Agenda

1. Wind Integration

2. Status Report on the Wind Power Forecasting Service Request for Proposal (RFP) released June 23rd

3. Cost Recovery for Wind Power Forecasting within the 2010 General Tariff Application

4. Update on key transmission reinforcement initiatives supporting wind integration
Wind Integration

August 12, 2009

Anita Lee
Director Wind Integration

Ruppa Minhas
Senior Market Implementation Analyst
Agenda

• Key considerations for wind integration
• Alberta characteristics
• Market comparison data (Alberta and other markets)
• Wind generation attributes and impacts
• Examples of recent wind events
• Managing wind: solutions for consideration (Alberta and other markets)
• Discussion
The AESO is committed to integrating as much wind generation into the Alberta electric system as is feasible without compromising system reliability or the fair, efficient and openly competitive operation of the market.
Key considerations

1. How will the integration of additional wind generation affect the reliable operation of the AIES in real time?

2. How will the integration of additional wind generation affect the fair, efficient and openly competitive operation of the market?

3. What are the changes needed to mitigate the impacts?
AESO’s wind integration journey

Study 1200 MW of Wind Power

Phase 1 Study
Study up to 2000 MW

PH II Study and Temporary Threshold

Market and Operational Framework introduced

Supply Surplus

2003

New Standard specific for Wind Power Facilities

2004

Wind Power Forecasting Pilot initiated

2005

OR market redesign

2006

Workgroups for Wind Integration initiated

Finalize Forecasting Pilot

2007

Forecasting RFP

2008

Demand Response

2009

AS product design
Alberta characteristics

• Alberta:
  – is a small market facing the same challenges as other, larger markets for integrating wind
  – has a large amount of industrial load
  – Limited interconnections
  – has transmission congestion
  – is currently growing at a slow rate due to economic conditions

• The supply stack in Alberta is heavily weighted to base load coal, which is not flexible
<table>
<thead>
<tr>
<th>Size of market</th>
<th>Peak demand</th>
<th>Wind installed capacity</th>
<th>Wind in queue</th>
<th>Other relevant data</th>
</tr>
</thead>
<tbody>
<tr>
<td>AESO</td>
<td>12,267 MW</td>
<td>2008: 9,806 MW/hr &amp; highest peak demand 2009: 9,753 MW/hr</td>
<td>550 MW</td>
<td>12,900 MW</td>
</tr>
</tbody>
</table>

- Estimated wind interest in South: >7,800 MW
- Estimated wind interest in Central area: >3,400 MW
- Estimated wind interest elsewhere: >1,700 MW
## Market Comparison Data (cont’d)

<table>
<thead>
<tr>
<th></th>
<th>Size of market</th>
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</tr>
</thead>
</table>
| PJM            | 164,895 MW     | 144,644 MW  | 2,100 MW                | 47,572 MW     | -Currently 21 wind farm projects under construction: 2,346 MW  
<pre><code>             |                |             |                         |               | -Wind installed capacity expected to double in 5 to 10 years |
</code></pre>
<table>
<thead>
<tr>
<th>Market</th>
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<th>Wind in queue</th>
<th>Other relevant data</th>
</tr>
</thead>
</table>
| ERCOT  | 80,076 MW      | 62,339 MW   | 8,300 MW                | 51,897        | -Peak wind output: 4,700 MW  
-Experienced 1000 MW change in an hour |
## Market Comparison Data (cont’d)

<table>
<thead>
<tr>
<th></th>
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<th>Wind in queue</th>
<th>Other relevant data</th>
</tr>
</thead>
</table>
| MISO     | 159,000 MW (reliability) | 136,520 MW (reliability) | 5,096 MW              | 55,000 MW     | -Nov 2008 peak wind output: 2,779 MW  
- Dec 2008 to Feb 2009 peak wind output: 3,500 MW |
|          | 131,306 MW (market) | 116,030 MW (market)      |                        |               |                                     |
## Wind generation attributes and impacts

