



Scarcity Pricing in ERCOT

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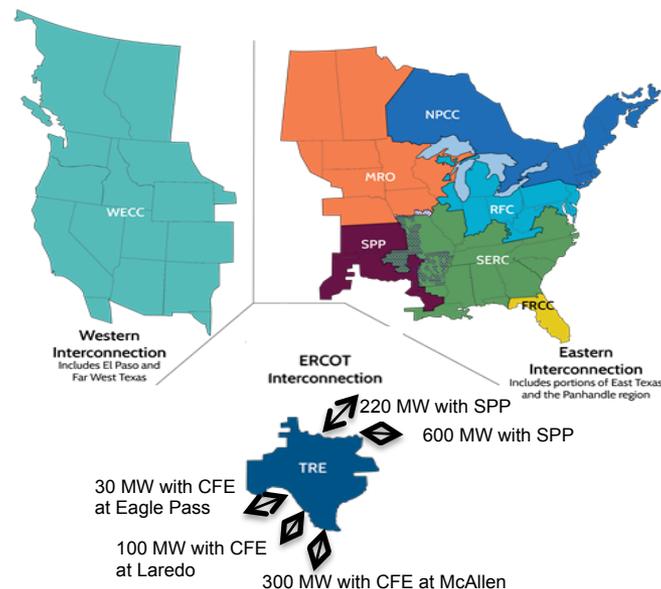
Chien-Ning Yu, ABB Inc.

FERC Technical Conference

June 27-29, 2016

ERCOT Region

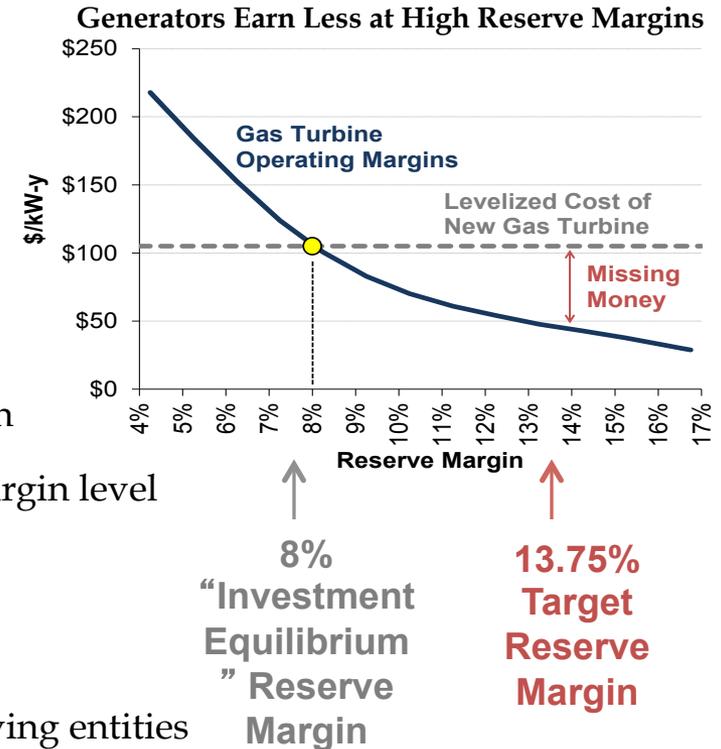
- ~90% of Texas load ~75% land
 - 24 million consumers
- 406,500 circuit miles of high-voltage transmission
- 77,000 megawatts (MW) capacity for peak demand
 - 550 generation resources
 - ~16GW Wind with ~17% capacity included
 - 288MW solar
- 69,877 MW peak demand (Aug.10, 2015)
 - Peak Wind 14,023 MW (February 18, 2016)
 - Wind penetration record: 48.28 percent (March 23, 2016)
- ~\$35 billion Market
 - ~1,400 active Market entities



Market Design Discussions

Brattle recommended market design options

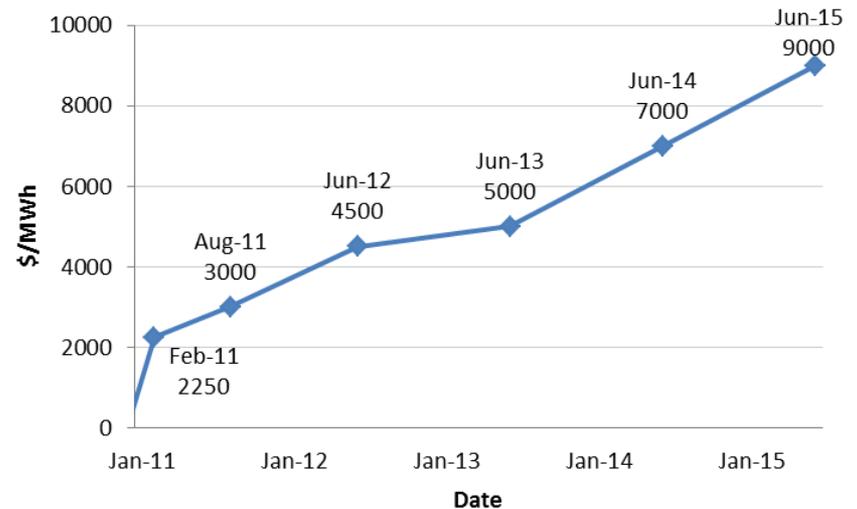
- Energy Only Market
 - Pure energy-only with market based reserve margin
 - Energy-only with adders to support target reserve margin
 - Energy-only with backstop procurement at minimum margin level
- Capacity & Energy Markets
 - Mandatory resource adequacy requirements for load serving entities
 - Resource adequacy requirement with centralized capacity market



From Brattle presentation based on a \$9,000 price cap and scarcity pricing without ORDC

Nodal Policy Changes

- System Wide Offer Cap raised to
 - \$4,500/MWh - Aug 1, 2012
 - \$5,000/MWh - June 1, 2013
 - \$7,000/MWh - June 1, 2014
 - \$9,000/MWh - June 1, 2015



- Implemented an Operating Reserve Demand Curve (ORDC) with the Value of Lost Load equal to \$9,000/MWh effective June 1, 2014

Scarcity Pricing in Real-Time Market

The Real Time prices determined by Security Constraint Economic Dispatch (SCED) would be increased by the 'Real-Time Reserve Price' which is determined based on remaining reserves in the system and a predefined Operating Reserve Demand Curve (ORDC) to reflect the incremental value of scarce operating reserves.

The value of ORDC at any given level of available operating reserves is determined as the Loss of Load Probability (LOLP) at that reserve level multiplied by Value of Lost Load (VOLL)

The RT price adder is an increasing function that values the remaining reserves as a function of the total generation in the system, sum of base points, offline Non-Spin, RRS from Load Resources, and Resources that can be started and available in 30 minutes

Reserves in Real-Time are paid based on the 'Real-Time Reserve Price' and reserves awarded in the Day-Ahead Market but are dispatched for energy in Real-Time are charged the 'Real-Time Reserve Price'

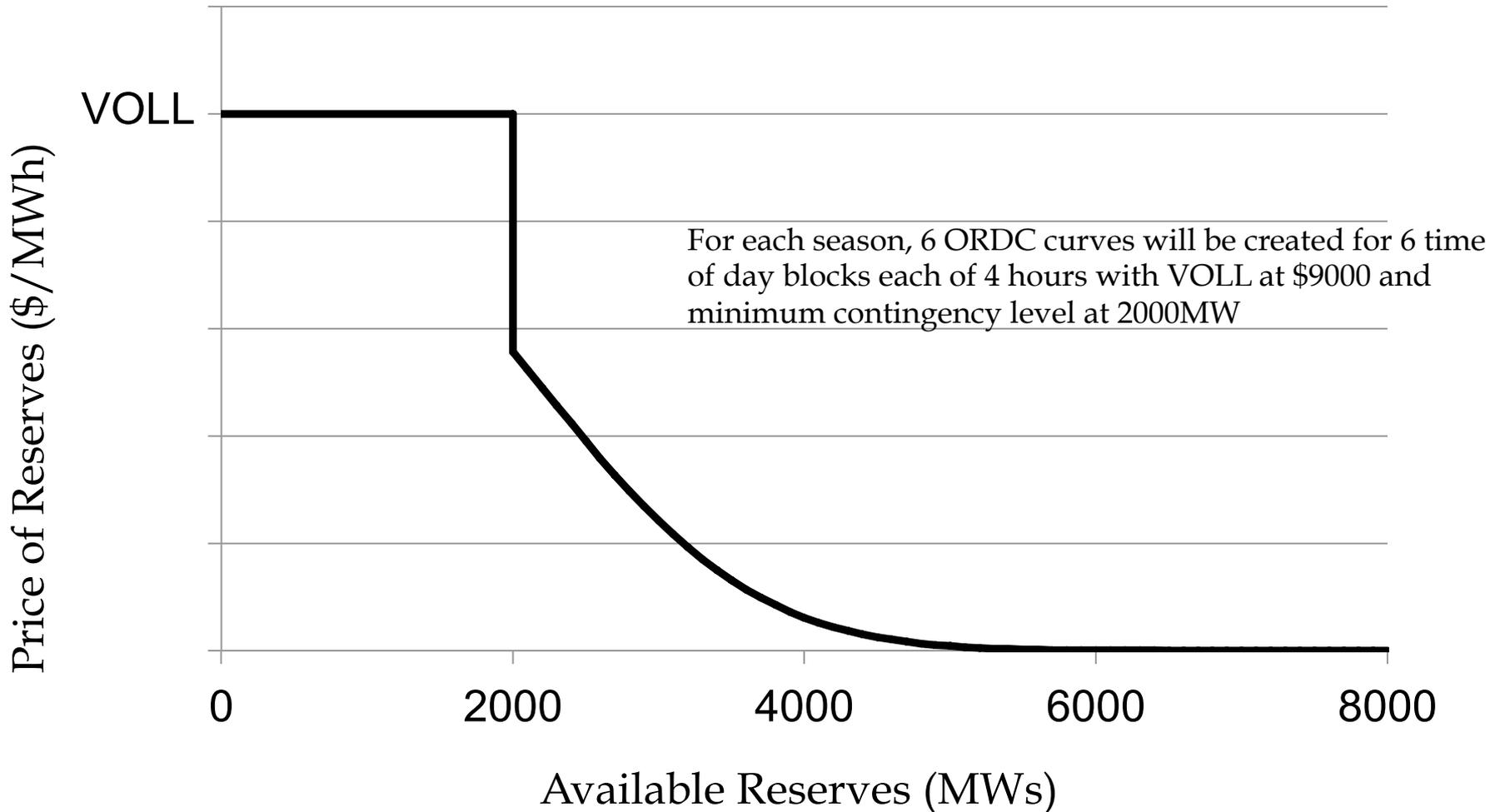
Loss of Load Probability (LOLP)

LOLP would be determined based on a mean (μ) and standard deviation (σ) of the error in system reserves forecasted at the end of Adjustment Period for the hour with respect to the reserves available in RT (HRUC reserves - RT reserves)

Due to normal distribution of errors, LOLP which is equivalent to probability of occurrence of an event of magnitude greater than the remaining reserve $[P(Y \geq x)]$, is determined as $1 - (1/2 + 1/2[\text{erf}((x - \mu) / \sqrt{2\sigma^2})])$ for each reserve (x MW) level

Seasonal and time of day specific LOLPs would be created to capture the potential differences between the different time periods and risk levels that occur throughout the year.

