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Alberta's Restructured Energy Market

AESO Recommendation to the Minister of Affordability and Utilities

JANUARY 31, 2024

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Terms and Abbreviations

Abbreviation	Term	Page Defined
AESO	Alberta Electric System Operator	1
AIES	Alberta Interconnected Electric System	9
AS	Ancillary Services	35
AUC	Alberta Utilities Commission	7
AUCA	Alberta Utilities Commission Act	37
CCS	Carbon Capture and Storage	17
CCUS	Carbon Capture, Utilization and Storage	32
CER	Clean Electricity Regulations	7
DFO	Distribution Facility Owner	48
EUA	Electric Utilities Act	7
EWG	Executive Working Group	2
FEOC	Fair, Efficient and Open Competition Regulation	8
FFR	Fast Frequency Response	19
GoA	Government of Alberta	1
GUOC	Generating Unit Owner's Contribution	17
IRP	Integrated Resource Planning	54
ISO	Independent System Operator	2
MAU	Ministry of Affordability and Utilities	1
Minister	Minister of Affordability and Utilities	1
MSA	Market Surveillance Administrator	1
MWh	Megawatt Hour	5
Net-Zero Report	AESO Net-Zero Emissions Pathways Report	3
ORDC	Operating Reserve Demand Curve	30
PJM	Pennsylvania, New Jersey and Maryland (ISO)	21
PPA	Power Purchase Arrangements	16
Primer	Market Pathways Primer	19
Reliability Roadmap	AESO 2023 Reliability Requirements Roadmap	3
REM	Restructured Energy Market	1
RRO	Regulated Rate Option	1
RUC	Reliability Unit Commitment	62
SCED	Security Constrained Economic Dispatch	5
SMR	Small Modular Reactor	17
TMR	Transmission Must-Run	64

1. Executive Summary

The Government of Alberta's (GoA) Minister of Affordability and Utilities (Minister) issued a letter to the Alberta Electric System Operator (AESO) on August 31, 2023, requesting the AESO to conduct a study, in conjunction with the Market Surveillance Administrator (MSA), on the current energy market framework and to make observations and recommendations on the following:

- Market incentives that could be used to mitigate the impacts of the intermittency of supply and promote grid reliability within the province.
- Market design and legislative changes required to deliver those required market incentives affordably.
- The current and future role and potential of different dispatchable technologies, such as carbon-abated natural gas power, full-scale nuclear, small modular reactors, hydrogen-fueled generation, hydroelectric power, and energy storage resources, in supporting this reliability objective.

The AESO's study, observations and recommendations are due to be provided in a written report to the Minister by February 1, 2024.

AESO RECOMMENDATION

The AESO is recommending a Restructured Energy Market with the ability to procure contracts for controllable technologies if required.

The electricity sector is in a time of fundamental change. Every jurisdiction, regardless of its framework, is experiencing reliability and affordability challenges that are becoming more significant as the pace of change increases. Relying on markets and competition will result in the most affordable solutions in the long-term; however, some immediate action is needed. During the transition to a Restructured Energy Market (REM), the AESO, as the system planner and operator, is well-positioned to ensure reliability through deliberate and immediate actions.

AESO Recommendation Objectives

The REM represents a significant change. Combined with foundational and structural changes to Alberta's long-standing transmission policy as recommended by the AESO in its submission to the Ministry of Affordability and Utilities (MAU) recent Transmission Policy Review consultation, the REM will best meet the objectives of:

- Reliability
- Affordability
- Decarbonization by 2050
- Reasonable Implementation

The objectives above were documented by the AESO in response to the Minister's direction, and in consideration of the AESO's core mandate, its understanding of government policy related to decarbonization by 2050 and other objectives, and the practical realities of implementing a large-scale restructuring of the electricity sector. The Minister has confirmed that these objectives are aligned with government objectives.

The AESO's REM recommendation will achieve the objectives as follows:

- **Reliability |** This objective will be met through:
  - Incentivizing the development of controllable[1] generation and technologies.
  - Defining and establishing sound technical requirements for all technologies, especially a new and growing class of inverter-based resources (e.g., wind turbines, solar arrays, and batteries).
  - Procuring the right mix and amount of reliability services to operate the grid.
- **Affordability |** This objective will be met through:
  - Enabling overall least-cost solutions for generation and transmission.
  - Modifying the market design to reduce the role of market power: establishing rules to protect customers by managing market power and preventing sustained excess high-price conditions.
  - The AESO notes that affordability is also addressed through related electricity framework policies including the transmission policy, particularly the cost-allocation and congestion policy, and retail policy such as reform of the regulated rate option (RRO). The AESO supports any government initiative to reform these policies and align them with the recommendation presented in this report.
- **Decarbonization by 2050 |** This objective will be met through:
  - Relying on market forces to drive decarbonization.
  - Contracting for new low carbon emission dispatchable technologies using competitive mechanisms, if needed, to support new investment.
- **Reasonable Implementation |** This objective will be met through:
  - Restructuring the energy market in a timely and transparent manner, which would include a fair and truncated consultation and approval process for the necessary Independent System Operator (ISO) rule changes once the required legislative changes are confirmed.

As part of its assessment in developing its recommendation, the AESO considered the perspectives and views of stakeholders. An Executive Working Group (EWG), which included a broad set of senior leaders representing various stakeholder groups[2], met on multiple occasions through October and November 2023. While a broad range of perspectives were shared that reflected the stakeholders' respective areas of interest, most EWG members recognized the benefits of competition in meeting the objectives and the need for change to the existing market framework, but views varied on the extent of change needed. The critical importance of maintaining reliability through the transition was unanimously supported.

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[1] When referring to different types of supply, the terms dispatchable and controllable are used interchangeably to represent technologies that can be dispatched and controlled in real time.

[2] Including load customers, consumer groups, representatives of municipal utilities, chamber of commerce and rural electrification associations, generators (incumbent, renewable, and new developers), transmission and distribution facility owners and academia.

The MSA participated as an observer in the EWG sessions and collaborated with the AESO through regular meetings. To the AESO's knowledge, the AESO and MSA are recommending materially similar reforms to Alberta's electricity market.

In addition to the EWG, the AESO also engaged with the broader industry through an industry session in November 2023, allowing opportunities for all stakeholders to provide their input on the evolution of the market.

Need for Change

Alberta's current electricity system is being impacted by transformational change. The *AESO Net-Zero Emissions Pathways Report* (Net-Zero Report) and the *AESO 2023 Reliability Requirements Roadmap* (Reliability Roadmap) noted key operational and reliability challenges that are having implications on the sustainability of the electricity market as currently designed in Alberta. Taken individually, the market has proven to be adaptable to many of these changes. However, the need for more structural change to the market design and provincial electricity policy, such as the *Transmission Regulation,* is being driven by the combination of the following emerging trends:

- Technological shifts changing where and what type of resources power the grid.
  - Like other regions across the globe, Alberta is experiencing a significant change in its generation fleet with the reduction in carbon-emitting generation sources and the increasing pace of development of variable renewable generation resources (i.e., wind and solar). The integration of these resources is important to support a carbon-neutral future. However, these resources must be operated with an accompanying mix of controllable resources.
  - Increasingly, supply is not providing attributes that are required to maintain reliability without the need for additional ancillary services and/or technical requirements.
- Factors external to the market such as renewable energy credits and other similar revenue sources that incentivize renewables development outside of electricity market incentives.
- Uncertainty related to federal policy such as the proposed *Clean Electricity Regulations*, which represents high-risk to investors in gas-fired controllable generation technology. Generation may not be available to ensure adequate supply.

These changes are resulting in challenges to both reliability and investor confidence, which negatively impact the long-term investment signal for supply in Alberta's electricity market. Ensuring effective price signals to manage short-term reliability and incent investment in technologies to maintain reliability is increasingly important as the electricity system transforms into a carbon-neutral future.

Provincial policy changes in separate but related electricity framework elements such as the *Transmission Regulation* are also needed to support the transformational changes on the AIES.

Alberta's open grid access and unconstrained transmission policy have enabled the rapid development of emission-free renewables in concentrated areas of the province, resulting in additional constraints on the transmission system, reliability challenges, and increasing system costs borne by consumers.

Policies and the current electricity market are not structured to address current and emerging challenges.

Recommended Changes and Implementation Approach

The AESO remains steadfast that a competitive, market-based structure for wholesale electricity is the best means of promoting continued investment in the province, ensuring affordability through competitive outcomes, and delivering on Alberta's long-term supply adequacy and reliability needs.

The AESO believes a phased-in REM design will most effectively address the issues previously outlined, while ensuring reliability and affordability into the future. The design changes under the REM represent significant changes to the Energy-Only Market while still leveraging the underpinning structure. These are "no regrets" modifications that are required regardless of future path. The restructuring of the energy market will result in stronger incentives for dispatchable generation, lessen the impacts of market power, and provide long-term signals for investment to promote grid reliability within the province. A phased-in approach will enable key actions under the REM that will provide:

- Immediate price protection for consumers and maximize the reliability characteristics of the current supply fleet in the near-term.
- Incentives for investments in dispatchable technologies and demand response in the medium-term.
- The option to directly contract for new controllable supply if needed in the long-term to ensure reliability.
  - This lever, if enacted, will impact investor confidence and the investment signal in the REM. Therefore, it is viewed as a "no turning back" option that should only be used if REM changes are ineffective at getting the required investment. These are discussed further in the following contracting sections.

Transmission policy changes are also a key factor in the overall restructuring of the electricity market. In addition to the recommended restructuring of the energy market, transmission policy changes to support stronger locational signals and optimize new transmission build, while ensuring reliability, are expected to:

- Address reliability challenges.
- Provide effective long-term investment signals in an affordable way.

NEAR-TERM IMPLEMENTATION (6 MONTHS TO 2 YEARS)

The REM is a major, phased overhaul of the existing energy market and will take at least three years to implement. While development is underway for the more complex changes, the following are actions the AESO can implement on a near-term basis to promote affordability and manage reliability.

- Establish an interim market power mitigation framework focused on limiting the offer prices of large generation firms when they have substantial market power once sufficient revenue has been earned to recover fixed costs.
- Pursue additional operational actions to commit units for reliability.

- Procure additional reliability services from dispatchable assets.
- Enhance technical requirements to mitigate the intermittency of supply.
- Increase intertie capability through the procurement of services to enable further access to neighbouring jurisdictions.
- Other actions as needed to support system reliability.

The AESO expects there to be adequate supply in the near-term with gas generation additions under development; however, if required the AESO can also engage in contracts for strategic reserve to ensure the continued availability of the existing generating fleet to maintain supply adequacy.

MEDIUM-TERM IMPLEMENTATION (2 TO 5 YEARS)

While the near-term implementation is underway, it is important to progress the development of the REM design changes that are needed to further augment the market. The following changes will provide incentives for investments in dispatchable technologies and demand response, further address the price volatility issues, improve grid operation, and improve utilization of the transmission system.

- Introduce a day-ahead market to provide additional certainty for generation and to incentivize the availability of controllable generation.
- Replace economic withholding with administrative scarcity pricing mechanisms as the fixed cost recovery mechanism for suppliers.
  - Economic withholding allows generators to recover their fixed costs and promotes long-term investment.
  - If economic withholding is removed or limited from the market, an increase in the price cap is necessary to promote long-term investment and reasonable cost recovery.
- Increase the price above $1,000/megawatt hour (MWh) during limited situations (supply scarcity) to support long-term investment and ensure fixed cost recovery.
  - This will replace the current approach, where high prices are tied only to generators' offers; instead, they will occur during limited instances of true supply scarcity.
- Include a measure to limit the price cap once reasonable fixed cost recovery is achieved to protect consumers against excessive cost.
- Implement improved dispatching tools, such as Security Constrained Economic Dispatch (SCED), to ensure efficient and reliable dispatch of resources reflecting various constraints on the system and minimizing cost.
- Co-optimize energy and ancillary services to minimize costs and enable additional reliability.
- Shorten settlement intervals and implement negative pricing to improve price signals for flexible generation, controllable demand, intertie transactions, and storage.
- Modify the *Transmission Regulation* and the ISO tariff to send improved locational signals for siting generation, and allocating costs based on cost causation.

LONG-TERM IMPLEMENTATION (5+ YEARS)

With expected installed capacity additions, the AESO anticipates that there is enough supply to meet forecasted demand over the next decade. Further, the REM is expected to better support the needed investment in controllable, firm generation to meet the province's needs for supply adequacy.

The AESO will continue to monitor supply adequacy closely and, should further support be required to incent the development of controllable generation to maintain supply adequacy, the AESO recommends the use of targeted contracts for controllable capacity to enable additional investment in the province at that point in time.

Specific contracts for controllable technologies that are compatible with the REM could be introduced to support new investment in the supply necessary to reliably meet demand. The introduction of these contracts is a "no turning back" decision and should therefore not be taken lightly. This is because long-term contracting represents a significant intervention in the market that could result in a cessation of investments in controllable supply not supported by contracts, impacting the market's ability to maintain adequate supply.

The AESO has reviewed alternative frameworks, such as Long-Term Contracts under an integrated or centralized resource planning model. In the review, the AESO found significant drawbacks to moving to such a structure, absent a strong need for it, including the following:

- Centralized planning models:
  - Limit the information and knowledge determining the resource mix and location, from a full set of market players to one central planner, hindering innovation.
  - Transfer cost risk onto consumers from private investors, including potentially locking in sub-optimal technologies for long periods of time.
  - Are expected to lead to higher-cost delivered electricity.
  - Require significant regulatory oversight and a mechanism to address or cover the costs of past investments made.

The AESO's long-term adequacy studies indicate sufficient supply over the next decade. As such, the AESO recommends launching targeted procurements for new controllable supply only on an as-needed basis. To ensure sufficient time for contracting and development should the supply not materialize in the REM, a procurement would need to be initiated in the late 2020s/early 2030s. As noted above, the AESO will continue to monitor adequacy of supply, and if the REM is not forecasted to incent sufficient investment, a procurement to ensure sufficient supply adequacy to maintain long-term reliability would be launched.

CONSIDERATIONS RELATING TO CONTRACTUAL MECHANISMS

The development of generation through any form of contract will negatively impact the efficiency outcomes of the wholesale market and the long-term investment signal. To support overall affordability, out-of-market action, in particular contracts, should have a clear and fixed boundary on how much capacity should be procured. Typical boundaries that can be employed to alleviate the impact of contracts on the energy market investment signal and rate-payer risk include:

- Limiting the contracting of generation to the megawatt volume anticipated to be needed to serve reliability and supply adequacy needs over a given timeframe.
- Limiting technology-specific procurements; procurements should aim to be technology-agnostic.

- Limiting contract payments to cover only a portion of total resource costs, so that resource owners must continue to recover variable costs and a portion of investment costs via the energy and ancillary services markets.
- Limiting the timeframe for the contract.
- Communicating the timing and size of procurements to investors so the market can respond to expected changes in supply, and many project developers can offer the most competitive projects.

These contracts would provide sufficient certainty of fixed-cost recovery for investments in new supply, while encouraging participation in the energy market, limiting consumer liability, and promoting efficiency through competition. This would represent a significant shift to the long-term investment mechanism in the electricity market and, once announced as the path forward, nearly impossible to adjust from.

If the use of contracts for controllable capacity to enable additional investment in the province is needed, they are expected to have a potential term of up to 10 to 20 years, which will achieve certainty around long-term adequacy. These contracts can be designed to incent new dispatchable, low-emitting, controllable generation. The AESO could identify the need for the contracted supply, lead their procurement, and act as a counterparty with private generation companies that would build, own and operate their facilities under the terms of the contract. The AESO has experience in developing and executing fit-for-purpose procurement processes through the procurement of reliability services, the Renewable Electricity Program and the competitive procurement of transmission infrastructure.

Alternative to Contracting Mechanisms

The AESO recognizes that existing decarbonization policies such as the *Clean Electricity Regulations* (CER) as currently proposed introduce significant uncertainty to the market. This will have an impact on the long-term investment signal. The short timelines and stricter requirements under a potential CER negatively impact investment in controllable technologies such as carbon capture utilization and storage (CCUS).

There are circumstances where alternative mechanisms to the proposed contract for controllable capacity may be required, these include:

- A policy desire to support the development of specific technologies for which a private entity would have difficulty taking on the financial and regulatory risk, such as nuclear power generation; or
- A need to manage the legal liability of accelerated federal emissions reduction requirements.

In these circumstances, more direct government support or ownership may be appropriate to financially underpin the investment or assign liability to the province. There are several ways to implement these alternative mechanisms that may be explored, if required.

Next Steps

The AESO notes that the electricity framework is comprised of multiple overlapping policies related to wholesale power generation, transmission and distribution, and retail and consumer demand participation. The AESO recognizes that at the time of submitting this report to the Minister, the Government of Alberta has initiated a review of many of these policies. The recommendations presented in this report are compatible with a variety of related policy alternatives, especially those related to the transmission policy.

The REM changes proposed by the AESO are significant and will require further detailed design. Impacted legislation includes the *Electric Utilities Act* (EUA) and related regulations including the *Fair, Efficient and Open Competition Regulation* (FEOC). Further consultation by the AESO with industry will be required to determine the specific REM design and implementation details, ISO rule revisions, and information systems that will be required.

In conjunction with the process for required legislative change, the AESO proposes a detailed design phase to be launched in 2024, which includes comprehensive stakeholder consultation to consider the ISO rule changes required to implement the REM design.

Following this consultation process, the AESO believes that a condensed six-month Alberta Utilities Commission (AUC) process for ISO rule approval would be a preferred approach to minimize industry uncertainty and implement these changes in a reasonable amount of time.

The AESO's proposal for a time-bound, condensed regulatory process before the AUC will streamline the standard ISO rule approval process and ensure efficient implementation of the provincial government's desired path forward. If clear policy direction from the provincial government is secured in early 2024, implementation of the necessary new and amended ISO rules required for the REM could occur in 2026. Further details, such as necessary IT system changes, would be initiated and developed in parallel with staged implementation.

In parallel with the detailed design consultation, the AESO will continue to progress the near-term changes to support reliability, and if directed the design and implementation of an interim market power mitigation framework.

The REM is most effective if implemented in its entirety as many changes proposed in the REM are interrelated and work together to achieve reliable and efficient market outcomes. The exception is long-term contracting, which should only be implemented if required.

The AESO thanks the Alberta government for the opportunity to provide recommendations on the evolution of the future electricity framework in the province.

2. Introduction

The AESO has a critical function in Alberta's electricity market and is responsible for the safe, reliable, and economic operation of Alberta's electric system. Further, the AESO has a public interest mandate, with no commercial ownership interests within the industry, and therefore the AESO's expert analysis is objective and considers the impacts on a wide range of stakeholders.

Since Alberta's electricity market de-regulation, the AESO has fulfilled its mandate of acting in the public interest, providing vital leadership and knowledge in the ongoing transformation of the electricity system in Alberta. The AESO has proven expertise in effectively managing and operating the electricity grid, planning and operating the market, planning the future of the electricity system and its infrastructure, and connecting customers to the electricity grid. The AESO is also the interface between the Alberta electric system and neighbouring power grids, responsible for coordinating exchange over the interties with our neighbouring provinces and with Montana.

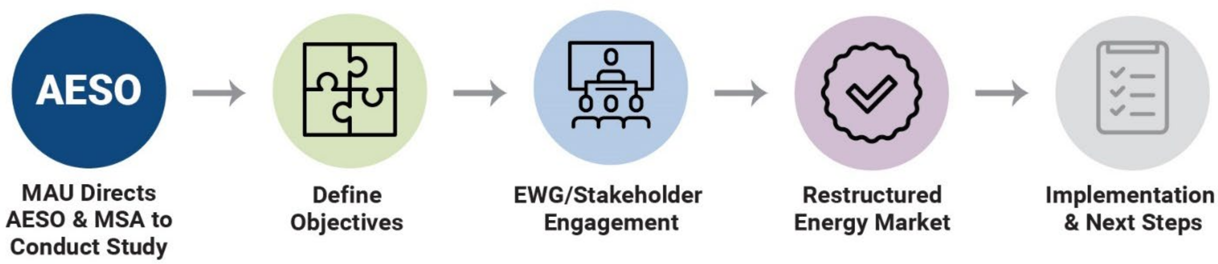
During the past several years, the AESO has actively planned and managed the Alberta Interconnected Electric System (AIES) during an unprecedented rate of change within the electricity sector driven by accelerated technological shifts, external factors affecting the market, and a rapidly evolving carbon policy environment.

As part of the AESO's leadership role in industry, this report presents its observations and recommendations on Alberta's wholesale market design and role for dispatchable technologies as requested by the Minister on August 31, 2023. The AESO recommends a Restructured Energy Market (REM) to meet the primary objectives for the wholesale electricity market; and provides observations on the range of dispatchable technologies that can play a role in supporting reliability.

The AESO's recommendation considered input from industry stakeholders (an overview of the stakeholder consultation process is provided in Appendix I). An EWG was developed to gain insights from industry on the challenges facing the electricity industry and the future evolution of the electricity market. The AESO engaged with senior industry leaders from a diverse range of stakeholder groups (conventional generation, renewables/storage, distribution and transmission facility owners, load, consumer groups, associations, and academia). Stakeholder input from the EWG is summarized in Appendix II.

The AESO also coordinated with the MSA throughout the development of this recommendation. To the AESO's knowledge, the AESO and MSA are recommending materially similar reforms to Alberta's electricity market.

Figure 1: AESO Recommendation Development



3. Objectives

The AESO developed objectives that have guided its recommendations captured in this report. These objectives reflect the needs of a rapidly transforming grid, the reliability mandate of the AESO, and the affordability and decarbonization objectives of the Government of Alberta and its supporting agencies in the electricity sector. These objectives were confirmed by the Alberta Minister of Affordability and Utilities in correspondence on November 7, 2023, and are outlined below.

- **Affordable Electricity for Consumers** – Market incentives and design should achieve the lowest overall delivered cost of electricity. Specifically, recommended solutions should:
  - Create price signals that promote economically efficient outcomes.
  - Reduce reliance on the exercise of market power via economic withholding.
  - Bring about more stable energy prices that are as low as possible when considering other objectives.
  - Incent the optimal use of existing transmission and distribution infrastructure.

  In achieving these outcomes, market incentives and design should maintain a high degree of confidence and willingness to invest in new generation supply from private investors and allocate risk to those who can most efficiently manage it.

- **A Reliable and Resilient Electricity Grid** – Market incentives and design should ensure reliable power delivery. A sufficient range of reliability attributes and supply technologies is available to keep the lights on during the various system conditions for which Alberta must be prepared.

- **Decarbonization by 2050** – Market incentives and design should enable a net-zero electricity sector by 2050 by delivering on the key objectives and principles in Alberta's Emissions Reduction and Energy Development Plan. Recommended solutions should:
  - Drive innovation and investment in new sources of low-emitting, dispatchable power that supports the continued development and delivery of Alberta oil and gas (e.g., carbon capture, utilization and storage; small modular reactors; hydrogen).
  - Support reasonable, affordable and socially responsible development of renewables generation.
  - Ultimately, be compatible with the outcome of federal and provincial negotiations on the *Clean Electricity Regulations*.

- **Strategic Opportunities with Neighbour Jurisdictions** – Market incentives and design should support a range of transmission intertie scenarios, including increasing existing intertie capacity or creating new interties that could, among other things:
  - Contribute to greater reliability and affordability for Alberta consumers.
  - Facilitate export opportunities for Alberta's renewables generation to offset extra-jurisdictional emissions.
  - Formulate partnerships with Alberta's neighbours to set up energy corridors or unlock other energy synergies.

- **Implementation by 2026** – Recommended market incentives and design, as well as corresponding legislative changes, should be capable of being implemented within two years of policy confirmation. Costs of implementation and resources required to support implementation are practicable.

During its stakeholder consultation with the EWG, the AESO undertook an in-depth review and discussion of these objectives. An insight from this process was to recognize the overlap of two objectives: *Decarbonization by 2050* and *Strategic Opportunities with Neighbouring Jurisdictions*. Fundamental to this overlap was a recognition that future development of intertie infrastructure would be informed by policy that addresses both these objectives. As such, the AESO has considered these objectives concurrently in our evaluation of recommendation alternatives in Section 5.3. The EWG further identified:

- The importance of the objectives highlighting the role of customer choice.
- The need for a robust investment climate in any market design.
- Recognition of potential alternative decarbonization timelines and transition considerations.

These points were incorporated into the objectives guiding this recommendation.

4. Current Market Framework & Need for Change

Alberta's current electricity system is being impacted by transformational change. Every jurisdiction, regardless of its electricity delivery framework, is experiencing reliability and affordability challenges that are becoming more significant as the pace of change increases.

Alberta's current market framework has supported investment in reliable, affordable electricity over the past two decades. However, the transformation in the sector is having impacts that are driving the need for fundamental changes to the current market framework.

4.1 Current Market Framework

It is important to provide context and background on the current Alberta market framework to understand the recommendations in this report. The following is a brief summary.

Alberta currently operates a self-commitment, real-time, Energy-Only Market with a single clearing price. An Energy-Only Market means generators compete to deliver energy to serve load and earn the wholesale market price, which is paid to generators only when they produce and deliver energy to load customers. Generators in Alberta do not receive payments for capacity. Alongside a comparatively small market for ancillary services, the revenue earned in the wholesale market is the key revenue available to attract investment in conventional forms of dispatchable generation (renewable technologies have recently become an important exception to this, which is discussed further in Section 4.2.1).

The Energy-Only Market aims to ensure a reliable supply of energy in both the short- and long-term. Short-term supply adequacy refers to the immediate balance between supply and demand, which depends on the availability and flexibility of current generation resources and import/export capability across the interties. Long-term supply adequacy means sufficient generation capacity and import capability are in place to meet demand over an extended period.

The current market design attracts investment through suppliers having the potential to raise the energy price by offering above their marginal cost (economic withholding). This feature allows suppliers to earn the necessary return on capital to support their investment. Without it, suppliers would not be able to recover their fixed costs. Periods of tight supply allow for increased economic withholding and higher prices. However, the exercise of market power will be limited over a multi-year timeframe because high prices will attract new entry, lowering average prices.

The price in the wholesale electricity market is limited to $1,000/MWh. The price cap balances protecting consumers by limiting wealth transfers from consumers to producers while still allowing suppliers to recover their investment. A price cap that is **too low** will not:

- Allow prices to reach sufficient levels to incent load to reduce consumption.
- Encourage adequate response from generators or importers in the short term in scarcity conditions.
- Incent new entry in the long term.

A price cap that is **too high** may allow suppliers to collect excessive rents or profits.

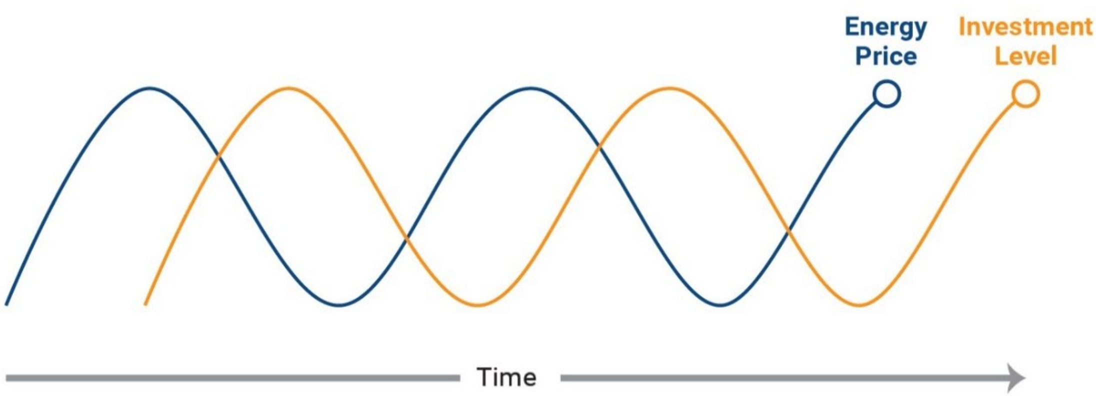
4.1.1 Alberta's Investment Cycle and Long-Term Supply Adequacy Mechanism

Alberta relies on private investment in new generation to ensure long-term supply adequacy, by attracting needed investments primarily through wholesale energy prices[3]. The AESO has a role in this dynamic as the architect of the overall market design, informing the incentives for private investors to develop future generation. Generation developers currently consider a number of factors in their decision to invest in Alberta:

- Stability and predictability related to market structure and policy.
- Transmission access and ability to deliver electricity to customers.
- Construction and financing costs.
- Future expectations for revenue from energy and ancillary services markets sufficient to provide an attractive return on capital.

To date, private investment decisions based on wholesale prices from the Energy-Only Market have attracted timely entry of new generation and the retirement of aging assets. Relative stability in the market policy framework over time has supported private investors in assessing market conditions and deciding what type, when and where to build generation assets. Once built, new assets are included in the merit order and can set price based on real-time demand. Because of this, Alberta's energy price level is dynamic over the long-term and provides a stronger investment signal when prices are high and a weaker signal when prices are low. Figure 2 provides a stylized depiction of this investment cycle. Historically, this has resulted in adequate supply of power generation along with the attributes needed to maintain the reliable operation of the electricity system.

Figure 2: Investment Cycle

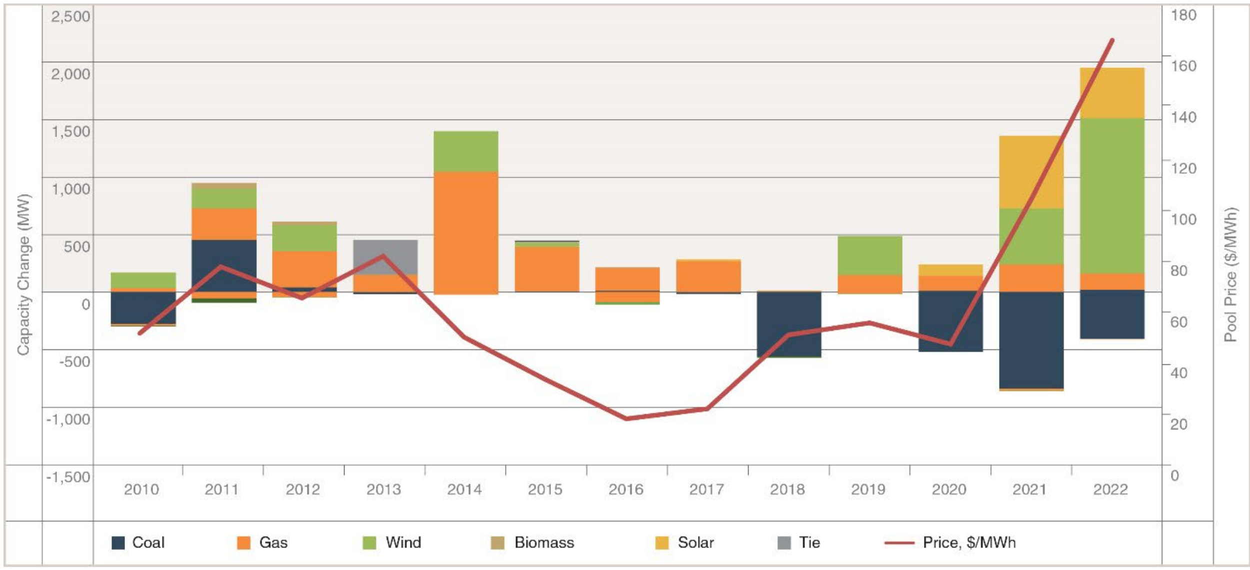


The historical performance of the Alberta energy market aligns with the theoretical performance expectations of an Energy-Only Market. The past three years have seen relatively high prices. However, when put in context of the supply cycles previously described, prices over the past decade have been modest compared to previous periods. The inflation-adjusted 10-year average pool price for 2014–2023 was $74/MWh, compared to $109/MWh for the 2000–2009 period.

[3] The AESO monitors supply adequacy through Long-Term Adequacy metrics and would take out-of-market action to address shortfalls if they exceed the defined threshold for a two year forward period.

While high-priced periods may be undesirable for consumers in the short-term, they support new investment in generation, which drives down the cost of electricity over the long run. Figure 3 shows the impact of generation additions on price since 2010.

Figure 3: Historic Generation Additions/Retirements and Pool Price



As a result, the current market design has enabled both long-term supply adequacy and a reliable system. The market design feature of a price cap high enough to permit a reasonable level of economic withholding while protecting consumers from extreme price spikes has resulted in adequate returns in generation for investors. The generation types that have made up the bulk of historical supply investments have largely come with reliability attributes that the power system needs:

- Inertia
- Frequency stability
- Voltage and reactive power support
- Overall controllability

An unconstrained transmission system and open system access have made Alberta an attractive place to invest in generation. These two policies have worked in tandem to ensure enough generation investment in the province to meet demand growth over time.

A more detailed description of the current market framework is included in Appendix III.

4.1.2 Alberta's Current Short-Term Supply Adequacy Mechanism

The AESO is at the center of managing short-term supply adequacy and reliability by:

- Dispatching generation in the energy market.
- Procuring ancillary services for reliability needs.
- Planning and directing the operation of the transmission system.
- Coordinating imports and exports.
- Ensuring that the correct technical requirements are in place for the reliable operation of all generation assets connected to the electric system.

The AESO's tools for managing short-term adequacy and reliability are limited by the capabilities and reliability attributes of existing generation, transmission, and intertie assets. As the mix of these assets evolves through market participants' individual investment decisions, so too do the capabilities and attributes of the system.

In Alberta's market, individual market participants decide to start a unit or take it offline based on expectations of system conditions and price outcomes. This is referred to as self-commitment. A benefit of this feature is that market participants are in the best position to make decisions for their assets as they are responsible for managing the costs of starting units. However, this does not provide a guarantee that short-term supply adequacy needs are met, as there is no centralized commitment process to ensure enough online dispatchable firm generation is available to manage real-time variability in supply from intermittent generation.

4.2 Need for Change

The current market design has resulted in a significant amount of investment in a diverse supply mix that has met the long- and short-term supply adequacy and reliability needs of the market. However, the existing market was designed at a time when all generation resources were built:

- Mainly to serve load.
- When their output could be controlled.
- When new investment did not face increasingly strict (and highly uncertain) emissions limits.

Taken individually, the flexibility of the market has proven to be adaptable to many of these changes. However, the need for more structural change to the market design and provincial electricity policy, such as the *Transmission Regulation,* is being driven by the combination of the following emerging trends:

- **Accelerated technological shifts** are driving the need for broader electricity market and policy changes.
- **Increasing investment is being driven by incentives external to the market** such as renewable energy credits that incentivize renewable-resource development.
- **Uncertainty related to federal policy** such as the proposed *Clean Electricity Regulations*, creates substantial risk to investors in gas-fired controllable generation technology.

Following is an overview of the impact of these emerging trends on current provincial electricity policy, and considerations for change.

4.2.1 Consequences of Emerging Trends

Accelerated technology shifts are driving the need for broader electricity market and policy changes.

The electricity market and policy must adapt to growing technology-related changes to the generation fleet to ensure sufficient supply adequacy in the short- and long-term. Consistent with global trends, Alberta is experiencing a significant shift from carbon-emitting controllable generation sources to variable renewable generation resources (i.e., wind and solar). While the integration of renewables supports a carbon-neutral future, they cannot directly replace controllable generation, and in Alberta must therefore be used in conjunction with a mix of controllable resources.

- **New technologies have a deficiency of certain reliability attributes.** The rise of inverter-based technologies alongside a decline in grid-synchronized generation is creating deficiencies in important reliability attributes like frequency stability, system strength, and flexibility. It is crucial to incentivize investments in technologies that can provide all necessary reliability attributes. The evolving generation mix is driving the need for improved technical requirements and well-defined ancillary services to encourage investment in technologies with these attributes.
- **New resources added to the grid have increased transmission congestion.** In the past two years, real-time congestion has surged due to a concentration of wind and solar in certain areas. Typical transmission development timelines of greater than five years are misaligned with the pace of renewables development, with typical development timelines of less than two years. Further exacerbating the issue is that the production from many renewable generation facilities commonly occurs at the same time, stressing the transmission network during peak renewables output. This reduces the ability to deliver low-cost renewables generation.
- **The market has experienced increased price volatility and overall sustained higher energy prices.** Two main factors that have recently impacted wholesale market prices are the exercise of market power from large participants and the price-dampening effect of additional zero marginal cost offers from renewable resources. These factors have affected the distribution of wholesale prices, resulting in higher average prices and more instances of zero-dollar prices. The average wholesale price has climbed from $55/MWh in 2019 to $162/MWh in 2022. Market concentration has recently increased with the expiry of the Power Purchase Arrangements (PPAs) at the end of 2020 (the offer control of several large thermal assets was returned to the original owners of the assets from the Balancing Pool). This results in more opportunities to exercise market power during tight supply conditions. Other factors are also impacting prices, such as:
  - Increased generation retirements.
  - Less investment in controllable technologies like natural gas-fired generation.
  - More investment in non-controllable technologies like wind and solar.

  Low prices have occurred more frequently, as production from wind and solar resources offer at zero dollars. In the future, higher price volatility and lower overall prices may discourage entry by new participants to invest and compete in the market.

