

Integrated Resource Plan Public Input Meeting

February 29, 2008



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Introduction

Greg Duvall



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Agenda

- IRP Regulatory Compliance – Pete Warnken
- IRP Process Improvements – Pete Warnken
 - ▶ IRP/Business Plan Alignment Strategy
 - ▶ Public Process Changes
 - ▶ IRP Report Changes
- 2008 IRP Modeling Plan – Pete Warnken
- 2008 IRP Activity Timeline – Pete Warnken
- 10-Year Business Planning Process – Mark Cunningham
- Resource Portfolio Development for the IRP Update/2008-2017 Business Plan
 - ▶ Load Forecast – Greg Duvall
- **Lunch Break (30 min.)**
 - ▶ Demand-side Management Resources – Jeff Bumgarner
 - ▶ Capacity Load and Resource Balance – Stan Williams
 - ▶ Resource and Other Input Assumptions – Elaine Biggs
 - ▶ Resource Additions – Elaine Biggs

Why are we changing our resource planning process?

- Improve the alignment of IRP and business planning activities
- Need to make the modeling process more flexible to accommodate regulatory or other external events that occur later in the IRP preparation cycle
- Addressing transparency of resource planning decision-making raised by several stakeholders
- IRP public process issues:
 - ▶ Accounting for state energy interests and policies
 - ▶ Improve the effectiveness of information sharing

IRP Regulatory Compliance

Pete Warnken



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2007 IRP Acknowledgment Status, Orders, and Other Regulatory Activities

– 2007 IRP Acknowledgment Status

State	Acknowledgment Date	Disposition
Idaho	10/15/07	Acknowledged
Washington	11/15/07	Acknowledged
Utah	02/06/08	Not acknowledged
Oregon	?	?
Wyoming	Not Applicable	Not Applicable
California	Not Applicable	Not Applicable

– Significant 2007 IRP acknowledgment order items

- ▶ Utah commission

- Directed PacifiCorp to consider alternate optimal portfolio development approach
- Intending to open a proceeding on the June 2007 DSM potentials study

– Other regulatory activities affecting the IRP

- ▶ Utah commission: Fuel source plan – addresses PURPA fuels sources standard under the 2005 Energy Policy Act of 2005
- ▶ Oregon commission: Development of new IRP guidelines for environmental cost analysis
- ▶ Idaho commission: Order on wind integration costs for avoided-cost rate determination

IRP Process Improvements

Pete Warnken



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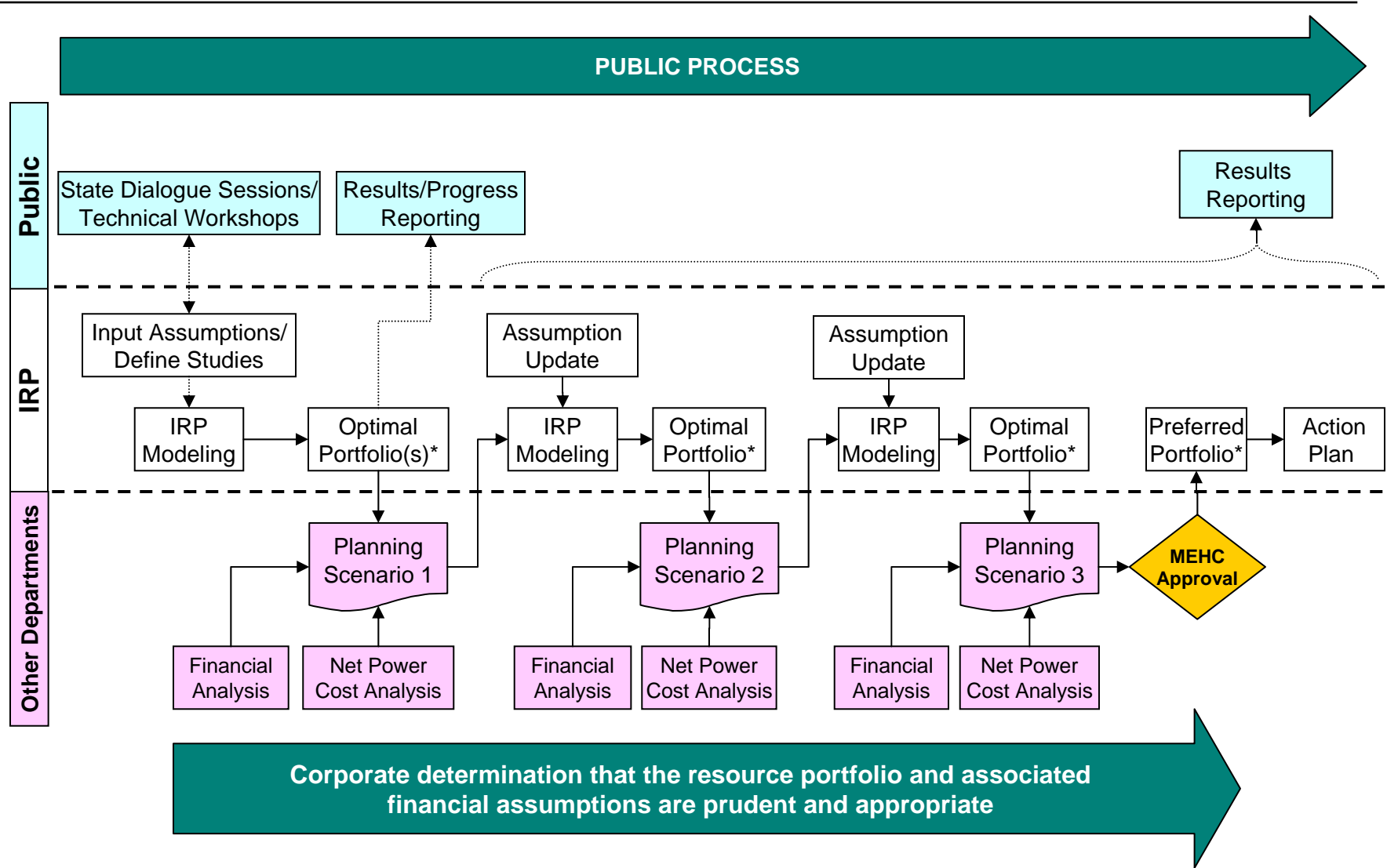
Process Improvements

Issue	Strategy
Improve the alignment of IRP and business planning processes	<ul style="list-style-type: none">● Streamline and standardize IRP modeling framework for adoption as an annual process● Directly link IRP modeling framework to iterative business plan development cycles● Use existing business plan resource portfolio as benchmark for new portfolio analysis● Same inputs and assumptions used for both IRP and business planning activities● Extend IRP filing date to March 31 to accommodate MEHC business planning schedule● Off-year IRP and business planning activities use IRP acknowledgment proceedings/orders to help define analysis requirements

Process Improvements

Issue	Strategy
Modeling flexibility to handle input/assumption updates	<ul style="list-style-type: none"> ● Look into automating data import/reporting routines, computer infrastructure improvements, and process improvements ● Establish modeling/portfolio analysis procedures tied to the scope of assumption changes during the annual planning cycle
Transparency of resource planning decision-making	<ul style="list-style-type: none"> ● All resource portfolios evaluated for business planning analysis—and ultimately the preferred portfolio—meet the IRP best cost/risk standard ● Documentation of decision processes occurring throughout the annual IRP/business planning cycle; shared via the public process and IRP report
IRP public process improvements	<ul style="list-style-type: none"> ● State stakeholder dialogue sessions ● Standardized packaging of model results

IRP/Business Plan Alignment Strategy



* Meets the IRP best cost/risk standard, and is consistent with current and expected government energy policies.

