ALBERTA

ENVIRONMENT AND PROTECTED AREAS

Office of the Minister

Dear Minister Guilbeault:

In no way does the attached technical submission alter Alberta's position that the draft regulations are unconstitutional. Legislating and regulating the development of electricity explicitly falls within the jurisdiction of the provinces as per the *Constitution Act, 1867* (92A (1) (c)). The responsibility to power Alberta's electricity grid is the province's exclusive area of jurisdiction.

I would also encourage you to carefully review the October 13, 2023, Supreme Court of Canada ruling on the *Impact Assessment Act.* This ruling confirms the unconstitutionality of the federal government's ongoing efforts to interfere with electricity and natural resource sectors of all provinces. This ruling should have resulted in ECCC pausing all work on the federal electricity regulations – it is disappointing to see the federal government disregard this decision and continue with these regulations.

Our technical submission will outline the severe consequences that your electricity regulations will impose on Albertans. In Alberta, your regulations will increase power bills, lead to job losses, compromise the grid, and impose health and safety risks when blackouts occur. The federal electricity regulations are simply unworkable and I encourage you to scrap them entirely, before it is too late.

Instead of pursuing these flawed and unworkable regulations, I would encourage you to endorse Alberta's approach. Our plan will work to achieve carbon neutrality by 2050, while maintaining energy affordability and reliability.

The attached technical submission outlines key information and evidence supporting Alberta's position, including:

1. Alberta's plan and approach to achieve carbon neutrality by 2050 while maintaining energy affordability and reliability, and lessons learned from Alberta's significant reduction in emissions from the electricity sector;

2. Comprehensive list of flaws with the federal electricity regulations;

3. List of concerns related to faulty and inadequate federal modelling and impact assessments; and

4. Failure of the federal government to offer adequate funding in reducing emissions.

204 Legislature Building, 10800 - 97 Avenue NW, Edmonton, Alberta T5K 2B6 Canada   Telephone 780-427-2391

As when we first met, I'll reiterate that this is a time to put politics aside and use common sense as we look to ensure affordable and reliable electricity and energy for Canadians. This is why we entered bilateral discussions with your government in good faith.

Alberta is confident that the many of issues raised in this document are shared by other provinces and industry leaders, both within the electricity sector and beyond. We sincerely hope that the federal government responds to this evidence with the only reasonable course: completely scrapping the federal electricity regulations.

Sincerely,

Rebecca Schulz
Minister of Environment and Protected Areas

cc: Honourable Danielle Smith, Premier
Honourable Nathan Neudorf, Minister, Alberta Affordability and Utilities
Paul Wynnyk, Deputy Minister, Alberta Intergovernmental Relations
Kasha Piquette, Deputy Minister, Alberta Environment and Protected Areas
Tim Grant, Deputy Minister, Alberta Affordability and Utilities
Kate Rich, ADM, Policy, Alberta Environment and Protected Areas
Andrew Buffin, ADM, Utilities, Alberta Affordability and Utilities

Federal Draft Clean Electricity Regulations

Government of Alberta Technical Submission

Contents

Federal Draft Clean Electricity Regulations – Government of Alberta Technical Submission

This submission supplements the letter provided by the Premier of Alberta to the Prime Minister regarding the proposed federal Clean Electricity Regulations (CER) and earlier letters and submissions from the department.

In no way does this technical submission alter the Alberta position that the draft regulations are unconstitutional. Legislating and regulating the development of electricity explicitly falls within the jurisdiction of the provinces as per the *Constitution Act, 1867* (92A (1) (c)). The responsibility to power Alberta's electricity grid is the province's exclusive area of jurisdiction.

The October 13, 2023 Supreme Court of Canada ruling on the *Impact Assessment Act* confirms the unconstitutionality of the federal government's ongoing efforts to interfere with electricity and natural resource sectors of all provinces. This court decision significantly strengthens Alberta's legal position as we work to protect our province from federal intrusion into various areas of exclusive provincial jurisdiction.

We continue to call on the federal government to learn the lessons from this decision and abandon their ongoing unconstitutional efforts in this area. We invite the Federal Government to align its policy with Alberta's responsible approach to achieving emissions reduction in the electricity sector.

Alberta has a clear plan and approach to achieve carbon neutral by 2050 while maintaining energy affordability and reliability. Our successes to date have already yielded significant reduction in emissions from the electricity sector. Our substantial experience informs our submission that highlights the: considerable flaws of a draft CER that is unworkable in Alberta; weaknesses in the modelling and impact assessment underpinning that draft; and regardless of the approach adopted for electricity transition, the need for additional federal supports.

The draft CER as written is unworkable. Given the review and vetting associated with the Canada Gazette process, given the challenges of crafting a national legislation for electricity which, as a provincial jurisdiction, has different models of delivery across Canada, and given the need for the federal government to work meaningfully with provinces on any such policy, we do not believe ECCC is in any position to finalize these regulations. ECCC should, therefore scrap these regulations, and seek to work within well-established provincial regulatory regimes for electricity regulation and emissions reduction.

Alberta is confident that the many issues raised in this document are shared by other provinces and key industry stakeholders, both within the electricity industry and beyond. We hope that the federal government responds to this weight of evidence with the only reasonable course, a complete re-evaluation of the approach being misapplied to achieving our shared objective of a carbon-neutral electricity industry.

Part 1: Alberta's Emissions Reduction Plan and Lessons Learned

Albertans need their electricity system to deliver three important objectives - affordability, reliability and environmental performance.

Affordability cannot be achieved without a regulation that is properly crafted to allow for a practicable approach to decarbonization that ensures the most cost-effective emissions reductions are achieved over a realistic timeline. As currently drafted, the CER will cause:

- investor uncertainty;
- stranded assets leading to costly and unnecessary development of redundant new assets and infrastructure; and
- an expensive and volatile electricity market, the costs of which would be borne by Alberta consumers.

Affordability is further compromised by the absence of clarity and budget for federal funding supports to support the transition of our electricity system.

Reliability can only be accomplished by ensuring an appropriate amount of baseload energy and system supports are available throughout every hour of every day. The draft CER compromises grid reliability to an unacceptable degree resulting in the very real risk that Albertans will not have access to an essential service when they need it.
In the short to medium-term, one of the most cost-effective sources to provide this reliability is high-efficiency natural gas, including cogeneration. To ensure a reliable and affordable electricity system throughout the path to a carbon neutral grid, Alberta will need access to new and innovative technologies, such as carbon capture, utilization, and storage (CCUS), small

modular reactors (SMRs), energy storage, and hydrogen generation. Many of these technologies require various federal supports in order to advance, including capital investment incentives and operational supports like carbon contracts for difference. In many cases such as CCUS, these funding arrangements still need to be finalized to support investment decisions and to move these technologies forward at scale. A sustainable amount of wind, solar and other renewables will also provide low-cost energy to help manage energy costs, noting associated costs for storage and transmission must be considered. In this way, decarbonization can continue apace.

As currently drafted, the CER creates significant reliability risk. CER has rendered CCUS (and potentially other new technologies) uninvestable, will lead cogeneration units to retire early or to stop exporting to the grid, and will not provide sufficient run time or economic certainty for natural gas to support intermittent renewables.

The Alberta Electric System Operator (AESO) resource adequacy assessment shows the draft regulations would create significant unserved energy (up to 3 million megawatt hours (MWh)) beginning in 2038 if CCUS, cogeneration and greater flexibilities for natural gas are not enabled. Ontario's Independent Electricity System Operator has also publicly criticized the draft regulations, stating that as proposed, the regulations could impede an orderly energy transition and could slow the electrification of their economy by compromising the reliability of the grid and increasing electricity costs. Other stakeholders have asked Canada to better consider how provisions for peak demand will work, how cogeneration plants will be treated, and how the end of prescribed life provisions determine how assets built under previous regulations should be allowed to operate.

