

Energy and Capacity Markets: Tradeoffs in Reliability, Costs, and Risks

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THE **Brattle** GROUP

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- I. When might we need a capacity market? (Or do we really?)
- II. Implications of ERCOT Report: Reliability, cost, and risk tradeoffs between energy-only and capacity markets
- III. Highlights from FERC Report: Impacts of inerties, price caps, DR
- IV. Things to think about before implementing a capacity market
- V. Policy implications

Appendix A: Additional FERC Study Results

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Appendix C: Additional Reading, Author Contacts, About Brattle

This presentation is based on the following two reports:

- Newell, Spees, Pfeifenberger, Karkatsouli, Wintermantel, and Carden, *Estimating the Economically Optimal Reserve Margin in ERCOT*, Report prepared for The Public Utility Commission of Texas, The Brattle Group, January 31, 2014.
- Pfeifenberger, Spees, Carden, and Wintermantel, *Resource Adequacy Requirements: Reliability and Economic Implications*, Prepared for the Federal Energy Regulatory Commission (FERC), The Brattle Group, September 2013.

I. When Might We Need Capacity Markets?

Reserve-margin mandates (and the capacity market created by them) are generally called for when energy-only markets do not attract “adequate” investments:

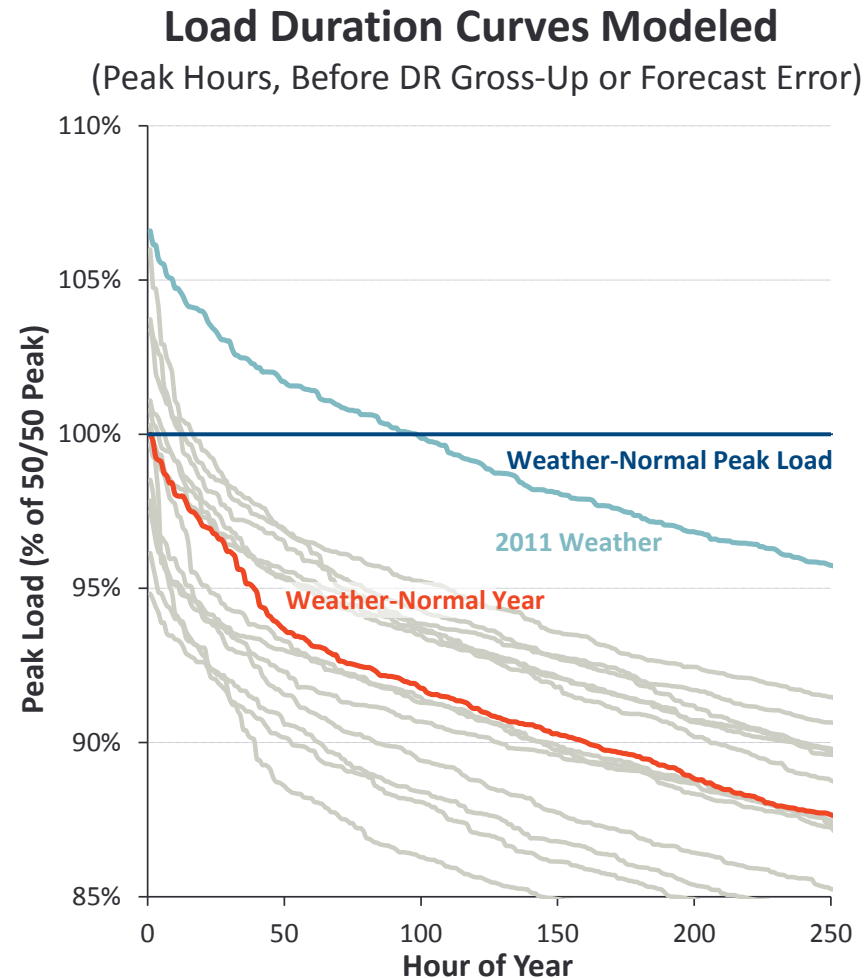
- Energy market designs that lead to price suppression?
 - Low price caps and inadequate scarcity pricing?
 - Poor integration of demand-response resources?
 - Substantial locational differences not reflected in market prices?
 - Operational actions (e.g., dispatch of emergency resources) that depress clearing prices?
- Challenging investment risks (e.g., in hydro-dominated markets)?
- Distortions created by out-of-market payments for some resources that lead to over-supply or high costs?
- Incomplete or poorly-designed ancillary service markets?
 - Missing ramping products?
 - Not co-optimized with energy market?
 - Operational actions that depress clearing prices?
- **Most Likely:** Resource adequacy preferences (e.g., 1-in-10) higher than what even fully-efficient energy and A/S markets would provide

II. Summary of Recent ERCOT Report

- The PUCT asked us to estimate the economically-optimal reserve margin in ERCOT to inform their ongoing review of market design for resource adequacy.
- Under base case assumptions, we estimate reserve margins of:
 - 10.2% economic optimum
 - 11.5% in equilibrium of current energy market design (minimizes customer cost)
 - 14.1% required to meet 1-in-10 reliability standard
- Enforcing a 1-in-10 reserve margin requirement at 14.1% (with or without a centralized capacity market) would increase long-run average customer costs by approximately 1% of retail rates relative to the 11.5% energy-only market in equilibrium :
 - Considered only energy and capacity price impacts
 - Potential additional benefits: risk mitigation, DR integration
 - Potential additional costs: implementation, added complexity, disputes

II. Modeling Approach

- Implemented study with SERVIM, a probabilistic multi-area reliability and economic modeling tool, representing:
 - **Demand** in ERCOT and external regions
 - **Generation** with randomized outages
 - **Demand response** of several types with differing availability and emergency or economic triggers
 - **Emergency procedures** that ERCOT triggers in shortage conditions
- Monte Carlo simulation of 7,500 full annual (hourly-sequential) simulations at each reserve margin
- Primary outputs reported at each reserve margin include:
 - **Reliability metrics** (LOLE, LOLH, EUE)
 - **Economic costs** (production costs, DR curtailment costs, emergency intervention costs)
 - **Market results** (prices, energy margins)



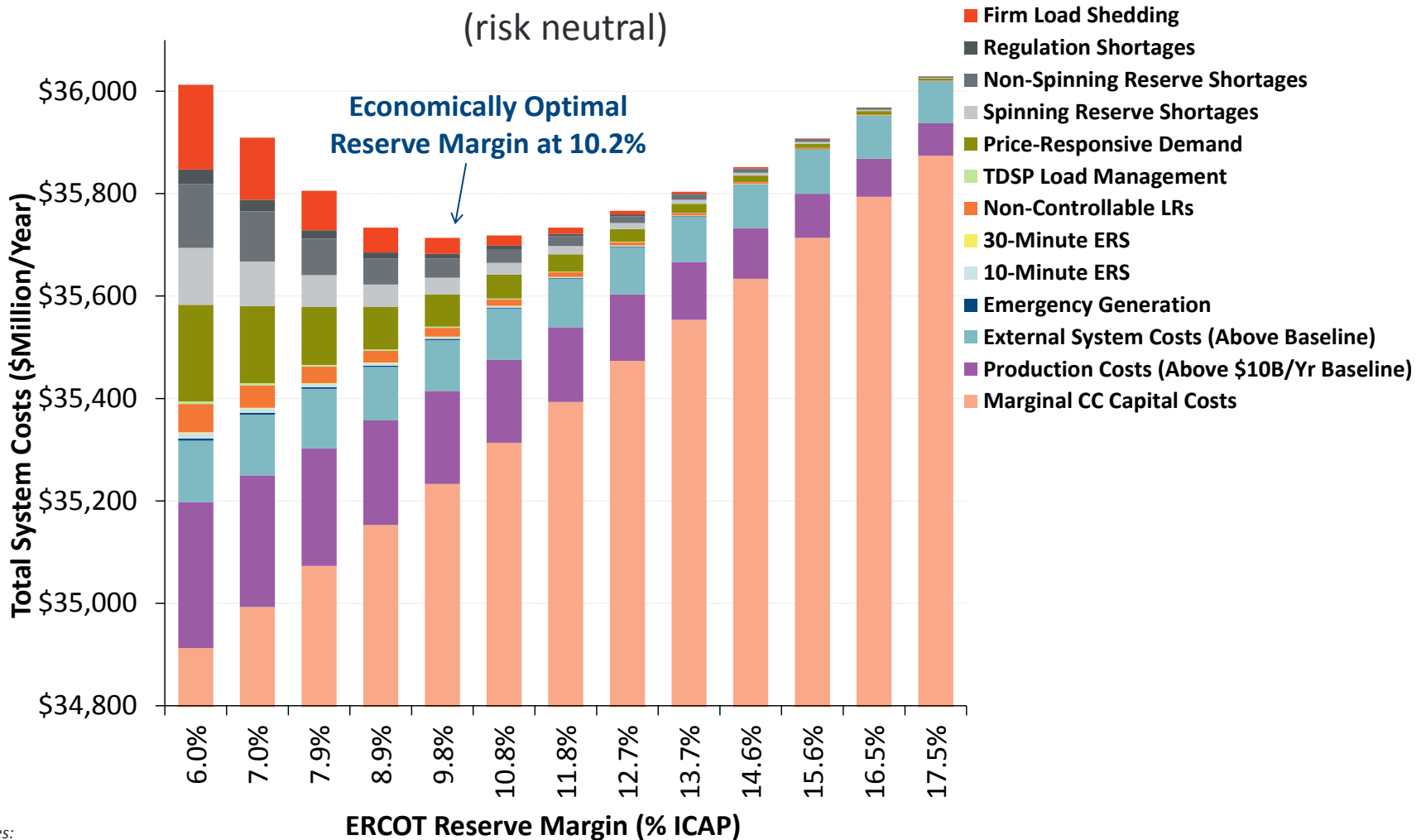
II. Reliability-Based Reserve Margin Targets

- We estimated that a 14.1% reserve margin would be required to meet the traditional 1-in-10 loss of load event (LOLE) standard;
 - At 11.5%, average LOLE is three times higher (with average MWh shed 25% higher)
- Results sensitive to:
 - **Forward period** at which supply decisions are locked in, and consequential load forecast error (LFE) that needs to be considered in analysis (removing LFE drops the reserve margin to 12.6%)
 - **Likelihood of extreme 2011 weather** recurring treated at 1% chance in base case (raising it to 1/15 or equal chance would increase the reserve margin to 16.1%)

Reserve Margin (%)	Total Annual Loss of Load			Average Outage Event			Reliability Index
	LOLE (events/yr)	LOLH (hours/yr)	EUE (MWh)	Duration (hours)	Energy Lost (MWh)	Depth (MW)	1/LOLE (1-in-X)
6.0%	2.51	7.99	16,402	3.18	6,531	2,053	0.4
7.9%	1.36	4.02	7,555	2.95	5,555	1,882	0.7
8.9%	0.91	2.62	4,750	2.88	5,214	1,811	1.1
9.8%	0.64	1.77	3,020	2.76	4,719	1,709	1.6
10.8%	0.44	1.19	1,921	2.68	4,323	1,614	2.2
11.8%	0.29	0.74	1,145	2.56	3,938	1,541	3.4
12.7%	0.18	0.46	664	2.49	3,592	1,445	5.4
13.7%	0.12	0.28	370	2.38	3,186	1,339	8.6
14.6%	0.08	0.18	229	2.26	2,939	1,300	12.8
15.6%	0.04	0.08	97	2.14	2,517	1,174	25.9
17.5%	0.01	0.03	29	2.00	2,142	1,069	72.9