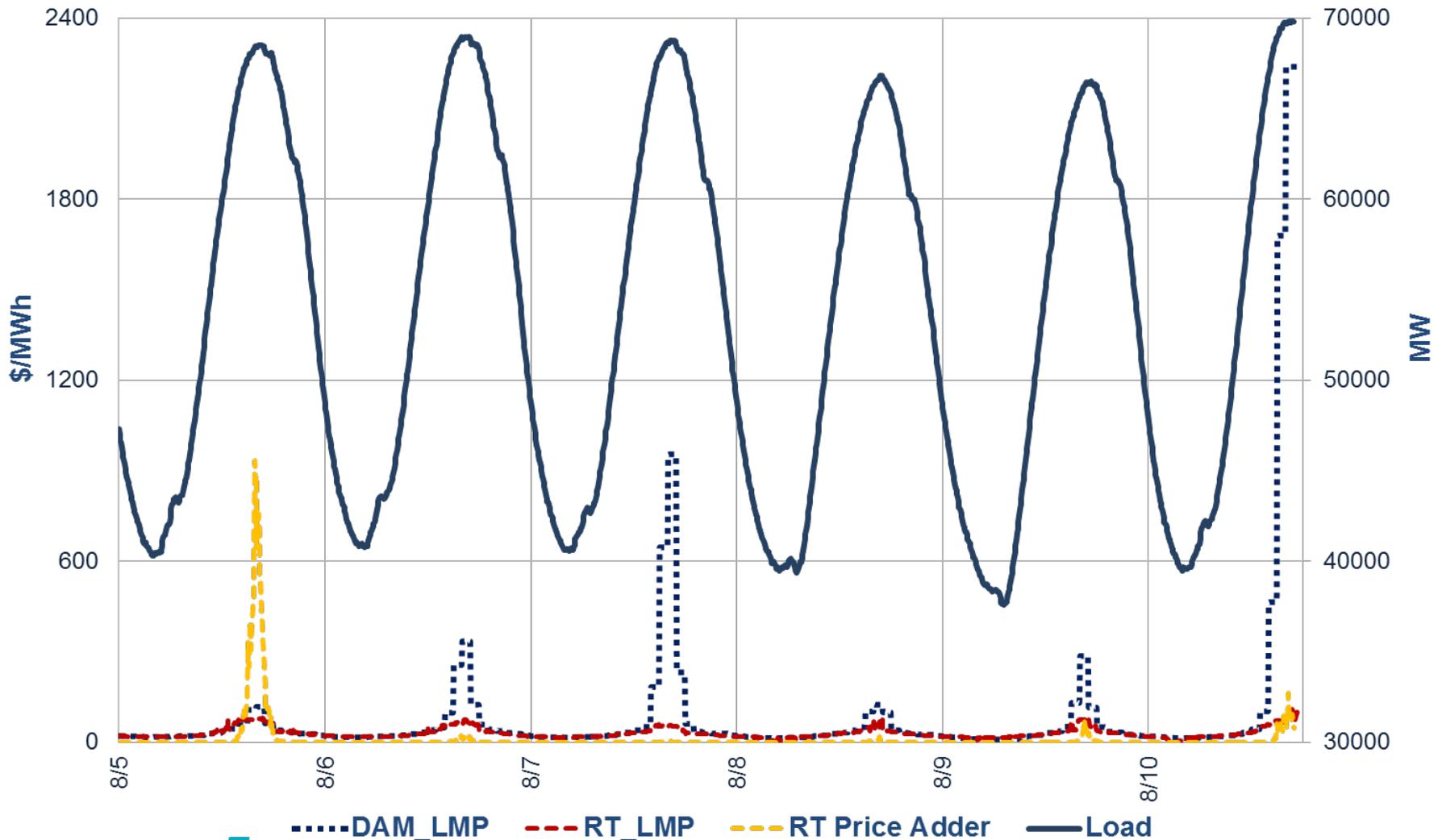
Operating Reserve Demand Curve (ORDC)



