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A "SuperOPF" Framework

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Enhanced Optimal Power Flow Models

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U.S. DEPARTMENT OF ENERGY

CERTS

Consortium for Electric Reliability Technology Solutions

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Background Motivation

The ability to optimally allocate and properly value system resources, including reliability, is needed for …

- design and operation of electricity markets for energy, capacity, ancillary services, on all time scales from real-time to multi-year forward markets
- power grid operations: unit commitment, dispatch, maintenance
- regulatory oversight: market monitoring, reliability standards, impacts of environmental regulation
- resource planning: optimal investment, reliability studies, economic and reliability impacts of changes in technology (wind, solar, PHEV, DER, CHP, smart grid)

Limitations of Current Practice

- Problem broken into sequential sub-problems
- DC models with proxies for AC constraints
  - misleading prices, especially for stressed system
- Stressed conditions are exactly when correct prices are most informative for identifying …
  - location of existing network weaknesses
  - new equipment needed to upgrade network
  - net economic benefits of upgrades

Extend Traditional OPF

- consistent framework for scheduling on multiple time scales
- handling of different levels of uncertainty
  - increased penetration of uncertain sources (wind, solar)
- new technologies
  - increased storage, smart grid applications (smart charging)
- proper valuation of resources, including reliability
  - proxy constraints can result in misleading prices
  - especially important under stressed conditions

General Approach

Power systems operations and planning problems are computationally **very** complex.

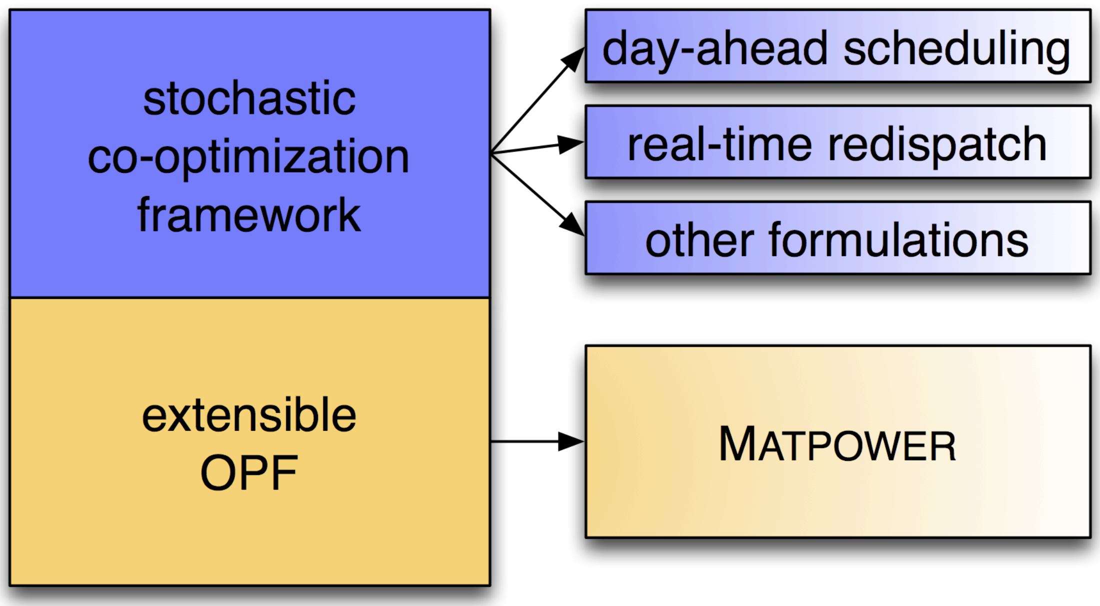
Traditional Approach	**SuperOPF**
Break into manageable sub-problems.	Combine into single mathematical programming framework.
DC network approximations	full AC network model
sequential optimization using proxy constraints	simultaneous co-optimization with explicit contingencies
misleading prices	more accurate prices

Problems Combined

Combines several standard problems found in system operation & planning into single mathematical programming framework

- standard OPF with full AC non-linear network model & constraints
- *n*-1 contingency security with static (post-contingency voltage and flow limits) and dynamic (generator ramp limits, voltage angle difference limits) constraints
- procurement of adequate supply of active & reactive energy and corresponding geographically distributed reserves
- uncertainty of demand, wind, contingencies
- stochastic cost, including cost of post-contingency states
- explicit valuation of reliability through cost of involuntary load shedding
- more accurate prices for day-ahead contracts for energy, reactive supply, reserves
- consistent mechanism for subsequent redispatch and pricing, given specific realization of uncertain quantities

Two Level Structure



Co-optimization Structure

- power flow scenario
  - all standard OPF variables, constraints, costs
  - "high probability", "base" or "intact" case

$$\min_{\Theta, V, P, Q} \sum_{i=1}^{n_g} \left[f_P^i(p_i) + f_Q^i(q_i) \right]$$

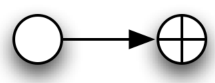
subject to

$$\begin{aligned}
g_P(\Theta, V, P) &= 0 \\
g_Q(\Theta, V, Q) &= 0 \\
h_f(\Theta, V) &\le 0 \\
h_t(\Theta, V) &\le 0 \\
\theta_{\mathrm{ref}} \le \theta_i &\le \theta_{\mathrm{ref}}, && i = i_{\mathrm{ref}} \\
v_i^{\min} \le v_i &\le v_i^{\max}, && i = 1 \ldots n_b \\
p_i^{\min} \le p_i &\le p_i^{\max}, && i = 1 \ldots n_g \\
q_i^{\min} \le q_i &\le q_i^{\max}, && i = 1 \ldots n_g
\end{aligned}$$

Co-optimization Structure

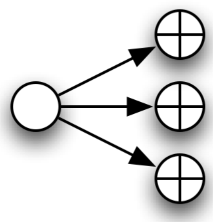
- power flow scenario
  - all standard OPF variables, constraints, costs
  - "low probability", "contingency" case

Co-optimization Structure



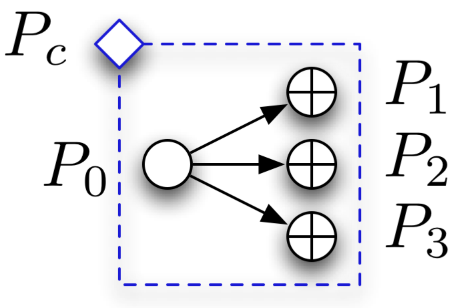
- transition constraint (e.g. ramp rate)
- restricts deviations of dispatch in contingency from dispatch in base case
- costs of scenarios are weighted (e.g. by probability)

