Quantifying Benefits of Demand Response and Look-ahead Dispatch in Systems with Variable Resources

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PSERC Webinar

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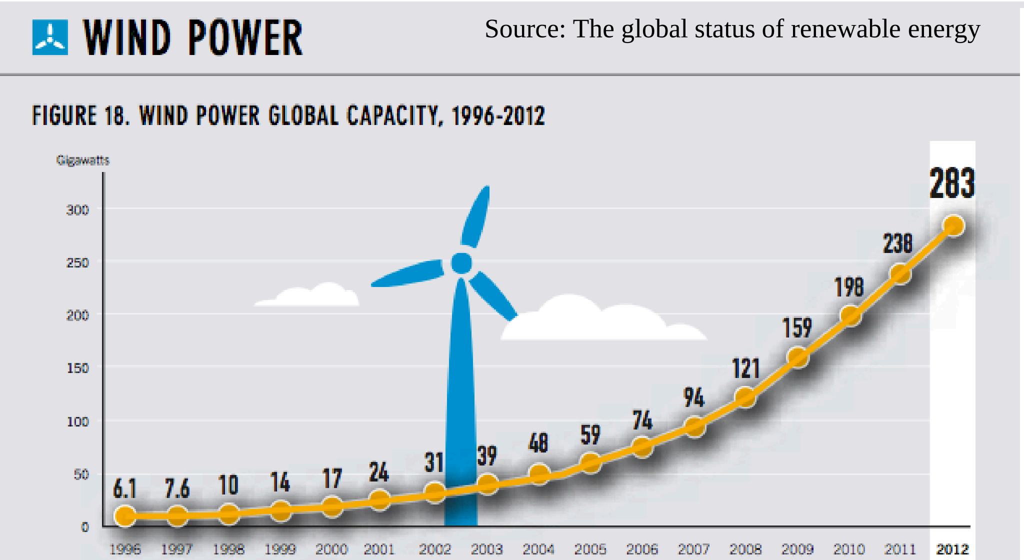
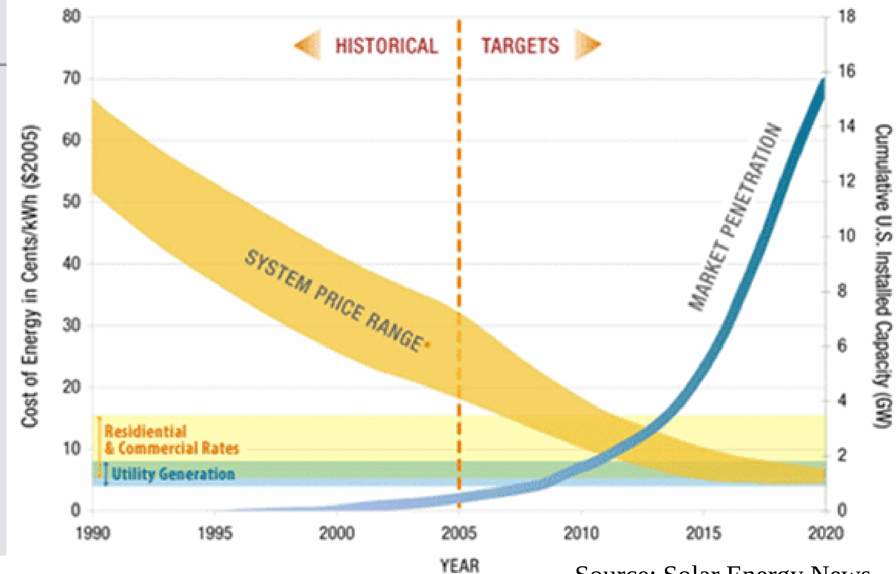
Outline

- Motivation
- Look-ahead Dispatch
  - Economic Benefits and Security Benefits
- Demand Response with Real Data
- Quantifying Benefits of Look-ahead Dispatch coupled with Demand Response
- Summary

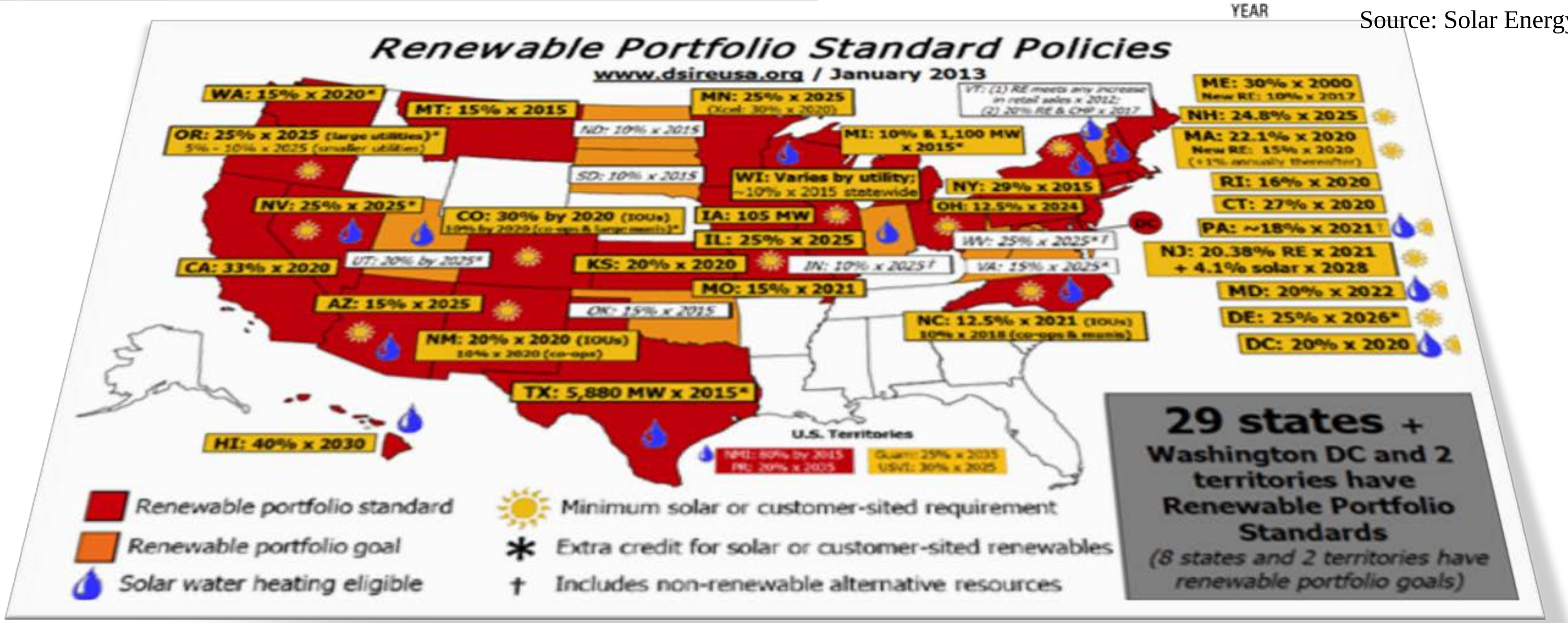
Increasing Renewable Penetration



Source: The global status of renewable energy

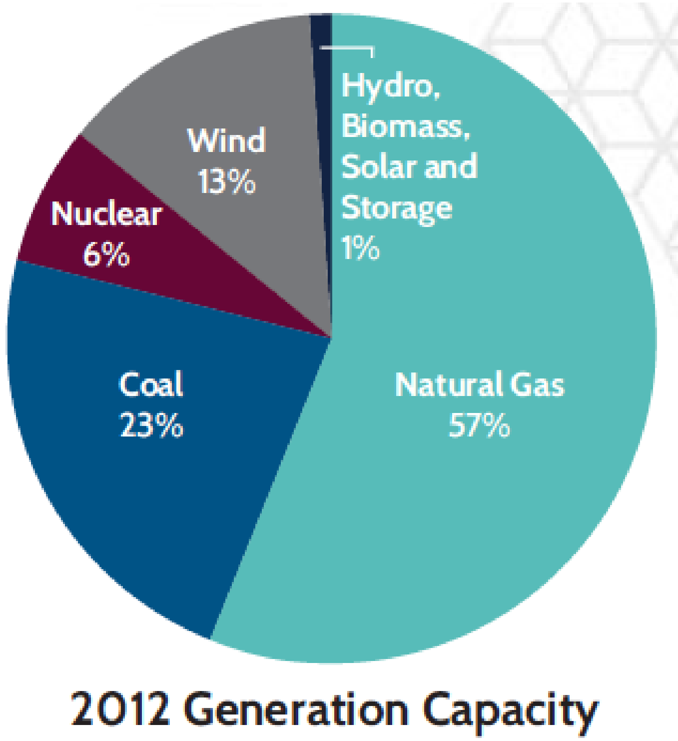


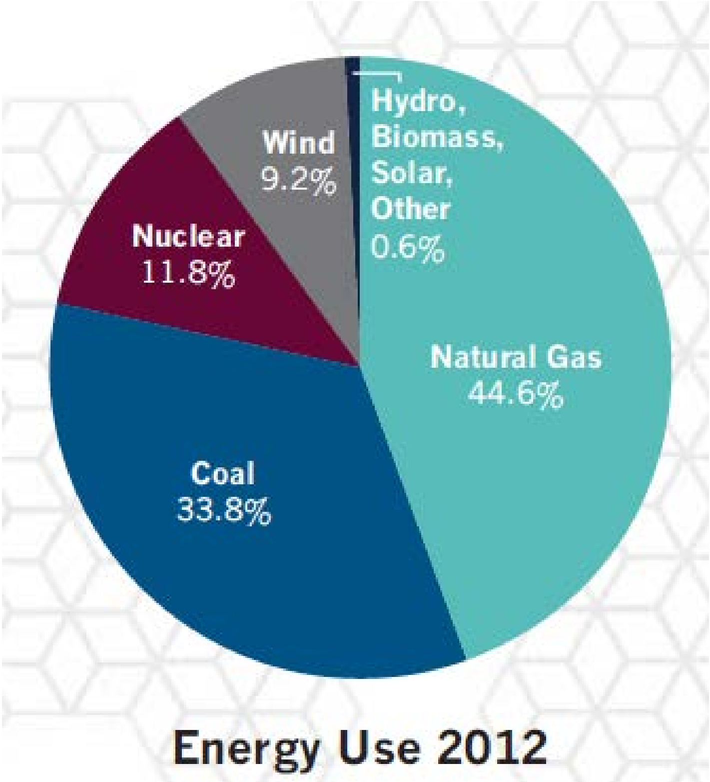
Source: Solar Energy News



ERCOT 2013

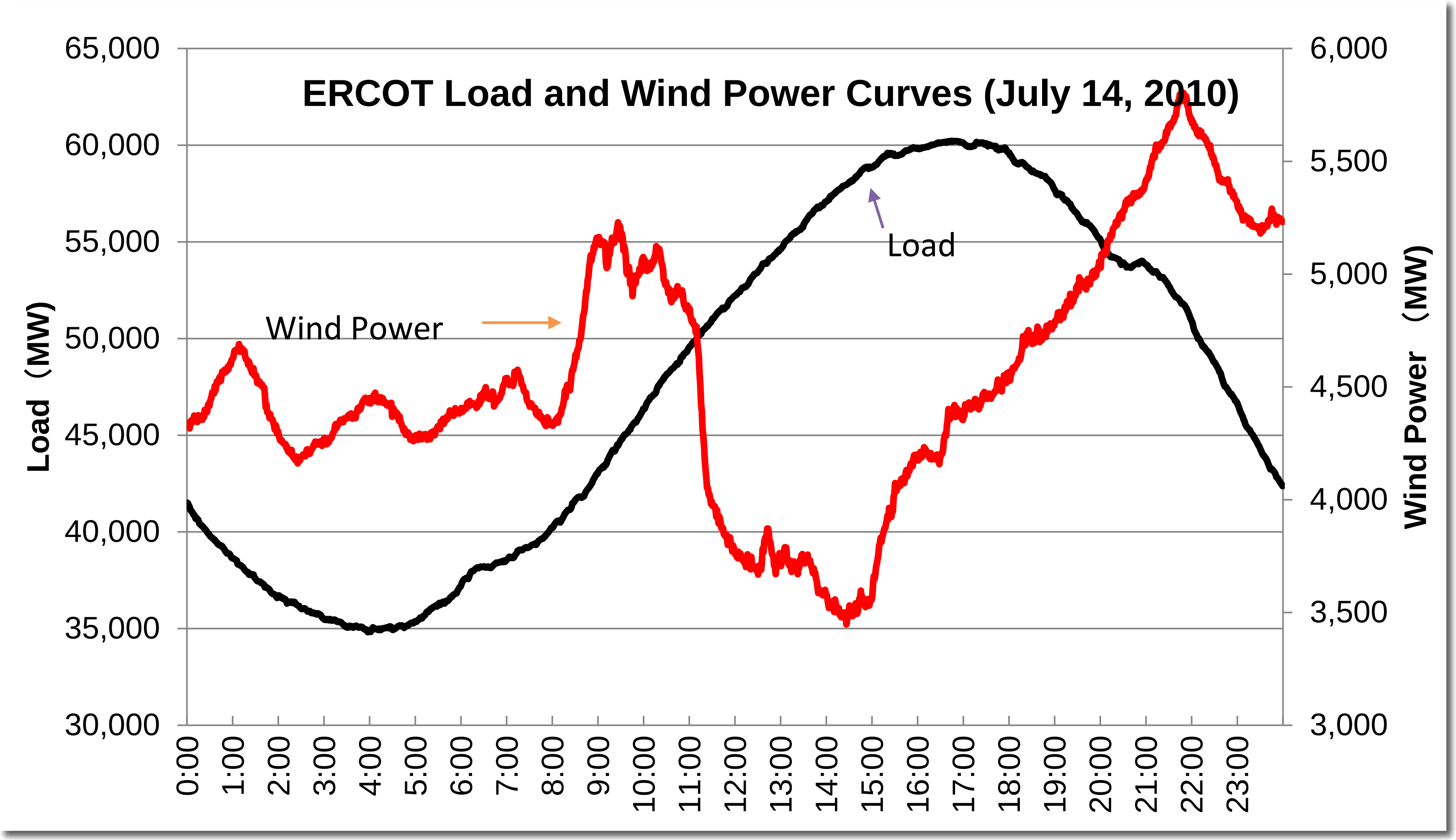
- ❑85% of Texas load
- ❑6.1 million advanced meters, >1.9GW demand response resources
- ❑Peak demand: 68,305 MW (Aug 3, 2011)
- ❑Wind capacity: 10,407 MW
- ❑Wind generation record: 9,674 MW (Mar 2, 2013), ~28.05% of load at that time