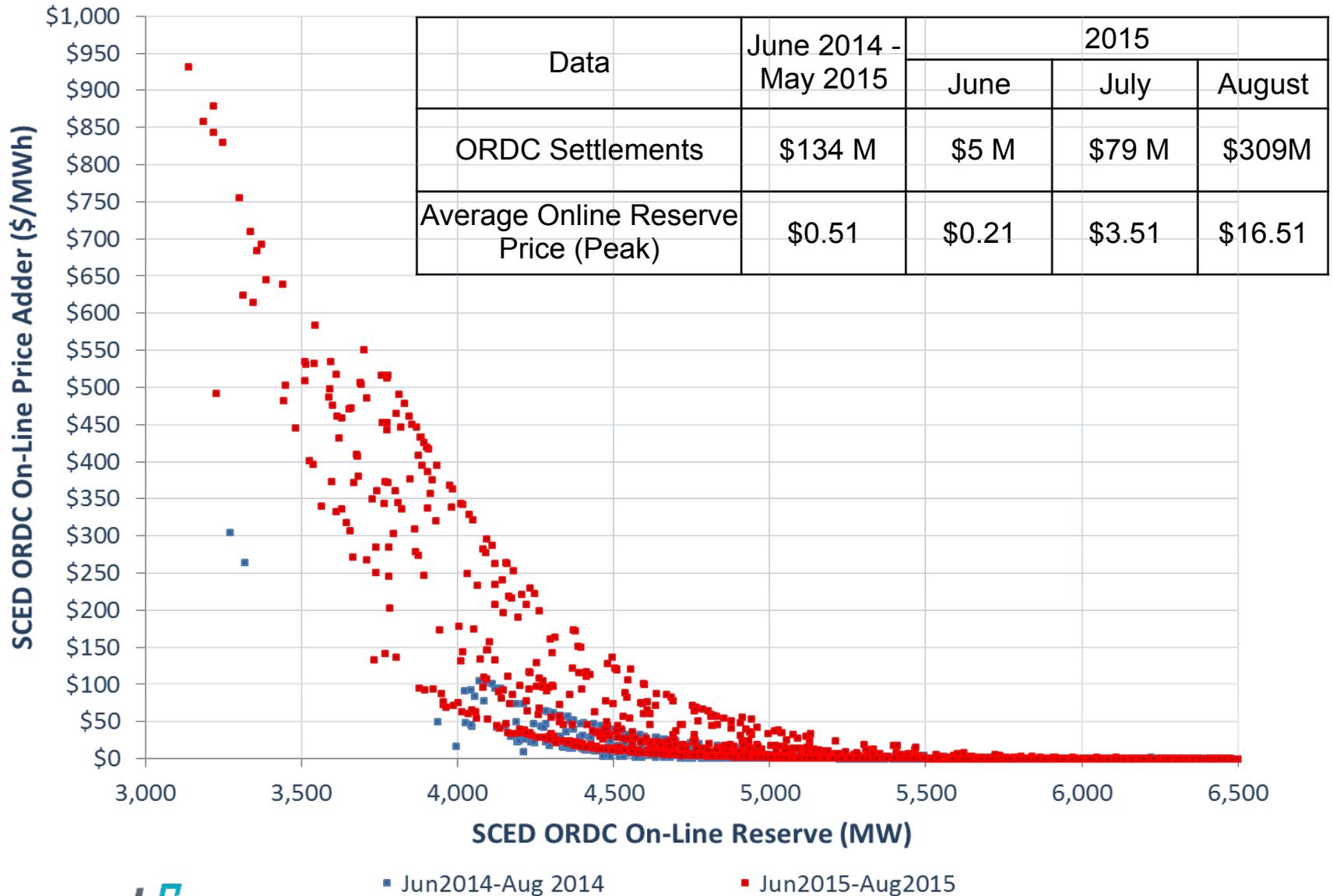
VOLL = Value of Lost Load

Tight Days: Aug 4th - 10th 2015

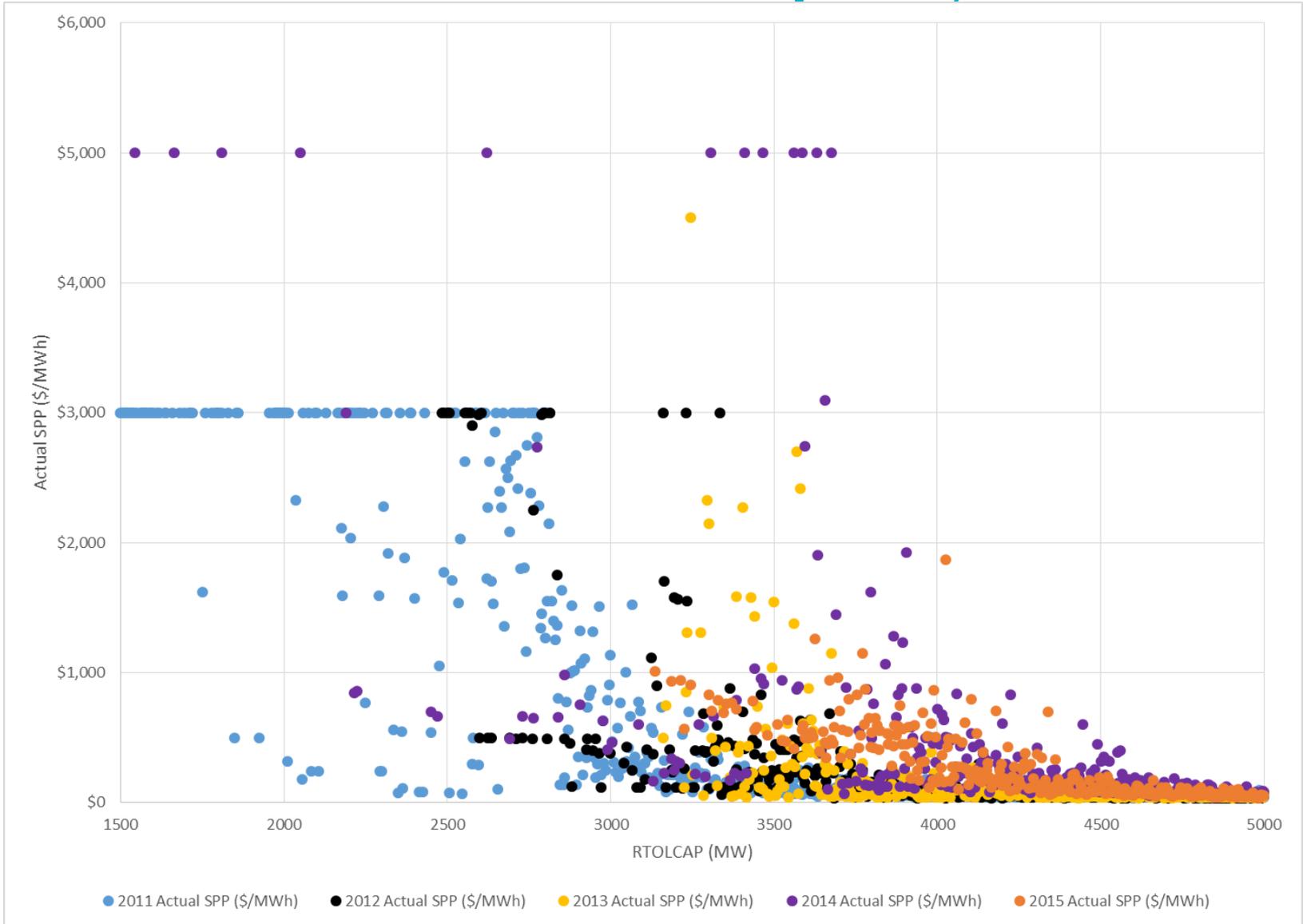
5 Minute RT Load Vs RT/DAM Prices



SCED ORDC On-Line Reserve and Price Adder



Actual Price Vs Reserve Capacity



Back-casted Price Vs Reserve Capacity



Reliability Deployment Price Adders

- ERCOT implemented a pricing run to mitigate the price reversals due to
 - Must take capacity (0-LDL) of RUC commit Resources
 - Must take capacity (0-LDL) of RMR commit Resources
 - Blocky MWs of ERS deployments
 - Blocky MWs of Load Resource deployments
- Increase in energy cost identified in the pricing run will be added to the RTLMPs and Resources will be paid lost opportunity make whole payments.

Load Participation in SCED

- Load Resources capable of following 5-minute SCED instructions
 - Existing or new single-site Controllable Load Resources (CLRs)
 - Aggregate Load Resources (ALRs) composed of multiple sites within single ERCOT Load Zone (subset of CLR)
- Will not support direct participation by third-party DR QSEs
- SCED will honor LR's telemetered ramp rates
- QSEs with LRs in SCED will submit Bids to buy (not Offers to sell)
 - 'Bid to buy' creates settlement outcomes equivalent to the "volumetric flow" LMP minus G methodology, while avoiding need for ERCOT to "send back" the DR value to the LSE
 - Bid will modify the SCED demand curve and have ability to set price
 - SCED demand will be adjusted to accommodate LR participation

Brattle Study Results

- Brattle study with the ORDC in place showed the following Reserve Margins

Market Based	Equilibrium	11.5%
Reliability Based	for 0.1 LOLE	14.1%
	for 2.4 LOLH	9.1%
	for 0.001% EUE	9.6%

- ERCOT's current target reserve margin is 13.75%

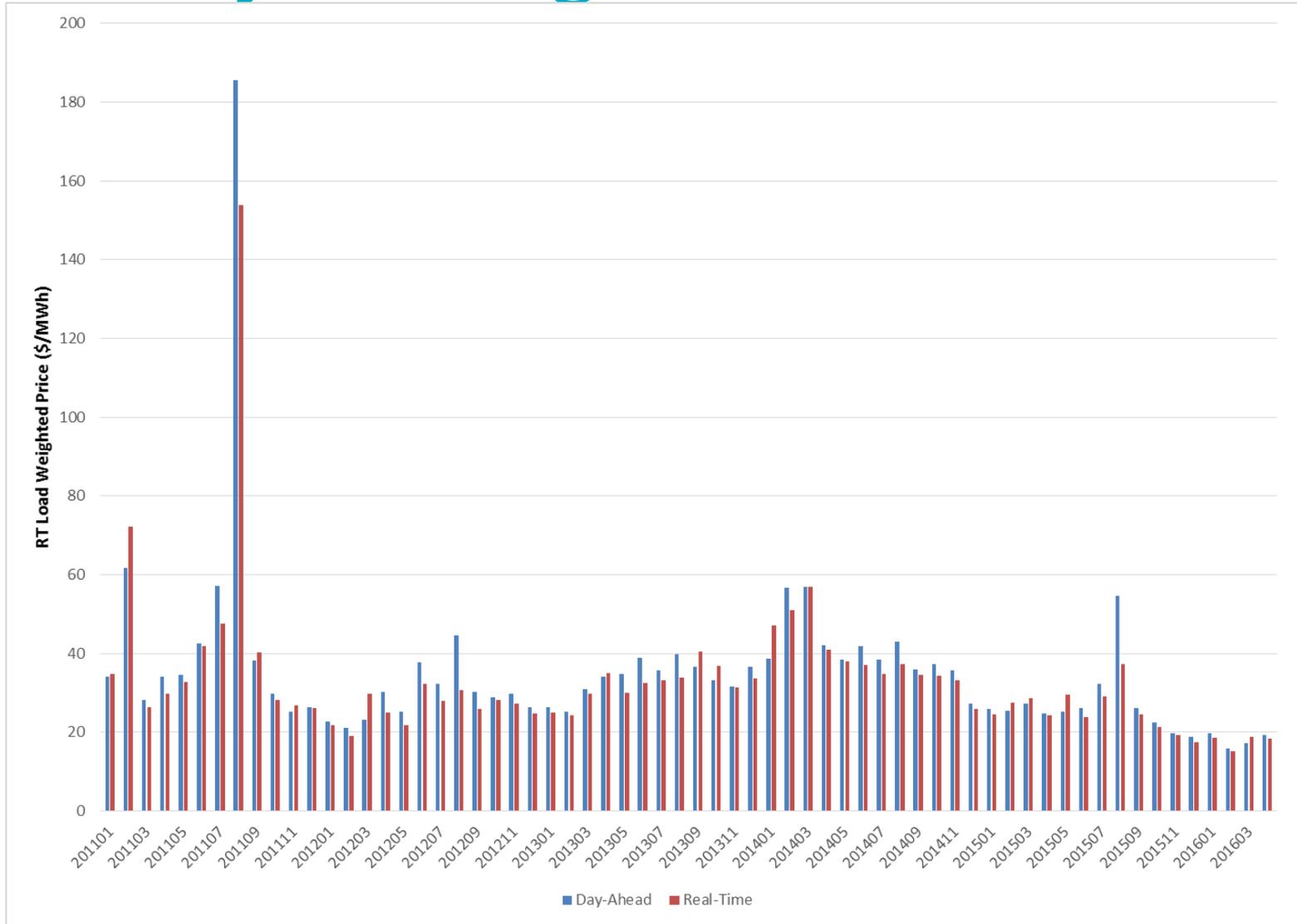
May 2016 CDR	2017	2018	2019	2020	2021
	18.2%	25.4%	23.2%	22.4%	21.6%

Questions?

Market Conditions (2011 to 2015)