Co-optimization Structure



- base case and set of contingencies with
  - ramp limits constraining transitions from the base case to contingency cases
  - probability weighted costs

Co-optimization Structure

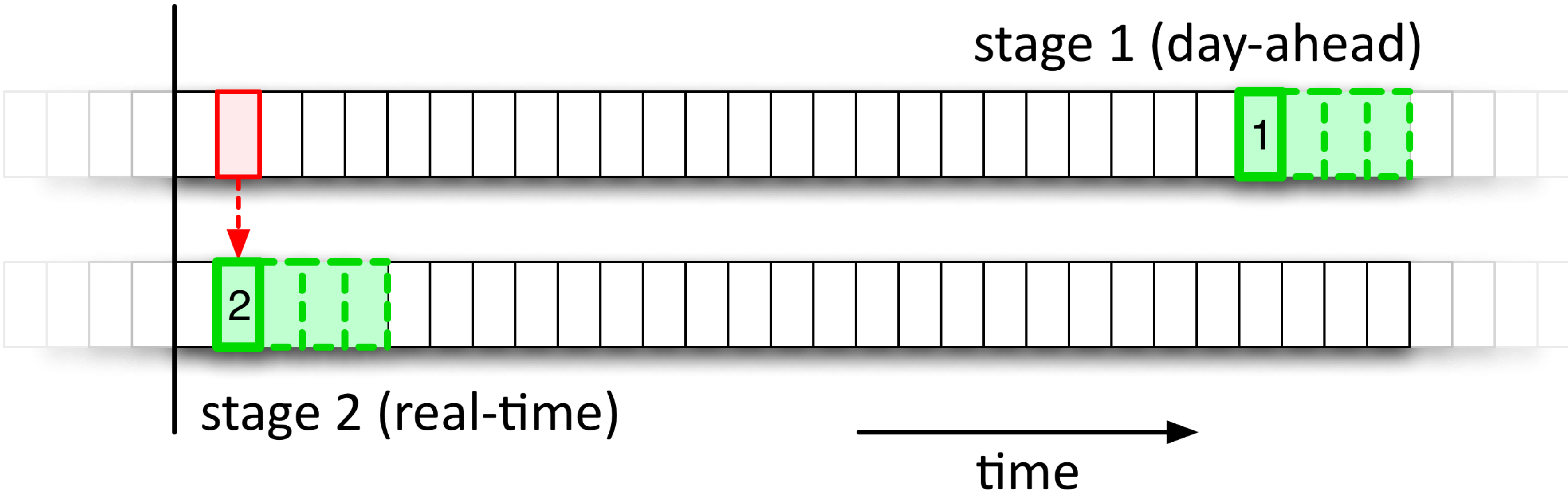


- root variable set with
  - upward and downward deviation variables
  - deviation limit variables
  - costs on deviations
  - costs and constraints on limits
- e.g. optimal energy contract, incs/decs from the contract, reserves

Additional Comments on Structure

- contingency selection is important
- not simple Monte Carlo sampling
  - typical Monte Carlo misses low probability tails
- limits are hard limits that define an envelope that captures all operating points
  - still conservative
  - samples high probability cases sparsely
  - oversamples low probability cases
- expected prices
  - note: these are not probability weighted LMPs

Two Stage, Receding Horizon



Stage 1

- higher uncertainty
- make availability decisions
- set up financial contracts

Stage 2

- some financial positions already taken
- some availability commitments already made
- decreased resource flexibility
- decreased uncertainty about system conditions
- updated system conditions
- possible additional resources available
- possible updated bids/offers

Notation

n_c	number of contingencies
n_g	total number of dispatchable units (gens or loads)
k	index for contingencies (0 for base case)
i	index for dispatchable units (gens or loads)
p_{ik}	real power output for unit i in contingency k
p_{ci}	day-ahead contracted real power output for unit i
p_{ik}^+, p_{ik}^-	upward, downward deviations of p_{ik} from p_{ci}
r_{Pi}^+, r_{Pi}^-	upward, downward reserves $(\max_k p_{ik}^+, \max_k p_{ik}^-)$ for unit i
π_k	probability of contingency k
$C(\cdot)$	cost function
G^k	set of units available in contingency k
$R_{Pi}^{\max+}, R_{Pi}^{\max-}$	upward, downward reserve capacity limits for unit i
$\Delta_{Pi}^+, \Delta_{Pi}^-$	upward, downward physical ramp limits for unit i

replace p with q and P with Q for corresponding values for reactive power

Stage 1 Objective Function

$$\min_{\substack{\Theta, V, P, Q, \\ P_c, P^+, P^-, \\ R_P^+, R_P^-}} \left\{ \sum_{k=0}^{n_c} \pi_k \sum_{i \in G^k} C_{Pi}(p_{ik}) + C_{Pi}^+(p_{ik}^+) + C_{Pi}^-(p_{ik}^-) \right.$$

$$\left. + \sum_{i=1}^{n_g} C_{RPi}^+(r_{Pi}^+) + C_{RPi}^-(r_{Pi}^-) \right\}$$

plus corresponding terms for reactive power

Standard OPF Constraints

… replicated for each contingency

- nodal real & reactive power balance equations
- branch flow limits, voltage limits, generation limits, etc.

$$\left.\begin{aligned} g_P^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ g_Q^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ h^k(\theta^k, V^k, P^k, Q^k) &\leq 0 \end{aligned}\right\} \quad k = 0 \ldots n_c$$

Stage 1 Linking Constraints

$$\left.\begin{aligned} 0 &\le p_{ik}^{+} \\ p_{ik} - p_{ci} &\le p_{ik}^{+} \\ p_{ik}^{+} \le r_{Pi}^{+} &\le R_{Pi}^{\max+} \\ \\ 0 &\le p_{ik}^{-} \\ p_{ci} - p_{ik} &\le p_{ik}^{-} \\ p_{ik}^{-} \le r_{Pi}^{-} &\le R_{Pi}^{\max-} \end{aligned}\right\} \qquad \forall k, \forall i \in G_k$$

$$-\Delta_{Pi}^{-} \le p_{ik} - p_{i0} \le \Delta_{Pi}^{+} \qquad k = 1 \ldots n_c, \forall i \in G_k$$

$$-\alpha \le p_{i0} - p_{ci} \le \alpha \qquad \forall i,\ \alpha \in \{0, \infty\}$$

plus corresponding constraints for reactive power

Stage 2 : Real-time Redispatch

- Same as day-head except:
  - updated scenarios (demand forecasts, available equipment, wind forecasts, credible contingencies, probabilities, etc.)
  - redispatch is relative to the now fixed contract from stage 1
  - reserve quantities from stage 1 appear as fixed limits on redispatch
- Implemented two formulations to simulate the two types of realized scenarios

1. base or "intact" scenario
   - continue to guard against contingencies
2. contingency or "outage" scenario
   - becomes new base case, temporarily ignore possibility of further contingencies (did not plan for *n*-2).

