



# **IRP Public Input Meeting**

November 10, 2004

# Agenda

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- » Update on IGCC – [Jim Lacy](#)
- » Renewables Results using CEM - [Elaine Prause](#)
- » Updated Results of Stochastic Analysis - [Mike Rife](#)
- » Results of Scenario Analysis - [Elaine Prause](#)
- » Supply Side Portfolio Selection – [Melissa Seymour](#)
- » DSM Analysis - [Mike Koszalka](#)
- » Review Draft IRP - [Melissa Seymour](#)
- » Review Action Plan & Path Analysis - [Melissa Seymour](#)
- » Next Steps - [Melissa Seymour](#)



# **Update on IGCC**

(Integrated Gasification Combined Cycle)

Jim Lacey

# Principal Gasifier Options

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- » GE purchase of the Texaco-Chevron technology
  - Plan on offering full commercial wrap in the future
  - October 7, 2004 announced will form an alliance with Bechtel to develop a standard IGCC design.
    - ⇒ Standard design approximately 1.5 to 2 years away
    - ⇒ Will use a GE 7FB gas turbine
    - ⇒ Initial design will use eastern bituminous coal and/or pet coke for fuel
    - ⇒ Undecided on whether design will include specific Hg removal or SCR
- » ConocoPhillips (Global E-Gas or Destec)
  - Willing to offer full commercial wrap
  - More flexible with gas turbine options
  - Good performance on Utah and PRB coals
- » Shell
  - Multiple demonstrations - mostly overseas
  - Dry coal feed results in greater efficiency
  - Potentially good western fuel option

# Change in IGCC Assumptions

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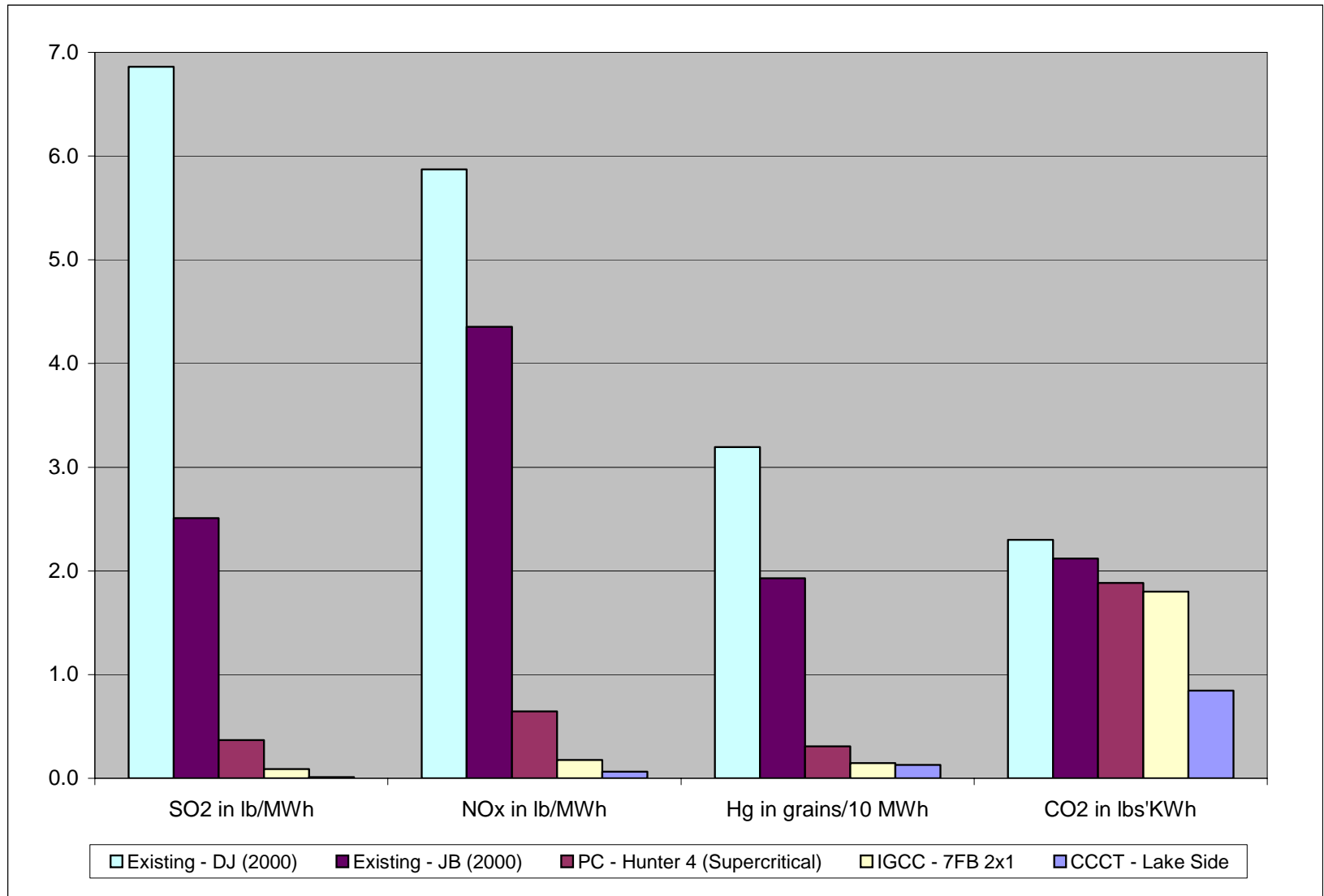
- » Based on recent GE and Conoco discussions. Comparison is very preliminary and investigations are on-going.
- » Supply Side Resources Table used an “H” combined cycle without a spare gasifier. “H” technology is more a 2015 expectation. Assumed a 75% availability.
- » New assumption uses a “7FB” combined cycle in a 3x2x1 configuration (spare gasifier). Potential GE/Bechtel standard plant offering. Expect 90% availability.
- » Heat rate and capital cost will not be as good as previous assumptions.
- » Emissions look a little better based on GE’s recent presentations.

# IGCC Assumptions

Characteristic	IGCC - No Carbon Capture or Sequestration		PC - Utah Supercritical
	Original Assumption - H Technology	Updated Assumption - 7FB Technology	
Capacity (MW)	368	460	575
Heat Rate (Btu/kWh)	8,311	8,600 to 8,700	9,200
Capital Cost (\$/kW)	\$2,171	\$2,350	\$1,750
Variable O&M (\$/MWh)	\$1.83	\$1.80	\$0.80
Fixed O&M (\$/kW-yr)	\$31	\$52	\$32
SO <sub>2</sub> Emissions (lb/mmBtu)	0.03	0.01	0.04
NO <sub>x</sub> Emissions (lb/mmBtu)	0.05	0.02	0.07
Hg Emissions (lb/trillion Btu)	0.60	0.24	0.50
CO <sub>2</sub> Emissions (lb/mmBtu)	205	205	205

- » Versus pulverized coal, IGCC still has higher capital but better heat rate and lower emissions

# Emissions Comparison

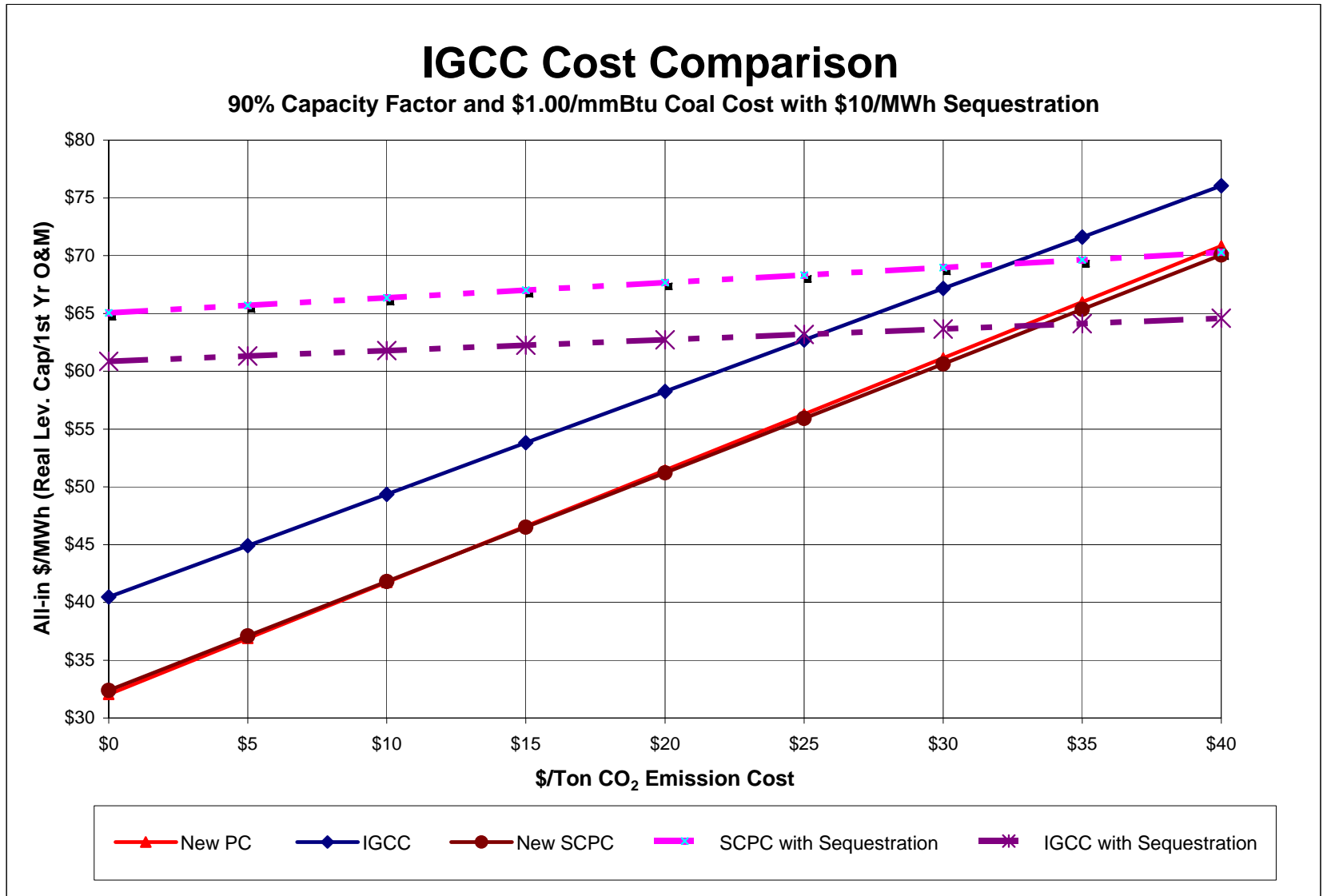


# Impacts of Carbon Capture & Sequestration

- » Up to 90% of CO<sub>2</sub> emissions can be captured with water shift reaction and amine scrubbing.
- » Assume Sequestration cost after carbon capture of \$10/MWh
- » Less costly to add carbon capture to IGCC than to pulverized coal. Data extrapolated from EPRI & GE data.