II. Economically Optimal Reserve Margin

Total System Costs across Planning Reserve Margins
(risk neutral)

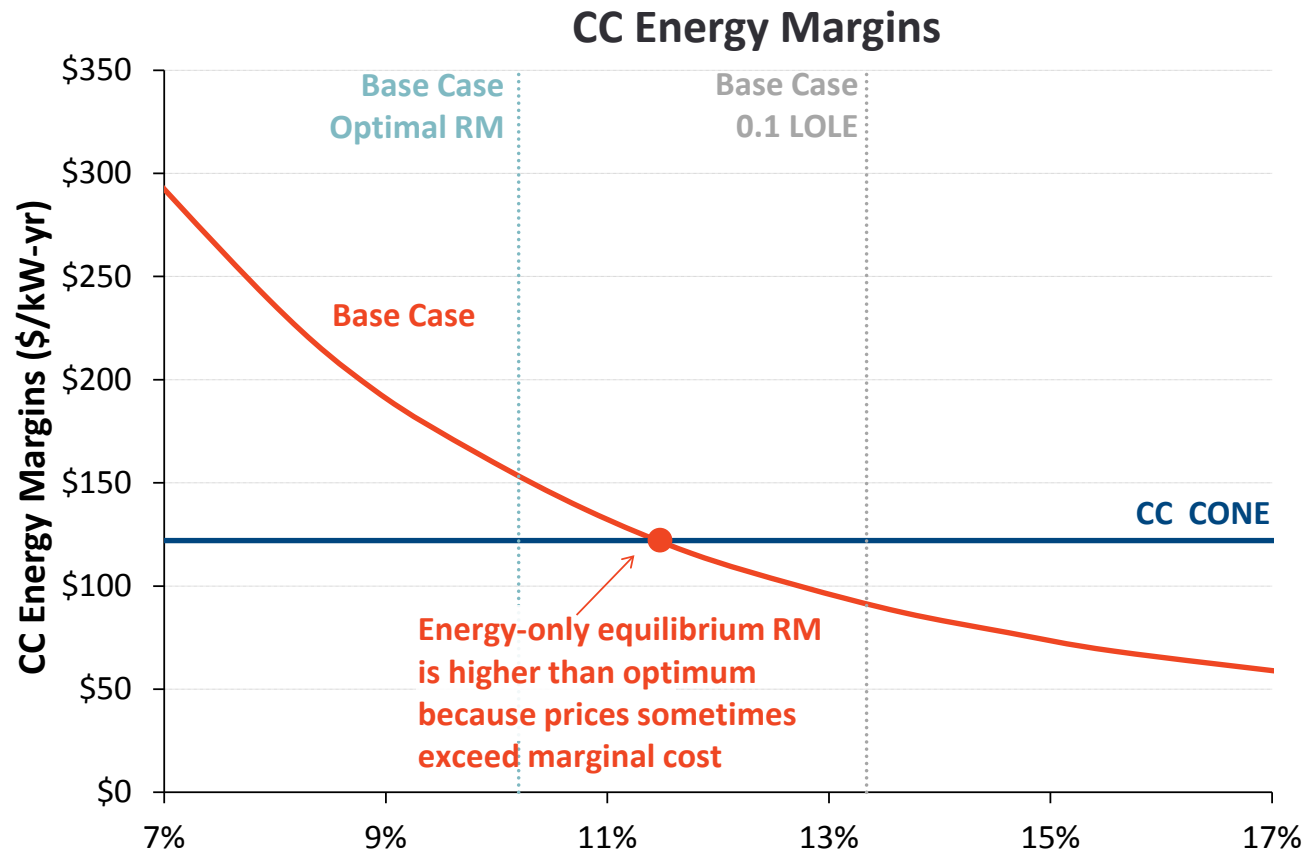


Notes:

Total system costs include a large baseline of total system costs that do not change across reserve margins, including \$15.2 B/year in transmission and distribution, \$9.6 B/year in fixed costs for generators other than the marginal unit, and \$10B/year in production costs.

II. Energy-Only Market Equilibrium

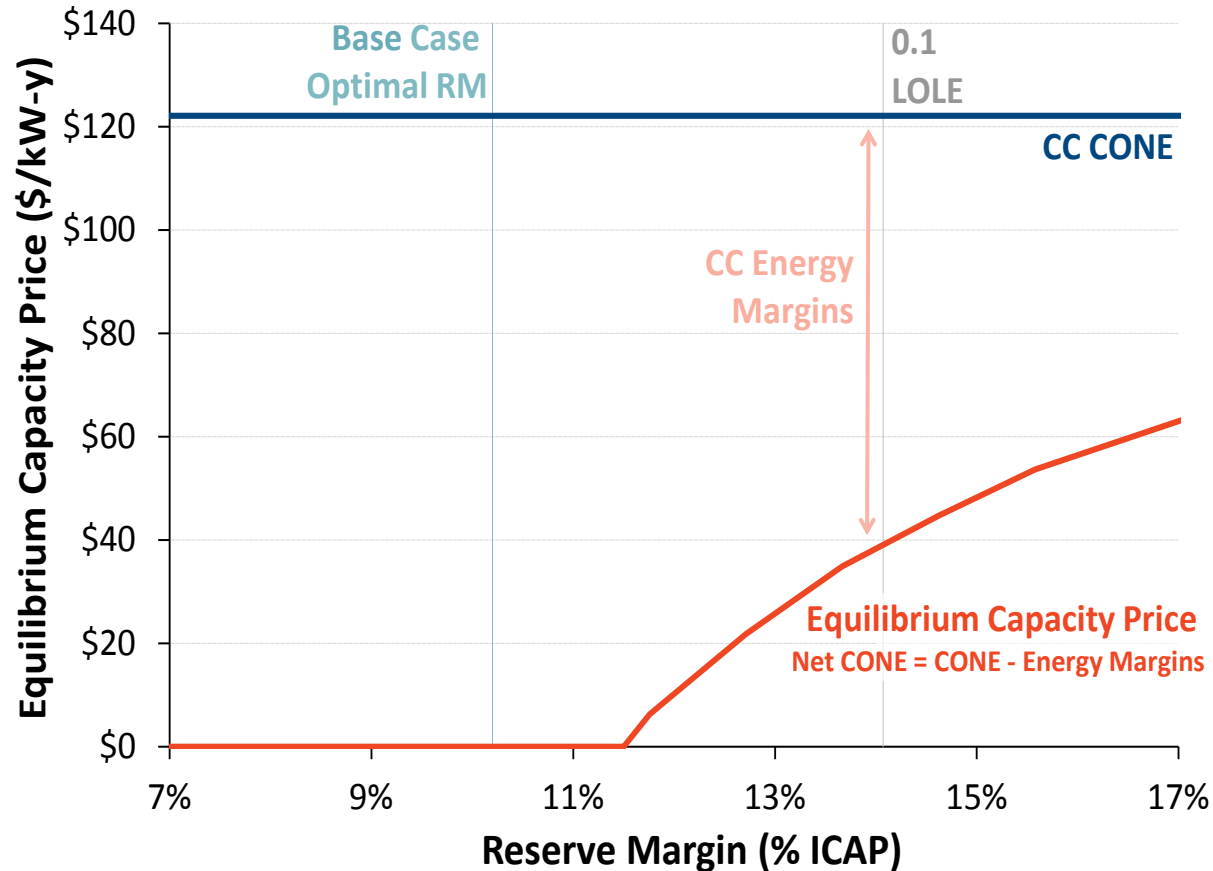
- Risk neutral, equilibrium reserve margin determined by market forces, where supplier energy margins equal the gross Cost of New Entry (CONE)
- Current ERCOT market design results in 11.5% equilibrium reserve margin for base case (9-13% for sensitivity cases)
 - Equilibrium exceeds economic optimum because administrative scarcity prices exceed marginal costs in some cases
- Significantly greater uncertainty of actual outcomes



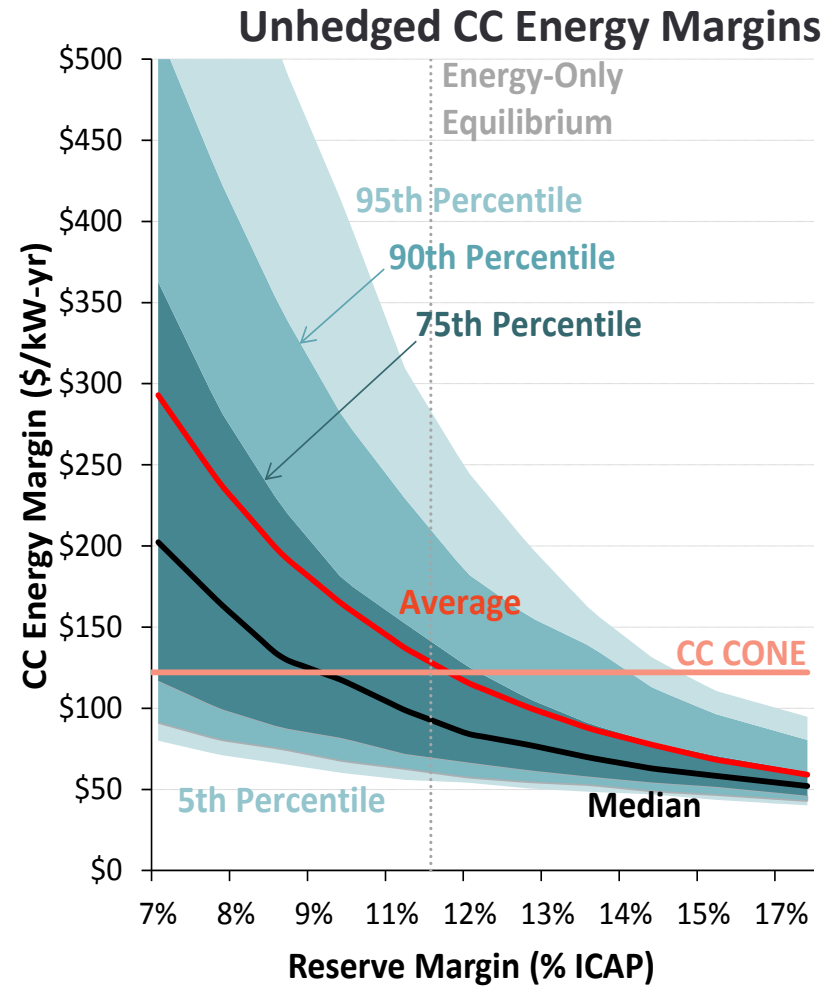
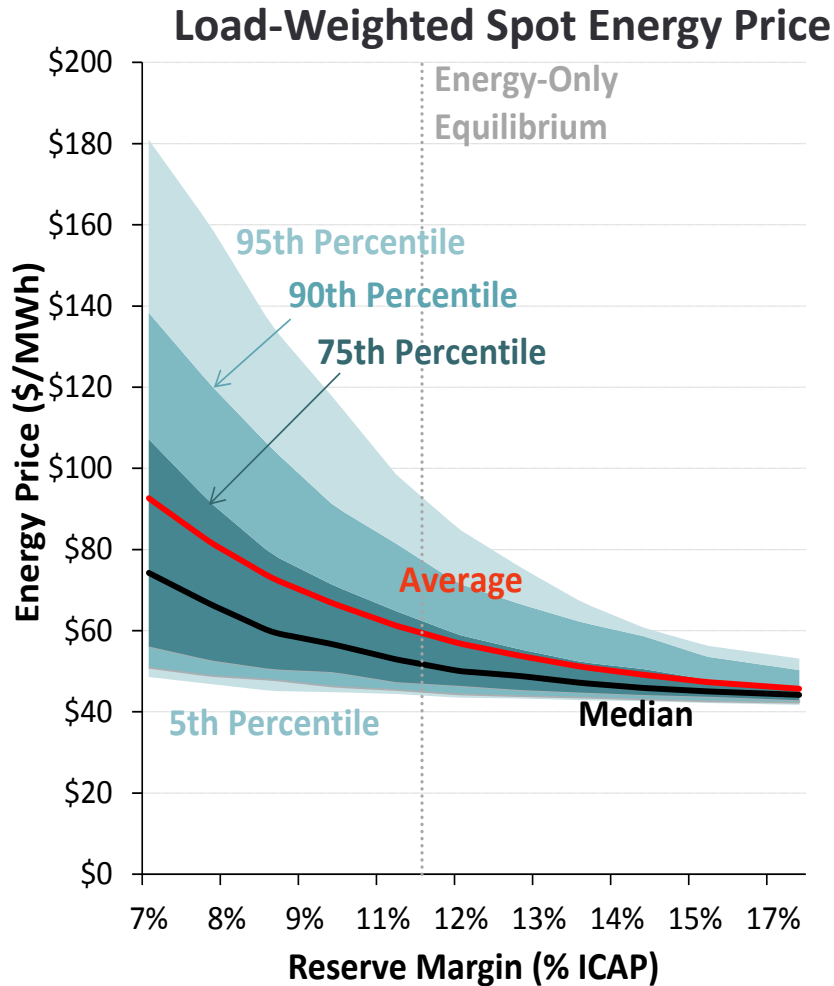
II. Equilibrium Capacity Market Prices

