2015 IRP Overview

PUGET SOUND ENERGY

WUTC

Phillip Popoff
Manager Integrated Resource Planning

March 4, 2016

PSE 2015 IRP Overview

- Nature of the Integrated Resource Plan
- Market Context
- Electric Resource Needs
- Electric Resource Plan and Key Resource Issues
- Gas Resource Needs
- Gas Resource Plan and Key Resource Issues
- Action Plans

Integrated Resource Planning

Plans versus PLANS

Action Plan: Specific actions PSE intends to take.

Resource Plans Are…

- More of a forecast of what we expect will be cost effective in the future, given what we think we know about the future today.
- Focused on minimizing costs to customers.

Why is IRP Useful

- Understand how long-term uncertainties might affect near term decisions.
- Broader perspective of the future than if PSE operated in a vacuum.
- Prepare analytical frameworks for making real-time decisions.

Market Context

Electric Market Concerns: Resource Adequacy

- Northwest Power and Conservation Council
  - May 2015 Adequacy Assessment: Region short 1,150 MW by 2021
  - August 2015 Draft 7th Power Plan: Region okay if meet conservation and demand response targets.
- Conclusion: No longer assume short-term market 100% reliable
  - Regional adequacy assessments never supported that assumption.

Gas Market Concerns

- Pipeline capacity on Westcoast (upstream of Northwest Pipeline) is being fully utilized to peak capacity.
  - Short-term commodity markets may not be available to meet demand at Sumas under significantly cold weather conditions.
- Generation Fuel: Sufficient back-up fuel critical economic factor.

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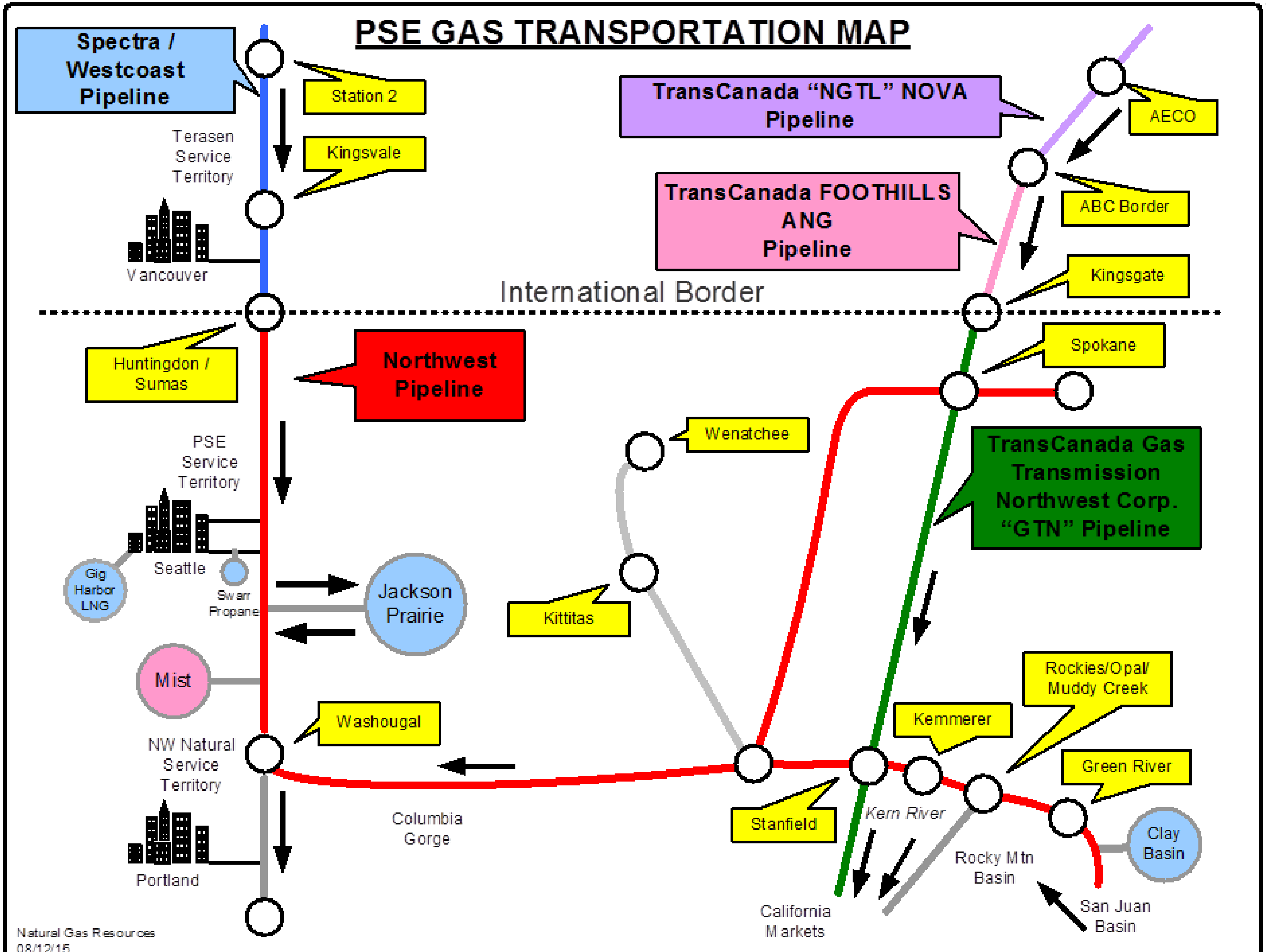
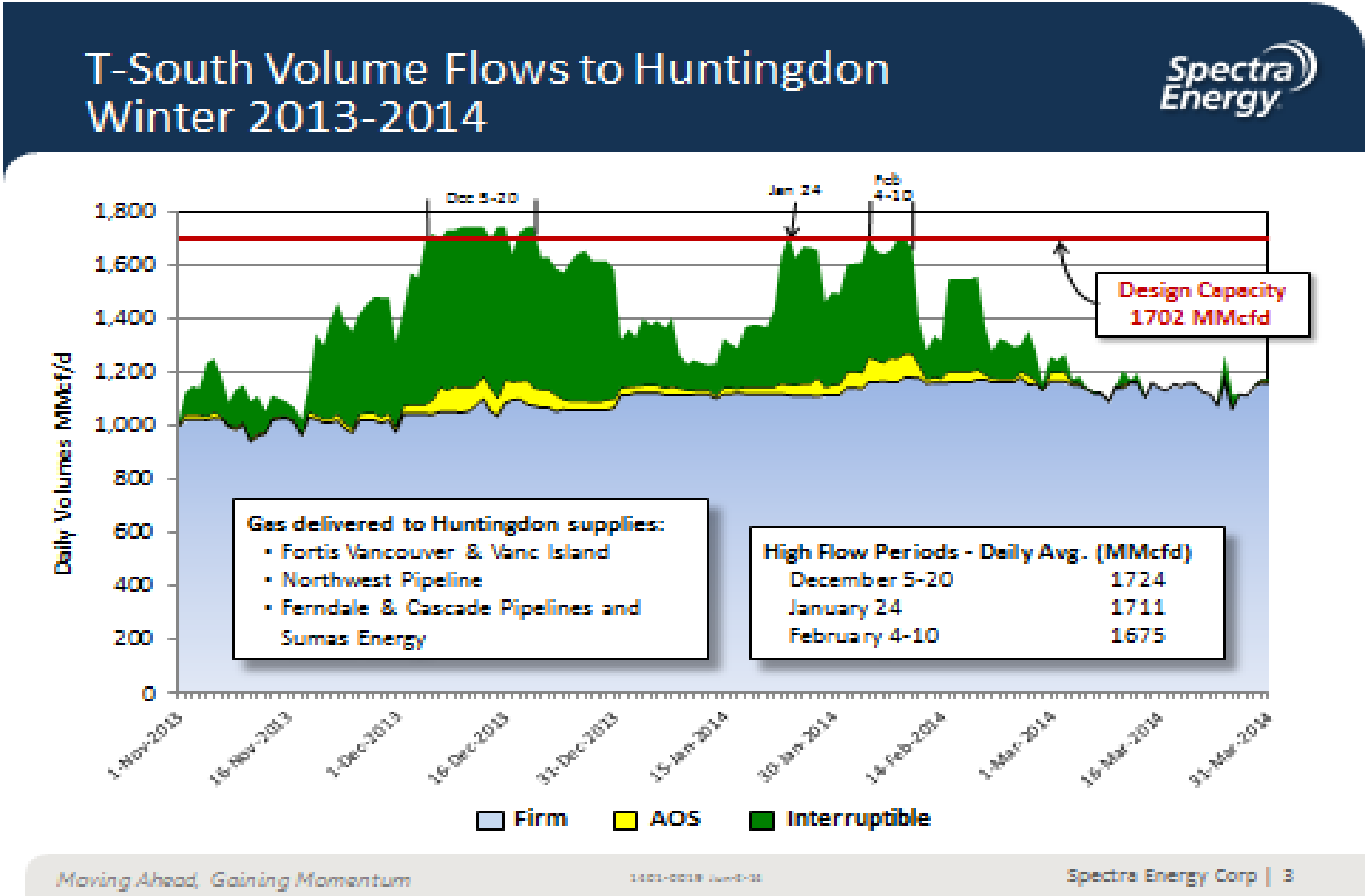
Pacific Northwest Gas Supply System





From a recent Westcoast presentation

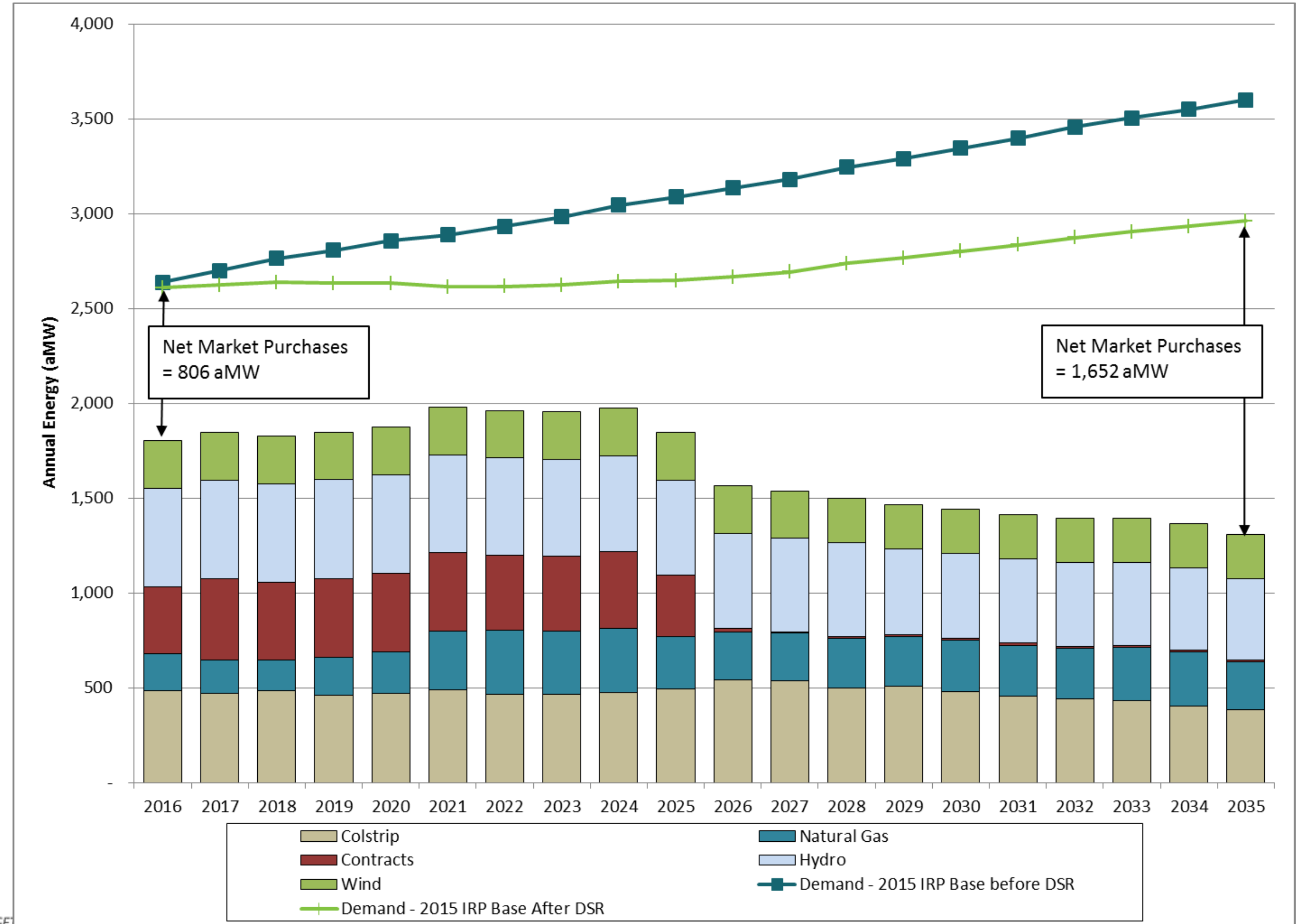
PSE 2015 IRP Overview

- Nature of the Integrated Resource Plan
- Market Context
- Electric Resource Needs
  1. Load Forecast
  2. Reflect Wholesale Market Risk
  3. Planning Standard Based on Value to Customers
  4. LOLP to EUE
- Electric Resource Plan and Key Resource Issues
- Gas Resource Needs
- Gas Resource Plan and Key Resource Issues
- Action Plans

Electric Resource Need: 4 Key Updates

1. Updated Load Forecast
   - Clear feedback from Commission in 2013 IRP
   - Comprehensive update
2. Reflect Physical Risk of Wholesale Markets
   - Had assumed wholesale markets 100% reliable
   - Never aligned with region—concern by 2021
3. Revised Capacity Standard to Minimize Costs to Customers
   - Old 5% LOLP: Used at Regional Level
   - New: Minimizes Cost for Customers & Dramatically Reduces Risk
4. Changed metric from LOLP to EUE
   - Used to compare different resources, not establish capacity need
   - LOLP does not reflect magnitude, duration, or frequency of outages.

