Technical Advisory Committee Meeting Agendas

Appendix A
Thursday, October 23

Integrated Resource Plan and DSM 10:00 AM – 2:00 PM

1. DSM in the 2003 IRP
   • Errata filed in July
   • Assumptions
   • Results

2. Integration methodologies
   • Avoided cost price signal
   • Full integration into AURORA model
   • Approach used in 2003 IRP (Errata)

3. Integration specifics (2003 IRP as example)
   • Cost attributes
   • Supply curves
   • “Resource” bundles
   • Load research
   • Other resources
     o Distribution efficiencies (e.g., CVR)
     o Peak shaving efficiencies (e.g., voluntary curtailment, TOU)

4. Issues to consider
   • Quality of inputs
   • Usefulness of outputs
     o Is AURORA smarter than Jon?
     o Examples

5. Next steps

Lunch provided 12 Noon
Avista Utilities 2005 Integrated Resource Plan
Technical Advisory Committee Meeting No. 2
August 4, 2004

- Introductions 9:30a Kalich
- Overview of Planning Process and Review of IRP Schedule 9:40a Young
- TAC Participant Brainstorm on IRP Topics 10:00a Folsom
- Review of October 2003 DSM Meeting 11:00a Powell
- Lunch Speaker & Lunch 12:00p Anderson
- Load Forecast 1:00p Barcus
- Future Resource Requirements (L&R) 3:00p Fletcher
- Adjourn 3:30p
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<td>Introductions</td>
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<td>Barcus</td>
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<tr>
<td>Review of 2\textsuperscript{nd} TAC Meeting</td>
<td>10:15</td>
<td>Kalich</td>
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<tr>
<td>Overview of Natural Gas Forecast</td>
<td>11:00</td>
<td>Gall</td>
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<tr>
<td>Capacity Planning Overview</td>
<td>11:30</td>
<td>Kalich</td>
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<tr>
<td>Lunch Speaker (and lunch)</td>
<td>12:00</td>
<td>Folsom</td>
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<tr>
<td>Capacity Planning Overview, Cont.</td>
<td>12:45</td>
<td>Kalich</td>
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<td>Load Forecast Update</td>
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<td>Barcus</td>
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<td>Loads and Resources Update</td>
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<td>Imputed Debt</td>
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<td>Overview of Feb. 17 TAC Meeting</td>
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<td>Adjourn</td>
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## Technical Advisory Committee Meeting No. 4 Agenda

**4th Floor Technology Room—Avista Headquarters, Spokane**  
**February 17, 2005**

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<td>Kalich</td>
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<td>2. Review of 3rd TAC Meeting</td>
<td>10:15</td>
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<tr>
<td>3. IRP Modeling Overview</td>
<td>10:30</td>
<td>Gall</td>
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<tr>
<td>4. Modeling Futures and Scenarios</td>
<td>11:00</td>
<td>Kalich</td>
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<td>5. More on Modeling Assumptions</td>
<td>11:45</td>
<td>Gall</td>
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<td>6. Lunch and AURORA_XMP Demo</td>
<td>12:15</td>
<td>Gall</td>
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<td>7. Modeling Emissions in IRP</td>
<td>1:15</td>
<td>Lyons</td>
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<td>8. Supply-Side Resource Alternatives</td>
<td>2:45</td>
<td>Gall/Lyons</td>
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<td>9. Selection of Future TAC Dates</td>
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<td>Kalich</td>
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<td>10. Adjourn</td>
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<td>2. Review of 4th TAC Meeting</td>
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<td>3. DSM Integration Into IRP</td>
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<td>Powell</td>
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<td>4. Stochastic (Risk) Modeling Part 1</td>
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<td>5. Lunch and Transmission Planning</td>
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<td>6. Stochastic (Risk) Modeling Part 2</td>
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<td>7. Preliminary Capacity Expansion Results</td>
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<td>8. Update on Scenarios &amp; Futures</td>
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<td>9. 2005 Draft IRP Outline</td>
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<td>10. Adjourn</td>
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## Avista Utilities 2005 Integrated Resource Plan

### Technical Advisory Committee Meeting No. 6 Agenda

**May 18, 2005**

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<td>3. Natural Gas Price Forecast Update</td>
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<td>4. Base Case Results</td>
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<td>5. LP Module/Selection Criteria</td>
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<td>7. Transmission Planning</td>
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<td>8. Scenario Results</td>
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<td>Lyons</td>
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<td>9. Avoided Costs</td>
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<td>Kalich</td>
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<td>10. Action Item for 2005 IRP</td>
<td>3:15</td>
<td>Kalich</td>
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<td>11. Housekeeping Items</td>
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<td>3. Hydro Upgrades</td>
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<td>4. Emissions</td>
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<td>7. Preferred Resource Strategy</td>
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Technical Advisory Committee
Members

Appendix B
## 2005 IRP TAC Member List

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<tr>
<th>Name</th>
<th>Organization</th>
<th>Phone Number</th>
<th>E-Mail</th>
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<tr>
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<td>Andy Ford</td>
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<tr>
<td>Bruce Folsom</td>
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<tr>
<td>Charlie Grist</td>
<td>NPCC</td>
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<td>Chris Bevil</td>
<td>Puget Sound Energy</td>
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<tr>
<td>Chris Turner</td>
<td>PacificCorp</td>
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<td>Clint Kalich</td>
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<td>Danielle Dixon</td>
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<td>Dave Van Herset</td>
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<td>Diane Thoren</td>
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<td>Doug Loreen</td>
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<tr>
<td>Hank McIntosh</td>
<td>WUTC</td>
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<td>Harry McLean</td>
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<td>Heidi Heath</td>
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<td>Howard Ray</td>
<td>Potlatch</td>
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<td>Joelle Steward</td>
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<td>John Lyons</td>
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<td>Jon Powell</td>
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<td>Ken Canon</td>
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<td>Leonard Goldiron</td>
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<td>Liz Klumpp</td>
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<td>360.956.2071</td>
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<tr>
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<td>Mallur Nandagopal</td>
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<td>Patrick Saad</td>
<td>Dana-Saad Co.</td>
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<td>Randy Barcus</td>
<td>Avista Utilities</td>
<td>509.495.4160</td>
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<td>Renee Coelho</td>
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<td>Richard Nagy</td>
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<td>Steve Silworth</td>
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<td>Tom Dempsey</td>
<td>Avista Utilities</td>
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<tr>
<td>Tom Eckman</td>
<td>NPCC</td>
<td>503.222.5161</td>
<td>teckman@nw council.org</td>
<td>X</td>
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<tr>
<td>Tom McLaughlin</td>
<td>Potlatch</td>
<td>208.799.1935</td>
<td><a href="mailto:Tom.McLaughlin@potlatchcorp.com">Tom.McLaughlin@potlatchcorp.com</a></td>
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<tr>
<td>Yohannes Mariam</td>
<td>WUTC</td>
<td>360.664.1316</td>
<td><a href="mailto:ymariam@wutc.wa.gov">ymariam@wutc.wa.gov</a></td>
<td>X</td>
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</tbody>
</table>

Appendix B
Technical Advisory Committee Meeting Presentation Slides

Appendix C
# TAC Presentation Table of Contents

**TAC 1**  
October 23, 2003  
- Integration of DSM into the IRP

**TAC 2**  
August 4, 2004  
- Overview of Planning Process  
- TAC Brainstorming Review Summary  
- Avista Electric Demand Side Management- Update and Proposed Integration  
- Clark Fork River Projects Update  
- Spokane River Relicensing Update  
- 2005 Load Forecast  
- Future Resource Requirements

**TAC 3**  
January 25, 2005  
- Overview of Natural Gas Forecast  
- Sustained Capacity and Planning Margin Concepts  
- 2005 Load Forecast Update and Scenarios  
- Future Resource Requirement Update  
- Imputed Debt Discussion

**TAC 4**  
February 17, 2005  
- Modeling Overview and Process  
- Modeling Futures and Scenarios  
- Modeling Assumptions  
- Treatment of Emissions  
- Supply Side Options

**TAC 5**  
March 23, 2005  
- DSM Integration Brief  
- Stochastic Modeling  
- Avista’s 230kV Upgrade Projects  
- Preliminary Long-term Electric Forecast and Capacity Expansion Results  
- Modeling Futures and Scenarios  
- 2005 Draft IRP Outline

**TAC 6**  
May 18, 2005  
- Gas & Inflation Forecast Update  
- Base Case Results- Electric Price Forecast  
- LP Module, The Selection Criteria & Efficient Frontier  
- Estimated Resource Integration Costs for the 2005 IRP  
- Scenario Results  
- Avoided Costs

**TAC 7**  
June 23, 2005  
- Hydro Upgrades  
- Emissions  
- Demand Side Management  
- Preferred Resource Strategy

---

Appendix C
Integration of DSM into the IRP

Technical Advisory Committee
Triple-E Board Meeting

October 23, 2003
Jack Stewart Training Center

DSM in the 2003 IRP

- Errata filed in July
  - New DSM run – third time’s a charm!
- Assumptions
- Results
2003 IRP Assumptions

• DSM bundles
  – Based on actual conservation activities
  – Six components account for vast majority of historic energy savings:
    • Commercial DHW, HVAC, and lighting
    • Residential DHW, HVAC, and lighting

DSM supply curves

  – For each component, curves were based on actual and three incremental points
  – Incremental points – 25% increase in funding results in 10% increase in savings
2003 IRP Assumptions

- DSM load shapes
  - Hourly shapes estimated for typical week for each of twelve months
  - Based on internal M&E and BPA End Use Load and Consumer Assessment Program (ELCAP)
  - Modified to include engineering estimates of new technologies

Illustration – August Load Shapes
2003 IRP Results

Illustration – Residential HVAC vs. 2004 Prices

32,302 selected by AURORA
3,142 "odd-ball"
2,365 limited income
37,810 total MWh (or 4.32 aMW)
Integration Methodologies

- Avoided cost price signal
- Full integration into AURORA model
- Approach used in 2003 IRP

Avoided Cost Price Signal

AURORA Resource Stacks → Deferrable Resource Avoided Cost → DSM Department “Goes & Gets”

WECC Supply-Side Resources

Decrement Deferrable Resource by Amount of DSM
Full Integration Into AURORA

- Cost Attributes
- Supply Curves
- DSM Bundles
- Load Shapes

Avista Demand-Side Resources → AURORA Resource Stacks → AURORA Selection of Demand-Side Resources

Appendix C

Approach Used In 2003 IRP

- Cost Attributes
- Supply Curves
- DSM Bundles
- Load Shapes

Avista Demand-Side Resources → WECC Supply-Side Resources → AURORA Resource Stacks → Pass/Fail DSM Resource Bundles
**Integration Specifics**

- Cost attributes
- Supply curves
- DSM bundles
- Load shapes
- Other resources
  - Distribution efficiencies (CVR)
  - Peak shaving (voluntary curtailment)
  - Load shifting (TOU)

**Issues to Consider**

- Quality of inputs
  - Supply curves, bundles, and load shapes
- Usefulness of outputs
  - Is AURORA smarter than Jon?
  - Examples
Next Steps?
Overview of Planning Process

2005 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 4, 2004
Doug Young

• Avista is continuously evaluating the balance between requirements and resources.

• Avista does an update each year when the new load forecast is completed.

• Avista strives to reach balanced business decisions.
Overview of Planning Process

- The Company expects public participation will continue to play an important role in resource planning.

- This is the eighth IRP that will be submitted since 1989.

- The plan’s goal is to describe the mix of generating resources and improvements in efficiency that is expected to meet future needs at the lowest cost to the Company and its customers.

- The 2003 IRP focused on developing a set of tools and methods within which potential resource decisions could be evaluated.

Overview of Planning Process

- The Company’s near-term action plan outlined activities that supported the Preferred Resource Strategy (PRS) and improved the planning process. During the first ten years the PRS includes:
  - 149 aMW of CCCT
  - 25 aMW of wind
  - 197 aMW of coal
  - 40 aMW of SCCT
Overview of Planning Process

- Work is proceeding on some of the action items, such as:
  - Spokane River relicensing effort,
  - Integrating wind generation into Avista’s system,
  - Adding coal facilities to the resource mix,
  - Determining the optimum reserve margin, and
  - Assessing the cost-effectiveness of new resource additions

Review of 2005 IRP Schedule

- Avista had four TAC meetings during the last IRP planning cycle.

- In October 2003 Avista held its first TAC meeting for the 2005 IRP planning cycle to discuss the various alternatives for integrating DSM into the IRP process.

- The Company will hold TAC meetings in October and December of this year. Another TAC meeting will be held in February 2005, and the draft IRP will be released in March. A final TAC meeting to review the draft report will be held the first of April. The final IRP report will be released at the end of April.
Review of 2005 IRP Schedule

• This will be Doug’s last IRP. Doug is retiring at the end of 2004!
# August 4, 2004 IRP TAC Brainstorming Summary

<table>
<thead>
<tr>
<th>Issue</th>
<th>Area</th>
<th>Index</th>
<th>Details of Issue</th>
<th>Utility Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Risk</td>
<td>Analysis</td>
<td>consider fuel supply and price risk, as well as value of resource diversity</td>
<td>will be evaluated</td>
</tr>
<tr>
<td>2</td>
<td>DSM</td>
<td>Buybacks</td>
<td>Council is focusing on buy-backs and would like utility to consider it in 2005</td>
<td>IRP will include in plan</td>
</tr>
<tr>
<td>3</td>
<td>L&amp;R</td>
<td>Capacity</td>
<td>discuss what planning capacity is (single- versus multi-hour peak)</td>
<td>include in plan</td>
</tr>
<tr>
<td>4</td>
<td>L&amp;R</td>
<td>Capacity</td>
<td>discuss if adjusting hydro maintenance/upgrades would eliminate need for</td>
<td>additional peaking plants</td>
</tr>
<tr>
<td>5</td>
<td>L&amp;R</td>
<td>Capacity</td>
<td>Look to hydro for new capacity</td>
<td>include in plan</td>
</tr>
<tr>
<td>6</td>
<td>DSM</td>
<td>Codes</td>
<td>Model future code revisions and quantify their impact on load forecast</td>
<td>The econometric forecast methodology captures improved energy codes. Improvements over and above the code are quantified within the DSM resource acquisition.</td>
</tr>
<tr>
<td>7</td>
<td>Resources</td>
<td>Cogen</td>
<td>Keep Cogen discussion in '05 IRP</td>
<td>will include in IRP</td>
</tr>
<tr>
<td>8</td>
<td>Resources</td>
<td>Cogen</td>
<td>Include discussion on what makes a good cogen project (maybe to appendix?)</td>
<td>look to power council, AVA research</td>
</tr>
<tr>
<td>9</td>
<td>Resources</td>
<td>Cogen</td>
<td>emphasize importance of flexibility, dispatchability, as historical projects</td>
<td>haven't been perfect fits</td>
</tr>
<tr>
<td>10</td>
<td>Resources</td>
<td>Cogen</td>
<td>Do we have estimate of cogen potential? Consider strength of cogen facility</td>
<td>(i.e., how long will it be around) in matrix</td>
</tr>
<tr>
<td>11</td>
<td>Resources</td>
<td>Cogen</td>
<td>Rate structure makes cogen hard. Consider demand charges with ratchets, seasonal</td>
<td>rates, TOU, etc.</td>
</tr>
<tr>
<td>12</td>
<td>Resources</td>
<td>Cogen</td>
<td>Cogen makes more sense in a transmission constrained region than any other form</td>
<td>of generation because it will occur at a load center and it provides</td>
</tr>
<tr>
<td>13</td>
<td>Risk</td>
<td>Contingency</td>
<td>Develop plan for the shelf to use in event of 00-01 happening again (ST solution</td>
<td>Evaluate the development of DSM-funded contingency plans to include customer buyback and various emergency DSM options</td>
</tr>
<tr>
<td>14</td>
<td>Credit</td>
<td>Credit</td>
<td>Discuss pros and cons of PPA versus ownership of resources</td>
<td>include in discussion</td>
</tr>
<tr>
<td>15</td>
<td>Resources</td>
<td>DG</td>
<td>discuss DG and its impact on transmission/distribution systems</td>
<td>include in discussion</td>
</tr>
<tr>
<td>16</td>
<td>DSM</td>
<td>DSM</td>
<td>Be aggressive on DSM, AVA should consider higher incentives</td>
<td>literature search &amp; consider controlled experiment on higher incentives</td>
</tr>
<tr>
<td>Issue</td>
<td>Area</td>
<td>Index</td>
<td>Details of Issue</td>
<td>Utility Response</td>
</tr>
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<tr>
<td>17</td>
<td>DSM</td>
<td>DSM</td>
<td>Evaluate accelerating the DSM acquisition schedule</td>
<td>We will review the assumptions and methodology behind the slight front-loading of</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>the draft 20-year regional supply curve. Avista is currently engaging in a</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>significant expansion of DSM resource acquisition.</td>
</tr>
<tr>
<td>18</td>
<td>Resources</td>
<td>Emissions</td>
<td>consider risk of future emission (CO2 and Mercury)</td>
<td>will be evaluated as scenarios, consider including in stochastic runs.</td>
</tr>
<tr>
<td>19</td>
<td>Risk</td>
<td>Emissions</td>
<td>look at a couple levels of mitigation costs when evaluating impact on resource</td>
<td>will evaluate as scenarios.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>decisions</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>Risk</td>
<td>Gas</td>
<td>consider buying gas model or a consultant forecast</td>
<td>Company purchases Global Insights forecast.</td>
</tr>
<tr>
<td>21</td>
<td>Resources</td>
<td>IPP</td>
<td>Consider IPP plants in plan</td>
<td>include in plan</td>
</tr>
<tr>
<td>22</td>
<td>L&amp;R</td>
<td>L&amp;R</td>
<td>include monthly L&amp;R tables in IRP</td>
<td>will include in tech. Appendix</td>
</tr>
<tr>
<td>23</td>
<td>L&amp;R</td>
<td>L&amp;R</td>
<td>Include 24-hour seasonal load shapes for utility, by customer class where available</td>
<td>will include system hourly loads by season, as class-level data is not available.</td>
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<tr>
<td>24</td>
<td>L&amp;R</td>
<td>L&amp;R</td>
<td>Evaluate forecasts besides base case, what happens if Fairchild Airforce Base</td>
<td>will include hi/lo forecasts &amp; scenarios, including discussion of FAB changes.</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>closes, expands</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>L&amp;R</td>
<td>L&amp;R</td>
<td>look at plans to address supply/demand shocks (FAB closure, Noxon failure, etc.)</td>
<td>include in plan</td>
</tr>
<tr>
<td>26</td>
<td>DSM</td>
<td>Load Control</td>
<td>If IRP finds it a good idea, recognize need to go in for rate schedule changes to</td>
<td>include in discussion</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>address cost shifts</td>
<td></td>
</tr>
<tr>
<td>27</td>
<td>Risk</td>
<td>Loads</td>
<td>Plan of how utility will address changing conditions (e.g., new load or load loss).</td>
<td>include in IRP discussion/scenarios</td>
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<td>How would a LT commitment to a coal plant be addressed if after the decision load</td>
<td></td>
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<td></td>
<td></td>
<td>fell</td>
<td></td>
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<td>28</td>
<td>Resources</td>
<td>Nuclear</td>
<td>Consider this resource to address emissions and availability of fossil fuels</td>
<td>add as resource alternative to IRP</td>
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<td>Risk</td>
<td>Risk</td>
<td>Address how long-term risk planning transitions to short-term risk management</td>
<td>include in discussion</td>
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<td>procedures</td>
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<td>Risk</td>
<td>Risk</td>
<td>Evaluate the hedge value of efficiency and renewables</td>
<td>will be included in analysis/discussion</td>
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<td>31</td>
<td>DSM</td>
<td>Supply Curves</td>
<td>develop supply curves for IRP, possibly starting with NPCC curves</td>
<td>Review regional DSM supply curves to determine if they can be extrapolated to</td>
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<td>Avista’s DSM portfolio</td>
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<td>32</td>
<td>Trans.</td>
<td>Trans.</td>
<td>Discuss transmission in plan</td>
<td>include in plan</td>
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<td>33</td>
<td>Resources</td>
<td>Wind</td>
<td>Look at studies out there on wind integration to see what the latest information</td>
<td>will include extensive eval. of wind in IRP</td>
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Avista Electric
Demand-Side Management

