Dispatchable Renewables and Energy Storage

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Stakeholder Session
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What we will cover today

- Objectives
- Approach
- Reliability needs
- Dispatchable renewables
- Energy storage
- Next steps and recommendations

Objectives

Government of Alberta request

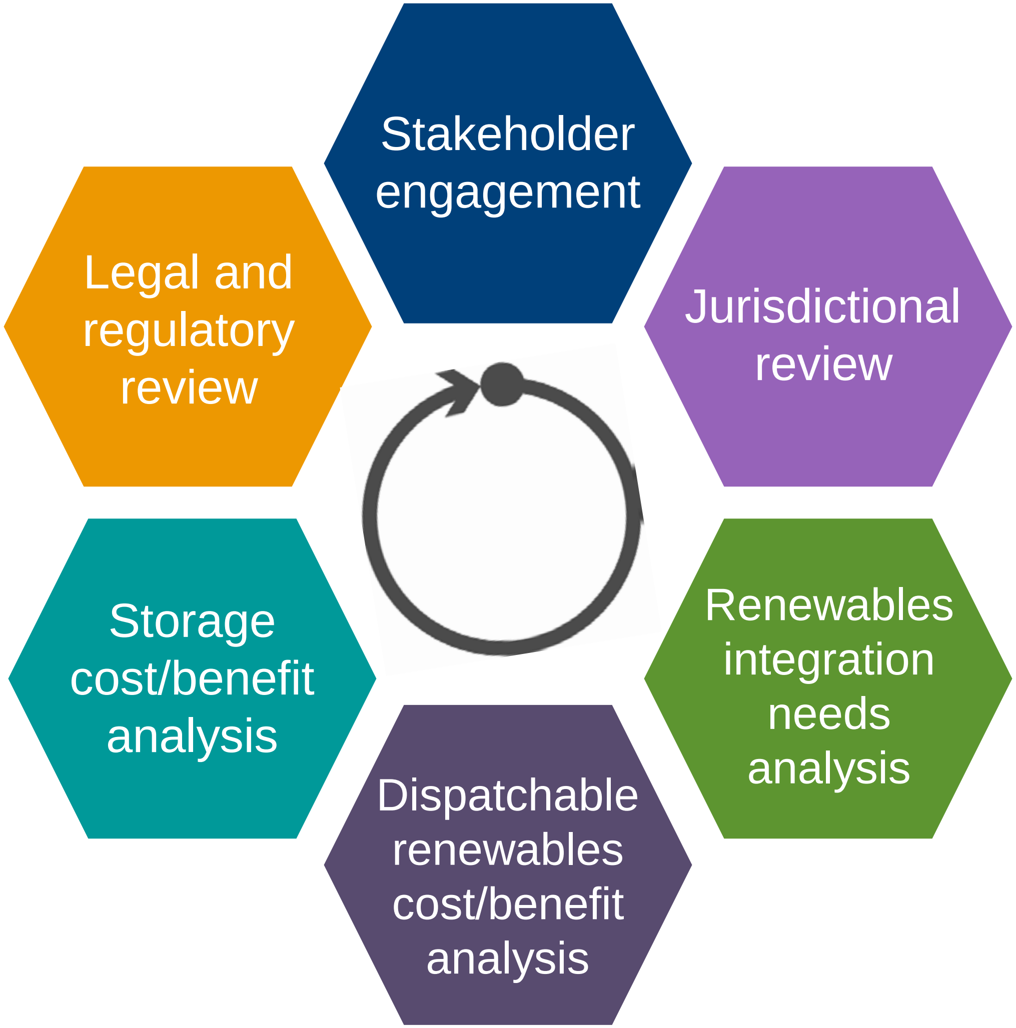
- By May 31, assess specific need for dispatchable renewables and energy storage (DR&S) as Alberta transitions toward 30% renewables by 2030
- If a system need is identified, determine if additional products or services are required and the market mechanisms to procure them
- Ensure recommendations are consistent with government's desired outcomes
  - Maintain or improve future reliability
  - Be cost-effective
  - Ensure minimal market impacts
  - Contribute toward meeting renewables generation target

AESO objectives

- Listen to and learn from others
- Understand Alberta's potential reliability implications of integrating 30% by 2030
- Directionally understand cost effectiveness of different technologies, dispatchable renewables and storage
- Identify and remove barriers to enable market participation and improve competition
- Remain agnostic to technology and project types

Approach

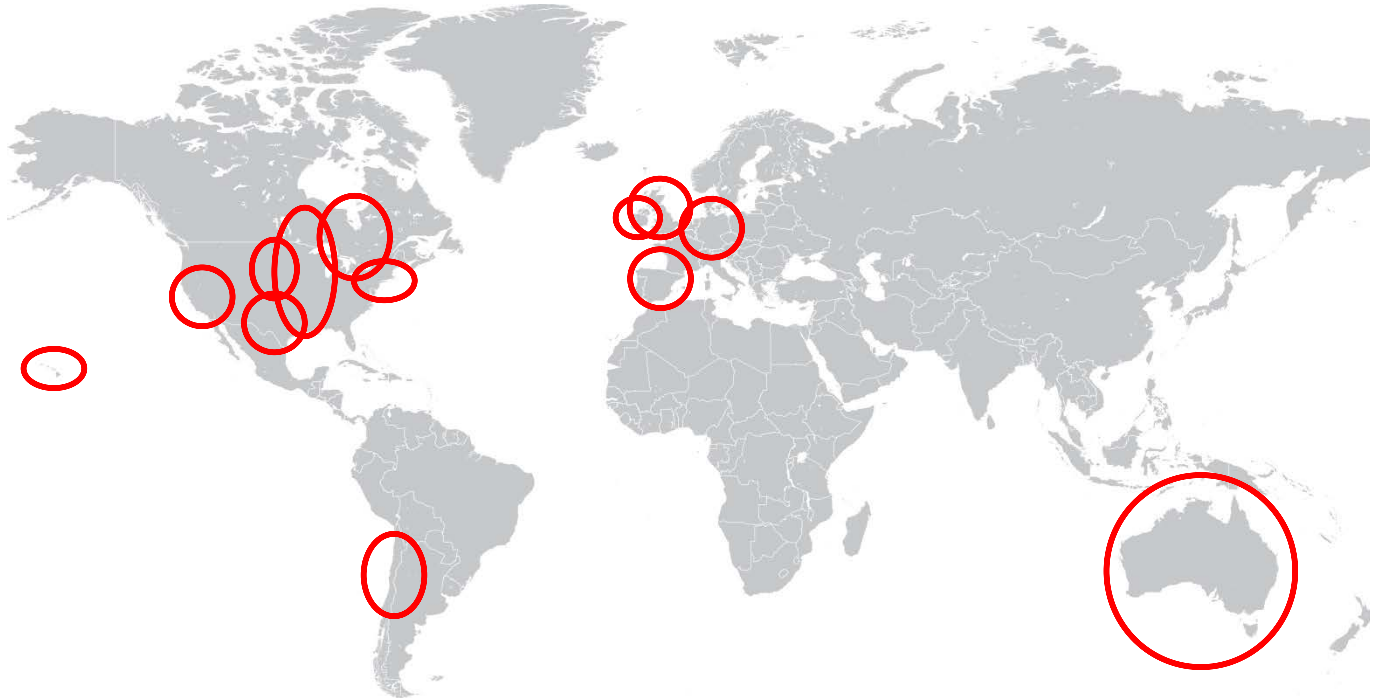
AESO's review: six work streams



Broad stakeholder engagement

- 80+ responses to stakeholder questionnaire
- 30+ meetings with industry incumbents, key associations, project developers and Indigenous working group
- Comprehensive feedback helped define review scope
  - Jurisdictions to learn from
  - Perform a comparative cost/benefit analysis
  - Technology and project cost information used in AESO analysis
  - Identified barriers to DR&S technologies entering Alberta market
  - Noted desire for long-term contract arrangements

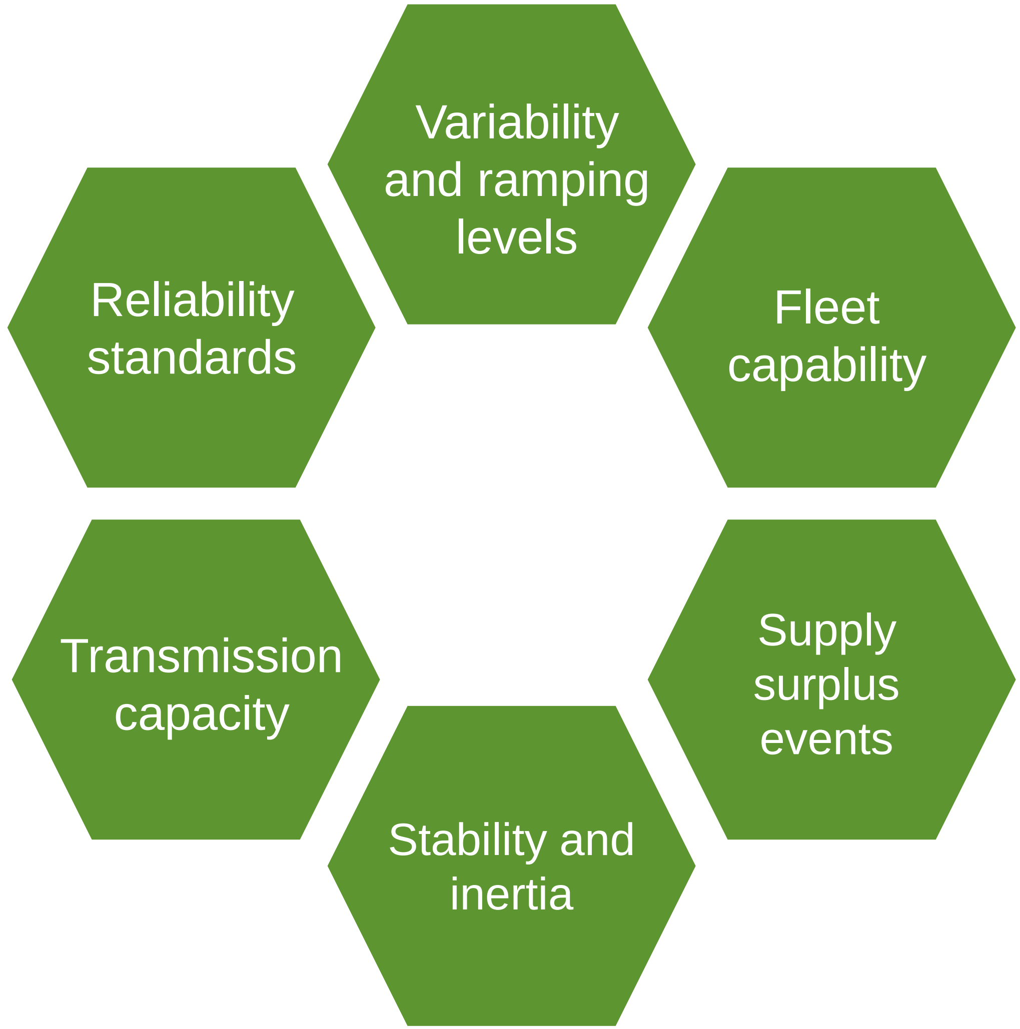
Jurisdictional review



14 regions	Typical challenges	Flexibility options
• A few nearing 30% penetration • Some are setting 40%–60% targets • Curtailments near 5%	• Dispatchable flexibility to meet increasing variability • Managing supply surpluses when renewables generating in low-demand periods	• Regional coordination • Load adjustment • Renewable diversity, curtailment • Existing resources and market products • Storage

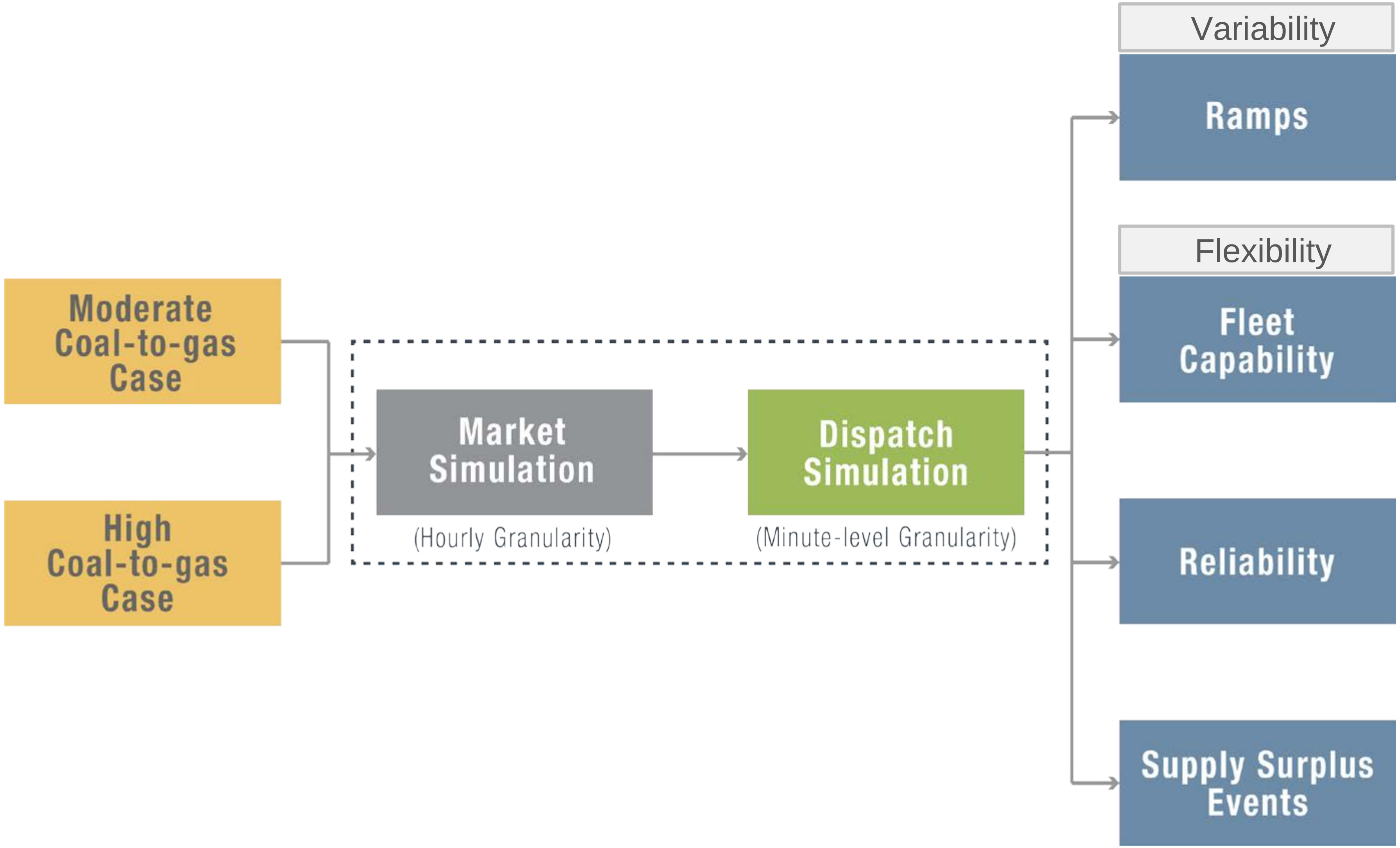
Understanding Reliability Implications to Achieve 30% by 2030

Several renewable integration needs were assessed



Variability and Flexibility

How did we assess our renewable integration needs to meet 30% by 2030?