- Capacity is valuable for reserve margin requirements above the 11.5% energy-only equilibrium
 - Equilibrium capacity price set by the market at Net CONE (gross CONE minus energy margins)
 - 1-in-10 reliability at 14.1% requires average capacity price of \$40/kW-yr (\$30-\$60/kW-y in sensitivity cases)
- Even at lower levels, a reserve margin mandate will prevent very low reserve margin outcomes, mitigate some boom-bust cycles, and make capacity more valuable than in equilibrium

Equilibrium Capacity Prices at different Reserve Margin Requirements



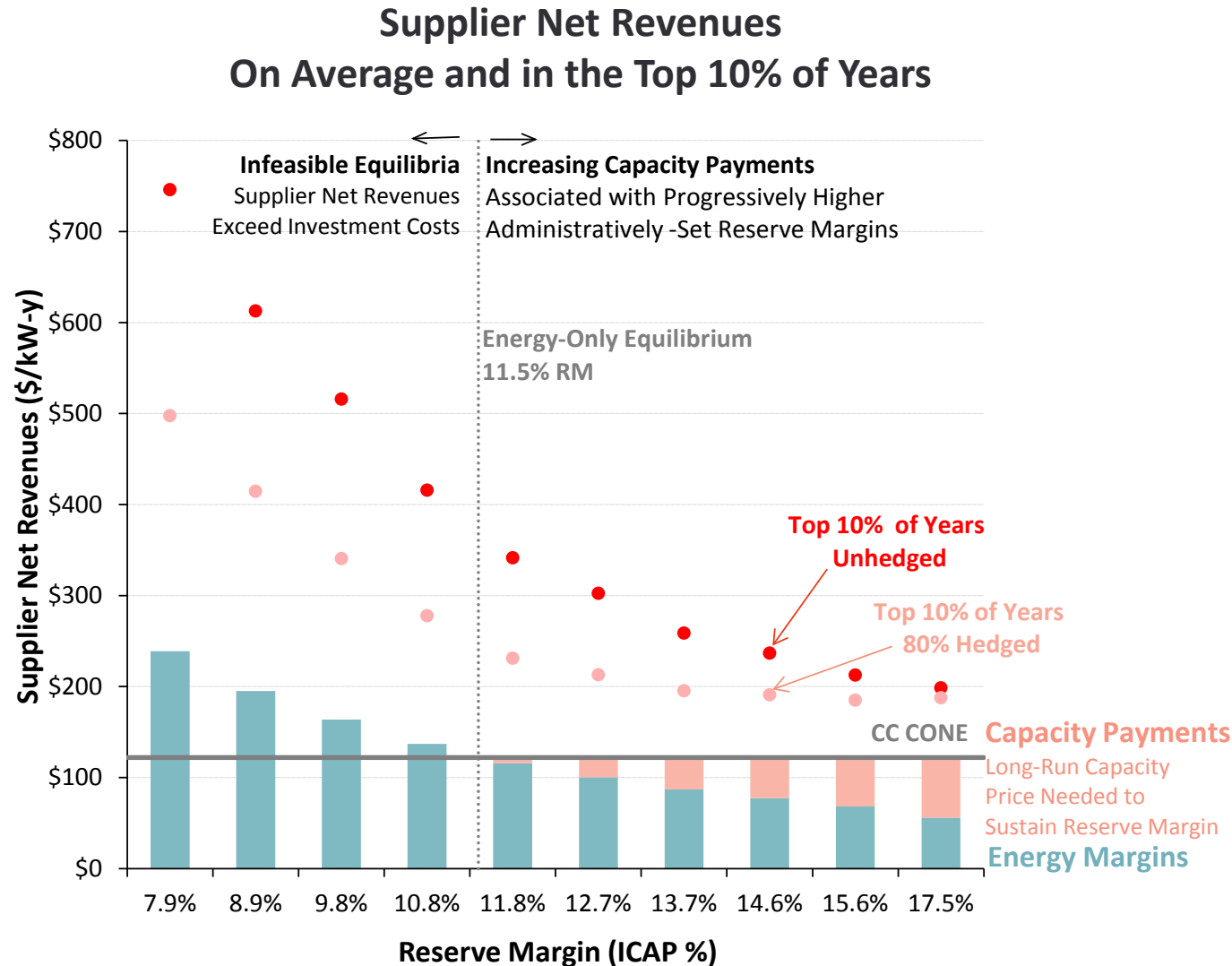
II. Volatility in Spot Prices and Energy Margins



- At 11.5% the average annual energy price is 20% higher than at 14%; average of top 10% of annual prices (unhedged) is 50% higher. Median prices significantly below average.

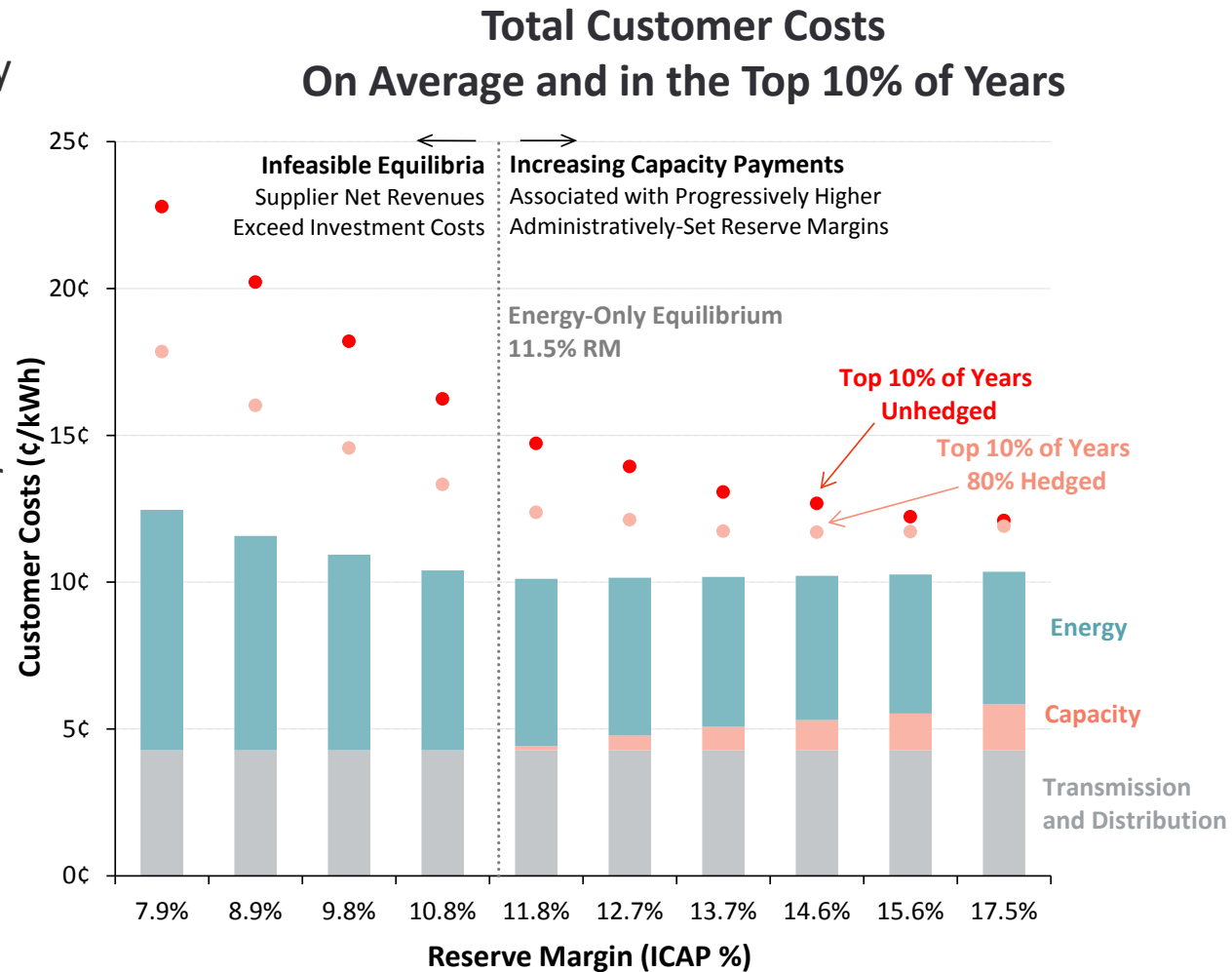
II. Supplier Net Revenues

- Total supplier net revenues must reach CONE (on a long-run average basis) to attract new entry
- At higher reserve margin mandates, the source of revenues shifts from energy to capacity market (capacity makes up 32% of net revenues at 1-in-10)
- Volatility in supplier net revenues is reduced at higher reserve margins (but much of it can also be achieved through hedging)