Operational Update and Proposed IRP Integration

August 4, 2004

Avista Electric DSM

• Operational update
  – Where we are

• Proposed methodology for assessing Avista DSM potential in the IRP
  – Where we’re going
DSM Funding

- Washington
  - $/kWh tariff rider
  - An amount equal to 1.48% of retail rates
- Idaho
  - Tariff rider established at 1.95% of retail rates
- These amounts do not include non-efficiency funding received through the same tariff rider

Proposed Revisions to the Idaho Tariff Rider Mechanism

- Revise tariff rider mechanism to break the % tie to retail rates
- Institute a “PGA-style” procedure that annually establishes a tariff rider level based upon
  - Estimated budget necessary to acquire all cost-effective kWhs
  - Carryover balance (positive or negative)
Proposed Revisions to the Idaho Electric Tariff Rider Level

- Reduce tariff rider to an amount equal to 1.25% of current retail rates
- Funding sufficient to support a three-fold increase in expenditures

Current and Proposed Funds Available for DSM

<table>
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<tr>
<th>Balance carryover</th>
<th>Revenue @ 1.25% of current rate</th>
<th>Prior years unexpended funds</th>
<th>Prior years expended funds</th>
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<td>Current</td>
<td>$500,000</td>
<td>$1,000,000</td>
<td>$1,500,000</td>
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<tr>
<td>Proposed</td>
<td>$2,000,000</td>
<td>$2,500,000</td>
<td>$3,000,000</td>
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</table>

Effect of these Revisions

- Increased responsiveness
  - Financial resources will be available when needed to acquire additional DSM resources
    - Avista will fund cost-effective kWh acquisition at the expense of establishing a negative intra-year tariff rider balance
  - There will be a timely reduction in the tariff rider when necessary to eliminate positive balances
Tariff Rider Balance Projections (in the absence of ramp-up programs)

Actual and Projected Rider Balances

- $(10,000,000)
- $(8,000,000)
- $(6,000,000)
- $(4,000,000)
- $(2,000,000)
- $-
- $2,000,000
- $4,000,000
- $6,000,000

January
March
May
July
September
November

January (BOM)
March
May
July
September
November
January
March
May
July
September
November

DSM Target Markets and Focus

- Washington Electric
  - Lost opportunities
    • Leave no lost opportunity behind
  - Low-Cost / No-Cost measures
    • Target measures that have the maximum immediate benefit to the customer
  - Preparing for early 2005 ramp-up

- Idaho Electric
  - Any kWh that can be cost-effectively acquired through utility programs
Ramp-up Programs and Targets

- Idaho
  - Any cost-effective kWh
    - Without regard to system coincidence
  - Implementing a series of “ramp-up” programs
    - 65 concepts developed
    - 25 concepts short-listed
    - 8 programs fielded
    - 9 programs nearing implementation
    - Generating concepts for next wave of programs

Launched & Developing Ramp-up programs

**New Programs and Efforts**
- Educational PSA’s
- Indirect Evaporative Cooling
- Participate in regional leveraging opportunities
  - E.g. “Double Your Saving”

**Programs in Development**
- Residential Controls Program
- Residential Lighting Program
  - Torchiere
    - New generation CFL’s
  - Hardwired exterior Energy Star Lights
- Energy Star Home Products
- Next Generation Outdoor Lighting Control Products

**Launched Enhancements to Current Portfolio**
- Prescriptive Motor program
- Enhanced marketing of Prescriptive Lighting program
- Intensified follow-up on previously identified opportunities
- Rooftop HVAC Maintenance program
- Prescriptive High Bay Lighting program

**Enhancement Programs in Development**
- Idaho residential program bill stuffers
- Prescriptive Compressed Air Program
- Efficiency “kit” for specified building types
- Industry Resource Management Support Group

Appendix C
Electric Savings Commitments

- Committed to delivering energy savings that were at least proportionate to expenditures
  - Analysis of Business Plan activity 1-1-02 to 10-31-03
    - Expended $6.8 million of $14.3 million tariff rider revenues (48%)
    - Achieved 87% of tariffed energy savings goal
    - Proportionality 181%

Avista’s Current Electric DSM Programs

- Commercial/Industrial qualifying measures
  - Any electric efficiency measure
  - Any electric to natural gas conversion measure exceeding the electric efficiency of deferrable natural gas-powered electrical generation

- Limited Income qualifying measures
  - Any electric efficiency measure
  - Any electric to natural gas conversion measure exceeding the electric efficiency of deferrable natural gas-powered electrical generation

- Residential qualifying measures
  - Heat pumps
  - High-Efficiency Water Heaters
  - Weatherization
  - Electric to Natural Gas Conversion

- Solar, wind or geothermal distributed generation
  - Customer owned, under 25 kW and not exceeding 50% of total customer load
Implementation

- Based upon a tiered incentive structure
  - “Standard” electric efficiency
    - 18 to 48 month customer simple payback ➔ 4 cents per 1st year kWh
    - 48 to 72 month customer simple payback ➔ 6 cents per 1st year kWh
    - Over 72 month customer simple payback ➔ 8 cents per 1st year kWh
    - Subject to 50% of incremental measure cost ceiling
  - “New Technology” electric efficiency
    - Under 48 month customer simple payback ➔ 10 cents per 1st year kWh
    - 48 to 72 month customer simple payback ➔ 12 cents per 1st year kWh
    - Over 72 month customer simple payback ➔ 14 cents per 1st year kWh
    - Subject to 75% of incremental measure cost ceiling
  - Fuel-Conversion
    - 24 to 48 month customer simple payback ➔ 1 cent per 1st year kWh
    - 48 to 72 month customer simple payback ➔ 2 cents per 1st year kWh
    - Over 72 month customer simple payback ➔ 3 cents per 1st year kWh
    - Subject to 50% of incremental measure cost ceiling

- Incentives for prescriptive programs and all residential programs are defined based upon typical installations
- Tiered incentive structure does not apply to limited income programs

Planning for the Future

- Use the IRP planning process as a meaningful exercise
  - Seeking actionable management actions
    - Target market focus
    - Long-range infrastructure planning
    - Revisions in valuation of DSM
    - Review of incentive levels
  - Unnecessary to incorporate into IRP
    - Budgeting
    - Tariff rider requirements forecasting
- Long-range objective …
  - Any kWh that can be cost-effectively acquired through utility programs
Past Integrations of DSM into the IRP

- Integration by price signal
  - DSM acquires all achievable kWh’s at or below the IRP-calculated avoided cost
    - Results in appropriate acquisition level as long as DSM is sufficiently small to be a price taker
    - Leads DSM to target the appropriate resources

Avoided Cost Price Signal

AURORA Resource Stacks ➔ Deferrable Resource Avoided Cost ➔ DSM Department “Goes & Gets”

WECC Supply-Side Resources ➔ Decrement Deferrable Resource by Amount of DSM
Explicitly Model DSM as a Resource

- Define DSM “bundles” that can be characterized within Aurora
  - Modeling issues
    - Defining DSM bundles to mimic supply-side resources
    - Sensitive to load research quality and applicability
    - Difficulty in establishing incremental / decremental resources available
      - Estimates must be specific to Avista service territory
      - Estimates are specific to an assumed time horizon
      - Distinctions between movements in a supply curve vs. movements along a supply curve

Approach Used In 2003 IRP

DSM in the IRP > Integration Methods
Proposed Methodology Attributes

- Adaptation of both the price signal and full integration approach
- Specific to the mid- and long-term management decisions regarding DSM operations and infrastructure development.
  - Should we target system-coincident and/or disproportionately on-peak end-uses?
  - Is our current incentive structure in need of revision?
    - Increase or decrease incentive levels?
    - Incorporate a preference for measures based upon load shape?

Methodology

- Disaggregate promising DSM measures into meaningful bundles
  - Including measures not currently significantly represented in our portfolio
- Estimate load shapes specific to that bundle and the most likely efficiency measures
- Apply measure / bundle specific load shapes against an 8760-hour avoided cost matrix to determine measure viability
- Actionable items
  - Target appropriate measures
  - Determine the value of targeting system coincident or on-peak measures
  - Evaluate revisions in tiered incentive structure based upon the differential per kWh value of energy savings of various measures / bundles / load shapes

Appendix C
26
Proposed Methodology Flow

Cost Attributes
DSM bundles
Load Shapes

Avista Demand-Side Resources

AURORA Resource Stacks

WECC Supply-Side Resources

AURORA Identifies 8760 Hour AC

Targeting of measure(s)
Review of incentive format & level
Establish appropriate infrastructure for operation

Determination of value of DSM bundle

Other Related Issues

- Conservation Voltage Regulation (2003 IRP action item)
  - Unlikely to have sufficient results from Avista’s pilot to support testing in this IRP
  - Will not have sufficient data for testing all alternative CVR technologies and their application to Avista’s distribution system
Total Dissolved Gas (TDG) Supersaturation

Clark Fork River

Clark Fork Project:
Cabinet Gorge and Noxon Rapids
Hydroelectric Developments

Noxon Rapids HED
Issue Identification

- State and Federal standards limit TDG levels to 110%
- TDG issue was identified during relicensing
- TDG issues at Noxon Rapids were easily resolved
- Resolution process at Cabinet Gorge incorporated into Clark Fork Settlement Agreement
FERC License Requirements

- Monitor TDG levels in the Clark Fork-Lake Pend Oreille system
- Develop interim TDG abatement alternatives
- Conduct biological studies
- Conduct “engineering study” to determine “default strategy”
- Develop Gas Supersaturation Control Program (GSCP) in 2002

Avista’s Strategy

1. Propose mitigation in lieu of structural modification
2. Propose single or phased bypass tunnels with mitigation
3. Propose concurrent construction of two bypass tunnels (estimated cost=$55 million, including AFUDC)

*Neither default strategy or alternatives meet state/federal standards*
Plan

- Engineering/Geotech (2004-07)
- Construct 1st Tunnel (2008-09)
- Evaluate (0-10 years)
- Decision on 2nd Tunnel

Financial

- One Tunnel ($38 Million)
- Annual Mitigation ($0.5 Million)
Spokane River Relicensing

TECHNICAL ADVISORY COMMITTEE MEETING

AUGUST 4, 2004

Long Lake Powerhouse - 1999

Avista Corp.'s Hydroelectric Projects

Spokane River FERC Project

Appendix C
32
Post Falls Facility
One of five in FERC License 2545

Post Falls Facility Data
- Located about 9 miles downstream from Coeur d’Alene Lake
- Initial operation in 1907
- Generation - 9.5 average megawatts, 5400 cfs flow
- Powerhouse Capacity - 15 MW
- Powerhouse Capacity - 5400 cubic feet per second (cfs)
- Project Capacity - 42,000 cfs
- Minimum flow - 300 cfs
Upper Falls Facility

- Construction completed and first operation in 1922
- "Run of river" facility with no operating storage
- Generating Capacity - 10 MW
- Average annual flow - 6,570 cfs
- Powerhouse capacity - 2,500 cfs

Monroe Street Facility

- Construction completed and first operation in 1890
- "Run of river" facility with no operating storage
- Minimum flow over dam - 200 cfs during viewing hours
- Generating Capacity - 15 MW
- Average annual flow - 6,570 cfs
- Powerhouse capacity - 2,850 cfs
Nine Mile Facility

- Construction completed and first operation in 1908
- Total usable storage - 3,130 acre feet
- Average annual inflow - 7,100 cfs
- Full pool forebay elevation - 1606.6 with 10' flashboards
- Powerhouse turbine capacity (4 units) - 6,400 cfs
- Generating Capacity - 26 MW
- Limited Storage Capacity Facility

Long Lake Facility

We are Avista...We improve life’s quality...With energy
Long Lake Facility Data

- Construction completed and first operation in 1915
- Full pool surface elevation - 1,536 ft
- Reservoir storage in top 14' - 65,270 acre feet
- Generating Capacity - 72 MW
- Spillway capacity - 115,000 cfs at 1535 ft
- Average annual inflow - 7,650 cfs
- Powerhouse turbine capacity (four units) - 7,000 cfs

How the Spokane River Plants Help Keep the Lights On --
Spokane River Generation Compared to Customer Load Requirements

Average Load = 895 MW
Average Spokane River Plant Generation = 125 MW

Avista Customer Load Requirement on March 23, 2001
Spokane River Plant Generation on March 23, 2001
Operational Flexibility

**Spokane River**
- Turbines sized at about average river flow or less
- 100 MW Energy -- 138 MW Capacity
- Only Long Lake has peaking capability

**Clark Fork River**
- Turbines sized at about twice the average river flow
- 328 MW Energy -- 780 MW Capacity
- 40 - 780 MW Peaking/Load following capability
- Daily to weekly storage

FERC Licenses
- Describe the facilities and operations
- Contain protection, mitigation and enhancement measures (PM&E) for project associated resources

Spokane River
Project FERC No. 2545

**LICENSE**
- Issued 1972
- Amended 1981
- Expires 2007
Spokane River Relicensing Regulatory Time-Line
Regulatory "Have To's"

- File Notice of Intent between 1/02 and 7/02
- File Application 7/05
- License Expires 7/07

We are Avista...We improve life’s quality...With energy

Alternative Licensing Process Features

- Collaborative Group designs the pre-application process - communications protocol, scoping, studies & study reports, procedures & deadlines
- Applicant files a preliminary draft NEPA document with application
Summary

♦ 96 stakeholder groups involved in 5 work groups and several sub groups and the plenary
♦ 137 meetings held since May 2002
♦ Interests identified, studies underway/completed and 17 PM&Es in draft
♦ Challenges include diversity of interests, number of participants, information needs, limited financial resources, and number of mandatory conditioning authorities
2005 Load Forecast

Presented by
Randy Barcus, Avista Corp. Chief Economist
August 4, 2004

Forecast Discussion Points

- Economic Forecast
  - Employment
  - Population
  - Scenario Options
- Degree Days
  - Heating
  - Cooling
- Prices
  - Electric—Retail
  - Natural Gas—Retail and Wholesale
- Electric Base Case Results
Economic Forecast

• Global Insight, Inc. Contract
  – National Outlook
  – Spokane County, Washington
  – Kootenai County, Idaho

• Adjustments
  – Fairchild Air Force Base Assessment
  – Economic Development Initiatives

• Allocation Scenario

National Outlook

The Consumer Markets Environment

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National Outlook

Employment Finally Begins to Recover

January employment was 2.36 million below its March 2001 peak.

(Percent change, annual rate)

National Outlook

The Saving Rate Remains Low, Limiting the Recovery in Household Net Worth

Saving Rate — Household Net Worth/Disposable income
National Outlook

Real Consumer Spending and Confidence

U.S. Consumer Spending Will Shift to Services
Regional Economy

- Service Area Population: 900,000
- Principal Counties—Growth Proxy
  - Spokane, Washington: 440,000
  - Kootenai, Idaho: 125,000
- Largest Employers
  - Fairchild Air Force Base
  - School Districts
  - Hospitals

Regional Economy

- Risks to Growth
  - Military Base Realignment and Closure Process during 2005
  - Continued Meltdown in Manufacturing
- Opportunities for Growth
  - Base expands with new missions
  - University District, Airport Freight Hub, Technology Parks
  - Convention Center Construction Underway
Regional Outlook--Jobs

1990-2000
Growth 62,000

2005-2015
No Action +41,000
FAFB + ED +29,000
Total +70% faster

Appendix C
Regional Outlook--Persons

1990-2000 growth 94,000

2005-2015
No Action +56,000
FAFB+ED +53,000
Total +94% faster
Degree Day Forecasts

- Usage normalization
  - Heating Degree Days
  - Cooling Degree Days
- Base Case Forecast at 96% of Normal
Price Forecasts

- **Electric Price Forecasts**
  - In 2005 – assumed 14% Idaho, 5% Washington
  - Out years – assumed 8% at 4 year intervals

- **Natural Gas Price Forecasts**
  - Retail – assumed 16% Idaho, 14% Washington
  - Cost of Gas – used Nymex index 7/1/04 through 2006, projected at Global Insight escalation afterward

- **Underlying Inflation**
  - GDP Deflator from Global Insight Forecast
  - 20 year average is 2.9%
Avista Corp. Natural Gas Cost Forecasts

Dollars per Dth

Results
Base Case
2005 Forecast
Avista Customer Forecasts

F2005 WA-ID Net-New Customer Forecast
Residential Schedule 1

Net New Customers

Washington-Electric
Idaho-Electric

2005-2015 2.2%, 2005-2025 1.8%

Residential Commercial Industrial Street Lights
# Detailed Forecast Example

The following table provides a detailed forecast example for Avista Utilities' native load over various years and months.

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Appendix C

55
Future Resource Requirements

2005 Integrated Resource Plan
Second Technical Advisory Committee Meeting
August 4, 2004

Jason Fletcher

Update on Coyote Springs 2

• The Confidentiality Agreement and Non-Binding Letter of Intent have been signed by both parties.

• The Asset Purchase and Sale Agreement is currently being negotiated. It is expected to be completed by the end of 2004.