Source: http://www.ercot.com/content/news/presentations/2013/ERCOT_Quick_Facts_May%202013.pdf

ERCOT Load and Wind Power Curves



Net Demand - No Wind

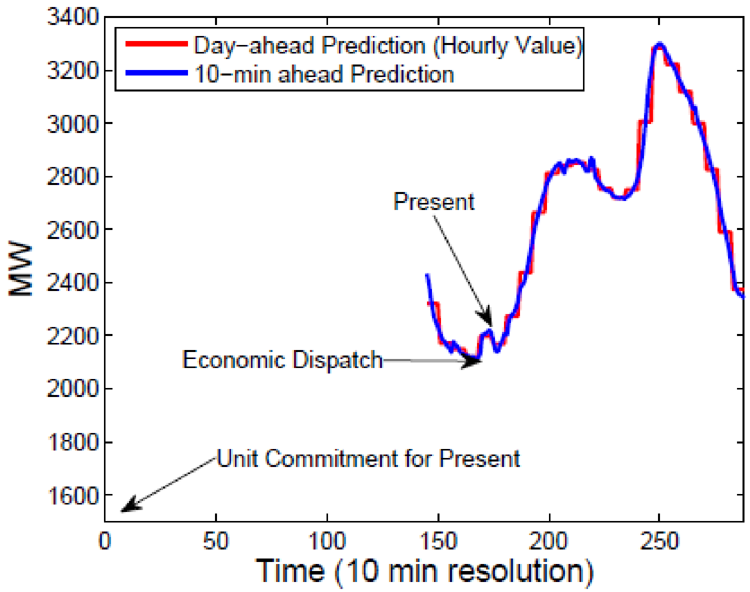


Fig. 2. Day-ahead and 10-min ahead load prediction, and timing of UC and ED functions

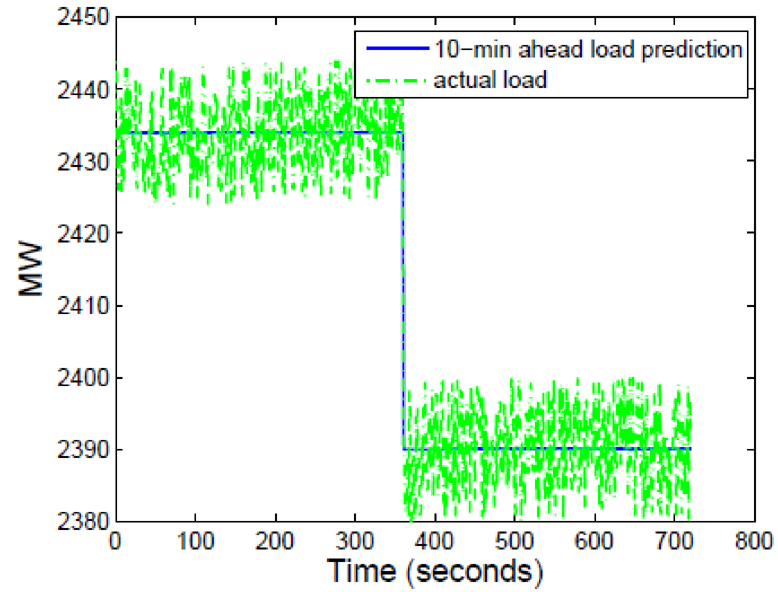


Fig. 3. 10-min ahead load prediction and second-by-second actual load

$$L(t) = \hat{L}[H] + \Delta_{LH}(t)$$ (Day-ahead forecast)

$$L(t) = \hat{L}[k] + \Delta_{Lk}(t)$$ (10-minute ahead forecast)

$$\left\|\hat{L}[H]\right\| \gg \|\Delta_{LH}(t)\|$$

$$\|\Delta_{LH}(t)\| > \|\Delta_{Lk}(t)\|.$$

(Day-ahead forecast *reasonably good*)

L. Xie, P. M. S. Carvalho, L. A. F. M. Ferreira, J. Liu, B. Krogh, and M. D. Ilić, "Integration of Variable Wind Energy in Power Systems: Operational Challenges and Possible Solutions," *Proceedings of The IEEE, Jan 2011*

With High Wind Penetration

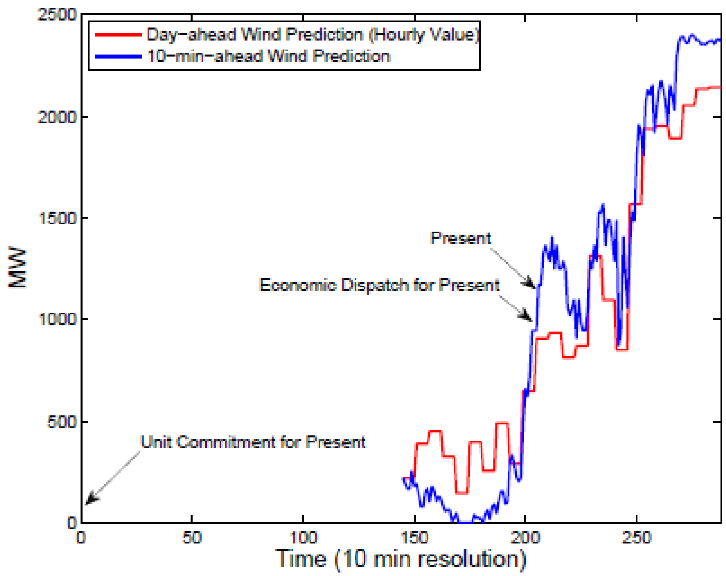


Fig. 4. Day-ahead and 10-min ahead wind prediction, timing of UC and ED functions

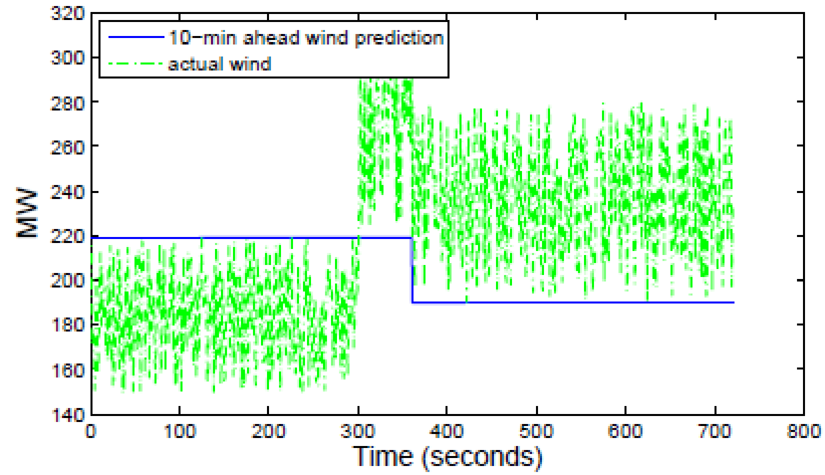


Fig. 5. 10-min ahead wind prediction and second-by-second actual wind

$$P_{Gw}(t) = \hat{P}_{Gw}[H] + \Delta_{Gw_H}(t)$$ (Day-ahead forecast)

$$P_{Gw}(t) = \hat{P}_{Gw}[k] + \Delta_{Gw_k}(t)$$ (10-minute ahead forecast)

$$\|\Delta_{Gw_H}(t)\| \gg \|\Delta_{Gw_k}(t)\|$$

$$\|\hat{P}_{Gw}[k]\| \gg \|\Delta_{Gw_k}(t)\|.$$

(*Substantial improvement of wind forecast* from Day-ahead to near real time)

L. Xie, P. M. S. Carvalho, L. A. F. M. Ferreira, J. Liu, B. Krogh, and M. D. Ilić, "Integration of Variable Wind Energy in Power Systems: Operational Challenges and Possible Solutions," *Proceedings of The IEEE, Jan 2011*

Literature Review

- Value of real-time pricing on cost and value of wind power based on *assumed* demand elasticity [Sioshansi, 2010]
- Value of coordinating wind with deferrable loads [Papavasiliou, Oren, 2010]
- Preliminary study of look-ahead coordination of wind with price responsive demands [Ilic, Xie, Joo, 2011]
- Industry transition from static real-time dispatch to look-ahead dynamic dispatch [Ott, 2010]

To our knowledge, potential benefits have never been quantified using *real-world demand response data* based upon a *look-ahead dynamic dispatch model*, which will

1. facilitate integration of intermittent generation sources
2. reduce dispatch costs (energy and ancillary services)

What We Propose

Quantifying System Benefits Using *Real-world Data*

Generation (look-ahead dynamic dispatch)

C&I price responsive demand (from ERCOT)

Dynamic Look Ahead Dispatch

Conventional Power System Scheduling (Economic Dispatch):

Source: [Xie et. al., 2011]

$$\min \sum \text{generation cost}$$

s.t.

system security constraints.

↓

Dynamic Look-ahead Scheduling:

$$\min \sum \sum \text{generation cost over a look-ahead window}$$

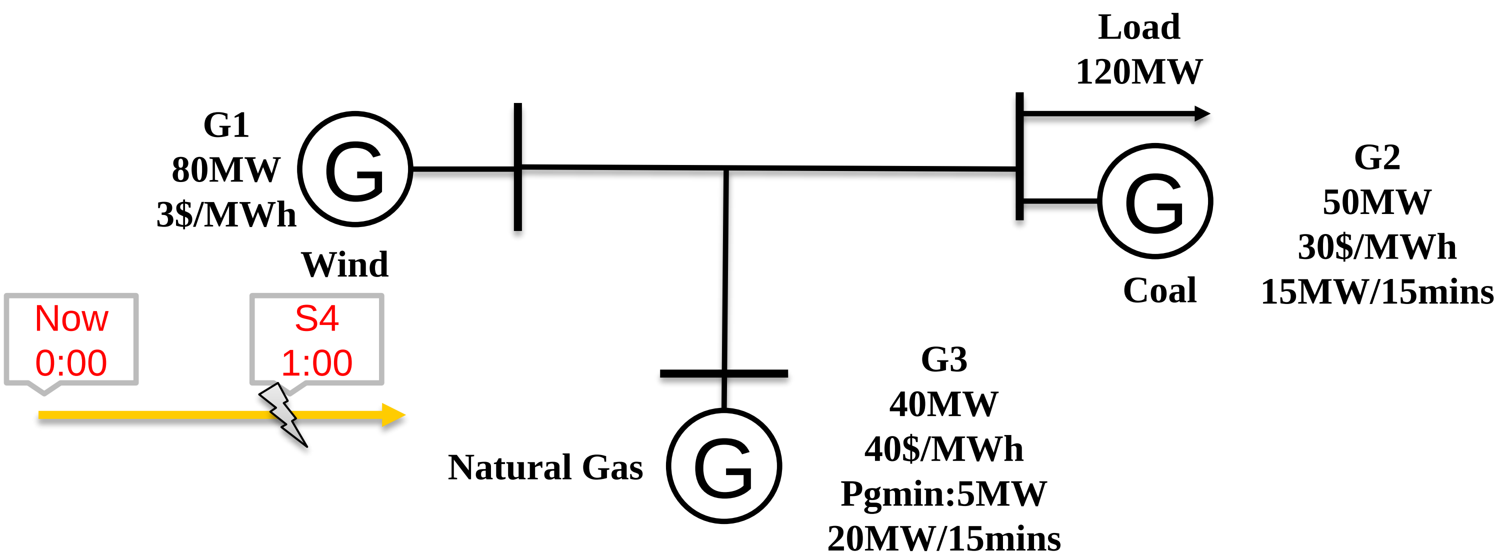
s.t.

system security constraints at each stage.

Multi-stage ramping constraints.

