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Karishma Boroowa
Director, Electricity and Combustion Division
Environment and Climate Change Canada
351 Saint-Joseph Boulevard, Gatineau, Quebec, K1A 0H3
(email: ECD-DEC@ec.gc.ca)

Re: **AESO Comments on the Canada Gazette, Part 1, Volume 157, Number 33: Clean Electricity Regulations**

The Alberta Electric System Operator (AESO) appreciates the opportunity to comment on the current preliminary framework of the Clean Electricity Regulations (CER).

The AESO has a public interest mandate to ensure the safe, reliable, economic operation of the Alberta electricity system. The AESO's core accountabilities include planning and managing operation of the grid 24 hours a day, ensuring Albertans have power when they need it; facilitating Alberta's competitive electricity market; planning the future of the transmission system and its infrastructure; and ensuring generators and large power consumers can connect to the system in a safe and reliable manner. Given its broad-based accountabilities, the AESO is uniquely positioned to assess the strength, stability, and reliability of Alberta's power system through time.

Alberta's grid is already transforming. Significant emissions reductions have been enabled by phasing out coal-fired generation while, in parallel, over 8,000 MW¹ of zero-emission wind and solar generation have been integrated into the system. Further increasing penetrations of intermittent renewable generation are being driven by carbon policy and reductions in technology costs, and traditional firm generation assets are shifting operations or retiring. Given the rapidly changing supply mix, the AESO will continue to assess the short-term and long-term risks to reliability and cost on behalf of Albertans and stakeholders of the Alberta Interconnected Electric System.

Key messages

- The AESO is **responsible** for the **safe and reliable** operation of the Alberta electricity system.
- Alberta is **already experiencing reliability challenges** (frequency, system strength and flexibility) due in part to the **pace and magnitude of intermittent renewables** penetration onto the grid.
- Reliability via **resource adequacy** is not a simplistic assessment solely based on planning reserve margin that exclusively focuses on peak hour conditions; it **requires sophisticated hourly dispatch and monte-carlo simulation tools, carefully calibrated to reflect the realities and uncertainties of supply and demand.**

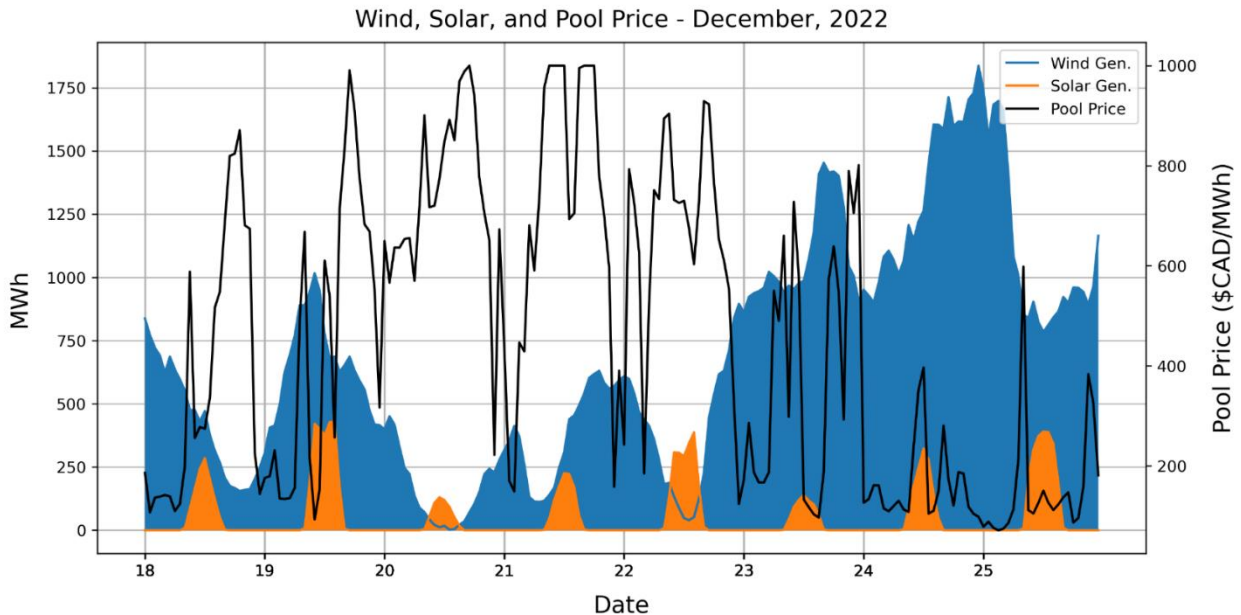
¹ [Aug 2023 Long Term Adequacy Metrics](#)

