Restructured Energy Market Report

Assessment of Market Outcomes & Efficiency of the Proposed REM Design

November 22nd, 2024

Update: December 12th, 2024

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Preliminary Results December 12th, 2024 Update

Energy+Environmental Economics

Disclaimer

This modeling is based on the current REM proposal which remains under development and is subject to change.

E3 created the following forecasts and analyses using the best available public information and our expertise and knowledge of the relevant markets, along with commercially available 3rd party software models and proprietary in-house energy market price forecasting tools. However, the future is uncertain, and these forecasts (along with underlying market expectations) may change due to many factors, including unforeseen events, new technology adoption or inventions, new market structures, regulatory actions, and changes in both provincial and federal government policies. E3 makes no guarantees related to these forecasts or the information presented herein and should not be held liable for any economic damages associated with independent investment decisions.

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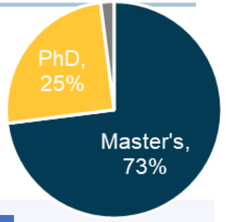
Energy+Environmental Economics

Who is E3?

Thought Leadership, Fact Based, Trusted.

130+ full-time consultants | 30 years of deep expertise | Engineering, Economics, Mathematics, Public Policy…



Calgary

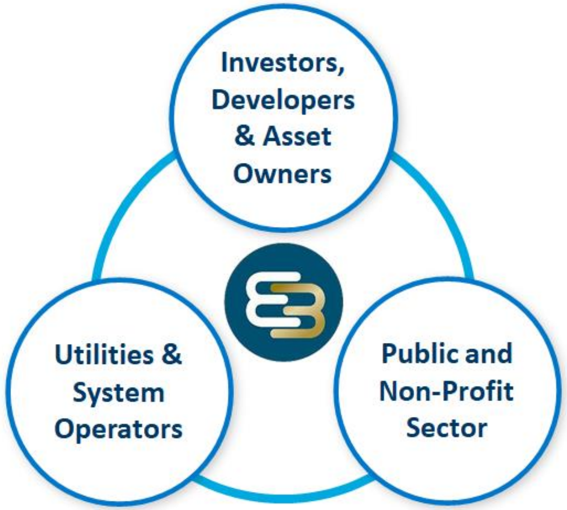
San Francisco

New York

Boston

E3 Clients

350+ projects per year across our diverse client base



Recent Examples of Alberta & Canadian Projects

Buy-side diligence support on several successful investments of renewable assets in Alberta, including Alberta's largest inner city solar project, and many other assets across Canada

Providing expert testimony in Alberta rate design including the ISO Tariff, Distribution System Inquiry, distribution rates, and Performance Based Regulation (PBR) proceedings

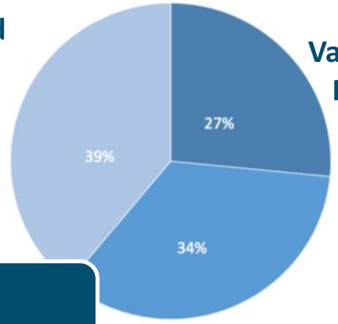
Energy storage and reliability investigated in the dispatchable renewables and storage study for AESO in capacity related design issues

Utility strategy and valuation worked with transmission owners and generators on strategy and valuation

Integrated resource planning and support for multiple Canadian jurisdictions including Nova Scotia, British Columbia, Yukon, Manitoba, New Brunswick, and Ontario

E3's 3 Practice Areas

+ E3 has organized itself across three main practice areas to maximize its impact through the diversity of clients, project work, and technical innovation to support the energy transition across North America in a holistic, transparent, and intellectually honest manner



Climate Pathways & Electrification

- Climate pathways studies
- Future of gas
- Low carbon fuels
- Building electrification
- Transportation electrification
- Load forecasting

Integrated System Planning

- Integrated system planning for electricity: G, T, & D & non-wires alternatives
- Utility procurement
- Rate design
- Grid modernization
- Avoided costs
- Distributed resource planning

Asset Valuation & Markets

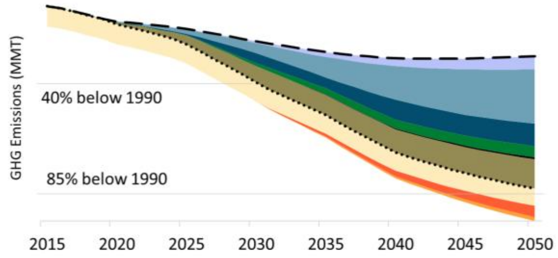
- Asset valuation and due diligence
- Strategic advisory for commercial clients
- Energy market price forecasting
- Market design & analysis
- DER dispatch & asset optimization

Policy ⟷ Integrated Energy Planning ⟷ Commercial Interests

E3's comprehensive and best-in-class modeling toolkit positions E3 well to study future energy system dynamics

PATHWAYS

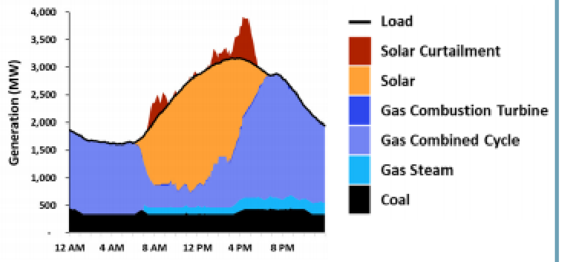
Economy-wide accounting of energy supplies and demands under deep decarbonization scenarios



Production Simulation

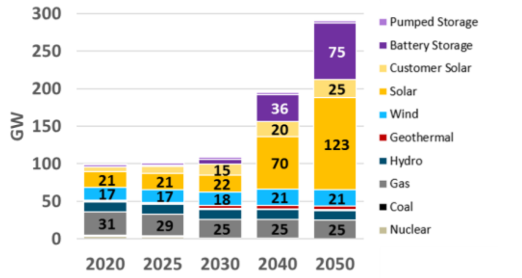
(PLEXOS)

Detailed operational simulations of system dispatch and flexibility needs



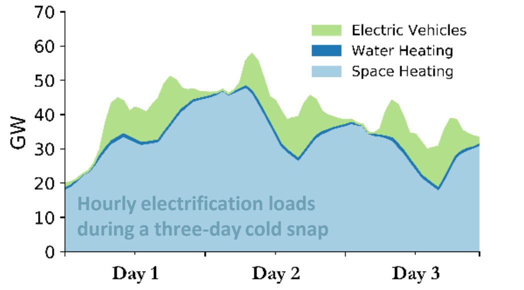
RESOLVE

Optimal capacity expansion model for electric systems



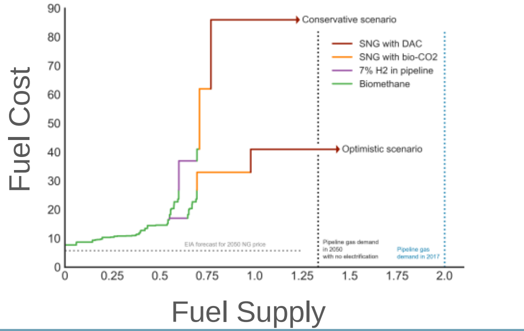
RESHAPE & EVGrid

Hourly simulations of electric loads for specific end uses



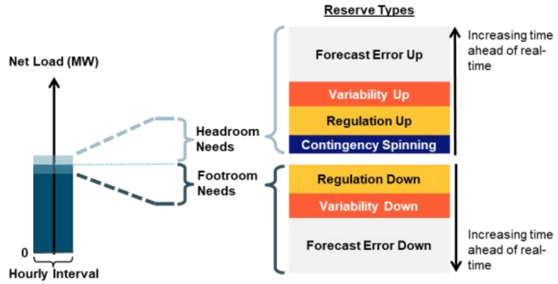
Low-Carbon Fuels and Future of Gas

Role of fuels in deep decarbonization



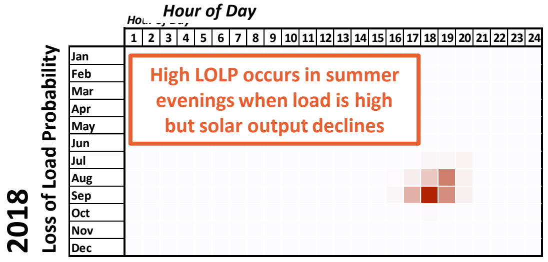
RESERVE

Dynamic operating reserves for renewable integration



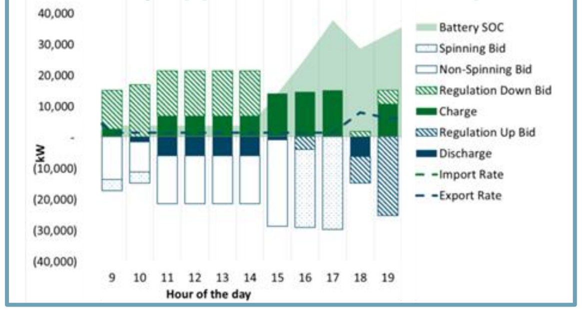
RECAP

Loss of load probability simulation to measure resource adequacy



RESTORE & IDSM

DER Toolkit for optimizing DER value stacking opportunities and adoption



Economy-wide energy systems | Bulk grid power systems | Grid edge & behind-the-meter

Report Introduction & Overview

Project Scope	
Deliverables	**Task**
Expert Report	Provide an independent, fair, objective, and non-partisan assessment of AESO's proposed Restructured Energy Market (REM) design
Modeling Effort	To provide this assessment, E3 leveraged its in-house PLEXOS model for AESO price forecasting to estimate market outcomes of the AESO's 2024 Restructured Energy Market (REM) proposed Design Elements as of Late October/Early November (up to Sprint 4/5/6). E3 utilized Plexos Long-term Expansion (LT), Short-term Optimization (ST) and unit commitment, combined with E3's strategic offer system to understand the impact to market outcomes, efficiency, revenue sufficiency, portfolio builds, and cost impacts of the design
Out of Scope	E3 was not asked to provide market design suggestions, but to assess and provide opinion on the elements of the proposed market design through quantitative modelling. E3 was not asked to provide a reliability assessment or loss of load expectation modelling

E3 Area's of Assessment

Areas of Assessment

1. **E3 provided expert modelling, views, and opinions on the anticipated prices, dispatch, and revenue streams of:**
   - The Day-ahead Market (DAM), the new Day-ahead Commitment product (DAC), Uncertainty/Ramping Reserve (R10/R60), the Operating Reserve Demand Curve (ORDC), and Shortened Settlement
2. **E3 provided a forecast build under the new market design to understand how reserve margins may change over time**
3. **E3 quantified market impacts of design elements like market prices, cost impacts, changes in dispatch, intertie exchange, production costs, and ability for different technologies to earn a return on and of capital**
4. **E3 quantified the static efficiency impacts of the design elements**

Questions E3 Sought to Answer Though Modeling Effort

+ ***What is the order of magnitude improvement in efficiency from the different options will have from the status quo and across design element changes?***
+ ***What is the energy market impact of different market design elements put forward in the REM discussions?***
+ ***How do generators' revenues and production change with the changes in the market? How do costs change?***
+ ***How does the system investment landscape evolve under the different options?***

Executive Summary

Preliminary Results December 12th, 2024 Update

Energy+Environmental Economics

Observations from E3's Perspective

1

REM Components Incent New CCS, Wind, and Storage

- The addition of *Day-ahead commitment (DAC), ramping reserves (R10/R60), Smooth Operating Reserve Demand Curve (ORDC)/Scarcity pricing curve, and an increased price cap* result in sufficient generator revenues to incent development of new thermal, firm, generation ~1.8 GW of Combined Cycle Gas Turbine with Carbon Capture and Storage (CCS)
- In addition, the renewable/storage/CCS Investment Tax Credit (ITC) and carbon pricing policies favour the deployment of ~5.3 GW of wind, ~1.9 GW of solar, and ~1 GW of storage above 2024 levels on the path to net zero

2

Net Effect of REM is an Increase in Operational Reliability and Moderate Increase in Costs

- The effects of additional day ahead commitment, priced interties, negative price floor, and market power mitigation have downward pressure on energy price
- DAC, ORDC, increased price cap, and new ancillary service products place upward pressure on costs
- Overall wholesale energy prices remain stable, with additional products designed for increased reliability adding cost

3

Market Concentration and Weather Events Provide Increase Revenues for New Builds

- Upon ITC expiry (2036) renewable and thermal builds required for a reliable and net-zero grid will require incremental revenues
- Extension of ITC, continuation of present level market concentration or severe weather events – which are likely in some years – result in increased returns to investment

REM Elements Increase Operational Reliability and Efficiency with Moderate Cost Implications

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E3 Scope of Work Overview

+ **E3 independently analyzed the outcomes of the AESO's proposed Restructured Energy Market (REM) design**
  - REM market design and assumptions were provided by the AESO, and market impact was analyzed by E3
+ **E3 modeled anticipated revenues and market outcomes in:**
  - The day-ahead market
  - The day-ahead commitment product
  - The R10 and R60 products, informing the operating reserves demand curve (ORDC)/scarcity pricing mechanism
  - Market Power Mitigation
+ **E3 provided sensitivity analyses on:**
  - A priced intertie with a border node along with the status quo intertie framework
  - The impact of new build ownership (test different levels of market power)
  - A weather simulation with tighter market conditions (severe weather)
+ **Included market design elements are provided in the AESO sprint sessions up to sprint sessions Sprint 4/5/6 and the AESO August Options papers**
  - E3 understands that REM design elements are fluid and change with stakeholder feedback – This analysis reflects the most recent data available at the time

Scenario & Inputs Overview

E3 modeled the status quo pricing under both builds to provide insights into the impact of REM

The matrix of scenarios identifies how each scenario will be referred to as shorthand in charts and throughout the report

Primary Results Shown

Design Feature	Value	SQ190	SQ381D	PI381D
Price Cap ($/MWh)	$3,000.00		X	X
Price Cap ($/MWh)	$1,000.00	X		
Price Floor ($/MWh)	$0.00	X		
Price Floor ($/MWh)	-$100.00		X	X
Offer Cap ($/MWh)	$800.00		X	X
Offer Cap ($/MWh)	$999.99	X		
Intertie Participation	Status Quo (SQ)	X	X	
Intertie Participation	Priced (PI)			X
ORDC	Stepped (T)			
ORDC	Smooth (S)		X	X
Reserves	R10/R60, DAC, CR, RR (D)		X	X
Reserves	CR, RR (C)	X		
Border Node	Yes (N)			X
Shortened Settlement	Yes		X	X
Mitigation	Yes		X	X
Build	REM Build	X (SQ190R)	X	X
Build	Status Quo	X (SQ190)		

Current Market Design

E3 also ran a sensitivity with **higher portfolio concentration** and a secondary **severe weather profile** to derive additional insights in the proposed market design

Model and Input Limitations

Deterministic Weather

- Model uses a single weather seed and is designed to assess market outcomes and not loss of load expectation
- Full range of reliability outcomes, revenues, and prices will be different across weather years. The weather sensitivity provides insight into this distribution
- Import/Export flows are heavily dependent on wind/solar/hydro resource in Alberta and across WECC
- **Implication:** Changes across scenarios are the most meaningful providing all-else-equal changes

Optimal Model Logic

- All production cost software are optimization engines that minimize total production cost
- Market events like intertie flows in the opposite direction of market prices are not possible
- Simplifying assumptions are required to capture the dynamics of intertie seams, and other operational aspects
- **Implication:** Directional conclusions about market design changes on intertie trade and operations are more significant than resulting values

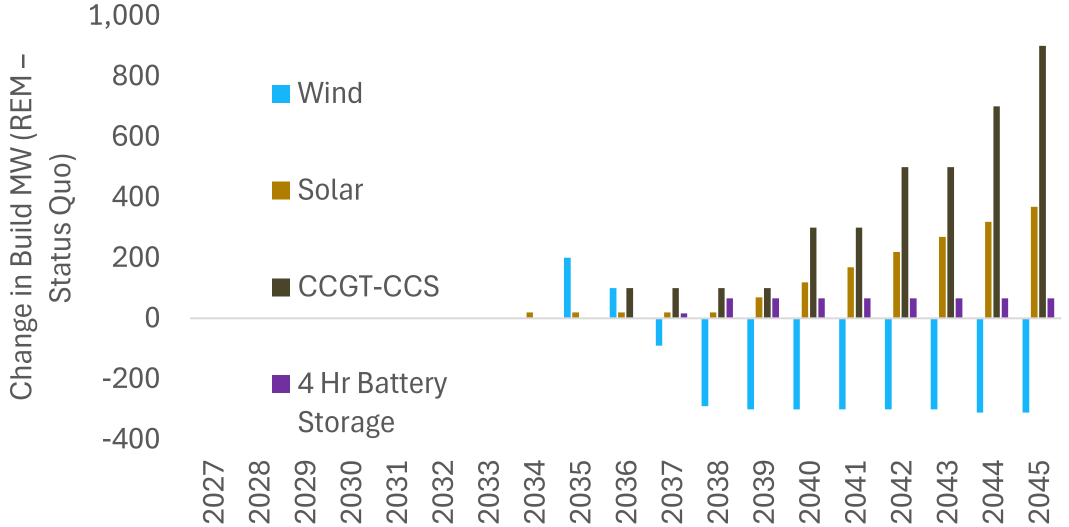
Zonal Model

- E3 modeled the system without a transmission network
- Generator dispatch does not consider the impact of redispatch due to congestion
- Interchange congestion is modeled using WECC interchange and transmission ratings
- **Implication:** Domestic production costs do not incorporate the impacts of real-time congestion. modeling not quantify the efficiency losses from zonal pricing

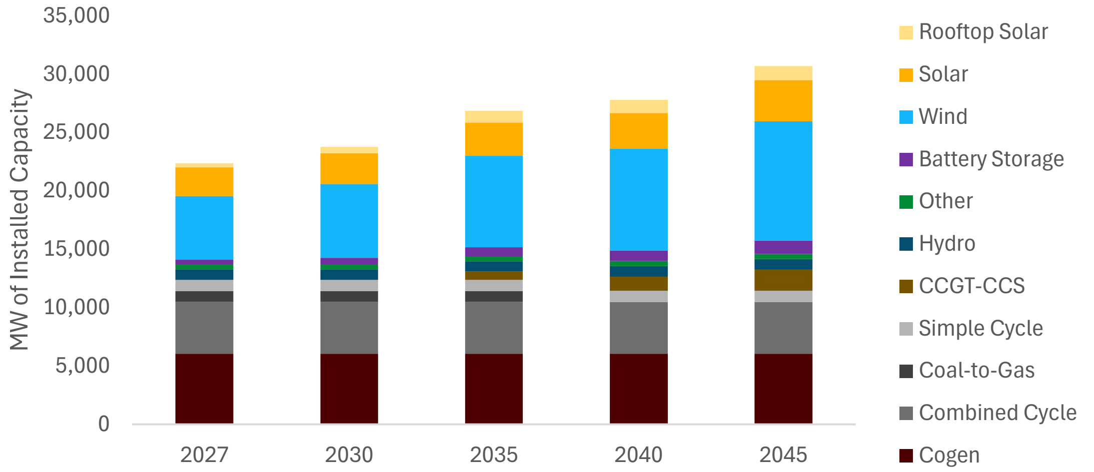
Long-term Expansion Results

- The long-term expansion results indicate that the REM design attracts ~1 GW of incremental investment in CCGT-CCS (~1.8 GW total), with incremental amounts of storage and solar, with less wind generation
- Both scenarios see large wind, CCS, and storage investments

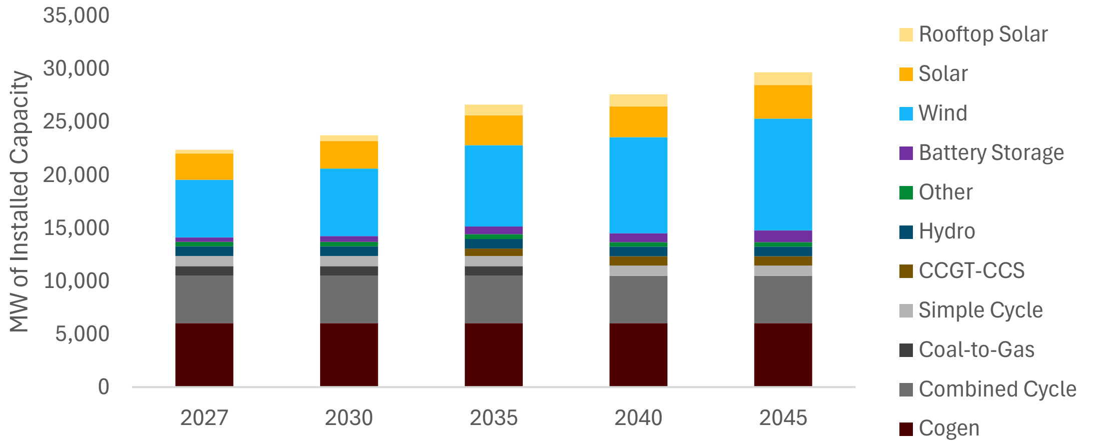
Build Comparison (REM – Status Quo)



REM Design – Long-term Build (PI381D)



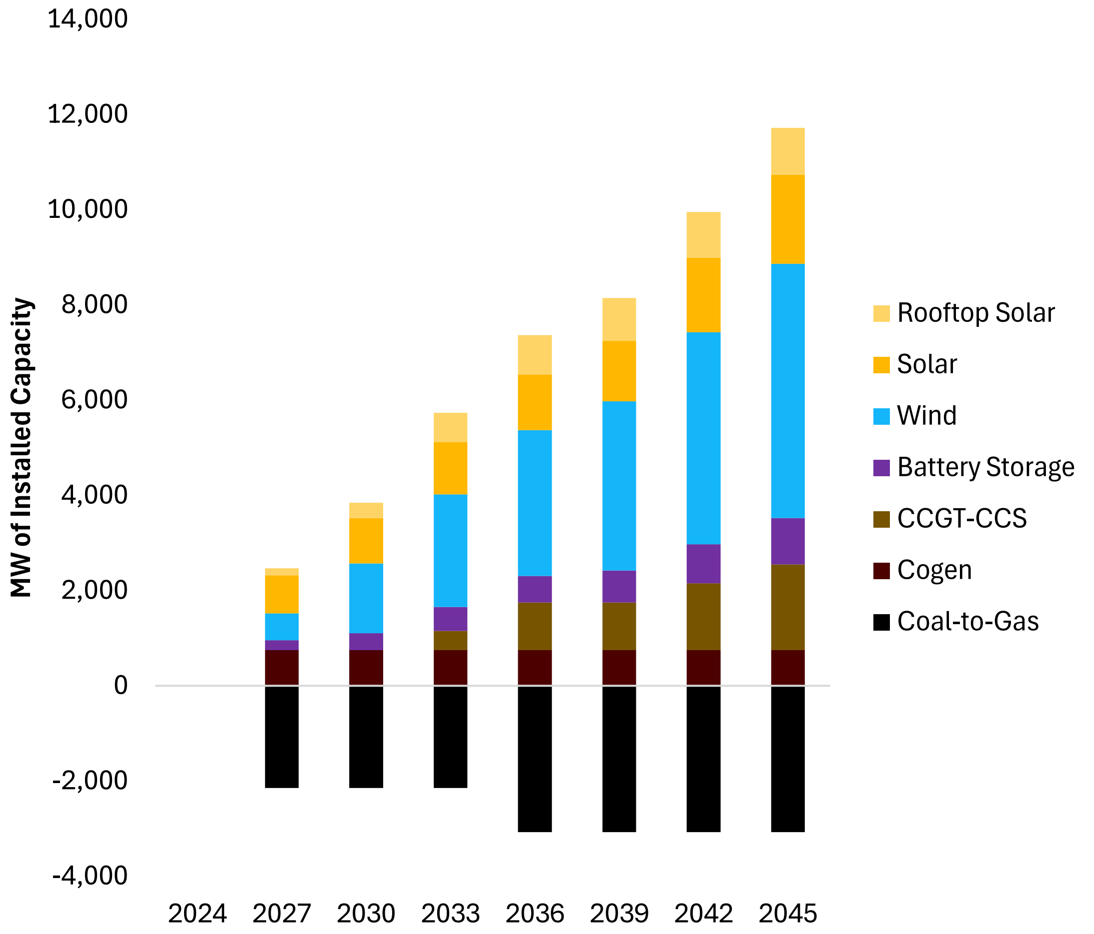
Status Quo – Long-term Build (SQ190)



Projected Build under REM Elements

+ **Alberta is anticipated to see continued changes in supply mix**
+ **E3 forecasts the following additions to the current installed capacity over the study horizon**
  - 2.9 GW of additional solar generation from current (of which 990 MW of rooftop solar)
  - 5.3 GW of wind
  - 1 GW of battery storage
  - 1.8 GW of CCGT-CCS
  - 800 MW of Cogeneration
  - 3 GW of coal-to-gas retirements

REM Build Additions*

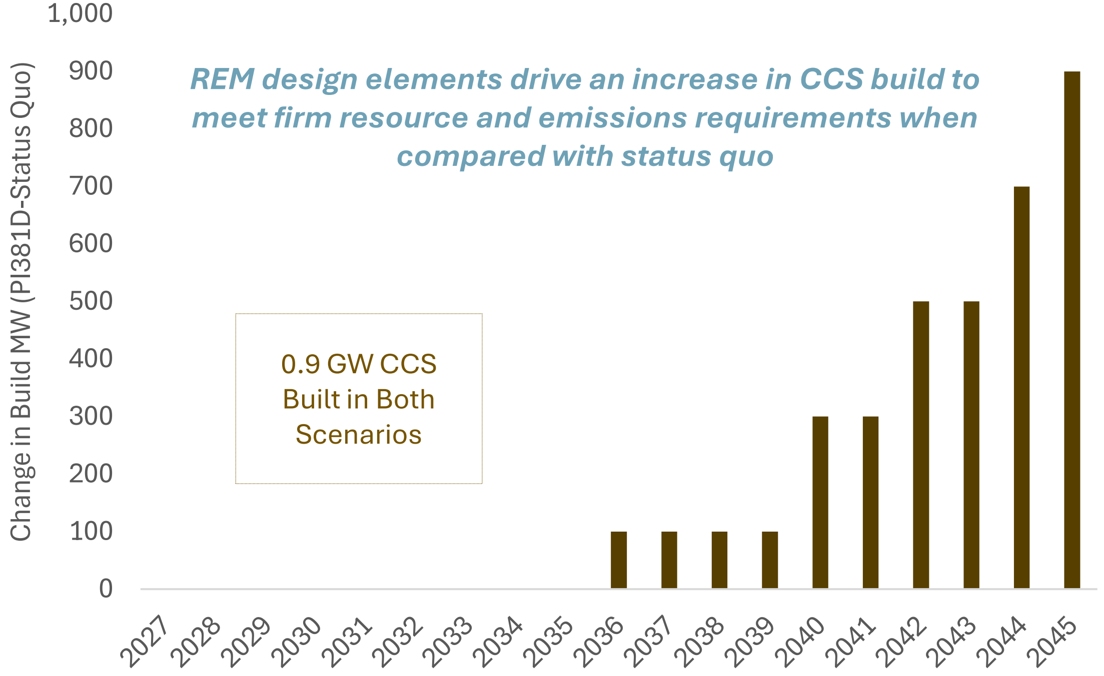


*2024 is based on the end of year 2024 forecast

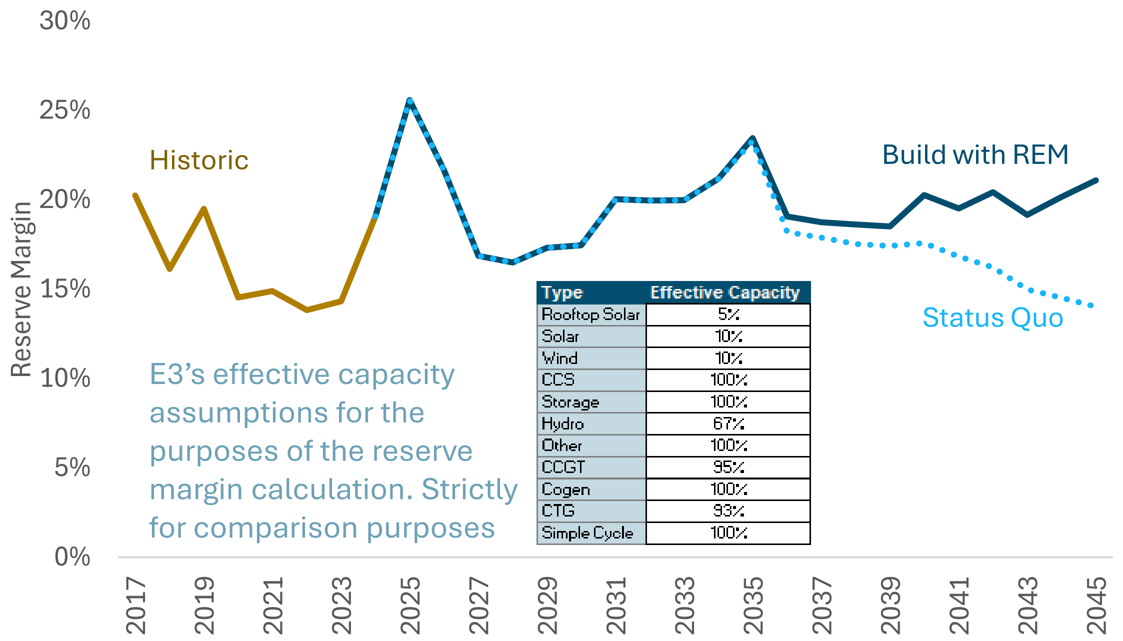
Additional REM Revenue Streams Increases Firm Generation Through CCS

The addition of Day-Ahead Commitment (DAC), reserve products (R10/R60), and Operating Reserve Demand Curve (ORDC) result in a net increase in firm resources across most of the study horizon, up to ~1 GW by 2045. The build under both market designs is the same to 2035. Post 2035, the REM market design can sustain additional firm generation, resulting in a higher overall reserve margin

Installed Capacity Results



Change in Reserve Margin* with REM Components

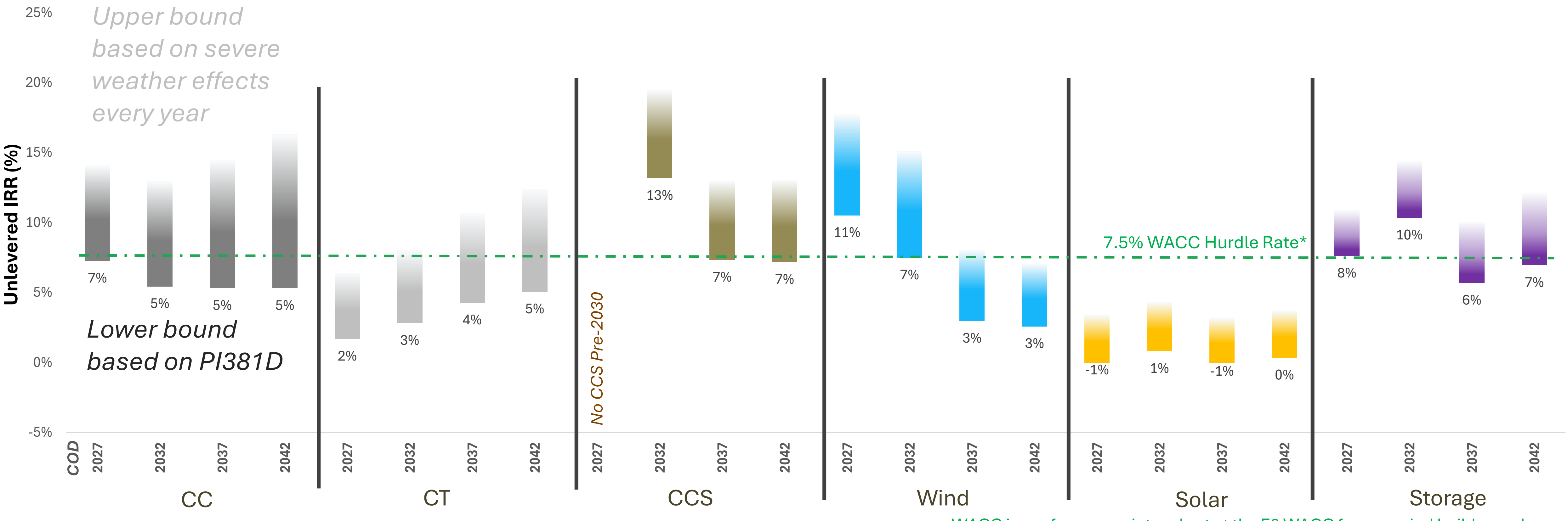


Type	Effective Capacity
Rooftop Solar	5%
Solar	10%
Wind	10%
CCS	100%
Storage	100%
Hydro	67%
Other	100%
CCGT	95%
Cogen	100%
CTG	93%
Simple Cycle	100%

*Reserve margin is effective capacity divided by Peak load

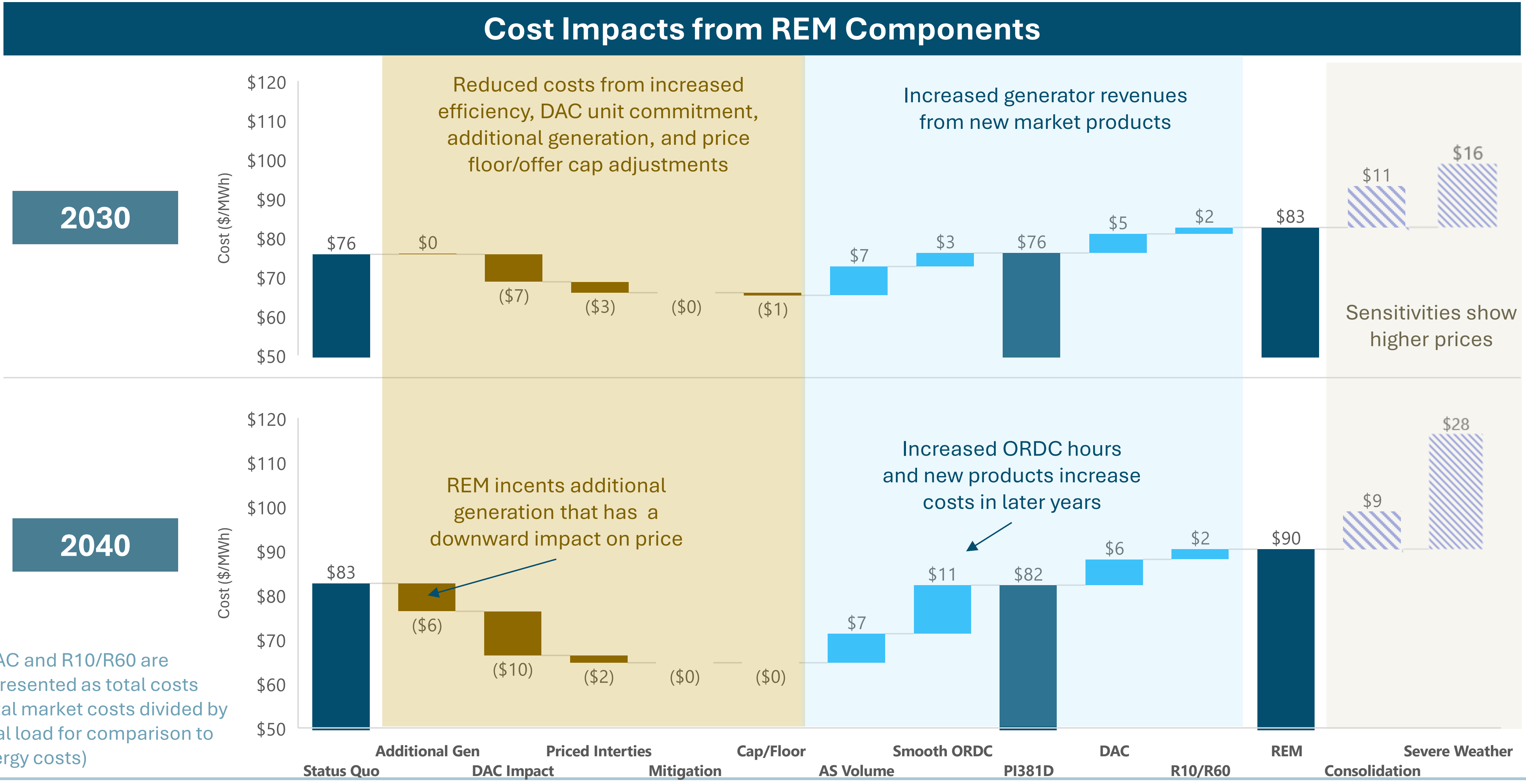
Investment signals across technologies change over time as new generation is built and the ITC expires

REM Market provides early investment signals for wind and CCS which are challenged by the expiration of ITC in 2036.
Upside opportunities provided by either increased market power (consolidation) or severe weather will drive increased returns



WACC is a reference point and set at the E3 WACC for new wind builds, each project will have its own unique WACC

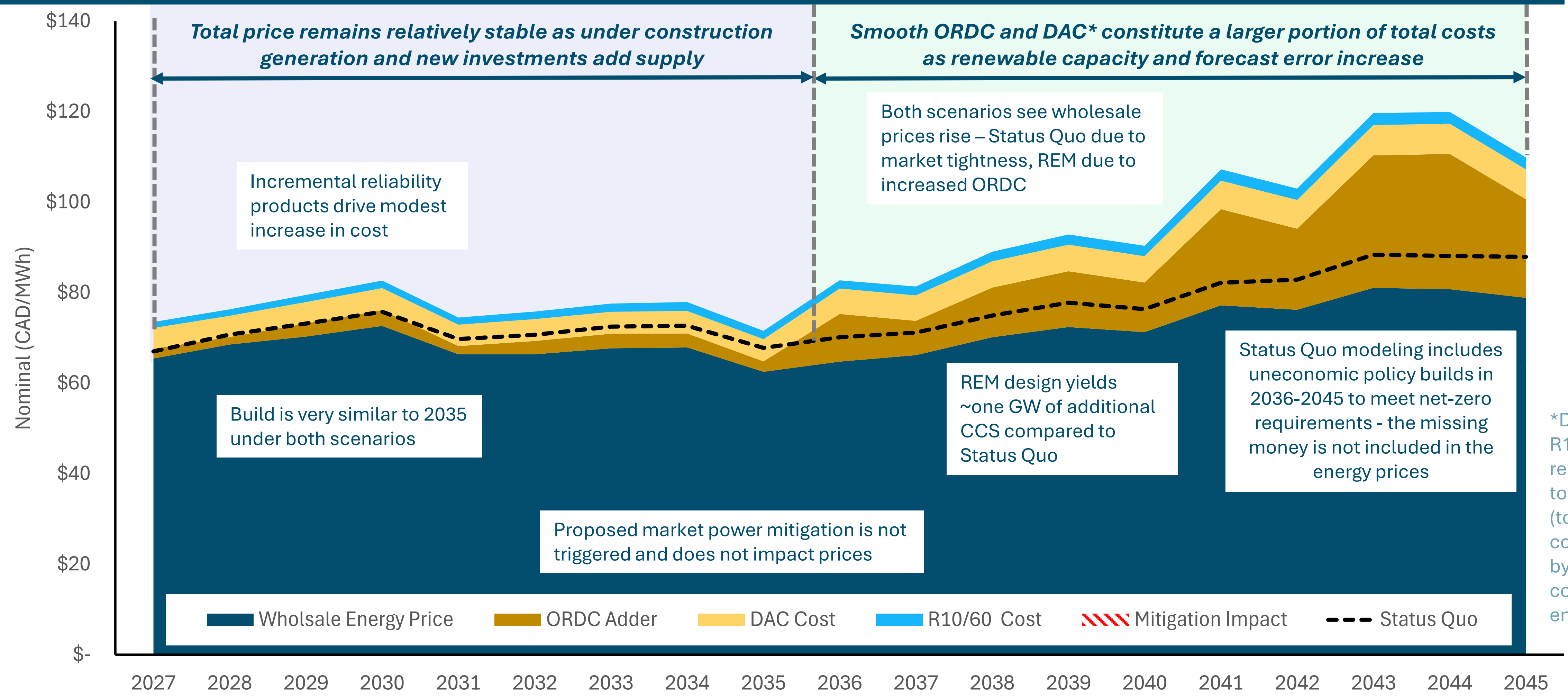
REM Components Have Counteracting Forces on Final Costs



*DAC and R10/R60 are represented as total costs (total market costs divided by total load for comparison to energy costs)

Energy Prices Under Proposed REM Remain Stable with ORDC and New Products Having a Bigger Effect in Later Years

