2007 Integrated Resource Plan

Public Input Meeting Presentation

April 18, 2007

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Agenda

"2006 IRP" will now be referred to as "2007 IRP"

- Introduction
- Load Forecast Update
  - Summary of Changes to Forecast
  - Changes in Economic Conditions
  - Major Sales Changes by Jurisdiction
- Load and Resource Balance Update
- Preferred Portfolio
- Action Plan
- Portfolio Modeling Update
  - Risk Analysis Portfolio Development
  - Cost and Risk Performance Results
  - Customer Rate Impacts
  - Carbon Dioxide Emissions Footprint
  - Supply Reliability Measures
- Class 2 DSM Decrement Analysis
- Next Steps

Long-Term Load Forecast Update

Reed Davis

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Summary of Changes for all Jurisdictions

	Changes in Coincident Peak Load						
Calendar Year	**Total**	Oregon	Washington	Wyoming	California	Utah	Idaho
2016	**105**	(104)	40	204	6	(140)	99

	Changes in Growth Rates						
Calendar Year	**Total**	Oregon	Washington	Wyoming	California	Utah	Idaho
2007-2016	**0.3%**	(0.4)%	0.3%	2.6%	0.0%	(0.3)%	(0.1)%
2016-2026	**0.1%**	0.0%	(0.1)%	1.0%	(0.2)%	0.0%	(0.2)%

- Coincident Peak Demand Change is a net positive
  - Increases in Wyoming and Idaho more than off-set declines in Oregon and Washington
- Long-term Load Growth Rate Change is a net positive
  - Increase in Wyoming more than off-sets declines in Utah and Oregon.

Changes in Economic Conditions

- Changing Conditions
  - Slower Economic Growth in Short-term
    - Employment
    - GDP
  - Housing bubble collapse in the early part of the forecast horizon
    - Has an effect in the short-term
  - Both of these effects cause increasing deviations for each year in the long-term
  - Higher Oil and Gas Prices
    - Caused by increasing demand and international instability
    - Incentive for increased extraction activities.
    - Wyoming has one of the largest “untapped” fields

Major Sales Changes by Jurisdiction

	MWh Changes by Jurisdiction	
	2016	**2026**
Wyoming	2,760,737	4,715,947
Utah	(1,099,510)	(1,407,819)
Oregon	(587,520)	(650,071)
Total	**1,123,582**	**2,562,607**

Wyoming

- Major Oil and Gas Extraction activity expected during forecast horizon

Utah

- Commercial sales expected to be slower due to slightly slower economic growth and commercial industry in-migration.

Oregon

- Slower growth in the residential and Industrial customer classes.
  - Slower residential growth due to slower electric heating saturation penetration rates
  - Slower industrial growth due to declines in the paper and lumber industries.

Load and Resource Balance Update

Stan Williams

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Load and Resource Assumptions

- Includes:
  - 12% - 15% planning reserve margin
  - All contracts that exist as of 5/1/2006
  - Blundell geothermal bottoming cycle upgrade
  - Cove Fort geothermal plant
  - 400 MW wind from MEHC commitments
  - Expiring Qualifying Facilities and Interruptible contracts extend until end of study period
- Does not include:
  - Renewal of the TransAlta agreement
  - Renewal of the BPA Peaking contract
  - West Valley extension

Load and Resource Assumptions (Continued)

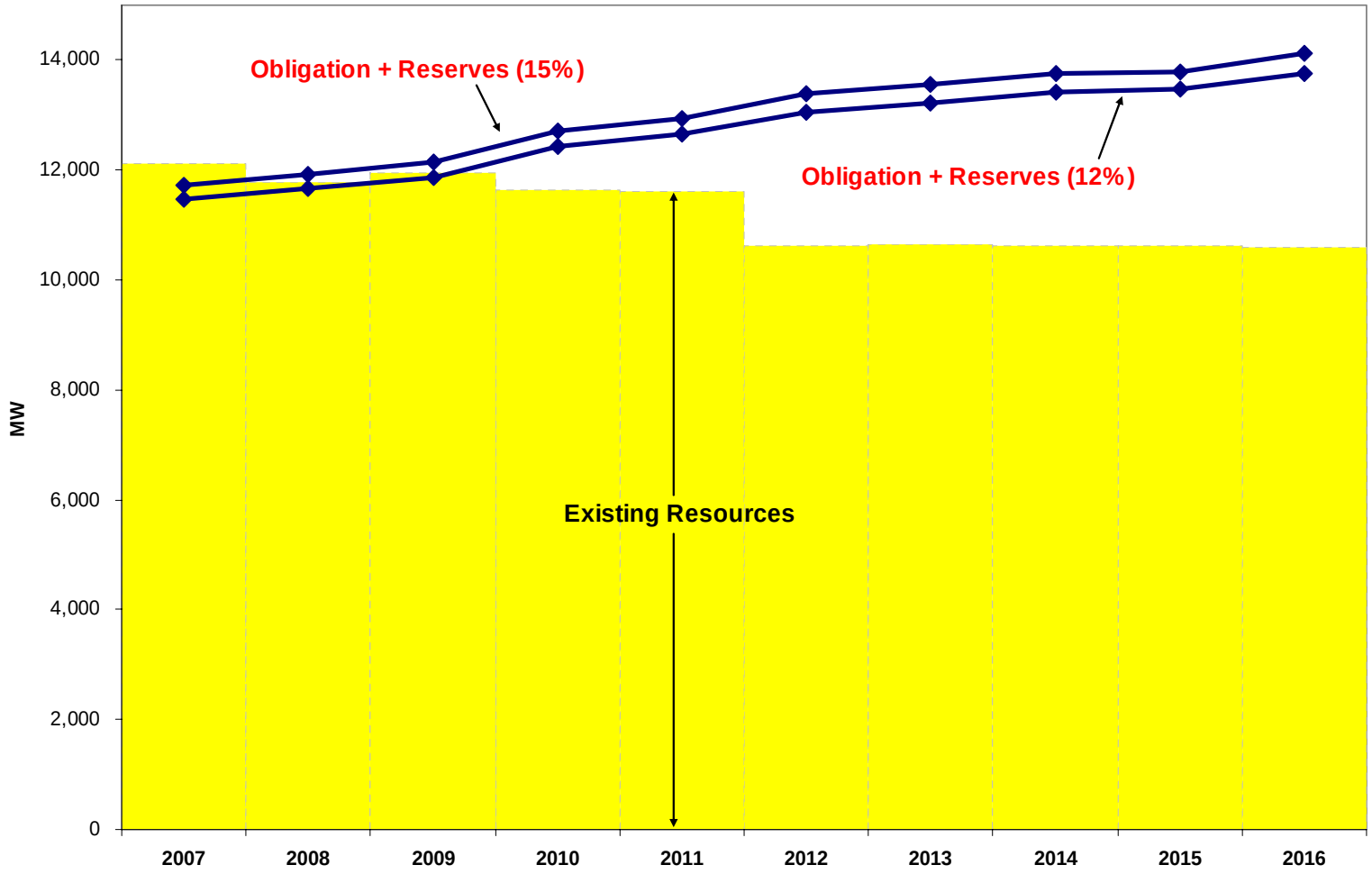
- Definitions
  - Existing Resources = Thermal + Hydro + Dispatchable Load Control + Renewable + Purchases + Qualifying Facilities + Interruptible
  - Obligation = Retail Load + Wholesale Sales
  - Planning Reserves = (Obligation – Firm Purchases – Load Curtailment Resources) * Planning Reserve Margin
  - Reserves = Planning Reserves + Non-owned Reserves

Capacity Balance Changes from April 2006

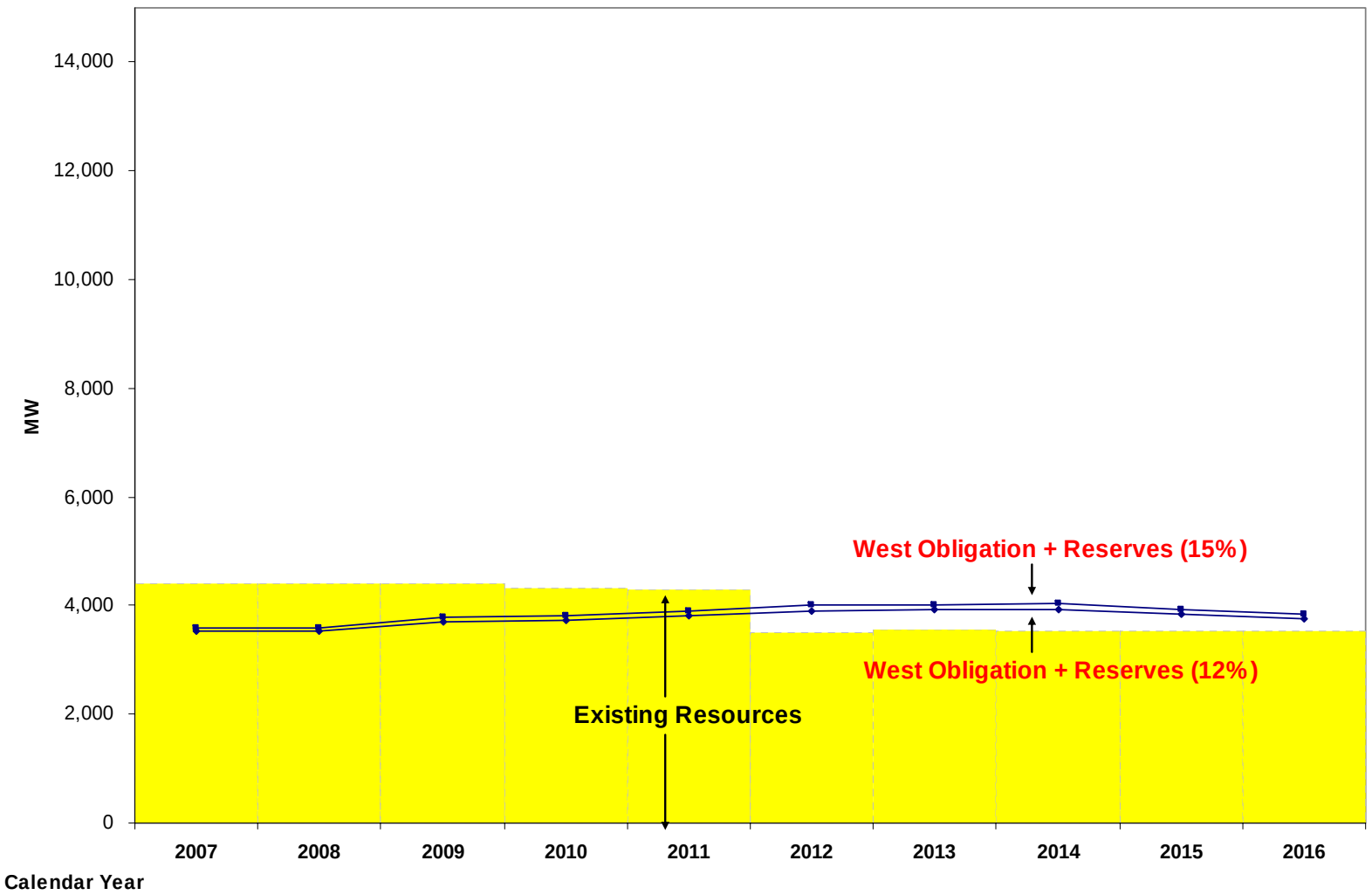
Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
System (4/2006)										
Total Resources	12,288	11,920	11,974	11,832	11,718	10,798	10,822	10,686	10,685	10,662
Obligation	10,462	10,858	10,965	11,163	11,359	11,426	11,627	11,844	11,975	12,163
15% Reserves	1,300	1,391	1,407	1,455	1,492	1,628	1,654	1,707	1,726	1,758
Obligation + 15% Reserves	11,761	12,248	12,372	12,618	12,851	13,053	13,281	13,551	13,702	13,921
System Position	527	(328)	(398)	(786)	(1,133)	(2,255)	(2,459)	(2,865)	(3,016)	(3,259)
Reserve Margin	21%	13%	12%	8%	6%	-4%	-6%	-9%	-10%	-11%
System (4/2007)										
Total Resources	12,131	11,780	11,948	11,631	11,605	10,611	10,663	10,624	10,620	10,598
Obligation	10,391	10,549	10,753	11,217	11,409	11,688	11,842	12,010	12,050	12,321
15% Reserves	1,324	1,378	1,383	1,487	1,524	1,691	1,710	1,740	1,746	1,790
Obligation + 15% Reserves	11,715	11,927	12,136	12,703	12,932	13,380	13,552	13,750	13,796	14,111
System Position	415	(147)	(188)	(1,073)	(1,327)	(2,768)	(2,890)	(3,126)	(3,176)	(3,513)
Reserve Margin	19%	14%	13%	5%	3%	-9%	-9%	-11%	-11%	-14%
System Changes										
Total Resources	(158)	(140)	(26)	(201)	(113)	(187)	(159)	(63)	(65)	(65)
Obligation	(71)	(309)	(212)	54	49	263	215	165	74	157
15% Reserves	25	(12)	(24)	31	32	63	56	34	20	33
Obligation + 15% Reserves	(46)	(321)	(237)	86	81	326	271	199	95	190
System Position	(112)	181	210	(286)	(194)	(513)	(431)	(262)	(160)	(255)
Reserve Margin	-2%	1%	1%	-3%	-2%	-4%	-4%	-2%	-2%	-2%
Drivers										
Existing Resources	(158)	(140)	(26)	(201)	(113)	(187)	(159)	(63)	(65)	(65)
Sale	100	85	73	58	44	30	30	30	30	30
Load	(171)	(394)	(286)	(4)	5	232	185	135	44	127

