Flexible Demand Response in Smart Grid Supported Power Markets

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Smart Grid Session
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CISE

Outline

- Today's Electricity Grid: Physical and Cyber Components
- Power System Idiosyncrasies: AC, Synchronization, Stability requirements: Markets and commodities
- Synergy amongst Renewable Generation and Flexible Distributed Loads and Resources:
  - EV & Storage-like Distributed Loads may Mitigate Renewable Generation Volatility and Intermittentcy
  - Distributed Resources Entering the Stage Can be put to Dual Use (e.g. power electronics/converters, variable speed rotating motors)
- New Market Clearing Paradigms: Uniform and Complex Bids, an Evolution towards Effective Demand Response.
- Data and Computational Requirements
- Numerical Experience Foreshadowing Power System Evolution.
- Open Research Issues

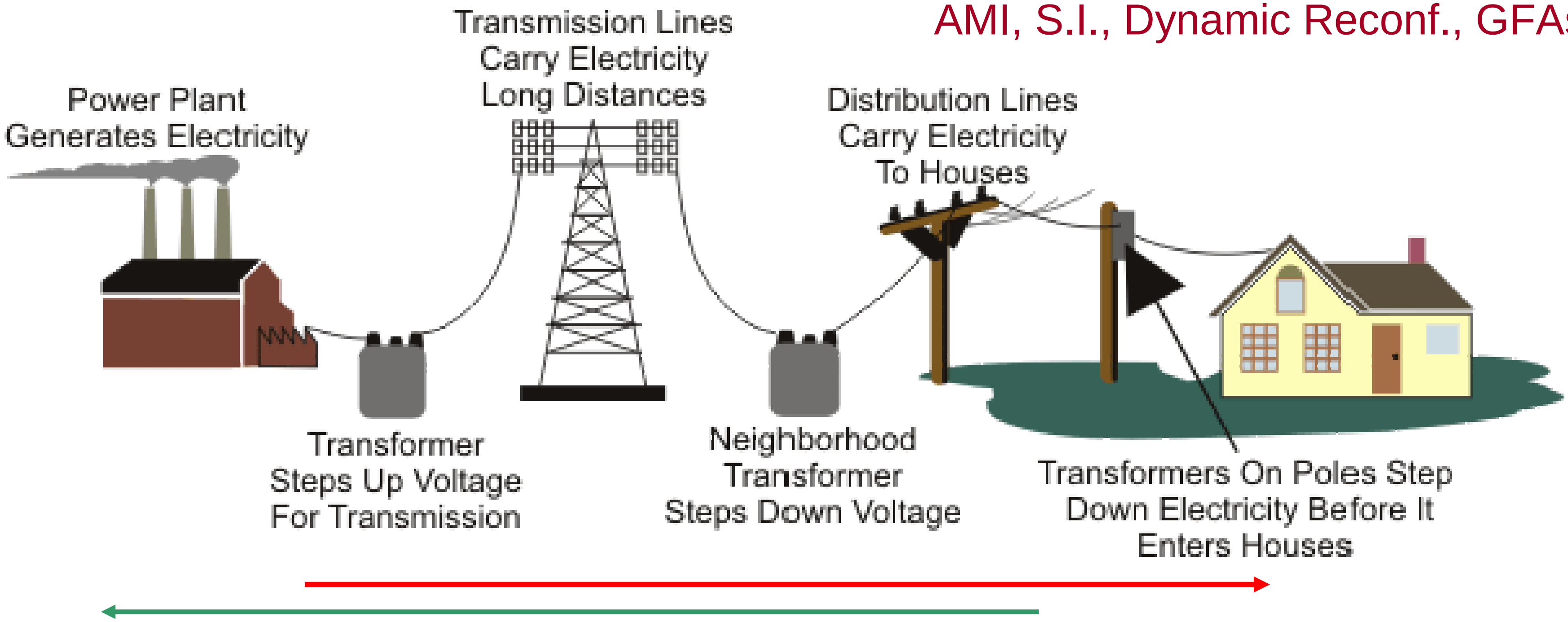
Need to Address T <u>and</u> D Costs!

Overview of Unbundled Cost of Electricity: Averages

60%: Cyber √ Market √

5%: Cyber √ Market √
SCADA→PMU+

35%: Cyber ? Market ?
AMI, S.I., Dynamic Reconf., GFAs,..



1. Direction of Power Flow no Longer Unidirectional!
2. "Cyber" Smart Grid Investments Can Reduce EACH Cost Component INCLUDING Distribution!

Cyber Components of Smart Grid

Examples of Existing Cyber Capabilities:

- AGC Automatic Generation Control
- SCADA Supervisory Control and Data Acquisition
- Autonomous Circuit Breakers (2mill in NE)
- Phase Shifters (expensive)
- Dynamic Var Compensators (Voltage Support/Power Factor Comp)
- Power System Control Center/ISO

Examples of Emerging Cyber Capabilities

- -PMU Phasor Measurement Unit (monitor Voltage and Current 30 times/sec)
- -AMI Advanced Measurement Infrastructure
- -SI System Identification, Situation Awareness
- -GFA Grid Friendly Appliances (FAPER, Dual Use of Power Electronics,…)

Idiosyncrasies of Power System

- Alternating Current (AC) Generation is Interconnected through the Grid => All Generators Must be Continuously Synchronized at 60Hz (cycles/sec).
- Small Synchronization Tolerance (± 0.2 Hz) Requires Adherence to instantaneous Energy Balance.
- Power Flow over Lines based on Laws of Physics => Out of Merit Congestion Costs

Transmission Network/Wholesale Power Market => Economies of Scale, BUT, Fast Reserves Required for System Stability/Integrity

Fallacy of Instantaneous-Price-Only Market Orthodoxy?

Given Uncertainty in Demand Response to Instantaneous –rather than trajectory -- Price signals, System Stability is secured by:

1. Planning/Scheduling Generation & Demand and
2. Procuring Fast Reserves in Short term forward markets including (ex ante Day ahead & hour ahead, ex post 5 minute for reconciliation of differences)

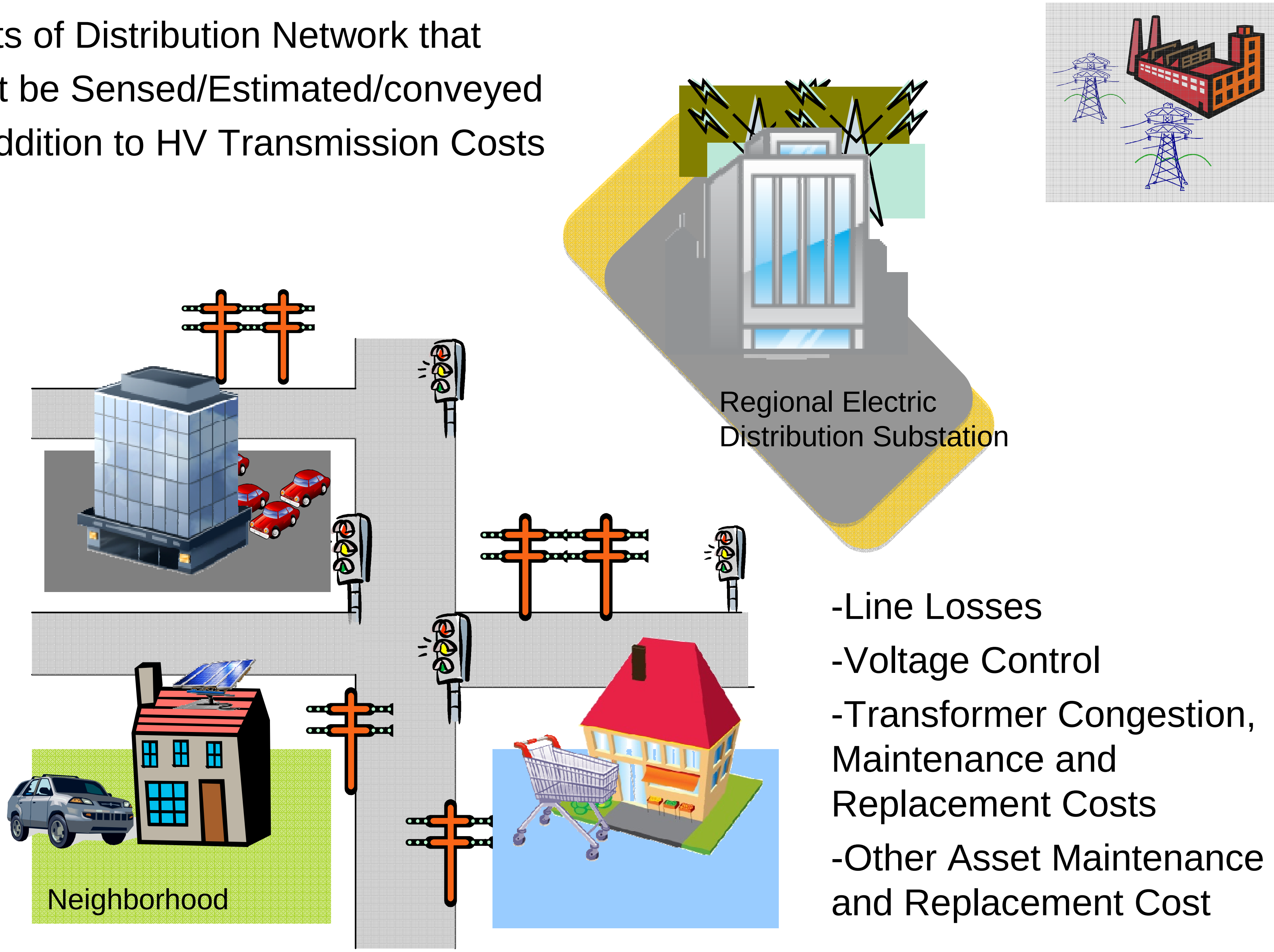
-Transmission Reserves for Transmission Failure Contingency Planning

-Gen. Capacity Reserves

- Primary/Freq Control: ~0.1% of peak today, bidirectional (up/down), Automatic freq. response, Must be capable of 100% delivery in 30 sec.
- Secondary/Regulation:~1% of peak today → 4-5% with heavy wind integration, Bidirectional (up/down), Control Center command triggered, Must be capable of 100% delivery in 2-5 minutes
- Tertiary : Unidirectional, up only), Scheduled by Control Center, Must be capable of 100% delivery in 15 minutes.