Price Comparison – REM vs Status Quo



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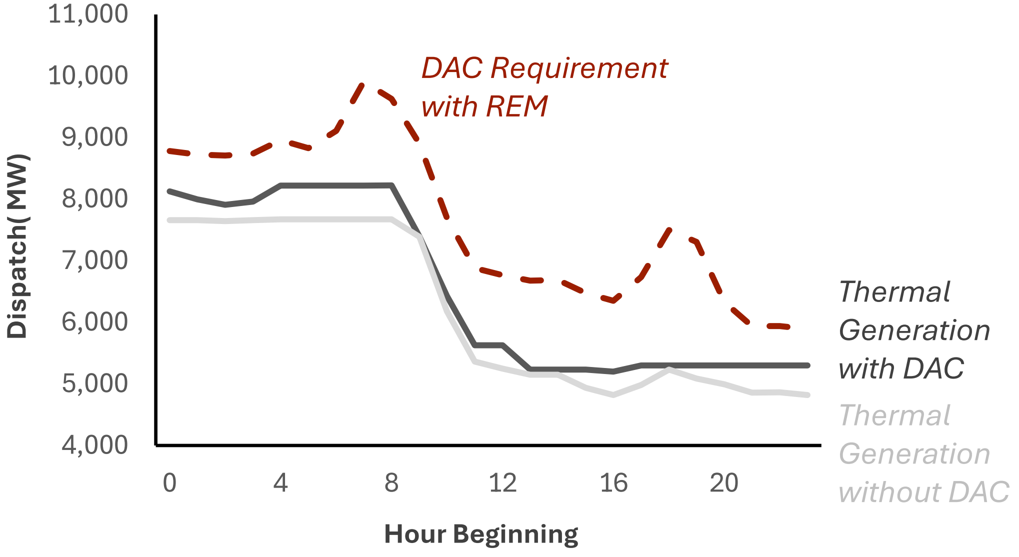
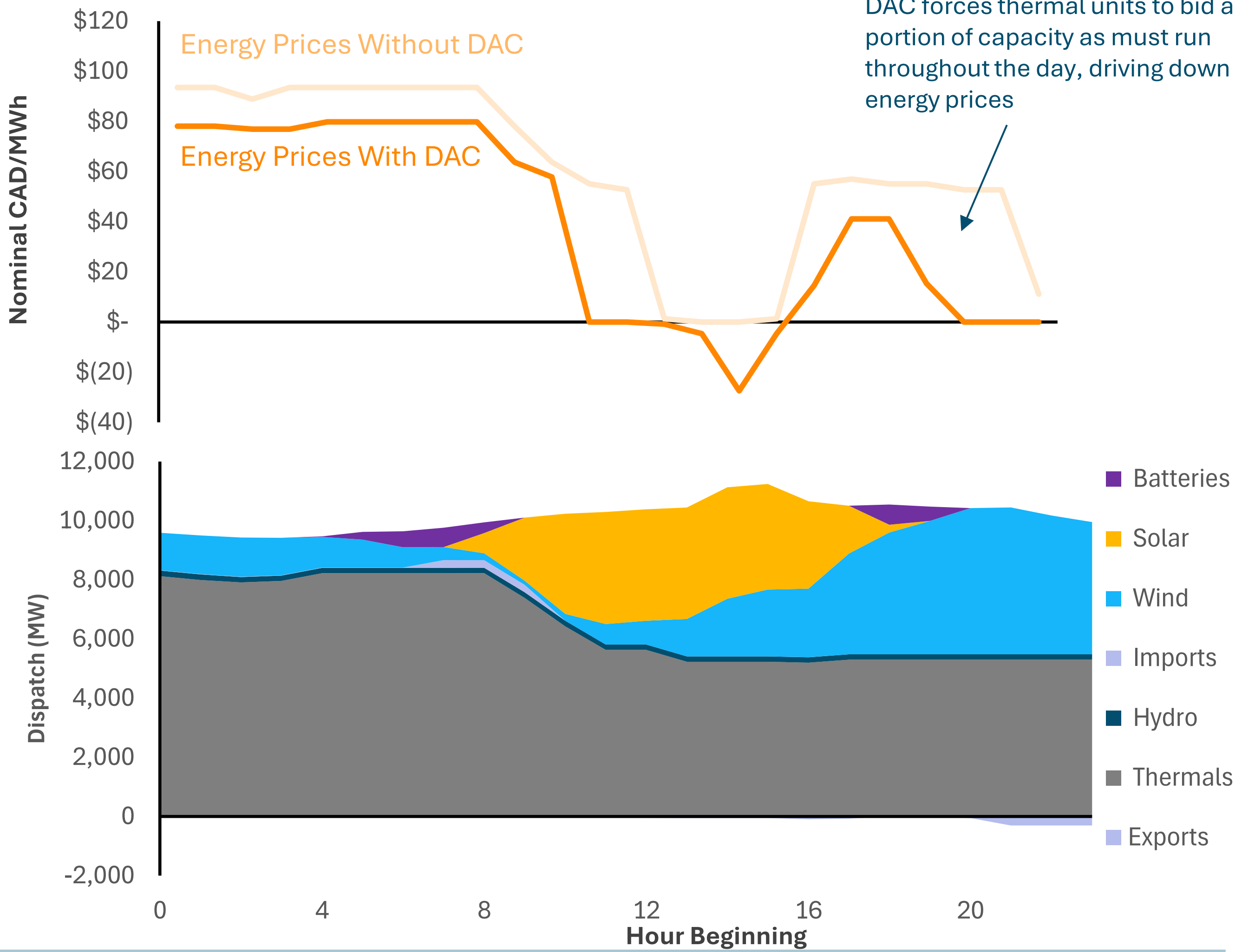
DAC Impacts Energy Price as More "Must Run" Thermal Enters the Market

Slow start resources need to spin to provide DAC when available fast-start generation and batteries are insufficient

EXAMPLE: DAC leads to an additional thermal unit spinning on a day with high renewables
Oct 8, 2034



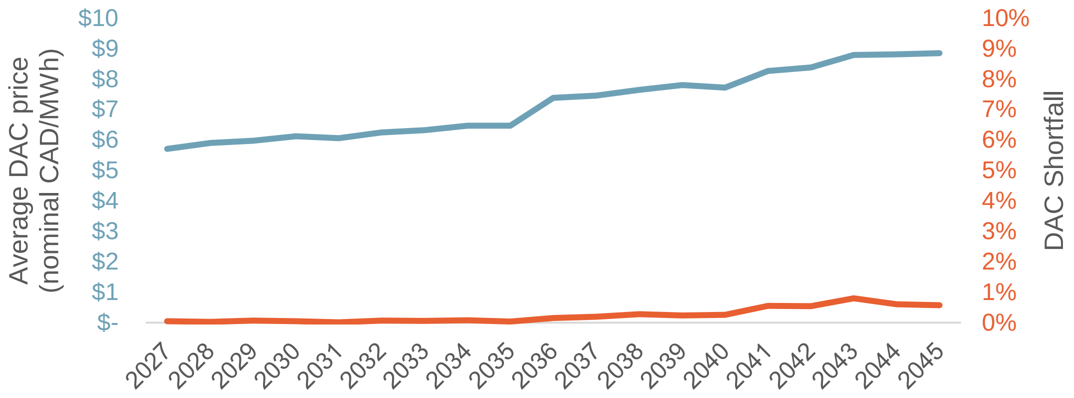
EXAMPLE: Prices & Energy Dispatch
Oct 8, 2034



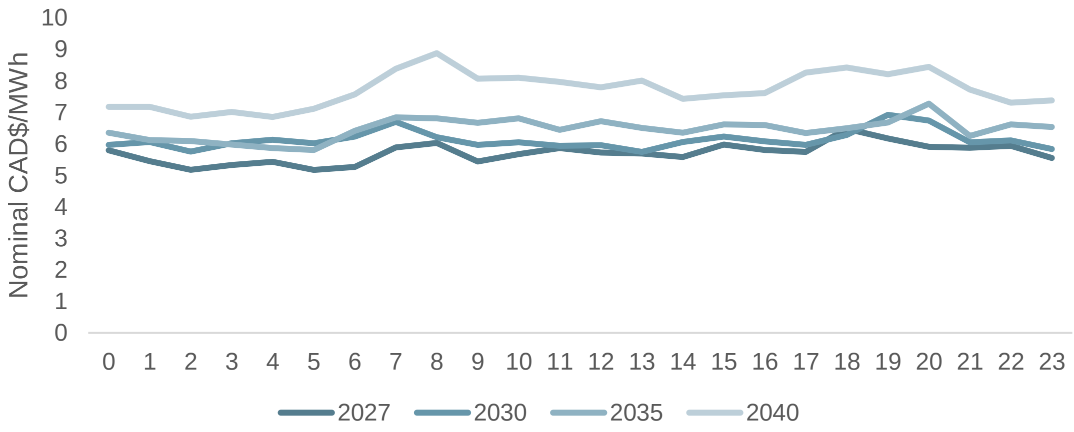
DAC Prices Grow Slowly Over Time as DAC Requirements Grow

+ **Yearly DAC prices increase as DAC requirements increase due to load and forecast error growth, causing more expensive generators to be committed to clear DAC**
+ **The DAC shortfall percentage moves from 0.05% of hours in 2027 to 0.57% of hours in 2045**
  - A DAC shortfall occurs when there is not enough firm capacity to meet DAC requirement
+ **DAC is priced competitively, based on cycling costs only, as it has no opportunity costs (DAC participation does not prevent from offering other products)**
  - DAC prices should be viewed as conservative as market power could result in increased price outcomes

DAC Prices & Hours with Shortfall *PI381D*



DAC Prices Annual Daily Profile

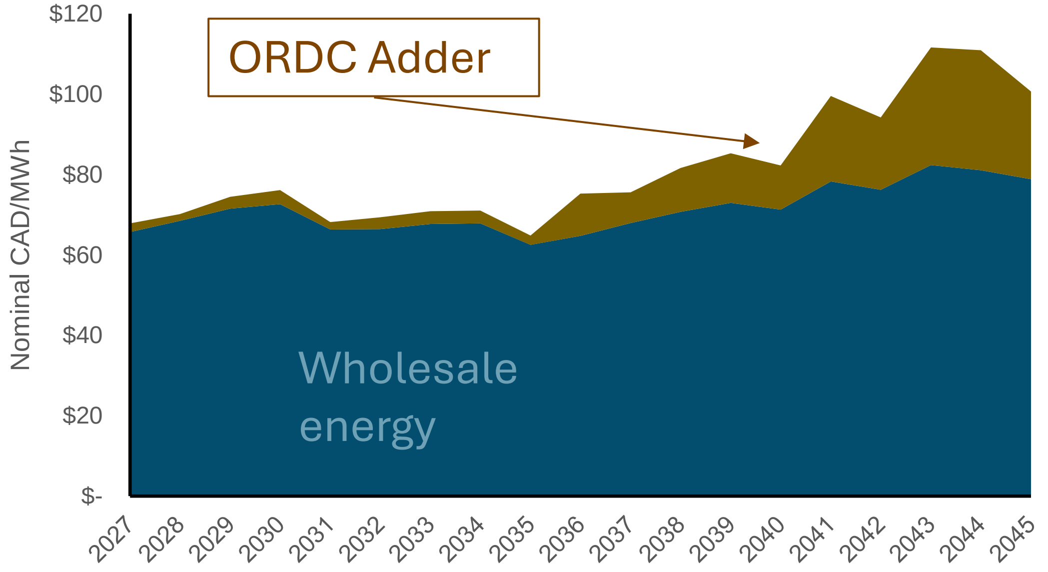


Stepped vs Smooth ORDC Adder

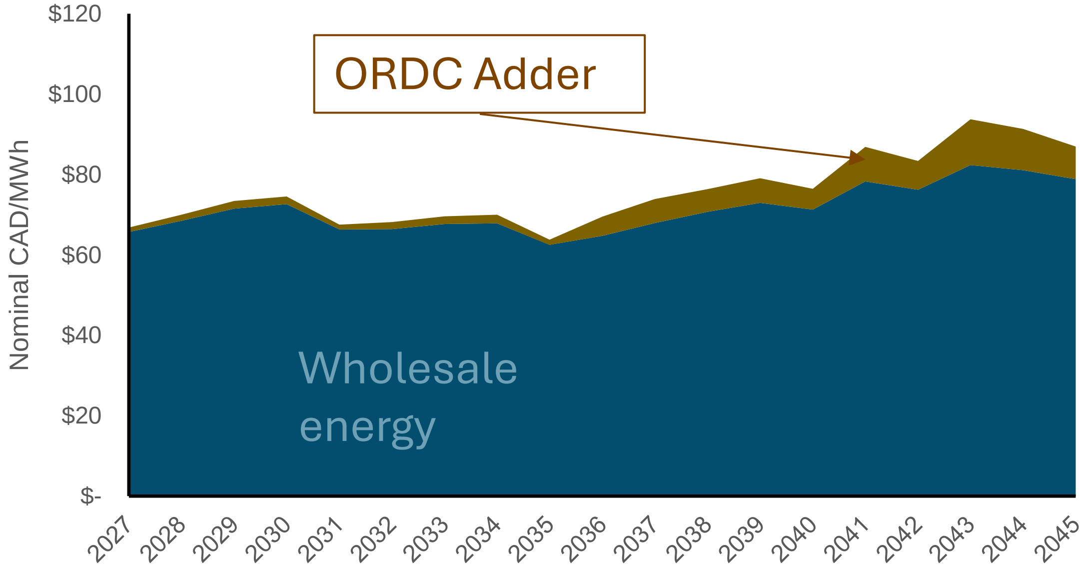
+ E3 tested both Stepped and Smooth ORDC adders

- The Stepped ORDC is increased as DAC, R10/R60 are depleted
- The Smooth ORDC is based on the size of day-ahead wind/solar/load forecast error, and the corresponding loss of load probability for a given level of supply cushion and value of lost load
- The adders are similar until the market begins to experience tightness and increased forecast error post 2035. The Smooth ORDC provides more revenues than stepped to generation present during tighter supply cushion hours

Smooth ORDC Adder



Stepped ORDC Adder

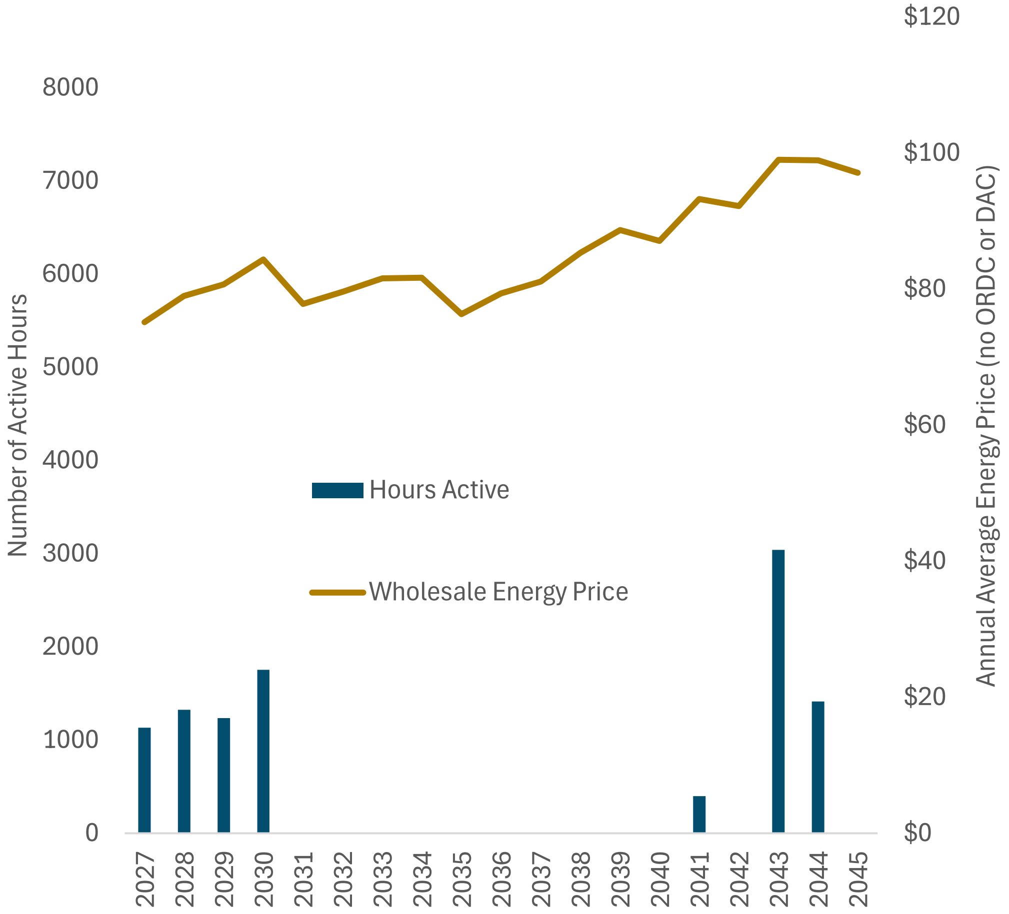


Market Power Mitigation (MPM) Does Not Trigger in a Normal Weather Year

- **MPM does not impact annual market prices under normal conditions**
  - Under normal conditions the trigger is not activated
- **MPM binds under the Severe Weather scenario**
  - The number of hours in which the mitigation trigger is active ranges from zero to ~3000 hours in 2043
  - In the near term, severe weather results in the last ~1500 hours triggered from 2027-2030
  - The overall price impact from severe weather is minimal as not many hours clear above the secondary offer cap leading up to the October window
    - Under a $250/MWh secondary offer cap the number of mitigated hours ranges from 1-7 hours in years with a trigger, under $400/MWh it is binding in 1 hour
  - Annual average prices are marginally impacted by mitigation, only being reduced by a few cents per year

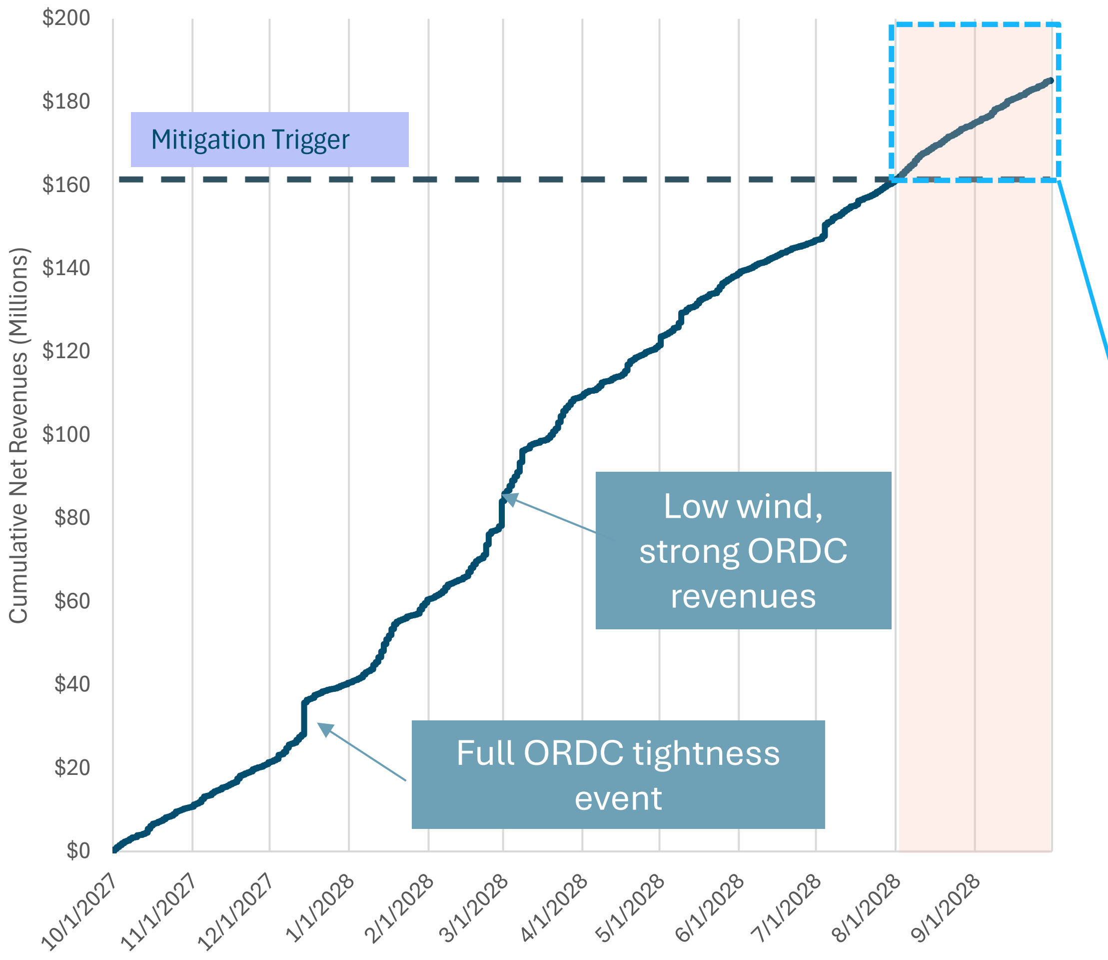
Results for Priced Interties Severe Weather scenario with $800 offer cap & $3000 price cap, 5% MSOC

Number of Trigger Hours in Severe Weather

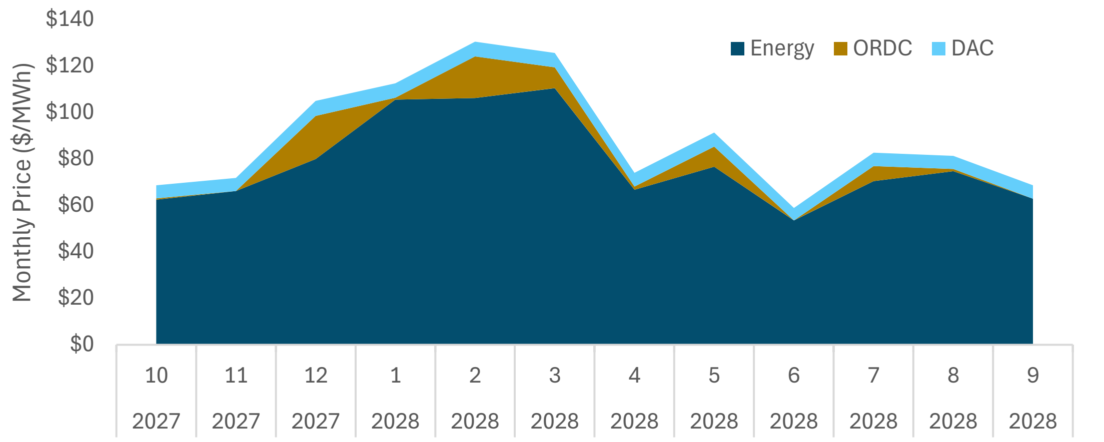


MPM Triggers in Late Summer, Remaining Season has Limited Volatility

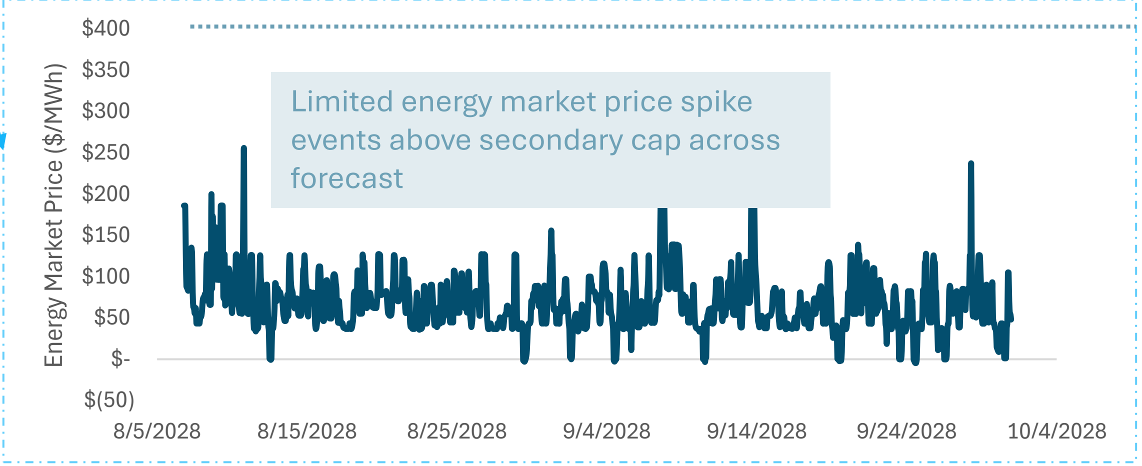
Cumulative Revenues (Under Severe Weather)



Monthly Revenue Profile



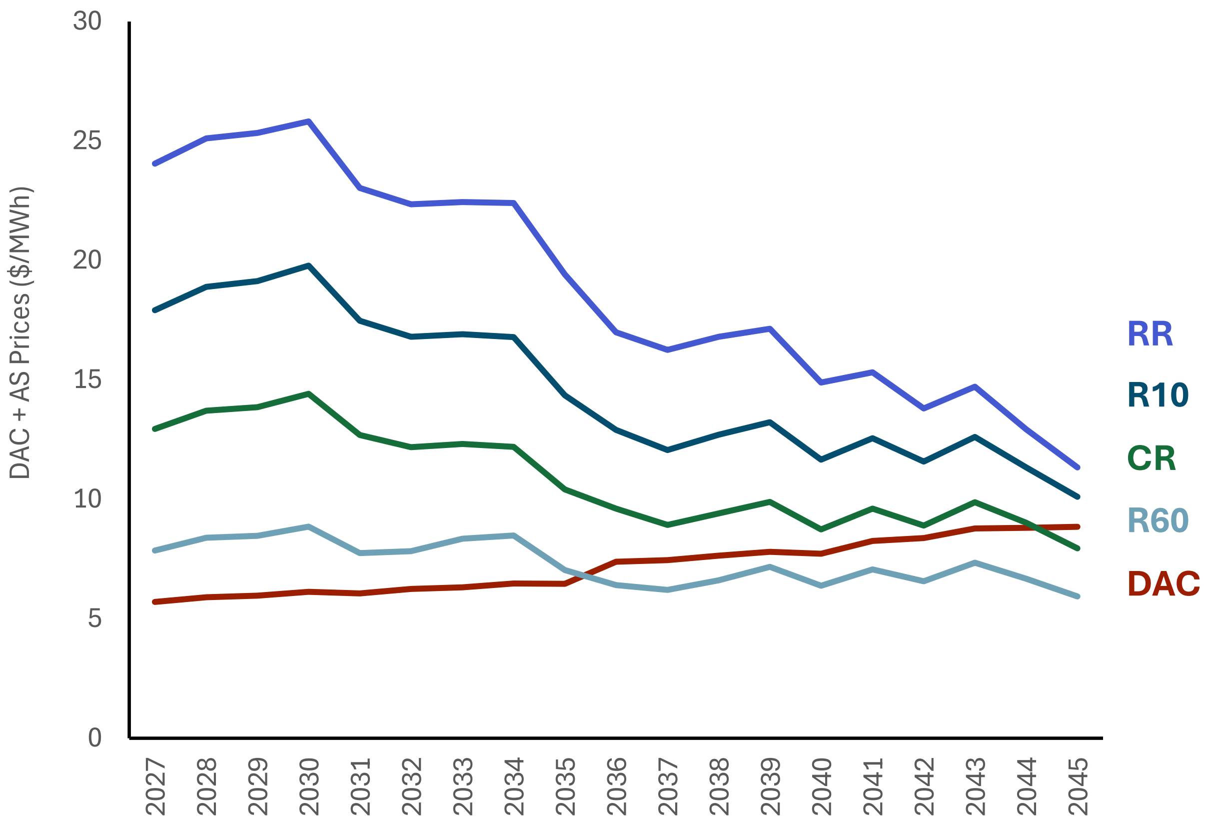
Energy Prices During Mitigation Window



Ancillary Prices are Saturated by Storage and Additional Generation

+ **E3 modelled the clearing prices of existing products (spinning, supplemental, regulating) plus the clearing prices of day-ahead commitment and ramping reserves (R10/R60)**
  - $100/MWh offer cap for all products except R60 ($80/MWh)
+ **AS prices are based on the opportunity costs of the assets providing them and incorporates saturation from storage and hydro**
  - E3 anticipates that energy storage, hydro, and thermal generation will saturate the AS market as products receive the ORDC adder clearing in the product provides that upside
  - Saturation creates decreases in price
+ **DAC is priced competitively as it has no opportunity costs (DAC participation does not prevent from offering other products)**

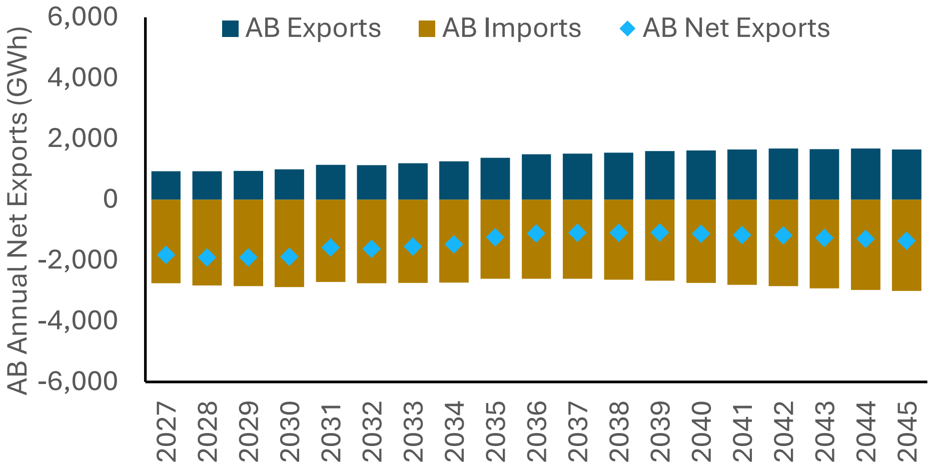
Annual Average Price by Ancillary Service [1]



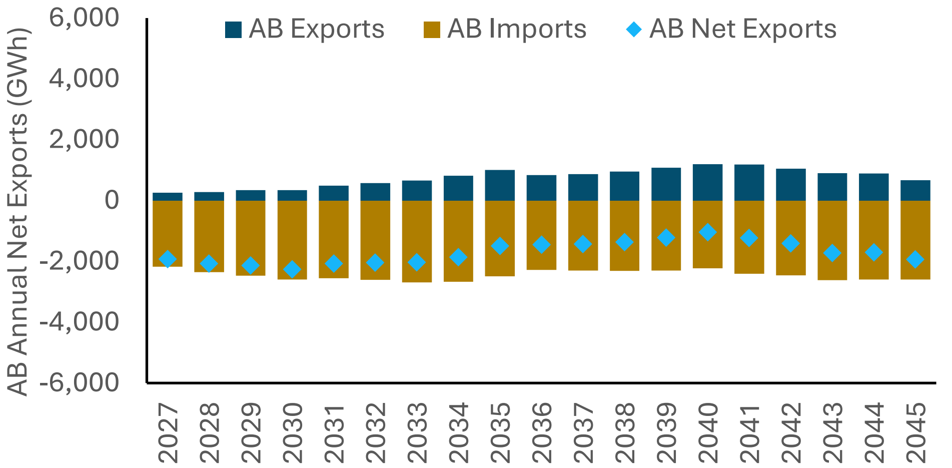
1. Cleared offer price (does not include ORDC adder) | PI381D

Alberta a Net Importer as Strategic Offers Keep Prices Above Short-run Marginal Costs, Priced Interties Impacts Balance

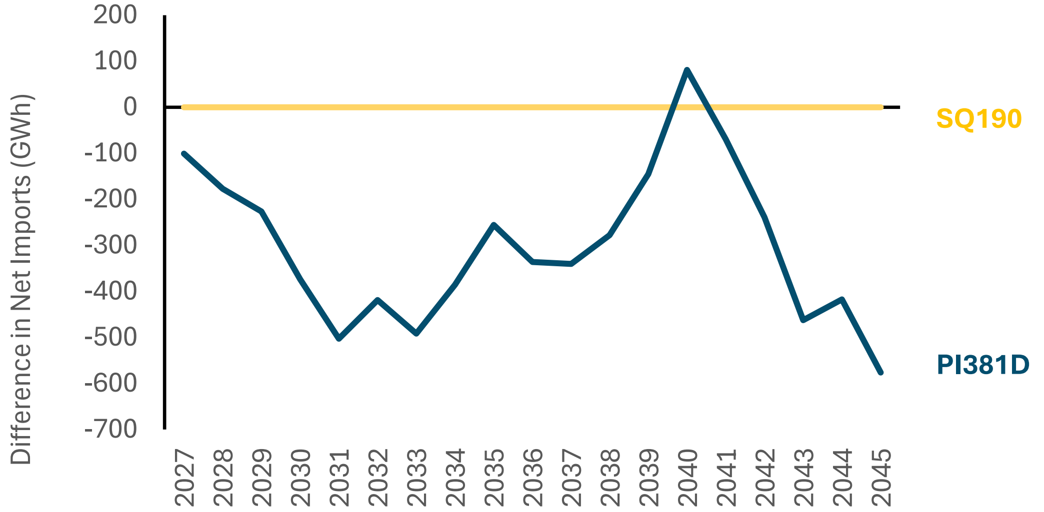
Status Quo (SQ190)



REM (PI381D)



PI381D difference relative to SQ190



1. MATL, BC, & Sask Interties modeled with static and identical available transfer capacity (ATC) in all scenarios – BC: 450 MW of Imports, 950 MW of exports, MATL: 250 MW of Imports, 300 MW of Exports, Sask: 150 MW of Imports and Exports

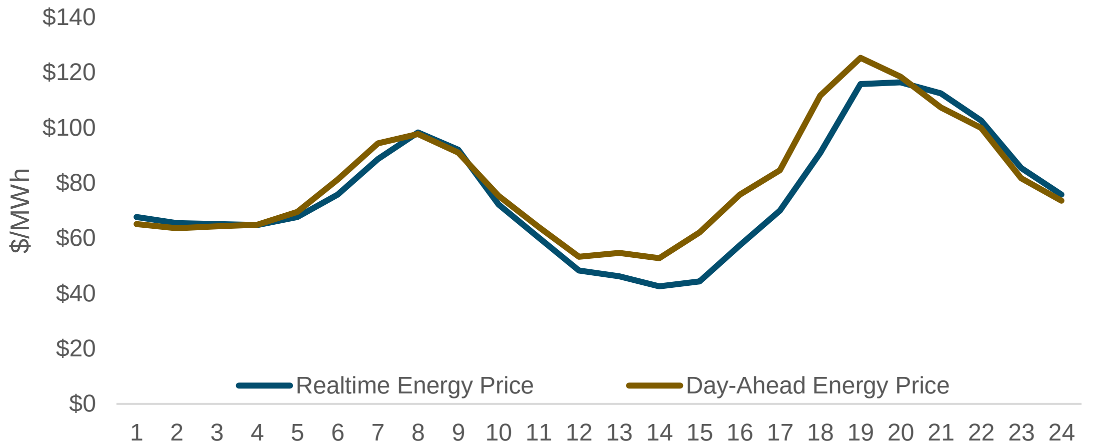
Priced Interties (PI381D) reduces uneconomic trade and reduces annual net export volumes relative to Status Quo (SQ190) by up to 500 GWh

Severe Weather (PI381D-SW) & Market Consolidation (PI381D-MC) sensitivities reduce net exports by an additional TWh per year

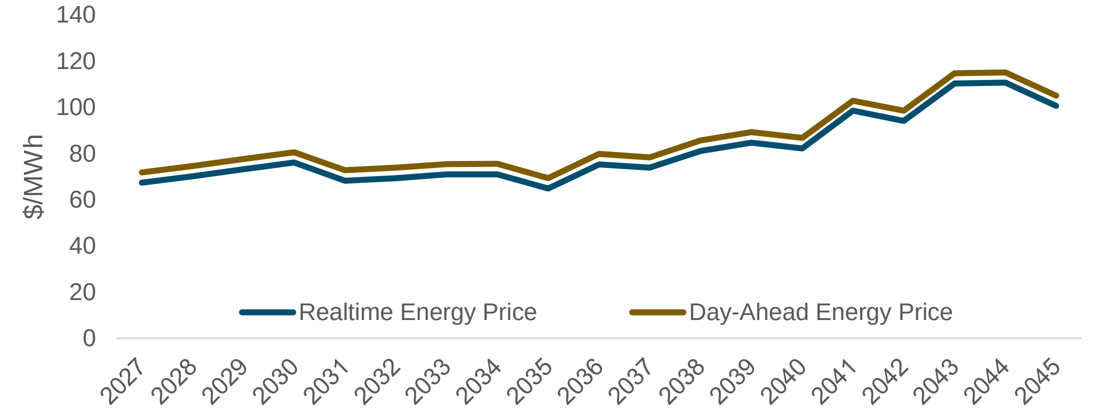
Real-Time Markets Trade at a Discount to Day-Ahead

- **E3 has used ERCOT as a proxy to estimate what the day-ahead premium could be in Alberta**
- **REM's financial DAM with a physical DAC, which is mandatory for supply but voluntary participation for loads, is not fully equivalent to other markets**
  - E3's utilized ERCOT data as supply mix and financial DAM characteristics have overlap
- **Day-ahead premiums are anticipated due to the risk aversion of loads and supply resources**
  - Real-time volatility is higher than day-ahead volatility
  - Loads that want to hedge their real-time risk historically will pay a premium to enter the day-ahead market
  - For generators to forego the upside of real-time volatility, they historically have charged a premium in the day-ahead market
  - Increased renewable penetration introduces more net demand variability in real-time contributing to the premium in day ahead

Day-ahead and Real-time Daily Shape in 2030



Annual Average Prices

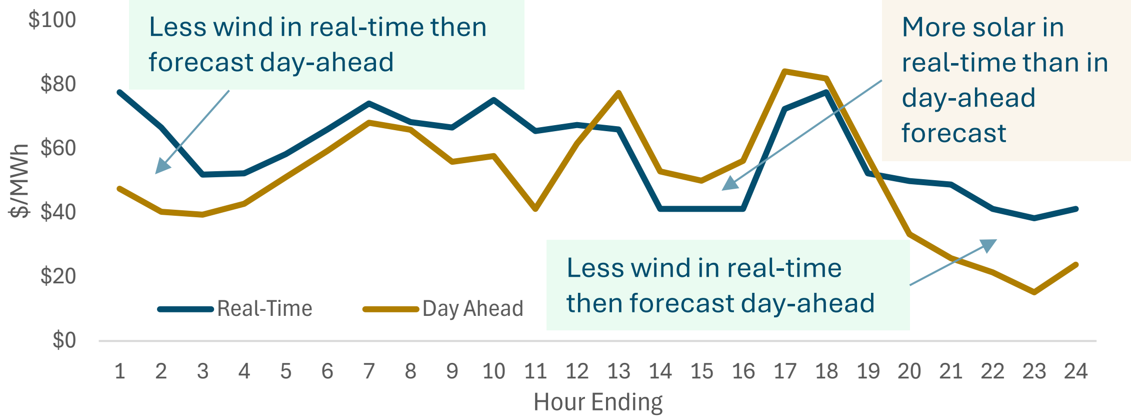


Results for Priced Interties scenario with $800 offer cap & $3000 price cap

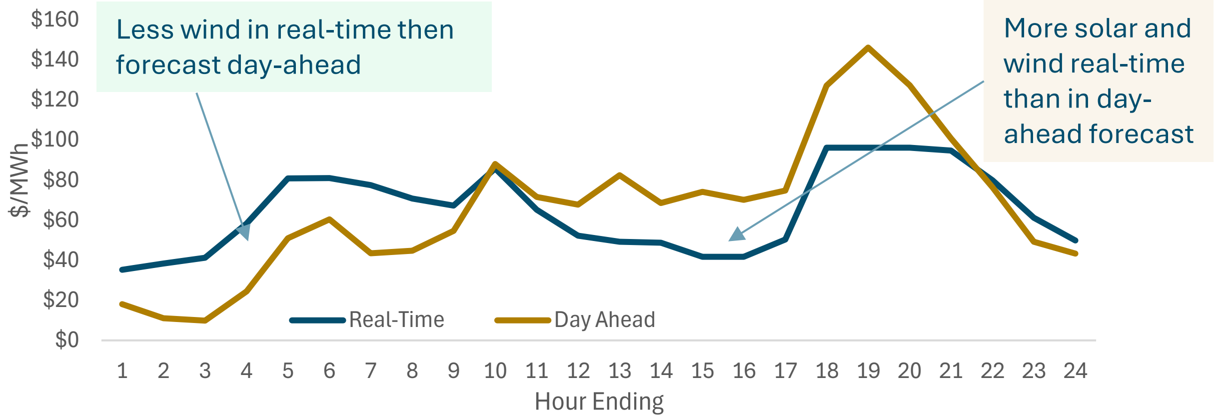
Forecast Error and Forced Outages Cause Day-ahead Real-time Basis

- **The factors that impact spreads between day-ahead prices and real-time are forecast error in wind, solar, load (load forecasts tend to be conservative), along with forced thermal outages**
  - Real-time markets are susceptible to large price spikes from forced outages that are not in the day-ahead forecast
  - This asymmetry in part motivates the day-ahead premium as loads benefit from not being exposed, and suppliers forgo that upside
- **High wind and solar penetration drive day-ahead (DA) real-time (RT) spreads**
- **August 21, 2027 forecast has a real-time premium of $8/MWh, while August 18, 2027 has a $1/MWh day-ahead premium**
  - Any given day the premium can be in the day-ahead or real-time market
  - Over the period of a year risk preferences converge to a consistent day-ahead premium

August 21, 2027 – DA RT Example (DA Discount)