- **Technology uncertainty is leading to concerns with long-term adequacy.** Alberta's long-term supply levels are expected to be adequate with new gas generation coming online in 2024. However, Alberta's coal-to-gas fleet is expected to fully retire by the late 2030s because of increasing carbon prices and federal natural gas regulations. Although many of these assets can operate through to 2037, they may retire earlier at their owner's discretion. This controllable capacity will need to be replaced. There is a potential risk that new low-carbon emission controllable technologies like abated natural gas generation, hydrogen-fueled generation, and nuclear small modular reactor (SMR) technologies may not materialize, as these replacement technologies are not yet commercialized. Further details on dispatchable technologies, including commercial readiness, are provided in Section 8 of this report.

Increasing investment driven by incentives external to the market.

External investment signals such as renewable energy credits and other similar revenue sources incentivize renewable development outside of the investment signals provided by the electricity market. These out-of-market incentives compensate for energy production from certain types of technology and have encouraged investment in the lowest-cost technologies, without accounting for the reliability and flexibility impacts on the broader system.

Investors in dispatchable technologies rely on the energy market price to recover their investment costs. Similar production incentives are not available to dispatchable technologies, which can lead to disproportionate investment in technology of one type. The current electricity market fails to fully provide sufficient revenues to incent investment in dispatchable technologies while also failing to impose the requirements and costs on variable technologies needed to maintain sufficient levels of reliability and flexibility. Modifications to the market are needed to value the attributes needed to maintain reliability more appropriately. Even after these modifications, the risk remains that investment will continue to be distorted in favour of non-dispatchable technologies by out-of-market production incentives.

Uncertainty related to federal policy such as the proposed *Clean Electricity Regulations* (CER) creates substantial investment risk.

Due to uncertainty related to federal policy such as the proposed CER, it is unclear if investment in new controllable thermal generation will continue. At this time investments in unabated dispatchable thermal technologies are hindered by the aggressive emissions reduction requirements in the draft CER. Also, it is widely recognized that the development and adoption of technologies aimed at reducing carbon emissions from fossil-fueled generation (such as carbon capture and storage [CCS] and investment in small modular reactors) face several impediments (described in detail in Section 8).

Provincial policy changes in separate but related electricity framework elements such as the Transmission Regulation are also needed to support the transformational changes on the AIES.

Alberta's open grid access and unconstrained transmission policy have enabled rapid investment in emission-free renewables. However, the pace and volume of investment in these resources are revealing some new challenges. The current transmission policy and electricity market are not structured to address these emerging challenges. Resolving these challenges will require careful restructuring of both the electricity market and provincial transmission policy.

Currently, locational signals such as the Generating Unit Owner's Contribution (GUOC) and loss factors have provided limited incentive to locate new investments that make efficient use of existing transmission capability. Stronger locational signals could help make better use of—and more cost-effective future investments in—the transmission system.

Recently, Alberta's "zero-congestion" and "load pays" policies have become increasingly pertinent to the electricity affordability discussion and a focus for stakeholders. Under the current transmission policy framework, the AESO is required to plan the transmission system such that all in-merit electricity can be delivered from suppliers to consumers without constraint.

Load customers pay for the costs of the transmission system because, historically, the main driver of transmission system development was to facilitate the one-way power flow from centralized generation sites to customers. From the load customer's perspective, there was value in an unconstrained transmission system to foster a competitive generation market, clustered in centralized areas, and efficiently dispatched to meet the highest demand hours.

Today, the transformation of the AIES is shifting the landscape and potentially altering the value proposition for load customers to pay for an unconstrained transmission network. Connecting renewables generation has become one of the main drivers for transmission system development. System access requests from renewables generation have begun to fully utilize the existing capabilities of the transmission network. Increasing volumes of transmission congestion and continued strong interest in developing additional generation indicate the need for future transmission expansion. Further, as transmission congestion increases, a more complex market for efficient and reliable dispatch is required. Given the transforming nature of Alberta's electricity grid and these emerging challenges, a broader review of cost allocation and congestion policy is warranted.

To address the challenges previously outlined, broader changes are required to incent the attributes and support the investment in controllable supply needed to support long-term supply adequacy in the future. However, to maintain reliability today, the AESO will continue to maximize the capabilities of the current system through enhanced rules, technical requirements, or ancillary services products. The section that follows outlines the current actions being taken to support the reliable operation of the electricity grid.

4.3 Current Actions to Address the Need for Change

The AESO has been taking immediate and deliberate action to address the current challenges on the system until the REM changes outlined under the Energy-Only Market recommendation can be implemented. The AESO has identified certain issues that will impact the electricity system in the Reliability Roadmap and the *Market Pathways Primer* (Primer). Among the initiatives that are currently underway, the most important are highlighted below. Further detail on each initiative, as well as other actions the AESO is exploring in the near-term, can be found in Appendix IV of this report.

Table 1: Priority Objectives and Actions

Objective	Near-Term Action	Implementation Details
Address intermittency of supply and promote grid reliability	Procure Fast Frequency Response (FFR)	Procuring additional FFR to increase intertie capability, supporting increased reliability in 2024.
	Increase Regulating Reserves	Procuring additional reserves to manage high variability periods.
	Define technical requirements on inverter-based resources such as wind, solar and energy storage	Developing technical requirements to improve performance to support reliability.
	Review long lead-time energy requirements	Reviewing long lead-time rule requirements and related information documents for changes to address potential gaps. Under the current framework and ISO rules, the AESO has the ability to direct or commit a long lead-time asset to meet short-term supply adequacy if the asset is offline. There is an associated payment mechanism if the asset is directed by the AESO. To date, the AESO has not needed to act on this reliability lever.
Provide more information on the availability of generation to promote competitive response	Increase market transparency for long lead-time energy	Currently publishing a market supply cushion report to provide better information to the market on available supply. The AESO intends to make further information available on long lead-time energy in 2024.

5. Options

The AESO has identified options to address the long-term and short-term adequacy challenges. Options to manage long-term adequacy vary based on the mechanism that incents long-term investment and could involve significant changes to the overall industry framework. Many short-term supply adequacy solutions are consistent across the different frameworks and could include minor or more extensive changes to the current energy market structure.

5.1 Framework Options

Four high-level electricity market frameworks meet long-term supply adequacy needs on a spectrum from market-oriented to centrally control. The main features that set each apart are listed, with more detailed features within the frameworks that vary by jurisdiction. Figure 4 shows how these frameworks relate to one another along the spectrum.

Figure 4: Framework Options

The advantages and disadvantages of each framework have been comprehensively considered by the AESO, in consultation with industry. There are extensive details and tradeoffs associated with each of the frameworks, but the main differences, advantages and disadvantages of each framework are summarized as follows.

5.1.1 Energy-Only Market

In an **Energy-Only Market** the supply type, size, and timing of investments are determined by private investors without direction from a central agency based on expected market conditions. For example, in Alberta, the long-term investment signal comes from wholesale prices in the Energy-Only Market. In these markets, the approach to economic withholding or scarcity pricing needs to be carefully designed to provide a sufficient return to investors to support investment over the long term. Inadvertently reducing this investment signal may result in inadequate supply to meet load and reliability.

Advantages	• Low administration costs. • Investment risks that are borne by investors. • Creates incentive for innovation. • Relatively little regulatory oversight by virtue of its simplicity.
Disadvantages	• Less certainty of sufficient supply over time. • Price volatility—needs periods with prices high enough to allow market participants to recover the costs of their investment (which may occur either through economic withholding or a scarcity pricing mechanism).

5.1.2 Capacity Market

A **Capacity Market** is a competitive auction for capacity to meet supply adequacy targets. The long-term investment signal comes through the auction (and to a lesser extent the energy market). A real-time energy market is used to coordinate real-time dispatch of generation. Many other electricity markets such as the New York ISO, ISO New England, and Pennsylvania, New Jersey and Maryland (PJM) rely on Capacity Markets to provide long-term investment signals.

Advantages	• Provides a long-term price signal to efficiently attract the desired level of long-term supply.
Disadvantages	• Higher administrative costs to administer the auction. • Risk of under or over-procurement due to forecast error of capacity requirement. • Some investment risk in generation is shifted from investors to consumers through the capacity payments.

5.1.3 Long-Term Contracts

Long-Term Contracts are issued by a central agency to support investment to meet long-term supply adequacy (and potentially other requirements). The type, size, and location of the resource can be specified through the contract structure, if desired. A real-time energy market is used to coordinate real-time dispatch of generation.

Contracts can be used to support the entire market or, if carefully designed, only a portion. Either a private entity or a crown corporation could own the resource. Ontario has Long-Term Contracts underpinning its electricity industry, with generation developed by both private entities and a crown corporation. Alberta supported private investment in renewable energy within the Energy-Only Market through Long-Term Contracts under the Renewable Electricity Program.

Advantages	• Provides more direct control over specific amounts and types of supply resources. • Enables policy goals, such as targeting the development of specific technologies or supply in specific locations, that may not be feasible under a market mechanism.
Disadvantages	• Higher cost of delivered electricity when market forces do not discipline investment decisions. • More difficult to encourage innovation as contracts can lock in sub-optimal technologies for long periods. • Largely transfers cost and investment risks from generators to consumers. • Broad transition to this structure could require a costly mechanism to transition current competitive generation investments, as they could be at a disadvantage competing in the market against contracted resources.

5.1.4 Cost of Service

Cost of Service is a centrally planned and controlled model where the type, size, and location of generation are determined as part of an overall integrated resource system plan. Investments are subject to cost-of-service oversight by a regulator or government and receive guaranteed rates of return on investment.

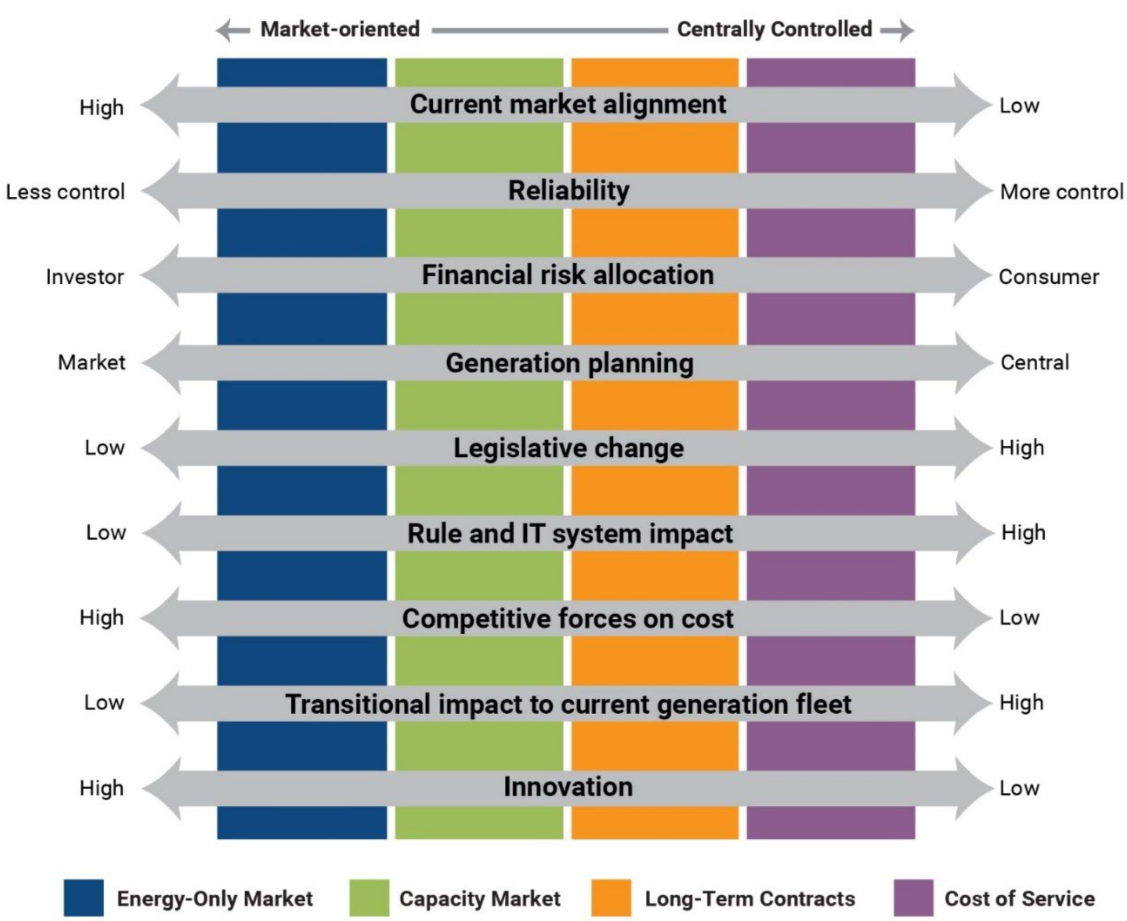
Generation assets under this structure are held by either a vertically integrated crown corporation (e.g., BC Hydro in British Columbia or SaskPower in Saskatchewan) or by several regulated utilities (e.g., Alberta prior to deregulation). Assets are dispatched based on operating costs and reliability needs in real-time, and not through a market.

Advantages	• Specific technologies can be developed that might not be feasible under a market-based mechanism. • More control of location of generation and transmission allows more integrated planning.
Disadvantages	• Higher cost of delivered electricity. • Requires significant regulatory oversight. • Decisions rely on central planner forecasts over the actions of many market players • Does not incent innovation as it can lock in sub-optimal technologies for long periods. • Completely transfers cost and investment risks onto consumers. • Transitioning to this structure would require a costly mechanism to transition current generation investments.

5.2 Framework Comparisons

The four high-level market frameworks are compared against a number of dimensions in the following Figure 5.

Figure 5: Detailed Framework Options



5.3 Evaluation of Framework Options

The AESO assessed each framework option presented in Section 5.1 against the objectives that guide the recommendations presented in this report. Each framework option has many different tradeoffs between the objectives, emphasizing some objectives at the expense of others. Overall, the Energy-Only Market model best meets the combined objectives of Reliability, Affordability, Decarbonization/Strategic Opportunities with Neighbours, and Reasonable implementation timeline. The assessment of each framework model against the objectives is summarized in the following table.

Table 2: Assessment of Framework Options Against Objectives

Objective likely met **Objective possible but challenges** **Objective unlikely met**

	Energy-Only Market	Capacity Market	Long-Term Contracts	Cost of Service
Reliability	Can meet the reliability requirements with some adjustments. Technological investments are determined through market forces which rely on effective market signals to incent the right technologies to enter the market.	Can meet the reliability requirements with some adjustments. Technological investments are determined through market forces that rely on effective market signals to incent the right technologies to enter the market.	Can meet reliability needs through the procurement of specific attributes.	Can meet reliability needs through the development of specific technologies.
Affordability	Allows customers to manage their exposure to very volatile real-time prices via hedges. Low administration costs—most simple market structure. Market signals and incentives result in the least cost provision of energy/ancillary services. The risk of investment is entirely borne by investors. Innovation across all market players incents new and least-cost technologies to enter the market.	Allows customers to manage their exposure to real-time prices via hedges. But cost of capacity is fixed. Medium administration costs—cost of administrating the capacity auction. Market signals and incentives result in the least cost provision of energy/ancillary services. There is an over-procurement risk as required capacity thresholds are determined by a central agency. The risk of investment is mostly borne by investors. Innovation across all market players incents new and least-cost technologies to enter the market.	Allows customers to manage their exposure to real-time prices and hedging. But greater cost of capacity through Long-Term Contracts is fixed. High administration costs—more central planning costs to procure and maintain contracts. There is an over-procurement risk (in terms of price and quantity) that cannot be quickly or inexpensively unwound. The cost risk of procurements is mostly borne by consumers. Innovation is only realized through targeted procurement of new technologies based on the values of the central planner. Also, long contract periods do not allow for newer technologies to enter.	No ability for customers to manage their exposure to prices via hedges. The costs of providing energy are fully fixed but more stable. High administration costs—cost-of-service oversight. There is an over-procurement risk (in terms of price and quantity) that cannot be quickly or inexpensively unwound. The cost of development is entirely borne by consumers. Innovation is only realized through targeted procurement of new technologies based on the values of the central planner. Also, concentrated ownership and investment decision-making do not allow for newer technologies to enter.

	Energy-Only Market	Capacity Market	Long-Term Contracts	Cost of Service
Decarbonization by 2050 / Strategic Opportunities with Neighbours	Energy and ancillary services market products can be created to incent specific attributes to meet the decarbonization goals and be designed to meet carbon policy goals at the lowest cost. Coordinating the development of new interties or opportunities on the interties is decentralized and therefore harder to realize.	Goal of the Capacity Market is to procure capacity without any consideration for the type of supply. The development of new interties or opportunities on the interties is better coordinated.	Can meet decarbonization goals through the procurement of technologies with specific environmental attributes. Long-term contracts make interties easier to realize. A contract for supply from a neighbouring jurisdiction or contracts with Alberta suppliers could mitigate negative revenue impacts and promote investment.	Can meet decarbonization goals through the development of specific technologies. Development of new interties or opportunities on the interties is centralized and therefore easier to realize.
Reasonable Implementation	Changes are required to restructure the energy market. Few legislative changes are required.	Capacity Market mechanism needs to be put in place. Some legislative changes are required.	Comprehensive planning required— procurement obligation and process needs to be determined. Some legislative changes are required. Address the impact to investment made in the current structure.	Re-regulation of the electricity industry. Comprehensive planning (i.e., integrated resource plan) is required—obligations and oversight processes need to be determined. Significant legislative changes are required. Address the impact to investment made in the current structure.

The Energy-Only Market framework remains the best framework to ensure an affordable and reliable electricity system for Albertans. Some changes will be needed in the next few years to ensure the system remains reliable, but these changes can be made relatively quickly compared to shifting to the other framework options considered.

> *The Energy-Only Market can support decarbonization goals given a long enough time horizon but may need support from long-term contracting if decarbonization goals are aggressive to ensure that low-emitting resources will enter the market in time to maintain reliability.*

Introducing Long-Term Contracts into the market would come at higher costs and require a lengthy implementation timeline, which is an important consideration.

Similar to Long-Term Contracts, Cost of Service can meet reliability and decarbonization goals through the procurement of specific technologies. However, it comes at much higher costs, completely transfers risk to consumers, and would involve a lengthy implementation timeline due to the significant legislative changes and transitional aspects required to implement this option. The AESO does not believe the cost justifies the benefit of implementing the cost-of-service option to meet the four objectives.

In 2016, the AESO recommended a shift to a Capacity Market framework because it best met the need for capacity to address the reliability risk of coal retirements. Since 2016, the market has evolved where the prevailing issue is not a lack of capacity on the system, but a lack of reliability attributes needed to balance supply and demand in real-time due to an increase of variable renewable generation on the system. The Capacity Market framework would struggle to meet present-day reliability and decarbonization challenges facing the electricity system.

5.4 Short-Term Supply Adequacy Options

The AESO has explored various options within the real-time energy market that could meet the need to provide more capability to manage short-term supply adequacy and maintain reliability. The options described in this section are compatible with any of the framework options that include a real-time energy market.

Since many of the challenges related to reliability stem from managing short-term variability to maintain continuous supply and demand balance, there are a variety of solutions across the different time dimensions (from second-to-second to day-to-day) that can improve short-term supply adequacy. This section provides an overview of key elements of energy market changes related to short-term supply adequacy, ranging from the present state (minimal change) to a more advanced state (extensive change).

The following Table 3 describes some of the design features that could evolve under minimal and extensive changes in the market. More detailed information on the specific market design options considered is provided in Appendix V.

Table 3: Energy Market Design Changes to Address Short-Term Supply Adequacy

Minimal Change (Current State)	Extensive Change (Advanced State)
Prices reflect market fundamentals and competitive entry disciplines economic withholding over time. Need to accept periods of high prices until new supply enters the market. Consumers who do not contract to lock in prices are exposed to price volatility.	Administratively set scarcity pricing ensures that high prices only occur during actual scarcity events. Extended periods of high prices are prevented through a cumulative pricing threshold. A day-ahead market reduces consumer exposure to price volatility in the real-time energy market by locking in energy prices before the operating day.
Ancillary services are procured to support grid stability. Technical standards for market participants are used to ensure reliability. Generators choose when they are online and provide energy.	Additional ancillary services would be procured, or market rules and infrastructure would enhance balancing ability, including those available over the interties. The preference would be to rely on market forces more than technical standards for market participants to maintain reliability. A day-ahead energy market would give generators more certainty of when they are expected online and to promote price stability. Co-optimization of energy and ancillary services would enhance affordability by reducing costs.
Existing transmission congestion management protocols are used to manage real-time congestion. Some locational signals are provided through GUOC payment and losses.	Modified transmission policy could provide enhanced locational signals that make better use of the existing transmission system and drive more efficient transmission expansions. Security Constrained Economic Dispatch (SCED) provides the lowest-cost dispatch including operational constraints, improving affordability.

The energy market design elements previously described are examples of changes on a spectrum. Each of the potential changes would require more extensive details to be considered and evaluated before they could be implemented. The current market has benefitted from its simplicity. However, as noted in Section 4.2 on the need for change, the combination and pace of drivers affecting the industry are very challenging to accommodate within the existing framework, creating an opportunity to implement innovative market mechanisms that can sustain grid reliability in an affordable way. This will create more certainty in grid operations and incent more dispatchable generation in the future. The next section provides further detail on the recommended approach to meet this challenge.

6. Recommendation: Restructured Energy Market

The AESO remains steadfast that a competitive, market-based structure for wholesale electricity is the best means of promoting continued investment in the province, ensuring affordability through competitive outcomes, and delivering on Alberta's long-term supply adequacy and reliability needs. A competitive, market-based structure also effectively allocates risk to those electricity market participants that can most effectively manage it and avoids undue allocation of risk or cost to taxpayers.

The AESO is recommending a Restructured Energy Market with the ability to procure contracts for controllable technologies if required.

The AESO believes the Restructured Energy Market (REM) will most effectively address the issues facing our industry, while ensuring reliability and affordability into the future. The design changes under the REM represent significant changes to the Energy-Only Market while still leveraging the underpinning structure. They are "no regrets" modifications that are required regardless of future path. The restructuring of the energy market will result in stronger incentives for dispatchable generation, reduce the impact of market power, and provide long-term signals for investment to promote reliability within the province. A phased-in approach will enable key actions to provide:

- Immediate price protection for consumers in the near term through the implementation of an interim market power mitigation framework to reduce the impact of economic withholding on prices.
- Enhanced reliability by maximizing the reliability characteristics of the current supply fleet by progressing the procurement of reliability services and/or establishing or enhancing technical requirements.
- Incentives for investments in dispatchable technologies and demand response in the medium term expected to be strengthened through a scarcity-based administrative pricing mechanism and a day-ahead market.
- The option to directly contract for controllable supply if needed in the long-term to ensure reliability. This lever, if enacted, will impact investor confidence and the investment signal in the REM. Therefore, it is a "no turning back" option that should only be used if REM changes are ineffective in securing the required investment.

The REM is expected to support investment in controllable generation to meet supply adequacy needs in the province. The AESO anticipates sufficient supply to meet forecasted demand over the next decade and recommends introducing contracts for controllable capacity only if and when needed.

6.1 REM Recommendations & Expected Outcomes

The REM is a comprehensive market design package that addresses wholesale electricity market issues. It should be implemented in its entirety, with the exception of long-term contracting, to provide investor confidence and reduce uncertainty. Long-term contracting mechanisms should only be implemented if required, as noted in Section 6.2. Phased implementation of the REM is required to effectively manage challenges and risks associated with a change of this scale. The following Table 4 outlines the expected REM design outcomes through a phased-in implementation.

Table 4: Restructured Energy Market Design Recommendation

REM Design Outcome	High-Level REM Design Recommendation	Implementation Timeframe
Protect against excessive use of market power and its impact on price to ensure affordability	1. Establish an interim market power mitigation framework focused on limiting the offer prices of large generation firms when they have substantial market power once sufficient revenue has been earned to recover fixed costs. The proposed medium-term replacement for this mechanism is described in row 10.	Near-term (6 months to 2 years)
Address intermittency of supply and promote grid reliability	2. Procure additional ancillary services and enhance technical requirements to address supply intermittency and promote reliability by ensuring controllable resources provide needed frequency and flexibility, and support system strength.	
	3. Increasing intertie capability through the procurement of services to enable further access to neighbouring jurisdictions.	
	4. If necessary, procure strategic reserves to maintain controllable capacity to protect against supply shortfall.	
Address market inefficiencies to ensure affordability	5. Co-optimize dispatch of energy and ancillary services to minimize costs and enable additional reliability.	Medium-term (2 to 5 years)
	6. Shorten settlement intervals and implement negative pricing to improve price signals for flexible generation, controllable demand, intertie transactions and storage.	
Provide certainty and control over the commitment of generation on a time-ahead basis, promoting stability and minimizing price volatility	7. Introduce a day-ahead market to provide additional certainty for generation and to incentivize the availability of controllable generation.	
Optimal use of transmission infrastructure	8. Modifications to the *Transmission Regulation* and the ISO tariff to send improved locational signals for siting generation, and allocating costs based on cost causation.	
	9. Implement improved dispatching tools, such as Security Constrained Economic Dispatch, to ensure efficient dispatch of resources reflecting various constraints on the system and minimizing cost.	
Promoting investment and long-term supply adequacy in the province	10. Implement an administrative scarcity pricing curve with a higher price cap and mitigated offers to replace the economic withholding feature in Alberta's electricity market design. This would increase the price above $1,000/MWh during limited situations (supply scarcity). A higher price cap is required to allow generation to recover investment costs. With a higher price cap, economic withholding can be limited through market power mitigation to prevent excessively high prices in the energy market.	
	11. Develop a mechanism where the price cap is lowered once reasonable fixed cost recovery is achieved to protect consumers against excessive cost.	
	12. If needed, procure new controllable capacity through Long-Term Contracts. Current forecasts indicate that the earliest the contracting process would need to start would be the late 2020s.	Long-term (5+ years)

6.1.1 Protect Against Excessive Use of Market Power and Price Impact

Supply has been tight over the past few years resulting in high prices in Alberta's wholesale electricity market. One of the reasons for these higher prices has been the exercise of market power by large market participants. The interim market power mitigation framework is intended to provide immediate protection from the high prices currently being observed by limiting the exercise of market power by the larger participants. The AESO recommends that in the medium term (2 to 5 years) this interim market power mitigation measure be replaced with a more robust mechanism to mitigate the impact of market power on prices while still providing incentives for investment to ensure long-term supply adequacy. Section 6.1.6. describes the recommended replacement mechanism—an administrative scarcity pricing mechanism.

6.1.2 Address Intermittency of Supply and Promote Grid Reliability

The AESO is currently procuring additional ancillary services and enhancing technical requirements to address the intermittency of supply and promote reliability. These services will be procured from controllable resources to provide needed frequency and flexibility, and support system strength. Technical requirements will also be enhanced for all technologies, including intermittent resources, to ensure that all technology types support reliability needs as much as possible. The AESO is also procuring additional fast frequency response ancillary services to increase intertie capability to enable greater access to neighbouring jurisdictions.

6.1.3 Address Market Inefficiencies to Ensure Affordability

Well-defined market signals are the most efficient means to meet the needs of the electric system and will lead to investment in reliability attributes at the lowest overall cost. Two market design recommendations that will enhance the efficiency of the wholesale market and improve short-term supply adequacy involve changes to how prices are settled and changes to how energy and ancillary services are scheduled. These are described in further detail below.

Introducing shorter settlement intervals provides better incentives for dispatchable generation, controllable demand, importers/exporters, and storage to respond to minute-by-minute changes in price. This improvement in the granularity of the price signal incents a more flexible response and can help to manage supply/demand imbalances, improving short-term adequacy. Shorter settlement intervals would also facilitate more flexible exchange with other neighbouring markets that are largely settled on 15-minute intervals.

Negative pricing also provides better incentives for generation, controllable demand, importers/exporters, and storage to respond when there is an excess amount of supply. It would allow the wholesale price to go below the current price floor of zero dollars. Today, generators cannot submit an offer below zero dollars. When more supply is offered at zero dollars than is needed to meet demand (supply surplus), some supply must be curtailed. Negative pricing would allow generators to better indicate at what price they would be willing to curtail. The resulting negative price during supply surplus events would provide even greater incentives for generation to reduce output or export, and for storage and load to increase demand. Negative pricing would also improve the price signals for renewable generation, signaling when increased energy production from these variable renewable generation resources has limited value (such as during supply surplus events). With increasing zero-dollar offers from non-controllable resources, this pricing mechanism will become more important in resolving supply surplus events.

Alberta's electricity market currently has one energy market and six different day-ahead operating reserve markets. The number of markets is likely to grow as more ancillary services are needed to maintain reliability on the grid. These markets are cleared separately, creating circumstances where some higher-cost resources are dispatched instead of a lower-cost alternative. Co-optimization of the energy and ancillary service markets would ensure that the total cost is minimized by dispatching generators, storage assets, and controllable loads in a manner that provides the highest value to Albertans.

6.1.4 Optimize Use of Transmission Infrastructure

The dispatch of generation assets requires constant management to balance supply with demand and consider limits on the transmission system. This process currently uses relatively simple tools. Security Constrained Economic Dispatch (SCED) is a more sophisticated tool to better optimize the dispatch of all resources and respect all constraints. The process dispatches the lowest-cost generation to meet energy demand while meeting constraints (such as transmission constraints, generation and transmission contingencies, and generator operational limits). Tools that implement SCED can be leveraged to implement other key features in this recommendation including the day-ahead market, co-optimization of energy and ancillary services, and shorter settlement. The benefits of SCED arise from identifying the lowest-cost resources to meet demand while accounting for all constraints. This would help short-term supply adequacy as it provides the best means to manage a growing number of resources and a more complex set of physical limits.

Transmission Policy Considerations

The REM recommendation does not depend on a specific transmission policy. An energy market with administrative scarcity pricing and mitigated offers with expanded ancillary service products and technical rules to acquire reliability attributes is compatible with the current transmission policy or an alternative one that allows more transmission congestion or changes the allocation of transmission costs. As discussed in the need for change (Section 4.2), areas of transmission policy that would benefit from changes include sending improved locational signals for generation and allocating transmission costs based on stronger cost causation principles. These changes would drive more efficient use of the existing transmission system and support more efficient expansions to the transmission system. The AESO has provided detailed recommendations on transmission policy in response to the November 2023 Transmission Policy Review consultation initiated by the Ministry of Affordability and Utilities.

6.1.5 Provide Certainty and Control Over Generation Commitment

The AESO is proposing that more certainty and control over the commitment of generation be provided through a mandatory day-ahead energy market. The benefits of a mandatory day-ahead market include:

- More centralized coordination and control of generator operation to ensure that the AESO can achieve its reliability needs.
- Short-term revenue certainty to dispatchable generators that need to incur one-time startup costs and other unavoidable commitment costs to come online.
- Optimization of generator scheduling decisions to reduce the system cost of maintaining short-term supply adequacy.
- Improved competitiveness and market power mitigation to ensure competitive outcomes.
- Mechanism for market participants to manage their exposure to real-time price volatility.
- Opportunity for system operators to reliably accommodate uncertainties related to demand and variable supply.

A centrally cleared day-ahead market would commit generation to meet forecasted load. All generation types would offer their expected available generation in the day-ahead market. Participation can reduce exposure to price volatility, but other incentives can encourage additional participation.

Generator offers in day-ahead markets have three parts:

- An incremental energy offer.
- A start-up cost.
- The cost of running the generation at its minimum level.

The three-part offer is used to determine the lowest cost set of resources to meet demand. Incentives and penalties would address differences between the day-ahead schedules and real-time production. If the quantity of energy generated or consumed in real time is higher or lower than the day-ahead energy quantity, the difference is settled at the real-time price.

Day-ahead markets improve the operational decisions of dispatchable technologies by providing a more certain revenue stream and production schedule, and a financial penalty for not being available when needed in real-time. Generators that clear in the day-ahead market are guaranteed a price for producing to their schedule, providing sellers with certainty that daily revenues can cover their short-term costs regardless of real-time system conditions. Generators that clear the day-ahead market but are not available in real time might be penalized since they must purchase the missing power from the real-time market. Day-ahead markets often include financial penalties for not meeting the day-ahead schedule. These mechanisms create incentives for non-controllable resources to become more dispatchable. Participants are rewarded for the ability to commit energy production with certainty a day in advance. Participants who are unable to do so may face penalties in the day-ahead market if their production deviates from the day-ahead schedule.

Alberta's current market structure does not have a day-ahead market for energy, only operating reserves. The addition of a day-ahead market for energy would be a significant change to the market design. Notably, a binding day-ahead market will shift some control of unit commitment to the AESO and place more responsibility on generators to meet day-ahead supply obligations. The relative stability of the day-ahead market would also decrease load exposure to price volatility.

6.1.6 Promote Investment and Long-Term Supply Adequacy

Affordability concerns related to Alberta's current reliance on economic withholding to attract investment that provides long-term supply adequacy have prompted the AESO to investigate alternatives. The removal of economic withholding from Alberta's electricity market design would result in the need for an alternate design mechanism to enable generators to recover investment costs.

> *The AESO is recommending an administrative scarcity pricing curve with a higher price cap and mitigated offers to replace the economic withholding feature in Alberta's electricity market design.*

A higher price cap is required to allow generation to recover investment costs. With a higher price cap, economic withholding can be limited through market power mitigation to prevent excessively high prices in the energy market.

An administrative scarcity pricing mechanism in the form of an Operating Reserve Demand Curve (ORDC) with offers mitigated closer to marginal cost is the most effective means to implement a higher price cap and introduce market power mitigation. The ORDC increases the energy price up to the high price cap during shortage conditions and the offer mitigation restricts generators from exercising market power by preventing offers significantly higher than their marginal cost.

The higher price cap is only reached when approaching shortage conditions. Shortage conditions exist when supply is not sufficient to satisfy both energy and reserve requirements, which can lead to reduced reliability. As reserves are dispatched to satisfy energy demand, the system becomes less capable of responding to contingencies and the risk of shedding load increases. Administrative scarcity pricing reflects these conditions by signaling higher prices.

It is possible under an ORDC mechanism that extended shortage events can lead to long periods of high prices and excessive generator profits. These types of events could be driven by extreme weather or unexpected unit failures, for example. The recommended method of mitigating this risk is to implement a secondary price cap. This mechanism would track the hypothetical profits of a marginal unit, like a simple cycle natural gas unit, and if the profits reach a certain threshold the administratively set price cap will be adjusted downward to the secondary price cap for a certain period. This protects consumers from prolonged high-price events that create excessive generator profits. Australia and ERCOT currently employ this type of mechanism in their Energy-Only Markets.

The day-ahead market also allows consumers to mitigate the risk of exposure to high prices by facilitating the transaction of energy on a day-ahead basis. Electricity transacted in the day-ahead market is not exposed to the real-time price and this can reduce the exposure for consumers to unexpected price volatility. Consumers can also purchase electricity further in advance to reduce exposure to the real-time price through forward contracting.

A market design that includes market power mitigation with a high price cap and an ORDC enables competitive market outcomes because it ensures the wholesale price reflects the marginal cost of serving load. High prices motivate consumers to curtail their consumption in real-time and invest in energy efficiency over the long term, while producers maximize their availability in real-time and make additional investments in generation capacity that can respond to high prices. The ORDC price signal also is a strong incentive to attract imports when Alberta is nearing supply shortfall. Altogether, this ensures that both consumers and producers respond to system conditions in real-time and over the long-term, improving both short-term and long-term adequacy, while protecting consumers from supporting excessive generator profits in prolonged shortage events.

6.2 Contracts for New Controllable Capacity (Long-Term)

The AESO's long-term adequacy studies indicate sufficient supply over the next decade. The REM is expected to better support the needed investment in controllable generation to provide short-term and long-term supply adequacy. As such, the AESO recommends launching targeted procurements only on an as-needed basis. Should the need for controllable capacity arise, due to Alberta's coal-to-gas fleet retirement by the late 2030s from increasing carbon prices and federal natural gas regulations, a procurement could be initiated in the late 2020s/early 2030s to provide sufficient time for contracting and development. The AESO will continue to monitor supply adequacy and if the risk of insufficient investment materializes, a procurement could be launched at that time.

These specific contracts would be designed to be compatible with the REM with the intent of supporting investment in new controllable technologies. Long-term contracting is a significant intervention in the market and is likely to dampen investments in controllable supply not supported by contracts, which will reduce the market's ability to maintain long-term supply adequacy. The introduction of these contracts is therefore a "no turning back" decision and should not be taken lightly.

The development of generation through any form of contract will negatively impact the long-term investment signal provided through the energy market. To support overall affordability, contracts should have a clear and fixed boundary on how much capacity should be procured. Other boundaries that can alleviate the distortionary impact of contracts on the energy market and limit ratepayer risk include:

- Limiting the contracting of generation to the volume anticipated to be needed to serve reliability and supply adequacy needs over a given timeframe.
- Limiting technology-specific procurements; procurements should be technology-agnostic.
- Limiting contract payments to cover only a portion of total resource costs, so that resource owners must continue to recover variable costs and a portion of investment costs in the energy and ancillary services markets.
- Limiting the timeframe for the contract.
- Communicating the timing and size of procurements to investors so the market can respond to expected changes in supply.
- Encouraging developers to compete to offer the most competitive projects.