Indeed Markets Have Been Formed to Clear Energy AND Reserves Simultaneously with ISO Managing them in R-T!

Costs of Distribution Network that
Must be Sensed/Estimated/conveyed
In Addition to HV Transmission Costs

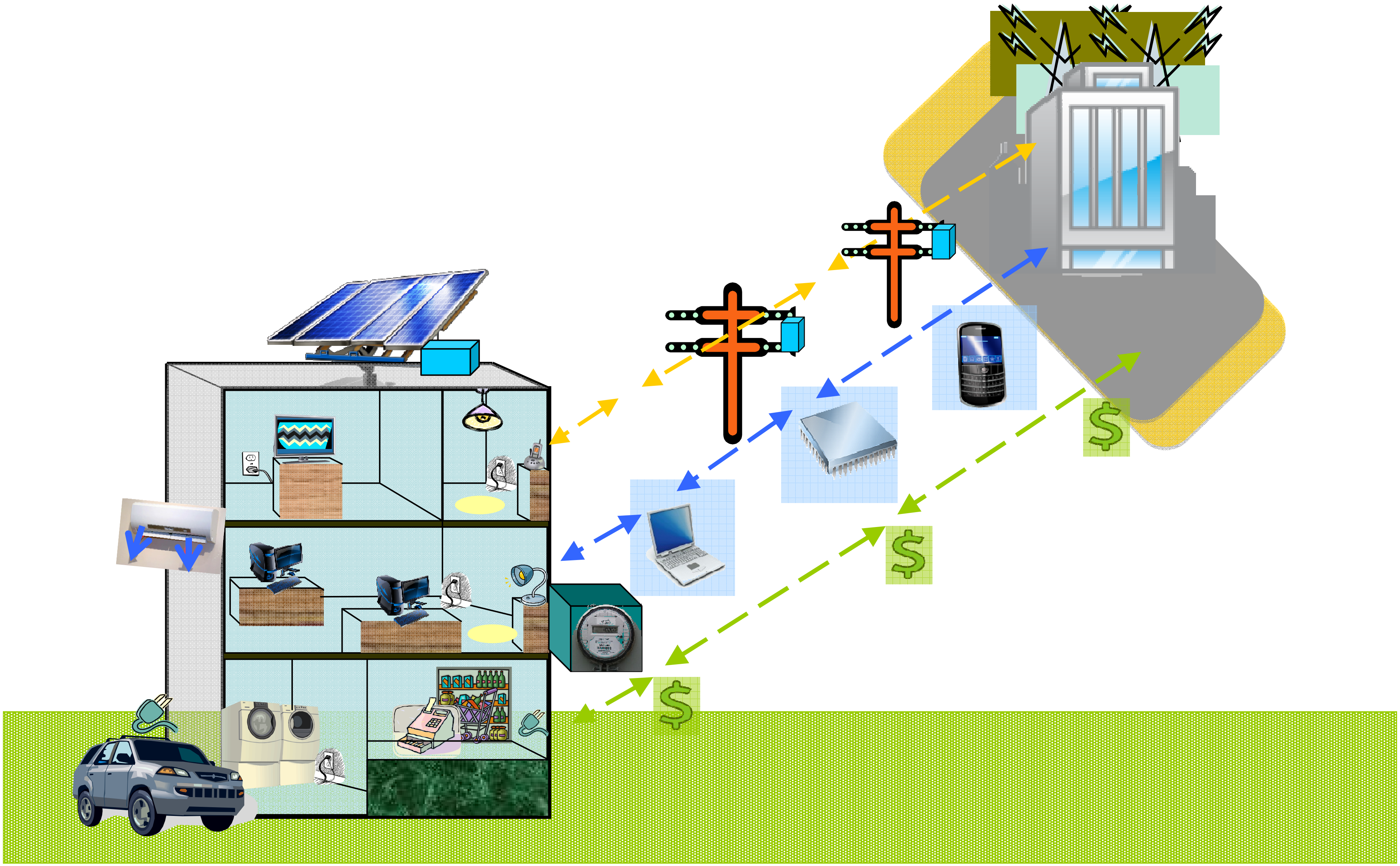


-Line Losses

-Voltage Control

-Transformer Congestion, Maintenance and Replacement Costs

-Other Asset Maintenance and Replacement Cost



Obvious Smart Grid Contributions

- Decrease Black Out Likelihood: How? By rendering Power system More Stable.
- Decrease Congestion Cost: How? Reconfigure Network topology or control Tr. Line electrical properties
- Decrease Distribution O&M: How? Anticipate asset failure, Reduce ware and tear, Remote monitoring of consumption and electric service level management.
- Increase Resilience of T&D System to load growth and Renewable Integration. How? Same means as above.

However, Contribution is Marginal under Business as Usual on the Demand Side!

Potential Smart Grid Contributions

- Enable Load Side and Distributed Resources to Become Responsive to System needs and thus realize their SIGNIFICANT potential to decrease costs
- Realize System-Integration-Based Value Adding Opportunities that Exist already or will Avail themselves in the near future as Distributed Generation, EV, and other Distributed Resources.

Issues with Wind Generation

- Due to its intermittency, full harvesting of wind generation requires additional reserves! (~5% to 10% of installed wind capacity)
- To meet 20-25% of Load (≈EV load), Wind Generation must represent 40-50% of installed capacity.
- This will increase Reg. Res requirements from 1% today to 3-5% of load!
- Potentially prohibitive cost implications – at current cost of $20-80 per MW per hour. *Unless Supply of RS Increases*.

Issues with Mass Adoption of Hybrid Electric Vehicles (EVs)

- Cost of hybrid vehicles is approaching competitiveness with oil powered vehicles
- BUT Congestion issues loom: Are T&D and Reserve Capacity Sufficient?

Synergy of Renewable Wind Generation EV Battery Charging and Distributed Sources

Dynamic Spatio-temporal Information on

- (i) Transmission System Energy and Reserve Prices and
- (ii) Distribution System State

Can Realize Synergies of Renewables with New Loads and Distributed Resources

OPPORTUNITY

- Utilize Smart Grid Capabilities to Enable Loads Connected at the Distribution Network, i.e. Moderate to Small Loads, to participate on a par basis with centralized Generation
- Is there reason to believe this is possible?

Power System: What is Really New on the Horizon?

- Renewable Generation: Clean BUT Intermittent and Volatile. However:
  - Forecast of Av. Hourly Wind Generation (day ahead vs hour ahead) possible with Cv 10%-2% => Tertiary Reserves
  - Shorter term Wind Generation Statistics, say Max-Min output=Range, => Secondary Reserves or Regulation service requirements.
- Distributed Resources: Generation, Storage, Demand Control (Load Aggregator ESCO), G.F.A.s (Appliance level control possibly supervised by LA), **and** Power Electronics as well as Synchronous Electr. Machines (e.g., heat pumps)
- Smart Grid => Significantly Enhanced:
  - Sensing/Measurement of Distribution network State ((i) line losses, (ii) distr. Asset congestion, (iii) voltage-current phase shift), (iv) customer side of meter Distributed Generation.
  - Communication of Distribution Network State Information (TPA!)
  - Intelligent Control for asset repair and Maintenance, Cost control, and Personnel Safety.

Power System Operations: Is a Paradigm Shift Inevitable?

Given:

- Considerable portion of Generation Capacity will be NON-Dispatchable
- Considerable Portion of Load will be Controllable/Dispatchable/Manageable

Is it Likely that: Load will Follow Generation as much as or more than Generation Follows Load today?

To be Useful and Effective, Demand Response Must be Enabled by Market Redesign

- Current Markets, In particular Day-Ahead markets that plan/hedge generation and consumption, Operate with Uniform Bids and Offers that **assume time Additive Utility** of Consumption and Cost of Generation in multi period markets:

Min $\Sigma_t\,[U(D_t)\text{-}C(G_t)]$ subject to reliability, capacity and congestion constraints

- But time additive decomposition of utility of demand is a Fallacy! Particularly for Flexible Loads! Why?

Utility is often a Function of State which may be Achieved by many Consumption Trajectories

- Example of EVs: Charge state of Battery at time of Departure is important utility determinant! Not time specific consumption.
- Example of Heating and Cooling: Building Temperature being within a comfort zone matters: Not exact consumption of energy during a specific period.
- Denoting the state at t by X_t we can clear the market by selecting D_t and G_t to:

Min $\sum_t [U(x_t)\text{-}C(G_t)]$ s.t. usual constr plus X_t dyns

Note: the same X_t can be derived from many D_τ trajectories $\tau \leq$ t.

