2011 IRP Public Input Meeting

August 4, 2010
Agenda

- Demand-side management / distributed generation
- Supply-side Resources
- Planning Reserve Margin (PRM) analysis
- Proposed portfolio development cases
Demand-side Management / Distributed Generation
DSM Update Overview – Potential Study Update

• **Scope of Potential Study Update:**
  – Update 2007 study to reflect:
    • Changes in measures, savings (kW and kWh), costs, measure lives
    • Changes in baselines (e.g., Federal Lighting Standards, Energy Codes)
    • Changes in state load forecasts
    • Evolving Supplemental Resource data (CHP, On-site Solar)
    • Impact of varying acquisition rates i.e. retrofit vs. lost opportunities
    • State specific developments i.e. Utah and UCT perspective
    • Program achievements since last study
  – Development of updated supply curves for use in 2011 IRP
  – Summary report (No preliminary economic screening this go around)

• **Timeline:**
  – RFP issued April 2010
  – RFP Responses May 2010
  – Vendor Selected May 2010
  – Work Initiated June 2010
  – Supply Curves August 2010
  – Draft Report September 2010
**DSM Update Overview – Class 1 & 3 Resources**

- Update Direct Load Management (Class 1) and Pricing/Indirect (Class 3) Resource Assumptions:

<table>
<thead>
<tr>
<th>Segment</th>
<th>Measures</th>
<th>Changes/Notes</th>
</tr>
</thead>
</table>
| Class 1 - Residential and Small Commercial | - Direct Load Control (Air Conditioners)  
- AC Control with and without complementary loads (water heating) | No significant changes other than improved analysis on assumed kW per home |
| Class 1 – Commercial and Industrial | - Load curtailment program (combination load shedding and use of customer standby generation)  
- Thermal Energy Storage | Customer standby generation was treated as Supplemental resource in 2007 assessment |
| Class 3 - Residential and Small Commercial | - Critical Peak Pricing (CPP)  
- Time Of Use (TOU) | Adding Mandatory TOU w/ CPP to product list, smart-grid planning information |
| Class 3 – Commercial and Industrial | - Critical Peak Pricing  
- Real Time Pricing  
- Demand buy-back | No significant changes, just updating information |
| Class 1&3 - Irrigation | - Direct Load Control (DLC)  
- Time of Use | Revising DLC control assumption and adding Mandatory TOU to product list |
DSM Update Overview – Class 2 Resources

• Update Energy Efficiency (Class 2) measures and measure assumptions

• Principle adjustments include:
  – Residential
    • Update home electronics measure list, saturations, baselines (standard verses efficient)
    • Revise showerhead baseline from 4 gpm to 2.5 gpm
    • Incorporate EISA 2007 (lighting) and water heater standards
  – Commercial:
    • Update Rooftop DX cooling efficiency standard
    • Change motor efficiency to reflect NEMA Premium +
    • Account for pending commercial lighting/ballast standard
  – Industrial
    • Include more strategic energy management measures beyond standard O&M
    • Change motor efficiency to reflect NEMA Premium +
  – All
    • Identification of measures with non-electric benefits and included as a reduction to cost
    • Expanding potential assessment data in Oregon from 10 to 20 years
DSM Update Overview – Supplemental Resources

• Update Supplemental Resource measures and measure assumptions:
  – On-site Solar
    • Photovoltaics, solar water heater, solar attic fans
    • Update cost/performance parameters
      – Validating our source of assumptions with stakeholders
      – Weighted average of capacity factor based on location
      – Sector-specific costs ($/Watt)
  – Combined Heat and Power (CHP)
    • Update cost/performance parameters based on recent data
  – Dispatchable Standby Generation
    • Potential to be moved and incorporated into a Class 1 commercial curtailment product
DSM Update Overview – Supply Curves

