



# Technical Advisory Committee Meeting Agendas

## Appendix A

**Avista Utilities**  
**Technical Advisory Committee/External Energy Efficiency Board Meeting**  
**October 23, 2003**

**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
    - Distribution efficiencies (e.g., CVR)
    - Peak shaving efficiencies (e.g., voluntary curtailment, TOU)
4. Issues to consider
  - Quality of inputs
  - Usefulness of outputs
    - Is AURORA smarter than Jon?
    - 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

# Avista Utilities 2005 Integrated Resource Plan

## Technical Advisory Committee Meeting No. 3 Agenda

January 25, 2005

	<u>Topic</u>	<u>Time</u>	<u>Staff</u>
1.	Introductions	10:00	Barcus
2.	Review of 2 <sup>nd</sup> TAC Meeting	10:15	Kalich
3.	Overview of Natural Gas Forecast	11:00	Gall
4.	Capacity Planning Overview	11:30	Kalich
5.	Lunch Speaker (and lunch)	12:00	Folsom
6.	Capacity Planning Overview, Cont.	12:45	Kalich
7.	Load Forecast Update	1:15	Barcus
8.	Loads and Resources Update	1:45	Lyons
9.	Imputed Debt	2:15	Thoren
10.	Overview of Feb. 17 TAC Meeting	2:45	Kalich
11.	Adjourn	3:00	

**Avista Utilities 2005 Integrated Resource Plan**  
**Technical Advisory Committee Meeting No. 4 Agenda**  
**4<sup>th</sup> Floor Technology Room—Avista Headquarters, Spokane**  
**February 17, 2005**

	<u>Topic</u>	<u>Time</u>	<u>Staff</u>
1.	Introductions	10:00	Kalich
2.	Review of 3 <sup>rd</sup> TAC Meeting	10:15	Kalich
3.	IRP Modeling Overview	10:30	Gall
4.	Modeling Futures and Scenarios	11:00	Kalich
5.	More on Modeling Assumptions	11:45	Gall
6.	Lunch and AURORA <sub>XMP</sub> Demo	12:15	Gall
7.	Modeling Emissions in IRP	1:15	Lyons
8.	Supply-Side Resource Alternatives	2:45	Gall/Lyons
9.	Selection of Future TAC Dates	3:30	Kalich
10.	Adjourn	4:00	

**Avista Utilities 2005 Integrated Resource Plan**  
**Technical Advisory Committee Meeting No. 5 Agenda**  
**4<sup>th</sup> Floor Technology Room—Avista Headquarters, Spokane**  
**March 23, 2005**

	<u>Topic</u>	<u>Time</u>	<u>Staff</u>
1.	Introductions	10:00	Barcus
2.	Review of 4 <sup>th</sup> TAC Meeting	10:15	Lyons
3.	DSM Integration Into IRP	10:30	Powell
4.	Stochastic (Risk) Modeling Part 1	11:30	Kalich
5.	Lunch and Transmission Planning Discussion	12:00	Cloward
6.	Stochastic (Risk) Modeling Part 2	1:00	Kalich
7.	Preliminary Capacity Expansion Results	1:30	Gall
8.	Update on Scenarios & Futures	2:15	Lyons
9.	2005 Draft IRP Outline	2:45	Lyons
10.	Adjourn	3:00	

# Avista Utilities 2005 Integrated Resource Plan

## Technical Advisory Committee Meeting No. 6 Agenda

May 18, 2005

	<u>Topic</u>	<u>Time</u>	<u>Staff</u>
1.	Introductions	10:00	Barcus
2.	Review of 5 <sup>th</sup> TAC Meeting	10:15	Lyons
3.	Natural Gas Price Forecast Update	10:30	Gall
4.	Base Case Results	10:45	Gall
5.	LP Module/Selection Criteria	11:45	Kalich
6.	Lunch	12:30	
7.	Transmission Planning	1:00	Waples
8.	Scenario Results	2:00	Lyons
9.	Avoided Costs	2:45	Kalich
10.	Action Item for 2005 IRP	3:15	Kalich
11.	Housekeeping Items	3:45	Lyons
12.	Adjourn	4:00	



# Avista Utilities 2005 Integrated Resource Plan

## Technical Advisory Committee Meeting No. 7 Agenda

June 23, 2005

	<u>Topic</u>	<u>Time</u>	<u>Staff</u>
1.	Introductions	10:00	Barcus
2.	Review of 6 <sup>th</sup> TAC Meeting	10:15	Lyons
3.	Hydro Upgrades	10:30	Kalich
4.	Emissions	11:00	Lyons
5.	Lunch	12:00	
6.	DSM	1:00	Powell
7.	Preferred Resource Strategy	3:00	Kalich
8.	Adjourn	4:00	

# Technical Advisory Committee Members

## Appendix B

## 2005 IRP TAC Member List

<u>Name</u>	<u>Organization</u>	<u>Phone Number</u>	<u>E-Mail</u>	<u>TAC1</u>	<u>TAC2</u>	<u>TAC3</u>	<u>TAC4</u>	<u>TAC5</u>	<u>TAC6</u>	<u>TAC7</u>
Aliza Seelig	Puget Sound Energy	425.462.3122	<a href="mailto:aliza.seelig@pse.com">aliza.seelig@pse.com</a>		X					
Andy Ford	WSU		<a href="mailto:FordA@mail.wsu.edu">FordA@mail.wsu.edu</a>			X		X	X	
Bruce Folsom	Avista Utilities	509.495.8706	<a href="mailto:bruce.folsom@avistacorp.com">bruce.folsom@avistacorp.com</a>	X	X	X			X	
Charlie Grist	NPCC	503.222.5161	<a href="mailto:cgrist@nwcouncil.org">cgrist@nwcouncil.org</a>							X
Chris Bevil	Puget Sound Energy	425.456.2757	<a href="mailto:chris.bevil@pse.com">chris.bevil@pse.com</a>		X					
Chris Turner	PacifiCorp	503.813.6114	<a href="mailto:chris.turner2@pacificorp.com">chris.turner2@pacificorp.com</a>		X					
Clint Kalich	Avista Utilities	509.495.4532	<a href="mailto:clint.kalich@avistacorp.com">clint.kalich@avistacorp.com</a>		X	X	X	X	X	X
Danielle Dixon	NW Energy Coalition	206.621.0094	<a href="mailto:danielle@nwenergy.org">danielle@nwenergy.org</a>		X					
Dave Van Hersett	NW Energy Services	509.838.9190	<a href="mailto:davev@nwenergy.com">davev@nwenergy.com</a>	X	X	X			X	X
Diane Thoren	Avista Utilities	509.495.4331				X				
Doug Loreen	Puget Sound Energy	425.454.2988	<a href="mailto:doug.loreen@pse.com">doug.loreen@pse.com</a>							
Doug Young	Avista Utilities			X	X					
Hank McIntosh	WUTC	360.664.1309	<a href="mailto:hmcintos@wutc.wa.gov">hmcintos@wutc.wa.gov</a>		X	X	X	X	X	X
Harry McLean	City of Spokane	509.625.7804	<a href="mailto:hmclean@spokanecity.org">hmclean@spokanecity.org</a>							X
Heidi Heath	Avista Utilities	509.495.4129	<a href="mailto:heidi.heath@avistacorp.com">heidi.heath@avistacorp.com</a>							X
Howard Ray	Potlatch	208.799.1030	<a href="mailto:Howard.Ray@potlatchcorp.com">Howard.Ray@potlatchcorp.com</a>			X		X	X	
James Gall	Avista Utilities	509.495.2189	<a href="mailto:james.gall@avistacorp.com">james.gall@avistacorp.com</a>			X	X	X	X	X
Jamie Stark	Idaho Power	208.388.5648		X						
Jason Fletcher	Avista Utilities			X	X					
Joe Brabeck	Avista Utilities	509.495.4108	<a href="mailto:joe.brabeck@avistacorp.com">joe.brabeck@avistacorp.com</a>					X	X	
Joelle Steward	WUTC	360.664.1308	<a href="mailto:jsteward@wutc.wa.gov">jsteward@wutc.wa.gov</a>	X		X				X
John Lyons	Avista Utilities	509.495.8515	<a href="mailto:john.lyons@avistacorp.com">john.lyons@avistacorp.com</a>			X	X	X	X	X
John Seymour	FPL Energy	561.691.7138	<a href="mailto:john_seymour@fpl.com">john_seymour@fpl.com</a>			X				
Jon Powell	Avista Utilities	509.495.4047	<a href="mailto:jon.powell@avistacorp.com">jon.powell@avistacorp.com</a>	X	X			X		X
Ken Canon	ICNU	503.239.9169	<a href="mailto:kcanon@icnu.org">kcanon@icnu.org</a>	X						
Leonard Coldiron	Potlatch	208.799.7483	<a href="mailto:Leonard.coldiron@potlatchcorp.com">Leonard.coldiron@potlatchcorp.com</a>			X				
Liz Klumpp	WCTED	360.956.2071	<a href="mailto:ElizabethK@ep.cted.wa.gov">ElizabethK@ep.cted.wa.gov</a>	X	X		X	X		X
Lynn Anderson	IPUC	208.334.0350	<a href="mailto:landers@puc.state.id.us">landers@puc.state.id.us</a>	X						
Mallur Nandagopal	City of Spokane	509.625.7811	<a href="mailto:MNandagopal@SpokaneCity.org">MNandagopal@SpokaneCity.org</a>	X						
Patrick Saad	Dana-Saad Co.	509.924.6711	<a href="mailto:patsaad@qwest.net">patsaad@qwest.net</a>				X	X		
Randy Barcus	Avista Utilities	509.495.4160	<a href="mailto:randy.barcus@avistacorp.com">randy.barcus@avistacorp.com</a>		X	X	X	X	X	X
Renee Coelho	Avista Utilities	509.495.8607	<a href="mailto:renee.coelho@avistacorp.com">renee.coelho@avistacorp.com</a>	X	X					
Richard Nagy	Univ. of Idaho	208.885.7350	<a href="mailto:richardn@uidaho.edu">richardn@uidaho.edu</a>		X				X	
Rick Sterling	IPUC	208.334.0351	<a href="mailto:rsterli@puc.state.id.us">rsterli@puc.state.id.us</a>		X	X	X	X	X	X
Steve Silkworth	Avista Utilities	509.495.8093	<a href="mailto:steve.silkworth@avistacorp.com">steve.silkworth@avistacorp.com</a>		X					
Terry Morlan	NPCC	503.222.5161	<a href="mailto:tmorlan@nwcouncil.org">tmorlan@nwcouncil.org</a>		X					
Tom Dempsey	Avista Utilities	509.495.4960	<a href="mailto:tom.dempsey@avistacorp.com">tom.dempsey@avistacorp.com</a>			X		X		
Tom Eckman	NPCC	503.222.5161	<a href="mailto:teckman@nwcouncil.org">teckman@nwcouncil.org</a>	X				X		
Tom McLaughlin	Potlatch	208.799.1935	<a href="mailto:Tom.McLaughlin@potlatchcorp.com">Tom.McLaughlin@potlatchcorp.com</a>			X				X
Yohannes Mariam	WUTC	360.664.1316	<a href="mailto:ymariam@wutc.wa.gov">ymariam@wutc.wa.gov</a>			X	X			X

# 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

# 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

## 2003 IRP Assumptions

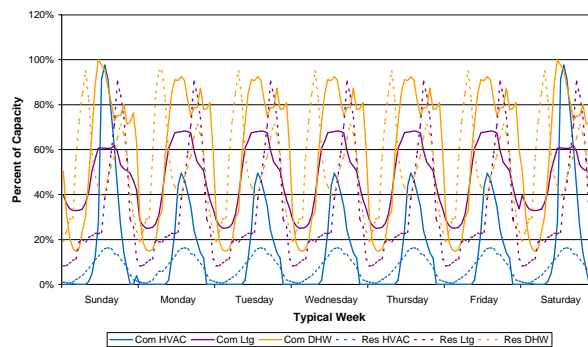
- DSM supply curves
  - For each component, curves were based on actual and three incremental points
  - Incremental points – 25% increase in funding results in 10% increase in savings

## 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

## 2003 IRP Assumptions

Illustration – August Load Shapes







## 2003 IRP Results

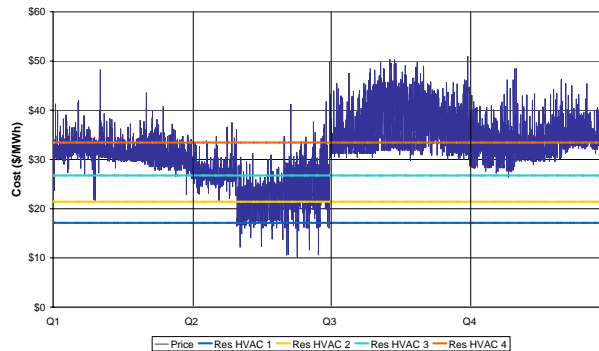
Measure	NPV	Status	Measure	NPV	Status	Measure	NPV	Status
Com DHW 1	64.0	pass	Com HVAC 1	861.8	pass	Com Light 1	3,159.3	pass
Com DHW 2	5.5	pass	Com HVAC 2	1.2	pass	Com Light 2	268.8	pass
Com DHW 3	0.4	pass	Com HVAC 3	-10.5	fail	Com Light 3	21.0	pass
Com DHW 4	0.0	pass	Com HVAC 4	-2.4	fail	Com Light 4	1.4	pass
<b>255 MWh passed</b>			<b>8,480 MWh passed</b>			<b>12,931 MWh passed</b>		
Res DHW 1	3.3	pass	Res HVAC 1	238.2	pass	Res Light 1	2,664.5	pass
Res DHW 2	-0.3	fail	Res HVAC 2	16.5	pass	Res Light 2	218.4	pass
Res DHW 3	-0.1	fail	Res HVAC 3	0.7	pass	Res Light 3	15.8	pass
Res DHW 4	-0.0	fail	Res HVAC 4	0.0	fail	Res Light 4	0.8	pass
<b>69 MWh passed</b>			<b>1,563 MWh passed</b>			<b>9,007 MWh passed</b>		

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



## 2003 IRP Results

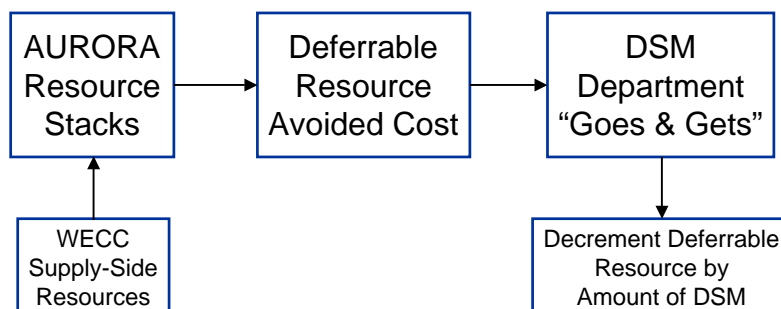
Illustration – Residential HVAC vs. 2004 Prices



## Integration Methodologies

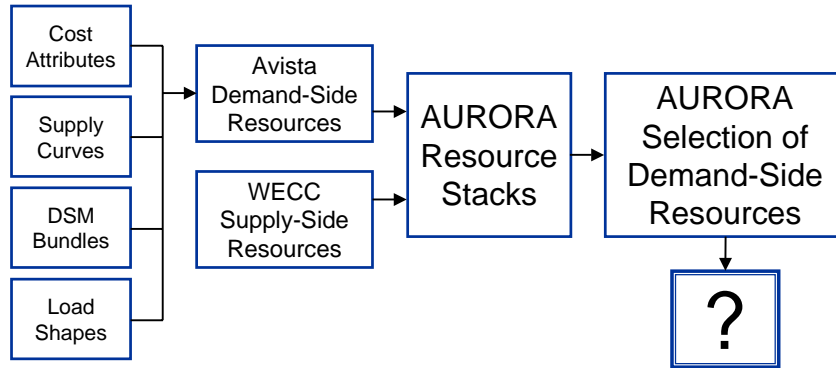
- Avoided cost price signal
- Full integration into AURORA model
- Approach used in 2003 IRP

## Avoided Cost Price Signal

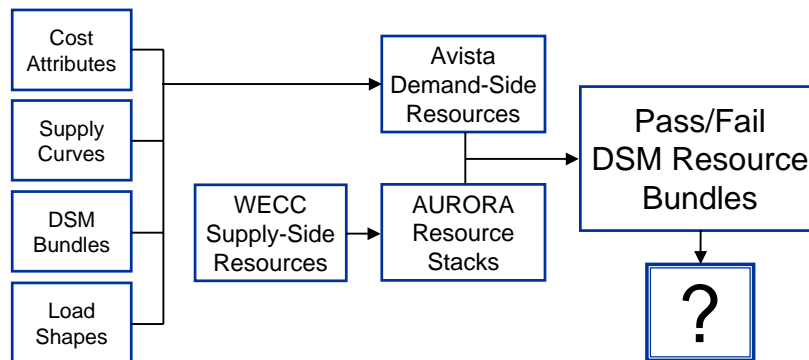




## Full Integration Into AURORA



## Approach Used In 2003 IRP



## 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

## Overview of Planning Process

---

- 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

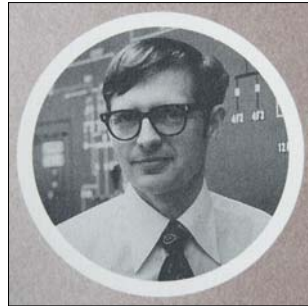
## Review of 2005 IRP Schedule

- 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

Issue	Area	Index	Details of Issue	Utility Response
1	Risk	Analysis	consider fuel supply and price risk, as well as value of resource diversity	will be evaluated
2	DSM	Buybacks	Council is focusing on buy-backs and would like utility to consider it in 2005 IRP	will include in plan
3	L&R	Capacity	discuss what planning capacity is (single- versus multi-hour peak)	include in plan
4	L&R	Capacity	discuss if adjusting hydro maintenance/upgrades would eliminate need for additional peaking plants	include in plan
5	L&R	Capacity	Look to hydro for new capacity	include in plan
6	DSM	Codes	Model future code revisions and quantify their impact on load forecast	The econometric forecast methodology captures improved energy codes. Improvements over and above the code are quantified within the DSM resource acquisition.
7	Resources	Cogen	Keep Cogen discussion in '05 IRP	will include in IRP
8	Resources	Cogen	Include discussion on what makes a good cogen project (maybe to appendix?)	look to power council, AVA research
9	Resources	Cogen	emphasize importance of flexibility, dispatchability, as historical projects haven't been perfect fits	include in discussion above
10	Resources	Cogen	Do we have estimate of cogen potential? Consider strength of cogen facility (i.e., how long will it be around) in matrix	include discussion of potential
11	Resources	Cogen	Rate structure makes cogen hard. Consider demand charges with ratchets, seasonal rates, TOU, etc.	include in discussion, recognizing this as rate issue
12	Resources	Cogen	Cogen makes more sense in a transmission constrained region than any other form of generation because it will occur at a load center and it provides twice the usage of some portion of the natural gas	include in discussion
13	Risk	Contingency Planning	Develop plan for the shelf to use in event of 00-01 happening again (ST solution for ST problems)	Evaluate the development of DSM-funded contingency plans to include customer buyback and various emergency DSM options
14	Credit	Credit	Discuss pros and cons of PPA versus ownership of resources	include in discussion
15	Resources	DG	discuss DG and its impact on transmission/distribution systems	include in discussion
16	DSM	DSM	Be aggressive on DSM, AVA should consider higher incentives	literature search & consider controlled experiment on higher incentives

## August 4, 2004 IRP TAC Brainstorming Summary

Issue	Area	Index	Details of Issue	Utility Response
17	DSM	DSM	Evaluate accelerating the DSM acquisition schedule	We will review the assumptions and methodology behind the slight front-loading of the draft 20-year regional supply curve. Avista is currently engaging in a significant expansion of DSM resource acquisition.
18	Resources	Emissions	consider risk of future emission (CO2 and Mercury)	will be evaluated as scenarios, consider including in stochastic runs
19	Risk	Emissions	look at a couple levels of mitigation costs when evaluating impact on resource decisions	will evaluate as scenarios
20	Risk	Gas	consider buying gas model or a consultant forecast	Company purchases Global Insights forecast
21	Resources	IPP	Consider IPP plants in plan	include in plan
22	L&R	L&R	include monthly L&R tables in IRP	will include in tech. Appendix
23	L&R	L&R	Include 24-hour seasonal load shapes for utility, by customer class where available	will include system hourly loads by season, as class-level data is not available
24	L&R	L&R	Evaluate forecasts besides base case, what happens if Fairchild Airforce Base closes, expands	will include hi/lo forecasts & scenarios, including discussion of FAB changes
25	L&R	L&R	look at plans to address supply/demand shocks (FAB closure, Noxon failure, etc.)	include in plan
26	DSM	Load Control	If IRP finds it a good idea, recognize need to go in for rate schedule changes to address cost shifts	include in discussion
27	Risk	Loads	Plan of how utility will address changing conditions (e.g., new load or load loss). How would a LT commitment to a coal plant be addressed if after the decision load fell	include in IRP discussion/scenarios
28	Resources	Nuclear	Consider this resource to address emissions and availability of fossil fuels	add as resource alternative to IRP
29	Risk	Risk	Address how long-term risk planning transitions to short-term risk management procedures	include in discussion
30	Risk	Risk	Evaluate the hedge value of efficiency and renewables	will be included in analysis/discussion
31	DSM	Supply Curves	develop supply curves for IRP, possibly starting with NPCC curves	Review regional DSM supply curves to determine if they can be extrapolated to Avista's DSM portfolio
32	Trans.	Trans.	Discuss transmission in plan	include in plan
33	Resources	Wind	Look at studies out there on wind integration to see what the latest information is	will include extensive eval. of wind in IRP

# **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

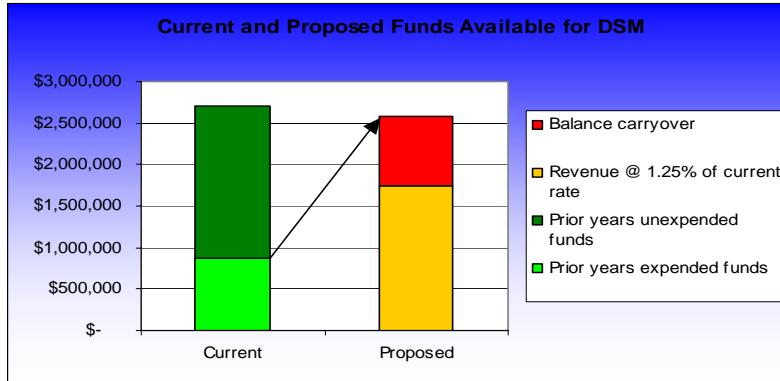
- Washington
  - \$/kWh tariff rider
  - An amount equal to 1.48% of retail rates
- Idaho
  - Tariff rider established at 1.95% of retail rates
- These amounts do not include non-efficiency funding received through the same tariff rider

## 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

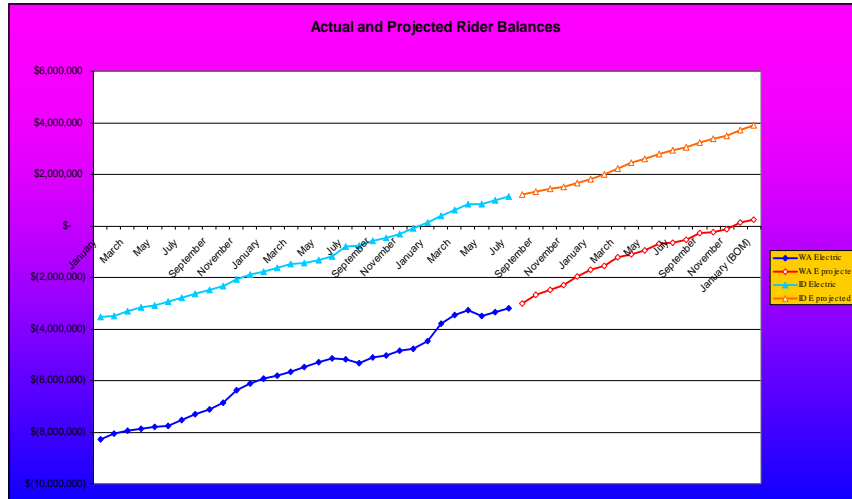
- Reduce tariff rider to an amount equal to 1.25% of current retail rates
- Funding sufficient to support a three-fold increase in expenditures



## 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)



## 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
  - Torchieres
  - 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

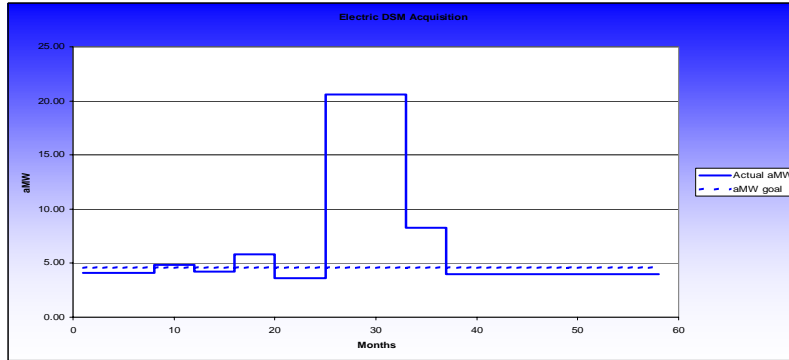
### Enhancement Programs in Development

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



## 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 1<sup>st</sup> year kWh
    - 48 to 72 month customer simple payback → 6 cents per 1<sup>st</sup> year kWh
    - Over 72 month customer simple payback → 8 cents per 1<sup>st</sup> year kWh
    - Subject to 50% of incremental measure cost ceiling
  - “New Technology” electric efficiency
    - Under 48 month customer simple payback → 10 cents per 1<sup>st</sup> year kWh
    - 48 to 72 month customer simple payback → 12 cents per 1<sup>st</sup> year kWh
    - Over 72 month customer simple payback → 14 cents per 1<sup>st</sup> year kWh
    - Subject to 75% of incremental measure cost ceiling
  - Fuel-Conversion
    - 24 to 48 month customer simple payback → 1 cent per 1<sup>st</sup> year kWh
    - 48 to 72 month customer simple payback → 2 cents per 1<sup>st</sup> year kWh
    - Over 72 month customer simple payback → 3 cents per 1<sup>st</sup> 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

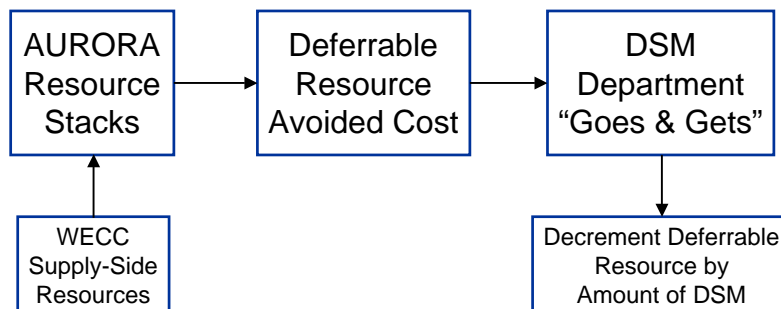
## Planning for the Future

- 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

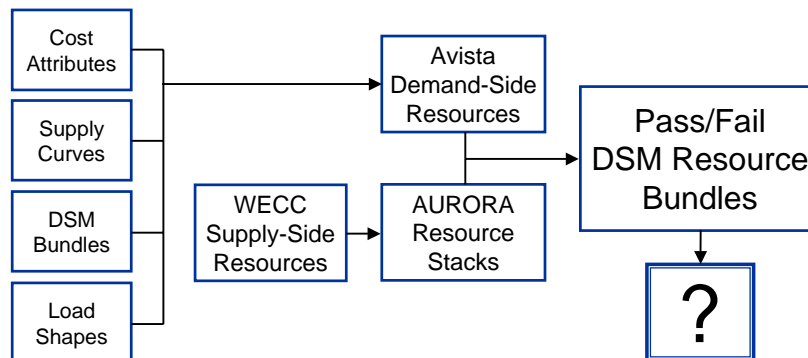
## Avoided Cost Price Signal



## 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



## Proposed Methodology Attributes

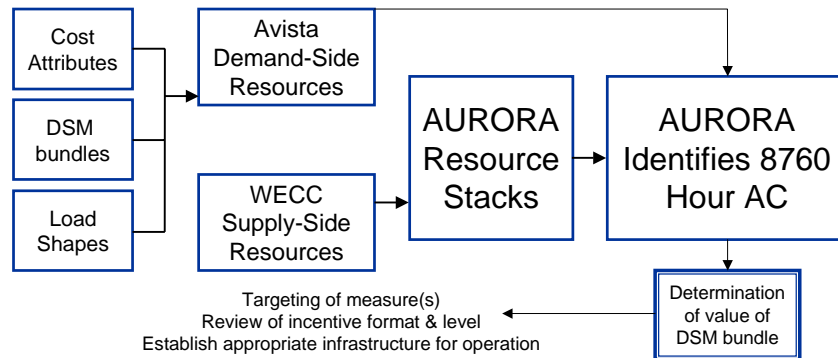
- Adaptation of both the price signal and full integration approach
- Specific to the mid- and long-term management decisions regarding DSM operations and infrastructure development.
  - Should we target system-coincident and/or disproportionately on-peak end-uses?
  - Is our current incentive structure 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



## Proposed Methodology Flow



## 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 Project:  
Cabinet Gorge and Noxon Rapids  
Hydroelectric Developments

## Noxon Rapids HED



## Cabinet Gorge 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

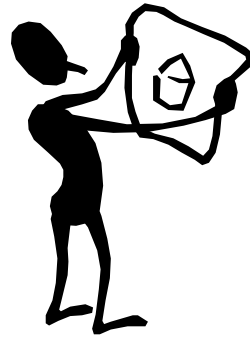
## Avista’s Strategy

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*

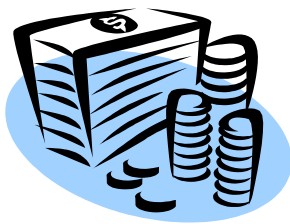
## Plan

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



## Financial

- One Tunnel (\$ 38 Million)
- Annual Mitigation (\$ 0.5 Million)



*We are Avista...We improve life's quality...With energy*

# Spokane River Relicensing

TECHNICAL ADVISORY  
COMMITTEE MEETING

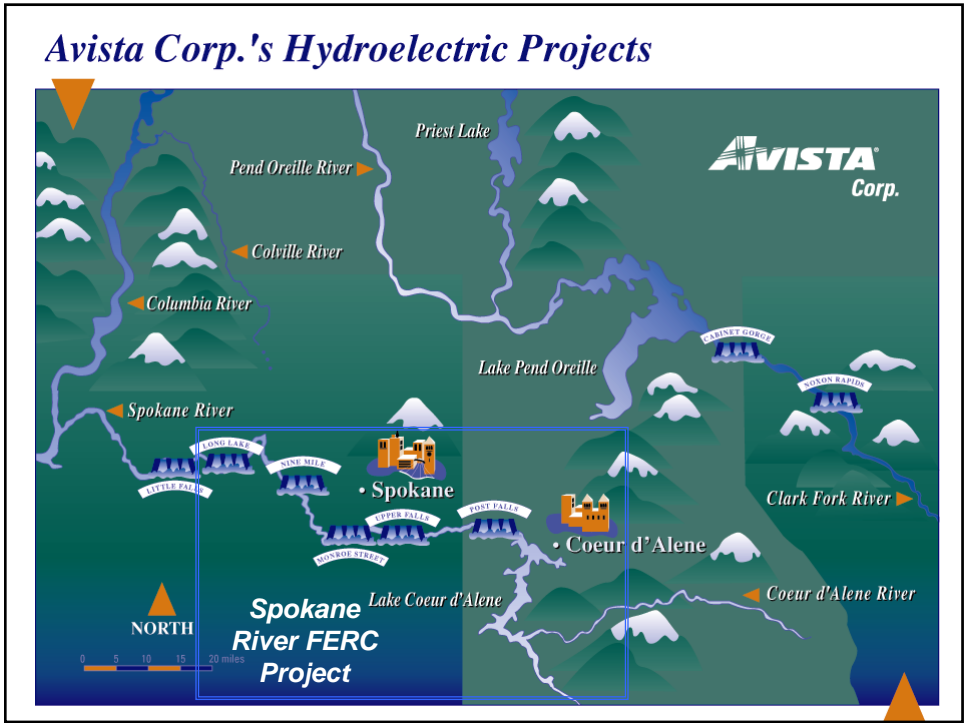
AUGUST 4, 2004



Long Lake Powerhouse - 1999



## Avista Corp.'s Hydroelectric Projects



## **Post Falls Facility**

*One of five in FERC License 2545*



August 4, 2004

3

## **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



August 4, 2004

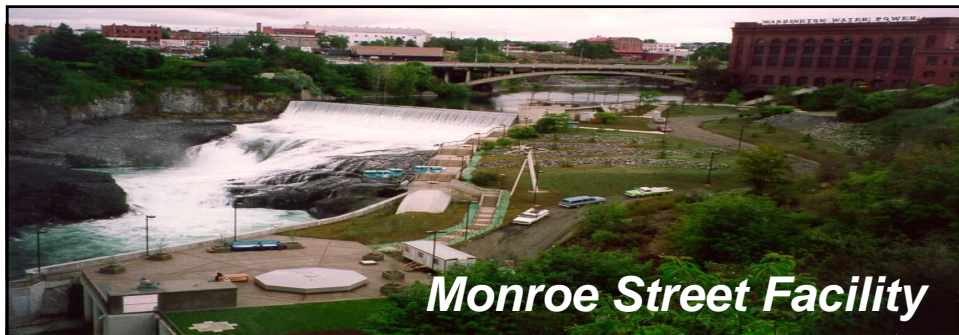
4



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

August 4, 2004

5



- ◆ 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

August 4, 2004

6



## ***Nine Mile Facility***

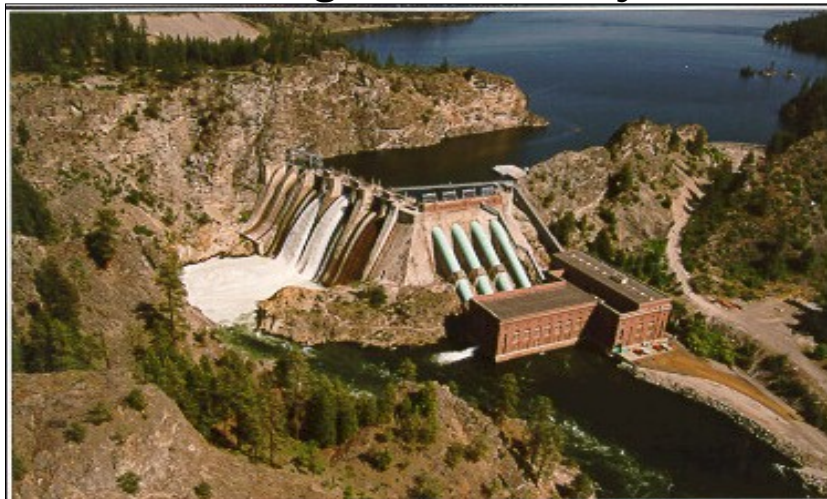
- ◆ Construction completed and first operation in 1908
- ◆ Total usable storage - 3,130 acre feet
- ◆ Average annual inflow - 7,100 cfs
- ◆ Full pool forebay elevation - 1606.6 with 10' flashboards
- ◆ Powerhouse turbine capacity (4 units) - 6,400 cfs
- ◆ Generating Capacity - 26 MW
- ◆ Limited Storage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

August 4, 2004

7

***We are Avista...We improve life's quality...With energy***

## ***Long Lake Facility***



August 4, 2004

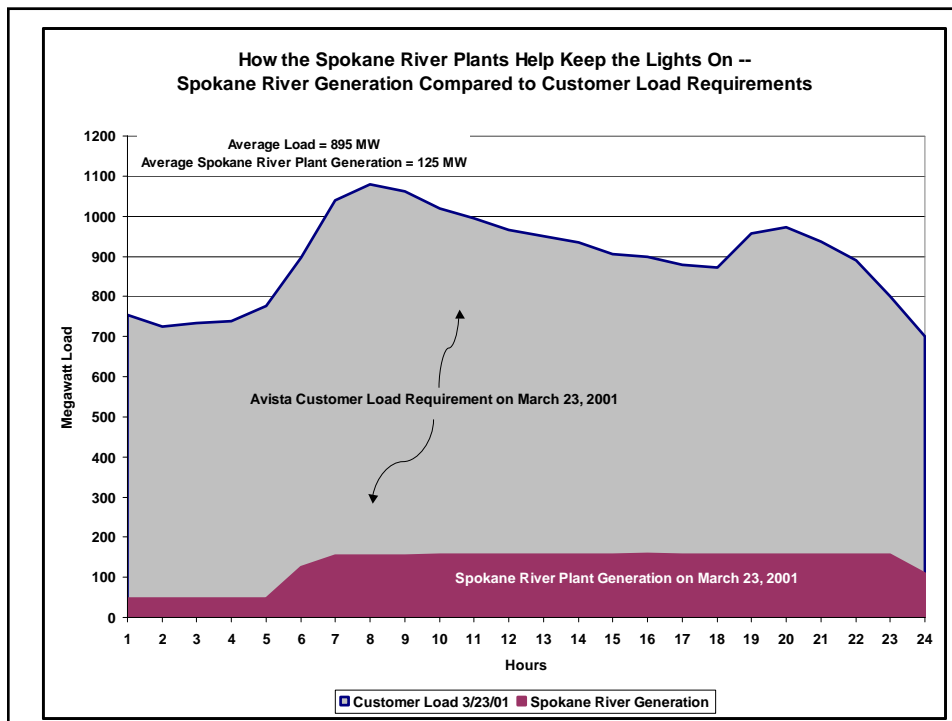
8

## 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

August 4, 2004

9



## **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

August 4, 2004

11

## **FERC Licenses**

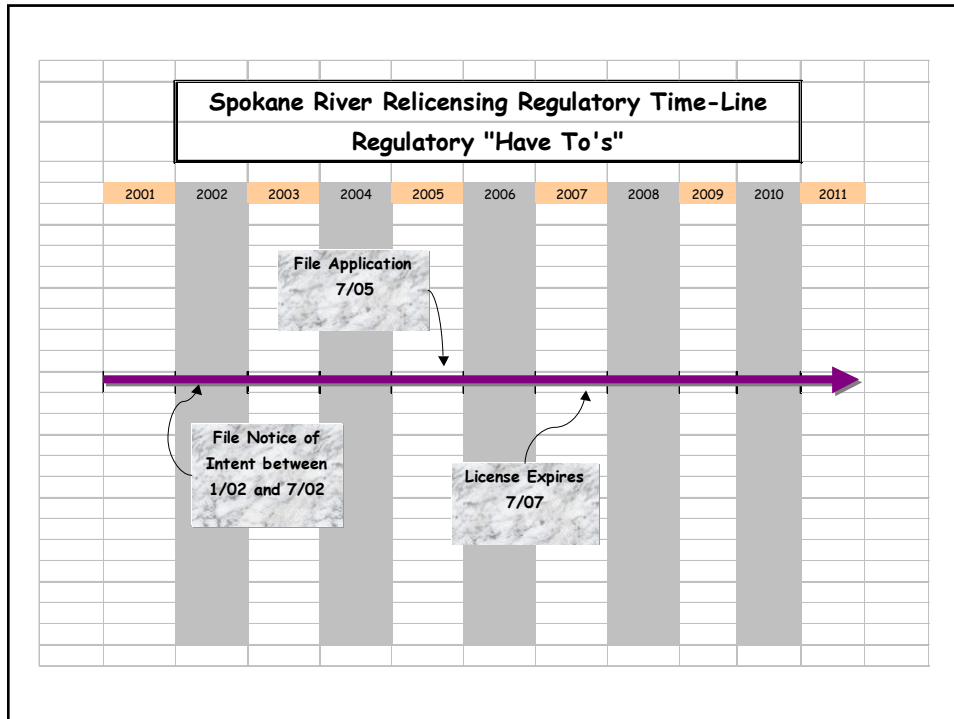


- ◆ Describe the facilities and operations
- ◆ Contain protection, mitigation and enhancement measures (PM&E) for project associated resources

August 4, 2004

12





*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

1

## 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

2

## 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

3

## National Outlook

### The Consumer Markets Environment

(Percent change)

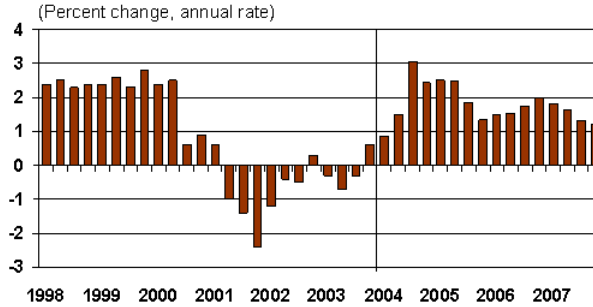
	2002	2003	2004	2005	2006
Real Consumption	3.4	3.1	3.8	3.1	3.5
Real Disposable Income	3.8	2.5	3.5	3.0	3.8
Payroll Employment	-1.1	-0.3	1.1	2.3	1.6
Unemployment Rate, %	5.8	6.0	5.6	5.3	5.3
Real Household Net Worth	-3.0	2.0	8.2	3.1	2.7
Consumer Price Index	1.6	2.3	1.4	1.3	1.5
Light Vehicle Sales, millions	16.8	16.6	17.2	17.3	17.5
Home Sales, millions	6.6	7.2	7.2	6.6	6.5
Existing Home Prices	8.9	7.3	5.4	2.3	3.1
30-Year Mortgage Rate, %	6.5	5.8	6.2	6.7	6.8

4

# National Outlook

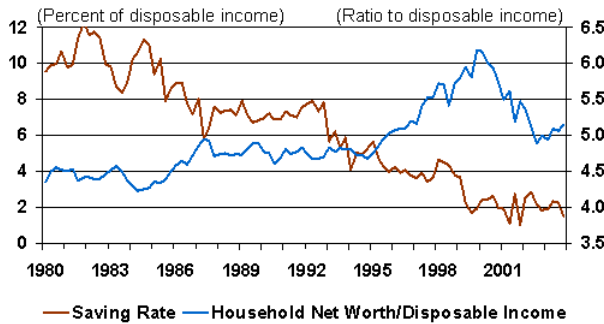
## Employment Finally Begins to Recover

January employment was 2.35 million below its March 2001 peak.



