Computational Challenges and Analysis Under Increasingly Dynamic and Uncertain Electric Power System Conditions

A PSERC Future Grid Initiative Progress Report

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PSERC

PSERC Future Grid Webinar
April 16, 2013

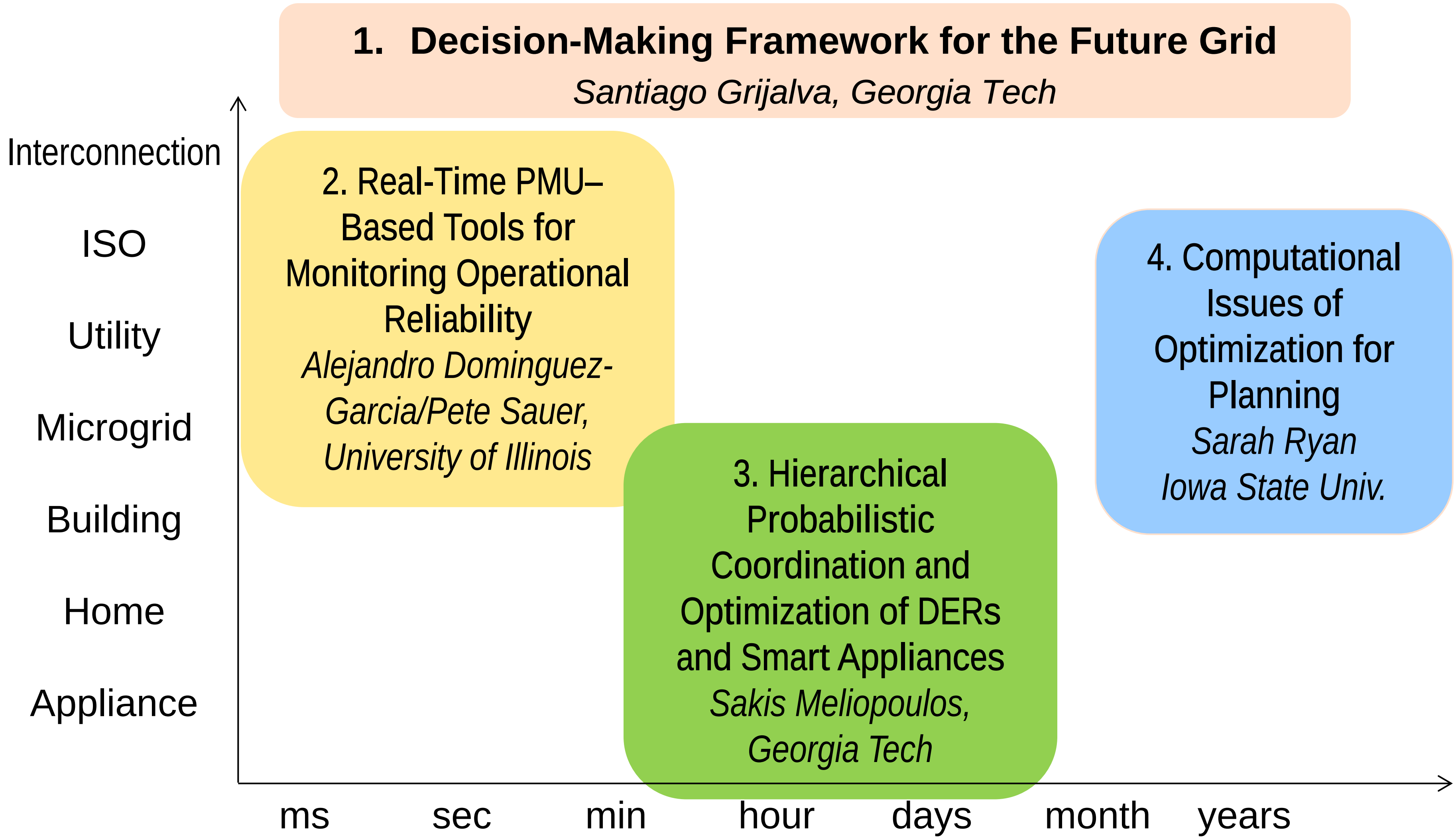
PSERC Future Grid Initiative

- DOE-funded project entitled "The Future Grid to Enable Sustainable Energy Systems”
(see http://www.pserc.org/research/FutureGrid.aspx)

- Overall Project Objective: Enabling higher penetrations of renewable generation and other future technologies into the grid while enhancing grid stability, reliability, and efficiency

- This webinar’s focus: accomplishments in the research area of computational and analysis challenges for the future grid.

Task Areas


1. Decision-Making Framework for the Future Grid
Santiago Grijalva, Georgia Tech
2. Real-Time PMU–Based Tools for Monitoring Operational Reliability
Alejandro Dominguez-Garcia/Pete Sauer, University of Illinois
3. Hierarchical Probabilistic Coordination and Optimization of DERs and Smart Appliances
Sakis Meliopoulos, Georgia Tech
4. Computational Issues of Optimization for Planning
Sarah Ryan
Iowa State Univ.
Interconnection
ISO
Utility
Microgrid
Building
Home
Appliance
ms
sec
min
hour
days
month
years

Decision-Making Framework for the Future Grid

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Research Objectives

- The future grid will consists of a billion devices and millions of decision-makers.
- The project objective is to develop and demonstrate **decision-making mechanisms** that:

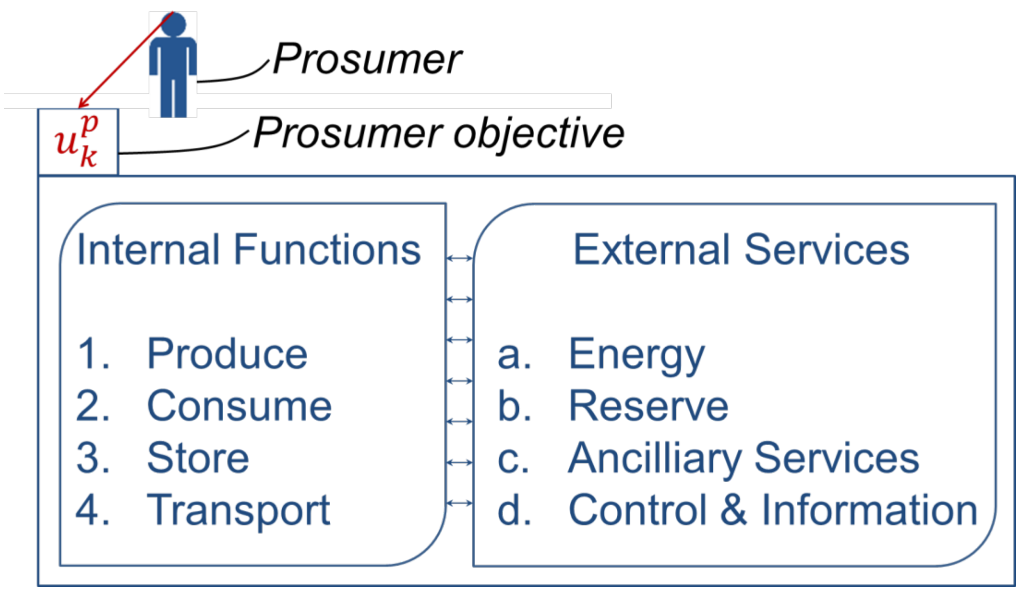
1. Are scalable to millions of decision-makers
2. Address decision complexity through layered abstractions.
3. Cover multiple spatial and temporal decision scales.
4. Uncover gaps and technological needs as the industry evolves into the future grid.

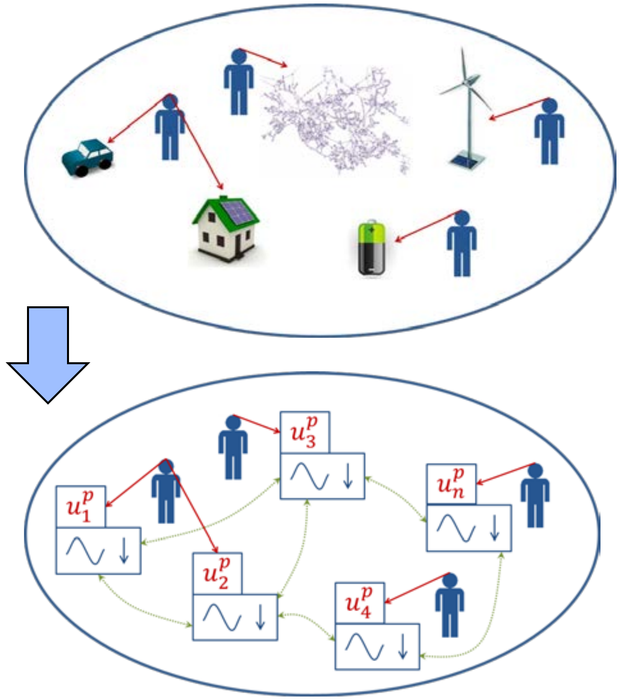
Approach

1. Developed the decision-making framework
2. Developed a scheduling algorithm to allow residential prosumers to optimally schedule their energy use in a dynamic pricing environment.
3. Developed a method to optimally design electricity price signals on retail markets.

A Shared Representation: Prosumers

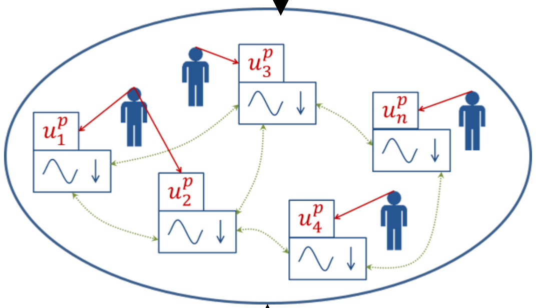
- Heterogeneous **communities of practice** are involved in the “making” of the future grid: engineering, policy, etc.
- Need a **shared representation** of the future grid that improves collective intelligence for decision making.
- The **prosumer** abstraction is flexible enough to be adaptable across multiple view points and scales.





