PROBABILISTIC FORECASTING FOR POWER SYSTEM OPERATIONS

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Support in part by DoE (CERTS) and NSF

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June 10, 2016

Presented at CERTS Review

Overview

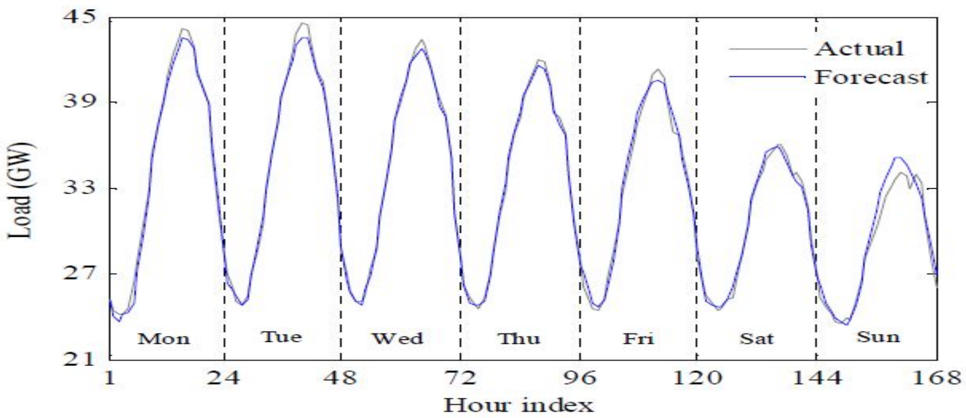
- Objectives
  - Develop scalable probabilistic forecasting and system simulation tools for real-time market operations.

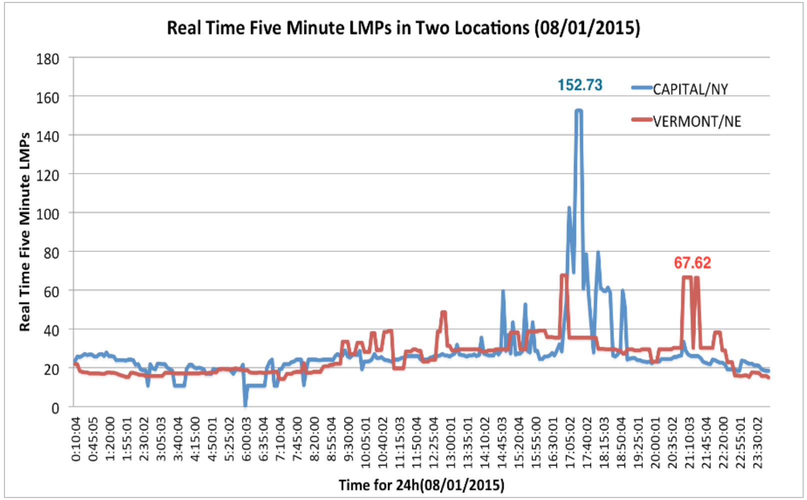
- Applications
  - Provide market participants locational price distributions for integrating flexible demand and distributed energy resources
  - Provide operator short-term forecast of LMP distribution, power flow distribution, and probability distributions of discrete events such as congestions and contingencies.
  - Multi-area interchange scheduling under uncertainty

Outline

- A scalable forecasting and system simulation tool
  - Real-time operation models
  - Geometry of parametric DC OPF
  - Online learning via dynamic critical region generation
  - Complexity and performance: numerical results
- Multi-area interchange scheduling under uncertainty
  - Multi-area and multi-interface models
  - Stochastic interchange scheduling
  - Numerical results
- Conclusions and future work

Load vs. LMP forecasting

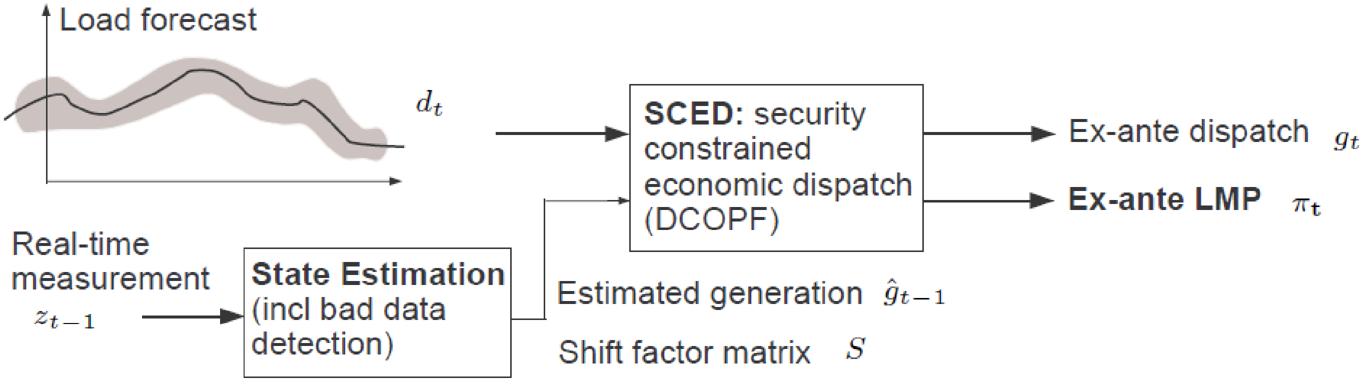




- Load are physical processes
- a variety of techniques on both point and probabilistic forecasting
- accuracy typically at 1-3% mean absolute percentage error (MAPE)

- LMPs are solutions of OPF
- Many black-box techniques on (point) LMP forecasting.
- Limited accuracy (10-20% in MAPE)

A real time LMP model



$$
\begin{array}{lll}
\min_g & C(g) & \\
\text{subject to} & \mathbf{1}^\mathsf{T}(g - d_t) = 0 \quad (\lambda_{t-1}) & \text{power balance} \\
 & S(g - d_t) \leq F \quad (\mu_{t-1}) & \text{transmission limit} \\
 & g \leq G & \text{generation capacity} \\
 & g \leq \hat{g}_{t-1} + \Delta. & \text{generation ramp}
\end{array}
$$

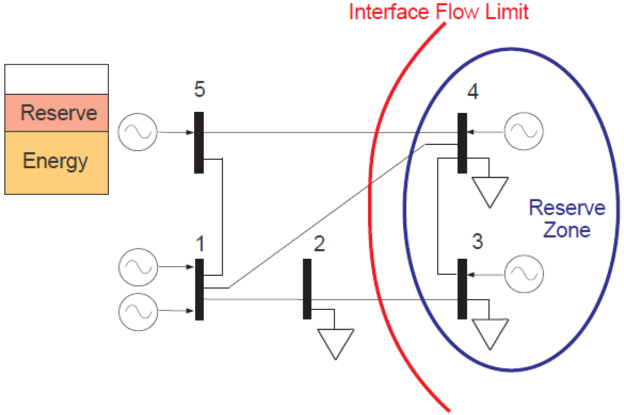
$$\pi_t = \lambda_{t-1}\mathbf{1} + S^\mathsf{T}\mu_{t-1}.$$

Real time LMP model with reserve co-optimization

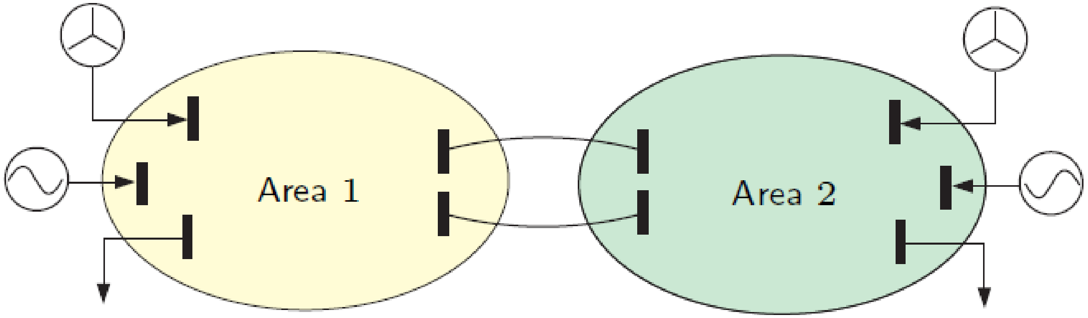
$$\min_{g,r,s} \quad \sum_i \left(c_i^g g_i + \sum_j c_{i,j}^r r_{i,j} \right) + \sum_u c_u^p s_u^l + \sum_v c_v^p s_v^s$$

subject to

$$\begin{aligned}
&\sum_i (g_i - d_i) = 0, && \text{energy balance,}\\
&\sum_i S_{ik}(g_i - d_i) \le F_k, && \text{transmission constraint } k,\\
&\sum_i \sum_j \delta_{i,j}^u r_{i,j} + (I_u^+ - I_u) + s_u^l \ge Q_u^l, && \text{locational reserve } u,\\
&I_u = \sum_i \sum_{k \in I_u} A_{ik}(g_i - d_i), && \text{interface flow,}\\
&\sum_i \sum_j \delta_{i,j}^v r_{i,j} + s_v^s \ge Q_v^s, && \text{system reserve } v,\\
&g_i + \sum_j r_{i,j} \le g_i^+, && \text{generator capacity } i,\\
&\hat{g}_i - \Delta_i^- \le g_i \le \hat{g}_i + \Delta_i^+, && \text{generation ramp } i,\\
&0 \le r_{i,j} \le r_{i,j}^+, && \text{reserve ramp } i,j,\\
&g_i \ge g_i^-, && \text{generation capacity } i,\\
&s_u^l, s_v^s \ge 0.
\end{aligned}$$



Seams in multi-area operations



$$
\begin{aligned}
\min_{q, g_1, g_2} \quad & C_1(g_1) + C_2(g_2) \\
\text{subject to} \quad & \mathbf{1}^\intercal(d_1 - g_1) + q = 0 & (\lambda_1) \\
& \mathbf{1}^\intercal(d_2 - g_2) - q = 0 & (\lambda_2) \\
& S_1(d_1 - g_1) + T_1 q \le F_1 & (\mu_1) \\
& S_2(d_2 - g_2) + T_2 q \le F_2 & (\mu_2) \\
& g_1 \in \mathcal{G}_1, g_2 \in \mathcal{G}_2.
\end{aligned}
$$

Simulation of large stochastic power networks

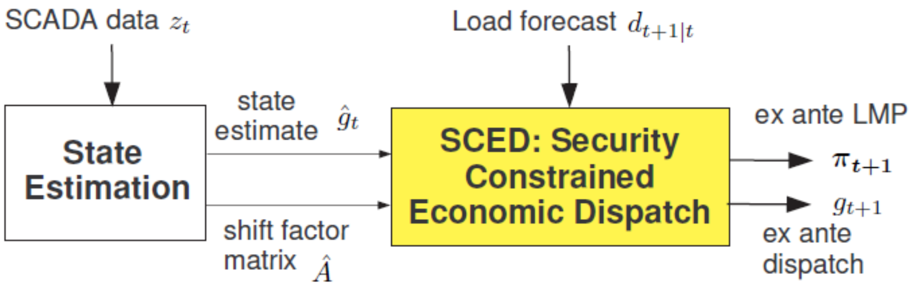
Characteristics:

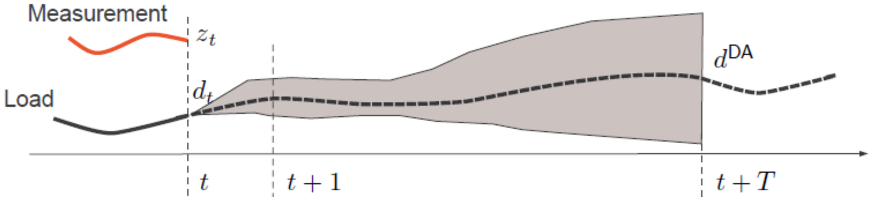
- Random generation and load
- Probabilistic contingencies
- Multiperiod security constrained economic dispatch (SCED) with ramp constraints

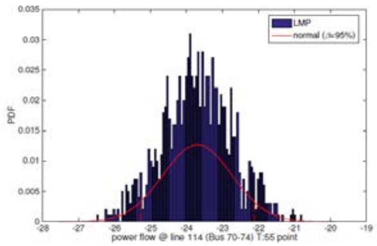
Features:

- Joint and marginal distributions of nodal prices
- Joint and marginal distributions of power flows
- Joint and marginal distribution of generation dispatch and reserve
- ……….