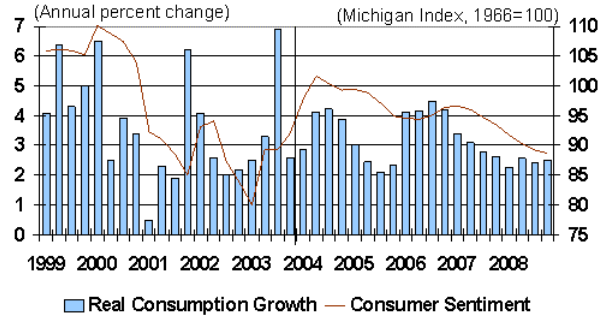
# National Outlook

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



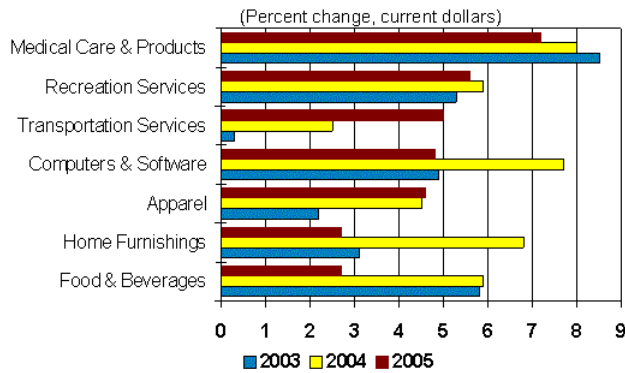
# National Outlook

## Real Consumer Spending and Confidence



# National Outlook

## 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

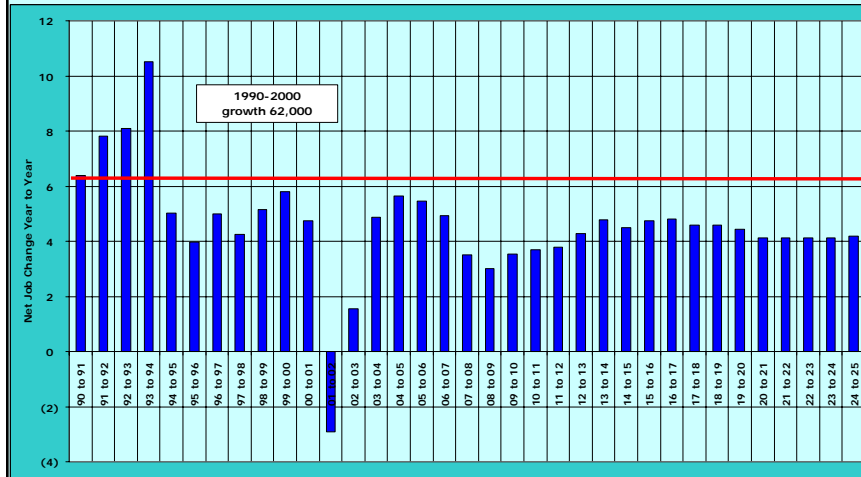
9

## 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

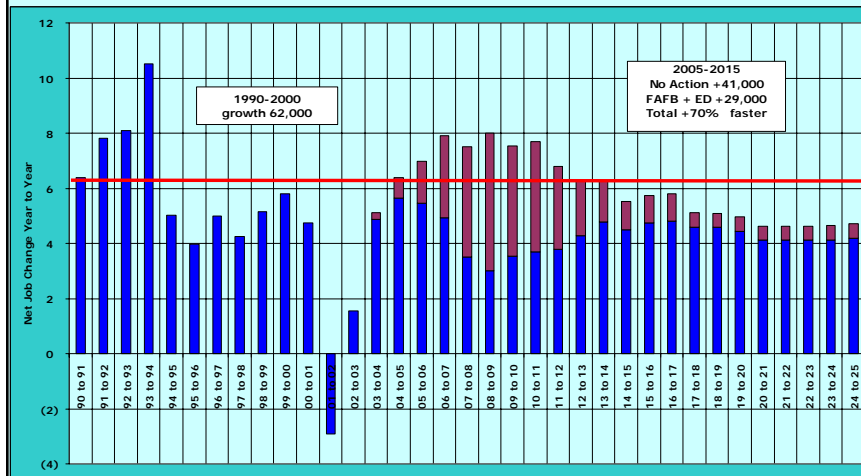
10

# Regional Outlook--Jobs



11

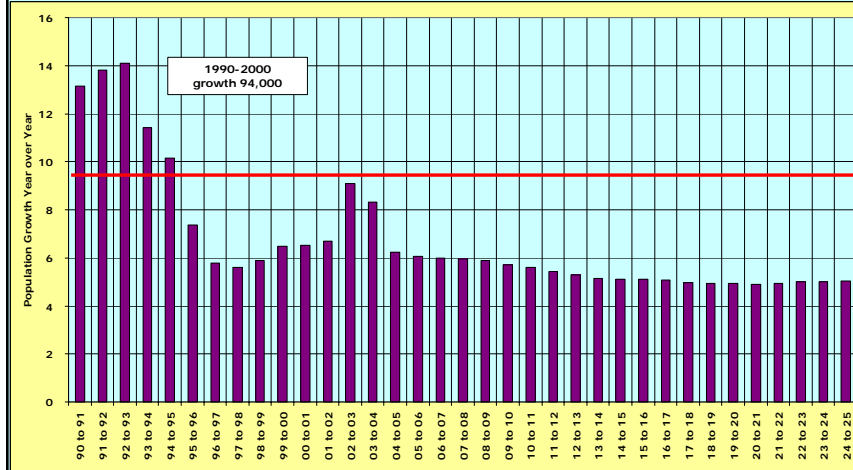
# Regional Outlook--Jobs



12

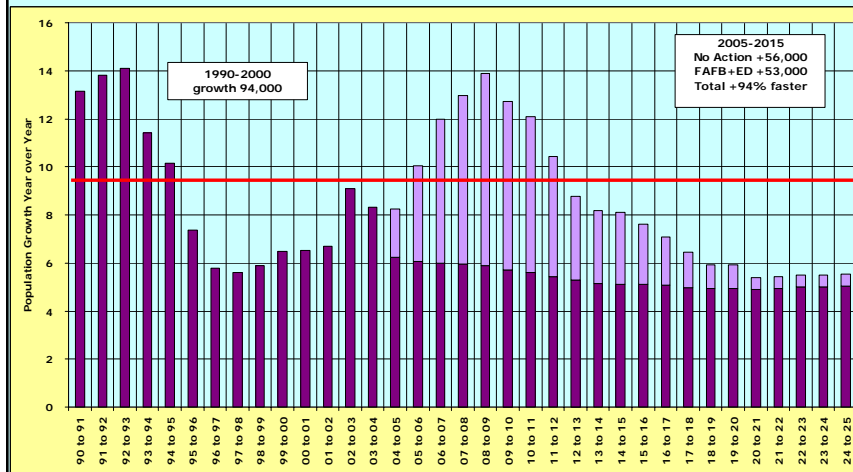


# Regional Outlook--Persons



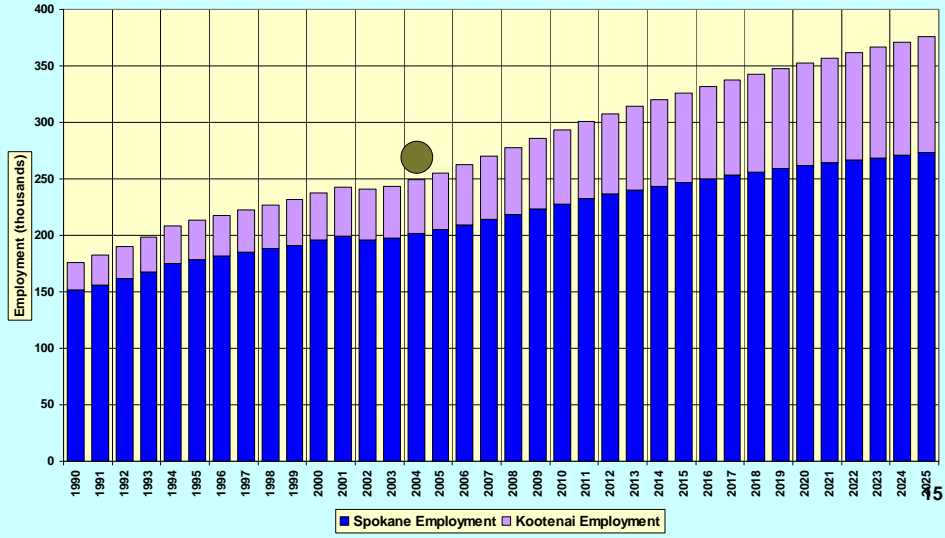
13

# Regional Outlook--Persons

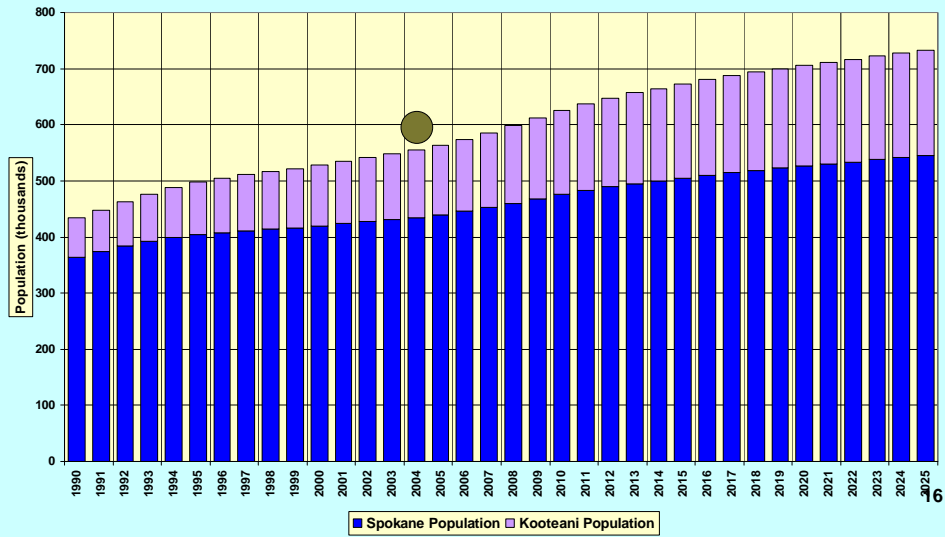


14

# Kootenai & Spokane Employment



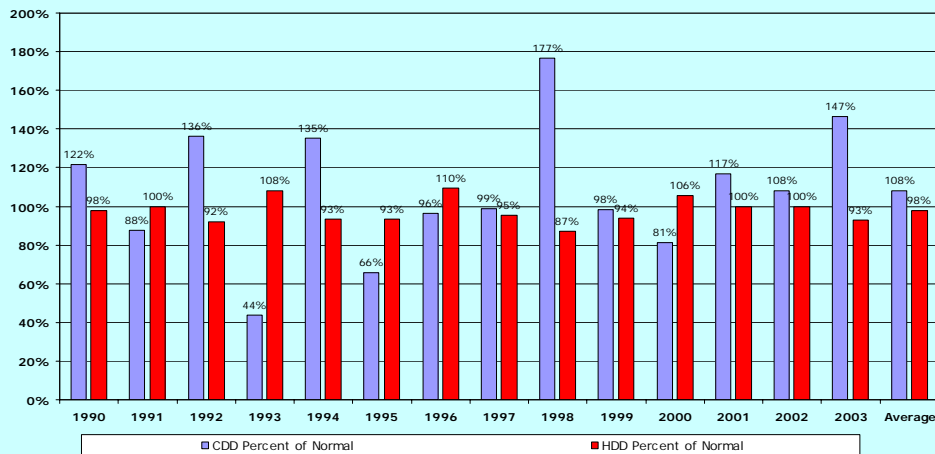
# Kootenai & Spokane Population



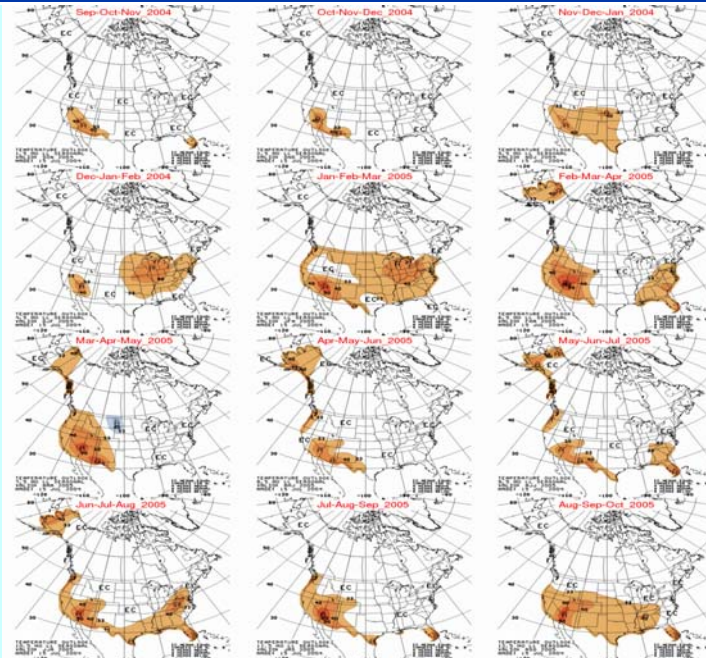
# Degree Day Forecasts

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

## Spokane NWS Calendar Year Degree Days



July 2004  
NOAA  
Climate  
Prediction  
Center



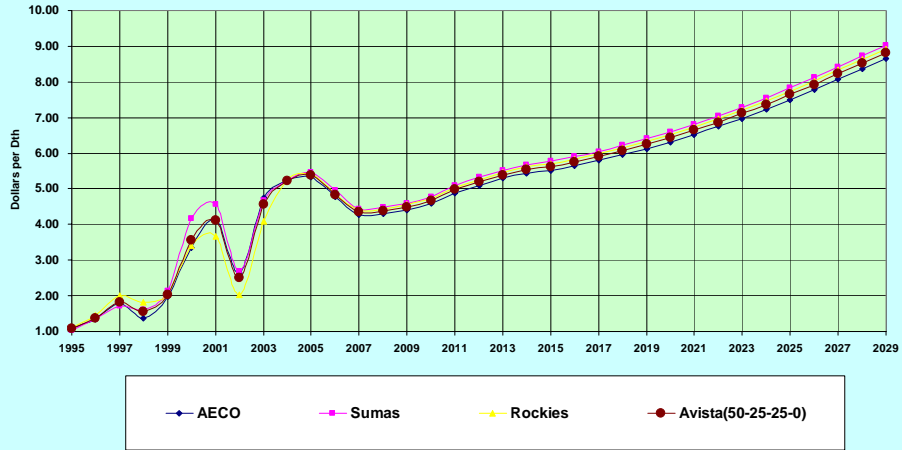
19

## Price Forecasts

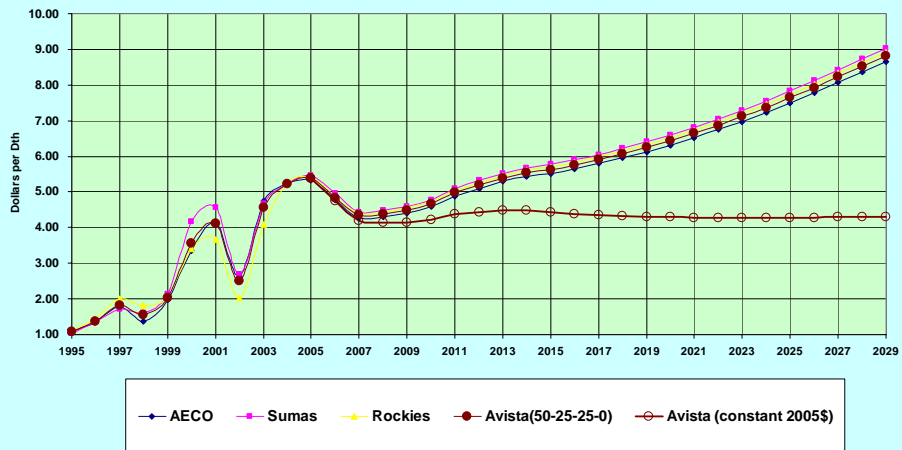
- **Electric Price Forecasts**
  - In 2005 – assumed 14% Idaho, 5% Washington
  - Out years – assumed 8% at 4 year intervals
- **Natural Gas Price Forecasts**
  - Retail – assumed 16% Idaho, 14% Washington
  - Cost of Gas – used Nymex index 7/1/04 through 2006, projected at Global Insight escalation afterward
- **Underlying Inflation**
  - GDP Deflator from Global Insight Forecast
  - 20 year average is 2.9%

20

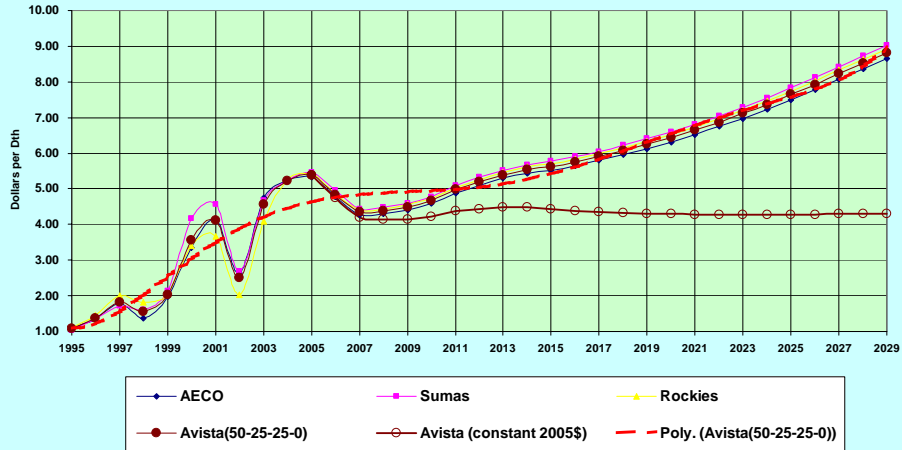
Avista Corp. Natural Gas Cost Forecasts



Avista Corp. Natural Gas Cost Forecasts



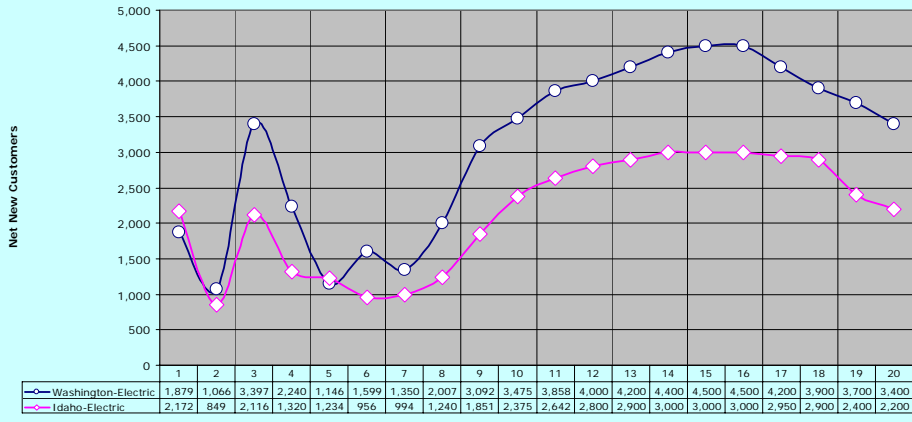
Avista Corp. Natural Gas Cost Forecasts



Results  
Base Case  
2005 Forecast

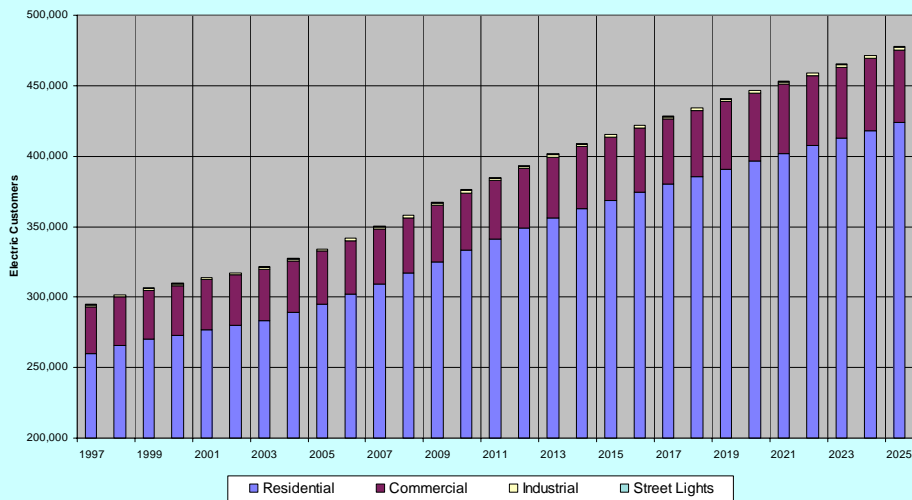
# Avista Customer Forecasts

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

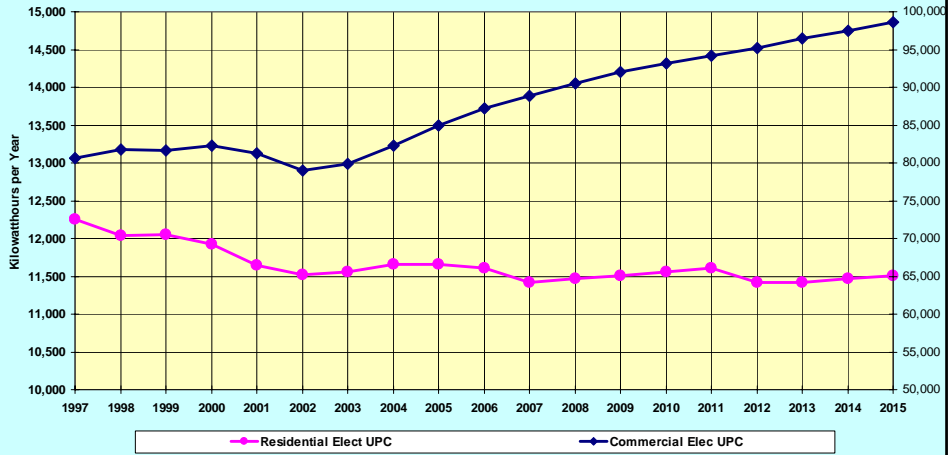


# Avista Customer Forecasts

2005-2015 2.2%, 2005-2025 1.8%

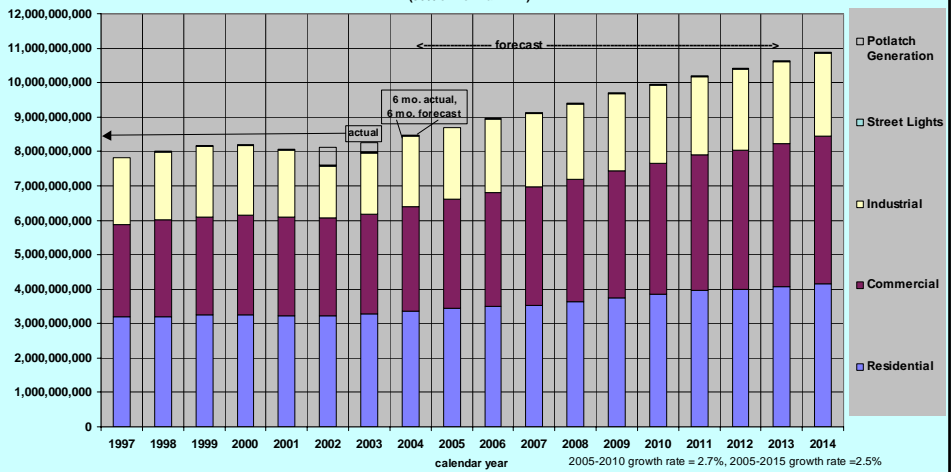


Electric Use Per Customer



2005 ELECTRIC RETAIL SALES FORECAST

(96% of Normal HDD)





## Detailed Forecast Example

Year	Month	Customer EBS	Residential	Commercial	Industrial	Residential	Commercial	Industrial	WWh
2004	JAN	186,120	214,940,564						1,265,004
	FEB	186,120	228,408,122						1,285,056
	MAR	186,014	205,888,320						1,428,908
	APR	186,018	189,031,735						1,328,123
	MAY	185,446	148,732,891						1,618,864
	JUN	186,440	140,271,921						1,688,999
	JUL	186,103	144,032,921						2,510,707
	AUG	186,665	171,729,824						2,980,039
	SEP	186,883	164,228,084						3,274,743
	OCT	188,037	157,548,507						3,778,556
	NOV	188,300	159,365,396						4,021,471
	DEC	189,559	249,458,820						4,933,073
ANNUAL	186,765	2,223,620,215						30,346,419	
2005	JAN	189,629	276,105,356						3,305,951
	FEB	189,620	229,029,393						3,194,250
	MAR	189,614	238,742,192						3,193,752
	APR	189,418	178,171,171						3,369,875
	MAY	188,046	151,166,000						3,545,340
	JUN	188,340	143,102,482						3,721,676
	JUL	188,403	146,002,799						4,279,808
	AUG	190,165	176,888,810						4,709,709
	SEP	190,483	169,061,531						5,240,782
	OCT	191,737	162,265,173						5,834,250
	NOV	192,720	174,499,789						6,325,477
	DEC	193,569	267,001,933						7,018,034
ANNUAL	190,213	2,284,065,688						34,423,139	
2006	JAN	193,229	282,757,893						3,359,523
	FEB	193,230	234,646,977						3,241,461
	MAR	193,414	222,198,384						3,148,443
	APR	193,519	182,746,004						3,346,665
	MAY	191,348	158,631,213						3,609,740
	JUN	192,140	146,719,708						3,785,005
	JUL	193,403	151,938,422						4,242,263
	AUG	194,285	181,606,085						4,919,955
	SEP	194,483	173,479,807						5,346,319
	OCT	195,857	166,553,008						5,870,949
	NOV	196,720	179,072,228						6,400,807
	DEC	197,359	243,636,101						7,044,795
ANNUAL	194,071	2,341,913,028						36,943,810	
2007	JAN	197,305	230,312,246						3,668,640
	FEB	197,327	218,925,250						3,526,585
	MAR	197,562	218,321,535						3,453,762
	APR	197,178	216,348,987						3,438,833
	MAY	190,306	219,678,050						3,757,157
	JUN	181,656	218,771,135						3,950,263
	JUL	193,693	217,428,856						4,526,696
	AUG	194,285	223,630,215						5,127,725
	SEP	195,213	224,065,688						5,620,699
	OCT	196,071	231,913,028						6,100,149
	NOV	196,871	248,583,580						6,568,288
	DEC	198,021	249,407,745						7,274,014
ANNUAL	192,271	2,494,007,745						38,502,711	
2008	JAN	200,671	248,583,580						4,258,790
	FEB	211,171	234,949,456						4,027,711
	MAR	215,671	246,900,315						3,948,761
	APR	219,871	239,921,552						3,849,761
	MAY	223,711	268,865,274						4,248,742
	JUN	227,471	276,343,987						4,511,732
	JUL	229,871	270,228,801						4,929,222
	AUG	230,121	282,548,456						5,428,456
	SEP	230,121	282,548,456						5,937,725
	OCT	230,121	282,548,456						6,447,018
	NOV	230,121	282,548,456						6,956,311
	DEC	230,121	282,548,456						7,465,604
ANNUAL	230,121	2,825,228,801						41,929,222	

29

## Avista Utilities Native Load

Load (MW)	F2005 Annual Avg	744	672	744	720	744	720	744	740	720	744	720	744
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	929	1,098	1,035	952	878	832	786	845	918	815	854	1,071	1,071
1998	954	1,065	994	943	902	941	845	966	936	866	886	960	1,140
1999	988	1,076	1,075	1,020	950	917	933	971	991	904	933	982	1,117
2000	1,012	1,153	1,114	1,034	921	889	924	961	985	889	950	1,163	1,173
2001	964	1,147	1,110	975	905	862	868	911	956	864	911	957	1,114
2002	994	1,095	1,072	1,040	929	898	950	1,018	953	891	968	1,034	1,090
2003	1,013	1,087	1,076	991	926	900	968	1,056	997	934	957	1,111	1,161
2004	1,029	1,194	1,108	987	925	900	963	1,020	1,057	956	1,016	1,044	1,184
2005	1,067	1,226	1,180	1,107	985	928	927	1,048	1,087	984	1,045	1,073	1,219
2006	1,099	1,262	1,211	1,139	1,014	955	955	1,081	1,121	1,018	1,079	1,106	1,258
2007	1,122	1,289	1,235	1,162	1,035	975	975	1,102	1,144	1,041	1,101	1,127	1,284
2008	1,152	1,325	1,267	1,193	1,064	1,001	1,002	1,129	1,174	1,070	1,129	1,156	1,319
2009	1,185	1,365	1,302	1,227	1,095	1,030	1,031	1,160	1,208	1,103	1,161	1,187	1,358
2010	1,215	1,401	1,334	1,257	1,123	1,055	1,057	1,188	1,238	1,133	1,189	1,216	1,393
2011	1,246	1,439	1,367	1,289	1,153	1,083	1,085	1,217	1,270	1,164	1,219	1,246	1,429
2012	1,270	1,469	1,393	1,314	1,175	1,104	1,106	1,239	1,294	1,188	1,242	1,269	1,458
2013	1,296	1,500	1,421	1,340	1,200	1,126	1,129	1,263	1,320	1,214	1,267	1,293	1,488
2014	1,323	1,533	1,450	1,368	1,225	1,150	1,153	1,289	1,348	1,241	1,293	1,319	1,520
2015	1,354	1,570	1,482	1,400	1,254	1,177	1,180	1,317	1,379	1,272	1,322	1,349	1,555
2016	1,379	1,600	1,509	1,425	1,278	1,198	1,202	1,340	1,404	1,297	1,346	1,372	1,585
2017	1,395	1,619	1,526	1,441	1,293	1,212	1,216	1,355	1,420	1,312	1,361	1,387	1,603
2018	1,417	1,646	1,550	1,464	1,314	1,231	1,235	1,376	1,443	1,335	1,382	1,409	1,629
2019	1,447	1,682	1,581	1,495	1,342	1,257	1,262	1,403	1,473	1,364	1,410	1,437	1,664
2020	1,472	1,713	1,608	1,521	1,366	1,279	1,284	1,427	1,499	1,389	1,434	1,461	1,694
2021	1,499	1,745	1,636	1,548	1,391	1,302	1,307	1,452	1,526	1,416	1,460	1,486	1,725
2022	1,517	1,767	1,656	1,567	1,408	1,318	1,323	1,469	1,544	1,434	1,477	1,504	1,746
2023	1,549	1,805	1,689	1,599	1,438	1,346	1,351	1,498	1,576	1,465	1,507	1,534	1,783
2024	1,577	1,839	1,719	1,628	1,464	1,370	1,376	1,524	1,604	1,493	1,534	1,561	1,816
2025	1,605	1,873	1,750	1,657	1,491	1,395	1,401	1,551	1,633	1,522	1,561	1,588	1,849

30

## Avista Utilities Native Peak Demand

	Calendar	Operating Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1997	1,512		1,508	1,391	1,286	1,228	1,115	1,019	1,202	1,289	1,122	1,146	1,403	1,373
1998	1,665	1,578	1,575	1,255	1,195	1,251	1,249	1,164	1,521	1,422	1,317	1,246	1,296	1,663
1999	1,436	1,666	1,357	1,379	1,300	1,209	1,213	1,338	1,405	1,402	1,175	1,232	1,308	1,434
2000	1,570	1,475	1,458	1,474	1,301	1,262	1,147	1,308	1,454	1,396	1,183	1,254	1,492	1,561
2001	1,519	1,566	1,474	1,490	1,329	1,209	1,243	1,228	1,382	1,370	1,169	1,175	1,380	1,429
2002	1,457	1,452	1,388	1,362	1,398	1,180	1,149	1,376	1,457	1,335	1,197	1,360	1,337	1,412
2003	1,510	1,458	1,393	1,408	1,258	1,221	1,179	1,321	1,487	1,400	1,332	1,323	1,432	1,509
2004	1,779	1,779	1,766	1,434	1,366	1,177	1,121	1,391	1,514	1,501	1,275	1,352	1,389	1,566
2005	1,622	1,622	1,619	1,562	1,477	1,315	1,243	1,308	1,549	1,538	1,311	1,389	1,425	1,611
2006	1,669	1,669	1,666	1,602	1,518	1,353	1,278	1,344	1,590	1,582	1,354	1,432	1,467	1,660
2007	1,702	1,702	1,699	1,632	1,546	1,379	1,302	1,369	1,616	1,610	1,381	1,459	1,494	1,692
2008	1,748	1,748	1,745	1,672	1,585	1,415	1,335	1,402	1,651	1,649	1,419	1,495	1,530	1,736
2009	1,799	1,799	1,796	1,717	1,628	1,454	1,371	1,439	1,690	1,691	1,461	1,535	1,570	1,785
2010	1,844	1,844	1,841	1,757	1,666	1,490	1,404	1,472	1,725	1,729	1,498	1,571	1,606	1,829
2011	1,891	1,891	1,889	1,798	1,707	1,527	1,438	1,507	1,762	1,769	1,537	1,608	1,643	1,875
2012	1,928	1,928	1,926	1,831	1,738	1,556	1,464	1,533	1,790	1,800	1,568	1,637	1,672	1,911
2013	1,968	1,968	1,965	1,866	1,771	1,587	1,493	1,562	1,820	1,833	1,600	1,668	1,703	1,949
2014	2,010	2,010	2,007	1,903	1,807	1,619	1,523	1,593	1,852	1,868	1,635	1,701	1,736	1,990
2015	2,056	2,056	2,053	1,943	1,846	1,655	1,556	1,626	1,888	1,906	1,673	1,738	1,773	2,034
2016	2,094	2,094	2,091	1,977	1,878	1,685	1,583	1,654	1,917	1,938	1,704	1,768	1,803	2,071
2017	2,118	2,118	2,115	1,998	1,898	1,704	1,601	1,672	1,936	1,958	1,724	1,787	1,822	2,094
2018	2,153	2,153	2,150	2,028	1,928	1,730	1,625	1,697	1,962	1,987	1,752	1,814	1,849	2,128
2019	2,197	2,197	2,194	2,067	1,965	1,765	1,657	1,729	1,996	2,024	1,789	1,849	1,884	2,170
2020	2,236	2,236	2,233	2,102	1,998	1,796	1,685	1,757	2,026	2,057	1,821	1,880	1,915	2,208
2021	2,277	2,277	2,274	2,137	2,033	1,827	1,715	1,787	2,057	2,091	1,854	1,912	1,947	2,248
2022	2,305	2,305	2,302	2,162	2,056	1,849	1,735	1,807	2,079	2,115	1,877	1,934	1,969	2,275
2023	2,352	2,352	2,349	2,204	2,097	1,886	1,769	1,842	2,116	2,154	1,916	1,971	2,006	2,321
2024	2,395	2,395	2,392	2,242	2,133	1,920	1,800	1,873	2,148	2,190	1,952	2,005	2,040	2,362
2025	2,439	2,439	2,436	2,280	2,170	1,954	1,831	1,905	2,182	2,227	1,988	2,039	2,074	2,405

31

# Future Resource Requirements

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

Jason Fletcher

## Update on Coyote Springs 2

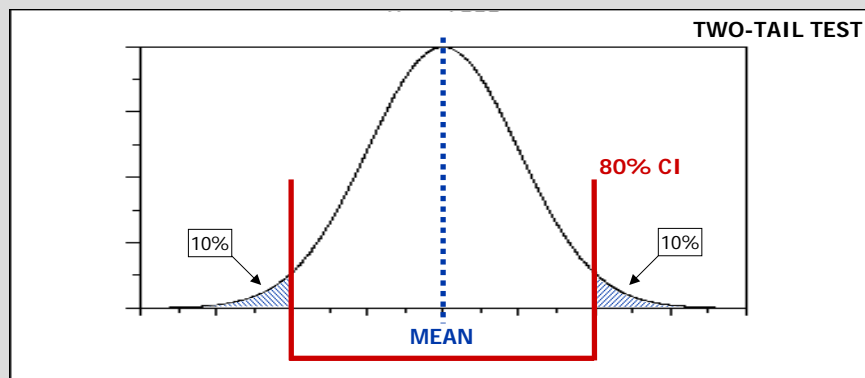
- The Confidentiality Agreement and Non-Binding Letter of Intent have been signed by both parties.
- The Asset Purchase and Sale Agreement is currently being negotiated. It is expected to be completed by the end of 2004.
- 100% of Coyote Springs 2 will be included in the 2005 Integrated Resource Plan.