Public Process Changes

- State stakeholder dialogue sessions
 - ▶ To be scheduled for mid-March through April, 2008
 - ▶ Meeting outcomes to be captured in a report for PacifiCorp management and IRP public participants
- Technical review sessions
 - ▶ CO₂ risk analysis
 - ▶ Load Forecast
- Email distribution of results packages and updates on significant planning activities; solicit informal written stakeholder feedback
- Move back to a 30-day public comment period for the IRP draft
- Off-year IRP activities
 - ▶ Three public meetings: planning, input assumptions, results
 - ▶ Incorporate acknowledgment order requirements and public recommendations associated with the prior filed IRP
 - ▶ Public comment period for the IRP update draft
 - ▶ Commission briefings/public meeting

IRP Report Changes

- Retain general report structure used for 2007 IRP
- Areas cited as needed improvement/expansion
 - ▶ Better job of justifying how the preferred portfolio meets the best cost/risk standard as defined by the Company
 - ▶ More detail on the load forecast and changes with respect to prior forecasts
 - ▶ More transmission planning information
 - ▶ Improve the reporting of contract information
 - ▶ Action Plan
 - More detail on specific actions
 - Resource acquisition path analysis and procurement contingency plans
- New sections
 - ▶ Results chapter to profile modeling and decision-making in support of Business Planning Scenarios
 - ▶ Preferred Portfolio “Path Analysis”
 - CO₂ Trigger Point Analysis (Expected Oregon Commission requirement)
 - Simulation with Alternative Future Scenarios
 - ▶ Fuel sources plan (Utah Commission requirement)

2008 Modeling Plan

Pete Warnken



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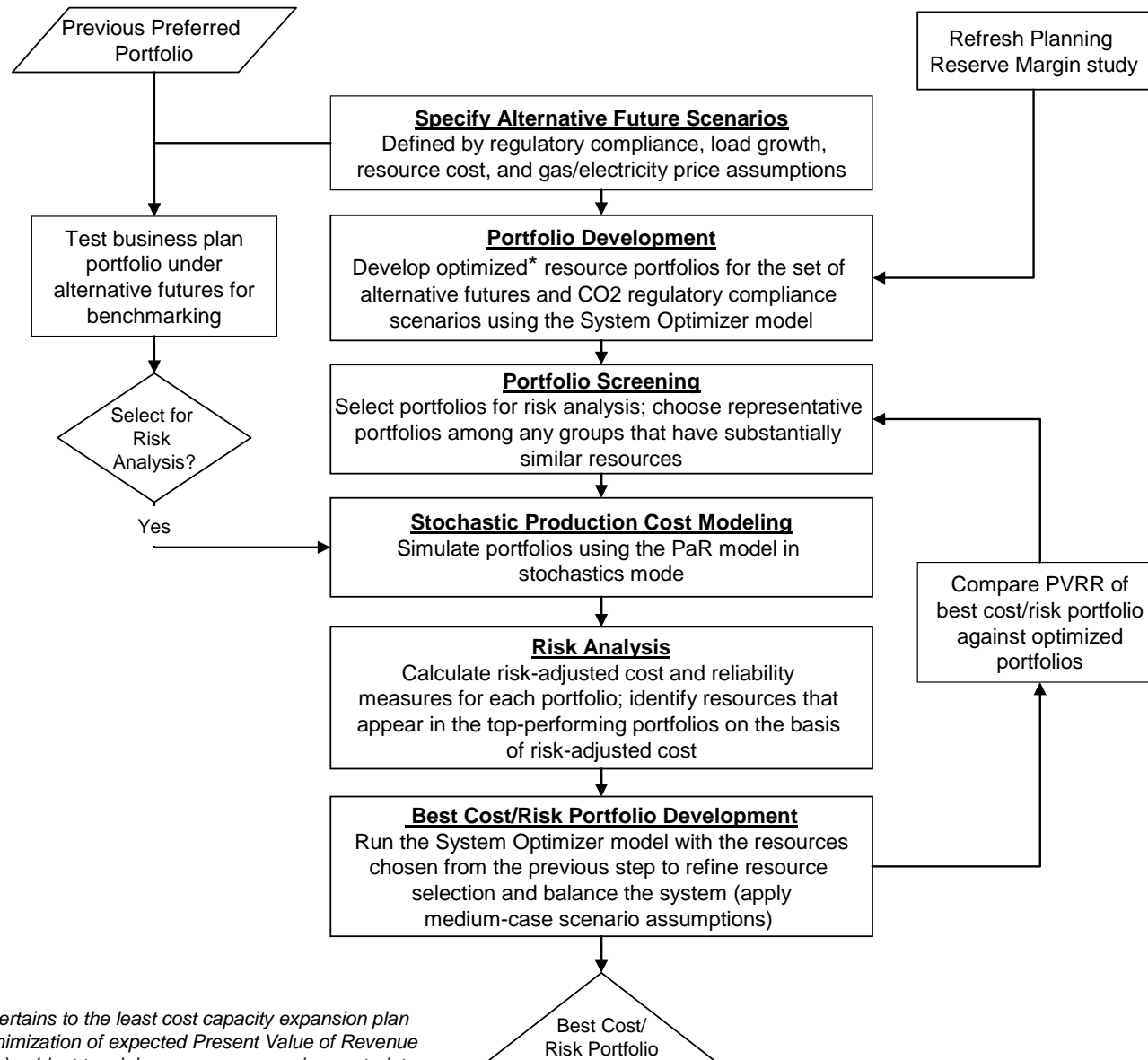
Selection of the Preferred Portfolio

- The Company's preferred portfolio will meet the following conditions
 - ▶ Has the best performance according to the IRP best cost/risk standard
 - ▶ Is determined by senior management as prudent on the basis of customer affordability and financial risk
 - ▶ Is consistent with current state and federal energy regulations

Best Cost/Risk Standard

- Composite definition of portfolio “best cost/risk” standard gathered from the various state commission IRP guidelines:
Contains resources with the best combination of expected costs and associated risks for the utility and its customers, after accounting for uncertainty and the long-run public interest as expressed by government energy policies
- PacifiCorp’s working definition of the portfolio “best cost/risk” standard:
Contains those resources most frequently found in the top-performing portfolios on the basis of stochastic risk-adjusted cost
 - ▶ The top-performing portfolios are a subset of the optimized portfolios derived by the System Optimizer capacity expansion model for sets of input assumptions (alternative future scenarios)
 - ▶ Alternative future scenarios capture deterministic uncertainty in (1) regulatory resource costs and constraints, (2) loads, and (3) electricity/fuel prices

Proposed Modeling Framework



* *Optimized* pertains to the least cost capacity expansion plan (based on minimization of expected Present Value of Revenue Requirements) subject to minimum reserve margin constraints.

Supporting Studies / System Enhancements

- Resource Adequacy
 - ▶ Stochastic Planning Reserve Margin study – update of work conducted for the 2004 IRP
 - ▶ Evaluate new LOLP (Loss of Load Probability) constraint functionality in the System Optimizer model
 - ▶ Hydro availability methodology for the Load & Resource balance
- Demand-side Management/Distributed Generation
 - ▶ Input supply curves derived from the DSM potentials study
 - Class 1, Class 2, and Class 3 DSM programs
 - Combined Heat and Power
 - Solar
 - Customer-owned standby generators
- Renewables
 - ▶ Wind supply curves
 - ▶ Refresh Renewable Energy Credit valuation assumption
 - ▶ Renewable Portfolio Standard assumptions update
 - ▶ Wind integration study initiatives

Supporting Studies / System Enhancements

- Regulatory analysis
 - ▶ System Optimizer vendor preparing a proposal to add functionality for modeling load-based emission performance standards, cap-and-trade, and renewable portfolio standards
- Computer Infrastructure
 - ▶ Move to more powerful computers to handle expanded population of resource options in the System Optimizer model; also required to support the model's enhanced regulatory constraint functionality

2008 IRP Activity Timeline

- State stakeholder dialogue sessions to be scheduled for mid-March through April, 2008
- IRP modeling cycles tied to Planning Scenario submission deadlines to MEHC
- General public meetings scheduled for mid-June, late July, and mid-February 2009
- Schedule for technical review sessions still under development
- Action Plan and acquisition path analysis activities occur after MEHC board approval of the business plan on December 10, 2008
- IRP filed with state commissions on March 31, 2009

10-Year Business Planning Process

Mark Cunningham



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Goals and Products of the 10-year Planning Process

- Determine how to best provide reliable electricity from both a source and delivery standpoint
 - ▶ Identify additional generation required to meet the needs of new and existing customers and to accommodate expiring contracts
 - ▶ Set an appropriate balance for utility-owned generation assets versus large purchased contracts so that customers are benefited
 - ▶ Reduce reliance on the volatile wholesale market which reduces rate volatility
 - ▶ Determine the level of investments in generation and transmission and distribution assets required to enhance delivery-system reliability
- Increase PacifiCorp’s ability to manage the timing of expenditures and methods of recovery to smooth the impacts upon customers through 10 year planning

Key Product

- Documentation of the significant assumptions underlying the 10-year business plan and a high-level set of pro-forma financial statements conveying the financial impacts of these assumptions

Global Assumptions

- Established key variables and inputs underlying the 10 Year Plan
- Examples of these include:
 - ▶ Assumed levels of wages and benefits
 - ▶ Inflation and discount rates
 - ▶ Commodity prices
 - Electricity
 - Natural gas
 - Coal
 - Carbon tax assumptions
 - ▶ Short and long-term interest rates

Step #1 - IRP Process

The planning process is an iterative process where business assumptions are refined and optimized. It is comprised of four basic steps.

