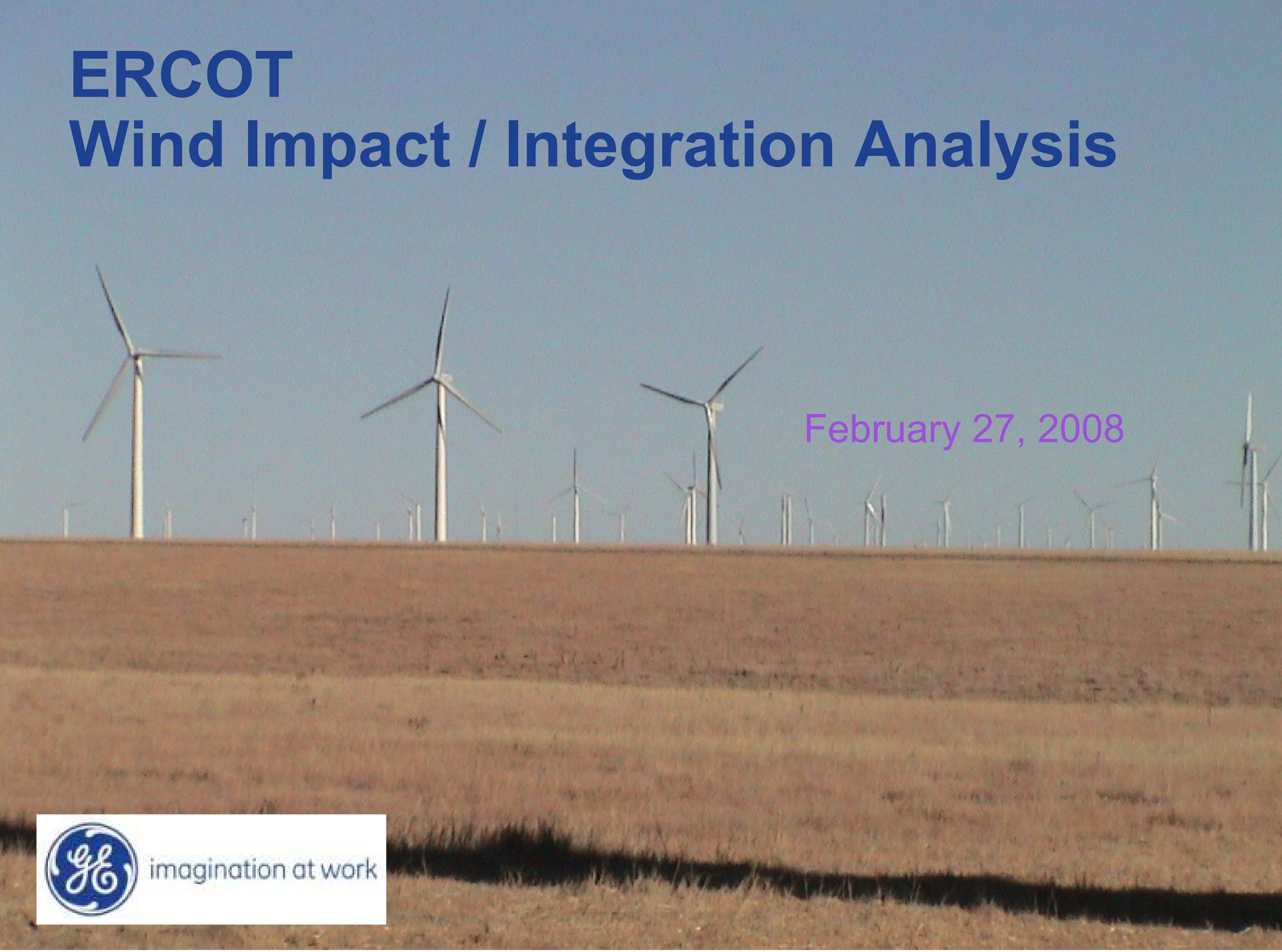

ERCOT
Wind Impact / Integration Analysis

February 27, 2008

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Project Scope

Evaluate the impacts of wind development in the ERCOT system on ancillary services requirements and related practices.

Specifically:

- Evaluate the suitability of ERCOT’s existing practices for determining A/S procurement
- Recommend improvements to accommodate wind penetration
- Determine amount and estimated cost of A/S requirements for various wind scenarios
- Recommend procedures for impending severe weather

A Few Words About **Net Load**

Net Load is the instantaneous system consumer load, minus the generation output of non-dispatchable wind generation

Net load* is the amount of generation required from dispatchable units

The study is concentrated on net load, instead of the wind generation in isolation, because some amount of the variations in each cancel

---

* Net load is also called “Load – Wind” in parts of this presentation

Project Overview

Phase 1 - Net Load Variability and Predictability Characterization

Objective is to obtain fundamental qualitative and quantitative information on the characteristics and predictability of net load in the ERCOT system.

- Comparison of wind development scenarios
- Correlations of variability and predictability with load level, season, time of day

The insights obtained in this analytic investigation help to identify system operating challenges and determine when they will occur

Phase 2 - Ancillary Services Evaluation

Evaluate A/S requirements and recommend improvements to ERCOT's A/S procedures

- A/S requirements as a function of wind penetration
- Evaluate existing methodologies to determine A/S needed
- Recommend changes to accommodate wind
- Evaluate and improve practices for impending severe weather

Analysis Approach

- Construct system load, wind generation, and net load model time series database
- Time series analysis
  - Characterize impact on load curve
  - Daily maxima and minima
  - Net load ramp rates
- Statistical analysis of variability
  - Analyze variations over different timeframes
  - Analysis of operating periods with particular challenges
- Model and analyze regulation requirements
  - Regulation requirements
  - Regulation procurement procedure
- Extreme wind analysis – responsive reserves
- Analysis of day-ahead prediction error
  - Impacts on non-spin reserve requirements

Net Load Model

- Two years of data used
  - More accuracy and consistency
  - Two consecutive years needed later in Phase 2 for testing A/S methodology
- Essential for system load and wind generation data to be for consistent time period
  - Common factors affect both wind and load
- System one-minute load data
  - Based on 2005 and 2006 ERCOT historical recordings
  - 2006 data scaled up to achieve average load (energy) consistent with 2008 ERCOT predictions – “Study Year”
  - 2005 data scaled by the same factor – “Previous Year”
  - Scale factor = 1.037, computed from the average ratio of forecasted 2008 load to 2006 actual load across all hours
  - Day-ahead load forecasts provided by ERCOT

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Wind Generation Model

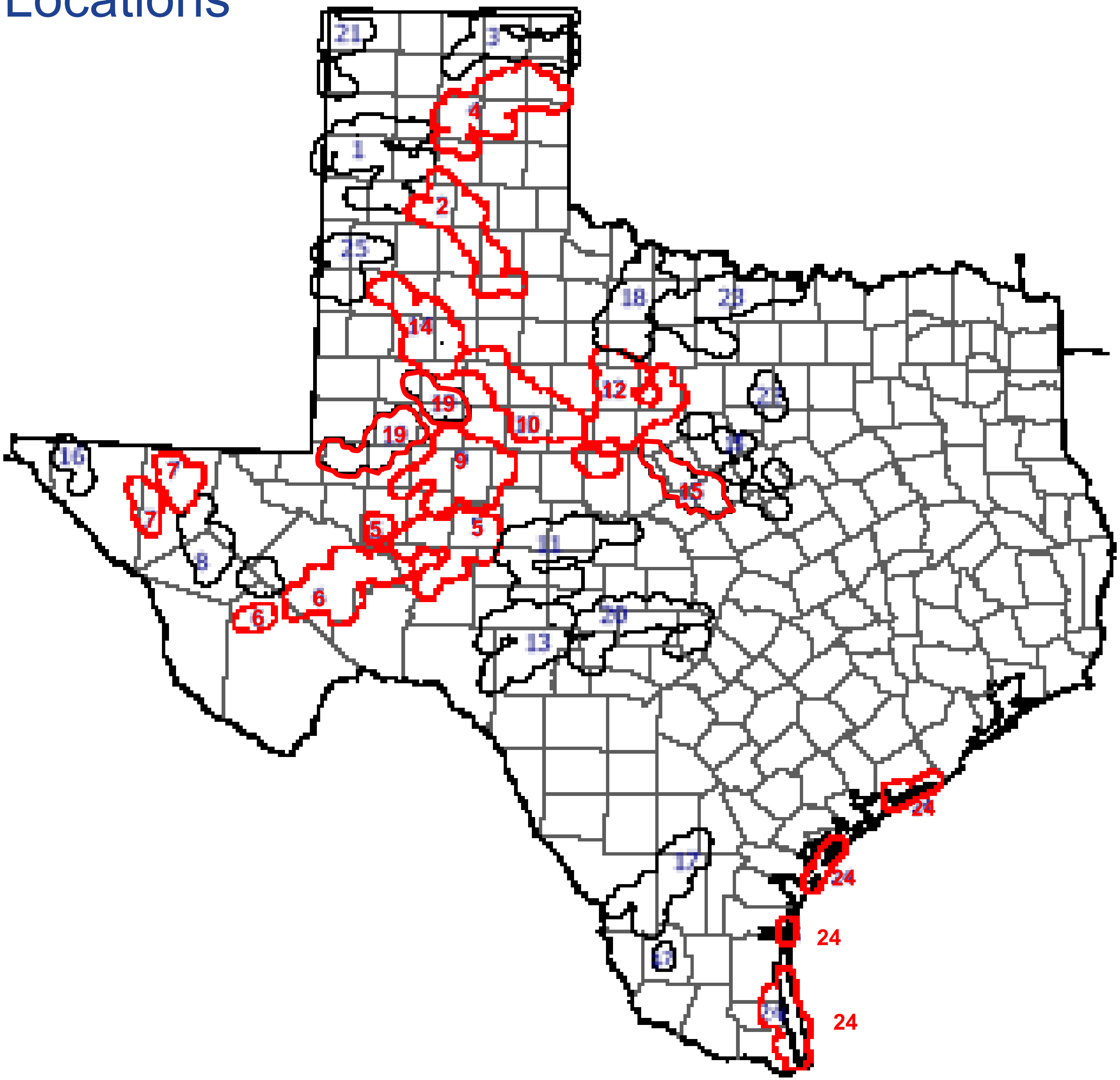
- Wind data developed for 2005 and 2006 by AWS Truewind
  - Hourly meso-scale weather model
  - Wind generation output defined for multiple individual hypothetical wind plants in each CREZ
  - Minute-by-minute variations synthesized based on ERCOT wind data for seventeen existing sites (2 years of data)
  - Wind data for other time-frames (5-minute, 15-minute, 30-minute) obtained by integrating 1-minute data
- CREZ scenarios developed
  - 5000 MW, 15000 MW and two 10000 MW scenarios
  - Wind capacity totals per CREZ per ERCOT selection (next slide)
  - Wind plants added to CREZ portfolio in order of decreasing annual capacity factor (most productive sites used first)
  - Plant capacity scaled up to produce desired output for CREZ
- Day-ahead wind generation predictions synthesized by AWS Truewind

CREZ Scenarios

	Wind Development Scenario			
CREZ Zone	**5000 MW**	**10,000 MW (1)**	**10,000 MW (2)**	**15,000 MW**
none	120	120	120	120
2	60	1,560	1,560	2,340
4	0	1,500	0	0
5	355	1,355	1,355	1,355
6	400.5	400.5	400.5	1,278.3
7	65	65	65	97.5
9	814	1,314	1,314	1,971
10	2,464.5	2,964.5	2,964.5	4,446.8
12	400	400	400	600
14	160	160	160	240
15	60	60	60	90
19	101	101	101	211.5
24	0	0	1,500	2,250

Difference in two 10,000 MW scenarios is that the second has 1,500 MW of wind generation in the Gulf coastal area, substituting for a like amount in the panhandle

CREZ Locations



Time Series Plots and Daily Profiles

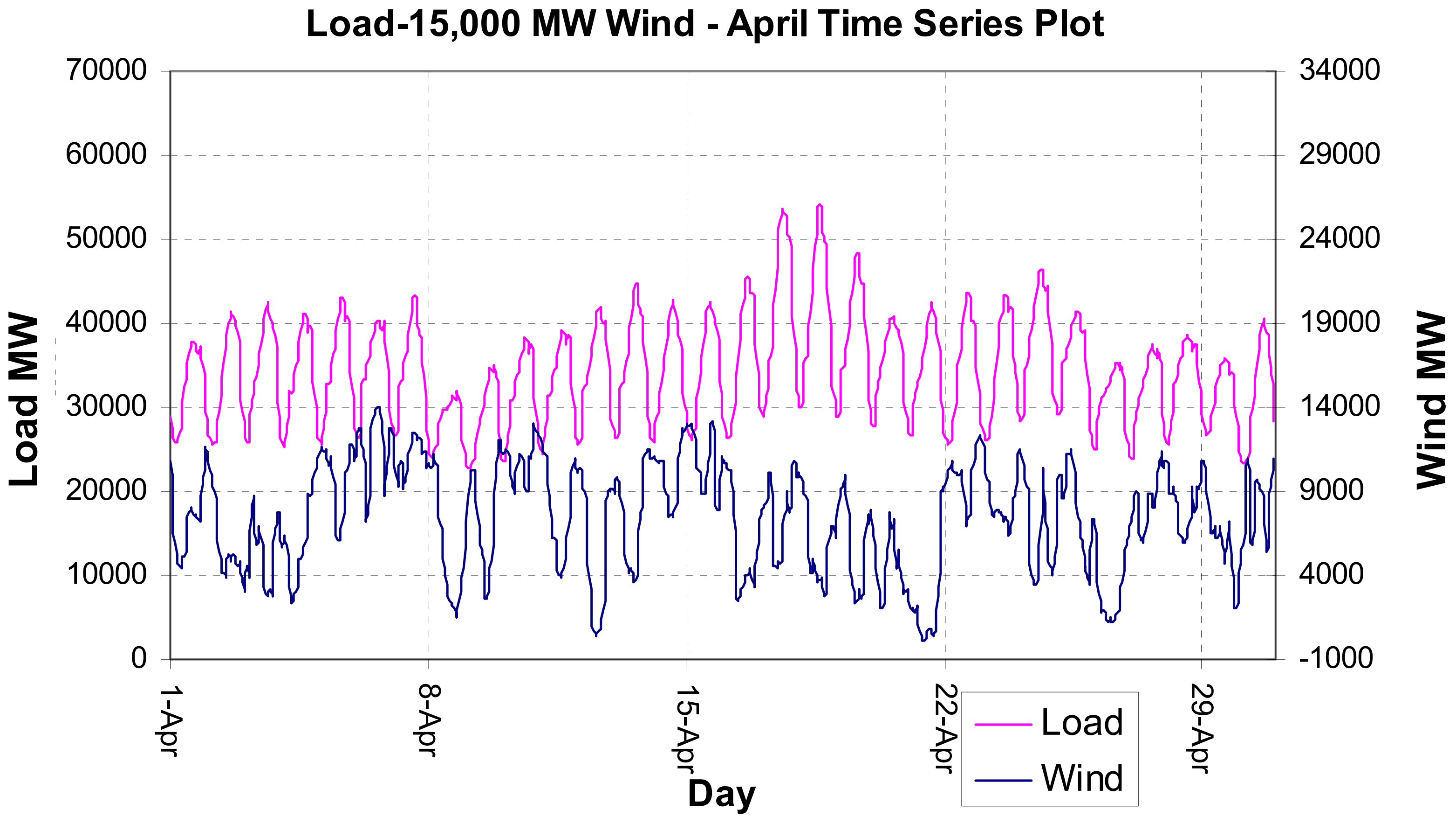
In this next set of slides, we will show how wind and load interact to create the net load curves.

Key issues are:

- Impacts on net load peaks and valleys
- Increases in ramp rates
- Common factors affecting wind and load

Wind and Load (15,000 MW Wind Scenario)

(Study Year Hourly Data)



Both wind and load have variability

(note that the wind curve is on the right-hand scale and thus its dynamic range is amplified two times)

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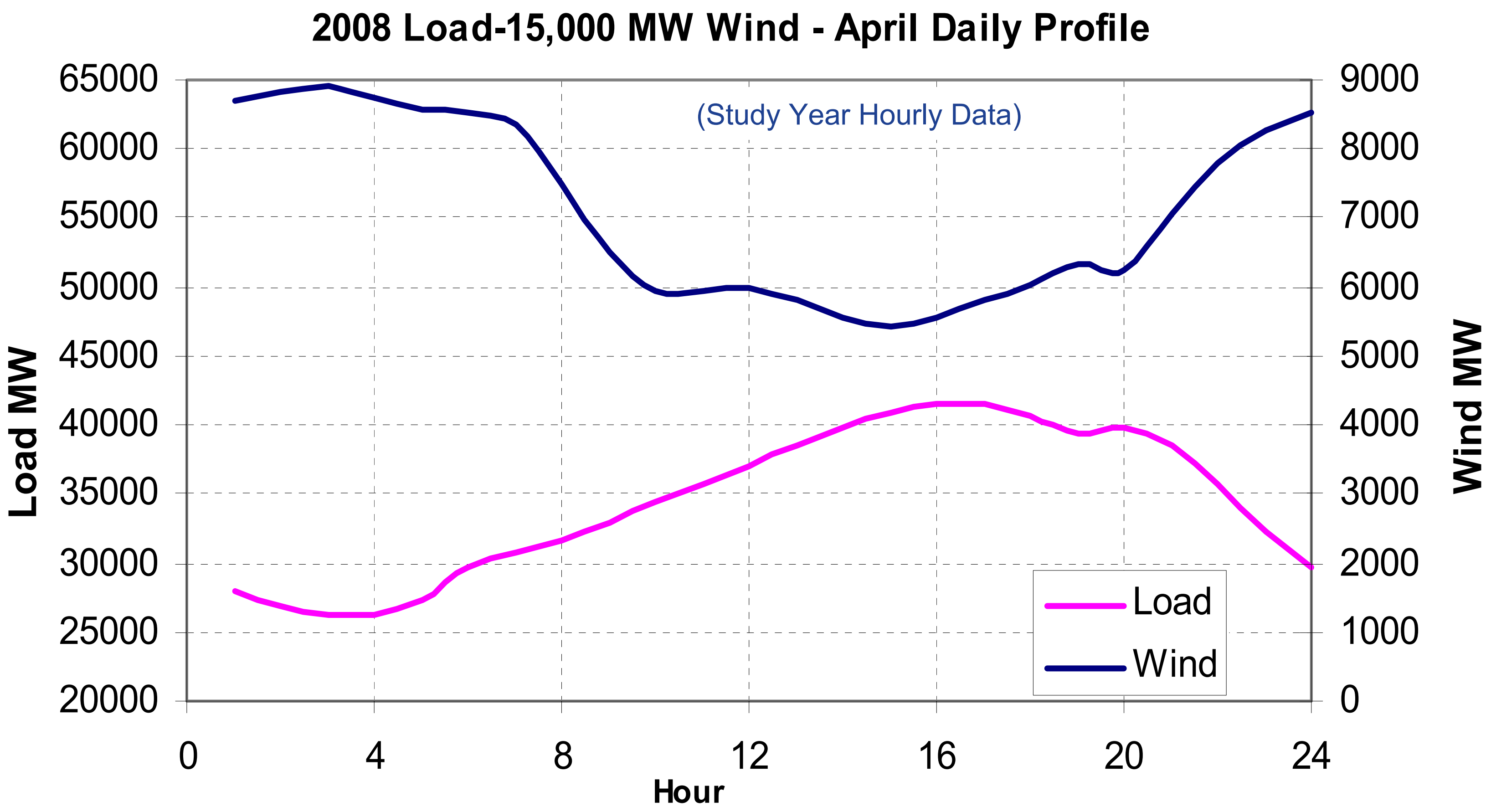
Average April Daily Load and Wind Profile (15,000 MW Wind)



- *Wind is generally out-of-phase with load*
- *Sharp drop in wind in the morning when load is rising*
- *Sharp wind increase when load drops sharply in the evening*

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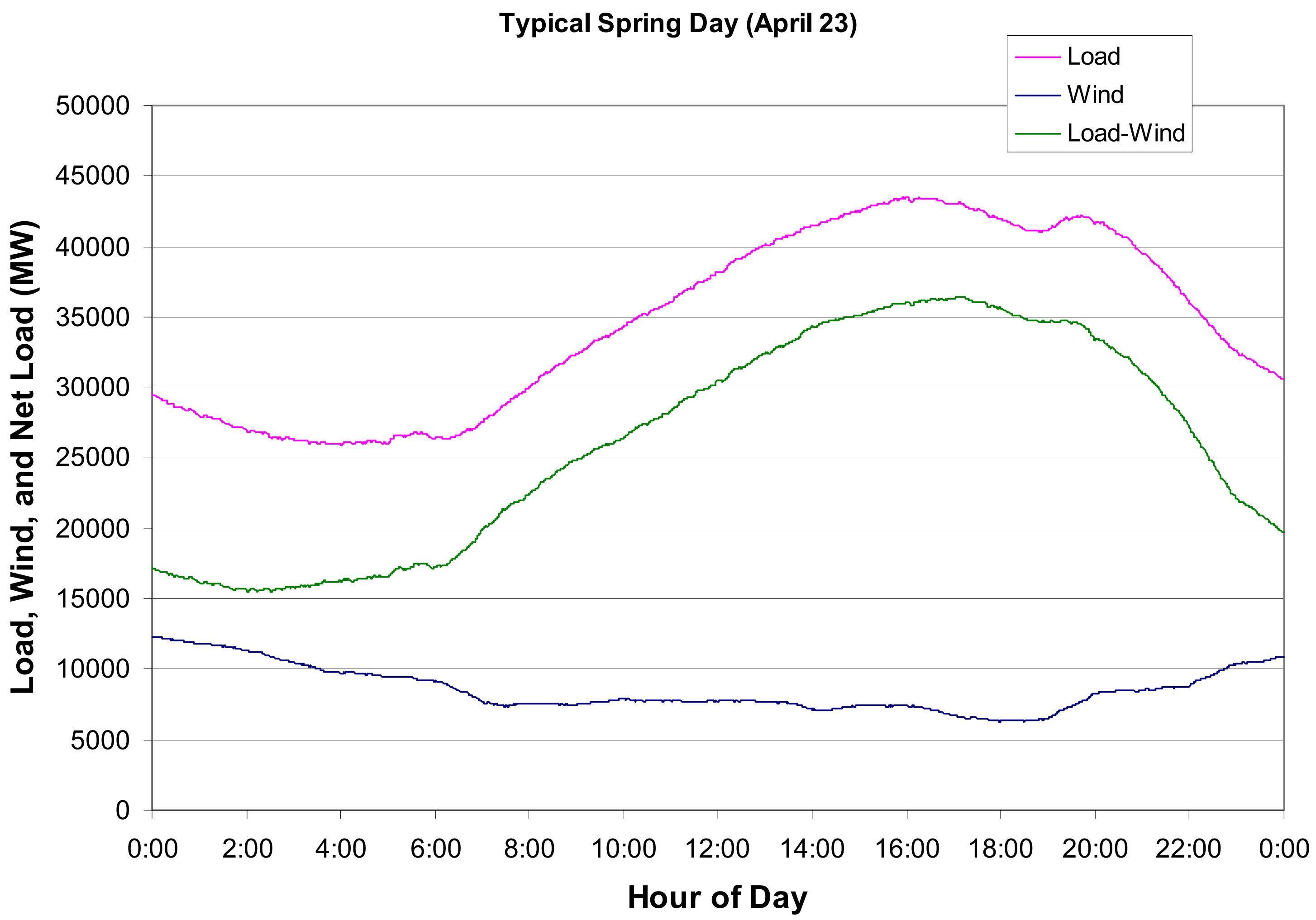
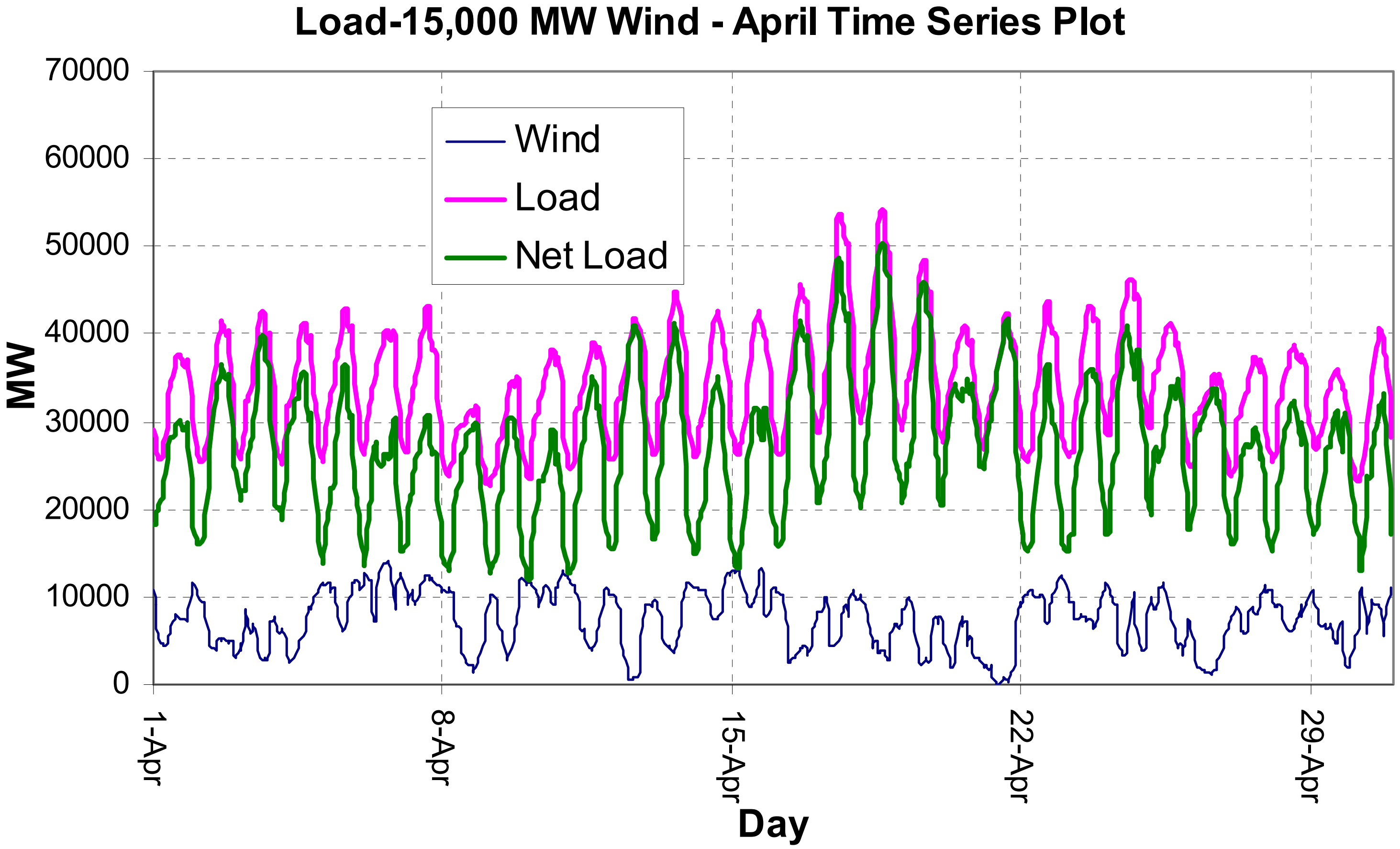
Daily Curve From One-Minute Data (Study Year Hourly Data, 15000 MW Scenario)



- Curves are quite smooth, wind appears smoother
- Diversity smoothes out wind, just as it does for loads

Net Load (15,000 MW Wind Scenario)

(Study Year Hourly Data)



- *Load peaks are reduced, some days more than others*
- *Valleys are greatly deepened*

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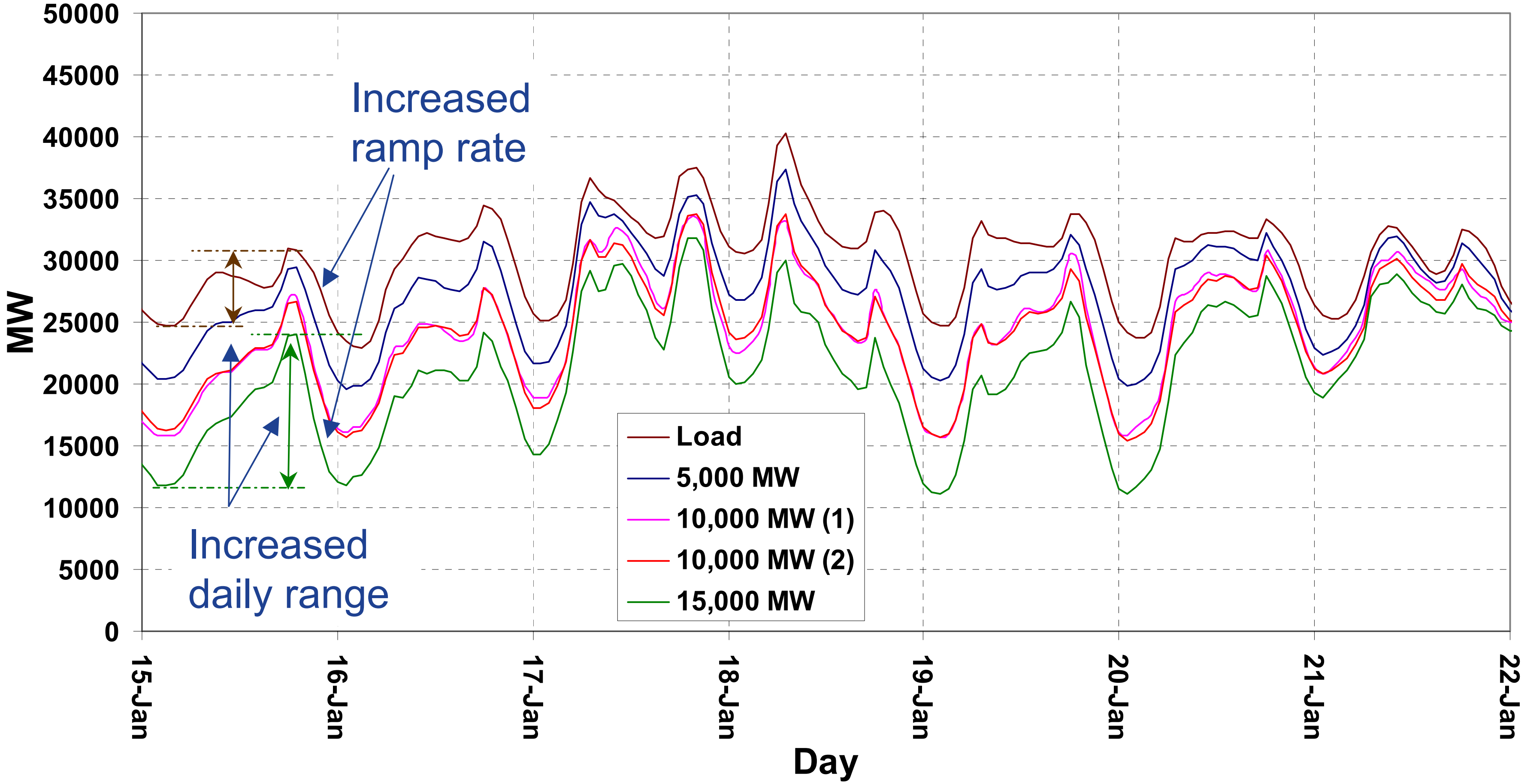
Net Load Comparisons – One January Week

(Study Year Hourly Data)



Increased ramp rate

Increased daily range

- *Curve shape is relatively similar for all scenarios*
- *Peak-to-valley change increases with wind generation*
- *Result is ramp rates increasing with more wind*

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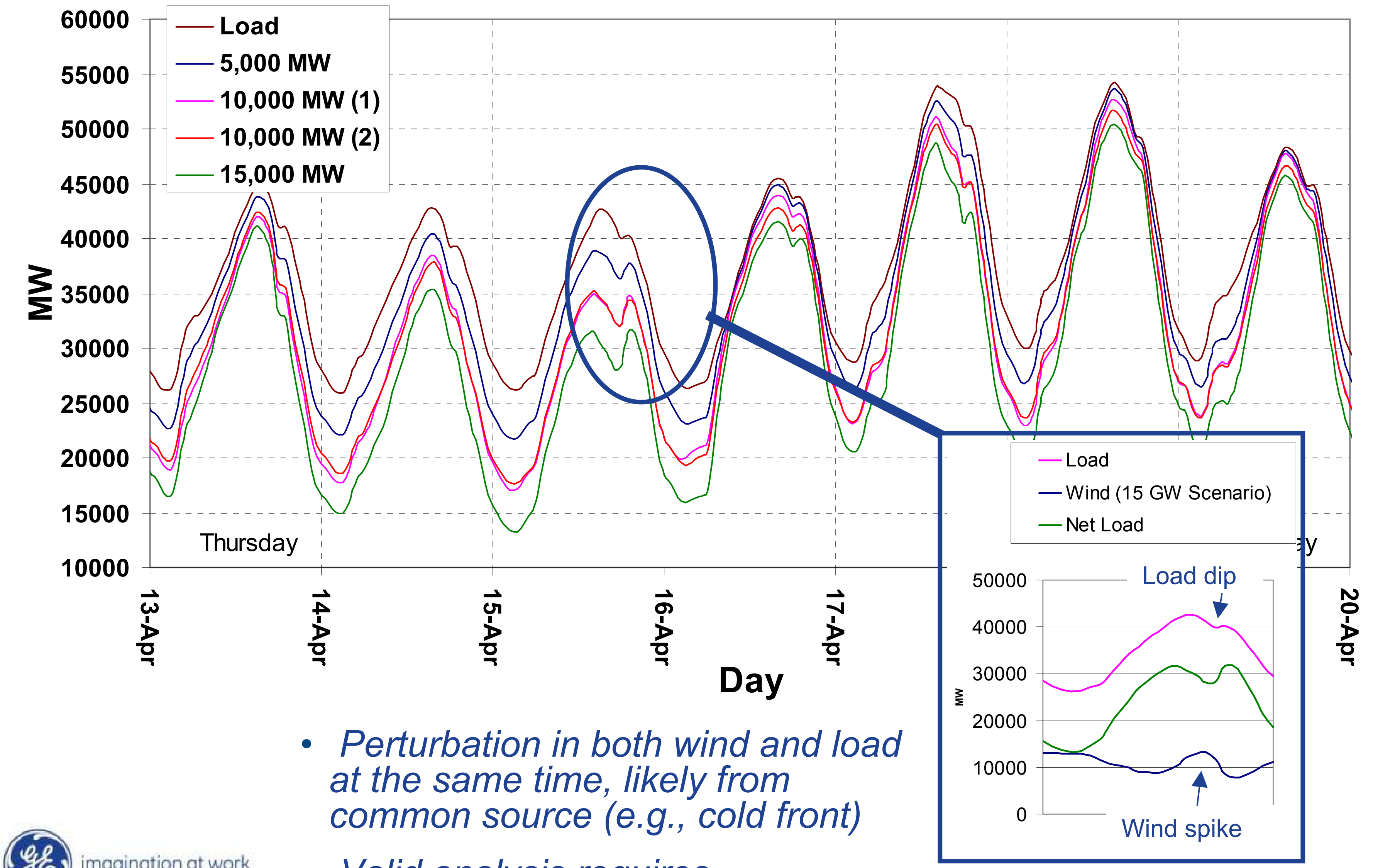
Net Load Comparisons – One April Week

(Study Year Data)



- *Perturbation in both wind and load at the same time, likely from common source (e.g., cold front)*
- *Valid analysis requires synchronized load and wind data*

In summary:

- Both wind and load are variable
  - Daily wind generation cycle is generally out-of-phase with load
  - Shorter term variations tend to be less correlated
- Common factors affect both wind and load
  - Wind impacts cannot be correctly considered independently of load behavior

Time of Year (Seasonal) Analysis

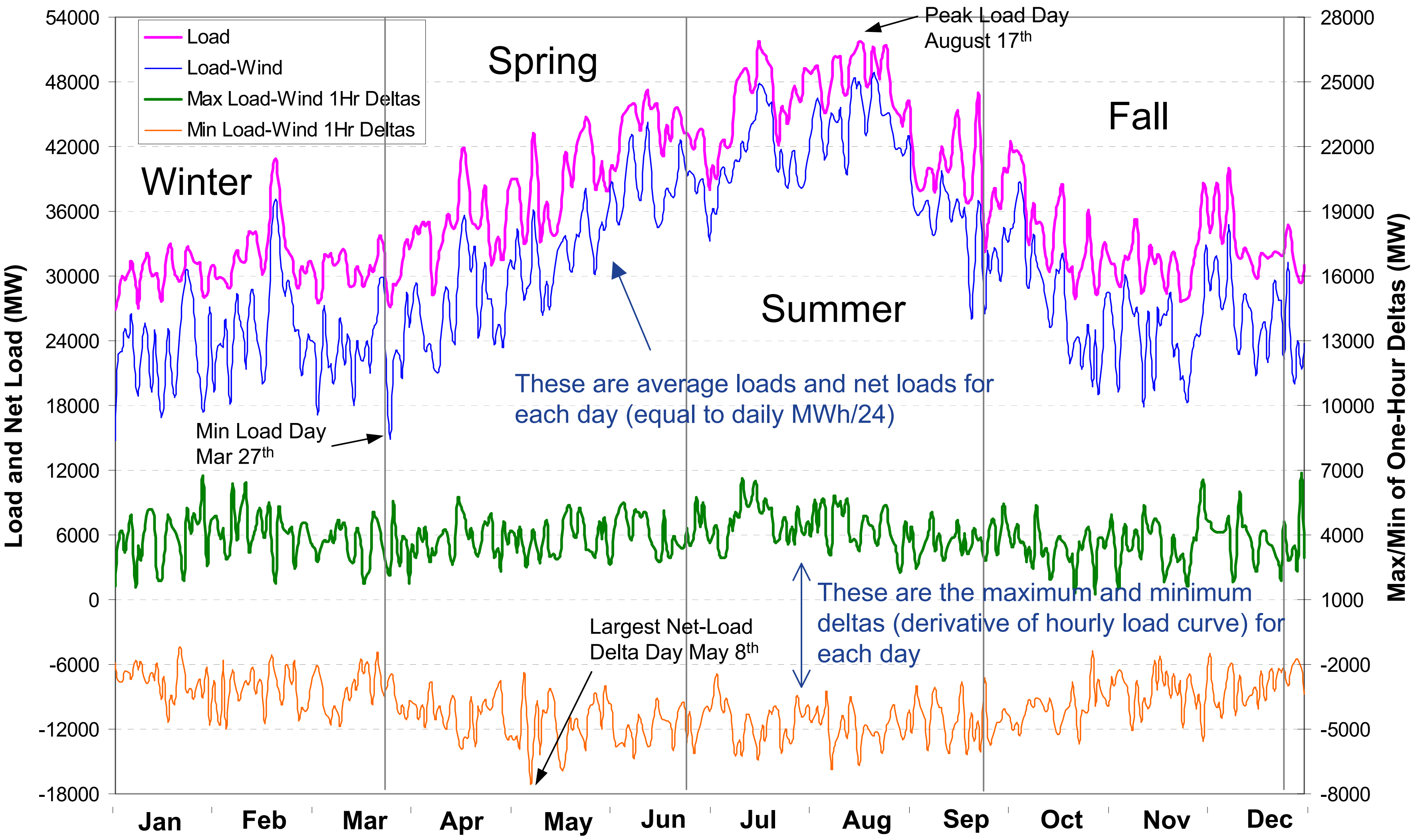
In the next series of slides, time periods with critical operating situations are identified and the impacts of wind are illustrated by time series plots (all with the 15000 MW scenario to more clearly demonstrate wind impacts)

Critical situations include:

- Maximum system load
- Minimum net load
- Maximum net load
- Most variable day

Profiles of Daily Average Load and Net Load and 1-Hour Deltas

(Study Year Data, 15000 MW Scenario)



Peak Load Day
August 17th

Min Load Day
Mar 27th

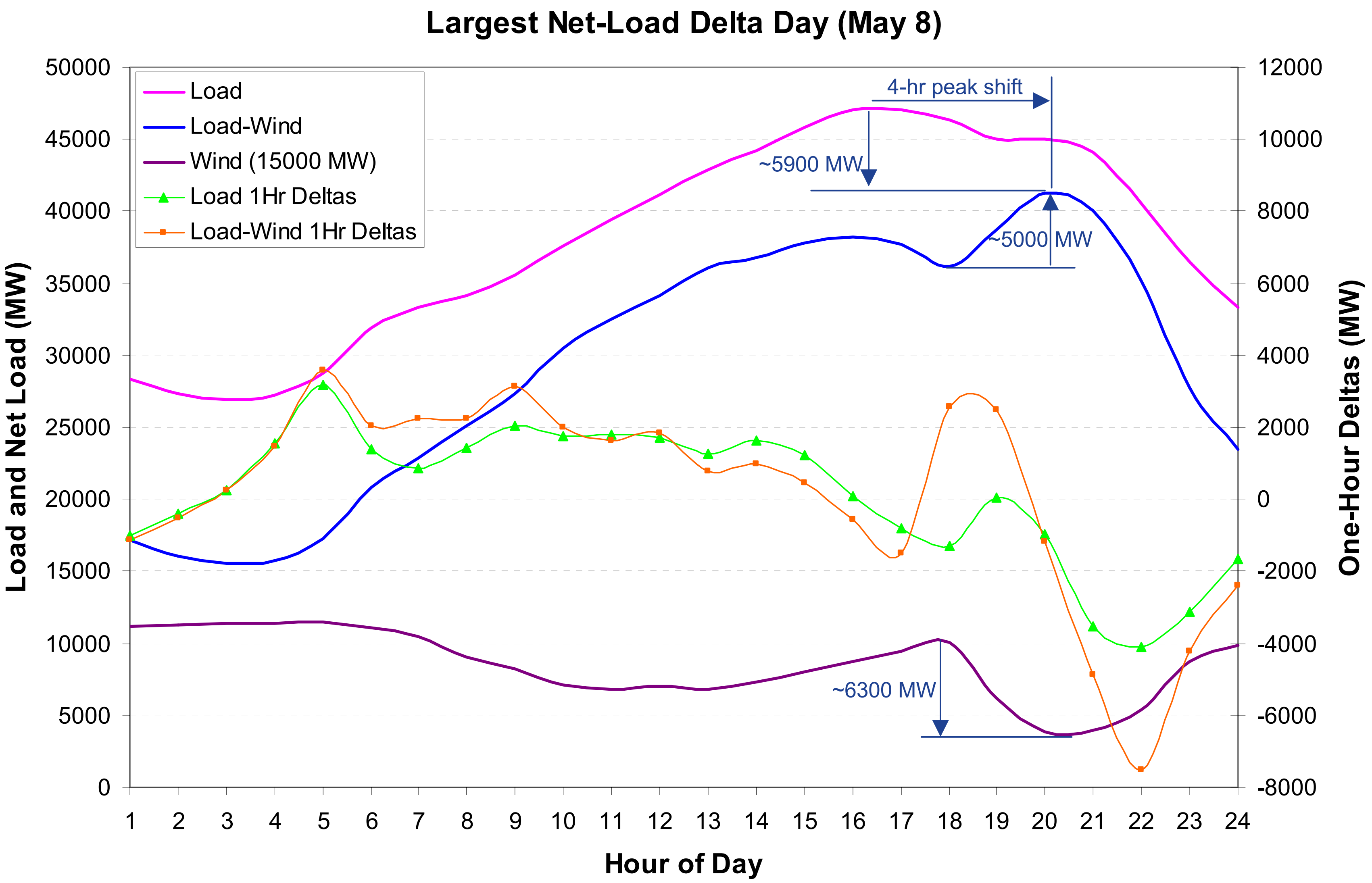
These are average loads and net loads for each day (equal to daily MWh/24)

Largest Net-Load
Delta Day May 8th

These are the maximum and minimum deltas (derivative of hourly load curve) for each day

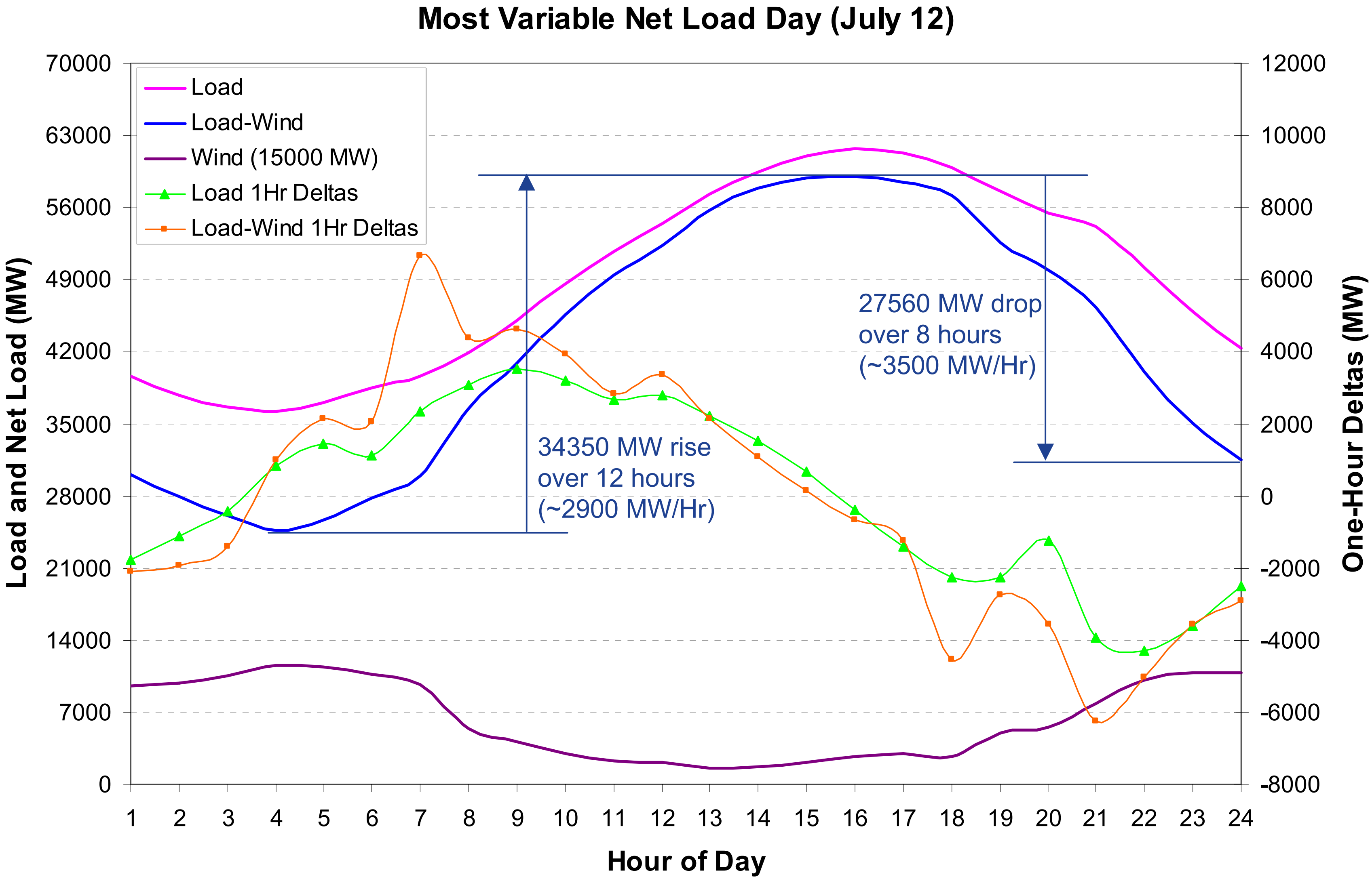
- *Basis for selection of key dates for further illustration and analysis*