Detailed Mathematical Formulation

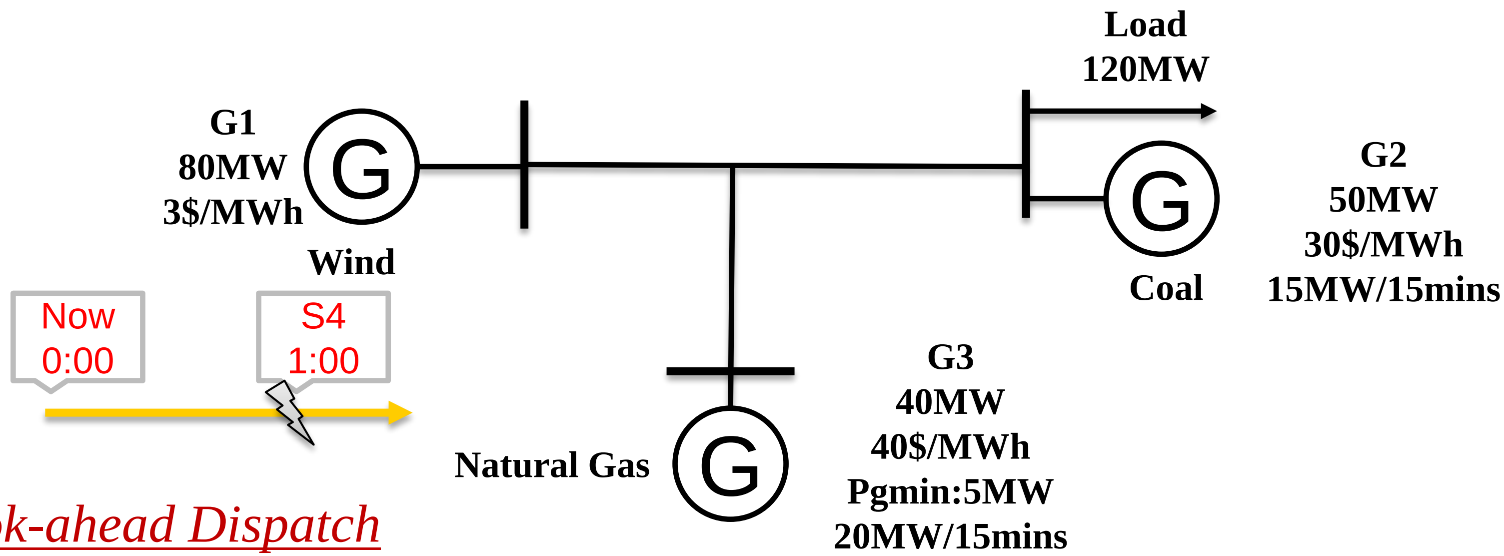
Illustrative Examples



	0:00	0:15	0:30	0:45	1:00	1:15	1:30
Wind	65MW	80MW					
G1	65MW	60MW					
G2	40MW	25MW					
G3	5MW	5MW					
PL	110MW	90MW					

Wind got 20MW curtailment

Illustrative Examples: Economic Benefits

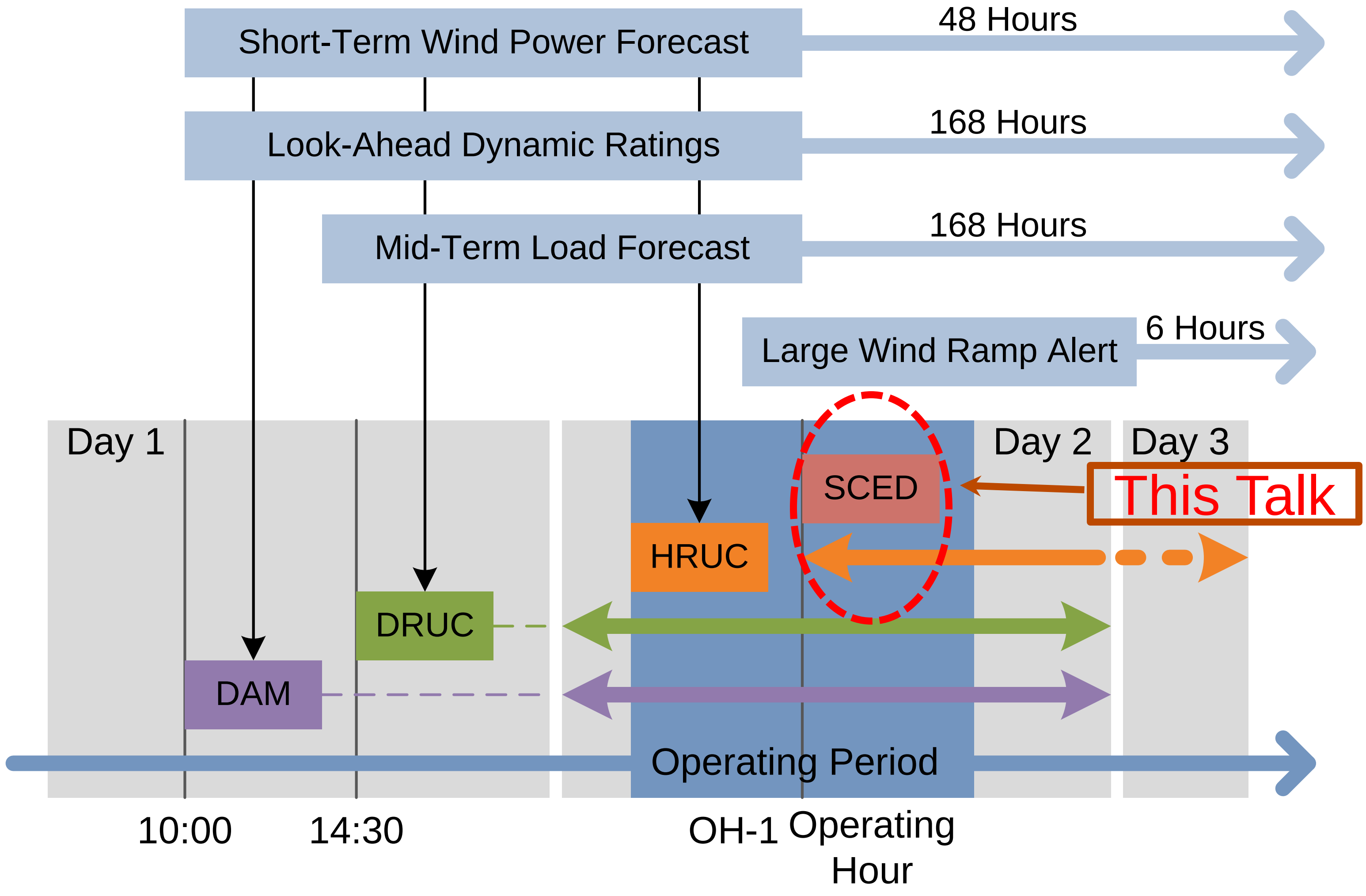


Look-ahead Dispatch

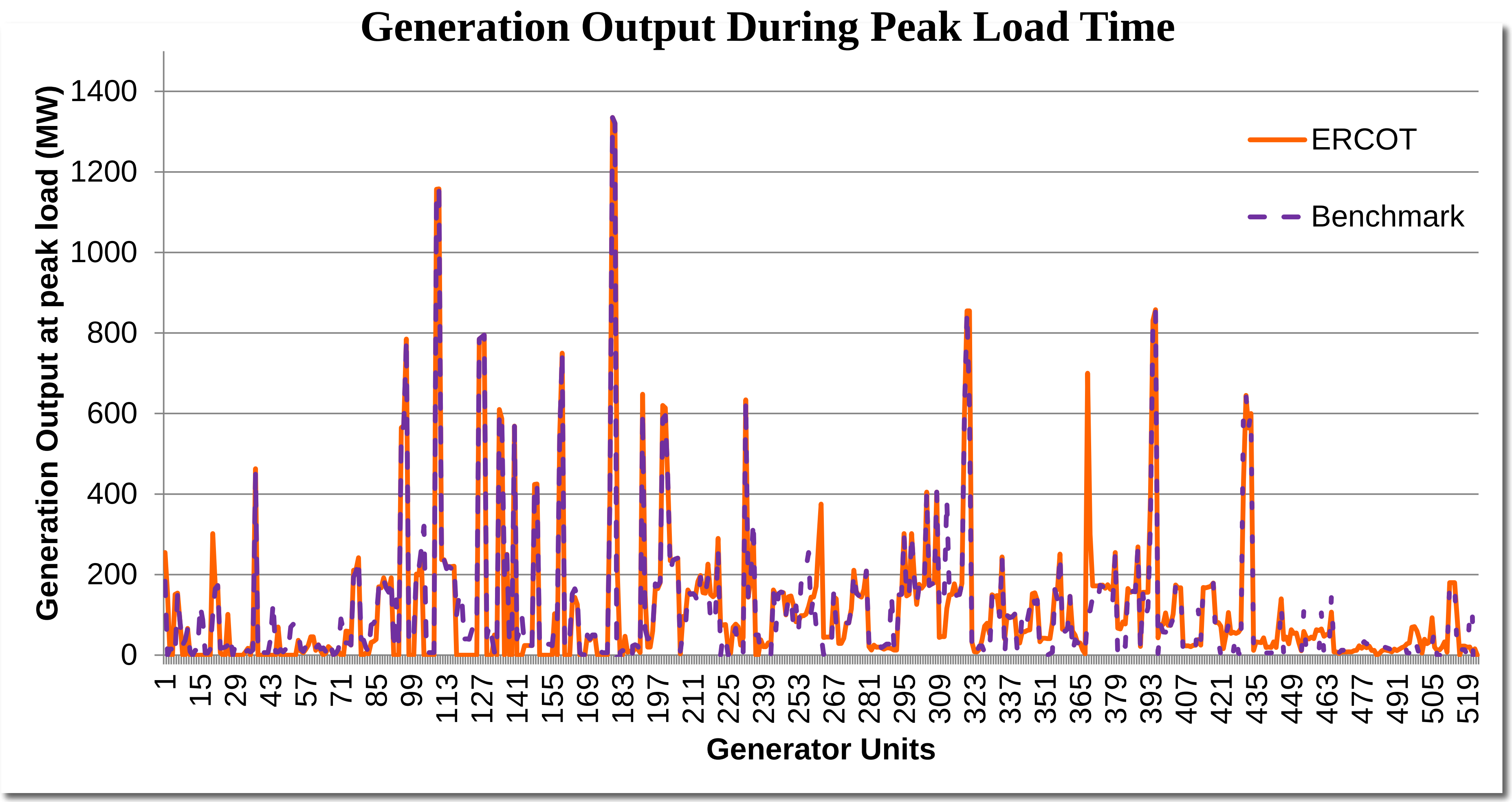
	0:00	0:15	0:30	0:45	1:00	1:15	1:30
Wind	65MW	80MW					
G1	65MW	80MW					
G2	20MW	5MW					
G3	25MW	5MW					
PL	110MW	90MW					

No curtailment
For conventional SCED
0.25*[(65+60)*3+(40+25)*30+(5+5)*40]=681.25
For Look-ahead Dispatch
0.25*[(65+80)*3+(20+5)*30+(25+5)*40]=596.25

Empirical Study of Look-ahead in ERCOT



Benchmark of ERCOT



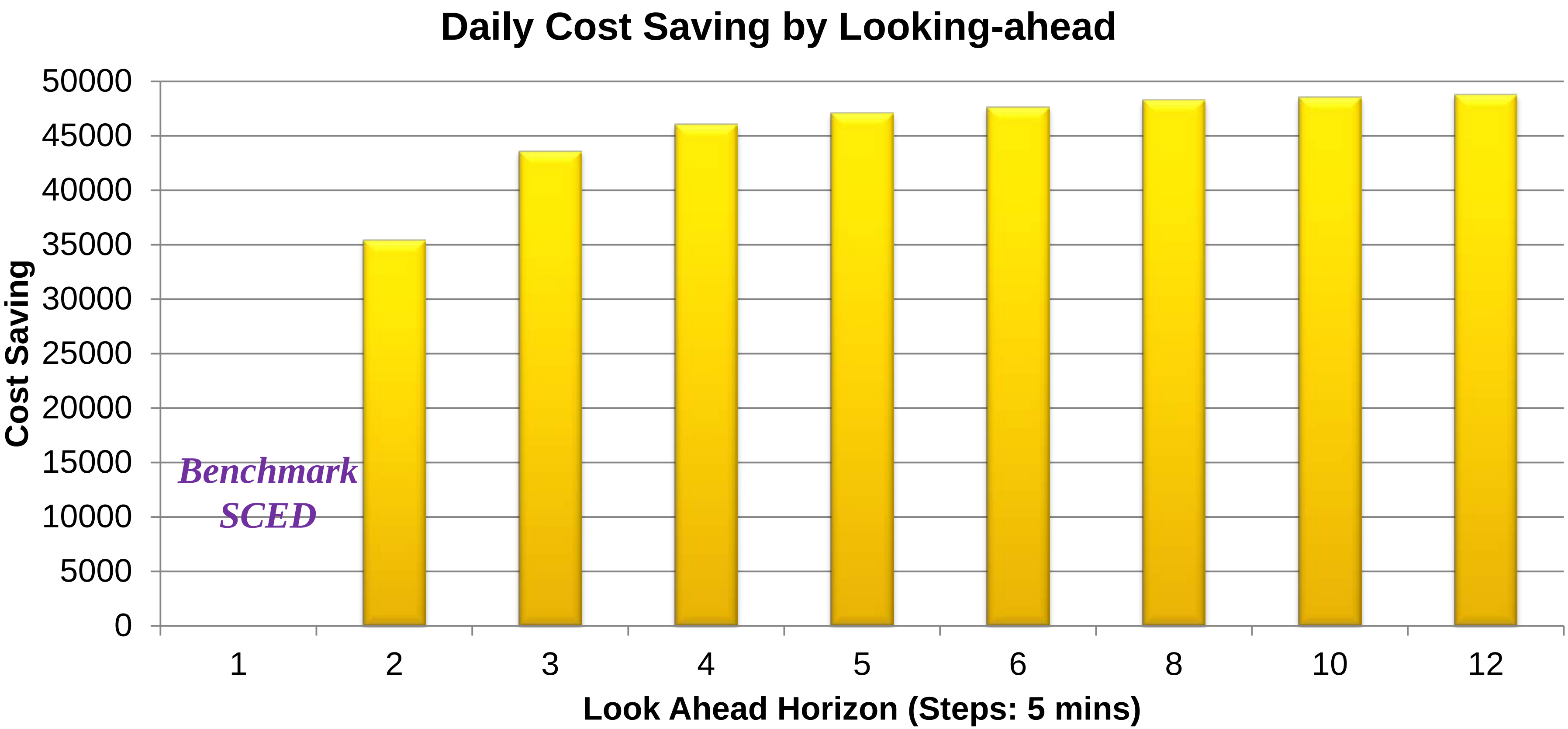
Look-ahead vs. Benchmark SCED

Comparison of Two Dispatch Methods for a Typical Day (Jul 11, 2009)

	Benchmark SCED	Look-ahead (30 min)	Difference
Entire Day	$ 26,191,710	$ 26,144,585	$ 47,125
Early Morning	$ 3,514,925	$ 3,506,689	$ 8,326
Peak Wind Period	$ 1,226,447	$ 1,219,948	$ 6,499
Wind Generation (MWh)	96071 MWh	96432 MWh	361 MWh

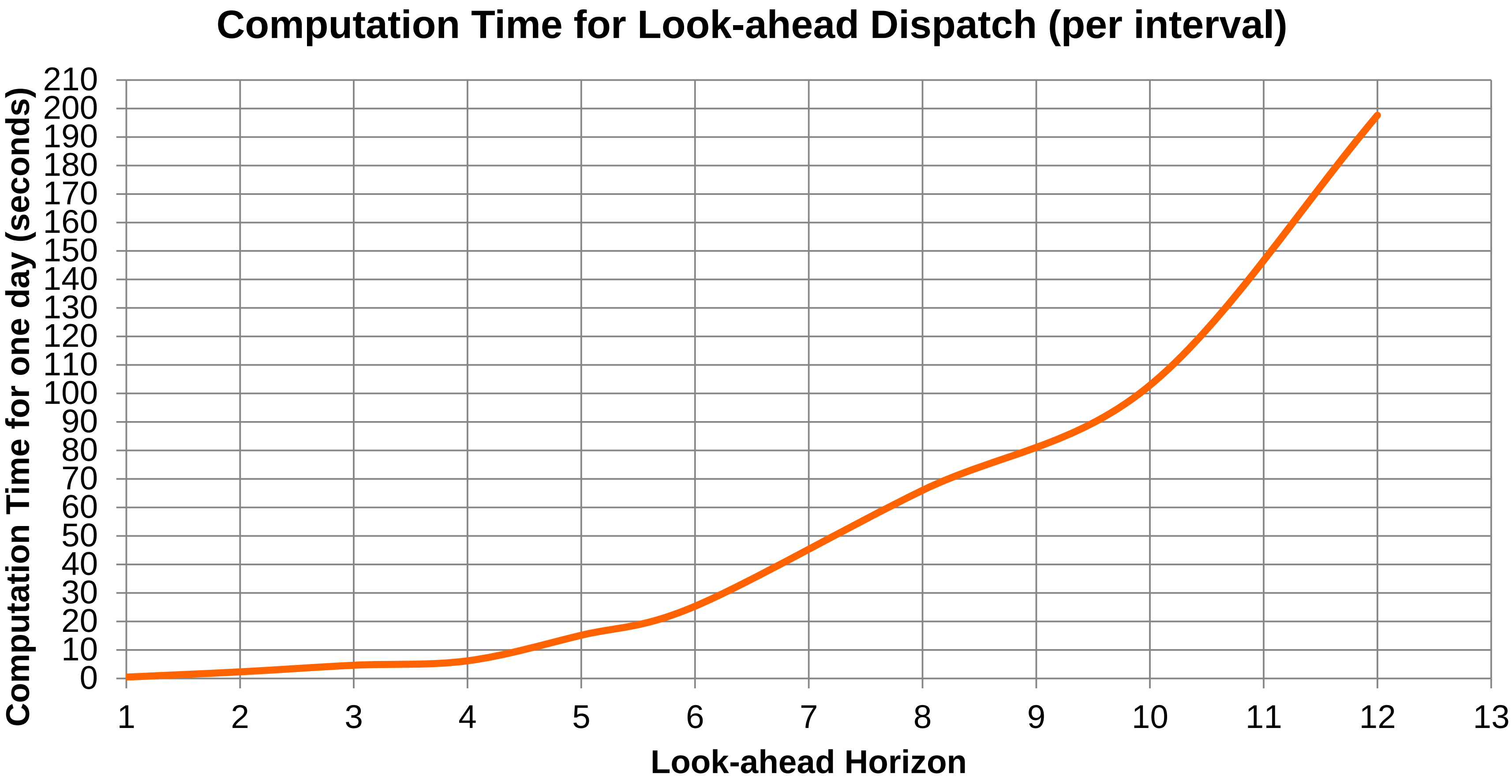
Early Morning: midnight-8am, July 11, 2009
Peak Wind Period: 3am-5am, July 11, 2009