August 18, 2027 – DA RT Example (DA Premium)

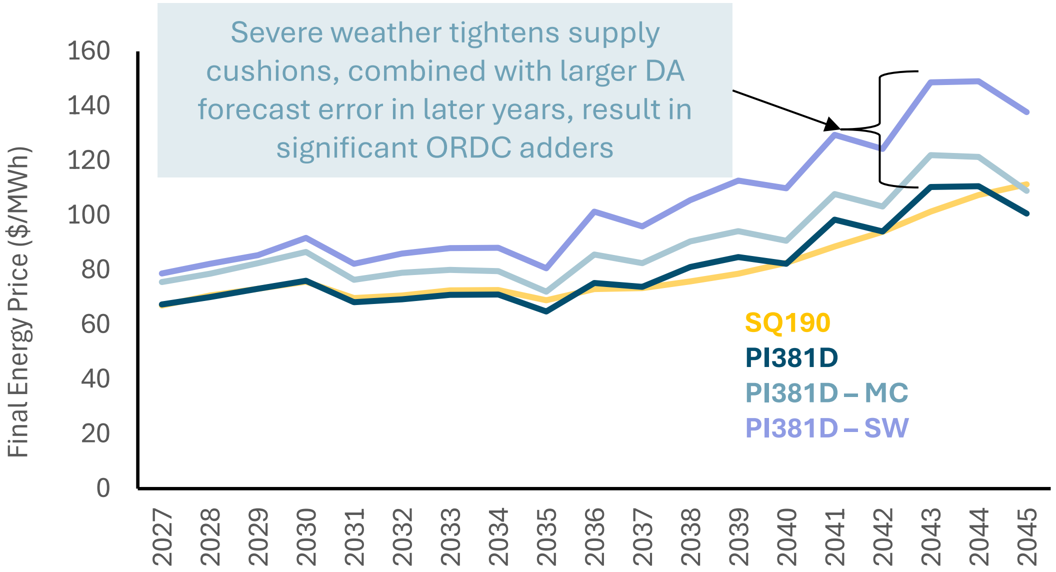


See: Zarnikau, Jay & Woo, Chi-Keung & Gillett, Carlos & Ho, Tony & Zhu, Shuangshuang & Leung, Eric. (2015). Day-ahead forward premiums in the Texas electricity market. The Journal of Energy Markets. The authors find that forecast error in renewables plays a large role in the premium. https://www.researchgate.net/publication/305192259_Day-ahead_forward_premiums_in_the_Texas_electricity_market

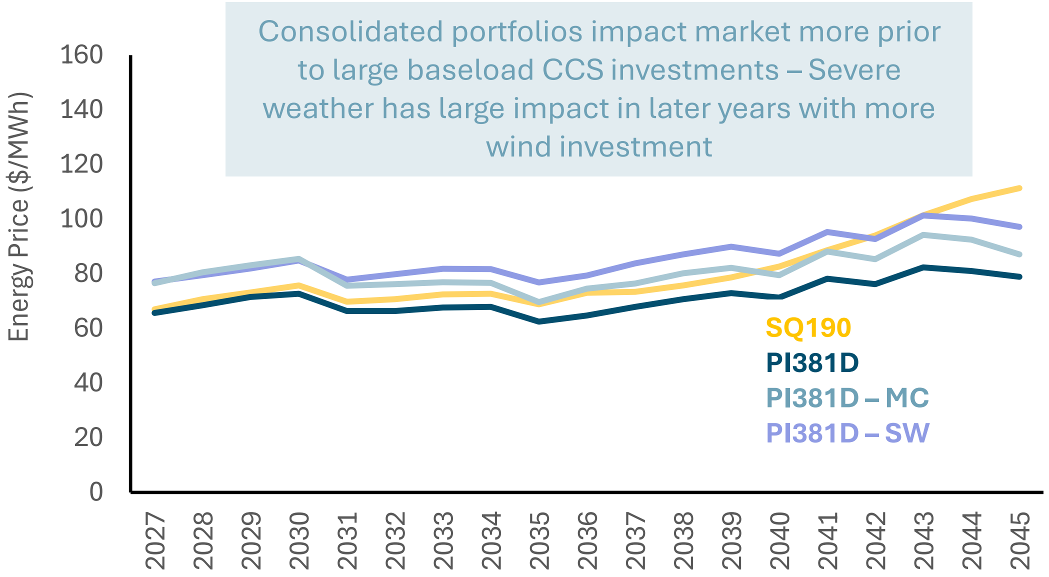
Energy Price Comparison – Sensitivity Analysis

+ **To better understand the impacts on total energy prices from changes in weather and future market participant portfolio sizes, E3 ran two sensitivities on the PI381D case**
  - Severe weather - PI381D-SW – tests a case where wind output is lowered by 10% (fleet weighted average capacity factor of 33% by 2045) and load is increased 3%
  - Market Consolidation – PI381-MC – is a scenario where all CCGT-CCS builds are by incumbents, and many new wind and solar investments are completed by incumbents, resulting in low residual supplier index (RSI) – a measure of market power – an input into the strategic offer model

Sensitivity Results With Mitigation + ORDC Adder



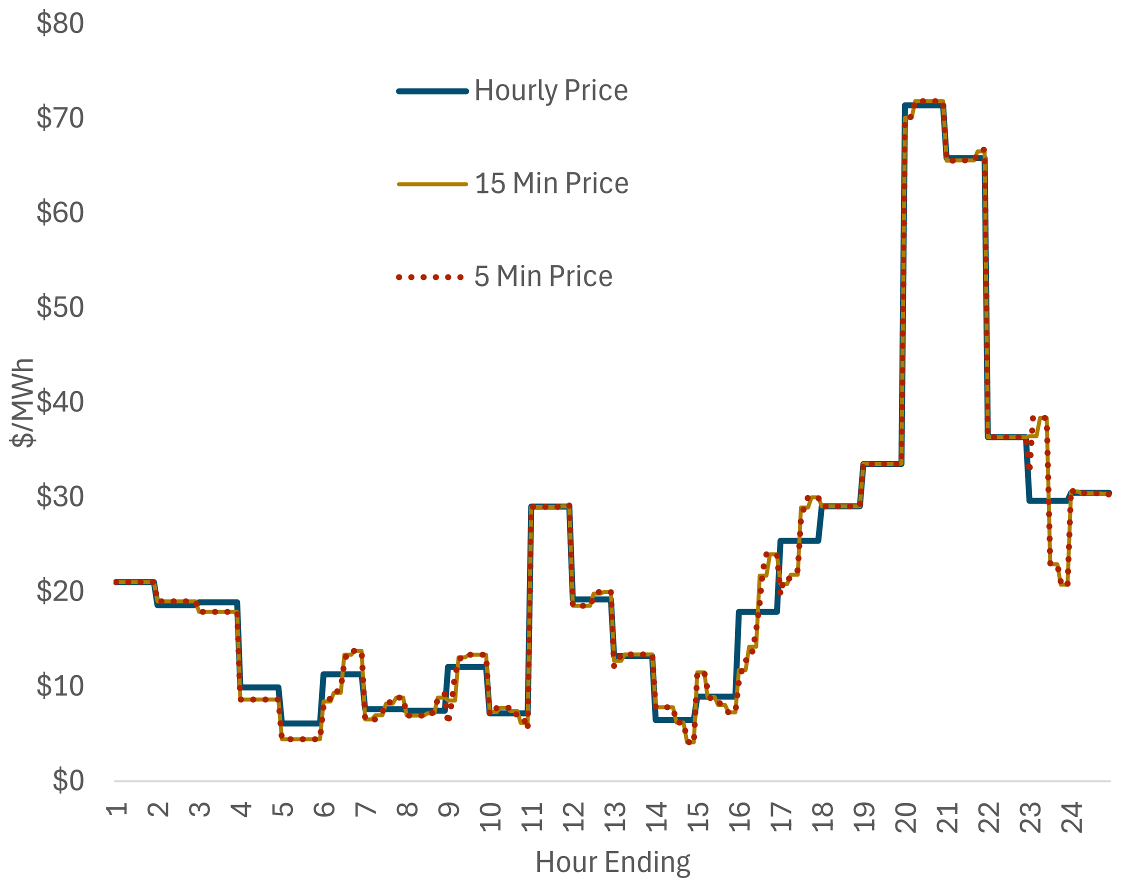
Sensitivity Results before ORDC & Mitigation



Opportunity Exists for Generators to Optimize at Shorter Settlement Intervals

- **E3 utilized historical SMP data to estimate a 5- and 15-minute settlement profile**
  - Shortened settlement profile resulted in a lower overall average price by $2.90/MWh for both 5-minute and 15-minute profiles
- **Energy storage and fast ramping CTs are likely able to increase revenues if they can respond on a 5/15 minute basis**
- **Incremental granularity results in more efficient pricing as fast acting resources (loads, storage, peakers) have larger incentive to respond**
- **Hours with large net demand variability can see substantial five and 15 minute swings around the hourly price**

Shortened Settlement Example



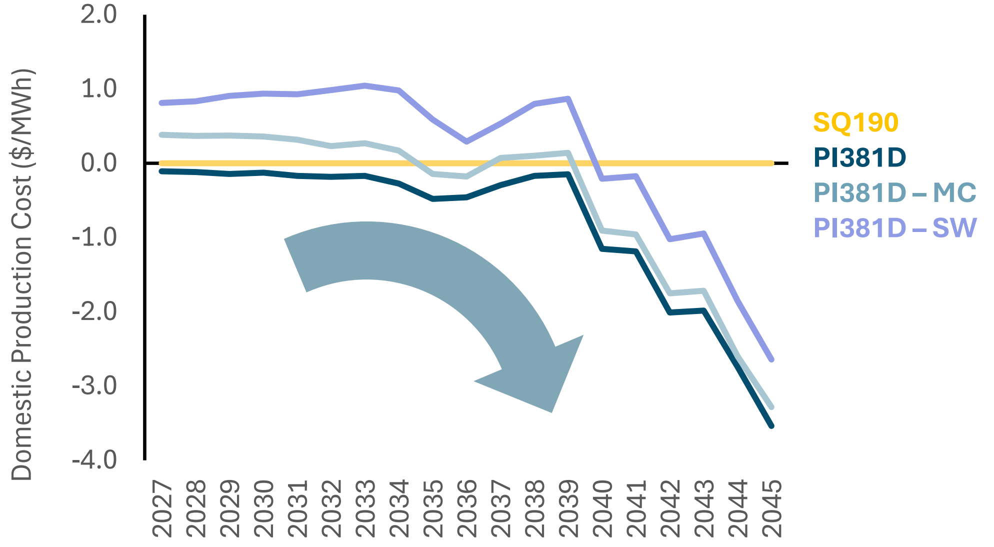
Results for Priced Interties scenario with $800 offer cap & $3000 price cap

REM Increases Overall Static Efficiency – Total Static Efficiency Impact

+ **E3 estimated the static efficiency (reduction in cost of production including price responsive loads) comparing the REM design against the status quo but with their different long run portfolios. The charts below include the impact from incremental investment under the REM scenario**

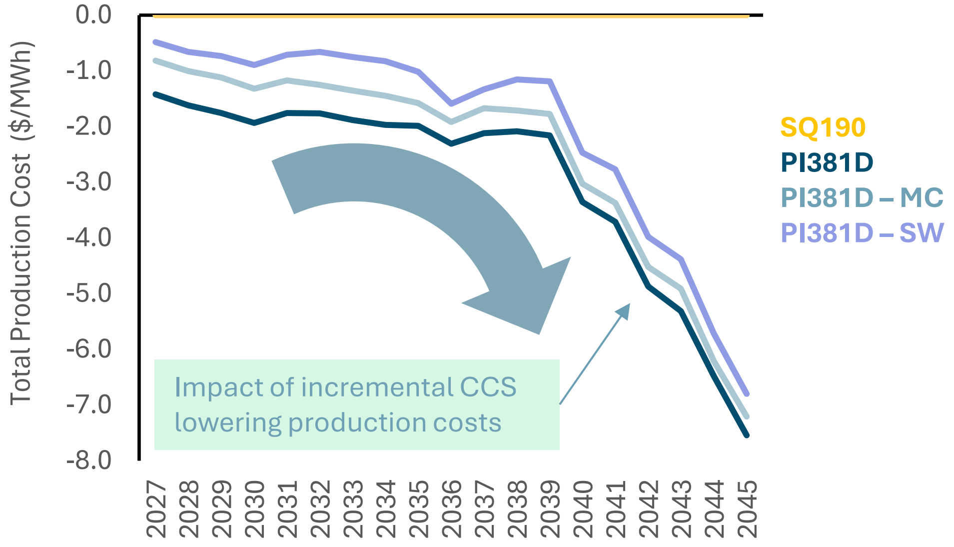
Builds and operational efficiency benefits from REM lowers base domestic production costs, trend holds consistent in Market Consolidation and Severe Weather sensitivities

Change in Domestic Production Cost
SQ and PI Scenarios | per MWh domestic generation



Total production cost benefits, including trade & border nodes, grow from ~$2/MWh in near term to ~$8/MWh in the mid 2040s

Change in Total Production Cost incl. Trade
SQ and PI Scenarios | per MWh domestic load

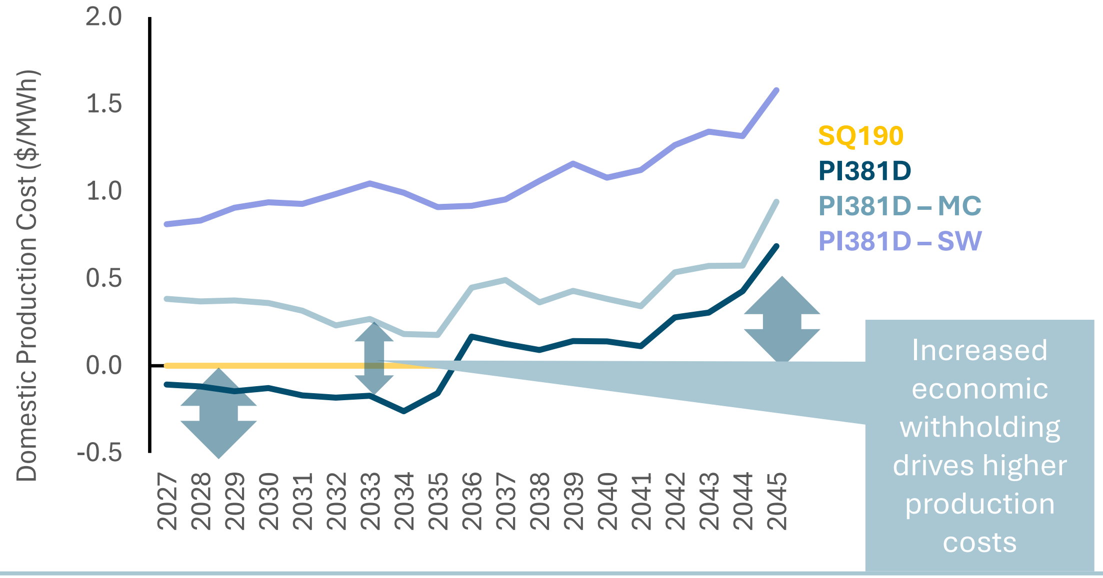


REM Increases Overall Static Efficiency – Impacts Domestic Dispatch Efficiency

+ **E3 estimated the static efficiency gains comparing the REM design against the status quo but with the same long run portfolios. These results highlight the impact of the change is dispatch/operational components from the change in REM components is this comparison does not include change in build**

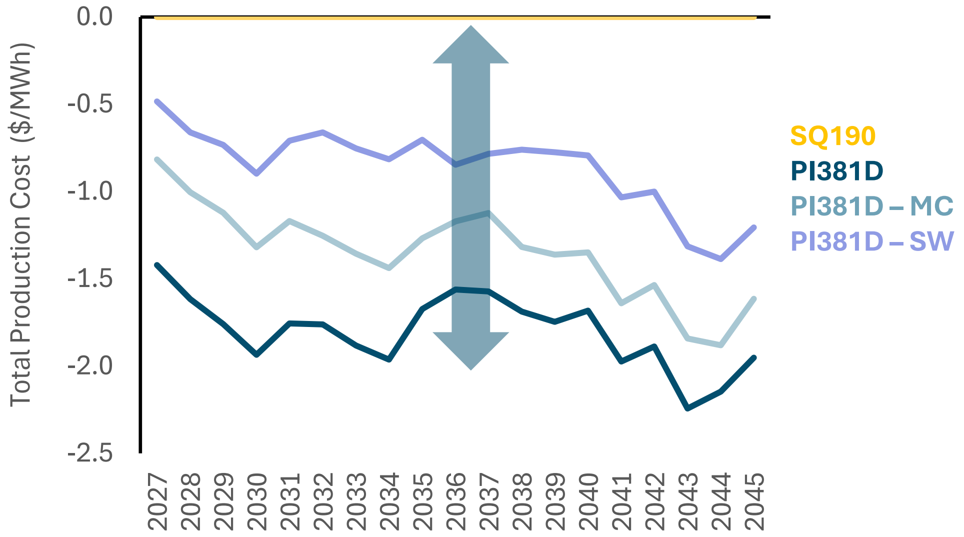
Priced Interties drives efficiency gains, whereas DAC drives additional unit commitment and R10/R60 volumes drive up domestic production cost

Change in Domestic Production Cost
SQ and PI Scenarios | per MWh domestic generation



Total production cost benefits, including trade & price nodes, stay flat at ~$2/MWh for the duration of the forecast

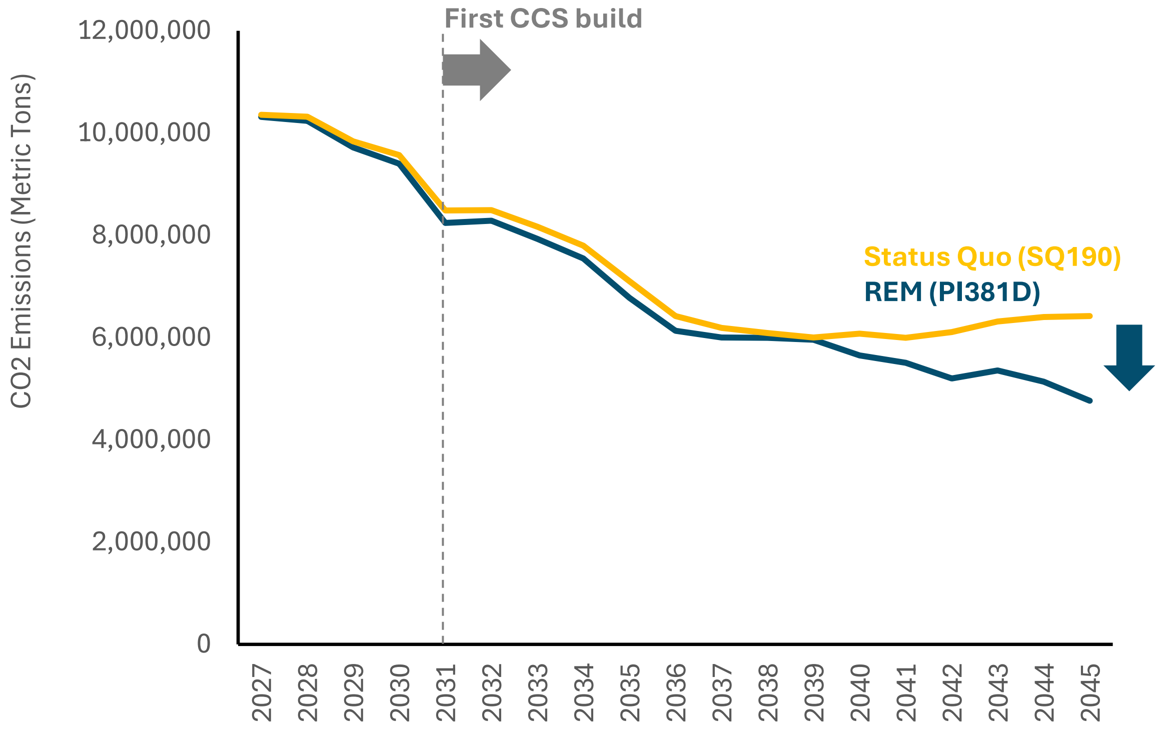
Change in Total Production Cost incl. Trade
SQ and PI Scenarios | per MWh domestic load



Additional CCS Build Under REM Lowers GHG Emissions

+ **Emissions reductions are driven by an evolving supply mix with increased wind, solar, CCS, and more efficient gas units**
+ **Lower emissions in PI381D driven by portfolio differences, primarily more CCS**
  - Additional unit commitment to meet DAC requirements does not create a net increase emissions given less wind but additional CCS, solar, and storage capacity under REM
+ **Emissions associated with power production from Cogeneration is not accounted for in the electricity sector's emissions**
+ **By 2045 PI381D reaches less than 5 MT of emissions**

Annual Power Sector Emissions[1]



Source: GoA: [Emissions Reduction Performance | Alberta.ca]

Scenario Design

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Scenario Design Overview

- **E3 designed the scenarios to help analyze the impacts of the AESO's proposed REM design on the Alberta electricity market**
  - E3 created a baseline scenario, which includes the current market rules, which projects a potential future under the current set of market rules (status quo)
  - E3 also created two main scenarios for REM market design
    - One with intertie trade using priced interties, one with the current intertie mechanics
- **E3 then ran severe weather and market consolidation scenarios on the REM design to test the potential effects**
  - Severe Weather: Low wind weather year with worse than average output, combined with higher average loads
  - Market Consolidation: Incumbent firms build the majority of new investment, E3's base assumption is that future investment comes from new entrants
- **E3 has endeavored to capture the most recent REM design elements directed by the AESO for testing – but the process is fluid, and some design elements may have differed by report release - E3 was able to incorporate REM material to Sprint 4/5**
  - Sprint 6 market power mitigation and other aspects incorporated in the update

Scenario & Inputs Overview

E3 modeled the status quo pricing under both builds to provide insights into the impact of REM

The matrix of scenarios identifies how each scenario will be referred to as shorthand in charts and throughout the report

Primary Results Shown

Design Feature	Value	SQ190	SQ381D	PI381D
Price Cap ($/MWh)	$3,000.00		X	X
Price Cap ($/MWh)	$1,000.00	X		
Price Floor ($/MWh)	$0.00	X		
Price Floor ($/MWh)	-$100.00		X	X
Offer Cap ($/MWh)	$800.00		X	X
Offer Cap ($/MWh)	$999.99	X		
Intertie Participation	Status Quo (SQ)	X	X	
Intertie Participation	Priced (PI)			X
ORDC	Stepped (T)			
ORDC	Smooth (S)		X	X
Reserves	R10/R60, DAC, CR, RR (D)		X	X
Reserves	CR, RR (C)	X		
Border Node	Yes (N)			X
Shortened Settlement	Yes		X	X
Mitigation	Yes		X	X
Build	REM Build	X (SQ190R)	X	X
Build	Status Quo	X (SQ190)		

Current Market Design

E3 also ran a sensitivity with **higher portfolio concentration** and a secondary **severe weather profile** to derive additional insights in the proposed market design

Model and Input Limitations

Deterministic Weather

- Model uses a single weather seed and is designed to assess market outcomes and not loss of load expectation
- Full range of reliability outcomes, revenues, and prices will be different across weather years. The weather sensitivity provides insight into this distribution
- Import/Export flows are heavily dependent on wind/solar/hydro resource in Alberta and across WECC
- **Implication:** Changes across scenarios are the most meaningful providing all-else-equal changes

Optimal Model Logic

- All production cost software are optimization engines that minimize total production cost
- Market events like intertie flows in the opposite direction of market prices are not possible
- Simplifying assumptions are required to capture the dynamics of intertie seams, and other operational aspects
- **Implication:** Directional conclusions about market design changes on intertie trade and operations are more significant than resulting values

Zonal Model

- E3 modeled the system without a transmission network
- Generator dispatch does not consider the impact of redispatch due to congestion
- Interchange congestion is modeled using WECC interchange and transmission ratings
- **Implication:** Domestic production costs do not incorporate the impacts of real-time congestion. modeling not quantify the efficiency losses from zonal pricing

Methodology

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Methodology

- Portfolio Build
- Intertie Participation
- Reserve Quantity
- Reserve Price Formation
- ORDC Estimation
- Market Power Mitigation
- Day-ahead and Realtime
- Sub-hourly Settlement

Introduction

This section is intended to detail how E3 has modelled each component of the REM design

Each part of the modelling process, and each market dynamic is separated by its own section

Long-term expansion Modeling

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E3 Model Ecosystem for Market Price Forecasts: Built on Decades of Experience and 360˚ Analysis

E3 Model Toolkit

Input Models

E3 PATHWAYS
Least-cost decarbonization pathways across sectors to meet GHG targets

E3 RESHAPE
Load simulation for building electrification & EVs

E3 Pro Forma Model
Levelized costs of new resources including financing and tax incentives

E3 RECAP
Stochastic reliability modeling for ELCCs of renewables and storage

Output Models

E3 RESTORE
Optimized battery operations and revenues

E3 Scarcity + RT Price Model
Forecasts scarcity and real-time energy prices with regression analysis

E3 Nodal Price Model
Node-zone basis forecast for nodal prices

E3 Ancillary Services Model
Forecasts AS prices with regression analysis and market saturation

E3 Capacity Market Models
Capacity price formation by market, aligned with unique market dynamics

E3 REC Market Models
Renewable Energy Credit prices aligned with unique market dynamics

Market Price Forecasting Approach

Scenario Variables

1 **Load Forecasts**
Regional load growth, energy efficiency, building electrification, and EVs

2 **Policies**
RPS, CES, GHG, other mandates

3 **Regional Coordination**
Transmission, Trading, and policy alignment

4 **Costs:**
- New resource costs
- Gas prices
- Carbon prices

PLEXOS Model Outputs

5 **Long-Term Capacity Expansion (Annual)**

New Resource Additions
- Economics
- Policies and mandates (RPS, CES, GHGs)
- System reliability needs
- Retirements

6 **Production Cost Simulation (Hourly)**

Energy Market Forecasts
- Hourly day-ahead energy prices by zone
- Dispatch, renewable curtailment, and transmission flows

E3 Forecasts

Market Product	Geographic Granularity	Temporal Granularity
Energy (Day-Ahead and Real-Time)	Zonal	Hourly
Capacity (low, medium, high forecasts)	System / Local	Annual
Ancillary Services (Reg, Spin, Non-Spin)	ISO	Hourly
ELCC Curves	Regional	Annual
RECs	State / ISO	Annual
System Operations	System / Local	Hourly / Monthly

Fundamentals-based market modeling built on day-ahead energy prices

Note: Forecasting methodology is tailored to each jurisdiction and market

Modeling Approach for Long-Run Resource Builds

Baseline Data
Current load, existing resources, planned retirements, Tx

Resource Buildout
Build out resources that are economic over time

Scenario-specific Assumptions
RPS policies, gas prices, load growth, technology costs, renewable shapes, etc.

Resource Revenues
Hourly output * market prices

System Dispatch
renewable curtailment, and transmission flows

Market Prices
Marginal cost of resources used in dispatch

For more details on the inputs to the Long-term Expansion (LTE) model see the detailed inputs section

Energy Market Price Forecasts

- Energy: RT adjusted for scarcity by hour
- Ancillary Services: Regulating, Spinning and Supplemental Reserves
- Resource Adequacy: Planning Reserve Margin
- Storage Revenues: Ancillary and Energy by hour

LT Model Details

+ The LT model contemplates the following (details in the assumptions sections):

- Load Forecast
- Existing and under construction generation
- Carbon pricing/TIER regime
- Renewables profiles
- Resource costs
- Forecast Gas and Hydrogen pricing
- Maximum cumulative and per year build constraints
  - Wind 300 MW
  - Solar 300 MW
  - Total wind 12 GW
- Forecast reserve requirements
- Intertie capacity

+ The LT model can choose the following technologies

- Solar
- Wind
- Battery Energy Storage Systems (BESS): two-hour, four-hour, six-hour, eight-hour
- Combined cycle natural gas
- Simple cycle AERO-Derivative
- Geothermal
- Combined Cycle with carbon capture and storge (CCS)
- Small Modular Nuclear Reactors
- Hydrogen Peaking

Strategic Offers

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Strategic Offer Behaviour – Model Implementation

- **Strategic offers are included as part of unit characteristics in the modelling process, allowing both trade and capacity expansion to take account of the economics**
  - Hourly asset level mark-ups are used to set price and dispatch

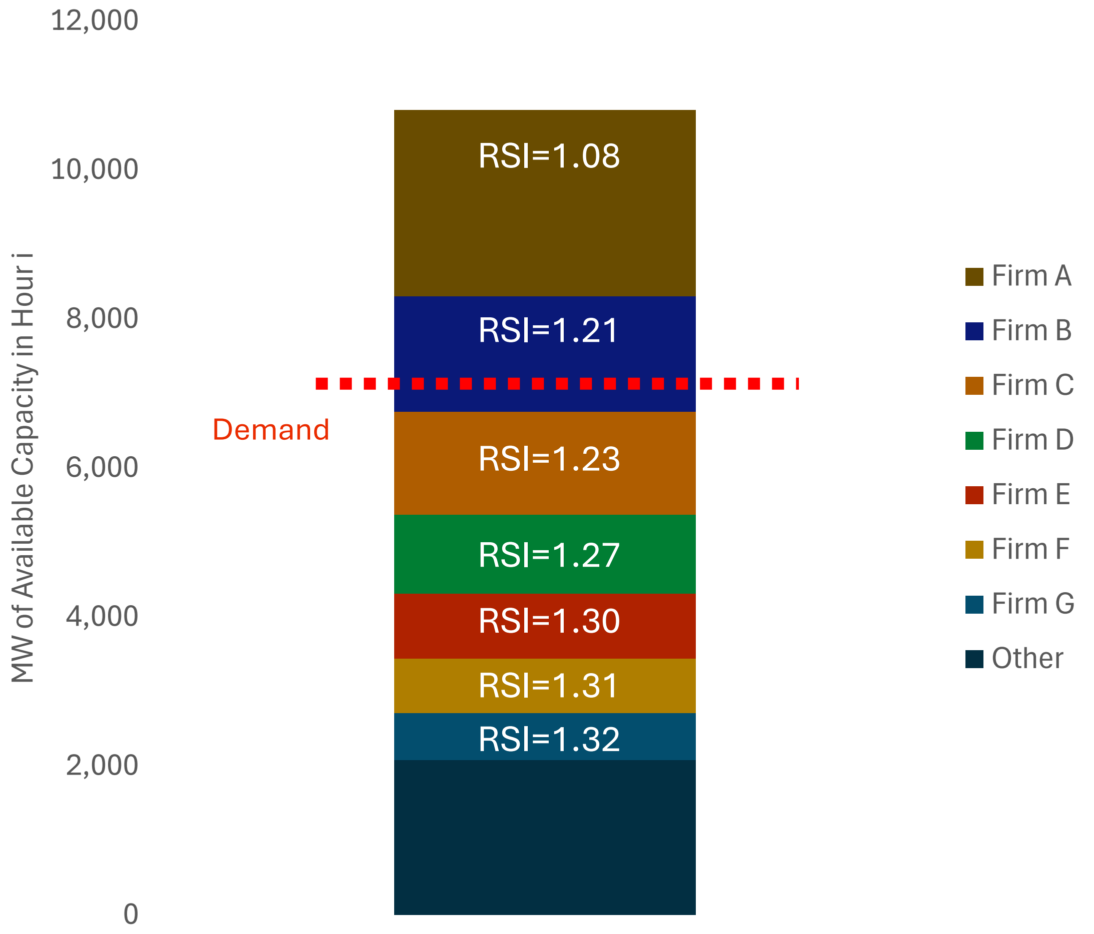
- **E3 has created a dynamic strategic offer model to estimate each firm's portfolio and residual supplier index (RSI) to generate strategic offers for each of their assets in each hour**
  - Initial hourly RSI is based off an initial naïve run – then the model is iterated to capture a final RSI measure

- **These offers are then utilized in the long-term expansion and short-term production cost model to ensure that strategic offers impact the build and short run dispatch**

Strategic Offer Behaviour – Residual Supplier Index

- **The Residual Supplier Index (RSI) is a measure of how pivotal a firm is in any given hour**
  - RSI asks the question – if this firm was removed from the merit order, could the market clear
- **RSI is therefore: (i is firm, j is hour)**
  - $RSI_{ij} = \frac{Total\ Market\ AC_i - Company\ AC_{ij}}{Market\ Demand_i}$
- **E3 took in merit order data from AESO's ETS system and calculated the Residual Supplier Index (RSI) in each hour, *for each firm***
- **Using this data, E3 then examined how each firms RSI impacted the offer blocks of each asset under their control**
  - An RSI of 1 or less indicates that an individual firm is pivotal

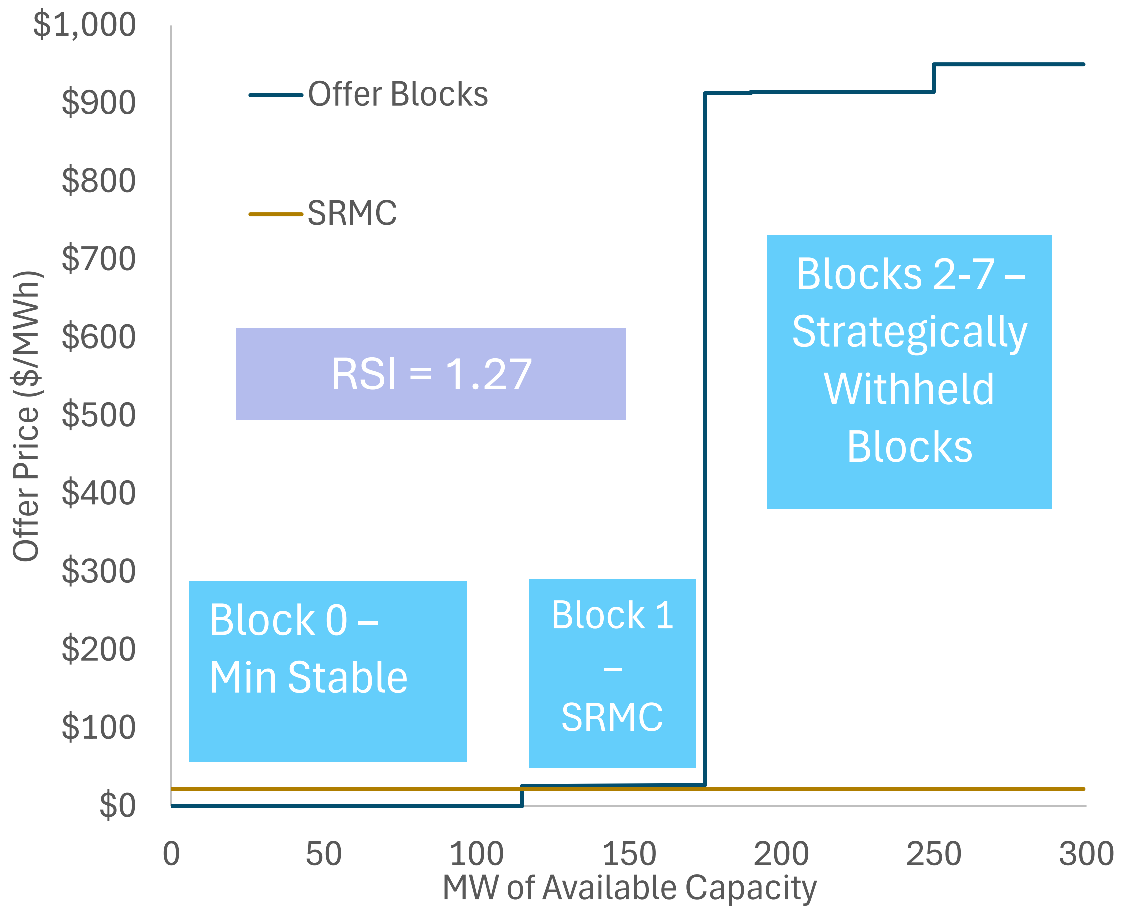
Firm level RSI Calculation – Illustrative Example



Strategic Offer Behaviour – Asset Level Markups

+ E3 took in merit order data from AESO's ETS system and calculated the Residual Supplier Index (RSI) in each hour, for each asset, *for each firm*
+ Using this data, E3 then examined how each firm's RSI impacted the offer blocks of each asset under their control
+ E3 estimated the unit's historic SRMC using historic gas price, unit heat rate, carbon pricing, and other cost data to understand what the markup on each block was for each hour, given the Firm's RSI
+ Using estimated SRMC in each hour, E3 estimated the markup on each block

Asset Markup Measurement – Historic Data Example

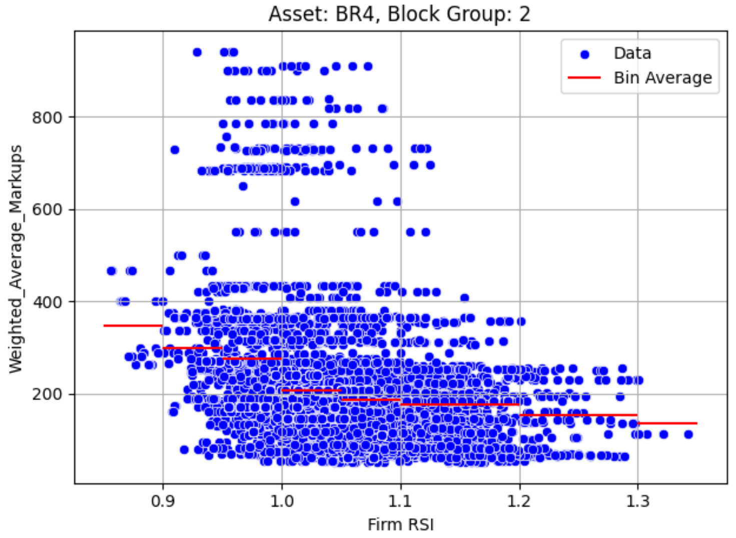


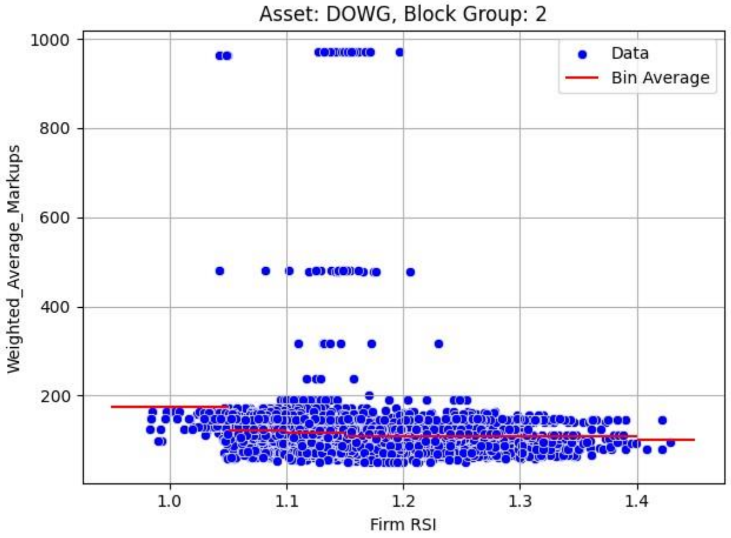
Strategic Offer Behaviour - RSI Markup Relationship

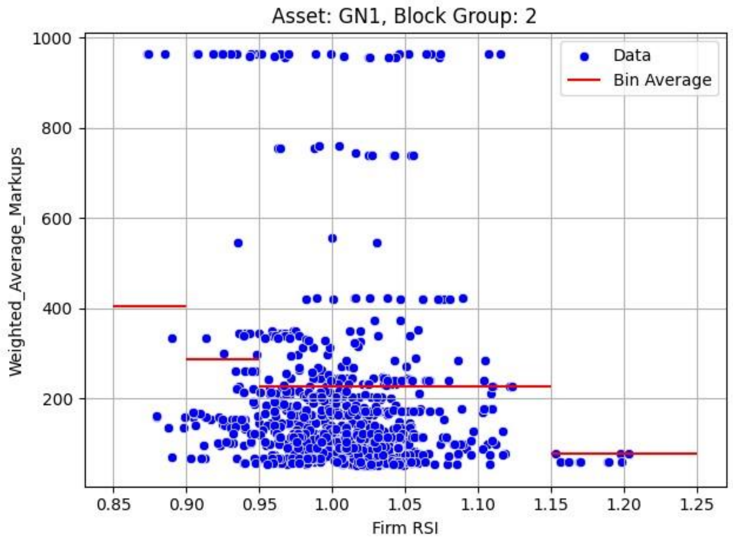
+ Using E3's estimated markup for each asset and corresponding Firm level RSI, the strategically withheld block is binned for a given level of RSI. Data used for this relationship was 2021-2023 reflecting current market structure – all hours used capturing a wide range of RSI for each firm