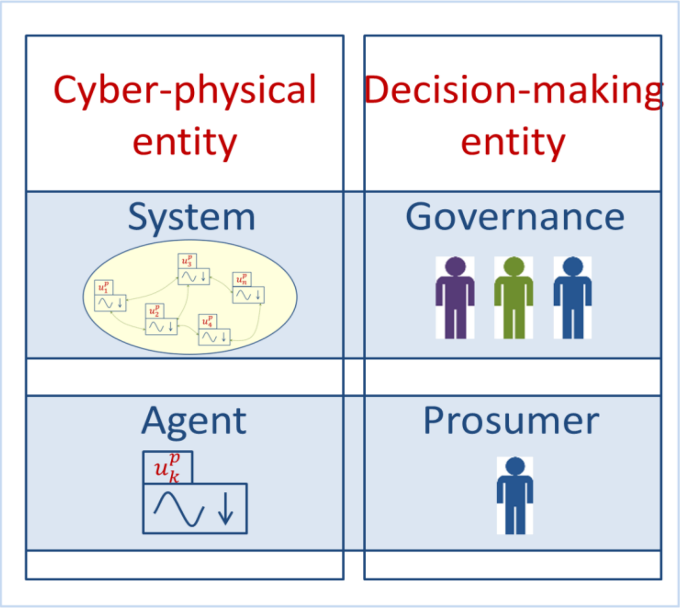
Decision-Making Framework

System level: "set rules" applicable to prosumer functions and services



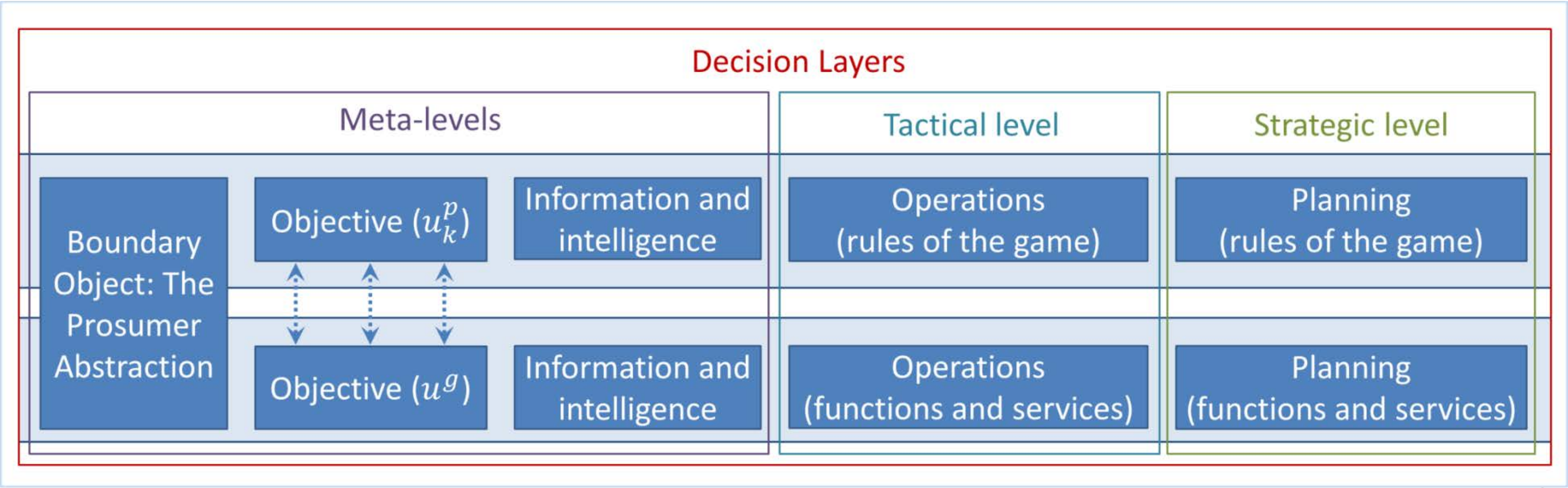
Our focus

Prosumers: "set mechanisms"