Stage 2 Objective Function

$$\min_{\substack{\Theta,V,P,Q,\\ P^+,P^-}} \left\{ \sum_{k=0}^{n_c} \pi_k \sum_{i \in G^k} C_{Pi}(p_{ik}) + C_{Pi}^{+}(p_{ik}^{+}) + C_{Pi}^{-}(p_{ik}^{-}) \right\}$$

plus corresponding terms for reactive power

Standard OPF Constraints

… replicated for each contingency

- nodal real & reactive power balance equations
- branch flow limits, voltage limits, generation limits, etc.

$$\left.\begin{aligned} g_P^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ g_Q^k(\theta^k, V^k, P^k, Q^k) &= 0 \\ h^k(\theta^k, V^k, P^k, Q^k) &\leq 0 \end{aligned}\right\} \quad k = 0 \dots n_c$$

Stage 2 Linking Constraints

$$\left.\begin{aligned} 0 &\leq p_{ik}^{+} \\ p_{ik} - \hat{p}_{ci} &\leq p_{ik}^{+} \\ p_{ik}^{+} &\leq \hat{r}_{Pi}^{+} \\ \\ 0 &\leq p_{ik}^{-} \\ \hat{p}_{ci} - p_{ik} &\leq p_{ik}^{-} \\ p_{ik}^{-} &\leq \hat{r}_{Pi}^{-} \end{aligned}\right\} \qquad \forall k, \forall i \in G_k$$

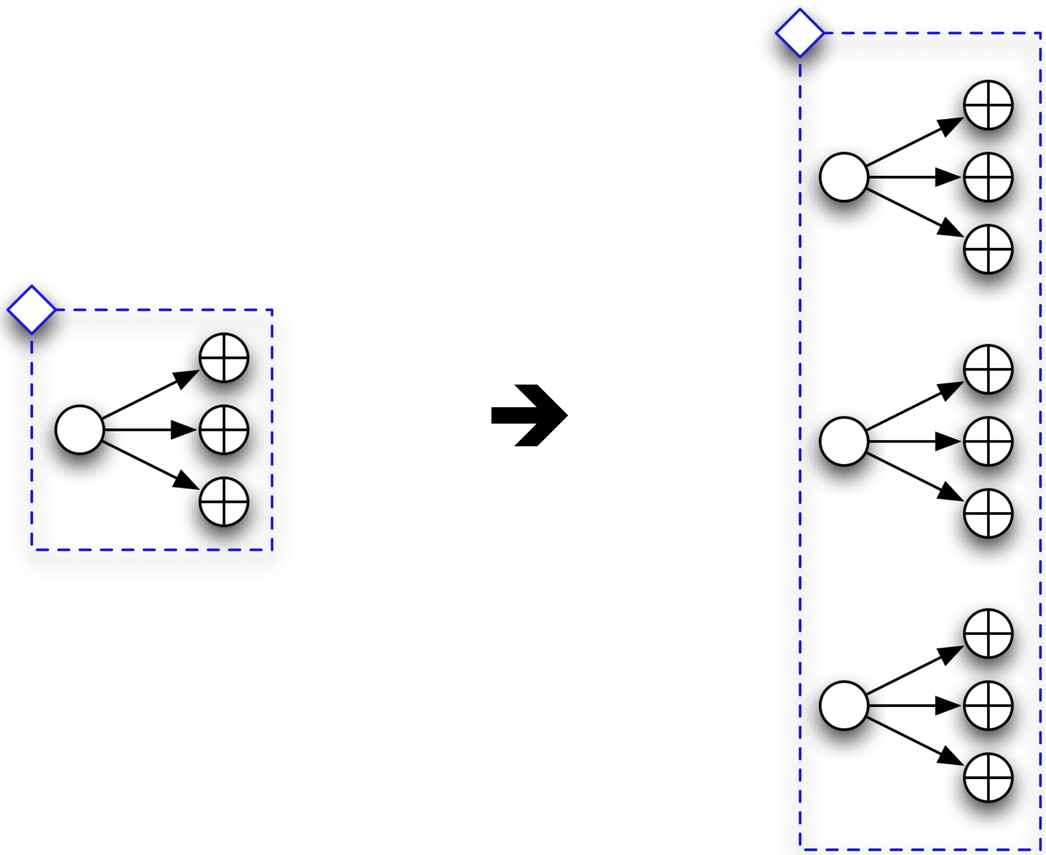
$$-\Delta_{Pi}^{-} \leq p_{ik} - p_{i0} \leq \Delta_{Pi}^{+} \qquad k = 1 \ldots n_c, \forall i \in G_k$$

plus corresponding constraints for reactive power

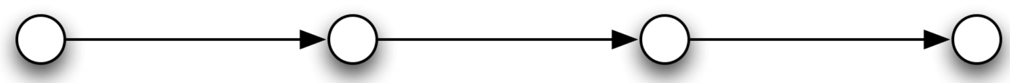
New Formulations

- multiple "base" cases for improved modeling of sources with uncertainty (e.g. wind)
- multiple time periods
- intertemporal storage constraints
- discrete decision variables (unit commitment)
- generation and transmission investment

Sources with Uncertainty (Wind)