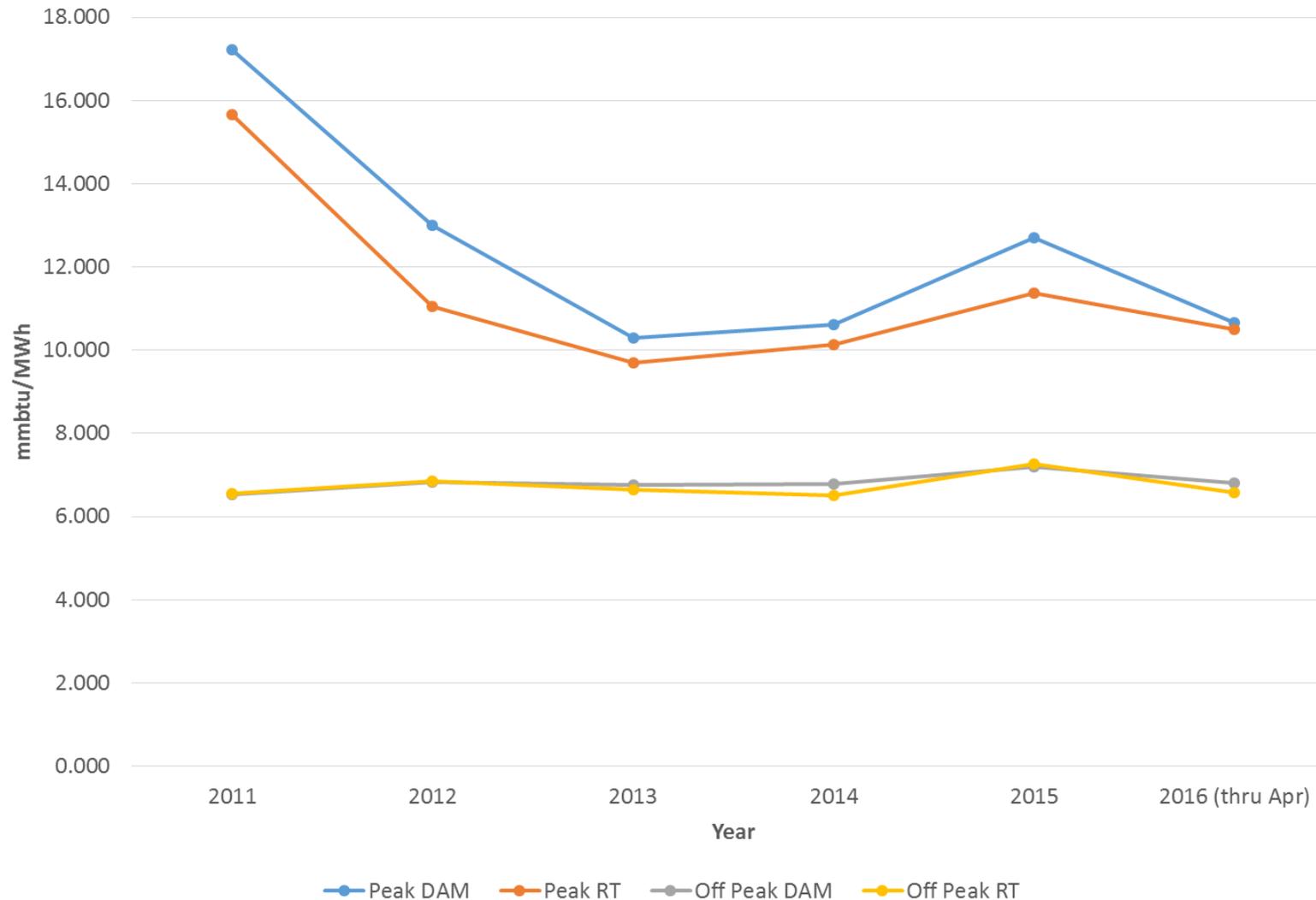
Year	Peak Load (MW)	EEA	Duration >\$3,000	Issues	More Issues
2011	68,379 (8/3/2011)	10 Energy Emergency Alert (EEA) and 12 watch for PRC issued	HubAvg SPP at or above \$3,000 for 16.75 hours	Up to 4000MW firm load shed on Feb2nd (~ 7hrs)	Two Emergency Interruptible Load Service deployments Feb 2nd -3rd : 467.7 MW Aug 4th : 440.2 MW
2012	66,626 (6/26/2012)	No EEA events	HubAvg SPP never at or above \$3,000	One watch for Physical Responsive Capability (PRC) below 2500 MW due to the tripping of two large generating units on July 30 th	High load growth in west Texas causing one major congestion and consistent price separation between hub & load zone
2013	67,245 (8/7/2013)	No EEA events	HubAvg SPP at or above \$3,000 for 0.5 hours		
2014	66,454 (8/25/2014)	2 EEA events in January	HubAvg SPP at or above \$3,000 for 1.25 hours	High prices occurred in the winter months	Three Load Resource group deployments: 2 on 1/6 (546.4 MW and 536.2 MW) and 1 on 1/18 (875 MW)
2015	69,877 (8/10/2015)	No EEA events	HubAvg SPP never at or above \$3,000		RRS deployment from load on 7/29 (21.8 MW)
2016 Forecast (per May 2015 CDR)	70,014				

Monthly Average Hub Price



ERCOT Market Heat Rates

ERCOT Hub Average Real Time and Day Ahead Market Heat Rates



May 2016 CDR

Report on the Capacity, Demand and Reserves in the ERCOT Region

Summer Summary: 2017-2026

	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>
Load Forecast, MW:										
Total Summer Peak Demand (based on normal weather)	71,416	72,277	73,663	74,288	74,966	75,660	76,350	77,036	77,732	78,572
less: Load Resource providing Responsive Reserve	-1,153	-1,153	-1,153	-1,153	-1,153	-1,153	-1,153	-1,153	-1,153	-1,153
less: Load Resource providing Non-Spinning Reserve	0	0	0	0	0	0	0	0	0	0
less: Emergency Response Service (10- and 30-min ramp products)	-1,507	-1,507	-1,507	-1,507	-1,507	-1,507	-1,507	-1,507	-1,507	-1,507
less: TDSP Standard Offer Load Management Programs	-208	-208	-208	-208	-208	-208	-208	-208	-208	-208
Firm Peak Load, MW	68,548	69,409	70,795	71,420	72,098	72,792	73,482	74,168	74,864	75,704
Resources, MW:										
Installed Capacity, Thermal/Hydro	65,990	66,165	65,325	65,325	65,325	65,325	65,325	65,325	65,325	65,325
Switchable Capacity, MW	2,972	2,972	2,972	2,972	2,972	2,972	2,972	2,972	2,972	2,972
less: Switchable Capacity Unavailable to ERCOT, MW	-300	-300	-300	-300	0	0	0	0	0	0
Available Mothballed Capacity, MW	805	805	805	805	805	805	805	805	805	805
Capacity from Private Use Networks	4,292	4,540	4,536	4,465	4,436	4,496	4,496	4,486	4,486	4,486
Non-Coastal Wind, Peak Average Capacity Contribution (12%)	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693
Coastal Wind, Peak Average Capacity Contribution (55%)	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015	1,015
Solar Utility-Scale, Peak Average Capacity Contribution (80%)	230	230	230	230	230	230	230	230	230	230
RMR Capacity to be under Contract	0	0	0	0	0	0	0	0	0	0
Operational Generation Capacity, MW	76,697	77,120	76,276	76,205	76,476	76,536	76,536	76,526	76,526	76,526
Capacity Contribution - Non-Synchronous Ties, MW	577	577	577	577	577	577	577	577	577	577
Planned Thermal Resources with Signed IA, Air Permits and Water Rights, MW	1,400	6,207	7,185	7,425	7,425	7,425	7,425	7,425	7,425	7,425
Planned Non-Coastal Wind with Signed IA, Peak Average Capacity Contribution (12%)	838	1,083	1,167	1,167	1,167	1,167	1,167	1,167	1,167	1,167
Planned Coastal Wind with Signed IA, Peak Average Capacity Contribution (55%)	305	619	619	619	619	619	619	619	619	619
Planned Solar Utility-Scale, Peak Average Capacity Contribution (80%)	1,177	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412	1,412
Total Capacity, MW	80,995	87,019	87,238	87,407	87,678	87,738	87,738	87,728	87,728	87,728
Reserve Margin	18.2%	25.4%	23.2%	22.4%	21.6%	20.5%	19.4%	18.3%	17.2%	15.9%



April 2016 GIS

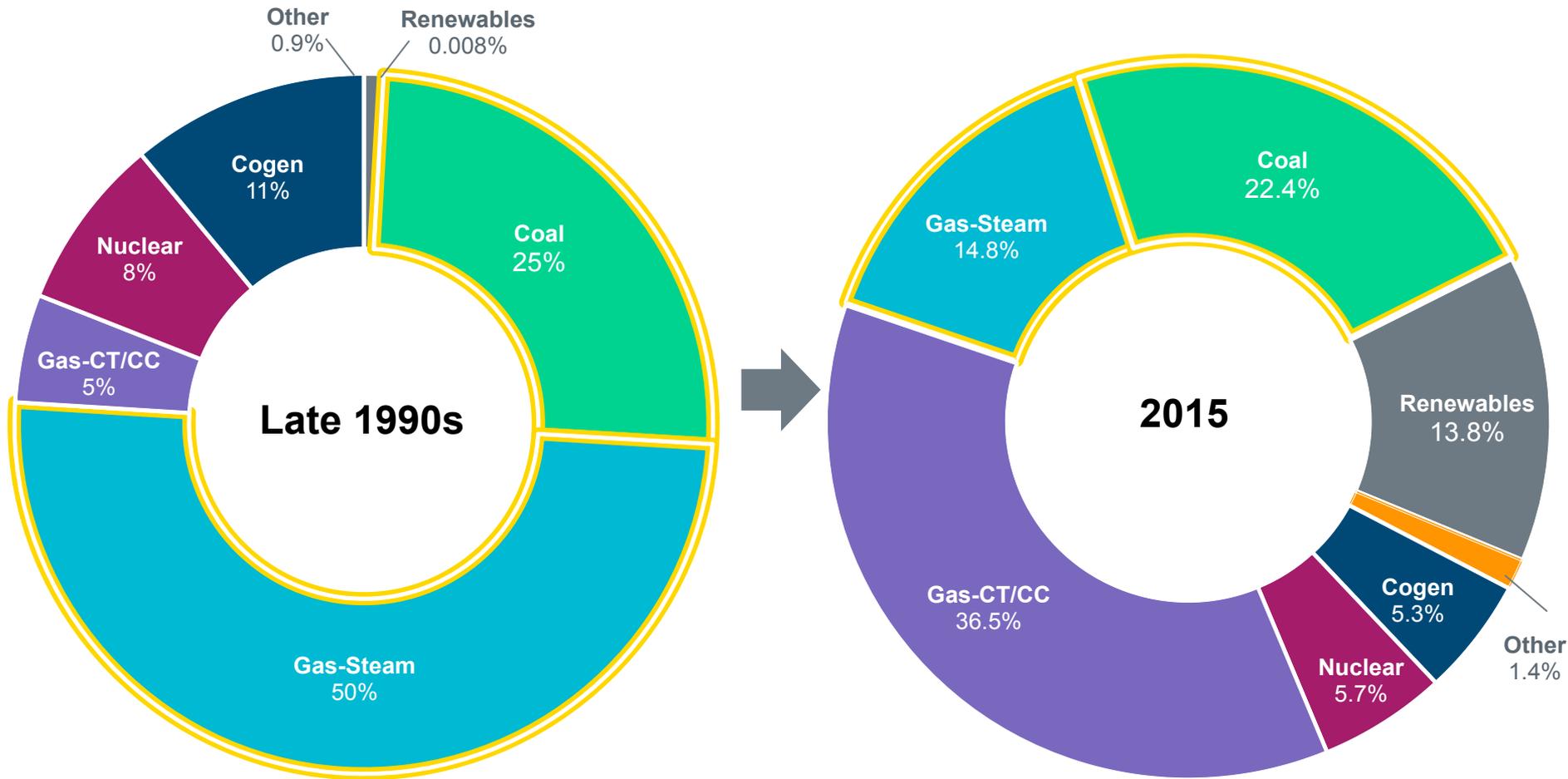
Fuel Type	Screening Study (MW)*	Screening Study w/ PL (MW)**	Full Study (MW)	Full Study w/ PL (MW)	IA Executed (MW)	IA Executed FIS Pending (MW)	Grand Total (MW)***
Gas-AllOther	200	0	3,712	0	4,017	1,591	9,520
Gas-CombinedCycle	1,480	0	3,283	0	6,984	1,715	13,462
Total Gas	1,680	0	6,995	0	11,001	3,306	22,982
Nuclear	0	0	0	0	0	0	0
Coal	0	0	0	0	240	0	240
Wind	2,328	0	11,684	0	5,847	5,092	24,951
Solar	1,540	0	3,957	0	956	1,309	7,762
Biomass	0	0	0	0	0	0	0
Storage	0	0	320	0	324	0	644
Petroleum Coke	0	0	0	0	0	0	0
Total	5,548	0	22,956	0	18,368	9,707	56,579