- Estimate the production of approximately 1,580 DSM supply curves
  - Class 1 (40), Class 2 (1,480), and Class 3 (60) for use in IRP modeling work
- Other DSM resource granularity being developed
  - **Class 1 and 3:** Low, medium and high potential scenarios and associated costs for consideration in development of supply curves
  - **Class 2:** Measure bundles based on the upper limit of the levelized costs per bundle. Load shapes will follow from measures in each bundle and will be weighted average of measure types
    - Bundles for CA, ID, WA and WY will be levelized costs based on Total Resource Cost.
      - Costs that are levelized for TRC are measure costs + 15% adder for admin
    - Bundles for Utah will be levelized costs based on Utility Costs (incentives and admin) – will build 3 cost/quantity scenarios at varying incentive levels; i.e. low, medium, and high. One scenario will be selected for the development of Utah’s supply curves
    - For Oregon, ETO is screening their assessment study data by economics provided by IRP team; Cadmus will translate the data into supply curves for modeling
DSM Update Overview - Potential Study Recap

- Recap of potential assessment work
  - Changes in measures, savings (kW and kWh), costs, measure lives
  - Changes in baselines (e.g., Federal Lighting Standards, Energy Codes)
  - Align update information, where applicable with NWPCC and RTF
  - Identification of measures with non-electric benefits
  - Use of 20 year assessment data for Class 2 supply curves in Oregon
  - Changes in state load forecasts
  - Evolving Supplemental Resource data (CHP, On-site Solar)
  - Impact of varying acquisition rates i.e. retrofit vs. lost opportunities
  - State specific developments i.e. Utah and UCT perspective
  - Program achievements since last study
  - Development of over 1,500 supply curves for use in 2011 IRP
  - Summary report (No preliminary economic screening this go around)
Supply Side Resources
Supply Side Discussion

- Supply Side Resource Table
  - Assumptions
  - Changes

- Geothermal Resources Study

- Discussion on energy storage evaluation options to enhance the value of intermittent renewable energy sources
Supply Side Resource Table

• Assumptions
  – Compare to 2008 IRP
  – Use recent studies and benchmarks for performance and operating costs
  – Costs are all-in including AFUDC in 2010 dollars. Simple escalation to year of operation
  – Capital cost low estimate - 5% less than base
  – Capital cost high estimate - 20% greater than base
Supply Side Resource Table

- Coal Assumptions – Largely unchanged
  - Carbon Capture and Sequestration (CCS) not available until 2030
  - Capital costs:
    - Slightly lower for coal without CCS
    - CCS costs slightly higher
  - CCS energy loss adjusted higher (negative resource)
### Supply Side Table Options - Coal

<table>
<thead>
<tr>
<th></th>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>Utah PC without Carbon Capture &amp; Sequestration</td>
<td>600</td>
<td>PC Supercritical</td>
<td>$3,077</td>
<td>9,106</td>
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<tr>
<td>Utah PC with Carbon Capture &amp; Sequestration</td>
<td>526</td>
<td>PC Supercritical</td>
<td>$5,563</td>
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<td>Utah IGCC without Carbon Capture &amp; Sequestration</td>
<td>508</td>
<td>IGCC - (2x1)</td>
<td>$4,239</td>
<td>8,734</td>
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<td>Utah IGCC with Carbon Capture &amp; Sequestration</td>
<td>466</td>
<td>IGCC - (2x1)</td>
<td>$5,386</td>
<td>10,823</td>
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<tr>
<td>Wyoming PC without Carbon Capture &amp; Sequestration</td>
<td>790</td>
<td>PC Supercritical</td>
<td>$3,484</td>
<td>9,214</td>
</tr>
<tr>
<td>Wyoming PC with Carbon Capture &amp; Sequestration</td>
<td>692</td>
<td>PC Supercritical</td>
<td>$6,299</td>
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<td>Wyoming IGCC without Carbon Capture &amp; Sequestration</td>
<td>497</td>
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<td>$4,799</td>
<td>8,915</td>
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<td>Wyoming IGCC with Carbon Capture &amp; Sequestration</td>
<td>456</td>
<td>IGCC - (2x1)</td>
<td>$6,099</td>
<td>11,047</td>
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<tr>
<td>Existing PC with Carbon Capture &amp; Sequestration (500 MW)</td>
<td>(139)</td>
<td>PC Subcritical</td>
<td>$1,383</td>
<td>14,372</td>
</tr>
</tbody>
</table>

