



2006 Integrated Resource Plan Public Input Meeting

May 10, 2006



Agenda

- Natural Gas and Electricity Forecasts
- Renewables Studies
- Procurement Update
- Next Steps



Natural Gas and Electricity Price Forecasts

Market Analysis Group



Agenda

- Methodology
- MIDAS pricing overview
- Key inputs
- Average price changes



Methodology

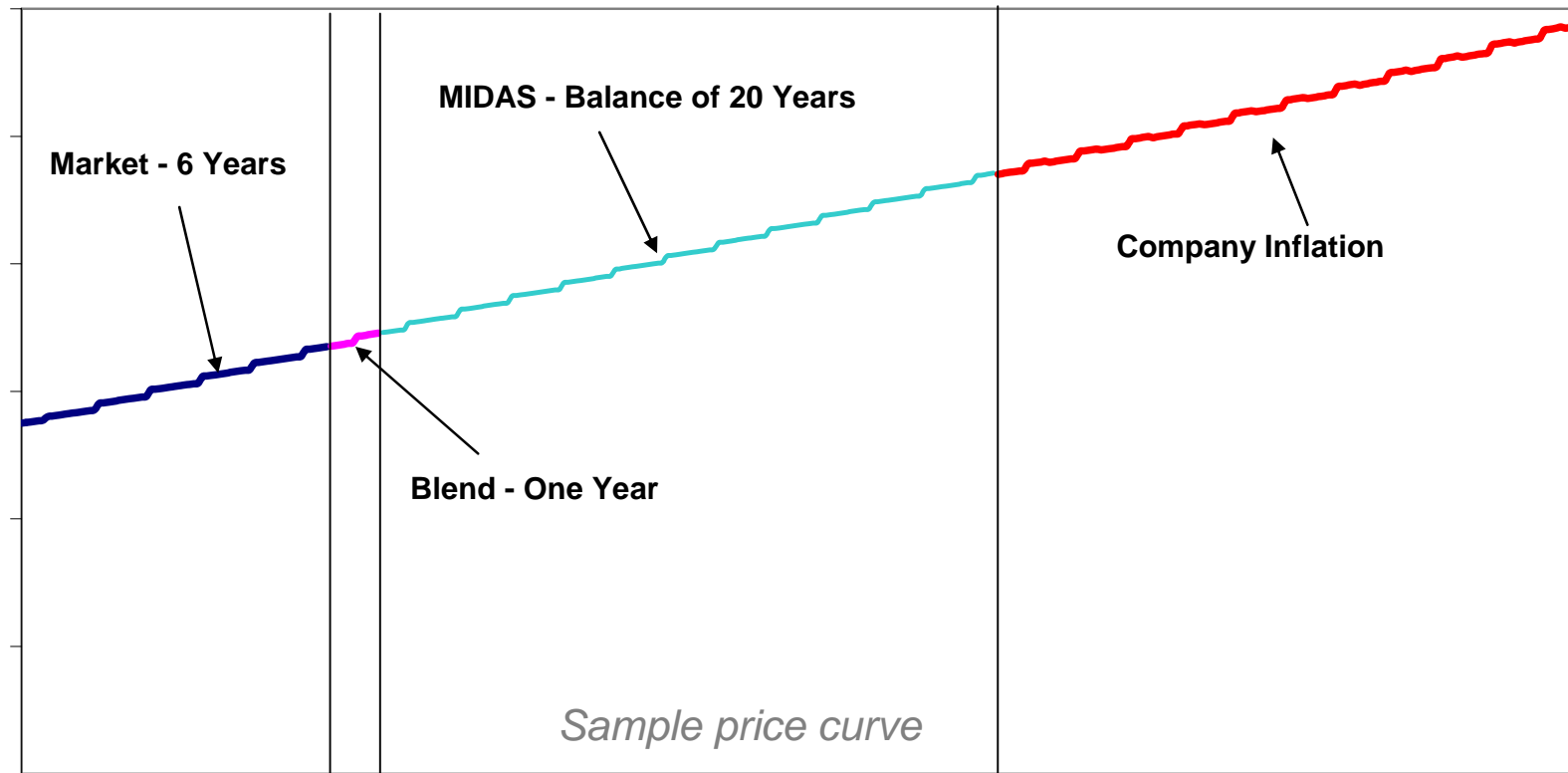


Forward Price Curve - Introduction

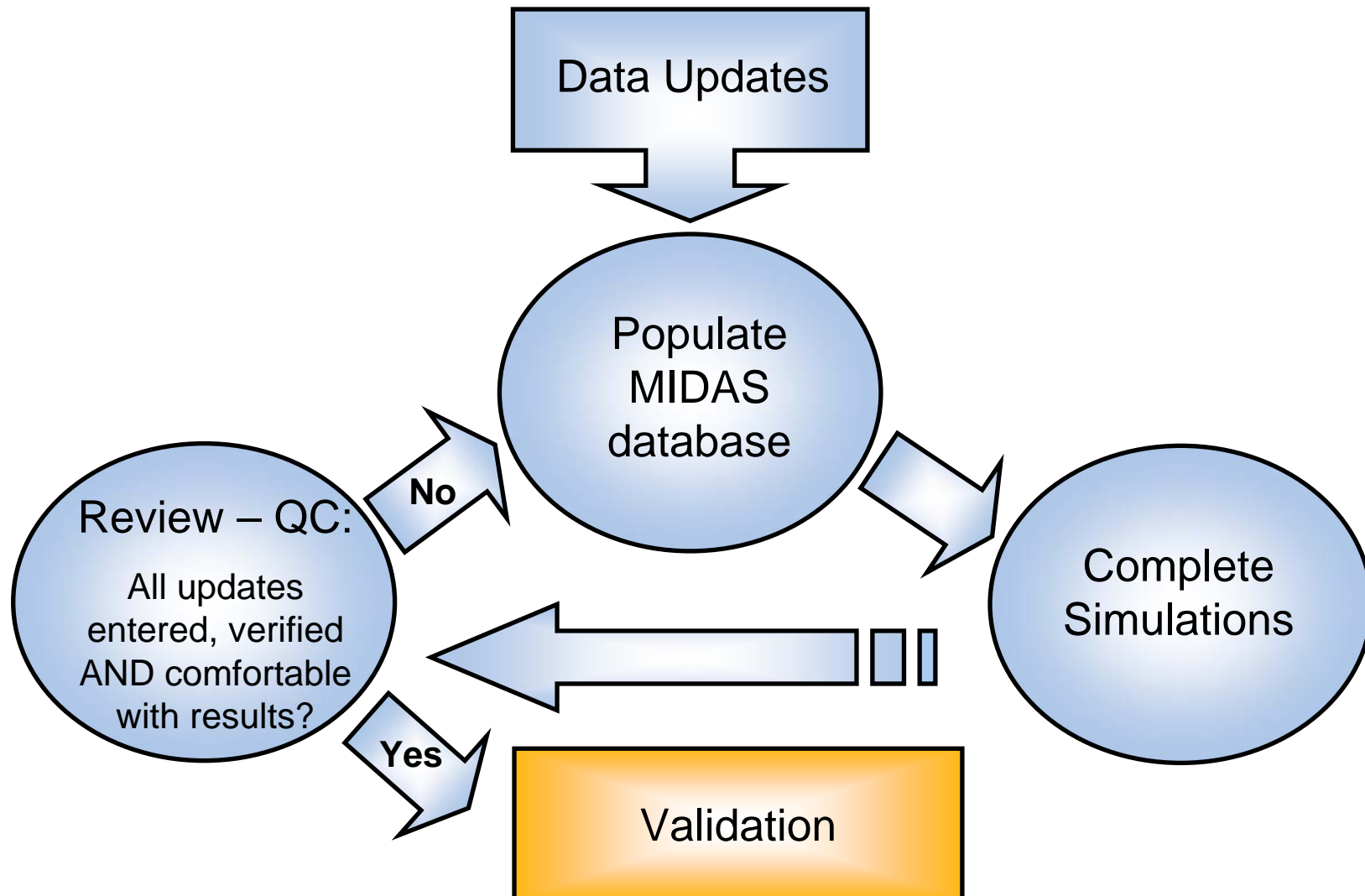
- MIDAS forward price curve is updated:
 - At minimum on a quarterly basis, with
 - More frequent updates if significant data input changes occur
- Key impact of forward price curve is on PacifiCorp financial statements with mark-to-market accounting of FAS 133 contracts
- Rigorous review and validation
 - Internal risk management
 - External audit by PricewaterhouseCoopers
 - Sarbanes-Oxley compliance
 - Passed 2005 internal audit of process and controls
- One official price curve is used throughout PacifiCorp

Forward Price Curve - Components

- Market: actual market quotes from front office (6 years)
- Blending: transition to MIDAS forecast (1 year)
- Fundamentals: MIDAS outputs (through 2025)
- Extrapolation: growth at inflation (beyond 2025)