Market simulation modelling assumptions

- ‘30 by 30’ achieved with 6,200 MW of additional wind
  - Procured via Renewable Electricity Program
  - Bid energy in at $0
  - Test bookend of high variability and market price volatility
- Two cases were simulated, providing different fleet flexibility
  - 2018-MCTG; 0.9% load growth; 2,400 MW coal-to-gas conversion
  - 2018-HCTG; 5,200 MW coal-to-gas conversion, less flexible fleet
- Other market drivers are based on most recent projections

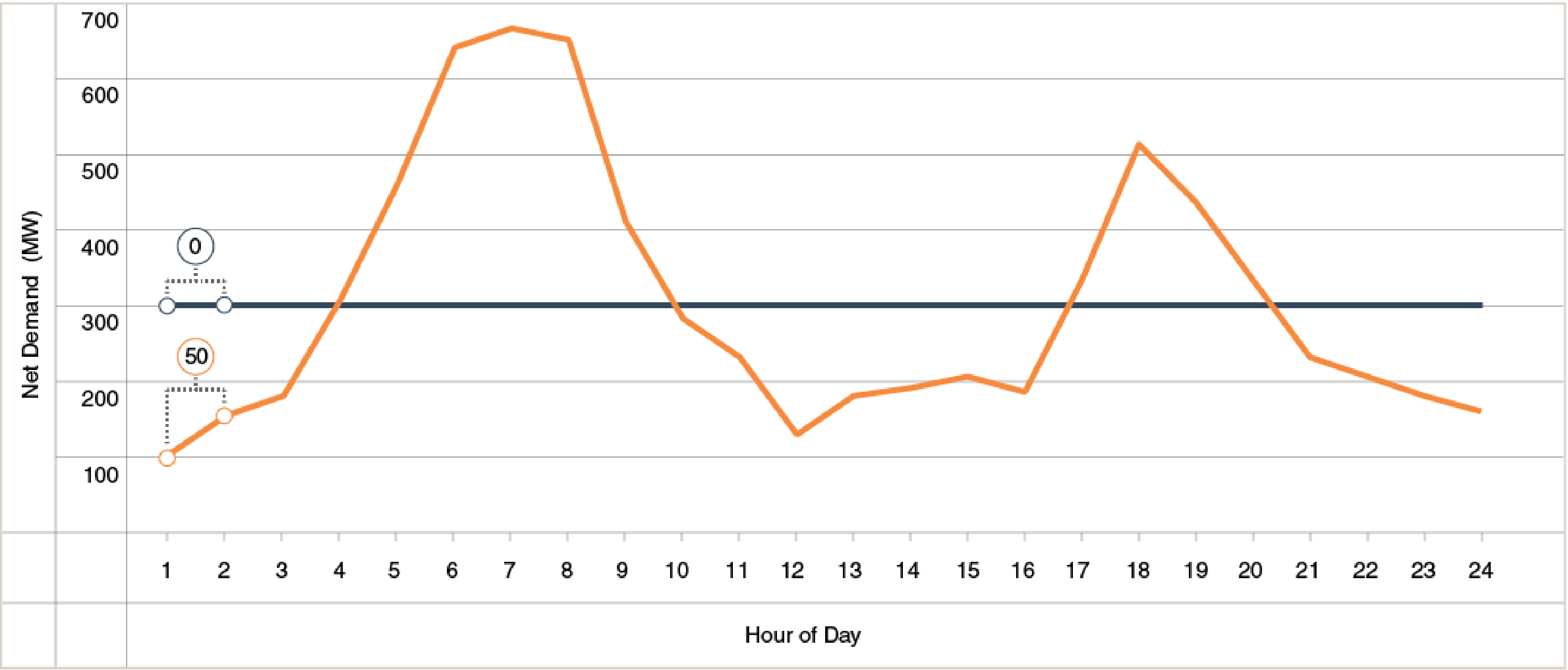
Natural gas prices	$1.50 – $2.40GJ
Carbon tax	$30/tCO2 rising to $50/tCO2
Output-based allocation	Starting at 0.370 tCO2/MWh, declining post-2020

Market simulation assumptions aligned with evolving capacity market design

- Energy market
  - Large participants mitigated to 3x variable costs
- Ancillary Services market
  - New supply entrants can participate in operating reserves
- Capacity market
  - Capacity procured to meet government set reliability standard
  - Eligible resources participate based on UCAP estimates
  - Aero-derivative is the CONE reference technology
  - Demand curve is downward-sloping and convex
  - REP and “REP substitutes” not eligible to participate

Variability of net demand is needed to match with supply, all the time, reliably

Net Demand = Load - Variable Generation



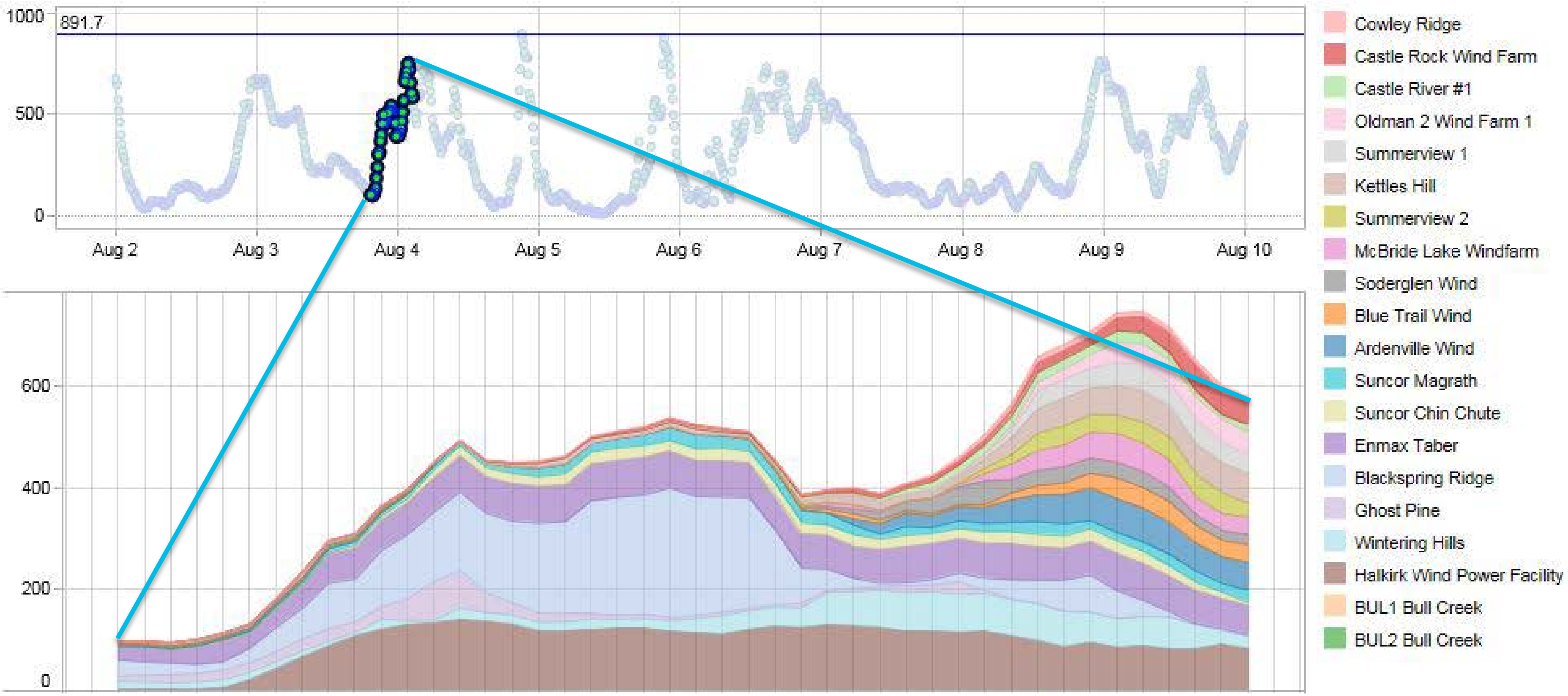
	Change in Net Demand (MW)																								Total Change
Line 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Line 2	50	25	125	150	175	25	15	235	125	50	100	50	10	15	20	145	175	75	100	100	25	25	20		1,835

(illustration – not actual data)

Dispatch simulation uses historical patterns to create net demand profile

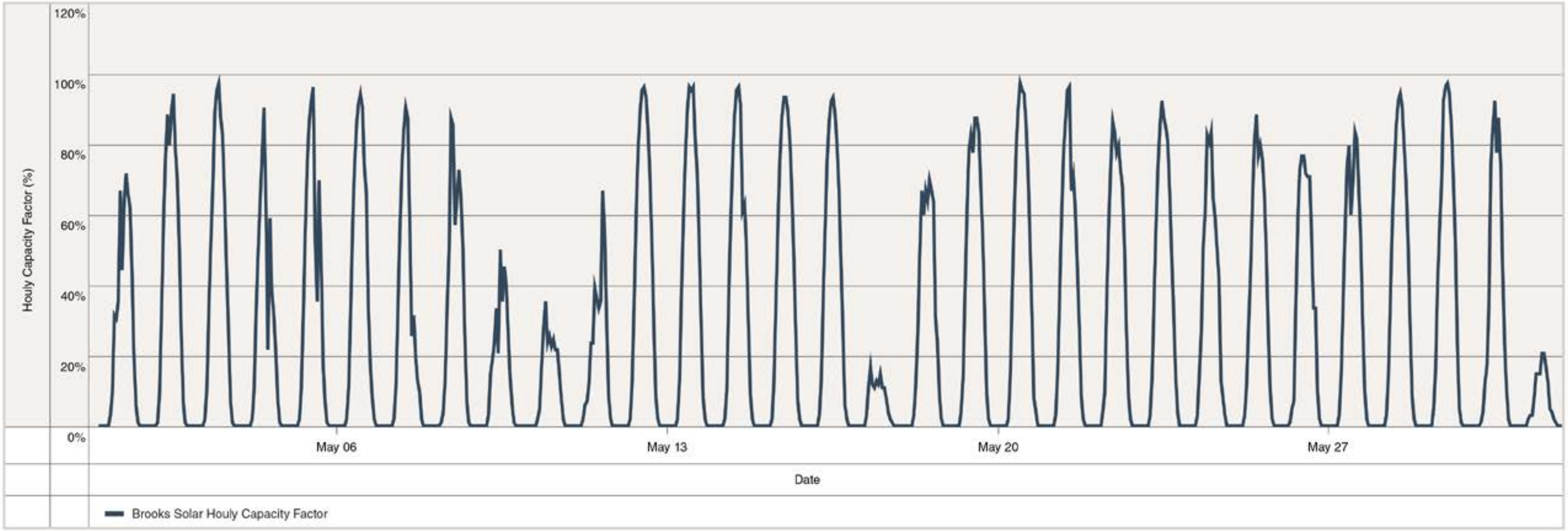
- Load pattern
  - Used 2015 historical load pattern after statistically testing 3 years (2014-2016)
  - Hourly and minute level detail
  - Scaled by minute to match future forecast hourly load (minimum, average and maximum within the hour)
- Variable wind generation pattern
  - Weather synchronized: wind generation correlated to load pattern
  - Incorporated geographical diversification effects of wind sites
  - Simulated for 120+ sites across the province
    - 10 minute resolution, provided by wind forecast firm
    - Used historical weather data and wind power output at existing sites