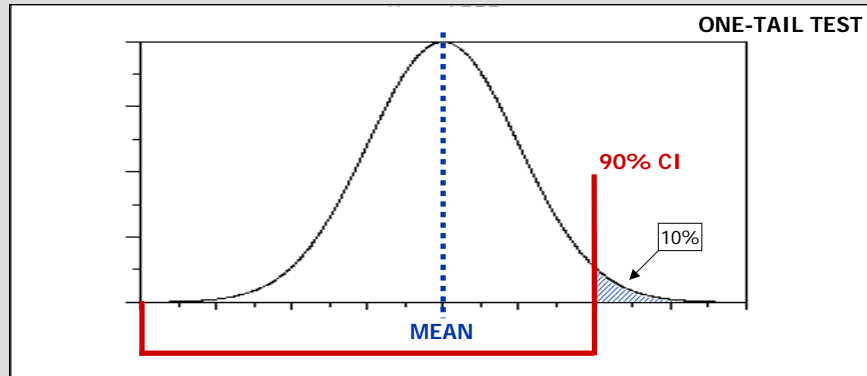
## Future Resource Requirements

- 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

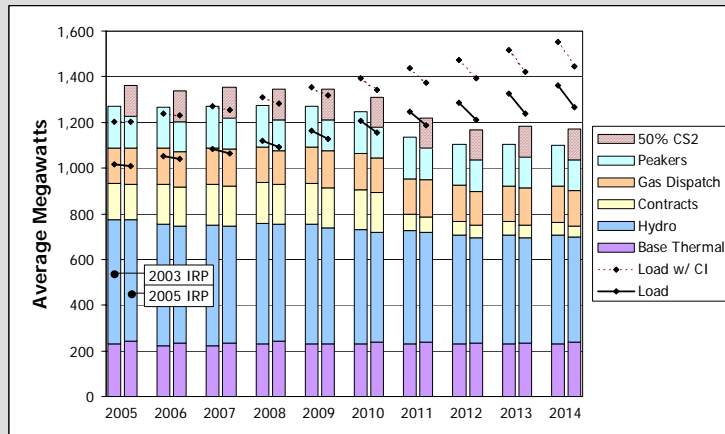


## Energy Loads & Resources (aMW)

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

Last Updated July 30, 2004	Notes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
<b>REQUIREMENTS</b>											
System Load	1	(1,008)	(1,041)	(1,063)	(1,093)	(1,126)	(1,156)	(1,187)	(1,212)	(1,237)	(1,265)
Contracts Out	2	(13)	(11)	(11)	(11)	(11)	(9)	(9)	(8)	(8)	(8)
WHP-3 Obligation	3	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
Confidence Interval	4	(163)	(160)	(160)	(160)	(159)	(155)	(155)	(151)	(151)	(151)
<b>Total Requirements</b>		<b>(1,215)</b>	<b>(1,243)</b>	<b>(1,265)</b>	<b>(1,296)</b>	<b>(1,327)</b>	<b>(1,351)</b>	<b>(1,382)</b>	<b>(1,402)</b>	<b>(1,428)</b>	<b>(1,455)</b>
<b>RESOURCES</b>											
Hydro	5	532	511	511	511	505	481	477	461	460	459
Contracts In	6	167	184	186	186	186	185	79	64	64	58
Base Load Thermals	7	241	234	234	242	232	236	240	235	234	238
Gas Dispatch Units	8	295	284	294	279	294	284	294	279	294	284
Peaking Units	9	139	135	138	138	137	134	138	138	137	138
<b>Total Resources</b>		<b>1,374</b>	<b>1,349</b>	<b>1,364</b>	<b>1,356</b>	<b>1,355</b>	<b>1,328</b>	<b>1,229</b>	<b>1,177</b>	<b>1,189</b>	<b>1,178</b>
<b>Surplus (Deficit)</b>		<b>159</b>	<b>106</b>	<b>99</b>	<b>61</b>	<b>28</b>	<b>(31)</b>	<b>(153)</b>	<b>(225)</b>	<b>(238)</b>	<b>(276)</b>
<b>ABSENT MIRANT SHARE OF CS2</b>											
Generation Reduction	10	(133)	(133)	(133)	(125)	(133)	(128)	(133)	(125)	(133)	(128)
<b>Net Position</b>		<b>27</b>	<b>(22)</b>	<b>(34)</b>	<b>(64)</b>	<b>(105)</b>	<b>(159)</b>	<b>(285)</b>	<b>(350)</b>	<b>(371)</b>	<b>(404)</b>

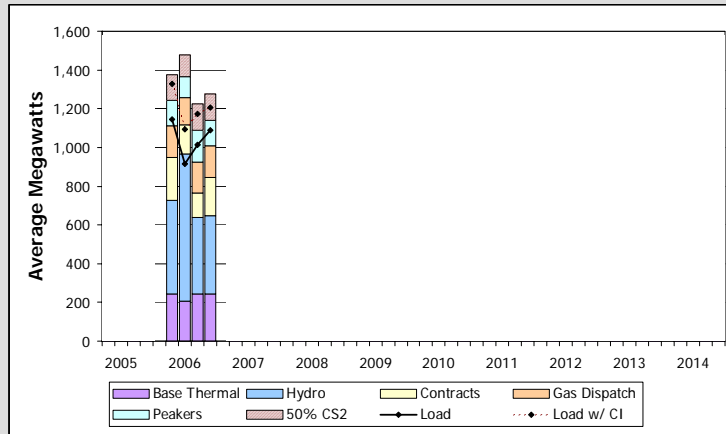
## Energy L&R – 2003 vs. 2005 IRP



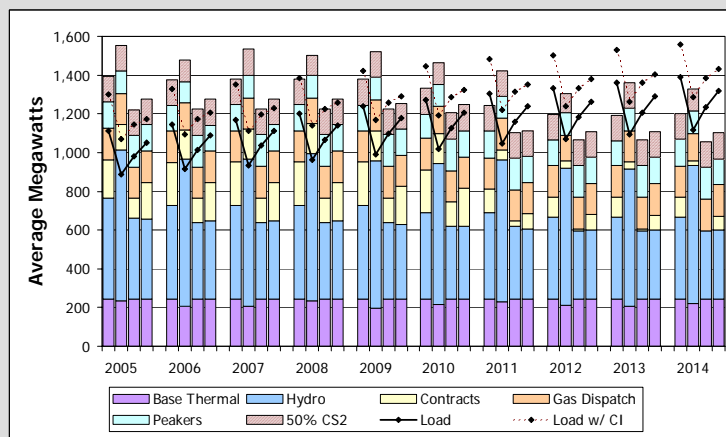
## Energy L&R – What's Changed?

- Load Forecast ← 99 aMW in 2014
- Contracts
  - 4 aMW → - Haleywest
  - 6 aMW → - Potlatch
  - Nichol's Pumping ← -6 aMW
  - 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

## Energy L&R – Annual to Quarterly



## Energy L&R – Annual to Quarterly



## Capacity Loads & Resources (MW)

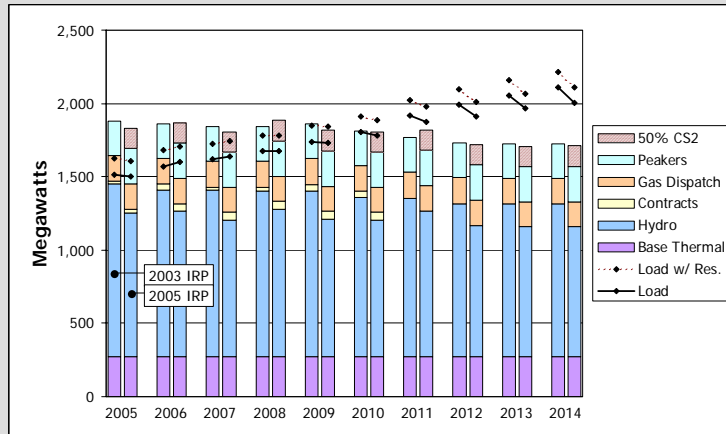
Long-Term Peak Load and Resource Tabulation (MW)											
CONFIDENTIAL											
Last Updated July 30, 2004	Notes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
<b>REQUIREMENTS</b>											
System Load	1	(1,500)	(1,598)	(1,637)	(1,674)	(1,734)	(1,779)	(1,813)	(1,849)	(1,903)	(1,945)
Contracts Out	2	(170)	(166)	(166)	(166)	(166)	(161)	(159)	(159)	(159)	(159)
Hydro Reserves (5%)	3	(61)	(59)	(58)	(59)	(58)	(55)	(53)	(53)	(53)	(53)
Thermal Reserves (7%)	4	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
<b>Total Requirements</b>		<b>(1,779)</b>	<b>(1,871)</b>	<b>(1,910)</b>	<b>(1,947)</b>	<b>(2,007)</b>	<b>(2,044)</b>	<b>(2,074)</b>	<b>(2,110)</b>	<b>(2,164)</b>	<b>(2,205)</b>
<b>RESOURCES</b>											
Hydro	5	975	991	930	1,003	935	925	993	893	884	883
Contracts In	6	199	217	220	219	220	218	97	97	98	98
Base Load Thermals	7	275	275	275	275	275	275	275	275	275	275
Gas Dispatch Units	8	308	310	305	310	309	305	310	310	305	309
Peaking Units	9	243	243	243	243	243	243	243	243	243	243
<b>Total Resources</b>		<b>2,000</b>	<b>2,035</b>	<b>1,973</b>	<b>2,049</b>	<b>1,982</b>	<b>1,967</b>	<b>1,917</b>	<b>1,817</b>	<b>1,805</b>	<b>1,808</b>
<b>Surplus (Deficit)</b>		<b>220</b>	<b>165</b>	<b>63</b>	<b>102</b>	<b>(25)</b>	<b>(77)</b>	<b>(157)</b>	<b>(293)</b>	<b>(359)</b>	<b>(398)</b>
<b>ABSENT MIRANT SHARE OF CS2</b>											
Generation Reduction	10	(138)	(139)	(139)	(139)	(139)	(139)	(139)	(139)	(139)	(139)
<b>Net Surplus (Deficit)</b>		<b>82</b>	<b>26</b>	<b>(76)</b>	<b>(37)</b>	<b>(164)</b>	<b>(216)</b>	<b>(296)</b>	<b>(432)</b>	<b>(498)</b>	<b>(536)</b>

## Capacity Loads & Resources (MW)

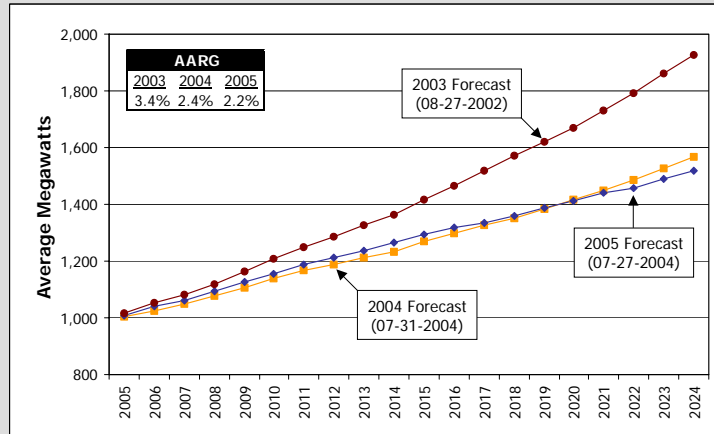
Long-Term Peak Load and Resource Tabulation (MW)											
CONFIDENTIAL											
Last Updated July 30, 2004	Notes	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
<b>REQUIREMENTS</b>											
System Load	1	(1,500)	(1,598)	(1,637)	(1,674)	(1,734)	(1,779)	(1,813)	(1,849)	(1,903)	(1,945)
Contracts Out	2	(170)	(166)	(166)	(166)	(166)	(161)	(159)	(159)	(159)	(159)
Hydro Reserves (5%)	3	(61)	(59)	(58)	(59)	(58)	(55)	(53)	(53)	(53)	(53)
Thermal Reserves (7%)	4	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)	(48)
<b>Total Requirements</b>		<b>(1,779)</b>	<b>(1,871)</b>	<b>(1,910)</b>	<b>(1,947)</b>	<b>(2,007)</b>	<b>(2,044)</b>	<b>(2,074)</b>	<b>(2,110)</b>	<b>(2,164)</b>	<b>(2,205)</b>
<b>RESOURCES</b>											
Hydro	5	975	991	930	1,003	935	925	993	893	884	883
Contracts In	6	199	217	220	219	220	218	97	97	98	98
Base Load Thermals	7	275	275	275	275	275	275	275	275	275	275
Gas Dispatch Units	8	308	310	305	310	309	305	310	310	305	309
Peaking Units	9	243	243	243	243	243	243	243	243	243	243
<b>Total Resources</b>		<b>2,000</b>	<b>2,035</b>	<b>1,973</b>	<b>2,049</b>	<b>1,982</b>	<b>1,967</b>	<b>1,917</b>	<b>1,817</b>	<b>1,805</b>	<b>1,808</b>
<b>Surplus (Deficit)</b>		<b>220</b>	<b>165</b>	<b>63</b>	<b>102</b>	<b>(25)</b>	<b>(77)</b>	<b>(157)</b>	<b>(293)</b>	<b>(359)</b>	<b>(398)</b>
<b>ABSENT MIRANT SHARE OF CS2</b>											
Generation Reduction	10	(138)	(139)	(139)	(139)	(139)	(139)	(139)	(139)	(139)	(139)
<b>Net Surplus (Deficit)</b>		<b>82</b>	<b>26</b>	<b>(76)</b>	<b>(37)</b>	<b>(164)</b>	<b>(216)</b>	<b>(296)</b>	<b>(432)</b>	<b>(498)</b>	<b>(536)</b>
<b>Planning Reserve Margin</b>		<b>20%</b>	<b>15%</b>	<b>9%</b>	<b>11%</b>	<b>4%</b>	<b>-2%</b>	<b>-3%</b>	<b>-10%</b>	<b>-12%</b>	<b>-14%</b>



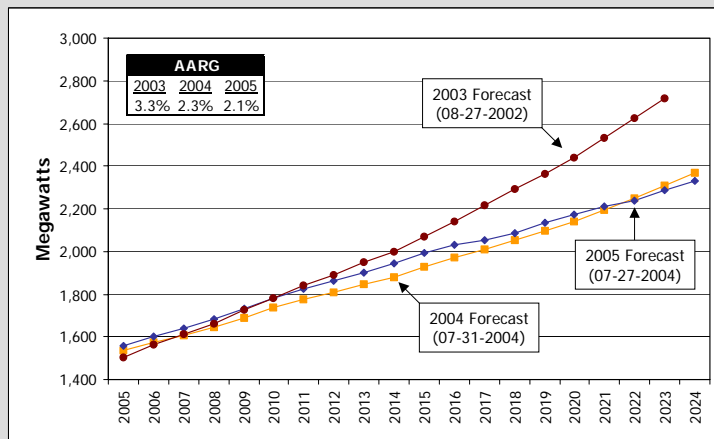
## Capacity L&R – 2003 vs. 2005 IRP



## 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

1

## Introduction

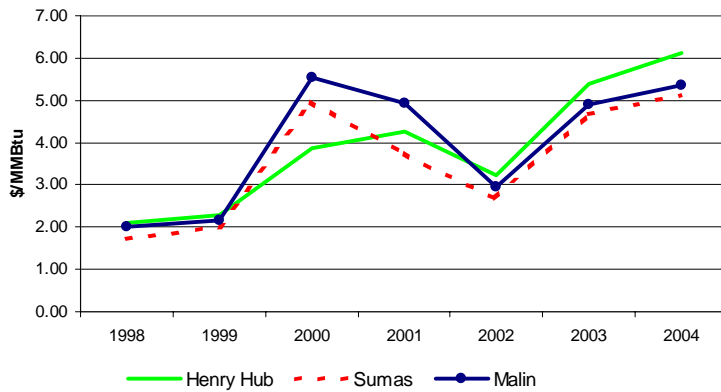
---

- 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

2

## Recent Natural Gas Prices

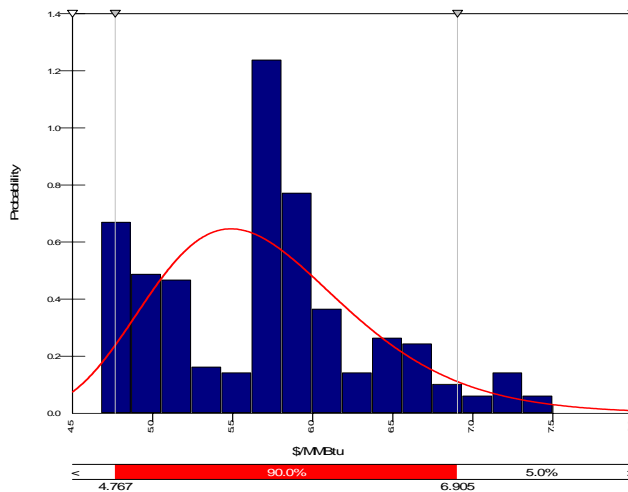
Annual Average Prices (Nominal Dollars)



3

## Recent Volatility of the Forward Market

2005 Annual Average Prices Traded at Malin in 2004

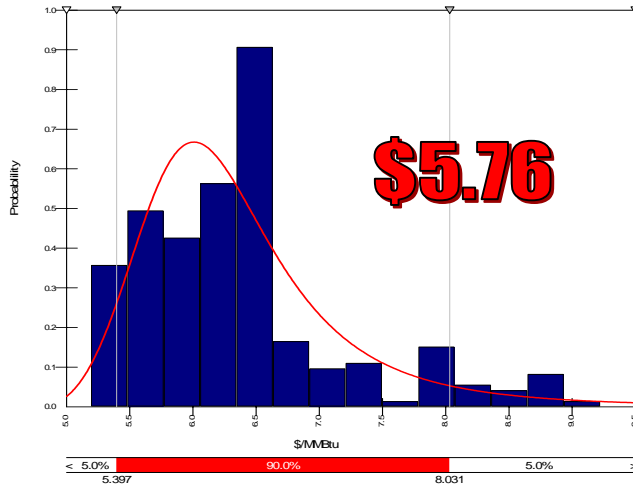


**Statistics:**  
 -Mean: \$5.71  
 -Median: \$5.75  
 -Mode: \$4.90  
 -Min: \$4.68  
 -Max: \$7.50  
 -Standard Deviation: \$0.65  
 -Variance: 0.42  
 -Skewness: 0.43  
 -Kurtosis: 3.94

4

## Recent Volatility of the Forward Market

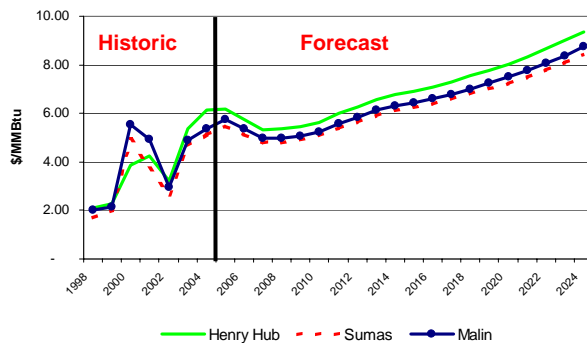
January 2005 Average Prices Traded at Malin in 2004



**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)



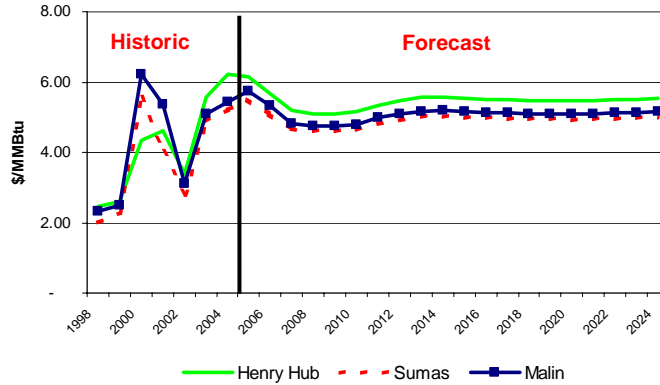
**Key Assumptions**

- July 2004 Forward Price Curves for 2005 through 2007
  - 2005- 07: -7.1%
- Avg. Growth Rates – Based on July Global Insights forecast
  - 2007- 09: 1.9%
  - 2010- 20: 3.2%
  - 2020- 30: 3.8%

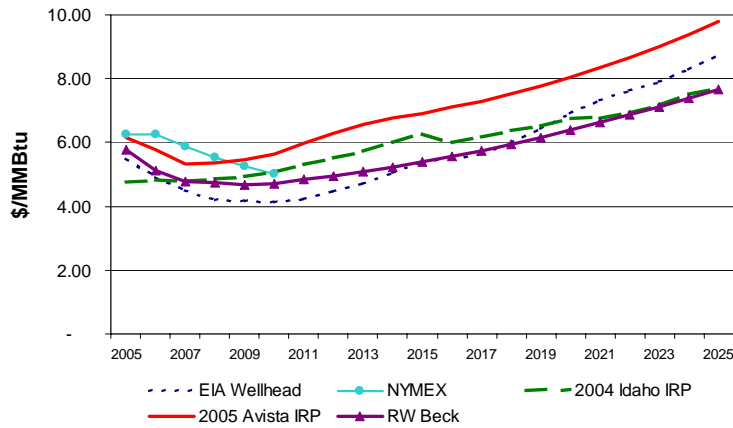
**New Escalation Rates Available in April**

## Forecasted Natural Gas Prices

Annual Average Prices (2005 Dollars)

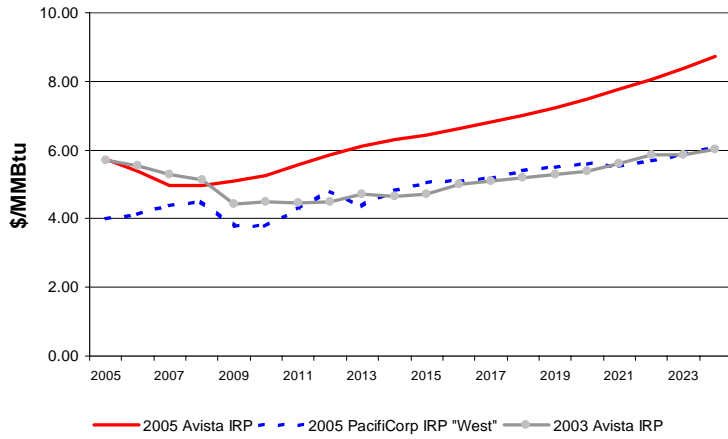


## How Does Our Forecast Compare with Others at Henry Hub?

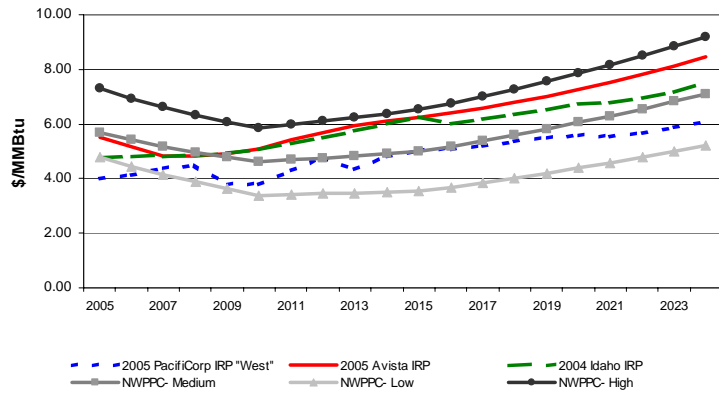


EIA Wellhead- Annual Energy Outlook 2005 Early Release (Avg. price for lower 48 states)  
 NYMEX- www.NYMEX.com on 12/30/2004

### How Does Our Forecast Compare with Others at Malin?



### How Does Our Forecast Compare with Others at Sumas?

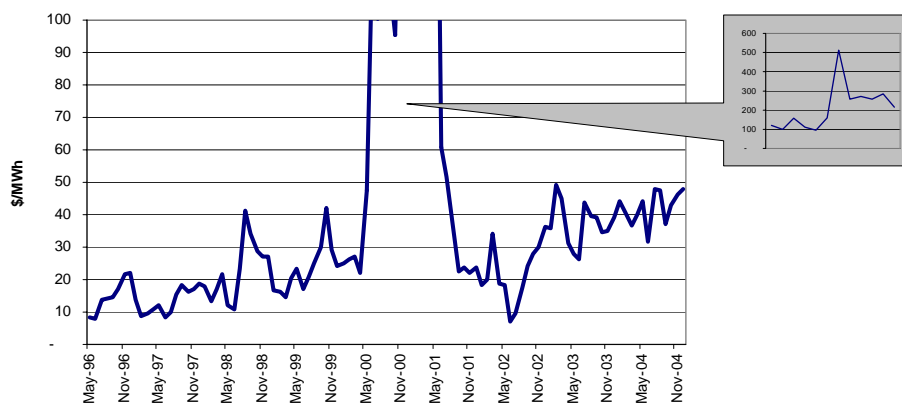


## Why are Gas Prices Important?

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

11

## Historical Mid-C Prices



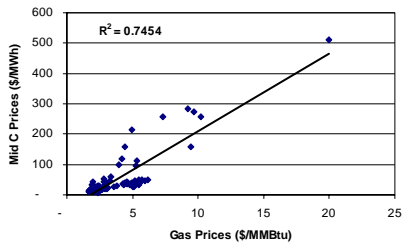
12



# Regression Analysis

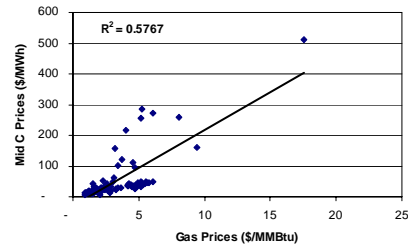
Mid C Prices and Northwest Gas Markets (1996- 2004)

Mid C vs Malin



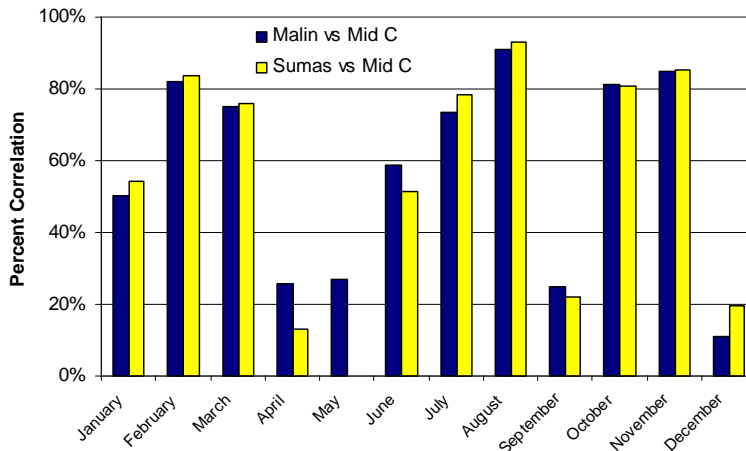
- 86% correlation between Malin Gas Prices and Mid C Electric Prices
- 74% of the time a change to Malin Prices will have an effect on the Mid C Market

Mid C vs Sumas

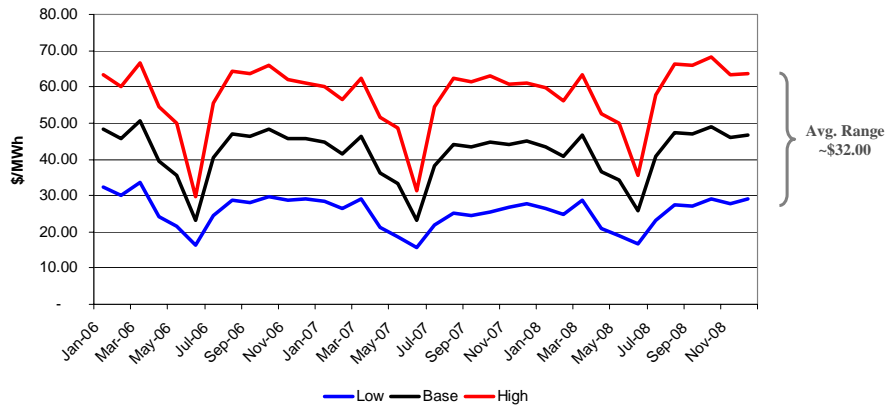


- 76% correlation between Sumas Gas Prices and Mid C Electric Prices
- 58% of the time a change to Sumas Prices will have an effect on the Mid C Market

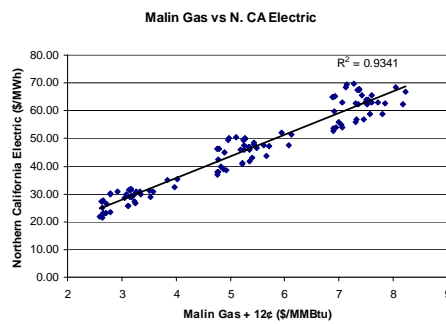
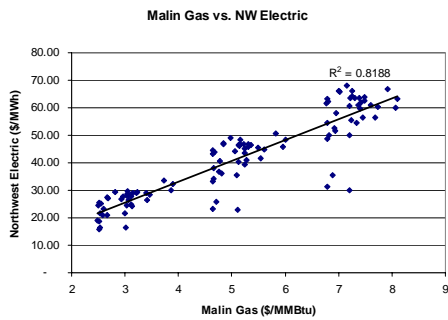
# 2004 Daily NW Gas vs NW Electric Correlation by Month



### Change to Mid C Electric Market with +/- \$2 Gas Price Variations- Example Only



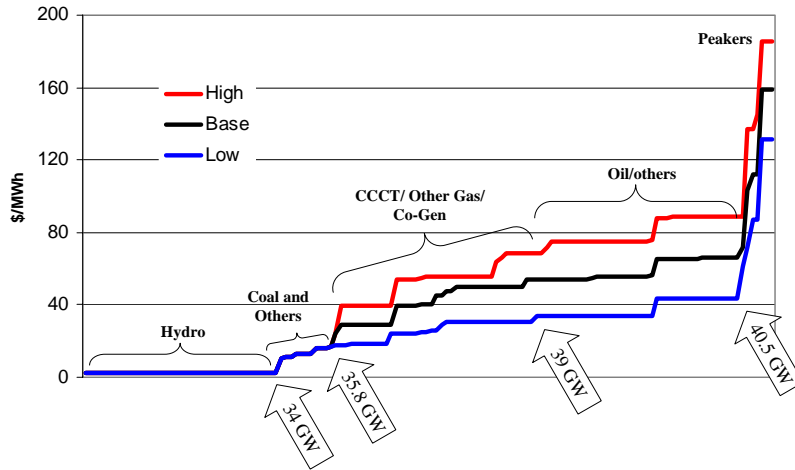
### Regression Analysis Aurora Fuel Price Sensitivity Results (2006-2008)



- 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

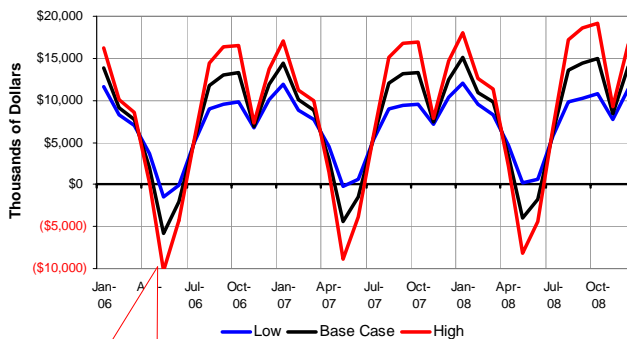
- 97% correlation between Malin Gas Prices and Northern California Electric Prices
- 93% of the time a change to Malin Prices will have an effect on the Northern California Area Market

### Change to 2006 Northwest Resource Stack with Gas Price Variations- Example Only



17

### Change to Avista's Power Costs 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

18

## Coal and Other Fuels

---

- These forecasts will be presented at the next TAC meeting

19

## 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?

20

## 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

	<u>Slide #</u>
• 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

2

## 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”

3

## 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

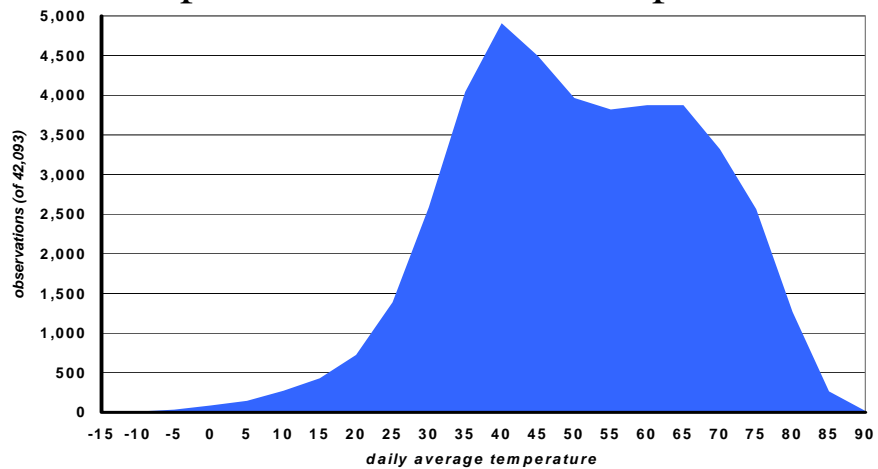
4

## Comparison to Peak Forecasting

Item	Capacity L&R	Sustained Capacity
Period	One Hour	One Hour to Three Days, or More
Peak Load	Average Coldest Day Temp	Lowest Load on Record ~ 120-160 MW in 2005
Thermals	Average Temps	Lowest Temps & Colstrip Reduced for Freeze (~ 30 MW)
Hydro	Maximum Capability	Maximum Capability Reduced for Freeze (~ 60 MW)
Contracts	Actual Forecast	Actual Forecast

5

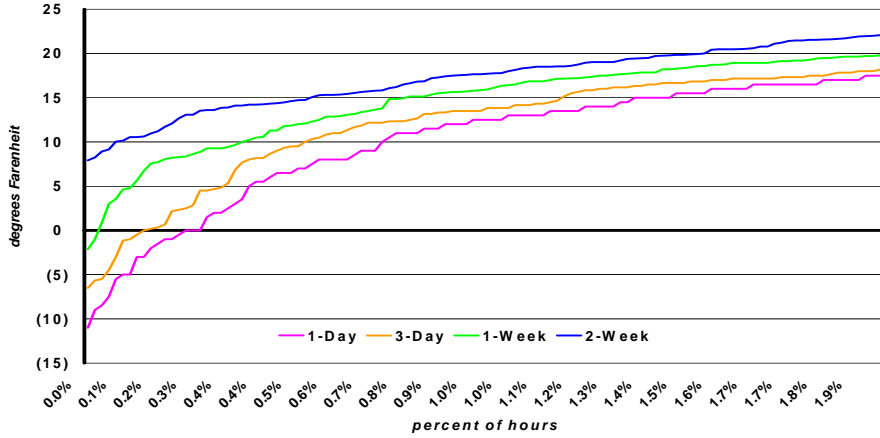
## Temp. Distribution (1889-2004) Spokane International Airport



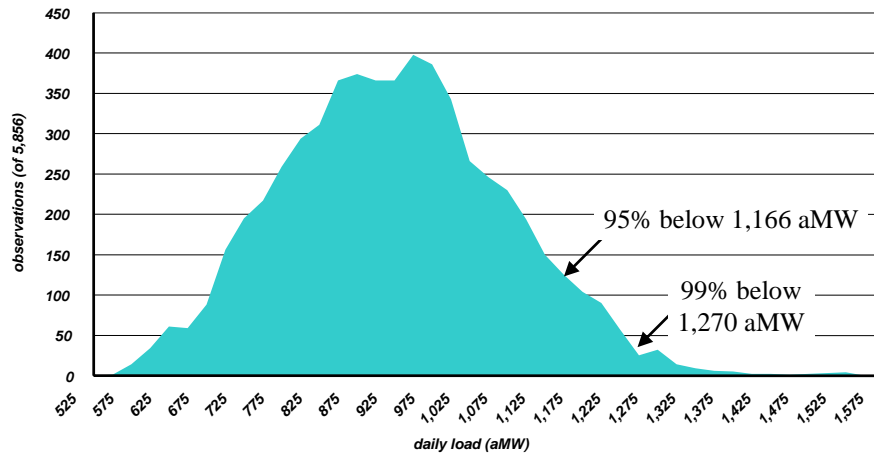
6



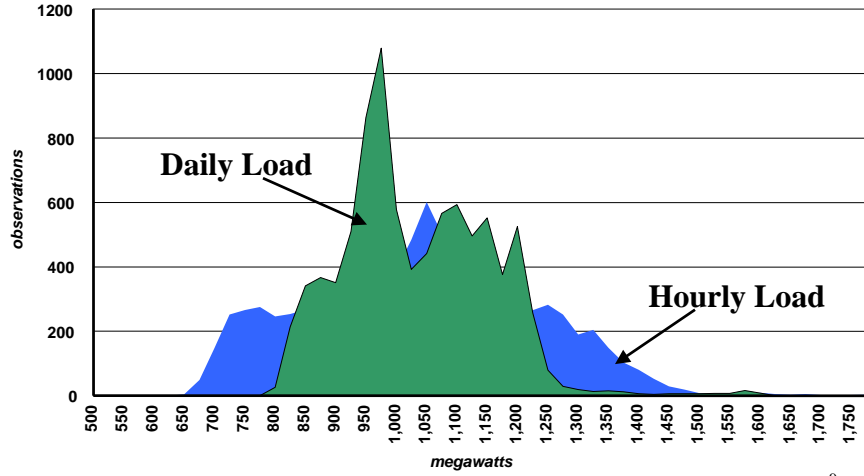
# Temperature History (1989-04) Spokane International Airport



# Peak Load History (1989-04) Avista Total

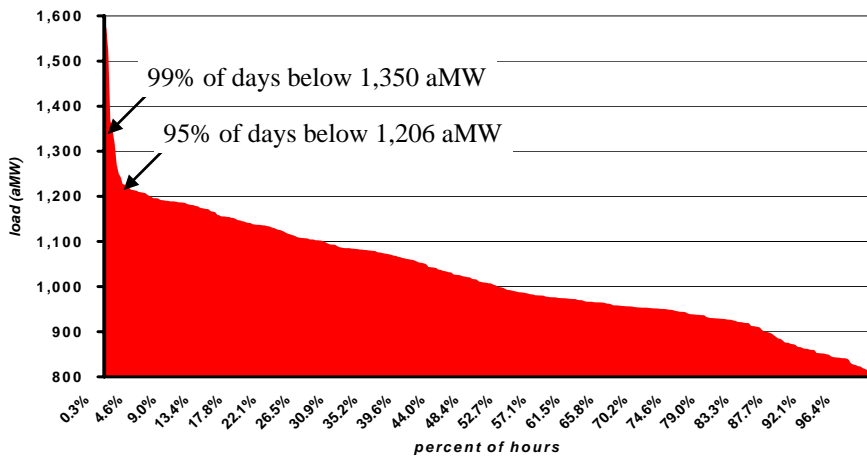


## Daily Versus Hourly Peaks 2004 Load

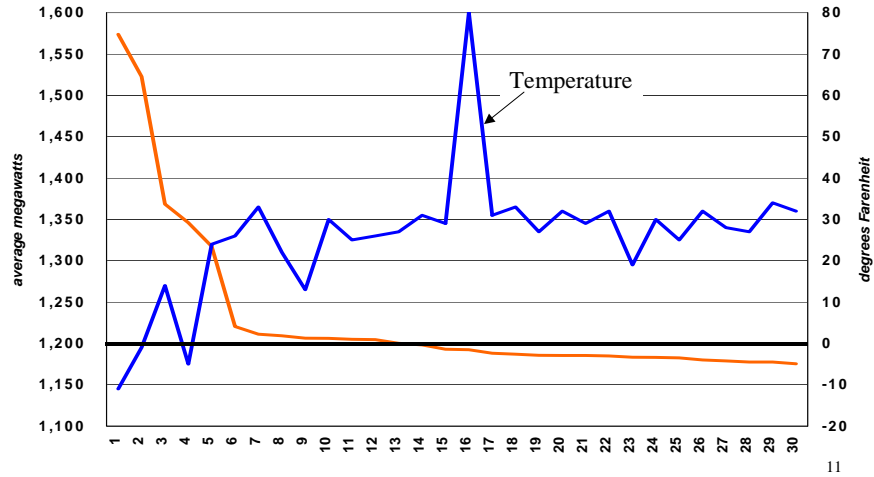


## 2004 Daily Load Duration

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

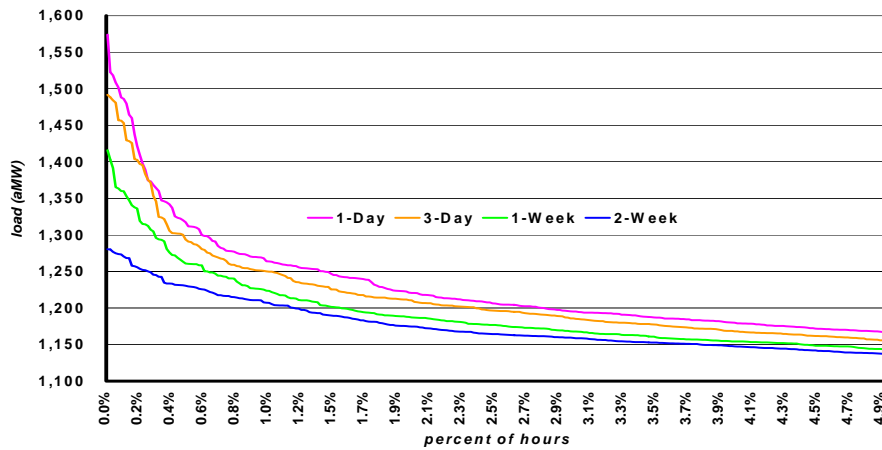


## 2004 Peak Load and Temps 30 Highest Load Days



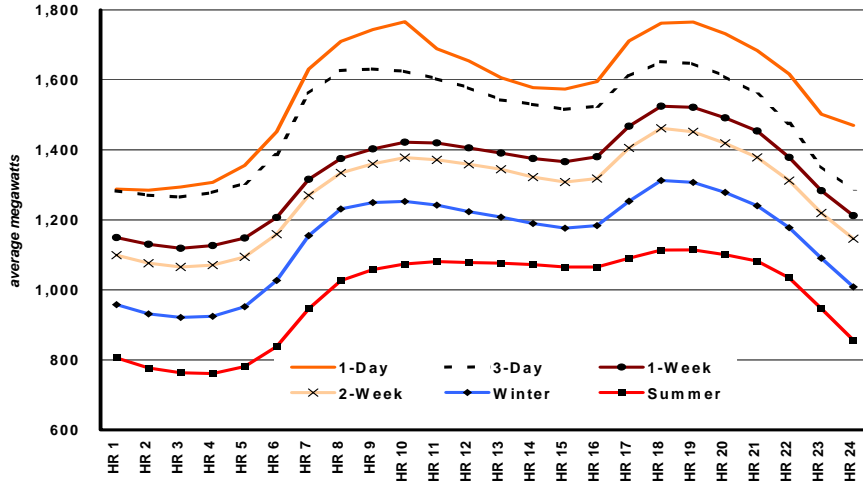
11

## Peak Load History (1989-04) Avista Total



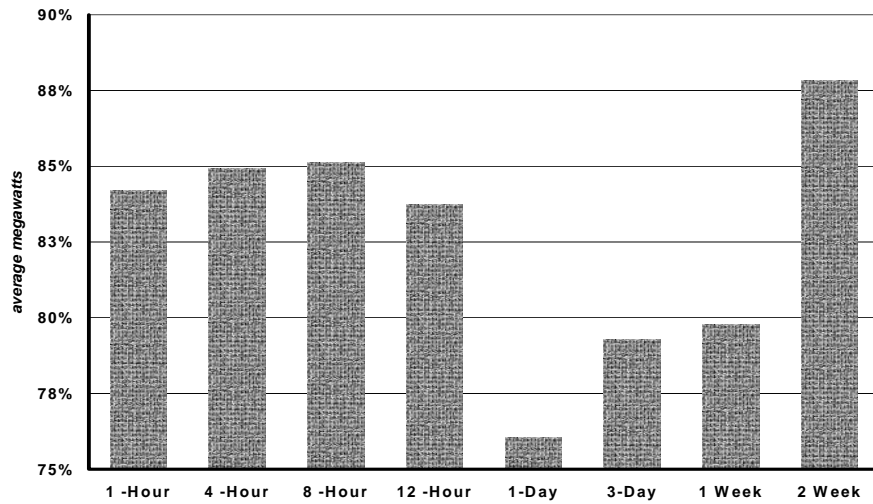
12

## Peak Load Shape Comparison



13

## Summer Vs. Winter Peaks



14

# Sustained Peak Estimate—2005

## Sustained Peak Period L&R Calculation Comparison 2005

Peak Period Considered	1 -Hour	4 -Hour	8 -Hour	12 -Hour	24 -Hour	72 -Hour	168 -Hour	336 -Hour
<b>Load</b>								
Peak Load	(1,619)	(1,598)	(1,579)	(1,542)	(1,450)	(1,377)	(1,369)	(1,175)
10% Contingency	(162)	(160)	(158)	(154)	(145)	(138)	(137)	(117)
Load Subtotal	(1,781)	(1,758)	(1,736)	(1,696)	(1,595)	(1,515)	(1,506)	(1,292)
<b>Hydro Capability</b>								
Hydro @ 90% CI	208	208	208	326	326	326	326	326
Hydro Storage	959	871	825	550	275	211	154	77
River Freeze Up	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
Hydro Subtotal	1,107	1,019	973	816	541	477	419	342
<b>Thermal Capability</b>								
Coyote Springs II	308	308	308	308	308	308	308	308
Colstrip	222	222	222	222	222	222	222	222
Rathdrum	184	184	184	184	184	184	184	184
Northeast	69	69	69	69	69	69	69	69
Kettle Falls	62	62	62	62	62	62	62	62
Boulder Park	25	25	25	25	25	25	25	25
Fuel Delivery System Freeze Up	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Thermal Subtotal	839	839	839	839	839	839	839	839
<b>Contracts</b>								
Net Contracts	139	139	139	139	139	139	139	139
PGE Adjustment	0	0	0	25	38	46	105	105
PPM Wind @ 25% of Capacity	0	0	0	0	0	0	0	0
000 MW Spot Purchases	0	0	0	0	0	0	0	0
Contracts Subtotal	139	139	139	164	177	185	245	245
<b>Net Position</b>	304	240	215	123	(38)	(14)	(3)	134