<table>
<thead>
<tr>
<th>Wind Attributes</th>
<th>Planning Impacts</th>
<th>Operations Impacts</th>
<th>Market Impacts</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Variability</strong></td>
<td>• Transmission investment to build to accommodate 100% anticipated wind capacity</td>
<td>• Energy supply and demand imbalance</td>
<td>• Potential for price volatility</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Potential for reliability limit violations</td>
<td>• Short term adequacy</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Potential for Alberta Reliability Standards sanctions (WECC, NERC)</td>
<td>• Long term adequacy</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Potential for Area voltage regulation and stability issues</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Potential for supply surplus conditions</td>
<td></td>
</tr>
<tr>
<td><strong>Dispatchability</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Low Capacity Factor</strong></td>
<td>• Wind generation average capacity factor is 30 to 35%</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Recent Wind Events
May 21st, 2009

Wind and Demand
May 21st - 22, 2009

Ramp Up
Ramp Down
Recent Wind Events
May 21st, 2009 (cont’d)

Wind Ramp Event Summary - Market
May 21st - 22nd, 2009
Recent Wind Events
July 30th, 2009

Wind Ramp Event
July 30th, 2009

Time

MW
0 50 100 150 200 250 300 350

Wind Generation
### Market Comparison: Solutions to manage wind in other markets

<table>
<thead>
<tr>
<th>Products or Tools to manage wind</th>
<th>Comments</th>
</tr>
</thead>
</table>
| **PJM**                         | -ramping issues due to wind are managed procedurally, mainly through the use of operating reserves  
|                                 | -procedures in place to constrain wind farms under certain system conditions (ie. light load)  
|                                 | -queue management: projects not using capacity rights within an allotted time are removed from the queue |
|                                 | -wind generation is a price taker |
### Market Comparison: Solutions to manage wind in other markets (cont’d)

<table>
<thead>
<tr>
<th>ERCOT</th>
<th>Products or Tools to manage wind</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>- Actively curtail wind generation, when required</td>
<td>- transmission is a constraint</td>
</tr>
<tr>
<td></td>
<td>- Plan to provide wind forecast hourly</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Ramp rate limits for wind facilities (when responding to or after the release of wind generation curtailments)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Operating reserves for wind variability (RR and non-spinning reserves)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Special protection schemes and tx upgrades to address transient stability issues due to wind</td>
<td></td>
</tr>
</tbody>
</table>
## Market Comparison: Solutions to manage wind in other markets (cont’d)

<table>
<thead>
<tr>
<th>Products or Tools to manage wind</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MISO</strong></td>
<td>-day ahead pricing of wind supports merit order curtailment</td>
</tr>
</tbody>
</table>
| - Queue management: “first ready, first serve”  
- centralized wind forecast  
- wind is not a price taker in day ahead market, price taker in real time market  
- normal curtailment priorities followed for wind curtailment: by price and tx service  
- operational procedures  
- wind energy ramp histogram graph used to determine OR requirement |
## Alberta: Solutions to manage wind

<table>
<thead>
<tr>
<th>Planning solutions for consideration</th>
<th>Regional transmission enhancements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operations solutions for consideration</td>
<td>Wind power forecasting</td>
</tr>
<tr>
<td></td>
<td>Wind power limit</td>
</tr>
<tr>
<td></td>
<td>Wind power ramp limit</td>
</tr>
<tr>
<td>Market solutions for consideration</td>
<td>Possible products to manage volatility of wind ramping:</td>
</tr>
<tr>
<td></td>
<td>Ancillary Services - use of existing or modified AS products (RR, SPIN or SUP)</td>
</tr>
<tr>
<td></td>
<td>Demand response</td>
</tr>
<tr>
<td></td>
<td>Must-forecast-must-comply for wind</td>
</tr>
<tr>
<td></td>
<td>Supply surplus rule review</td>
</tr>
<tr>
<td></td>
<td>- Market suspension rule review</td>
</tr>
</tbody>
</table>
Outline

• Current Status
• RFP Response Summary
• Next Step
Current Status

- RFP released June 23
- Vendor responses received July 24
- Now evaluating responses
  - AESO has selected a short list following the defined criteria and procedures
  - A working group of Wind Power Facility Owners (Canadian Hydro, ENMAX, Suncor and TransAlta) who have signed a non-disclosure agreement (NDA), have been reviewing the short list and assisting with scoring
  - CanWEA with signed a NDA have been observing the evaluation process
RFP Response Summary