Probabilistic forecasting and simulation



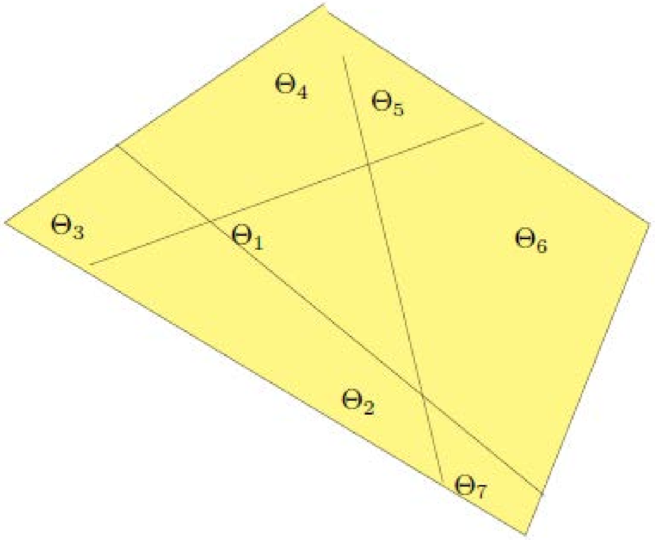


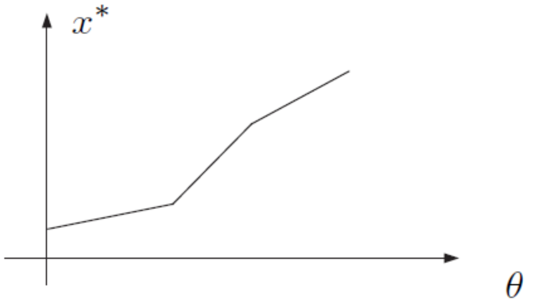


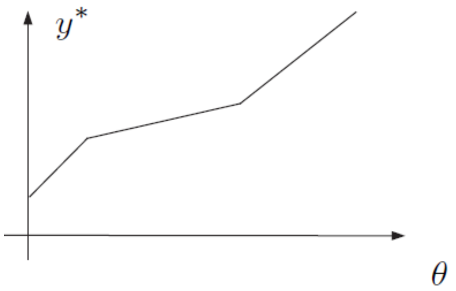
- Generic Monte Carlo
  - Generate sample paths of random generation, demand, contingency scenarios
  - Simulate real-time dispatch (OPF)
  - Complexity: #OPF=MT
- Online Learning via Dynamic Critical Region Generation
  - Exploit structures of OPF solution
  - Online learning of solution dictionary
  - Complexity: #OPF=10^{-x}MT

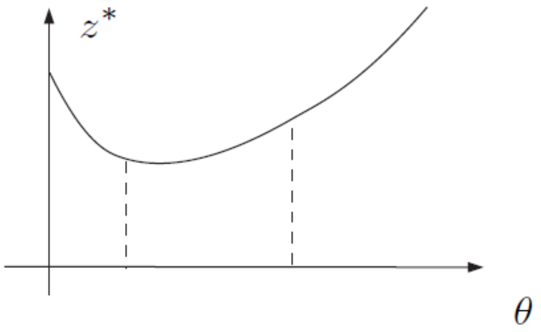
Geometry of Multiparametric Programming

$$\begin{array}{ll} \min_x & z(x) \\ \text{subject to} & Ax \leq b + E\theta \quad (y) \end{array}$$

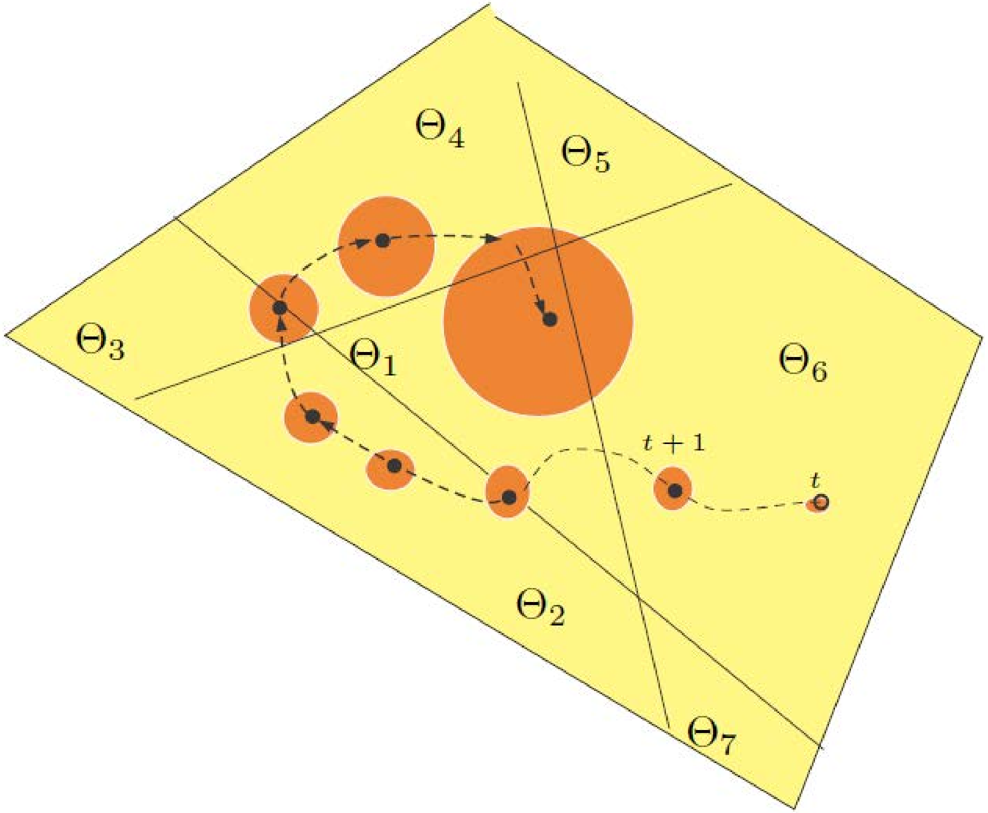


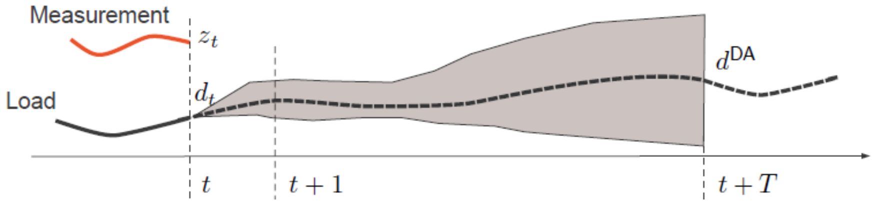






DCRG: Dynamic Critical Region Generation





Algorithm 1 Dynamic Critical Region Generation

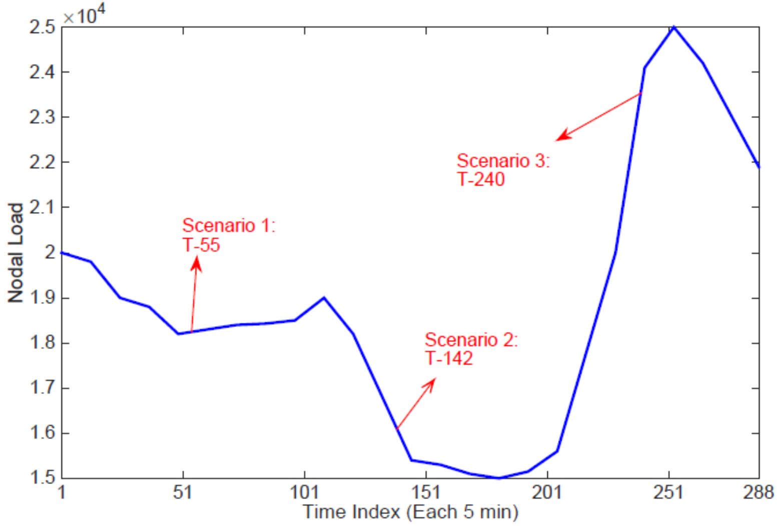
Input: load distribution and the mean trajectory $\bar{d}_t$, $t = 1, \cdots, T$.
Initialization: compute the initial critical region dictionary $\mathcal{C}_0$ from $\bar{d}_t$.
for $m = 1, \cdots, M$ **do**
  Generate a sample path $\{d_t^1, d_t^2, \cdots, d_t^M\}$ from load distribution.
  for $t = 1, \cdots, T$ **do**
    Search $\mathcal{C}_{t-1}^m$ for critical region $C(d_t^m)$.
    if $C(d_t^m) \notin \mathcal{C}_{t-1}^m$ **then**
      Compute the critical region $C(d_t^m)$ and update $\mathcal{C}_t^m = \mathcal{C}_{t-1}^m \cup \{C(d_t^m)\}$.
    end if
  end for
end for
Output: The critical region dictionary $\mathcal{C}_T^M$.

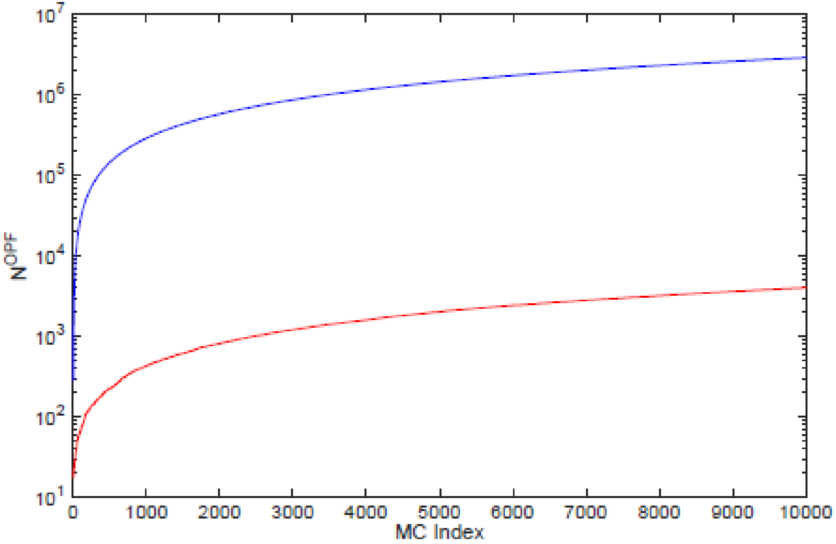
The Polish Network

- 3120 buses, 3693 branches
- 505 thermal units with ramp constraints
- 30 wind farms (Gaussian)
- 10 constrained transmission lines
- 10,000 Monte Carlo runs
- 24 hour simulation horizon

