Dispatchable Renewables and Energy Storage
Dennis Frehlich, P. Eng., Senior Strategic Advisor

Stakeholder Session
October 3, 2018
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

- Legal and regulatory review
- Storage cost/benefit analysis
- Stakeholder engagement
- Jurisdictional review
- Dispatchable renewables cost/benefit analysis
- Renewables integration needs analysis
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
- A few nearing 30% penetration
- Some are setting 40%-60% targets
- Curtailments near 5%

### Typical challenges
- Dispatchable flexibility to meet increasing variability
- Managing supply surpluses when renewables generating in low-demand periods

### Flexibility options
- 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

- Reliability standards
- Transmission capacity
- Variability and ramping levels
- Fleet capability
- Supply surplus events
- Stability and inertia

10/03/18  Public
Variability and Flexibility
How did we assess our renewable integration needs to meet 30% by 2030?

- Variability
  - Ramps
- Flexibility
  - Fleet Capability
- Reliability
- Supply Surplus Events

Moderate Coal-to-gas Case

High Coal-to-gas Case

Market Simulation (Hourly Granularity)

Dispatch Simulation (Minute-level Granularity)
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

<table>
<thead>
<tr>
<th>Natural gas prices</th>
<th>$1.50 – $2.40GJ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon tax</td>
<td>$30/tCO2 rising to $50/tCO2</td>
</tr>
<tr>
<td>Output-based allocation</td>
<td>Starting at 0.370 tCO2/MWh, declining post-2020</td>
</tr>
</tbody>
</table>
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

(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
Is Alberta like California with a solar driven ‘duck curve’? 

Typical Spring Day

Steeper Ramps

- Over generation risk
- Deeper Belly

- Actual 3-hour ramp of 14,777 MW on March 4, 2018
- Net Load of 7,149 MW on February 18, 2018

Megawatts

Hour

12am 3am 6am 9am 12pm 3pm 6pm 9pm

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

<table>
<thead>
<tr>
<th>Technology</th>
<th>Non-Generating Status Average</th>
<th>Generating Status Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Delay (min.)</td>
<td>Ramp Rate (MW/min.)</td>
</tr>
<tr>
<td>Coal</td>
<td>3.0</td>
<td>2.2</td>
</tr>
<tr>
<td>Combined Cycle</td>
<td>4.1</td>
<td>2.3</td>
</tr>
<tr>
<td>Simple Cycle</td>
<td>6.8</td>
<td>13.6</td>
</tr>
<tr>
<td>Cogeneration</td>
<td>3.1</td>
<td>2.6</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Scenario</th>
<th>CPS2 (&gt; 90)</th>
<th>SOL (&lt;5)</th>
<th>Large ACE (proactive indicator)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MCTG</td>
<td>98.5 to 99.9</td>
<td>0 to 1</td>
<td>0 to 11</td>
</tr>
<tr>
<td>HCTG</td>
<td>98.9 to 99.9</td>
<td>0 to 2</td>
<td>0 to 18</td>
</tr>
</tbody>
</table>
Supply surpluses?
Potentially, but less than 1% of renewables
Dispatchable Renewables
What **directionally** is the cost/benefit of dispatchable renewables?

**FIGURE 11: Comparative scenario analysis approach**

**FIGURE 12: Substitution cases**

<table>
<thead>
<tr>
<th>Substitution Case Inputs</th>
<th>Run-of-river Hydro</th>
<th>Biomass</th>
<th>Geothermal</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>250 MW</td>
<td>250 MW</td>
<td>250 MW</td>
</tr>
<tr>
<td></td>
<td>500 MW</td>
<td>500 MW</td>
<td>500 MW</td>
</tr>
<tr>
<td></td>
<td>1,000 MW</td>
<td>1,000 MW</td>
<td>1,000 MW</td>
</tr>
</tbody>
</table>
Renewable asset mix meets 30% by 2030 across simulation scenarios

Wind Installed Capacity

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

Replaced Wind Capacity Across Substitution Levels

- 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

<table>
<thead>
<tr>
<th>Capital Cost</th>
<th>Operating Cost</th>
<th>LCOE (2017$/MWh)</th>
<th>Capital Cost Share of LCOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017 $/kW</td>
<td>2017 $/MWh</td>
<td>Long-term Contract (4.3%)</td>
<td>Merchant (8.2%) (%)</td>
</tr>
<tr>
<td>Wind</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1,250</td>
<td>14</td>
<td>42</td>
<td>55</td>
</tr>
<tr>
<td>1,400</td>
<td>14</td>
<td>46</td>
<td>60</td>
</tr>
<tr>
<td>1,600</td>
<td>14</td>
<td>50</td>
<td>66</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>67% - 79%</td>
</tr>
<tr>
<td>Run of River Hydro</td>
<td>4,000</td>
<td>10</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>6,500</td>
<td>10</td>
<td>74</td>
</tr>
<tr>
<td></td>
<td>8,000</td>
<td>10</td>
<td>89</td>
</tr>
<tr>
<td></td>
<td>9,750</td>
<td>10</td>
<td>107</td>
</tr>
<tr>
<td></td>
<td>13,000</td>
<td>10</td>
<td>139</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>79% - 95%</td>
</tr>
<tr>
<td>Biomass</td>
<td>4,750</td>
<td>75</td>
<td>115</td>
</tr>
<tr>
<td></td>
<td>5,000</td>
<td>75</td>
<td>117</td>
</tr>
<tr>
<td></td>
<td>5,600</td>
<td>75</td>
<td>122</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>35% - 47%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>7,677</td>
<td>12</td>
<td>80</td>
</tr>
<tr>
<td></td>
<td>9,801</td>
<td>12</td>
<td>98</td>
</tr>
<tr>
<td></td>
<td>13,842</td>
<td>12</td>
<td>134</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>85% - 93%</td>
</tr>
</tbody>
</table>
LCOE ranges incorporate various cost risks including capacity factor, technology, financial life and construction.