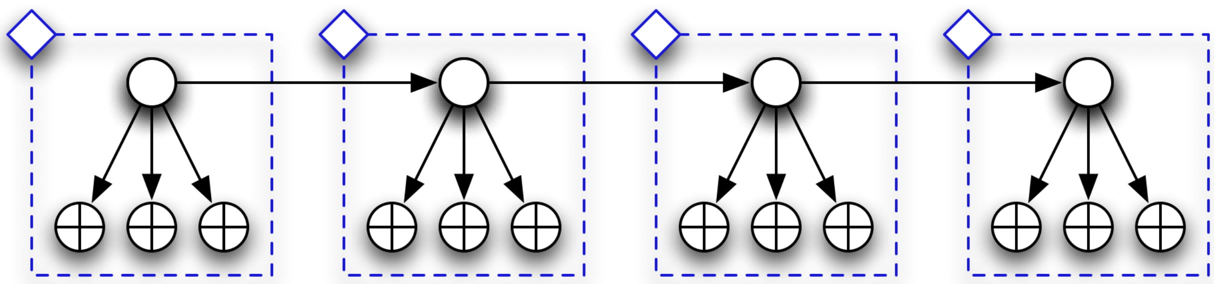


Multi-period Optimization

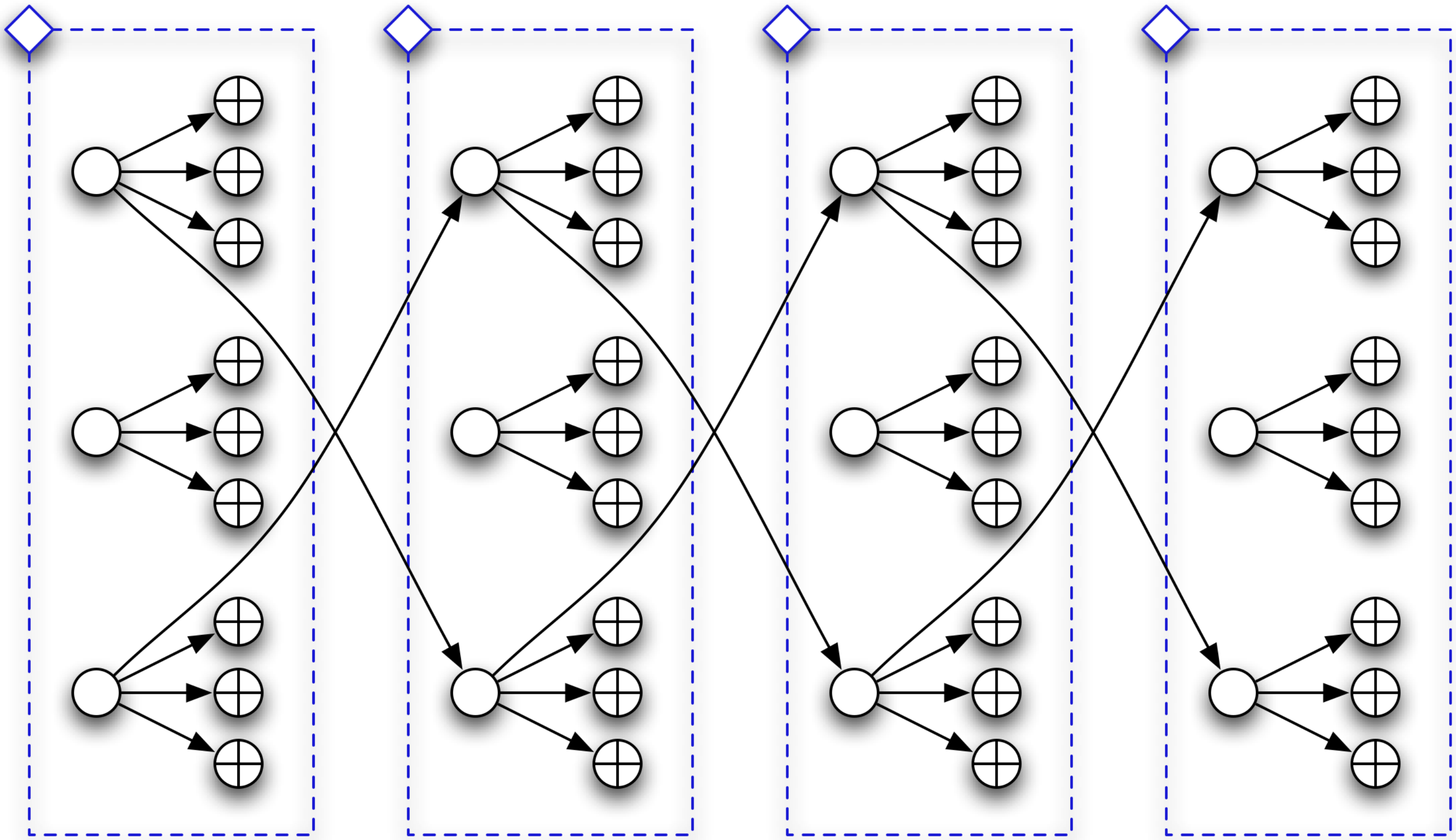


- independent OPFs, plus
- linking ramp constraints and costs

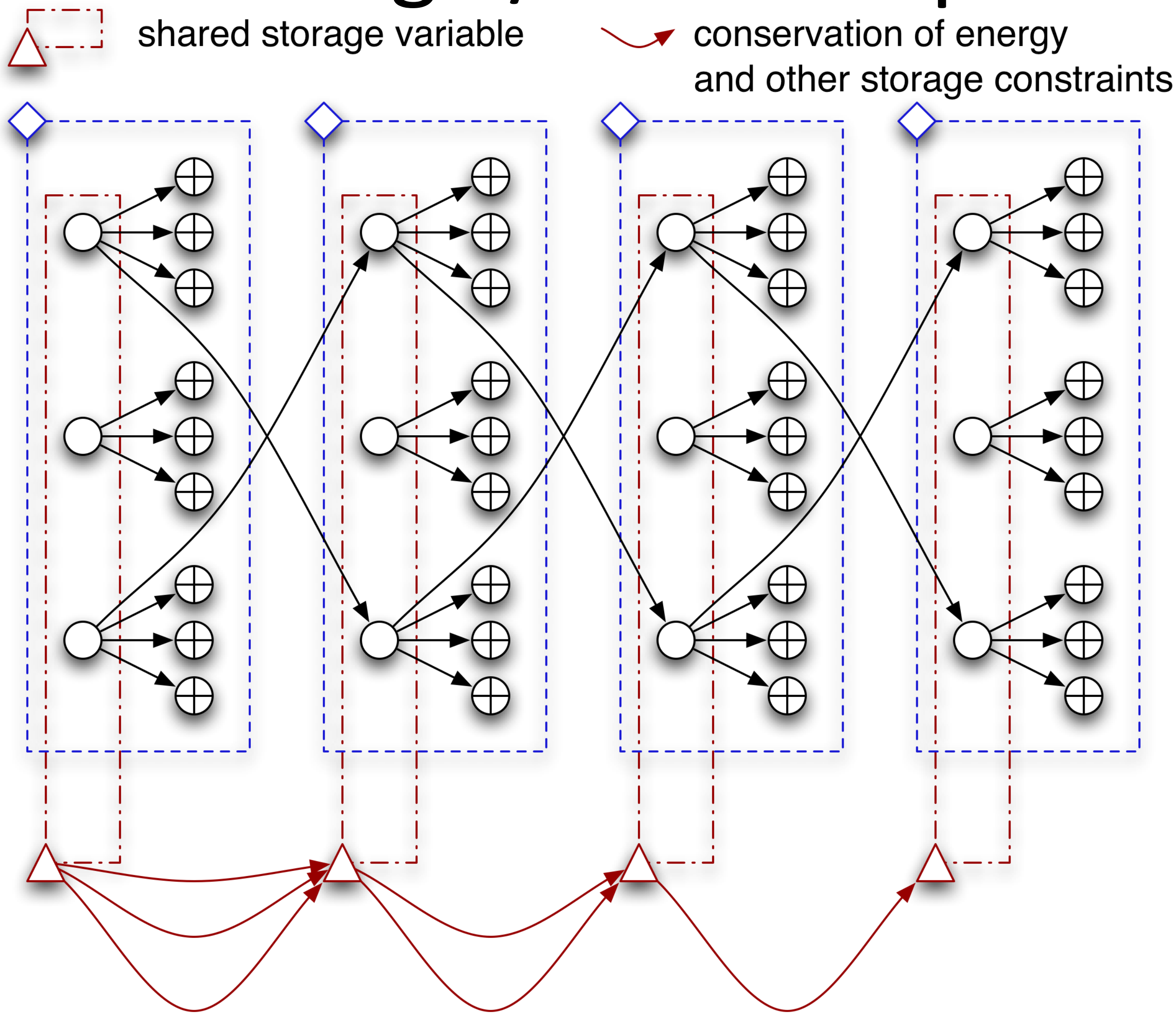
Multi-period Optimization



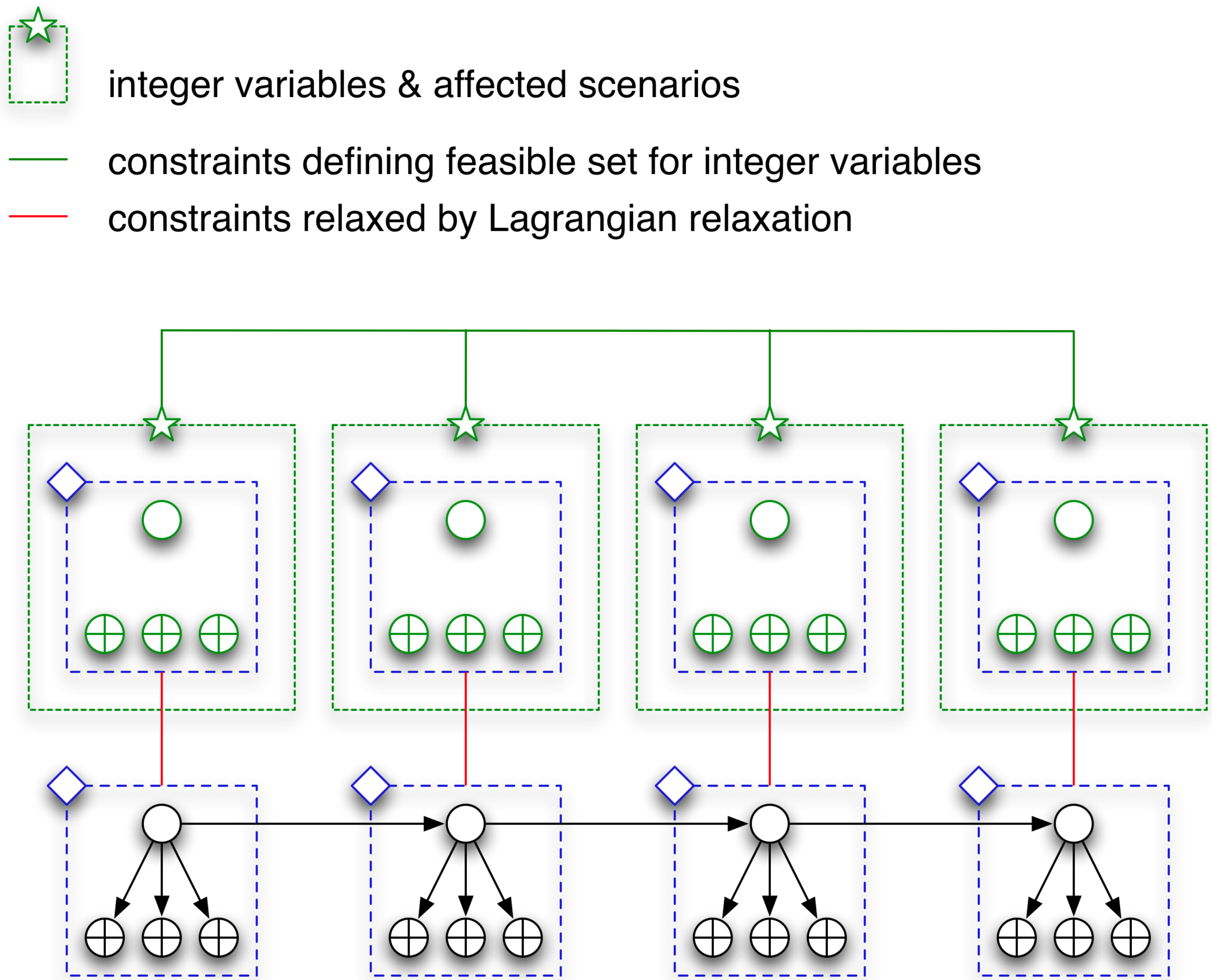
Multi-period Wind