The IRP process performs the following actions

- Develop and document the load forecast and average pricing assumptions for base revenues
- Develop and document the optimal portfolio of supply, demand-side management, and supporting transmission resources required to meet forecasted load

Step #2 – Develop Functional Unit Inputs

Each of the functional units comprising PacifiCorp develop and document the following:

- Operating and maintenance assumptions including those
 - ▶ Recognizing the impacts of existing plant and operations
 - ▶ Arising from the preferred portfolio selected through the IRP process
 - ▶ Changed by evaluating the estimated costs for various levels of reliability and customer service
- Capital expenditure requirements including those
 - ▶ Arising from the impacts of the IRP portfolio assumptions and from evaluations of the condition of existing plant and equipment
 - ▶ Additional estimated investments required to achieve desired levels of service reliability
- Depreciation and taxes-other-than-income implied by the level of capital investment assumed

Step #3 – Integration and Consolidation of Results

- The company completes each scenario by performing the following actions:
 - ▶ Assume additional revenues to be provided in accordance with existing tariff rates and through rate case activity
 - ▶ Determine the optimum amount of external debt, equity investment and dividends required to meet cash flow requirements
 - ▶ Compute estimated income taxes in accordance with existing federal and state statutes
 - ▶ Review and document all business assumptions to ensure that they are prudent and exhibit appropriate levels of consistency and integration

Step #4 – Presentation, Approval and Communication

- Executives of PacifiCorp and MidAmerican Energy Holdings Company review business plan results along with supporting documentation to ascertain that business assumptions are prudent and appropriate.
- Any required revisions are incorporated and when final results are satisfactory executive management approves the business plan assumptions and results.
- After approval, high-level business planning information is released through filings as required by various state and federal regulations. Additionally, information is released on a confidential basis to various rating agency analysts and in certain regulatory dockets or venues where necessary.

Resource Portfolio Development for the IRP Update/2008-2017 Business Plan



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Load Forecast

Greg Duvall



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Introduction

Purpose:

Provide an updated forecast and compare to the forecast used in the 2007 IRP.

Summary:

PacifiCorp updated its load forecast in October 2007. Relative to the 2007 IRP load forecast, PacifiCorp system sales and peak are virtually unchanged from 2008 through 2010. 2011 and beyond sales and peak are revised slightly downward.

What has changed since last forecast?

Increase in DSM

Slowdown in economic growth

- The increase in DSM and slowdown results in slight decrease in sales and peak growth

Shift in sales between classes and states

- Increased Industrial (non-wood and lumber) sales in Utah and Oregon from 2007 IRP forecast
- Decrease of about 147 aMW by 2017 in Wyoming oil and gas sales from 2007 IRP forecast
- Utah Residential and Commercial has slight increase in the early years and then decreasing from the 2007 IRP forecast
- Oregon Residential and Commercial is slightly lower than in previous forecast

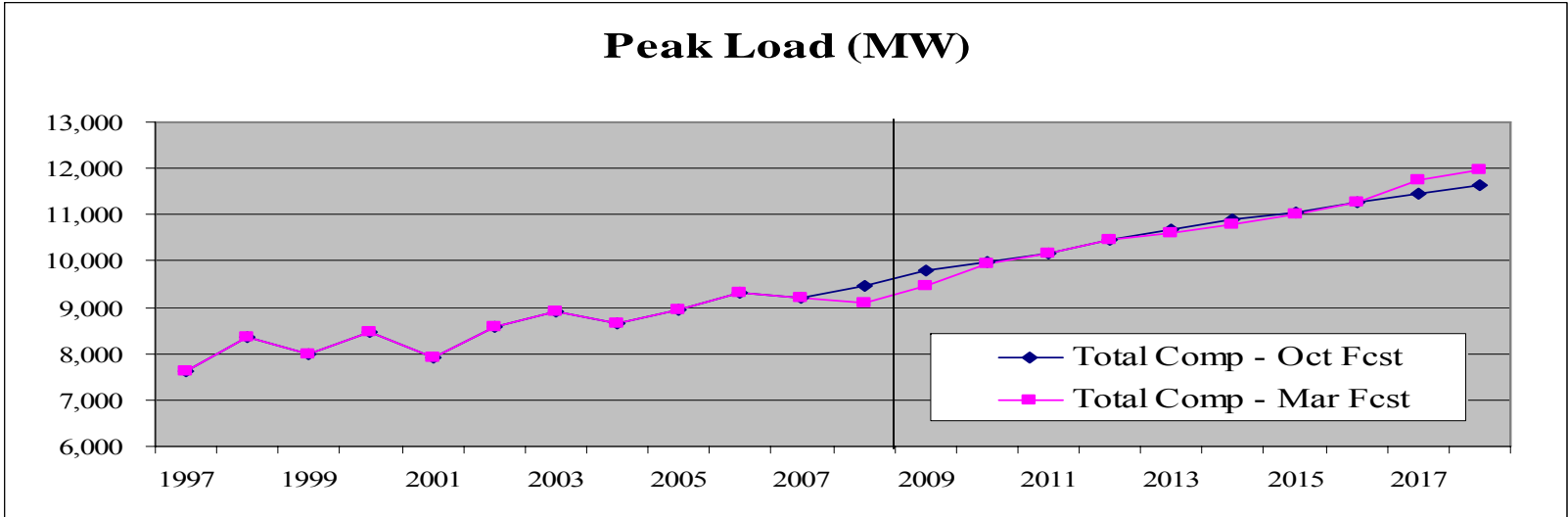
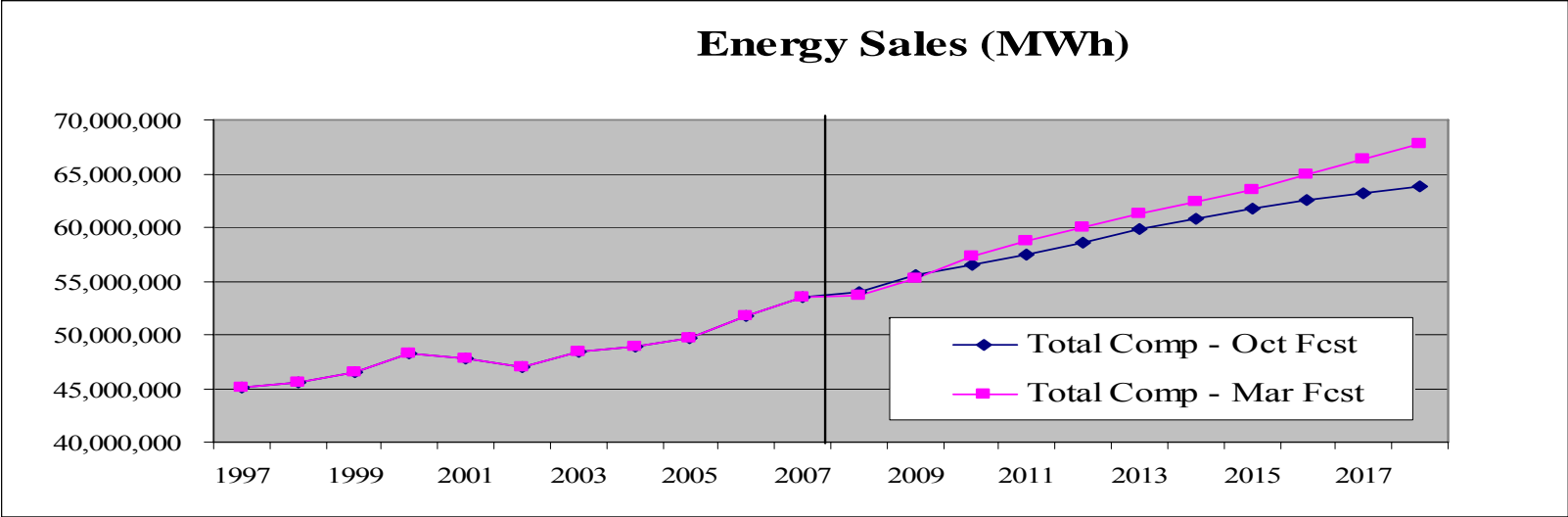
Total Sales Average Annual Growth Summary