Contracts should provide sufficient certainty of fixed-cost recovery for investments in new supply, while encouraging participation in the energy market, limiting consumer liability, and promoting efficiency through competition. Introducing widespread contracts is a significant change to the long-term investment mechanism, and once announced as the path forward, nearly impossible to adjust from.

If the use of contracts for controllable capacity to enable additional investment in the province is needed, a term of up to 10 to 20 years will achieve certainty around long-term adequacy. These contracts can be designed to incentivize investment in dispatchable, low-emitting, controllable generation. Under this framework, the AESO is well suited to identify the need for the contracted supply, lead competitive procurements, and act as a counterparty to private investors who would build, own, and operate facilities under the terms of the contract. The AESO has experience in developing and executing fit-for-purpose procurement processes through the procurement of reliability services, the Renewable Electricity Program, and the competitive procurement of transmission infrastructure.

6.2.1 Long-Term Contracting in Other Jurisdictions

There are examples of contracting in other electricity markets. These examples provide valuable learning opportunities for Alberta and are summarized as follows.

- **Ontario established a government agency to procure new generation** via long-term contracting in 2004 and today nearly all the electricity supply in the province is rate-regulated or contracted. This has led to a decrease in Ontario's wholesale energy prices since contracted generation is not exposed to the market price. However, the reduction in the wholesale price did not lead to a decrease in consumer costs of electricity as the recovery of capital costs has shifted from the wholesale market to administrative costs (i.e., the Global Adjustment), and the delivered cost of electricity has continued to increase over time.
  - The Ontario example illustrates how the introduction of long-term contracting has eliminated the investment signal from the wholesale market, as no investment has occurred without a supporting contract.
- **The Australian federal government created a capacity investment scheme** designed to limit the distortionary impact of contracts for dispatchable technologies on the country's regional electricity markets. The mechanism specifies a cap and a floor on revenue that can be earned in the market. The participant is reimbursed if the revenues in the market go below the floor and, conversely, the participant pays if the revenues exceed the cap.

The amount of procured capacity and timing of installation are communicated in advance, allowing the market to adjust.

– Australia's capacity investment scheme is a new initiative and the first tender opened in December 2023. The success of the initiative to bring dispatchable technologies to Australia's grid while minimizing the impact on the broader wholesale electricity markets has yet to be tested.

6.2.2 Alternative to Contracting Mechanisms

The AESO recognizes that existing decarbonization policies such as the currently proposed *Clean Electricity Regulations* (CER) introduce significant uncertainty to the market. The short timelines and strict requirements under the proposed CER negatively impact investment in some controllable technologies such as CCS.

There are circumstances where alternative mechanisms to support investment in controllable capacity may be required, including:

- A policy desire to support the development of specific technologies for which a private entity would have difficulty taking on the financial and regulatory risk, such as nuclear power generation; or
- A need to manage the legal liability of accelerated federal emissions reduction requirements.

In these circumstances, more direct government support or ownership may be appropriate to financially underpin the investment or assign a liability to the province. There are several ways to implement these alternative mechanisms that can be explored, if required.

6.3 Summary of Recommendation

The Restructured Energy Market provides the needed changes to address affordability concerns, meet policy goals (such as decarbonization), and continue to provide reliable electricity to Albertans.

The market design changes will work in tandem to deliver on these objectives. The interim market power mitigation will protect against excessive market power in the near-term and the ORDC mechanism including co-optimized dispatch, shorter settlement intervals, and negative price floor will leverage competitive forces in the medium- to long-term to provide affordable electricity to Albertans. The procurement of additional ancillary services and development of new rules and technical standards alongside the strong scarcity pricing signals in the energy market, the improved dispatch tools like SCED, the increased intertie capability, and the day-ahead market will drive reliable dispatch and operation in real-time and increase incentives for dispatchable resources guiding a reliable supply mix going forward to meet the grid's evolving needs. Decarbonization goals will be met through market outcomes in the energy market and, if necessary, long-term contracting to meet technology-specific requirements.

The REM represents a significant set of changes to the market framework to provide more control of outcomes while still leveraging competitive forces to deliver reliability at lowest cost. It can also be effectively implemented in a short timeframe because it leverages the existing competitive market structure. The REM is most effective if implemented in its entirety as many changes proposed in the REM are interrelated and work together to achieve reliable and efficient market outcomes.

7. Implementation and Legislative Changes

Time is of the essence to introduce the significant changes that will have far-reaching impacts on the sector. The AESO recommends a streamlined AUC regulatory process to ensure efficient implementation of the REM. If clear policy direction from the provincial government is secured in early 2024, implementation of the necessary new and amended ISO rules required for the REM could occur in 2026. Further details, including IT systems implementation, would be initiated and developed in parallel with staged implementation.

Legislative changes are expected to be required to implement the REM. Legislation that may require changes includes the *Electric Utilities Act* (EUA) and related regulations including the *Transmission Regulation* and the *Fair, Efficient and Open Competition Regulation* (FEOC).

The AESO plans to implement near-term changes to support reliability, with most requiring minimal market design changes, and expects to be completed by the end of 2024. Expedited implementation of the recommendation on interim market power mitigation will require timely policy direction and associated changes to regulations.

7.1 Legislative Changes Required for Implementation

The AESO has identified the statutes and regulations that may need to change to successfully implement the REM. Most notably, the EUA and its associated FEOC Regulation will need amendments and new provisions.

The REM may conflict with energy market principles in the EUA, including open, non-discriminatory market access and may require legislative change to reflect the more complex details of the REM design and establish acceptance of these design elements within the FEOC Regulation. The following list provides a broad overview of how the EUA and its regulations may need to be amended to implement the REM. Further legislative amendments may also be needed to support an expedited implementation of the policy direction.

Table 5: Potential Legislative Changes Required to Support Design Recommendations

Design Recommendation	Potential Legislative Changes Required
Day-Ahead Market	• Potential changes to the EUA or FEOC Regulation to enable the AESO to implement and administer a day-ahead market; changes to clarify that the day-ahead market is consistent with FEOC principles. • Possible changes to EUA to clarify that two distinct pool prices and markets for energy and ancillary services can exist under the legislative framework.
Introduce offer mitigation with a low price cap to mitigate extreme price events	• Changes to FEOC principles, including in s. 5 of the EUA and the FEOC Regulation. • Potential changes to FEOC Regulation to codify prohibition on economic withholding.
Administrative scarcity pricing, higher price cap and negative price floor	• Changes to clarify that administrative scarcity pricing is permitted to ensure long-term investment and is consistent with FEOC principles. • Potential EUA or FEOC Regulation changes to codify the AESO's ability to determine an appropriate price floor and cap.

Design Recommendation	Potential Legislative Changes Required
Additional ancillary service products, ramp-up reserves, strategic reserves and enhanced technical requirements	• Potential broadening of the definition of "ancillary services" in EUA.
Co-optimization of dispatch of energy and ancillary services	• Potential broadening of the definition of "ancillary services" in the EUA. • Potential changes to the EUA to confirm that the AESO has the authority to place participants in the market (energy, ancillary services) where they provide the most value. • Potential change to the EUA to ensure that the Energy-Only Market can be designed with co-optimization of ancillary services markets in mind.
Shorter settlement intervals	• Likely no legislative changes needed to implement.
Security Constrained Economic Dispatch (SCED)	• Changes to the EUA regarding concepts like no undue discrimination and reasonable access. • Changes to the EUA to develop an objective function to replace ISO duty to "dispatch according to economic merit" in s. 17(c) of EUA (i.e., changes to s. 17 to codify ISO duty as to "maximize total benefits of exchange" to enable co-optimization and SCED).

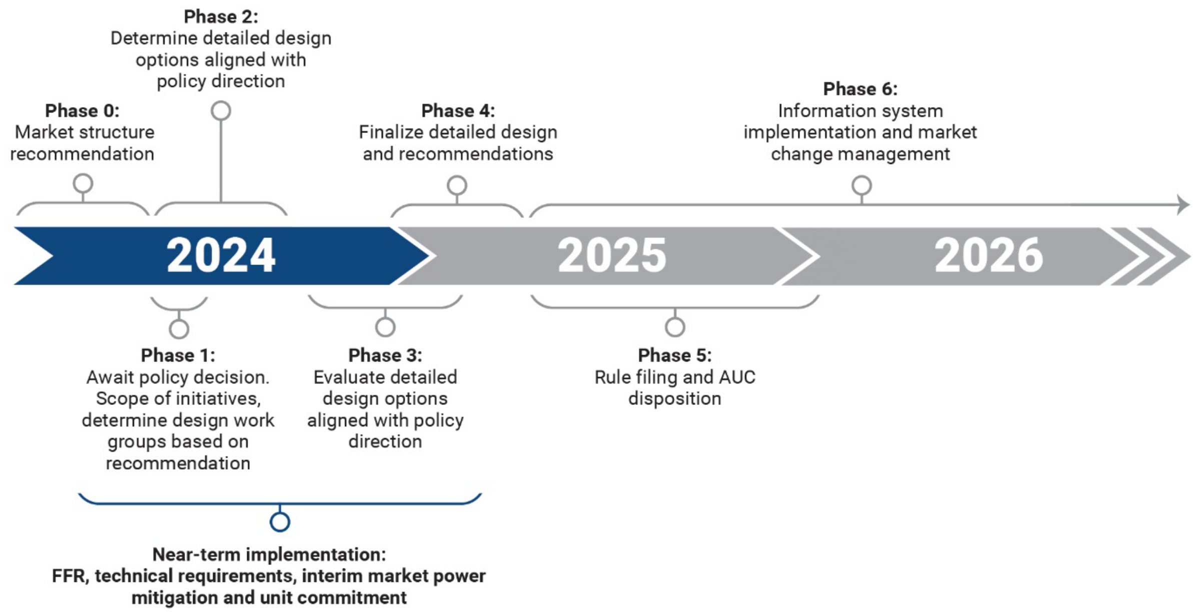
While the preceding list provides an overview of potential legislative changes, it is not intended to be comprehensive. The AESO can provide additional details on the relevant legislative changes with the MAU and legislative counsel if requested.

7.2 REM Implementation Timeline

The AESO's proposed REM changes require detailed design, further industry consultation to determine the specific REM design and implementation details, ISO rule revisions, market participant education and training, and new or modified information systems and AESO processes.

The AESO proposes a detailed design phase to be launched in 2024, which includes comprehensive stakeholder consultation to consider the ISO rule changes required to implement the REM design. Following this consultation process, the AESO recommends a condensed six-month AUC process for ISO rule approval to minimize industry uncertainty and efficiently implement the REM. This is a significant and complex undertaking that will impact many existing processes and systems, which will require time and resources to achieve successful implementation.

Figure 6: Implementation Timeline



At least three years will be needed to design the REM, determine the legislative and ISO rule requirements to move those through their approval processes, and build the IT systems on which the market is operated.

The implementation consists of six overlapping phases with completion expected by the end of 2026 if activities can be progressed in parallel on the proposed timeline. However, delays in any one phase could impact subsequent phases and delay the completion date. Should risks to the schedule materialize, the AESO may need to phase in certain scope elements at a later date to ensure key components of the recommendation can be implemented by 2026.

Phase 1:	Minister to review the AESO's recommendation and advise on the policy direction.
Phase 2:	AESO will develop proposed design options while adjusting for the policy decisions once they are available.
Phase 3:	Feedback on design options from industry stakeholders.
Phase 4:	Develop the detailed design by drafting ISO rule and tariff changes (if required) utilizing the stakeholder process initiated in Phase 3.
Phase 5:	Development and filing of the rule application with the AUC, and the AUC's process to hear the application and issue a disposition. Further details on regulatory changes required to complete this phase are provided in the next section.
Phase 6:	Implement the rules within AESO systems and processes. Phase 6 is expected to take 18 to 20 months to design and implement the necessary systems required to operate the REM and may need to be adjusted to accommodate additional AUC directions. The AESO will focus on implementing the foundational market components first. Additional time beyond 2026 may be required to phase in more complex elements to de-risk overall implementation and ensure foundational components are in place by 2026.

Given the number of significant activities that must be achieved over the coming months, the proposed timeline is aggressive. The AESO must maintain flexibility in scope and schedule to advance work earlier than planned or proceed with different phases. The AESO will continue to work on the recommendations outlined in this document in concert with the MAU with time being critical for successful implementation of the REM.

7.3 Regulatory Process Changes Required for Timely Implementation

7.3.1 Alternative Process Needed for Implementation of New and Revised ISO Rules

The current ISO rule approval process will not be sufficient to implement the REM within the specified timeframes. The AESO therefore recommends a time-bound, collaborative market design consultation process followed by a targeted and condensed regulatory process before the AUC. This requires clear policy objectives at the legislative and regulatory level. The ISO rules should include detailed market design considerations to provide flexibility for detailed technical, operational and market design considerations to adapt and evolve without the need for legislative change.

The proposed ISO rule approval process described in this section will streamline the existing process, ensuring efficient implementation of the REM. This process will ensure transparency and regulatory oversight of new ISO rules required to restructure the energy market while being exempt from the more extensive and time-consuming requirements that typically apply to the development of ISO rules.

The proposed process could apply regardless of whether the government adopts the REM or takes another path forward that may require significant changes to the ISO rules.

7.3.2 Specific Details of the Proposed Approach

A modified approach will be needed to allow the implementation of the REM by the end of 2026. This approach would begin with a 12-month market design and ISO rule consultation, followed by a 6-month hearing before the AUC, with a 60-day decision period for the AUC after the close of the proceeding. To limit uncertainty regarding the implementation of the approved ISO rules, the AESO also recommends shielding the initial ISO rules from appeal under section 29 of the *Alberta Utilities Commission Act* (AUCA) and limiting complaints under section 25 of the EUA to a "patently unreasonable" or comparably high standard.

Details of this recommended process are set out in the following table. This recommendation would need to be prescribed by legislation, likely in amendments to the EUA. The amendments to the EUA would need to be in place prior to the AESO filing its application for approval of the new and amended ISO rules.

Table 6: Recommended Process and Details

Recommended Process	Details
Twelve-month market design and ISO rule stakeholder consultation process	• The AESO would file its application for approval of the new and amended ISO rules at the end of this period. • The AESO would not be required to meet the standard AUC consultation requirements applicable to ISO rules, but would instead consult on the draft new and amended ISO rules during the market design process and seek comments from stakeholders during this process. • The AESO would file its consultation record with the AUC, but efficiency would be achieved by eliminating the need for two distinct, yet overlapping, consultation processes.

Recommended Process	Details
Six-month AUC proceeding period with limited scope	• The AUC would have six months after filing the ISO rules application to consider the application. • This would include a hearing process, if necessary, where the AUC would deal with process on all ISO rules together with the scope of the hearing focused on the actual content of proposed and amended ISO rules.
Inapplicability of Rule 017 and the AUC's refusal to approve ISO rules package	• The AESO would be exempt from meeting the requirements of s. 20.21(2)(c) of the EUA (standard AUC consultation requirements) but would still be required to demonstrate that the new rules are consistent with the policy objectives and requirements set out in legislation, not technically deficient, and otherwise in the public interest. • The AUC would be prevented from simply refusing to approve an ISO rule. However, based solely on the evidence, the AUC would be permitted either to approve an ISO rule or direct the AESO to revise the rules within a prescribed time period.
Truncated AUC decision period	• The AUC would have a prescribed 60-day decision period after the six-month hearing process by which to issue its decision.
18-month period where approved ISO rules package is shielded from challenge by stakeholders	• The AESO recommends an 18-month period following implementation without the typical avenues of challenge available to stakeholders to allow time to observe how the approved ISO rules work in practice. • This carve-out would preclude the use of the appeal process under section 29 of the AUCA and limit complaints to the AUC under section 25 of the EUA to the "patently unreasonable" or comparable standard.

In the AESO's view, the recommended approach set out in the table above would strike an appropriate balance between ensuring robust and transparent stakeholder consultation and regulatory oversight, and efficient implementation of the government's chosen path forward.

7.3.3 Current ISO Rule Approval Process and the Need for Alternative Process

Under the current ISO rule implementation process, amending or proposing a new ISO rule typically requires the AESO to engage in a significant and often lengthy regulatory process as required under section 20.21 of the EUA. This includes:

- Following the stakeholder consultation and other processes in AUC rules including responding to every written comment provided by stakeholders.
- Submitting an application to the AUC where the AESO must prove that the proposed or amended ISO rule is FEOC, is in the public interest, and not technically deficient.
- Participating in a proceeding with processes established by the AUC—this can include information requests, intervener evidence, rebuttal evidence, written or oral arguments, or other process steps depending on the nature of the ISO rule application. This can take significant time and resources depending on the nature of the ISO rule application.

The AESO believes that the current ISO rule approval process will hinder the efficient implementation of the REM. While a robust consultation and regulatory process can be effective when there are multiple ways to achieve a market design outcome and reasonable parties could disagree, a different process is needed to efficiently implement clear and specific policy direction for significant structural change.

Outcomes can be uncertain with the current ISO rule approval process. The existing process depends upon the evidence filed by the AESO, as well as stakeholder involvement, and the public interest assessment undertaken by the AUC when coming to a decision.

Complaints made about approved ISO rules, appeals, and applications for review and variance of the AUC's decision create uncertainty around what rule will ultimately apply and how it may be interpreted. The AESO's proposed approach is intended to maximize efficiency and certainty while upholding the cornerstones of the existing ISO rule approval approach set out in the EUA. As described previously, the AESO is proposing that the Commission decision be shielded from appeal under section 29 of the AUCA for a period of 18 months to ensure that the approved ISO rules can be tested in practice. The AESO proposes that parties be precluded from filing complaints about the approved ISO rules under section 25 of the EUA during this period.

There is precedent for this approach. When the AESO was directed to establish and operate the Capacity Market, the EUA was subsequently amended to allow for a special ISO rules approval process. While this was a distinct scheme, a targeted regulatory process is familiar to stakeholders and the AESO.

A range of alternative ISO rule approval options is provided in Appendix VI.

The AESO recognizes that the REM recommendation involves significant changes to a number of the legislative elements underpinning the current electricity market framework.

There is a need for the immediate implementation of legislative changes to establish the foundations that will enable a successful transformation of the power system and meet the objectives outlined in this report.

The trends that are impacting the electricity sector will continue, putting a greater degree of pressure on the existing framework.

8. Role of Dispatchable Technologies

The mix of technologies powering Alberta's electricity system is evolving. As described earlier in this report, the increasing pace of development of variable renewable generation resources (i.e., wind and solar) has created new challenges for the operation of the system. The integration of variable generation resources is anticipated to continue as interest in using lower carbon forms of energy increases across the province. To enable this transition, investment in an accompanying mix of controllable resources will be needed to maintain reliability and manage the intermittent output of variable generation resources. This section details the types of dispatchable and controllable resources and technologies that can play a role in maintaining reliability through this transformation.

The REM framework is designed to incent the lowest-cost forms of generation that can provide the required short-term and long-term supply adequacy. While incentives that reward more flexible and controllable technologies may encourage the development of low-carbon controllable generation, there are risks for select resources and technologies that may be insurmountable for private investors without some form of additional support.

There is a diverse set of dispatchable, low-emitting technologies that can play an important role in ensuring Alberta maintains a reliable electric system. To assess this potential, the AESO commissioned a report from 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. to comment on the strengths, weaknesses, opportunities, and threats associated with low-carbon controllable generation to meet the decarbonization by 2050 objective while maintaining system reliability. The full report can be found in Appendix VII. Overall:

- Abated natural gas technology holds significant potential for baseload generation in Alberta due to the successful deployment of carbon capture technologies in the oil and gas sector and strong natural gas reserves in Alberta.
- Hydrogen-fired generation also has potential in Alberta's electricity market due to its ability to provide flexible generation and the potential for expanded domestic blue hydrogen (hydrogen fuel produced primarily with natural gas) production in Alberta. However, near-term challenges to hydrogen include the need for transportation and storage infrastructure, and high costs compared to other fuel sources.
- Storage technologies are already participating in Alberta's market and are expected to grow due to cost reductions and increasing ancillary service needs.
- New developments of hydroelectric and nuclear technologies require lengthy development timelines and may require some form of government support to be developed in Alberta, with Small Modular Reactor (SMR) nuclear technology having the highest potential for cost reductions and deployment in Alberta should they reach commercialization.

Each low-emitting dispatchable technology has different characteristics that could aid Alberta's grid in different ways to mitigate the intermittency of renewables and promote grid reliability. The following table summarizes each technology's characteristics and costs. For technology readiness (column two): the **highest score (9)** indicates the technology has been proven in an operational environment; a **low score (1-3)** indicates it is still in the research phase; and, a **middle score (4-6)** indicates a prototype has been proven in a laboratory or relevant environment.

Table 7: Summary of Generation Technology Attributes

Technology	Technological Readiness	Unit or Facility Capacity, MW	Construction Timeline, years	Heat Rate or Efficiency, GJ/MWh or %	Capital Cost, $/kW	Fixed O&M, $/kW-yr	Variable O&M, $/MWh	Inertial Capacity, GVA-sec	Flexibility
Combined-cycle with CCS	Early Deployment (7)	626	4 years	7.42 GJ/MWh	$4,724	$33.12	$4.63	4.02	Somewhat flexible
Nuclear Fission	Mature (9)	1,110	6 to 10 years	10.44 GJ/MWh	$19,864	$198.11	$3.86	5.97	Baseload
Nuclear Fission SMR	Developing (6)	300	5 to 8 years	11.58 GJ/MWh	$15,554	$226.23	$4.89	1.56	Baseload
Hydrogen Simple-Cycle	Developing (5)	51	2 years	9.82 GJ/MWh	$19,760	$47.73	$7.60	0.15	Flexible
Hydrogen Combined-Cycle	Developing (5)	682	3 years	6.81 GJ/MWh	$3,594	$11.57	$1.90	4.09	Flexible
Hydroelectric	Mature (9)	500	5 to 10 years	N/A	$13,814	$174.00	$0.00	3.69	Flexible
Lithium-Ion Battery, 4hr	Mature (9)	100 (400 MWh)	4 years	85%	$2,109	$39.00	$0.00	-	Flexible
Pumped Hydroelectric Storage	Mature (9)	500 (4,000 MWh)	10 years	80%	$1,800	$32.20	$0.62	3.69	Flexible
Compressed Air Energy Storage	Developing (7)	500 (4,000 MWh)	6 to 8 years	60%	$4,430 to $6,190	$28.94	$3.40	2.94	Flexible

8.1 Characteristics of Low-Emitting Dispatchable Technology

8.1.1 Carbon-Abated Natural Gas Power

Carbon-abated natural gas generation has significant potential in Alberta and is expected to provide a meaningful contribution to the decarbonization of Alberta's electricity sector. Carbon capture technology has not currently been applied to electricity generation facilities in Alberta; however, there are existing applications in the hydrocarbon and petrochemical industries. Post-combustion carbon capture and sequestration is currently operational at several sites in Alberta, including:

- Quest Steam Methane Reformer
- Northwest Redwater Partnership's Sturgeon Refinery
- Nutrien Redwater Fertilizer Facility
- Entropy Glacier Gas Plant

Many additional facilities are at various stages of development and planning in Alberta.

The application of post-combustion carbon capture technology to power generation is in the early stages of deployment. Saskatchewan hosts the only operating power generator in Canada with post-combustion carbon capture. While there are no power generation facilities with carbon capture in Alberta, some larger thermal generation companies are conducting feasibility studies to apply carbon capture to natural gas-fired generation.

Benefits of carbon-abated natural gas technology include:

- Significant growth potential due to Alberta's favourable geology for carbon sequestration and rich natural gas resources.
- Expected to be applied to natural gas-fired combined cycle and co-generation.
- Expected to provide either baseload or mid-merit generation opportunities.

Challenges include:

- Limitations on the flexibility of carbon-abated natural gas power due to the complexity and operations of carbon capture systems; however, some load-following capability is anticipated.
- High water use.
- Increased parasitic load since the carbon capture system will reduce the net output of the generator.

8.1.2 Large-Scale Nuclear

Large-scale nuclear refers to larger fission reactor designs with capacities exceeding 1,000 MW for one generating unit. This is a mature technology with existing plants in Canada; however, there are no nuclear generators currently operating in Alberta.

Operationally, large-scale nuclear fission power plants provide stable base-load power with limited flexibility. The large size and mass of a synchronous generator provides a significant amount of inertia and primary frequency response capability to the power system.

Although there is potential for nuclear generation capacity deployment in Alberta, significant economic and practical hurdles and challenges facing potential investors include:

- High initial upfront investment.
- Long development and construction timeline.
- Compatibility with the market (i.e., a large-scale nuclear unit is not well suited to Alberta's small market size due to the high impact on system stability in the event the unit trips offline, as well as the potential for prolonged depressed prices in the energy market when such a large unit energizes).
- Regulatory approval process.

- Nuclear waste management.
- Large water requirements.
- Potential public opposition.

8.1.3 Small Modular Reactors

Small modular reactors (SMRs) use a nuclear fission reaction to produce electricity, but the size is much smaller compared to large-scale nuclear (i.e., generation is typically 50 to 300 MW). Other features of SMRs include:

- Technology is in the development stage.
- While engineering principles have been successfully validated, the technology has not been demonstrated in an operational environment.
- While the technology is not currently commercially available, small reactor designs are expected to be built in Canada within the next decade (e.g., a GE-Hitachi BWR-X300 reactor is anticipated to be built in Darlington, Ontario).
- Organizations have recently expressed private investment interest in developing SMRs in Alberta.

The benefits of adopting SMR technology in Alberta include:

- Reliable baseload thermal power generation with strong inertia and primary frequency response capabilities.
- The smaller size is more appropriate in smaller markets.
- Reduced costs and expedited construction timelines in comparison to large-scale nuclear.
- Offsite modularization and factory production of key plant components could lead to broader adoption in Alberta's market.

Similar to large-scale nuclear technology, challenges include:

- Regulatory approval process.
- Nuclear waste management.
- Potential public opposition.

8.1.4 Hydrogen-Fueled Generation

Hydrogen-fueled generation technologies refer to combustion turbines, internal combustion engines, and fuel cells that are hydrogen-fueled. Hydrogen fuel is not currently used at a wide scale to produce electricity in Alberta or other jurisdictions, and the technology is in the development stage. However, there are near-term plans to power a three-turbine cogeneration facility using 100 per cent hydrogen at Air Products' Fort Saskatchewan plant in Alberta. This plant is expected to be operational in 2024.

Benefits of hydrogen-fueled generation include:

- Flexible electricity generation using simple-cycle, combined-cycle, reciprocating engine, and fuel cell technologies.
- Many of these technologies implement synchronous generators, which provide inertia and primary frequency response to power systems while enabling flexible fast-ramp operation that can respond quickly to changes in system demand and supply.

Key challenges include:

- Gas turbine technology advancements.
- Extremely high cost of compression, transportation and storage of hydrogen fuel.
- Very low density of hydrogen gas, which can lead to safety concerns when combusted in a turbine.

8.1.5 Hydroelectric Power

Alberta has approximately 900 MW of hydroelectric generation capacity. The three largest plants are primarily used to meet peak demand and provide ancillary services. The remaining smaller facilities are sized less than 50 MW, and most are dispatched infrequently.

Alberta has five main river basins with the following expansion potential:

River Basin	Expansion Potential
Athabasca Peace Slave	Substantial
North Saskatchewan South Saskatchewan	Limited

If all of the potential areas were developed for hydroelectric power, these new resources could meet approximately 80 per cent of today's system load.

Benefits of hydroelectric power include:

- Can generally be controlled with great flexibility and power quality.
- Commonly used in black-start planning.

- Provide excellent operating reserves to balance the electricity system.
- Provide significant fast-ramp capability.
- Large turbines provide significant inertial capacity.
- Well suited to provide the reliability attributes that are becoming increasingly scarce in Alberta’s market.

Key challenges to developing more hydroelectric power in Alberta include:

- Long development timelines.
- Extremely complex environmental permitting and stakeholder engagement processes.
- Large upfront investment with a high risk of cost overruns.
- High transmission system costs to connect remote locations.

8.1.6 Energy Storage Technology

Energy storage resources represent a diverse class of technology intended to capture energy produced at one time for use at a later time. They provide both energy and reliability attributes like inertia and primary frequency response. The four energy storage types include:

- Lithium-Ion
  - Very fast response times
  - Well-suited to provide frequency response services
- Non-Lithium
  - Fast response times
  - Long duration
  - Technology is generally not as mature as lithium-ion
- Compressed Air and Pumped Hydroelectric
  - Longer durations
  - Suitable for energy arbitrage opportunities

Key challenges for this technology include:

- Charging requirement makes them less reliable than some other dispatchable technologies.
- Energy losses occur during charging and discharging.
- Issues with battery performance degradation over time.

Energy storage has the potential to enhance the flexibility and reliability needs of Alberta’s electricity system. Currently, Alberta has 190 MW of electrochemical energy storage, primarily lithium-ion batteries.

These batteries are currently operating as reserves in the ancillary services market and are used to balance supply and demand in real time.

8.2 Risks to Controllable Generation Development

Four major risks associated with developing controllable generation include:

- **Policy uncertainty**—Refers to potential or actual changes in government policy that create risk around development for generation investors.
- **Technology uncertainty**—Refers to risk around cost and operational performance outcomes for a technology.
- **Cost competitiveness**—Refers to the relative cost of dispatchable low-emitting technologies to one another and those technologies used today.
- **Social acceptability**—Refers to the public's perception of the technology and willingness to see it developed in Alberta.

If the combination of these risks is perceived to be too high, then investors will not be willing to develop low-emitting dispatchable generation in the market, and other mechanisms will be needed to secure investment in these types of technologies.

8.2.1 Policy Uncertainty

All controllable generation types face risks, with some more significant than others. Policy uncertainty is a major risk for controllable generation. For example, decarbonization policy changes present significant risk to investments in certain types of technologies. Technologies like abated gas and hydrogen derived from fossil fuels could face performance standards that are beyond the stringency that can be achieved in commercial operation. Similarly, capital-intensive technologies that rely on capital subsidies, like nuclear or large-scale hydroelectric, could be subject to changes in policy during development and construction.

8.2.2 Technology Uncertainty

Technology uncertainty is driven by a variety of factors, including how close the technology is to operating. Technologies that are in the early development stage face uncertainty in performance, construction, and costs. Dispatchable technologies have been ranked based on their "technology readiness," as listed in Table 7, and a quantitative indicator of the level of risk faced by each technology has been assigned. When considering this factor on its own, technologies with a higher "technology readiness" score generally face less technology risk.

8.2.3 Cost Competitiveness

Risks around cost competitiveness are high for technologies that are not yet commercialized and for those that have historic examples of cost overruns. Hydroelectric power generation has experienced large cost overruns in Canada requiring significant government support. Nuclear technologies have also seen large cost overruns in the past, but other examples would be very cost-competitive.

Carbon-abated natural gas power and hydrogen-fueled generation are not yet commercialized and face risks of higher costs. Initial assessments indicate that combined-cycle with CCUS and hydrogen technologies with some storage technologies will be the most cost-competitive in Alberta's energy market going forward.

8.2.4 Social Acceptability

Risks around social acceptability vary and are likely highest for nuclear technologies due to concerns around operational safety and waste management. Hydroelectric power also has challenges with social acceptability due to the large impact on land, as well as upstream and downstream water flows. Extensive stakeholder engagement is required to develop nuclear and hydroelectric facilities. In some cases the environmental and social issues are too great, leading to the cancellation of projects. For this reason, along with the policy, cost competitiveness, and technology risk associated with nuclear and hydroelectric technologies, the AESO is of the view that any nuclear and hydroelectric development over the next 10 to15 years would require significant government support.

The remaining dispatchable technologies (carbon-abated natural gas power, hydrogen-fueled generation, and storage technologies) also carry social acceptability risks but to a lesser extent due to their smaller geographic footprints and less controversial fuel sources.

Technologies with higher policy, technology, cost competitiveness, and social acceptability risk are less likely to be developed in Alberta's market going forward. Large-scale hydroelectric power generation and nuclear technologies are unlikely to be developed without some form of government support. The remaining technologies (combined cycle with CCUS, hydrogen technologies and storage) are more likely to be developed under a REM. The AESO reiterates its recommendation that this can be monitored, with further action only if required.

8.3 Investment in Dispatchable Technologies

Alberta's electricity sector has benefited from significant private investments in new supply resources over the past several decades. Investors have responded to the price signal in Alberta's Energy-Only Market by making investments based on their assessment of potential risks and rewards.

> *While the pace and scale of the electricity sector's transformation are significant, the AESO believes that the majority of new investments required to maintain reliability through the transformation can be supported by the recommendations contained in this report.*

A flexible market structure where all technologies are encouraged to compete, and where investors assume the majority of the risks associated with investing in new technology, will continue to serve the needs of Albertans for affordable and reliable electricity today and in the future.

Appendix I: Stakeholder Consultation

Appendix I: Stakeholder Consultation

The AESO developed the REM recommendation in consideration of input and feedback provided to the AESO by stakeholders. This section outlines the key takeaways gathered during the AESO-led engagements.

To support the development of this recommendation the AESO led an Executive Working Group (EWG) of senior industry leaders from a diverse range of stakeholder groups (conventional generation, consumer groups, renewables/storage, DFO/TFO, load, associations, and academia) to explore and understand the various perspectives across industry. Discussions had a strategic focus on issues to solve in the context of Alberta's electricity market including the:

- Objectives for the electricity industry
- Future market design
- Framework options
- Reliability
- Affordability

The input gathered from the EWG was augmented with further input from the broader stakeholder group.

EWG AREAS OF GENERAL AGREEMENT AND DIVERGING VIEWS

Through the EWG engagement, a broad range of perspectives were shared, which reflect the stakeholders' respective areas of concern and interest. The following highlights the areas of agreement as well as areas of diverging views.

Areas of General Agreement

- The benefit of competition in meeting the objectives was strongly recognized.
- The critical importance of maintaining reliability through the transition was unanimously supported.
- The need for change to the existing market framework was accepted, but views varied on the extent of change needed.
  - There was general agreement that long-term structural discussion is required, owing in part to the uncertainty surrounding the CER.
- The group generally accepted that some change is required and that, at a minimum, change to the existing Energy-Only Market is required to ensure the market's ability to deliver short-term adequacy but views varied on how much change should be made now.
- The need for larger framework shifts to maintain long-term adequacy, and support required investments in dispatchable generation, was generally agreed to hinge on decarbonization policy, with more stringent policies requiring larger change.

- The objectives were accepted following modifications to highlight the:
  - Role of customer choice.
  - Need for a robust investment climate of any market design.
  - Recognition of potential alternative decarbonization timelines and transition considerations.
- The Capacity Market model was generally unpopular and the least preferred framework model. The group viewed the model as:
  - Adding significant administrative complexity for limited to no improvement in the ability to attract new investment.
  - Not addressing the full range of reliability needs.
  - Potentially increasing costs or making costs more difficult to manage from a consumer perspective.
- A concern was highlighted about the treatment of investments made under the current structure, and how those should be fairly considered in any transition to a significantly different structure.
- During discussions on new technologies, the group considered that investments in nuclear technology would not be possible under any market structure and would require a long-term contract to build. Other decarbonized dispatchable technologies may be incented by the market depending on the deployment timeline.
- Although the implementation of enhancements to the EOM structure are not trivial, changes can be achieved within a 2 to 3 year window. Significant change from the current structure would require multiple-year implementation.
- There was recognition that policies (i.e., *Transmission Regulation*, retail treatment, market structure) interact and must work together to achieve objectives.
- A common theme from loads and generators was the desire to maintain the benefits of supplier and consumer choice that are available in the current structure.
- The group agreed that any contracting approaches should be designed to leverage market signals and minimize distortions rather than replace these signals.
- There was resounding agreement that if elements of central planning and contracting are introduced, competition and innovation must be maintained as much as possible.

Areas of Diverging Views

The greatest areas of diverging views were the extent of change that is needed and how the affordability issue should be addressed.

A significant number of the EWG members expressed the view that targeted adjustments to the existing market structure should be made to address concerns, and that a fundamental shift to an alternate framework model isn't necessary. This view was shared by those who either benefit from the Energy-Only Market structure or those who see it as beneficial to await clarity on CER before deciding.