Largest Net-Load Delta Day - Profiles and Deltas (Study Year Data, 15000 MW Scenario)



- *Wind drop in evening before load drop causes a late peak in net load, with resulting increases in ramp rates*

Most Variable* Day - Profiles and 1-Hour Deltas (Study Year Data, 15000 MW Scenario)



Most Variable Net Load Day (July 12)

* Largest net-load sigma

- *Anti-correlation of diurnal load and wind curves cause severe morning and evening ramps*

In summary:

- Wind has the greatest impact on hour-to-hour net load variation in the late spring and summer
  - Strong coincidence of wind drop-off with morning load pickup
  - Strong coincidence of wind pickup with evening load drop-off
  - Larger day vs. night net load swing results in greater ramp rates
- Variations in the winter and early spring may be more operationally significant, however, due to low net load levels
- Net load peaks can be shifted to unusual times of day by wind changes with high penetration

Net-Load Variability for Various Timeframes

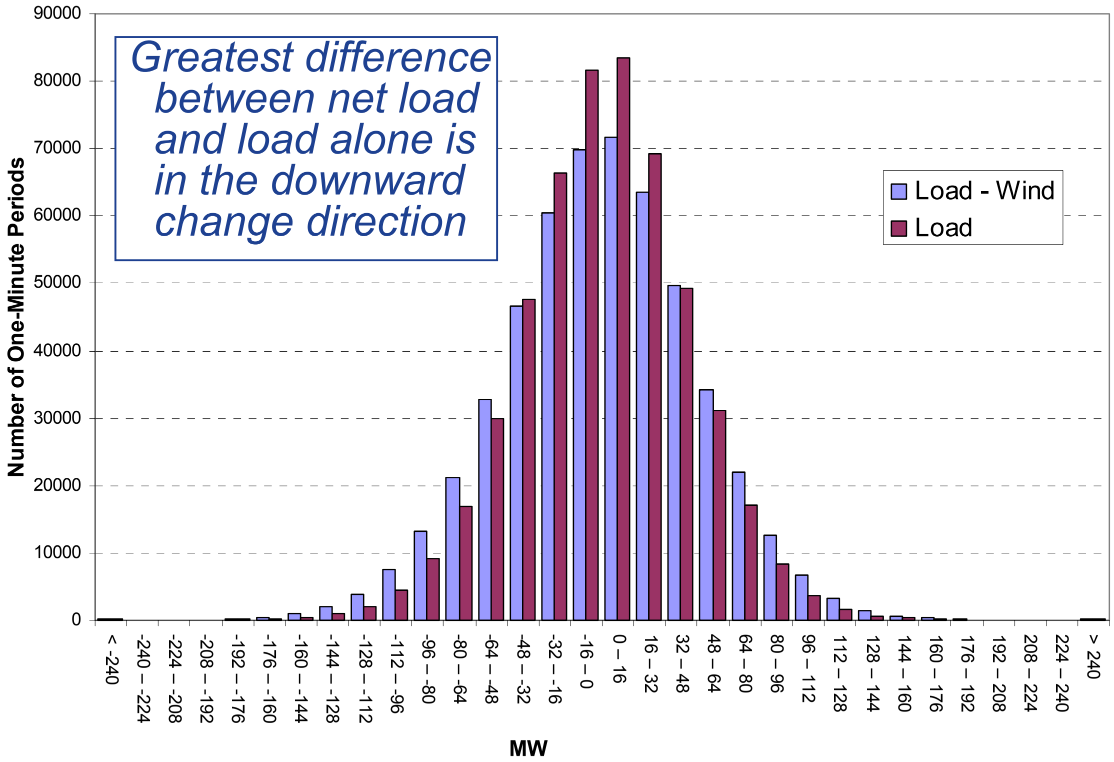
Statistical analysis of the load and net load variability is shown in the next series of slides, for different timeframes

Some explanations and points to consider:

- Deltas are the changes in average net load for successive periods – (1, 5, 15, and 60 minutes considered in this study)
- Average deltas over a day or longer period are inherently near zero, so the standard deviation of the deltas are used as a measure of variability
- Deltas include both the effects of longer-cycle ramping as well as random “jitter”

One-Minute Load-Wind Variability

(Study Year Data, 15000 MW Scenario)



Greatest difference between net load and load alone is in the downward change direction

1-minute standard deviation (σ) increases by **14.9%**
Maximum 1-minute rise increases by 46.4 MW
Maximum 1-minute drop increases by 38.9 MW
Number of 1-minute deltas greater than 2.5 (load)σ increases 96%

Statistical Summary

	Load-alone (MW)	**With Wind (MW)**
Mean (-/+ Deltas)	-33.6 / 33.0	-39.2 / 38.1
Sigma (Delta)	43.22	49.67
Min. Delta	-513.7	-552.6
Max. Delta	491.6	538.3

Extreme 1-Minute Deltas

	Load-alone (Delta-MW) $\sigma = 43.22$	**With Wind (Delta-MW)** $\sigma = 49.67$	**With Wind (Delta-MW)** Using load σ
$>\mu \pm 2.5\sigma$ (–/+)	4696 / 3805	4604 / 3547	9277 / 7408
$>\mu \pm 3\sigma$ (–/+)	1711 / 1435	1517 / 1239	3593 / 2769
$>\mu \pm 4\sigma$ (–/+)	338 / 391	247 / 297	571 / 551
$>\mu \pm 5\sigma$ (–/+)	147 / 203	117 / 159	175 / 225
$>\mu \pm 6\sigma$ (–/+)	105 / 129	79 / 87	111 / 139
% > 2.5σ	1.61%	1.55%	3.17%

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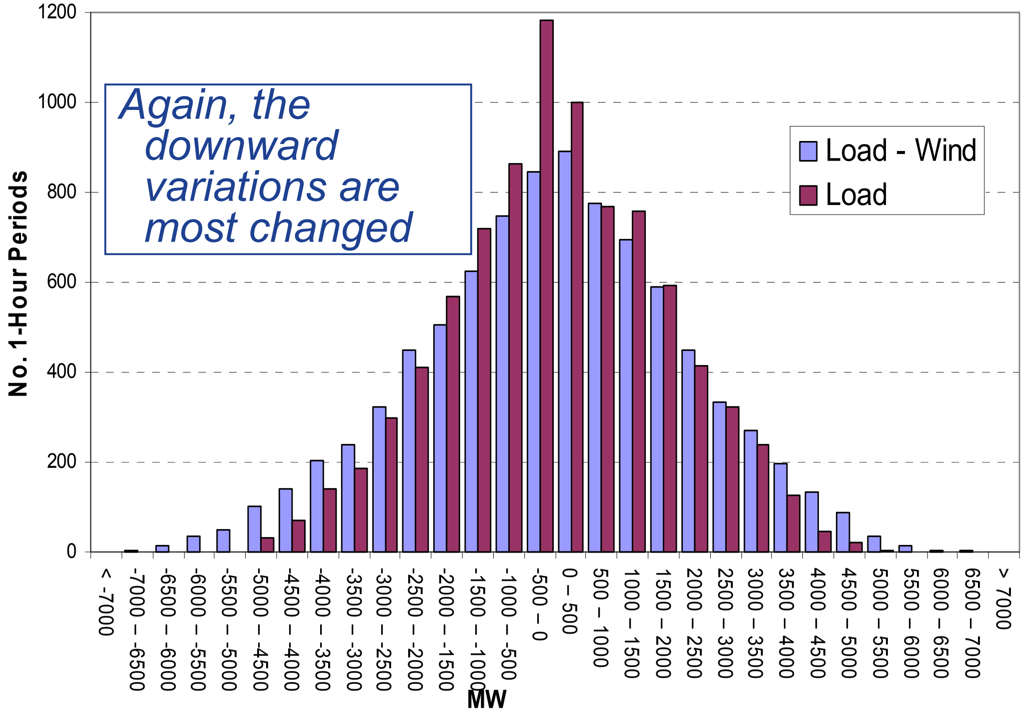
Hourly Load-Wind Variability

(Study Year Data, 15000 MW Scenario)



Again, the downward variations are most changed

	Load-alone (MW)	With Wind (MW)
Mean (-/+ Deltas)	-1366 / 1425	-1741 / 1677
Sigma (Delta)	1758	2159
Min. Delta	-4838	-7507
Max. Delta	5203	6861

1-hr standard deviation (σ) increases by 22.8%
Maximum 1-hour rise increases by 1658 MW
Maximum 1-hour drop increases by 2669 MW
Number of 1-hr deltas greater than 2.5 (load)σ increases 458%

Extreme 1-Hour Deltas

	Load-alone (Delta-MW) $\sigma = 1758$	**With Wind (Delta-MW)** $\sigma = 2159$	**With Wind (Delta-MW)** Using load σ
$>\mu \pm 2.5\sigma$ $(-/+)$	43 / 26	6 / 26	224 / 161
$>\mu \pm 3\sigma$ $(-/+)$	0 / 0	6 / 5	78 / 36
$>\mu \pm 4\sigma$ $(-/+)$	0 / 0	0 / 0	1 / 0
% > 2.5σ	0.79%	0.37%	4.39%

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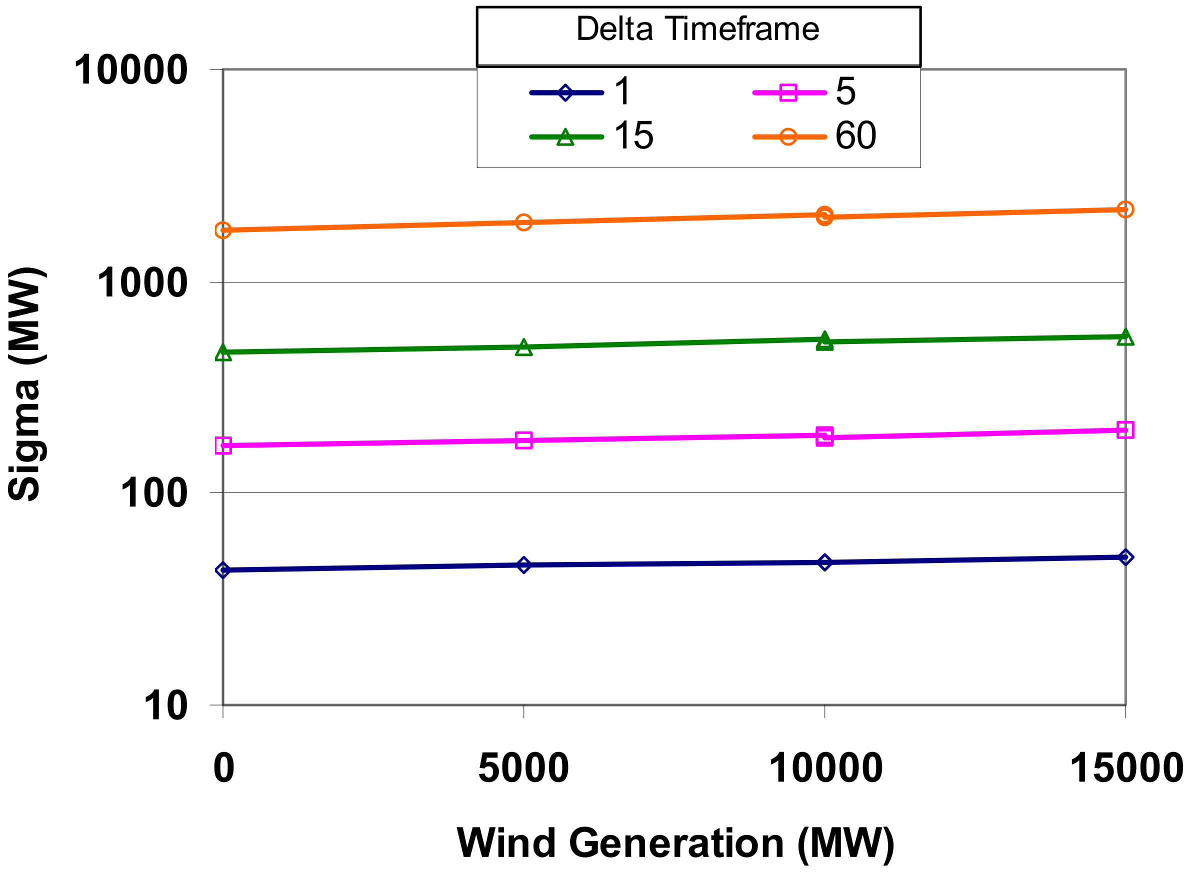
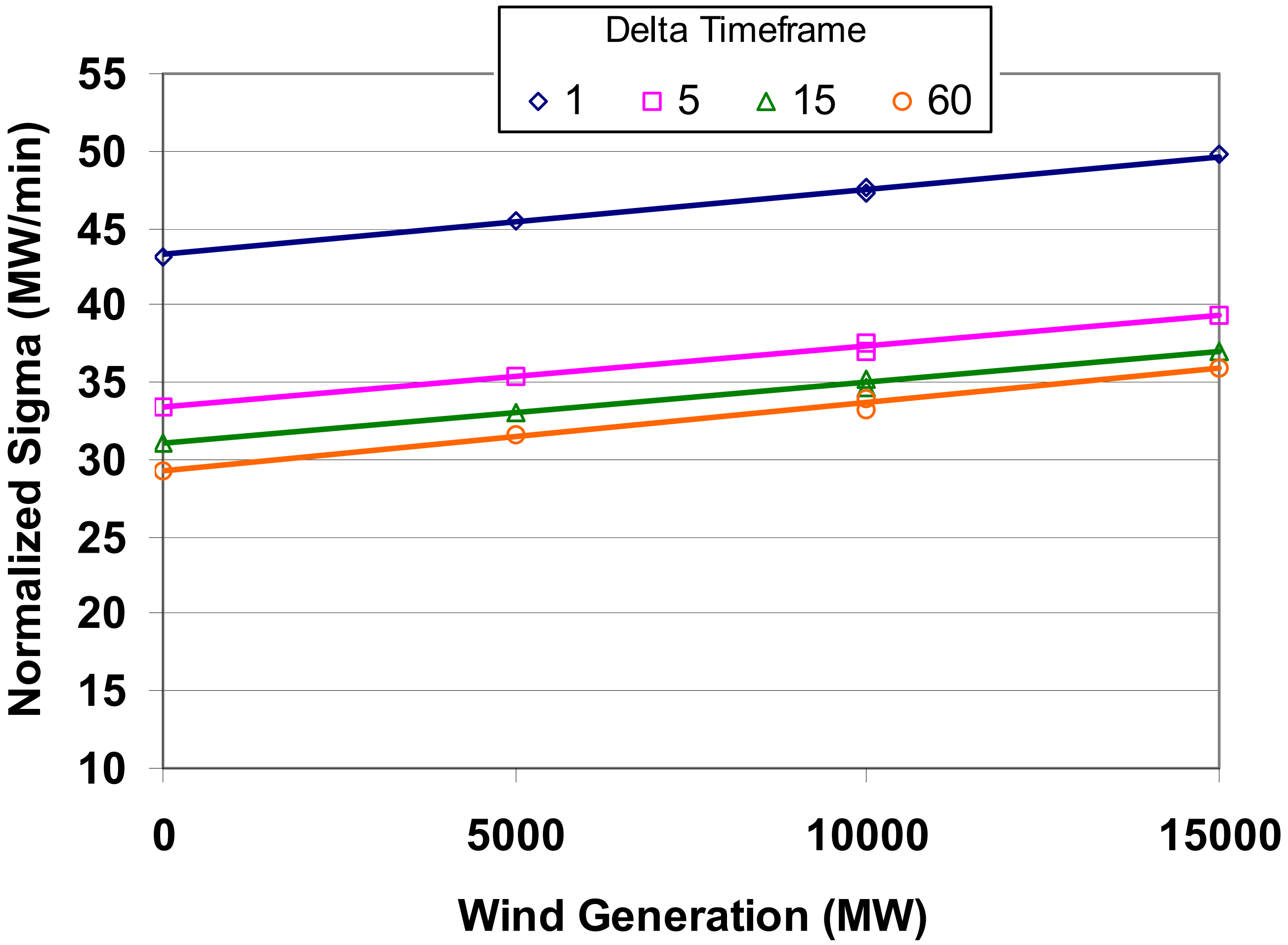
Variability as a Function of Wind Penetration



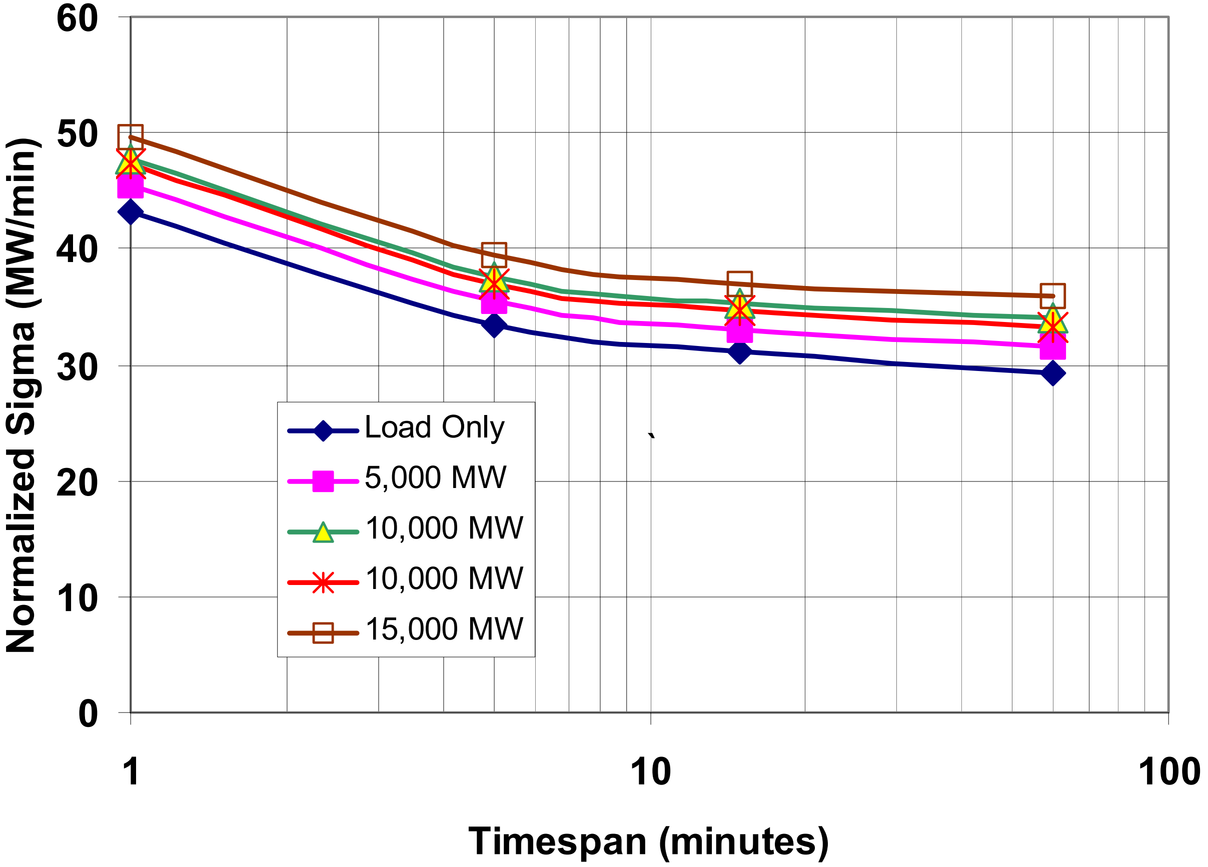
- *Variability increases with wind penetration.*
- *Increase is very slight on this scale*

Normalized Variability as a Function of Wind Penetration



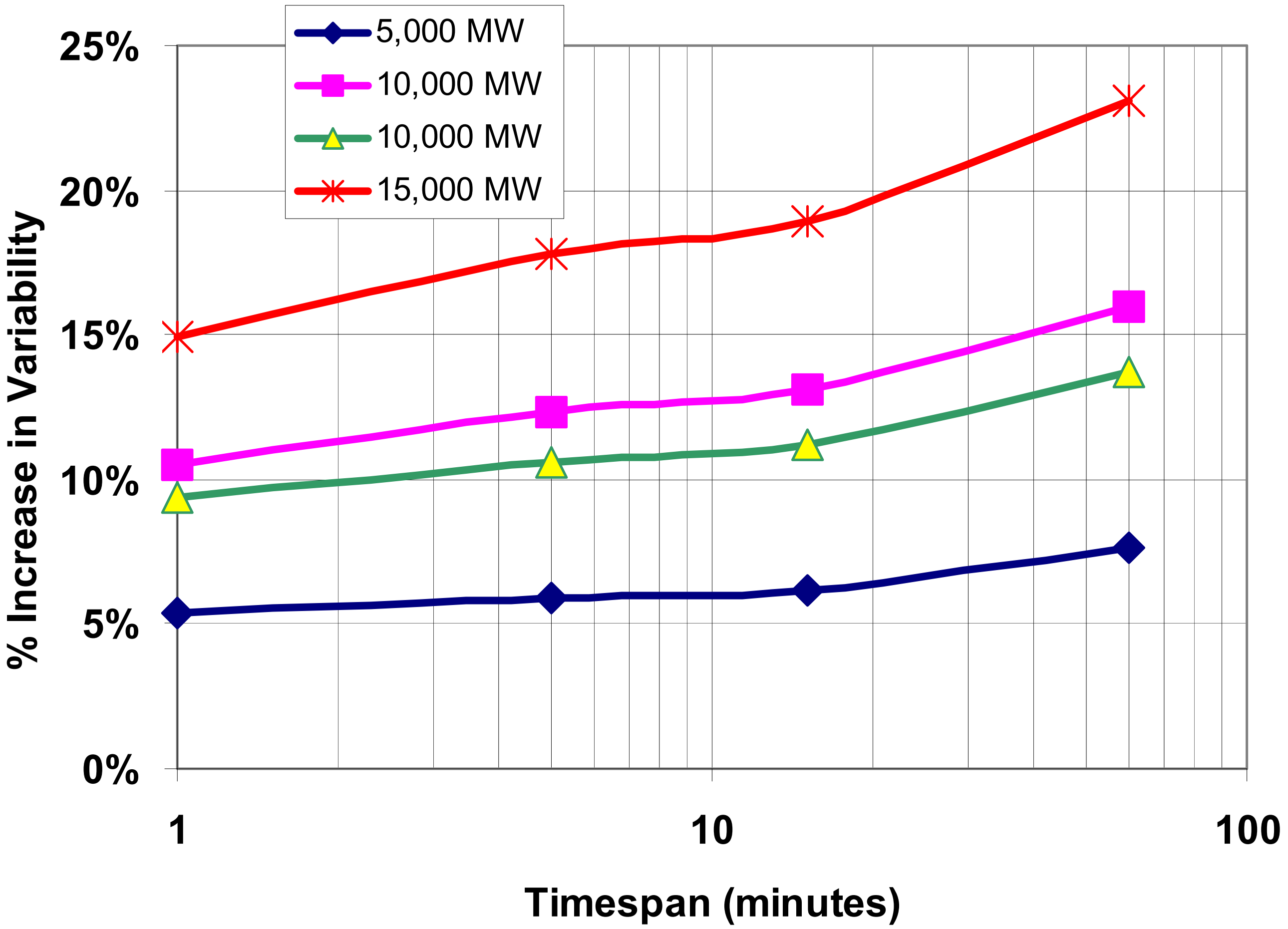
- *Sigmas normalized in terms of MW/min (e.g., σ_5 / 5)*
- *Increase is linear, but with a shallow slope*

Normalized Sigma as a Function of Timespan



- There is a baseline of variability that is a function of the longer-term load cycle.
- An incremental amount of variation appears at the shortest timeframes (1 & 5 min.)

Increase in Variability Relative to Time Span



For all wind scenarios, the relative increase in variability (sigma), relative to sigma of load alone, becomes more significant for longer time windows

In summary:

- Variations over timespans of 10+ minutes are primarily due to load cycle
- Shorter timespans have an incremental component due to random “noise” variations
- Wind causes a slight, linear increase in period-to-period variability over all timespans
- Impact is somewhat more significant for longer timespans
  - I.e., wind adds to variability primarily due to creating larger daily net load swings
  - Addition to the random “noise” is less significant
- Small differences in statistical metrics between “study year” (based on 2006) and “previous year” (based on 2005) indicate stability of results

Variability at Different Load Levels

The ability of the system to accommodate net load variations is greatly a function of the absolute net load level.

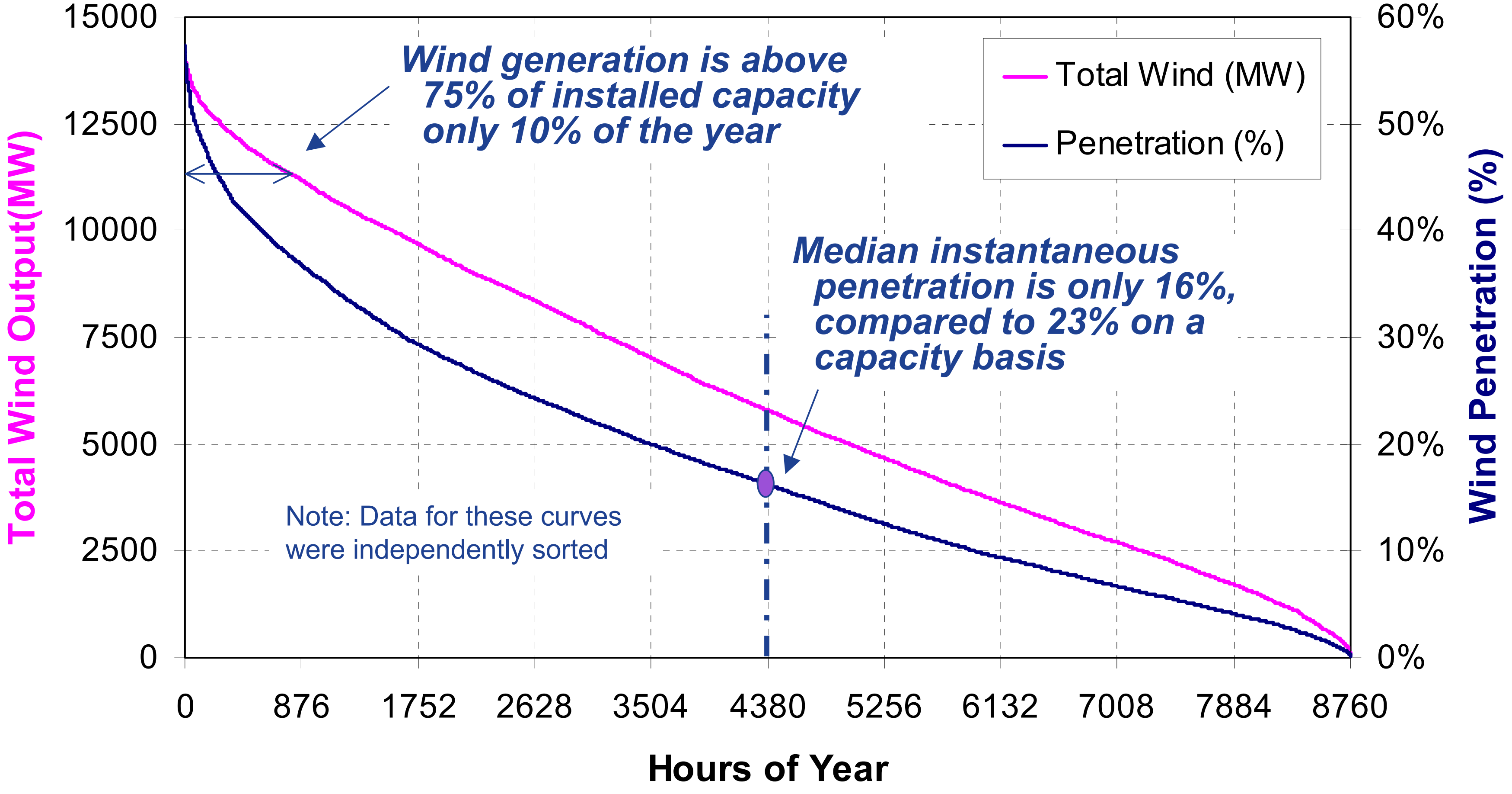
System maneuverability tends to increase with the generation level because:

- Variations of a given magnitude are larger in proportion to the committed generators
- Units lower on the dispatch stack tend to be base load units that are less maneuverable

The following slides correlate variability with load level

Wind Duration and Penetration (15000 MW)

(Study Year Data)



Wind generation is above 75% of installed capacity only 10% of the year

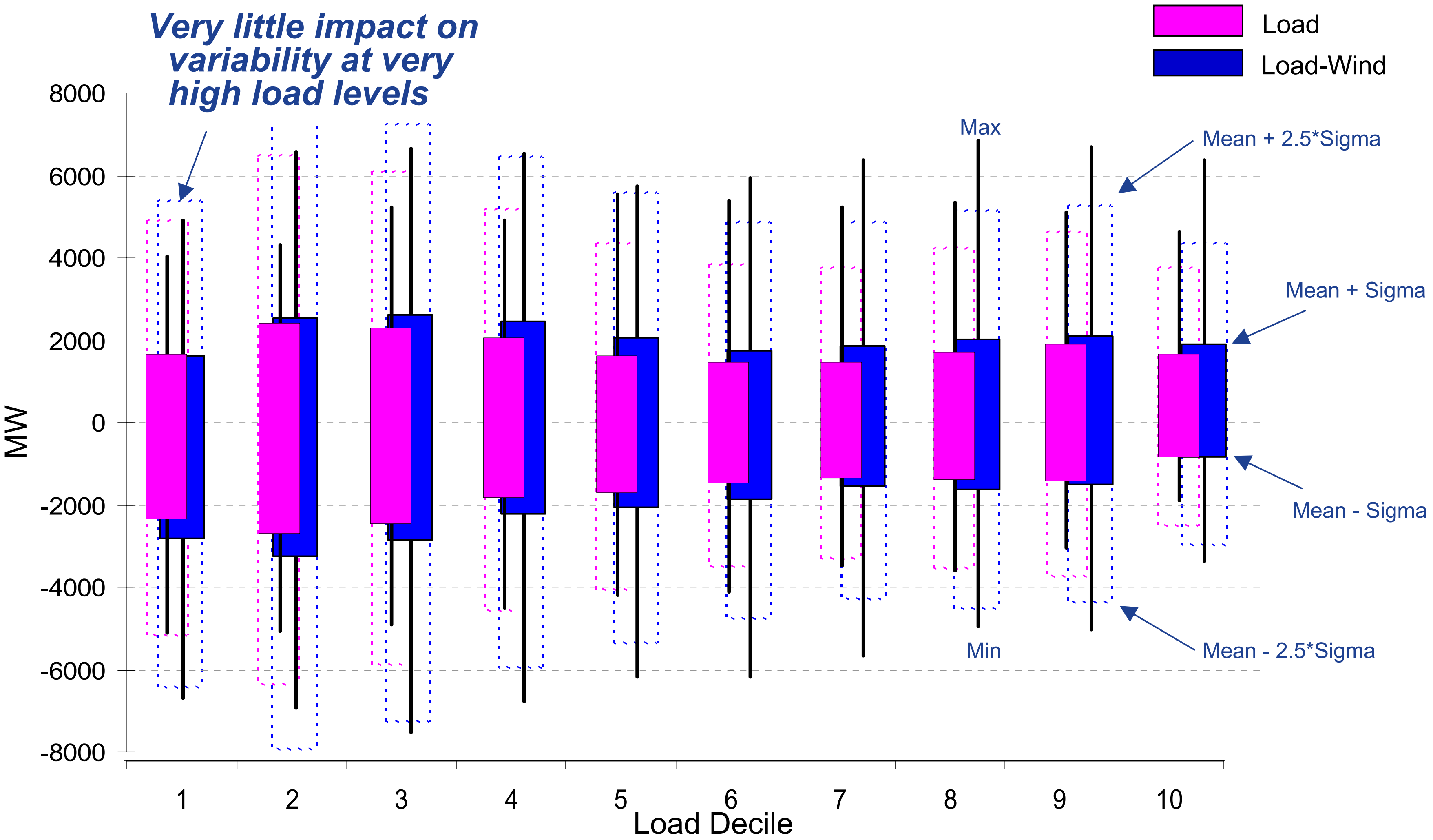
Median instantaneous penetration is only 16%, compared to 23% on a capacity basis

Note: Data for these curves were independently sorted

Wind Scenario	**Max Instantaneous Penetration**
5000	21%
10000 (1)	39%
10000 (2)	39%
15000	57%

Load and Net Load Variability by Load Level (Average +/- *x**sigma, Minimum, Maximum)

(Study Year Hourly Data, 15000 MW Scenario)

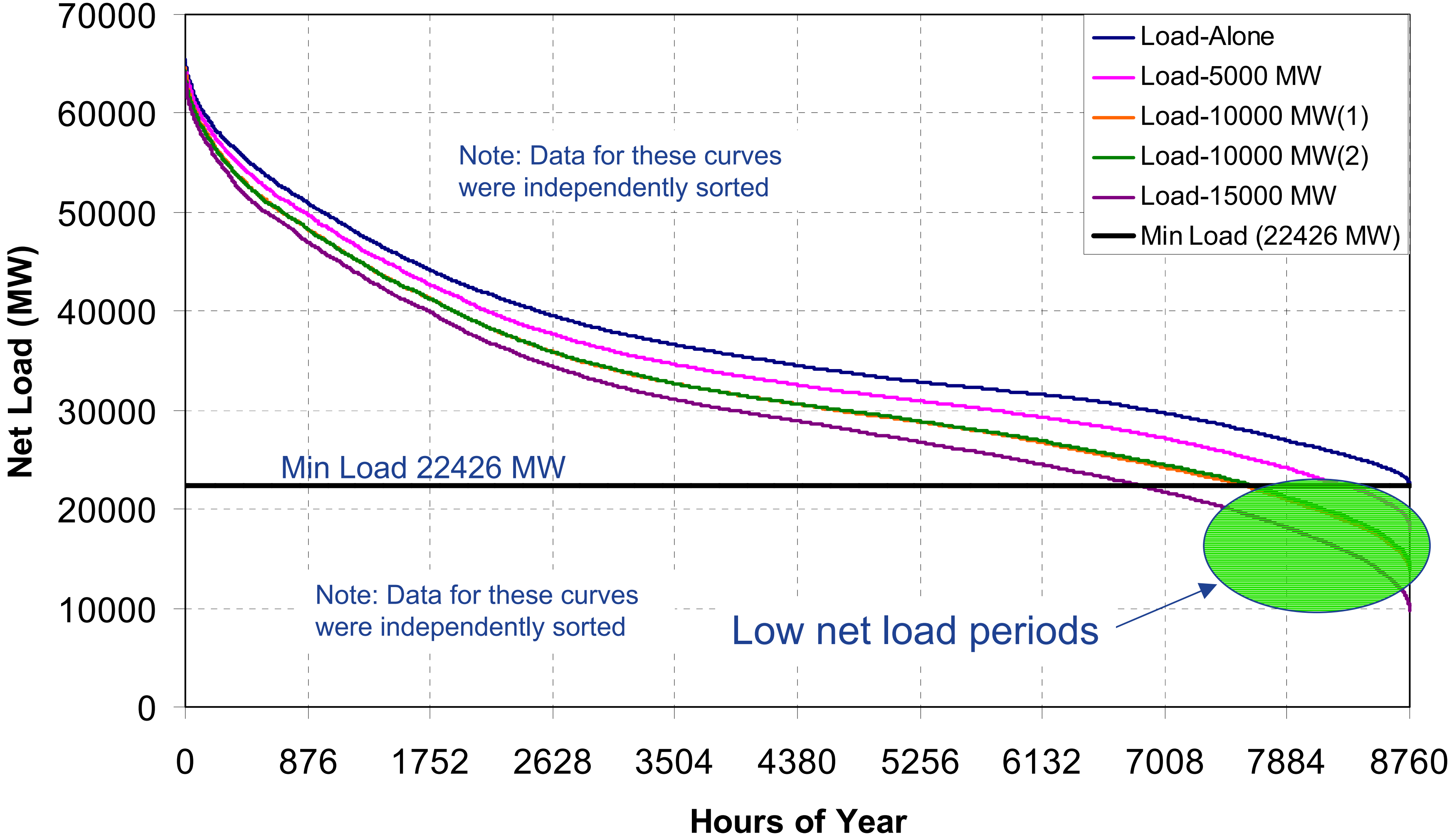


Very little impact on variability at very high load levels

- *Variability is changed little at lower loads*
- *Same variability, but with fewer dispatchable generators*

Net Load Duration Curves for Various Wind Scenarios

(Study Year Data)



Note: Data for these curves were independently sorted

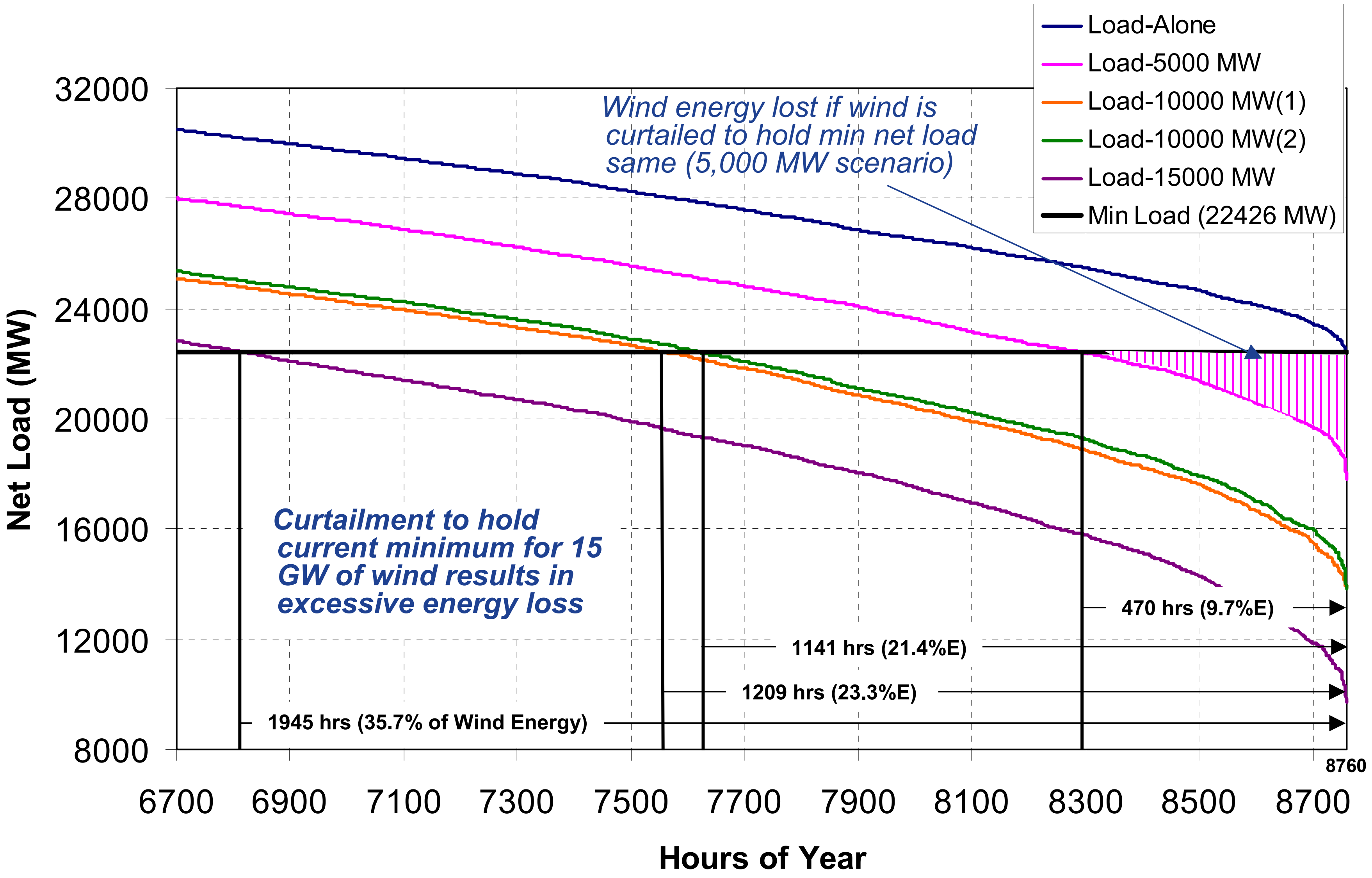
Note: Data for these curves were independently sorted

Low net load periods

- *Net loads below current minimum load may be a real operational challenge*
- ***Average wind output is double during low net-load hours***

Net Load Duration Curves for Low Load Periods

(Study Year Data)



Wind energy lost if wind is curtailed to hold min net load same (5,000 MW scenario)

Curtailment to hold current minimum for 15 GW of wind results in excessive energy loss

- *There are inherent tradeoffs between costs of generation flexibility and energy lost to curtailment*

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In summary:

- In general, variability is relatively constant over the range of load levels
- Wind contribution to variability is also relatively constant
- Net loads can be driven to low levels with large wind capacity
  - Instantaneous penetration reaches 55% with 15,000 MW of wind and 2008 load levels
- It is not feasible to maintain the same minimum load levels

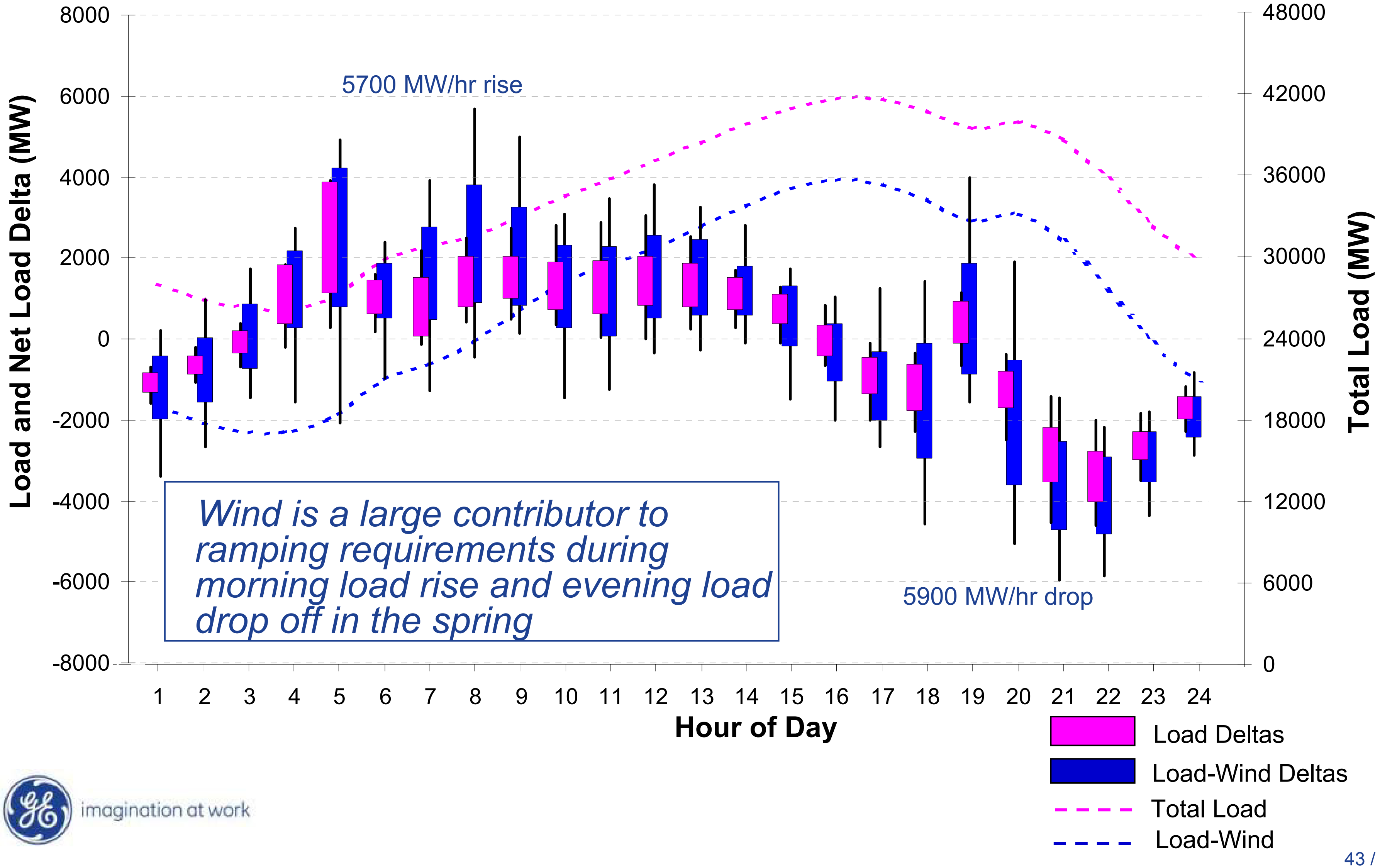
Ability of the ERCOT system to meet ramping requirements will be specifically studied in Phase 2

Time of Day Variability Analysis

The next slides examine how load variability varies over the hours of the day for different seasons

April, Hourly Load and Net Load Deltas (Avg. +/- sigma, Minimum, Maximum)

(Study Year Data, 15000 MW Scenario)



Wind is a large contributor to ramping requirements during morning load rise and evening load drop off in the spring

