax — not a valid regulatory charge — that was not passed by the legislature. NSCL contended that it served no regulatory purpose other than to provide economic stimulus.[148] The application judge found the FIT Program was a valid regulatory charge related to the regulation of electricity even though it might also provide economic stimulus.[149] The Ontario Court of Appeal agreed, noting that "[t]he record revealed a Provincial Government working towards the regulatory purpose of increasing and incentivizing renewable electricity generation in Ontario."[150]

Legislation in British Columbia avoids doubt and includes provisions providing direction and alignment between Crown policy and regulation by the British Columbia Utilities Commission ("**BCUC**"). Unlike the legislative framework in Ontario, section 46(3.1) of the *Utilities*

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144 Government of Ontario, "Backgrounder: The Keeping Energy Costs Down Act" (22 February 2024), online: <news.ontario.ca/en/backgrounder/1004216/the-keeping-energy-costs-down-act>.
145 2024 ONCA 265 ["***National Steel***"].
146 *Ibid* at para 1.
147 *Ibid* at para 2.
148 *Ibid* at paras 63-64.
149 *Ibid* at paras 66.
150 *Ibid* at para 119.

Commission Act[151] requires that the BCUC consider "the applicable of British Columbia's energy objectives" in determining whether to issue a Certificate of Public Convenience and Necessity ("**CPCN**") (enabling rate regulatory cost recovery for a particular undertaking). Section 2 of the *Clean Energy Act*[152] sets out British Columbia's energy objectives, which among other things, include: to reduce greenhouse gas emissions and to encourage the switching from one kind of energy source or use to another that decreases GHG emissions. FortisBC Energy ("**FortisBC**") filed an the application for a CPCN for the Okanagan Capacity Upgrade Project ("**Project**")[153] on the basis that an increase in its pipeline capacity was necessary due to the increase of the populations of Kelowna, Penticton, and the surrounding Okanagan area.[154] The proposed 30km natural gas pipeline, and associated facilities, was estimated to cost $327.410 million.[155] The BCUC denied FortisBC's application.[156] The BCUC agreed that demand for natural gas was increasing and the potential shortfall needed to be addressed.[157] However, the Panel noted that FortisBC's forecast did not account for the potential flattening demand as a result of the Province's CleanBC Roadmap, which commits to requiring increasingly stringent emission requirements for new buildings in 2024 and 2027 and by 2030 for all new buildings to be zero carbon. For these reasons, the BCUC denied the Project as public necessity was not proven and the expenditure was too great to justify the Project. Instead, the BCUC directed FortisBC to address the potential energy shortfall with short-term mitigation solutions to be filed by July 31, 2024.

The British Columbia legislation's express recognition that BCUC, as a utility regulator, must

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[151] RSBC 1996, c 473.
[152] SBC 2010, c 22.
[153] British Columbia Utilities Commission, *"*Fortis Energy Inc. Application for Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project – Decision and Order G-361-23*"* (22 December 2023) at PDF 3, online(pdf): <www.ordersdecisions.bcuc.com/bcuc/decisions/en/522057/1/document.do>.
[154] *Ibid.*
[155] *Ibid* at page 2.
[156] *Ibid* at page 26.
[157] *Ibid*.

consider emissions reductions and climate goals in executing its mandate, is similar to regulatory changes proposed in Nova Scotia. The NS Task Force Report[158] recommended that the legislative include provisions that clarify utility regulator purpose and objectives to provide "the flexibility it needs to accommodate approaches in rate setting, appropriate to implement government's policy objectives."[159] This recommendation was carried forward to the new *Energy and Regulatory Boards Act*[160] and the *More Access to Energy Act,*[161] created under the *NS ERA 2024.* The *Energy and Regulatory Boards Act* creates the Nova Scotia Energy Board and states that, in setting rates or approving capital projects, the Board must consider, among other things, whether the application supports "sustainable development and sustainable prosperity" and other matters consistent with the purposes of the *More Access to Energy Act*.[162] One of the purposes of the *More Access to Energy Act* is to "support the sustainable development, sustainable prosperity, energy efficiency and greenhouse gas emissions reduction goals of the Province articulated in the *Environmental Goals and Climate Change Reduction Act*.[163]"[164]

