2022 Net-Zero Emissions Pathways Report Stakeholder Information Session

June 29, 2022

Notice

In accordance with its mandate to operate in the public interest, the AESO will be audio recording this session and making the session recording available to the general public at www.aeso.ca. The accessibility of these discussions is important to ensure the openness and transparency of this AESO process, and to facilitate the participation of stakeholders. Participation in this session is completely voluntary and subject to the terms of this notice.

The collection of personal information by the AESO for this session will be used for the purpose of capturing stakeholder input for the Net-Zero Emissions Pathways stakeholder sessions. This information is collected in accordance with Section 33(c) of the Freedom of Information and Protection of Privacy Act. If you have any questions or concerns regarding how your information will be handled, please contact the Director, Information and Governance Services at 2500, 330 – 5th Avenue S.W., Calgary, Alberta, T2P 0L4, by telephone at 403-539-2528, or by email at privacy@aeso.ca.

Asking questions

- Before asking your question, please introduce yourself including your organization
- If you are accessing the webinar using your computer or smartphone
  - Click the "Raise Hand" icon and the host will be notified that you have a question
    - When it is your turn to ask a question, the host will unmute your microphone, you in turn will need to unmute your microphone before you can ask your question
    - Your name will appear on the screen, but your camera will remain turned off
  - You can also ask questions by clicking on the "Q&A" icon and typing them in. Please include your organization when typing your question into the Q&A
    - Opportunity available to up-vote questions that have been already asked
- If you are accessing the webinar via conference call
  - Press *9 on your phone's dial pad and the host will be notified that you have a question
    - When it is your turn to ask a question, the host will unmute your microphone, you in turn will need to unmute your microphone by hitting *6 on your phone's dial pad before you can ask your question
    - Your number will appear on the screen

Welcome and introductions

- Kevin Dawson, Director, Forecasting & Analytics
- Adam Gaffney, Senior Forecasting Analyst
- Abbas Badami, Forecasting Analyst
- Chad Ayers, Senior Market Simulation Analyst
- Lars Renborg, Forecasting Analyst
- Leo Tovar, Senior Market Simulation Analyst

Agenda

Time	Agenda Item	Presenter
9:00 - 9:05	Introductions and Session Objectives	Kevin Dawson
9:05 - 9:25	Key Conclusions	
9:25 - 9:45	Open Q&A	All
9:45 - 10:00	Electrification Pathways	Leo Tovar
10:00 - 10:10	Net-Zero Generation and Regulatory Assumptions	Adam Gaffney
10:10 - 10:30	Scenario Details: Generation	Lars Renborg & Chad Ayers
10:30 - 10:55	Open Q&A	All
10:55 - 11:05	Break	
11:05 - 11:10	Emissions Outcomes	Lars Renborg
11:10 - 11:25	Resource Adequacy and Reliability Considerations	Abbas Badami
11:25 - 11:40	Scenario Cost Estimates	Adam Gaffney
11:40 - 11:55	Open Q&A	All
11:55 - 12:00	Recap, Next Steps and Session Close-Out	Kevin Dawson

Session purpose and objectives

- Purpose
  - The purpose of the information session is to present the AESO's final modelling results around the Net-Zero Emissions Pathways report, provide clarification and share next steps
- Session objectives
  - Present the final Net-Zero Emissions Pathways modelling results
  - Provide clarification around current assumptions and framework
  - Highlight insights and signposts provided within the report
  - Provide a forum to address stakeholder questions
  - Share proposed next steps

Registrants (as of June 24, 2022)

- Acestes Power
- AEP
- Alberta Energy
- Alberta Energy Efficiency Alliance (AEEA)
- Alberta Environment and Parks
- Alberta Forest Products Association
- Alberta Heath Services (AHS)
- Alberta Innovates
- Alberta Municipalities
- Alberta Newsprint Company
- Alberta-Pacific Forest Industries Inc.
- Alberta Utilities Commission (AUC)
- AltaLink Management Ltd.
- Amber Infrastructure
- Arcus Power
- ATCO Electric & Energy Infrastructure
- BECL and Associates Ltd.
- Best Consulting Solutions Inc.
- BLG
- Blouz Energy
- BluEarth Renewables
- Boost Energy Ventures
- BP
- Business Renewables Centre Canada (BRCC)
- Calgary Economic Development
- Campus Energy
- Canadian Nuclear Association
- Canadian Renewable Energy Association (CanREA)
- CANDU Owners Group
- Capital Power
- Capstone Infrastructure Corporation
- Chapman Ventures Inc.
- Charles River Associates
- CIBC
- City of Airdrie
- City of Edmonton
- City of Grande Prairie
- City of Medicine Hat
- City of Red Deer
- City of St.Albert
- CNOOC
- Computare
- Customized Energy Solutions
- DePal Consulting Ltd.
- Direct Energy
- EDF Renewables
- Edison Energy
- Emissions Reduction Alberta (ERA)
- Enbridge
- Enel NA
- Energy Storage Canada
- Enfinite
- ENMAX Corporation & Energy
- EPCOR Utilities Inc. & Distribution & Transmission Inc.
- EQUS
- Evolugen by Brookfield Renewable
- FortisAlberta
- Friends of Science
- GHD
- Global Public Affairs
- Government of Alberta
- Greengate Power
- Heartland Generation Ltd
- Hestia Consulting
- Hill+Knowlton Strategies
- IBI Group
- Imperial Oil
- Independent consultant
- Independent Power Producers Society of Alberta (IPPSA)
- Industrial Power Consumers Association of Alberta (IPCAA)
- Iridium Risk Services
- Keyera Corporation
- Kiwetinohk Energy
- KnightFork
- Lionstooth Energy Inc.
- Market Surveillance Administrator (MSA)
- Maxim Power Corporation
- METSCO
- Ministry of Energy – Generation Transmission & Markets
- NB Power
- NorthPoint Energy
- Northstone Power Corporation
- NOVA Chemicals
- NRCAN
- NRG/Direct Energy
- NWPCC
- Ontario Power Generation (OPG)
- Pembina Institute
- Pembina Pipeline Corporation
- Power Advisory
- Powerex
- Prairie Sky Strategy
- PSI Power System Innovation
- RMP Energy Storage
- RVM Developers Inc.
- Signalta Resources Limited
- Solas Energy Consulting
- Spartan Controls
- Strathcona County
- Suncor Energy Inc.
- TC Energy
- TD Securities
- Town of Edson
- Town of Okotoks
- TransAlta Corporation
- Transition Accelerator
- University of Alberta
- URICA Asset Optimization
- Utilities Consumer Advocate (UCA)
- Voltus Energy Canada Ltd
- Wolf Midstream

AESO Stakeholder Engagement Framework

Stakeholder participation

- The participation of everyone here is critical to the engagement process. To ensure everyone has the opportunity to participate, we ask you to:
  - Listen to understand others' perspectives
  - Disagree respectfully
  - Balance airtime fairly
  - Keep an open mind

Key Conclusions

Objectives

- The intent of the AESO's Net-Zero Emissions Pathways Report (AESO Net-Zero Report) is to:
  - Provide policy makers and all stakeholders will timely insights regarding the implications of a transforming electric system
  - Focus on operational, market and cost implications of a net-zero transformation by 2035
  - Address uncertainty of future outcomes through the development of scenarios with tangible signposts for future assessment
  - Allow the AESO and stakeholders to identify and prioritize additional work and focus areas
  - Start the conversation now understanding it will be iterative
  - NOT intended as a policy recommendation

Report scope

Included in June 2022 AESO Net-Zero Report

> Electrification Scenario with Sensitivity Analysis

> Three Potential Supply Mix Futures (Not including 100% renewables)

> Resource Adequacy Assessment

> Electricity Sector Carbon Output (Less oilsands)

> Generation Cost Estimates (High level – capital and operating)

> Transmission Cost (High level)

> High-level assessment of other market and reliability considerations

Not included in June 2022 AESO Net-Zero Report

> Recommendation to Policy Makers (e.g. CES, TIER)

> Market Enhancements

> Detailed Delivered Cost of Electricity

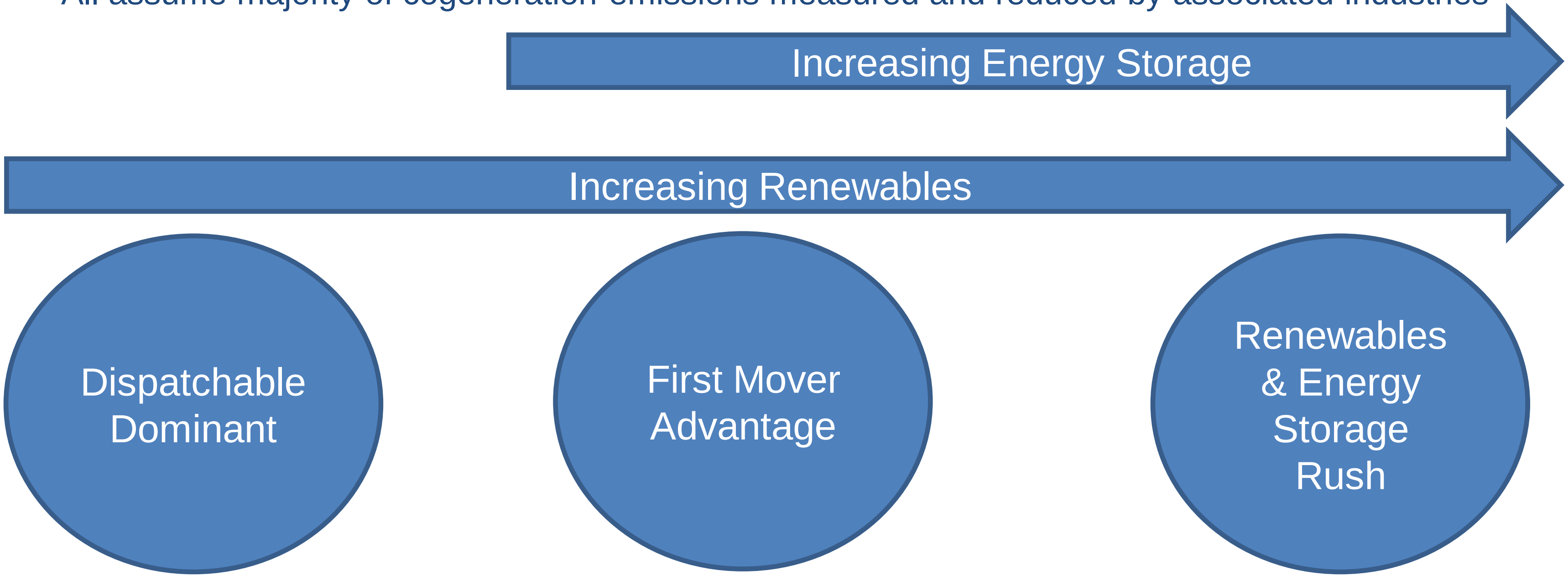
> Flexibility/Reliability Assessments

> Detailed Transmission Costs and Rate Impacts

Determine additional analysis required and expect to begin conducting analysis starting Q3 2022 and continue through 2023 LTO / 2024 LTP

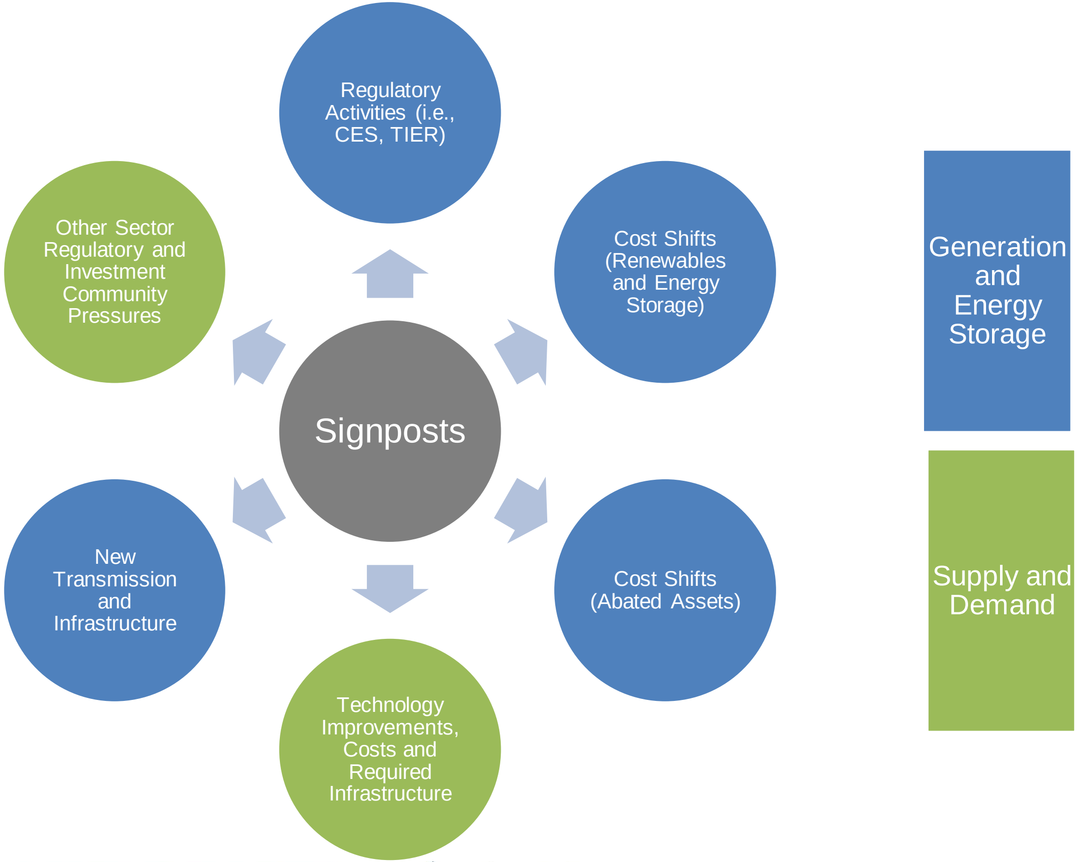
Generation scenarios

- Multiple pathways may achieve a net-zero electricity sector for Alberta
  - Selected three scenarios covering a range of renewables and energy storage penetration
  - All utilize same load forecast
  - All assume majority of cogeneration emissions measured and reduced by associated industries