Price Projection, Checking, and Validation





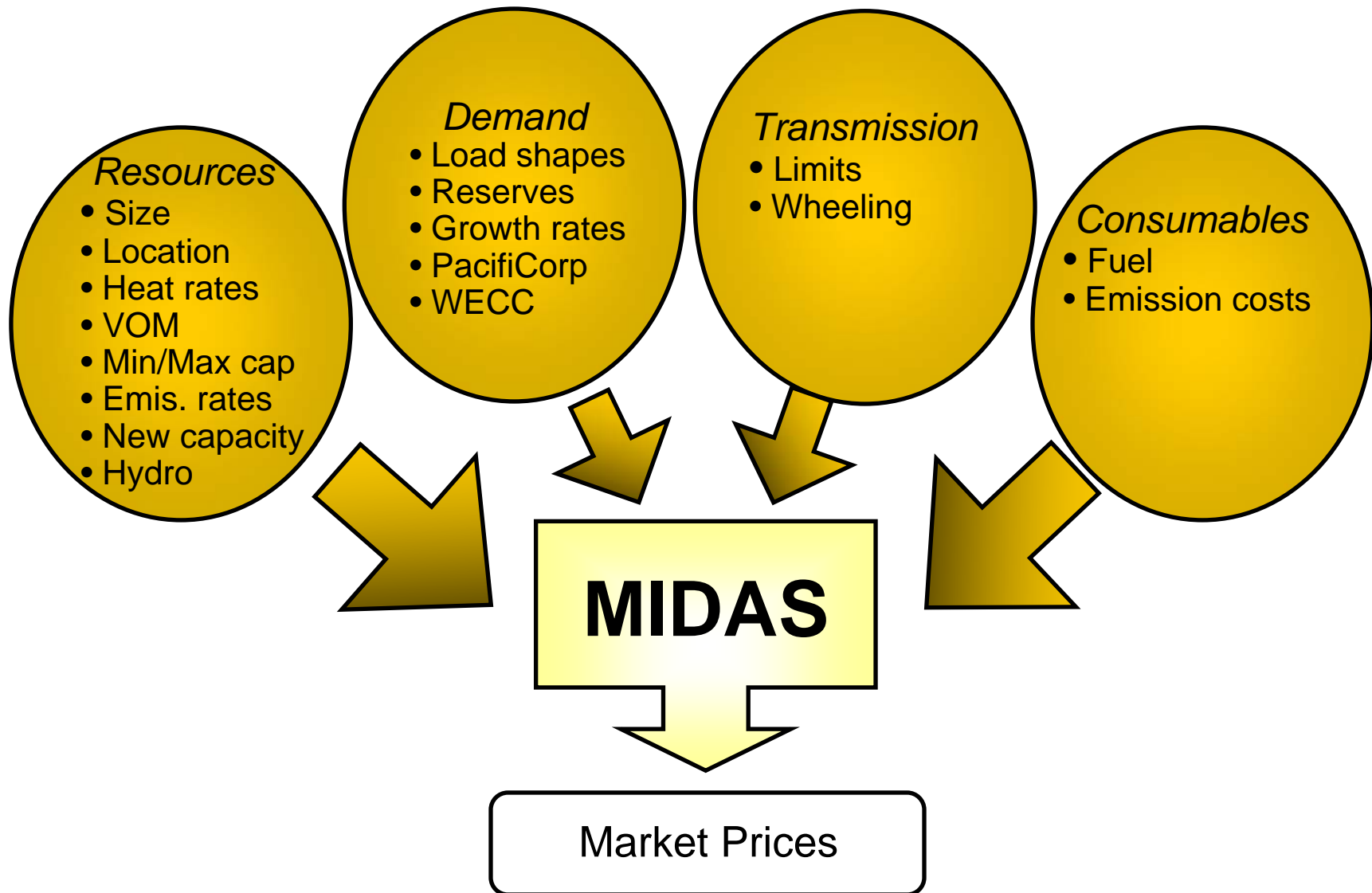
MIDAS Pricing Overview



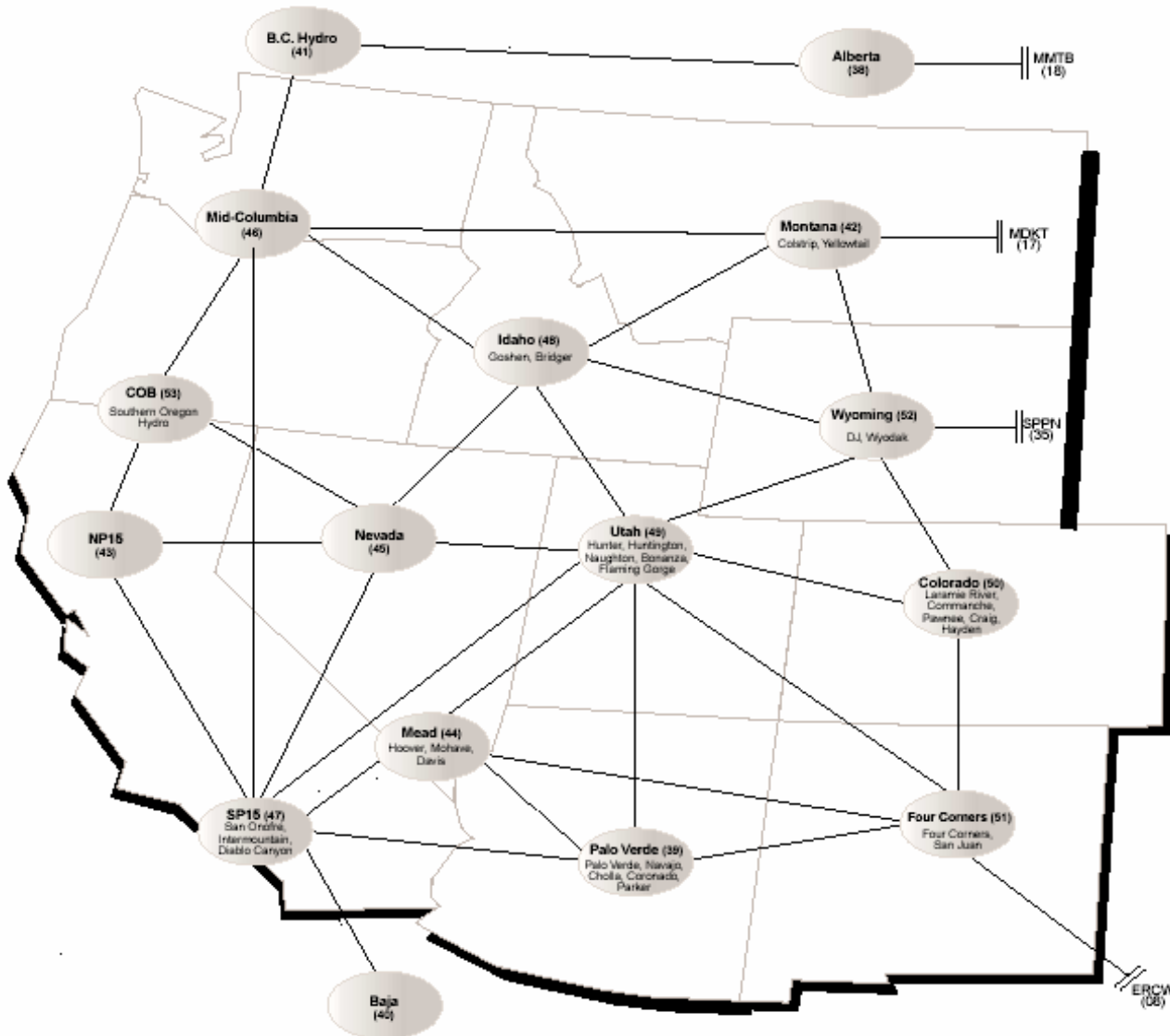
MIDAS Gold® - Introduction

- Licensed from MS Gerber (owned by Global Energy Decisions)
 - User support
 - Data delivery
 - Updates
- Powerful planning and analysis module
 - Ability to model complex scenarios
 - Flexible to user-defined inputs
 - Decision framework – ability to recognize uncertainties in fundamental drivers
- Chronological, hourly dispatch

Fundamentals Drive Long-term Forecast

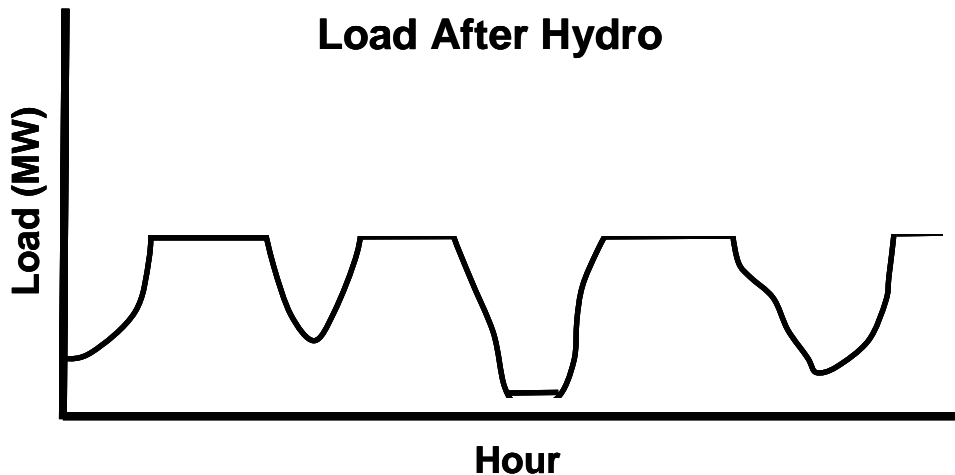
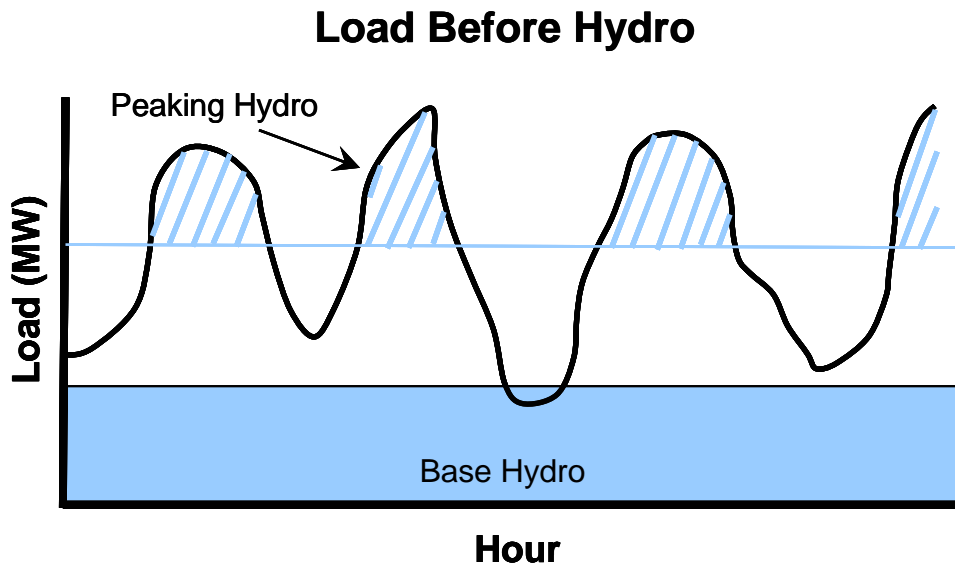


WECC Load Centers & Transmission Topology



- Transmission limits represent total transfer capability
- MIDAS is “blind” to transmission ownership