Given the potential for conflict to arise between traditional utility regulation principles, such as affordability and the lowest cost option and treatment of stranded costs, where regulated entities are making investments or retiring assets early to achieve government policy objectives, clear legislative guidance will be needed to ensure regulatory review and cost recovery related to such actions aligns with these objectives. Given the potential for lack of alignment between regulators and government policy, it is anticipated that governments will increasingly be mandating

[158] NS Task Force Report, *supra* note 87.
[159] *Ibid* at PDF 45.
[160] SNS 2024, c 2, Sch A ["***ERB Act***"].
[161] SNS. 2024, c 2, Sch B ["***MAE Act***"].
[162] *ERB Act*, *supra* note 160, s 4.
[163] SNS 2021, c 20. This Act contains 28 goals that are intended to reduce greenhouse gas emissions, grow the green and circular economies, improve the health and sustainability of Nova Scotia's environment, and move to clean and renewable energy.
[164] *MAE Act*, *supra* note 161, s 2(e).

alignment through legislative changes or other legislatively enabled measures.

VII. Reactions and Initiatives to Address Affordability and Customer Choice

Of critical importance to customers is affordability. However, utilities and independent power producers that invest in cleaner sources of electricity generation to facilitate compliance with the *Draft CERs* can be expected to seek a return of and on their investment through customer rates, long-term contracted rates with government, private off-taker agreements or long-term market prices (as applicable). The Federal Government has indicated it expects higher incremental increases to residential, commercial, and industrial electricity rates in provinces more reliant on electricity generated using fossil fuel.[165] Multiple parties raised affordability concerns in their submissions on the *Draft CERs*. For example, SaskPower estimates that residential, commercial and industrial electricity rates in Saskatchewan will more than double by 2035 to cover the costs associated with the *Draft CERs* and federal coal regulations, costing Saskatchewan approximately $40 billion from now until 2035.[166] The AESO concluded in its June 2022 Net Zero Emissions Pathways Report that achieving net zero by 2035 would require a 30-36% ($44 to $52 billion) increase in generation capital investments, generation operating costs and transmission system revenue requirements from 2022-2041.[167] The implications of the *Draft CERs* come at a time when jurisdictions are already grappling with supply adequacy, affordability and decarbonization issues, and assessing how to allocate the costs of electricity and related infrastructure amongst customers and market participants. In turn, customers are seeking greater flexibility in meeting their

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[165] RIAS, *supra* note 11 at 2786.

[166] Government of Saskatchewan, "Saskatchewan Responds To Unaffordable, Unconstitutional And Unattainable Proposed Federal Clean Electricity Regulations" (21 November 2023) online: < saskatchewan.ca/government/news-and-media/2023/november/21/saskatchewan-responds-to-unaffordable-unconstitutional-and-unattainable-proposed-federal-clean-elect>.

[167] Alberta Electric System Operator, "Net Zero Emissions Pathways Report" (June 2022) at PDF 9, online (pdf): < www.aeso.ca/assets/Uploads/net-zero/AESO-Net-Zero-Emissions-Pathways-Report.pdf>.

electricity demands.

A. Who pays for what?

In its submissions on the *Draft CERs*, the Alberta Government submitted that despite the scale of infrastructure needed to achieve a net-zero grid, the Federal Government has "not identified sufficient funding support to enable the transition"[168] and called for federal funding commensurate with the *Draft CERs*' impact on Alberta.[169] Similarly, the Saskatchewan Government submitted that the cost to comply with the *Draft CERs* should be shared by the national tax base rather than exclusively by the provincial rate base.[170]