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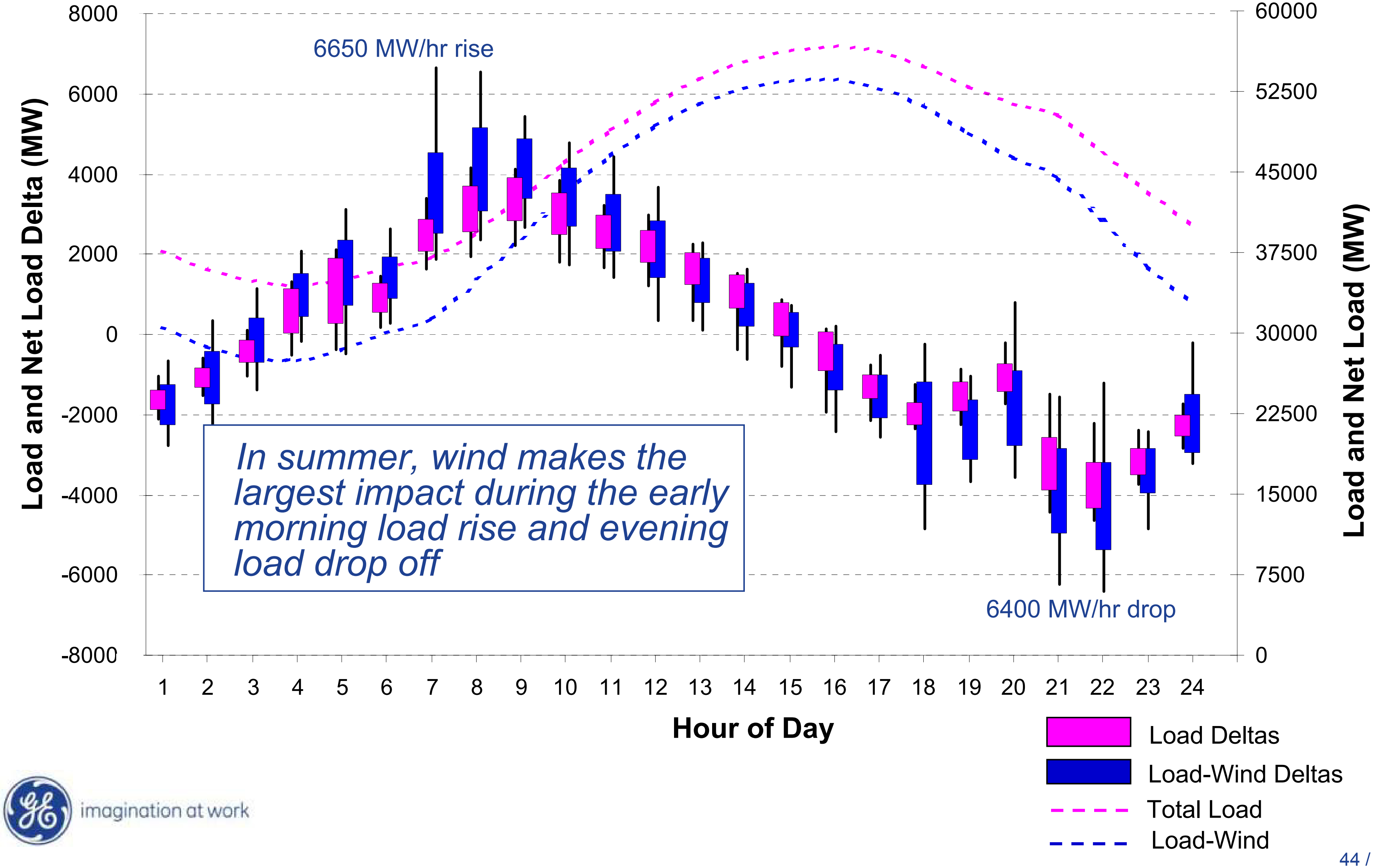
July, Hourly Load and Net Load Deltas (Avg. +/- sigma, Minimum, Maximum)

(Study Year Data, 15000 MW Scenario)



In summer, wind makes the largest impact during the early morning load rise and evening load drop off

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Summer Morning Load Rise Period
June – September
7 – 11 AM

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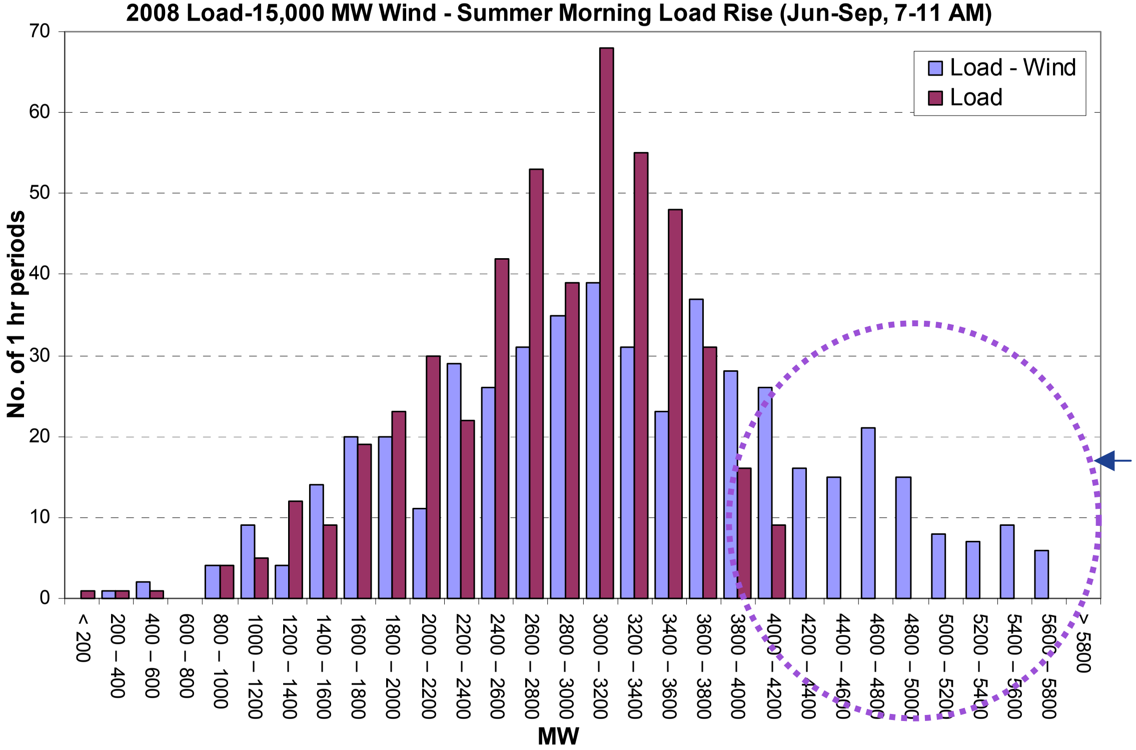
Summer Morning Load Rise Variability – 15,000 MW

(Study Year Data)



Mean 1-hour delta increases by 15.7% due to wind

Sigma increases by 53.3%

Number of 1-hour rises greater than 4000 MW increases from 9 to 123

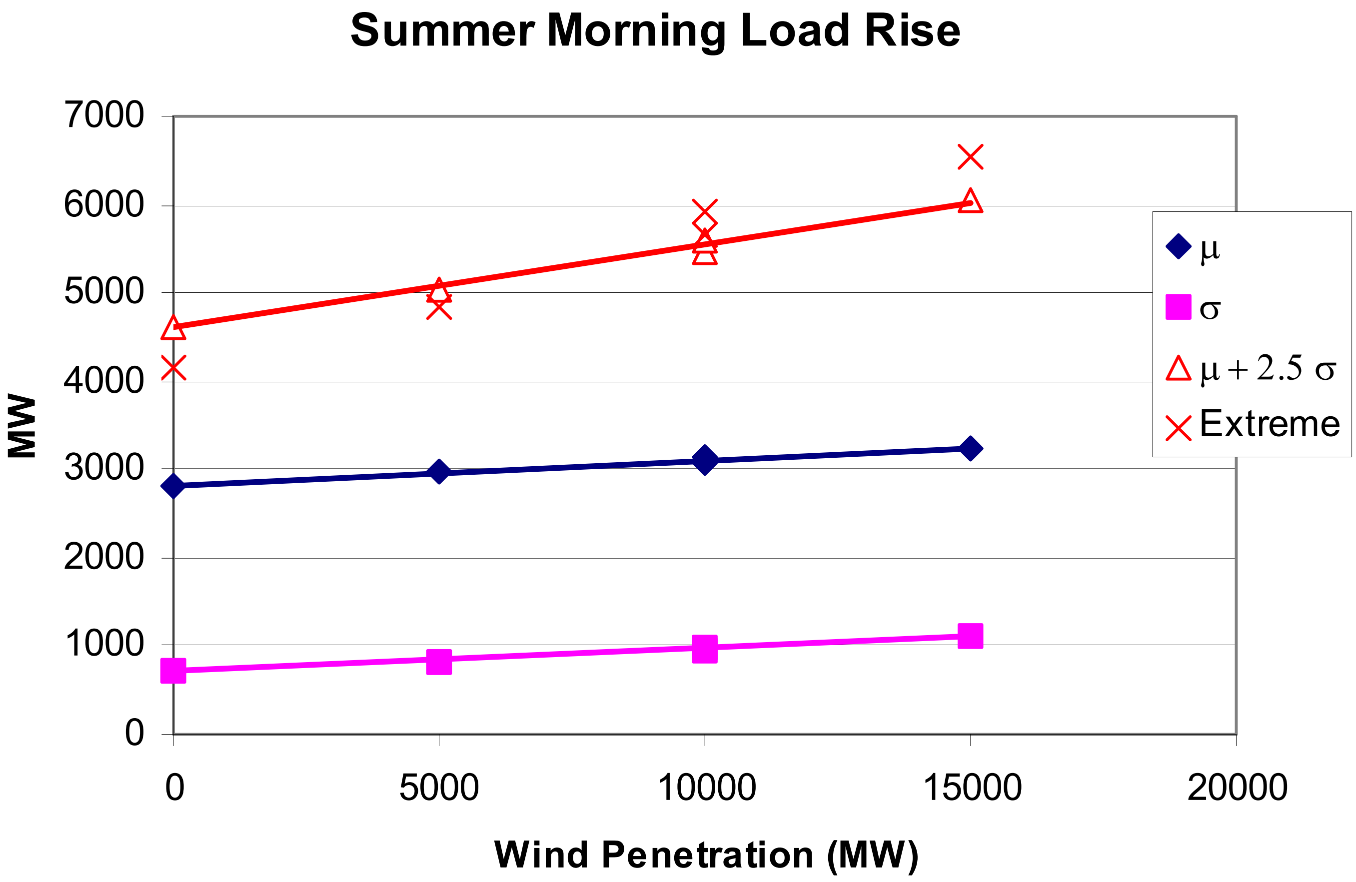
	Load-alone (MW)	with Wind (MW)
Mean (Delta)	2797	3237
Sigma (Delta)	732	1122
Min. Delta	9	250
Max. Delta	4160	6528

Extreme 1-Hour Rises

	Load-alone (Delta-MW) $\sigma = 732$	With Wind (Delta-MW) $\sigma = 1122$	With Wind (Delta-MW) Using load σ
$> \mu + 2.5\sigma$	0	1	29
$> \mu + 3\sigma$	0	0	15
$> \mu + 4\sigma$	0	0	1

Summer Morning Load Rise Variability

(Study Year Data)



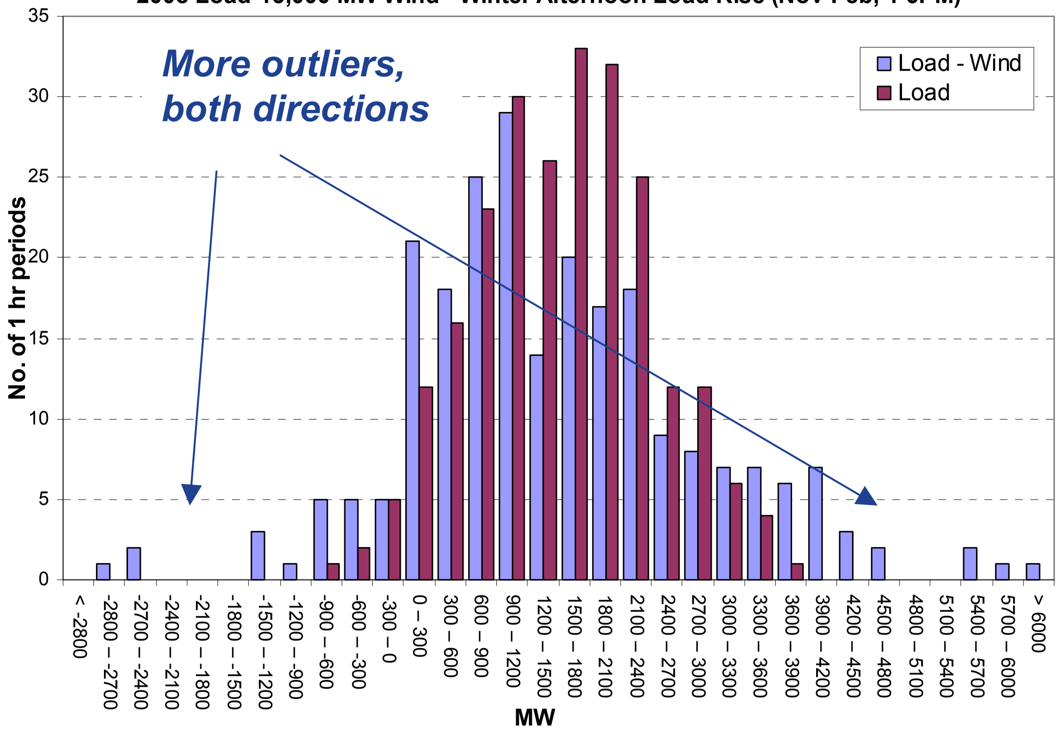
- *Extrema increase more quickly with additional wind generation than mean + 2.5 s.d.*
- *Distribution is less characterized by a normal distribution; more outliers*

Winter Afternoon Load Rise Period
November – February
4 – 6 PM

Winter Afternoon Load Rise Variability

(Study Year Data)

2008 Load-15,000 MW Wind - Winter Afternoon Load Rise (Nov-Feb, 4-6PM)



More outliers, both directions

Mean 1-hour delta increases by 3.7% due to wind

Sigma increases by 79.7%

Number of 1-hour rises greater than 3000 MW increases from 11 to 36

	Load-alone (MW)	**with Wind (MW)**
Mean (Delta)	1517	1573
Sigma (Delta)	866	1556
Min. Delta	-886	-2768
Max. Delta	3678	6861

Extreme 1-Hour Rises

	Load-alone (Delta-MW) $\sigma = 866$	**With Wind (Delta-MW)** $\sigma = 1550$	**With Wind (Delta-MW)** **Using load σ**
$> \mu + 2.5\sigma$	0	5	22
$> \mu + 3\sigma$	0	4	14
$> \mu + 4\sigma$	0	0	7

Variability Analysis Summary

- Wind variability increases linearly with penetration
  - 1-hour sigma increases by 23% with 15,000 MW of wind
  - Greater variability and extreme ramps observed during certain morning, afternoon and evening periods
  - Greater net load variability in the spring and summer
- The more significant impact is that minimum net loads are greatly reduced
  - Greater relative variability at light load
  - Less system responsiveness
- Wind impact on variability is primarily due to multi-hour cycles, increment due to “noise” is small
- Wind has incremental impact on average and extreme errors, especially during early mornings and afternoons in winter & spring
  - On average, net load is nearly as predictable as load alone

Extreme Weather Conditions

Impact on Ancillary Services

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Impact of Extreme Weather Conditions

- ERCOT’s current “extreme” weather conditions are largely defined by temperature …
  - Regulation reserves may be increased by a factor of two
  - Responsive reserves and non-spinning reserves may be procured
- With large amounts of wind, other weather conditions may create abnormal net load deviations
  - Investigate most severe events in wind and Net-Load
  - Develop modified procedures or requirements for identifying and responding to the ancillary service needs driven by extreme weather.

Impact on Responsive Reserve Services (RRS)
(Spinning Reserves)

- Used to restore ERCOT system frequency within the first few minutes of an event …
- Set at 2300 MW for normal conditions
  - based on simultaneous loss of largest two generation units
- May be increased under “extreme conditions”
- Non-spinning reserves (NSRS) may be deployed when “large” amounts of spin are not available
  - NSRS can be ramped to output level within 30-minutes

Extreme drops in wind production within 30 mins are investigated to determine impact on RRS

In this next set of slides, we will show:

- AWST analysis of ramp events in existing wind
  - Causes, frequency and predictability
  - Implications for wind scenarios
- Probability of “large” wind transitions/ramp events
- Impact of diversity on wind ramp events
- Distribution, timing and magnitude of events
- Implications for RRS requirements

Analysis of West Texas Wind Plant Ramp Events

To identify and classify events, AWS Truewind:

- Examined two years of one-minute plant output data provided by ERCOT
  - Identified 30-minute periods with aggregate wind generation changes > 200 MW
    - Total 976 MW rated capacity for plants in analysis
    - Obvious cases of non-weather curtailments and shutdowns excluded
  - Examined available meteorological records for the periods
  - Categorized the events by meteorological causes
- Analyzed significant 2005-2006 weather events identified by ERCOT, determined those were associated with large changes in wind generation
- Analyzed the event of 24 February 2007 and established the cause for the decrease in energy production.

From the results, AWS Truewind estimated the maximum likely change in a 30-minute period for the 15,000 MW scenario

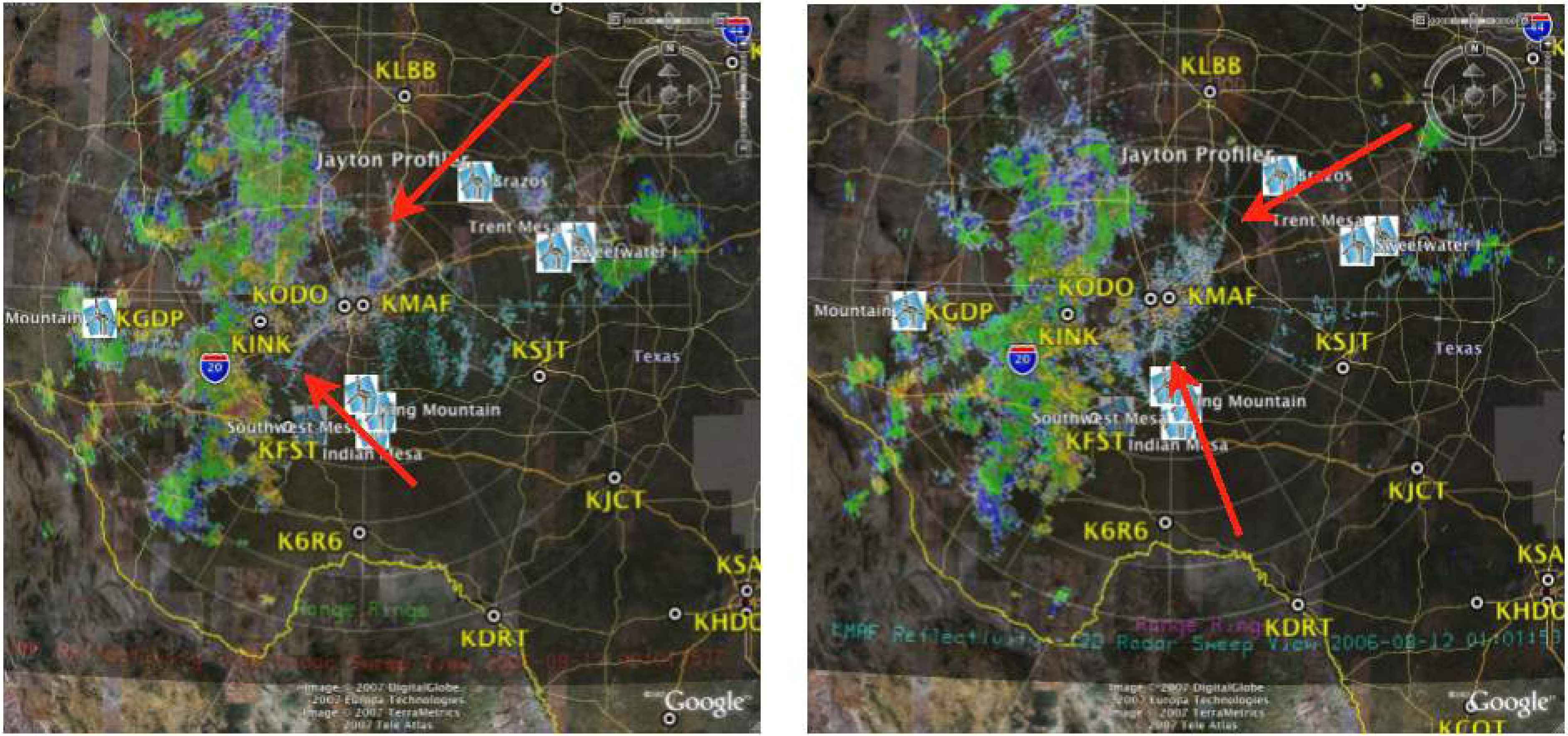
Meteorological Causes of Wind Ramp-Up Events

- Frontal system/trough/dry line
  - Density fronts or air mass discontinuities
  - Accompanying fall/rise pressure couplet, results in rapid wind-speed change,
  - Mostly move west to east or northwest to southeast
  - Up to 1000 km long and 100-200 km wide
  - Propagate at over 15 m/s (34 mph)
- Convection-induced outflow or gust fronts
  - Occur on the mesoscale (tens to hundreds of square km)
  - Usually propagate radially outward from thunderstorm clusters
  - Propogation speeds in excess of 25 m/s
- Low-level jet (LLJ)
  - Occur regularly year-round in the Southern Great Plains
  - Two types:
    1) Nocturnal LLJ – maximum at 5 AM
    2) Pre-frontal LLJ – ahead of cold front

Meteorological Causes of Wind Ramp-Down Events

- Slackening of a pressure gradient
- Passage of a local pressure couplet
- Each can occur for same events causing ramp-up
- High wind speeds that exceed wind turbine cut-out
  - Threshold (22-25 m/s)
  - Responsible for February 24, 2007 event

Event Propagation Example (August 11, 2006)



- **LEFT**: NEXRAD (radar) image from Midland TX (KMAF) for 1801 LT on 11 August 2006 - Red arrows show outflow from thunderstorm complex to the west
- **RIGHT**: Outflow boundary an hour later (1901 LT) now approaching cluster of wind plants south and northeast of KMAF
- Shortly after, ramp event of +600 MW was observed within a 30 minute period
- Lower arrows indicate boundary traversed about 100 km (62 miles) in an hour

Extreme Wind Events* in Existing Data (2006)**

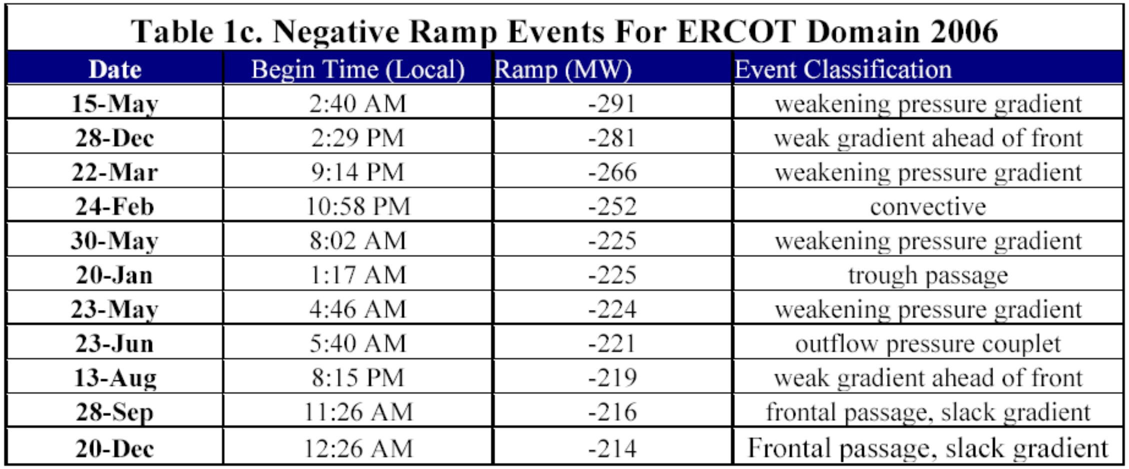


Table 1c. Negative Ramp Events For ERCOT Domain 2006

Date	Begin Time (Local)	Ramp (MW)	Event Classification
15-May	2:40 AM	-291	weakening pressure gradient
28-Dec	2:29 PM	-281	weak gradient ahead of front
22-Mar	9:14 PM	-266	weakening pressure gradient
24-Feb	10:58 PM	-252	convective
30-May	8:02 AM	-225	weakening pressure gradient
20-Jan	1:17 AM	-225	trough passage
23-May	4:46 AM	-224	weakening pressure gradient
23-Jun	5:40 AM	-221	outflow pressure couplet
13-Aug	8:15 PM	-219	weak gradient ahead of front
28-Sep	11:26 AM	-216	frontal passage, slack gradient
20-Dec	12:26 AM	-214	Frontal passage, slack gradient

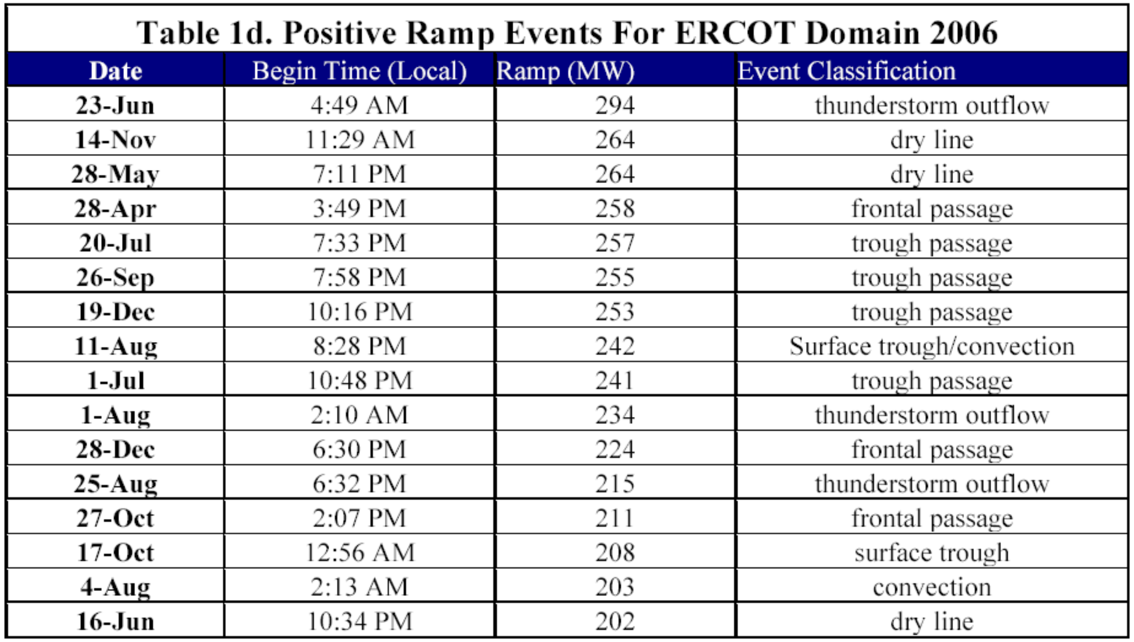


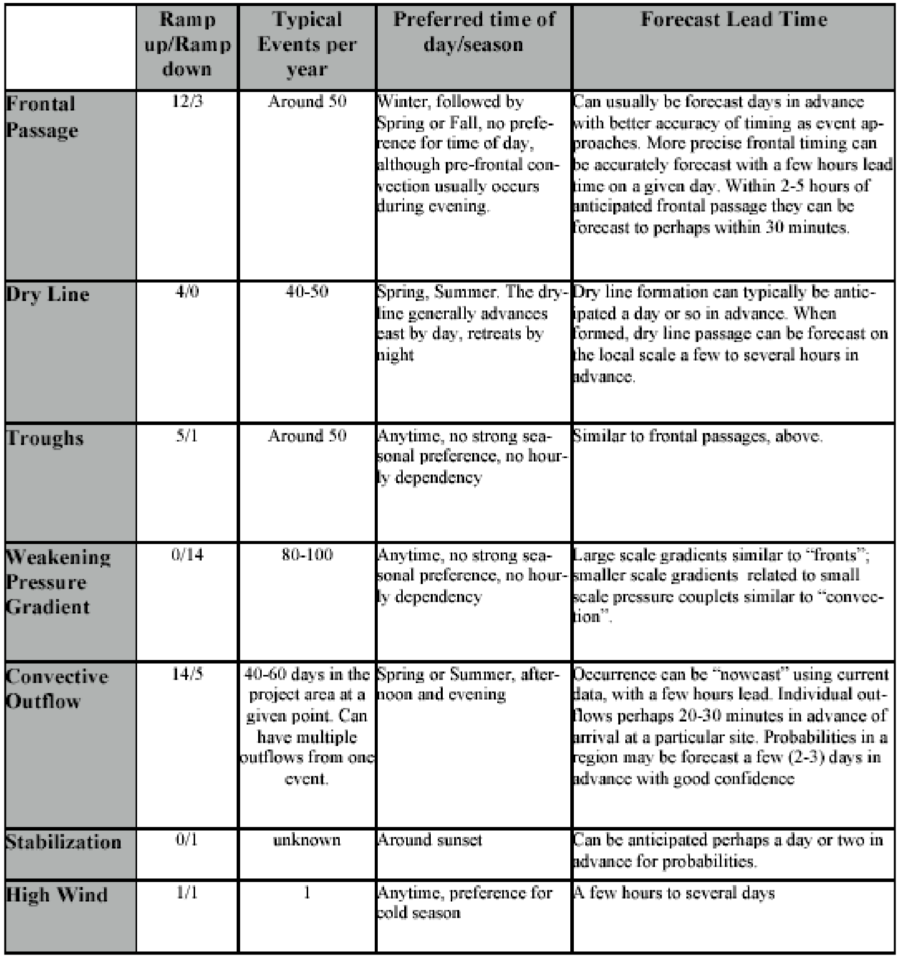
Table 1d. Positive Ramp Events For ERCOT Domain 2006

Date	Begin Time (Local)	Ramp (MW)	Event Classification
23-Jun	4:49 AM	294	thunderstorm outflow
14-Nov	11:29 AM	264	dry line
28-May	7:11 PM	264	dry line
28-Apr	3:49 PM	258	frontal passage
20-Jul	7:33 PM	257	trough passage
26-Sep	7:58 PM	255	trough passage
19-Dec	10:16 PM	253	trough passage
11-Aug	8:28 PM	242	Surface trough/convection
1-Jul	10:48 PM	241	trough passage
1-Aug	2:10 AM	234	thunderstorm outflow
28-Dec	6:30 PM	224	frontal passage
25-Aug	6:32 PM	215	thunderstorm outflow
27-Oct	2:07 PM	211	frontal passage
17-Oct	12:56 AM	208	surface trough
4-Aug	2:13 AM	203	convection
16-Jun	10:34 PM	202	dry line

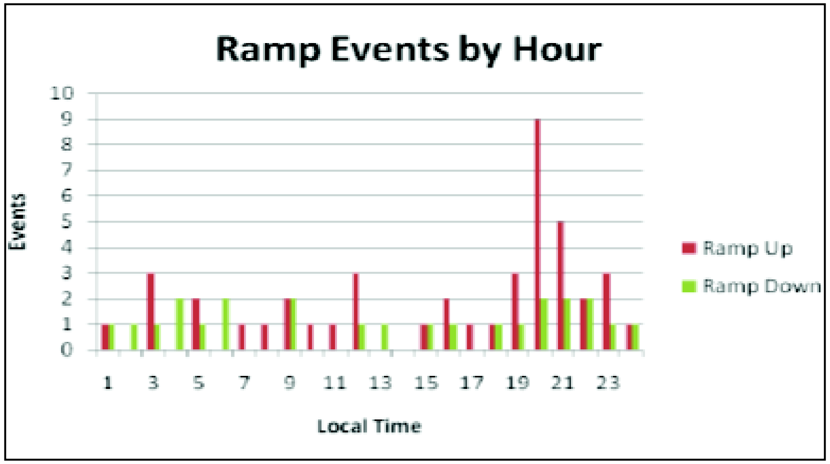
** 200 MW excursion within 30 minutes*

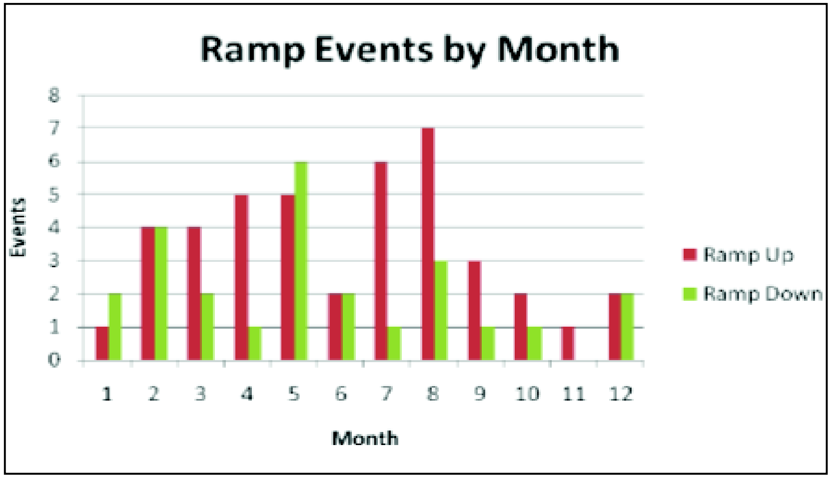
*** Based on approximately 976 MW of installed capacity*

Summary of Ramp Events for Existing Wind Data (2005/2006)



	Ramp up/Ramp down	Typical Events per year	Preferred time of day/season	Forecast Lead Time
Frontal Passage	12/3	Around 50	Winter, followed by Spring or Fall, no preference for time of day, although pre-frontal convection usually occurs during evening.	Can usually be forecast days in advance with better accuracy of timing as event approaches. More precise frontal timing can be accurately forecast with a few hours lead time on a given day. Within 2-5 hours of anticipated frontal passage they can be forecast to perhaps within 30 minutes.
Dry Line	4/0	40-50	Spring, Summer. The dry-line generally advances east by day, retreats by night	Dry line formation can typically be anticipated a day or so in advance. When formed, dry line passage can be forecast on the local scale a few to several hours in advance.
Troughs	5/1	Around 50	Anytime, no strong seasonal preference, no hourly dependency	Similar to frontal passages, above.
Weakening Pressure Gradient	0/14	80-100	Anytime, no strong seasonal preference, no hourly dependency	Large scale gradients similar to "fronts"; smaller scale gradients related to small scale pressure couplets similar to "convection".
Convective Outflow	14/5	40-60 days in the project area at a given point. Can have multiple outflows from one event.	Spring or Summer, afternoon and evening	Occurrence can be "nowcast" using current data, with a few hours lead. Individual outflows perhaps 20-30 minutes in advance of arrival at a particular site. Probabilities in a region may be forecast a few (2-3) days in advance with good confidence
Stabilization	0/1	unknown	Around sunset	Can be anticipated perhaps a day or two in advance for probabilities.
High Wind	1/1	1	Anytime, preference for cold season	A few hours to several days

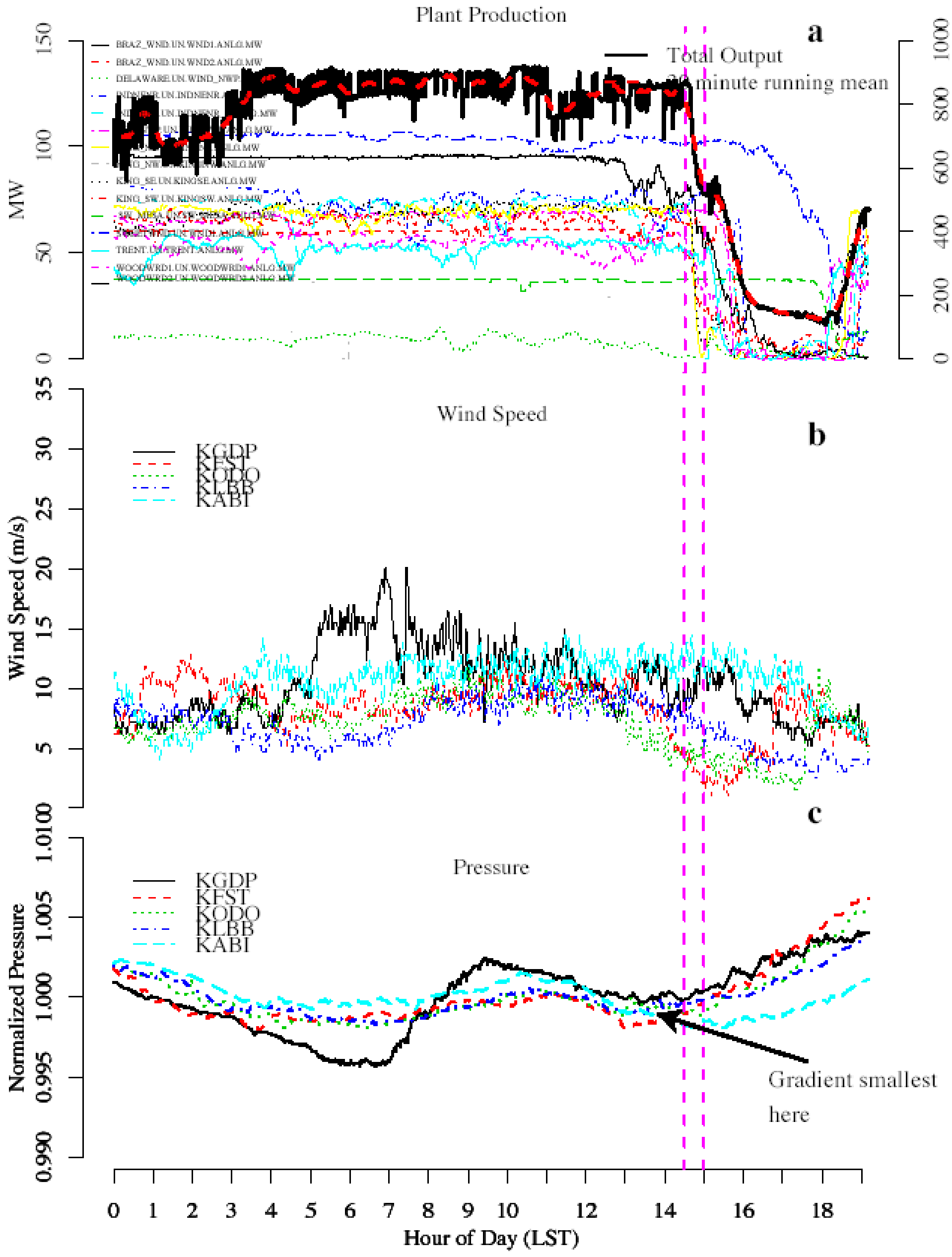




- 59 ramp events identified (60% up, 40% down)
- Largest ramp-up event on 9 July 2005
  - nearly 400 MW increase (over 300% from 200 MW)
- Largest ramp-down event on 12 May 2005
  - 331 MW decrease, (more than 58% from 571 MW)
- Primary causes: (1) convective (2) frontal passages (3) weakening pressure gradients

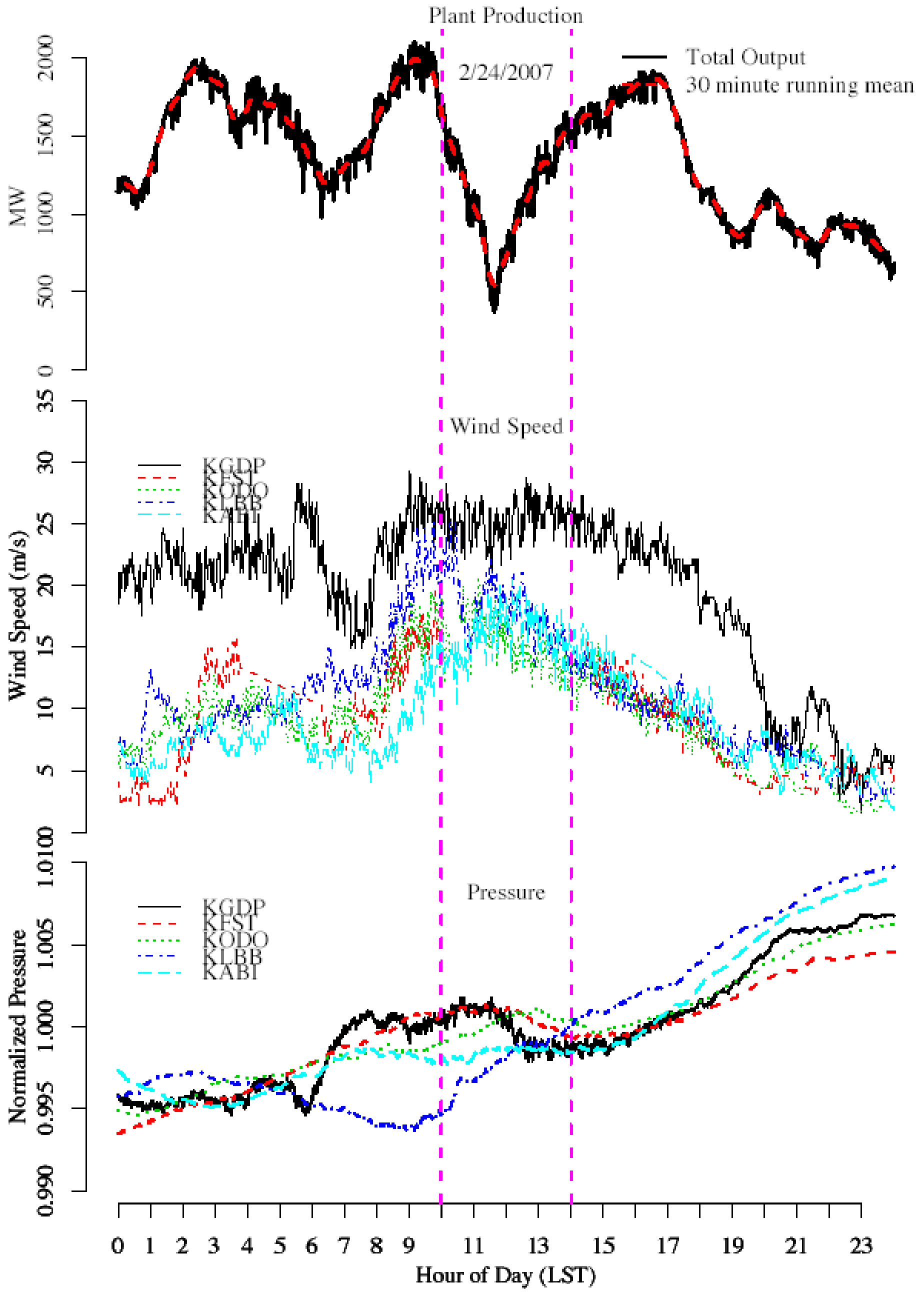
- Distinct diurnal increase in the frequency of ramp-up events during the evening hours, particularly around 5 PM local time, due to convection, especially strong to severe thunderstorms
- Seasonal increase in frequency of ramp-up events from late winter through summer, while ramp-down events show no clear pattern.

Ramp Event Case Study (December 28, 2006)



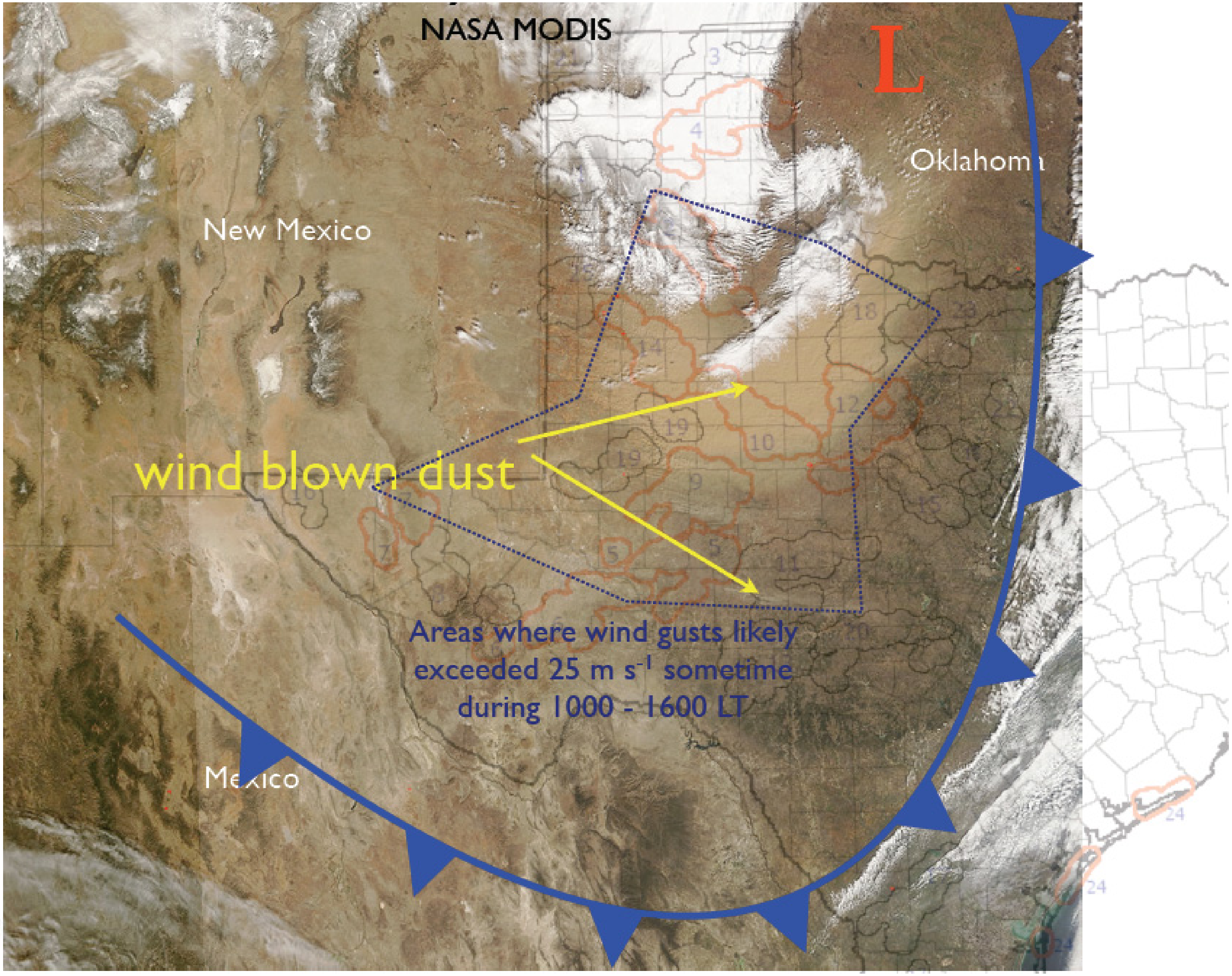
- **Weak gradient ahead of cold front**
  - An area of weak pressure gradient moves eastward across west-central Texas between 14:00 and 15:00 LST
  - Since wind speed is proportional to the pressure gradient, there is a significant reduction in wind power output and wind speed as this feature passes
  - The drop in wind speed is most notable at Fort Stockton (KFST), Lubbock (KLBB) and Odessa (KODO)
  - There is a secondary drop in power output around 16:00 LST as winds continue to diminish (to below the cut-in value of 4 m/s at the stations)
- **Frontal passage**
  - Following the weak pressure field, a stronger gradient moves into the area after the frontal passage (approximately 15:00 – 16:00 LST)
  - Wind speeds and output increase rapidly by 18:00
  - Plant output, which had decreased to about 100 MW (or 10% of the rated capacity), then rapidly rose as wind speeds rose above the cut-in value.