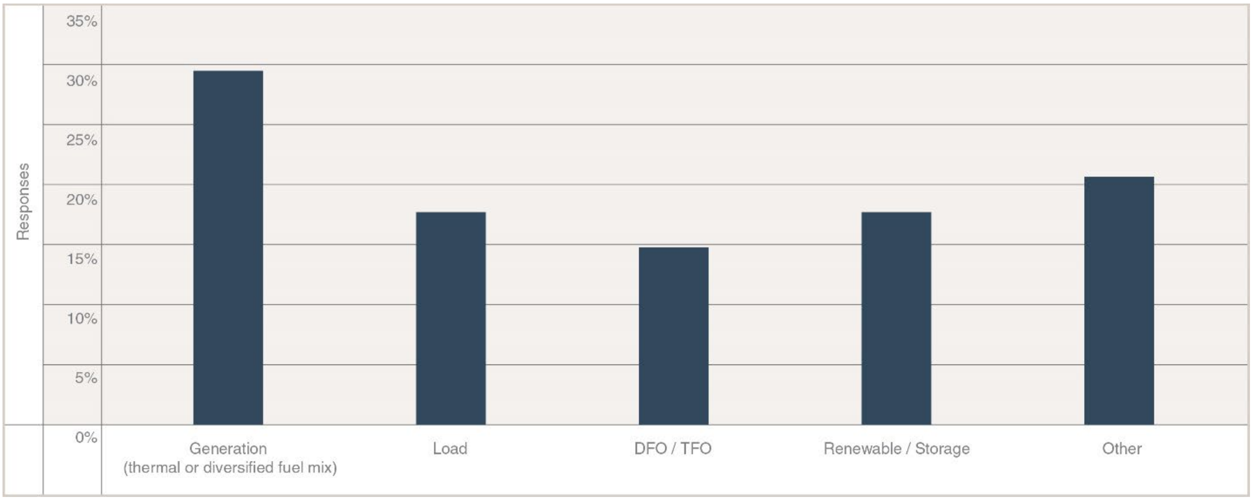
The other area of varied or diverging views is related to affordability. Some felt affordability would resolve itself through future supply additions. Others, mainly consumers, felt the burden on consumers was too great. To this, some suggested that changes to retail product design was the solution, while others raised concerns regarding the degree of competition in the market, and contemplated if changes to design and policy are needed to address this. A general expectation was that decarbonization would drive higher overall costs or price levels as options become more limited and carbon costs are factored into overall price levels. This led to discussions on the level, pace, and importance of decarbonization relative to affordability.

EWG EVALUATION OF FRAMEWORK OPTIONS

The AESO conducted a focused survey with EWG members to gain individual perspectives on the framework models considered and to evaluate these models against the objectives. The categorization of the market frameworks in the survey differs slightly from those presented in this paper, as they were grouped into three high-level models instead of four to help streamline discussions with EWG members. The survey combined the long-term contracts and cost of service frameworks under Integrated Resource Planning (IRP), as both represented the centrally controlled models in the framework spectrum.

Stakeholder respondent composition is shown in the following Figure 7.

Figure 7: Market Model Evaluation Survey



Key observations from the survey are provided as follows:

Survey Category: A Reliable Electric Grid

- Comments suggested that any of the framework models could achieve a reliable electricity grid, with the IRP model ranked slightly higher than the other models.

Survey Category: Affordable Electricity for Consumers

- The Energy-Only Market was identified as driving the most competition and customer choice, therefore achieving the lowest overall cost.
- IRP was identified as best able to provide stable prices, with a risk that the prices are overall at higher levels.

Survey Category: Decarbonization by 2050 and Related Policy Objectives

- The Energy-Only Market was identified as the best for driving technology innovation.
- IRP is more compatible with more stringent policy and policy uncertainty.

Survey Category: Reasonable and Realistic Implementation

- The Energy-Only Market ranked highest for this objective by all; the IRP was ranked as the lowest.
- The Energy-Only Market design was ranked highest of all framework models across the load, generation, and renewable stakeholder groups for the overarching objectives.
- Load viewed IRP as beneficial to ensure appropriate checks on market power, provide stable prices, and incent optimal use of transmission and distribution infrastructure.

Generation (thermal or diversified fuel mix) flagged the following challenges with IRP:

- Creating price signals to promote competition and economically efficient outcomes.
- Allowing flexibility and choice in how participants manage market exposure.
- Allocating risk to those who can most efficiently manage it.

Generation ranked IRP as most compatible with the eventual outcome of the *Clean Electricity Regulations.*

FEEDBACK FROM BROADER INDUSTRY

In addition to the EWG, the AESO also engaged with the broader industry through an industry session in November 2023, providing opportunities for all interested stakeholders (including EWG members) to provide their input on the engagement process and evolution of the market. The majority of participants agreed that an Energy-Only Market with modifications is the best way to achieve the objectives defined in this recommendation and drive the best outcomes for Albertans. Participants provided a range of modifications that could be implemented; however, there was no consensus reached on the scope of change needed. Detailed stakeholder comments posted on the AESO Engage Market Pathways page can be accessed via the following link: EWG Summary and Straw Market Models Stakeholder Comments.

Appendix II: Development of AESO Recommendation

Appendix II: Development of AESO Recommendation

Given the transformational changes to the Alberta electric system, the AESO recognized a need for changes to the current market design to maintain reliability and launched an initiative to evolve the wholesale electricity market. On August 1, 2023, the *Market Pathways Primer* (Primer) was published, which set out:

- Guiding principles for potential changes.
- Issues and priorities of the electric system.
- Market Pathways process.
- Stakeholder engagement approach.

The AESO requested stakeholder feedback on each of these points, which was received on September 5, 2023.

In the Primer, the AESO committed to a collaborative stakeholder engagement approach through the establishment of a working group. However, the AESO recognized that its approach may need to change if there are changes to the scope of issues/priorities and/or regulatory policy considerations.

Subsequent to the publication of the Primer, the Minister issued a letter to the AESO on August 31, 2023, requesting the AESO to conduct a study, in conjunction with the MSA, on the current market framework and make observations and recommendations on the following by February 1, 2024:

- Market incentives that could be used to mitigate the impacts of the intermittency of supply and promote grid reliability within the province.
- Market design and legislative changes required to deliver those required market incentives affordably.
- The current and future role and potential of different dispatchable technologies, such as carbon-abated natural gas power, full-scale nuclear, small modular reactors, hydrogen-fueled generation, hydroelectric power, and energy storage resources, in supporting this reliability objective.

Upon receipt of the request from the Minister, the AESO decided to pivot its stakeholder engagement approach to hold three working group meetings with senior industry leadership. The wider stakeholder community was informed about this change in direction in the October 12, 2023, Market Pathways industry update stakeholder session.

On September 19, 2023, the AESO sent a reply to the Minister outlining the AESO's interpretation of the government's primary objectives for the wholesale electricity market structure that should guide the AESO's recommendations. The objectives considered the AESO's core mandate, understanding of government policy related to decarbonization by 2050 and other objectives, and the practical realities of implementing a large-scale restructuring of the electricity sector. On November 7, 2023, the Minister confirmed the AESO's description of the objectives to align with the government's objective of achieving a carbon-neutral, reliable, and affordable power grid by 2050. The AESO notes that some minor changes to the detailed objectives were made in consultation with senior industry leaders through the EWG process outlined in this Section.

The objectives to guide the restructuring of the wholesale market framework are outlined in Section 3 of this report.

An Executive Working Group (EWG) was formed to gain insights from industry on the future evolution of the market. The AESO engaged with senior industry leaders from a diverse range of stakeholder groups (conventional generation, renewables/storage, DFO/TFO, load, associations, consumer groups and academia).

The AESO held three sprint sessions through October and November 2023 with senior leaders to:

- Gather insights to assist the AESO in developing its recommendations to government.
- Consider views on a future market framework, incentives, reliability, and affordability.
- Gain alignment on objectives for the electricity system to help guide the future electricity market in Alberta.
- Provide EWG members with information on the spectrum of market framework options available and solicit EWG members' proposals for alternative market reform models.
- Evaluate options against the objectives to inform AESO recommendations.

The EWG sprint pre-read materials were posted on the AESO Engage Market Pathways page and can be accessed via the following link: Executive Working Group Sprint Pre-Read Materials.

The sessions were facilitated by Stack'd Consulting with market design expertise support provided by The Brattle Group. Along with the in-person sprint discussions, a survey was issued to EWG members to gather their impressions on the market models and to allow members to conduct a preliminary evaluation of the market models against the agreed-upon objectives for the electricity system. A summary of the sprint discussions and the survey results were communicated to the wider stakeholder community at the AESO's Stakeholder Symposium on November 30, 2023. After the Stakeholder Symposium, the broader stakeholder community was given the opportunity to comment on the market models and working group approach.

Key Dates	Topics for Discussion
Sprint I: October 16, 17 & 18	• Discuss and gain alignment on objectives for Alberta's electricity system • Review the spectrum of straw market models
Sprint II: November 1	• EWG members' opportunity to present alternative straw market models • Discuss any follow-up questions on the spectrum of straw market models and objectives for Alberta's electricity system
Survey issued to EWG members: November 7 to 15	The intent of the survey was to: • Gather initial impressions of market models • Conduct preliminary evaluation of market models against objectives
Sprint III: November 20	• Explore and capture potential risks, triggers, and thresholds
Stakeholder Symposium: November 30	• Report back to industry on what we heard from EWG

The AESO considered feedback from the EWG, the broader industry, as well as internal analysis, with support from The Brattle Group, to establish the recommendation in this report. The AESO did not seek to achieve a consensus on the preferred path amongst EWG participants, but rather to gather sufficient information and viewpoints to identify the best solution for the province as a whole and in alignment with the defined objectives. The MSA was also an observer in the EWG sessions. In addition, the AESO also coordinated with the MSA in arriving at the final recommendation as instructed by the Minister in his August 31, 2023, letter to the AESO.

On August 31, 2023, the Minister requested the MSA "provide the government advice as to whether any further legislative or regulatory reforms are required to support more effective competition in our electricity market in order to support affordability and other outcomes in the consumer interest." The AESO understands that this advice was provided to the government on or before December 24, 2023. Meetings were held regularly between the AESO and the MSA. To the AESO's knowledge, the AESO and MSA are recommending materially similar reforms to Alberta's electricity market.

Appendix III: Description of Market

Appendix III: Description of Market

Alberta currently has a de-regulated self-commitment, real-time, Energy-Only Market with a single clearing price.

- An **Energy-Only Market** involves generators competing to deliver energy to serve load and earn the prevailing market price, which attracts the investment necessary to maintain supply adequacy.
- Alberta's **single clearing price** can be subject to volatility, providing a stronger investment signal when prices are high and a weaker signal when prices are low. This is predicated on maintaining an uncongested system, where the price for electric energy excludes any costs associated with the delivery of that energy.

Transmission development in Alberta is centrally planned by the AESO, with transmission costs regulated and charged through the ISO and distribution facility owner (DFO) tariffs.

In accordance with the FEOC Regulation, generators cannot physically withhold available generation capacity from the market and must offer their entire capability to the market. However, economic withholding by pricing energy above short-run marginal cost is permitted. Economic withholding is an important feature of the current market design because suppliers can unilaterally exercise market power to raise the energy price above marginal cost, which allows them to earn the necessary return of and on capital to support their investment. This may result in a generator not providing energy into the market until the marginal price in the market is high enough that the generator's offer is dispatched by the AESO. To mitigate the extent to which sellers can exercise market power, the current market design includes a maximum offer control share that prevents any one entity from holding more than 30 per cent supply share. On a longer-term basis, the exercise of market power is disciplined by competitive entry from new suppliers.

Loads can also participate in the market by submitting bids indicating the price at which they are willing to buy electricity from the grid. However, no loads currently participate in the market in this way. In practice, some large loads respond to high pool prices by voluntarily reducing electricity consumption. Additionally, some loads, including end-use electricity retailers, manage price volatility through forward contracts.

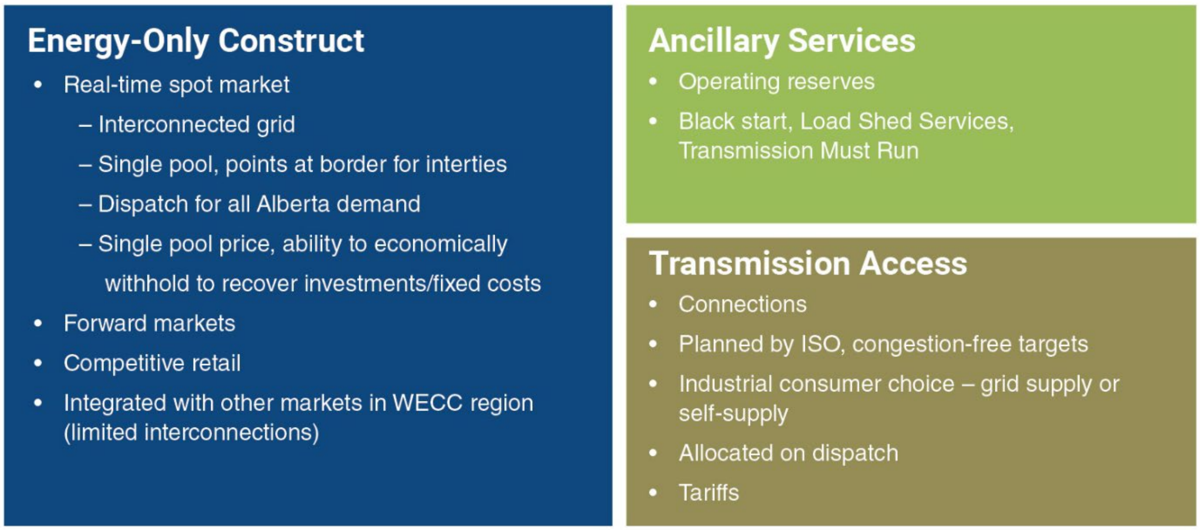
In addition to the energy market, the AESO has mechanisms in place to procure ancillary services to maintain reliability. Ancillary services include services such as:

- Operating reserves are used to ensure supply and demand remain in balance, in normal operation and during unexpected events on the electrical grid.
- Transmission must-run is used to ensure load continues to be served when there are constraints on the transmission system.
- Load shed services used to enable reliable increases in imports.
- Black Start Services for use to restore the electric system in the unlikely event that it goes down.

The AESO procures operating reserves through a day-ahead market, while other ancillary services are either competitively procured or conscripted when required. Currently, the cost of these ancillary services is charged to electricity consumers through the ISO tariff.

The Energy-Only Market design has supported a sustainable balance of investment and operational signals, customer costs, and reliability outcomes for more than two decades. However, given the transformation in the system, the market structure and rules need to be revisited to ensure a robust FEOC platform for attracting investment and maintaining reliability going forward.

Figure 8: Current Market Structure

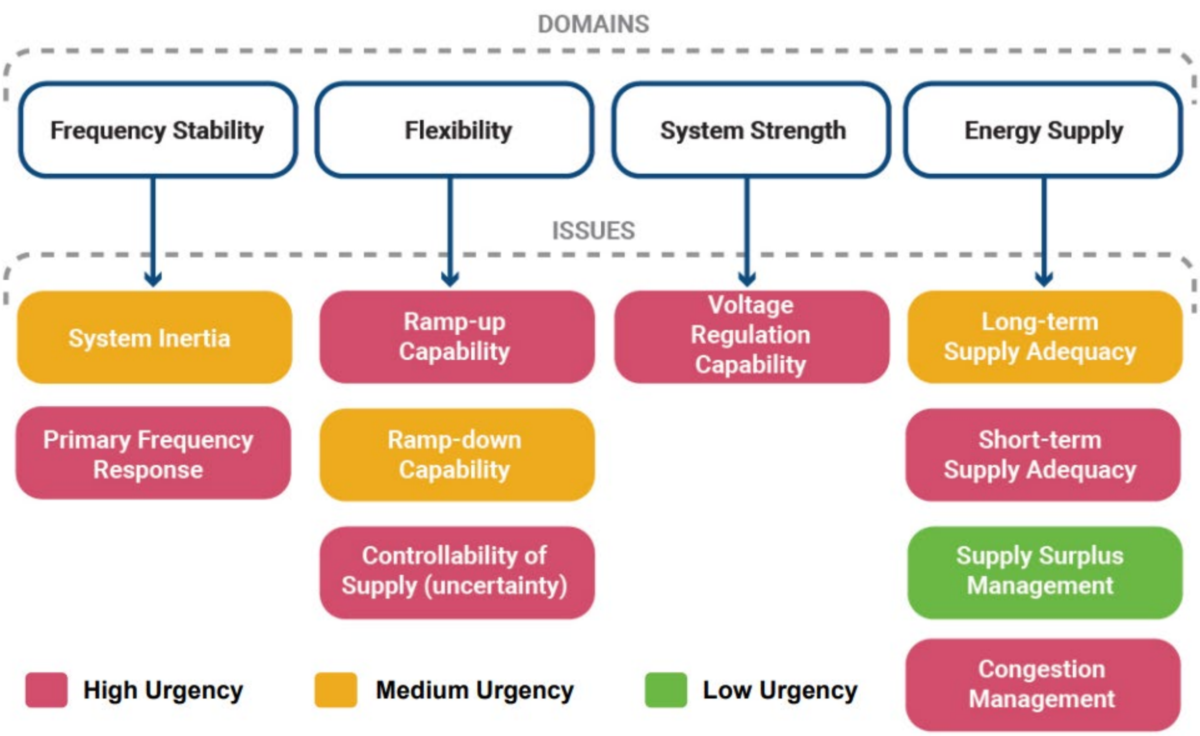


Appendix IV: Near-Term Recommendations

Appendix IV: Near-Term Recommendations

To maintain reliability, the AESO has identified certain issues that will impact the electricity system in the coming decade. These issues were identified and described, with their respective urgency, in the Market Pathways Primer after being further developed from the issues described in the Reliability Roadmap and Net-Zero Report. Four issues and related challenges are defined in Figure 8.

Figure 9: Reliability Requirements



INCREASED REGULATING RESERVE PROCUREMENT

Forecast error leads to imbalances in the system, which is generally managed by regulating reserves. As this forecast error gets larger or more frequent, more regulating reserves or other solutions will be needed. In 2023, the AESO began to procure additional regulating response to manage performance standards and controllability during high variability periods. The AESO continues to monitor performance and controllability of the system and update the regulating reserve procurement volumes as needed to address reliability needs.

TECHNICAL REQUIREMENTS

Developing technical requirements on inverter-based resources such as wind, solar and energy storage to improve performance to support reliability.

UNIT COMMITMENT

Near-term actions surrounding unit commitment relate to the availability of long lead-time assets. Long lead-time assets refer to generation assets that require more than one hour to start up. The AESO is addressing gaps and improving the operation of long lead-time energy to ensure energy is available to support reliable grid operations. Actions include:

- Publication of a new market supply cushion report in Q4 2023 to better inform market participants on supply available in the merit order, enabling more informed decisions to bring and/or keep long lead-time assets online.
- Publication of a new report in 2024 on real-time MW volume associated with long lead-time energy (available energy that is offline for reasons other than an outage, but subject to the long-lead constraint), which will further improve market transparency.
- An AESO review of long-lead time rule requirements and related information documents for changes to address gaps associated with the application of long lead-time energy. One aspect subject to review is the criteria in which AESO System Controllers issue directives for long-lead assets in specific supply adequacy conditions, and if additional flexibility is required.

STRATEGIC RESERVE

The AESO expects there to be adequate supply in the near-term with gas generation additions under development. However, if required the AESO can also engage in contracts for strategic reserves to ensure the continued availability of the existing generating fleet to maintain supply adequacy.[4]

[4] Strategic reserves refer to when an additional reliability service is procured outside the existing market structure as a short-term solution to meet reliability needs until the existing market structure can be updated to address the issue. Since strategic reserves are procured outside the existing market structure, they may weaken existing price signals or procurement mechanisms. To limit this risk, strategic reserves are only used when all other existing methods of addressing the reliability issue have been exhausted.

Appendix V: Options Considered to Inform the REM Design

Appendix V: Options Considered to Inform the REM Design

As part of its evaluation of the potential options to address long-term and short-term adequacy, the AESO has identified three broad approaches:

- A market-based approach in the form of leveraging existing markets or creating new ones to acquire the desired attributes relevant to each issue. Also included under this market-based approach is running competitive procurements for required services.
- A rules-based approach where the AESO uses new rules to enforce outcomes on the grid.
- A wires-based approach which considers services to be provided through the regulated, "wires-based" entities in Alberta's electricity market. This could be from TFOs or DFOs.

Determining which approach is best to address an issue depends on a number of factors. Ideally, the AESO would optimize between these options to minimize the cost of maintaining short-term supply adequacy. Examples of factors that would need to be considered include:

- Cost: whether imposing uniform standards on generators for the provision of energy is more effective and lower cost than designing an ancillary service product and procuring it from generators based on their willingness to provide it.
- Impact on the price signal in the energy market.
- Timing of need to address an issue: different approaches may be required in the short-term versus the longer-term to address an imminent need.

Following is a list of all options that the AESO determined could address the issues that the electricity system is encountering while ensuring reliability and affordability into the future. Given the scope of this initiative is related to changes to the wholesale market structure, the list of options is comprised of market-based and rules-based options.

The AESO can pursue potential wires-based options and will continue to do so as part of other AESO initiatives. The implementation of wires-based options does not require policy changes. Some of these options work together to address the issue, and some may be implemented individually. The AESO considered all options in determining the REM recommendation and put together a cohesive design package that best meets the objectives outlined in this report. Shaded rows denote options that were selected to form the REM recommendation package.

Table 8: Restructured Energy Market Options

Option	Definition	Issue Resolved
Short-Term Supply Adequacy		
Additional ancillary service products	Additional ancillary services products to support the grid procured through contracts or markets (i.e., ramping, inertia, voltage, and primary frequency response).	Helps to resolve reliability issues such as frequency, flexibility, and system strength, depending on the type of ancillary service product procured.

Option	Definition	Issue Resolved
Additional technical requirements	Mandating certain technical standards for units to connect to the grid through rules (i.e., grid forming inverters, etc.).	Helps to resolve reliability issues such as frequency, flexibility, and system strength, depending on the technical standard.
Leverage existing ancillary service products	Contingency Reserves, Regulating Reserves, Black Start, Transmission Must-Run, Load Shed Services, Fast Frequency Response, etc. continue to be used to maintain reliability.	Helps to resolve reliability issues such as frequency, flexibility, and system strength, depending on the type of ancillary service product used.
Co-optimization of ancillary services and energy	Optimize across energy and ancillary service markets to ensure the lowest cost providers across both markets.	Helps ensure the lowest costs between different markets which in turn helps with affordability.
Economic dispatch	Dispatch lowest to highest cost based on offers.	Helps ensure the lowest-cost dispatch in the energy market which contributes to affordability.
Intertie energy offers/bids	Allow intertie participants to put in an offer/bid at a price other than $0/$999.99. Intertie resources are currently price takers in the market.	Helps to resolve flexibility issues by providing a price signal on the intertie.
Multi-part offers	Requires generators to include start cost, minimum generation cost and incremental energy cost in their offers.	Part of the solution for the unit commitment issue and helps achieve efficient dispatch by ensuring that all operations costs are covered in the market.
Negative price floor	Decrease the price floor below $0/MWh.	Helps incent flexibility and helps to ensure the lowest-cost supply is dispatched
Reliability unit commitment (RUC)	Centralized time-ahead process that studies supply and demand conditions and will physically commit units if deemed necessary to maintain reliability——does not require a method of valuing congestion.	Centralized method of unit commitment that addresses some of the uncertainty associated with self-commitment.
Security Constrained Economic Dispatch (SCED)	Method of dispatch which optimizes cost subject to constraints (transmission, demand, ramp).	Ensures efficient dispatch which helps with affordability. Sophisticated SCED engines enable more complicated grid and market operations that incorporate various security constraints such as system congestion, ramping capability, frequency, intertie requirements, etc.
Security Constrained Unit Commitment	Method of committing units time ahead subject to constraints (transmission, demand, ramp)—requires a method of valuing congestion.	Centralized method of resolving unit commitment issues that accounts for constraints and removes the uncertainty found with self-unit commitment.
Shorter settlement and dispatch intervals	Decrease the settlement and dispatch timeframes in the energy market.	Helps to resolve flexibility issues by providing a more granular price signal to both supply and demand.
Time-ahead markets	Loads and generators can transact on future electricity delivery while considering the impact of transmission constraints and unit commitment. i.e., day-ahead markets.	One method of setting energy prices in advance of delivery. Helps with unit commitment issues and price volatility

Option	Definition	Issue Resolved
Long-Term Supply Adequacy		
Increase price cap	Increase the price cap above $1,000/MWh.	Helps to resolve long-term and short-term supply adequacy issues through scarcity pricing. Helps incent demand response.
Financial Transmission Rights (FTR)	Allow market participants to offset potential losses (hedge) related to the differential price risk found in markets with locational prices.	Helps generate investment opportunities by allowing market participants to hedge transmission constraint risks.
Locational Marginal Price	Market prices in the province differ based on predefined transmission nodes/zones due to congestion.	Allows for more efficient use of the transmission system which can help with affordability and resolve congestion.
Offer-based scarcity pricing	Form of scarcity pricing that determines price based on the ability of generators to price energy offers above marginal cost (i.e., economic withholding).	Helps to resolve long-term and short-term supply adequacy issues by communicating short-term scarcity and facilitating fixed cost recovery.
Prohibit physical withholding	Physically removing generating capability from the grid without an operational reason.	Prohibiting physical withholding ensures efficient dispatch by ensuring all available generation is offered into the market.
Supply cushion-based administrative scarcity pricing	Form of scarcity pricing that determines price based on supply cushion in the energy market (i.e., operating reserve demand curve). Offers are typically capped at short-run marginal cost.	Helps to resolve long-term and short-term supply adequacy issues by communicating short-term scarcity and facilitating fixed cost recovery. May also be foundational for further market enhancements such as SCED and Locational Marginal Price.

Appendix VI: Alternative Processes for Implementation of New and Revised ISO Rules

Appendix VI: Alternative Processes for Implementation of New and Revised ISO Rules

The AESO has considered a range of alternative ISO rule implementation processes in developing its recommendation on the proposed approach, as is set out in Section 7. This Appendix presents the possible alternative approval options that could be used to implement the government's path forward and provide an assessment of their benefits and drawbacks. As noted in Section 7.2, the AESO recommends that the government adopt an expedited time-bound approach to ensure the implementation of its market changes.

THE IMMEDIATE LEGISLATIVE OPTION

At one end of the spectrum, the government could legislate the new and amended ISO rules into existence. The AESO envisions this would be done via an Order-in-Council or another mechanism that set out that the ISO rules would be in effect as of "X" date. Under this approach, there would be no proceeding before the AUC with respect to the new or proposed ISO rules. The benefits of this approach include immediate implementation and full certainty with respect to the content of the ISO rules. If the new and amended ISO rules were legislated into existence, no changes would result from regulatory process.

While immediate implementation is a benefit of this option, the AESO sees significant risk with an alternative approval process that does not include a public proceeding before the AUC. The appearance of a "behind closed doors" decision-making process could run the risk of legal challenge from impacted stakeholders that participate in the existing public and transparent process. The AESO also foresees heightened risk of post-implementation regulatory proceedings in response to complaints about the legislated ISO rules. The AESO is also of the view that legislating ISO rules into existence may lack the flexibility the AESO needs to ensure its market design and ISO rules-based approach is fit-for-purpose to implement the government's path forward.

THE EXISTING APPROACH

The current ISO rule approval process is set out in section 20.21 of the EUA, with further details found in the AUC's rules, specifically AUC Rule 017, *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission*.

The existing approach has the benefit of transparency and full regulatory oversight prior to the implementation of the ISO rules package. It also provides the AESO with the discretion to implement changes to the ISO rules in a flexible manner and provides the AUC with similar flexibility to determine what process is needed in an ISO rule proceeding. This approach would also mitigate the possibility of challenges to approved ISO rules succeeding on procedural fairness grounds.

Despite these above-described benefits, the AESO does not view the existing approach as the appropriate vehicle by which to advance significant structural changes to the energy market and the ISO rules. The existing approach takes significant time to complete and will hinder the effective implementation of any proposed ISO rules package. In the AESO's experience, even minimal changes to one ISO rule can run the risk of a protracted proceeding before the AUC depending on the involvement and views of stakeholders. This risk is heightened when implementing a suite of changes to the ISO rules impacting a broad set of stakeholders. Beyond a protracted proceeding process, the existing approach could mean that some of the approved ISO rules are tied up in regulatory process indefinitely through complaints, appeals or review and variance proceedings. There is also the risk that the AUC may not approve some of the ISO rules package, putting the timely implementation of the government's path forward at risk. Finally, the existing approach requires the AESO to engage in stakeholder consultation after it engages in a lengthy market design stakeholder consultation process. Given the likely extent of market changes, this will delay the effective implementation of the government's path forward.

THE HYBRID APPROACH

The hybrid approach draws on the existing ISO rules consultation and approval process, but with modifications. The AESO has recommended that this approach be used to facilitate the necessary new and amended ISO rules. As is set out in the details of the AESO's approach described in Section 7.2, the hybrid approach achieves both certainty and efficiency, while still ensuring transparency and stakeholder input.

Some of the downsides to this approach include an expedited timeline which may be challenging to meet if the AESO and stakeholders are divided on the best path forward. While the AESO is recommending that any approved ISO rules are temporarily shielded from challenge for a period of 18 months so that the AESO and stakeholders can observe the implementation of the new and amended ISO rules in practice, this does not preclude stakeholders from challenging approved ISO rules after this period expires, which could put some of the structural market changes at risk. There is also the risk that the AUC could direct the AESO to change some of its proposed new or amended ISO rules, which may somewhat lengthen the time period for implementation of the ISO rules.

aeso

Appendix VII: Engineering Study on the Current and Future Role and Potential of Different Dispatchable Technologies

1898 & CO.

PART OF BURNS & McDONNELL

REPORT

DISPATCHABLE LOW-CARBON GENERATION TECHNOLOGY ASSESSMENT

ALBERTA ELECTRIC SYSTEM OPERATOR

PROJECT NO. 164770

Disclaimer

ABBREVIATIONS

Abbreviation	Term/Phrase/Name
°C	Degrees Celsius
1898 & Co.	1898 & Co. a part of Burns & McDonnell
A-CAES	Adiabatic Compressed Air Energy Storage
ACCIP	Alberta Carbon Capture Incentive Program
ACG	Alberta Carbon Grid
ACR	Advanced CANDU Reactor
ACTL	Alberta Carbon Trunk Line
AESO	Alberta Electric System Operator
AFCR	Advanced Fuel CANDU Reactor
APIP	Alberta Petrochemicals Incentive Program
Assessment	Dispatchable Carbon-Free Generation Assessment
AZETEC	Alberta Zero Emissions Truck Electrification Collaboration
BOP	Balance of Plant
BWR	Boiling Water Reactor
CAD	Canadian Dollars
CAES	Compressed Air Energy Storage
CANDU	Canada Deuterium Uranium
CAP	Chilled Ammonia Process
CaSb	Calcium-Antimony
CCGT	Combined-Cycle Gas Turbine
CCUS	Carbon Capture, Utilization, and Storage
CNL	Canadian Nuclear Laboratories
CNSC	Canadian Nuclear Safety Commission
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
D-CAES	Diabatic Compressed Air Energy Storage
DLN	Dry Low NO_x
DOE	United States Department of Energy
EC6	Enhanced CANDU-6 Reactor
ECCC	Environment and Climate Change Canada
EMS	Energy Management System
EOR	Enhanced Oil Recovery
EPC	Engineer, Procure, Construct
EPR	European Pressurized Water Reactor
EPRI	The Electric Power Research Institute
ERA	Emissions Reduction Alberta
Fluor	Fluor Corporation
FNTP	Full Notice to Proceed
GE	General Electric
GE Hitachi	GE Hitachi Nuclear Energy
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

ABBREVIATIONS

Abbreviation	Term/Phrase/Name
IDC	Interest During Construction
IMSR	Integral Molten Salt Reactor
KEPCO	Konsai Electric Power Co., Inc.
km	Kilometre
KM CDR	Kansai Mitsubishi Carbon Dioxide Recovery
kWh	Kilowatt hour
LDES	Long Duration Energy Storage
LFP	Lithium-Iron-Phosphate
Mitsubishi	Mitsubishi Heavy Industries Engineering, Ltd.
MMR	Micro Modular Reactor
MOU	Memorandum of Understanding
MW	Megawatt
MWh	Megawatt hour
NACSA	North American Carbon Storage Atlas
NaS	Sodium-Sulfur
NASA	National Aeronautics and Space Administration
NB Power	New Brunswick Electric Power Corporation
Ni	Nickel
NMC	Nickel-Manganese-Cobalt
NRC	United States Nuclear Regulatory Commission

Abbreviation	Term/Phrase/Name
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OPG	Ontario Power Generation
PBE	Purpose-built enclosure
PCOR	Plains CO2 Reduction
PCS	Power Conversion System
PHES	Pumped hydroelectric energy storage
Program	Enabling Small Modular Reactors Program
PWR	Pressurized Water Reactor
redox	Reduction-oxidation reaction
RTE	Round Trip Efficiency
SCGT	Simple-Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SMR	Small Modular Reactor
Study	Assessment of dispatchable, low-carbon power generation technologies
SWOT	Strengths, Weaknesses, Opportunities, and Threats
TES	Thermal Energy Storage
TRL	Technology Readiness Level
UAMPS	Utah Associated Municipal Power Systems
Westinghouse	Westinghouse Electric Corporation

TABLE OF CONTENTS

EXECUTIVE SUMMARY

1898 & Co., a part of Burns & McDonnell, ("1898 & Co.") was retained by Alberta Electric System Operator ("AESO") to assess the strengths, weaknesses, opportunities, and threats ("SWOT") associated with dispatchable, low-carbon power generation technologies to meet Canada's decarbonization by 2050 goals while maintaining the Alberta electric system reliability ("Assessment"). This report details the methodology, assumptions, and findings from the Assessment.

Carbon-abated natural gas-fired combined-cycle, simple-cycle, and cogeneration power generation

Hydrogen-fired combined-cycle, simple-cycle, and cogeneration power generation

Advanced nuclear fission power generation

Hydroelectric power generation

Energy storage systems including lithium-ion batteries, long duration non-lithium batteries, compressed air energy storage ("CAES"), and pumped hydroelectric energy storage ("PHES")

The Assessment included the following technologies:

For each technology included in the Assessment, 1898 & Co. provided the following technical information in

- Total installed capital cost
- Performance estimates
- Fixed and variable operations and maintenance ("O&M") costs
- Estimated implantation schedule durations
- Operational useful life
- Carbon emission intensity, measured in kilogram of carbon dioxide ("CO_2") per megawatt hour ("MWh") generated
- Inertia provided by generator

Appendix A:
Additionally, for each technology, this Assessment provides a technology description and commercial status update; analyzes the technology SWOT; and opines on the potential future role of the technology in Alberta.

SWOT ANALYSIS SUMMARY

The following summarizes the SWOT analysis of each technology included in the Assessment.

Carbon Capture SWOT Analysis Summary

Strengths

- Leverages proven, mature technologies while reducing CO_2 emissions.
- Grid inertia and frequency response
- Some load-following capabilities
- Ability to retrofit existing facilities

Weaknesses

- No full scale commercially operating plants in North America
- Limited operational flexibility
- High capital and O&M cost
- Significant reduction in plant efficiency
- Requires additional operational expertise
- Water usage
- CO_2 transportation and sequestration infrastructure

Opportunities

- National and provincial incentives (grants and tax credits)
  - Investment tax credit
  - Alberta Carbon Capture Incentive Program
- Alberta's abundance of favorable carbon sequestration geology

Threats

- Risk associated with long-term storage of CO_2
- Social perception of continual investment in fossil generation
- Dependency on government incentives
- Dependency on global oil prices

Hydrogen SWOT Analysis Summary

Strengths

- Leverages proven, mature technologies while reducing CO_2 emissions
- Ability to retrofit existing facilities
- Similar operational characteristics to existing facilities
- Grid inertia and frequency response
- Peaking and load following capabilities

Weaknesses

- High fuel costs
- Hydrogen combustion technology still under development
- Safety considerations
- Limited fuel infrastructure in place
- Fuel production efficiency

Opportunities

- Prolific existence of hydrogen

Threats

- Hydrogen versatility could lead to high demand from other industries

Small Modular Reactor SWOT Analysis Summary

Strengths

- High energy density; small footprint
- Modularity
- Passive safety features
- Carbon-free, dispatchable, load-following ability

Weaknesses

- Permitting, licensing, and construction timeline
- High-levelized cost of electricity
- Spent fuel management
- First-of-kind technology

Opportunities

- Potential collaboration for global SMR deployment
- Various SMR technology providers
- Governmental interest
- Job creation
- Historical Canadian nuclear success
- International collaboration

Threats

- Public safety, waste management, and costs concern
- Regional difference in public acceptance

Pressurized Water Reactor SWOT Analysis Summary

Strengths

- Reliable generation resource
- Zero emissions
- Built to withstand extreme weather
- Proven technology
- Multiple operating nuclear stations in Canada

Weaknesses

- Permitting, licensing, and construction timeline
- High-levelized cost of electricity
- Spent fuel management
- Water requirement

Opportunities

- Multiple, approved reactor designs
- Uranium supply in Saskatchewan
- Public support

Threats

- Public safety, waste management, and costs concern
- Regional difference in public acceptance

Hydroelectric SWOT Analysis Summary

Strengths

- Reliable source of power
- Grid inertia and frequency response
- Potential for large generation capacity
- Black start capabilities and flexible operation profile
- Zero emissions

Weaknesses

- Permitting and construction schedule
- Environmental and social impacts
- Significant capital investment

Opportunities

- Large developable potential in Alberta
- Large generating capacities

Threats

- Unfavorable public perception
- Locations could require substantial transmission infrastructure expansion
- Historical difficulties with large scale projects
- Limited site suitability

Lithium-ion Battery Energy Storage SWOT Analysis Summary

Strengths	Weaknesses	Opportunities	Threats
• Lowest capital cost of comparable technology • Technology maturity and multiple suppliers • High round trip efficiency (“RTE”) • Quick response time	• High capacity degradation over time • Less flexibility (cycling limits and behaviors) • Augmentation and overbuild costs • Thermal runaway and fire risk • Finite amount of energy can be discharged • Charging time required between use	• Potential for shorter lead times and better availability • Benefit from electric vehicle research and development	• Growth of the electric vehicle market • Safety concerns • Raw material supply

Non-Lithium Battery Energy Storage SWOT Analysis Summary

Strengths	Weaknesses	Opportunities	Threats
• Longer duration battery • Reduced risk of thermal runaway • Reduced capacity degradation • Unit costs improve for longer durations • Better potential for raw material sourcing • Quick response time	• Technological maturity • Technology provider size • Unproven O&M costs • Lower RTE • Finite amount of energy can be discharged • Charging time required between use	• Recent interest into energy storage diversity • Increasing long-duration needs • Potential for cost reductions from continued research and development	• Alternative technology competitiveness • Risk due to smaller companies performing research and development

Compressed Air Energy Storage SWOT Analysis Summary

Strengths	Weaknesses	Opportunities	Threats
• Technology maturity • Long life • No performance degradation • Customizable	• Unproven commercially • Lower RTE • Geological condition requirements • Longer development and construction timelines	• Alberta geology may be suitable for development • Recent project development may increase pricing stability • Canadian company is a leader in space	• Technology competitiveness • Largely dependent on single supplier/developer

Pumped Hydroelectric Energy Storage SWOT Analysis Summary

Strengths

- Technology maturity
- Relatively high RTE
- Long operational useful life
- Customizable

Weaknesses

- High upfront cost
- Siting restrictions
- Increased permitting and environmental impact studies
- Longer construction timeline
- Finite amount of energy can be discharged
- Charging time required between use

Opportunities

- Retrofit of existing facilities
- Growing need for long duration energy storage

Threats

- Increased regulatory and permitting restrictions
- Technology competitiveness

TECHNOLOGY READINESS LEVELS

The Technology Readiness Levels ("TRL") of each technology evaluated in the Assessment is displayed in **Table 1**.