The RIAS states that the Federal Government has committed more than $50B to help decarbonize the electricity sector, which can help reduce the impact on rates, especially in Atlantic Canada and the Prairies.[171] One such measure Federal Government has announced is the proposed clean electricity investment tax credit ("**Clean Electricity ITC**"). The Clean Electricity ITC would be available to taxable and tax-exempt entities investing in clean energy equipment, such as: non-emitting electricity generation; natural gas generation with CCS; electricity storage; and interprovincial transmission infrastructure.[172] Provincial and territorial Crown corporations will only be eligible for the Clean Electricity ITC if they are located in a jurisdiction that publicly commits to work towards a net-zero electricity grid by 2035 and to pass through the value of the Clean Energy ITC to electricity ratepayers to reduce energy bills.[173]

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[168] GoA Technical Submissions, *supra* note 120 at PDF 19.
[169] *Ibid*.
[170] SaskPower, Letter to Hon. Steven Guilbeault, re: Proposed Clean Electricity Regulations – Canada Gazette, Part I (2 November 2023) at PDF 4, online (pdf): <saskatchewan.ca/government/news-and-media/2023/november/21/saskatchewan-responds-to-unaffordable-unconstitutional-and-unattainable-proposed-federal-clean-elect> ["**SaskPower Response Letter**"].
[171] RIAS, *supra* note 11 at 2812.
[172] Government of Canada, "Budget 2024: Fairness for Every Generation" (April 16, 2024) at PDF 200, online (pdf): <budget.canada.ca/2024/report-rapport/budget-2024.pdf>.
[173] *Ibid.*

Even absent the impact of the *Draft CERs,* greater government intervention in setting customer rates and electricity pricing can be anticipated in the pursuit of affordability in an era of energy transition and increased electrification. For example, throughout its electricity market review, the Alberta government has been keenly focused on affordability. In March 2024, following receipt of the MSA and the AESO market review reports, the Alberta government announced interim regulatory changes to address perceived concerns regarding high electricity prices. The *Market Power Mitigation Regulation*[174] is intended to address economic withholding[175] by implementing a secondary offer cap that limits the offer price[176] of natural gas generating units owned by large generators in the event that net revenues cross a predefined threshold in a given month.[177] The secondary offer cap remains in effect until the first day of the following month and does not apply to generators that use renewable energy sources, or any market participant with less than 5% of total maximum capability of energy generating units in Alberta.[178] The regulation does not impose a *price* cap of $125 MWh. Other suppliers remain free to submit higher offers and if dispatched, set the system marginal price.

The *Supply Cushion Regulation* ("***SCR***")[179] is a complementary measure intended to ensure reliability and to the curb exercise of market power where long lead assets are deliberately left offline during periods of high prices.[180] The *SCR* requires the AESO to issue directives to certain

[174] Alta Reg 43/2024 ["***MPMR***"].
[175] Under the current Alberta EOM framework, generators cannot physically withhold available generation capacity from the market and must offer their entire capability to the market. However, economic withholding by pricing energy above marginal cost is permitted. This is intended to allow generators to raise the energy price above marginal cost to ensure they earn the necessary return of and on capital investment.
[176] *MPMR*, *supra* note 174, s 3(6), the offer limit is 25 times the day ahead gas price or $125/MWh.
[177] *Ibid,* ss 1(1)(g), 3(1)-(4), Schedule. The predefined revenue threshold is equivalent to 1/6 of the annualized unavoidable capital investment costs and fixed operating costs of the reference generating unit. The reference generating unit is premised on combined cycle natural gas generating unit with a net generating capacity of 418 MW.
[178] *Ibid*, s 4.
[179] Alta Reg 42/2024 ["*SCR*"]. Both regulations expire in November 2027 unless extended by the Minister.
[180] A generator that requires more than one hour to start (synchronize to the interconnected electric system) is allowed to go on long lead time status if it goes offline. See Alberta Electric System Operator, "ISO Rules – Part 200

long lead time assets to come online or stay online when the supply cushion is calculated to be below a specified threshold of 932 MW.[181] The AESO must determine the order of directives according to relative economic merit and physical constraints, and the owner is guaranteed recovery of its costs for operating up to a minimum level.[182] The AESO is currently developing rules to implement the *SCR* by July 1, 2024. Whether these measures achieve their intended objectives, and what their impacts on the operation of the EOM and investment in Alberta, remains to be seen.