- Major changes to existing resources
  - BPA Summer Exchange (-101 MW), Desert Power QF (-95 MW) Exxon Power QF (-72 MW)
- Major changes to sales
  - Public Service of Colorado sale (+70 MW)
- Load trend
  - Lower in early years and higher in later years

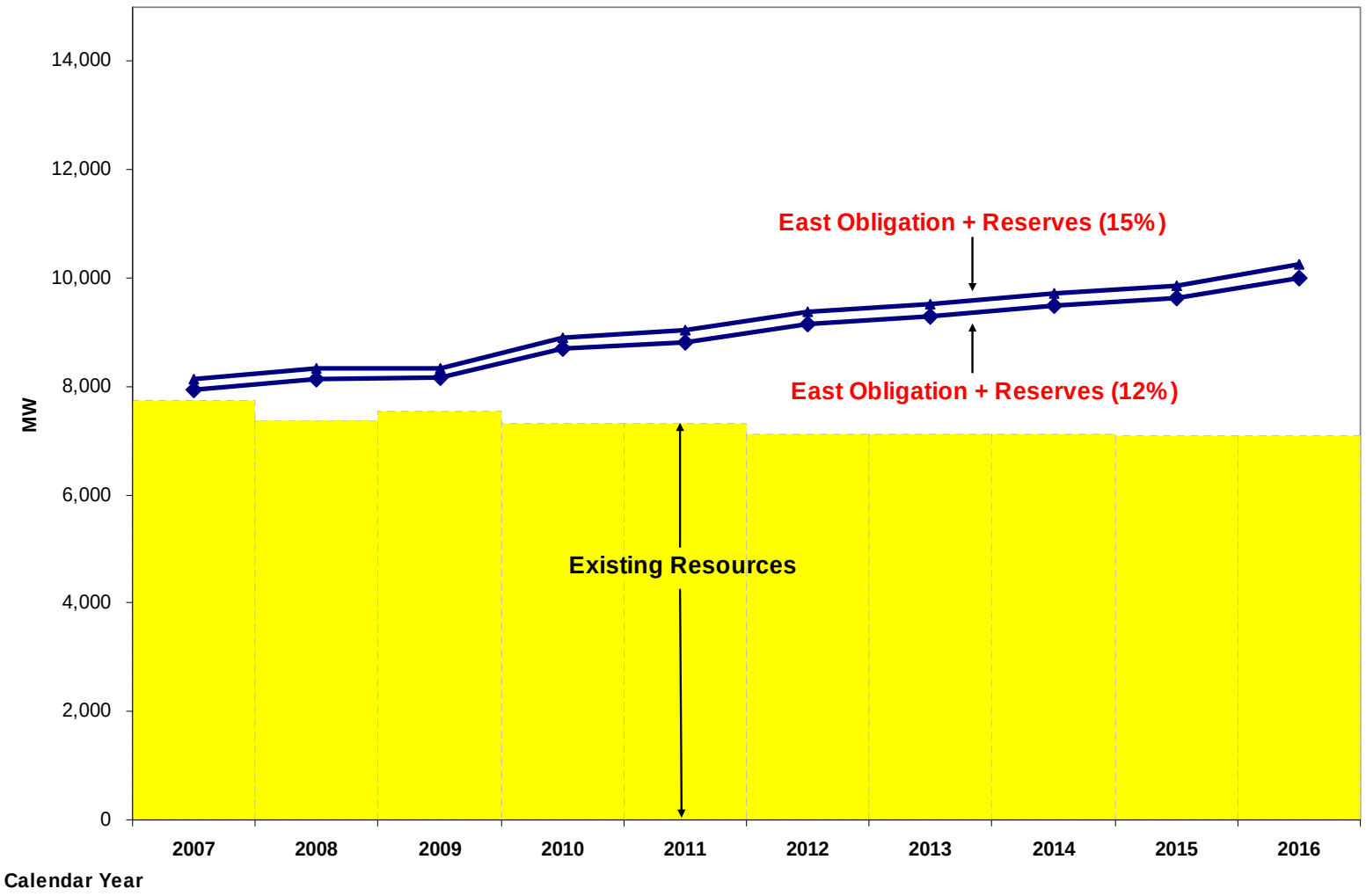
System Capacity Chart



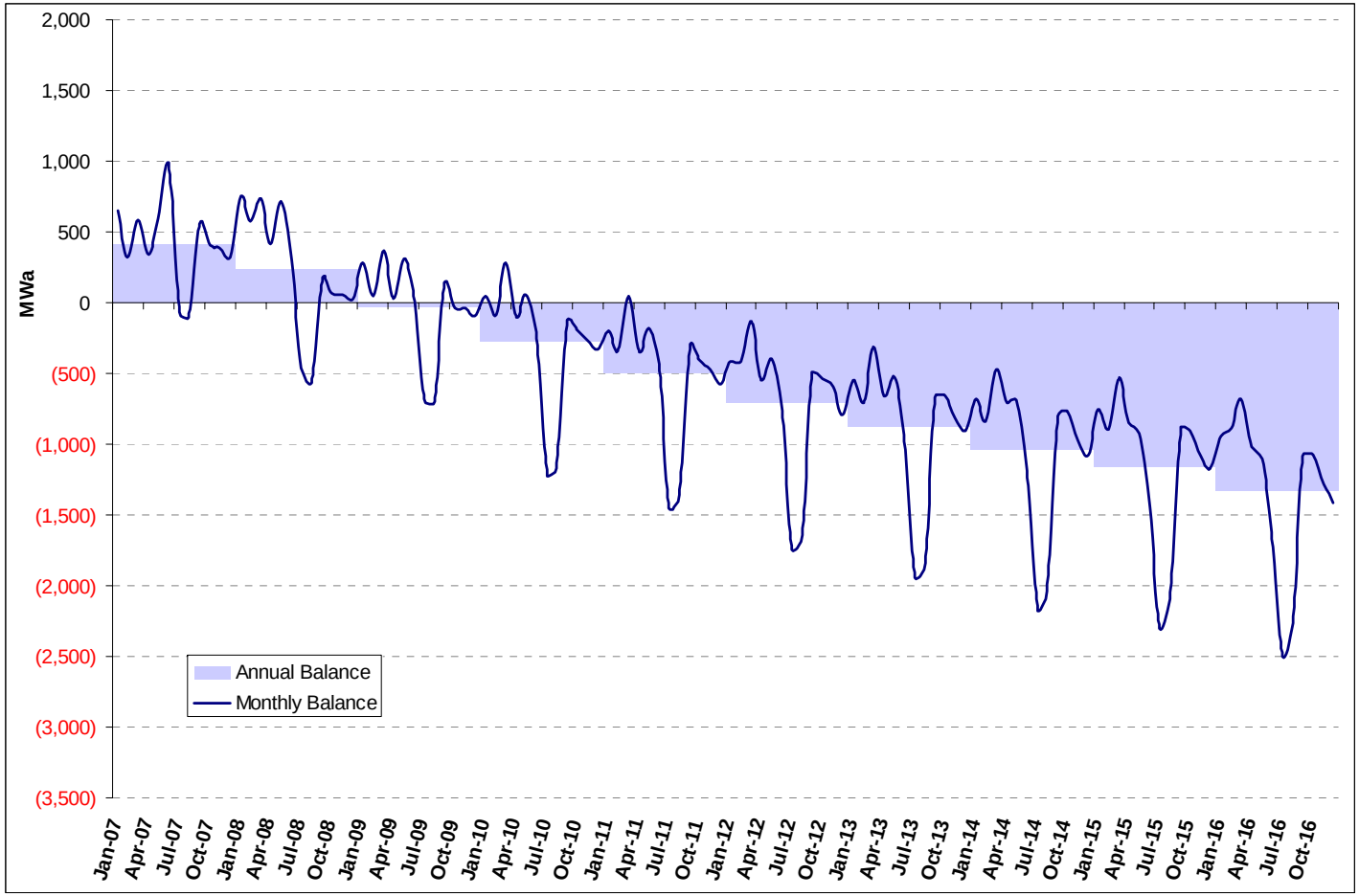
West Capacity Chart



East Capacity Chart



Monthly and Annual Average Energy Balance



- Assumes critical water hydro and a 12 percent planning reserve margin
- Energy from Gadsby units assumed to be available during heavy load hours
- Does not include economic considerations (addressed with IRP models)

Load and Resource Balance Observations

Capacity (12% planning reserve margin)

- Resource deficit starts at 791 MW in 2010
  - Increased load of 509 MW from 2009 to 2010 (5.2%)
- Deficit increases to 2,446 MW in 2012
  - Expiration of BPA Peaking contract
  - Reduction of Mid-Columbia contracts
  - Increased load of 1,592 MW from 2007 to 2012 (3.2% avg)
- Deficit increases to 3,171 MW in 2016
  - Increased load of 2,375 MW from 2007 to 2016 (2.6% avg)

Energy

- When not considering economic implications, on an annual basis the company becomes energy deficient by 2009

Preferred Portfolio

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PacifiCorp's 2007 IRP Preferred Portfolio

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combine Cycle CT	2x1 F class with duct firing						548				
	Combine Cycle CT	1x1 G class with duct firing										357
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	-	46	-	-	-	-	-
West	Combine Cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	687	330	730	739	442	491	463
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**839**	**1,125**	**318**	**527**	**-**	**357**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**687**	**376**	**730**	**739**	**442**	**491**	**463**
	Total Annual Additions		**300**	**300**	**100**	**999**	**1,216**	**1,856**	**1,057**	**969**	**491**	**820**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

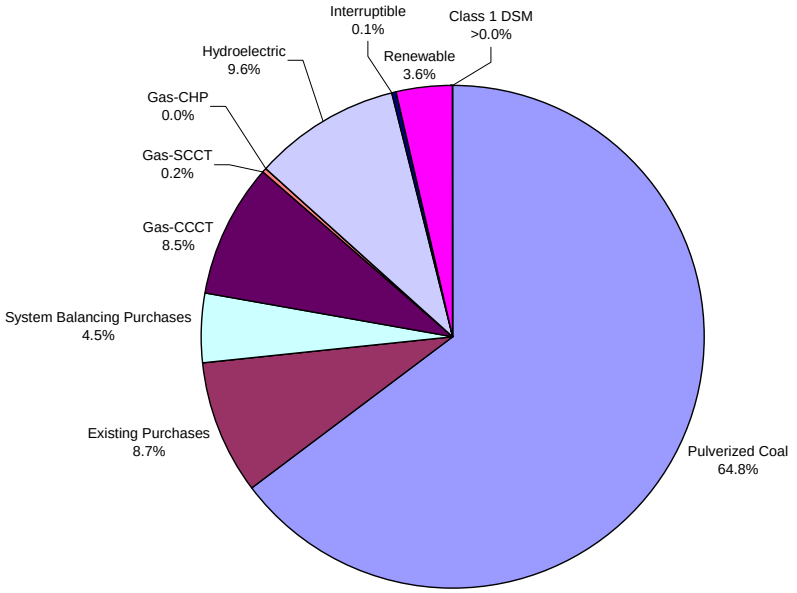
		Transfer Capability, Megawatts									
	Resource	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Path C Upgrade: Borah to Path-C South to Utah North				300						
	Utah - Desert Southwest (Includes Mona - Oquirrh)						600				
	Mona - Utah North						400				
	Craig-Hayden to Park City						176				
	Miners - Jim Bridger - Terminal						600				
	Jim Bridger - Terminal								500		
West	Walla Walla - Yakima				400						
	West Main - Walla Walla					630					
	Total Annual Additions	**-**	**-**	**-**	**700**	**630**	**1,776**	**-**	**500**	**-**	**-**