Effect of geographic diversity

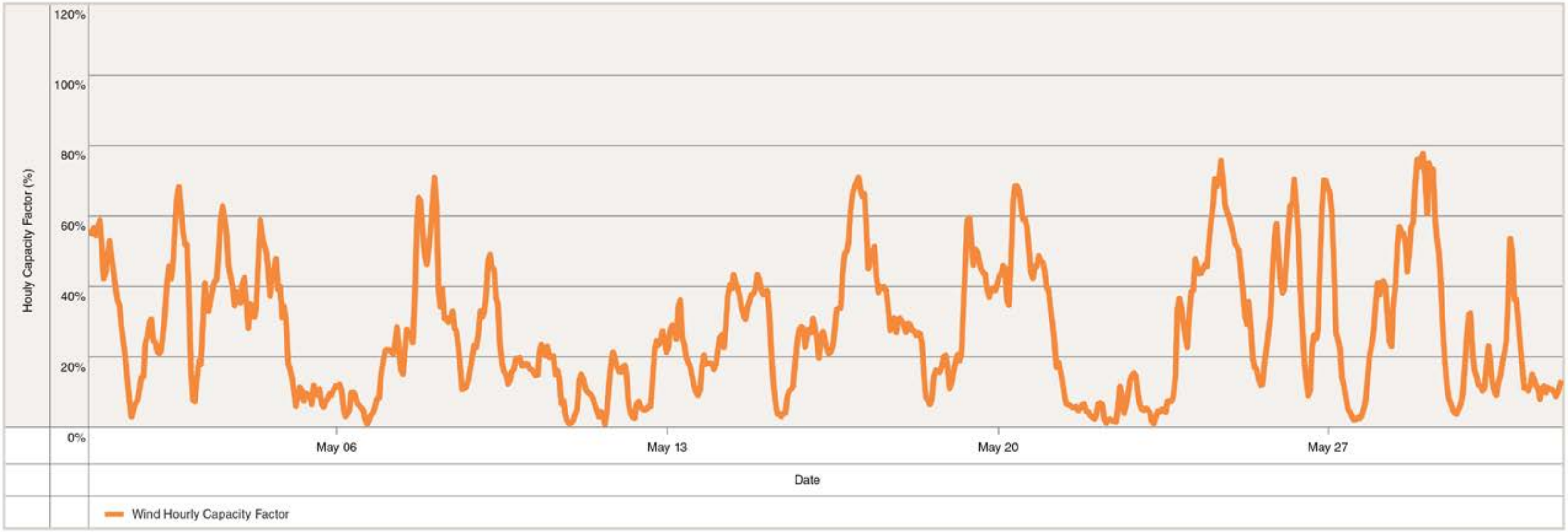


Solar is predictable; wind…not as much

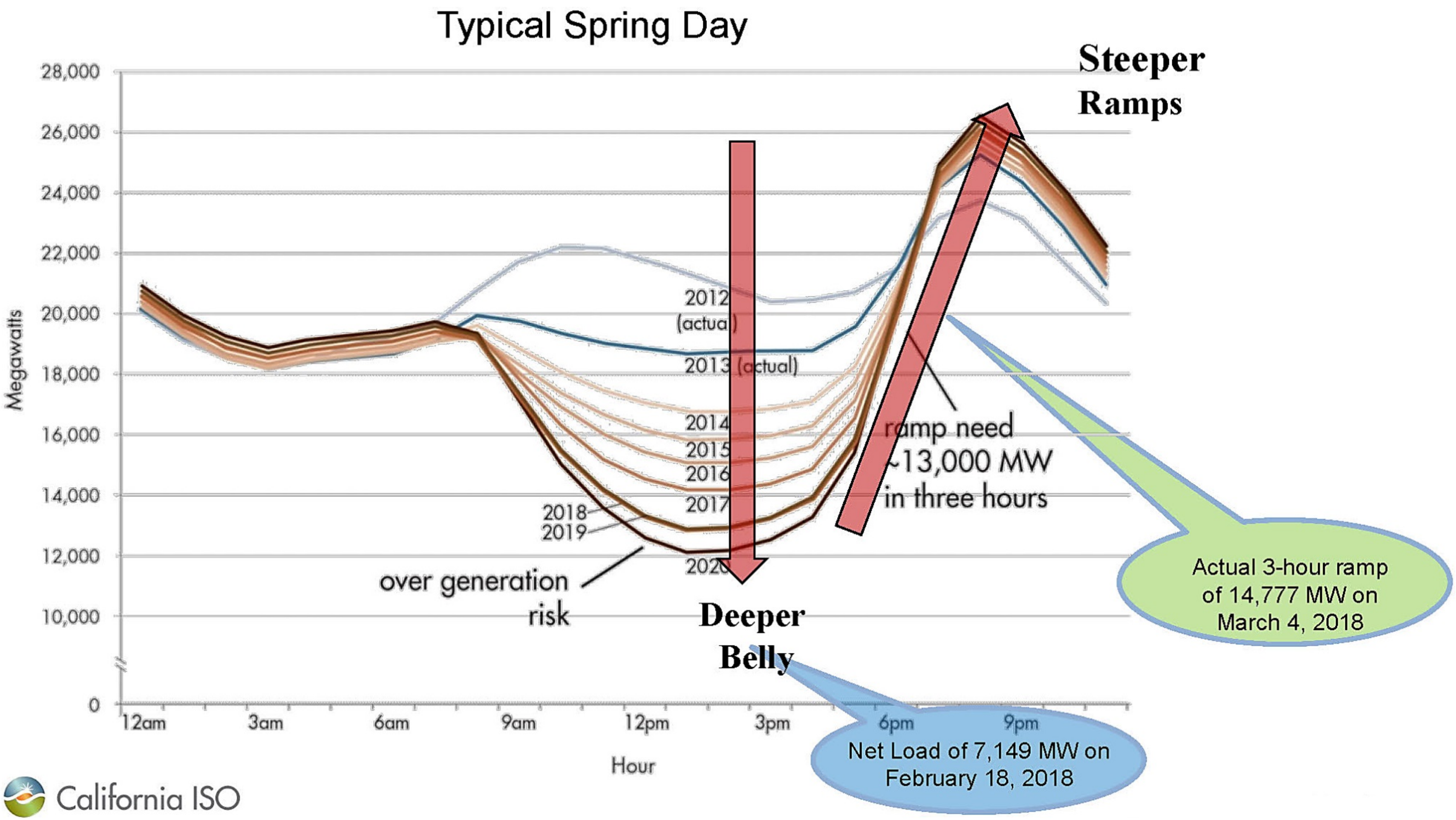
Solar



Wind

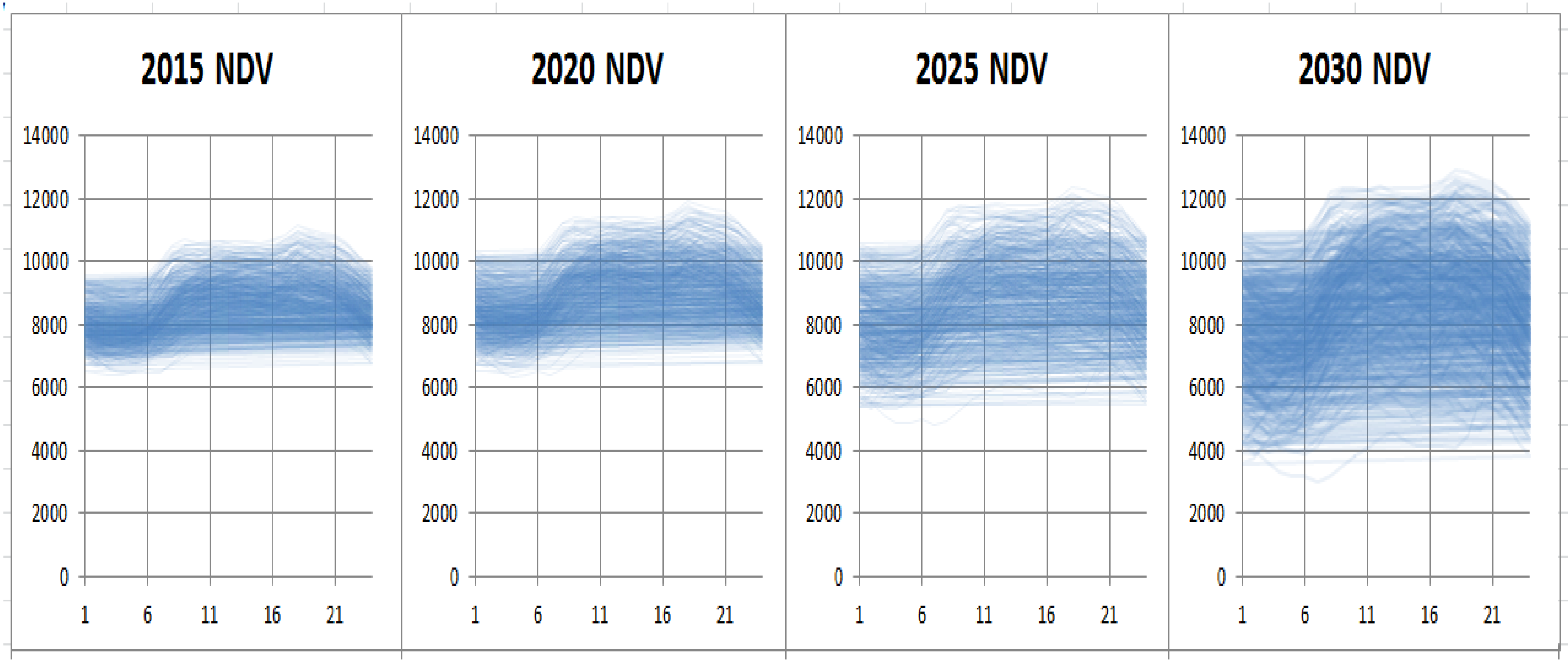


Is Alberta like California with a solar driven 'duck curve'?

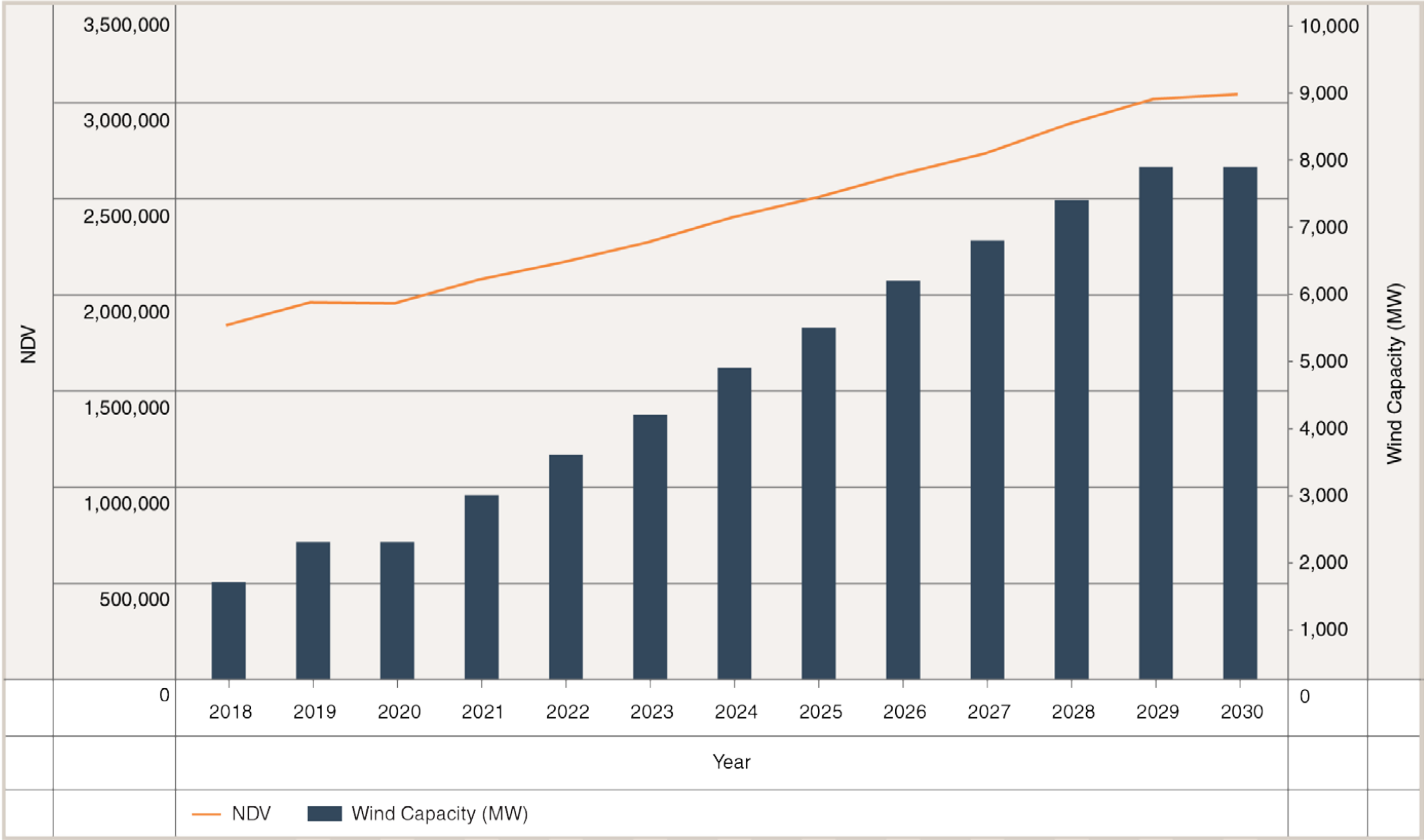


Unlike California, Alberta has a wind driven ‘spaghetti plot’

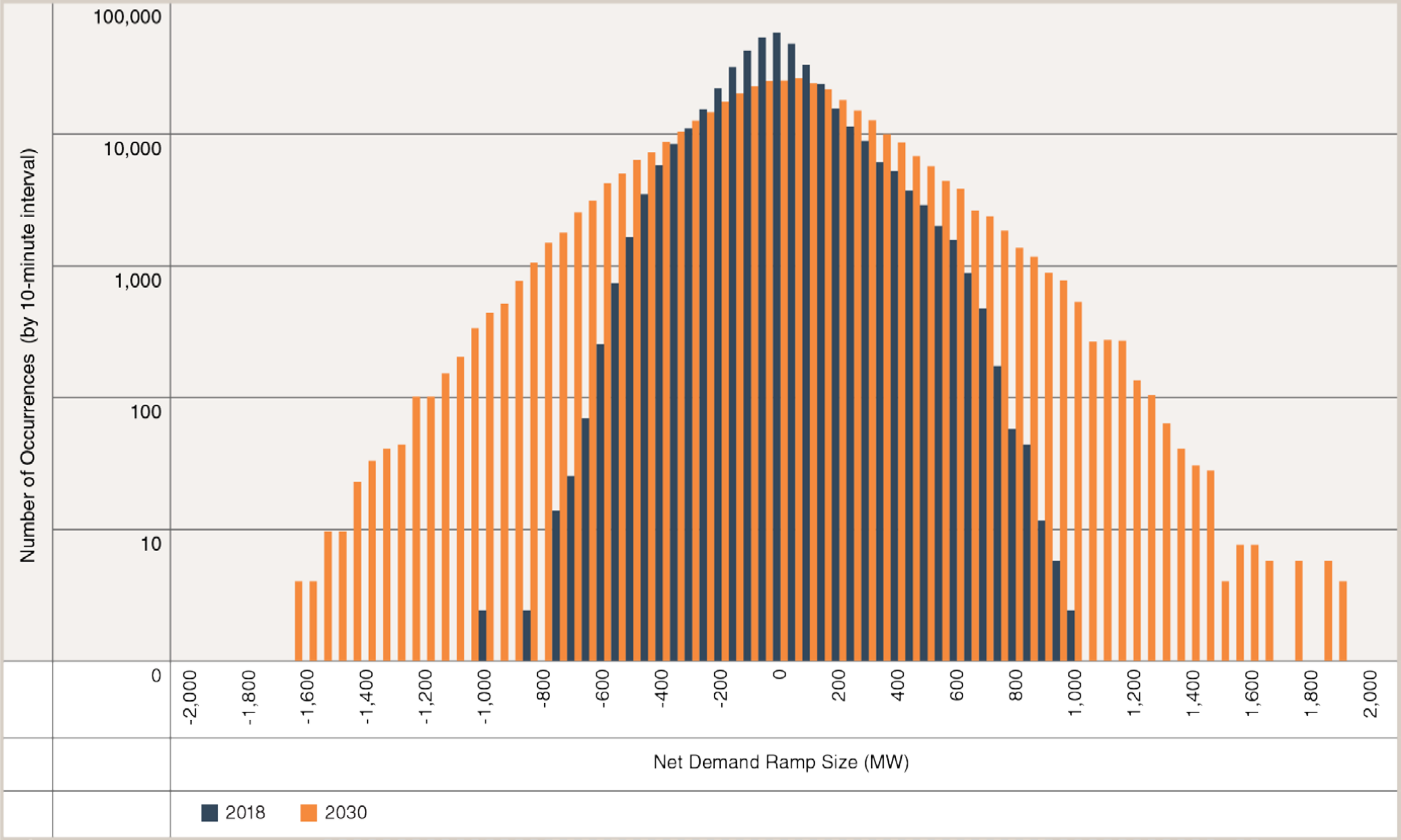
Net Demand profiles, one per day



Variability increases ~5% annually; tied to additional intermittent renewables



Net demand hourly ramps will grow in size and frequency; will need flexibility to manage



Dispatch simulation uses historical fleet average dispatch response and ramp rates

- New supply assets were assigned average fleet characteristics by technology type
- Dispatched resources up and down the energy market merit order to match net demand
- Any difference between energy dispatch and net demand is supplied by regulating reserves