1. Load Forecast: Annual Load (aMW)



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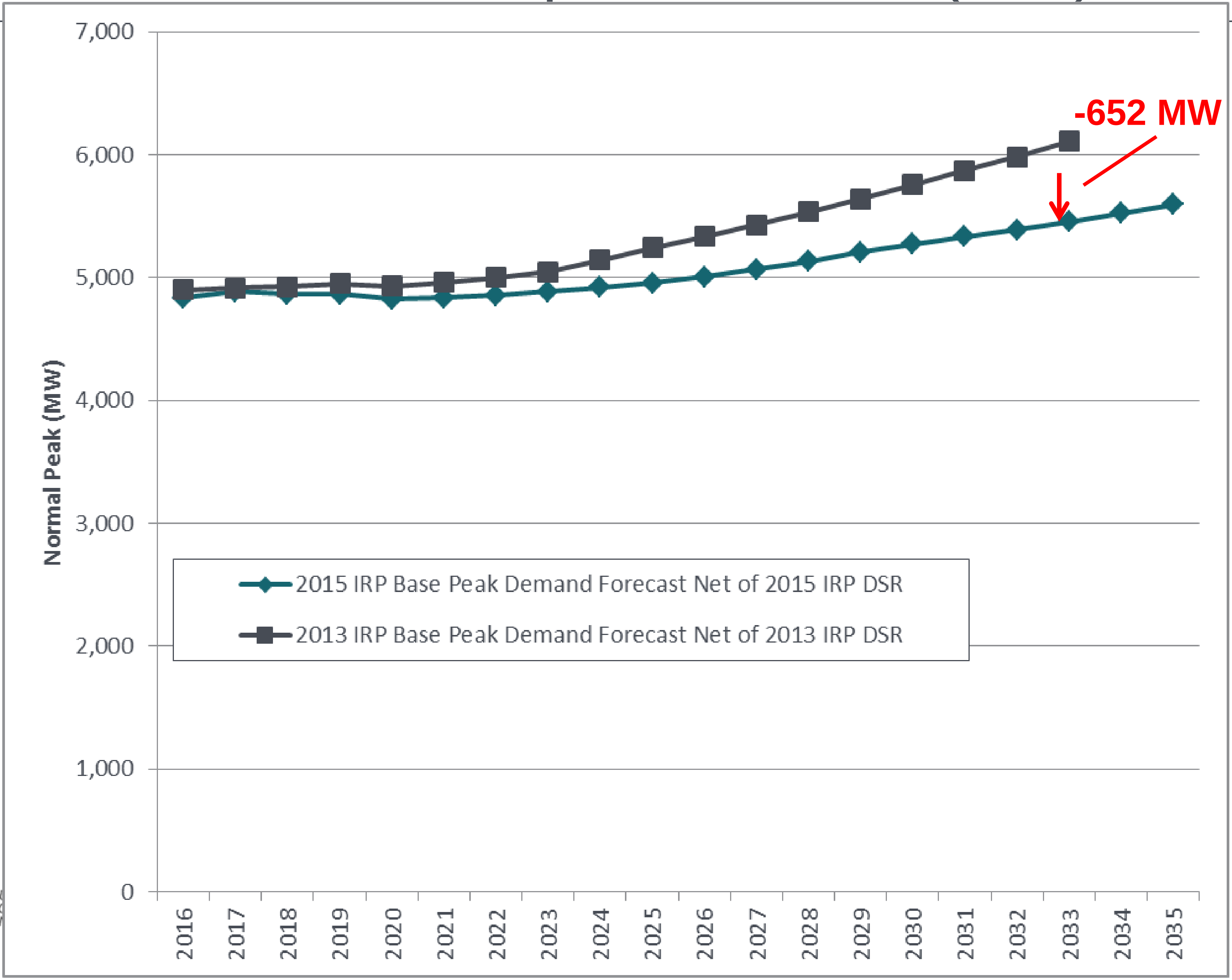
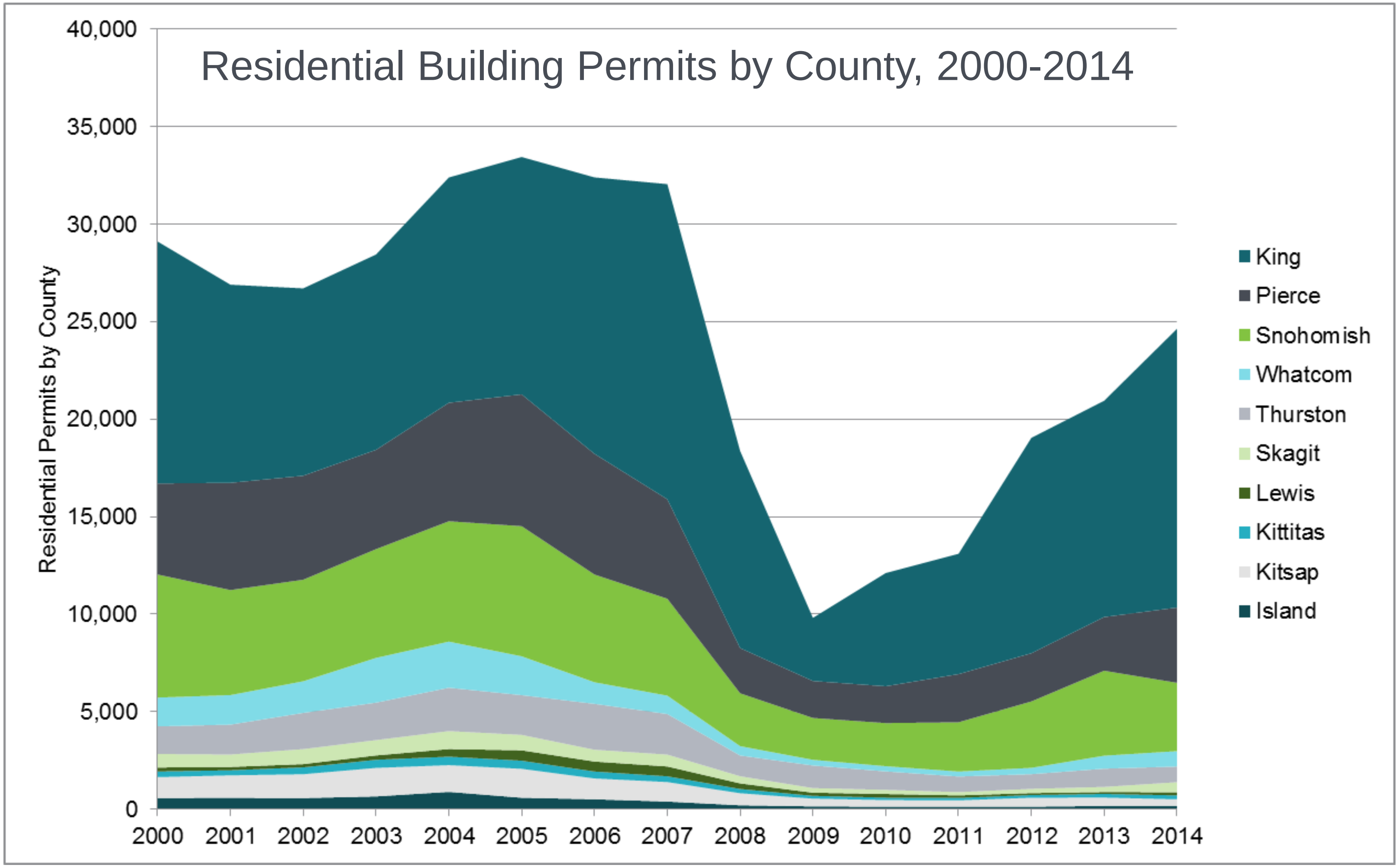
1. Load Forecast Updates: Peak (MW)



Except for King County, growth in residential building permits has not returned to pre-recession levels.



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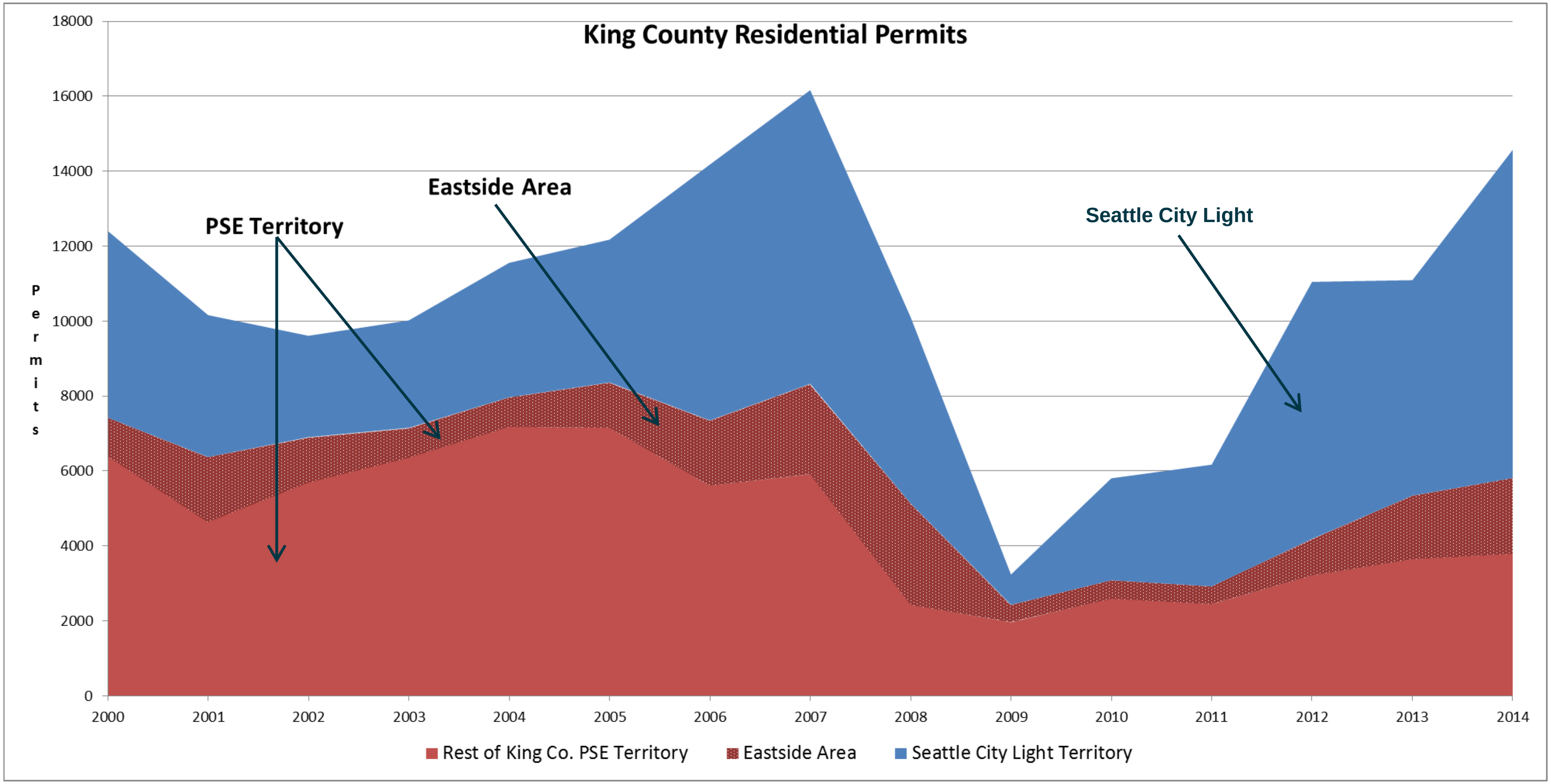
Data from on Building Industry Association of Washington Reports, US Bureau of Census

Within King County the majority of post-recession permits growth is outside of PSE's service area.



Data from Building Industry Association of Washington Reports, US Bureau of Census

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1. 2013 IRP versus 2015 IRP Load Forecast Differences

- 2013 IRP LF assumed faster recovery of US economy from recession, while 2015 IRP LF assumed a more gradual recovery
- 2015 IRP LF used updated US population growth forecast from the US Bureau of Census which is lower compared to 2013 IRP LF
- Customer growth and customer counts in the 2015 IRP LF forecast are lower than in 2013 IRP LF because of slower housing recovery
- Peak load growth and peak load levels are also projected to be lower in 2015 IRP LF versus 2013 IRP LF
- Disaggregated system wide forecast to county and sub-county regions to examine reasonableness from both system and sub-system perspectives

Background: Adequacy Metrics

Loss of Load Probability (LOLP)

- Expected simulations with any load-resource balance shortfall.
- (#Simulations with shortfall) / (total # of simulations).
- No recognition of magnitude, duration, or frequency.

Expected Unserved Energy (EUE)

- (Sum MWh shortfalls across all simulations) / (total # simulations).
- Magnitude of energy lost, but not duration or frequency.

Loss of Load Hours/Loss of Load Expectations (LOLH/LOLE)

- (Sum of hours short across all simulations) / (total # simulations).
- Measure of duration, not magnitude or frequency.

Expected Value of Lost Load (VOLL)

- DOE’s Interruption Cost Estimator—consumer value of lost load.
- Calculations incorporate frequency, magnitude, and duration.

$$\frac{\text{(Sum of consumer value of lost energy across all simulations)}}{\text{(total \# simulations)}}$$

2. Incorporating Physical Wholesale Market Risk

In the past, PSE assumed wholesale markets were 100% reliable.

- Inconsistent with NPCC's resource adequacy modeling.
- As long as region passed adequacy test, update not worth expense.

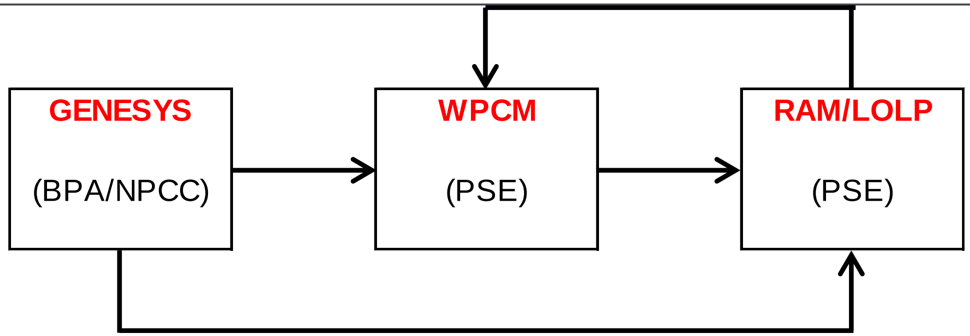
By 2021, over 1300 MW of coal plants will be retired in the region.

- May 2015 adequacy assessment showed region short 1150 MW.

Needed to harmonize PSE's wholesale market view with analysis of the region.

- Very complicated to align PSE's resource adequacy model with regional model.

2. Incorporating Physical Wholesale Market Risk: Process Overview



GENESYS: Regional Adequacy Model

- Supports annual resource adequacy reports at NPCC.
- 6160 simulations of loads and resources.
- Starting point for PSE's outlook on market reliability.

Wholesale Purchase Curtailment Model (WPCM)

- Allocates regional curtailments to PSE, which may cause PSE's resources to fall short of load.
- Market-based approach as there is no centralized decision maker.

PSE's Resource Adequacy Model (RAM)

- Same 6160 simulations of loads/resource data as GENSYS.
- PSE's loads/resources with wholesale market curtailments.

2. Incorporating Physical Wholesale Market Risk

Started with base assumptions for regional assessment.

Adjustments to Regional Model Assumptions

- Increased SW imports by 425 MW: Better ways to reflect “friction”
- Increased resources by 440 MW: PGE can build Carty 2
- Reduced 650 MW for Grays Harbor: No sign of firm pipeline capacity in a constrained gas pipeline corridor.
- Indirectly reflected 700 MW “stand-by resources”
  - Banks Lake 314 MW not operational now…maybe later?
  - PGE’s stand-by resources dispatch limited…for wholesale sales?
  - Reflected in Wholesale Purchase Curtailment Model.

3. Update to Planning Standard Needed

Updated Planning Standard Reduces Expected Costs

	5% LOLP Standard	Optimal Standard	Savings
Expected Value of Lost Load ($ Million/yr):	$ 169	$ 39	$ 130
Expected Annual Cost to Achieve Savings ($ Million/yr):			$ (63)
Annual Net Savings to Customers from Updating Planning Standard:			$ 67

Conclusion: Update from 5 % LOLP needed to ensure lowest reasonable cost to customers.

