ERCOT
Wind Impact / Integration Analysis

Phase 2 Review

Ancillary Services Requirements

February 1, 2008

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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

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

This presentation covers Phase 2

Recap of Phase 1

- Detailed minute-by-minute models of net load developed for five scenarios:
  - 0, 5000, (2x) 10000, 15000 MW wind
  - Load data based on ERCOT historic records from 2005-2006, scaled to projected 2007-2008 level
  - Synchronized wind data developed by AWS Truewind using mesoscale meteorological models
- Major conclusions:
  - Diurnal behavior of wind anti-correlated with load
  - Larger daily swings in net load with increasing wind
  - Wind has more impact on longer-term ramp rates than on random net-load variation
  - Net load can reach low values at 15,000 MW wind capacity, 57% instantaneous penetration
  - Net load forecast error driven primarily by load forecast error – net load forecast with 15,000 MW wind is incrementally > load alone
  - 15,000 MW of wind yields +23% in 1-hr variability, +23% in forecast error – all results are very linear with wind

Regulation Requirements

In this next set of slides, we will show:

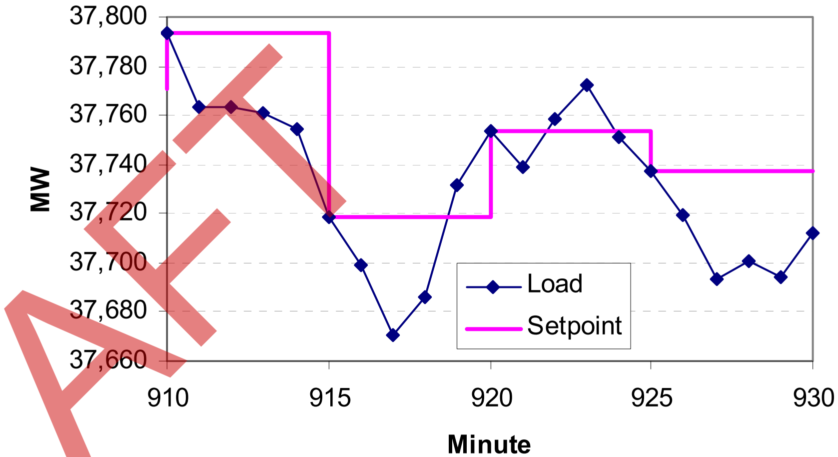
- The definitions of regulation in the ERCOT nodal market
- Regulation required (deployed)

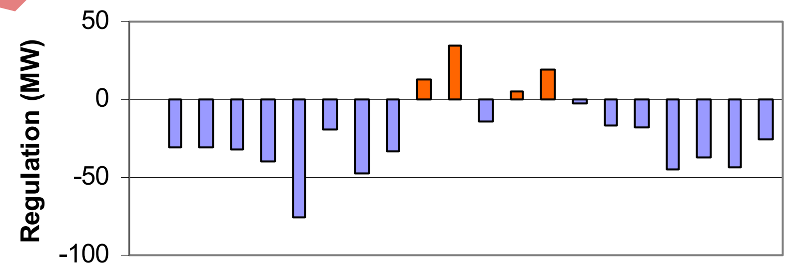
Key issues are:

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

Regulation Definition in the Nodal Market
(per ERCOT staff)

- Units on economic dispatch “step” to actual load levels 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)





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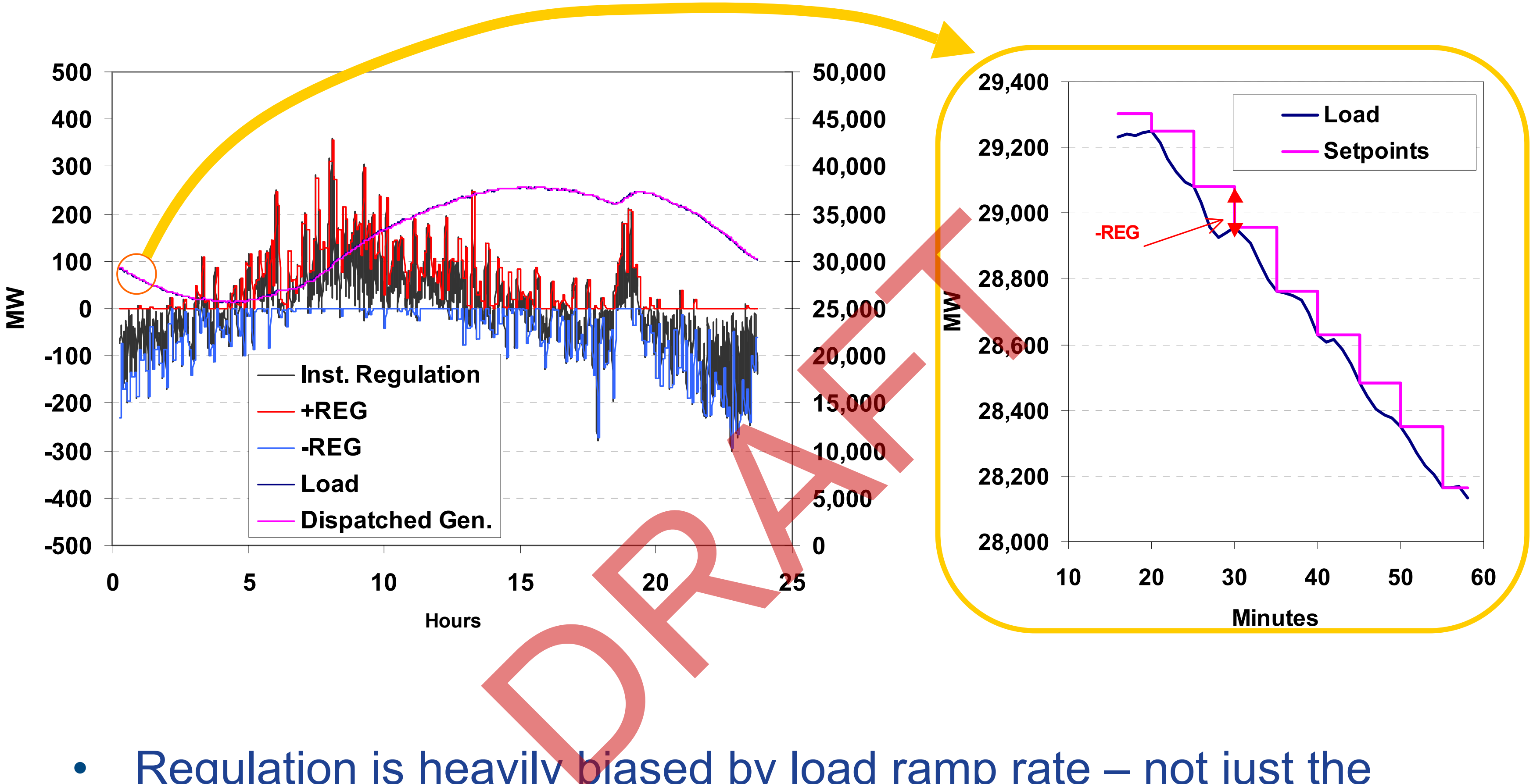
Regulation Through a Typical Day (without wind)



- Regulation is heavily 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

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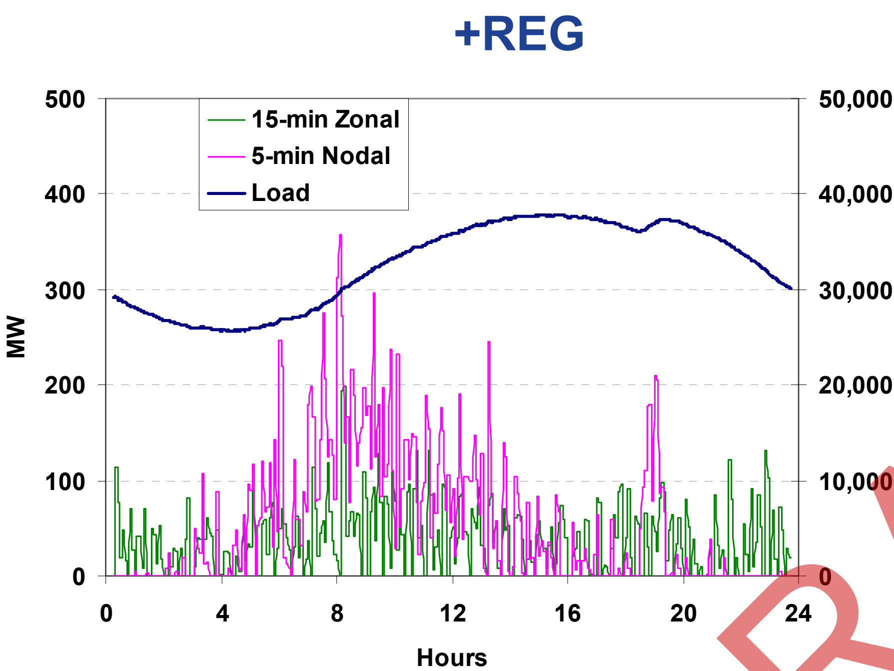
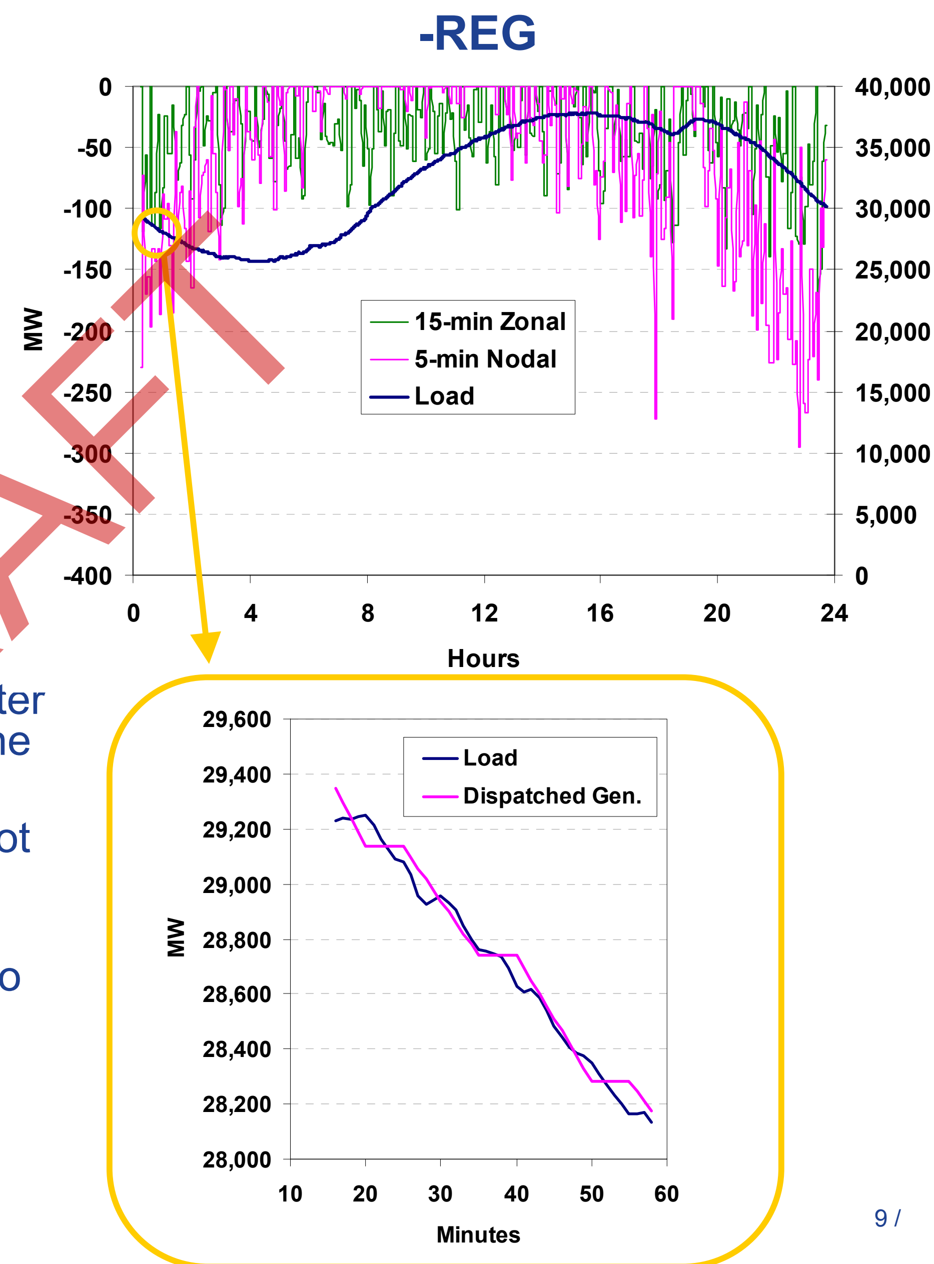
Differences with Zonal Method

Typical spring day (April 1), without wind





- Regulation requirements are much greater with the new nodal method, relative to the zonal method presently employed
- Regulation results in this study should not be evaluated relative to historic requirements
- Increased regulation requirements due to wind should be viewed incrementally, relative to no wind with the same regulation methodology

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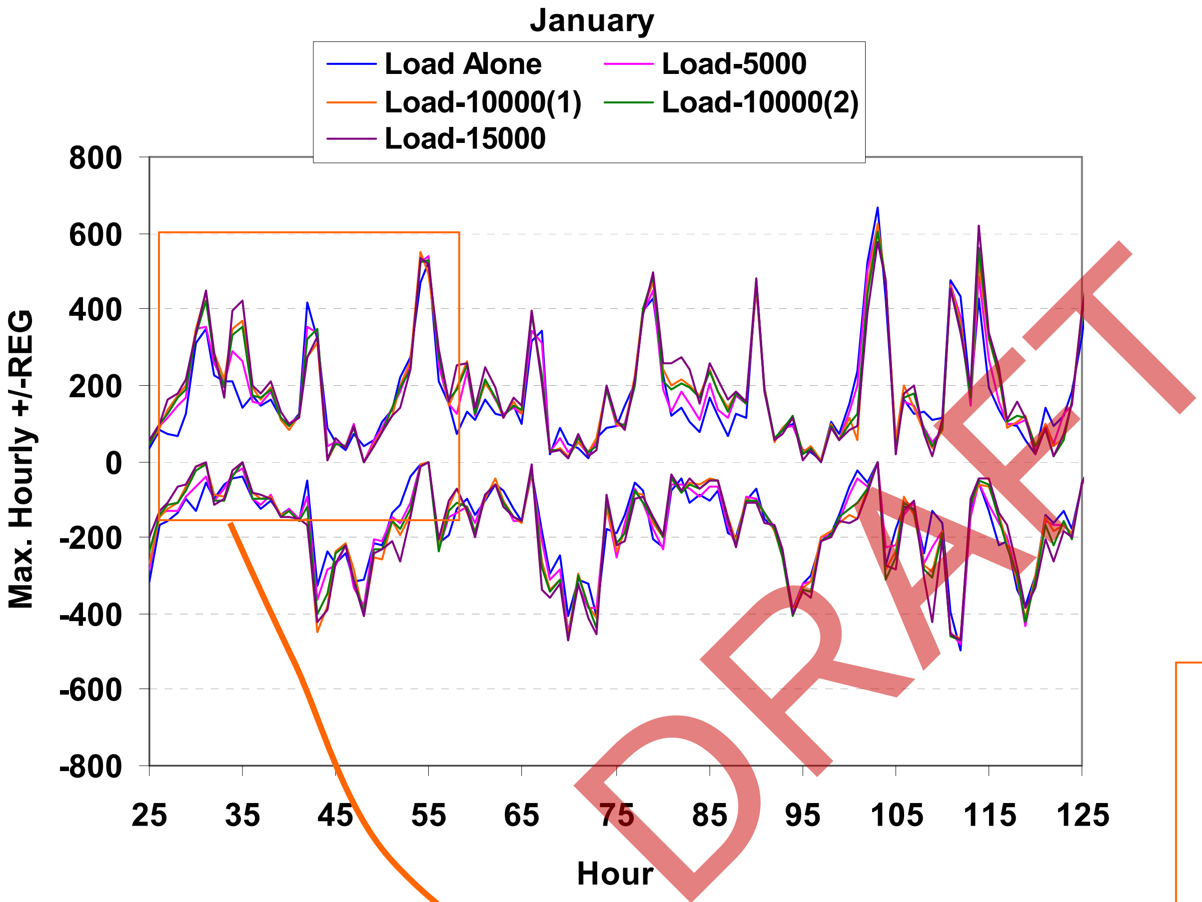
Terminology and Abbreviations

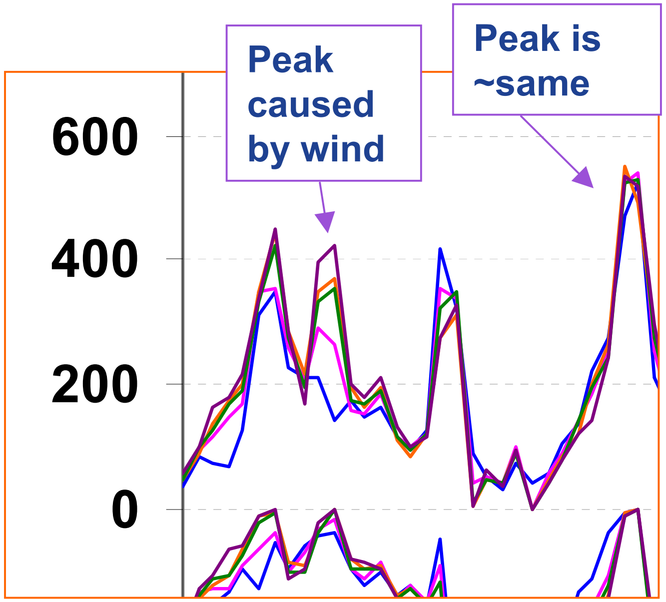
The following terminology and abbreviations regarding regulation are used in this presentation:

- **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)

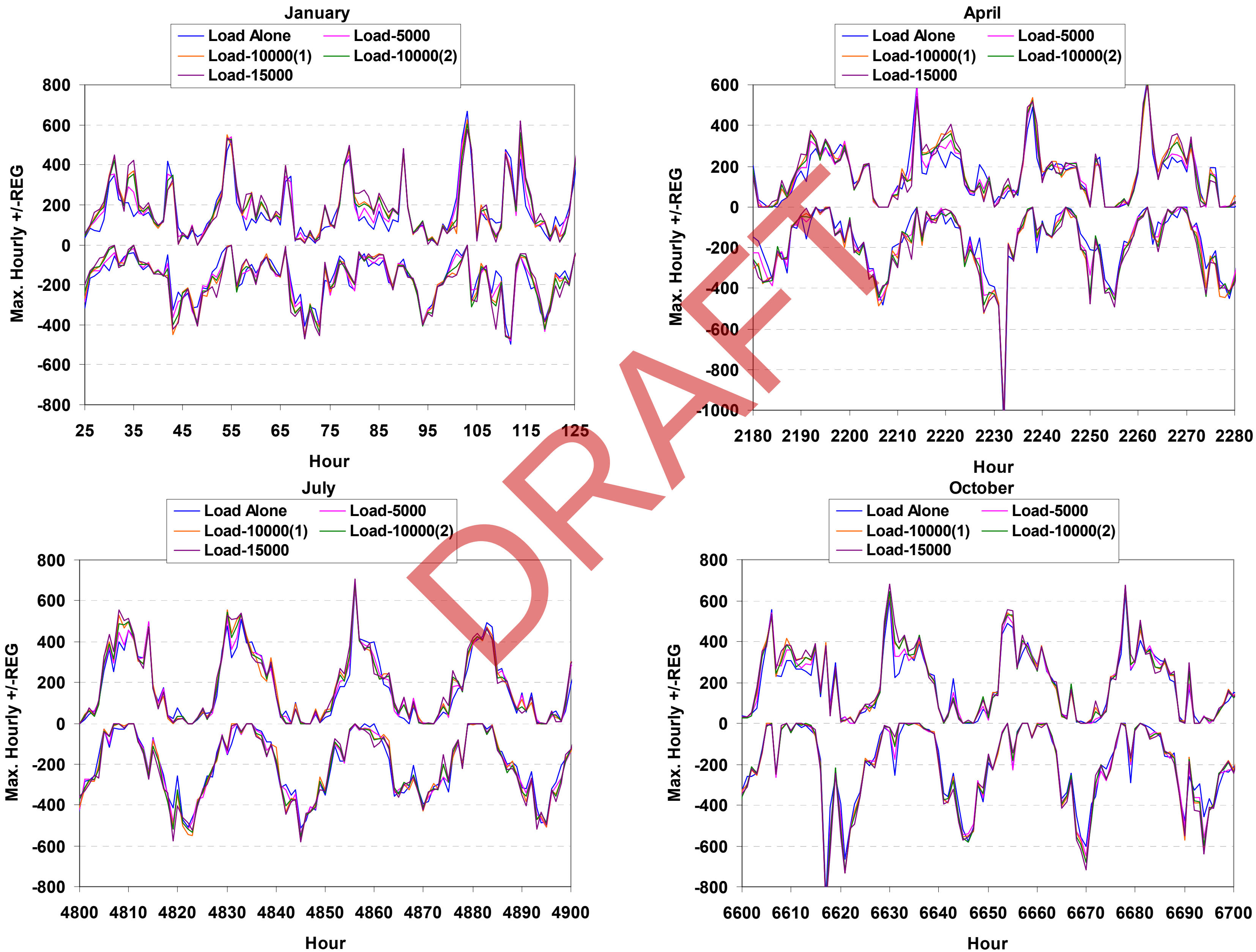
Max. Hourly Deployed Regulation – January Example



- ~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

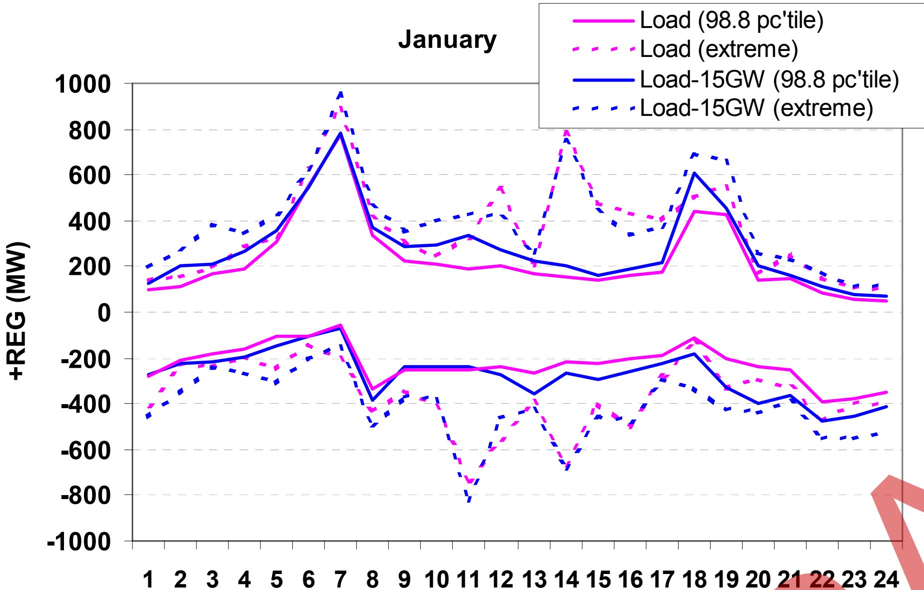


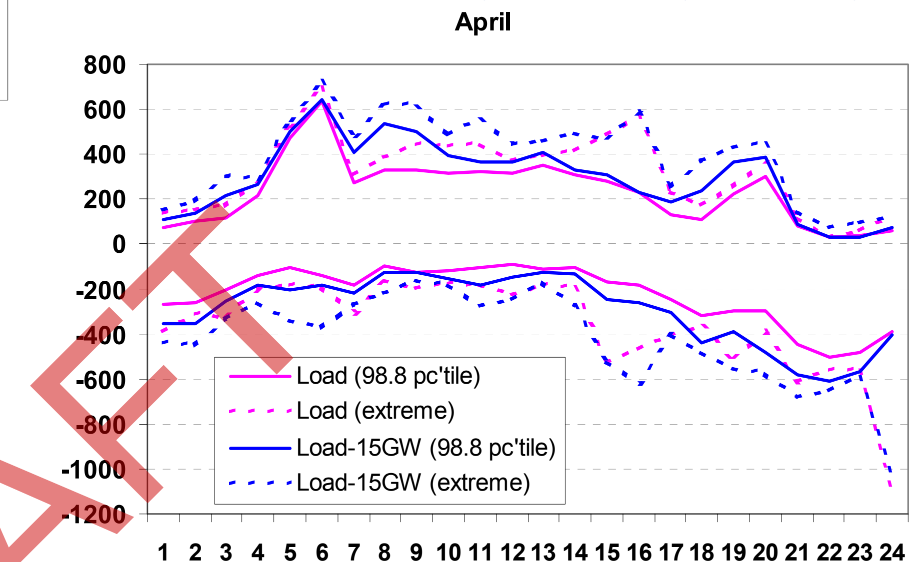
Max. Hourly Deployed Regulation Time Series Samples

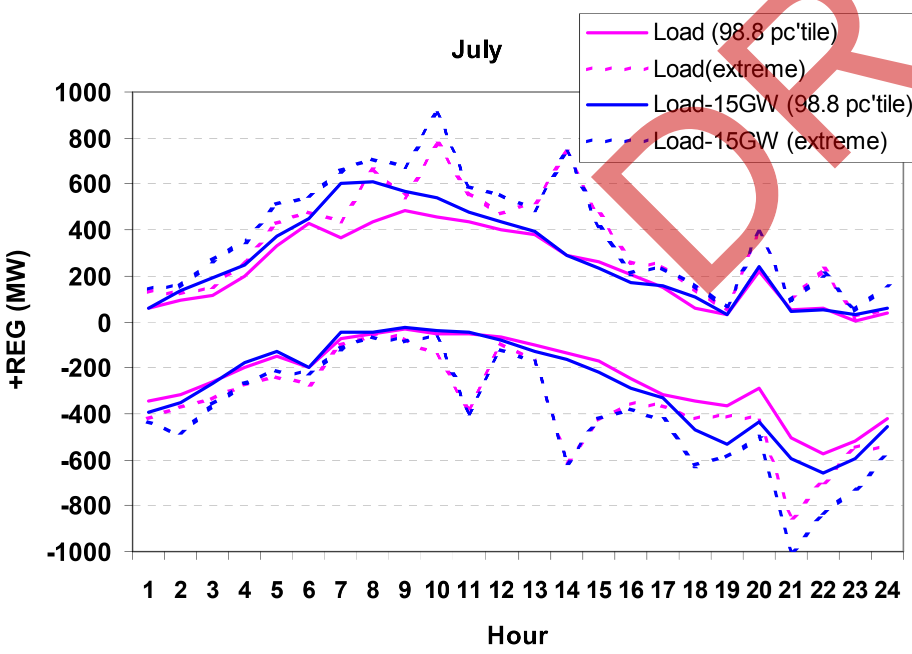


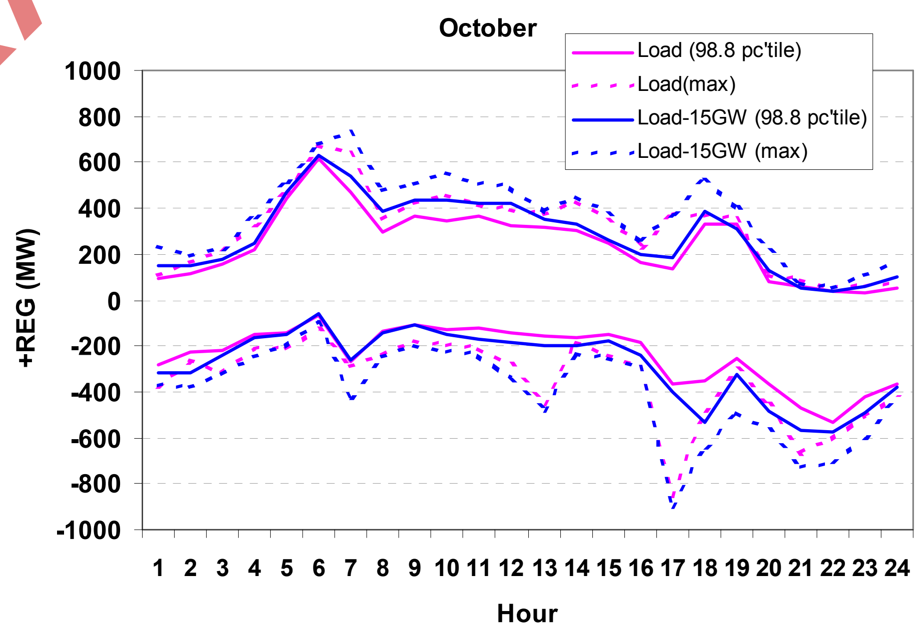
Hourly Extreme and 98.8th Percentile Regulation Deployed

Statistics compiled from all days of month, by hour of day









Deployed Regulation Statistics

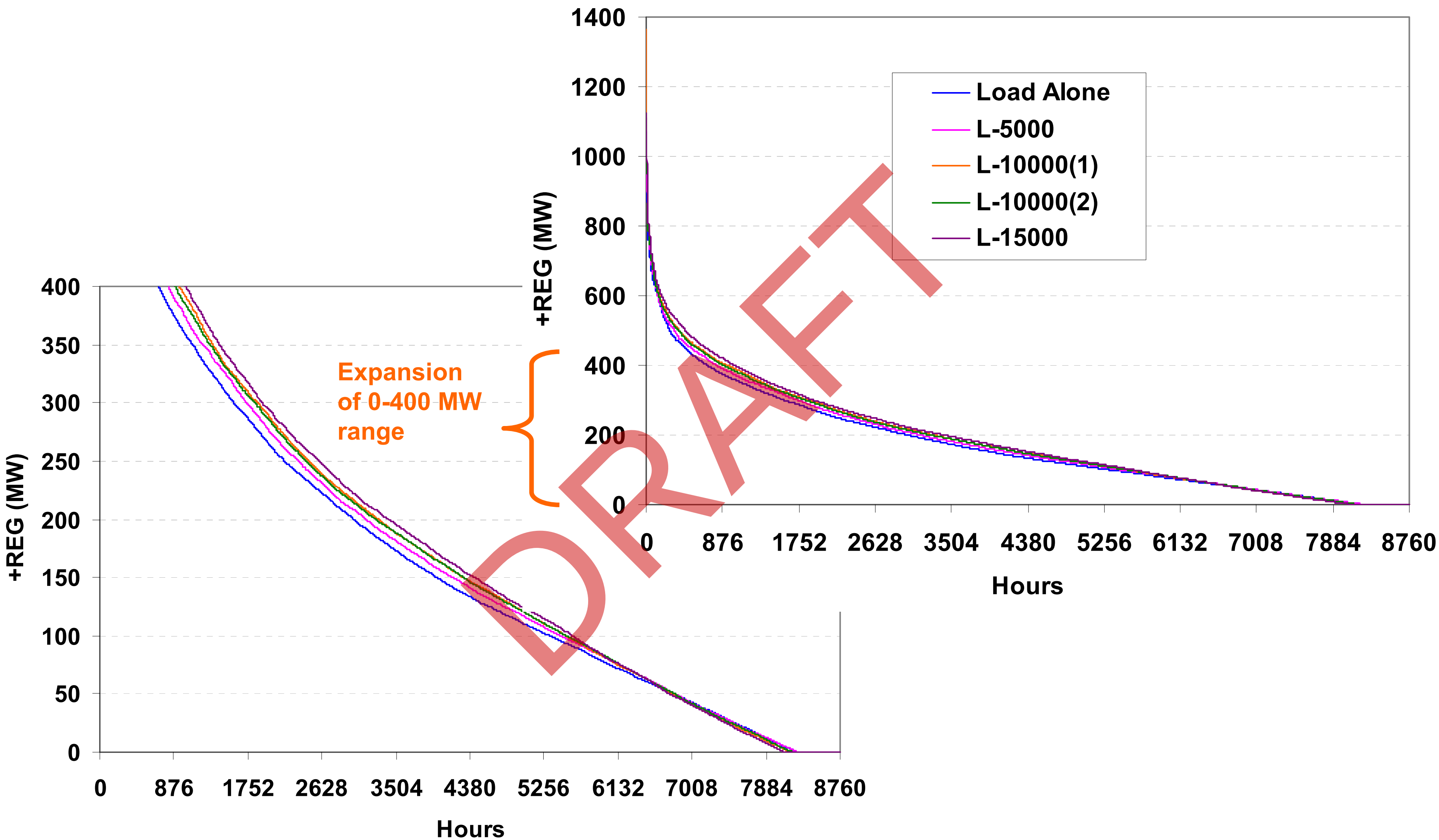
Up-Regulation

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%

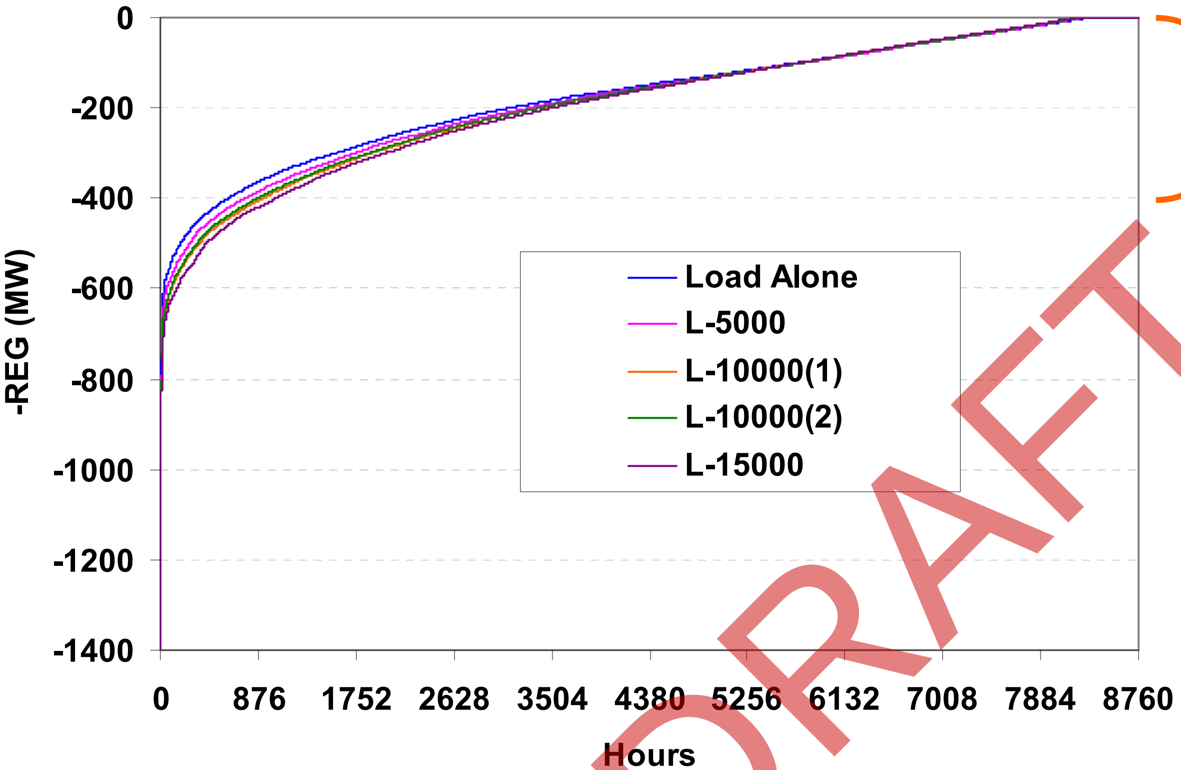
Down-Regulation

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%

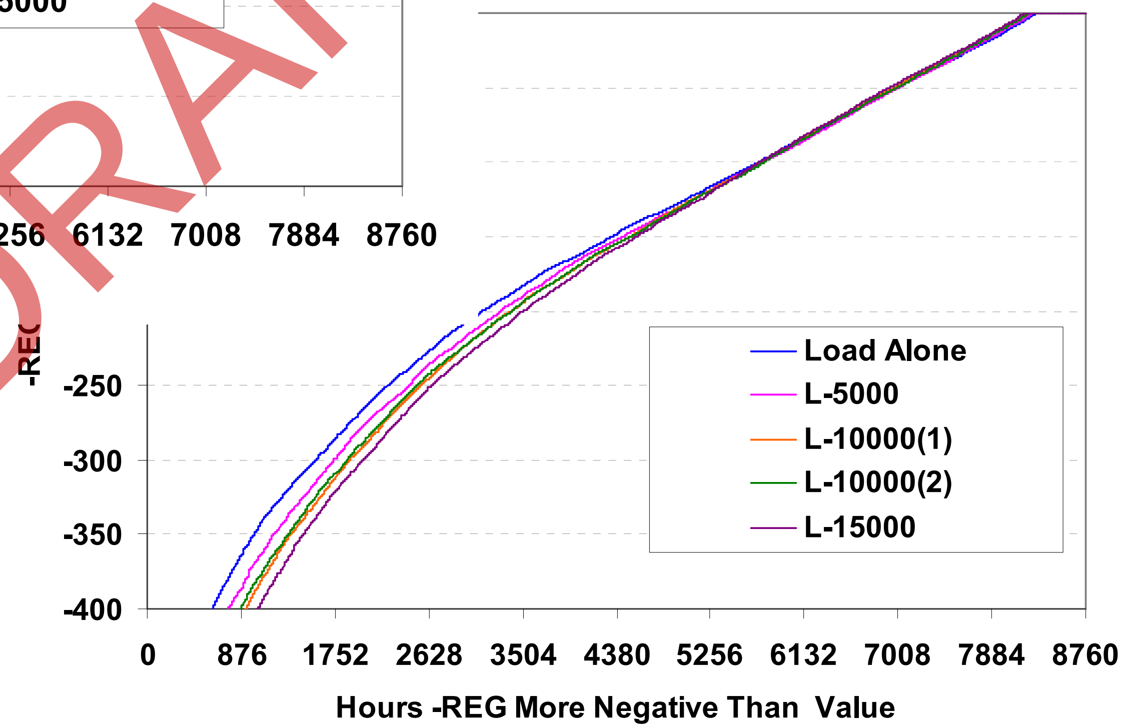
Cumulative Distributions of Maximum Hourly Up-Regulation



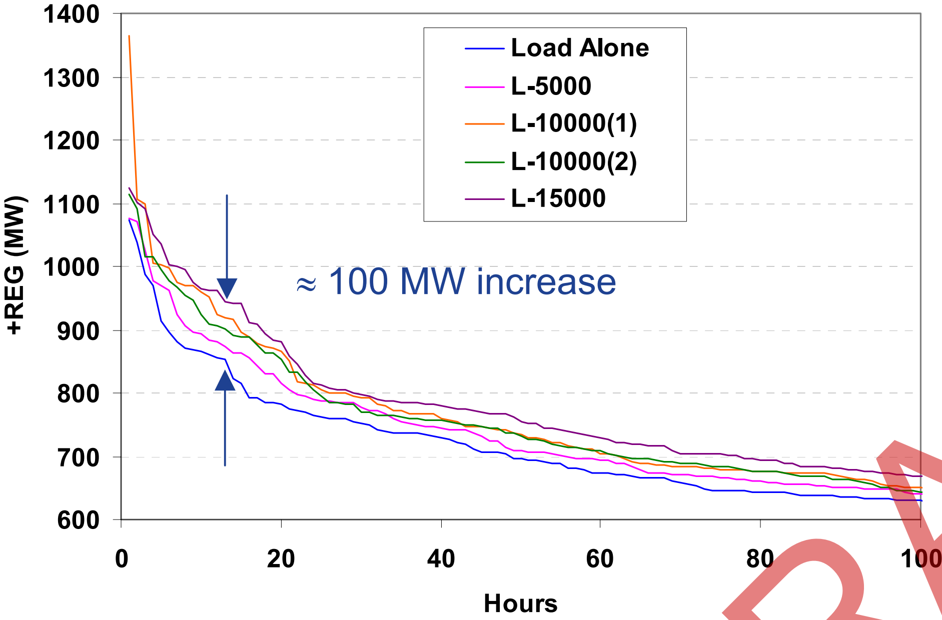
Cumulative Distributions of Maximum Hourly Down-Regulation



Expansion of 0 - -400 MW range



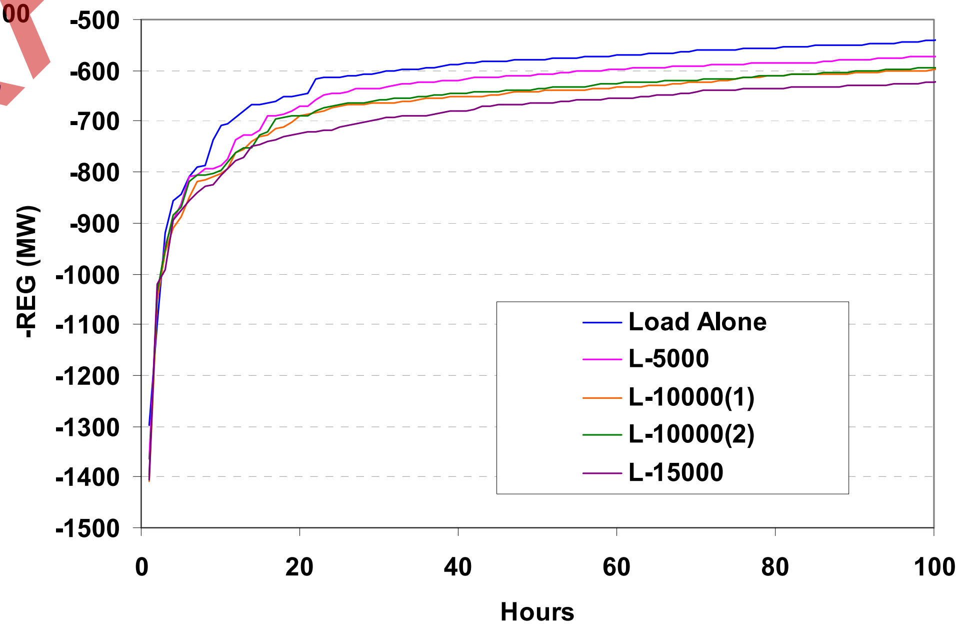
Extreme Up-Regulation and Down-Regulation



100 hrs is ≈ 1.2% of year

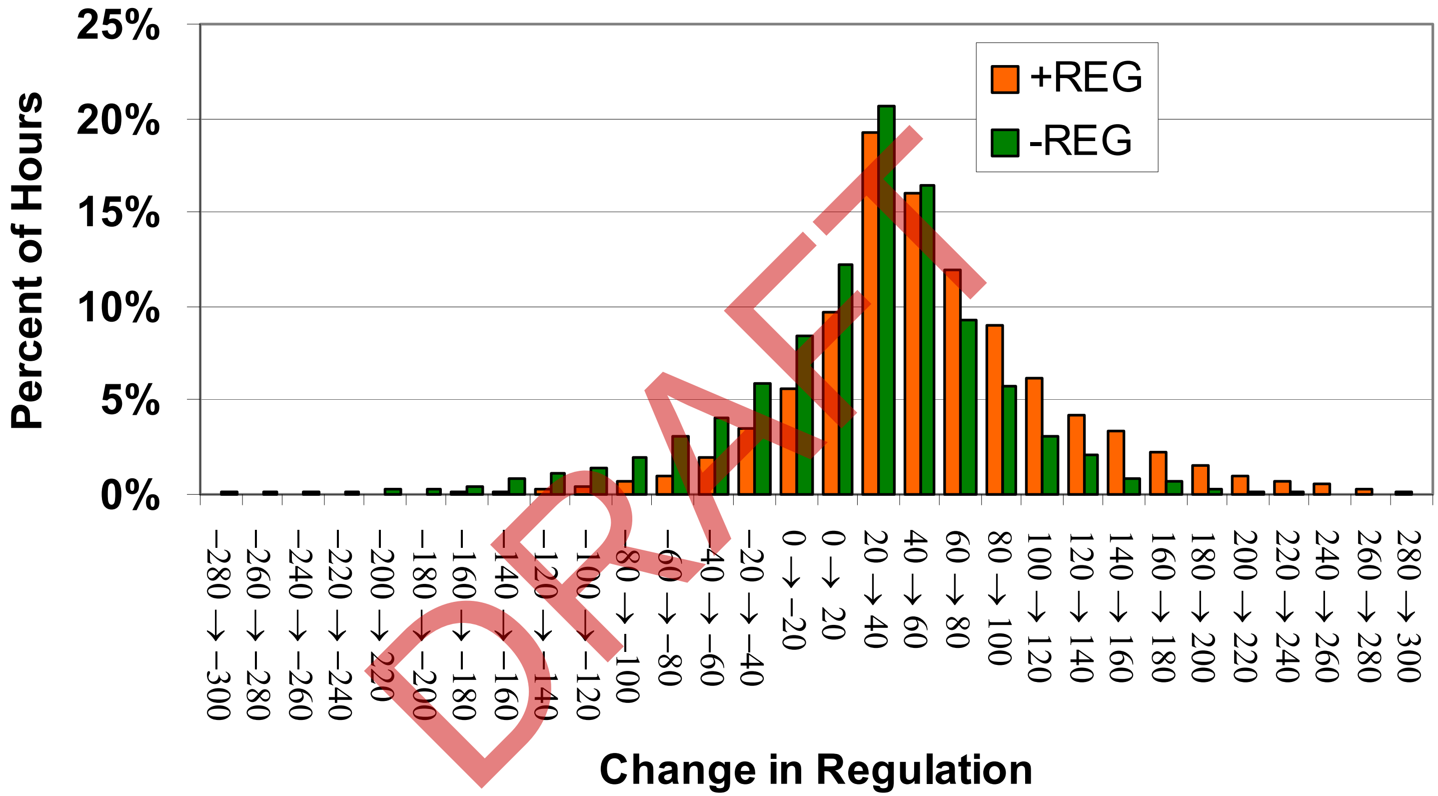
Except for an extreme outlier in one 10GW wind scenario, maximum, extreme +/-REG is increased modestly.