<u>Energy</u>	Average Annual Growth Rates		
	Actual	Mar-07	Oct-07
	<u>1997 to 07*</u>	<u>2008 to 17</u>	<u>2008 to 17</u>
Total Company	1.71%	2.39%	1.74%
Utah	3.03 %	2.70 %	2.19 %
Oregon	0.45 %	0.71 %	(0.09)%
Wyoming	1.59 %	4.75 %	4.12 %
Washington	0.31 %	1.37 %	0.63 %
Idaho	1.46 %	1.06 %	0.41 %
California	1.43 %	1.12 %	0.91 %

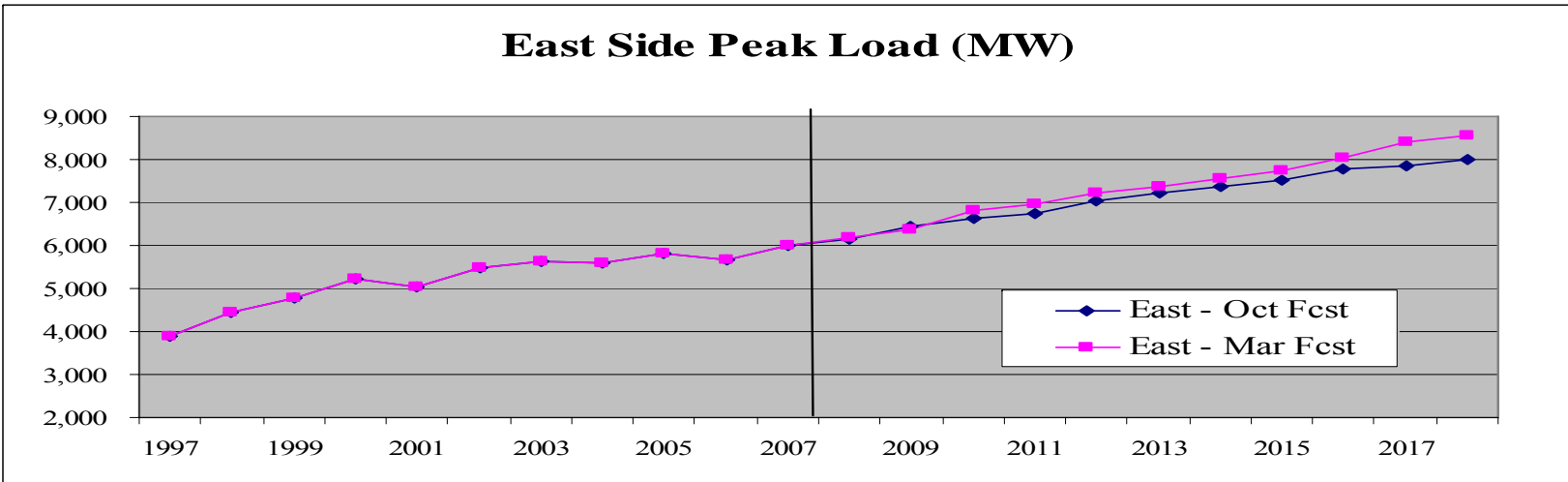
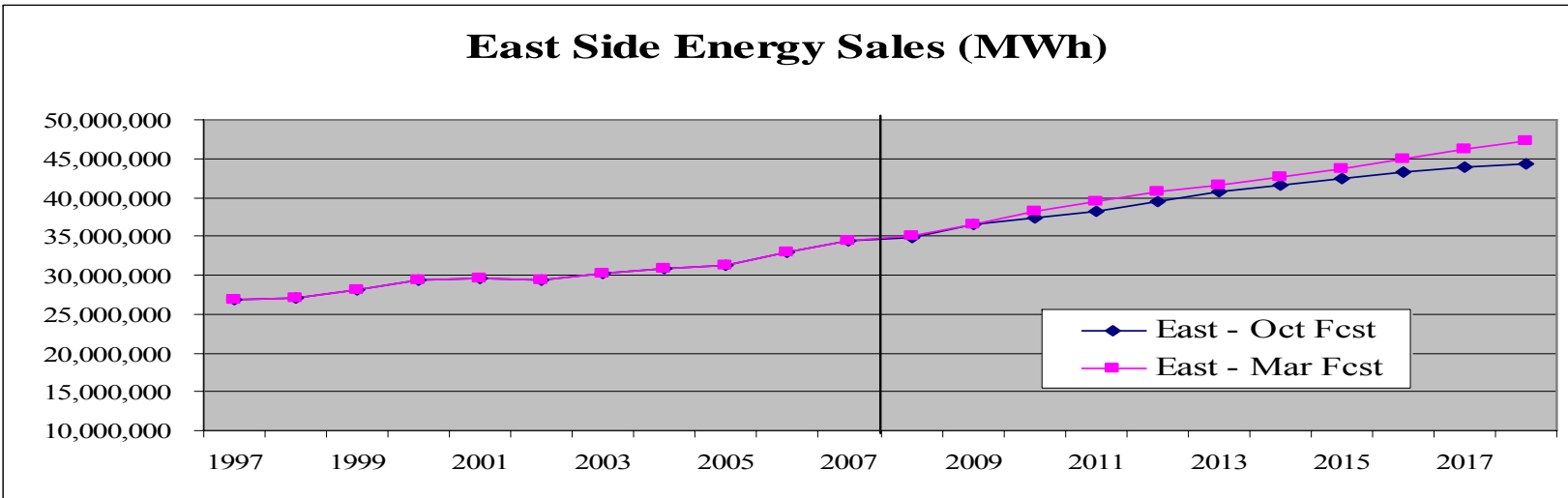
<u>Coincident Peak</u>	Average Annual Growth Rates		
	Actual	Mar-07	Oct-07
	<u>1997 to 07*</u>	<u>2008 to 17</u>	<u>2008 to 17</u>
Total Company	2.50%	2.80%	2.14%
Utah	5.93 %	3.27 %	2.67 %
Oregon	(0.62)%	1.58 %	0.98 %
Wyoming	1.33 %	5.12 %	4.02 %
Washington	(0.56)%	1.43 %	1.08 %
Idaho	5.49 %	1.27 %	0.10 %
California	(0.83)%	1.09 %	0.53 %

* Amounts from 2007 and prior are not weather normalized. 2008-2017 is forecasted based on normal weather