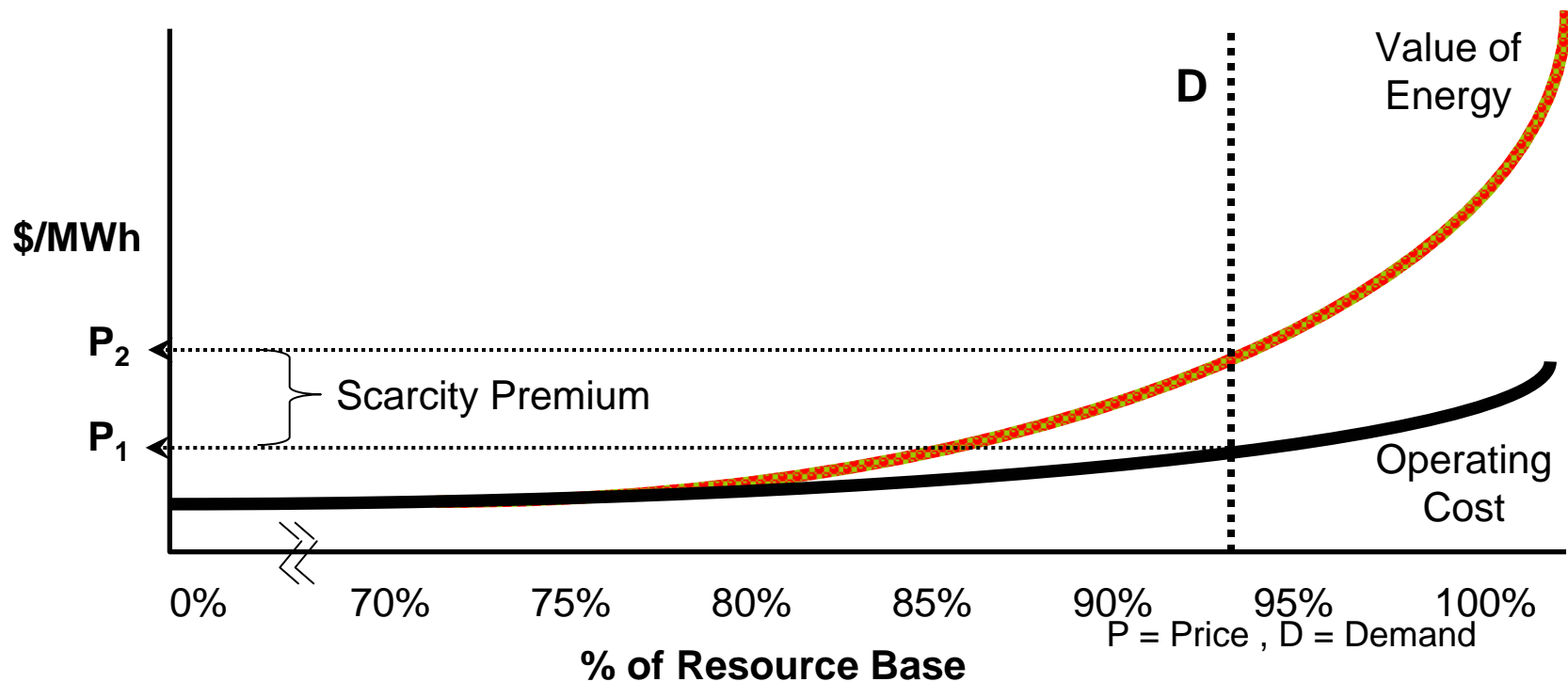
Model Logic: Hydro Generation



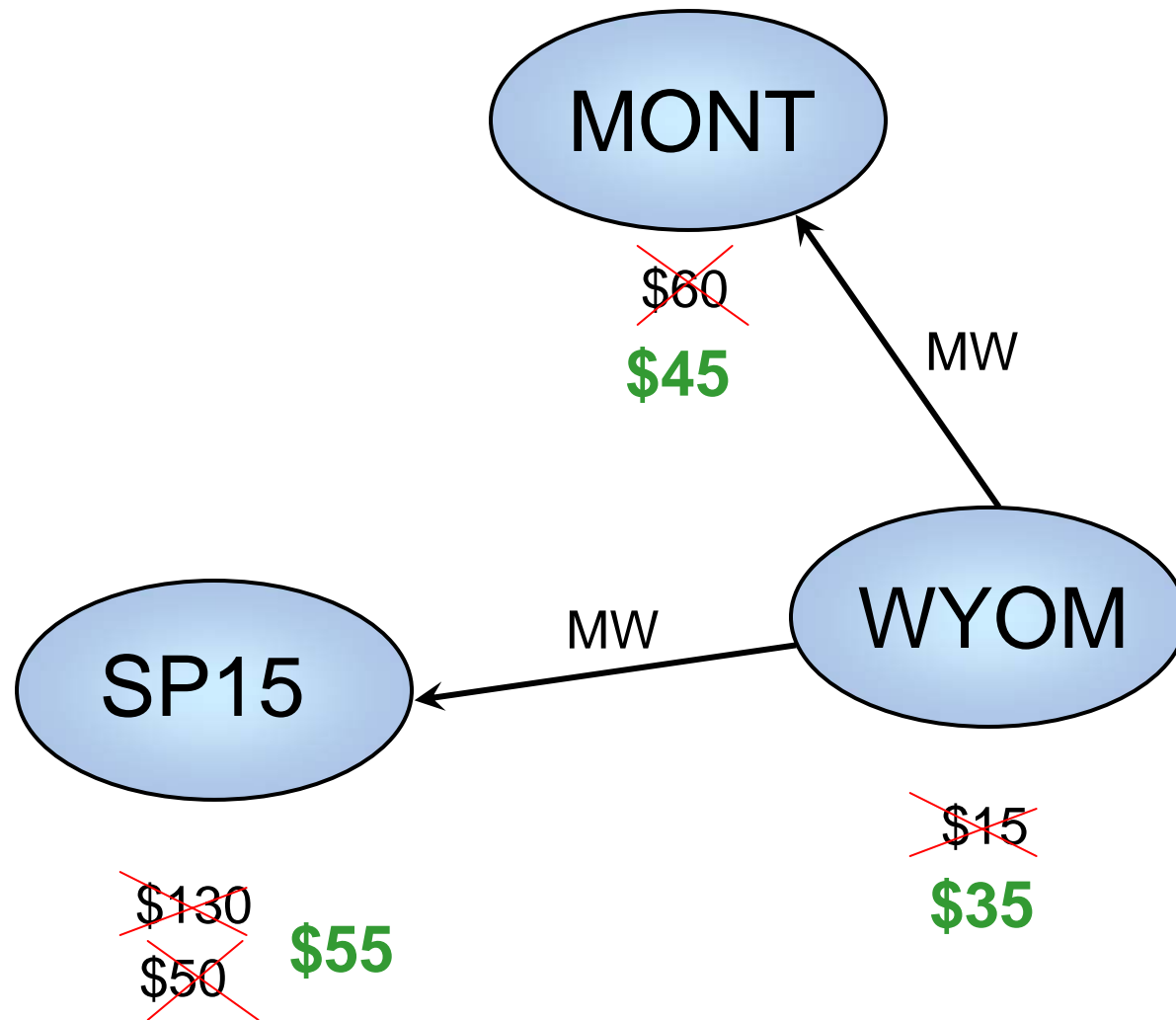
- Hydro generation is used to shave load
- “Peaking” hydro units shave peaks
- “Base” hydro units shave load equally in all hours
- “Thermal” hydro units are not used to shave load, but are dispatched; this allows regions with excess hydro (Mid C and BC Hydro) to export via transmission

Model Logic: Resource Scarcity Premiums

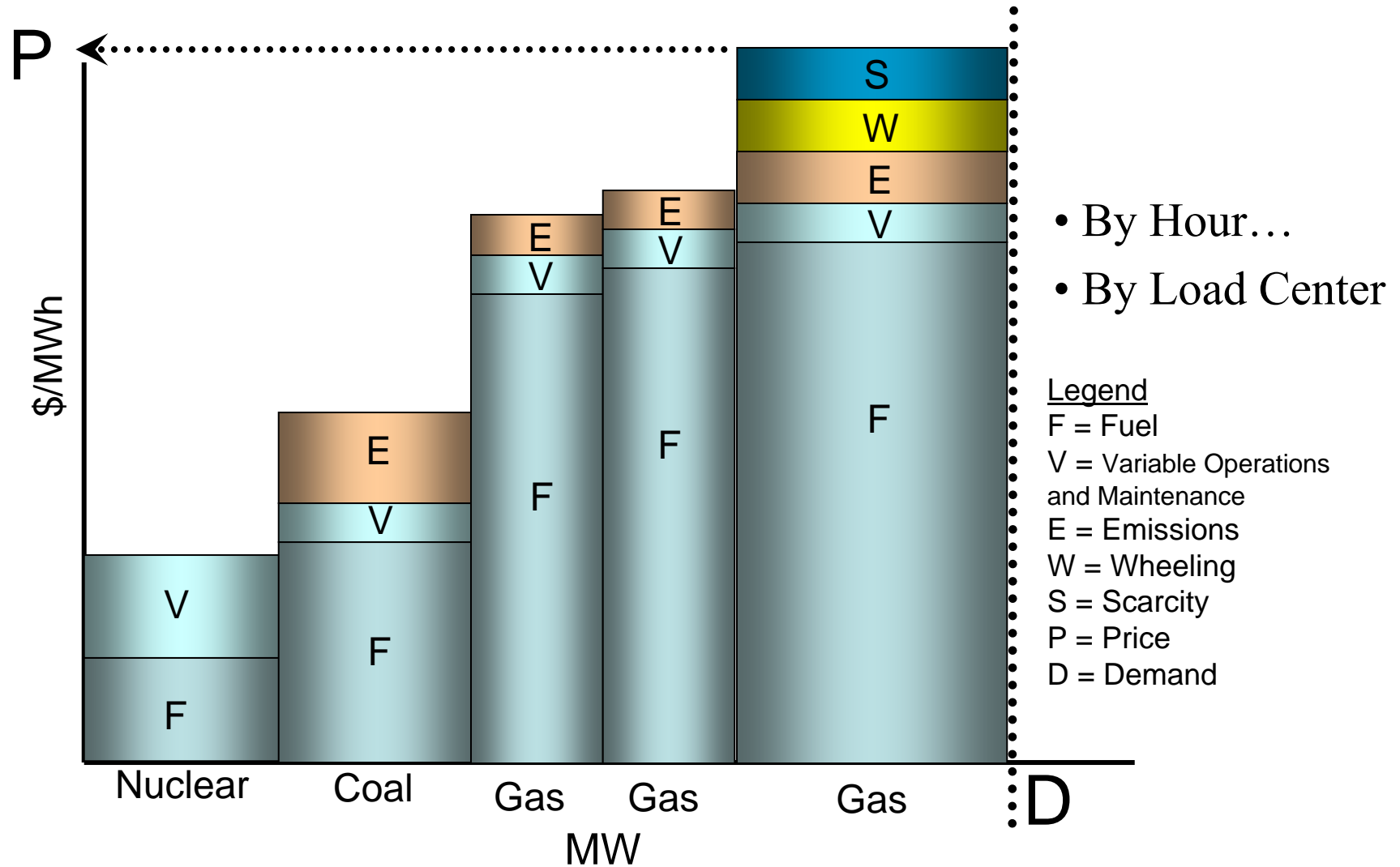
- Reflects ability of sellers to charge higher prices in scarcity situations
- Energy costs + a premium when demand stretches available resources
- Market gas and power prices are used to calibrate MIDAS prices to market toward the end of each quarter