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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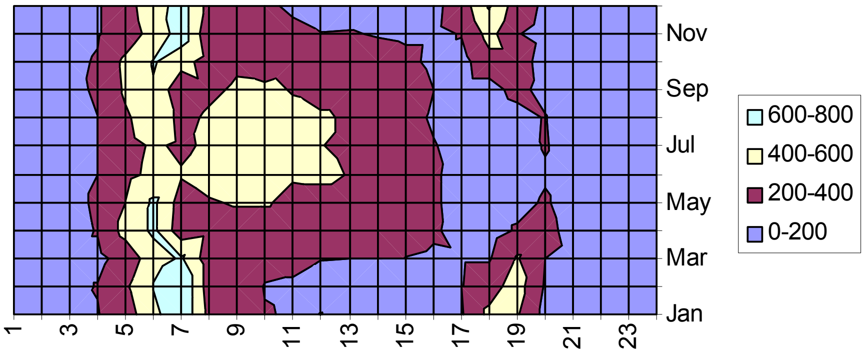
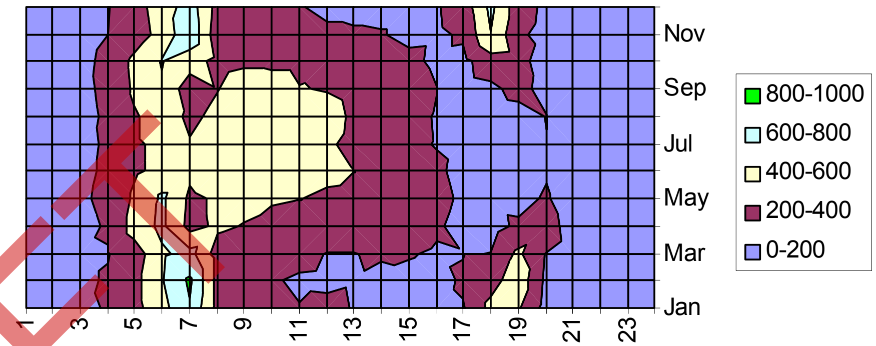
Up Regulation Correlation with Time of Day and Month

98.8th Percentile of +REG Deployed

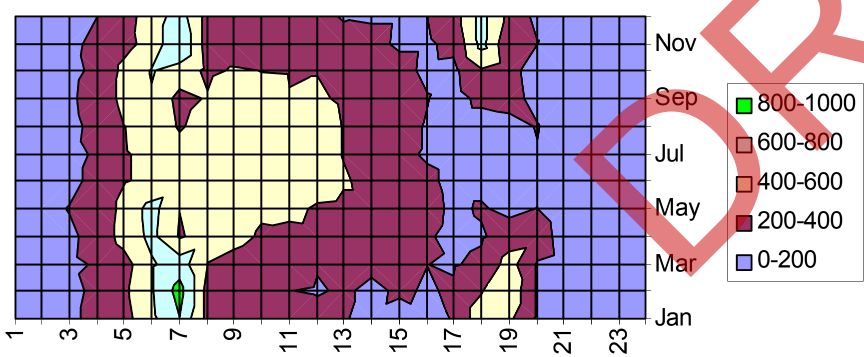
Load Alone



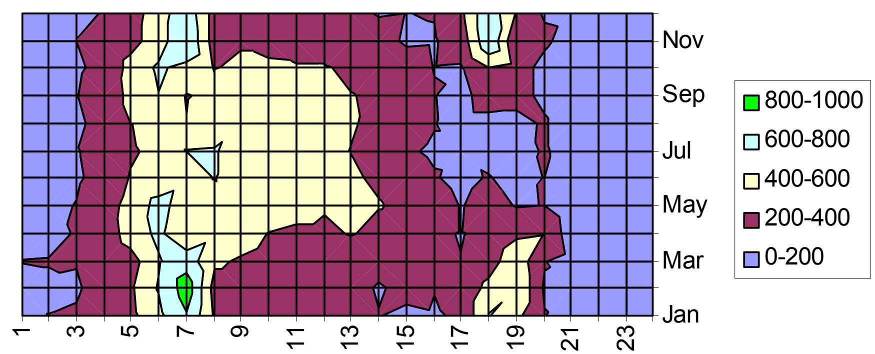
Load – 5000 MW Wind



Load – 10,000 MW Wind (1)



Load – 15,000 MW Wind



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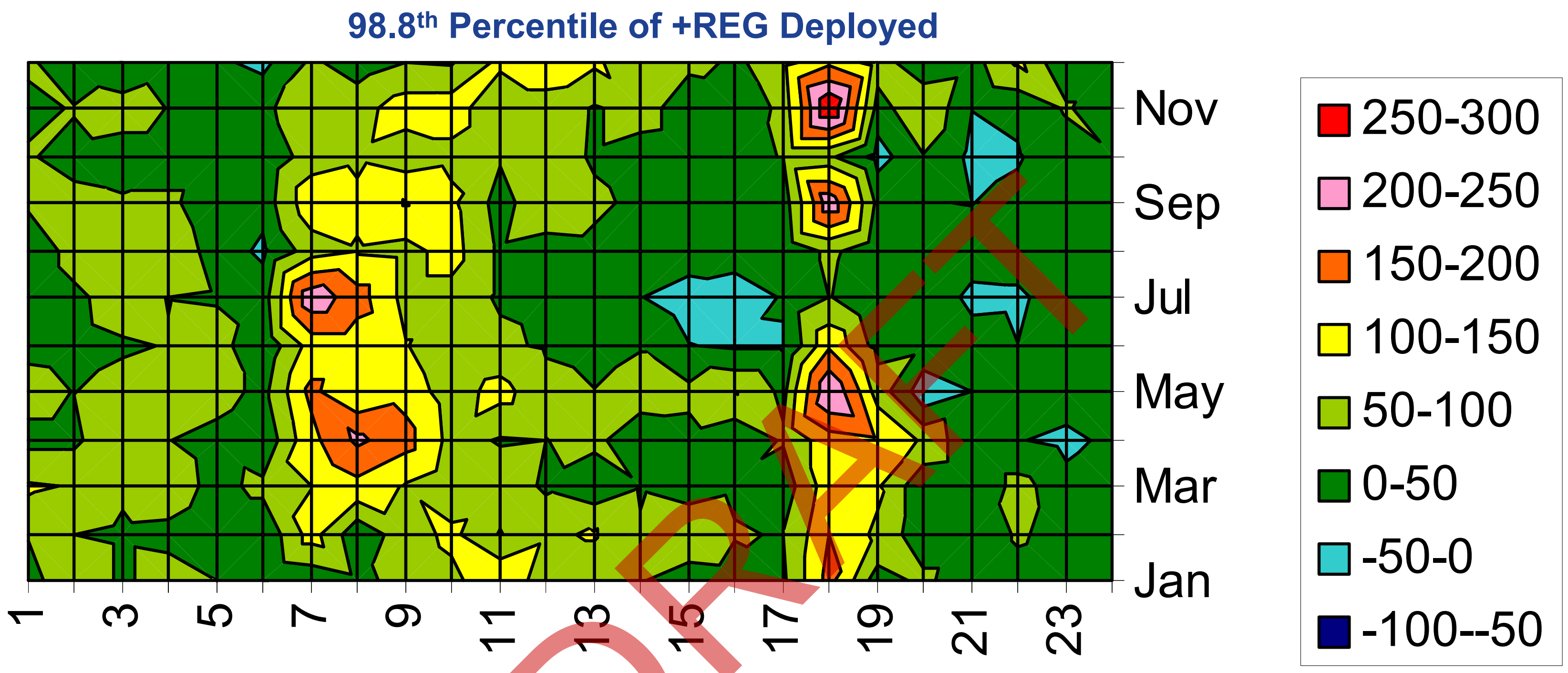
Differential Up Regulation Requirements for 15 GW Wind



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

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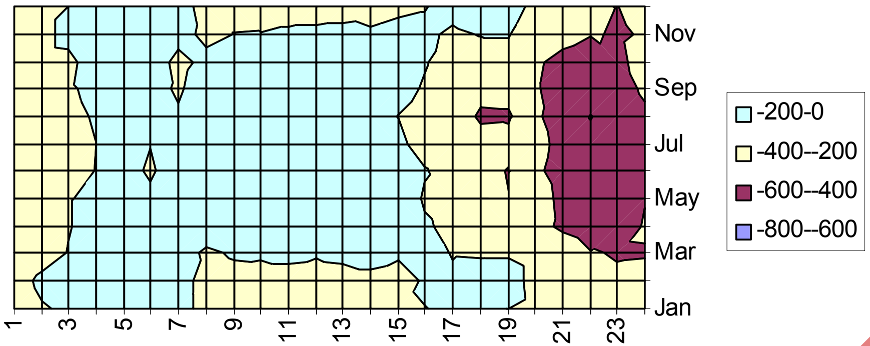
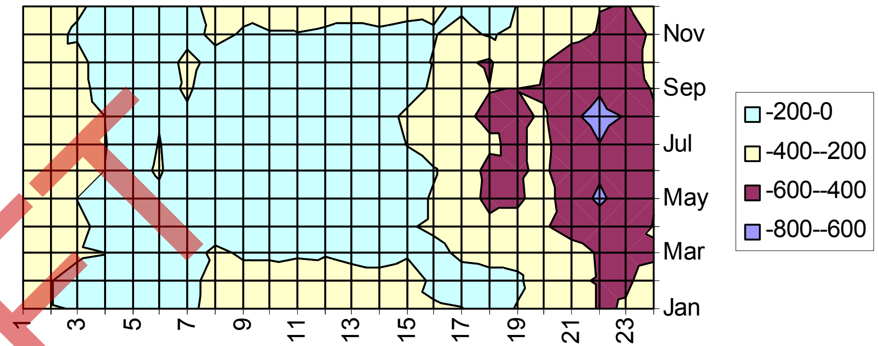
Down Regulation Correlation with Time of Day and Month

98.8th Percentile of –REG Deployed

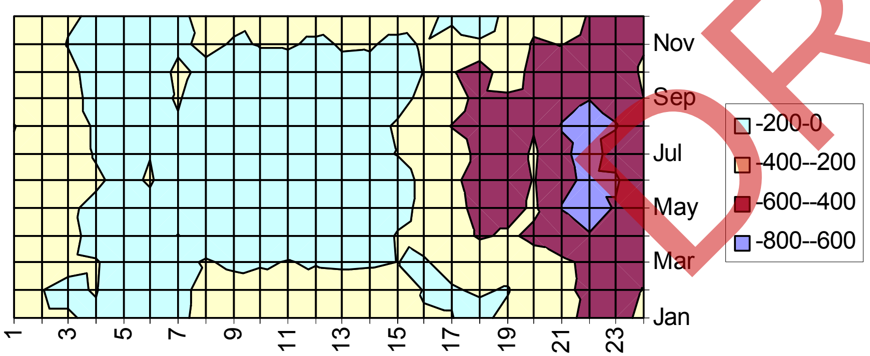
Load Alone



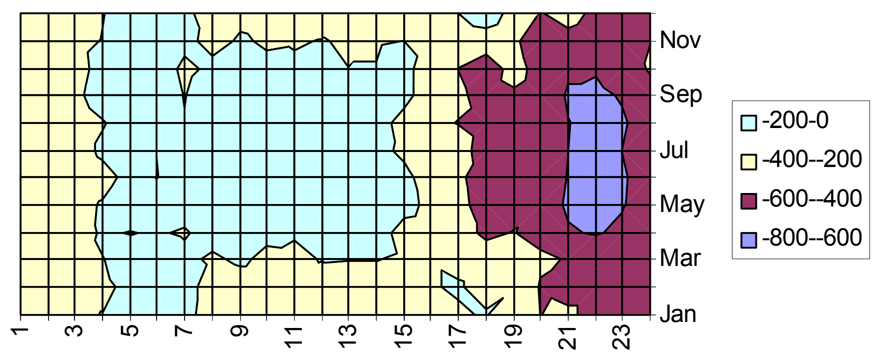
Load – 5000 MW Wind



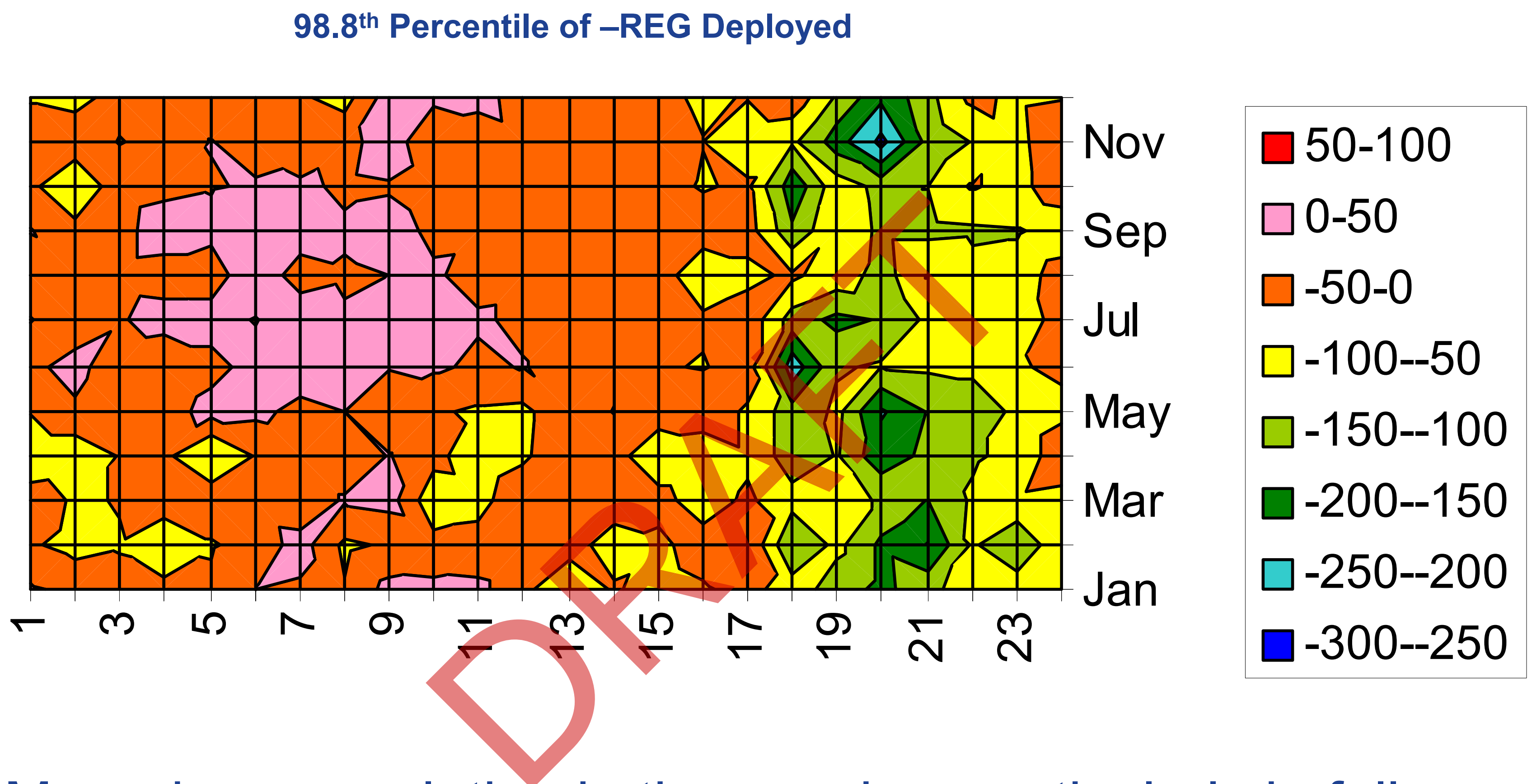
Load – 10,000 MW Wind (1)



Load – 15,000 MW Wind



Differential Down Regulation Requirements for 15 GW Wind



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

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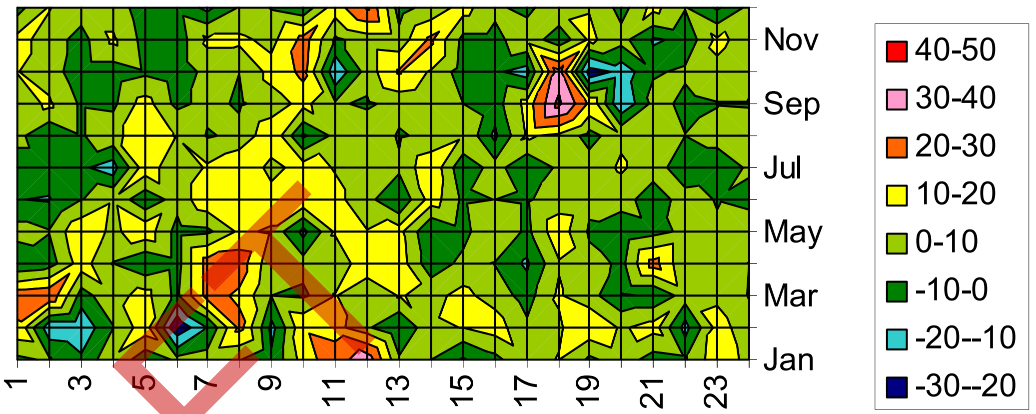
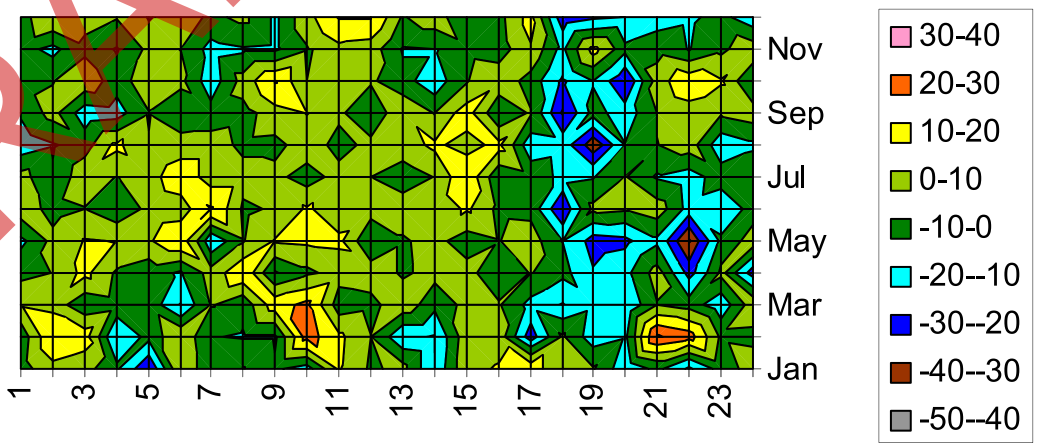
Differential Regulation Between 10,000 MW Wind Scenarios

	Case 1	Case 2
Up-Regulation (MW)		
Mean	82.5	81.4
Sigma	64.9	64.1
98.8th Percentile	265.2	261.5
Maximum	1105.6	1112.7
Down-Regulation (MW)		
Mean	-83.0	-81.5
Sigma	63.7	63.1
98.8th Percentile	-262.7	-260.4
Maximum	-554.9	-565.9

+REG, Case 1 – Case 2



-REG, Case 1 – Case 2



Case 2 (1,500 MW of South Texas wind substituted for panhandle wind) shows slightly less severe regulation requirements due to better diversity

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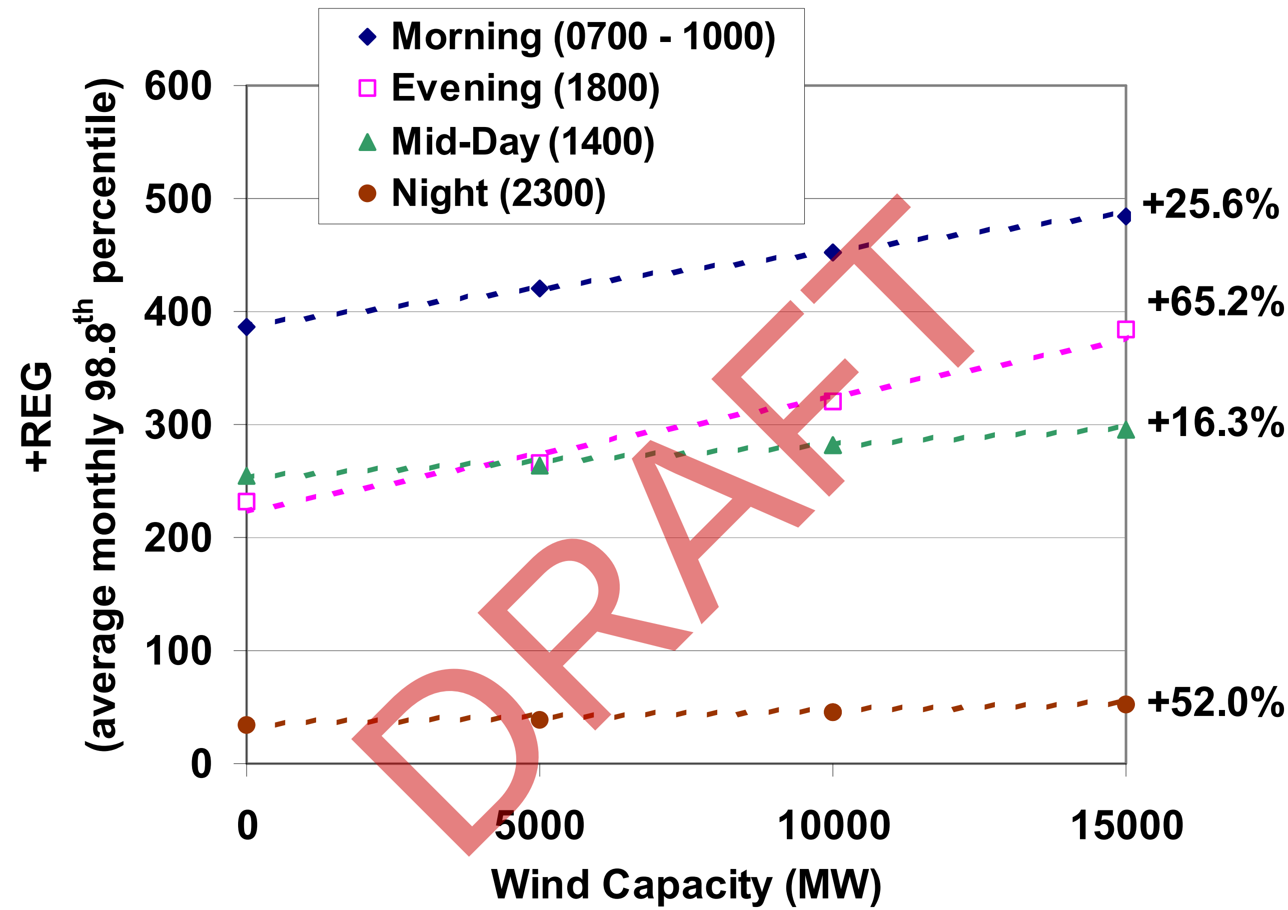
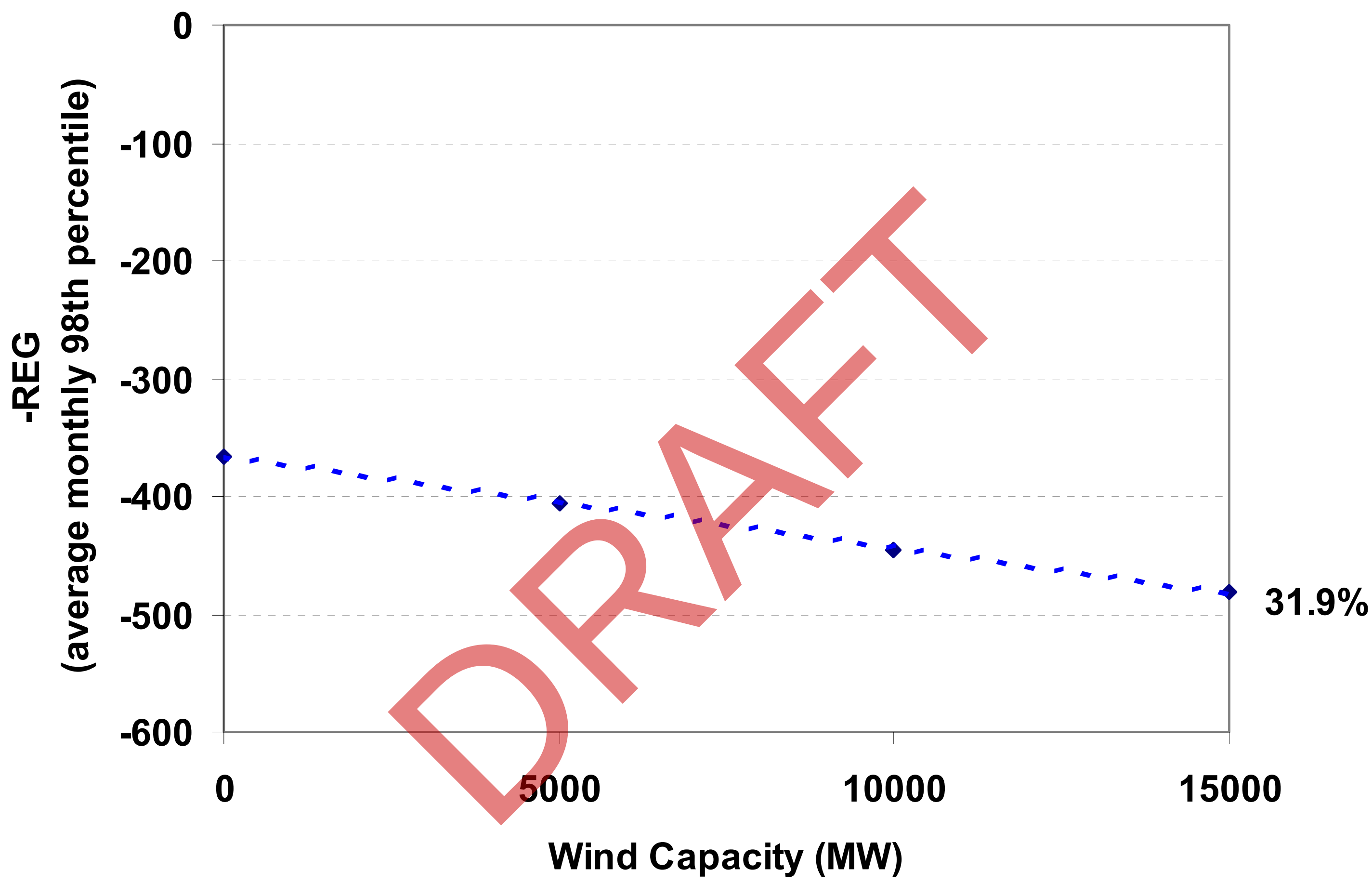
Variation in Up Regulation for Selected Periods



- 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

Increase of Evening Down Regulation Requirements



Evening wind increase coincides with load drop

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In summary:

- With the new definition of regulation for the nodal market:
  - Regulation is heavily biased by load ramp rate
  - Generally, more regulation is necessary compared to zonal definition
- Impact of wind penetration:
  - Regulation peaks caused by load ramping are incrementally increased due to added ramp caused by wind
  - Relative to load alone, 98^{th} 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:

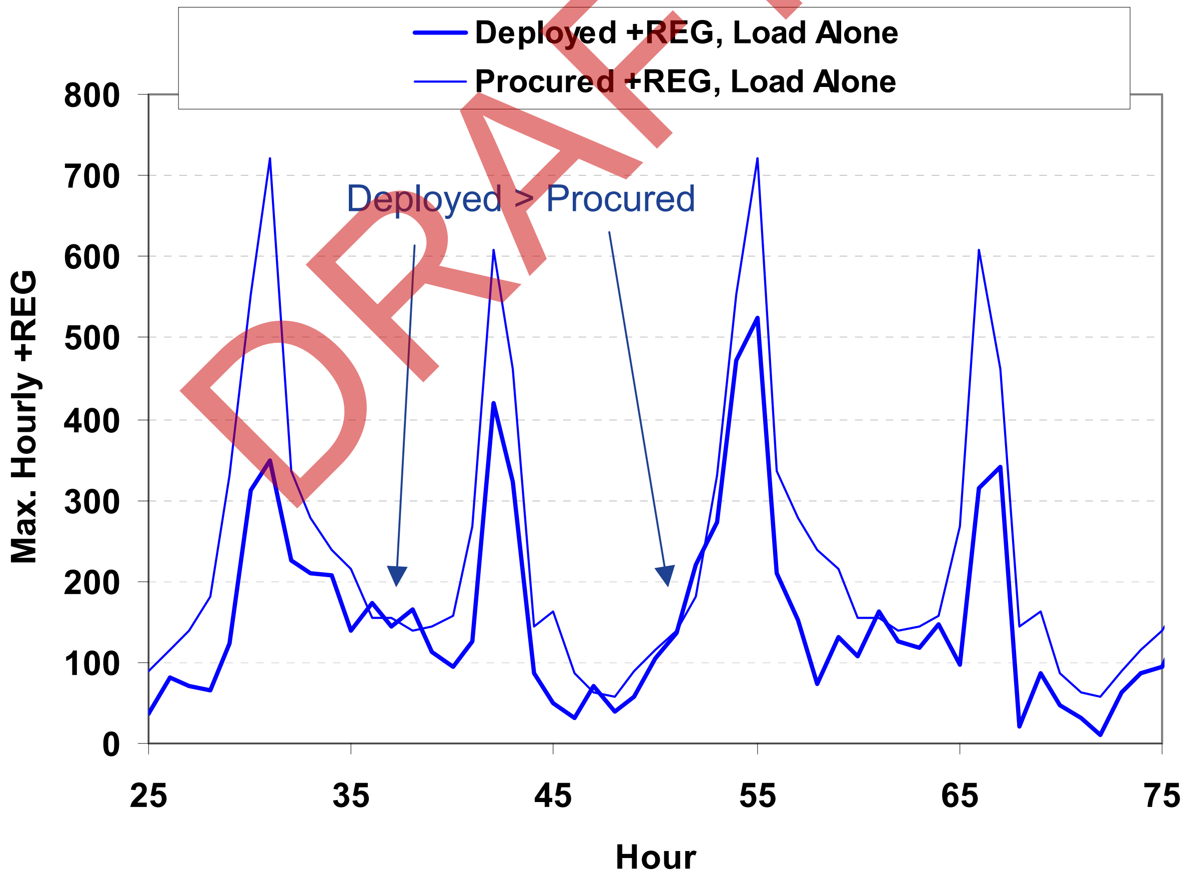
- How ERCOT presently determines the amount of regulation to procure
- The robustness of this methodology to increased wind penetration

Key issues are:

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

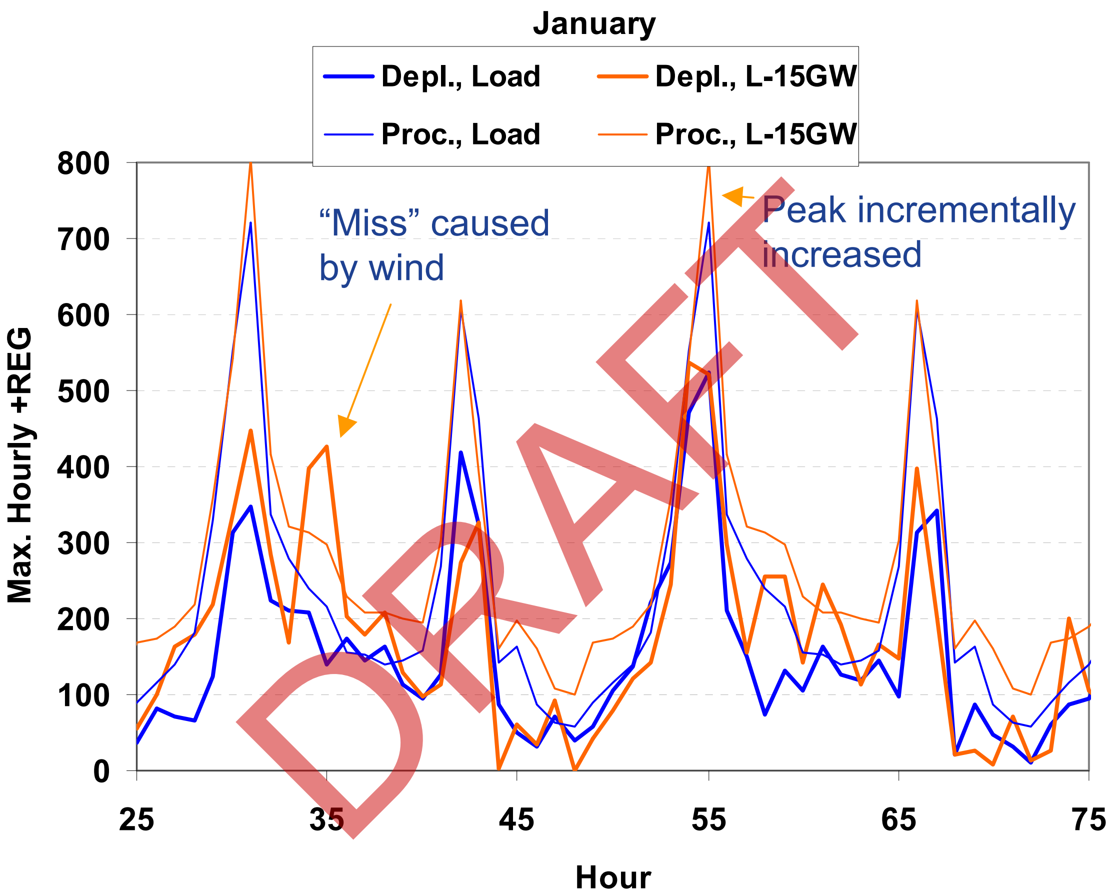
ERCOT Regulation Procurement Methodology

- 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



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

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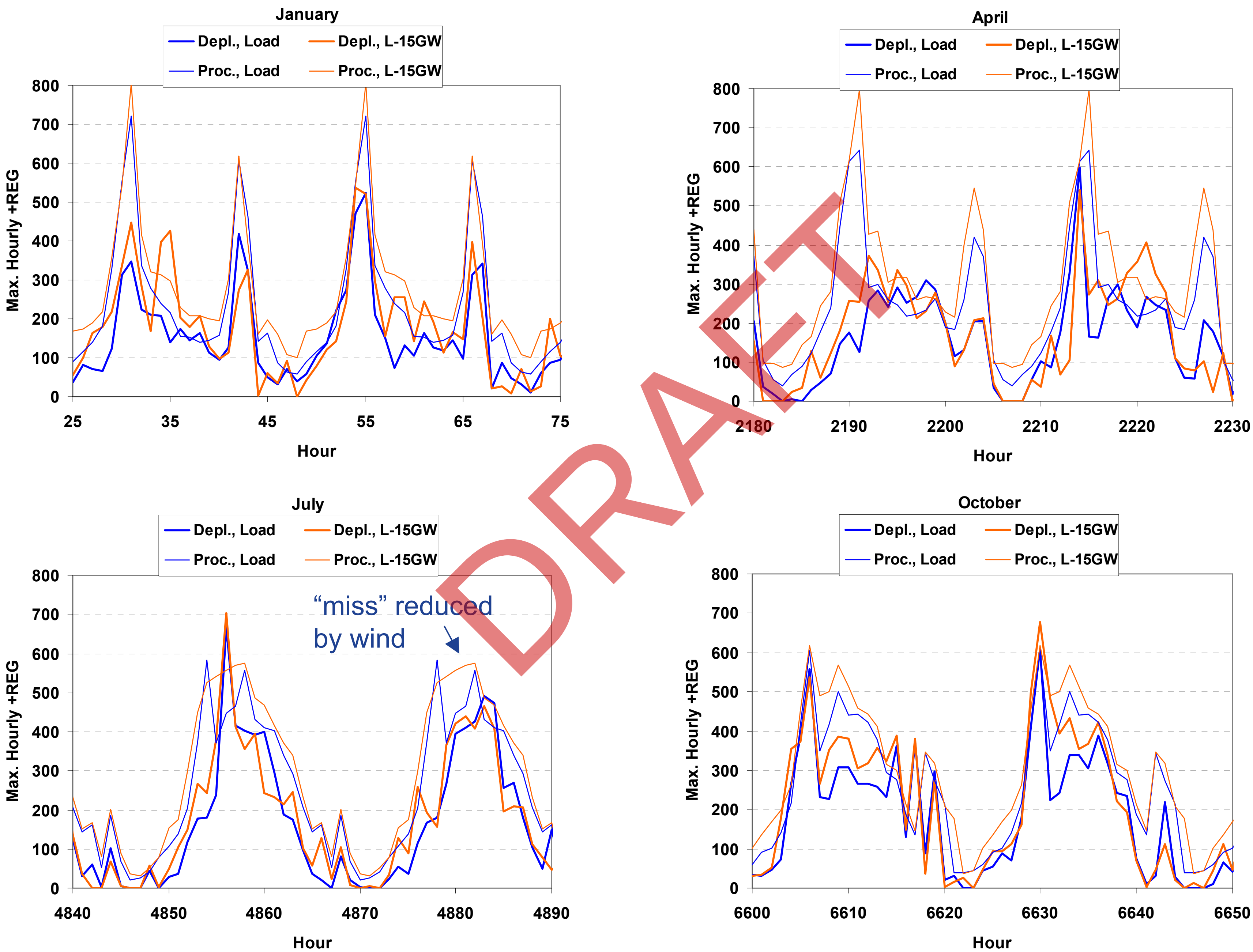
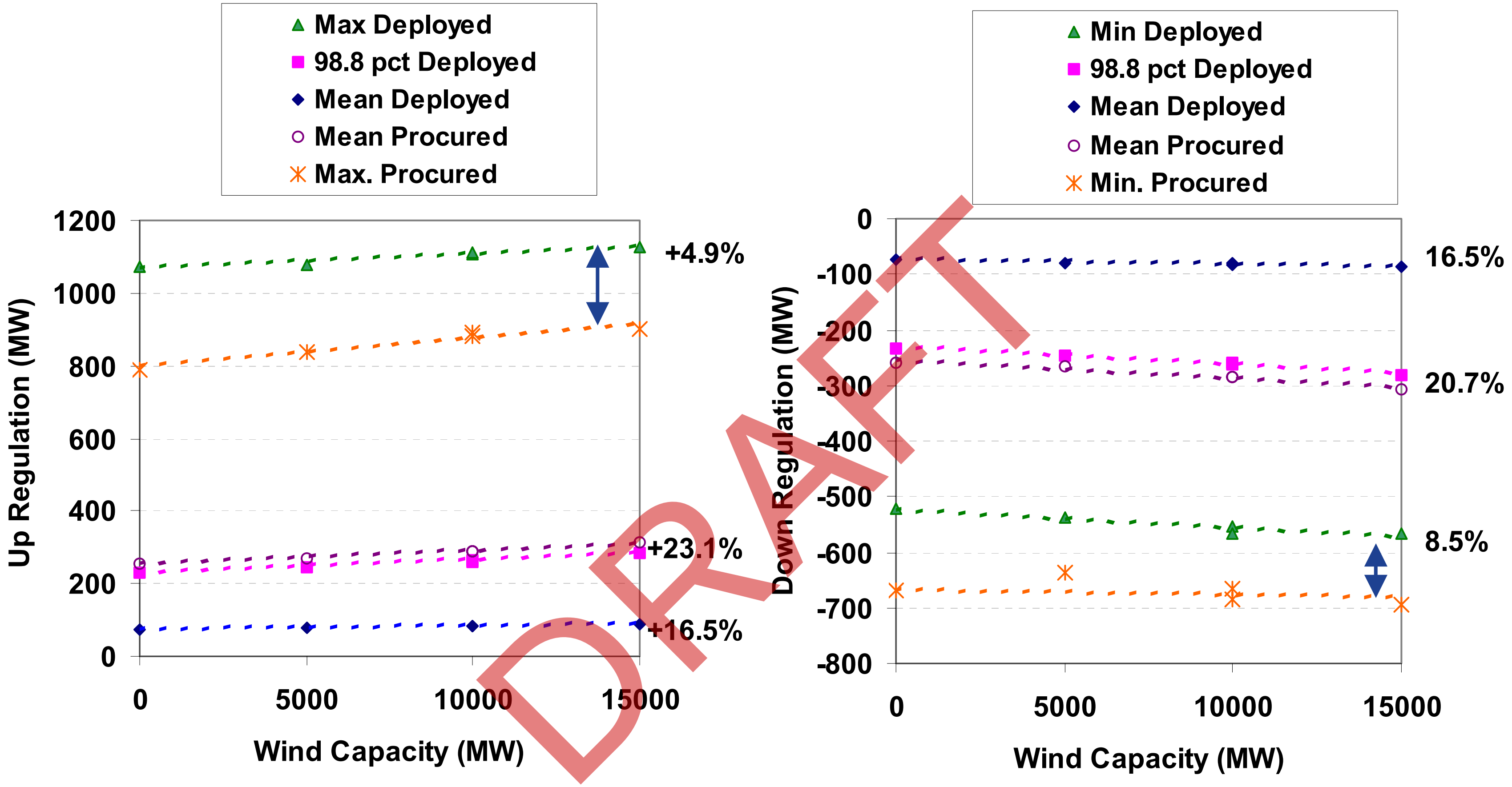
Procured vs. Max. Hourly Deployed Up-Regulation Time Series



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

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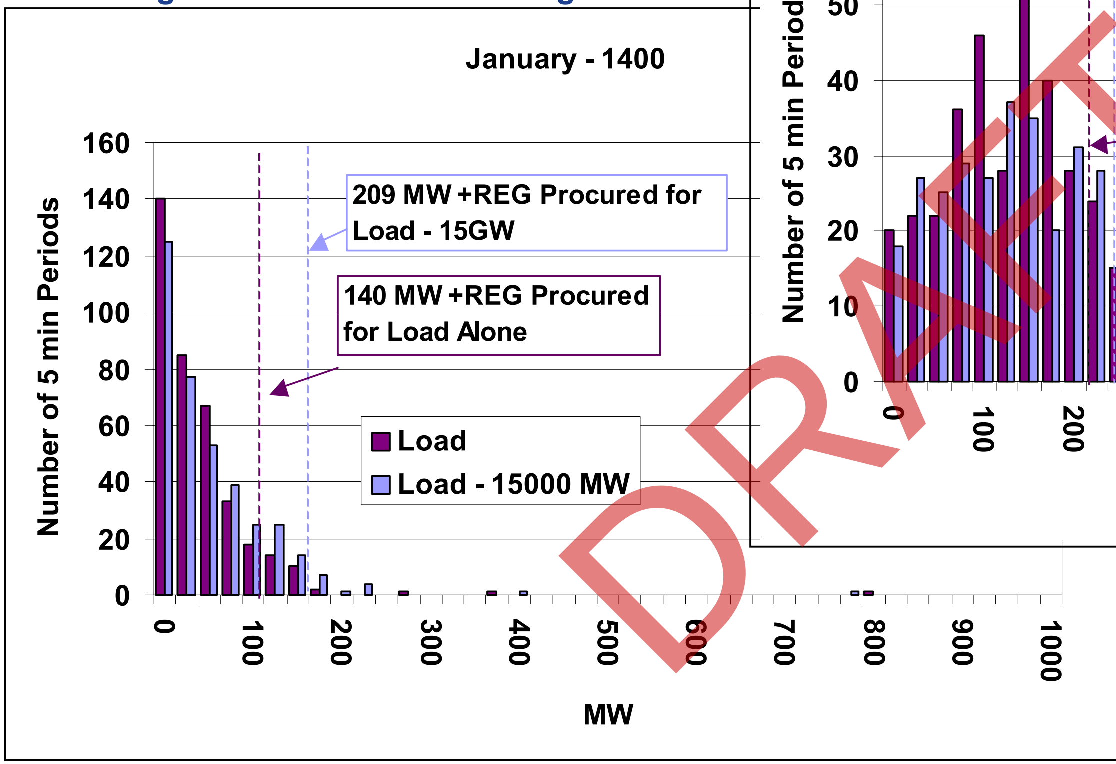
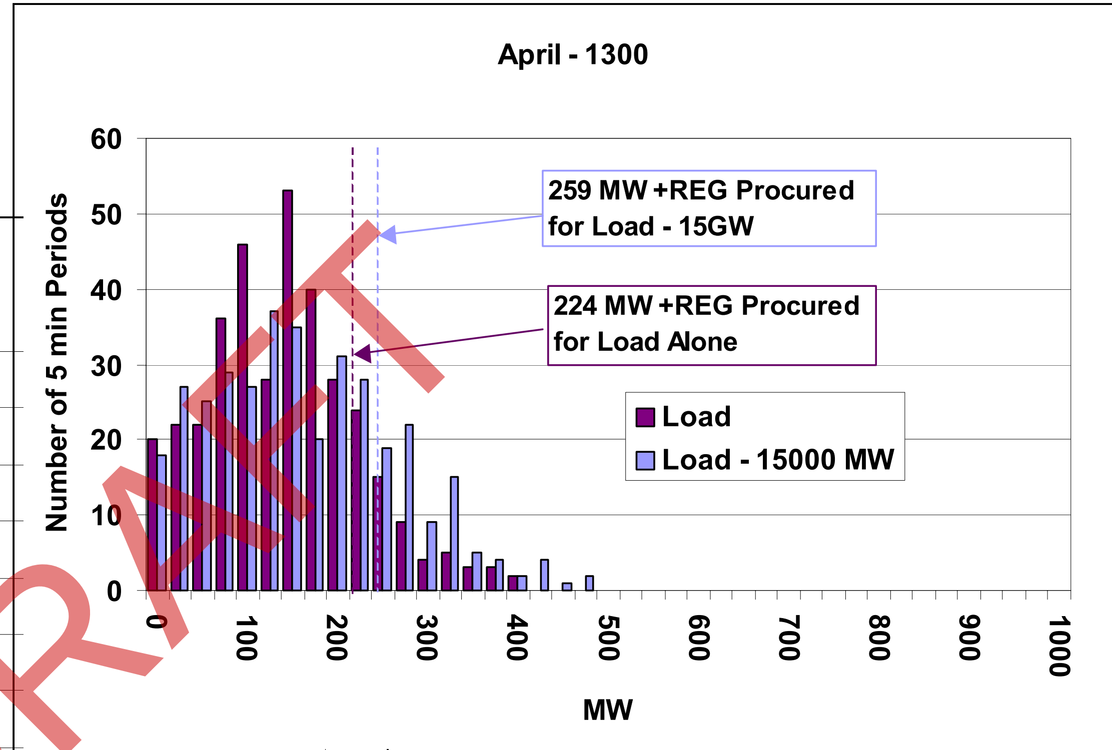
Up Regulation Frequency Distribution Examples