• 100% of Coyote Springs 2 will been included in the 2005 Integrated Resource Plan.
Future Resource Requirements

- The need for new resources is determined by the balance (imbalance) of expected loads and resources.

- Energy and capacity values for expected loads and resources are tabulated for twenty years and included in Planning L&R’s.

- Expected deficit years are as follows...
  - Energy – 2010
  - Capacity – 2009 (?)

Confidence Interval Planning

Confidence Interval Planning

MEAN

TWO-TAIL TEST

10% 80% CI 10%
Confidence Interval Planning

![Diagram of a normal distribution with a confidence interval]

### Energy Loads & Resources (aMW)

#### Long-Term Energy Load and Resource Tabulation (aMW)

**Requirements**
- **System Load:** 1,008, 1,041, 1,063, 1,093, 1,126, 1,156, 1,187, 1,212, 1,237, 1,265
- **Contracts Out:** 13, 11, 11, 11, 11, 9, 9, 8, 8, 8
- **Confidence Interval:** 163, 160, 160, 160, 159, 155, 155, 155, 155, 155

**Total Requirements:** 1,215, 1,243, 1,265, 1,296, 1,327, 1,351, 1,382, 1,402, 1,428, 1,455

**Resources**
- **Hydro:** 532, 521, 521, 521, 505, 481, 481, 461, 460, 458
- **Contracts In:** 167, 184, 186, 186, 185, 79, 64, 64, 58
- **Base Load Thermals:** 241, 234, 234, 242, 232, 236, 240, 235, 234, 238
- **Gas Dispatch Units:** 295, 284, 294, 279, 294, 294, 294, 279, 294, 284
- **Peaking Units:** 139, 135, 138, 138, 137, 137, 137, 137, 137, 137

**Total Resources:** 1,374, 1,349, 1,364, 1,356, 1,355, 1,320, 1,229, 1,177, 1,189, 1,178

**Surplus (Deficit):** 159, 106, 90, 61, 28, 131, 153, 225, 238, 270

**Absent INT/RANT SHARE OF CS2 Generation Reduction:** 12, 12, 12, 12, 12, 12, 12, 12, 12, 12

**Net Position:** 27, 27, 34, 34, 40, 45, 50, 55, 60, 65

---

Appendix C

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Energy L&R - 2003 vs. 2005 IRP

Energy L&R - What’s Changed?

- Load Forecast 99 aMW in 2014
- Contracts
  - Haleywest - Nichol’s Pumping -6 aMW
  - Potlatch - Upriver -2 aMW
- 60-Year Hydro Calculation -12 aMW
- Grant Contract Estimates -16 aMW in 2014
- Northeast Emissions Limit -43 aMW
- Mirant Share of Coyote Springs 2 133 aMW
### Capacity Loads & Resources (MW)

#### Long-Term Peak Load and Resource Tabulation (MW)

**CONFIDENTIAL**

**Last Updated July 30, 2004**

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**A BSENT MIRANT SHARE OF CS2 Generation Reduction**

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**Planning Reserve Margin**

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Capacity L&R - 2003 vs. 2005 IRP
Average Load Forecast Comparison

Peak Load Forecast Comparison
Overview of Natural Gas Forecast

2005 Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 25, 2005

James Gall

Introduction

- Historical gas prices
- Proposed gas forecast
- Review of peer forecasts
- Why are gas prices important?
- Historical electric prices
- Regression analysis for electric and gas prices
- How gas prices affect prices/costs in Aurora
Recent Natural Gas Prices
Annual Average Prices (Nominal Dollars)

Recent Volatility of the Forward Market
2005 Annual Average Prices Traded at Malin in 2004

Statistics:
- Mean: $5.71
- Median: $5.75
- Mode: $4.90
- Min: $4.68
- Max: $7.50
- Standard Deviation: $0.65
- Variance: 0.42
- Skewness: 0.43
- Kurtosis: 3.94
Recent Volatility of the Forward Market
January 2005 Average Prices Traded at Malin in 2004

Statistics:
- Mean: $6.38
- Median: $6.32
- Mode: $5.76
- Min: $5.20
- Max: $9.23
- Standard Deviation: $0.81
- Variance: 0.65
- Skewness: 1.22
- Kurtosis: 4.48

Forecasted Natural Gas Prices
Annual Average Prices (Nominal Dollars)

Key Assumptions
- Avg. Growth Rates – Based on July Global Insights forecast
  - 2005-07: -7.1%
  - 2007-09: 1.9%
  - 2010-20: 3.2%
  - 2020-30: 3.8%

New Escalation Rates
Available in April
Forecasted Natural Gas Prices
Annual Average Prices (2005 Dollars)

How Does Our Forecast Compare with Others at Henry Hub?
How Does Our Forecast Compare with Others at Malin?

How Does Our Forecast Compare with Others at Sumas?
Why are Gas Prices Important?

- Electric Market prices
- Power costs
- Build/buy decisions
- Type of resource

Historical Mid-C Prices
Regression Analysis
Mid C Prices and Northwest Gas Markets (1996-2004)

- 86% correlation between Malin Gas Prices and Mid C Electric Prices
- 74% of the time a change to Malin Prices will have an effect on the Mid C Market

- 76% correlation between Sumas Gas Prices and Mid C Electric Prices
- 58% of the time a change to Sumas Prices will have an effect on the Mid C Market

2004 Daily NW Gas vs NW Electric Correlation by Month
Change to Mid C Electric Market with +/- $2 Gas Price Variations - Example Only

Regression Analysis
Aurora Fuel Price Sensitivity Results (2006-2008)

- 90% correlation between Malin Gas Prices and Northwest Electric Prices
- 81% of the time a change to Malin Prices will have an effect on the Northwest Area Market

- 97% correlation between Malin Gas Prices and Northern California Electric Prices
- 93% of the time a change to Malin Prices will have an effect on the Northern California Area Market
Change to 2006 Northwest Resource Stack with Gas Price Variations - Example Only

Impact:
$2.00 (~35\%)$ increase/decrease in gas prices changes Avista’s annual power supply costs by ~11\%.

Spring months favor high prices because of increased market sales.

Change to Avista’s Power Costs with Gas Price Variations - Example Only

Appendix C
Coal and Other Fuels

- These forecasts will be presented at the next TAC meeting

Gas Price Sensitivities - What Types Should We Do?

- Gas price variations will be tested during stochastic studies
  - Should we study gas variations deterministically
    - Percentage increase/decrease?
    - Value increase/decrease?
    - Scenario based?
    - Others?
Conclusions

- After 2009, inflation drives natural gas prices from today's forward prices
- The proposed gas forecast tends to be higher than some peer forecasts, and lower than others
- Historical gas prices are correlated with the Northwest electric market when hydro/coal are not on the margin
- Aurora results indicate a higher correlation between gas and electric prices for the future
- A change in gas prices can have a large effect on the electric price and Avista's power costs
Sustained Capacity and Planning Margin Concepts

2005 Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 25, 2005

Clint Kalich

Presentation Overview

- What Is Sustained Capacity 3
- Why Capacity Methods Matter 4
- Comparison to Peak Forecasting 5
- Various Views of Historical Temperatures 6-7
- Various Views of Historical Loads 8-14
- Sustained Peak Calculations & Positions 2005/07/10 15-18
- Avista vs. FERC SMD 19-20
- Key Capacity Planning Questions 21
- Planning Margin Methods Summary 22
- Capacity Plan for 2005 IRP 23
What Is Sustained Capacity

- A Tabulation of Loads and Resources Over a Period(s) Exceeding the Traditional 1-Hour Definition of Peak
- A Measure of Reliability
- An Essential Concept of Utility Planning
- A Recognition that Peak Loads Do Not Stress the System For Just One Hour
  - Especially important in energy-limited NW hydro system
- The “Grey Area” Between Energy and Capacity Planning
- An Event Which Occurs Infrequently
- A Concept Parallel to “Planning Margins”

Why Capacity Methods Matter

- Planning Method Defines Level of Capacity Required to Meet Load
- Larger Capacity Margins Cost Customers More
  - Capital and fixed costs are built into rates
    • 100 MW ~ $35-50MM, or ~$5-$8MM per year
  - Offsetting operating revenues are limited
    • capacity resources generally are inefficient relative to energy resources and therefore operate for very few hours
Comparison to Peak Forecasting

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Appendix C
Temperature History (1989-04)
Spokane International Airport

Peak Load History (1989-04)
Avista Total

95% below 1,166 aMW
99% below 1,270 aMW
Daily Versus Hourly Peaks

2004 Load

Daily Load

Hourly Load

95% of days below 1,206 aMW

99% of days below 1,350 aMW

2004 Daily Load Duration

Peak Day = 1,574 aMW  Peak Hour = 1,766 MW

95% of days below 1,206 aMW

99% of days below 1,350 aMW
2004 Peak Load and Temps
30 Highest Load Days

Peak Load History (1989-04)
Avista Total
Peak Load Shape Comparison

Summer Vs. Winter Peaks
### Sustained Peak Estimate—2005

**Sustained Peak Period L&R Calculation Comparison 2005**

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### Sustained Peak Estimate—2007

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## Sustained Peak Estimate—2010

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### Avista Net Positions

![Avista Net Positions Chart](chart)
### Avista vs. FERC SMD

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### SMD Net Positions – 15%

![Graph showing SMD Net Positions for 2005, 2007, and 2010](image)
Key Capacity Planning Questions

- Which Sustained Period is Adequate
- How Much Can/Should Avista Rely On The Market During Extreme Load Conditions
- What Capacity Should Be Given to Wind
- With Move To Gas-Fired Turbines, Will Gas Be Available To Meet Coincident Demands
- How Will Federal Projects Act During a Cold Snap
- What is the Significance of Transmission
- Is LOLP a Better Method & How Would We Do LOLP

Planning Margin Methods Summary

- FERC Standard Market Design
  - Carry between 12% & 18% of average peak day load
  - California has moved toward 15%
- Loss of Load Probability
- Sustained Capacity Evaluations
- Avista Method For Calculating Planning Margin
  - 110% of Peak demand forecast
  - ~ 30 MW for Colstrip fuel handling
  - ~ 60 MW for river freeze-ups
Capacity Plan for the 2005 IRP

• Rely On Historical Method Adopted in 1980s
  – ~250 MW over forecasted peak demand
  – Modestly better protection than FERC SMD

• Build Resources To Meet Energy AND Capacity Needs—Consider Purchases if Appropriate

• Encourage and Assist Regional Entities With Regional Capacity Planning Effort
  – e.g., NPCC, NWPP, BPA
2005 Load Forecast
Scenarios

Presented by
Randy Barcus, Avista Corp. Chief Economist
January 25, 2005

Forecast Discussion Points

• Economic Forecast
  – Employment
  – Population
  – Scenario Options
• Degree Days
  – Heating
  – Cooling
• Prices
  – Electric—Retail
  – Natural Gas—Retail and Wholesale
• Electric Base Case Results
Economic Forecast

• Global Insight, Inc. Contract
  – National Outlook
  – Spokane County, Washington
  – Kootenai County, Idaho

• Adjustments
  – Fairchild Air Force Base Assessment
  – Economic Development Initiatives

• Allocation Scenario

Regional Economy

• Risk to Growth *(Low Scenario)*
  – Military Base Realignment and Closure Process during 2005 indicates closure
  – Continued Meltdown in Manufacturing

• Opportunity for Growth *(High Scenario)*
  – Base expands with new missions
  – University District, Airport Freight Hub, Technology Parks
  – Convention Center Tourism Expansion
Results
High & Low Case
2005 Forecast

Avista High Customer Forecasts

F2005 WA-ID High Case Net-New Customer Forecast
Residential Schedule 1
Avista Low Customer Forecasts

F2005 WA-ID Low Case Net-New Customer Forecast
Residential Schedule 1

F2005 Avista Megawatthour Forecast
Excluding Potlatch Lewiston

Appendix C
F2005 High-Low MW Variation Forecast
Excluding Potlatch Lewiston

Average MW

High MW Variation

Low MW Variation


High MW Variation

Low MW Variation

Appendix C

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Future Resource Requirements Update

2005 Integrated Resource Plan
Third Technical Advisory Committee Meeting
January 25, 2005
John Lyons

Future Resource Requirements

- New resource requirements are determined by the net balance of expected loads and resources.

- Energy and capacity values for expected loads and resources are calculated twenty years into the future and are included in Planning L&R’s.

- Expected deficit years are as follows:
  - Energy – 2010
  - Capacity – 2009
# Energy Loads & Resources (aMW)

**LONG-TERM LOAD AND RESOURCES TABULATION—ENERGY (aMW)**

**CONFIDENTIAL**

**Last Updated: January 13, 2005**

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**Energy L&R - Changes Since August**

- Contracts ~ 3 aMW Increase
- Hydro ~ 7 aMW Increase
- Peaking Units ~ 7 aMW Increase
- Base Thermal ~ 5 aMW Decrease
- Gas Dispatch ~ 12 aMW Decrease

---

Appendix C
93
Capacity L&R - Annual Resource Capability

2005-2016
Annual Available Resource Capability (in MW)

IRP Requirements

Energy:
- 33 aMW in 2010
- 308 aMW in 2015
- 590 aMW in 2025

Capacity:
- 83 MW in 2010
- 497 MW in 2015
- 860 MW in 2025
Imputed Debt Discussion

TAC Meeting

January 25, 2005

Costs of Financing for Acquiring New Resources

- Buy versus build
  - Incremental cost of capital
  - Margin call costs
  - L/C costs
- Credit ratings impact
  - Balance sheet – capital structure
  - Interest coverages
  - Debt ratio
S&P Financial Ratio Benchmarks

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Financing Costs of Purchased Power Contracts

- S&P methodology (see attached articles)
  - Input portion of contracts as debt in our capital structure
    - Increases debt leverage
    - Increases interest expense and lowers coverage ratios
    - Assigns risk factor to each contract
Current Situation

- Avista
  - Limited to date due to minimal level of contracts
  - Current contracts at very low costs
  - Future contracts may have bigger impact
- Other Northwest utilities
  - Depends on level of PPA’s they have currently
  - Each company is different
Modeling Overview and Process

2005 Integrated Resource Plan
Technical Advisory Committee Meeting
February 17, 2005

James Gall

Topics of Discussion

- Aurora\textsubscript{XMP} Overview
- IRP Timeline
- IRP Modeling Process
Aurora Overview

What is AuroraXMP?

- Electric production cost model
- Avista’s use is to model the Western Interconnect, but could model any system
- Models operations on an hourly basis for up to 50 years
- Forecasts electric prices
- Determines when and what type of new resources to build
- Determines the value of a utilities portfolio of resources and contractual rights
What are Aurora Inputs

- AuroraXMP
- Resource Attributes
- Loads
- Fuel Prices
- Avista’s Portfolio
- Topology
- Hydro Conditions

What are Aurora Outputs

- AuroraXMP
- Market Prices/Resource Stacks
- Cost of Emissions
- Resource Dispatch/Cost
- Major Transmission Usage
- Cost of Avista’s Portfolio
- New Resources/Retired Resources
- Avista's Portfolio
I RP Timeline

Timeline

February
- Gather Assumptions
- Set up Aurora database
- Build Stochastic Models

March-April
- Complete Base Case
- Complete Long-Term Studies
- Complete Stochastic Analysis
- Outline of Report Released

May
- Complete Scenarios/Futures
- Evaluate Potential Avista Resources
- June
- Draft document

July-August
- Draft of Report Released
- Feedback
- Final Draft Released
IRP Modeling Process
“Base Case Example”

Base Case Process

Aurora LT Studies
- Uses Aurora XMP
- Market price forecast 2007-2026
- Identifies resources expansions given its cost assumptions

Stochastic Model
- Excel model that produces Monte Carlo data sets for Aurora
- Used for hydro, natural gas prices, loads, and wind
- Distributions will be discussed at the March TAC meeting

Aurora Stochastic Runs
- Uses Aurora LT resource build and Monte Carlo data sets derived from the stochastic model
- Aurora runs each a Monte Carlo simulation hourly for 20 years with different hydro, NG, load and wind data points entered each iteration
- Results in a distribution of market prices for each area and the cost to serve Avista’s load
- For example, the base case will take 33-41 days on one processor, on eight processors this should take 4-7 days to process for 200 iterations

Appendix C
Base Case Process (cont.)

Aurora Stochastic Runs
- Uses Aurora LT resource build and Monte Carlo data sets derived from the stochastic model
- Aurora runs each a Monte Carlo simulation hourly for 20 years with different hydro, NG, load and wind data points entered each iteration
- Results in a distribution of market prices for each area and the cost to serve Avista’s load
- For example the base case will take 33-41 days on one processor, on eight processors this should take 4-7 days to process for 200 iterations

Resource Optimization
- Excel linear program
- Optimizes Avista’s resource selection taking into account resource need
- Takes into account capital requirements and timing of resource deficits
- Evaluates costs on a NPV and risk basis
- Evaluates scenarios

Prices & Costs
Modeling Futures and Scenarios

2005 Integrated Resource Plan
Fourth Technical Advisory Committee Meeting
February 17th 2005

Clint Kalich

Presentation Overview

- IRP Definition Of A Future 3
- IRP Definition Of A Scenario 4
- Uses For Futures/Scenarios 5
- Some Basic Modeling Questions For Futures/Scenarios 6
- Proposed List of Scenarios 7
- Proposed List of Futures 8
- Additional Scenarios & Futures 9
Definition Of A Future

A **FUTURE** is modeled stochastically. In other words, Avista will model its options over 20 years with up to 200 Monte Carlo draws of varying hydro, load, gas, and wind conditions.

**Advantages:** ability to quantitatively assess risk in addition to the expected base value  
**Disadvantage:** long solution times (i.e., 8 CPUs for up to a week), and results of a specific change can be more difficult to comprehend

Definition Of A Scenario

A **SCENARIO** is not modeled stochastically. Instead we will use average forecasts of hydro, load, gas, and wind generation to simulate the impact of one assumption change.