Inter-temporal Coupling of Utility: Definitions

Market Participant Related Variables:

$G^{E}_{n_g,t}, G^{R}_{n_g,t}$ Conv. Dispatchable Generation/Reserves at node n, t

$D_{n_d,t}$ Conventional Inflexible Load at node n, time t

$\tilde{G}^{W}_{n,t}$ Random Variable of Wind Generation Potential at n, t

$Q^{E}_{n_i,t}, Q^{R}_{n_i,t}$ Flexible Load, Reserves at n_i, t

$R^{ContPlann}_{t} + R(\tilde{G}^{W}_{t})$ Reserve Requirements Associated with Conventional Contingency Planning and from Intermittent Wind

$\overline{G}^{W,\max}_{n,t}, \underline{G}^{W,\min}_{n,t}$ range of Wind output, $\overline{G}^{W,\min}_{n,t} \le \tilde{G}^{W}_{n,t} \le \underline{G}^{W,\max}_{n,t}$

$U(\bullet), C(\bullet)$ Additive across Time Utility, Cost functions

Participant related parameters Cont: Index notation:

n Transmission Node (Bus)

t Time period/hour

n_i Specific Location in Distribution net connected to Bus n

$\tilde{C}^{\max}_{n_i,t}$, $\tilde{m}_{n_i,t}$ Local Constraints and Marginal Losses factor

S indicates Market Cleared/Scheduled Quantities

$*$ indicates Participant selected Quantities

Why is Utility Not Time Additive?

n_i LA Dynamics, Local Constraints and Costs for **EV** Loads

$$x_{n_i,t+1}(\tau) = x_{n_i,t}(\tau) + \tilde{\Delta} x_{n_i,t}(\tau) - \tilde{m}_{n_i,t}[Q^E_{n_i,t}(\tau) + Q^R_{n_i,t}(\tau)]$$

$$\Sigma_\tau \tilde{m}_{n_i,t}[Q^E_{n_i,t}(\tau) + 2Q^R_{n_i,t}(\tau)] \leq \tilde{C}^{\max}_{n_i,t}$$

$$\tilde{m}_{n_i,t}[Q^E_{n_i,t}(\tau) + Q^R_{n_i,t}(\tau)] \leq x_{n_i,t}(\tau)$$

$$\text{when } x_{n_i,\tau}(\tau) > 0, \text{ we incure cost } M x_{n_i,\tau}(\tau)$$

Why is Utility Not Time Additive?

n_i LA Dynamics, Local Constraints and Costs for **HVAC** Loads

$$\Theta_{n_i,t+1} = \Theta_{n_i,t} - K_1(\Theta_{n_i,t} - \tilde{\Theta}^{\text{outside}}_{n_i,t}) + K_2 \tilde{m}_{n_i,t} [Q^E_{n_i,t} + Q^R_{n_i,t}]$$

$$\Sigma_\tau \tilde{m}_{i,t} [Q^E_{i,t} + 2Q^R_{i,t}] \le \tilde{C}^{\max}_{i,t}$$

$$\Theta^{\min}_{n_i,t} \le \Theta_{n_i,t} \le \Theta^{\max}_{n_i,t}$$

$$Q^E_{n_i,t} + 2Q^R_{n_i,t} \le \text{Cons. capacity of HVAC}$$

Whole Sale Market: Uniform Bids

A1. Load Aggregator/Flexible Demand Day Ahead:

- Given pdf

$$f_{\boldsymbol{\lambda}^E,\boldsymbol{\lambda}^R}(\boldsymbol{\lambda}^E,\boldsymbol{\lambda}^R), \quad \boldsymbol{\lambda}^E = [\lambda_1^E,\lambda_2^E,\ldots,\lambda_{24}^E], \boldsymbol{\lambda}^R = [\lambda_1^R,\lambda_2^R,\ldots,\lambda_{24}^R]$$

Determine Prices-Quantities $Q^E_{n_i,t}, u^E_{n_i,t}; Q^R_{n_i,t}, u^R_{n_i,t}$

(in order to bid a fictitious additive utility)

To Minimize

$$\sum_{n_i,t} E[\boldsymbol{\lambda}_t^{E\ S} Q^E_{n_i,t} - \boldsymbol{\lambda}_t^{R\ S} Q^R_{n_i,t} + \text{State Dep. Costs, e.g. } Mx_{n_i,\tau}(\tau)]$$

Subject to Forecasted Local Constraints and Dynamics of LAs shown in two previous Slides.

from market operator

to market operator

Whole Sale Market: Uniform Bids

A2. Wind Generation Bids Day Ahead:

- Given pdf

$$f_{\boldsymbol{\lambda}^E,\boldsymbol{\lambda}^R}(\boldsymbol{\lambda}^E,\boldsymbol{\lambda}^R), \quad \boldsymbol{\lambda}^E=[\lambda_1^E,\lambda_2^E,\ldots,\lambda_{24}^E], \boldsymbol{\lambda}^R=[\lambda_1^R,\lambda_2^R,\ldots,\lambda_{24}^R]$$

Determine Prices-Quantities $G_{n,t}^W, u_{n,t}^W$

(in order to bid a fictitious additive utility)

To Maximize

$$\sum_{n_i,t} E[\boldsymbol{\lambda}_t^E\,{}^S G_{n,t}^W - \boldsymbol{\lambda}_t^R\,{}^S \frac{\partial R^W(\mathbf{G}_t^W)}{\partial G_{n,t}^W}]$$

Subject to $\overline{G}_{n,t}^{W,\min} \le G_{n,t}^W \le \underline{G}_{n,t}^{W,\max}$

from market operator

to market operator

Whole Sale Market: Uniform Bids

A2. Wind Generation Bids Day Ahead (continued):

Solution Comments:

Optimal $G_{n,t}^{W}$ will satisfy

$$G_{n,t}^{W} = \bar{G}_{n,t}^{W,\min} \text{ if } \boldsymbol{\lambda}_{n,t}^{E}\, {}^{S}G_{n,t}^{W} - \boldsymbol{\lambda}_{n,t}^{R}\, {}^{S} \frac{\partial R^{W}(\mathbf{G}_{t}^{W})}{\partial G_{n,t}^{W}} < 0$$

$$G_{n,t}^{W} = \bar{G}_{n,t}^{W,\max} \text{ if } \boldsymbol{\lambda}_{n,t}^{E}\, {}^{S}G_{n,t}^{W} - \boldsymbol{\lambda}_{n,t}^{R}\, {}^{S} \frac{\partial R^{W}(\mathbf{G}_{t}^{W})}{\partial G_{n,t}^{W}} > 0$$

With singularity arrising when $\boldsymbol{\lambda}_{n,t}^{E}\, {}^{S}G_{n,t}^{W} - \boldsymbol{\lambda}_{n,t}^{R}\, {}^{S} \frac{\partial R^{W}(\mathbf{G}_{t}^{W})}{\partial G_{n,t}^{W}} = 0$

note: in general knowledge of the derivative requires knowledge of bids of all wind farms

Whole Sale Market: Uniform Bids

To LAs and Wind Gen

From Las and Wind Gen

B. Market Operator Day Ahead:

Given Wind and LA Quantities marked by * and Conv. Gen. and Dem. Bids,

Schedule:

$$D_{n_d,t}, G^E_{n_g,t}, G^R_{n_g,t}$$

to max:

$$\sum_{d,g,t} [U(D_{n_d,t}) - C^E_{n_g,t}(G^E_{n_g,t}) - C^R_{n_i,t}(G^R_{n_g,t})]$$

subject to

Energy Bal. $\sum_{n_i,n_d} {}^*Q^E_{n_i,t} + {}^*Q^R_{n_i,t} + D_{n_d,t} = \sum_{n,n_g} [G^E_{n_g,t} + {}^*G^W_{n,t}] \rightarrow \text{Dual Var } \boldsymbol{\lambda}^E_t$

Reserve Constr. $\sum_{n_i,n_g} [{}^*Q^R_{n_i,t} + G^R_{n_g,t}] \geq R^{ContPlann}_t + R({}^*\mathbf{G}^W_t) \rightarrow \text{Dual Var } \boldsymbol{\lambda}^R_t$

Plus Line Flow, capacity and other constraints

Nash Equilibrium and other Issues

- If LAs self schedule and each is big enough to affect clearing prices, Iterations shown above will generally NOT Converge! Unless… LAs know every participant's cost and "real" utility functions…
- What if more than one LA is associated with same local costs and constraints?
- What if multiple Load types are managed by one or more LAs? (HVAC and other flexible loads with non-negligible degrees of freedom are Qualitatively similar to EVs)
- Under reasonable regularity assumptions iteration converges if clearing price estimates adapt smoothly or approach price averages.

Whole Sale Market: Complex Bids

- LA Day Ahead (**Price taker EV example**):

Given $P(\mathbf{C}_{n_i}^{\max}, \Delta\mathbf{x}_{n_i}(\tau), \tilde{G}_{n,t}^{W})$

Bid Constr., Dyns Est. & Costs of each n_i LA: $\hat{C}_{n_i,t}^{\max}, \Delta\hat{x}_{n_i,t}(\tau), \hat{m}_{n_i,t}, Mx_{n_i,\tau}(\tau)$

to Minimize $\sum_{n_i,t} E[\boldsymbol{\lambda}_t^{E\ S}Q_{n_i,t}^{E} - \boldsymbol{\lambda}_t^{R\ S}Q_{n_i,t}^{R} + \text{State Dep. Costs, e.g. } Mx_{n_i,\tau}(\tau)$

Subject to Forecasted Local Constraints and Dynamics of Affiliates

- Market Operator Day Ahead:

Given Conventional Gen., and Dem. Constr & Bids, plus LA & Wind Constr.

Select $D_{n_d,t}^{E}, Q_{n_i,t}^{E}, Q_{n_i,t}^{R}, G_{n_g,t}^{E}, G_{n_g,t}^{R}, G_{n,t}^{W}$

to maximize $\sum_{d,g,i,t} [U(D_{n_d,t}) - C_{n_g,t}^{E}(G_{n_g,t}^{E}) - \sum_{\tau} Mx_{n_i,\tau}(\tau)]$

s.t. En. Balance $\sum_{n_i,n_d} Q_{n_i,t}^{E} + Q_{n_i,t}^{R} + D_{n_d,t} = \sum_{n,n_g} [G_{n_g,t}^{E} + \tilde{G}_{n,t}^{W}] \rightarrow \text{Dual Var } \boldsymbol{\lambda}_t^{E}$

Reserve Constr. $\sum_{n_i,n_g} [Q_{n_i,t}^{R} + G_{n_g,t}^{R}] \geq R_t^{ContPlann} + R(\mathbf{G}_t^{W}) \rightarrow \text{Dual Var } \boldsymbol{\lambda}_t^{R}$

and usual line flow and cap constraints plus LA and Wind constraints

Whole Sale Market: Complex Bids Cont.