Large Under-Procurement Magnitude





High Frequency of Under-Procuremeent

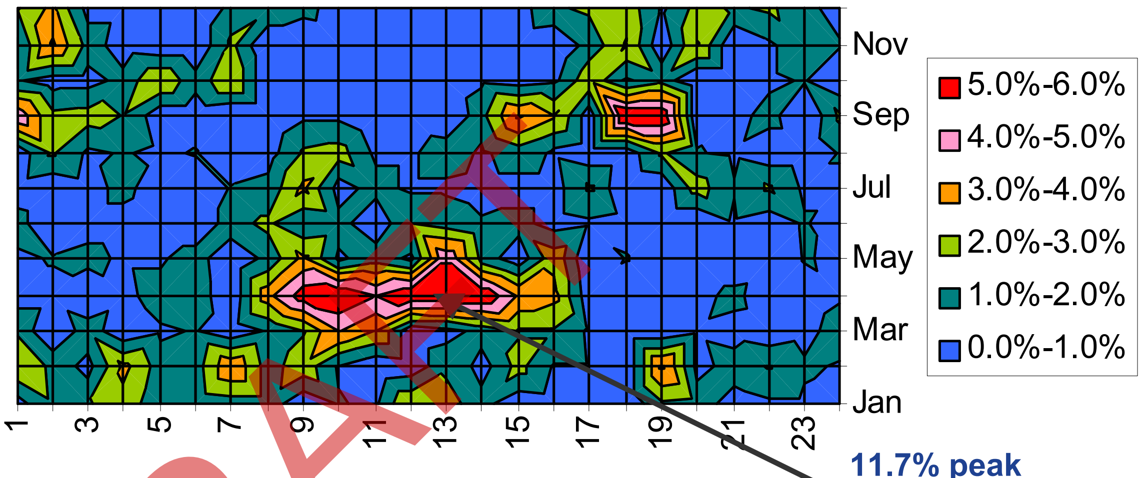
Percentage of Hours with +REG Under-Procurement

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

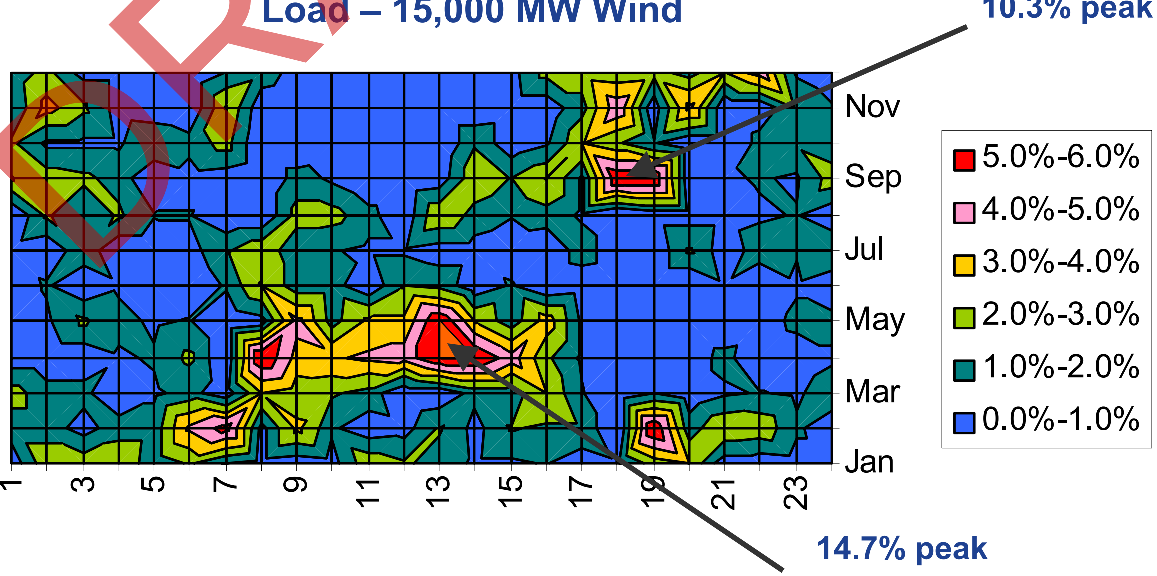
Increased overall +REG deployment with 15 GW of wind diminishes the high concentration of misses during these periods

A few limited points were somewhat more severe

Load Alone



Load – 15,000 MW Wind



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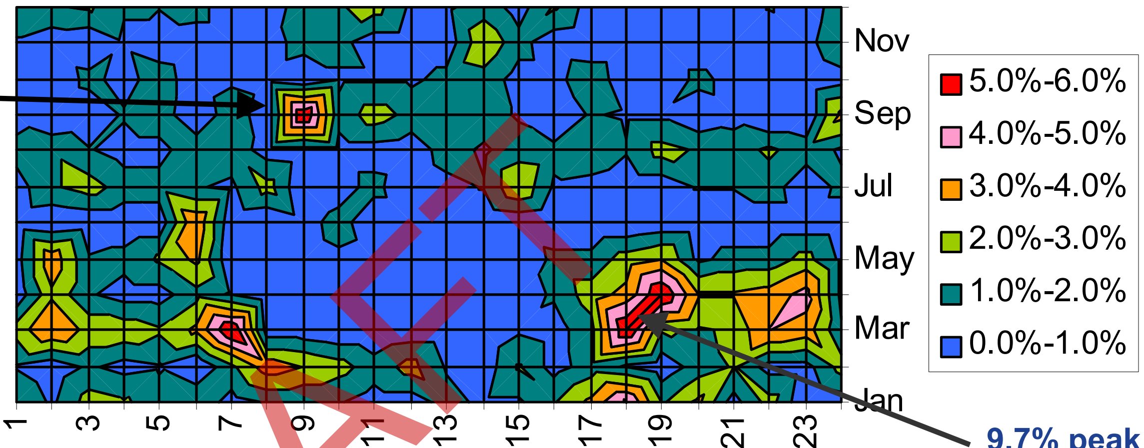
Percentage of Hours with -REG Under-Procurement

Annual percentage of periods with a –REG shortfall is 1.2% in both cases.

Procurement is <u>as designed</u>

Load Alone

6.4% peak

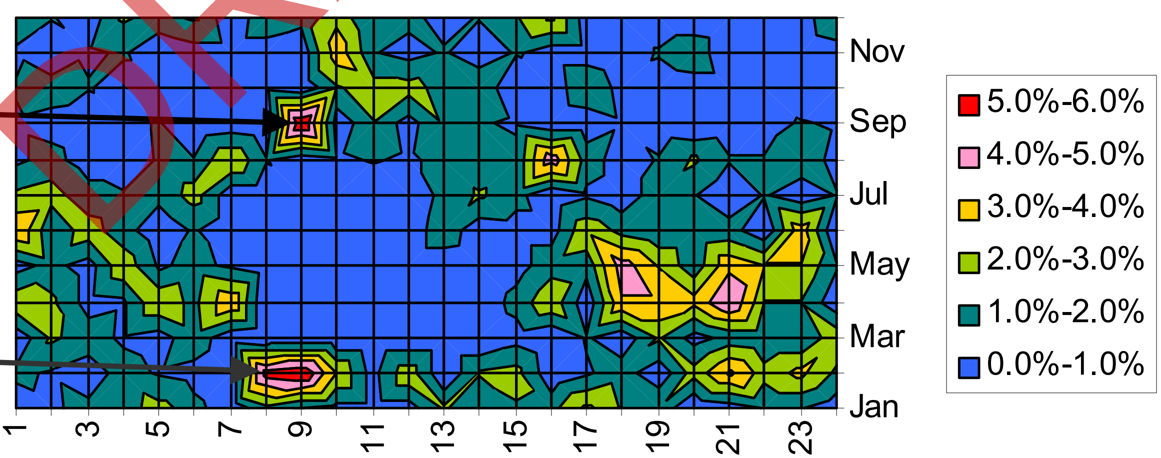


9.7% peak

Load – 15,000 MW Wind

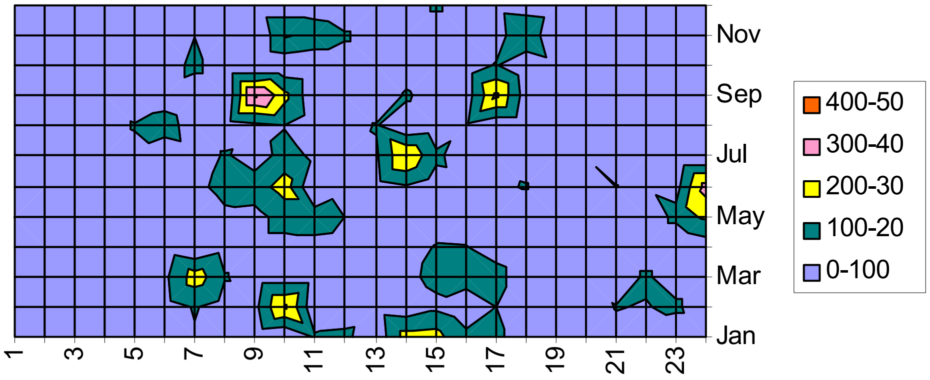
6.9% peak

6.0% peak

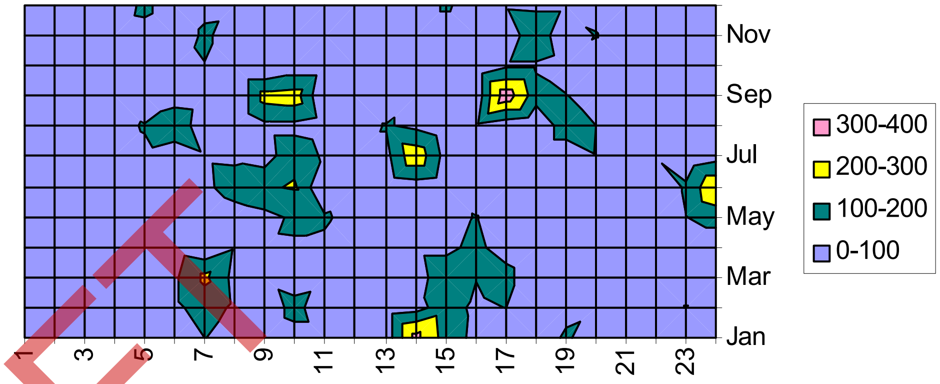


Root Mean Square of +REG Under-Procurement

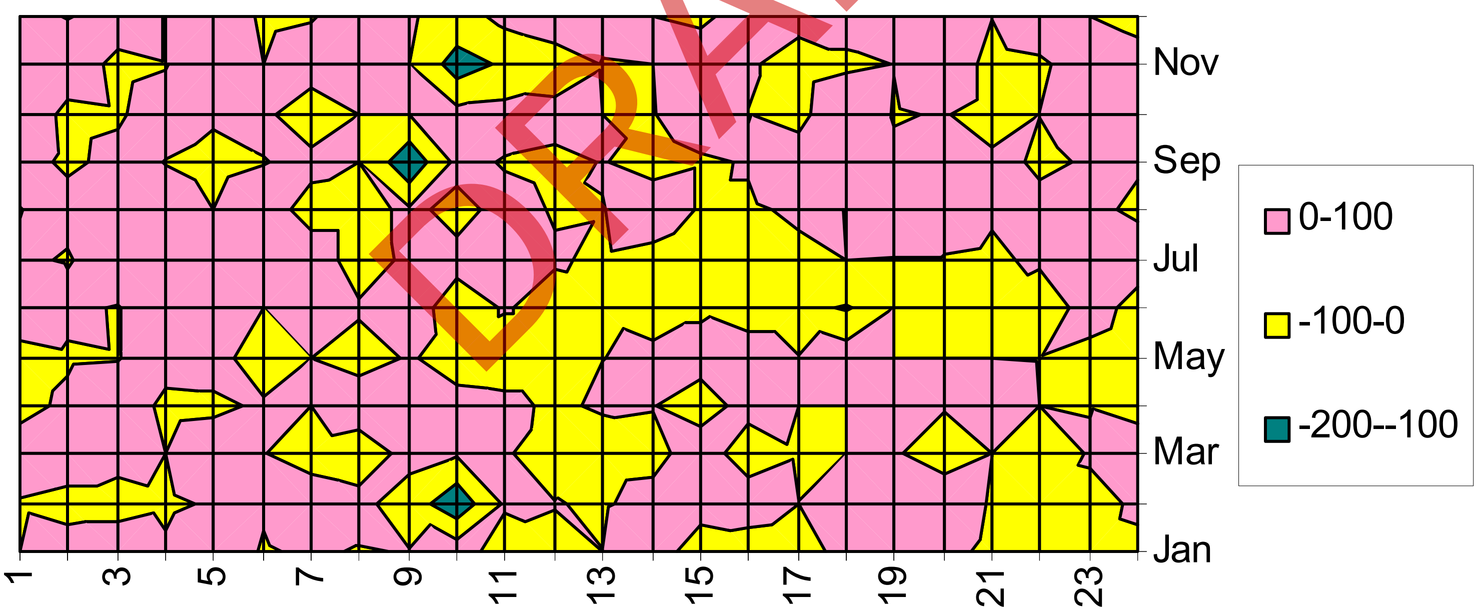
Load Alone



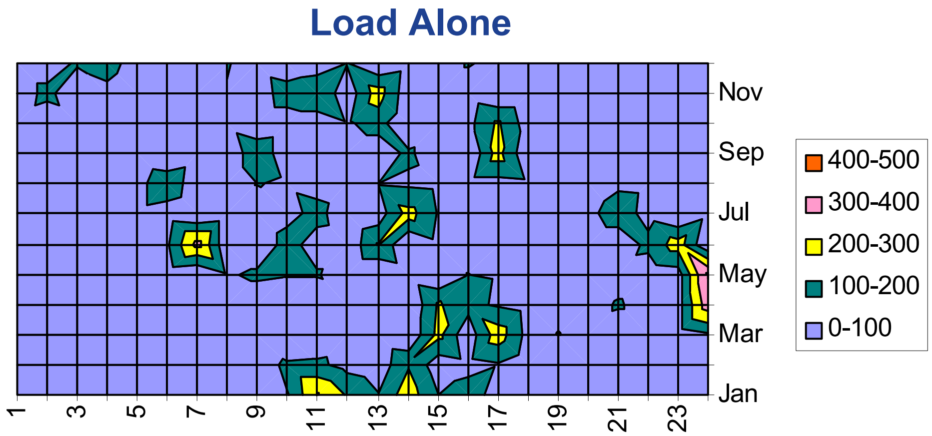
Load – 15,000 MW Wind

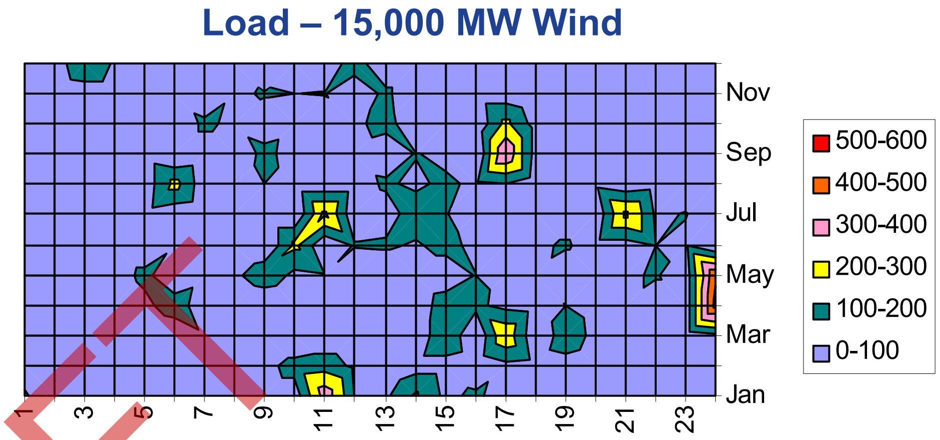


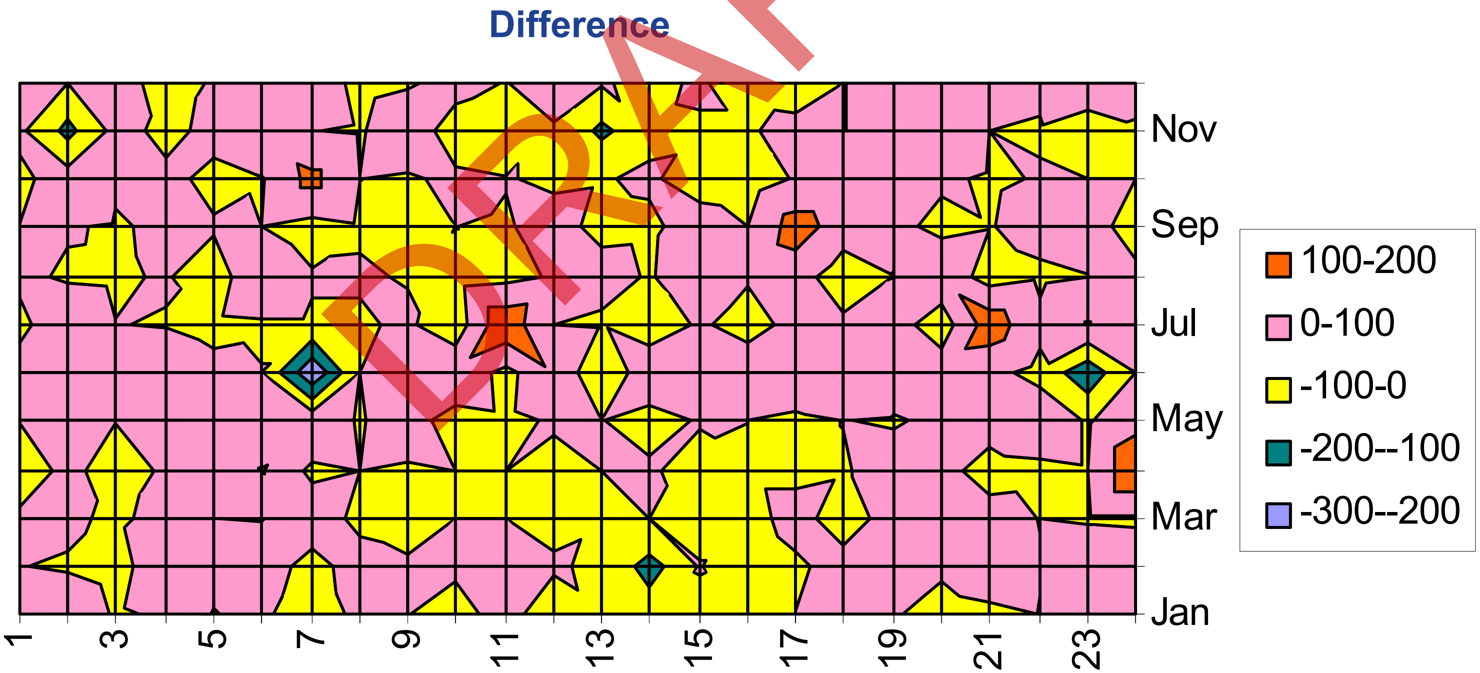
Difference



Root Mean Square of -REG Under-Procurement







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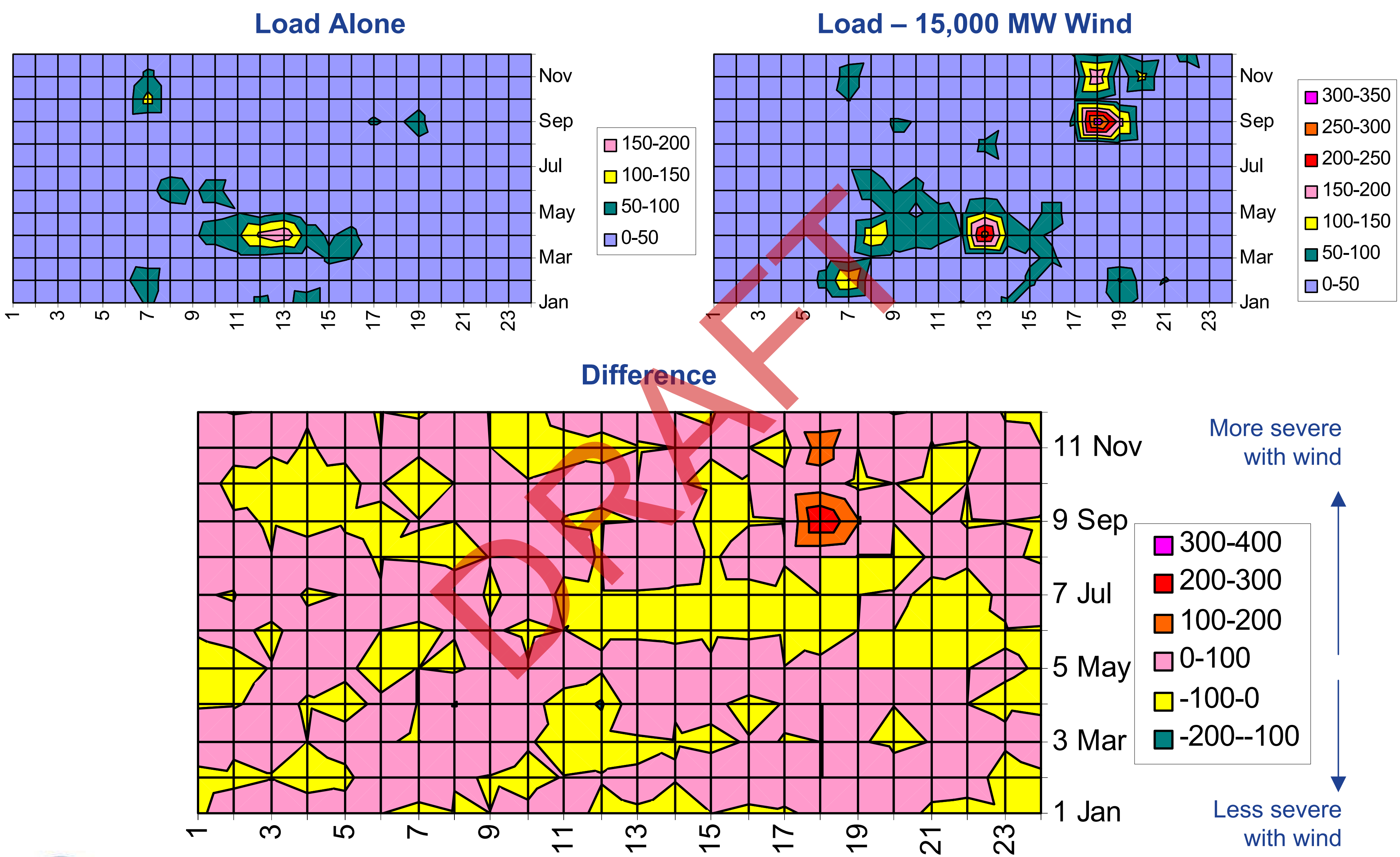
MW x Hours of +REG Under-Procurement



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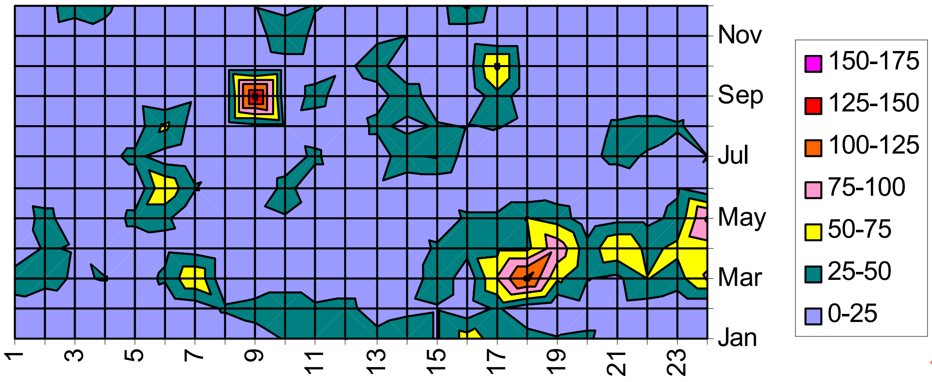
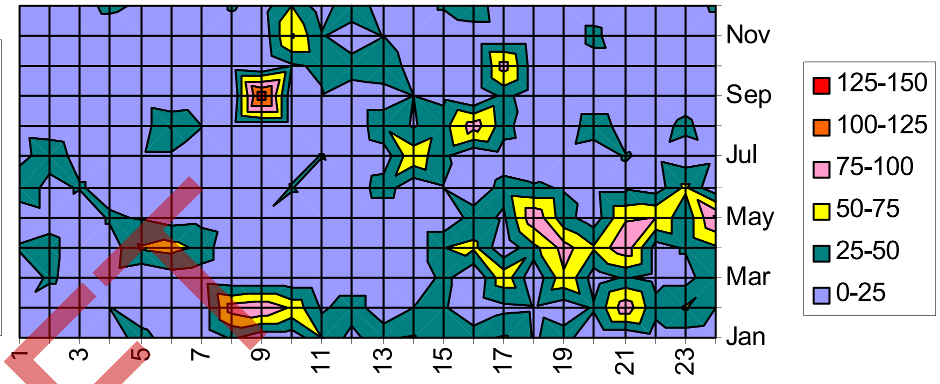
MW x Hours of -REG Under-Procurement

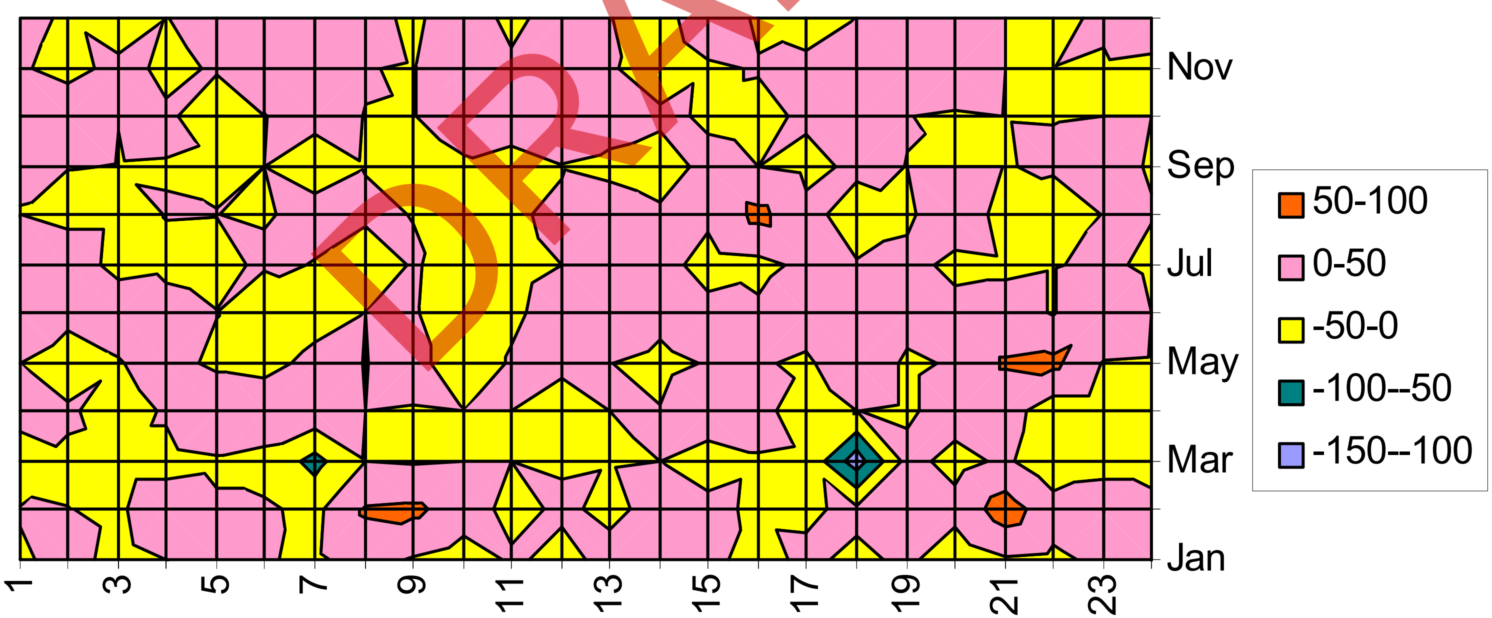
Load Alone



Load – 15,000 MW Wind



Difference



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

In summary:

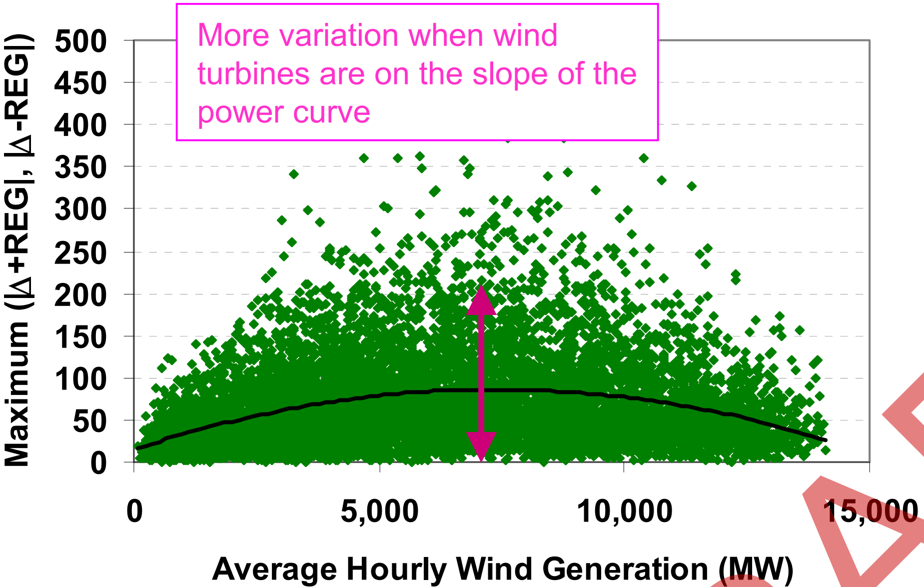
- Regulation requirements for net load with high wind penetration are statistically as “well behaved” as load only
- The present ERCOT methodology for determining the amount of regulation to procure remains effective with 15 GW of wind
- Linearity allows scale-up of regulation procurement to accommodate 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

Improvement of Regulation Procurement Methodology

In this next set of slides, we will examine:

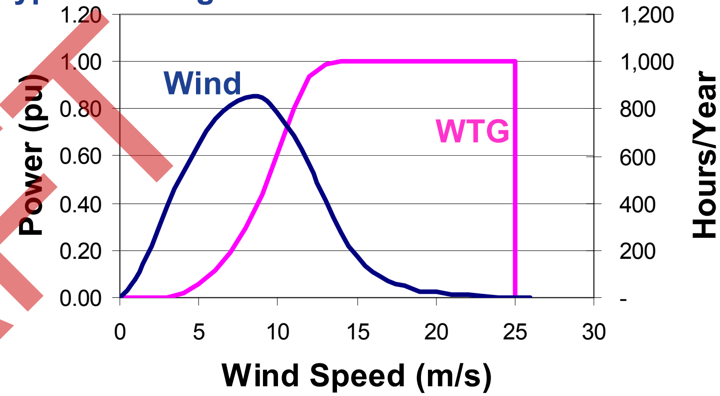
- Attributes of wind affecting regulation requirements
- A possible approach to improving the regulation procurement algorithm
- Effectiveness of the modified approach

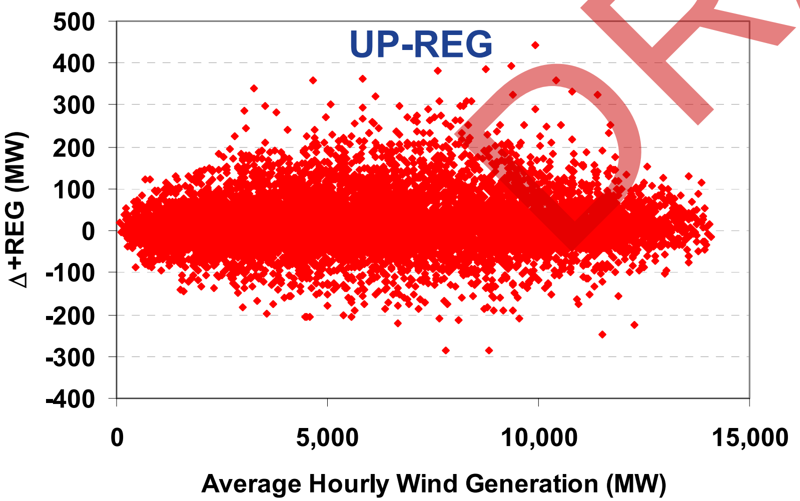
Correlation of Incremental (Δ) Regulation to Wind Production

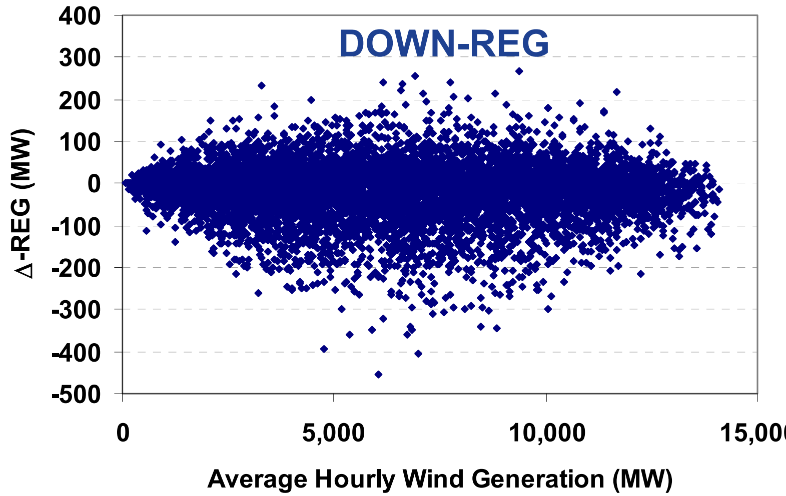


Difference between hourly max. regulation for load only and load – 15GW wind

Typical wind generator and wind distribution curves







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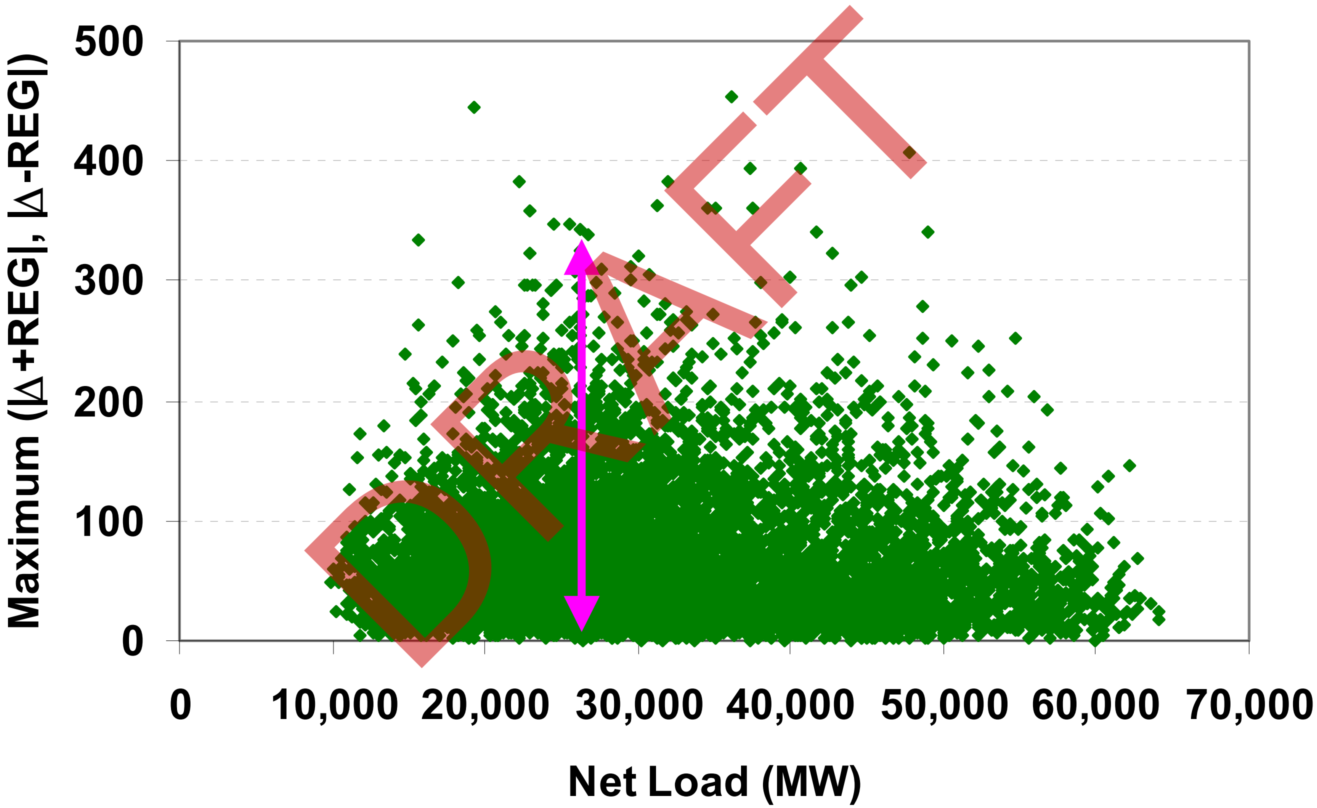
Correlation of Incremental (Δ) Regulation to Net Load

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



Greatest impact on regulation at lighter load levels

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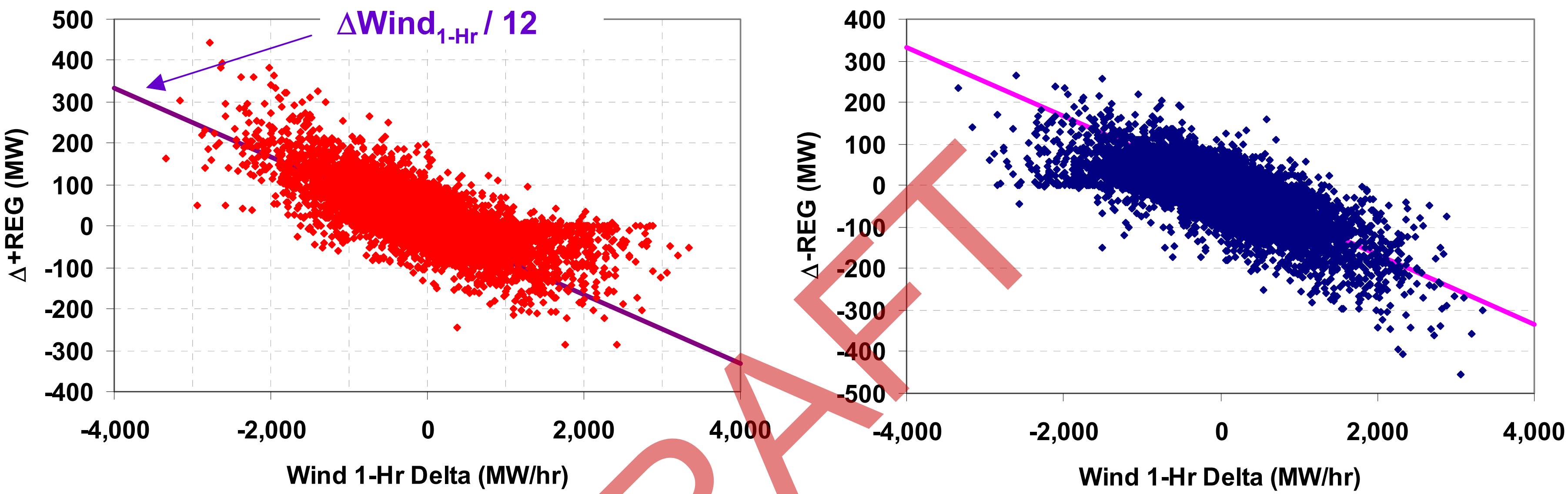
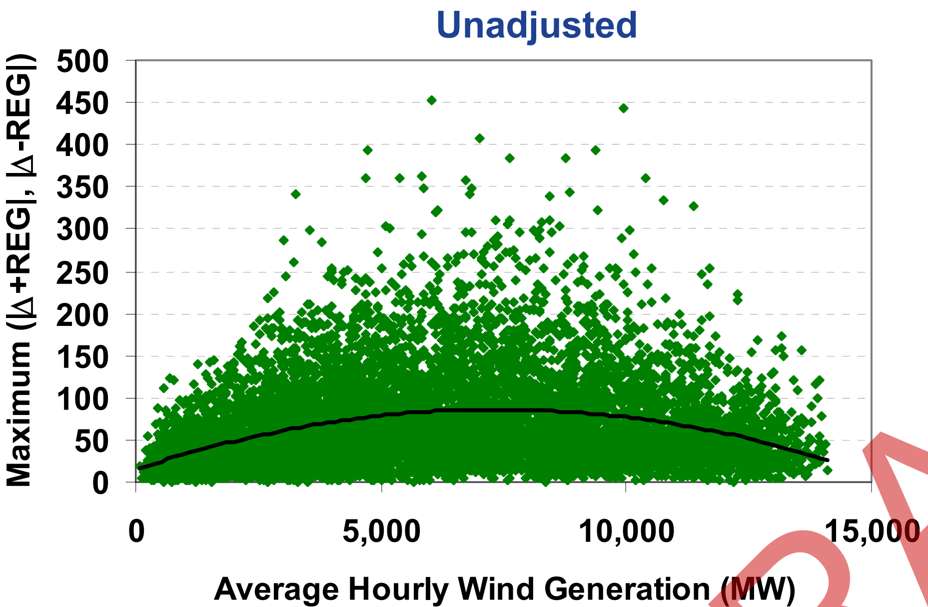
Correlation of Incremental (Δ) Regulation to Wind Ramp Rate