Note: The capacity shown for retrofitting CCS on existing PC plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.
Gas Turbine World Equipment Price Trends
(2010 GTW Handbook)

Year of Order

Index

Simple Cycle

Combined Cycle
Supply Side Resource Table

• Gas Assumptions
  – Gas Turbine cost trend has peaked
  – Recent look at site specific SCCT costs
    • Environmental issues, such as SCR, have kept costs up in the IRP estimates (especially for frame technology)
    • LMS100 and LM6000 costs are consistent with earlier estimates
  – New “F” technology coming to market
    • Higher capacity – additional 10%
    • Better heat rate – 1.5% better
    • Will help to mitigate the SCCT costs in the future
<table>
<thead>
<tr>
<th></th>
<th>Average Capacity MW - Not Incl. Degradation</th>
<th>Technology</th>
<th>Capital Cost Estimate in $/kW (Average)</th>
<th>Annual Average Heat Rate Btu/kWh HHV - Incl. Degradation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas (4500 feet)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Utility Cogeneration</td>
<td>10</td>
<td>Compressor Heat</td>
<td>$4,683</td>
<td>4,974</td>
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<tr>
<td>Fuel Cell - Large</td>
<td>5</td>
<td>SOFC</td>
<td>$1,755</td>
<td>7,262</td>
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<tr>
<td>SCCT Aero</td>
<td>118</td>
<td>SCCT - 3 x LM6000</td>
<td>$1,102</td>
<td>9,773</td>
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<tr>
<td>Intercooled Aero SCCT</td>
<td>279</td>
<td>SCCT - 3 x LMS100</td>
<td>$1,294</td>
<td>9,379</td>
</tr>
<tr>
<td>Internal Combustion Engines</td>
<td>301</td>
<td>Natural Gas Engines</td>
<td>$1,267</td>
<td>8,806</td>
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<tr>
<td>SCCT Frame (2 Frame &quot;F&quot;)</td>
<td>362</td>
<td>SCCT - 2 - Frame F</td>
<td>$1,092</td>
<td>10,446</td>
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<tr>
<td>CCCT (Wet &quot;F&quot; 1x1)</td>
<td>263</td>
<td>CCCT - &quot;F&quot; (1x1)</td>
<td>$1,319</td>
<td>7,302</td>
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<tr>
<td>CCCT Duct Firing (Wet &quot;F&quot; 1x1)</td>
<td>42</td>
<td>&quot;F&quot; Duct Firing</td>
<td>$538</td>
<td>8,869</td>
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<tr>
<td>CCCT (Wet &quot;F&quot; 2x1)</td>
<td>525</td>
<td>CCCT - &quot;F&quot; (2x1)</td>
<td>$1,191</td>
<td>6,911</td>
</tr>
<tr>
<td>CCCT Duct Firing (Wet &quot;F&quot; 2x1)</td>
<td>84</td>
<td>&quot;F&quot; Duct Firing</td>
<td>$601</td>
<td>9,329</td>
</tr>
<tr>
<td>CCCT (Wet &quot;G&quot; 1x1)</td>
<td>333</td>
<td>CCCT - &quot;G&quot; (1x1)</td>
<td>$1,247</td>
<td>6,777</td>
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<tr>
<td>CCCT Duct Firing (Wet &quot;G&quot; 1x1)</td>
<td>72</td>
<td>&quot;G&quot; Duct Firing</td>
<td>$528</td>
<td>9,021</td>
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<td>CCCT Advanced (Wet)</td>
<td>400</td>
<td>&quot;H&quot; Technology</td>
<td>$1,377</td>
<td>6,651</td>
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<td>CCCT Advanced Duct Firing (Wet)</td>
<td>75</td>
<td>&quot;H&quot; Duct Firing</td>
<td>$676</td>
<td>9,021</td>
</tr>
</tbody>
</table>
Supply Side Resource Table