II. Total Customer Costs

- ERCOT customer costs are minimized at the energy-only equilibrium and increase if higher reserve margin mandates are imposed
- A 14.1% reserve margin mandate (at 1-in-10) would increase customer costs by approximately \$400 mil/year or 1% in long-run equilibrium
- The near-term difference between energy-only and capacity markets is more substantial because energy prices are currently below equilibrium levels (excess capacity relative to energy-only equilibrium)



II. Summary of Results from ERCOT Report

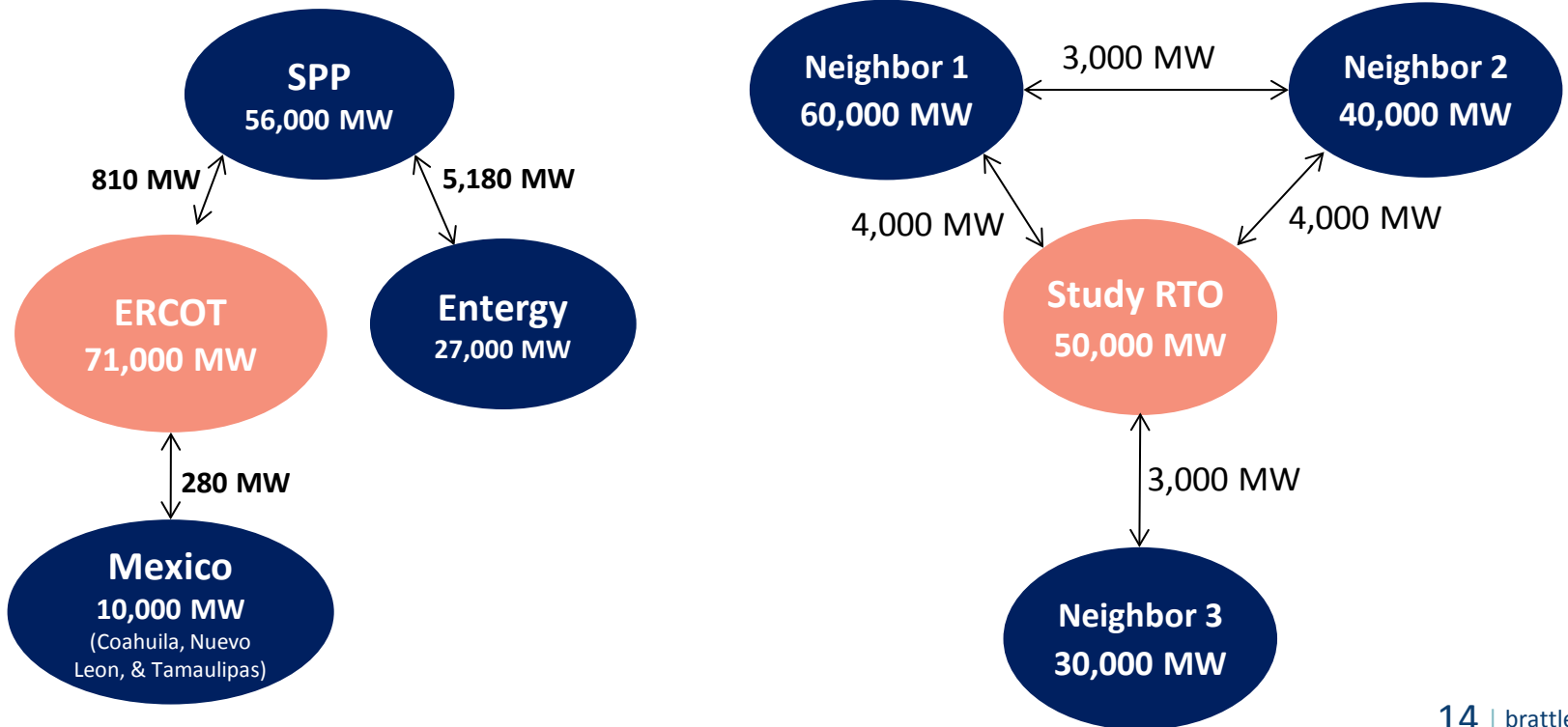
		Energy-Only Market		Capacity Market at 1-in-10	
		Base Case	Sensitivity Cases	Base Case	Sensitivity Cases
Equilibrium Reserve Margin	(%)	11.5%	9.3%-12.9%	14.1%	12.6% - 16.1%
Realized Reliability					
Loss of Load Events	(events/yr)	0.33	0.27 - 0.85	0.10	0.10 - 0.10
Loss of Load Hours	(hours/yr)	0.86	0.68 - 2.37	0.23	0.22 - 0.23
Normalized EUE	(% of MWh)	0.0004%	0.0003% - 0.0013%	0.0001%	0.00008% - 0.0001%
Economics in Average Year					
Energy Price	(\$/MWh)	\$58	\$58 - \$60	\$48	\$46 - \$53
Capacity Price	(\$/kW-yr)	\$0	\$0 - \$0	\$39	\$30 - \$60
Supplier Net Revenue	(\$/kW-yr)	\$122	\$97 - \$122	\$122	\$97 - \$122
Average Customer Cost	(¢/kWh)	10.1¢	10.1¢ - 10.7¢	10.2¢	10.2¢ - 10.8¢
Total Customer Costs	(\$B/Yr)	\$35.7	\$35.7 - \$37.8	\$36.1	\$36.0 - \$38.3
Economics in Top 10% of Years					
Energy Price	(\$/MWh)	\$99	\$95 - \$102	\$65	\$58 - \$77
Capacity Price	(\$/kW-yr)	\$0	\$0 - \$0	\$76	\$30 - \$116
Supplier Net Revenue (Unhedged)	(\$/kW-yr)	\$362	\$173 - \$444	\$249	\$152 - \$302
Supplier Net Revenue (80% Hedged)	(\$/kW-yr)	\$244	\$119 - \$259	\$193	\$128 - \$289
Average Customer Cost (Unhedged)	(¢/kWh)	15.1¢	13.4¢ - 23.0¢	12.9¢	12.4¢ - 17.9¢
Average Customer Cost (80% Hedged)	(¢/kWh)	12.6¢	9.8¢ - 21.8¢	11.7¢	10.2¢ - 17.7¢
Total Customer Costs (Unhedged)	(\$B/Yr)	\$53.6	\$37.4 - \$81.5	\$45.7	\$43.9 - \$63.3
Total Customer Costs (80% Hedged)	(\$B/Yr)	\$44.7	\$34.6 - \$77.2	\$41.5	\$36.2 - \$62.9

III. FERC Study of Resource Adequacy

- Scope of September 2013 Study (released by FERC in Feb 2014):
 - Assessed economic/reliability implications of different resource adequacy standards.
 - Examine the widely-used one-day-in-ten-years (1-in-10) loss of load standard and compare it to alternative approaches to defining resource adequacy
 - Evaluate the implications of different resource adequacy standards from a customer cost, societal cost, risk mitigation, market structure, and market design perspective.
- Documented wide differences in application of 1-in-10 standard
 - 0.1 loss of load events (LOLE) per year interpretation is most widely used
 - 2.4 loss of load hours (LOLH) per year, economic reserve margins, and normalized expected unserved energy (EUE) also applied
- Even different applications of 0.1 LOLE standard and calculation of reserve margin have up to 5 percentage point impact on planning reserve margin
 - Different definition of “event” (e.g., load shed vs. operating reserve depletion)
 - Reserve margin based on name plate or de-rated capacity (e.g. for renewables)
 - Different treatment of intertie benefits, load growth uncertainty, etc.
- More explicit recognition of these wide difference would provide much-needed flexibility in market design for resource adequacy and flexibility needs

III. ERCOT vs. FERC Study Design

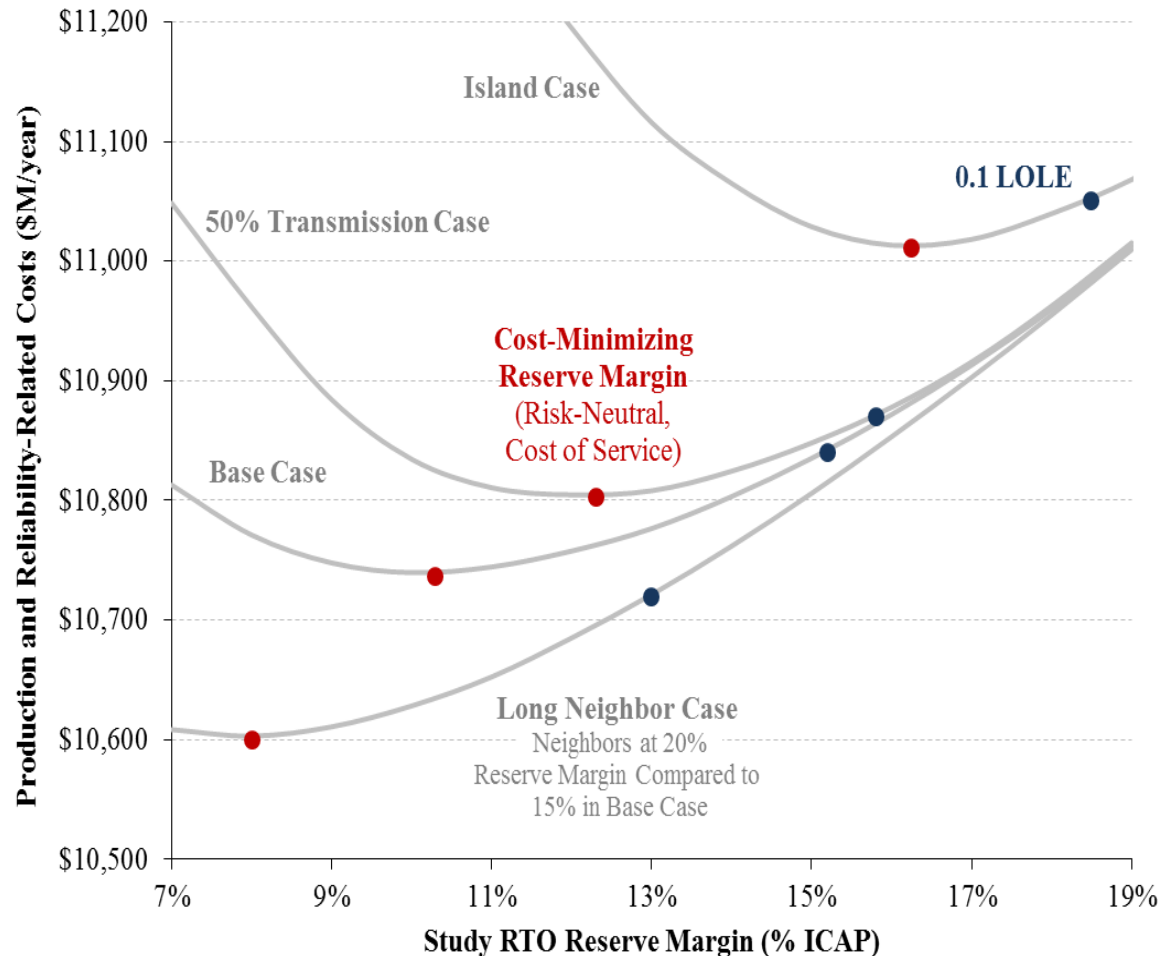
- The study design for FERC was based on a hypothetical but realistic, medium-sized “Study RTO”
- Unlike ERCOT, the Study RTO has significant transmission interconnections to three similarly-sized neighboring regions
 - Realistic resource mix based on scaled NYISO, MISO, PJM, and Southern Company data
 - Weather (hourly load and renewable generation) based on actual TVA, MISO, PJM, and SoCo data