**Advantages:** quick solution time (i.e., 1 CPU for 4 hours), simpler to understand impact(s) of assumption change  
**Disadvantage:** unable to quantitatively assess risk of market volatility
Uses For Futures/Scenarios

• Understand Potential Future Impacts And Their Magnitudes On:
  – Wholesale marketplace
  – Different resource options
  – Avista’s existing portfolio of load and resources
  – The Preferred Resource Strategy

Some Basic Modeling Questions For Futures And Scenarios

• Will Future/Scenario Be Significantly Different Enough From Base Case To Warrant The Work?
  – We have to manage our time to meet Sept. 1 filing date
• Will New Long-Term Runs Be Required?
  – Adds an extra day or more to work load
• Is The Scenario AVA-Centric Or Must We Model Entire Northwest And/Or WECC?
• Is Market Volatility Critical To What We Want To Measure (i.e., Do We Need Stochastic Output)?
• Is Future/Scenario Reasonably Likely To Occur?
• Can Future/Scenario Be Combined With Another?
Proposed List of Scenarios

- **High Gas** *
  - Increase prices 50% to ~$9/dth
- **Low Gas** *
  - Decrease prices 50% to approximately $3/dth
- **Emissions 2** *
  - $25/ton CO₂
- **Low Transmission** *
  - Reduce NPCC estimate by approx. 2/3 to $500/kW
- **High Wind Penetration**
  - 5,000 MW NW wind replaces other new resources

* Indicates new capacity expansion run will be required

- **Boom/Bust**
  - Change timing of new resources to “starve” and then “gorge” the marketplace
- **Loss of Large AVA Plant**
  - Noxon “lost” for 5 years
- **High AVA Load**
  - Double load growth to ~4%
- **Low AVA Load**
  - No load growth
- **WECC-Wide Renewable Portfolio Standard**
  - 25% renewables by end of study, replacing other new resources

Proposed List of Futures

- **Base Case**
  - All Base Case assumptions included
- **Volatile Gas Prices**
  - Double base case volatility (sigma) from 50% of mean to 100% of mean
  - Remaining Base Case assumptions unchanged
- **Emissions Case 1**
  - See Lyons presentation
  - Remaining Base Case assumptions unchanged
Additional Scenarios and Futures

• TAC Recommendations/Changes to Proposed Scenarios/Futures
Modeling Assumptions

2005 Integrated Resource Plan
Technical Advisory Committee Meeting
February 17, 2005

James Gall

Discussion Items

- Time frame
- Inflation
- What we are modeling
- Fuel forecasts
  - Gas revisited
  - Coal
  - Other
- New Resources
  - Resources under construction
  - Renewable Resources Portfolio (RPS)
- Hydro
- Wind
- Thermal resource commitment logic & variable O&M
- Thermal forced outage and maintenance
- Loads
Time Frame

- Hourly 20 year study
- Study time frame is between 2007-2026
- Why begin in 2007?
  - Report will not be completed until end of 2005
  - 2006 is within short-term planning cycle
  - Avista does not have a resource need until 2009/10

Inflation

- Inflation is used on Aurora’s cost inputs
- Based on Global Insights July 2004 Forecast
- Growth Rates:
  - 2005-2009: 1.6%
  - 2010-2014: 2.2%
  - 2015-2019: 2.7%
  - 2020-2027: 3.1%
- What is the value of $100 invested today if you earned the assumed inflation each year for the life of this study

$100
$110
$120
$130
$140
$150
$160
$170
$180
$190
$200
2005 2010 2015 2020 2025

$136
North American Electric Grid

Picture Courtesy of NERC

Aurora Topology
### Forecasted Natural Gas Prices

#### Forecasted Natural Gas Prices

**Annual Average Prices (Nominal Dollars)**

#### Key Assumptions
- 2005-07: -7.1%
- Avg. Growth Rates – Based on July Global Insights forecast
  - 2007-09: 1.9%
  - 2010-20: 3.2%
  - 2020-30: 3.6%

#### New Escalation Rates
- Available in April

- Malin, Sumas, Rockies, AECO prices are directly input into Aurora
- Topock & Opal use EPIS basin differentials versus Henry Hub
- Local transportation charges are applied to the basis to reach each area in Aurora ~11 to 32 cents

### Coal Forecast

Western Interconnect coal prices are based on Aurora database prices which are derived from FERC Form 423 and Electric Power Monthly:

- $2005 per MMBtu
  - Arizona: $1.32
  - Canada: $1.22
  - California: $2.02
  - Colorado: $1.01
  - Montana: $0.65
  - Nevada: $1.41
  - New Mexico: $1.62
  - Utah: $1.08
  - Washington/Oregon: $1.22
  - Wyoming: $0.88

Colstrip prices are mine mouth estimates and are lower than the estimate for Montana

EIA’s Annual Energy Outlook 2005 was used to as growth rates for all coal prices (real escalation)
New Resources Under Construction Today

- Resources added to the Aurora database
- New resources is based on the California Energy Commission list as of Dec 2004
- We included plants that are either under construction or likely to be build
- 12,150 MW of capacity
  - 10,000 MW of gas
  - 1,300 MW are renewable
  - 850 MW of coal

Renewable Portfolio Standards (RPS)

- Currently RPS is law in 5 Western States
  1. Arizona - by 2007 1.1% of energy is from renewables, 50% of which is solar
  2. California - by 2017, 20% of energy is from renewables
  3. Colorado - by 2015, 10% of energy is from renewables of which 4% is from solar
  4. Nevada - by 2013, 15% of energy is from renewables, .75% from Solar
  5. New Mexico - by 2011, 10% of energy is from renewables
- Northwest Conservation Council assumptions used for resource types and construction dates and amended for change in study period

Appendix C
### RPS Resources Added per Year

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<th>Area</th>
<th>Wind</th>
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<th>Biofuels</th>
<th>Solar</th>
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<tr>
<td>Nevada-South</td>
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<td>Avg 4.6 MW</td>
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<td>Avg 2.2 MW</td>
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<td>Nevada-North</td>
<td>Avg 44 MW</td>
<td>Avg 13.6 MW</td>
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<td>Avg 6.7 MW</td>
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* Total equals approximately 10.4 GW of Capacity by 2007

### Hydro

- 60 year average hydro conditions based on a recent head water study used for Aurora expansion studies
- For stochastic studies 1 of the 60 years will be used for each of the Monte Carlo iteration
- Energy is shaped to load using the Aurora hydro shaping logic
- All Pacific Northwest hydro operations are modeled as a single plant with a 44% capacity factor for the average water year
- Avista resources are modeled separately to track portfolio costs and use these average water year capacity factors
  - Clark Fork: 39.3%
  - Mid Columbia: 52.5%
  - Spokane River: 69.3%
Wind

- Concerns with previous studies that model wind
  - Wind is constant for each month, no hourly variation
  - Overstates the operational and financial value of these projects
- Our plan to model wind
  - Each area modeled has an hourly wind shape using a Monte Carlo distribution
  - Wind shapes for the Northwest use historical wind speeds to develop mean capacity factors
  - Wind shapes for outside the Northwest use mean capacity factors developed by SSG-WI (Seems Steering Group-Western Interconnect)
- We plan to model a high wind penetration scenario to determine impact on wholesale market place in the Northwest

Thermal Resource Commitment Logic and VOM

- Startup Fuel Amounts and Costs
  - CCCT: $25/MW per start & 3.6/mmBTU per MW
  - SCCT Aero: $75/MW per start & 0/mmBTU per MW
  - SCCT Frame: $25/MW per start 3.45/mmBTU per MW
  - Steam: TBD
  - Coal: Not Modeled
- Min/Up times
  - CCCT: 16 hours up & 8 hours down
  - SCCT Aero: 13 hours up & 6 hours down
  - SCCT Frame: 16 hours up & 8 hours down
  - Steam: 19 hours up & 10 hours down
  - Coal: 96 hours up & 24 hours down
- Variable O&M
  - Based on Aurora database except for Avista’s generators
**Thermal Resource Forced Outages and Maintenance**

- Modeled as derates

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Forced Outage Rate</th>
<th>Maintenance Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCCT</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>SCCT- Aero</td>
<td>7.5%</td>
<td>7.5%</td>
</tr>
<tr>
<td>SCCT- Frame</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Gas- Steam</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>Coal</td>
<td>10%</td>
<td>17.8% in shoulder months</td>
</tr>
<tr>
<td>Nuclear</td>
<td>10%</td>
<td>10-12% in shoulder months &amp; 0-5% in others</td>
</tr>
<tr>
<td>Solar</td>
<td>Assumed in hourly distribution</td>
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</tr>
<tr>
<td>Geothermal</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Wind</td>
<td>Assumed in hourly distribution</td>
<td>Assumed in hourly distribution</td>
</tr>
<tr>
<td>Other</td>
<td>5%</td>
<td>5%</td>
</tr>
</tbody>
</table>

**Regional Load and Growth**

- Area loads are based on the Aurora database (2003 levels displayed in blue)
- Annual load growth is based on WECC sub area forecasts between 2003 to 2013 (aMW displayed in red)
  - Load growth estimates are applied to all years
  - Total Western Interconnect loads grow at 2.25% each year
- Annual and monthly load shapes are consistent with the latest Aurora database

Appendix C

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Western Interconnect and NW Loads by Year

% of Western Interconnect

Appendix C

120
Presentation Overview

- Issues in the Treatment of Emissions: 3
- Environmental Issues: 4 - 5
- Policy Issues: 6 - 15
- Engineering Issues: 16
- Economic Issues: 17 - 19
- Planning Recommendations: 20 - 21
Issues in the Treatment of Emissions

There are four main issues to consider in resource planning concerning the treatment of emissions:

1. Environmental
2. Policy
3. Engineering
4. Economic

Environmental Issues

- Environmental issues in regards to emissions are a result of greenhouse gases or carcinogenic substances as a result of the burning of fossil fuels.

- Greenhouse gases include: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

- Greenhouse gases are often measured in global warming potentials (GWP) or converted into CO2 equivalents (CO2e)

- Greenhouse gases are not currently being regulated on a federal level for utilities, but there have and are several attempts to do so

- The US, EU, Canada, Russia, Japan, China and India collectively account for 75% of greenhouse gas emissions (Associated Press, 2005)
Magnitude of Environmental Issues

![Figure 1. Annual Change in U.S. Carbon Dioxide Emissions, 1990-2003](source: EIA)

Policy Issues

Emissions can best be described as an externality, so there is an inherent benefit for producers to allow emissions because markets will not take societal costs into account.

There are three approaches to regulating an externality:

1. Direct command-and-control regulation: nearly impossible to get right.
2. Quantitative limits: give each entity a quantity and allow them to trade, which develops a market.
3. Price or tax mechanisms: set prices, fees or taxes.

(Nordhaus, 2001)
Western State Laws Concerning Emissions

California
- 2002 vehicle CO2 emissions bill effective 1/1/06.
- Noxious oxide emissions limits on power plants to 5 parts per million Jan. 1, down from 8 ppm
- Governor is expected to propose new restrictions for sulfur oxide, noxious oxide and mercury emissions this year.
- CPUC is currently considering if utilities and energy generators can “add the cost of meeting any new state and/or federal CO2 emission regulations to existing contracts.” (Hamm, 2005)

Idaho
- No active legislation regarding greenhouse gases

Nevada
- No active legislation regarding greenhouse gases
Western State Laws Concerning Emissions

Oregon

- 1997 – first state level CO2 standards in the nation
- Requires utilities offset CO2 emissions exceeding 83% of state-of-the-art gas CCCT by paying into the Climate Trust of Oregon
- Compliance with the CO2 standard through 4 methods
  1. Efficiency improvements
  2. Cogeneration
  3. Offset projects – tree planting
  4. Pay fee to offset project fund

Western State Laws Concerning Emissions

Washington

- 2004 – New fossil-fueled thermal electric generating facilities of greater than 25 MW will have a CO2 mitigation plan including one or more of the following:
  (a) Pay a third party to provide mitigation
  (b) Purchase carbon credits
  (c) Cogeneration
**Federal Emissions Regulations**

**The Clean Air Act of 1990**

- Capped sulfur dioxide emissions at 8.9 million tons per year starting in 2008
- Capped nitrogen oxide emissions at 2 million tons per year starting in 2008.
- This will result in about 85% reduction in current allowances.

(Silverstein, 2005)

**McCain – Lieberman (Climate Stewardship Act) S. 139**

- Originally submitted in January 2003 and resubmitted in March 2004
- Goal - reduce heat trapping gas emissions in two phases through “a market-based system of tradable allowances”
- Utility would possess a permit for each ton of heat-trapping gases emitted
- Covers four groups who emit over 10,000 metric tons annually
- Essentially covers 90% of all CO2 emissions in 2 phases
  - Phase 1 2010 – 2015: reduce to 2000 levels
  - Phase 2 2016 – 2020: reduce to 1990 levels
Federal Emissions Regulations

Possible Effects of McCain – Lieberman

• MIT study concluded that the bill would impact consumers $20 per year
• Charles River Associates (CRA) study found a cost of $350 per year to 2010 and increasing to $530 per household by 2020. Also found that costs could be as high as $1,300 per year given different assumptions
• CRA estimates increased price of electricity to be 7 – 9%, and the cost of coal to increase 51 – 140% (Glassman, 2003)

Federal Emissions Regulations

Clear Skies Act of 2005

• Currently being debated as an amendment to the Clean Air Act of 1990
• Ignores carbon and sets limits on sulfur dioxide, nitrogen oxides and mercury
• Reduce the 3 pollutants by 70% by 2018
• Companies operating below their cap can sell credits
International Emissions Regulations

Kyoto Protocol - 1997

• Goal is to reduce CO2 emissions by 20% below 1990 levels internationally
• Accepted by 141 countries but restrictions only affect 35 industrial nations
• Became effective on February 16, 2005 when Russia ratified it in November
• Rejected by the US because of cost and lack of inclusion of emerging industrial economies like China and India
• Covers six different greenhouse gases, mainly CO2
• The EU started an emissions trading system within the last few months to trade credits from the quotas assigned to 12,000 industrial facilities

Engineering Issues

• The current state of emissions control technology is going to be in direct correlation with current and expected emissions regulations.
• Coal fired facilities have the greatest cost risk for emissions because of the high carbon content
• Higher initial costs but greater coal burning efficiencies
• Movement from sub-critical to supercritical units in steam-electric pulverized coal within 20 years
• Coal gasification – full commercialization as soon as 2011
• Coal gasification with sequestration – in development
• Can significantly reduce the other 3 regulated pollutants (SOx, NOx, and HG) – i.e. new technologies promise 95% mercury capture
Economic Issues - Treatment of Emissions

The planning issue of emissions regulation consists of three key ideas:

1. What is or will be regulated?
   - CO2 or CO2e?
   - Tighter Hg, SOx, and NOx standards?

2. When will it be regulated?
   - 2010 and 2016 for McCain-Lieberman?

3. What type of regulation will be enacted?
   - State, federal or combination?

Economic Issues - Other Utilities

PacifiCorp
• 2004 IRP base case was developed using the McCain-Lieberman legislation proposal as a basis.
• Used an inflation adjusted amount of $8/ton of CO2 in 2008 dollars.

PGE
• 2002 IRP - no CO2 tax in the base case and a $40 per ton CO2 tax scenario

Idaho Power
• 2004 IRP has a base case of $12.80/ton of CO2 by 2008.

Avista
• 2003 IRP - Modeled a scenario with then-current NPCC assumption—prices rising to $11/ton in 2023
**Economic Issues - Recommendations**

The National Commission on Energy Policy – December 2004

- 2010 - Implement a mandatory tradable permit system with an initial cost of $7 per metric ton of CO2 equivalent
- 2015 - Link to efforts by other developing and developed countries to reduce greenhouse gases

**Planning Recommendations - Scenarios**

- Base Case recognizes that there might be future regulation that will have an economic impact, but a cost is not being assigned at this time because of the uncertainty regarding the level and timing of the regulations. There presently is no law or regulation that requires CO2 mitigation.

- Scenario 1: assume that a mandatory market-based tradable credit system for greenhouse gases with initial costs set at $7 per metric ton of CO2e and prices escalated into the future. (National Commission on Energy Policy, 2004)

- Scenario 2: assume that a mandatory market-based tradable credit system for greenhouse gases with initial costs set at $40 per metric ton of CO2e and prices escalated into the future.
Planning Recommendations from TAC

Do you believe that the range of prices assumed in the 3 cases adequately reflects potential CO2 obligations?

• Base case with no assumed CO2e costs
• Scenario 1 with $7 per metric ton costs
• Scenario 2 with $40 per metric ton costs

Other recommendations?
Supply Side Options

2005 Integrated Resource Plan
Technical Advisory Committee Meeting
February 17, 2005

James Gall & John Lyons

Modeled Supply Side Options

- NG Combined Cycle (CCCT)
- NG Single Cycle (SCCT)
- Wind Turbine
- Coal (*Pulverized, IGCC, IGCC with seq.)*
- Solar
- Geothermal
- Biomass
- Alberta’s Tar Sands
- Nuclear
- Co-Gen
- DSM – Will be covered in *March*
NG Combined Cycle (CCCT) 2005 dollars

- Type: Natural gas-fired combined cycle F class gas turbine
- Size (MW): 540 baseload and 610 peak
- Heat Rate (Btu/kWh): 7,030
- Fuel source: Natural Gas
- First Available On-Line Date: 2007
- Capital Cost $/KW: $632
- Variable O&M: $3.02
- Fixed O&M kW/Year: $9.00
- Emissions (T/GWh): $S_O_2 = .002 \quad NO_X = .039 \quad CO_2 = 411-429$
- Location options: Any location
- Interconnection Costs: $16.80 kW/ year

NG Single Cycle (SCCT) 2005 dollars

- Type: Aero, such as the General Electric LM6000
- Size (MW): 47
- Heat Rate (Btu/kWh): 9,900
- Fuel source: Pipeline natural gas
- First Available On-Line Date: 2007
- Capital Cost $/KW: $672
- Variable O&M: $8.96/MWh
- Fixed O&M kW/Year: $9.00
- Emissions (T/GWh): $S_O_2 = 0.09 \quad NO_X = 0.009-0.01 \quad CO_2 = 582$
- Location options: Any location
- Interconnection Costs: $0 kW/Year
NG Single Cycle (SCCT) 2005 dollars

- Type: Generic NWCC Industrial Machine
- Size (MW): 47
- Heat Rate (Btu/kWh): 10,500
- Fuel source: Pipeline natural gas
- First Available On-Line Date: 2007
- Capital Cost $/KW: $420
- Variable O&M: $4.48/MWh
- Fixed O&M kW/Year: $6.72
- Emissions (T/GWh): \( \text{SO}_2 = 0.09 \quad \text{NO}_X = 0.009-0.01 \quad \text{CO}_2 = 582 \)
- Location options: Any location
- Interconnection Costs: $0 kW/Year

Wind Turbine 2005 dollars

- Type: Central station wind power project
- Size (MW): 100
- Heat Rate (Btu/kWh): N/A
- Fuel source: Wind
- First Available On-Line Date: 2008
- Capital Cost ($/KW): $1,131
- Variable O&M ($/MWh): $1.12 (no PTC) + $4 shaping for first 1000 MW and $8 for remaining wind
- Fixed O&M kW/Year: $19.60
- Emissions: N/A
- How many per study: 1,000 MW without new transmission
- Location options for NW Delivery: East of Cascades or Eastern Montana
- Interconnection Costs: $16.80 kW/Year
- Transmission cost from E. Montana to C. Washington: $1,781 kW (NPCC) $530/kW RMATS/Northwestern
Coal - Pulverized  2005 dollars