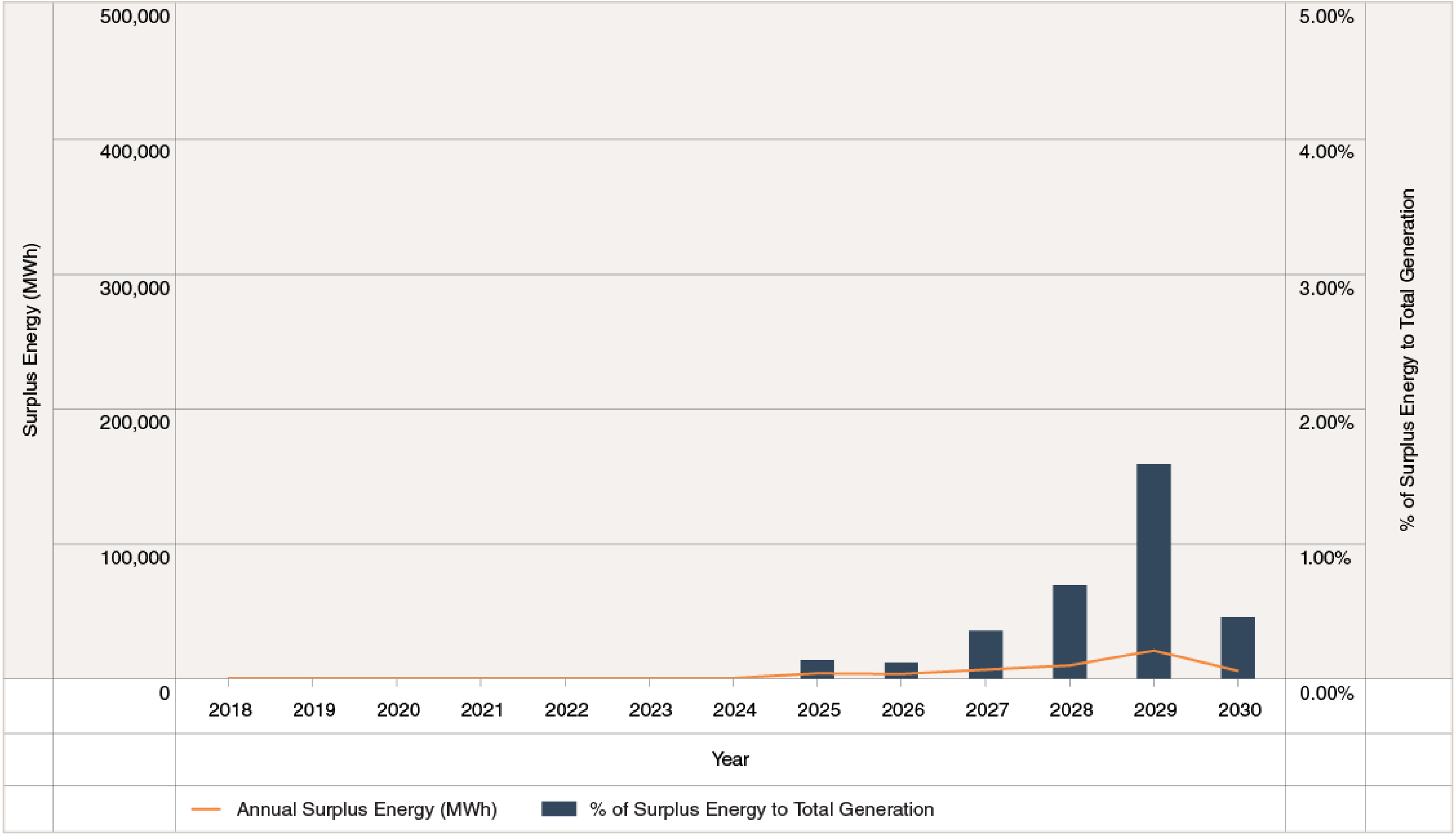
	Non-Generating Status Average		Generating Status Average		
Technology	**Delay (min.)**	**Ramp Rate (MW/min.)**	**Delay (min.)**	**Ramp Down (MW/min.)**	**Ramp Up (MW/min.)**
Coal	3.0	2.2	2.4	4.6	4.5
Combined Cycle	4.1	2.3	2.2	2.3	1.9
Simple Cycle	6.8	13.6	2.5	10.6	10.0
Cogeneration	3.1	2.6	2.4	3.8	2.8

Reliability remains acceptable as ‘30 x 30’ target level is achieved

- Transmission development plans will reliably accommodate renewable integration
- Energy and ancillary services markets will provide flexibility needed
- Key reliability metrics remain within acceptable ranges for both scenarios

Scenario	CPS2 (> 90)	SOL (<5)	Large ACE (proactive indicator)
MCTG	98.5 to 99.9	0 to 1	0 to 11
HCTG	98.9 to 99.9	0 to 2	0 to 18

Supply surpluses?
Potentially, but less than 1% of renewables



Dispatchable Renewables

What <u>directionally</u> is the cost/benefit of dispatchable renewables?

FIGURE 11: Comparative scenario analysis approach

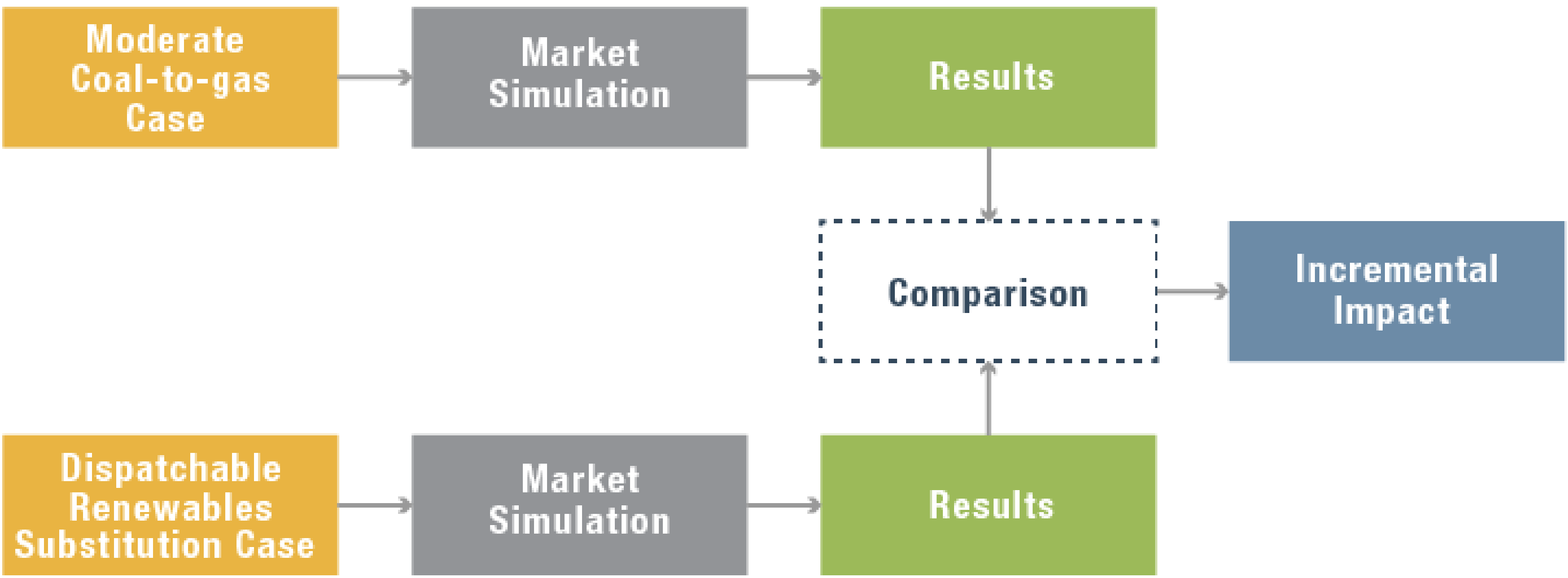
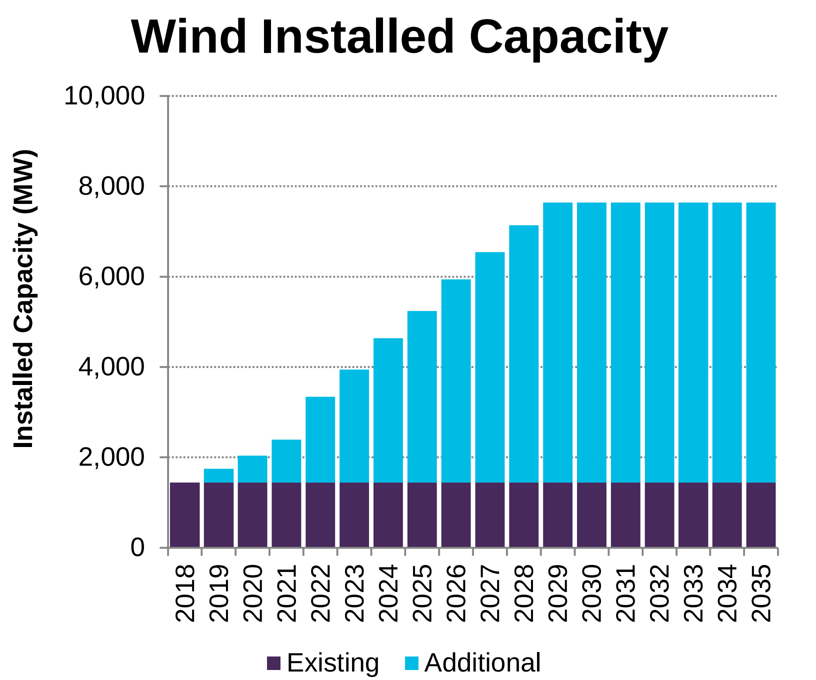


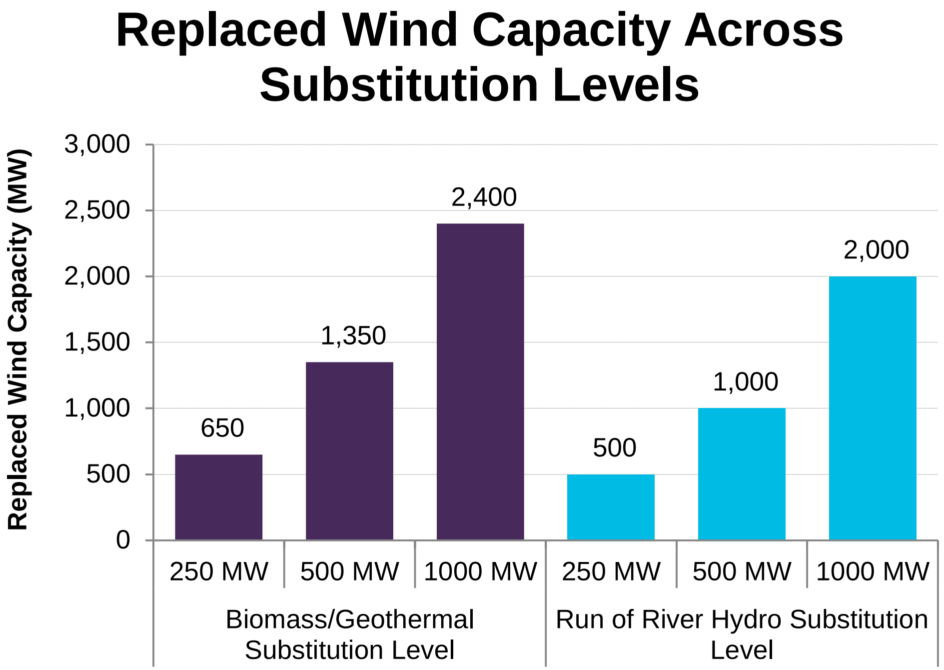
FIGURE 12: Substitution cases

	Run-of-river Hydro	Biomass	Geothermal
Substitution Case Inputs	250 MW	250 MW	250 MW
	500 MW	500 MW	500 MW
	1,000 MW	1,000 MW	1,000 MW

Renewable asset mix meets 30% by 2030 across simulation scenarios



- 6,200 MW of wind capacity added by 2030, totaling 7,640 MW



- Different levels of wind were replaced, based on these capacity factors:

  Wind = 34%

  Biomass/Geothermal = 92%

  Run-of-river hydro (managed system) = 78%

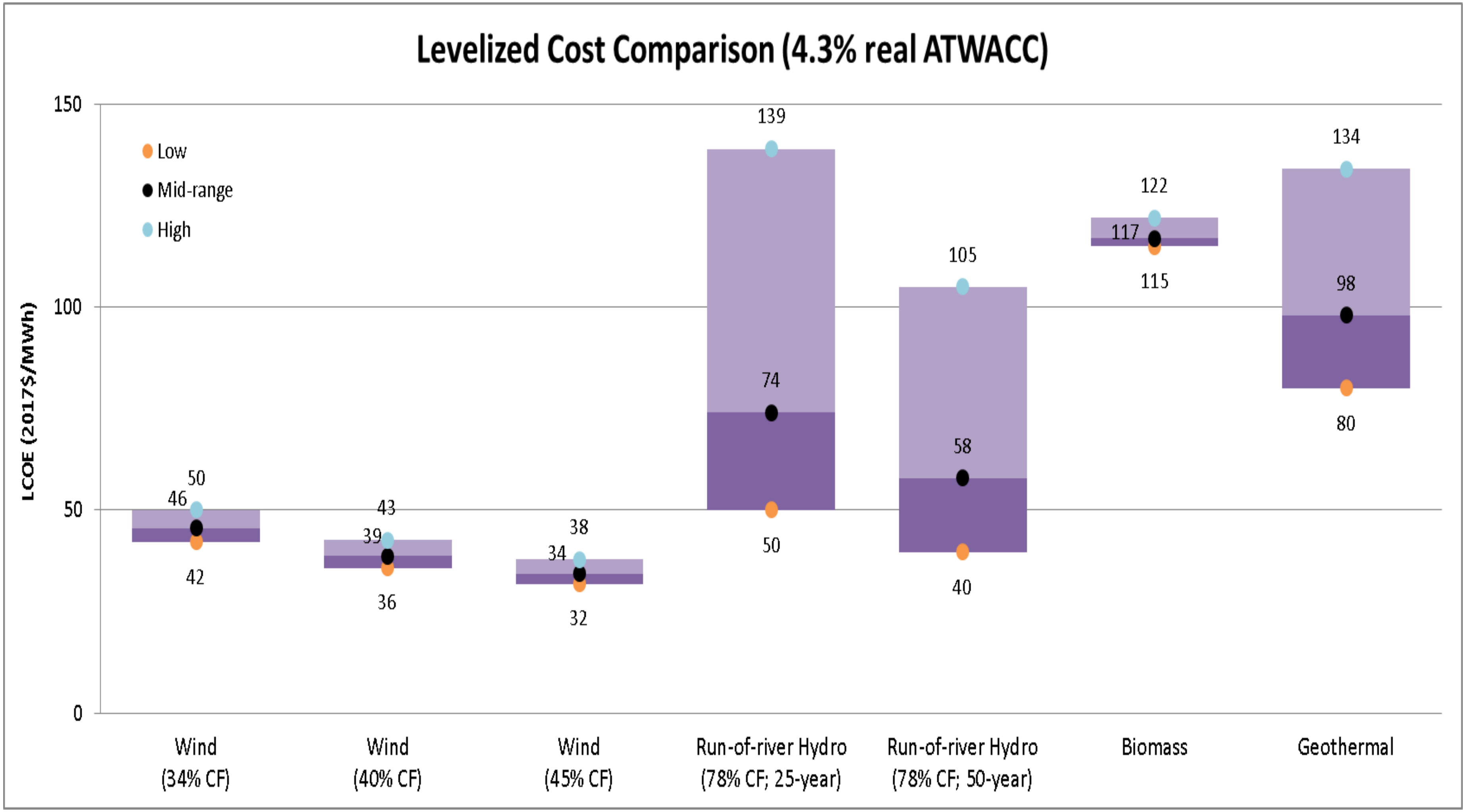
Three cost categories included in the comparison

- Market costs (ratepayer)
  - Costs incurred in the energy, capacity and ancillary service markets
  - Less capacity to procure, depending on the capacity quality of the substitute
- Emission costs (within market costs)
  - $50/tonne applied to carbon emissions produced from the energy market
  - Provided separately to see the carbon emissions impact of different scenarios
- REP proxy costs (carbon levy)
  - “REP like” costs incurred to procure the dispatchable renewable out of market
  - Use the levelized cost of energy (LCOE) as the proxy strike price in a contract-for-difference payment structure
  - For every hour, calculate the REP proxy costs comparing the pool price to the strike price