III. Sensitivity to Intertie Capacity

- Overall, the results in FERC Study are very similar to ERCOT Report; however, difference in study scope provides additional insights on a number of topics
- Size of interconnection to neighboring system has large impact on both 1-in-10 (blue dots) and economically-optimal reserve margins (red dots)
- Strongly dependent reserve margins in neighboring systems

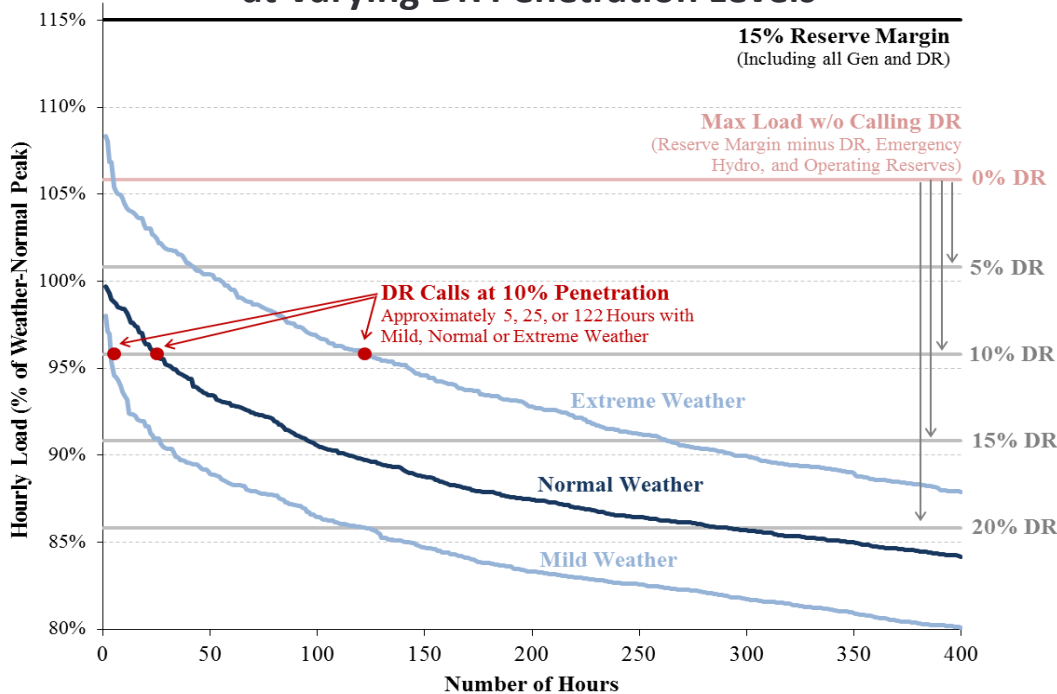
Total System Costs vs. Reserve Margin with Varying Intertie Assumptions



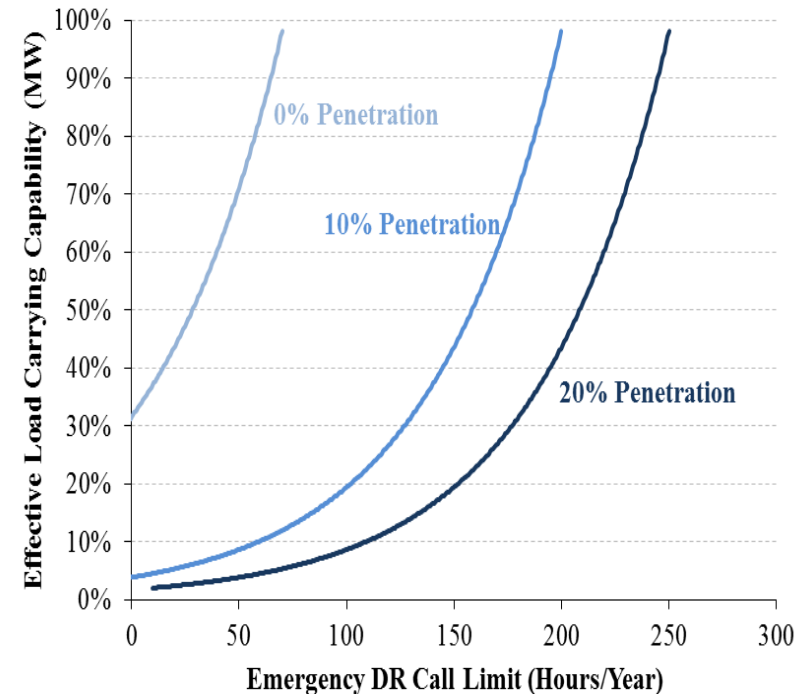
III. Capacity Value of Demand Response

- Simulations of different levels of economic and (call-hour-limited) emergency DR show significant benefits of DR with economically optimal levels in 8%-14% range
 - Lower total costs, improved scarcity pricing, lower capacity prices
- Capacity value decreases with higher penetration for: (a) emergency DR with call-hour limits and (b) economic DR with bid caps

Approximate Emergency DR Dispatch Hours at Varying DR Penetration Levels



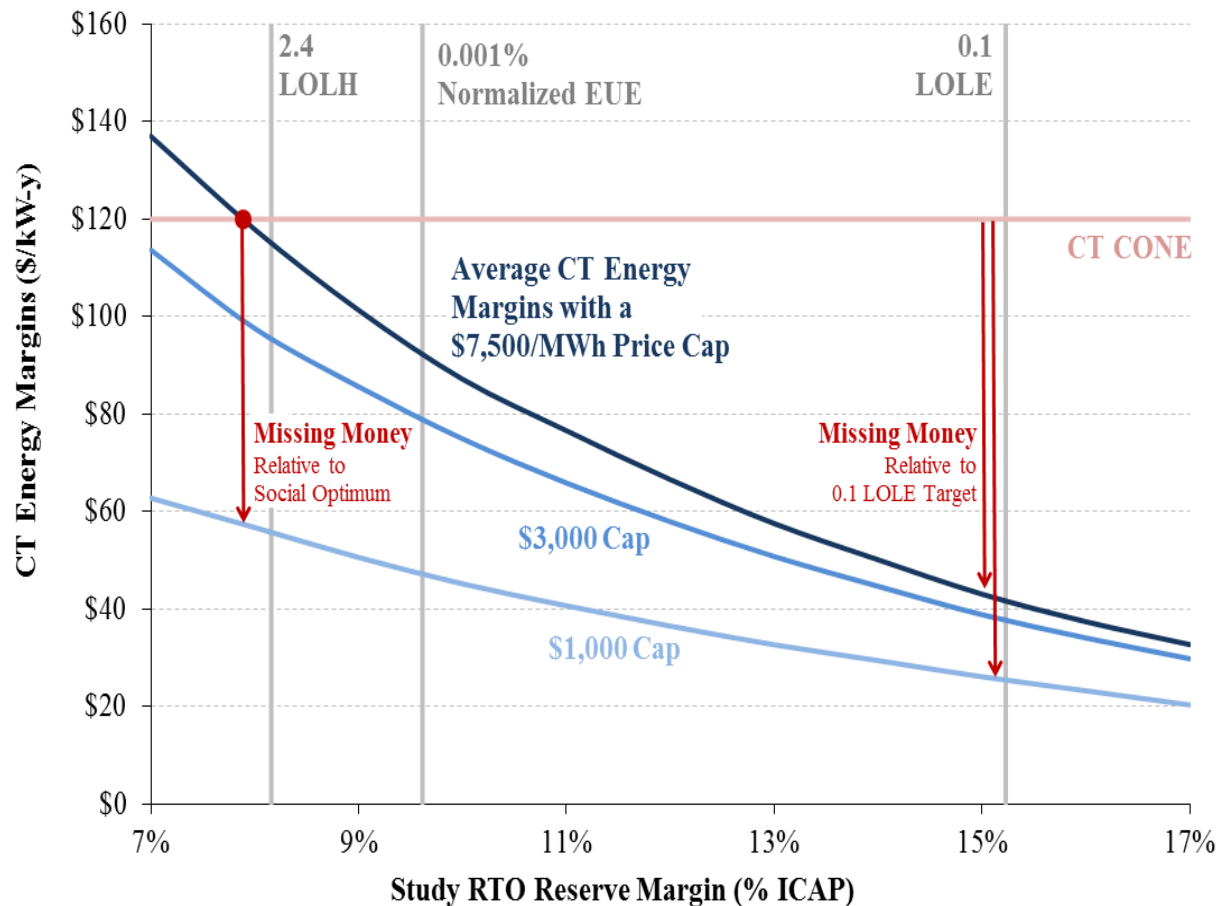
Emergency DR's Effective Load Carrying Capability (Varying DR Penetration and Call Hours)



III. Impact of Price Caps

- Simulations show that price caps substantially reduce the equilibrium reserve margins that can be achieved by energy-only market
- Energy market prices capped at levels below \$3,000/MWh significantly increase the “missing money” at any particular reserve margin
- Price caps shift necessary generator revenues from energy market to capacity market; reducing dispatch efficiencies and demand response during scarcity pricing periods