3. Update Significantly Reduces Customer Risk

Figure 1-1: Comparison of Old and New Electric Capacity Planning Standard

		Reliability Metric		**2021 Capacity (Surplus)/ Need after DSR (MW)**	**Customer Value of Lost Load**	
		LOLP	EUE (MWh)		Expected ($million/yr)	Risk-TailVar90 ($million/yr)
1	2013 Planning Standard with Market Risk	5%	50.0	(117)	169	1,691
2	2015 Optimal Customer Planning Standard (Includes Market Risk)	1%	10.9	234	39	385
	Change			351	(130)	(1,306)

3. Planning Standard Update: Process Overview

Annualized Benefit/Cost Analysis

Benefit

- Using MWh shortfalls from PSE's RAM: 6160 simulations in 2021
- Apply value of lost load from DOE's ICE calculator
- Changing resources leads to change in VOLL

Cost: Levelized cost of CT

3. Value of Lost Load-Example

Figure N-23: Interruption Cost Calculation of an Average PSE Customer per Event of One-hour Duration

Customer Type	Number of Customers	Per Customer InterrCost per Event - 2011$	Per Customer InterrCost per AvgKW/Hr - 2011$	Implied Avg KW per Yr(Flat)	PSE Load Factors	Peak KW/Yr	PSE Peak Shares	Avg Peak per Yr per Cust, KW
	Year End 2020	**1HR Duration**	**1HR Duration**					
Medium&Large C&I	10,889	$4,122.40	$27.80	148.3	1.47	218	0.2	43.6
Small Comm&Ind	126,531	$758.90	$179.70	4.2	1.42	6	0.1	0.6
Residential	1,060,975	$2.80	$1.90	1.5	2.05	3	0.7	2.1
All Customers	1,198,395	**$120.06**	$38.76	3.1	1.71	5.3		**46.3**
Interr Cost Aver Per Cust per Hr($2020)		**$149.94**						

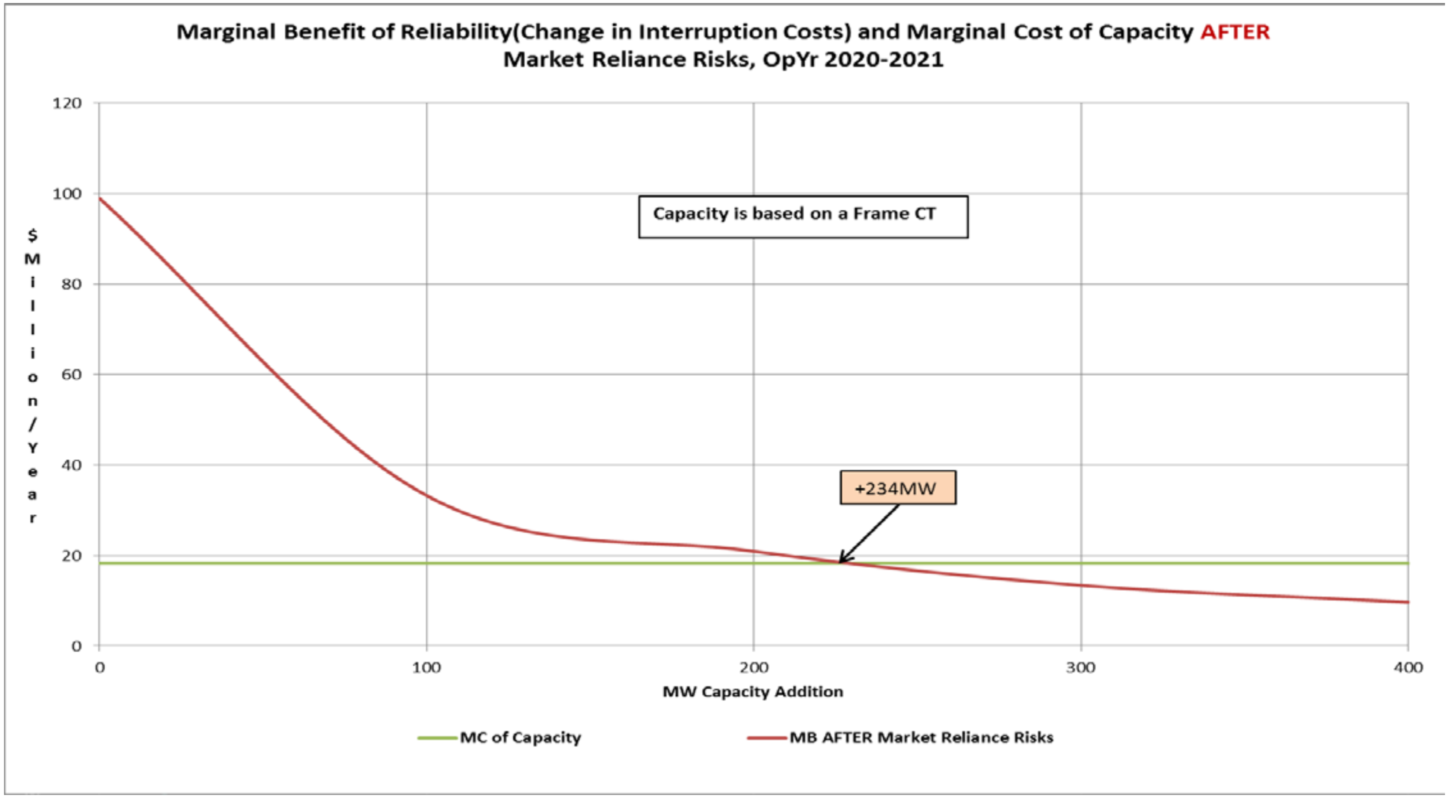
values appear reasonable

Feedback at PNUCC Board Presentation

- **Values may be too low for today's high-tech end-uses.**

3. Benefit-Cost Analysis

Figure 6-4: Marginal Benefit of Reliability, 2015 Optimal Planning Standard



- Reflects <u>expected</u> VOLL, not <u>risk</u>.
- Additional generation would further reduce risk.
- Previous slide showed risk from updated standard all ready drops from $1.6 billion to $385 million.

4. LOLP to EUE

Clarification

- EUE used to compare resources
- B/C analysis drives capacity need, not change from LOLP to EUE

	LOLP	EUE (MWh)
2013 Planning Standard	5%	26
2013 Planning Standard with Market Risk	5%	50

Reason to Update

- Compared EUE for 5% LOLP with and without market risk.
- Expected unserved energy doubles, though achieved same LOLP.
- LOLP misses the mark.
- Additionally, LOLP disadvantages intermittent resources, which may reduce MWh of lost load, but not completely avoid all shortfalls.

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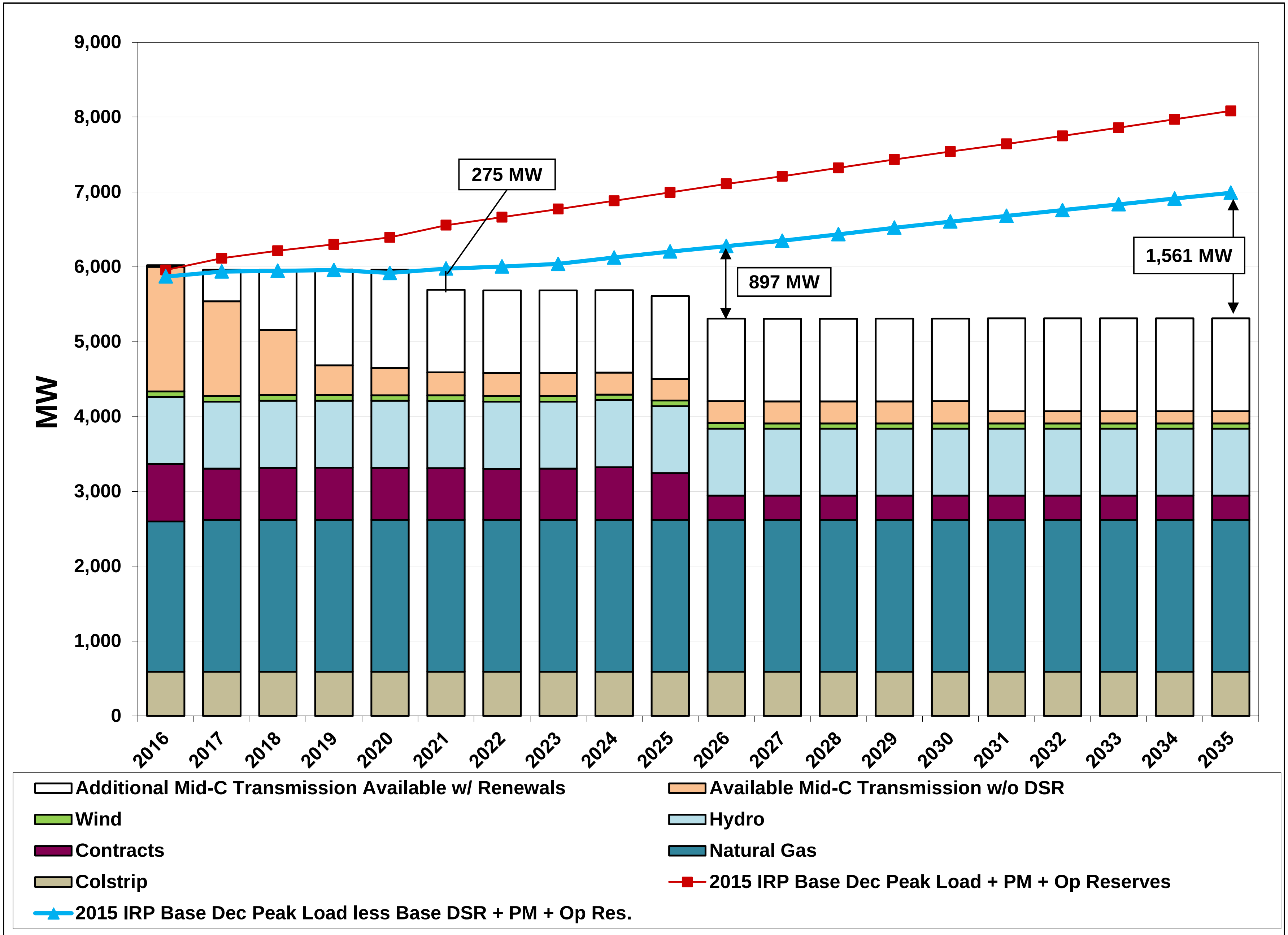
Combining Impact of Incorporating Market Risk and Planning Standard Update

Figure 6-2: Summary of Planning Standard Changes

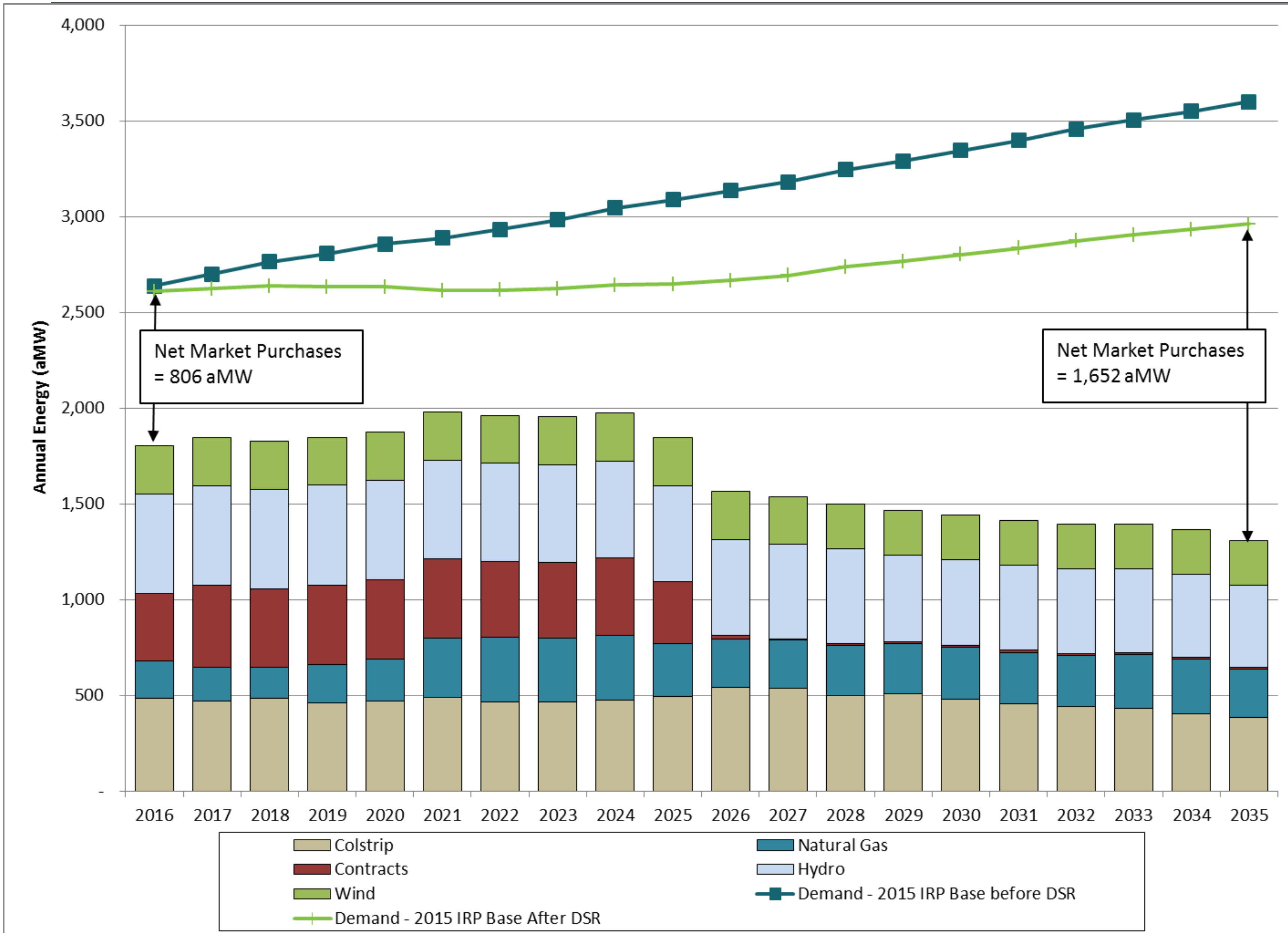
		Reliability Metric		2021 Peaker Capacity Added after DSR (MW)	Customer Value of Lost Load	
		LOLP	EUE (MWh)		Expected ($mill/yr)	TVar90 ($mill/yr)
1	2013 Planning Standard with No Market Risk	5%	26	(150)	86*	858*
2	2013 Planning Standard with Market Risk	5%	50	(117)	169	1,691
3	2015 Optimal Planning Standard (Includes Market Risk)	1%	10.9	234	39	385

** Inaccurate estimate because it ignores reliability impact of wholesale market risk.*

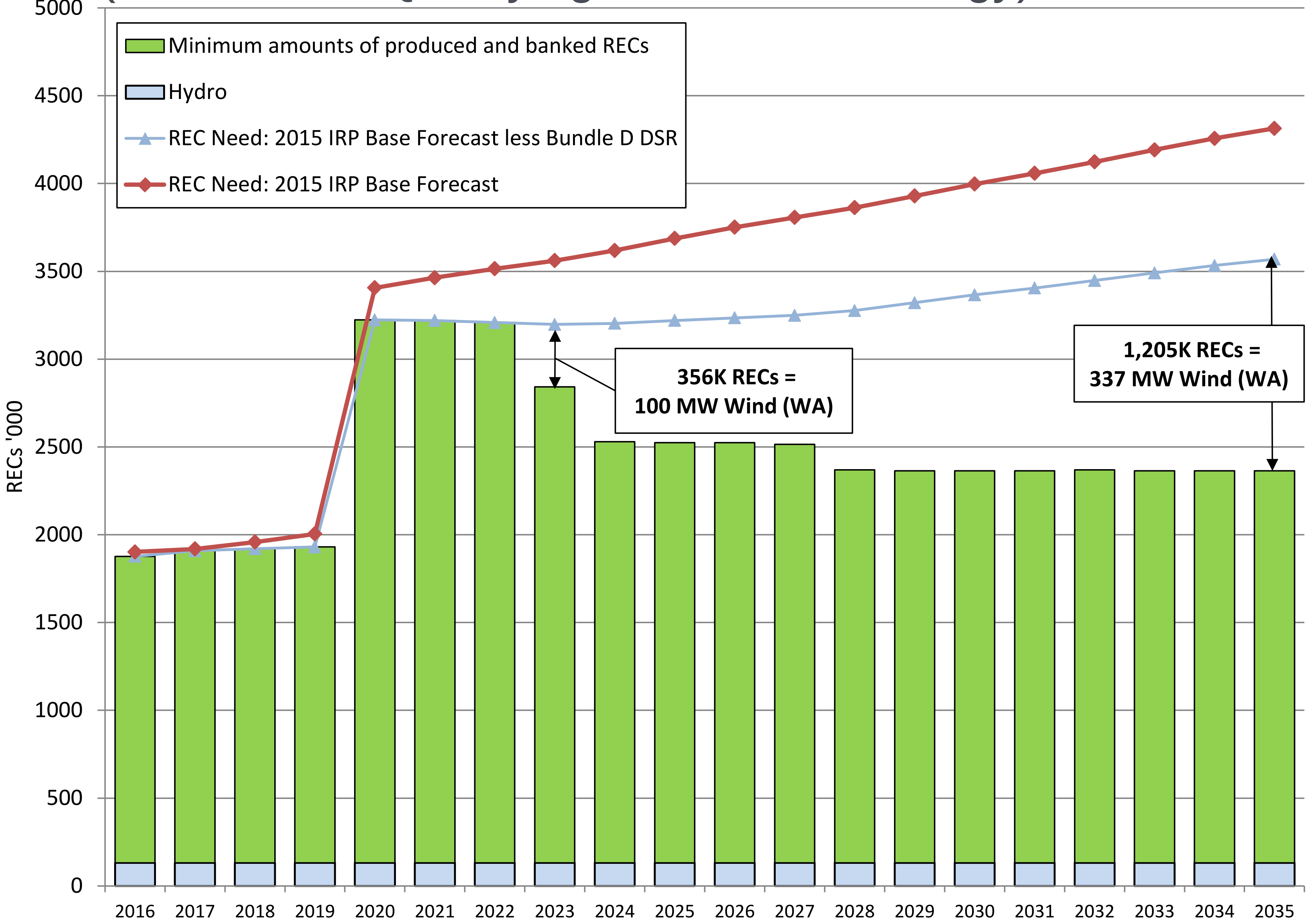
Electric Peak Capacity Load/Resource Balance