System

Agent

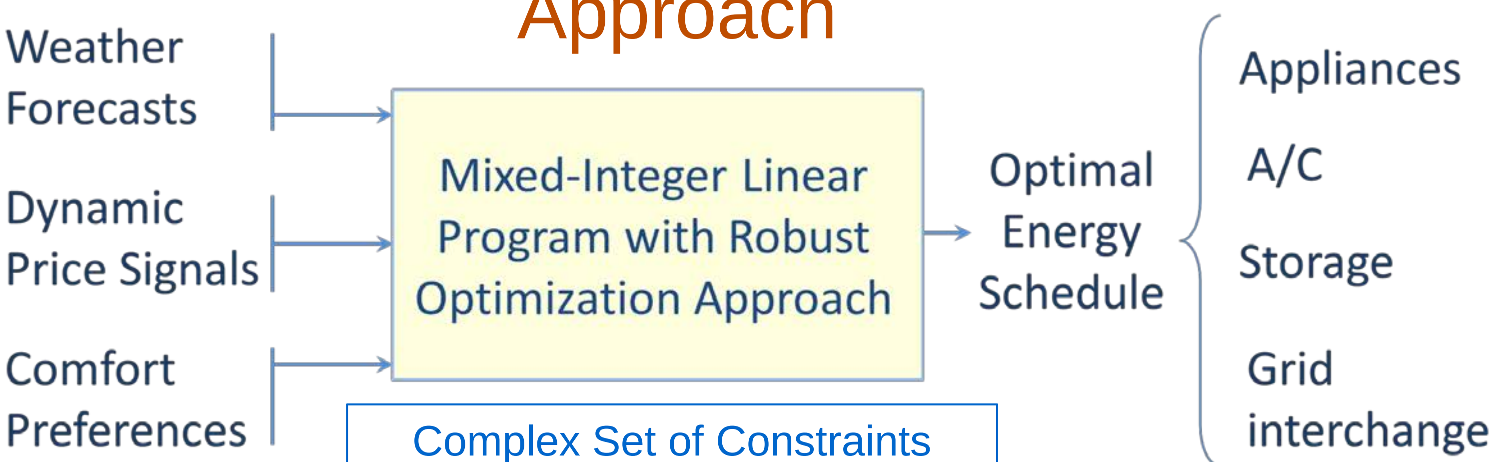


Mechanism 1: Residential Prosumers

<u>Prosumer</u>: residential electricity user

<u>Mechanism</u>: optimize energy usage in dynamic pricing environment

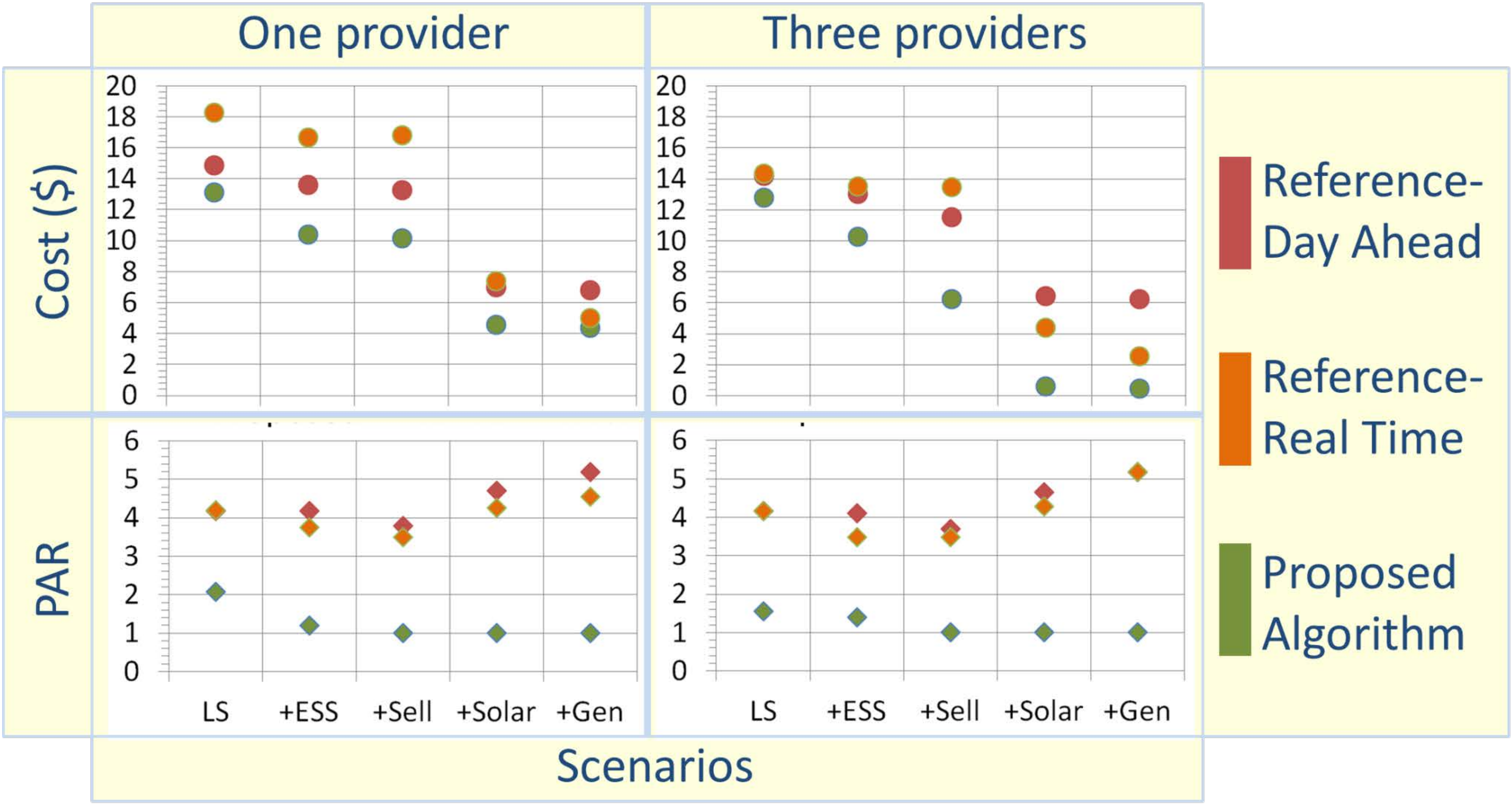
Approach



Complex Set of Constraints

- Physical
- Comfort Preferences
- Modeling
- Market

Results

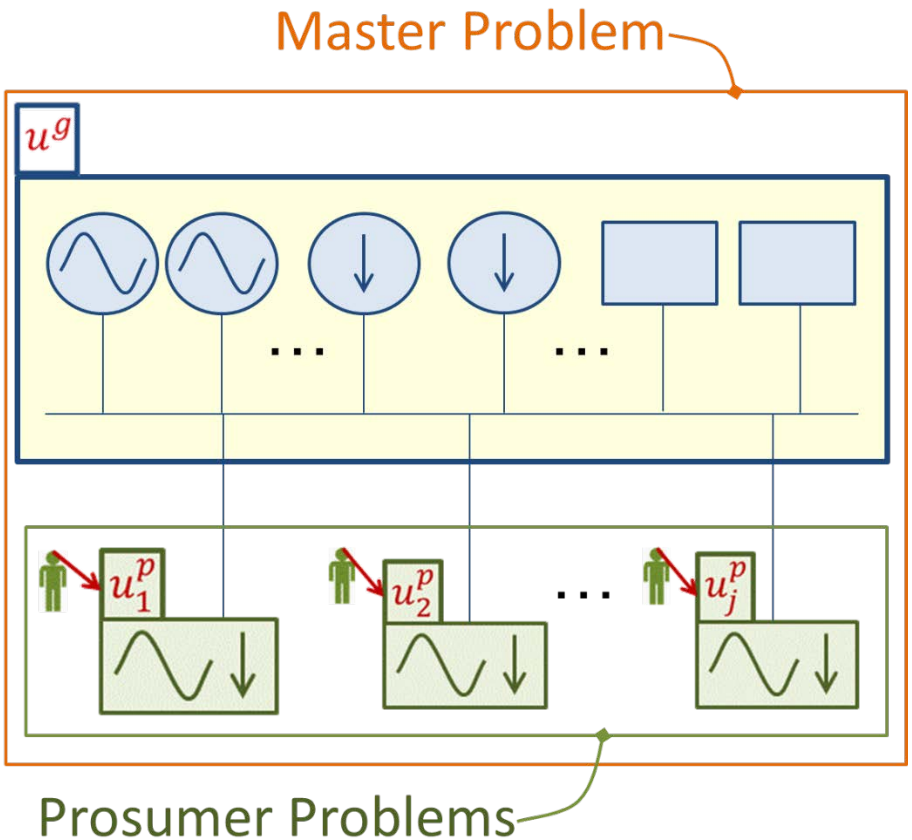


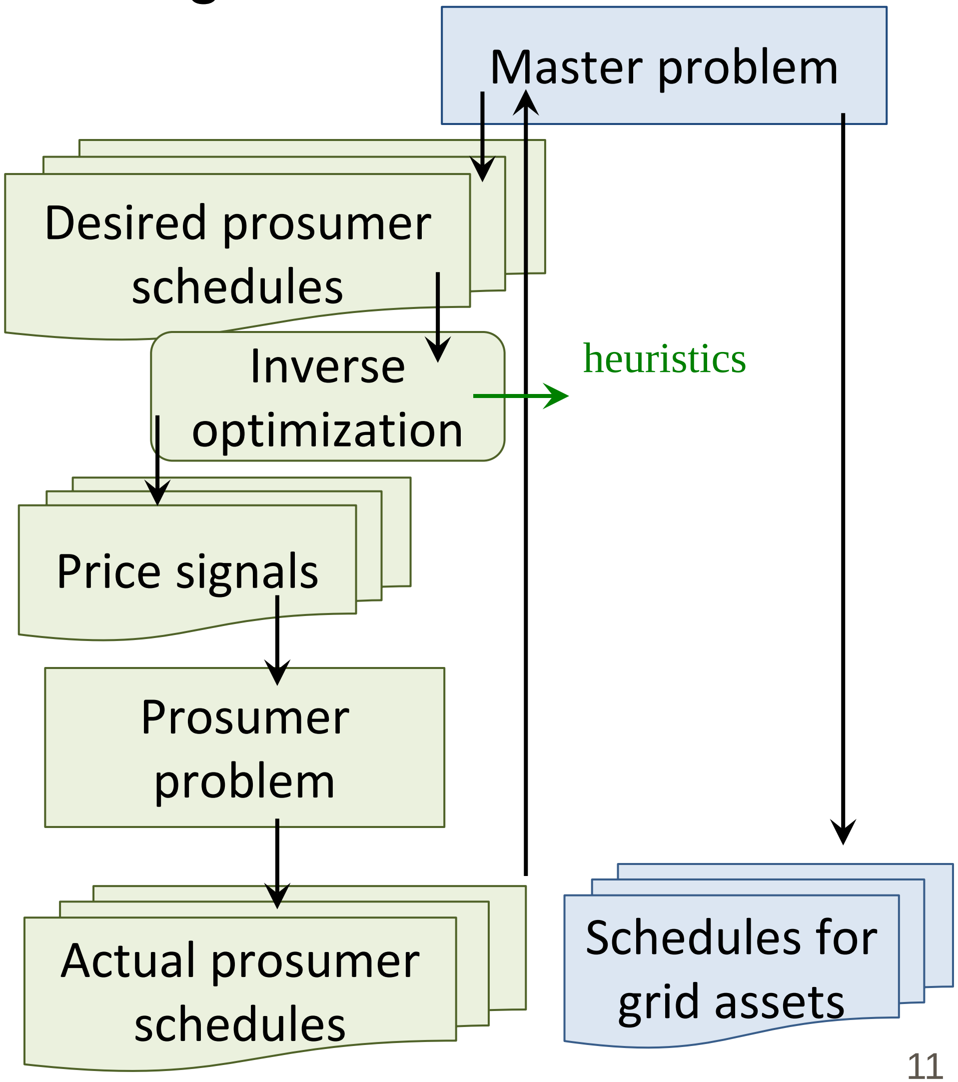
T. Hubert, S. Grijalva, "Modeling for Residential Electricity Optimization in Dynamic Pricing Environments", IEEE Transactions on Smart Grid, Dec 2012

Mechanism 2: Utility Prosumers

<u>Prosumer</u>: utility serving electricity prosumers

<u>Mechanism</u>: optimally design price signals



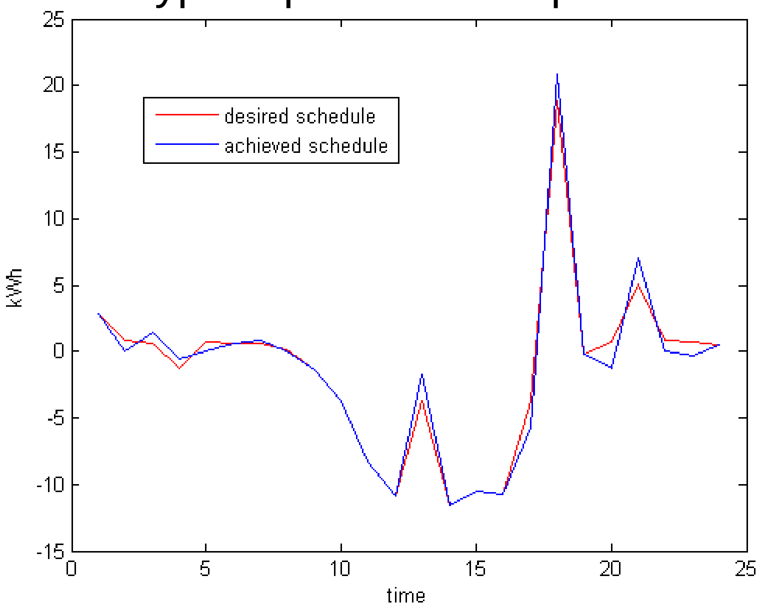


Results

<u>Pilot simulation</u>: 1,000 distinct residential prosumers

Optimization Problem	**Running time (4-core machine)**
Master Problem (initial)	20.49 s
Price generation algorithm (1 prosumer)	Average = 1.94 s Std = 1.95 s
Master Problem (final balancing)	<1s

Typical prosumer response



Performance

Error	Value
Error on individual desired schedules	Average = 11.4% Std = 16.5%
Error on aggregated schedules (daily)	4.9%

Potential Uses of Research Results

Framework proposed

- Introduce the prosumer abstraction
- Enable collaborative research on the future electricity grid.
- Support innovation coming from multidisciplinary collaboration.
- Shared understanding among the various decision makers.

Scheduling algorithm for residential users

- Simulate and analyze the impact of the various ongoing changes on residential electricity markets (DG, use of dynamic pricing, V2G, etc.)
- Implement home energy controllers (HEMS)

Pricing design

- Enhance dispatch by controlling resources through price signals

Potential Benefits

Prosumer concept & general framework: can serve as a medium enabling multidisciplinary teams to collaborate on the future grid research, and foster innovation in the long term.

Energy scheduling algorithms:

- Prescriptive potential: provide concrete guidance on how decision makers should act.
- Descriptive potential: illustrate through simulations *why* decision makers could be better off if new technology or policy are implemented
- Normative potentials: demonstrate *how* decisions should be made so that these changes are effectively realized

Potential Benefits

Pricing design method:

- New control strategies based on engineered price signals
- New business models as electricity providers transition to the future grid and adapt to its new rules and mechanisms.

Project Publications to Date

Hubert, Tanguy, and Santiago Grijalva. "Modeling for Residential Electricity Optimization in Dynamic Pricing Environments." In *Smart Grid, IEEE Transactions on*, vol.3, no.4, pp. 2224-2231, Dec. 2012.

Costley, M., and Santiago Grijalva. "Efficient distributed OPF for decentralized power system operations and electricity markets." In *Innovative Smart Grid Technologies (ISGT), 2012 IEEE PES*, pp.1-6, 16-20 Jan. 2012.

Hubert, Tanguy, and Santiago Grijalva. "Realizing smart grid benefits requires energy optimization algorithms at residential level." In *Innovative Smart Grid Technologies (ISGT), 2011 IEEE PES*, pp.1-8, 17-19 Jan. 2011.

Grijalva, Santiago, and M. U. Tariq. "Prosumer-based smart grid architecture enables a flat, sustainable electricity industry." In *Innovative Smart Grid Technologies (ISGT), 2011 IEEE PES*, pp.1-6, 17-19 Jan. 2011.

Real-Time PMU-Based Tools for Monitoring Operational Reliability

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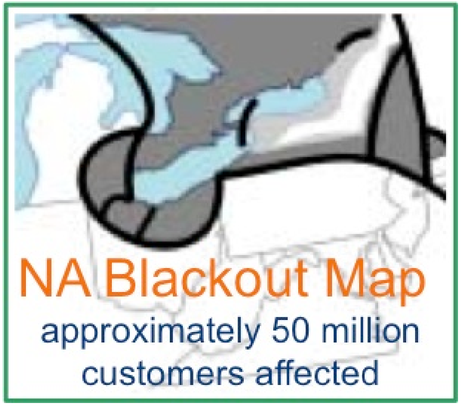
Context of the Research

2003 North America and 2011 San Diego blackouts

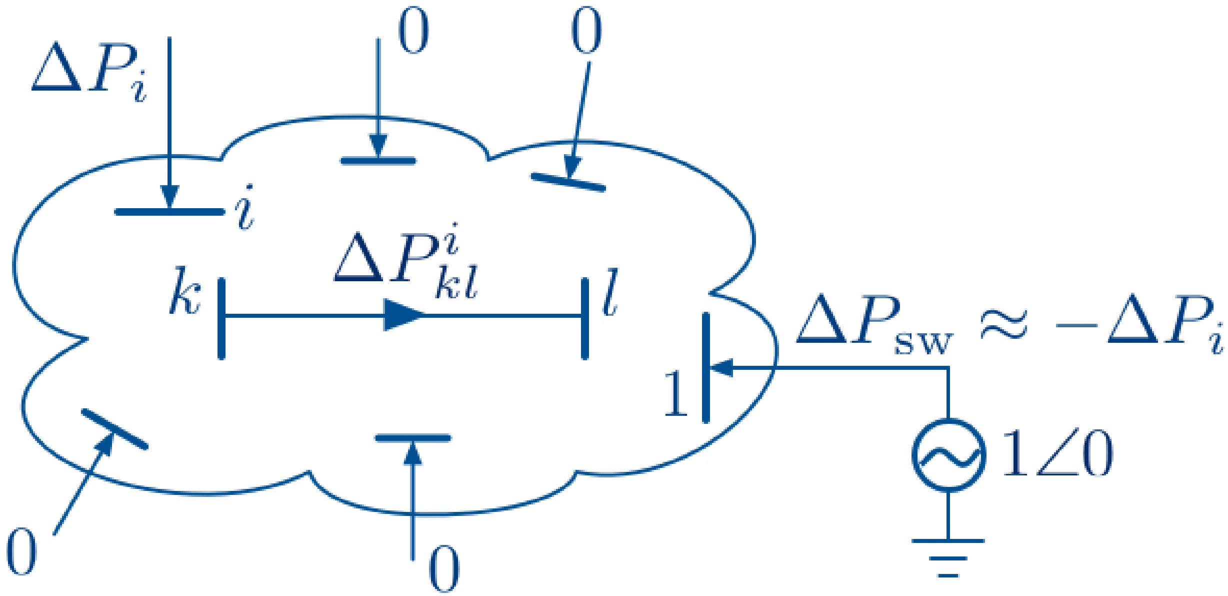


1. Lack of situational awareness — limited visibility outside of system
2. Lack of accurate model — may not have accurate and timely information about key pieces of system

Research Objective

- Heavy reliance on studies conducted on a model of the system obtained offline based on
  - historical electricity demand patterns
  - equipment maintenance schedules
- Linear sensitivity distribution factors (DFs) are used to help determine whether the system is N-1 secure
  Not ideal because
  1. accurate model containing up-to-date network topology is required
  2. results may not be applicable if actual system evolution does not match predicted operating points
- Phasor measurement units (PMUs) provide high-speed voltage and current measurements that are time-synchronized
- **Objective:** Estimate linear sensitivity DFs by exploiting measurements obtained from PMUs <u>without relying on the system power flow model</u>

Injection Shift Factor (ISF)



- Ψ_{kl}^i : the ISF of line kl w.r.t. bus i
- ISF definition: derivative of the real power flow through line kl w.r.t. to the real power injection at bus i, with the real power injections at all other buses (except for the slack bus) held constant
- Thus, the ISF gives the estimated change in power flow on a transmission line due to a unit change in power injected at a particular bus

$$\Psi_{kl}^i := \frac{\partial P_{kl}}{\partial P_i} \approx \frac{\Delta P_{kl}^i(t)}{\Delta P_i(t)}$$

Other Distribution Factors

- Power transfer distribution factor (PTDF) — the MW change in a branch flow for a 1MW exchange between two buses
- Line outage distribution factor (LODF) — the MW change in a branch flow due to the outage of a branch with 1MW pre-outage flow
- Outage transfer distribution factor (OTDF) — the post-contingency MW change in a branch for a 1MW pre-contingency bus-to-reference exchange

These can all be computed once ISFs are known!