Environmental performance is a deep concern for Albertans and our government. Alberta has already reduced electricity emissions by 53 per cent from 2005 to 2021 (2023 National Inventory Report, Annex 12). Furthermore, ECCC should recognize Alberta's early emission reductions compared to the federal coal phase-out regulation, with a cumulative reduction of 175 Mt of emissions between 2017 and 2030.

Alberta's Emissions Reduction and Energy Development (ERED) Plan will enhance our position as a global leader in emissions reductions, clean technology and innovation, and sustainable resource development. Alberta's plan aspires to achieve a carbon neutral economy by 2050, and to do so without compromising affordable, reliable, and secure energy for Albertans, Canadians and the world. Alberta's pathway to carbon neutrality will leverage our existing infrastructure, expertise, ingenuity, and ability to support emissions reductions beyond our borders. We are confident that Alberta's ERED Plan will get us to a reliable and affordable carbon neutral power grid by 2050.

Through current policies and programs — both federal and provincial — Alberta's electricity system is already on a trajectory that will significantly reduce greenhouse gas emissions by 2035, without the need for layering on a punitive CER. Third-party modelling indicates that Alberta's electricity sector will have fewer than 10 Mt of emissions by 2035 in its reference case scenario, which includes current policies absent the CER.

Through Alberta's rapid transformation away from coal-fired power to lower emitting natural gas power alongside exponential growth in wind and solar renewables, our province is an active study in decarbonization of grids. Lessons learned and challenges on the grid today to achieve reliability and affordability must be carefully reviewed to ensure the next phase of decarbonization is done thoughtfully and without creating unintended consequences. As drafted, the CER does not incorporate the key lessons learned and will only exacerbate issues of reliability and affordability in Alberta, and likely elsewhere in the country. The 2035 goal is especially ambitious given the range of uncertainties associated with the maturation of low-carbon technologies, supply chain readiness, skilled labour shortages, and development timelines for energy-related infrastructure.

Alberta acknowledges ECCC intends to offer potential of equivalency agreements to address some provincial concerns with the proposed regulations. This demonstrates that the federal government's regulatory design is not fit for purpose and requires reconsideration.

Part 2: Concerns with Draft CER as Published in Canada Gazette 1

Faulty Design Principles

- By targeting national electricity generation emissions, the CER fails to recognize Canada is comprised of a collection of regionally different grids, each with their own generation and demand profiles. Provinces and territories without favourable natural geography or low-emitting legacy assets, such as hydroelectric or nuclear power generation, rely on natural gas.
    - Canada must recognize regional differences, providing flexibilities that can work for regions that are disproportionately impacted by the electricity transition, such as Alberta.

- The draft CER is overwhelmingly and unnecessarily punitive with inflexible compliance options - generators must not emit or they could face criminal penalties under the *Canadian Environmental Protection Act* (CEPA), which includes a threat of incarceration.
    - The CER should be removed from CEPA due to its criminal code implications, which unnecessarily negatively impact investment and reliability in Alberta's electricity system.
    - Alternatively, the criminal provisions of CEPA could be removed.
- Alberta stakeholders have expressed bewilderment at ECCC's apparent abandonment of industrial carbon pricing as the driver of effective and efficient decarbonization. The approach to supporting the electricity transition should complement carbon pricing, where at $170 per tonne of CO_2 equivalent, the non-emitting technologies are generally already less expensive than emitting ones.
    - Industrial carbon pricing and emissions trading, rather than sector-specific policies, are more efficient and cost-effective in reducing emissions.
    - The draft CER adds administrative burden.
- More cost-effective emissions reductions should be achieved through enabling greater flexibility with compliance alternatives such as high-quality offsets, better incorporating the existing price on carbon, and enhanced supports for technology and innovation.
    - Based on data provided by ECCC, Alberta estimates the CER achieves reductions in Alberta at an average cost of at least $184 per tonne over the 2024-2050 period. This cost is in addition to the federal carbon price, scheduled to rise to $170 per tonne by 2030.
    - Federal programs for capital investment and operational supports are required to support the transition to a carbon neutral grid by 2050.
- The CER should not assume future technologies will be easily or quickly available that are not deployable today. Modelling must reflect the risks and uncertainties in developing new technology at scale, otherwise it demonstrates an artificial perspective on costs, reliability, and emission reduction outcomes.
- Allocation of federal financial support must reflect the anticipated economic impacts provinces and territories will incur from CER implementation.
    - Federal modelling indicates total net-cost of the CER to be $58 billion, of which $35 billion (or 60 per cent) of the net costs are borne by Alberta, meaning Alberta must receive the majority of the available federal funding. Third party assessments project notably higher cost impacts to Canada and Alberta.
    - The impact and cost of emission reductions varies widely across Canada, with some provinces earning net revenues under the CER modeling with a range estimated by the province using fuel use saving figures of $2,000 per tonne to - $5,000 per tonne reduced.
    - Federal capital and operational funding supports must be outlined and secured to support the electricity transition regardless of the regulatory framework.

Key takeaways:
- **The CER does not respect the differences among the provincial electricity systems.**
- **The CER is unnecessarily punitive with jail time for non-compliance.**
- **The CER has abandoned the existing efficient, economical, flexible and effective carbon pricing approach to reduce emissions.**

The Vital Role of Natural Gas Generation in Alberta

- Alberta relies on natural gas baseload, supplemented with intermittent renewable generation and a small amount of hydro and geothermal generation, to provide affordable and reliable power to Albertans. Unlike provinces with abundant hydroelectric resources, Alberta's grid reliability is maintained through natural gas generation to backup and balance intermittent sources of power such as wind and solar.
- This baseload is critical to annual and hourly reliability in Alberta's electricity grid, supplying capacity, frequency, voltage, inertia, and more.
    - The AESO's 2023 Reliability Requirements Roadmap[1] notes the decline of coal and natural gas generation at the same time as increased inverter-based wind and solar has created urgent frequency response issues requiring active management and expansion of new services such as fast frequency response. Wind and solar with some battery storage do not contribute to voltage support, which is required to maintain system strength. Real-time balancing of supply and demand is also challenged with the introduction of more intermittent

[1] https://www.aeso.ca/future-of-electricity/reliability-requirements-roadmap/

renewable generation replacing coal and natural gas power. All three of these reliability issues will increase over time. The CER does not fully account for reliability issues, and its aggressive timeline adds additional challenges.
    - Alberta requires reliable electricity power in periods when intermittent sources are not generating.
        - In December 2022, during a period of cold weather with little wind or solar generation, the 5,000 megawatts (MW) of installed renewable capacity only generated 187 MW to 1,796 MW of power through the month. Natural gas generation was required to meet the demands of the grid.
- In Alberta, cogeneration currently constitutes over half of our natural gas supply and is critical to maintaining reliable and affordable electricity in the province. Cogeneration provides the lowest greenhouse gas (GHG) intensive baseload power in Alberta, with cogeneration having approximately one-third lower GHG intensity than the most efficient natural gas combined cycle units (370 kg CO_2e/MWh). This has resulted in cogeneration achieving significant emissions reductions in other sectors, including oil and gas and forestry.
    - As such, cogeneration is a critical feature that is unique to Alberta's electricity supply where 40 per cent of electricity generated in Alberta is from cogeneration.
    - There is a significant co-benefit of cogeneration to emissions reductions in industrial sectors (e.g., oil and gas, forestry, petrochemical). The CER design should not jeopardize cogeneration in Alberta, nor business competitiveness (generally energy-intensive and trade-exposed industries).
    - Moreover, if the cogeneration stops providing electricity to the grid because they choose to for business operation and economic reasons, or if they cannot physically comply, Alberta's reliability is jeopardized.
        - Per AESO modelling, impaired cogeneration could result in 830,000 MWh in 2038 of expected unserved energy.
- Dispatchable generation is needed to cover load as wind and solar output varies, and as capacity, startup time and ramp rate constraints apply.
- The ERED Plan is a comprehensive approach, one that leans into collaboration and partnerships to develop new, clean technology, and to push the envelope of innovation in areas such as energy storage.
- With appropriate incentives, the role of gas is likely to evolve through carbon capture and storage, production of hydrogen and build out of renewable natural gas capacity. The timeframes of these changes remain uncertain and must not be assumed. In the interim, natural gas plays an incomparable role in providing necessary capacity and reliability system supports.
- Considering the seasonality of renewable resources in the province we would anticipate the need for efficient high capacity factor gas units through to the 2050 timeframe.