Total Energy and Coincident Peak Load Forecast Comparisons

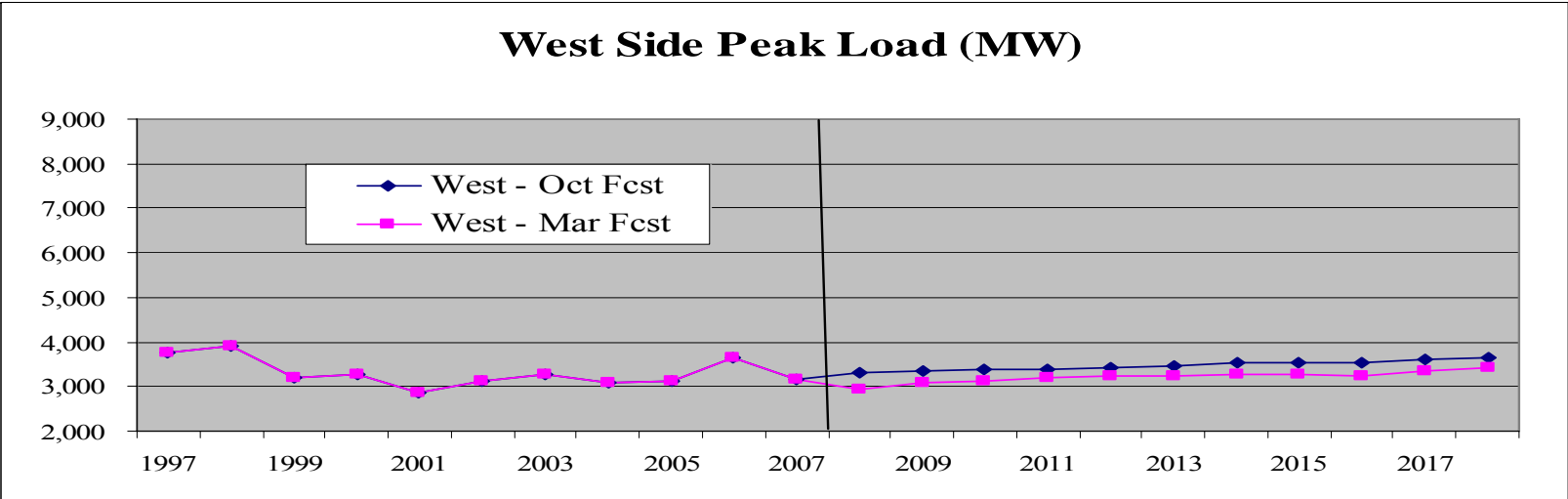
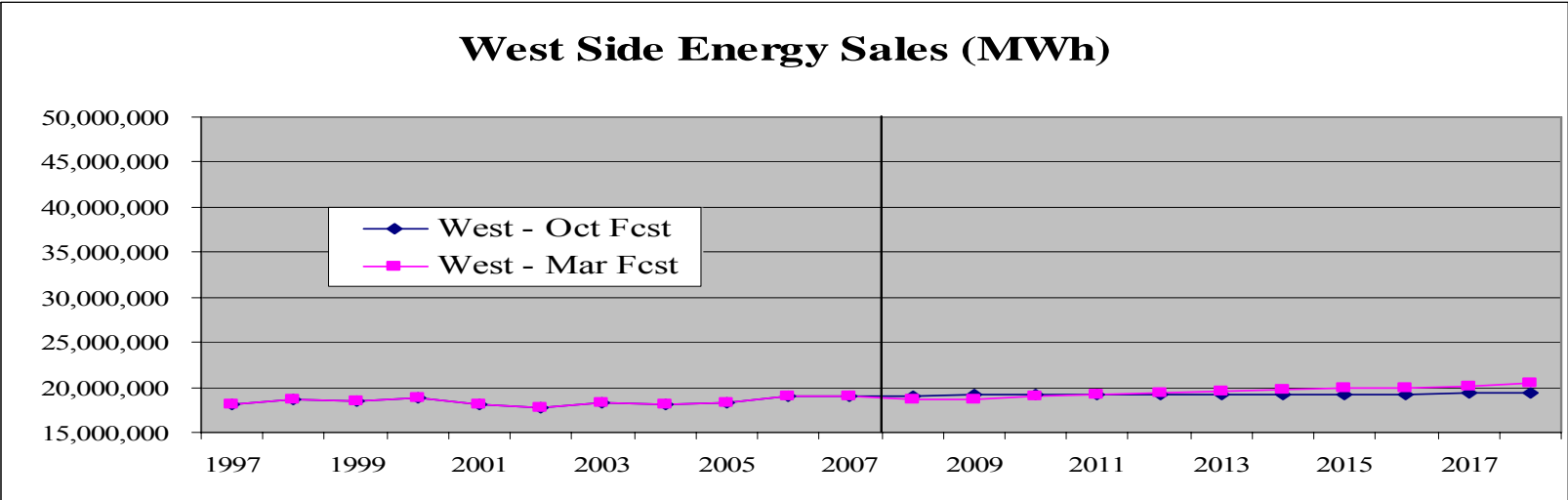


East Side Energy and Coincident Peak Load Forecast Comparisons



1997 and 1998 are winter peaks. 1999-2007 are summer peaks. Forecasted peaks are all summer.

West Side Energy and Coincident Peak Load Forecast Comparisons



1997 and 1998 are winter peaks. 1999-2007 are summer peaks. Forecasted peaks are all summer.

Primary Drivers of the Latest Forecast

Residential

- Increases in cooling load driven by central air conditioner saturation and larger homes
- Where natural gas is available, decreases in heating saturation

Commercial

- Increasing growth in the office and health care sectors

Industrial

- Wyoming oil and gas is still forecasted to be the fastest growing sector, even though we are forecasting slower growth from the previous forecast
- Utah oil and gas growth near Vernal
- Oregon sales to specialty food manufacturing, metal, and glass still have strong outlook

Risks to the Forecast

Residential

- Continued problems with the housing market could slow sales to the residential sector

Commercial

- Spill over from the Residential sector could slow Commercial sales

Industrial

- A general economic downturn could affect energy prices which would slow Wyoming Industrial sales
- A general economic downturn could affect Industrial sales including non-oil and gas sectors

Demand-Side Management Resources

Jeff Bumgarner



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10-Year Plan – Demand-side Management Resources

- Initial adjustments based on two factors
 - ▶ Better DSM potential information – June, 2007 study
 - ▶ Passage of Oregon SB838
- Energy Efficiency: 1,800,000 MWh (2007 IRP) to 4,600,000 MWh (10-year plan)
 - ▶ Study’s economic screen based on 2007 IRP decrement values + 15%
 - ▶ Revised study’s achievable assumption from 55% to 70%
 - ▶ Slight acceleration in 20-yr acquisition timeline (55%/45%)
 - ▶ Worked with ETO on revised forecast of CE opportunity
- Load Management: 258 MW by 2013 (2007 IRP) to 272 MW by 2012 (10-year plan)
 - ▶ Study used non-resource-specific high end estimates based loosely on 2007 IRP modeling work
 - ▶ Target adjustment exceeds study assumption of 265 MW by 2027
- 10-year plan resource adjustments will be tested utilizing supply-curve modeling methodology in 2008 IRP process
 - ▶ Careful review of lighting legislation necessary in development of curves