Select signposts

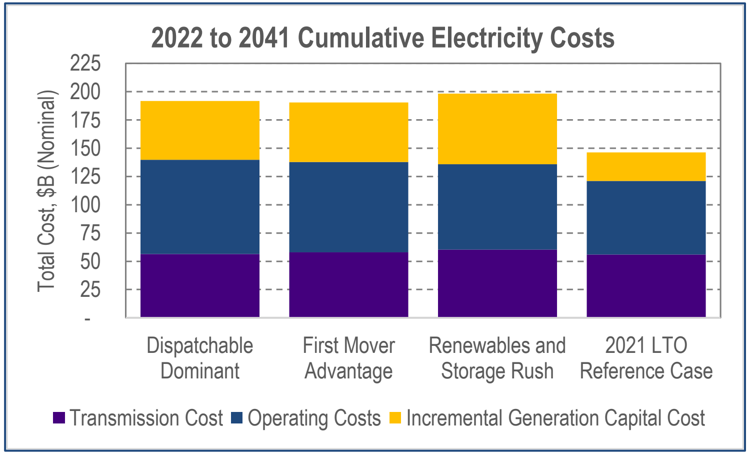
Signposts will be monitored to assess which scenario is emerging over time or whether new scenarios are required

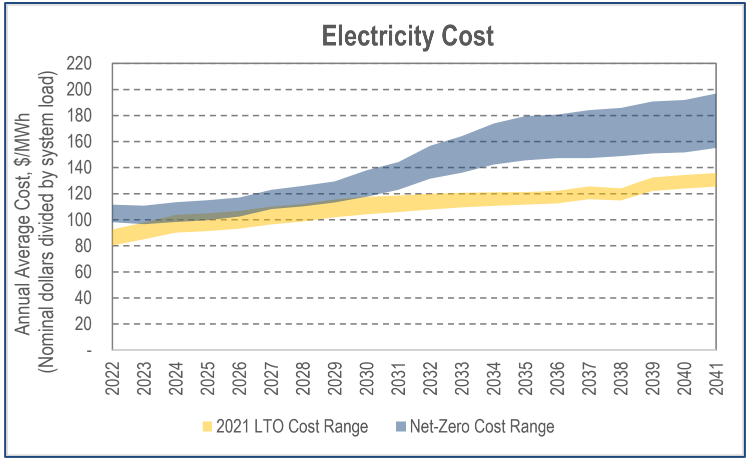


Pathways and timelines risk

- There are multiple potential pathways to achieve net-zero
  - Three of the many potential pathways were studied, all pathways
    - Are highly uncertain
    - Face significant risk to achieving the end goal by 2035
  - Meeting the less than 13-year timeline is ambitious considering
    - Policy/regulation uncertainty
    - Layered regulatory approvals for projects
    - Technology commercialization timing and cost curves
    - Supply chain challenges
    - Long development timelines for all types of energy-related infrastructure

Cost





- Relative to a non-net-zero future, transitioning to a net-zero electric system with increased electrification will require an additional $44 to $52 billion in generation capital (including returns), generation operating costs and transmission revenue requirements from 2022-2041 representing a 30-36% increase relative to baseline (2021 LTO Reference Case)
  - Generation capital: 59-71% of increased costs
  - Generation operating costs: 20-41% of increased costs
  - Transmission: 1-10% of increased costs
  - Normalized across system load, costs may be $50/MWh, or 40% higher, by 2035
  - The costs estimated by the AESO represent a subset of electric system costs
    - Consumers may face higher costs in some areas offset by lower costs in others
    - Not an economy-wide assessment
    - Additional work and industry discussion will be required to better understand potential distribution system and integration costs

Resource adequacy and reliability

- Alberta's market structure is capable of delivering sufficient supply to meet demand ("resource adequacy") during the net-zero transformation with the following considerations:
  - Risk is dependent on the timing of generation entry and exit
  - Risk is unacceptable if legacy unabated gas units exit the market and are not replaced by supply with similar operating characteristics
  - Increased demand response and flexibility can significantly decrease risk
  - Sufficient energy storage is critical to resource adequacy in a high renewables case
  - Other aspects of reliability such as ramping capability, inertia, frequency response and system fault response are likely to be negatively impacted by a net-zero transformation but further study to fully assess impacts and mitigation is required

2035 Forecast Resource Adequacy by Scenario	
2035 Long-Term Adequacy Threshold	1,113 MWh EUE
Dispatchable Dominant Scenario	560 MWh EUE
First-Mover Advantage Scenario	180 MWh EUE
Renewable and Storage Rush Scenario	140 MWh EUE

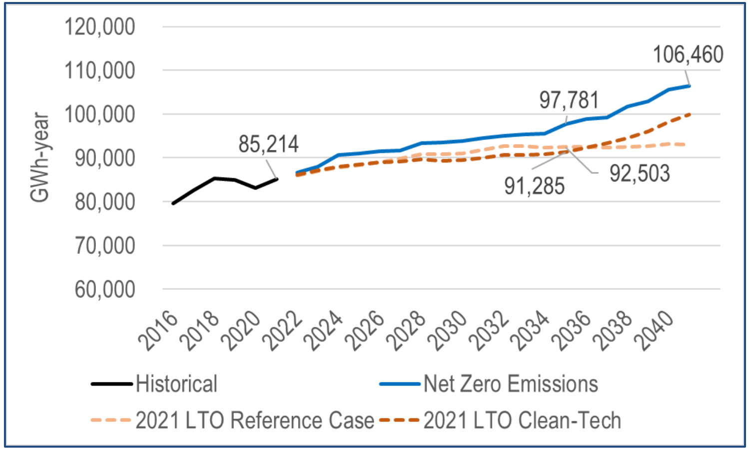
Electricity sector emissions

- The application of offsets will be required to achieve a net-zero electricity system by 2035
  - All net-zero pathways scenarios modelled result in residual physical emissions
  - Abating all emissions to zero would come with rapidly increasing costs and is operationally unrealistic
  - Most cogeneration emissions are associated with industries outside the electric sector
    - Omitted from the analysis
    - Widespread application of carbon capture and storage to these cogeneration assets would increase Alberta load by 5%

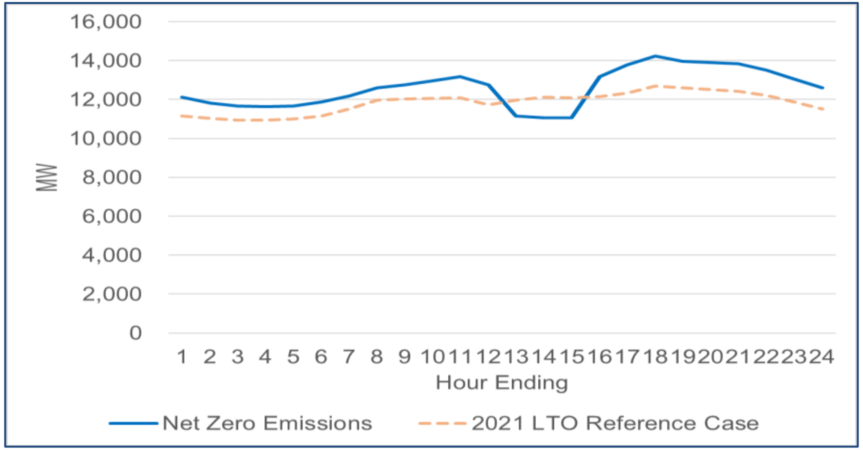
2035 Forecast Physical Greenhouse-Gas Emissions by Scenario	
2021 LTO Reference Case	17.7 Mt
Dispatchable Dominant Scenario	4.8 Mt
First-Mover Advantage Scenario	4.3 Mt
Renewables and Storage Rush Scenario	3.8 Mt

Demand

Alberta Internal Load Forecast Comparison



Winter 2035 Peak AIL Day Hourly Shape



- Demand growth under a net-zero transition, even considering increased electrification, is expected to be lower than historically observed rates which the Alberta market has accommodated
  - New components of load from transportation, heating and new industrial production are partially offset by increased rooftop solar
  - Demand will become considerably more variable over time
  - Demand growth rates accelerate post 2035 as electrification takes hold
  - Demand growth remains most sensitive to oilsands production, but EV adoption rates are expected to become a comparable source of uncertainty during the net-zero transformation

Stakeholder engagement and feedback

- The AESO launched stakeholder engagement regarding its Net-Zero Emissions Pathways analysis in late 2021 and has followed that up in 2022 with:
  - Two opportunities to provide written commentary and feedback. The initial round focused on scope and input assumptions and the second round the preliminary results.
  - Two virtual stakeholder sessions which concentrated on preliminary and reported results
- Feedback was reviewed, integrated across several themes:
  - Scope and input assumptions: Scope of Analysis and Government Policy, Macroeconomic Drivers and Electricity Load, Generation and Technological Forecast Drivers
  - Preliminary results: Enabling Technologies, Cogeneration Emissions, Policy Developments, Informational Insights
- Stakeholder knowledge of future trends, development costs, technological expertise, and perspectives on decarbonization pathways have helped to shape the report
- The AESO values stakeholder feedback and thanks participants for taking the time to share their insights and perspectives with us. It was well regarded and improved the analysis and the AESO fully intends to continue a similar level of engagement going forward.

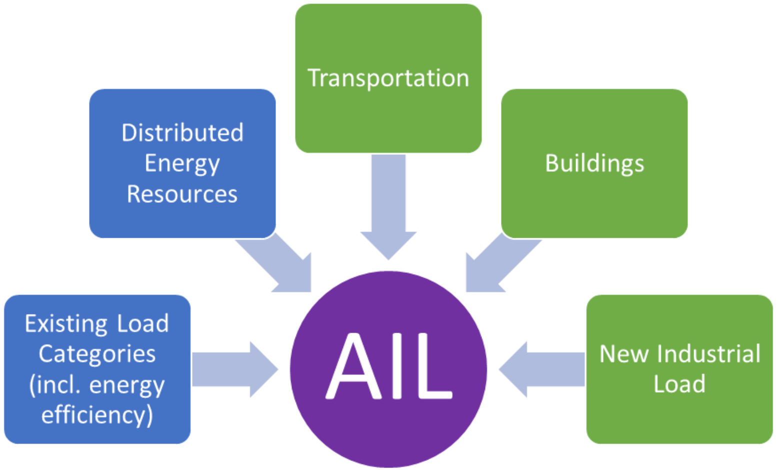
Open Q&A

Electrification Pathways

Load forecast: modeling and drivers

The AESO produced a single 20-year load forecast in addition to multiple sensitivities focusing on 2035

Alberta Internal Load Forecast Components



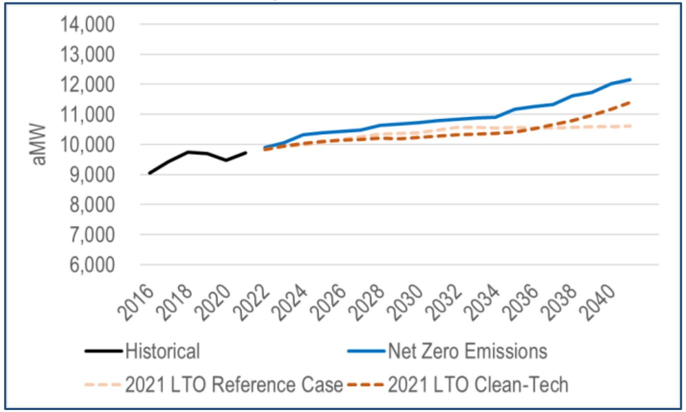
- Load drivers are forecast separately
  - Existing load categories assumes economic rebound post-pandemic, no more greenfield projects in the oil sands sector, energy efficiency based on historical trends (no policy drivers)
  - DER growth, dominated by significant rooftop solar adoption, will not offset load growth in other areas
  - Transportation electrification is based on the federal 2030 Emissions Reduction Plan targets
  - Building heating assumes mass fuel-switching from natural gas to heat pumps to start in the 2030s
  - New industrial load expected to primarily come via natural gas-based (blue) hydrogen production