Characteristic	IGCC - Utah	PC - Utah Supercritical
Capacity (MW)	435	415
Heat Rate (Btu/kWh)	9,150	12,750
Capital Cost (\$/kW)	\$2,950	\$3,050
Sequestration (\$/MWh)	\$10.00	\$10.00
Variable O&M (\$/MWh)	\$2.75	\$4.80
Fixed O&M (\$/kW-yr)	\$65	\$45
CO <sub>2</sub> Emissions (lb/mmBtu)	20.5	20.5
COE Increase (at \$8/ton CO <sub>2</sub> )	30%	66%

# Sequestration vs. CO<sub>2</sub> Allowance Cost



# IGCC Summary

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- » IGCC still high cost but shows benefits relative to conventional coal:
  - Incrementally lower NO<sub>x</sub>, SO<sub>2</sub>, Hg emissions
  - Easier transition to carbon capture and sequestration
- » At a CO<sub>2</sub> allowance cost of approximately \$33/ton, IGCC with carbon capture and sequestration would break-even with the cost of pulverized coal without carbon capture or sequestration.
- » Will continue to investigate potential for use in the PacifiCorp system for the next coal unit
  - Look at ways to recover elevation disadvantage
  - Byproduct value with excess gasifier



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# **Renewables Results using CEM**

Elaine Prause

# Background

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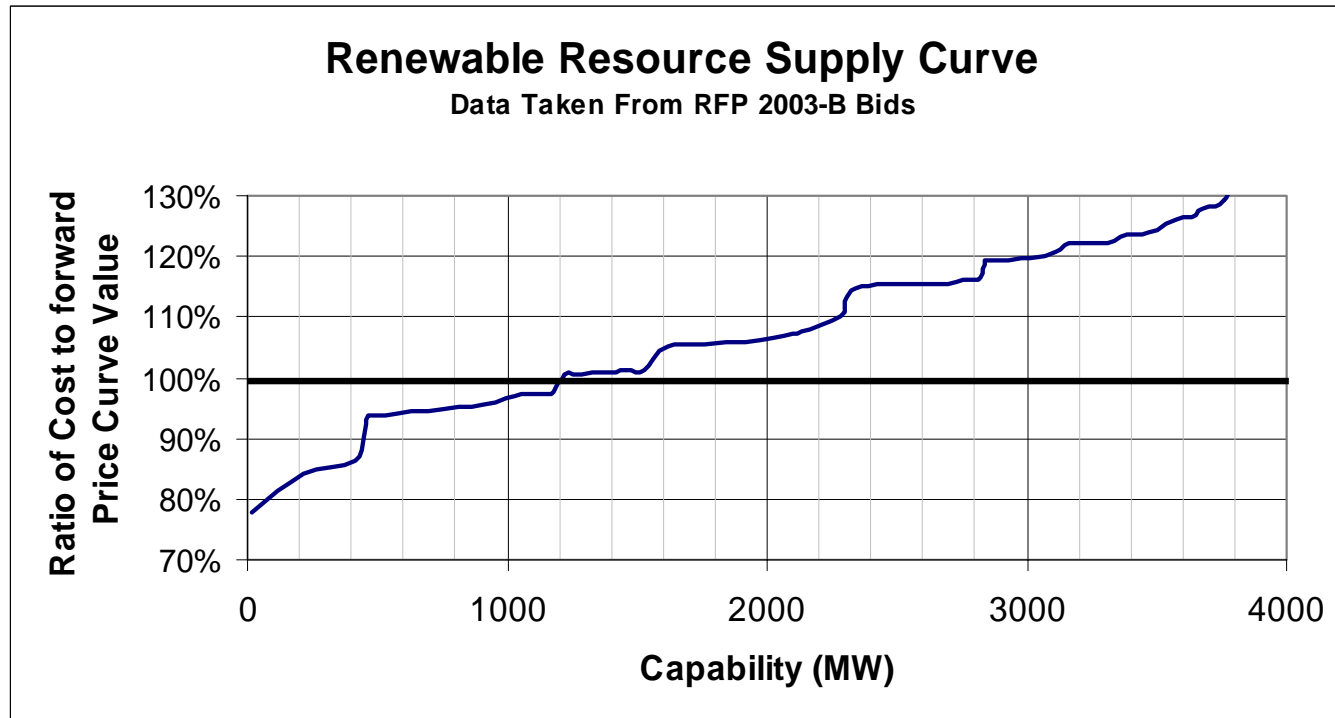
- » In the 2003 IRP, we found that 1,400 MW of renewables were cost-effective
- » Valid conclusion based on assumptions used at the time
  - Availability of economic projects and PTC extension
  - Capacity factors similar to Foote Creek and Stateline
  - Cost of integration (~\$5.50/MWh for 1,000 MW)
  - Transmission cost and availability
  - Effective load carrying capability (ELCC)
  - “Learn as we go”

# What have we learned?

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- » Since the January 2003 IRP...
  - Added 41 MW wind generation with Combine Hills project
  - Refreshed wind integration cost for incremental reserve costs
  - Calculated a 20% ELCC for wind resources
  - Issued RFP 2003-B in February 2004
    - ⇒ Over 6,000 MW total nameplate capability
    - ⇒ 85% wind
    - ⇒ Informed as to quantity, location, and cost of potential resources
    - ⇒ Best Available Data

# Cumulative Renewable Supply Curve



- Costs relative to market prices represent all in costs of generation (transmission, integration, PTC...)
- Not all bids may be viable, includes “add-on”s to projects and various install dates
- Not a definitive look at the renewable market
- Lends credibility to 1,400 MW base assumption (1,200 < market)

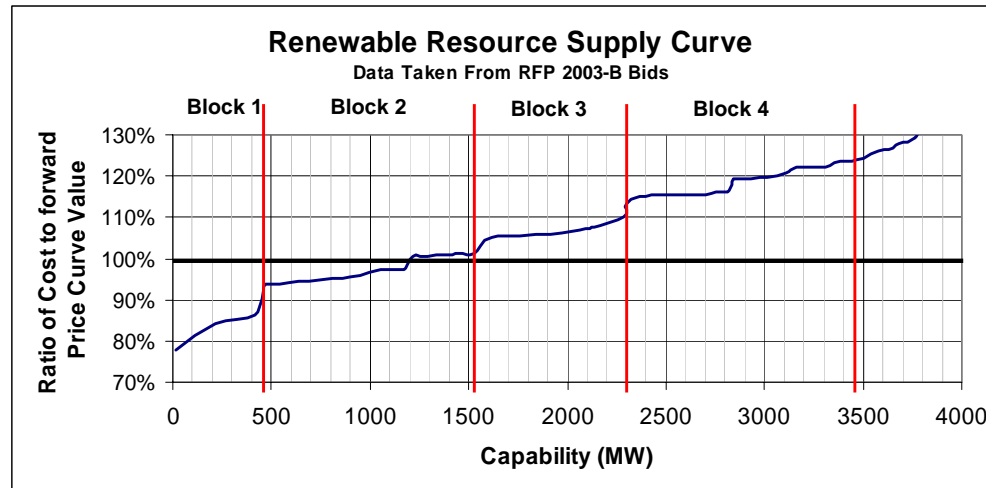
# Modeling Approach with CEM

- » Further test the 1,400 MW renewable assumption through use of resource selection tool, Capacity Expansion Model (CEM)
- » Side bar study to the IRP to validate continuing the base assumption
- » Let the model select optimal size, timing and cost effective pricing for renewable generation along with other traditional resources
  - Removed base case 1,400 MW
  - Created new resources for the model to select based upon the market depth and pricing from the renewable supply curve
    - ⇒ 8 new resource blocks defined
    - ⇒ Total of 3,400 MW split equally E / W
    - ⇒ Assume 3,400 MW available starting FY 2007, FY 2006 fixes 100 MW of wind in the West
    - ⇒ Pricing calculated each year for each block as the present value of 20-years of forward market prices, adjusted by block pricing factor (% relative to forward market)

# Definition of Renewable Resource Blocks

» For both the East and West, created four blocks structured as follows

	Block 1	Block 2	Block 3	Block 4	Total
Size (MW)	250	500	400	550	1,700
# of Units	5	10	8	11	34
Price % of FPC	83%	98%	109%	120%	106%



- Each block represents a section of the supply curve with similar price structure relative to forward market prices
- Each unit defined as 50 MW capacity with 30% capacity factor, 20% ELCC
- Block pricing in the East is relative to Palo Verde, West block prices relative to Mid-C

# CEM Results

Area	Resource	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
East	Brownfield PC Subcritical						575					575
	Greenfield PC 2								383			383
	CCCT (2x1) - (Dry Cooling)				420					420		840
	Dry CCCT Duct Firing (2x1)				105					105		210
	Block 1 East		50			150		50				50
	Block 2 East								250	50		60
West	Greenfield CCCT 2x1 - (Dry Cooling)								469			469
	Greenfield CCCT Duct Firing 2x1 - (Dry Cooling)								117			117
	Base Renewables	100										20
	Block 1 West		100	50			100					50
	Block 2 West		50	50			100		200			80
	Block 3 West										50	10
TOTAL MW		100	200	100	525	250	675	250	1,219	575	50	2864

- » 100 MW fixed in 2006 L&R
- » CEM selected 1250 MW
  - 550 in the East
  - 700 in the West

# Conclusions

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- » Responses to the RFP show the availability and cost effectiveness of renewable generation
- » Although still not fully validated, CEM produced similar results to the 1,400 MW base assumption
- » PacifiCorp concludes that the base assumption is a reasonable estimate for new renewable generation in the 2004 IRP



# Updated Results of Stochastic Analysis

Michael Rife

# Updated Stochastic Runs

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- » All portfolio runs were redone for each type of stochastic analysis
  - 'All-In': All five stochastic parameters considered variable: load, hydro, gas price, power price, and forced outages
  - 'Spark Spread' analysis
    - ⇒ Considers only power prices, gas prices, and forced outages as stochastic processes
    - ⇒ Assumes no variability in load forecast and hydro generation
- » Results are more in line with expectations
- » Results make it difficult to conclude a single portfolio is best

# Summary Risk Measures

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## » Average Risk

- Average amount of risk for each portfolio
- Stochastic average total cost over 100 iterations
- 90% Confidence Interval for stochastic average total cost
- Difference between the deterministic and stochastic average total cost vs. the stochastic average total costs

## » Risk Exposure

- Measures the potential extreme risk for each portfolio
- Average of the five highest iterations
- Standard Deviation of the five highest iterations
- Difference between average stochastic and deterministic variable costs vs. the average of the upper tail stochastic total costs

## » Risk/Cost Trade-off

- Measures the risk/cost combination for each portfolio
- Total average stochastic costs vs. the average of the upper tail
- Total deterministic costs vs. the average of the upper tail of stochastic total costs