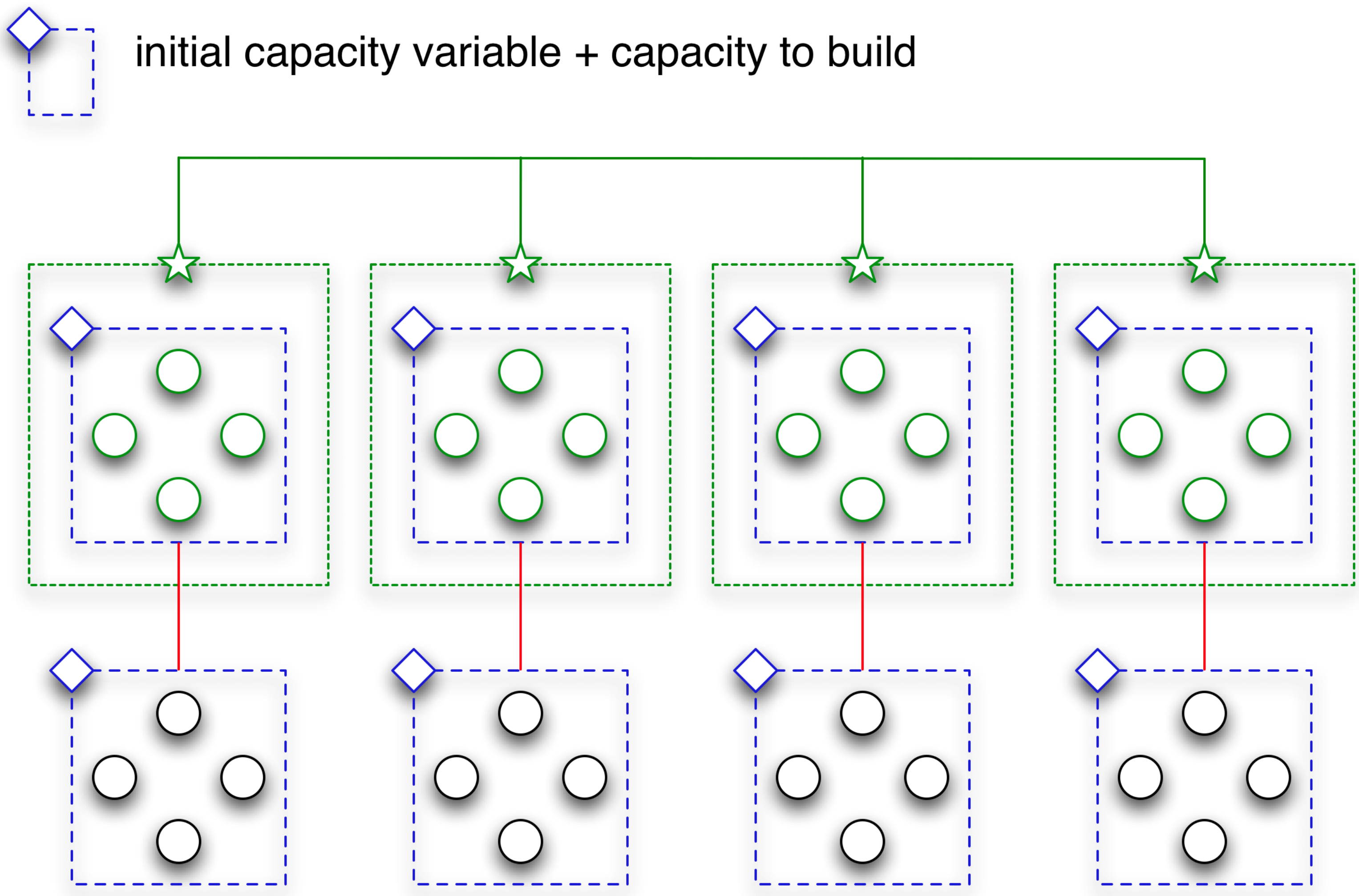
With Storage / PHEV dispatch



Unit Commitment via Duplication + LR



Generation Investment



Large Scale Problems

- Based on the Polish portion of the European UCTE interconnected network
  - 400, 220 and 110 kV networks
  - 2007-2008 winter evening peak
  - 3012 buses