Key takeaways:

- **Natural gas generation is dispatchable and a vital technology for providing reliable and economic electricity.**
- **The CER has ignored the critical role that cogeneration plays, including the respective hosts' contribution to GDP and jobs.**
- **Both CCUS and hydrogen can maintain roles for natural gas, while addressing emission reductions.**

Removing 40% of Alberta's Generation by Targeting Industrial Cogeneration

- Approximately 40 per cent of the generation in Alberta comes from cogeneration at industrial facilities.
    - Electricity **exported** from these facilities to the grid accounts for approximately 25 per cent of the total grid generation.
    - The availability of reliable and affordable electricity from cogeneration in Alberta is essential to maintaining grid reliability.
    - Industrial cogeneration operators produce electricity as a secondary activity to their primary activity in oil and gas, forestry, petrochemical or other areas. If the CER introduces strictly punitive actions towards their export to the grid, they are likely to reduce or cease all exports. This loss of generation capacity from cogeneration on the Alberta grid would have devastating consequences to reliability and affordability.
- Cogeneration in Alberta is driven by the demand for industrial heat, the demand for which will remain regardless of the implementation of the CER.
    - Should the CER be enforced on cogeneration as drafted, there is a real possibility that industry will opt to replace their cogeneration units with conventional boilers, resulting in poorer emissions performance.
- The CER assumes that all cogeneration that currently provides net electricity to the grid will undertake the necessary modifications to comply with the CER standards. This is a false assumption.
    - The CER policy package is unlikely to drive cogeneration to invest in CCUS and maintain their key supply necessary to maintain reliability.
    - Many cogeneration units are embedded in industrial settings where the physical space required to install CCUS is not available.

    - For some industrial sites, there are more concentrated sources of CO_2 which would be the first most economic targets of CCUS rather than cogeneration units. It would be non-optimal to target cogeneration sources first because of the CER.
    - Given the significant costs involved in retrofitting technologies like CCUS to existing cogeneration facilities, rather than attempting to comply with the CER, they could stop supplying to the grid altogether and focus on their own industrial needs.
    - The loss of cogeneration would have a significant impact on the costs associated with filling the gap left by their absence from the market.
- The performance standard coupled with the capture of all emissions from a cogeneration unit, including behind-the-fence use (of a net exporter), will likely drive operators to cut off grid supply and move to solely providing behind-the-fence generation, or may even drive them back to less efficient technology such as use of boilers.
- The draft CER limits the access of industrial cogeneration and the spare capacity that is foundational to the safe and reliable operation of Alberta's grid.
    - The draft CER requires that all existing and future cogeneration be abated. This added cost will result in the shut-in of efficient units that today provide low-cost baseload to Alberta's grid.
    - Under the proposed CER, a large portion of grid-exported cogeneration may opt to shut in, or cease net grid exports in order to not be subject to the CER. It may even drive some facilities towards less efficient technology such as use of boilers.
    - The AESO has estimated that a defection of 1,600 MW of industrial generation from the grid would lead to 830,000 MWh of unserved load in 2038.
- Cogeneration units are facing policy uncertainty creating further investment risk due to the pancaking of regulatory actions, including the CER and the federal oil and gas emissions cap.
- Units needed for reliability may end up being shut down unnecessarily in order to meet the limit if the standard remains inflexible.

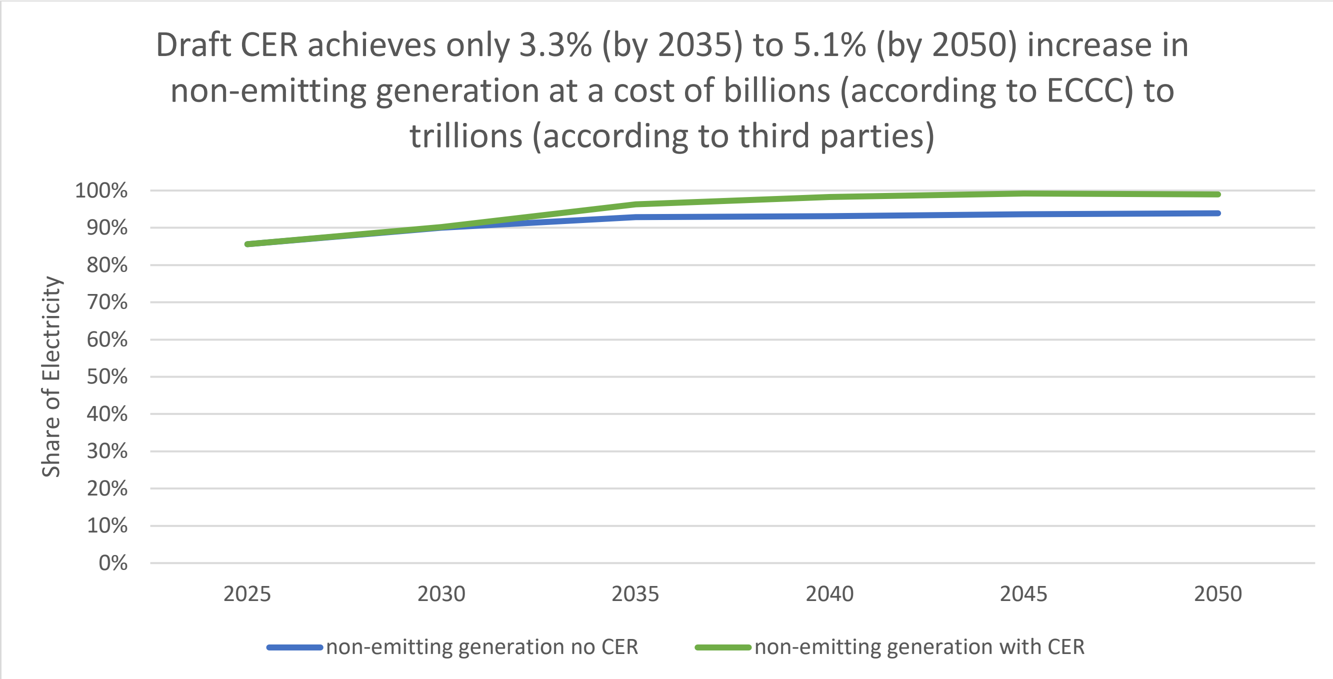
Key takeaways:

- **Cogeneration accounts for 40 per cent of Alberta's electricity and is an important feature to maintain reliability, and is endangered by CER.**
- **Cogeneration cannot physically or economically implement CCUS and may just stop operating or install inexpensive and inefficient boilers.**
- **Policy uncertainty and an inability to comply with the CER will hurt jobs and the economy.**

Targeting Alberta Causing Additional Costs

- Third-party estimates have pegged the cost of Canada's transition to a carbon neutral grid and electrification in the trillions. Canada's own faulty Regulatory Impact Analysis Statement (RIAS) puts the cost of its regulations in the billions.
- Canada's proposed regulations would only result in an overall 3-5% increase in non-emitting generation across the country, with a disproportionate 60% of costs coming from the pockets of Albertans. Trillions or billions, the cost is punitive to Albertans.
    - Canada already has the second greenest grid among G7 nations, according to the International Energy Agency[2].
    - The 3.3 percent increase in non-emitting generation by 2035 and 5.1 per cent increase by 2050 driven by the draft regulations comes at a significant cost to Canadians.
    - In the RIAS, ECCC estimates that Alberta will bear 60 per cent of the total net-cost of the proposed CER. Alberta is disproportionally affected.