Is this a better Solution? Relative to iterative Solution?

Convergence and Price Forecast not an Issue!

Price Manipulation possible but will it be desirable?

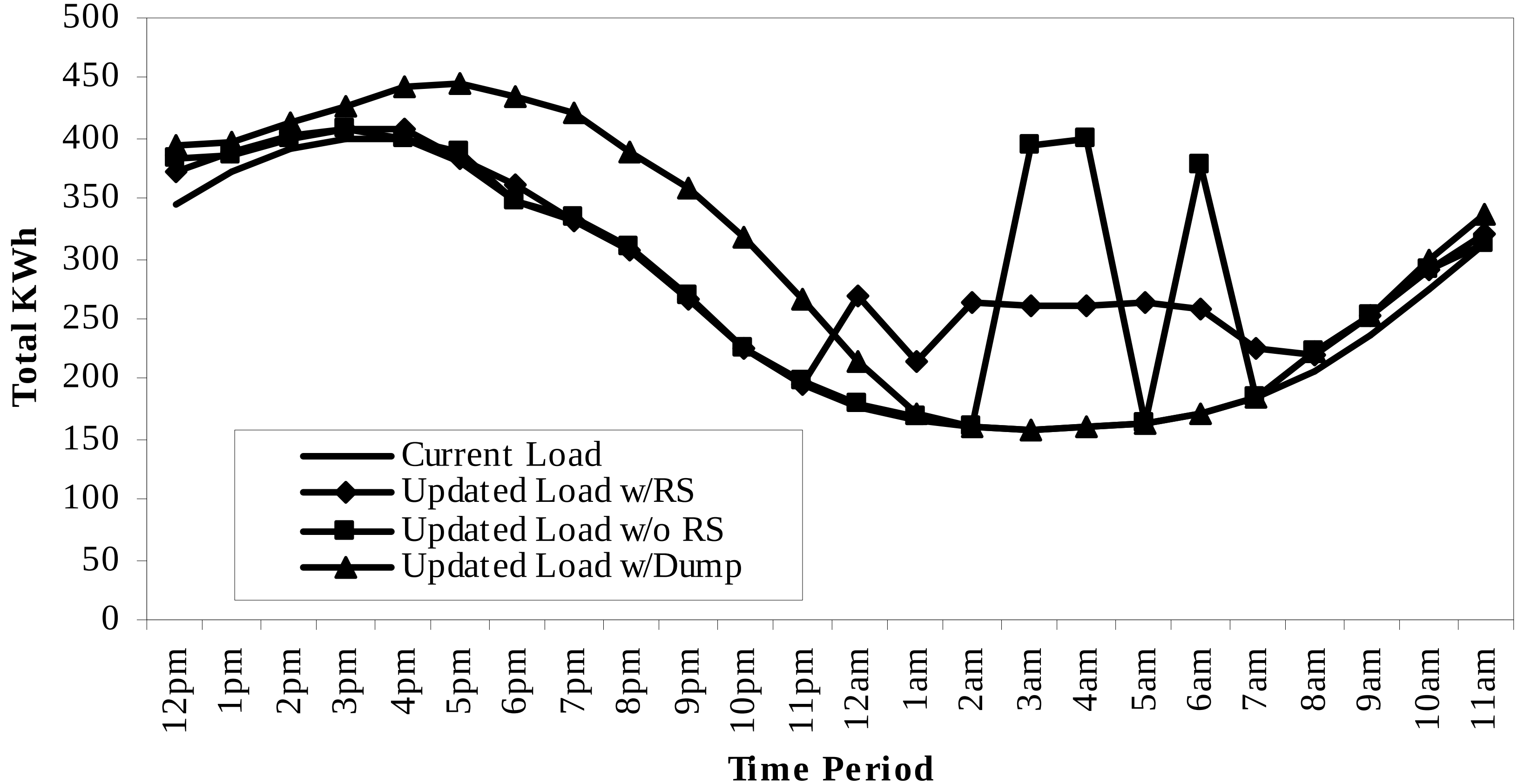
Singularities Arising in Wind Generation Bid determination Not an Issue

Is Complex Bid based Whole Sale Market clearing computationally Tractable?

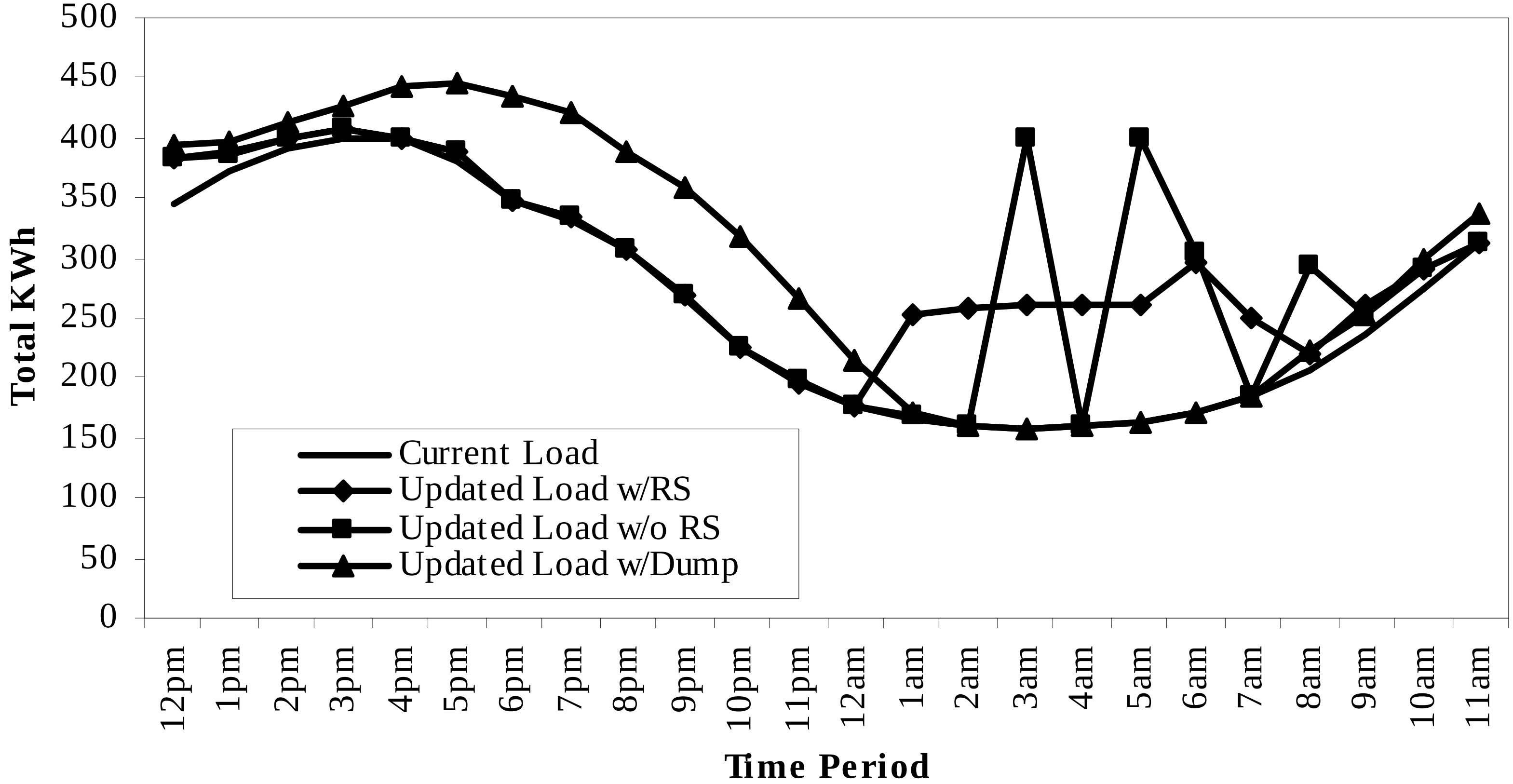
Uniform vs Complex Bids

- Uniform bids are appropriate when utility/cost of Consuming/Generating Q_t, G_t is additive in t and is not affected by inter-temporal considerations
- Complex Bids are appropriate when the utility/cost is dependent on a non time-additive function of hourly consumption or generation, and moreover, if the possible consumption or generation depends on inter-temporal constraints.
- The complex bid concept can be extended to Wind generators who bid energy AND their cumulative forecast error characteristics. These characteristics can determine the additional reserves made necessary by the cumulative wind offers, taking into consideration dependencies across wind farms. The resulting clearing price for reserves would then be used to assess a charge on wind generators as a whole. Individual wind farms could then be assessed their individual share to this cost on the basis of a reasonable criterion, for example, their statistically estimated marginal contribution to the res. requirements. Note that a wind farm bidding conservatively against its forecasted output will have a lower marginal contribution. The combination of marginal contribution estimates and the market determined clearing price for reserves is an efficient tool for <u>taxing</u> wind based on a market based price discovery. It goes without saying, however, that the wind output forecast error process will have to be transparent, fair and previously agreed upon by all parties.