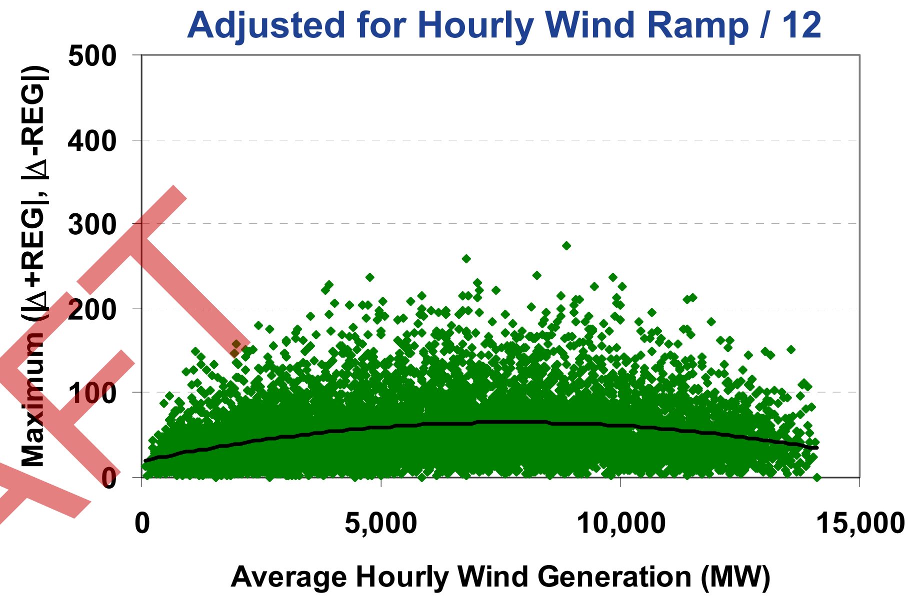


Incremental regulation requirements due to wind in the new nodal scheme are heavily driven by the long-term (multi-hour) ramping of wind output

imagination at work

Regulation Requirements Adjusted for Wind Ramp Rate





- Much less scatter of the points implies regulation requirements can be better predicted if the wind ramp rate can be predicted
- Some tendency for more scatter at mid-levels of wind output where more wind turbines are on the steep slope of their power curves

Wind and Regulation Requirements Determination

- Load alone has a distinct diurnal curve
  - Randomness due to weather and other factors is secondary
  - Existing methodology accurately predicts regulation requirements
- Success of algorithm on net load with wind is due to brute-force statistics
- Factoring the impact of wind ramping should provide similar accuracy and less regulation procured than just correlation to time of day and month

Candidate "Improved" Algorithm

1. Factor out wind multi-hour ramp rate contribution to historical deployed regulation data
2. Determine the maximum of 98.8th percentiles for previous month and previous year, as in present approach, but with adjusted data
3. Use the day-ahead wind forecast to determine the expected hourly wind ramp rates
4. Adjust the regulation procurement on a day-ahead basis, applying the forecast wind ramp rates

imagination at work

Production Simulation

In this next set of slides, we will show:

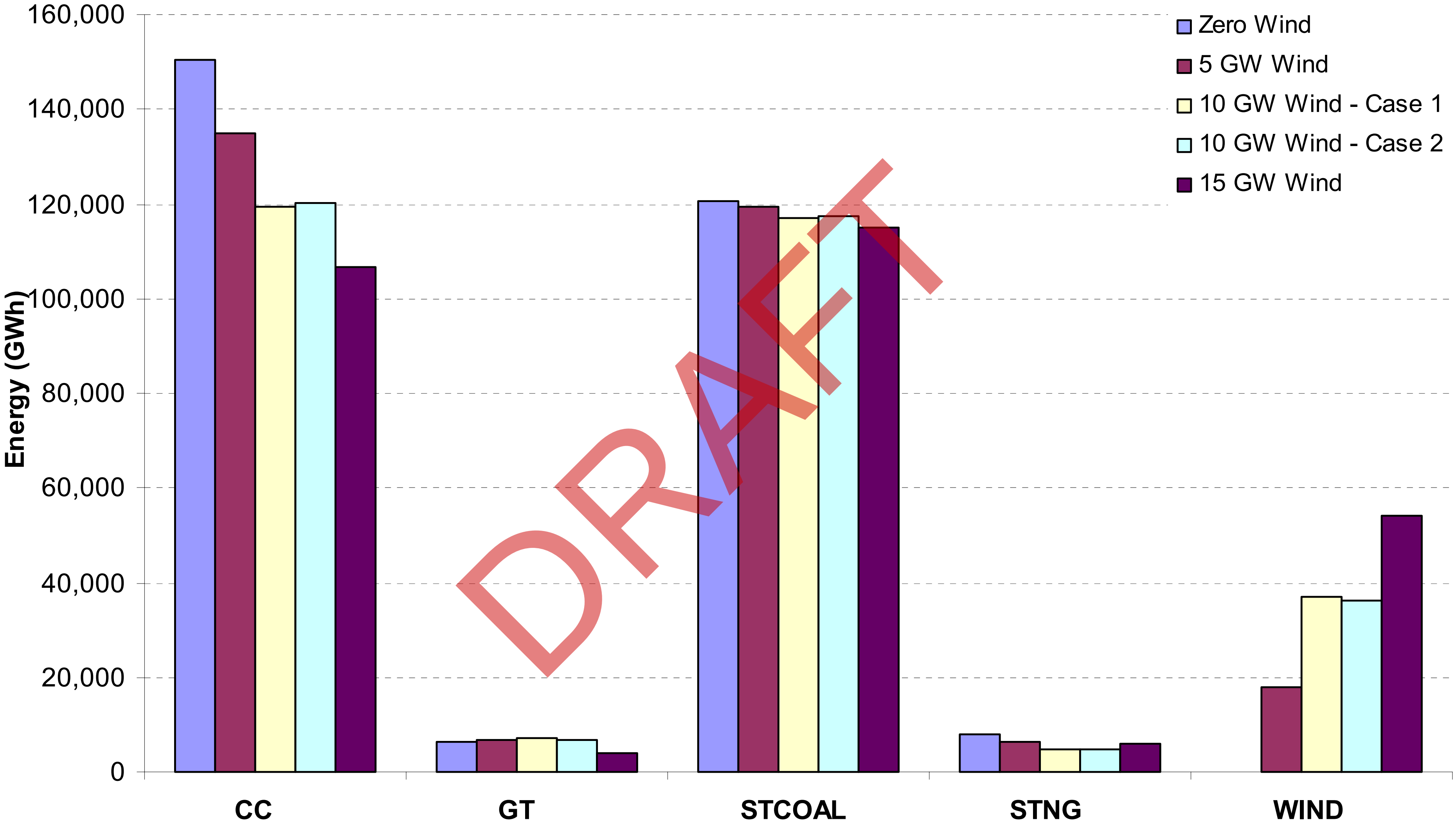
- Hour-by-hour power production simulations for the wind scenarios, using GE **M**ulti-**A**rea **P**roduction **S**imulation (MAPS) program
  - Unit commitment
  - Dispatch
- Program outputs
  - Production costs
  - Spot prices
  - Spinning reserve prices
  - Ramping capability and range
  - Emissions

Issues:

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

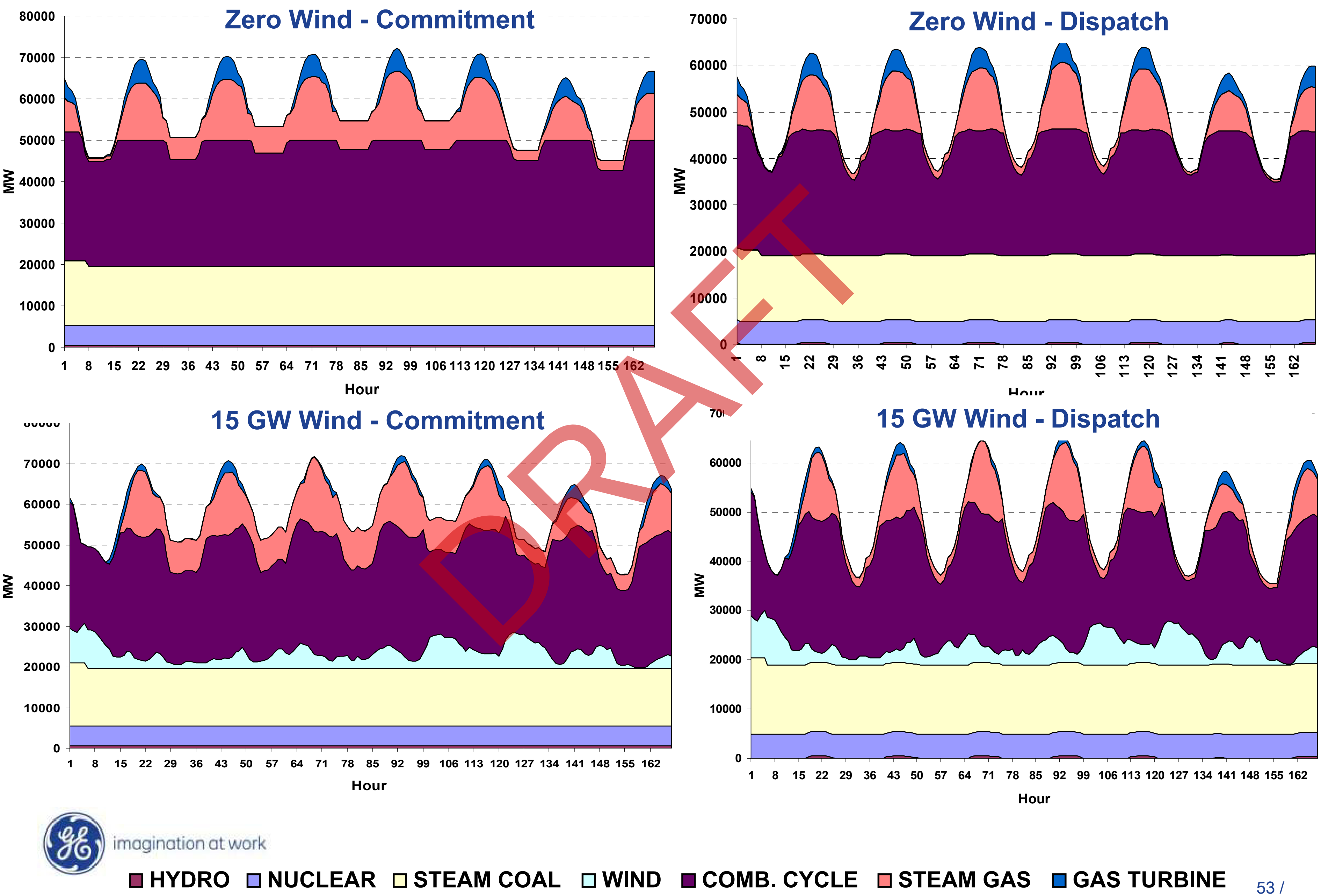
Energy Output

Commitment Based on State-of-Art Forecast

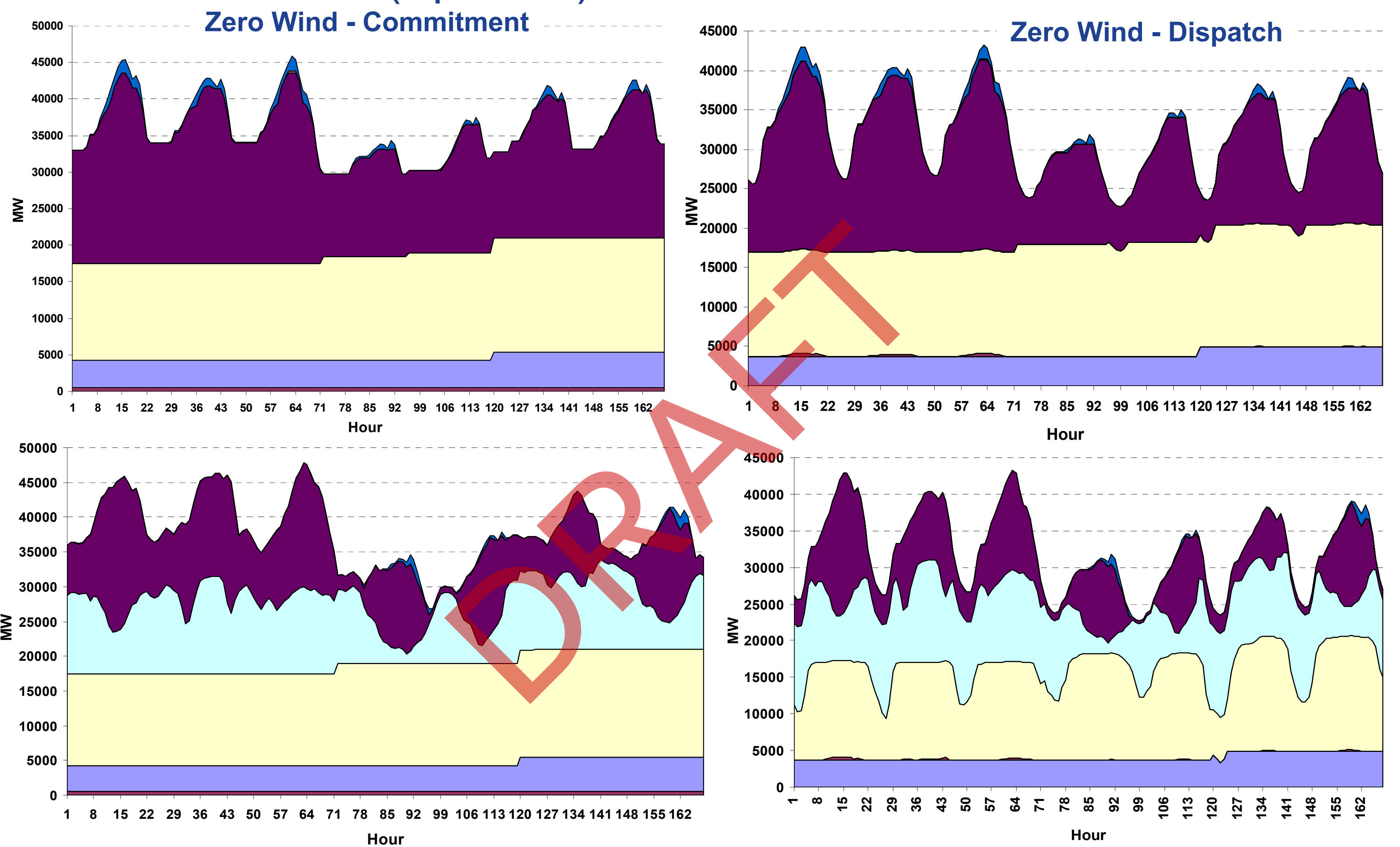


Major impact is on combined cycle unit operation, consistent with results observed in other studies

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



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



15 GW Wind - Commitment

15 GW Wind - Dispatch

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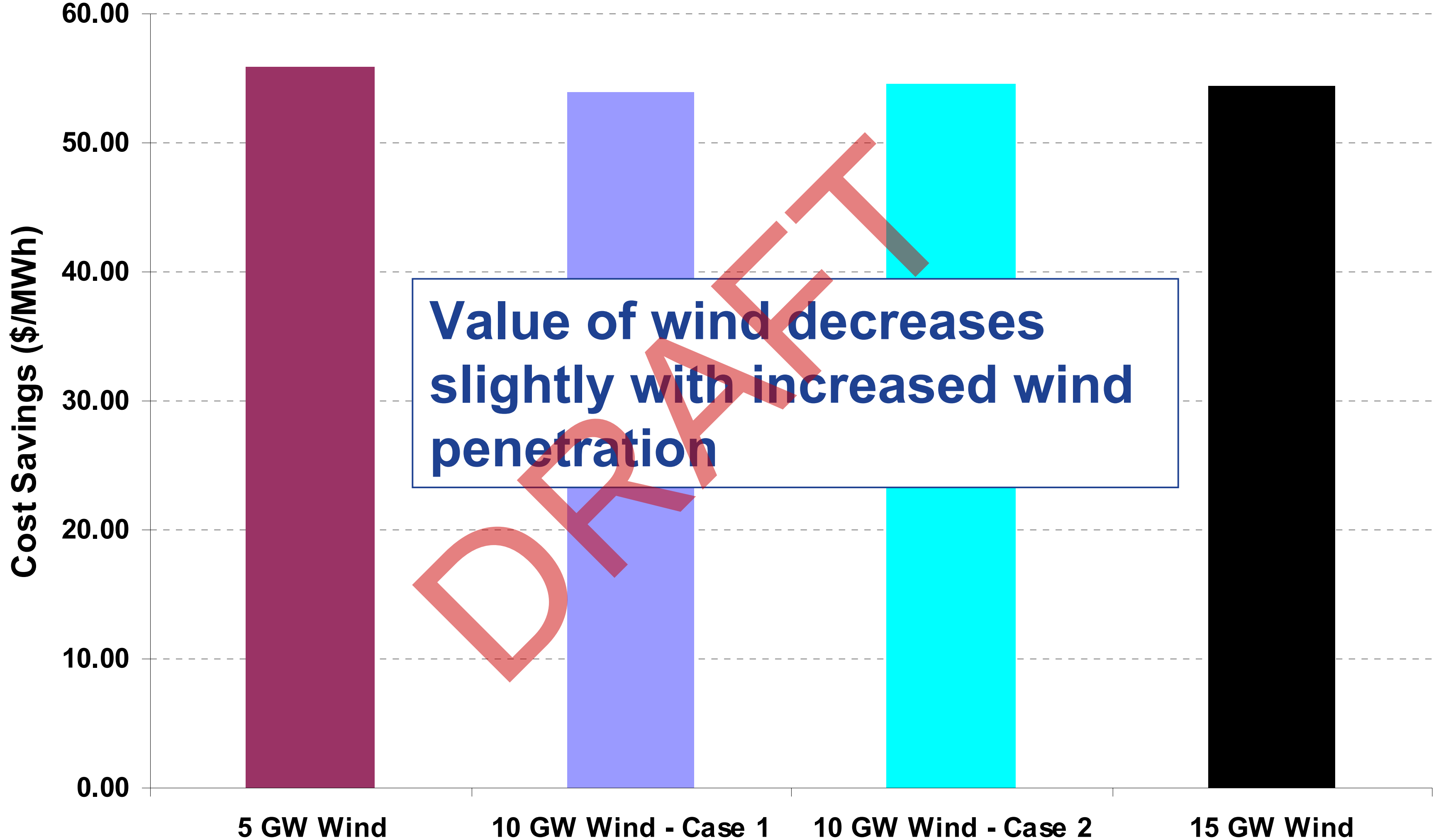
HYDRO NUCLEAR STEAM COAL WIND COMB. CYCLE STEAM GAS GAS TURBINE

Production Cost Reductions Due to Wind



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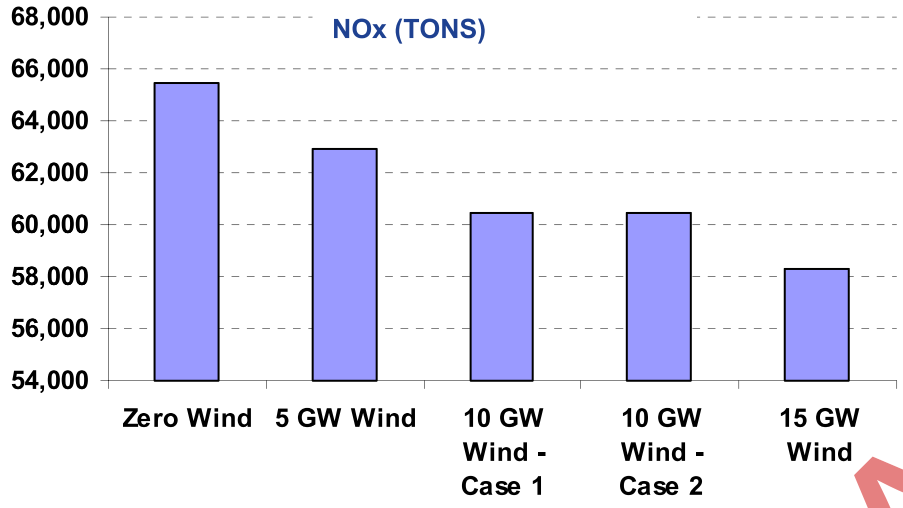
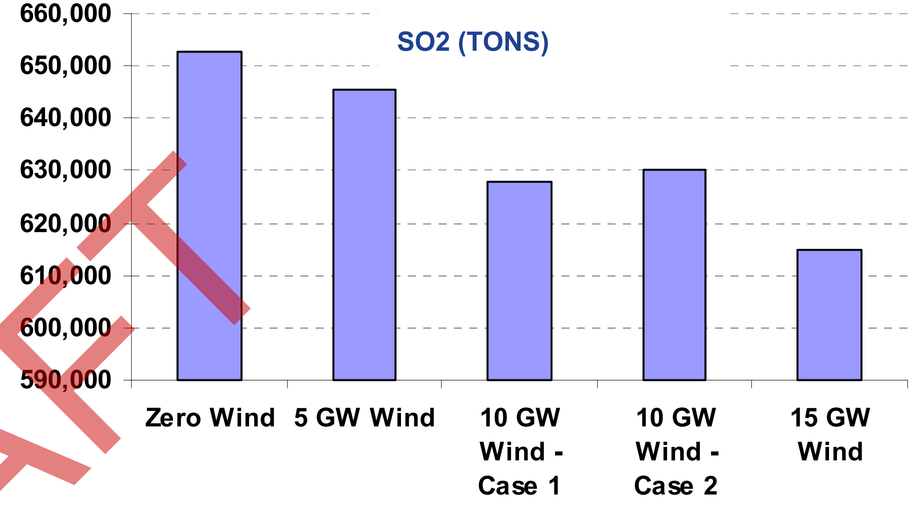
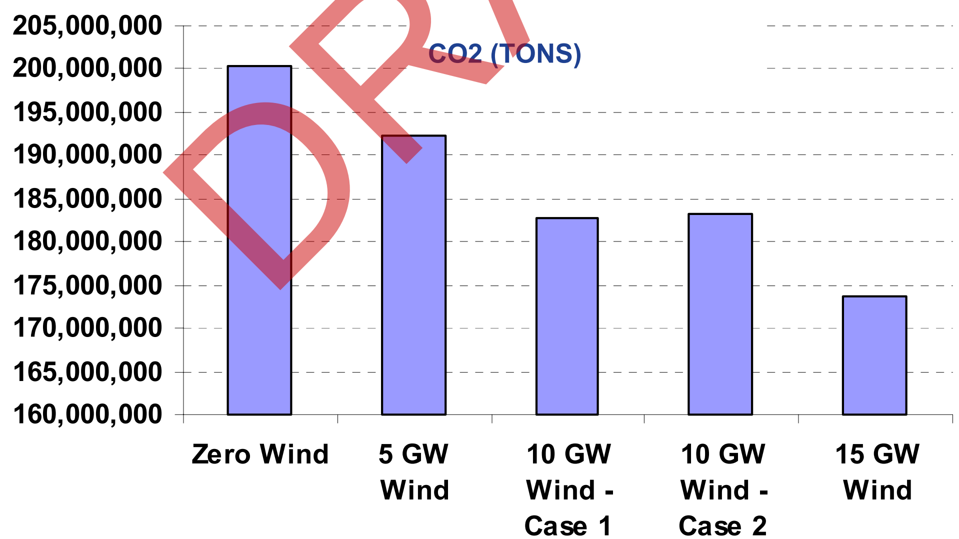
Total Annual Emissions

(State-of-Art Wind Forecast Assumed)







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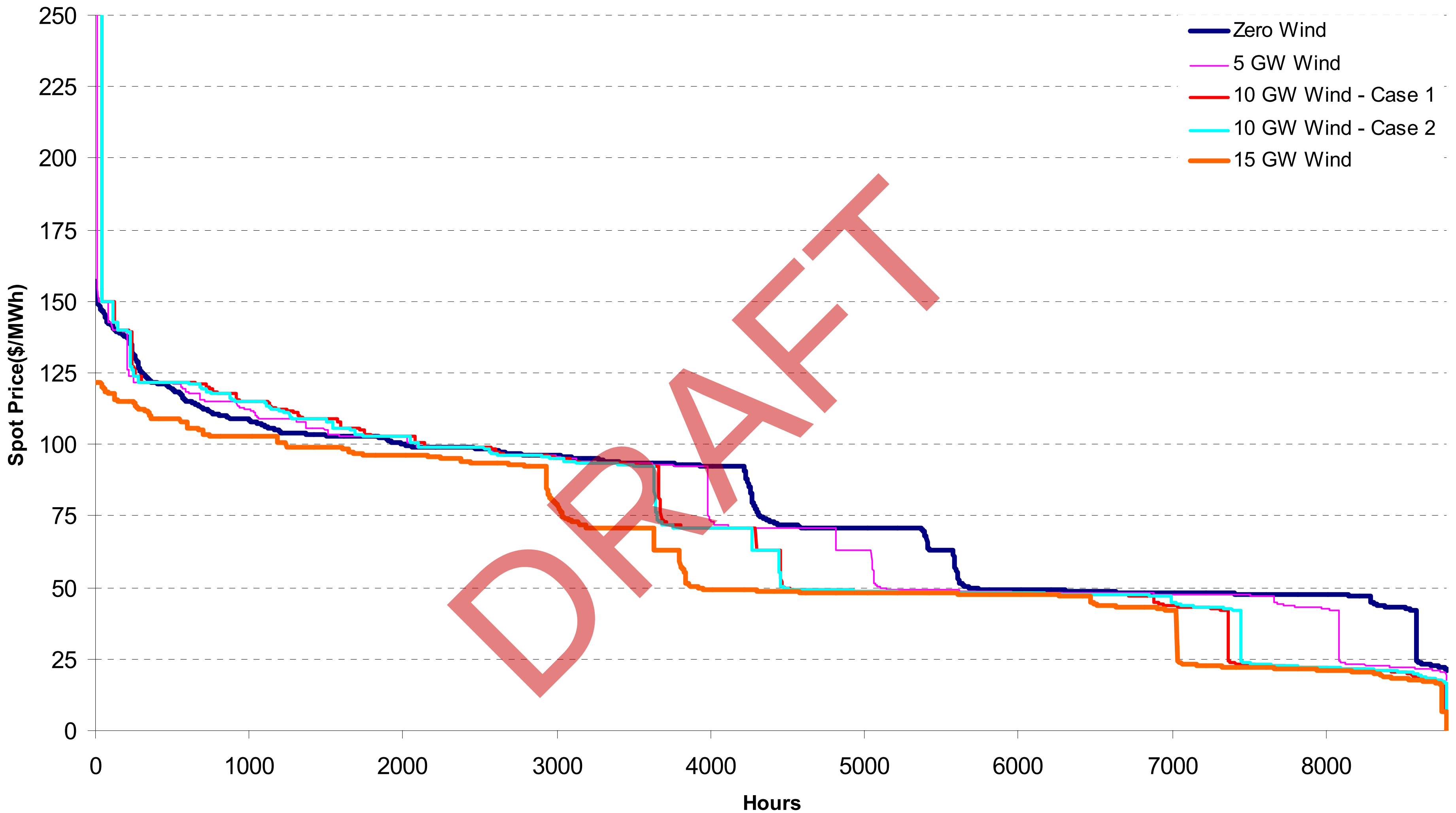
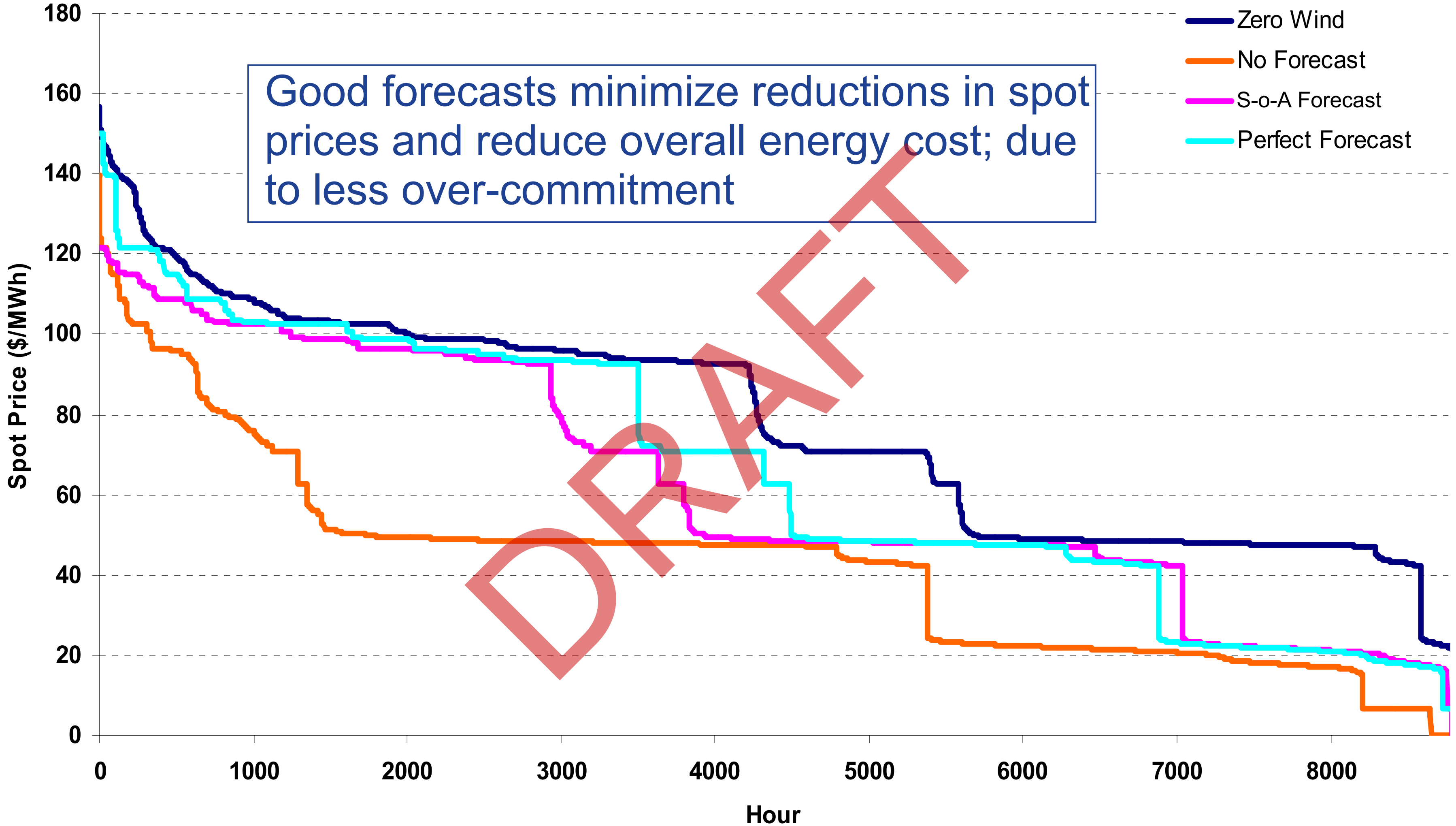
Energy Spot Prices – Assumes State of the Art Forecast



imagination at work

Impact of Wind Forecast on Energy Prices – 15 GW Wind



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:

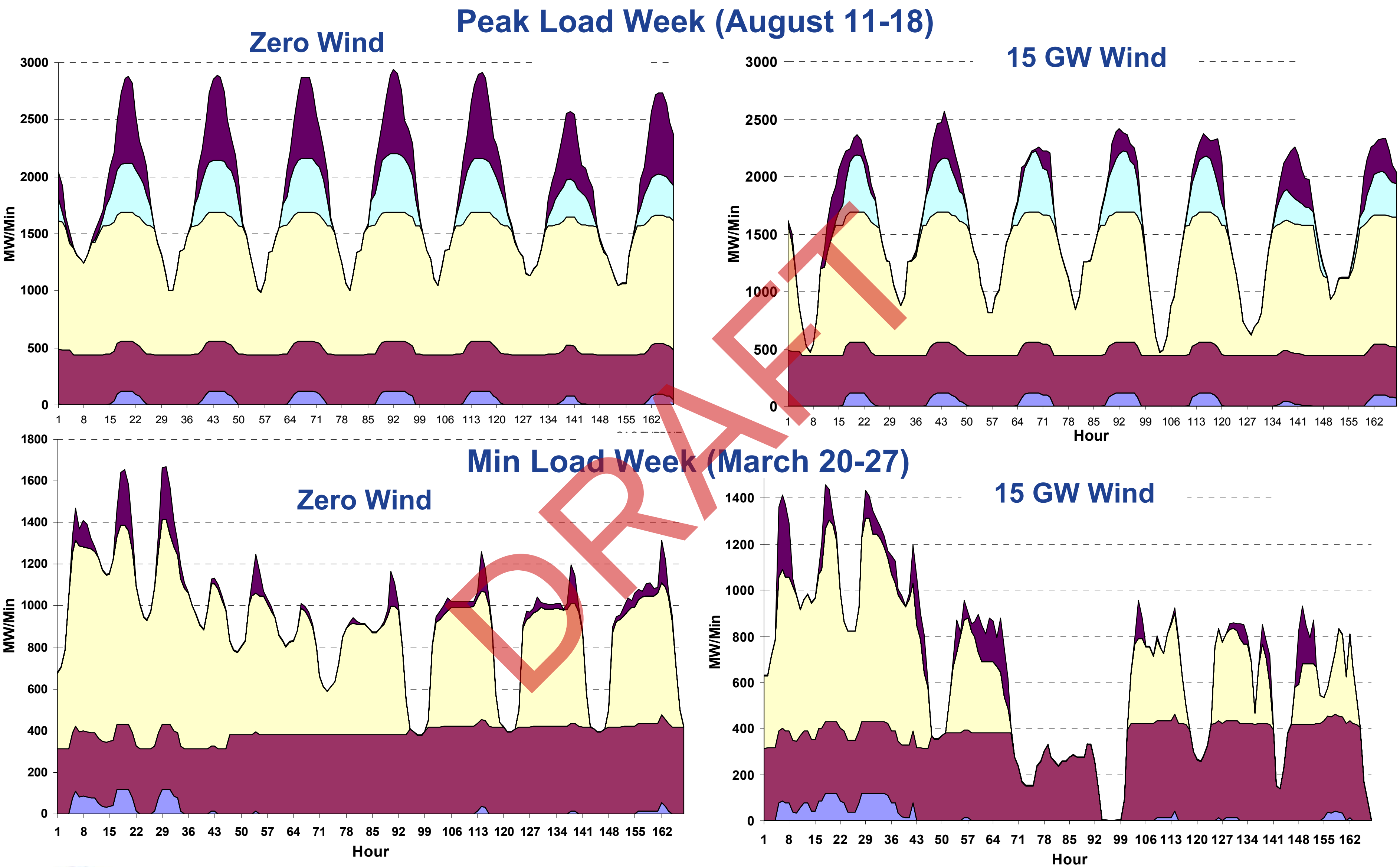
- Displacement of conventional generation
- Flexibility of committed units

Ramp Rate Assumptions

Unit Type	% MW rating/minute
Hydro	22.3
Renewables	0
Combined Cycle	3.8
Steam	3.1
Gas Turbine	13.5
Pumped Storage	18.7
Nuclear	0

Down Regulation Resources

Based on state of the art forecast

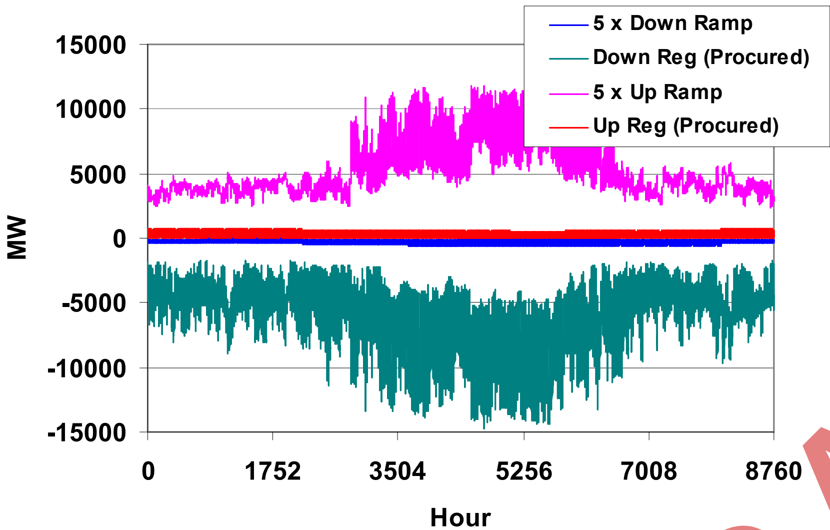


■ Hydro ■ Steam Coal ■ Combined Cycle ■ Steam Gas ■ Gas Turbine

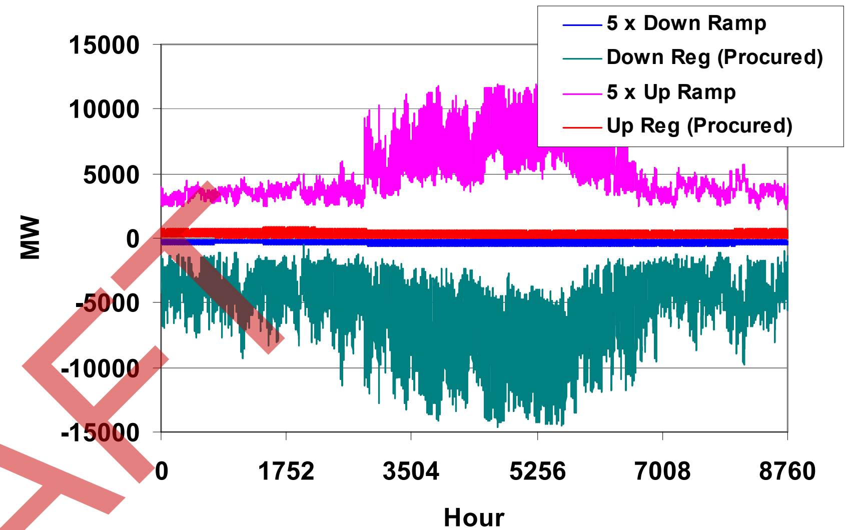
imagination at work

System Regulation Capacity

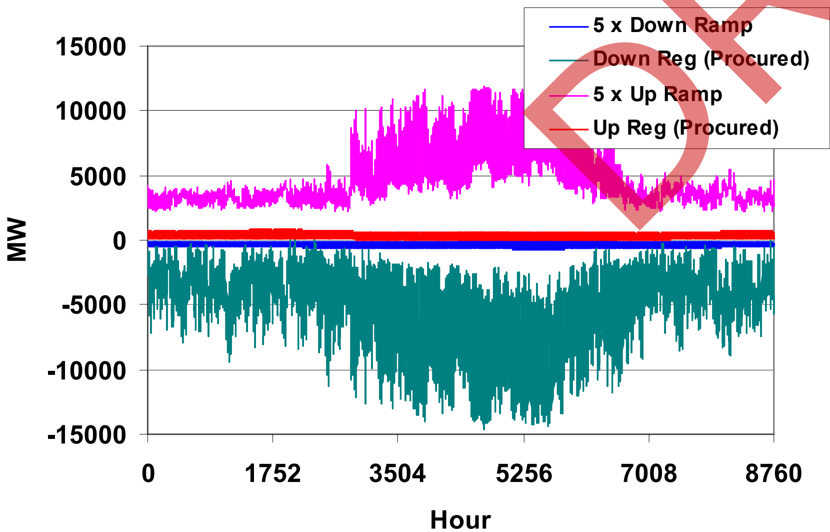
Load Alone



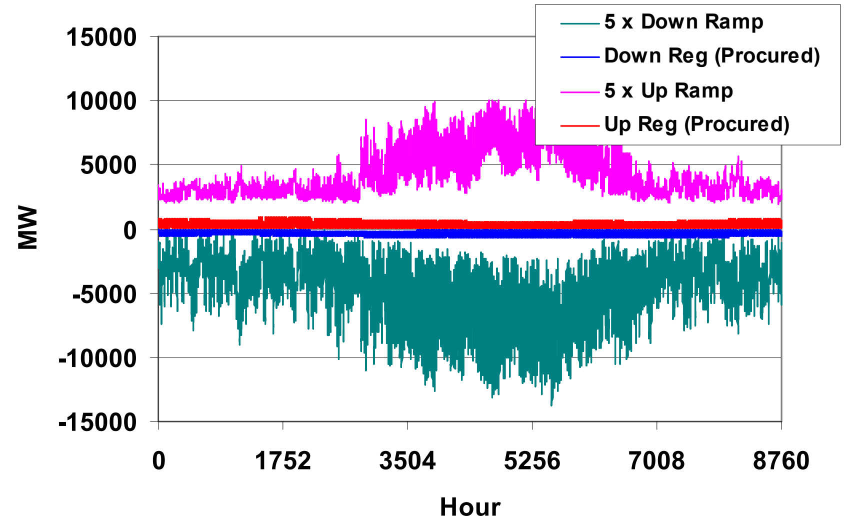
Load – 5000 MW Wind



Load – 10,000 MW Wind (1)

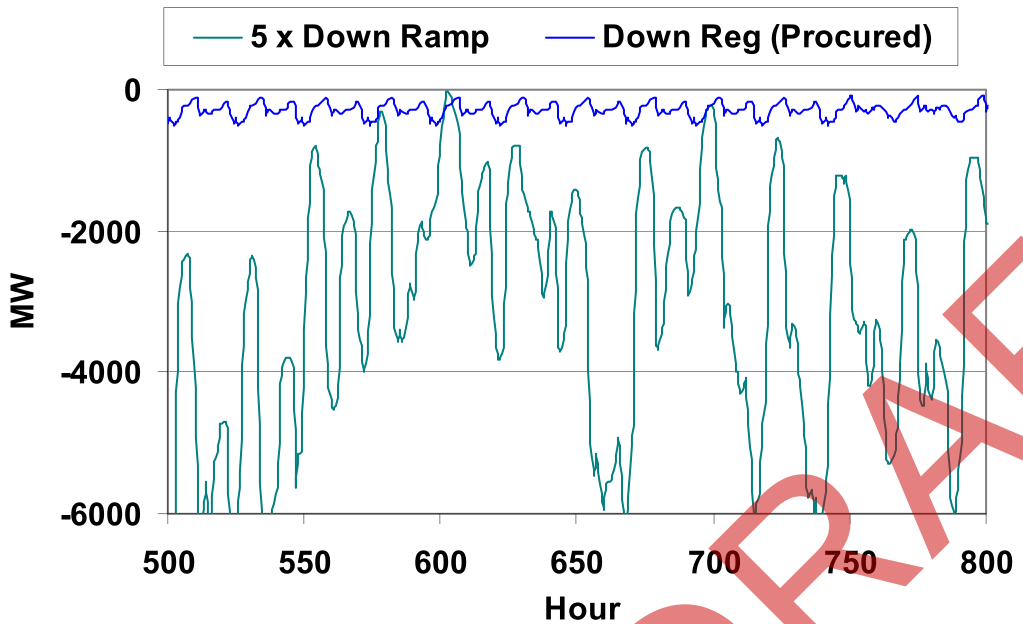


Load – 15,000 MW Wind



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

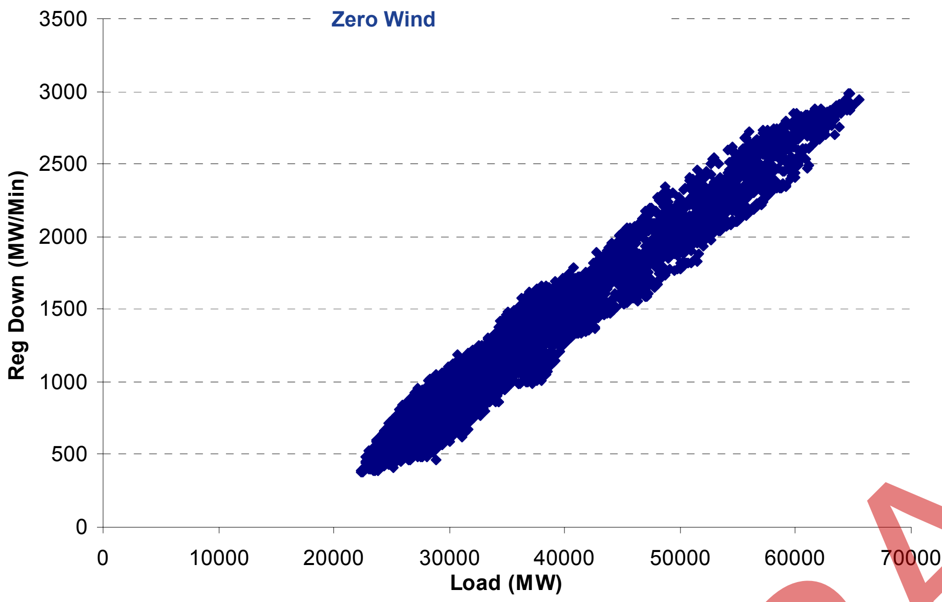
Down Regulation Range Deficiencies

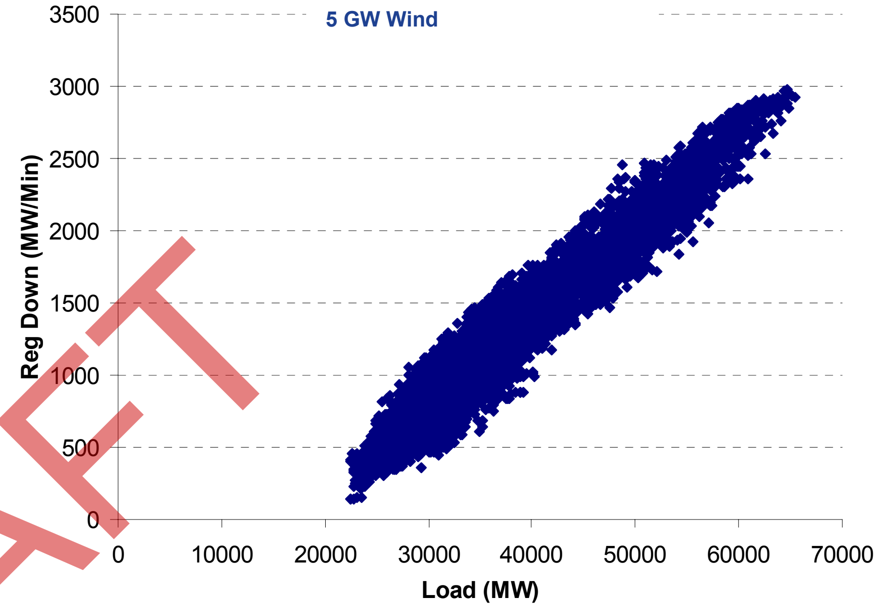


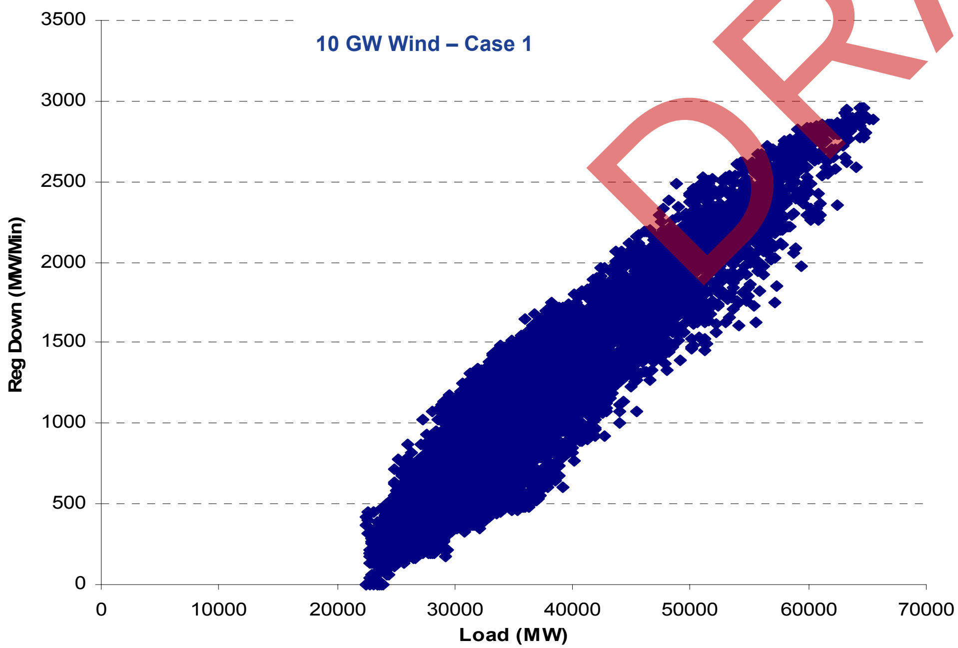
- Down-regulation requirements increase slightly.
- System flexibility is decreased due to reduced net load
- Result: system cannot accommodate down-regulation needs without adjusting dispatch
- Tradeoff between costs of adjusting dispatch versus curtailment or ramp limit of wind generators.