## » Measures are Progressive in Terms of Importance

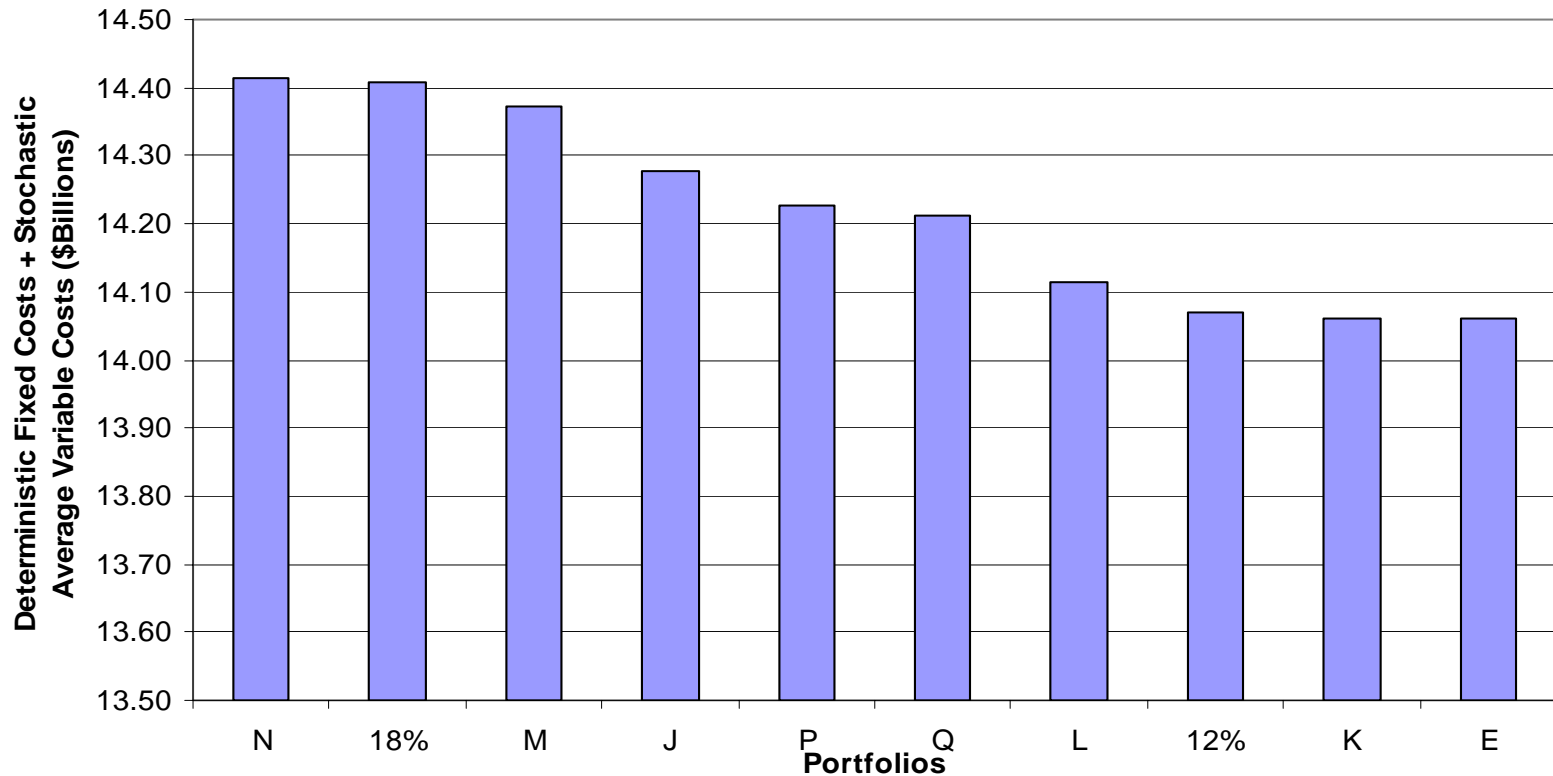
# Portfolios Analyzed in Stochastic Analysis

- » Portfolios E, J, K, L, M, N, K, Q, 18%, 12% (See Handout)
- » Portfolio Q
  - Portfolio developed to more closely match RMATS thermal and transmission resource assumptions.
  - Wyoming Coal Resources: Two 575 MW pulverized coal units at Jim Bridger site (958MW)
  - Build two 345 kV lines from Jim Bridger to serve Utah load
    - ⇒ 100% PacifiCorp owned
    - ⇒ Capital Cost - \$554 million (Cost is rough estimate)

Portfolio	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
<b>Q: Transmission Expansion with Additional Wyoming Pulverized Coal</b>													
<b>East</b>	Brownfield Coal	Utah-S						575					575
	Greenfield Coal	WY									958		958
	Dry Cool CCCT w/ DF	Utah-S				525							525
<b>West</b>	Dry Cool CCCT w/ DF	WMAIN (ISO)								586			586
	IC Aero SCCT	WMAIN (ISO)								194			194

# Average Risk Measure Example – ‘All – In’ Case

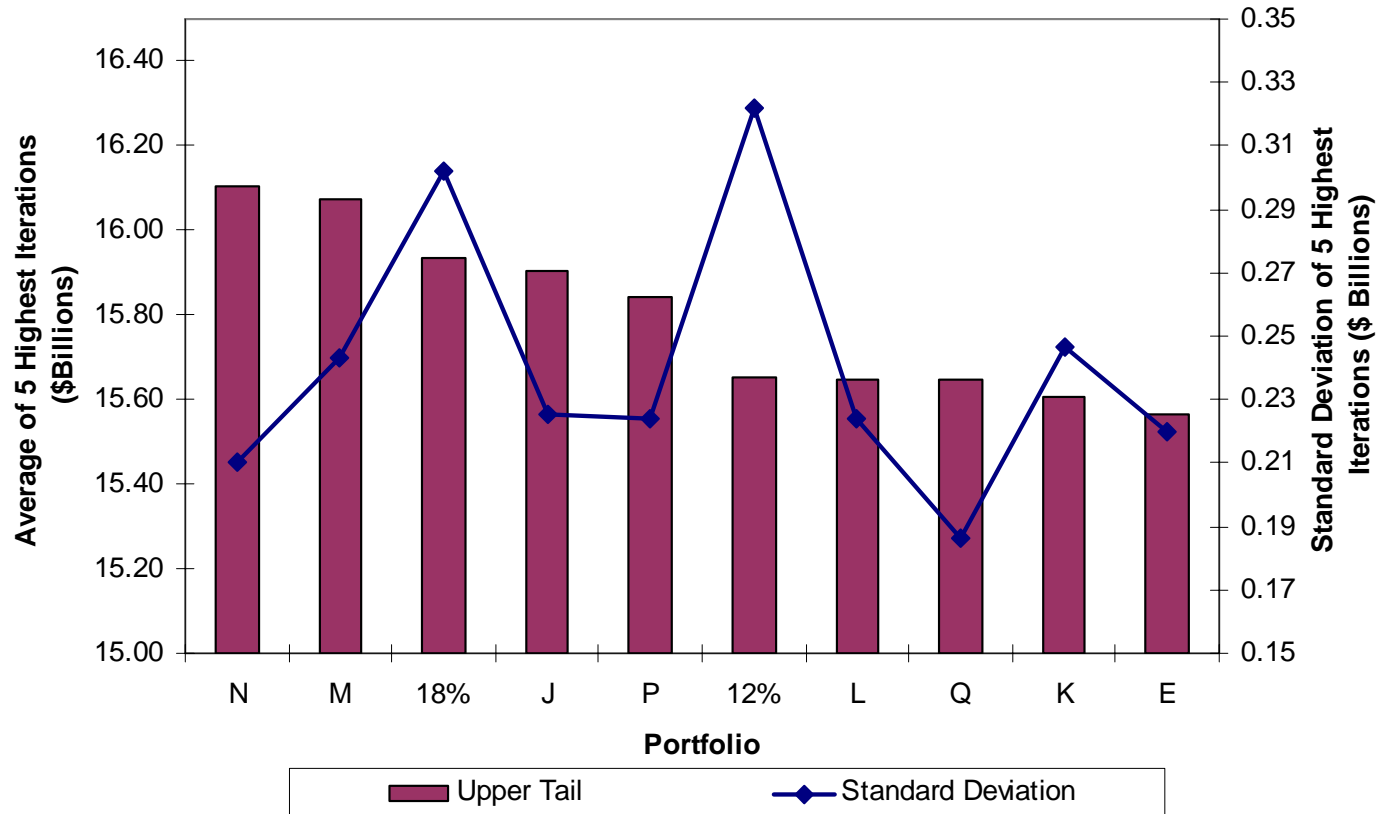
Fixed Deterministic Costs + Average Stochastic Variable Costs



» Portfolios E, K, 12%, and L perform well.

# Risk Exposure Measure Example – ‘All – In’ Case

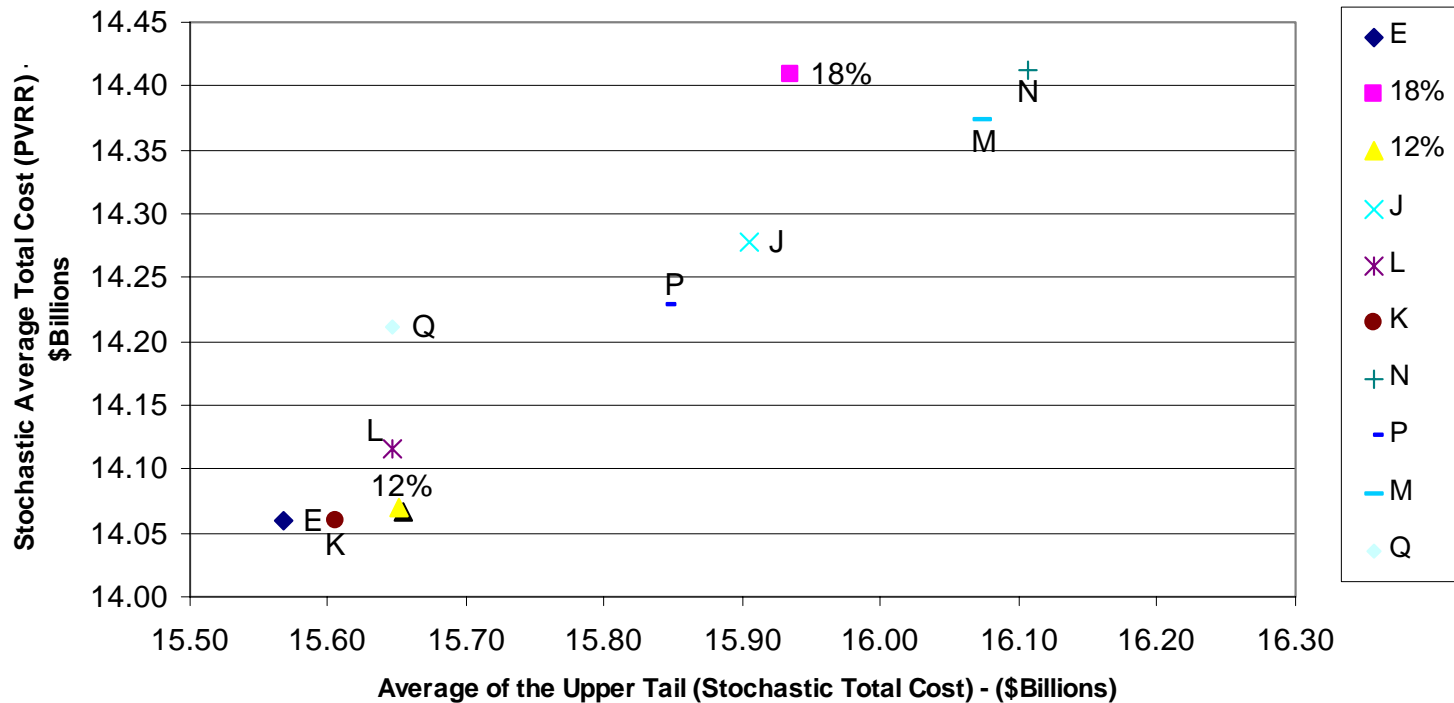
Upper Tail Cost and Standard Deviation



- » Portfolios E, K, Q, L, and 12% perform well with the Average
- » Portfolios Q, J, P, N, and E perform well with the Standard Deviation.