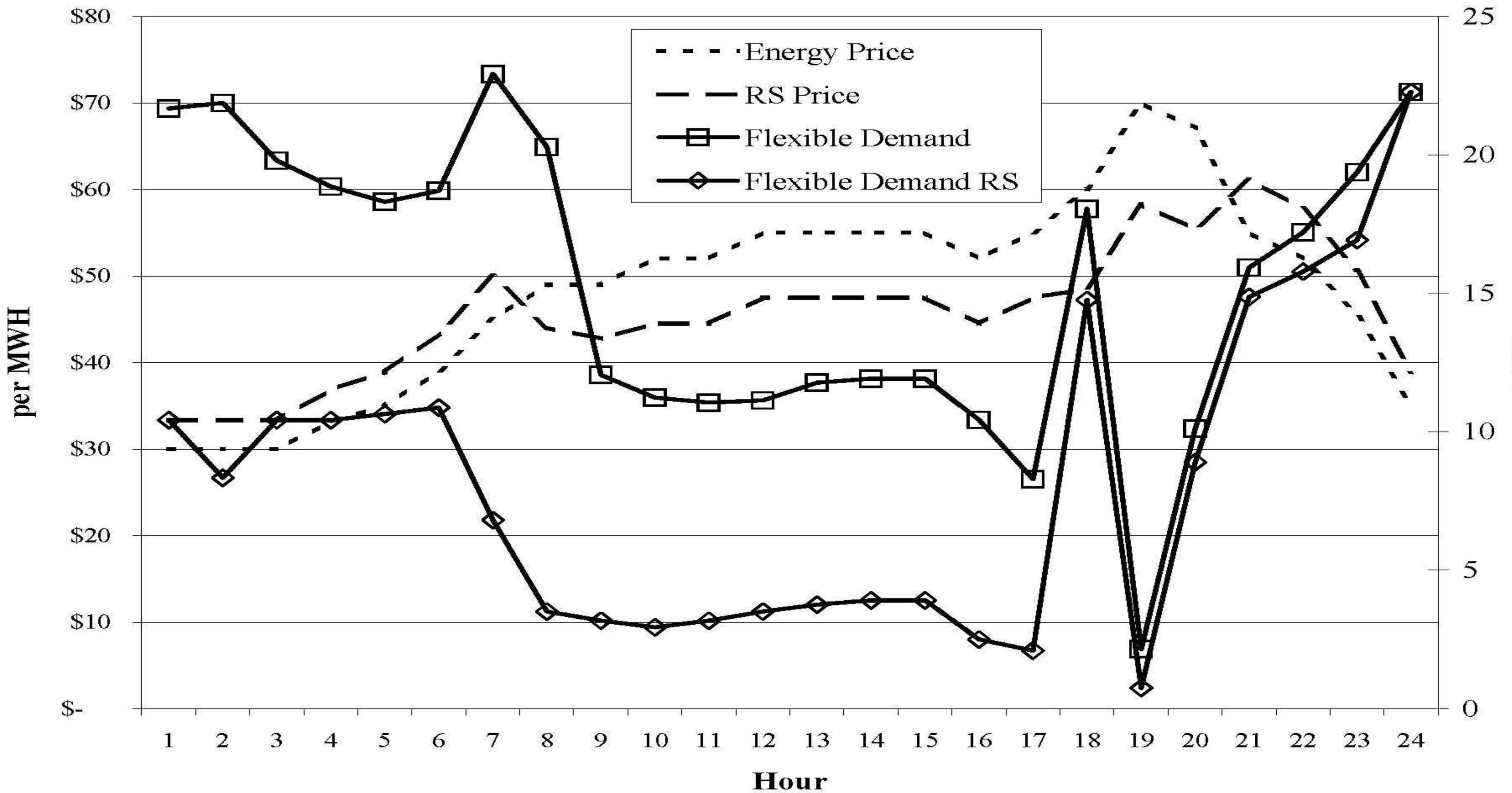
Numerical results ERCOT Data for Inter-temporally Coupled Utility Model



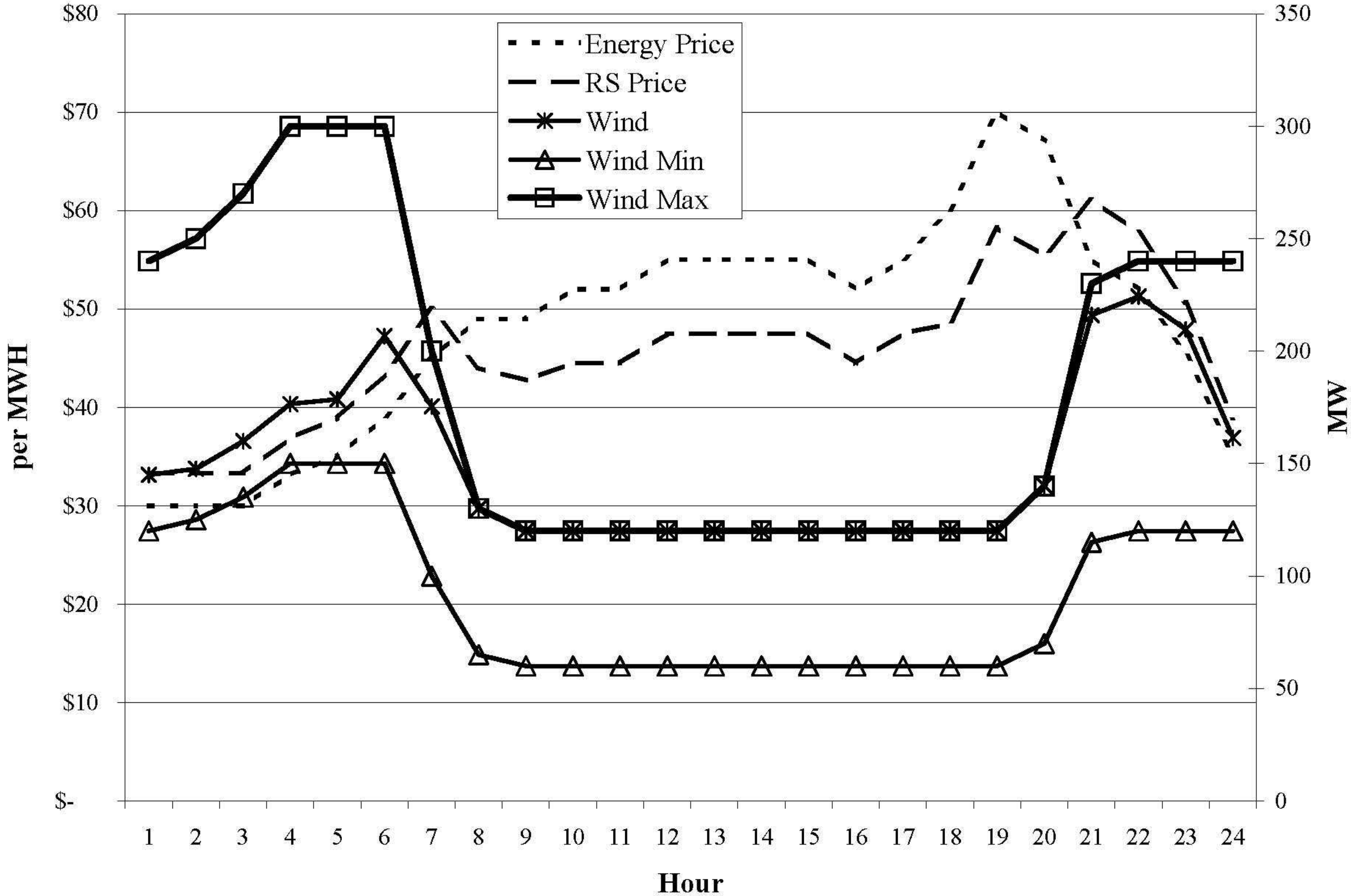
Numerical results CAISO Data for Inter-temporally Coupled Utility Model



Example of Flexible Demand Energy Consumption and Reserves Offered versus Clearing Prices Synthetic Data



Wind Bids versus Clearing Prices



Optimal Market Participation of Loads: Info and Comp. Requirements - Research Issues

- Retail Markets must be developed to price: **1.** Losses, **2**. Reactive Power, **3**. Transformer/Asset Capacity Utilization
- Whole Sale Markets and Complex Bids: Can we Handle Large Numbers of Load Aggregators? (Italian ISO Lessons)
- Aggregation of Loads in Complex Bids.
- Robust Selection of Local Load Dynamics and Constraint Estimates in Day Ahead Market Bids
- Hour Ahead Markets. LA-Neighborhood Affiliate Interaction.
- Event Scheduler/Physical Layer for Safe implementation of Demand Response. Design and Implement CPS Infrastructure!
- Wind Bidding: To Pay cost of Requisite Reserves, Need Forecast Marginal Contribution to System Reserve Requirements.
- Redesign Power Electronics & Other Resources for Dual Use and Implement Information Communication for Distributed Control.

Multi-Disciplinary Approach Required

- Power Engineering
- Finance, Risk Management, Contract Design
- Regulatory Economics
- Information Technology
- Cyber Physical Interface
- Decision Support, OR, Information Communication, Stochastic Control, etc.
- Social Science and Human Behavior
- Organizational Behavior
- Climate/Environment Science

Thank you!