Broad range of LCOEs assessed in REP proxy cost analysis

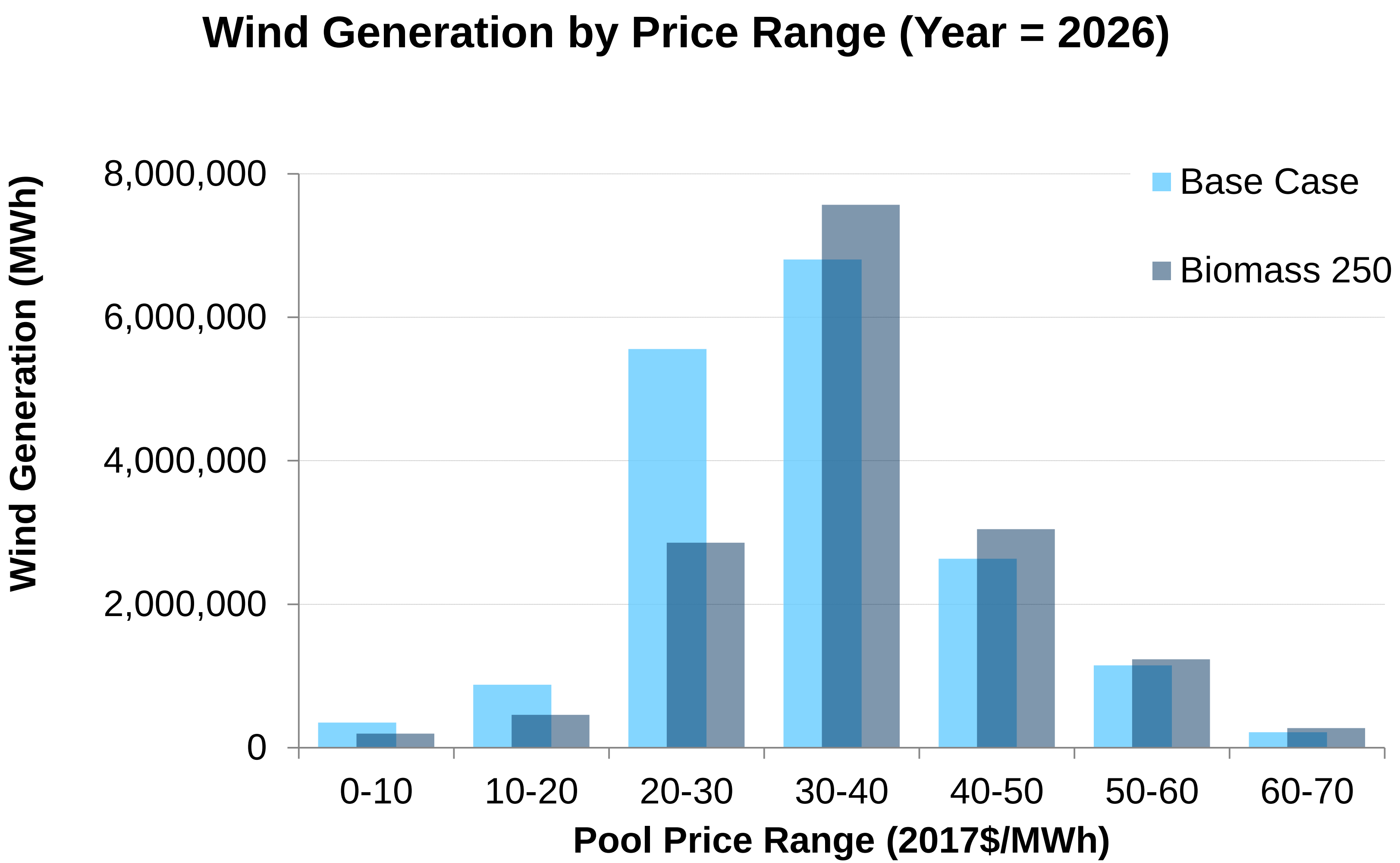
	Capital Cost	Operating Cost	LCOE (2017$/MWh) 25-year Financial Life		Capital Cost Share of LCOE
	2017 $/kW	2017 $/MWh	Long-term Contract (4.3%)	Merchant (8.2%)	(%)
Wind	1,250	14	42	55	67% - 79%
	1,400	14	46	60	
	1,600	14	50	66	
Run of River Hydro	4,000	10	50	67	79% - 95%
	6,500	10	74	103	
	8,000	10	89	124	
	9,750	10	107	149	
	13,000	10	139	195	
Biomass	4,750	75	115	132	35% - 47%
	5,000	75	117	135	
	5,600	75	122	142	
Geothermal	7,677	12	80	109	85% - 93%
	9,801	12	98	136	
	13,842	12	134	188	

LCOE ranges incorporate various cost risks including capacity factor, technology, financial life and construction

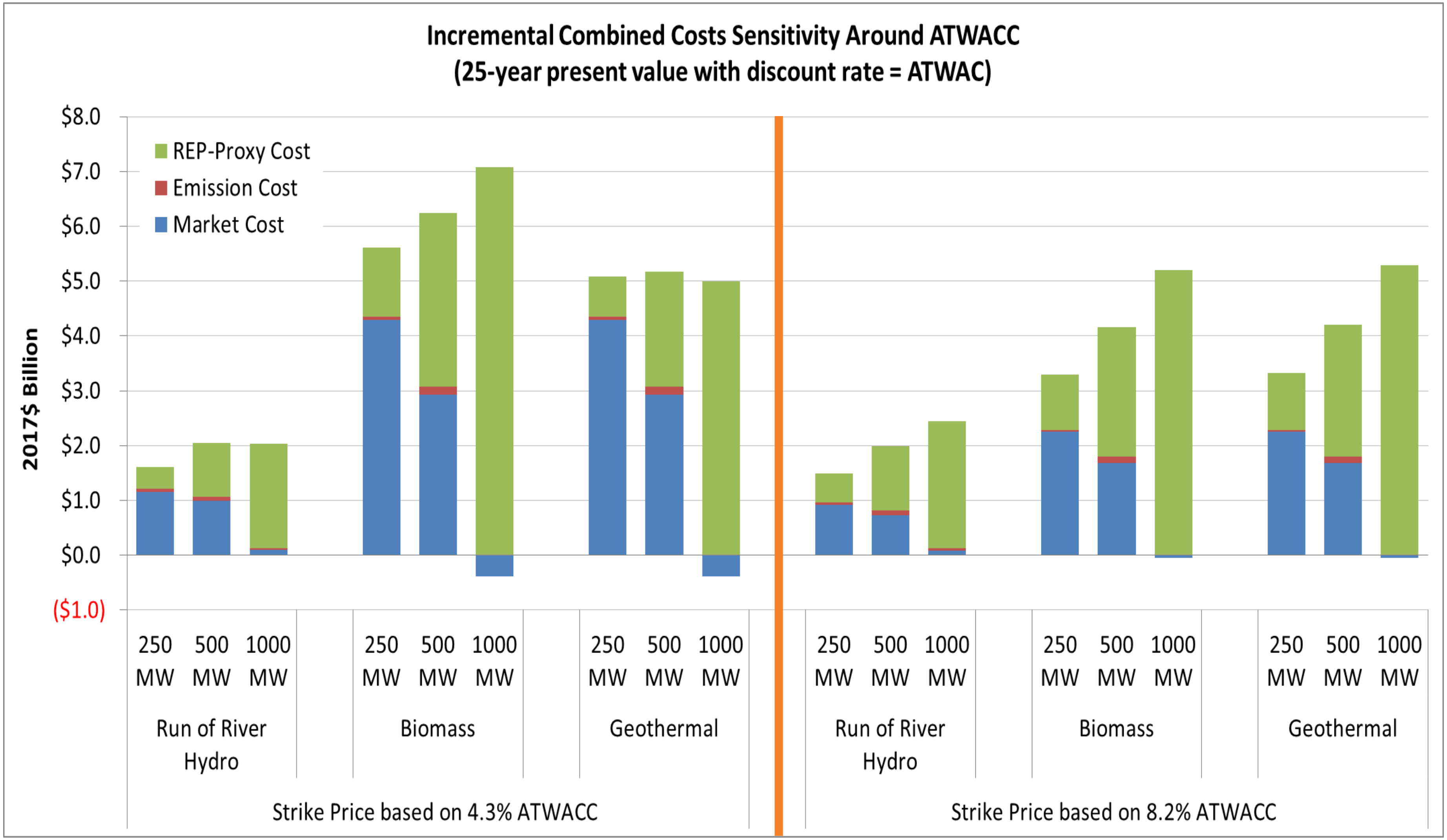


Note: levelized cost estimates based on 25 year life, unless noted otherwise *CF = capacity factor*

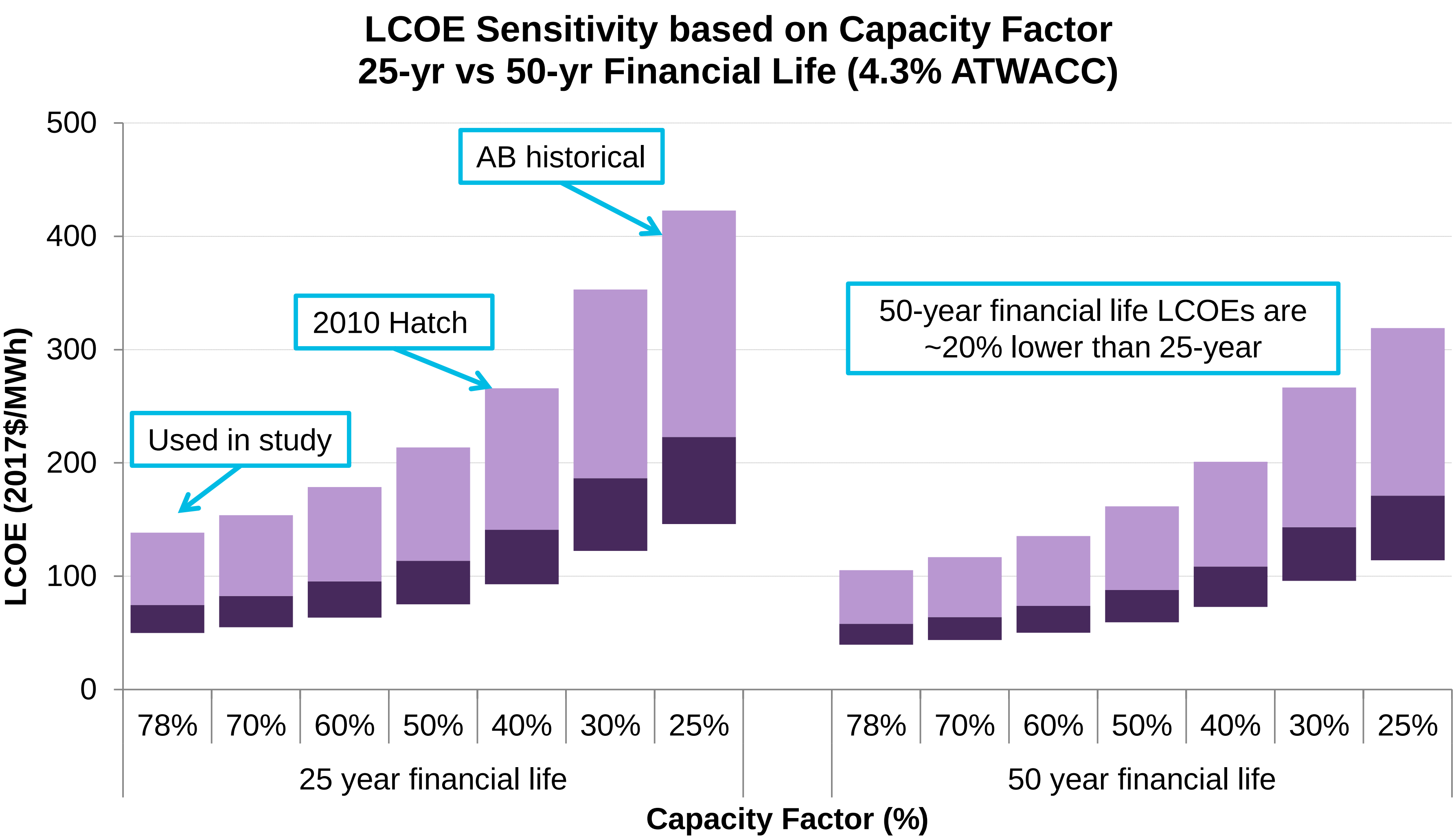
Higher pool prices occur in substitution cases



Substitution cases are higher cost, at 4.3% or 8.2% ATWACC

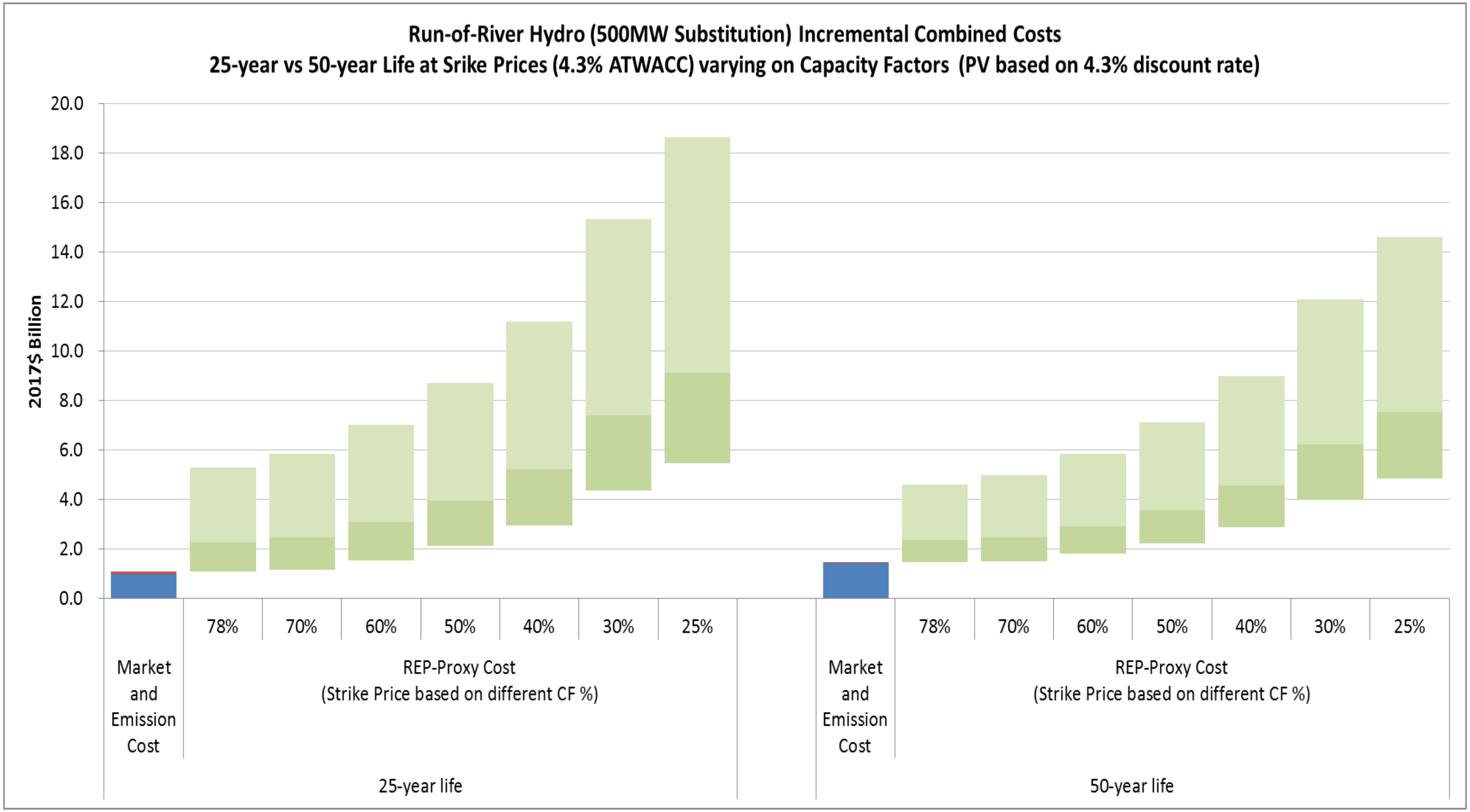


Hydro LCOEs are sensitive to capacity factor assumptions – even with a 50-year life