# Risk/Cost Trade-Off – ‘All – In’ Case

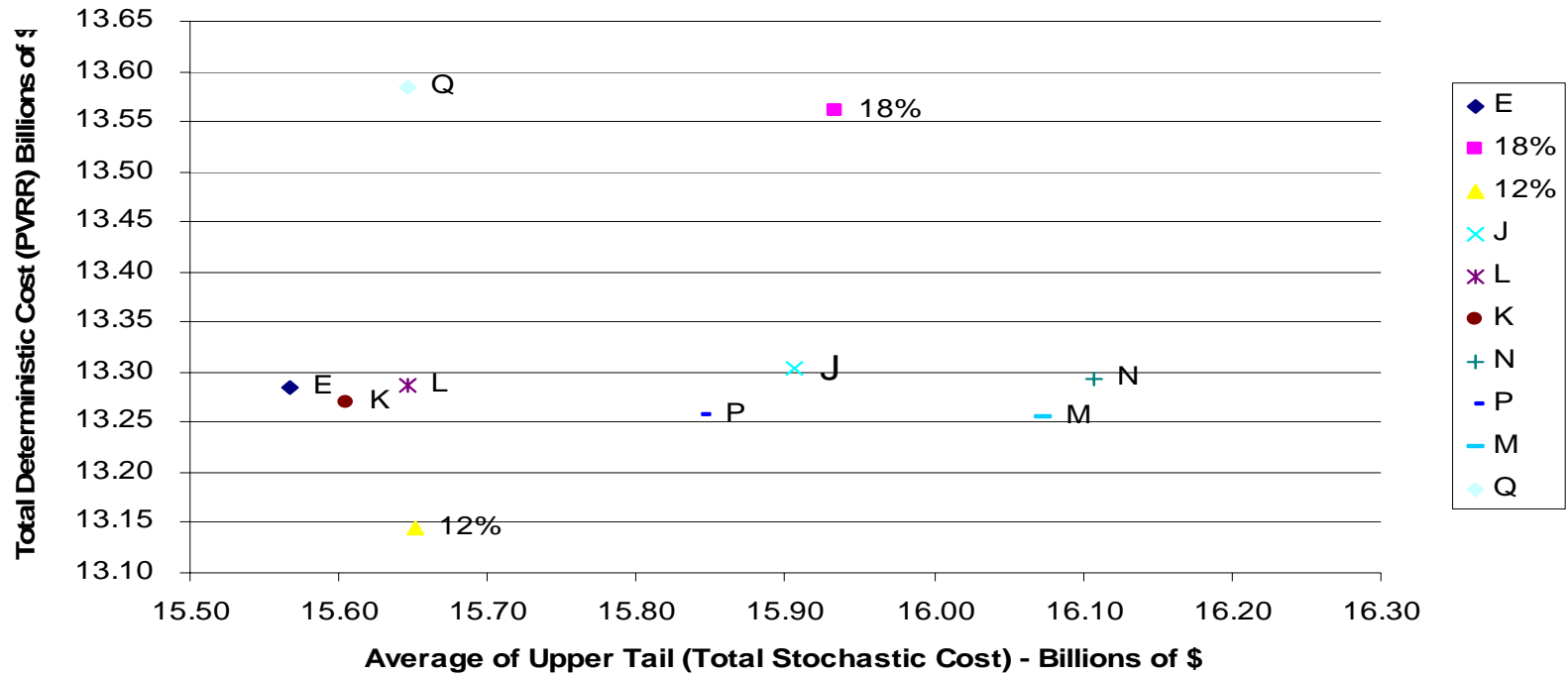
Total Stochastic Cost vs Upper Tail Average Total Cost



» Portfolios K, E, 12%, and L perform well

# Risk/Cost Trade-Off – ‘All – In’ Case

Total Deterministic Cost vs. Upper Tail Average Total Cost



» Portfolios K, E, 12%, and L perform well

# Risk Measure Summary for 'All In' Stochastics

Risk Measure	Measure Type	1	2	3	4	5
Stochastic Average Cost	Average	E	K	12%	L	Q
Difference between Avg. Stochastic and Deterministic	Average	Q	E	K	L	18%
Average Risk Measures	Average	E	K	Q	L	J
Average of 5 Highest Iterations	Risk Exposure	E	K	Q	L	12%
Standard Deviation of the Five Highest Iterations	Risk Exposure	Q	E	18%	L	K
Average and Extreme Risk Measure	Risk Exposure	Q	E	K	L	12%
% Difference between Stochastic Average and Five Highest Iterations	Risk Exposure	Q	18%	E	L	K
Stochastic Average Total Cost vs. Average of the Stochastic Upper Tail	Risk/Cost Trade-Off	E	K	12%	L	Q
Deterministic Total Cost vs. Average of the Stochastic Upper Tail	Risk/Cost Trade-Off	12%	E	K	L	P

- » Portfolios E, K and Q perform well over all measures.
- » Portfolios E, K, and 12% perform well with the most important measures.

# Risk Measure Summary for 'Spark Spread' Stochastics

Risk Measure	Measure Type	1	2	3	4	5
Stochastic Average Cost	Average	K	E	M	Q	L
Difference between Avg. Stochastic and Deterministic	Average	Q	K	E	L	M
Average Risk Measures	Average	Q	K	E	L	M
Average of 5 Highest Iterations	Risk Exposure	K	E	Q	L	P
Standard Deviation of the Five Highest Iterations	Risk Exposure	P	K	Q	M	E
Average and Extreme Risk Measure	Risk Exposure	Q	K	E	L	M
% Difference between Stochastic Average and Five Highest Iterations	Risk Exposure	Q	E	K	P	L
Stochastic Average Total Cost vs. Average of the Stochastic Upper Tail	Risk/Cost Trade-Off	K	E	Q	L	M
Deterministic Total Cost vs. Average of the Stochastic Upper Tail	Risk/Cost Trade-Off	K	E	L	M	P

- » E, K and Q perform well over all risk measures
- » E and K perform well on the most important risk measure

# Conclusions

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- » Stochastic results marginally favor portfolios with diversified additions in terms of fuel mix (i.e. gas and coal)
- » Generally, portfolios with additional generation that is mostly gas performed comparatively worse

## **Portfolios to be Targeted for Scenario Analysis**

- » Hard to eliminate any portfolio based on deterministic and stochastic analysis
- » Selected portfolios are low cost or low risk – L, E, K, Q, P, M
- » Eliminate portfolios performing poorly on stochastic and deterministic analysis J, N, and 18%
- » 12% eliminated due to high ENS
  - ENS was modeled at \$750/MWh
  - Societal costs are immeasurable
- » Scenario runs to be performed on selected portfolios
  - CO2 and High Gas



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# **Scenario Results**

Elaine Prause

# Scenario Risk Defined

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- » Risk associated with a large and consistent departure from the expected behavior
- » Probability of occurrence can not be quantified but can be evaluated numerically through scenario analysis
- » Two Scenario Risks tested in IRP model
  - CO<sub>2</sub> allowance cost
  - High gas cost

# CO<sub>2</sub> Scenario Description

- » \$0, \$10, \$25, and \$40 per ton (1990\$) scenarios were evaluated in the IRP model (Consistent with Oregon Order 93-695)
- » The same probability weights used in the base case are applied to each CO<sub>2</sub> scenario:
  - 50% probability in 2010 (0.50 x inflation adjusted price)
  - 75% probability in 2011 (0.75 x inflation adjusted price)
  - 100% probability in 2012 (full inflation adjusted price)
- » Each case modeled against 6 portfolios
  - Low cost and low risk portfolios, E, K, L, and Q
  - Least cost deterministic portfolios, M and P
- » Three additional variables impacted in each case
  - Electric power market prices
  - Gas market prices
  - NO<sub>x</sub> and SO<sub>2</sub> allowance costs

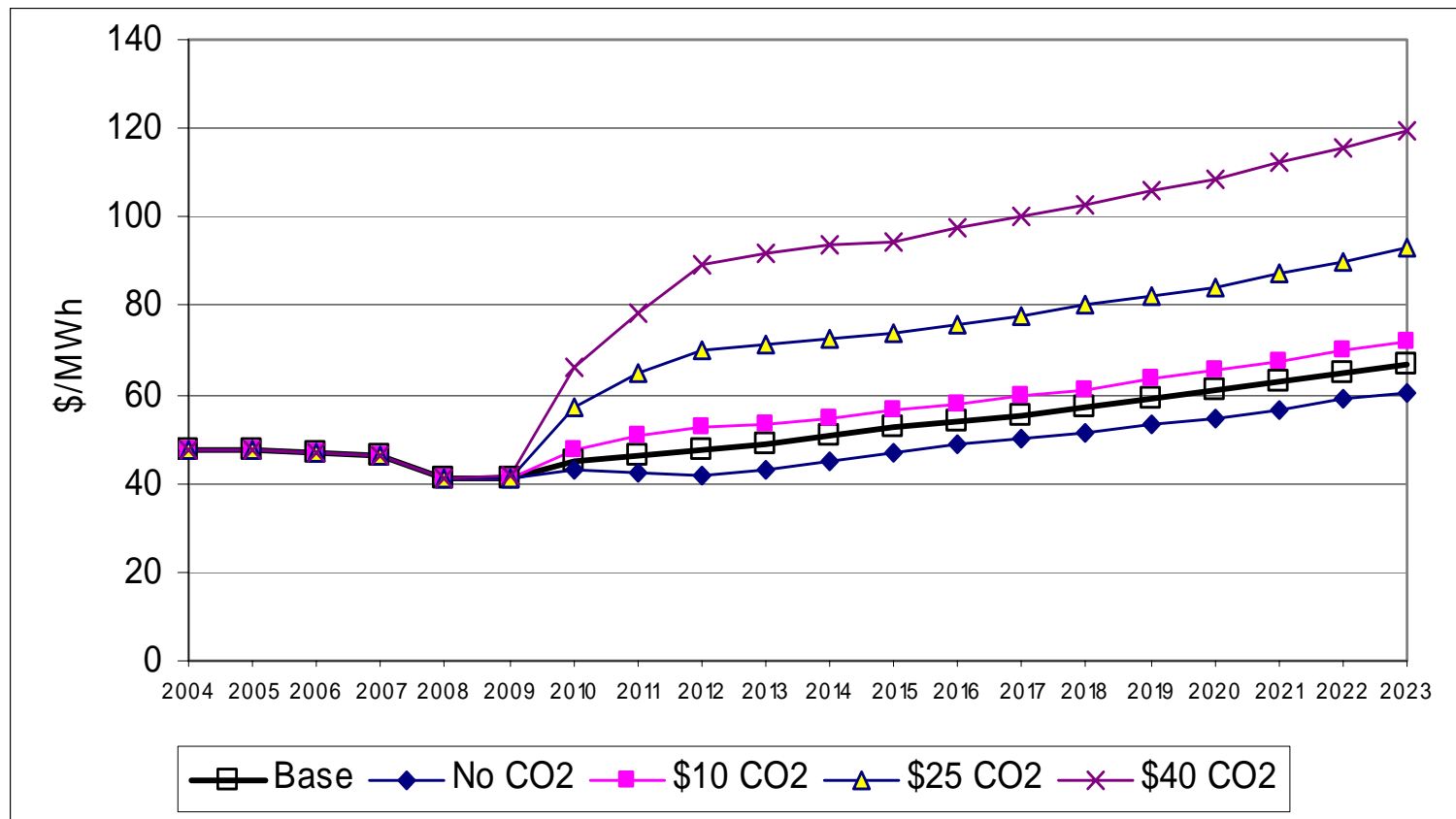
# Capturing Market Effects of CO<sub>2</sub>