15

# Sustained Peak Estimate—2007

## Sustained Peak Period L&R Calculation Comparison 2007

Peak Period Considered	1 -Hour	4 -Hour	8 -Hour	12 -Hour	24 -Hour	72 -Hour	168 -Hour	336 -Hour
<b>Load</b>								
Peak Load	(1,699)	(1,677)	(1,656)	(1,618)	(1,521)	(1,445)	(1,436)	(1,233)
10% Contingency	(170)	(168)	(166)	(162)	(152)	(145)	(144)	(123)
Load Subtotal	(1,869)	(1,844)	(1,822)	(1,780)	(1,673)	(1,590)	(1,580)	(1,356)
<b>Hydro Capability</b>								
Hydro @ 90% CI	195	195	195	274	274	274	274	274
Hydro Storage	929	929	757	505	252	204	150	75
River Freeze Up	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
Hydro Subtotal	1,064	1,064	892	718	466	417	364	289
<b>Thermal Capability</b>								
Coyote Springs II	308	308	308	308	308	308	308	308
Colstrip	222	222	222	222	222	222	222	222
Rathdrum	184	184	184	184	184	184	184	184
Northeast	69	69	69	69	69	69	69	69
Kettle Falls	62	62	62	62	62	62	62	62
Boulder Park	25	25	25	25	25	25	25	25
Fuel Delivery System Freeze Up	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Thermal Subtotal	839	839	839	839	839	839	839	839
<b>Contracts</b>								
Net Contracts	160	160	160	160	160	160	160	160
PGE Adjustment	0	0	0	25	38	46	105	105
PPM Wind @ 25% of Capacity	0	0	0	0	0	0	0	0
000 MW Spot Purchases	0	0	0	0	0	0	0	0
Contracts Subtotal	160	160	160	185	198	206	266	266
<b>Net Position</b>	195	220	70	(37)	(170)	(127)	(111)	38

16

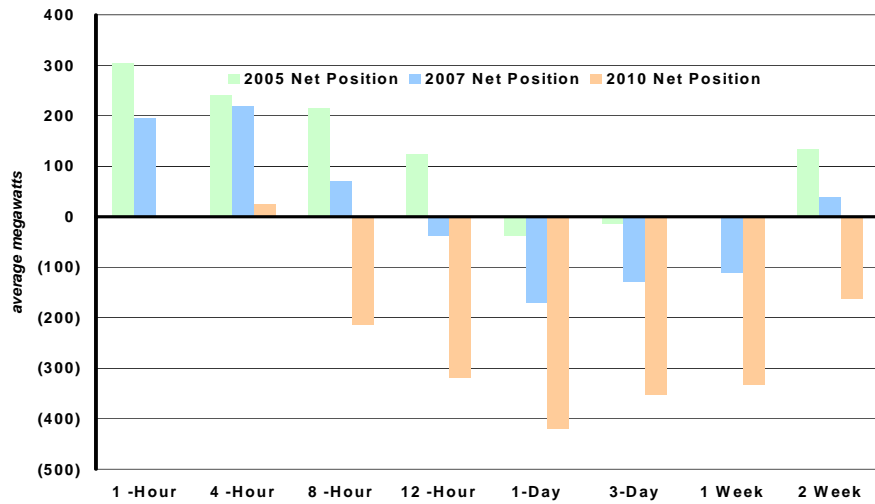
# Sustained Peak Estimate—2010

Sustained Peak Period L&R Calculation Comparison  
2010

Peak Period Considered	1 -Hour	4 -Hour	8 -Hour	12 -Hour	24 -Hour	72 -Hour	168 -Hour	336 -Hour
<b>Load</b>								
Peak Load	(1,841)	(1,817)	(1,795)	(1,753)	(1,648)	(1,566)	(1,556)	(1,336)
10% Contingency	(184)	(182)	(179)	(175)	(165)	(157)	(156)	(134)
Load Subtotal	(2,026)	(1,999)	(1,974)	(1,928)	(1,813)	(1,723)	(1,712)	(1,469)
<b>Hydro Capability</b>								
Hydro @ 90% CI	131	131	131	184	184	184	184	184
Hydro Storage	948	948	685	456	228	196	147	73
River Freeze Up	(60)	(60)	(60)	(60)	(60)	(60)	(60)	(60)
Hydro Subtotal	1,019	1,019	756	580	352	319	270	197
<b>Thermal Capability</b>								
Coyote Springs II	308	308	308	308	308	308	308	308
Colstrip	222	222	222	222	222	222	222	222
Rathdrum	184	184	184	184	184	184	184	184
Northeast	69	69	69	69	69	69	69	69
Kettle Falls	62	62	62	62	62	62	62	62
Boulder Park	25	25	25	25	25	25	25	25
Fuel Delivery System Freeze Up	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
Thermal Subtotal	839	839	839	839	839	839	839	839
<b>Contracts</b>								
Net Contracts	165	165	165	165	165	165	165	165
PGE Adjustment	0	0	0	25	38	46	105	105
PPM Wind @ 25% of Capacity	0	0	0	0	0	0	0	0
000 MW Spot Purchases	0	0	0	0	0	0	0	0
Contracts Subtotal	165	165	165	190	203	211	271	271
<b>Net Position</b>	(2)	25	(214)	(319)	(419)	(353)	(332)	(162)

17

# Avista Net Positions



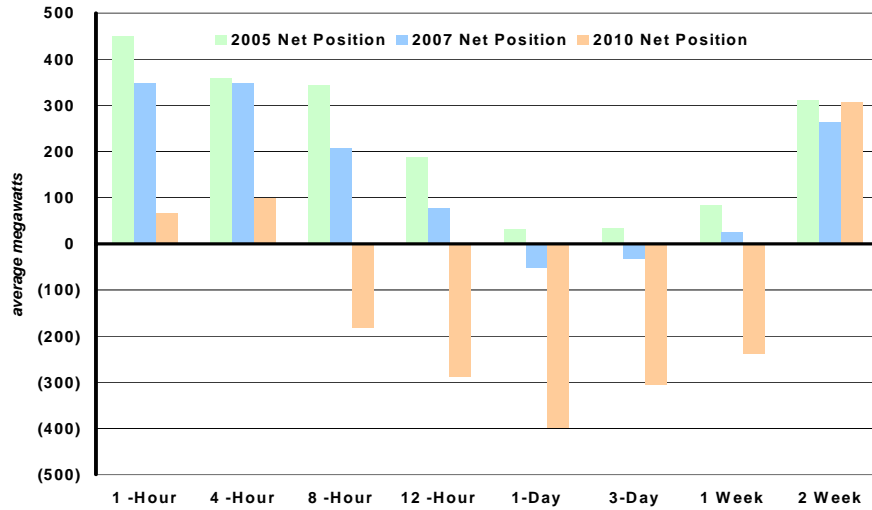
18

## Avista vs. FERC SMD

	1 -Hour	4 -Hour	8 -Hour	12 -Hour	24 -Hour	72 -Hour	168 -Hour	336 -Hour
<b>2005</b>								
Avista Criteria	345	281	256	129	(32)	(9)	3	138
SMD - 12%	538	448	433	275	115	113	165	385
SMD - 15%	490	401	385	229	72	72	124	350
SMD - 18%	442	353	338	183	28	31	83	315
<b>2007</b>								
Avista Criteria	212	237	87	(19)	(153)	(110)	(94)	55
SMD - 12%	417	416	275	142	11	29	85	319
SMD - 15%	366	366	225	93	(35)	(15)	42	282
SMD - 18%	315	315	175	45	(81)	(58)	(1)	245
<b>2010</b>								
Avista Criteria	16	43	(197)	(301)	(402)	(336)	(314)	(145)
SMD - 12%	138	170	(88)	(192)	(307)	(215)	(142)	416
SMD - 15%	82	116	(142)	(245)	(357)	(262)	(189)	376
SMD - 18%	27	61	(196)	(297)	(406)	(309)	(235)	335

19

## SMD Net Positions – 15%



20

## 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

21

## 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

22



## 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

1

## 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

2

## 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

3

## Regional Economy

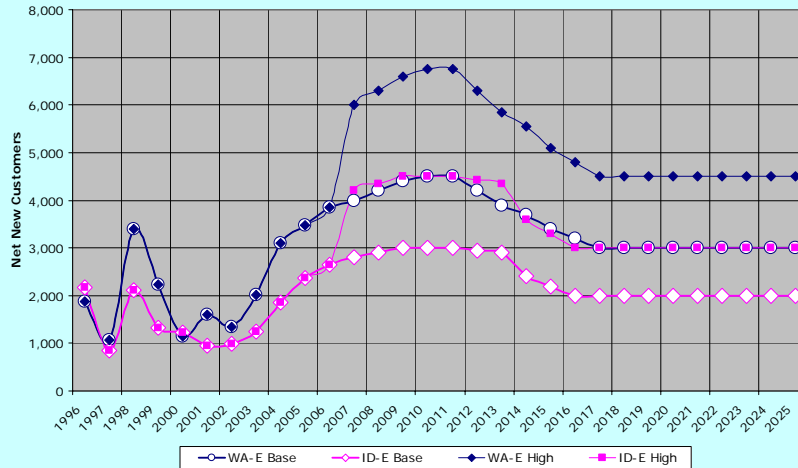
- Risk to Growth (**Low Scenario**)
  - Military Base Realignment and Closure Process during 2005 indicates closure
  - Continued Meltdown in Manufacturing
- Opportunity for Growth (**High Scenario**)
  - Base expands with new missions
  - University District, Airport Freight Hub, Technology Parks
  - Convention Center Tourism Expansion

4

# Results High & Low Case 2005 Forecast

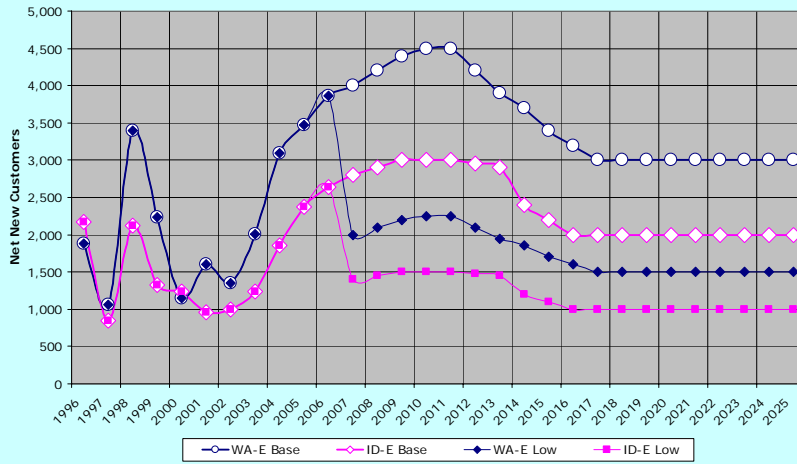
## Avista High Customer Forecasts

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



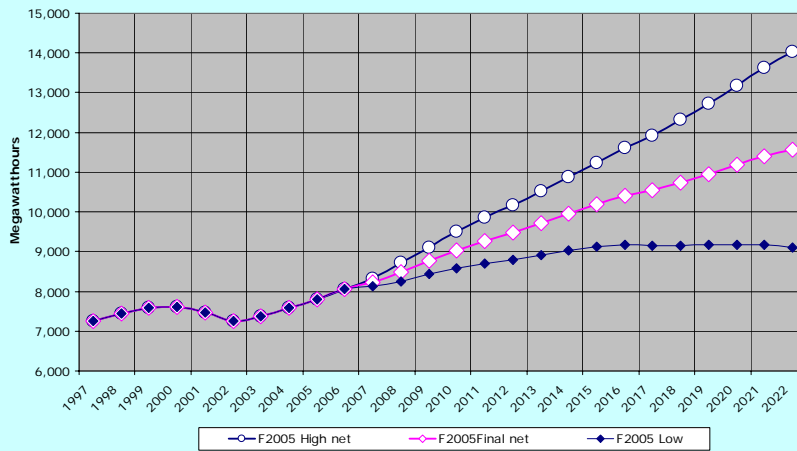
# Avista Low Customer Forecasts

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



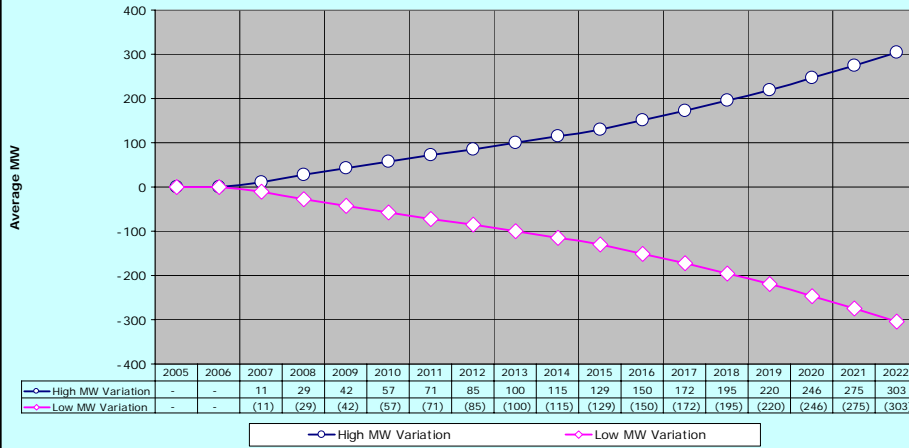
7

F2005 Avista Megawatthour Forecast  
Excluding Potlatch Lewiston



8

F2005 High-Low MW Variation Forecast  
Excluding Potlatch Lewiston



# 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)

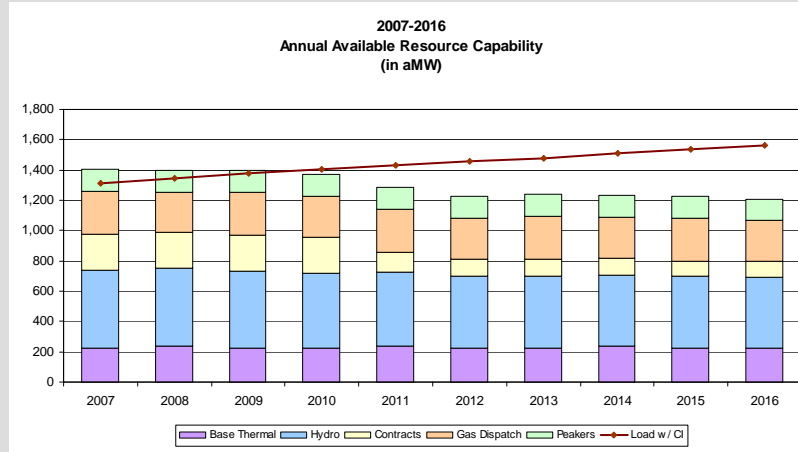
LONG-TERM LOAD AND RESOURCES TABULATION—ENERGY (aMW)												
CONFIDENTIAL												
Last Updated January 13, 2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
<b>REQUIREMENTS</b>												
System Load	(1,065)	(1,098)	(1,120)	(1,151)	(1,183)	(1,213)	(1,245)	(1,269)	(1,295)	(1,322)	(1,353)	(1,378)
Contract Obligations	(62)	(60)	(60)	(60)	(60)	(59)	(58)	(57)	(57)	(57)	(57)	(57)
Total Requirements	(1,127)	(1,158)	(1,181)	(1,211)	(1,244)	(1,272)	(1,303)	(1,327)	(1,352)	(1,379)	(1,410)	(1,435)
<b>RESOURCES</b>												
Contract Rights	283	292	295	294	295	294	189	171	172	164	162	162
Hydro	539	517	517	517	512	494	490	473	472	472	471	471
Base Load Thermals	236	224	224	237	221	226	235	225	224	237	225	224
Gas Dispatch Units	262	272	282	268	282	272	282	268	282	273	282	268
Total Resources	1,320	1,306	1,318	1,316	1,310	1,286	1,196	1,137	1,150	1,145	1,140	1,124
<b>POSITION</b>	<b>193</b>	<b>147</b>	<b>137</b>	<b>105</b>	<b>67</b>	<b>14</b>	<b>(107)</b>	<b>(190)</b>	<b>(202)</b>	<b>(234)</b>	<b>(270)</b>	<b>(311)</b>
<b>CONTINGENCY PLANNING</b>												
Confidence Interval	(163)	(160)	(160)	(160)	(159)	(155)	(155)	(151)	(151)	(151)	(151)	(151)
WNP-3 Obligation	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
Peaking Resources	146	142	145	145	145	141	145	145	144	146	146	142
<b>CONTINGENCY NET POSITION</b>	<b>143</b>	<b>96</b>	<b>89</b>	<b>57</b>	<b>19</b>	<b>(33)</b>	<b>(150)</b>	<b>(229)</b>	<b>(243)</b>	<b>(273)</b>	<b>(308)</b>	<b>(353)</b>

## Energy L&R – Changes Since August

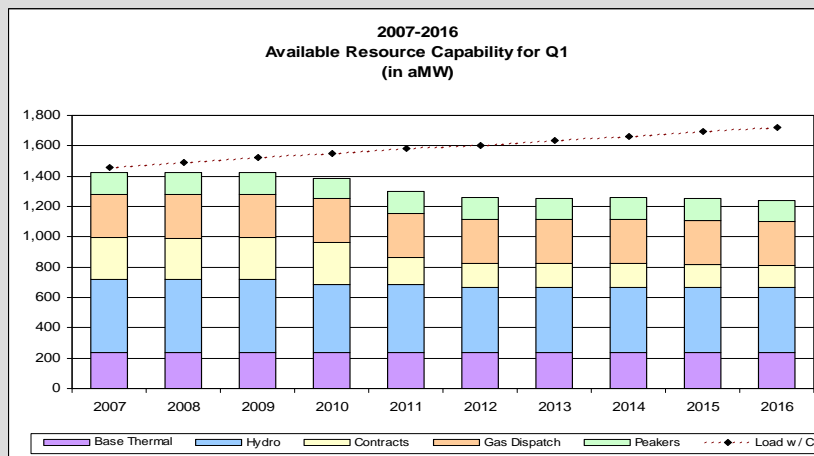
- Contracts ~ 3 aMW Increase
- Hydro ~ 7 aMW Increase
- Peaking Units ~ 7 aMW Increase
- Base Thermal ~ 5 aMW Decrease
- Gas Dispatch ~ 12 aMW Decrease



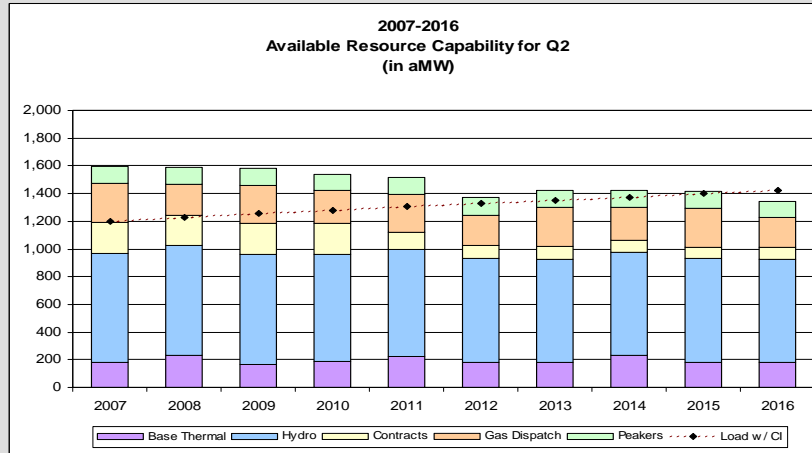
### Energy L&R – Annual Resource Capability



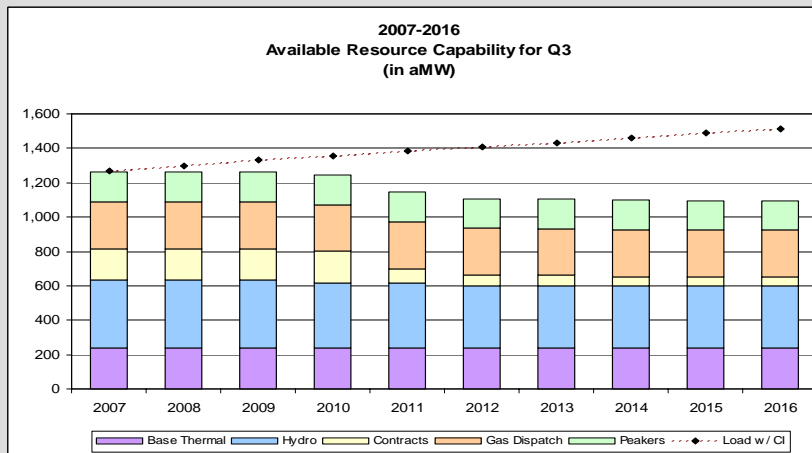
### Energy L&R – First Quarter Resource Capability



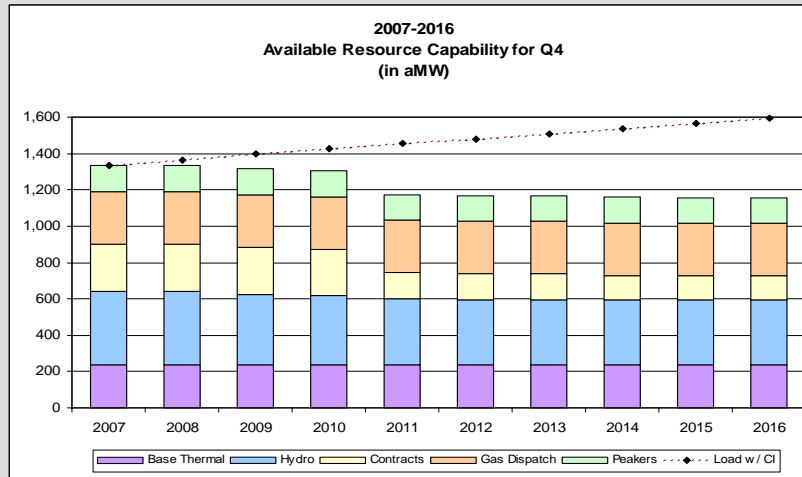
### Energy L&R – Second Quarter Resource Capability



### Energy L&R – Third Quarter Resource Capability



### Energy L&R – Fourth Quarter Resource Capability

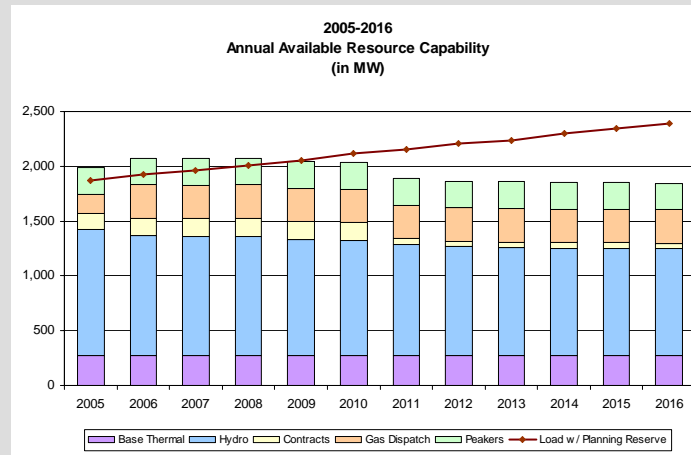


### Capacity Loads & Resources (MW)

LONG-TERM L&R TABULATION—CAPACITY (MW)  
CONFIDENTIAL

Last Updated January 13, 2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
<b>REQUIREMENTS</b>												
Native Load	(1,619)	(1,666)	(1,699)	(1,745)	(1,785)	(1,841)	(1,875)	(1,926)	(1,949)	(2,007)	(2,053)	(2,091)
Contracts Obligations	(173)	(169)	(169)	(169)	(164)	(164)	(162)	(162)	(162)	(162)	(162)	(162)
Total Requirements	(1,792)	(1,835)	(1,868)	(1,914)	(1,949)	(2,005)	(2,037)	(2,087)	(2,111)	(2,169)	(2,215)	(2,253)
<b>RESOURCES</b>												
Contracts Rights	312	326	329	329	330	329	211	212	211	212	212	212
Hydro Resources	1,156	1,098	1,090	1,090	1,056	1,049	1,018	996	988	980	979	978
Base Load Thermals	272	272	272	272	272	272	272	272	272	272	272	272
Gas Dispatch Units	179	303	303	308	303	303	307	303	307	308	308	303
Peaking Units	243	243	243	243	243	243	243	243	243	243	243	243
Total Resources	2,161	2,243	2,238	2,242	2,204	2,196	2,051	2,026	2,021	2,014	2,013	2,008
<b>PEAK POSITION</b>	<b>369</b>	<b>408</b>	<b>370</b>	<b>328</b>	<b>255</b>	<b>191</b>	<b>14</b>	<b>(61)</b>	<b>(90)</b>	<b>(155)</b>	<b>(202)</b>	<b>(245)</b>
<b>RESERVE PLANNING</b>												
Planning Reserve Margin	(252)	(257)	(260)	(265)	(269)	(274)	(278)	(283)	(285)	(291)	(295)	(299)
<b>RESERVE PEAK POSITION</b>	<b>118</b>	<b>152</b>	<b>110</b>	<b>63</b>	<b>(13)</b>	<b>(83)</b>	<b>(263)</b>	<b>(344)</b>	<b>(375)</b>	<b>(445)</b>	<b>(497)</b>	<b>(544)</b>

## Capacity L&R – Annual Resource Capability



## 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

INTEREST COVERAGE BUSINESS PROFILE		A		BBB		BB	
1		2.5	1.5	1.5	1.0		
2		3.0	2.0	2.0	1.0		
3		3.5	2.5	2.5	1.5	1.5	1.0
4		4.2	3.5	3.5	2.5	2.5	1.5
5		4.5	3.8	3.8	2.8	2.8	1.8
6		5.2	4.2	4.2	3.0	3.0	2.0
7		6.5	4.5	4.5	3.2	3.2	2.2
8		7.5	5.5	5.5	3.5	3.5	2.5
9		10.0	7.0	7.0	4.0	4.0	2.8
10		11.0	8.0	8.0	5.0	5.0	3.0
TOTAL DEBT/TOTAL CAPITAL BUSINESS PROFILE		A		BBB		BB	
1		55	60	60	70		
2		52	58	58	68		
3		50	55	55	65	65	70
4		45	52	52	62	62	68
5		42	50	50	60	60	65
6		40	48	48	58	58	62
7		38	45	45	55	55	60
8		35	42	42	52	52	58
9		32	40	40	50	50	55
10		25	35	35	48	48	52

■ Avista today    □ Avista's goal

3

## 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

4

## 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

1

## Topics of Discussion

---

- Aurora<sub>XMP</sub> Overview
- IRP Timeline
- IRP Modeling Process

2



# Aurora Overview

3

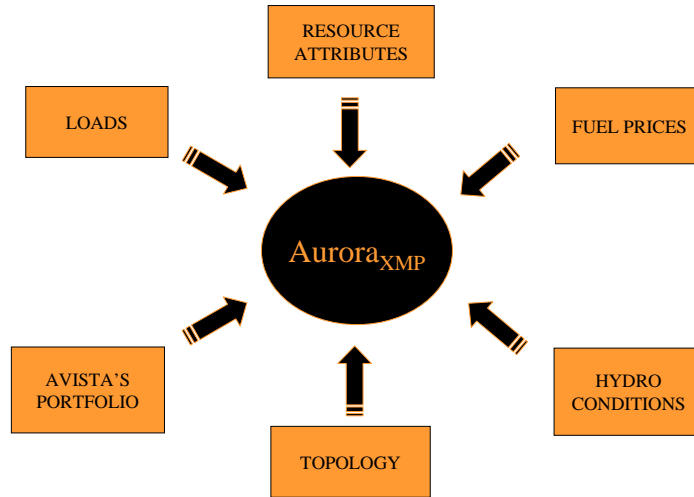
## What is Aurora<sub>XMP</sub>?

---

- 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

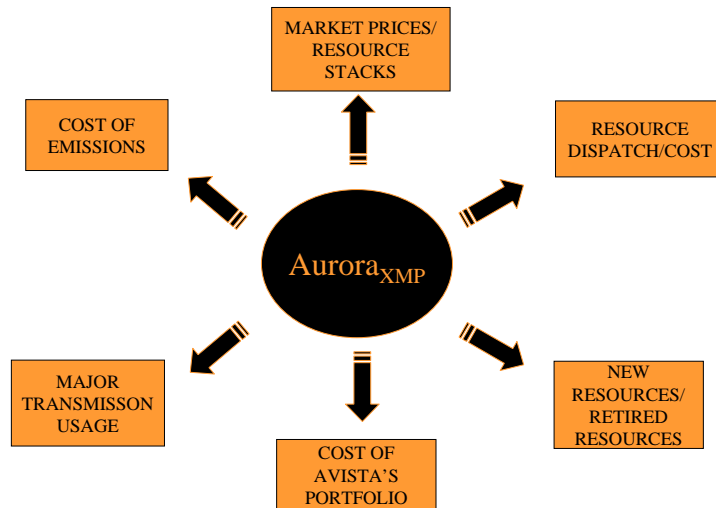
4

## What are Aurora Inputs



5

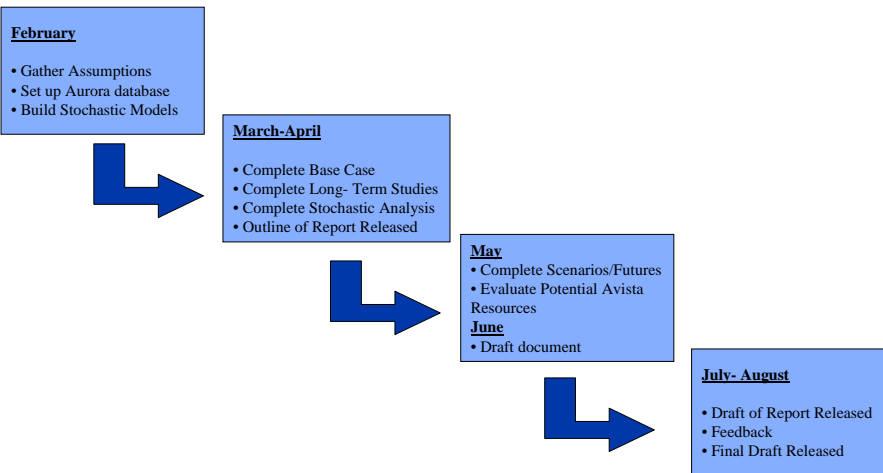
## What are Aurora Outputs



6

# IRP Timeline

## Timeline



# IRP Modeling Process

## “Base Case Example”

9

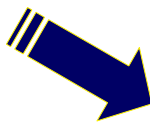
### Base Case Process

#### Aurora LT Studies

- Uses Aurora XMP
- Market price forecast 2007-2026
- Identifies resource 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

10

## 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

# Modeling Futures and Scenarios

---

2005 Integrated Resource Plan  
Fourth Technical Advisory Committee Meeting  
February 17<sup>th</sup> 2005

Clint Kalich

## Presentation Overview

	<u>Slide #</u>
• 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

3

## 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

4

## 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

5

## 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?

6



## 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 CO<sub>2</sub>
- Low Transmission \*
  - Reduce NPCC estimate by approx. 2/3 to \$500/kW
- High Wind Penetration
  - 5,000 MW NW wind replaces other new resources
- 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

\* Indicates new capacity expansion run will be required

7

## 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

8

## 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

1

## 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

2

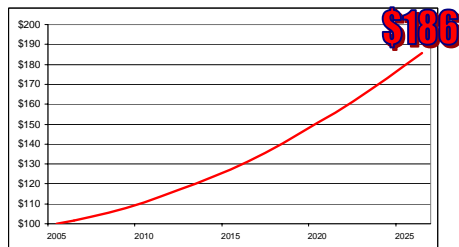
## Time Frame

- 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

3

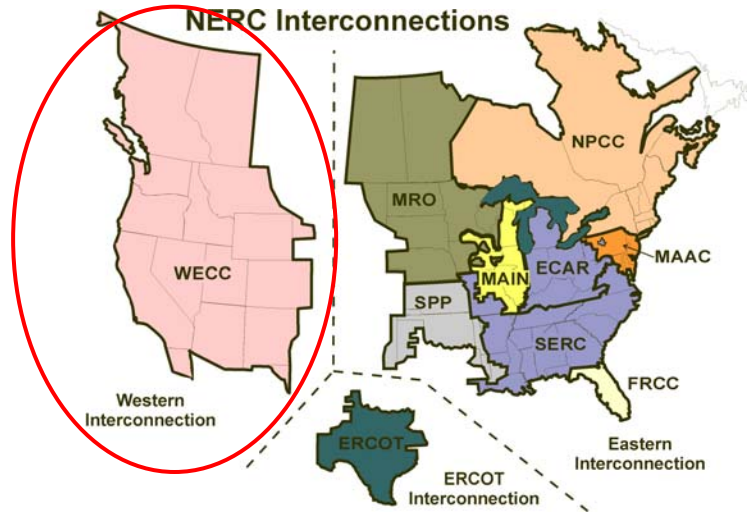
## Inflation

- 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



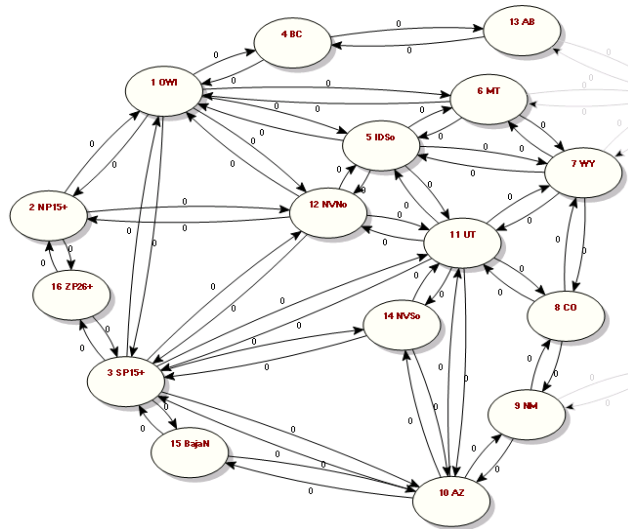
4

# North American Electric Grid



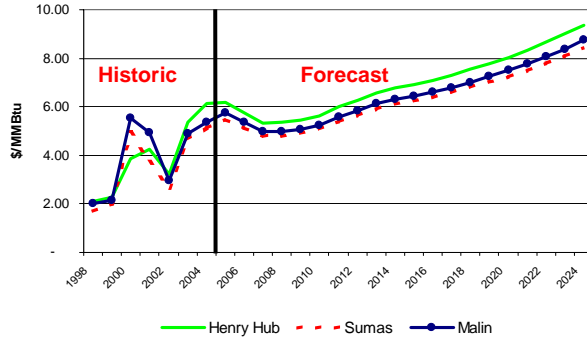
Picture Courtesy of NERC

# Aurora Topology



## Forecasted Natural Gas Prices

Annual Average Prices (Nominal Dollars)



**Key Assumptions**

- July 2004 Forward Price Curves for 2005 through 2007
- 2005-07: -7.1%
- Avg. Growth Rates – Based on July Global Insights forecast
- 2007-09: 1.9%
- 2010-20: 3.2%
- 2020-30: 3.8%

- 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

**New Escalation Rates Available in April**

## 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)

Year	Escalation
2005	0.50%
2006	0.20%
2007	-0.90%
2008	-0.20%
2009	-0.80%
2010	-1.20%
2011	-0.60%
2012	-0.40%
2013	-0.30%
2014	0.00%
2015	0.00%
2016	-0.20%
2017	0.20%
2018	0.30%
2019	0.30%
2020	0.30%
2021	0.70%
2022	0.70%
2023	2.40%
2024	0.70%
2025	0.20%
2025+	0.10%

## 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

9

## 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

10

## RPS Resources Added per Year

Area	Wind	Geothermal	Biofuels	Solar
California-North	Pre 2010: 53.25 MW Post 2010: 59.25 MW	Pre 2010: 2.25 MW Post 2010: 9 MW	Pre 2010: 11.25 MW Post 2010: 27 MW	
California-South	Pre 2010: 90.75 MW Post 2010: 101.25 MW	Pre 2010: 18.75 MW Post 2010: 69 MW	Pre 2010: 12.75 MW Post 2010: 28.5 MW	
Arizona	Pre 2012: 20.4 MW Post 2012: 3 MW			Pre 2012: 38.7 MW Post 2012: 5.25 MW
New Mexico	Pre 2012: 87 MW Post 2012: 115MW			
Nevada-South	Avg 14.3 MW	Avg 4.6 MW		Avg 2.2 MW
Nevada-North	Avg 44 MW	Avg 13.6 MW		Avg 6.7 MW
Colorado	Pre 2014: 25 MW + 200 MW 2011 + 250 MW 2014 Post 2015: 50 MW			Avg 2.2 MW

\* Total equals approximately 10.4 GW of Capacity by 2007

11

## Hydro

- 60 year average hydro conditions based 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%

12



## 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 project
- 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

13

## 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

14

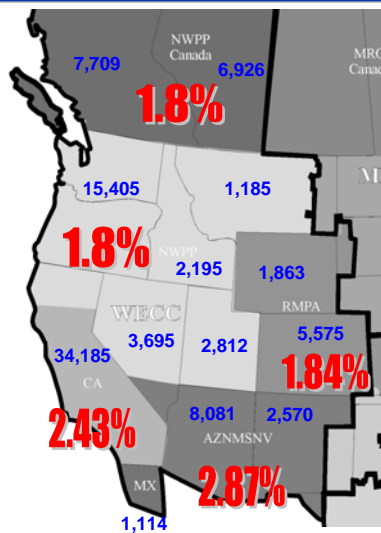
### Thermal Resource Forced Outages and Maintenance - Modeled as derates

Plant Type	Forced Outage Rate	Maintenance Rate
CCCT	5%	5%
SCCT- Aero	7.5%	7.5%
SCCT- Frame	10%	10%
Gas- Steam	10%	10%
Coal	10%	17.6% in shoulder months
Nuclear	10%	10-12% in shoulder months & 0-5% in others
Solar	Assumed in hourly distribution	10%
Geothermal	5%	5%
Wind	Assumed in hourly distribution	Assumed in hourly distribution
Other	5%	5%

15

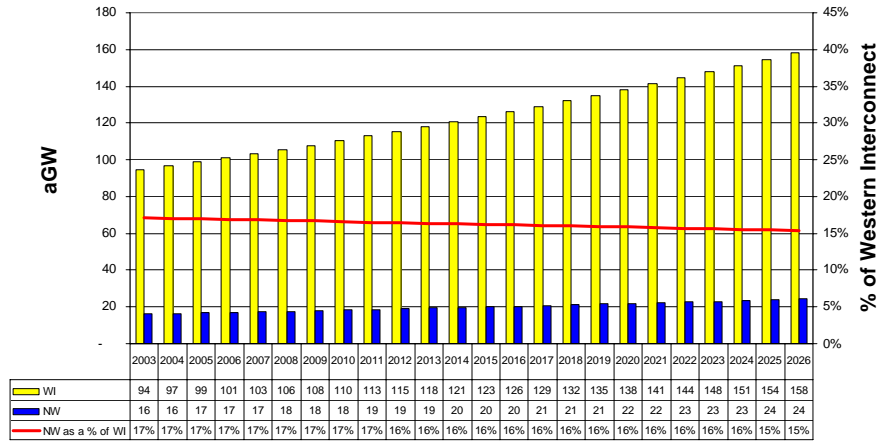
### Regional Load and Growth

- 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



16

## Western Interconnect and NW Loads by Year



# Treatment of Emissions

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

John Lyons

1

## Presentation Overview

	<u>Slide #'s</u>
• 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

2

## 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

3

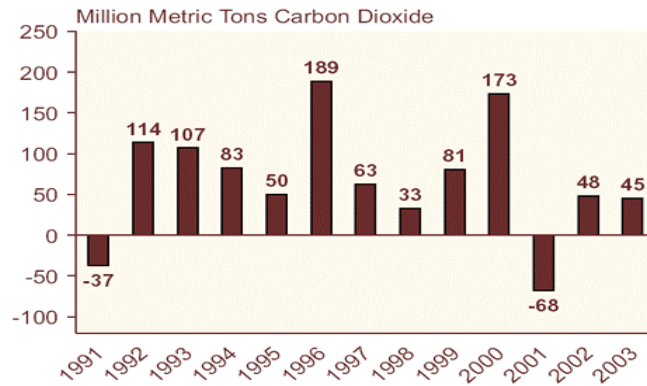
## Environmental Issues

- 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 CO<sub>2</sub> equivalents (CO<sub>2</sub>e)
- 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)

4

## Magnitude of Environmental Issues

**Figure 1. Annual Change in U.S. Carbon Dioxide Emissions, 1990-2003**



Source: EIA

5

## 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.

(Nordhause, 2001)

6

## 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)

7

## Western State Laws Concerning Emissions

### Idaho

- No active legislation regarding greenhouse gases

### Nevada

- No active legislation regarding greenhouse gases

8

## Western State Laws Concerning Emissions

### Oregon

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

9

## Western State Laws Concerning Emissions

### Washington

- 2004 – New fossil-fueled thermal electric generating facilities of greater than 25 MW will have a CO<sub>2</sub> mitigation plan including one or more of the following:
  - (a) Pay a third party to provide mitigation
  - (b) Purchase carbon credits
  - (c) Cogeneration

10



## 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)

11

## Federal Emissions Regulations

### 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 CO<sub>2</sub> emissions in 2 phases

Phase 1 2010 – 2015: reduce to 2000 levels

Phase 2 2016 – 2020: reduce to 1990 levels

12

## 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)

13

## 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, nitrogenoxides and mercury
- Reduce the 3 pollutants by 70% by 2018
- Companies operating below their cap can sell credits

14

## International Emissions Regulations

### Kyoto Protocol - 1997

- Goal is to reduce CO<sub>2</sub> 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 CO<sub>2</sub>
- The EU started an emissions trading system within the last few months to trade credits from the quotas assigned to 12,000 industrial facilities

15

## 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 (SO<sub>x</sub>, NO<sub>x</sub>, and HG) – i.e. new technologies promise 95% mercury capture

16

## Economic Issues - Treatment of Emissions

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

1. What is or will be regulated?
  - CO<sub>2</sub> or CO<sub>2</sub>e?
  - Tighter Hg, SO<sub>x</sub>, and NO<sub>x</sub> 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?