Potential Uses of Research Results

- Contingency analysis — establish whether system is N-1 secure based solely on up-to-date measurements
- Generation and flexible load re-dispatch — determine optimal re-dispatch policy to avoid contingency without predefined system model
- Congestion relief — compute transmission congestion charges with up-to-date DFs obtained in real-time
- Model validation — detect model inaccuracy origin by comparing measurement- and model-based results
- Impact of renewable resource uncertainty on line flows — deduce the uncertainty in line flows arising from renewable power injection uncertainty

ISF Computation Approach

- Measurements are taken every Δt units of time
- The total change in active power flow in line kl can be approximated as the sum of the change due to the real power injection at each bus by superposition, i.e.,

$$\begin{aligned}\Delta P_{kl}(t) &\approx \Delta P_{kl}^{1}(t) + \cdots + \Delta P_{kl}^{i}(t) + \cdots + \Delta P_{kl}^{n}(t) \\ &\approx \Delta P_1(t)\Psi_{kl}^{1} + \cdots + \Delta P_i(t)\Psi_{kl}^{i} + \cdots + \Delta P_n(t)\Psi_{kl}^{n}\end{aligned}$$

where

$$\Delta P_i(t) = P_i(t+\Delta t) - P_i(t)$$

and

$$\Delta P_{kl}(t) = P_{kl}(t+\Delta t) - P_{kl}(t)$$

- Let $t = j\Delta t$, then we discretize the above as

$$\Delta P_{kl}[j] \approx \Delta P_1[j]\Psi_{kl}^{1} + \cdots + \Delta P_i[j]\Psi_{kl}^{i} + \cdots + \Delta P_n[j]\Psi_{kl}^{n}$$

ISF Computation Approach

- Stacking m of these measurement instances up, where $m > n$, we obtain

$$\underbrace{\begin{bmatrix} \Delta P_{kl}[1] \\ \vdots \\ \Delta P_{kl}[j] \\ \vdots \\ \Delta P_{kl}[m] \end{bmatrix}}_{y} = \underbrace{\begin{bmatrix} \Delta P_1[1] & \cdots & \Delta P_i[1] & \cdots & \Delta P_n[1] \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \Delta P_1[j] & \cdots & \Delta P_i[j] & \cdots & \Delta P_n[j] \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \Delta P_1[m] & \cdots & \Delta P_i[m] & \cdots & \Delta P_n[m] \end{bmatrix}}_{H} \underbrace{\begin{bmatrix} \Psi_{kl}^1 \\ \vdots \\ \Psi_{kl}^i \\ \vdots \\ \Psi_{kl}^n \end{bmatrix}}_{x}$$

- An over-determined system of the form $y = Hx$, which we solve via least-squares estimation:

$$\hat{x} = (H^T H)^{-1} H^T y$$

- Method relies on inherent fluctuations in load and generation
- Other assumptions
  1. The ISFs are approximately constant across the m+1 measurements
  2. The regressor matrix H has full column rank

Case Study Methodology

- Simulate PMU measurements of random fluctuations in active power injection at each bus

$$P_i = P_i^0 + \sigma_1 P_i^0 v_1 + \sigma_2 v_2$$

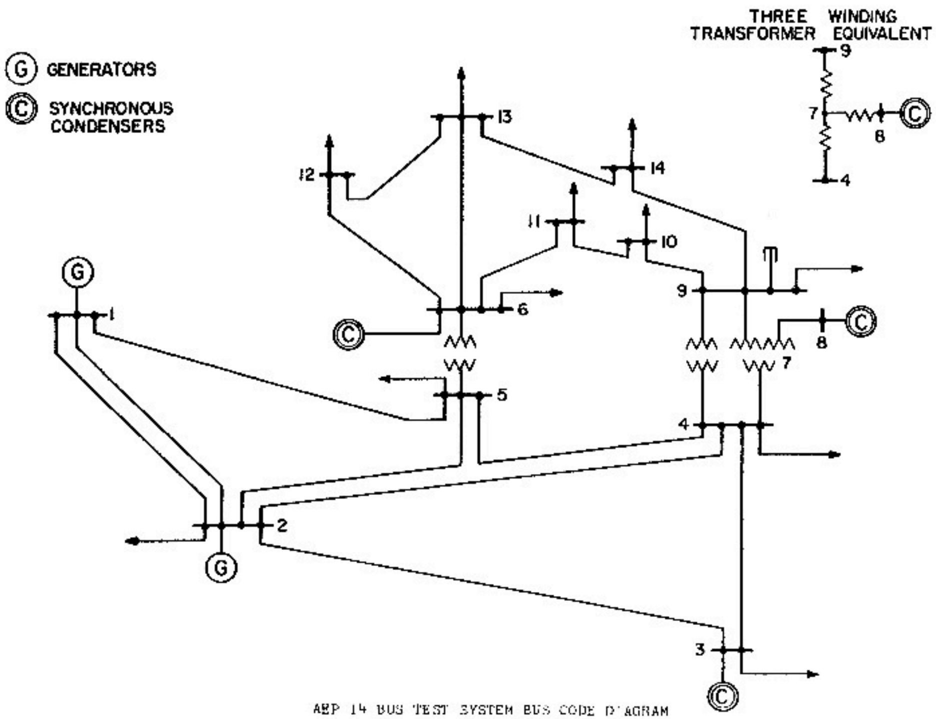
  - P_i^0 — nominal power injection at node i
  - v_1 and v_2 — pseudorandom values drawn from standard normal distribution
  - $\sigma_1 P_1^0 v_1$ — inherent variability in power injection with time
  - $\sigma_2 v_2$ — measurement noise

- For each set of random power injection data, compute the power flow, with the slack bus absorbing all power imbalances

$$\begin{bmatrix} \Delta P_l[1] \\ \vdots \\ \Delta P_l[k] \\ \vdots \\ \Delta P_l[m] \end{bmatrix} = \begin{bmatrix} \Delta P_1[1] & \cdots & \Delta P_i[1] & \cdots & \Delta P_n[1] \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \Delta P_1[k] & \cdots & \Delta P_i[k] & \cdots & \Delta P_n[k] \\ \vdots & \vdots & \vdots & \vdots & \vdots \\ \Delta P_1[m] & \cdots & \Delta P_i[m] & \cdots & \Delta P_n[m] \end{bmatrix} \begin{bmatrix} \Psi_l^1 \\ \vdots \\ \Psi_l^i \\ \vdots \\ \Psi_l^n \end{bmatrix}$$

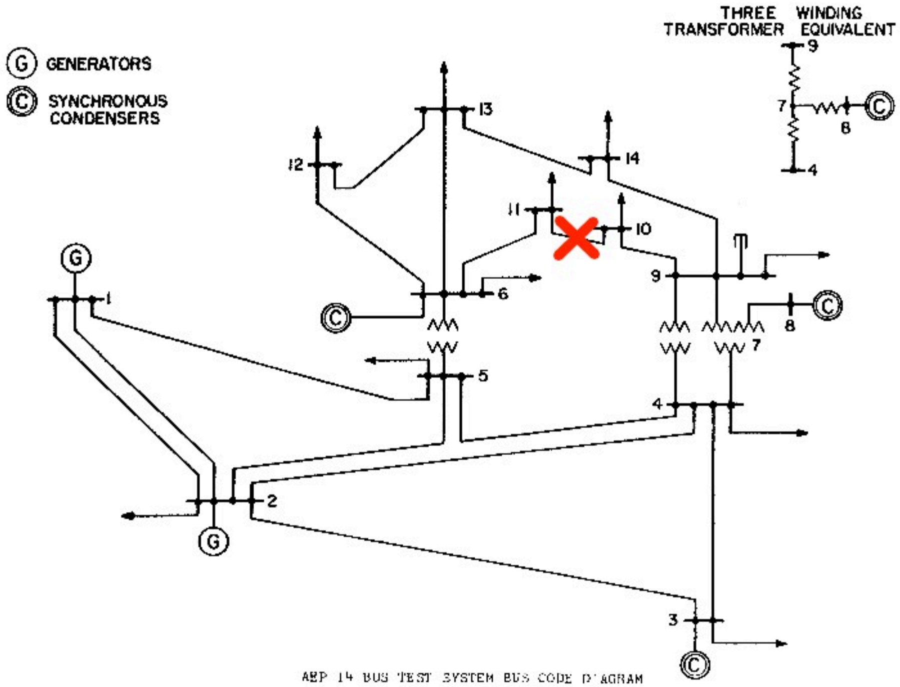
IEEE 14 Bus Test System

Suppose a 100 MW increase is applied at bus 2:



Line	Actual (MW)	Model-based (MW)	LSE (MW)
P_{1-2}	69.96	73.39	68.40
P_{1-5}	58.84	59.22	58.46
P_{2-3}	75.64	75.67	75.63
P_{2-4}	61.91	61.88	61.89
P_{2-5}	49.86	49.84	49.83
P_{3-4}	-21.05	-20.85	-21.01
$\vdots$	$\vdots$	$\vdots$	$\vdots$

IEEE 14 Bus Test System



- Undetected outage in l_{10-11}
- Contingency analysis: what if outage in l_{4-5} occurs?
- Compare LODFs obtained from
  - original system model
  - real-time measurements

Line	Pre-contingency Actual (p.u.)	Post-contingency (p.u.) Actual	Model-based	LSE
P_{2-3}	0.7295	0.9065	0.8803	0.9052
P_{13-14}	0.0976	0.2116	0.1551	0.2053

Conclusion and Future Work

- Estimate distribution factors
  - using real-time PMU measurements
  - without the use of the system power flow model
- Key advantages
  - Eliminate reliance on system models and corresponding accuracy
  - Resilient to unexpected system topology and operating point changes
  - Opportunity to explore distributed algorithms to solve the problem, using only local PMU data
- Further work
  - Accurate estimate in the presence of corrupted or availability of only a subset of measurements
  - Distributed computation using local information from neighboring nodes
  - Accurate estimate with fewer sets of measurements — would increase responsiveness to system changes

Project Publications to Date

K. E. Reinhard, P. W. Sauer, and A. D. Domínguez-García, "On Computing Power System Steady-State Stability Using Synchrophasor Data," in *Proc. of the Hawaii International Conference on System Sciences*, Maui, HI, January 2013.

Y. C. Chen, P. Sauer and A. D. Domínguez-García, "Online Computation of Power System Linear Sensitivity Distribution Factors," in *Proc. of the IREP Bulk Power System Dynamics and Control Symposium*, Crete, Greece, August 2013.

Y. C. Chen, P. Sauer and A. D. Domínguez-García, "On the Use of PMU Measurements for Estimating Linear Sensitivity Distribution Factors," in preparation for submission to IEEE Transactions on Power Systems.

Hierarchical Probabilistic Coordination and Optimization of DERs and Smart Appliances

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Background and Motivation

Massive deployment of Distributed Energy Resources (DERs) (wind, solar, PHEVs, smart appliances, storage, etc) with power electronic interfaces will change the characteristics of the distribution system:

- Bidirectional flow of power with ancillary services.
- Presence of non-dispatchable and variable generation.
- Non-conventional dynamics → inertial-less characteristics of inverters.