Offer Markup ($/MWh) vs Firm RSI

BR4 block 2-7	DOWG block 2-7	GN1 block 2-7





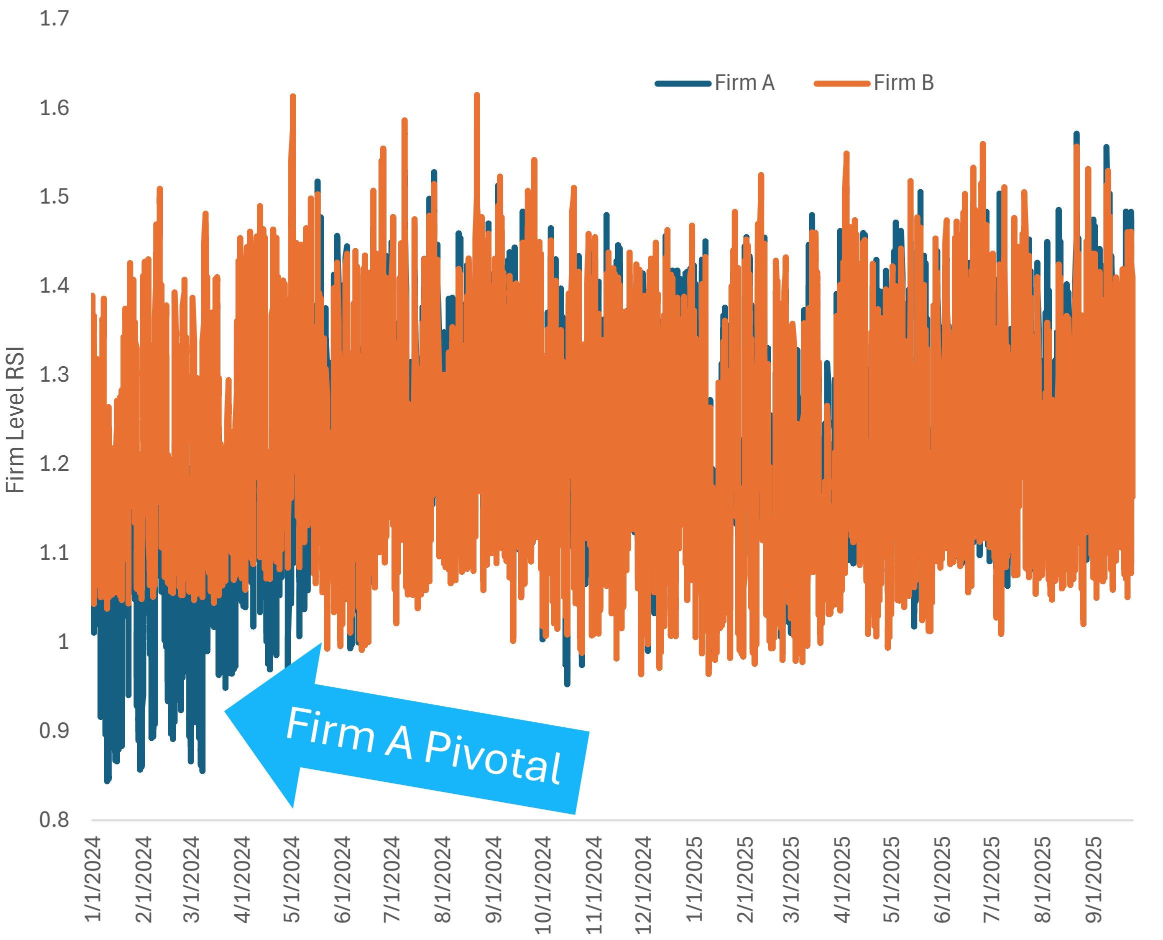


Opted for a binning approach to better match historic data and produce monotonically increasing results

Strategic Offer Behaviour – Withheld Block Forecast

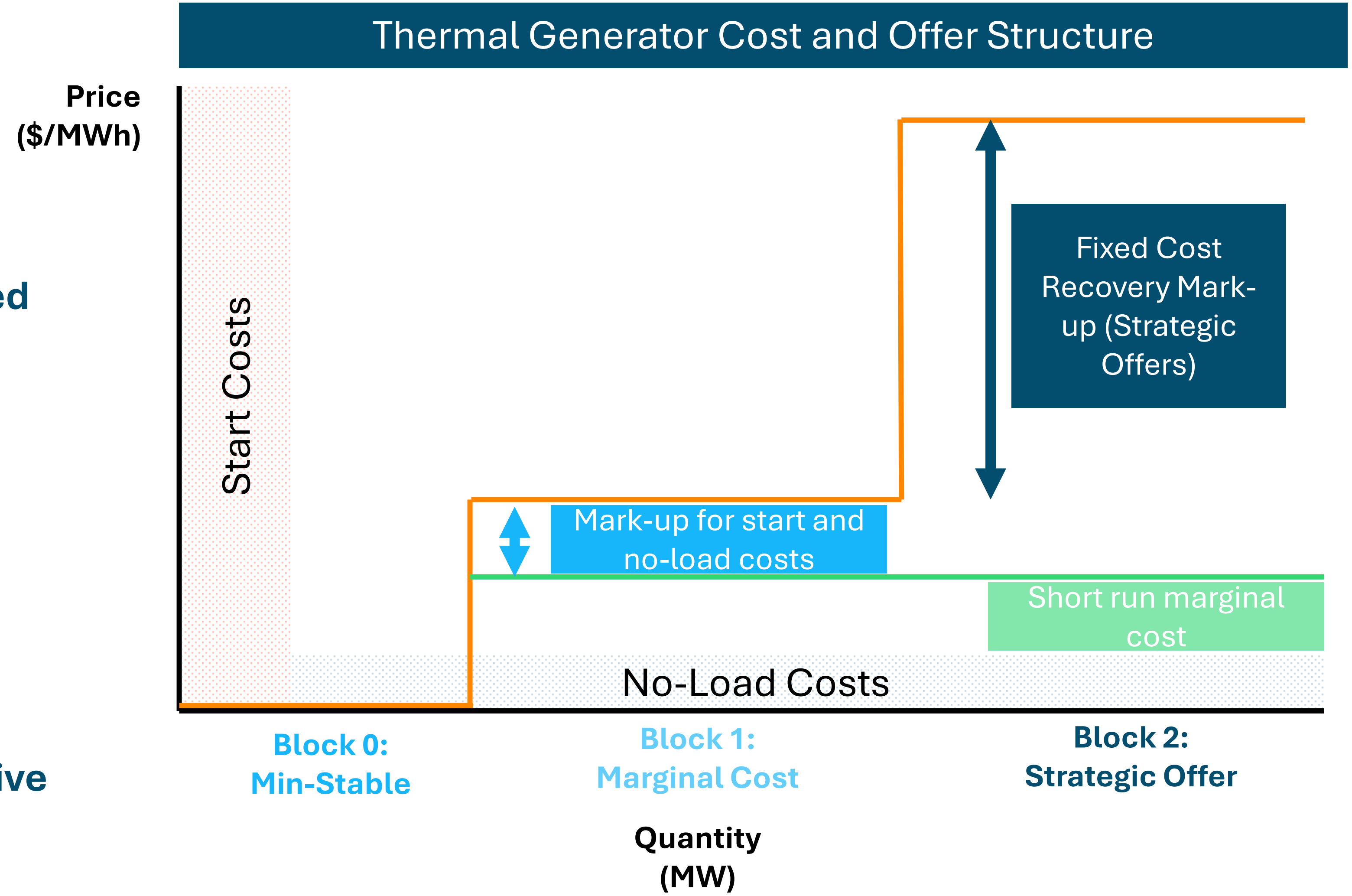
- To generate RSI measures for future hours, E3 ran a full forecast from 2024-2050 without any strategic offer behaviour (naïve run) – an additional run is completed with the strategic offer dispatch to generate the final RSI
- Plexos ST generates which units are committed and available, along with load – providing all variables required to forecast firm level RSI
- Mapping the available generators to our forecast of firm ownership, combined with demand, RSI for every hour for every firm is generated
- This data is then fed into our RSI – markup model to generate the dynamic markups for each asset for each firm for each hour to be run in the scenarios with strategic offer control

Forward RSI Projection Example



Strategic Offer Behaviour: Generator Costs & Properties

- All Thermal generators have start cost, no-load, and heat rate assumptions that drive their costs
- Ramp rates are enforced on combined cycle and cogeneration
- All thermal generators have planned and forced maintenance assumptions
  - With time to repair assumptions
- Large thermals have minimum uptime, minimum down time assumptions
- Ambient air derates incorporated
- Carbon price, VO&M, gas price - drive short run marginal cost (SRMC)



Intertie Participation

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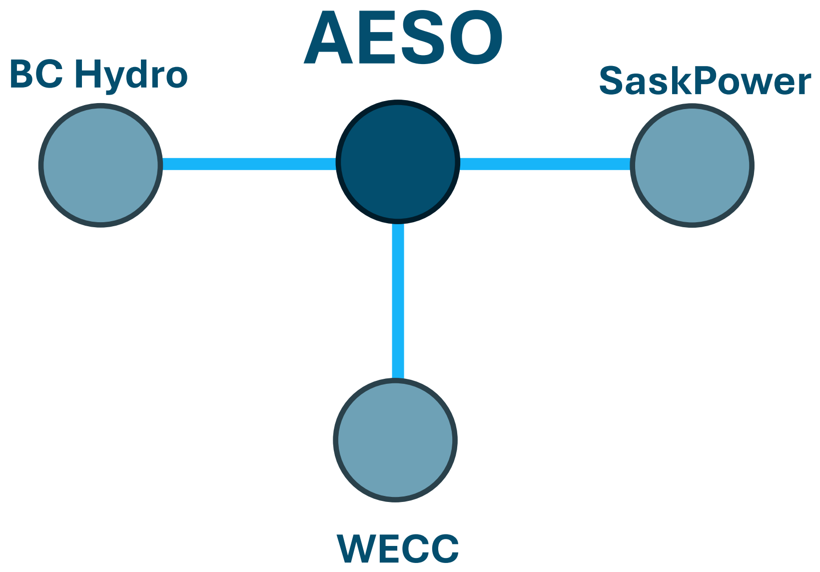
Overview of Interties and Trade

- **Trade between Alberta and neighbours impact price formation, production efficiency, and total system costs**
  - Market frictions and physical constraints to trade are modeled hourly across the full forecast horizon
- **Components of REM which impact trade include:**
  - Change from day-ahead quantity-only trade offers to priced offers
  - Introduction of border price nodes at each intertie
  - Introduction of DAC, ORDC, R10/60
  - Changes in price floor, price cap, and offer cap
  - Changes to generation portfolios and load in response to policy and market conditions

Common Model Topology Across Scenarios



Available transfer capacity (ATC) on each intertie is held constant across all model years and scenarios

WECC Model

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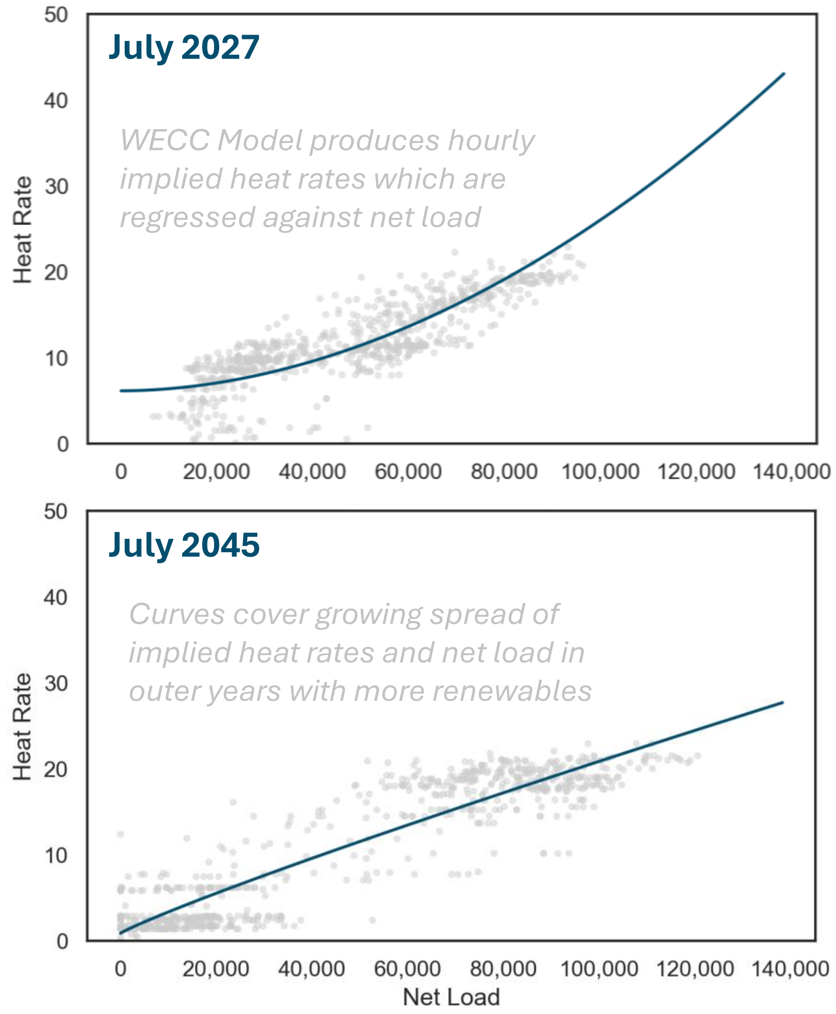
WECC Region: Interaction with AESO

- **E3 produces price forecasts for the entire WECC model including Alberta, the Pacific Northwest (PNW), California, and the Desert Southwest**
  - E3 leveraged the entire WECC model to interact with Alberta in this study
- **For WECC and British Columbia (BC), E3 created dynamic supply curves PNW for Alberta to trade with using the WECC model**
  - This supply curve is derived from the entire WECC model – E3 created monthly variable-heat-rate supply curves based on hourly price outcomes in the Bonneville Power Authority (BPA's) service territory as a function of WECC net load
  - This methodology allows us to run many iterations and many long-term expansions, while capturing the dynamics of WECC including hourly and seasonal weather, transmission, impact of BC's hydro fleet, and CAISO are captured in the supply curves, simplifying the runs

WECC Supply Curves Development



Status Quo

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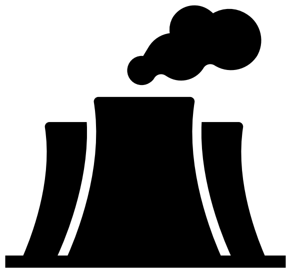
Status Quo AESO Imports from WECC – Illustrative Decision Making

WECC Scheduling Milestones:

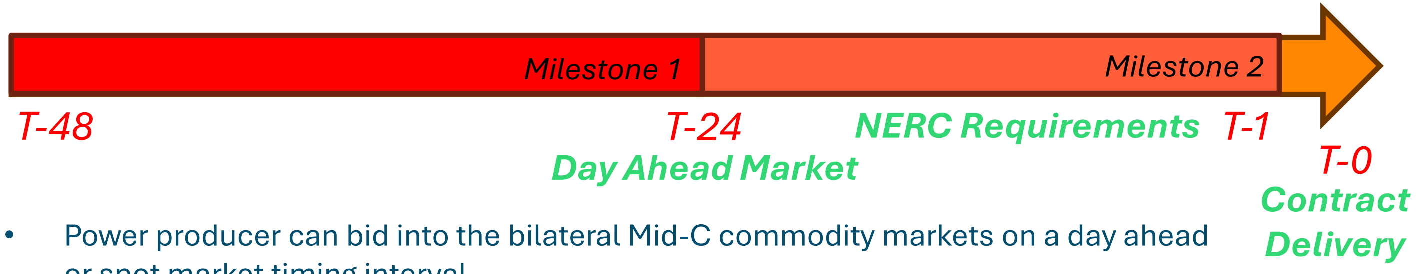
1. Mid-C trading opportunities reduce significantly at 9 am the day before delivery
2. NERC E-Tag policy requires trading details to be confirmed at least 1 hour before delivery



WECC Merchant Power Producer

Trading Options

Mid-C (WECC)



- Power producer can bid into the bilateral Mid-C commodity markets on a day ahead or spot market timing interval
- Power producer has likely decided bidding behavior in Mid-C at a day ahead interval
- Producer can submit **priced bids** into the Mid-C commodity markets
- Producer must secure transmission access to contract offtaker

AESO

Status Quo

- Power producer can bid into the AESO day-time market, but offers are not priced and **are subject to AESO scheduling rules**
- Given that offers are not priced, producer must essentially **make a bet** to determine **if AESO prices will yield a profit** in the delivery hour
- Producer must secure transmission access into AESO (MATL)
- At T-85 minutes, AESO determines if transfer limits may be exceeded and allocates transfer capacity to bidders

Proposed REM Day-ahead market closes at 10:30 MST the day before delivery

Status Quo Intertie: Scenario Explanation

- The current market rules for intertie transactions necessitates that exchange volumes are price takers as exports are set at $999.99/ megawatt hour (MWh) and imports are set at $0/MWh
- This allows Importers the flexibility to schedule volumes based on price forecasts in neighbouring markets
- Imports/exports are scheduled with the AESO at least two-hours prior to delivery
- Under the Status Quo, economic conditions of a trade are also difficult to examine as publicly available prices may not reflect realized prices. For example, Mid-C trading hub allows for bilateral trades which reduce the transparency of pricing as not all transactions are registered with the index
  - To capture the dynamics of this scenario – E3 utilized historic data on how Importers are scheduling imports
  - Because of the lack of real-time certainty, all trade was strictly modeled based on the historic offer curves, and not based on fundamentals within WECC of using E3's WECC model

	Description	Dynamics	Modeling
Status Quo	Import offers are scheduled two hours ahead on a volume basis, and entered merit order at $0/MWh	Importers do not have price certainty, and must only trade for sufficiently high expected margins	• Import and Export offer curves build based on historic data - not optimized to WECC fundamentals • Strategic offers in Alberta

Status Quo: Import Curve Design

Currently, imports/exports with AESO are not individually priced and offers are made based on volume.
Imports** are priced in the merit order at **$0/MWh
Exports** are priced in the merit order at **$999/MWh

This dynamic can be challenging to capture with traditional modeling practices. To overcome this, historical offer data was used to develop status quo scenario import/export curves…

Historical import/export data for each jurisdiction with associated AESO price

Data disaggregated using binning into average trade quantities based on AESO price in each month

Outlying data points smoothed to more effectively capture offer trends

Binned data meshed into monthly import/export curves as a function of AESO pool price

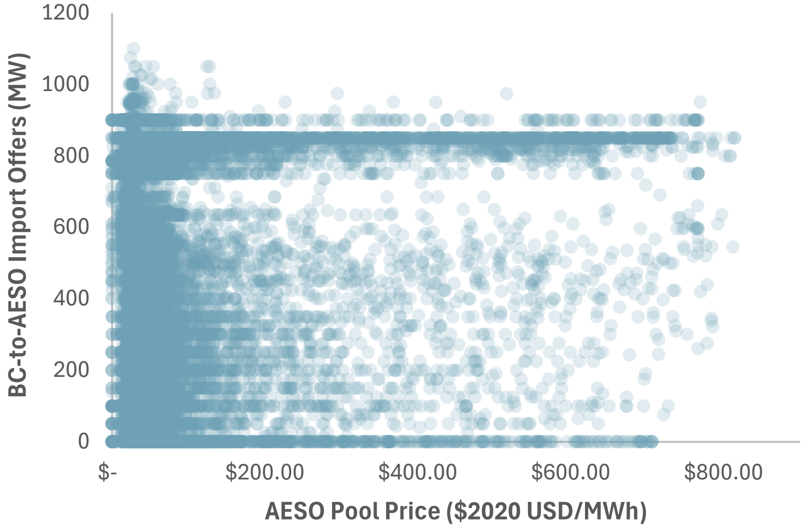
QA/QC process by comparing output curves to expected and observed import/export dynamics

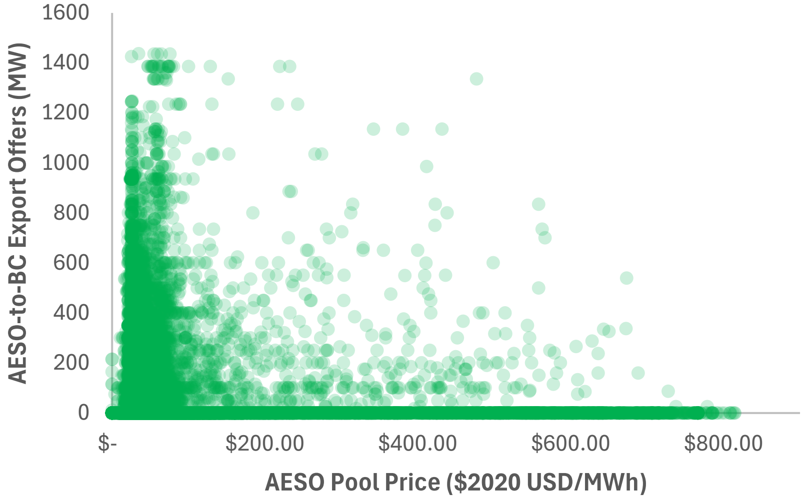
Finalized import/export curves produced by interpolating between data bins to reduce supply shock effects

Status Quo: Import/Export Curve Methodology

- **Currently, imports/exports with AESO are not individually priced and offers are made on volume**
  - All imports are priced in the merit order at $0/MWh
  - All exports are priced in the merit order at $999/MWh
- **This results in some volumes of suboptimal trade as Importers take positions on the AESO price to determine the quantity to import or export**
- **Importers receive AESO price regardless of intertie congestion → due to market power markups, this results in high AESO prices and lots of imports**
- **Empirical historical data is used to develop import and export curves from BC, MATL, and SASK**
  - These dynamics would be challenging to capture in a model non-empirically
  - Deriving monthly import/export curves for each jurisdiction
- **Data sources:**
  - Imports: January 2018 through December 2022 import data
  - Exports: August 2023 through July 2024 export data
    - Exports are changing rapidly as renewables penetration increases, so recent data is heavily weighted

Data Disaggregation and Analysis





Data binning was used to breakdown the aggregate data into monthly average import/export quantities as a function of the AESO pool price ($2020USD/MWh)

Binning Variable	*Price*		Max Price	1000 *$/MWh*
Output Variable	*Import*		Min Price	0 *$/MWh*

Max of Bin -->

Month	0	25	50	100	150	200	250	300
1		121.70	291.17	562.07	598.17	680.81	783.47	660.65
2		408.07	403.57	404.85	519.28	522.05	552.61	632.32
3		313.87	290.37	562.56	550.77	673.62	526.61	636.00
4	470.08	236.20	409.62	528.90	553.21	585.67	601.00	619.06
5	624.69	548.33	441.43	446.01	484.53	544.91	565.40	598.81
6	644.56	567.27	478.06	653.99	614.18	661.13	605.91	600.17
7	719.00	421.62	308.85	473.26	554.00	548.50	544.28	609.61
8	134.34	383.08	179.06	267.71	351.42	438.50	534.23	393.28
9	287.00	49.00	66.30	222.85	241.95	325.12	363.08	209.64
10		32.32	68.17	140.36	215.85	329.46	259.93	191.66
11		105.90	164.81	278.82	404.42	459.85	580.12	334.56
12		43.42	125.86	178.91	223.31	181.76	192.01	154.28

Generally, expected trends were observed (i.e. higher imports at higher AESO prices, seasonality of hydro)

Building Import Curves

Binned data was used to build import/export curves for each month in each jurisdiction

BC Hydro

AESO Pool Price ($/MWh)

Month	0	25	50	100	150	200	250	300	350	400	450	500
1	122	122	291	562	624	687	783	846	870	870	870	870
2	404	408	439	469	519	550	580	632	719	750	771	771
3	314	314	344	563	593	674	674	674	674	674	674	674
4	236	236	410	529	565	601	637	669	669	669	669	669
5	441	548	573	597	622	647	671	696	720	736	736	736
6	478	567	598	654	685	716	747	778	809	840	850	850
7	309	422	467	512	557	602	647	692	737	782	827	850
8	134	383	441	499	557	614	672	730	788	829	829	829
9	49	49	96	223	270	325	372	419	495	542	591	614
10	32	32	76	140	216	329	373	416	460	503	547	554
11	106	106	165	279	404	463	580	638	696	754	803	803
12	43	43	126	184	243	301	359	418	476	535	593	744

Import Offer (MW)

Min monthly import

Average import at $25/MWh block

Max between block import and (monthly max - monthly min) / # of chunks + previous chunk import

goal is to create an offer curve that is always increasing with price but captures volatility of actual market

Max monthly import

Building Export Curves

- **Due to the introduction of negative pricing, export curves required additional extrapolation from historical data**
- **Assumption: trends observed in exports at low prices in historical data (i.e. approaching $0/MWh) will be reflected in negative pricing**
  - Historical minimum price = $0/MWh
  - New minimum price = -$100/MWh
- **Increasing renewable generation will result in more exports moving forward**

BC Hydro

Month	-100	-75	-50	-25	0	25	50
1	741.16	553.01	281.61	111.83	5.95	0.00	0.00
2	800.00	372.46	189.37	75.08	0.00	0.00	0.00
3	955.00	782.29	573.91	421.88	285.46	149.03	0.00
4	955.00	736.91	600.48	464.05	327.62	191.20	0.00
5	546.79	468.67	389.95	311.84	233.73	62.48	0.00
6	953.33	817.14	680.95	544.76	408.57	272.38	0.00
7	953.33	761.24	625.05	488.86	352.67	216.48	0.00
8	953.33	817.14	680.95	544.76	408.57	272.38	0.00
9	454.00	346.54	281.64	216.78	151.92	87.06	0.00
10	935.00	801.43	610.43	476.86	343.29	209.72	0.00
11	935.00	775.38	641.81	477.10	343.53	191.44	0.00
12	883.06	606.93	414.34	288.19	126.25	0.10	0.00

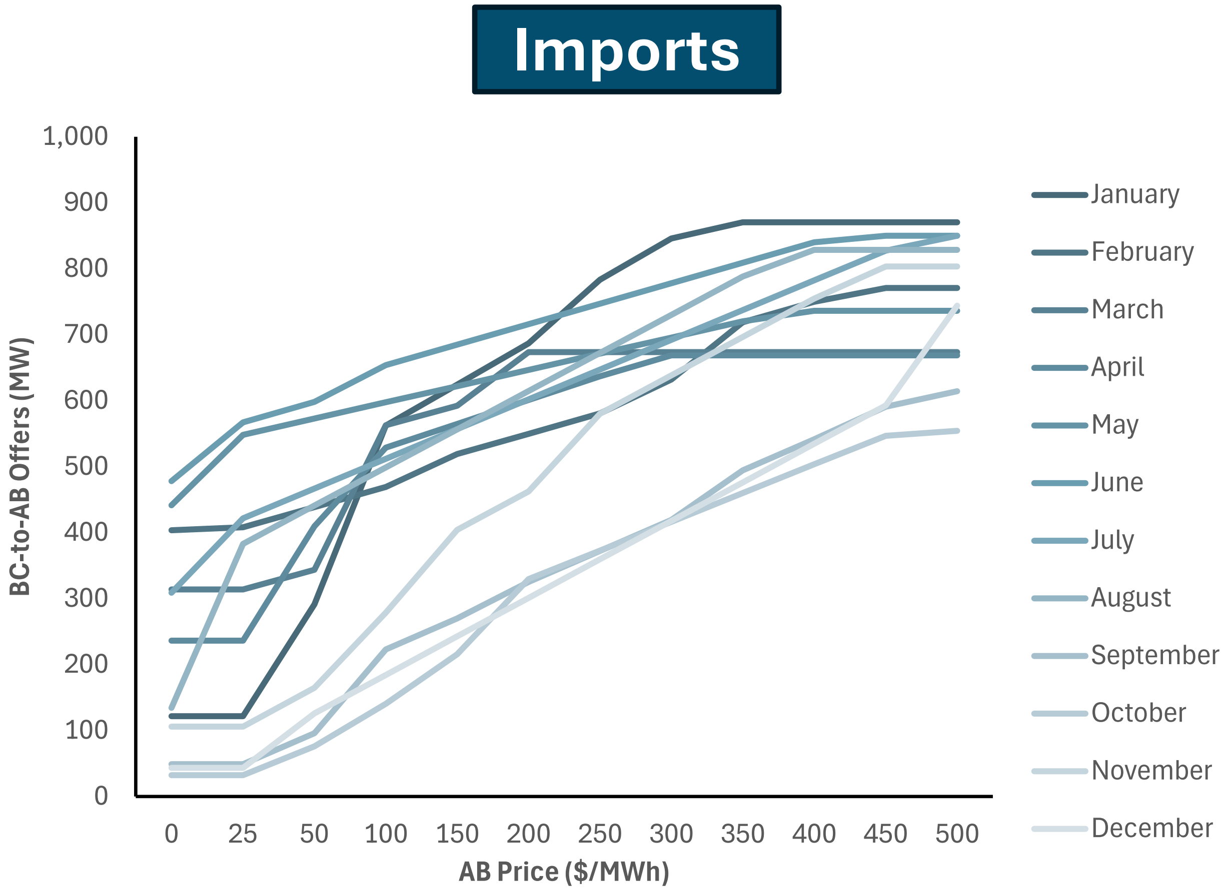
Max monthly export

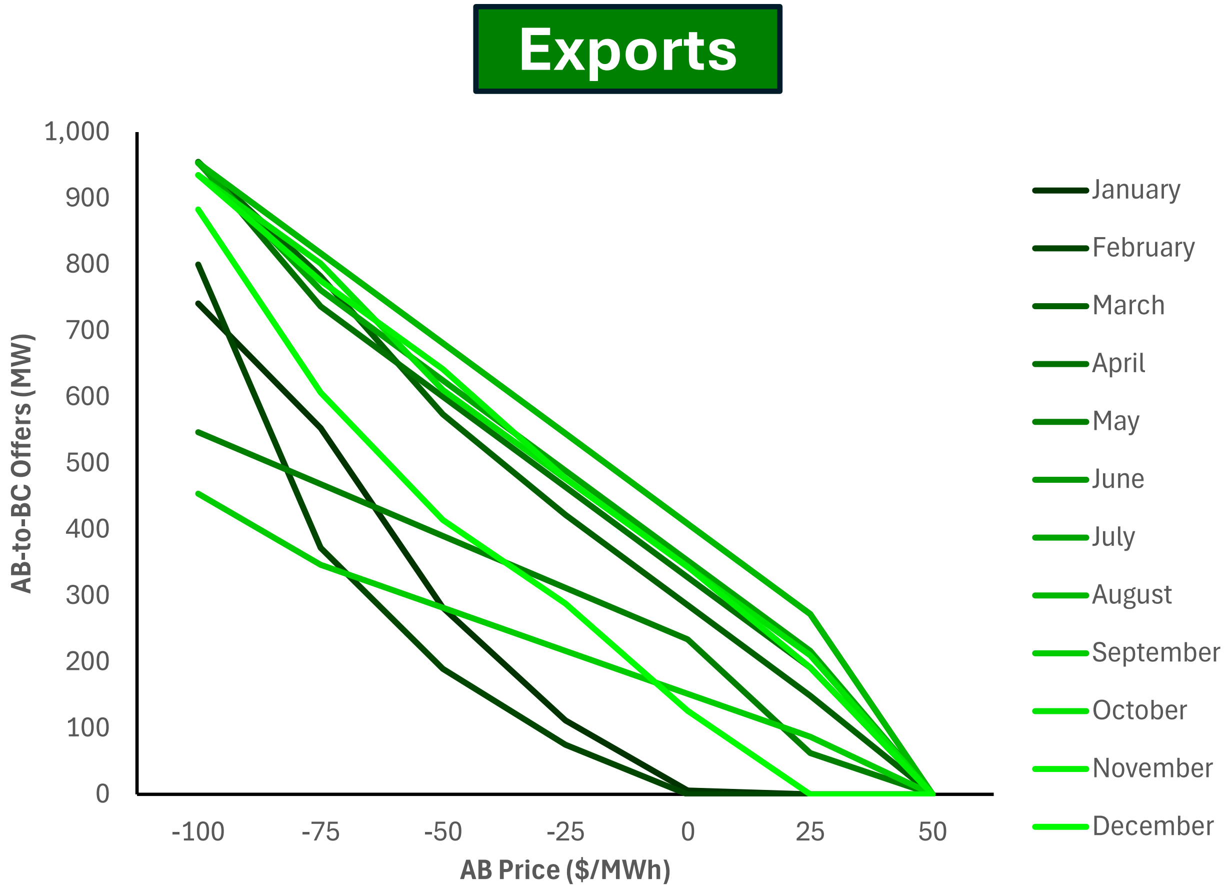
Change in export is maximum between (max monthly export - min monthly export)/# of chunks and comparable change in export data

goal is to create an offer curve that is always decreasing with price but captures volatility of actual market

Min monthly export

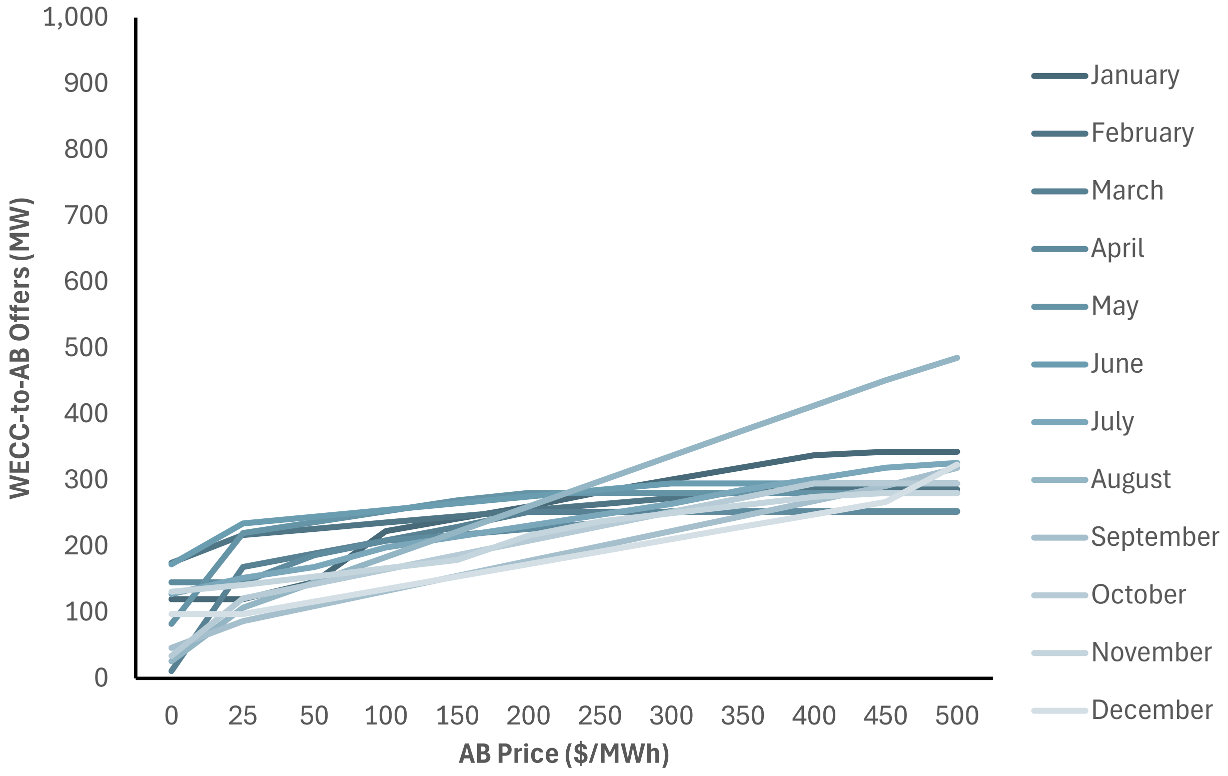
Historical Import/Export Curve Results: BC



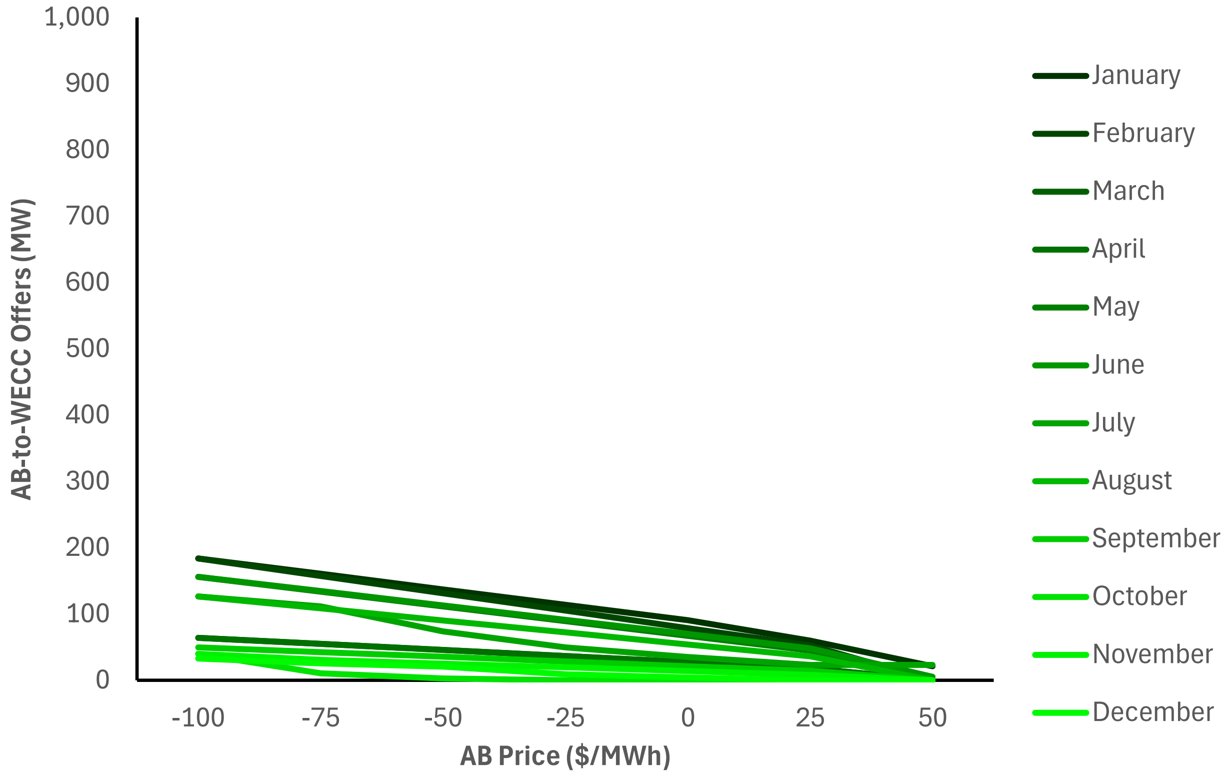


Historical Import/Export Curve Results: MATL

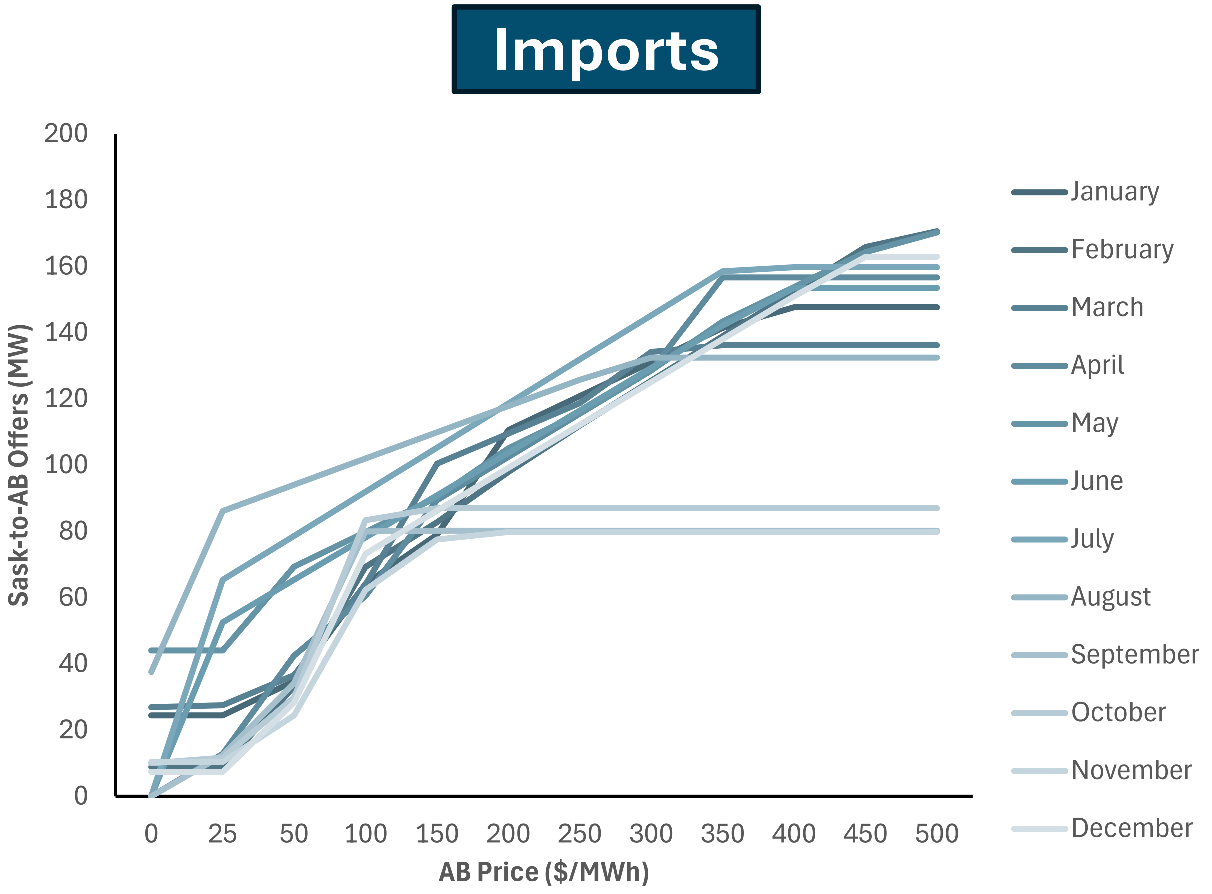
Imports

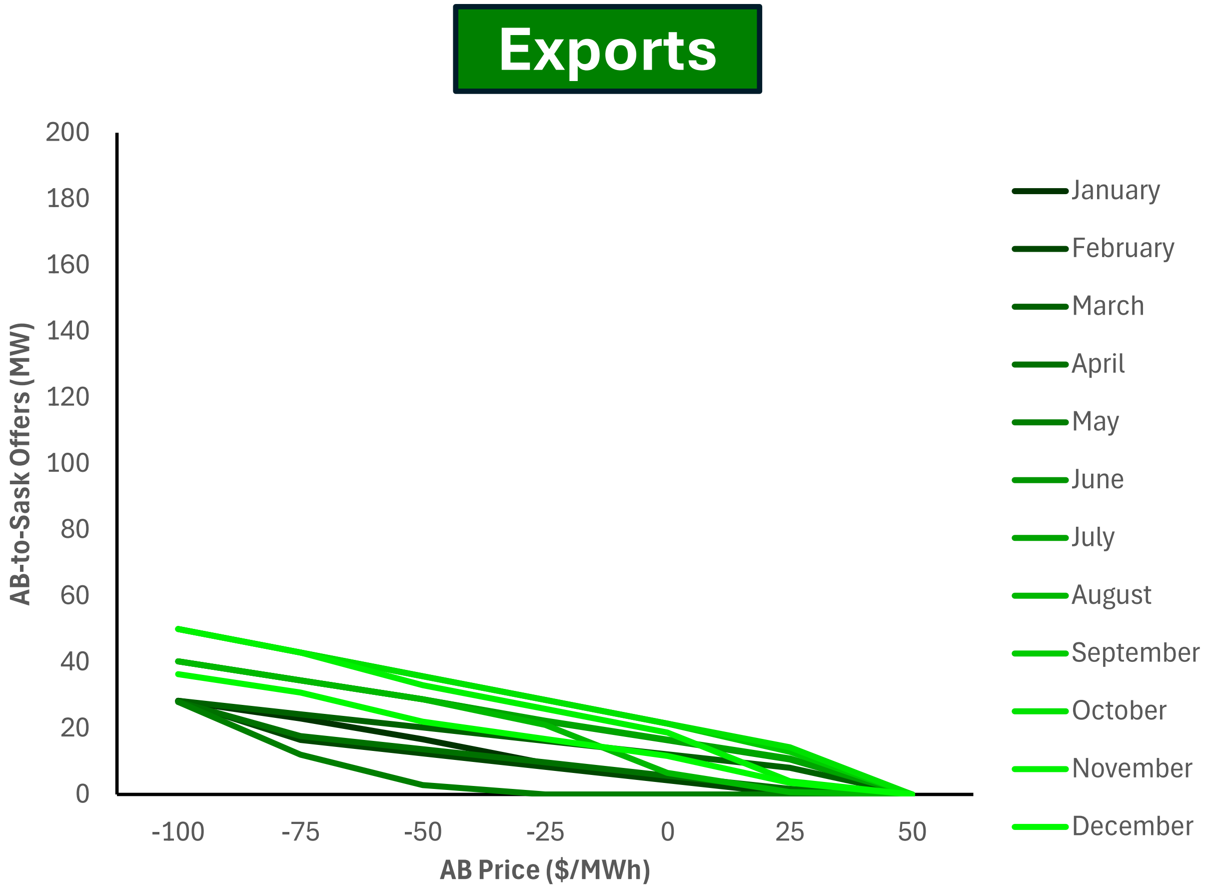


Exports



Historical Import/Export Curve Results: SASK





Priced Interties

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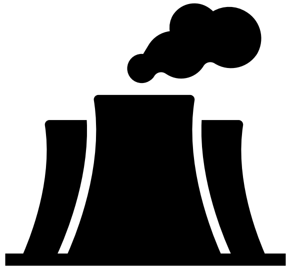
Priced Interties with Border Node AESO Imports from WECC – Illustrative Decision Making