Model Logic: Transmission

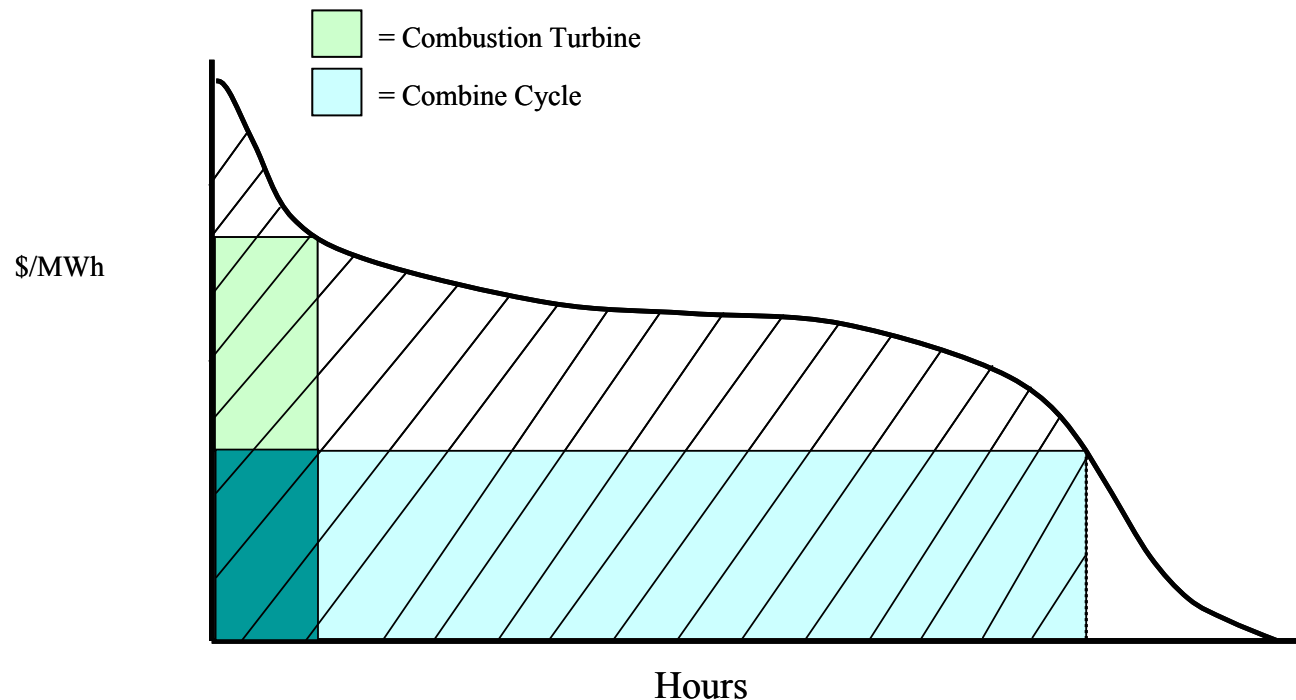


Model Logic: Supply/Demand & Marginal Pricing

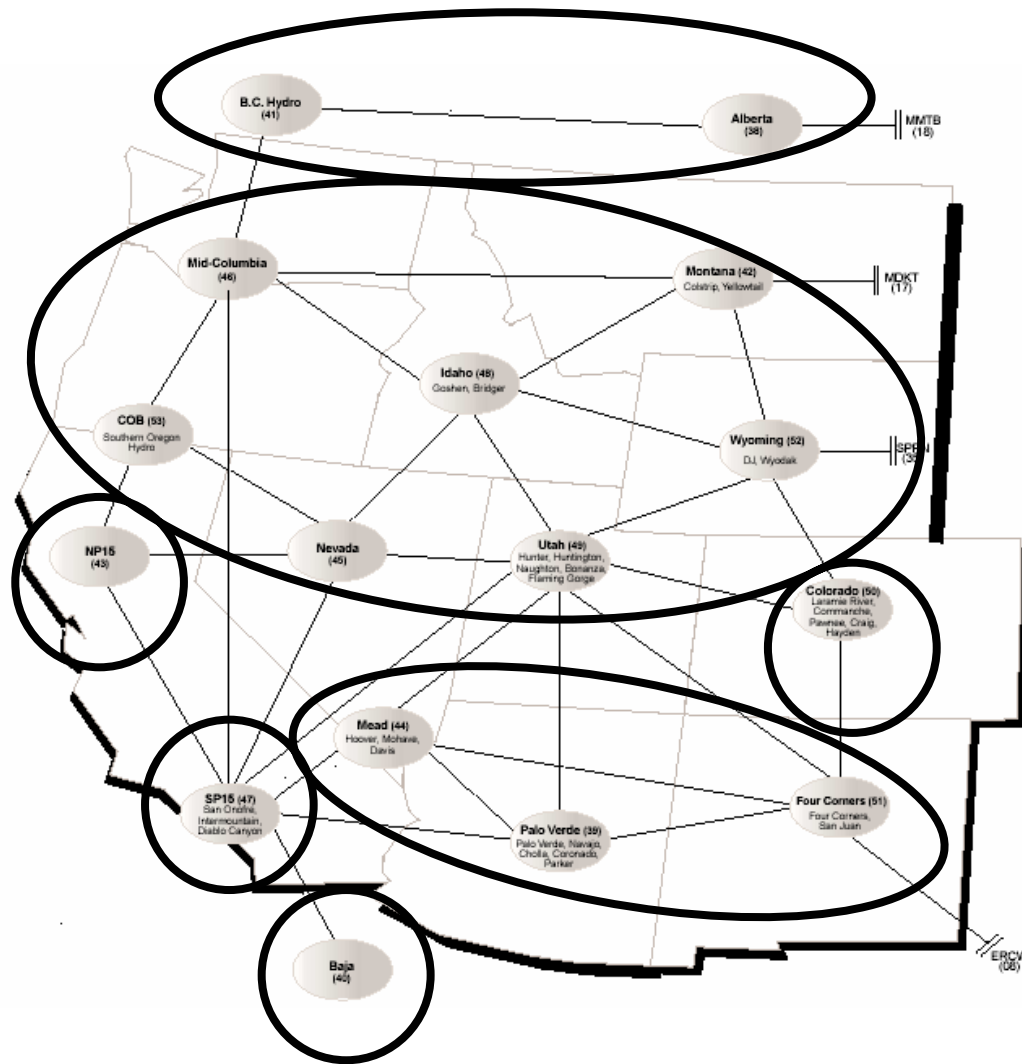


Model Logic: Economic Resource Additions

- Compares revenues to dispatch costs among potential new resource options
- Revenues = Market Price (\$/MWh) x Generation (MWh)
- Operating Costs = Fuel + Variable Operations and Maintenance + Emissions
- Revenues – Operating Costs = Net Operating Margin
- Net Operating Margin > Fixed Costs (levelized capital and Fixed Operations and Maintenance), resource added



Model Logic: Reliability Resource Additions



- Planning reserve margins assumed at 15%
- Economic additions not always enough to satisfy planning reserves
- Options having least negative margins added until reserves are met

Model Logic: Reliability Resource Additions

(part 2)

- MIDAS can add resources to meet reliability requirements even if they are not “economic”
 - Resources evaluated by MIDAS include:
 - Natural gas intercooled aeros, simple cycle combustion turbines, and combined cycles (with and without duct firing),
 - Coal-fired units, and
 - IGCC units
 - Different regions may have different resource options – for example, MIDAS would not be given the option to add a coal plant in Southern California
- Resource options are evaluated and those with best margin are added to the resource mix



Key Inputs



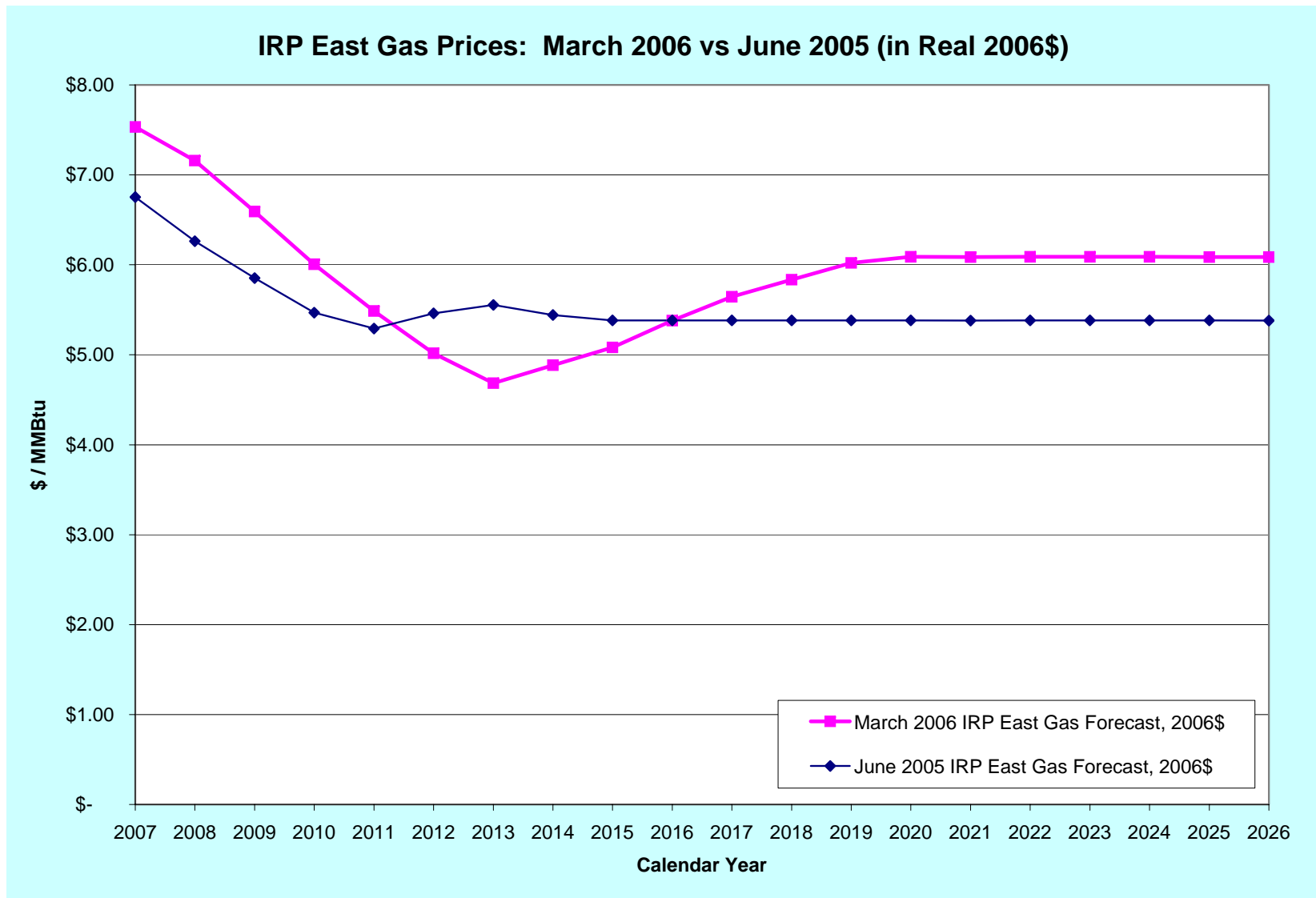
Input Updates

- The MIDAS database is updated regularly using a blend of purchased, public, and proprietary sources
- New WECC generation units are only added to MIDAS after independent sources have verified that the units are under construction or operational
- Changes in transmission data inputs are verified with external sources (if applicable) and reviewed with internal transmission experts

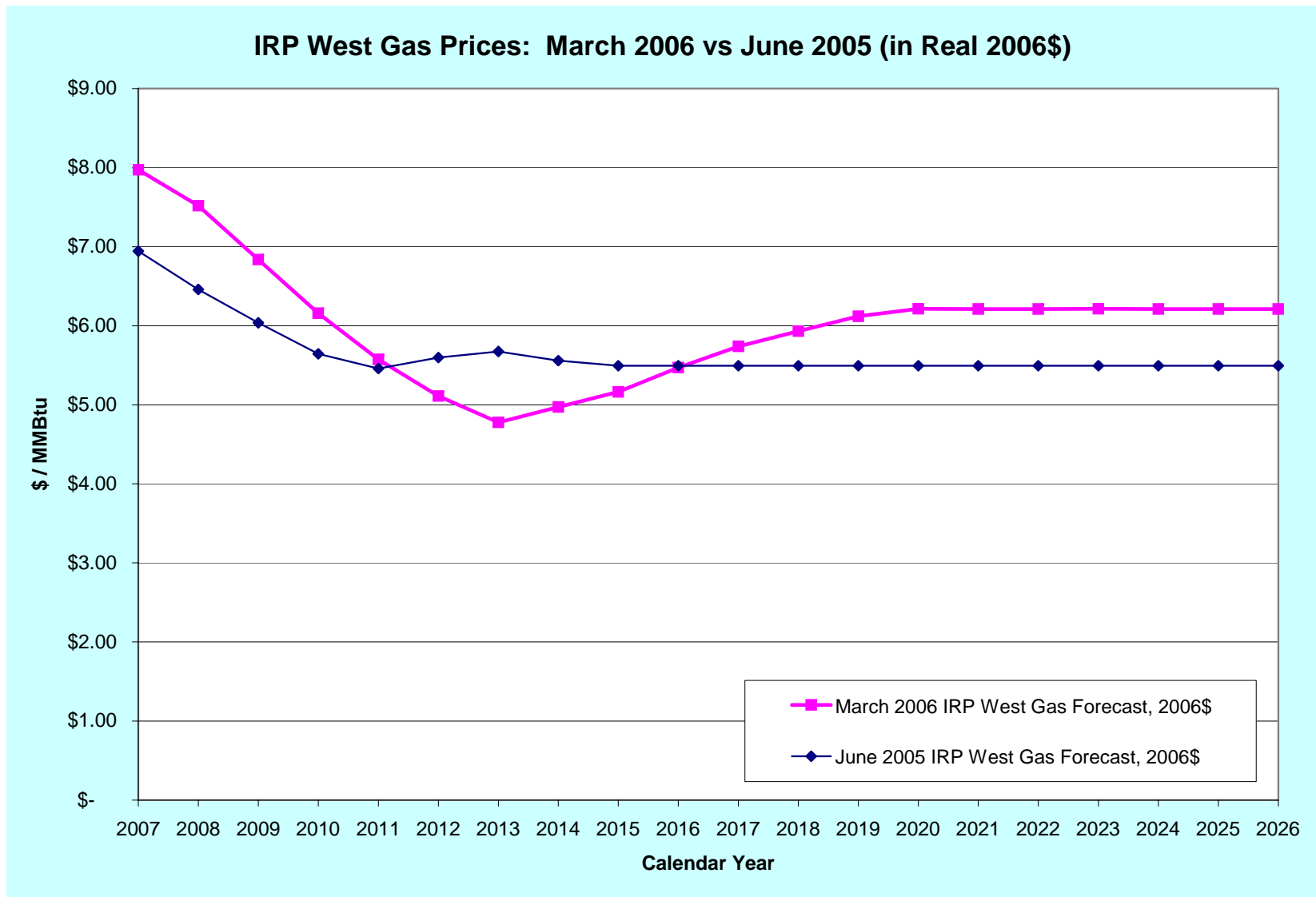
Natural Gas and Oil Forecasts

- Natural gas price assumptions are based on PIRA's proprietary gas and oil forecast, which are used to derive the MIDAS gas and oil forecasts through 2020. Gas and oil prices for 2021 and beyond are escalated using PacifiCorp's inflation curve in effect at the time the MIDAS price forecast is calculated
- PIRA's long-term gas price forecast dated 2/27/06 shows decline in prices over the 2006-10 period, similar but more pronounced than earlier forecasts. The following charts, shown in real 2006 dollars, compare these forecasts.
- The decline in medium term is consistent with ongoing market shifts arising from recent sustained high prices:
 - Accelerated loss of marginal industrial gas demand
 - Accelerated coal generation new build
 - Ongoing success of LNG permitting, contracting & construction