[2] https://iea.blob.core.windows.net/assets/9a1c057a-385a-4659-80c5-3ff40f217370/AchievingNetZeroElectricitySectorsinG7Members.pdf

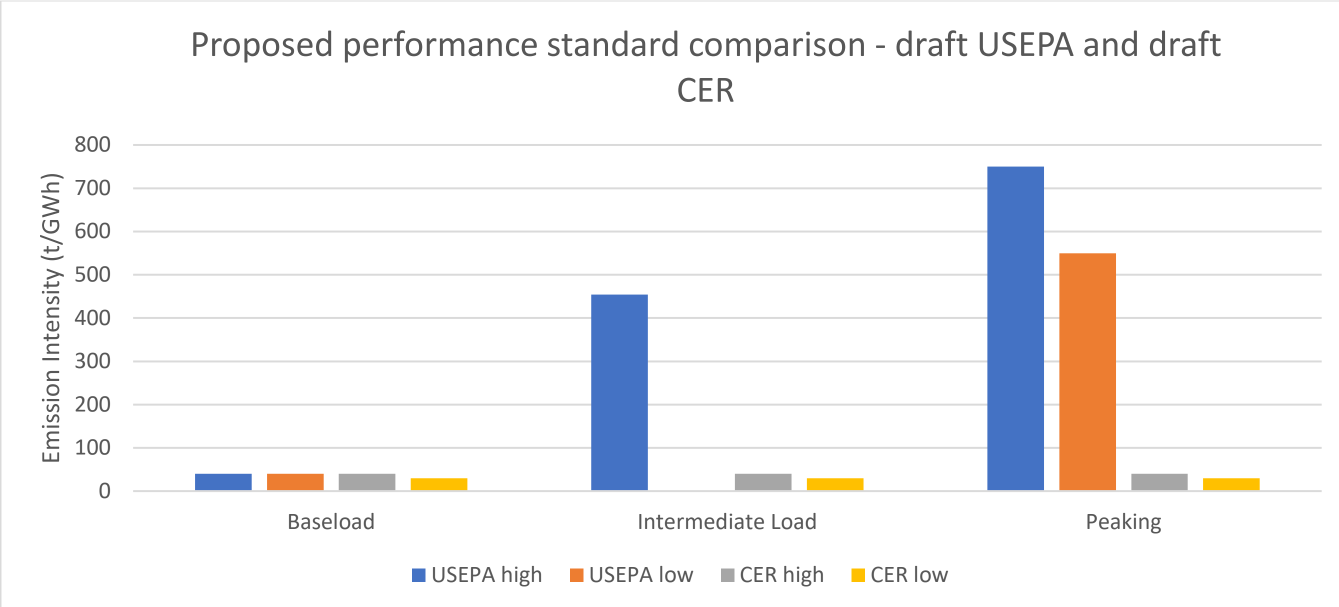


Key takeaways:

- **Third party assessments project notably higher cost impacts to Canada and Alberta than estimated by the federal government in the draft CER RIAS.**
- **Alberta will pay more than any other province.**
- **Of the underestimated $58 billion ECCC suggests as the total cost of CER, Alberta's share would be 60% or $35 billion.**

Inflexible Performance Standard that Reduces System Reliability

- Historically, Canada and the United States have set performance benchmarks recognizing Best Available Technology Economically Achievable (BATEA). This approach encourages best practices while recognizing that design specifications must be tested through operations and should be re-evaluated over time with demonstrated performance.
- The inflexible performance standard will limit rather than drive the adoption of necessary new technologies such as CCUS and hydrogen.
- A performance standard of 30 tonnes per gigawatt hour (t/GWh), with a small flexibility of 40 t/GWh for the first four years for CCUS, is both too stringent and inflexible to encourage investment.
- Natural gas with CCUS would have to meet the standard through an approximately 95 per cent capture rate, which is an unproven design specification that will be very challenging to meet under optimal operational settings, and potentially impossible to meet given the operational variability that occurs on a daily basis on electricity grids.
- The US Environmental Protection Agency (USEPA) released proposed regulations on May 11, 2023 which would limit CO_2 emissions for electricity generating facilities in the USA and shows a more flexible approach.
  - The draft regulations vary by age, fuel type and capacity factor of the generating units.
  - Though the timelines for emissions reduction vary depending on fuel type and configuration, by 2038 all new baseload generation is subject to an emissions standard of approximately 40 tCO_2/GWh.
  - Across all generation types and capacities, the USEPA proposed regulations are significantly less stringent than the proposed CER.
  - Alberta competes for investments in our electricity system with US jurisdictions and Canada's proposed approach will negatively impact the ability of the Alberta system to attract highly-mobile capital.