In addition to their impact on the cost of electricity generated, the *Draft CERs* and the transition to low-emitting generation will have other costs impacts that need to be accounted for and funded. Two significant categories of potential costs are the early retirement of emitting generation, and significant investments in transmission and distribution infrastructure to connect new generation and support electrification.

The RIAS forecasts that only 9% of regulated units would retire earlier than otherwise in the absence of the *Draft CERs*, on the assumption that units would implement CCS or operate under the exemption for peaking units.[183] The Saskatchewan Government has said this forecast is significantly underestimated due to uncertainty regarding cost and availability of CCS for gas-fired units.[184] Regardless of the quantum of early retirements, there may be significant unrecovered costs if generating units are retired before the end of their useful lives.

Recent consideration of the retirement of coal-fired assets in Nova Scotia by the Nova Scotia

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Markets – Division 202 Dispatching the Markets – Section 202.4 Managing Long Lead Time Assets" (31 March 2023), online: <aeso.ca/rules-standards-and-tariff/iso-rules/section-202-4-managing-long-lead-time-assets/>.

[181] *SCR, supra* note 179, ss 1(1)(i), 4, 5(1).

[182] *Ibid*, ss 5(1), 7(1).

[183] As discussed above, the *Draft CERs* propose an exemption allowing such units to operate subject to a 150 kt/yr emissions limit and maximum hour duration of 450h/yr. RIAS, *supra* note 11 at 2772.

[184] SK Technical Appendix, *supra* note 125 at PDF 16.

Utility and Review Board ("**NS URB**") is illustrative of the potential rate implications of early asset retirement. NS Power expects it will have to retire coal-fired assets and associated infrastructure by 2030 due to its legal decarbonization obligations, prior to fully recovering its investment in these assets or its decommission costs in rates. The undepreciated costs associated with these early retirements may be as much as $750 million.[185] Seeking approval to accelerate the recovery of depreciation expense (i.e., recovery of its remaining capital investment) and decommissioning costs over the years of operation remaining to 2030 would cause a substantial increase in rates.[186] Therefore, NS Power proposed, and the NS URB approved with some changes, the transfer of these costs to a regulatory asset account (the Decarbonization Deferral Account ("**DDA**")) to facilitate rate stability and affordability for customers.[187] The NS URB found that the transfer of the costs to the DDA would allow flexibility around the timing of the recovery of the costs[188] and stated:

> To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.[189]

As is evident from the foregoing, absent government funding and in the pursuit of affordability, regulators may need to consider novel and flexible approaches to address the financial impacts of early retirements and other energy-transition costs while ensuring utilities have an opportunity to recover the return of and on their investment.

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[185] NS Task Force Report, *supra* note 87 at PDF 49.

[186] Nova Scotia Utility and Review Board Decision regarding an Application by Nova Scotia Power Incorporated for Approval of a Decarbonization Deferral Account (2024 NSUARB 67) at PDF 4, online (pdf): <nsuarb.novascotia.ca/sites/default/files/NSUARB%20Board%20Decision%20-%20Nova%20Scotia%20Power%20Incoporated%20-%20M11067.pdf>.

[187] *Ibid* at PDF 6-7.

[188] *Ibid* at PDF 9.

[189] *Ibid* at PDF 4.

While the *Draft CERs* highlight the need to invest in new generation, an equally important consideration in an era of increased electrification and changing generation supply mix is the need for operational reliability and investments in transmission and distribution infrastructure. Various stakeholders criticized the RIAS as underestimating the cost of implementing the *Draft CERs* because it did not include additional infrastructure costs, such as added grid support (ancillary services cost based on increasing renewables) and other added costs beyond generation (i.e., increasing transmission costs).[190]