- 505 decision variables
- 2041 constraints
- ~3M OPFs

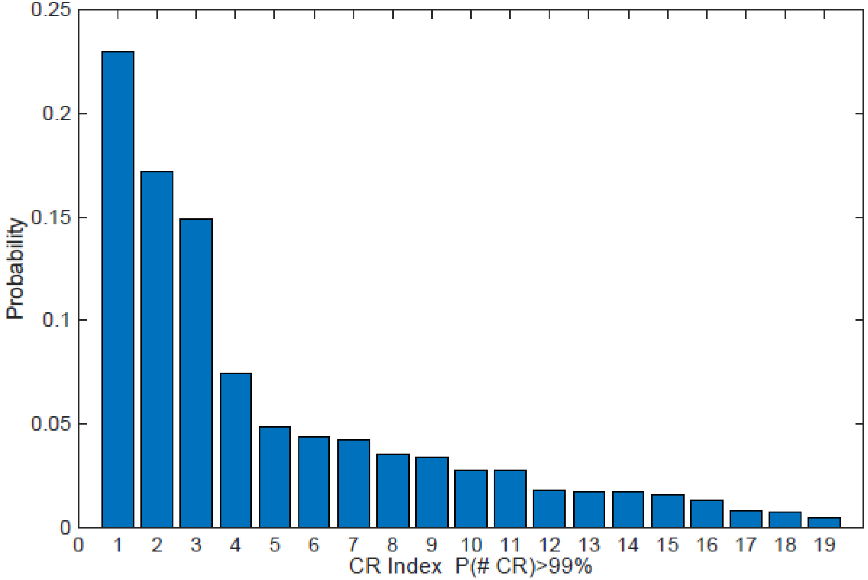
Computation cost comparison

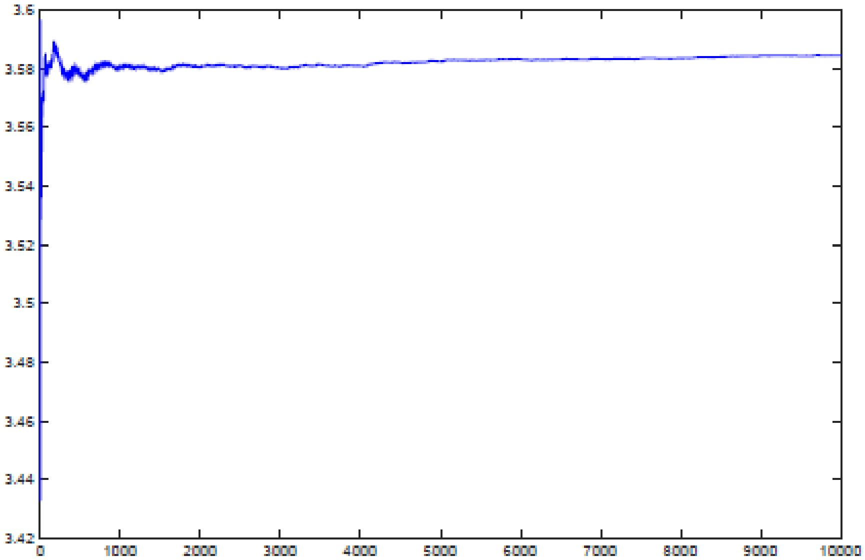




Critical region distribution

$$H = -\sum_i (p_i \times \log_2 p_i)$$

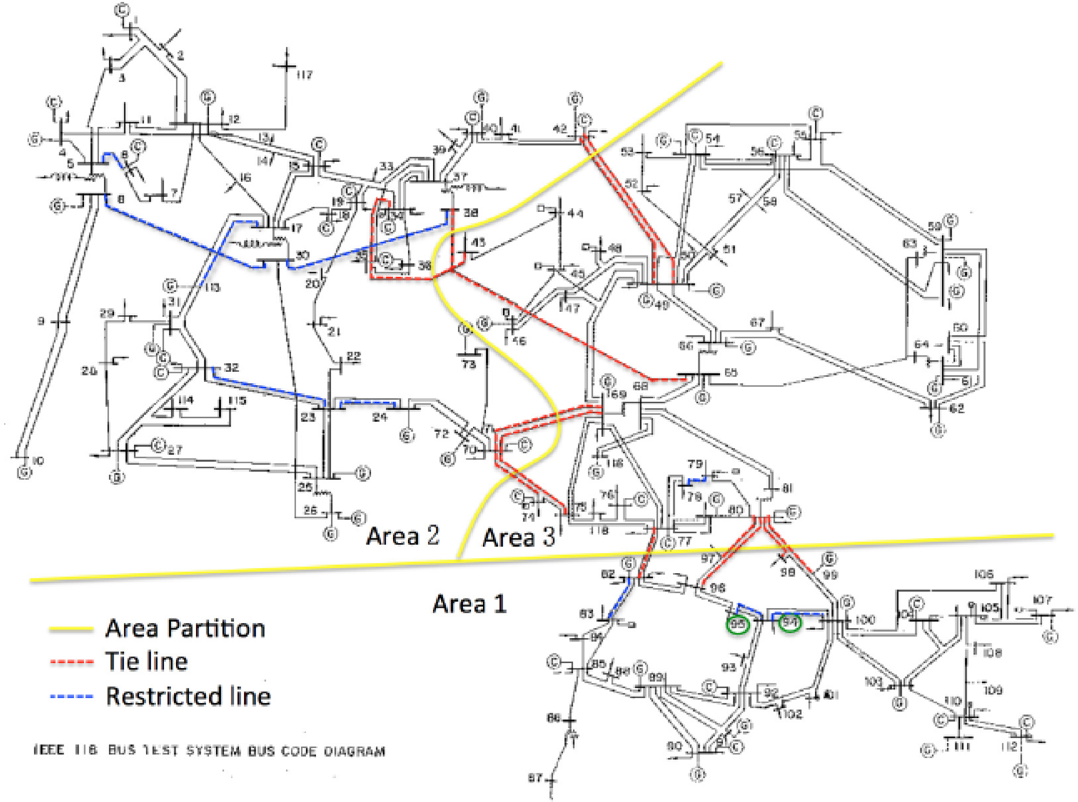


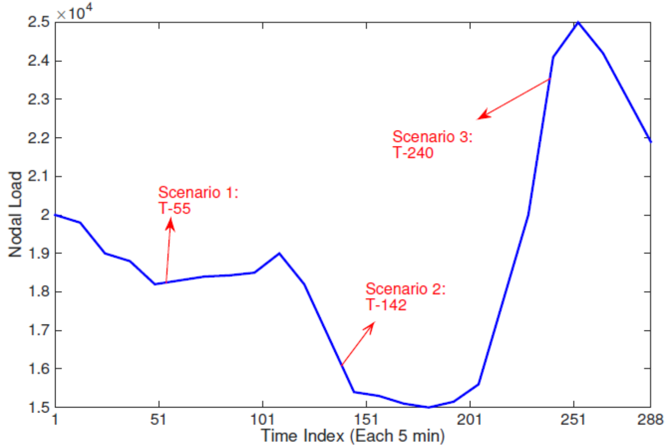


3000 critical region observed in 3M samples

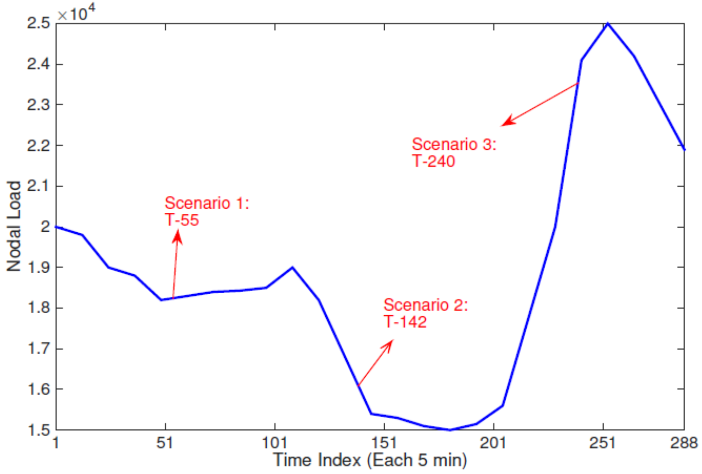
There are ~2^(HT) typical sequences

The IEEE 118 system

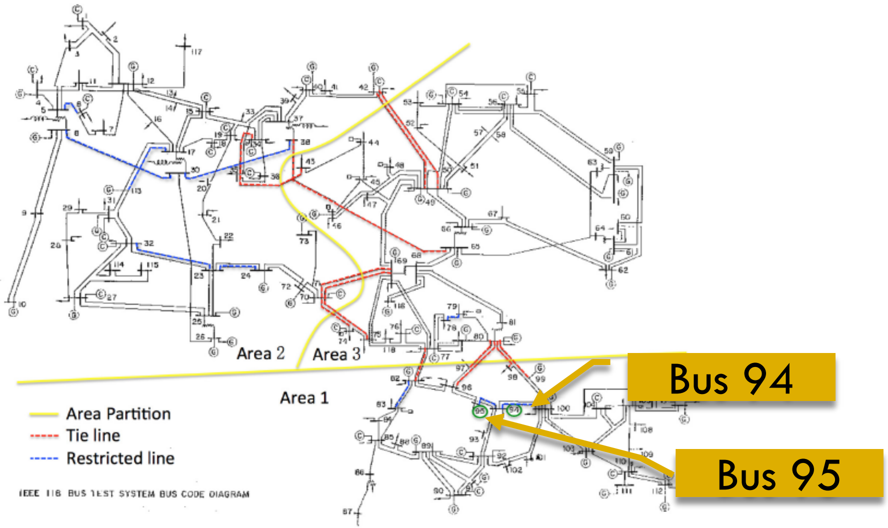




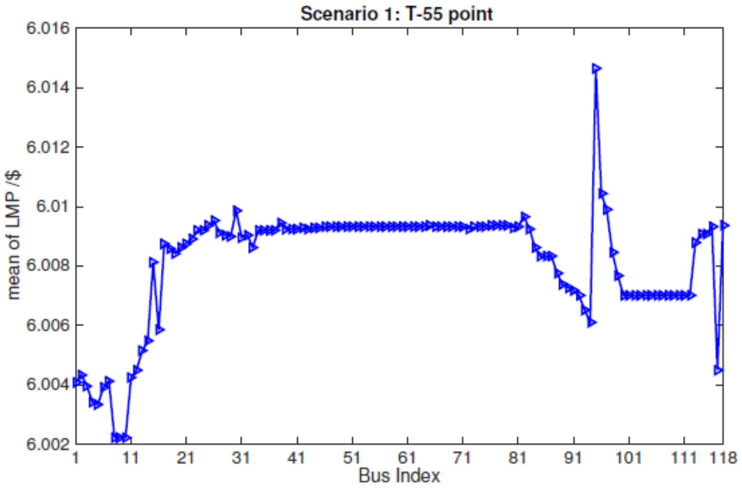
- 118 buses in three areas
- 10 capacity constraints
- 91 stochastic loads (Gaussian)
- 54 thermal generators
- 1000 Monte Carlo runs



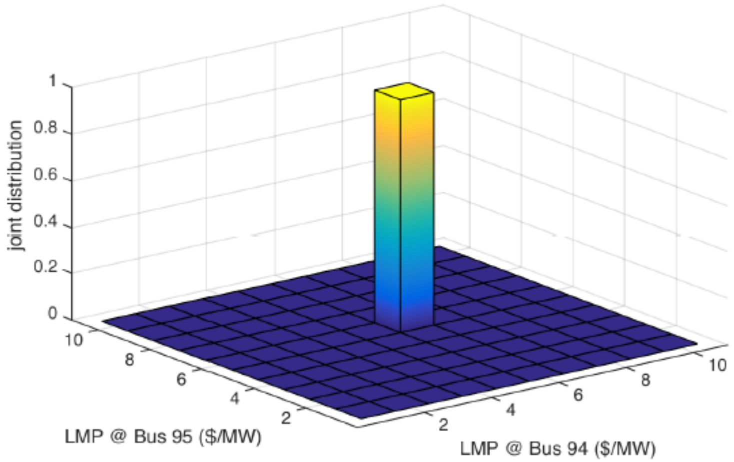
×10^4
Nodal Load
Time Index (Each 5 min)
Scenario 1:
T-55
Scenario 2:
T-142
Scenario 3:
T-240
2.5
2.4
2.3
2.2
2.1
2
1.9
1.8
1.7
1.6
1.5
1
51
101
151
201
251
288



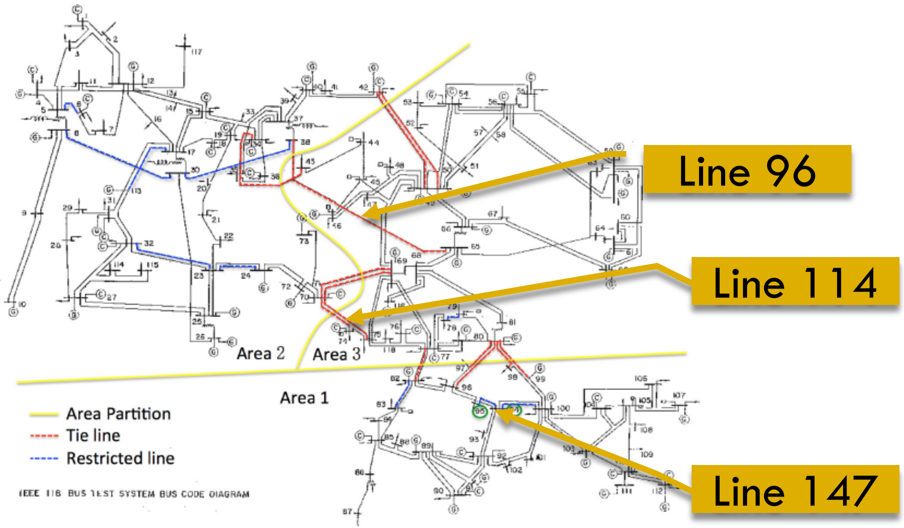
Area 2
Area 3
Area 1
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM
Bus 94
Bus 95

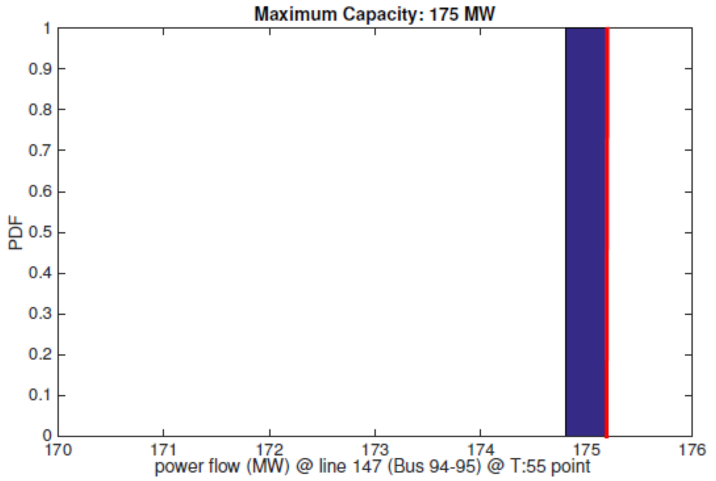


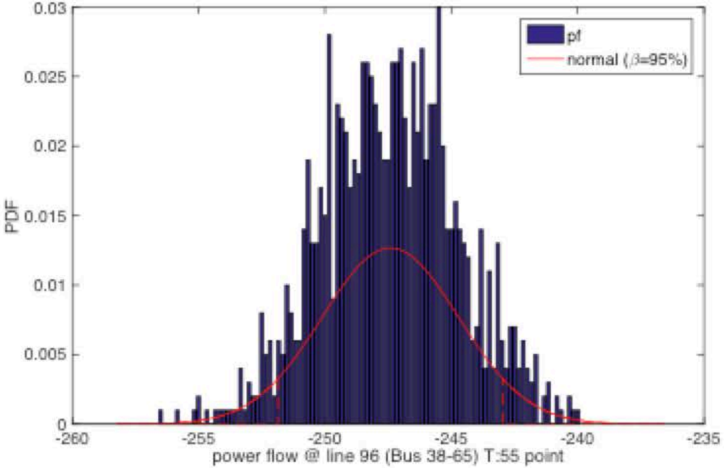
Scenario 1: T-55 point
mean of LMP /$
Bus Index
6.016
6.014
6.012
6.01
6.008
6.006
6.004
6.002
1
11
21
31
41
51
61
71
81
91
101
111
118