Electrification pathways accelerate load growth

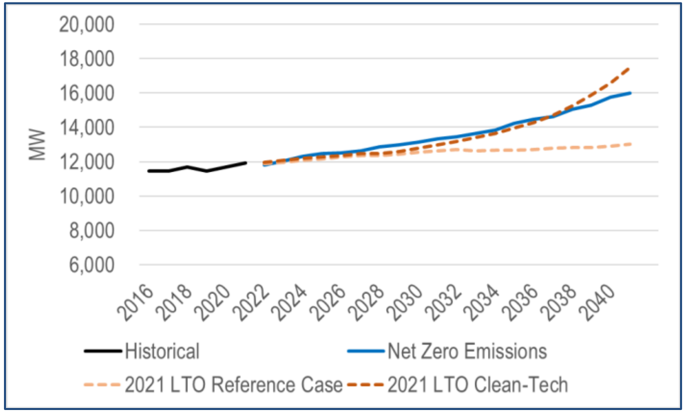
Decarbonization of other sectors and net-zero policies boost load growth, yet rates remain below the 2000s-2010s

- Total electricity consumption (AIL) and peak load is forecast to increase by 15% and 19% respectively by 2035, compared to 2021
- Annual growth is considerably higher than the 2021 LTO scenarios yet still below historical rates observed in Alberta

Average AIL Forecast



Peak AIL Forecast



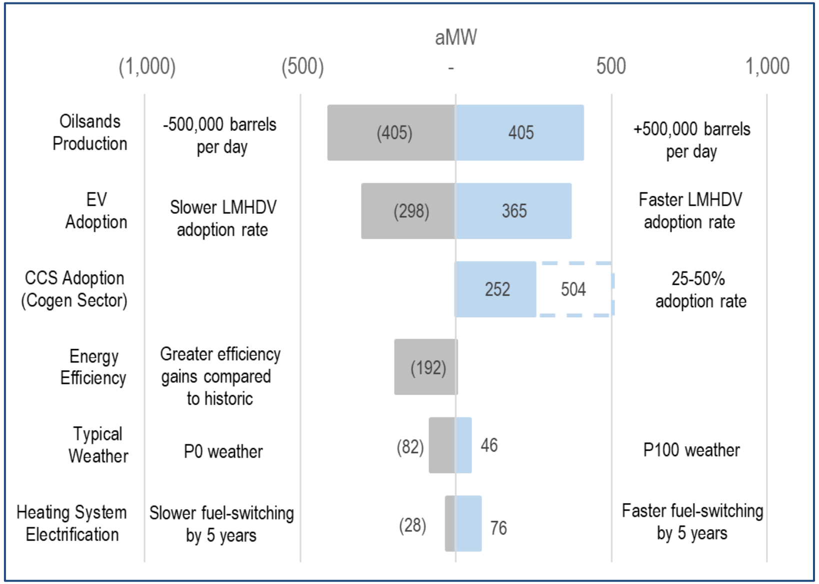
Note: aMW means average MW

Sensitivity impact of load drivers and signposts

2035 load sensitivities help assess the individual impact of the multiple factors that would lead to a net-zero future and identify signposts to monitor

- Signposts highlighted during the sensitivity analysis
  - Growth prospects of the energy sector in Alberta
  - Policies, subsidies, and/or technological advancements incenting EV adoption
  - Decarbonization of industrial sectors with behind-the-fence (BTF) generation
  - Technological and/or policy push towards more energy efficiency
  - Changes in typical weather conditions
  - Policy changes (e.g., building code) and subsidies to promote fuel-switching of heating systems

Impact Sensitivity by Load Driver: Change in Average Load in 2035 (base of 11,162 aMW)

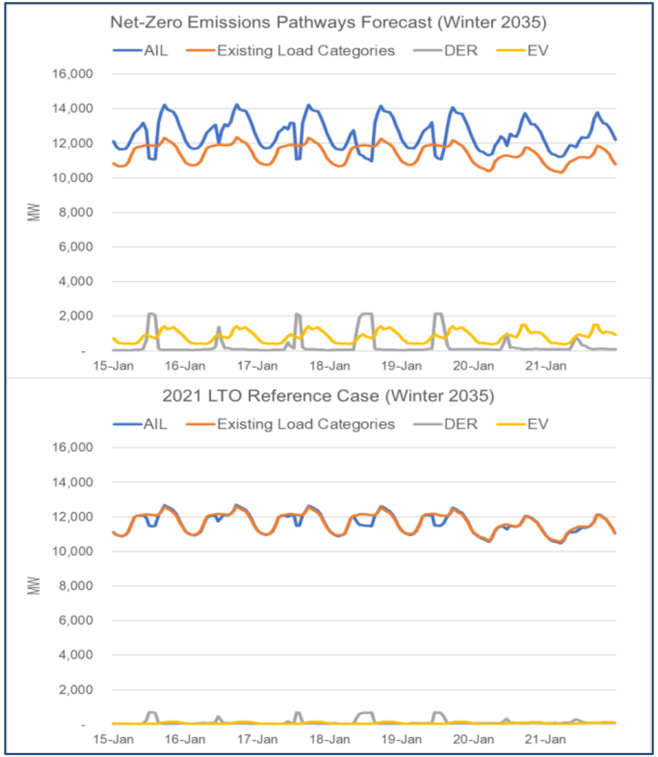


Net-zero impact to peaking conditions

A net-zero future is expected to introduce seasonally distinct changes to the load shape historically observed in Alberta

- Combination of solar DER and EV adoption will lead to greater AIL variability and greater frequency of non-typical daily shapes
  - Cloud coverage, precipitation conditions, EV charging behaviour will influence daily dispatch conditions
- These conditions are markedly different than what's expected in the 2021 LTO Reference Case

EV and DER Impact to AIL Shape during Winter Peaking Week Conditions

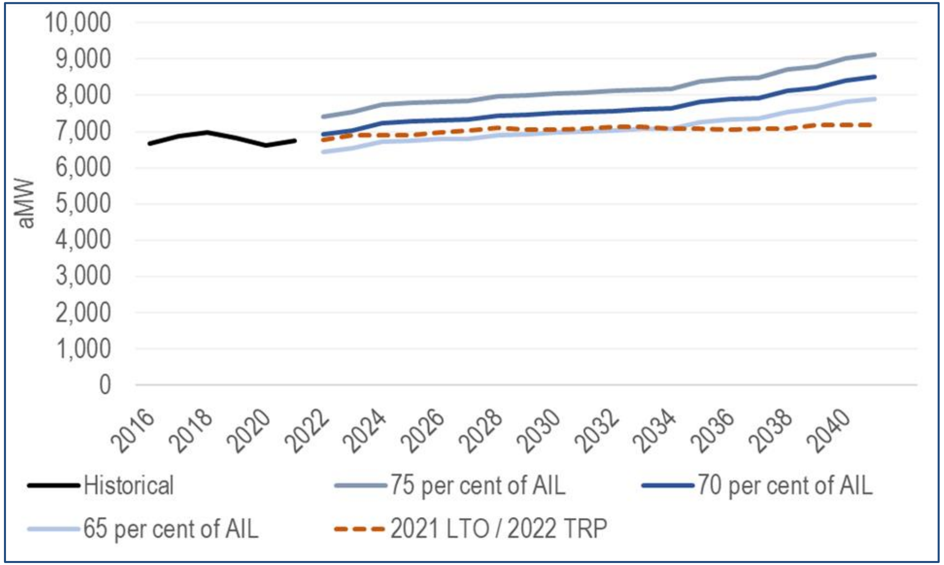


Uncertainty related to DTS load

Increased sectoral electrification, higher industrial load and greater DERs may impact demand transmission service (DTS) load growth in many ways

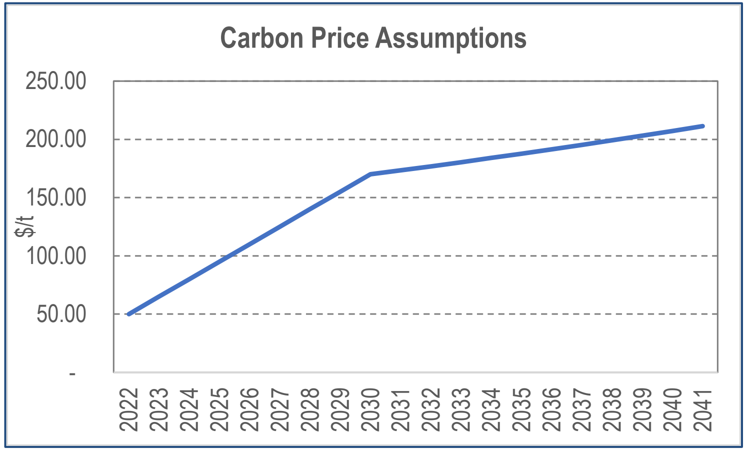
- Since 2010, AIL and DTS load have increased at a different pace due to an increase in BTF generation or self-supply growth
  - DTS to AIL ratio went from 75% in 2010 to ~70% in 2021
- Uncertainty related future DTS growth path in a net-zero future led the AESO to estimate future DTS around a range of 65-75% of AIL

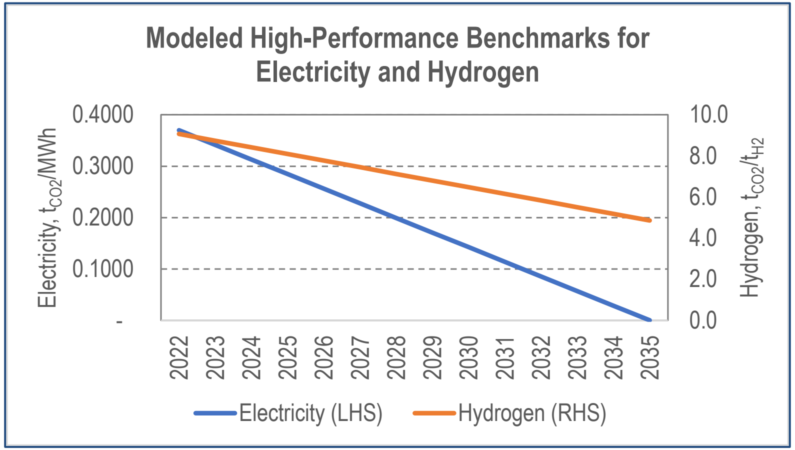
DTS Estimates based on Simplified Ratio-based Approach



Net-Zero Generation and Regulatory Assumptions

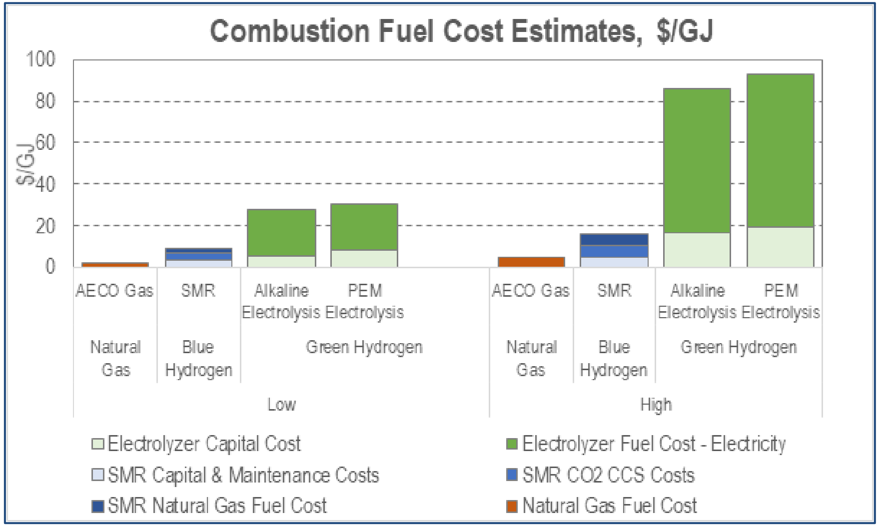
Key regulatory assumptions





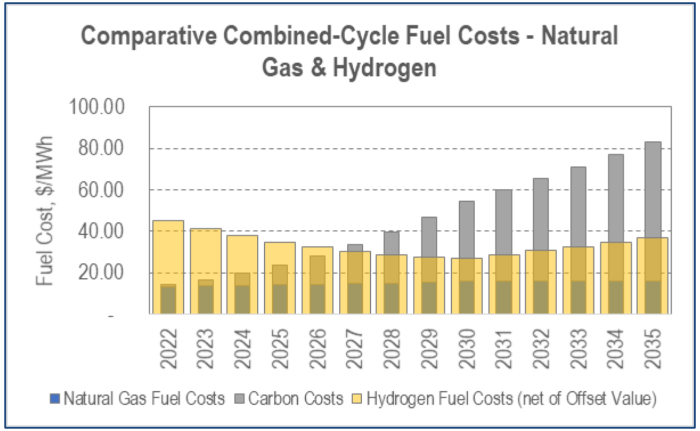
- Carbon prices are forecast to rise to $170/tonne by 2030, and then escalate at an inflationary rate
- The forecast assumes the continuation of Alberta's *TIER Regulation,* with a modification of the "high-performance benchmark" for the electricity sector, declining to zero by 2035
  - The impact in the electricity sector is that there will be no allowance for emissions by 2035 (currently benchmarked against "best-in-class" combined cycle technology)
  - Carbon emissions will be fully exposed to the carbon price by 2035
  - Emissions Performance Credits generated by the electricity sector will decline in value until 2035 (based on the "high-performance benchmark" for electricity), at which point they will no longer generate value