- » Varying levels of CO<sub>2</sub> costs influence market fundamentals such as gas prices, electricity prices, and allowance prices
- » Changes to gas and allowance prices are based upon an analysis completed by ICF Consulting
  - Integrated Planning Model (IPM) used to capture changes to gas prices and allowance prices (SO<sub>2</sub> and NO<sub>x</sub>) under each CO<sub>2</sub> scenario
  - IPM is the same model used by EPA to model policy proposals
  - For each scenario, changes to gas, NO<sub>x</sub>, and SO<sub>2</sub> prices were compared against the base case
- » Results from ICF Consulting's analysis were used to generate a consistent electricity price forecast in Midas

# CO<sub>2</sub> Scenario Assumptions

- » Electric power price assumptions impacted by CO<sub>2</sub> \$/ton variation

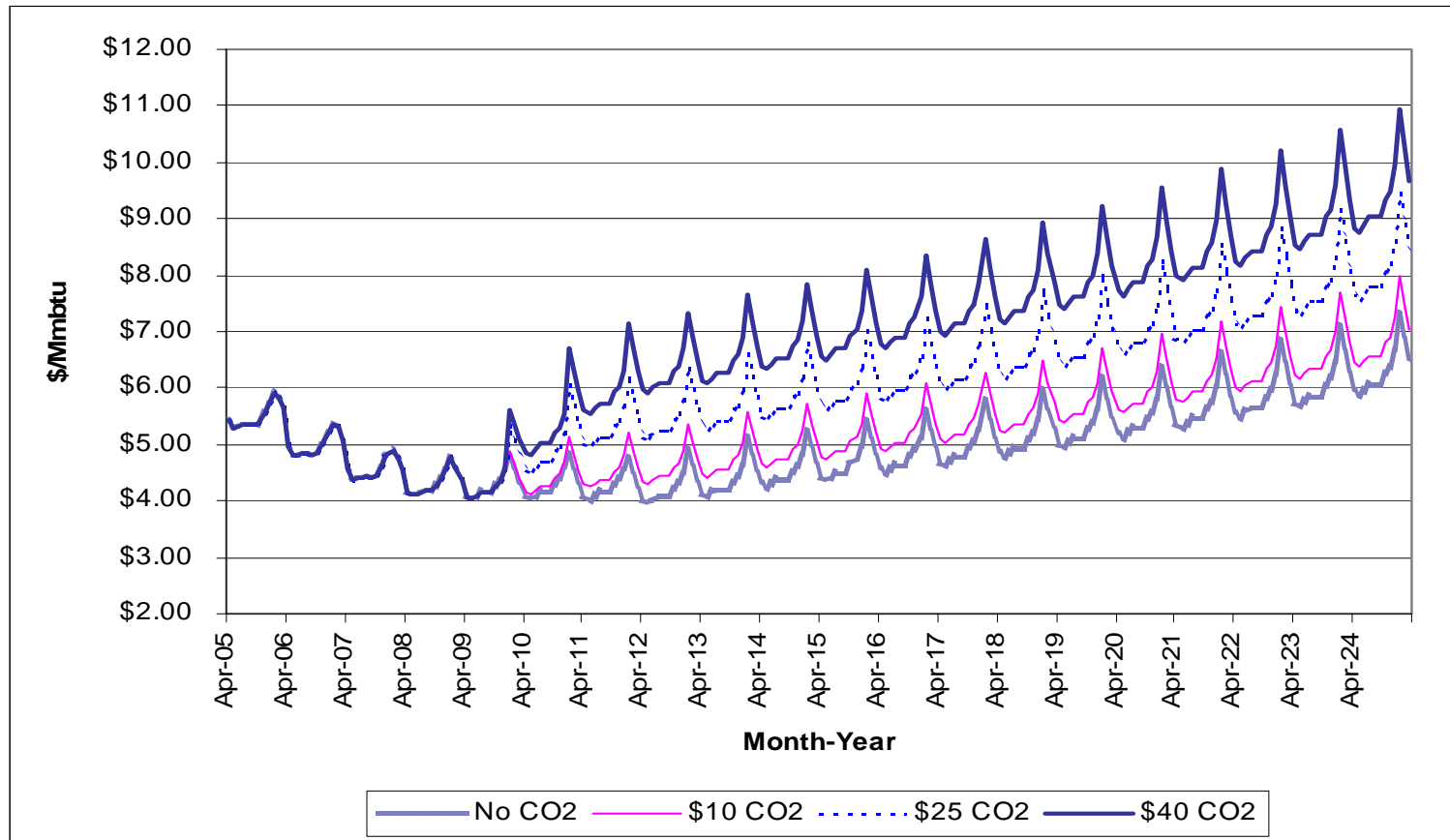
Palo Verde Average Annual Forward Prices



# CO<sub>2</sub> Scenario Assumptions

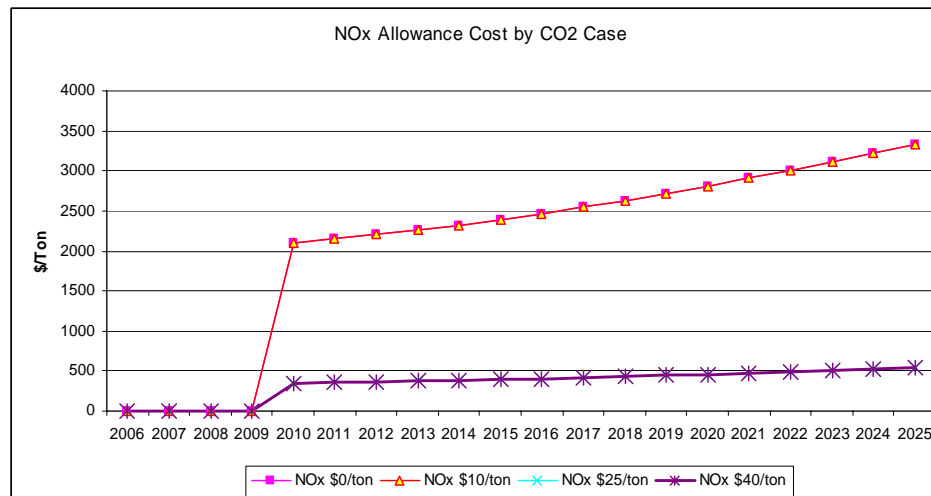
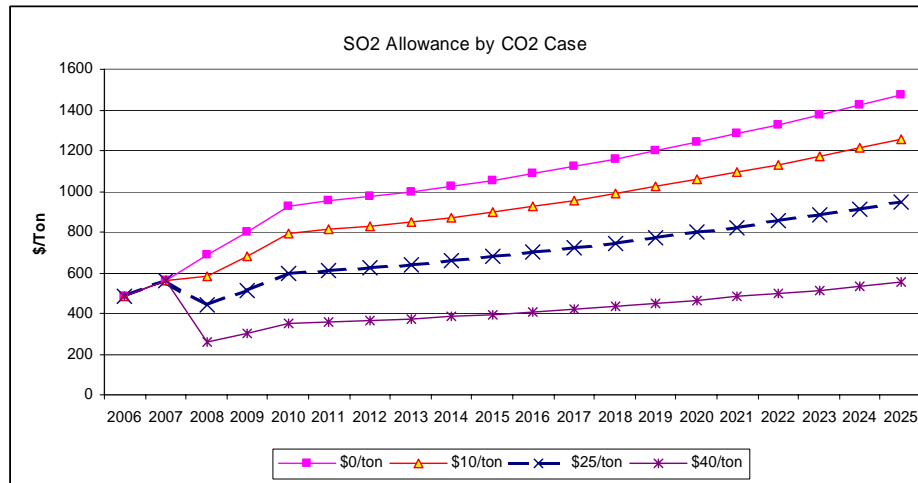
- » Gas price assumptions impacted by CO<sub>2</sub> \$/ton variation