- With increased intermittent supply in the system, **having adequate resources** able to produce sufficient energy to meet demand in all hours is complex and necessitates robust analysis.
- Post-2034, AESO's modelling indicates the **CER leads to an unreliable system** based on resource adequacy analysis that outlines adverse impacts due to restrictions in cogeneration operations, stringent emissions requirements for unproven abated technologies, anticipated plant-life and operations post the end of plant life.
- The application of the draft CER in Alberta creates significant **reliability, cost and technology risk** to achieve **limited emissions reductions** and **does not support the objective of an electricity system further supporting the decarbonization of the economy as a whole**.
- Large-scale dispatchable generation investment is at risk due to **investor uncertainty** created by the **draft CER** and **impracticable 2025 deadline**.

The CER must recognize Regional Differences

The CER does not consider the vast difference between provinces in terms of generation resource mix and the corresponding challenges to decarbonize their respective power systems. Alberta's generation fleet was developed in part due to the abundance and availability of natural gas and coal reserves. Consequently, Alberta does not have legacy hydro and nuclear generating assets like many other provinces. Indeed, amongst all provinces, Alberta faces the greatest challenge to decarbonize its electricity system, since its starting point has the highest emissions. In 2022, 72 per cent of Alberta's electricity was derived from natural gas-fired resources and 12 per cent from coal-fired resources. However, Alberta is already moving faster than any other province to reduce electricity sector emissions: it achieved a 44 per cent reduction between 2005 and 2021 in response to a provincial government policy to phase out coal as a fuel source in electricity generation.

Alberta must be able to always meet demand with dispatchable generation, now and in the foreseeable future. Experience has demonstrated that during periods of extreme heat or cold intermittent resources cannot be relied upon to meet all of Alberta's electricity demand. As highlighted in the wind, solar and pool price figure shown for a week in December 2022, there are long periods when intermittent resources are unavailable, and the system is reliant on firm dispatchable resources which in Alberta primarily consists of unabated natural gas. The CER creates significant operational restrictions to Alberta's flexible natural gas generation fleet that cannot be easily met with cost-effective decarbonized technologies presently available. Alberta also has a significant high-efficiency cogeneration fleet that supplies the electricity system, and which will be put at risk of early retirement or disconnection from the grid under the CER. Moreover, increased intertie capacity does not provide a complete solution, since other authorities (B.C., Montana, Saskatchewan, and Manitoba) already project future supply challenges by the 2030s and will necessarily prioritize their needs above external jurisdictions. Uncertainty with developing low-carbon technologies (carbon capture, hydrogen, storage, small modular nuclear) means Alberta is at greater reliability and affordability risk if cost and performance of these technologies do not materialize as envisioned in the CER modelling.



The reliability risks around energy policy that the AESO is articulating are not unique to Alberta. NERC’s Electric Reliability Organization (ERO) recently published its Reliability Risk Priorities report² which highlights policy as the number one risk profile. NERC recognizes that energy policy drives changes in planning and operating the power system and thus can affect reliability and resilience and may present risks to its reliable operation. The AESO agrees with the premise that ensuring reliability during and after policy-driven transitions must be a key priority when setting energy policy.