Comparative costs of natural gas, blue hydrogen and green hydrogen



- The AESO reviewed the cost of “blue” hydrogen as a function of natural gas as feedstock, plus steam methane reformer (SMR) capital/operating costs, and sequestration costs
- The AESO also estimated the cost of “green” hydrogen, produced from electrolysis of water using renewable electricity as a feedstock and added the expected levelized capital cost of the electrolyzer to the feedstock cost
- At present, green hydrogen production techniques appear to be significantly higher cost than blue hydrogen
  - The AESO’s net-zero analysis focused on blue hydrogen fuel as a feedstock for low-carbon generation given the 2035 timelines

Impact of regulatory assumptions on combined-cycle generation fuel costs (natural gas and hydrogen-fired)



- Carbon pricing is expected to increase the variable cost of natural-gas fired generators
  - A combined cycle plant with a 7.0 GJ/MWh heat-rate is modestly exposed to carbon price in 2022, given the TIER “high-performance benchmark” of 0.37 t/MWh
  - As the “high-performance benchmark” declines toward zero in 2035, the exposure to carbon price increases
  - Simultaneously to the increased stringency of the “high-performance benchmark”, the carbon price increases from $50/tonne in 2022 to $170/tonne in 2030
  - The impact is significantly higher carbon costs for natural gas fired generation throughout the forecast period
- Blue hydrogen fuel costs are comprised of natural gas feedstock costs (including lost energy), plus the capital and operating costs of the SMR or ATR, less the value of offsets derived from sequestration of carbon
  - Offset value increases over the production period since the carbon price is increasing more quickly than the “high-performance benchmark” for hydrogen is decreasing
  - The cost of residual emissions from blue hydrogen also increases, resulting in an increase in net-fuel costs for hydrogen produced from “blue” sources after 2030
- Given the assumptions regarding “high-performance benchmarks”, blue hydrogen becomes a more economic fuel than natural gas by 2027

Scenario Details: Generation

Scenario comparison

- The AESO has selected three scenarios from a much larger set of potential net-zero pathways
  - The three scenarios utilize the same load forecast and include various levels of wind, solar, energy storage, and abated thermal assets to achieve net-zero emissions by 2035

Dispatchable Dominant	First-Mover Advantage	Renewable & Storage Rush
▪ Focuses on dispatchable low-emissions technologies with carbon-capture as major contributors to capacity development – Hydrogen-fired generation and post-combustion carbon capture techniques are expected to dominate supply additions	▪ Rapidly decreasing cost for wind and solar energy lead to increased penetration in Alberta's generation landscape – These technologies, readily available today, accelerate through the 2020s – Favored by corporate sustainability objectives, renewables continue to develop ▪ Hydrogen simple-cycle generation fills some of the voids left by intermittent renewables	▪ Significant development of wind and solar generation continues through the forecast horizon and dominates generation capacity additions ▪ Diverse energy storage technologies provide the dispatchability requirements of the grid, as a result of significant cost declines ▪ Thermal generation is limited to hydrogen peaking units

Alternative net-zero pathways

- The AESO’s initial Net-Zero Pathways quantitative analysis does not include alternative approaches that could achieve decarbonization policy objectives
  - Hydroelectric capacity additions could contribute significantly to decarbonization efforts
  - Nuclear generation could also reduce reliance on fossil-fuel generation sources
  - Interties with low-carbon jurisdictions may also enable decarbonization
- Many alternative net-zero technologies may require significant development timelines and regulatory processes likely to extend beyond 2035
- High capital costs and/or interactions between regulated and competitive market structures make it more challenging to incorporate material amounts of large hydroelectric generation, nuclear generation, or transmission interconnections with other jurisdictions into Alberta’s market construct

Total generation capacity and load comparison

Description	Dispatchable Dominant 2035	First-Mover Advantage 2035	Renewables and Storage Rush 2035	2021 LTO Clean-Tech 2035	2021 LTO Ref Case 2035
Equal and Greater than 5 MW Generation (MW Installed Capacity)					
Wind	3,922	6,922	9,422	4,997	4,747
Solar	1,872	2,572	3,724	2,539	1,189
Storage - Battery	330	330	3,060	1,020	85
Storage - Compressed Air	-	-	496	-	-
Storage - Pumped Hydro	-	-	600	75	-
Hydrogen Simple Cycle	2,049	1,599	1,494	-	-
Combined-Cycle with CCUS	2,262	1,508	-	-	-
Natural Gas Combined-Cycle	1,768	1,548	1,548	4,822	2,648
Natural Gas Simple-Cycle	751	1,278	1,205	1,544	1,397
Coal-to-Gas - Steam Boiler	929	929	-	935	2,535
Cogeneration	6,712	6,712	6,712	6,669	6,669
Hydroelectric	894	894	894	894	894
Other	443	443	443	483	423
Total	**21,932**	**24,735**	**29,598**	**23,978**	**20,587**
Less than 5 MW Generation (MW Installed Capacity)					
Solar	2,074	2,074	2,074	1,780	638
Wind	45	45	45	52	44
Gas	158	158	158	174	138
Load Forecast (After Factoring Energy of Less than 5 MW Generation)					
Peak AIL (MW)	**14,245**	**14,245**	**14,245**	**13,660**	**12,949**
Average AIL (aMW)	**11,162**	**11,162**	**11,162**	**10,421**	**10,560**

Percentage of generation and load provided from renewable sources

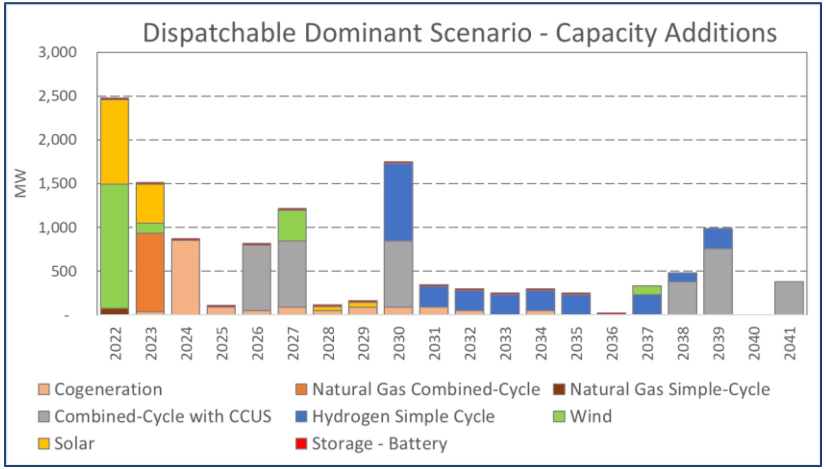
	Percentage of Total Domestic Generation provided by Renewables				Percentage of System Load Forecast (estimated as 70% of AIL Forecast) provided by Renewables			
Scenario	**2022**	**2030**	**2035**	**2041**	**2022**	**2030**	**2035**	**2041**
Dispatchable Dominant	18%	23%	24%	22%	25%	33%	34%	31%
First-Mover Advantage	18%	32%	35%	32%	25%	44%	50%	46%
Renewable and Storage Rush	18%	35%	46%	47%	25%	49%	66%	68%

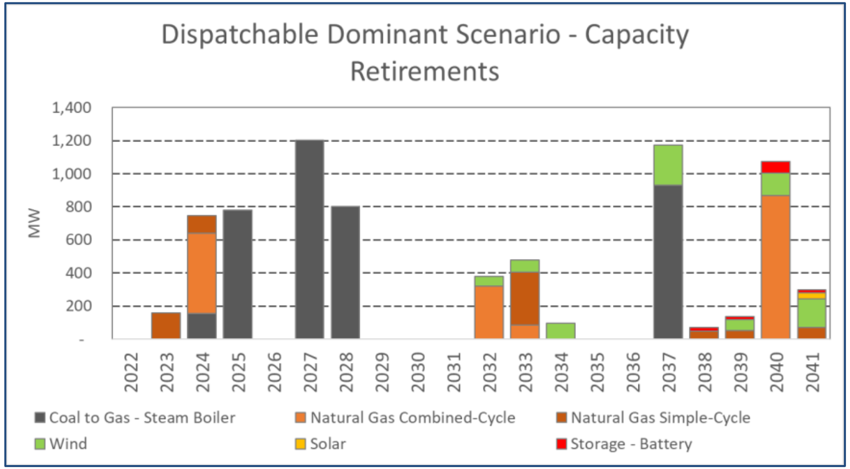
- In each scenario renewable generation is forecast to increase as a percentage of total generation until 2035
  - Renewable percentages vary significantly by scenario with the Renewable and Storage Rush scenario resulting in the highest proportion of renewable generation and the Dispatchable Dominant scenario resulting in the lowest

Dispatchable dominant scenario – Assumptions and signposts

- Combined-cycle with CCS dominant through 2035 with hydrogen peaking units following post 2030
- Scenario presumes cost declines, enabled by government support for carbon capture technologies
  - Full CCS capability for combined-cycle assets by 2026 (including storage hubs and transport)
  - Hydrogen pipeline infrastructure available post-2030

Dispatchable dominant scenario – Generation additions and retirements



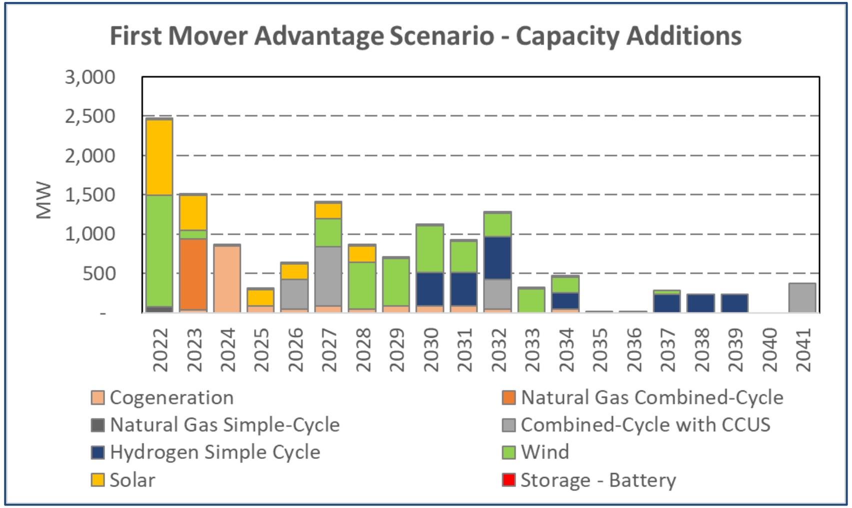


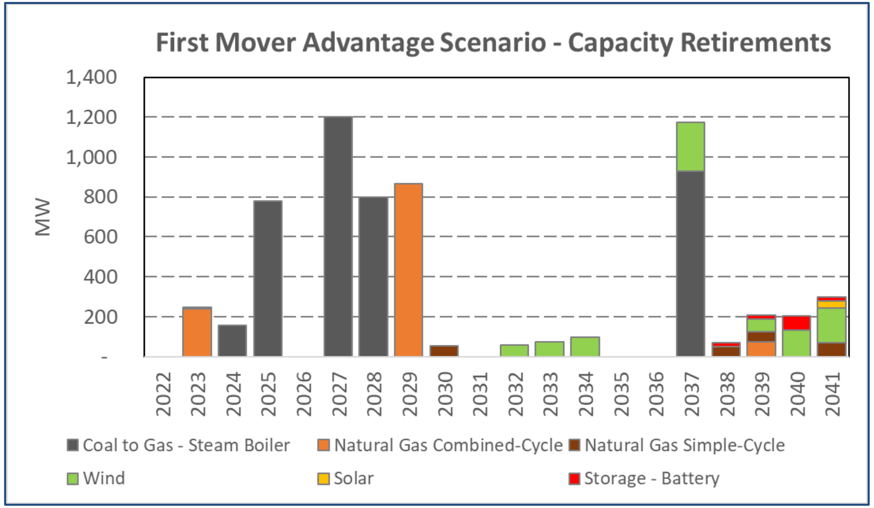
- A diverse suite of new technologies is added to Alberta's generation fleet, including:
  - 3,770 MW of combined cycle with CCS
  - 2,622 MW of hydrogen-fired simple cycle generation
  - 1,515 MW of cogeneration
  - Limited amounts of wind (1,982 MW) and solar (1,509 MW) generation
- Significant volumes of coal-to-gas and other gas assets are forecast to retire throughout the forecast period, as carbon prices impact their economics

First-mover advantage scenario – Assumptions and signposts

- Renewable Corporate PPAs continue to add supply to Alberta's grid
- Renewable cost declines are anticipated to continue, supporting wind and solar economics
- Wind and solar additions continue in the 2020s and slow after 2035 due to the decreasing EPCs and offset value
- Combined-cycle generation with CCS and required infrastructure is developed on a timely basis
- Hydrogen infrastructure in place for the start of the next decade