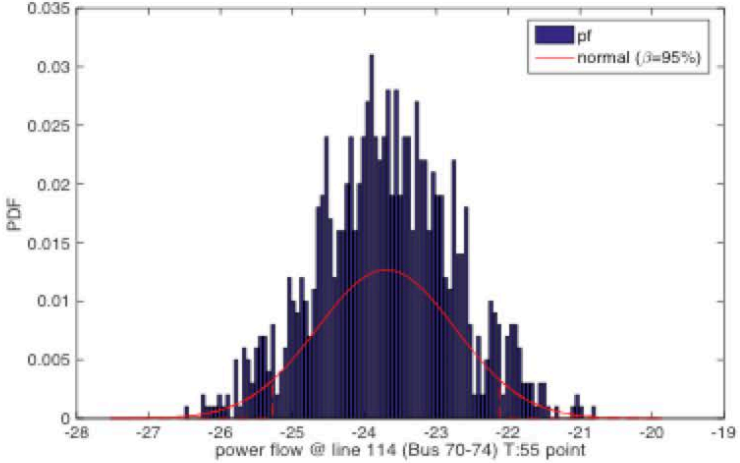


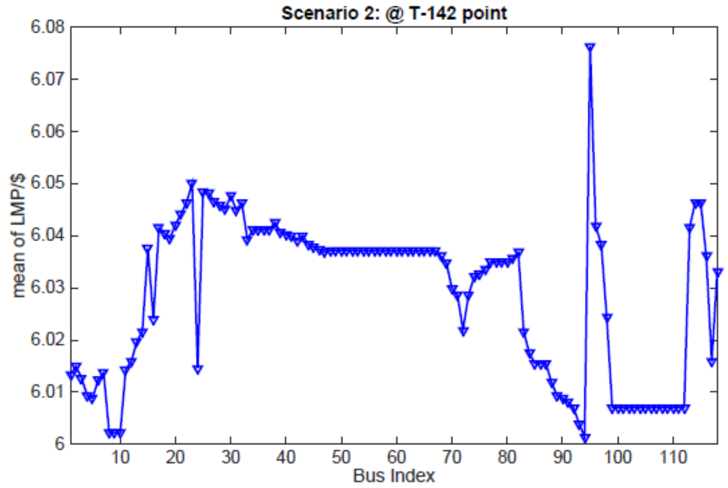
joint distribution
LMP @ Bus 95 ($/MW)
LMP @ Bus 94 ($/MW)
1
0.8
0.6
0.4
0.2
0
10
8
6
4
2

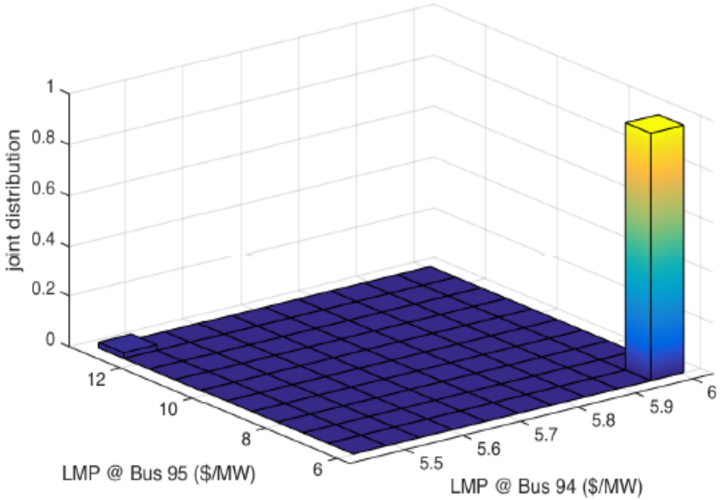

Line 96
Line 114
Line 147
Area 2
Area 3
Area 1
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM

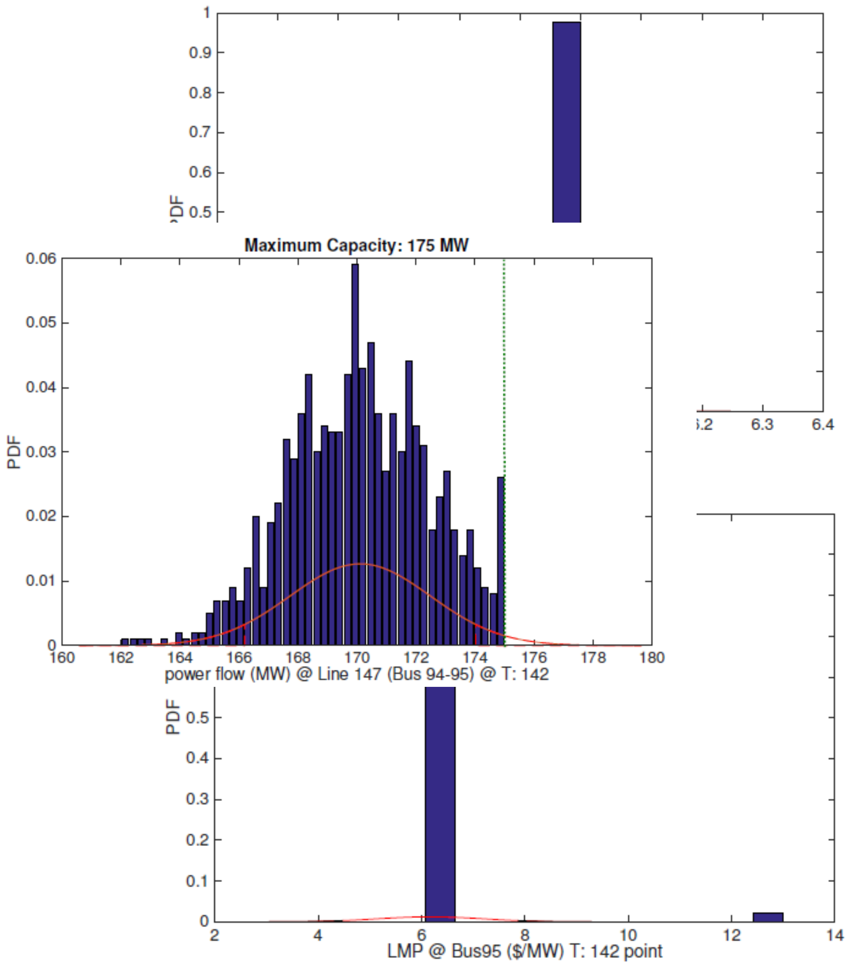

Maximum Capacity: 175 MW
PDF
power flow (MW) @ line 147 (Bus 94-95) @ T:55 point

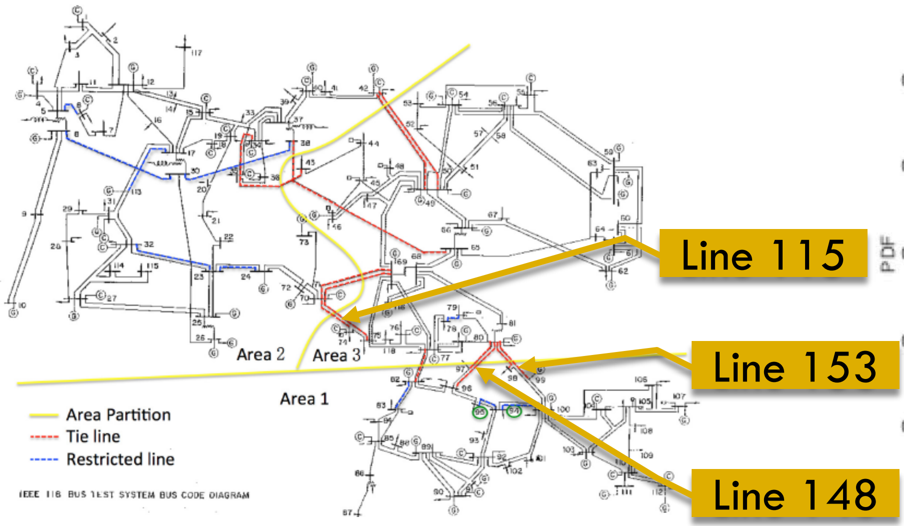

pf
normal (β=95%)
PDF
power flow @ line 96 (Bus 38-65) T:55 point

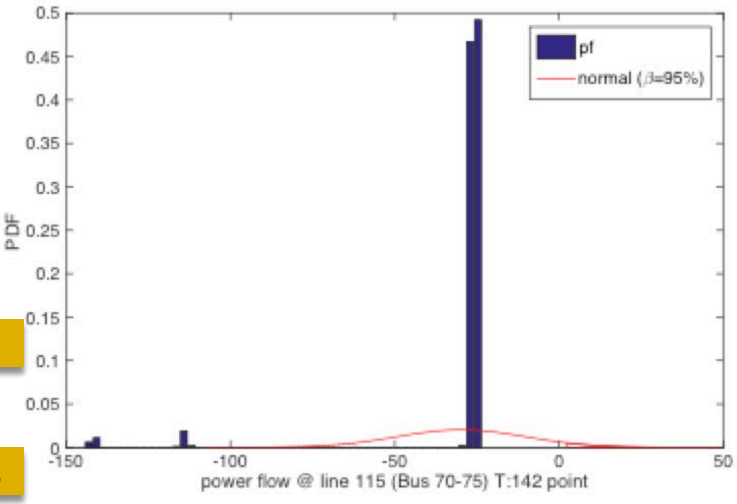

pf
normal (β=95%)
PDF
power flow @ line 114 (Bus 70-74) T:55 point

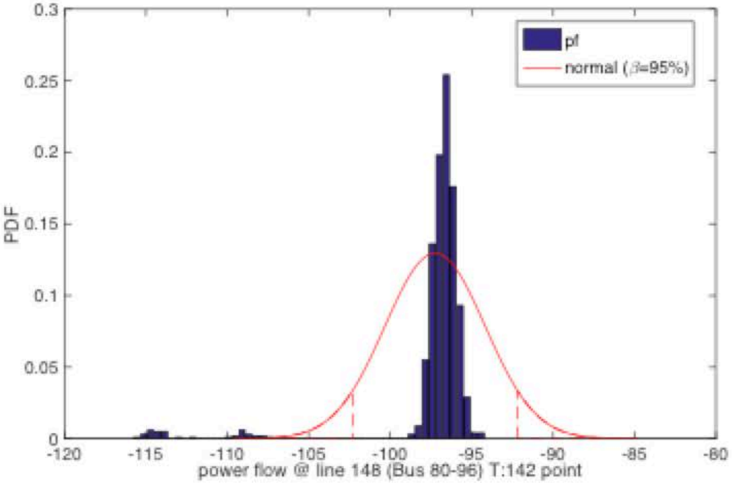

Scenario 2: @ T-142 point
mean of LMP/$
Bus Index

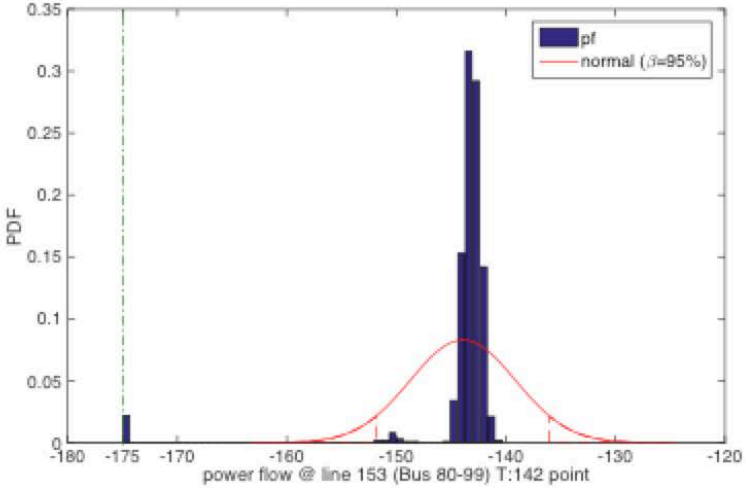

joint distribution
LMP @ Bus 95 ($/MW)
LMP @ Bus 94 ($/MW)

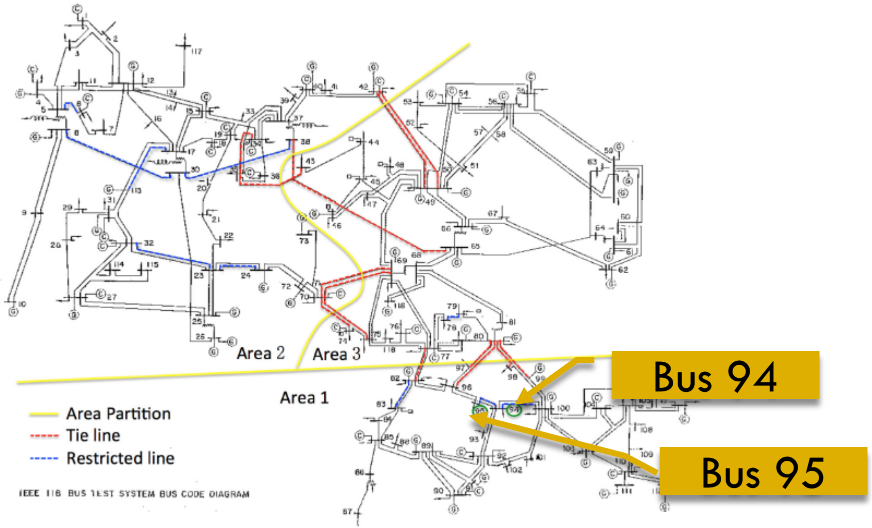

Maximum Capacity: 175 MW
PDF
power flow (MW) @ Line 147 (Bus 94-95) @ T: 142
PDF
LMP @ Bus95 ($/MW) T: 142 point