The AESO is not alone in voicing its concerns on policy-driven reliability risk. Case in point: On May 11, 2023, the U.S. Environmental Protection Agency (EPA) released its proposed rule under the Clean Air Act that would impose new emissions regulations on coal and natural gas-fired power plants between 2032 and 2038. On August 8, 2023, the independent system operators of four U.S. jurisdictions submitted a joint statement³ in response to the proposed rule, expressing many of the same concerns as the AESO; namely, that the rule could adversely impact grid reliability. Their shared concerns include time-limited exceptions needed to address specific local reliability needs; continual review of whether CCS and hydrogen technology are progressing at the required pace to be commercially available for wide deployment and processes to modify timelines as needed; and updating definitions of “System Emergency” to reduce uncertainty around when a unit may be called upon for reliability.

In general, Independent System Operators across North America are underlining the practical risks associated with emissions and energy policy that are not captured in assessments by entities that are not electricity system operators.

² [2023 ERO Reliability Risk Priorities Report](#)

³ [Joint comments of ERCOT, MISO, PJM Interconnection and SPP](#)

Reliability

Reliability is multi-faceted and the AESO assesses many aspects of system reliability such as resource adequacy, frequency stability, system strength (resilience to contingencies, fault ride-through), balancing capability (flexibility), and transmission capacity.⁴

The CER, as presently drafted, creates very significant resource adequacy and reliability challenges for Alberta's power system from 2035 and beyond. The AESO's assessment indicates there may not be sufficient supply to meet firm load. This increased risk is a result of the restrictions that the CER places on firm dispatchable natural gas assets. This increase in energy shortfall is sensitive to increasing energy demand, the CER impact on cogeneration, and retirements of the remaining gas-fired steam units by 2037. **Without sufficient firm dispatchable natural gas generation, large areas of Alberta could be left without power for multiple hours during peak demand periods (extreme weather), creating serious public health and safety risks. The AESO is mandated to and will take actions in advance to deal with this situation, but with limited technological options available under CER, the AESO may have to rely on the emergency clause as a planning tool which would be unsustainable.**

The AESO understands the ECCC evaluated the reliability of the supply mix using a planning reserve margin. A planning reserve margin is an initial starting point and has the advantage of being easier to share and explain to a wider audience as a measure of adequacy. However, utilizing only a planning reserve margin based on single peak hour conditions is simplistic and does not account for the uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation, and thus will not capture a robust accounting of adequacy/reliability within system modelling. To account for these uncertainties, system operators utilize hourly probabilistic models and methods, such as the AESO's Resource Adequacy Model (RAM), to monitor, strengthen and provide robustness for their analysis. Based on interactions with ECCC, the AESO has not seen these dimensions and concerns represented or addressed within its modelling. The AESO has shared our preliminary views and analysis with ECCC and this is reviewed in the Summary of Resource Adequacy Assessment appendix to this submission.

The AESO has undertaken resource adequacy assessments^{5 6}, and found the CER, in its current form, creates significant reliability risks for Alberta when the regulation comes into effect for 2035 and beyond. This is further exacerbated by potential impacts of cogeneration that may be restricted in exporting electricity to the grid. With the Clean Electricity Regulations binding in 2035, the Long-Term Outlook forecasted generation mix is constrained from operating in a manner that would meet the AESO's adequacy standard⁷. The expected unserved energy (EUE) for the Decarbonization by 2035 Long-Term Outlook scenario and various sensitivities exceed the standard by a significant and concerning margin. This resource adequacy risk increases over time, which is attributed to both increasing load requirements and a reduction in firm peaking capacity, as more existing generation and future firm peaking options are limited by the CER.