Average Monthly Forward Gas Prices - West



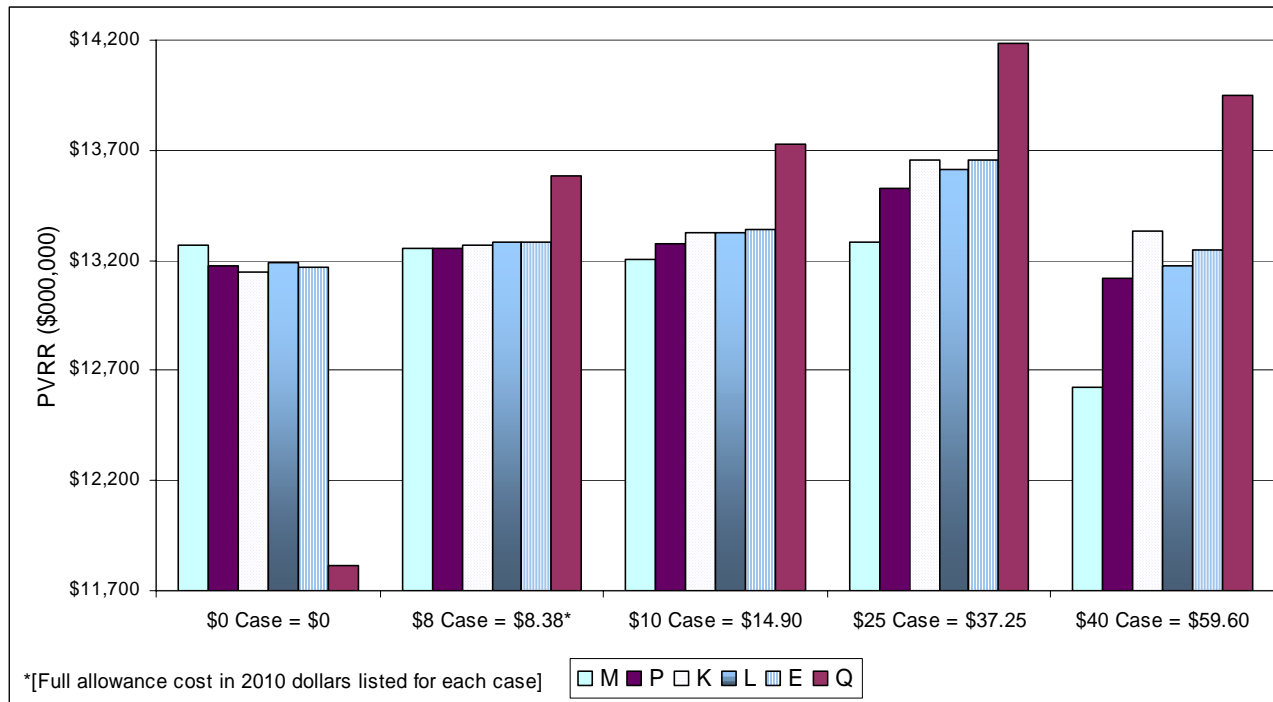
# CO<sub>2</sub> Scenario Assumptions

- » Additional pollutant cost impacts
  - As CO<sub>2</sub> \$/ton increases, NO<sub>x</sub> and SO<sub>2</sub> \$/ton decreases



# CO<sub>2</sub> Scenario Results

- » Portfolio rank by PVRR changes as CO<sub>2</sub> allowance increases



- » Portfolios with more gas perform well at high CO<sub>2</sub> values
- » Crossover point between gas heavy, Portfolio M and coal heavy, Portfolio Q favorability lies just at about \$6.50/ton

# CO<sub>2</sub> Scenario Observations

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- » There is little difference between portfolio PVRRs in the \$8/ton base case
- » At high CO<sub>2</sub> allowance costs, fuel switching alters dispatch in all portfolios, capacity factors of coal units decrease significantly, gas unit use increases
- » Results highlight modeling limitations
  - Assumes that a perfect cap and trade market will exist and that there will be a purchaser for each ton of CO<sub>2</sub> emitted below the cap through the term of the study

# CO<sub>2</sub> Scenario Conclusions

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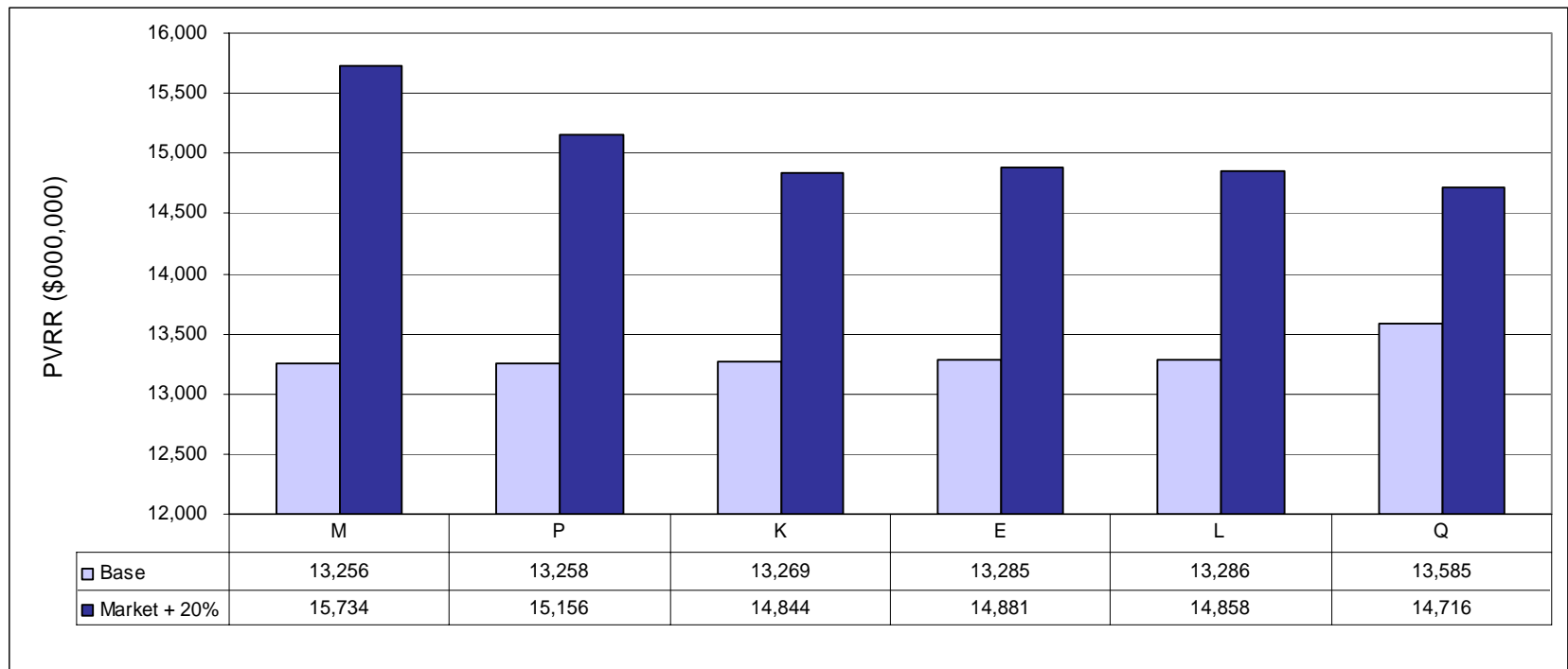
- » A high CO<sub>2</sub> allowance cost will provide enough incentive to alter the dispatch of the system, reducing the total amount of emissions
- » Although the All Gas portfolio fared best in higher cases, there is additional fuel price risk captured in stochastic analysis
- » A balance of resource types helps to reduce system costs from environmental pollutants and risk of high fuel costs

# High Gas Scenario Description

- » Goal - To test sensitivity of selected portfolios to a large fundamental increase in gas prices.
  - Low Stochastic Risk Portfolios E, K, L and Q and Deterministic least cost M and P
  - East and West natural gas prices increased by 20%
  - All electric markets increased by 20%
- » This scenario represents paradigm shifts where gas prices are impacted.
  - For example - anticipated LNG terminals are not realized, increasing reliance on domestic gas market

# High Gas Scenario Results

- » All PVRRs rise by 8-19%
- » All Gas Portfolio M changes rank from least cost to highest cost



# High Gas Scenario Results

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- » Differences between portfolio PVRRs become significant compared to the base case
- » Portfolios with coal fair well, with little impact to their fuel cost although all portfolios are impacted by high energy market prices
- » Gas unit capacity factors decrease from 55-65% to 25-38%
- » This Scenario Risk is best hedged with a diverse mix of new generation resources



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# **Supply Side Portfolio Selection**

Melissa Seymour

# Supply Side Portfolio Selection

- » Selection of the final supply side portfolio is based on a combination of modeling results
  - Deterministically, all portfolio PVRRs are within 2% of each other
  - Stochastically, portfolios with increased diversification in new resource fuel type has the greatest positive impact on the performance of a portfolio with respect to the combination of cost and risk
  - The Scenario Risk results emphasize the positive diversification effect by showing that less diversification results in higher costs under high-risk scenarios
- » PacifiCorp therefore concludes that Portfolios E and K, with their balanced resource mixes and superior showing on several risk measures, are the best performing portfolios
  - Portfolios E and K are indistinguishable from a modeling perspective
  - Non-modeling factors therefore must determine which one is selected as the Preferred Portfolio.

# Comparison of Portfolio E vs. K

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- » Only difference in portfolios is first unit:
  - Portfolio E has Dry Cool CCCT 525 MW in FY 2009
  - Portfolio K has 6 IC Aero units 522 MW in FY 2009
- » PacifiCorp evaluated the desirability of the two technology types, and Portfolio E was selected as the preferred supply-side portfolio on this basis.
- » The key factors that influenced the decision include the following:
  - Synergies of plant knowledge.
  - Ability to potentially share common plant facilities and spare parts with other CCCT units located in Utah.
  - A CCCT has a lower heat rate than an IC Aero SCCT.
  - A CCCT has lower per-MWh emission rates than an IC Aero SCCT.
- » Next Step - Run DSM analysis on Preferred Supply Side Portfolio



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## DSM Analysis

Mike Koszalka

# DSM Analysis

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- » Class 1 DSM
  - Apply programs to the preferred supply side portfolio to improve PVRR
  - This analysis results in the Preferred Portfolio
- » Class 2 DSM
  - Use Preferred Portfolio for the decrement analysis
  - Results determine values against which potential programs can be evaluated

# Class 1 DSM Programs Evaluated

- » Class 1 DSM program options for CEM model

DSM Resource Name	Location	Maximum Program Megawatts	Program Cost, \$/kW-yr
Residential/Small Commercial Air Conditioning Control	West	45	58.35
Commercial Lighting Control	West	45	58.35
Commercial Electric Space/Water Heat Control	West	44	58.35
Irrigation Control	West	44	27.19
Commercial Cooling Control	East	44	58.90
Irrigation Control	East	44	27.19
Cool Keeper Program Extension	East	45	58.35
Idaho Irrigation Extension	East	44	27.19

# Class 1 DSM Analysis Results

- » CEM selected DSM resources and start years
  - 44 MW East Irrigation Load Control, 2009
  - 44 MW West Irrigation Load Control, 2009
  - 44 MW East Commercial Cooling, 2014
  - 45 MW West Residential A/C Load Control, 2014
- » Supply Side Resource deferrals
  - FY 2009 2x1 CCCT moves to FY 2010
  - FY 2011 UT Coal plant moves to FY 2012
  - FY 2013 West IC Aeros moves beyond planning horizon
- » Maintains at least 15% planning margin all years
- » Deterministic PVRR reduced by \$135 Million
  - ⇒ Lower capital costs
  - ⇒ Lower fuel costs and total emissions
  - ⇒ Decrease in market sales

# The Preferred Portfolio

	Unit Type	Region	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
<b>Portfolio E with Class 1 DSM (MW)</b>												
<b>East</b>	Brownfield Coal	Utah-S							575			
	Brownfield Coal	WY										383
	Wet Cool CCCT w/DF	Utah-N									560	
	Dry Cool CCCT w/DF	Utah-S					525					
	Irrigation Load Control	Utah-N				44						
<b>West</b>	Commercial Cooling	Utah-N									44	
	Dry Cool CCCT w/DF	WMAIN (ISO)								586		
	Irrigation Load Control	WMAIN (ISO)				44						
	Residential AC	WMAIN (ISO)									45	