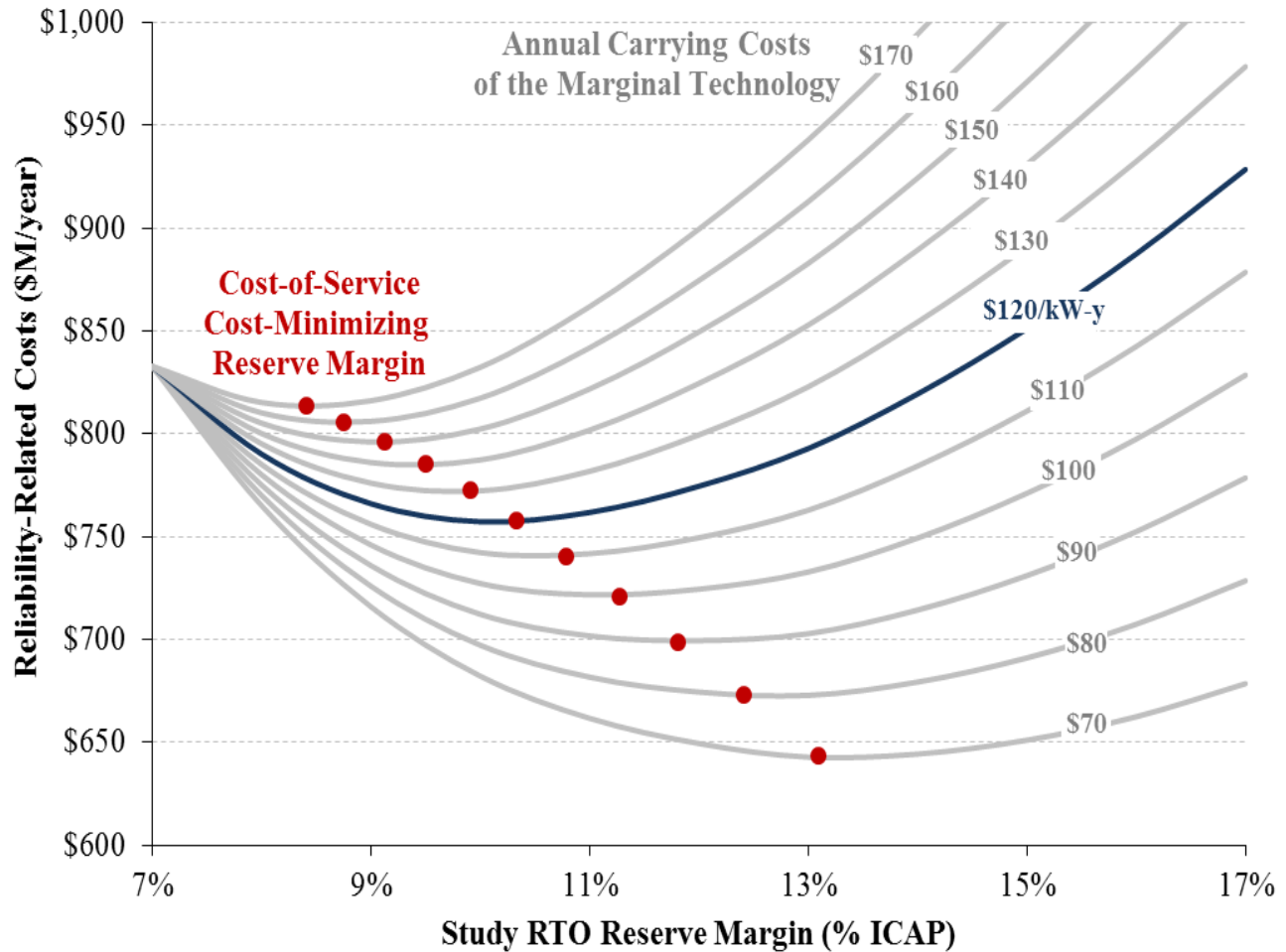
Energy Margins and Capacity Prices (“Missing Money”) at Different Price Caps



III. Economic RM vs. Cost of New Entry

- Economically-optimal reserve margins decrease as the marginal cost of adding new resources increases
- Allows estimation of a capacity market “demand curve” that is not dependent on estimates for Net CONE

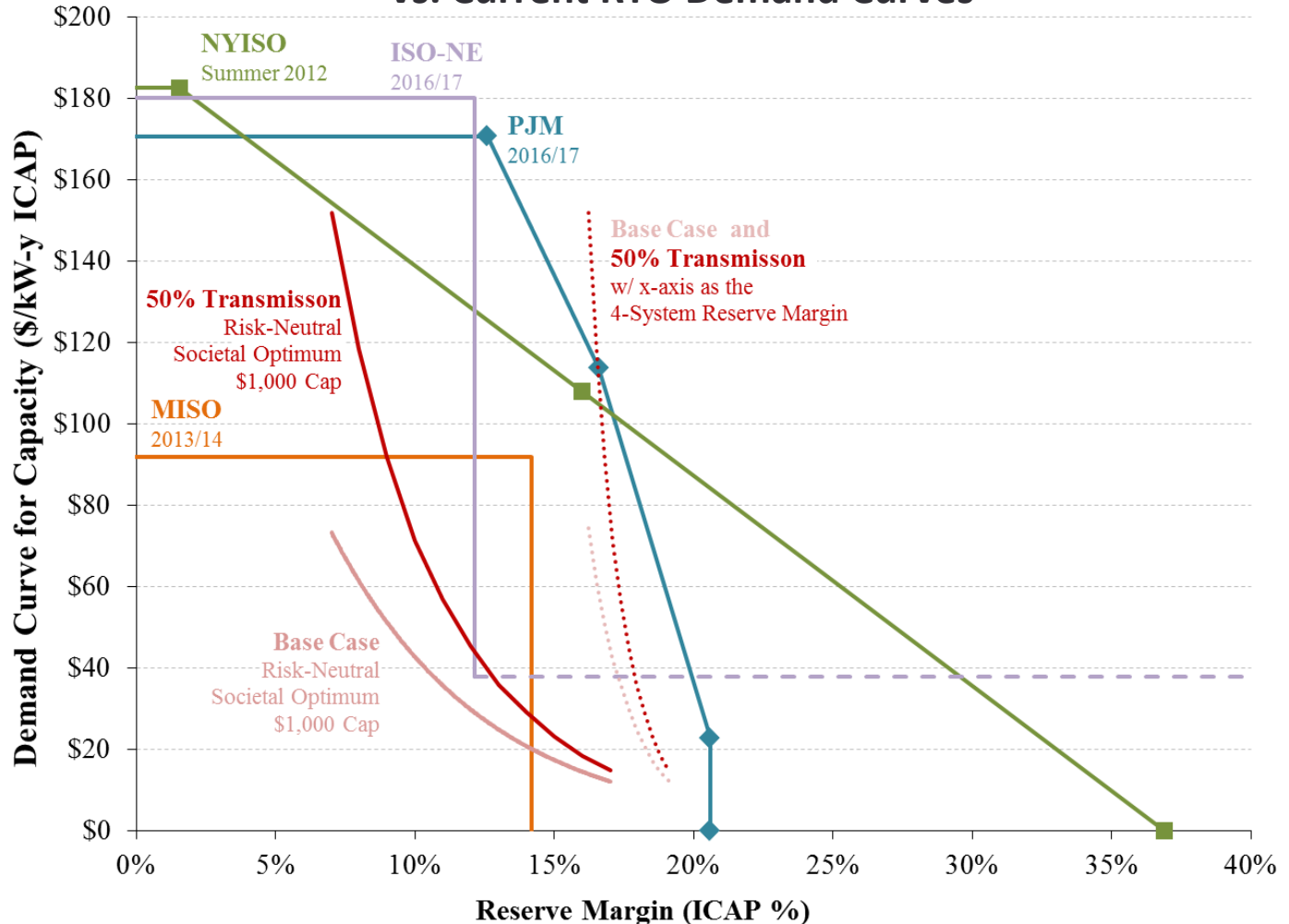
Cost-Minimizing Reserve Margin with Varying CT CONE
(Risk-Neutral, Cost of Service Perspective)



III. Demand-Curves for Capacity Markets

- Economically-determined demand curves for capacity are in the general range of RTOs' actual demand curve
- Very sensitive to market structure (such as inertias with neighboring systems) and market design features (such as price caps)

Cost-Minimizing Capacity Demand Curve from FERC Study vs. Current RTO Demand Curves



IV. Characteristics of Successful Capacity Markets

Experience from the last decade strongly suggests that successful capacity markets require:

1. Well-defined resource adequacy objectives and drivers
2. Clear understanding why market design is deficient without capacity market (inefficient or not able to achieve resource adequacy targets)
3. Clearly-defined capacity products, consistent with needs
4. Well-defined obligations, auctions, verifications, and monitoring
5. Efficient spot markets for energy and ancillary services
6. Addressing locational reliability challenges
7. Participation from all resource types
8. Carefully-designed forward obligations
9. Staying power to reduce regulatory risk while improving designs and addressing deficiencies
10. Capitalizing and building on experience from other markets

IV. Some Caution About Capacity Markets

Market-based mechanisms, including capacity markets, offer unique efficiency and innovation advantages, reducing out-of market costs imposed on consumers

But don't prematurely add capacity markets...

- ...that explicitly or inadvertently:
 - discriminate between existing and new resources
 - exclude participation by demand-side and renewable resources
 - ignore locational constraints and transmission inerties
- ...just to add revenues for certain resources or to address a perceived lack of long-term contracting
- ...while also providing out-of-market payments (including long-term contracts) to some resources that oversupply the market and distort both short- and long-term investment signals
- ...without understanding and addressing deficiencies in energy and ancillary service markets

V. Policy Implications

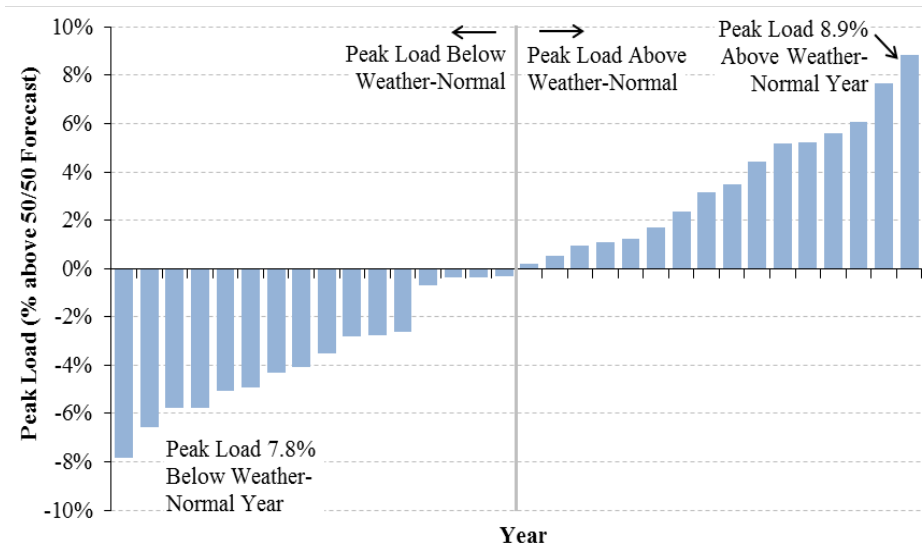
- The most appropriate market design (and reserve margin) depends on a regions' policy objectives and risk tolerance:
 - **Energy-Only Market:** likely the most appropriate design if economic efficiency is the primary policy objective, and the anticipated reserve margin, outage levels, and potential for periodic scarcity events is sustainable from a public policy perspective
 - **Mandated Reserve Margins (e.g., implemented with Capacity Market):** likely the most appropriate design if maintaining physical resource adequacy standards is the primary policy concern or policy makers wish to prevent potential low-reliability, high-cost events (thereby creating potential long-run benefits through risk-mitigation)
- Addressing this market design question appears to be less pressing while reserve margins are high, but doing so before reserve margins fall will:
 - Enable market participants to plan investment and contracting decisions under less regulatory uncertainty, and
 - If opting for a reserve margin mandate, provide sufficient time to carefully develop and implement the market design to avoid design flaws introduced through hasty implementation