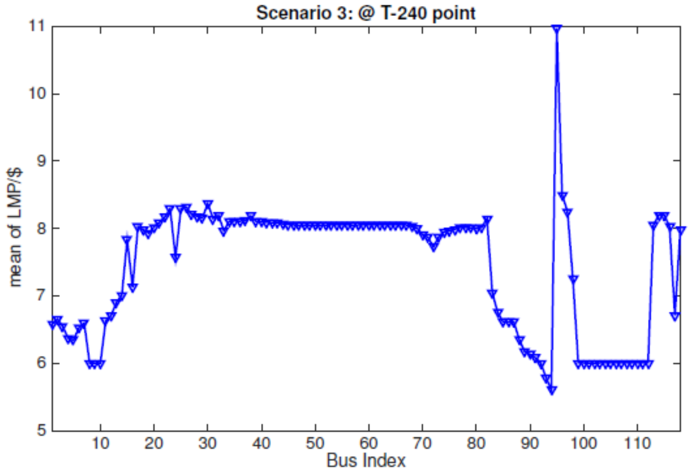

Line 115
Line 153
Line 148
Area 1
Area 2
Area 3
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM

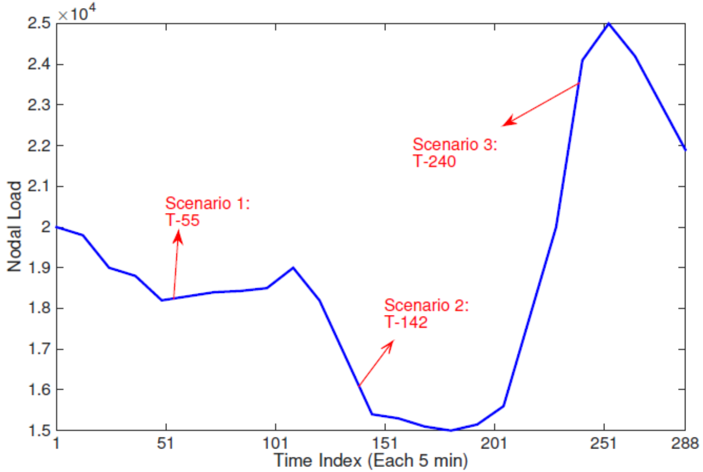

pf
normal (β=95%)
PDF
power flow @ line 115 (Bus 70-75) T:142 point

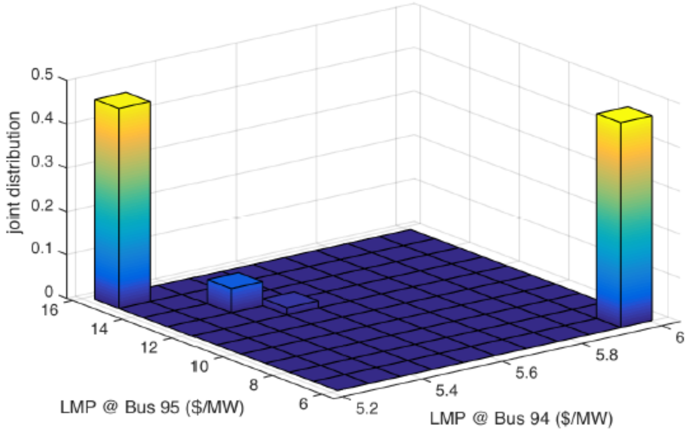

pf
normal (β=95%)
PDF
power flow @ line 148 (Bus 80-96) T:142 point

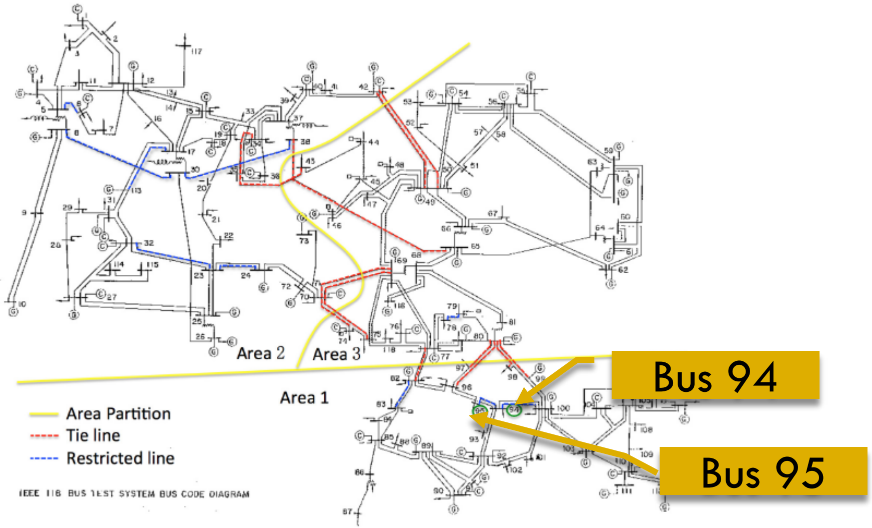

pf
normal (β=95%)
PDF
power flow @ line 153 (Bus 80-99) T:142 point


Area 2
Area 3
Area 1
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM
Bus 94
Bus 95

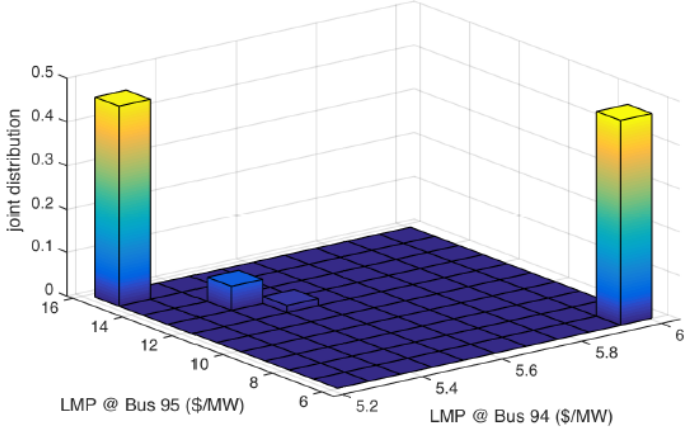

Scenario 3: @ T-240 point
mean of LMP/$
Bus Index
5
6
7
8
9
10
11
10
20
30
40
50
60
70
80
90
100
110


×10^4
Nodal Load
Time Index (Each 5 min)
Scenario 1:
T-55
Scenario 2:
T-142
Scenario 3:
T-240
1.5
1.6
1.7
1.8
1.9
2
2.1
2.2
2.3
2.4
2.5
1
51
101
151
201
251
288

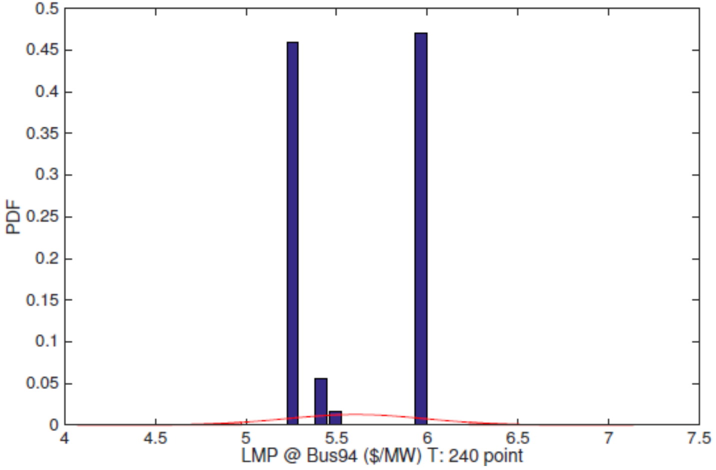

joint distribution
LMP @ Bus 95 ($/MW)
LMP @ Bus 94 ($/MW)
0
0.1
0.2
0.3
0.4
0.5
16
14
12
10
8
6
5.2
5.4
5.6
5.8
6



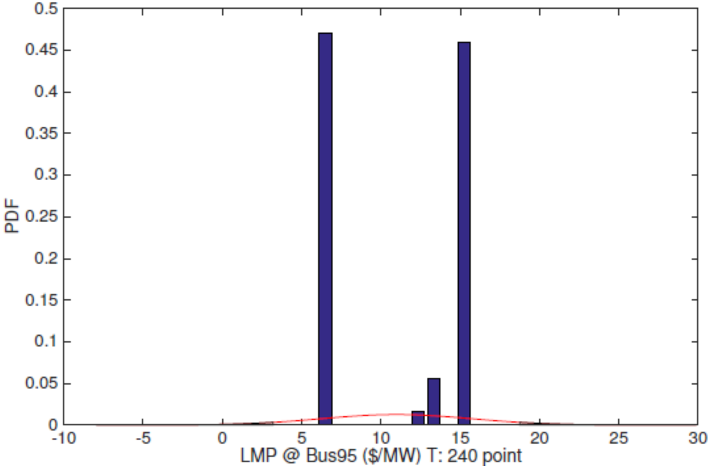
Area 2
Area 3
Area 1
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM
Bus 94
Bus 95



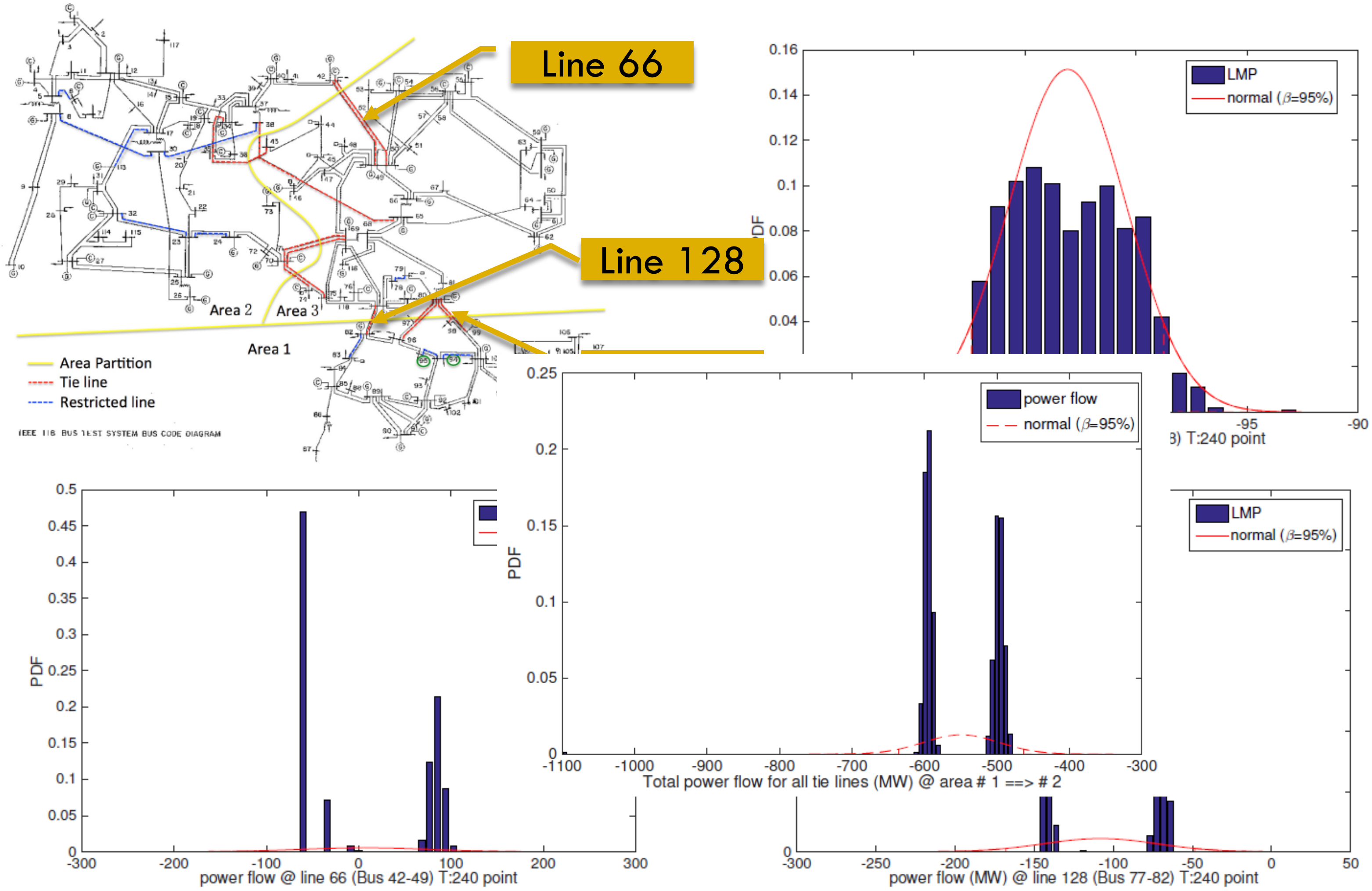
joint distribution
LMP @ Bus 95 ($/MW)
LMP @ Bus 94 ($/MW)