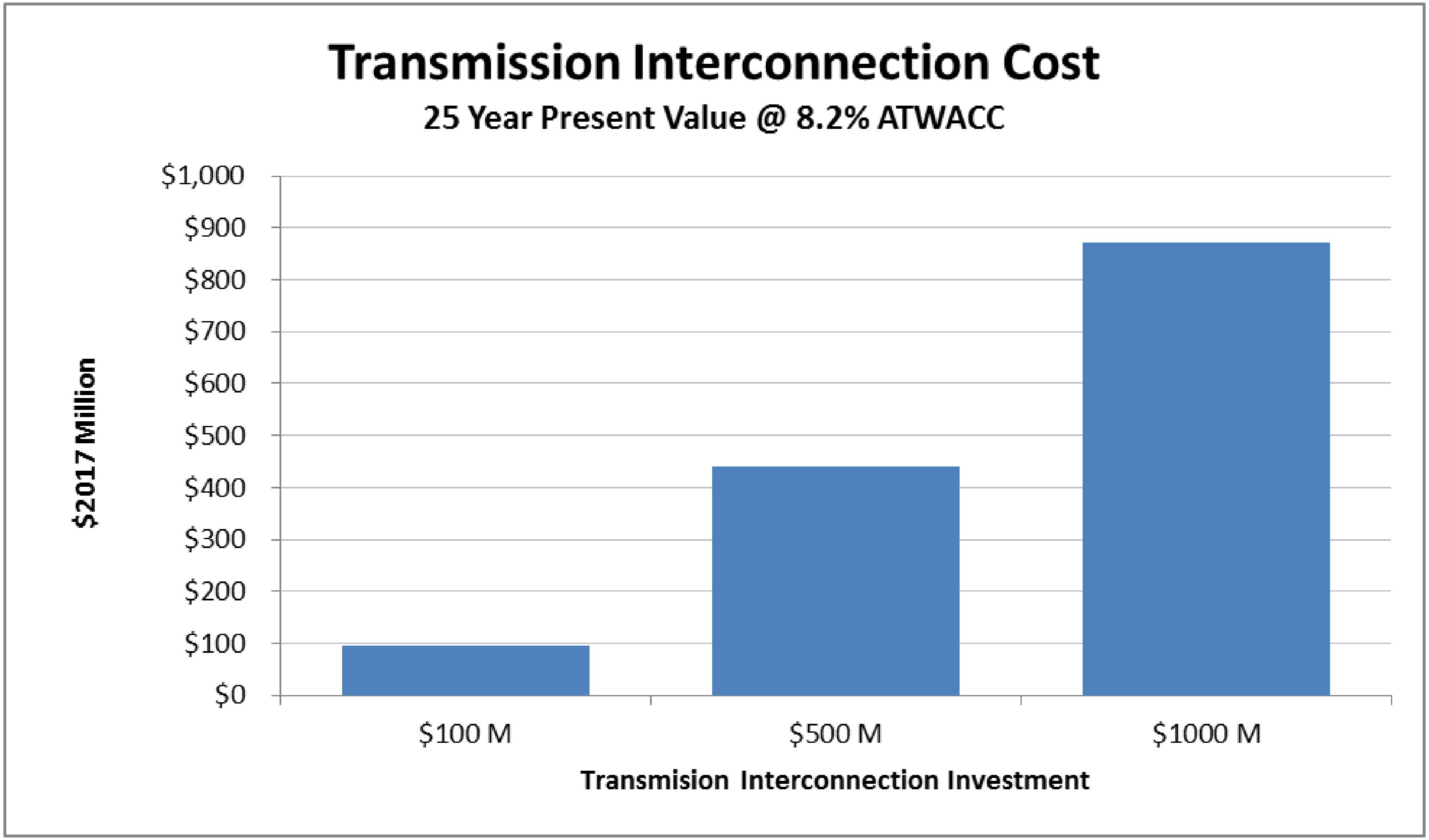


Hydro REP proxy costs correspond to capacity factor and financial life assumptions

- 50-year life REP proxy cost ranges: $1.5-$4.4B at 78% CF; $4.8-$14.6B at 25% CF

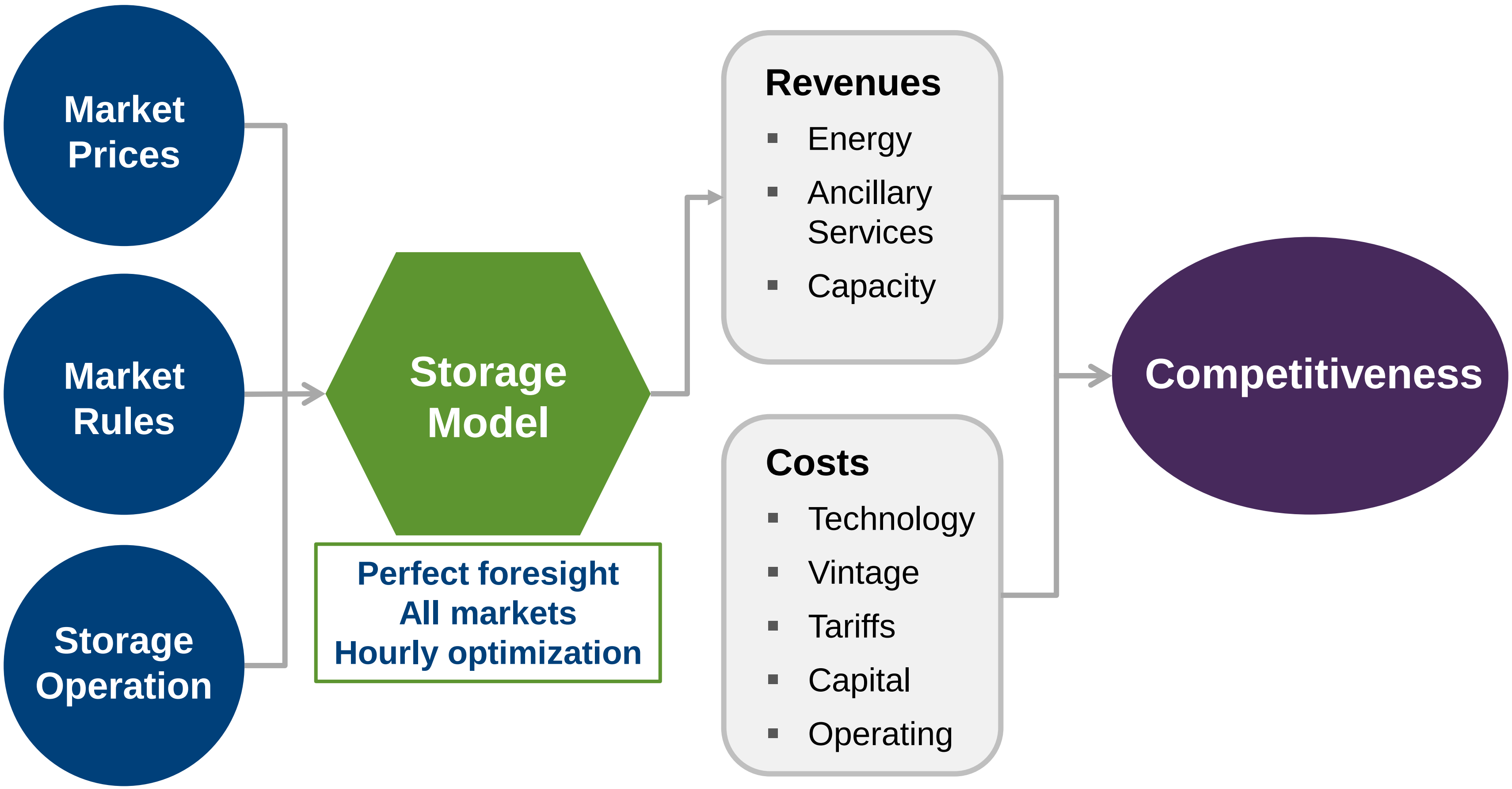


Transmission interconnections may further increase costs, depending on project location/size



Energy Storage

What is the role for energy storage in Alberta's markets?

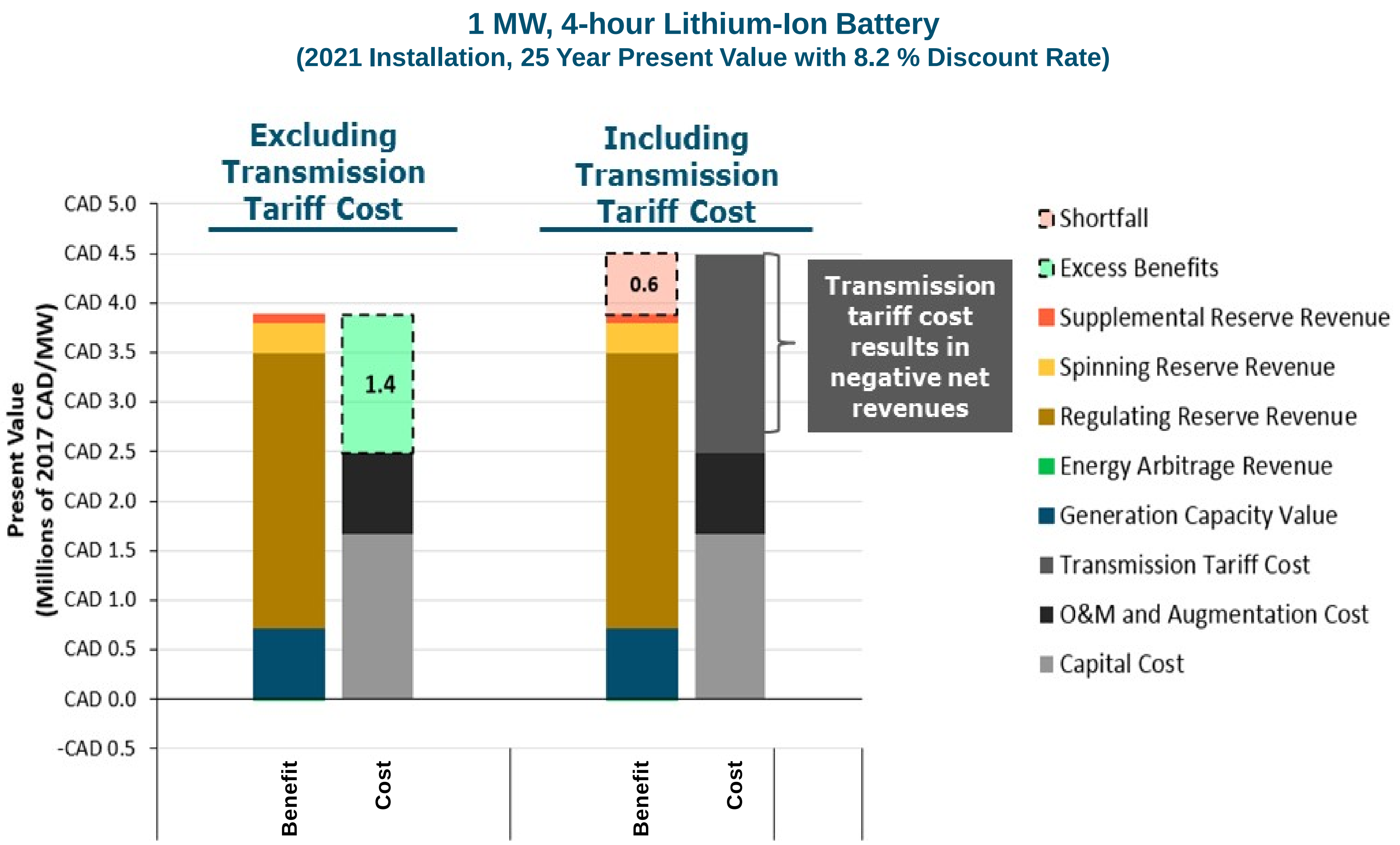


We did not assess “wires deferral” or “customer bill” related benefits

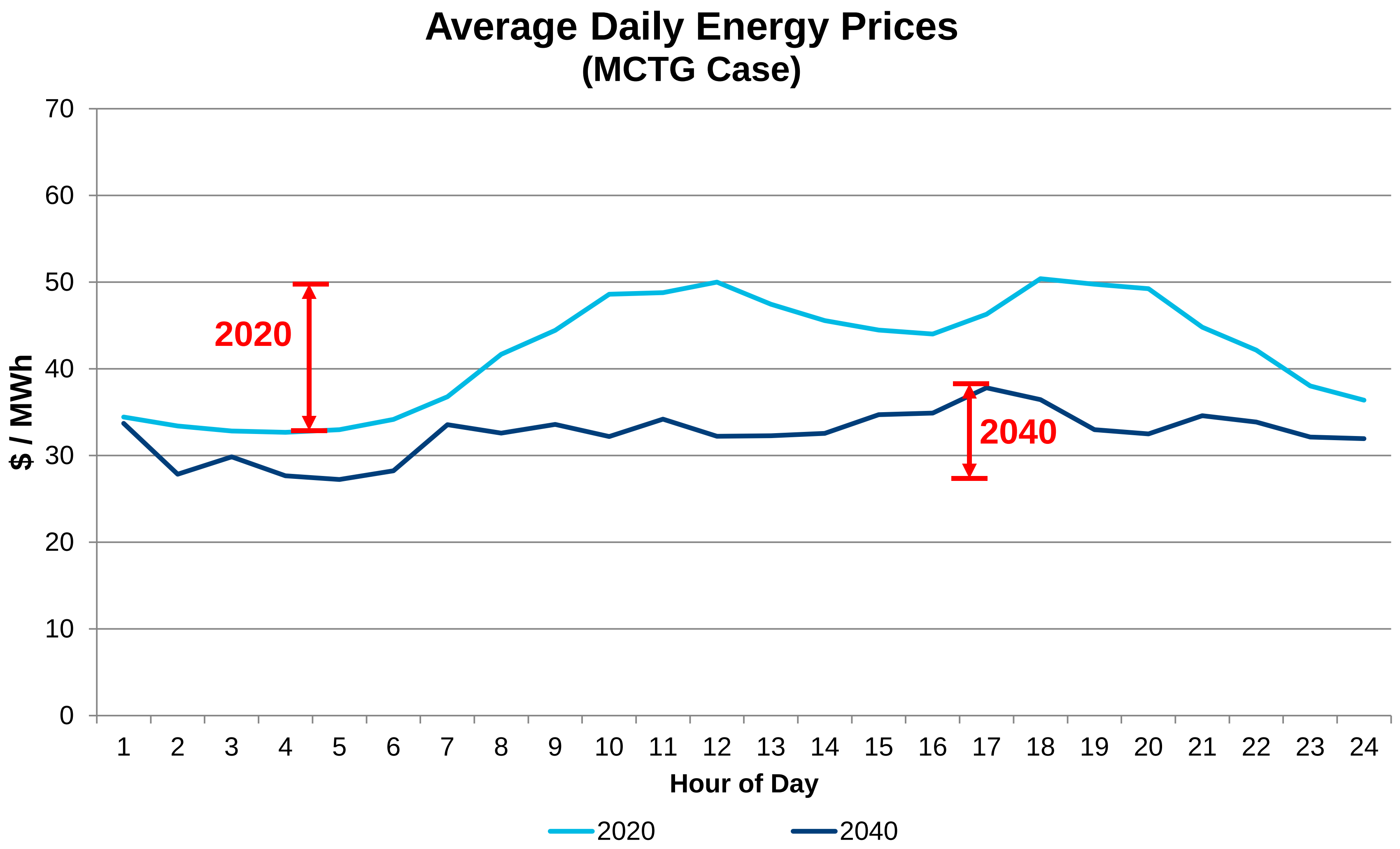
Performed a wide range of storage scenarios