# Class 2 DSM Decrement Analysis

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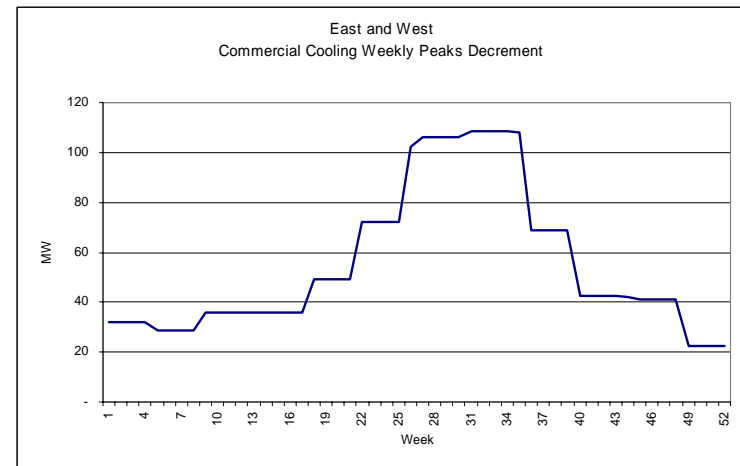
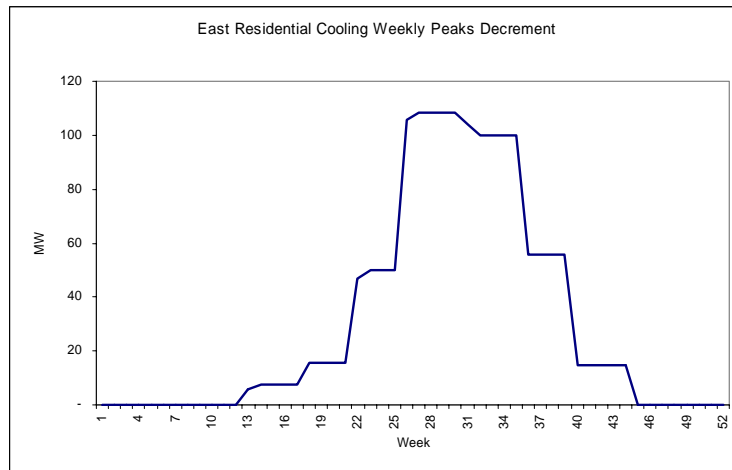
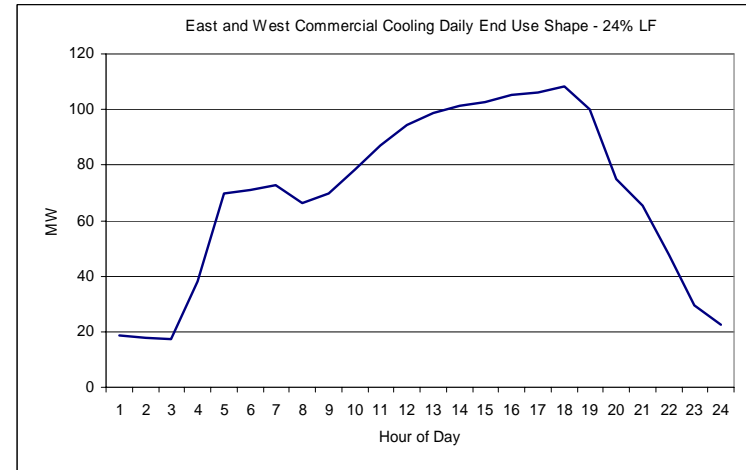
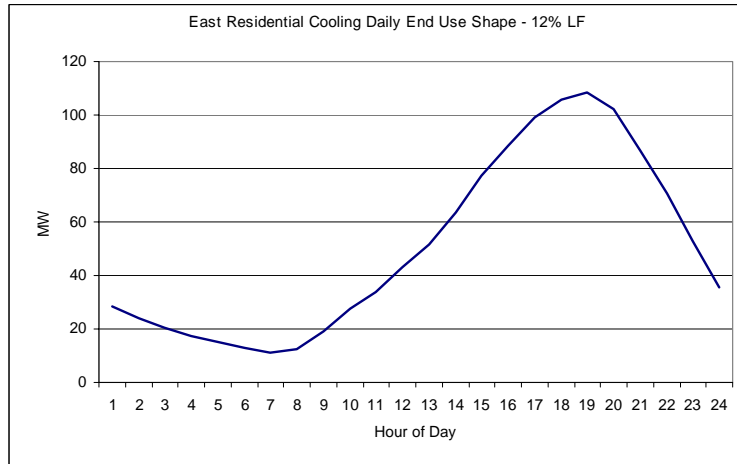
- » Provides \$/MWh values for various types of Class 2 programs based on the Preferred Portfolio of resources
- » Use these values to evaluate cost effectiveness of potential programs between IRP cycles
- » Load reductions from these new Class 2 programs will be applied to the load forecast for next IRP

# DSM Decrement Procedure

- » 8 hourly end use load shapes used to represent typical Class 2 programs
- » Each shape sized to reach 100 MW peak load reduction

End Use	Location	Load Factor	Average MW
Residential Cooling	East	12%	13
Commercial Cooling	East	24%	25.6
Commercial Lighting	East	51%	55.5
System Load Shape	East	65%	70.5
Residential Cooling	West	7%	7.7
Commercial Cooling	West	24%	25.6
Commercial Lighting	West	51%	55.5
System Load Shape	West	67%	72.7

# Decrement Analysis - End Use Shapes



Source: NWPCC curves, also used in 2003 IRP Decrement Analysis

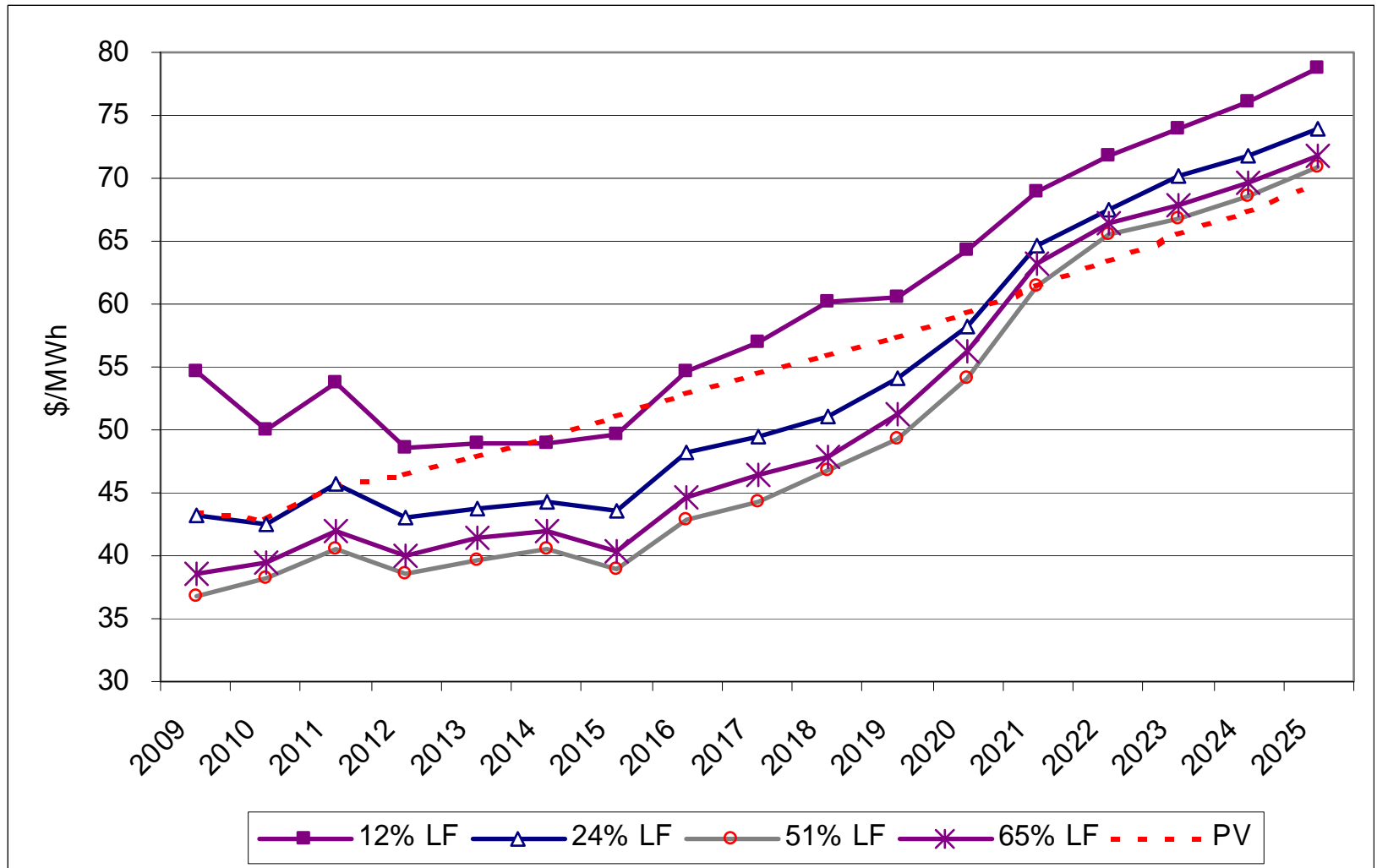
# Decrement Modeling Approach

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- » 8 model runs, one for each decrement
- » Hourly end use shape subtracted from the base hourly load in either West Main or UT-N
- » No resources in plan were deferred or eliminated
- » Compare total system costs with decrement to base case