17

## 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 CO<sub>2</sub> in 2008 dollars.

### PGE

- 2002 IRP - no CO<sub>2</sub> tax in the base case and a \$40 per ton CO<sub>2</sub> tax scenario

### Idaho Power

- 2004 IRP has a base case of \$12.80/ton of CO<sub>2</sub> by 2008.

### Avista

- 2003 IRP - Modeled a scenario with then-current NPCC assumption— prices rising to \$11/ton in 2023

18

## 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 CO<sub>2</sub> equivalent
- 2015 - Link to efforts by other developing and developed countries to reduce greenhouse gases

19

## 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 CO<sub>2</sub> 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 CO<sub>2</sub>e 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 CO<sub>2</sub>e and prices escalated into the future.

20

## 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

1

## 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*

2

## 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): **SO<sub>2</sub> = .002 NO<sub>x</sub> = .039 CO<sub>2</sub> = 411- 429**
- Location options: **Any location**
- Interconnection Costs: **\$16.80 kW/ year**

3

## 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): **SO<sub>2</sub> = 0.09 NO<sub>x</sub> = 0.009-0.01 CO<sub>2</sub> = 582**
- Location options: **Any location**
- Interconnection Costs: **\$0 kW/Year**

4



## 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): **SO<sub>2</sub> = 0.09 NO<sub>x</sub> = 0.009-0.01 CO<sub>2</sub> = 582**
- Location options: **Any location**
- Interconnection Costs: **\$0 kW/Year**

5

## 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**

6

## 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): SO<sub>2</sub> = 0.575 NO<sub>x</sub> = 0.336 CO<sub>2</sub> = 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

7

## 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): SO<sub>2</sub> = Neg. NO<sub>x</sub> = < 0.11 CO<sub>2</sub> = 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

8

## Coal – IGCC with Sequestration 2005 dollars

- Type: Coal-fired integrated gasification combined-cycle with 90% CO<sub>2</sub> 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): SO<sub>2</sub> = Neg. NO<sub>x</sub> = < 0.11 CO<sub>2</sub> = 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

9

## 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

10

## 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**

11

## Biomass 2005 dollars

- Type: **Wood Residue, Landfill, Manure**
- Size (MW): **.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<sub>2</sub> = N/A NO<sub>x</sub> = N/A CO<sub>2</sub> = 720 – 1,116**
- Location options for NW delivery : **Any Location**
- Interconnection Costs: **\$16.80 kW per year**

12

**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**

13

**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): **SO<sub>2</sub> = Not Avail NO<sub>x</sub> = Not Avail CO<sub>2</sub> = 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 Celilio: **\$1,166/ kW (1,089 miles of DC at \$2 million per mile and \$1.32 billion for inverter stations)**

14

## 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**

15

## 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

16

## 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)

17

## New Resource Summary

Resource Type	Fuel Source	Size (MW)	Heat Rate	Year Available	Capital Cost \$/kW	Variable O&M \$/MWh	Fixed O&M \$/kW	Location	Transmission Costs	SO <sub>2</sub> Tons/GWh	NO <sub>x</sub> Tons/GWh	CO <sub>2</sub> Tons/GWh
CCCT	Gas	610	7,030	2007	632	3.02	9.00	OR/WA	\$16.80 kW/year	.002	.039	411-429
SCCT- Aero	Gas	47	9,900	2007	672	8.96	9.00	OR/WA	\$16.80 kW/year	.09	.009-.01	582
SCCT- Industrial	Gas	47	10,500	2007	420	4.48	6.72	OR/WA	\$0/kW/year	.09	.009-.01	582
Coal- Pulverized	Coal	400	9,550	2011	1,392	1.96	44.80	MT	\$530 - \$1,781/kW Capital	.575	.336	1,012
Coal- IGCC- Montana	Coal	474	7,915	2011	1,568	1.68	50.51	MT	\$530 - \$1,781/kW Capital	Neg.	<.11	791
Coal- IGCC- Eastern WA/OR	Coal	474	7,915	2011	1,568	1.68	50.51	OR/WA	\$352/kW Capital	Neg.	<.11	791
Coal- IGCC w/ Seq.	Coal	401	9,290	2013	2,022	1.79	59.36	MT	\$530 - \$1,781/kW Capital	Neg.	<.11	81
Wind	Wind	100	N/A	2008	1,131	6.12 - 9.12	19.60	OR/WA	\$16.80 kW/year	N/A	N/A	N/A
Wind	Wind	100	N/A	2011	1,131	6.12 - 9.12	19.60	MT	\$530 - \$1,781/kW Capital	N/A	N/A	N/A
Geo-thermal- not NW	Geological Steam	50	9,300	2007	2,050	Included in FC	108.00	CA/NV	\$16.80 kW/year	N/A	N/A	N/A
Solar-not NW	Sun	2	N/A	2007	7,804	0	36.00	DSW	\$16.80 kW/year	N/A	N/A	N/A
Biomass	Refuse/Other	.5 - 25	11,000-14,500	2007	1,523 - 3,472	0 - 10.38	75 - 140	OR/WA	\$16.80 kW/year	N/A	N/A	720 - 1,116
Nuclear	Uranium	1,100	9,600	2020	1,624	1.12	44.80	OR/WA	\$16.80 kW/year	N/A	N/A	N/A
Tar Sands	Oil Sands/ Co-Gen	180	5,800	2011	566	3.11	Included in VC	AB	1,166 kW Capital	N/A	N/A	365
Co-Gen	TBA	25	5,500	2007	1,120	2.24	29.00	OR/WA	\$16.80 kW/year	TBD	TBD	TBD

## DSM Integration Brief

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

Jon Powell

1

## 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

2



## 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

3

## 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.

4

## 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

5

## Significant Issues in Integrating DSM into the IRP

- 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

6

## 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

7

## Our 2000 (and prior) Integration Methodology

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

8

## 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

9

## 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)

10

## 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

11

## 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

12

## Our 2005 Methodology

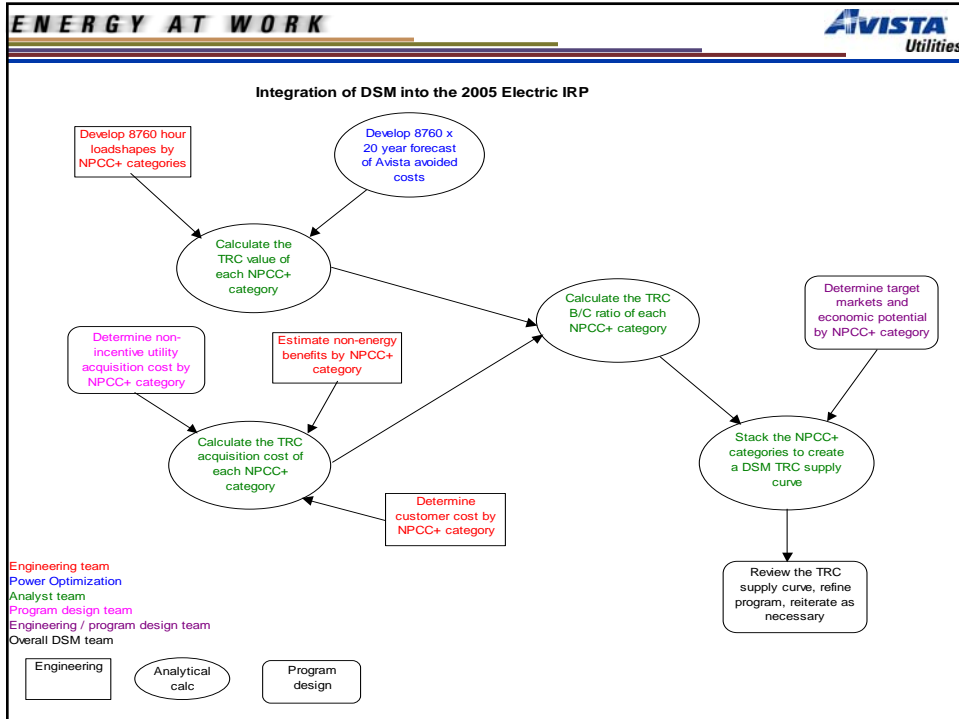
- Utilizes price signal integration for energy DSM programs
  - Any future demand-response options would most likely be explicitly integrated into AURORA
- Applies a “richer” 8760 hour x 20 year avoided cost price signal
  - Improved ability to distinguish and appropriately value different load shapes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

13

## 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

14



**ENERGY AT WORK** **AVISTA**  
Utilities

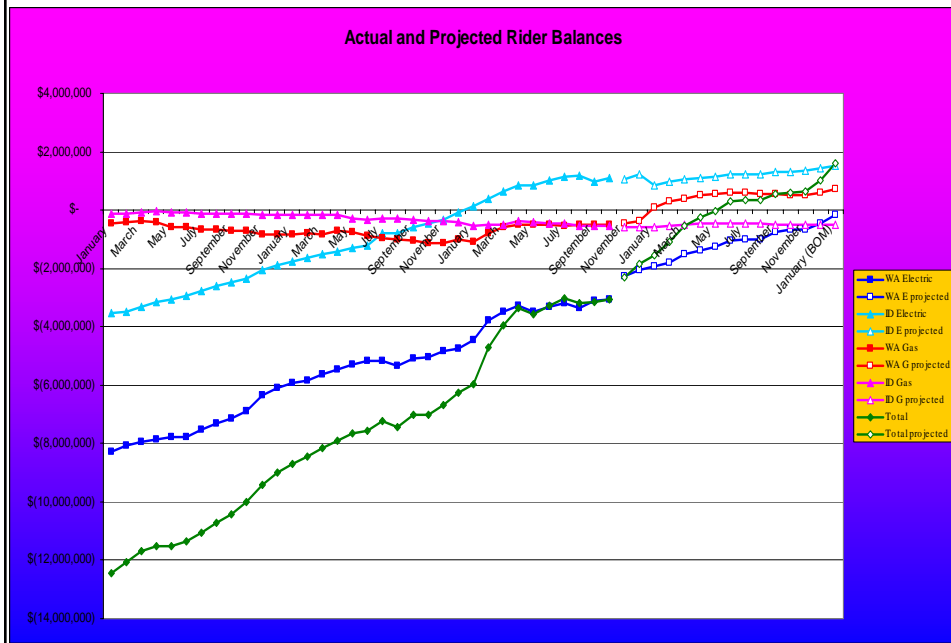
## Anticipated Results

- 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)

16

## 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





## 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

19

## 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 15<sup>th</sup>)

20

## 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

21

## 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

22

# Questions

# Stochastic Modeling

---

2005 Integrated Resource Plan  
Fifth Technical Advisory Committee Meeting  
March 23<sup>rd</sup> 2005

Clint Kalich

## Presentation Overview

---

	<u>Slide #</u>
• Why Model Risk?	3
• Risk Modeled In AURORA	4
• Limits of AURORA Risk Module	5
• Risk Modeling For 2005 IRP	6
• Hydro Variability	7-12
• Natural Gas Variability	13-18
• Load Variability	19-22
• Wind Variability	23-27

## 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!!!

3

## 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

4

## 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

5

## 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

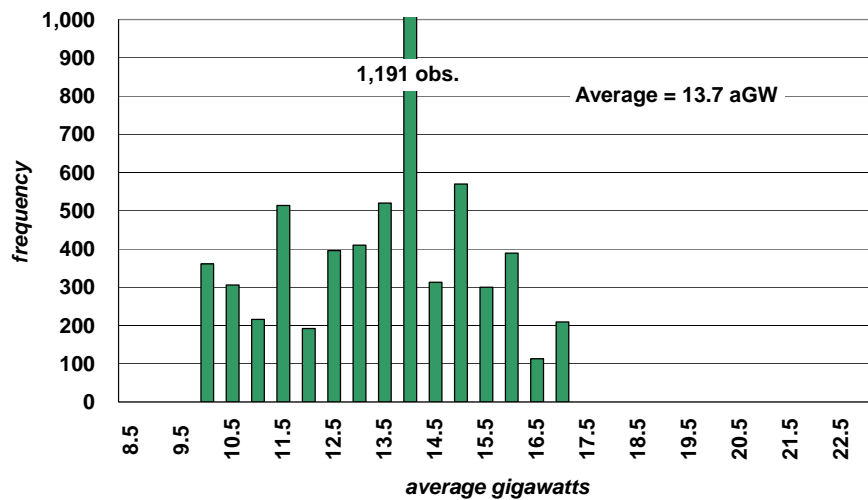
6

## 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

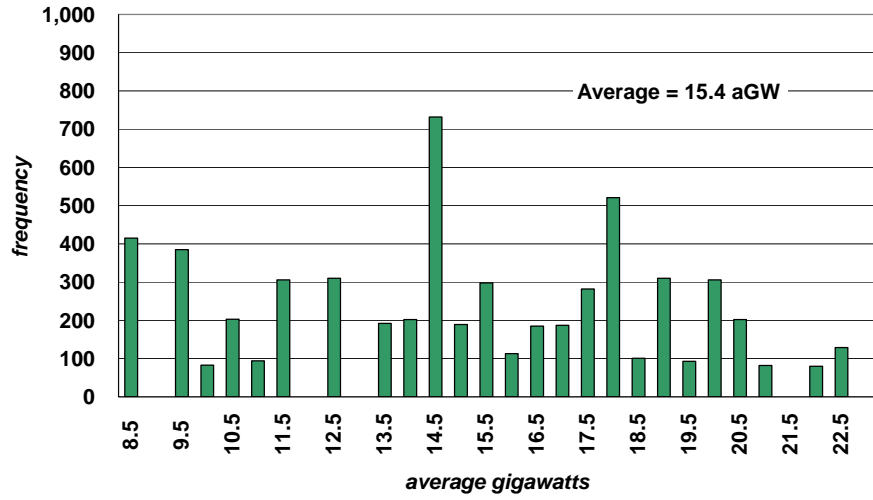
7

### Hydro Distribution - OWI Annual Average



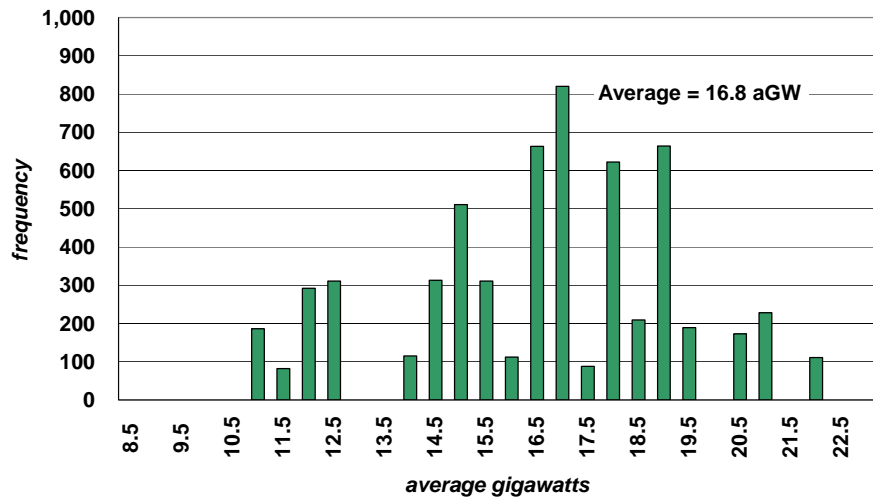
8

### Hydro Distribution - OWI First Quarter



9

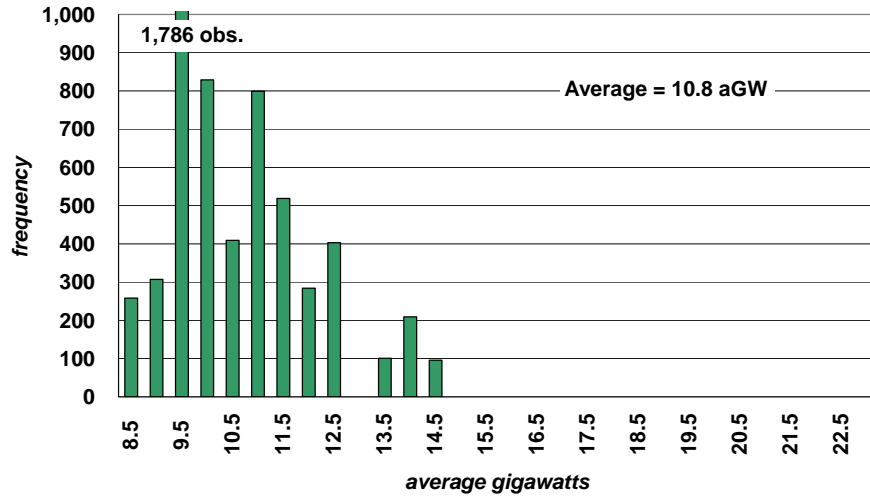
### Hydro Distribution - OWI Second Quarter



10

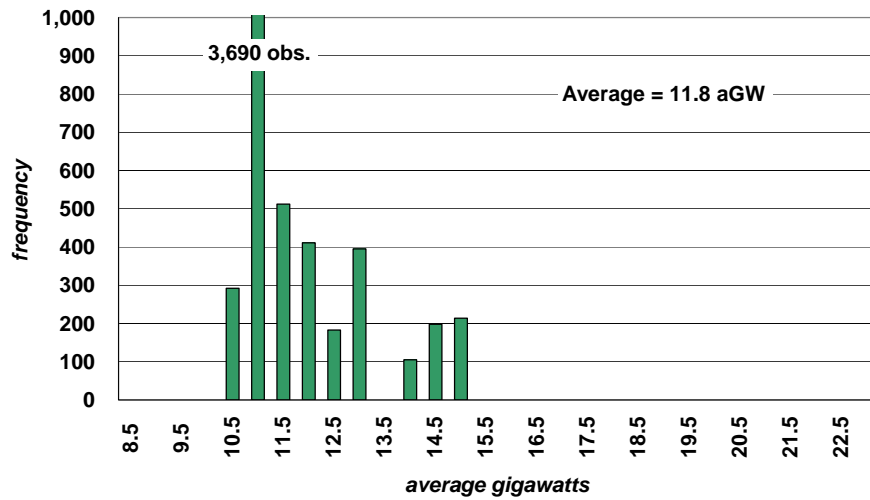


### Hydro Distribution - OWI Third Quarter



11

### Hydro Distribution - OWI Fourth Quarter



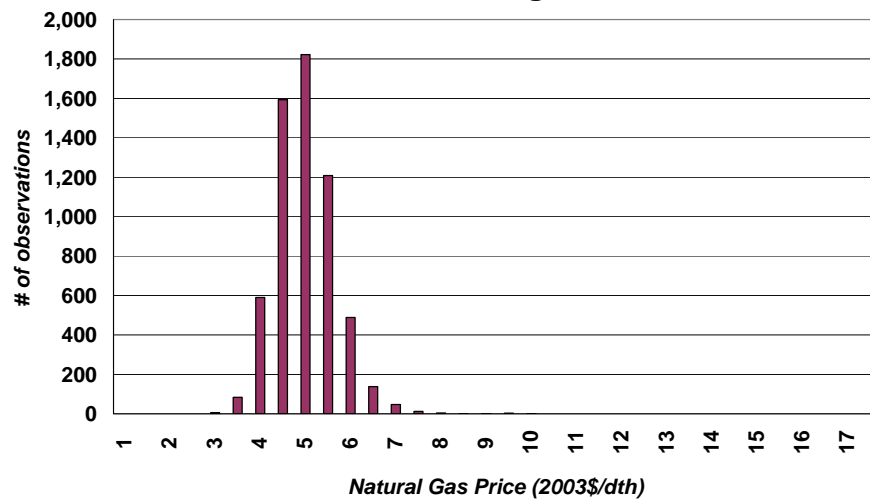
12

## 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

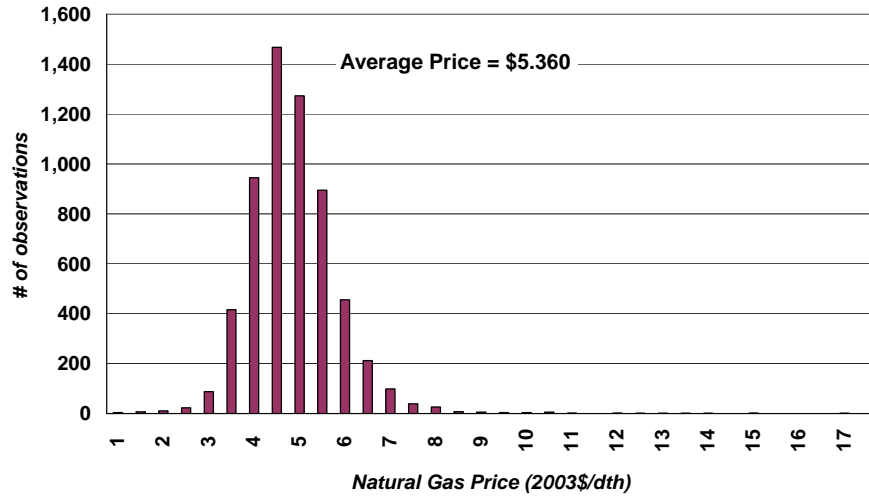
13

## Natural Gas Price Distribution Annual Average



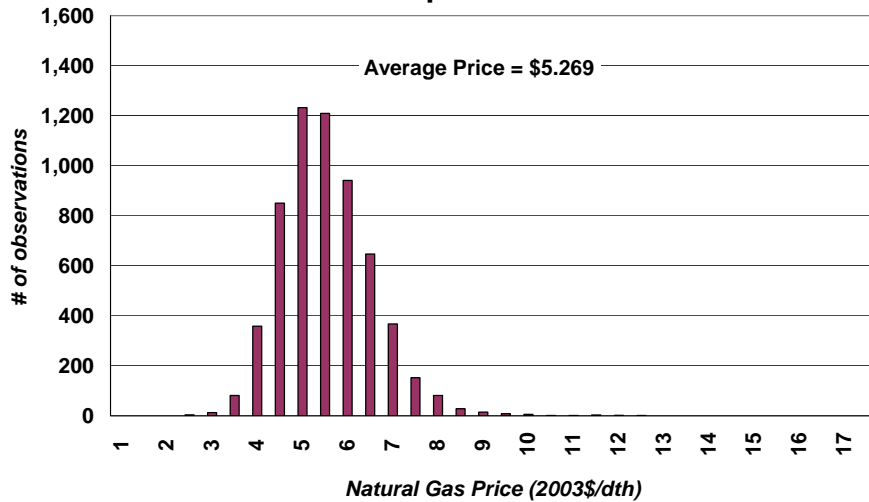
14

### Natural Gas Price Distribution January



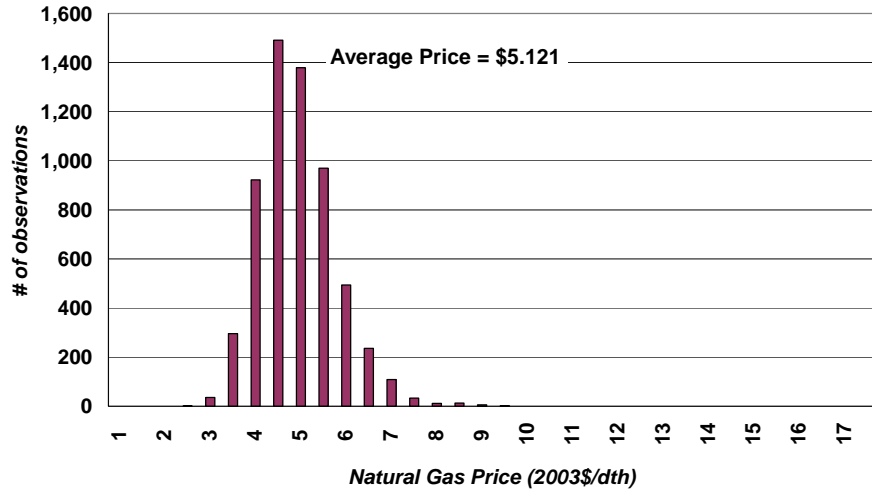
15

### Natural Gas Price Distribution April



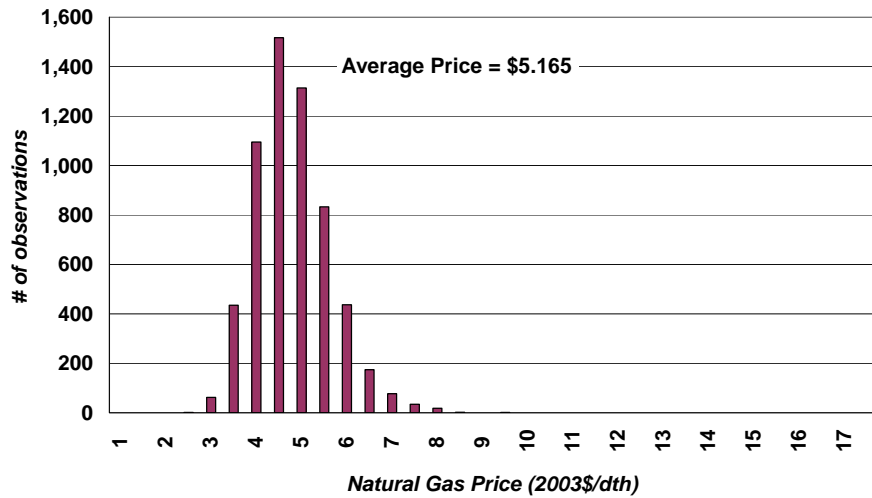
16

### Natural Gas Price Distribution July



17

### Natural Gas Price Distribution October



18

## 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

19

## 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

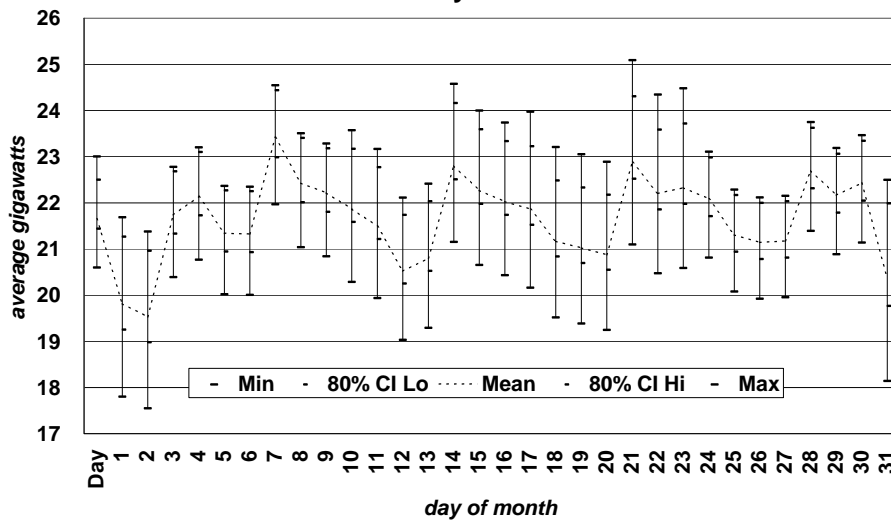
20

## Load Variability, Continued

Load Correlation Values to OWI (Average of Weekdays)												
	January	February	March	April	May	June	July	August	September	October	November	December
Alberta	0.659	Not Sig	0.481	Not Sig	Mix	0.635	0.668	Mix	Mix	0.479	Not Sig	Not Sig
Arizona	0.440	0.664	Not Sig	Mix	(0.289)	0.666	Not Sig	Not Sig	Not Sig	Not Sig	Mix	Not Sig
British Col	0.918	0.838	0.825	0.733	0.617	Not Sig	0.560	Not Sig	0.638	0.809	0.525	0.890
CA North	Not Sig	0.734	Not Sig	Not Sig	Not Sig	0.771	Mix	0.757	0.789	Not Sig	Mix	Not Sig
CA South	Not Sig	Mix	Not Sig	Not Sig	Mix	0.680	Mix	0.500	0.778	Not Sig	Not Sig	Not Sig
Colorado	0.623	Not Sig	0.567	Mix	Mix	Not Sig	Not Sig	Not Sig	Not Sig	0.655	0.629	0.571
ID South	0.673	0.747	0.882	Not Sig	Not Sig	0.758	Mix	0.789	0.733	0.561	0.587	0.813
Montana	0.894	0.773	0.755	0.651	0.405	0.599	0.786	0.648	0.752	Not Sig	0.856	0.898
NV North	Mix	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	Mix	0.476	Not Sig
NV South	Not Sig	0.641	0.513	Mix	Not Sig	0.729	Mix	Not Sig	Mix	Not Sig	0.461	Mix
New Mexico	0.384	Mix	Mix	Not Sig	Not Sig	Mix	Not Sig	Mix	Not Sig	Not Sig	Mix	Mix
Utah	0.816	Not Sig	0.669	0.697	0.610	0.698	0.703	0.604	0.611	Not Sig	0.561	0.837
Wyoming	0.765	Mix	0.641	Not Sig	Mix	Mix	Not Sig	Not Sig	0.483	Not Sig	0.522	0.633

\* "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

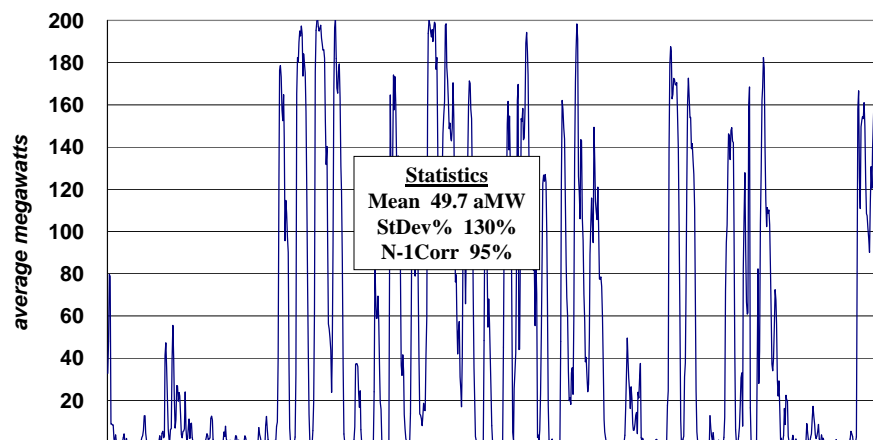


## Wind Variability

- 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

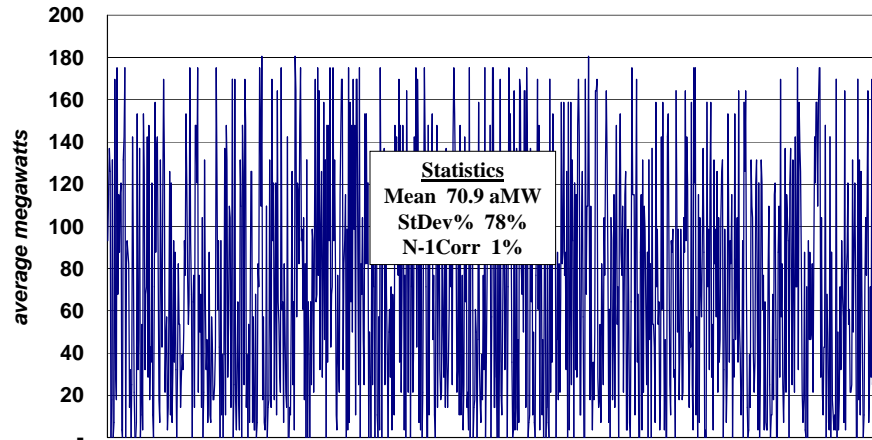
23

### Stateline Data 1000 Continuous Hours

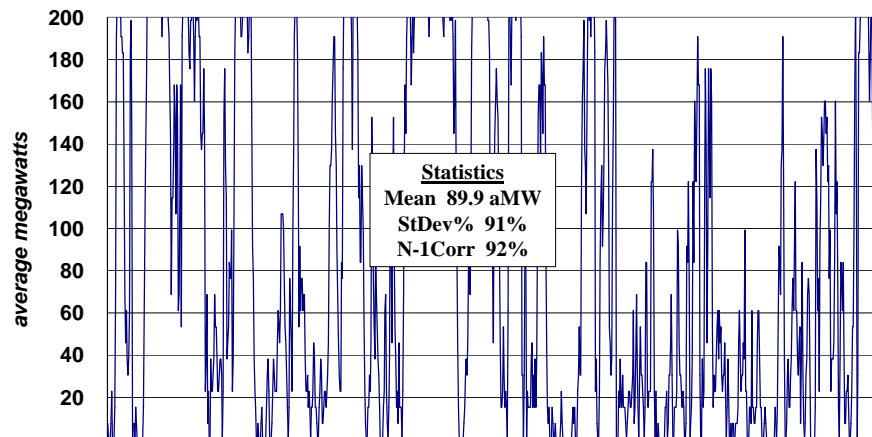


24

### Simple Mean/StDev 1000 Continuous Hours

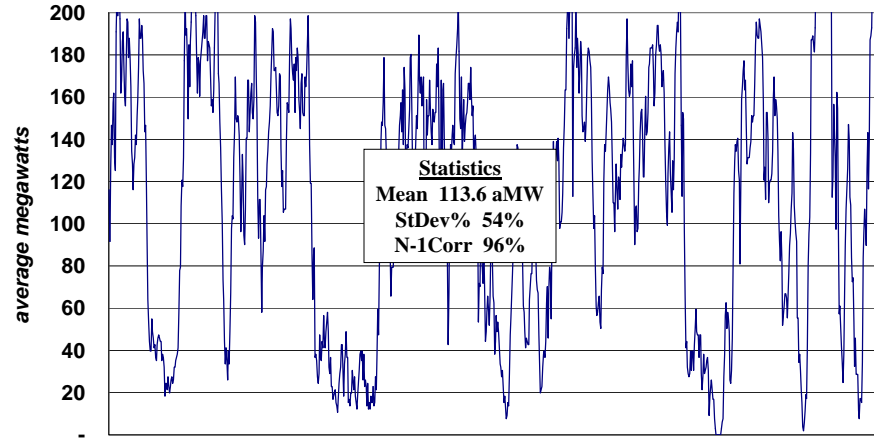


### OSU Kennewick, WA 1000 Continuous Hours





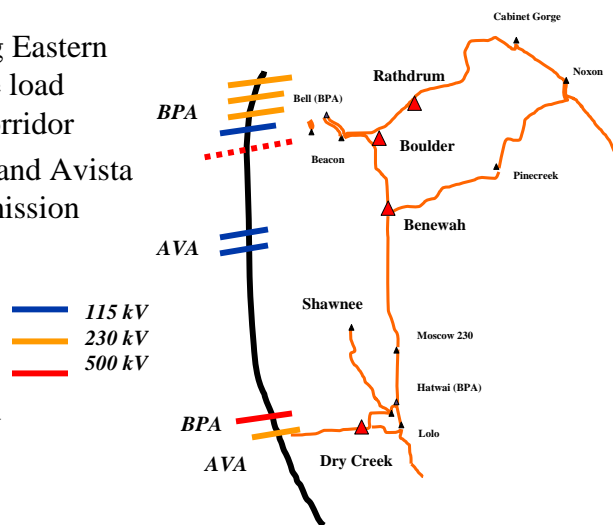
### 5-Site NW Average (OSU Database) 1000 Continuous Hours





## The West of Hatwai Transmission Path

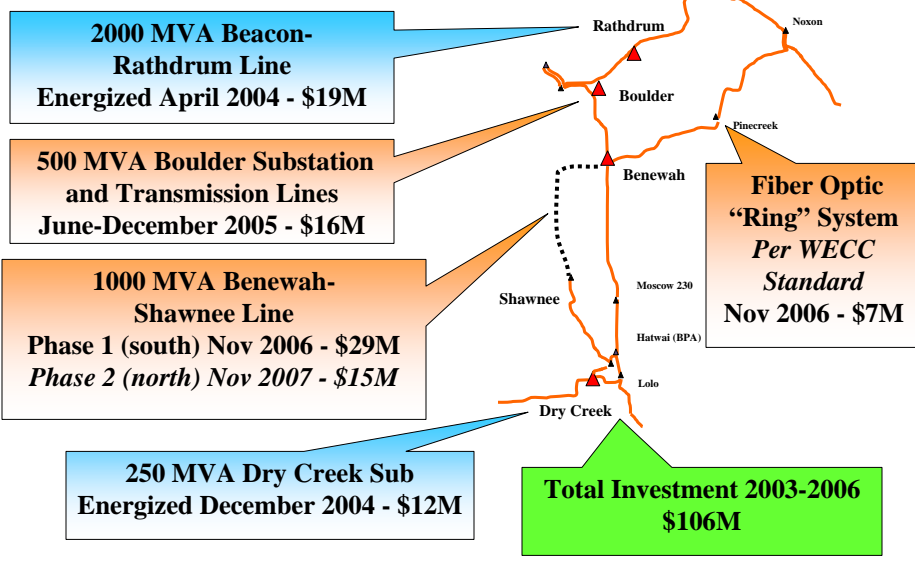
- Flowgate separating Eastern Washington and the load centers of the I-5 corridor
- Consisting of BPA and Avista 115-500 kV Transmission Lines
- 2002 Rating
  - 2800 MW
- 2002 Peak Demand
  - 3500-4000 MW