**Levelized Cost Comparison (4.3% real ATWACC)**

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

LCOE Sensitivity based on Capacity Factor
25-yr vs 50-yr Financial Life (4.3% ATWACC)

- 50-year financial life LCOEs are ~20% lower than 25-year
- AB historical
- 2010 Hatch
- Used in study
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?

Market Prices
Market Rules
Storage Operation

Storage Model

Perfect foresight
All markets
Hourly optimization

Revenues
- Energy
- Ancillary Services
- Capacity

Costs
- Technology
- Vintage
- Tariffs
- Capital
- Operating

Competitiveness

We did not assess “wires deferral” or “customer bill” related benefits
Performed a wide range of storage scenarios

<table>
<thead>
<tr>
<th>Technologies</th>
<th>Market Conditions</th>
<th>Cost Projections</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Lithium-ion batteries: 2-hour, 4-hour and 12-hour</td>
<td>• Future Alberta generation mix: moderate vs high coal conversion, no intertie</td>
<td>• Technology uncertainty: range of potential costs for batteries and pumped storage</td>
</tr>
<tr>
<td>• Pumped storage hydro: 6-hour and 12-hour</td>
<td>• Saturation: effect of increased storage on operating reserve and pool prices</td>
<td>• Cost changes by year of installation: 2021 and 2025</td>
</tr>
</tbody>
</table>
Storage may be cost-effective in operating reserve market, with no transmission tariff costs

1 MW, 4-hour Lithium-Ion Battery
(2021 Installation, 25 Year Present Value with 8.2 % Discount Rate)

Excluding Transmission Tariff Cost

Including Transmission Tariff Cost

Transmission tariff cost results in negative net revenues

- Benefit
- Cost

CAD 0.0

CAD 0.5

CAD 1.0

CAD 1.5

CAD 2.0

CAD 2.5

CAD 3.0

CAD 3.5

CAD 4.0

CAD 4.5

CAD 5.0

Present Value (Millions of 2017 CAD/MW)

O&M and Augmentation Cost
Transmission Tariff Cost
Capital Cost
Generation Capacity Value
Energy Arbitrage Revenue
Regulating Reserve Revenue
Spinning Reserve Revenue
Supplemental Reserve Revenue
Excess Benefits
Shortfall
Capacity market expected to narrow average daily energy price spreads in the future

Average Daily Energy Prices (MCTG Case)

$ / MWh

Hour of Day

2020

2040
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)

<table>
<thead>
<tr>
<th></th>
<th>Benefit</th>
<th>Cost</th>
<th>Benefit</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>With operating reserve + capacity revenues</td>
<td>CAD 1.4</td>
<td></td>
<td>CAD 1.5</td>
<td></td>
</tr>
<tr>
<td>If excluding operating reserve participation</td>
<td></td>
<td>CAD 0.5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Note: Results above exclude transmission tariff cost*
If storage enters operating reserve market, it is expected to drive prices down.

**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)

*Each facility assumed to provide maximum 50 MW regulating reserves + 50 MW contingency reserves; remaining capacity used for energy arbitrage

<table>
<thead>
<tr>
<th>Present Value (Millions of 2017 CAD/MW)</th>
<th>75 MW* Storage</th>
<th>500 MW* Storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAD 5.0</td>
<td></td>
<td>$3,950 capital cost per kw</td>
</tr>
<tr>
<td>CAD 4.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAD 4.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAD 3.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAD 3.0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAD 2.5</td>
<td></td>
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<tr>
<td>CAD 2.0</td>
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<tr>
<td>CAD 1.5</td>
<td></td>
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<tr>
<td>CAD 1.0</td>
<td></td>
<td></td>
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<tr>
<td>CAD 0.5</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CAD 0.0</td>
<td></td>
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</tr>
</tbody>
</table>

If reserves limited to 20% of 500 MW facility, diminishes total revenues per MW

- Shortfall
- Excess Benefits
- Supplemental Reserve Revenue
- Spinning Reserve Revenue
- Regulating Reserve Revenue
- Energy Arbitrage Revenue
- Generation Capacity Value
- Transmission Tariff Cost
- O&M and Augmentation Cost
- Capital Cost
Storage duration beyond two hours provides diminishing incremental value in Alberta.

1 MW Storage; 2021 Install
(excludes operating reserve revenue opportunities)

*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

- **Base cost range for 12+ hour pumped storage hydro facility:** $2500-4000 per kw
- **4-hour Li-Ion battery cost range for 2021 install:** $1400-2000 per kw
- **2-hour Li-Ion battery cost range for 2021 install:** $825-1200 per kw

*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
Predicting the future is tricky

Technology Cost Curves

Government Policy

New Innovations

Globalization

Customer Motivation

Competition
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?