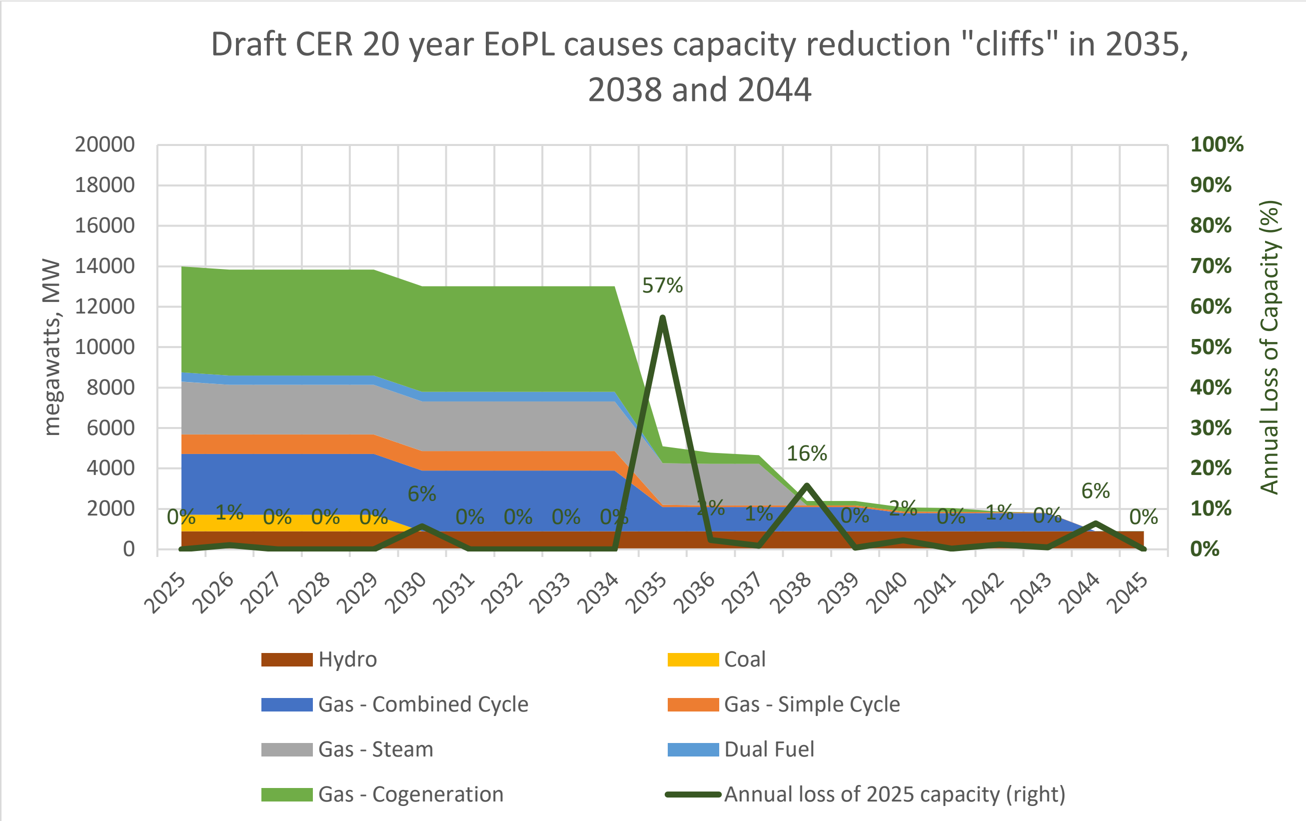
- Most Alberta thermal generators have indicated that the physical standards proposed in the CER cannot be met by CCUS. The combination of the criminality provisions of CEPA, the inflexibility of the draft CER physical standards, the flawed modelling and assumptions used by ECCC and the ridiculous assumption that these projects could be designed, approved, sourced and built within a 10 year window could eliminate investment in CCUS
  - The estimated cost associated with CCUS on a 800 to 900 MW combined cycle unit is about $2 billion.
  - CER does not offer flexible compliance mechanisms.
  - The penalties associated with non-compliance are so onerous as to dissuade any investors from making a commitment to CCUS.
  - There remains an uncertain regulatory environment: for example, investment tax credits and contracts for differences — federal promises — have not materialized.
  - If electricity companies choose not to implement CCUS or cannot make CCUS work sufficiently to meet compliance obligations, there will be a significant shortage of electricity in Alberta prior to and post-2035. Per the AESO analysis, not having the CCUS as projected represents 3,000,000 MWh of expected unserved energy in year 2038.
- Operational needs could also change capture rates over time, as current baseload natural gas generators may operate differently as the grid decarbonizes overall. Natural gas may shift to more 'load following' suppliers of energy requiring daily ramping, and/or non-energy ancillary services during critical hours when wind and solar are reduced or not available. Companies should be rewarded rather than penalized for supporting the technical realities of a decarbonized grid.
  - Current CCUS technologies are not compatible with highly variable power outputs, such as would be seen on peaking plants.
- In order to meet the performance standard of the draft CER, a natural gas plant would require an approximately 95 per cent capture rate on an already high-performing facility, which is continuously running at a high capacity. This is an unproven technical standard, which has not been tested through industrial performance. This creates untenable risk to investors, imposes significant costs and technology hurdles, and is potentially technologically unattainable for retrofits on older facilities as well as new units.
  - Technology providers design for and advertise 95 per cent capture, but none are able to provide written performance guarantees or warranties, thus limiting financing opportunities, and jeopardizing investments.
  - Numerous Alberta generators have told Alberta that while vendors claim to be able to achieve capture rates consistent with the draft standards, none of the vendors are willing to make written guarantees or warranties of their equipment performance. Without guarantees or warranties, generators are unable to finance CCUS projects since there is a real risk that a multi-billion dollar investment in CCUS could be rendered worthless by emitting above the emissions standard, even if only exceeding the standard by a tiny amount.
- The Global CCS Institute CORE data base [Facilities - Global CCS Institute (co2re.co)][3] lists three commercial, operational CCUS projects in the power sector. None are on gas-fired power plants, and physical performance for gas generation is still unproven.

[3] https://co2re.co/FacilityData

- It is clear that the electricity transition will hinge on natural gas abated by CCUS. Future costs to support grid growth and CCUS deployment must be supported well into the future by the federal investment tax credits and carbon contracts for difference.

Key takeaways:
- **The standard, as set, is inflexible and is not backed by manufacturers' warranties or proven in-production experience.**
- **The US EPA has proposed more lenient standards, and rightly recognizes difference classes of generation require different standards.**
- **Industry feedback is unanimous that the proposed physical standards cannot be met, and their companies will not invest in CCUS with that much risk.**

Stranding Capital through Unreasonable End of Prescribed Life (EoPL)
- Generating units require significant capital and an expected return on investment in order to move forward. Unnecessarily stranding resources before their end of operational life is an expensive approach to climate mitigation, as new generation capacity will be required to replace existing units – the costs of which will be borne by consumers and taxpayers.
- The proposed EoPL for existing units is 20 years, though ECCC's own RIAS analysis demonstrates a typical operating life of natural gas units is closer to 45 years. This early shut-down is punitive and results in limited emissions savings over and above $170 per tonne carbon pricing.
    - ECCC's draft has not considered federal obligations related to compensation for its shortening of assets' lifespan.
- The financial consequences of shortening the amortization period for these assets is to significantly increase their financing costs.
- The financial impact of changes to the EoPL provisions were estimated using a net present value analysis on a per megawatt basis of natural gas generation.
    - It was determined that moving from a 20 year EoPL to a 30 year EoPL would result in an additional $401,120 per MW of capacity in present value as a result of increased operating revenue from a longer EoPL.
- The draft CER proposal of 20 year EoPL is not based on the technical lifespan of generating assets. It will result in significant stranded assets, with unnecessary retirement of best-in-class natural gas units needed to maintain reliable supply, could harm future investment, and will require new replacement generation costs and system supports, all borne by consumers.
- Under the 20 year EoPL treatment, approximately 55 per cent of Alberta's existing and approved natural gas generation installed capacity would be subject to the CER emissions standard by 2035, compared to 46 per cent under a 25 year EoPL, and 38 per cent under a 30 year EoPL.
    - Under the 20 year EoPL treatment, all of Alberta's existing and approved natural gas generation installed capacity would be subject to the CER emissions standard by 2043.
- Below are graphs of capacity retirement cliffs that would be experienced under 20 year EoPL.
    - The line with percentages is the amount of capacity that retires in that year vs the 2025 capacity.



Key takeaways:

- **The 20 year EoPL is not based on the technical and economic lifespan of generating assets and is contradictory to the RIAS that indicates a typical operating life of closer to 45 years.**
- **Approximately 55 per cent of Alberta's existing and approved natural gas generation would be negatively impacted by the EoPL by 2035.**
- **Efficient assets will be stranded, resulting in reliability concerns and unnecessary new capital requirements which increase costs to consumers.**

Constraining Reliability through Allowable Hours Restrictions

- The proposed allowable hours for operating — also known as the peaking provisions — cause significant operational and investment problems, including:
  1. The allowable hours will not provide sufficient capacity to the system without a significant, uneconomic, overbuild of capacity or deployment of exempt sub-25 MW units.
  2. The allowable hours do not provide enough revenue certainty to keep existing units running economically, or to incent enough new efficient generation to fill much-needed peaking or load-following capabilities.
  3. The evaluation over a calendar year is also problematic as the month most likely to experience issues in December, co-incident with winter load peaks.
  4. The 450 hr/150 kt exemption provided to gas generation to backup intermittent renewables is insufficient for the vast majority of commercial operators to remain in business and absolutely insufficient on a grid-scale to provide reliable electricity.
  5. The approach taken to ensure emissions reductions by setting an hourly limit leads to a perverse environmental outcome. The allowable hours provision does not account for emissions efficiency, resulting in a perverse outcome where inefficient generation could run up to 450 hours while much more efficient generation that had already reached its 450 hour limit would be sitting idle.
  6. The capital and upkeep costs of natural gas units required to back up intermittent generating sources are too large for these plants to be economic under the peaking provisions of the CER.
  7. A 450 annual-run-hour restriction will not enable flexible natural gas assets to respond to increasing system demands and to the variability of intermittent generation.

a. AESO modelling of the draft CER concludes that the CER creates a significant violation of the resource adequacy thresholds past 2035. Extreme weather conditions (i.e., heat or cold) further exacerbate resource adequacy challenges.