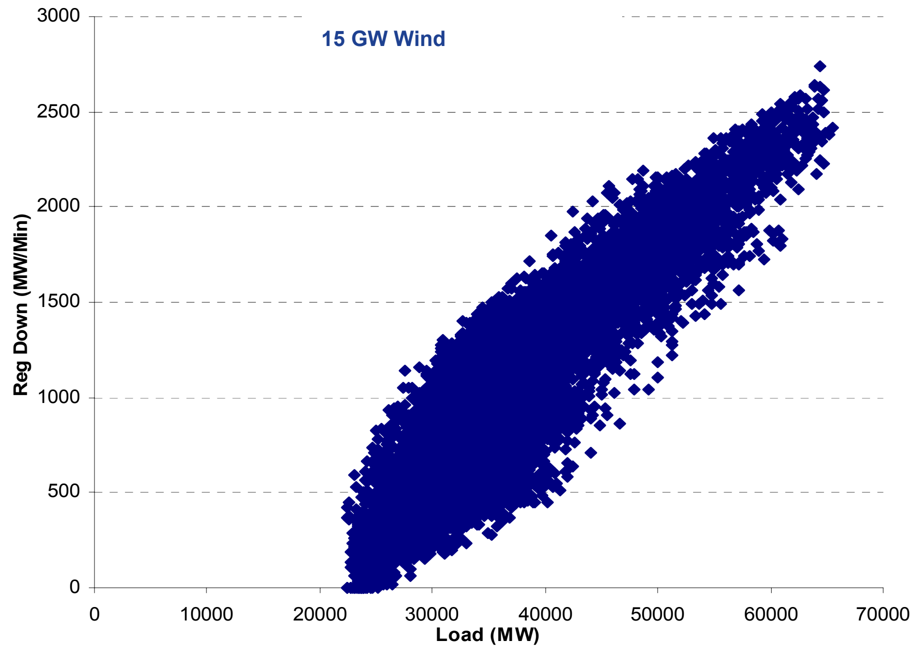
Wind (MW)	Hours Deficient	Total MWh Deficient	Average Deficiency (MW)	Maximum Shortfall (MW)
0	0	0	0	0
5,000	0	0	0	0
10,000 (1)	11	2709	246	482
10,000 (2)	7	1097	157	316
15,000	51	10308	202	712

System Load vs Down Regulation Capability









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

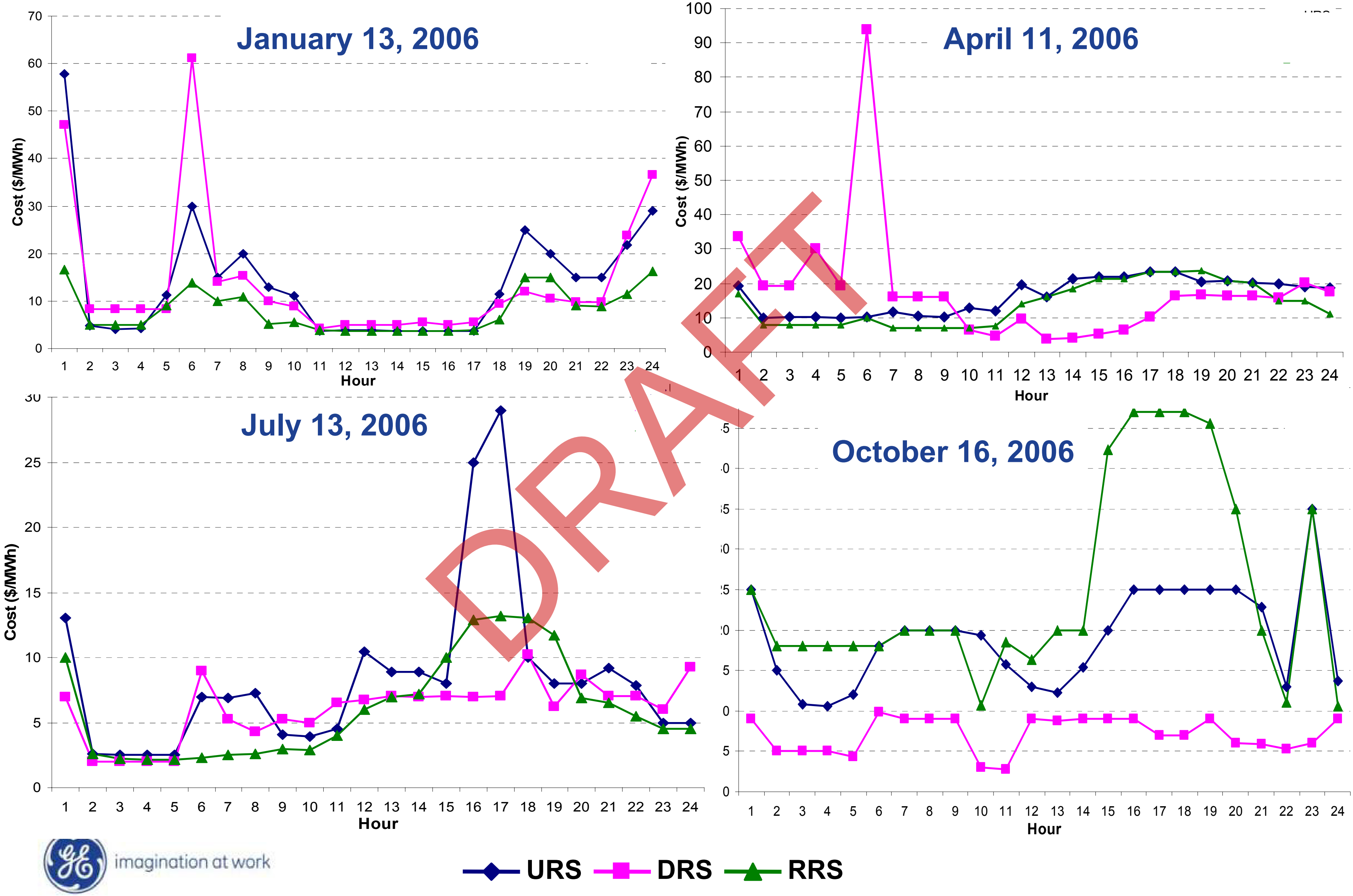
imagination at work

Regulation Service Costs

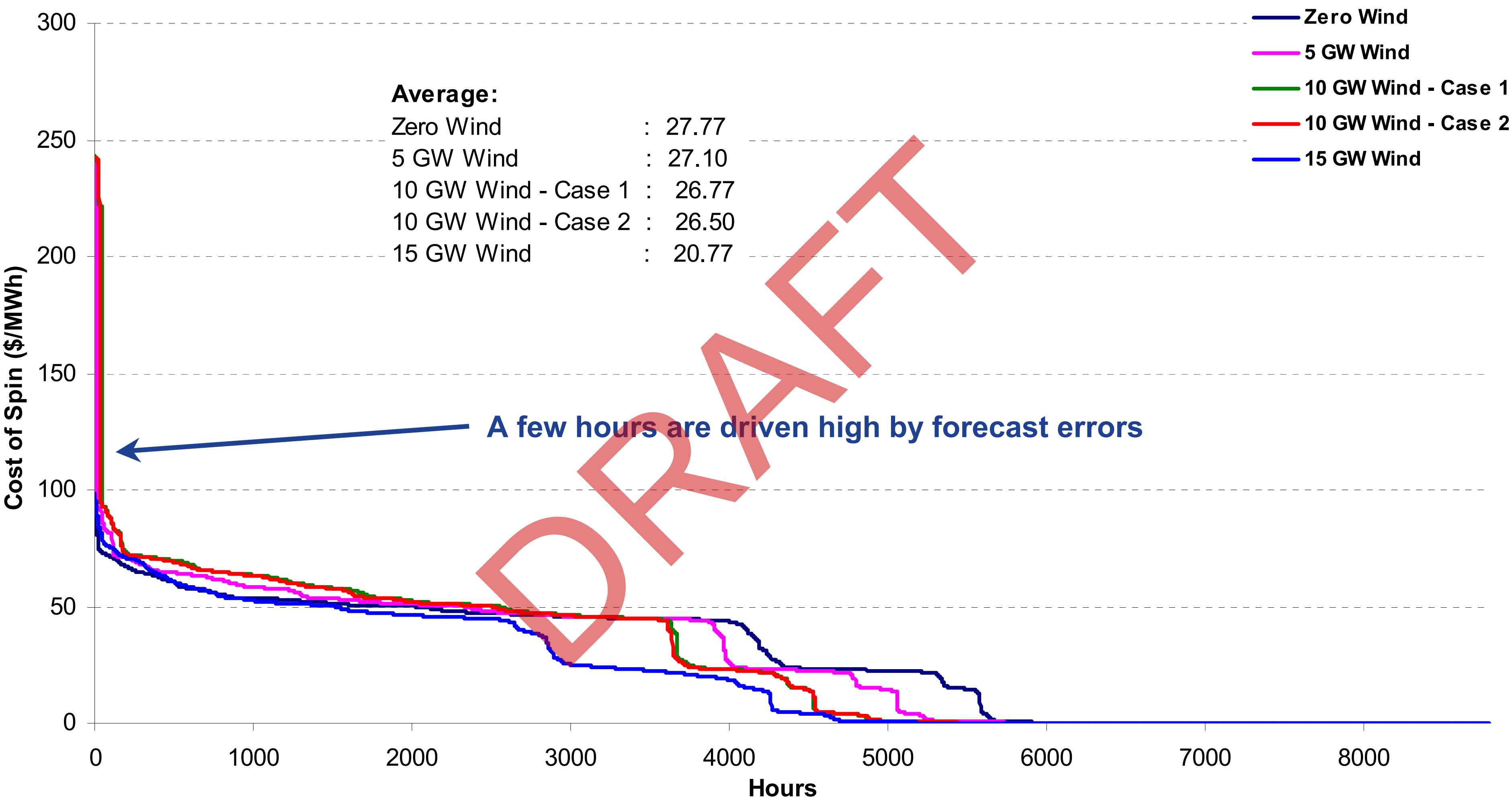
In this next set of slides, we will show:

- 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

Actual ERCOT data for Reg and Reserve Prices



Spin Cost with State-of-Art Forecast Used in Commitment



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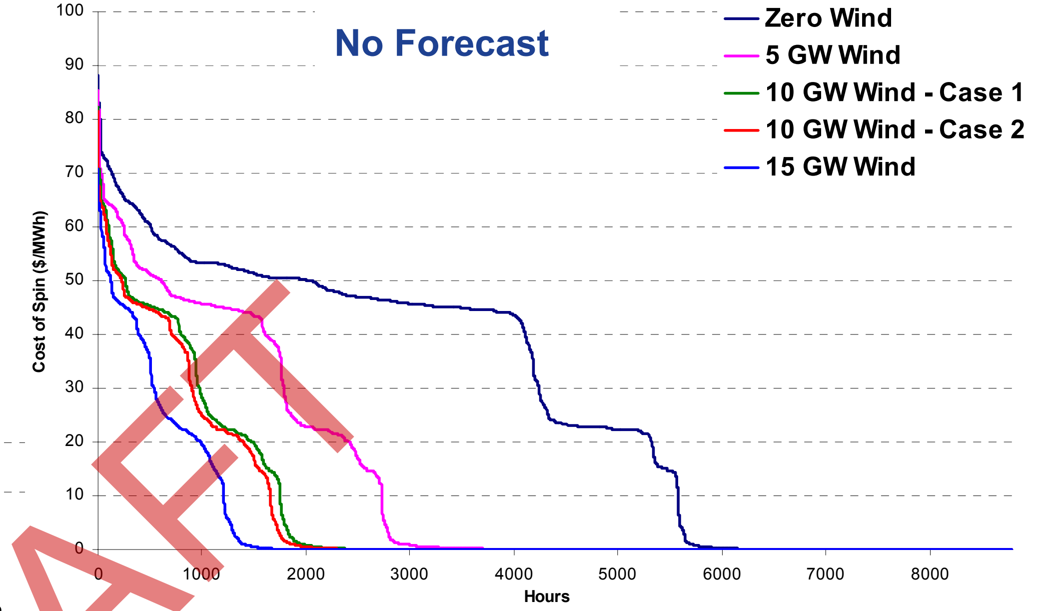
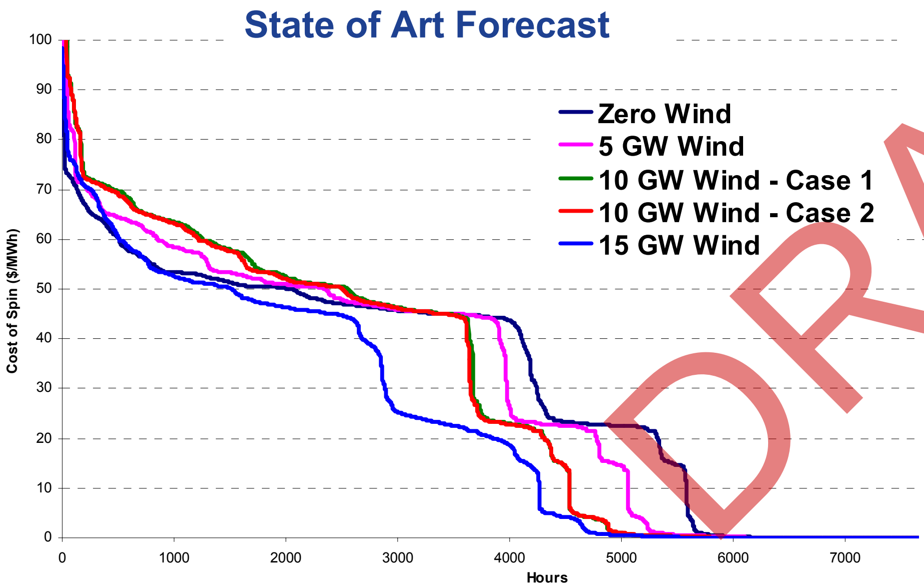
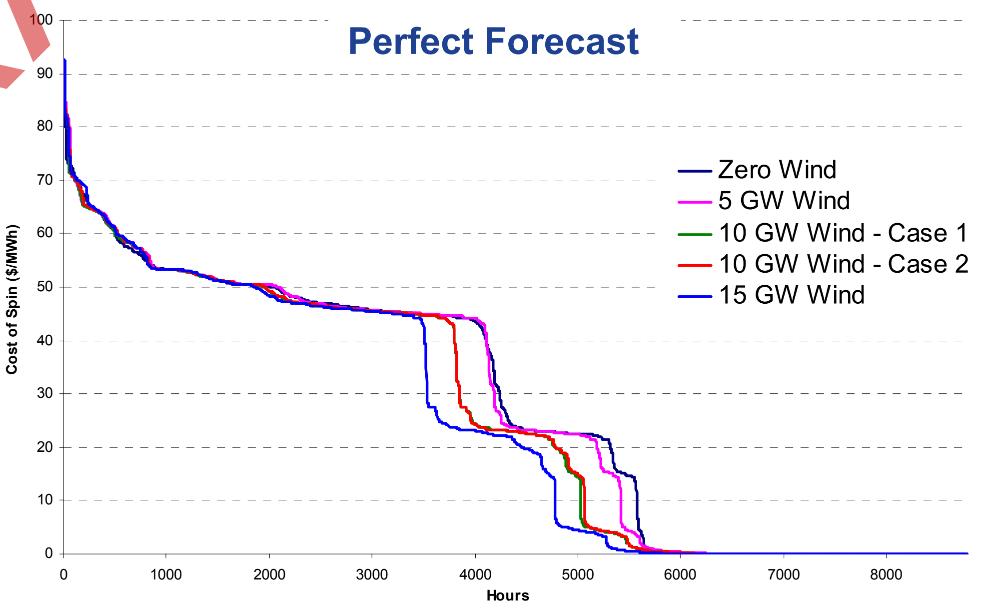
Spin Cost for Various Wind Penetrations







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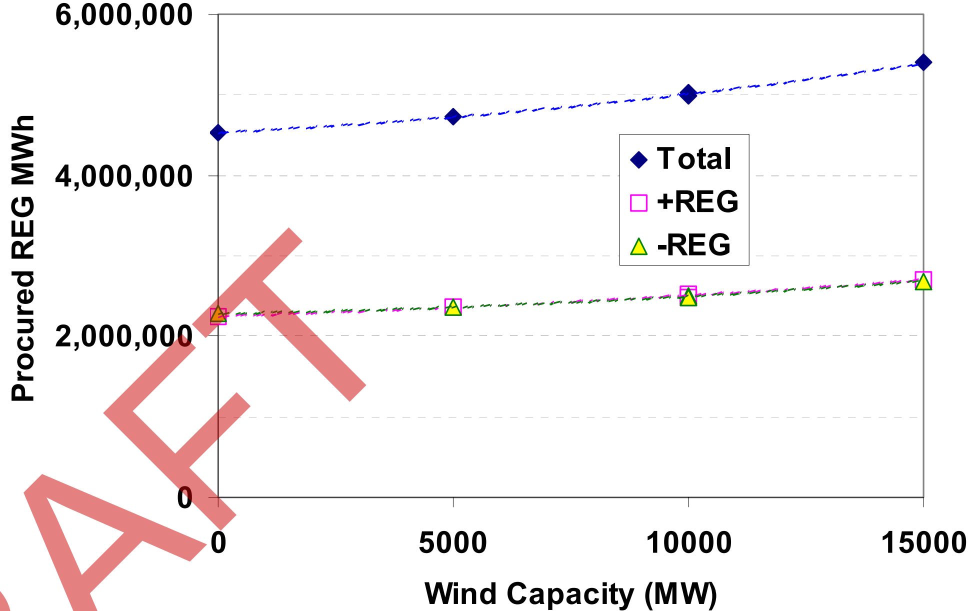
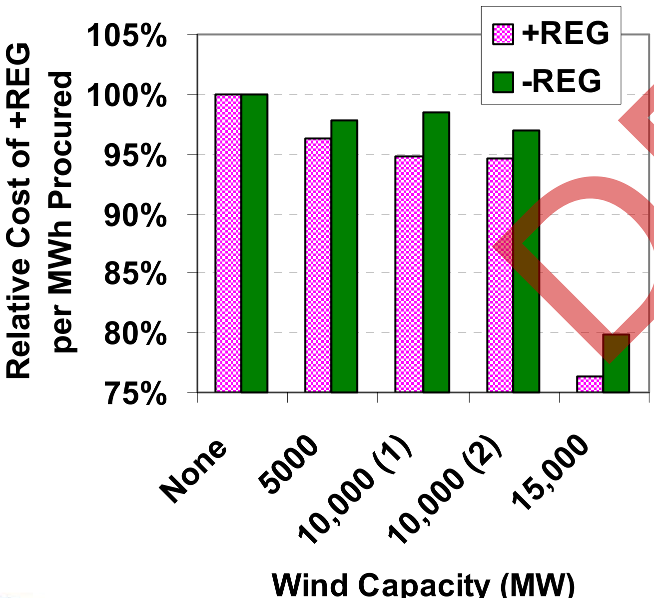
Regulation Cost Assumptions

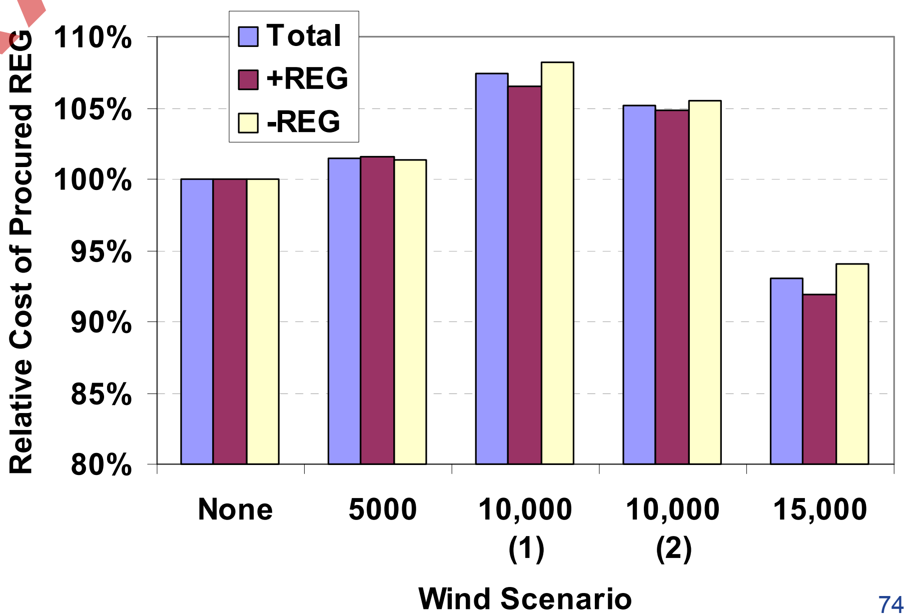
- REG cost is the greater of $5/MWh or the cost of spinning reserve
- Cost of wind curtailment added when –REG exceeds available range
(spot price)
- Results most useful when considered on a relative basis

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

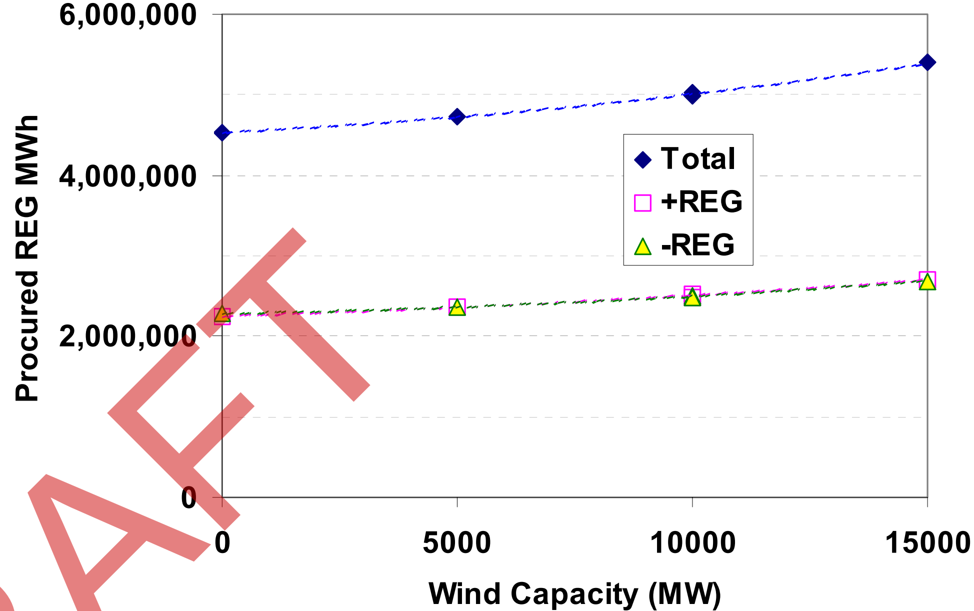


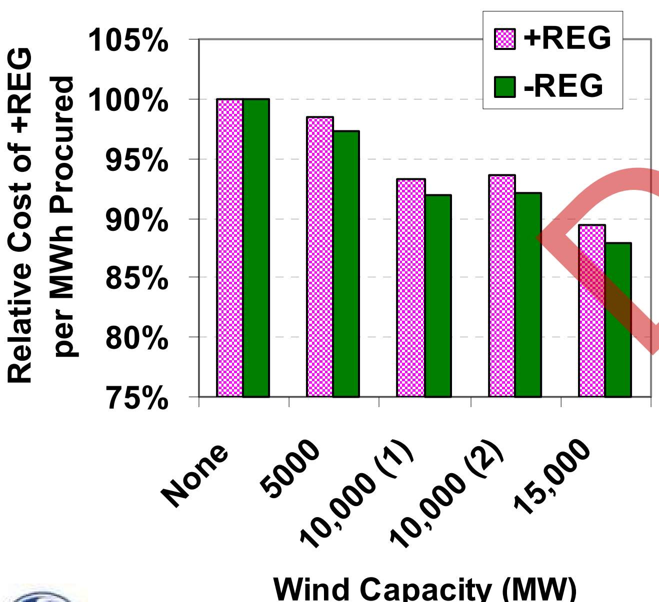


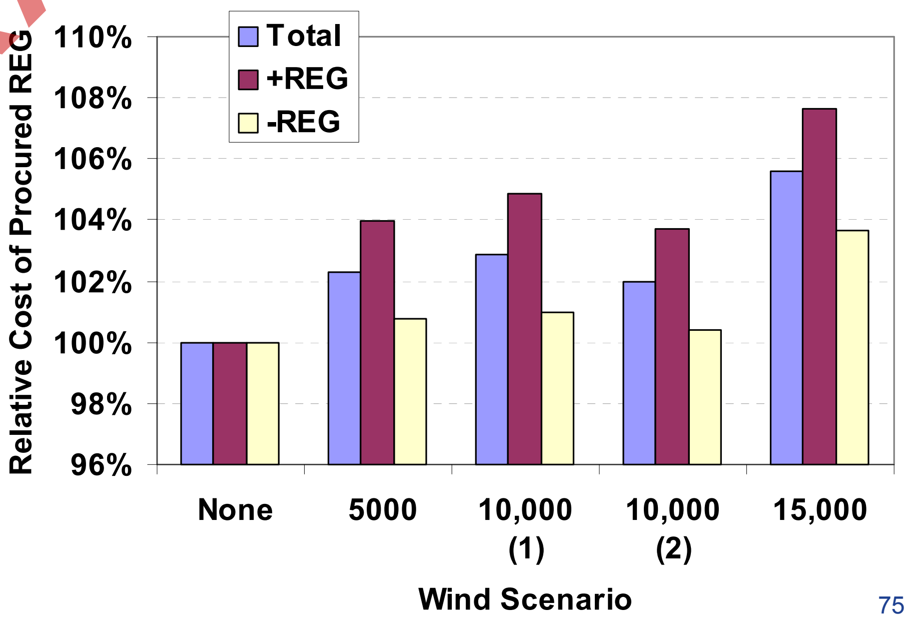


Cost of Meeting Regulation Service Requirements –
Perfect Forecast

- 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







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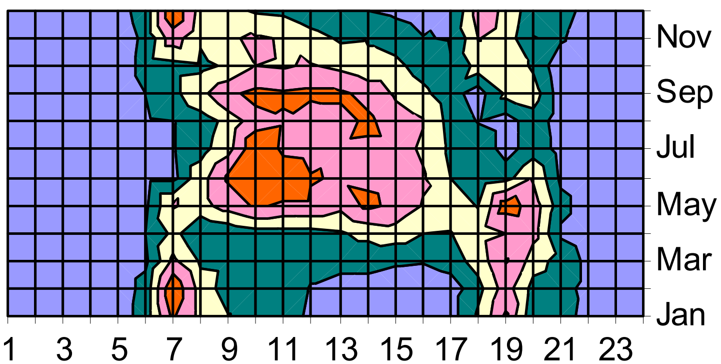
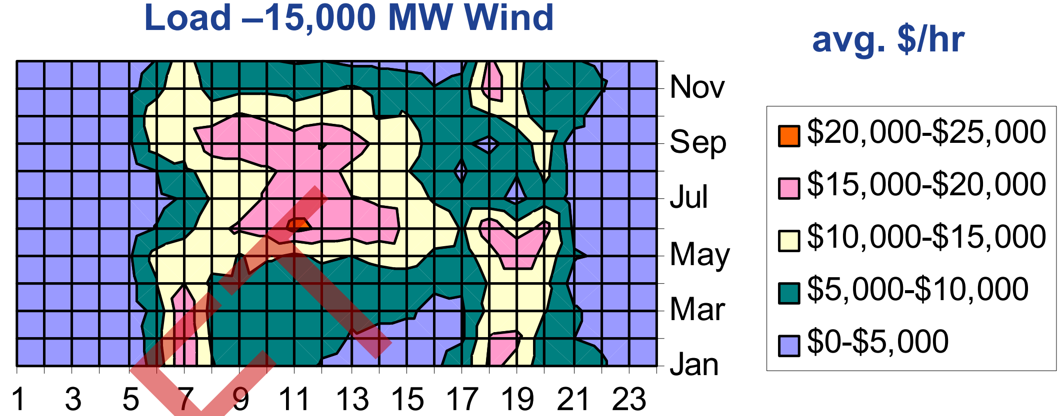
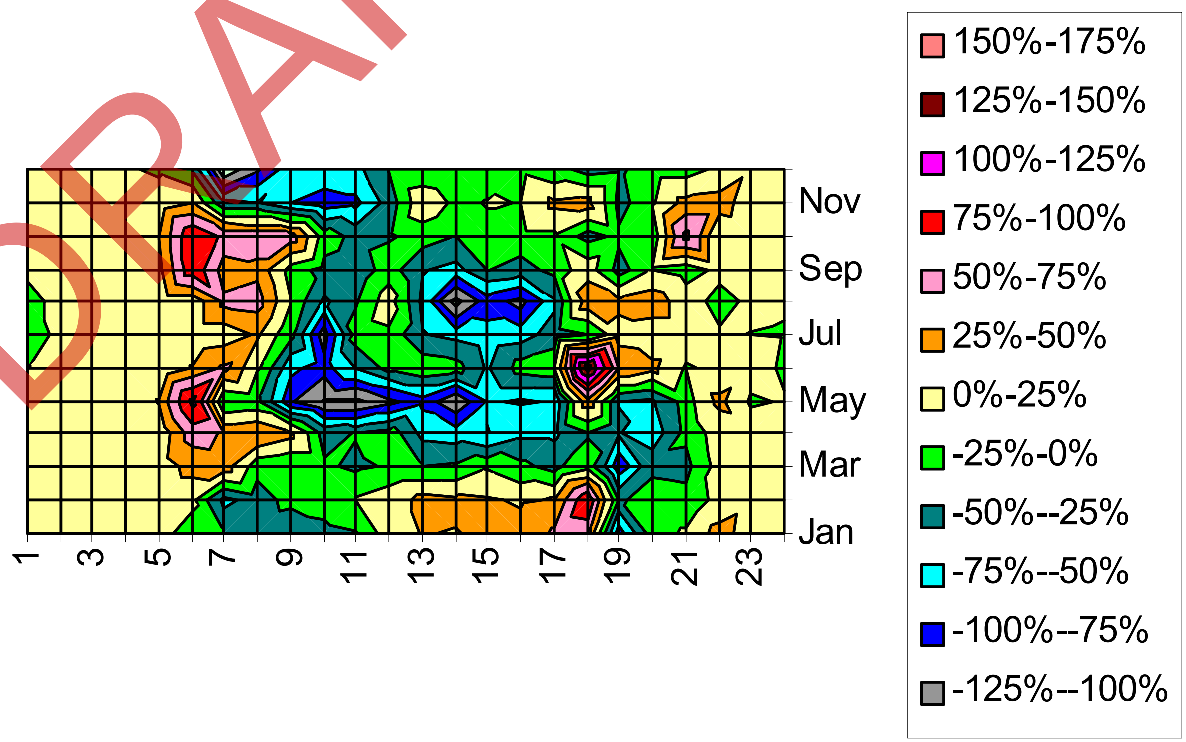
Up-Regulation Cost Impacts – By Month and Hour S-o-A Forecast



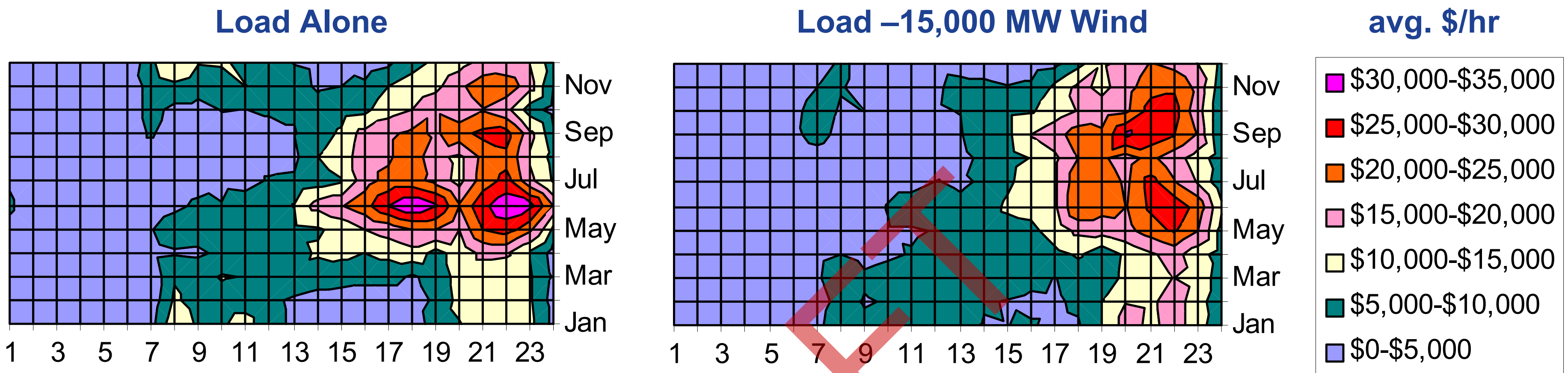


- **Sharp increase in morning, sping and fall**
- **Sharp decrease morning through mid-day except in mid-winter**

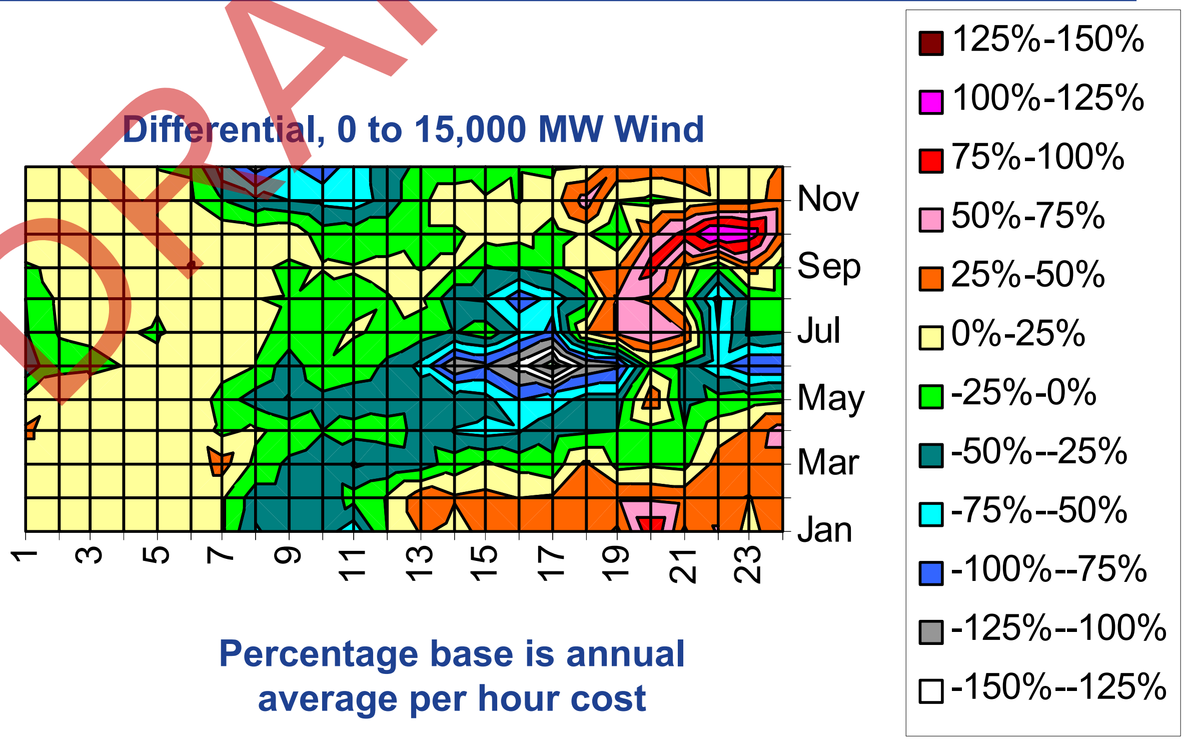


Down-Regulation Cost Impacts – By Month and Hour

S-o-A Forecast



- **Slight increase in early morning**
- **Sharp decrease morning through mid-day in spring and summer**
- **Late-evening increase in spring**
- **Sharp increase for late evenings in fall**



Percentage base is annual average per hour cost

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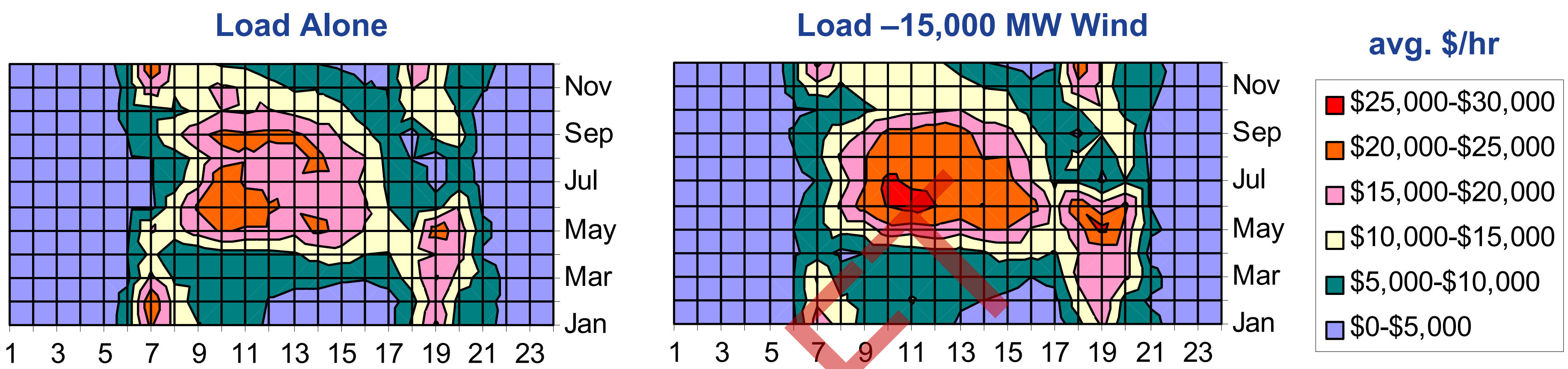
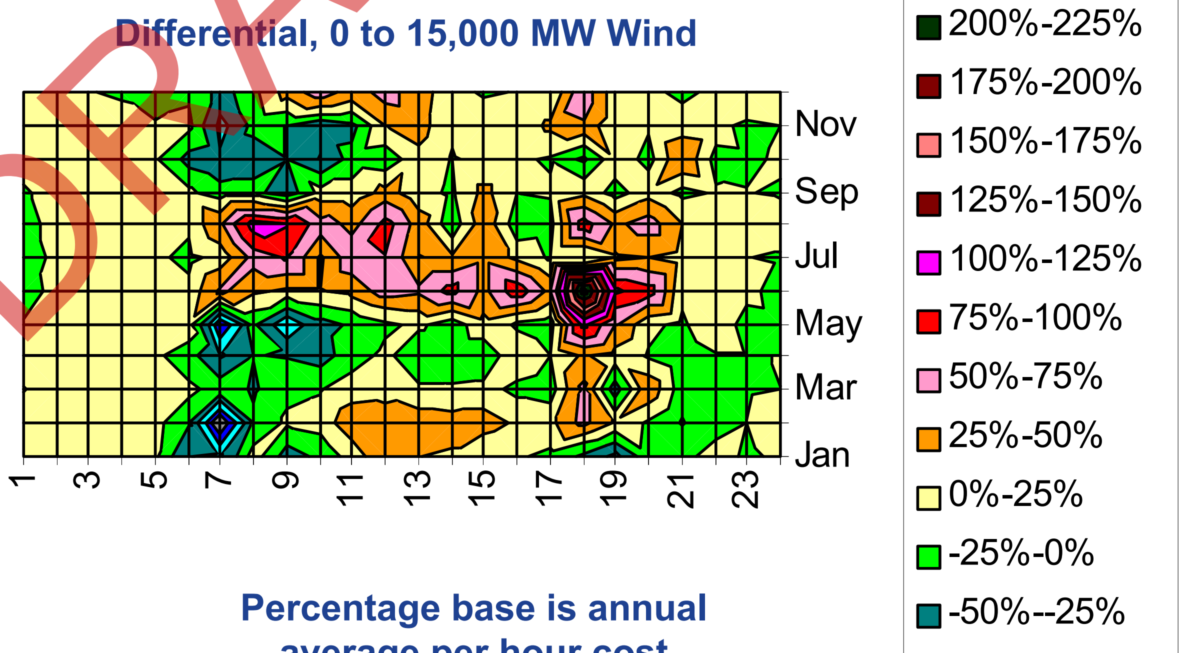
Up-Regulation Cost Impacts – By Month and Hour Perfect Forecast

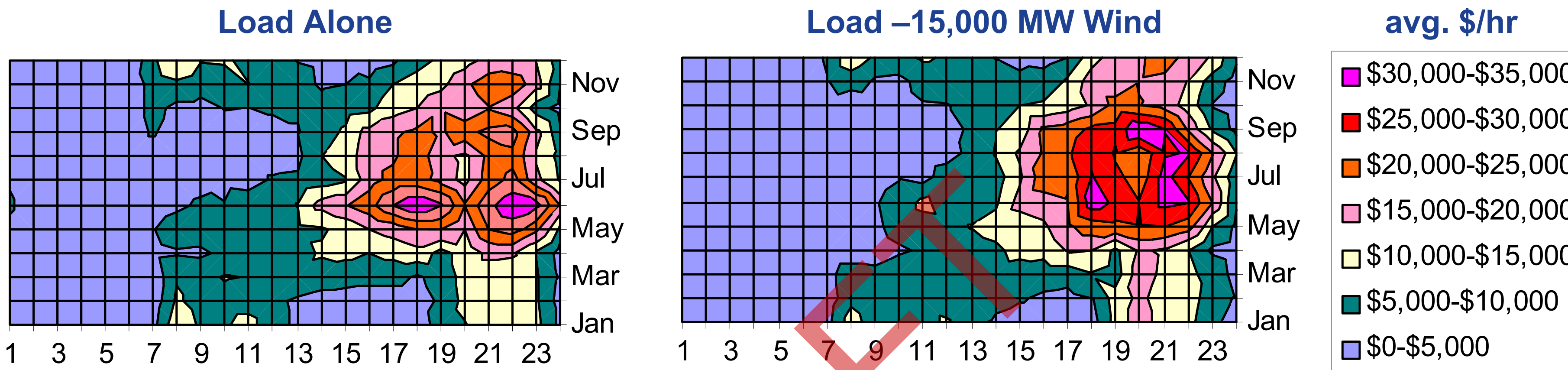


- Decrease during non-summer mornings
- Increase during summer daytime
- Large increase in evening during spring and early summer