Annual Energy Need/Position



Renewable Resource/Renewable Energy Credit Need (RECs/MWh Qualifying Renewable Energy)



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Resource Plan

Figure 1-7: Electric Resource Plan Forecast,

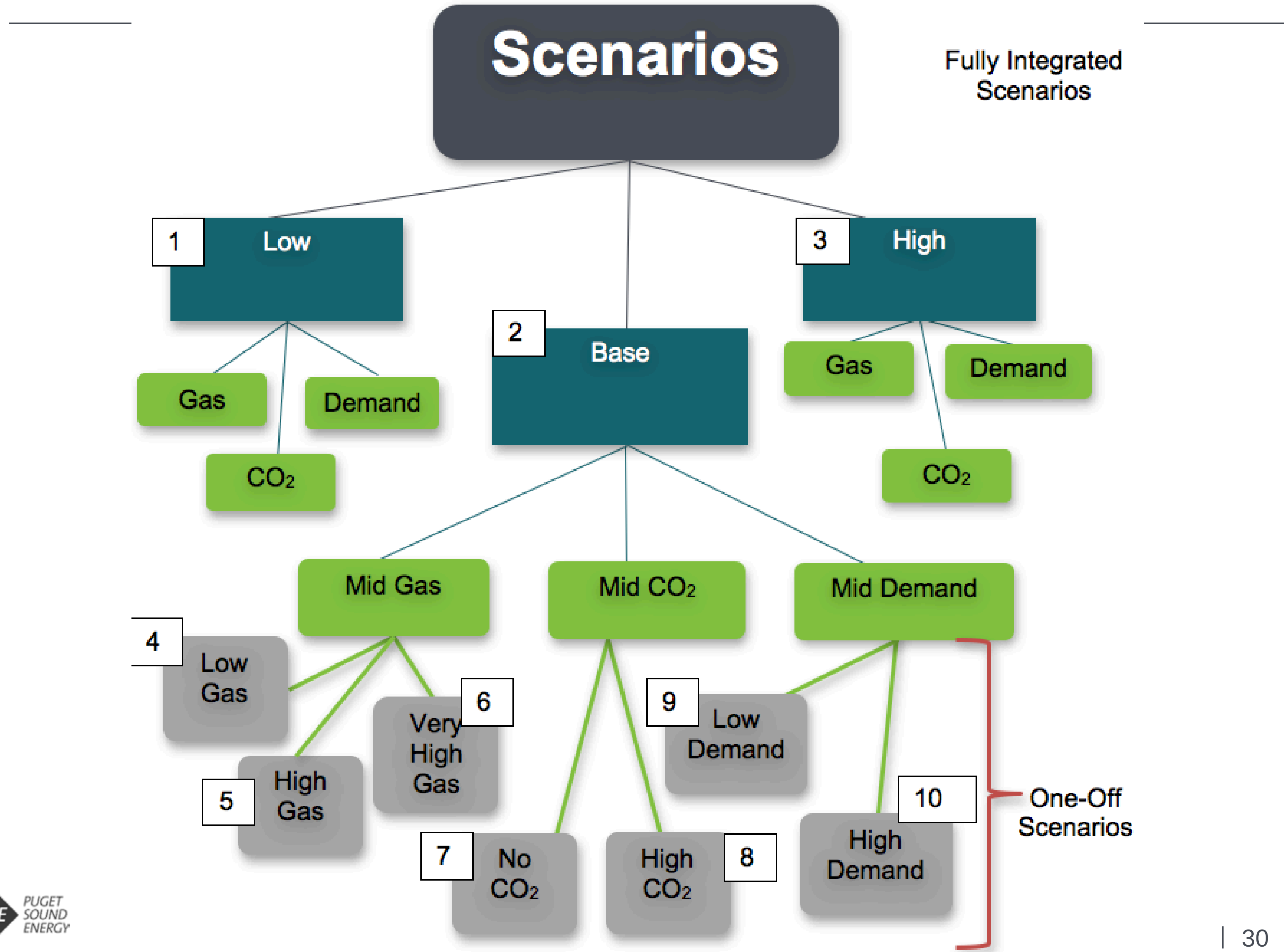
Cumulative Nameplate Capacity of Resource Additions

	2021	2026	2030	2035
Conservation (MW)	411	669	770	906
Demand Response (MW)	121	130	138	148
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	-	577	577	805
Peaker/CT Dual Fuel (MW)	277	403	609	609

Additional…if Colstrip Retired by 2026

- Units 1 & 2: Additional Peaker/CT
- All 4 Units: Additional Combined Cycle Gas

Figure 4-1: Diagram of 2015 IRP Scenarios



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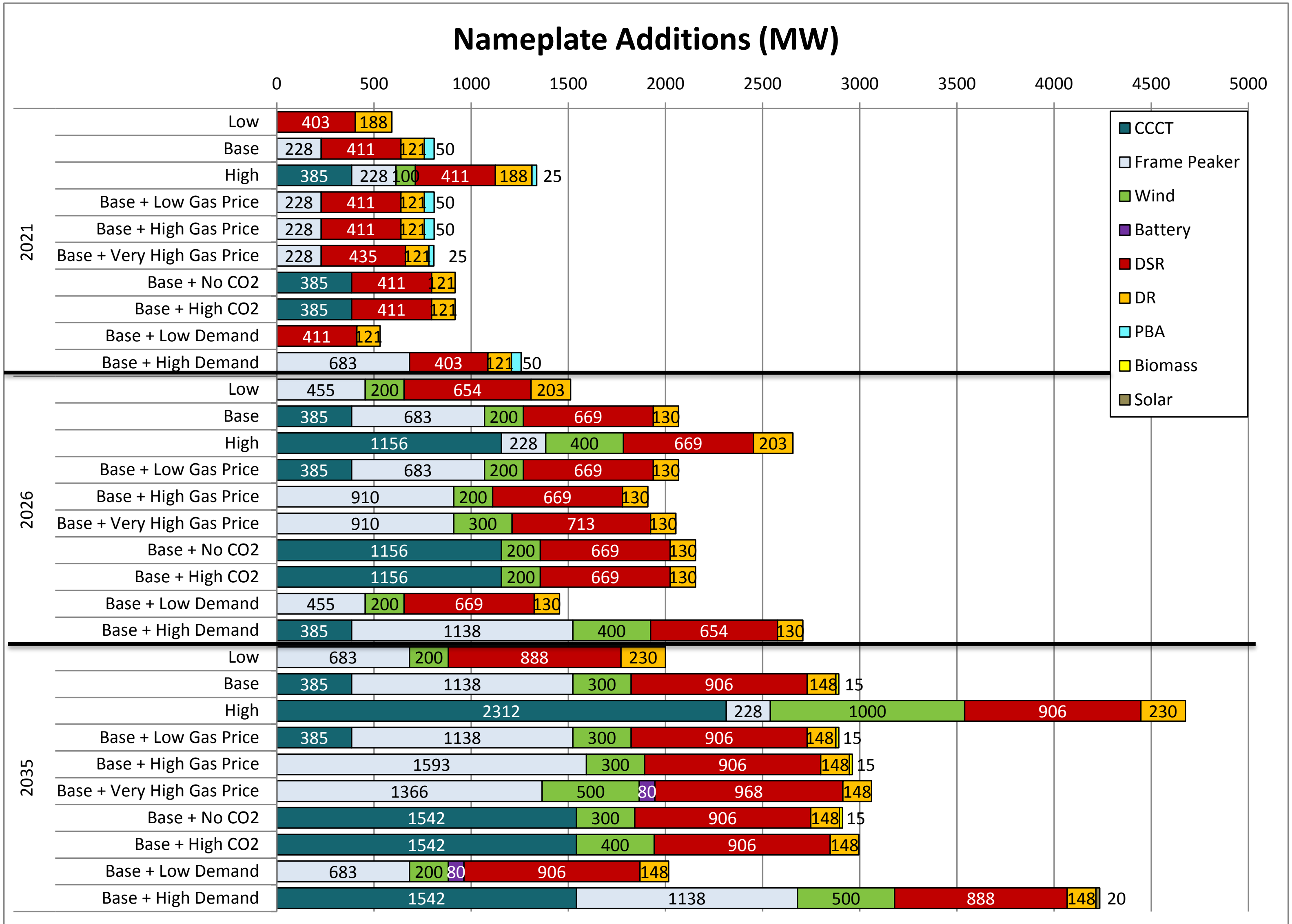
Additional Portfolio Sensitivites

A. Colstrip
   1. Units 1 & 2 Retire 2026
   2. All 4 Units Retire 2026
B. Demand Side Resources
C. Thermal Mix
D. Gas Plant Location—East/West Cascades
E. Gas Transport Needed for Peakers
F. Energy Storage/Flexibility
G. Reciprocating Engine/Flexibility
H. Montana Wind
   1. Base line
   2. Lower
   3. Colstrip Embedded Transmission Cost
I. Solar Penetration—Increased Distributed Solar Penetration
J. Carbon Reduction Impact of Added Wind

Results of Deterministic Optimization Analysis



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Deterministic Analysis Informs Stochastic

Next Step is Determine Focus of Stochastic Portfolio Analysis

Conservation & Demand Response Nearly Same in Every Scenario

Renewables Stable Across Scenarios

- Driven by RPS: Washington wind forecast to be least cost
- Variation primarily driven by load forecast.
- MT wind driven by binary issue: access to embedded cost transmission—not well suited to stochastic analysis.

Variability: CCCT vs Peakers

- 2 Scenarios only CCCT
- 2 Scenarios only Peaker
- 5 Scenarios different Combinations

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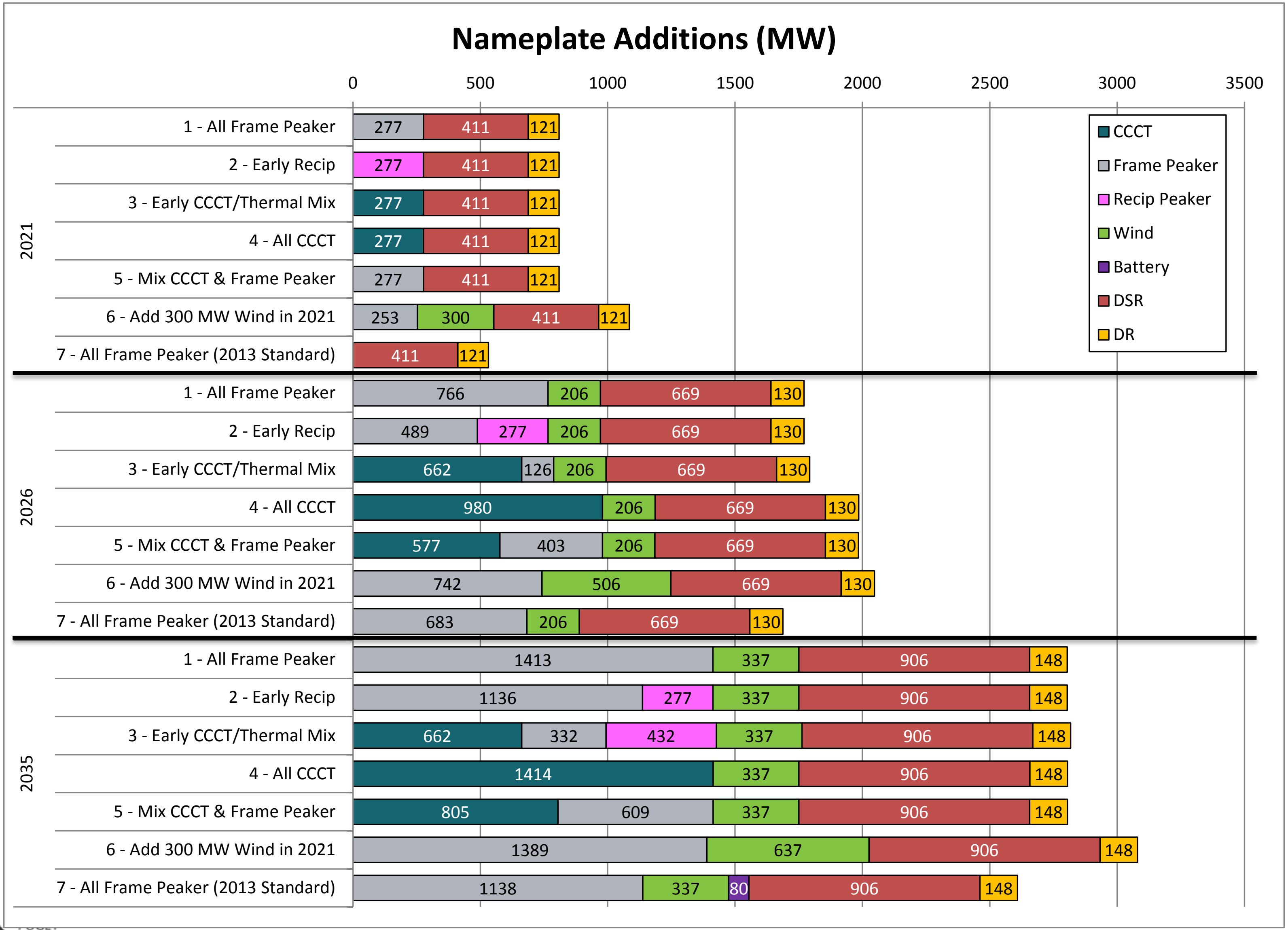
Led to Portfolios for Stochastic Analysis