Accommodating new supply with different attributes and increases in load will require significant investments in expanding and modernizing the electricity system and improving grid resiliency and reliability. In addition, investments are needed to harden assets against severe weather events, and other increasing climate related risks such as wildfire, to strengthen system reliability. Although less than projected generation investment, the AESO's Net Zero report projects that over the 2022-2041 timeframe, to achieve net-zero by 2035 the incremental cost in utility rates for incremental transmission infrastructure would be between $300 million to $4.3 billion (depending on the generation supply scenario).[191] Similarly, other Canadian jurisdictions have identified the need for significant investments in transmission infrastructure to connect new generation and in distribution systems.[192]

The magnitude of these investments may require reconsideration of how such costs are most fairly recovered. In Alberta, the *Transmission Regulation*[193] currently allocates the majority of the cost

[190] Electricity Canada Response, *supra* note 41 at PDF 7; SK Technical Appendix, *supra* note 125 at PDF 16.
[191] AESO Net Zero Report, *supra* note 91 at PDF 9.
[192] For example, in British Columbia, BC Hydro recently released its 10-Year Capital plan which includes $21 billion of investments in existing assets and $5 billion to support electrification of residential, industrial and transportation sectors. See BC Hydro, "Power Pathway: Building B.C.'s energy future" (January 2024) at PDF 3, online (pdf): <bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/capital-plan/capital-plan-2024.pdf>.
[193] *Transmission Regulation*, Alta Reg 86/2007 ["***Transmission Regulation***"].

of transmission infrastructure to load, which are recovered through the AESO tariff.[194] Among other things, this was intended to encourage investment in generation with the freedom to locate in areas to maximize access to resources.[195] However, with changes in generation supply mix, this policy is under review. As noted above, the Alberta Government has released a Green Paper on transmission policy, and is reviewing the allocation of transmission costs to introduce locational signals and allocate transmission costs based on causation.[196] Options under consideration include the creation of transmission rights, splitting transmission costs more equally between generation and load, and redefining system costs to allocate more costs to generation during the connection process.[197] The AESO has stated that it favours changes to the current cost allocation to require generating unit owners to pay more to reflect the impact on system costs.[198] The allocation of electricity infrastructure costs is a complex issue with no easy answer.[199] Nonetheless, if new allocations for transmission costs are adopted, generating unit owners will need to consider the added cost of transmission in project economics, adding to the complexity of investment decisions at a time when significantly more generation supply will be needed in Alberta.

In adopting legislative changes to address the cost ramifications of the energy transition, governments need to strike an appropriate balance between affordability measures, decarbonization goals and ensuring regulated utilities maintain an opportunity to earn a fair return.

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[194] *Electric Utilities Act*, SA 2003, c E-5.1, s 30 ["***EUA***"]; *Transmission Regulation*, *supra* note 193, s 47. The costs of local connection of a generator to the transmission system, the cost of line losses, the generator unit owner's contribution (which is refundable) are currently the exceptions to the load-pays policy, with all other transmission costs assigned to load.

[195] Green Paper, *supra* note 121 at PDF 16.

[196] *Ibid* at PDF 18.

[197] *Ibid.*

[198] Alberta Electric System Operator, Letter to Deputy Minister re AESO Comments on Transmission Policy Review (30 November 2023), online (pdf): <aesoengage.aeso.ca/37884/widgets/156642/documents/125519>.

[199] See for example, Alberta Utilities Commission, "Decision 26911-D01-2022: Alberta Electric System Operator re Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application" (10 November 2022), where after a lengthy hearing, the AUC rejected a rate design proposal by the AESO that would have reallocated transmission costs amongst load customers.