Appendix A: Additional FERC Study Results

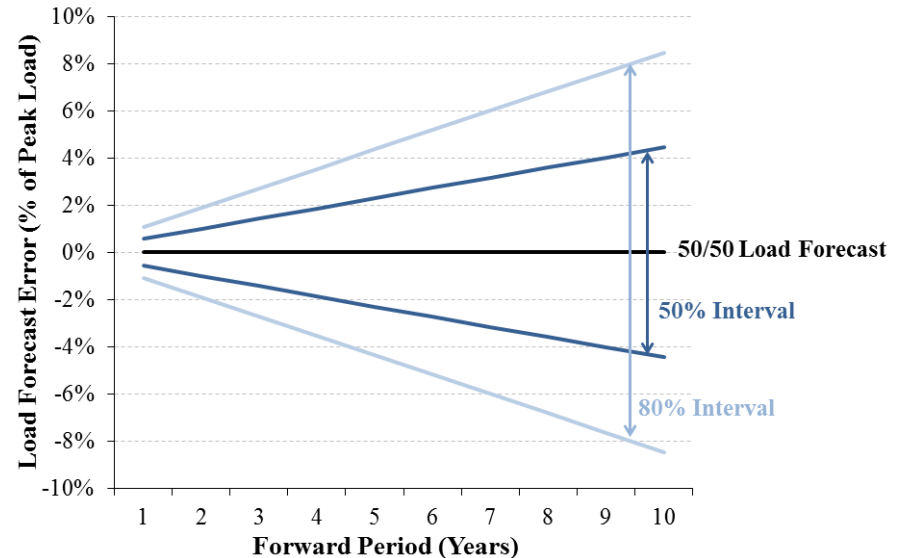
Uncertainties Considered in FERC Study

- Key uncertainties considered in FERC Study:
 - Forced/planned generation outages and intertie-transmission derates
 - Weather-related impacts on load and renewable generation (32 weather years)
 - Economic load-growth uncertainty over range of forward periods (1 to 10 years, 4-yr base)
- Administrative scarcity pricing, reserve depletion, DR- and emergency-generation

Study RTO Summer Peak Load under Different Weather Profiles

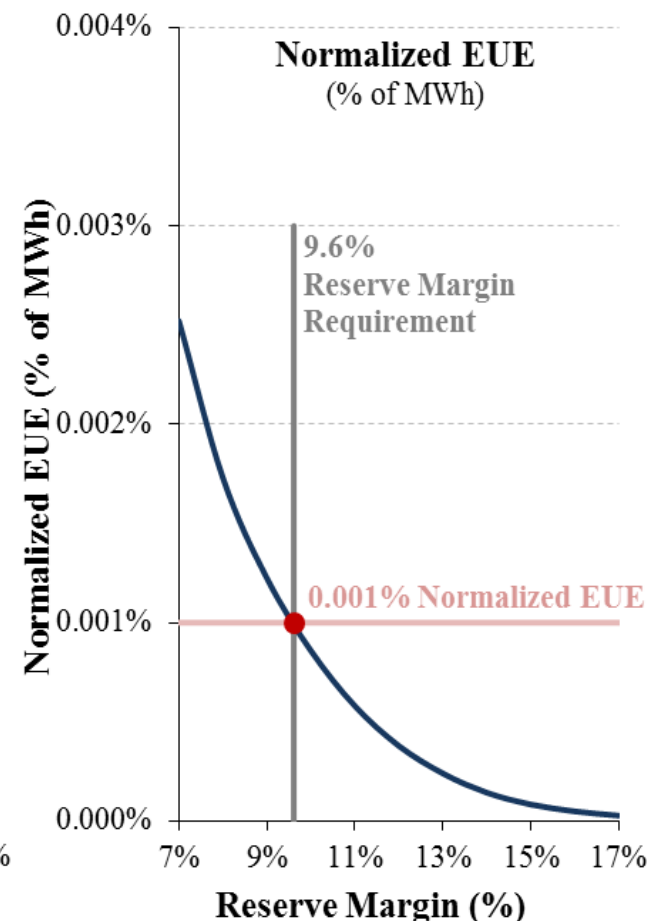
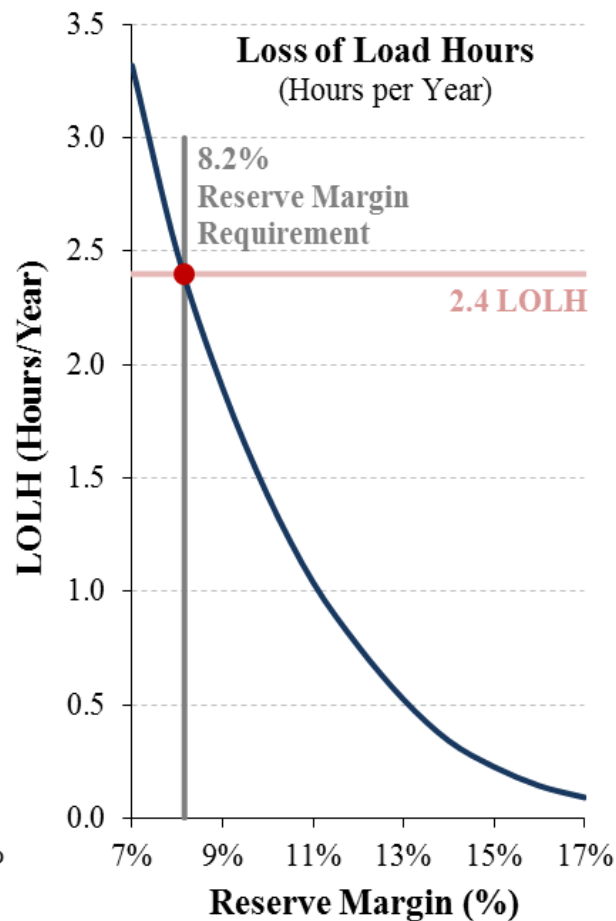
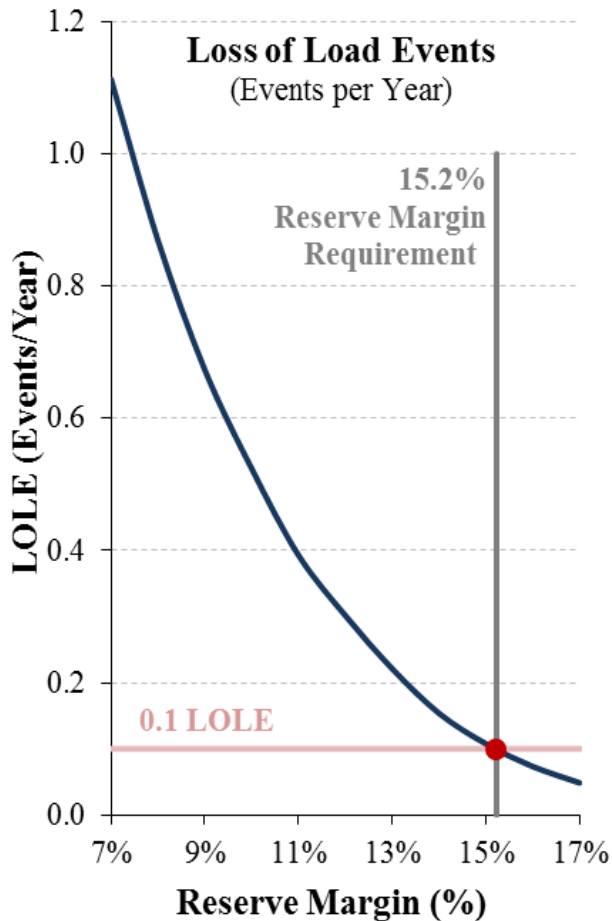


Economic Load Forecast Error vs. Forward Planning Period



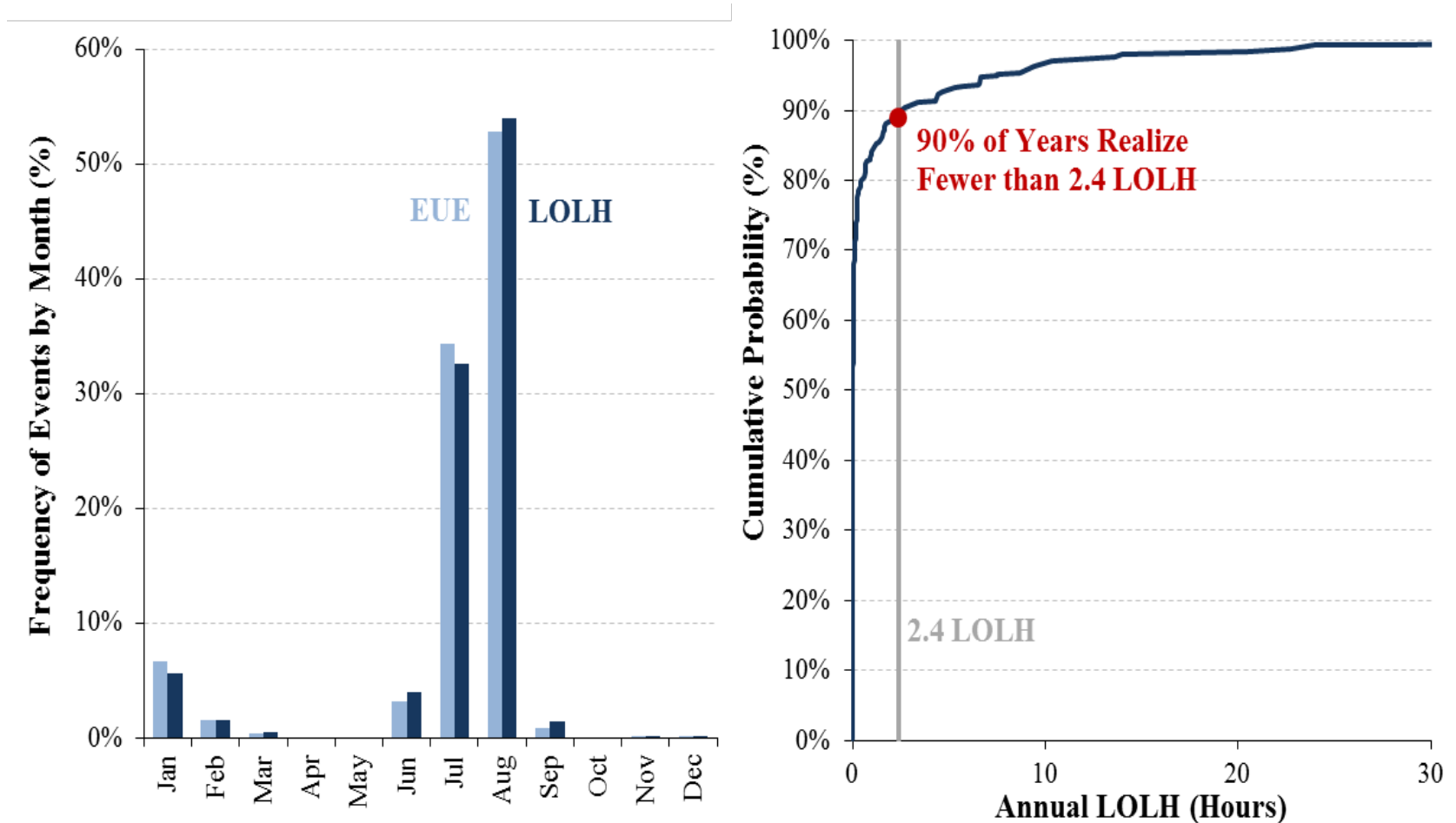
FERC Study Results

Planning Reserve Margins Required to Meet Different Physical Reliability Standards