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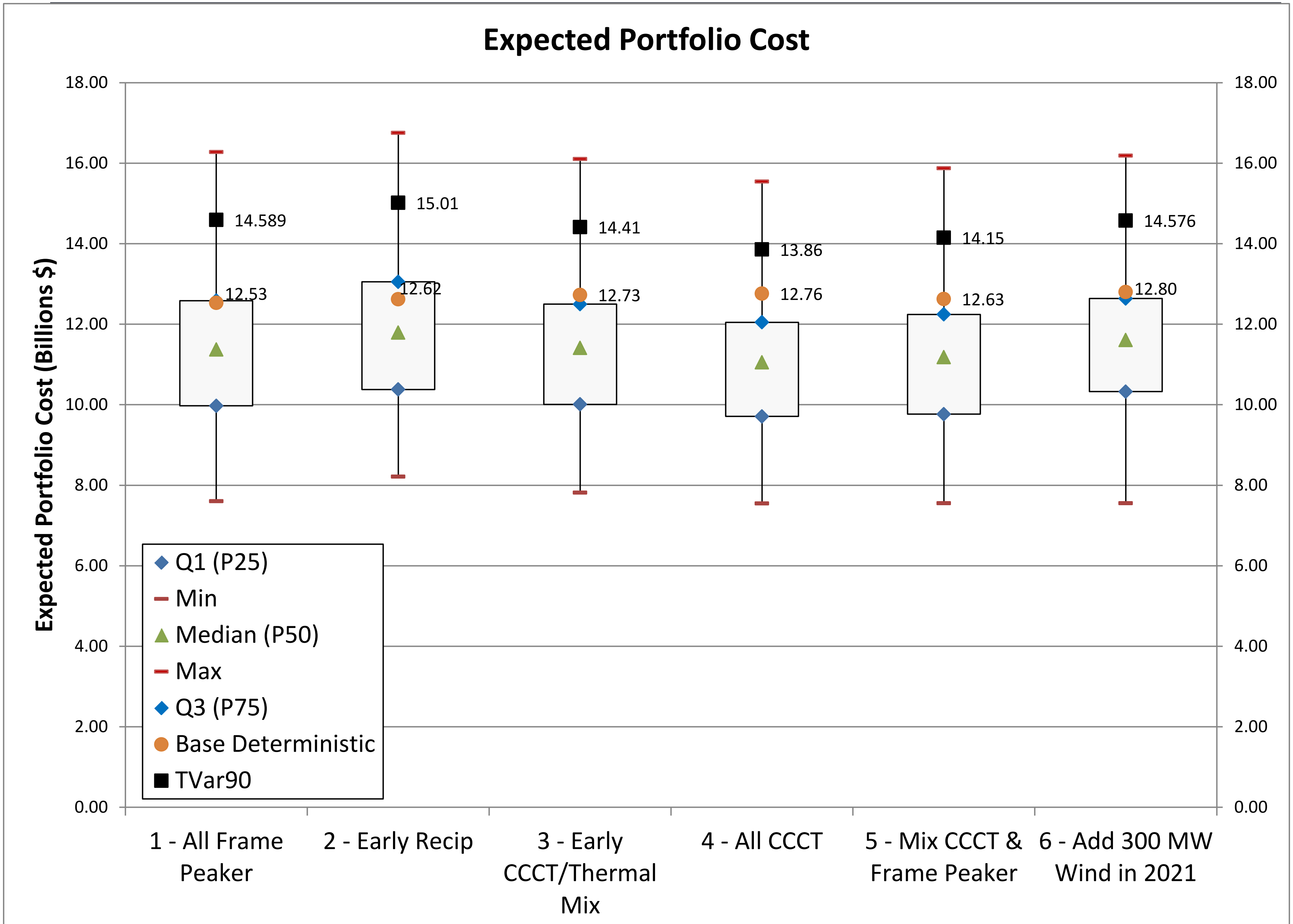
Results of Stochastic Portfolio Analysis



Results of Stochastic Portfolio Analysis

Figure 2-7: Stochastic Analysis Resource Addition Results

NPV ($Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	**12,531**		**11,343**		**14,589**	
2 - Early Recip Peaker	12,620	89	11,782	439	15,014	426
3 - Early CCCT/Thermal Mix	12,729	198	11,392	49	14,412	(177)
4 - All CCCT	12,761	230	10,993	(350)	13,856	(733)
5 - Mix CCCT & Frame Peaker	12,627	96	11,138	(205)	14,147	(442)

If All CCCT is lower cost and lower risk…why are frame peakers in the Plan?

Background: How Portfolio Analysis Works…

Resources dispatched to market price signals

- Includes unit commitment logic: start-up costs, ramping efficiencies, minimum run times, minimum down times, etc.,
- Units not "dispatched to load" because PSE is not on an island.
- "Out of the money" means cheaper to buy market than run plants for load.
- "In the money," run the plant. If generation in excess of load—sell to market.

Net Cost= Fixed Cost – (Market Price – Variable Cost)

- Stochastic analysis varies market prices and variable costs over planning horizon.

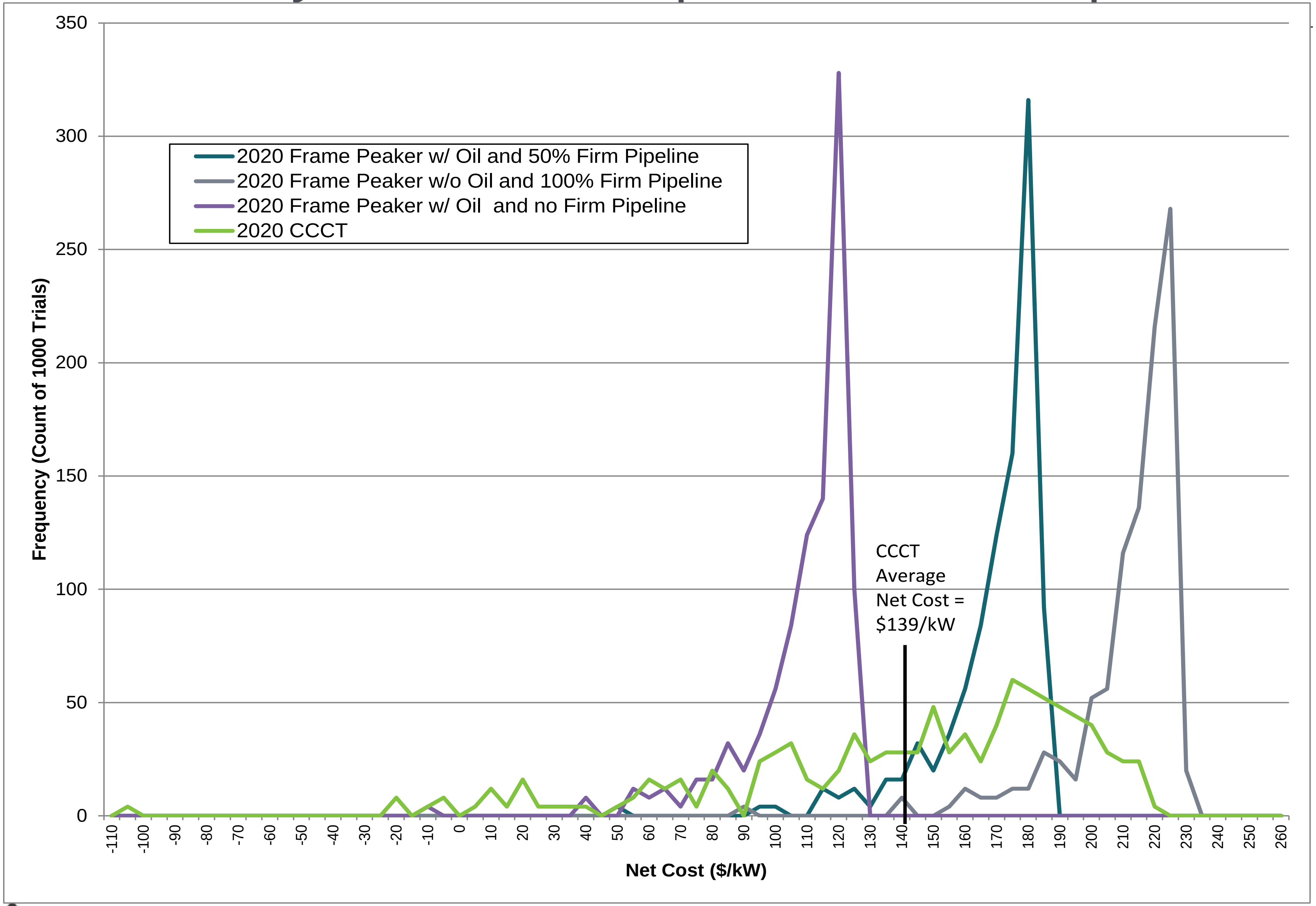
Relative Net Cost of Different Resources is Focus

- Different operational characteristics can affect fixed and/or variable costs.
- Includes the market value of dispatch: Market Price – Variable Cost
- Capacity contribution to portfolio impacts fixed costs.

Relative Cost of Resource Alternatives is Focus

- Compare the net cost of different resource alternatives.

Sufficiency of Oil Back-Up Critical Assumption



Frame peakers lower cost, IF firm pipeline capacity not needed.

Examined "Supply/Demand" Non-Firm Gas Capacity

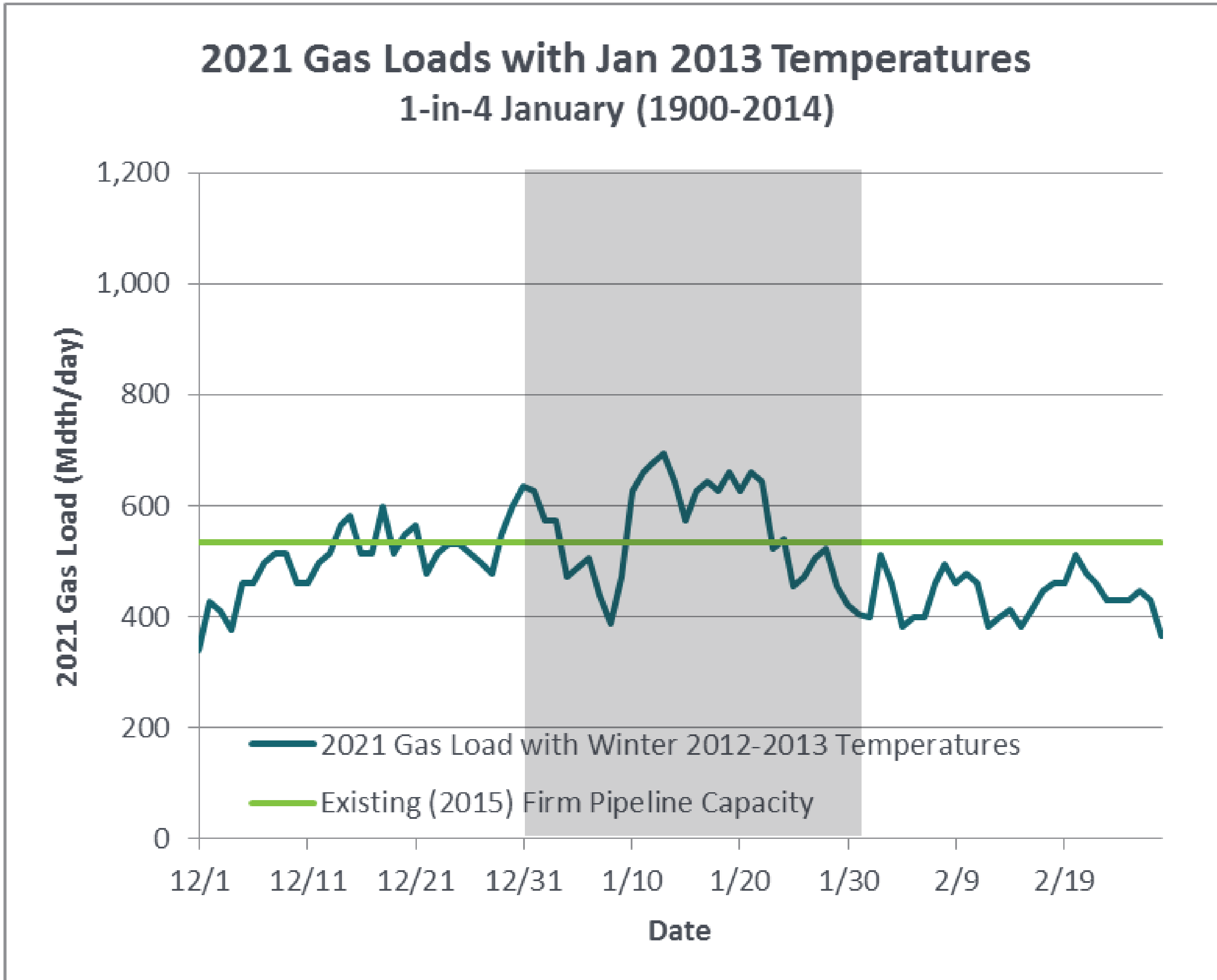
"Supply" of non-firm pipeline capacity based on PSE's gas utility

- No information available from NWP on conditions when non-firm gas transport unavailable…very complicated.
- Examined weather conditions under-which PSE's gas utility would not be expected to have surplus firm, TF-1 transport capacity.
- Seasonal firm transport from storage not available for generation.

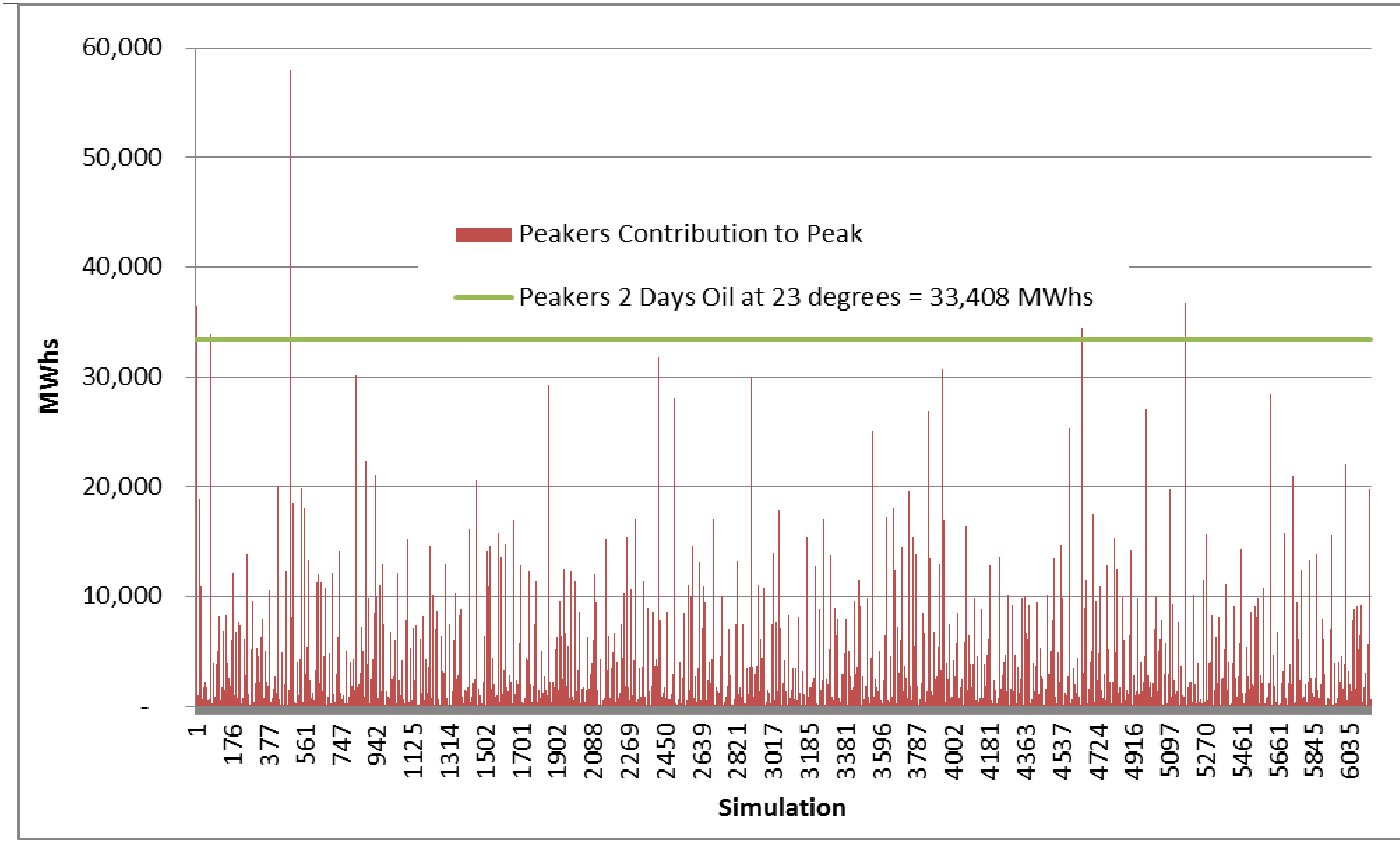
"Demand" for non-firm gas from PSE's RAM

- Identified simulations from the 6160 when dispatch of existing dual-fuel units was needed for resource adequacy.
- Converted MWh needed to run hours, to compare with back-up fuel inventory.