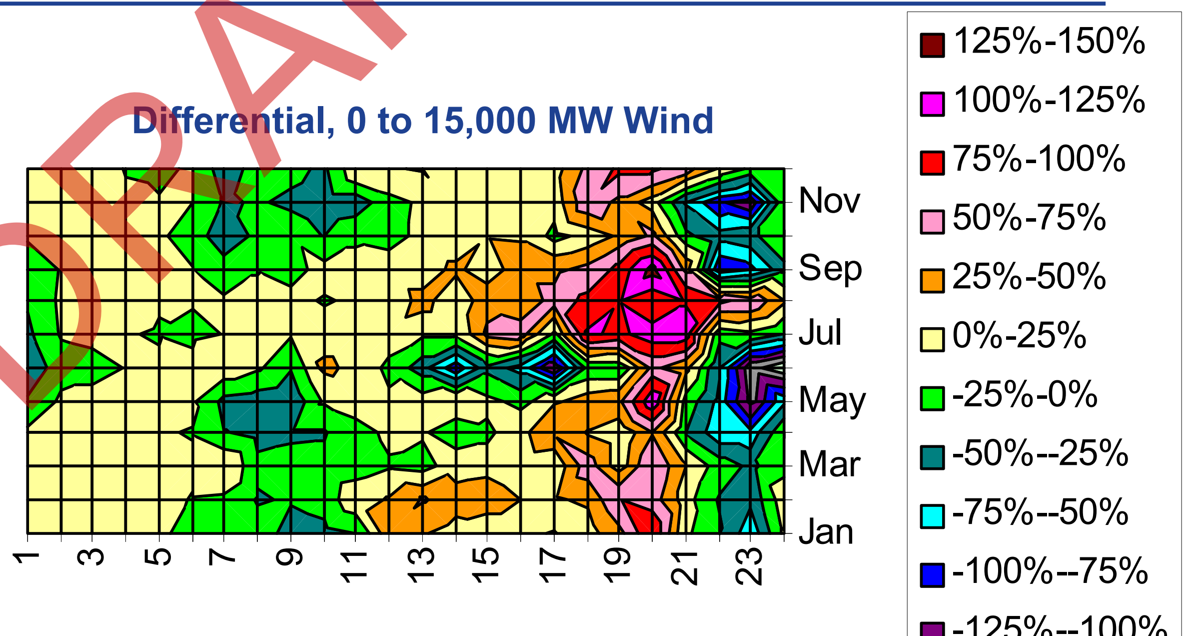


Percentage base is annual average per hour cost

Down-Regulation Cost Impacts – By Month and Hour
Perfect Forecast



- **Sharp reduction just prior to midnight**
- **General morning decrease**
- **Sharp increase in summer evenings**

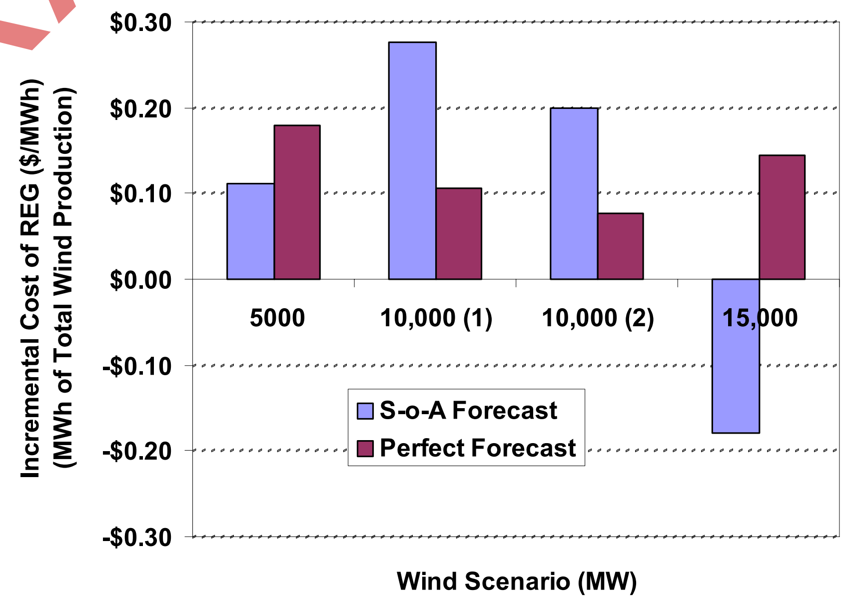


Percentage base is annual average per hour cost

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



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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
  - 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

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

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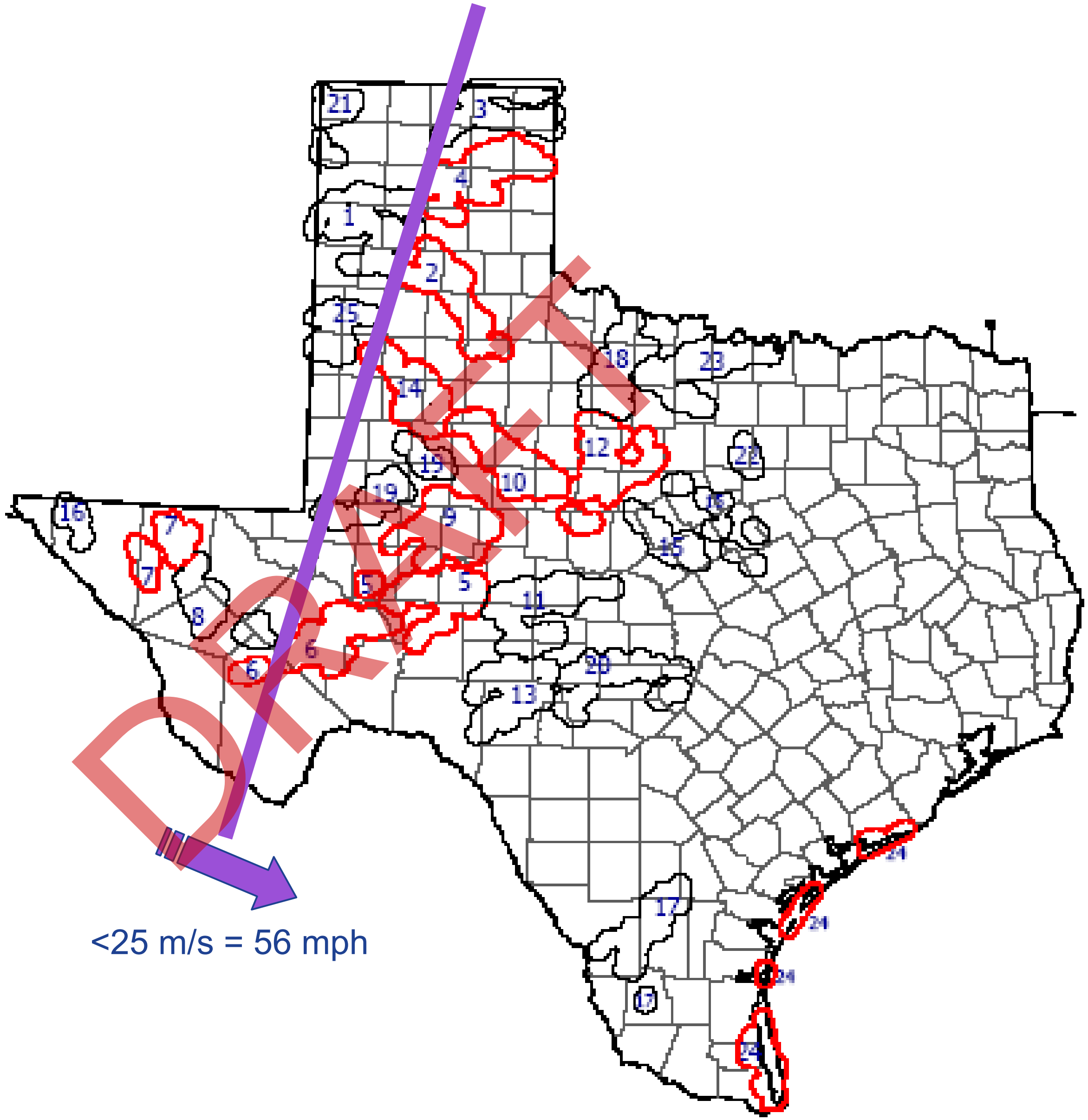
Meteorological Causes of Wind Ramp-Down Events

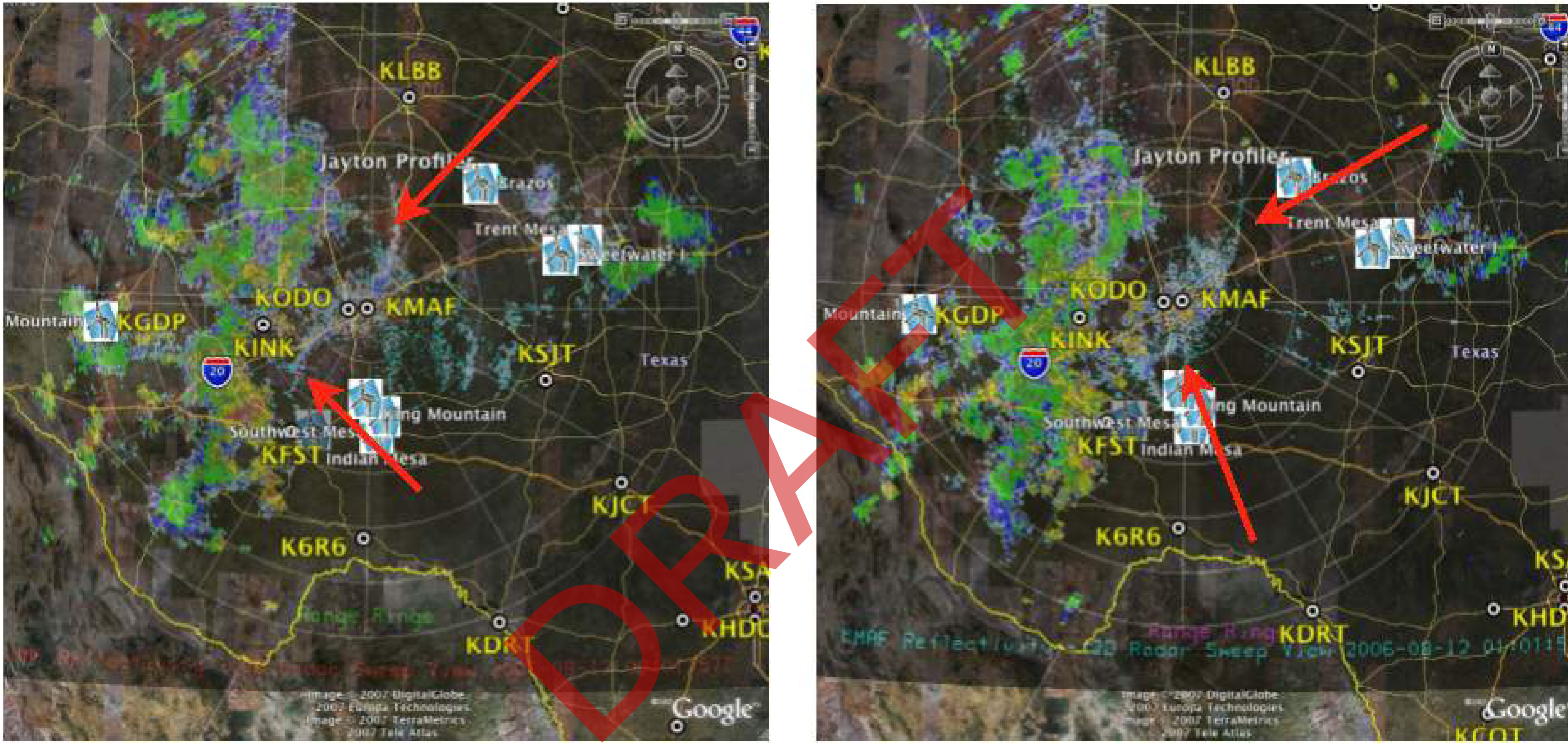
- Slackening of a pressure gradient
- Passage of a local pressure couplet
- Each can occur for same events causing ramp-up
- High wind speeds that exceed wind turbine cut-out
  - Threshold (22-25 m/s)
  - Responsible for February 24, 2007 event

Severe Frontal Orientation



<25 m/s = 56 mph

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

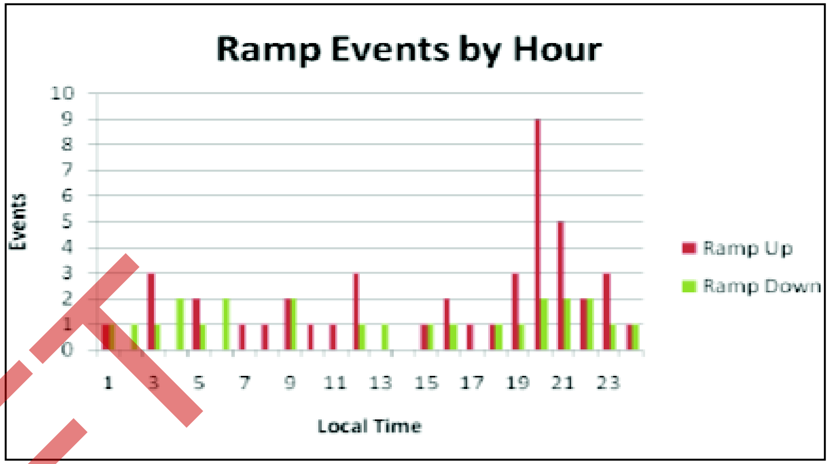
Table 1d. Positive Ramp Events For ERCOT Domain 2006			
Date	**Begin Time (Local)**	**Ramp (MW)**	**Event Classification**
23-Jun	4:49 AM	294	thunderstorm outflow
14-Nov	11:29 AM	264	dry line
28-May	7:11 PM	264	dry line
28-Apr	3:49 PM	258	frontal passage
20-Jul	7:33 PM	257	trough passage
26-Sep	7:58 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

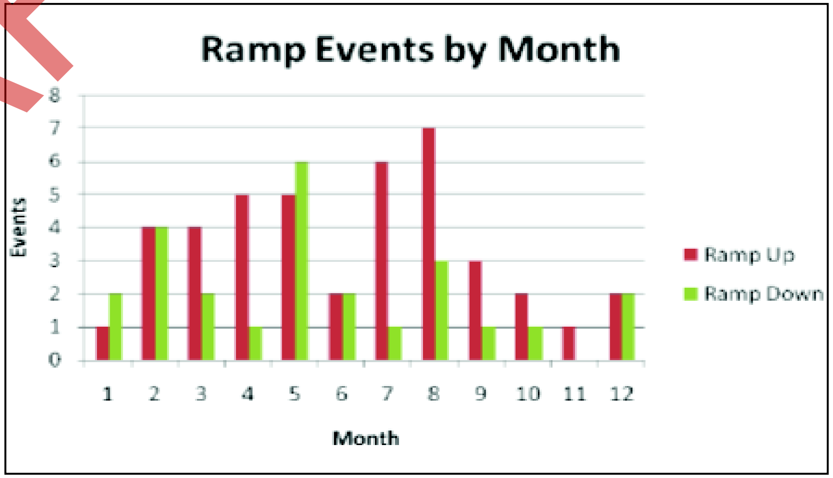
** 200 MW excursion within 30 minutes*

*** 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

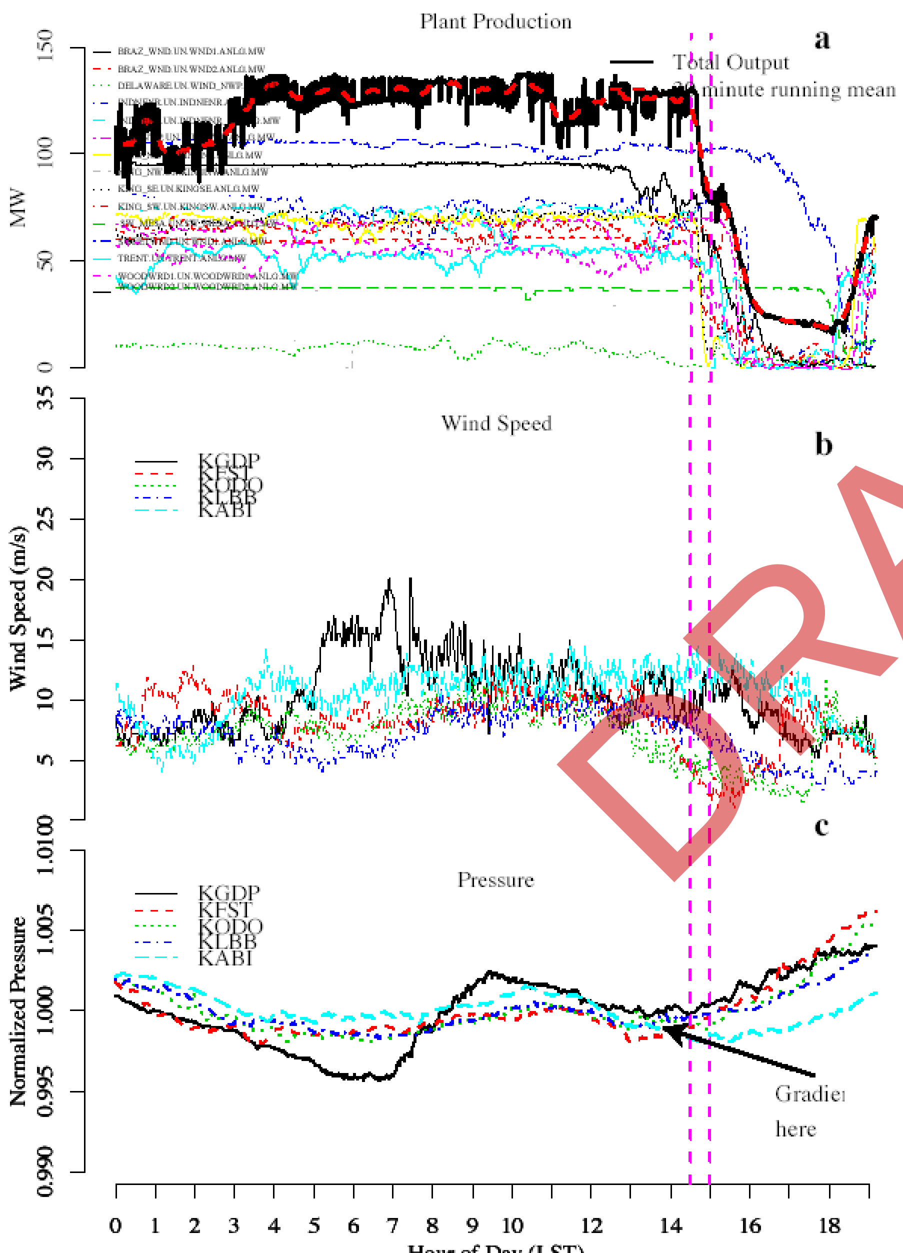




- 59 ramp events identified (60% up, 40% down)
- Largest ramp-up event on 9 July 2005
  - nearly 400 MW increase (over 300% from 200 MW)
- Largest ramp-down event on 12 May 2005
  - 331 MW decrease, (more than 58% from 571 MW)
- Primary causes: (1) convective (2) frontal passages (3) weakening pressure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

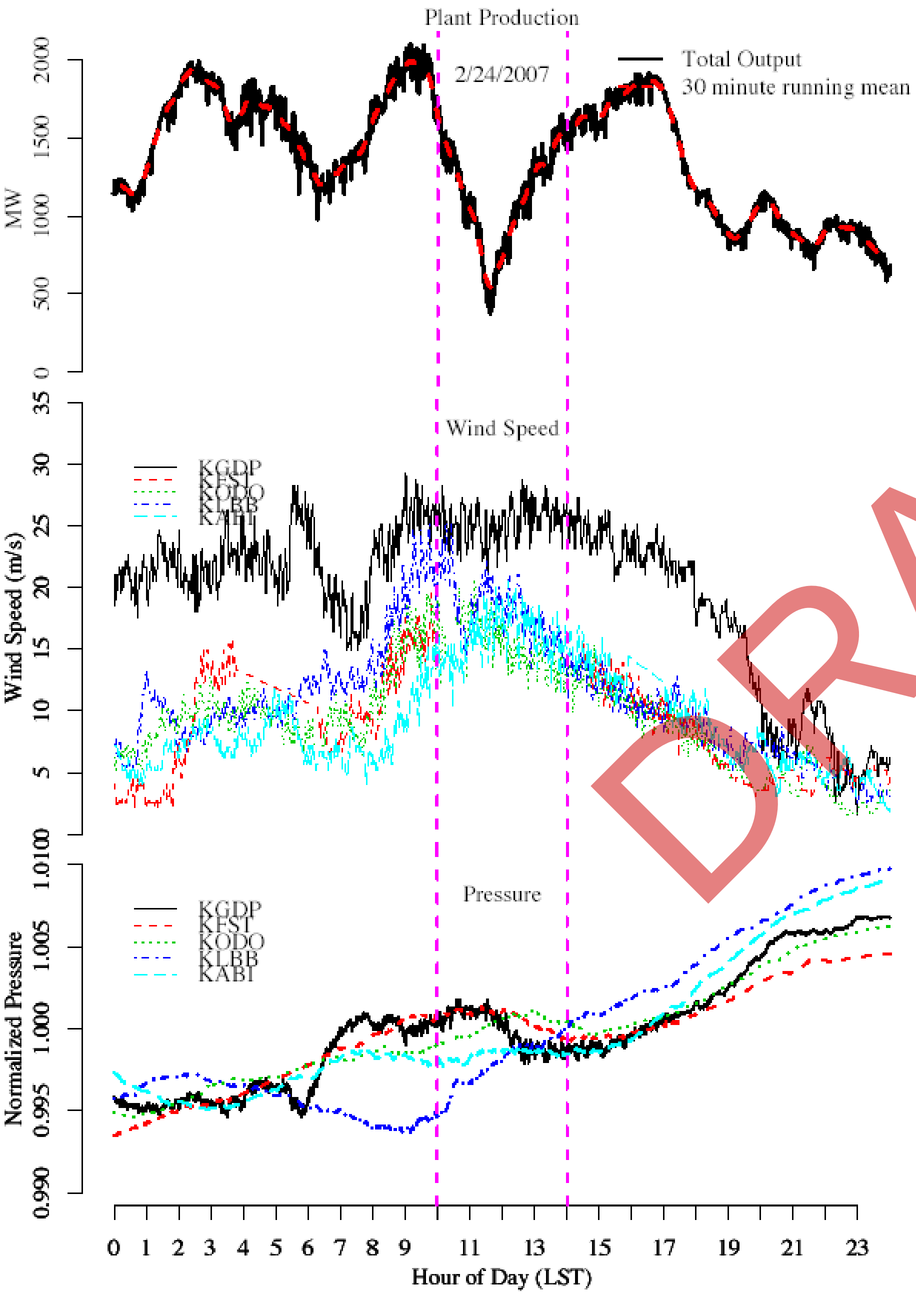
- Distinct diurnal increase in the frequency of ramp-up events during the evening hours, particularly around 5 PM local time, due to convection, especially strong to severe thunderstorms
- Seasonal increase in frequency of ramp-up events from late winter through summer, while ramp-down events show no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

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
High Wind	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

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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

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

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

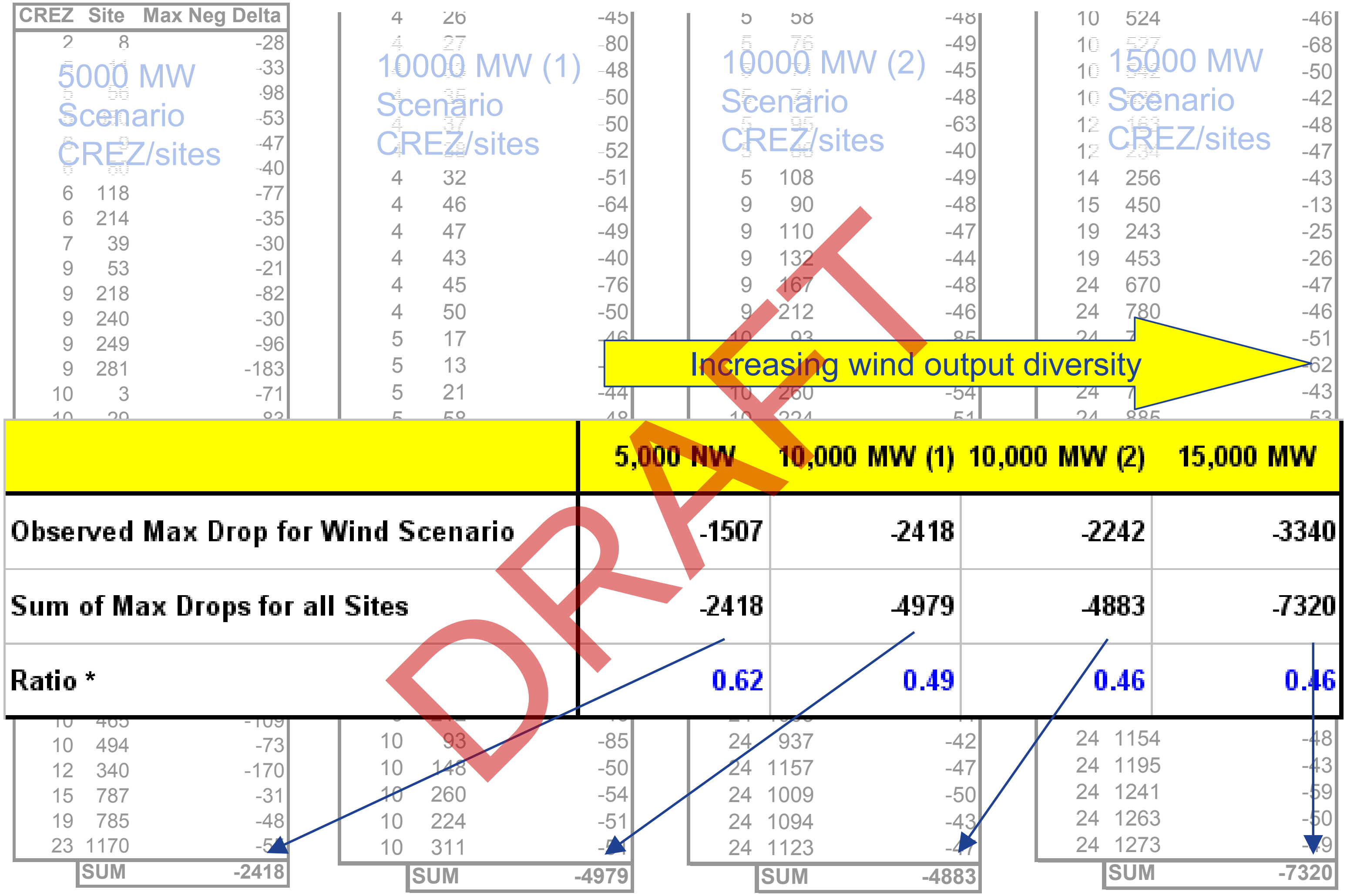
Next State (Output, % rated capacity)

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

One-Hour Wind Diversity Analysis

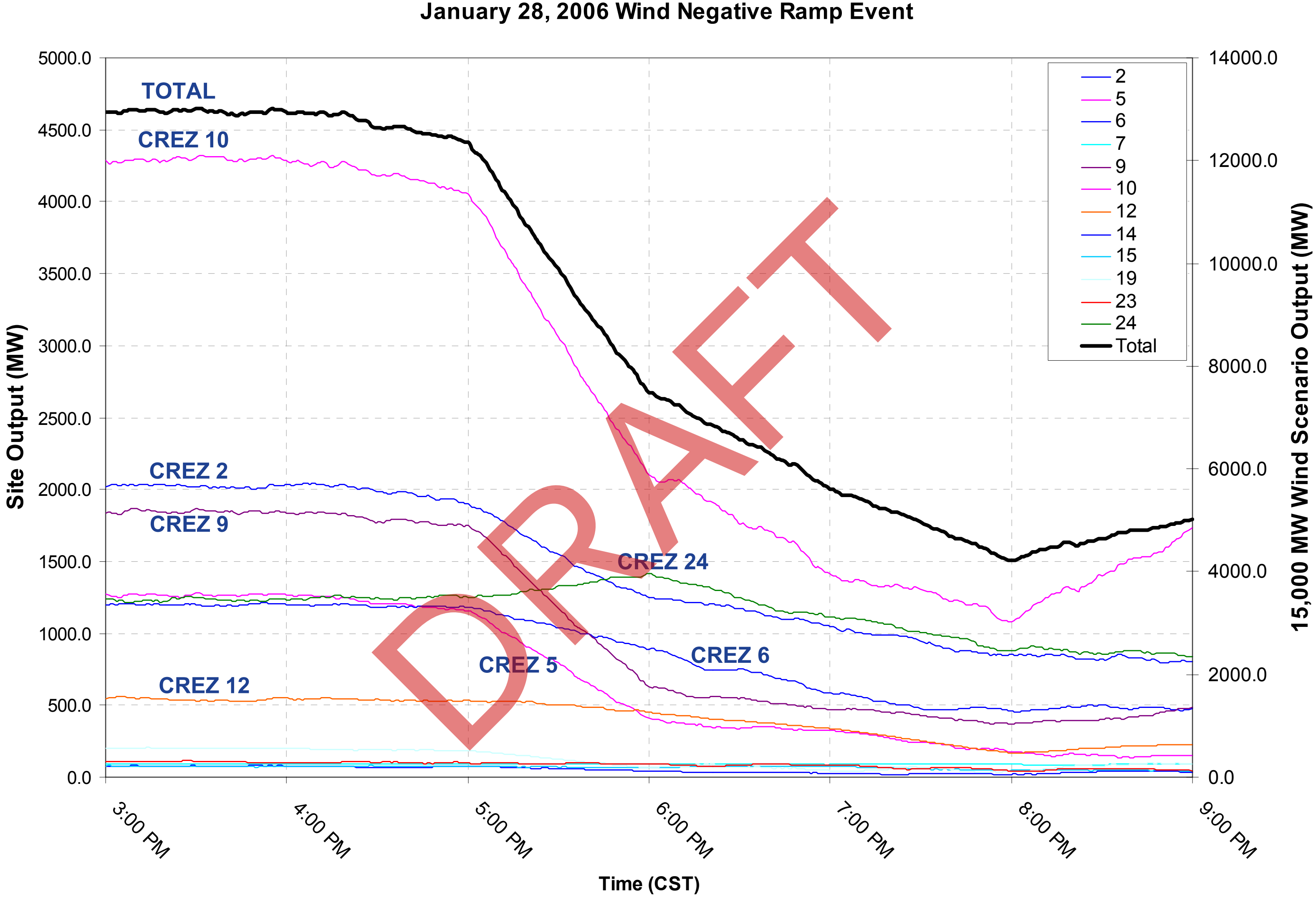


	5,000 MW	10,000 MW (1)	10,000 MW (2)	15,000 MW
Observed Max Drop for Wind Scenario	-1507	-2418	-2242	-3340
Sum of Max Drops for all Sites	-2418	-4979	-4883	-7320
Ratio *	0.62	0.49	0.46	0.46

As penetration increases, diversity in wind output reduces the impact of any single extreme change on the aggregate wind scenario

* Ratio of observed maximum coincident 1-hour wind drop divided by the sum of the non-coincident maximum drops

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

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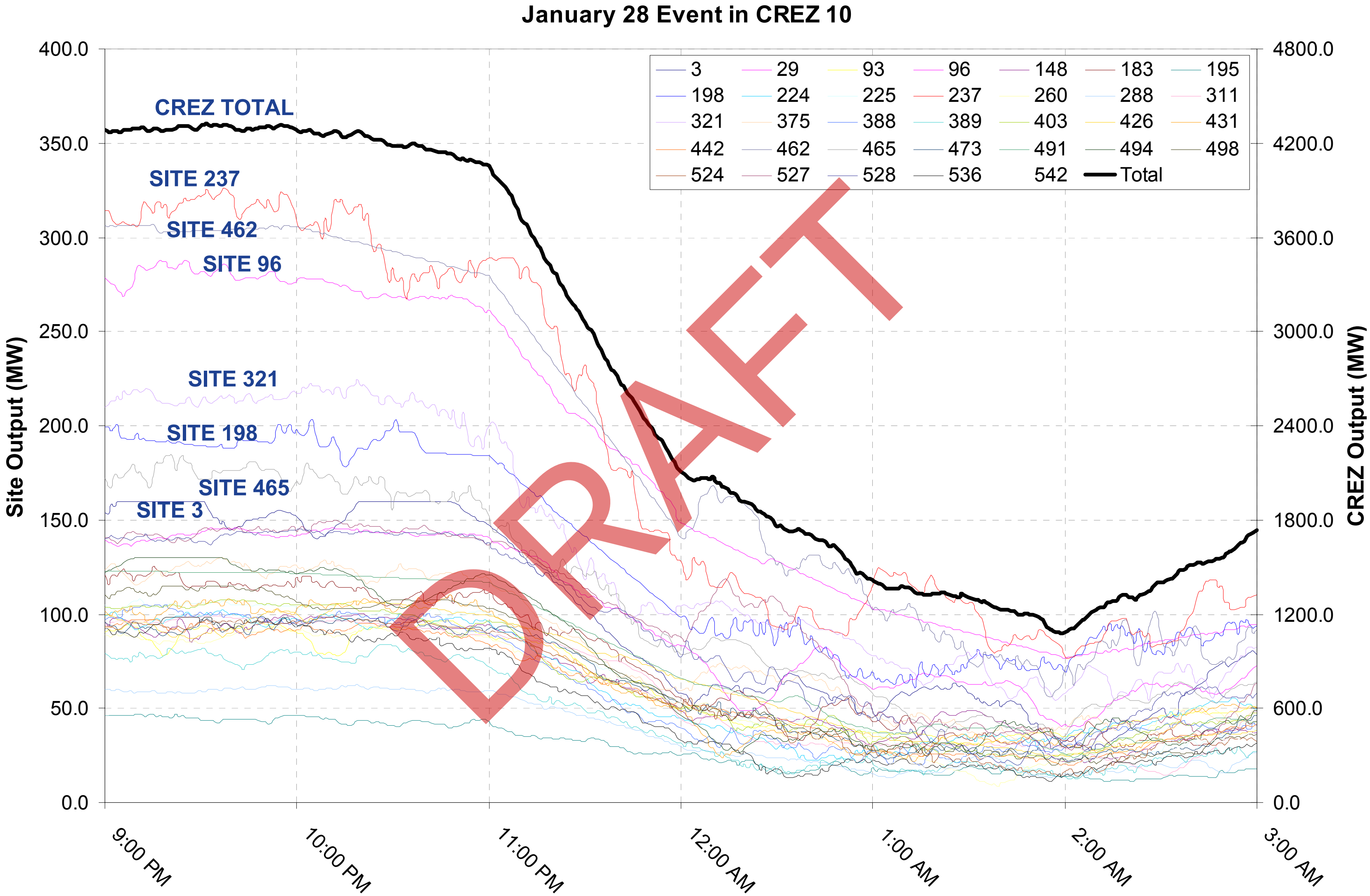
Largest One-Hour Wind Drop in CREZ 10 Wind (Jan 28 '06)



Most sites in CREZ 10 are similarly impacted by the event

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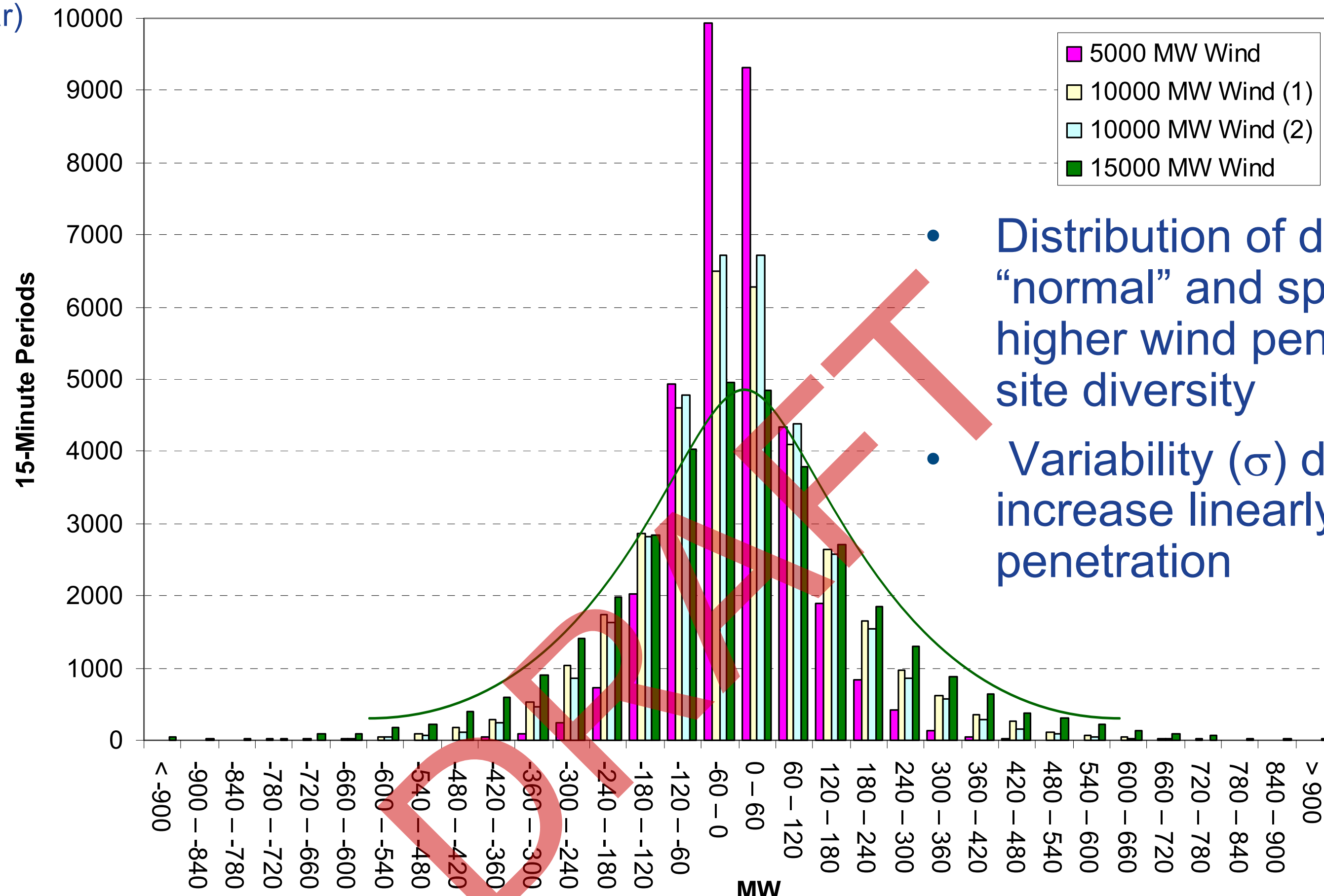
Distribution of Fifteen-Minute Wind Changes (Deltas)

(Study Year)



- Distribution of deltas is more "normal" and spread with higher wind penetration and site diversity
- Variability (σ) does not increase linearly with wind penetration

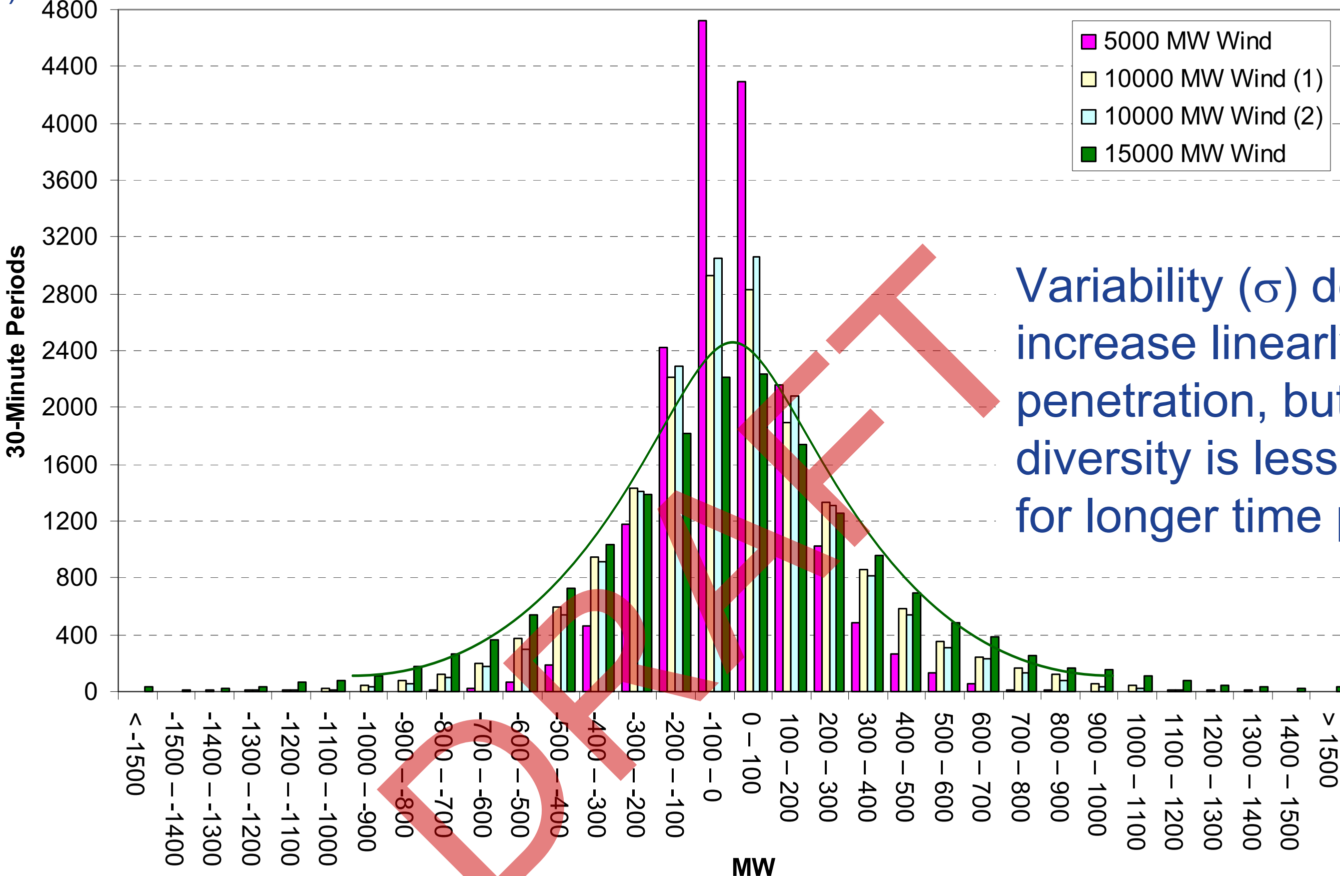
	5000 MW	10000 MW (1)	10000 MW (2)	15000 MW
Mean (-/+)	-70 / 74	-119 / 125	-111 / 114	-160 / 165
Sigma (σ)	**98**	**166**	**153**	**220**
> $\mu \pm 2.5\sigma$ (–/+)	344 / 564	400 / 551	400 / 497	422 / 521
> $\mu \pm 3.0\sigma$ (–/+)	160 / 237	174 / 215	178 / 206	193 / 216

125% increase in σ for 200% increase in wind

imagination

Distribution of Thirty-Minute Wind 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