Look-ahead vs. Benchmark SCED Different Look-ahead Horizon

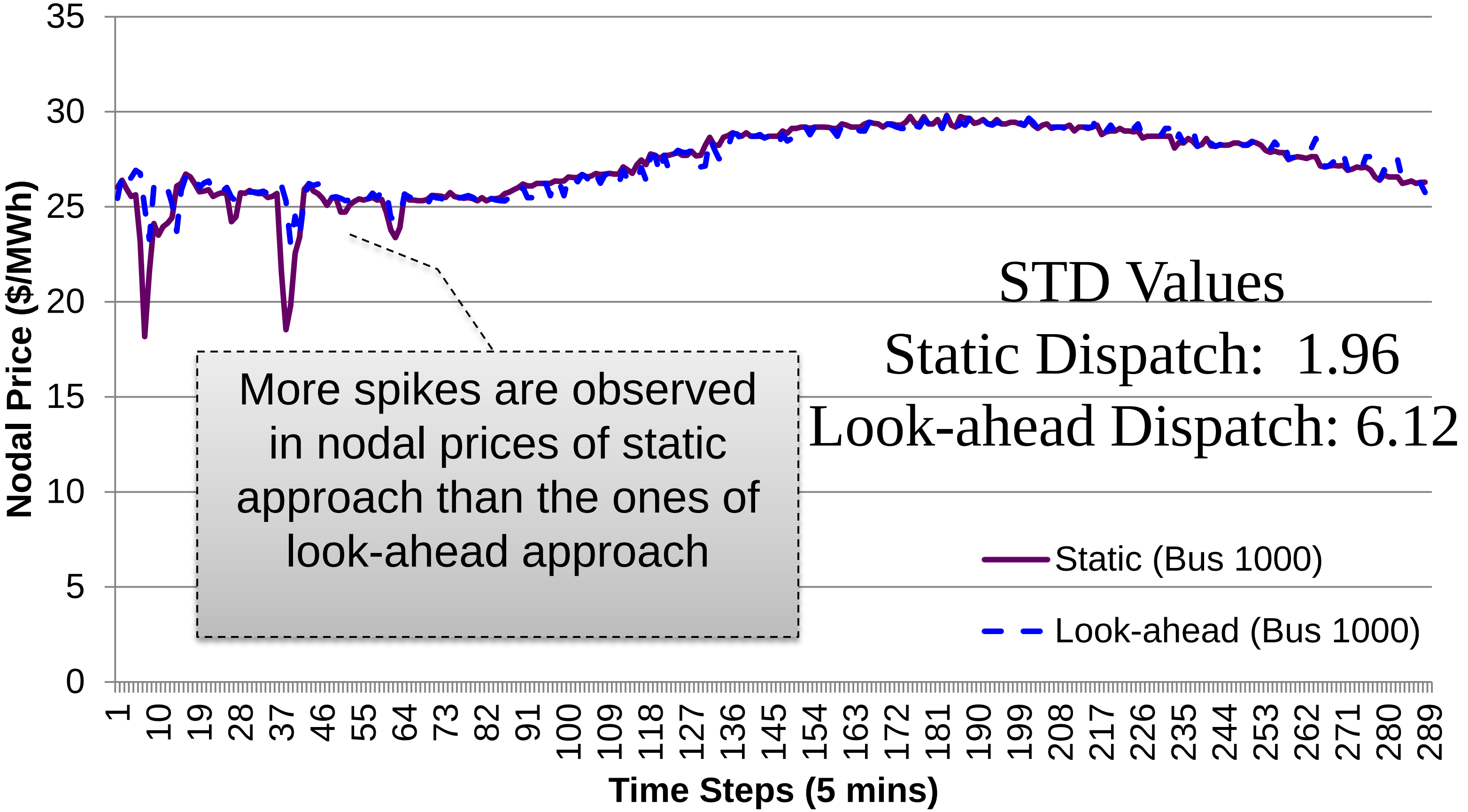


Look-ahead Horizon Response of Total Savings

Look-ahead vs. Benchmark SCED Computational Time

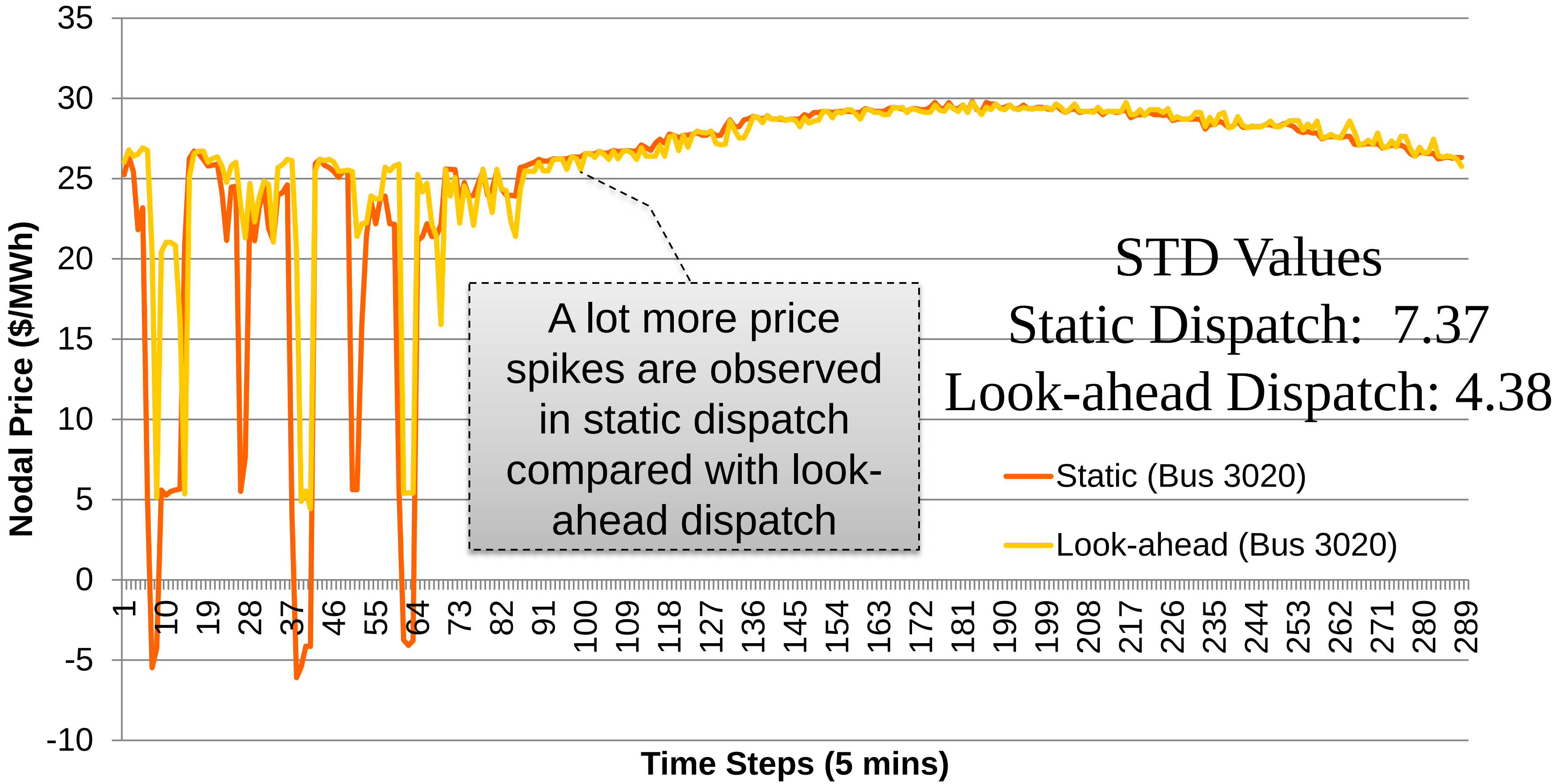


Nodal Price: Look-ahead vs. Static Economic Dispatch



Nodal Prices at Bus 1626 on July.16th

Nodal Price: Look-ahead vs. Static Economic Dispatch

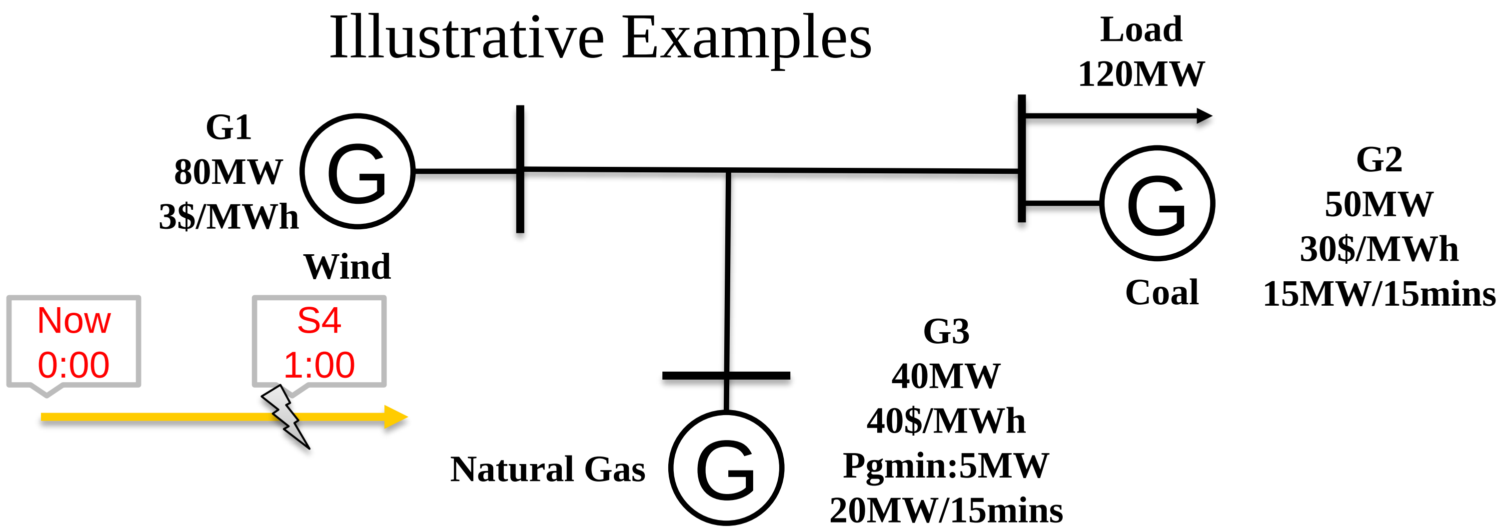


Nodal Prices at Bus 6272 on July.16th

Nodal Price: Preliminary Findings

- Look-ahead dispatch leads to a *more smoothed* nodal price pattern
- The nodal prices at selected buses may be *higher* under look-ahead dispatch than in static dispatch

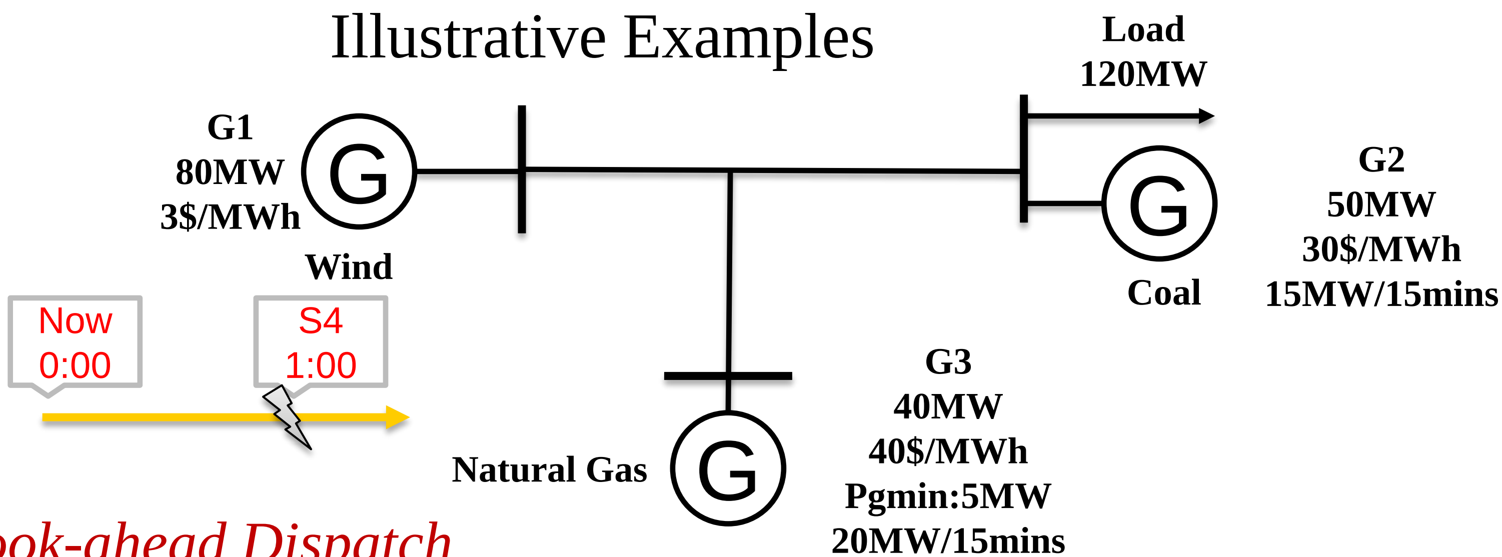
Illustrative Example: Security Benefits



	0:00	0:15	0:30	0:45	1:00	1:15	1:30
Wind	65MW	80MW	70MW	75MW	50MW		
G1	65MW	60MW	70MW	75MW	50MW		
G2	40MW	25MW	25MW	20MW	35MW		
G3	5MW	5MW	5MW	5MW	25MW		
PL	110MW	90MW	100MW	100MW	115MW		