- Preferred Portfolio is Risk Analysis Portfolio No. 14 (RA14)

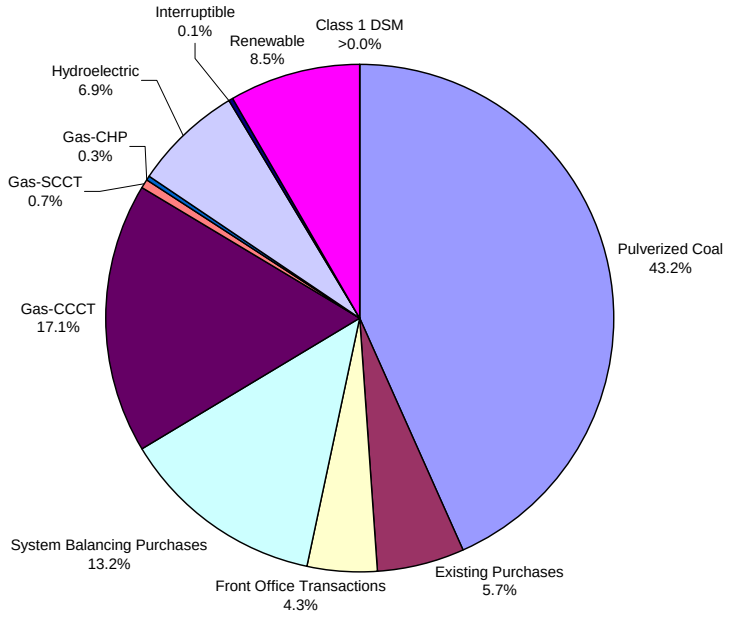
Portfolio Evaluation and Risk Analysis Conclusions (Continued)

- The preferred portfolio makes significant strides in diversifying generation; the pie charts below show the large shift to renewables, gas, and market purchases with a CO_2 adder in place

2007 Resource Energy Mix with Preferred Portfolio Resources
(Average for five CO2 Adder Cases)



2016 Resource Energy Mix with Preferred Portfolio Resources
(Average for five CO2 Adder Cases)



2007 Action Plan

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2007 IRP Action Plan

Item	Action Type	CY Timing	**Size** (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
1	New Renewables	2007 - 2013	2,000	System	Wind	Acquire 2,000 MW of renewables by 2013, including the 1,400 MW outlined in the Renewable Plan. Seek to add transmission infrastructure and flexible generating resources, including the potential of accelerating a natural gas plant to complement the accelerated and expanded acquisition of renewable wind facilities.
2	Existing and New Class 2 DSM programs	2007 - 2016	450 MWa	System	100 MW decrements at various load shapes	Use decrement values to assess cost-effectiveness of new program proposals. Acquire the base DSM (PacifiCorp and ETO combined) of 250 MWa and up to an additional 200 MWa if cost-effective initiatives can be identified. Will reassess Class 2 objectives upon completion of system-wide DSM potential study to be completed by June 2007. Will incorporate potentials study findings into the 2007 update and 2008 integrated resource planning processes.
3	New Class 1 DSM programs	2007 - 2016	100	East - 50 West - 50	East and West irrigation load control, East summer loads	Targets were established through potential study work performed for the 2007 IRP. A new potential study is expected to be completed by June 2007, and associated findings will be incorporated into the 2007 update and the 2008 integrated resource planning processes.
4	Existing and New Class 3 DSM programs	2007 - 2016	To be determined	System	Class 3: demand buy-back, hourly pricing, seasonal pricing, etc. Class 4: system messaging and education	Although not currently in the base resource stack, the company will seek to leverage Class 3 and 4 resources to improve system reliability during peak load hours. Will incorporate potential study findings into the 2007 update and/or 2008 integrated resource planning processes.
5	Combined Heat and Power (CHP)	2007-2012	100	System	25 MW steam topping cycle CHP; 5 MW gas combustion turbine CHP	Pursue at least 75 MW of CHP generation for the west-side and 25 MW for the east-side, to include purchase of CHP output pursuant to PURPA regulations and from supply-side RFP outcomes. The potential study results will be incorporated into the 2007 update and 2008 integrated resource planning processes

2007 IRP Action Plan (continued)

Item	Action Type	CY Timing	**Size** (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
6	Standby Generators	2007-2012	To be determined	System	60 MW of diesel engine capacity on the west side	Will incorporate potential study findings into the 2007 update and 2008 integrated resource planning processes
7	Baseload / Intermediate	2012	550	East	CCCT (Wet "F" 2X1) with duct firing	Procure a baseload / intermediate resource in the east by the summer of 2012. This is part of the requirement included in the 2012 RFP
8	Baseload / Intermediate	2012	350	East	Supercritical pulverized coal (340 MW Utah unit)	Procure a baseload / intermediate resource in the east by the summer of 2012. This is part of the requirement included in the 2012 RFP
9	Baseload / Intermediate	2014	550	East	Supercritical pulverized coal (527 MW Wyoming unit)	Procure a baseload / intermediate resource in the east by the summer of 2014. This is part of the requirement included in the 2012 RFP
10	Baseload / Intermediate	2016	350	East	CCCT (Wet "G" 1X1) with duct firing	Procure a baseload / intermediate resource in the east by the summer of 2016. This is not part of the requirement included in the 2012 RFP
11	Baseload / Intermediate	2011	600	West	CCCT (Wet “F” 2X1) with duct firing	Procure a baseload / intermediate resource in the west by the summer of 2011 - 2012
12	Baseload / Intermediate	2010-2016	300-700	West	Front office transactions - flat annual product	Procure baseload / intermediate resource in the west beginning in the summer of 2010
13	Transmission	2010 and beyond	Various	System	Path C Upgrade Utah - Desert Southwest Mona - Utah North Craig Hayden - Utah North Miners - Utah North Jim Bridger - Utah North Walla Walla - Yakima Walla Walla - West Main	Pursue the addition of transmission facilities or wheeling contracts as identified in the IRP to cost-effectively meet retail load requirements, integrate wind and provide system reliability. Work with other transmission providers to facilitate joint projects where appropriate

2007 IRP Action Plan (continued)

Item	Action Type	CY Timing	**Size** (rounded to the nearest 50 MW for generation resources)	Location	IRP Proxy Resource Modeled	Action
14	Strategy and Policy: Climate Change	Ongoing	Not applicable	System	Not applicable	Continue to have dialogue with stakeholders on Global Climate Change issues
15	Strategy and Policy: Carbon Reducing Technology	Ongoing	Not applicable	System	Not applicable	Evaluate technologies that can reduce the carbon dioxide emissions of the company's resource portfolio in a cost-effective manner, including but not limited to, clean coal, sequestration, and nuclear power
16	IRP: Modeling and Analysis	2007-2008	Not applicable	System	Not applicable	Continue to investigate implications of integrating at least 2,000 MW of wind to PacifiCorp's system
17	IRP: Modeling and Analysis	2007-2008	Not applicable	System	Not applicable	Update modeling tools and assumptions to reflect policy changes in the area of renewable portfolio standards and carbon dioxide emissions
18	IRP Acknowledge-ment: Policy and cost recovery	2007	Not applicable	System	Not applicable	Work with states to gain acknowledgement or acceptance of the 2007 integrated resource plan and action plan. To the extent state policies result in different acknowledged plans, work with states to achieve state policy goals in a manner that results in full cost recovery of prudently incurred costs

- The 2007 Action Plan was developed using the Preferred Portfolio - Risk Analysis Portfolio 14 (RA14)

Portfolio Modeling Update

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Risk Analysis Portfolio Development

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Overview of Risk Analysis Portfolio Development

- Risk analysis portfolios (formerly called "Candidate Portfolios") refer to portfolios that were subjected to stochastic production cost simulation using the Planning and Risk module
  - Based on manual specification of portfolios to reflect different resource strategies (defer conventional coal resources, include additional renewables, use an alternate planning reserve margin, etc.)
  - Includes fixed investment schedules for renewables, Class 1 DSM, and combined heat and power
    - based on assessment of "alternative future" scenario studies
  - Obtained from one or more CEM runs; the CEM was used to:
    - Select the type and timing of resources
    - test the robustness of a resource under different portfolio assumptions
    - Establish the amount of market purchases needed to balance the system after other resources have been added to the portfolio
  - CEM inputs reflect "medium case" assumptions, including \$8/ton CO_2 adder escalated using PacifiCorp's inflation forecast

Overview of Risk Analysis Portfolio Development (Continued)

- Stochastic analysis of portfolios conducted in two phases
  - Original 12 portfolios ("Group 1")
    - Based on the May 2006 load forecast
    - Results distributed to participants after the February 1, 2007 public meeting
  - Five new portfolios ("Group 2")
    - One of the five portfolios was constructed with the Business Plan baseload resources, and serves as a base case for comparison against the others
    - Alternative portfolios designed in consideration of new/evolving state resource policies, public feedback on the IRP and RFP, and IRP acknowledgement hurdles expected in each state
    - Based on the March 2007 load forecast
    - Includes updated resource assumptions to conform to PacifiCorp's 10-year Business Plan
  - Both portfolio groups use the same natural gas and electricity price curves (August 2006); difference between August and December 2006 curves is small

Group 2 Portfolio Development – Resource Assumptions

- Resource assumptions for the four alternative portfolios
  - Include two supercritical pulverized coal resources: small Utah (340 MW) and Wyoming (Bridger 5)
    - CEM chose two coal plants for 2012–2014 in all portfolios for which the model was allowed to optimize their selection and timing
    - Stochastic simulations indicated that removing or deferring these coal resources raised both portfolio cost and risk, even under the higher CO2 adder cases
    - To be consistent with Business Plan resource assumptions, the Wyoming coal resources were resized from 750 MW each to 527 MW. Also, the large Utah resource was changed from 600 MW to 575 MW
    - The CEM was allowed to select the small Utah unit for 2012 or 2013 only, while the Wyoming resource could be acquired in any year after 2013
  - West IGCC resources were removed as options for all portfolios

Group 2 Portfolio Development – Resource Assumptions (Continued)

- No restrictions placed on the type and timing of gas resources for initial CEM resource screening runs
- Wind resource assumptions:
  - Developed two wind investment schedules predicated on accelerated acquisition to take advantage of the renewables production tax credit
    - » Business Plan schedule includes 1,000 MW acquired by 2013 (400 MW already factored in the resource balance)
    - » Alternative schedule includes 1,600 MW: 1,000 MW by 2010 and another 600 MW acquired from 2011 – 2013
    - » Increased capacity factor of southeast Wyoming wind resources from 32% to 40% to reflect updated operational expectations for these wind sites
- CEM allowed to select front office transactions after 2011; no constraints placed on amounts
- 100 MW Desert Power qualifying facility and Blundell geothermal expansion project removed (consistent with Business Plan)

Group 2 Portfolio Development – Resource Assumptions (Continued)

- Incorporated the following set of transmission resources in all the Group 2 portfolios:
  - Path C Upgrade: Borah to Path-C South to Utah North
  - Utah - Desert Southwest, including Mona – Oquirrh (This resource was included in the Business Plan)
  - Mona - Utah North
  - Craig - Hayden to Park City
  - Miners - Jim Bridger - Terminal
  - Jim Bridger - Terminal
  - Walla Walla - Yakima
  - West Main - Walla Walla
- Transmission resources supported by previous portfolio analysis, and are consistent with both the Business Plan and MEHC transmission commitments
  - A reminder that these resources represent proxies for future transmission requirements, and could lead to new wheeling contracts or construction of transmission facilities either by the company or as a joint project with others

Group 2 Portfolio Development – Resource Screening

- CEM screening runs designed to test
  - The timing of the two coal resources
  - The combination of gas resources versus front office transactions selected to address east-side load growth
  - The timing and type of resources needed to make up for the loss of the BPA peaking contract in August 2011 (i.e., determine the resource selection impact of removing the contract in 2011 rather than 2012 to ensure that new resources are selected to meet load by August 2011)
- Key Findings
  - The Utah coal resource was always selected in 2012, while the Wyoming supercritical coal resource was always selected in 2014
  - When the CEM was allowed to optimize the selection and timing of gas resources, it chose a combination of CCCTs and SCCT frames
  - The west CCCT was always selected in 2012
  - Restricting the model to choose only CCCTs resulted in just one east CCCT selected in 2012 along with the west CCCT in 2012
  - Removing the BPA contract in 2011 (as opposed to 2012) had no effect on the timing of the west CCCT, assuming unlimited availability of front office transactions in 2011

Group 2 Portfolio Development – Final Resource Specifications

ID	Description	Design Rationale	Features
RA13	An updated "Base Case" resource proposal that mirrors the original PacifiCorp Business Plan's baseload resources. This portfolio, based on a 12% planning reserve margin, includes four supercritical pulverized coal resources: the small Utah SCPC (2012), the Wyoming SCPC (2014), the large Utah SCPC (2017), and the second Wyoming SCPC (2018).	This portfolio serves as the reference portfolio for comparison with the other risk analysis portfolios. It reflects a coal- and market-intensive resource strategy.	• Based on the revised load forecast (March 2007) • Wind investment schedule assumed for original Business Plan • All portfolios use the same transmission investment schedule
RA14	This portfolio addresses the revised load forecast by adding two east CCCTs: one in 2012 (2x1 F type) and one in 2016 (1x1 G type).	Tests the strategy of meeting east load growth with CCCTs as opposed to the market.	• Based on the revised load forecast (March 2007) • Small Utah SCPC plant acquired in 2012 • Wyoming SCPC acquired in 2014 • West CCCT acquired in 2011 • Revised wind investment schedule (1,400 MW by 2010; 600 MW by 2013 – Total of 2,000 MW by 2013) • All portfolios use the same transmission investment schedule • 12% Planning reserve margin except RA16
RA15	This portfolio addresses the revised load forecast by adding just one east CCCT in 2012. A 12% planning reserve margin is met with front office transactions.	Tests the strategy of meeting east load growth with a mix of CCCT capacity and the market.	
RA16	RA14 based on a 15% planning reserve margin; the higher reserve margin is met with CCCT capacity and front office transactions	Tests the consequences of meeting the higher planning reserve margin with market resources.	
RA17	This portfolio addresses the revised load forecast by relying on front office transactions only.	Tests the strategy of using market purchases to meet the increased forecasted load.	