WECC Scheduling Milestones:

1. Mid-C trading opportunities reduce significantly at 9 am the day before delivery
2. NERC E-Tag policy requires trading details to be confirmed at least 1 hour before delivery



WECC Merchant Power Producer

Trading Options

Mid-C (WECC)

Milestone 1 · *Milestone 2*

T-48 · *T-24 Day Ahead Market* · *NERC Requirements T-1* · *T-0 Contract Delivery*

- Power producer can bid into the bilateral Mid-C commodity markets on a day ahead or spot market timing interval
- Power producer has likely decided bidding behavior in Mid-C at a day ahead interval
- Producer can submit **priced bids** into the Mid-C commodity markets
- Producer must secure transmission access to contract offtaker

AESO Priced Interties

Demand Curve · *DA Offer Close* · *RT Offer Close*

T-48+ · *T-24 Day Ahead Market* · *T-2 Real-time Market* · *T-0 Contract Delivery*

- Power producer can bid into the AESO day-ahead market with **priced bids**
- Producer **will not be dispatched** if the clearing border node price is **below their offer price**
- Priced interties offers **downside protection** for producer
- Producer must secure transmission access into AESO (MATL)

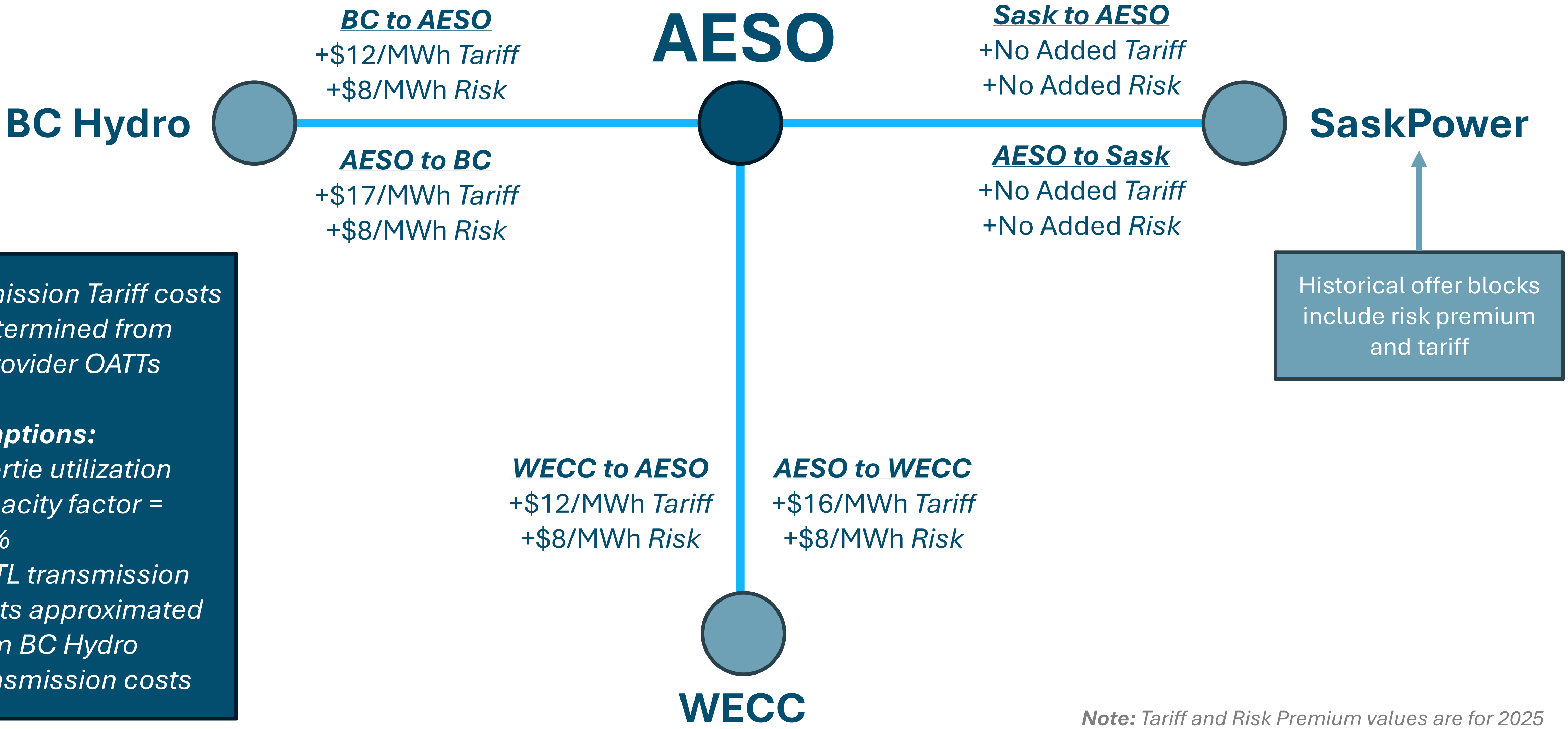
Proposed REM Day-ahead market closes at 10:30 MST the day before delivery

Priced Interties: Scenario Explanation

- This Scenario contemplates one in which importers can submit a price into the Alberta market, and potentially be the marginal resource
- Importers can now observe the Mid-C day-ahead price, and then price in a schedule to Alberta with that information as their opportunity cost, reducing importers' reliance on forecasting Alberta prices
- Hurdle rates/risk premiums may still exist, as there are timing mismatches with different types of transmission rights and other market factors, but the market now has visibility into other market opportunity costs – reducing uneconomic flows, or missed opportunities
- Transmission tariffs still exist and play a role in import offers
- Modeling therefore uses the full WECC model, and prices Mid-C based on model fundamentals, plus tariffs, plus Importer risk premiums
- BC is anticipated to be able to continue to optimize offers between both markets, and dispatch strategically

Priced Interties	Import offers are now given the ability to price and can be dispatched as a marginal block by the AESO	Importers can now guarantee a price floor – and can optimize offers into AESO against Mid-C opportunity costs	• WECC Dynamic Heat Rate Offer Prices Over MATL • BC WECC / Alberta Optimization • Sask Historic Offers • Transmission tariff, and risk premium in offers • Strategic offers in Alberta

Priced Interties: Tariffs and Risk Premiums Assumed



Transmission Tariff costs determined from provider OATTs

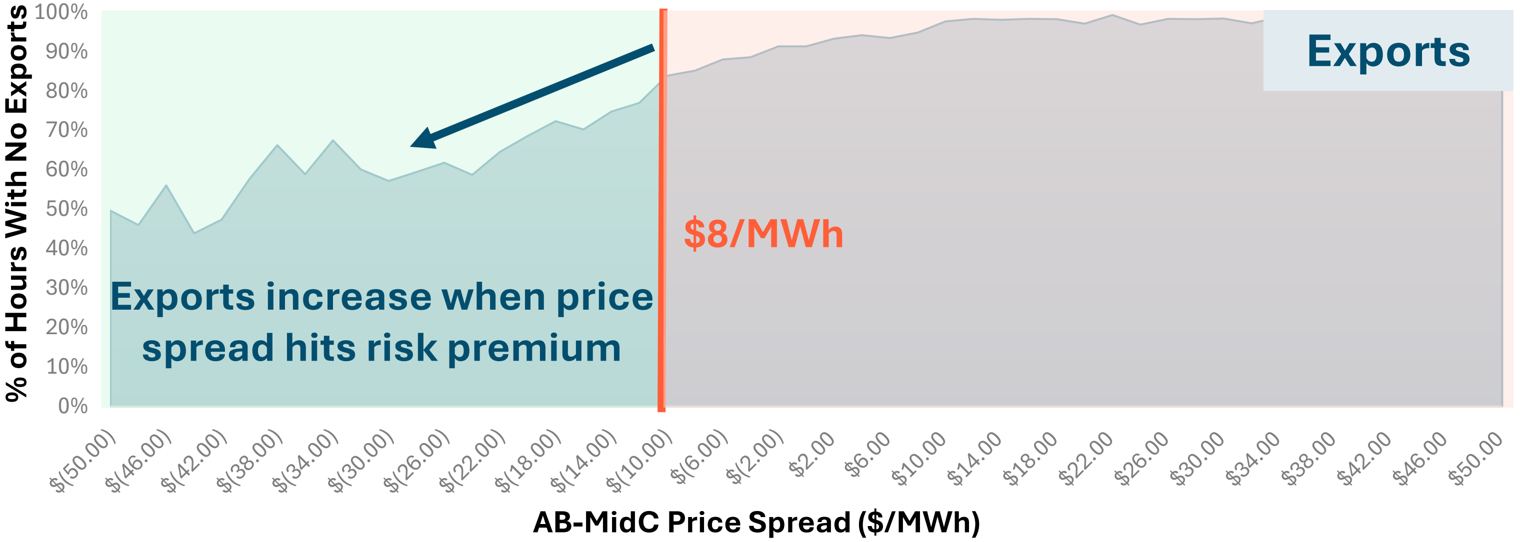
Assumptions:

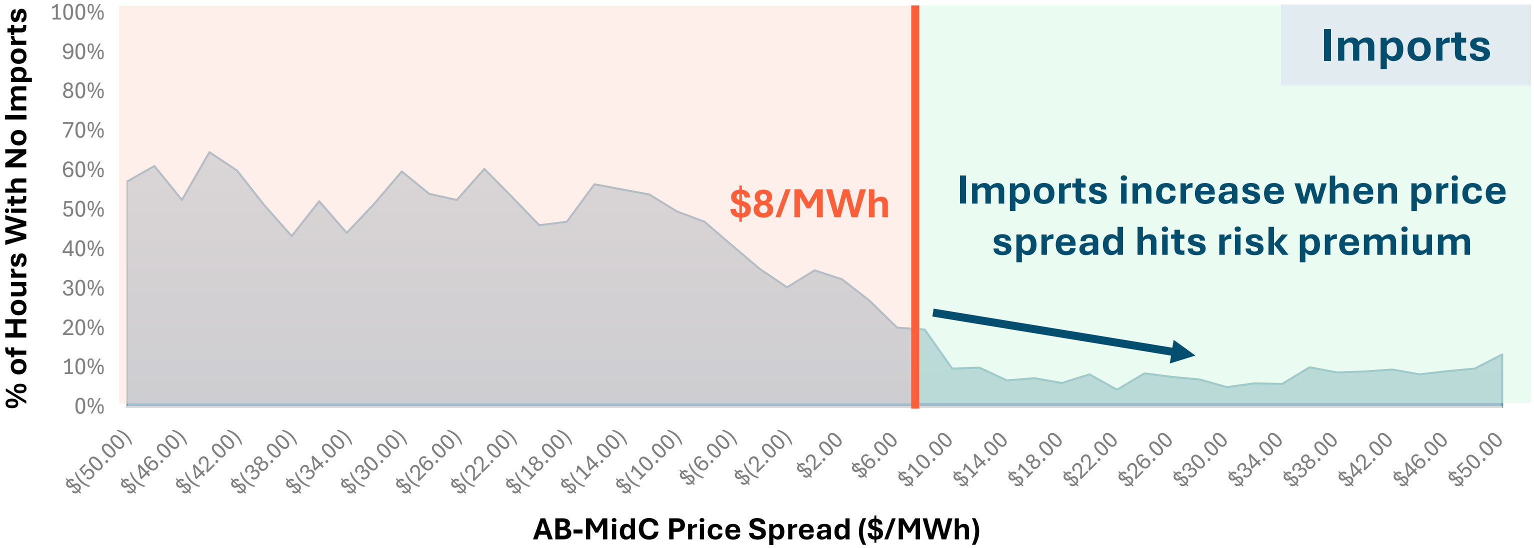
- *Intertie utilization capacity factor = 60%*
- *MATL transmission costs approximated from BC Hydro transmission costs*

Note: *Tariff and Risk Premium values are for 2025*

PI Risk Premiums

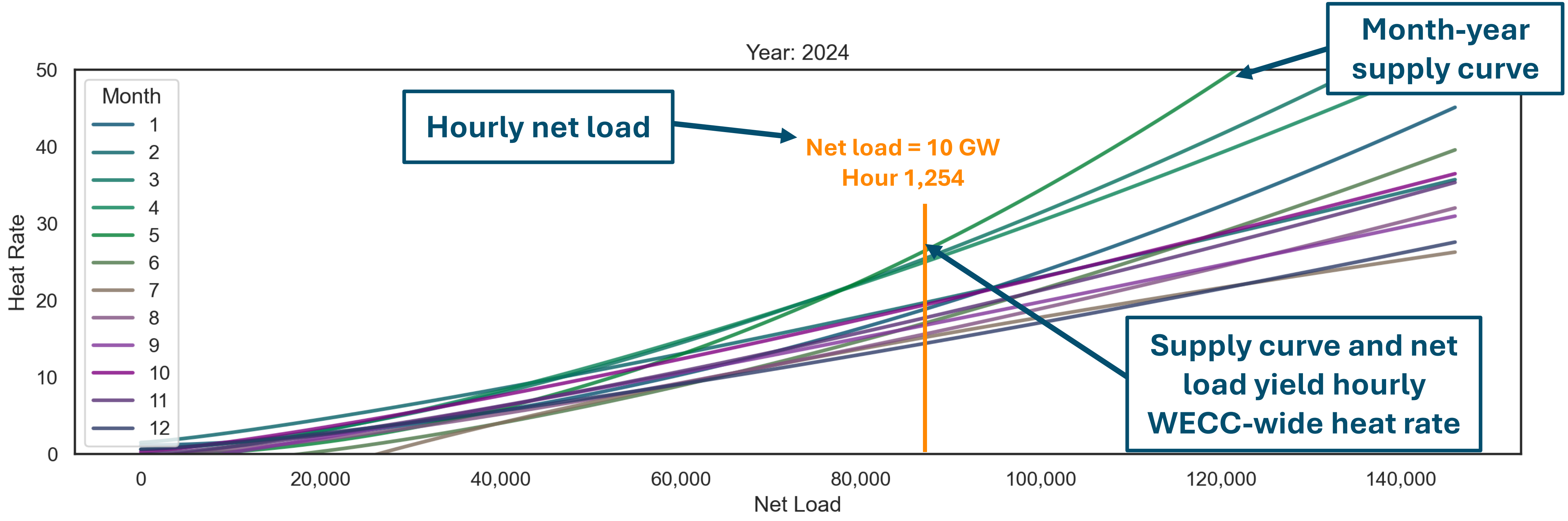
Risk premiums were added to capture trade frictions – premiums determined based on historical import/export data with correlated price spreads





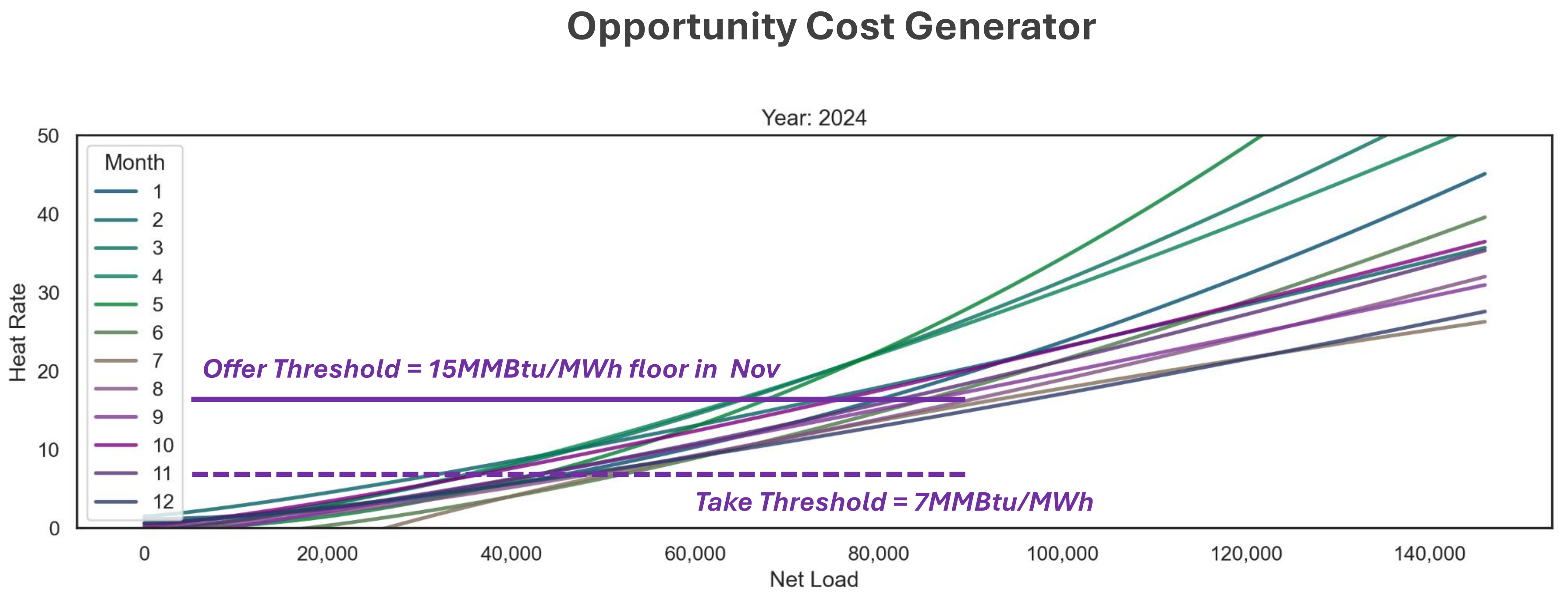
WECC Dynamic Heat Rate Curves

The available supply, demand, and pricing for the WECC region was determined on an hourly basis using month-year supply curves and hourly net load data



BC Optimized Offer Logic

BC Hydro is modeled as an opportunity cost generator between AB and WECC – Offer thresholds and take thresholds are based on historical trading behavior across months

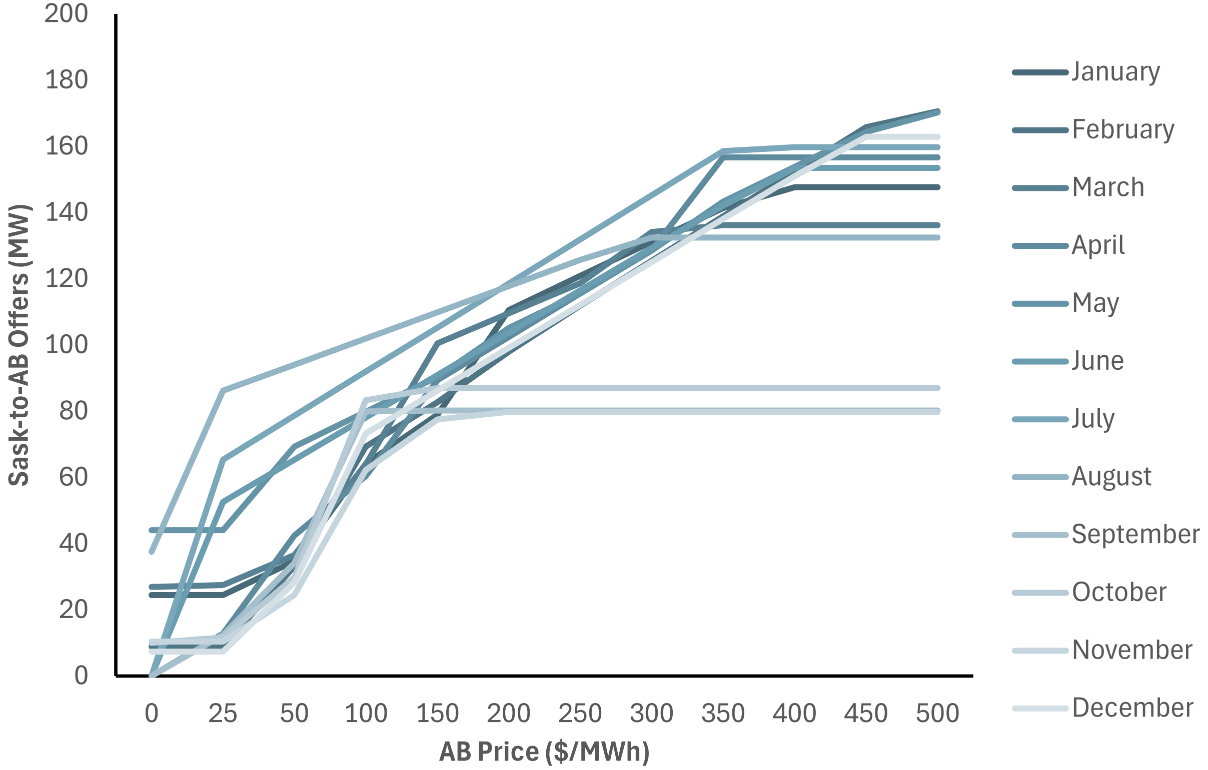


	(MMBTU/MWh)	(MMBTU/MWh)	(MMBTU/MWh)	(MW)
Month	**Offer Threshold**	**Take Threshold**	**Take Tariff Adder**	**BC 3HR Gen**
1	15.0	7.0	*8.0*	100
2	7.5	7.0	*0.5*	100
3	0.0	0.0	*0.0*	0
4	0.0	0.0	*0.0*	0
5	0.0	0.0	*0.0*	0
6	0.0	0.0	*0.0*	0
7	0.0	0.0	*0.0*	0
8	0.0	0.0	*0.0*	0
9	7.5	7.0	*0.5*	100
10	15.0	7.0	*8.0*	100
11	15.0	7.0	*8.0*	100
12	15.0	7.0	*8.0*	100

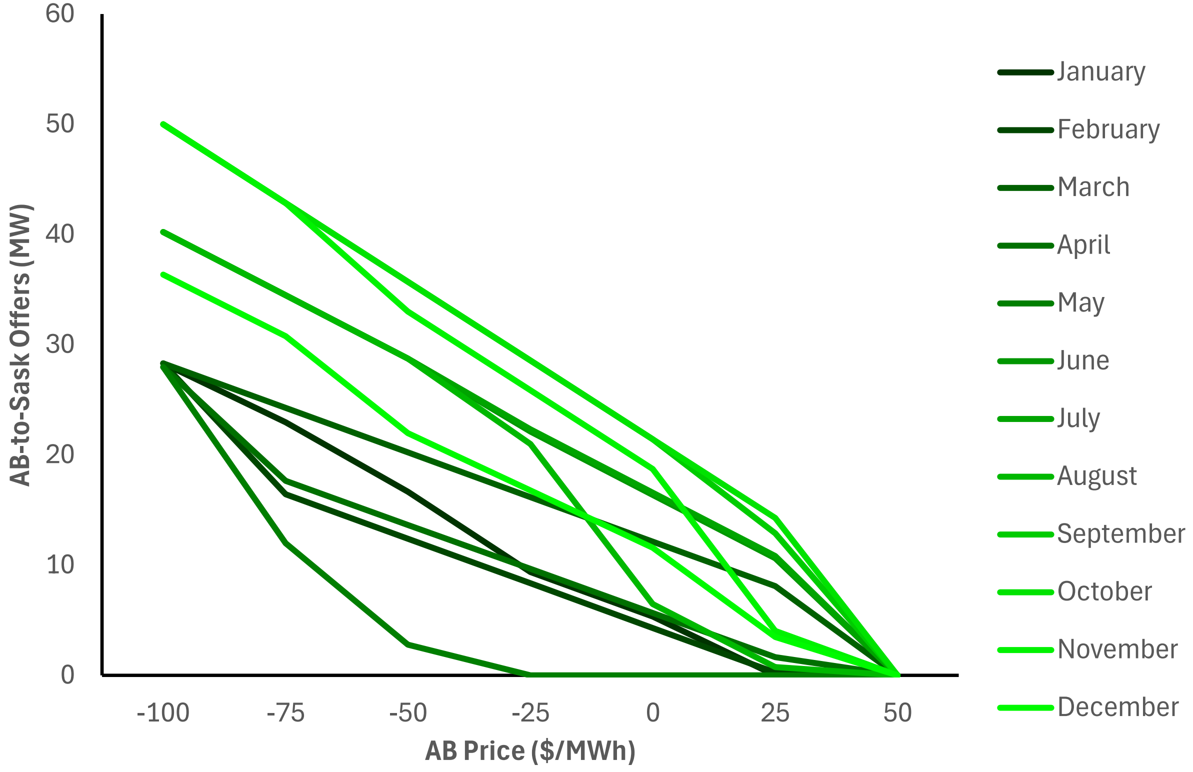
Historical Import/Export Curve Results: SASK

E3 continues to use the historic import/export curves for Saskatchewan due to limited data on the Saskatchewan system, even though SaskPower can now price between SPP and AESO

Imports



Exports



Border Node

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No-Node vs. Node

Border nodes account for the impact of congestion in intertie pricing. Impacts of border nodes include import/export placement in the merit order and congestion price impacts.

Modeling Considerations	PLEXOS Modeling	Exports	Imports
	No-Node	*AESO Price*	*AESO Price*
	With-Node	*AESO Price*	*External Zone Price*

No Border Node (Status Quo)

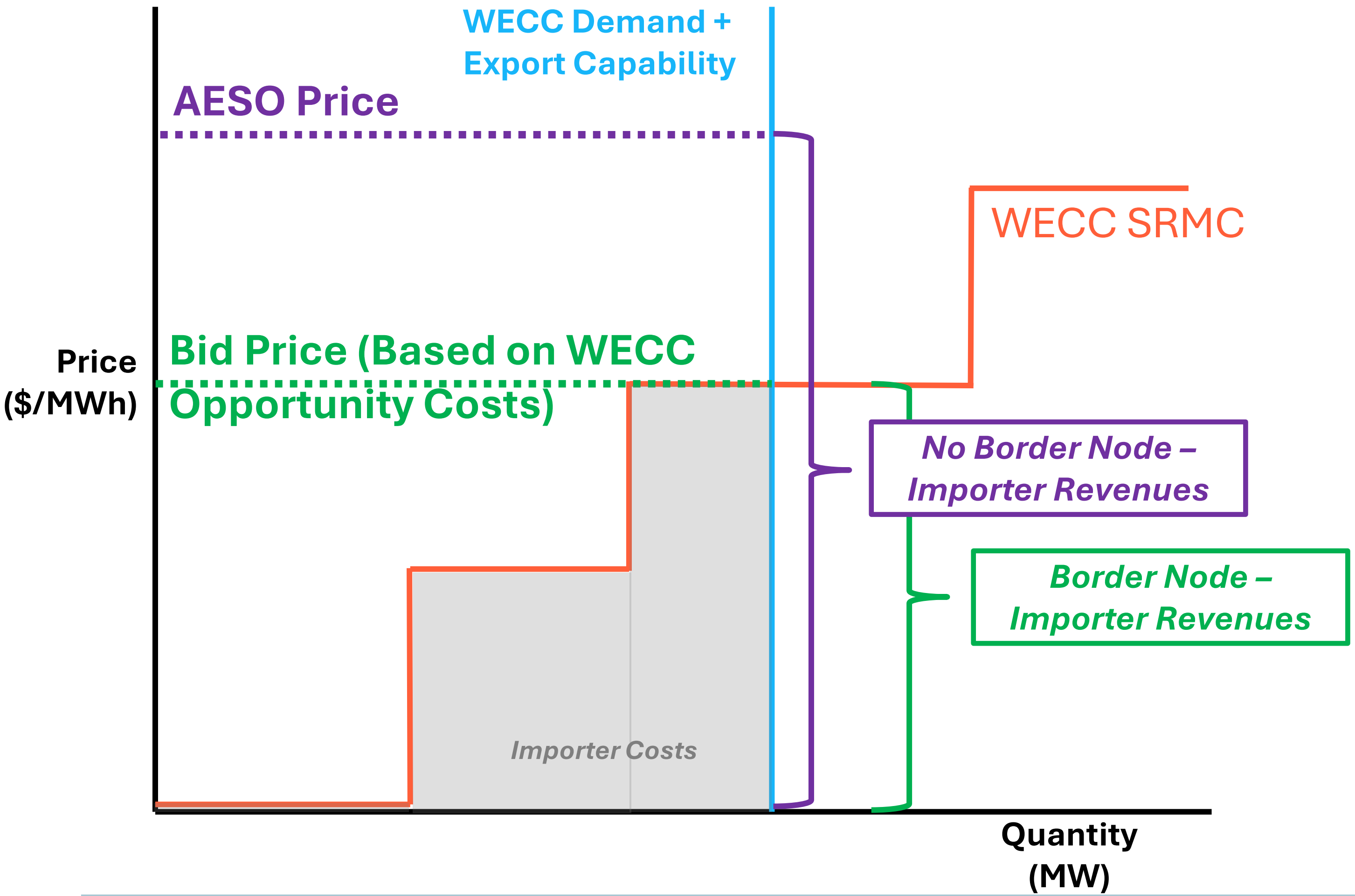
- Imports and exports make trade decisions based solely on the AESO price
- Importers receive AESO price regardless of border node congestion – resulting in higher importer revenues
- Import offers are cleared via a pro-rata curtailment scheme

Border Node (Priced Interties)

- Imports and exports make trade decisions based on the AESO price and WECC price
- Importers receive border node price – resulting in a reduction in revenues during congestion
- Import offers are cleared based on offer price

Border Node Considerations – Merit Order

E3 calculates the difference in total cost paid by Alberta loads to compensate for the increase in importer payments without the border node



No Border Node (Status Quo)

- **Importers receive AESO price** regardless of congestion
- Generators looking to import into AESO will have the incentive to clear the market if they expect congestion
- Importers will be cleared based on a pro-rata curtailment scheme
- Offers at the border during congestion converge to $0/MWh as imports enter the market to get the AESO price

Border Node (Priced Interties)

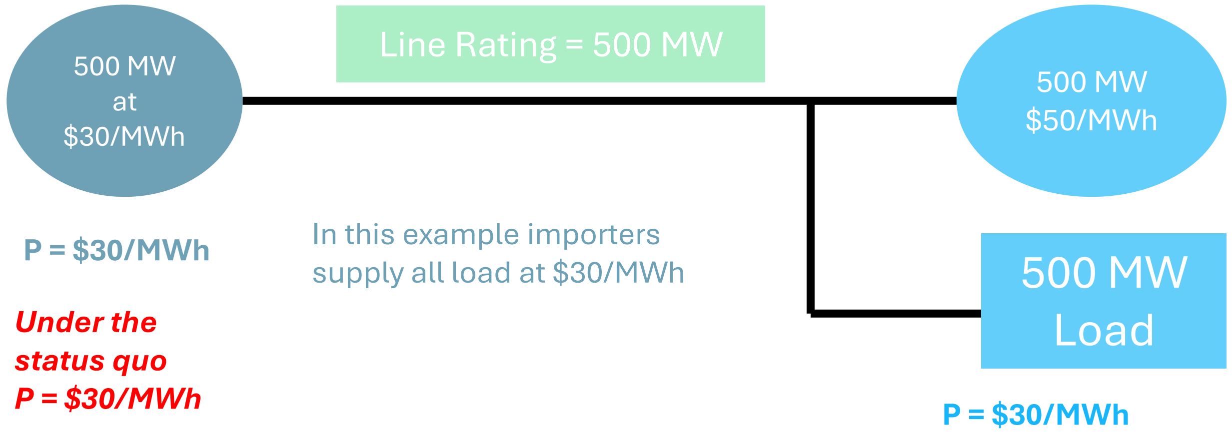
- **Importers receive border node price**
- Generators looking to import into AESO will have the incentive to clear the market if the ***border node*** price is higher than the WECC price
- Importers will be cleared based on offer price
- Offers at the border during congestion reflect marginal costs

Border Node Considerations – Congestion

- **Congestion impacts with no border node (Status Quo):**
  - All imports are paid the AESO market price for imported volumes, regardless of if the line is congested or not
  - Imports have the incentive to price at $0/MWh *if congestion is expected* as they get the AESO clearing price no matter what
- **Congestion impacts with a border node (Priced Interties):**
  - Imports do not "race to zero" *if congestion is expected* as they receive the border node price, rather than the AESO clearing price
  - Congestion impacts on redispatch shown in the example below

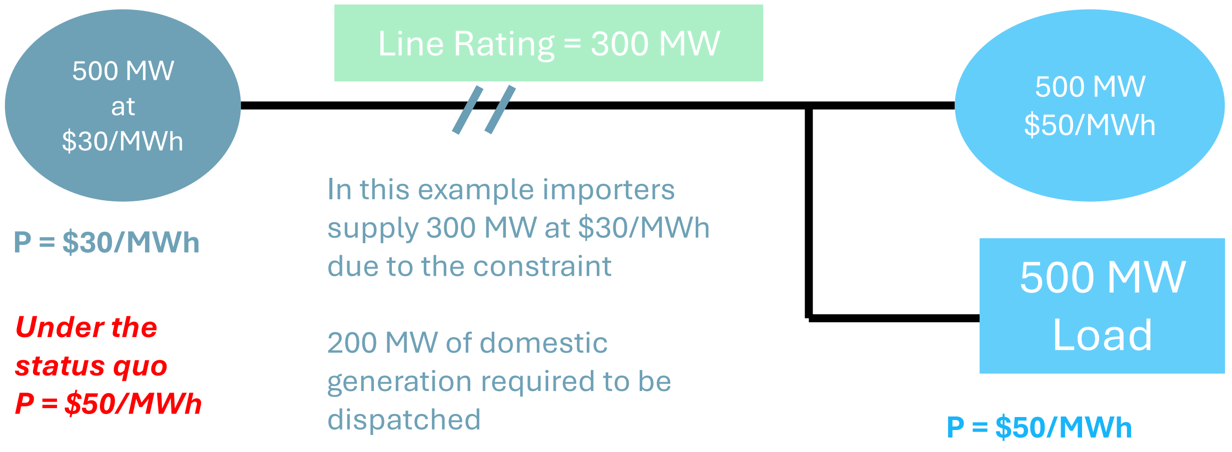
Uncongested Border Node (Same as No Node)

AESO price and border node price are the same – no redispatch required



Congested Border Node

Importers are paid the highest marginal offer that is dispatched from the import offer stack – which sets the border node price



DAC & AS Requirements

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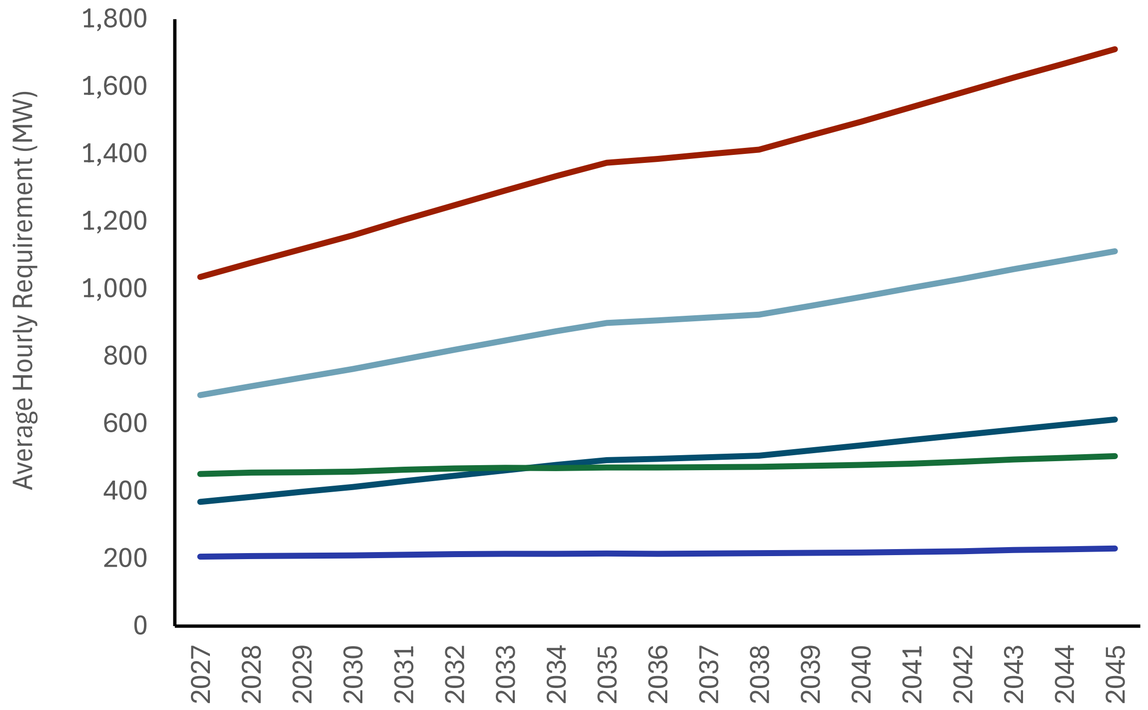
Summary of AS Products & DAC Modeling

Each REM AS product & DAC modeled with a long-term fundamentals driven outlook

Forecast of Non-Energy Market Products Size



1. DAC shown only includes day ahead forecast error. The full DAC requirement also includes net load.

DAC [1]

R60

R10

CR*

RR

New REM products, significant growth driven by renewables forecast uncertainty & ramping, synchronous with storage growth

Existing AESO AS products, minor growth over time – tied to only load growth

* CR is forecast to maintain BAL-WECC-002 and is tied to the forecast of load over the horizon. It grows from an average of 450 MW to 500 MW over the forecast horizon

Multiple new REM products are linked to net load forecast uncertainty and ramping requirements

Net load forecast uncertainty and ramping needs are driven by operational risk standards and are impacted by long-term changes to load and renewables. Fundamentals-based modeling captures hourly shapes and overall growth in operational balancing needs

DAC, R10, R60 requirement development process

Forecasted + observed load, solar, & wind from DA to 10-min horizon
Jan 2022 – May 2024 historical data

Quantify P95 forecast uncertainty & expected ramp need as a function of portfolio load, solar, & wind

Forecast hourly DAC, R60, & R10 requirements over full modeling horizon

DAC, R60, & R10 price formation based on supply, demand, & opportunity cost

See ORDC section for discussion of parallel method

Develop loss-of-load probability (LOLP) curve at DA operational timescale

Extent LOLP x VOLL smooth ORDC curves over full modeling horizon

Model revenue impacts of smooth ORDC curve

Development of Forecast Uncertainty & Ramping Requirements

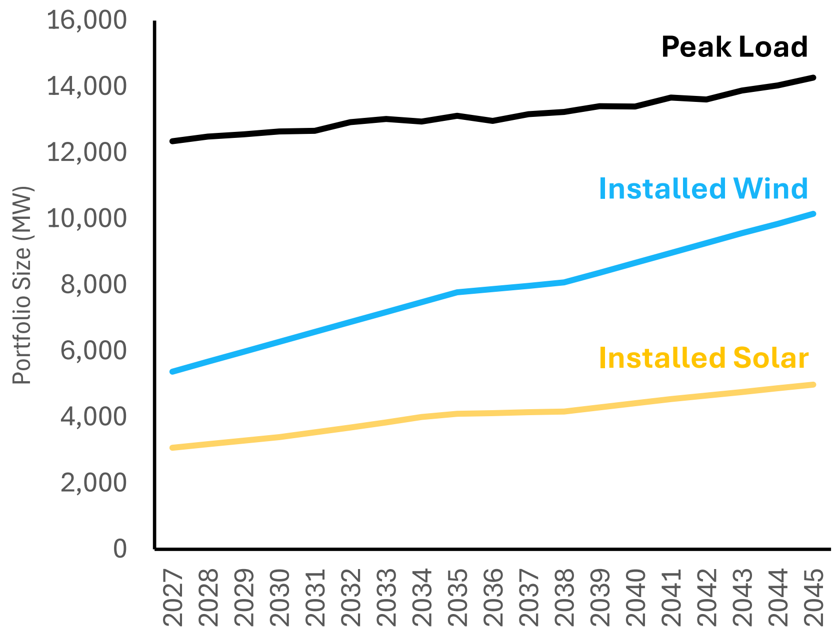
Requirements are derived using historical dataset of forecast error and ramping needs. Selected specifications to not achieve 100% coverage of each net load component, but the summation of each component assumes correlated forecast error resulting in reliable net load coverage.