⁴ The AESO's Reliability Requirements Roadmap, released in early 2023, identified many reliability and system operating challenges already beginning to emerge and expected to grow in significance in the next decade due to changes in supply mix. URL: <https://www.aeso.ca/future-of-electricity/reliability-requirements-roadmap/>

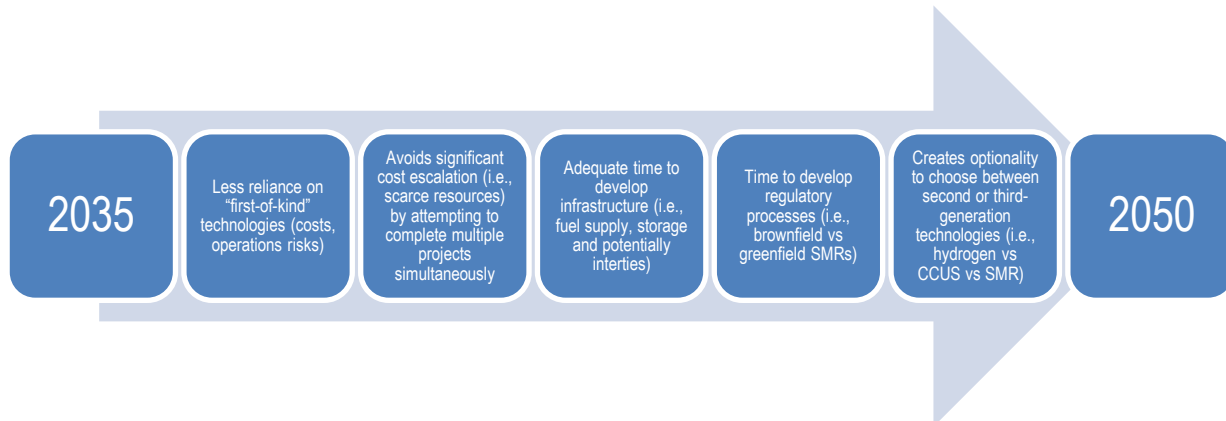
⁵ [LTO Resource Adequacy CER Assessment](#)

⁶ [AESO Media Briefing on Proposed Federal Clean Electricity Regulations \(Media Materials\) » AESO](#)

⁷ [AESO rule 202.6](#)

A Measured Pace to the Transition

The AESO, as part of its Long-Term Outlook process, has developed preliminary scenario views for Decarbonization by 2035 and by 2050. In addition to the reliability issues shared above, these views have helped highlight the uncertainty around technology development risk and emission outcomes.



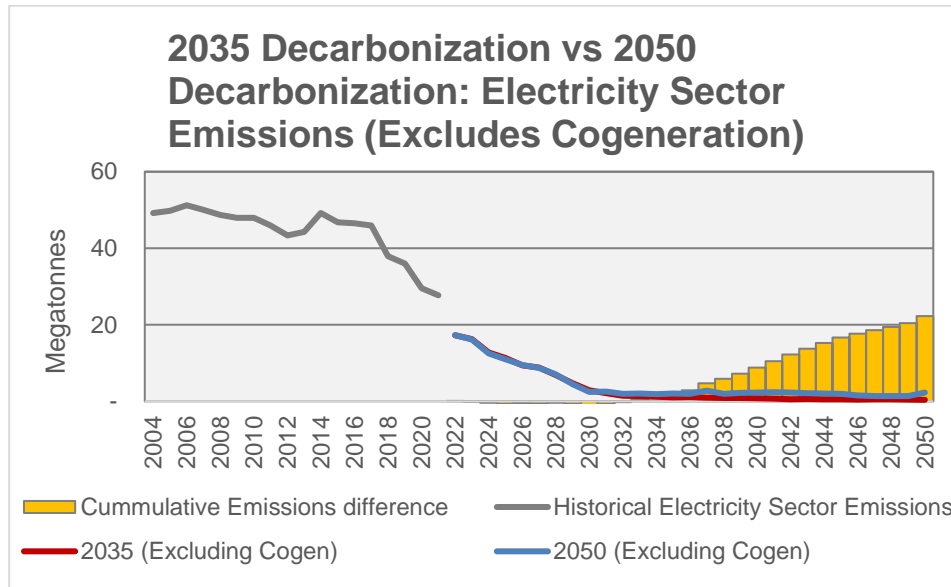
The AESO has been and continues to be supportive of new technologies. However, the AESO believes the proposed CER parameters create significant uncertainty about the commercial viability of CCS and hydrogen co-firing units today by ignoring the costs and practicalities of developing new units, retrofitting existing units, and developing the supporting infrastructure within the prescribed timeframes. Without firm examples of the commercial and operational viability of these technologies at the performance levels required by the CER, uncertainty will continue to hinder investment decisions and timelines, putting reliability of the grid at risk.