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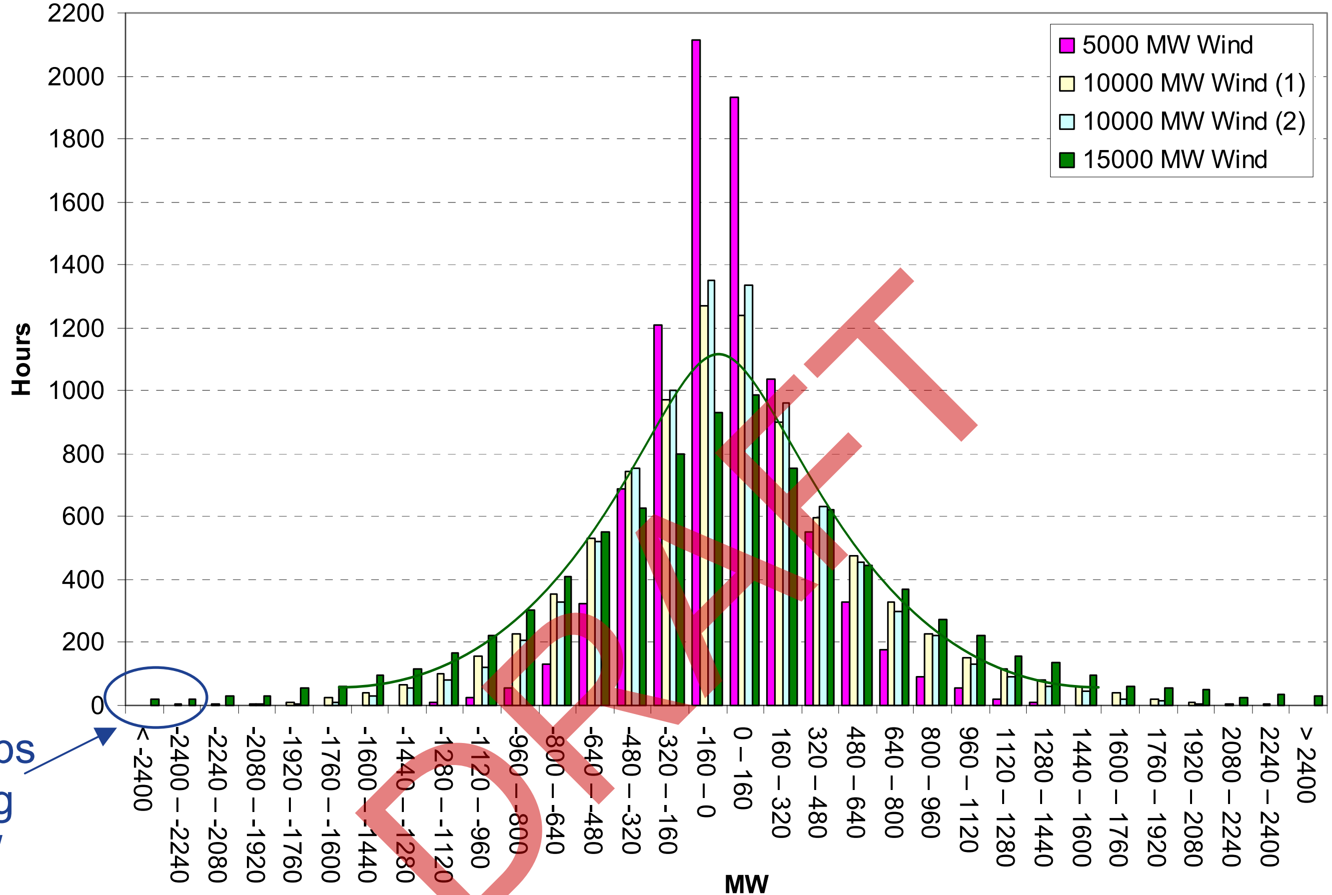
Distribution of One-Hour Wind Changes (Deltas)

(Study Year)

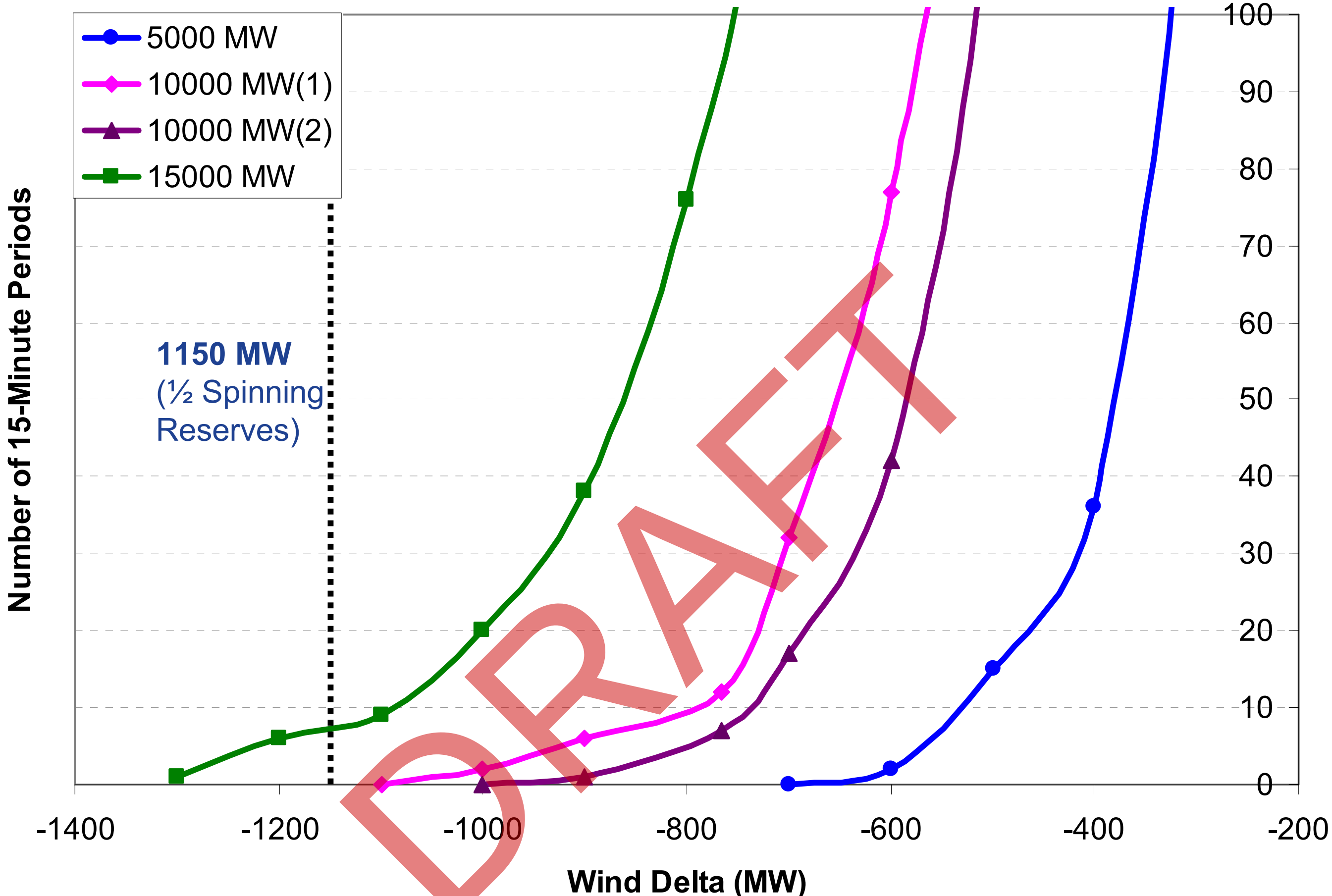


Wind drops exceeding 2300 MW

	5000 MW	10000 MW (1)	10000 MW (2)	15000 MW
Mean (-/+)	-234 / 254	-419 / 444	-385 / 403	-570 / 585
Sigma	**332**	**580**	**529**	**776**
> $\mu \pm$ **2.5**σ (–/+)	75 / 155	87 / 138	96 / 139	95 / 141
> $\mu \pm$ **3.0**σ (–/+)	33 / 64	29 / 50	27 / 46	29 / 43

134% increase in σ for 200% increase in wind

Extreme Fifteen-Minute Wind Drops (Down-Ramps)
(Study Year)



	5000 MW Wind	10,000 MW Wind (1)	10,000 MW Wind (2)	15,000 MW Wind
Max Pos Delta	603	895	833	1193
Max Neg Delta	**-625**	**-1062**	**-923**	**-1337**
No. Drops > 1000 MW	**0**	**2**	**0**	**20**
No. Drops > 1150 MW	**0**	**0**	**0**	**7**

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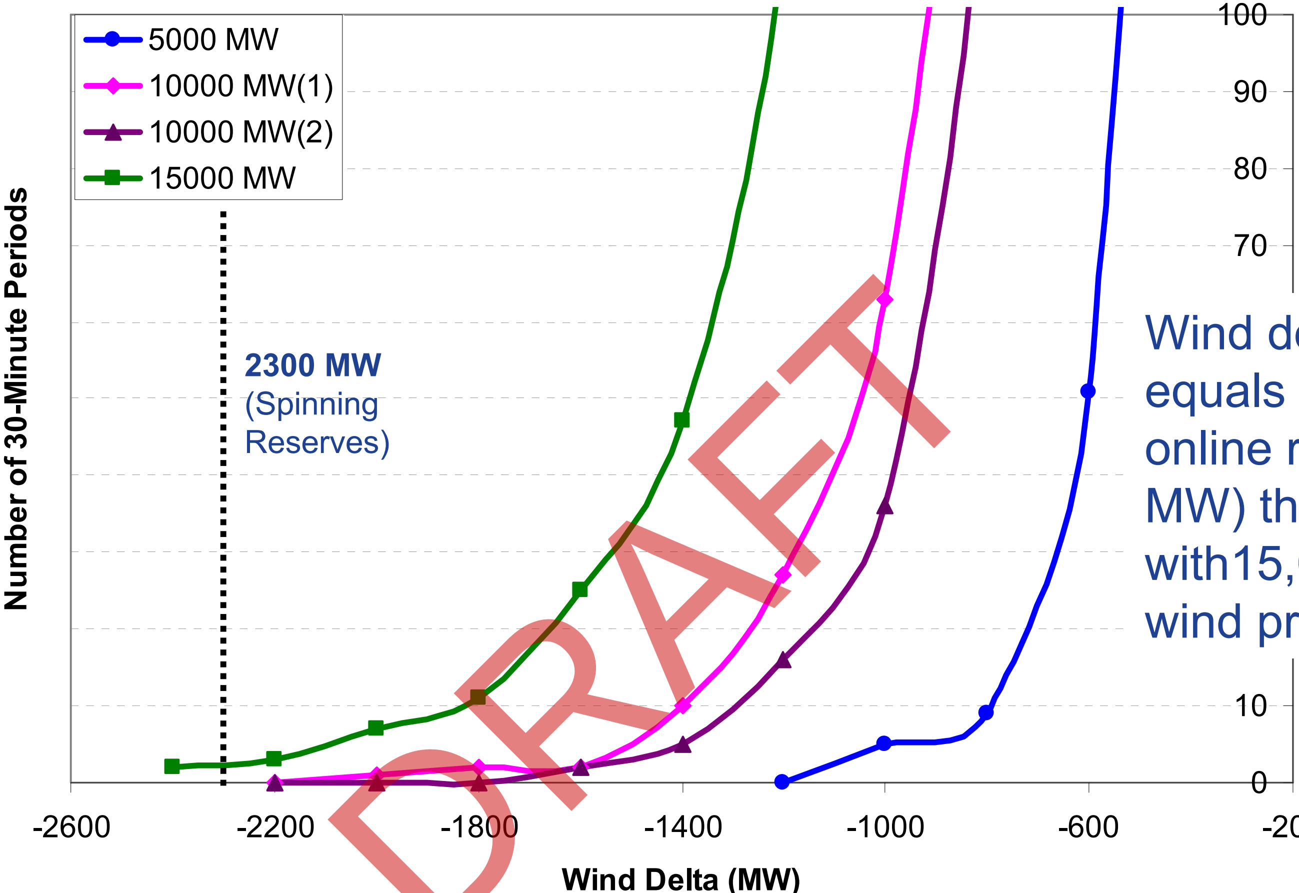
Extreme Thirty-Minute Wind Drops (Down-Ramps)

(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**

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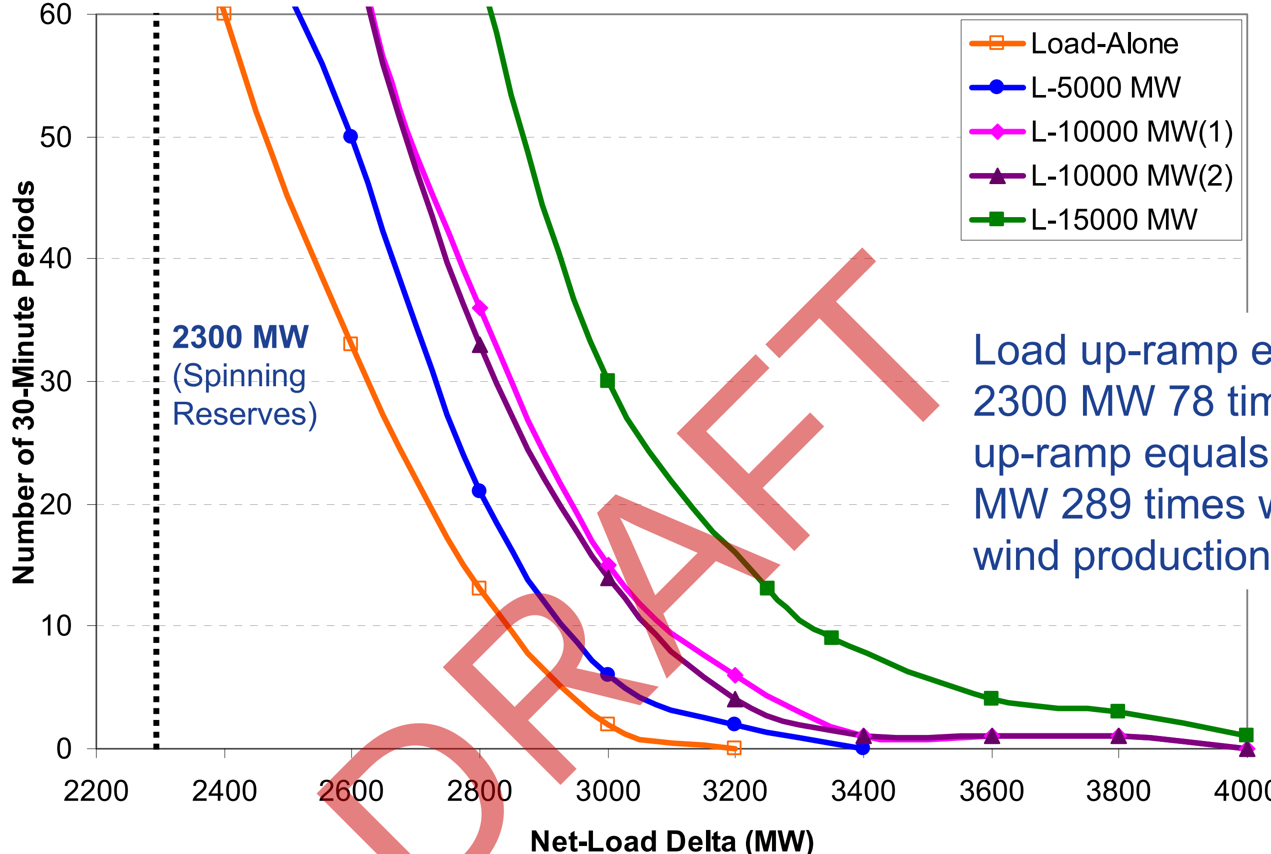
Extreme Thirty-Minute Net-Load Rises (Up-Ramps)

(Study Year)

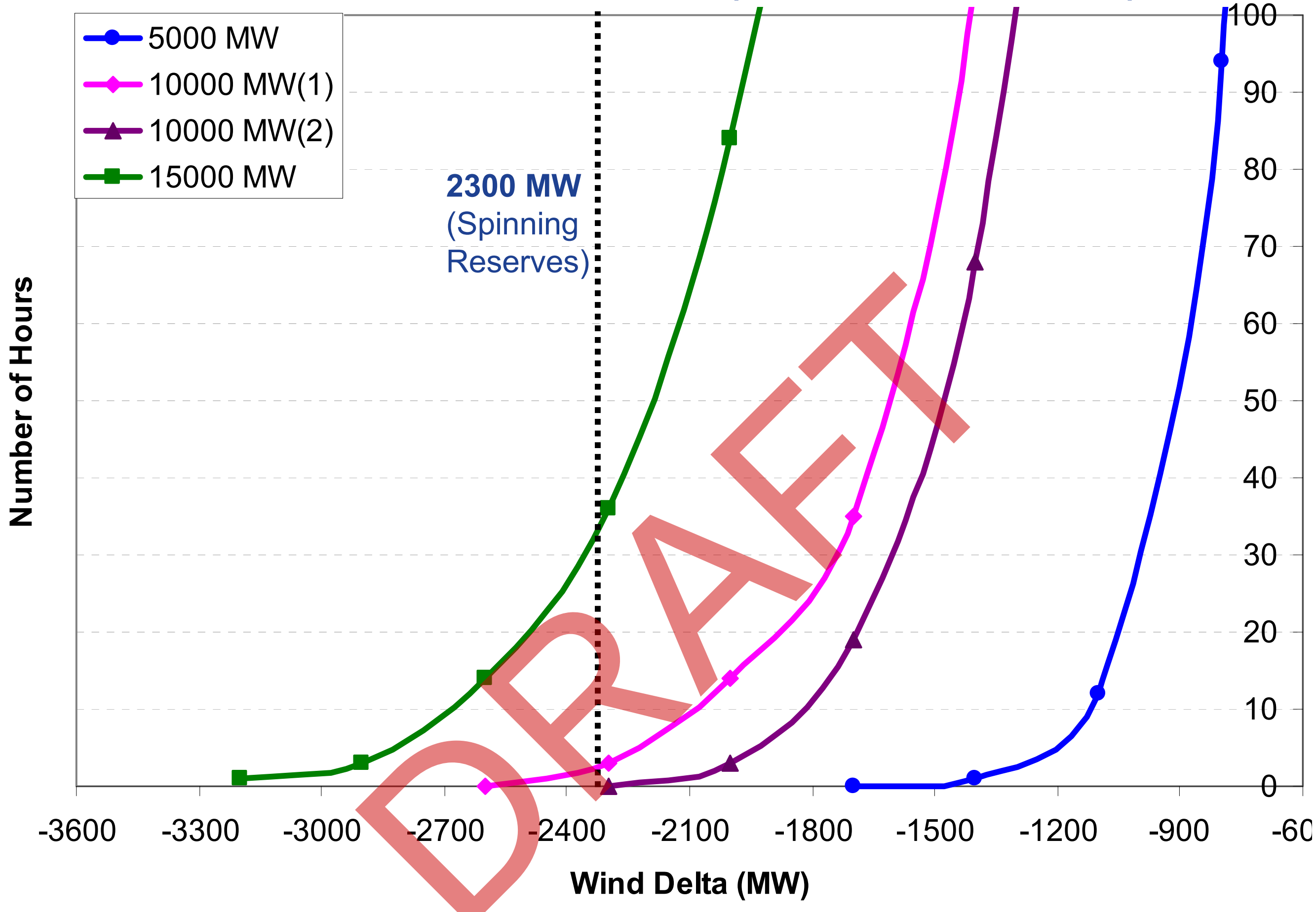


Load up-ramp equals or exceeds 2300 MW 78 times, and net-load up-ramp equals or exceeds 2300 MW 289 times with15,000 MW of wind production

	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**

Extreme One-Hour Wind Drops (Down-Ramps)

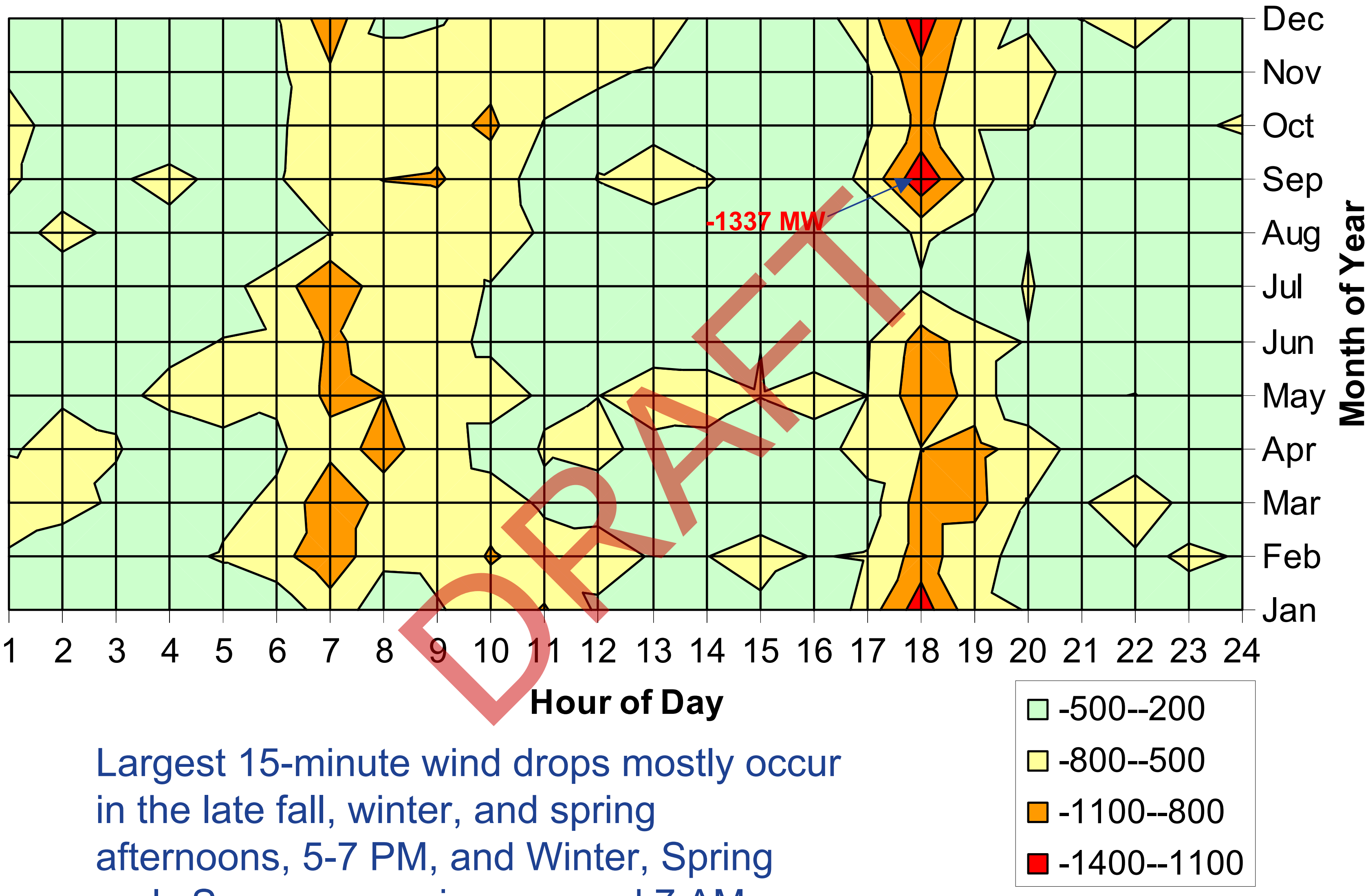
(Study Year)



	5000 MW Wind	10,000 MW Wind (1)	10,000 MW Wind (2)	15,000 MW Wind
Max Pos Delta	1459	2477	2322	3338
Max Neg Delta	**-1507**	**-2418**	**-2242**	**-3340**
No. Drops > 1000 MW	33	373	270	757
No. Drops > 2300 MW	**0**	**3**	**0**	**36**

Timing of Extreme Fifteen-Minute Wind Drops

(Study Year)



Largest 15-minute wind drops mostly occur in the late fall, winter, and spring afternoons, 5-7 PM, and Winter, Spring early Summer mornings around 7 AM

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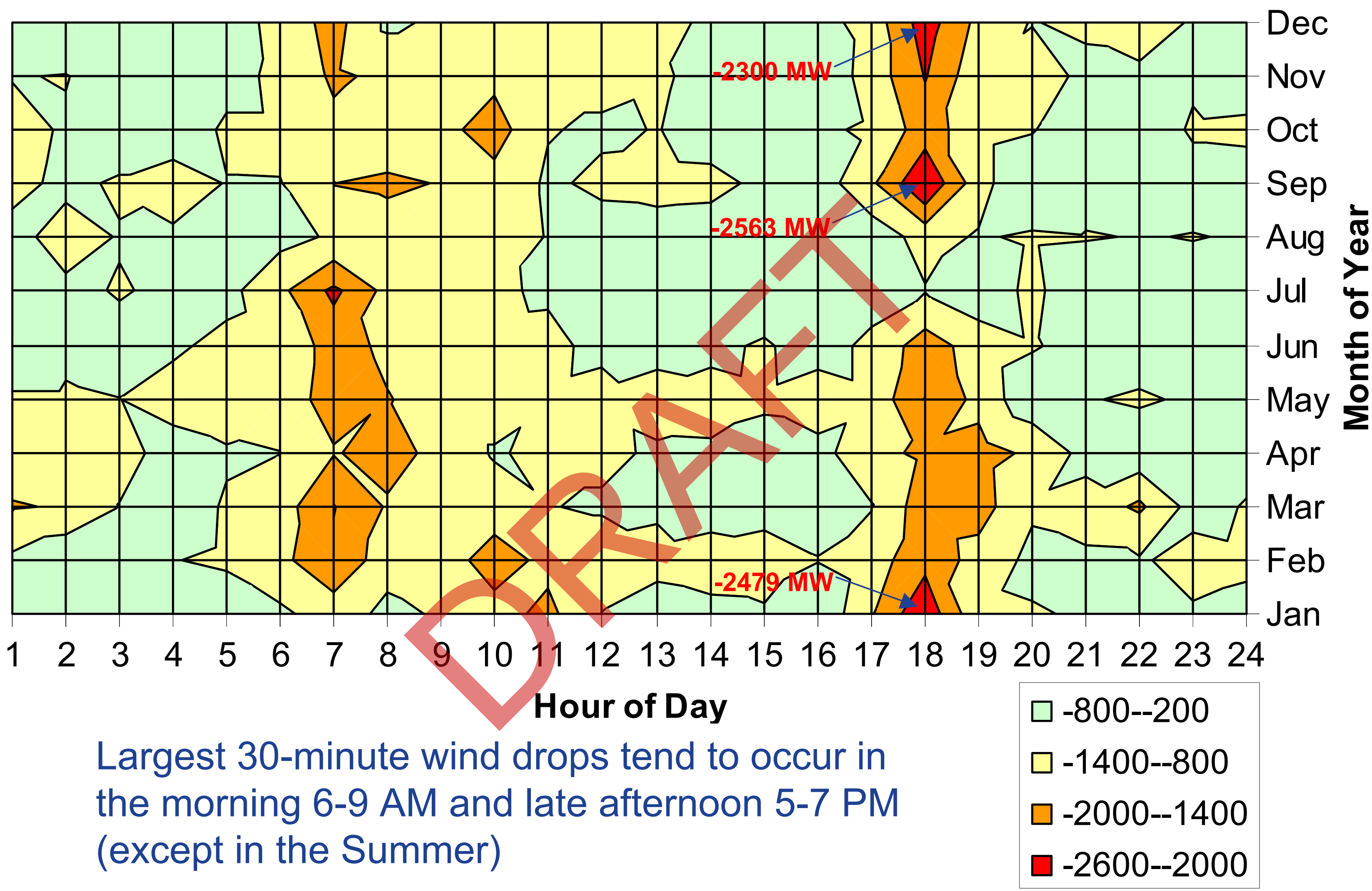
Timing of Extreme Thirty-Minute Wind Drops

(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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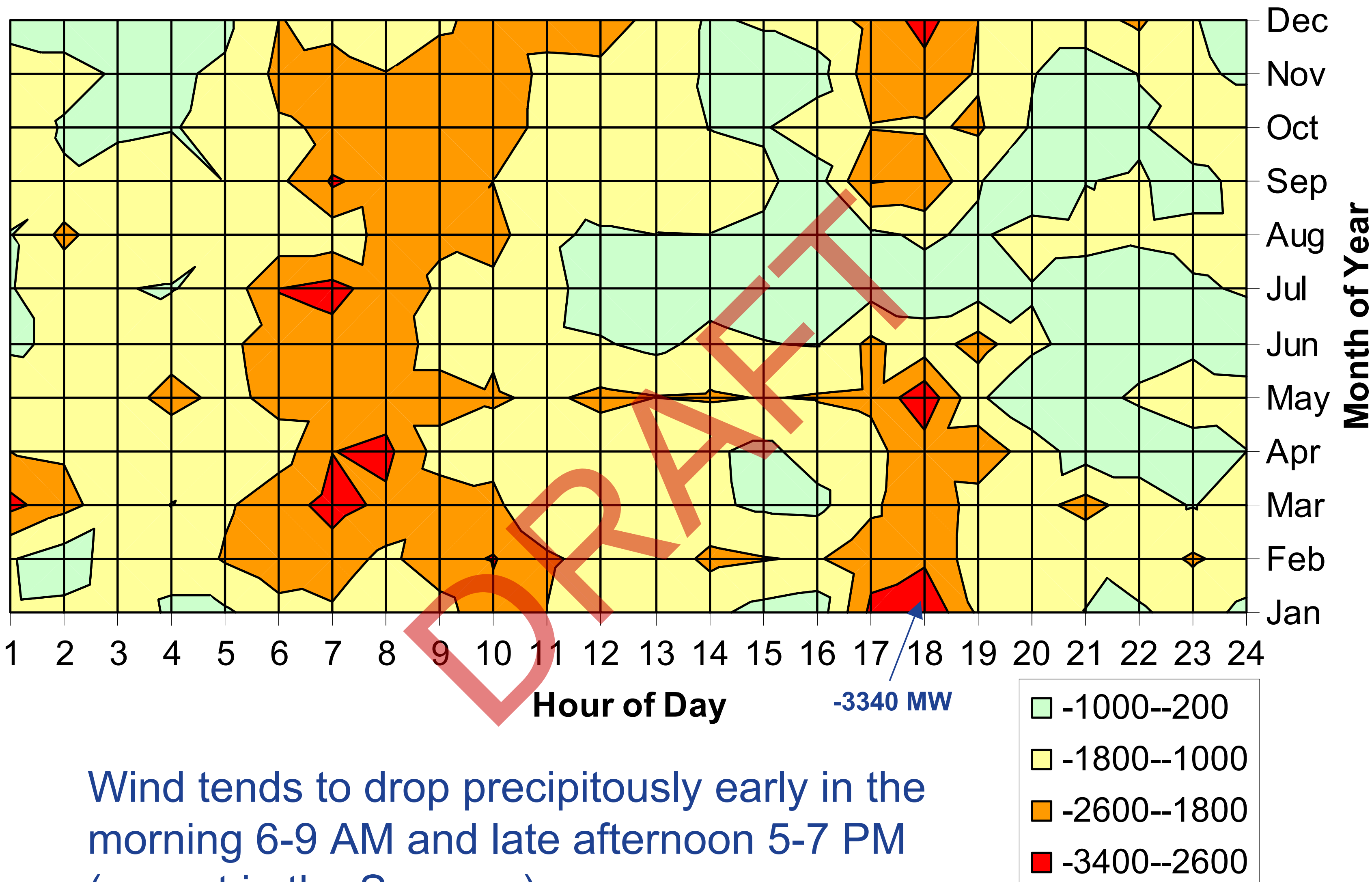
Timing of Extreme One-Hour Wind Drops

(Study Year)



Wind tends to drop precipitously early in the morning 6-9 AM and late afternoon 5-7 PM (except in the Summer)

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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

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
- 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

Forecast Error Analysis

Impact on Non-Spinning Reserves

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

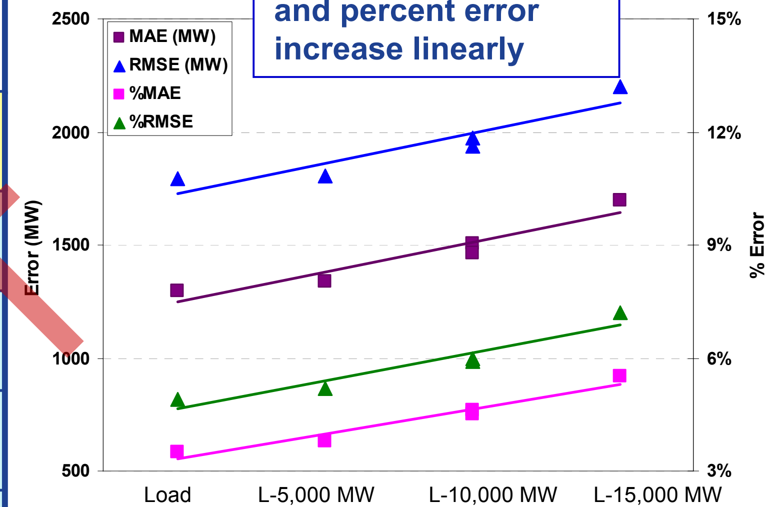
** Root mean square error – more affected by large deviations

Wind

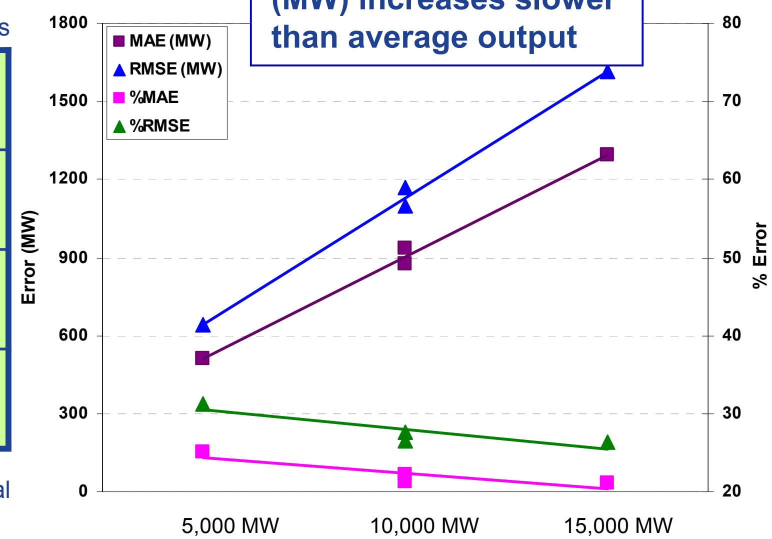
5000 MW Wind	638 (31.2)	511 (25.0)	639 (31.3)	-2529
10,000 MW Wind (1)	1167 (27.7)	935 (22.2)	1169 (27.7)	-4264
10,000 MW Wind (2)	1093 (26.5)	876 (21.3)	1096 (26.6)	-4078
15,000 MW Wind	1611 (26.2)	1294 (21.1)	1614 (26.3)	-5921

Error = forecast – actual

Absolute error (MW) and percent error increase linearly



Wind absolute error (MW) increases slower than average output



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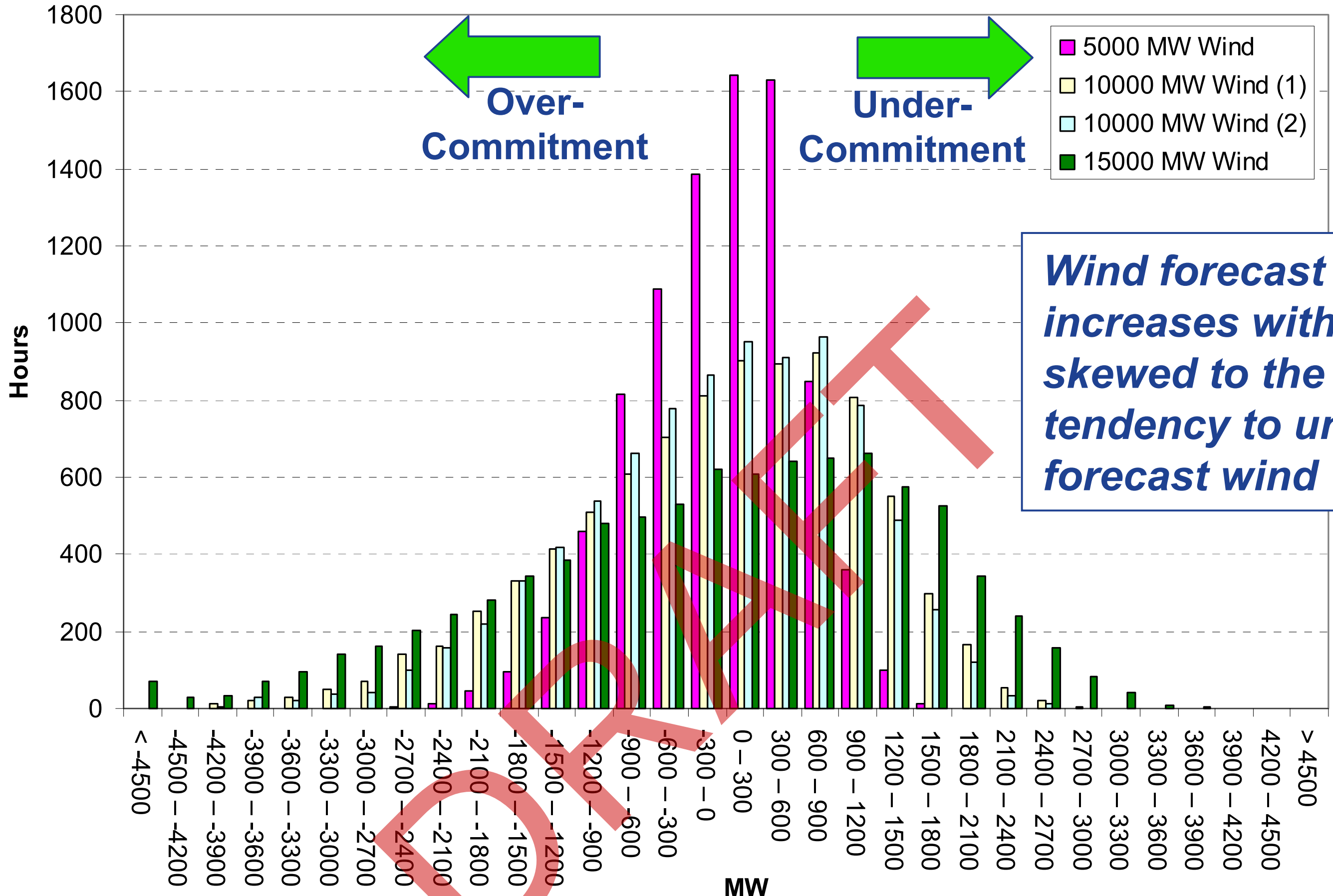
NB: Percent errors based on average output

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

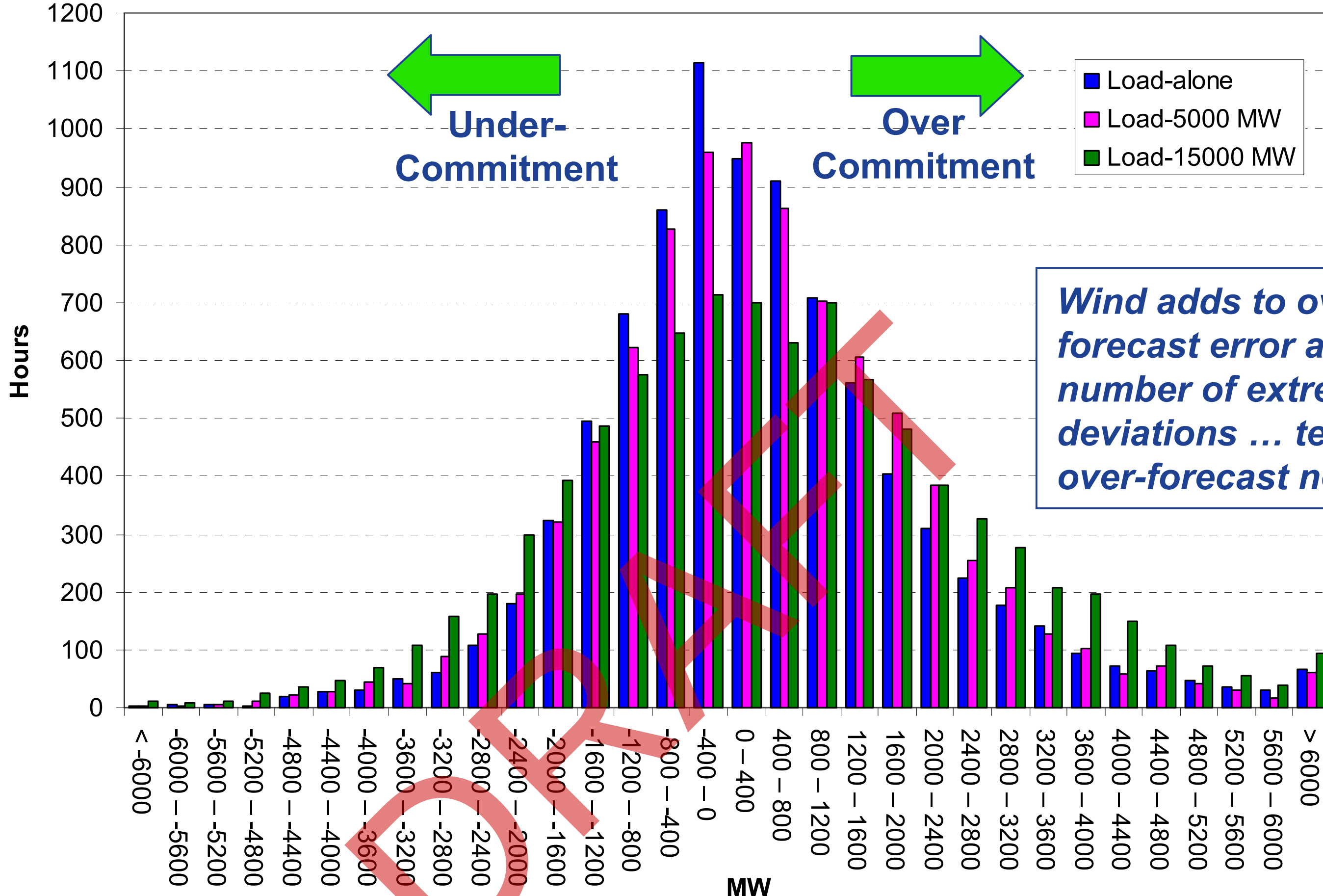
	5000 MW Wind	10,000 MW Wind (1)	10,000 MW Wind (2)	15,000 MW Wind
> $\mu \pm$ **2.5**σ (–/+)	107 / 9	125 / 2	121 / 1	114 / 1
> $\mu \pm$ **3**σ (–/+)	33 / 0	38 / 0	48 / 0	43 / 0
> ± 2300 MW (–/+)	8 / 0	384 / 41	296 / 19	910 / 364
> ± 4600 MW (–/+)	0 / 0	0 / 0	0 / 0	67 / 0

Wind Forecast Confidence Levels

- Present ERCOT practice is to use 80% confidence level wind forecast, but mean (50% confidence) load forecast
- Leads to unit overcommitment due to biased under-estimate of wind
  - Operating difficulties at low load
  - Depresses spot prices
- This analysis is based on mean wind forecast