Don’t Count on Non-Firm Gas Capacity



Current Back-Up Fuel Seems Adequate



Conclusion: Include Frame Peaker

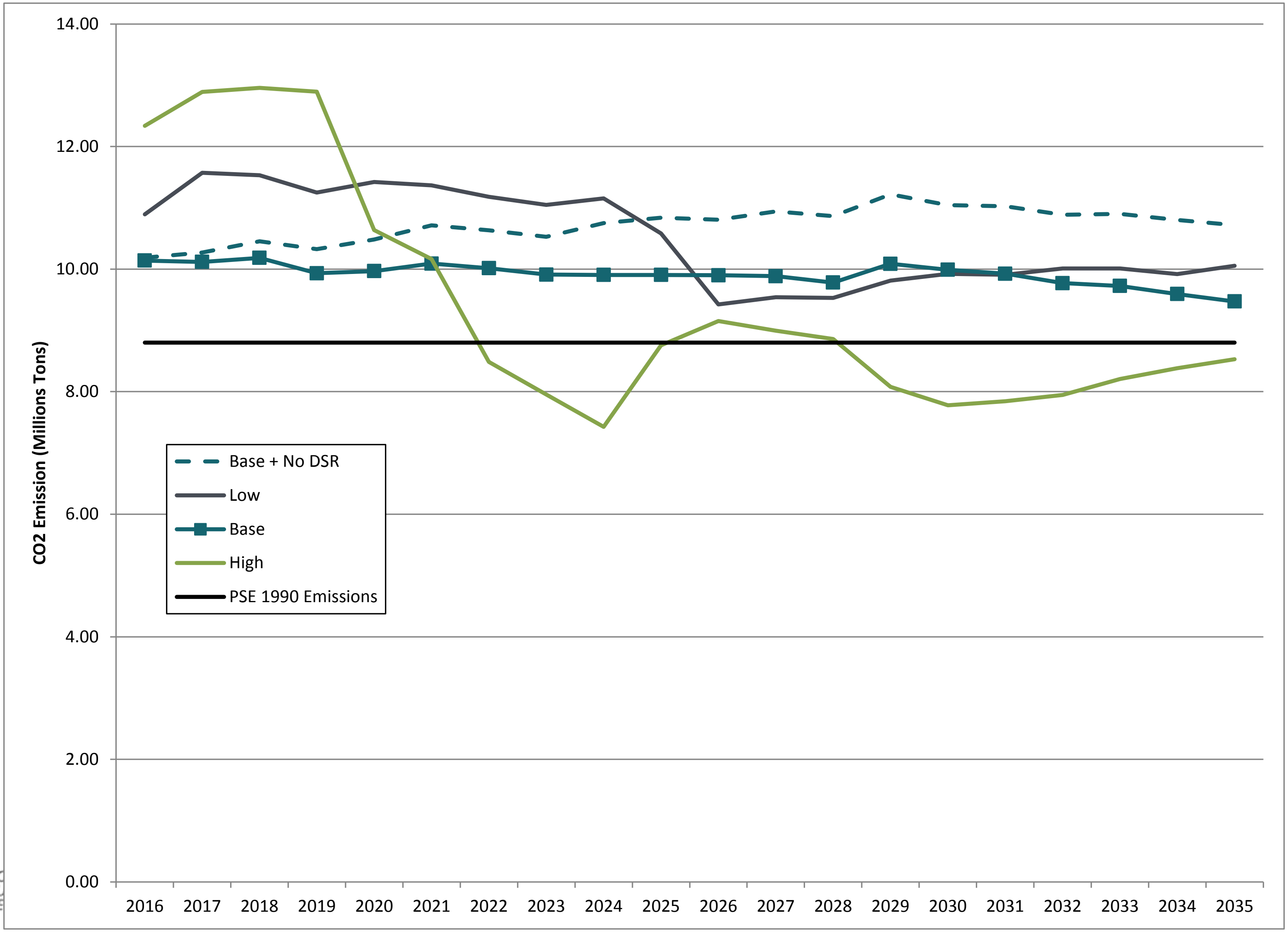
At least one additional dual-fuel frame peaker could probably be sited with sufficient run hours to avoid need for firm pipeline capacity.

Need More Analysis in 2017 IRP:

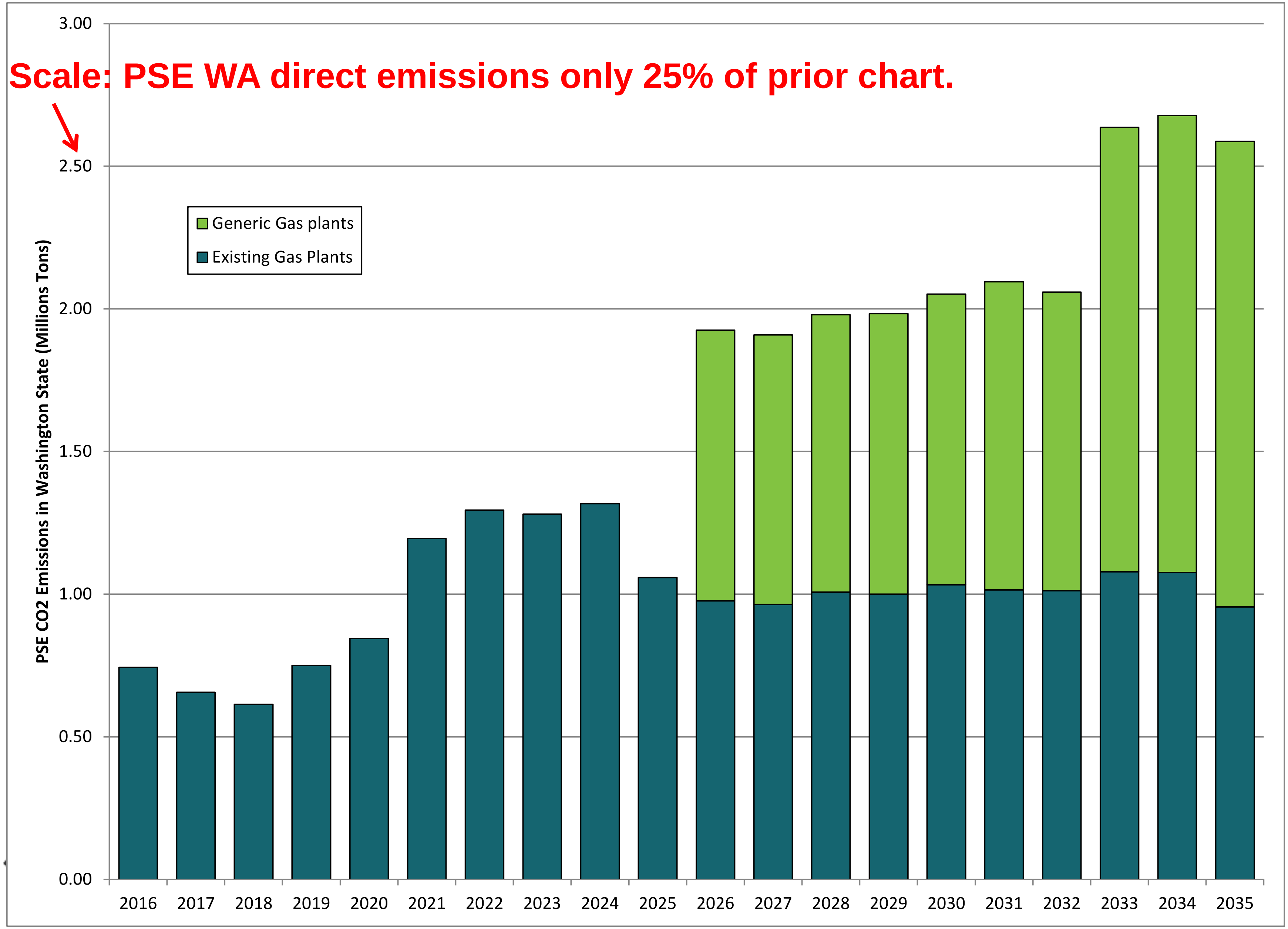
- 2015 IRP focused on gas capacity for existing units.
- Update to scale up for additional dual fuel units.
- Potential carbon regulation impact on availability of non-firm fuel?
- Include potential dispatch for reserves/flexibility.
- At least qualitative consideration to impact of EIM participation.

“Portfolio” Carbon Emissions

Figure 1-9: Projected Annual Total PSE Portfolio CO_2 Emissions and Savings from Conservation



Forecast of PSE Emissions from Generation in Washington



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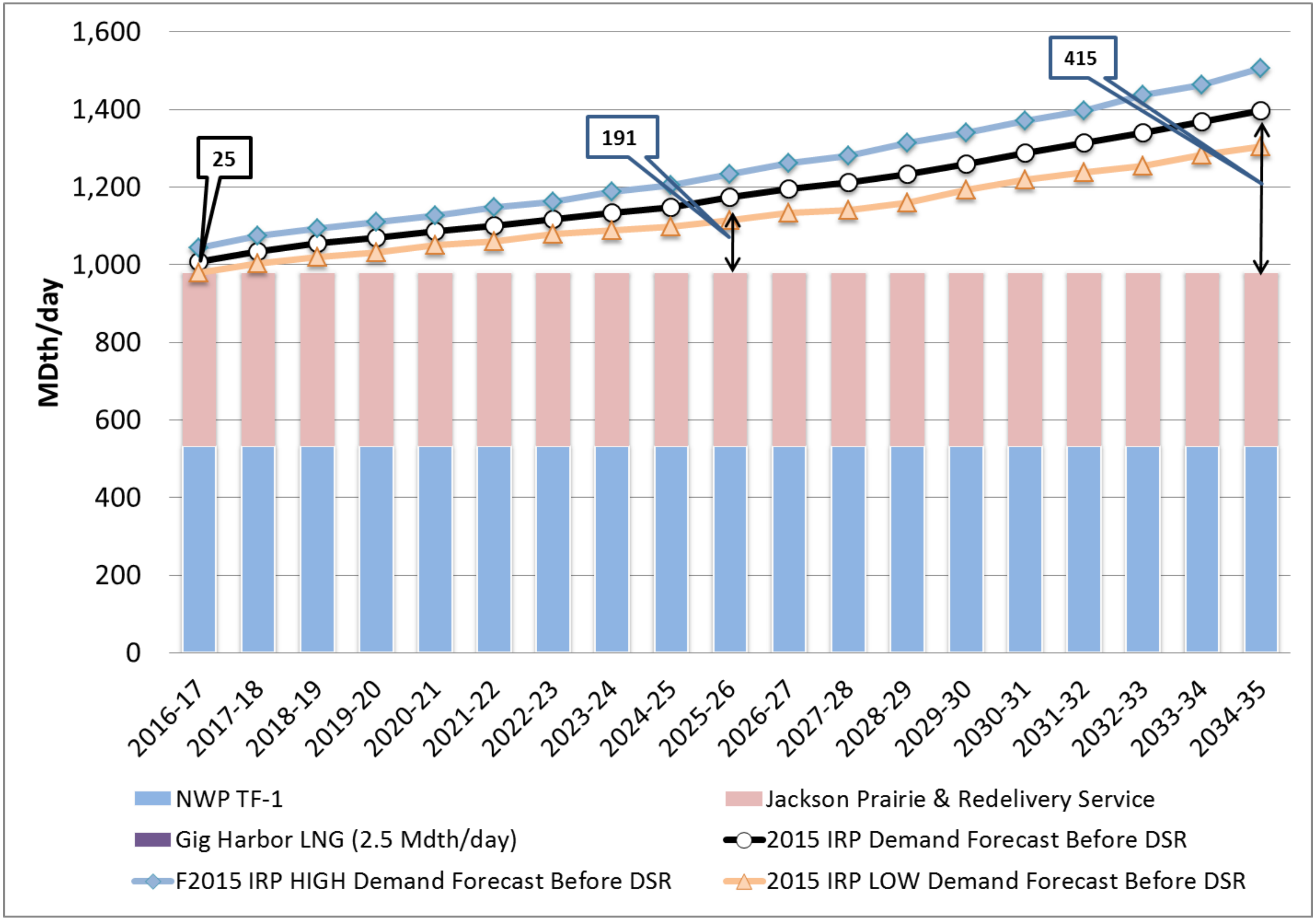
Gas Utility Peak Resource Need



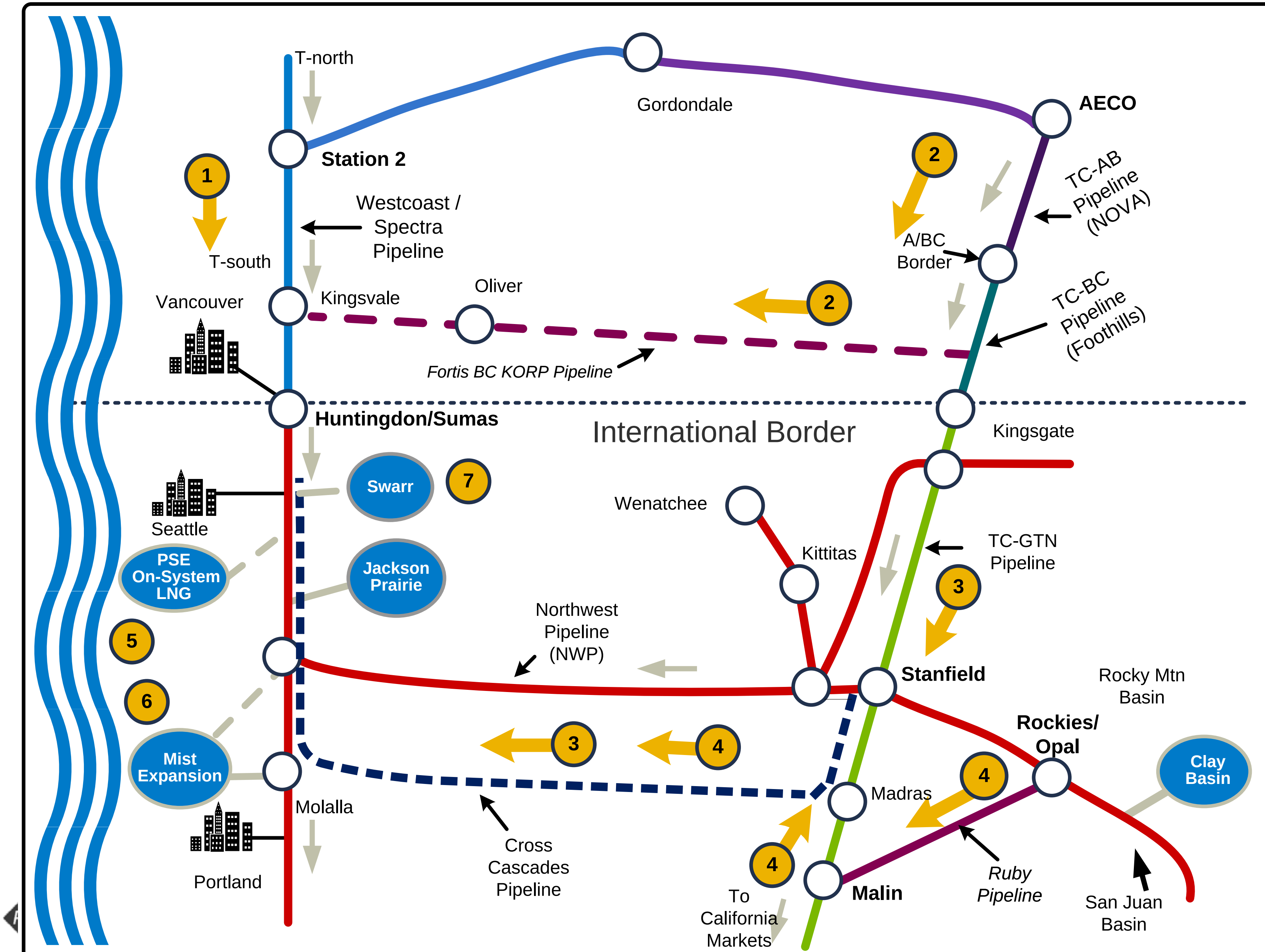
Market Scenarios: Gas Same as Electric

	Scenario Name	Gas Price	CO_2 Price	Demand
1	Low Scenario	Low	None	Low
2	Base Scenario	Mid	Mid	Mid
3	High Scenario	High	High	High
4	Base + Low Gas Price	Low	Mid	Mid
5	Base + High Gas Price	High	Mid	Mid
6	Base + Very High Gas Price	Very High	Mid	Mid
7	Base + No CO_2	Mid	None	Mid
8	Base + High CO_2	Mid	High	Mid
9	Base + Low Demand	Mid	Mid	Low
10	Base + High Demand	Mid	Mid	High