Table 1: Technology Readiness Level Summary

Decarbonization Technology	Technology Specification	Technology Readiness Level
Carbon Capture	Simple-Cycle Gas Turbine Facility	N/A
	Combined-Cycle Gas Turbine Facility	7
	Cogeneration Facility	7
Hydrogen-fueled	Simple-Cycle Gas Turbine Facility	5
	Combined-Cycle Gas Turbine Facility	5
	Cogeneration Facility	5
Nuclear	Small Modular Reactor ("SMR")	6
	Advanced Pressure Water Reactor	9
Hydroelectric	Conventional	9
Energy Storage	Lithium-ion Battery	9
	Non-Lithium Battery	5-8
	Compressed Air	7
	Pumped Hydroelectric	9

Key Findings

Alberta is heavily investing in carbon reduction technologies and has already seen a significant reduction in CO_2 emissions from the electricity sector from coal retirements and increased renewable generation. Despite these efforts, wind, solar, and lithium-ion batteries alone are not sufficient to achieve a zero-carbon emissions future. **Alberta will need to utilize dispatchable carbon-free generation to achieve a decarbonized future while maintaining a reliable electric grid.**

This report provides an update on the current status, capabilities, and costs associated with dispatchable low-carbon generation resources. A decarbonized future will likely rely on some combination of all of these technologies. However, it is clear that these technologies will result in an overall increase in electricity prices compared to the current generation resource mix.

INTRODUCTION

AESO desires to better understand the strengths, weaknesses, opportunities, and threats associated with dispatchable, low-carbon generation technologies to support planning efforts as the Alberta electric system targets reduced carbon emissions while maintaining system reliability.

Evaluated Technologies

The following technologies were evaluated as part of this assessment:

Carbon abated (post combustion amine-based capture) natural gas-fired power generation

- Combined-cycle (Represented by 2x1 F-class CC)
- Cogeneration (Represented by 1x E-class)
- Simple-cycle gas turbine (Represented by 1x LM6000)

Hydrogen-fired power generation

- Combined-cycle (Represented by 2x1 F-class CC)
- Cogeneration (Represented by 1x E-class)
- Simple-cycle gas turbine (Represented by 1x LM6000)

Nuclear fission power generation

- Small Modular Reactor
- Advanced Pressure Water Reactor

Hydroelectric power generation

Battery storage resources

- Lithium-ion batteries
- Long duration non-lithium batteries
- CAES
- PHES

The Dispatchable Carbon-Free Generation Assessment report summarizes the assessment of the above dispatchable, low-carbon generation technologies and provides technical information regarding the capital cost, O&M costs, performance, dispatch capabilities, greenhouse gas ("GHG") emissions, and implementation schedules. Additionally, the current status, advantages and disadvantages, market potential, and risks of each technology were evaluated.

Alberta's Current Energy Consumption and Emissionsww

Publicly available data from the Environment and Climate Change Canada ("ECCC") and AESO's 2022 Annual Market Statistics report from March of 2023 were reviewed to provide a high-level overview of Alberta's current power generation mix, energy consumption, energy prices, and emission data.

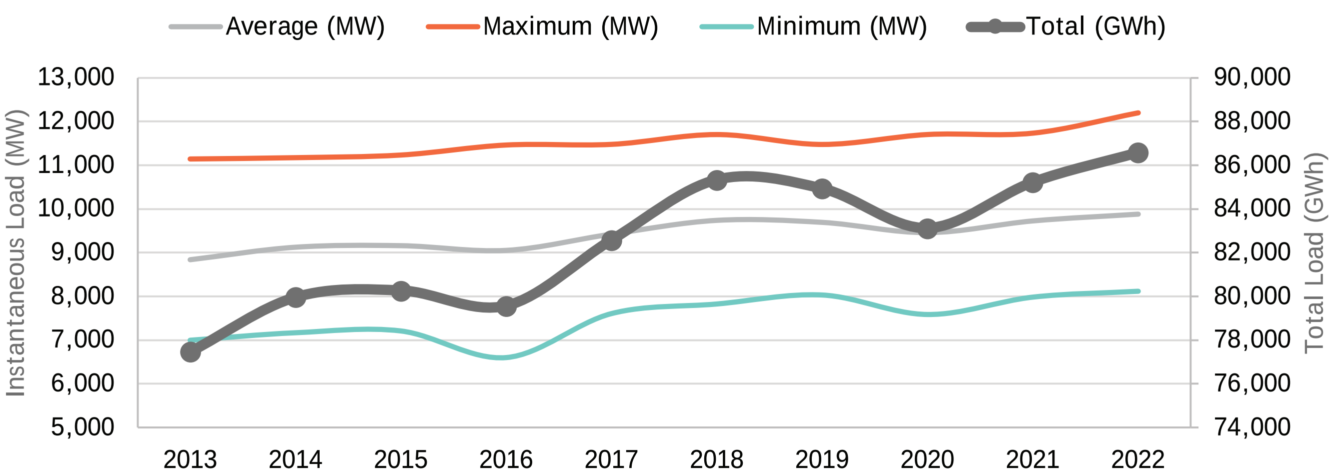
Based on the year-end capacity data from 2022, 1.8 gigawatts ("GW") of new generation was installed throughout 2022 in Alberta, increasing the total installed generation capacity to 18.4 GW. Of the new generation capacity added to the grid, almost all (98.3%) was solar, wind, or energy storage. Multiple coal units were retired or transitioned to a different fuel source (natural gas or dual fuel).

From 2018 to 2022, Alberta has experienced a total reduction in installed coal generation of 85.3% (from 5,568 megawatts ("MW") installed to 820 MW installed). Over the same period (2018-2022), Alberta experienced a 150% increase of installed wind capacity (from 1,445 MW installed to 3,618 MW installed). To ensure grid stability and reliability as additional renewable, intermittent power generation is installed while simultaneously coal generation facilities are retired, reliable and dispatchable generation technology will be required.

At the end of 2022, Alberta's installed power generation capacity mix was as follows:

Alberta has experienced consistent load growth over the past 10 years. Provincial energy use in 2022 totalled 86,572 GW hours ("GWh"), which represents a 1.6% year over year load growth and an 11.8% load growth over the past 10 years. **Figure 1** displays Alberta's minimum load (MW), maximum load (MW), average load (MW), and total load (GWh) over the past 10 years.[1]

Figure 1: Alberta 2013-2022 Load



[1] https://www.aeso.ca/assets/Uploads/market-and-system-reporting/2022_Annual_Market_Stats_Final.pdf

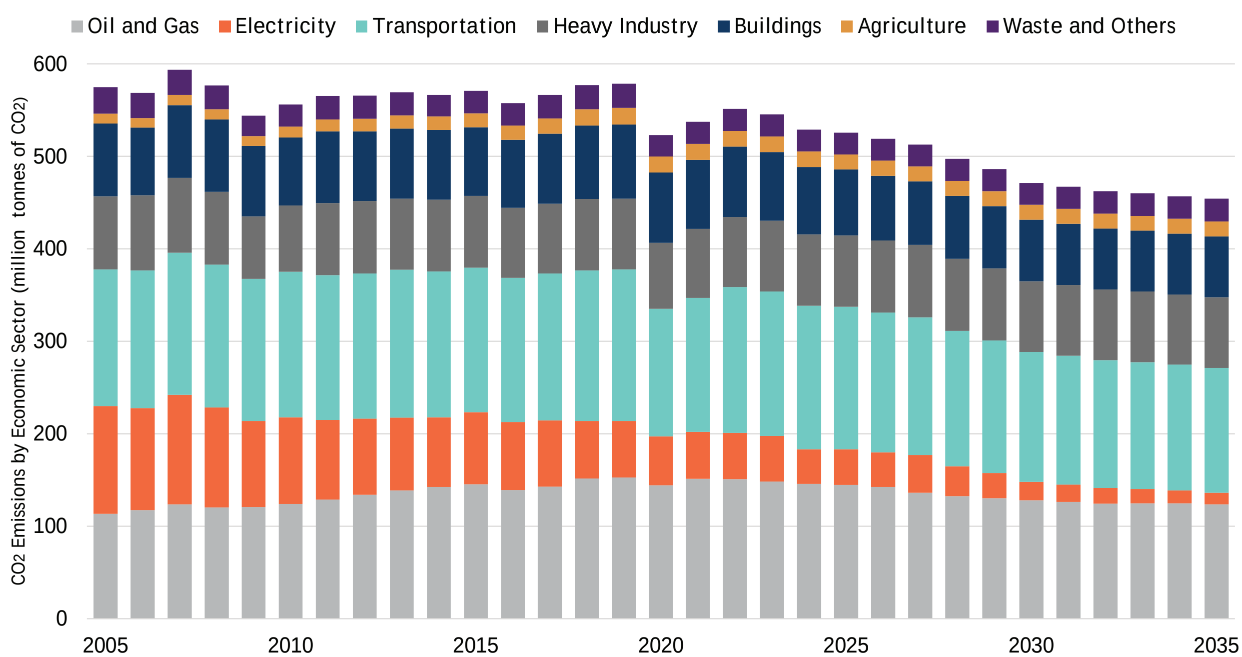
The ECCC provides historical Canadian GHG and CO_2 emission data, as well as emission projections through 2035. The base case projection, which was used in this Assessment, includes all current governmental policies as of August 2023, and assumes no further policies will be enacted. According to these projections, a reduction of slightly less than 96.8 million tonnes of CO_2 emissions will occur from 2022 to 2035 across all economic sectors in Canada. Of those CO_2 emission reductions, 37.4 million tonnes (38.6%) are attributable to the electricity economic sector. **Table 2** displays the top five producers of carbon emissions by economic sector from 2022. Emission values are presented in million tonnes of CO_2.[2]

Table 2: Alberta 2013-2022 Load

Economic Sector	2022 CO_2 Emissions (MM tonnes)	Percentage of 2022 Total CO_2 Emissions	Projected 2035 CO_2 Emissions (MM tonnes)
Transportation	157.8	28.9%	135.0
Oil and Gas	150.8	27.7%	123.7
Buildings	76.0	13.9%	65.8
Heavy Industry	75.9	13.9%	76.5
Electricity	49.9	9.2%	12.5

The historical and projected CO_2 emissions, including the breakdown by economic sector are graphically displayed in **Figure 2**. The electricity sector has drastically cut CO_2 emissions since 2005 and continues to project further reductions. This is largely driven by coal retirements and increased addition of wind and solar generation on the grid. While these technologies have been effective in reducing CO_2 emissions, these technologies alone are not sufficient to achieve a zero-carbon emissions future while maintaining grid reliability. Alberta will need to utilize dispatchable carbon-free generation to achieve a fully decarbonized future.

Figure 2: Historical and Projected Emissions by Economic Sector



[2] https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/projections.html

ASSESSMENT BASIS AND ASSUMPTIONS

General Assumptions

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- All information is preliminary and should not be used for construction purposes.
- All capital cost and O&M estimates are stated in 2023 Canadian dollars ("CAD"). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct ("EPC") fixed price contract for project execution.
- All options are based on a generic site in Alberta with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material.
- Sites are assumed to be flat with minimal rock and with soils suitable for spread footings.
- Ambient conditions were assumed based on Edmonton, Alberta:
  Elevation: 670 m | Winter Conditions: -28.9°C and 65.1% RH
  Summer Conditions: 26.1°C and 42.9% RH | Annual Average Conditions: 4.4°C and 58.7% RH
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Owner's costs are developed as a percentage of the EPC execution costs.
- Capital cost estimates include the costs associated with "inside the fence" scope. All off-site infrastructure is not included.
- Electrical scope is assumed to end at the high side of the generator step up transformer.

Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees
- Interest during construction ("IDC")
- Escalation
- Sales tax
- Property taxes and insurance
- Transmission interconnect
- Transmission system network upgrades
- Natural gas and hydrogen pipeline infrastructure (including laterals to site)
- Water supply (including pipelines and wells)
- Off-site infrastructure
- Utility demand costs
- Decommissioning/demolition costs and hazardous waste removal

Operating and Maintenance Assumptions

O&M estimates are based on the following assumptions:

- O&M costs are in 2023 CAD.
- O&M estimates exclude emissions credit costs.
- O&M estimates exclude property taxes and property insurance.
- Where applicable, fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Where applicable, variable O&M costs include routine maintenance, makeup water, water treatment, water disposal, ammonia, selective catalytic reduction ("SCR") replacements, and other consumables not including fuel.
- Fuel costs are excluded from O&M estimates.
- Where applicable, major maintenance costs are shown separately from variable O&M costs.
- Gas turbine major maintenance assumes third party maintenance based on the recommended maintenance schedule set forth by the original equipment manufacturer ("OEM").
- Base O&M costs are based on performance estimates at ISO ambient conditions unless otherwise stated.

Technology Readiness Level

The National Aeronautics and Space Administration ("NASA") developed the TRL scale to assess the maturity of emerging technologies. The United States Department of Energy ("DOE") has subsequently adapted this TRL scale specifically for energy-related projects, facilitating the evaluation of technology readiness levels to ensure project success. The TRLs can be split into three groups. TRL 1-3 are the least mature and typically indicate the research level of development for those technologies. Projects at TRL 4-6 indicate technologies in the development stage. TRL 7-9 are the most mature and are typical of technologies in the deployment stage of development.

Technology Readiness Levels (TRLs)

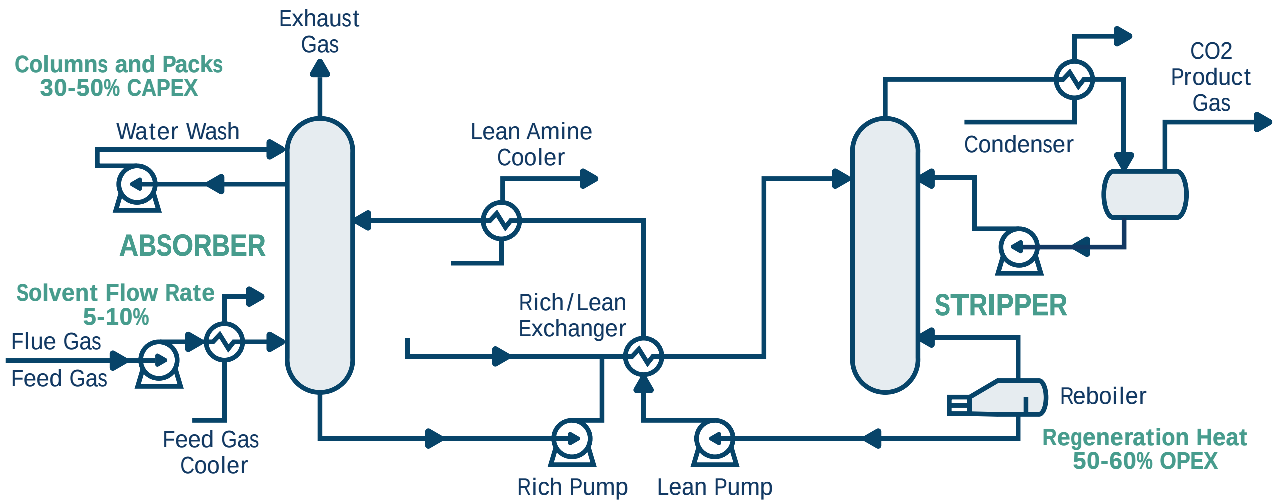
RESEARCH			DEVELOPMENT			DEPLOYMENT		
TRL 1	TRL 2	TRL 3	TRL 4	TRL 5	TRL 6	TRL 7	TRL 8	TRL 9
Basic principles observed and reported	Technology concept and/or application formulated	Experimental critical function and/or characteristic proof-of-concept	Prototype validation in laboratory/local environment	Prototype validation in relevant environment	Prototype demonstration in a relevant environment	Prototype demonstration in operational environment	Compliance and qualified through demonstration	Proven in operational environment

CARBON CAPTURE TECHNOLOGY

Carbon capture, utilization, and storage ("CCUS") is a process that permanently prevents CO_2 from being emitted into the atmosphere. This Assessment focuses on post-combustion carbon capture from exhaust gas from natural gas-fired power generation facilities. The captured CO_2 can either be utilized for industrial processes or permanently stored in geologic formations. Permanent storage in geologic formations is assumed for the purpose of this Assessment.

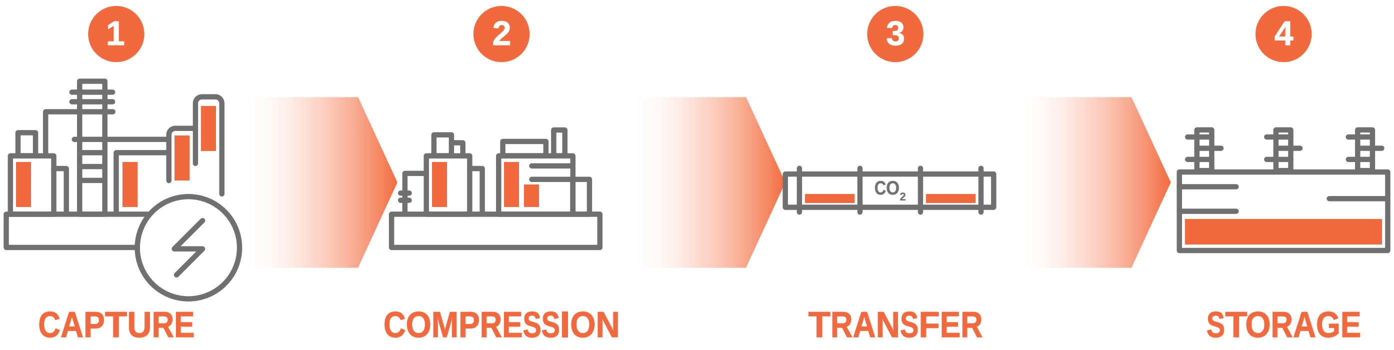
Post-combustion carbon capture utilizes a reversible solvent-based (usually an Amine solution) process to separate the carbon from the exhaust flue gas. Firstly, the CO_2 is extracted from cooled exhaust gas through a selective reaction with an amine solution. The CO_2-rich amine solution is then transferred to a regenerator vessel, where it is heated (typically with steam) to separate the CO_2 from the amine solution, resulting in a relatively pure CO_2 stream.

Figure 3: Post Combustion Carbon Capture System Diagram



The captured CO_2 is dehydrated and compressed into a supercritical fluid for transportation and injection. Due to the potential for well corrosion and subsurface gas migration, the supercritical fluid is more suitable for CO_2 geologic storage. Many of the sites where CO_2 emissions occur do not have an adjacent geological storage site, resulting in the need to transport the compressed gas to a suitable injection site. The supercritical state is also more suitable for CO_2 transport via pipeline. Upon arrival at the storage facility, CO_2 is injected into the targeted subsurface formation via one or more wells.

Figure 4: CCUS Process Overview



Geological storage options currently being investigated for secure storage include but are not limited to:

- **Depleted oil and gas reservoirs [with or without enhanced oil recovery ("EOR")]**
- **Deep unused saline water-saturated reservoir rocks**
- **Deep, unmineable coal seams**
- **Shallow unmineable coal seams (CO_2 storage with coal bed methane recovery)**
- **Other options include deep basalts, oil shales, and cavities.**

The minimum injection depth, based on the hydrostatic head needed to maintain the supercritical state, is approximately 800 metres.

Post-combustion carbon capture technology has been under development for several decades. Manufacturers have been developing more efficient amine-based solvents to capture CO_2 with less auxiliary loads. Despite significant investments in technology, post-combustion carbon capture has continued to be cost-prohibitive. As a result, there have been very few pilot facilities in North America. Post-combustion carbon capture technology is considered a TRL of 7. There are three coal facilities in North America that have captured CO_2 for exhaust flue gas slipstreams. These were not full-scale (only treated a portion of the flue gas) and most have stopped operation after completing validation due to costs or operational challenges.

Simple-Cycle Gas-Fired Technology with Carbon Capture

A simple-cycle gas turbine ("SCGT") power generation facility utilizes a fuel source (typically a hydrocarbon, such as natural gas which was assumed for this Assessment) to produce power in a gas turbine generator. The gas turbine (Brayton) cycle is an efficient method for the conversion of gaseous fuels to mechanical power or electricity. SCGTs are typically used for peaking power due to their quick startups, fast load ramp rates and relatively low capital costs. However, the units have high heat rates compared to combined-cycle technologies. SCGT power generation is a widely used, mature technology.

When considering utilizing post-combustion carbon capture technologies with an SCGT, there are a few challenges. Typically, steam is used as the heat source in the regenerator vessel for carbon capture. An SCGT does not generate steam. In order to produce steam, an auxiliary boiler or heat recovery steam generator ("HRSG") would be required. A boiler or HRSG would not only add significant costs to the project (and potentially burn more fuel) but would also limit the operational flexibility of the SCGT. One of the primary reasons to construct an SCGT is the capability of quickly responding to market demands. The steam generation would take significantly more time to startup and would hinder the ability of the unit to quickly respond to the market. For this purpose, the SCGT with carbon capture was not further evaluated as part of this Assessment.

Combined-Cycle Gas-Fired Technology with Carbon Capture

A combined-cycle gas turbine ("CCGT") power generation facility utilizes a gas turbine generator and a steam turbine generator to produce electric power. The exhaust gases produced by the gas turbine (Brayton cycle) are used in a HRSG to produce and provide superheated steam to a steam turbine generator (Rankine cycle), which produces additional electric power. The use of both gas and steam turbine cycles in a single plant to produce electricity results in high conversion efficiencies and relatively low emissions.

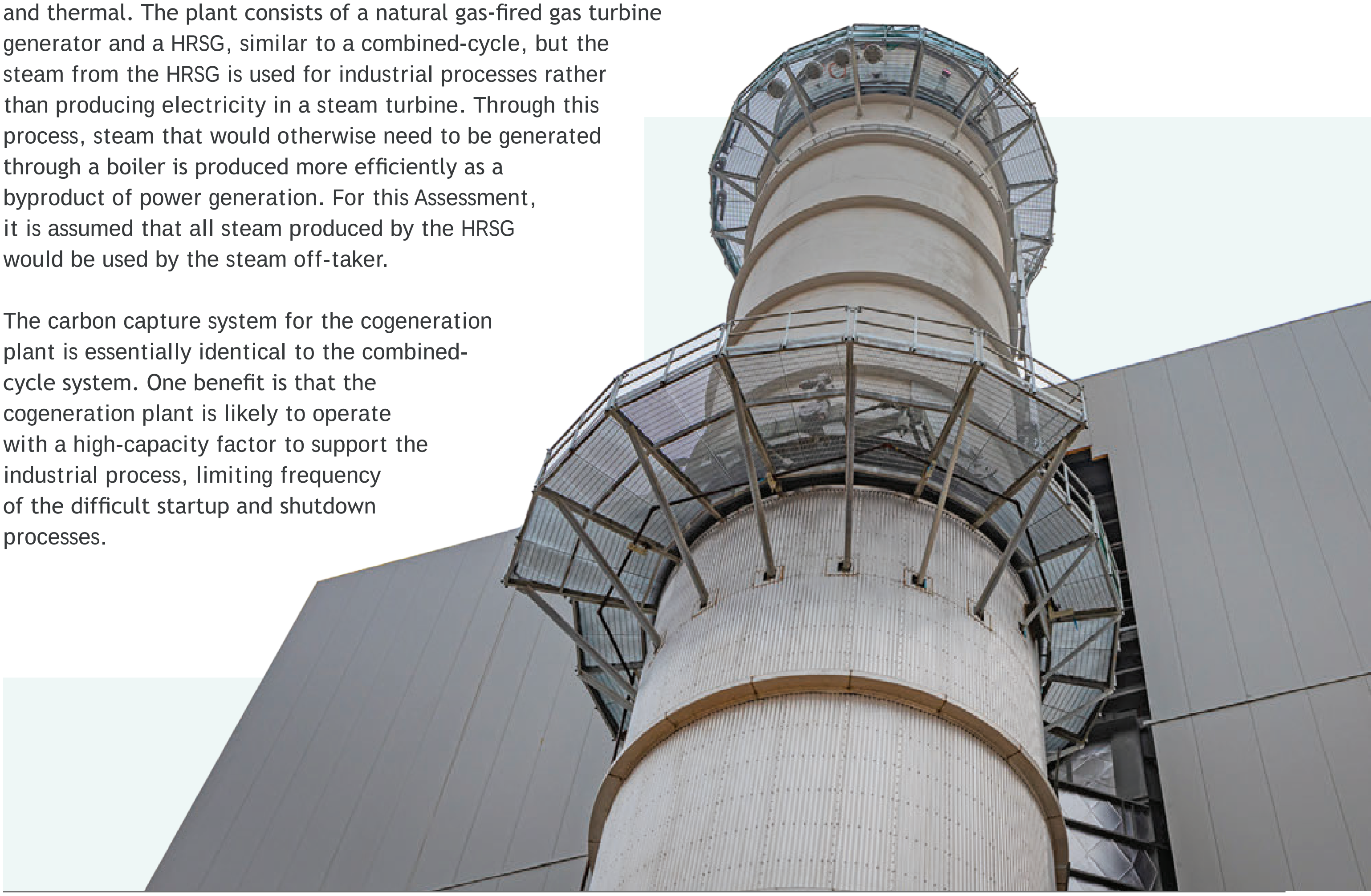
The carbon capture system takes exhaust flue gas from each HRSG and increases gas pressure via a blower to account for pressure drop through the carbon capture system. The flue gas is then cooled prior to entering the absorber vessel. The amine based solvent solution reacts with the CO_2 in the absorber vessel, allowing for clean exhaust to be vented to the atmosphere. The CO_2-rich amine solution is then pumped to the regenerator vessel where the solvent is heated using steam from the steam cycle such that CO_2 is released from the solution. The CO_2 is then dehydrated and compressed for transportation and storage and the CO_2-lean amine solution is cooled and returned to the absorber vessel.

The carbon capture system is the equivalent of a chemical processing facility on the backend of the combined-cycle. The addition of the carbon capture system to a power generation facility adds operational challenges. Due to the complexity of the carbon capture system and integration with the steam cycle, startup and shutdown cycles are undesirable. The carbon capture system would likely be started prior to the overall CCGT so that the power generation facility startup times are not significantly impacted.

Cogeneration Gas Turbine Technology Description

A cogeneration facility generates two types of energy: electrical and thermal. The plant consists of a natural gas-fired gas turbine generator and a HRSG, similar to a combined-cycle, but the steam from the HRSG is used for industrial processes rather than producing electricity in a steam turbine. Through this process, steam that would otherwise need to be generated through a boiler is produced more efficiently as a byproduct of power generation. For this Assessment, it is assumed that all steam produced by the HRSG would be used by the steam off-taker.

The carbon capture system for the cogeneration plant is essentially identical to the combined-cycle system. One benefit is that the cogeneration plant is likely to operate with a high-capacity factor to support the industrial process, limiting frequency of the difficult startup and shutdown processes.



Scope Assumptions

The technical information for CCUS provided in Appendix A is governed by the following assumptions:

- Technical information for CCUS is based on post-combustion carbon capture utilizing an amine-based solvent designed for 90% continuous CO_2 removal from the exhaust flue gas.
- CO_2 is assumed to be compressed to supercritical conditions for transport in a pipeline for sequestration.
- The cost information provided does not capture the pipeline infrastructure and sequestration costs for CO_2.
- Steam supplied to the CCUS system for the regenerator reboiler is assumed to be provided from the power generation facility steam cycle resulting in a reduction in steam turbine output or steam to industrial process off-taker.

Technology Providers and Status

Mitsubishi

Mitsubishi Heavy Industries Engineering, Ltd. ("Mitsubishi"), in collaboration with the Konsai Electric Power Co., Inc. ("KEPCO"), has developed a carbon capture technology called the Kansai Mitsubishi Carbon Dioxide Recovery ("KM CDR") Process. The Process utilizes a Mitsubishi-developed, amine-based solvent (KS-1) to capture over 90% of CO_2 contained in flue gas emitted from a gas turbine through chemical absorption. Mitsubishi has also demonstrated a new solvent, KS-21, which is incorporated into Mitsubishi's improved carbon capture technology, the Advanced KM CDR Process. Following demonstration testing of KS-21 in 2021, the solvent was commercialized and offers lower volatility and higher stability against degradation when compared to the KS-1 solvent.[3]

Fluor

Fluor Corporation ("Fluor") has developed the patented carbon capture technology, Econamine FG Plus, which has a pilot facility in Northern Germany capturing CO_2 from a slip stream. Fluor is also working with several other utilities in the U.S. on CCUS projects on coal and gas plants.

Baker Hughes

Baker Hughes has developed the Chilled Ammonia Process ("CAP") for post-combustion carbon capture on power generation facilities. The CAP technology utilizes non-proprietary ammonia as the amine in the capture process. While the ammonia solution is not as efficient at capturing CO_2 as some other advanced amines, it has the advantage of being a significantly less expensive solvent that is readily available. CAP is one of just a few technologies that have been demonstrated at an operating coal plant, a 235 MW slipstream at AEP's Mountaineer Plant.[4]

Shell (CANSOLV)

The Shell company has developed a proprietary regenerable amine-solvent system for post-combustion CO_2 capture called CANSOLV. Their technology guarantees the removal of 90% of flue gas CO_2. This technology is utilized at a variety of sites worldwide but, most notably, is currently being used on the only existing power generation facility with CCUS capabilities in North America, the Boundary Dam coal-fired power generation facility.[5]

[3] https://www.mhi.com/products/engineering/co2plants_process.html
[4] https://www.bakerhughes.com/process-soilutions/chilled-ammonia-process
[5] https://f.hubspotusercontent00.net/hubfs/3433801/Shell Cansolv CO2 Capture System Fact sheet.pdf

Recent Projects

As of 2023, there is only one operating power generation facility with CCUS capabilities in North America. The Boundary Dam Carbon Capture Project in Saskatchewan, Canada, consists of a retrofitted coal-fired power generation facility that uses captured CO_2 for EOR. CCUS operation began on Unit #3 in 2014, a 110 MW unit. The carbon capture system was designed for 90% removal of CO_2, and captures approximately 1 million tonnes of CO_2 a year. The facility has recently had reduced availability due to challenges with its main CO_2 compressor motor.

The Petra Nova Project, located near Houston, Texas, was a retrofitted coal-fired power generation facility that captured CO_2 for use in EOR. Operations began in 2017 but were suspended in response to low oil prices, primarily caused by the 2020 pandemic. The CCUS facility is a 240 MW system and captured 92.4% of CO_2 emissions from the unit's exhaust gas slipstream during its 3 years of operation. In September 2023, the Petra Nova Project was officially restarted under the new ownership of JX Nippon, a Japanese energy company.[6]

The Quest Carbon Capture and Storage Project, developed and completed by Shell in 2015, successfully captures, transports, and stores CO_2 in the Basal Cambrian Sands rock formation near Edmonton, Alberta, for permanent underground storage. Quest was a retrofit of Shell's Scotford Upgrader facility, which uses three steam-methane reforming hydrogen manufacturing units to produce hydrogen from the upgrading of oil sands to synthetic crude oil. Carbon captured during this process is transported through 65 kilometres ("km") of pipeline to reach the injection site. The maximum design injection rate for the wells is approximately 145 tonnes per hour, resulting in an annual injection capacity of 1.2 million tonnes of CO_2. During 2021, the average capture ratio for the hydrogen units was 78.2%. Fluor performed the engineering, procurement, and construction of the CCUS project.[7]

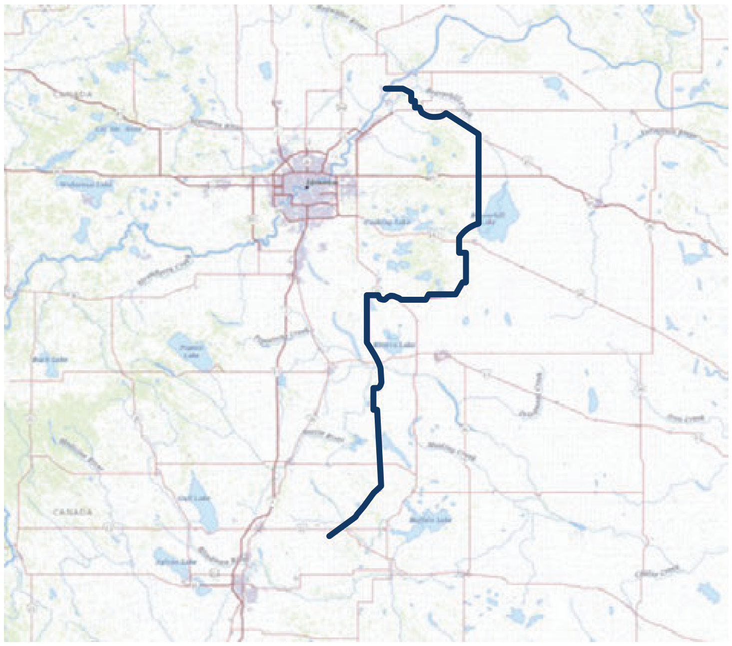
Alberta Carbon Grid ("ACG") Industrial Heartland Project is a CCUS hub and spoke model with the potential capability of transporting and storing up to 10 million tonnes of CO_2 annually. Project partners include Pembina Pipeline Corporation and TC Energy Corporation. The project is still in the planning phase; the ACG has entered into an evaluation agreement with the Government of Alberta to examine further and confirm the subsurface qualities of the Area of Interest. The Area of Interest covers over 900,000 hectares of land that contain deep porous geological formations ideal for carbon sequestration. Project completion is estimated for 2027.[8]

As of 2023, there is **only one** operating power generation facility with CCUS capabilities in North America.

[6] https://www.energy.gov/fecm/petra-nova-wa-parish-project
[7] https://www.fluor.com/projects/shell-quest-carbon-capture-epc
[8] https://albertacarbongrid.ca/wp-content/uploads/2023/09/AlbertaCarbonGrid_Factsheet.pdf

The Alberta Carbon Trunk Line ("ACTL") system became fully operational in June of 2020, transporting carbon through a 240 km pipeline system to be used for EOR in the Clive Oil Reservoir. The project includes gasification, carbon capture, transportation, storage, and EOR, with the potential to transport up to 14.6 million tonnes per year.[9] Initially, the gathering system will be used to pipe and store CO_2 from the Sturgeon Refinery and Agrium Fertilizer Plant near Redwater, Alberta, with additional projects to be added as the project matures. Enhance Energy and Wolf Carbon Solutions own and operate the CO_2 utilization and sequestration portion of the ACTL.[10] Since operations began in 2020, the project has captured and sequestered over 3.5 million tonnes of CO_2.[11]

Figure 5: Alberta Carbon Trunk Line



Technical Information

Natural gas-fired combined cycle and cogeneration facilities with CCUS systems will maintain many of their technical capabilities. There is additional capital and O&M costs associated with the CCUS system and net output decreases due to parasitic loads but carbon emissions are significantly reduced. The ramp rates are not significantly impacted. Minimum continuous operating load may be increased slightly based on the GT minimum emissions compliance load (likely limited to approximately 50% load). The facility is still capable of providing the same system inertia and frequency response. The CCUS system can also be retrofitted onto existing facilities. The facility will need sufficient space for CCUS equipment, and the steam system will need to be integrated with the CCUS system. The capital cost, performance, and O&M cost information for the CCGT and cogeneration power generation facilities with CCUS is summarized in **Appendix A**.