The SCED problem turns to be infeasible at 1:00

Illustrative Examples: Security Benefits



Look-ahead Dispatch

	0:00	0:15	0:30	0:45	1:00	1:15	1:30
Wind	65MW	80MW	70MW	75MW	50MW		
G1	65MW	80MW	70MW	70MW	50MW		
G2	40MW	5MW	25MW	25MW	40MW		
G3	5MW	5MW	5MW	5MW	25MW		
PL	110MW	90MW	100MW	100MW	115MW		

Wind got 5MW curtailment

The look-ahead scheduling problem is feasible at 1:00

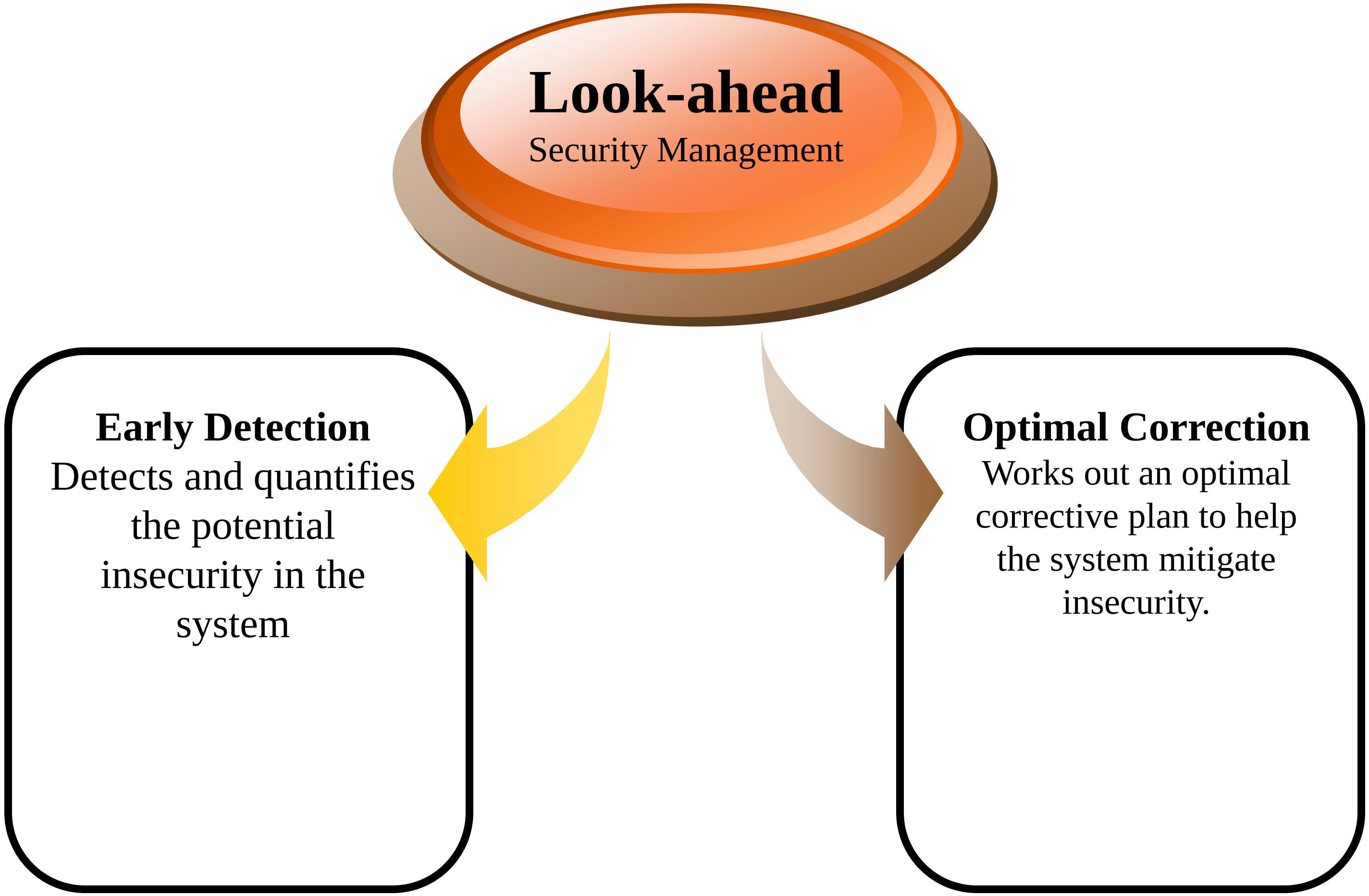
Look-ahead Security Management

- The potential added value of look-ahead dispatch in improving system security
  - ✓ **Predict** and **identify** the potential security[1] problems
  - ✓ **Quantify** the extent of insecurity
  - ✓ Provide an **optimal corrective plan** with minimized correction costs

Note: Security here refers to violation of power system operational security constraints (e.g., energy balancing, ramping).

Source: [Vada et. al., 2001]

Look-ahead Security Management



Y. Gu, and L. Xie, "Early Detection and Optimal Corrective Measures of Power System Insecurity in Enhanced Look-Ahead Dispatch," *IEEE Transactions on Power Systems*, vol.28, no.2, pp.1297,1307, May 2013.

Early Identification of Insecurity

$$\min f = \sum_{k=k_0}^{T} \sum_{i \in G} C_{G_i}(P_{G_i}^k)$$

$$+I(r_{N_j}^k, r_F, r_{R_i}, r_{G_i}, r_{SU_i}, r_{SD_i})$$

$$\sum_{i \in G_j} P_{G_i}^k - P_{D_j}^k + r_{N_j}^k = P_{N_j}^k(\theta), k = 1 \dots T, j \in N$$

$$-\mathbf{F}^{max} - r_F^k \leqslant \mathbf{F}^k \leqslant \mathbf{F}^{max} + r_F^k, k = 1 \dots T$$

$$-P_i^R - r_{R_i}^k \leqslant \frac{P_{G_i}^k - P_{G_i}^{k-1}}{\Delta T} \leqslant P_i^R + r_{R_i}^k, i \in G$$

$$P_{G_i}^{min} - r_{G_i}^k \leqslant P_{G_i}^k \leqslant P_{G_i}^{max} + r_{G_i}^k, i \in G, k = 1 \dots T$$

$$0 \leqslant P_{SU_i}^k \leqslant P_{Ui}^R \Delta T + r_{SU_i}^k, i \in G, k = 1 \dots T$$

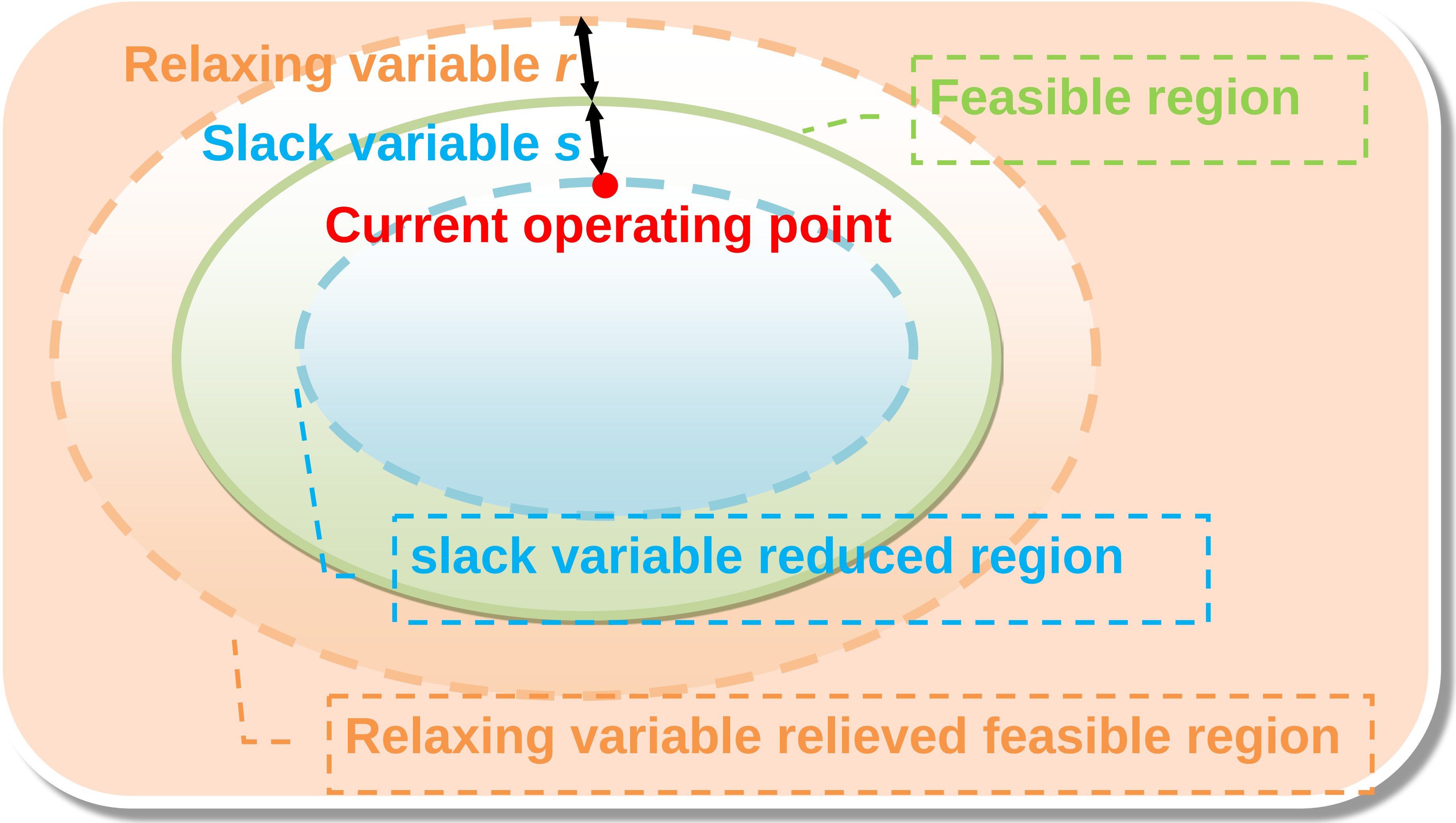
$$0 \leqslant P_{SD_i}^k \leqslant P_{Di}^D \Delta T + r_{SD_i}^k, i \in G, k = 1 \dots T$$

Relaxing variables are introduced into security constraints

For Details

Y. Gu, and L. Xie, "Early Detection and Optimal Corrective Measures of Power System Insecurity in Enhanced Look-Ahead Dispatch," *IEEE Transactions on Power Systems*, vol.28, no.2, pp.1297,1307, May 2013.

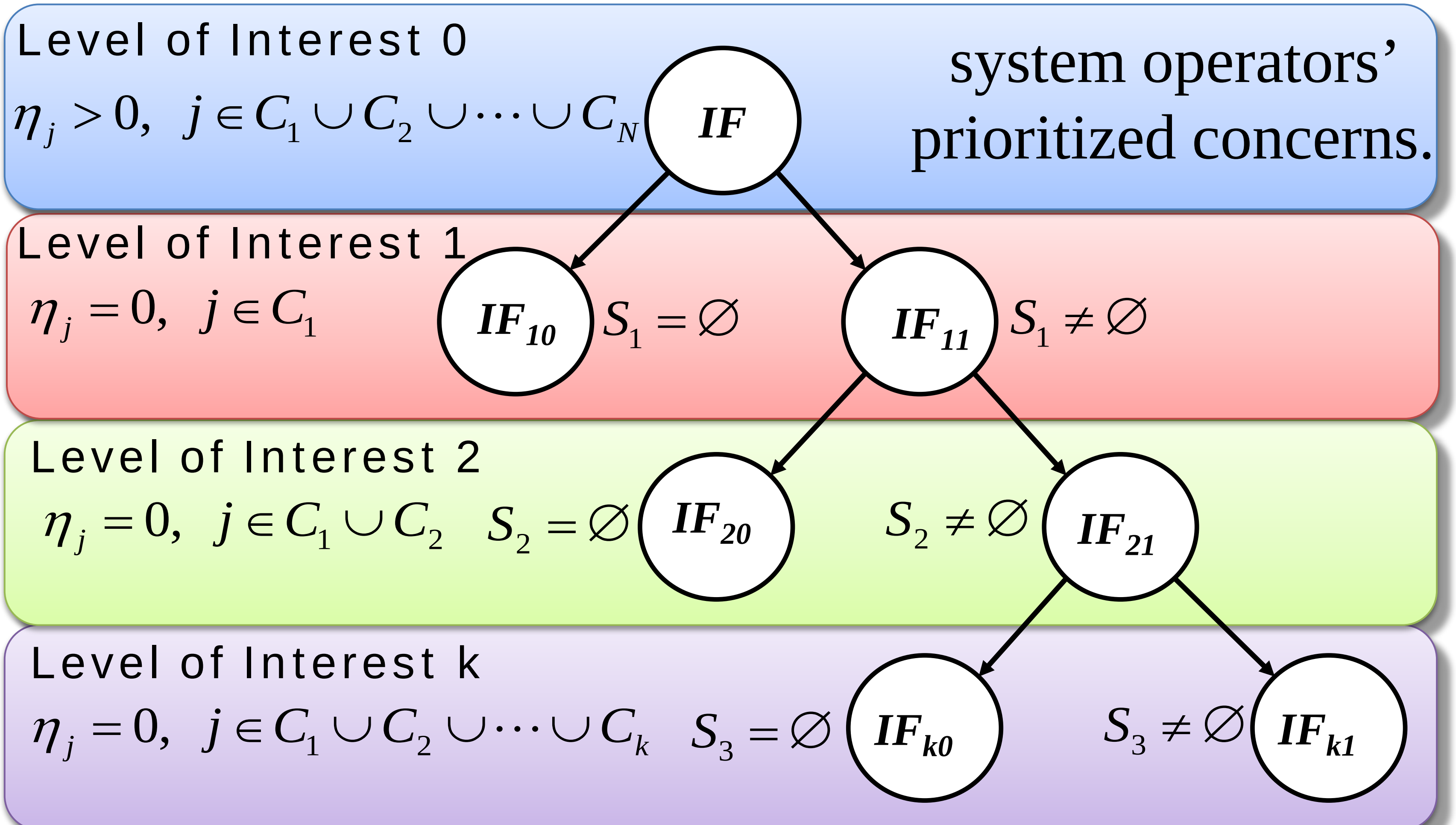
Relaxing Variables



Introduction of Relaxing Variables

Early Identification of Insecurity

- The enumeration tree approach is proposed to identify multiple insecurity factors.