Comparison of IRP East Gas Prices (in 2006 Real \$)



Comparison of IRP West Gas Prices (in 2006 Real \$)



Liquefied Natural Gas Developments

- 2005 Liquefied Natural Gas (LNG) Imports
 - 1.9 bcf/d, or about 2% of US production
 - Five facilities (4 onshore, 1 offshore) operated at about 60% capacity factor, having to compete in a tight global supply market
- Approved projects/expansions
 - 23 bcf/d import capacity
 - 75% in US, remainder in Canada and Mexico
 - Not all will be built, but a substantial fraction is already under construction
- Forecasts assume rapidly growing contribution
 - AEO2005 projection – 2010 LNG imports 300% of 2005, 2015 imports 575% of 2005

Allowance Prices

Sulfur Dioxide (SO₂):

- Continue to assume reductions in national cap on emissions in 2010 and 2015, consistent with EPA's Clean Air Interstate Rule
- Forecasted western spot SO₂ prices are higher compared to the IRP update, reflecting CAIR's distinction between eastern and western states and escalation in marginal control costs, as per PIRA forecast

Nitrogen Oxides (NO_x):

- No significant change from IRP update – assumed a Clear Skies type trading scheme, with western incremental control costs reflective of selective non-catalytic reduction costs
- Under review - Clean Air Interstate Rule currently doesn't envision such program for Western generators

Allowance Prices, Continued

Mercury (Hg):

- Cap-and-trade mercury program with allowances at \$7,155/pound in 2010, consistent with EPA's Clean Air Mercury Rule
 - This cost is only 20-25% of costs assumed in IRP Update, reflecting PIRA's assessment of advances in controls
 - Still large uncertainty in control cost and in CAMR implementation, as a number of states have or are likely to opt out

Effect of SO₂/NO_x/Hg on Wholesale Electricity Prices:

- Very small – gas generation is price setting in most hours and these emissions costs contribute a few cents to CCCT variable cost.

Carbon Dioxide (CO₂):

- Delayed timing (little activity since last IRP) and probability weighted prices in 2010 - 2011

MIDAS Demand Forecast

- The demand forecast used in the March 2006 price forecast is based on the 2006 Global Energy Decisions (GED) demand forecast
- The GED demand forecast is derived from historical information, short-term forecasting from utility-provided data, and longer-term forecasts projected using average annual growth rates, with some improvements for quality control and consistency

MIDAS Demand Forecast, continued

- The average annual WECC growth rates is about 2% per year for both energy and peak, which is consistent with assumptions underlying the June 2005 price forecast
- Changes in peaks and load varied by load center and by year, with some increasing and others decreasing
- These changes affect the MIDAS build pattern

Hydro Generation Forecast

- The Hydro generation forecast was developed by Global Energy Decisions (GED).
 - The forecast was based on median hydro conditions
 - The GED hydro data are based upon historical hydro generation unique to each generating unit in the WECC.
 - Total WECC average annual hydro production is forecasted to be approximately 248,000 GWh.

Inflation Forecast

- The official PacifiCorp inflation curve is a blend of GDP and CPI indices, which are derived from data from Global Insights
- Compared to the June 2005 inflation curve, inflation is assumed to be lower

Inflation Table

Average Annual Rate

Calendar Years	March 2006	June 2005
2007-2012	1.88%	2.28%
2013-2018	2.02%	2.47%
2019-2026	2.08%	2.55%

MIDAS Resource Additions

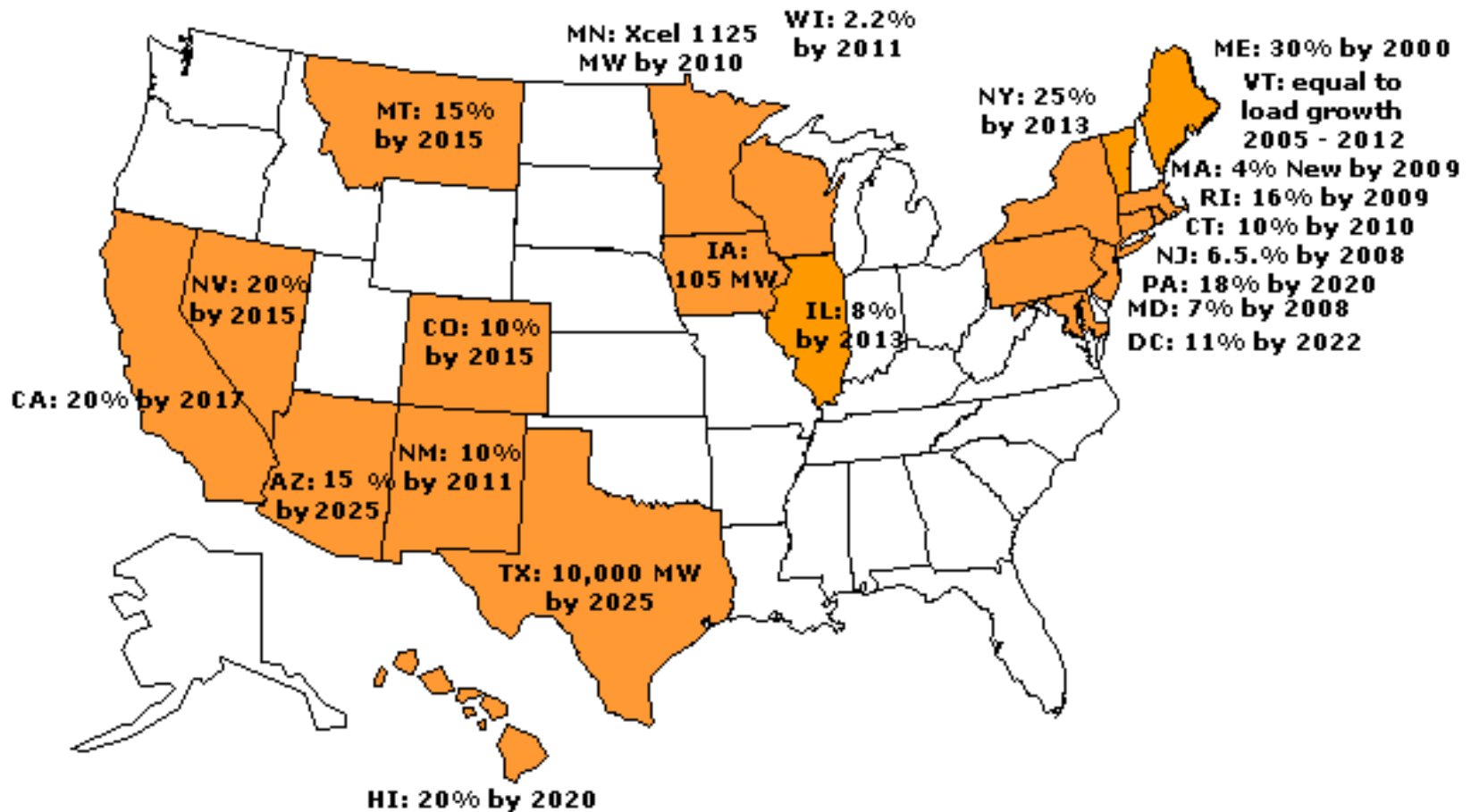
- MIDAS adds any additional resources required to meet growing demand and planning reserves through its automated resource addition logic
- This logic also simulates the addition of generation in response to market prices. The following table summarizes the new resources added throughout WECC by MIDAS in the March 2006 forecast through 2025.

Total MIDAS Resource Additions (MW)

Resource	March 2006
CCCT	44,637
Duct Fire	9,614
SCCT	13,902
Aero	204
Coal	3,450
IGCC	1,038
Total	72,845

Renewable Portfolio Standards

Many states in the West are developing aggressive RPS requirements



Source: Modified from Pew Center on Global Climate Change
(http://www.pewclimate.org/what_s_being_done/in_the_states/rps.cfm)

Renewable Portfolio Standards and Pacific Northwest Renewable IRP Generation in MIDAS

- A goal in MIDAS is to assess market impacts on western power markets of:
 - RPS initiatives in California, Arizona, New Mexico, Nevada, and Montana; these initiatives vary considerably by state and by utility.
 - Proposed IRP renewable generation in Oregon, Washington, Idaho, Utah, Wyoming, Alberta and British Columbia
- In MIDAS, renewable resources are low- to no-cost resources.
- The impact of adding renewable resources in MIDAS is to decrease average market prices.
- By 2025, renewable resources added in MIDAS represent approximately 6% of total WECC demand.

Renewable Portfolio Standards and Pacific Northwest Renewable IRP Generation in MIDAS, continued

Renewable Generation Additions in MIDAS by 2025:

	<i>State RPS Requirements:</i>		<i>Pacific NW IRP Renewables:</i>		<i>Total Renewable Additions</i>	
	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)
Alberta			4,125	1,570	4,125	1,570
British Columbia			2,356	897	2,356	897
Colorado	4,036	1,517			4,036	1,517
Four Corners	328	43			328	43
Idaho			1,945	550	1,945	550
Mead	360	111			360	111
Mid Columbia			4,102	1,561	4,102	1,561
Montana	1,446	460			1,446	460
Montana (from Avista's IRP)			657	250	657	250
Nevada	8,808	1,770			8,808	1,770
NP15	9,913	2,080			9,913	2,080
Palo Verde	9,686	2,575			9,686	2,575
SP15	23,039	5,419			23,039	5,419
Utah / SW Wyoming			1,577	600	1,577	600
<i>Total</i>	57,616	13,973	14,761	5,427	72,378	19,400