The CCGT facility is anticipated to be an intermediate load facility with a capacity factor between 50%-80%. The cogeneration facility is anticipated to be a base load facility with a capacity factor of 90% or greater. Since both technologies provide synchronous generation, they offer favorable inertia capacity and frequency response capability compared to inverter-based resources. While the CCGT and cogeneration units could be made to be black start capable, the costs associated with black start equipment are not included in this assessment. Additionally, in a black start scenario, the gas turbine and HRSG would have to be started prior to the CCUS equipment in order to have sufficient generation to start the pumps, cooling tower, and compressors associated with the CCUS system. This would likely result in several hours of CO_2 being emitted uncontrolled.

[9] https://enhanceenergy.com/actl/
[10] https://www.hydrocarbons-technology.com/projects/alberta-carbon-trunk-line-alberta/
[11] https://www.alberta.ca/carbon-capture-utilization-and-storage-development-and-innovation

Carbon Capture Technology SWOT Analysis

Strengths

- CCUS allows for natural gas-fired combined-cycle and cogeneration facilities to continue to provide reliable, dispatchable generation to the Alberta electric grid while capturing over 90% of CO_2 emissions.
- CCUS offers the ability to retrofit existing natural gas-fired generation assets. This allows for lower total capital investment and fewer abandoned generation assets. Additionally, the existing natural gas infrastructure can continue to be utilized.
- Synchronous generation provides inertia capacity and frequency response to the grid that inverter-based resources cannot.
- Even though startup times are increased by CCUS, the generation facility still has the ability to load follow.

Weaknesses

- Even though CCUS technology has been under development for decades, it is still considered a developing technology since the technology has only been implemented at a pilot scale and not installed on a commercially operating natural gas-fired combined cycle or cogeneration facility.
- The addition of the carbon capture system does limit operational flexibility including increasing startup times.
- One of the biggest obstacles for CCUS to overcome is the high capital cost investment and the increased O&M costs. These additional costs typically make CCUS economically infeasible in today's market.
- There is a significant reduction in net electrical output of the combined cycle and cogeneration facilities due to the additional parasitic load and reduction in steam turbine output to supply steam to carbon capture system. This increases facility heat rate and makes the unit less competitive in the current market.
- The CCUS system is essentially a chemical processing facility on the backend of the power generation facility. While this is not entirely unlike other air quality control systems, such as flue gas desulfurization, it does take a different expertise in the operations and maintenance of the equipment that would need to be developed (or hired) by the power generation operations staff.
- The CCUS system uses a significant amount of water in order to provide the necessary cooling for the CCUS system. This can be mitigated with air-cooled systems, but at an additional cost and increased footprint.
- The CO_2 pipeline infrastructure to transport and sequester CO_2 can be a significant cost and drive siting of new power generation facilities.

Opportunities

- CCUS has experienced recent national and provincial support including a number of grants and tax credits intended to incentivize further development and implementation of the technology.
  - Canada offers an investment tax credit of up to 50% of capital spent on eligible equipment for CCUS and 37.5% for capital spent on transportation, storage, and use of captured CO_2 through 2030.
  - The Government of Alberta has announced plans for 12% of investment tax credit for CCUS projects through the Alberta Carbon Capture Incentive Program.
- Alberta has an abundance of favorable geology for permanent carbon sequestration.

Threats

- While permanent storage of CO_2 in geologic formations is expected to be viable, there is inevitably a long-term risk associated with sequestered CO_2 being released at some point in the future. It is still to be determined who will own this long-term risk.
- Social perception of CCUS is that it extends the life of fossil generation and is not necessarily carbon free. This could limit future support for the technology.
- CCUS is not currently economically viable without government support (tax incentives or carbon tax). If this government support goes away, then the long-term viability of CCUS projects does not look favorable.
- EOR economic viability is highly dependent on global oil prices.

Future Role of Carbon Capture in Alberta

The province of Alberta has shown a keen interest in CCUS technology as a means to reduce carbon emissions, as extensively discussed in their Emissions Reduction and Energy Development Plan.[12] The government has initiated a program to issue carbon sequestration rights to companies willing to develop carbon storage hubs. Six projects were initially selected for further evaluation, and a second competition has resulted in additional projects being granted further review.[13] While none of these projects have broken ground yet, feasibility studies are ongoing.

Shell's proposed Polaris Carbon Capture Project, announced in 2021, is a significant potential development in this area. Although an investment decision has not been made as of 2023, if approved, Shell estimates the project could provide 300 million tonnes of CO_2 storage capacity. The second phase of the project aims to develop a CO_2 storage hub that could sequester up to 10 million tonnes of CO_2 annually from other commercial operators.[14]

The Canadian government's annual projections for GHG emissions by area and economic sector anticipate 16.1 million tonnes of CO_2 equivalent ("CO_2e") emissions from Alberta's electricity industry. The ACTL project sequestered over 3,200,000 tonnes of CO_2 in 2022 at an average rate of slightly less than 2835 tonnes per calendar day, with 98.9% online time. The Clive reservoir has approximately 9.2 million tonnes of CO_2 capacity left as of the end of 2022.

The Alberta Carbon Capture Incentive Program ("ACCIP"), recently announced by the government, aims to support and accelerate the development of new CCUS infrastructure by providing a grant of 12% for new eligible CCUS Capital costs.[15]

Potential Capacity in Alberta

Alberta, known for its success in the oil and gas sector, has significant potential for CO_2 sequestration deep underground. The North American Carbon Storage Atlas ("NACSA") has estimated Alberta's total CO_2 storage capacity and found between 38-145 billion tonnes of potential storage in Oil & Gas reservoirs, unmineable coal deposits, and Saline formations.[16]

Furthermore, Alberta Innovates, a crown corporation funded by the Alberta government, released a whitepaper in July 2023 that included more specific site information for EOR potential at Beaverhill Lake, Redwater Reef, and Pembina Cardium, estimating a total capacity of 253 to 933 million tonnes.[17]

[12] https://open.alberta.ca/publications/alberta-emissions-reduction-and-energy-development-plan
[13] https://www.alberta.ca/carbon-capture-utilization-and-storage-carbon-sequestration-tenure
[14] https://www.shell.ca/en_ca/media/news-and-media-releases/news-releases-2021/shell-proposes-large-scale-ccs-facility-in-alberta.html
[15] https://www.alberta.ca/alberta-carbon-capture-incentive-program
[16] https://www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf
[17] https://albertainnovates.ca/projects/carbon-storage-a-summary-of-experience-and-lessons-learned-from-publicly-supported-projects/

Even if CO_2e emissions from all sectors within Alberta remained the same, instead of continuing to drop as predicted, Alberta's geographical area has enough capacity to store approximately 155 years' worth of carbon emissions, even when using the lowest total storage estimate from the NACSA. However, the physical capacity to store sufficient CO_2 does not necessarily equate to economically, socially, and geographically acceptable storage capacity. Notably, Alberta legislation currently prohibits sequestration at depths between 0 m and 1000 m, although this additional capacity could be utilized through legislative changes.

The Plains CO_2 Reductions ("PCOR") Partnership has characterized the potential for carbon utilization and storage in an area extending from Missouri to the north of Alberta. They have identified a potential of 340 to 1,100 billion tonnes in saline formations alone, 23 billion tonnes in depleted oil reserves, and between 1.5 to 9 billion tonnes of CO_2 storage in EOR sites.[18] Given the international scope of these reserves, cooperation between the United States and Canada would be required to utilize these capacities fully.

The Pathways Alliance is a significant initiative in Alberta's oil sands region. This long-term carbon capture project involves major oil sands companies, including Canadian Natural, Cenovus, Imperial, MEG Energy, Suncor, and ConocoPhillips Canada. These companies operate 95% of Canada's oil sands production. The Alliance's focus is on developing a three-phase carbon capture and storage network, aiming to reduce CO_2 emissions from 20 oil sands facilities by 10 to 12 million tonnes annually. The collaboration between the Alliance and the government has resulted in an investment of over $23 billion CAD in new and existing technology. This project includes a proposed 400 km pipeline connecting 20 oil sands facilities.[19]

Siting Considerations

Due to transportation expenses and specific criteria for storage, site selection will play a significant role in the success of carbon capture-fitted generation facilities. When developing new fossil fuel plants with the plan to add carbon capture or retrofit existing sites, proximity to existing/possible geological sequestration sites must be considered. There are currently four operating carbon sequestration sites in Alberta. These are all located near Fort Saskatchewan, Edmonton, Lacombe, and relatively close to the existing ACTL.

Shell Quest[20] (Sequestration)	Clive[21] (ATCL) (EOR)	Joffre[22] (EOR)	Chigwell[23] (EOR)
CO_2 Sequestered: 7.78 million tonnes	**CO_2 Sequestered:** 3.2 million tonnes	**CO_2 Sequestered:** 1.35 million tonnes	**CO_2 Sequestered:** 2.63 million tonnes
Capacity Remaining: 19.22 million tonnes	**Capacity Remaining:** 9.2 million tonnes	**Capacity Remaining:** 36,000 tonnes/year	**Capacity Remaining:** 0.17 million tonnes/year
Total Capacity: 27 million tonnes	**Total Capacity:** 12.4 million tonnes to 18.8 million tonnes	**Total Capacity:** Unknown	**Total Capacity:** Unknown

Additional permitting and well leases are under development to further expand carbon sequestration capabilities across Alberta.

[18] https://netl.doe.gov/coal/carbon-storage/atlas/pcor/phase-III
[19] https://majorprojects.alberta.ca/details/Pathways-Alliance-Carbon-Capture-Storage-Hub-Phase-1/
[20] https://open.alberta.ca/publications/quest-carbon-capture-and-storage-project-annual-report-2022
[21] https://open.alberta.ca/publications/alberta-carbon-trunk-line-project-knowledge-sharing-report-2022
[22] https://www.wcap.ca/sustainability/co2-sequestration
[23] https://www.sciencedirect.com/science/article/pii/S001623612201081X

HYDROGEN TECHNOLOGY

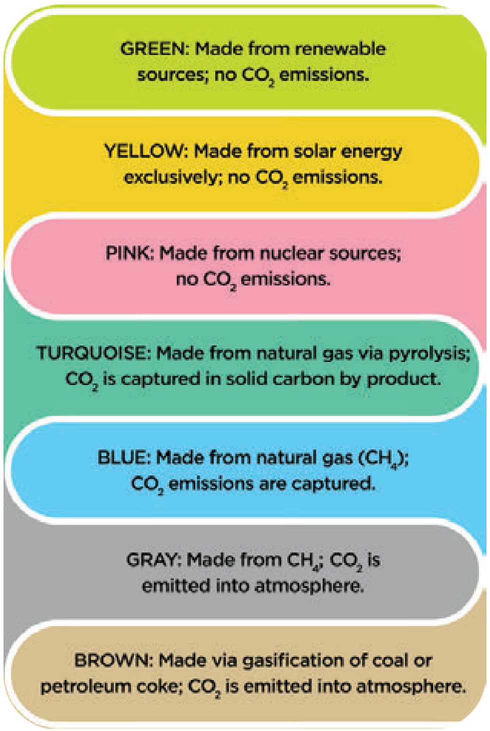
In Alberta, natural gas power generation has historically been the leading source of electricity, making up 60% of installed capacity at the end of 2022.[1] Natural gas-fired power generation facilities have provided reliable, cost-effective, and dispatchable electricity production. However, due to GHG emissions from natural gas-fired power generation, alternative fuel sources are being considered.

Hydrogen is an attractive alternative fuel source to the traditional usage of natural gas, due to its limited emissions and dispatchability. Original equipment manufacturers ("OEM") have been actively developing technology capable of burning hydrogen in gas turbines. OEMs project to have multiple turbines capable of burning 100% hydrogen with Dry Low NO_x ("DLN") combustors in commercial operation by 2030.

Colors of Hydrogen

Pure hydrogen is rarely found in nature and therefore needs to be produced using chemical processes. Most natural hydrogen is bound together with oxygen as water or is found in other biological matter or fossil fuels. Hydrogen is produced using different processes, which will determine the "color" of hydrogen. Not to be confused with the physical color of hydrogen (a colorless, odorless gas), the "color" of hydrogen is directly related with its production method. The methods of producing hydrogen are displayed in **Figure 6**.

Figure 6: Colors of Hydrogen

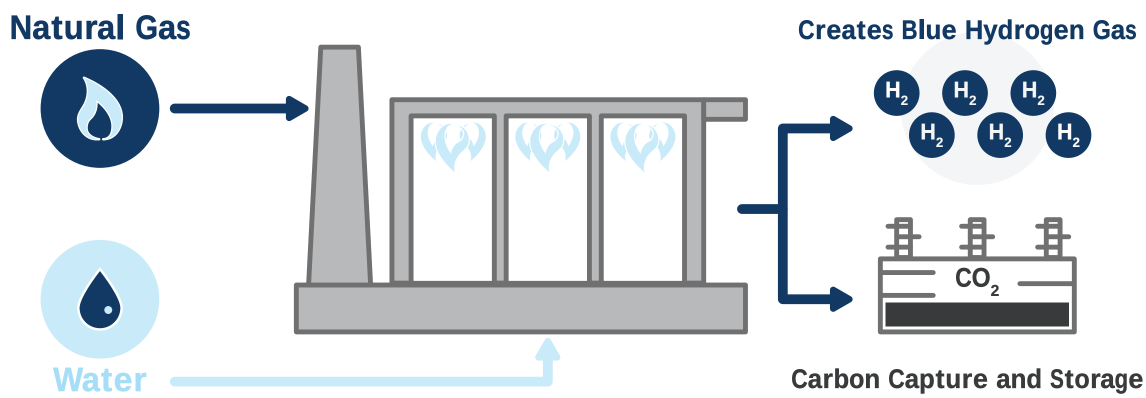


Most hydrogen produced in Alberta in 2022 was gray hydrogen at an estimated 2.0 million tonnes, followed by blue hydrogen at an estimated 0.5 million tonnes.[24] As displayed in **Figure 5**, both gray and blue hydrogen are produced from natural gas (methane) by using the steam-methane reforming process.

Currently, natural gas (methane) is the most common source of hydrogen in gas-rich parts of the world. Hydrogen is usually recovered from natural gas using water in the steam-methane reforming process. Steam-methane reforming combines methane and steam at high temperature and pressure in the presence of a catalyst. The reforming reactions produce hydrogen, with CO_2 as a byproduct. Most existing steam-methane reforming units emit CO_2 to the atmosphere, producing what is increasingly categorized as gray hydrogen. If the CO_2 stream is captured for sequestration or use, the resulting blue hydrogen is considered a low-carbon hydrogen solution.

Figure 7 displays a graphic depiction of the blue hydrogen production process.

Figure 7: Blue Hydrogen



For this Assessment, it is assumed that Alberta's future hydrogen pipeline infrastructure will be able to support the hydrogen requirements of the power generation facilities without on-site hydrogen production.

Challenges with Hydrogen as an Alternative Fuel

Hydrogen as an alternative fuel source poses two main logistical challenges, which currently hinder its widespread implementation. These challenges are the required gas turbine technology advancements and hydrogen fuel handling challenges (transportation, and storage).

Hydrogen poses technical challenges that will impact turbine design and operations due to its unique physical properties when compared to other, more traditional hydrocarbon fuels. Due to its low energy density per volume (compared with natural gas), for the same heat input, the volumetric flow rate of hydrogen must be approximately three times greater. Hydrogen also has a much higher flame speed, which raises concerns with flashback in the turbine (upstream propagation of flame in combustor). Another technical consideration with burning of hydrogen is the flame detection from an equipment perspective as well as a safety perspective. Hydrogen flames are difficult to detect by equipment as well as by the human eye, which can cause additional costs to alleviate safety concerns. These challenges impact turbine design, as well as auxiliary and fuel handling equipment.[25]

[24] https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98/emerging-resources/hydrogen
[25] https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861 Power to Gas - Hydrogen for Power Generation.pdf

Currently, there are no units in commercial operation that burn 100% hydrogen with DLN combustors (no steam or water injection). There are multiple OEMs who are developing 100% hydrogen-fired gas turbines, and the common projection across OEMs is that the technology will be commercially available for multiple turbines by 2030. Some smaller gas turbines are already available with the capability to burn high hydrogen content with water injection. These turbines typically have a higher heat rate and higher operating costs compared to state of the art gas turbines with DLN combustors.

It is expected that existing gas turbines could also be retrofit to burn hydrogen. Depending on the turbine model, different equipment modifications will be required, resulting in varying performance impacts and costs. Typically, the major equipment modifications will include the combustion system, purge system, fire or hazardous gas detection, ventilation, gas manifold materials and size, and numerous balance of plant ("BOP") modifications, ranging from pipe materials and sizes to fuel blending skid installations.

The second major challenge that hydrogen poses is with regards to transportation and storage. Since hydrogen is the lightest existing gas, with the lowest density of any element, it is extremely difficult to handle. Prior to transporting or storing hydrogen, it must first be compressed to high pressures to manage the volumes. Due to the low density of hydrogen, electrical parasitic load for compression can be very large. Additionally, the hydrogen molecules can easily escape flanged joints and even migrate into carbon steel materials causing hydrogen embrittlement. This results in hydrogen piping systems to be welded and using alloys such as stainless steel. This is manageable but increases project costs.

Hydrogen combustion in gas turbines is currently at a TRL of 5, as 100% hydrogen combustion in DLN combustors are being validated at test stand scale by various OEM but there are not any in operation.

Simple-Cycle Hydrogen-Fired Technology Description

A hydrogen-fired simple-cycle generating facility provides low-carbon generation while maintaining the ability to cycle frequently and respond to fluctuations in non-dispatchable, energy generating resources.

To combust high hydrogen blended fuels or pure hydrogen, available gas turbine models typically require either steam injection or water injection methods to control NO_x emissions. This requirement for water can greatly influence the viability of these technologies depending on project siting and conditions. Plants firing high hydrogen fuels would accordingly be expected to have variable O&M impacts to acquire water of the quality necessary to meet these needs.

For this Assessment, it is assumed that the combustor technology will advance such that DLN combustors will be capable of burning 100% hydrogen with minimal performance impacts (i.e. steam or water injection for emissions controls is not required).

Historically, due to the large volume of hydrogen fuel necessary to fully meet the heat input requirements for larger frame turbines, smaller frame and aeroderivative turbines have had greater experience in hydrogen combustion applications.

The simple-cycle gas turbine facility with hydrogen fuel will have a similar appearance to a natural gas-fired simple-cycle turbine facility, displayed in **Figure 8**.

Figure 8: Simple-Cycle Gas Turbine

Combined-Cycle Hydrogen-Fired Technology Description

A combined-cycle facility is an energy generating facility that includes a gas turbine(s) which exhausts waste heat to a HRSG that provides superheated steam to a steam turbine. If the gas turbine(s) burns 100% hydrogen, then the combined cycle will not emit any carbon emissions out of the stack. Combined-cycle facilities typically achieve higher efficiencies than simple-cycle facilities, but also have more limited operational flexibility due to longer start up times associated with the steam cycle. Combined-cycle facilities are typically dispatched more frequently, achieving capacity factors between 50%-80%.

Combined-cycle hydrogen fuel combustion applications share similar performance and cost considerations as the simple-cycle plant described in the previous section. A hydrogen fueled combined-cycle plant will have a similar appearance to a natural gas-fired combined-cycle plant, displayed in **Figure 9**.

Figure 9: Combined-Cycle Power Generation Facility

Scope Assumptions

The technical information for hydrogen combustion provided in **Appendix A** is governed by the following assumptions:

- Hydrogen costs are based on blue hydrogen produced from natural gas via steam-methane reforming or auto-thermal reforming.
- Blue hydrogen will be supplied to the site between 30-35 bar and at rates sufficient for the power generation facilities to operate.
- While 100% hydrogen combustion in DLN combustors is not currently commercially available, this Assessment assumes that OEMs will be capable of providing DLN combustors, with minimal performance derates and similar NO_x emissions as with natural gas by 2030.
- Operating as a peaking generator with an assumed capacity factor of 10%, a simple-cycle power generation facility would require only intermittent fuel supply. A steam-methane reforming facility is a high-cost asset to construct and operate and would likely not operate solely due to the demands of the simple-cycle power generation facility. Due to this constraint, 72 hours of hydrogen storage is assumed.
- Cogeneration and combined-cycle power generation facilities would require a more consistent supply of fuel that would likely be large enough to dictate when the steam-methane reforming facility operates. 24 hours of hydrogen storage was assumed for the cogeneration and combined-cycle technologies.
- Burning 100% hydrogen produces no carbon emissions directly from the power generation facility. Carbon emissions from the blue hydrogen production were included in the carbon intensity calculation. Blue hydrogen production carbon emissions include the following:
  - Electricity consumption carbon emissions, at 540 grams of CO_2 per kilowatt hour ("kWh")[26]
  - 10% of the carbon emissions of the steam-methane reforming facility (assuming 90% effective CCUS)

[26] https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/emission-factors-reference-values.html

Technology Providers and Status

Current Providers

Gas turbines capable of firing hydrogen blended with natural gas are currently offered in a range of sizes from multiple OEMs, including General Electric ("GE"), Siemens, and Mitsubishi. These three leading providers are expected to have commercially available turbines capable of burning 100% hydrogen fuel in DLN combustors with minimal performance impacts by 2030.

Technology Updates and Recent Projects

Air Products Hydrogen production and Liquefaction facility in Alberta received $475 million CAD in federal and provincial government funding. The hydrogen complex will deploy Auto-Thermal Reforming with carbon capture technology and include a hydrogen-fueled power generation facility and a liquid hydrogen facility. The hydrogen-fueled power generation facility will consist of three Baker Hughes NovaLT16 gas turbines. Baker Hughes claims that the 17.5 MW turbines can start and burn gas blends up to 100% hydrogen with no hardware changes. Utilizing DLN mode, the turbines can burn up to 30% hydrogen blends.[27]

The facility is expected to produce 4.34 million normalized cubic metres of hydrogen per day and will supply hydrogen to a proposed renewable diesel complex nearby. Completion of construction is expected in 2024. The blue hydrogen facility aims to capture 95% of the CO_2 it will emit.[28]

In 2021, the Long Ridge Power Plant in Hannibal, Ohio began commercial operation. The 485 MW plant started blending hydrogen and natural gas in 2022 using GE's 7HA.02 turbine, which is currently capable of burning 15%-20% hydrogen by volume. The Long Ridge plant is the first plant in the United States to be purpose built for burning hydrogen.[29]

From fall of 2021 to spring of 2022, the New York Power Authority ("NYPA") demonstrated successful hydrogen and natural gas blending in GE's LM6000. The project was first-of-its-kind with blending of 5%-40% and was a collaboration between NYPA, The Electric Power Research Institute ("EPRI"), GE, and Airgas. The green hydrogen demonstration took place at Brentwood Small Clean Power Plant on Long Island. Results show that CO_2 emissions were reduced by 14% when using a 35% hydrogen blend on the 47 MW unit.[30]

Technical Information

While not currently commercially available, this Assessment assumes gas turbines with the capability to burn 100% hydrogen with DLN combustors and similar performance and NO_x emissions as with natural gas. The capital cost includes a premium for the hydrogen capable gas turbine (including modifications to the combustors, flame detection, fuel piping, ventilation and gas detection, and turbine controls systems) and modifications to the fuel gas piping (including increased pipe sizing, stainless steel, and welded connections). These cost modifications are relatively minor when compared to the cost required for onsite hydrogen storage. Due to the low density of hydrogen, the storage tanks store hydrogen at over 400 bar. This requires large compressors to fill the tanks. The capital cost, performance, and O&M costs information for the SCGT, CCGT, and cogeneration plants combusting 100% blue hydrogen is summarized in **Appendix A**.

The simple-cycle facility is anticipated to be a peaking facility with capacity factor between 5% and 20%. The combined cycle facility is anticipated to be an intermediate load facility with a capacity factor between 50% and 80%. The cogeneration facility is anticipated to be base loaded with a capacity factor of 90% or greater. Since all the technologies provide synchronous generation, they offer favorable inertia capacity and frequency response capability compared to inverter-based resources. While the combined-cycle and cogeneration units could be made to be black start capable, the costs associated with black start equipment are not included in this Assessment.

[27] ttps://www.bakerhughes.com/gas-turbines/novalt-technology/novalt16
[28] ttps://www.airproducts.com/company/news-center/2022/09/0906-imperial-advances-renewable-diesel-plans-awards-hydrogen-contract-to-air-products
[29] ttps://www.ge.com/gas-power/resources/case-studies/long-ridge-energy
[30] ttps://nypa.gov/news/press-releases/2022/20220923-greenhydrogen

Hydrogen Technology SWOT Analysis

Strengths

- Hydrogen-fired gas turbines allow for simple cycle, combined-cycle, and cogeneration facilities to continue to provide reliable, dispatchable generation to the Alberta electric grid while reducing carbon emission. This includes peaking and load following capabilities similar to natural gas-fired generation assets.
- Existing gas turbine units could be retrofitted to burn hydrogen. The ability to retrofit existing natural gas-fired generation assets allows for lower total capital investment and fewer abandoned generation assets.
- Synchronous generation provides inertia capacity and frequency response to the grid that inverter-based resources cannot.

Weaknesses

- Hydrogen is currently very expensive to produce, transport, and store. The cost of fuel makes up a large portion of the operating cost of a power generation facility and currently hydrogen-fired gas turbines are not economical.
- Gas turbines are not yet capable of burning 100% hydrogen with DLN combustors. Using current technologies to burn hydrogen in a gas turbine would result in increased operating costs (water treatment), increased water usage, and less efficient turbines resulting in additional hydrogen production needs. These would all result in even less economical operation.
- Hydrogen is a highly flammable gas. Safety measures would have to be taken to prevent gas leaks.
- Significant hydrogen infrastructure needs to be developed to support the production and transportation of hydrogen for widespread power generation.
- The amount of energy input into hydrogen production is higher than the energy content of the hydrogen. In other words, if all natural gas-fired generation facilities were converted to hydrogen-fired facilities, the total natural gas consumption of the industry would need to increase. This would result in additional CO_2 being produced, captured, and sequestered. This, of course, is based on blue hydrogen production.

Opportunities

- White hydrogen is naturally occurring hydrogen that can be extracted from deep beneath the surface similar to natural gas. If significant amounts of white hydrogen were identified, hydrogen cost could be significantly reduced, and the hydrogen carbon intensity would be near zero. White hydrogen has not yet been discovered in large enough quantities to support the electric grid.

Threats

- Hydrogen can be used for a number of chemical and refining processes that could be a higher value chain than power generation. The reliance on third-party to produce hydrogen fuel could be a risk that creates potential fuel supply and cost volatility risk.
- The carbon intensity of producing blue hydrogen is higher than a natural gas-fired combined cycle with carbon capture. This could result in less support for blue hydrogen in the future. Currently, green hydrogen is significantly more expensive than blue hydrogen.

Future Role of Hydrogen in Alberta

Alberta's decarbonization strategy is heavily invested in the production of low-emission hydrogen. With a history of hydrogen production spanning five decades using natural gas, Alberta is keen on merging this with their growing support for CCUS technology. Their goal is to establish Alberta as a global frontrunner in the production of low-emission hydrogen.

Currently, Alberta generates approximately 2.4 million tonnes of hydrogen annually for diverse industrial applications. Efforts are underway to establish Canada's inaugural hydrogen hub in the Edmonton region, and the Southeast Alberta Hydrogen Taskforce has been formed to stimulate and expedite the development of a regional hydrogen economy. Additionally, as of 2021, Alberta already has over 100 km of pipelines that can be used to send pure hydrogen to industrial users.[31]

Alberta has identified five potential leading markets for this clean hydrogen:

The Alberta government has invested $50 million CAD into Alberta Innovates to establish the Hydrogen Centre of Excellence ("HCOE"). The objectives of the HCOE are to:

- Develop and deploy hydrogen-focused technologies
- Enhance Alberta's environmental, social, and corporate governance credentials and stimulate economic growth
- Establish a sustainable and self-sufficient clean hydrogen economy in Alberta
- Boost Alberta's technological prowess in clean hydrogen technology deployment

The HCOE has three active programs aimed at advancing hydrogen technology alongside Emission Reduction Alberta's Accelerating Hydrogen Challenge.[32] The ongoing Services Capacity program is currently supporting studies, ecosystem development, public awareness, opportunity identification, life-cycle analyses, and the development of codes and standards. Advancing Hydrogen – Competition 1, which has already closed applications, is funding projects that further the development of hydrogen technology.[33] Advancing Hydrogen - Competition 2 is still accepting applications and has $20-25 million CAD to distribute on low TRL 3-6 projects.[34] The Accelerating Hydrogen Challenge is also still accepting applications and has $25 million CAD to support high TRL 7-9 projects.[32]

Alberta generates approximately **2.4 million tonnes of hydrogen annually** for diverse industrial applications.

[31] https://open.alberta.ca/publications/alberta-hydrogen-roadmap
[32] https://www.eralberta.ca/funding-technology/accelerating-hydrogen-challenge/
[33] https://albertainnovates.ca/funding/advancing-hydrogen-competition-1/
[34] https://albertainnovates.ca/funding/advancing-hydrogen-competition-2

Potential Capacity in Alberta

Alberta is known for its abundant energy resources, which hold the potential for generating significant quantities of clean hydrogen for both domestic and global markets when combined with CCUS. While there are significant hurdles that need to be solved, investor interest in producing clean hydrogen in Alberta for export markets remains significant, and Alberta's hydrogen roadmap highlights why.[31]

According to Canada's Hydrogen Strategy, by 2050, the domestic market for clean hydrogen in Canada could reach up to 20 million tonnes per year, with international export demand potentially doubling that figure. Alberta's clean hydrogen production capacity is projected to be approximately 45 million tonnes per year, indicating that Alberta has the production capacity to meet local demand and provide significant export quantities to other Canadian provinces and international markets. With Alberta's proximity to the United States, hydrogen export by pipeline could help establish a foothold in a key North American market. By 2050, the entire U.S. forecasted demand for clean hydrogen will be approximately 22 to 40 million tonnes per year. Hydrogen export could significantly contribute to Alberta's future hydrogen production competitiveness by increasing the scale of hydrogen production facilities.

Siting Considerations

The biggest difference between siting a hydrogen-fired generation facility and a natural gas-fired generation facility is the fuel transportation. To transport hydrogen fuel, it must be highly pressurized and delivered by pipeline, stored in highly pressurized tube trailers and shipped to site, or liquified and shipped to site. Alberta currently has approximately 100 km of hydrogen piping compared to thousands of kilometres of natural gas pipelines. Natural gas pipelines are not designed to transport smaller hydrogen molecules, therefore, using natural gas pipelines is not an option for transportation of hydrogen. Shipping hydrogen in highly pressurized tube trailers or liquified tankers is traditionally used only for short distance travel and would be insufficient for quantities needed to support power generation (i.e. it is impractical to deliver enough trucks to site to support continuous operation of a gas turbine).

When attempting longer distances of delivery, in the absence of a pipeline, highly specialized cryogenically cooled trucks can be used to transport hydrogen that has been cooled to -235°C However, the process to liquify hydrogen requires more than 30% of the energy content of hydrogen — a costly and inefficient process.

In short, co-locating hydrogen generation facilities with hydrogen production facilities may be necessary in the near term. In the future, expansion of a hydrogen pipeline infrastructure may make siting hydrogen generation facilities less constrained.

Commercial Availability by 2050

As mentioned above, Alberta is heavily invested in the expansion of hydrogen production and usage in the province. All of the gas turbine manufacturers are also heavily investing into the research and development of combustion technology capable of burning 100% hydrogen efficiently. Some smaller gas turbines are already available with the capability to burn high hydrogen content with water injection. There is no reason to believe that hydrogen combustion in simple cycle, combined cycle, and cogeneration facilities will not be commercially available by 2050 or earlier. The biggest challenge that needs to be overcome is the economic viability of the fuel production, transportation, and storage.

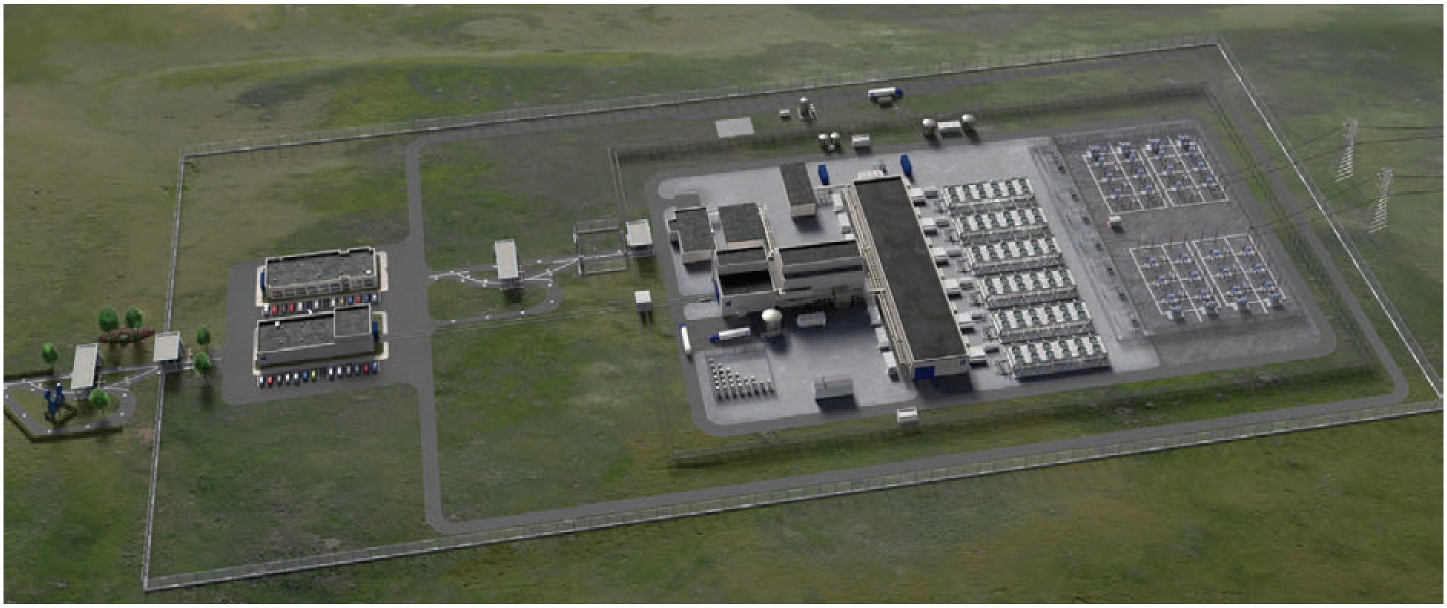
The biggest challenge that needs to be overcome is the economic viability of the fuel production, transportation, and storage.

NUCLEAR TECHNOLOGY

Nuclear power has provided a reliable base load of electrical generation in many countries for decades. However, in North America, very few new nuclear generation projects have been completed since the 1980's. Due to a growing interest for decarbonized and reliable electric generation, the nuclear industry is focusing on the development of SMR and advanced reactor technology at an increasing pace. The objective of SMRs and advanced reactors is to provide a flexible and safe source of carbon-free electrical generation.

Small Modular Reactor Technology Description

Manufacturers are designing SMRs to create a smaller scale, completely modular nuclear reactor. SMRs use nuclear fission to create heat in a reactor core containing uranium fuel. Energy from the nuclear reaction heats the primary reactor fluid, which then creates steam via an integral heat exchanger. The heat exchanger isolates the steam from possible contamination, which is then used to drive a turbine coupled with a generator to produce electrical energy. The nuclear reactor and steam generation is contained in one modular vessel. Each module generates between 50 MW and 300 MW. There are a number of SMR technology providers, each developing unique designs. SMRs are currently at a TRL of 6, indicating their successful validation of engineering principles, but SMRs have not been demonstrated in an operational environment. Nuclear reactors are mature technology, but SMR technology specifically has not been demonstrated in commercial operation. The first SMRs are anticipated to reach commercial operation in the 2030 timeframe.



Advanced Pressure Water Reactor Technology Description

Advanced pressurized water reactors ("PWR") use nuclear fission to create heat in a reactor core containing uranium fuel. Pressurized water is used to cool the core and create steam through an indirect heat exchanger. This steam is used to drive a turbine coupled with a generator to produce electrical energy. Advanced reactors are at a TRL of 9 as this is a mature technology that is well established in the industry.

As of 2023, 19 reactors are fully operational in Canada. Collectively, the total capacity of the nuclear reactors in Canada is 13,624 MW. Most of the nuclear reactors are located in Ontario, and currently, Alberta has no active nuclear reactors. The 19 operating reactors are all CANDU reactors and are spread across four nuclear generating stations.[35]

Technology Providers and Status

Current SMR Providers

The following list includes leading SMR technology providers that have developed various designs, such as molten-salt, boiling water, light-water, and sodium-cooled reactors. Currently, SMRs are considered to be conceptual in design, but some leading providers are projecting to have operational demonstrations by the early 2030's. These manufacturers have completed conceptual designs of modular units to target lower output and costs and are in various stages of review by the CNSC.

In 2023, the Enabling Small Modular Reactors Program ("Program") was launched by the Canadian government. The Program will provide $29.6 million CAD over a 4-year period to develop supply chains for SMRs and fund research on SMR waste management solutions.[36]

While no SMR facility has been constructed or commissioned in Canada at the time of this Assessment, indicative timelines have been published by OEMs in developmental stages. The expected timeline for development and construction of an SMR facility is at least 10 years.