- Combined cycle plants chosen as the proxy for gas-fired resources
  - Better economics than single cycles due to capture of extrinsic (or optionality) value in stochastic modeling
  - CO_2 emission rate of a single cycle does not meet the California greenhouse gas emission performance standard
- Except for the base case portfolio (RA13), all have a west CCCT added in 2011 to ensure that a resource is available to meet west-side load by August 2011

Cost and Risk Performance Results

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Stochastic Mean Cost

ID	Stochastic Mean PVRR (Million $)						Rank
	$0 Adder (2008$)	$8 Adder (2008$)	$15 Adder (2008$)	$38 Adder (2008$)	$61 Adder (2008$)	Average	
RA13	21,575	21,979	22,251	22,641	22,685	22,226	4
RA14	21,344	21,649	21,775	21,636	21,130	21,507	1
RA15	21,593	21,923	22,063	22,005	21,600	21,837	3
RA16	21,584	21,892	22,013	21,866	21,339	21,739	2
RA17	22,149	22,506	22,668	22,764	22,559	22,529	5

- Portfolio RA14 has lowest cost at each adder level
- RA17 has highest cost under $0, $8, $15 and $38 adders
- RA13 has highest cost under $61 adder
- Average cost deviation is about $200 million for $0 adder
  - Increases to over $600 million at $61 adder

Emissions Externality Cost

- Externality cost: Increase in stochastic mean PVRR for each CO_2 adder case relative to the $0 adder case

ID	Incremental Stochastic Mean PVRR by CO_2 Adder (Tax Strategy), Million $						
	CO_2 Adder Level (2008$)						
	$0	$8	$15	$38	$61	Average	Rank
RA13	-	4,013	6,085	13,244	20,451	10,948	5
RA14	-	3,915	5,841	12,470	19,127	10,338	2
RA15	-	3,940	5,880	12,589	19,349	10,440	3
RA16	-	3,918	5,838	12,460	19,097	10,328	1
RA17	-	3,967	5,928	12,792	19,752	10,610	4

ID	Incremental Stochastic Mean PVRR by CO_2 Adder (Cap and Trade Strategy), Million $						
	CO_2 Adder Level (2008$)						
	$0	$8	$15	$38	$61	Average	Rank
RA13	-	404	676	1,067	1110.00	814	5
RA14	-	306	431	292	(214.00)	204	2
RA15	-	331	471	412	7.00	305	3
RA16	-	308	429	283	(245.00)	194	1
RA17	-	357	518	615	410.00	475	4

- Two regulatory strategies used: cap-and-trade and a per-ton tax
- Portfolio rankings were the same for both strategies
- Portfolio RA16 had lowest externality cost, followed closely by RA14
- RA13 had highest externality cost due to the two additional coal plants
  - Only six percent higher than the best-performing portfolio, RA1
- Under cap-and-trade scheme, RA14 and RA16 have negative externality cost under $61 adder
  - Due to positive annual allowance balances accrued as a result of cap-and-trade assumptions
  - Future modeling work will focus on alternative specifications for CO2 compliance strategies

Stochastic Risk Measures

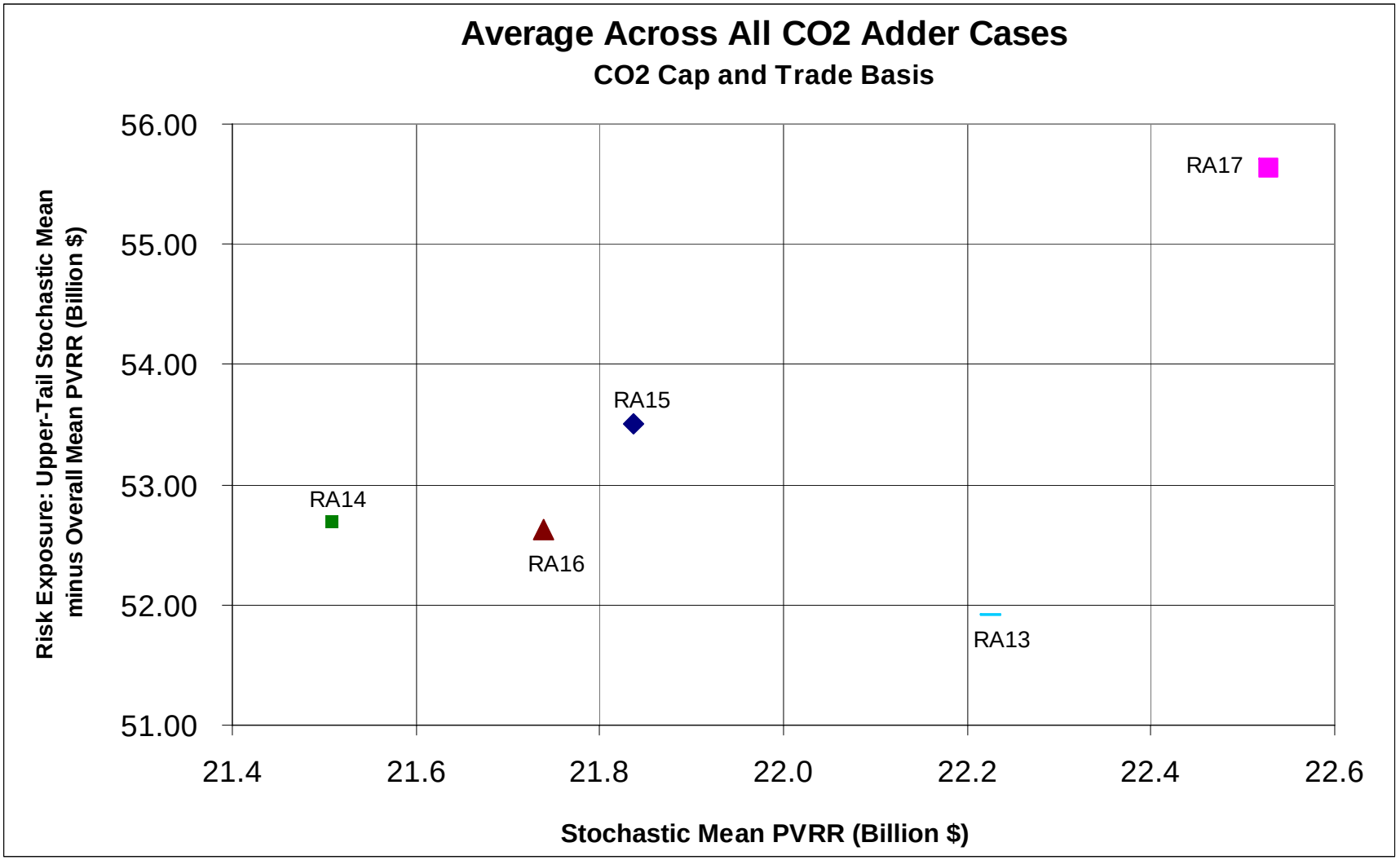
- Portfolio risk measures include risk exposure (Upper-Tail PVRR minus Mean PVRR), PVRR standard deviation, 5th percentile PVRR, and 95th percentile PVRR
- Portfolio RA13, with four pulverized coal plants, performed the best overall
- Followed by RA16 with its two east CCCT resources and 15% planning reserve margin
- RA17 has the highest risk due to heavy reliance on market
- RA14 performed the best on 5th percentile measure
  - Possible good performer under confluence of low-cost conditions

ID	Risk Exposure (Upper-Tail PVRR minus Mean PVRR)		Standard Deviation	5th Percentile	95th Percentile
	Million $	Rank			
$8 Adder (2008$)					
RA13	46,984	1	13,016	11,814	38,621
RA14	47,871	3	13,263	11,603	37,409
RA15	48,638	4	13,516	11,772	38,328
RA16	47,836	2	13,286	11,787	37,945
RA17	50,637	5	14,161	11,903	40,724
$61 Adder (2008$)					
RA13	64,344	1	18,544	6,708	48,221
RA14	65,029	3	18,728	4,622	45,205
RA15	65,959	4	18,992	5,214	46,094
RA16	64,929	2	18,735	4,867	45,595
RA17	68,378	5	19,735	6,163	49,173
Average Across Adder Cases					
RA13	51,911	1	14,598	10,590	41,434
RA14	52,694	3	14,813	9,759	39,679
RA15	53,509	4	15,069	10,129	40,583
RA16	52,630	2	14,829	10,044	40,168
RA17	55,628	5	15,741	10,637	43,164

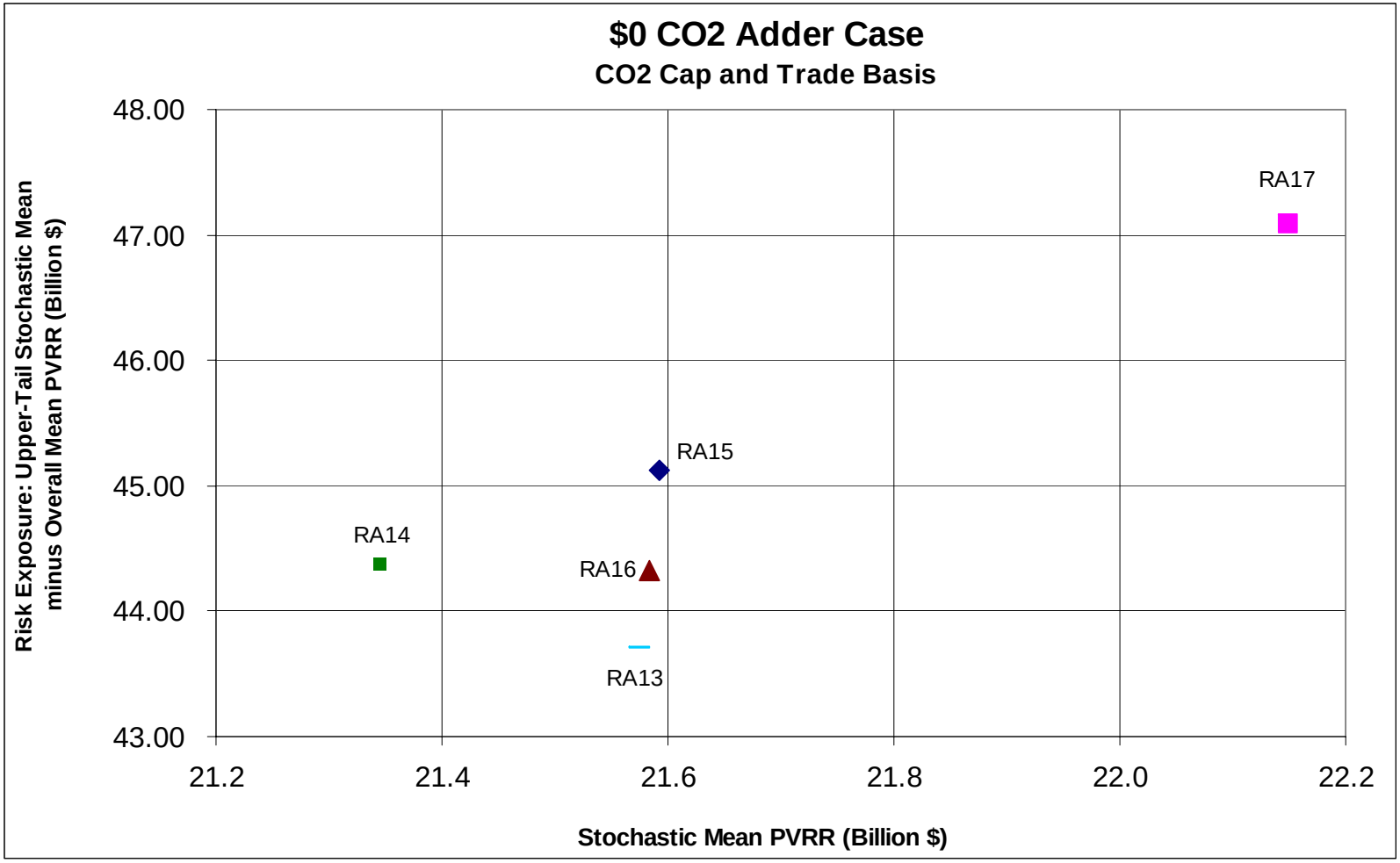
Cost/Risk Tradeoff Analysis

- PacifiCorp focused on three portfolio cost/risk tradeoff comparisons
  1. Average PVRR and risk exposure across $0, $8, $15, $38 and $61 CO_2 adder cases
  2. PVRR and risk exposure for $0 CO2 adder case
  3. PVRR and risk exposure for $61 CO2 adder case
- RA14 has the lowest cost and a moderate amount of risk exposure – has the best balance of cost and risk
  - Also the best balance for adders greater than $0
- RA17 has highest cost and risk