Market Approach: Incentive/price market and local controls

Our Approach: Create an active distribution system supervised with a distributed optimization tool. Specifically:

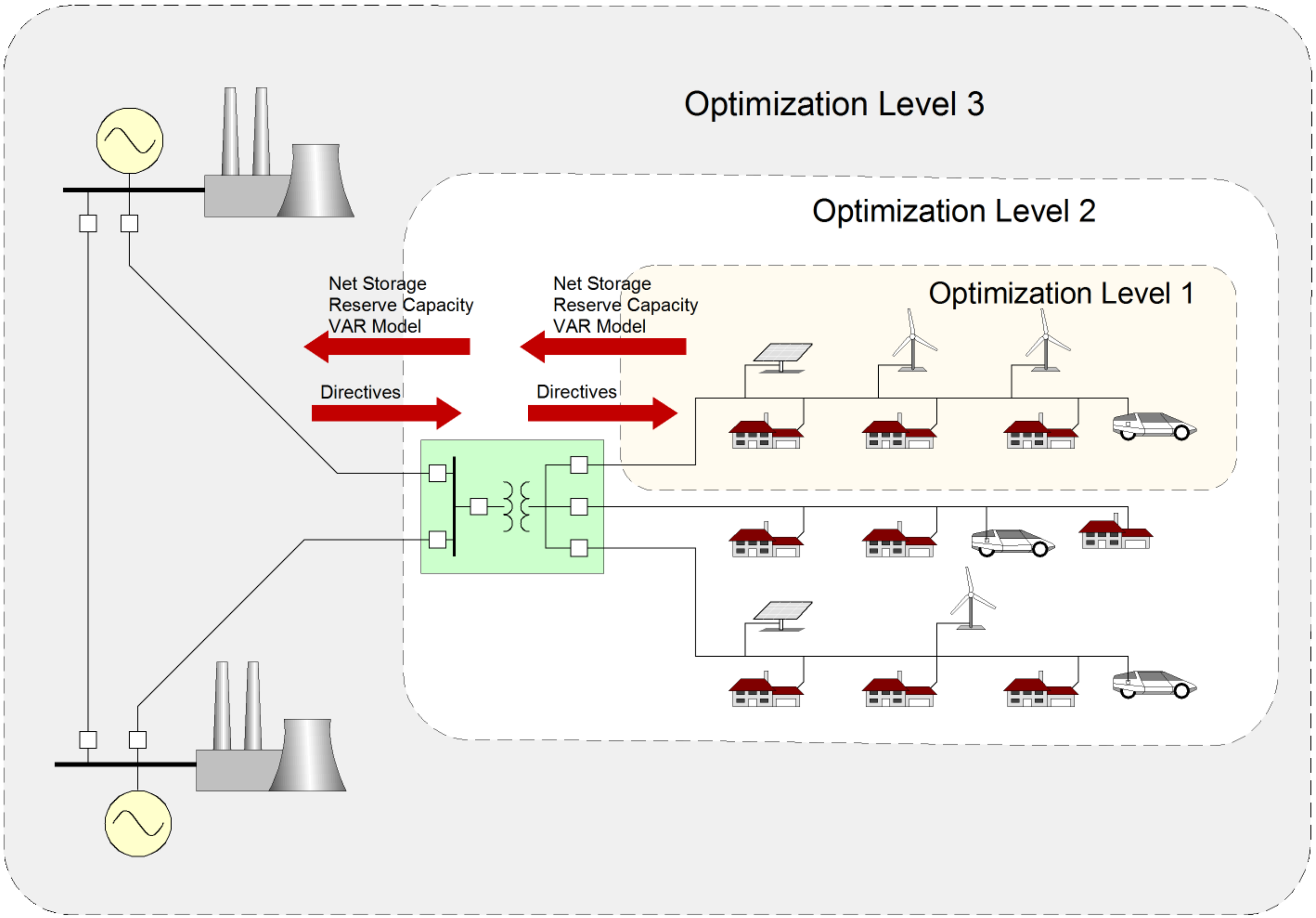
Develop an infrastructure for monitoring and control supervised by a hierarchical stochastic optimization tool that will enable:

- Maximize value of renewables.
- Improve economics by load levelization (peak load reduction) and loss minimization.
- Improve environmental impact by maximizing use of clean energy sources.
- Improve operational reliability by distributed ancillary services and controls.

Hierarchical Optimization Scheme

Three-level hierarchical optimization architecture:

Optimization Level 1: feeder optimization (including aggregators, utility and customer owned resources, etc.)
Optimization Level 2: substation optimization (optimize all feeders connected to a substation)
Optimization Level 3: system optimization (optimize all substations)



Feeder Optimization Problem: Definition

Given:

A planning period (typically one day).

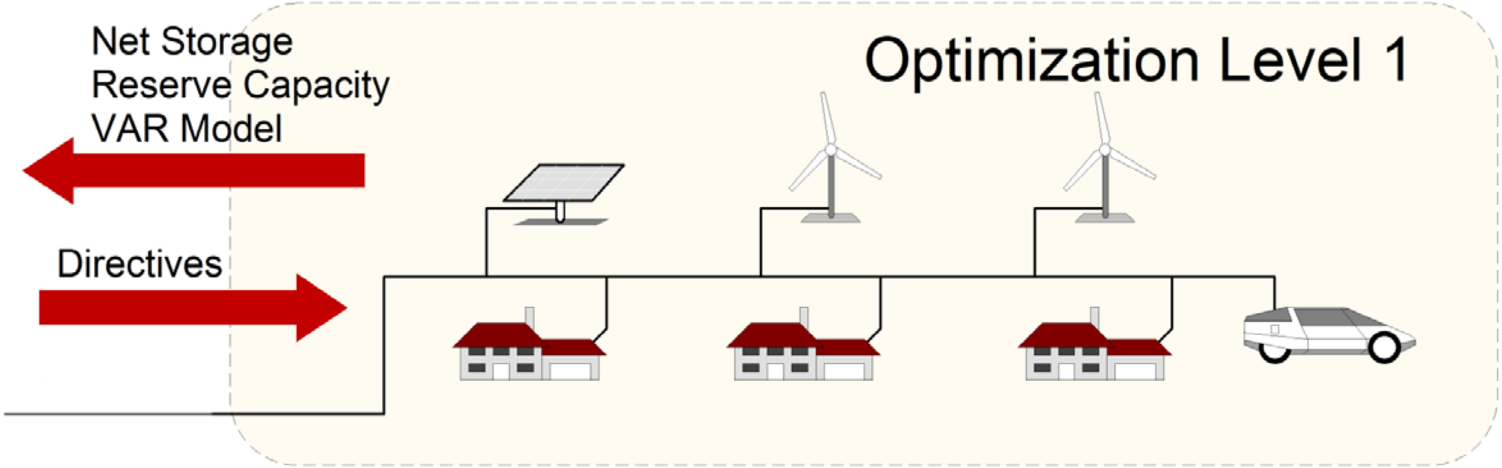
A feeder with a number of DERs and topology under direct control

Directives from the higher level optimization

- Total stored energy in all feeder resources during the planning period.
- Minimum reserve and spinning reserve margin in all feeder resources within the planning period.

Determine:

The optimal (minimum cost) operating conditions of DERs, appliances, etc. subject to meeting the directives from the higher optimization level over the planning period – with no inconvenience to customers



Feeder Optimization Problem: Formulation

Reference Only

$$\min = f\left(\mathbf{x},\mathbf{u}\right)$$ Operating cost of the feeder

s.t

$$E(t_h) = \sum_{si} E_{si}(t_h) \qquad h = 0,\dots,n$$: Total stored energy in all feeder resources during the planning period

$$SR(t_h) \le \sum_{\substack{si \\ P_{si}(t_h)\neq 0}} (S_{si,N} - P_{si}(t_h)) + \sum_{\substack{gi \\ P_{gi}(t_h)\neq 0}} (S_{gi,N} - P_{gi}(t_h)) \quad h = 0,\dots,n$$: Spinning Reserve Capacity

$$R(t_h) \le \sum_{\substack{si \\ P_{si}(t_h)=0}} (S_{si,N} - P_{si}(t_h)) + \sum_{\substack{gi \\ P_{gi}(t_h)=0}} (S_{gi,N} - P_{gi}(t_h)) \quad h = 0,\dots,n$$: Reserve Capacity

$$\left.\begin{array}{c} E_{si,0} \le E_{si}(t_h) = E_{si}(t_{h-1}) - P_{si}(t_h)\cdot\Delta t \le E_{si,N} \\ 0 \le \sqrt{P_{si}^2(t_h) + Q_{si}^2(t_h)} \le S_{si,N} \end{array}\right\} \begin{array}{c} h = 0,\dots,n \\ \textit{for all storage} \\ \textit{devices} \end{array}$$: Storage devices constraints

$$0 \le \sqrt{P_{gi}^2(t_h) + Q_{gi}^2(t_h)} \le S_{gi,N} \qquad \begin{array}{c} h = 0,\dots,n \\ \textit{for all generating units} \end{array}$$: Generating units capacity constraints

$$0 = g(x,u)$$: Power flow constraints

$$0 \le h(x,u)$$: Operational constraints of the feeder (eg. bus voltage magnitude, distribution lines and transformers capacity constraints

Feeder Optimization Problem: Object-oriented Methodology

Each Device is modeled with a set of Quadratized Equations in terms of State and Control variables in a standard syntax (QSnC model).

- Device QSnC model (Quadratized State 'n Control Form):