• Renewable Assumptions
  – Solar includes thermal and photovoltaic (PV)
    • Short-term focus on PV – Oregon
    • Conventional PV
      – lower cost at about $4,200/kW
      – lower capacity factor at about 19% (Oregon – Utah)
  – Geothermal will be updated based on geothermal resources study
  – Wind costs in slight decline due to decreased market demand combined with new manufacturing capacity for wind turbines
  – Estimates do not include tax benefits
## Supply Side Table Options - Renewable

<table>
<thead>
<tr>
<th>Other - Renewables</th>
<th>Average Capacity MW - Not Incl. Degradation</th>
<th>Technology</th>
<th>Capital Cost Estimate in $/kW (Average)</th>
<th>Annual Average Heat Rate Btu/kWh HHV - Incl. Degradation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wyoming Wind (35% CF)</td>
<td>100</td>
<td>1.5 to 2.5 MW Turbines</td>
<td>$2,239</td>
<td>n/a</td>
</tr>
<tr>
<td>Utah Wind (30% CF)</td>
<td>100</td>
<td>1.5 to 2.5 MW Turbines</td>
<td>$2,239</td>
<td>n/a</td>
</tr>
<tr>
<td>Oregon / Washington Wind (35% CF)</td>
<td>100</td>
<td>1.5 to 2.5 MW Turbines</td>
<td>$2,383</td>
<td>n/a</td>
</tr>
<tr>
<td>East Side Geothermal</td>
<td>35</td>
<td>Dual flash or Binary</td>
<td>$4,277</td>
<td>n/a</td>
</tr>
<tr>
<td>Biomass</td>
<td>50</td>
<td>Boiler</td>
<td>$3,509</td>
<td>10,979</td>
</tr>
<tr>
<td>Battery Storage</td>
<td>5</td>
<td>Advanced Batteries</td>
<td>$2,025</td>
<td>11,000</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>250</td>
<td>Pumped Hydro</td>
<td>$1,723</td>
<td>12,500</td>
</tr>
<tr>
<td>Compressed Air Energy Storage (CAES)</td>
<td>350</td>
<td>CAES</td>
<td>$1,440</td>
<td>11,980</td>
</tr>
<tr>
<td>Hydrokinetic (Wave) - 21% CF</td>
<td>100</td>
<td>Floating Buoy</td>
<td>$5,831</td>
<td>n/a</td>
</tr>
<tr>
<td>Solar (PV) - 19% CF</td>
<td>5</td>
<td>Thin Film PV</td>
<td>$4,191</td>
<td>n/a</td>
</tr>
<tr>
<td>Solar Concentrating (natural gas backup) - 25% solar</td>
<td>250</td>
<td>Thermal (trough)</td>
<td>$4,033</td>
<td>11,750</td>
</tr>
<tr>
<td>Solar Concentrating (thermal storage) - 30% solar</td>
<td>250</td>
<td>Thermal (trough)</td>
<td>$4,519</td>
<td>n/a</td>
</tr>
</tbody>
</table>
Geothermal Resources Study

• Recommended by Utah in April 1, 2010
acknowledgement order:
  – “The Division recommends that the Company conduct a geothermal commercial potential study for geothermal energy using both Blundell technology and other alternative geothermal technologies. The study should evaluate greenfield projects in both PacifiCorp’s east and west control areas. This study should be filed with the Commission for comments as soon as it is completed. Inasmuch as the Company does not currently have an estimate of the amount of economically developed geothermal resources in the states it serves, the Division recommends that the Company make this determination and include a description of all factor mentioned in the previously referred to in DPU data request 1.32e.”

• Began May 1, 2010 with review draft July 2010 and final report August 2010

• Identified 80 potential sites – narrowed to 8 commercial opportunities
Potential Geothermal Projects Near PacifiCorp-Owned Transmission

This map shows potential geothermal projects identified by GeothermEx for the WREZ and RETI initiatives that are located within 100 miles of PacifiCorp-owned transmission lines.