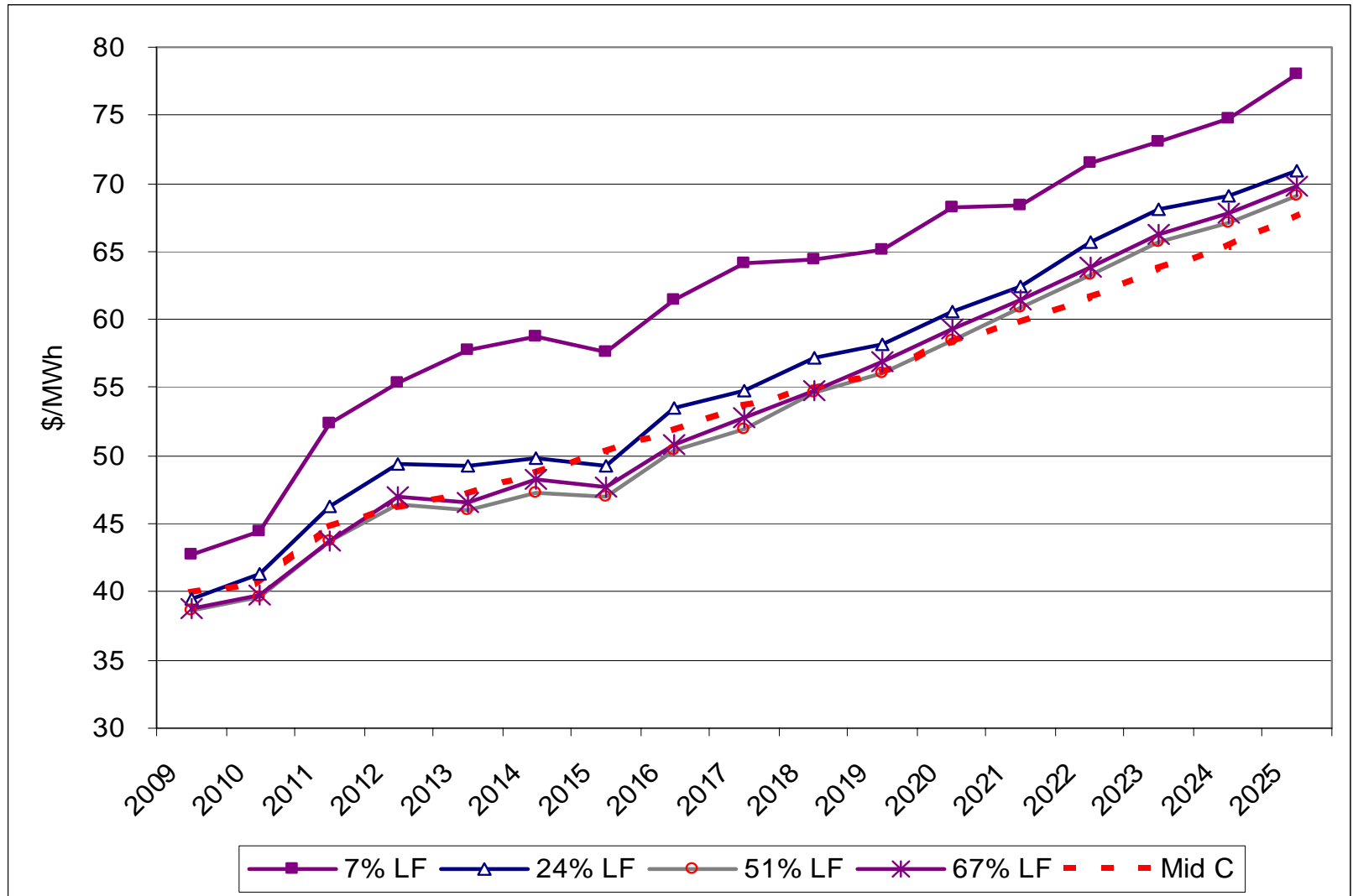
# Decrement Results

## Annual \$/MWh for East Decrements



# Decrement Results

## Annual \$/MWh for West Decrements





**PACIFICORP**

# **Review Draft IRP**

Melissa Seymour

# Draft IRP

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- » IRP will be produced in two volumes this year
  - Volume 1 – Main Document
  - Volume 2 – Appendices
- » Soliciting feedback from IRP Public Input Participants on Volume 1 prior to filing
  - Draft sent to participants on November 5
- » Receive all comments on draft document no later than December 3.
- » Feedback should be focused on compliance with Standards & Guidelines
  - Limit the additional analysis to what is required to comply with the Standards & Guidelines

# Draft IRP – Volume 1 (Main Document)

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- » **Executive Summary**
- » **Chapter 1 - Marketplace & Fundamentals** - Describes the environment in which we are planning. Discusses in detail issues related to Climate Change and Natural Gas Supply & Demand.
- » **Chapter 2: PacifiCorp Overview** - Includes an overview of the PacifiCorp system. This chapter also describes updates to existing units (i.e. Huntington 2 Scrubber, Hydro Relicensing), provides an update on regulatory and/or federal issues or mandates (i.e. RPS Standards, the Production Tax Credit, MSP), and finally provides an update on recent procurement activities.
- » **Chapter 3: Resource Needs Assessment** - Provides an overview of the major inputs and assumptions that drive the need for new resources, i.e. the load forecast, resource additions, contract expirations, Planning Margin, etc. Also describes the load and resource balances and the need for new resource additions.
- » **Chapter 4: Risk and Uncertainties** - Describes the different categories of risk and how each are evaluated in the IRP. This Chapter also contains a discussion on customer and shareholder risks.

# Draft IRP – Volume 1 (Main Document)

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- » **Chapter 5: Analytical Approach Used in the IRP** - Provides details of the modeling approach used to identify the Preferred Portfolio. Discusses the models used, the steps in the process, the DSM decrement analysis, and the determination of the final portfolio.
- » **Chapter 6: Resource Alternatives** - Provides a detailed description of all resource alternatives that were considered in the IRP (DSM, Distributed Generation, Supply Side Resources, and Transmission), and how they were evaluated in the IRP.
- » **Chapter 7: Portfolios** - Outlines the strategy used to develop the portfolios and provides an overview of each portfolio that was evaluated.
- » **Chapter 8: Results** - Provides the details of the modeling results (deterministic, stochastic, scenario analysis, stress cases, DSM) and ultimately arrives at a recommendation for the Preferred Portfolio.
- » **Chapter 9: The Action Plan** - Summarizes the results and provides an action plan for the 2-4 year time horizon. This Chapter also provides an overview of the circumstances that may require PacifiCorp to take a different path than what is outlined in the Action Plan. A discussion on procurement with regards to the Action Plan is also included in the chapter.

# Draft IRP – Volume 2 (Appendices)

- » A – Electric Utility Background
- » B – Public Input Process
- » C – Assumptions
- » D – Portfolio Summary Tables
- » E – Analysis Results
- » F – Portfolio Load and Resource Balances
- » G – Risk Assessment Methodology
- » H – Model Descriptions
- » I – Load Forecasting Methodology
- » J – Wind Assumptions
- » K – Standards & Guidelines
- » L – Response to Comments
- » M – Performance on 2003 IRP
- » N – Planning Margin Study
- » O – Revenue Requirement Methodology
- » Glossary



# **Review Action Plan & Path Analysis**

Melissa Seymour

# Summary of the IRP Action Plan

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- » The Preferred Portfolio was used to develop the Action Plan
- » The Action Plan includes an action item for any decision that needs to be made or action that needs to be taken in the next 2-4 years.
- » Each action item is categorized by:
  - Addition Type – Supply Side, DSM, Distributed, Transmission
  - Resource Type – Renewables, Class 1 DSM, Coal
  - Timing – year(s) in which action needs to be complete
  - Size – in MW, rounded to the nearest 50 MW
  - Location – State or System
  - IRP Resource Evaluated – Proxy resource
  - Required Action – description of the action that needs to be taken
- » There are 10 Action Items in the 2004 IRP

# IRP Action Plan

Action Item	Addition Type	Resource Type	Timing	Size (rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	Action
1	Supply-Side	Renewables	FY 2006 - 2015	1,400	System	Wind	Continue to aggressively pursue cost-effective renewable resources through current and future RFP(s).
2	DSM	Class 2	FY 2006 - 2015	450 MWa	System	100 MW Decrements at various load shapes	Use decrement values to assess cost-effective bids in DSM RFP(s). Acquire the base DSM (PacifiCorp and ETO combined) of 250MWa and up to an additional 200 MWa if cost effective programs can be found through the RFP process.
3	Distributed Generation	CHP	FY 2010 (summer of CY 2009) and FY 2012 (CY 2011)	n/a	System	Two 45 MW units using NREL cost estimates	Include CHP as eligible resources in supply-side RFPs.
4	Distributed Generation	Standby Generators	FY 2010 (summer of CY 2009) and FY 2012 (CY 2011)	n/a	Utah	75 MW in Utah	Include a provision for Standby Generators in the supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.
5	DSM	Class 1	FY 2009 (summer of CY 2008)	50	Utah	Irrigation Load Control	Procure cost-effective summer load control program in Utah by the summer of 2008.

# IRP Action Plan

Action Item	Addition Type	Resource Type	Timing	Size (rounded to the nearest 50 MW)	Location	IRP Resource Evaluated	Action
6	DSM	Class 1	FY 2009 (summer of CY 2008)	50	OR/WA	Irrigation Load Control	Procure cost-effective summer load control program in Oregon and/or Washington by the summer of 2008.
7	Supply-Side	Flexible, gas resource	FY 2010 (summer of CY 2009)	550	Utah	CCCT	Procure a flexible gas resource in or delivered to Utah by the summer of CY 2009.
8	Supply-Side	Coal resource	FY 2012 (summer of CY 2011)	600	Utah	Pulverized Coal Plant	Procure a coal resource in or delivered to Utah by the summer of CY 2011.
9	Transmission	Regional Transmission	FY 2013 and beyond	n/a	System	Transmission from Wyoming to Utah	Continue to actively participate in regional transmission initiatives (i.e. RMATS, NTAC)
10	IRP Process	Modeling	2006 IRP	n/a	n/a	n/a	Incorporate Capacity Expansion Model into portfolio and scenario analysis.

# Action Plan Path Analysis

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- » The majority of the items in the Action Plan will be acted upon prior to the next IRP planning cycle
  - Time frame for decisions is short
  - Not many changes in the projected future will affect the decision
- » The primary circumstances that could require PacifiCorp to make a decision to take a different path than what is outlined in the Action Plan:
  - The inability to procure designated resources in the required timeframe to meet the need
  - A significant shift (increase or decrease) in the forecasts of load and/or resources
  - A State or Federal mandate is imposed on the Company

# Inability to Procure Resource in Time Frame

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- » Could be various reasons why the designated resource could not be procured in the timeframe identified:
  - No cost-effective opportunities available through RFP
  - Delays in the process for procuring the resource (permitting, construction, negotiations)
- » Possible paths PacifiCorp could take:
  - Short term purchase to bridge the gap
  - Move up online date of next resource decision
  - Drop below 15% planning margin for a short period of time

# Significant Shift in Loads or Resources

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- » Major shifts in either loads or resources could affect the timing and size of major resource additions
  - Large loss of load (SB1149)
  - Substantial increase in the energy sold to PacifiCorp from Qualifying Facilities
  - Recession or economic boom
- » Possible paths PacifiCorp could take:
  - Delay or accelerate resource acquisition(s)
  - Reassess the need and timing for a new resource

# State or Federal Mandate Imposed

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- » Compliance with State or Federal mandates could require PacifiCorp to alter the strategy outlined in the Action Plan
  - Renewable Portfolio Standards
  - Portfolio Diversity Standards
  - Resource Adequacy Requirements
- » Possible paths PacifiCorp could take:
  - Re-evaluate current procurement activities to ensure adequate resources were being procured to meet the new standard



# PACIFICORP

## Next Steps

Melissa Seymour

# Next Steps

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- » The final IRP Public Input Meeting will be held on December 9.
  - The purpose of the meeting will be to clarify comments received by stakeholders.
  - Possibility that the meeting will be held via conference call.
- » The IRP will be filed with Commissions in early January.