Recent legislation introduced in Nova Scotia demonstrates the potential pitfalls of impeding a regulator's ability to set just and reasonable rates. In late 2022, the Nova Scotia Legislature passed Bill No. 212,[200] which amended the Nova Scotia's *Public Utilities Act* ("***NS PUA***")[201] to restrict rate increases for NS Power. Bill No. 212 was introduced during NS Power's 2022-2024 general rate application proceeding, in which the utility had applied for average smoothed rate increases of 3.6%, and was passed prior to the NS URB being able to issue its decision on the application.[202] Bill No. 212 capped net rate increases for NS Power, across all rate classes in 2022, 2023 and 2024 at 1.8% with limited exceptions.[203] Following the adoption of Bill 212, NS Power incurred two credit rating downgrades, which NS Power stated had a material impact on the company's ability to finance its operations, provide affordable rates and invest in capital.[204]

B. Customer Choice

In addition to affordability considerations that may be implemented directly through government or regulatory action, in the context of the energy transition, consumers are also looking for greater flexibility in meeting their energy needs, whether for policy preference or affordability reasons. In this context, the following are some examples of provincial initiatives aimed at providing industrial consumers with greater choice in sourcing electrical energy.

In Alberta, a particular focus over recent years has been the ability of consumers to self-supply and export electricity, pursuant to which a consumer may generate electricity for its own "behind the fence" use and export excess electricity to the grid. After a review by the AUC in 2020 and

[200] SNS 2022, c 52.
[201] RSNS 1989, c 380 ["***NS PUA***"].
[202] *Nova Scotia Power Inc (Re)*, 2023 NSUARB 12, at PDF 6, online (pdf): <nsuarb.novascotia.ca/sites/default/files/M10431%20Decision%20Nova%20Scotia%20Power%202022.pdf> ["***NSP 2022-2024 GTA Decision***"].
[203] *NS PUA*, *supra* note 200, s 64A(3).
[204] NS Task Force Report, *supra* note 87 at PDF 71.

draft legislation being tabled in 2021, on March 6, 2024, the Government of Alberta proclaimed in force the *Electricity Statues (Modernizing Alberta's Electricity Grid) Amendment Act* (the "***ESAA***").[205] Among other things, the *ESAA* amends the *Electric Utilities Act* ("***EUA***")[206] to expressly permit self-supply and export. The amendments to the EUA exempt the portion of electric energy produced by a generating unit that is "self-supply" from application of the *EUA* if the portion of the electricity that is "self-supply" is produced on a property of which a person is the owner or a tenant and is consumed on that same property by that owner or tenant.[207] However, such self-suppliers still may be subject to the payment of rates to recover a "just and reasonable share of the costs associated with the transmission system."[208] While this is a welcome clarification of electric policy in Alberta, as discussed above, if the *Draft CERs* are passed, industrial consumers with large on-site generation will be subject to the prescribed emissions limit if they have net exports of electricity to the grid.

In Saskatchewan, the provincial Government's recently announced Renewable Access Service ("**RAS"**) demonstrates regulatory change directed at emissions reduction in the electricity sector while facilitating customer choice. SaskPower, a vertically integrated government-owned utility has the exclusive right to supply, transmit, distribute and sell electricity in Saskatchewan under the *The Power Corporation Act* ("***PCA*"**).[209] However, under the *PCA*, SaskPower may consent to the supply, transmission, distribution or sale of electric energy by or to another person on any terms and conditions SaskPower deems advisable.[210] The RAS permits large commercial and industrial customers to negotiate a Power Purchase Agreement ("**PPA**") with an independent power producer

[205] SA 2022, c 8.
[206] *EUA, supra* note 194.
[207] *Ibid.,* ss 1(1)(vv.1), 2(1)(b)
[208] *Ibid.,* ss 2(1)(b), 122(2)(b).
[209] RSS 1978, c P-19, ss 2, 3(3), 38(1). Although the exclusive right is subject to the area not having supply by an entity other than SaskPower prior to January 1, 1958.
[210] *Ibid.*, s 38(2).

("**IPP**") of their choice and allows a qualifying renewable energy project to be developed for the purpose of supplying clean electricity. SaskPower operates as the wheeling agent, moving the power from the IPP's renewable generation site to the customer's site.[211] While currently limited in scope, the RAS provides optionality to consumers in sourcing electricity and may encourage the development of renewable energy generation.