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 $\sigma = 1755$	W/ 5000 MW Wind $\sigma = 1762$	Using load σ	W/ 15000 MW Wind $\sigma = 2149$	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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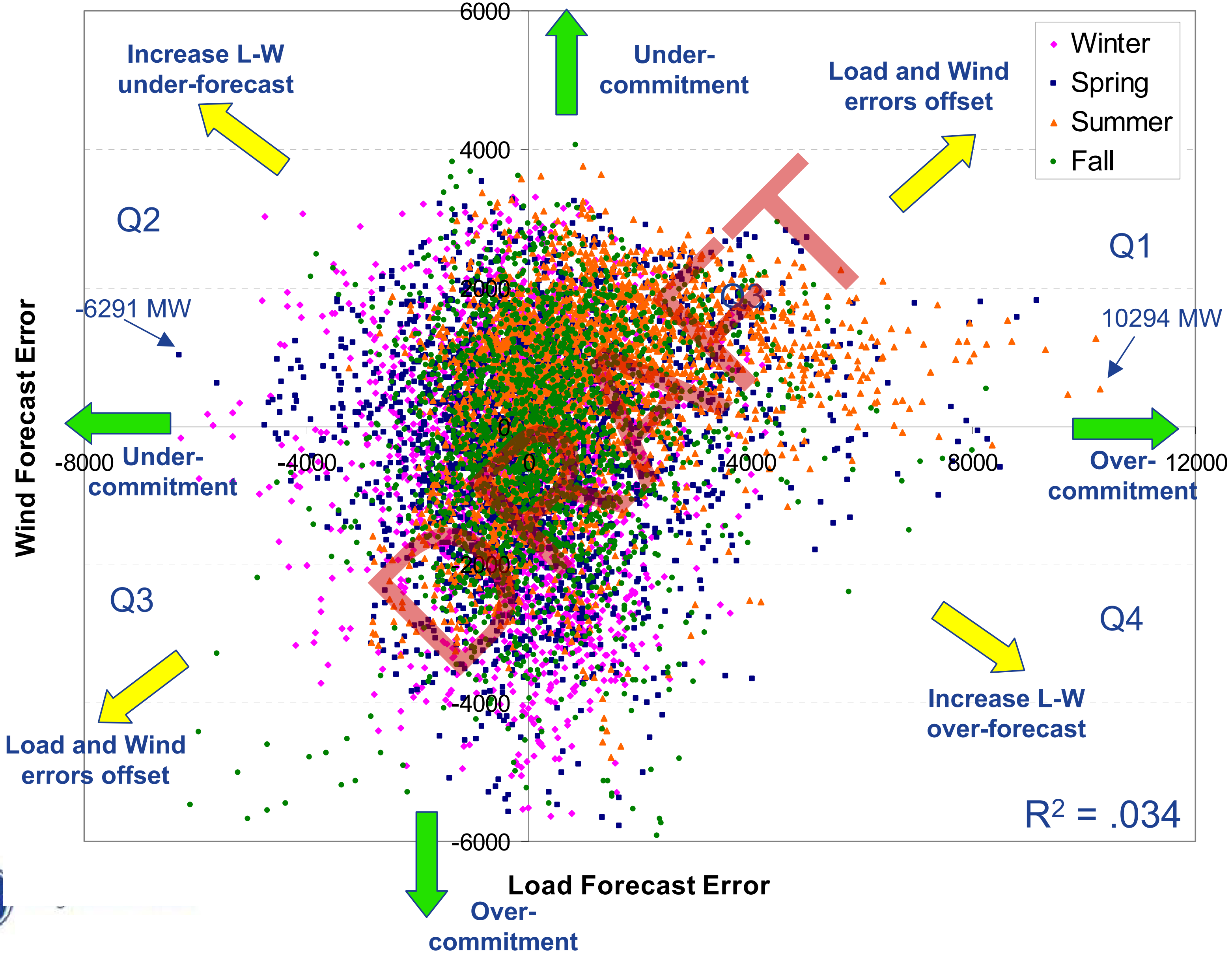
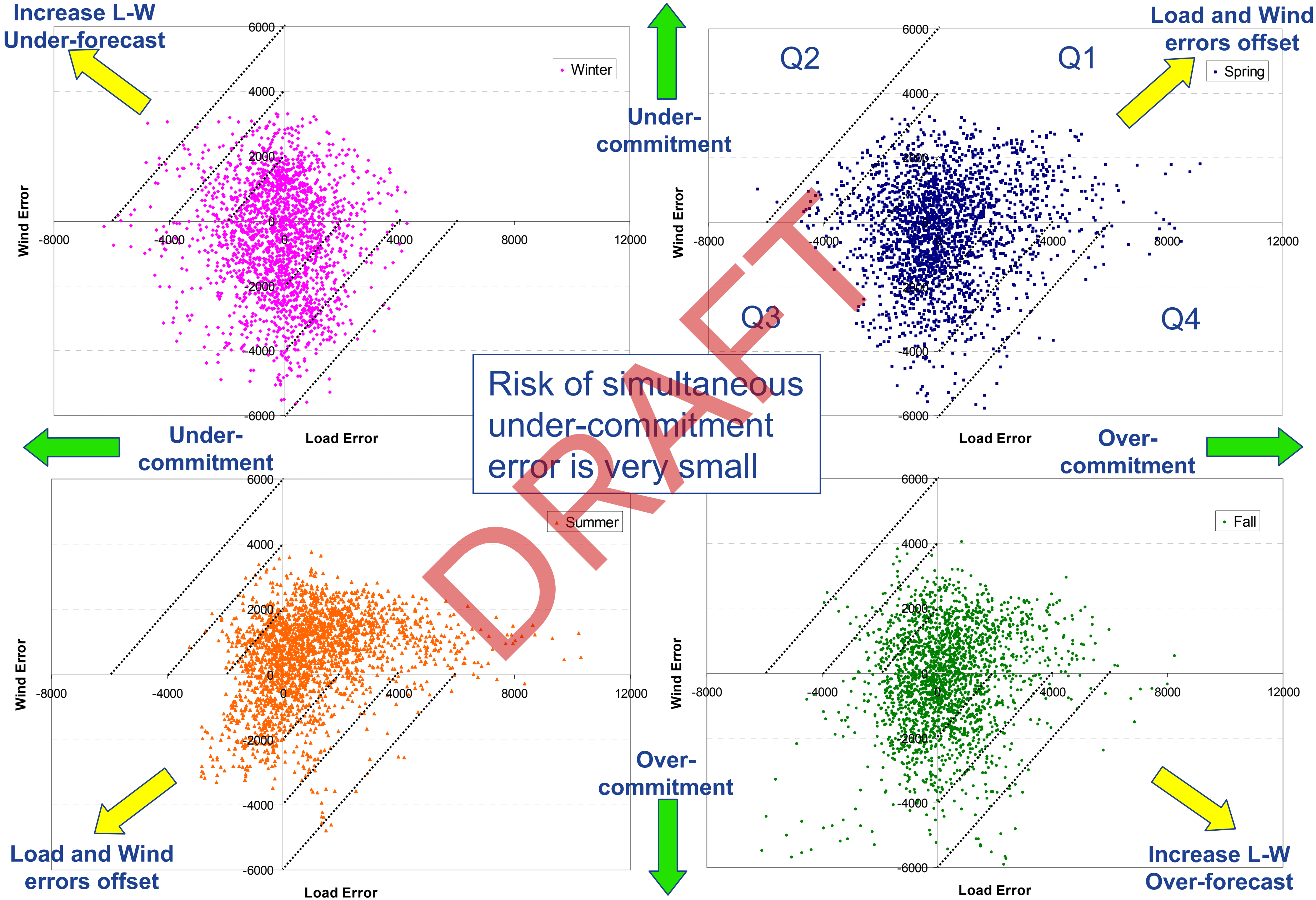
Correlation of Load and Wind Forecast Errors By Season

(Study Year Load and 15000 MW of Wind)

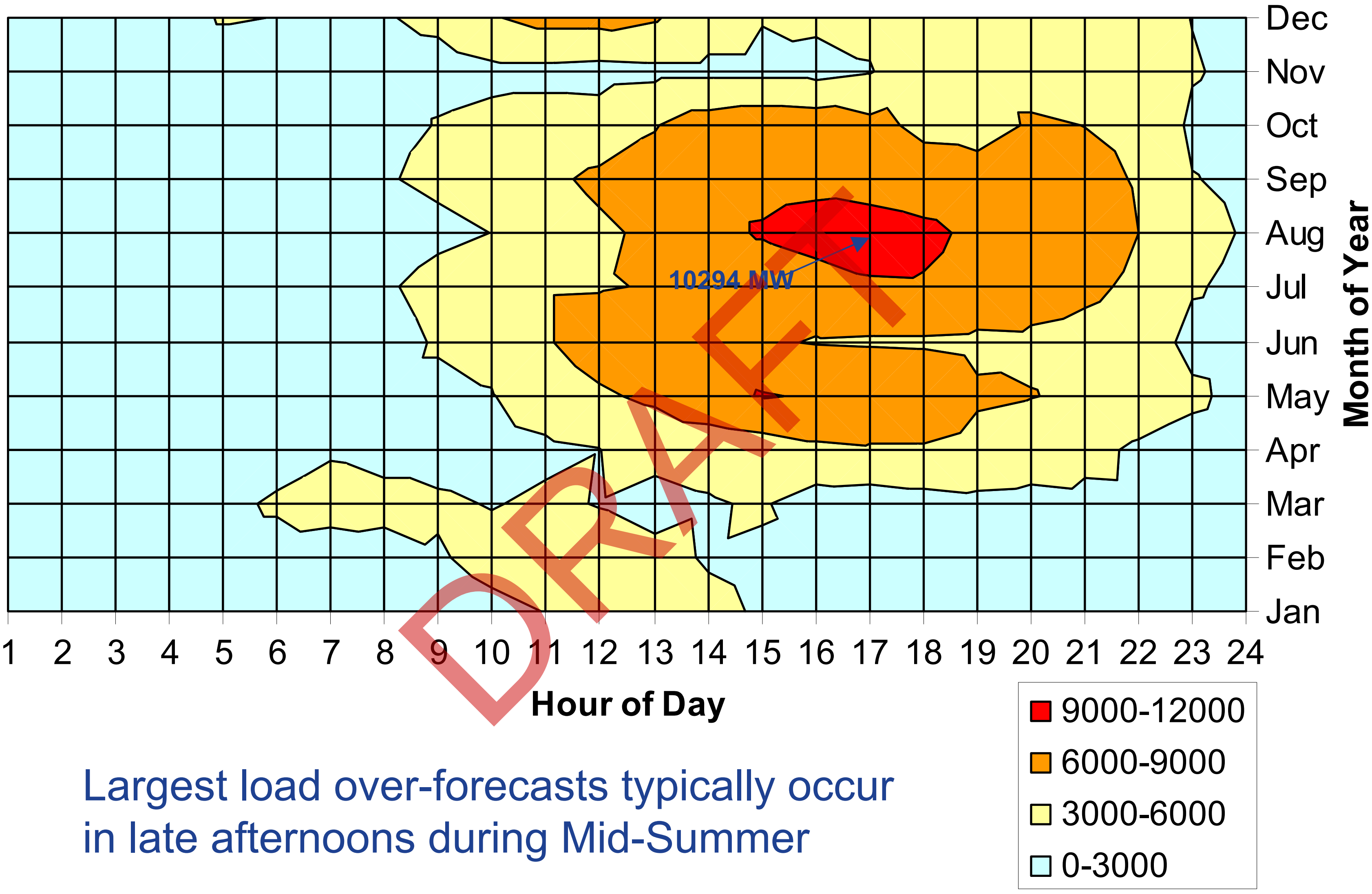


Correlation of Load and Wind Forecast Errors By Season (Study Year Load W/ 15000 MW)



Timing of Positive Load Forecast Errors (Over-Commitment)

(Study Year)



Largest load over-forecasts typically occur in late afternoons during Mid-Summer

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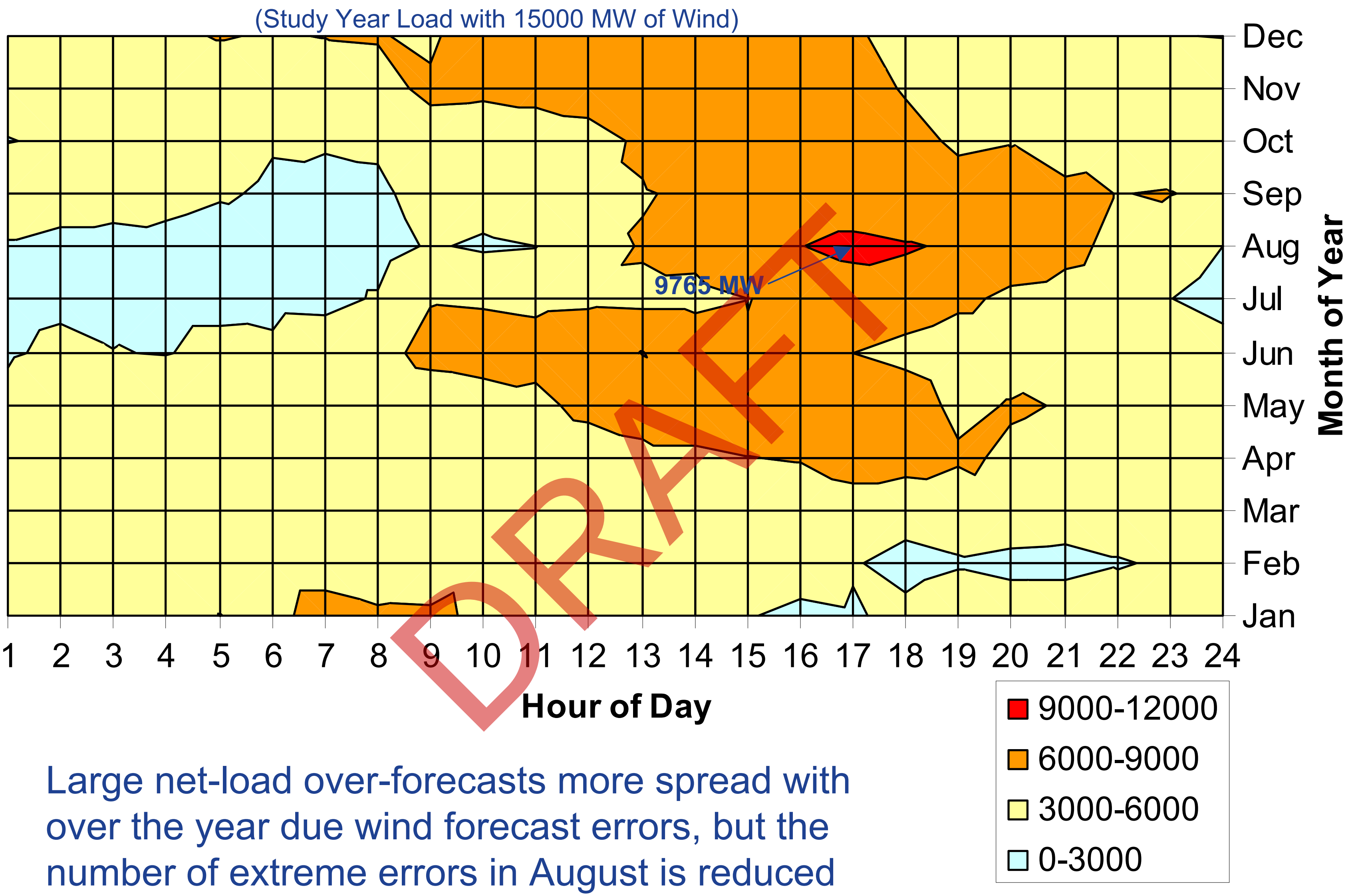
Timing of Positive Net-Load (Over-Commitment) Forecast Errors



Large net-load over-forecasts more spread with over the year due wind forecast errors, but the number of extreme errors in August is reduced

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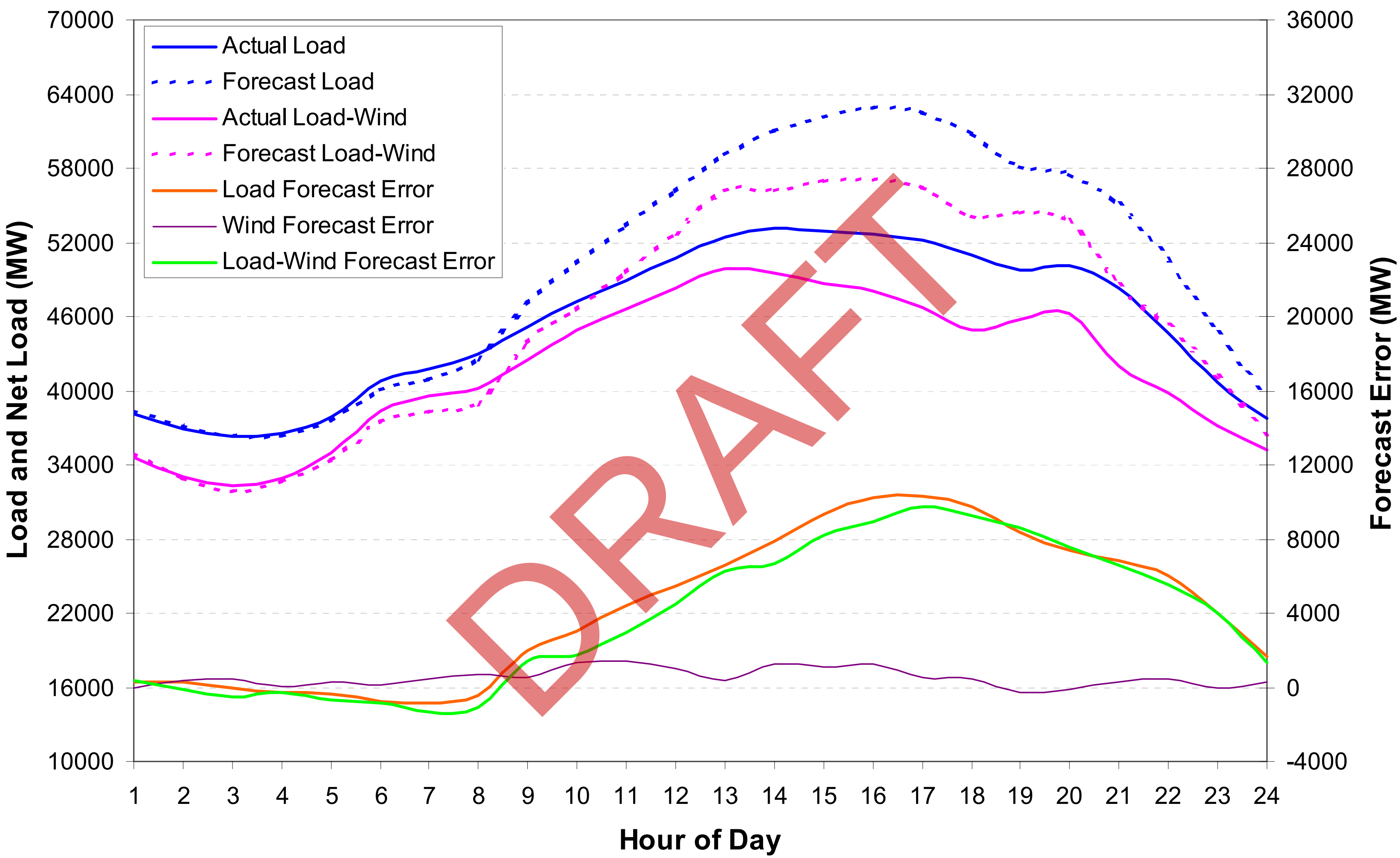
Large Positive Net Load Forecast Error Day (Aug 28th Peak Load Day)

Study Year Load with 15000 MW of Wind



Max L-W Error = 9675 MW (4-5 PM)
Sigma = 3866 (9.3% of Average)
MAE = **4103** MW (9.8% of Average)
RMSE = 5293 MW (12.7% of Average)

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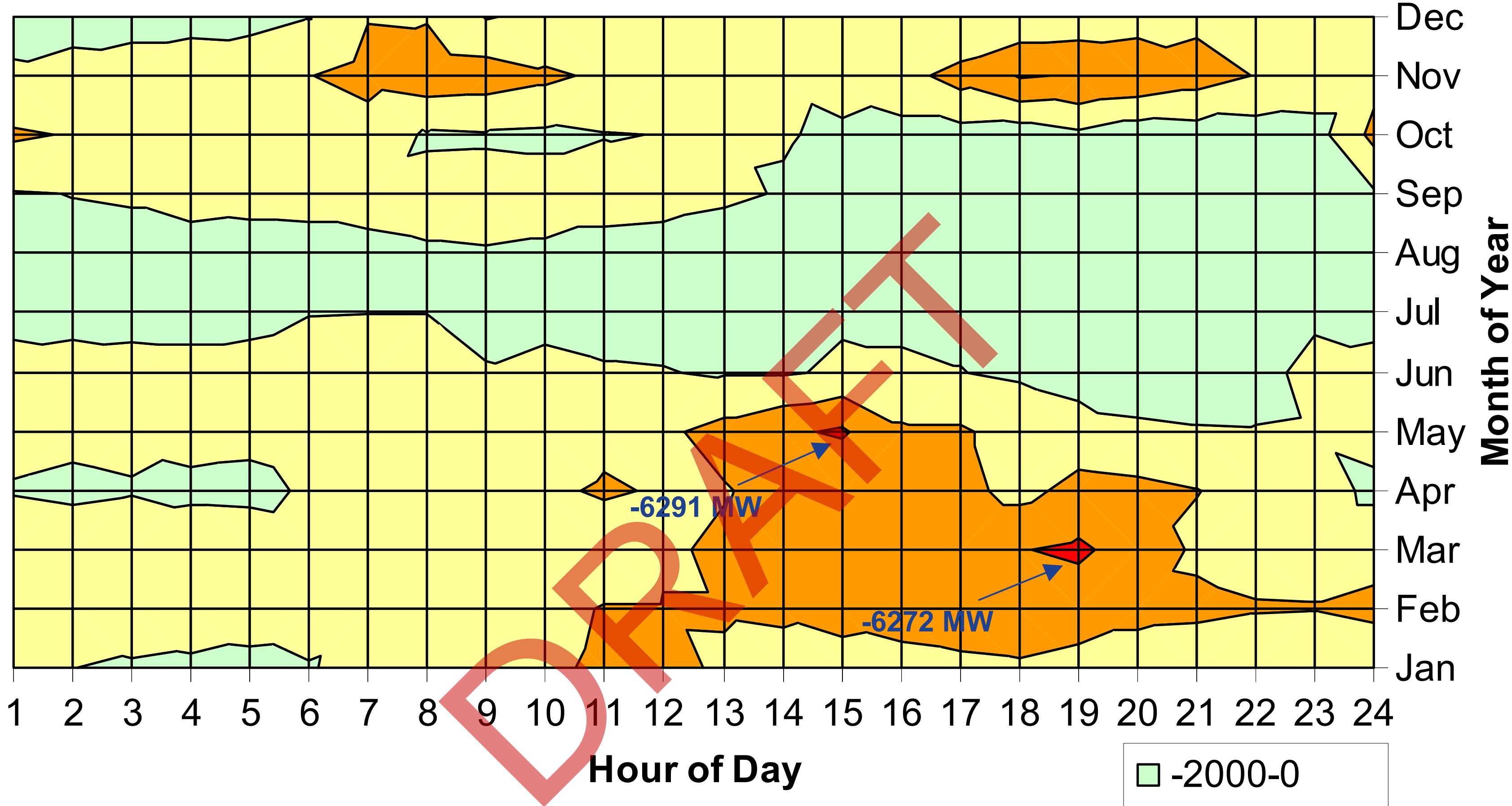
Timing of Negative Load Forecast Errors (Under-Commitment)

(Study Year)



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

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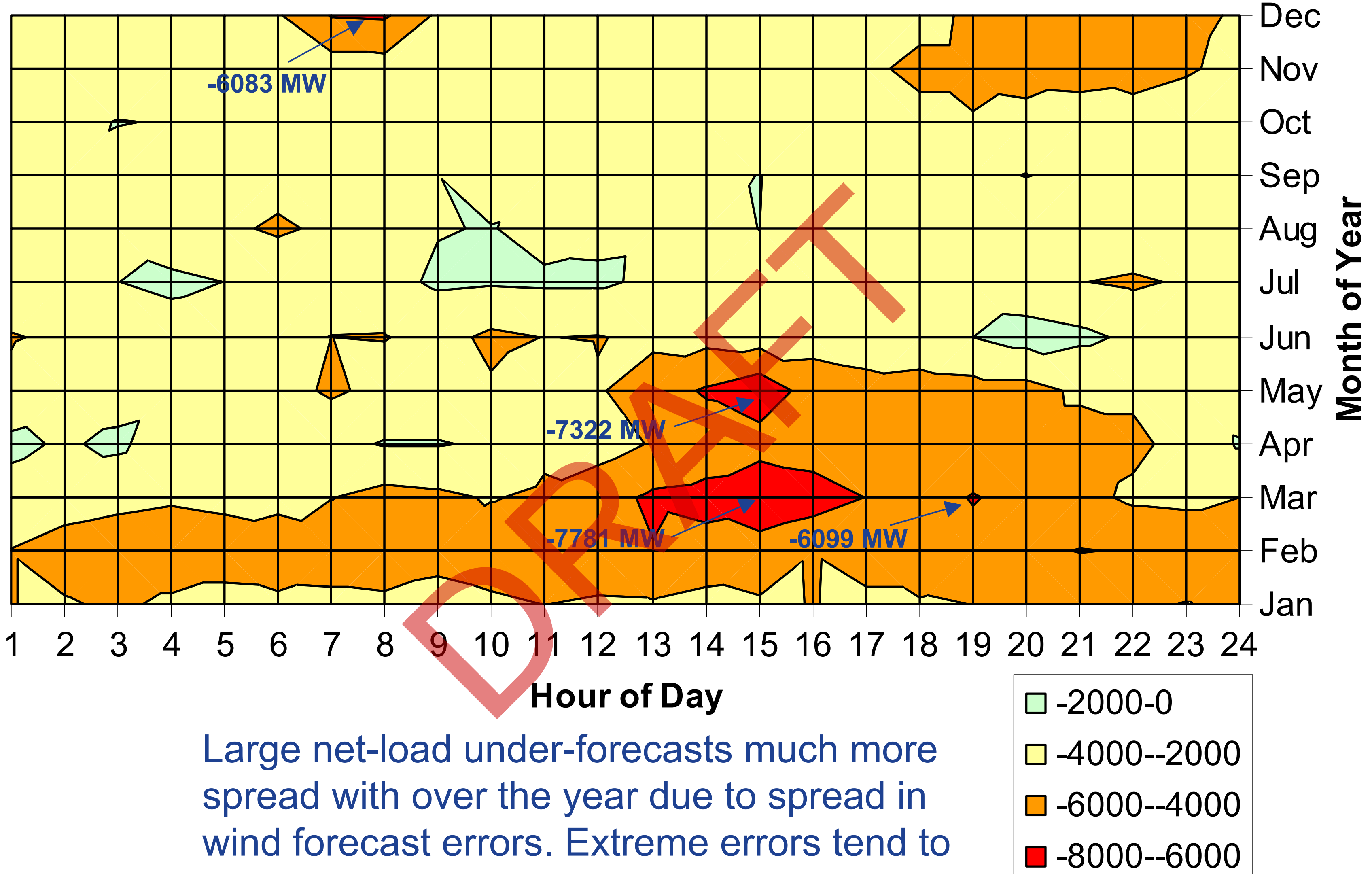
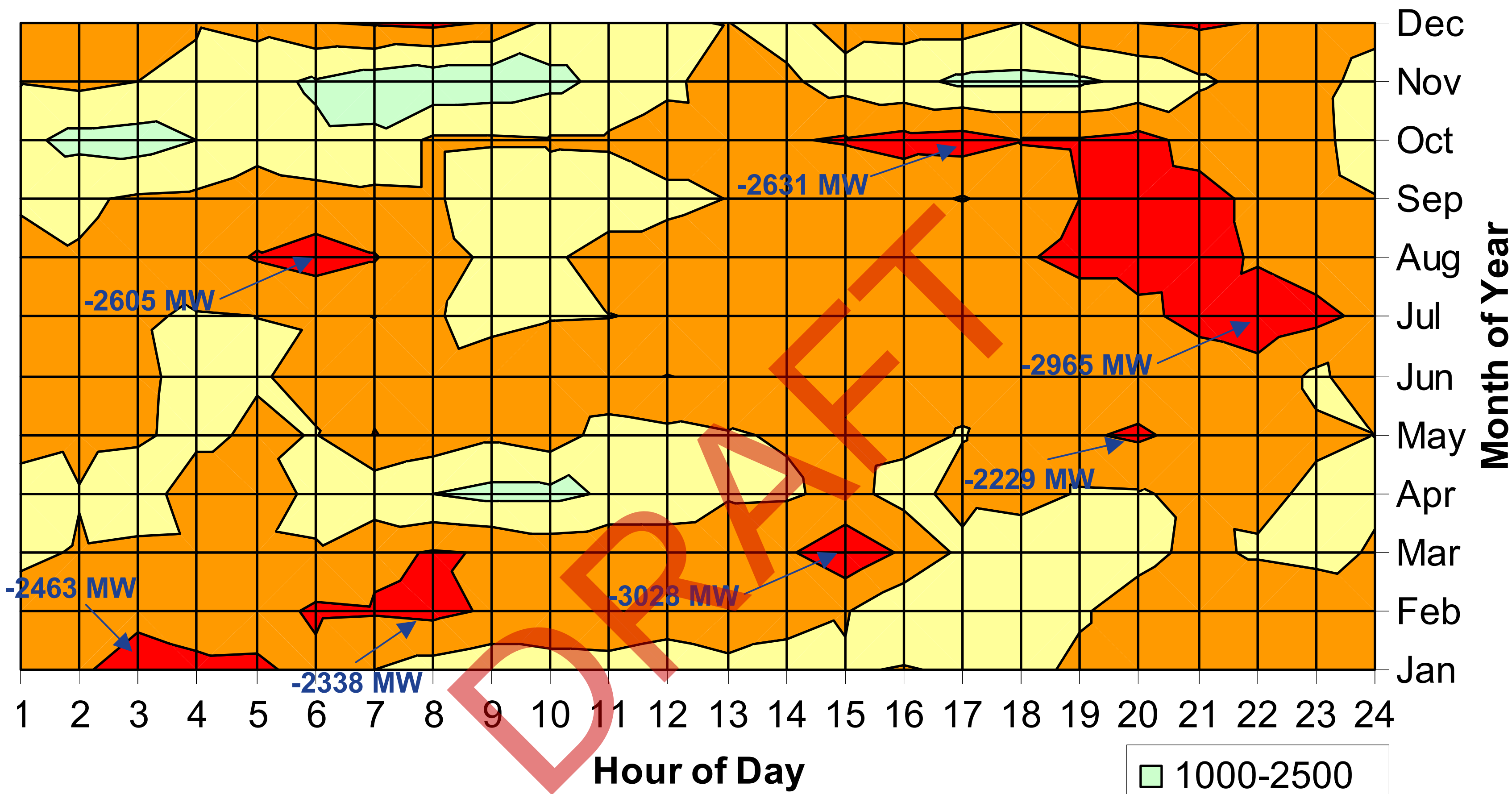
Timing of Negative Net-Load (Under-Commitment) Forecast Errors

(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.

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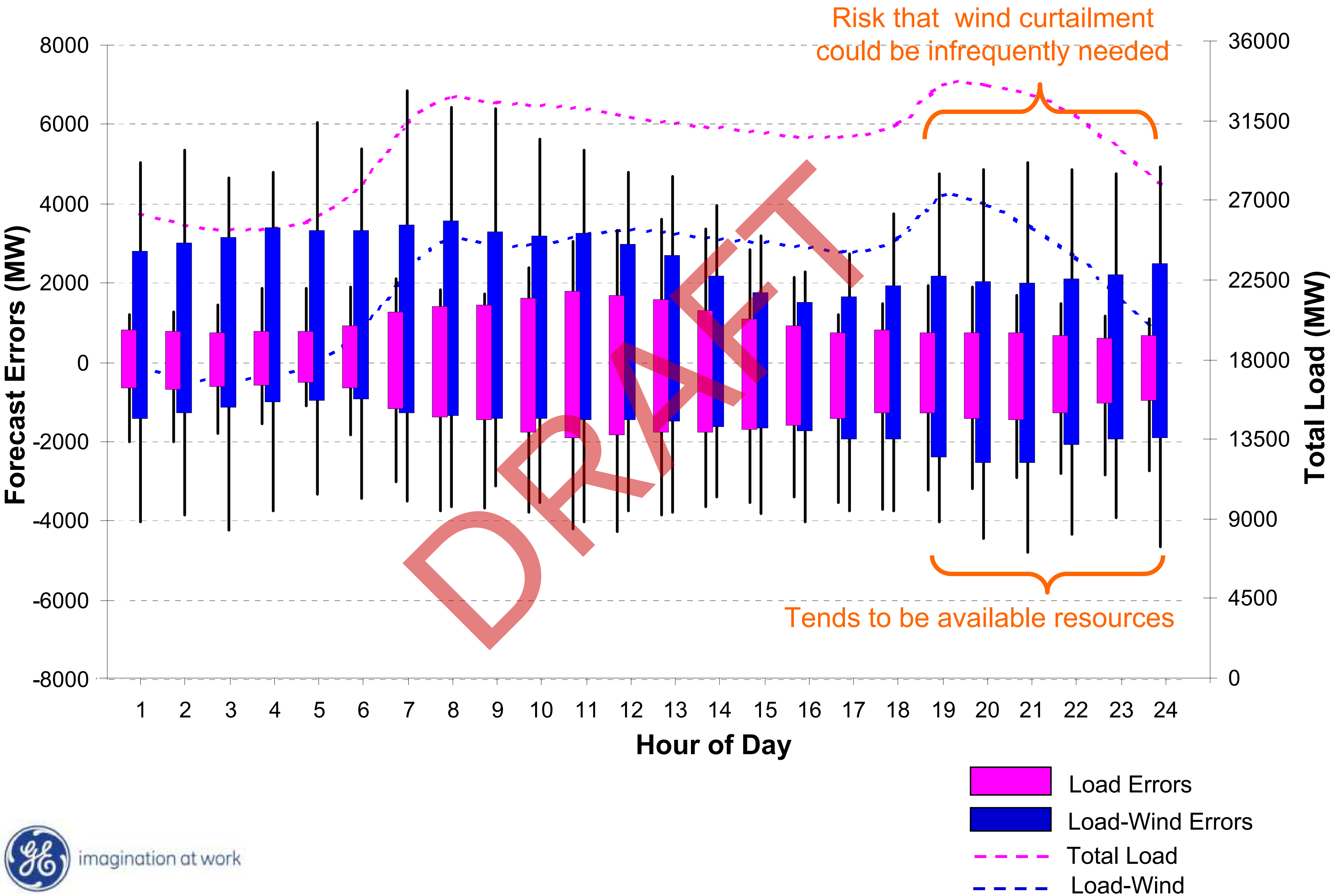
January Hourly Load and Net Load Forecast Errors (Avg. +/- sigma, Minimum, Maximum)

(Study Year Load with 15000 MW of Wind)



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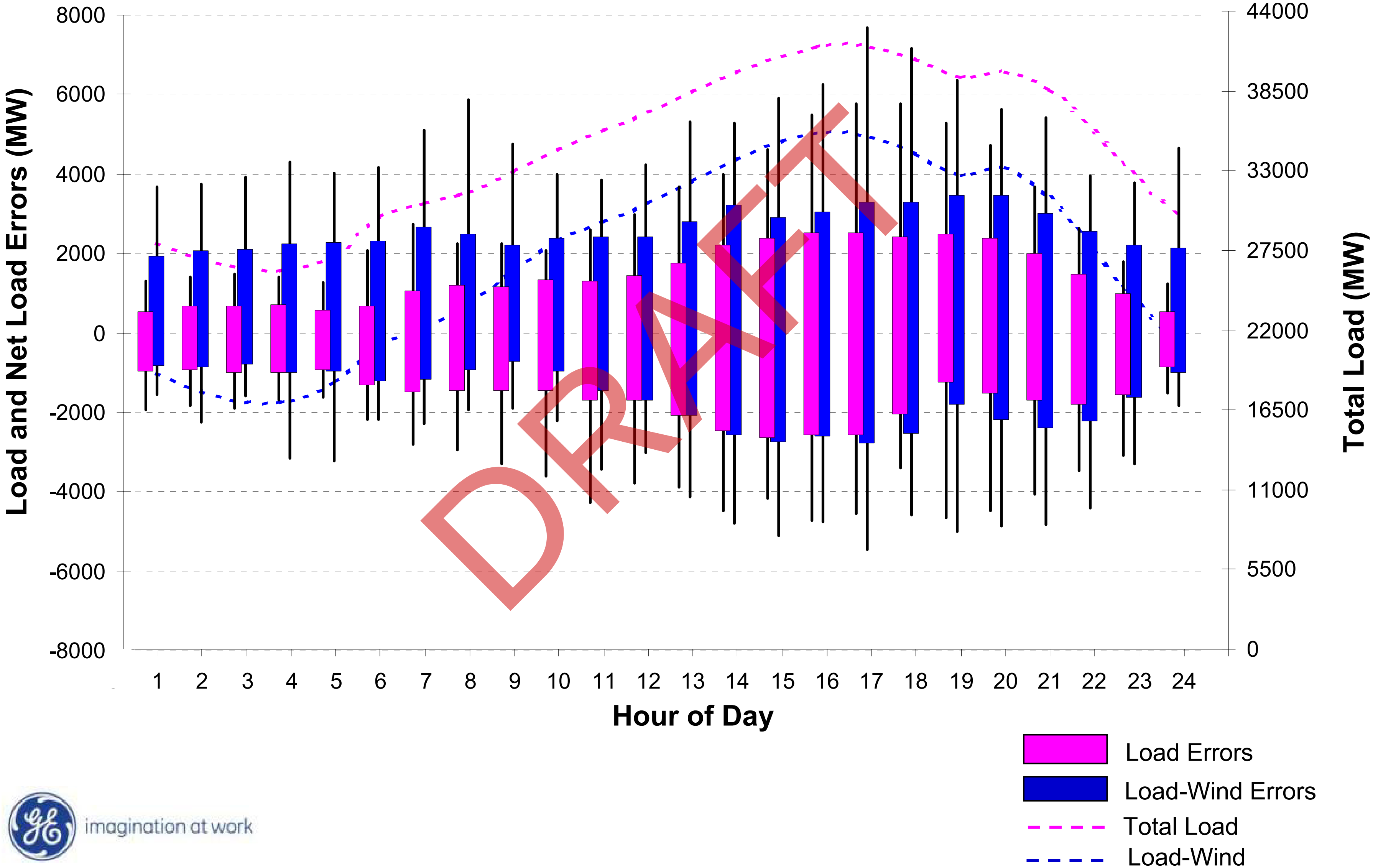
April Hourly Load and Net Load Forecast Errors (Study Year Load with 15000 MW of Wind) (Avg. +/- sigma, Minimum, Maximum)



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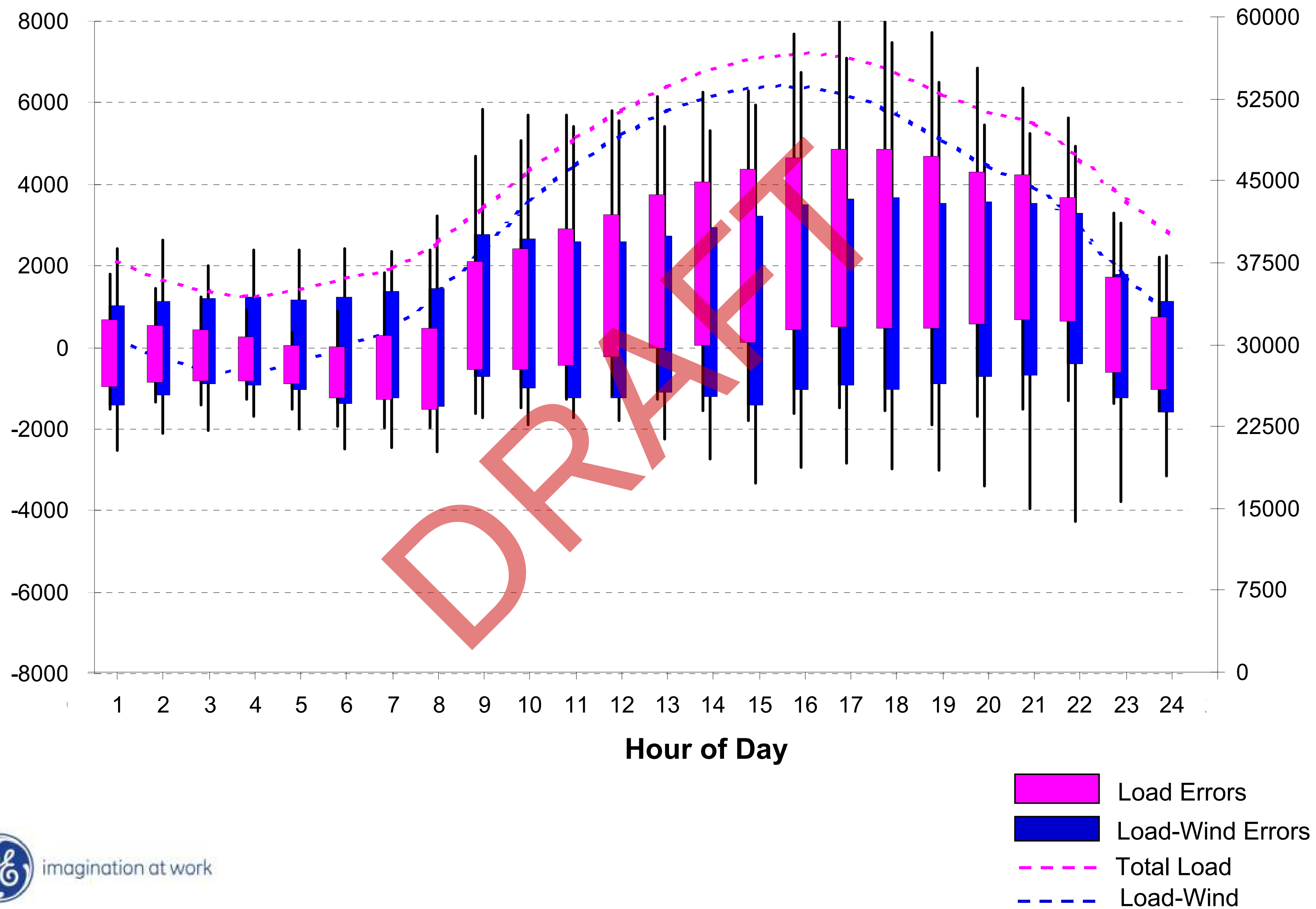
July Hourly Load and Net Load Forecast Errors (Study Year Load with 15000 MW of Wind) (Avg. +/- sigma, Minimum, Maximum)



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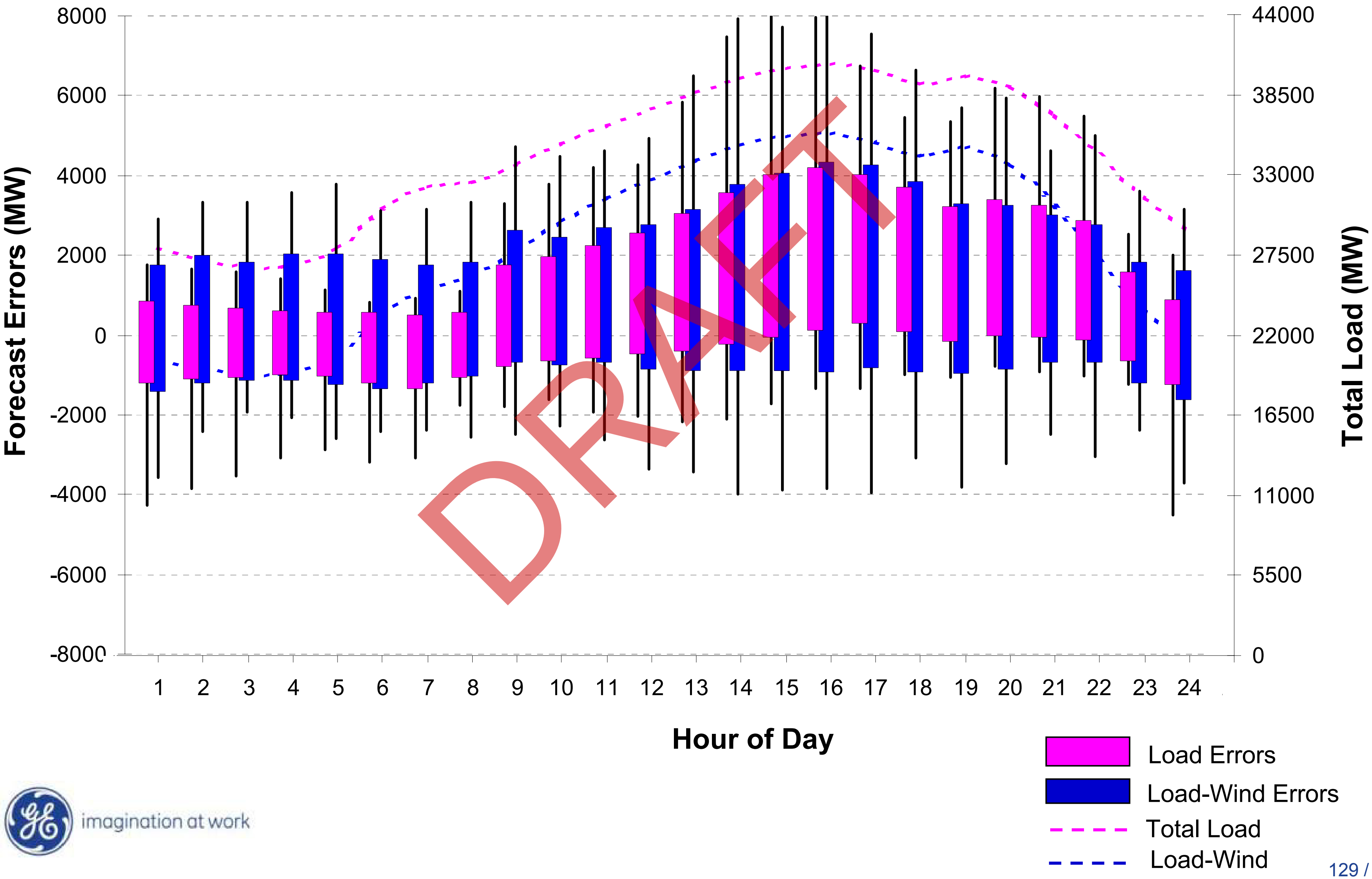
October Hourly Load and Net Load Forecast Errors (Study Year Load with 15000 MW of Wind) (Avg. +/- sigma, Minimum, Maximum)



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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 ancillary services create a small increment (1%) in cost relative to value of MWh supplied by wind

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Follow-On Recommendations

- Track ongoing data and wind performance
- Incent flexibility in new and existing generation units
  - Measure and monitor present flexibility