First-mover advantage scenario – Generation additions and retirements



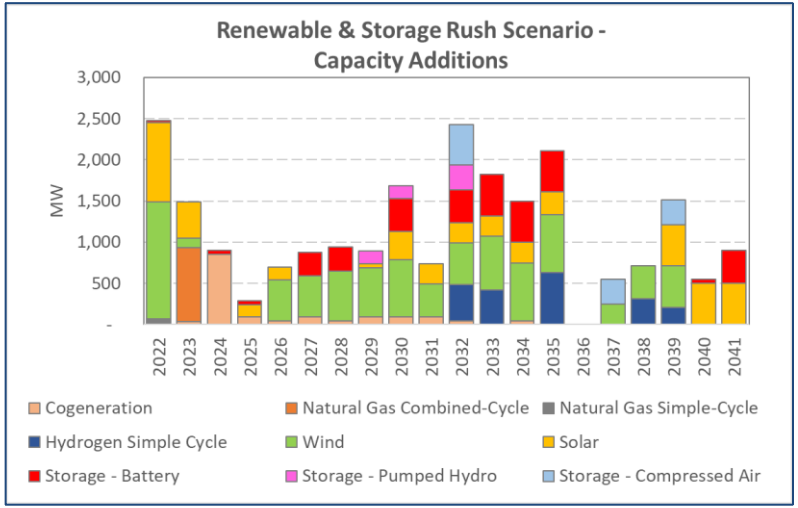


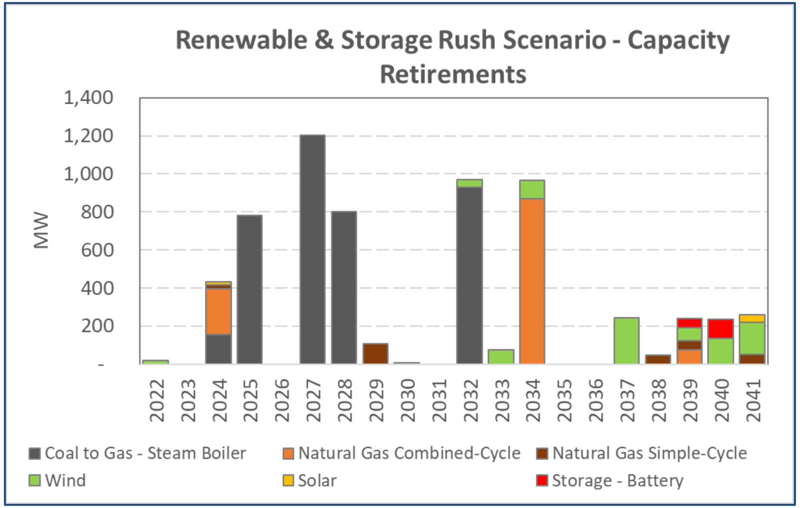
- Renewable growth is prominent in this scenario, with significant amounts of combined cycle with CCS and hydrogen-fired generation:
  - 1,885 MW of combined cycle with CCS
  - 2,297 MW of hydrogen-fired simple cycle generation
  - 1,515 MW of cogeneration
  - 4,932 MW of new wind and 2,209 MW of new solar generation
  - 300 MW of battery energy storage

Renewables and storage rush scenario – Assumptions and signposts

- Scenario assumes energy storage development resulting from significant cost reductions, technology advances, or government support
  - 4-hour, 19-hour, and 60-hour energy storage technologies were assumed
- Limit capacity additions from new dispatchable resources
  - Combined-Cycle with CCS and infrastructure does not advance
  - Limited hydrogen infrastructure in place before 2030

Renewables and storage rush scenario – Capacity additions and retirements





- Storage and renewable growth is very robust to 2041:
  - 1,515 MW of cogeneration
  - 8,532 MW of new wind and 4,876 MW of new solar generation
  - 5,157 MW of storage including 3,461 of battery energy storage, 1,096 MW of compressed air energy storage, and 600 MW of pumped hydro storage
  - Limited amounts of thermal capacity, 2,019 MW of hydrogen-fired simple cycle generation

Open Q&A

Break

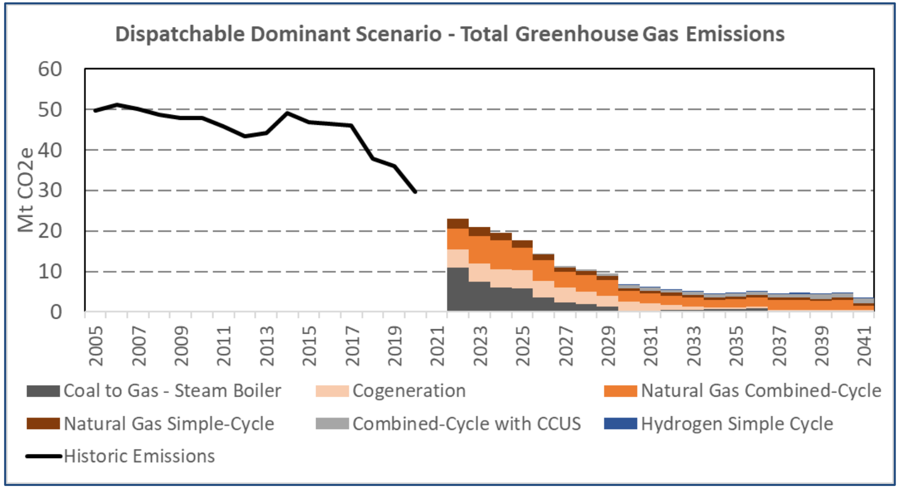
Emissions Outcomes

Scenario emissions outcomes

2035: Forecast Physical Greenhouse-Gas Emissions by Scenario	
2021 LTO Reference Case	17.7 Mt
Dispatchable Dominant Scenario	4.8 Mt
First-Mover Advantage Scenario	4.3 Mt
Renewable and Storage Rush Scenario	3.8 Mt

- Of the net-zero pathways scenarios modelled, each indicates an approximately equal level of residual physical emissions
- To achieve net-zero emissions by 2035, the application of offsets and credits is likely required, as physical abatement down to zero emissions is unlikely given both cost and operational considerations

Dispatchable dominant scenario – Emissions



- Low emissions hydrogen-fired and CC with CCS technologies produce a growing portion of net generation by 2035
- Other scenarios produce similar levels of physical emissions reductions, with most remaining emissions resulting from existing natural gas-fired generation sources
- Emissions are estimated to be approximately 4.8 Mt from the electricity industry
  - This level of emissions would need to be mitigated using offsets and emissions performance credits
  - May also see retrofitting/replacing brownfield thermal assets

Resource Adequacy Outcomes and Reliability Considerations

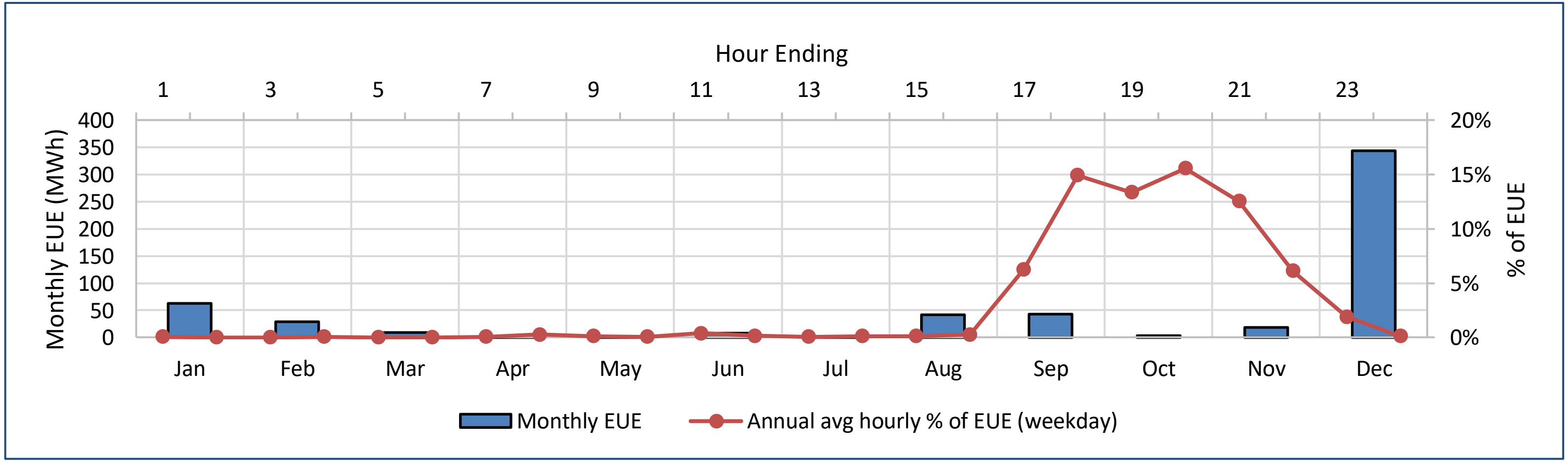
Resource Adequacy Modeling (RAM)

- The AESO evaluated resource adequacy utilizing its electric system risk model and the associated risk of unserved energy
  - Evaluated all three scenarios for resource adequacy for 2030 and 2035 using RAM with specifications aligned with the net-zero load and generation scenarios
  - Evaluated additional scenarios to test standard results and risks
- The tool allows for fast simulation of thousands of iterations of unit performance to identify frequency and magnitude of firm load shed events and determine if the Long-Term Adequacy Threshold is met
- The RAM determines the tradeoff between capacity (MW) and resource adequacy (EUE MWh) using a probabilistic approach that varies load and generation
  - Hourly chronological dispatch using a stochastic (Monte Carlo) simulation
  - Distribution for load/weather, load growth uncertainty, outages, intermittent renewable output, intertie, and emergency operating procedures
- Resource adequacy is only one aspect of reliability which includes other components such as ramping capability, inertia, frequency stability and short circuit levels

Resource adequacy results – Dispatchable dominant

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
Dispatchable Dominant	310	560	• Dispatch Dominant shows no issues in 2030 and 2035 • The results show higher EUE in 2035 due to increasing load and additional resource not keeping pace
DD + DR	100	225	• Demand Response resources (~300 MW) reduces EUE
DD + DM		120	• Demand management (shifting demand from peak to off peak hours) reduces EUE
DD - UNG		5,200	• Legacy unabated gas provides key resource adequacy support and the absence (i.e., early retirement) of ~900 MW is a key risk to resource adequacy

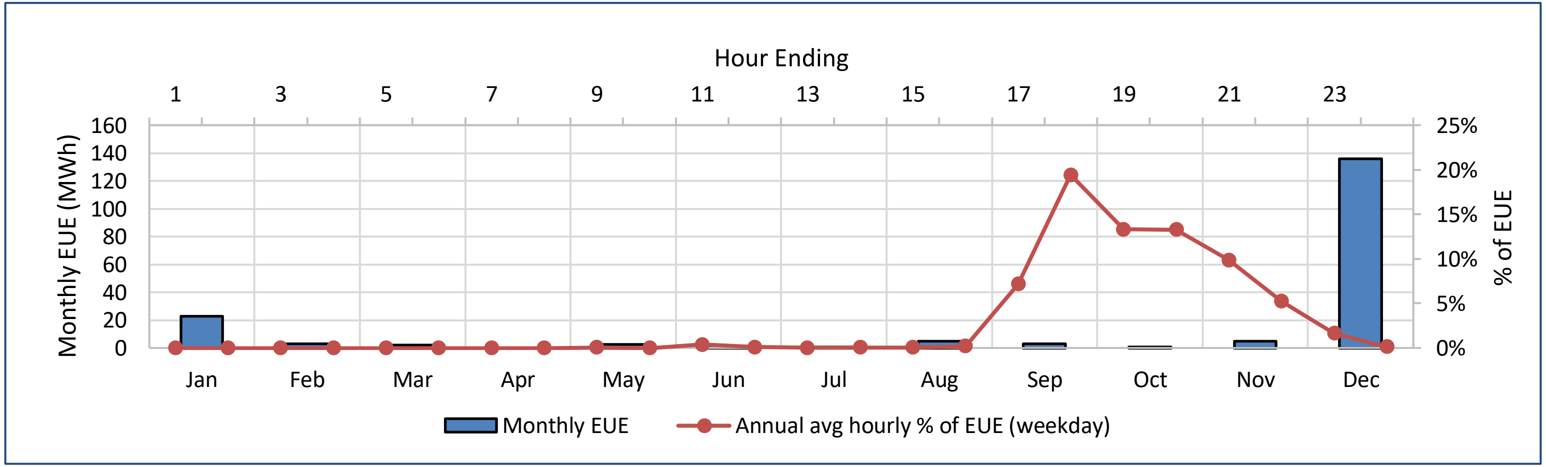
Note: The threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** represents RAM results that are well under the threshold, **orange** represents results within +/- 50% threshold, and **red** represents results exceeding the threshold by more than 50%.