8. On average, peaker plants in Alberta operate approximately 2,800 hours per year (approximately 32 per cent capacity factor) (Source: AESO Historical Hourly Production Data, 2022). As Alberta integrates more intermittent renewable generation, it is likely that peaker plants will be called on even more than the current average of 2800 hours per year.
    - For this analysis, peaker plants are defined as simple cycle gas plants with capacities of 25 – 50 MW.
    - In 2022, no gas generating assets with a capacity of at least 20 MW operated for fewer than 1,000 hours (approximately 11 per cent capacity factor). The proposed federal limit is 450 hours (approximately 5 per cent capacity factor).
9. The 25 MW minimum threshold may create a perverse incentive for building peaking units under the threshold to avoid being regulated under CER.
10. Alberta requires reliable electricity power in periods when intermittent sources are not generating.
    - In December 2022, during a period of cold weather with little wind or solar generation, the 5,000 MW of installed renewable capacity only generated 187 MW to 1,796 MW of power throughout the month. Natural gas generation was required to meet the demands of the grid.
    - Peakers play a vital role, and an increasingly important role in the future, in ensuring overall grid reliability and that Albertans have power in high demand or low intermittent supply periods.

- Unabated natural gas is needed in the transition to a non-emitting Canadian grid, and the current draft forces inefficient capital expenditure in excess capacity to meet energy requirements under the 450 hour run time constraint or in small units less than 25 MW capacity which are exempted.

Key takeaways:

- **Hourly limits on all units means that highly efficient new units will be capped in favour of inefficient units — a perverse outcome for investments and emissions.**
- **The limited number of hours and emissions are insufficient for operators who provide peaking services to earn an economic return; they will shut down, creating reliability issues.**
- **The limited number of hours and emissions are insufficient to cover system needs when intermittent generation is limited / unavailable. This puts households and businesses at unacceptable risk.**

Emergency Provisions

- The responsibility to power Alberta's electricity grid is the province's exclusive area of jurisdiction, and it is the mandate of the AESO to ensure reliability of Alberta's electricity system.
- The draft CER treatment of emergencies is unacceptable. It is untenable to require post-emergency sign-off by a Government of Canada Minister. The provincial system operator must have flexibility to call on generators during emergencies, without a threat of punitive action on either the system operator or the generator. It is totally inappropriate that a generator be put in federal legal jeopardy by following provincial requirements to respond to an emergency.

Key takeaways:

- **The mandate to power Alberta's electricity grid is the province's exclusive area of jurisdiction.**
- **The system operator is in the best position to manage emergencies.**
- **It is totally inappropriate that a generator be put in federal legal jeopardy by following provincial requirements to respond to an emergency.**

Part 3: Concerns of Federal Modelling and Impact Assessment

Alberta Electric System Operator Analysis

- The Alberta Electric System Operator (AESO) is uniquely and expertly qualified to analyze and evaluate the long term and real-time impacts of Canada's proposed CER.
- The AESO released its 2023 Long-Term Outlook Resource Adequacy assessment modelling the proposed parameters of the draft CER on September 27, 2023, building on its 2022 Pathways to Net-Zero report. The AESO report noted that:
    - The draft CER would impose disproportionate risk and costs on Alberta, compared to other provinces
    - The 2035 timeline to achieve the draft performance standard across the generation fleet was unrealistic.
    - The draft CER policies would result in Alberta lacking the resources to ensure grid reliability by 2035.

- The AESO found that the proposed CER will have a significant impact on grid reliability as early as 2035, with an estimated 36 gigawatt hours (GWh) in expected unserved energy, resulting in 77 hours of unserved energy.
  - These resource inadequacy concerns escalate significantly past 2035, with an expected 1,400 GWh of unserved energy in 2038, resulting in 1,473 hours of underserved energy.
- The AESO modelling indicates that, as proposed, the "*CER does not create a workable framework to allow an orderly transition of retiring generation infrastructure, or sufficient timelines for development of emerging low-emission technologies such as carbon capture, small modular nuclear reactors, hydrogen and energy storage*".
- The AESO noted that technological solutions to reduce electricity emissions, such as CCUS, hydrogen, SMRs, and energy storage require significant upgrades to existing infrastructure in order to be deployed at a large scale.
- The AESO also notes that industrial carbon pricing under Alberta's Technology Innovation and Emissions Reduction (TIER) Regulation will achieve significant decarbonization of the electricity grid even without the CER.
- The results of the assessment indicate that the CER creates significant adequacy risk when it comes into effect in 2035.

Federal Modelling

The modeling suite used by Canada relies on faulty assumptions and is, at present, incomplete and lacks economic impact analysis to properly address the Alberta market including the large share of cogeneration and that proxies used to evaluate system reliability are incomplete leading to incorrect design decisions and impact estimates.

Alberta's key modelling concern remains NextGrid's inability to model Alberta's energy-only market, with decisions on investment being held by individual companies, and the inability to perform necessary reliability assessments. The model's use of the federal Output-Based Pricing System underestimates the positive impact of carbon pricing. Lastly, ECCC has a number of problematic technology assumptions that have national impacts in federal modeling, including:

- Widespread and early adoption of CCUS on natural gas combined-cycle plants.
  - Currently there are no large-scale commercial combined-cycle units operating with CCUS in the world.
- Overly optimistic new technology development (including SMRs and hydrogen). While these technologies have promising futures, their technological advancement to economic commercialization remains speculative.
  - SMRs are in very early stages of deployment worldwide.
  - Hydrogen production is currently expensive, and technologies are still developing.
- Some stakeholders shared with Alberta some of their concerns with ECCC's modelling of the draft regulations.
  - The NextGrid model's temporal resolution does not adequately represent reserve requirements to cover historical periods of low renewables generation.
  - The NextGrid model does not sufficiently consider uncertainties to reflect situations of extreme loads, forced outages, low water years, and limited renewables output.
  - The NextGrid model assumes large intertie capacity and use that does not reflect the current reality.
  - Solving for the lowest cost solution for the entire Canadian system can underestimate the actual impacts of the draft regulations to the most affected regions, including Alberta.
  - The upstream costs for renewable natural gas (RNG) and hydrogen blending are not included in the NextGrid model which provides an unrealistic advantage to "capacity only" blending resources.
  - The modelled EoPL costs do not seem to include lost operating years which is an additional stranded asset cost under the CER.
  - The modelling does not consider time required for permitting, approvals, and engagement before new projects can be built.

Carbon Capture, Utilization and Storage (CCUS)

- ECCC's assumed 95 per cent carbon capture effectiveness is not achievable by today's technology, especially given application of CCUS technology on natural gas combine-cycle turbines is still new. Economic commercial maturity and wide-spread technology adoption will take years to achieve, and first-movers often have the disadvantage of working out the kinks and providing lessons learned to other developers.
- Capture rates ranges of 85 – 90 per cent appear to be consistently widespread in the CCUS literature, as they are the values used in Front-End Engineering and Design (FEED) studies, integrated assessment models (IAMs), pilot and demonstrated plants, and a substantial portion of technical analyses, regardless of the technology type, location or the fuel type (Source: IEA GHG[4], IPCC Special Report[5]).