  - 385 generators
  - 2271 loads
  - 3572 branches (201 transformers)

Contingencies

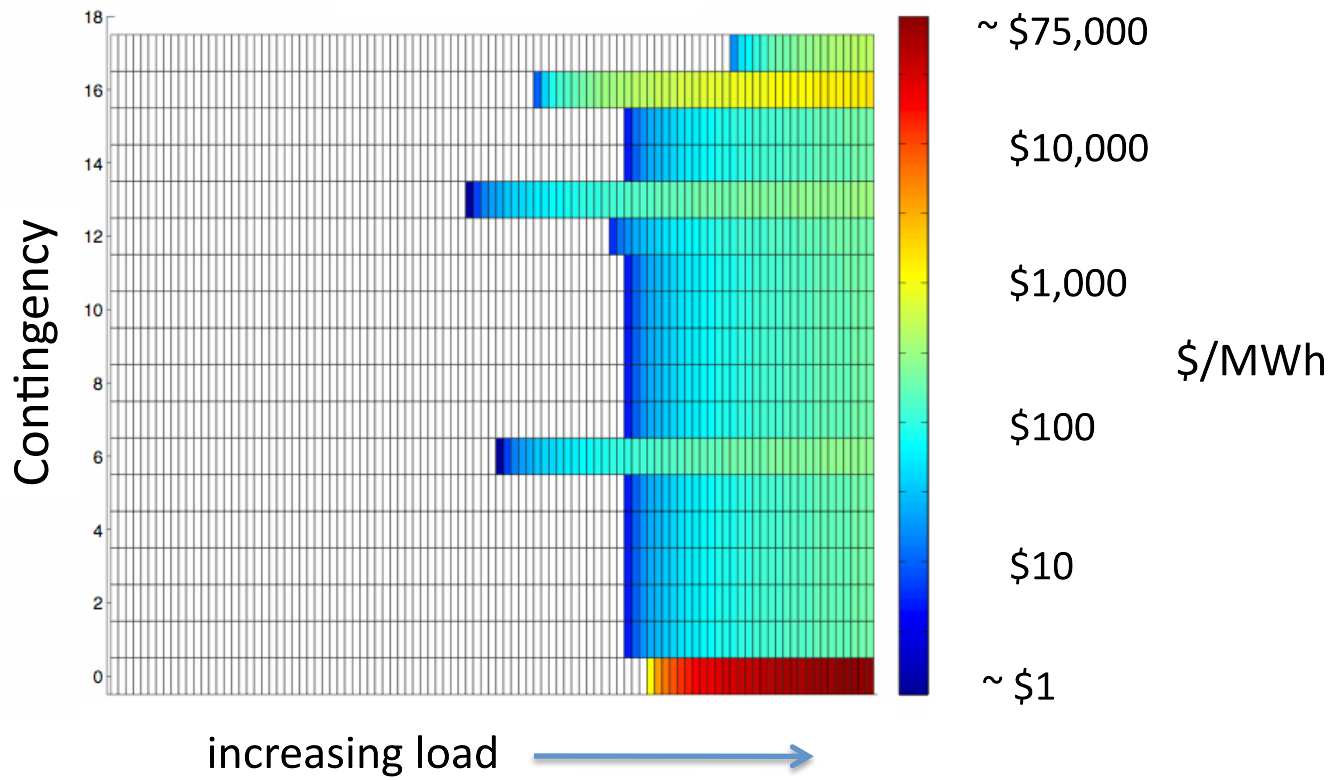
- Largest generator and line outages
  - 21 generator outages
  - 21 line outages
- Results in one huge network with 43 islands, each copies of original 3012 bus network with a different outage