- Type: Pulverized coal-fired sub-critical steam-electric plant
- Size (MW): 400
- Heat Rate (Btu/kWh): 9,550
- Fuel source: Western low-sulfur subbituminous coal
- First Available On-Line Date: 2011
- Capital Cost ($/KW): $1,392
- Variable O&M ($/MWh): $1.96
- Fixed O&M kW/Year: $44.80
- Emissions (T/GWh): \( \text{SO}_2 = 0.575 \), \( \text{NO}_x = 0.336 \), \( \text{CO}_2 = 1012 \)
- Location options for NW delivery: Montana
- Interconnection Costs: Included in Capital Cost
- Transmission cost from E. Montana to C. Washington: $1,781 kW (NPCC) $530/kW RMATS/Northwestern

Coal - IGCC  2005 dollars

- Type: Coal-fired integrated gasification combined-cycle with H-Class Turbine
- Size (MW): 474 gross and 425 net
- Heat Rate (Btu/kWh): 7,915
- Fuel source: Western low-sulfur sub-bituminous coal
- First Available On-Line Date: 2011
- Capital Cost ($/KW): $1,568 (Range is 1,456 – 1,792)
- Variable O&M ($/MWh): $1.68
- Fixed O&M kW/Year: $50.51
- Emissions (T/GWh): \( \text{SO}_2 = \text{Neg.} \), \( \text{NO}_x = < 0.11 \), \( \text{CO}_2 = 791 \)
- Location options for NW delivery: Montana or Eastern Wash/Ore
- Interconnection Costs: Included in Capital Cost
- Transmission cost from E. Montana to C. Washington: $1,781 kW (NPCC) $530/kW RMATS/Northwestern
- Transmission cost 200 miles of 500kV: $352 kW
Coal - IGCC with Sequestration 2005 dollars

- Type: Coal-fired integrated gasification combined-cycle with 90% CO2 capture (Conceptual H-Class GT)
- Size (MW): 490 gross and 401 net
- Heat Rate (Btu/kWh): 9,290
- Fuel source: Western low-sulfur sub-bituminous coal
- First Available On-Line Date: 2013
- Capital Cost $/KW: $2,022 (Range $1,848 – $2,185)
- Variable O&M: $1.79
- Fixed O&M kW/Year: $59.36
- Emissions (T/GWh): SO2 = Neg.  NOX = < 0.11  CO2 = 81
- Location options for NW delivery : E. Montana
- Interconnection Costs: Included in Capital Cost
- Transmission cost from E. Montana to C. Washington: $1,781 kW (NPCC) $530/kW RMATS/Northwestern

Solar 2005 dollars

- Type: Generic NPCC Unit
- Size (MW): 2
- Heat Rate (Btu/kWh): 0
- Fuel source: Sun
- First Available On-Line Date: 2007
- Capital Cost ($/KW): $7,804
- Variable O&M ($/MWh): N/A
- Fixed O&M kW/Year: $36.00
- Emissions (T/GWh): N/A
- Location options for NW delivery : Desert Southwest (not viable for NW at this time)
- Interconnection Costs: $16.80 kW per year
### Geothermal 2005 dollars

- **Type:** Generic NWCC Unit
- **Size (MW):** 50
- **Heat Rate (Btu/kWh):** 9,300
- **Fuel source:** Geological Steam
- **When available:** 2007
- **Capital Cost ($/KW):** $2,050
- **Variable O&M ($/MWh):** Included in fixed O&M
- **Fixed O&M kW/Year:** $108
- **Emissions (T/GWh):** N/A
- **Location options for NW delivery:** California, Nevada, Idaho
- **Interconnection Costs:** $16.80/kW per year

### Biomass 2005 dollars

- **Type:** Wood Residue, Landfill, Manure
- **Size (MW):** 0.5 – 25
- **Heat Rate (Btu/kWh):** 11,100 – 14,500
- **Fuel source:** Wood, Refuse, Manure
- **When available:** 2007
- **Capital Cost ($/KW):** $1,523 – $3,472
- **Variable O&M ($/MWh):** $0 – $10.38
- **Fixed O&M kW/Year:** $75 - $140
- **Emissions (T/GWh):** $SO_2 = N/A$  $NO_x = N/A$  $CO_2 = 720 – 1,116$
- **Location options for NW delivery:** Any Location
- **Interconnection Costs:** $16.80 kW per year
### Co-Gen (2005 dollars)

- **Type:** Generic Unit
- **Size (MW):** 25
- **Heat Rate (Btu/kWh):** 5,500
- **Fuel source:** TBD
- **First Available On-Line Date:** 2007
- **Capital Cost ($/KW):** $1,120
- **Variable O&M ($/MWh):** $2.24
- **Fixed O&M kW/Year:** $29
- **Emissions (T/GWh):** TBD
- **Location options for NW delivery:** Any Location
- **Interconnection Costs:** $16.80 kW per year

### Alberta’s Tar Sands (2005 dollars)

- **Type:** Natural gas-fired 7F-class simple-cycle gas turbine plant with heat recovery steam generator
- **Size (MW):** 180 per unit
- **Heat Rate (Btu/kWh):** 5,800 (fuel charged to power)
- **Fuel source:** Pipeline natural gas
- **First Available On-Line Date:** 2011
- **Capital Cost $/KW:** $566
- **Variable O&M ($/MWh):** $3.11
- **Fixed O&M kW/Year:** Included in Variable Costs
- **Emissions (T/GWh):** SO₂ = Not Avail  NOₓ = Not Avail  CO₂ = 365
- **How many per study:** (3,000 MW total NW)
- **Location options for NW delivery:** Alberta
- **Interconnection Costs:** $10.43 kW per year
- **Transmission cost from Fort McMurray to Cellilio:** $1,166/ kW (1,089 miles of DC at $2 million per mile and $1.32 billion for inverter stations)
Nuclear 2005 dollars

- Type: Advanced Nuclear Power Plant
- Size (MW): 1,100
- Heat Rate (Btu/kWh): 9,600
- Fuel source: Natural Uranium
- First Available On-Line Date: 2020
- Capital Cost ($/KW): $1,624
- Variable O&M ($/MWh): $1.12
- Fixed O&M kW/Year: $44.80
- Emissions (T/GWh): N/A
- Location options for NW delivery: Anywhere
- Interconnection Costs: $16.80 kW per year

Regional Coal Resource Options

- New Coal units are assumed to be an option for all areas in the Western Interconnect, although the costs to build new transmission is part of the capital requirement to build a new coal plant.
- Cost to build transmission is based on the Rocky Mountain Area Transmission Study (RMATS)
  - S. California from Utah: $130/kW (500 MW max)
  - S. California from Wyoming: $2,510/kW
  - N. California from Wyoming: $2,675/kW
  - Utah from Wyoming: $265/kW
  - S. Nevada from Wyoming: $1,635/kW
  - S. Idaho from Jim Bridger, Wyoming: $412/kW
- Transmission cost to serve local loads in states has a cost of $.5-$1.8 million per mile depending on voltage and location
Regional Tar Sands Transmission Options

- Based on BPA and PG&E Estimates provided at recent NTAC meeting
- The study included 3,000 MW of capacity from Northern Alberta on one 500kV DC line, and does not include any AC support
- Study assumed $2,000,000 per mile to build transmission and requires 4 inverter stations at $440 million each and $30 million of communication equipment
- Inverter stations locations are:
  - Fort McMurray (NE Alberta)
  - Bell (Spokane area)
  - Celilo (East of The Dalles, OR)
  - Tesla (SE of San Francisco)
- 1,729 miles
- $5.248 billion to build ($1,749 /kW)

New Resource Summary

<table>
<thead>
<tr>
<th>Resource Type</th>
<th>Fuel Source</th>
<th>Size (MW)</th>
<th>Heat Rate</th>
<th>Year Available</th>
<th>Capital Cost</th>
<th>Variable O&amp;M costs</th>
<th>Fixed O&amp;M costs</th>
<th>Location</th>
<th>Transmitter Costs</th>
<th>NOx O&amp;M (T/yr)</th>
<th>SO2 O&amp;M (T/yr)</th>
<th>CO2 Emissions (T/yr)</th>
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<tbody>
<tr>
<td>CCCT</td>
<td>Gas</td>
<td>610</td>
<td>7.81</td>
<td>2007</td>
<td>625</td>
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<td>0.19</td>
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<td>&lt; -11</td>
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<td>1,131</td>
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<td>N/A</td>
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<td>Biomass</td>
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<td>7 - 25</td>
<td>1,000 - 3,000</td>
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DSM Integration Brief

2005 Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
March 23, 2005

Jon Powell

The “Evolution” of DSM Integration into the Avista IRP

• General Avista DSM environment
• Three general period
  – Up to 2000
  – The 2003 IRP
  – The 2005 IRP
Overall Objective

• Achieve a maximum level of cost-effective DSM acquisition
• Equitably treat DSM in the development of that least-cost portfolio
• Provide feedback for DSM operations regarding target markets, technologies etc

Unique DSM Characteristics

• Annual resource acquisition is small relative to overall system or major supply-side acquisitions
• Cumulative effect is much more significant
  – Avista acquisition 1978 to 2004 approximately 111 aMw (without degradation)
• Historically Avista DSM has been a non-dispatchable resource
• Until 2003 Avista DSM was tested against a single annual avoided cost
  – Negating any consideration of TOU targeting, load-shifting etc.
Significant Issues in Integrating DSM into the IRP

• Avista desires to have obtain information useful to DSM operations from the IRP process
  – Actionable results
  – Meaningful insights
  – Relevant analytical feedback

• Quality load research relevant to our service territory and customer base is difficult to obtain
  – Historically the NW has not had the need for the same quality of LR as California and similar areas
  – ELCAP, NPCC and our own M&E were hybridized to create usable load research for 2003 and 2005
  – Improving the quality of our load research is costly
Significant Issues in Integrating DSM into the IRP

- Avista DSM is generally an “all-comers” DSM tariff (per Schedule 90 and 190)
  - All non-residential energy-efficiency measures qualify for our programs
  - Residential programs are prescriptive only
- An IRP that accepts or rejects specific non-residential measures is unrealistic from a regulatory obligation and operational standpoint
- The results of the IRP does provide us with feedback that is valuable in targeting measures and long-term planning of DSM strategy

Our 2000 (and prior) Integration Methodology

- Integration by price signal
  - Supply-side resource options are stacked / demand forecasts are calculated \( \rightarrow \) an annual avoided cost
  - DSM options were evaluated and cost-effective resources were acquired
    - Cost-effective relative to the avoided cost price signal
Results

• Analytical results were easily incorporated into DSM operations and provided for a consistent metric for operational decisions
• No interaction between demand-side and supply-side resource options
  – DSM resources were small annual acquisitions
  – DSM was non-dispatchable
• The annual avoided cost precluded targeting of on-peak loads, load-shifting options etc.
  – Relatively little TOU differential during this time period

Changing Resource Environment

• Increasing complexity of market prices
  – Resulting in an increased need for a “richer” avoided cost price signal to meaningfully integrate DSM into the resource plan
• Potential for increasing cost-effectiveness of dispatchable DSM options
• Potential for improved economics of demand-response measures
• Controlled Voltage Regulation (CVR)
2003 DSM Integration Methodology

• Define meaningful “bundles” of DSM
  – Residential / non-residential
  – Lighting, HVAC etc
  – “dogs and cats” category of undifferentiated measures
  – Indexed to historical acquisition levels
  – Estimates of alternative acquisition at two incremental / two decremental incentive levels

• Develop 8760 hour x 20 year load profile
• Explicitly incorporate into AURORA as a resource
• “Stack” results to develop a DSM supply curve

What we learned from the 2003 IRP

• Two major issues
  – DSM supply curve was UCT based
    • Premised on differential incentive levels
    • Consistent with the utility cost nature of the IRP
    • A different perspective than “acquire all TRC cost-effective resource” approach
      – Operationally TRC cost-effective DSM resources were targeted and acquired
  – Supply curve was steep
    • Two potential causes
      – Time horizon of our estimates of market reaction to incremental / decremental incentives
      – Impact of regulatory restrictions on discriminatory pricing upon the supply curve

• Explicitly integrating DSM into AURORA isn’t easy
Our 2005 Methodology

- Utilizes price signal integration for energy DSM programs
  - Any future demand-response options would most likely be explicitly integrated into AURORA
- Applies a “richer” 8760 hour x 20 year avoided cost price signal
  - Improved ability to distinguish and appropriately value different load shapes
  - Ability to determine value of load shifting strategies
  - Enhanced information for targeting of DSM operations
  - Is demanding of our load-research capabilities

Our 2005 Methodology

- Utilizes a TRC pricing methodology
- Subdivides DSM into more coherent and actionable components
- Incorporates indexing to a realistic baseline to ensure realistic results
- Is consistent with the NPCC DSM supply curve work
Integration of DSM into the 2005 Electric IRP

- Develop 8760 hour loadshapes by NPCC+ categories
- Estimate non-energy benefits by NPCC+ category
- Calculate the TRC value of each NPCC+ category
- Calculate the TRC B/C ratio of each NPCC+ category
- Stack the NPCC+ categories to create a DSM TRC supply curve
- Release the TRC supply curve, refine program, reiterate as necessary
- Determine target markets and economic potential by NPCC+ category
- Determine customer cost by NPCC+ category
- Calculate the TRC acquisition cost of each NPCC+ category
- Review the TRC supply curve, refine program, reiterate as necessary

Anticipated Results

- Need to be caution in translating IRP results (or extrapolations from NPCC Power Plan) into DSM operations
  - Actual results of field operations are a superior indication of program viability
- Reasonable likelihood that IRP will result in a 10% to 25% increase in DSM goal
  - Up from 4.6 aMW (40 million annual kWh’s)
DSM Business Plan Status

- In a transition from a 2002-2005 DSM business plan based upon
  - Targeting no-cost / low-cost and lost opportunity measures
  - Tight cost controls
  - Pursuing ordered priorities of
    - Meet all regulatory and legal obligations
    - Field a cost-effective DSM portfolio
    - Return the tariff rider balance to zero in a timely manner

Actual and Projected Rider Balances
2006 DSM Business Plan

• Be good stewards of ratepayer DSM funds
  – Pursue all available TRC cost-effective DSM resources
    • Maximize that cost-effectiveness by maintaining appropriate cost-control practices
  – Establish and maintain a regulatory mechanism that provides an adequate level of funding in the long-term
  – Nurture utility and non-utility infrastructure sufficient to acquire cost-effective DSM resources in the long-term

Recent Actions

• Initiated a ramp-up of Idaho electric DSM in late 2002
  – As the balance of that tariff rider approached zero
  – Several pilot programs in field or under consideration
    • Prescriptive rooftop HVAC program
    • Small commercial lighting marketing
    • Prescriptive Industrial compressed air
    • Prescriptive refrigeration
    • Grocery store re-commissioning
    • Residential CFL’s

• Recent approval of an increase in Idaho electric incentives (effective March 15th)
In-Progress

- Evaluating the timing of revisions to our Washington DSM tariff
  - To mirror our revisions in Idaho tariff
  - Expand successful pilot programs to Washington
  - Continue to evaluate additional pilot programs

DSM Actions Beyond the IRP

- Development of a demand-side drought contingency plan
  - Development of programs to mitigate the adverse impact to our ratepayers

- Approach
  - Develop appropriate programs
    - Rapid launch
    - Rapid impact
  - Perform necessary degree of program planning to prepare for rapid launch
  - Identify trigger conditions for launch and withdrawal of programs
  - Continual evaluation of conditions through the summer

- Realistically … relatively little mitigation opportunity
Questions
Stochastic Modeling

2005 Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
March 23rd 2005

Clint Kalich

Presentation Overview

<table>
<thead>
<tr>
<th>Topic</th>
<th>Slide #</th>
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<tbody>
<tr>
<td>Why Model Risk?</td>
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<tr>
<td>Risk Modeled In AURORA</td>
<td>4</td>
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<tr>
<td>Limits of AURORA Risk Module</td>
<td>5</td>
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<tr>
<td>Risk Modeling For 2005 IRP</td>
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<tr>
<td>Hydro Variability</td>
<td>7-12</td>
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<td>Natural Gas Variability</td>
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<td>Load Variability</td>
<td>19-22</td>
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<td>Wind Variability</td>
<td>23-27</td>
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</table>
**Why Model Risk?**

- Learn Of Potential Variation Associated With Each Future
- Measure Value Of Resources With Greater Degrees Of Optionality
- Quantify Relationship Between Least Cost And Least Risk
- Ensures Best Computer Hardware!!!

**Risk Modeled In AURORA**

- Modeling of Hydro, Fuel Prices, Forced Outage and Load
- Values Can Vary By Load Area
- Modeled Annually, Monthly, Daily and Hourly
- Correlations Between Variables Allowed
  - XMP allows for negative correlations
- Monte Carlo Iterations, & Latin Hypercube
Limits of AURORA Risk Module

- Cannot Model Custom Timeframes
  - e.g., weekly hydro with daily load

- Solution: Develop Risk Modules (i.e., Big Spreadsheets) Outside of AURORA
  - 300 Iterations were developed
  - Upload iterations into AURORA database
  - Run each iteration through AURORA

Risk Modeling for 2005 IRP

- Key Variables Considered
  - Load, hydro, natural gas prices, wind

- Entirely Outside Aurora
  - Through separate database tables linked into program

- IRP runs will use between 200-300 iterations
  - Output stored in SQL or Oracle database

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Hydro Variability

- Hydro Data
  - Streamflows Are Normally Distributed
  - Generation Is Not Normally Distributed
  - NWPP 60-yr study encompasses ~75% of WECC hydro
    - OR, WA, Idaho, BC, MT
    - OWI (OR, WA, No. Id.) ~50% of WECC hydro
- Random Draws Of Historical Years From Study
  - i.e., where calendar year 1965 is randomly drawn, hydro conditions from 1965 are used for all NW projects
- Other WECC Hydro Constant @ EPIS Values

Hydro Distribution - OWI

Average = 13.7 aGW

1,191 obs.
Hydro Distribution - OWI
First Quarter

Average = 15.4 aGW

Hydro Distribution - OWI
Second Quarter

Average = 16.8 aGW

Appendix C
157
**Hydro Distribution - OWI**

**Third Quarter**

- Frequency distribution of average gigawatts.
- 1,786 observations.
- Average = 10.8 aGW

**Fourth Quarter**

- Frequency distribution of average gigawatts.
- 3,690 observations.
- Average = 11.8 aGW
Natural Gas Variability

- St. Dev. Of Prices Set At 50% Of Mean
  - Approximately $2.50/dth on $5.00/dth gas (2007$)
  - 81.4% serial correlation month to month
    - Based on 1995-2004 average @ Malin
- Assumed Lognormal Price Distribution
  - Historical data does not appear lognormal
  - Standard industry assumption is lognormal
Natural Gas Price Distribution

January

Average Price = $5.360

Natural Gas Price Distribution

April

Average Price = $5.269
Natural Gas Price Distribution

July

Average Price = $5.121

Natural Gas Price Distribution

October

Average Price = $5.165

Appendix C
Load Variability

- Avista Wants to Accurately Model WECC
- Analyzed 1998-1999 Hourly Loads from EIA to Generate Statistics (3 million data points!)
  - Same as 2003 IRP
  - ignored volatile 2000-01 period
- Modeled Variation Both Weekly and Daily
  - Avista is assumed presently to have OWI statistics

Load Variability, Continued

- Each WECC Area Analyzed Separately
  - 14 Areas, plus Avista
  - Calculated means and standard deviations
    - monthly variation in OWI varies between 2.2% and 4.0%
  - Correlated each area to OWI
    - Ensured relationships were statistically significant
    - looked at each weekday separately to eliminate weekly trends
    - averaged weekday results to obtain final values
### Load Correlation Values to OWI (Average of Weekdays)

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<th></th>
<th>January</th>
<th>February</th>
<th>March</th>
<th>April</th>
<th>May</th>
<th>June</th>
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<th>September</th>
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<td>Not Sig</td>
<td>Not Sig</td>
<td>Mix</td>
<td>Not Sig</td>
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<td>0.463</td>
<td>Not Sig</td>
<td>0.622</td>
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* "Not Sig" implies that relationship was not statistically significant, "Mix" explains that the relationship was not a consistent across time.