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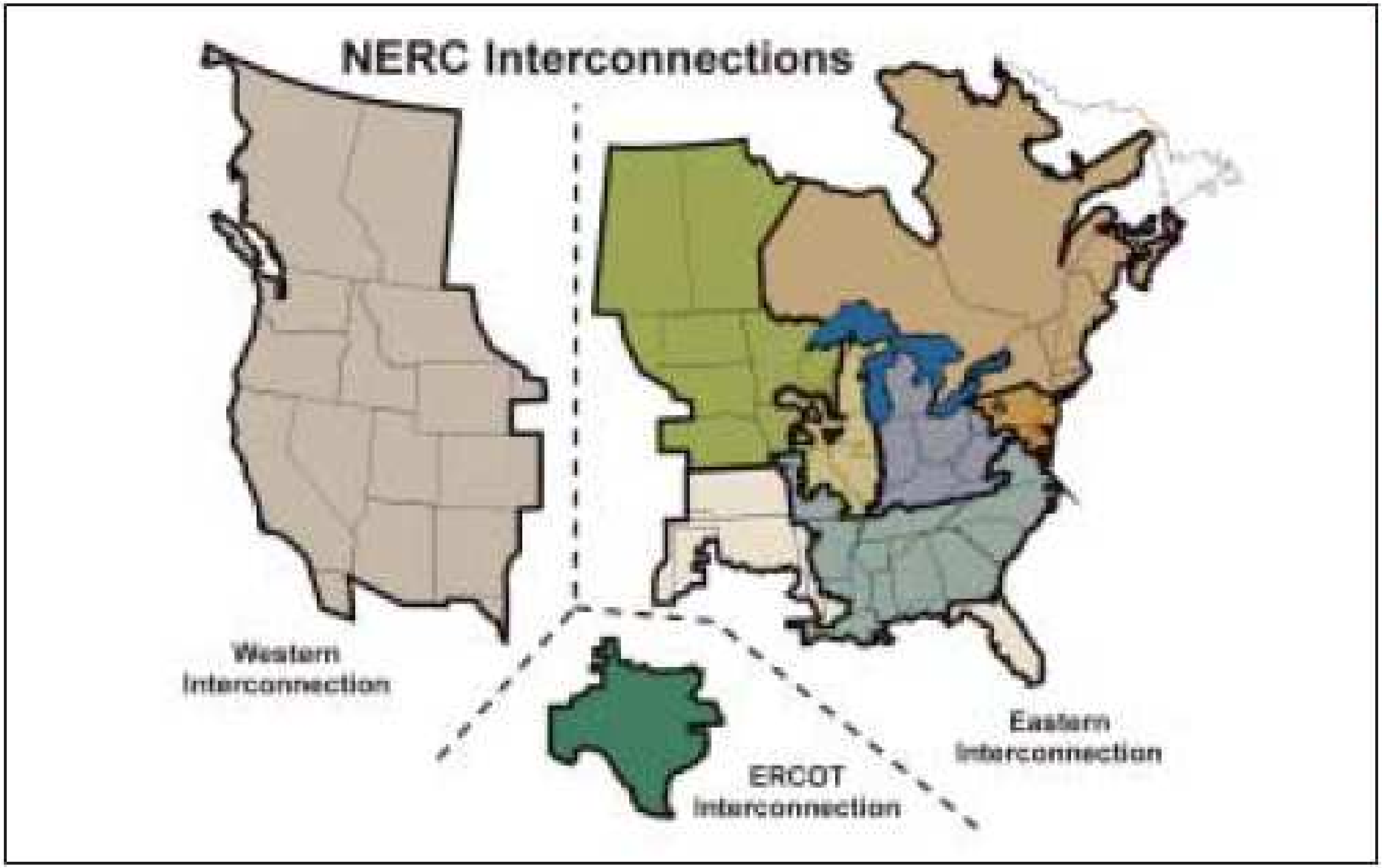
APPENDIX

Feel Free to Disregard the Slides that Follow! They

Contain a more detailed exposition of markets, including the interaction of day ahead and retail markets as well as LA-Neighborhood affiliate interactions

Note that Market Clearing Prices for Energy and Reserves are obtained with energy and reserves Co-optimized, in other words, energy and reserves Clear in a simultaneous Auction of Energy and Reserve Bids and Offers.

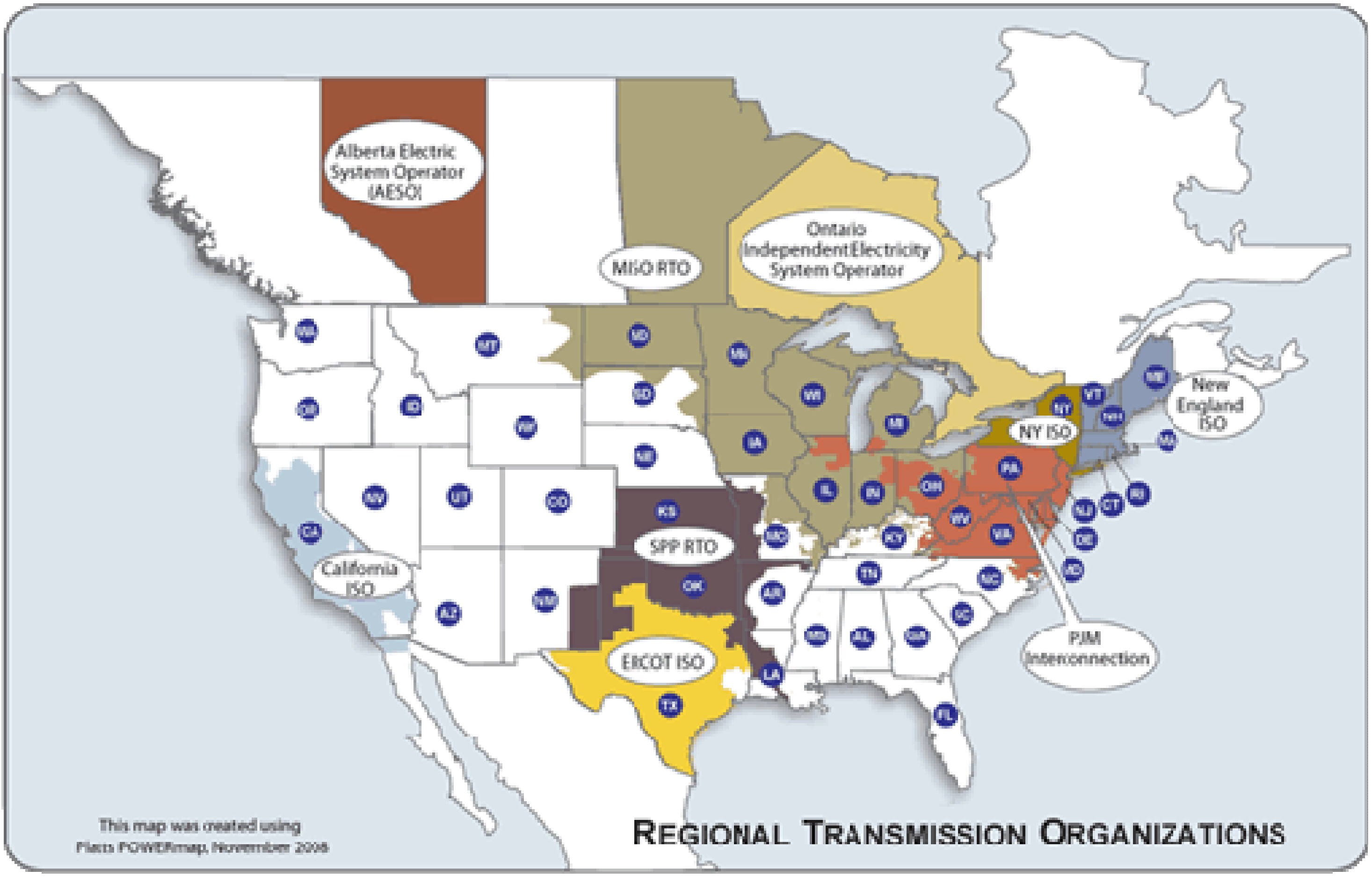


The North American electricity transmission system consists of three interconnected systems: the Eastern Interconnection, the Western Interconnection, and most of the state of Texas. Within these interconnections, more than 140 control areas manage electricity operations for local areas and coordinate reliability through 10 regional councils.

Source: NERC 2001.

Long Distances And Historical Development Of Transmission Grid Rendered Its Physical Capabilities such that Stability Requires **Partial Synchronization/ Fragmentation**! Even that fails Sometimes! Imbalance in Florida ⇒Oscillation all the way to Canada!

>50% of consumers in US in Regional Liberalized Whole-Sale Markets! ~0% in Retail Markets!



Regulatory Framework Evolving! Set by FERC (ISO/RTO governance developed in April 1996, FERC order 888/889 requires TPA to Tr. System and mandates Open Access Same-Time Information System (OASIS). Old investor utilities are restructuring as Generation or Transmission (often with many shareholders) or Distribution Companies

Regional Reliability Councils include:

- Western Electricity Coordinating Council (WECC) contains itself i.e. WECC which contains Western states and a portion of Baha California Norte, Mexico.
- Electric Reliability Council of Texas (ERCOT) contains itself i.e. ERCOT
- Eastern Canada-USGrid containing: Florida Reliability Coordination Council (GRCC); Midwest Reliability Organization (MRO); Northeast Power Coordination Council (NPCC); Southwest Power Pool, Inc. (SPP); SERC Reliability Corporation (SERC) in the southeast; Reliability First Corporation (RFC) in Ohio Pennsylvania and surrounding area.