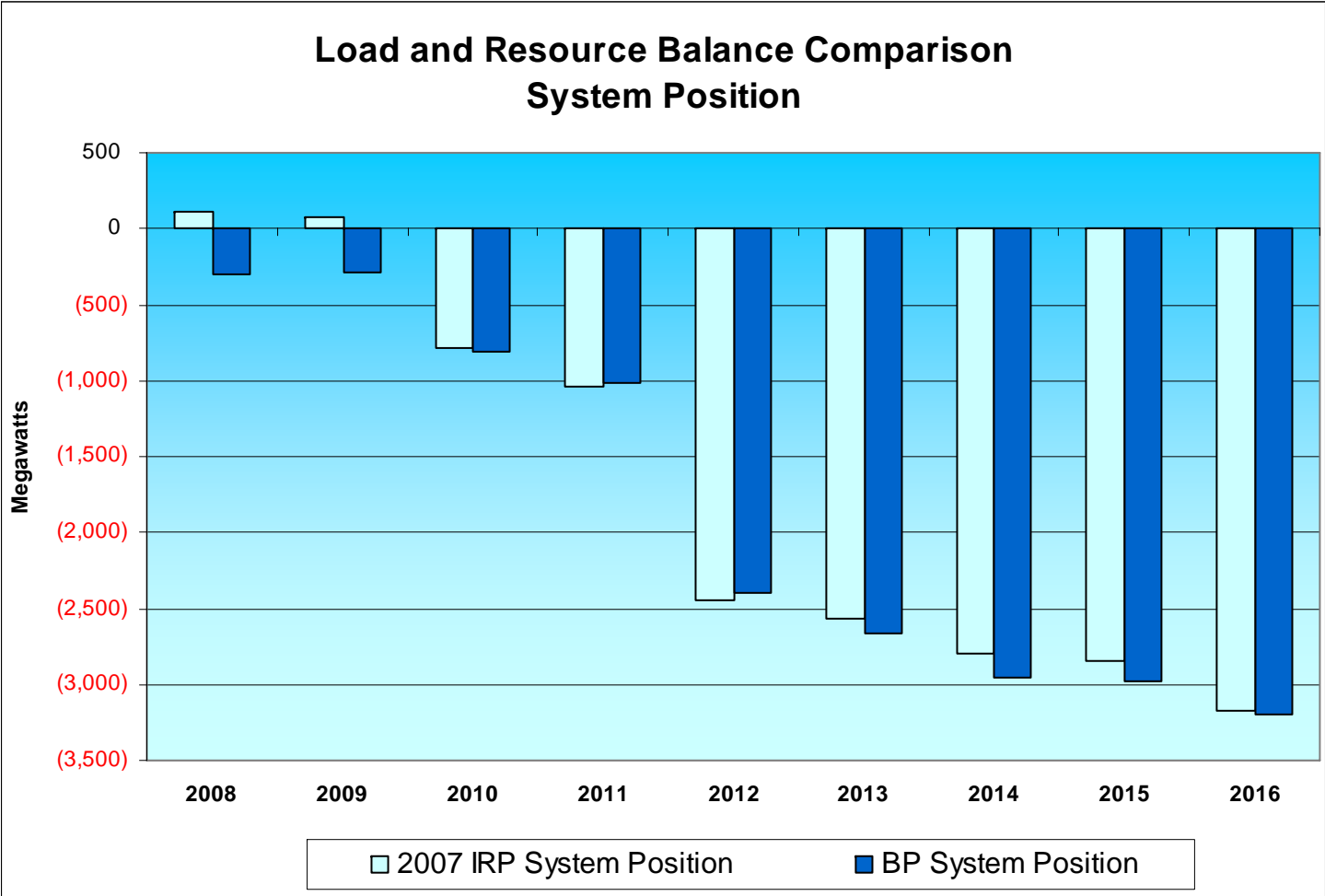
Capacity Load and Resource Balance

Stan Williams

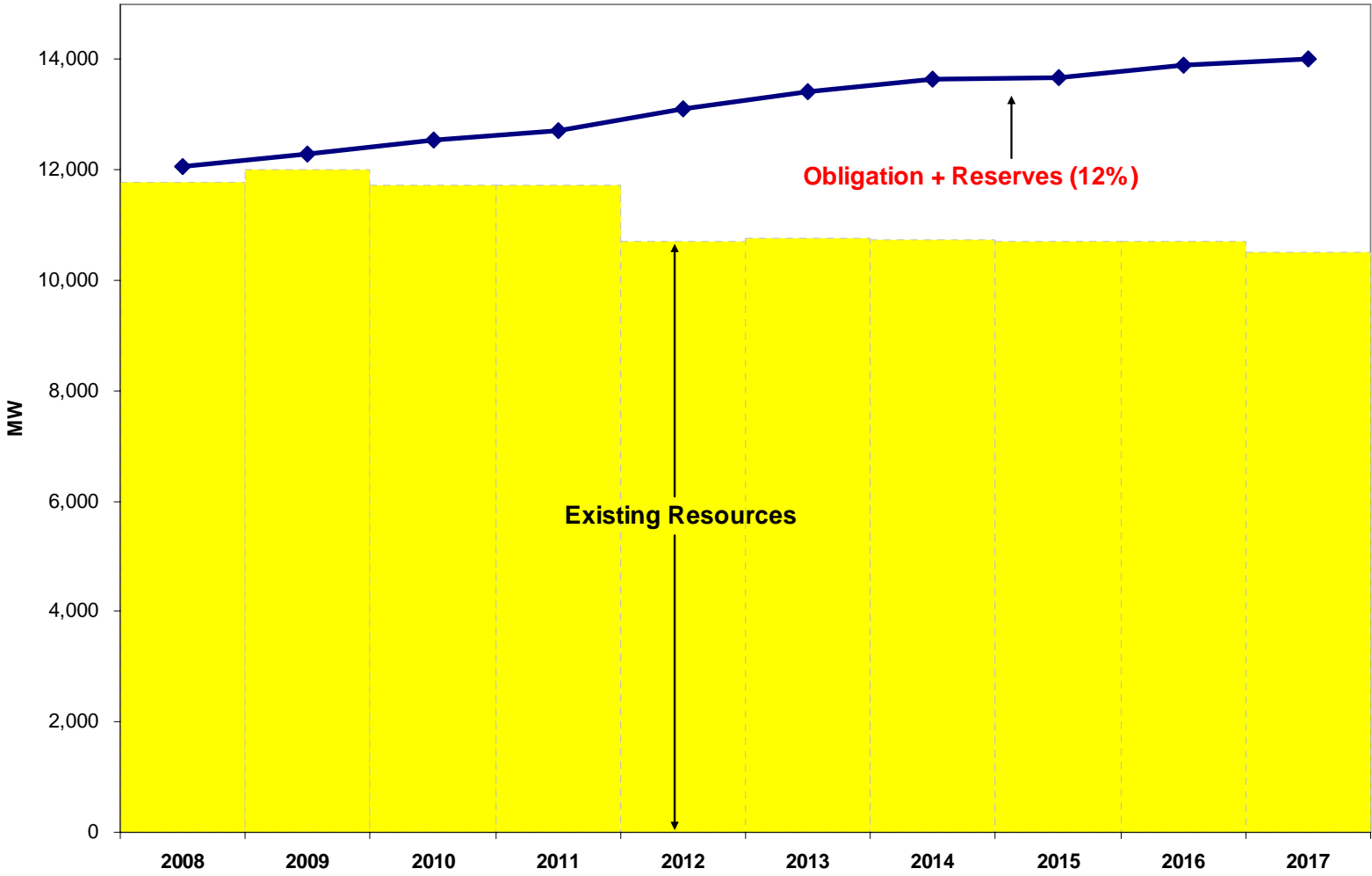


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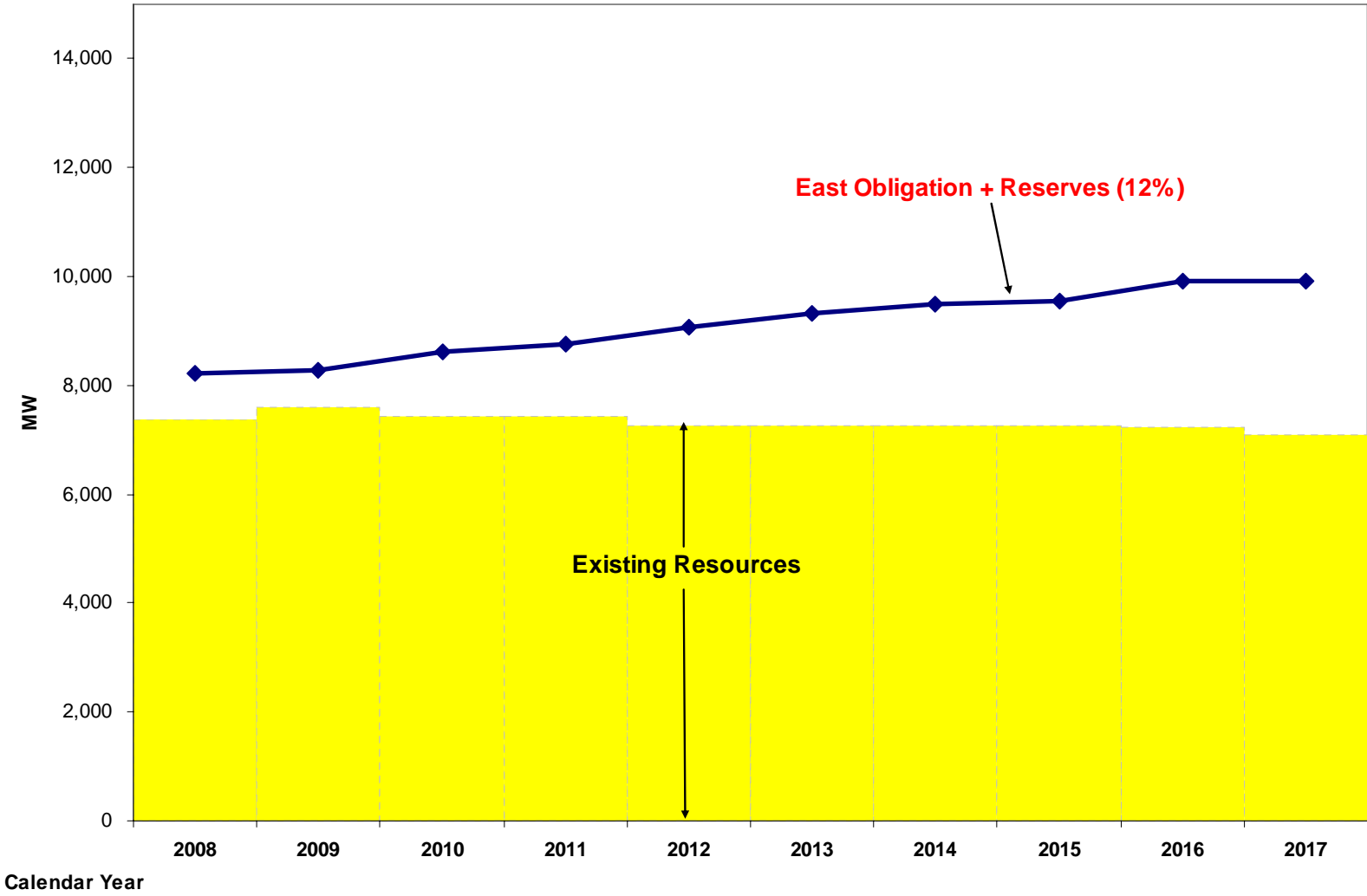
System Capacity Position Comparison