PDF
LMP @ Bus94 ($/MW) T: 240 point



PDF
LMP @ Bus95 ($/MW) T: 240 point



Line 66
Line 128
Area 2
Area 3
Area 1
Area Partition
Tie line
Restricted line
IEEE 118 BUS TEST SYSTEM BUS CODE DIAGRAM
LMP
normal (β=95%)
PDF
B) T:240 point
power flow
normal (β=95%)
Total power flow for all tie lines (MW) @ area # 1 ==> # 2
power flow @ line 66 (Bus 42-49) T:240 point
LMP
normal (β=95%)
power flow (MW) @ line 128 (Bus 77-82) T:240 point

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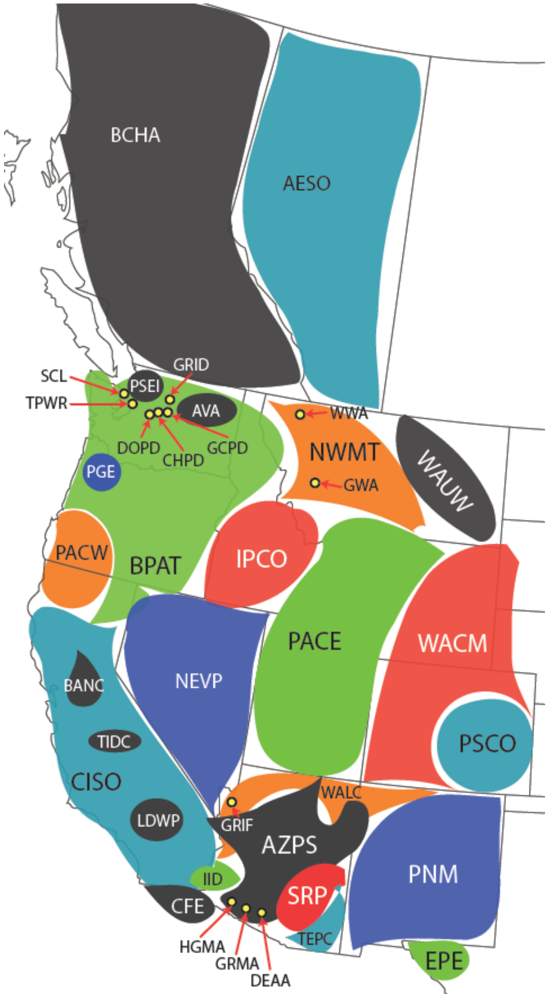
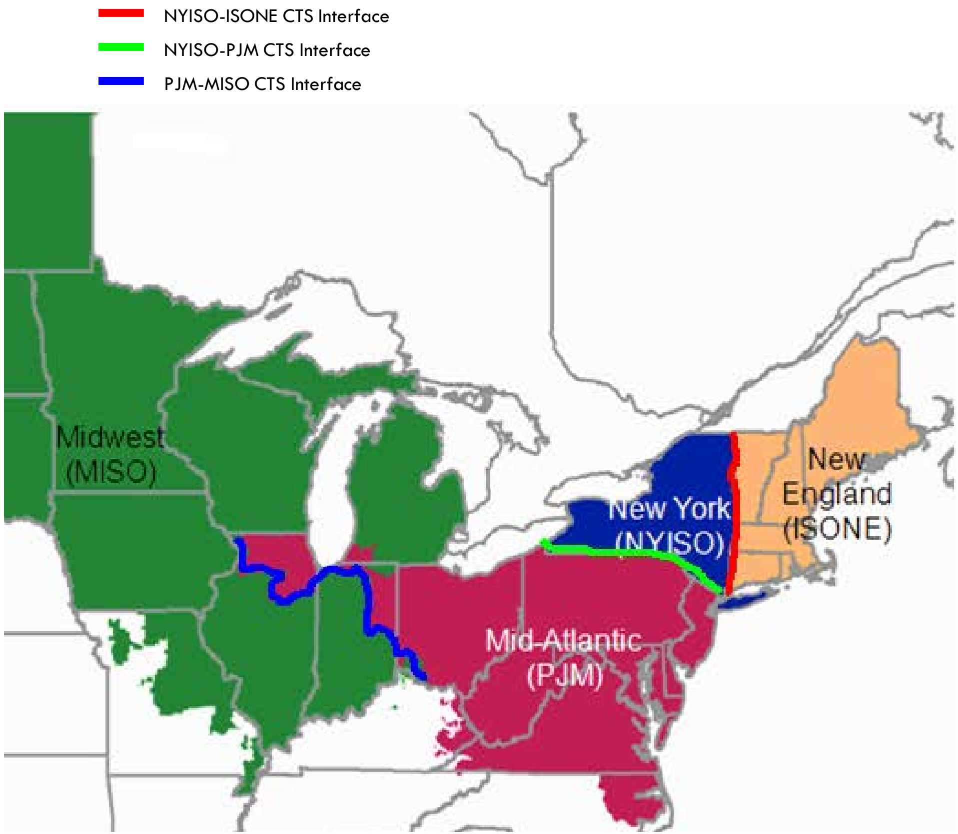
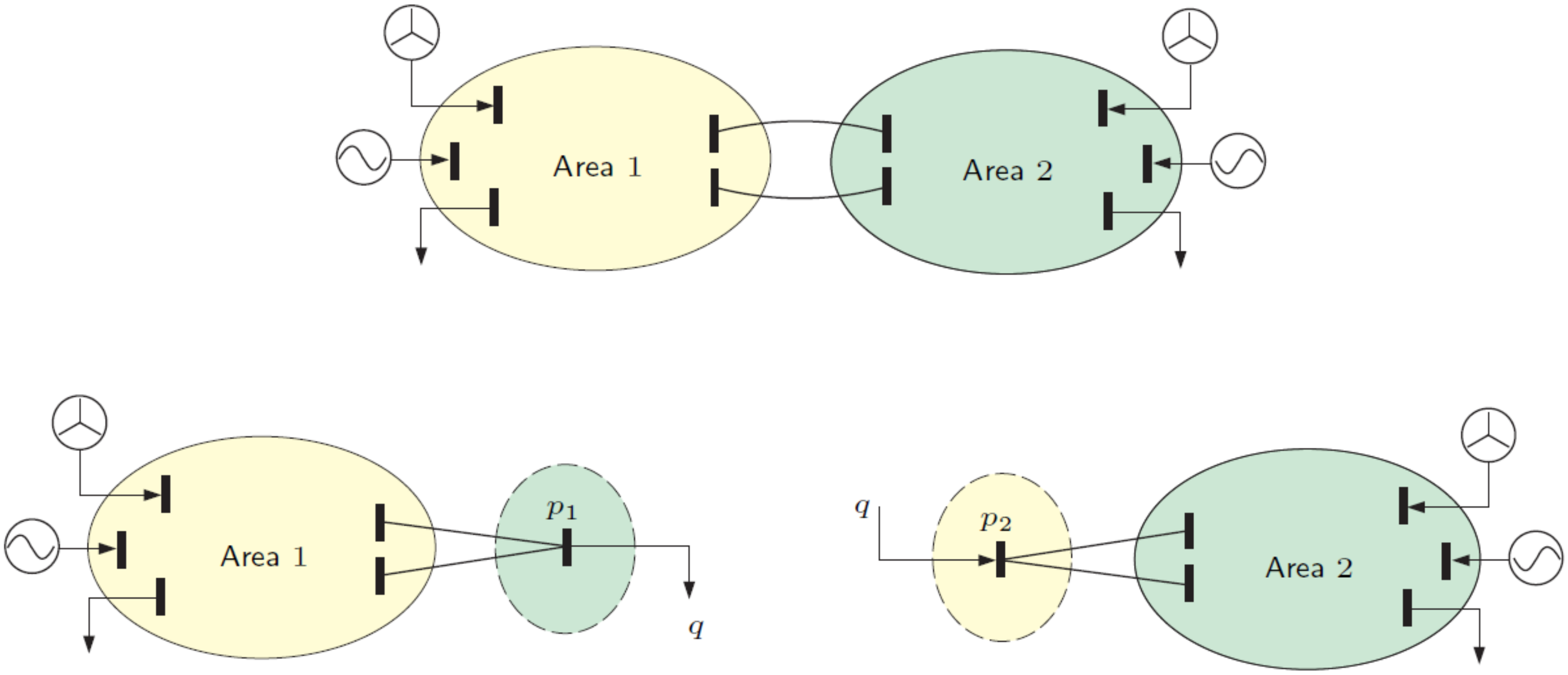
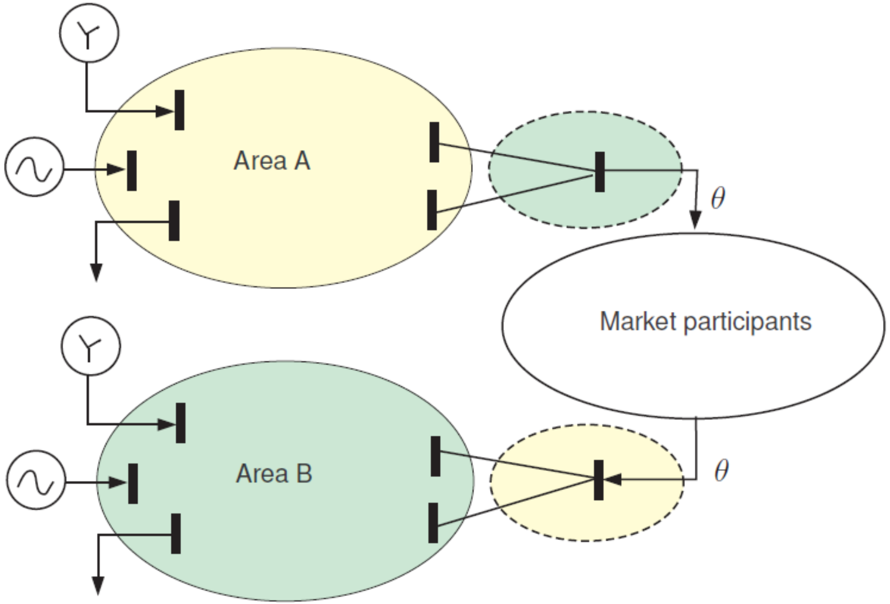

BCHA
AESO
SCL
TPWR
PSEI
GRID
AVA
WWA
DOPD
CHPD
GCPD
NWMT
PGE
GWA
WAUW
PACW
BPAT
IPCO
PACE
WACM
BANC
NEVP
TIDC
CISO
PSCO
LDWP
WALC
GRIF
AZPS
PNM
IID
SRP
CFE
TEPC
HGMA
GRMA
DEAA
EPE


NYISO-ISONE CTS Interface
NYISO-PJM CTS Interface
PJM-MISO CTS Interface
Midwest (MISO)
New York (NYISO)
New England (ISONE)
Mid-Atlantic (PJM)

Two-area single-interface proxy model



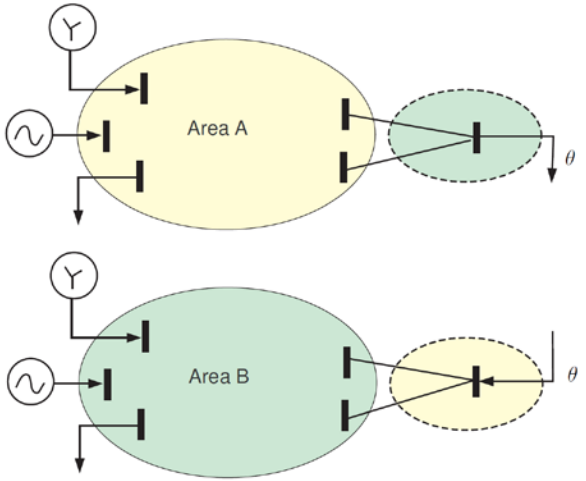
Two-area single-interfance interchange

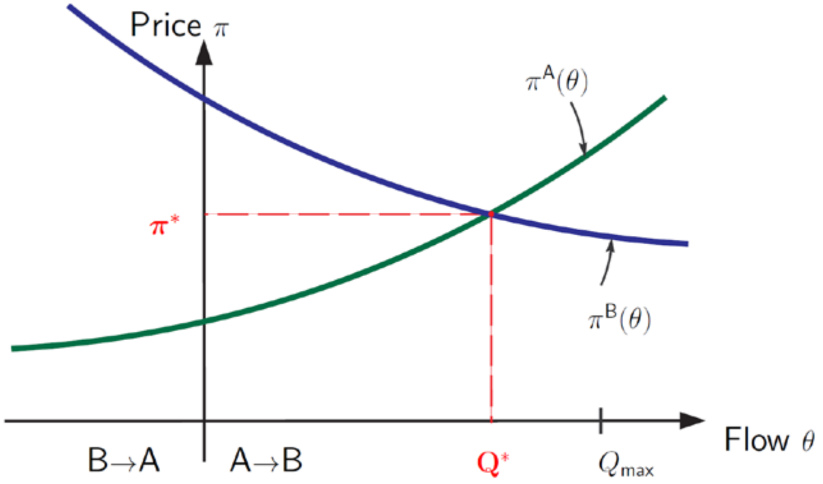


- Each ISO has a simplified model of the neighboring area with a proxy bus
- Market participants submit offers/bids for external transactions at proxy buses
- Export/import quantity is scheduled ahead of time.
- Each ISO schedules its own operations with fixed interchange.