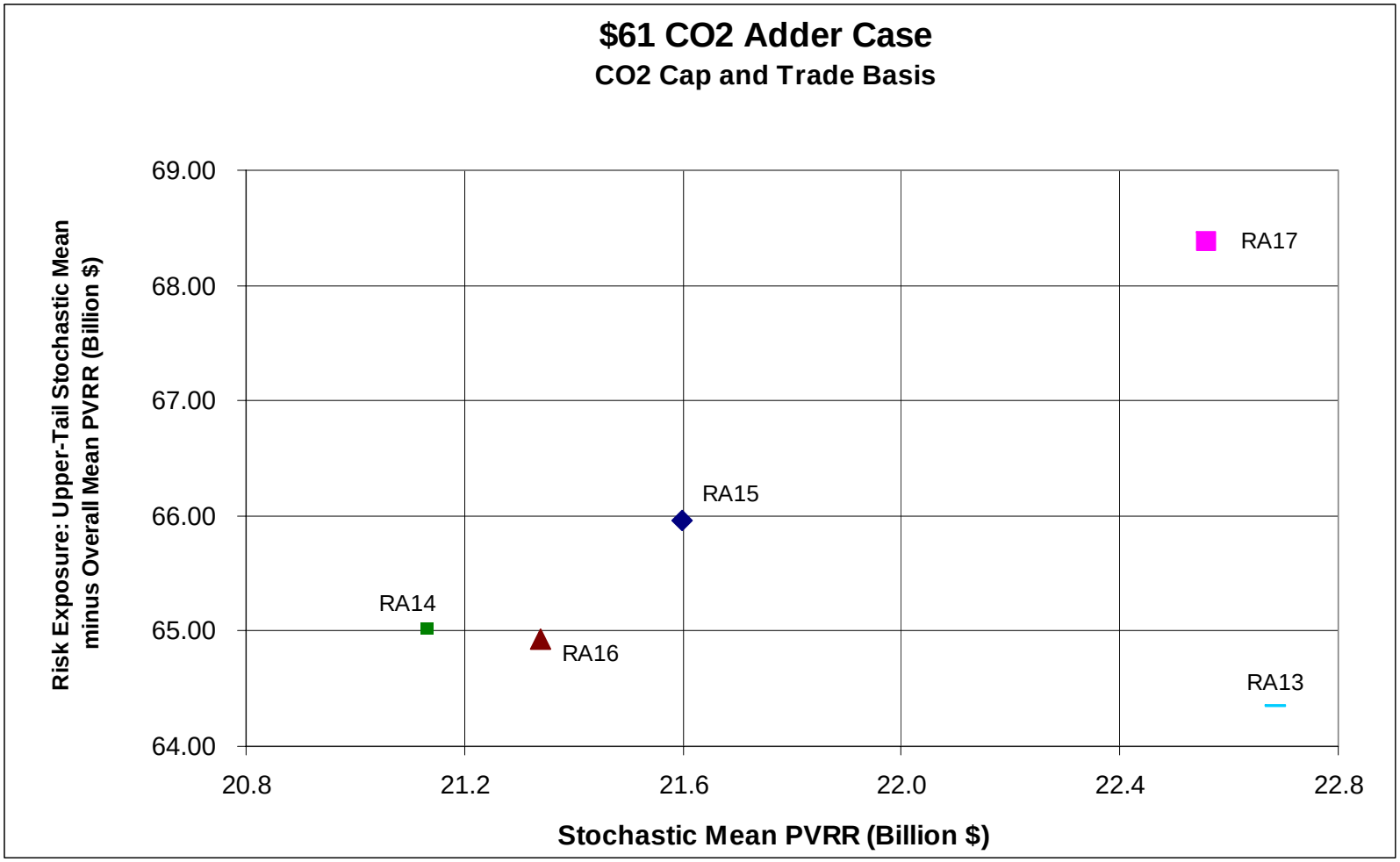
Cost/Risk Tradeoff Analysis (continued)



Cost/Risk Tradeoff Analysis (continued)



Cost/Risk Tradeoff Analysis (continued)



Customer Rate Impacts

Dan Swan

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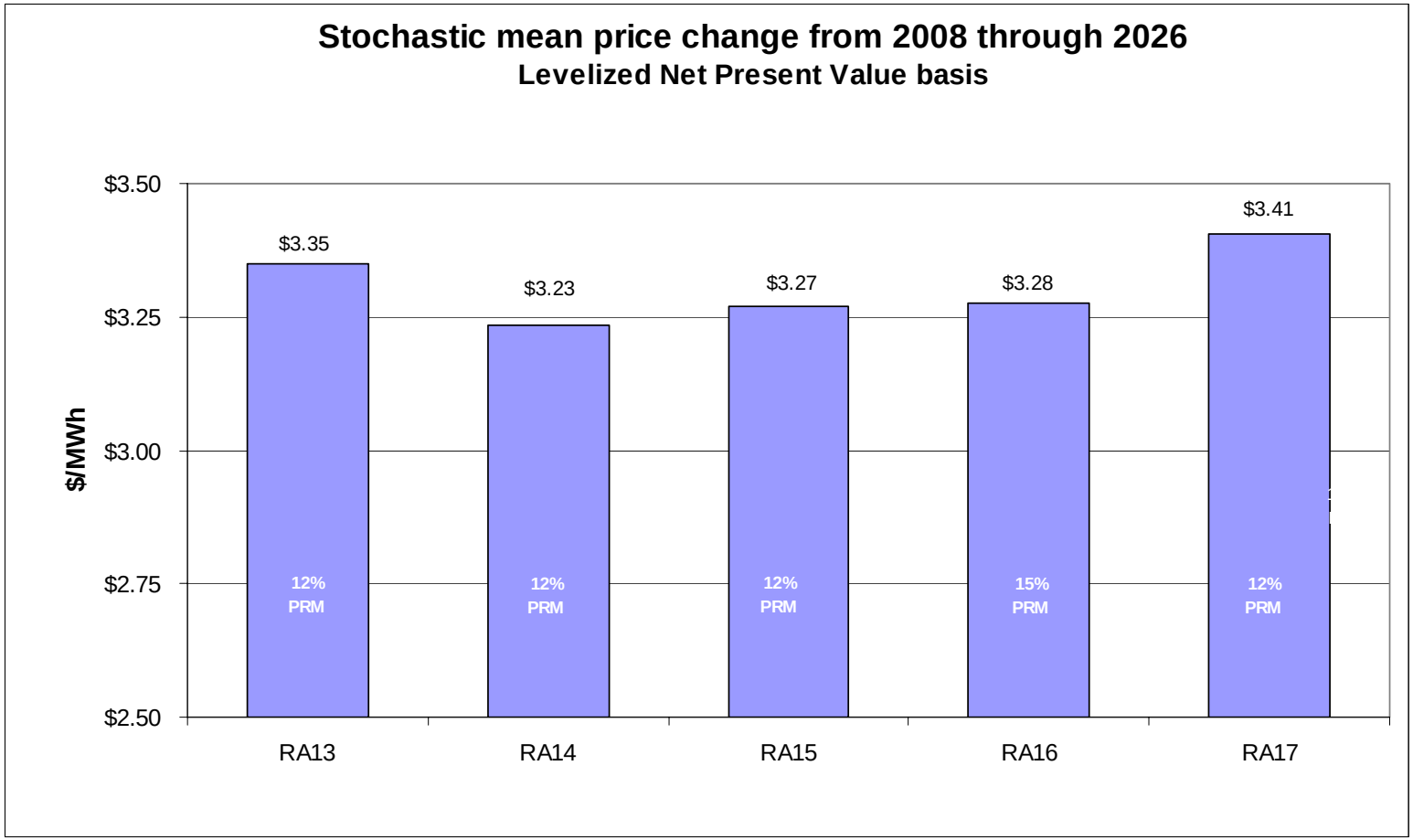
Customer Rate Impacts

- The $/MWh incremental customer rate impact associated with each portfolio was computed
- Change in customer $/MWh price for period 2008-2026, expressed on a levelized net present value basis
- Dollars numerator consists of the stochastic mean operating cost plus new IRP resources fixed costs
  - New IRP resource fixed costs are represented in 2006 dollars and grow with inflation but start in the year the resource added
- Denominator is retail load
- IRP revenue requirement is only a portion of the total Company revenue requirement impact (existing distribution, transmission, general plant and operating costs, fixed costs of existing generation assets)

Customer Rate Impact – Group 2

- The levelized customer rate for new resource additions at stochastic mean (levelized over 2008 to 2026) range from $3.23/MWh for the Preferred Portfolio (RA14) to $3.41/MWh for RA17
- The levelized customer rate impact varies by $0.18/MWh across the portfolios



Carbon Dioxide Emissions Footprint

Diane Lozovoy

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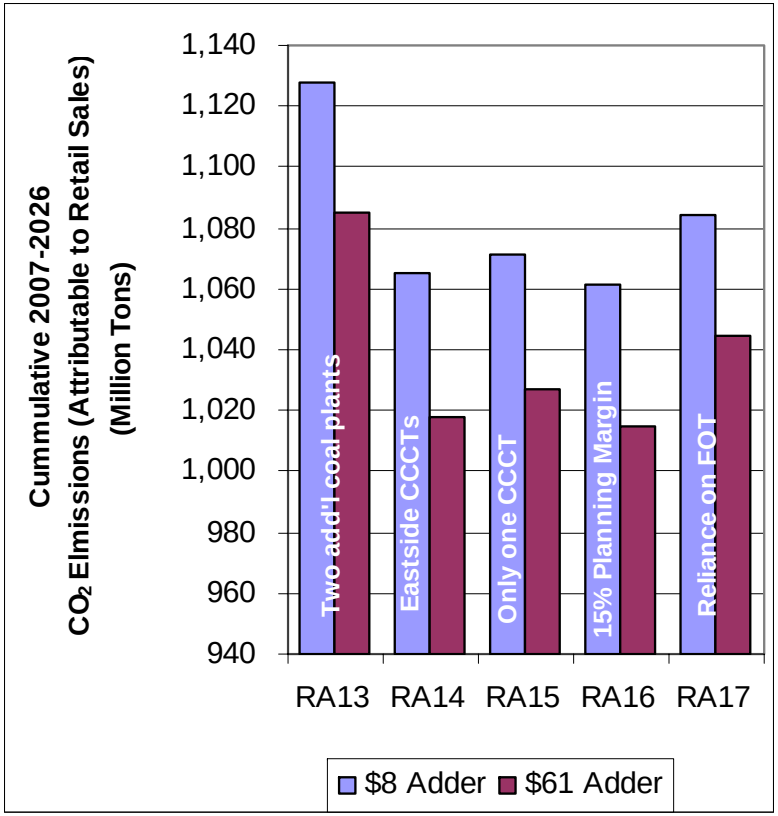
Emissions Modeling Approach

- The externality cost of emissions are included in both CEM and PaR
- Total emissions presented here modeled as part of the stochastic simulations done with PaR
- PaR model results include emission quantities
  - Carbon Dioxide (CO_2) , Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), and Mercury