* Confidential project interconnection requests per Protocol Section 1.3.1.1(l). If capacity for a single project is reported in the column, the capacity value

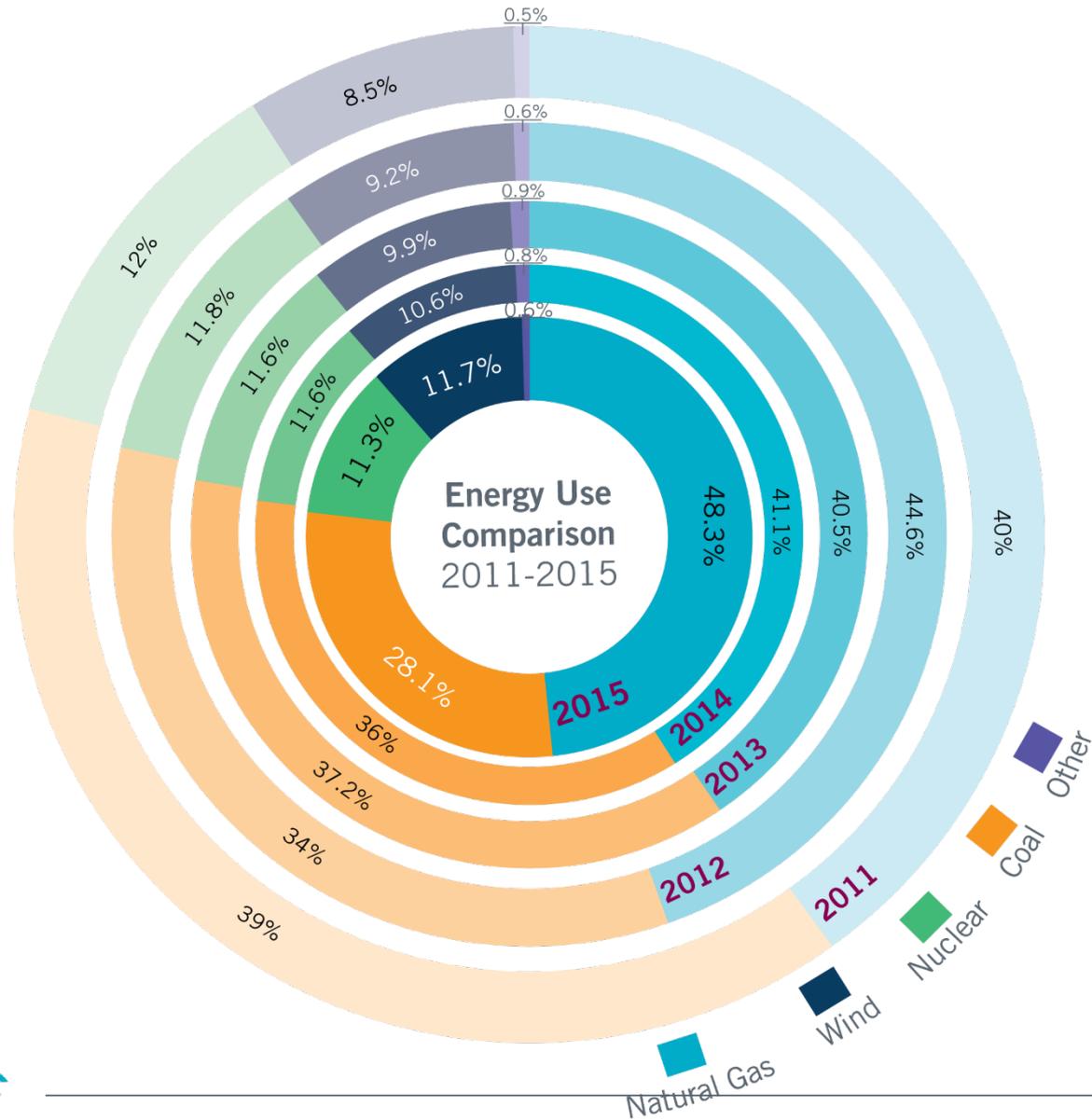
** Public project interconnection requests; waiver of confidential information received by ERCOT ("Public Letter").

*** Redacted project capacity from column E is excluded from the Grand Totals.

Changing Resource Mix



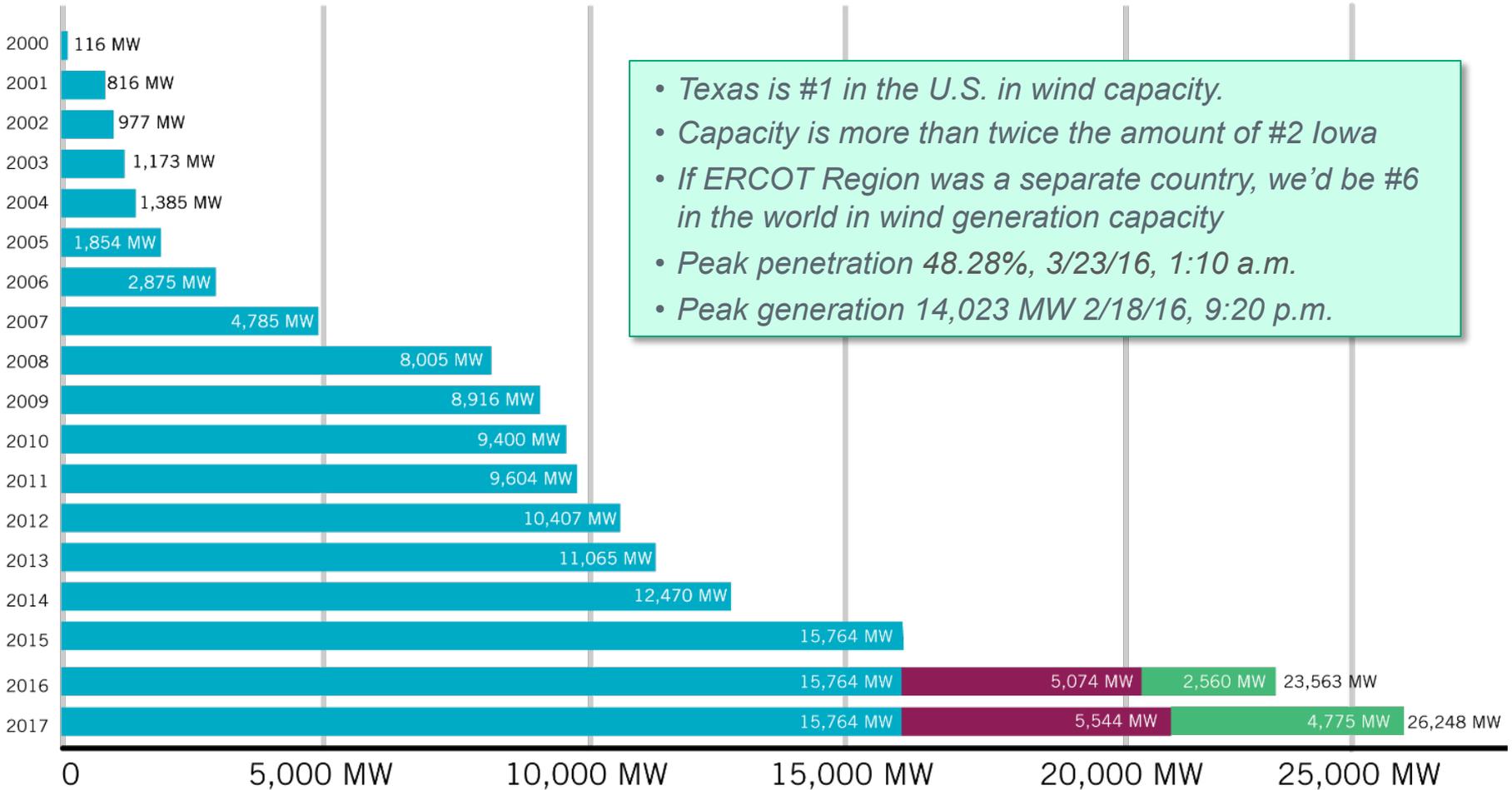
Energy Use Comparison



Wind Power Queue

ERCOT Wind Installations by Year
(as of January 2016)

■ Cumulative MW Installed
 ■ Cumulative Planned (Signed Interconnection Agreement with Financial Security)
 ■ IA Signed - No Financial Security