Resource adequacy results – First-mover advantage

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
First-Mover	3,100	180	• First-Mover shows increased EUE risk in 2030, generally due to the timing of resource retirement and new capacity coming online • The results show lower EUE that meets the threshold in 2035 due to sufficient additional resource coming online after 2030
FM + DR	990	70	• Demand Response resources (~300 MW) reduces EUE
FM + DM		30	• Demand management (shifting demand from peak to off peak hours) reduces EUE
FM - UNG		3,600	• Legacy unabated gas provides key resource adequacy support and the absence (i.e., early retirement) of ~900 MW is a key risk to resource adequacy

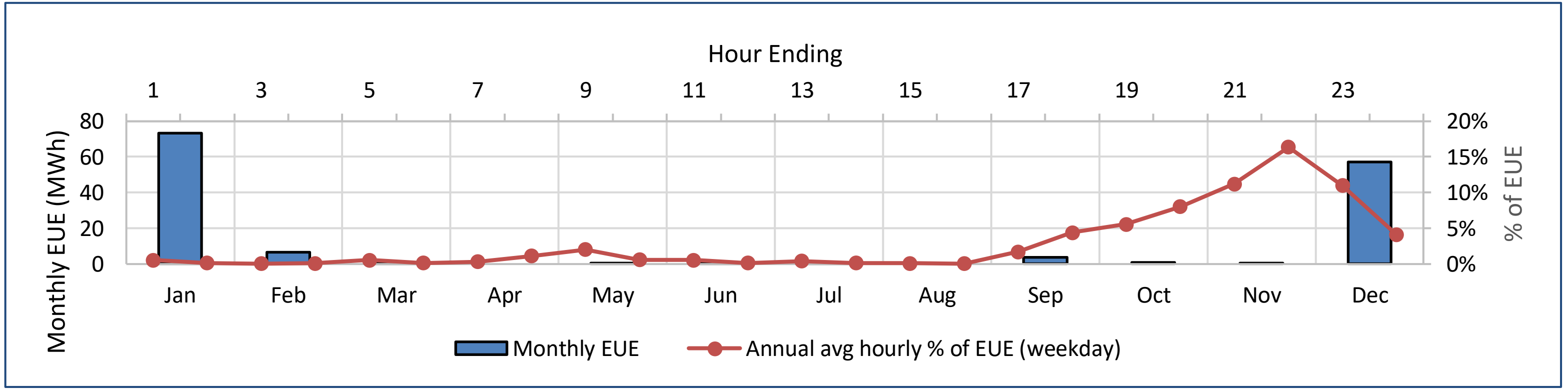
Note: The threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** represents RAM results that are well under the threshold, **orange** represents results within +/- 50% of threshold, and **red** represents results exceeding the threshold by more than 50%.



Resource adequacy results – Renewables and storage rush

EUE - MWh (Threshold)	2030 (1,069)	2035 (1,113)	Summary
Renewables and Storage Rush	2,400	140	• Renewable and Storage Rush shows increased EUE risk in 2030, generally due to the timing of resource retirement and new capacity coming online • The results show lower EUE that meets the threshold in 2035 due to sufficient additional resource coming online after 2030
RSR + DR	176	60	• Demand Response resources (~300 MW) reduces EUE
RSR + DM		60	• Demand management (shifting demand from peak to off peak hours) reduces EUE
RSR - Storage		3,250	• Storage (~2,100 MW) provides value, and its absence increases EUE risk
RSR - UNG		25,600	• Legacy unabated gas provides key resource adequacy support and the absence (i.e., early retirement) of ~900 MW is a key risk to resource adequacy

Note: The threshold is based on the AESO supply adequacy expected unserved energy metric threshold (as per ISO Rule 202.6). The **green** represents RAM results that are well under the threshold, **orange** represents results within +/- 50% of threshold, and **red** represents results exceeding the threshold by more than 50%.



Option value of existing unabated gas assets

- Each scenario has assumed retirement dates for unabated thermal assets
- Timing of abated gas, renewables and energy storage assets in the three scenarios is not certain given complexities pertaining to technology and infrastructure
- Each scenario could result in periods of energy supply constraints challenging resource adequacy for load
- Existing unabated gas assets have capability to support resource adequacy needs that may occur pre- or post-2035 as the system moves to net-zero
- Mandated uneconomic retirements negates the optionality to minimize potential resource adequacy challenges

Net-zero reliability considerations

- Resource adequacy overview
  - Alberta's market structure is capable of delivering sufficient supply for a net-zero 2035 system
  - Risks observed in 2030 can be attributed to and mitigated by entry and exit of legacy capacity with lower emission capacity
  - A key resource adequacy support is legacy unabated gas and its absence is a significant risk
  - Increased demand response and flexibility can significantly decrease risk
  - The risks of unserved energy for all scenarios are generally highest during winter peak conditions
  - It is anticipated that further electrification and decarbonization beyond 2035 will continue to require close monitoring of resource adequacy
- Additional potential reliability challenges
  - Resource adequacy is just one aspect of reliability. Additional work will be required to assess other reliability risks such as ensuring sufficient ramping capability, system inertia, frequency response, and short circuit levels across the network.
  - The increased concentration of inverter-based generation could present operational complexities for reliable system operations. The degree to which these operational challenges must be mitigated depends on the specific net-zero supply mix.
- The AESO will continue to monitor and evaluate the reliability impacts on the electric system and respond proactively to ensure the stable and reliable operation of the AIES

Scenario Cost Estimates

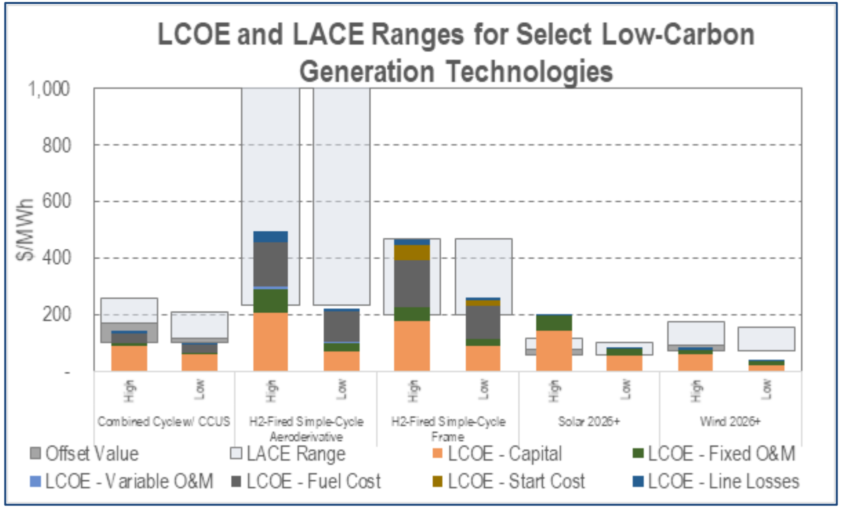
Estimated cost components

- Included: Generation capital (including return) and operating costs, transmission revenue requirements
- Excluded: Distribution system costs, integration costs (ancillary service requirements)
- Capital and operating costs associated with the generation technologies in each scenario estimated as:
  – Incremental capital costs for new generators estimated as the annual periodic payment required to produce a 10% return
  – Operating costs for the fleet were calculated based on scenario simulation results
- Transmissions needs for each scenario were estimated
  – Capital costs for required projects were added to the AESO's Transmission Rate Projection model to assess the revenue requirements associated with the new transmission projects

Incremental to 2021 LTO Reference Case (2022-2041 nominal)	Dispatchable Dominant	First-Mover Advantage	Renewable and Storage Rush	Investment Decision Process
Incremental Generation Capital Costs (with return), $ billion*	$26.7	$27.3	$37.2	At risk capital / market
Incremental Generation Operating Costs, $ billion*	$18.5	$15.0	$10.6	At risk capital / market
Incremental Transmission Revenue Requirement, $ billion*	$0.3	$1.8	$4.3	AESO need - AUC approval / cost of service regulation

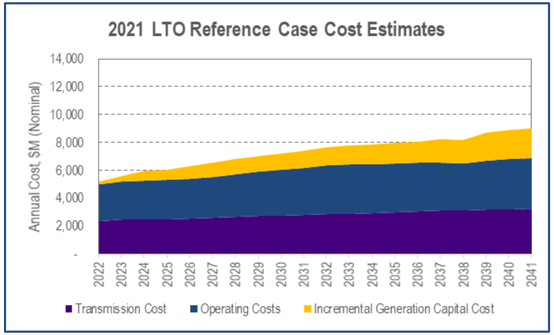
* Represented as incremental capital cost, without return, compared to the 2021 LTO Reference Case

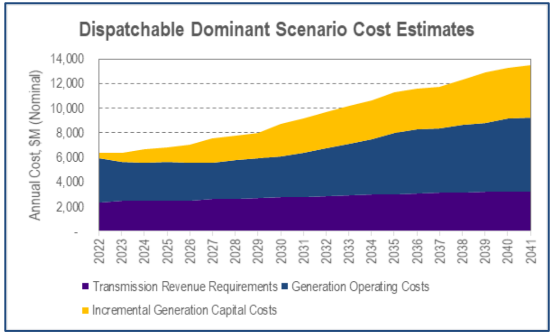
Levelized cost of electricity and levelized avoided cost of electricity for select low-carbon generation technologies

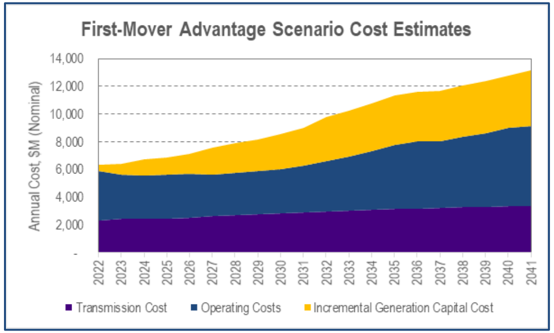


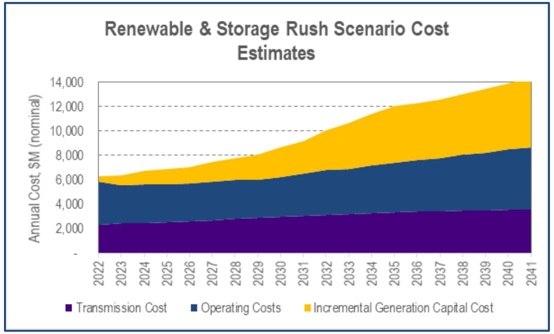
- The AESO has forecast a range for the levelized cost of electricity (LCOE) and levelized avoided cost of electricity (LACE) to approximate the value that select low-carbon resources can bring to the grid
  - LCOE includes all capital and operating costs for the generating assets
  - LACE calculations include the value of energy delivered by the assets and the value of offset produced from renewable energy or carbon sequestration
- Generally, the LCOE of the generation technologies is lower than the expected LACE, suggesting that resources can make required investment returns in the market

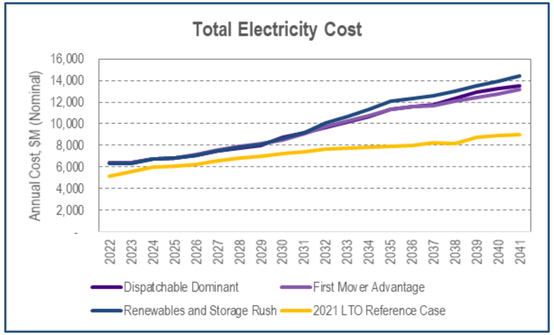
Annual electricity costs





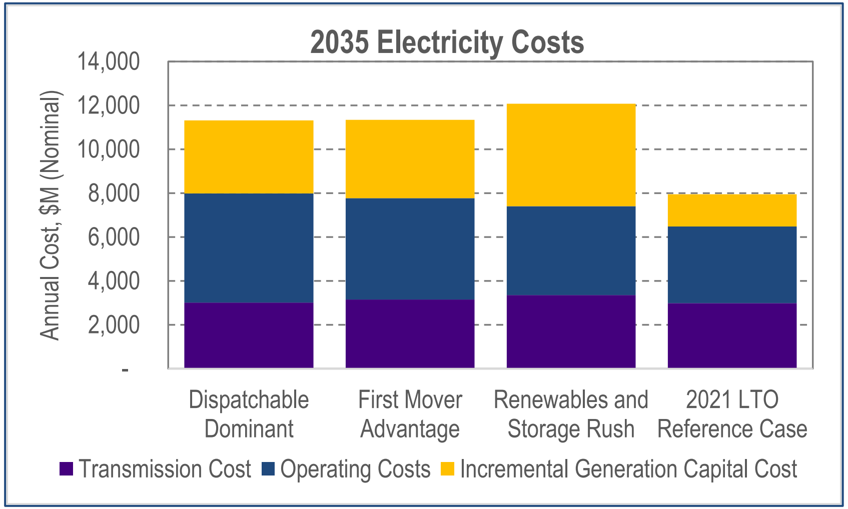


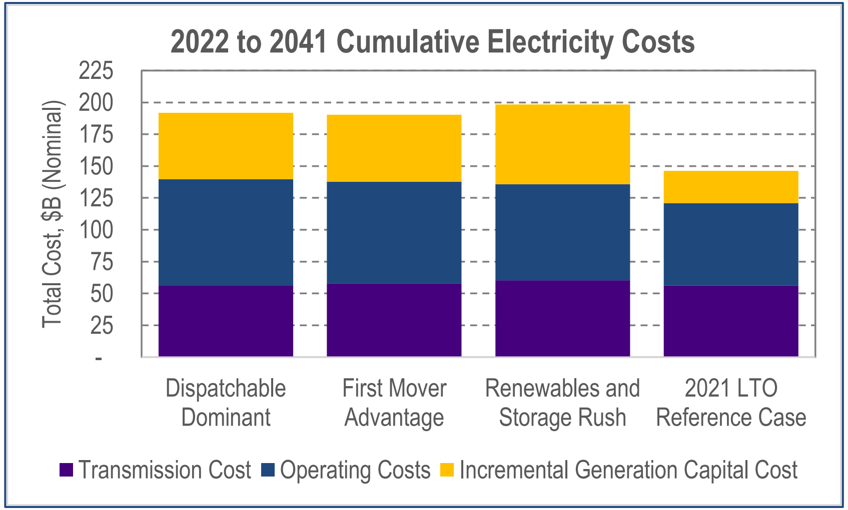




- The total annual electricity system costs are estimated to be higher in the net-zero scenarios than the 2021 LTO Reference Case
  - However, the increase in load due to electrification in the net-zero scenarios may offset some costs from other sectors (like transportation or heating)
- Amongst net-zero scenarios, the estimated costs are highest for the Renewable and Storage Rush Scenario and lowest for the First-Mover Advantage Scenario