### OWI Load Variation - 20 Iterations

**January 2007**

![OWI Load Variation Chart]

- Min - 80% CI Lo - Mean - 80% CI Hi - Max

**Day of Month**

**Average Gigawatts**
Wind Variability

• Previous Attempts At Modeling Wind Have Simplified Wind Problem
  – Assume monthly average generation is constant every hour
  – Simple mean & standard deviation without correlation
• Obtaining Good Wind Data is Difficult
• Avista Is Using OSU/BPA Database Of Hourly Wind Data As Source For 2005 IRP

Stateline Data
1000 Continuous Hours

Statistics
Mean 49.7 aMW
StDev% 130%
N-1Corr 95%
Simple Mean/StDev
1000 Continuous Hours

Statistics
Mean 70.9 aMW
StDev% 78%
N-1Corr 1%

OSU Kennewick, WA
1000 Continuous Hours

Statistics
Mean 89.9 aMW
StDev% 91%
N-1Corr 92%
5-Site NW Average (OSU Database)
1000 Continuous Hours

Statistics
Mean 113.6 aMW
StDev% 54%
N-1Corr 96%
Avista’s 230 kV Upgrade Project
March 23, 2005
Technical Advisory Committee
by Randy Cloward

The West of Hatwai Transmission Path

- Flowgate separating Eastern Washington and the load centers of the I-5 corridor
- Consisting of BPA and Avista 115-500 kV Transmission Lines
- 2002 Rating
  - 2800 MW
- 2002 Peak Demand
  - 3500-4000 MW
2001 - West of Hatwai Emerges as a Transmission Constraint

- During the Energy Crisis of 2001, Aluminum smelter loads are shutdown in Spokane and Western Montana
- The combined load loss and new generation adds nearly 1000 MW of flow on the West of Hatwai Transfer path
- Avista and BPA collaborate on a regional solution.
- BPA announces plans to construct a 500 kV transmission line between Bell (Spokane) and Grand Coulee
- Avista announces plans to reinforce its 230 kV delivery system before the end of 2006

Avista 230 kV Upgrade Project

- 2000 MVA Beacon-Rathdrum Line Energized April 2004 - $19M
- 500 MVA Boulder Substation and Transmission Lines June-December 2005 - $16M
- 250 MVA Dry Creek Sub Energized December 2004 - $12M
- Fiber Optic “Ring” System Per WECC Standard Nov 2006 - $7M
- Total Investment 2003-2006 $106M
Beacon-Rathdrum Facts

Rathdrum 230 kV Substation Reconstruction ($3M)

*Becomes Avista’s 1st Fully Redundant Substation*

Capacity Increase from 300 to 2000 MVA ($16M)

*Avista’s highest capacity transmission facility
“Mechanically” strongest transmission line ever
constructed by Avista Utilities

- 25.2 miles, 188 towers, 714 tons of conductor
- 2600 tons of steel, 12 months to construct*
Boulder Facts

Boulder 500 MVA Substation - New Construction ($8M)
1st Energization June 2005. December Completion
Three 230 kV and Six 115 kV Transmission Lines
500 yards of concrete, 10,000 control wire connections
Additional transformation to the Spokane Valley
Liberty Lake – 2nd fastest growing city in the State of Washington

230 and 115 kV Transmission Integration ($8M)
135 steel towers, 285,000 feet of conductor, 8 months of contract labor construction
**Dry Creek Facts**

Dry Creek 250 MVA Substation - New Construction ($8M)

- Capacitor Bank installation – 200 MVAR
- Forms 35-mile “ring” of 230 kV lines around the Lewiston-Clarkston Valley
- 135 Avista employees, 100 tons of steel, 1000 cubic yards of concrete, 10,000 control wire connections

230 kV Line Capacities Increase from 400 to 800 MVA ($2M)

Conversion of Lolo to Fully Redundant Substation ($2M)
Benewah-Shawnee Facts

Benewah 250 MVA Substation - Reconstruction ($8M)
Add 200 MVAR Capacitor Bank

1000 MVA Benewah-Shawnee Transmission Line ($36M)
60-Miles, 360 steel towers, 4000 tons of steel,
75% Reconstruction, 25% New Construction

Significant Challenges
Steel Escalation June 03 ($300/ton) – April 04 ($600/ton)
Chinese increase consumption from 100 to 300 M tons

Avista Response to Steel Escalation
Value Engineering Reduces Estimated Cost by $4M
Alliance Agreement with Steel Pole Supplier enables
dollar cost averaging of steel over project life (2005-07)
Communication Plan

Avista Constructing Two Fiber Optic Loops
   L/C Valley, 35 Miles ($1M)
   North of Benewah, 100 Miles of Fiber plus
      Microwave ($4M)
   Benewah-Shawnee Fiber and Substation Comm. ($2M)

“Redundant communication pathways required for the operation of stability limited 230 kV transmission lines” (WECC)
Summary

Reinforcement from Spokane, WA to Coeur d’ Alene, ID
- Beacon-Rathdrum (increase east-west capacity)
- Boulder Substation (load demand in Spokane Valley)
Reinforcement in Lewiston-Clarkston Valley
- Dry Creek Substation (“ring” of 230 kV lines)
- Hatwai transmission lines (increase capacity)
230 kV Connection through the Palouse
- Benewah-Shawnee (backup supply to Shawnee Substation
  – mitigates overloads on parallel path lines)
Fiber Optic Communication (automatic control of 230 kV
lines and Clark Fork hydro generation)
Preliminary Long-term Electric Forecast & Capacity Expansion Results

2005 Integrated Resource Plan
Technical Advisory Committee Meeting
March 23, 2005

James Gall

Discussion Items

1) Resource Assumptions
   A. Generation Assumptions
   B. Discount Rates
   C. Transmission Assumptions
   D. Resource Restrictions

2) Electric Market Forecasts
   A. Mid Columbia Prices
   B. Marginal Heat Rate for the Northwest
   C. Hourly Price Curve
   D. Other Hub’s Electric Price Forecasts

3) Capacity Expansion Results
   A. What Is a Capacity Expansion
   B. Northwest L&R
   C. Northwest New Resources
   D. Western Interconnect New Resources
### Resource Assumptions

### New Resource Summary

**Yellow Indicates Change From Last TAC Meeting**

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<thead>
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<th>Resource Type</th>
<th>Fuel Source</th>
<th>Size (MW)</th>
<th>Heat Rate</th>
<th>Year Available</th>
<th>Capital Cost</th>
<th>Variable O&amp;M $/MWh</th>
<th>Fixed O&amp;M $/MWh</th>
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<td>1,523 – 3,472</td>
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<td>25</td>
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<td>1,120</td>
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Discount Rates Used for Capacity Expansion

- Discount rates are required to calculate the fixed costs associated with each new resource (Model requires $/MW/Week for each resource) and to calculate the present value of each resource
- Discount Rates are based on NPCC 5th Power Plan

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<th>IPP</th>
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<th>Percent Ownership</th>
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<th>CCCT</th>
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<th>Renewables</th>
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<td>25%</td>
<td>25%</td>
<td>50%</td>
<td>8.9%</td>
<td></td>
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<td>20%</td>
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<td>60%</td>
<td>9.2%</td>
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<td>40%</td>
<td>40%</td>
<td>20%</td>
<td>7.8%</td>
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<td>15%</td>
<td>15%</td>
<td>70%</td>
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Transmission Costs

- AURORA\textsuperscript{XMP} does not have transmission expansion logic, nor does it account for transmission within a region
- To overcome simplistic topology within the model, transmission cost adders are included for resources that normally require new transmission to be built (Modeled in Capacity Expansion studies)
- If the model selects a plant outside its region, it is moved to that area for hourly price forecast studies

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<th>Resource Type</th>
<th>To</th>
<th>From</th>
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<th>Capacity (MW)</th>
<th>Miles</th>
<th>Cost per MWh ($/MWh)</th>
<th>Substation Costs ($/MWh)</th>
<th>Total Capital Cost (MWh)</th>
<th>Dollars per KW ($/KW/MWh)</th>
<th>Fixed O&amp;M ($/MWh)</th>
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<td>125</td>
<td>250</td>
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<td>125</td>
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<tr>
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<td>2.00</td>
<td>35</td>
<td>125</td>
<td>250</td>
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<td>8.90</td>
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<td>125</td>
<td>250</td>
<td>8.90</td>
<td>$4</td>
<td></td>
</tr>
</tbody>
</table>
Northwest Resource Options/ Limitations

- **Gas:**
  - CCCT: No Limitations
  - SCCT: No Limitations

- **Coal:**
  - Local Pulverized: No more than 2 plants after 2010
  - Imported Montana Pulverized: No Limitations
  - Local IGCC: No more than 5 plants after 2011 (2 max per year)
  - Imported Montana IGCC: No Limitations
  - Imported Montana IGCC w/ Seq: Limit 2 plants

- **Wind:**
  - Local: No more than 1,000MW of capacity without building new transmission
  - Imported: No limitations

- **Other:**
  - Geothermal: Limit 100 MW (2 plants)
  - Solar: Not available
  - Nuclear: Not available
  - Co-Gen: Limit 50 MW (2 plants)
  - Manure: Limit 2 MW (2 plants)
  - Landfill Gas: Limit 2 MW (2 plants)
  - Wood: Limit 50 MW (2 plants)
  - Tar Sands: Limit of 1,500MW after 2011

Western Interconnect Options/ Limitations

- **Gas:**
  - CCCT: No Limitations
  - SCCT: No Limitations

- **Coal:**
  - Local Pulverized: No Limitations (Not allowed in California)
  - Imported Wyoming Pulverized: No Limitations with new transmission build (S. Cal allowed to build 1 plant in Utah by upgrading the IPP DC Interconnect)
  - Local IGCC: No Limitations (Not allowed in California)
  - Imported Wyoming IGCC: No Limitations with new transmission build
  - Local IGCC w/ Seq: No Limitations (Not allowed in California)
  - Imported Wyoming IGCC w/ Seq: No Limitations with new transmission build

- **Wind:**
  - Local: Requires transmission to be built

- **Other:**
  - Geothermal: 100 MW per area (2 plants)
  - Solar: 10 MW per area (5 plants)
  - Nuclear: 1,100 MW in Arizona
  - Co-Gen: Not available
  - Manure: Not available
  - Landfill Gas: Not available
  - Wood: Not available
  - Tar Sands: California & S. Nevada with a limit of 2,500 MW after 2011

Appendix C
178
“PRELIMINARY”

Electric Market Forecasts

Mid Columbia Electric Prices (Qr. Avg.)

$/MWh

Year

Marginal Heat Rate

Hourly Price Curves
Annual Electric Forecasts

“PRELIMINARY”
Capacity Expansion Results
What is Capacity Expansion?

Definition:
- Simulates the addition of new resources based on a set of resource attributes, capital and variable costs
- Seeks to find the least cost set of resources

What does the AURORA<sup>XMP</sup> Expansion Logic Do?
- Creates a matrix of new resources and calculates its value compared to the market (~17,000 resources for studies shown today) on a present value basis
- Iterates until the optimal mix of generation is found (including resource type, timing, and location)
- Retires plants if plants that are no longer economic (retirement was not an option for the studies shown today)

Renewable Portfolio Standards (RPS):
- AURORA<sup>XMP</sup> does not currently add resources to meet RPS requirements, for this IRP, RPS requirements were manually added based on the NPCC 5th Power Plan

Northwest Loads & Resources

- Annual Resource Availability for the Northwest
- Does not include Imports/Exports

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<th>Resources</th>
<th>Balance</th>
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Estimated Average Annual Net Position (aMW)
### Northwest New Resources Selection

#### Annual Resource Selection (MW Capacity)

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<th>IGCC Coal</th>
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### Western Interconnect Resource Selection

#### Resource Origin

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<td>69%</td>
<td>1%</td>
<td>13%</td>
<td>15%</td>
<td>0%</td>
<td>1%</td>
<td>100%</td>
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New Resources for the Western Interconnect
Includes RPS

Total New Resource Capacity (2007-2026)
(Shown in Gigawatts)
Modeling Futures and Scenarios

2005 Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
March 23, 2005

John Lyons

Presentation Overview

- Definition Of A Future 3
- Definition Of A Scenario 4
- Uses For Futures/Scenarios 5
- Revised List of Scenarios 6 - 7
- List of Futures 8
**Definition Of A Future**

A **FUTURE** is modeled stochastically. Avista will model its options over 20 years with up to 300 Monte Carlo draws of varying hydro, load, gas, and wind conditions.

**Advantages:** ability to quantitatively assess risk in addition to the expected base value  
**Disadvantage:** long solution times (8 CPUs for up to a week), and results of a specific change can be more difficult to comprehend

---

**Definition Of A Scenario**

A **SCENARIO** is not modeled stochastically. Instead we will use average forecasts of hydro, load, gas, and wind generation to simulate the impact of a major change in a single assumption.

**Advantages:** faster solution time (1 CPU for 5 hours), easier to understand impacts of the change  
**Disadvantage:** unable to quantitatively assess risk of market volatility
**Uses For Futures/Scenarios**

- Understand Potential Future Impacts And Their Magnitudes On:
  - Wholesale marketplace
  - Different resource options
  - Avista’s existing portfolio of loads & resources
  - The Preferred Resource Strategy

**Revised List of Scenarios**

- **High Gas**: Increase prices 50% to ~$9/dth
- **Low Gas**: Decrease prices 50% to ~$3/dth
- **Emissions 2**: $25/ton CO₂
- **Low Transmission**: Reduce transmission capital costs by 33%
- **High Wind Penetration**: 5,000 MW NW wind replaces other new resources
- **Energy Market Bubbles**: Electricity market mimics real estate building cycles
- **Loss of Large AVA Plant**: Noxon “lost” for 5 years
- **High AVA Load**: Double load growth to ~4%
- **Low AVA Load**: No load growth
- **WECC-Wide Renewable Portfolio Standard**: 25% renewables by end of study, replacing other new resources

* Indicates new capacity expansion run will be required
Revised List of Scenarios

- Long Haul Coal
  - Site a new coal plant within our service territory and rail in coal
- Fundamental Hydro Shift *
  - Recent drought becomes new average (90% of mean value)
- Green Growth Initiative
  - All new Avista resources are renewable
- Double Avista DSM
  - Double the amount of DSM acquisition

* Indicates new capacity expansion run will be required

Loss of Spokane River Projects
- Current negotiations for relicensing fail and all projects on Spokane River are lost

List of Futures

- **Base Case**
  - All Base Case assumptions included
- **Volatile Gas Prices**
  - Double base case volatility (sigma) from 50% of mean to 100% of mean
  - Remaining Base Case assumptions unchanged
- **Emissions Case**
  - Based on the McCain Lieberman Bill
  - Remaining Base Case assumptions unchanged
The format of the 2003 IRP will be used as a template for the final draft of the 2005 IRP

Will be published in two parts: main report & technical appendix

Please let us know if there were any portions of the 2003 IRP that you want to see again, do not want to see again, or thought should have been included in the 2003 IRP.
2005 Draft IRP Outline

Section 1: Introduction & Summary
• Outline of the IRP process

Section 2: Loads & Resources
• Generating assets and long term contracts
• Load forecasts, energy & capacity positions
• Planning reserves and sustained capacity
• Wind capacity and forecasting

Section 3: Demand-Side Management
• Past and future activities
• DSM in AURORA

Section 4: New Resource Alternatives
• Approach, resources considered and resources not evaluated

Section 5: Modeling
• Modeling process
• Assumptions and Inputs
• Analysis of futures and scenarios

Section 6: Risk Analysis
• Stochastic risk analysis
• Risk and benefit analysis of resource options
Section 7: Results

• Market prices and volatility for the Western Interconnect
• Preferred resource strategy
• Comparisons of strategies and scenarios
• Efficient frontiers

Section 8: Action Plans & Avoided Costs

Questions?

• Any sections that you would like to see included or excluded from the IRP?
Gas & Inflation Forecast Update

2005 Integrated Resource Plan
Sixth Technical Advisory Committee Meeting
May 18, 2005

James Gall

Natural Gas Price & Inflation Assumptions and Caveats

  - March 2005 30-year forecast was received on April 4, 2005
  - Avista Corp. subscription with Global Insight parameters for usage of Global Insight’s data
    - Avista may use Global Insight information with attribution, and other parties may cite Avista information with attribution to Global Insight, although other parties may not privately use Avista or Global Insight information
    - Avista has permission to use Global Insight’s information to develop Avista-specific projections for Company use
  - Avista uses Global Insight inflation forecasts directly
    - Avista is responsible for interpreting how Avista perceives Global Insight’s inflation forecasts have changed between 2004 and 2005
    - The 2005 inflation forecast compared with the 2004 inflation forecast is slightly higher in the near term, and substantially lower in the long term (see slide), averaging 2.3% compared to the previous 3.0%
  - Avista uses Global Insight natural gas producer price index forecast escalation to create Avista’s own forecast of natural gas prices
Natural Gas Price & Inflation Assumptions and Caveats (Cont.)