ISOs, RTOs, IESOs (Canada) operating Wholesale Markets include:

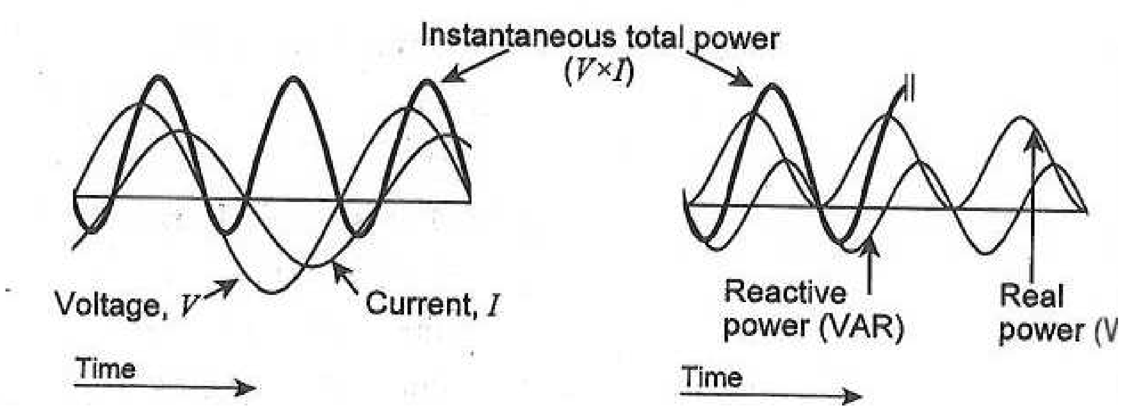
- Alberta Electric System Operator (AESO)
- California ISO (CAISO)
- ERCOT ALSO a Regional Reliability Council
- Independent Electricity System Operator (IESO) in Canada Operates Ontario Hydro System
- NYISO
- MISO
- ISONE
- Pennsylvania Jersey Maryland (PJM)
- SPP, Southwest Power Pool, also a Regional Reliability Council

Voltage and Current are Generated in Complete synchrony so that their product, i.e. associated power is maximized. Certain loads (capacitive or inductive) and T&D elements introduce an Undesirable Lead in either the Voltage or the Current, i.e. an Undesirable Phase Shift between them. The example below shows a voltage lead.

The phase shift reduces the Value of the product VxA allowing less real work to be obtainable.

The lost power, called reactive power, simply flows back and forth on the distribution lines causing overheating and losses!

Also, more power is needed by some appliances and other appliances may be damaged!



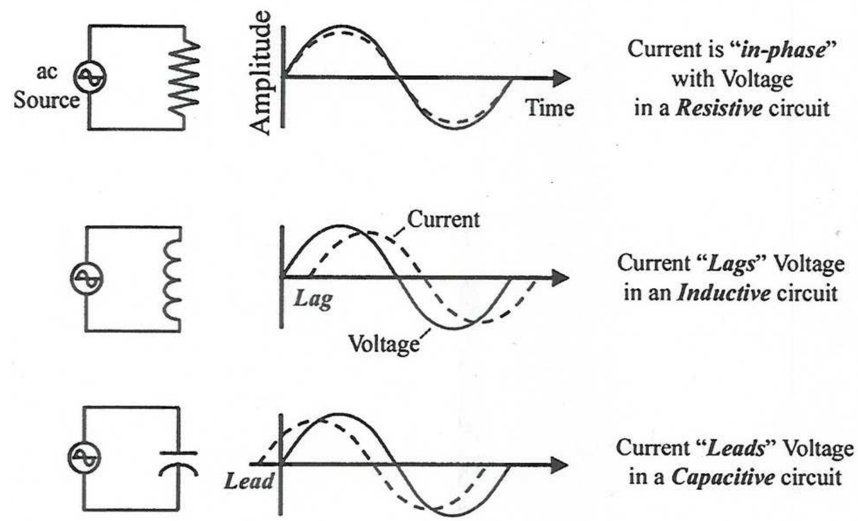
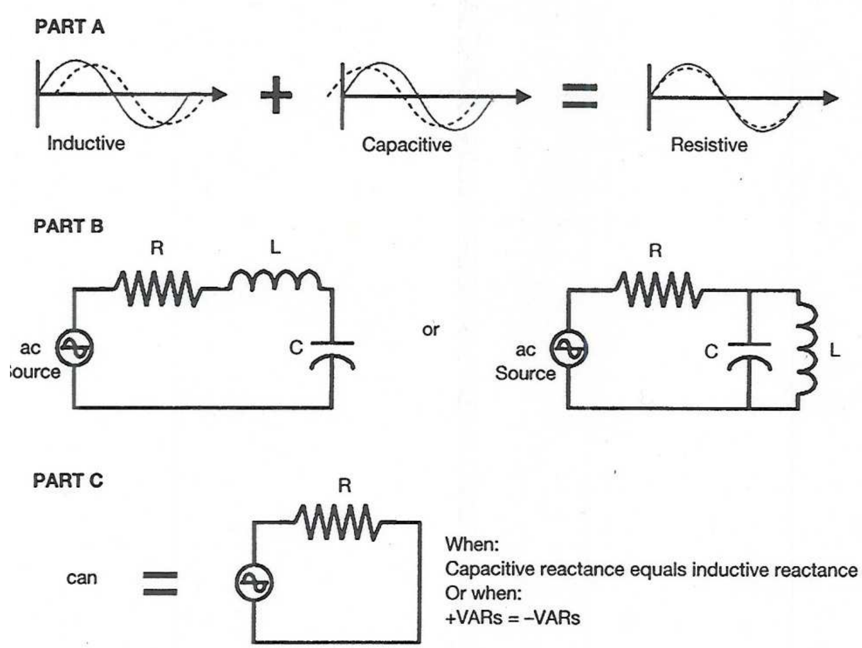
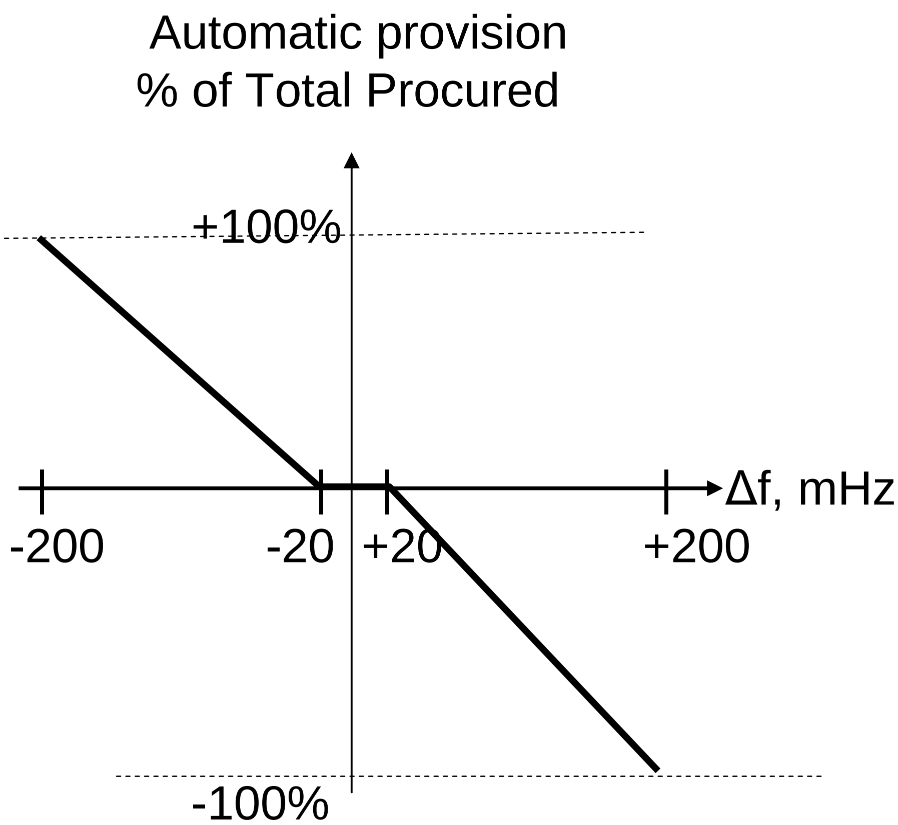


Figure 6-3. Voltage and current relationships.

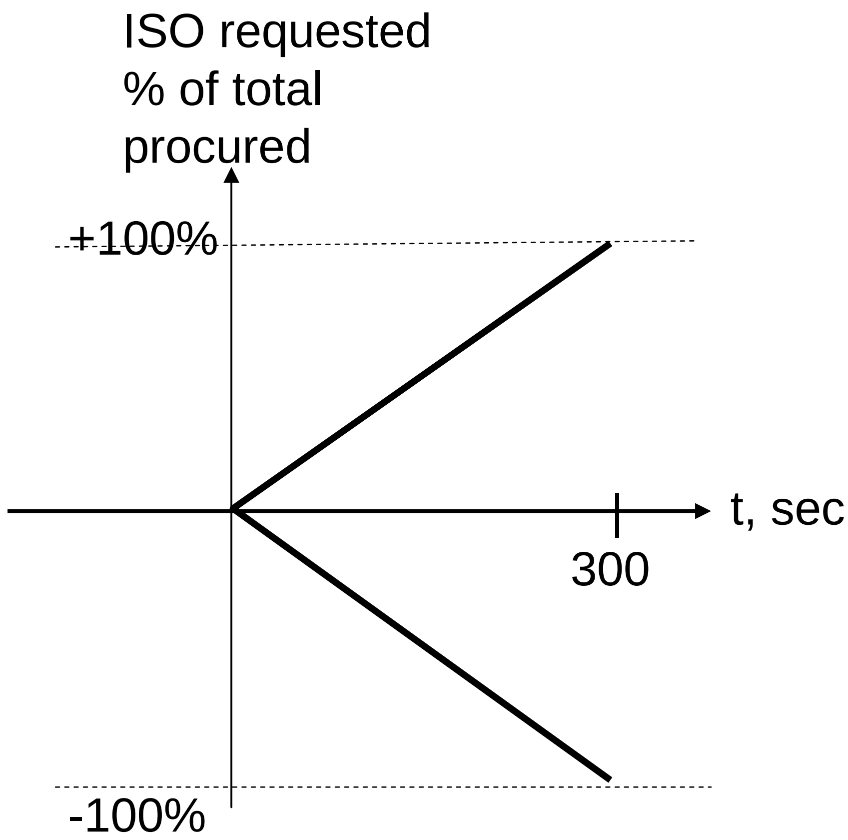


Capacitive/inductive loads => Voltage Lag or Lead Current. Power Electronics can Provide Dynamic Var Comp. and Voltage support