## 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





## Beacon-Rathdrum Facts

Rathdrum 230 kV Substation Reconstruction (\$3M)  
*Becomes Avista's 1<sup>st</sup> 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)

*1<sup>st</sup> Energization June 2005. December Completion*

*Three 230 kV and Six 115 kV Transmission Lines*

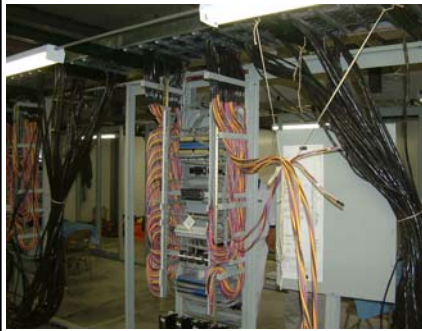
*500 yards of concrete, 10,000 control wire connections*

*Additional transformation to the Spokane Valley*

*Liberty Lake – 2<sup>nd</sup> 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

1

## 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

2

## Resource Assumptions

3

## New Resource Summary

Yellow Indicates Change From Last TAC Meeting

Resource Type	Fuel Source	Size (MW)	Heat Rate	Year Available	Capital Cost \$/kW	Variable O&M \$/MWh	Fixed O&M \$/kW
CCCT	Gas	610	7,030	2007	588	3.02	19.00
SCCT- Aero	Gas	47	9,900	2007	672	8.96	15.00
SCCT- Industrial	Gas	47	10,500	2007	420	4.48	11.25
Coal- Pulverized	Coal	400	9,550	2010	1,392	1.96	62.00
Coal- IGCC	Coal	425	7,915	2011	1,568	1.68	67.00
Coal- IGCC w/ Seq.	Coal	401	9,290	2013	2,022	1.79	76.00
Wind	Wind	100	N/A	2011	1,131	6.12 - 9.12	38.00
Geothermal	Geological Steam	50	9,300	2007	2,050	Inc. in FC	178.00
Solar	Sun	2	N/A	2007	7,804	0	36.00
Biomass	Refuse/Other	1 – 25	11,000-14,500	2007	1,523 – 3,472	0 – 10.38	125 – 250
Nuclear	Uranium	1,100	9,600	2020	1,624	1.12	75.00
Tar Sands	Oil Sands/ Co-Gen	180	5,800	2011	566	3.11	Inc. in VC
Co-Gen	TBA	25	5,500	2007	1,120	2.24	29.00

4

## 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 5<sup>th</sup> Power Plan

	PUD	IOU	IPP	Weighted Discount Rates
Discount Rate	4.9%	9.15%	10.68%	9.2%
<b>Percent Ownership</b>				
Coal/Tar Sands	25%	25%	50%	8.9%
CCCT	20%	20%	60%	9.2%
SCCT	40%	40%	20%	7.8%
Renewables	15%	15%	70%	9.6%

5

## Transmission Costs

- AURORA<sup>XMP</sup> 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

Resource Type	To	From	Line Size (KV)	Capacity (MW)	Miles	Cost per Mile (\$Mil)	Substation Costs (\$Mil)	Total Capital Cost (\$Mil)	Dollars per KW	Fixed O&M \$/KW/YR	\$/MWh @ 100% CF
Wind	Inter-regional		230	500	100	0.90	35	125	250	8.90	\$4
Wind	OWI	MT	500	1,500	900	2.00	40	1,840	1,227	8.90	\$13
Coal	Inter-regional		500	1,500	250	2.00	40	540	360	8.90	\$5
Coal	OWI	MT	500	1,500	900	2.00	40	1,840	1,227	8.90	\$13
Coal	IDSo	WY	500	1,500	500	2.00	40	1,040	693	8.90	\$9
Coal	UT	WY	500	1,500	425	2.00	40	890	593	8.90	\$7
Coal	S Cal	WY	500	1,500	1,500	2.30	100	3,550	2,367	8.90	\$25
Coal	N Cal	WY	500	1,500	1,600	2.30	100	3,780	2,520	8.90	\$27
Coal	NVSo	WY	500	1,500	1,100	2.10	100	2,410	1,607	8.90	\$17
Tar Sands	OWI	AB	500 DC	1,500	1,200	1.80	285	2,445	1,630	8.90	\$18
Tar Sands	S Cal	AB	500 DC	2,000	1,730	1.70	380	3,321	1,661	8.90	\$18
Tar Sands	AB	AB	500 DC	500	475	2.00	95	1,045	2,090	8.90	\$22
Gas/Other	Inter-regional		N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.80	\$2


6

## 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

7

## Western Interconnect Options/Limitations

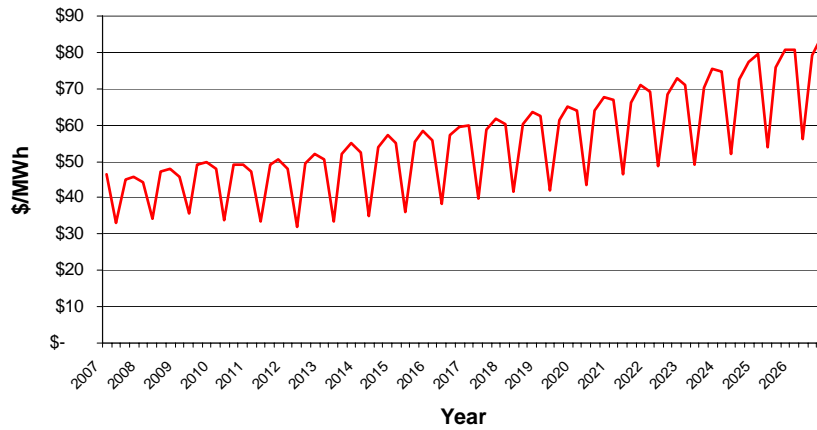
- Gas:
    - **CCCT:** No Limitations
    - **SCCT:** No Limitations
  - Coal:
    - **Local Pulverized:** No Limitations (Not allowed in California)
    - **Imported Wyoming Pulverized:** No Limitations with new transmission build (S. Cal allowed to build 1 plant in Utah by upgrading the IPP DC Interconnect)
    - **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
- 
*Not available for modeling simplicity and speed*

8

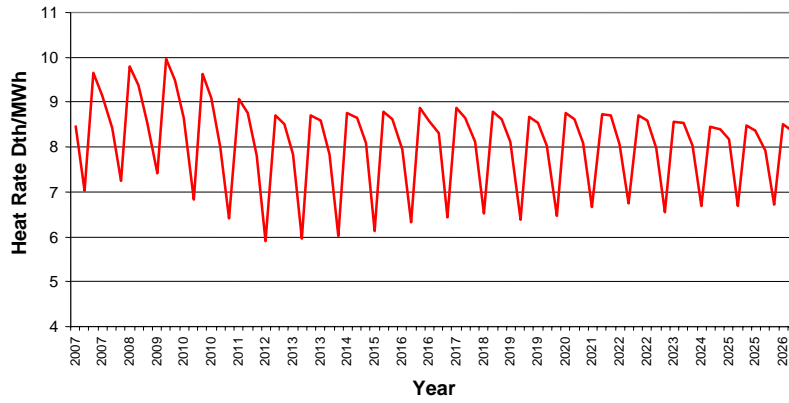
# "PRELIMINARY"

## Electric Market Forecasts

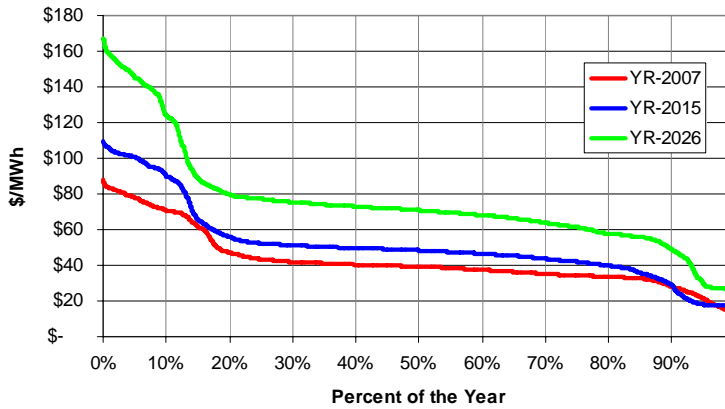
### Mid Columbia Electric Prices (Qr. Avg.)



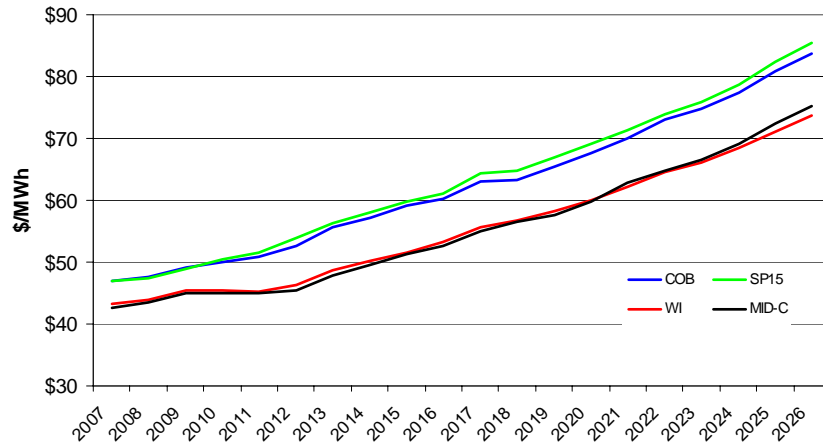
### Marginal Heat Rate



### 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):

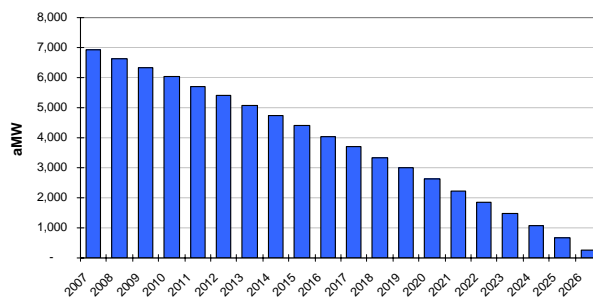
- AURORA<sup>XMP</sup> does not currently add resources to meet RPS requirements, for this IRP, RPS requirements were manually added based on the NPCC 5<sup>th</sup> Power Plan

## Northwest Loads & Resources

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

Year	Load	Resources	Balance
2007	16,544	23,478	6,934
2008	16,842	23,478	6,636
2009	17,145	23,478	6,333
2010	17,454	23,478	6,024
2011	17,768	23,478	5,710
2012	18,088	23,478	5,390
2013	18,414	23,478	5,064
2014	18,745	23,478	4,733
2015	19,082	23,478	4,396
2016	19,425	23,478	4,053
2017	19,775	23,478	3,703
2018	20,131	23,478	3,347
2019	20,493	23,478	2,985
2020	20,862	23,478	2,616
2021	21,238	23,478	2,240
2022	21,620	23,478	1,858
2023	22,009	23,478	1,469
2024	22,405	23,478	1,073
2025	22,808	23,478	670
2026	23,219	23,478	259

Estimated Average Annual Net Position (aMW)

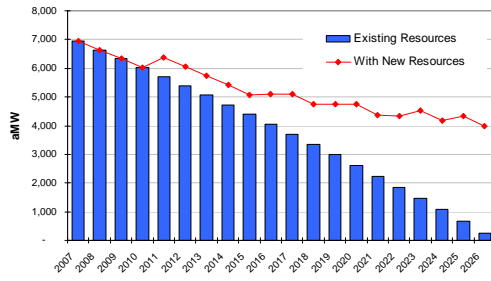


## Northwest New Resources Selection

Annual Resource Selection (MW Capacity)

Year	CCCT	SCCT	Pul. Coal	IGCC Coal	Wind	Total
2007						0
2008						0
2009						0
2010						0
2011			800			800
2012						0
2013						0
2014						0
2015						0
2016				425		425
2017				425		425
2018						0
2019				425		425
2020				425		425
2021						0
2022				425		425
2023	610				100	710
2024					100	100
2025	610					610
2026					200	200
<b>Total</b>	<b>1,220</b>	<b>0</b>	<b>800</b>	<b>2,125</b>	<b>400</b>	<b>4,545</b>

Estimated Average Annual Northwest Position

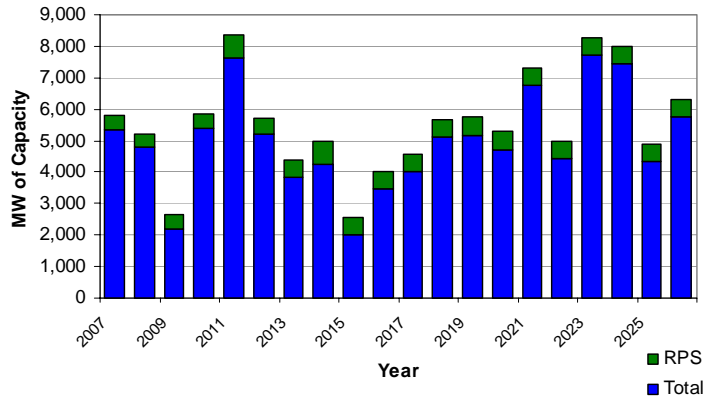


## Western Interconnect Resource Selection

Resource Begin Year	CCCT- Gas	SCCT- Gas	IGCC- Coal	Pulverized- Coal	Wind	Nuclear	Total
2007	3,660	1,692	0	0	0	0	5,352
2008	2,440	2,350	0	0	0	0	4,790
2009	1,830	376	0	0	0	0	2,206
2010	610	0	0	4,800	0	0	5,410
2011	3,660	376	0	3,600	0	0	7,636
2012	1,830	188	0	3,200	0	0	5,218
2013	1,830	0	425	1,600	0	0	3,855
2014	3,050	0	0	1,200	0	0	4,250
2015	1,220	0	0	800	0	0	2,020
2016	3,050	0	425	0	0	0	3,475
2017	3,050	0	850	0	100	0	4,000
2018	4,270	0	850	0	0	0	5,120
2019	3,050	0	2,125	0	0	0	5,175
2020	1,830	94	1,700	0	0	1,100	4,724
2021	5,490	0	1,275	0	0	0	6,765
2022	3,050	94	1,275	0	0	0	4,419
2023	6,100	564	850	0	200	0	7,714
2024	6,100	282	850	0	200	0	7,432
2025	3,050	0	1,275	0	0	0	4,325
2026	4,270	0	1,275	0	200	0	5,745
<b>Total Capacity</b>	<b>63,440</b>	<b>6,016</b>	<b>13,175</b>	<b>15,200</b>	<b>700</b>	<b>1,100</b>	<b>99,631</b>
<b>% of Energy</b>	<b>69%</b>	<b>1%</b>	<b>13%</b>	<b>15%</b>	<b>0%</b>	<b>1%</b>	<b>100%</b>

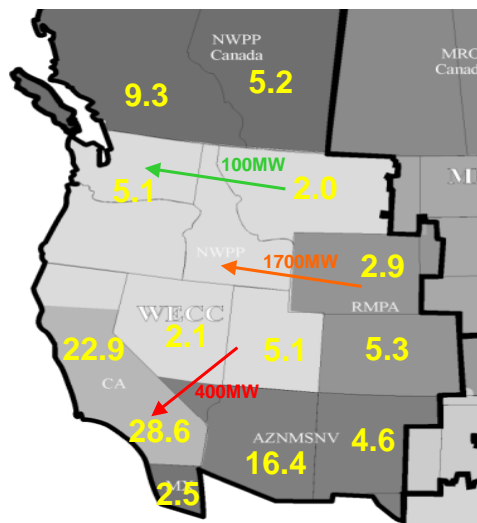
## New Resources for the Western Interconnect

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

---

	<u>Slide #</u>
• 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

3

## 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

4

## 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

5

## Revised List of Scenarios

- |   |  |
|---|--|
| <ul style="list-style-type: none"> <li>• High Gas *           <ul style="list-style-type: none"> <li>– Increase prices 50% to ~\$9/dth</li> </ul> </li> <li>• Low Gas *           <ul style="list-style-type: none"> <li>– Decrease prices 50% to ~\$3/dth</li> </ul> </li> <li>• Emissions 2 *           <ul style="list-style-type: none"> <li>– \$25/ton CO<sub>2</sub></li> </ul> </li> <li>• Low Transmission *           <ul style="list-style-type: none"> <li>– Reduce transmission capital costs by 33%</li> </ul> </li> <li>• High Wind Penetration           <ul style="list-style-type: none"> <li>– 5,000 MW NW wind replaces other new resources</li> </ul> </li> </ul> | <ul style="list-style-type: none"> <li>• Energy Market Bubbles           <ul style="list-style-type: none"> <li>– Electricity market mimics real estate building cycles</li> </ul> </li> <li>• Loss of Large AVA Plant           <ul style="list-style-type: none"> <li>– Noxon “lost” for 5 years</li> </ul> </li> <li>• High AVA Load           <ul style="list-style-type: none"> <li>– Double load growth to ~4%</li> </ul> </li> <li>• Low AVA Load           <ul style="list-style-type: none"> <li>– No load growth</li> </ul> </li> <li>• WECC-Wide Renewable Portfolio Standard           <ul style="list-style-type: none"> <li>– 25% renewables by end of study, replacing other new resources</li> </ul> </li> </ul> |
|---|--|

\* Indicates new capacity expansion run will be required

6

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

\* Indicates new capacity expansion run will be required

7

## 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

8

## 2005 Draft IRP Outline

---

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

John Lyons

1

## 2005 Draft IRP Outline

---

- 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.

2



## 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

3

## 2005 Draft IRP Outline

### 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

4

## 2005 Draft IRP Outline

---

### 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

5

## 2005 Draft IRP Outline

---

- Questions?
- Any sections that you would like to see included or excluded from the IRP?

6

## Gas & Inflation Forecast Update

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

James Gall

1

## Natural Gas Price & Inflation Assumptions and Caveats

- Global Insight, Inc. Winter 2005 Long Term Forecast Contract with Avista Corp.
  - 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

2

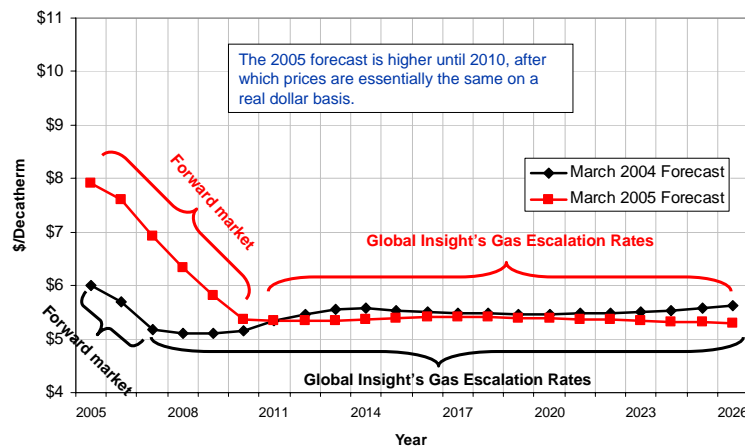
## Natural Gas Price & Inflation Assumptions and Caveats (Cont.)

- 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

3

## Henry Hub Gas Forecasts

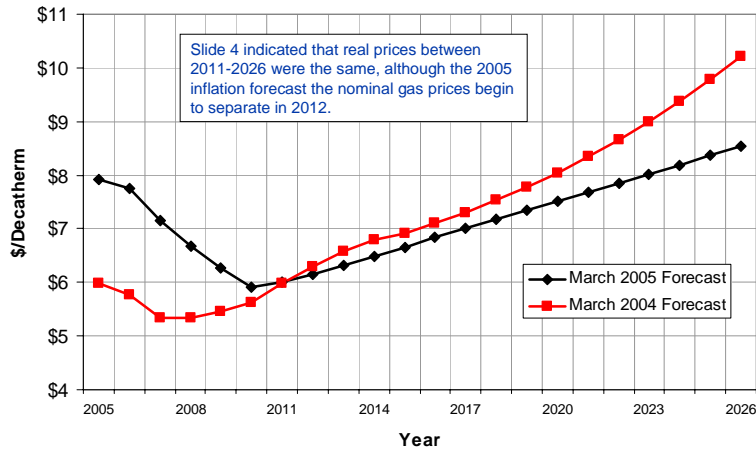
Real Dollars



4

## Henry Hub Gas Forecasts

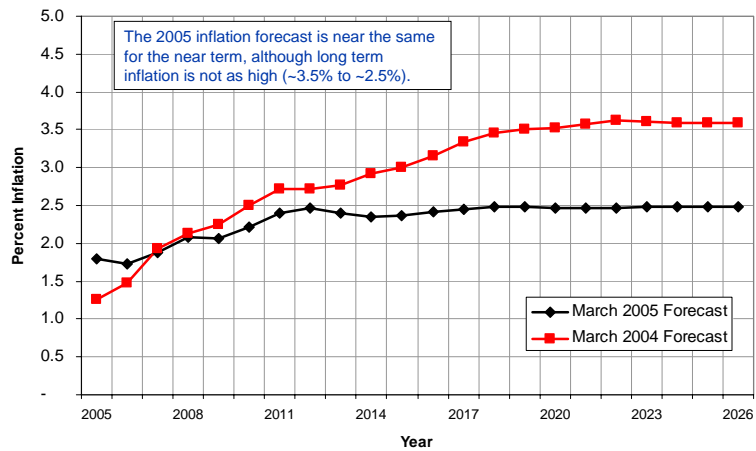
Nominal Dollars



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

5

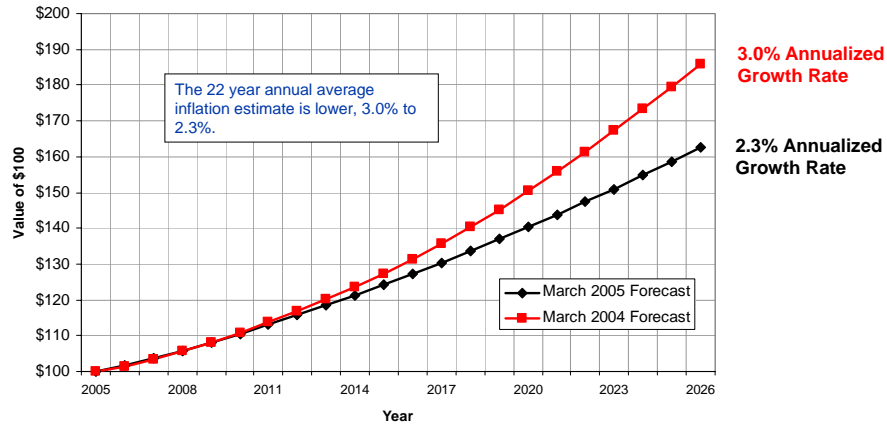
## Annual Inflation Rates



6

## Value of \$100 as it Grows with Inflation

Nominal Dollars



7

## 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

8

# Base Case Results- Electric Price Forecast

---

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

James Gall

1

## 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

2

# Capacity Expansion Results

---

3

## 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 they 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 NPCC 5<sup>th</sup> Power Plan approach

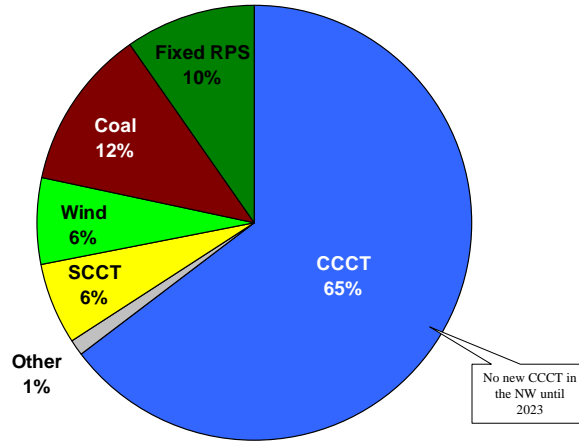
### Why is this all necessary?

- Without a forecasted set of new resource the market price forecast will be useless!

4



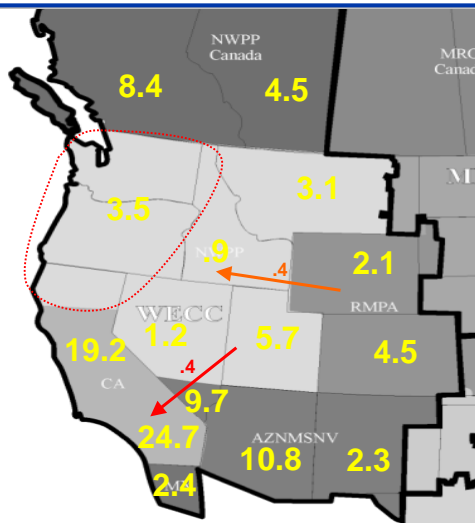
### Western Interconnect New Resource Mix



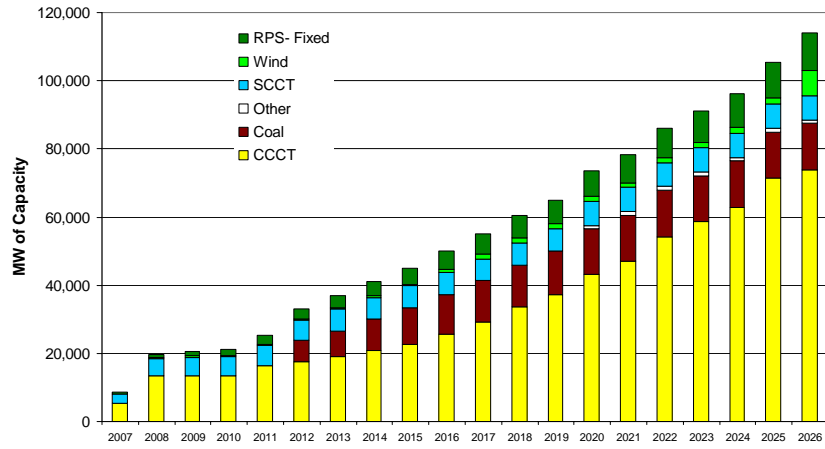
No new CCCT in the NW until 2023

114 GW of Installed Capacity

### Total New Resources (2007-2026) (Shown in GW Capacity, excludes RPS Resources)

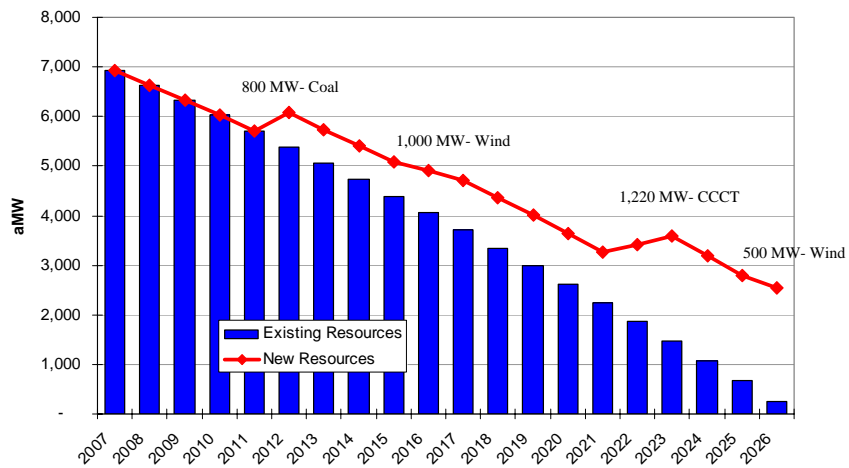


### Cumulative New Resources for the Western Interconnect



7

### NW Surplus Energy & New Resource Selection

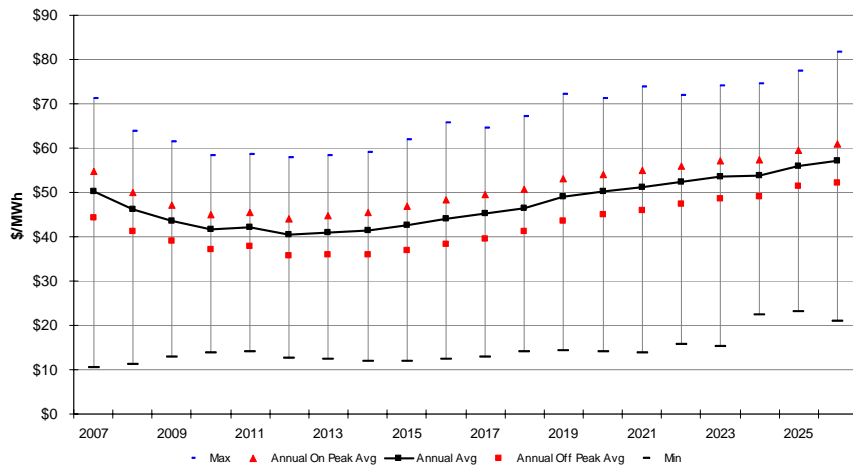


8

# Electric Price Forecasts

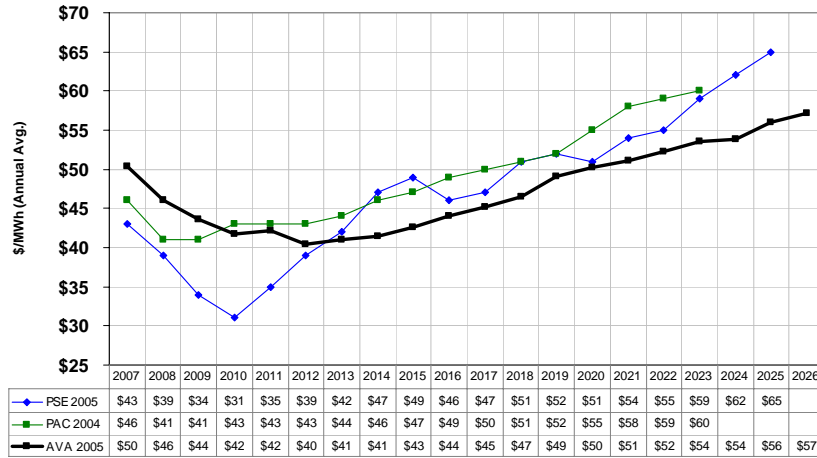
## Mid Columbia Electric Prices

Shown in Nominal Dollars per MWh



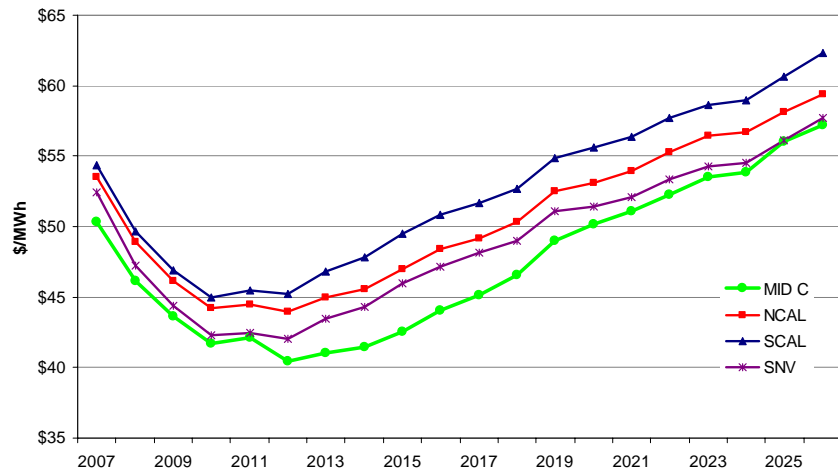
## How Do We Compare to Our Peers at Mid C?

Shown in Nominal Dollars per MWh



## Regional Electric Market Prices

Shown in Nominal Annual Average Dollars per MWh



## Stochastic Results

---

13

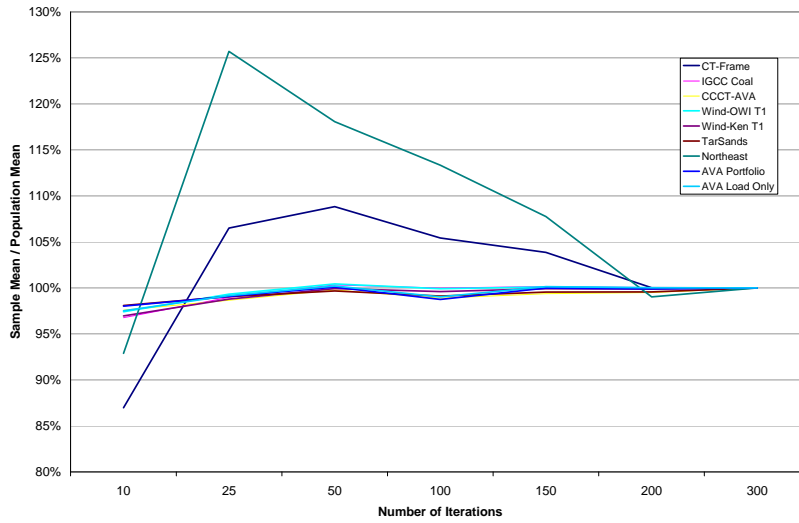
## Choosing a Sample Size

---

- 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

14

## Comparison of Resource Values



15

## Monthly Price Differences

### Market Price Sample Size Analysis

#### Monthly Market Price Standard Deviation Absolute Difference from 300 Iterations

Iterations	OWI	SP15	AZ	UT
50	8.2%	8.9%	8.8%	8.3%
75	6.6%	6.9%	6.8%	6.6%
100	5.6%	5.7%	5.7%	5.7%
150	4.0%	4.0%	3.9%	4.1%
175	3.1%	3.0%	3.0%	3.1%
200	2.7%	2.7%	2.7%	2.7%

#### Monthly Market Price Mean Absolute Difference from 300 Iterations

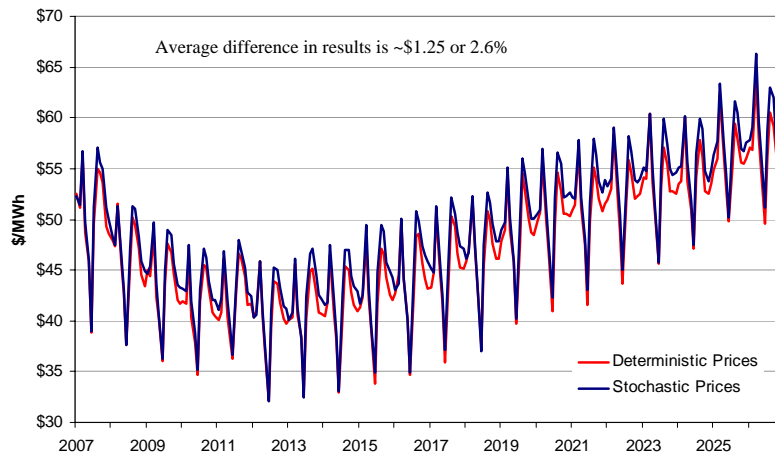
Iterations	OWI	SP15	AZ	UT
50	2.0%	1.7%	2.0%	2.0%
75	1.6%	1.3%	1.5%	1.5%
100	1.2%	1.0%	1.2%	1.2%
150	0.9%	0.8%	0.9%	0.9%
175	0.7%	0.6%	0.7%	0.7%
200	0.6%	0.5%	0.6%	0.6%

16

# Base Case Results

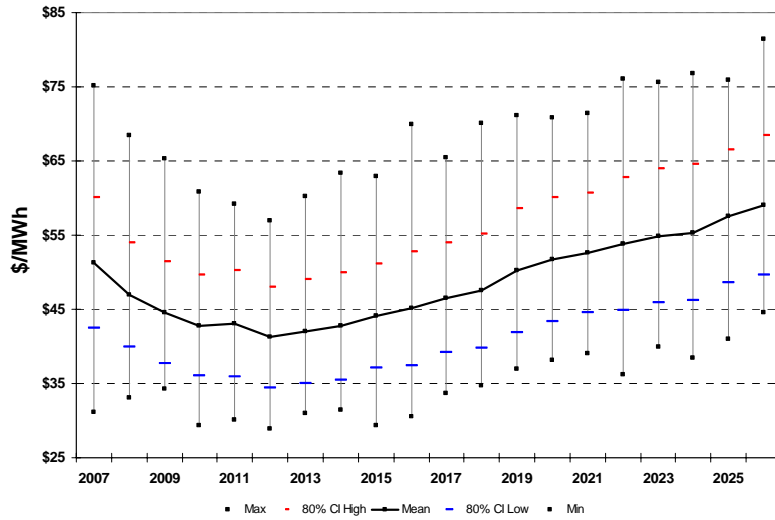
## Deterministic vs. Stochastic Mid C Prices

Shown in Nominal Dollars per MWh



## Mid Columbia Annual Average Prices

Shown in Nominal Dollars per MWh

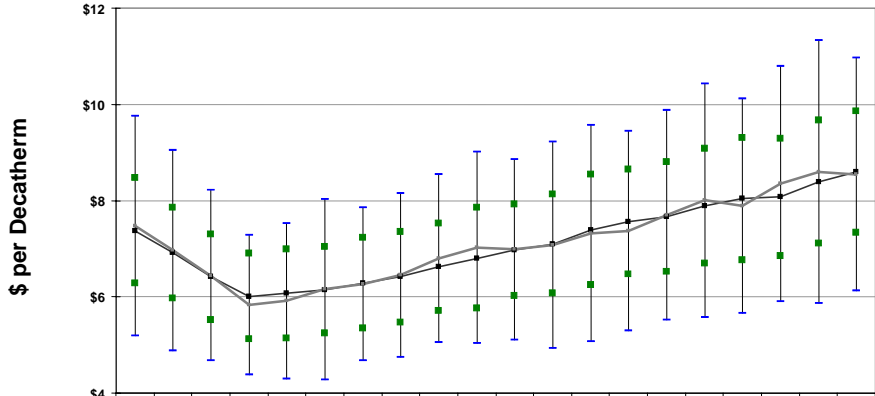


## Volatile Gas Results



### Henry Hub Natural Gas Price Comparison

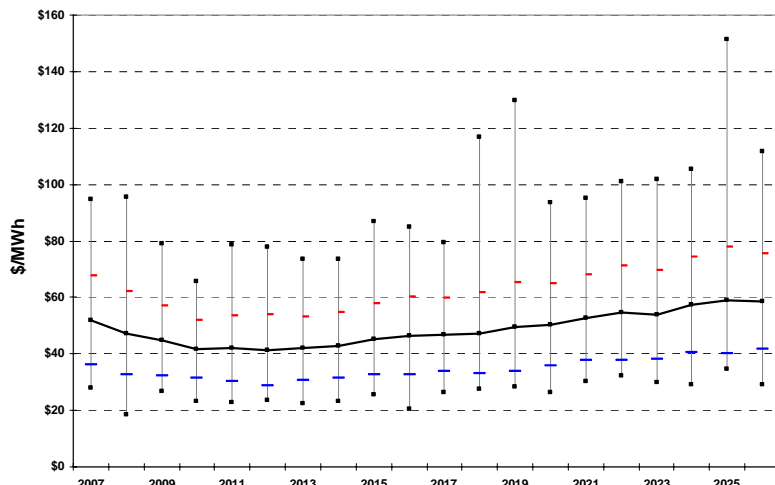
Base Case vs. Volatile Gas Case (Shown in Nominal Dollars per Decatherm)



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Base- Mean	7.37	6.92	6.41	6.01	6.07	6.15	6.29	6.42	6.62	6.81	6.97	7.10	7.39	7.57	7.66	7.89	8.04	8.07	8.39	8.60
Volatile- Mean	7.47	6.97	6.44	5.83	5.91	6.16	6.27	6.45	6.80	7.02	6.98	7.08	7.31	7.37	7.69	8.00	7.89	8.35	8.60	8.54
Base- 80% CI High	8.47	7.86	7.31	6.90	6.99	7.04	7.23	7.36	7.53	7.85	7.93	8.13	8.54	8.65	8.80	9.09	9.31	9.29	9.67	9.86
Volatile- 80% CI High	9.76	9.05	8.21	7.28	7.52	8.03	7.86	8.15	8.54	9.01	8.86	9.21	9.56	9.45	9.87	10.43	10.13	10.79	11.33	10.96
Base- 80% CI Low	6.28	5.98	5.52	5.12	5.15	5.25	5.34	5.47	5.71	5.76	6.01	6.07	6.25	6.48	6.52	6.70	6.77	6.86	7.10	7.33
Volatile- 80% CI Low	5.19	4.88	4.67	4.39	4.30	4.28	4.68	4.75	5.06	5.04	5.11	4.94	5.07	5.30	5.51	5.57	5.65	5.91	5.87	6.12

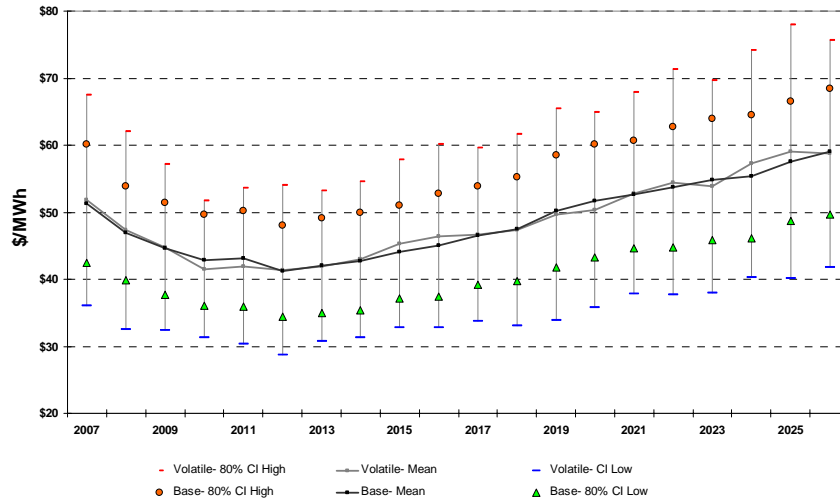
### Mid Columbia Annual Average Prices- Volatile Gas