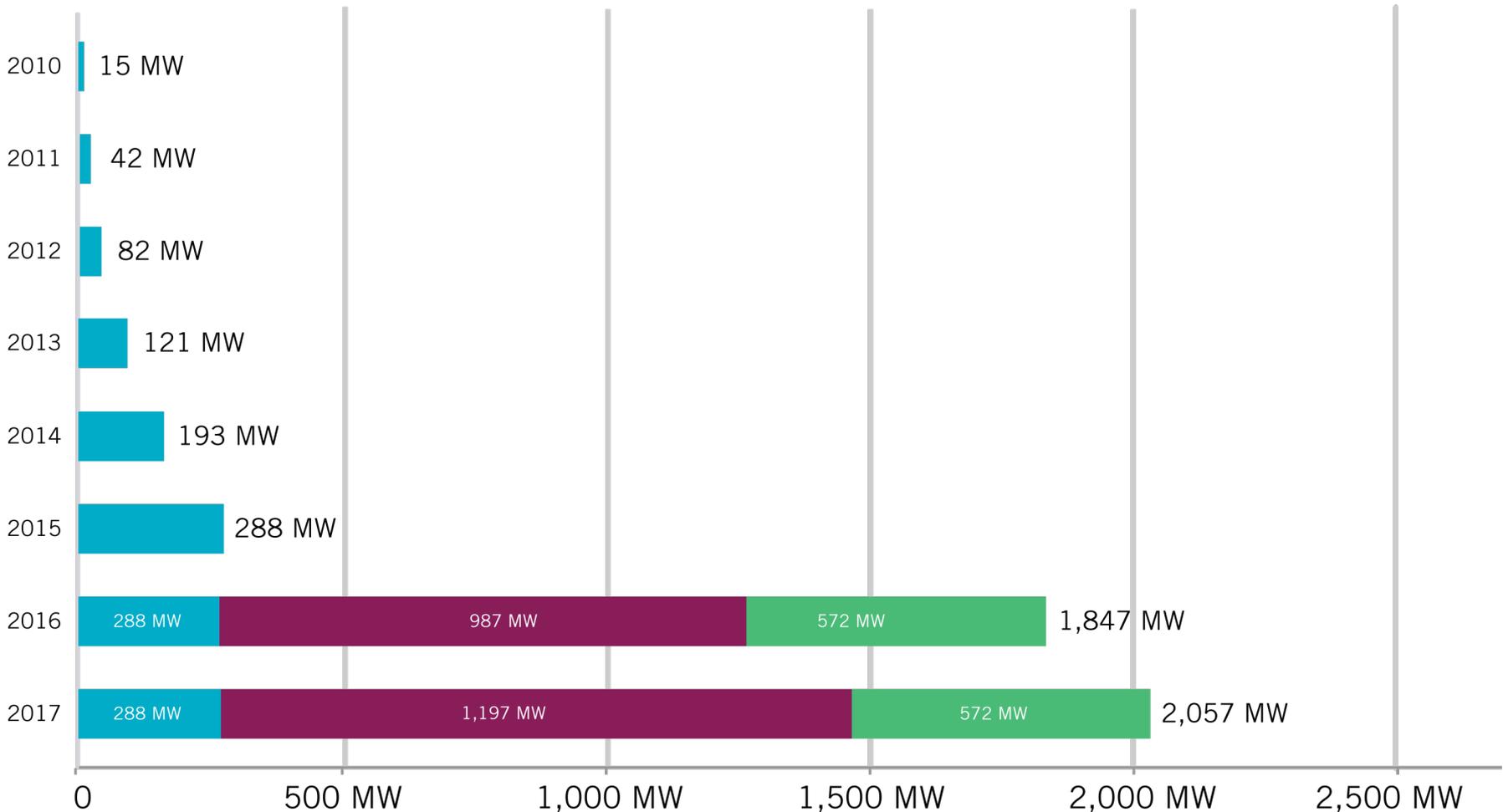
- Texas is #1 in the U.S. in wind capacity.
- Capacity is more than twice the amount of #2 Iowa
- If ERCOT Region was a separate country, we'd be #6 in the world in wind generation capacity
- Peak penetration 48.28%, 3/23/16, 1:10 a.m.
- Peak generation 14,023 MW 2/18/16, 9:20 p.m.



Utility Scale Solar Queue

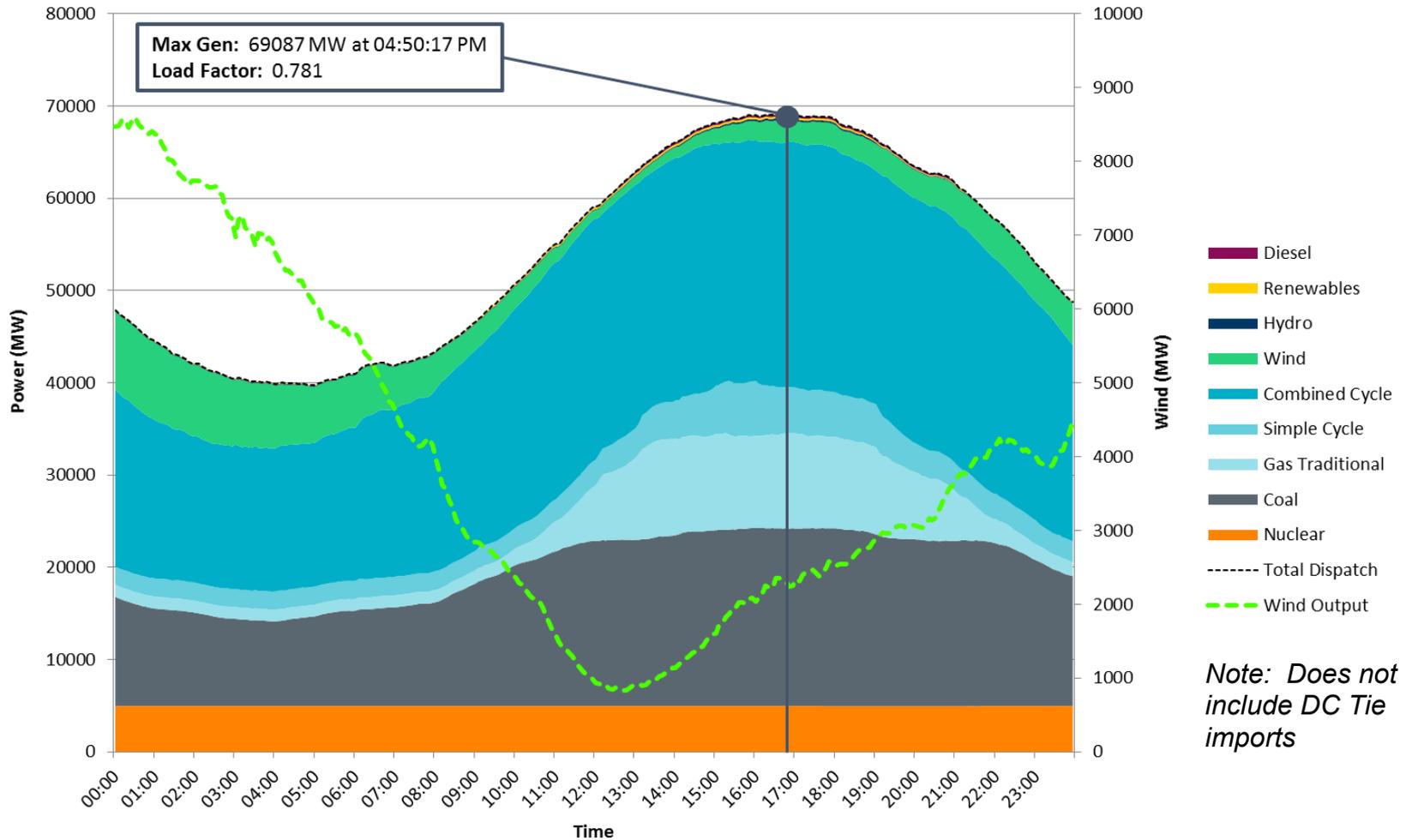
ERCOT Solar Installations by Year
(as of January 2016)

Cumulative MW Installed IA Signed - Financial Security Posted
IA Signed - No Financial Security



Business Case for Utility Scale Solar?

Power Dispatch Summary per Fuel Type for 8/10/2015

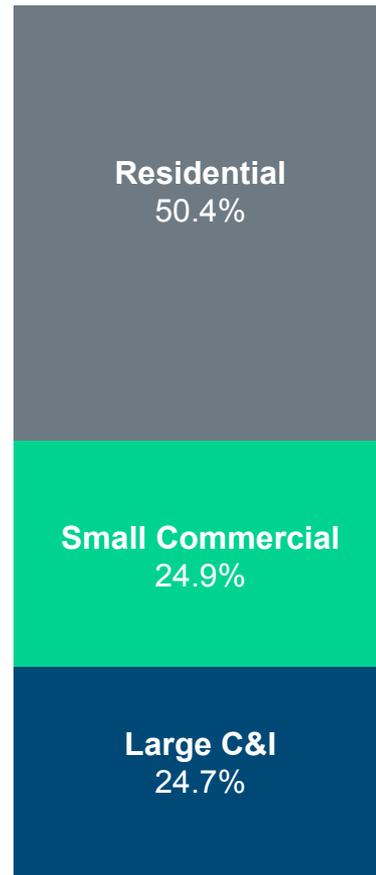


Business Case for Roof Top Solar?

Thursday,
March 12, 2015
5:00 PM
ERCOT Load: 32,955 MW
Temperature in Dallas: 69°

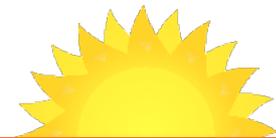


3/16/2015 IE 17:00



8/10/2015 IE 17:00

← Mon., Aug. 10, 2015
5:00 PM
ERCOT Load: 69,659 MW
Temperature in Dallas: 107°



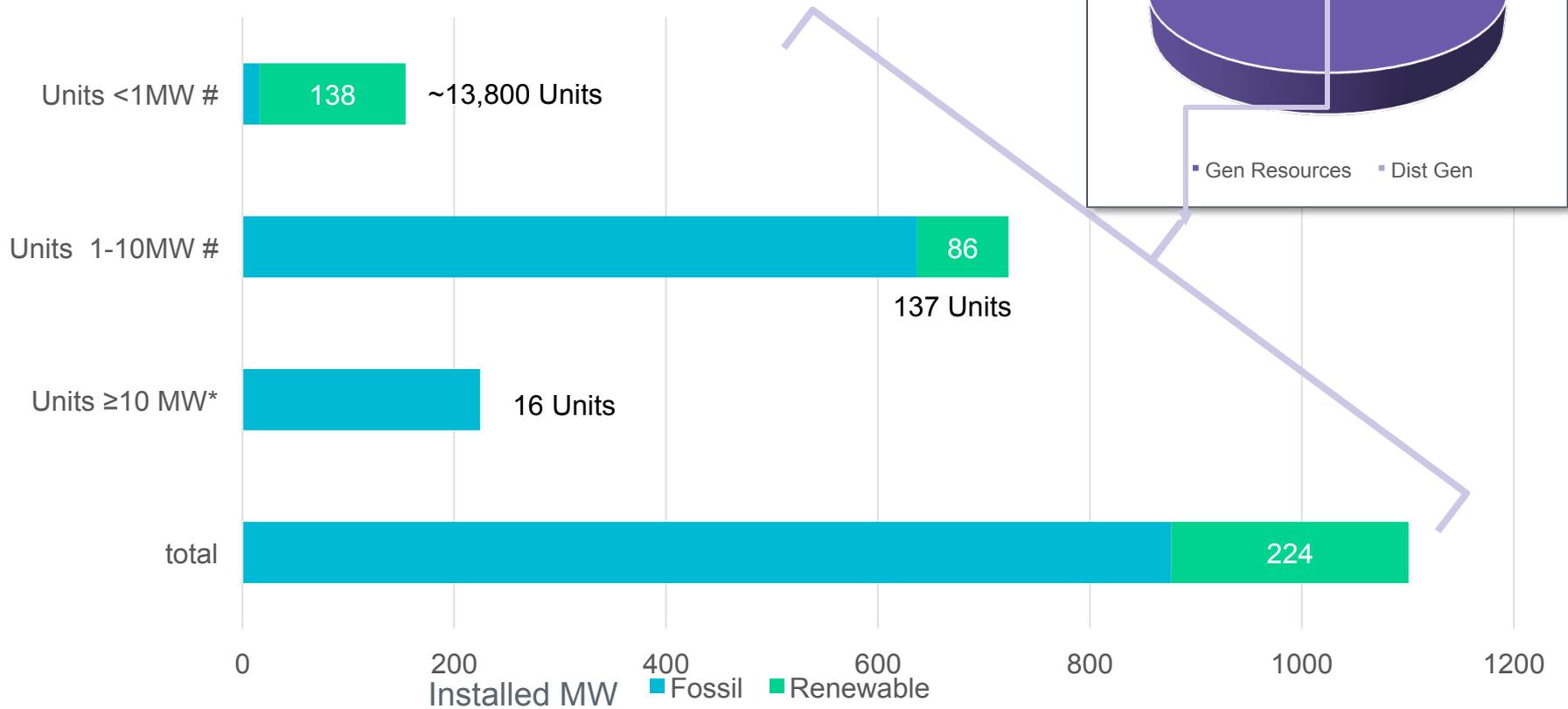
~37,000 MW of weather-sensitive load -- 53% of peak