- FERC approves coordinated transaction scheduling (CTS) for PJM & NYISO, March 2014.
- Estimated cost saving: 9M~26M per year.
- Versions of CTS are being implemented for MISO-PJM, NYISO-ISONE

Tie optimization (TO)

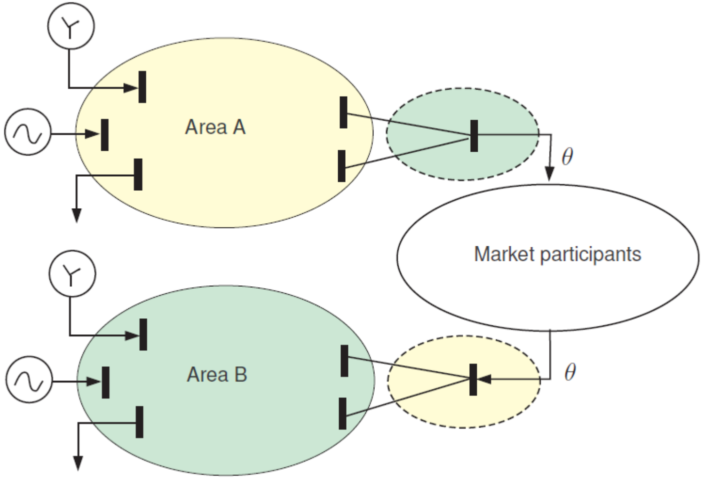


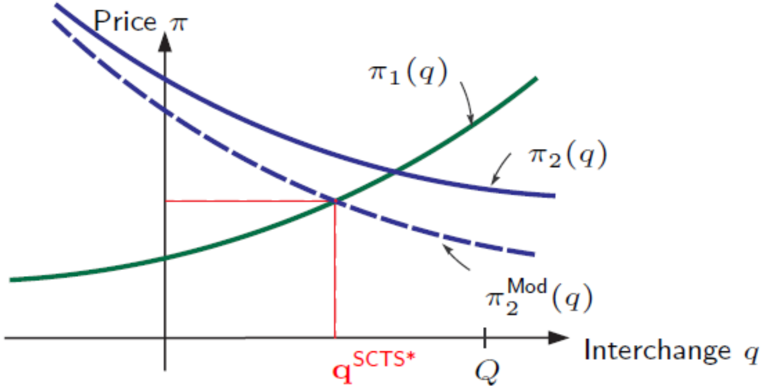


$$\min_{q, g_1, g_2} \quad C_1(g_1) + C_2(g_2)$$

subject to
- power balance constraints for Area 1 and 2
- transmission constraints for Area 1 and 2
- generator constraints for Area 1 and 2
- interface capacity constraint

Coordinated Transmission Scheduling (CTS)



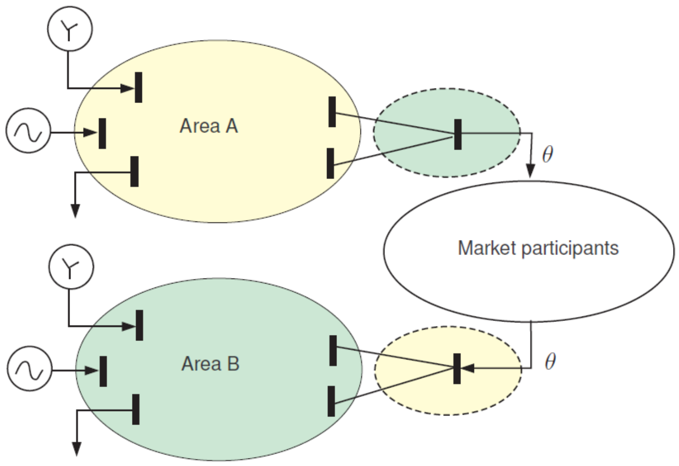


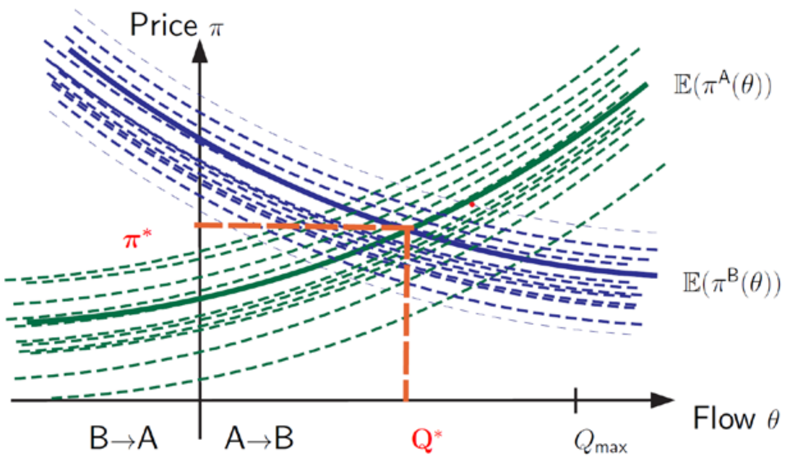
$$\pi_2^{\text{Mod}}(q) \triangleq \pi_2(q) - \pi_{\text{bid}}(q)$$

$$\min_{q,g_1,g_2} \quad C_1(g_1) + C_2(g_2) + C_{\text{bid}}(q)$$

subject to
power balance constraints for Area 1 and 2
transmission constraints for Area 1 and 2
generator constraints for Area 1 and 2
interface capacity constraint

Stochastic Coordinated Transmission Scheduling (SCTS)





$$(P_1)\ \min_{q \le Q}\ \sum_{i=1}^{2} \mathbb{E}_{d_i}\left[C_i(g_i^*(q, d_i))\right]$$

$$(P_{2i})\ \min_{g_i \in \mathcal{G}_i}\ C_i(g_i)$$

$$\text{subject to}\quad \mathbf{1}^\intercal (d_i - g_i) \pm q = 0, \qquad (\lambda_i)$$

$$S_i(d_i - g_i) \pm T_i q \le F_i. \qquad (\mu_i)$$

$$\pi_i(q, d_i) \triangleq \lambda_i(q, d_i) + (T_i)^\intercal \mu_i(q, d_i)$$

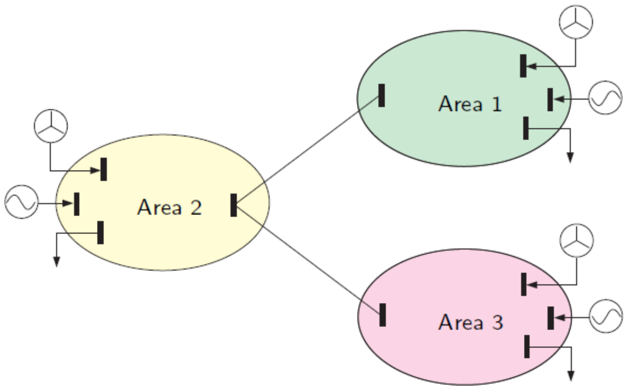
Theorem 1

The optimal interchange is given by the solution q^* of

$$\bar{\pi}_1(q) = \bar{\pi}_2(q)$$

if $q^* < Q$ and Q otherwise.

The mutli-interface interchange problem



Theorem 2

Interface-by-Interface Scheduling (IBIS) Algorithm generates a sequence $\{q^{(k)}\}_{k=0}^{\infty}$ that converges to the global optimal solution.

Two-stage stochastic optimization:

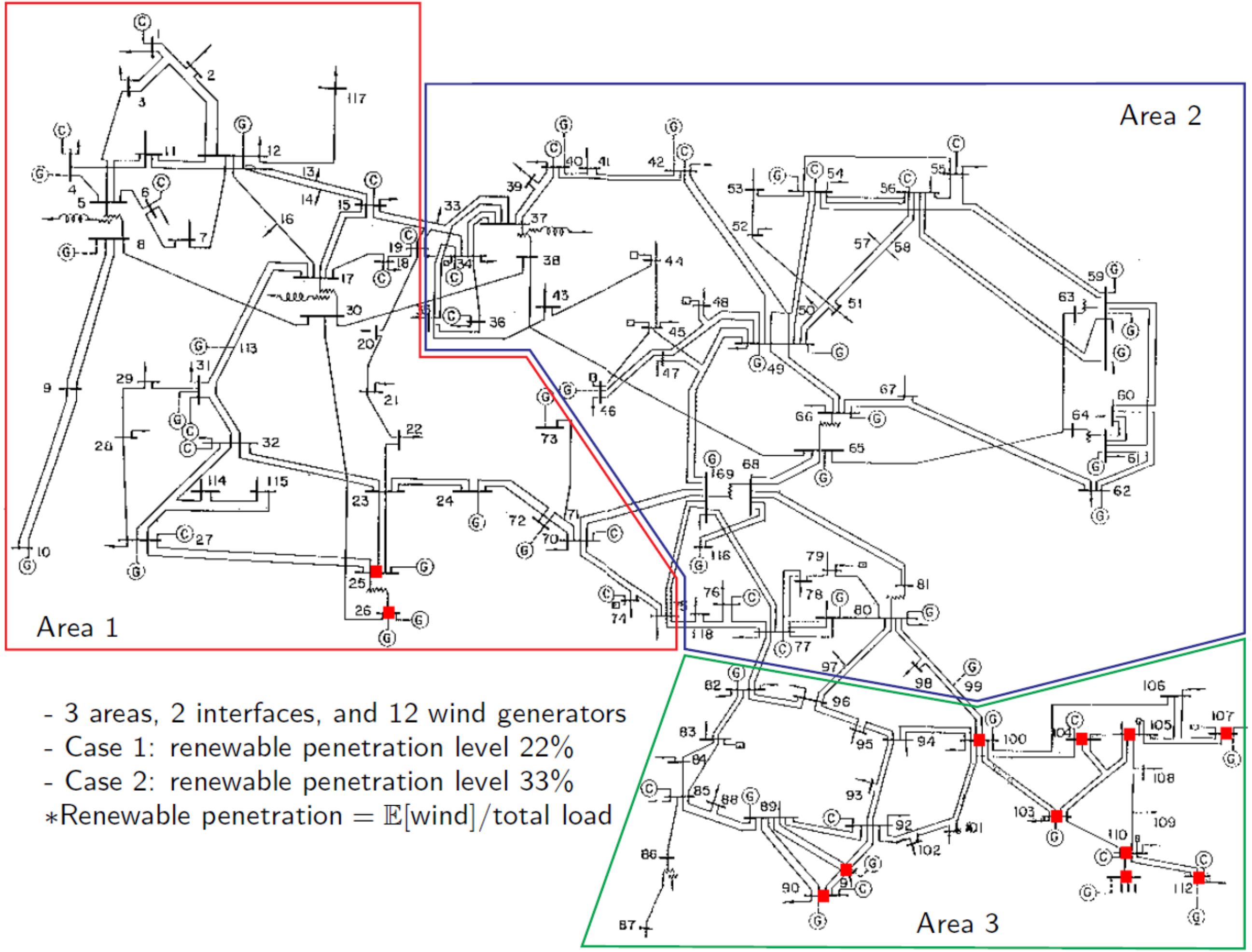
$$\begin{aligned}
(P_3)\ \min_{q \leq Q} \quad & \textstyle\sum_{i=1}^{N} \mathbb{E}_{d_i}\left[C_i(g_{i*}(q_i, d_i))\right] \\
(P_{4i})\ \min_{g_i \in \mathcal{G}_i} \quad & C_i(g_i) \\
\text{subject to} \quad & \mathbf{1}^\intercal(d_i - g_i) + \mathbf{1}^\intercal q_i = 0, \qquad (\lambda_i) \\
& S_i(d_i - g_i) + T_i q_i \leq F_i. \qquad (\mu_i)
\end{aligned}$$

Interface-by-Interface Scheduling (IBIS):

(1) Initialize $q^{(0)} = \mathbf{0}$.

(2) For iteration k, solve each interface flow sequentially with fixed flows on the other interfaces.

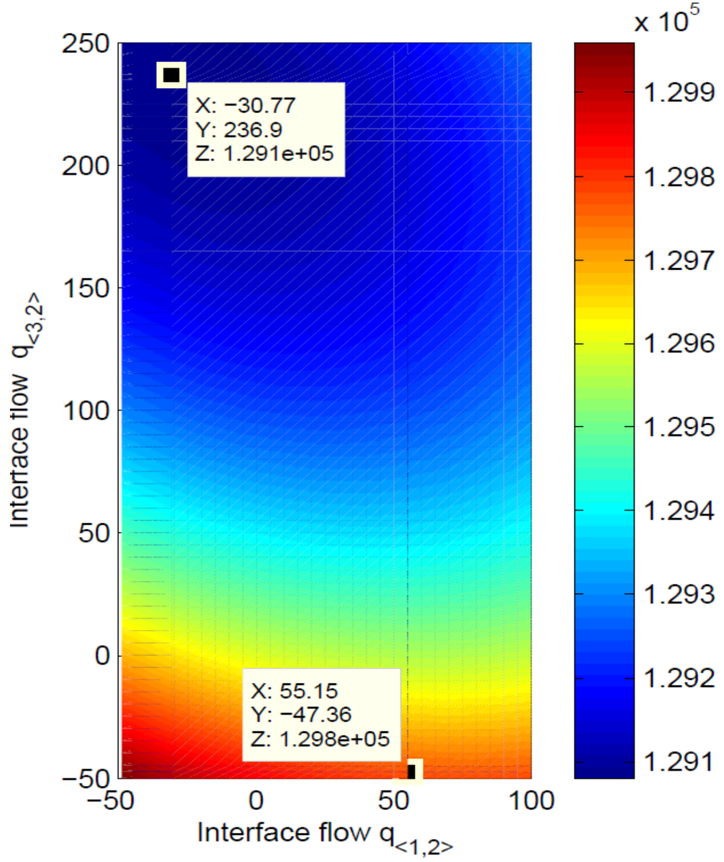
(3) If $\|q^{(k-1)} - q^{(k)}\|_2 \leq \epsilon$, terminate; otherwise, go to Step (2) for iteration $k+1$.