Shown in Nominal Dollars per MWh



Max 80% CI High Mean 80% CI Low Min

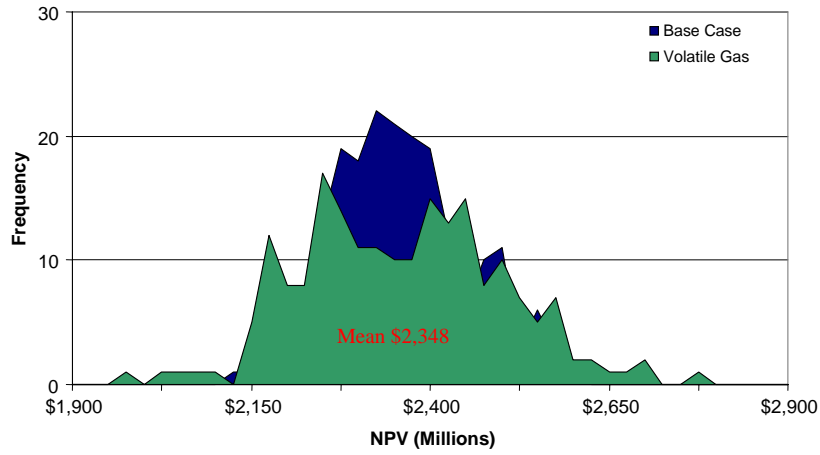
### Mid Columbia Annual Average Price Comparison Base Case vs. Volatile Gas Case (Shown in Nominal Dollars per MWh)



## Distribution of Net Power Costs

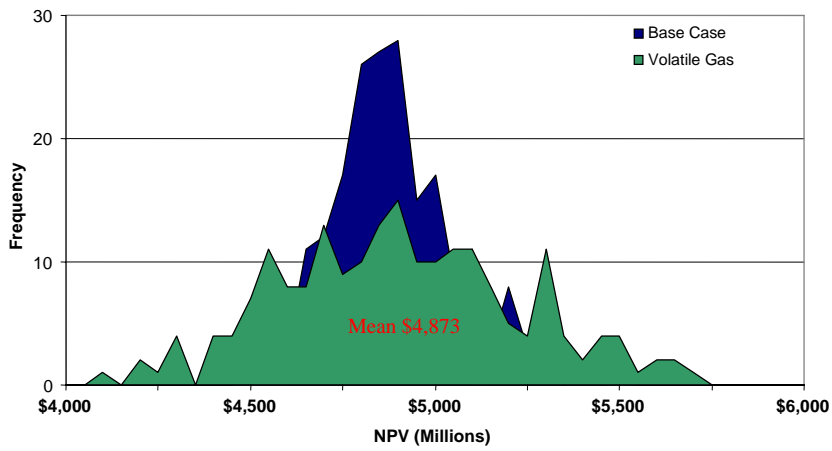
### Net Power Costs- No Change to Resources

200 Iterations



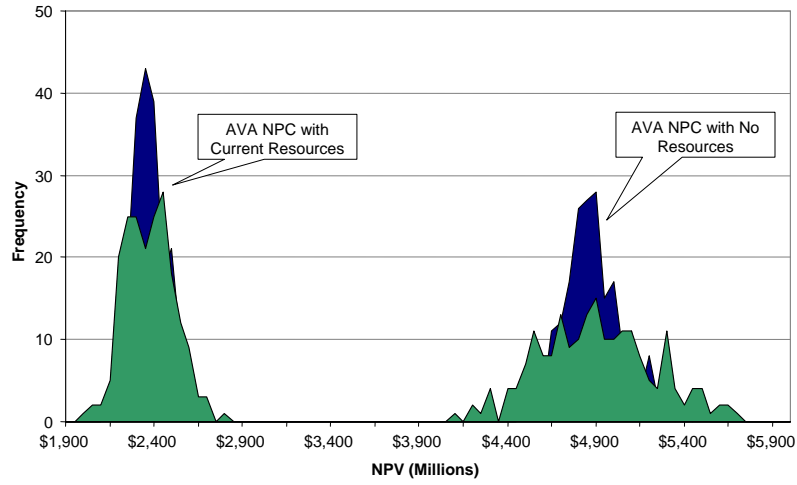
### NPC- If All AVA Load Was Served by Market

200 Iterations



## Side by Side

200 Iterations

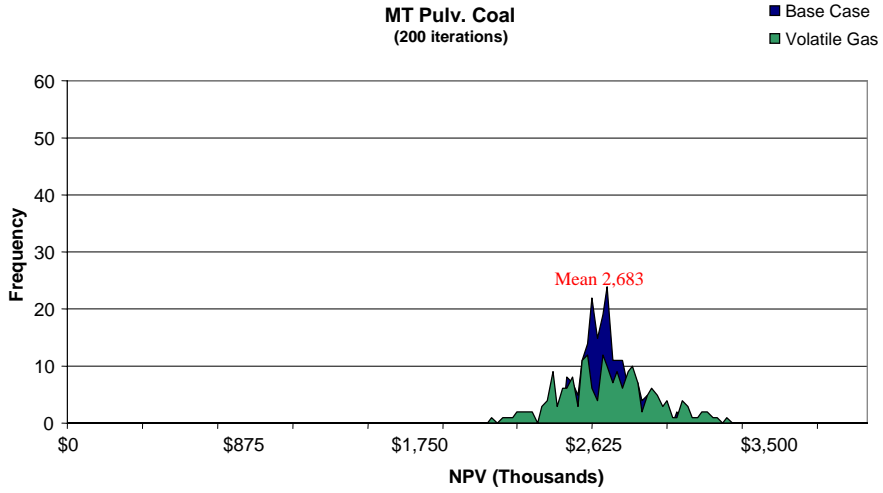


27

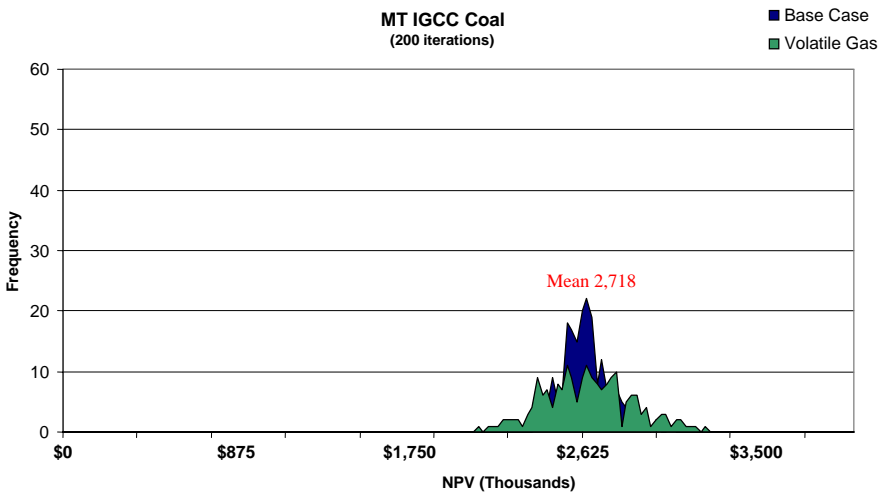
## Resource Value Comparison

28

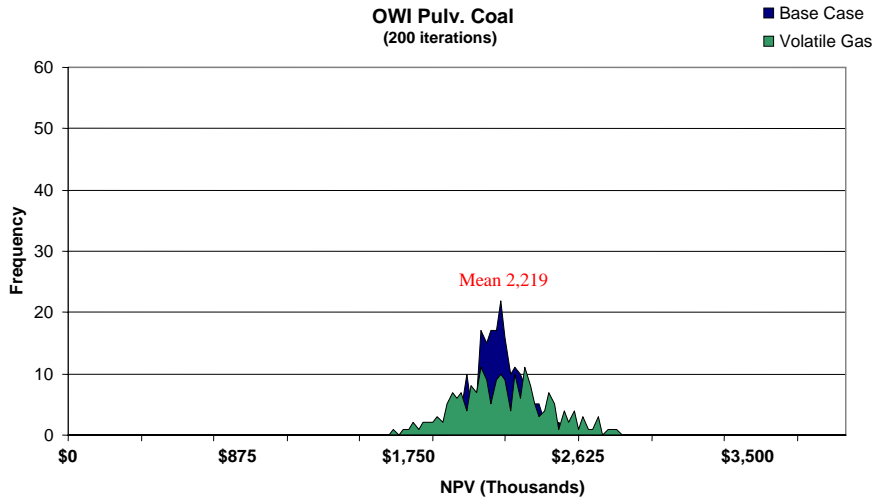
### 1 MW Resource Value (excludes Capital Costs)



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

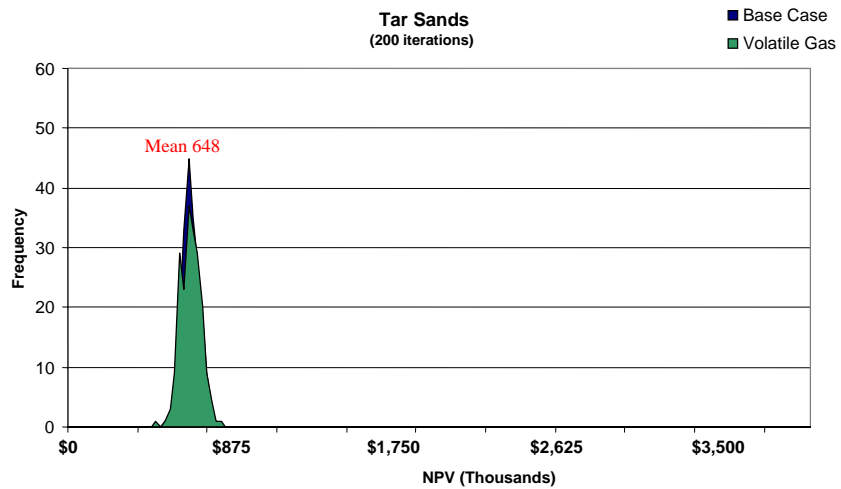


### 1 MW Resource Value (excludes Capital Costs)



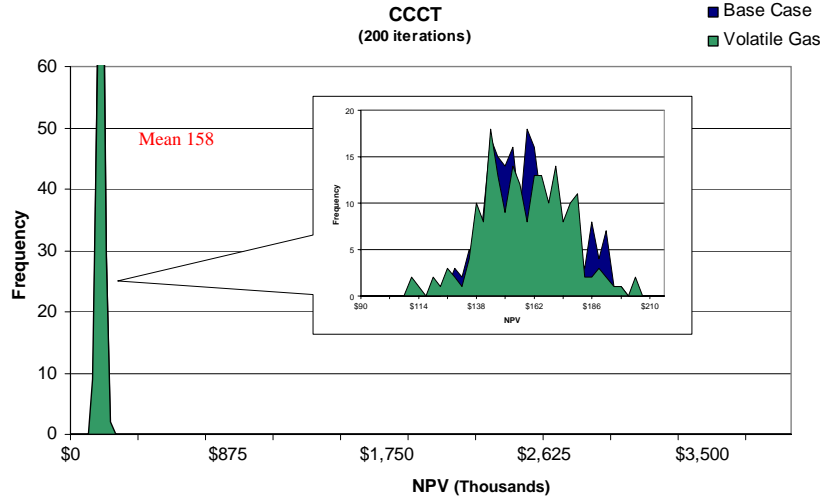
31

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



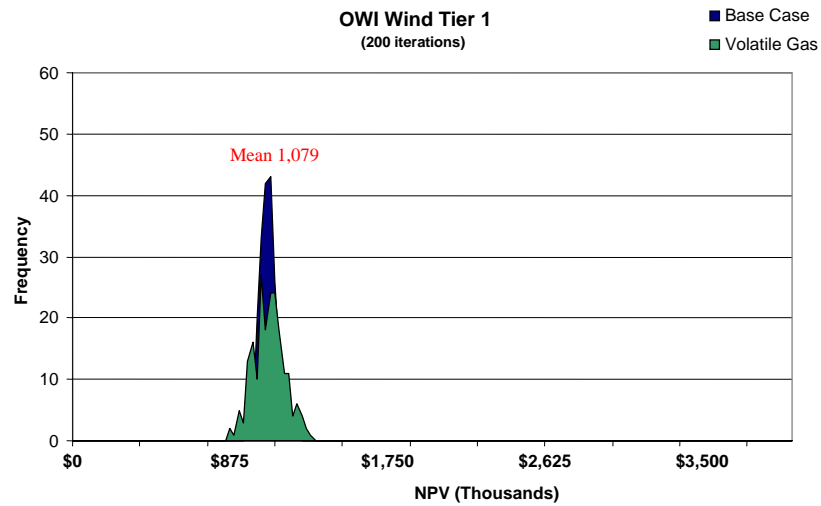
32

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



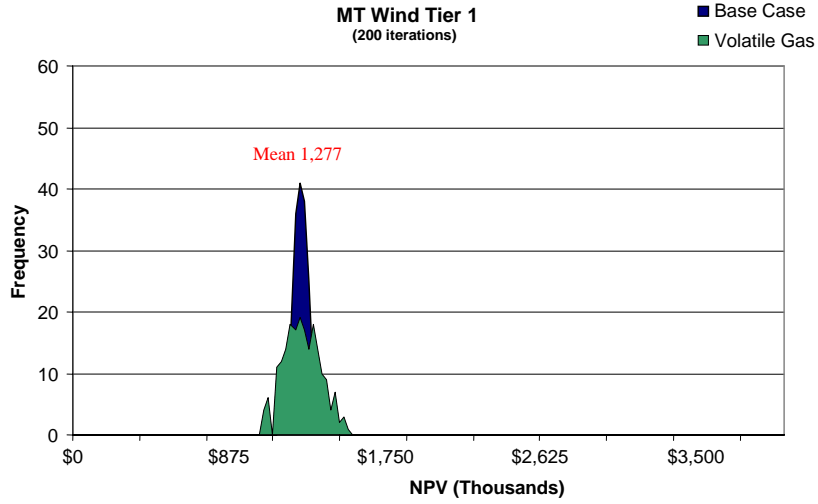
33

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



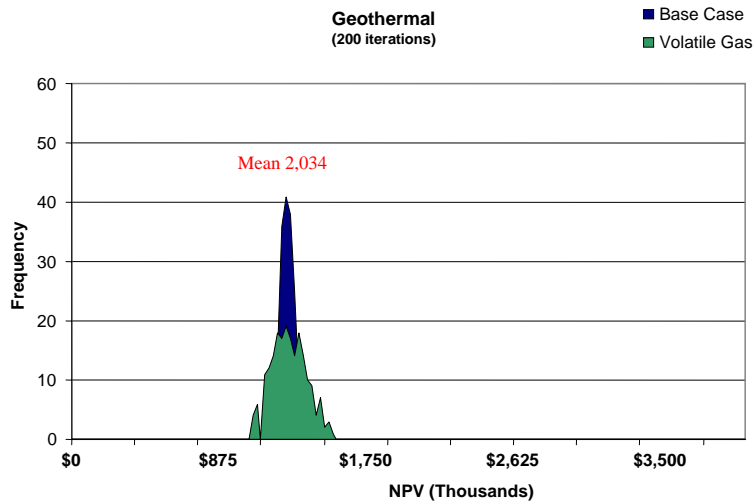
34

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



35

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



36



## 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

1

## 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

2

## 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

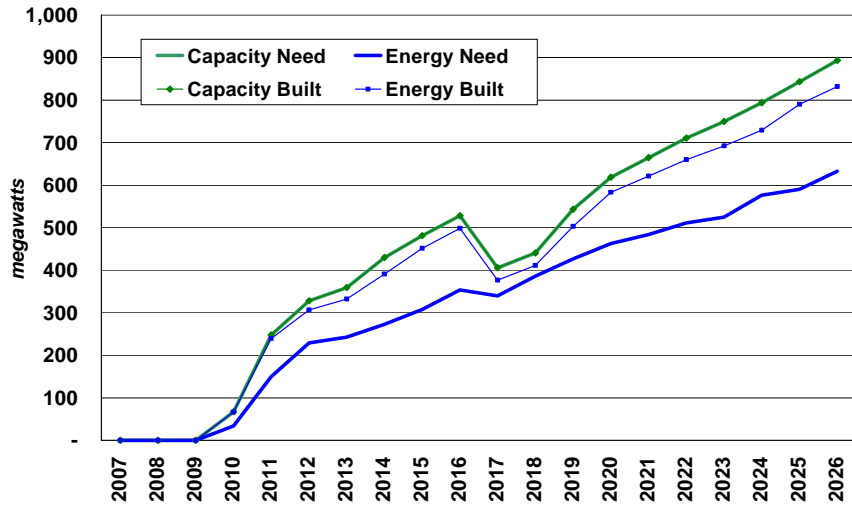
3

## 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

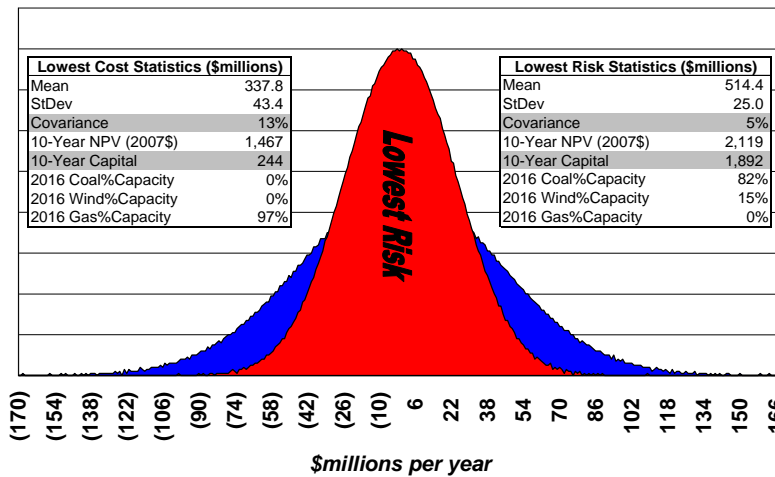
4

### Build Example—Capacity & Energy



5

### Power Supply Cost Illustration—2016



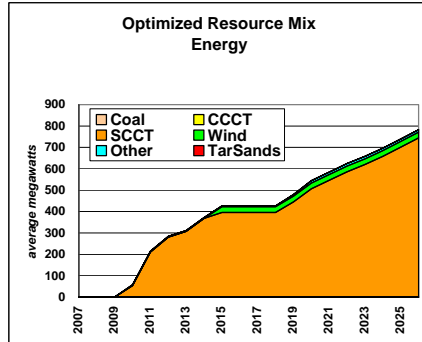
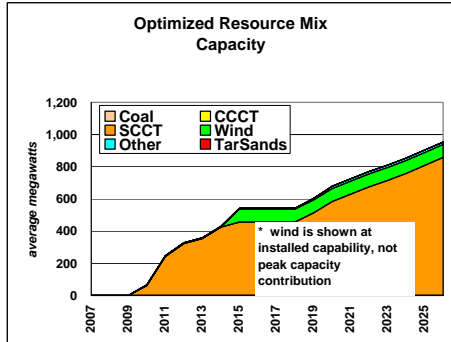
6

## LP Module—Illustration 1 Lowest Cost

Resource Selection Optimizer

**100.0** COST

0.0 RISK



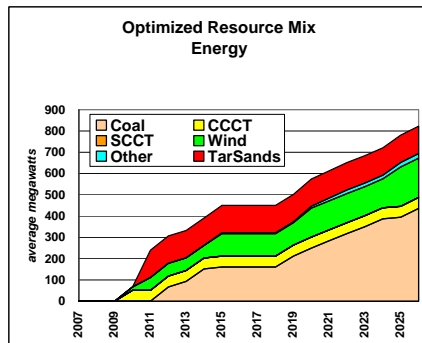
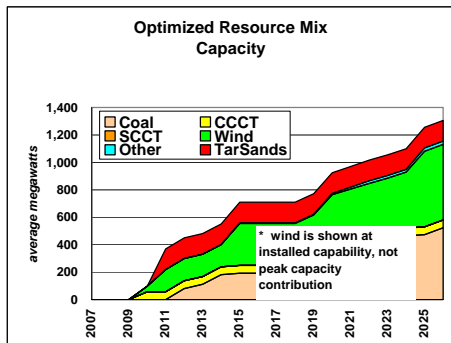
7

## LP Module—Illustration 2 Lowest Risk

Resource Selection Optimizer

**0.0** COST

100.0 RISK



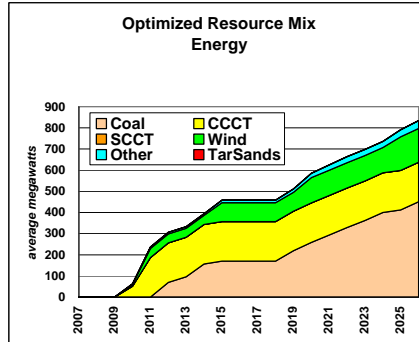
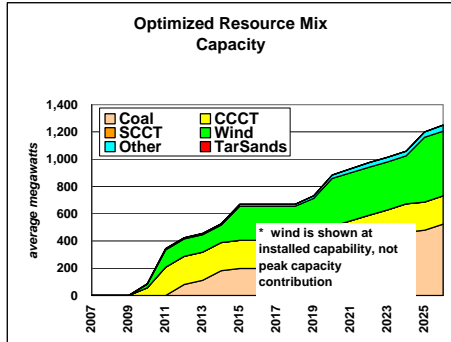
8

## LP Module—Illustration 3 50/50 Mix

Resource Selection Optimizer

**50.0** COST

50.0 RISK



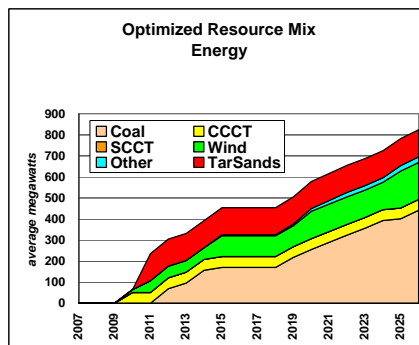
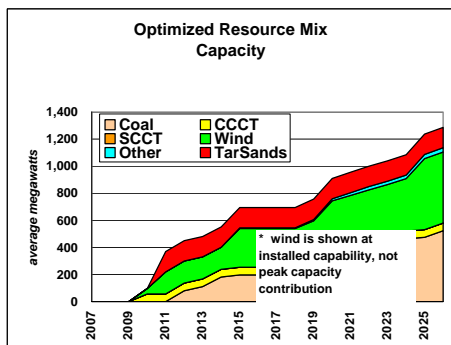
9

## LP Module—Illustration 4 25/75 Mix

Resource Selection Optimizer

**25.0** COST

75.0 RISK



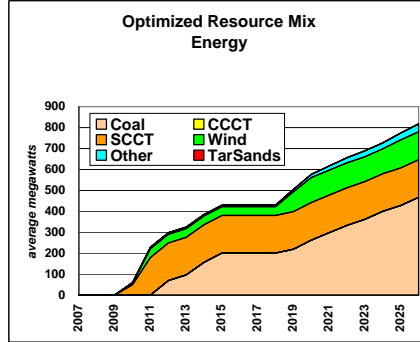
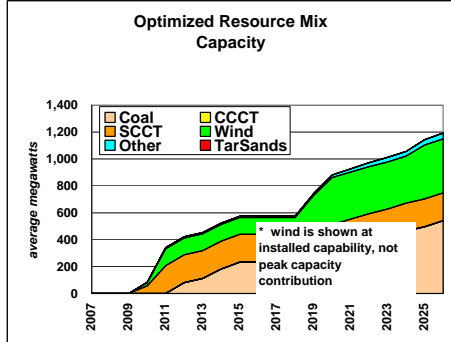
10

## LP Module—Illustration 5 75/25 Mix

Resource Selection Optimizer

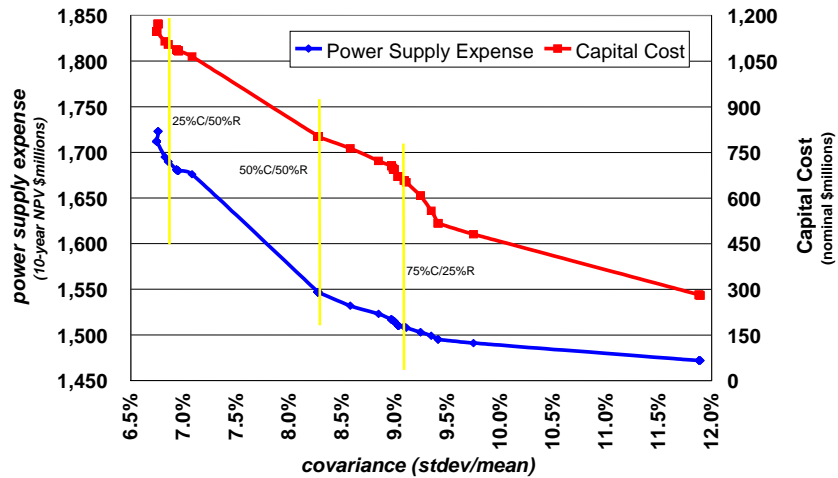
**75.0** COST

25.0 RISK



11

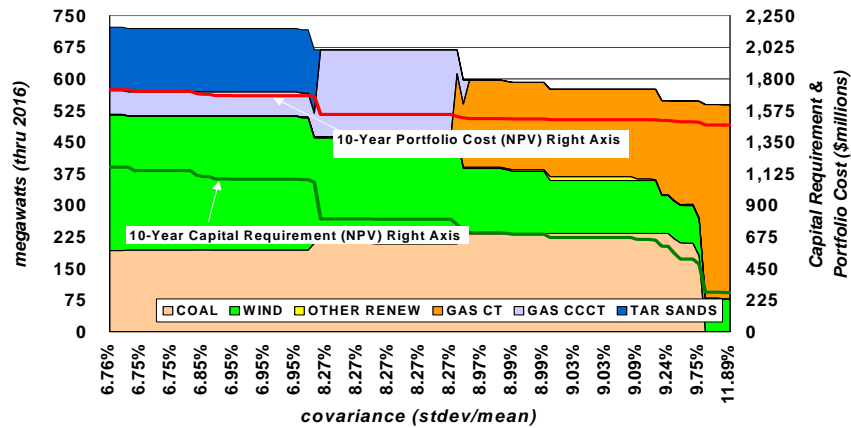
## Efficient Frontier—Trade-Offs Between Power Supply Expense, Capital, Risk



12

## Resource Builds of Efficient Frontier

2016



13

## 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

14



## 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

15

## Comments/Suggestions

---

16

**Avista Corporation**  
**Estimated Resource Integration Costs**  
**for the**  
**2005 IRP**  
April 29, 2005  
Scott A. Waples

**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

1

# 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.

2

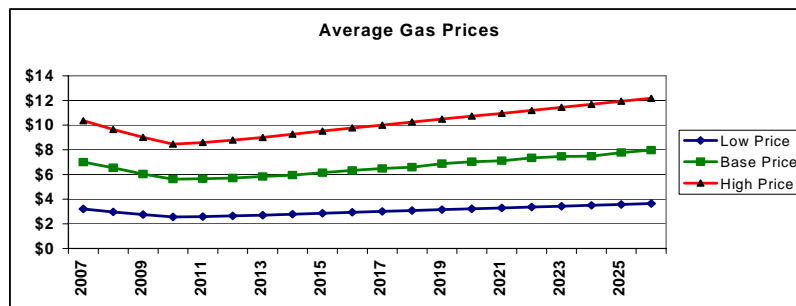
## Scenario Process

- 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.

3

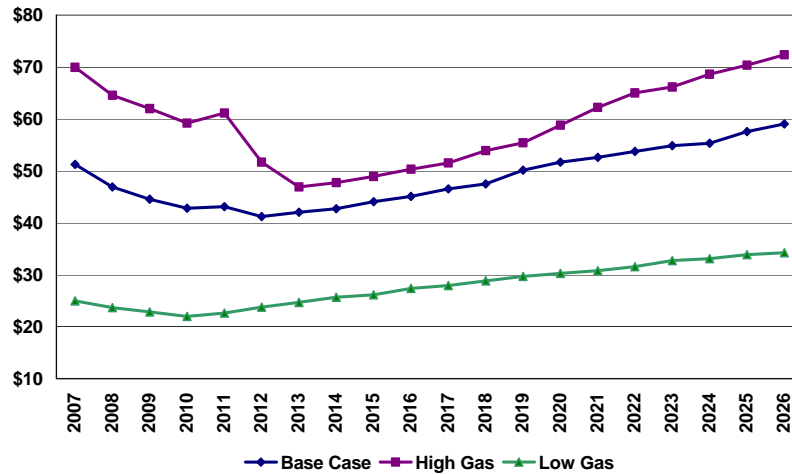
## Gas Sensitivity Scenarios

- 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



4

## Gas Sensitivity Scenario Results



5

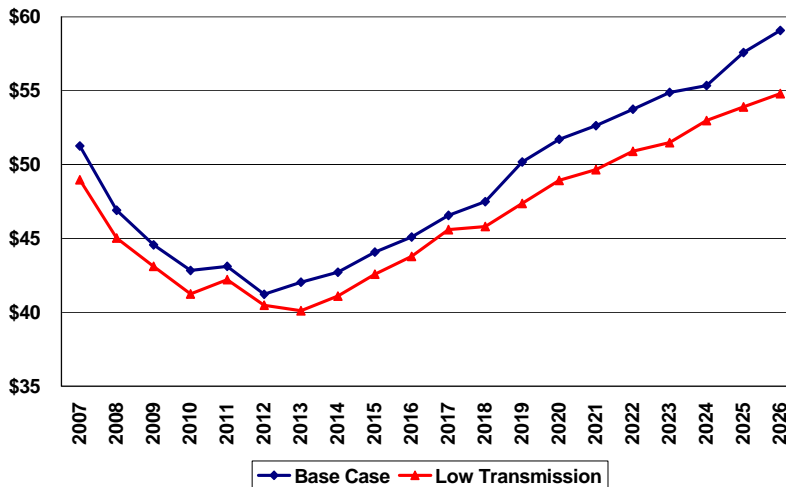
## Low Transmission Scenario

- 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.

6



## Low Transmission Scenario Results



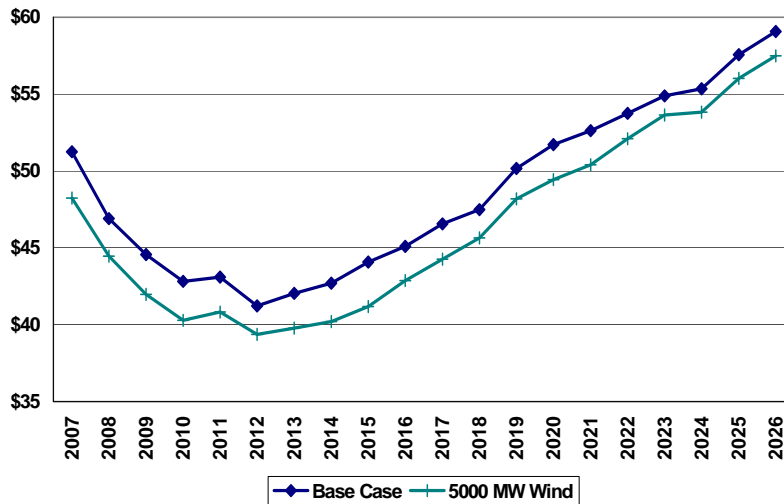
7

## High Wind Penetration Scenario

- 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.

8

## High Wind Penetration Scenario Results



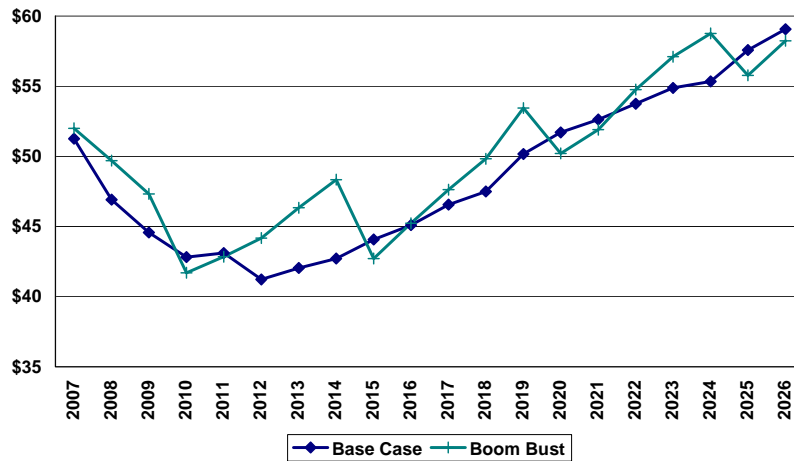
9

## 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?

10

## Boom Bust Scenario Results



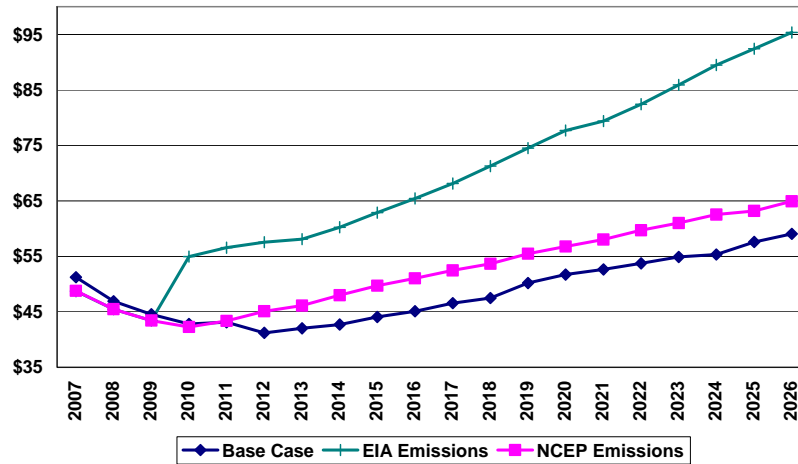
11

## 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 CO<sub>2</sub> 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 CO<sub>2</sub> equivalent and increases to \$60 per ton by 2026. Gas prices increase by 30% under this scenario.

12

## Emissions Scenario Results



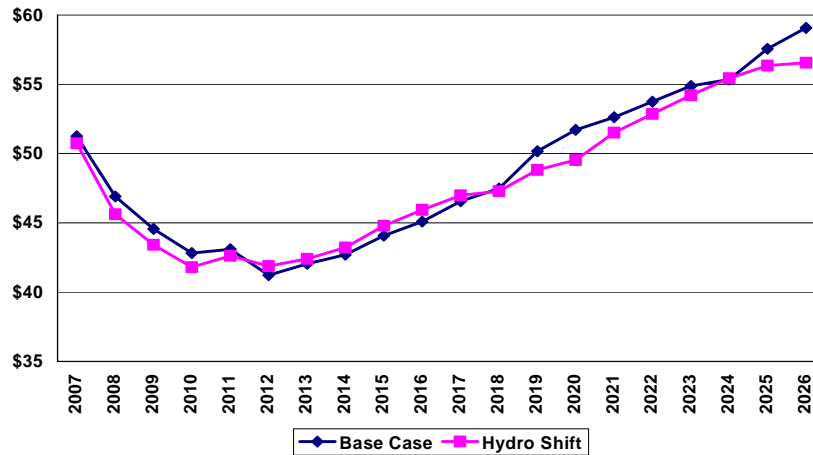
13

## 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.

14

## Fundamental Hydro Shift Scenario Results



15

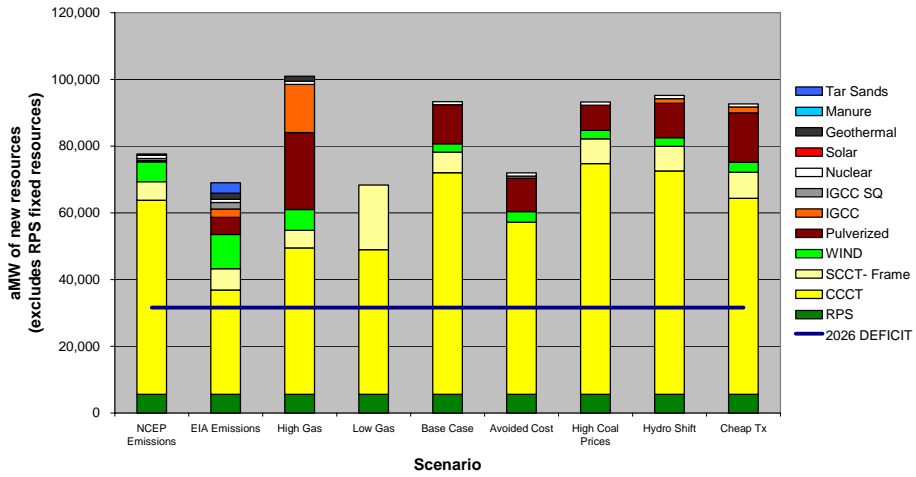
## Avista Only Scenarios

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

16

## Summary of Scenario Results



## Avoided Costs

---

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

Clint Kalich

1

## 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

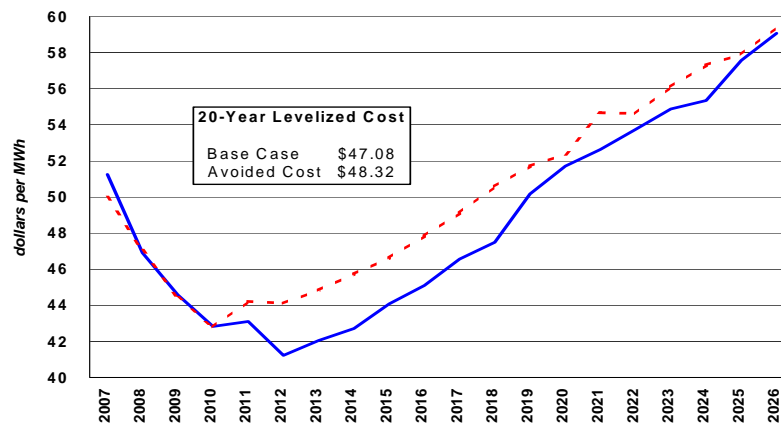
2

## 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

3

## Comparison of Avoided Costs and Wholesale Market Prices



4



## 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

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

Clint Kalich

1

## Hydro Upgrades



Noxon Rapids Development



Cabinet Gorge Development

- 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

2

## 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

3

## 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

4

## 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

5

## 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

6

## 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

7

## Summary

Year	Cab 4	Nox 1	Nox 3	Nox 4	Nox 2	Total
Capacity (MW)	7.0	10.0	10.0	7.0	11.0	45.0
Generation (GWh)	0.6	20.4	11.8	10.2	8.8	51.8
Generation (aMW)	0.1	2.3	1.3	1.2	1.0	5.9
Capital Cost (\$millions)	4.7	4.1	3.9	3.8	3.8	20.3
Avoided Major Maint. (\$millions)	0.0	3.6	3.6	3.6	3.6	14.4
35-Year NPV (\$millions)	5.1	10.6	6.8	3.6	3.3	29.4
20-Year NPV (\$millions)	4.3	8.3	5.3	2.5	2.5	22.9

8

# Emissions

---

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

John Lyons

1

## 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 22<sup>nd</sup> 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

2

## 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<sup>XMP</sup> model by adding a “tax” to CO<sub>2</sub> production
- The S. 342 CO<sub>2</sub> tax estimate was provided from the Analysis of S. 139, the Climate Stewardship Act of 2003, published in 2003 by the EIA

3

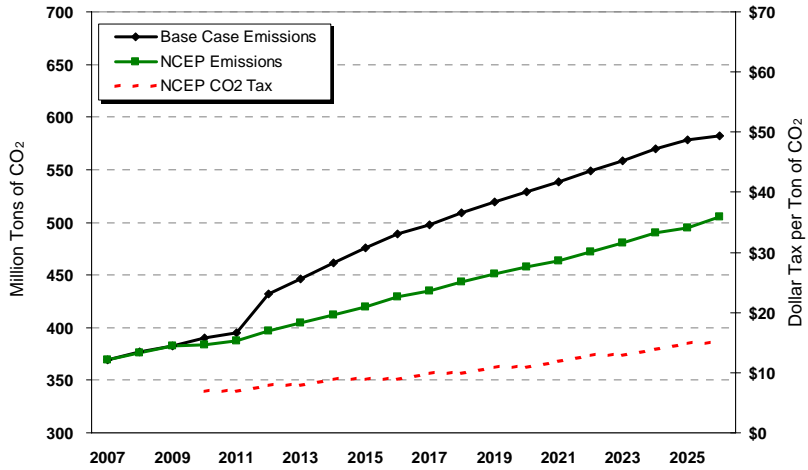
## Avista Studies (cont.)