The data created for these initiatives will be a starting point for the analysis that will be carried out by GeothermEx and Black & Veatch for this study, and an example of one of the work products that will be produced.
Commercial Geothermal

• Commercial Geothermal Defined
  – Exploration
    • Activities to first full-diameter well
    • Geologic mapping, sampling, surveys
    • Small diameter wells
  – Confirmation
    • Full-diameter wells up to 25% of target capacity
  – Development
    • Activities to full commercial operation

• For screening purposes – commercial was considered completion of the confirmation phase
• Consideration to be given to further define mitigating risk issues to better separate opportunities
Commerically Viable Geothermal Resources in and Near PacifiCorp's Service Territory

This map shows the 8 commercially developable potential geothermal projects identified by BVG for in-depth analysis in this study.
### Prioritized Geothermal Options

<table>
<thead>
<tr>
<th>Field Name</th>
<th>State</th>
<th>Additional Capacity Available (Gross MW)</th>
<th>Additional Capacity Available (Net MW)</th>
<th>Additional Capacity Available to PacifiCorp (Net MW)$^a$</th>
<th>Anticipated Plant Type for Additional Capacity</th>
<th>LCOE (Low, $/MWh)$^b,c$</th>
<th>LCOE (High, $/MWh)$^b,c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lake City</td>
<td>CA</td>
<td>30</td>
<td>24</td>
<td>24</td>
<td>Binary</td>
<td>$83</td>
<td>$90</td>
</tr>
<tr>
<td>Medicine Lake</td>
<td>CA</td>
<td>480</td>
<td>384</td>
<td>384</td>
<td>Binary</td>
<td>$91</td>
<td>$98</td>
</tr>
<tr>
<td>Raft River</td>
<td>ID</td>
<td>90</td>
<td>72</td>
<td>43</td>
<td>Binary</td>
<td>$93</td>
<td>$100</td>
</tr>
<tr>
<td>Neal Hot Springs</td>
<td>OR</td>
<td>30</td>
<td>24</td>
<td>0</td>
<td>Binary</td>
<td>$80</td>
<td>$87</td>
</tr>
<tr>
<td>Cove Fort</td>
<td>UT</td>
<td>100</td>
<td>80</td>
<td>60 to 63</td>
<td>Binary</td>
<td>$68</td>
<td>$75</td>
</tr>
<tr>
<td>Crystal-Madsen</td>
<td>UT</td>
<td>30</td>
<td>24</td>
<td>0</td>
<td>Binary</td>
<td>$93</td>
<td>$100</td>
</tr>
<tr>
<td>Roosevelt Hot Springs</td>
<td>UT</td>
<td>90</td>
<td>81$^d$</td>
<td>81$^d$</td>
<td>Flash/Binary Hybrid</td>
<td>$46</td>
<td>$51</td>
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<tr>
<td>Thermo Hot Springs</td>
<td>UT</td>
<td>118</td>
<td>94</td>
<td>0</td>
<td>Binary</td>
<td>$91</td>
<td>$98</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td>968</td>
<td>783</td>
<td>592 to 595</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: BVG analysis for PacifiCorp.

**Note:**

$^a$ Calculated by subtracting the amount of resource under contract to or in contract negotiations with other parties from the estimated net capacity available.

$^b$ Net basis

$^c$ These screening level cost estimates are based on available public information. More detailed estimates based on proprietary information and calculated on a consistent basis might yield different comparisons.