Ramp Event Case Study (February 24, 2007)



- Strong upper-level storm system passed over northern New Mexico and the panhandle of Texas substantially tightening the pressure gradients over west Texas, resulting in strong to severe winds along a straight line across much of the area
  - 8 AM - high wind speeds seen by most wind projects, maximum wind gust reported was 94 mph
  - 9 AM - aggregate output increased from just over 1100 MW to nearly 2000 MW (rated capacity)
  - 10 AM - sustained winds exceeded 25 m/s (55 mph) output at most wind farms, output declined as turbine-cutoff threshold reached
  - 11 AM - most intense pressure gradients and winds moved eastward, wind speeds relaxed, turbines resumed power production, resulting in a gradual increase in total output to pre-event levels
- Total drop in plant output was more than 1500 MW over a 90 minute period
- Most rapid declines occurred at the Horse Hollow interconnections
- Largest 30-minute drop of 450 MW (between 1104 and 1134 LST) represents about 22.5% of the plant rated capacity
- The event was unusual both in the magnitude of the 90-minute drop and the large geographic area affected
- **Arrival of such fronts is generally forecastable, several hours ahead within a 30-minute window**

February 24, 2007, 1400 Local Standard Time



Probability and Predictability of Ramp Events

- Frontal passages/troughs/dry lines of any severity occur every 3-5 days during cold season, and every 5-7 days during warm season
  - Fast ramp-up events (*as defined for 2005/2006 existing data*) likely to occur 20 times/year or every 2-3 weeks
  - Fast down-ramps likely to occur once every 2 months
- Convective events occur with varying frequency
  - Number of severe thunderstorms (winds over 29 m/s) in ERCOT territory over last 10 years varies from 32 in 2000 to 134 in 2003
- All weather phenomena causing ramp events can be forecasted
  - Lead time and accuracy varies considerably
  - Frontal passages (winter) can be forecasted several days in advance with limited accuracy and timing, but to within a 30-minute window several hours in advance
  - Severe thunderstorms (summer) more difficult to forecast, better for active periods – average lead time in West Texas is 20 minutes, 70-85% accuracy, but only 30-40% dependability

Analysis of 15,000 MW Wind Scenario

Weather Event	CREZs Affected	Aggregate Rated Capacity (MW)	Maximum 30-Minute Ramp (MW)	Frequency (# times approaching max ramp per year)
Convective	5, 9	3251	+1300	2 - 4
Frontal/dry line/trough	5, 6, 9	4529	+1324	2 - 4
Weak gradient	5, 6, 9	4529	-1313	2 - 4
Pressure Gradient Strengthening	2, 4, 5, 6, 7, 9, 10, 12, 14	12,329	-2836	< 1

- Additionally, since CREZ 10 has by far the largest wind capacity (4607 MW), a system affecting this entire zone could conceivably result in a 30-minute excursion of more than 1100 MW
- An event of the magnitude and coverage of 24 February 2007 could produce over a 20% reduction in power over most of the CREZs (see row 4 in table) once every 3 - 5 years.

15-Minute Wind State Transition Probabilities (15,000 MW*)

Probability that wind output will change from one level to another within 15 minutes

	Next State (Output, % rated capacity)									
Current State (Output)	**0-10%**	**11-20%**	**21-30%**	**31-40%**	**41-50%**	**51-60%**	**61-70%**	**71-80%**	**81-90%**	**91-100%**
0-10%	0.8386	0.1614	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-20%	0.0225	0.8602	0.1173	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21-30%	0.0000	0.0486	0.8445	0.1069	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
31-40%	0.0000	0.0000	0.0598	0.8232	0.1170	0.0000	0.0000	0.0000	0.0000	0.0000
41-50%	0.0000	0.0000	0.0000	0.0655	0.8176	0.1169	0.0000	0.0000	0.0000	0.0000
51-60%	0.0000	0.0000	0.0000	0.0000	0.0667	0.8079	0.1253	0.0000	0.0000	0.0000
61-70%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0641	0.8495	0.0864	0.0000	0.0000
71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0514	0.8701	0.0785	0.0000
81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0516	0.9134	0.0350
91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0791	0.9209

- Diagonal probabilities show that *on average* there is a **85%** chance that wind output will persist – change by no more that 10% of rated capacity in fifteen minutes
  - Average probability of <7% that wind output will drop by more than 10% of rated in 15 minutes
- Negligible chance that wind will change by more than 20% of rated in 15 minutes

imagination at work

*From AWST wind production data

30-Minute Wind State Transition Probabilities (15,000 MW*)

Probability that wind output will change from one level to another within 30 minutes

Next State (Output, % rated capacity)

Current State (Output)

	0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
0-10%	0.8139	0.1861	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-20%	0.0199	0.8094	0.1707	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
21-30%	0.0000	0.0595	0.7698	0.1699	0.0008	0.0000	0.0000	0.0000	0.0000	0.0000
31-40%	0.0000	0.0000	0.0820	0.7324	0.1835	0.0021	0.0000	0.0000	0.0000	0.0000
41-50%	0.0000	0.0000	0.0000	0.0916	0.7247	0.1832	0.0005	0.0000	0.0000	0.0000
51-60%	0.0000	0.0000	0.0000	0.0000	0.0939	0.7209	0.1847	0.0005	0.0000	0.0000
61-70%	0.0000	0.0000	0.0000	0.0000	0.0011	0.0879	0.7840	0.1270	0.0000	0.0000
71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013	0.0583	0.8362	0.1042	0.0000
81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0477	0.9019	0.0503
91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0658	0.9342

- Diagonal probabilities show that *on average* there is a **80%** chance that wind output will persist – change by no more that 10% of rated capacity in 30 minutes
  - Average probability of <10% that wind output will drop by more than 10% of rated in 30 minutes
- Minute chance that wind will change by more than 20% of rated in 30 minutes
- Persistence is greater at high and low output levels

imagination at work

*From AWST wind production data

1-Hour Wind State Transition Probabilities (15,000 MW*)

Probability that wind output will change from one level to another within 60 minutes

Next State (Output, % rated capacity)

Current State (Output)

	0-10%	11-20%	21-30%	31-40%	41-50%	51-60%	61-70%	71-80%	81-90%	91-100%
0-10%	0.7244	0.2742	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
11-20%	0.0590	0.6881	0.2419	0.0103	0.0007	0.0000	0.0000	0.0000	0.0000	0.0000
21-30%	0.0000	0.1398	0.6106	0.2250	0.0246	0.0000	0.0000	0.0000	0.0000	0.0000
31-40%	0.0000	0.0043	0.1845	0.5527	0.2355	0.0221	0.0009	0.0000	0.0000	0.0000
41-50%	0.0000	0.0000	0.0066	0.1915	0.5315	0.2357	0.0347	0.0000	0.0000	0.0000
51-60%	0.0000	0.0000	0.0000	0.0161	0.1847	0.5432	0.2390	0.0171	0.0000	0.0000
61-70%	0.0000	0.0000	0.0000	0.0000	0.0149	0.1943	0.5934	0.1890	0.0085	0.0000
71-80%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0039	0.1399	0.7242	0.1320	0.0000
81-90%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0077	0.1231	0.8077	0.0615
91-100%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0286	0.1429	0.8286

- Diagonal probabilities show that *on average* there is a **66%** chance that wind output will persist – change by no more that 10% of rated capacity in 60 minutes
    - Average probability of <18% that wind will change by more than 10% of rated in 60 minutes
- Small chance that wind will change by more than 20% of rated in 60 minutes
- Persistence is significantly greater at high and low output levels

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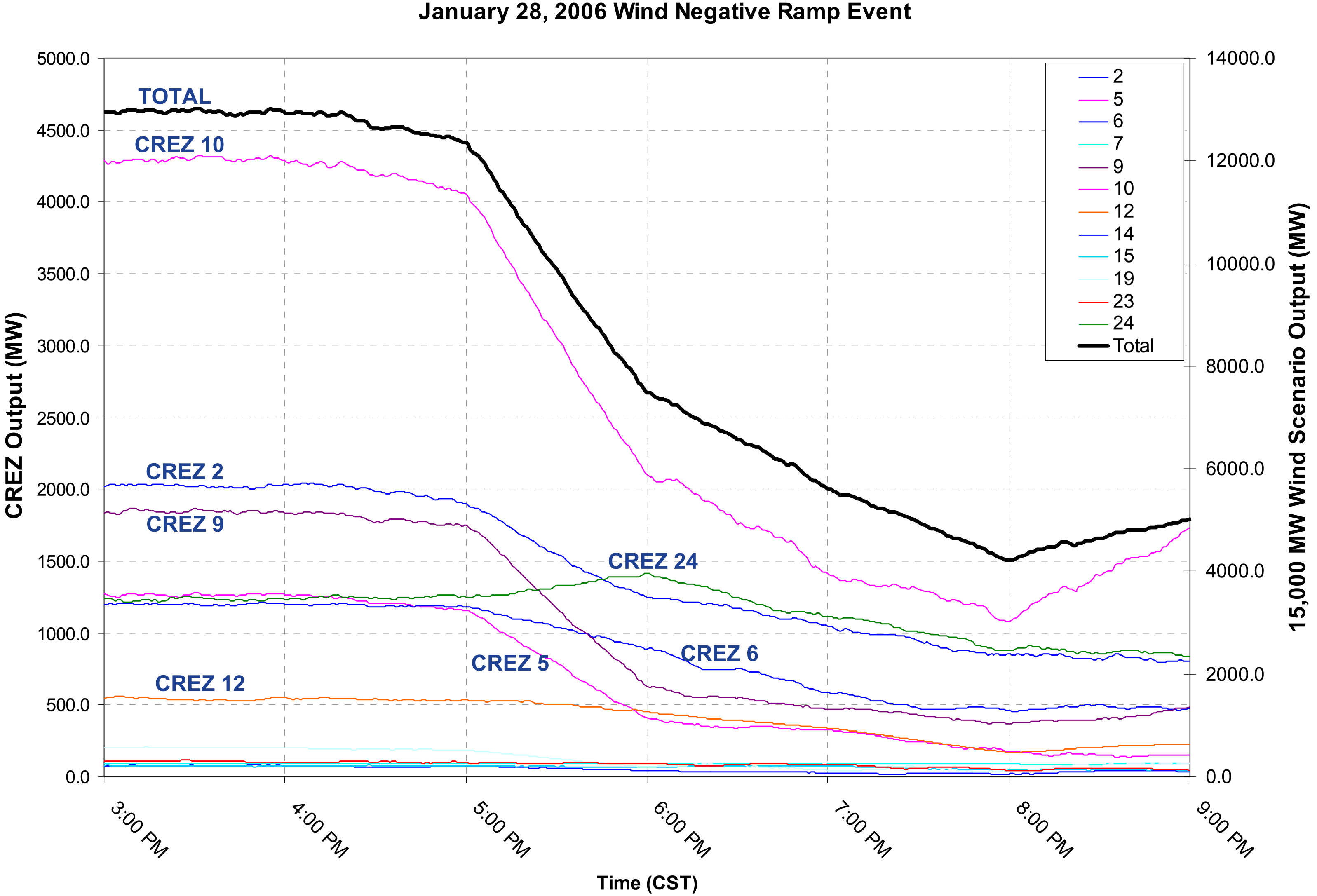
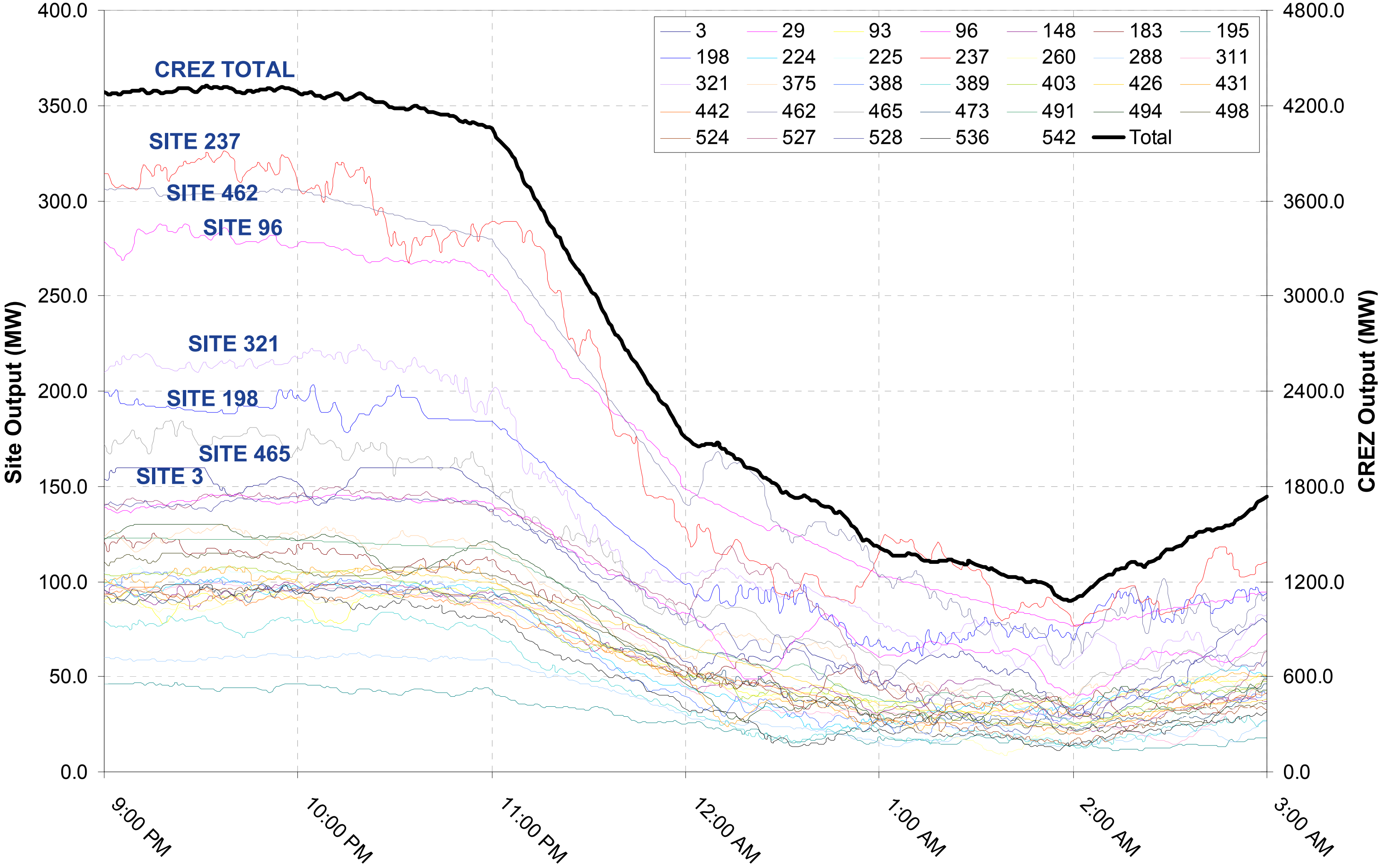
*From AWST wind production data

Largest One-Hour Wind Drop in 15,000 MW Wind (Jan 28 ’06)



Wind drops by 3340 MW in one hour, driven largely by an almost 2000 MW one-hour drop in CREZ 10

Largest One-Hour Wind Drop in CREZ 10 Wind (Jan 28 '06)

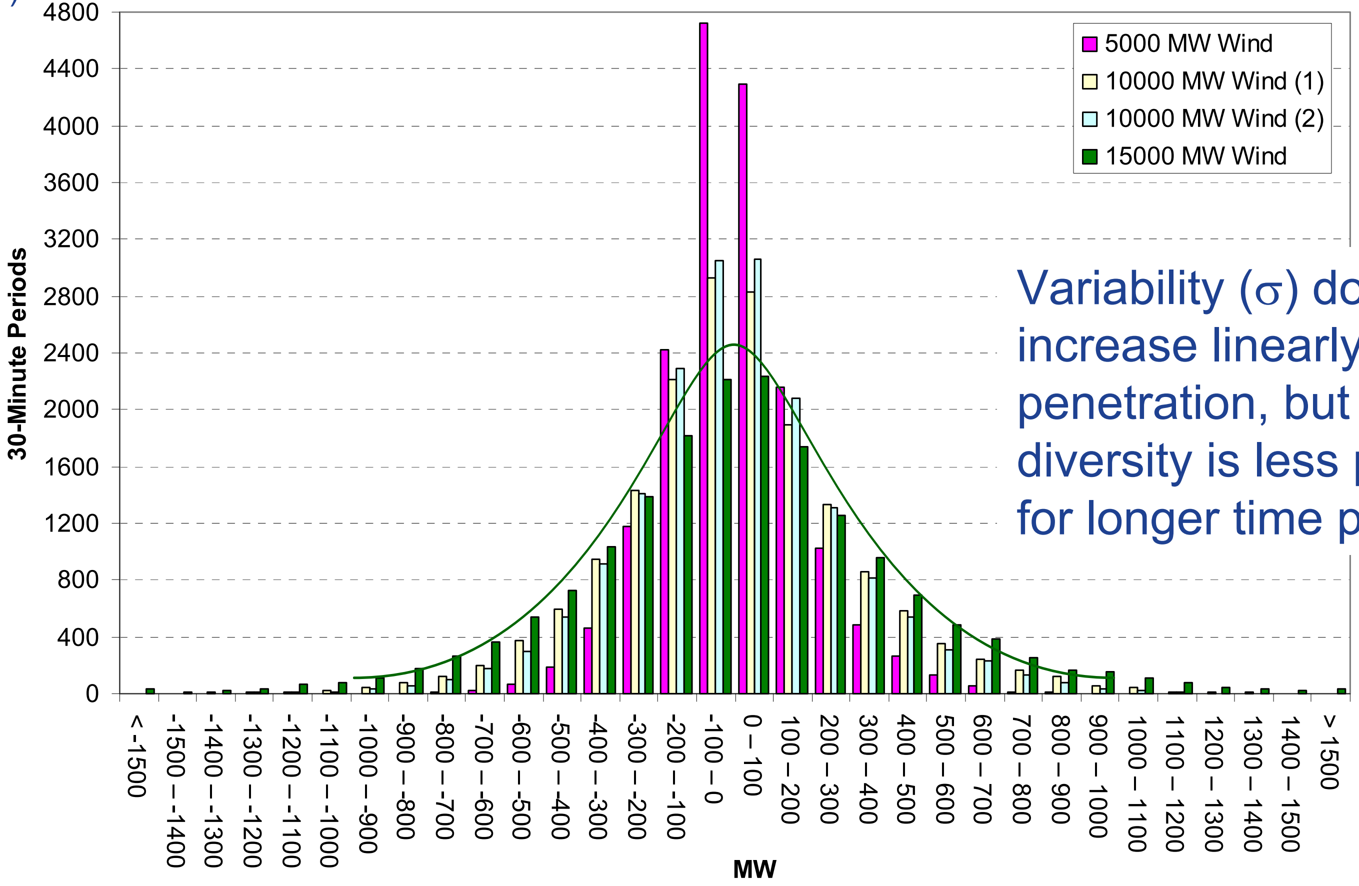


January 28 Event in CREZ 10

Most sites in CREZ 10 are similarly impacted by the event

Distribution of Thirty-Minute Wind Output Changes (Deltas)

(Study Year)



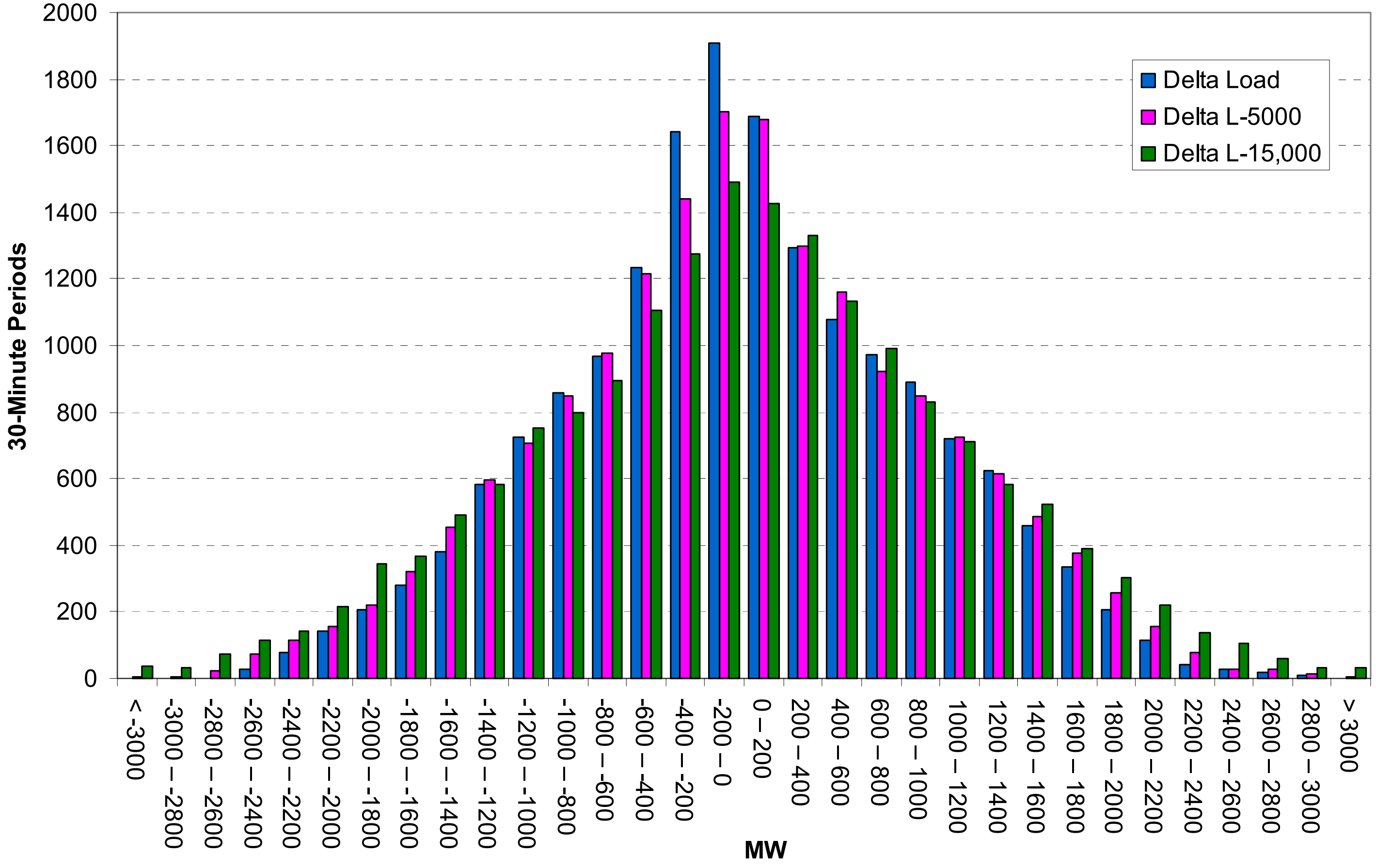
Variability (σ) does not increase linearly with wind penetration, but Impact of diversity is less pronounced for longer time periods

	5000 MW	10000 MW (1)	10000 MW (2)	15000 MW
Mean (-/+)	-128 / 138	-224 / 237	-208 / 215	-304 / 313
Sigma	**183**	**314**	**288**	**420**
> $\mu \pm 2.5\sigma$ (–/+)	171 / 318	197 / 270	189 / 258	203 / 262
> $\mu \pm 3.0\sigma$ (–/+)	75 / 128	78 / 117	81 / 103	83 / 98

130% increase in σ for 200% increase in wind

Distribution of Thirty-Minute Net Load Changes (Deltas)

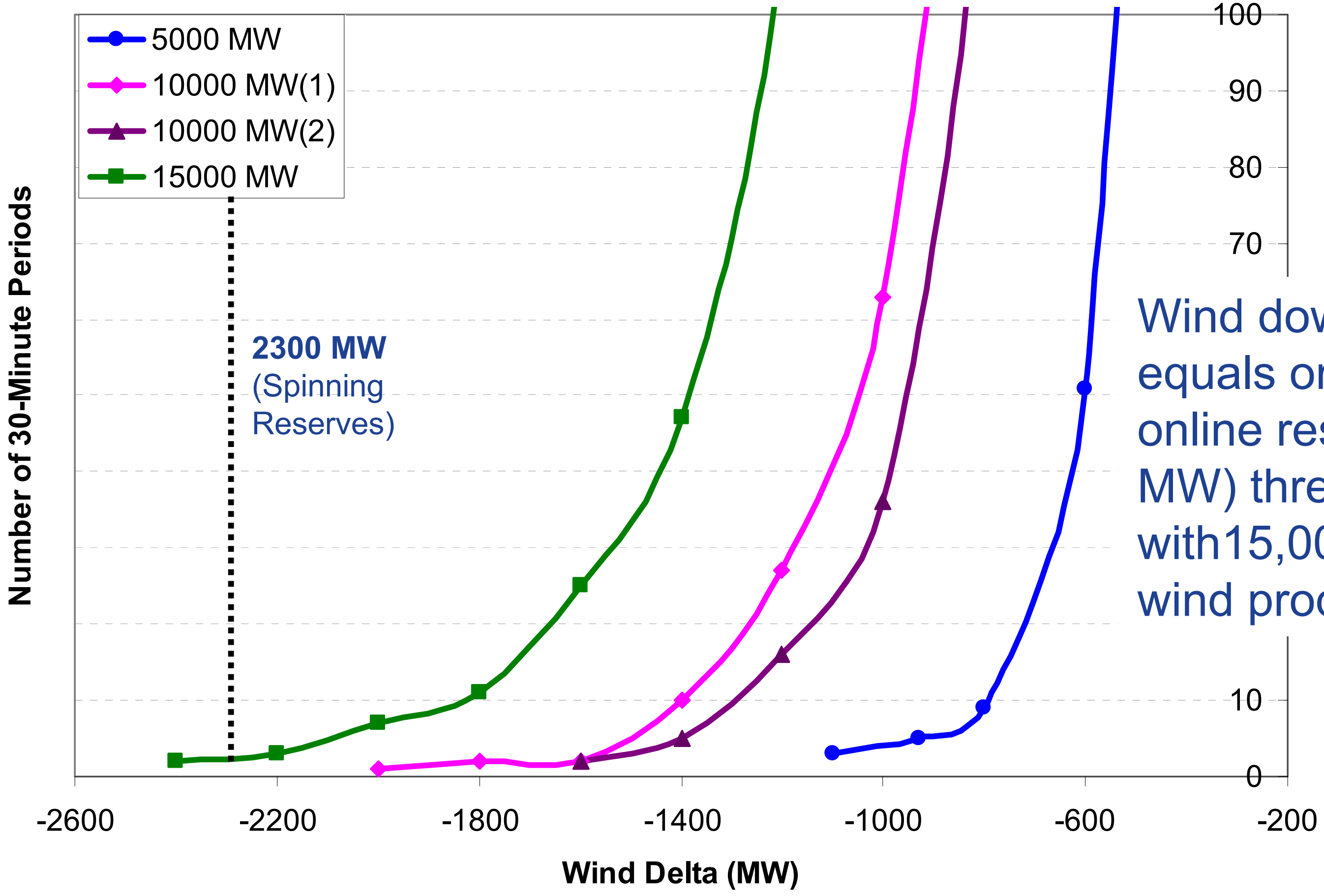
(Study Year)



	Load-alone	L-5000 MW	L-10000 MW (1)	L-10000 MW (2)	L-15000 MW
Mean (-/+)	-695 / 741	-755 / 771	-816 / 811	-797 / 801	-857 / 850
Sigma (σ)	**911**	**967**	**1031**	**1013**	**1083**
> $\mu \pm 2.5\sigma$ (–/+)	71 / 80	96 / 76	86 / 75	104 / 79	102 / 88
> $\mu \pm 3.0\sigma$ (–/+)	1 / 19	5 / 13	12 / 9	9 / 10	10 / 13

Extreme Thirty-Minute Wind Drops (Down-Ramps)

(Study Year)

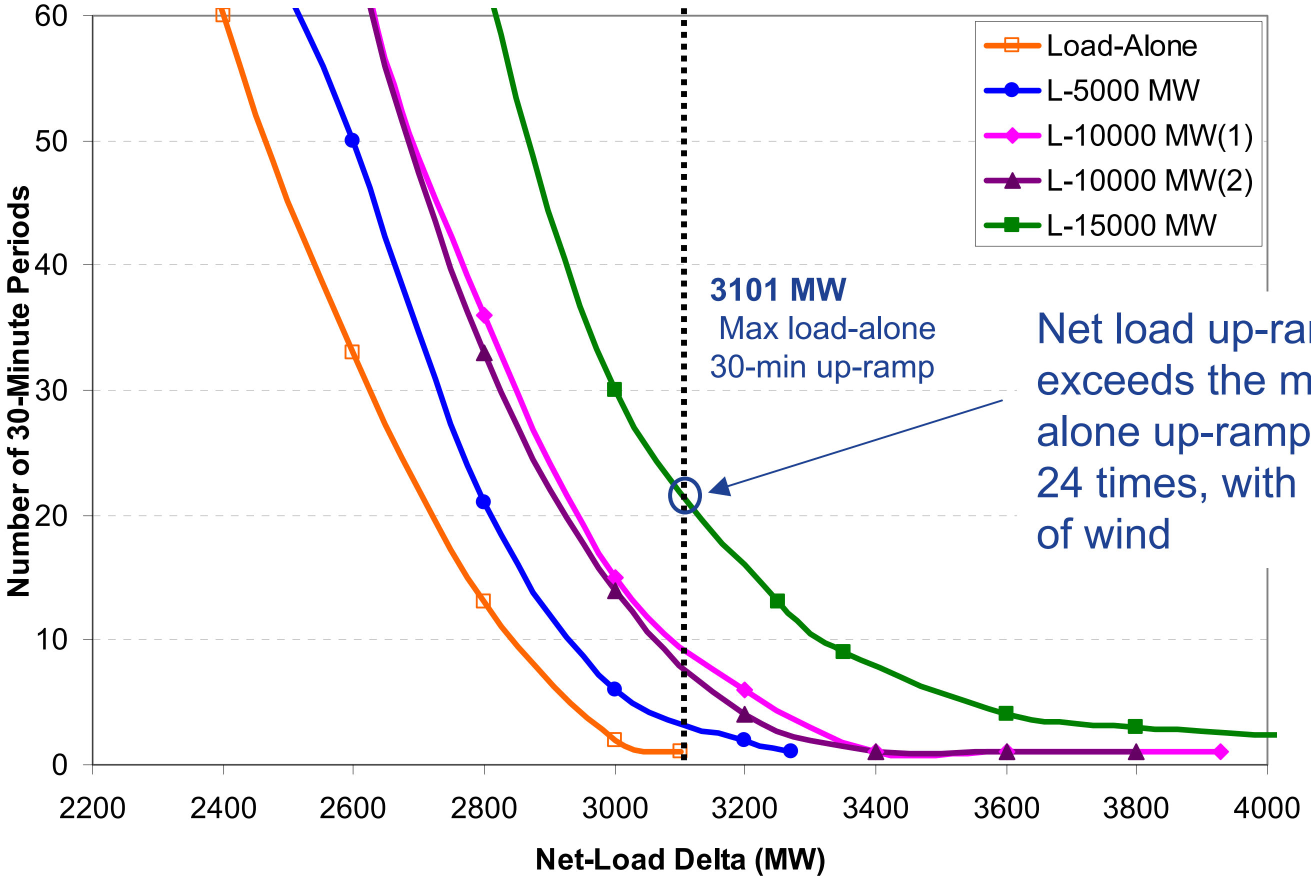


Wind down-ramp equals or exceeds online reserves (2300 MW) three times with15,000 MW of wind production

	5000 MW Wind	10,000 MW Wind (1)	10,000 MW Wind (2)	15,000 MW Wind
Max Pos Delta	1079	1611	1629	2370
Max Neg Delta	**-1167**	**-2053**	**-1771**	**-2563**
No. Drops > 1000 MW	5	63	36	249
No. Drops > 2300 MW	**0**	**0**	**0**	**3**

Extreme Thirty-Minute Net-Load Rises (Up-Ramps)

(Study Year)

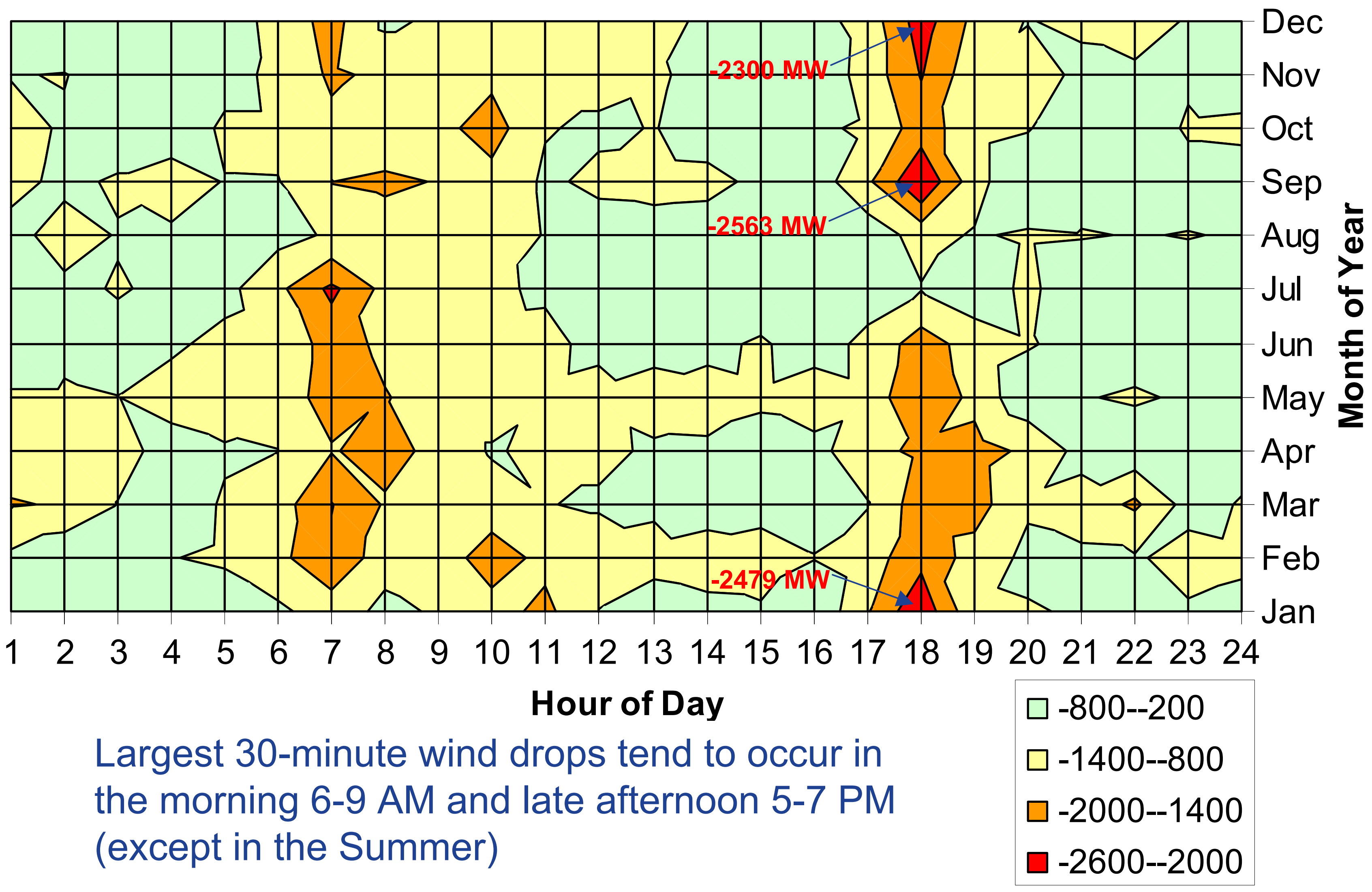


Net load up-ramp equals or exceeds the max load-alone up-ramp (3101 MW) 24 times, with 15,000 MW of wind

	Load-alone	L-5000 MW Wind (1)	L-10,000 MW Wind (1)	L-10,000 MW Wind (2)	L-15,000 MW Wind
Max Pos Delta	**3101**	**3271**	**3928**	**3805**	**4502**
Max Neg Delta	-2756	-3138	-3360	-3300	-3612
No. Rises > 1000 MW	2557	2769	2986	2916	3092
No. Rises > 2300 MW	**78**	**114**	**191**	**168**	**289**

Timing of Extreme Thirty-Minute Wind Drops

(Study Year)



Largest 30-minute wind drops tend to occur in the morning 6-9 AM and late afternoon 5-7 PM (except in the Summer)

Corresponds with REG observations

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Conclusions – Extreme Weather Conditions

- Large sudden wind excursions (greater than 20% of rated capacity within 30 minutes) are infrequent
  - Changes occur as fast ramps, not steps
- When sudden changes do occur, CREZ diversity significantly reduces the impact of any single change on the aggregate output
- Weather events causing widespread impact are reasonably predictable
- Local convective events are less predictable
  - Tend to have a limited geographic extent
  - Large wind concentrations increase vulnerability

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Conclusions - Impact on Spinning Reserves

- Maximum 15 minute wind drop for 15,000 MW scenario is 1337 MW; well within present 2300 MW RRS
- Across the year, three observed cases when wind drops by over 2300 MW in 30 minutes
  - Late afternoon September 21, January 28, December 30
  - Some severe drops will inherently fall in periods of “uncertain weather” where reserves are already boosted
- Load-alone has extreme up-ramps, but wind creates incremental requirements in net load, mostly in mornings and late winter afternoons
- Alternative approaches:
  - Increase RRS for periods of forecast “meteorological risk”
  - Revise the NSRS definition to provide for a 15-minute response service; procure this service at periods of designated risk

Regulation Requirements

In this next set of slides, we will show:

- How regulation in the ERCOT nodal market is calculated in this study
- Regulation required (deployed)

Key issues are:

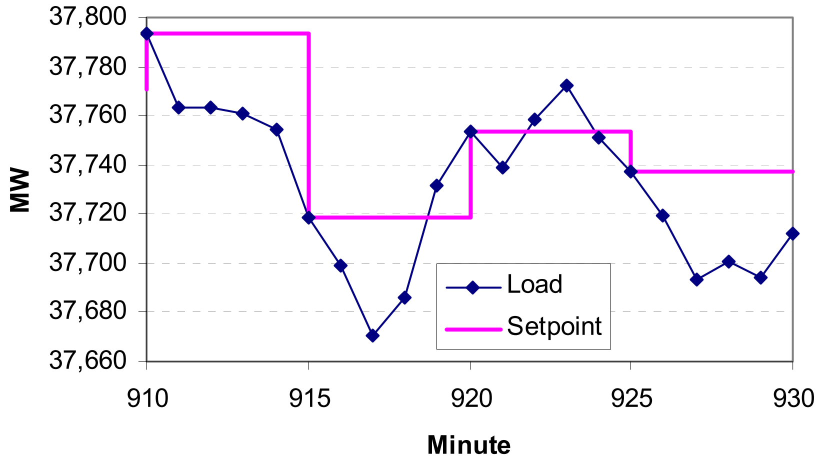
- Differences with regulation requirements in the present zonal market
- Changes in regulation requirements with increased wind penetration

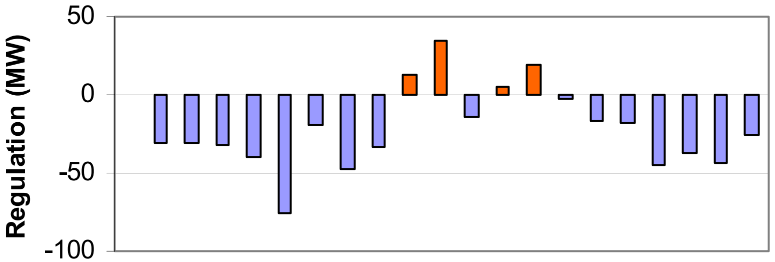
Dispatch Procedure in the ERCOT Nodal Market

- Economic dispatch is on a 5-minute basis;
- ERCOT is considering predictive tuning factors to reduce regulation requirements driven by load following
  - Dispatch setpoint is initial actual load + *k* times expected change over 5-minute period
  - Tuning factors have not yet been resolved
- Scope of this study focuses on wind, not operating practices independent of wind
  - Regulation results are intended for relative comparison between wind scenarios
  - Comparison with present regulation requirements are not appropriate
- Assuming k = 0 maximizes impact of ramp rate; most conservative with respect to wind impact

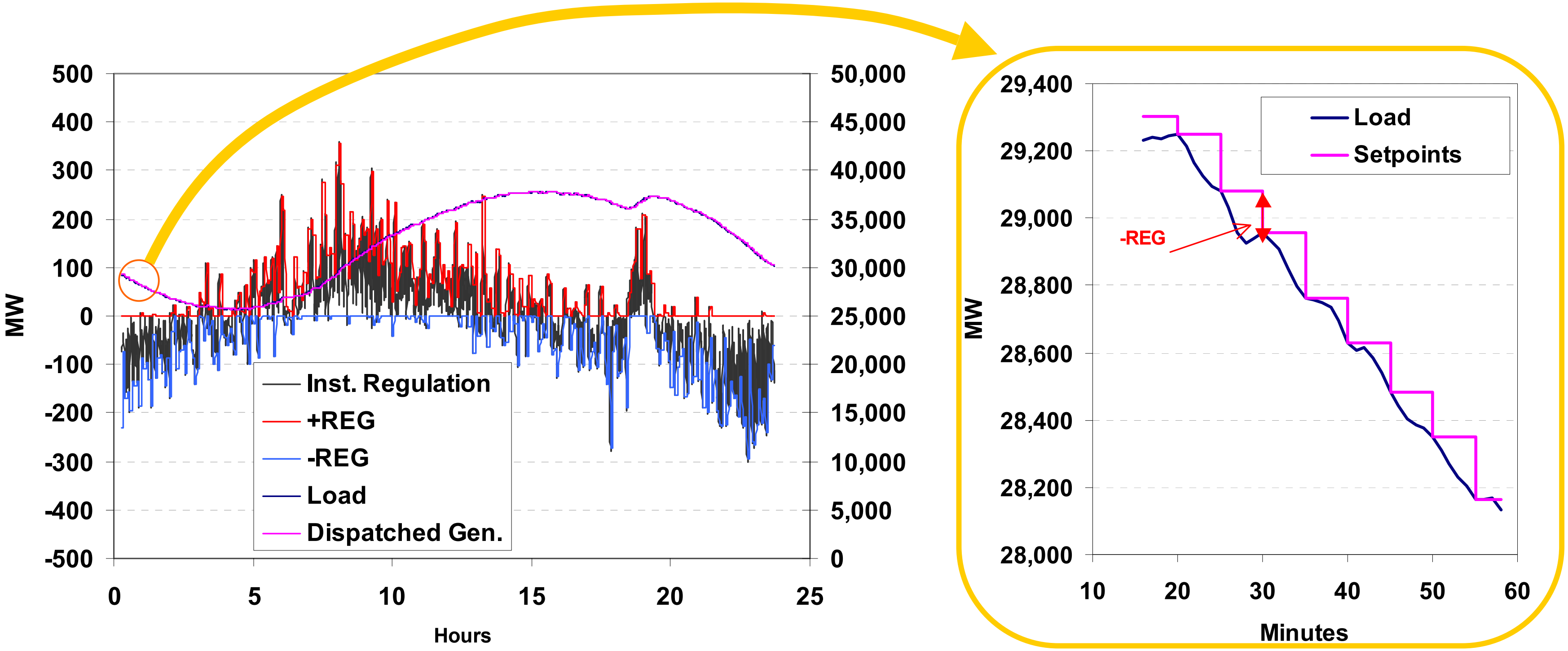
Regulation Calculation in the Nodal Market

- Units on economic dispatch “step” to setpoints at discrete 5-minute points
- Difference between actual load and economic setpoints is defined as regulation
  - Positive deviations defined as “Up Reg” (+REG)
  - Negative deviations defined as “Down Reg” (-REG)





Regulation Through a Typical Day (without wind)



- Regulation is biased by load ramp rate – not just the "random jitter" component
  - Virtually no Down Reg during load rise
  - Virtually no Up Reg during load drop

imagination at work

Terminology and Abbreviations

The following terminology and abbreviations regarding regulation are used in this presentation:

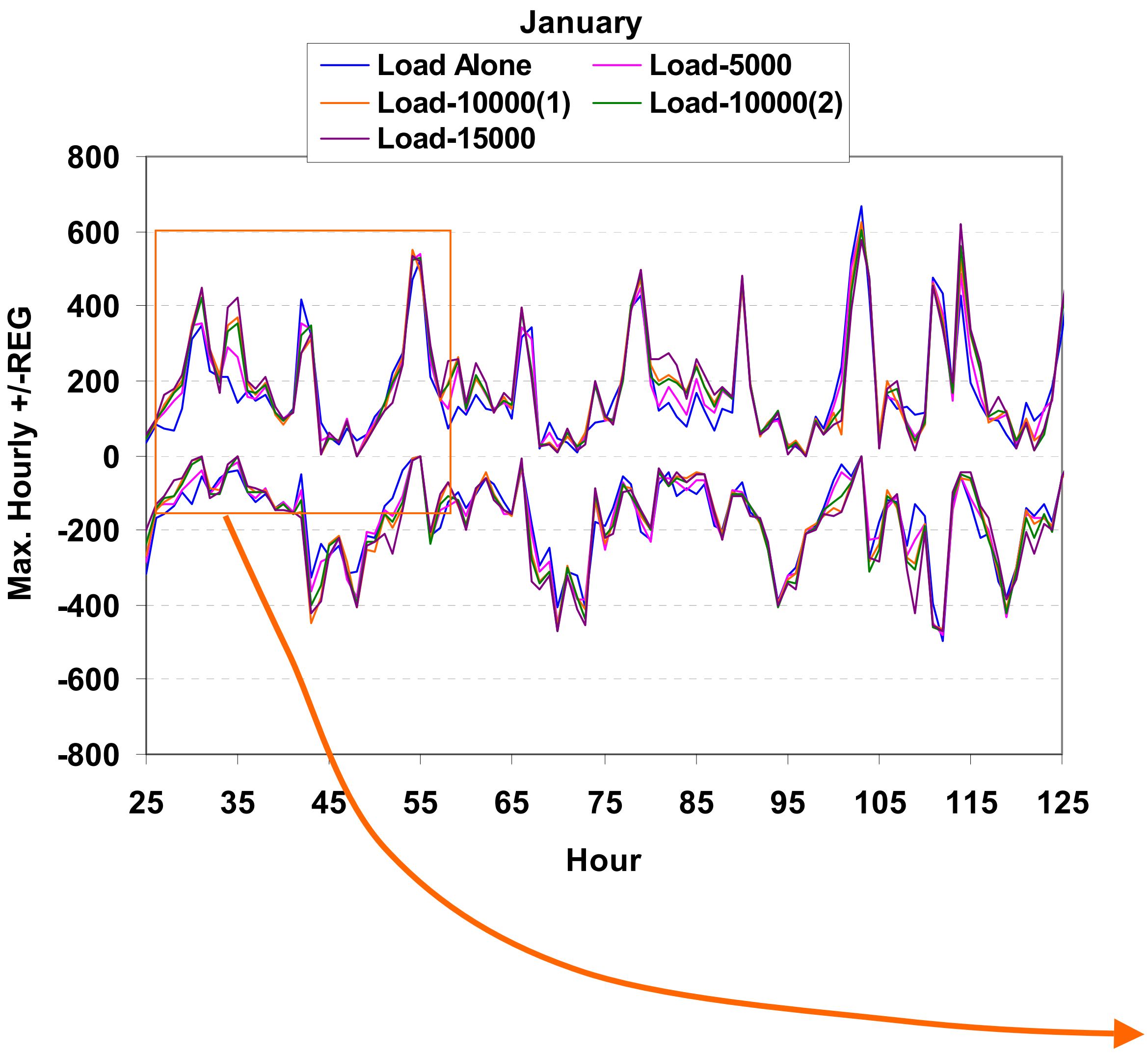
Deployed Regulation – Maximum difference over each 5-minute period between the net load and the dispatch base point (actual net load at the beginning of period)

Procured Regulation – Amount of regulation “reserved” based on statistical analysis of prior deployments

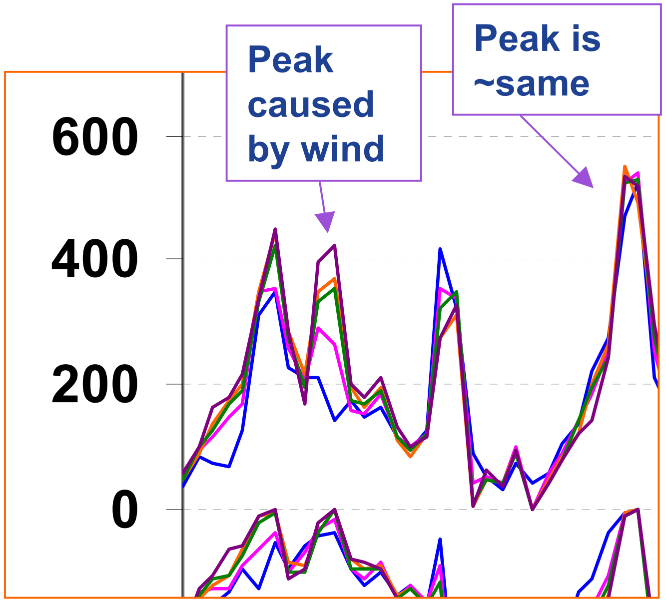
+REG – Up Regulation – Positive difference between net load and base point.