Wheeling Assumptions and RTO Formation

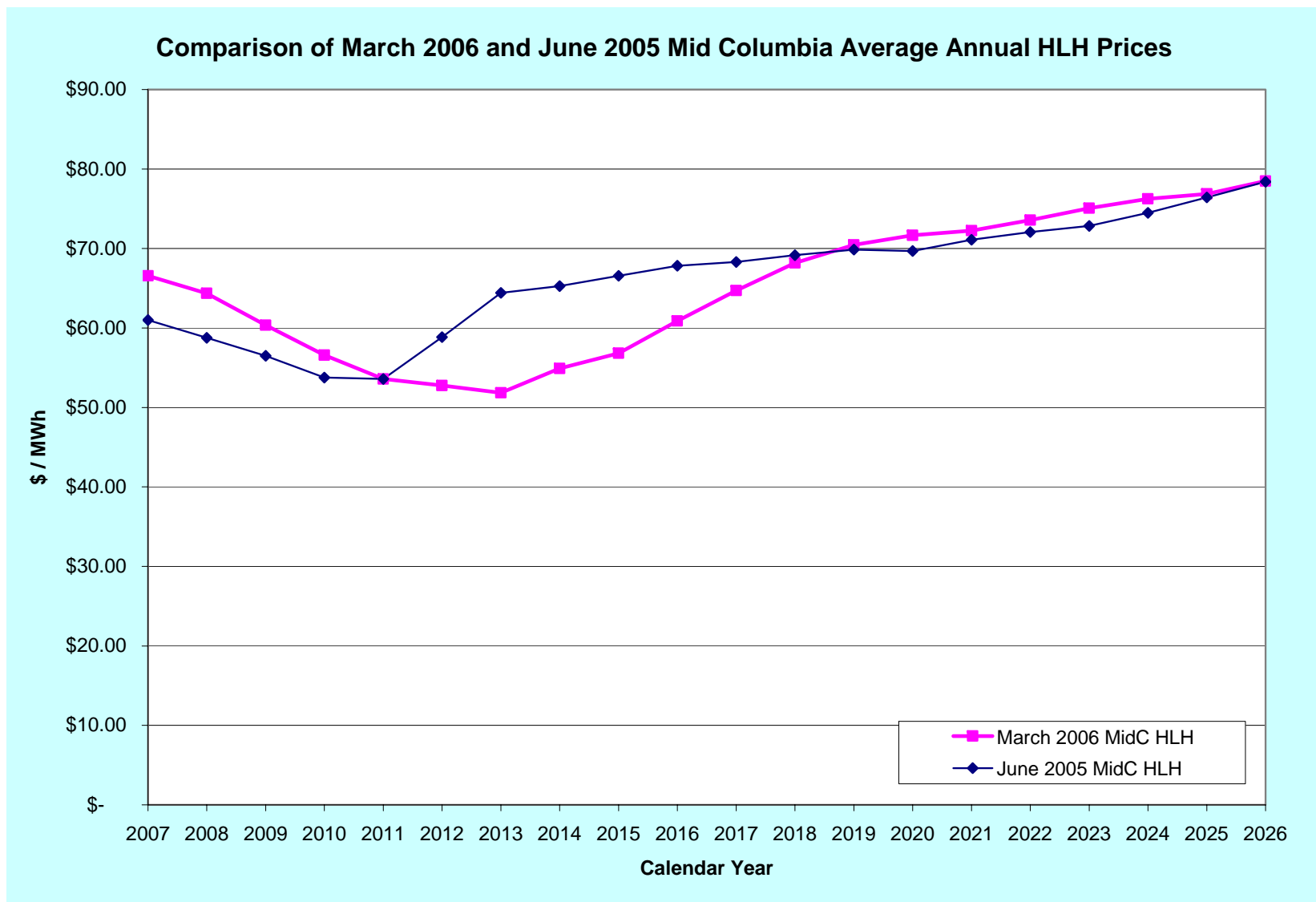
- Previous wheeling assumptions in MIDAS:
 - Grid West and WestConnect RTO configuration were assumed to eliminate current pancaked wheeling rates in 2009
 - Under these assumptions, MIDAS reflected decreased high load hour and low load hour wheeling rates within RTOs
- The current MIDAS wheeling assumption:
 - The recent dissolution of Grid West demonstrates the weakness of the movement to form RTOs within WECC
 - In MIDAS, pancaked wheeling rates are not assumed to be eliminated through RTO formation
 - Therefore, the MIDAS model does not show a change in wheeling rates over time



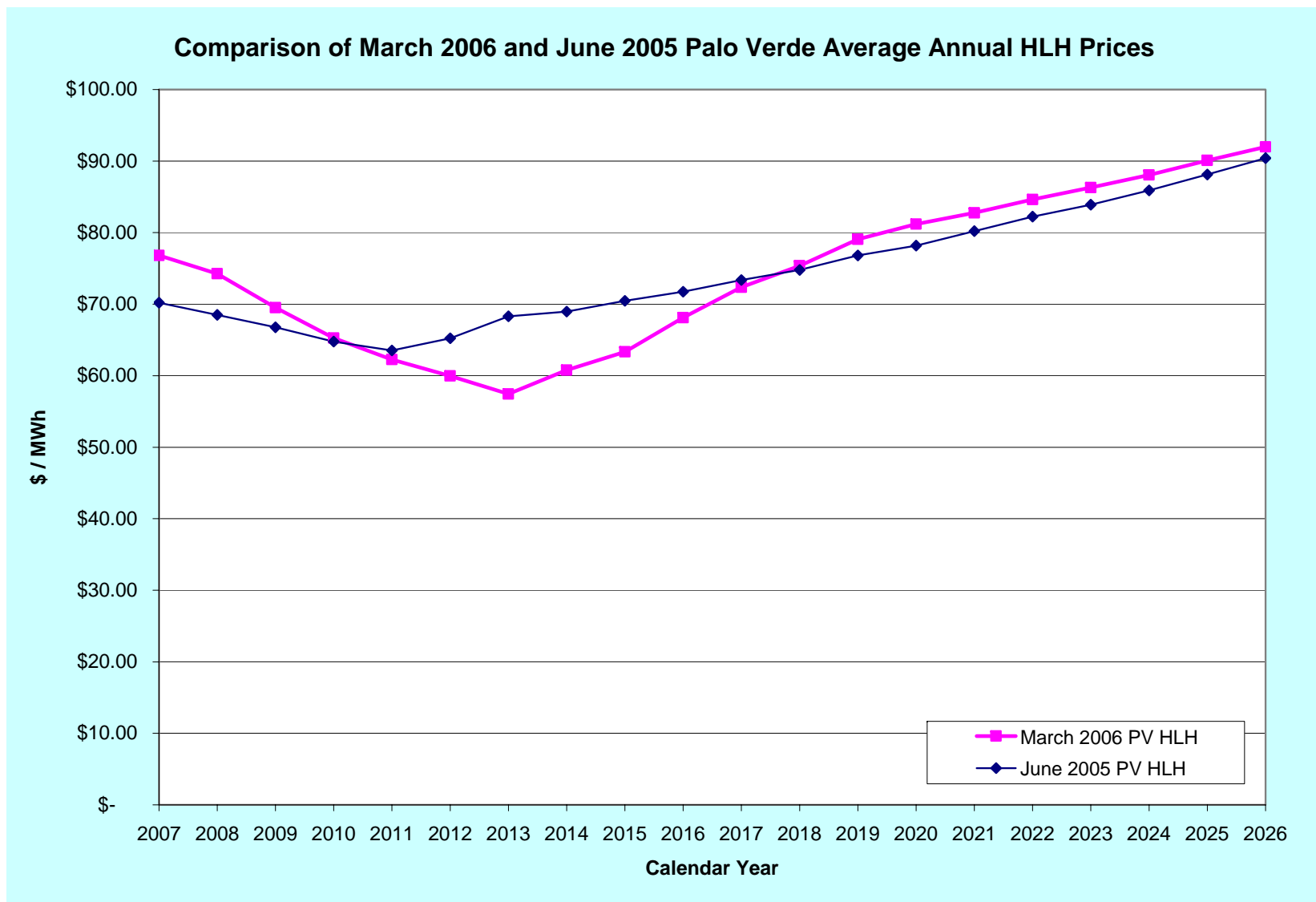
Average Price Impacts



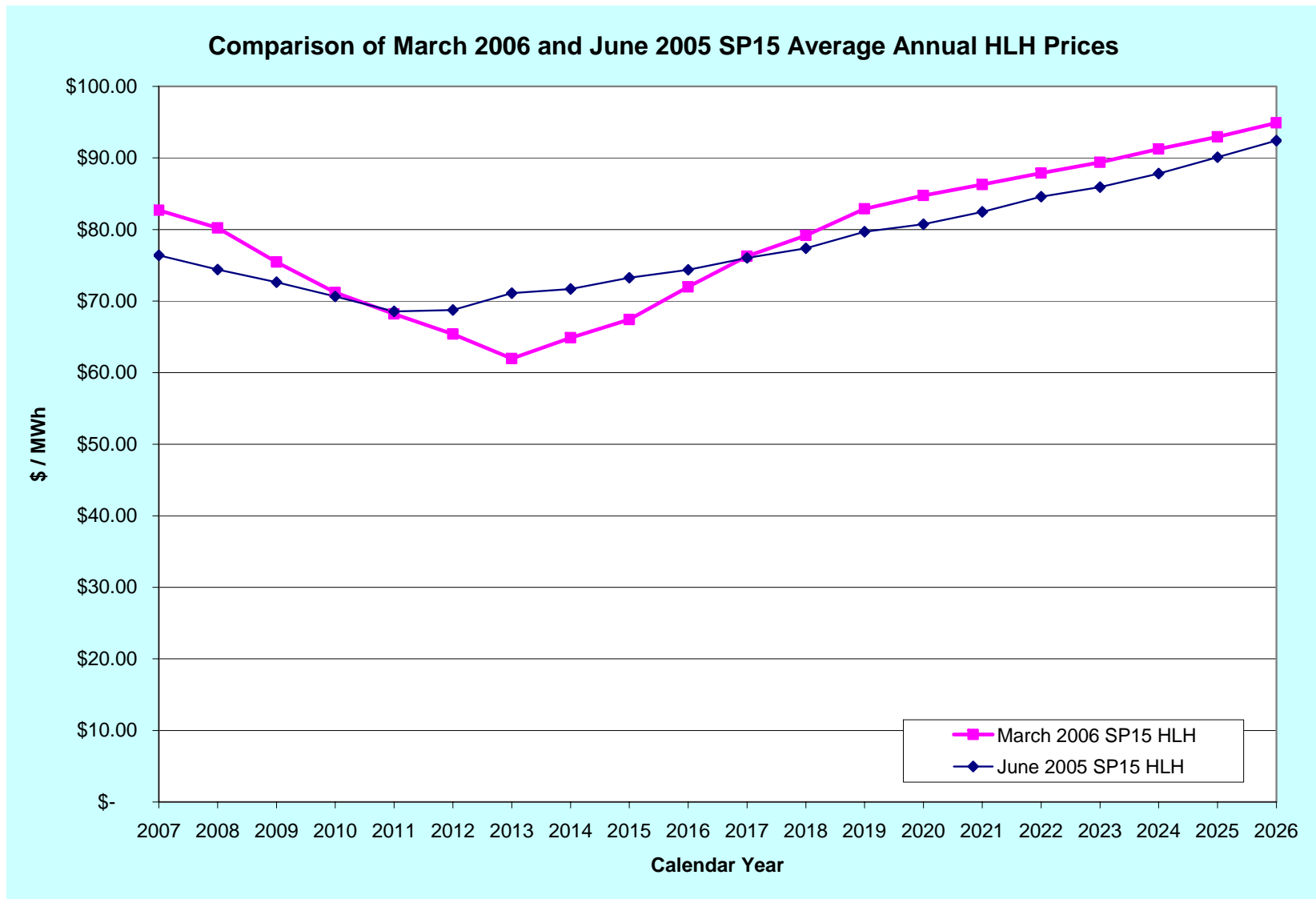
Average Price Changes: Mid Columbia High Load Hours



Average Price Changes: Palo Verde High Load Hours



Average Price Changes: SP15 High Load Hours





Renewables Studies

Ken Dragoon



Renewables Study

- Progress and initial results
 - Selection of wind resource proxy sites
 - Incremental reserve requirements
 - Wind peak load carrying capability
 - Green tag valuation review
- Remaining work
- Questions and comments on the results to date

Wind Resource Proxy Sites

- Selected based on data available to PacifiCorp, including from the renewable resource request for proposals
 - Quantities are somewhat subjective, with resource quantities potentially higher in some areas