$^d$ While 81 MW net are estimated to be available, the resource should be developed in smaller increments to verify resource sustainability.
We direct the Company to discuss methods for improving the evaluation of nontraditional resources in an IRP public input meeting. At a minimum, this discussion should include ideas for improving the evaluation of distributed solar technologies which provide opportunities for customer participation, i.e., a solar rooftop customer buy-down program, and options for improving the evaluation of storage technologies designed to enhance the value and performance of intermittent renewable resources.”
Energy Storage Options

• Storage Options
  – Battery Storage
    • Lithium-Ion – small / expensive on a $/MWh basis
    • Sodium-sulfur – larger / expensive / still in development
    • Redox flow – small / unique applications / expensive
  – Pumped Storage
    • Permitting and lead time
  – Compressed Air Energy Storage (CAES)
  – Solar Thermal (molten salt)
    • 4 to 6 hours
  – Fly Wheels – not commercial
  – Superconducting Materials – not commercial
Options for additional storage evaluation:

- **Technology verification:**
  - Test installations for utility scale batteries
  - Transformer deferral
  - Looking for economic opportunities

- **Location analysis:**
  - Include storage resources at the generation and/or at the load and optimize transmission cost and capacity based on location
Additional analysis (cont’d)

• Identify additional capacity value to wind, solar, etc. from the addition of system storage
• Identify ancillary services benefits inherent in storage not being currently captured
  – Frequency response
  – Spinning reserve
• Initiate consultant study on the issue
• Suggestions from the IRP stakeholders
Planning Reserve Margin Analysis
Capacity Planning Reserve Margin Modeling

• Capacity planning reserve margin (PRM) in System Optimizer covers the following:
  – Operating reserves (contingency and regulation reserves)
  – Load forecast error
  – Plant outages beyond expected outage rate
    • Expected outages modeled by de-rating plant capacity by equivalent forced outage rate and unit maintenance outage rate
  – Other resource availability uncertainties

• PRM analysis for the 2011 IRP will consist of:
  – Loss of Load Probability (LOLP) study
  – Comparison of selected PRM with WECC Building Block Guideline PRM
Loss of Load Probability (LOLP) Study

- Run Planning and Risk in stochastics mode with 100 model iterations
- Simulation year is 2013
- Reliability metric will be the average Loss of Load Hours (LOLH) over the 100 Monte Carlo iterations, divided by the number of hours in the year
  - Excludes the first hour of LOLH events if the event is due to a plant outage; the first hour is covered by the Northwest Power Pool’s reserve sharing program
• Resource starting point will be the forecasted resource base as of year-end 2010 plus resources needed to reach a 10% planning reserve margin in 2013, inclusive of operating reserves
• Stochastic variables include load, thermal/hydro availability, gas and electricity prices
• Long-term volatility parameters for the stochastic model will be turned off (not applicable to a one-year study)
• Energy Not Served cost will be set to zero
Capacity Planning Reserve Margin Modeling

• The model will be re-run with simple-cycle CT capacity added in increments in transmission areas with the most Energy Not Served, corresponding to higher PRM levels
• Develop data tables showing cost and LOLP at the various planning reserve margin levels
• Select a PRM that balances cost and the level of supply reliability
• PacifiCorp will share study results and selected PRM prior to portfolio development starting in September
PRM selected for portfolio development will be compared against a PRM derived using the WECC reserve margin Building Block Guidelines, based on:

- 1-in-10 Temperature Adder
- Regulating Reserve
- Contingency Reserve
- Forced Outage
- 1-in-2 Temperature Demand Forecast
Proposed Portfolio Development Cases
Portfolio Development Cases

• **Hand-out shows 50 proposed cases:** emphasis on DSM potentials, renewable policy scenarios, and carbon cap & trade with declining allowances

• **Several cases address IRP acknowledgment order analysis requirements**

• **Cases cover the following:**
  - Combinations of carbon cap & trade prices, gas price forecasts, and load forecasts (28 cases)
  - Alternative carbon policies and optimization of coal plant retirement dates (5 cases)
Portfolio Development Cases

– Alternative load forecasts: high/low industrial load activity and an extreme temperature forecast
– Renewable resource policies, Renewable Portfolio Standards and production tax credit (5 cases)
– Demand-side management potentials and utility incentive levels (6 cases)
– Two alternative distributed solar utility incentive levels
– A 2011 business plan reference case
Portfolio Development Cases

- Energy Gateway expansion options will also be investigated
- Four week review and written comment period for the proposed cases
  - Comments due August 26, 2010
- The final cases will be distributed at the next public input meeting to be scheduled for September 2010