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[4] https://documents.ieaghg.org/index.php/s/CLIZIvBI6OdMFnf

[5] https://archive.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf

- Most gas power plants designs have lower capture rates, often falling within the range of 85 to 90 per cent which is likely an economic compromise between cost and capture rate.
- While achieving a 90 per cent CO_2 carbon capture rate in gas power plants is theoretically possible, it may not be economically or operationally practical for every power plant. The 90 per cent capture rate is typically at the upper end of what is seen the norm in the gas power plants sector.
  Several factors can affect the practicality of achieving a 90 per cent carbon capture rate (Source: IEA GHG, IPCC Special Report).
- Process Limitation**:**
  - Chemical-absorption based processes are the most technologically advanced for post combustion capture of CO_2, with efficiencies that are generally in the range of 85 - 90 per cent. Physical-absorption based removal of CO_2 from high-pressure gas streams is already widely practiced in industry. Commercially available physical absorption processes include Selexol or Rectisol with a capture efficiency of 85 - 90 per cent.
- Cost:
  - With increasing the capture rate from 85 per cent to 99 per cent in the post-combustion capture processes, a 45 per cent increase in electricity costs for coal power plants and a 30 per cent increase for gas power plants would be resulted (Source: IEA GHG).
  - Achieving higher capture rates often requires more advanced equipment, which can impact the economic viability of a power generation facility. The table below provides a summary of how higher capture rate in fossil fuel power plants impact costs of electricity and power plant efficiency. As a reference, the efficiency for a gas power plant with no carbon capture is around 58 per cent (58% LHV%).

Impact of increased capture rate on efficiency and normalized electricity cost for the three capture processes routes for coal and gas fired power plants (Source: IEA GHG)

Process Route	Coal Power Plant		Gas Power Plant	
Post Combustion				
Carbon Capture Rate	85%	99%	85%	98%
Efficiency	33%	26%	47%	40%
Electricity Cost	100	145	100	130
Pre-combustion				
Carbon Capture Rate	85%	98%	88%	99%
Efficiency	39%	36%	47%	45%
Electricity Cost	100	118	100	111
Oxyfuel				
Carbon Capture Rate	90.8%	99%	98%	99%
Efficiency	35.4%	34.5%	45%	45%

Energy Usage and Efficiency

- The table below provides a techno-economic assessment of a natural gas fired combined cycle with post combustion at varied CO_2 capture rates.
- The process of capturing and compressing CO_2 for storage consumes energy, which can reduce the overall efficiency of the power plant. As shown in Table 2, increase of the CO_2 capture rate over the usual 85 - 90 per cent capture rate in a standard post combustion capture plant on a natural gas fired combined cycle results in efficiency decrease as well as capital cost and electricity generation cost increase.
- As CO_2 capture rates are increased, indirect emissions from fossil fuels use become significant, i.e. as the direct emissions tend to be zero, the indirect emissions become proportionately greater. This is a factor to be managed in reducing overall CO_2 emissions.
- Overall a natural gas fired combined cycle can be made CO_2-neutral with 99 per cent capture, at a 7 per cent electricity generation cost increase over the usual 90 per cent capture rate and with an 8 per cent increase in CO_2 avoided cost. It is worth noting that using different designs for the post-combustion capture process does not significantly improve the power plant's overall efficiency or cost-effectiveness.

Techno-economic assessment for a natural gas fired combined cycle with post combustion (PCC) at various CO_2 capture rates (Source: IEA GHG)

	NGCC without PCC	NGCC with PCC		
		Standard PCC plant design		
		90%	95%	99%[7]
Gross power output (MW)	890	890	890	890
Net power output (MW)	878	728	720	691
Net plant HHV efficiency (%)	52.66	43.91	43.37	41.94
Net plant LHV efficiency (%)	58.25	48.57	47.97	46.39
CO_2 emission intensity (t/MWh_e)	0.349	0.0372	0.0176	0.000
Equivalent electrical energy consumption ($MWh_e/t\ CO_2$)	-	0.523	0.526	0.583
Specific capital requirement ($€/kW_{net}$)[8]	939	1611	1629	1716
LCOE (€/MWh)[9]	52.9	77.6	78.9	82.7
CO_2 avoided cost (€/t CO_2)	-	79.3	78.6	85.5

- CER timelines will inhibit the development and widespread adoption of second and third generation CCUS technologies by imposing a strict 2035 date with performance standards that must be met or result in criminal penalties and will negatively impact the private investment decisions that Alberta relies on.
- CER timelines are not synchronized with the federal ITC which strongly incents investments to occur prior to 2030 (requiring decisions in the next year or so) and consideration on what vendors may be able to deliver in 2035.
- ECCC cost assumptions for CCUS are lower than other leading modelling organizations.
    - In the RIAS, ECCC assumes natural gas generation with CCUS has capital costs of $3,310/kilowatt (kW), fixed costs of $33/kW, and variable costs of $4/MWh in 2015.
    - Navius Research assumes natural gas generation with CCUS has capital costs of $3,097/kW, fixed costs of $79/kW, and variable costs of $7.1/MWh in 2015.
- The USEPA has proposed performance standards tied to 90 per cent capture for baseload units with hydrogen fuel blending expectations for intermediate capacity units and efficiency expectations for low-capacity units.
- Historically, Canada and the United States have set performance benchmarks recognizing Best Available Technology Economically Achievable (BATEA). This approach encourages best practices while recognizing that design specifications must be tested through operations and should be re-evaluated over time with demonstrated performance.

Small Modular Reactors (SMRs)

- Alberta is actively exploring the development of nuclear at a variety of scales.
    - Alberta, along with Saskatchewan, Ontario, and New Brunswick have developed a Strategic Plan for the development of SMRs.
    - Alberta has invested $7 million with Cenovus in order to assess how SMRs could be safely, technically and economically deployed in the oil sands. However, the technical, regulatory, and economic viability of this technology has yet to be established, and wide scale adoption in order to meet the arbitrary 2035 deadline is unrealistic.
- Under the Strategic Plan for the Deployment of SMRs, the first grid-scale unit is to be produced at the Darlington nuclear site in Ontario, with the next unit scheduled to be installed in Saskatchewan with an in-service date of 2034.
    - Widespread SMR uptake in Alberta is limited by technology development and will not be viable before the CER-imposed 2035 deadline.

- S&P Global was commissioned by the Government of Alberta to evaluate technology pathways for decarbonization in consultation with Alberta industry. S&P Global's analysis concluded that only a negligible amount of nuclear power could be on the Alberta grid by 2035.

Battery Storage

- Energy storage is poised to play an integral role in supporting grid system reliability, providing a lower-cost alternative to transmission and distribution wires, and utilizing energy arbitrage in Alberta's decarbonized electricity system creating positive outcomes for both reliability and affordability.
- In the RIAS, ECCC modeling shows 869 MW of storage connected to the Alberta grid in 2035, contributing 1,217 GWh to total generation.
    - ECCC assumes grid-level storage has capital costs in 2035 of $865/kW, fixed costs of $11.20/kW, and variable costs of $1.27/MWh.
    - Navius Research assumes 1-hour lithium ion battery storage costs for charging include capital costs of $294/kW, fixed operating costs are $4.5/kW, and variable operating costs are $0.3/MWh in 2015.
        - The only assumed costs for discharging are variable operating costs of $0.3/MWh in 2015.
    - Navius Research assumes hydrogen storage costs for charging include capital costs of $1,969/kW, fixed costs are $16.5/kW, and variable costs are $0.3/MWh in 2015.
        - The costs for discharging are capital costs of $1,658/kw, fixed operating costs of $17.0/kw, and variable operating costs of $0.3/MWh in 2015.