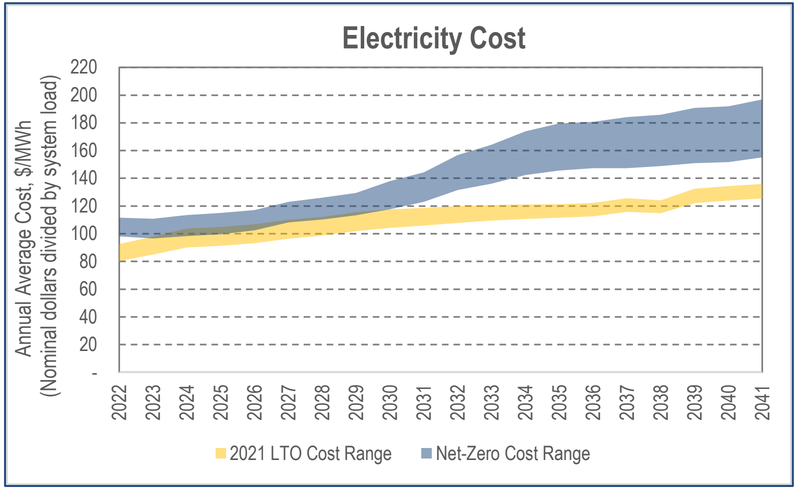
Annual electricity costs cont.





- A snapshot of 2035 costs illustrates that the total costs of the net-zero scenarios are within a modest range of one another, with the First-Mover Advantage being the least costly and the Renewables and Storage Rush being the most costly
- Although total costs are tightly rangebound, the composition of the costs in each scenario varies
- In comparison to the 2021 LTO Reference Case, all three scenarios' aggregated costs are significantly higher
- Between 2022 and 2041, the expected cost increase from the 2021 LTO Reference Case to achieve net-zero scenarios is between $44.1 billion and $52.1 billion
  - This range is between 30% and 36% higher than the expected cost of the 2021 LTO Reference Case

Unit electricity costs



- Unit costs can be estimated by dividing the total high and low net-zero electricity costs from each scenario by the higher and lower range of system load (65% to 75% of AIL)
  - Unit electricity costs are estimated to increase approximately 40% by 2035 in net-zero scenarios relative to the 2021 LTO Reference Case
- Distribution system upgrades and incremental supply integration costs have not been included in electricity cost estimates
- Unit electricity costs do not reflect potential cost reductions accruing to consumers from other sectors (e.g., transportation), and do not represent an economy-wide portrayal of net-zero impacts

Recap, Next Steps and Session Close-Out

Key conclusions recap

- There are multiple potential pathways to achieve net-zero of which the AESO has studied three; the pathways studied by the AESO and other potential pathways are highly uncertain and face significant risk to achieving the end goal by 2035
- Relative to a non-net-zero future, transitioning to a net-zero electric system with increased electrification will require an additional $44 to $52 billion in transmission, generation capital and operating costs from 2022-2041 representing a 30% to 36% increase relative to the 2021 LTO Reference Case
- Alberta's market structure is capable of delivering sufficient supply to meet demand during the net-zero transformation subject to considerations
- The application of offsets will be required to achieve a net-zero electricity system by 2035
- Demand growth under a net-zero transition, even considering increased electrification, is expected to be lower than historically observed rates which the Alberta market has accommodated

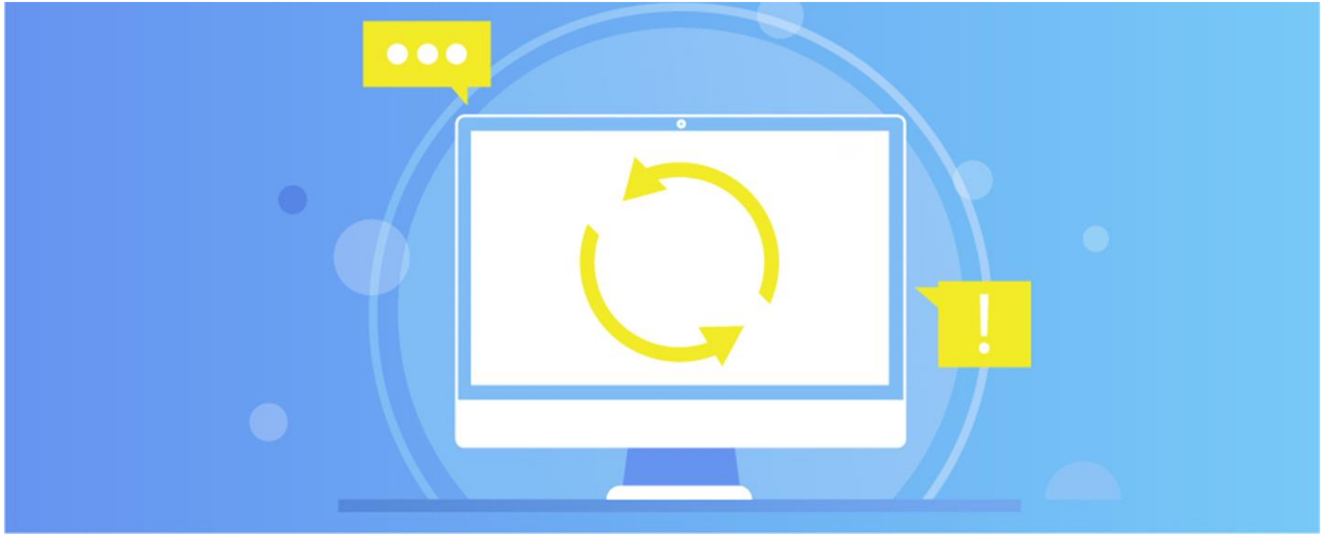
Next steps

- The AESO is committed to providing timely analysis and insights regarding the net-zero transformation. The AESO expects to follow this analysis with the following next steps and will inform stakeholders as they progress:
  - Continue to monitor and participate in the development around policy initiatives such as the Clean Electricity Standard (CES) and Technology Innovation and Emissions Reduction (TIER)
  - Develop a reliability requirements roadmap for future reliability services needed to support the future resource transformation based on operational impact assessments that utilize high renewable scenarios to identify potential operational and reliability challenges and potential mitigation measures
  - Through the Market Evolution Roadmap, identify other market initiatives to support long-term sustainability and competitiveness of the energy-only market structure based on output from carbon policy analysis and assessments
  - Engage with Distribution Facility Operators (DFO's) to better understand the impacts and potential costs of carbon policy analysis and assessments to the distribution system
  - Incorporate carbon policy analysis and assessments into the 2023 Long-term Outlook (LTO), which will inform subsequent iteration of the Long-term Planning (LTP) report and continue to provide further details of future transmission development activities to support a transformed resource mix

Session close-out

- We want to thank you for attending the Net-Zero Emissions Pathways Stakeholder Information Session and we would appreciate your feedback on the session
- Launch poll
  - The purpose of the session was clear
  - The information was presented in a clear manner
  - The presentation content was clear and informative
  - I found this session valuable

Contact the AESO



- ***Twitter:*** *@theAESO*
- ***Email:*** *forecast@aeso.ca*
- ***Website:*** *www.aeso.ca*
- Subscribe to our stakeholder newsletter

Appendix

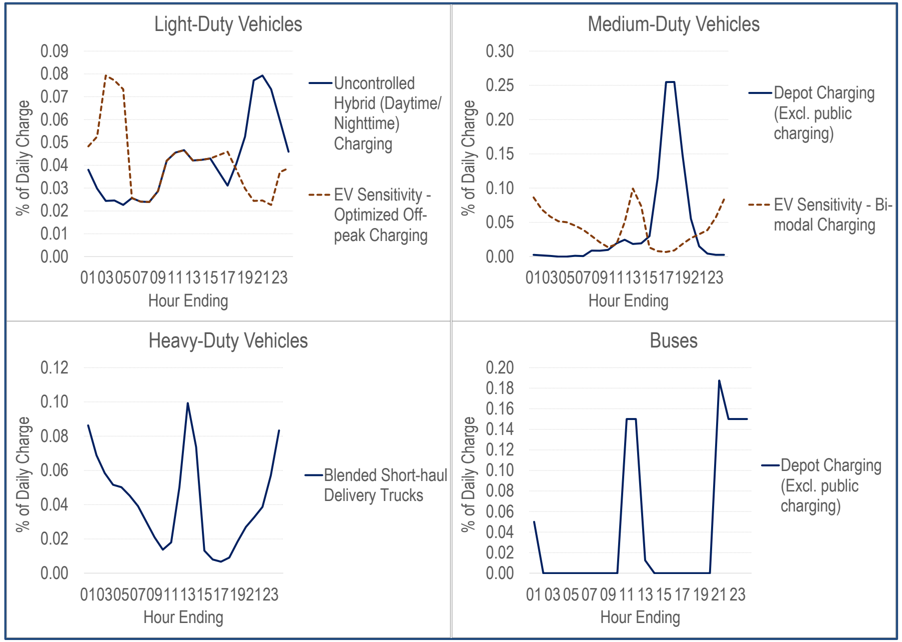
Electric vehicle modeling

- Each vehicle segment is uniquely assessed

Vehicle	Adoption	Daily charge*	Profile
Light-duty	Federal targets 20% by 2026, 60% by 2030, 100% by 2035	Passenger car = 6 kWh; Truck = 8 kWh	Home and workplace / public charging
Medium-duty	30% of new urban delivery / utility vehicles by 2040	70 kWh	Depot charging only (no public charging)
Heavy-duty	20% of new short-haul truck sales by 2040	350 kWh	Depot charging only (no public charging)
Buses	55-65% of new buses from 2030 onwards	110 kWh	Depot charging only (no on-route charging)

* Assumptions adapted by the AESO from a study developed by Dunsky Energy + Climate Advisors for use by EPCOR in assessing EVs in the utility's service territory

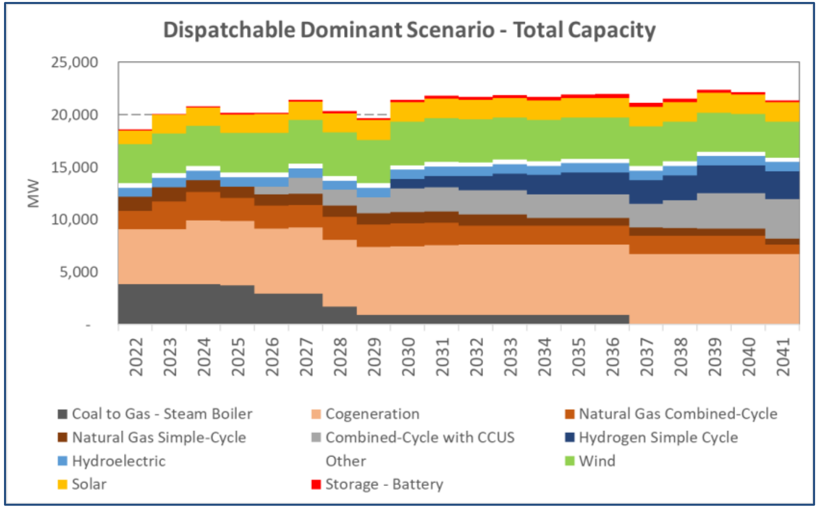
EV Charging Profiles and Sensitivities Tested in the RAM Model