The CER benchmarks minimum emissions performance to unproven, uncommercialized technologies which have significant capital and operating risks. The CER therefore needs to recognize that these decarbonization technologies are in early stages of commercialization and carry the attendant risks. Currently there are no large-scale commercial combined-cycle units operating with carbon capture, nuclear small modular reactors (SMRs) are unproven and still under development and hydrogen production is currently expensive. It will be challenging to develop the infrastructure fully and adequately (i.e., fuel supply, transportation networks, storage, supply chains) to support these nascent technologies by 2035. While these technologies have promising futures and will no doubt play a role in decarbonization efforts, the technological advancement to economic commercialization at this point remains speculative. The current CER parameters do not provide the necessary time and flexibility for these technologies to develop, allowing Alberta’s grid to decarbonize in an affordable and reliable manner.

A practical lens needs to be applied to interconnection with neighboring jurisdictions as Alberta has limited intertie connection capacity with neighboring jurisdictions. Alberta is not able to rely on large increases in non-emitting imports/exports to balance its system, as current ties are constrained and increasing intertie capability by material volumes to balance intermittent generation across regions will take notable time and coordination between jurisdictions, beyond the 2035 horizon.

Preliminary analysis between the two scenario views developed has found the emissions profiles between 2035 CER decarbonization and 2050 decarbonization scenarios are not meaningfully different. Within this analysis AESO has found the carbon price of \$170 per tonne by 2030 paired with the currently

announced Investment Tax Credits (ITCs)⁸ are expected to be sufficient to drive structural change of the generation fleet, enabling emissions reductions and further low- and zero-carbon electricity supply options in Alberta’s electricity sector. The remaining electricity sector emissions stem primarily from peaking capacity, which provides reliability with limited overall emissions. There will be significant reliability and operational risk to Alberta’s electricity grid if existing combined-cycle units face performance standard uncertainty, with investment decisions taken not to retrofit them as a result.



Overall

Reliability and affordability cannot be compromised in the transition to a carbon-neutral grid. Long-term economy-wide electrification and decarbonization objectives will depend on cost-effective and reliable electricity supply, in Alberta and across Canada. These objectives will be severely undermined if the electricity system is not reliable and affordable. Analysis by the AESO has determined that additional transition time and flexibility significantly reduces both cost and operational risks of decarbonizing Alberta’s electricity, while still reducing emissions to a level only marginally higher than those of the CER. The AESO believes Alberta must take a reliability and affordability-focused, pragmatic, thoughtful, paced approach to the energy transition. Such an approach enables growth in renewables while still maintaining sufficient dispatchable natural gas assets to ensure a reliable power system under all operating conditions. It will also reduce the risk associated with understanding which developing technologies are best positioned to help Alberta’s power system decarbonize in the long run — SMRs, post-combustion carbon capture, utility-scale energy storage, hydrogen, and other low-emission technologies.

Recommendation for the draft CER

- Emergency Operating Conditions:
 - **The current iteration of the CER does not use appropriate language and treatment of emergencies. It is unsustainable to require post-emergency sign-off by a**

⁸ Assumes a consistent carbon regulation regime on a go-forward basis.

Government of Canada Minister. The AESO must have the flexibility to call on generation during emergencies, without a threat of punitive action on either the AESO or the generator.