Historical Reserve Requirement Analysis Results			
DA Gross Load Forecast Error Hourly P95	% of Hourly Load	2.51%	Load uncertainty & ramping component follows size of load
HA Gross Load Forecast Error + Ramp	% of Hourly Load	1.85%	
10min Gross Load Forecast Error + Ramp	% of Hourly Load	0.72%	
DA Solar Forecast Error	% of Nameplate	10.70%	Solar component scales with installed capacity, but is only active during daylight hours
HA Solar Forecast Error + Ramp	% of Nameplate	8.30%	
10min Solar Forecast Error + Ramp	% of Nameplate	6.00%	
DA Wind Forecast Error	% of Nameplate	11.10%	Wind component scales with installed capacity due to high variability in forecast error and ramps
HA Wind Forecast Error + Ramp	% of Nameplate	6.60%	
10min Wind Forecast Error + Ramp	% of Nameplate	3.60%	

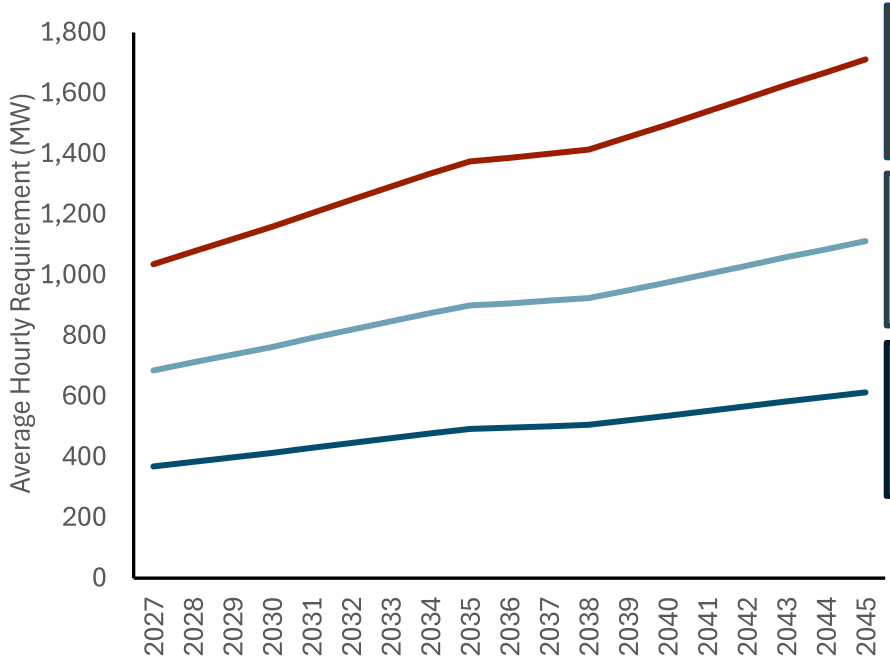
Projection of Forecast Uncertainty & Ramping Requirements

DAC, R60, & R10 requirements are sized to cover growing forecast uncertainty and ramping needs from renewables & load

Portfolio Changes that Impact LOLP



Forecast Uncertainty & Ramp Needs



DAC [1]
95% coverage of day ahead forecast error

R60
95% coverage of 60-min ahead forecast + average 60-min ramp needs

R10
95% coverage of 10-min ahead forecast + average 10-min ramp needs

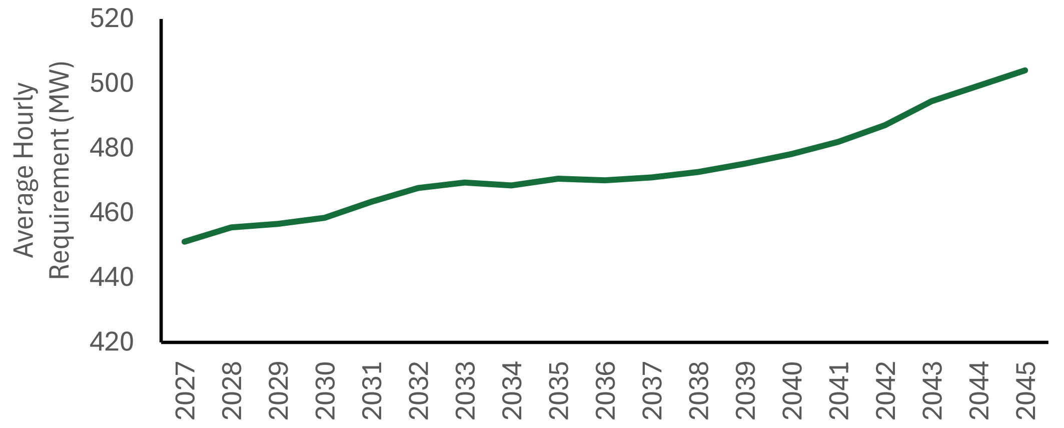
1. DAC shown only includes day ahead forecast error. The full DAC requirement also includes net load.

Contingency and Regulating Reserves

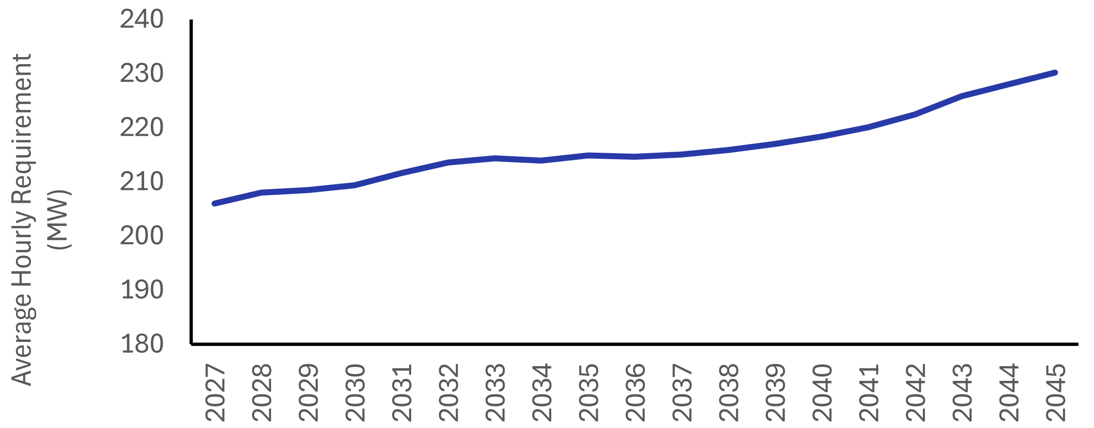
- **Contingency reserve volumes modelled in line with the current BAL-WECC-002 standard**
  - 3% of net-to-grid load + 3% of net to grid generation
- **E3 has estimates of behind-the-fence as a part of the AIL forecast and nets out that for the calculation**
- **As load grows over the forecast, so too do the contingency reserve requirements**
- **The AESO recently increased regulating reserve procurement to roughly 200 MW per day**
- **E3 has updated our volumes to reflect this and increase the regulating reserve with load over time**

Source: BAL-002-WECC Contingency Reserves » AESO
2013-005R-Operating-Reserve-2024-04-05.pdf

Contingency Reserve Requirement



Regulating Reserve Requirement



Reserve Price Formation

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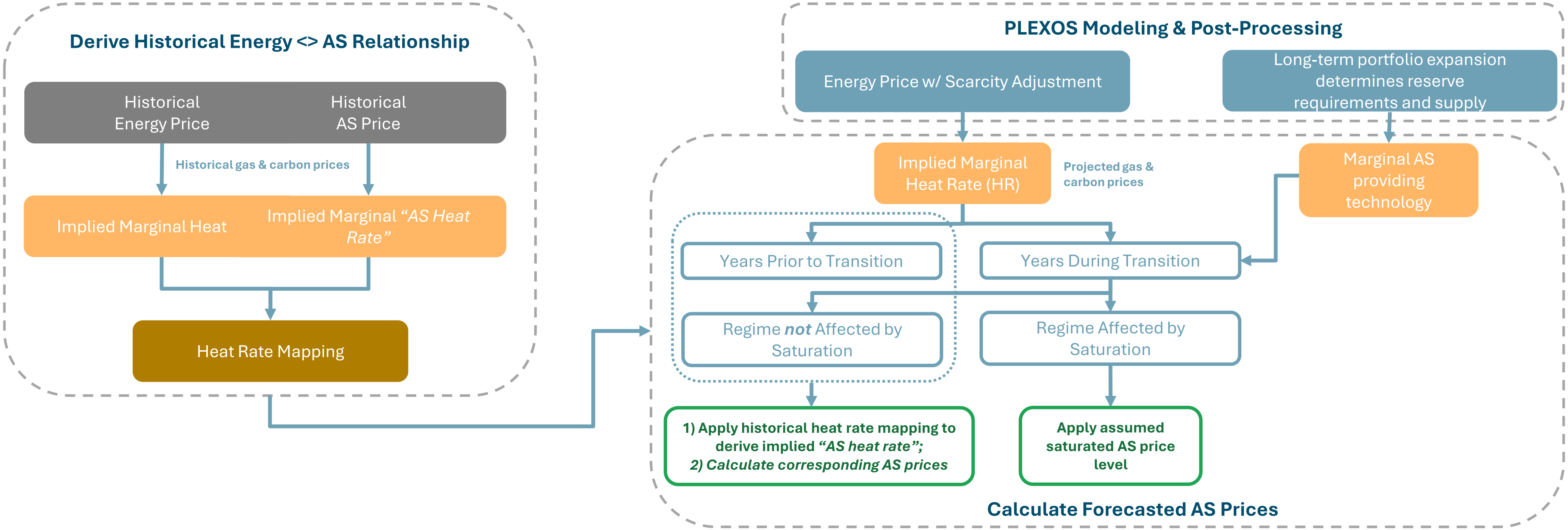
Forecast Methodology for Ancillary Services Prices

As batteries enter the system, Ancillary Services (AS) prices are saturated during specific hours:

1) **For all years pre-saturation, future AS prices are determined based on historical relationships with day-ahead energy prices**
2) **For all years post-saturation, saturated AS prices are applied to low energy priced hours, while AS prices follow historical relationships during high-priced thermal marginal hours**



Ancillary Services Revenue Methodology

+ **Ancillary Services (AS) prices saturate at different paces by product, depending on the size of system need:**
  - Expectation that batteries will start saturating the ancillary services market as early as 2026
  - Supplemental and Spinning Reserves to be the first product to be saturated first due to the lower requirements needed to bid. Supplemental to remain as the least attractive product for battery revenues
  - We expect batteries to start entering to bidding the Regulation Market as early as 2026
  - Saturation Prices (the price of the AS market at low heat rates):
    - Regulating Reserves: $1.31/MWh
    - Spinning Reserve $0.44/MWh
    - Supplemental Reserves: $0.32/MWh
  - Based on market build – E3 increased the market heat rate in which we anticipate AS prices stay saturated

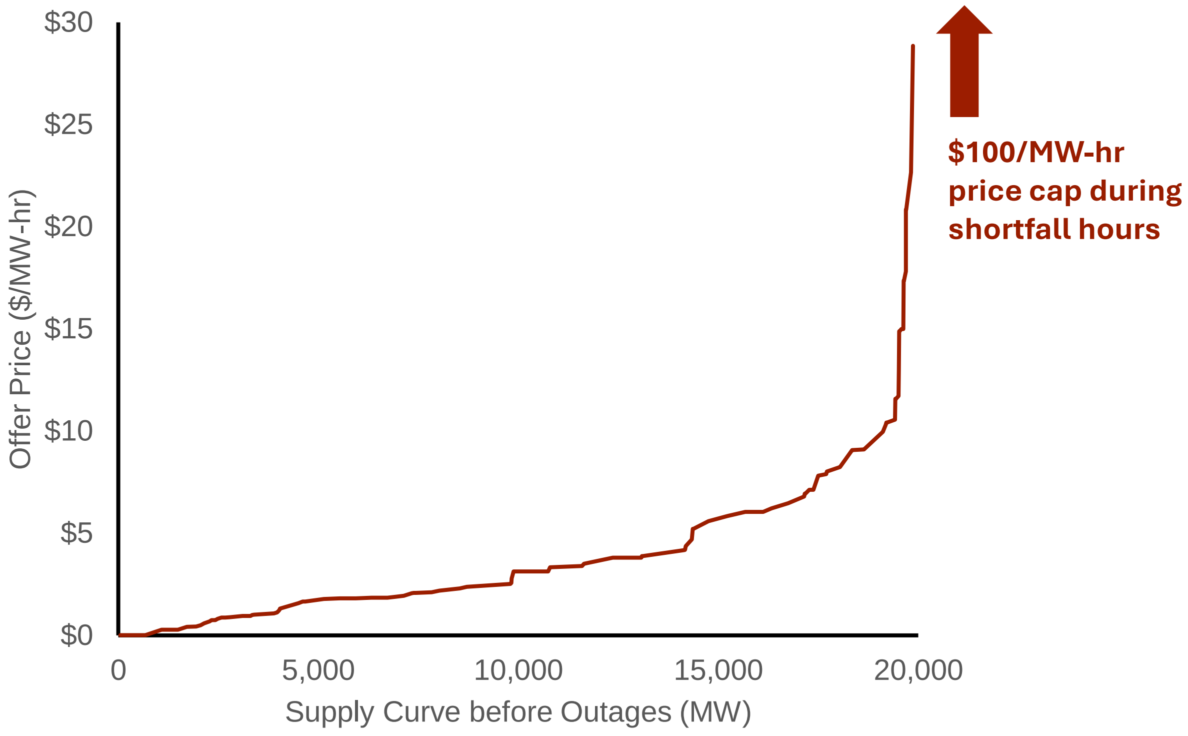
R10/R60 Pricing

- **Historic relationships between the existing products and energy prices were leveraged to produce the forecast of spinning, supplemental, and regulating reserve**
  - New offer caps where applicable
- **R10 and R60 do not have historic data to leverage**
  - E3 used the products' technical requirements to inform how they will price relative to the existing products
- **R60 Price**
  - Has a 1-hour response time – the easiest response time to make for all as products
  - Must provide an hour of duration
    - This product has similar requires to supplemental reserves (not synchronized, offline resources can provide)
  - As a result, E3 priced it such that If hourly battery availability was greater than the R60 requirement was saturated and set to the offer capped supplemental price
  - If hourly battery availability was less than R60 requirement: R60 Price was equal to uncapped supplemental (thermal opportunity cost) or the offer cap of $100/MWh
- **R10 Price**
  - R10 has a 10 minute response time and is required to react quickly to ramp events. This makes it more similar to spin or reg
  - As a result, we used spin as a proxy combined with the offer cap

DAC Pricing

- **Resources start costs to estimate DAC costs**
- **E3 created a market clearing price mechanism for DAC**
  - E3 created an hourly merit order of the commitment costs for all generators available to provide DAC that our Plexos model committed
  - Using the hourly DAC requirement in Plexos and the "merit order" of the daily commitment costs for each generator, E3 established an hour clearing price for DAC
- **DAC prices do not contain market power or strategic bidding – This is the competitive outcome which should be viewed as a price floor**

2045 DAC Supply Curve Before Outages & Derates [1]



1. Dynamic DAC supply curve is impacted by portfolio build, maintenance & forced outages, thermal unit ramping constraints, and battery unit state of charge

ORDC

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Development of Smooth ORDC from LOLP fundamentals

A smooth ORDC shaped by LOLP x VOLL produces an efficient price signal tied to risk and the economics of lost load

Smooth ORDC development process

Forecasted + observed load, solar, & wind from DA to 10-min horizon
Jan 2022 – May 2024 historical data

Quantify P95 forecast uncertainty & expected ramp need as a function of portfolio load, solar, & wind

Forecast hourly DAC, R60, & R10 requirements over full modeling horizon

DAC, R60, & R10 price formation based on supply, demand, & opportunity cost

See DAC + AS section for discussion of parallel method

Develop loss-of-load probability (LOLP) curve at DA operational timescale

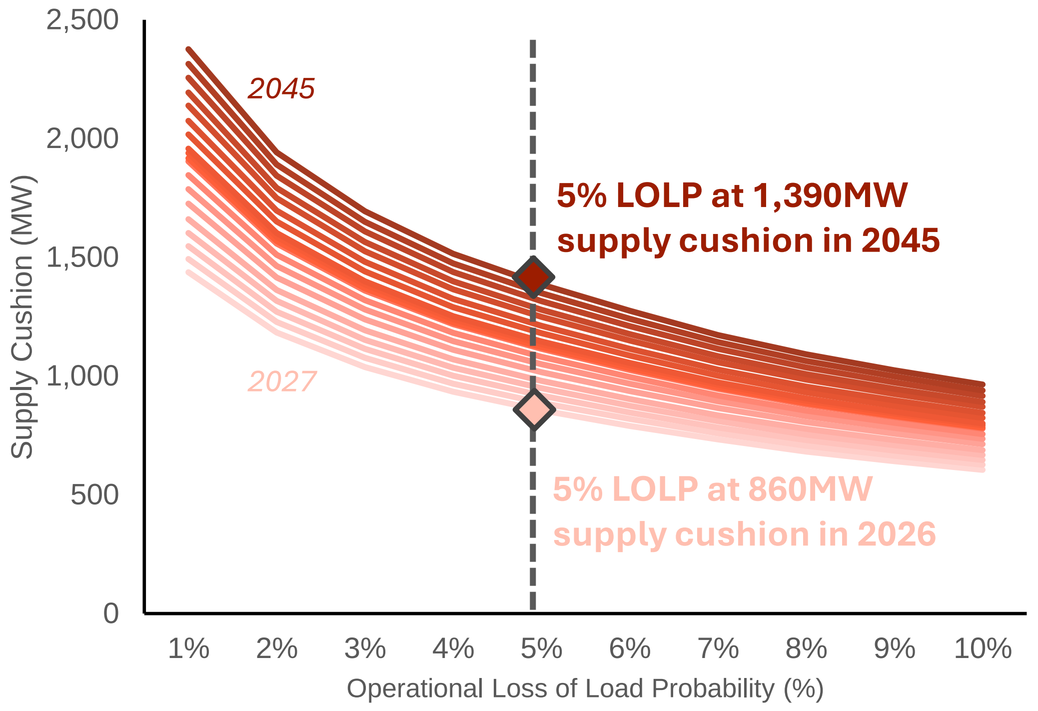
Extend LOLP x VOLL smooth ORDC curves over full modeling horizon

Model revenue impacts of smooth ORDC curve

Operational Loss of Load Probability (LOLP) Curve Development

- **Smooth ORDC prices are calculated as the product of hourly operational LOLP and VOLL**
  - $32,000 nominal CAD Value of Lost Load (VOLL) assumption based on Brattle Study[1]
- **Forward operational LOLP curve is developed for each forecast year**
  - LOLP curves calculates the probability that net load forecast error exceeds expected supply cushion at the day ahead timeframe
  - Curves shift to reflect increasing forecast uncertainty due to higher renewables and load
  - Probability of forecast exceedance calculated at 1% intervals for each net load component based on historical forecast errors from Jan 2022 – May 2024

Operational Loss of Load Probability Curves

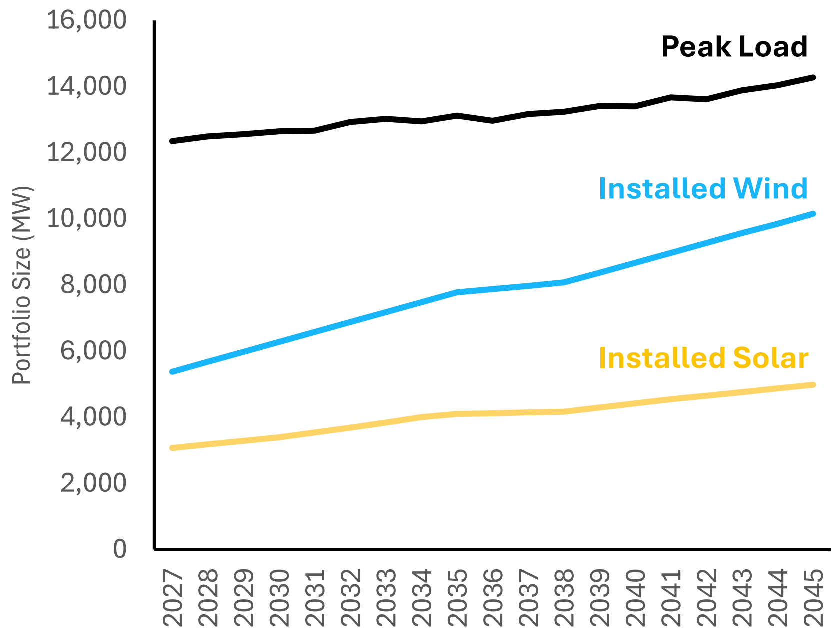


1. https://www.aesoengage.aeso.ca/42905/widgets/179261/documents/136884

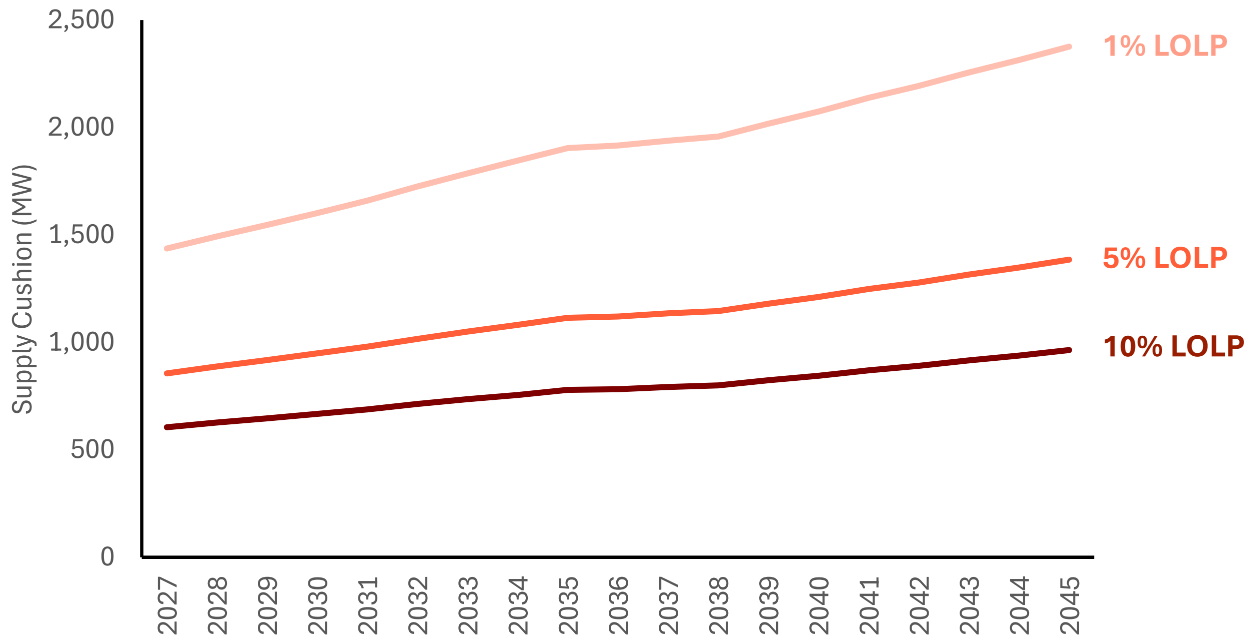
Projection of Long Term Operational LOLP during System Tightness

As load and renewables grow, larger supply cushions are required to maintain the same loss of load probability

Portfolio Changes Impacting LOLP



Operational LOLP



1. *DAC shown only includes day ahead forecast error. The full DAC requirement also includes net load.*

Market Power Mitigation

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Market Power Mitigation

- **E3 implemented a 12-month Market Power Mitigation (MPM) system on a combined cycle reference unit**
  - Evaluation period: October to September
- **Secondary Offer Cap of $250/MWh & $400/MWh, only large portfolio mitigated when MPM is triggered**
  - E3 tested both a 5% MSOC and 10% MSOC threshold – results were extremely similar given how many hours the secondary cap is binding

Mitigation System

- **Mitigation is triggered when the reference unit recovers 2x its cost-of-new-entry (CONE) during the evaluation period**
  - Applies to the remainder of the evaluation period once triggered
  - Reference unit revenues include DAC plus energy with ORDC revenues
- **If the mitigation threshold revenues are surpassed, energy prices are assumed to clear at the secondary offer cap if they are above it**
  - RSI for major firms is very low during tighter supply, indicating that the clearing price is likely to be at the secondary offer cap
  - When ORDC is present, a smaller firm is assumed to set price at the primary offer cap (entities with less than 10% market share offer control are exempt from mitigation)
- **Secondary offer cap was set at $250/MWh & $400/MWh**

Reference Unit

- **Reference unit operations:**
  - Price > SRMC = Unit runs at max capacity x capacity factor
  - Price < SRMC = Unit runs at min stable generation

Reference Unit Inputs	
CONE ($2024CAD/kW-yr)	$181.68
Variable O&M ($CAD/MWh)	$3.65
Min Stable Output (MW)	209
Output When Price Above SRMC(MW)	359
Max Capacity (MW)	418
Heat Rate (GJ/MWh)	6.7
Gas Emissions Factor (Tonnes CO2/MMBtu)	0.05291
Emissions Rate (Tonnes CO2/MWh)	0.338624
Inflation	2%
AESO Trading Charge ($CAD/MWh)	0.38
Loss Rate	3%
Capacity Factor	86%

Day-Ahead Realtime Price Formation

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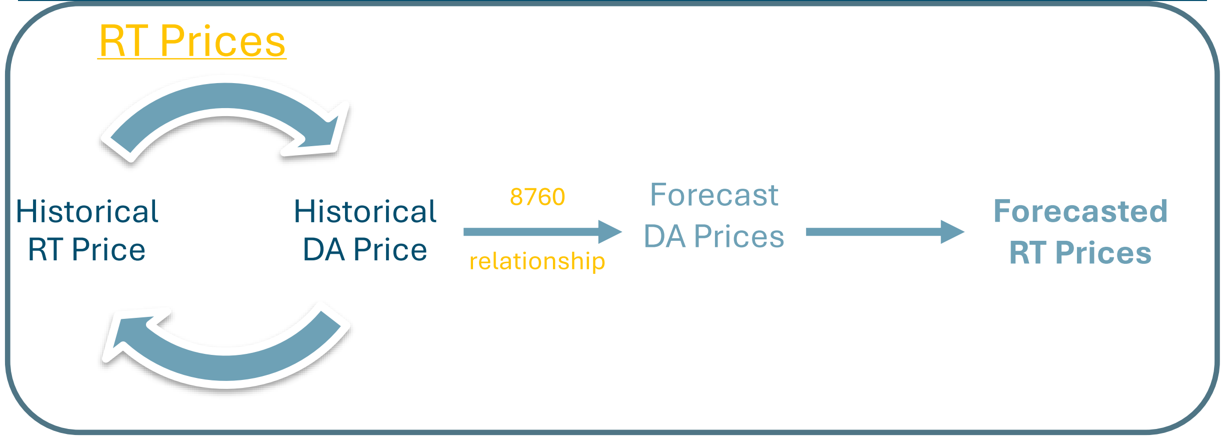
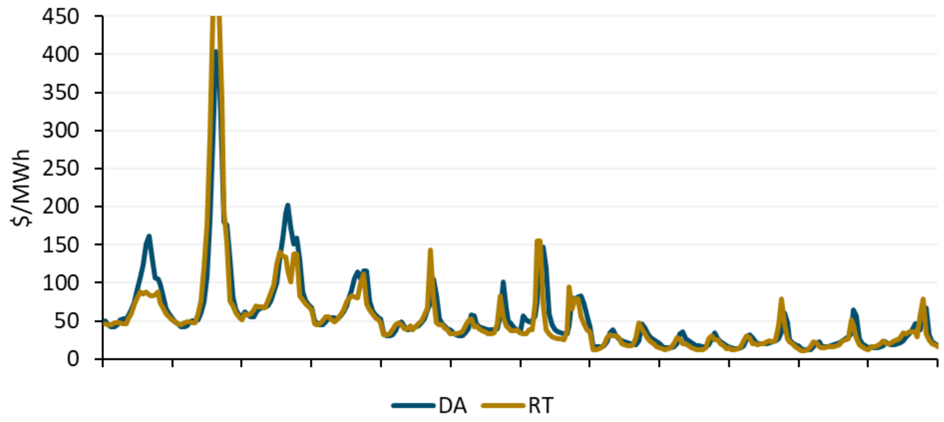
Day-Ahead and Real-time Prices

- **Real-time markets are characterized by sudden shifts in net load, generator outages, and many other operations issues that can result in unexpected supply or demand**
  - E3 has vast experience in modelling other markets like CAISO, PJM, ERCOT with both real-time and day-ahead markets
- **For the AESO market based we build a DA-RT profile leveraging our experience seeing the types of deviations between real-time and day-ahead that other markets we cover**
  - We used ERCOT as a proxy market to generate the devotions between real-time and day-ahead
    - ERCOT has an Opt-in financially binding day ahead market and;
    - ERCOT has numerous similarities to AESO, including:
      - High wind and solar penetration
      - Gas based system for dispatch
      - High industrial load
      - High volatility

Realtime Forecasting Process



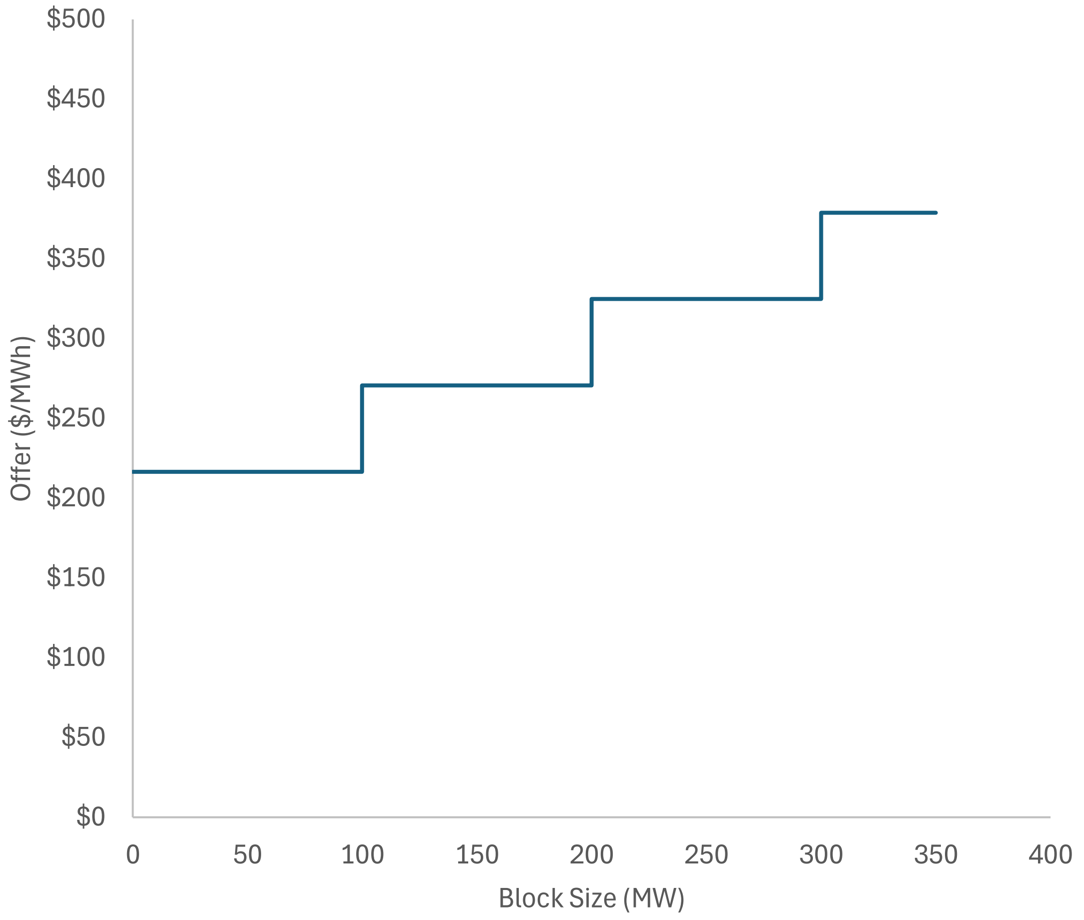
Realtime Forecasting Process



Load Participation

- **Alberta has roughly 350 MW of price responsive load**
- **To incorporate the impacts of this load in the day-ahead and real-time markets E3 created 4 different price responsive load blocks**
  - Three blocks of 100 MW at progressively higher prices, then a final 50 MW block
- **These assets interact with the merit order as a supply side resource**
- **These assets interact in the real-time and day ahead market**

Price Responsive Load



Sources: [Price Responsive Load in the Resource Adequacy Model](), [AESO 101]()

Sub-hourly Settlement

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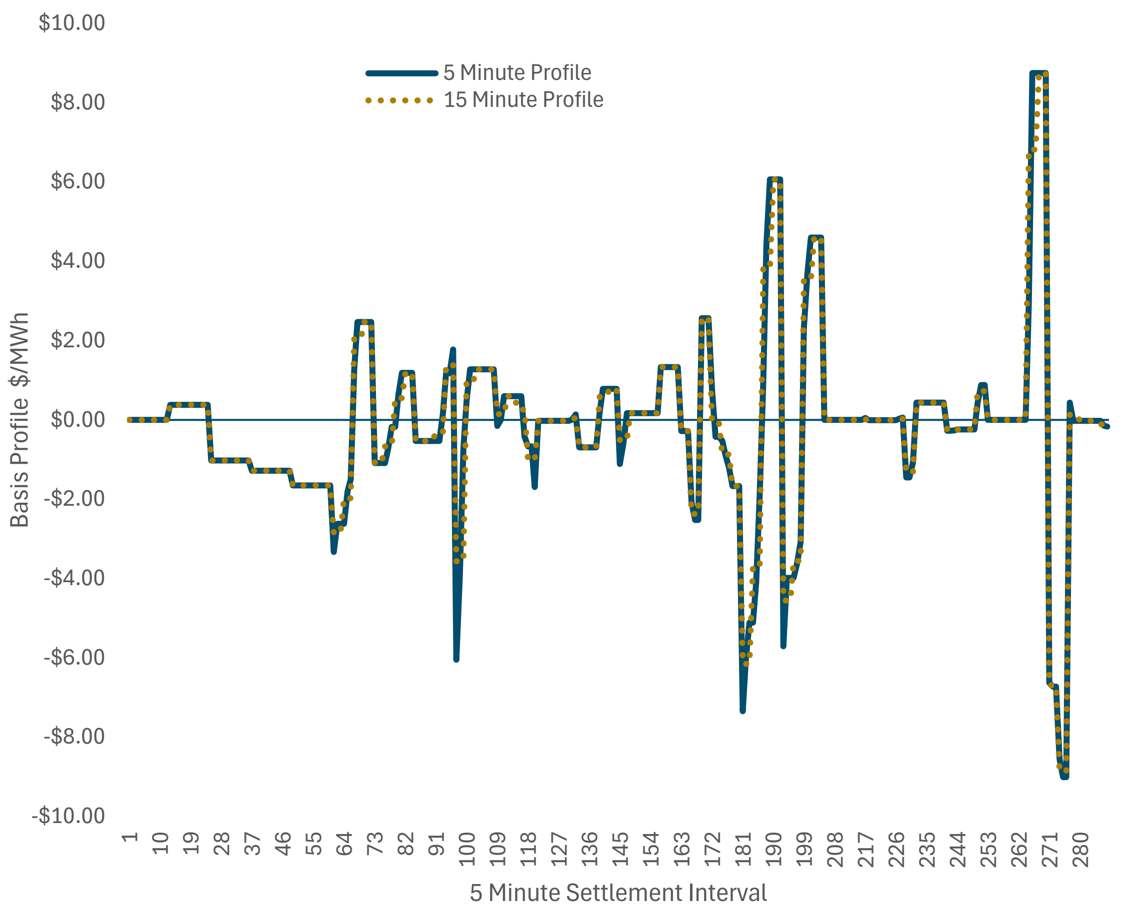
Shortened Settlement

+ **Alberta's current market utilizes an hourly Pool price and settlement interval**
+ **To create the hourly Pool price, the time-weighted average of minutely recorded system marginal prices (SMP) is calculated to produce an hourly price**
+ **E3 has utilized this minutely SMP data to analyze what a 5 minute and 15 minute settlement profile could look like**
  - E3 took the last 12 months of actual SMP data, and took the time weighted averaged it over 5 minute and 15 minute intervals to create a profile for shortened settlement
+ **The graph to the right shows an example of the difference from hourly average prices for each interval across one day (basis profile)**

Shortened Settlement Profile



Evaluation Framework

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Areas of Analysis

+ **To quantify the differences under each scenario, E3 has collected data from the modelling across the following areas**