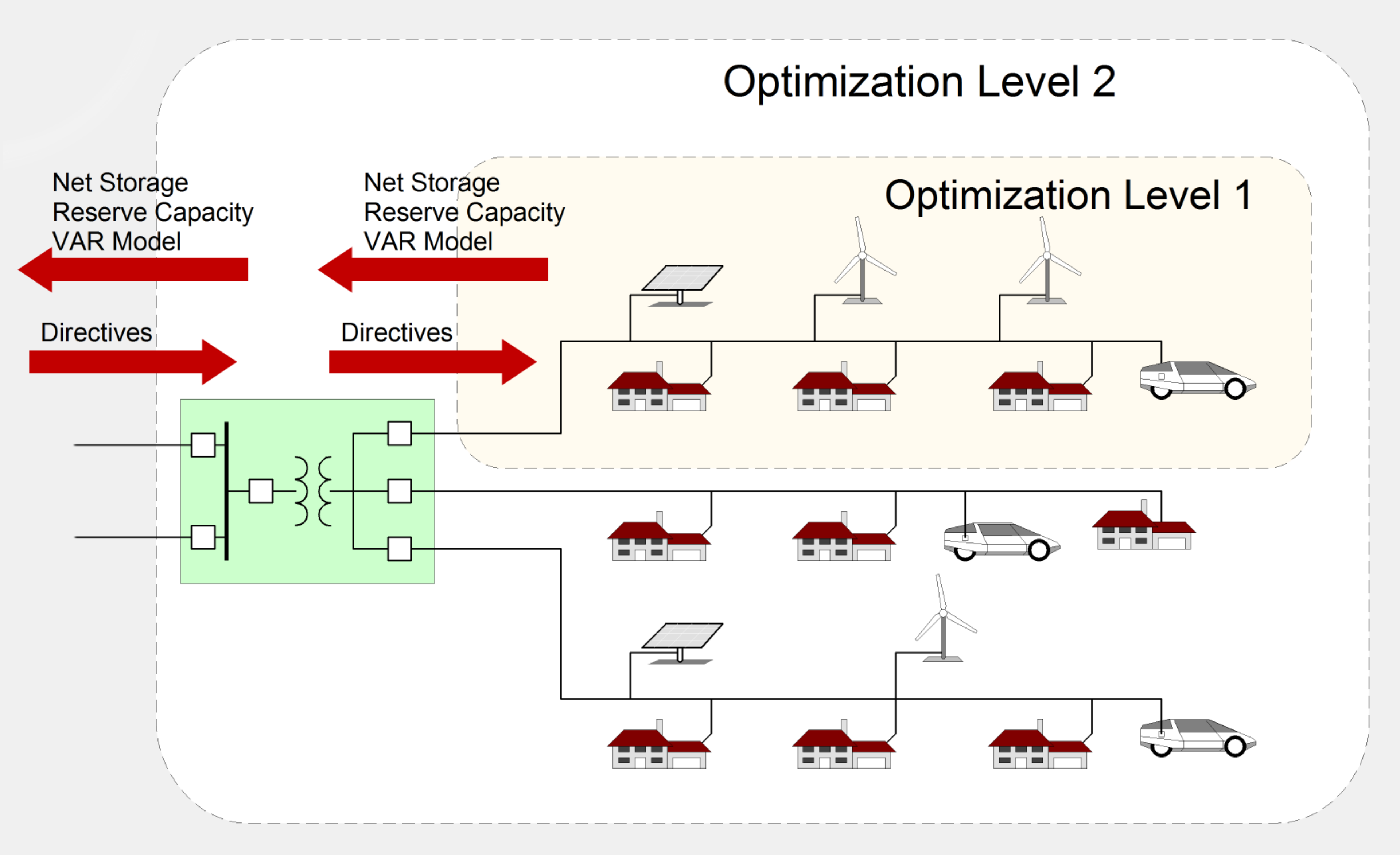
$$
\begin{bmatrix} \tilde{I}(t_k) \\ 0 \\ \tilde{I}(t_{k,m}) \\ 0 \end{bmatrix} = Y_{eq\_x}(t_k) \begin{bmatrix} \tilde{X}_v(t_k) \\ \tilde{X}_u(t_k) \\ \tilde{X}_v(t_{k,m}) \\ \tilde{X}_u(t_{k,m} \end{bmatrix} + \begin{bmatrix} \begin{bmatrix} \tilde{X}_v^T(t_k) & \tilde{X}_v^T(t_k) & \tilde{X}_u^T(t_{k,m}) & \tilde{X}_v^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_x\_1}(t_k) \cdot \begin{bmatrix} \tilde{X}_v(t_k) \\ \tilde{X}_v(t_k) \\ \tilde{X}_u(t_{k,m}) \\ \tilde{X}_v(t_{k,m}) \end{bmatrix} \\ \vdots \\ \begin{bmatrix} \tilde{X}_v^T(t_k) & \tilde{X}_v^T(t_k) & \tilde{X}_u^T(t_{k,m}) & \tilde{X}_v^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_x\_n}(t_k) \cdot \begin{bmatrix} \tilde{X}_v(t_k) \\ \tilde{X}_v(t_k) \\ \tilde{X}_u(t_{k,m}) \\ \tilde{X}_v(t_{k,m}) \end{bmatrix} \end{bmatrix} + Y_{eq\_u}(t_k) \begin{bmatrix} \tilde{U}(t_k) \\ \tilde{U}(t_{k,m}) \end{bmatrix} + \begin{bmatrix} \begin{bmatrix} \tilde{U}^T(t_k) & \tilde{U}^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_u\_1}(t_k) \cdot \begin{bmatrix} \tilde{U}(t_k) \\ \tilde{U}(t_{k,m}) \end{bmatrix} \\ \vdots \\ \begin{bmatrix} \tilde{U}^T(t_k) & \tilde{U}^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_u\_n}(t_k) \cdot \begin{bmatrix} \tilde{U}(t_k) \\ \tilde{U}(t_{k,m}) \end{bmatrix} \end{bmatrix}
$$

$$
+ \begin{bmatrix} \begin{bmatrix} \tilde{X}_v^T(t_k) & \tilde{X}_v^T(t_k) & \tilde{X}_u^T(t_{k,m}) & \tilde{X}_v^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_xu\_1}(t_k) \cdot \begin{bmatrix} \tilde{U}(t_k) \\ \tilde{U}(t_{k,m}) \end{bmatrix} \\ \vdots \\ \begin{bmatrix} \tilde{X}_v^T(t_k) & \tilde{X}_v^T(t_k) & \tilde{X}_u^T(t_{k,m}) & \tilde{X}_v^T(t_{k,m}) \end{bmatrix} \cdot F_{eq\_xu\_n}(t_k) \cdot \begin{bmatrix} \tilde{U}(t_k) \\ \tilde{U}(t_{k,m}) \end{bmatrix} \end{bmatrix} - B_{eq}(t_k)
$$

- In Matrix notation:

$$
I(\mathbf{x},\mathbf{u}) = Y_{eqx} \cdot \mathbf{x} + \left\{ \mathbf{x}^T \cdot F_{eqx,i} \cdot \mathbf{x} \right\} + Y_{equ} \cdot \mathbf{u} + \left\{ \mathbf{u}^T \cdot F_{equ,i} \cdot \mathbf{u} \right\} + \left\{ \mathbf{x}^T \cdot F_{eqxu,i} \cdot \mathbf{u} \right\} - B_{eq}
$$

Hierarchical Optimization Scheme: Substation



Substation Level Optimization: Stochastic DP

Given: A substation with several distribution feeders, Peak storage, peak capacity, etc. for each of the feeders, Performance criteria (e.g. operation cost), and A planning horizon (e.g. day, week, etc.)

Compute: Directive values for each feeder at each stage k that result in minimum optimal substation operation cost over planning horizon.

Solution method: Stochastic Dynamic Programming

$$R^*_{k+1}(E_{k+1}, R_{k+1}, SR_{k+1}) = \min_{E_k, R_k, SR_k} [R^*_k(E_k, R_k, SR_k) + E\{C^*(E_{k+1}, R_{k+1}, SR_{k+1}, G_A, L)]\}$$

$$Subject\_to:$$

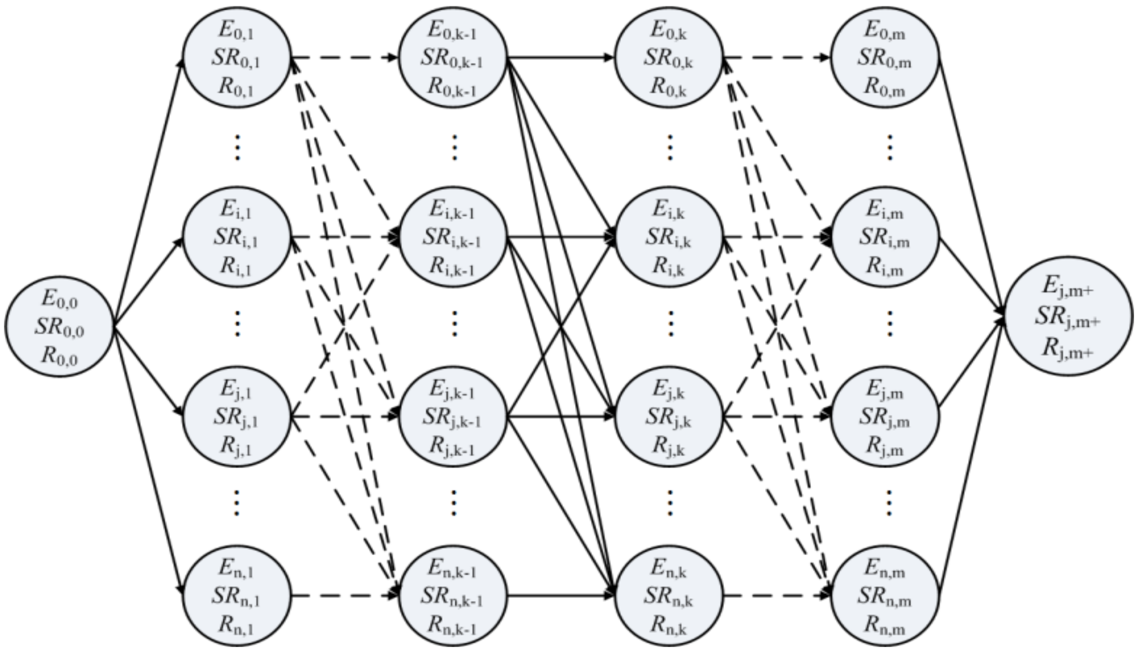
$$E_{\min} \le E_k \le E_{\max} \quad k = 0,1,\cdots$$

$$R_{\min} \le R_k \le R_{\max} \quad k = 0,1,\cdots$$

$$SR_{\min} \le SR_k \le SR_{\max} \quad k = 0,1,\cdots$$

$$Q_{\min} \le Q_k \le Q_{\max} \quad k = 0,1,\cdots$$

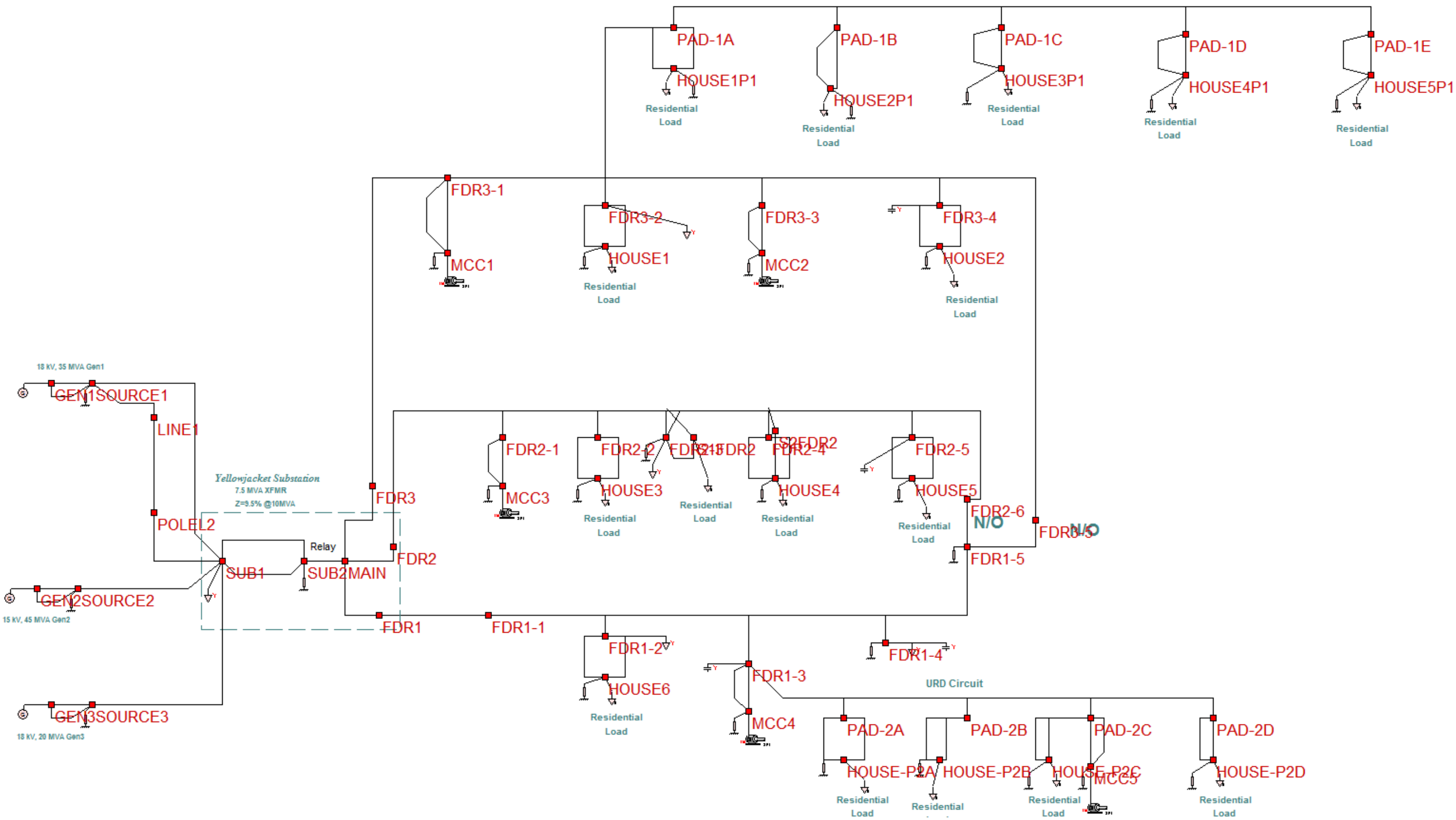
Transition cost:
$C(E_{j,k-1}, SR_{j,k-1}, R_{j,k-1}, E_{i,k}, SR_{i,k}, R_{i,k})$