- Very good response to the RFP. Nine proposals submitted with most experienced forecasters in the world
- All recommendations from the pilot have been addressed by short listed vendors
- All short listed vendors have some experience with ramp tuned forecasting
- All short listed vendors say they can provide initial forecast data by Jan. 2010
Next Steps

- Advise short listed vendors for presentations to the AESO and the Working Group in late August
- Detailed scoring and ranking of short listed vendors with working group members
- Final recommendation the week of Sept 11
- Contracting complete in October
- Establish Wind Power Forecasting Standing Group in 2010 to address continuous improvements in forecasting performance
Wind Power Forecasting
Service Cost Recovery

August 12, 2009

Anita Lee
Director, Wind Integration
Wind Power Forecasting Service
Cost Recovery

Scope:
- Proposal to recover the external wind power forecasting service costs (not AESO costs)

Approach:
- Engage a working group to assist with exploring alternatives and options
  - Existing Wind Power Facility Owners supporting Wind Power Forecast RFP (4)
  - Invite potential future Wind Power Developers (2 or 3)
- Broad Stakeholder consultation mid-Aug to end-Aug
- Include in the AESO 2010 GTA and file with the AUC end-Sept
Participants:

- Canadian Hydro
- ENMAX
- Greengate Power
- Mainstream
- TransAlta
- TransCanada
- Suncor
- AESO: Anita Lee, John Martin
Considerations:

1. Who should pay for the wind power forecasting service cost? The Final Recommendation paper proposed that the cost is to be paid by wind power facility owners.

2. Should costs be recovered through the tariff or through an ISO fee? The AESO proposes a tariff basis as it is more transparent and easier to charge a subset of customers.
Questions:

3. How should the payment be calculated?
   - Per wind power facility site, or
   - Per installed MW capacity, or
   - Per MWh of energy production, or
   - A combination of any of the above
Wind Power Forecasting Cost Recovery

Questions:

4. Should the costs be levelized over a period of time? If so, what should be the appropriate period of time?

5. Costs are currently expected to be on the order of $500,000 per year for the first few years of the program. How should variances of actual costs from forecast be addressed?
Questions:

6. How are other jurisdictions such as California ISO and New York ISO deal with cost recovery of wind power forecasting service?

7. Other considerations?
Discussion and recommendations

1. Participants agreed that wind power facility owners should pay for the wind power forecasting service cost, subject to the following understanding:

   • only external costs are included, not the AESO’s internal costs of managing the service, and
   • the aggregated wind power forecast data is not provided to the market in the real time or near term timeframe.
2. With respect to the payment of costs, the wind power forecasting service costs were considered to be generally comparable to costs incurred by non-wind market suppliers in meeting must-offer obligations. The wind power forecasting service can be viewed as an alternative to imposing must-offer obligations on wind suppliers.
3. With respect to sharing wind power forecast data, participants considered it reasonable to provide the data to all wind power suppliers, but not to the market in general. Participants expressed concern that provided forecast data to the market in general could affect the behaviour of non-wind market suppliers.

- Participants agreed that information could be provided to the market in general on a historical aggregate basis, especially with respect to accuracy metrics of the forecast.
4. Participants agreed that it is reasonable to recover the external costs of the wind power forecasting service through the AESO tariff. It is generally easier to assess charges to a subset of market participants through a tariff charge than through a market fee. Implementing a tariff charges provides a measure of transparency for the costs, as well.
Discussion and recommendations

5. Participants generally agreed with recovery of the external costs of the wind power forecasting service as a $/MWh charge based on production. Such a charge is easy to administer and validate.

- A per site charge may be somewhat better aligned with cost causation, but does not accommodate sites of varying capacity. Even though there are few small sites currently being planned in Alberta, a charge should not be implemented that might act as a barrier to entry for a small site in the future.

- A per MW charge would not reflect the impact of transmission constraints on generation or unit outages at wind generation sites.