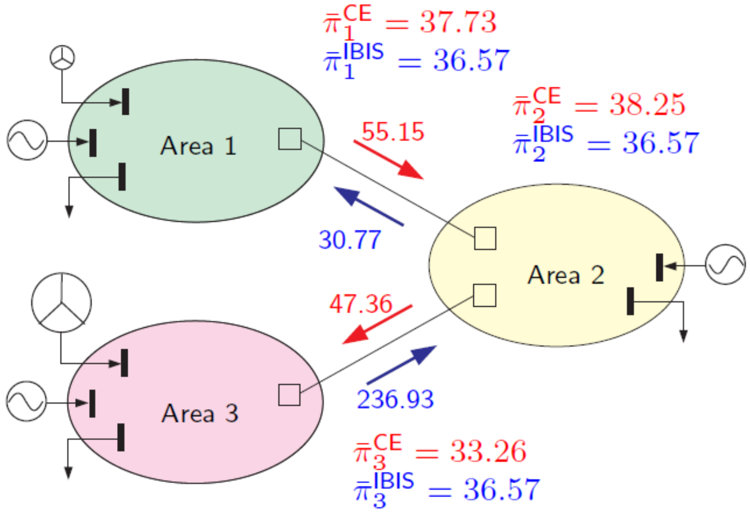


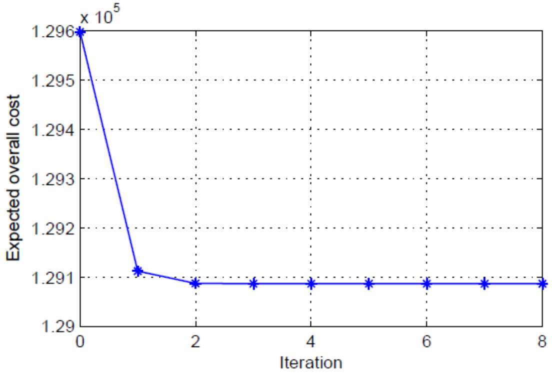
- 3 areas, 2 interfaces, and 12 wind generators
- Case 1: renewable penetration level 22%
- Case 2: renewable penetration level 33%

*Renewable penetration = $\mathbb{E}$[wind]/total load

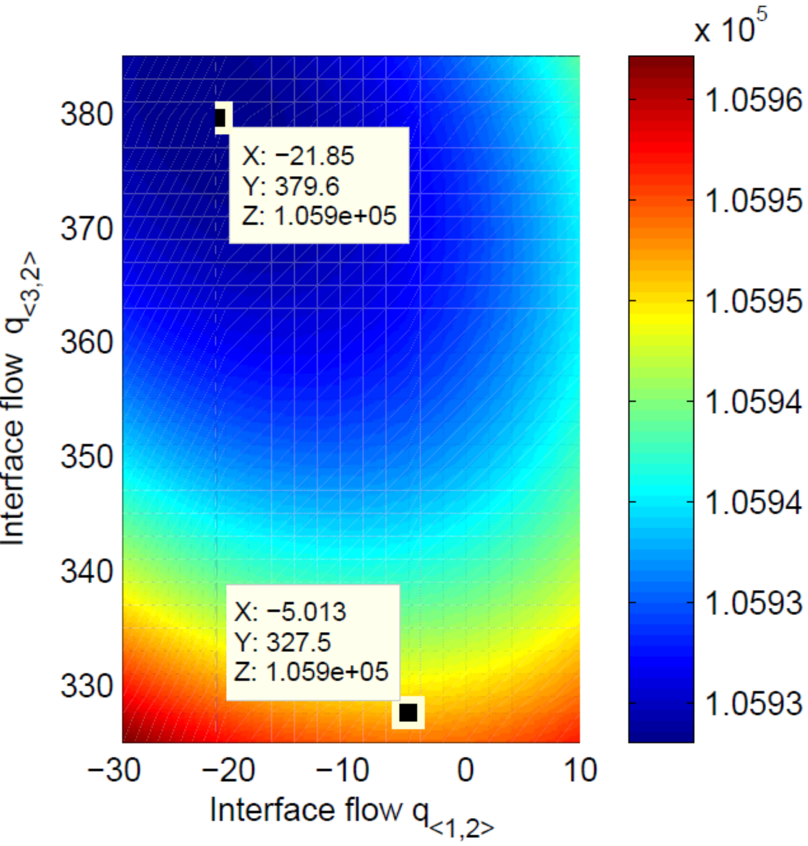
Scenario 1: 20% renewables

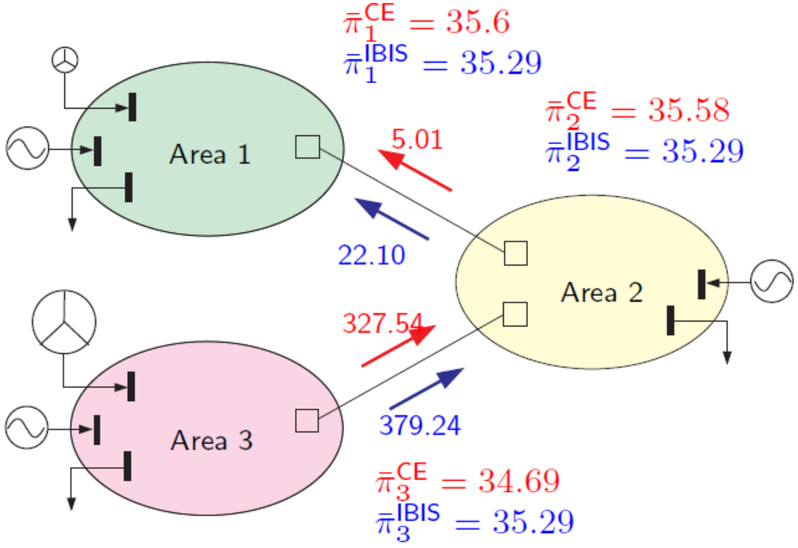


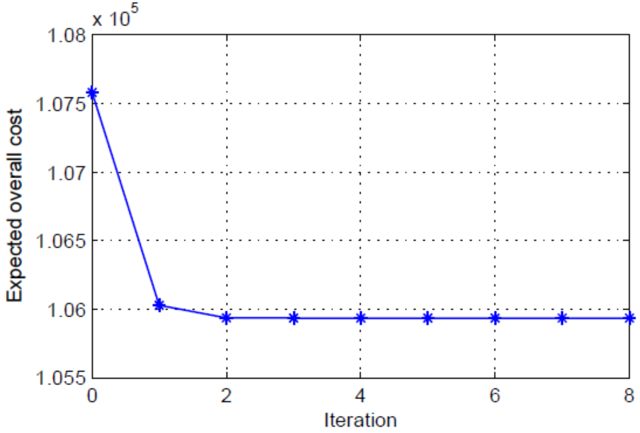


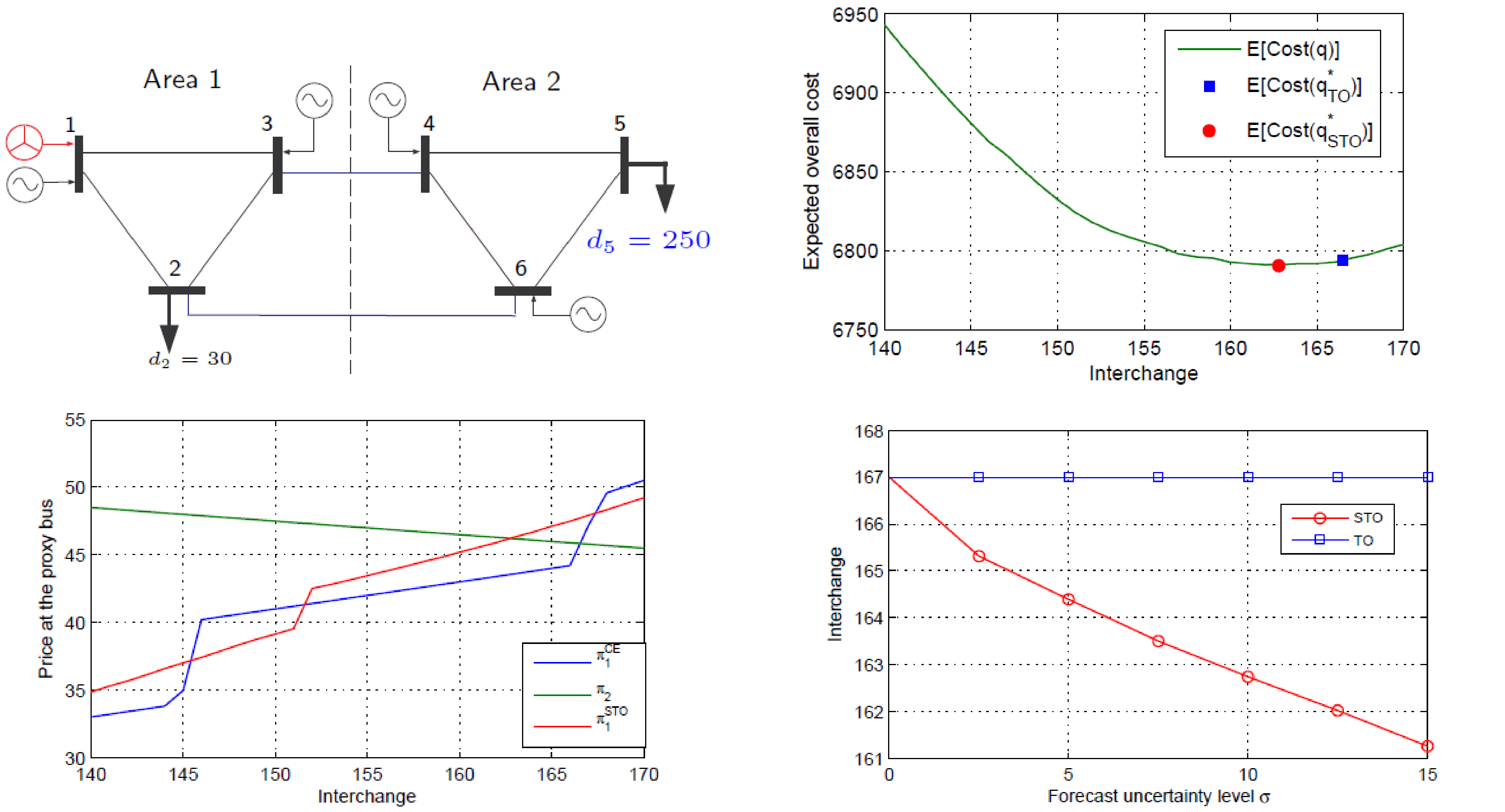


Scenario 2: 30% renewables









Area 1
Area 2
1
2
3
4
5
6
$d_5 = 250$
$d_2 = 30$
Expected overall cost
Interchange
E[Cost(q)]
E[Cost(q*TO)]
E[Cost(q*STO)]
Price at the proxy bus
Interchange
π1CE
π2
π1STO
Interchange
Forecast uncertainty level σ
STO
TO

Summary of results

- Real-time LMP models
  - Energy and energy-reserve markets
  - Deterministic and probabilistic contingencies
- Forecasting methodologies
  - Multiparametric programming approach to
  - Deterministic and probabilistic contingencies
  - Forecast methods and applications
    - An online learning approach of to forecasting of LMP and power flow distributions.
    - A Markov chain approach for ex ante and ex post LMPs
    - Multi-area interchange scheduling under uncertainties

Related publications

- Y. Ji, R. J. Thomas, L. Tong, “Probabilistic forecasting of real-time LMP and network congestion,” submitted to IEEE Trans. Power Systems, under 4th revision
- Y. Ji, T. Zhang, L. Tong, “Stochastic interchange scheduling in the real-time electricity market,” submitted to IEEE Trans. Power Systems, under second revision.
- G. Ye, L. Tong, et. al., “Coordinated multi-area economic dispatch via multiparametric programming,” submitted to IEEE Trans. Power System, under review, 2016.
- Y. Ji and L. Tong, “Multi-proxy interchange scheduling under uncertainty,” IEEE Power & Energy Scoeicty General Meeting, 2016
- G. Ye, L. Tong, et. al., “Multi-area economic dispatch via state space decomposition,” IEEE American Control Conf., 2016
- Y Ji, R.J. Thomas, and L. Tong, ”Probabilistic Forecast of Real-Time LMP via Multiparametric Programming,” 2015 48th Hawaii International Conference on System Sciences (HICSS), 2015.
- Yuting Ji, Jinsub Kim, Robert J. Thomas, and Lang Tong,“Forecasting Real-Time Locational Marginal Price: A State Space Approach,” The 47th Asilomar Conference on Signals, Systems, and Computers , Nov., 2013.
- Y. Ji and L. Tong, ”Stochastic coordinated transaction scheduling via probabilistic forecast,” IEEE Power & Energy Society General Meeting, 2015.