- Avista’s 2005 long term natural gas price forecast has been updated in April 2005
  - Avista has used NYMEX forward prices from April 6, 2005 to prepare natural gas prices for 2005 through 2010, inclusive.
  - After 2010, Avista has applied natural gas price escalation rates to the 2010 forward price to obtain forecasts for natural gas prices for the period 2011 through 2035, inclusive.
  - This estimate replaces a forecast prepared in July 2004, which used July 1, 2004 forward prices for 2004 through 2007, and applied Global Insight’s March 2005 natural gas price escalation forecast.
  - The NYMEX forward prices for April 6, 2005 are considerably higher than the July 1, 2004 forwards.
  - Global Insight’s forecast for natural gas price escalation is higher in the near term, and lower in the long term, but after adjusting for inflation, there is little change after 2010 in real prices.
Henry Hub Gas Forecasts

Nominal Dollars

Slide 4 indicated that real prices between 2011-2026 were the same, although the 2005 inflation forecast the nominal gas prices begin to separate in 2012.

Basin differentials remain the same as presented at the February 2005 TAC Meeting.

Annual Inflation Rates

The 2005 inflation forecast is near the same for the near term, although long term inflation is not as high (~3.5% to ~2.5%).
Value of $100 as it Grows with Inflation

Nominal Dollars

The 22 year annual average inflation estimate is lower, 3.0% to 2.3%.

Take-Aways

- April 2005 forecast is more in-line with current forward gas markets
- Medium-term gas prices are higher than previous forecast
- Long-term gas prices are lower nominally, but the same in real dollars
- Long-term inflation is lower
Base Case Results - Electric Price Forecast

2005 Integrated Resource Plan
Sixth Technical Advisory Committee Meeting
May 18, 2005

James Gall

Topics of Interest

**Deterministic Modeling**
- Western Interconnect Capacity Expansion Results
- Electric Market Prices

**Stochastic Modeling**
- Sample Size
- Base Case Results
- Volatile Gas Results
- Net Power Costs
- Resource Values
Capacity Expansion Results

What is Capacity Expansion?

Definition:
- Simulates the addition of new resources based on a set of resource attributes, capital and variable costs
- Seeks to find the least cost set of resources

What does the AURORA\textsuperscript{XM} Expansion Logic Do?
- Creates a matrix of new resources and calculates its value compared to the market (~17,000 resources for studies shown today) on a present value basis
- Iterates until the optimal mix of generation is found (including resource type, timing, and location)
- Retires plants if they are no longer economic (retirement was not an option for the studies shown today)

Renewable Portfolio Standards (RPS):
- AURORA\textsuperscript{XM} does not currently add resources to meet RPS requirements, for this IRP, RPS requirements were manually added based on NPCC 5th Power Plan approach

Why is this all necessary?
- Without a forecasted set of new resource the market price forecast will be useless!
Western Interconnect New Resource Mix

- CCCT: 65%
- Fixed RPS: 19%
- Coal: 12%
- Wind: 6%
- SCCT: 6%
- Other: 1%

114 GW of Installed Capacity

Total New Resources (2007-2026)
(Shown in GW Capacity, excludes RPS Resources)
Cumulative New Resources for the Western Interconnect

MW of Capacity

RPS- Fixed
Wind
SCCT
Other
Coal
CCCT

NW Surplus Energy & New Resource Selection

Existing Resources
New Resources

800 MW- Coal
1,220 MW- CCCT
500 MW- Wind
1,000 MW- Wind

MW
Electric Price Forecasts

Mid Columbia Electric Prices
Shown in Nominal Dollars per MWh

Appendix C
How Do We Compare to Our Peers at Mid C?
Shown in Nominal Dollars per MWh

Regional Electric Market Prices
Shown in Nominal Annual Average Dollars per MWh

Appendix C
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Stochastic Results

Choosing a Sample Size

- What is the right sample size to use?
  - 50, 100, 200, or 300
- At the March TAC meeting we indicated that a sample size of 300 was our target
- Analysis:
  - 300 draws of Gas Prices, Hydro Conditions, Wind Shapes, and Load Forecasts were simulated in AURORA to create 300 market price forecasts
  - The mean & standard deviations of certain resource values were compared to each other using a random draw of 10, 25, 50, 100, 150, 200, and 300 iterations
  - The results of 200 & 300 iterations were nearly identical
Comparison of Resource Values

Monthly Price Differences

Market Price Sample Size Analysis

Monthly Market Price Standard Deviation Absolute Difference from 300 Iterations

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<th>SP15</th>
<th>AZ</th>
<th>UT</th>
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Monthly Market Price Mean Absolute Difference from 300 Iterations

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<th>OWI</th>
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<td>2.0%</td>
<td>1.7%</td>
<td>2.0%</td>
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<tr>
<td>75</td>
<td>1.6%</td>
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<td>0.6%</td>
<td>0.5%</td>
<td>0.6%</td>
<td>0.6%</td>
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Base Case Results

Deterministic vs. Stochastic Mid C Prices
Shown in Nominal Dollars per MWh

Average difference in results is ~$1.25 or 2.6%
Mid Columbia Annual Average Prices

Shown in Nominal Dollars per MWh

Volatile Gas Results

Appendix C
Mid Columbia Annual Average Price Comparison
Base Case vs. Volatile Gas Case (Shown in Nominal Dollars per MWh)

Distribution of Net Power Costs
Net Power Costs - No Change to Resources
200 Iterations

NPV (Millions)

Frequency

Mean $2,348

Base Case
Volatile Gas

NPC - If All AVA Load Was Served by Market
200 Iterations

NPV (Millions)

Frequency

Mean $4,471

Base Case
Volatile Gas
Side by Side
200 Iterations

Resource Value Comparison
1 MW Resource Value (excludes Capital Costs)

OWI Pulv. Coal
(200 iterations)

Base Case
Volatile Gas

Mean 2,219

Frequency

NPV (Thousands)

$0 $875 $1,750 $2,625 $3,500

1 MW Resource Value (excludes Capital Costs)

Tar Sands
(200 iterations)

Base Case
Volatile Gas

Mean 648

Frequency

NPV (Thousands)

$0 $875 $1,750 $2,625 $3,500

Appendix C

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### 1 MW Resource Value (excludes Capital Costs)

#### CCCT

- **Base Case**
- **Volatile Gas**

Mean: 158

#### OWI Wind Tier 1

- **Base Case**
- **Volatile Gas**

Mean: 1,079

---

Appendix C

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1 MW Resource Value (excludes Capital Costs)

MT Wind Tier 1 (200 iterations)

- Base Case
- Volatile Gas

Mean 1,277

Frequency

NPV (Thousands)

0 $0 $875 $1,750 $2,625 $3,500

1 MW Resource Value (excludes Capital Costs)

Geothermal (200 iterations)

- Base Case
- Volatile Gas

Mean 2,034

Frequency

NPV (Thousands)

0 $0 $875 $1,750 $2,625 $3,500
Take-Aways

- New Generation over the next 20+ years is forecasted to be primarily Gas, Coal and Wind for the Western Interconnect, unless there is a shift in technology.
- The Northwest is best suited for new coal and wind generation over the next 10-15 years.
- The Mid Columbia electric market is expected to be correlated to natural gas prices, with the exception of Q2.
- The current Avista generation fleet nearly cuts in half the cost of generation supply, compared to an Avista Gen-Co. The preferred resource strategy will continue to lower these costs and reduce risk.
- New gas plants do not hold much value (ignoring capital requirements), but the value is less volatile (market price is not much different the generation cost).
LP Module, the Selection Criteria & Efficient Frontier

2005 Integrated Resource Plan
Fifth Technical Advisory Committee Meeting
May 18, 2005

Clint Kalich

LP Module Data Sources

• Portfolio Output from AURORA Runs
  – Margin generated in each studied year
  – 20 year x 200 matrix of value
    • Avista’s current portfolio
    • each new resource option

• Load Requirements
  – Both capacity and energy by year
    • Reduced by DSM and hydro upgrades

• Resource Capital Costs from NPCC
  – Transmission costs added where required
LP Module Optimization Routine

- Match Load Growth With Best Resources
- Weight First 10 Years of Study Heaviest
- Optimization For Mix of Low Cost and Low Risk
- Generate “Efficient Frontier”
  - Visual Basic code automates its creation
  - Illustrates trade-offs graphically
    - Cost, risk, capital requirements
  - Helps Avista determine an optimal mix

Limits Imposed on LP Routine

- 650 MW of Wind Over 20 Years
  - AVA share of NW wind estimate (250 MW)
  - Assume similar amount from E. Montana
  - Another 150 MW in Avista service territory
- Market Available for Short-Term Balancing
- Meet Both Energy and Capacity Needs
  - Cannot plan for more than capacity needs
Build Example - Capacity & Energy

![Graph showing Build Example of Capacity & Energy]

Power Supply Cost Illustration — 2016

![Graph showing Power Supply Cost Illustration — 2016]

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<th>Lowest Risk Statistics ($millions)</th>
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<td>10-Year Capital</td>
<td>10-Year Capital</td>
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<td>1,992</td>
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<td>2016 Coal% Capacity</td>
<td>2016 Coal% Capacity</td>
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<tr>
<td>0%</td>
<td>82%</td>
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<tr>
<td>2016 Wind% Capacity</td>
<td>2016 Wind% Capacity</td>
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<tr>
<td>0%</td>
<td>15%</td>
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<td>2016 Gas% Capacity</td>
<td>2016 Gas% Capacity</td>
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<tr>
<td>97%</td>
<td>0%</td>
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LP Module—Illustration 5 75/25 Mix

Resource Selection Optimizer

**75.0** COST

25.0 RISK

Optimized Resource Mix

Capacity

Energy

Efficient Frontier—Trade-Offs Between Power Supply Expense, Capital, Risk

Power Supply Expense vs. Capital Cost

Appendix C

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Preliminary Observations

- Lowest Cost Heavily Dependent on Peaking Gas Turbines
  - Implies heavy reliance on spot market
- Lowest Risk Includes More Wind and Coal
  - Capital costs likely are significant
  - $1.2B over 7 years
- Preferred Resource Strategy (PRS) will likely consist of balanced mix of coal, gas and wind
  - Biomass (animal waste) has potential, too
Next Steps

- Refine PRS With Complete Datasets
- Compare Alternative Builds to Efficient Frontier
- Select Point on Efficient Frontier
  – Considering capital cost power supply expense & risk factors
  – Account for “lumpiness” of resource additions

Comments/Suggestions
Introduction:

The Avista Merchant has requested integration costs for various resources that they might acquire in the future. Points of integration are critical for this discussion; however, although these resources vary in fuel type, the type of generation is not material for much of this discussion and will be considered only when necessary (when, as in some wind or biomass development, 1000 MW in one facility is not likely).

Various integration points for new generation will be discussed below. It should be noted that rigorous study has not been completed for any of these alternatives (engineering judgment only), thus the costs provided are not of a “construction estimate” quality. Also note that as the size of the resource to be integrated increases, the certainty of the estimates becomes more suspect. A 50 MW resource can be integrated in many places on our (or other) systems. 350 MW can be integrated in specific areas, 750 MW in fewer; and at the high end- 1000 MW of new resource- a generic integration cost of $1.5 billion has been assigned due to the uncertainty of impacts to the Avista system (and/or its neighboring systems). Should it become clear that Avista requires that size of resource, a detailed regional process would be undertaken to determine the exact impacts and integration costs.

Colstrip:

The present transmission system to the west of (and serving) the Colstrip generating complex is a double circuit 500 kV line. A regional study under the auspices of the Northwest Power Pool (NWPP) NTAC committee is presently underway to determine rough integration costs for such a project. Those studies are not yet complete, so the following estimates are subject to revision in the near future.

- 350 MW: It is expected that to integrate 350 MW at Colstrip, a 500 kV series capacitors and other reinforcements would be required. Cost: Approximately $100M.
- 750 MW: It is expected that to integrate 750 MW at Colstrip, 500 kV series capacitors and other reinforcements (including 230 kV reinforcements in Eastern Washington) would be required. Cost: Approximately $400M.
- 1000 MW: It is expected that major new 500 kV facilities would be required to integrate this capacity at Colstrip. Cost: Approximately $1.5B.
**Alberta Oil Sands, Mid Columbia Purchase, Nuclear Purchase, Kennewick Wind:**

Presently there is no suitable method of integrating energy from the Alberta oil sands into the Avista system. Because of the distances involved, integration into the United States power grid at capacity levels less than 3000 MW is unlikely. Because of the capacity required for the economics of the project to “pencil”, it is anticipated that transmission from the oil sands would be a Direct Current 500 kV line. We assume that one of the DC terminals would be at the Mid Columbia. Avista could then purchase portions of this energy to be delivered to its system from that market hub. It should be noted that a regional scoping effort is presently being undertaken to more closely estimate costs for this project, and thus these estimates should change in the near future.

The Mid Columbia Purchase option should be no different than the Oil Sands integration. Similarly, it is expected that power from a new nuclear plant would be delivered at the Mid Columbia for delivery into the Avista system.

- **350 MW**: Estimated Cost: $100M.
- **750 MW**: Estimated Cost: $150M.
- **1000 MW**: Cost: Approximately $600-800M.

**Rosalia:**

The present transmission system serving the Rosalia, Washington, area is a low capacity 115 kV line. It might be suitable for integration of 40-50 MW in its present configuration, however by the end of 2007, this line will be reconstructed to a high capacity 230 kV line.

- **350 MW**: It is expected that to integrate 350 MW at Rosalia, very little new transmission would be required. Cost: Approximately $10M.
- **750 MW**: It is expected that to integrate 350 MW at Sprague, additional 230 kV reinforcement would be required in the Avista system. Cost: Approximately $80M.
- **1000 MW**: It is expected that major new 500 kV facilities would be required to integrate this capacity at Sprague. Cost: Approximately $1.5B.

**Rathdrum:**

The present transmission system serving the Rathdrum, Idaho, area is a high capacity double circuit 230 kV line.

- **350 MW**: It is expected that to integrate 350 MW at Rathdrum, very little new transmission would be required. Cost: Approximately $20M.
- **750 MW**: It is expected that to integrate 350 MW at Rathdrum, additional 230 kV reinforcement would be required in the Avista system. Cost: Approximately $70M.
- **1000 MW**: It is expected that major new 500 kV facilities would be required to integrate this capacity at Rathdrum. Cost: Approximately $1.5B.
**Sprague:**

The present transmission system serving the Sprague, Washington, area is a low capacity 115 kV line. This line might be suitable for integration of 40-50 MW in its present configuration, however new 230 kV construction would be required for any larger amount of generation.

- 350 MW: It is expected that to integrate 350 MW at Sprague, a double circuit 230 kV line would be constructed between the plant and the Spokane area. Cost: Approximately $50M.
- 750 MW: It is expected that to integrate 350 MW at Sprague, a high capacity double circuit 230 kV line would be constructed between the plant and the Spokane area. Additional transmission would be required between the site and the Mid Columbia. Cost: Approximately $100M.
- 1000 MW: It is expected that major new 500 kV facilities would be required to integrate this capacity at Sprague. Cost: Approximately $1.5B.

**Eastern Montana Wind:**

The present transmission system to the west of (and serving) the present generation in Montana is a double circuit 500 kV line. A regional study under the auspices of the Northwest Power Pool (NWPP) NTAC committee is presently underway to determine rough integration costs for wind integration from eastern Montana. Those studies are not yet complete, so the following estimates are subject to revision in the near future.

- 350 MW: It is expected that to integrate 350 MW at Sprague, a double circuit 230 kV line would be constructed between the plant and the Spokane area. Cost: Approximately $150M.
- 750 MW: It is expected that to integrate 350 MW at Sprague, a high capacity double circuit 230 kV line would be constructed between the plant and the Spokane area. Additional transmission would be required between the site and the Mid Columbia. Cost: Approximately $450M.
- 1000 MW: It is expected that major new 500 kV facilities would be required to integrate this capacity at Sprague. Cost: Approximately $1.5B.

**Othello Area Wind**

Project sizes of between 80-150 MW have been proposed for the Othello area. Depending upon the final project size, location, and timing, integration costs could vary from $10M to $70M. Detailed studies would need to be completed to optimize the transmission in this area if this wind development were to occur.
Nevada Geothermal:

Generation from Nevada would have to be wheeled over other systems. Costs for this alternative is not known.

Landfill Biomass, Manure Biomass

Biomass generation is expected to be small. Integration costs are not known.
Scenario Results

2005 Integrated Resource Plan
Sixth Technical Advisory Committee Meeting
May 18, 2005

John Lyons

Scenario Definition

A scenario is not modeled stochastically. Scenarios use average forecasts for hydro, load, gas, and wind generation to simulate the impact of a major change in a single assumption. The change has to be plausible and significant enough to potentially alter resource decisions.

Advantages: faster solution time than stochastic modeling and easier to understand the impacts of a significant change in assumptions.

Disadvantages: unable to quantitatively assess risk of market volatility.
Scenario Process

- Each of the scenarios were developed to help us understand the impact of a significant change in our assumptions about the future.
- The values of different resources will fluctuate under different scenarios. The different resource values will be included in the final IRP.
- A wind plant will be worth more than a coal plant in a high carbon tax environment.
- An overall increase in the gas market will change marginal resources.
- These examples show our understanding of the general direction of resource changes under different scenarios, but we still need to calculate the scenarios to understand the magnitude of the changes.
- Some scenarios are calculated using Aurora because the entire WECC marketplace will be affected, while others are more easily solved outside of Aurora because they only affect Avista.

Gas Sensitivity Scenarios

- The high gas scenario increases average gas prices by 50%
- The low gas scenario decreases average gas prices by 50%
- These scenarios are designed to show to fundamental increases or decreases in the natural gas markets
Gas Sensitivity Scenario Results

Low Transmission Scenario

- The low transmission scenario reduces transmission capital costs by one third for every new resource type.

- Accurate transmission costs are a big unknown since there has not been significant large transmission projects completed recently. This scenario gives us another view on transmission to help with our preferred strategy.
Low Transmission Scenario Results

- The High Wind Penetration scenario assumes that 5,000 MW of wind power in the northwest is used to replace other generating resources.

- This scenario is designed to find out the overall resource impact of integrating a large amount of wind into the system.
High Wind Penetration Scenario Results

Boom Bust Scenario

- The Boom Bust scenario makes the assumption that a boom period of generating asset construction drives down market prices which results in a lack of new assets being developed for a period of time until markets are so tight that another building spree occurs.
- This scenario was analyzed by starting with the base case and only allowing new plants to be built every five years starting in 2010.
- This scenario shows the boom and bust building cycles that have been seen in recent years. Is this magnitude large enough?
Emissions Scenario

- The two emissions scenarios assume that a federally mandated cap and trade program is initiated to curb greenhouse gases (GHG).