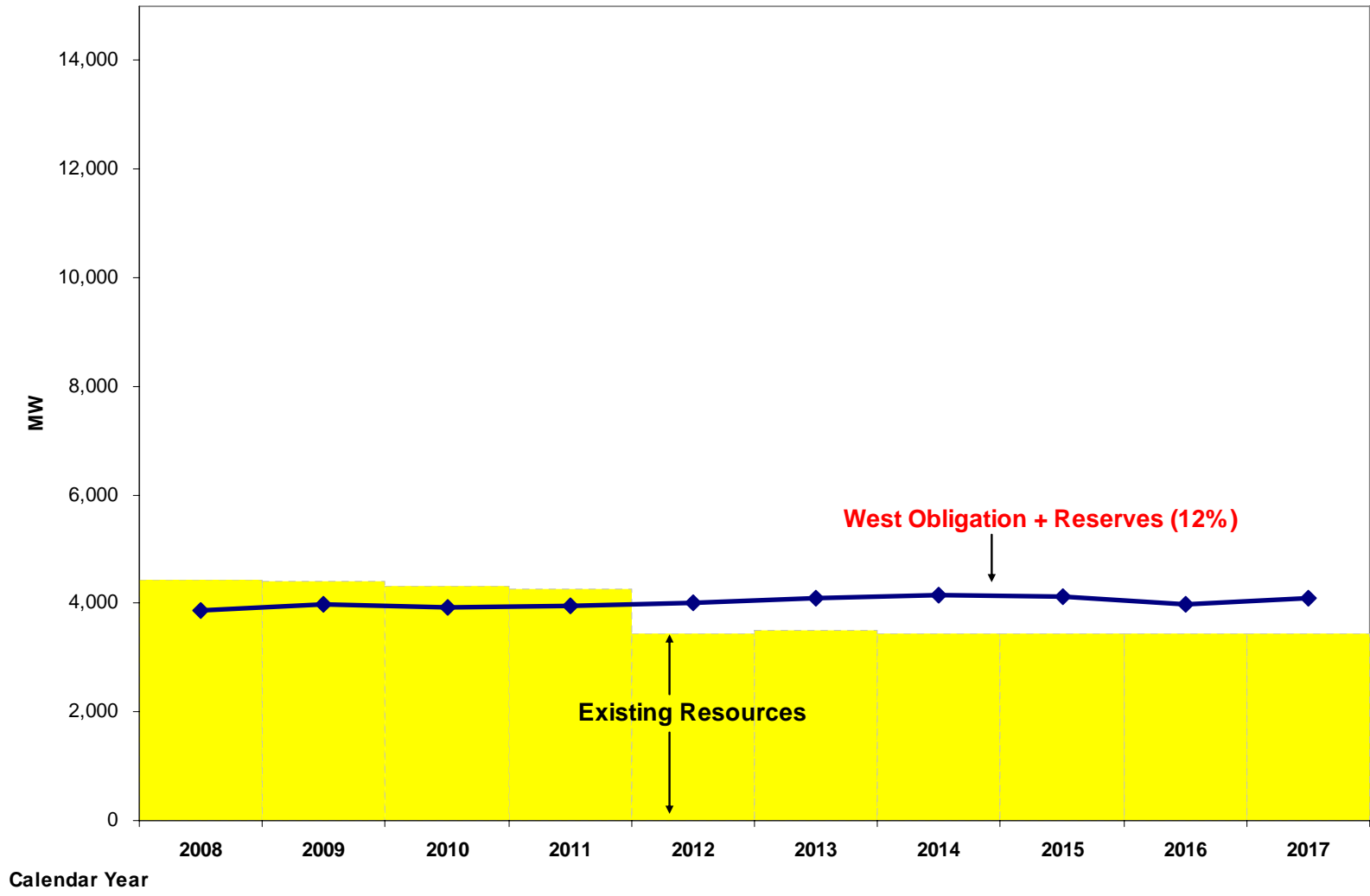
Business Plan System Capacity Position (Summer Peak)



Business Plan East Capacity Position (Summer Peak)



Business Plan West Capacity Position (Summer Peak)



Business Plan Capacity L&R Detail

Business Plan Capacity L&R Balance

Planning Reserve Margin Target = 12%

Calendar Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East										
Thermal	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932	5,932
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	163	163	163	163	163	163	163	163	163	0
Renewable	109	109	109	109	109	109	109	105	105	105
Purchase	704	828	648	668	493	493	493	493	472	472
QF	106	106	106	106	106	106	106	106	106	105
Interruptible	212	328	328	328	328	328	328	328	328	328
East Existing Resources	7,361	7,601	7,421	7,441	7,266	7,266	7,266	7,262	7,241	7,077
Load	6,547	6,725	6,975	7,130	7,404	7,612	7,782	7,827	8,147	8,208
Sale	836	752	766	756	745	745	745	745	745	659
East Obligation	7,383	7,477	7,741	7,886	8,149	8,357	8,527	8,572	8,892	8,867
Planning reserves (12%)	756	739	792	807	860	885	905	911	951	968
Non-owned reserves	71	71	71	71	71	71	71	71	71	72
East Reserves	827	810	863	878	930	955	976	981	1,022	1,040
East Obligation + Reserves	8,210	8,287	8,604	8,764	9,079	9,312	9,503	9,553	9,914	9,907
East Position	(850)	(686)	(1,183)	(1,323)	(1,813)	(2,046)	(2,237)	(2,291)	(2,673)	(2,830)
East Reserve Margin	0%	3%	-3%	-5%	-10%	-12%	-14%	-15%	-18%	-20%
West										
Thermal	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046	2,046
Hydro	1,421	1,414	1,328	1,332	1,175	1,174	1,168	1,169	1,168	1,177
DSM	0	0	0	0	0	0	0	0	0	0
Renewable	118	118	118	118	94	94	94	94	94	94
Purchase	800	800	800	750	112	141	107	107	107	107
QF	40	40	40	40	40	38	38	38	38	38
West Existing Resources	4,425	4,401	4,314	4,268	3,450	3,493	3,454	3,455	3,453	3,441
Load	3,228	3,343	3,302	3,316	3,341	3,409	3,457	3,531	3,444	3,550
Sale	299	299	290	290	258	258	258	158	108	108
West Obligation	3,527	3,642	3,592	3,606	3,599	3,667	3,715	3,689	3,552	3,658
Planning reserves (12%)	327	341	335	343	418	423	433	430	413	426
Non-owned reserves	7	7	7	7	7	7	7	7	7	8
West Reserves	334	348	342	349	425	430	439	436	420	434
West Obligation + Reserves	3,861	3,990	3,933	3,955	4,024	4,097	4,154	4,125	3,972	4,091
West Position	564	411	381	314	(575)	(603)	(700)	(670)	(518)	(651)
West Reserve Margin	28%	23%	23%	21%	-4%	-4%	-7%	-6%	-3%	-6%
System										
Total Resources	11,786	12,002	11,735	11,710	10,716	10,760	10,721	10,717	10,695	10,517
Obligation	10,910	11,119	11,333	11,492	11,748	12,024	12,242	12,261	12,444	12,525
Reserves	1,161	1,157	1,204	1,227	1,355	1,385	1,415	1,417	1,442	1,473
BP Obligation + Reserves	12,071	12,276	12,537	12,719	13,104	13,409	13,657	13,678	13,886	13,998
BP System Position	(294)	(285)	(813)	(1,020)	(2,398)	(2,664)	(2,950)	(2,975)	(3,202)	(3,495)
Reserve Margin	9%	10%	5%	3%	-8%	-10%	-12%	-12%	-14%	-16%