CO_2 Conclusions from the Group 1 Studies

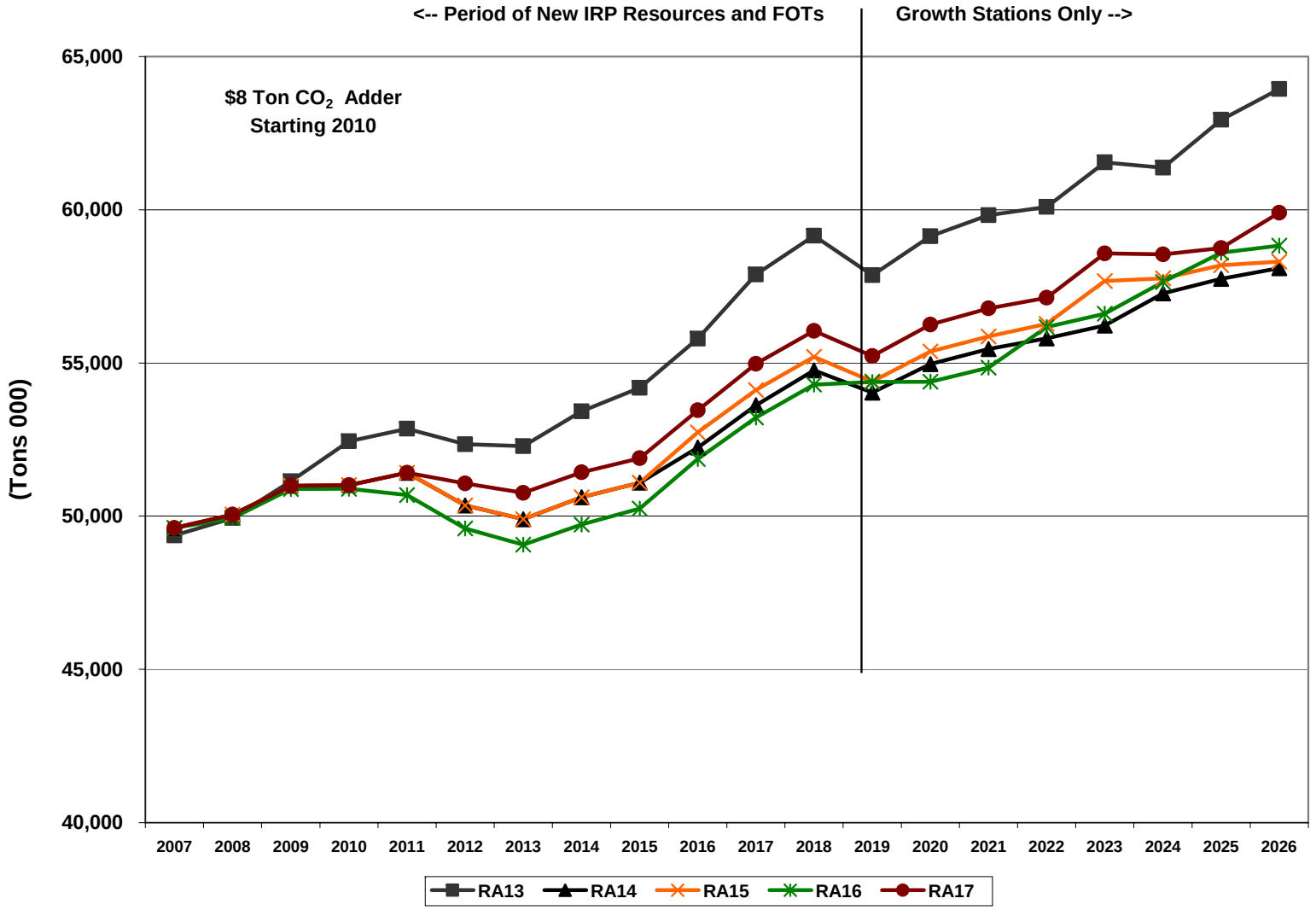
- Cumulative CO_2 emissions for each portfolio decline as the cost adder is increased
- Portfolios with large amounts of wind resources have lower externality cost
- Portfolios with lower planning reserve margins (12%) have higher emissions due to more reliance on existing coal resources

Group 2 CO_2 Emissions Footprint

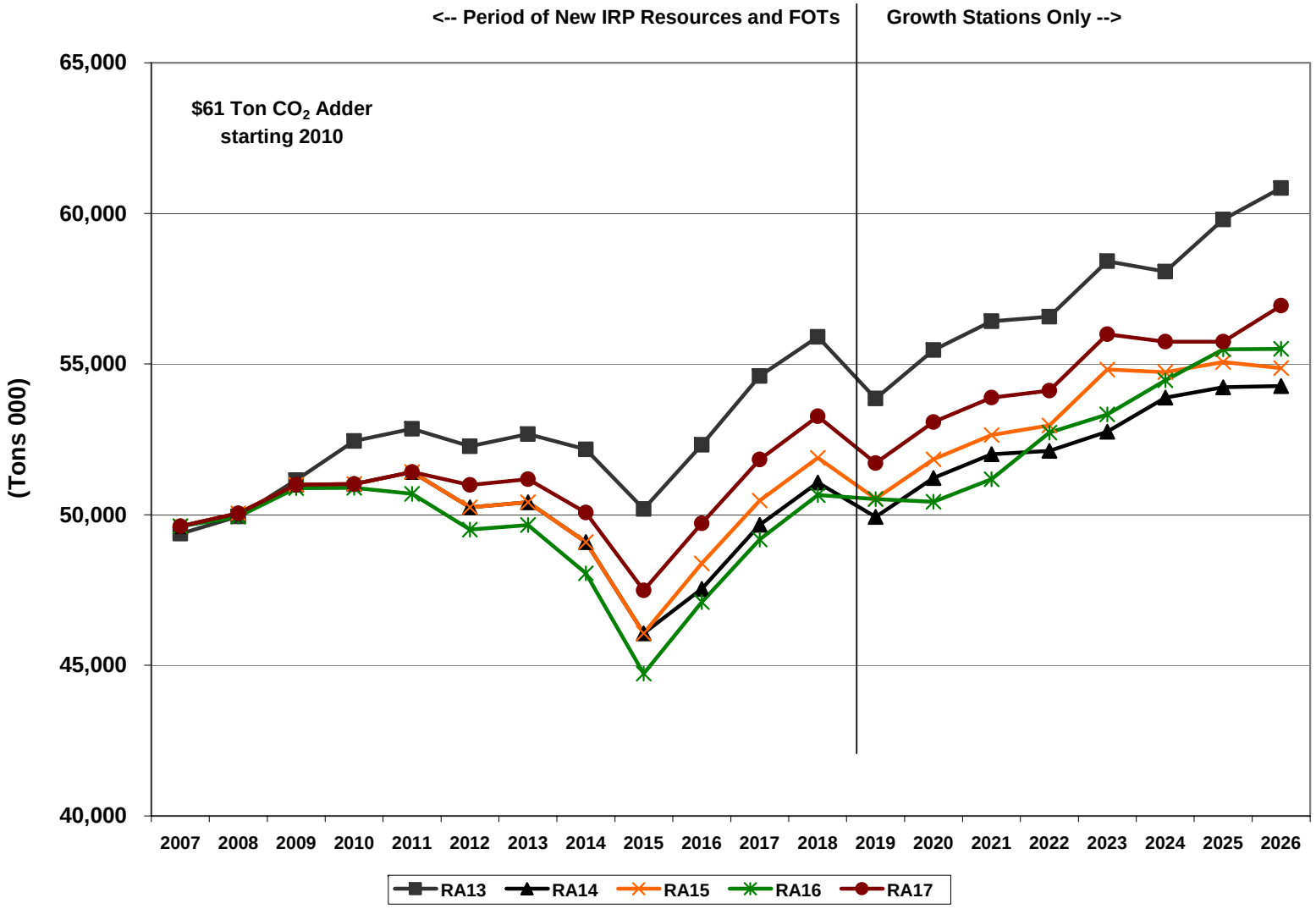


- Total CO_2 (tons)
  - Direct emissions from generating resources plus indirect emissions from purchases less emissions assumed to go with wholesale sales
- The overall range between highest and lowest emissions is less than 7% of the total
  - RA16 has lowest emissions (15% PRM)
  - RA14 is very close (CCCTs)
  - RA13 has the highest total emissions (4 Coal plants)

CO_2 Emission Trends, 2007-2026
($8 CO_2 Adder Case, Attributed to Retail Sales)



CO_2 Emission Trends, 2007-2026
($61 CO_2 Adder Case, Attributed to Retail Sales)



System Reliability

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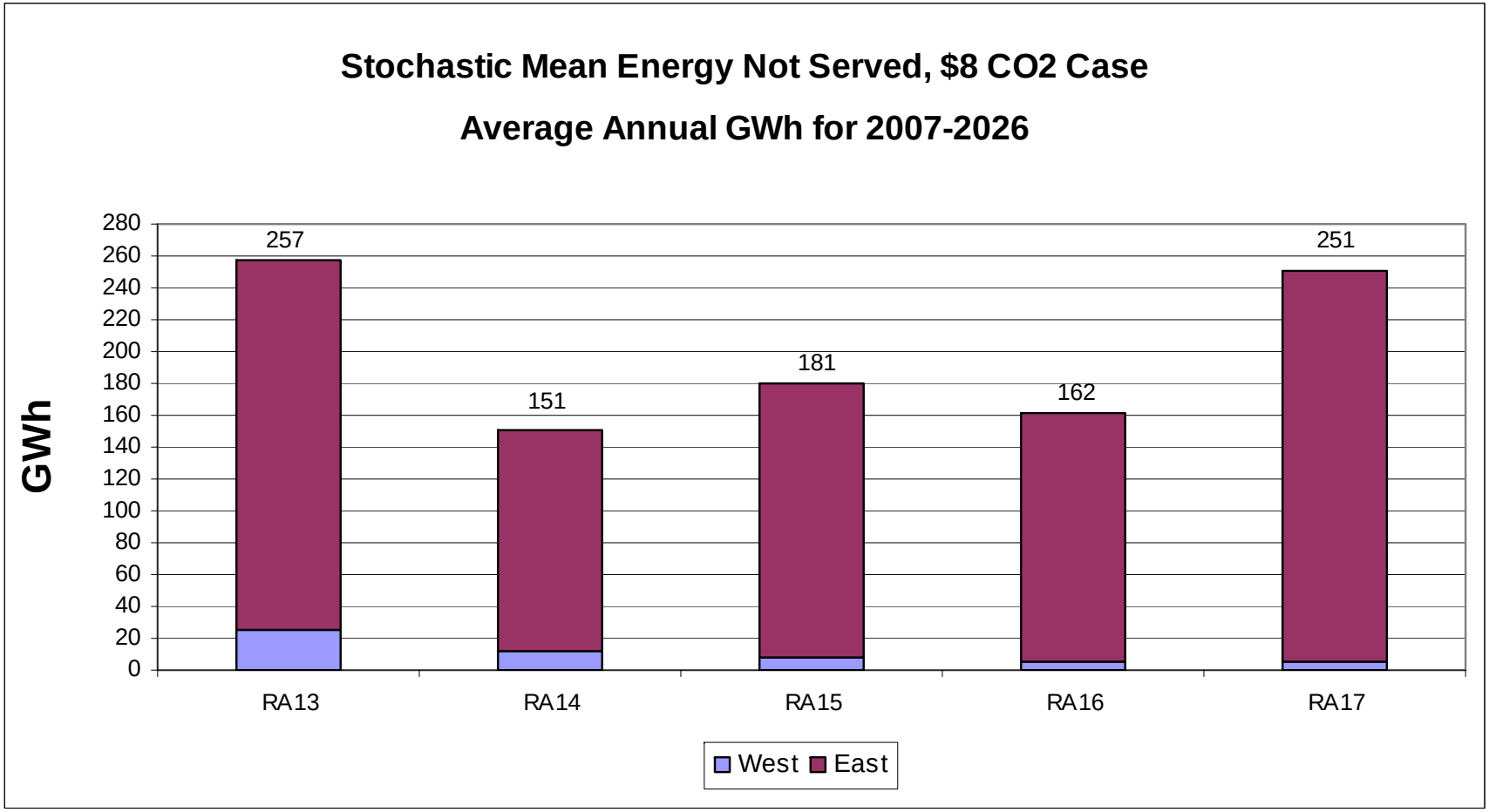
Measuring System Reliability

- PaR Stochastic Simulations
  - Energy Not Served (Quantity)
  - Loss of Load Probability using Energy Not Served (Probability)
- Energy Not Served (ENS)
  - Reported as MWh of energy demand not met
  - Prior to the occurrence of ENS – interruptible loads have been curtailed and reserves requirements are not met
- Causes of ENS include:
  - Load driven high by the stochastic parameters
  - Generating plant outages
  - Generation unable to get to load center
- Transmission outages are not modeled in PaR