Technologies	Market Conditions	Cost Projections
• **Lithium-ion batteries**: 2-hour, 4-hour and 12-hour • **Pumped storage hydro**: 6-hour and 12-hour	• **Future Alberta generation mix:** moderate vs high coal conversion, no intertie • **Saturation:** effect of increased storage on operating reserve and pool prices	• **Technology uncertainty**: range of potential costs for batteries and pumped storage • **Cost changes by year of installation:** 2021 and 2025

Storage may be cost-effective in operating reserve market, with no transmission tariff costs

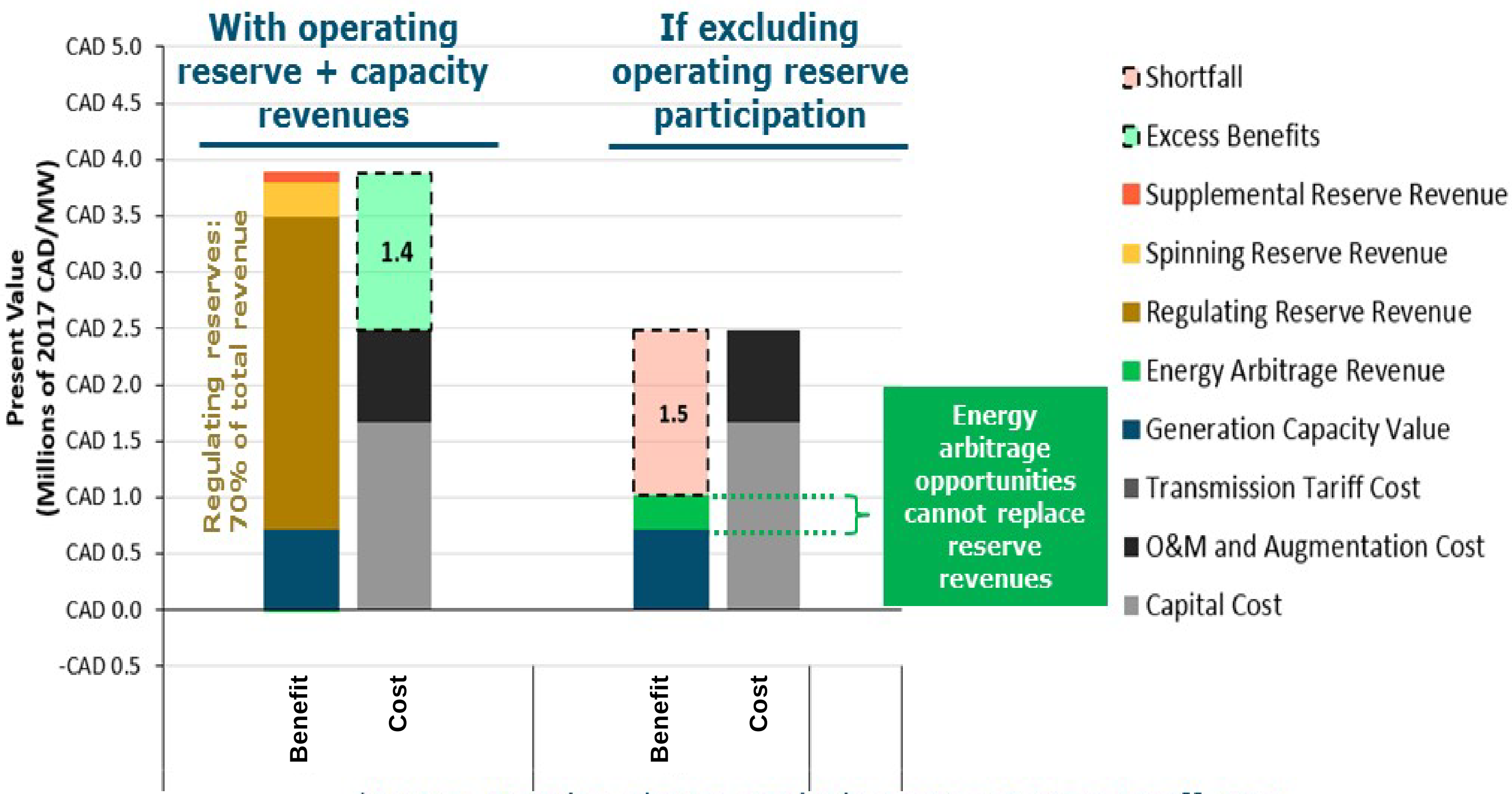


Capacity market expected to narrow average daily energy price spreads in the future



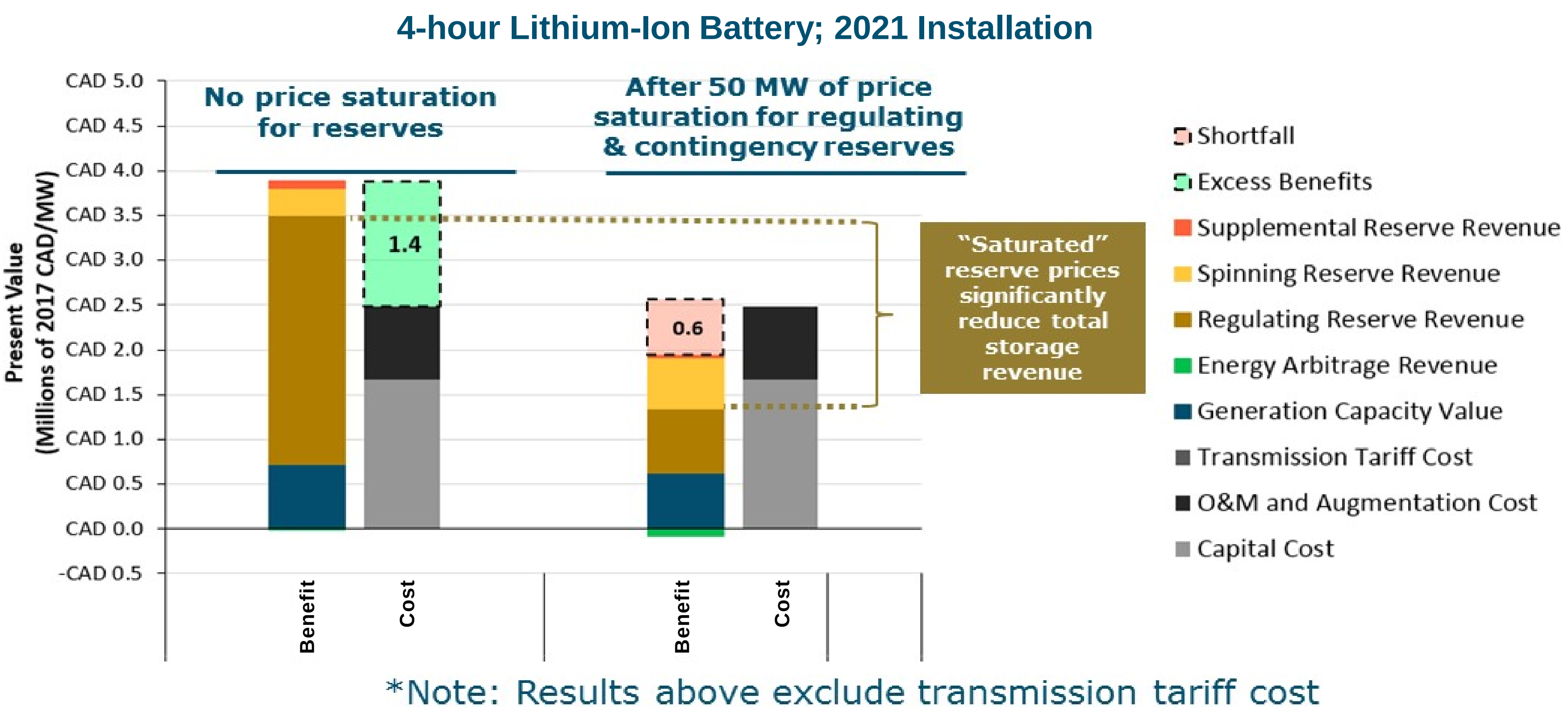
Operating reserve market provides 70% of revenues; energy price arbitraging not very cost-effective

1 MW, 4-hour Lithium-Ion Battery With and Without Regulating Reserve Revenue
(2021 Installation, 25 Year Present Value with 8.2 % Discount Rate)



*Note: Results above exclude transmission tariff cost

If storage enters operating reserve market, it is expected to drive prices down



*Note: Results above exclude transmission tariff cost

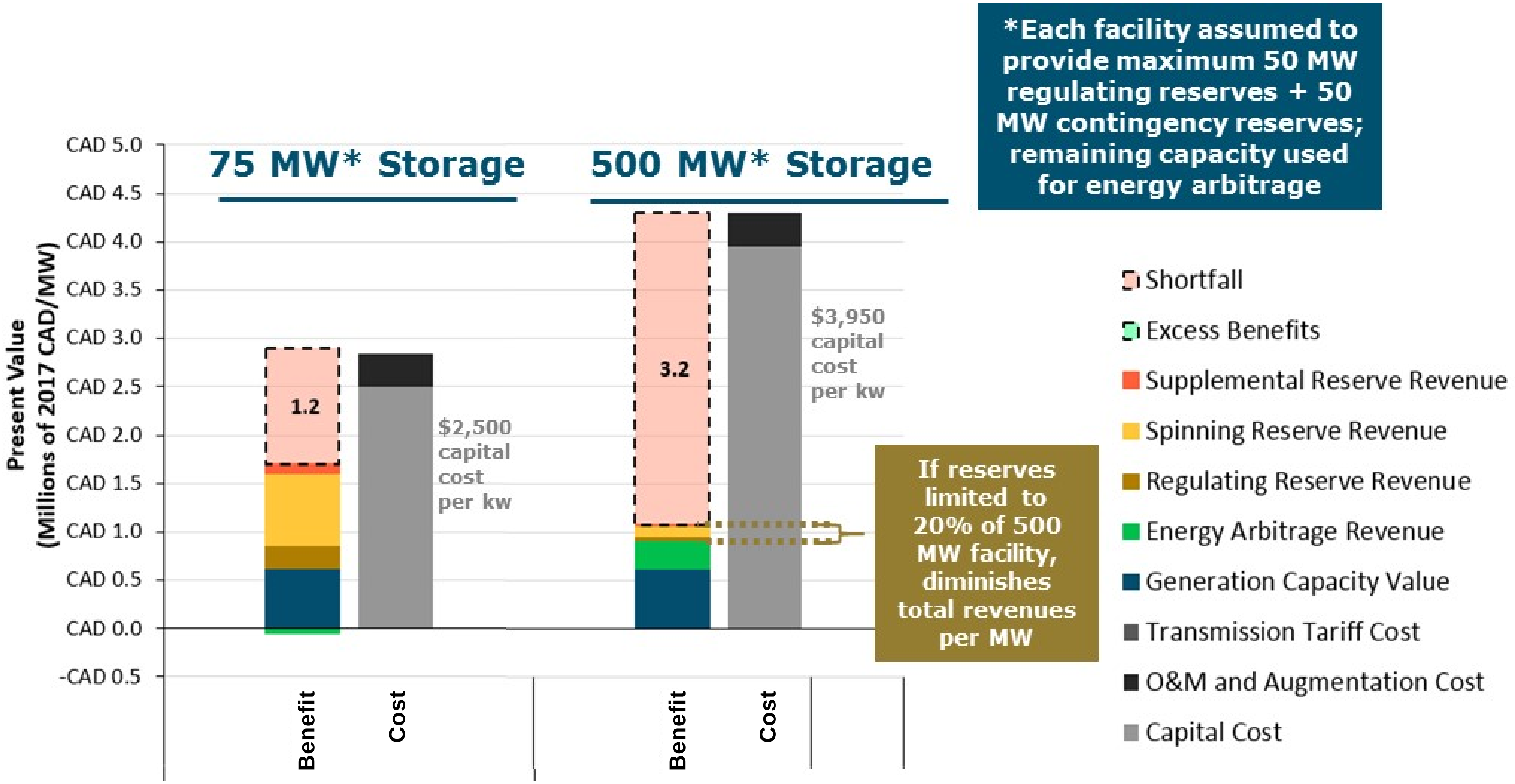
AESO-estimated impact of 50 MW saturation on reserve prices *(during peak/offpeak hours):*

- **Regulating: -40% / -88%**
- **Spinning: -14% / -32%**
- **Supplemental: -43% / -52%**

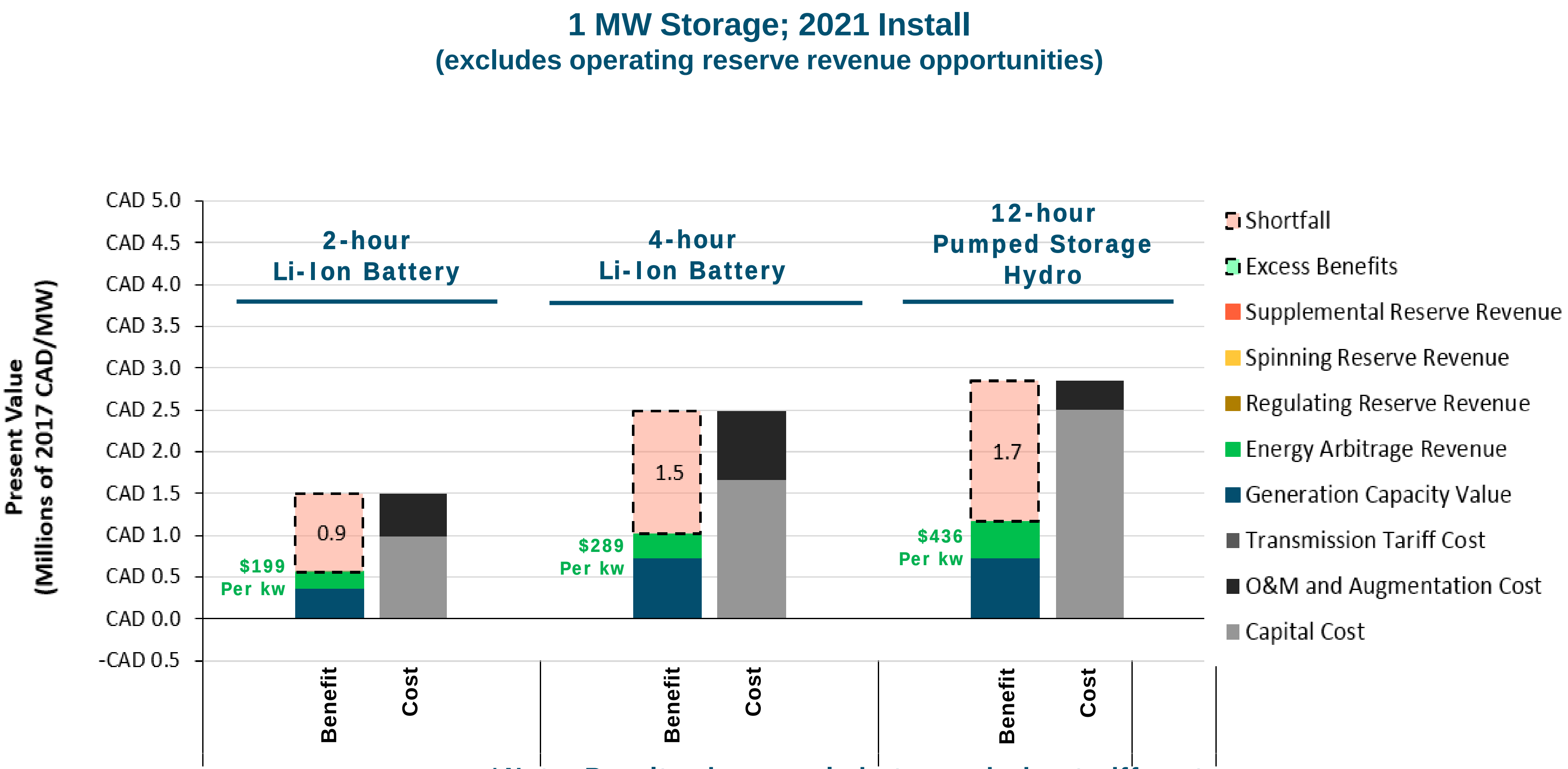
Note: 25 MW storage could provide up to 50 MW regulating reserves