NuScale

NuScale offers a light-water SMR capable of generating 77 MW of electricity. The module design is based on pressurized water-cooled reactor technology and can be scaled in 4-module, 6-module, or 12-module configurations. It is the first SMR to receive design approval from the United States Nuclear Regulatory Commission ("NRC"). NuScale had been working with Utah Associated Municipal Power Systems ("UAMPS") on the Carbon Free Power Project which was planned to be operational in 2029. In November of 2023, NuScale and UAMPS announced that the project was being terminated.[37]

ARC Clean Technologies

ARC Clean Technologies is developing the ARC-100 advanced SMR, which would provide 100 MW of electricity and heat. The ARC-100 SMR design is based on the Experimental Breeder Reactor II, a sodium-cooled fast-reactor developed by Argonne National Labs that operated for 30 years. As of February 2022, the CNSC is in Phase 2 of a pre-licensing vendor design review of the ARC-100 liquid sodium reactor.[37]

[35] https://world-nuclear.org/information-library/country-profiles/countries-a-f/canada-nuclear-power.aspx
[36] https://www.canada.ca/en/natural-resources-canada/news/2023/02/canada-launches-new-small-modular-reactor-funding-program.html
[37] https://nuclearsafety.gc.ca/eng/reactors/power-plants/pre-licensing-vendor-design-review/index.cfm

GE Hitachi

With over 60 years of experience with boiling water reactors ("BWR"), GE Hitachi Nuclear Energy ("GE Hitachi") has moved towards developing the BWRX-300 SMR. The SMR is expected to be capable of supplying 300 MW of electrical capacity in a significantly smaller footprint than traditional reactors. The BWRX-300 is not yet commercially operational but has completed Phase 1 and Phase 2 pre-licensing vendor design review by the CNSC and expects the first unit to be operational at the Darlington New Nuclear Project site in Ontario in 2029.[37]

X-Energy

The Xe-100 SMR, under development by X-Energy, is a pebble bed, high-temperature gas-cooled reactor expected to generate 80 MW and scalable into a 4-module configuration. The CNSC is in Phase 2 of a pre-licensing vendor design review of the Xe-100 high temperature gas reactor.[37]

TerraPower

In collaboration with GE Hitachi, TerraPower is developing the Natrium SMR. With a sodium fast reactor and molten-salt energy storage, the Natrium SMR is expected to generate 345 MW. The technology is not yet commercially operational, but a demonstration unit is expected to be completed in Wyoming by 2030.[37]

Terrestrial Energy

Terrestrial Energy is developing the Integral Molten Salt Reactor ("IMSR"). The IMSR uses molten salt as both a fuel and coolant and is able to supply heat to industrial facilities or use the energy to produce electricity. The IMSR enables passive cooling for additional safety and has a replaceable reactor core that is designed to operate for seven years. In April 2023, the IMSR completed the CNSC Phase 2 vendor design review.[37]

Current PWR Providers

Leading providers for large nuclear reactors include Candu Energy, Westinghouse Electric Corporation ("Westinghouse"), Mitsubishi, and GE Hitachi. While Candu Energy does not provide advanced PWRs, they are currently the only OEM with operating nuclear reactors in Canada.

The CANDU reactor is a unique, Canadian-designed reactor using horizontal fuel channels and natural uranium rather than enriched uranium, which results in lower fuel costs. An additional benefit of the CANDU reactor is that it can operate during refueling. Countries including Argentina, China, India, Pakistan, Romania, and South Korea also use the Canadian-designed reactors, with a total of 28 reactors in operation outside of Canada.[38]

[38] https://cna.ca/advantages/export/

SMR Technology Updates and Recent Projects

There are currently four proposed SMR projects under review by the CNSC, which include the Darlington New Nuclear Project, SaskPower, Global First Power's Chalk River Project, and New Brunswick Power's ARC-100 Project. The projects propose various SMR and Micro Modular Reactor ("MMR") designs from multiple providers to deliver reliable power across Canada.

In January of 2023, the Ontario Power Generation ("OPG") partnered with GE Hitachi, SNC-Lavalin, and Aecon to plan, construct, and deploy the BWRX-300 SMR at Darlington Nuclear Station. In July of 2023, the Ontario government announced work with OPG to begin planning and licensing for multiple additional SMRs at the Darlington new nuclear site. The four units will result in a total output of 1,200 MW at the Darlington New Nuclear Project site.[39]

In August 2023, the Canadian government approved $74 million CAD in federal funding for the development of SMR technology in Saskatchewan. SaskPower was selected to lead the development effort and is currently in the planning phase. The decision to move forward with construction on the project is expected to be made in 2029, with project completion expected in the mid-2030s.

Global First Power is developing the MMR Project at Chalk River Laboratories using Ultra Safe Nuclear's MMR. The Chalk River Laboratories site is located in Ontario and managed by Canadian Nuclear Laboratories ("CNL"). In May 2021, Ultra Safe Nuclear's reactor became the first MMR or SMR to begin the formal license review process by the CNSC.[35] The 5 MW MMR is expected to be deployed at the Chalk River site in 2026.

New Brunswick Power's proposed SMR project, utilizing the ARC-100, is adjacent to Point Lepreau Nuclear Generating Station's Canada Deuterium Uranium ("CANDU") reactor in New Brunswick. The ARC-100 SMR is a sodium-cooled fast reactor, reducing water needs and allowing the reactor to operate at lower pressures.[40] The CNSC received the license application to prepare the site in June 2023, which is currently undergoing regulatory and environmental protection review with plans to be operational by 2030. Construction for the ARC-100 is estimated to take 34 months, with the time between first nuclear concrete and fuel loading estimated to take only 23 months. The Point Lepreau project received $7 million CAD from the Government of Canada's Electricity Predevelopment Program.

In August 2023, the Canadian government approved **$74 million CAD** in federal funding for the development of SMR technology in Saskatchewan.

[39] https://www.opg.com/projects-services/projects/nuclear/smr/darlington-smr/
[40] https://www.arc-cleantech.com/technology

PWR Technology Updates and Recent Projects

Since its initial design in 1950, the CANDU reactor has undergone multiple generations of evolution, resulting in the Enhanced CANDU-6 reactor ("EC6"), advanced CANDU reactor ("ACR"), and advanced fuel CANDU reactor ("AFCR"). The EC6 completed three phases of pre-project design review by June 2013 and offers flexible fuel options. The ACR adopts some features from the PWR, including light water cooling, a more compact core, and the ability to run on slightly enriched uranium (about 1.5% U-235) with high burn up. Through these improvements, the reactor's fuel life has been extended by three times while reducing waste volumes. The ACR uses modular construction, intending to be built in pairs. In 2010, the CNSC gave pre-project design approval for the 1200 MW ACR-1000.[35]

The most recent CANDU reactor to begin commercial operation was at Romania's Cernavoda nuclear power plant. The first CANDU-6 reactor at the plant began commercial operation in 1996 and the second started up in 2007.

Bruce Nuclear Generating Station – Bruce Station has eight CANDU reactors that generate 6,288 MW, making it the largest operating nuclear power generation facility in the world. The generating station has been providing reliable power to the grid since initial operation in 1976. Six of the eight reactors are undergoing refurbishment efforts from 2020 through 2033, including steam generator and calandria tube replacement. The first refurbishment, Bruce Unit 6, completed fuel loading and was reconnected to the grid in September of 2023.

Darlington Nuclear Generating Station – Darlington Station has four CANDU-850 reactors, which generate 3,524 MW. Unit 2 and Unit 3 completed refurbishment in July of 2023, with the remaining two reactors undergoing refurbishment through 2026. The Darlington units became operational between 1990 and 1993.

Pickering Nuclear Generating Station – Pickering Station is Canada's smallest nuclear facility, with six operating CANDU-500 reactors and a total output of 3,100 MW. The design limit for the reactors is 210,000 equivalent full-power hours; in 2014, the limit for Pickering Unit 6 was extended by the CNSC to 247,000 hours (approximately 4 years). Pickering Unit 6 is the first Canadian reactor to surpass the 210,000-hour limit. OPG is currently conducting a feasibility assessment for the refurbishment of Pickering Units 5-8, but Unit 1 and Unit 4 are set to retire at the end of 2024. Pickering opened in 1971 and is Ontario's oldest nuclear station.

Point Lepreau - Completed in 1982, Point Lepreau's single nuclear reactor became the first CANDU-6 reactor to begin commercial operation. The reactor experienced a lengthy and complex refurbishment that included replacement of all calandria tubes and steam generators across a 54-month period. Located in New Brunswick, the 635 MW reactor's operating license was renewed in 2022 for a period of 10 years.[35]

Ontario's refurbishment projects total $26 billion CAD to extend the life of 10 operating reactors. These refurbishments were done in lieu of building new advanced PWRs.

While Alberta currently has no operating nuclear reactors, the Peace Region Nuclear Power Plant Project in northern Alberta was under consideration from 2005 to 2011. In 2009, a site capable of supporting four reactors was selected. The reactor designs under consideration included two European pressurized water reactor ("EPR") units, four AP1000 units, and two twin ACR-1000 units with a total capacity between 3200 to 4400 MW. Bruce Power, who filed the license application for the project, shelved all development efforts in 2011 after concern over proximity to a freshwater aquifer was raised by nearby residents who rely on the aquifer for drinking water.

Technical Information

Advanced PWR are anticipated to be a base load generation resource. While the goal for SMR technologies is to be more flexible than traditional nuclear reactors, they are still anticipated to be a base load generation resource. Since they provide synchronous generation, they offer favorable inertia capacity and frequency response capability compared to inverter-based resources. The APWR and SMR are not black start capable. The capital cost, performance, and O&M costs information for both nuclear technologies are summarized in **Appendix A**.

SWOT Analysis

SMR

Strengths

- SMRs offer a high energy density resulting in a relatively small land footprint compared to other carbon free generation technologies.
- The modular configuration allows for additional shop fabrication which should result in repeatability and reduced cost for Nth of a kind projects. This also reduces the amount of field labor required which allows for lower labor costs for installations in remote locations.
- Most advanced SMR designs incorporate passive safety features which allow the reactor to be cooled without operator intervention during an emergency. This reduces the risk of a catastrophic failure due to operator error or equipment failures.
- SMRs offer a carbon free dispatchable generation resource that has the ability to load follow.

Weaknesses

- Safety is closely regulated by the CNSC which can result in a lengthy permitting, licensing, and construction timeline of 10+ years.
- SMRs have a high levelized cost of electricity due to high capital and O&M costs.
- Long-term spent nuclear fuel management.
- Risks associated with developing a first of a kind technology.

Opportunities

- Nov. 28, 2023 – ARC Clean Technology, Korea Hydro and Nuclear Power Co, and New Brunswick Power sign a memorandum of understanding ("MOU") to explore potential collaboration for global SMR fleet deployment.
- Multiple projects, with various SMR technology providers, are under review in Canada. One project may be operational as soon as 2029.
- A Steering Committee comprised of Canadian provincial governments, territorial governments, and utilities interest in the demonstration and deployment of SMRs in Canada created an SMR Roadmap in 2018.
  - The roadmap resulted in several working groups to address waste management, engagement with indigenous and public groups, economic analysis, regulatory readiness, and social and environmental factors.
- Significant potential to contribute to Canada's economy by creating jobs and expanding Canada's nuclear supply chain.
- Support for more nuclear power in Ontario and New Brunswick due to their success with nuclear and continued investment in research, education, and innovation of nuclear facilities.
- Collaboration with international nuclear regulators to streamline review processes and licensing.

Threats

- Public groups are openly concerned about safety, waste management, and the cost of SMRs.
- There are significant regional differences in public opinion on nuclear energy.
- Capital cost is an important driver if SMRs are to be a competitive source of energy.

According to manufacturers, the primary benefits of modular SMR units are as follows: smaller unit size allows more resource generation flexibility, and the modular design will reduce overall project costs while providing increased benefits in the areas of safety, waste management, and the utilization of resources. Modular designs allow increased levels of factory fabrication when compared to larger scale reactors, which reduces field labor and shortens construction schedules. Modular reactors of lower capacity should also exhibit siting benefits due to a smaller footprint and less power transmission infrastructure requirements. Additionally, a generating station composed of multiple modular reactors could utilize staggered refueling intervals so that other units can remain in operation while refueling occurs. Refueling is expected to occur on a multi-year cycle.

PWR

Strengths

- Large scale nuclear reactors have provided reliable power generation across the globe for decades. It is a proven technology with evolutionary improvements since the last unit installed in Canada.
- Advanced PWRs offer carbon free dispatchable generation resource that has the ability to load follow.
- Advanced PWRs are designed to withstand extreme weather conditions and maintain operations. This allows for reliable generation regardless of the weather.
- Advanced PWRs only need to be refueled once every few years. This allows for very high availability factors compared to other generation resources.

Weaknesses

- Safety is closely regulated by the CNSC which can result in a lengthy permitting, licensing, and construction timeline of 10+ years.
- PWR's have a high levelized cost of electricity due to high capital and O&M costs. This can make PWR's less competitive in the market.
- Although Canada does have several operating nuclear facilities, Alberta does not have any operating nuclear stations. Therefore, Alberta will need to work closely with the CNSC to determine nuclear fuel delivery and spent fuel waste management.
- Advanced PWR's typically use substantial amounts of water for cooling purposes. This not only limits siting opportunities but can also be viewed negatively by environmental groups.
- The typical PWR is approximately 1,100 MW, which is larger than the current Most Severe Single Contingency of 465 MW in Alberta. If a 1,100 MW unit were to trip offline, that would be equivalent to more than two of Alberta's largest units tripping simultaneously.

Opportunities

- Multiple reactor designs have already been approved by the CNSC. This would hopefully shorten the permitting and licensing process compared to SMRs.
- Saskatchewan is the second largest exporter of uranium in the world. Public support for nuclear power in the province is high and fuel is readily available.

Threats

- Spent nuclear fuel management can be perceived as an environmental concern and potential challenge to new nuclear facilities.
- As indicated by the Peace Region Nuclear Power Plant Project, nuclear power can be seen by the public as a threat to environmental and public safety. Negative public perception can halt the development of a new nuclear plant.

Future Role of Nuclear in Alberta

Potential Capacity in Alberta

Canada has the third-largest uranium reserves in the world and is the second-largest exporter of uranium. Approximately 15% of the uranium Canada mines is used to power CANDU reactors.

The majority of Canadian uranium reserves are located in the Athabasca Basin in northern Saskatchewan, and the known uranium deposits are expected to last more than 40 years at current production levels. Canada's five operating uranium mines and mills are all located in Saskatchewan. The mined uranium is then processed at the world's largest uranium refinery, located in Ontario.[41] Two additional mines have been proposed in Saskatchewan and are currently under review by the CNSC. The proposed Wheeler River Project would produce 5,400 tonnes of uranium oxide annually for approximately 20 years, and the Rook I Project could process an average of 1,400 tonnes of uranium ore per day.[42]

For decades, the CNSC and Transport Canada have been safely transporting new and used nuclear fuel by road, rail, water, and air. Thousands of shipments of radioactive materials are transported in Canada annually under the Radioactive Material Transportation program without a single radiological event. The program includes the transportation of material to and from CNL sites.

There is significant potential for additional nuclear capacity in Alberta.

Canada's SMR Action Plan

The Alberta government announced in September 2023 that $7 million CAD will be invested in a study, totaling $27 million CAD, that is focused on future use of SMRs for oil sands operations in northern Alberta. The study will be conducted by Cenovus Energy, an oil and gas producer, to evaluate the feasibility of using SMR technology for steam-assisted gravity drainage projects in the oil sands.[43]

There is significant potential for SMRs in Alberta. The limiting factor is likely to be the overall cost of the technology.

There is significant potential for SMRs in Alberta. The limiting factor is likely to be the overall cost of the technology.

[41] https://natural-resources.canada.ca/energy/energy-sources-distribution/uranium-nuclear-energy/uranium-canada/about-uranium/7695
[42] https://nuclearsafety.gc.ca/eng/uranium/mines-and-mills/
[43] https://www.alberta.ca/release.cfm?xID=88960CFA3368C-CBE8-7EA8-D70E8A57FD9E0A90

Siting Considerations

A nuclear facility would need to consider several key criteria when selecting a suitable site. First would be safety. The permitting application would need to show a site selection process that includes considerations for a potential release of radionuclides. This includes an exclusionary zone around the facility that would avoid densely populated areas. Additionally, the site should avoid being located near other industrial facilities that could potentially have a catastrophic failure that would impact the neighboring nuclear facility.

Second, the site would need to consider preferred conditions for reducing project costs. This would include sufficient water supply for cooling to avoid air-cooling, preferential transmission interconnection to avoid significant transmission infrastructure upgrades, and suitable subsurface geology to reduce construction costs.

Finally, the site selection should consider the ability to deliver large equipment to site and supply skilled labor. The operating facility will likely have more than 150 full time staff made up of operators, technicians, and engineers. and the construction period may see over 3,000 construction personnel at peak.

Commercially Available by 2050

First of a kind SMRs are expected to become operational by 2030 (New Brunswick Electric Power Corporation ("NB Power") SMR Project). Given the development, permitting, licensing, and construction schedule of SMR's, it is reasonable to assume that additional SMRs could be installed in the late 2030's to early 2040's dependent on the success of the first of a kind SMRs. Large, advanced reactors are mature, well-established technology that can offer reliable generation. However, the overall cost and perceived safety threats of nuclear power have limited the implementation of large nuclear reactors in Alberta.

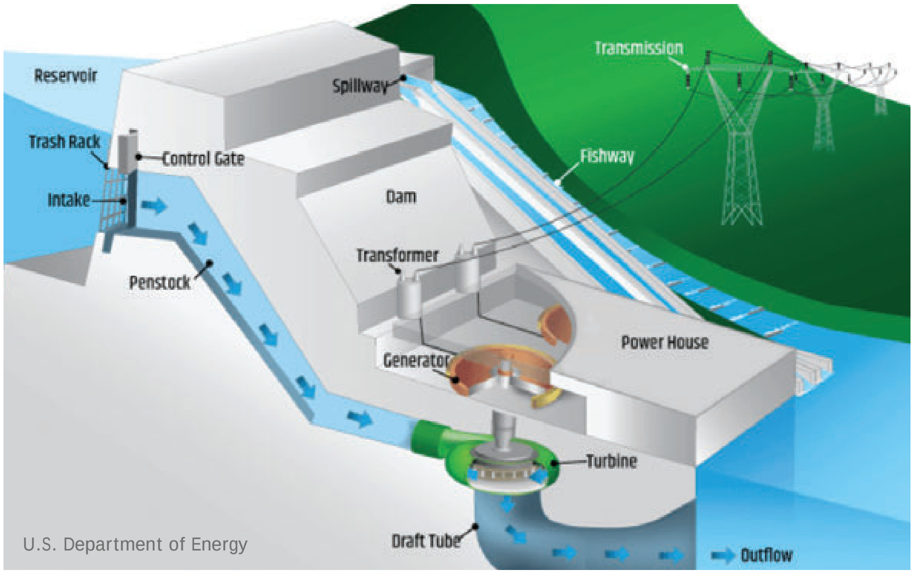
HYDROELECTRIC TECHNOLOGY

Hydroelectric power is generated by using a diversion structure that alters the flow of water from a river or reservoir through the hydropower turbine. The force of the moving water is utilized to turn a turbine that subsequently powers a generator to produce electricity for the grid. The use of dams and diversion facilities are the two most common types of hydroelectric generation facilities that operate on the gravitational potential energy of the flowing river water. For each type, a water intake channel, or penstock, directs water flow to the turbine-generators within the powerhouse to then be released to the river or another outflow channel. Hydroelectric power generation facilities have existed for decades. The TRL is a 9 as this is a mature technology that is well established in the industry.

Conventional Hydropower

A dam, or impoundment, creates a reservoir of river water from which the gravitational potential energy is extracted by releasing water under high pressure at the bottom of the reservoir to a location of lower elevation (lower pressure) — such as the river on the other side of the dam. The pressure difference between the bottom of the reservoir and the river on the other side of the dam forces a volume of water to flow from the intake, into the penstock and through the turbines as illustrated in **Figure 10**. Water flow from the reservoir may be directly managed to meet electricity needs, provide flood control, or meet other recreational and environmental needs. The resulting power output of the hydroelectric system is dependent on the water's flow rate, the turbine efficiency, and the height differential from the top of the reservoir and the turbine intake (hydraulic head).

Figure 10: Hydroelectric power generation facility using impoundment[44]

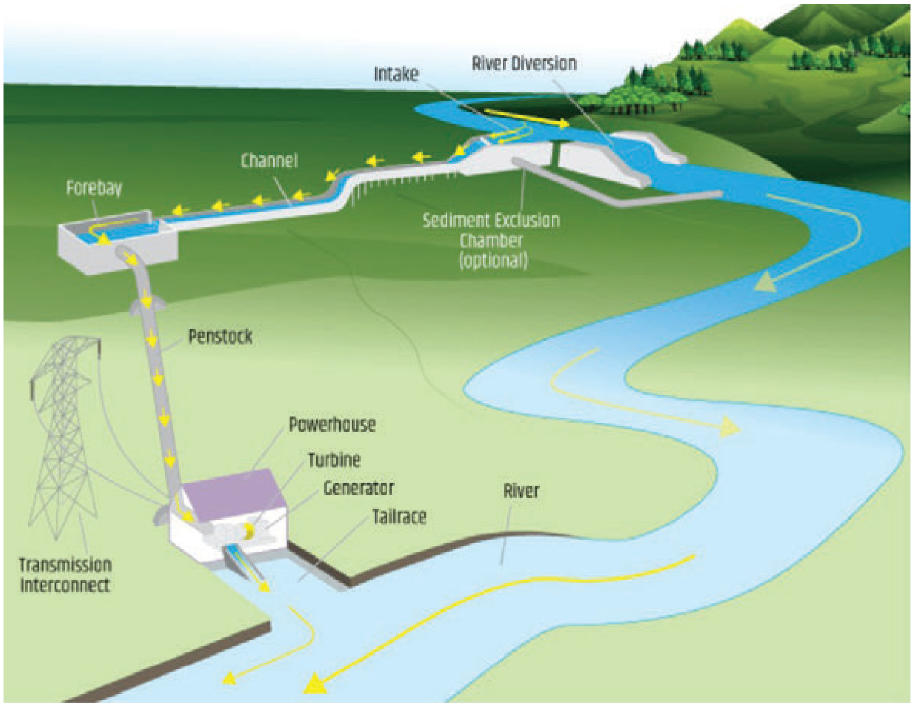


[44] https://www.energy.gov/eere/water/types-hydropower-plants

Run-of-River Hydropower

Run-of-river, or diversion, facilities are typically smaller than hydroelectric dams, and if dam structures are necessary, they are smaller in size and primarily function to ensure enough water is diverted to the penstock, rather than to create a reservoir. Once the water is diverted, the penstock will naturally decline with the topography of the riverbed towards the powerhouse and back to the river as illustrated in **Figure 11**. While there is no major reservoir created in run-of-river plants, a pondage can be included in the design to ensure a smaller volume of water is available for short terms needs, typically used for balancing intraday supply-demand changes. The lack of water storage in the design of a run-of-river plant results in smaller generation capacities and requires the plant to be located on rivers with higher flow rates year-round.

Figure 11: Hydroelectric power generation facility using diversion[44]



U.S. Department of Energy

Scope Assumptions

Hydroelectric power generation facilities are each sized and uniquely designed based on river hydrology and topology. Since this Assessment is based on a generic site, the scope assumptions and financial data are based on project-specific financials gathered from Canadian hydroelectric dams, as well as publicly available databases to develop the approximate cost values for a hydroelectric plant with a storage reservoir impoundment. The representative technology was chosen to follow project trends that reflect the country's most recent installations in multiple provinces while also tailored to the ideal project sizes and identified development potential within Alberta. It was found that large-scale hydropower projects with capacities greater than 100 MW have relatively stable capital and O&M costs for all installed technologies of both impoundment and run-of-river since the mid-1990s (when adjusted for inflation).

Challenges

Hydroelectric generation facilities typically have high upfront capital cost and long development schedules. The engineering and technical requirements of a facility's infrastructure (civil work, dam, structures, etc.) and large mechanical and electrical equipment alone require extensive investment. In addition to technical development, the most common challenge to constructing hydroelectric power generation facilities involves the permitting and negotiation process surrounding environmental and social issues. Issues in these areas can prolong development schedules, increase cost, and potentially prohibit a project altogether.

Hydroelectric generation facilities typically have high upfront capital cost and long development schedules.

Alberta, and Canada as a whole, have unique, rich, and diverse ecosystems that are home to critical habitats and endangered species. Not only are disputes over environmental studies common between developers and regulators, but an increasing complexity of habitats at a project site can lead to longer permitting timelines. This is to ensure that all environmental impacts are addressed and mitigation strategies for both upstream and downstream ecology are in place. In addition to the environmental concerns, the impacts on lands inhabited by Indigenous Nations are subject to additional appraisal under the constitutional rights established under First Nations treaties. General loss of land area, habitat disturbance, and archeological site destruction among other impacts can interfere with the cultural values of First Nations peoples, specifically those under Treaty 8, that inhabit the northern half of Alberta where there is extensive potential for new hydroelectric dam development.

Technology Providers and Status

With over 500 hydropower assets, Canada is the fourth-largest hydroelectricity-generating country in the world.[45 46] Hydropower has produced the majority of Canada's electricity for decades, reaching its peak generating capacity share at over 90% between 1920-1950. Moving into the 1970s, hydropower development slowed as other power sources such as fossil generation facilities gained popularity as the more cost-competitive option with lower transmission costs.[47] Today, 60% of Canada's electricity is produced from hydropower, illustrating the importance of the resource's contribution to servicing Canada's baseload; whereas only 3% of Alberta's electricity is produced from hydropower.[48] There are three large-scale hydroelectric power generation facilities within Alberta, all of which are owned by TransAlta. The three largest plants are primarily used to meet peak electrical demand, ultimately using a small portion of the total installed capacity at most hours. The remaining, smaller facilities are sized less than 50 MW, and most are not dispatched to the electric grid at all on a given day.

Today, Canada continues to build large scale hydroelectric power generation facilities in an effort to meet net-zero electricity goals and bolster clean energy generation capacity. Most of the hydroelectric power generation facilities built within the past decade were designed with dam impoundments. Over the same time period, Alberta has only had two large-scale hydroelectric projects under development: the 100 MW Dunvegan Hydroelectric project that is no longer under development, and the 370 MW Amisk Hydroelectric project, which has not yet started construction. Both projects are run-of-river plants sited within a 20 km radius of each other.

The average age of a hydroelectric power generation facility plant in North America is nearly 50 years, and facility lifespans typically range 50-100 years. Major refurbishments and modernization strategies are typically introduced around 40-60 years of operation to maintain flexibility and safety standards.[49 50] Plant refurbishment provides a solution to the lack of economic opportunities for large greenfield site development. Refurbishment also lowers costs due to the prior completion

[45] https://waterpowercanada.ca/wp-content/uploads/2021/07/WPC_National-Infrastructure-Assessment-Submission_July2021.pdf
[46] https:/iea.blob.core.windows.net/assets/4d2d4365-08c6-4171-9ea2-8549fabd1c8d/HydropowerSpecialMarketReport_corr.pdf
[47] https://www.thecanadianencyclopedia.ca/en/article/hydroelectricity
[48] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-canada.html
[49] https://www.iea.org/energy-system/renewables/hydroelectricity
[50] https:/natural-resources.canada.ca/sites/www.nrcan.gc.ca/files/energy/energy-resources/5_things_you_need_to_know_about_hydropower.pdf

of civil site work, permitting, and environmental mitigation strategies. Despite not having extensive timelines and high risks associated with the initial development of greenfield projects, investors interested in refurbishment are still often discouraged by uncertainties regarding concession renewal, water rights, new environmental policies, and the changing market conditions. Nonetheless, if greenfield and brownfield project development can overcome the large non-economic barriers as aforementioned, there is 51,000 of 53,050 GWh of developable hydropower in Alberta that remains to be utilized to move towards a net-zero future.[51]

Recent Project Developments

The three most recent hydroelectric projects in Canada are Site C, Keeyask, and Muskrat Falls. All have faced several forms of adversity and opposition from various stakeholders, and as a result project timelines and financials have suffered. The most prominent forms of scrutiny on all projects target the environmental and sociocultural impacts that the dams have on vital migratory habitats, lands of Indigenous importance, and poor working conditions.

The Keeyask Dam, completed in March 2022 on the Nelson River in Manitoba, is a 695 MW project that was completed approximately $2.2 billion CAD over its $6.5 billion CAD budget, took 9 years to construct, and ultimately cost $12,518 CAD/kW. The reservoir flooded 45 square km, impacting cultural lands of four First Nation community partners and animal habitat as water levels rose between 1m-3m in various locations along the waterway.[52]

The Muskrat Falls Dam, completed in September 2020 on the Churchill River in Newfoundland, is an 824 MW project that completed $7.2 billion CAD over budget, ultimately costing $16,262 CAD/kW. The financial turmoil of this project caused by poor planning, engineering issues, and lack of oversight over the developers led to the federal government providing a $5.2 billion CAD aid package, one of the largest in Canada's history. The aid package intended to mitigate substantial electricity cost increases that would have otherwise been incurred by residents.

While all three projects are located outside of Alberta, Site C, is sited closest along the Peace River near the British Columbia-Alberta border outside of Fort St. John. The 1,100 MW Site C dam is the third to be built along the Peace River, and the flood impacts incited a number of legal challenges from the First Nations for unconstitutional infringement on protected rights as specified under Treaty 8.[53] Site C is currently the most expensive dam in Canadian history at $16 billion CAD, approximately $9.4 billion CAD over budget, and has yet to be completed (the commercial operation date is projected to be in 2025, 10 years after construction began). There are various causes to such a large deviation from plan, but many of the financial and schedule impacts of this project were attributed to COVID-19 and existing geotechnical issues in the area that were more difficult to avoid than originally anticipated.

Hydroelectric Project	Location	Construction Term	Commercial Operation	Capacity	Estimated Capacity Factor, %	Budget Cost $MM CAD	Cost $MM CAD	Cost $ CAD/kW
Site C	Peace River, BC	10 yrs	Expected 2025	1,100	53%	$6,600	$16,000	$14,545
Keeyask	Nelson River, MB	9 yrs	March 2022	695	72%	$6,500	$8,700	$12,518
Muskrat Falls (dam)	Churchill River, NL	8 yrs	September 2020	824	62%	$6,200	$13,400	$16,262

[51] Hatch (2010) Update on Alberta's Hydroelectric Energy Resources (H334053)
[52] https:/keeyask.com/wp-content/uploads/2020/08/Pre-Impoundment-InfoSheet-082120.pdf
[53] https://news.gov.bc.ca/releases/2022EMLI0042-001009

Additionally, two other hydroelectric complexes have undergone construction within the last decade in Canada. The La Romaine Complex in Quebec contains four hydroelectric plants on the Riviere Romaine for a combined capacity of 1,550 MW. Total construction timeline lasted 14 years, finishing in 2023 after schedule delays from the COVID-19 pandemic. The Lower Mattagami Complex in Ontario is 438 MW capacity project that was delivered a year ahead of schedule in December 2015 and underbudget.[51]

Within Alberta, the 100 MW Dunvegan run-of-river plant was initially proposed by Canadian Hydro Developers, Inc. and then acquired by TransAlta and scheduled to be completed in 2014. This project, similar to Site C, targeted the large undeveloped potential within the Peace River Basin. Prior to the schedule completion date in May 2014, TransAlta proposed a 9-year delay (revising the schedule completion to May 2023) to Alberta Utilities Commission, citing poor economics and unstable market conditions.[54] As of late 2023, the TransAlta Dunvegan project has not re-commenced. Another project was proposed 15 km outside of Dunvegan on the Peace River, the Aminsk hydroelectric project. The Amisk hydroelectric project was a proposed 370 MW, run-of-river hydroelectric generation project and began initial consultations with First Nation communities in 2013, but has since been cancelled.

Technical Information

The ability for a hydroelectric power generation facility to generate power is subject to several variables including the seasonality of hydrological conditions, market and policy implications, the type of plant, and operational purpose (e.g. baseload or peak generation) among others. Hydroelectric generation facilities typically have a capacity factor ranging from 25%-80%, which falls to approximately 30%-40% when the plant's power generation operations compete with other needs such as irrigation, flood control, or other municipal and industrial processes. Capacity factor decreases further to 10%-15% when used for peak generation.[46] [55] Canada's average capacity factor for hydropower is approximately 54%, the second highest in the world behind Paraguay, which is above 80%.[56] In contrast, Alberta uses the three largest plants, Bighorn, Bow River, and Brazeau (pumped hydroelectric plant), primarily for meeting peak demand complementary to baseloaded fossil generation facilities.

The capital cost, performance, and O&M cost information for hydroelectric technology is summarized in **Appendix A**. The type of hydroelectric facility does impact the flexibility and response capabilities. Average start-up times range from 2-20 minutes and ramp rates range from 80%-100% of the plant's nominal power per minute, making hydropower one of the most flexible generation technologies available. Total project capital cost is estimated to be over $13,000 CAD/kW which is significantly higher than fossil units, even including CCUS. This value does not include transmission line infrastructure, which can further increase the capital investment.

If a hydroelectric facility includes a reservoir, then it should be capable of providing both black-start and load following capabilities. Additionally, both reservoir and run-of-river plants use synchronous generators with spinning inertia, providing primary frequency response and voltage support for the grid. These different services, especially from reservoir plants, provide additional flexibility and support that will be needed for accelerating variable renewable energy resource deployment.

54%

Canada's average capacity factor for hydropower is approximately 54%, the second highest in the world behind Paraguay.

[54] https://albertawilderness.ca/2015-01-20-awa-news-release-alberta-peace-river-dam-project-cancelled-by-transalta/
[55] https://www.eia.gov/todayinenergy/detail.php?id=30312
[56] https:/ccpabc2018.files.wordpress.com/2018/04/cmp_canadas-energy-outlook-2018_ch3.pdf

Hydroelectric Technology SWOT Analysis

Strengths

- Hydroelectric power generation facilities can generate a reliable source of power as long as there is enough water flowing through the turbines, which is more often a concern with run-of-river plants than with impoundment reservoirs. The turbines that produce hydroelectric power operate like conventional turbines at fossil-fuel-fired plants, meaning that inertial capacity and grid-support capabilities such as voltage and frequency response are provided to the grid when needed.
- Large generation capacities (e.g. over 1 GW as is the case with Site C) are possible with both types of generating stations. Run-of-river projects may have much less or no storage compared to large reservoir impoundment, but still have numerous operations over 100 MW. Both types of generation facilities benefit from economies of scale above 100 MW.
- With black start capabilities and short ramp times, hydropower can meet real-time energy needs as a peak demand unit or addressing fluctuations in baseload demand.
- Hydropower is an emissions free energy resource that is fully dispatchable if reservoirs are sufficient to sustain water supply through drier seasons.

Weaknesses

- Permitting and construction schedules can often take 5 years or longer to complete each. The more complex the ecology of the site is, the longer the environmental permitting and review process will typically take. Construction timelines are often faced with delays, either for unforeseen circumstances or inadequate planning, as exemplified in some of Canada's most recent hydroelectric projects.
- Adverse environmental and social impacts must be mitigated, especially in the case of large reservoirs that may place hundreds of square km of land under water.
- Significant up-front investment is necessary to initiate hydroelectric projects. With decreasing availability of suitable project sites, construction costs are anticipated to continue to rise.

Opportunities

- There is 51,000 GWh per year of developable potential within Alberta. This could make a significant contribution to the hydropower potential across Canada and power Alberta with several gigawatts of clean energy.
- Large generating capacities can play a pivotal role in supporting an increasing number of intermittent renewables as they are introduced to the grid, especially in the face of an electrified future.

Threats

- Overcoming an unfavorable stigma surrounding the environmental and social impacts of dams has proven to be a source of schedule delays and increased costs. Specifically in the northern region of Alberta where most of the hydroelectric generation potential has been sited, Treaty 8 and First Nations peoples must be considered and coordinated with in order for a project to be constructed.
- Interconnection capacities and transmission line expansion costs are significant project concerns for sites in more remote locations. This could be relevant to many of the developments that are sited in the northern portion of the province, further away from population centers in the south. Even if construction costs for a site are feasible, the costs of building or upgrading the necessary transmission infrastructure may hinder a project from consideration.
- Regarding some of the most recent large-scale hydroelectric projects in Canada, a number of them did not receive favorable media attention due to exceeding budget, schedule, controversial working conditions, and impacts on the First Nations communities and environment. The consequences of the Keeyask, Site C, and Muskrat Falls projects may lead Albertans to question the suitability of hydropower for their province.
- Limited site suitability becomes an increasing problem as more projects are built. The local hydrology, topography, and land uses compete with a project's power generation feasibility along a river or within a specific basin.

Future Role in Alberta

The province of Alberta currently has 907 MW of installed hydroelectric capacity, or 4% of the energy generation potential, and operates at an average capacity factor of 43% (slightly below Canada's overall average). The North Saskatchewan, South Saskatchewan, and Red Deer basins contain all but 1 MW of the current installed capacity. The remaining megawatt and 7 GWh are located within the Athabasca basin. These four basins contain 25,590 of the 53,050 GWh of developable hydropower, whereas the Hay, Peace, and Slave basins contain the remaining 100 GWh, 19,720 GWh, and 7,640 GWh, respectively.