Amount of Energy Not Served



Loss of Load Probability (LOLP)

- Loss of Load Probability (LOLP) is a traditional utility measure of reliability that accounts only for generator outages, assuming no uncertainty in demand

- Interconnected utilities and commercially driven market places lead utilities to a broader definition:
  - *Probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time.*

- This can be measured by the probability of the occurrence of Energy Not Served

Measuring Loss of Load Probability

- If defining Energy Not Served as a loss of load event, then PaR stochastic results can be used as a measure of LOLP by evaluating the individual iteration results
  - Considerations include timing, magnitude, and geography of an "Event"

- Keeping the analysis simple, count occurrences of ENS in July rolled up to the total system level

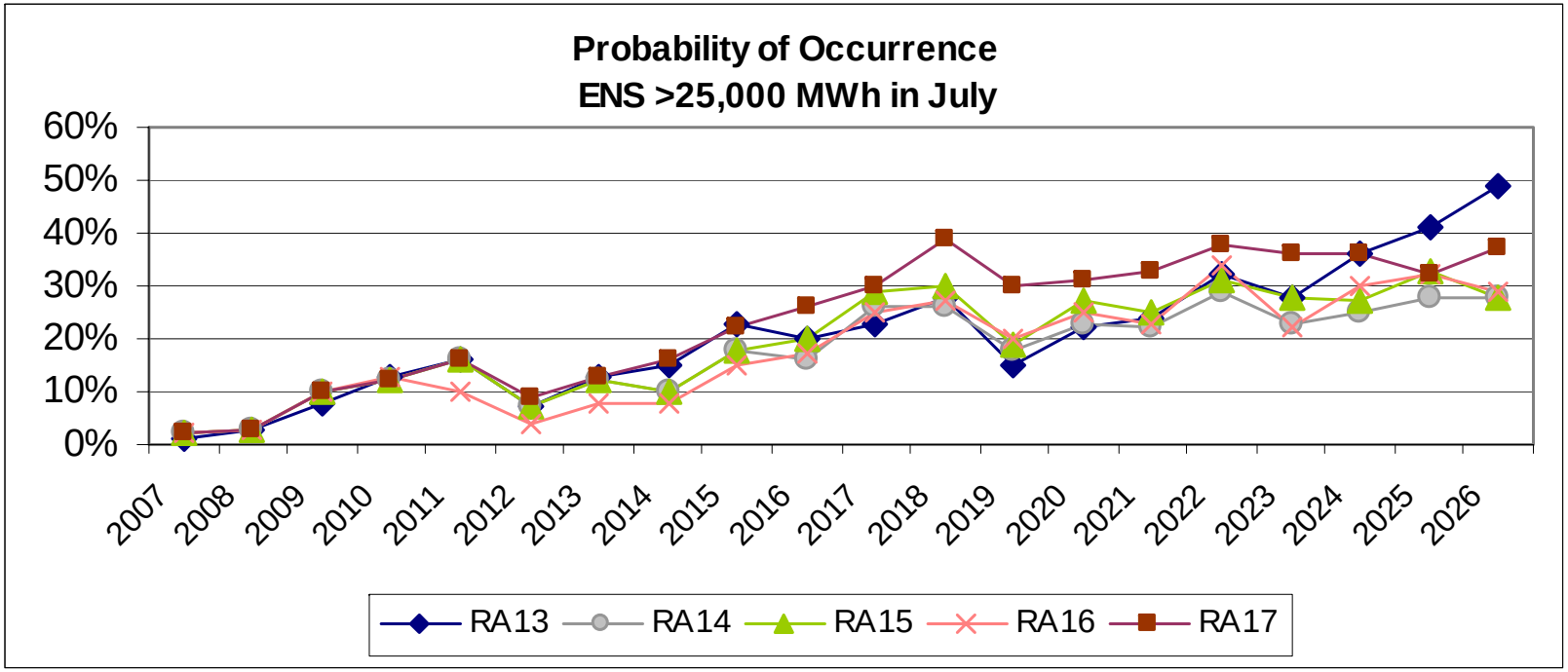
  Probability by year = # occurrences of ENS / 100

  Overall Probability = # occurrences of ENS / (20*100)

- This can also be evaluated at various threshold levels

  # occurrences of ENS > X (MWh)

Loss of Load Probability



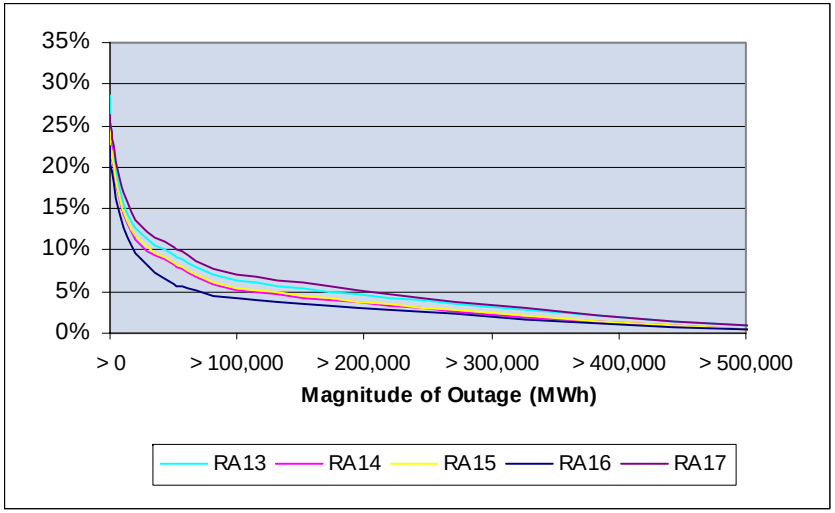
- Stochastic analysis reflects load volatility that increases through time – creating a greater likelihood and larger magnitude for ENS events in the out years

Loss of Load Probability

Probability of Loss of Load During Summer Peak

Average for operating years 2007 through 2016

Event Size (MWh)	RA13	RA14	RA15	RA16	RA17
> 0	29%	24%	25%	23%	26%
> 1,000	24%	22%	22%	20%	24%
> 10,000	16%	14%	15%	13%	17%
> 25,000	12%	11%	11%	9%	13%
> 50,000	9%	8%	8%	6%	10%
> 100,000	6%	5%	5%	4%	7%
> 500,000	1%	1%	1%	0%	1%
> 1,000,000	0%	0%	0%	0%	0%



- Looking at ENS by threshold levels provides further information about the loss of load risk
- Overall, RA16 has the lowest incidence of ENS and RA17 has the highest
- The difference among studies is small

Class 2 DSM Decrement Analysis

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Class 2 - Demand Side Management Decrement Analysis

- Provides system $/MWh revenue requirement savings for various types of Class 2 programs based on the preferred portfolio (RA14)
  - Determined from Planning & Risk Model runs with and without Class 2 decrements at no cost.
  - Class 2 program size 100 MW at Peak
  - Hourly load shape for each Class 2 programs
  - Resulting dollar difference divided by Class 2 energy savings
  - No resources were deferred or eliminated
- Decrements values used to evaluate cost-effectiveness of potential new demand side management programs between IRP cycles
- Class 2 DSM programs implemented are reduced from the load forecast

Class 2 - Demand Side Management Decrement Approach

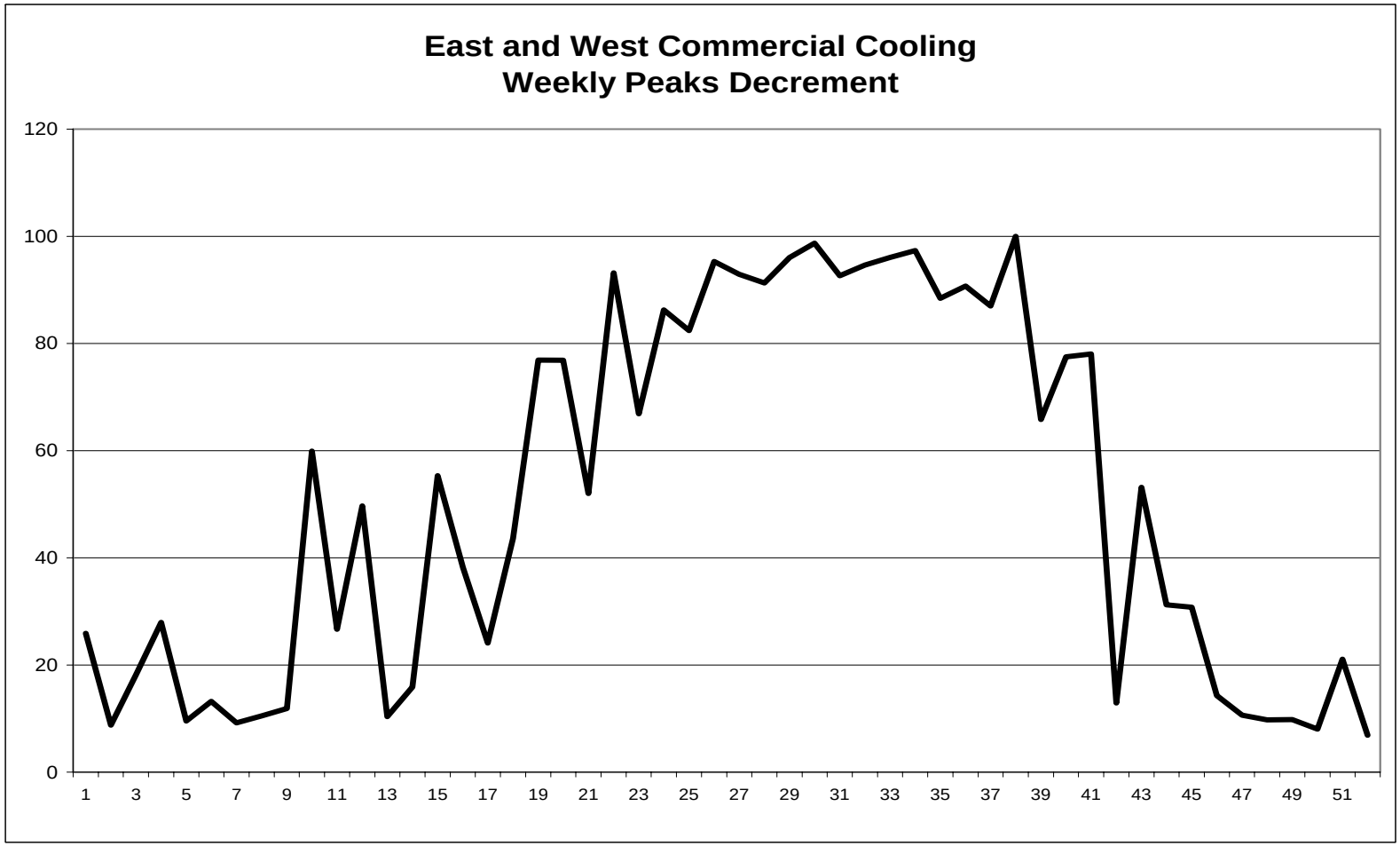
- 2004 IRP
  - Decrement approach applied to deterministic modeling in Planning and Risk Model (PaR)
    - Provides expected value for cost effectiveness test
    - Class 2 Modeled as load reduction
- 2007 IRP
  - Decrement approach applied to stochastic modeling in Planning and Risk Model (PaR)
    - Provides stochastic mean for cost effectiveness test
    - Class 2 modeled as contract at expected value - recognizing this is a surrogate to reflect planning decrements to the load forecast
- Next IRP
  - Demand Side Potential Study delivered - Summer of 2007
    - Study provides Class 2 Demand Side Management supply curves for selection in IRP modeling