Interties and Transmission

- The CER RIAS has overly optimistic assumptions about capacity and timelines for increased interties with British Columbia (BC). Alberta will work with AESO to validate ECCC's assumptions.
- In the RIAS, ECCC NextGrid model had 1,000 to 1,900 MW with BC in 2034 and then to 2,700 MW in 2044. As noted by the AESO, Alberta has limited intertie connection capacity with neighboring jurisdictions. Alberta cannot rely on significant increases in non-emitting imports/exports to balance its system, as 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 (AESO).[6]
- The weaknesses in the federal impact assessment regime and the time taken to approve major projects such as transmission interties further undermine the credibility of the assumptions of intertie availability.
- Alberta's transmission system evolved to support cogeneration and cannot easily be reconfigured to integrate alternative generation resources (AESO).
    - This contrasts significantly with other centrally planned grids, which consolidate generation and transmission into more linear "backbone" transmission systems like BC, Quebec, Ontario and Manitoba.
    - Development of alternative generation forms would require significant changes to the topography and power flows on the Alberta system, stranding capital and requiring additional investment.

Alternative Modeling of Decarbonization of Alberta's Electricity System

The Government of Alberta is currently working with third party contractors to better model the assumptions outlined in the draft CER as well as to better understand viable decarbonization pathways that consider technological feasibility and costs.

Part 4 – Need for Additional Federal Support

Funding Support

Alberta has been leading the country in decarbonization with our coal phase out and rapid renewable development. However, the province is now faced with an expensive generation, transmission, distribution and system support build out to support continued decarbonization. The 2022 AESO Long-term Transmission Plan (LTP) showed there were already over $1.5 billion in new transmission infrastructure required to support the near-term renewable builds foreseen at that time, which were underestimated – the required transmission build in the province will be much greater.

Alberta is concerned with the significant electrification assumed in the base case as part of the draft CER RIAS – nearly $400 billion attributed to business-as-usual expenses. Canada must acknowledge ratepayers will be faced with the burden to pay

[6] https://www.aeso.ca/assets/CER-Media-Backgrounder_FINAL_Sept-2023.pdf

these tremendous costs, which is likely to present as a significant barrier for decarbonization efforts. Canada should share these costs to reduce this barrier.

The federal government has not acknowledged Alberta's progress to date in reducing emissions, nor has ECCC acknowledged the significant capital costs associated with transmission and distribution to enable renewable generation.

The proposed federal CCUS ITC is insufficient. The draft ITC covers a portion of the capital costs, but there is nothing to support the operating costs. The US *Inflation Reduction Act* offers generous production credits as carrots, while here in Canada we rely solely on carbon pricing. Further, recent rejections of federal CCUS contracts for difference from the Canadian Infrastructure Bank stemming from underfunding and mixed mandate do little to encourage new technology development.

Though the federal government recognizes that national grid decarbonization will be a project rivalling the scope of the railway buildout a century ago, it has not identified sufficient funding support to enable the transition. There must be federal funding provided to Alberta commensurate with the CER impact.

In order to enable the efficient reductions that are available through carbon pricing under TIER for the electricity sector, federal operational supports such as contracts for difference and investment tax credits are necessary. On investment tax credits, the federal government should ensure that it does not inadvertently undermine its emissions reduction goals because some of its key tools, specifically, investment tax credits have key design flaws. Two prime examples are prevailing wage and apprenticeship requirements. Alberta and Canada are competing for investment with other jurisdictions that have significantly more flexible approaches to prevailing wages than is envisioned in the current Canadian proposal; also, these jurisdictions have not mandated apprenticeship requirements that experts in Canadian labour markets acknowledge are unattainable today and in the medium term. Governments, labour organizations, and prospective investors have raised these issues with the federal government repeatedly. Alberta encourages the federal government to work at pace on these issues, and to finalize the investment tax credits in line with the advice it has been provided, in order to allow some projects to advance.

Alberta has achieved significant progress in decarbonizing our grid within a very short time frame. During that time, however, we have experienced price spikes as a result of a number of factors including the coal phase out, retirement of the Power Purchase Arrangements, and proliferation of intermittent wind and solar resources. Price spikes have led to a situation of tight supply and greater opportunity for units to exercise market power. The rapid decarbonization has also created a number of reliability challenges due in part to the pace and magnitude of renewable penetration. For these reasons, affordability and reliability are threatened based on price escalation and intermittency. The CER must build on Alberta's lessons learned in decarbonization and must be significantly altered to support emissions reductions without jeopardizing affordability and reliability.

In 2022, Alberta had 3.123 TWh of generation from simple-cycle (peaking) plants with a total rated capacity of 959 MW. This corresponds to an operating capacity factor of 37 per cent. Responsive peaking plants are required in order to maintain adequate supply in periods of high demand and or low generation from intermittent sources. In order to comply with the CER-imposed 450 hour runtime limit, an additional 6,000 MW of peaking capacity would be required, costing approximately $6.5 billion based on Navius model capital costs of 1,086 $/kW.

Cogeneration has been identified by Alberta and electricity stakeholders as vital to our grid. Cogeneration in Alberta supplies approximately 25 per cent of the power to the Alberta grid. Industry stakeholders have indicated that cogeneration units may opt to shut in and use boilers to meet their heat demand. In such a scenario, Alberta could lose as much as 5,235 MW of baseload capacity required to maintain adequate electricity supply on the grid. Replacing this much generation could cost 1,223 $/kW, totaling up to $6.4 billion for the entire cogeneration fleet.

It is not technically or economically feasible for CCS technology to be applied to peaking plants, as their power output is highly variable. Currently, Alberta has approximately 12,140 MW of installed base-load generation (excluding peakers) from gas fired and cogeneration plants. Navius research cost models assumes carbon capture capital costs of 1,874 $/kW for 90 per cent capture. It is estimated that equipping the existing generation fleet with 90 per cent capture technology would cost at least $22.8 billion.

The typical technical design life of a natural gas generating facility is approximately 45 years. Using a net present value analysis of a typical combined cycle gas plant, it is estimated that the foregone value as a result of a 20 year life instead of 45 years is approximately $606,000 per MW of capacity. The net present value is calculated using capital and operating costs provided by Navius Research and electricity and natural gas prices forecasted to 2050 using Navius Research's gTech model under a reference policies scenario. The calculated value of $606,000 per MW represents the economic value of a generating asset that may be curtailed as a result of the EoPL provision of the CER. If, as many industry stakeholder have indicated, cogeneration units opt to shut in instead of complying with the CER, the foregone value due to the early retirement of these assets is estimated at $3.2 billion.

Policy Outcome	**Potential Cost to Alberta ($ Billions)**
Build-out of peaking plants to comply with 450 hour limit	6.5
Replace generation due to cogeneration shut-in	6.4
Lost economic value from early cogeneration shut-in	3.2
Outfit existing baseload generation with CCS	22.8
TOTAL:	38.8

The information and table above do not represent all the costs of transition in Alberta, but are provided to support ECCC beginning to identify federal funding to support transition of Alberta's electricity sector.

Acceleration of Regulatory Approval for SMRs and Clean Technology

Alberta is a champion of technology innovation to decarbonize our energy sectors. In 2021, Alberta entered an inter-provincial Memorandum of Understanding (MOU) with Ontario, New Brunswick and Saskatchewan to advance the SMRs in Canada. The jurisdictions jointly released a Strategic Plan for Development of SMRs in March 2022, as a path forward for the advancement of SMRs and the opportunity they bring as a source of safe and reliable, zero-emissions energy to power our communities, while meeting the demands of a growing economy and population. Alberta acknowledges that early adoption of SMRs would position the nation as a world leader in new nuclear innovation and a global SMR technology hub, and simultaneously support Alberta achieving our own carbon neutral by 2050 goals.

Alberta expects Canada to work collaboratively with the province to ensure there are no unnecessary regulatory delays in decision-making related to electricity system projects, including the development and adoption of small modular reactors. We would also expect that the importance of timely generation additions be considered when prioritizing potential approvals.