- Customer class breakdown is for competitive choice areas; percentages are extrapolated for munis and co-ops to achieve region-wide estimate
- Large C&I are IDR Meter Required (>700kW)
- 15-minute settlement interval demand values

DG snapshot as of Dec. 31, 2015

From Competitive Choice TDSP annual reports to PUC, plus estimated NOIE DG
 DG Capacity based on these reports: **1,101 MW**

Capacity from Generation Resources based on Dec. 2015 CDR: **79,280 MW**



* An unknown number of these units may be among the 77 units registered with PUC as Self-Generators.

Anecdotal as reported by Austin Energy & CPS Energy, plus some other NOIE >50kW. NOIEs are not required to report unregistered DG to ERCOT unless >50kW and injects to grid.

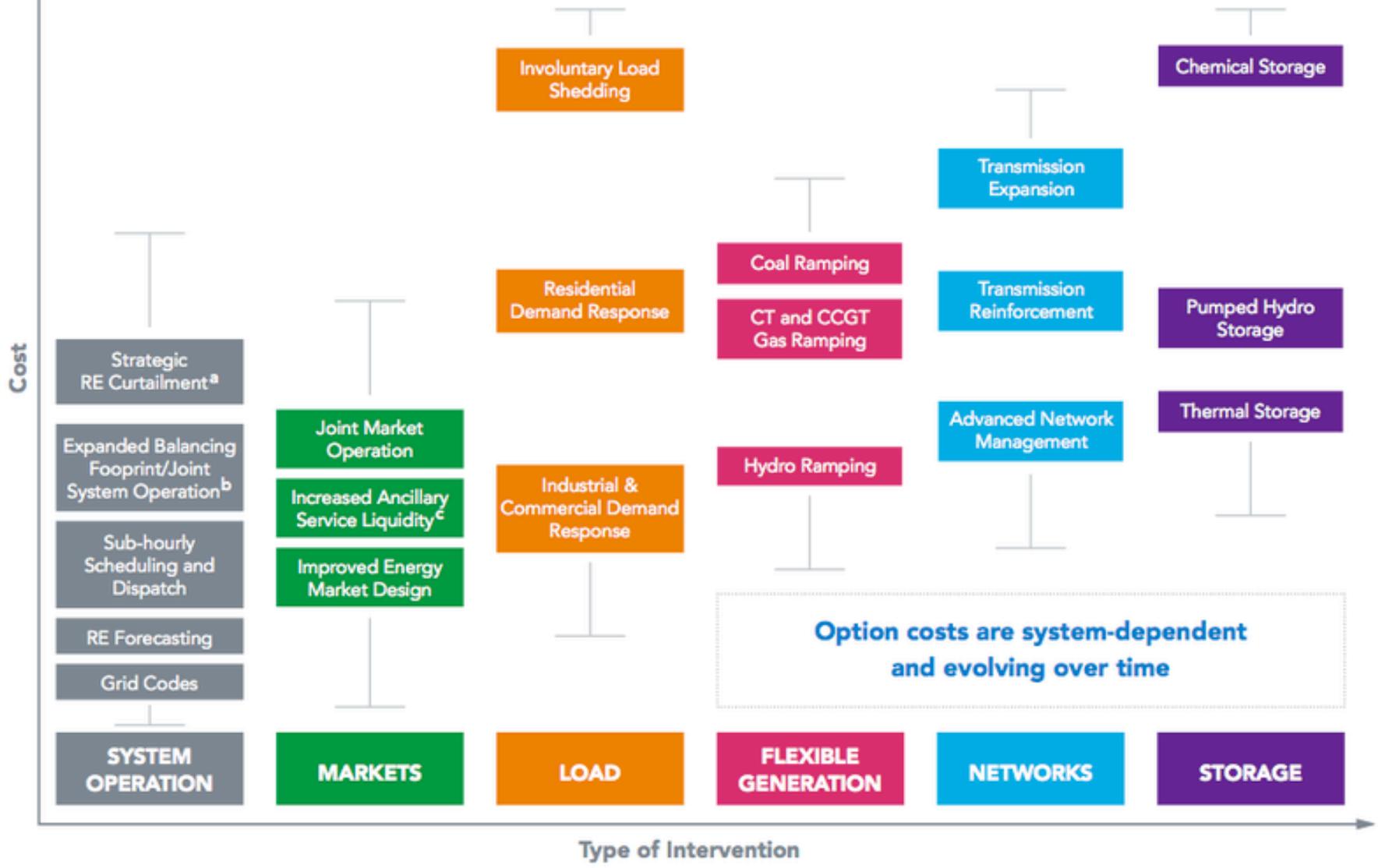
ERCOT's 2 primary goals for DERs

- **Data Collection**
 - ERCOT has outlined what data it believes it will need to ensure future reliability as DER penetration begins to impact the bulk power grid
 - Mainly, accurately mapping DERs to the transmission grid
- **Market Access**
 - Integrating some (especially larger) DERs into the energy and Ancillary Services markets can improve efficiency
 - 3 potential categories:
 - **DER Minimal:** Business as usual, what we have today
 - **DER Light:** Passive participation (no ERCOT dispatch) but settled at the Nodal (local) wholesale price, rather than at the average price at the Load Zone
 - Would require separate metering of gross load and gross generation
 - **DER Heavy:** Active participation in Energy and AS, much like Generation Resources today
 - Would require:
 - » Separate metering of gross load and gross generation
 - » Significant real-time data to ERCOT

Reliability Challenges for Solar

- Volatility and uncertainty of fuel source
 - Uncertainty in ramp requirements
 - Frequency excursions
 - Congestion management problems
- Lack of Visibility, Controllability and Dispatchability
 - Uncertainty on transmission-level congestion management;
 - Load Forecast accuracy
 - Uncertainty in Ancillary Service needs
 - Less accurate inputs to the State Estimator and Load Adaptation
 - Inaccurate Load Distribution Factors (LDFs)
- Evolving state of voltage and frequency standards
 - Lower reactive power
 - Lower voltage control
 - Reduced dynamic response to faults
 - Coordination of system restoration

RELATIVE ECONOMICS OF INTEGRATION OPTIONS



Reliability Challenges From Wind

- Large frequency deviations
- Inadequate transmission for projected wind growth
- Constraint management under high & low wind
- Maintaining transient stability
- Constraint oscillation
- Voltage issue
- Increased volatility in prices
- Higher ancillary service requirement
- Reduced inertial response

Solar Energy Investment Tax Credit (ITC) Extended

- The Act extends the **30%** ITC for solar power facilities, previously available for such facilities placed in service on or before December 31, 2016, to such facilities where construction **commences on or before December 31, 2019** and which are placed **in service before 2024**.
- For solar facilities whose construction commences after December 31, 2019, the ITC decreases. Projects that
 - (i) commence construction **during 2020** and are placed in service before **2024** are eligible for an ITC of **26%**,
 - (ii) commence construction **during 2021** and are placed in service before **2024** are eligible for an ITC of **22%** and
 - (iii) commence construction **after 2021** or are placed in service **after 2023** are eligible for an ITC of **10%**. Changing from a deadline based solely on placement in service to one focused on commencement of construction was intended to provide facility developers with greater certainty, although the retention of an outside, hard, placed-in-service deadline of December 31, 2023 will provide an incentive for developers to follow through to completion once they have satisfied the “begun construction” guidelines previously released by the Internal Revenue Service. (Technically, these guidelines will need to be updated by the Service to reflect the dates contained in the new legislation.)

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– Source:

<http://www.windpowerengineering.com/policy/five-things-you-need-to-know-about-the-extension-of-the-itcptc/>