-REG – Down Regulation - Difference between net load and base point (expressed in this presentation as a negative number)

Max. Hourly Deployed Regulation – January Example



- ~4 days plotted
- Diurnal pattern in REG are visible
- Significant impact of outliers
  - A few driven by wind
  - Most outliers changed incrementally
  - Some not changed at all



Peak caused by wind

Peak is ~same

Deployed Regulation Statistics

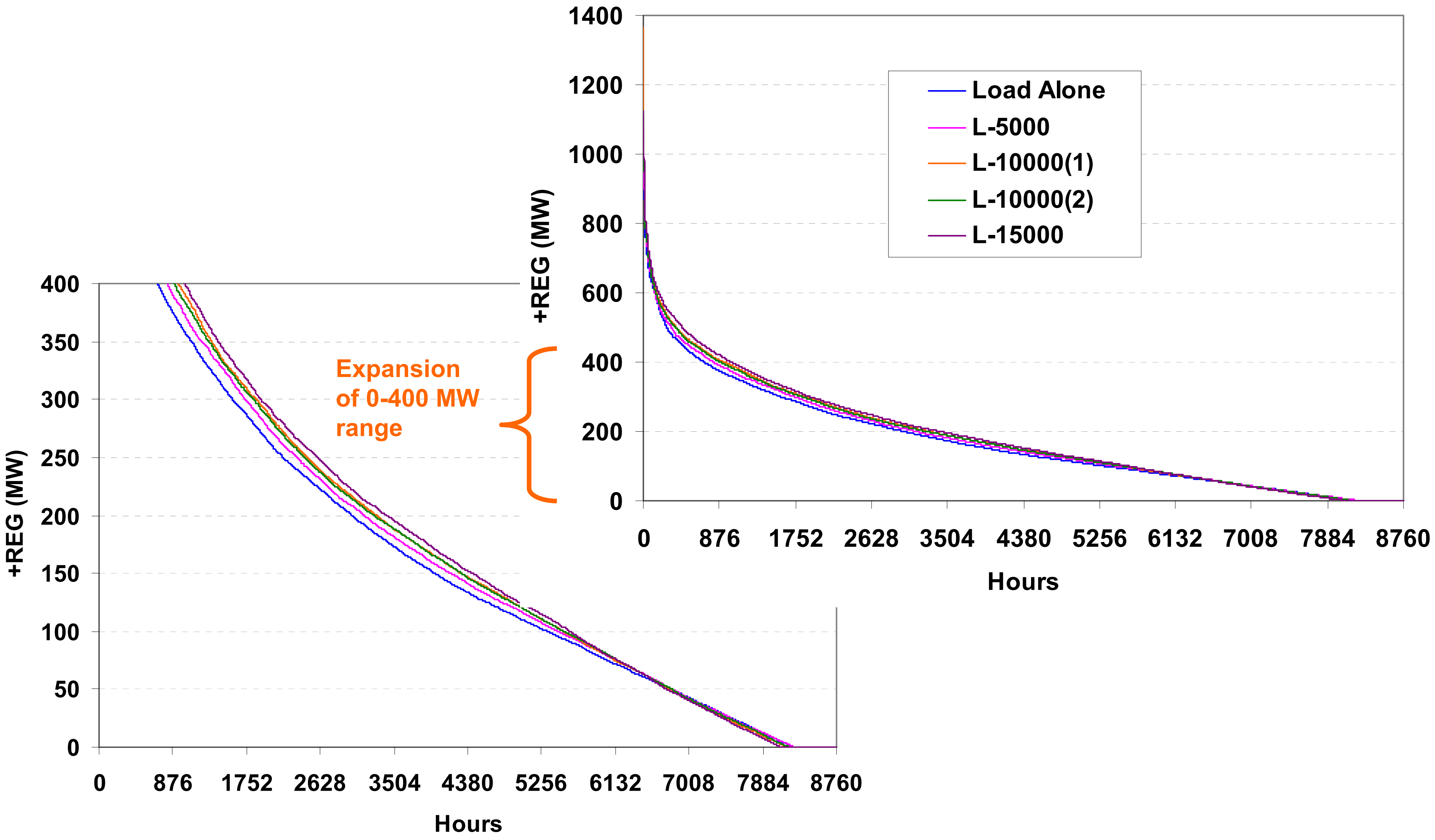
Up-Regulation

Wind (MW)	Average Max of 5-min Periods	% Change	98th Percentile of 5-min Periods	% Change	Maximum	% Change
0	73.8 MW		232.1 MW		1072.5 MW	
5,000	78.1 MW	5.8%	247.0 MW	6.4%	1075.9 MW	0.3%
10,000 (1)	82.5 MW	11.7%	265.2 MW	14.2%	1105.6 MW	3.1%
10,000 (2)	81.4 MW	10.2%	261.5 MW	12.7%	1112.7 MW	3.7%
15,000	86.1 MW	16.5%	285.8 MW	23.1%	1124.9 MW	4.9%

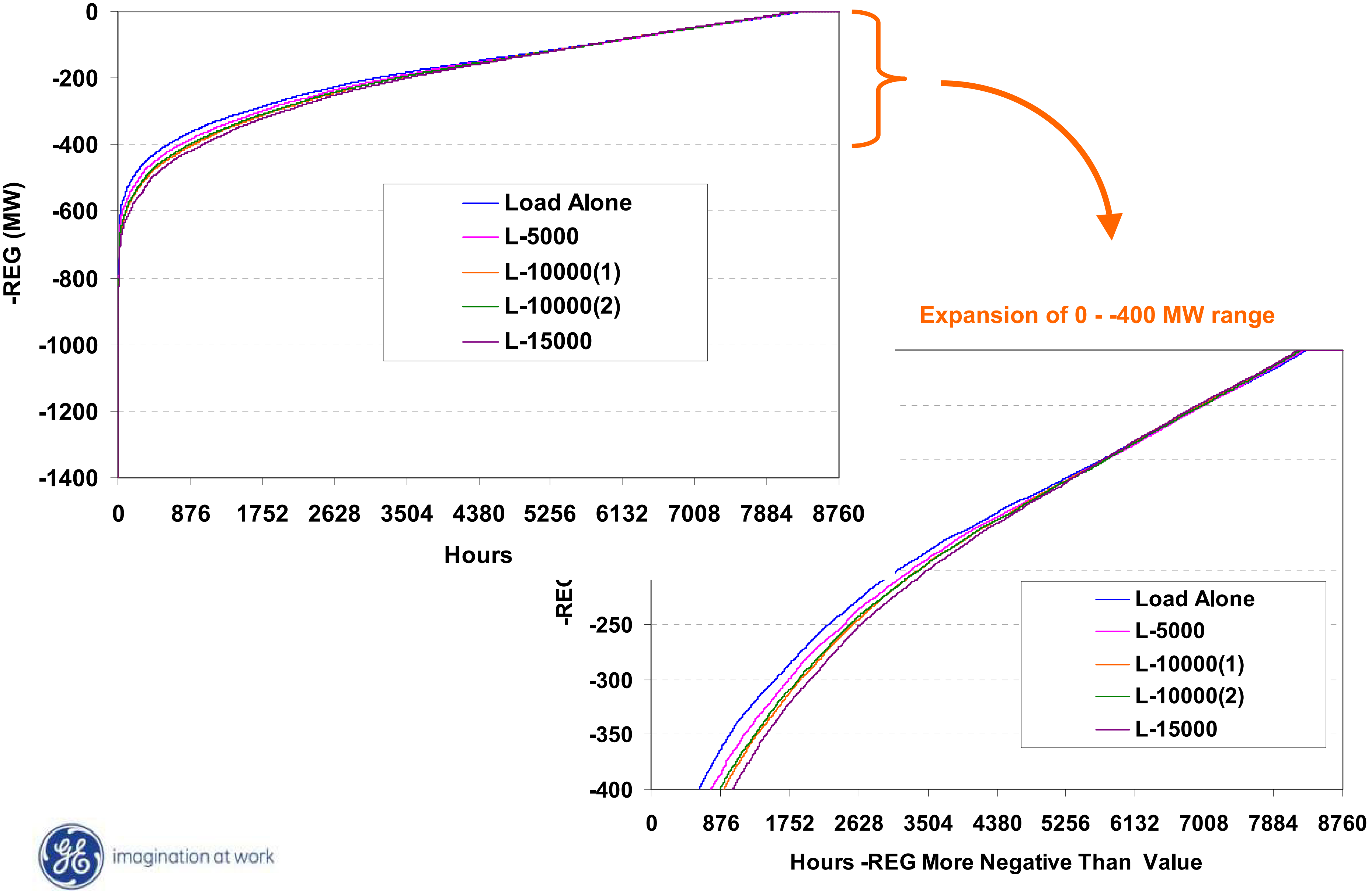
Down-Regulation

Wind (MW)	Average Min of 5-min Periods	% Change	98th Percentile of 5-min Periods	% Change	Minimum	% Change
0	-74.3 MW		-233.0 MW		-522.2	
5,000	-78.6 MW	5.8%	-246.7 MW	5.9%	-538.9	3.2%
10,000 (1)	-83.0 MW	11.7%	-262.7 MW	12.8%	-554.9	6.3%
10,000 (2)	-81.5 MW	9.7%	-260.4 MW	11.8%	-565.9	8.4%
15,000	-86.6 MW	16.5%	-281.2 MW	20.7%	-566.4	8.5%

Cumulative Distributions of Maximum Hourly Up-Regulation

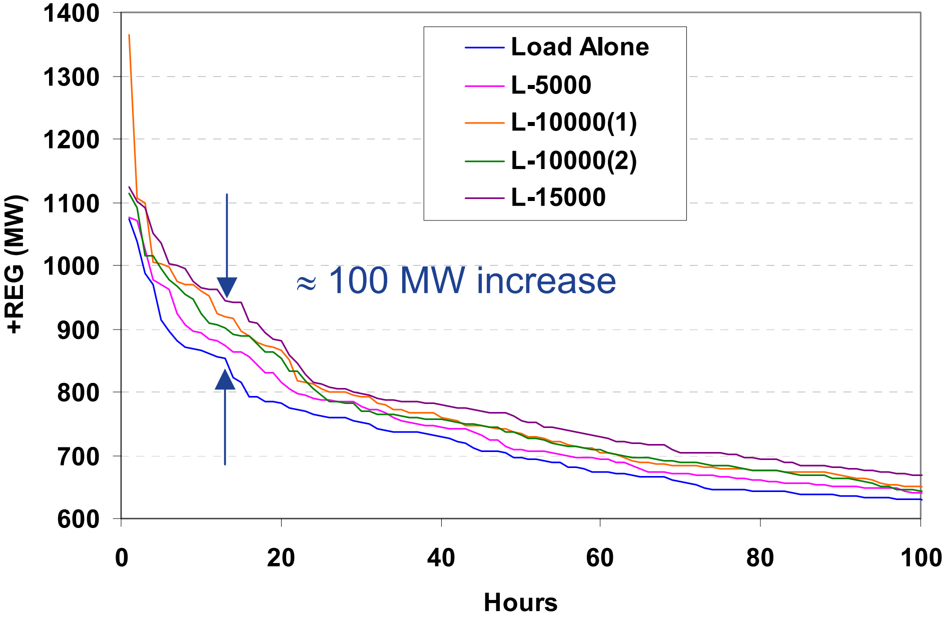


Cumulative Distributions of Maximum Hourly Down-Regulation



imagination at work

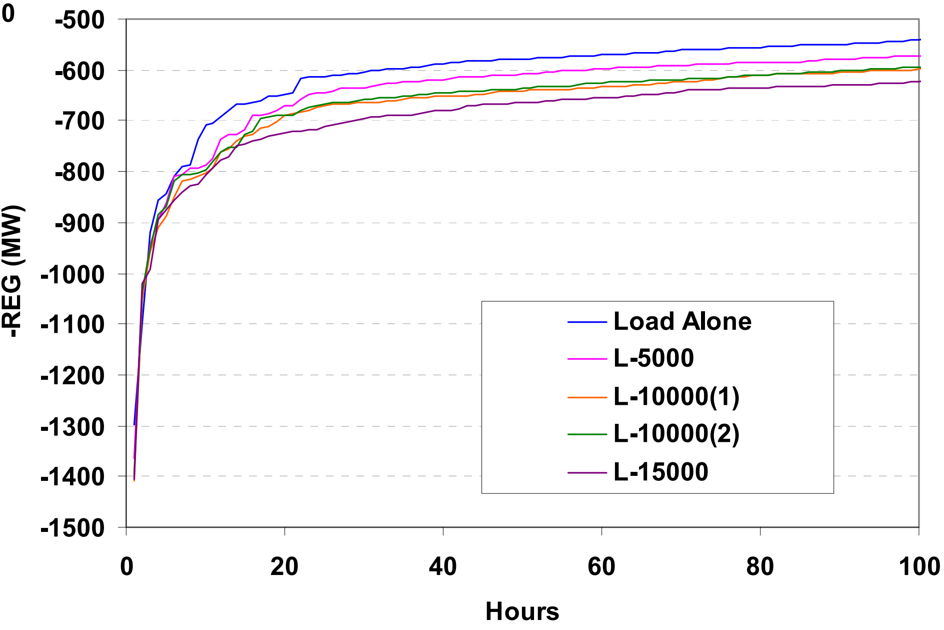
Extreme Up-Regulation and Down-Regulation



100 hrs is ≈ 1.2% of year

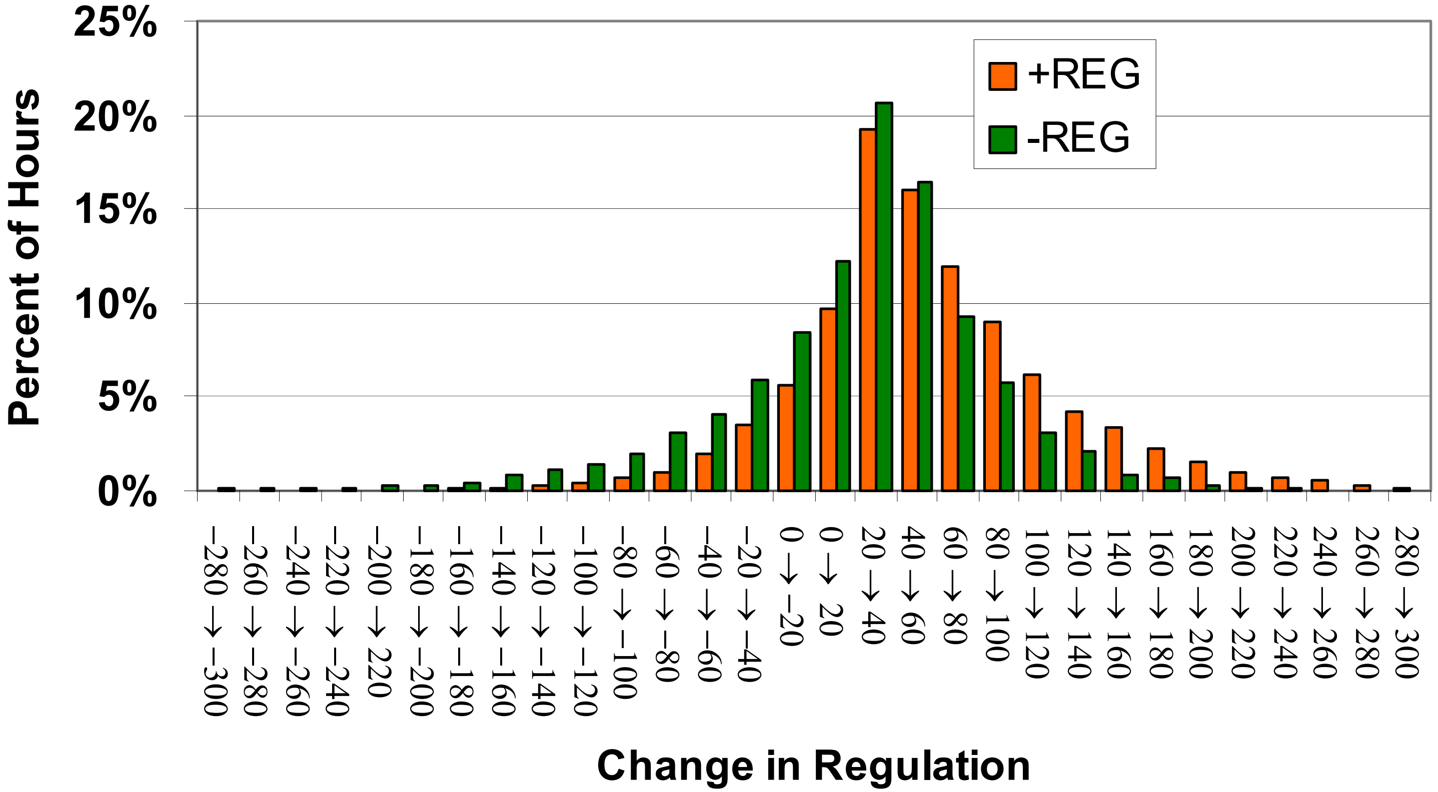
Except for an extreme outlier in one 10GW wind scenario, maximum, extreme +/-REG is increased modestly.

Increase ≈ proportionate with the amount of wind resources



Hourly Maximum Regulation Increase with 15,000 MW Wind

Difference between hourly max. regulation for load only and load –15GW wind



These statistics describe the maximum regulation within each 1-hr period

Results are ≈ symmetric

	+REG	-REG
Mean	17.7	-18.2
Sigma	64.9	65.1
Maximum	444.2	265.3
Minimum	-287.2	-453.1

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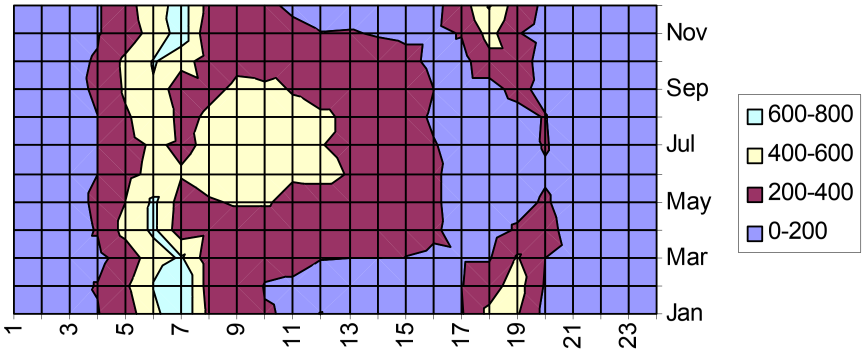
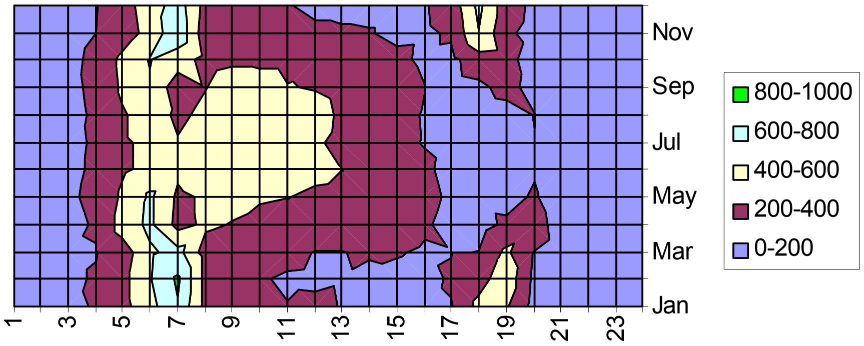
Up Regulation Correlation with Time of Day and Month

98.8th Percentile of +REG Deployed

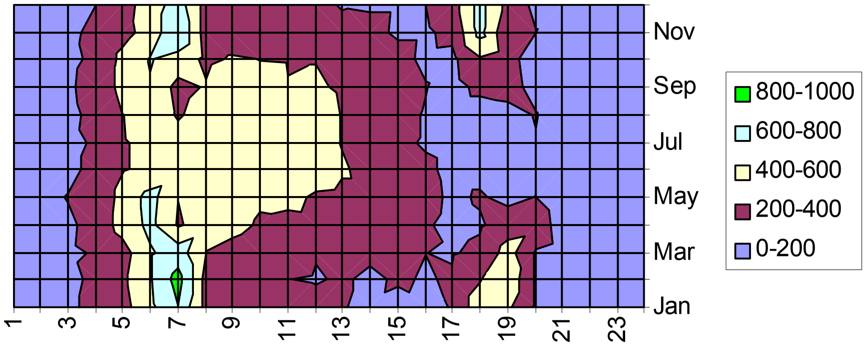
Load Alone



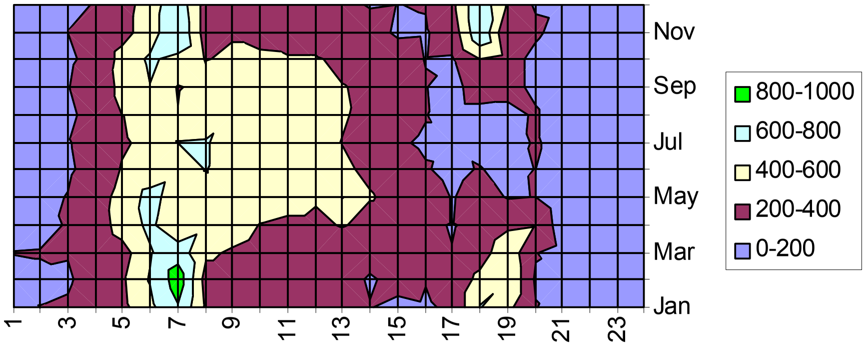
Load – 5000 MW Wind



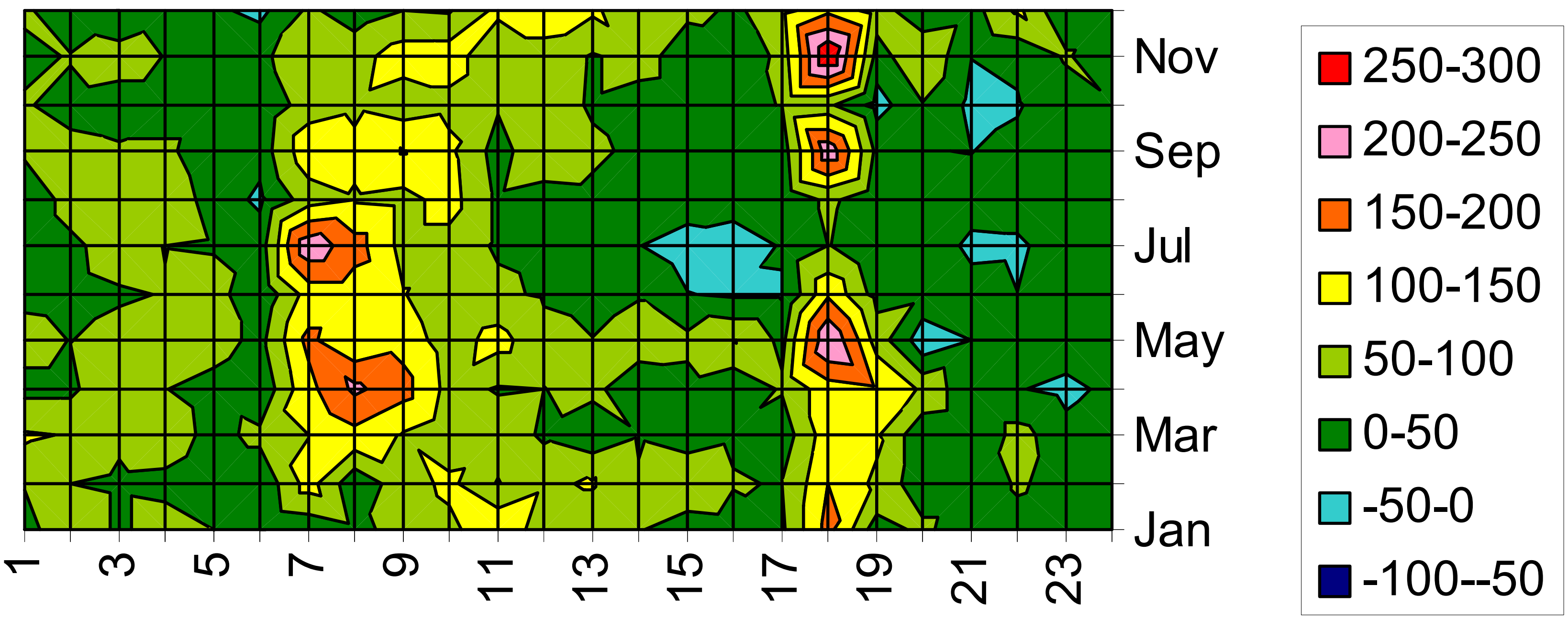
Load – 10,000 MW Wind (1)



Load – 15,000 MW Wind



Differential Up Regulation Requirements for 15 GW Wind

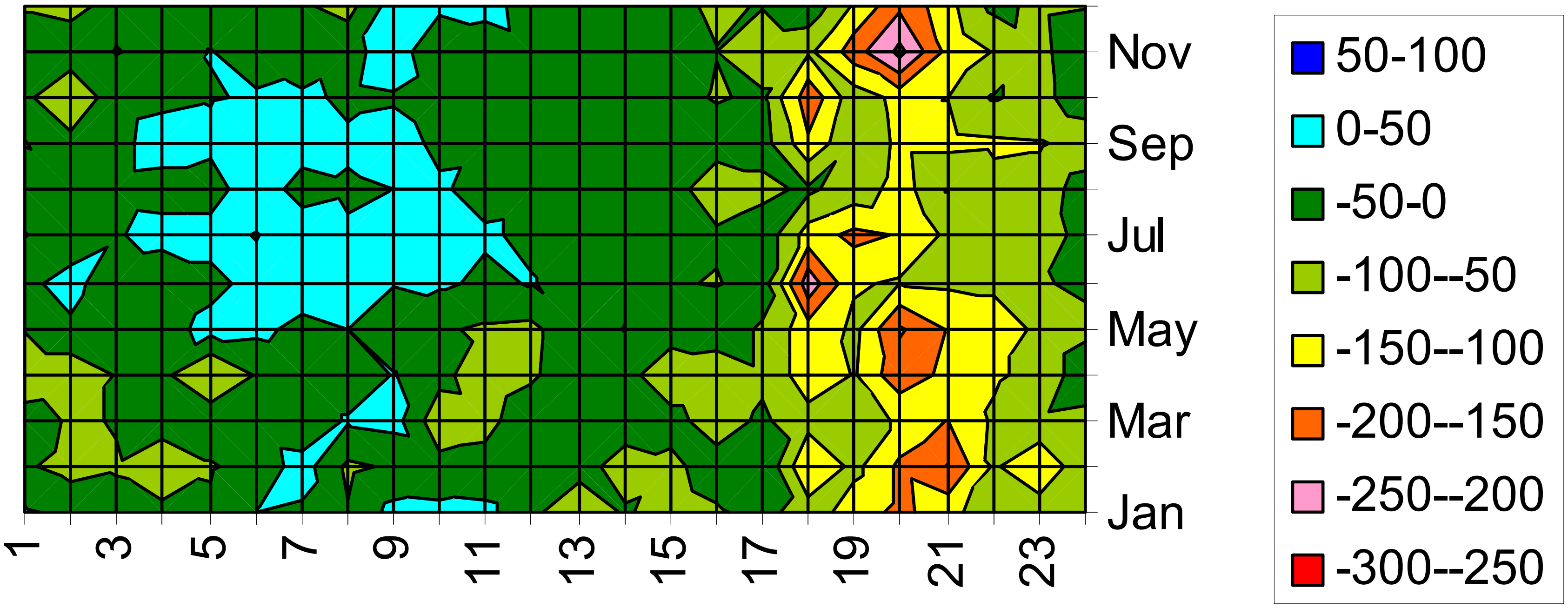


98.8th Percentile of +REG Deployed

- Increases during morning load ramp due to wind decline
- Increases during early evening during spring and fall

Differential Down Regulation Requirements for 15 GW Wind

98.8th Percentile of –REG Deployed



- More down regulation in the evening, particularly in fall, winter and spring
- Decreased down regulation during summer mornings

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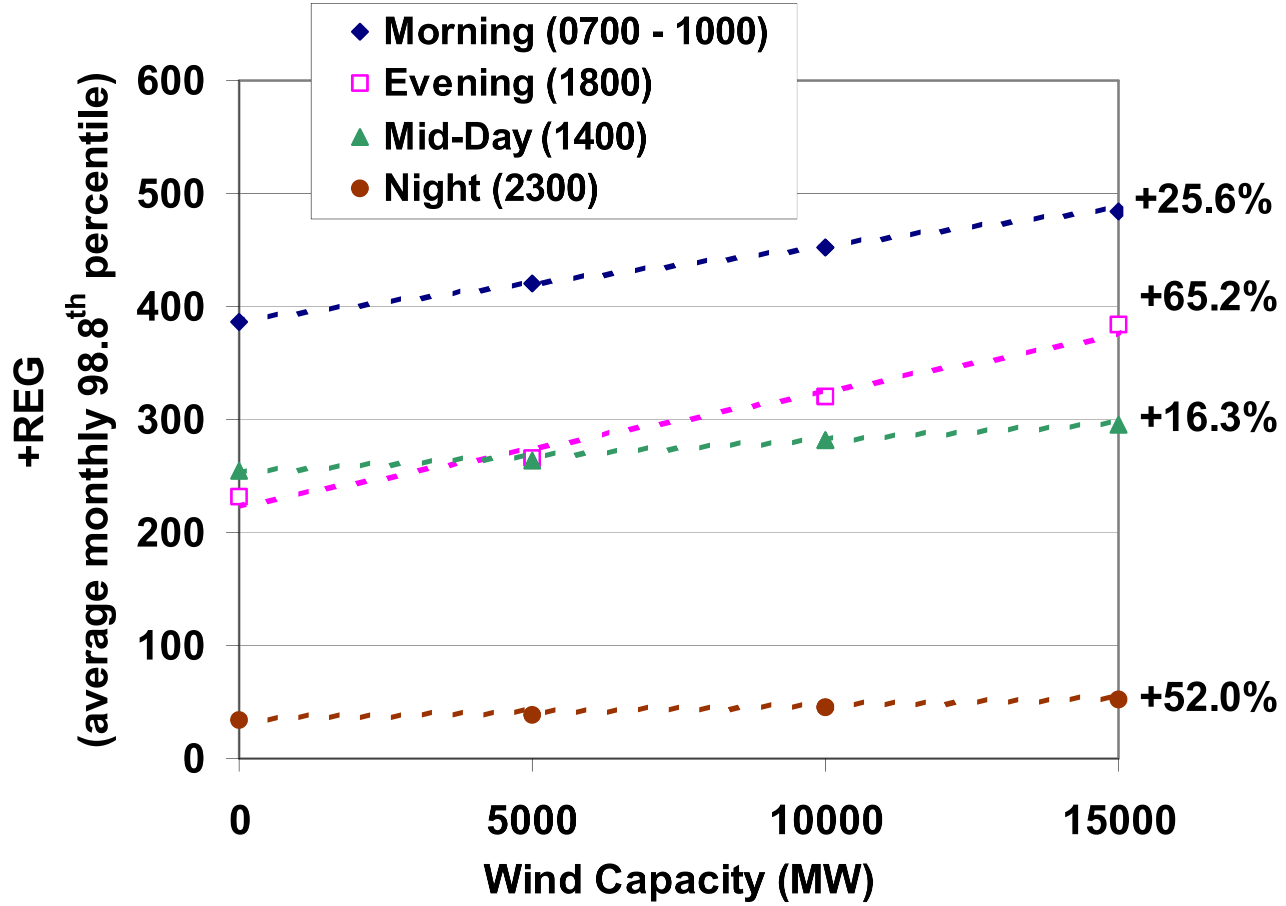
Variation in Up Regulation for Selected Periods



- Relative impact is not uniform, wind does substantially increase regulation requirements at times when regulation requirements had been small to moderate
- Linearity allows scale-up of regulation procurement to accommodate year-to-year wind additions

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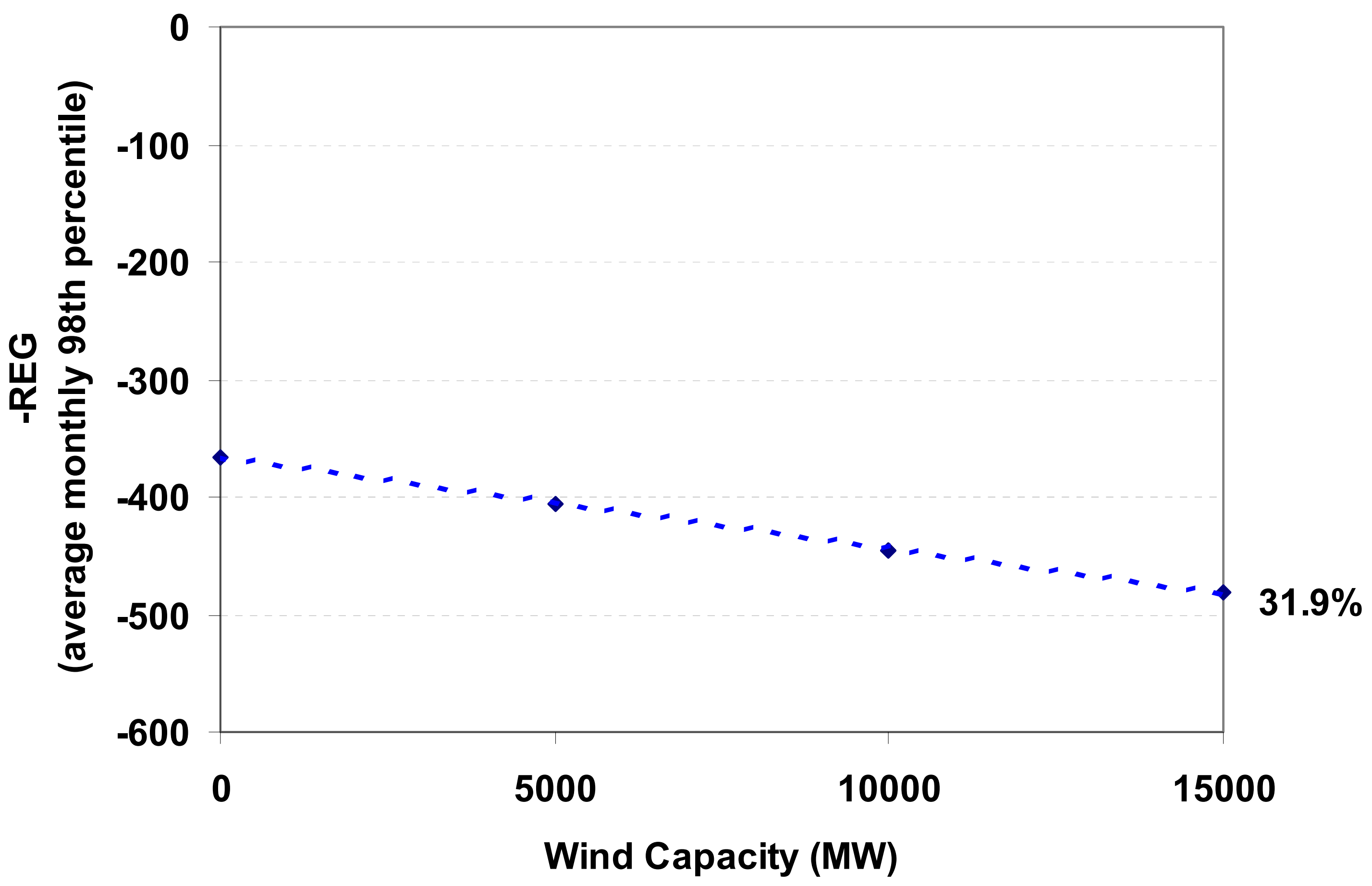
Increase of Evening Down Regulation Requirements



Evening wind increase coincides with load drop

Impact of Wind Penetration on Regulation

- Regulation peaks caused by load ramping are incrementally increased due to added ramp caused by wind
- Relative to load alone, 98th percentile of regulation increases on the order of 20% - 23% at 15 GW of wind
- Regulation increases linearly with wind penetration
- Extrema appear both with and without wind, with magnitudes incrementally greater with 15 GW of wind
- Largest changes are concentrated in particular times of day and seasons -- +REG in the evenings increases 65%

Evaluation of Regulation Procurement Methodology

In this next set of slides, we will show:

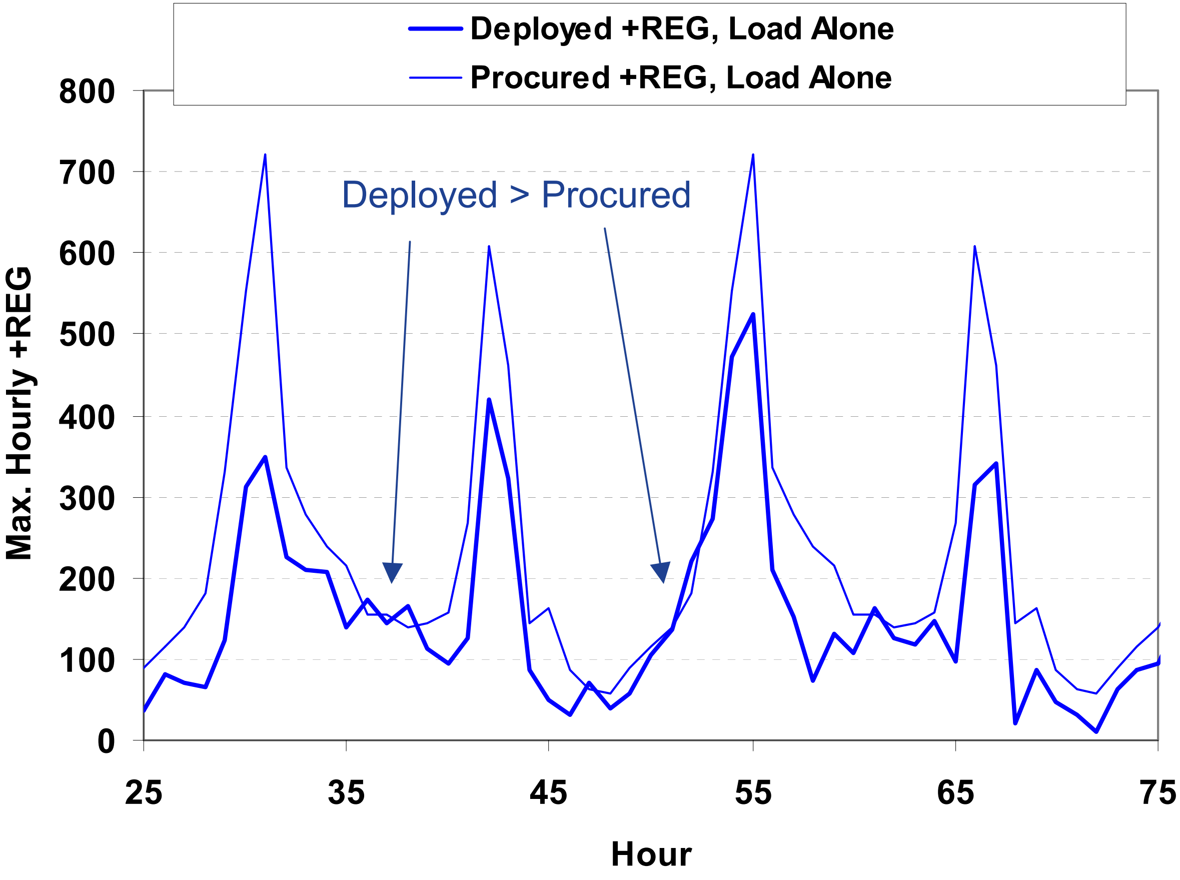
- How ERCOT presently determines the amount of regulation to procure
- The robustness of this methodology to increased wind penetration

Key issues are:

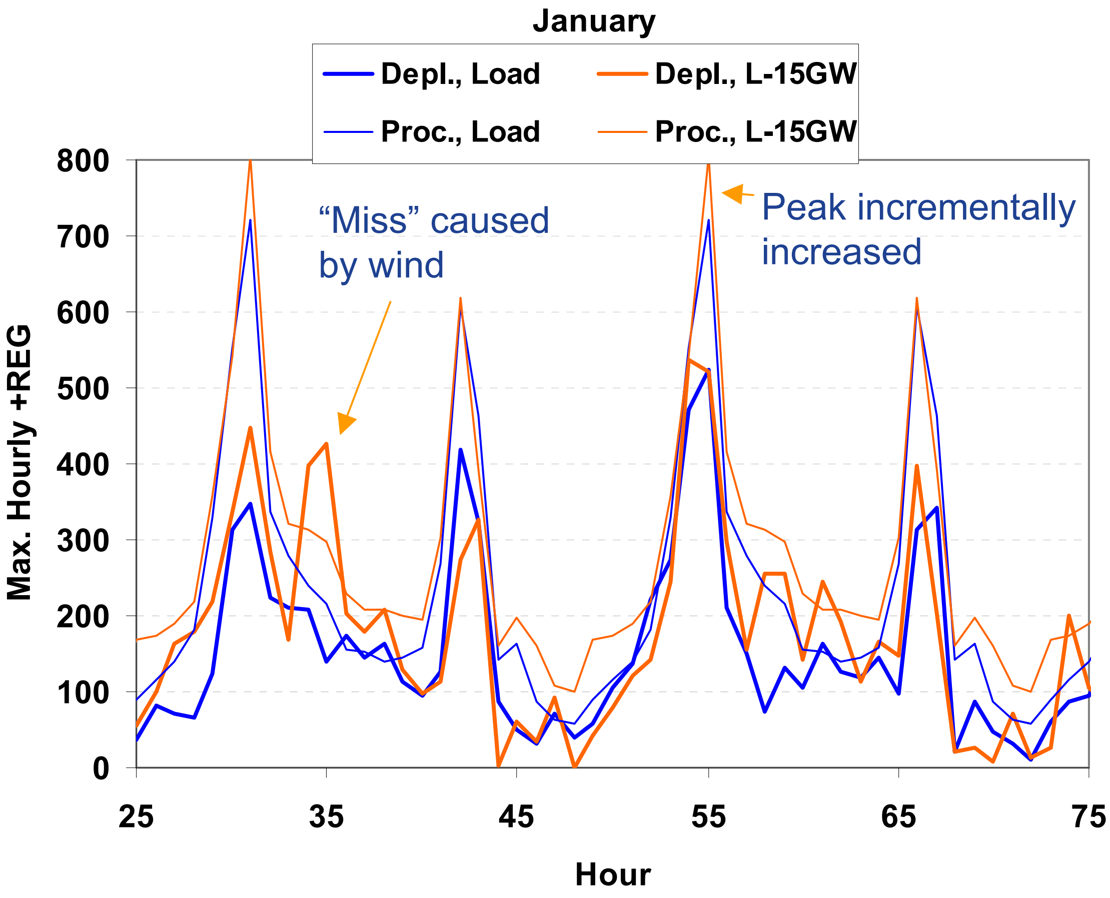
- Frequency of under-procurement
- Severity of under-procurement