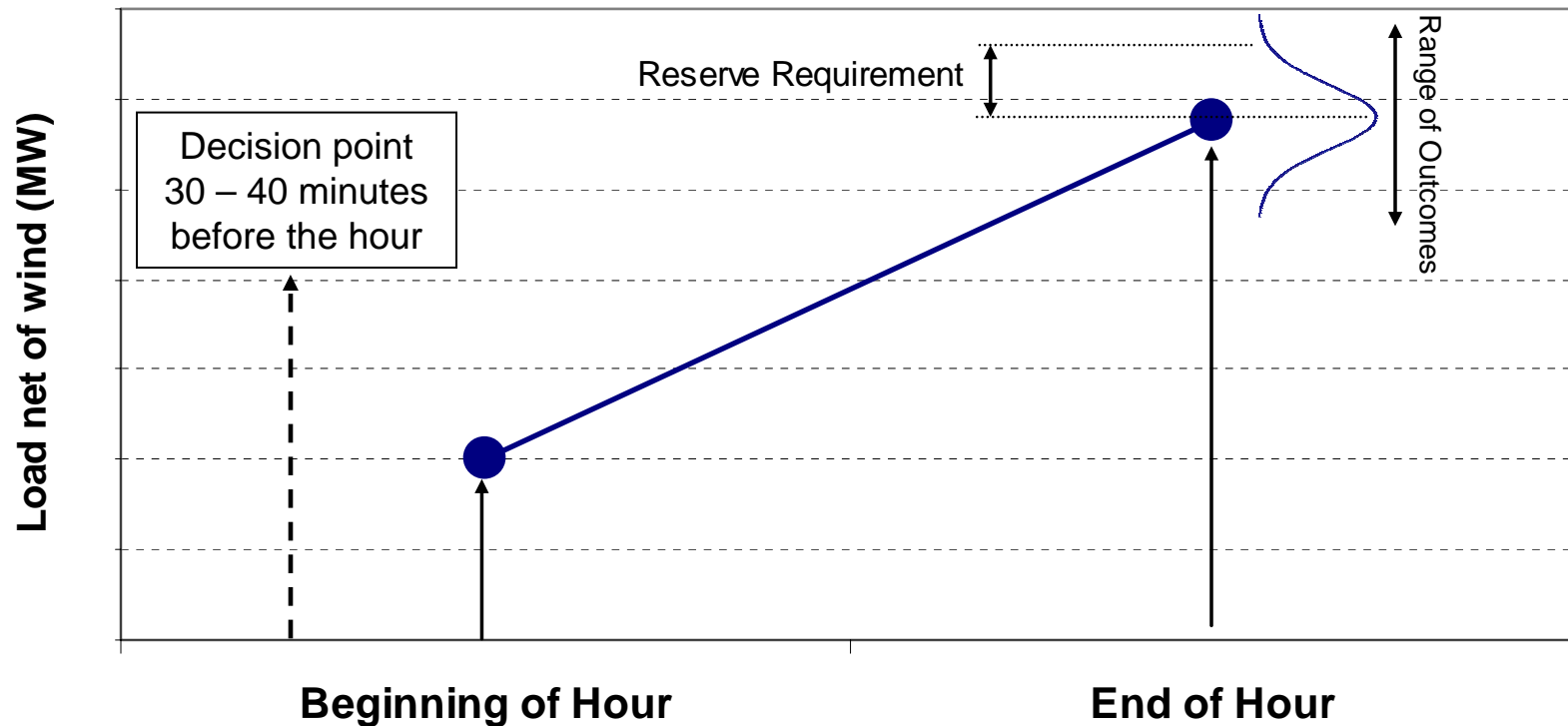


Incremental Reserve Requirements

- Methodology
 - Base the reserve requirements on 95th percentile probability level of short term forecast error
 - Create short term (hour ahead) forecasts of load net of wind generation at various levels of installed wind capacity
 - Observe how the forecast error changes with increasing amounts of wind on the system

Incremental Reserve Requirements

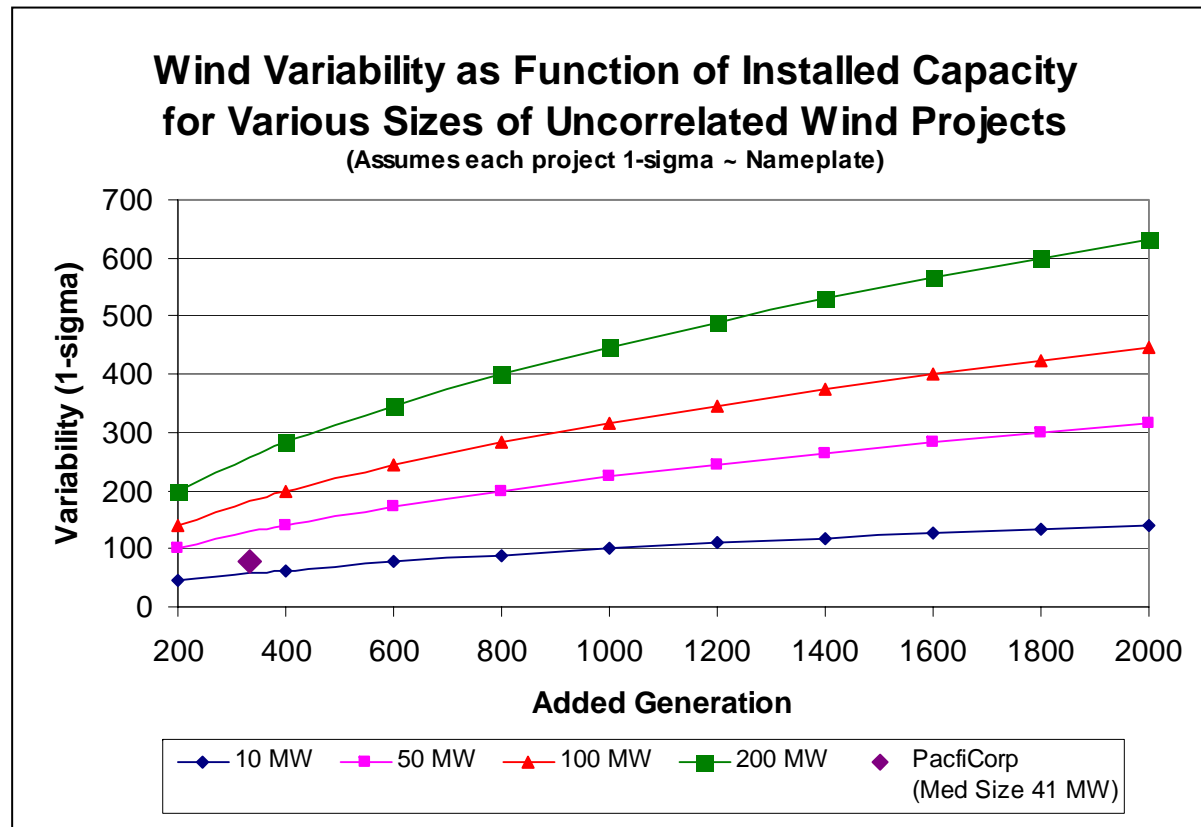
Reserve Requirement Illustration



- Choose a regulating reserve margin that covers unexpected load/wind changes 95% of the time

Incremental Reserve Requirements Results

- Overall wind variability depends on quantity, size, and correlation of wind project output

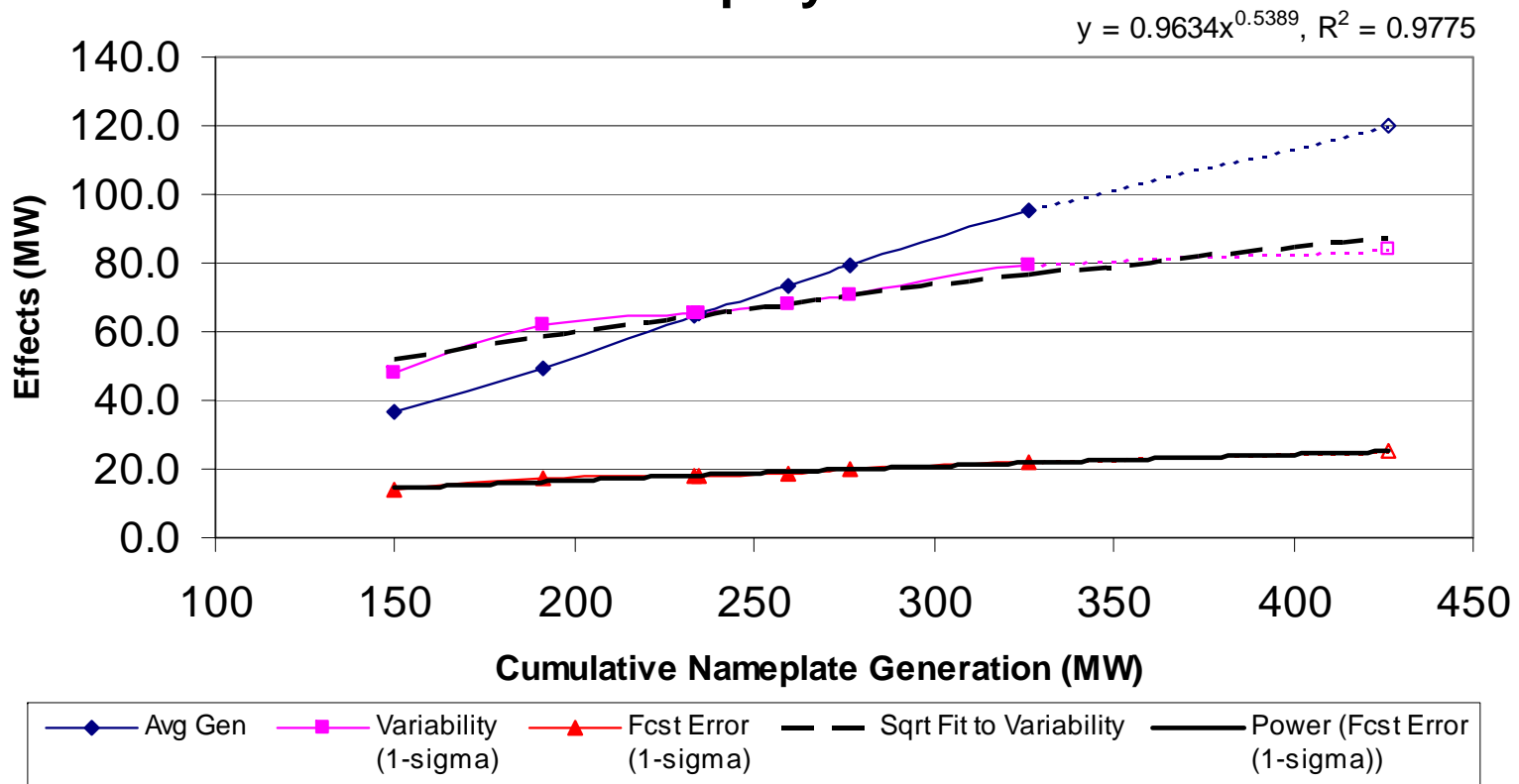


- Variability grows as the square root of installed generation for uncorrelated wind projects

Incremental Reserve Requirements Results

- Forecast error also grows roughly as the square root of the added generation, but at a significantly lower level