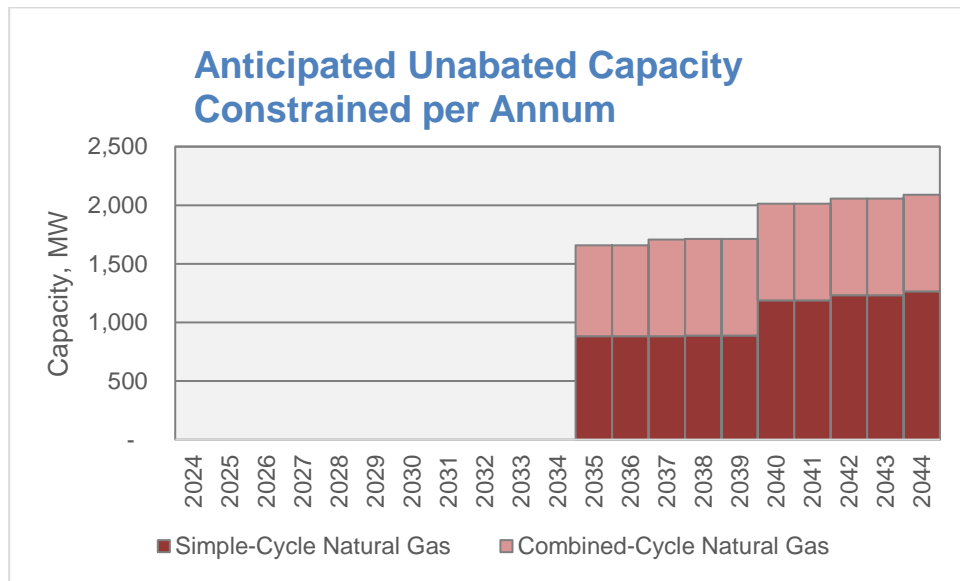
- Emergency conditions are generally difficult to forecast; and ultimate flexibility to manage them is required. It creates significant uncertainty with the prospect of after the fact approvals. It is necessary to further define the bounds of operation and consequence (and for whom) so that it is clear for all involved parties.
- As the system operator, AESO is looking for a clearer definition of what is considered an emergency circumstance within the regulation. (ie. extraordinary, unforeseen, and irresistible event).
 - Threat to reliability (lost load, system flexibility, system strength, frequency, etc.)
 - There is unacceptable ambiguity involved with who is held responsible if an event is retroactively deemed not to be an emergency circumstance.
 - The system operator **must have the authority** to determine and approve what is an emergency operating condition.
- **It is inherent to our mandate that this regulation allow the ability for AESO to direct assets on for periods of time to maintain reliability and avoid lost load as needed.**

Areas of concern within the draft CER

- Emissions Standard
 - An implied capture rate of approximately 92-95% of emissions (30t/GWh), with no other compliance mechanism other than the threat of criminal consequences for non-compliance creates significant uncertainty.
 - The threshold is based on a “theoretical” construct with no proven application.
 - Technology may be challenged to meet this level of stringency, despite best efforts and significant investment.
 - Current temporary Operating limit (40t/GWh for first 7 years of operation) does not provide the flexibility or certainty needed for investment decisions.
 - Retrofits may be discouraged since legacy unit are less efficient than best in class new units and may not meet 30 t/GWh.
 - This strict limitation ensures that generation providers need to take a conservative approach to the application of new and emerging technologies (carbon capture, hydrogen) with uncertain technological operational parameters.
 - Flexible operations of thermal units would become restricted by capture rate requirements.
 - There are advantages to allowing “first of kind technologies” to be invested in without investor concern of standard assets; learn from each project and evolve the standard accordingly.
 - International CCS Knowledge Center has expressed similar reservations within their review of the proposed Clean Electricity Regulation⁹

⁹ [Canada's Proposed Clean Electricity Regulations – Implications for CCUS – International CCS Knowledge Center](#)