Empirical Study of Security Benefits

❖ Numerical Experiment of ERCOT Nodal System

Fig.9 Map of the area regulated by ERCOT

5889 Buses;
7220 Branches;
523 Power Plants;
76 Aggregated Wind Farms;
9710.4 MW Installed Wind Capacity;
Represent 85% of Texas Demand.

Numerical Experiments

Considering the computation performance (1s to 1min) and recovery cost savings (up to 96%), the approach is effective and implementable in a practical case.

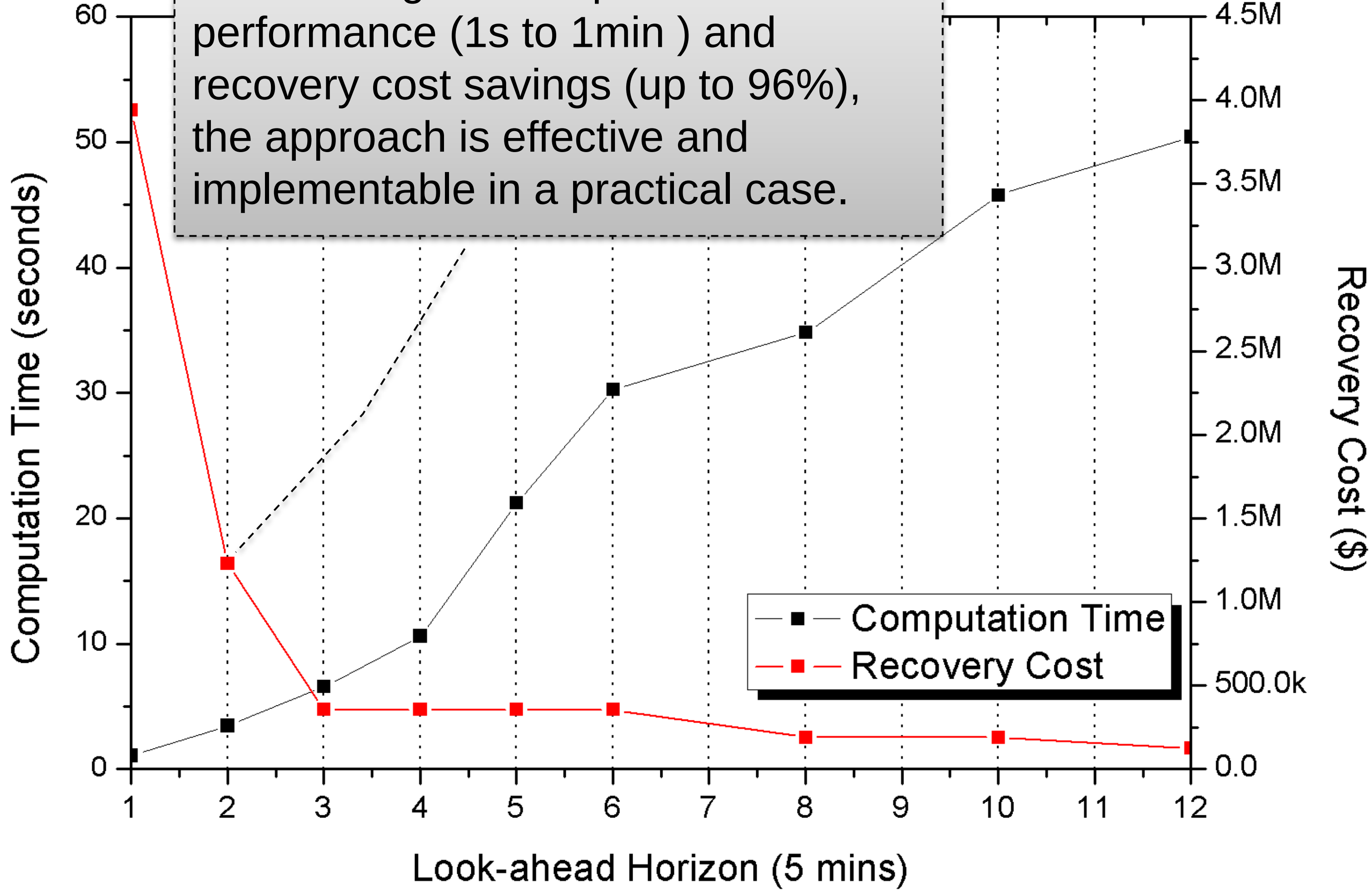


Fig.10 Computation Time and Recovery Cost of ERCOT Nodal system

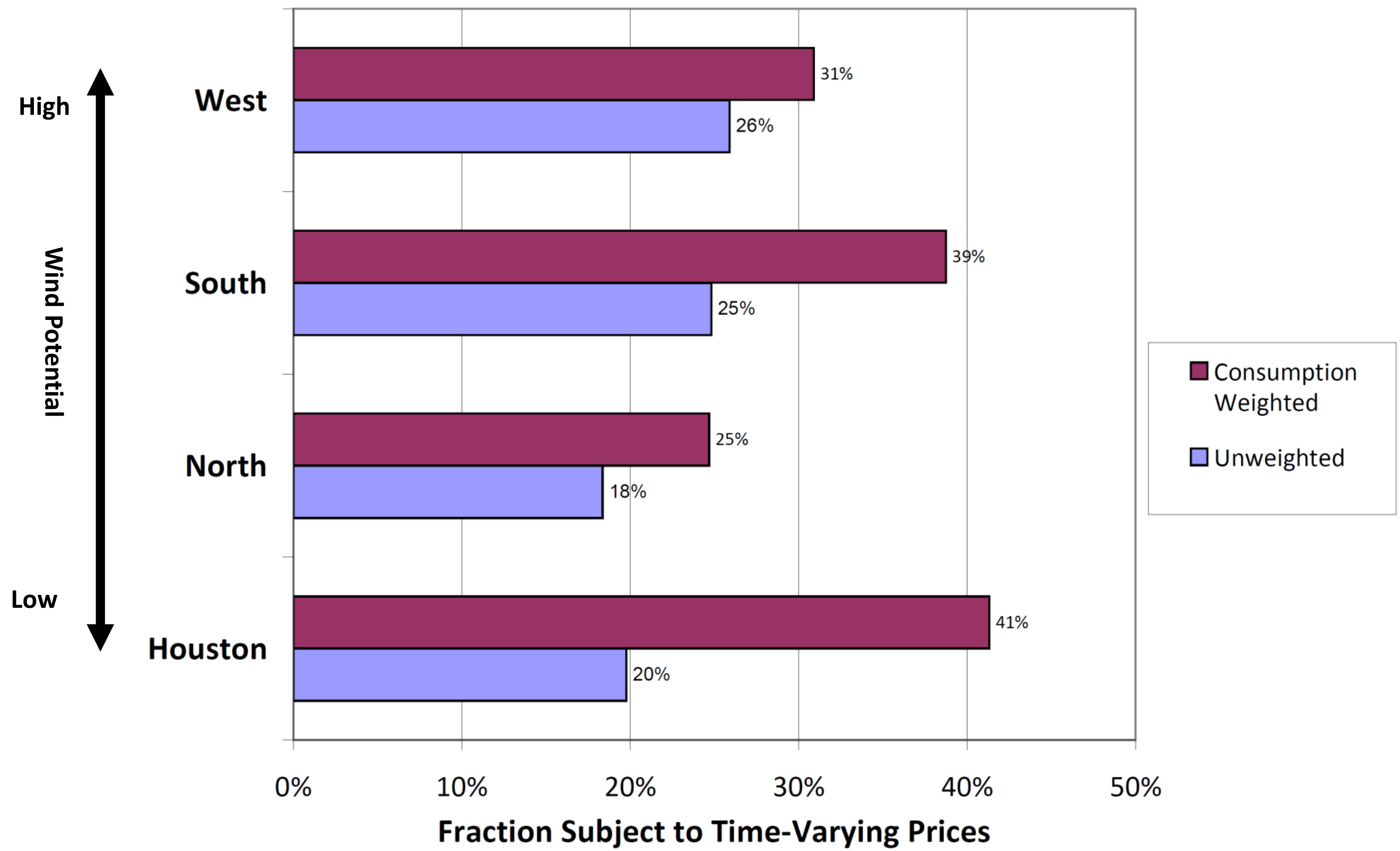
Quantify Demand Response by Location in Network

- Econometrically estimate DR for Commercial & Industrial customers
- Econometric analysis will yield:
  - Quantity of DR (“demand elasticity”) by customer, substation, time interval of day, and season of year
- *Novel*: Quantity of DR based on actual data!

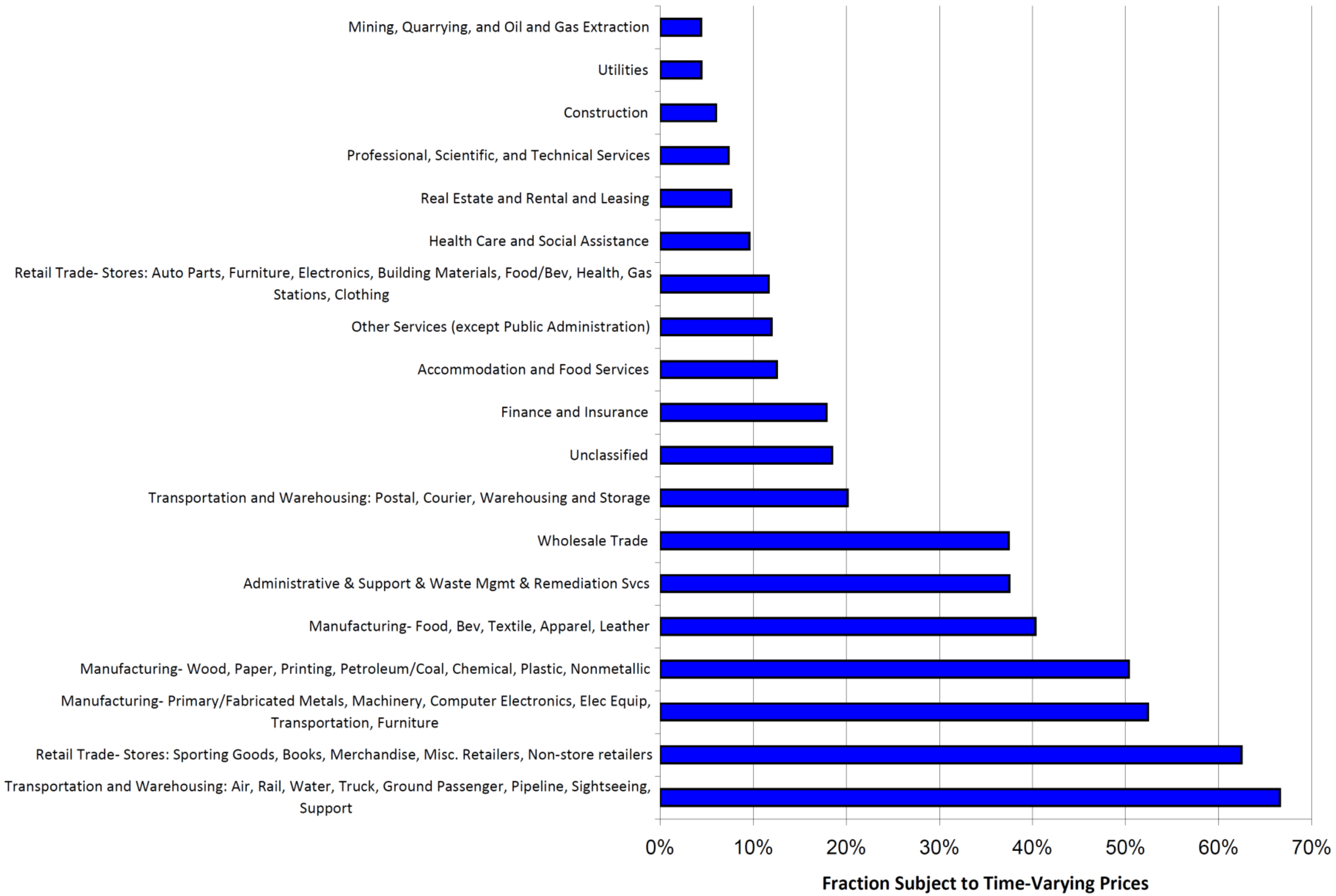
Quantifying Actual Demand Response in ERCOT

- ERCOT provided us with customer-level data for each “large” C&I customer:
  - Customer location
  - Information on whether retail contract uses time-varying prices (TVP)
    - TVP includes e.g. real-time pricing, critical peak pricing. Excludes simple time-of-use
  - Consumption (every 15-min for summer 2008)
  - 8537 customers (23% of ERCOT load)
    - 1250 are exposed to time-varying wholesale prices

TVP take-up occurs in areas with current and future wind generation



TVP take-up varies substantially by industry



Note: take-up is consumption weighted.

But, does signing TVP contracts lead to substantial demand response?