In a similar vein, on November 2, 2023, the Ontario government opened a consultation regarding amendments to the global adjustment ("**GA**") charge that Ontario's large commercial electricity consumers must pay to fund the cost of non-wholesale market electricity contracts.[212] The GA fees currently represent a substantial portion of the electricity commodity cost in Ontario. If adopted, the proposed amendments to the GA are designed to expand customer choice by enabling large commercial loads to reduce their GA costs by entering into virtual PPAs with renewable generation facilities – similar to a virtual net metering arrangement – allowing such large loads to offset their facility's demand in the top five peak hours of a base period through the qualifying PPA with renewable generation. Eligible technologies for such corporate PPAs may include wind, solar, hydroelectric and biofuel. The consultation is ongoing with a proposed effective date of May 1, 2025.[213] While still subject to considerable uncertainty as to scope and mechanics, the consultation is a limited step towards allowing access to non-emitting electricity supplies for large customers and providing businesses with more choice to meet their energy needs.

VIII. Conclusion

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[211] SaskPower, "Renewable Access Service", online: <saskpower.com/Our-Power-Future/Our-Electricity/Connecting-to-the-Power-Grid/Using-SaskPower-Transmission-Lines/~/link.aspx?_id=41D7D56757CC4327B0C125BBE969E119&_z=z>

[212] *Adjustments Under Section 25.33 of the Electricity Act, 1998*, O Reg 429/04; Amendments Related to the Treatment of Corporate Power Purchase Agreements, O Reg 429/04.

[213] Government of Ontario, "Ontario Regulation 429/04 Amendments Related to the Treatment of Corporate Power Purchase Agreements", online: <ero.ontario.ca/notice/019-8666>.

A consistent thread that manifests itself through the various Federal and provincial initiatives described in this paper is the complexity in balancing competing objectives - the irreversible drive towards electrification, affordability and reliability – are made more complex in some jurisdictions by the *Draft CERs'* ambition to achieve decarbonization of the energy grid in an abbreviated time frame. The *Draft CERs* are posited on the Federal Government's conviction that the latter is the more urgent and overriding goal, while the provinces are unsurprisingly focused on the imperative of ensuring reliability and affordability for their residents through the various policies described herein. These complexities are the reality of the diverse supply models and electricity frameworks across the country, which render a one-size-fits-all approach unworkable.

As we have described, supply adequacy is not just a challenge for provinces which currently rely on emitting sources of generation, as all provinces will need to grow their supply to meet future demand. To meet what is anticipated to be an exponential increase in demand, jurisdictions faced with not only increasing supply but also replacing emitting generation in the proposed timeframe will require unprecedented investment, regulatory efficiency, and political will.

While measures such as the Clean Electricity ITC may attract needed investment by mitigating up-front capital costs to an extent, the *Draft CERs* also come at a time when a critical concern for all stakeholders, and elected governments across the country, is whether this infrastructure can be built in sufficient time and at costs that maintain affordability for consumers. As we note, utilities and independent power producers that invest in cleaner sources of electricity generation to facilitate compliance with the *Draft CERs* can be reasonably expected to seek a return of and on their investment. We anticipate the inevitably corresponding rise in rates for residential, commercial, and industrial consumers to prompt greater government intervention in electricity pricing.

If promulgated in their current form, the *Draft CERs* appear poised to collide with provincial policies – such those in Saskatchewan and Alberta – that have declared a current intent to continue to rely on natural-gas generation. Leaving aside whether the Federal Government has the authority to regulate electricity emissions as contemplated by the *Draft CERs*, federal policy should embed sufficient flexibility to accommodate provincial differences. The Canadian electricity sector is in a state of flux, and federal and provincial policies will continue to play a pivotal role in shaping the future of generation investments and the pace of increased electricity demand. While many provinces are grappling with the same challenge – the complexity of balancing the goals of sustainable, affordable, and reliable electricity – solutions will necessarily vary by jurisdiction and resist a one-size-fits-all approach. However, one commonality is that adherence to the *status quo* will not be sufficient. Regulators and governments will need to adopt novel and flexible approaches reconcile these occasionally competing demands to deliver a balanced, realistic, and well-designed roadmap for the electricity sector.