ERCOT Regulation Procurement Methodology

- Regulation procurement algorithm seeks to cover most, but not all time periods; occasional “misses” are expected
- Procurement based on 98.8th percentile of maximum deployment in 5-minute intervals for same hour of day in:
  - Same month, prior year
  - Prior month, same year



Regulation Deployed vs. Procured Time Series Example
January with 15,000 MW Wind

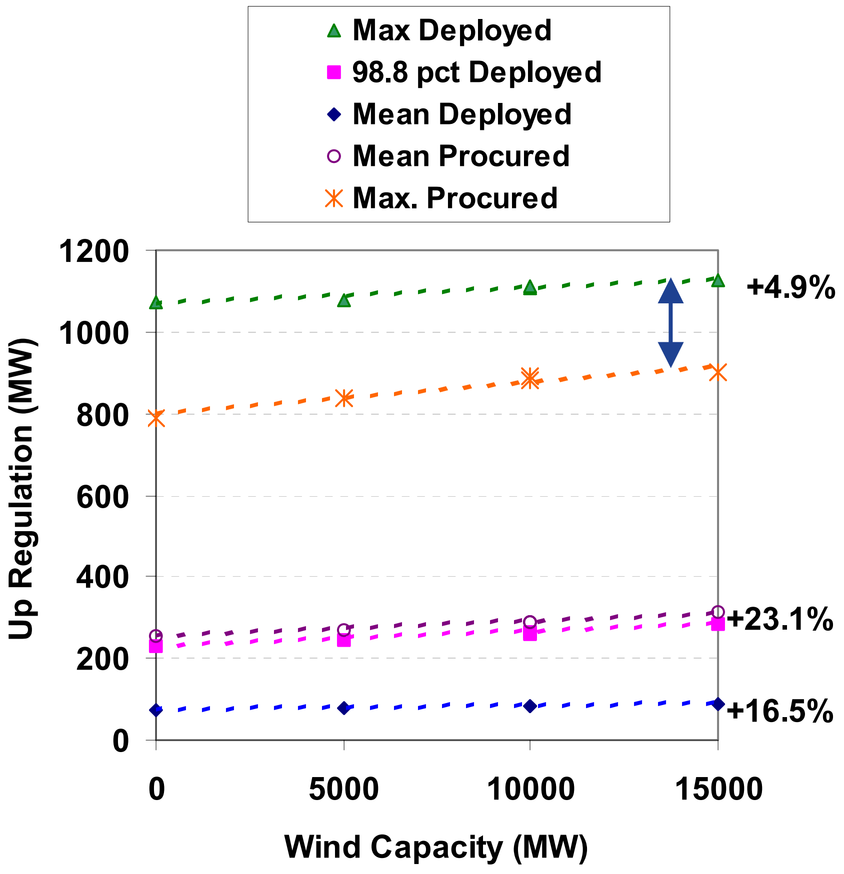


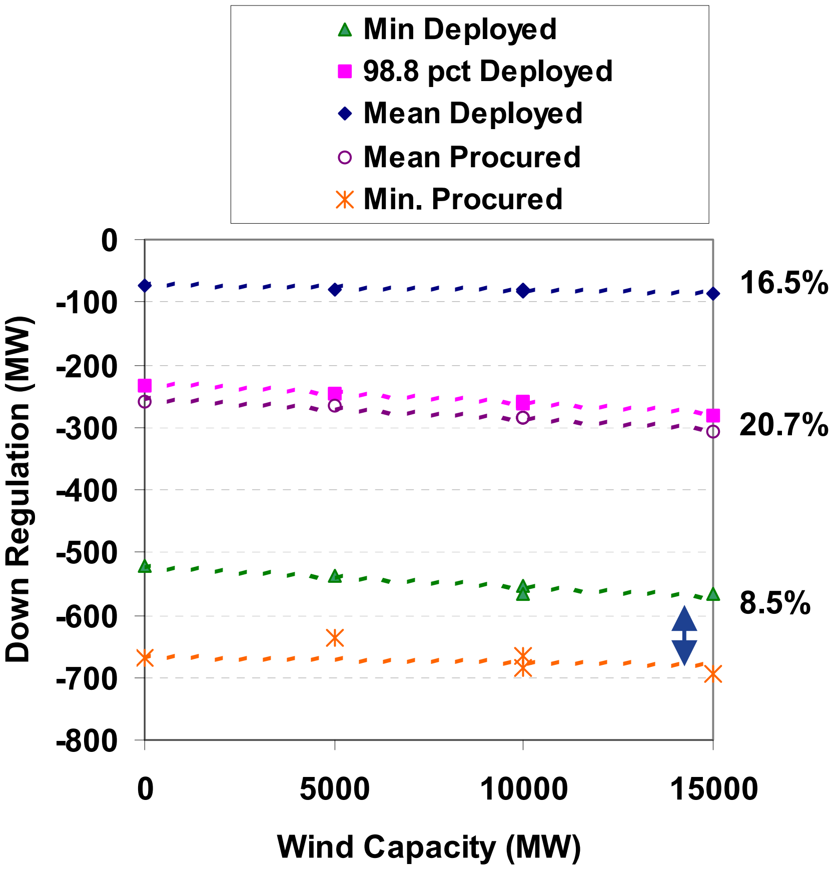
“Miss” caused by wind

Peak incrementally increased

- Procurement modified (generally increased) due to wind (historical presence of wind assumed)

Changes in Deployed and Procured Regulation

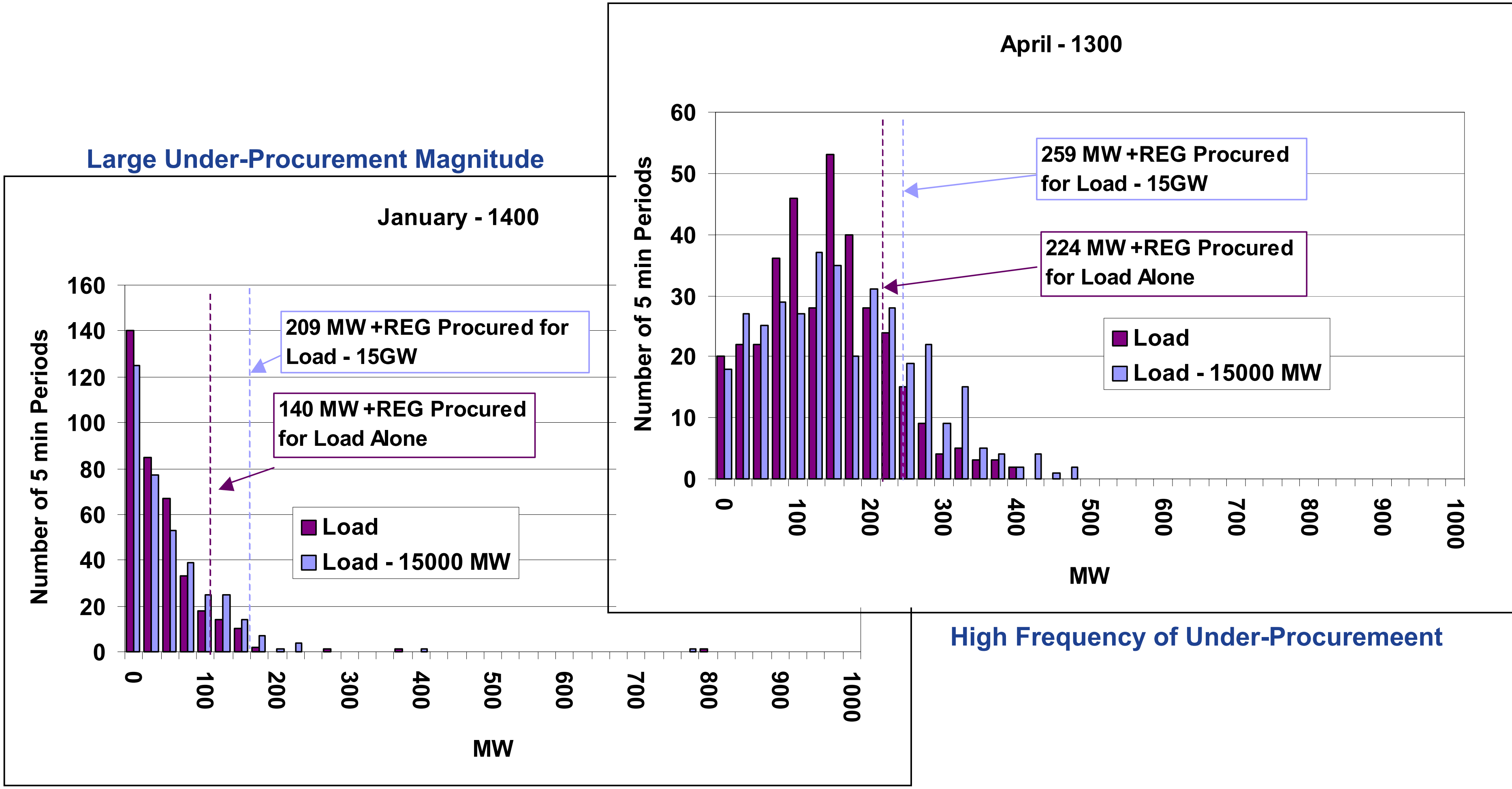




- Gap between maximum deployed and maximum procured narrows as wind penetration increases
- Point of comparison: sigma of 5-min delta increased 18% from load alone to load minus 15 GW of wind

imagination at work

Up Regulation Frequency Distribution Examples



Large Under-Procurement Magnitude

High Frequency of Under-Procuremeent

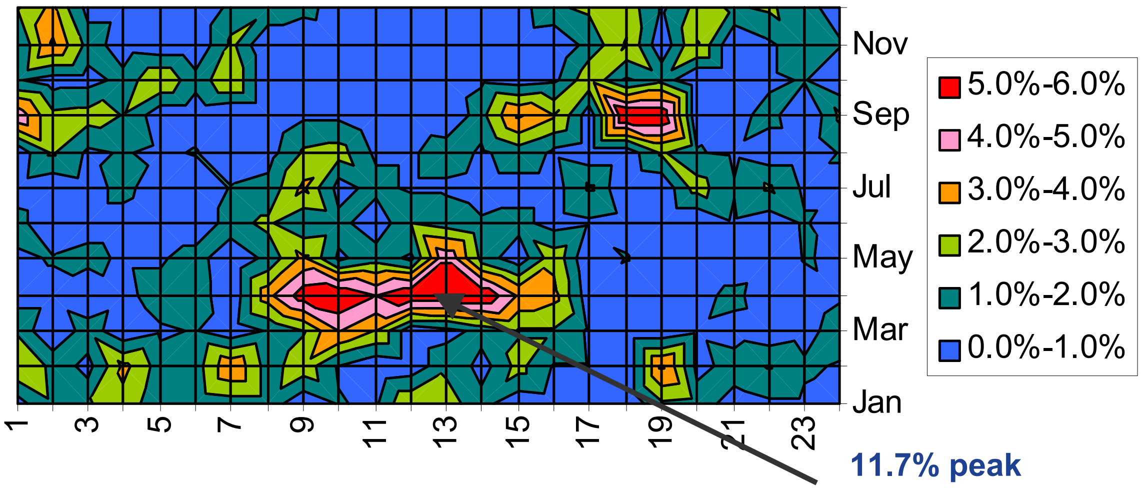
Percentage of Hours with +REG Under-Procurement

Present approach has a relatively large number of misses in the spring (morning to mid-afternoon) and autumn evenings

Increased overall +REG deployment with 15 GW of wind diminishes the high concentration of misses during these periods

A few limited points were somewhat more severe

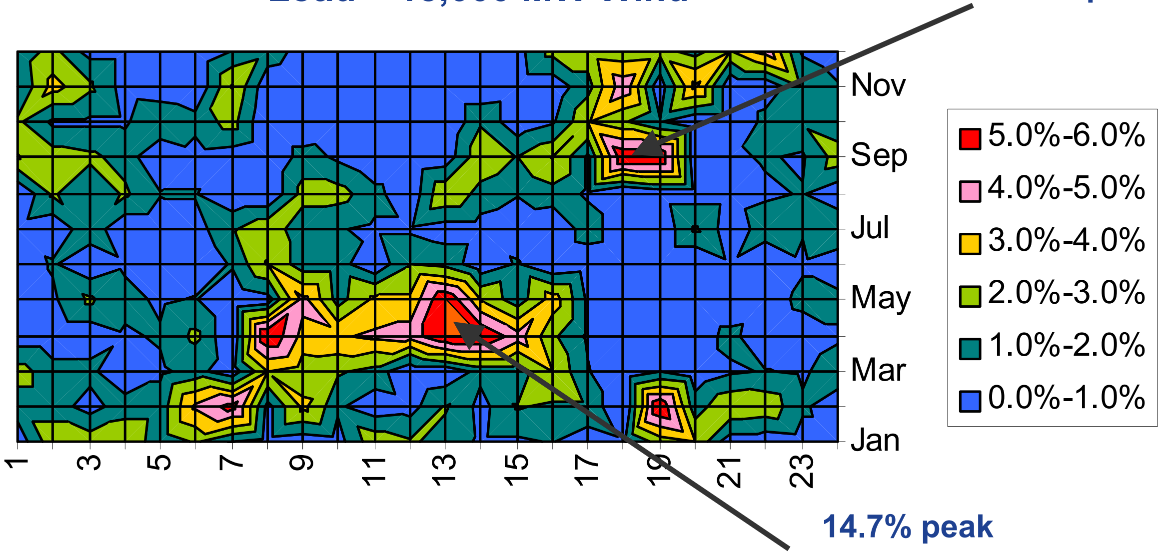
Load Alone



11.7% peak

Load – 15,000 MW Wind

10.3% peak



14.7% peak

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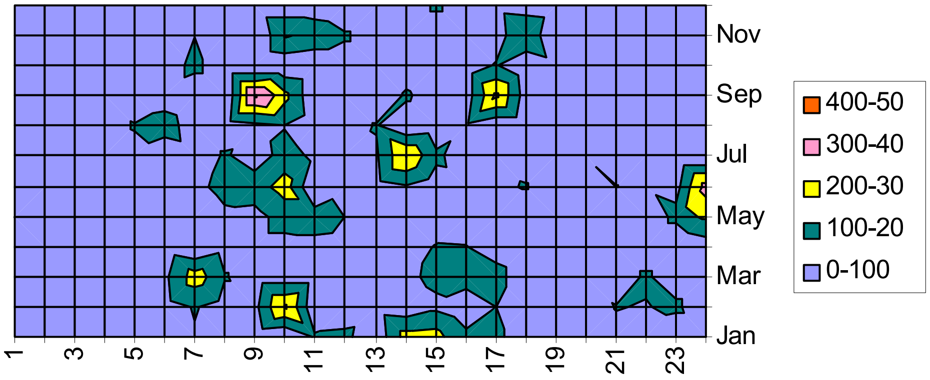
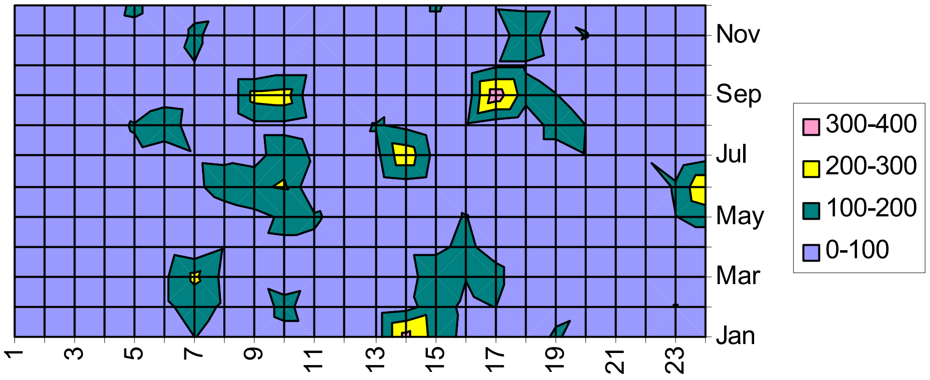
Root Mean Square of +REG Under-Procurement

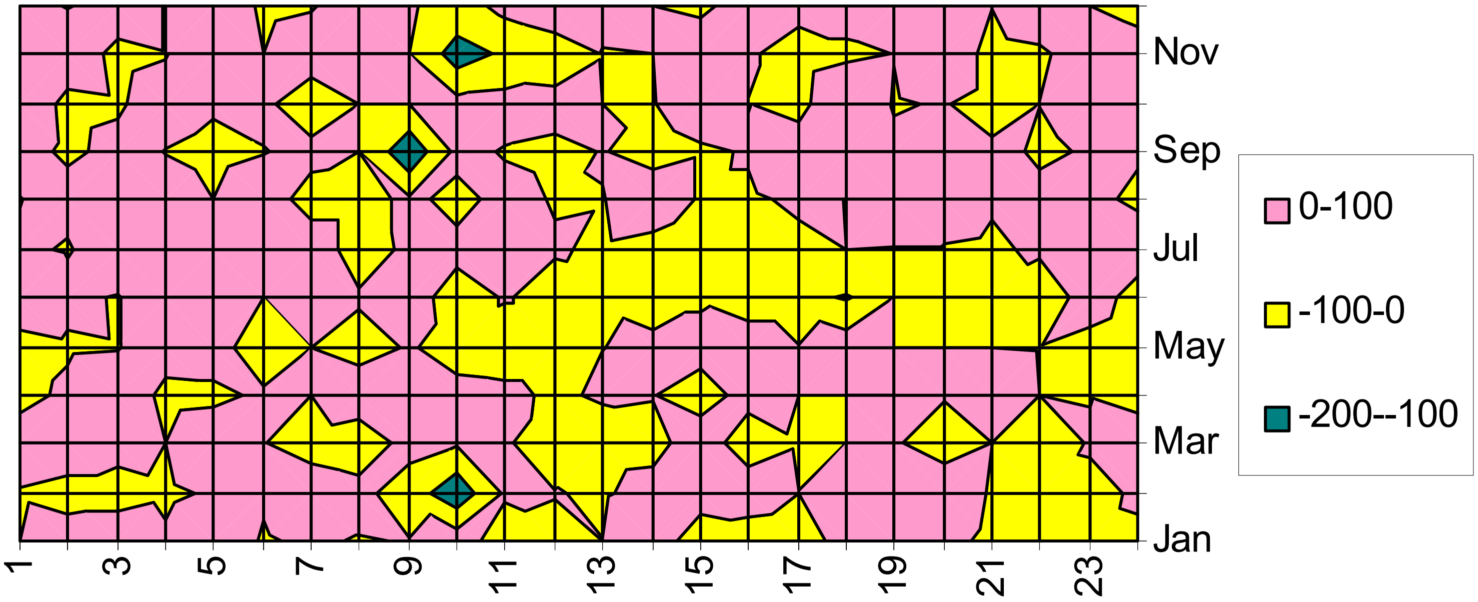
Load Alone



Load – 15,000 MW Wind



Difference



imagination at work

Regulation Under-Procurement Statistics

Up-Regulation

Wind	Percentage of Periods	Total MWh Under-Proc.	Average Under-Proc.	RMS of Deficiency	Extreme Deficiency
0	1.29%	5,141	45.5 MW	80.1 MW	653 MW
5000	1.26%	5,320	48.2 MW	82.1 MW	634 MW
10,000 (1)	1.36%	6,201	52.0 MW	85.0 MW	638 MW
10,000 (2)	1.35%	6,004	50.8 MW	84.2 MW	643 MW
15,000	1.37%	6,712	55.9 MW	88.5 MW	632 MW

Down-Regulation

Wind	Percentage of Periods	Total MWh Under-Proc.	Average Under-Proc.	RMS of Deficiency	Extreme Deficiency
0	1.18%	5,011	48.5 MW	89.2 MW	886 MW
5000	1.12%	5,148	52.5 MW	90.4 MW	911 MW
10,000 (1)	1.20%	5,439	51.7 MW	87.9 MW	946 MW
10,000 (2)	1.16%	5,301	52.2 MW	89.2 MW	940 MW
15,000	1.16%	5,562	54.7 MW	90.1 MW	927 MW

- Present methodology produces regulation requirements consistent with current accuracy
- Growth in absolute magnitude of deficiencies commensurate with regulation increase

imagination at work

In summary:

- Regulation requirements for net load with high wind penetration are statistically as “well behaved” as load only
- The present ERCOT methodology for determining the amount of regulation to procure remains effective with 15 GW of wind
- Linearity allows scale-up of regulation procurement to accommodate year-to-year wind additions
- Under-procurements are not substantially more severe
- There may be improvements which might be made to the methodology to reduce the amount of regulation procured while maintaining accuracy of procurement

Production Simulation

In this next set of slides, we will show:

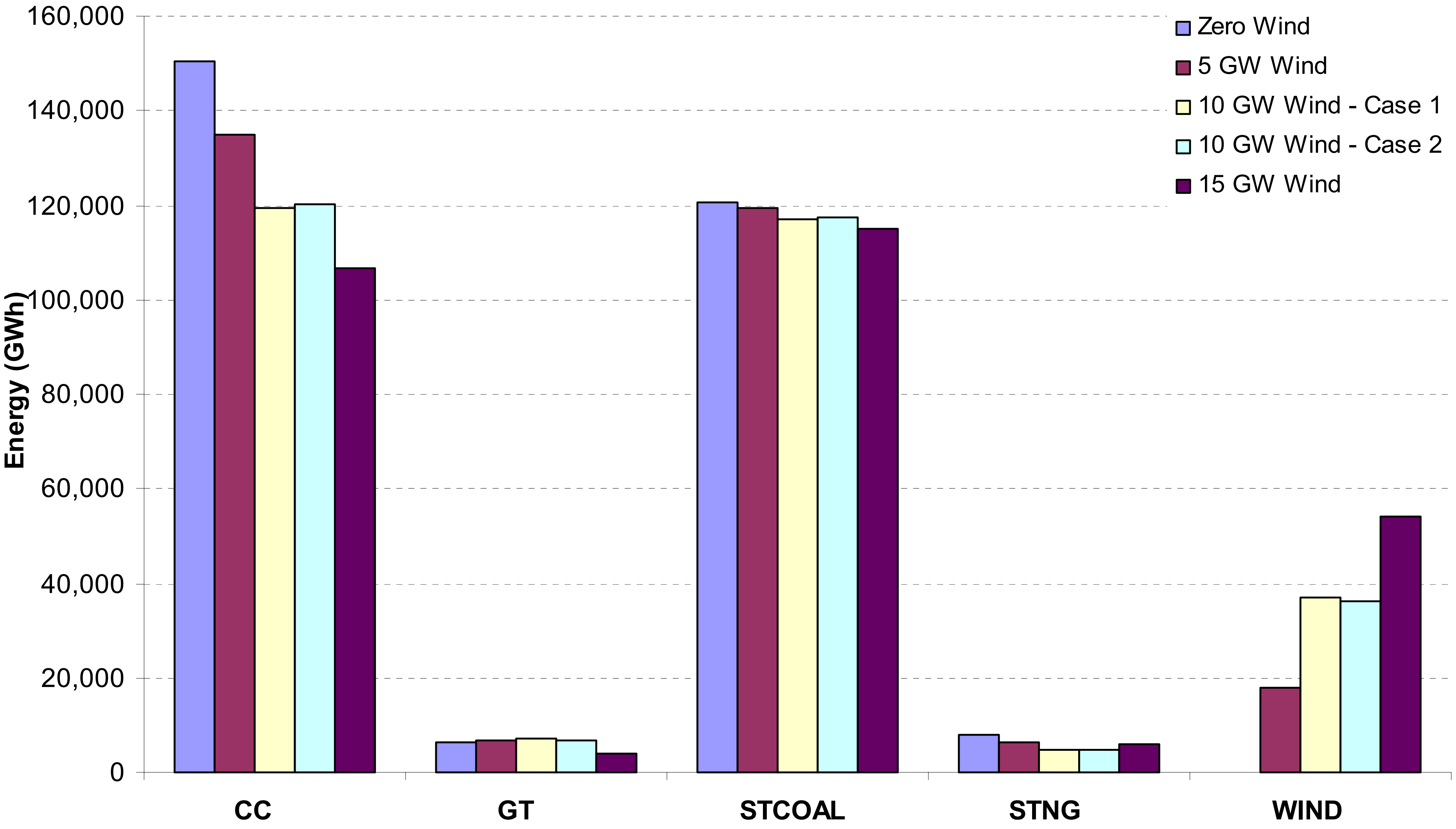
- Hour-by-hour power production simulations for the wind scenarios, using GE **M**ulti-**A**rea **P**roduction **S**imulation (MAPS) program
  - Unit commitment
  - Dispatch
- Program outputs
  - Production costs
  - Spot prices
  - Spinning reserve prices
  - Ramping capability and range
  - Emissions

Issues:

- How wind affects unit commitment and production
- Impact on market prices (energy and ancillary services)

Energy Output

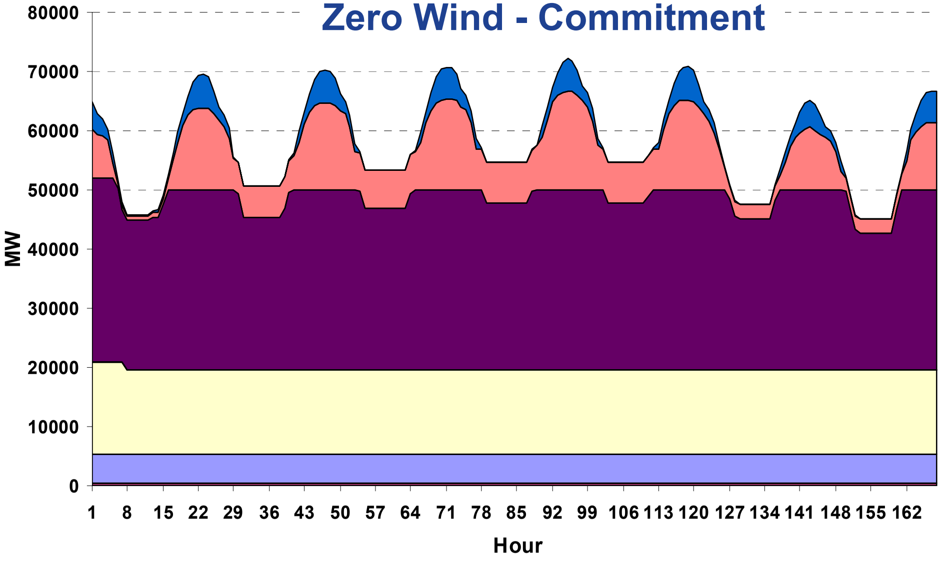
Commitment Based on State-of-Art Forecast



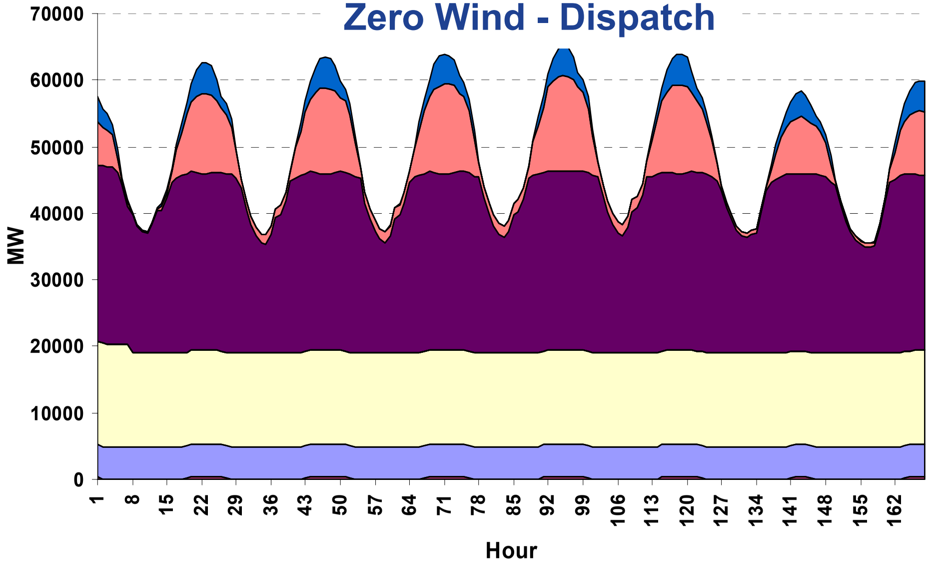
Major impact is on combined cycle unit operation, consistent with results observed in other studies

Peak Load Week (Aug 11-18) - State of the Art Forecast

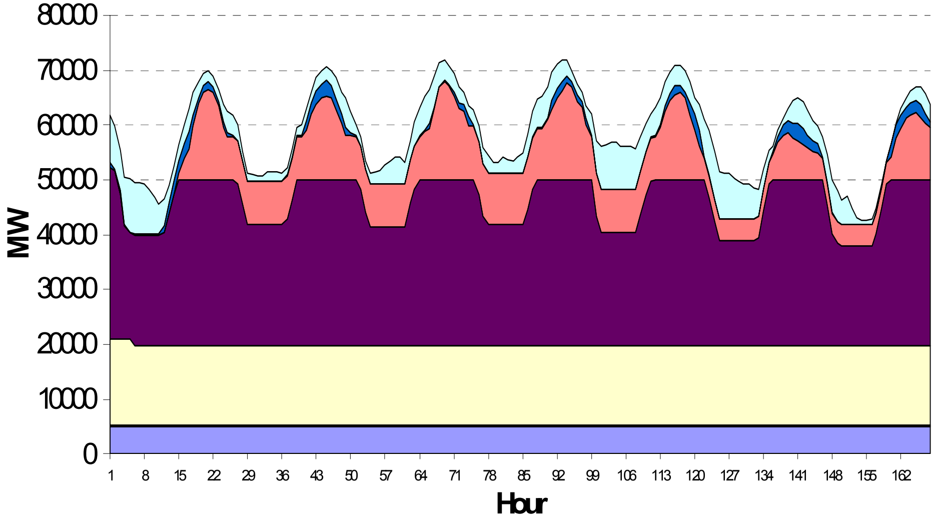
Zero Wind - Commitment



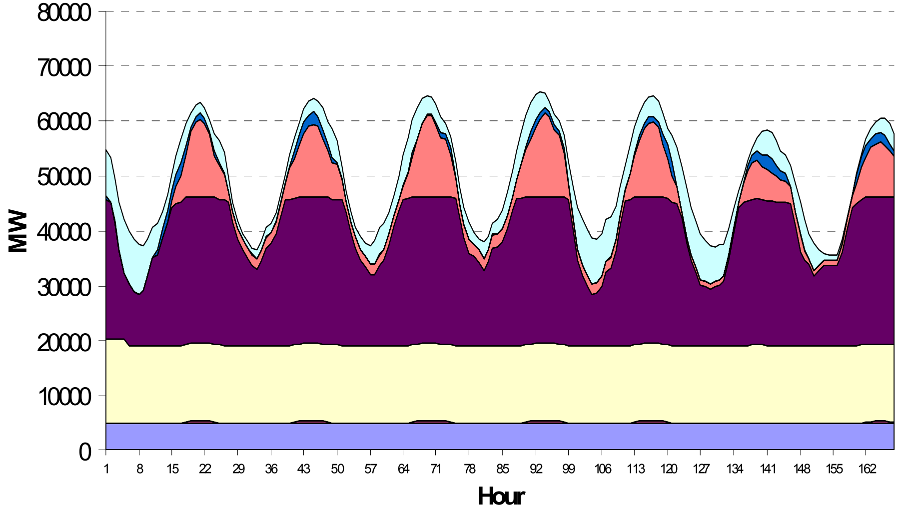
Zero Wind - Dispatch



15 GW Wind - Commitment



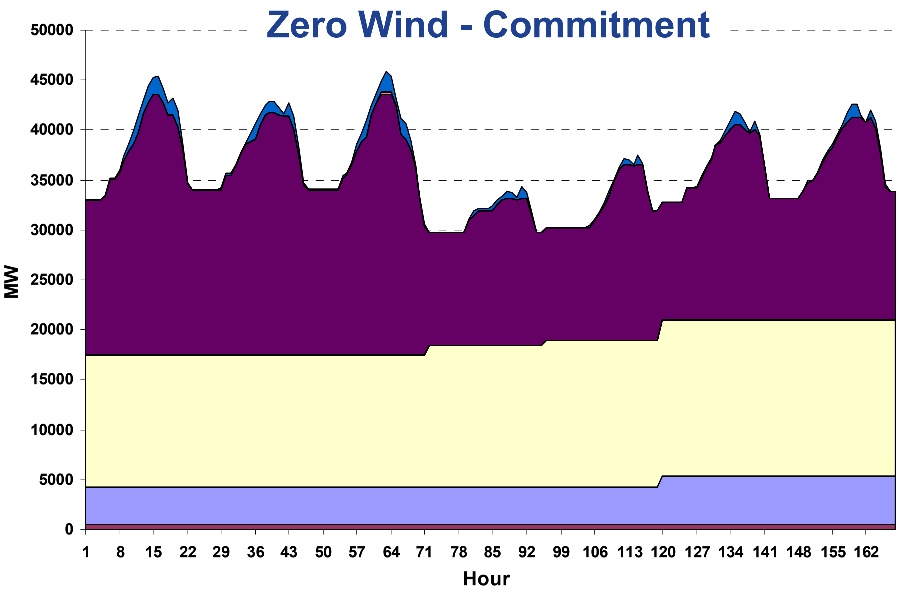
15 GW Wind - Dispatch



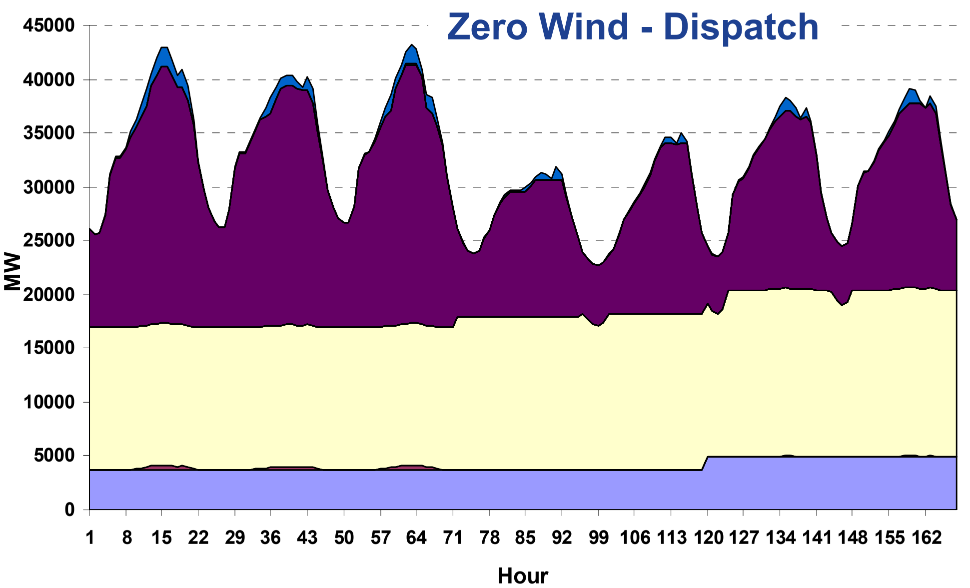
imagination at work

■ HYDRO ■ NUCLEAR □ STEAM COAL □ WIND ■ COMB. CYCLE ■ STEAM GAS ■ GAS TURBINE

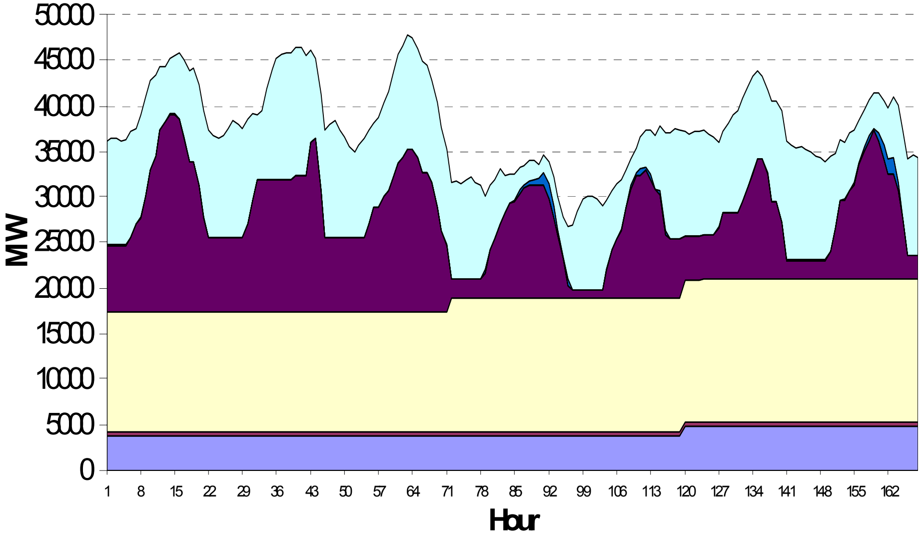
Peak Wind Week (April 2-9) - State of the Art Forecast



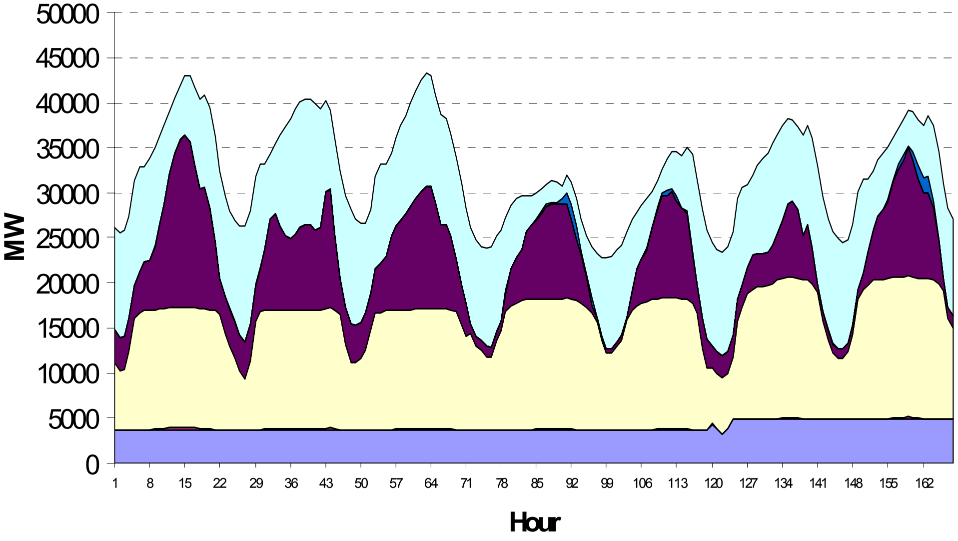
Zero Wind - Commitment



Zero Wind - Dispatch



15 GW Wind - Commitment

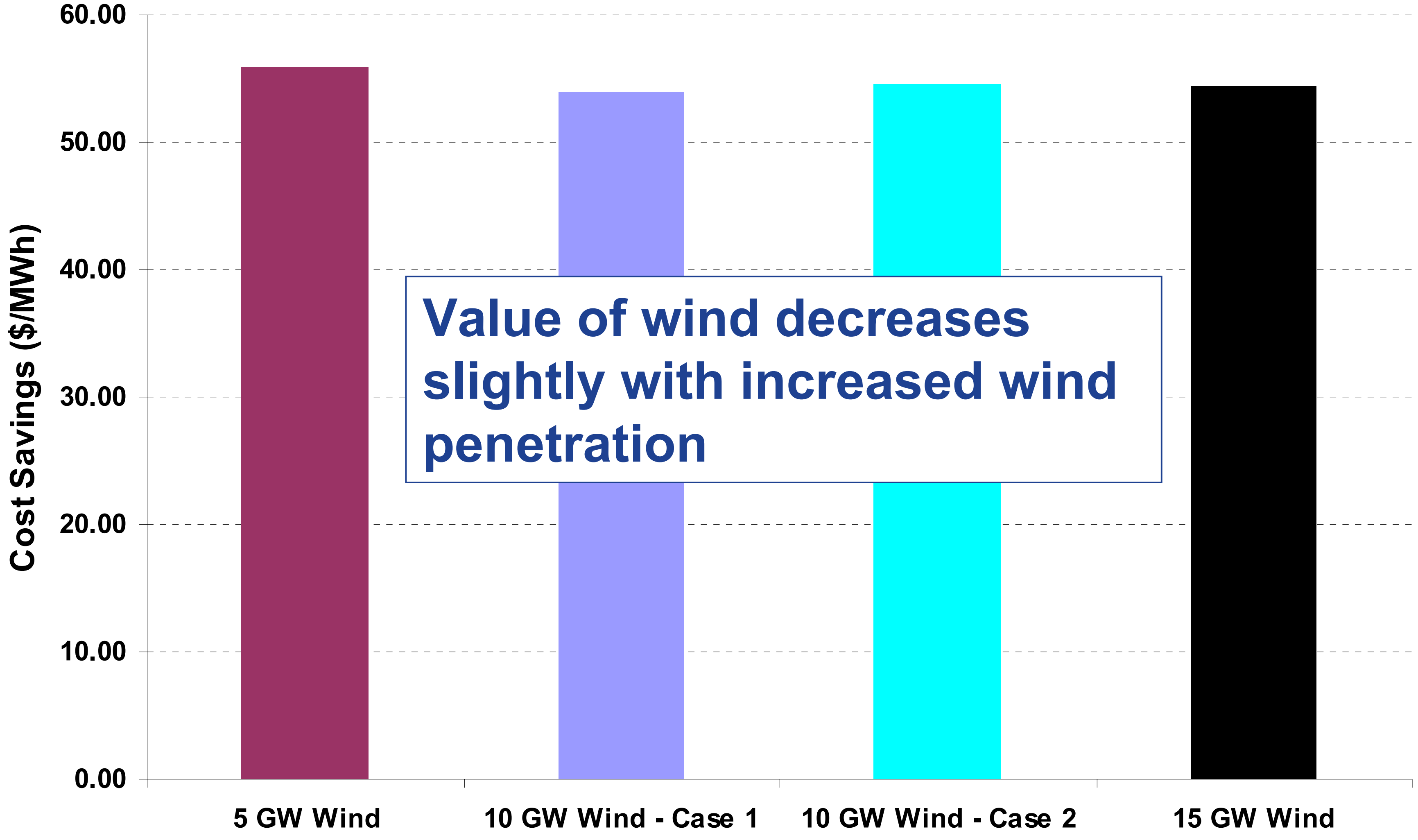


15 GW Wind - Dispatch

imagination at work

■ HYDRO ■ NUCLEAR □ STEAM COAL □ WIND ■ COMB. CYCLE ■ STEAM GAS ■ GAS TURBINE

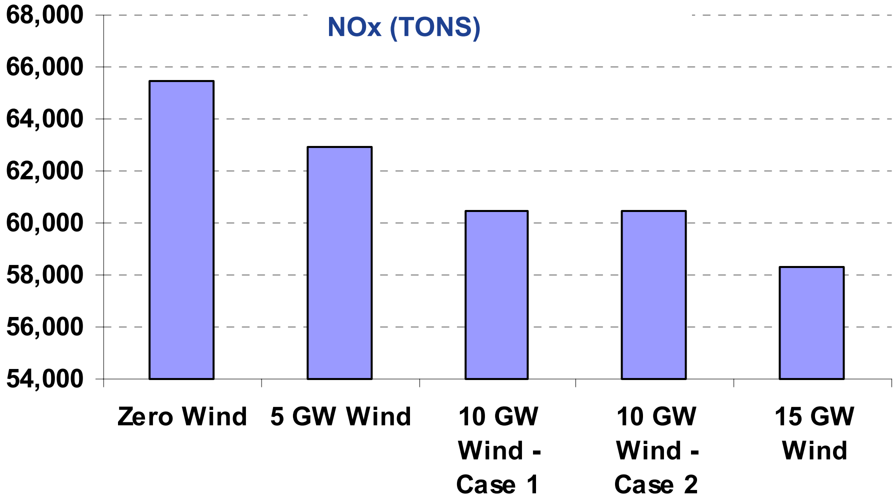
Production Cost Reductions Due to Wind

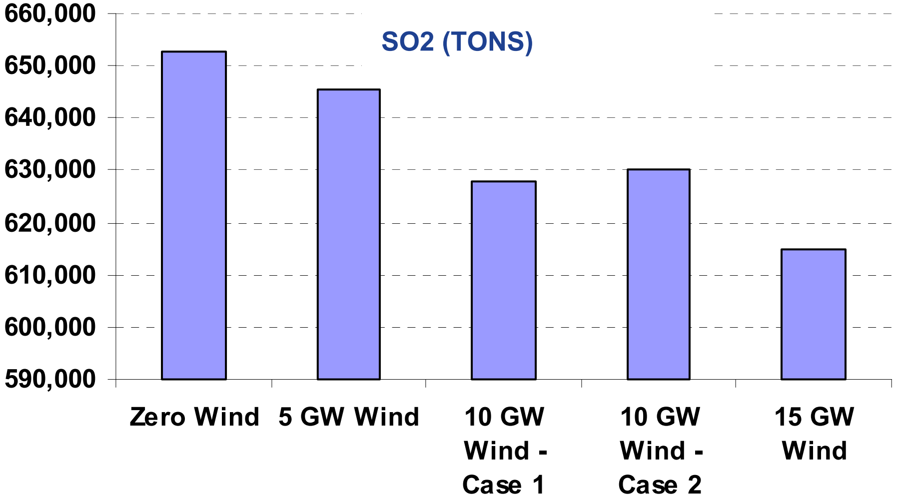


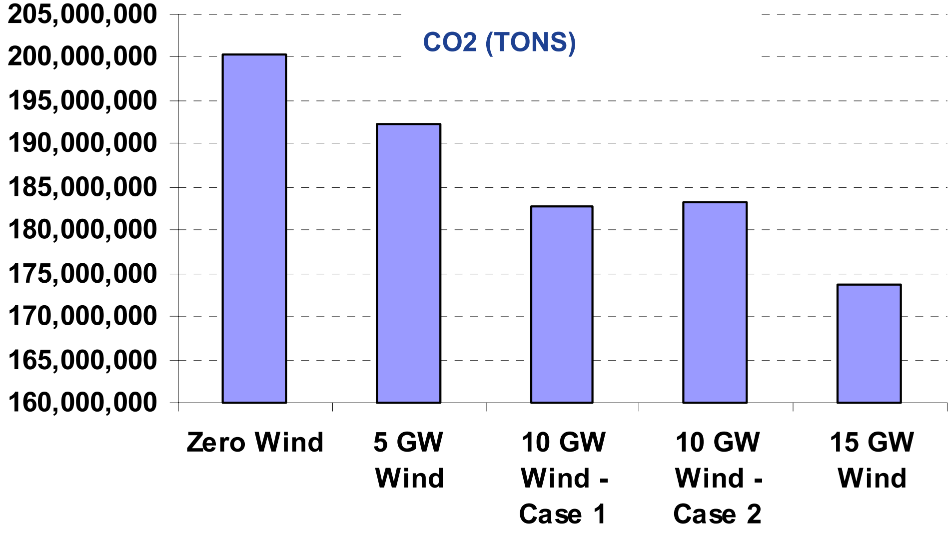
Value of wind decreases slightly with increased wind penetration