- How "elastic" is demand to price?
- Estimate own and cross-price elasticities across 96 daily intervals for each customer
- Imagine the following experiment:
  - Wholesale spot price rises in interval *t*
  - Consumption in *t* might fall (or not)
  - Consumption in any other interval of the *same day t´* may rise or fall
- We use consumer-level data to estimate the amount of "demand response"

But, does signing TVP contracts lead to substantial demand response? (cont'd)

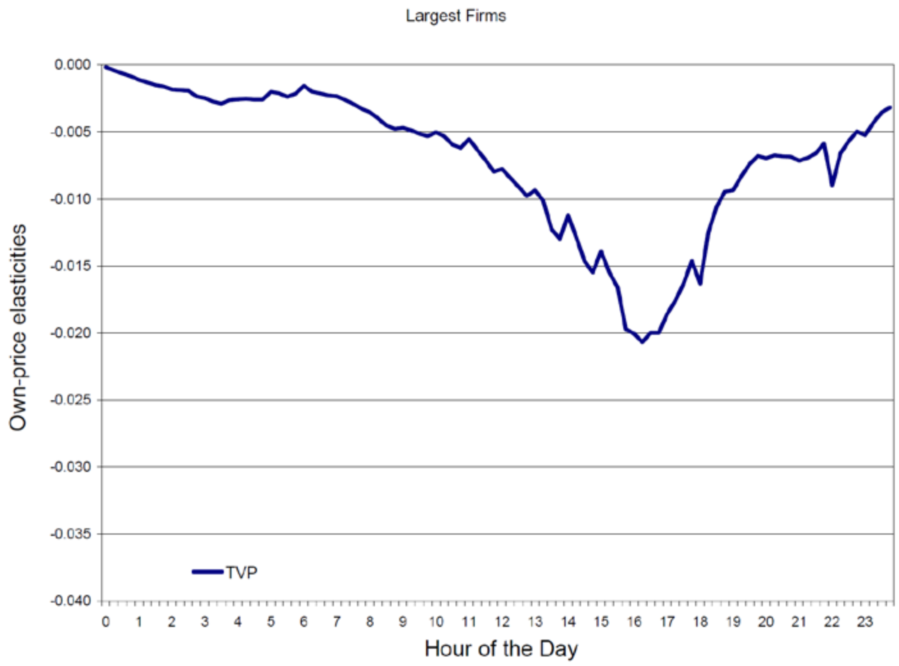
- Econometric model allows for substitution across intervals that is:
  - Consistent with economic theory
    - Concave in input prices
  - Flexible
    - Generalized McFadden Function
  - Parsimonious
    - use Fourier series to parameterize terms of lower triangular and diagonal matrix that generate c_{ij} of C matrix

$$C_{kd}(p,y) = \left[\frac{1}{2}\sum_{i=1}^{96}\sum_{j=1}^{96} c_{ij} p_{id} p_{jd}\right] y_d + \sum_{i=1}^{96} b_{ii} p_{id} y_d +$$

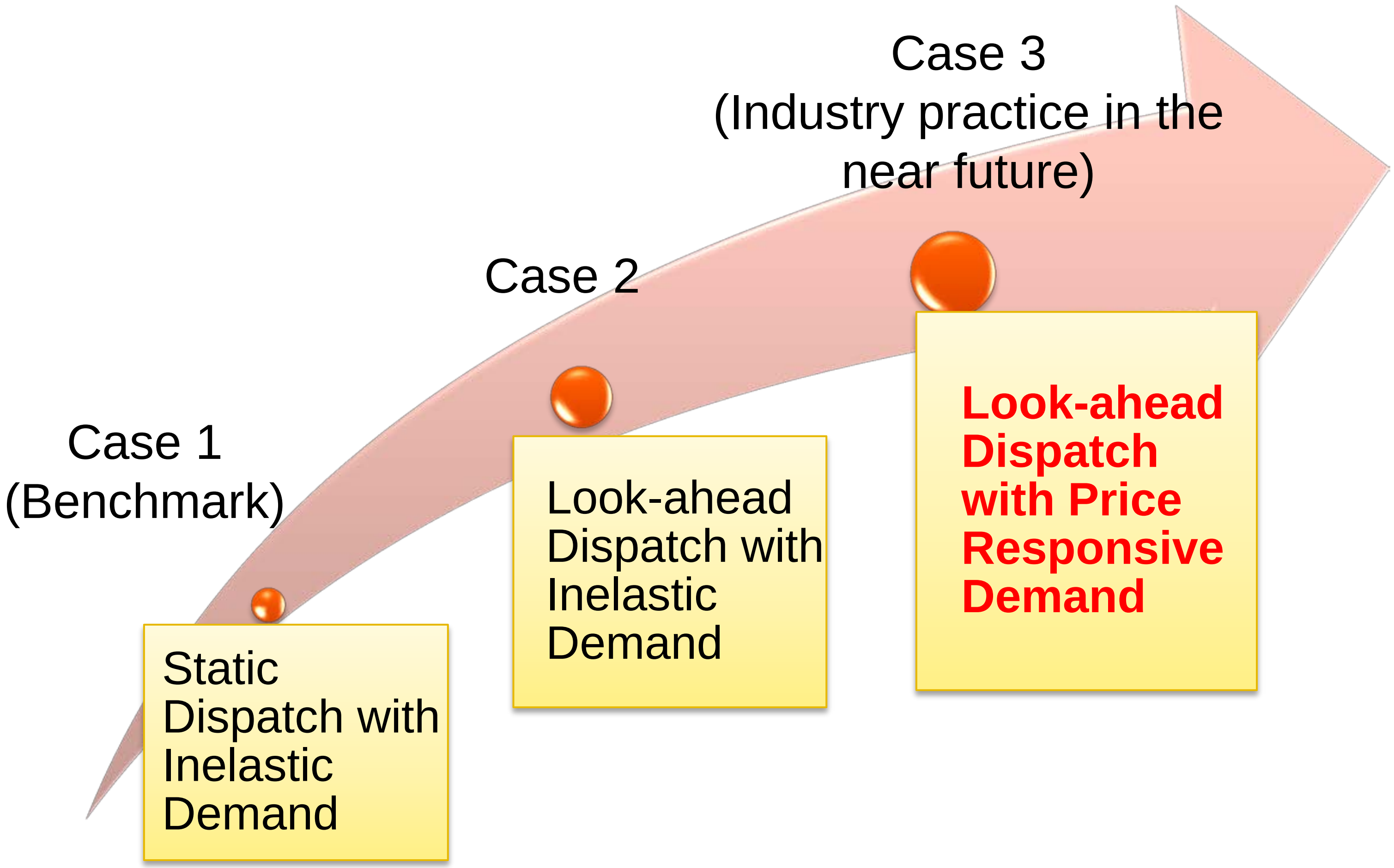
$$\sum_{i=1}^{96} b_i p_{id} + \sum_{i=1}^{96} \left[d_i f\left(W_{id}\right) + \theta F_k + U_{ikd}\right] p_{id}$$

But, does signing TVP contracts lead to substantial demand response? (cont'd)

- Econometric estimation generates "substitution matrix" that is fed into look-ahead dispatch model
- Qualitative result: very little demand response
  - Illustration:



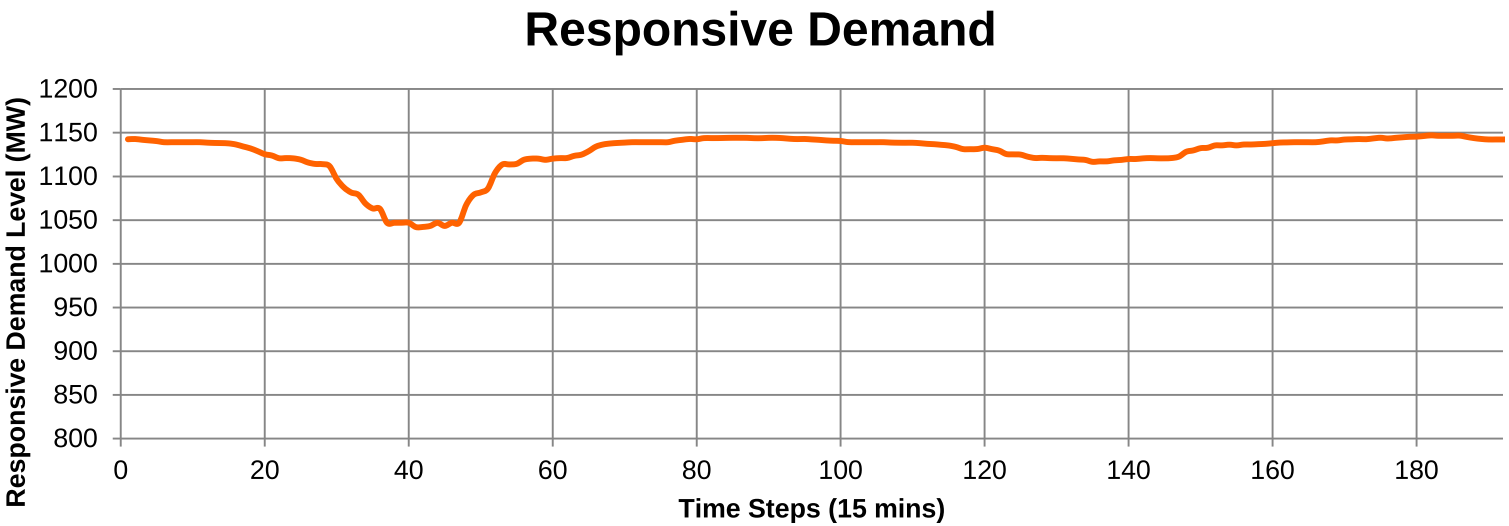
Quantifying Benefits of DR and Look-ahead Dispatch in ERCOT

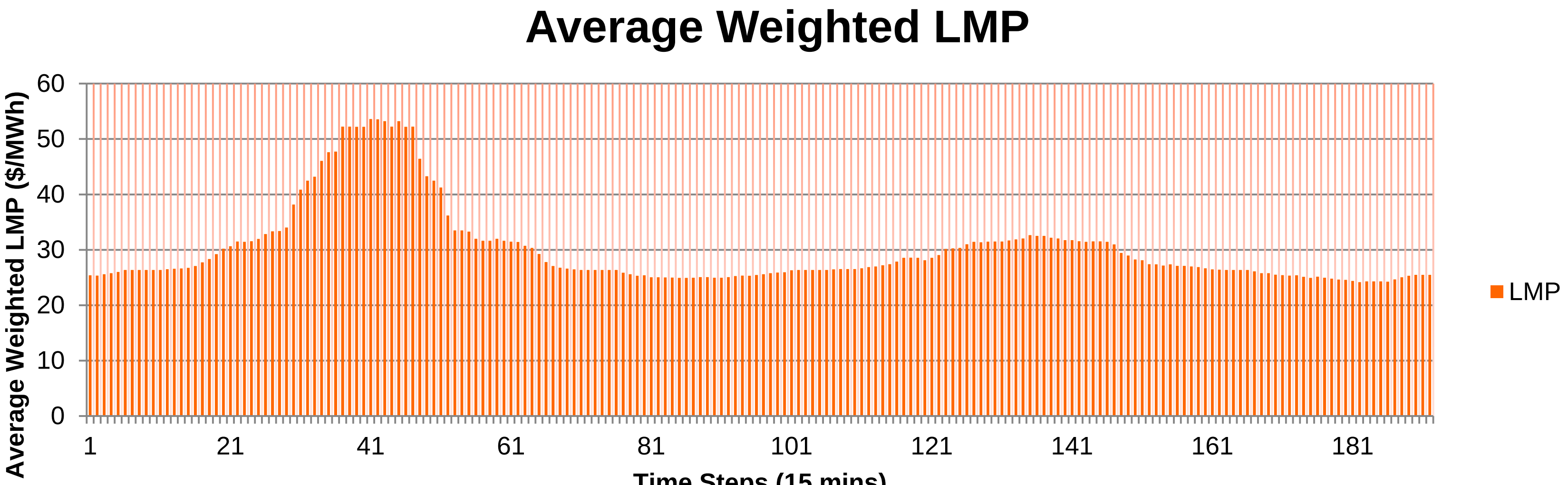


System Setup for Elastic Demand

- 5.96% of the ERCOT demand is considered as elastic
- The demand elasticity comes from the study of thousands of C&I firms (Task 1)
- The elastic demand is evenly distributed in the Houston zone
- The benefit function is scaled according to PUC of Texas annual rate report.

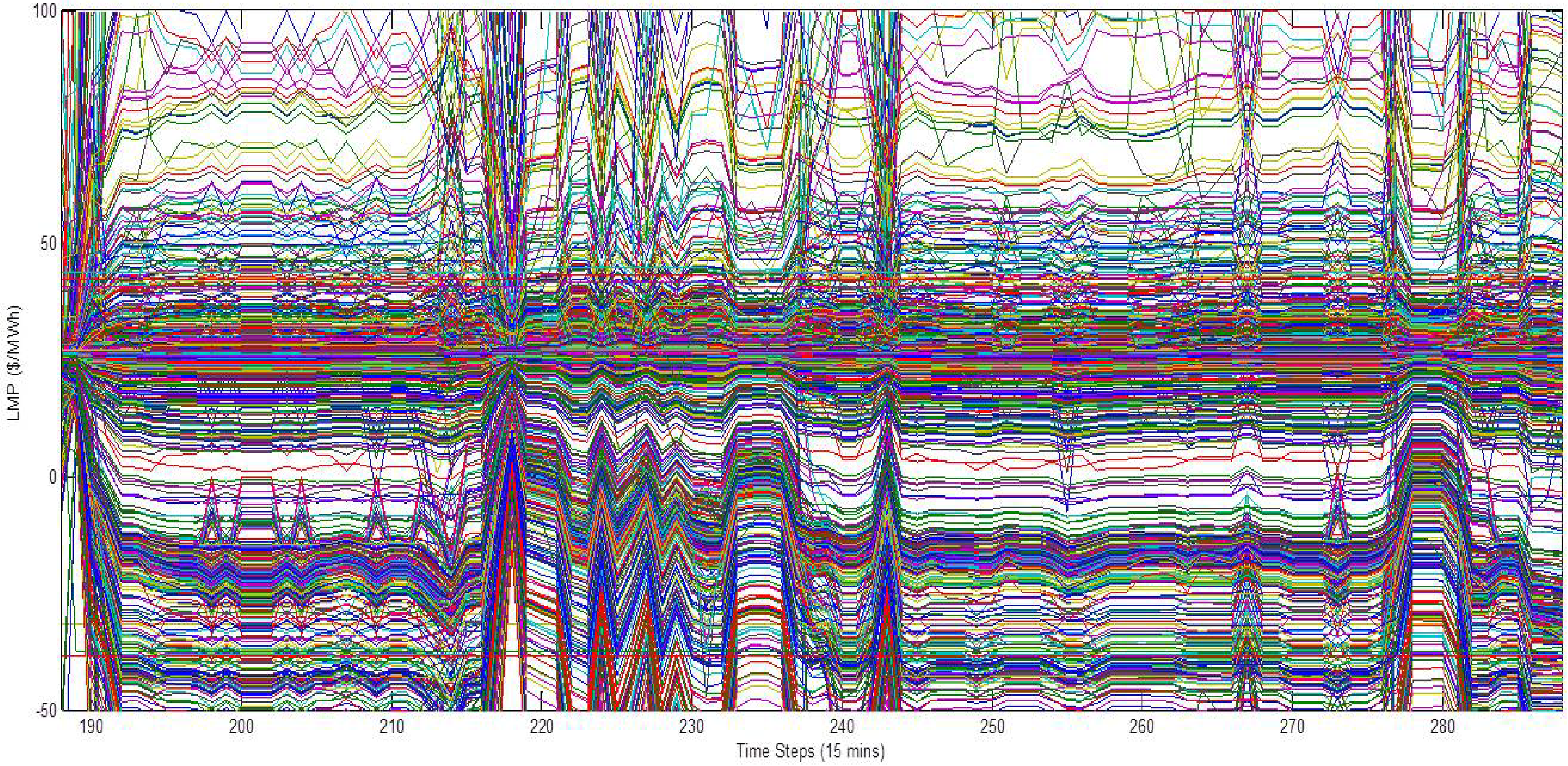
Price Responsive Demand





Market Behavior: LMP Patterns

Nodal Market Clearing Price Pattern



Economic Benefits:
Elastic versus Inelastic Case

(2008 Whole Year)