---

- CO<sub>2</sub> 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

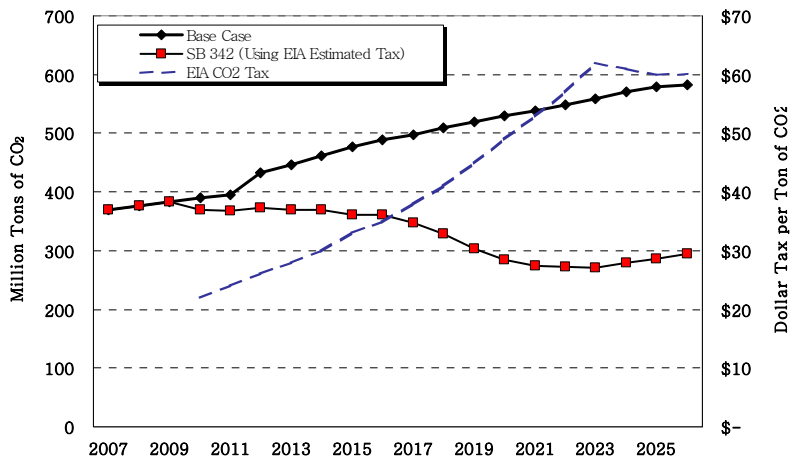
4

### NCEP Study Results - Emission Levels Entire Western Interconnect



5

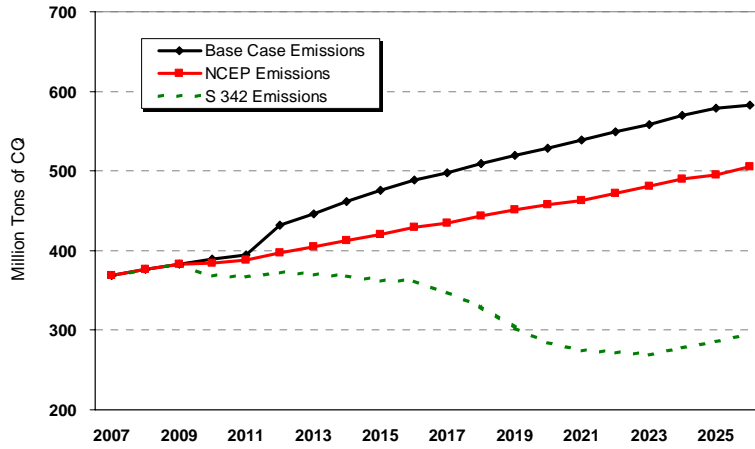
### S. 342 Study Results - Emission Levels Entire Western Interconnect



6

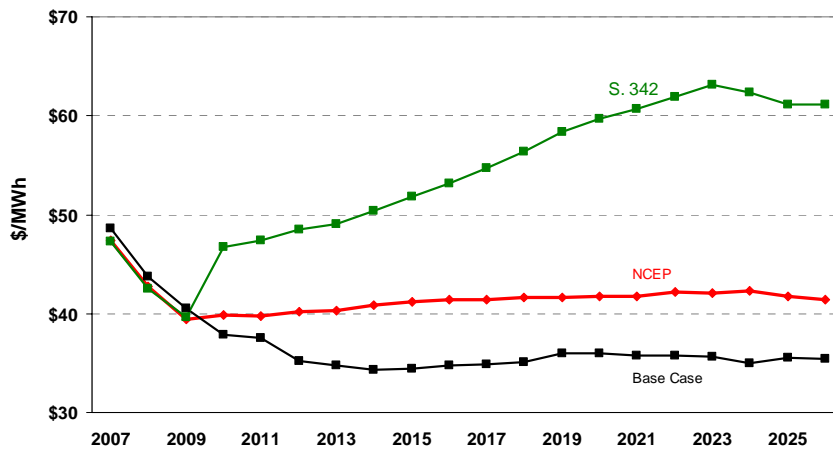


### Western Interconnect Emission Levels



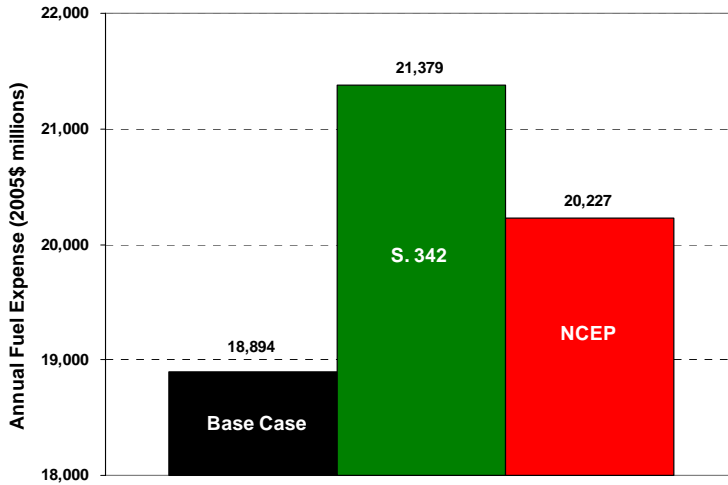
7

### Comparison of Mid Columbia Prices 2005 Dollars



8

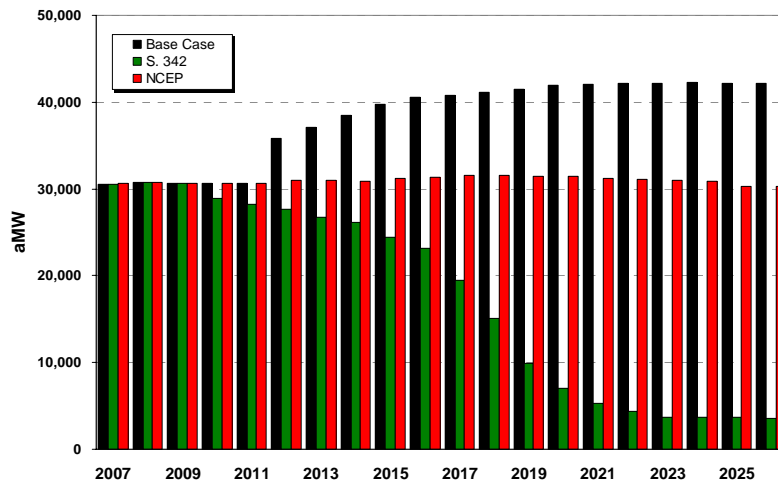
### Comparison of Average Annual Fuel Expense 2005 Dollars



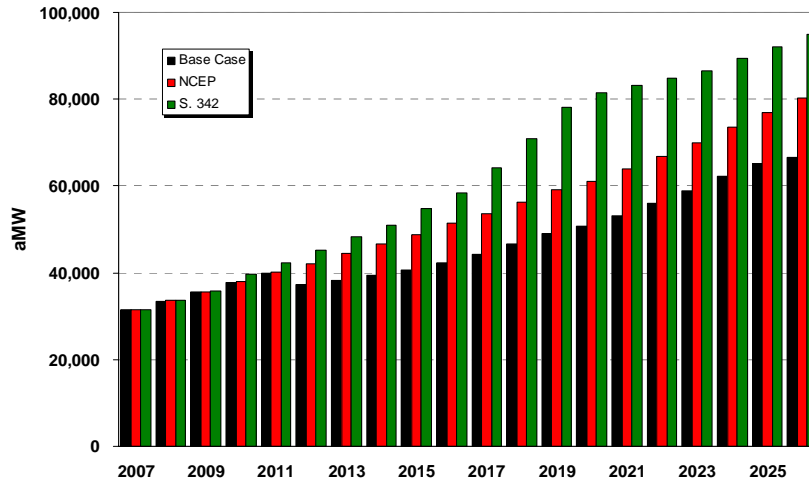
S. 342 is a 13% increase over the Base Case

NCEP is a 7% increase over the Base Case

### Comparison- Coal Generation aMW

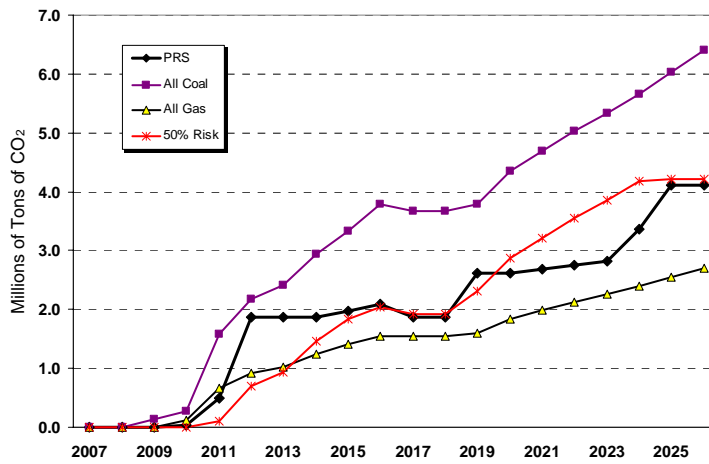


### Comparison- Gas Generation aMW



11

### Avista Portfolios- Millions of Tons of CO<sub>2</sub>



12

# Demand-Side Management

---

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

Jon Powell

1

## 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

2

## DSM Operational Issues

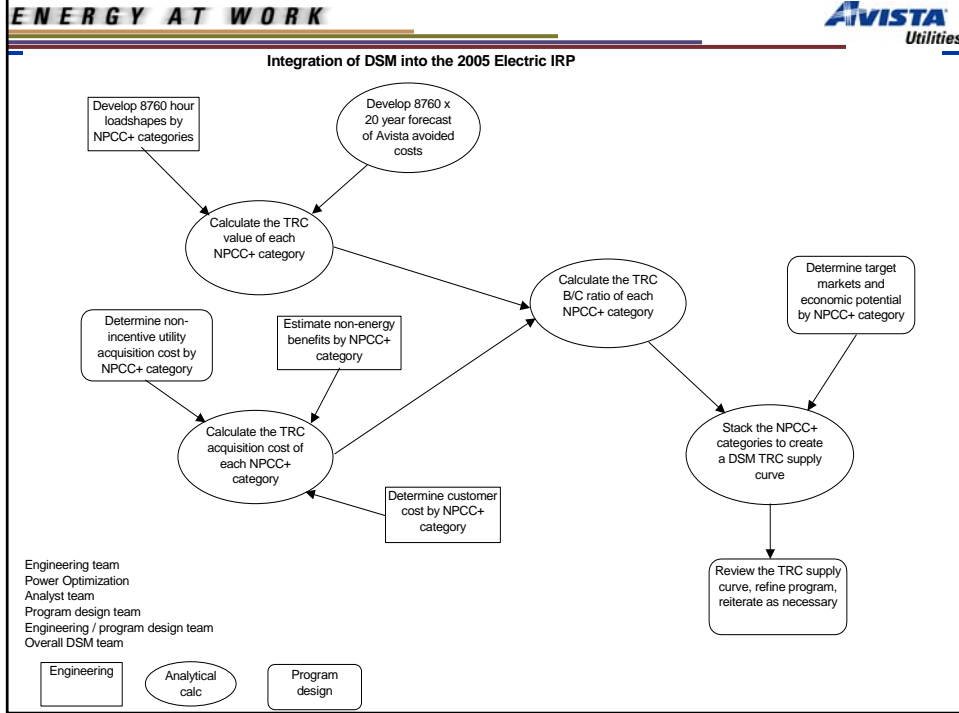
- Our “All Comers” tariff
- Diversity of projects within an IRP category
- Customer service issues
- Trade Allies, Vendors, Retailers
- Regional Market Transformation
- Measure / Program packages

3

## 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**

4



**ENERGY AT WORK** **AVISTA**  
Utilities

## 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

6

## 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 1<sup>st</sup> year kWh
  - Other characteristics (NEB, non-incentive utility cost, natural gas impact)

7

### Measures tested

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

### Measures eliminated

Individual PC network controls

### Measures not tested

Controlled voltage reduction  
Rooftop HVAC

8

## 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 → NEBs and gas AC are benefits
  - TRC levelized cost → NEBs and gas AC are costs

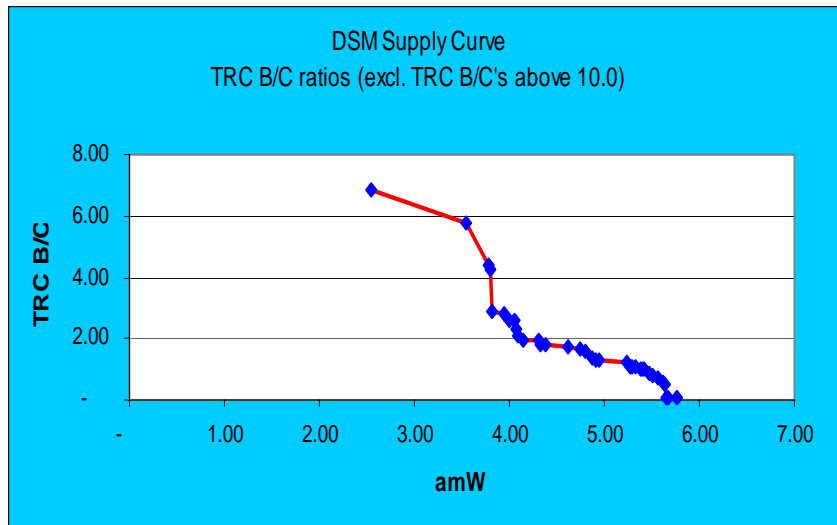
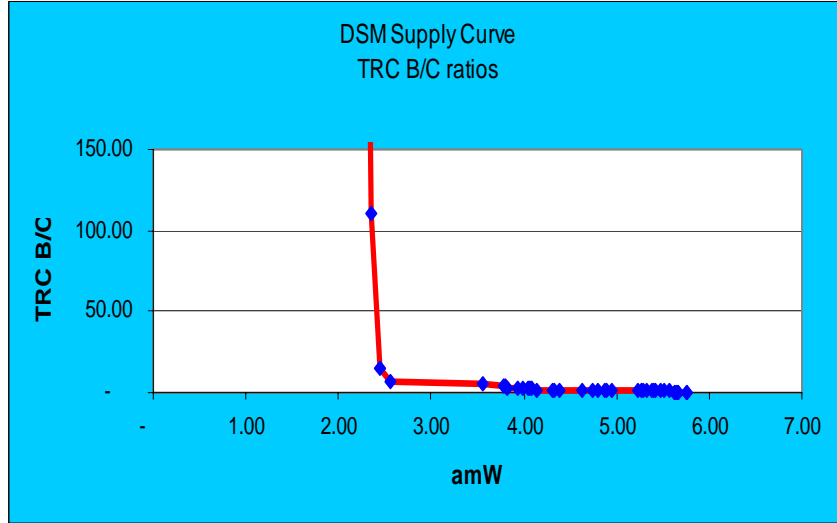
9

## 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

10

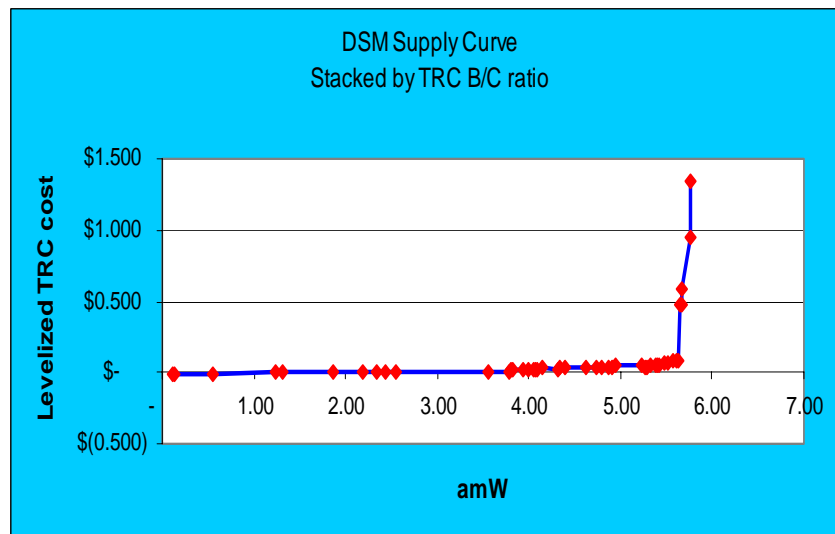




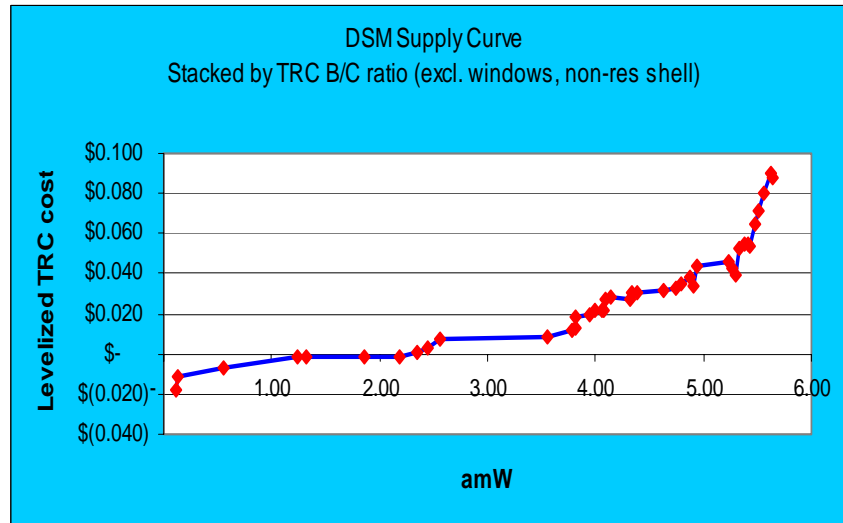
## Traditional (upward sloping) supply curve

- 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)

13



14



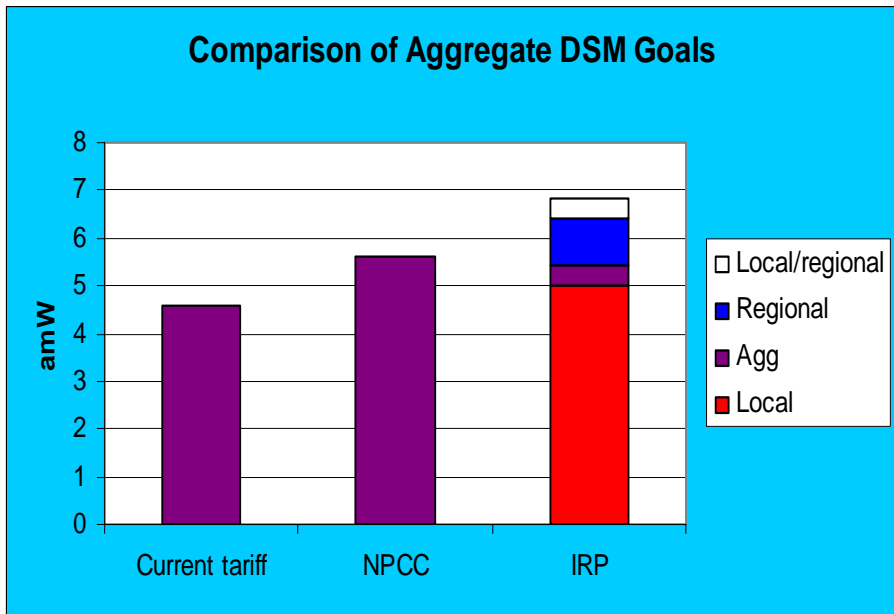
15

## Regional Program Interaction

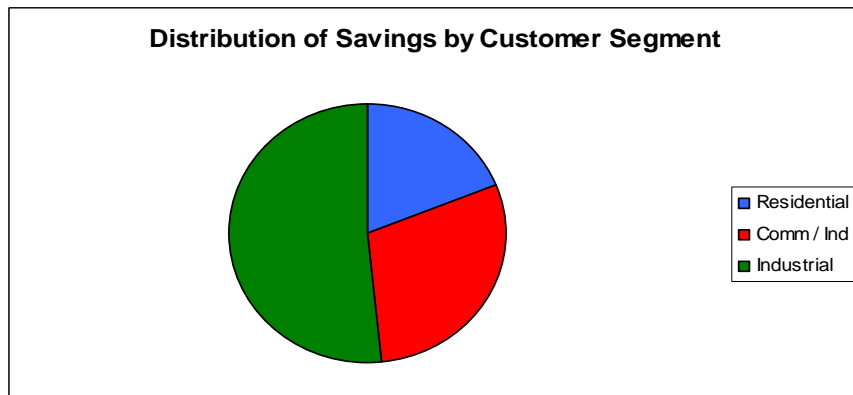
- Previous measures are local utility acquired resources
  - Any kWh “touched” by local utility is a local kWh
  - Local kWh’s are excluded from regional tally
  - → Avoids double-counting of resource
    - (Local acquisition overestimate / regional underestimate of attribution)
- → Generally local utility 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

16

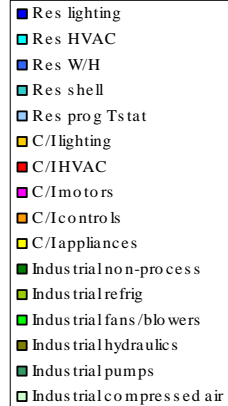
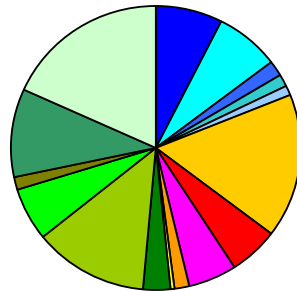
### Comparison of Aggregate DSM Goals



### Distribution of Savings by Customer Segment



## Distribution of Savings by Measure



19

## Segment distribution of acquisition

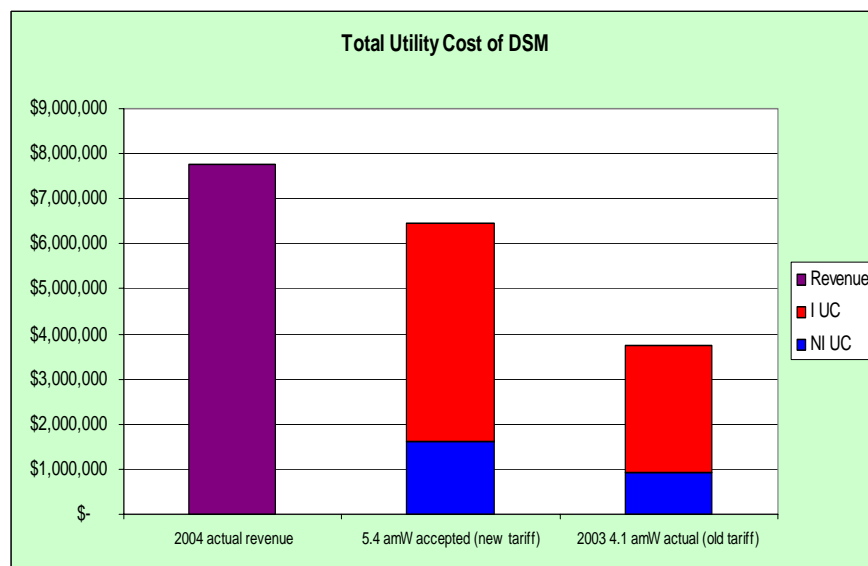
- Lots of industrial
  - Primarily compressed air, refig, pumps
  - Attributable to participant economics in new retail rate environment
  - Local acquisition most effective approach
  - Some of the most cost-effective measures
- Residential
  - Primarily CFL's, HE A/C, space heat fuel-efficiency
  - 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)

20

## 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

21



22

## 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

23

## 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

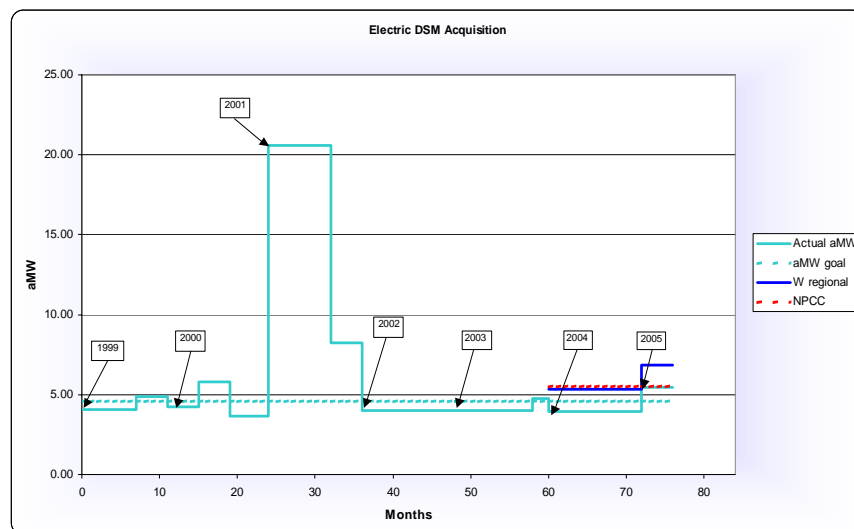
24

## 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)

25

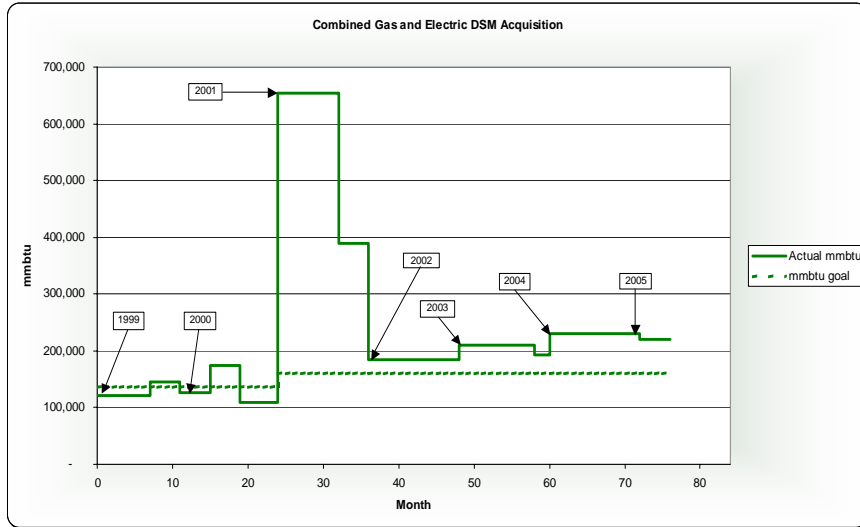
## DSM Acquisition History



26

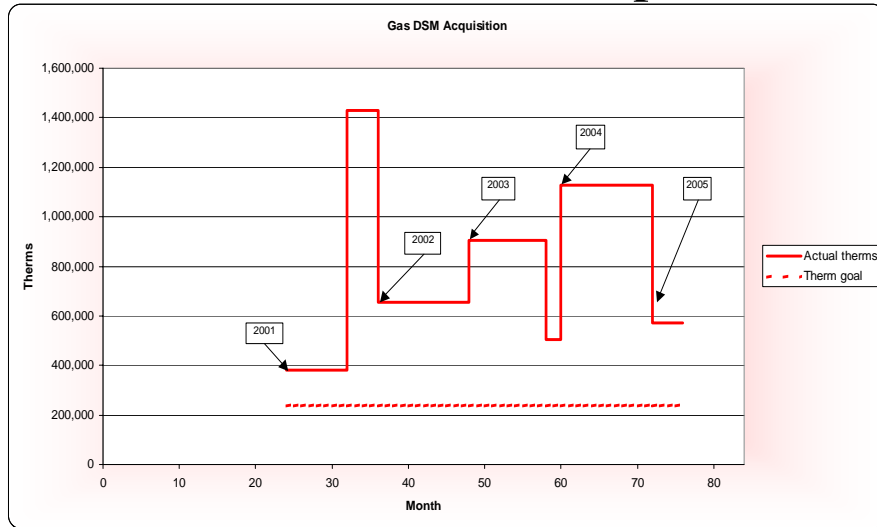


# Mmbtu acquisition



27

# Natural Gas DSM component



28

## 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

29

## 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

30

## 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

31

## Questions ?

32

# Preferred Resource Strategy

---

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

Clint Kalich

1

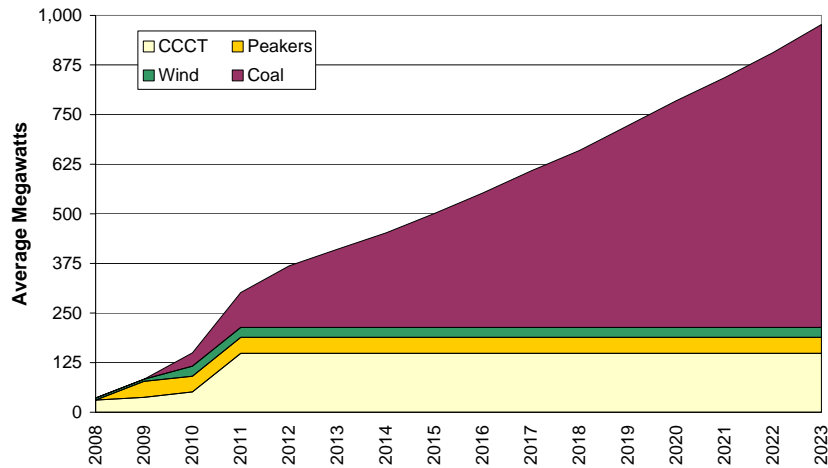
## Goals of PRS

---

- Meet Future Capacity & Energy Requirements
- Keep Rates Low
- Stable Rates
- Good Performance Across Scenarios

2

## Preferred Resource Strategy—2003 IRP



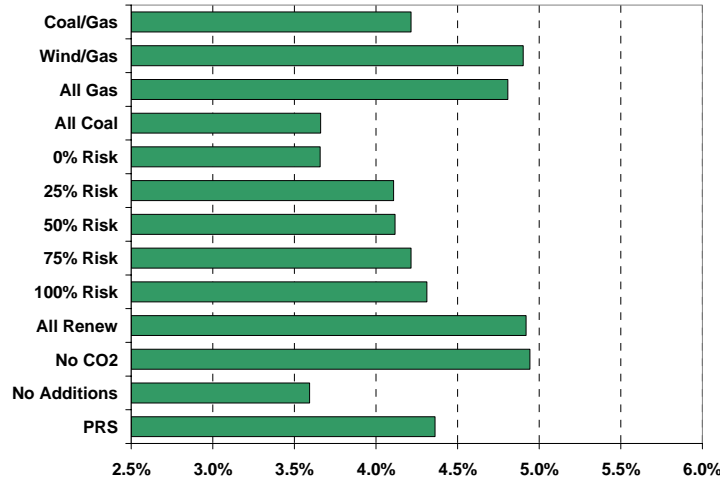
3

## 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

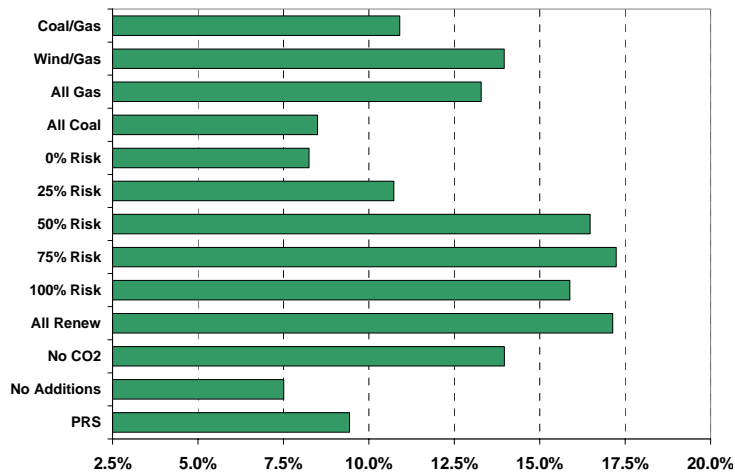
4

## Performance Comparison—Rate Impacts 2007-16



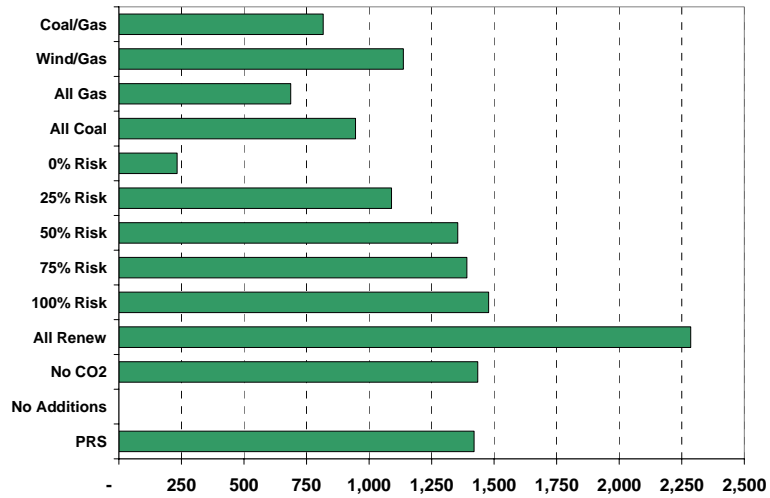
5

## Performance Comparison—Max Rate Increase



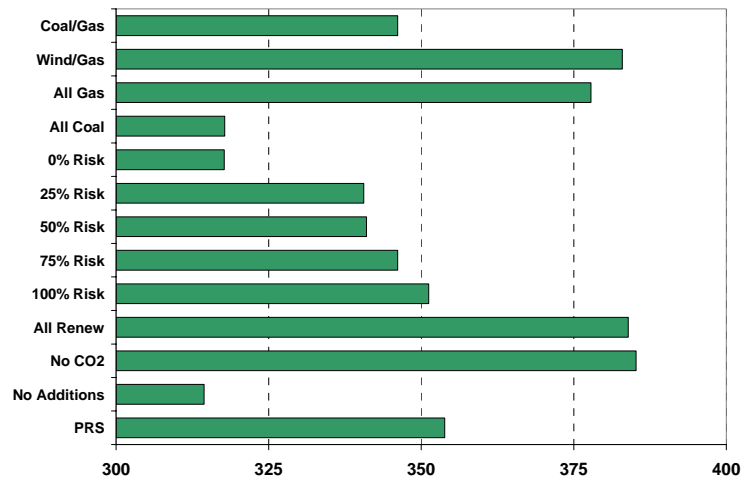
6

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



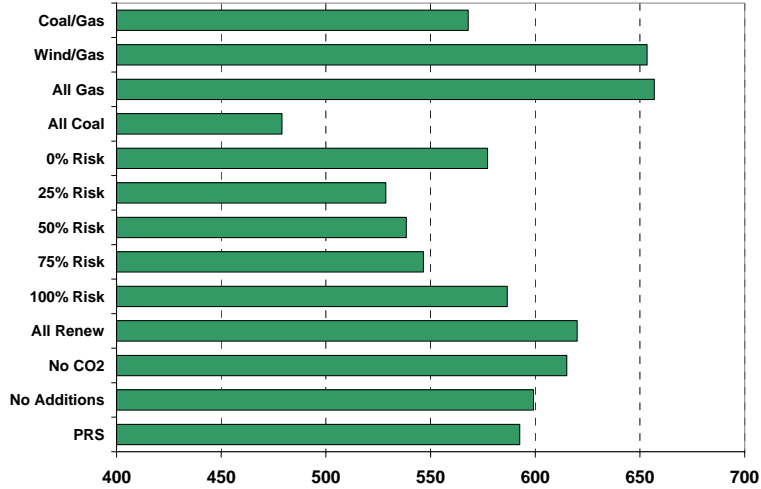
7

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



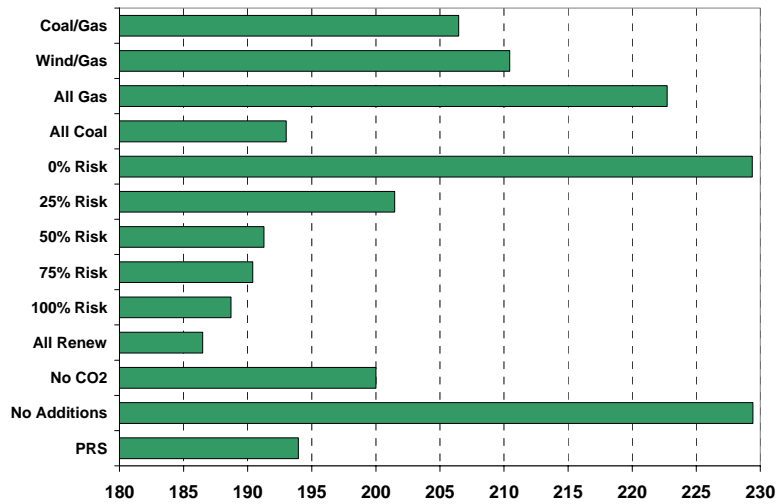
8

### Performance Comparison—2026 Incremental Power Supply Expense (\$millions)



9

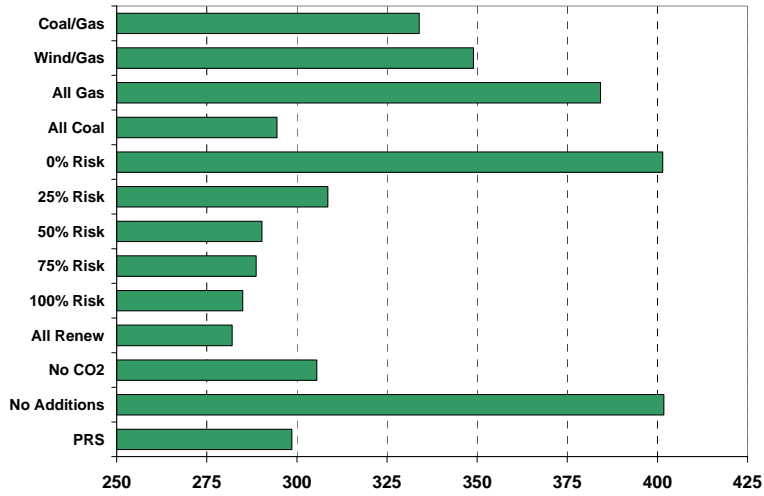
### Performance Comparison—Risk (2007-16 NPV of StDev \$millions)



10

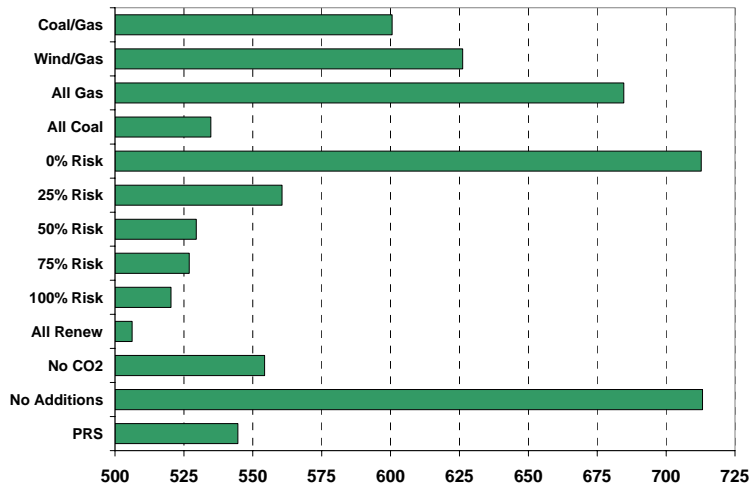


### Performance Comparison—Risk (2007-26 NPV of StDev \$millions)



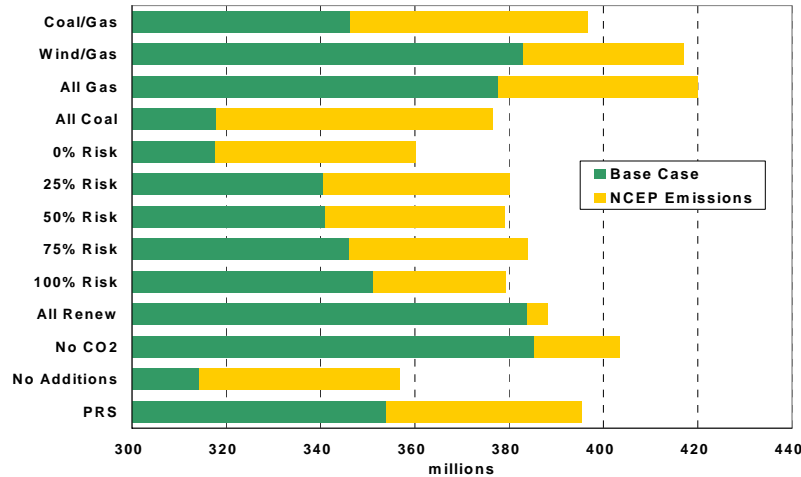
11

### Performance Comparison—Tail Risk (2007-26 NPV of 95<sup>th</sup> % Vs. StDev \$millions)



12

## Performance Comparison—NCEP Carbon Market Scenario 2016 Incremental PSE



13

## 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

14

## DRAFT Preferred Resource Strategy