Total Annual Emissions

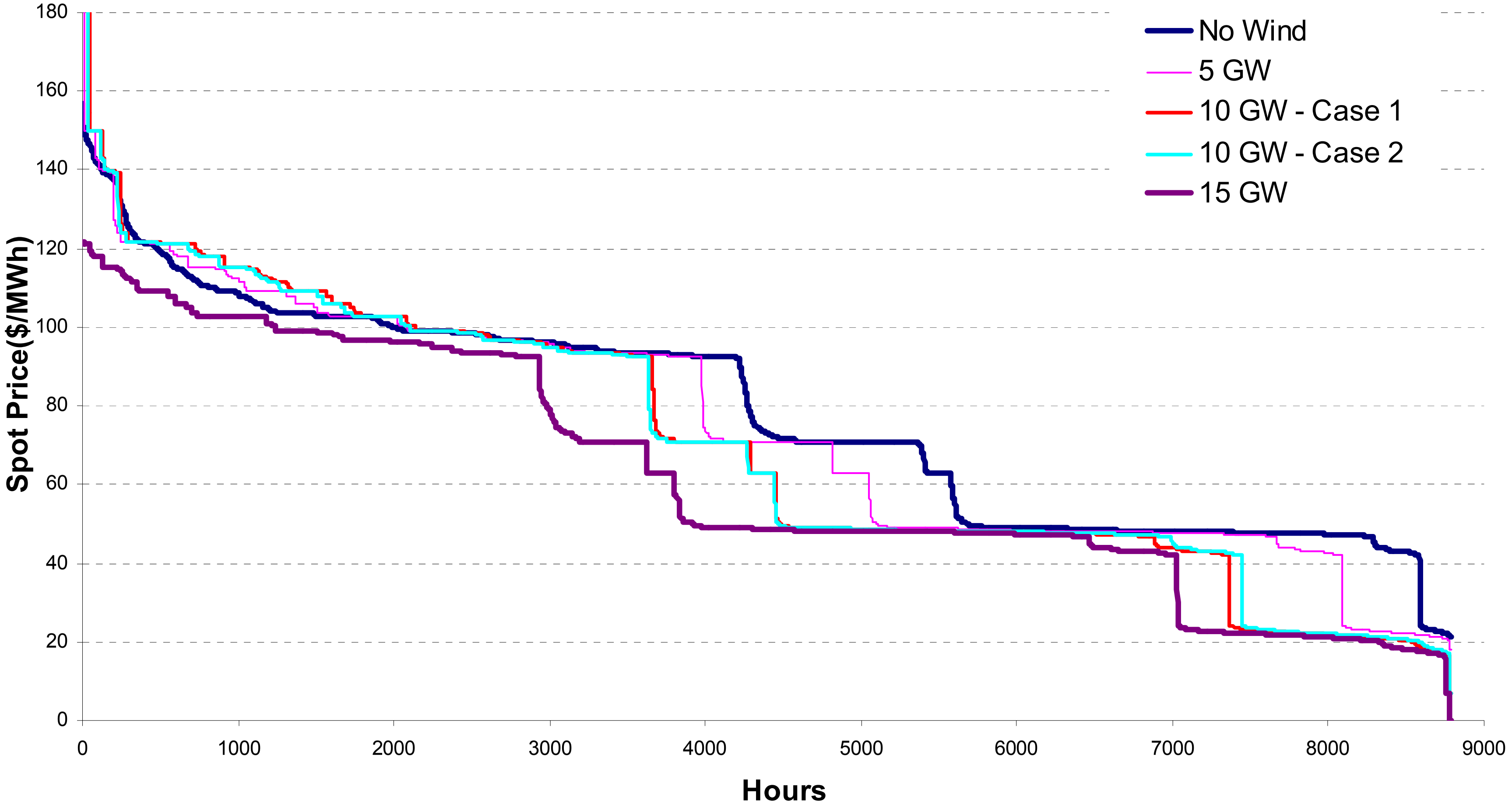
(State-of-Art Wind Forecast Assumed)





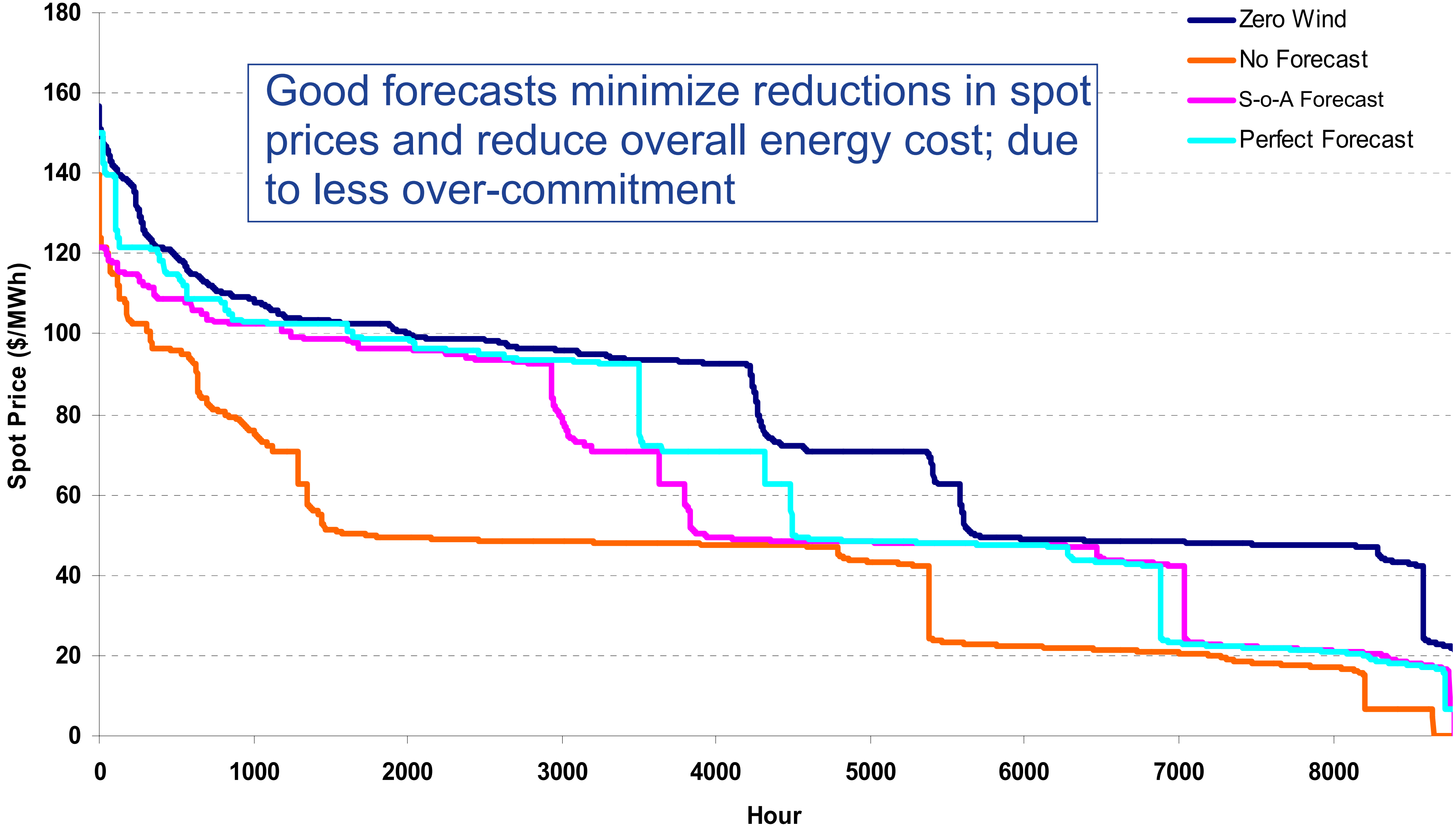


Energy Spot Prices – Assumes State of the Art Forecast



imagination at work

Impact of Wind Forecast on Energy Prices – 15 GW Wind



Good forecasts minimize reductions in spot prices and reduce overall energy cost; due to less over-commitment

imagination at work

In summary:

- Emissions and nodal energy prices decrease as wind penetration increases
- Value of wind per MWh decreases slightly with increased wind penetration
- Bulk of energy displacement is from combined cycle units
- Lack of wind forecast results in significant over commitment of units – depressing nodal prices

Available
Regulation Range

In this next set of slides, we will show:

- How the changes in unit commitment and dispatch affect the ability to meet regulation requirements with increased wind penetration

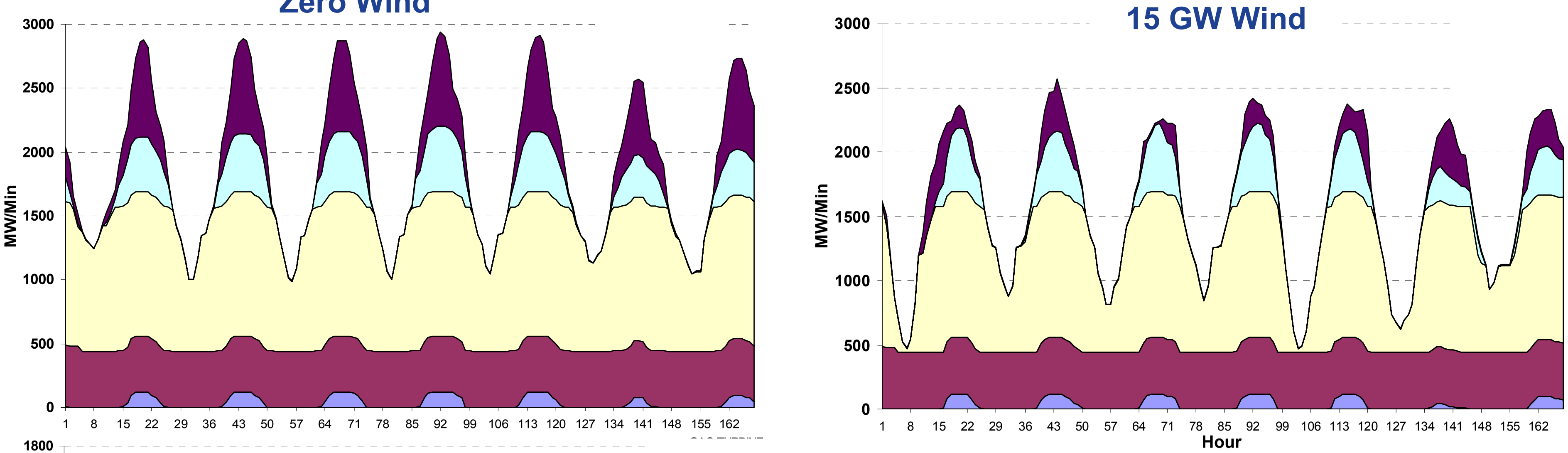
Key issues are:

- Displacement of conventional generation
- Flexibility of committed units

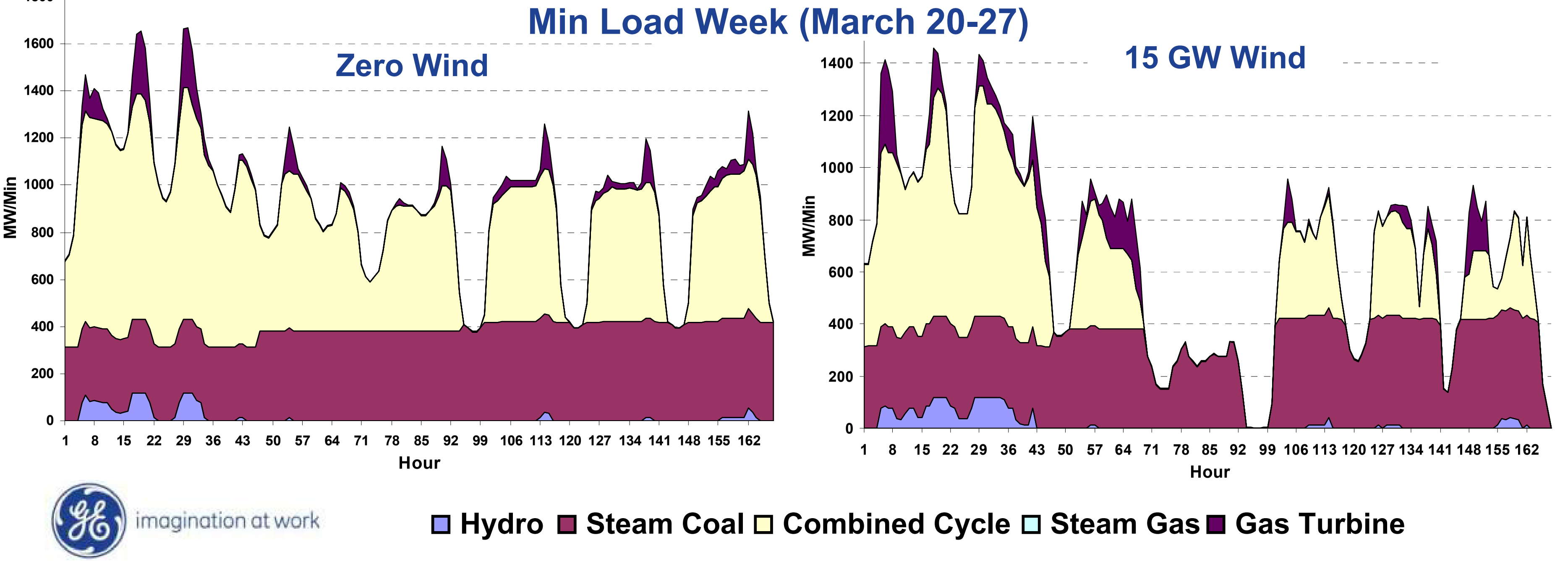
Down Regulation Resources

Based on state of the art forecast

Peak Load Week (August 11-18)



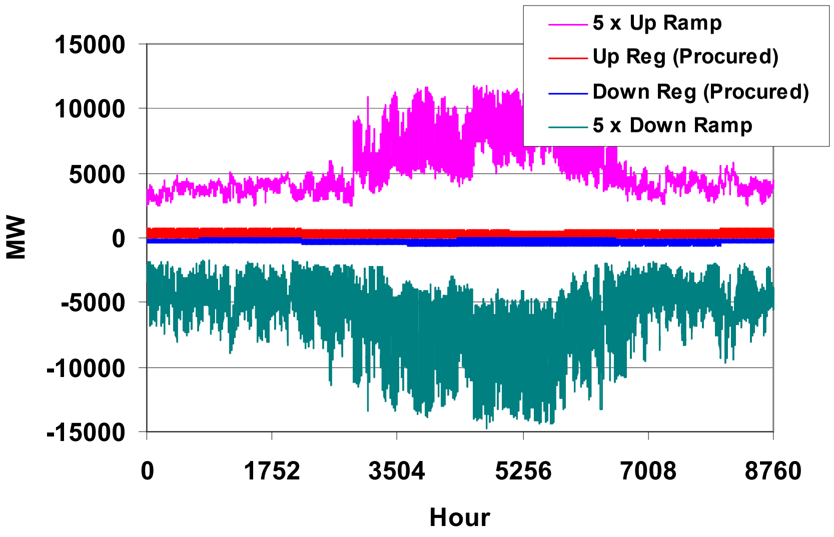
Min Load Week (March 20-27)



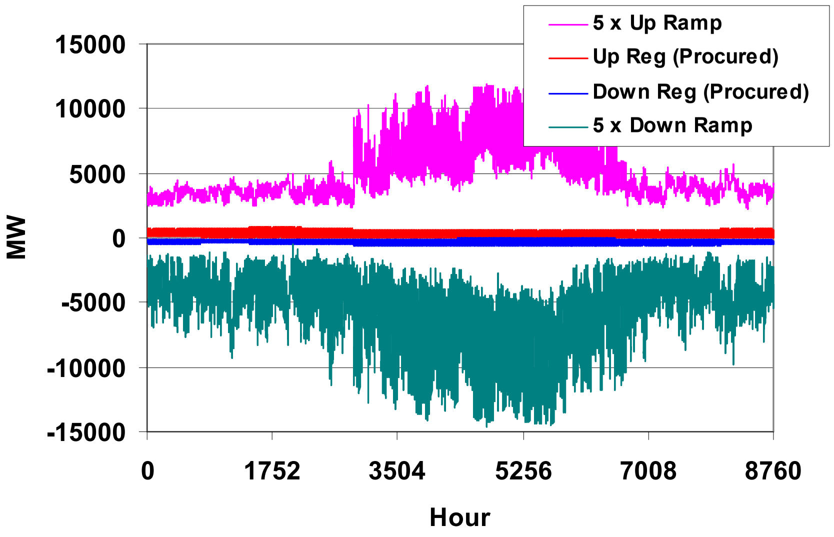
imagination at work

System Regulation Capacity

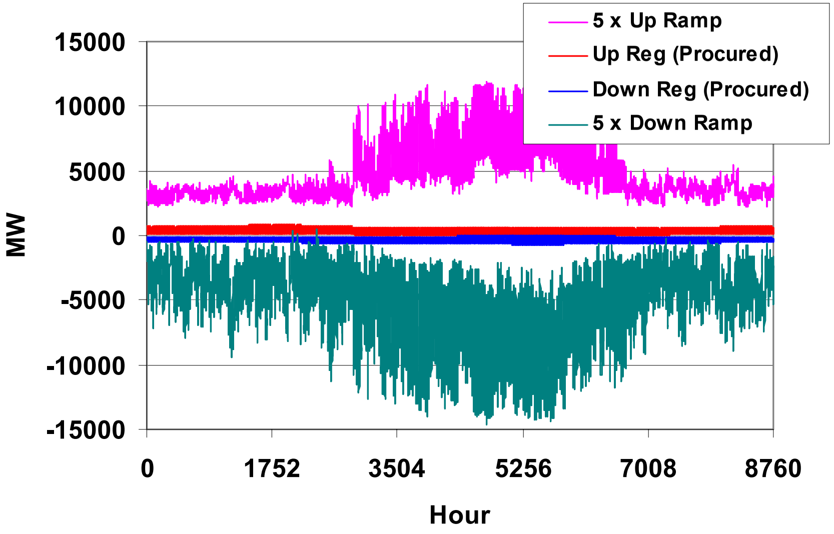
Load Alone



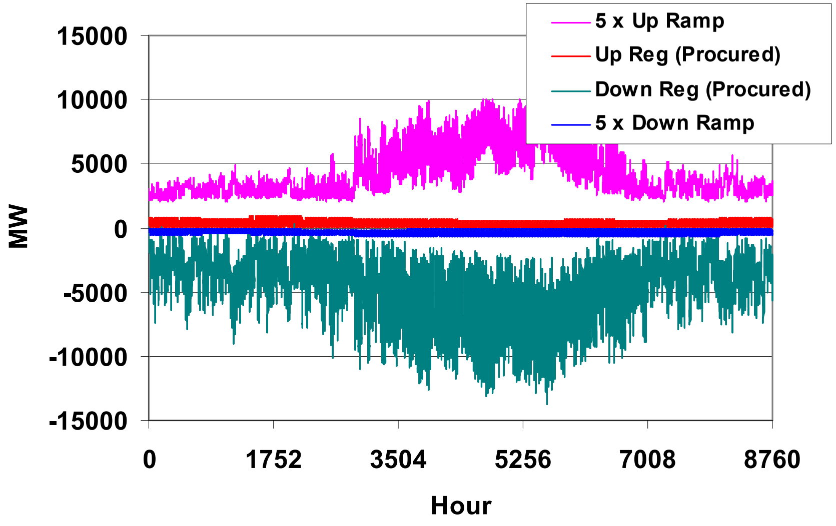
Load – 5000 MW Wind



Load – 10,000 MW Wind (1)

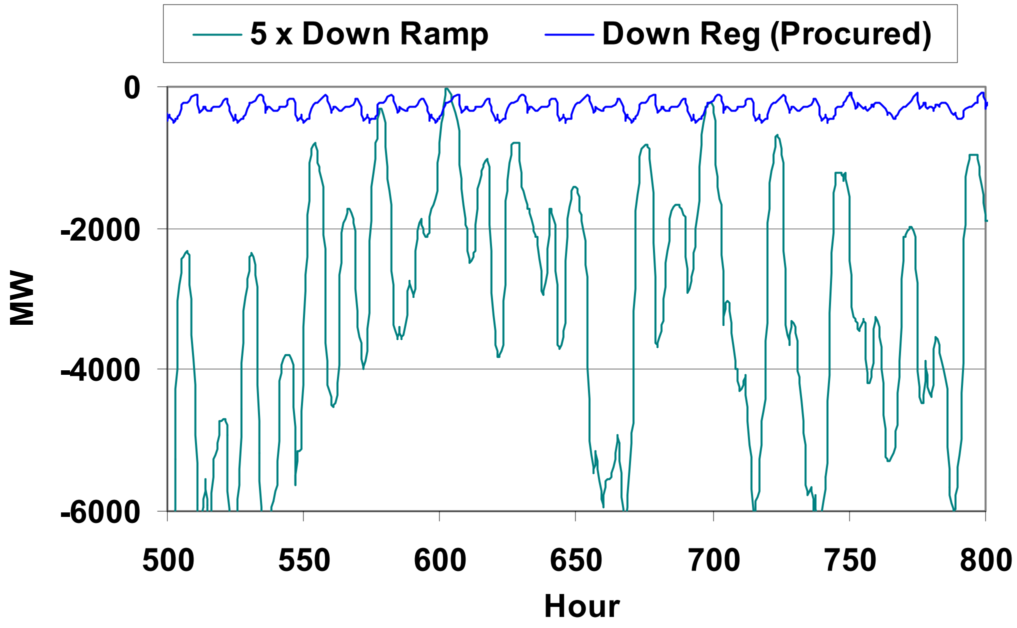


Load – 15,000 MW Wind



Range is limited to the amount which can be supplied in five minutes

Down Regulation Range Deficiencies



- Down-regulation requirements increase slightly.
- System flexibility is decreased due to reduced net load
- Result: system cannot accommodate down-regulation needs without adjusting dispatch
- Tradeoff between costs of adjusting dispatch versus curtailment or ramp limit of wind generators.

Wind (MW)	Hours Deficient	Total MWh Deficient	Average Deficiency (MW)	Maximum Shortfall (MW)
0	0	0	0	0
5,000	0	0	0	0
10,000 (1)	11	2709	246	482
10,000 (2)	7	1097	157	316
15,000	51	10308	202	712

Regulation Range

- Up-regulation range margin is reduced, but remains ample
  - Assuming 5-minute delivery
  - Margin could be less if a faster delivery is required
- Down-regulation range becomes an occasional issue for > 5,000 MW of wind
  - Committed conventional units are pushed toward their minimum load levels
  - Relatively few hours are involved for wind levels investigated
- Alternatives
  - Conventional units can be de-committed to provide range, can adversely impact economics during the next day
  - Allow wind plants to provide down-regulation
  - Apply up-ramp limits on wind generation
  - Curtail wind output
- Future operations will require increased flexibility from balance of generation

Regulation Service Costs

In this next set of slides, we will show:

- The impact of wind on per-unit costs of regulation services
- The costs of increased regulation services to accommodate wind penetration
- Emphasis on relative metrics

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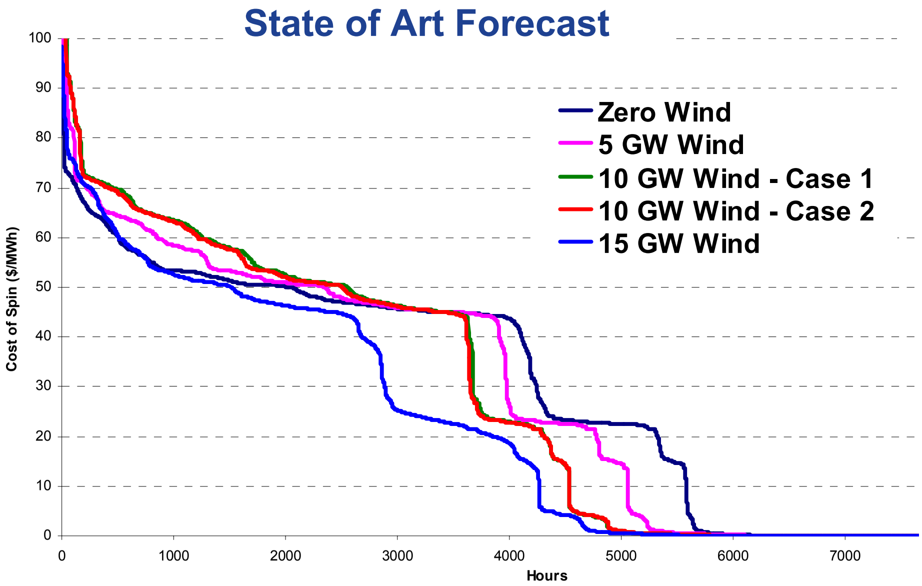
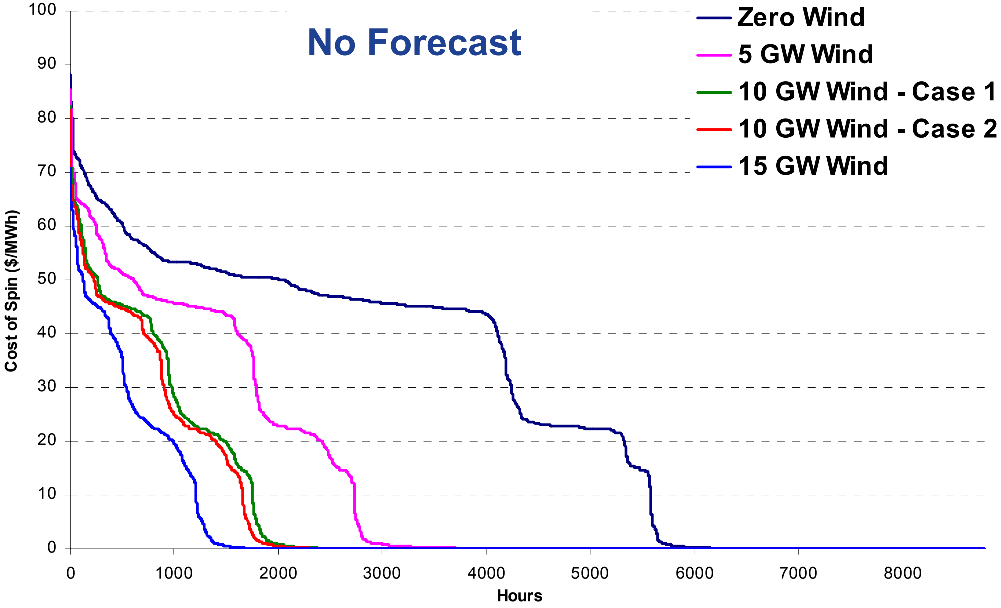
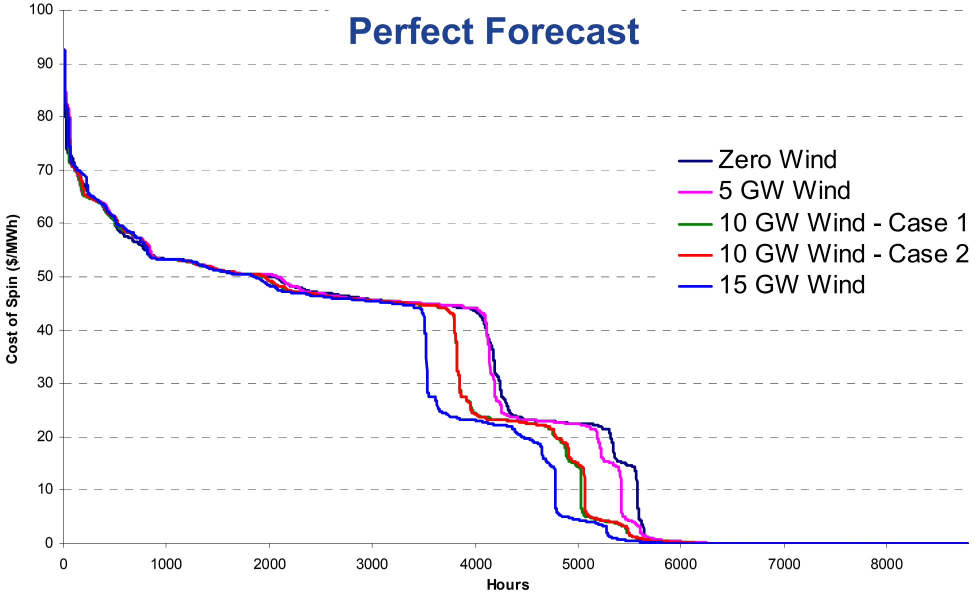
Spin Cost for Various Wind Penetrations


State of Art Forecast


No Forecast


Perfect Forecast

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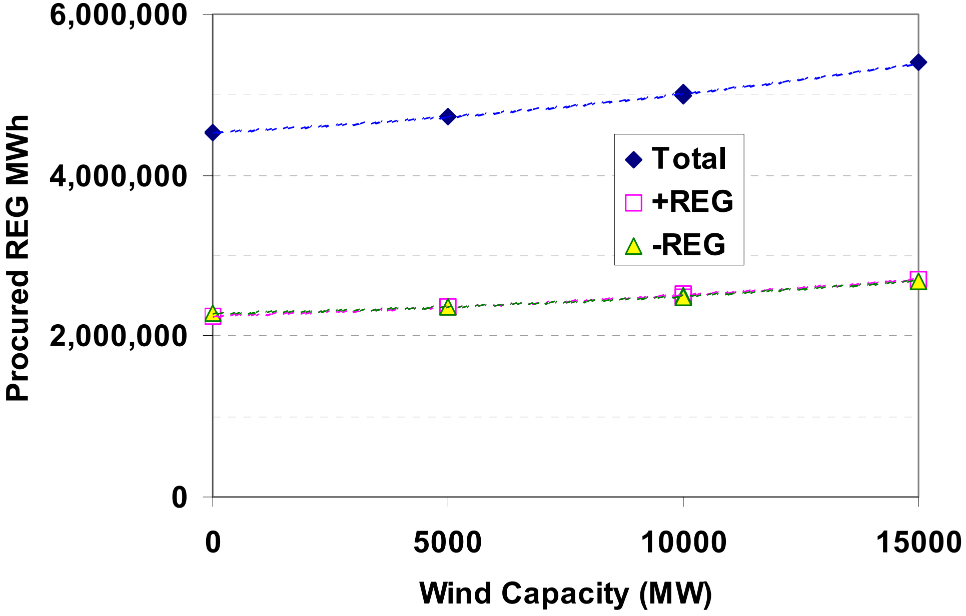
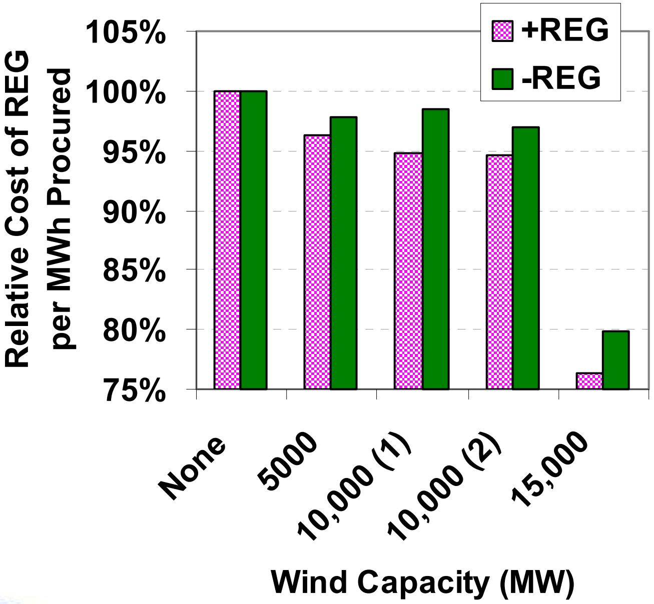
Regulation Cost Assumptions

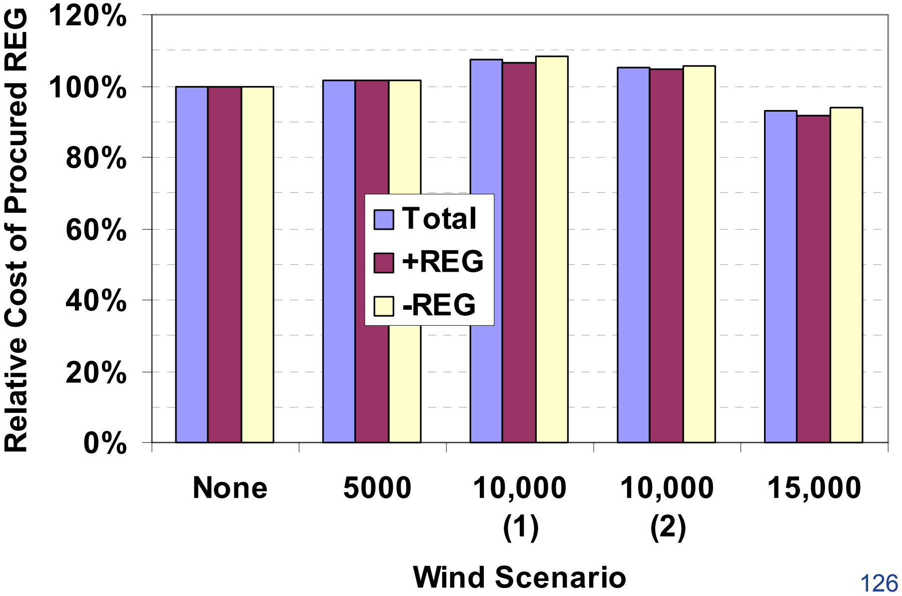
- REG cost is the greater of $5/MWh or the cost of spinning reserve
- Cost of wind curtailment added when –REG exceeds available range
  (spot price)
- Results most useful when considered on a relative basis

Cost of Meeting Regulation Service Requirements – S-o-A Forecast

- Reduction of net load slightly decreases per MWh cost of +REG and –REG, up through 10,000 MW scenarios
- Excess unit commitments due to load forecast errors, and reduced net load sharply drops regulation cost at 15,000 MW







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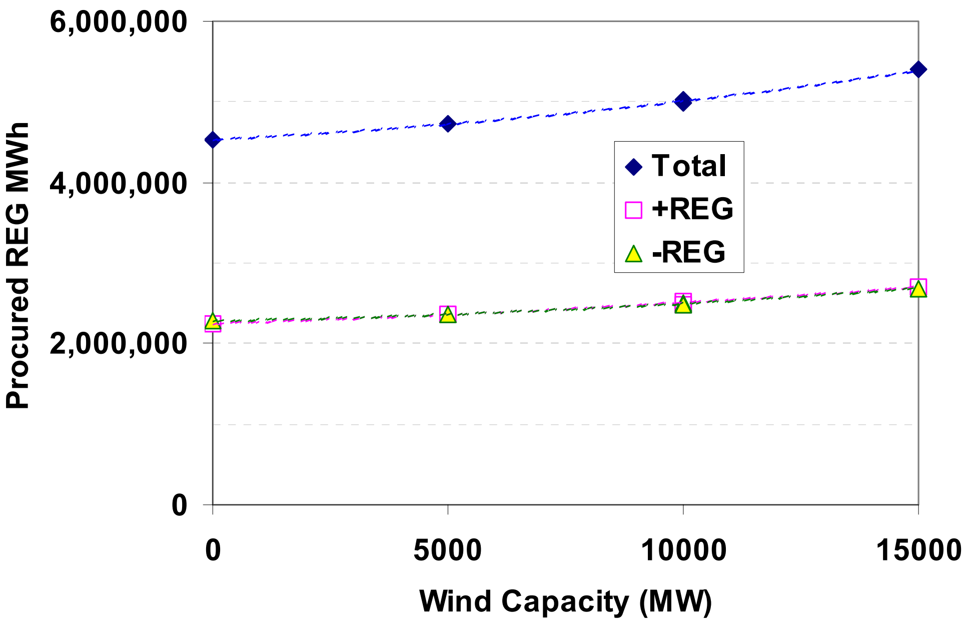
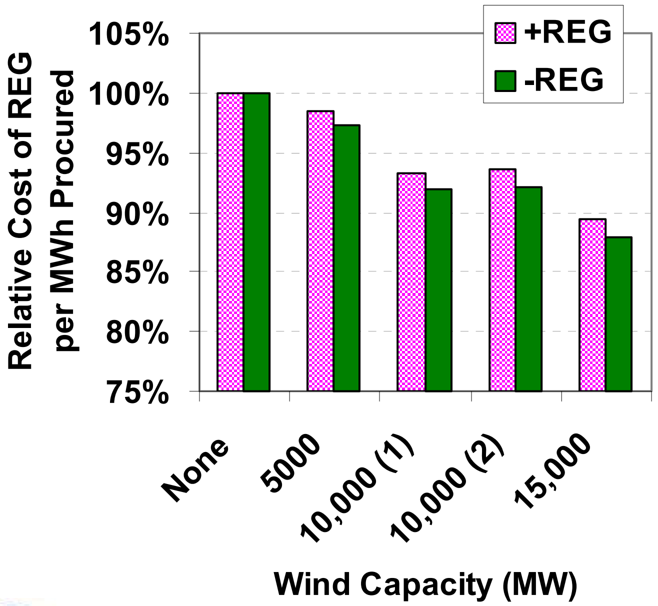
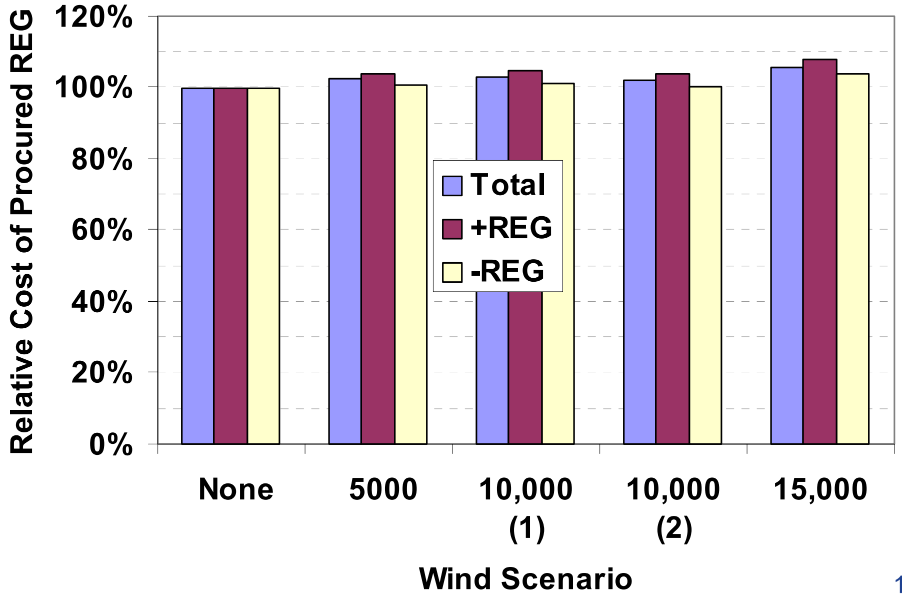
Cost of Meeting Regulation Service Requirements –

Perfect Forecast

- Reduced unit over-commitment allows unit costs of regulation to decrease gradually as net load is reduced by increased wind
- Total cost of +/- REG increases at a much lower rate than linear with respect to wind capacity



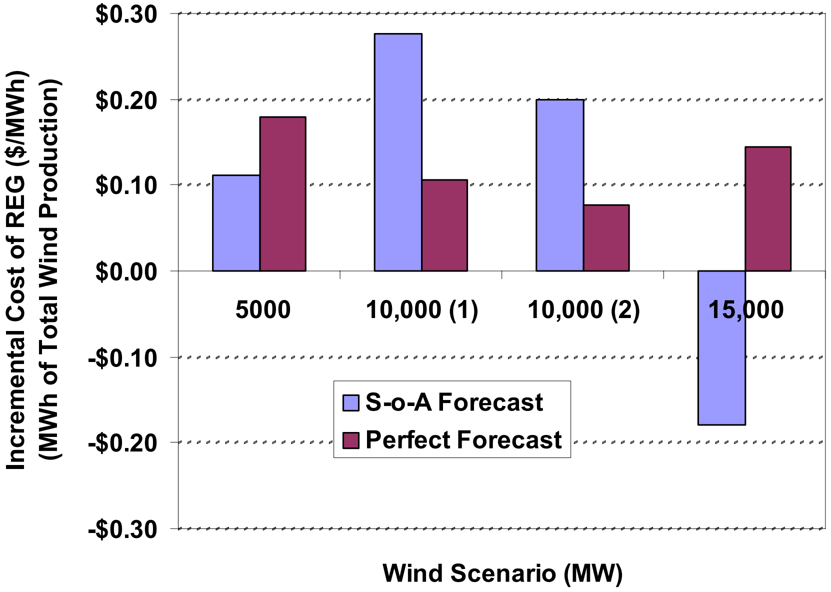




Regulation Costs Summary

	Wind Capacity (MW)	Reg-Up Cost ($MM)	Reg-Down Cost ($MM)	Total Reg. Cost ($MM)	Total Wind Generation (MWh)	Inc. Cost of Regulation ($/MWh)
	0	$66.88	$72.21	$139.09	0	
State-of-Art Wind Forecast	5,000	$67.90	$73.21	$141.11	17,940,311	$0.112
	10,000 (1)	$71.22	$78.14	$149.35	37,037,236	$0.277
	10,000 (2)	$70.12	$76.21	$146.33	36,180,453	$0.200
	15,000	$61.44	$67.94	$129.37	53,933,379	-$0.180
Perfect Wind Forecast	5,000	$69.54	$72.76	$139.09	17,940,311	$0.179
	10,000 (1)	$70.12	$72.93	$142.30	37,037,236	$0.107
	10,000 (2)	$69.36	$72.49	$143.05	36,180,453	$0.076
	15,000	$72.01	$74.83	$141.85	53,933,379	$0.144

- Per-unit costs of regulation are highly dependent on impacts of wind on dispatch
- Imperfect wind forecast leads to unit excess unit commitment, reducing regulation costs
- Results are volatile, makeup of future generation portfolio is critical



Forecast Error Analysis

Impact on Non-Spinning Reserves

Predictability Analysis

Day-ahead predictability of net load is important to unit commitment; inaccuracies increase operating costs and may require greater A/S procurement.