- Overall, a per MWh charge best addressed the concerns with respect to cost recovery.
6. Participants suggested the wind power forecasting service is not essential until installed capacity reaches the 900-1,000 MW range. However, the forecasting service needs to be implemented and tested prior to that time. Participants considered that levelizing the charge over a three-year period would avoid current wind power suppliers from paying an unreasonable share of the “start-up” costs. Recovery of some costs would be deferred and recovered over a larger volume of wind production in the second and third years of the service, assuming the wind production volumes will increase over time.

- Participants also recommended an escalation factor be used in the rates (e.g. each year rate increases by 10%) to ease the adjustment.
7. Participants suggested variances from forecast costs and revenues should be reconciled on an annual basis. Such variances would then be recovered through the wind power forecasting service charge in the following year. Reconciling of variances recognizes the uncertainty in the cost and revenue forecast, and also accommodates bonuses or penalties that may be incorporated in the wind power forecasting service contract to recognize excellent or poor forecast accuracy.
Sample rider for wind power forecasting service

<table>
<thead>
<tr>
<th>Year</th>
<th>Cost ($)</th>
<th>Energy (MWh)</th>
<th>Charge ($/MWh)</th>
<th>Revenue ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>250,000</td>
<td>300,000</td>
<td>0.23/MWh</td>
<td>69,000</td>
</tr>
<tr>
<td>2011</td>
<td>500,000</td>
<td>1,600,000</td>
<td>0.25/MWh</td>
<td>400,000</td>
</tr>
<tr>
<td>2012</td>
<td>500,000</td>
<td>2,000,000</td>
<td>0.28/MWh</td>
<td>560,000</td>
</tr>
<tr>
<td>2013</td>
<td>500,000</td>
<td>2,400,000</td>
<td>0.31/MWh</td>
<td>744,000</td>
</tr>
<tr>
<td>Total</td>
<td>1,750,000</td>
<td>6,300,000</td>
<td></td>
<td>1,773,000</td>
</tr>
</tbody>
</table>
Wind Integration Transmission Reinforcement

August 12, 2009

Bill Strongman, P.Eng.
Director, Regional System Planning
Wind Need

- Current Total Wind Interest > 12,900 MW
- Wind Interest in South > 7,800 MW
- Wind Interest in Central Area > 3,400 MW
- Wind Interest elsewhere > 1,700 MW

  • Our role to plan transmission facilities to meet the anticipated generation capacity in a timely and efficient way
South

- 240 kV loop system will accommodate up to 2,700 MW of wind generation
- Recommended system is staged to ensure that we move forward in a timely yet prudent manner and provide justification for each component
Recommended Alternative – 240 kV Looped System
Stage 1:
- 911L rebuild
- Milo Switching Stn
- Sub D – W. Brooks
- Coleman Phase
- Shifting Transformer

Stage 2:
- 500 kV tie
- Goose L – Sub C
- Sub C – Sub D
- Sub C – N.
- Lethbridge

Stage 3:
- Ware Jnc - Langdon
Staging

• A staged approach is recommended to move in a timely yet prudent way
• Each stage includes triggers/off-ramps to justify the development
• Cost Estimate (2008 $)
  – 1\textsuperscript{st} Stage $ 750 M
  – 2\textsuperscript{nd} Stage $ 800 M
  – 3\textsuperscript{rd} Stage $ 280 M
Schedule for South

• NID Application – Dec 30, 08
• NID Hearing Closed – June 29, 09
• AUC Decision Due – Sept 30, 09
• Direction to TFO to begin Facilities App – May 18, 09
• Facilities Application to AUC – Mar 2010
• Facilities Approval – Jan 2011
• Construction begins – May 2011
• Construction complete on first stages – October 2012
• The 240 kV reinforcements required to accommodate up to 700 MW of wind generation
Hanna Transmission for Wind
Schedule for Hanna Wind Reinforcement

- NID Posted – July 30 09
- NID Filing – Aug 17 09
- NID Hearing – Q4, 09
- AUC Decision – Q1 10
- Direction to TFO to begin Facilities App – Aug 30 09
- Facilities Application to AUC – Q2 10
- Facilities Approval – Q3 10
- Construction begins (wind related) – Q4 10
- Construction complete (wind related) – Q4 11
THANK YOU!