Sensitives

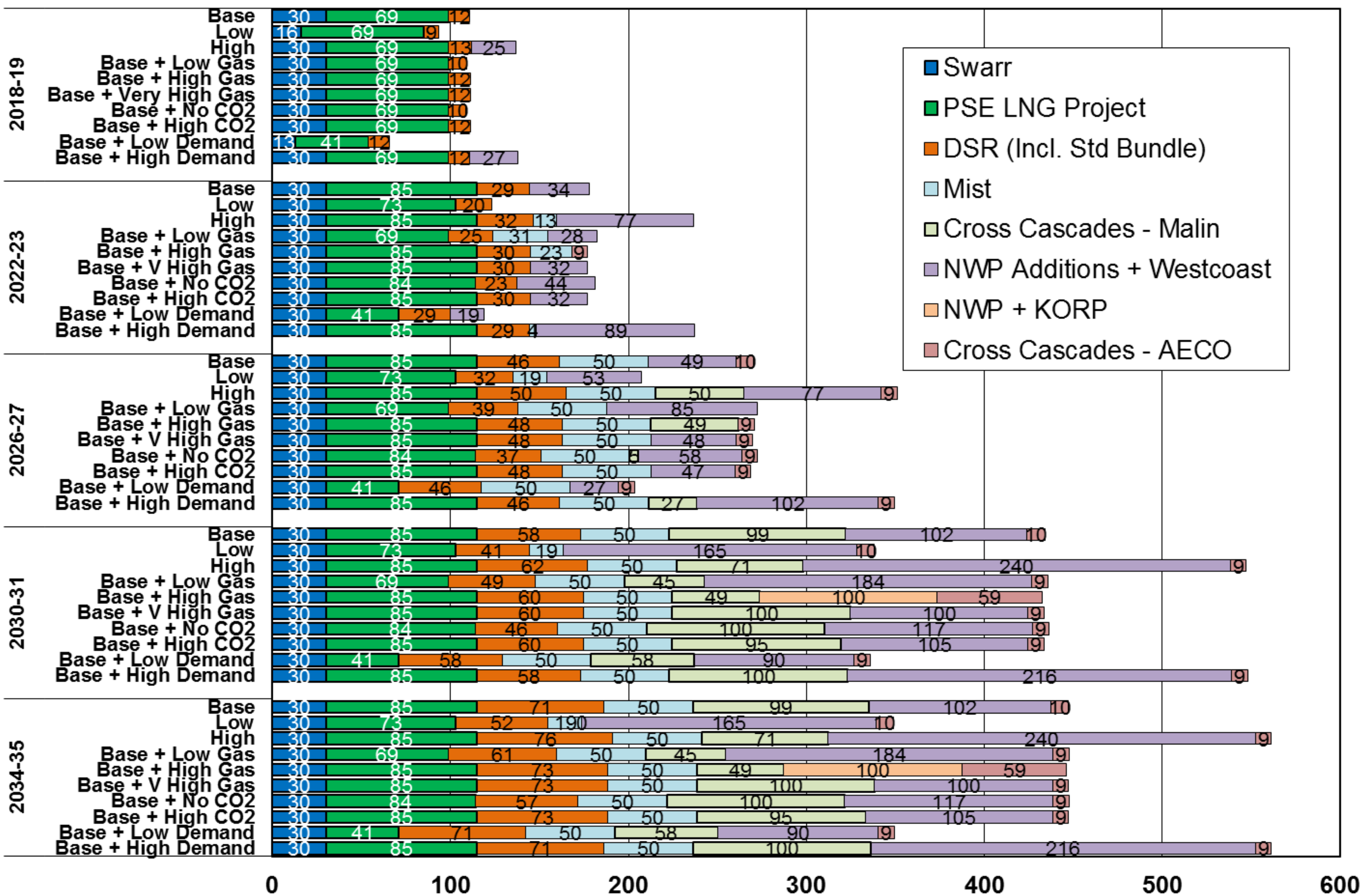
- Discount Rate: Would lower discount rate change amount of conservation?
  - Confuses Perspective: IRP is customer focused, not societal planning.
- Lumpiness of Pipeline Expansions: Would eliminating lumpiness in later years impact near-term decisions?

Figure 7-9: PSE Gas Transportation Map Showing Supply Alternatives



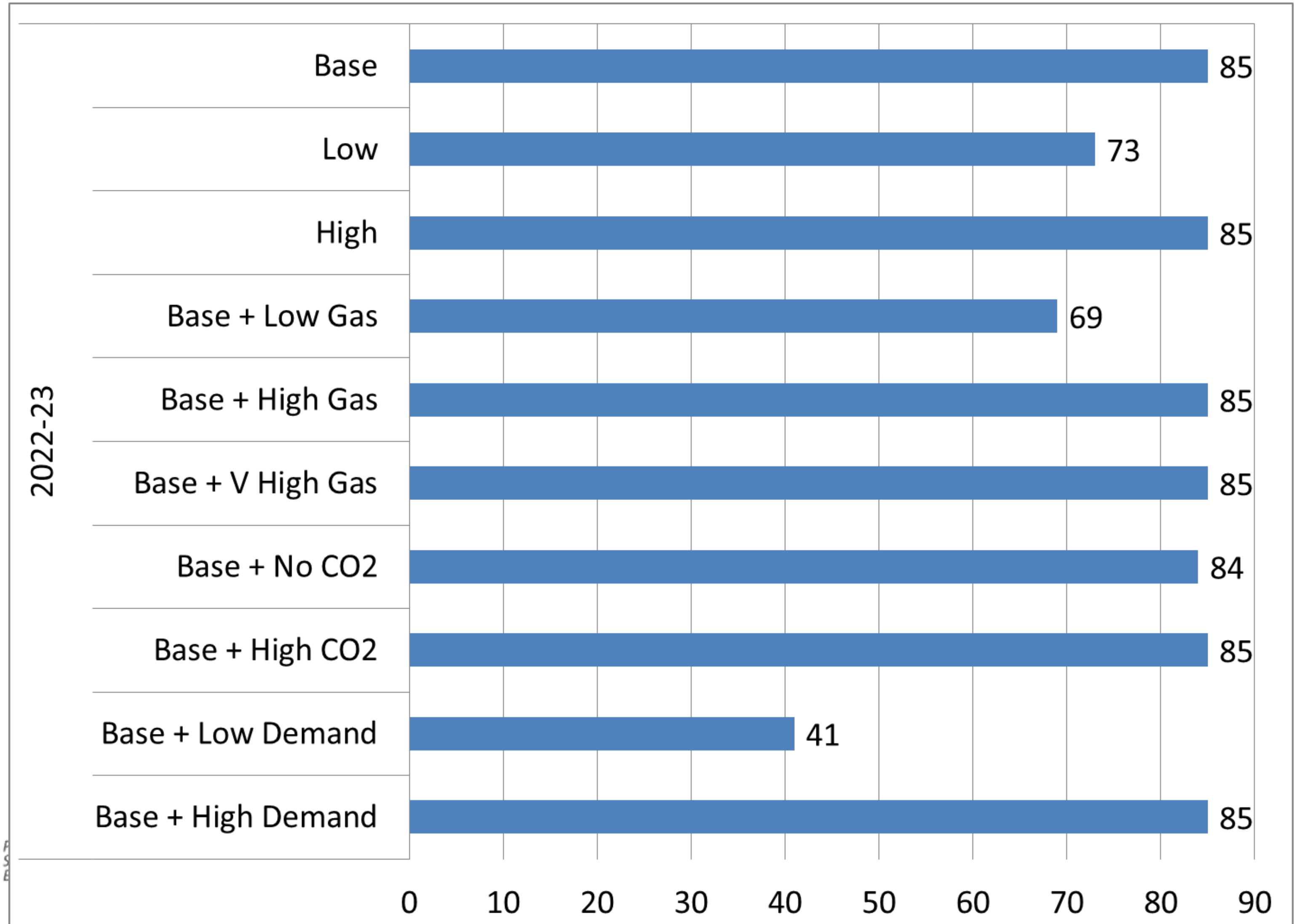
Optimal Plans Across Scenarios

Figure 2-10: Gas Sales Portfolios by Scenario (MDth/day)



LNG Results: Assumed Linear Cost Scale

Figure 7-25: PSE LNG Project Resource Additions by Scenario
(MDth per day)



LNG Real Choice—Clear Portfolio Benefit

	Gas Portfolio Costs Net Present Value ($000s)		
SCENARIO	FULL LNG	NO LNG	(Benefit) / Cost of LNG
BASE	$ 9,366,925	$ 9,464,726	$ (97,801)
LOW	$ 6,257,998	$ 6,294,659	$ (36,661)
HIGH	$ 12,963,307	$ 13,052,452	$ (89,146)
BASE + LOW GAS	$ 8,212,622	$ 8,263,903	$ (51,281)
BASE + HIGH GAS	$ 10,719,839	$ 10,823,632	$ (103,794)
BASE+VERY HIGH GAS	$ 11,906,047	$ 11,994,805	$ (88,758)
BASE+NO CO2	$ 7,775,728	$ 7,846,172	$ (70,444)
BASE+HIGH CO2	$ 10,465,655	$ 10,565,404	$ (99,748)
BASE+LOW DEMAND	$ 9,031,721	$ 9,040,101	$ (8,379)
BASE+HIGH DEMAND	$ 10,450,532	$ 10,550,911	$ (100,379)

Figure 7-31: Compare Cost-effective Level of Gas DSR, Base vs. Alternate Discount Rate

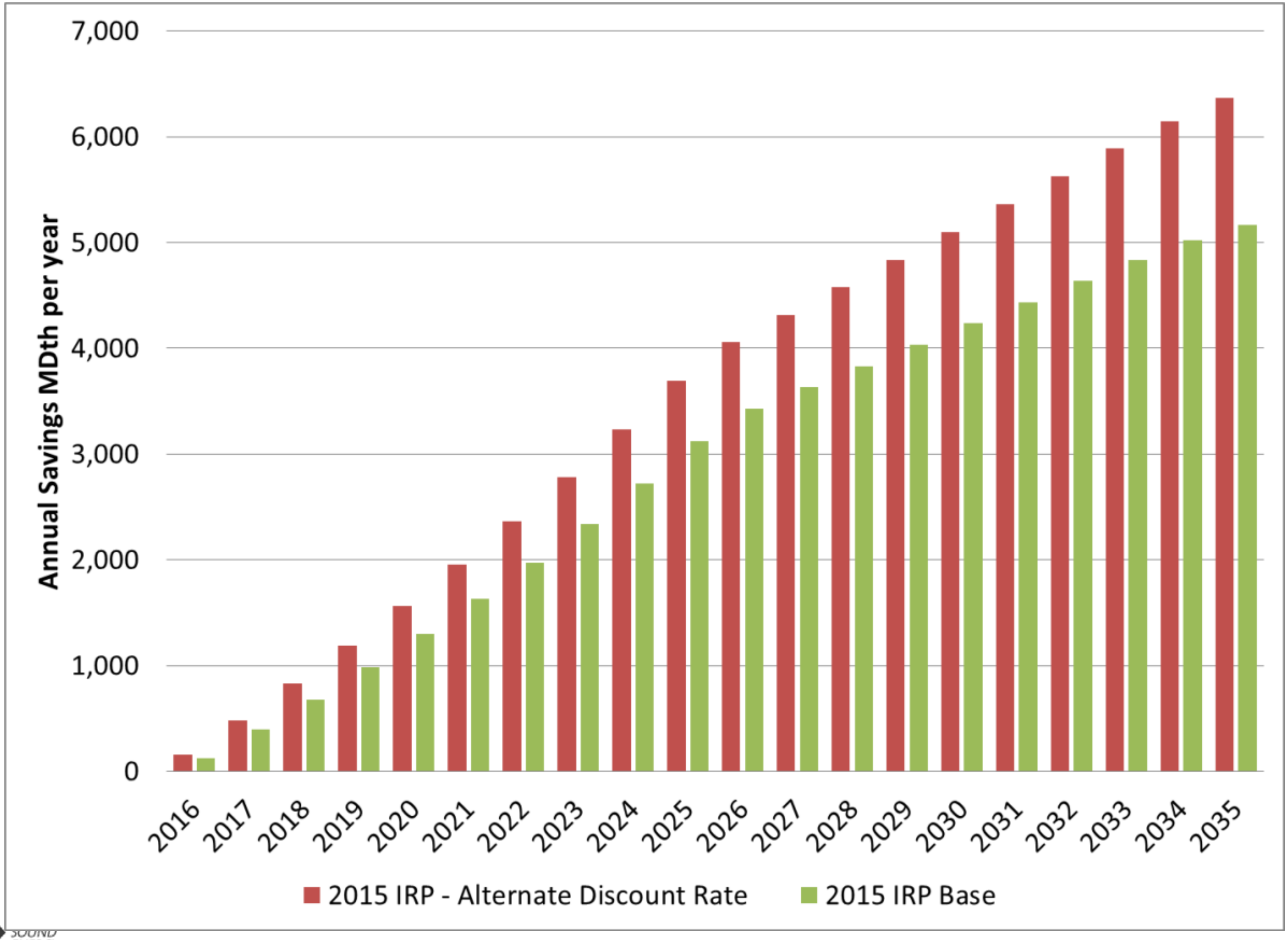


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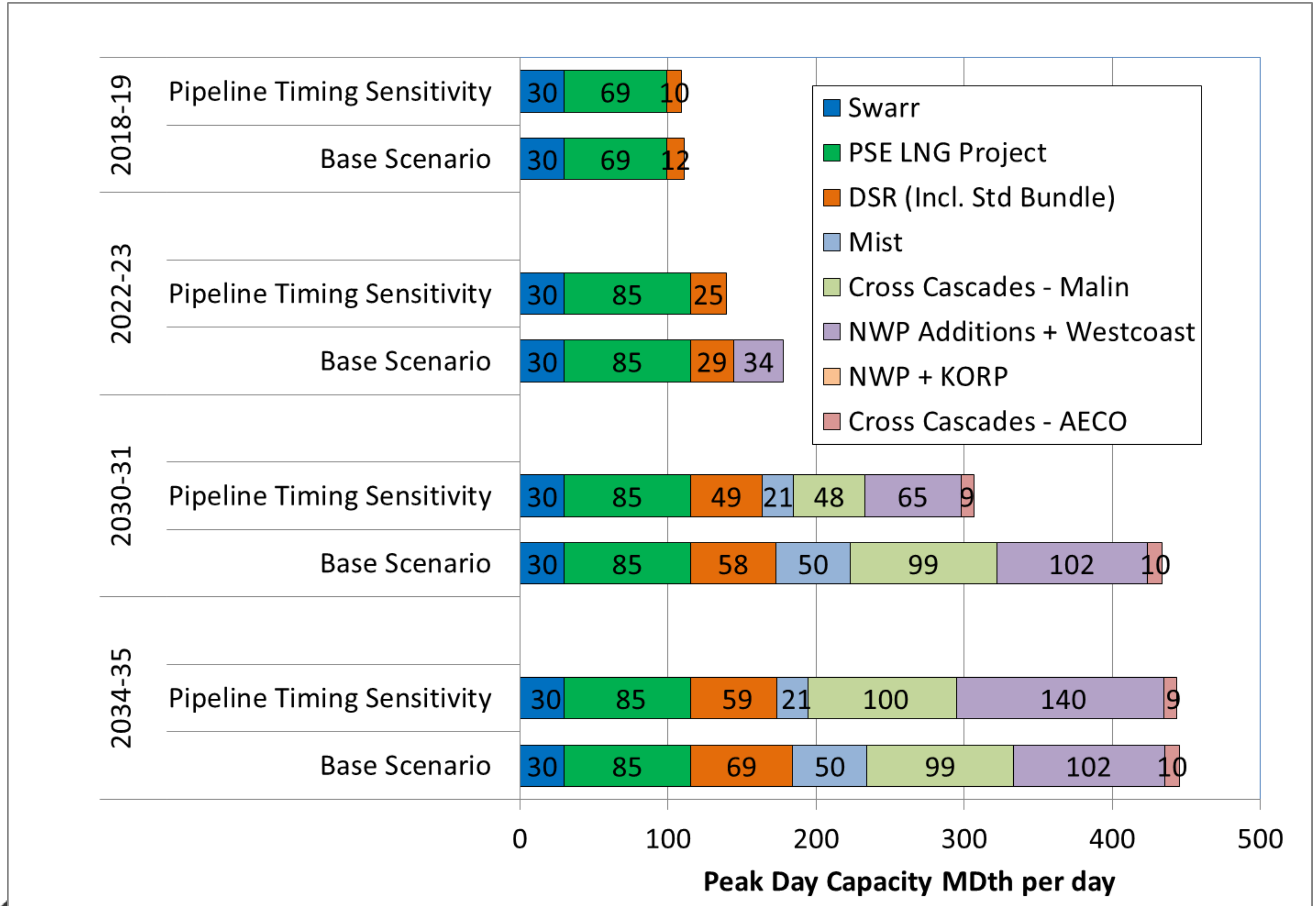
Figure 7-33. Impact on other Resource Builds from Pipeline Timing Sensitivity