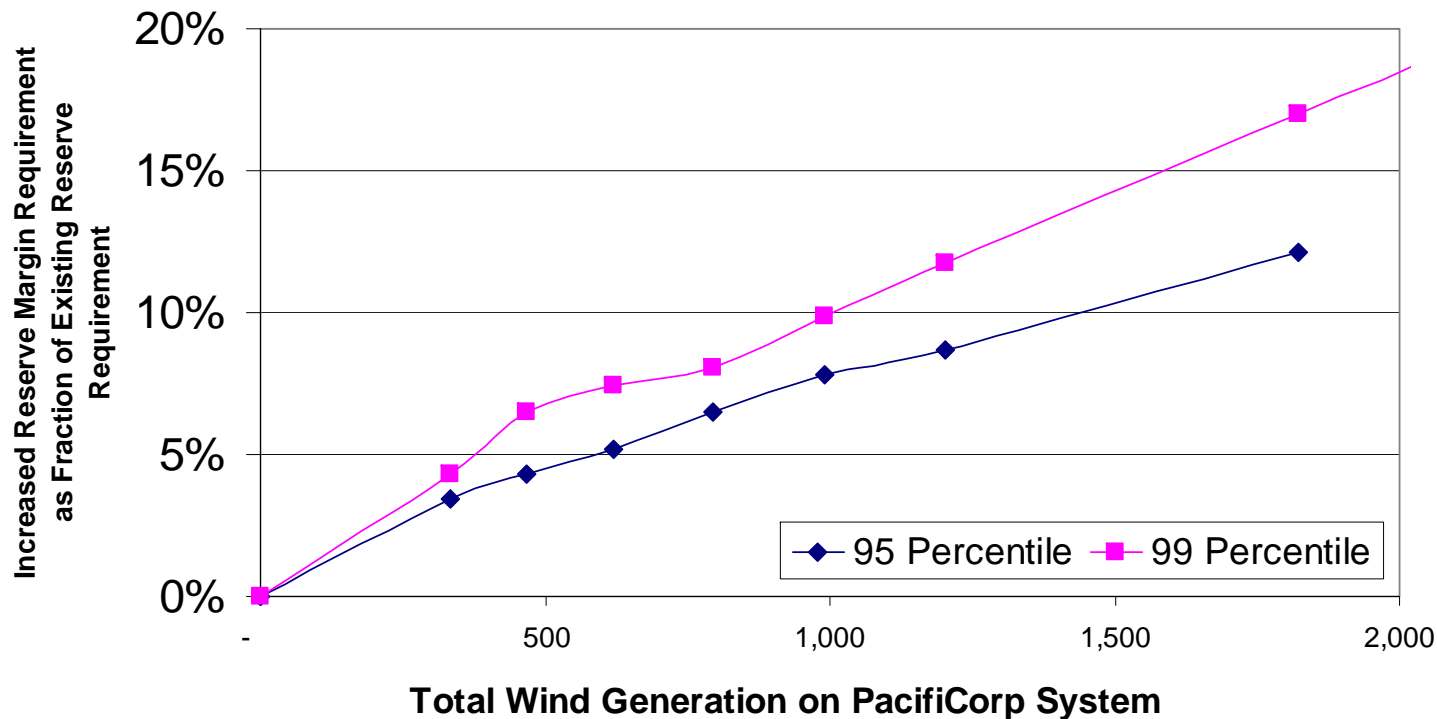
Trends in Cumulative Wind Effects on PacifiCorp System



Incremental Reserve Requirements Results

- Increasing levels of forecast error were related back to nameplate capacity to derive the relationship between incremental reserve requirements and nameplate wind additions

**Wind Incremental Reserve
Margin Requirement**



Incremental Reserve Requirements Results

- Summary
 - Addition of 1,400 MW of nameplate wind equates to approximately 11% increase (<30 MW) of current load following reserve margin requirements at the 95th percentile level
- Caveats
 - Need to institute short term load forecasting on operational basis to estimate next hour wind generation
 - Need to have sufficient generation available to ramp up or down to meet the forecasted hourly change

Capacity Contribution Analysis

- Methodology

- Ran stochastic model to find capacity contribution of an added wind resource

- Used relation

$$P \approx R' - K \cdot \sigma_{R'}^2$$

- to calculate K for the system

- Used the relation above to estimate capacity contribution of other wind projects

- A little complicated because of correlations of hourly generation between added projects in same and adjacent regions

P = Capacity Contribution (PLCC)
R' = Expected generation during on-peak hours
K = Constant related to power system size and reliability level
$\sigma_{R'}^2$ = Variance of on-peak generation

Capacity Contribution Analysis

- Peak Load Carrying Capability (PLCC) for existing projects

PLCC of Existing Projects	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1 SE WA / NE OR (MW)	31	24	57	36	37	39	30	30	33	35	33	31
2 SE WY & SE ID (MW)	79	66	89	55	55	49	35	38	46	57	83	83
Total (MW)	110	90	147	91	92	88	66	68	78	92	117	114
As percent of nameplate	28%	23%	37%	23%	23%	22%	17%	17%	20%	24%	30%	29%

- Capacity contributions were calculated for every month of the year based on expected generation for the month

1 Stateline, Combine Hills

2 Foote Creek I-IV, Rock River, and Wolverine Creek

Capacity Contribution Results

Observations:

- Incremental capacity contribution within an area declines due to correlations (lack of diversity) among wind projects in an area
- Decline is greatest for projects with more variability of on-peak contribution
- Capacity varies over the year primarily due to expected on-peak generation

Regional Resource Additions (MW)		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NC OR	-100	1	18	28	17	25	35	37	27	22	14	5	5
	-200	0	8	16	7	14	24	28	18	12	5	0	0
	-300	0	0	3	0	3	14	19	10	2	0	0	0
	-400	0	0	0	0	0	3	10	1	0	0	0	0
SE WA	-100	19	14	33	13	13	10	12	7	10	14	16	16
	-200	8	2	20	2	1	0	2	0	0	3	5	4
	-300	0	0	8	0	0	0	0	0	0	0	0	0
	-400	0	0	0	0	0	0	0	0	0	0	0	0
EC NV	-100	18	20	32	32	23	28	27	23	21	23	19	28
	-200	15	17	29	26	20	24	23	20	17	20	17	24
	-300	13	14	25	20	16	20	20	18	13	16	14	21
	-400	10	12	21	14	13	17	16	15	9	13	12	17
SE ID	-100	26	37	59	35	31	32	25	32	22	32	38	32
	-200	20	31	53	29	26	27	21	28	17	26	32	26
	-300	14	24	47	24	22	22	17	24	13	21	25	20
	-400	8	17	41	18	17	17	13	20	8	16	18	14
WC UT	-100	13	10	25	31	35	27	20	26	26	24	20	19
	-200	10	9	21	27	31	24	18	22	22	20	17	16
	-300	7	7	17	22	26	20	15	18	18	16	14	13
	-400	4	6	13	17	21	17	12	15	13	13	11	10
SW WY	-100	33	27	36	33	30	30	23	24	25	31	24	34
	-200	27	24	29	27	26	25	20	21	22	26	21	28
	-300	21	20	22	21	21	21	18	18	19	21	18	22
	-400	16	16	15	16	16	16	15	16	16	16	15	16
	-500	10	12	8	10	11	11	13	13	13	11	13	10
	-600	5	8	1	4	6	7	10	10	9	6	10	4
SC MT	-100	0	5	0	0	2	2	7	7	6	1	7	0
	-200	42	34	35	24	26	26	27	26	28	32	42	33
	-300	34	27	26	19	23	21	24	23	24	28	33	26
	-400	26	20	18	14	19	16	21	20	21	23	25	18
SE WY	-100	18	14	10	9	15	11	18	18	18	19	17	11
	-200	35	26	30	25	22	19	13	15	18	23	44	37
	-300	30	21	24	21	18	16	11	13	15	18	43	32
	-400	25	16	19	17	14	12	9	10	11	13	43	27
	-500	20	12	13	13	10	9	7	8	7	9	42	23
	-600	15	7	7	9	6	6	5	6	3	4	41	18
	-700	9	2	2	5	2	3	3	3	0	0	40	13
	-700	4	0	0	1	0	0	1	1	0	0	39	8

Capacity Contribution Caveats

- Capacity contribution assumes sufficient transmission to integrate all wind projects into load areas
- Capacity contributions represent estimates that are less accurate at higher penetration levels
- Correlations, hourly output variability, and expected on peak generation are all based on relatively sparse data, and can be significantly different for specific wind site proposals

System Balancing Costs

- Will be necessary for both CEM runs and project valuation
 - Estimated by taking hourly wind generation into hourly dispatch model and comparing with identical amount of energy generated at constant rate
 - Contacted NREL scientist, and now propose to use same method except that the comparison generation will be shaped into heavy and light load hour blocks by month

Green Tag Valuation

- Market value of green tags has dropped since the \$5/MWh for 5 year assumption was adopted in 2003
 - Currently in the \$3-4.50/MWh range, with some expectation that they may rise to \$4-5/MWh in 2007
- More states are adopting renewable portfolio standards (RPS)
 - PacifiCorp is subject to the California RPS
 - Washington State is considering an RPS ballot measure
- RPS requirements do not necessarily increase the value of green tags
 - California requirements for renewable power deliveries into the state left tag value virtually unchanged
 - The proposed Washington RPS may provide upward pressure on tag prices

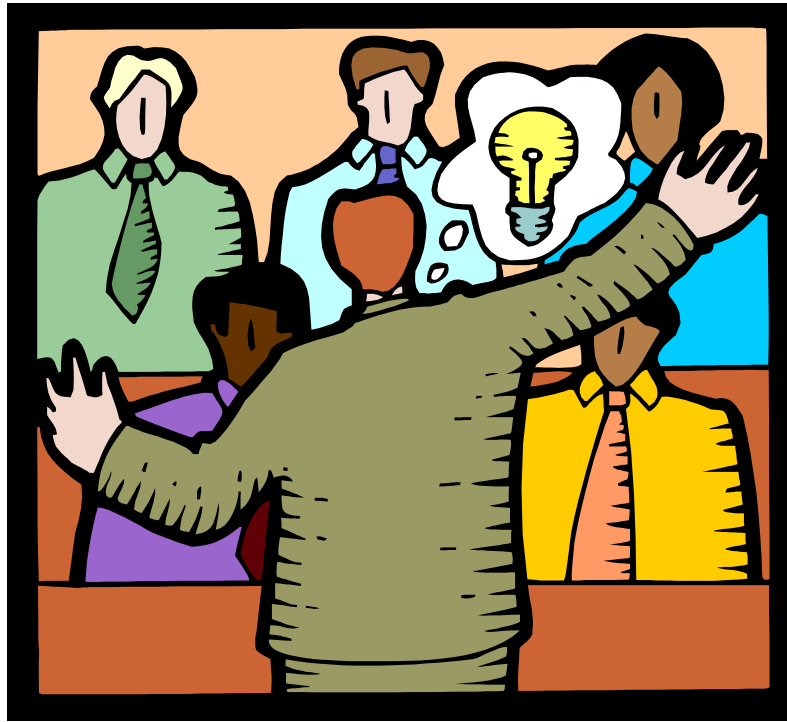
Green Tag Valuation Conclusion

- No paradigm shift observed with respect to tag values
 - Market prices have generally fallen since 2003
 - RPS requirements expanding, but with uncertain impacts
- PacifiCorp plans to retain the 2003 assumption
 - Present value of \$5/MWh spread over 5 years in constant nominal terms

Remaining Work

- Wind Supply Curve Modeling and Penetration Analysis
 - Develop revised capital costs
 - Based on combination of sources (including RFP responses and EPRI TAG data where available)
 - Develop transmission upgrade cost assumptions
 - Run Capacity Expansion Model with proxy wind sites in 100 MW increments, along with updated capital costs and transmission upgrades
 - With estimated integration costs, tax credits, and green tag value
 - Integration costs will not include adder for unit commitment

Comments, Questions, and Suggestions





Procurement Update

Stacey Kusters



Requests for Proposals

Request for Proposal - 2003 B Renewables

- Amendment issued March 24, 2006 for up to 400 MW prior to December 31, 2007
 - Proposals were due April 12
 - Evaluation completed April 17
 - Target negotiations complete June 2007
- Results on the 2003B RFP, as amended consist of a mix of proposals
 - Power Purchase Agreements
 - Build Own Transfers
 - Sites Sales
- Shortlist currently consists of multiple projects with up to hundreds of MW in opportunities beyond the 400 MW target

Request for Proposal – 2012 Resources

- | | |
|--|------------------------------------|
| • Pre-Draft RFP Presentation to Bidders | June 1, 2006 |
| • Pre-Draft RFP Presentation to Stakeholders | June 2, 2006 |
| • PacifiCorp files Draft RFP | July 11, 2006 |
| • PacifiCorp files RFP | Target for 90 days after the Draft |



Next Steps

Pete Warnken



Next Steps

- IRP Meeting Schedule
 - June 7th – Currently Scheduled
 - July 19th – Currently Scheduled
 - October 17th – Currently Scheduled
- Continue with Wyoming Teleconference Video Link