The next slides analyze net load predictability

Time of Year Predictability Analysis

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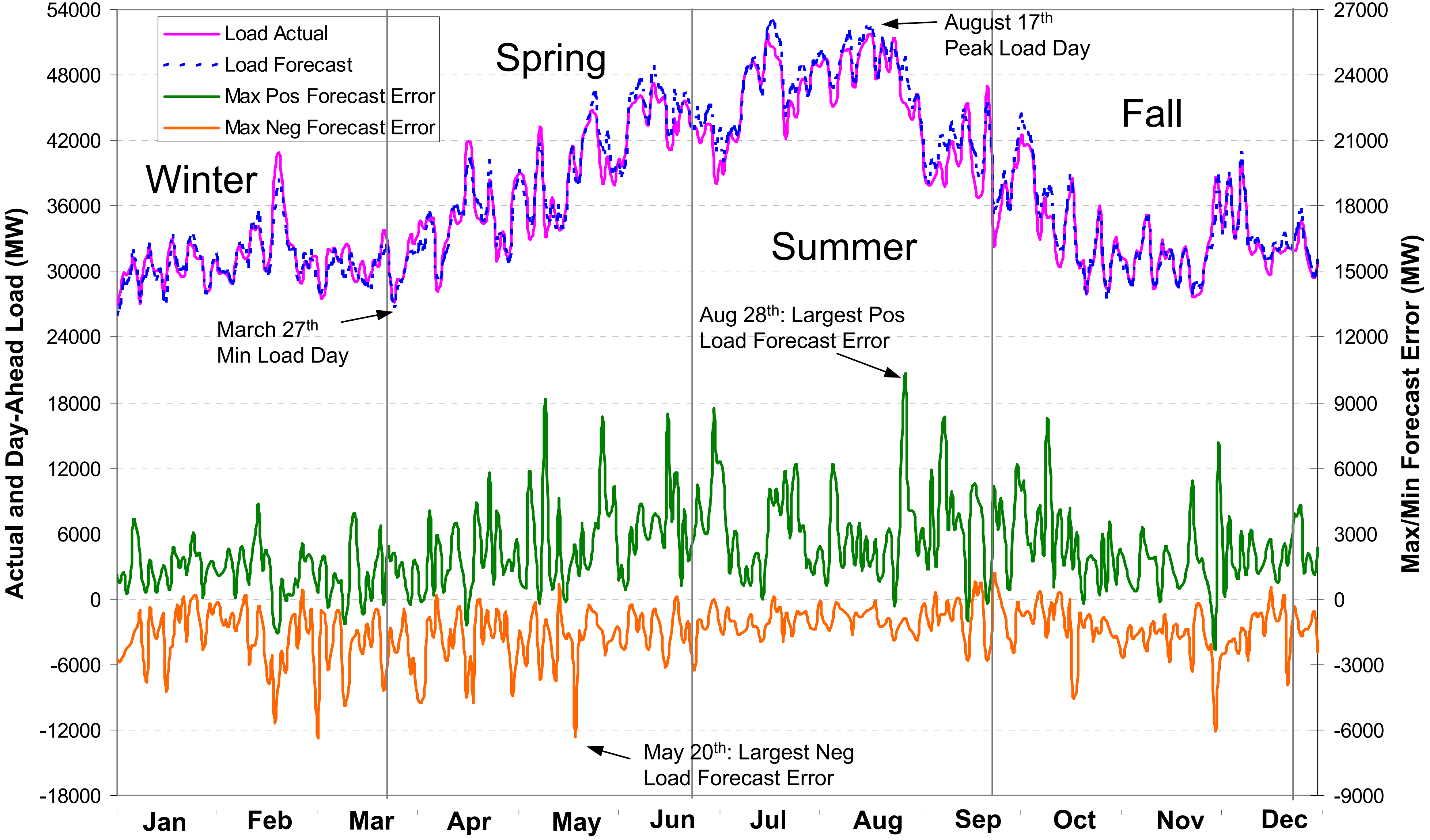
Load Yearly Average Profile and Largest Forecast Errors

Study Year Load with 15000 MW of Wind

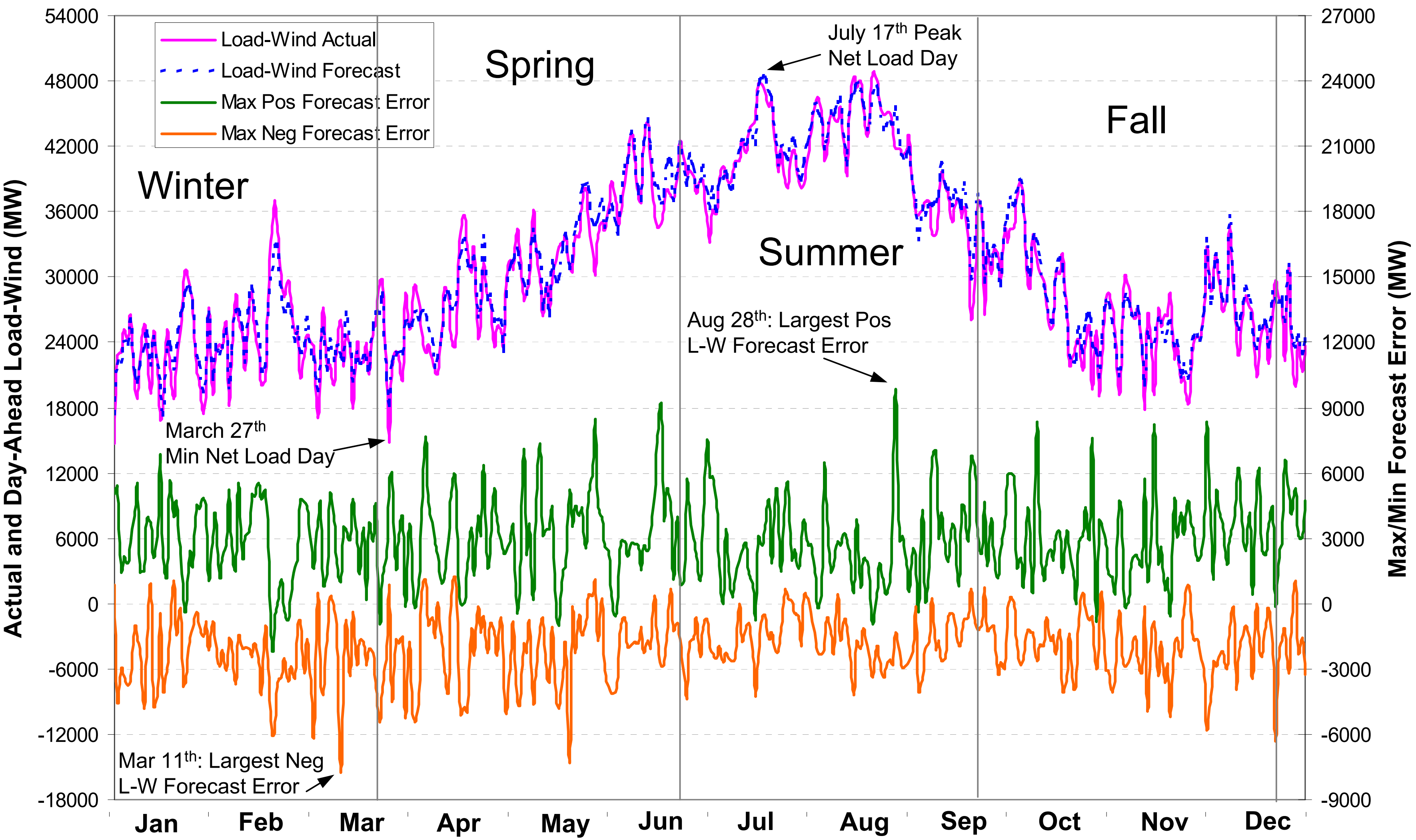


Max L-W Error = 10294 MW (Aug 28th)
MAE = **1296** MW (**3.5%** of Average)
RMSE = 1792 MW (4.9% of Average)
Sigma = 1755 (4.8% of Average)

Greater tendency to over-forecast load during the summer months

Net Load Yearly Average Profile and Largest Forecast Errors

Study Year Load with 15000 MW of Wind



Max L-W Error = 9675 MW (Aug 28th)
MAE = **1698** MW (**5.5%** of Average)
RMSE = 2199 MW (7.2% of Average)
Sigma = 2149 (7.0% of Average)

Wind generally increases net-load forecast errors in Winter and Spring more than Summer

Net Load and Wind Day-Ahead Predictability – Summary

(Study Year Data)

Net Load

Case	Std Dev MW (%)	MAE* MW (%)	RMSE** MW (%)	Max Error (MW)
Base Case: Load w/ no Wind	1755 (4.8)	1296 (3.5)	1792 (4.9)	10294
Load w/ 5000 MW Wind	1762 (5.1)	1338 (3.8)	1805 (5.2)	9951
Load w/ 10,000 MW Wind (1)	1928 (5.9)	1505 (4.6)	1974 (6.0)	9763
Load w/ 10,000 MW Wind (2)	1887 (5.8)	1467 (4.5)	1936 (5.9)	9786
Load w/ 15,000 MW Wind	2149 (7.0)	1698 (5.5)	2199 (7.2)	9765

* Mean absolute error

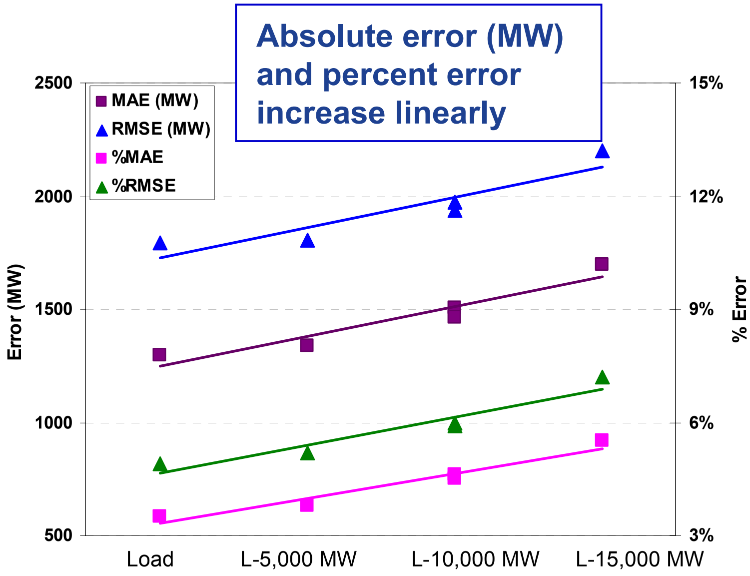
** Root mean square error – more affected by large deviations

Wind

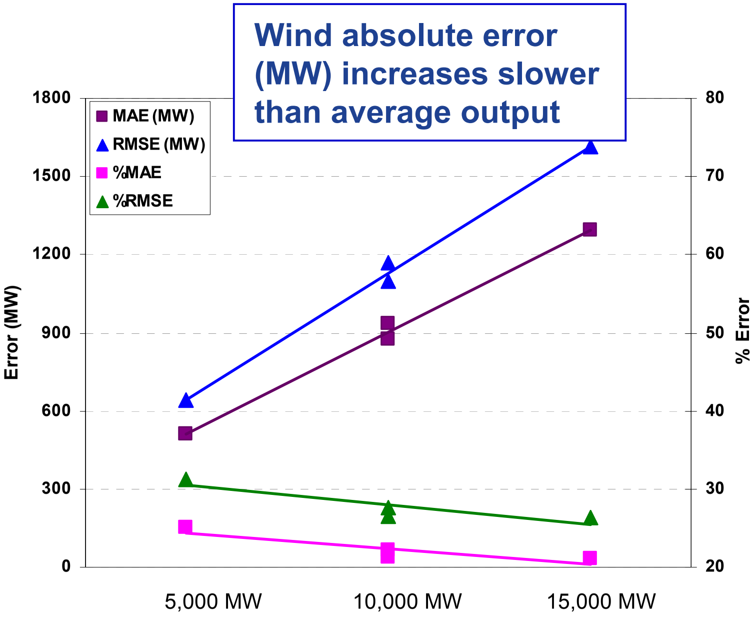
5000 MW Wind	638 (31.2)	511 (25.0)	639 (31.3)	-2529
10,000 MW Wind (1)	1167 (27.7)	935 (22.2)	1169 (27.7)	-4264
10,000 MW Wind (2)	1093 (26.5)	876 (21.3)	1096 (26.6)	-4078
15,000 MW Wind	1611 (26.2)	1294 (21.1)	1614 (26.3)	-5921

Error = forecast – actual

NB: Percent errors based on average output



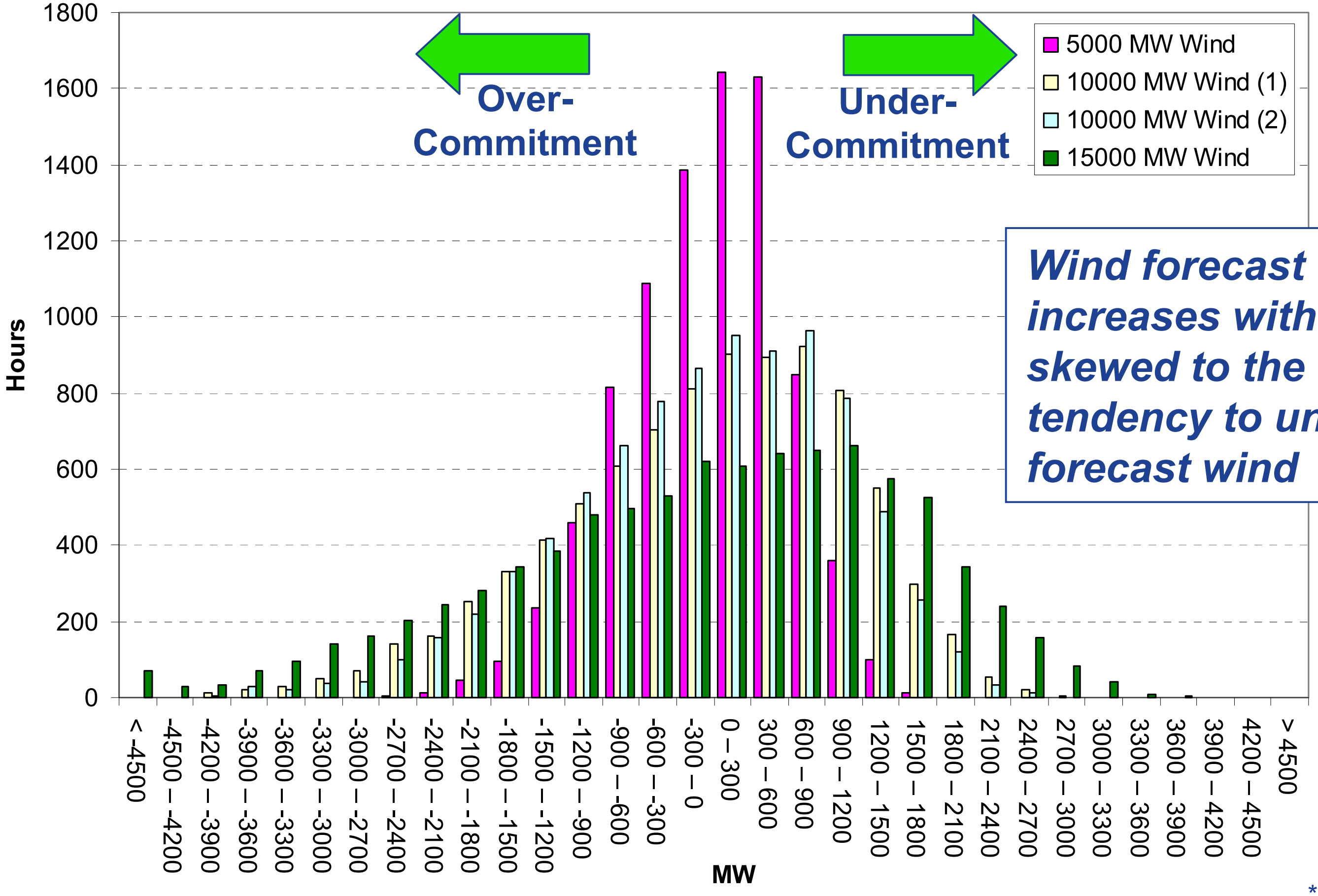
Absolute error (MW) and percent error increase linearly



Wind absolute error (MW) increases slower than average output

Hourly Wind Predictability (Forecast Errors*)

(Study Year Data)



Wind forecast error increases with wind, skewed to the left … tendency to under-forecast wind

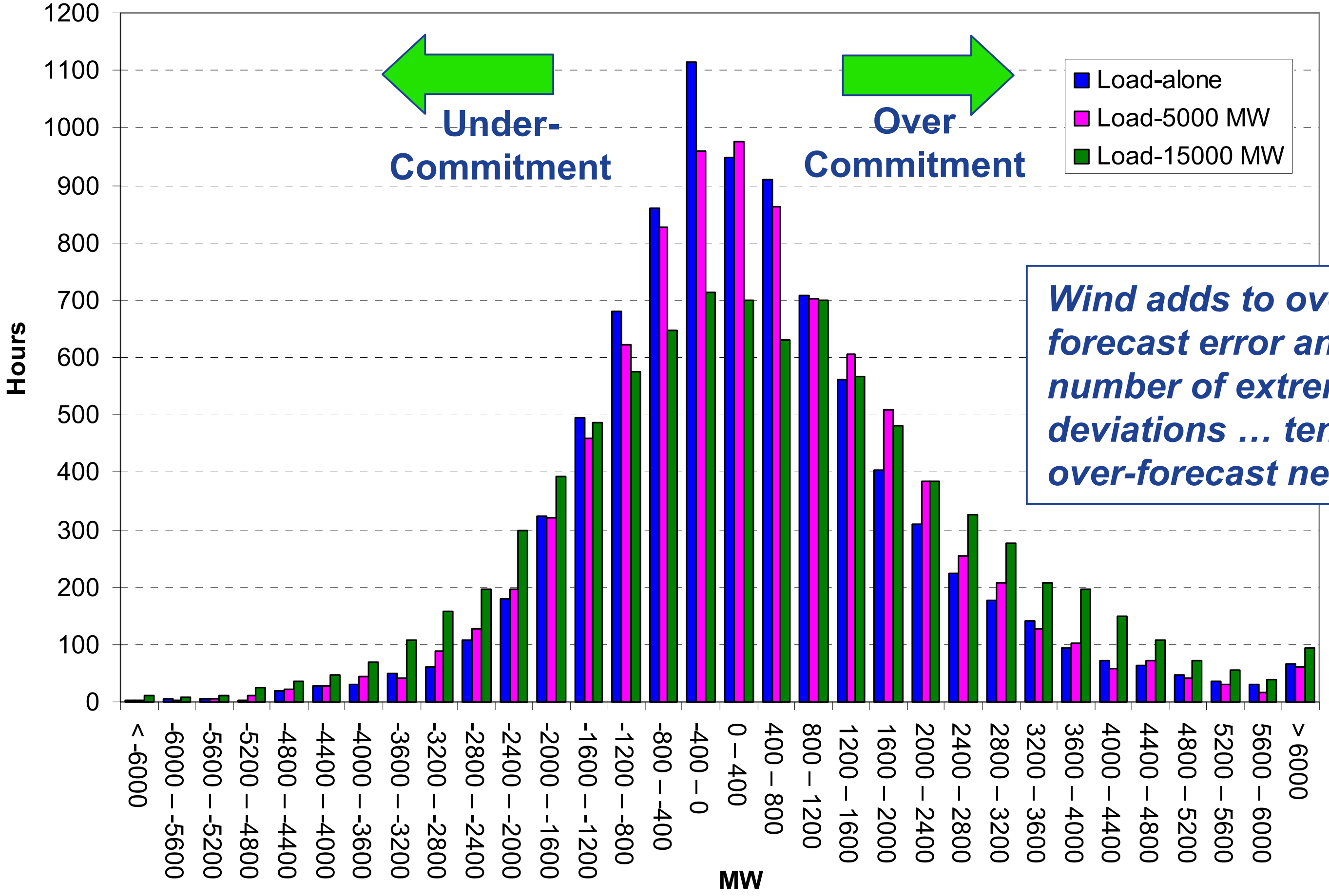
* Error = forecast – actual

Extreme Forecast Errors

	5000 MW Wind	**10,000 MW Wind (1)**	**10,000 MW Wind (2)**	**15,000 MW Wind**
>$\mu \pm 2.5\sigma$ (–/+)	107 / 9	125 / 2	121 / 1	114 / 1
>$\mu \pm 3\sigma$ (–/+)	33 / 0	38 / 0	48 / 0	43 / 0
> ± 2300 MW (–/+)	8 / 0	384 / 41	296 / 19	910 / 364
> ± 4600 MW (–/+)	0 / 0	0 / 0	0 / 0	67 / 0

Hourly Load-Wind Predictability (Forecast Errors*)

(Study Year Data)



Wind adds to overall net load forecast error and increases number of extreme deviations … tendency to over-forecast net load

* Error = forecast – actual

Extreme Forecast Errors

	Load-alone σ = 1755	**W/ 5000 MW Wind** σ = 1762	**Using load σ**	**W/ 15000 MW Wind** σ = 2149	**Using load σ**
>$\mu \pm 2.5\sigma$ (–/+)	64 / 185	67 / 152	66 / 160	51 / 111	132 / 271
>$\mu \pm 3\sigma$ (–/+)	15 / 95	17 / 74	17 / 77	10 / 43	51 / 129
> ± 2300 MW (–/+)	413 / 1048	547 / 1357		731 / 1591	
> ± 4600 MW (–/+)	26 / 186	51 / 217		72 / 316	

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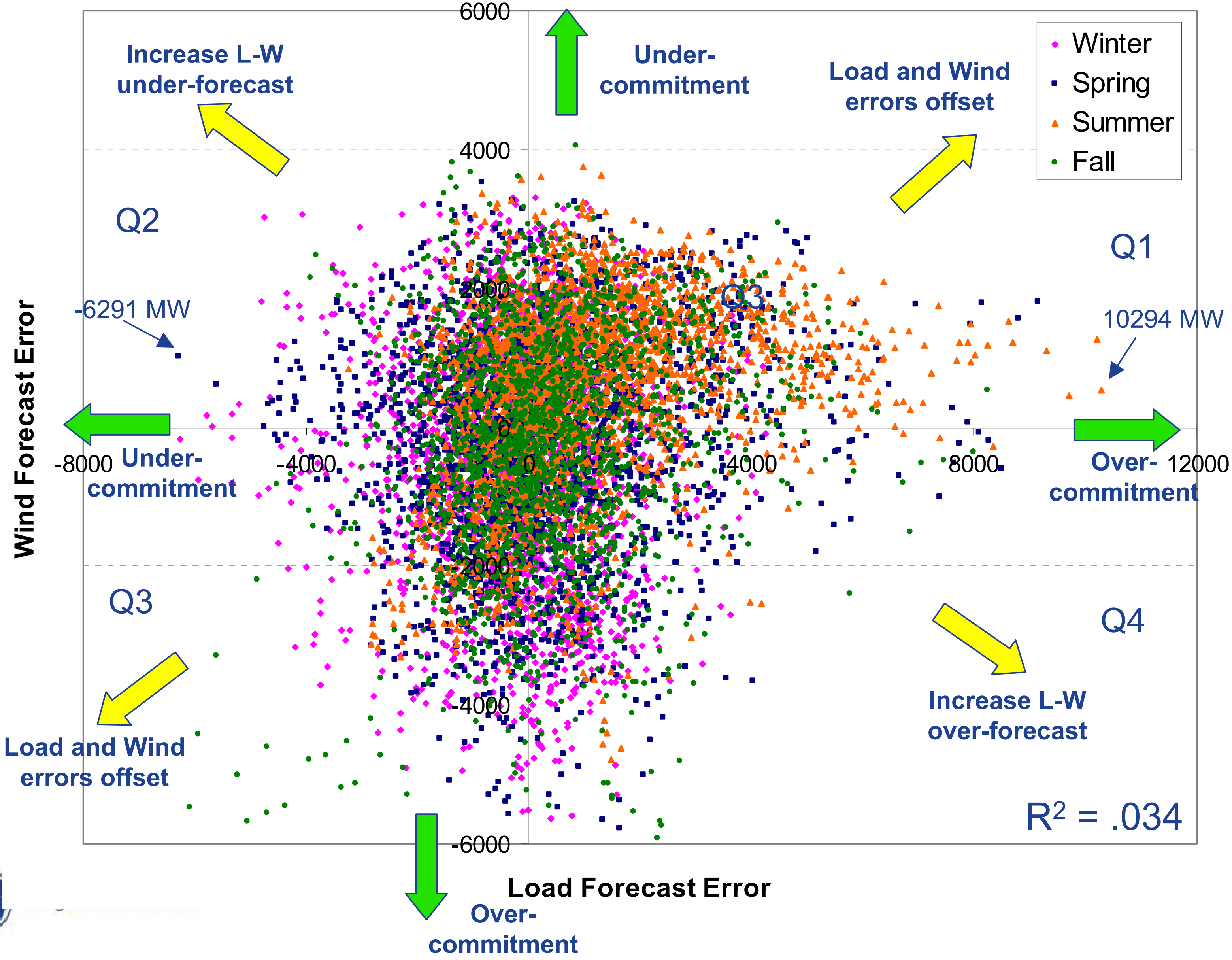
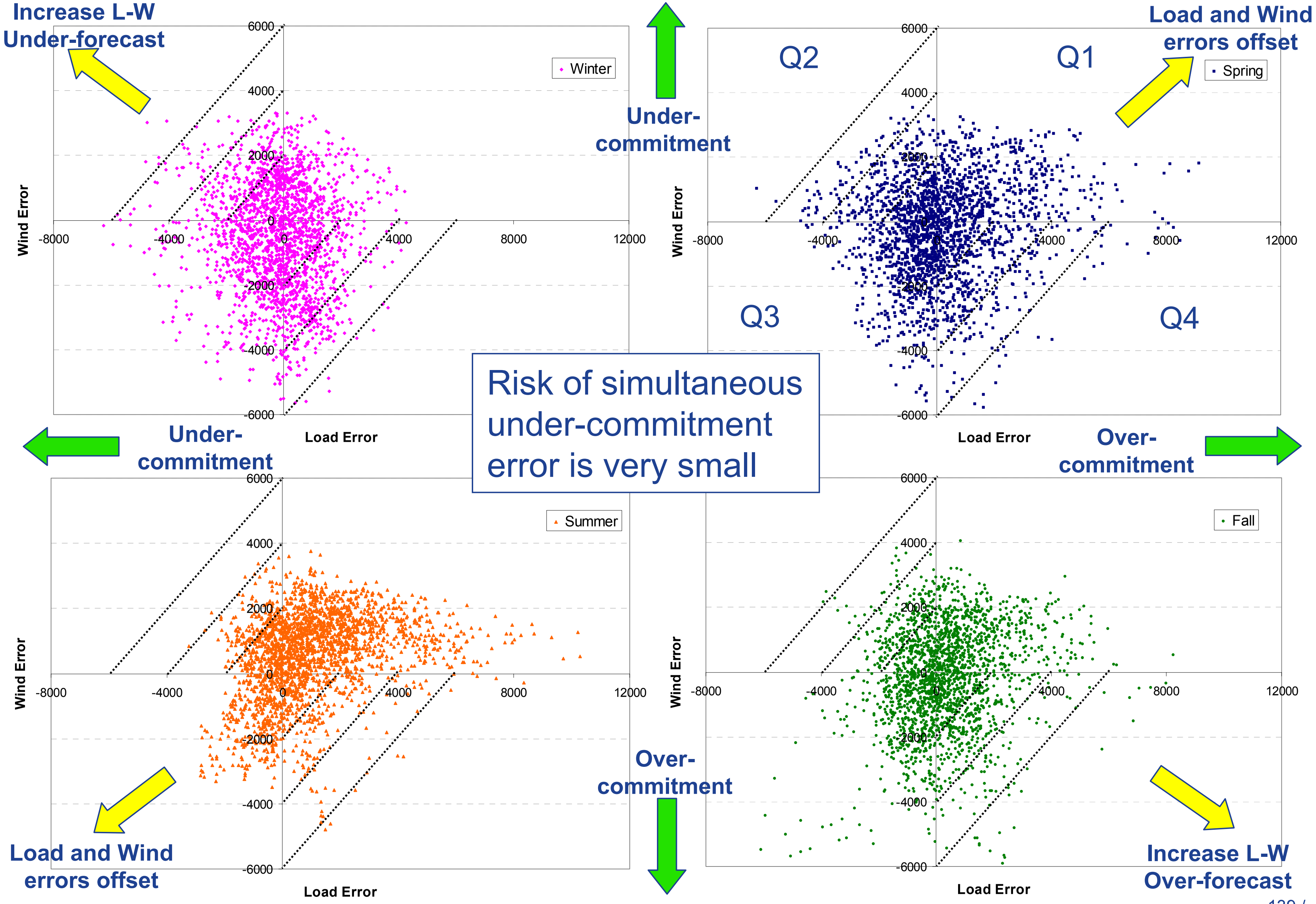
Correlation of Load and Wind Forecast Errors By Season

(Study Year Load and 15000 MW of Wind)



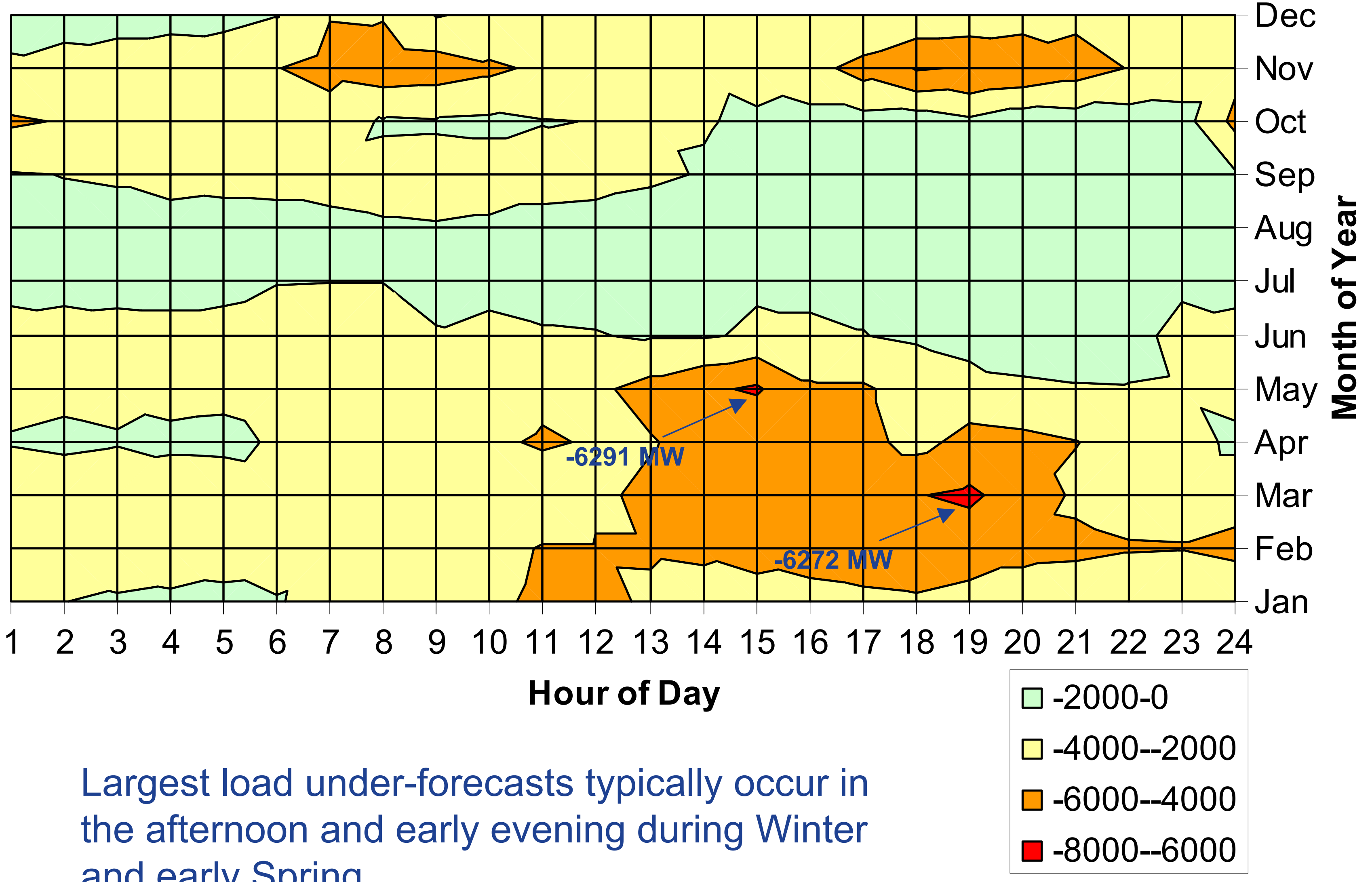
Correlation of Load and Wind Forecast Errors By Season (Study Year Load W/ 15000 MW)



Risk of simultaneous under-commitment error is very small

Timing of Negative Load Forecast Errors (Under-Commitment)

(Study Year)



Largest load under-forecasts typically occur in the afternoon and early evening during Winter and early Spring

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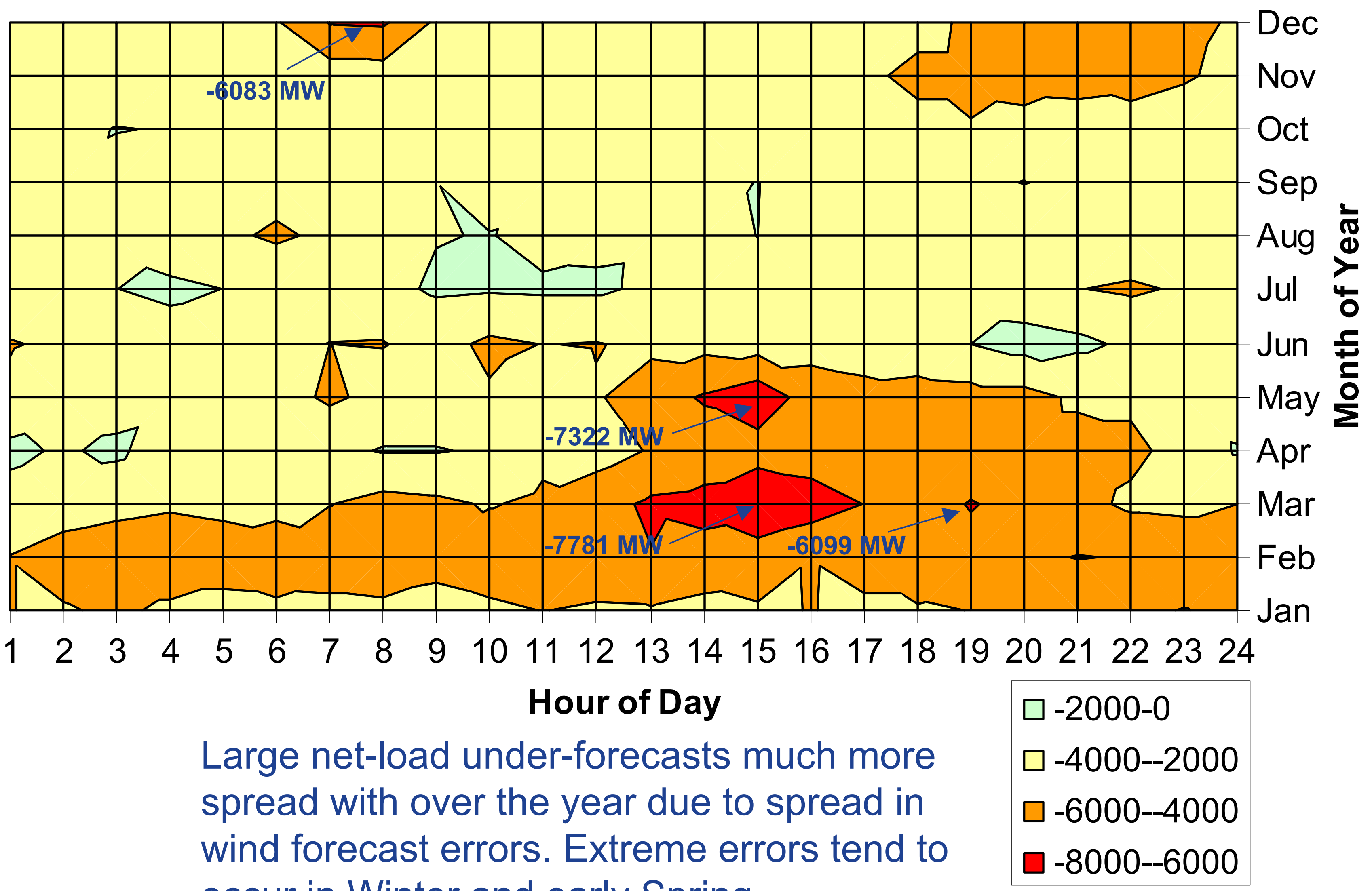
Timing of Negative Net-Load (Under-Commitment) Forecast Errors

(Study Year Load with 15000 MW of Wind)



Large net-load under-forecasts much more spread with over the year due to spread in wind forecast errors. Extreme errors tend to occur in Winter and early Spring.

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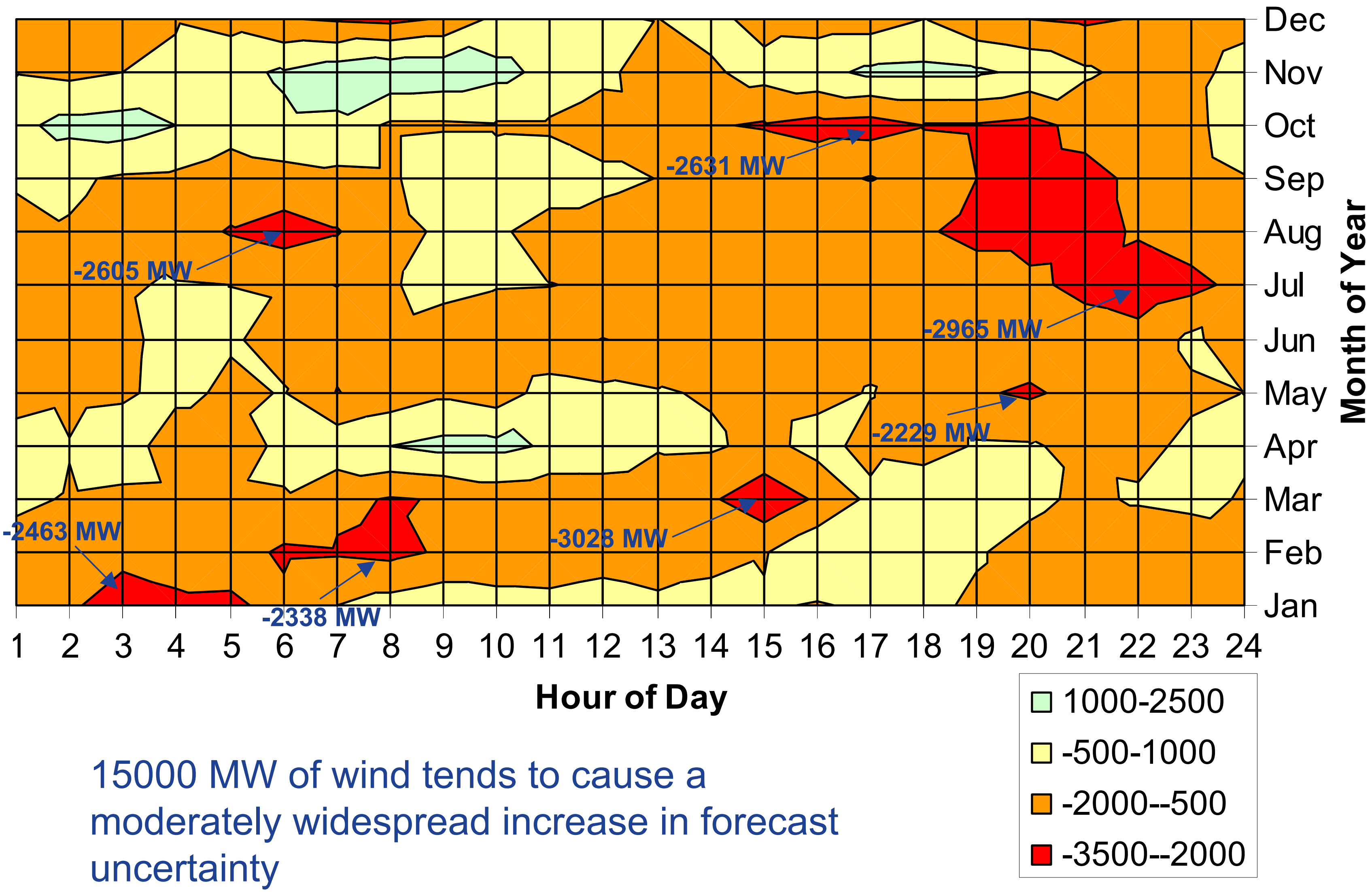
Incremental Under-Forecast Errors Due to Wind (Study Year Load with 15000 MW of Wind)



15000 MW of wind tends to cause a moderately widespread increase in forecast uncertainty

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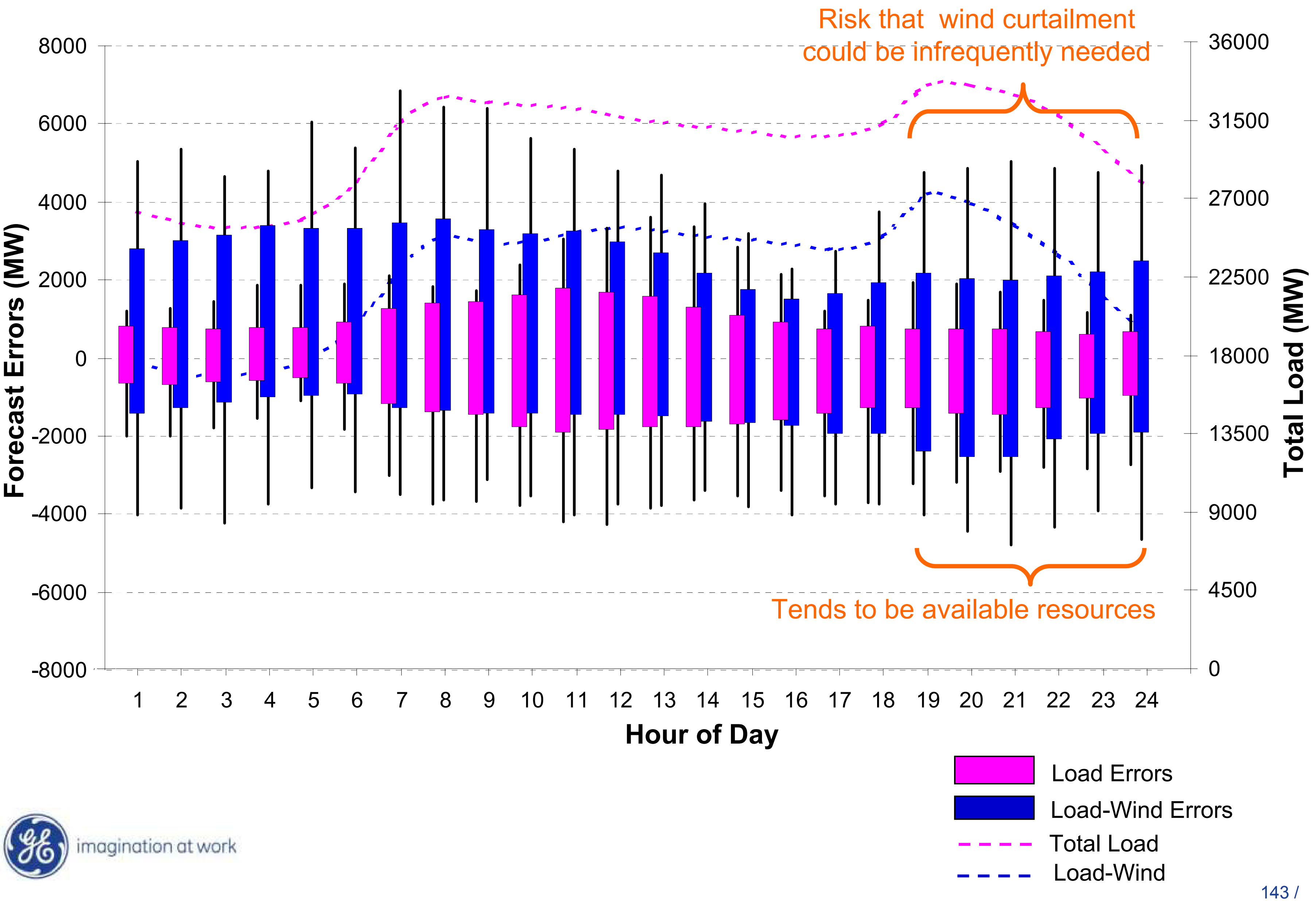
January Hourly Load and Net Load Forecast Errors (Avg. +/- sigma, Minimum, Maximum)

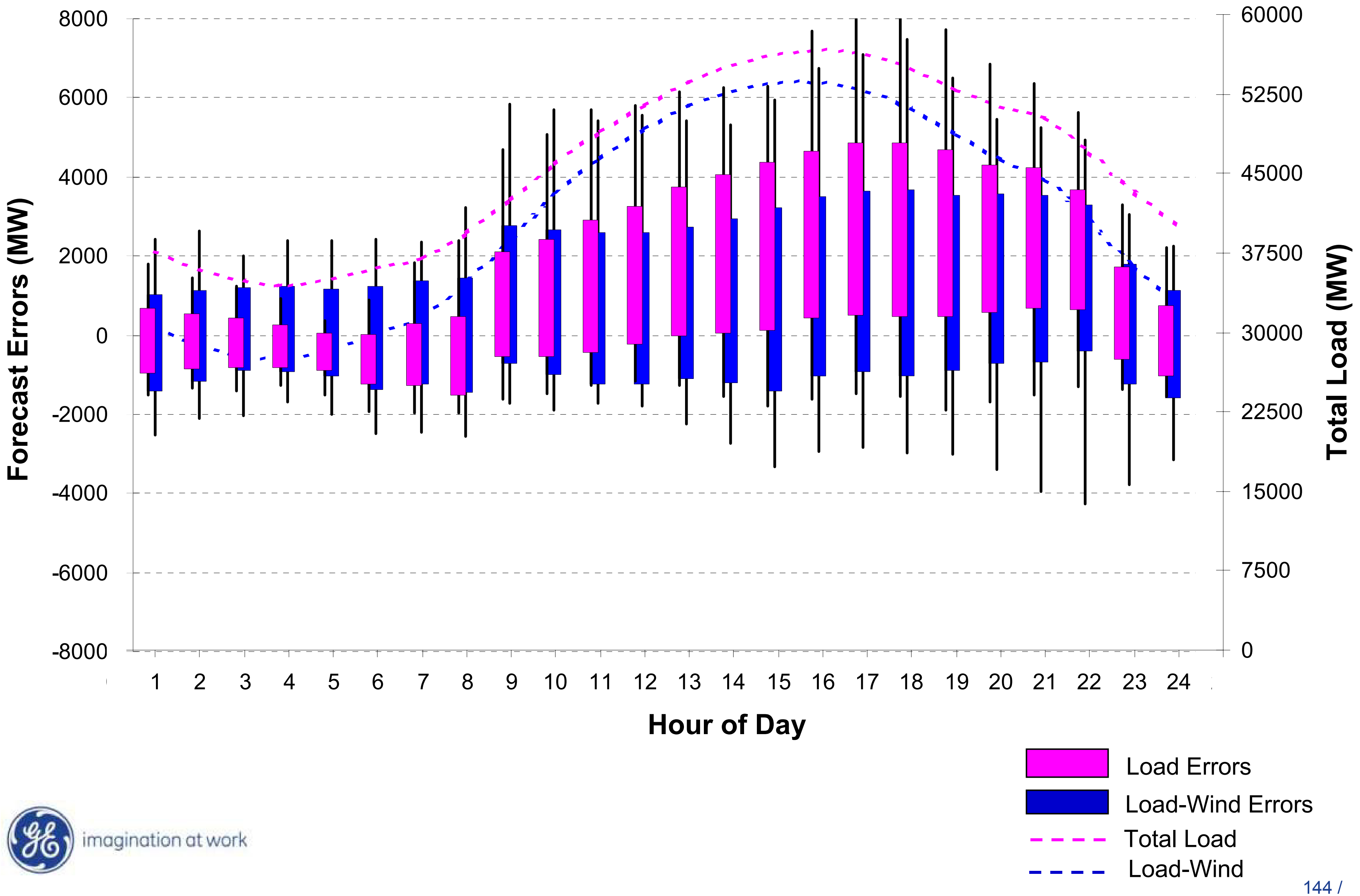
(Study Year Load with 15000 MW of Wind)



Risk that wind curtailment could be infrequently needed

Tends to be available resources

July Hourly Load and Net Load Forecast Errors (Study Year Load with 15000 MW of Wind) (Avg. +/- sigma, Minimum, Maximum)



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Observations and Conclusions

- Risk of under-commitment tends to occur off-peak when impact is low
  - Under-commitment aggravated by using a higher confidence level wind forecast
- During summer peak hours, wind forecast error tends to partially cancel apparent bias in mean load forecast towards over-commitment
- Increased wind penetration does not create an obvious requirement for across-the-board non-spin reserve requirements increase
  - Periods where uncertainty is high and resources are tight may require addition of NSRS
  - Consider a longer-term NSRS service

Overall Conclusions

- Addition of wind requires a moderate increase of ancillary service requirements
- At certain low-load, high-wind conditions, providing down-regulation can be a challenge
- Present ERCOT procurement methodologies:
  - Regulation algorithm adequate, some incremental improvements are possible
  - Responsive reserve procedure adequate, may need to account for predicted wind risk periods
  - Non-spin can be a preferable alternative to carrying large amounts of RRS during high-risk periods
- Increased regulation services create a small increment (1%) in cost relative to value of MWh supplied by wind