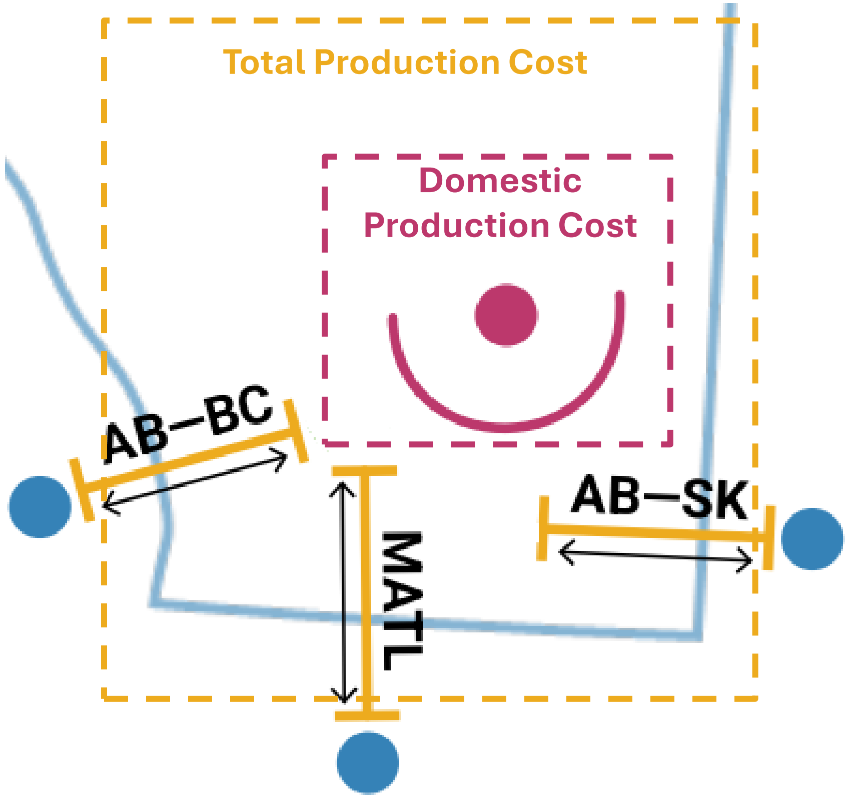
  - Production costs and efficiency
    - Detailed explanation in this section

  - Technology returns and missing money
    - Detailed explanation in this section

Productive Efficiency – Measure Explanation

- **E3 has measured the full cost of operations in Alberta under each scenario, i.e., domestic production costs, and the marginal price at each intertie**
  - Full fuel costs
  - Cycling costs
  - Carbon costs
  - VO&M costs
- **E3 developed two ways to understand the efficiency gain of the dispatches under the different scenarios**
  - E3 measured total cost of generation of Alberta only resources. E3 then divides this cost by total domestic production. This measures the gain dispatching the Alberta fleet more efficiently and normalizing it by production. Normalization is important as different scenarios could have differing imports/exports
    - This is referred to in this report as Domestic Production cost
  - E3 then created an efficiency metric that looks at the total change in production cost for meeting all Alberta Load including imports and exports. We measure the cost of domestic generation, and the cost of imports, minus the revenues from any export opportunities. Here we use border node prices, or imports at the AESO prices as the cost of imports. Export revenue is measured at the nodal price it receives
    - This is referred to as Total Production Cost. This is the cost of meeting Alberta load across each scenario including imports

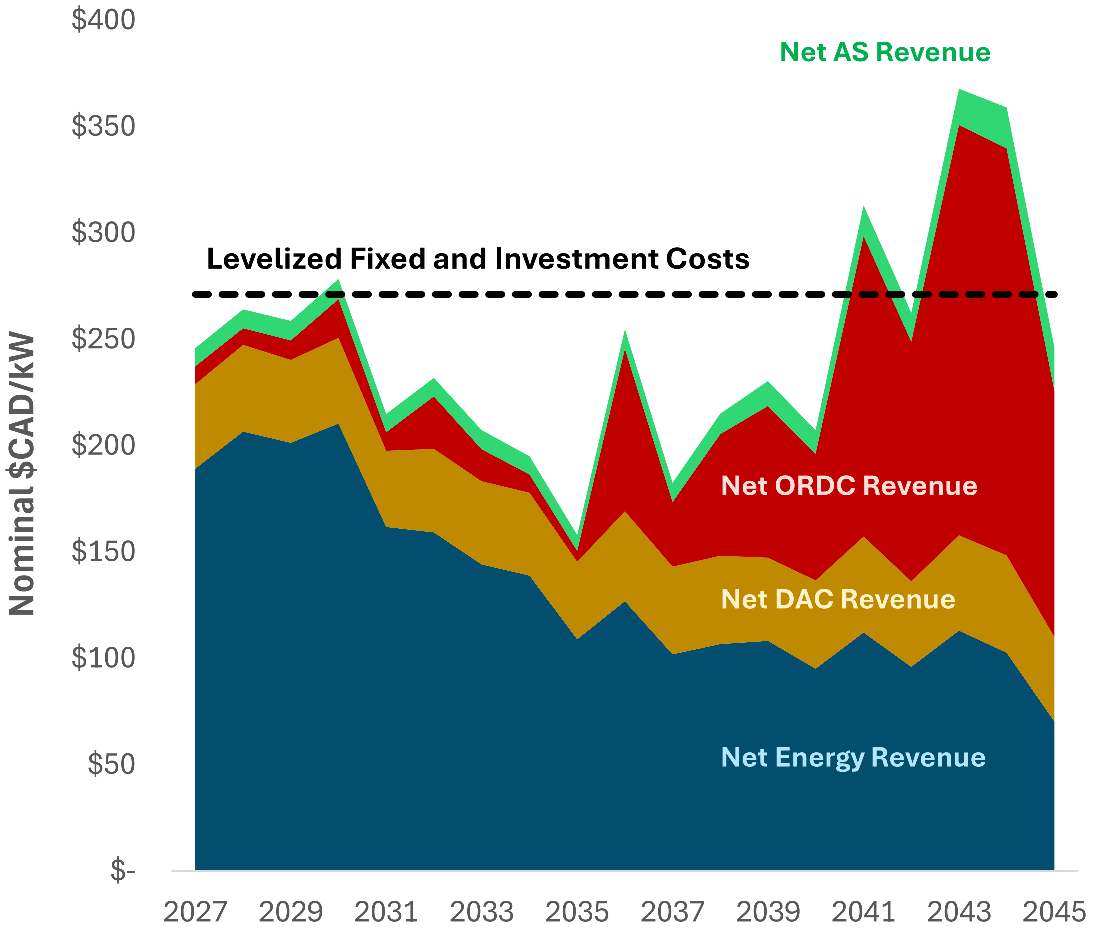
Production Cost Measures



Technology Returns and Missing Money

- To understand the economics of each technology, E3 looks at the net energy revenues from operations, and compares it to the fixed capital and operating costs a technology incurs
- Net energy revenues are calculated as follows:
  - $(Price - SRMC) * Quantity\ Produced\ - Start\ Costs$
- This is done including all revenue streams including energy, DAC, other AS, and ORDC and is then compared to the fixed O&M costs + all capital costs (return on and of capital)
- In the missing money example, the technology does not earn sufficient revenue to recover its return on and of capital. This would indicate that the build is uneconomic

Missing Money Example



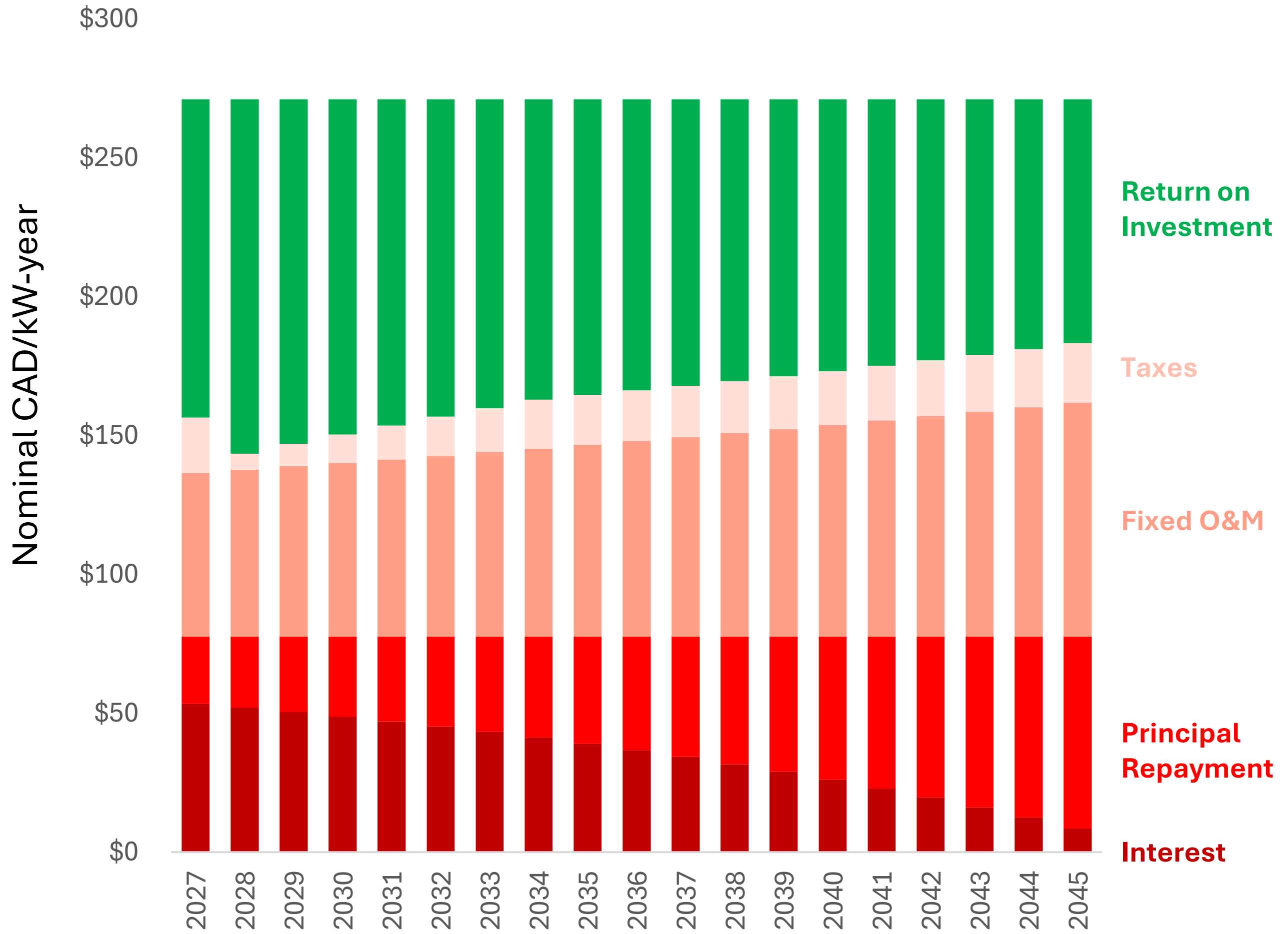
Technology Costs

- **Missing money is assessed relative to two asset profitability criteria**
  - **Levelized Fixed and Investment Costs:** Levelized annual return required for new assets to meet applicable technology rates of return
    - **Based on a selected investment year**
    - Accounts for investment tax credits
  - **Going Forward Costs:** Annual return required for existing assets to avoid retirement
    - Based on fixed operations & maintenance costs, escalates with inflation
    - Fixed operations & maintenance costs sourced from the 2024 NREL ATB

Required Rate of Return by Technology

CC	CT	CCS	Solar	Wind	Storage
12%	12%	12%	10%	10%	12%

Example Levelized Fixed and Investment Costs



Model Assumptions

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Model Assumptions

- **Reserves Product Assumptions**
- **Transmission Tariffs**
- **Common assumptions across all model runs**
  - Carbon, fuel, load, DERs, resource costs and profiles
  - Net-Zero 2050 Constraint
  - Carbon price and Benchmark
  - Intertie Ratings into Alberta
  - Fuel Prices (natural gas, hydrogen)
  - Rooftop solar build
  - Load Growth
  - Renewables Profiles
  - Resource Costs
  - Generator Structure

Reserves Product Assumptions

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Reserve Product Technical Requirements

Requirement	R10	R60	RR	CR	FFR	FRR	DAC
Volume	Expected ramp up requirement + uncertainty (net demand forecast error) over 10 minutes	Expected ramp up requirement + uncertainty (net demand forecast error) over 60 minutes	Volume determined by engineering studies based on variability and forecast error.	Greater of either the largest single contingency or 3% of hourly load + 3% of net generation	Based on provider availability and import volume	To be determined based on providers' capabilities and prices discovered through pilot	Expected net demand and additional volume to cover the day ahead forecast error or only day ahead forecast error.
Response Time	10 minutes	60 minutes	<1 minute	10 minutes	<1 second	<1 minute	N/A
Period*	1 hour	1 hour	1 hour	1 hour	1 hour	1 hour	1 hour
Offer Cap	$100/MW-hr	$80/MW-hr	$100/MW-hr	$100/MW-hr	N/A Contracted	N/A Contracted	$100/MW-hr
Price Cap	Stepped $2,200/MW-hr Smooth $3,0000/MW-hr	Stepped $1,100/MW-hr Smooth $3,0000/MW-hr	Stepped $3,000/MW-hr Smooth $3,0000/MW-hr	Stepped $3,000/MW-hr Smooth $3,0000/MW-hr	N/A Contracted	N/A Contracted	Stepped $100/MW-hr Smooth $100/MW-hr

AS Product Hierarchy

Speed of response to imbalances:

Slowest *Fastest*

DAC → R60 → R10 → CR → RR → FRR → FFR

Note: DAC is only procured in the day ahead market – DAC in this case refers to dispatching a DAC resource into the energy market

Order of reserve activation in a shortfall:

First

Shed load before converting to energy

DAC → R60 → R10 → CR → RR = FRR = FFR

New Ancillary Service Products

R10 Uncertainty/Ramping Reserve	R60 Uncertainty/Ramping Reserve	Day Ahead Commitment (DAC)

• **Purpose:** Capability to meet expected and unexpected **10-minute** ramping needs
• **Procurement:** Market-based
• **Volume procured:** Expected ramp up requirement + uncertainty (net demand forecast error) over 10 minutes
  ◦ *Calculated based on a percentile of forecast error using historical data, scales based on renewable capacity*
• **Markets:** Real time
• **Offer Cap:** $100/MWh
  ◦ *Set on O&M costs, assumed there is no cycling*
• **Price Cap:** $2,2000/MWh (stepped) or $3,000/MWh (smooth)
	• **Purpose:** Capability to meet expected and unexpected **60-minute** ramping needs
	• **Procurement:** Market-based
	• **Volume procured:** Expected ramp up requirement + uncertainty (net demand forecast error) over 60 minutes
	  ◦ *Calculated based on a percentile of forecast error using historical data, scales based on renewable capacity*
	• **Markets:** Real time
	• **Offer Cap:** $80/MWh
	• **Price Cap:** $1,1000/MWh (stepped) or $3,000/MWh (smooth)
	• ***Mutually exclusive with DAC***
	• ***Total volume required can be reduced based on volume of R10 cleared***
		• **Purpose:** Used to meet expected net demand forecast and uncertainty in the day ahead market
		• **Procurement:** Market-based
		• **Volume procured:** Dependent on DAM design option, volume will need to meet expected net demand and additional volume to cover forecast error
		• **Markets:** Day ahead only
		• **Offer Cap:** $100/MWh
		• **Price Cap:** $100/MWh (stepped) or $3,000/MWh (smooth)
		• ***Most relaxed requirements for ramping speed and start times***
		• ***Mutually exclusive with R60***
		• ***Volume can be reduced based on volume of R10 and R60 procured***

Other Reserve Products

Regulating Reserve (RR)	Contingency Reserves (CR)	Fast Frequency Response (FFR)	Fast Regulating Reserve (FRR)
• **Purpose:** Balances expected and unexpected net demand variability within 5-minute SCED intervals • **Procurement:** Market-based • **Volume procured:** Based on variability and forecast error • **Markets:** Day ahead and real time • **Offer Cap:** $100/MWh • **Price Cap:** $3,000/MWh • **Requirements:** Responds to area control error (ACE) without manual intervention • **Mutually exclusive with CR**	• **Purpose:** Provide energy to cover generation contingencies • **Procurement:** Market-based • **Volume procured:** Greater of the most severe single contingency on the grid and a % of AESO generation • **Markets:** Day ahead and real time • **Offer Cap:** $100/MWh • **Price Cap:** $3,000/MWh • **Requirements:** Generator must be able to deliver volume within 10 minutes, must be at least 50% spinning reserves • **Mutually exclusive with RR**	• **Purpose:** Mitigate reliability risk of frequency decay when the BC-MATL intertie trips • **Procurement:** Contracted • **Volume procured:** Based on provider availability and import volume • **Markets:** N/A • **Offer Cap:** N/A • **Price Cap:** N/A • **Requirements:** Sub-second response time • **Mutually exclusive with other ramping products**	• **Purpose:** Mitigate reliability risks such as system operating limit exceedance or instability from variable resource output decreases rapidly • **Procurement:** Contracted • **Volume procured:** Based on providers' capabilities and prices discovered through pilot • **Markets:** N/A • **Offer Cap:** N/A • **Price Cap:** N/A • **Requirements:** Fast response time, limited energy use • **Mutually exclusive with other ramping products**

Intertie Seams

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Intertie Transmission Tariffs

Applicable transmission tariffs **include point-to-point transmission service** within neighboring jurisdictions and **AESO import/export service** for some scenarios

Service	Rate	Assumptions	Result ($2020 USD)
AESO			
Import Opportunity Service (IOS)	Applicable transmission loss factor (LF) at the intertie	BC LF = 2.96%, MATL LF = 5.25%, Sask LF = 4.84%; Losses are a function of price and change by year	*Varies by jurisdiction and year*
Export Opportunity Service (XOS)	$9.11/MWh + applicable LF at the intertie	BC LF = 1.08%, MATL LF = 0.0%, Sask LF = 2.34%; Losses are a function of price and change by year	*Varies by jurisdiction and year*
BC			
Firm point-to-point transmission service	$80,808/MW per year	Intertie is utilized at a 60% capacity factor (CF)	$10.27/MWh
MATL			
Firm point-to-point transmission service	$78,107/MW per year (MATL > NWE > BPA)	Full Path is utilized at a 60% CF	$9.93/MWh
SaskPower			
Firm point-to-point transmission service	$44,796/MW per year	Intertie is utilized at a 60% CF	$5.69/MWh

Sources: AESO, BC, Sask, Intertie Loss Factors

Importer Offer Behaviour – Risk Premiums

- **Importers add a premium to their offers to account for the risk of changing prices and inaccurate day-ahead forecasts that can result in uneconomic bids**
  - This also accounts for the dynamic of importers being reluctant to submit offers for small differences in price
- **Risk premium must be accounted for in modeling to accurately represent intertie utilization and importer behavior**
  - Implemented as an additional wheeling charge
- **Risk premium was estimated by assessing historical import/export data and prices to determine the average price spread at which trades occur**
  - Different risk premiums for imports and exports and across each intertie line

AESO <> WECC

- Mid-C and AESO prices were compared with associated MATL import and export quantities

AESO <> BC

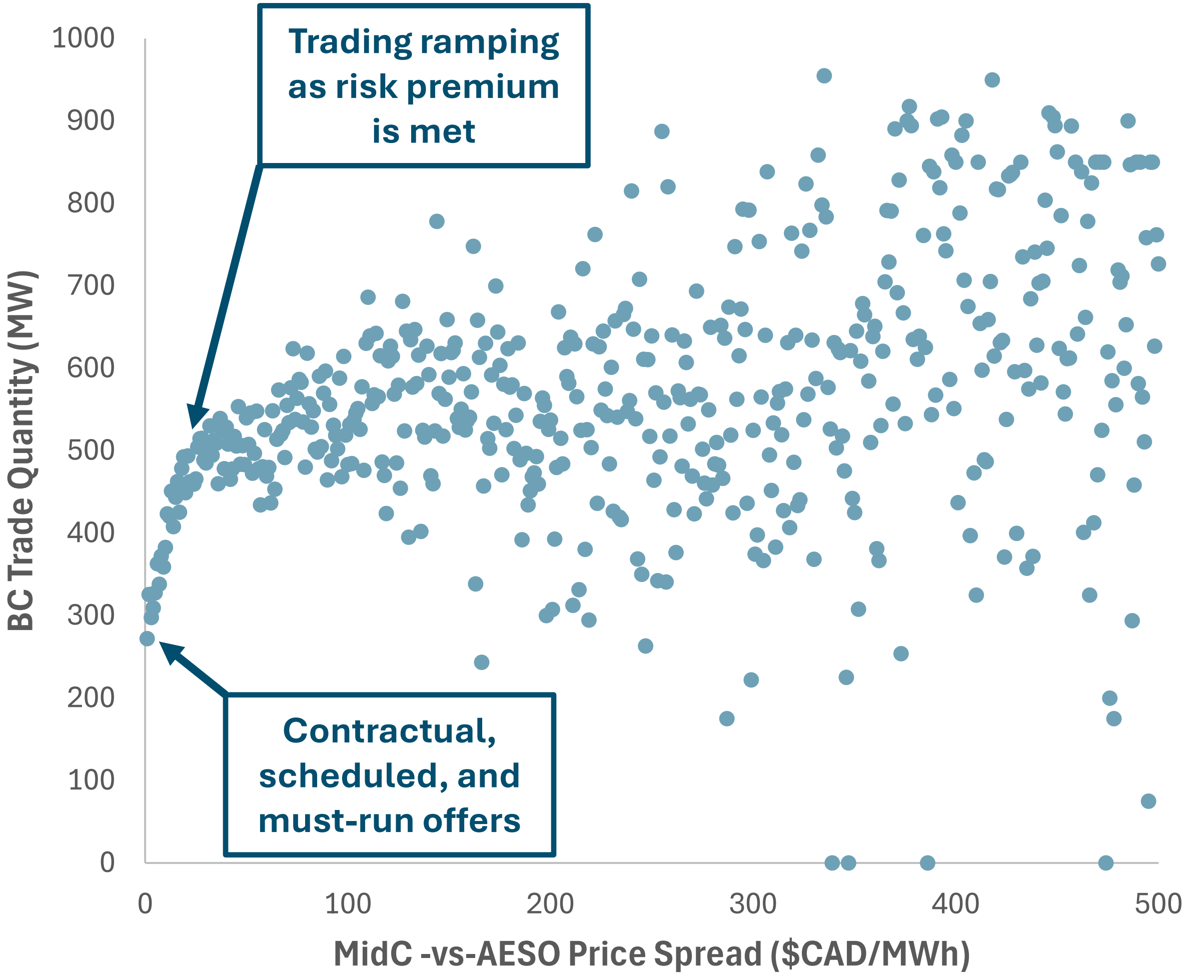
- Mid-C and AESO prices were compared with associated BC intertie import and export quantities
  - Mid-C was used as a proxy price for BC

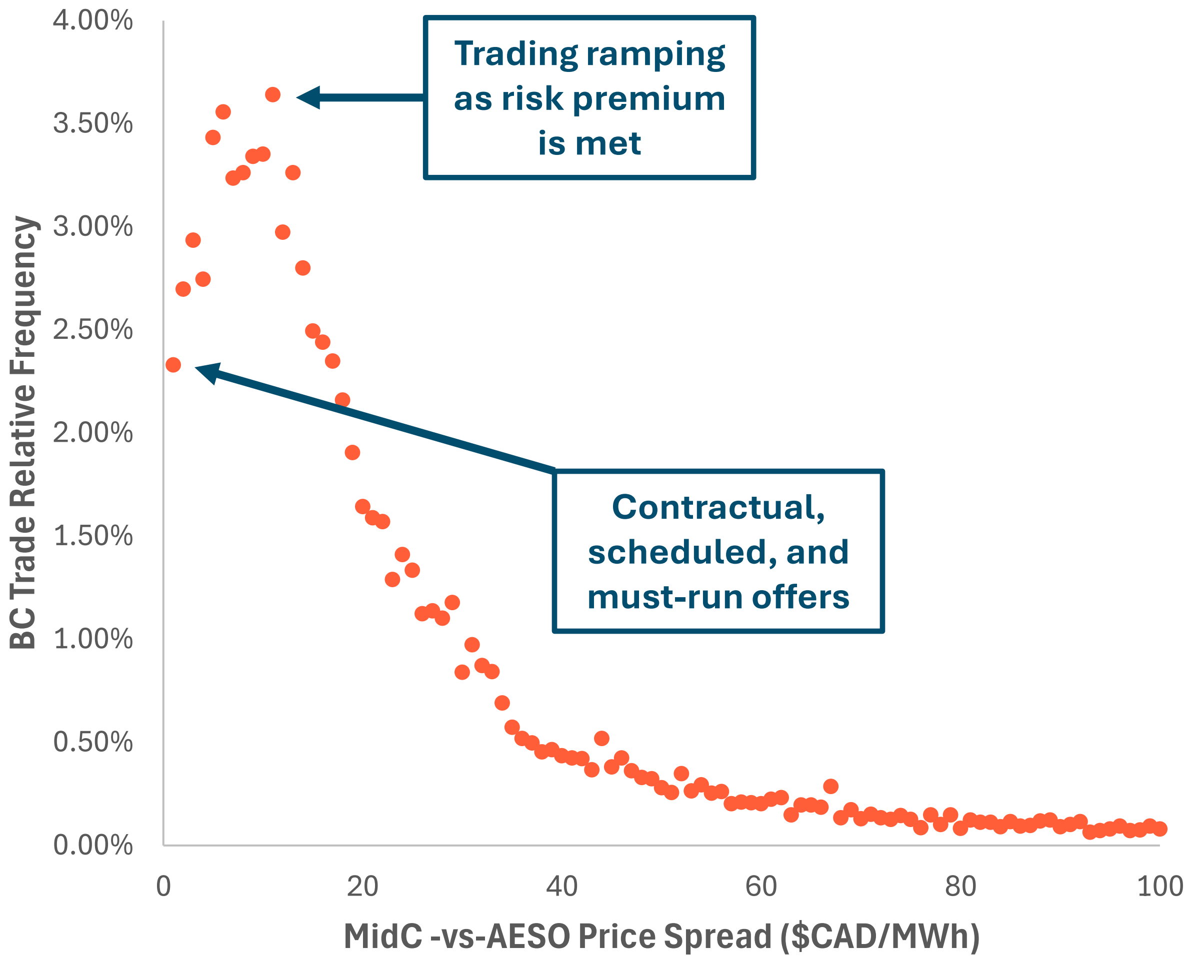
AESO <> SaskPower

- AESO and SPP-North prices were compared with associated SaskPower intertie import and export quantities
  - SPP-North was used as a proxy price for SaskPower

Importer Offer Behaviour – Risk Premiums

Risk premiums are visible in Importer offer behaviour by assessing average trade quantity and relative trade frequency as a function of price spread





Importer Offer Behaviour - Inefficient Flows

- **Historical intertie trade efficiency was assessed by reviewing historical trade volumes and price spreads between jurisdictions**
  - Timeseries utilized: 2018 to 2022
- **Economic efficiency of intertie trade was assessed by comparing prices between jurisdictions**
  - Trade is deemed economic if power flow is directed from lower cost to higher cost, or vice versa

Economic Trade Percentage 2018-2022		
BC<>AESO	WECC<>AESO	Sask<>AESO
73%	66%	75%

Note: *Trade value represents aggregate value from 2018 to 2022*

Fuel, Profiles, Loads, Carbon Pricing, Resource Costs, Offer Structure

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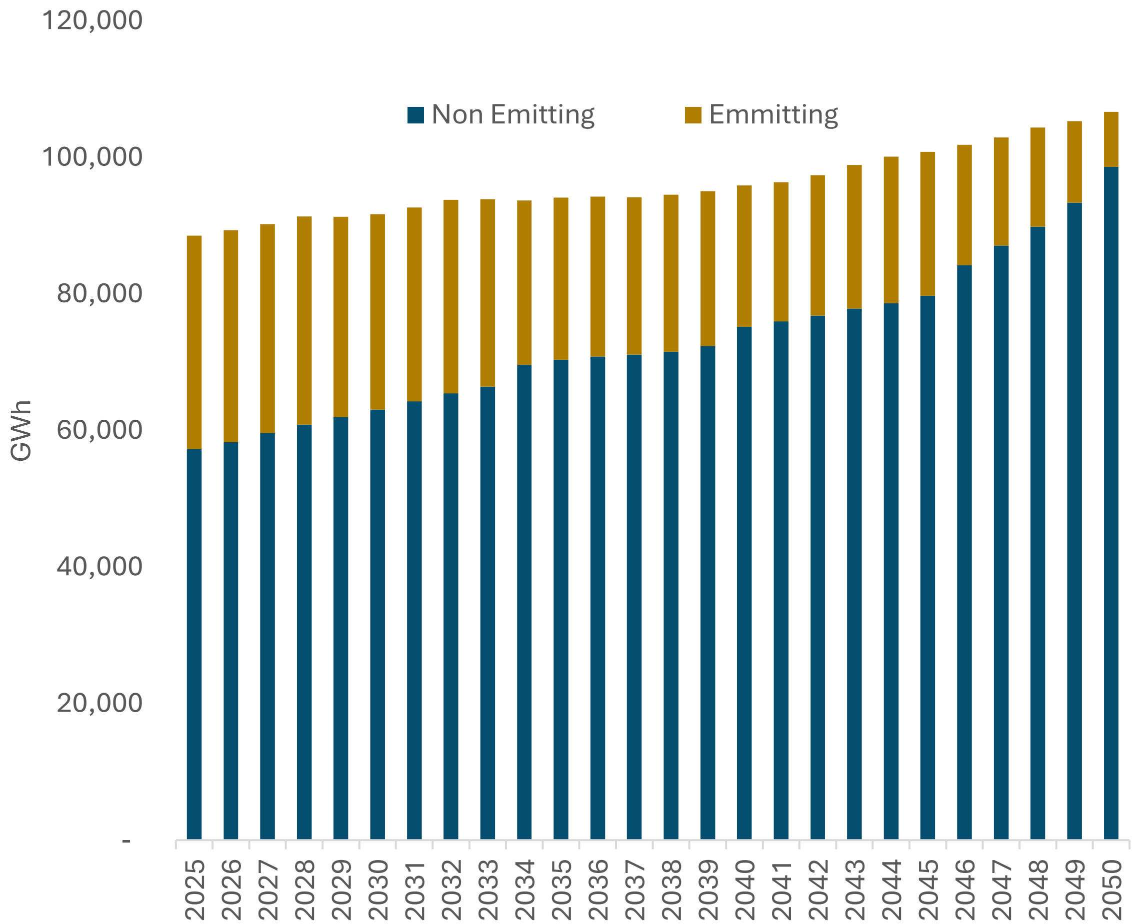
2050 Net Zero

- Alberta has a stated goal to have a net-zero power sector by 2050
- E3 has implemented this constraint by requiring that all metered load is met by non-emitting resources by 2050 – starting with 30% of energy by 2030, 50% of energy by 2040, and then 93% of energy by 2050
  - 7% of energy is assumed to be distribution and transmission line losses
- Non emitting resources include:
  - Solar, Wind, CCGT with CCS, Biomass/Other, Imports, Geothermal, Hydrogen, Hydro, and Demand Response, Nuclear
- Cogeneration production is considered non emitting in the power sector (emissions allocated to oil production)

Net Zero Trajectory

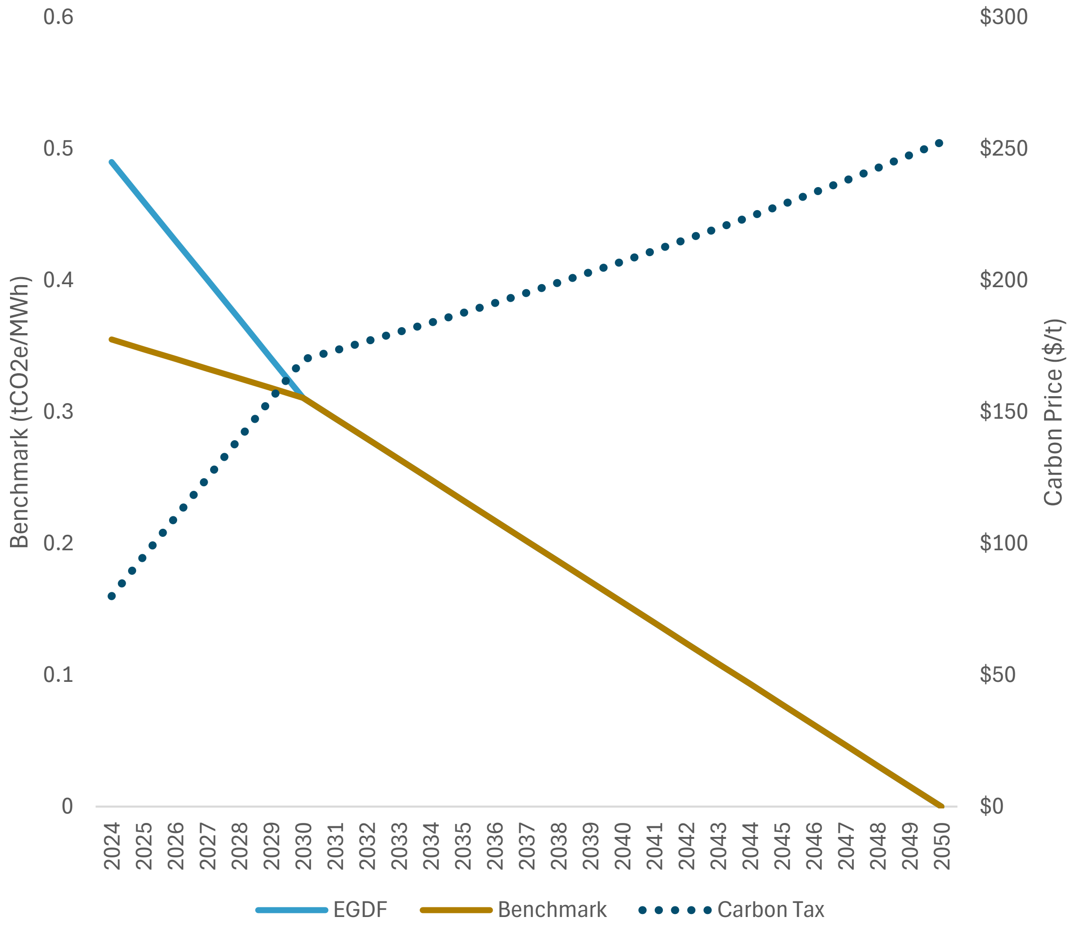


Source: GoA: Emissions Reduction and Energy Development Plan | Alberta.ca
Source: AESO: Intertie Options Paper

Carbon Pricing – Total Carbon Price

- E3 modelled the Alberta electricity system to align with the provincial target of net-zero by 2050
- Carbon price follows the federal trajectory of increasing $15/t per year until reaching 2030 and thereafter a 2% escalator is applied until reaching $250/t nominal by 2050
- The High-Performance Benchmark (HPB) aligns with the current trajectory under TIER out to 2030 and then exhibits a linear decline to 0t/MWh by 2050
  - The Electricity Grid Displacement Factor (EGDF) also follows the current TIER trajectory until 2030, after which it decreases linearly in conjunction with the HPB, reaching 0t/MWh by 2050

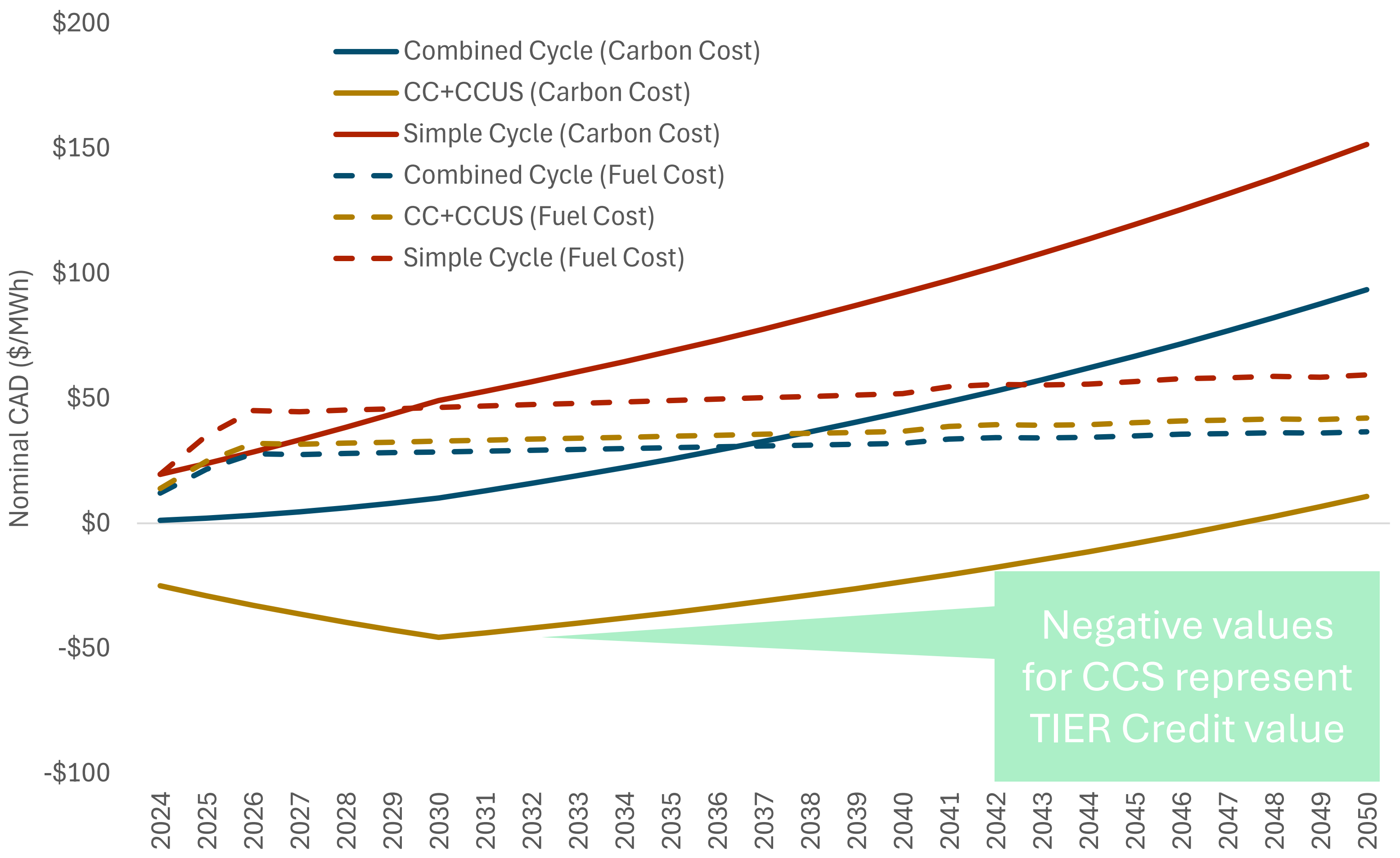
Modelled Alberta Carbon Policy



Carbon Pricing – Variable Cost Impact on Thermal

- **By the end of the forecast carbon pricing becomes expensive for thermal generation – exceeding fuel costs for unabated gas generation**
  - Combined cycle: $93/MWh
  - Simple cycle units: $151/MWh
  - CCS with 90% capture: $11/MWh
    - By 2050 there is no HPB and CCS faces the carbon price on the 10% that is not captured
- **Pricing of environmental attributes combined with must run blocks cause negative price outcomes**

Impact of Carbon Policy on Thermal Generation

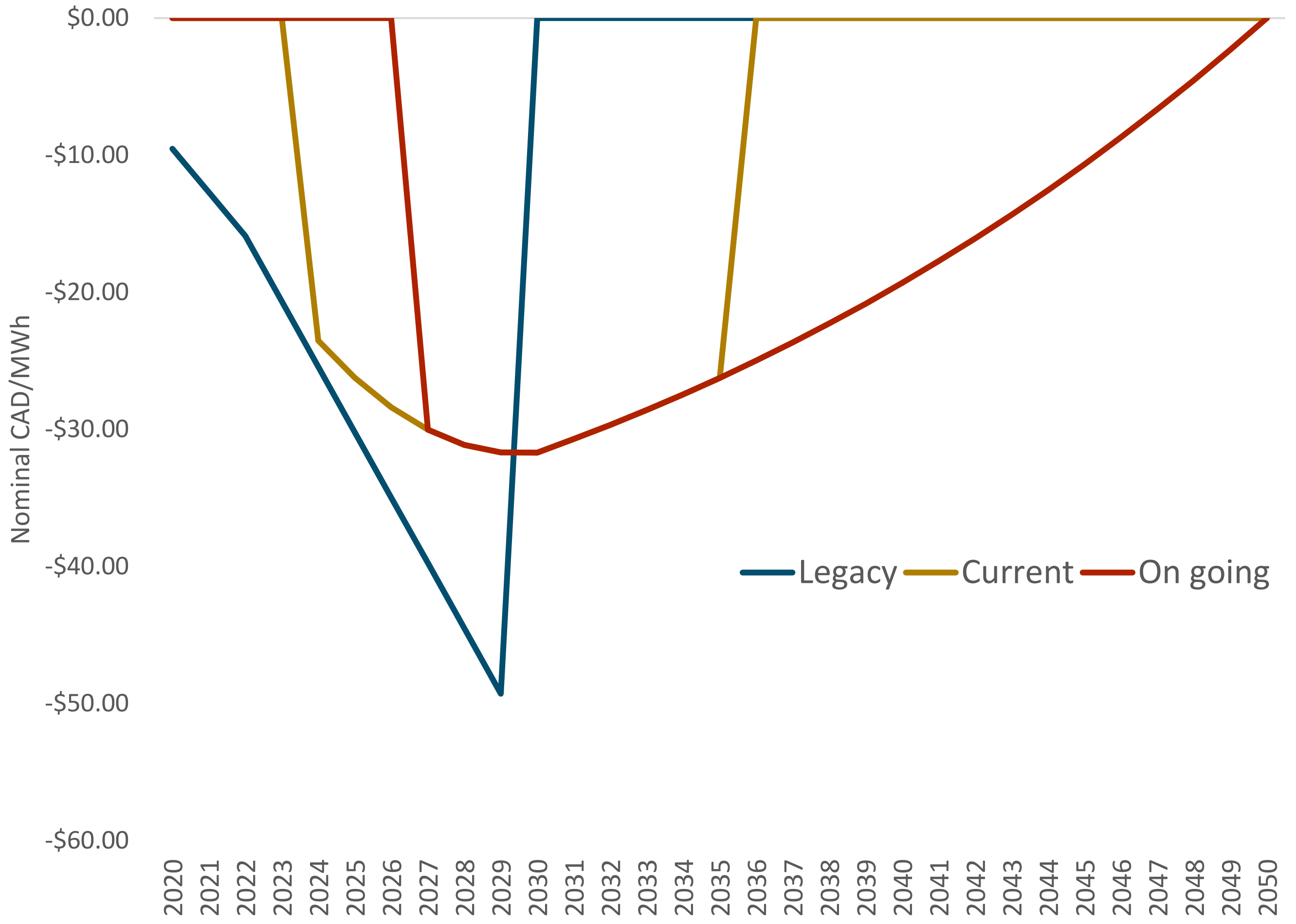


Carbon Pricing – Renewables Credit Pricing

+ **Wind, Solar, CCS, are assumed to bid their TIER credit value below zero as their floor**
  - TIER credits are only generated from producing assets, therefore any TIER credit generating facility will run at a negative price up to the value of their credits
+ **Different vintages of assets have different lock-in grid intensities**
  - E3 simplified this by creating three vintages
  - A lock in of 0.53 (tCO2e/MWh) for ten years if placed into service before 2023 **[Legacy Assets]**
  - Units placed into service in 2024+ are assumed to get 10 years at the declining EDGF **[Current Assets]**
+ **Wind with REP contracts are assumed to bid at the price floor**
  - The Renewable Electricity Support Agreements (RESA) are a fixed for floating swaps, which incents generators to bid at the price floor