Details of changes from 2007 IRP to Business Plan

Business Plan L&R minus IRP L&R

Planning Reserve Margin Target = 12%

Calendar Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
East									
Thermal	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
Hydro	0	0	0	0	0	0	0	0	0
DSM	0	0	0	0	0	0	0	0	0
Renewable	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Purchase	25	50	100	125	150	150	150	150	150
QF	0	0	0	0	0	0	0	0	0
Interruptible	(21)	20	20	20	20	20	20	20	20
East Existing Resources	(5)	61	111	136	161	161	161	161	161
Load	32	68	(162)	(159)	(191)	(126)	(113)	(199)	(219)
Sale	25	50	100	125	150	150	150	150	150
East Obligation	57	118	(62)	(34)	(41)	24	37	(49)	(69)
Planning reserves (12%)	6	6	(22)	(21)	(25)	(18)	(16)	(26)	(29)
Non-owned reserves	0	0	0	0	0	0	0	0	0
East Reserves	6	6	(22)	(21)	(25)	(18)	(16)	(26)	(29)
East Obligation + Reserves	63	124	(84)	(55)	(66)	6	21	(75)	(98)
East Position	(68)	(63)	195	192	228	155	140	237	259
East Reserve Margin	-1%	-1%	2%	2%	3%	2%	2%	3%	3%
West									
Thermal	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	(25)	(50)	(75)	(75)	(75)	(75)
DSM	0	0	0	0	0	0	0	0	0
Renewable	10	10	10	10	10	10	10	10	10
Purchase	0	0	0	0	0	0	0	0	0
QF	0	0	0	0	0	0	0	0	0
West Existing Resources	10	(7)	(6)	(32)	(57)	(64)	(64)	(64)	(64)
Load	304	248	178	117	101	158	195	260	192
Sale	0	0	0	0	0	0	(0)	(0)	(0)
West Obligation	304	248	178	117	101	158	195	260	192
Planning reserves (12%)	37	30	21	14	12	19	23	31	23
Non-owned reserves	0	0	0	0	0	0	0	0	0
West Reserves	37	30	21	14	12	19	23	31	23
West Obligation + Reserves	341	278	200	131	113	177	218	291	215
West Position	(330)	(285)	(206)	(163)	(170)	(241)	(283)	(356)	(279)
West Reserve Margin	-12%	-9%	-7%	-5%	-4%	-6%	-7%	-9%	-7%
System									
Total Resources	5	54	104	105	104	97	97	97	97
Obligation	361	366	116	83	60	182	232	211	123
Reserves	43	36	(1)	(7)	(13)	1	7	5	(6)
Obligation + Reserves	404	402	116	76	47	183	239	216	117
System Position	(408)	(358)	(22)	18	48	(101)	(157)	(133)	(31)
Reserve Margin	-4%	-3%	0%	0%	1%	0%	-1%	-1%	0%

Resource and Other Input Assumptions

Elaine Biggs



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Resource Portfolio Development Assumptions

2007 Business Plan includes:

- October 2007 demand forecast
 - ▶ 2007 IRP used the March 2007 demand forecast
- October 2007 interim forward electricity price curve scenario
 - ▶ 2007 IRP used the August 2006 official forward price curve
 - Average annual on-peak prices from 2007-2016 are up by \$3.80/MWh relative to 2007 IRP prices
 - Average annual off-peak prices from 2007-2016 are up by \$0.81/MWh relative to 2007 IRP prices
- Natural gas price assumptions based on July 2007 short-term forecast and August 2007 long-term forecast
 - ▶ 2007 IRP used natural gas forecasts from July and August 2006
- Updated thermal resource capital costs

Resource Portfolio Development Assumptions: CO₂ Regulations

- Cap-and-trade System
- CO₂ compliance emission costs:
 - ▶ \$8/ton in 2008\$, adjusted for inflation using PacifiCorp's June 2007 inflation curve
 - For 2007 IRP, \$8/ton in 2008\$, adjusted for inflation using PacifiCorp's June 2006 inflation curve
 - ▶ 2007 IRP CO₂ costs are applied at the full value starting in 2012
 - For 2007 IRP, CO₂ costs begin in 2010 with costs phased in at 50%, escalating to 75% in 2011 and 100% in 2012
- CO₂ cap:
 - ▶ 2007 level by 2025; 1990 level by 2030
 - For 2007 IRP, Year 2000 level for all years (53 million tons)

Portfolio Development Assumptions

- Reflects \$4 billion transmission investment announced in PacifiCorp's May 30, 2007 press release
 - ▶ Includes enhanced 500 kV Rectangle with Wyoming and Northwest Build
 - ▶ 600 MW build in 2012 to Desert Southwest at Mead market and cost of delivery
- Maintains 2,000 nameplate megawatts of renewables by 2013; wind resources updated to reflect business plan assumptions for start dates, sites and capacities

Portfolio Development Assumptions: Front Office Transactions

- Front Office Transaction¹ Market Availability by Market Hub
 - ▶ Mid-C third-quarter HLH product:
 - 400 MW (2007-2026)
 - ▶ COB flat product:
 - 400 MW (2007-2026)
 - ▶ Mona third-quarter HLH product:
 - 200 MW (2007-2026)
 - ▶ Mead third-quarter HLH product:
 - 0 MW (2007-2012)
 - 600 MW (2013-2026)
 - Replaces Four Corners as a market proxy as a result of incorporating the \$4 billion transmission investment plan
- All markets are constrained by transmission except for Mona, which is constrained by market availability

^{1/} Front Office Transactions are solely forward firm purchases required to maintain minimum firm capacity reserve margins whereas system balancing are spot market transactions at market hubs.

Business Plan Resource Additions

Elaine Biggs



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Comparison of Resource Additions

2007 Business Plan ^{1/}

			Nameplate Capacity, MW									
	Resource	Type	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
East	Upgrades - thermal generation	Various east coal-fired units	-	21	36	38	37	-	-	-	-	-
	Combined cycle CT	2x1 F class with duct firing	-	-	-	-	1,096	-	-	-	-	-
	Geothermal	Blundell	-	-	35	-	-	-	-	-	-	-
	Combined heat and power	Generic east-wide	-	-	19	-	-	-	-	-	-	-
	Class 1 DSM ^{2/}	Load control, scheduled irrigation	-	-	-	-	15	48	-	-	-	-
	Renewable	Wind, Wyoming	300	100	100	200	-	200	-	-	-	-
	Front office transactions ^{3/}	Heavy load hour, 3rd quarter	-	-	-	-	115	633	746	800	800	783
West	Upgrades - thermal generation	Jim Bridger coal-fired units	-	-	17	17	17	17	-	-	-	-
	Upgrades - hydro generation	Swift Hydro	-	-	-	-	-	25	25	25	-	-
	Class 1 DSM ^{2/}	Load control, scheduled irrigation	-	-	-	-	32	-	-	-	-	-
	Renewable	Wind, North-central Oregon	-	-	200	-	100	-	-	-	-	-
	Renewable	Wind, Southeast Washington	70	-	-	-	-	-	-	-	-	-
	Front office transactions ^{3/}	Flat annual product	400	400	389	389	400	400	400	388	338	400
	Front office transactions ^{3/}	Heavy load hour, 3rd quarter	-	-	268	347	400	59	144	101	334	548
Annual Additions, Long Term Resources			370	121	408	256	1,297	290	25	25	-	-
Annual Additions, Short Term Resources			400	400	657	736	915	1,092	1,290	1,289	1,472	1,731
Total Annual Additions			770	521	1,065	992	2,212	1,382	1,315	1,314	1,472	1,731

2007 IRP Preferred Portfolio ^{4/}

			Nameplate Capacity, MW									
	Resource	Type	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East	Wyoming pulverized coal	Supercritical	-	-	-	-	-	-	-	527	-	-
	Utah pulverized coal	Supercritical	-	-	-	-	-	340	-	-	-	-
	Combined cycle CT	2x1 F class with duct firing	-	-	-	-	-	548	-	-	-	-
	Combined cycle CT	1x1 G class with duct firing	-	-	-	-	-	-	-	-	-	357
	Combined heat and power	Generic east-wide	-	-	-	-	-	25	-	-	-	-
	Class 1 DSM ^{2/}	Load control, scheduled irrigation	-	-	-	-	-	15	48	-	-	-
	Renewable	Wind, Wyoming	-	200	-	200	200	-	300	-	-	-
	Front office transactions ^{3/}	Heavy load hour, 3rd quarter	-	-	-	393	272	97	3	149	192	165
West	Combined cycle CT	2x1 F class with duct firing	-	-	-	-	548	-	-	-	-	-
	Combined heat and power	Generic west-wide	-	-	-	-	-	75	-	-	-	-
	Class 1 DSM ^{2/}	Load control, scheduled irrigation	-	-	-	-	-	32	-	-	-	-
	Renewable	Wind, North-central Oregon	-	-	100	100	-	100	-	-	-	-
	Renewable	Wind, Southeast Washington	300	100	-	-	-	-	-	-	-	-
	Front office transactions ^{3/}	Flat annual product	-	-	-	219	64	555	657	247	246	249
Annual Additions, Long Term Resources			300	300	100	300	748	1,135	348	527	-	357
Annual Additions, Short Term Resources			-	-	-	612	336	652	660	396	438	414
Total Annual Additions			300	300	100	912	1,084	1,787	1,008	923	438	771

1. Resources in the 2007 Business Plan table are shown by their in-service date whereas the 2007 IRP table reflects the year for which they meet the system peak.

2. DSM amounts reflect the maximum program capacity anticipated, as measured at the customer meter

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

4. 75 MW of upgrades to the Swift Hydro project and a number of small hydro upgrades, totaling about 22 MW and over 20 projects, are not shown on this table, but are included in existing hydro.