- The NCEP scenario uses the analysis of the National Commission on Energy Policy. This scenario starts at $7 per metric ton of CO2 equivalent in 2010 and increases to $15 per metric ton in 2026. Gas prices do not increase under this scenario.

- The EIA scenario is based upon the EIA analysis of the McCain-Lieberman Climate Stewardship Act. The act starts in 2010 with an initial price of $22 per metric ton of CO2 equivalent and increases to $60 per ton by 2026. Gas prices increase by 30% under this scenario.
Emissions Scenario Results

Fundamental Hydro Shift Scenario

- The Fundamental Hydro Shift scenario assumes that the recent low water conditions are actually a permanent shift instead of temporary drought.
- Average streamflow conditions are reduced by 10% in this scenario.
- This scenario was developed to help us understand our resource decisions under a permanent water change.
- The analysis shows that there is no significant impact on the market because gas is still on the margin.
Avista Only Scenarios

The following scenarios do not require new capacity expansion runs and have not been completed yet:

- Loss of Large Avista Plant – simulates loss of Noxon for 5 years
- High Avista Load – doubles the projected load growth to 4%
- Low Avista Load – zero projected load growth
- Loss of Spokane River Projects – All Avista projects on the Spokane River are lost
- Long Haul Coal – new coal plant is sited within Avista service territory and coal is railed to the plant
- Green Growth Initiative – all new Avista resources are renewable
- Double Avista DSM – DSM acquisitions are doubled
Summary of Scenario Results

The chart illustrates the results of various scenarios in terms of emissions and costs. The scenarios include different energy sources such as Tar Sands, Manure, Geothermal, Solar, Nuclear, IGCC SQ, IGCC, Pulverized, IGCC, WIND, SCCT-Frame, RPS, and 2026 DEFICIT. Each scenario is represented by a bar, showing the level of emissions and costs associated with each energy source. The chart helps in visualizing the impact of different energy strategies on the environment and economic factors.
Avoided Costs

2005 Integrated Resource Plan
Sixth Technical Advisory Committee Meeting
May 18, 2005

Clint Kalich

What Is An Avoided Cost?

• Theoretical Price Company Would Pay For A New Resource
• Based On Least-Cost Resource
• Includes Both Capital and Operating Expenses of the Resource
Avoided Cost In 2005 IRP

• AURORA Model Run Sets Avoided Cost
• Capacity Credits Assumed For Base Case Are Eliminated for AC Run
  – Capacity credits are used to help AURORA better emulate the regulated power supply market (i.e., over-build)
  – Market price with capacity credits necessarily understates cost of power since capacity credits are “theoretical” and cannot be avoided

Comparison of Avoided Costs and Wholesale Market Prices

20-Year Levelized Cost

Base Case $47.08
Avoided Cost $48.32

dollars per MWh

Conclusions

- Wholesale Marketplace Likely Understates Avoided Cost
- Caused By Societal Desire To Build More Resources Than Price Alone Would Support
  - Reduces market volatility
- 2005 IRP Shows Cost Of Extra Resources is Modest (~ $1.50/MWh, or 3%)
- IRP Schedule Will Be Used In WA For PURPA <1 MW
Hydro Upgrades

Upgrades to Clark Fork River Project
- Cabinet 4
- Noxon 1 - 4

- Hydro upgrades will begin September 2006 and last through March 2011
  - Each upgrade will be a 6-month project

- Upgrades will avoid future maintenance costs and outages and have favorable Net Present Values
Cabinet Gorge #4 Upgrade

- 6 month project beginning September 2006
- Increase Energy Production by 0.1 aMW and Capacity by 6 MW
- Expected Capital Cost of $4.7 Million
- Avoided Major Maintenance: N/A
- 20 year NPV: $4.3 Million
- 35 year NPV: $5.1 Million

Noxon Rapids #4 Upgrade

- 6 month project beginning September 2007
- Increase Energy Production by 1.2 aMW and Capacity by 7 MW
- Expected Capital Cost of $3.8 Million
- Avoided Major Maintenance: $3.6 Million
- 20 year NPV: $2.5 Million
- 35 year NPV: $3.6 Million
Noxon Rapids #1 Upgrade

- 6 month project beginning September 2008
- Increase Energy Production by 2.3 aMW and Capacity by 10 MW
- Expected Capital Cost of $4.1 Million
- Avoided Major Maintenance: $3.6 Million
- 20 year NPV: $8.3 Million
- 35 year NPV: $10.6 Million

Noxon Rapids #2 Upgrade

- 6 month project beginning September 2009
- Increase Energy Production by 1.1 aMW and Capacity by 11 MW
- Expected Capital Cost of $3.8 Million
- Avoided Major Maintenance: $3.6 Million
- 20 year NPV: $2.5 Million
- 35 year NPV: $3.3 Million
Noxon Rapids #3 Upgrade

- 6 month project beginning September 2010
- Increase Energy Production by 1.3 aMW and Capacity by 10 MW
- Expected Capital Cost of $3.9 Million
- Avoided Major Maintenance: $3.6 Million
- 20 year NPV: $5.3 Million
- 35 year NPV: $6.8 Million

Summary

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<th>Year</th>
<th>Cab 4</th>
<th>Nox 1</th>
<th>Nox 3</th>
<th>Nox 4</th>
<th>Nox 2</th>
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<td>10.0</td>
<td>7.0</td>
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<td>Generation (GWh)</td>
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<td>20-Year NPV ($millions)</td>
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<td>8.3</td>
<td>5.3</td>
<td>2.5</td>
<td>2.5</td>
<td>22.9</td>
</tr>
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</table>
Emissions

2005 Integrated Resource Plan
Seventh Technical Advisory Committee Meeting
June 23, 2005
John Lyons

Current Emissions News

- Senator Jeff Bingaman (D-NM) recently considered legislation similar to the National Commission on Energy Policy recommendations

- The Amended McCain-Lieberman bill was defeated on June 22nd in favor of the voluntary reductions by Senator Chuck Hegel (R-Neb.)

- Another attempt to reduce greenhouse gas emissions is to require a 10% renewable portfolio standard (net of hydro) by 2020
Avista Studies

- The Company studied and modeled the National Commission on Energy Policy and the McCain-Lieberman bill (S. 342)

- The company modeled these scenarios using the AURORA\textsuperscript{MP} model by adding a “tax” to CO\textsubscript{2} production

- The S. 342 CO\textsubscript{2} tax estimate was provided from the Analysis of S. 139, the Climate Stewardship Act of 2003, published in 2003 by the EIA

Avista Studies (cont.)

- CO\textsubscript{2} taxes were applied to all plants expected to produce taxable emissions

- Each plant has an opportunity cost of producing power or selling emission credits

- The studies did not include a production tax credit for renewable resources such as wind

- S. 342 scenario includes a small demand response reduction in load based on the study done by the EIA.

- The model was tasked with optimizing cost and emissions based on the estimated cap and trade costs of the two scenarios
Comparison of Average Annual Fuel Expense
2005 Dollars

S. 342 is a 13% increase over the Base Case
NCEP is a 7% increase over the Base Case

Comparison- Coal Generation
aMW

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Comparison - Gas Generation

Avista Portfolios - Millions of Tons of CO₂
Demand-Side Management

2005 Integrated Resource Plan
Seventh Technical Advisory Committee Meeting
June 23, 2005

Jon Powell

Overview

• Defined 49 DSM measures
  – Combined two measures into one
  – Insufficient data to evaluate two measures
• Tested against a 8760-hour avoided cost +10%
• 36 measures passed the TRC test
• 5.4 amW (47.5 million kWhs) pass TRC test
  – Local acquisition component only
    • Excludes 1.0 to 1.4 amW share of regional acquisition
  – Local acquisition 19% over current goal
  – Local +regional acquisition 41% to 49% over current
  – Overall acquisition goal exceeds share of NPCC goal
• Applying IRP results in completing the tactical stage of Avista’s 2006 DSM business plan
DSM Operational Issues

- Our “All Comers” tariff
- Diversity of projects within an IRP category
- Customer service issues
- Trade Allies, Vendors, Retailers
- Regional Market Transformation
- Measure / Program packages

Integration Methodology

- Integration by price
  - DSM is
    - A small acquisition on an annual basis
    - Currently non-dispatchable
  - Consequently DSM
    - will not change the dispatch or Avista or regional resources
    - will not influence avoided cost (not interactive with price)
    - can be modeled as a “price taker”
  - An avoided cost “price signal” is sent to DSM
  - DSM acquires all TRC cost-effective measures relative to that avoided cost
  - Allows for addition and refinement of testing of DSM measures over time against the 2005 IRP avoided cost
Assumptions

- Global assumptions
  - Discount rate / inflation consistent with IRP forecast

- TRC calculations
  - Two alternate approaches
    - TRC with NEB’s and natural gas as benefits
      - The traditional approach used by Avista for past reporting
      - Results in a more meaningful B/C ratio
    - TRC with NEB’s and natural gas AC as negative costs
      - Results in a more meaningful TRC levelized cost
Definition of the Measures

- 49 measures defined
  - 8 industrial, 21 commercial, 19 residential, 1 utility distribution
  - Two PC control measures combined
  - CVR, rooftop HVAC measures placed on hold
- Measure distinctions primarily based upon
  - 8760-hour load shape
  - Customer cost per 1st year kWh
  - Other characteristics (NEB, non-incentive utility cost, natural gas impact)

Measures tested

<table>
<thead>
<tr>
<th>Measures tested</th>
<th>Measures eliminated</th>
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</thead>
<tbody>
<tr>
<td>Commercial CFL</td>
<td>T12-T8 commercial</td>
</tr>
<tr>
<td>School CFL</td>
<td>HE A/C, skin load buildings</td>
</tr>
<tr>
<td>Residential CFL</td>
<td>MH to PS, manufacturing</td>
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<tr>
<td>Industrial CFL</td>
<td>Residential W/H E to G conversion</td>
</tr>
<tr>
<td>Refrigeration</td>
<td>Residential prog TS, el resistance</td>
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<tr>
<td>Hydraulics</td>
<td>Res HE AC</td>
</tr>
<tr>
<td>Industrial pumps</td>
<td>Res SH FS (ducted)</td>
</tr>
<tr>
<td>Industrial fans blowers</td>
<td>MH to PS, parking lots</td>
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<tr>
<td>HE A/C, internal load bldg</td>
<td>Residential prog TS, heat pump</td>
</tr>
<tr>
<td>Avista network computer</td>
<td>MH to T5, gyms</td>
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<tr>
<td>Exit signs</td>
<td>Res heat pump</td>
</tr>
<tr>
<td>Industrial compressed air</td>
<td>Non residential appliances</td>
</tr>
<tr>
<td>T12-T8 convenience retail</td>
<td>Residential floor insulation</td>
</tr>
<tr>
<td>Residential duct insulation</td>
<td>Res SH FS (ducted)</td>
</tr>
<tr>
<td>Residential roof insulation</td>
<td>MH to PS, gyms</td>
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<tr>
<td>Liquid VFDs</td>
<td>T12-T8 schools</td>
</tr>
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<td>MH to PS, commercial</td>
<td>Residential water heating efficiency</td>
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<td>MH to T5, commercial</td>
<td>Residential prog TS, AC only</td>
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<tr>
<td>Res water heating blanket</td>
<td>Residential E facing windows</td>
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<tr>
<td>Commercial HE heat pumps</td>
<td>Residential W facing windows</td>
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<tr>
<td>T12-T8 industrial</td>
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<td>Vapor VFDs</td>
<td>Non residential shell</td>
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<td>Residential wall insulation</td>
<td>Residential N facing windows</td>
</tr>
<tr>
<td>MH to T5, manufacturing</td>
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</tr>
</tbody>
</table>

Measures not tested

- Controlled voltage reduction
- Rooftop HVAC
Characterization of the Measures

- 8760-hour load shape
- Measure costs & benefits
  - Avoided electric cost
  - Non-energy benefits
  - Natural gas impact
  - Customer cost
  - Non-incentive utility cost
- Calculations
  - TRC B/C ratio $\Rightarrow$ NEBs and gas AC are benefits
  - TRC levelized cost $\Rightarrow$ NEBs and gas AC are costs

The Analysis

- Began with complete indexing to historical acquisition
- Iterative improvement process
  - Fine-tuned to maximize net TRC benefits
- Aggregate resource acquisition tested ranged from 4.1 amW to 7.0 amW
- Final test portfolio consisted of 5.8 amW
  - 5.4 amW of this passing the TRC test
  - 36 of 46 measures tested passed
- All evaluated measures stacked by TRC B/C
  - Creating a downward sloping supply curve
- Methodology allows for post-IRP refinement to be integrated into DSM operations
Traditional (upward sloping) supply curve

- Graphically represent TRC levelized cost for TRC B/C ranked measures
- Results in a “notched” upward sloping supply curve
  - Attributable to recognition of load shape in B/C ratio (not recognized in TRC levelized cost)
Regional Program Interaction

- Previous measures are local utility acquired resources
  - Any kWh “touched” by local utility is a local kWh
  - Local kWh’s are excluded from regional tally
  - → Avoids double-counting of resource
    - (Local acquisition overestimate / regional underestimate of attribution)
- → Generally local utility can layer share of regional acquisition on local acquisition
  - 2004 Avista “share” 1.4 amW
- 2005 special note
  - Acceptance of res CFL program results in an overlap
Comparison of Aggregate DSM Goals

- Current tariff
- NPCC
- IRP

Distribution of Savings by Customer Segment

- Residential
- Comm / Ind
- Industrial
Segment distribution of acquisition

- **Lots of industrial**
  - Primarily compressed air, refrigeration, pumps
  - Attributable to participant economics in new retail rate environment
  - Local acquisition most effective approach
  - Some of the most cost-effective measures
- **Residential**
  - Primarily CFL’s, HE A/C, space heat fuel-efficiency
  - Relatively marginal TRC B/C’s
  - Large share of residential acquisition achieved via regional programs
- **Commercial**
  - An expected level of total acquisition
  - Primarily lighting (as expected)
What will it cost?

- Targeted goals are achievable within a reasonable range of current DSM funding
  - 52% of 2002-2004 electric DSM revenues were expended
    - Resulting in the recovery of $10.7 million of the $11.8 million in negative electric DSM balance
    - Current (May ’05) combined WA / ID electric DSM balance = $0.2 million

- Future DSM funding strategy
  - Annual revisions to DSM tariff rider sufficient to
    - Eliminate any positive or negative DSM forward balance
    - Fund all TRC cost-effective DSM acquisition in the following year
Application of these Results

• Initiation of our 2006 business planning process
  – Centered around appropriate stewardship of customer tariff rider funds
    • Target all TRC cost-effective resources appropriate for local acquisition

• Currently in a transitional period
  – Idaho electric transition to “all CE” initiated in late 2003
  – Washington gas transition initiated in early 2005
  – Washington electric transition initiating in mid-2005
  – Idaho gas transition will occur in late 2005
    • Pending discussion with the IPUC staff and the Triple-E board

Progress to date

• Late 2003 ramp-up of Idaho electric projects demonstrated utility incentive constraint
  – Effective March 2005 Idaho electric incentives were approximately doubled
  – Same revisions are currently in-process in Washington

• Infrastructure
  – 2.5 FTE added via re-organization in early ’05
  – 1.0 FTE of incremental field technical resources in process
Progress to date

- Funding
  - Recovered $11.9 million of the $12.4 million negative balance left after 2001 emergency program portfolio
    - $11.7 million of the $11.9 million electric balance recovered
  - Future plan is to annually revise tariff riders to recover
    - forward balance
    - Fund acquisition efforts for subsequent year

- YTD May 2005 acquisition
  - 5.44 amW local acquisition
  - Caution: extrapolating five months of data …
  - Not driven by Idaho incentive revisions
  - Retail rate response (efficiency as a substitute for energy)
Mmbtu acquisition

Combined Gas and Electric DSM Acquisition

Natural Gas DSM component

Gas DSM Acquisition

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Next Steps

- Complete revisions in Washington electric incentives
- Complete pilot projects for
  - Small commercial rooftop HVAC
  - Conservation Voltage Control
- Review the role of non-utility infrastructure in the utility acquisition of DSM
- Complete program design for new prescriptive residential programs identified in IRP
- Review commercial / industrial DSM efforts in light of IRP results
  - Particular attention to industrial segment
- Maintain / augment infrastructure as necessary

Realistic Considerations

- Diversity of projects within measure category
  - Our “all comers” tariff issue
- Alternative feedback via project-specific calculation of sub-TRC
  - Refine target markets
  - Individual assessment of efficiency opportunities
- Continual re-assessment of evaluated measures
- Addition of new measures as necessary
Issues for the Future

• Complete rooftop HVAC pilot program and evaluation
• “DSM in mass” through distribution efficiencies
  – Controlled Voltage Regulation
• Demand-response
  – Capable of testing options against a “richer” 8760-hour load profile
• Continued refinement of our ability to rapidly respond to changing market conditions
  – 2001 western energy crisis response
  – 2005 drought contingency plan response

Questions?
Preferred Resource Strategy

2005 Integrated Resource Plan
Seventh Technical Advisory Committee Meeting
June 23, 2005
Clint Kalich

Goals of PRS

- Meet Future Capacity & Energy Requirements
- Keep Rates Low
- Stable Rates
- Good Performance Across Scenarios
Preferred Resource Strategy—2003 IRP

Average Megawatts

- CCCT
- Peakers
- Wind
- Coal


Alternative Portfolio Strategies

- No Additions
- All Coal
- All Gas
- 50%/50% Coal/Gas
- All Renewables
- Wind/Gas
- No CO2 Emissions
- Efficient Frontier Strategies
  - 0% Risk
  - 25% Risk
  - 50% Risk
  - 75% Risk
  - 100% Risk

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Performance Comparison—Rate Impacts 2007-16

Performance Comparison—Max Rate Increase

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Performance Comparison—Capital Cost 2007-26 (NPV $millions)

Performance Comparison—2016 Incremental Power Supply Expense ($millions)

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Performance Comparison—Risk (2007-26 NPV of StDev $millions)

Performance Comparison—Tail Risk (2007-26 NPV of 95th % Vs. StDev $millions)
Performance Comparison—NCEP Carbon Market Scenario 2016 Incremental PSE

Highlights of Preferred Resource Strategy

- Large Contribution from Renewable Resources
- 50% Higher Level of DSM
- Significant Reduction in Year-On-Year Rate Volatility
- Strong Performance Across Scenarios
- Reasonable Rate Impacts When Compared to Alternatives
DRAFT Preferred Resource Strategy

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