	Elastic Case + Look-ahead (What We Propose) (Million Dollars)	Benchmark (Million Dollars)	Ratio (%)
Generation Cost	$ 4,816.62	$ 4,808.72	0.16%
Total Demand Surplus	$ 15,618.45	$ 14,479.17	7.87%

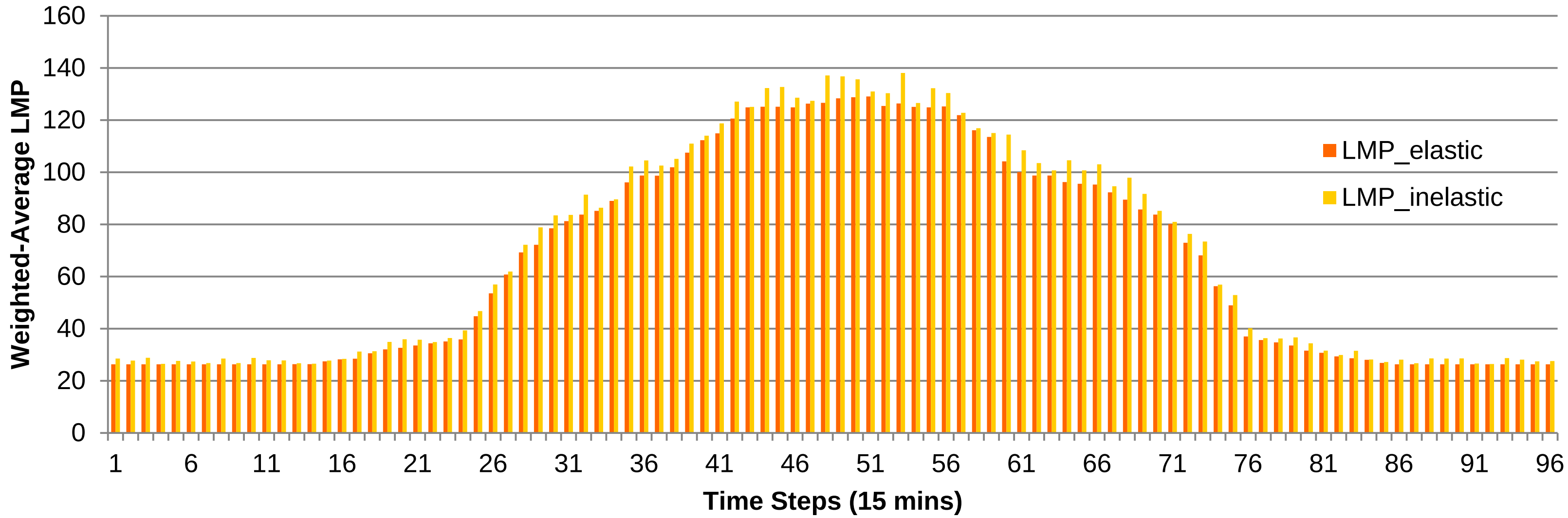
Market Behavior: LMP Patterns

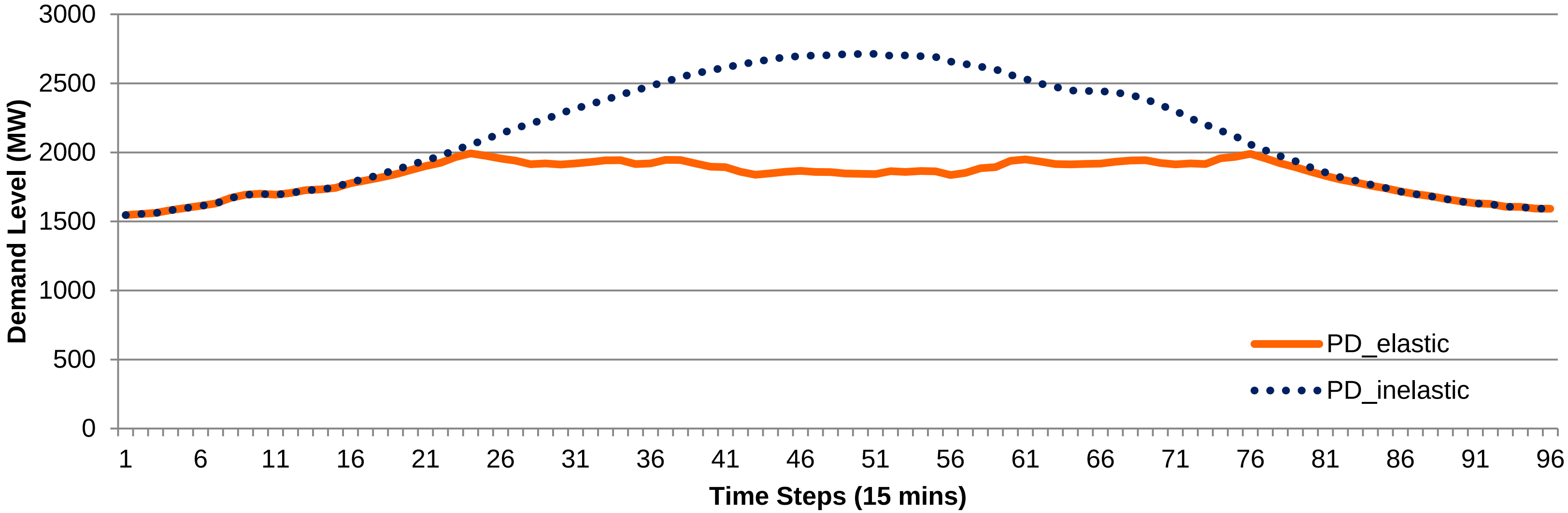
Standard Deviation of the LMPs: Impacts due to demand elasticity

	Elastic	Inelastic	Difference
Temporal LMP STD	63098.9	72567.7	13.05%
Spatial LMP STD	985466.3	1103669	10.71%

Introducing Elastic Demand Reduces Price Volatility

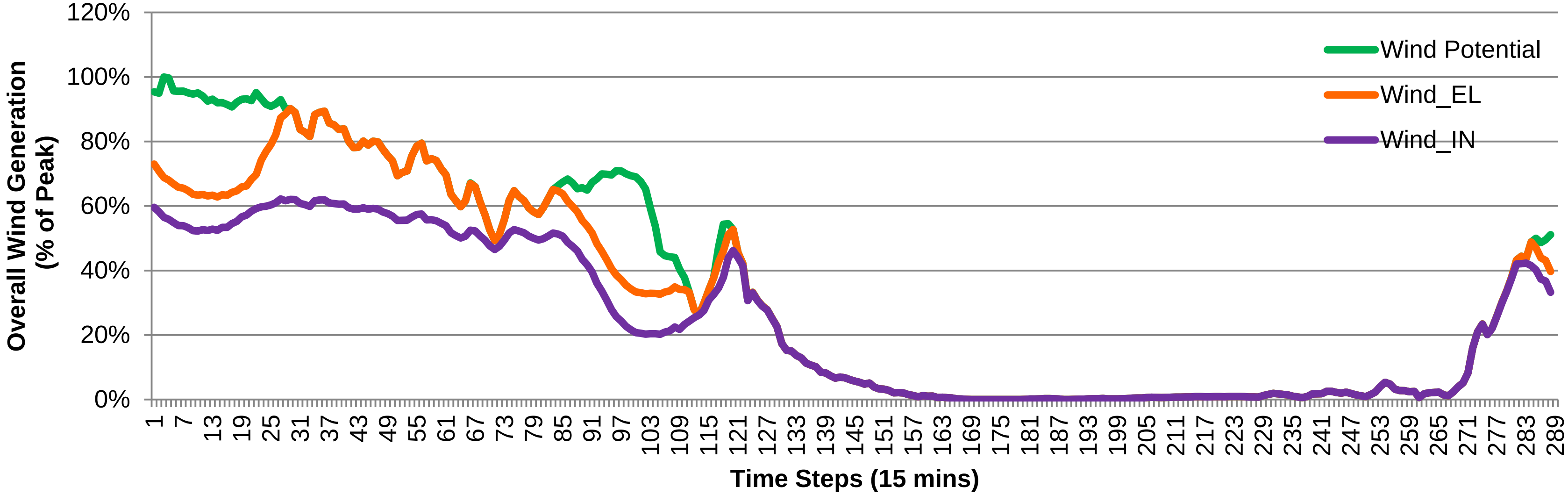
Summer Case

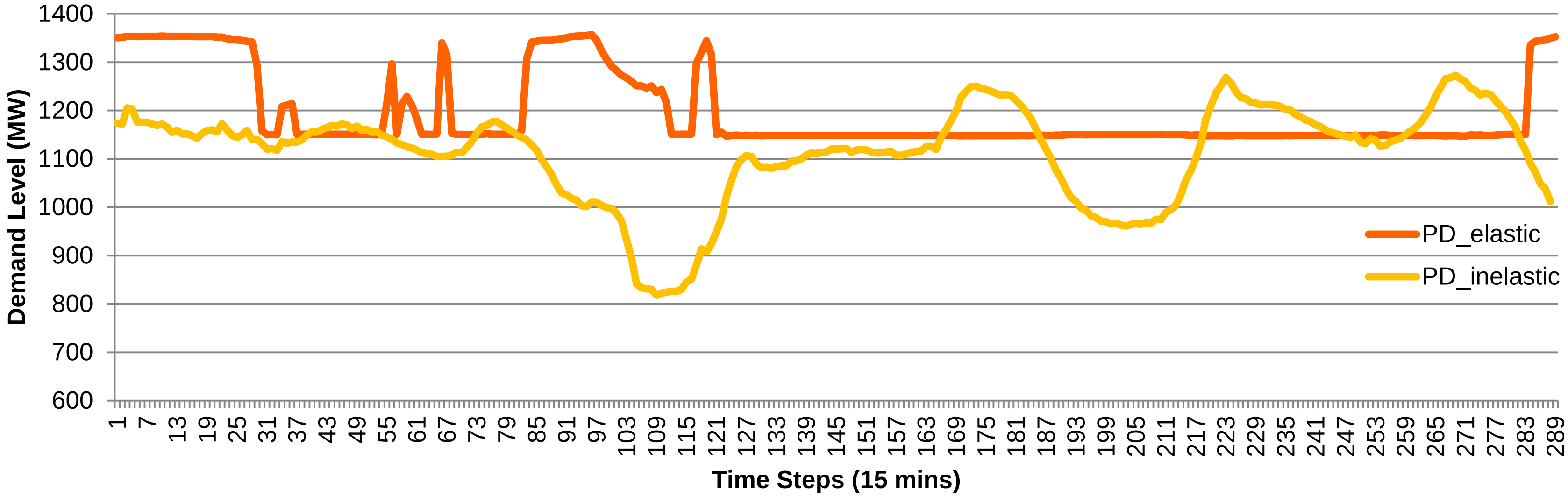




Introducing Elastic Demand Reduces Peak Load

Heavy Wind Case





Elastic Demand Could Increase Renewable Utilization

Summary

- We have developed simulation platform to analyze look-ahead dispatch in a realistic system (ERCOT)
- Demand elasticity is quantified empirically using realistic C&I data
- ERCOT-scale look-ahead dispatch with elastic demand is conducted to quantify the benefits
- Future work:
  - Quantifying inter-temporal demand shift
  - Fundamental coupling between look-ahead, elastic demand, and price volatility.
  - Price-based v.s. incentive-based demand response

Selected References

- [1] L. Xie, P. M. S. Carvalho, L. A. F. M. Ferreira, L. Juhua, B. H. Krogh, N. Popli, and M. D. Ilić., “Wind integration in power systems: Operational challenges and possible solutions,” *Proceedings of the IEEE*, vol. 99, no. 1, pp. 214–232, 2011.
- [2] Y. Gu, and L. Xie, "Early Detection and Optimal Corrective Measures of Power System Insecurity in Enhanced Look-Ahead Dispatch," *Power Systems, IEEE Transactions on* , vol.28, no.2, pp.1297,1307, May 2013.
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Thank You!

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Backup Slides

Dynamic Look Ahead Dispatch

Return

$$\max : \sum_{k=k_0}^{T} \sum_{i \in G} C_i^G \left(P_{Gi}^k \right)$$

To minimize the overall generation costs

$$\sum_{i \in G} P_{Gi}^k = \sum_{i \in D} P_{D_i}^k \,,\; k = k_0, \cdots, T$$

Energy Balancing Equations

$$\sum_{i \in G} P_{SUi}^k \geq SU_D^k \,,\; k = k_0, \cdots, T$$

$$\sum_{i \in G} P_{SDi}^k \geq SD_D^k \,,\; k = k_0, \cdots, T$$

Upward/Downward Short Term Dispatchable Capacity (STDC) Requirement

$$\left| \boldsymbol{F}^k \right| \leq \boldsymbol{F}^{\max} \quad k = k_0, \cdots, T$$

Branch Flow Constraints

$$-P_{Di}^R \leq \frac{1}{\Delta T} \left(P_{Gi}^k - P_{Gi}^{k-1} \right) \leq P_{Ui}^R \,,\; i \in G, \; k = k_0, \cdots, T$$

Generators' Ramping Constraints

$$P_{Gi}^k + P_{SUi}^k \leq P_{Gi}^{\max} \,,\; k = k_0, \cdots, T$$

$$P_{SDi}^k - P_{Gi}^k \leq -P_{Gi}^{\min} \,,\; k = k_0, \cdots, T$$

Generators' Capacity Constraints

$$P_{Gi}^{\min} \leq P_{Gi}^k \leq P_{Gi}^{\max} \,,\; k = k_0, \cdots, T$$

Generators' Output Constraints

$$0 \leq P_{SUi}^k \leq P_{Ui}^R \Delta T \,,\; k = k_0, \cdots, T$$

$$0 \leq P_{SDi}^k \leq P_{Di}^R \Delta T \,,\; k = k_0, \cdots, T$$

Upward/downward Generators' STDC

Quantification of Inelastic Demand Benefits

The benefits values reported for the inelastic portion of the demand is based on the assumption that retail electric customers are heterogeneous with different willingness to pay for energy given by the same demand elasticity of the customers belonging to the elastic portion. ([Sioshansi, 2010])