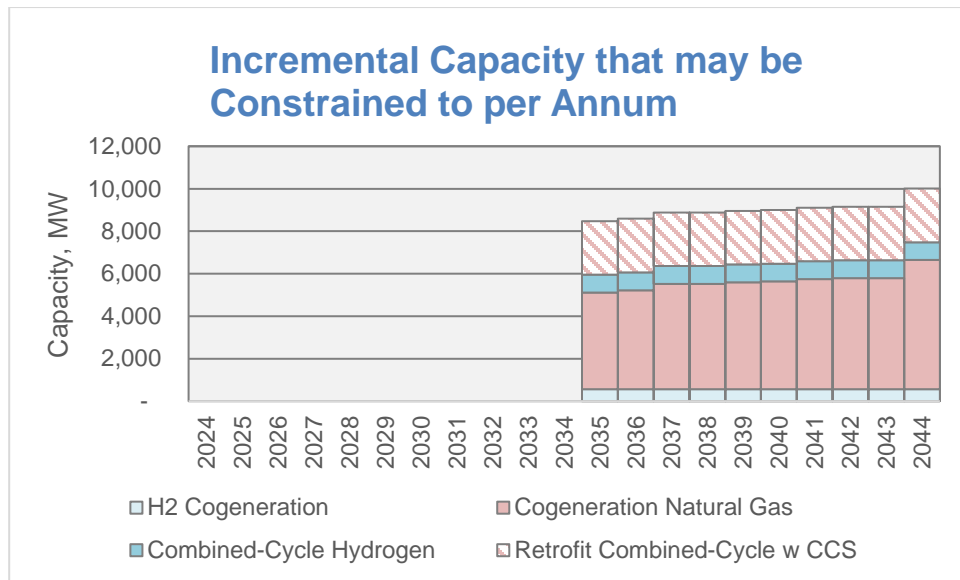
- The United States Environmental Protection Agency (EPA) has proposed a 90% carbon capture rate¹⁰ that has been criticized by ERCOT, MISO, SPP and PJM as too stringent and will impact needed investment decisions.¹¹
- End of Prescribed Life (EoPL)
 - 20 years does not allow investor to recover cost plus reasonable return.
 - May accelerate powerplant retirements once EOPL is reached.
 - 20-year EoPL creates the potential for capacity cliffs with a range of values of natural gas capacity being constrained under the regulation in 2035, creating uncertainty around the necessary dispatchable ramping capacity that is needed to reliably replace it.
 - Existing generation capacity potentially constrained by the CER represents a significant contribution of Alberta load in 2035 and will grow over time as shown below.



- The 30t/GWh is sufficiently restrictive that potentially abated technologies may not be able to achieve it in combination with a 20-year EoPL will subject them to capacity constraints.

¹⁰ <https://www.federalregister.gov/documents/2023/05/23/2023-10141/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed>

¹¹ [Joint comments of ERCOT, MISO, PJM Interconnection and SPP](#)



- Peak Firing (Flexibility) - Allowable hours (emission cap) for unabated thermal resources
 - A 450-annual-run-hour restriction (150 Kilotonne limit) will not enable flexible natural gas assets to respond to increasing system demands and to the loss of intermittent generation.
 - Peak demand hours in January may be adequately supplied, while units will not be able to operate by December.
 - Initial analysis shows that 1,800 hours improves resource adequacy outcomes but **does not** solve the issue.
 - The requirements each year will change subject to supply mix and turnover of existing assets to new technologies.
 - Efficient units would be curtailed, requiring the extended use of less-efficient, higher-emitting units to support resource adequacy.

- Net Exports, Behind-the Fence Generation (Cogeneration)
 - Generation facilities were built at sites that consume significant amounts of thermal and electrical energy via the most efficient utilization of natural gas/waste heat available (cogeneration and combined-heat-and-power).
 - A significant portion of Alberta’s existing generation assets are integrated into industrial processes spanning multiple economic sectors, including oil and gas, forestry and pulp/paper, materials, chemical production and institutional combined heat and power.
 - Alberta’s transmission system evolved to support large net to grid generation and cannot easily be reconfigured to integrate alternative generation resources.
 - This contrasts significantly with other centrally planned grids, which consolidate generation and transmission into more linear “backbone” transmission systems like B.C., Quebec, Ontario and Manitoba.
 - Development of alternative generation forms would require significant changes to the topography and power flows on the system, stranding capital and requiring additional investment.
 - Alberta has the most impactful cogeneration fleet in Canada, which supplies a significant amount of energy to the Bulk Power System (BPS), and the CER could put this supply at risk of retirement or disconnection from the BPS.
 - 40% of total generation in Alberta is sourced from high efficiency cogeneration.