The transition costs are computed from the feeder optimization level

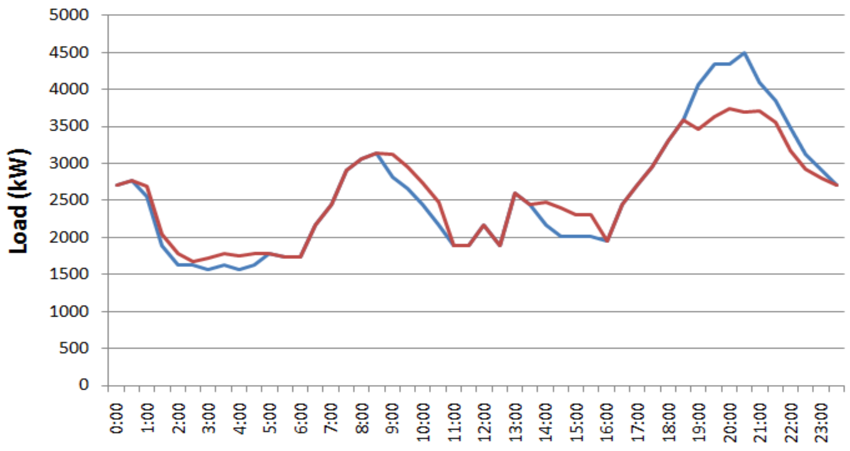
Hierarchical Optimization: Example Test System

12.47 kV, 9 MVA substation, 3 distribution feeders

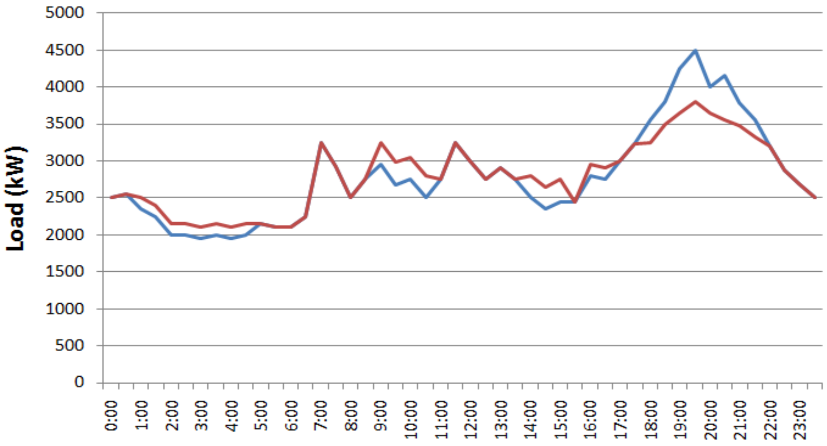


- The loading of the feeder is about 50% of its capacity, i.e. 4.5 MVA
- 3.3% penetration of DERs (total of 300kW).
- 60% of the houses are assumed to have storage devices that comprise an additional 3.3% of the feeder rating (300 kW total capacity) with a storage capability of 600 kWh.

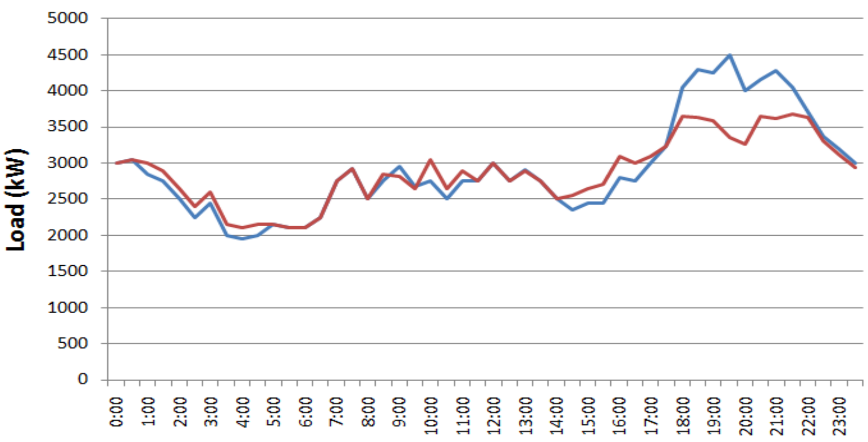
Hierarchical Optimization Results (One Day)



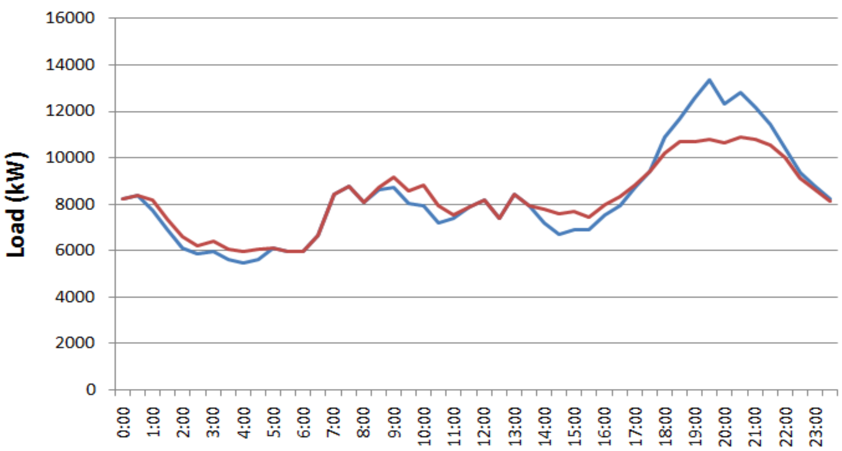
Feeder 1



Feeder 2



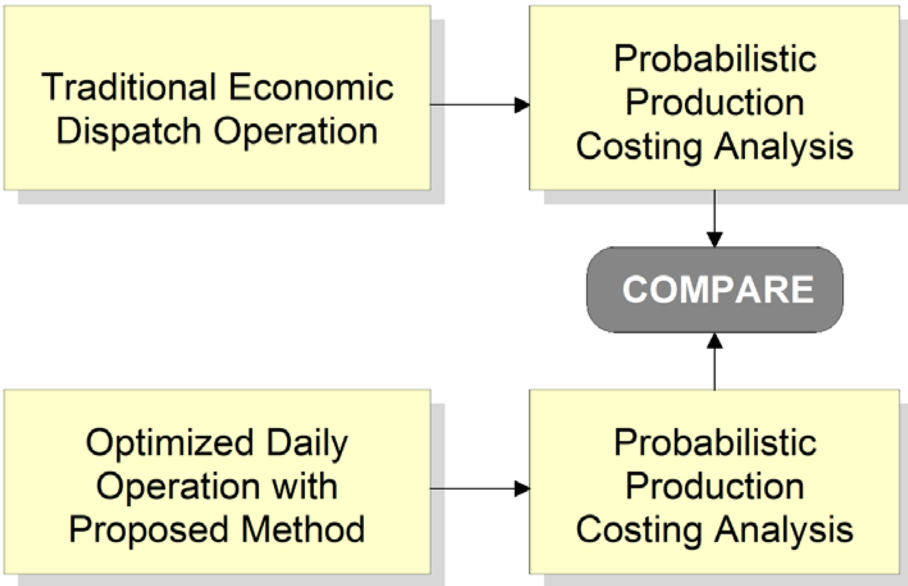
Feeder 3



Substation (Total)

Achieved 20% peak load reduction

Business Case
Probabilistic Production Cost (PPC) Analysis



Given a probabilistic “composite load” model (composite load demand curves - forecast) for the time period under consideration and the available generating units of the system:

The expected generated energy for each unit taking into account the effects of scheduling functions (economic dispatch, pollution dispatch, etc.) within the time period considered, the random forced outages of the units and maintenance schedules

The expected operating cost and fuel utilization

Reliability indices such as LOL, EUE, etc.

Comparison Methodology:

(a) Probabilistic simulations to evaluate and compare operating costs, fuel utilization (pollution) and reliability with and without the proposed optimization.
(b) Quantify benefits resulting from the proposed optimization scheme

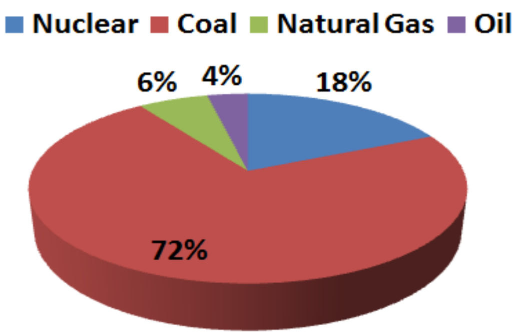
PPC Analysis—Results

(Thermal Units: Economic Dispatch based on Fuel Cost)

Increased Reliability

A typical utility system was used as a test-bed with 22 GW capacity and 40 generator units (coal, nuclear, oil, natural gas).

Assumed 6.6% penetration of DERs and storage devices.



	Non-Optimized Scenario	Optimized Scenario
Loss of load probability	0.04173	**0.00227**
Generated energy (MWh)	297,841.709	297,018.599
Unserviced energy (MWh)	1,103.695	32.896
Total production cost (k$)	8,234.674	7,945.566
Average production cost (cents/KWH)	2.7648	2.6751
Total CO2 emissions (kg)	125,671,208.46	**124,906,337.604**
Total NOx emissions (kg)	381,722.746	**379,289.922**

Decreased Pollutant emissions

Annual Production Cost Savings:

(k$ 8234.67 - k$ 7945.57) $\times$ 365 days = $ 105.520 M

Cost / Benefit Analysis

Expected Investment Cost

Investment	Cost (Million $)	Comments
DERs & Storage	1,470	Investment Cost
AMI	200	Instrumentation Cost
DMS Software & Hardware	5	Distribution Management System Cost
Total	1,675	Total Investment Cost

Annualized Equivalent Cost (AE) – Assume: Interest rate of 8%, 20 year Economic Lifetime, Zero Salvage Value at the End of Life

$$1{,}675 = \sum_{n=0}^{19} \frac{AE}{1.08^n} \longrightarrow AE = \mathbf{\$157.96\ Million}$$

The cost of the infrastructure is higher (by 33.2%) than the expected benefit. However if the benefits from improved reliability, and reduced pollutants is taken into account, the attractiveness of the proposed approach will increase.

Accomplishments and Potential Uses

Accomplishments

- Infrastructure for real time monitoring and extraction of the real time model of the system (utility and customer owned equipment).
- Object-oriented and autonomously executed hierarchical stochastic optimization algorithm that provides the control signals for the distributed resources (model based control).
- Business case analysis that quantifies implementation costs and benefits / comprehensive studies.

Potential Uses

- Load Levelization (peak load reduction) with no customer inconvenience (coordinated approach to demand response).
- Loss minimization by balancing the feeder (coordinated scheduling of non-essential customer loads and resources).
- Increased Operational Reliability by utilizing (a) the ability of inverters to provide ancillary services, (b) the ability of distributed resources to provide reserve capacity, and (c) the ability of the proposed system to provide coordinated demand response.
- Reduction of conventional generating unit cycling

Project Publications to Date

A. P. Meliopoulos, G. Cokkinides, R. Huang, E. Farantatos, S. Choi, Y. Lee, and X. Yu, “Smart Grid Technologies for Autonomous Operation and Control”, *IEEE Trans. on Smart Grid*, vol. 2, issue 1, 2011.