Class 2 - Demand Side Management Decrement Compare

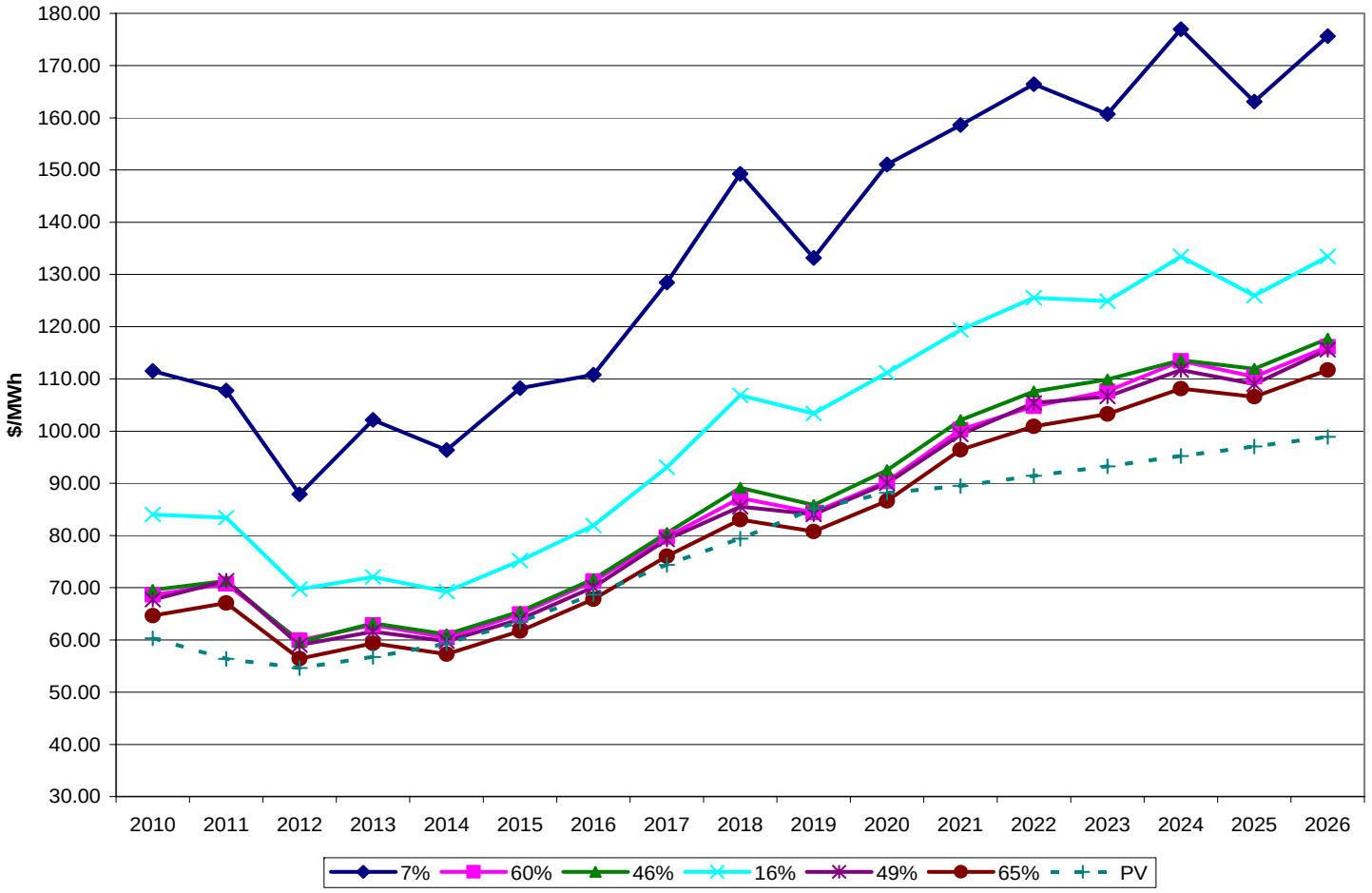
	2004 IRP	2007 IRP
IRP Model	Planning and Risk	Planning and Risk
Approach	Deterministic – Expected Case	Stochastic – Average and Upper Tail Risk
Methodology	Delta revenue requirement savings with and without Class 2 DSM; divided by program energy	Delta revenue requirement savings with and without Class 2 DSM; divided by program energy
Decrement Size (at Peak)	100 MW	100 MW
Modeled as	Load Reduction	Contract at expected value - recognizing this is a surrogate to reflect planning decrements to the load forecast
Load Shape (East/West)	12%/7% Residential Cooling 24% Commercial Cooling 51% Commercial Lighting 65%/67% System Load	7%/20% Residential Cooling 16% Commercial Cooling 49% Commercial Lighting 65%/67% System Load
New Load Shapes	-	60% Residential Lighting 28% Residential Heating (West) 46% Residential Whole House (East)

DSM Class 2 –Example of Week Load Shape

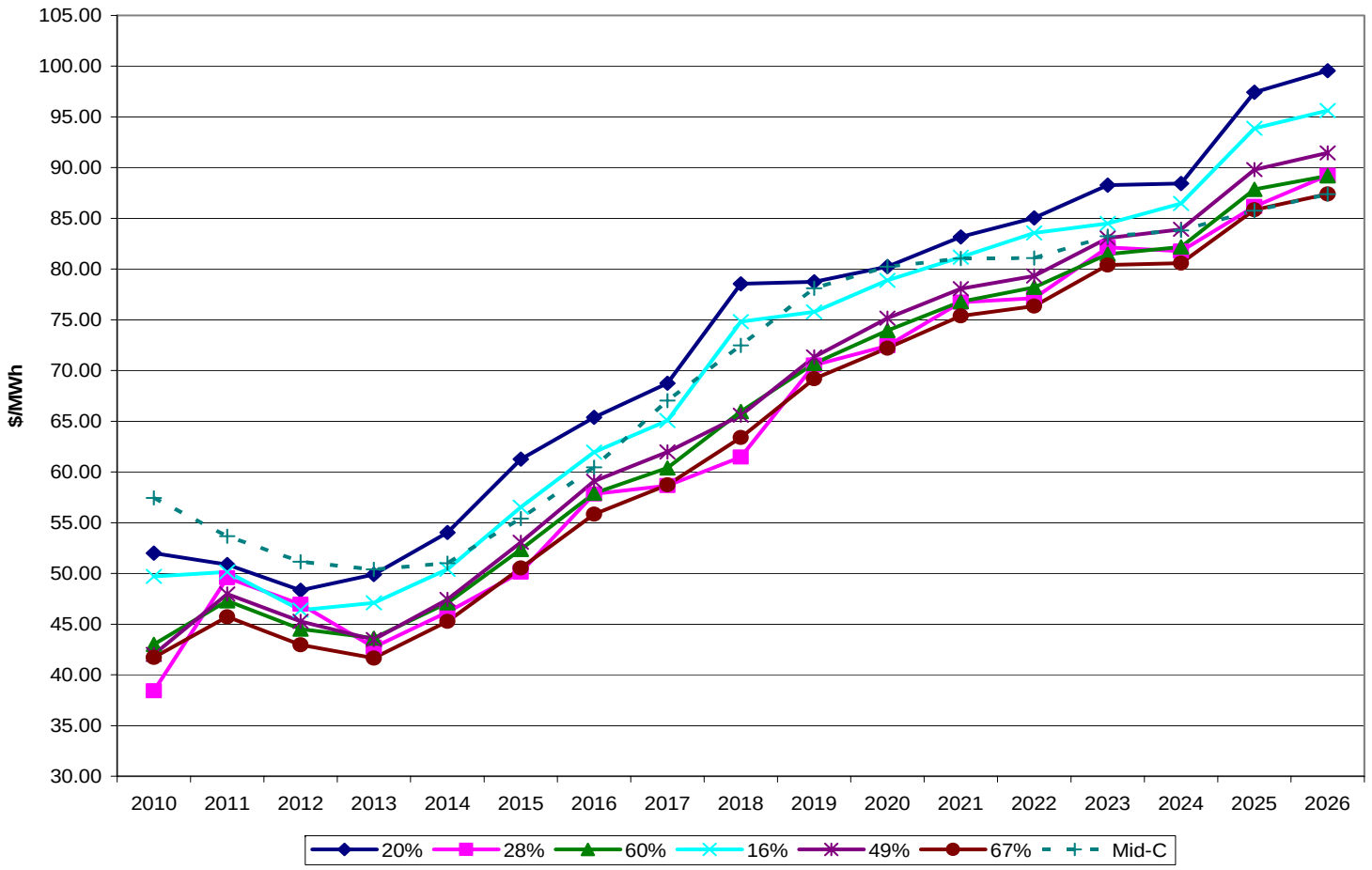
– 16% Annual Load Factor for Commercial Cooling



DSM Class 2 – East Decrement Price Trends



DSM Class 2 – West Decrement Price Trend



Next Steps

- IRP Stakeholders to review draft document
- Send draft on April 20, 2007
  - Will include the Base Assumptions appendix
- Three week review period
  - Submit comments by May 11, 2007 to IRP Mailbox
- 2007 IRP Filing Date: May 30, 2007

Appendix

Group 2 – Risk Analysis Investment Schedules

– Risk Analysis Portfolio 13 (RA13)

			Nameplate Capacity, MW											
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
East	Utah pulverized coal	Supercritical						340						
	Wyoming pulverized coal	Supercritical								527				
	Utah pulverized coal	Supercritical											575	
	Wyoming pulverized coal	Supercritical												527
	Combined Cycle CT	2x1 F class with duct firing												
	Combined Cycle CT	1x1 G class with duct firing												
	Combined Heat and Power	Generic east-wide						25						
	Renewable	Wind, Wyoming and Idaho	100	200		100	200	100	100					
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18					
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	505	616	315	315	1,020	1,180	1,354		
West	Combined Cycle CT	2x1 F Type with duct firing												
	Combined Heat and Power	Generic west-wide						75						
	Renewable	Wind, SE Washington												
	Renewable	Wind, NC Oregon	200											
	Class 1 DSM*	Sch. irrigation				12	11	12						
	Front office transactions**	Flat annual product	-	-	-	150	249	1,456	1,512	575	463	617		
	Annual Additions, Long Term Resources		**300**	**200**	**-**	**112**	**237**	**577**	**118**	**527**	**-**	**-**	**575**	**527**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**655**	**865**	**1,771**	**1,827**	**1,595**	**1,643**	**1,971**	**-**	**-**
	Total Annual Additions		**300**	**200**	**-**	**767**	**1,102**	**2,348**	**1,944**	**2,122**	**1,643**	**1,971**	**575**	**527**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

– Risk Analysis 14 (RA14) is provided in the presentation

Group 2 – Risk Analysis Investment Schedules

– Risk Analysis Portfolio 15 (RA15)

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined Cycle CT	2x1 F class with duct firing						548				
	Combined Cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	-	46	-	-	-	-	-
West	Combined Cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	687	376	730	739	442	491	820
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**839**	**1,125**	**318**	**527**	**-**	**-**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**687**	**422**	**730**	**739**	**442**	**491**	**820**
	Total Annual Additions		**300**	**300**	**100**	**999**	**1,262**	**1,856**	**1,057**	**969**	**491**	**820**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Group 2 – Risk Analysis Investment Schedules

– Risk Analysis Portfolio 16 (RA16)

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined Cycle CT	2x1 F class with duct firing					548					
	Combined Cycle CT	2x1 F class with duct firing						548				
	Combined Cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	162	-	-	-	-	-	-
West	Combined Cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	128	808	118	506	518	300	298	614
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**1,387**	**1,125**	**318**	**527**	**-**	**-**
	Annual Additions, Short Term Resources		**-**	**-**	**128**	**970**	**118**	**506**	**518**	**300**	**298**	**614**
	Total Annual Additions		**300**	**300**	**228**	**1,282**	**1,505**	**1,631**	**836**	**827**	**298**	**614**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.

Group 2 – Risk Analysis Investment Schedules

– Risk Analysis Portfolio 17 (RA17)

			Nameplate Capacity, MW									
	Resource	**Type**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
East	Utah pulverized coal	Supercritical						340				
	Wyoming pulverized coal	Supercritical								527		
	Combined Cycle CT	2x1 F class with duct firing										
	Combined Cycle CT	1x1 G class with duct firing										
	Combined Heat and Power	Generic east-wide						25				
	Renewable	Wind, Wyoming		200		200	200		300			
	Class 1 DSM*	Load control, Sch. irrigation					26	25	18			
	Front office transactions**	Heavy Load Hour, 3rd Qtr	-	-	-	-	46	178	194	-	55	-
West	Combined Cycle CT	2x1 F Type with duct firing					602					
	Combined Heat and Power	Generic west-wide						75				
	Renewable	Wind, SE Washington	300	100								
	Renewable	Wind, NC Oregon			100	100		100				
	Class 1 DSM*	Sch. irrigation				12	11	12				
	Front office transactions**	Flat annual product	-	-	-	687	330	1,103	1,093	991	985	1,368
	Annual Additions, Long Term Resources		**300**	**300**	**100**	**312**	**839**	**577**	**318**	**527**	**-**	**-**
	Annual Additions, Short Term Resources		**-**	**-**	**-**	**687**	**376**	**1,281**	**1,287**	**991**	**1,040**	**1,368**
	Total Annual Additions		**300**	**300**	**100**	**999**	**1,215**	**1,858**	**1,605**	**1,518**	**1,040**	**1,368**

* DSM is scaled up by 10% to account for avoided line losses.

** Front office transaction amounts reflect purchases made for the year, and are not additive.