The Slave, Peace, and Athabasca basins contain the largest hydroelectric resource potential within the northern half of the province, and future development will depend on how the social and environmental implications of a project are weighted relative to the project financials. In addition, if projects were to be sited in more remote areas with less impact on significant wildlife habitats or cultural landmarks, the cost of building transmission to load centers could still be a significant hurdle. If development is to occur closer to the more densely populated areas of the province, which impact the North Saskatchewan, South Saskatchewan, and Red Deer basin rivers, it will most likely have to operate within a multipurpose project that serves industrial, irrigation, or other local needs. These considerations illustrate that even if a hydroelectric project has a successful path forward (satisfying environmental, cultural, and financial requirements), there may still be a need to accommodate the surrounding communities' water needs which reduces the operating capacity dedicated to utility-scale power generation.

In contrast to the large hydroelectric potential within the province, Alberta has only had two utility-scale projects under review within the past decade - Dunvegan and Amisk. Both were sited within 20 km of each other, thus only targeting capacity expansions along the already highly developed Peace River. All other large-scale projects over 100 MW (of which there are only three operating today) in Alberta were completed no later than the 1970s, making Amisk the closest hydroelectric project to beginning construction in the past nearly 50 years. The otherwise aging infrastructure provides a wide range of opportunities for refurbishment and expansion projects in the province, but with large variances in costs due to site-specific needs, it is difficult to estimate how much more potential is economically feasible to achieve at existing sites without comprehensive assessments for each site.

Given the most recently completed projects throughout Canada, with Muskrat Fall's 8-year construction schedule being the shortest, it is unlikely that additional hydroelectric generation facilities will play a major role in meeting 2035 targets.

If the Amisk project is completed within the anticipated timeline, hydroelectric generation in Alberta will be increased by approximately 76% and 1.2 million tonnes of CO_2 emission will be displaced per year. This equates to 4% of the 29.3 million tonnes of CO_2e emitted by Alberta's electricity sector in 2020.[57] Hydroelectric power generation facilities are not only some of the lowest GHG emitting plants per unit of generated energy, but future development will benefit Alberta's energy-only market by bringing more flexible power online to the grid. Otherwise, the lengthy development timelines for large-scale hydroelectric projects, especially in the face of significant schedule delays seen by Canada's most recent projects, prohibit additional hydroelectric generation facilities in Alberta from being brought online in time to make a greater contribution to Canada's 2035 net-zero electrical grid.

If the Amisk project is completed within the anticipated timeline, **hydroelectric generation** in Alberta will be increased by approximately **76%** and 1.2 million tonnes of CO_2 emission will be displaced per year.

[57] https://nebula.wsimg.com/6633a9b8caa1b8a74357a9089585c1ba?AccessKeyId=3AE63B7BFE2CDEDB204E&disposition=0

Commercially Available by 2050

Ultimately, 51,000 GWh per year of hydroelectric energy generation potential remains to be developed within Alberta. This potential represents approximately 80% of 61,853 GWh that was Alberta's total system load in 2022.[1] In reality, resistance from environmental, social, and financial avenues will limit future hydroelectric expansions to far less than 51,000 GWh of new generation. Nonetheless, existing hydropower has the potential to provide more than half of Canada's reserve requirements through 2050, even more so with future expansion and being especially useful in a fully electric future. Solidifying hydropower's vital role in maintaining the grid's reliability and stability and highlighting the need for government support through sustainability standards and measures that can increase investor confidence. Yet the fact that two of the three most recent large-scale projects in Canada resulted in Canada's most expensive project (Site C), and one of the largest federal aid packages in Canadian history at Muskrat Falls, presents a significant hurdle in overcoming negative public perception towards how hydroelectric projects are completed.

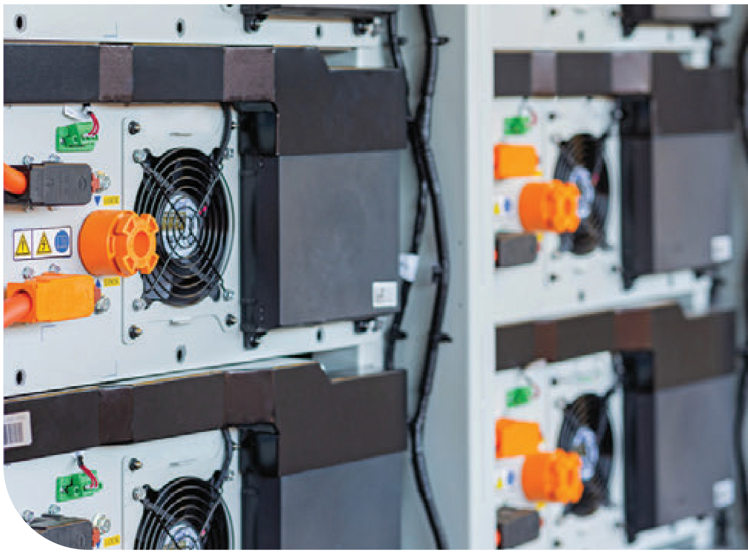
ENERGY STORAGE TECHNOLOGY

Since the electric grid was first established, researchers have been focused on developing new ways to capture and store energy to meet increasingly dynamic shifts in electricity demand. As aging fossil fueled assets retire and intermittent renewable energy facilities replace them, concern for grid stability has grown. The increase in renewable production capabilities has driven the demand for energy storage technology at utility scale. Energy storage systems have begun to play a significant role within the power industry, as AESO alone has already integrated 130 MW of energy storage capacity at the time of this report.[58]

1898 & Co. has analyzed four energy storage technology categories for implementation in AESO's territory: lithium-ion battery energy storage, non-lithium battery energy storage, adiabatic compressed air energy storage, and pumped hydroelectric energy storage. The power and energy capacity of each technology was selected based on industry trends for utility-scale projects and correspondence from AESO. Project capital costs were estimated using EPC methodology and assumed a general site layout near Alberta, Canada.

Lithium-ion Battery Energy Storage

A lithium-ion battery is an electrochemical energy storage system that contains a cathodic and an anodic electrode sealed within a cell container. During charging, a reduction-oxidation reaction ("redox") occurs and liberates lithium ions from the cathode to the anode via a high-conductivity electrolyte. During discharging, the reverse redox reaction occurs, which forces electrons to migrate from the anode to the cathode through an external circuit, thereby generating electric current. The most common lithium-ion chemistries utilized for utility-scale applications include lithium-iron-phosphate ("LFP") and nickel-manganese-cobalt ("NMC"). NMC is known for being a favorable chemistry for electric vehicles due to the chemistry's high energy density. LFP has recently been increasing its market share in the stationary storage industry because it is commonly less expensive than NMC and has a higher thermal stability.



[58] http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet

Lithium-ion technology has seen a surge of utility scale project implementation and development in recent years due to its high energy density, low self-discharge, and fast response times when compared to other alternatives. Lithium-ion as a stationary storage technology has benefitted greatly from the R&D efforts in the electric vehicle industry, which enabled technology and commercial maturity timelines that have outpaced alternative technologies. Lithium-ion is currently the dominant technology for new installations of utility-scale energy storage.

As the stationary storage market evolves, there is a continued focus on product development, manufacturing scale, and designs for reducing manufacturing and construction costs. In addition, as intermittent renewable generating technologies increasingly populate the grid, there is an expectation that storage duration requirements will increase. It is the view of 1898 & Co. that in the current energy storage marketplace, these emerging technologies must compete directly with lithium-ion for their targeted customer use cases in four main ways: safety, performance, life-cycle cost, and environmental impact.

For the remainder of this report, 1898 & Co. will reference generic lithium-ion batteries built for utility-scale energy storage applications for all technology descriptions, performance, and analyses of lithium-ion battery energy storage with respect to the AESO market.

Non-Lithium Battery Energy Storage

The non-lithium battery energy storage market is comprised of technologies of varying technological and commercial maturity that seek to compete and/or differentiate from the technical and commercial capabilities of lithium-ion battery energy storage system ("BESS"). Non-lithium systems are commonly categorized as Long Duration Energy Storage ("LDES") technologies in the industry. While it may be true that many of the non-lithium providers are aiming for longer duration use cases, the term "long duration" has no consistent definition in the industry and may mean anything from "greater than 4 hours" to "seasonal storage" depending on context. This report does not aim to define "long duration" or "LDES" specifically, but rather aims to note that AESO should recognize the potential ambiguity in terminology and context that results from the dynamic market and product development activities in the energy storage industry. In this report, the term "non-lithium" is used to differentiate from lithium-ion (rather than "LDES") because lithium-ion is capable of long duration storage under some definitions and operational constructs. It is also noted that this non-lithium section is focused on non-lithium battery technologies. Other forms of non-lithium storage like compressed air and pumped hydro are discussed separately.

Non-lithium systems are commonly categorized as Long Duration Energy Storage ("LDES") technologies in the industry.

Non-lithium systems have gained market share in the energy storage industry in recent years for a variety of reasons. One reason for this trend involves the growing need for longer duration storage. Duration is a term that defines the capability and not necessarily the operation of the battery. The simplest definition of duration is the time it takes to discharge 100% of the useable energy in a battery at rated power conditions. If a battery system is rated for 100 MW power and has 400 MWh of energy capacity, the duration is defined as 4 hours because it can discharge 100 MWh each hour for 4 hours. That battery cannot discharge at a power level higher than its rated power, so it cannot discharge 100% of the energy in a time less than 4 hours. Note that in operation, a battery can be discharged at lower power conditions for longer durations in operation, but that does not necessarily change its rated power or rated duration.

Lithium-ion systems being installed today are typically sized for use cases that call for 1-4 hours of rated duration, but there are several examples of lithium-ion technologies being used for longer (i.e. 8-hour) duration use cases. Lithium-ion systems are typically designed for modularity, so there is a generally stable unit cost ($ CAD/kWh of energy capacity) for designs sized for longer rated durations. A common goal for non-lithium technologies is to achieve lower unit costs than lithium at longer durations, and hence most non-lithium technology providers are marketing capabilities between 6-24 hours, with some touting significantly longer durations (i.e. 100 hours). In addition to the need for longer duration systems, the dynamics of the lithium supply chain have motivated investments in alternative storage solutions that do not utilize lithium. In addition to diversity of supply, the perceived weaknesses of lithium-ion systems with respect to thermal runaway, capacity degradation, and environmental impact have paved a way for alternative technologies to enter the stationary storage market.

There are a multitude of developing/maturing technologies that fit within the non-lithium battery energy storage market. This section considers a range of technologies that are generally considered technically mature and commercially available (though not commercially mature when compared to lithium). The results/findings are presented as ranges encompassing the broad class of technologies, but not individual technologies or OEMs specifically. The technologies included in this category are iron flow batteries, vanadium redox flow batteries, zinc bromine flow batteries, aqueous zinc batteries, and high temperature batteries such as sodium-sulfur and calcium-antimony technologies.

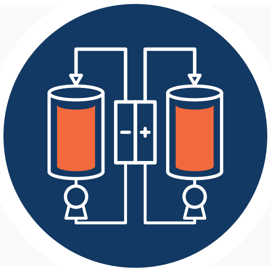
Flow batteries are a type of energy storage system where electrolyte is pumped through one or more electrochemical cells to create an electrochemical reaction. There are many different chemistries of flow batteries, many of which can generally be classified by the following categories: full redox vs. hybrid, inorganic vs. organic, and vanadium-based vs. zinc-bromine-based vs. iron-based.

For all combinations of flow battery types, the electrodes do not contain any active elements that participate in electrochemical reactions. Therefore, the electrodes are not subject to the same irreversible chemical deterioration that depletes electrical performance from lithium-ion batteries, resulting in theoretically high cycle lives for flow batteries. In many cases, however, stack components are prone to mechanical deterioration that may cause some performance degradation over time.

Examples of other electrochemical batteries include **high temperature batteries** and **aqueous zinc batteries**. Battery cells that require high temperatures to keep a metal in its molten state for operation are referred to as high temperature batteries. In their charged state, high temperature batteries have the pure form of a metal anode and the pure form of another element as its cathode. The battery chemistry leverages the natural electrochemical potential difference of the two elements. The operation of these technologies is typically considered reversible alloying. Two leading chemistries of high temperature batteries are Sodium-Sulfur and Calcium-Antimony. High temperature batteries have the most similar performance attributes to lithium-ion systems and are among the more competitive non-lithium technology on a cost basis.

Aqueous-zinc batteries were first explored in the 1980s, but research activity has recently surged due to technological developments and the quest for safer and less expensive raw material alternatives to lithium-ion batteries. Aqueous-zinc batteries take on a similar chemistry to a zinc-bromine flow battery, but all the necessary electrolyte is contained within a battery cell instead of being stored in tanks and pumped into and out of the battery stack.

For the remainder of this report, 1898 & Co. will reference flow batteries and other electrochemical batteries for all technology descriptions, performance, and analyses of non-lithium battery energy storage with respect to the AESO market.



Flow batteries are a type of energy storage system where electrolyte is pumped through one or more electrochemical cells to create an electrochemical reaction.

Compressed Air Energy Storage

Compressed air energy storage ("CAES") is a mature form of energy storage that has been in operation globally for over 30 years. CAES systems utilize off-peak electricity to power a compressor train that compresses ambient air. The compressed ambient air is cooled and then injected into underground storage formations. During peak demand, the compressed air is brought to the surface, heated, and expanded through turbine to run a generator. Traditional CAES systems require suitable underground storage at the development site, which is typically a salt cavern or a mined hard-rock cavern.

There are two main types of CAES systems: diabatic and adiabatic. Diabatic CAES ("D-CAES") utilizes natural gas to reheat the compressed air during expansion. The 110 MW CAES facility located in McIntosh, Alabama is an example of an operational D-CAES system. This facility was the first operational case of D-CAES in the U.S. and is one of two globally operating D-CAES facilities. D-CAES facilities are considered hybrid systems that combine the attributes of a traditional fossil generating plant and a pure energy storage system. The McIntosh D-CAES facility still requires about one-third the amount of natural gas per kWh produced when compared to a conventional gas turbine plant. Alternatively, adiabatic CAES ("A-CAES") reuses heat stored from compression to reheat the compressed air during expansion. Therefore, A-CAES loses less energy to waste heat and has a higher RTE than D-CAES. Future CAES implementations are expected to rely on A-CAES technology over D-CAES due to its avoidance of fossil fuel combustion when generating process heat.

For the remainder of this report, 1898 & Co. will reference A-CAES for all technology descriptions, performance, and analyses of CAES with respect to the AESO market.

Pumped Hydroelectric Energy Storage

Pumped hydroelectric energy storage ("PHES") is another mature form of long duration energy storage that accounts for a vast majority of the world's energy storage capacity. PHES stores energy via the gravitational potential energy of water kept in two reservoirs at different elevations. The PHES system cycles the water held in the reservoirs through a pump-turbine/generator-motor system to store or generate energy. During peak demand, water flows from the higher reservoir to the lower reservoir and passes through a turbine that produces electricity. To charge the PHES system, water from the lower reservoir is pumped back up to the higher reservoir typically using surplus off-peak electrical power. PHES systems can either be open-loop or closed-loop systems. Open-loop systems are continuously connected to a natural water body such as a lake or river. Closed-loop systems operate independently of natural water sources.

Optimal PHES sites include those with ample buildable area that are situated near bodies of water at varied elevations. For example, the Canadian Rockies to the west of Alberta may provide opportunities for PHES development. Since PHES can require significant land and infrastructure for larger capacity systems, purpose-built greenfield PHES systems are not optimal for all regions. For areas that have existing hydropower assets, such as Canada, the option of retrofitting plants with pump-back capability may be an attractive alternative to purpose-built greenfield development. This alternative would allow for decreased construction costs and construction schedules, but the option may potentially face environmental considerations due to disturbing open-loop, natural river systems.

For the remainder of this report, 1898 & Co. will reference traditional, purpose-built greenfield PHES for all technology descriptions, performance, and analyses of PHES with respect to the AESO market.

Emerging Energy Storage Technologies

There are a multitude of emerging energy storage technologies that range from early development to early commercial maturity. This market growth is said to be predominantly motivated by industry analysts forecasting significant increases in demand for storage capacity and for longer storage duration as renewable generation capacity increases. 1898 & Co. has highlighted the following four emerging technologies, but AESO should be aware that this list is not exhaustive and is not intended to represent opinions on quality or expected market penetration.

Iron-air battery	Metal-hydrogen battery	Thermal energy storage	CO_2-based battery

Iron-air batteries were first explored by NASA in the 1960s but have recently regained interest in the eyes of the storage world after recent development and commercialization investment into the technology motivated by a perception of utility-scale, long duration energy storage potential. Iron-air batteries use a process known as "reversible rusting." Form Energy ("Form") is an iron-air battery vendor that is currently headquartered in the Boston area, and who is currently constructing a manufacturing facility in West Virginia. Form's Multi-Day Storage System is a 100-hour duration iron-air battery that has been awarded several projects across the U.S. in the 5-15 MW range. The first few projects are anticipated to be installed in the 2024-2026 timeframe, per press releases. Energy densities are claimed to be similar to lithium-ion, though it follows that power densities would be much lower than lithium due to the significantly longer duration design.

Metal-hydrogen batteries were invented in the 1970s originally for the purpose of aerospace energy storage. The battery combines the reactions of a Nickel ("Ni")-Cadmium battery and a fuel cell. The cathode consists of a nickel hydroxide composition while the anode is made up of a platinum hydrogen composition. Metal-hydrogen batteries are known for their high efficiencies, flexible power/current operating ranges, and low lifetime capacity degradations. Aside from low volumetric energy density, these batteries are considered some of the higher performing technologies available. NASA has been known to use this type of battery in some of their technologies and this battery is still commonly used on satellites. Enervenue, a Fremont, CA based company started in 2020, is targeting a Metal-hydrogen battery for stationary storage applications and is attempting to deliver the industry leading performance characteristics of metal-hydrogen systems while solving the cost challenges typically associated with this technology. Enervenue is constructing a manufacturing facility in Kentucky to serve the commercial/industrial and utility storage markets. They have an advertised backlog but have yet to demonstrate their product with a completed and operational utility-scale project.

Thermal energy storage ("TES") utilizes a storage medium to store and release sensible heat through heating and cooling processes. Storage mediums can range from molten salt, concrete blocks, rocks, or sand-like particles. The energy capacity of a sensible TES system is defined by the density, specific heat, and volume of the storage medium as well as the temperature change expected of the system. Malta's "Long Duration Storage Technology" is an example TES technology aimed at utility-scale development. Malta's technology utilizes sensible TES with molten salt as the storage medium creating a "pumped heat energy storage" system. The system operates using a recuperated air-loop Brayton-cycle. During off-peak periods of surplus energy, the system charges by sending electricity to a heat pump, which converts the electricity to thermal energy by creating a temperature difference. The heat stream is stored in molten salt and the cold stream is stored in anti-freeze liquid. When the system needs to discharge, a heat engine converts the temperature difference back to electrical energy which is then sent to the grid.

Another form of mechanical energy storage is being developed by Energy Dome, founded in 2020, which has patented the **"CO_2 battery"**. The CO_2 battery operates via a closed thermodynamic manipulation of CO_2 between its gaseous and liquid phases. CO_2 is compressed into its liquid form using a two stage inter-cooled compressor and is stored for future use. Storing CO_2 in its liquid phase at an ambient temperature allows for significant reduction in operating costs. Remaining CO_2 for the closed-loop system is stored in a fabric "dome" at pressures slightly above atmospheric levels. Energy Dome claims to have an AC RTE of over 75% as well as a usable life of over 30 years.

1898 & Co. has not included these technologies in the technology assessment summary tables but has included this section for informational purposes. 1898 & Co. recommends that AESO monitor these and other technologies as they mature for future energy storage developments opportunities.

Technology Providers and Status

The following section highlights example vendors for each of the energy storage technology categories. Vendor descriptions are based on 1898 & Co. experience as well as publicly available information. This is not intended to be a comprehensive list and is not intended to represent any opinion of quality or bias, but rather simply identifies examples of well-known providers in this market based on 1898 & Co. experience.

Lithium-ion Battery Energy Storage

There are many companies that are currently competing in the utility-scale lithium-ion battery market. 1898 & Co. has outlined a list of companies in this market in **Table 4** based on 1898 & Co. experience.

Table 4: Lithium-Ion Battery Vendor Overview

OEM/Vendor	Battery Cell	Battery Enclosure	Energy Management System
BYD	✓	✓	✗
CATL	✓	✓	✗
LG	✓	✓	✓
Samsung	✓	✓	✗
Tesla	✗	✓	✓
Wärtsilä	✗	✓	✓
Sungrow	✗	✓	✓

Table 4 compares the common offerings of several different players in the battery and battery containers supply chain. Note that there are many other vendors playing various roles, and that many suppliers are developing new capabilities, but the table is intended to identify whether the supplier is currently known to provide their own product or service in three key categories for the utility storage market:

- **Battery Cell:** this is intended to mean the original manufacturer of the battery cell, which would then be packaged into battery modules for use in energy storage projects.
- **Battery Enclosure:** this is intended identify whether the supplier provides a modular, integrated, purpose-built-enclosure ("PBE"). The PBE form factor typically includes battery modules, HVAC, safety, and battery level controls that are installed in an enclosure in a manufacturing setting. PBE suppliers may provide their own battery cells and/or modules or may procure them from another manufacturer.
- **Energy Management System ("EMS"):** An EMS is a broad term, but in this context, it is intended to identify whether the supplier is currently marketing a project level controls solution that integrates and operates the BESS equipment, power conversion system ("PCS"), and other balance of plant systems as a complete system. Controls contractors, EPC contractors, or integrators that are not BESS equipment suppliers, and hence not shown on the list, also offer EMS solutions for utility applications.

It is important to also note that the definition and/or role of an “integrator” is an important term that is not always consistently defined. Vendors that supply batteries, enclosures, PCS, EMS, and commissioning support required for an integrated solution may be considered an integrator, regardless of the original manufacturer of the equipment. EPC contractors can also serve as an integrator if they are providing a controls system and pairing the controls to integrate the BESS and PCS components.

Non-Lithium Battery Energy Storage

There are many companies that are currently advancing technology solutions in the non-lithium storage space, including those highlighted in **Table 5**. This is not intended to be a comprehensive list and is not intended to represent any opinion of quality or bias, but rather simply identifies examples of well-known providers in this market based on 1898 & Co. experience.

Table 5: Non-Lithium Battery Vendor Overview

Manufacturer	Headquarters Location	Chemistry
CellCube	Toronto, ON, Canada	Vanadium Redox Flow
ESS Inc.	Wilsonville, OR, US	Iron Salt Hybrid Flow
Invinity Energy Systems	Vancouver, BC, Canada	Vanadium Redox Flow
Largo Clean Energy	Toronto, ON, Canada	Vanadium Redox Flow
Lockheed Martin	Bethesda, MD, US	Undisclosed Redox Flow
Sumitomo Electric	Japan	Vanadium Redox Flow
Redflow	Australia	Zinc Bromine Hybrid Flow
VRB Energy	China	Vanadium Redox Flow
CMBlu	Germany	Organic Redox Flow
Eos	Edison, NJ, US	Aqueous-Zinc
Ambri	Marlborough, MA, US	Calcium-Antimony
BASF	Germany	Sodium-Sulfur

While vanadium-based chemistries are generally considered to be mature and proven technologies, the relatively high cost of vanadium is an important consideration for storage technology selection. This is a competitive space for product development, but other flow battery technologies have also been vying for market share. ESS technology utilizes an iron-based electrolyte, which is a relatively cost-effective electrolyte option.[59] Lockheed Martin has also announced a redox flow battery system with an undisclosed non-hybrid chemistry. Lockheed Martin and Sumitomo are somewhat unique to the flow battery OEM space that is commonly made up of start-up companies, as they are large, well-established corporations with long histories of product developments.

[59] https://essinc.com/how-we-stack-up/

CMBlu, a Germany based startup, is commercializing the first organic flow battery. The electrolyte composition and performance characteristics of organic flow batteries are thought to be more customizable and therefore have better cost and performance potential compared to inorganic flow batteries. An important concern with organic flow batteries is long term instability of their electrolytes which could lead to capacity degradation over time. CMBlu made news this year when they announced plans to build a 5MW-50MWh battery for Salt River Project.[60] If successfully brought online, this is set to be the largest flow battery in the US.

The high temperature battery market contains two major players: BASF and Ambri. Through a partnership with NGK Insulators, BASF is the leading vendor of Sodium-Sulfur ("NaS") batteries for stationary storage applications.[61] BASF NaS products are designed as modular, integrated enclosures that are targeted for discharge durations between 6-8 hours but can be flexible for longer durations. NaS batteries are expected to last a calendar life of 20 years or a cycle life of 7,300 cycles. BASF currently claims more than 200 projects totaling over currently in operation as well as 15+ years of operating performance.

Ambri is a leading supplier of Calcium-Antimony batteries known as Liquid Metal™ batteries.[62] The Ambri product is a modular enclosure housing multiple battery modules with integrated ventilation, controls, and safety systems. It is designed for a 20 year-life for high cycling applications.

Eos is a vendor of U.S.-designed and -manufactured aqueous-zinc batteries.[63] Eos has shipped hundreds of modular enclosures with various generations of their technology. Eos systems can typically accommodate use cases calling for 4–12-hour discharge durations. The latest designs are modular, integrated enclosures, in line with industry trends.

Compressed Air Energy Storage

Hydrostor, a Toronto-based company founded in 2010, has proven A-CAES feasibility at a pilot scale in Canada utilizing thermal storage units to capture the CAES process heat.[64] Hydrostor is currently working to developing multiple utility scale projects globally, including the 500 MW, 8-hour duration Willow Rock project near Los Angeles, California in the US. That project is anticipated for commercial operation in 2028 and Hydrostor has agreed on a PPA for 200 MW of the project capacity with a local utility.[65]

Pumped Hydroelectric Energy Storage

PHES systems are comprised of similar major equipment that is used in various pump or turbine applications (i.e., hydroelectric power generation facilities). 1898 & Co. experience suggests that common providers of this type of equipment include Voith, General Electric, and Siemens, among others.

60 https://media.srpnet.com/salt-river-project-and-cmblu-energy-announce-launch-of-innovative-long-duration-energy-storage-project/
61 https://www.basf.com/global/en/who-we-are/organization/group-companies/BASF-Stationary-Energy-Storage-GmbH/designed-for-stationary-enegy-storage.html
62 https://ambri.com/solution/
63 https://www.eose.com/
64 https://www.hydrostor.ca/technology/
65 https://www.energy-storage.news/first-offtake-deal-signed-for-500mw-4000mwh-advanced-compressed-air-energy-storage-project-in-california/

Technical Information

The following section summarizes key technical information for each energy storage technology category as well as each technology's typical operation.

Non-Lithium Battery Energy Storage

1898 & Co. has collected market data from a variety of long duration battery energy storage technology providers and incorporated information from 1898 & Co. project experience. The technical, performance, capital cost, and O&M cost information for non-lithium technologies is intended to be indicative of a broad class of commercially available products. Because of the relative nascency of the non-lithium battery storage market, the variability of publicly available information, and the confidentiality of certain technology-specific information received from suppliers, 1898 & Co. is normalizing a large swath of information into ranges across multiple technologies to generalize the current market capabilities.

In general, non-lithium long duration battery energy storage technologies exhibit higher capital costs than lithium-ion technologies when competing directly for 4-8 hour discharge durations. However, technologies like flow batteries generally improve cost efficiency with longer duration system. OEMs are seeking to increase manufacturing scale and improve designs to drive manufacturing and installation costs down.

RTE values are also typically lower than lithium-ion RTE, which can increase costs associated with charging the BESS. The appeal of non-lithium technologies is generally in the life cycle cost for projects with use cases that are better suited for longer duration applications. Many non-lithium battery technologies exhibit little degradation throughout the project life, and therefore may not require overbuilds or augmentation events that are common with lithium-ion systems. While this can limit O&M costs and enable favorable life cycle cost trends, these O&M costs are largely unproven due to limited implementation of most non-lithium technologies.

Lithium-ion Battery Energy Storage

1898 & Co. has collected technical, performance, capital cost, and O&M cost information from numerous lithium-ion battery OEMS and 1898 & Co. project experience for utility-scale applications. Recent utility-scale lithium-ion battery developments have ranged in discharge duration from 1-8 hours depending on system use case. 1898 & Co. selected a 4-hour duration lithium-ion battery system for this analysis.

At the time of this report, lithium-ion battery systems have dominated the stationary energy storage market due to the maturity and relative cost of the available products/systems. Additionally, lithium-ion battery systems have a higher RTE and a higher energy density than most other storage systems. However, lithium-ion battery systems have experienced safety concerns related to fire and thermal runaway and are susceptible to broader supply chain impacts for lithium carbonate and graphite, among other commodities. These concerns have accelerated research and development for alternative storage solutions. The industry expects lithium-ion battery systems to maintain a significant majority market share of new utility-scale battery storage in the next several years.

Compressed Air Energy Storage

1898 & Co. has collected relevant data for A-CAES systems from Hydrostor and from 1898 & Co. experience. The selected generic unit for the evaluation is 500 MW, 8-hr that includes the construction of a purpose-built cavern with hard rock geologic conditions common to Alberta.

The assumed use case is a daily cycling pattern similar to the assumptions used for the other storage technologies. A-CAES systems designed for an 8-hour duration are capable of a full charge and discharge daily, and the systems do not have specific cycling limits. They are capable of switching between charge to discharge intermittently, though not as rapidly as inverter-based electrochemical batteries. The A-CAES process has a lower RTE than other battery energy storage systems and will also require a full time O&M staff. The systems are designed for a 50-year project life, so there is potential for project returns to support these operational costs. In terms of schedule, A-CAES systems can take anywhere from 2-3 for permitting and development and an additional 4-5 years for construction. The land requirements to support a 500 MW A-CAES project are approximately 35 hectares. 1898 & Co. considers A-CAES to be relatively mature from a technology perspective, but still developmental from a commercial perspective until utility scale project(s) are installed and proven out in operation.

A-CAES systems, unlike battery energy storage systems, have the ability to provide inertial capacity. Inertial capacity allows for the system to maintain a stable electric frequency. Inertial capacity is common of traditional power plants but not of inverted-based resources like wind and solar.

Pumped Hydroelectric Storage

1898 & Co. selected a 500 MW, 10-hr generic project for this evaluation, which is within the range of common power and energy ratings for PHES developments in the industry. 1898 & Co. has collected market data from a variety of publicly available sources and 1898 & Co. experience related to PHES development. PHES systems are anticipated to exhibit favorable capital costs ($ CAD/kWh) when compared to other technologies, but they generally require large scale projects (GWhs energy capacity) to achieve those costs. Because of the site specific and geography specific nature of the projects, PHES is customizable to the application, but can be difficult to normalize costs and apply to generic sites. PHES systems have demonstrated useful project lives greater than 60 years in existing projects, so there is a longer time horizon to achieve project returns than other storage technologies. The downside of the geographic and environmental impacts of PHES systems is that permitting and construction timeframes are significantly longer than those of battery storage systems.

PHES technology exhibits an RTE that is among the leaders in storage technologies available today. Response times are fast in relation to most fossil plants, but are not as fast in comparison to inverter based storage technologies.

Energy Storage SWOT Analysis

The following section highlights strengths and weaknesses of each of the energy storage technology categories as well as external market influences that may produce opportunities or threats to market development. This information is based on 1898 & Co. experience and is broadly focused on the utility scale energy storage market.

Lithium-ion Battery Energy Storage

Strengths

- Lowest installed capital cost ($/kWh) for typical use cases in today's market (1-4 hour discharge duration).
- Technology and commercial maturity with significant supplier competition in utility storage market.
- Lithium-ion systems have a high RTE compared to the rest of storage market.
- Response times are on the order of milliseconds to seconds. This is considered to be significantly faster than non-inverter based storage options like CAES and PHES.

Weaknesses

- High capacity degradation over the course of the project life cycle.
- Less flexibility to adjust cycling limits/behaviors over the life of the project due to warranty limits and degradation.
- Augmentation costs and/or overbuild costs required to maintain energy capacity.
- Thermal runaway and fire risk.
- Finite amount of energy can be discharged at a given time. In addition, time needs to be set aside between discharge cycles for charging.

Opportunities

- Research and development into the recyclability of lithium-ion cells may reduce environmental concerns over lithium-ion battery systems.
- US tax incentives expected to drive US manufacturing, which may benefit lead times/availability for Canadian market.
- Shared R&D with electric vehicle market driving efficiency throughout value chain, from raw material sourcing through manufacturing.

Threats

- Exponential growth of EV market paired with limited raw material reserves and processing may limit availability or affordability of lithium-ion systems for stationary storage.
- Safety concerns over fire and thermal runaway may drive regulation that limits implementation or increases costs
- Increasing lithium-ion manufacturing may put strain on graphite supply.

Compressed Air Energy Storage

Strengths

- Technological maturity (industry standard turbomachinery equipment and subsurface construction).
- Long project life (50 years).
- No performance degradation.
- Power and energy are decoupled and customizable to specific needs.

Weaknesses

- Unproven commercially without utility scale projects completed yet.
- Lower RTE compared to other storage technologies.
- A-CAES systems require specific geologic conditions for cost effectiveness.
- Longer development and construction timelines than most battery technologies.
- Finite amount of energy can be discharged at a given time. In addition, time needs to be set aside between discharge cycles for charging.

Opportunities

- Alberta is known to have both hard-rock and salt-based geologies that may be suitable for A-CAES development.
- If Willow Rock and other projects reach commercial operation this decade, greater cost certainty for future projects will be known.
- Because a significant portion of the project scope and cost is the subsurface construction, A-CAES is less susceptible to price swings from technology supply chain.
- Hydrostor, the primary A-CAES supplier/developer in the market is a Canadian company.

Threats

- Reduced costs and speed to market from other technologies may limit interest in CAES.
- CAES market segment is largely dependent on a single A-CAES supplier/developer.

Non-Lithium Battery Energy Storage

Strengths

- Well suited for longer duration needs compared to lithium-ion systems.
- Reduced risk of thermal runaway or fire compared to lithium-ion.
- Reduced capacity degradation compared to lithium-ion.
- Unit costs ($ CAD/kWh) commonly improve for longer duration applications, which should drive implementation as longer duration use cases emerge.
- Some technologies have better potential for sourcing raw materials and manufacturing in North America.
- Response times are on the order of milliseconds to seconds. This is considered to be significantly faster than non-inverter based storage options like CAES and PHES.

Weaknesses

- Some technologies are not technologically mature. Most technologies are not commercially mature at the scale of lithium-ion. Costs and performance have yet to be proven on a large, utility-scale basis.
- Startup companies have less reliable operating cash flow and less ability to provide guarantees for 20-year (or longer) project life.
- O&M costs at scale for non-lithium battery technologies are generally estimates and/or unproven.
- Most non-lithium battery technologies are less energy dense than lithium and therefore require a larger footprint.
- Most non-lithium battery technologies have a lower RTE than lithium batteries.
- Finite amount of energy can be discharged at a given time. In addition, time needs to be set aside between discharge cycles for charging.

Opportunities

- Recent trend for utilities and developers to look into greater technology diversity in energy storage plans and portfolios.
- Increased penetration of intermittent renewable generation is anticipated to require technologies developed for long duration.
- Because most non-lithium technologies are relatively lower on technology readiness than lithium-ion, there may be more opportunity for significant cost reductions with continued R&D and manufacturing scale.

Threats

- Lithium-ion research and development for both the EV and utility storage markets will further drive down the capital cost for lithium-ion systems, thus reducing the baseline capital costs for alternative technologies to be considered competitive.
- The competitiveness of other non-lithium options outside of the examples evaluated here, including emerging technologies and non-battery storage technologies.
- Non-lithium startups are often reliant on venture capital investors. If market dynamics turn investor attention elsewhere, then development in the storage industry may be hampered.

Pumped Hydroelectric Energy Storage

Strengths

- PHES is a mature technology that has been successfully implemented and operated for decades in North America and globally.
- PHES has a relatively high RTE compared to non-lithium long duration systems and A-CAES systems.
- PHES has a significantly longer operational useful life than battery technologies.
- PHES systems can be highly customizable to the use case requirements.

Weaknesses

- Even though unit costs may be favorable, the first cost is still generally very high because large project sizes are generally required to achieve cost scale.
- PHES is dependent on elevation changes and other geographic considerations, and therefore is not uniformly available.
- PHES can impact environmental conditions of existing waterbodies. Increased permitting and environmental impact studies lead to longer project development timelines.
- Longer construction times than battery technologies.
- Response times are on the order of minutes. This is relatively slow compared to inverter-based storage options.
- Finite amount of energy can be discharged at a given time. In addition, time needs to be set aside between discharge cycles for charging.

Opportunities

- AESO's territory contains existing hydroelectric power generation facilities that may be retrofitted to include PHES capabilities. This has the potential to reduce upfront capital costs associated with greenfield development.
- Increased penetration of intermittent renewable generation is anticipated to require technologies developed for long duration.

Threats

- Increased regulatory and permitting restrictions may limit availability of open loop systems.
- Reduced costs and speed to market from other technologies may limit interest in PHES.

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