- These make up a significant part of the Alberta Supply Mix, with nearly 6 GW (under construction and installed) and exports on a net basis of around 1.6 GW (~23% of Alberta system load of 7 GW)

Thank you for the opportunity to provide input to support the development of the proposed CER. It is critically important to the reliability and affordability for power consumers within Alberta, and the economy overall, that Environment and Climate Change Canada have all available information for a robust outcome.

Appendix: Summary of Resource Adequacy Assessment

The AESO completed a number of resource adequacy assessments of the preliminary Long-Term Outlook Decarbonization by 2035 forecast¹² using the AESO Resource Adequacy Model (RAM). The RAM determines the impact of the modelled supply mix capacity (MW) on resource adequacy (EUE MWh) using a probabilistic approach that varies load and generation. By utilizing hourly chronological dispatch using a stochastic (Monte Carlo) simulation that accounts for a distribution of weather, economic, outage, intermittent renewable output, inertia and emergency operations uncertainties.

This assessment evaluated resource adequacy and the associated risk of unserved energy for forecast years 2035 and 2038. The results are measured against the Long-Term Adequacy threshold as outlined in ISO rule 202.6 Adequacy of Supply¹³. For forecast years 2035 and 2038, this is approximately 1,135 MWh annually. At a high level, the Decarbonization by 2035 forecast assumes the current market structure, an unconstrained transmission system and carbon policy/regulations (Carbon price, Emissions Reduction Plan, Technology Innovation and Emission Reduction and the Clean Electricity Regulation).

The following sensitivities within the Decarbonization by 2035 forecast were modelled to understand the magnitude of impact to resource adequacy of key assumptions:

- Unmanaged Load – Electric vehicle (EV) load shifting (load management) has **not** been integrated into load forecast to reflect the potential to mitigate EV coincidental load peaks when penetration levels increase.
 - The remaining scenario/sensitivity are all run with a managed load profile with some load shifting adjustment to non-peak hours.
- Cogeneration Defection – Assumes that ~1,600 MW of Cogeneration that currently supplies energy net to grid is removed due to uncertainty and inability to comply with the draft CER parameters with regards to behind-the-fence generation
- No CCUS Retrofits – Assumes that ~2,400 MW of natural gas generation CCS retrofits do not occur or occur but do not meet 30t/GWh standard and thus are constrained to 450 hours annual operations.
- 1,800 allowable hours – Testing assets assumed within the preliminary Long-Term Outlook Decarbonization by 2035 forecast that are unabated and are limited to 1,800 allowable hours as opposed to the current draft 450 allowable hours.

¹² [2023 LTO Preliminary Results Engagement Session](#)

¹³ [AESO rule 202.6](#)

Study	Forecast year	EUE (MWh)
Decarbonization by 2035 – Unmanaged Load w/ Cogen Defection	2035	36,000
Decarbonization by 2035 – Unmanaged Load w/ Cogen Defection	2038	1,400,000
Decarbonization by 2035 – Managed Load	2035	35
Decarbonization by 2035 – Managed Load	2038	42,300
Decarbonization by 2035 – Managed Load w/Cogen Defection	2035	25,400
Decarbonization by 2035 – Managed Load w/Cogen Defection	2038	830,000
Decarbonization by 2035 – Managed Load w/No CCUS Retrofits	2038	3,000,000
Decarbonization by 2035 – Managed Load w/1,800 allowable hours	2038	15,400

As observed in the assessment with the CER binding in 2035, the preliminary LTO forecast generation mix is unable to meet Alberta’s adequacy standard. The unserved energy in 2035 shows significant risk to resource adequacy that only increases with time. The sensitivities indicate significant upside risk. Given its mandate, the AESO would take appropriate action in advance of breaching the threshold, to avoid such an outcome. The analysis and observations made within this submission are in service to that mandate.