Larger storage projects will likely be less cost-effective

12-Hour Pumped Storage Hydro
(assuming 50 MW price saturation in regulating and contingency reserve markets)



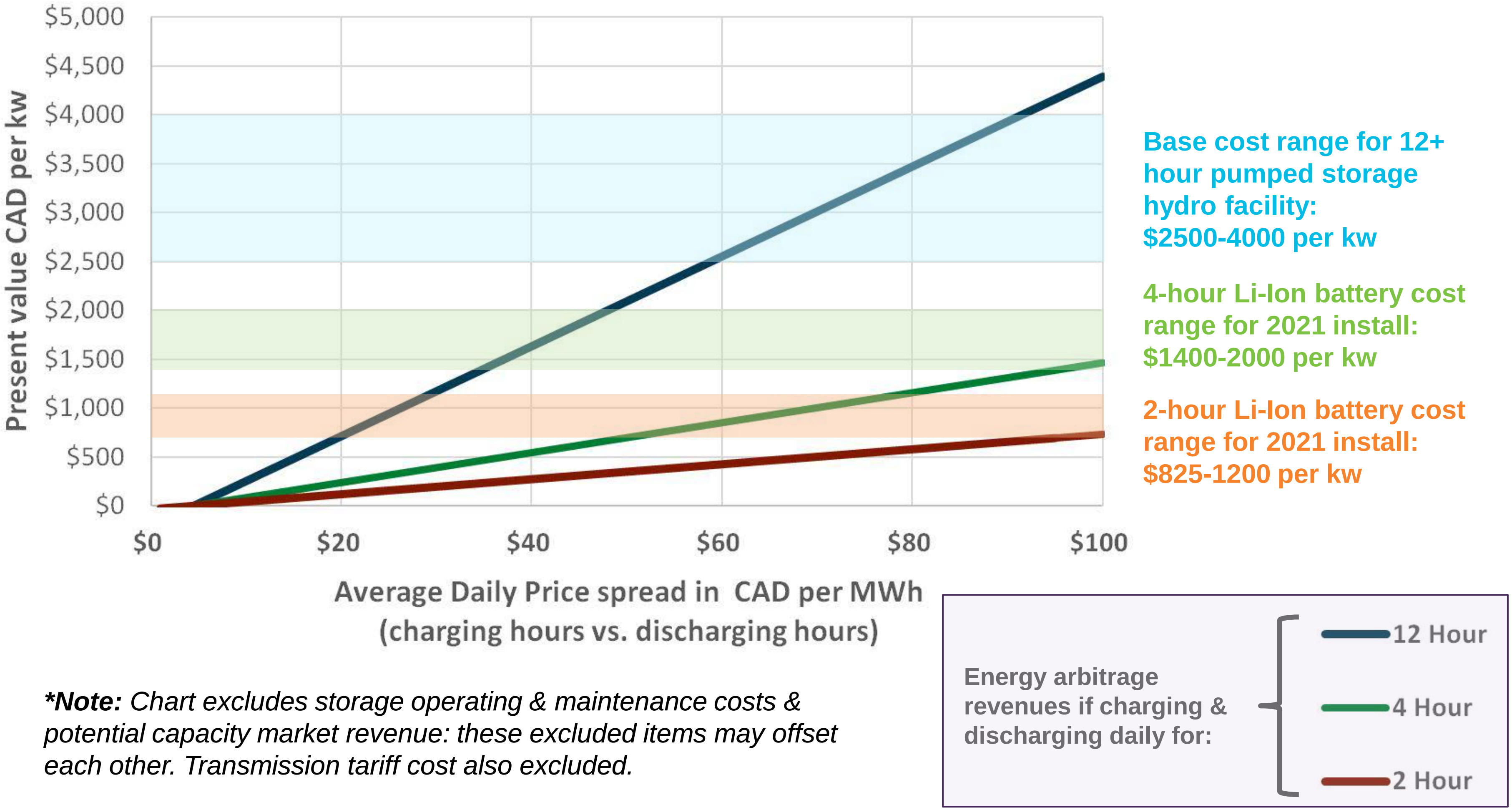
Storage duration beyond two hours provides diminishing incremental value in Alberta



*Note: Results above exclude transmission tariff cost, do not assume price saturation from storage installation

Directional energy price spreads needed to cover storage costs from energy arbitraging

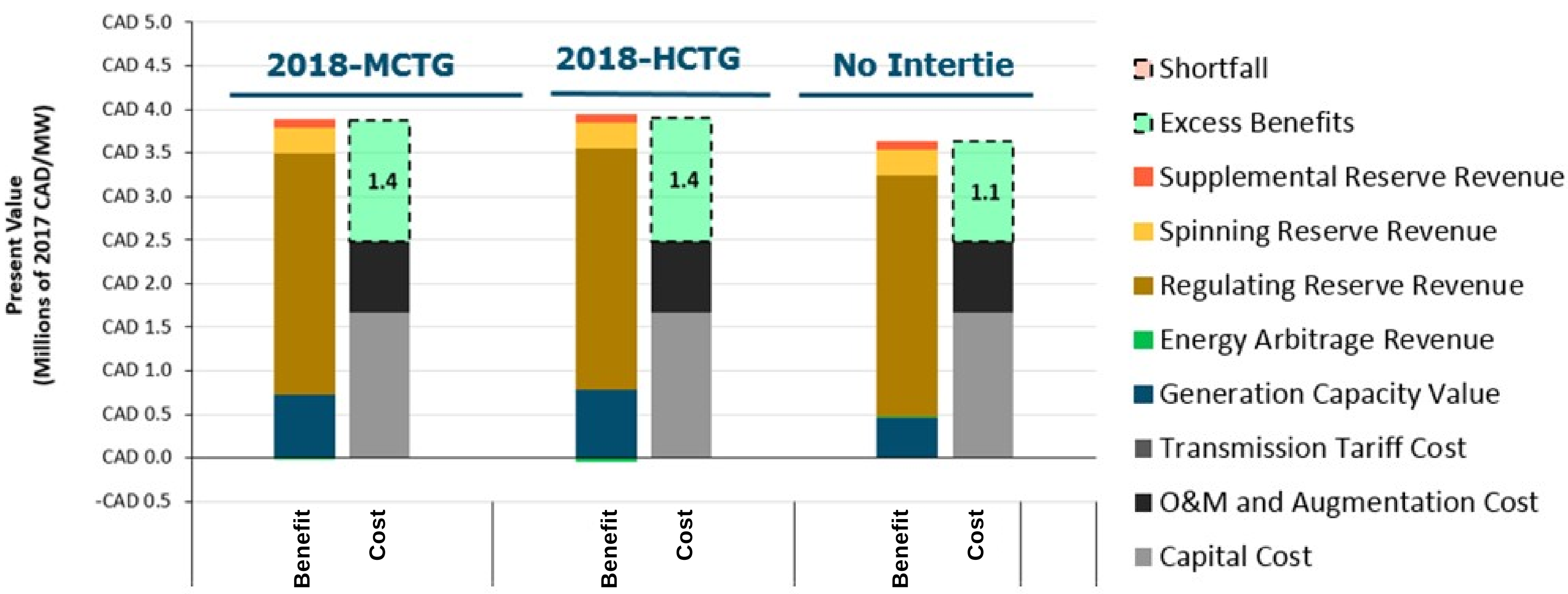
Figure 12: Implied Present Value of 2, 4 and 12-hour Duration Storage used for Energy Arbitrage as a Function of Average Daily Price Spread



***Note:** Chart excludes storage operating & maintenance costs & potential capacity market revenue: these excluded items may offset each other. Transmission tariff cost also excluded.*

Fleet supply mix has marginal effect on results

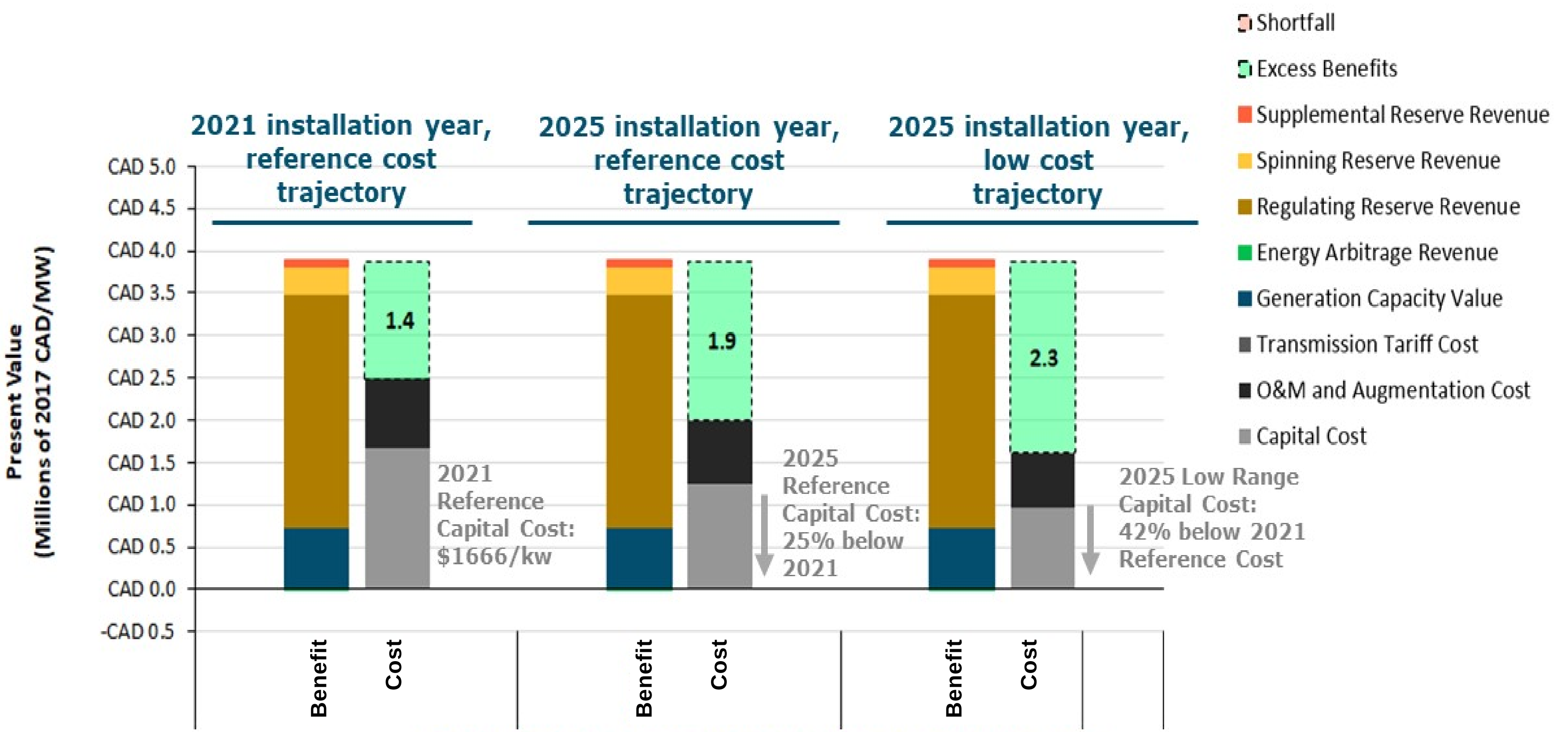
1 MW, 4-hour Lithium-Ion Battery; 2021 installation year



*Note: Excludes transmission tariff cost

Battery storage costs are declining; the pace of the cost curve decline is uncertain

1 MW, 4-hour Lithium-Ion Battery



*Note: Results above exclude transmission tariff cost, do not assume price saturation of operating reserve markets

Key energy storage findings

- Transmission tariff likely to be a material cost for storage
- Smaller sizes and volume of storage (<50 MW) may be cost-effective, primarily in the ancillary services market
- Larger sizes and volumes of storage (>50 MW) unlikely to be cost-effective due to insufficient energy price spreads
- Storage will be able to participate in the capacity market
- As energy storage costs continue to fall, future cost curves will drive the level of market penetration

Summary and Recommendations

Reliable, renewable, affordable, and market aligned

RELIABLE

- Reliability maintained at 30% x 2030
- Existing and planned transmission will enable renewables to connect
- Generation surpluses to be <1% of renewable energy (<0.3% total energy)
- Reaffirms no reliability concerns with coal phase-out

RENEWABLE

- 30% x 2030 achievable
- REP achieves best $/tonne carbon reduction

AFFORDABLE

- Wind is currently the least-cost renewable
- Capacity market reduces price volatility and value of storage

MARKET ALIGNMENT

- Flexibility and supply surplus not forecast to create material market impacts

Recommendations

- CLP and REP have placed Alberta on a reliable path to attain the renewable energy target without any additional products or services
- AESO will develop two roadmaps, with industry engagement, to assess ongoing flexibility needs and integrate storage as technologies advance
  - AESO will monitor DR&S as costs are expected to decline in the future

Next Steps

Predicting the future is tricky

Technology Cost Curves

Government Policy

New Innovations

Globalization

Competition

Customer Motivation

Energy storage – a roadmap

Enable competition

Storage as an option

Engage stakeholders

Tariffs

Hybrid assets

Market rules

Integration

Future flexibility – a roadmap

Assess need and capability

Enable future capability

Engage stakeholders

Existing asset capability

Remove barriers

Enhance forecasting, dispatching

Assess pricing signals

AESO's next steps

- Energy Storage Roadmap
  - AESO will lead the development
  - Create an Energy Storage Stakeholder Group in October/November
  - Integrate with other action already underway
- Flexibility Roadmap
  - AESO will lead the development
  - Energy and Ancillary Services roadmap already progressing some elements of the Flexibility Roadmap
  - Integrate with other action already underway
- Open to additional feedback or questions on report
  - Contact dennis.frehlich@aeso.ca

Questions?