IRP Action Plan Items

Electric

- Acquire Energy Efficiency-In Process
- Demand Response RFP-Under Development
- Pause on All Source RFP-Inconsistent Council Messages
- Improve Flexibility Analysis
- Continue Investigating Emerging Resources
- Participate in CA EIM

Gas

- Acquire Energy Efficiency-In Process
- Continue Developing PSE LNG Project
- Begin Upgrades to Swarr
- Improve Basin Risk Analysis

Appendix Slides

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Flexibility

Flexibility Values

Figure 6-41: Summary Results from 2013 IRP Stochastic Flexibility Analysis, 50 Simulations

Portfolio	Capacity (MW)	Expected Annual Balancing Savings ($)	Expected Annual Balancing Savings ($/kW Capacity)
Base Portfolio + CCCT	343	$800,000	$2.33
Base Portfolio + Frame CT	220	$1,037,000	$4.69
Base Portfolio + Recip	18	$328,000	$18.23

Annual Savings Batteries: $99.52/kW

Values from 2013 IRP Vintage Analysis

- In process of developing framework to update for 2017 IRP

Energy Storage and Flexibility

Figure 6-40: Battery and Pumped Storage Portfolio Cost

	NPV Portfolio Cost ($Millions)	Difference from Base
Base Portfolio[1]	12,277	
80 MW Pumped Storage in 2023	12,478	201
200 MW Pumped Storage in 2023	12,915	638
80 MW Batteries in 2023	12,374	97
80 MW Batteries in 2023 with $150/kw-yr Flexibility Value[2]	12,277	-

NOTES

1 Includes 80 MW of batteries in 2035

2 Represents the tipping point for the flexibility value to bring batteries in line with the base portfolio.

Flexibility: Reciprocating Engines Valuable

NPV ($Millions)	No Flexibility Benefit		With Flexibility Benefit			With Flexibility Benefits at 50% for Recip Peakers		
	Portfolio Cost (a)	Difference from Base (b)	Portfolio Cost (c)	Difference from Base (d)	Value of Flexibility to Portfolio (e) = (a)-(c)	Portfolio Cost (f)	Difference from Base (g)	Value of Flexibility to Portfolio (h) = (a)-(f)
Base Portfolio	12,277		12,221		56	12,221		56
Recip Peaker 75 MW*	12,263	14	12,202	19	61	12,208	14	56
Recip Peaker 75 MW in 2023	12,282	(5)	12,212	10	70	12,221	1	61
Recip Peaker 224 MW in 2023	12,354	(77)	12,235	(13)	120	12,260	(40)	93

Conclusion: Flexibility value of Recips may change relative costs.

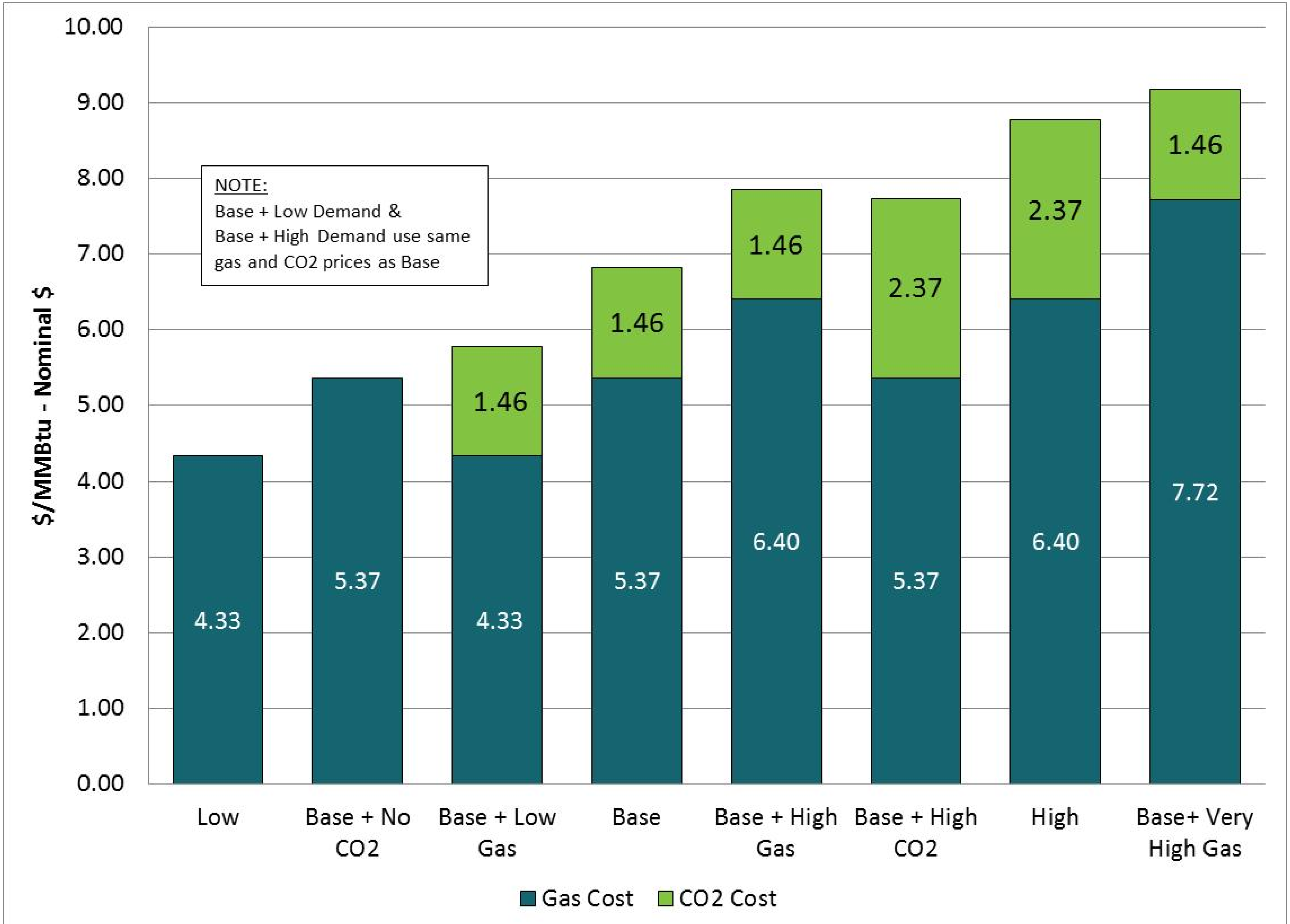
Next Steps:

- Improve flexibility framework for 2017 IRP.
- Clarify particulate emission concerns in 2017 IRP.
- EIM implications important…beyond 2017 IRP.

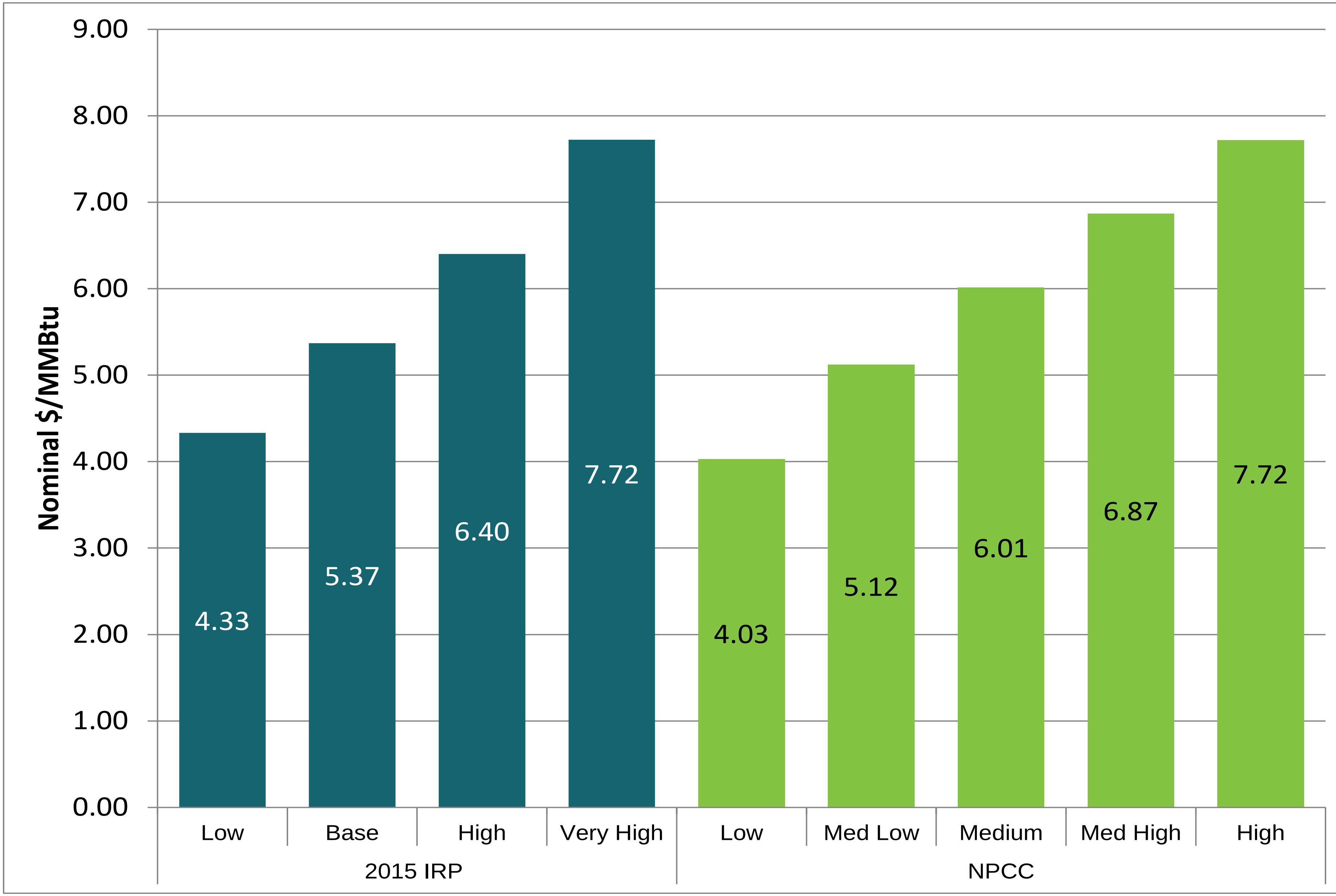
PSE PUGET SOUND ENERGY

Base Key Assumptions

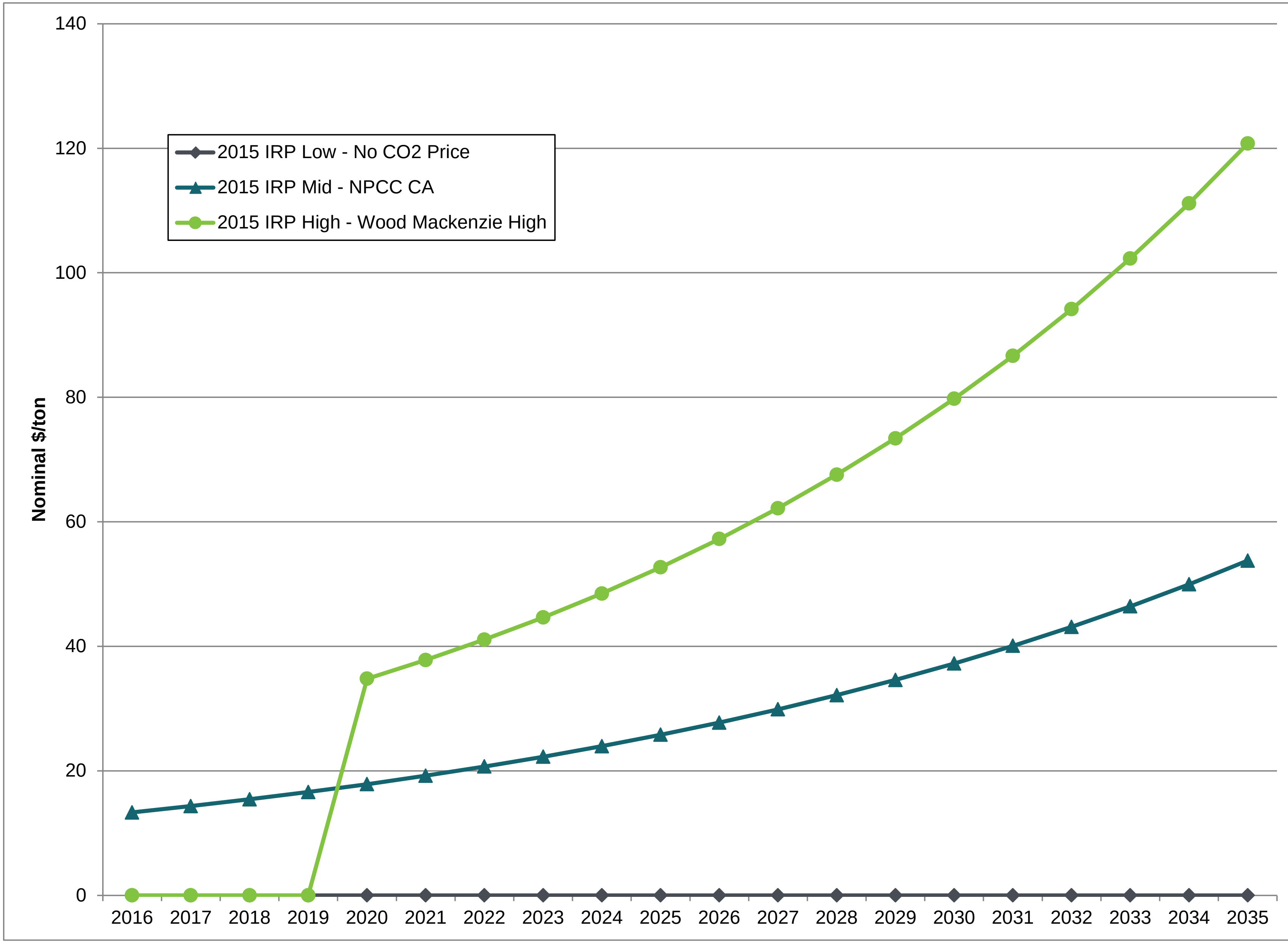
Nominal Sumas Gas Prices



Gas Prices Compared to Council's 7th Plan



Range of CO2 Prices



Range of Mid-C Power Price Forecasts