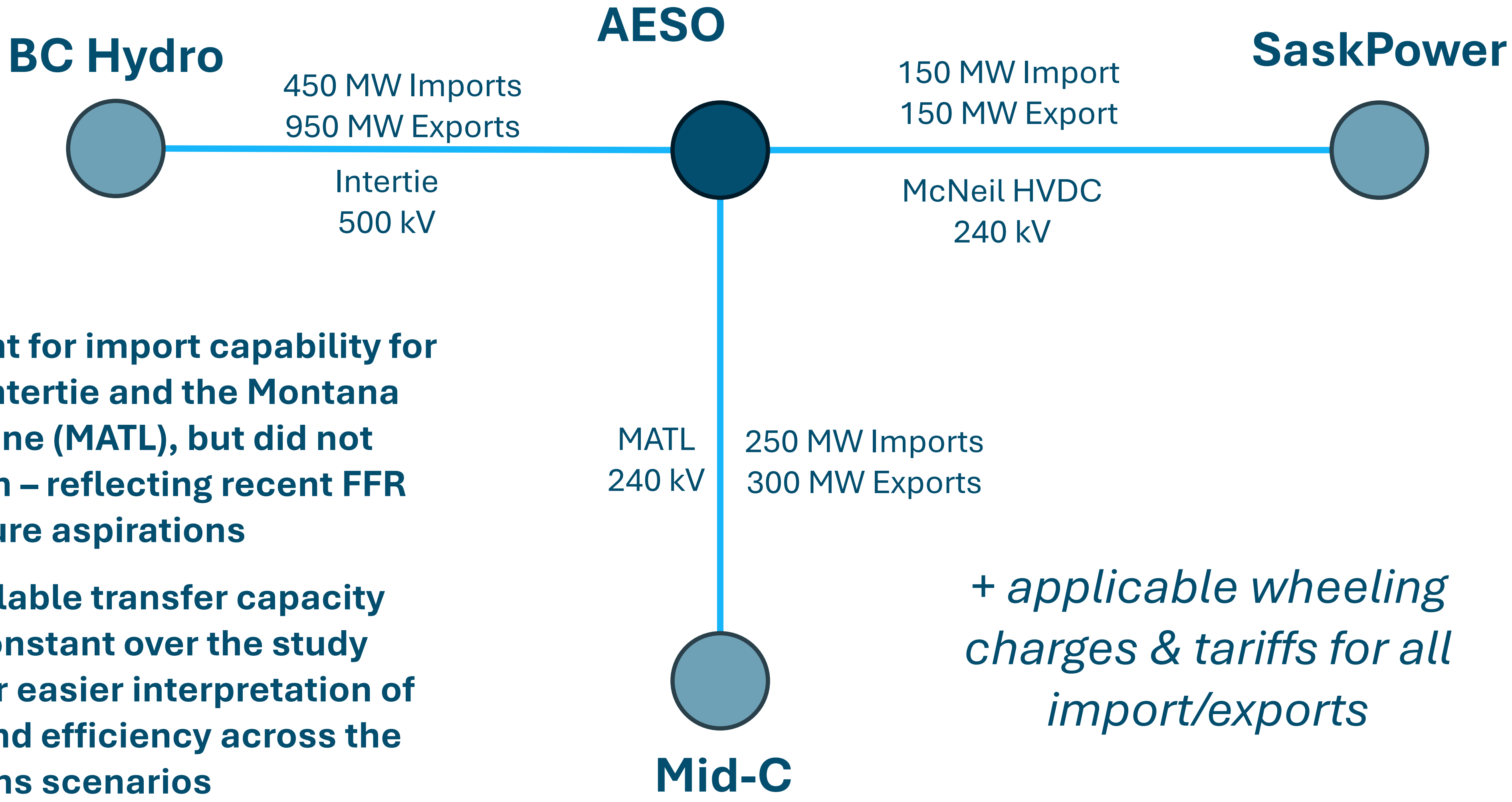
Source: GoA: [Renewable Electricity fact sheet (alberta.ca)](), **AESO RESA:** [REP-Round-1-RESA-Execution-Version-As-Approved-by-Minister-of-Energy.pdf]()

Negative Price Offers



Assumed Line Ratings and Zonal Construct

- E3 needed to make reasonable assumptions regarding import and export capability
- E3 built in improvement for import capability for the British Columbia intertie and the Montana Alberta transmission line (MATL), but did not assume full restoration – reflecting recent FFR procurements and future aspirations
- For this study, the available transfer capacity (ATC) level was held constant over the study horizon. This allows for easier interpretation of the changes in trade and efficiency across the different intertie options scenarios



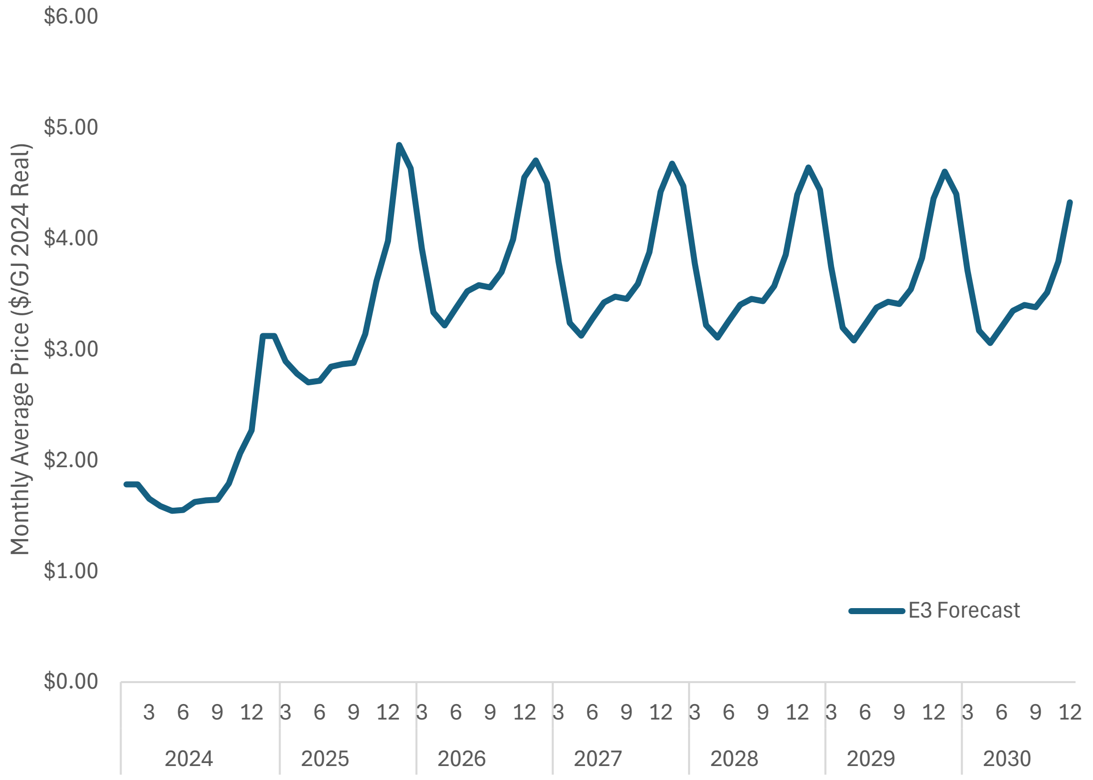
+ applicable wheeling charges & tariffs for all import/exports

Source: AESO: [Interconnected Fast Frequency Response Services Procurement | AESO Engage]

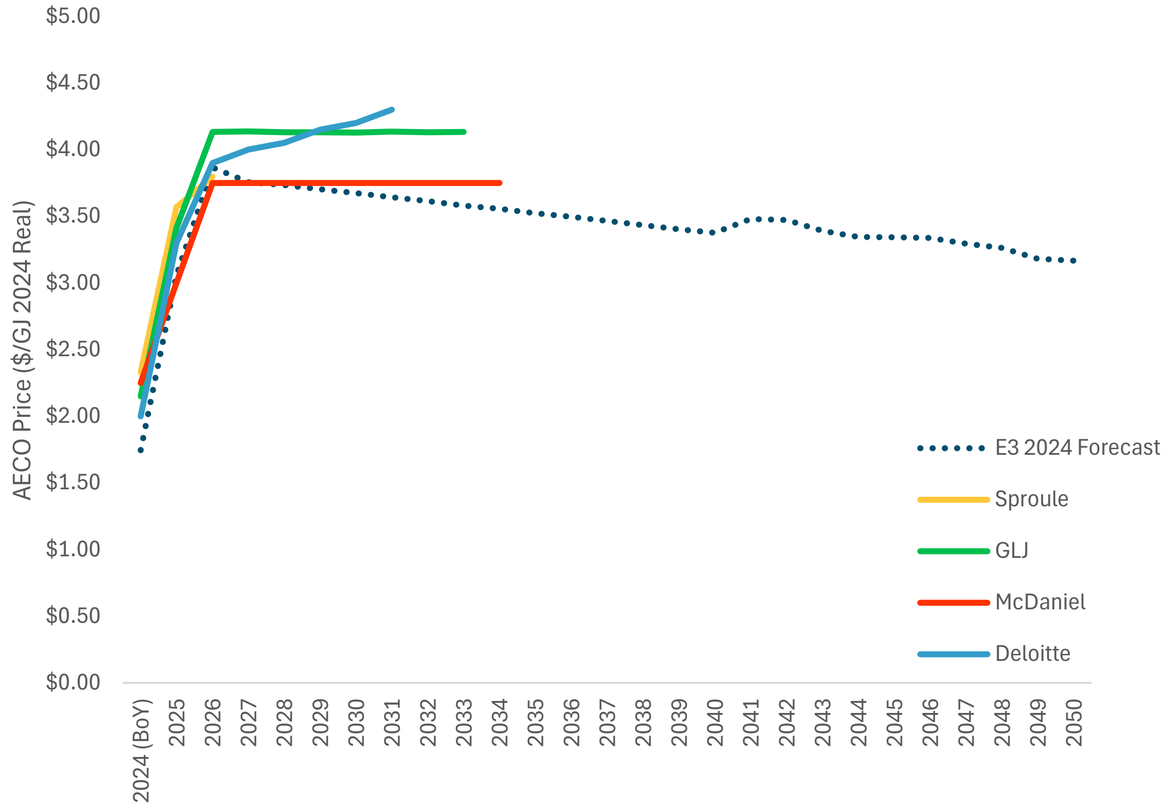
Fuel Prices: Natural Gas

Base gas prices are derived using a combination of forwards in the near-term (through 2034) which trend to the fundamentals-based 2040 forecast (EIA Annual Energy Outlook) in the long run

Short Term Monthly Average Prices



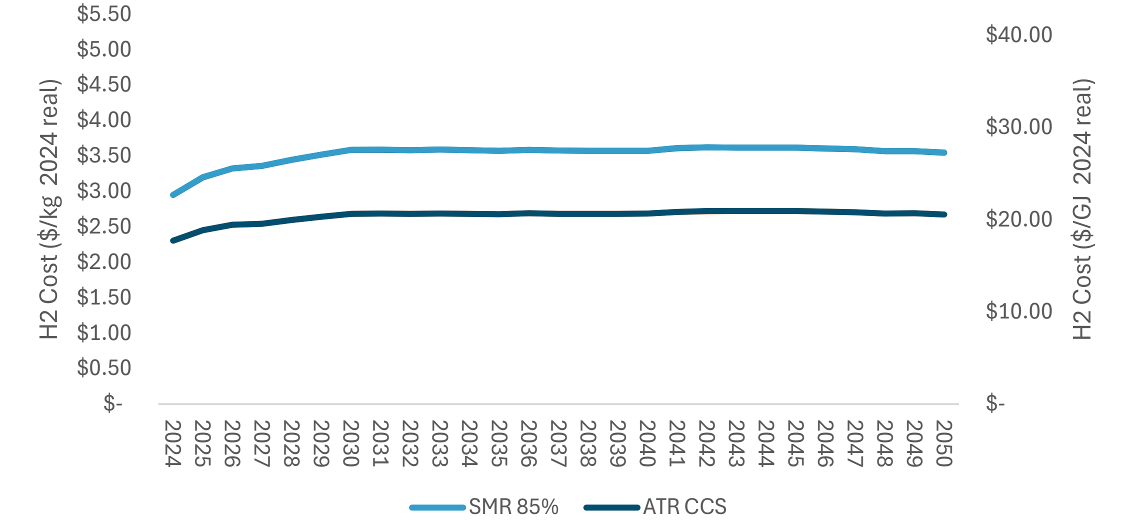
Long Term Annual Average Prices



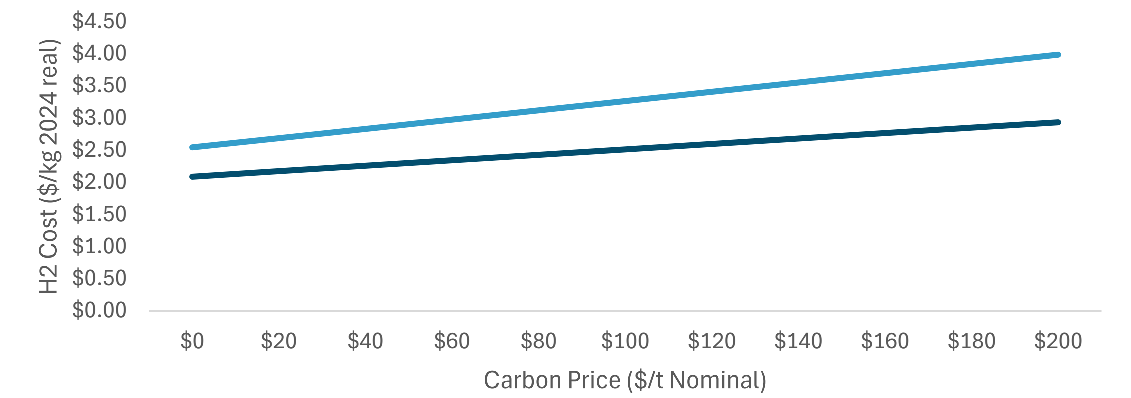
Fuel Prices: Hydrogen

- **Due to the abundance of natural gas and challenges in water licensing in Alberta, E3 assumes the use of "Blue Hydrogen" which is derived from a natural gas feedstock**
  - Blue Hydrogen is decarbonized hydrogen, that is manufactured by natural gas reforming coupled with carbon capture and storage (CCS)
- **The forecast assumes SMR with 85% carbon capture will be the preferred choice until 2040 due to technological availability, despite higher lifecycle emissions than ATR**
  - Steam methane reforming (SMR) is a mature technology that has been used for hydrogen production for decades and currently accounts for 48% of the hydrogen produced globally[1]
  - Blue hydrogen from autothermal reforming (ATR) has the lowest life cycle GHG emissions of 3.91 kgCO2eq/kg H2, compared to 6.66 kgCO2eq/kg for SMR[2]
  - The forecast assumes carbon for all non-sequestered emissions is priced into the feedstock cost of the hydrogen fuel
- **Post-2040, the model assumes fuel availability from ATR-based technology which causes downward pressure on hydrogen fuel cost**

Hydrogen forecast (Real 2024$)



SMR and ATR Fuel Costs vs Carbon Price[3]



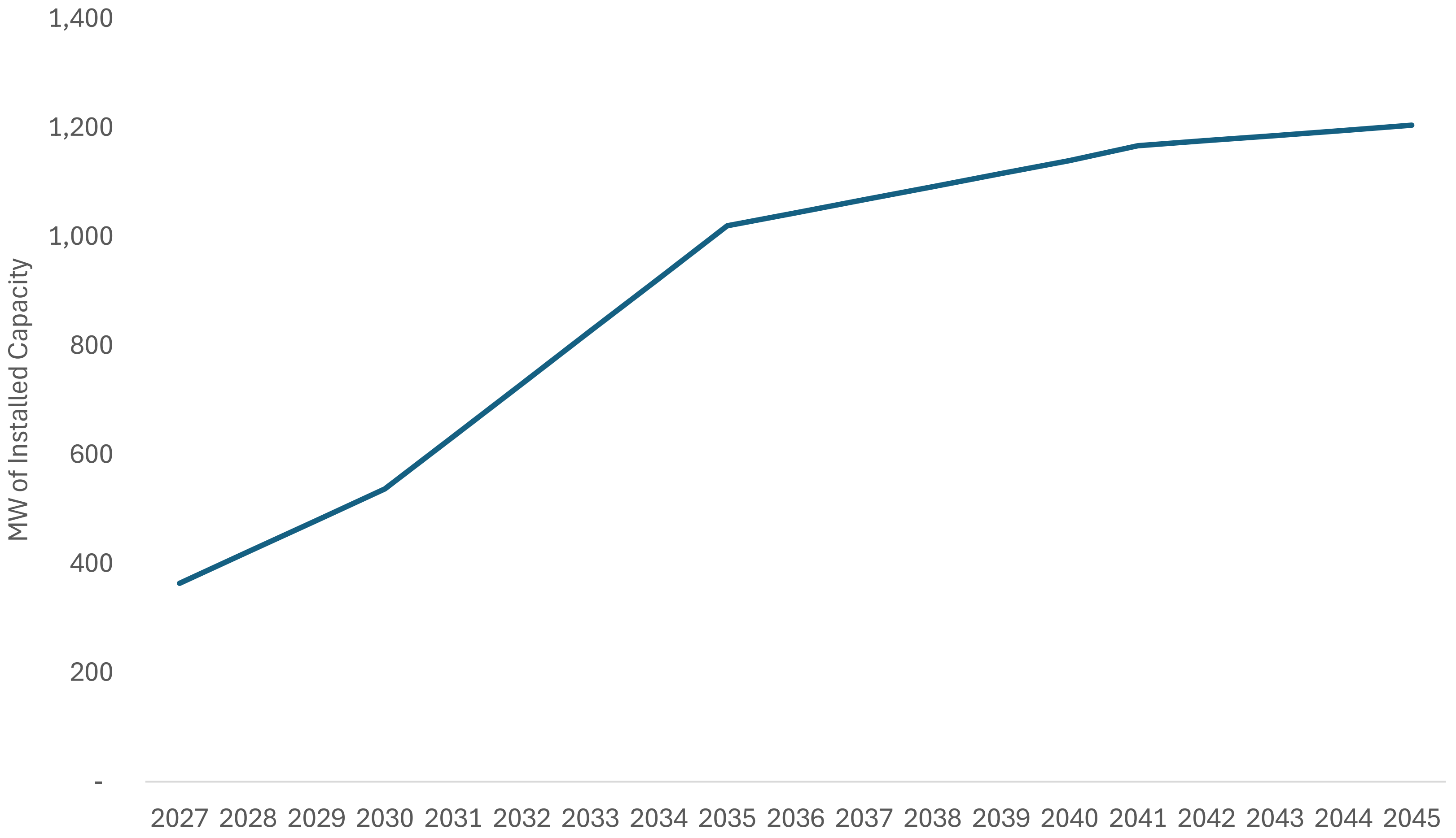
1,2 Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions: A.O. Oni, K. Anaya, T. Giwa, G. Di Lullo, A. Kumar, Department of Mechanical Engineering, University of Alberta

3 – Power price fixed at $85/MWh and natural gas at $2.85/GJ, $2024 real

Rooftop Solar

- Rooftop solar forecast is based on AESO 2021 LTO projections, with E3 modifications
- E3 updated the 2021 LTO's trajectory based on recent increased adoptions
- Recent actuals tracking the "Clean Tech" scenario much closer
- Forecast expected to begin to reach saturation when credits and other incentives roll off by 2035

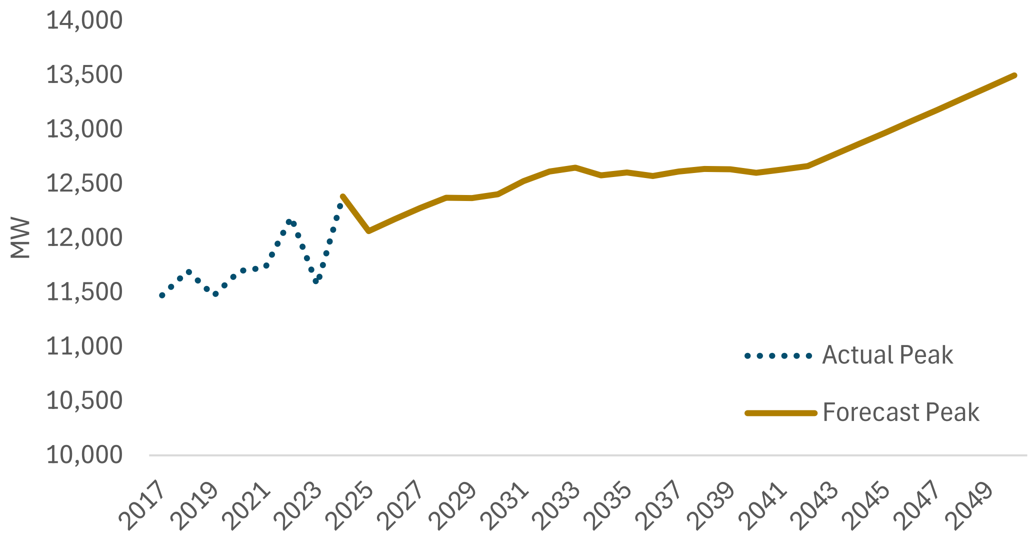
Rooftop Solar Adoption Assumptions



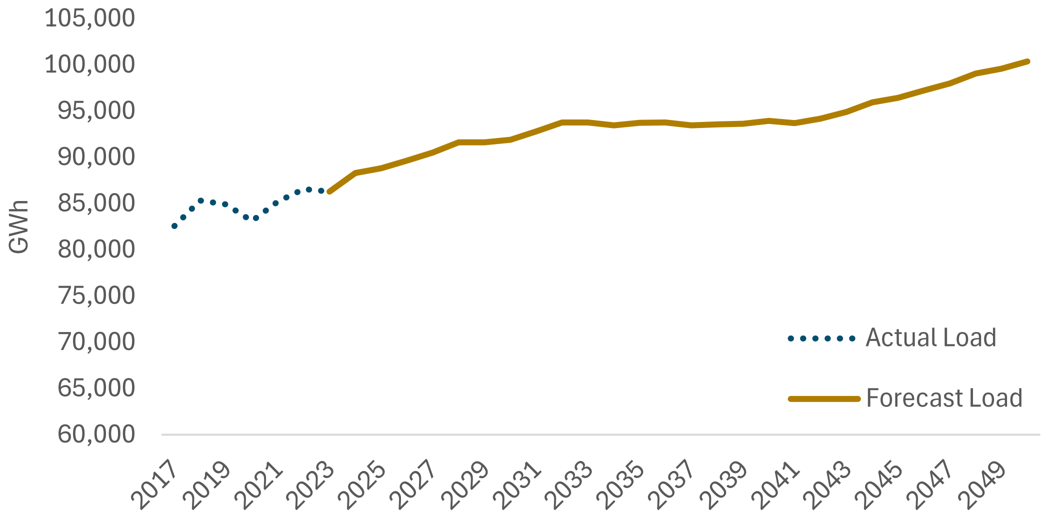
Source: AESO: [Micro- and Small Distributed Generation Reporting » AESO]

Load Growth

Alberta Peak Demand Forecast



Alberta Annual Energy Forecast



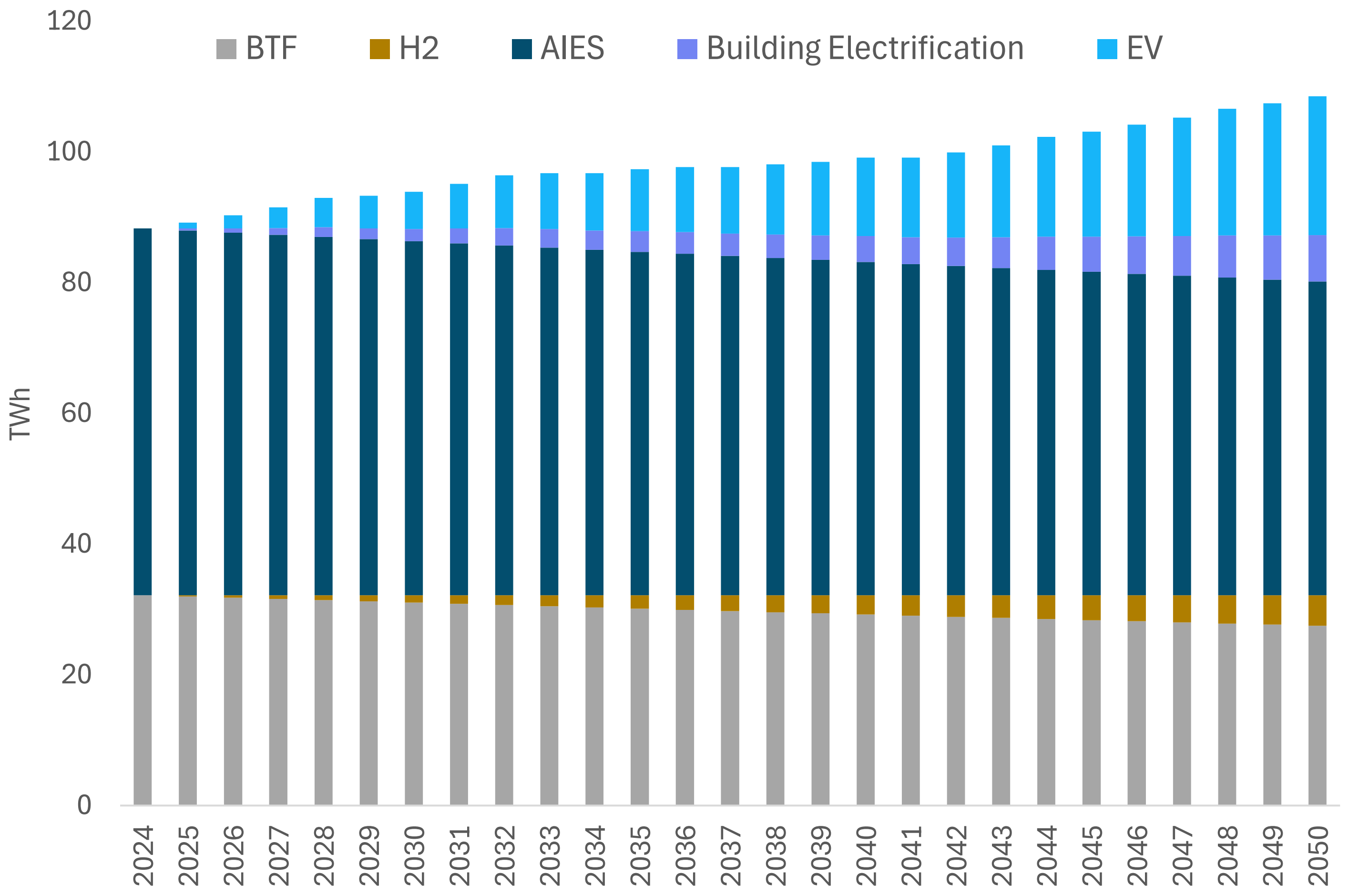
+ **Alberta's peak load growth is expected to grow in line with its historical trends through 2040**
  - Electrification accelerates incremental load growth post-2040
  - Upside for peaks exists as E3 used managed EV charging profiles and moderate electrification trends, which work to dampen peaks
+ **Annual energy load growth is expected to continue growing at a similar pace to historical, moderating in the 2030's**
  - Electrification of buildings post-2040 starts to increase annual energy demand at a strong rate
+ **E3 utilized the 2021 hourly AIL raw forecast as a base and added electrification, H2 production, rooftop solar, and EV assumptions to that outlook, based on E3 work and the 2024 LTO preliminary study**

Source: *2021 Long-Term Outlook » AESO*, *Forecasting Insights | AESO Engage*

Load Forecast – AESO 2021/2024 LTO with E3 EV, Electrification, and Rooftop PV Assumptions

- **E3 used the AESO's 2021 LTO and 2024 preliminary data to create the load forecast in our outlook**
  - 2021 hourly AIL raw forecast used as a base
  - Electrification, H2 (Hydrogen) production, rooftop solar, and EV assumptions layered in based on E3 work and the 2024 LTO preliminary study
- **E3 internal modelling provides EV and Electrification profiles used**
- **Energy efficiency gains are more than offset by organic load growth**
  - Industrial hydrogen production, EV charging, and building electrification outpace efficiency related reduction

Load Forecast by Component

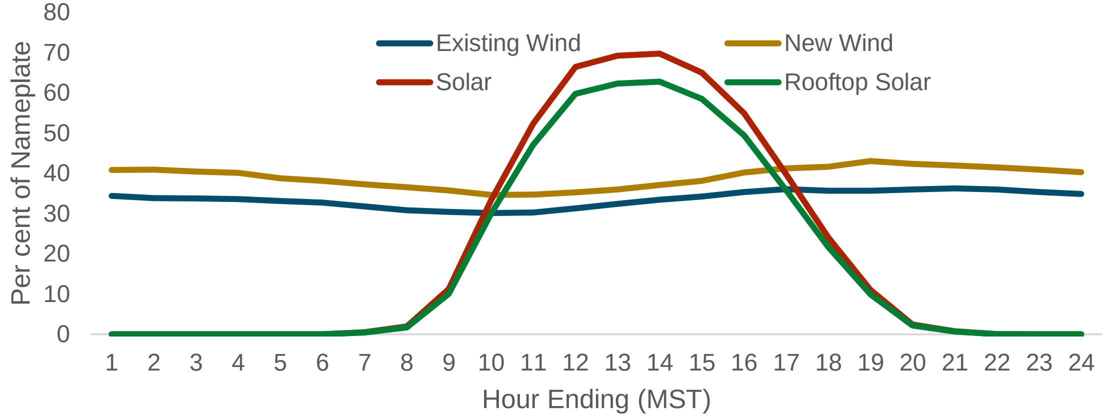


BTF: Behind the Fence Load, H2: load from hydrogen production, AIES: Alberta Interconnected Electric System (transmission served loads), EV: Electric Vehicle

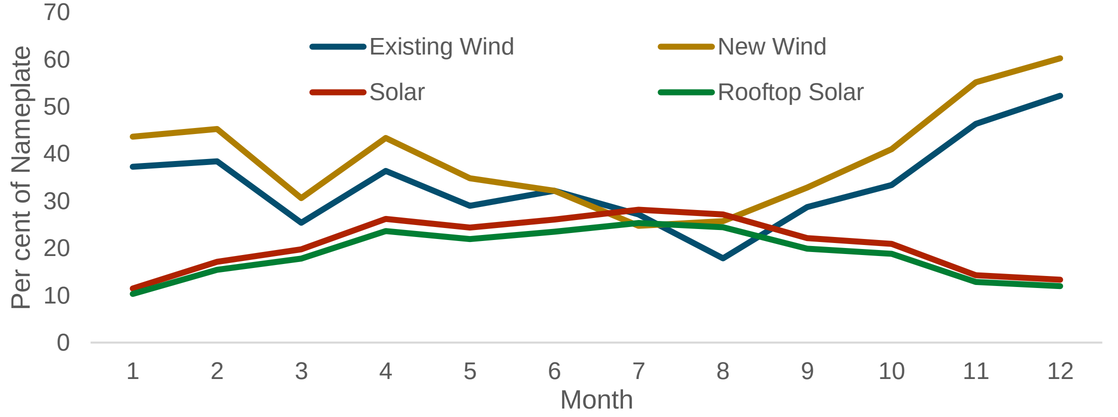
Renewables Profiles and Potential

- **E3 utilized Alberta historical wind and solar generation data to develop the solar profiles**
  - E3 matched the AESO's 2021 weather year which includes a 2011 Winter profile, and a 2003 summer profile
  - This alignment preserved the historical wind, solar & load correlations integral to price forecasting
- **Rooftop solar exhibits 18.8% capacity factor while utility scale sees a 20.9% capacity factor**
- **Existing wind (pre-2020) has a 33.6% capacity factor while new wind has a 39% capacity factor**
  - Increased capacity factor is a function of improved turbine technology and higher quality wind sites
- **Hydro is a profile based on historic run rates**

Hourly Average Profile



Monthly Average Profile



Expected Costs of Renewable Resources and Storage

+ **Utility solar, battery storage, and onshore wind upfront capex assumptions reflect current market conditions based on latest E3 RECOST (LCOE) model**
  - Underlying capital cost data is sourced from NREL ATB 2023 and AESO, while applying E3's assumptions on long-term trajectories of capital costs
  - Regional multipliers are applied to overnight capital costs and FOM for wind and solar based on labor cost differences between provinces and farmland land lease costs
+ **Levelized costs of new resources for solar, wind, and batteries use the Federal ITC of 30%**
  - ITC applied to solar, wind, and storage as per The Clean Technology ITC in the Federal Budget
  - ITC is then removed in 2035 as per current proposal
+ **For wind and solar – TIER Credits are monetized up front and removed from capital costs**
  - Assumes the EDGF for 10 years and model actual capacity factors

**Note: A capacity factor of 40% is assumed for wind resources and 23% for solar resources*

	Wind		Solar		Battery	
Nominal $CAD	Capital Cost ($/kW)	LCOE ($/MWh*)	Capital Cost ($/kW)	LCOE ($/MWh*)	Capital Cost ($/kW)	Investment LFC ($/kW-yr)
2027	$1,089	$31.37	$1,379	$66.53	$2,650	$276.49
2036	$1,345	$46.15	$1,299	$84.52	$3,448	$414.40

Expected Costs of Thermal Resources

+ **CCGT - CCS units are assumed to run with an 80% capacity factor or higher, and have reduced heat rate efficiency due to the CCS parasitic loads**
  - Heat rate increased by 10% from state-of-the-art CCGT
  - TIER Credits are assumed to be generated as per current TIER Regulations
  - 30% ITC included for CCS deployments pre 2035
+ **CCGT and CT costs are expected to remain flat in real dollars**
  - Modest gains in heat rates are expected over time
  - Subject to carbon tax via TIER HPB and carbon tax

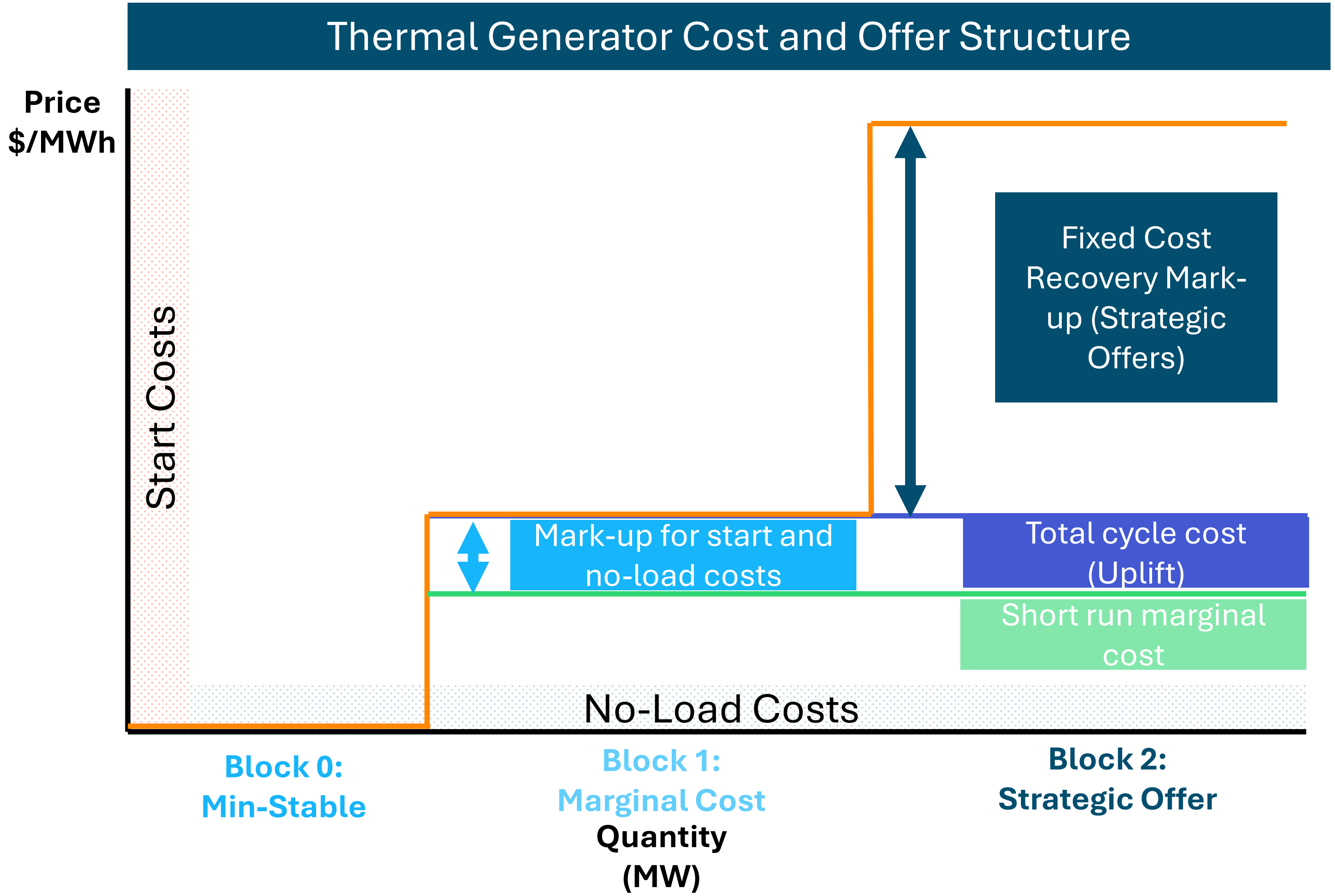
**Note: CCS numbers in row 2027 reflect the year 2031, based on the timing of expected CCS installation*

	CC			CT			CCS		
Nominal $CAD	Capital Cost ($/kW)	Investment LFC ($/kW-yr)	LCOE Snapshot[1] ($/MWh)	Capital Cost ($/kW)	Investment LFC ($/kW-yr)	LCOE Snapshot[1] ($/MWh)	Capital Cost ($/kW)	Investment LFC ($/kW-yr)	LCOE Snapshot[1] ($/MWh)
2027*	$1,799	$271.13	$67.70	$2,050	$283.77	$193.38	$4,652	$542.10	$60.54
2036	$2,150	$324.03	$100.89	$2,450	$339.14	$260.71	$5,560	$776.36	$103.05

Footnote 1: LCOE numbers reflect a snapshot of SRMC in the applicable year, not a 20-year projection. Capacity factor assumptions: CC = 75%, CT = 35%, CCS = 90%

Thermal Offers Across Scenarios

- E3 has modelled thermal plants in AESO's single part bid, strategic offer energy only market to recover all operating and capital costs through bidding
- Minimum stable blocks are offer as must run
- Block one is a marginal cost block, that is grossed up for recovery of cycling and no-load costs
- Based on the firm's market power, block two is strategically offered. This block is the economically withheld portion that helps with fixed cost recovery



Thank You

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Energy+Environmental Economics