Equivalent OPF

- Equivalent network
  - 129,516 buses
  - 16,534 generators
  - 97,653 loads
  - 153,575 branches
- Optimization problem
  - 326,323 total optimization variables
  - 682,690 total constraints
    - 566,182 non-linear, 116,508 linear

Expected Cost of Lost Load

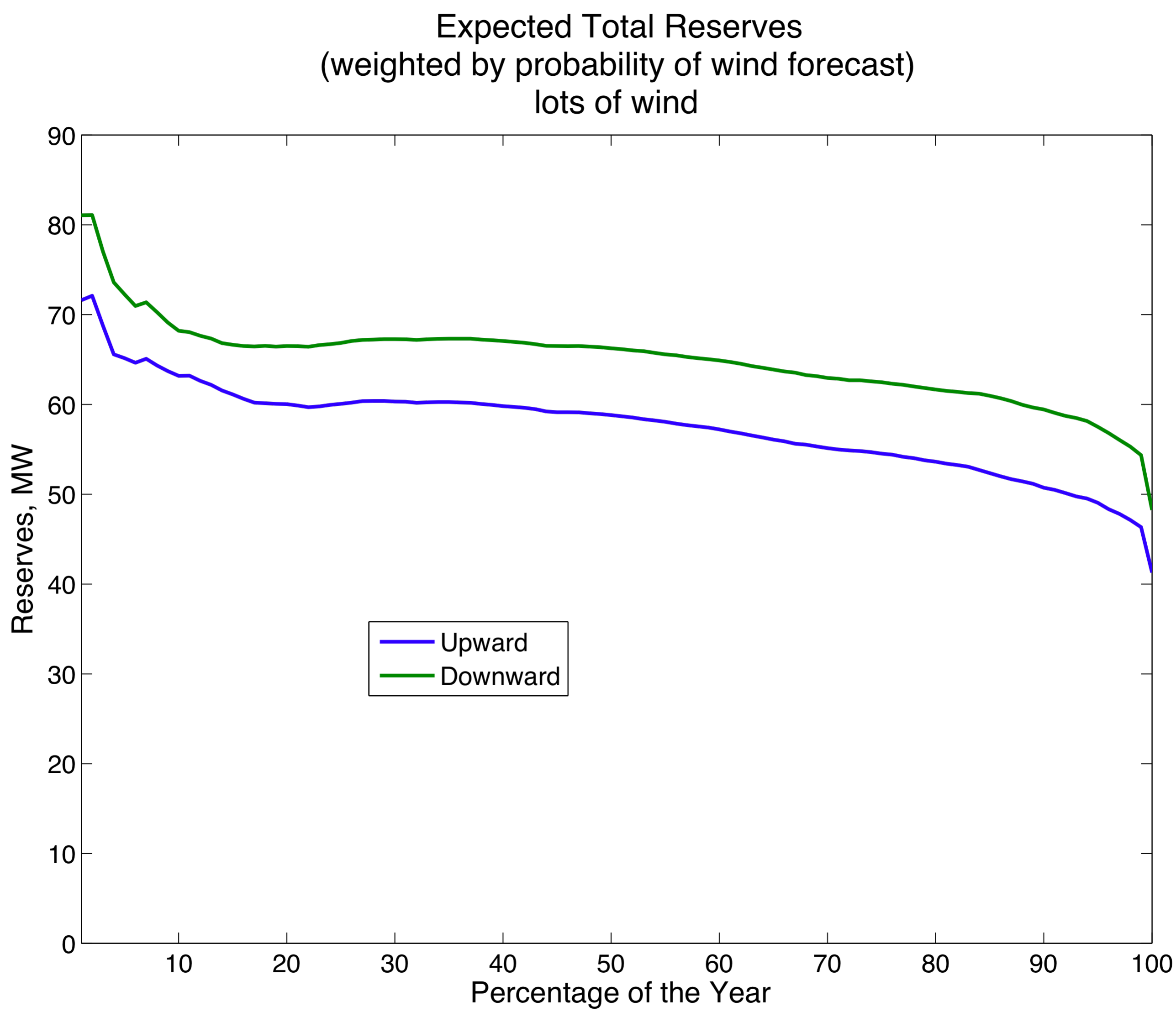