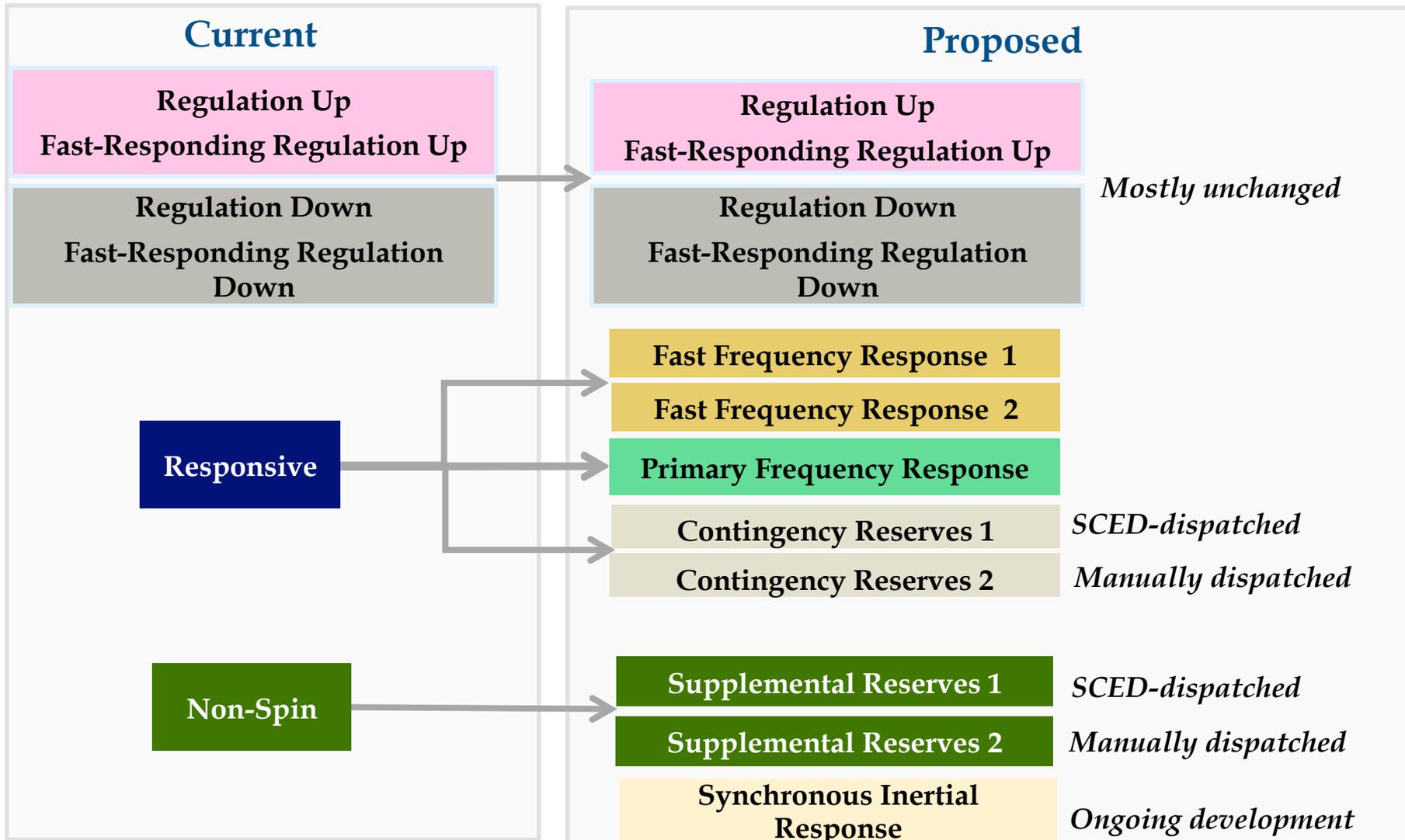
Wind Energy Production Tax Credit (PTC) Extended

- The Act restores PTCs for wind power projects that begin construction before 2020.
- Like the solar ITC, PTCs will be subject to a ratchet down beginning in 2017.
- Projects that begin **construction before 2017** are eligible for PTCs for sales of electricity equal to 1.5 cents per kilowatt, as adjusted for inflation. (For sales occurring in 2015, the applicable inflation-adjusted rate is 2.3 cents per kilowatt.)
 - Thereafter, PTCs will be **reduced** by (i) **20% for projects beginning construction in 2017**;
 - (ii) **40% for projects beginning construction in 2018**; and
 - (iii) **60% for projects beginning construction in 2019**.
 - These extensions are retroactive to January 1, 2015; thus projects beginning construction in 2015 qualify. It should be noted that, because the PTC is generally available over a 10-year credit period, the impact of the credit phase-out will be felt over the entire 10-year period in which the PTCs are available.

PTC/ITC Option Extended

- The Act extends the right for “qualified investment credit facilities” (as defined in Code Section 48(a)(5)(C)), **including wind power projects, to opt for an ITC equal to 30% of qualified costs in lieu of PTCs.**
- For qualified investment credit facilities other than wind projects, the election is available for those facilities whose construction has commenced prior to January 1, 2017.
- In the case of wind power projects, the construction commencement deadline is extended to January 1, 2020, provided that
 - (i) for wind projects **beginning construction in 2017**, the ITC is **reduced to 24%**
 - (ii) for wind projects **beginning construction in 2018**, the ITC is further **reduced to 18%** and
 - (iii) for projects **beginning construction in 2019**, the ITC is limited to **12%**.

Proposed Future Ancillary Services (FAST)



Proposed Responsive Reserves Changes

Types of Products	Descriptions of Products
Fast Frequency Response 1 (FFR 1)	Fast Frequency Response (FFR) provides a full MW response within 30 cycles (half a second) , slowing the frequency decay and allowing sufficient time for PFR-capable resources to respond. A resource providing FFR1 must be able to sustain a full response for maximum of 10 minutes and should fully restore within 10 minutes of receiving ERCOT's recall instruction or continuous 10 minutes of deployment , whichever comes first.
Fast Frequency Resource 2 (FFR2)	A response from a resource that is automatically self-deployed and provides a full response within 30 cycles after frequency meets or drops below a preset threshold. FFR may also be manually deployed and full response must be provided within 10 minutes . FFR Resources based on their sustainability and ability to restore may participate in sub-group FFR1 or FFR2. A resource providing FFR2 must be able to sustain a full response until ERCOT issues a recall instruction or the resource no longer has a responsibility to provide the service, whichever comes first. The resource must be able to fully restore its FFR2 responsibility within 90 minutes after receiving ERCOT's recall instruction.
Primary Frequency Response (PFR)	PFR operates within the first few seconds following the initiating event and is fully delivered within 12 to 14 seconds and thus has significant implications on the rate of change of frequency (RoCoF) during sudden power imbalance.
Contingency Reserves 1 (CR1)	Contingency Reserve provided by Resources available for deployment in SCED, e.g. Generation Resources and Controllable Load Resources (CLR). Can be synchronized and ramped to a specific output level within 10 minutes .
Contingency Reserves 2 (CR2)	Contingency Reserve provided by Resources not available for deployment in SCED, e.g. non-controllable "blocky" Load Resources. Can be synchronized and ramped to a specific output level within 10 minutes .

Proposed Non-Spin Changes

Types of Products	Descriptions of Products
Supplemental Reserves 1 (SR 1)	Generation Resources (SR1) that are Off-Line and capable of: Being synchronized and ramped to a specified output level within 30 minutes ; and Running at a specified output level for at least one hour ; or Controllable Load Resources (SR1) qualified for Dispatch by Security-Constrained Economic Dispatch (SCED) and capable of: Ramping to an ERCOT-instructed consumption level within 30 minutes ; and Consuming at the ERCOT-instructed level for at least one hour .
Supplemental Reserves 2 (SR 2)	Non-Controllable Load Resources (SR2) which are manually deployed and are capable of: Delivering their demand response within 30 minutes ; and Sustaining the response for at least one hour . Once recalled, Resource providing SR2 should be capable of restoring its SR2 responsibility, within 180 minutes for it to be qualified as SR2.
Synchronous Inertial Response (SIR)	SIR is stored kinetic energy that is extracted from the rotating mass of synchronous machines following a disturbance in a power system. SIR is not included in the proposed future AS framework and the draft NPRR.

Load Participation in SCED

- Eligibility to participate: LSE QSEs representing Load Resources capable of following 5-minute SCED base point instructions
 - Existing or new single-site Controllable Load Resources (CLRs)
 - ✓ SCED qualification will be a new attribute for redefined CLR
 - Aggregate Load Resources (ALRs) composed of multiple sites within single ERCOT Load Zone (subset of CLR)
- Will not support direct participation by third-party DR QSEs
- Will not support DR with temporal constraints or block energy bids
 - If LR's bid is on the margin, base point instructions could require LR to move up or down incrementally every 5 minutes to any level between its LPC and MPC
 - SCED will honor LR's telemetered ramp rates

Load Participation in SCED(cont.)

- QSEs with LRs in SCED will submit Bids to buy (not Offers to sell)
 - Bids will reflect LR's willingness to consume "up to" a specified five-minute Load Zone LMP
 - May be a curve or a MW bid at single strike price
- Bid will modify the SCED demand curve and have ability to set price
 - SCED Generation to be Dispatched (GTBD) will be adjusted to accommodate LR participation
 - This will ensure proper price formation and reduce the likelihood of oscillating dispatch instructions
- Bids from LRs capped at the System Wide Offer Cap
 - This is to avoid stranded AS and PRC
- 'Bid to buy' creates settlement outcomes equivalent to the "volumetric flow" LMP minus G methodology endorsed by TAC, while avoiding need for ERCOT to "send back" the DR value to the LSE
- SCED will dispatch LRs for power balance and congestion management using the applicable Load Zone Shift Factor

Load Participation in SCED(cont.)

- LR benefits and opportunity:
 - Avoided cost of consumption above specified price
 - Price certainty due to ERCOT dispatch
 - Eligibility to provide Non-spin
 - ✓ Treated similarly to Offline Generation providing Non-spin
 - ✓ Energy Bids will be released to SCED within 20 minutes following ERCOT deployment of Non-spin
 - Eligibility to receive ORDC payments/charges
 - ✓ ORDC price adders will be paid to QSE for any un-deployed SCED capacity in excess of AS responsibility
 - ✓ QSE will be charged for AS capacity converted to energy by ERCOT
- Market impacts:
 - LR Bids may set price in the RTM
 - No make-whole payments
 - No load ratio share uplifts to market for DR value

LiSCED-SCED Objective & Power Balance

SCED optimization will minimize cost of dispatch of supply and maximize revenue from demand while meeting Power Balance

Minimize { $\text{Sum}(\text{OfferPrice}_{\text{gen}} * \text{BasePoint}_{\text{gen}}) - \text{Sum}(\text{BidPrice}_{\text{CLR}} * \text{BasePoint}_{\text{CLR}}) \}$

- $\text{BasePoint}_{\text{gen}}$ is instruction on how much to produce
- $\text{BasePoint}_{\text{CLR}}$ is instruction on how much to consume
- NPF_{CLR} is current telemetered real power consumption
- All Resources can follow 5 minute SCED Base Points
- Power Balance Constraint:
 - Supply=Demand
 - Supply = $\text{Sum}(\text{BasePoint}_{\text{gen}})$
 - Demand = GTBD = Inelastic Demand + Elastic Demand
 - Inelastic Demand = $\text{GTBD} - \text{Sum}(\text{NPF}_{\text{CLR}})$
 - Elastic Demand = $\text{Sum}(\text{BasePoint}_{\text{CLR}})$
 - $\text{Sum}(\text{BasePoint}_{\text{gen}}) = \text{GTBD} - \text{Sum}(\text{NPF}_{\text{CLR}}) + \text{Sum}(\text{BasePoint}_{\text{CLR}})$

LiSCED: CLR with Bid to Buy