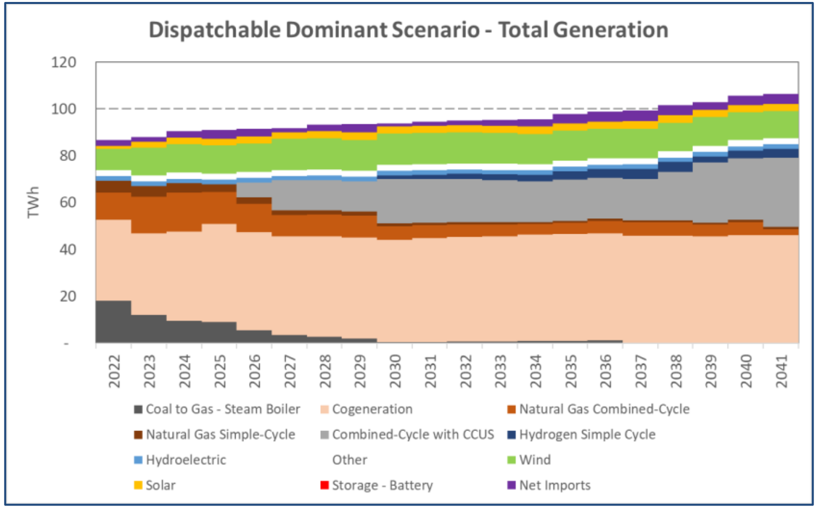


Generation assumptions

- Hydrogen (H_2) fired generation assumptions
  - Earliest availability date: estimated at 2027
  - H_2 source : Steam Methane Reformer (SMR) or Autothermal Reformer (ATR)
    - Capital and operating costs associated with H2 production have been rolled into commodity price ($/kg)
    - CO_2 sequestration costs and estimated value of offset credits rolled into commodity price
- CC with CCS modeling assumptions
  - Parasitic load: 7.4% of gross power output, plus steam losses for carbon capture
  - Variable cost increases: approximately double
- Hydro assumptions
  - Build cycle (at least 10 years)
  - Capital cost updated to $14,545/kW (based on a $16B capital cost and 1,100 MW capacity)
- Nuclear
  - Build cycle (estimated to be at least 10 years)
- Wind / Solar modeling assumptions
  - Capital cost reductions expected for both technologies
- Storage cost assumptions
  - Battery storage costs are expected to decline
- Carbon & Emissions
  - $170/t by 2030 Federal policy assumed
  - Use of carbon offsets and credits allowed to achieve "Net-Zero" emissions
  - Cogeneration emissions will be dealt with in the sectors under which they report their emissions (not the electricity sector in many cases)

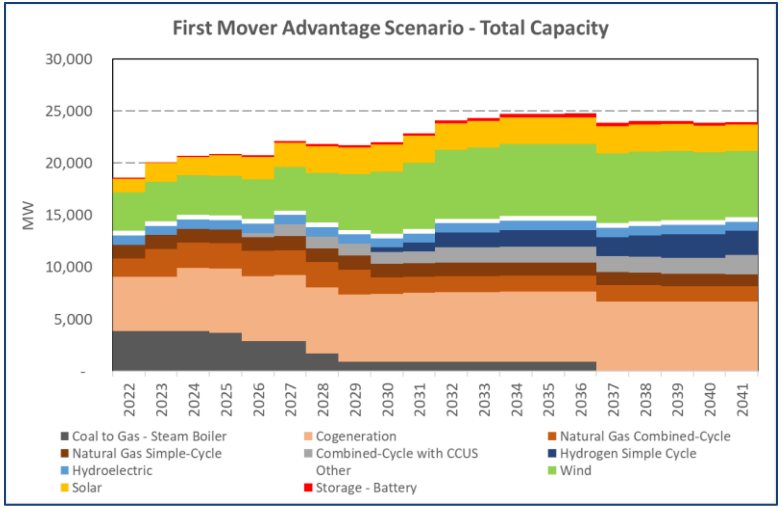
Dispatchable dominant scenario – Total capacity and total generation

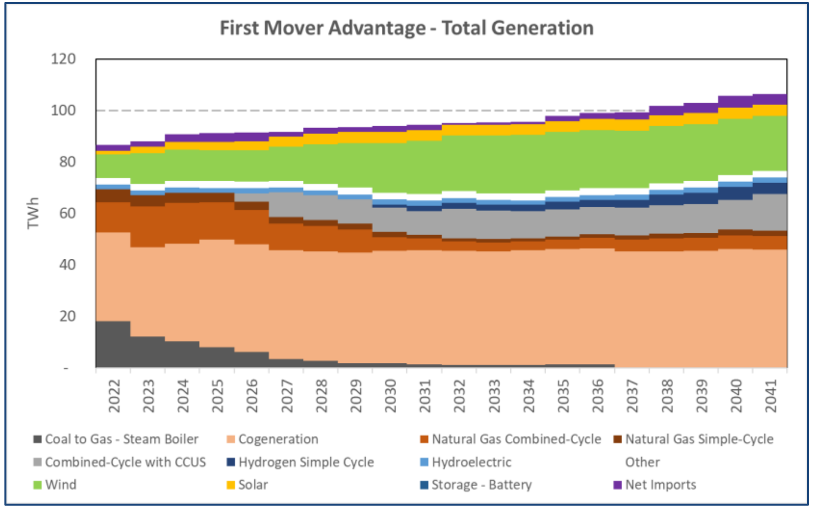




- The generation capacity reflects a transition away from coal-to-gas assets and unabated natural gas fired generation
- Natural gas capacity is gradually replaced by combined-cycle with carbon capture and hydrogen fired capacity
- Renewable capacity and generation remain relatively constant throughout the forecast horizon accounting for 24% of total domestic generation by 2035 (23% by 2030)

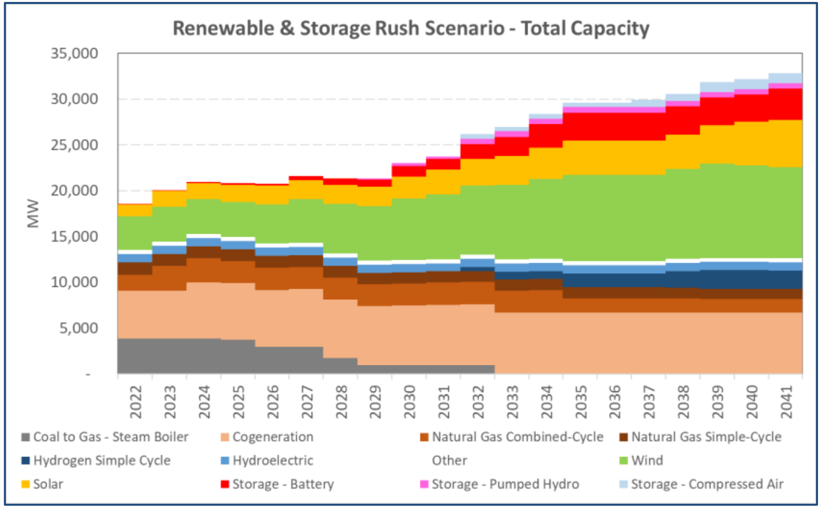
First-mover advantage scenario – Total capacity and total generation

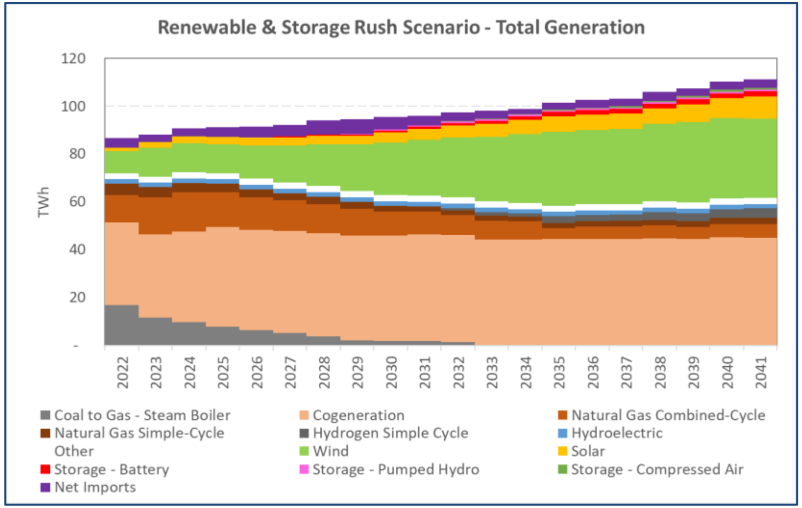




- Zero emissions renewables account for 35% of total domestic generation by 2035 (32% by 2030)
- Low emissions hydrogen-fired and CC with CCS technologies produce a growing portion of net generation by 2035

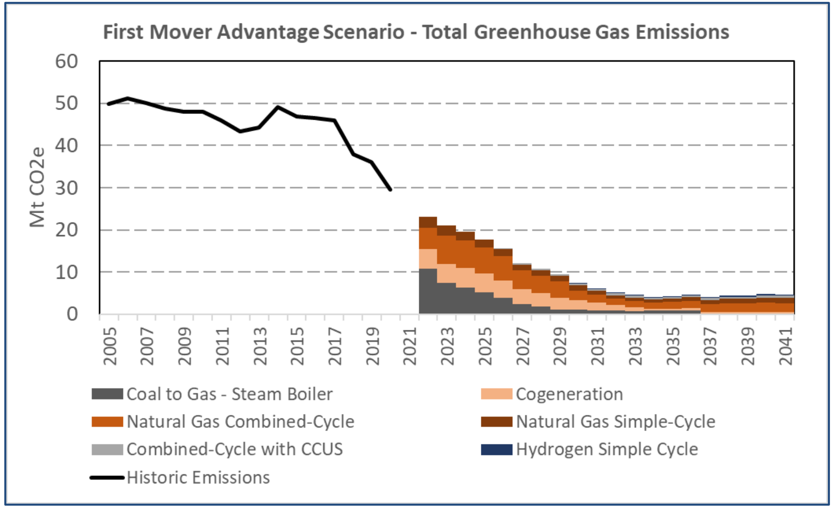
Renewable and storage rush scenario – Total capacity and total generation





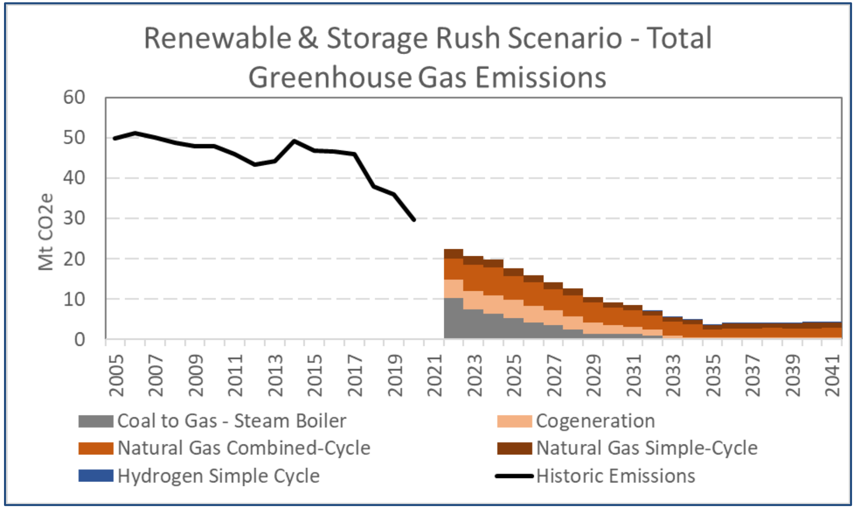
- Zero emissions renewables account for 46% of total domestic generation by 2035 (35% by 2030)

First-Mover Advantage scenario – Emissions



- Renewable generation displaces a significant amount of unabated gas emissions
- Low emissions hydrogen-fired and CC with CCS technologies produce a growing portion of net generation by 2035
- Emissions are estimated to be approximately 4.3 Mt in 2035 from the electricity industry
  - Emissions are modestly lower than the Dispatchable Dominant scenario
  - Existing units may also retrofit/replacing brownfield thermal assets with low emission technology

Renewable and storage rush scenario – Emissions



- Emissions are estimated to be approximately 3.8 Mt from the electricity industry
  - This level of emissions would need to be mitigated using offsets and emissions performance credits
  - May also see retrofitting/replacing brownfield thermal assets

Acronyms

- AIL = Alberta Internal Load
- aMW = Average MW
- AS = Ancillary Services
- ATR = Autothermal Reformer
- BTF = Behind-the-fence
- CBoC = Conference Board of Canada
- CC = Carbon Capture
- CCS = Carbon Capture and Storage
- DER = Distributed Energy Resource
- DFO = Distribution Facility Owner
- DTS = Demand Transmission Service
- EPC = Emissions Performance Credits
- ES = Energy Storage
- EUE = Expected Unserved Energy
- EV = Electric Vehicle
- GHG = Green House Gas
- HDV = Heavy-Duty Vehicle
- LACE = Levelized Avoided Cost of Electricity
- LCOE = Levelized Cost of Electricity
- LDV = Light-Duty Vehicle
- LTO = Long-term Outlook
- LTP = Long-term Transmission Plan
- MDV = Medium-Duty Vehicle
- MHDV = Medium and Heavy-Duty Vehicle
- OR = Operating Reserve
- PPA = Power Purchasing Agreement
- RAM = Resource Adequacy Modeling
- SMR = Steam Methane Reformer
- TIER = Technology Innovation and Emissions Reduction Regulation