Bi-directional Primary and Secondary Reserve Dynamics

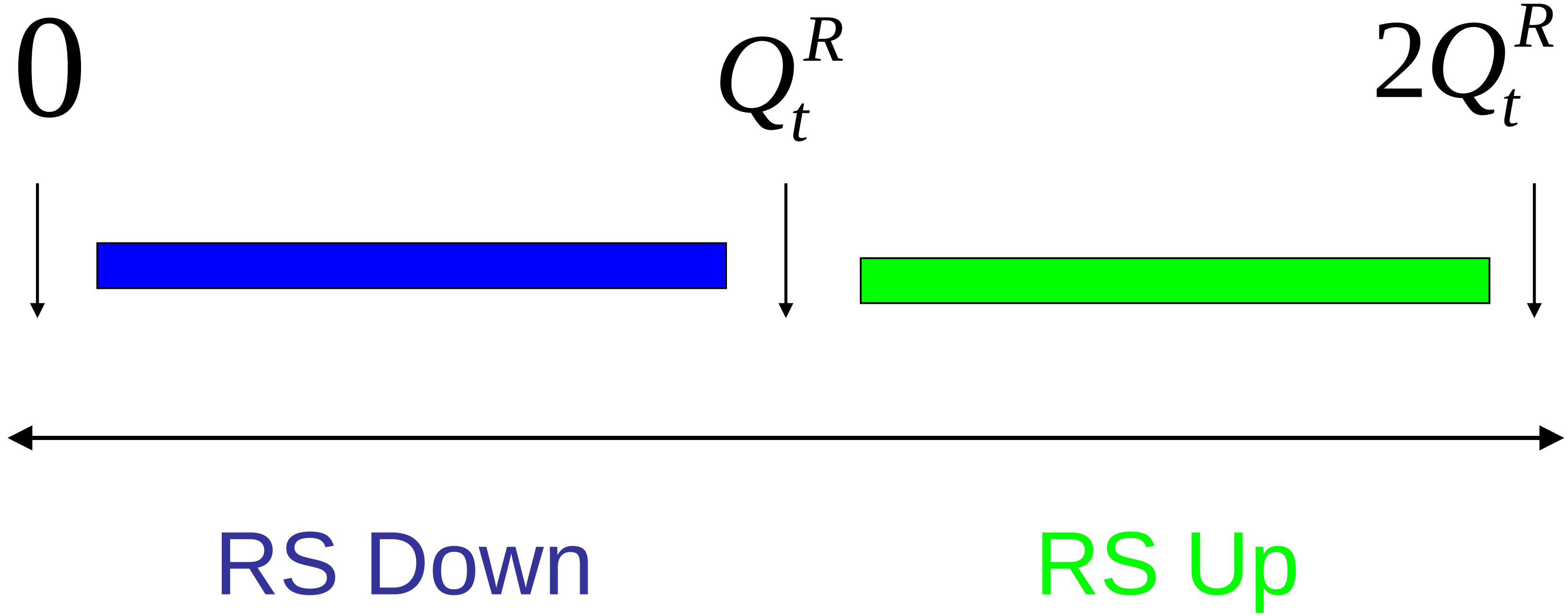


Automatic Primary/Freq-resp. Reserves
Provided as a function of Δf.
Provision Scheduled at constant
ramp rate (100% per 30 sec)



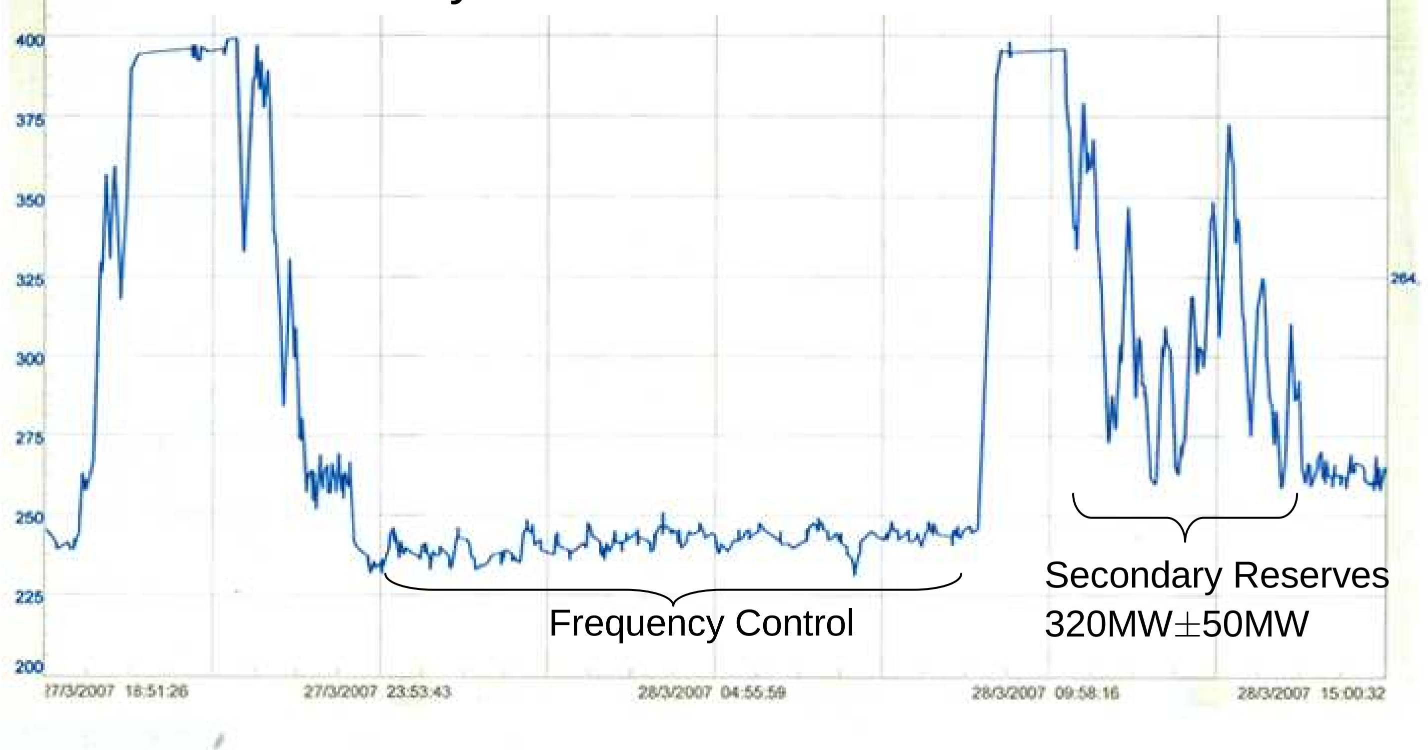
Secondary/Regulation Reserve Provision
Schedule as a function of ISO requested
% target (may reset in 6-8 sec intervals)

Regulation Service Provider Obligation: Generate/Consume on Average Q^R but Reserved available Capacity (Generation/Consumption and Grid Connection) must be $2Q^R$!



Today Generating Units are Only Reserve Providers

Example of Generator providing Super Fast Reserves: Frequency control and ± 50MW of Secondary Reserves on AGC



Source: Courtesy of EnThes Inc., March 2007

Retail/Distribution Markets Important for Load Participants and Distributed Resource Integration: Line Losses, Dynamic Var Compensation, Local Asset Congestion

- Demand connected physically to distribution networks which are in tern connected to the the Transmission/Wholesale markets
- Important cost components in Future(?) Retail Markets:
  - Marginal Line Losses: 5-25% as opposed to 0.5 to 2% in Transmission system
  - Reactive Power/Dynamic Var Compensation (not included in wholesale markets for good reason. Why?)
  - Distribution asset congestion and degradation (prospective dynamic level loading through Grid reconfiguration synergistic to demand adaptation)

Load Aggregators (LA) and Smart Microgrid Affiliates (SMAs)

- A Load Aggregator participates in day ahead markets: Hedges for its SMAs
- SMAs participate in Retail market: Each SMA i sees different local marginal losses, local asset congestion, local Var compensation requirements
- LA sells/buys energy reserves secured in the day ahead market to its SMAs in the Real-Time market

Coordinated Participation in Interacting Cascaded Markets

- How does a LA bid optimally into the wholesale day ahead market?
- How does a LA bid optimally into the wholesale real-time market, while trading at the same time with its SMAs?
- How does a SMA trade with the LA and bid optimally to the Real-Time market?
- Information needed to facilitate Optimal Bidding?

Challenges in Optimal Bidding in a Coordinated Market Setting

- Coordination of three Stochastic DP Problems is hard. Does an Iterative algorithm Converge?
- Robust Selection of R.V. Estimates in Complex Bid LA day ahead problem
- Do the various Markets Reach Equilibrium under Demand Response?
- Under Oligopolystic Conditions, does a Nash Equilibrium exist?
- Aggregation of SMAs, particularly under multiple load types.
- Competition of Multiple SMAs for same capacity constraint: Auction? Retail Submarket?

SOME COMMENTS ON ROBUST OPTIMIZATION

Recall that the cost function has terms of the form

$$\sum_{\tau} \mathbf{E}_{t*}\{\tilde{\lambda}_t^E Q_t^E(\tau) + [\tilde{\lambda}_t^E - \tilde{\lambda}_t^R] Q_t^R(\tau) \Pi_t^{\tau}(t*)\} \Delta t$$

while constraints of available feeder capacity are,

$$\Sigma_{\tau}[Q_t^E(\tau) + 2Q_t^R(\tau)] \leq \hat{C}_t^{\max,t*}$$

Note that $\tilde{\lambda}_t^E, \tilde{\lambda}_t^R$ and $\hat{C}_t^{\max,t*}$ are random variables.

Can consider ellipsoid or polyhedral sets where $\tilde{\lambda}_t^E$ and $\tilde{\lambda}_t^R$ are included while assuming $\hat{C}_t^{\max,t*}$ are independent across time.