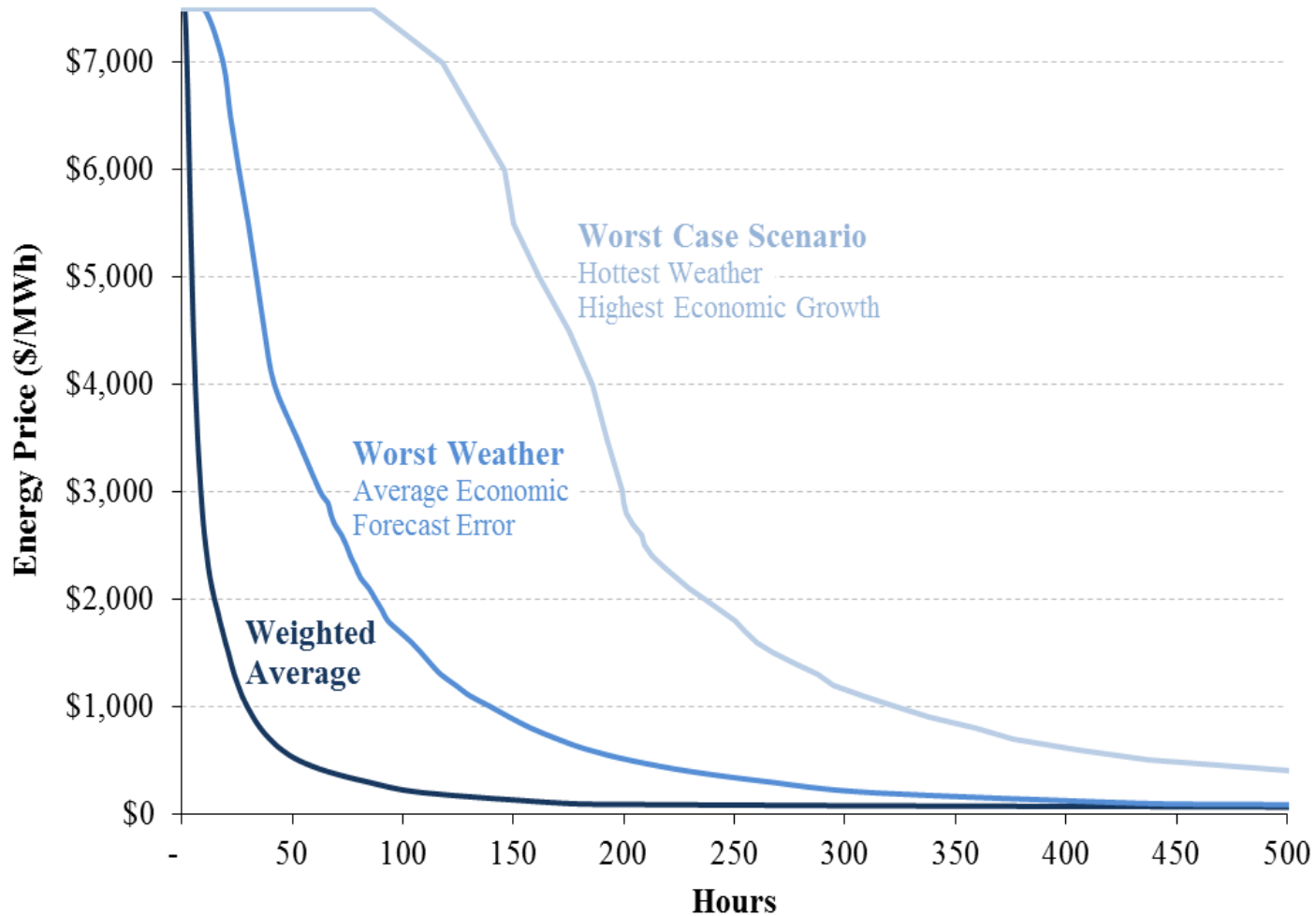
FERC Study Results

Distribution of Loss of Load Hours at 12% Planning Reserve Margin
Across Months (Left) and Across Simulation Years (Right)



FERC Study Results: Spot Energy Prices

Price Duration Curve at the Equilibrium Reserve Margin



Sensitivities: Physical and Economic RM

Reliability-Based and Economically-Based Reserve Margin Targets (Across Base and Sensitivity Case Simulations)

Simulation	Reliability-Based			Risk-Neutral, Cost-Minimizing	
	0.1 LOLE	2.4 LOLH	0.001% Normalized EUE	Cost-of-Service Perspective	Societal Perspective
Base Case	15.2%	8.2%	9.6%	10.3%	7.9%
Lower Price Caps					
\$1,000 Price Cap Case	15.2%	8.2%	9.6%	8.7%	7.9%
\$3,000 Price Cap Case	15.2%	8.2%	9.6%	9.5%	7.9%
Smaller System Size					
40% Size Case	14.8%	<6%	7.5%	<6%	<6%
40% Size and Transmission	15.1%	6.9%	8.1%	<6%	<6%
Neighbor Assistance					
Long Neighbors Case	13.0%	<6%	7.0%	8.0%	<6%
50% Transmission Case	15.8%	9.8%	10.0%	12.3%	10.5%
Island Case	18.5%	16.5%	15.8%	16.5%	16.5%
Marginal CC Case	15.3%	8.3%	9.8%	10.1%	7.7%

Additional Sensitivities: Economic RM

Sensitivity of Economically Optimal Reserve Margin to Economic Study Assumptions (Risk Neutral, Cost-of-Service Perspective)

	Reserve Margin Range (% ICAP)	Base Case	Low/High Sensitivity
Base Case	10.30%	n/a	n/a
Emergency Event Costs			
Emergency Generation	10.2% - 10.5%	\$500/MWh	\$250 - \$1000/MWh
Emergency DR	9.9% - 10.9%	\$2000/MWh	\$1000 - \$3000/MWh
Emergency Hydro	10.2% - 10.5%	\$3,000/MWh	\$1,500 - \$6,000/MWh
Voltage Reduction	10.2% - 10.4%	\$7,000/MWh	\$3,500 - \$14,000/MWh
VOLL	10.0% - 11.6%	\$7,500/MWh	\$3,750 - \$15,000/MWh
<i>All Emergency Event Costs</i>	<i>9.2% - 12.1%</i>	<i>Base</i>	<i>50% or 200% Base</i>
Other Assumptions			
Load Forecast Error	9.4% - 11.0%	4 Years Forward	2 Years - 6 Years
CONE	9.5% - 11.3%	\$120/kW-y	\$100 - \$140/kW-y
Transmission Ownership	8.3% - 12.3%	50/50 Ownership	Importer/Exporter Owns

Appendix B: Characteristics of Successful Capacity Markets (additional detail)

Characteristics of Successful Capacity Markets

1. Well-defined resource adequacy objectives and drivers

- Meet seasonal/annual peak loads or ramping/flexibility constraints?
- Drivers of the identified needs?
- System-wide or location-specific due to transmission constraints?
- Near-term vs. multi-year forward deficiencies? Uncertainty of projected multi-year forward needs?
- Ability of all demand- and supply-side resources , including inerties, to meet the identified need?

Characteristics of Successful Capacity Markets

2. Clear understanding why the market design is inefficient or will not achieve resource adequacy targets without a capacity market
 - Energy market designs that lead to price suppression?
 - Low price caps and inadequate scarcity pricing?
 - Poor integration of demand-response resources?
 - Substantial locational differences not reflected in market prices?
 - Operational actions that depress clearing prices?
 - Challenging investment risks (e.g., in hydro-dominated markets)?
 - Distortions created by out-of-market payments for some resources that lead to over-supply or high costs?
 - Incomplete or poorly-designed ancillary service markets?
 - Missing ramping products?
 - Not co-optimized with energy market?
 - Operational actions that depress clearing prices?
 - **Most Likely**: Resource adequacy preferences higher than what even fully-efficient energy and ancillary service markets would provide

Characteristics of Successful Capacity Markets

3. Clearly-defined capacity products, consistent with needs

- Annual and seasonal capability
- Near-term or multi-year forward obligations
- Peak load carrying vs. ramping capability
- Effective load carrying capability and outage rates of different resource types (including renewables, demand-response, and interties)
- Integration with energy and ancillary service markets

4. Well-defined obligations, auctions, verifications, monitoring, and penalties

- Ensure quality of resources and compliance without creating inadvertent bias against certain resources (e.g., demand-response, intermittent resources, imports)

Characteristics of Successful Capacity Markets

5. Efficient spot markets for energy and ancillary services

- Capacity markets can “patch-up” deficiencies in energy and ancillary service markets from a resource adequacy perspective
- Less efficient investment signals (e.g., resource types, supply- vs. demand-side resources, locations) if deficiencies in energy and ancillary service are not addressed

6. Addressing locational reliability challenges

- Resource adequacy won't be addressed efficiently if reliability concerns are locational but capacity markets aren't
- Requires locational resource adequacy targets and market design
- Requires understanding of how transmission (including inerties between power markets) affect resource adequacy

Characteristics of Successful Capacity Markets

7. Participation from all resource types

- Existing and new generating plants
- Conventional, renewable/intermittent, and distributed generation
- Load (demand response)
- Interties (actively committed imports vs. resource adequacy value of uncommitted interties)

8. Carefully-designed forward obligations

- Efficiency of near-term obligations (avoid forecasting uncertainty, adjust to changes in market conditions, reduced commitment risk)
- Benefits of multi-year forward obligations (competition between new and existing resources; forward visibility; financial certainty)
- Questionable need for forward commitments greater than 3-4 years
- Avoid capacity markets as substitute for long-term contracts

Characteristics of Successful Capacity Markets

9. Staying power to reduce regulatory risk while improving designs

- Staying power of market design reduces regulatory risk and improves investment climate
- Requires careful balancing of staying power and the need to improve design elements and address deficiencies
- Challenge due to strong financial interests of different stakeholders

10. Capitalizing and building on experience from other markets

- Regional differences are important but often overstated
- Avoid the “not invented here” syndrome
- Avoid “urban myths” (e.g., no new generation built in regions with capacity markets; insufficient to support merchant investments unless 5-10 year payments can be locked in)

**Appendix C:
Additional Reading,
About the Authors and Brattle**

Additional Reading

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About the Brattle Group

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