A. P. Meliopoulos, G. Cokkinides, R. Huang, and E. Farantatos, “Integrated Smart Grid Hierarchical Control”, in *Proceedings of the 45th Annual Hawaii International Conference on System Sciences (HICSS)*, Maui, Hawaii, Jan. 4-7, 2012.

R. Huang, E. Farantatos, G. Cokkinides and A. P. Meliopoulos, “Impact of Non-Dispatchable Renewables on Generator Cycling and Control via a Hierarchical Control Scheme”, in *Proceedings of the 2024 IEEE PES Transmission & Distribution Conference & Exposition*, Orlando, FL, May 7-10, 2012.

Computational Issues of Optimization for Planning

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PSERC

Research Goals

Improved computational methods for long-term resource planning under uncertainty:

- Efficiently and effectively reduce the number of scenarios considered in stochastic program for generation expansion planning
- Multi-level models for transmission planning, generation expansion, and market operations
  - Solve tri-level model for transmission plans
  - Include uncertainty in bi-level model for transmission and generation expansion

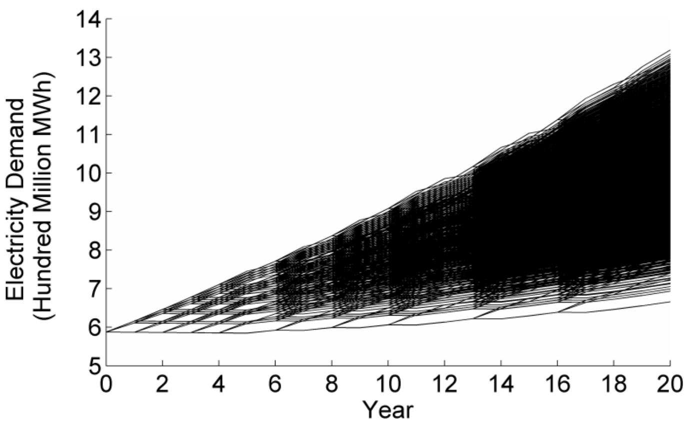
Generation Expansion Planning Under Uncertainty

- Stage 1: investment plan over long time horizon
- Stage 2: for realized scenario paths of load and natural gas price
  - Energy generated by each unit, in each load duration curve (LDC) segment, each year
  - Unserved energy in each LDC segment, each year
- Minimize investment plus operational cost
  - Expected value
  - Conditional Value at Risk = expected cost in the α-fraction of worst cases

Scenario Generation and Reduction

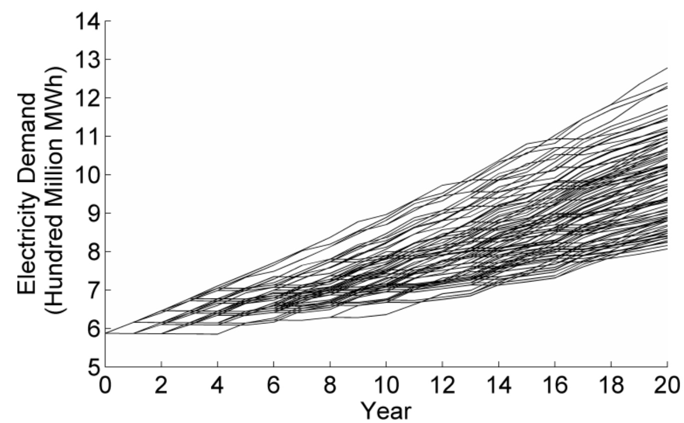
Correlated processes for demand and fuel prices

- Match historical properties: mean, variance, skewness, cross-correlation
- Scenario tree for conditional evolution
- 3 branches per stage * 10 stages



Forward Selection in Wait-and-See Clusters (FSWC)

1. Solve subproblem for each scenario path
2. Cluster scenarios based on similarity of investment decisions and total costs
3. Apply *Forward Selection* within each cluster



Results: Accuracy and Computation Time

- 100 scenarios selected by two heuristics

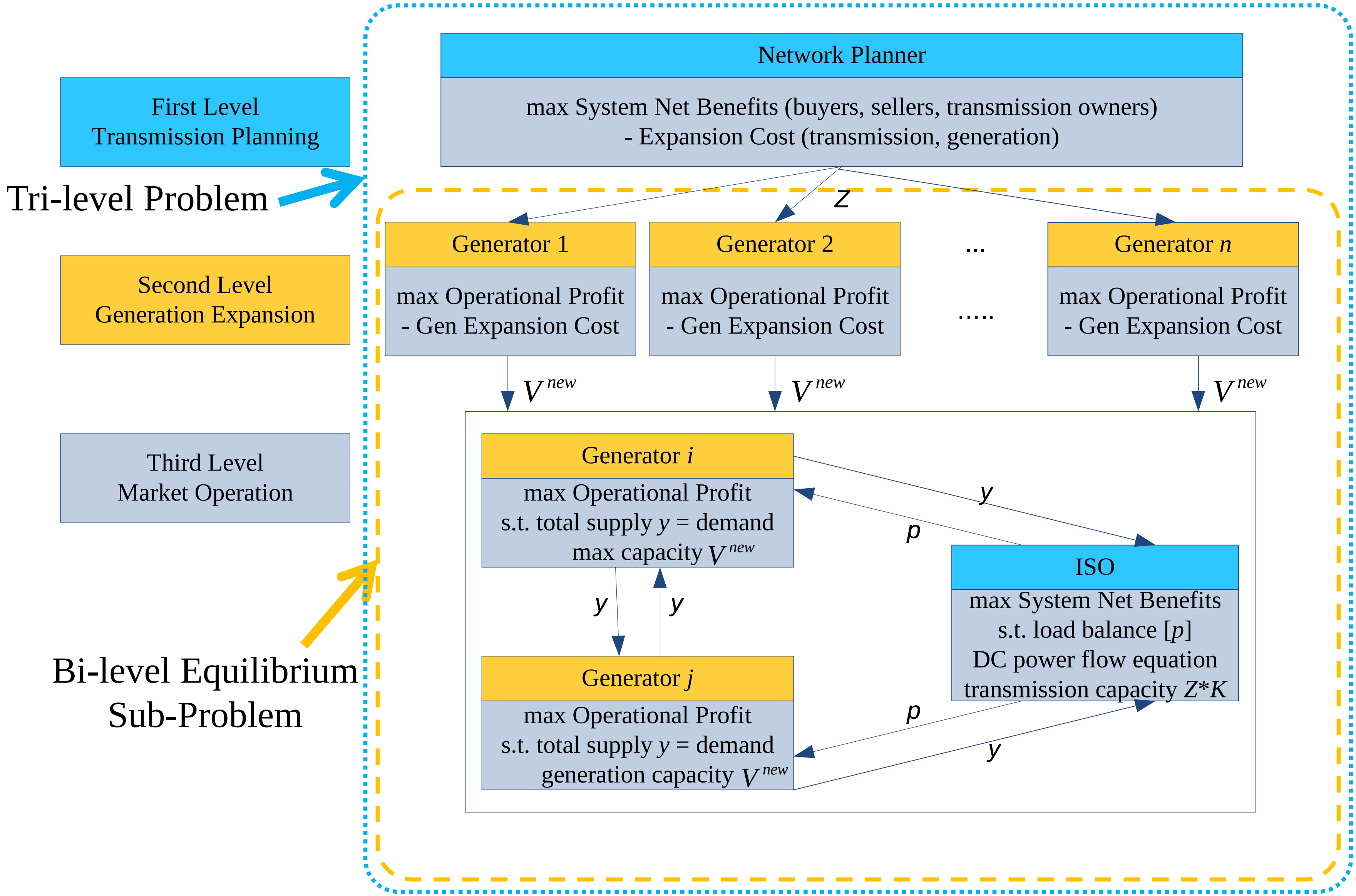
Performance	Forward Selection	FSWC
Investment Cost ($B)	99.42	99.61
Generation Cost* ($B)	81.31	81.53
Unserved energy** (MWh)	4388	7259
Total Cost* ($B)	224.61	253.73
Scen. Red. (CPU seconds)	1.067E6	1.11E5
Solution (CPU seconds)	1672	1534
Total time (CPU seconds)	1.068E6	1.12E5

* Expectation across *all* scenarios

** Total over 20 year time horizon

- Order of magnitude time reduction, similar results

Transmission and Generation Expansion in Market Environment



Solution Approach

Iterative process

- Complementarity reformulation: convert 3-level optimization problem to 1-level master problem
  - Binary and continuous variables
  - Linear, nonlinear, and complementarity constraints
  - Necessary, but not sufficient, conditions for equilibrium of generator expansions and market operations
- Evaluate candidate transmission plan by diagonalization to find “true” equilibrium
- Send cuts back to master problem based on bounds and feasibility

Results in IEEE Test Systems

- Modified 30-bus system
  - 10 candidate lines: 1,024 possible expansion plans

Major Iteration	**MINLP Master Problem A**			**Bi-Level Sub-problem B**	**Adding Constraints to Master Problem A**	
	Status	Transmission Plan	Net Surplus	Net Surplus	Lower Bound	Cut Point
1	Feasible	None	13235.34	13038.62	13038.62	None
2	Feasible	B	13057.90	12727.90	13038.62	B
3	Feasible	E	13216.10	12957.11	13038.62	E
4	**Feasible**	**H**	**13246.07**	**13066.56**	**13066.56**	**H**
5	Infeasible					

  - Computation time: 1.55 hours
- 118-bus test system, 4 candidate lines
  - Optimal transmission plan found in first iteration

Multiple Scenarios in Bi-Level Model

- Upper level – investments in transmission and generation capacity
- Lower level – wholesale market equilibrium
- Deterministic version can be reformulated as a mixed integer program
- Multiple scenarios for lower level result in stochastic mixed integer program
  - Changing hourly conditions
  - High- and low-frequency uncertainties
- Ongoing: customize and apply FSWC scenario reduction heuristic in this context

Accomplishments

- New scenario reduction heuristic for two-stage stochastic programs works much faster than current one on very large scenario trees
  - Incorporates cost and constraint information in addition to scenario probabilities
- Iterative method to search among, not just test, alternative transmission plans anticipating generator expansions and market operation
  - Allows exploration of a variety of conditions

Benefits and Applications

- Reducing the computational burden of long-term planning under uncertainty can
  - Allow inclusion of more operational, spatial, or temporal detail
  - Identify plans that avoid risks of under- or over-expanding
- Multi-level model of transmission planning
  - Understand how follower decision-makers may respond to planning decisions
  - Better transmission plans can expand use of renewables, equalize locational prices, and prevent or mitigate undue market influences

Project Publications to Date

1. Feng, Y. and S. M. Ryan, Scenario construction and reduction applied to stochastic power generation expansion planning. *Computers and Operations Research*, Vol. 40, pp. 9-23, 2013.
2. Feng, Y. and S. M. Ryan. Application of scenario reduction to LDC and risk based generation expansion planning. *Proceedings of the IEEE Power & Energy Society General Meeting*, San Diego, CA, July 22-26, 2012.
3. Jin, S. and S. M. Ryan, A tri-level model of centralized transmission and decentralized generation expansion planning for an electricity market: Part I. *IEEE Transactions on Power Systems*, under revision.
4. Jin, S. and S. M. Ryan, A tri-level model of centralized transmission and decentralized generation expansion planning for an electricity market: Part II. *IEEE Transactions on Power Systems*, under revision.
5. Jin, S., Electricity System Expansion Studies to Consider Uncertainties and Interactions in Restructured Markets. Ph.D. Dissertation, Iowa State Univ., 2012.
6. Jin, S. and S. M. Ryan, Impact of carbon emission policies on capacity expansion in the integrated supply network for an electricity market. Presented in *Industrial Engineering Research Conference*, Reno, NV, May, 2012.

Computational Challenges and Analysis Under Increasingly Dynamic and Uncertain Electric Power System Conditions

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