weighted by probability of contingency



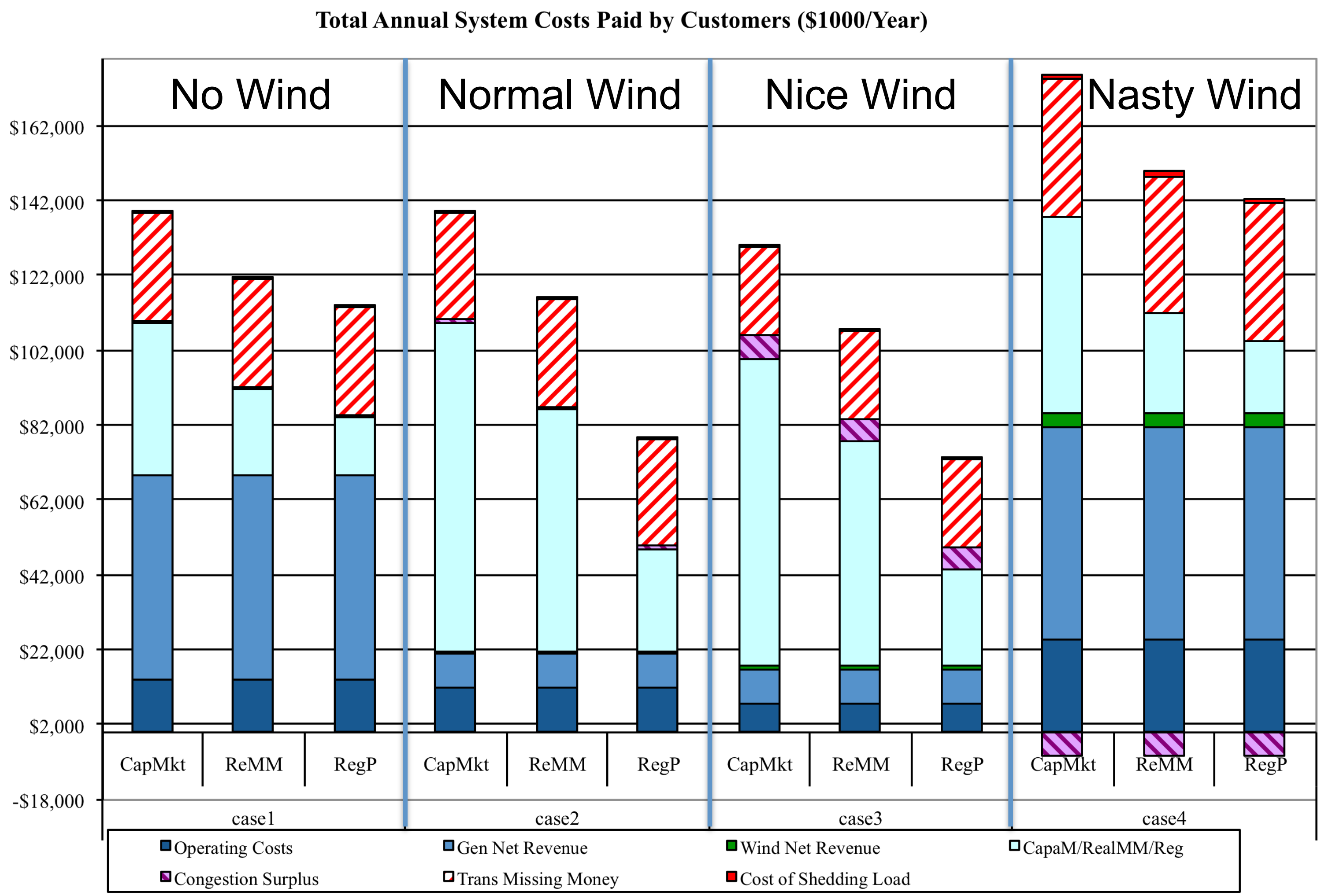
– as load increases problems show up first in contingencies

– caused by a line limit

Effect of Wind on Reserves

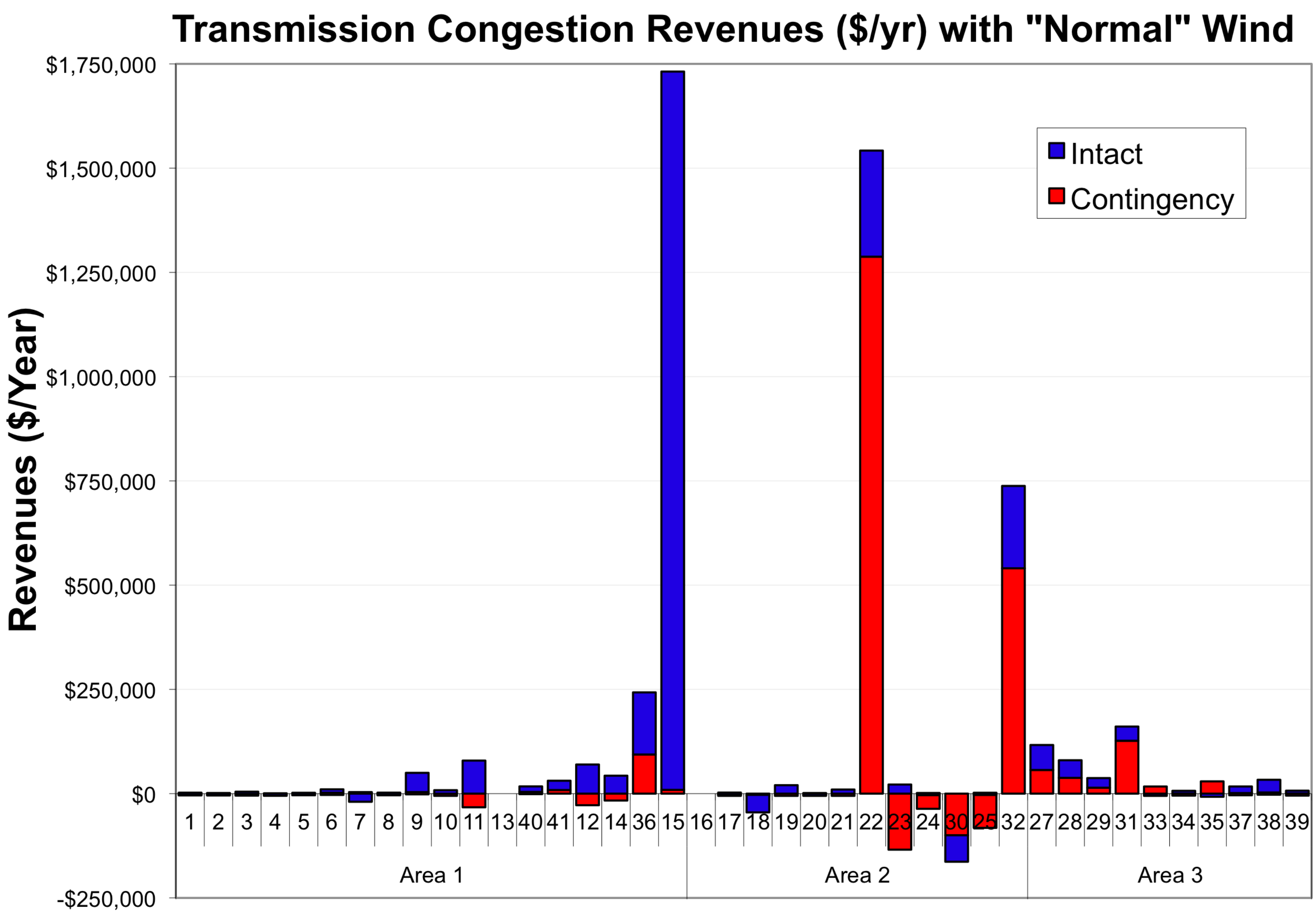


Annual System Costs



Expected Annual Congestion Revenues

*(based on line flows * price differences)*



Questions?