Optimizing the Operation of Power System Open Markets

Bruce Wollenberg

University of Minnesota

Problem: How to measure of the impact of each transaction

- Consider a bilateral transfer of energy to be from one generator (seller) to one load (buyer)
- What is the impact of each such transfer on the transmission system
  - Losses
  - Transmission line loading
  - Bus voltage drop
  - Reactive power support

Management of Transmission one transaction at a time

- Now done with linear (DC power flow) analysis: PTDF’s and LODF’s, NERC’s TLR procedures
- Linear analysis, as usual, only goes so far:
  - Ignores voltage magnitudes, MVAR flow, MVA flow, etc.
  - Losses are estimated using guess work resulting in constant (inaccurate) factors

Real power losses

- Loss in a line (current in a resistor)
  - 1 transaction : $$Ploss = I^2 R$$
  - 2 transactions : $$Ploss = \left(I_a + I_b\right)^2 R$$ $$Ploss = I_a{}^2 R + I_b{}^2 R + 2 I_a I_b R$$
  - Problem: $$Ploss \neq Ploss_a + Ploss_b$$

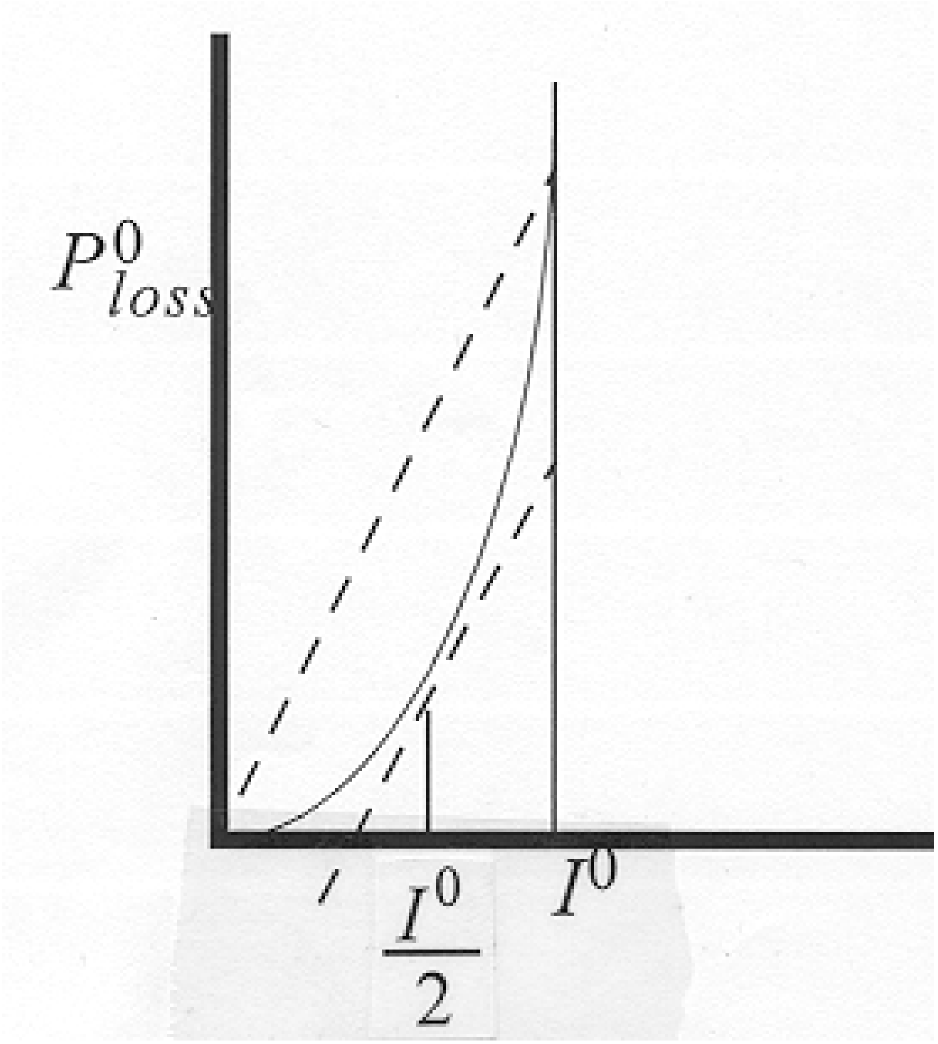
Basic Concept

- Loss in a line : $Ploss = I_0^2 R$
- Rate of change in loss in a line: $\frac{dPloss}{dI} = 2 I R$

- Mid-Point Incremental Loss Formula:

$$Ploss = \left(\frac{dPloss}{dI} \bigg|_{I = \frac{I_0}{2}} \right) I_0 = 2 \left(\frac{I_0}{2} \right) I_0 R = I_0^2 R$$

Mid-Point Incremental Loss Formula



2-Transaction Example

$$I_0 = I_a + I_b$$

$$Ploss = (I_a + I_b)^2 R = I_a^2 R + I_b^2 R + 2I_a I_b R$$

$$Ploss_a = \left(\left. \frac{dPloss}{dI} \right|_{I=\frac{I_0}{2}} \right) I_a = 2\left(\frac{I_0}{2}\right) R * I_a = 2\left(\frac{I_a + I_b}{2}\right) R * I_a = I_a^2 R + I_a I_b R$$

$$Ploss_b = \left(\left. \frac{dPloss}{dI} \right|_{I=\frac{I_0}{2}} \right) I_b = 2\left(\frac{I_0}{2}\right) R * I_b = 2\left(\frac{I_a + I_b}{2}\right) R * I_b = I_b^2 R + I_a I_b R$$

$$Ploss = Ploss_a + Ploss_b$$

Proposed Scheme Formulation

- Base case electric quantity f

$$f^{0} = f(q_{1}^{0}, V_{1}^{0}, \ldots, q_{N}^{0}, V_{N}^{0})$$

- f changes from f^{0} to $f^{0}+Df$

- Allocation of Df to each transaction ?

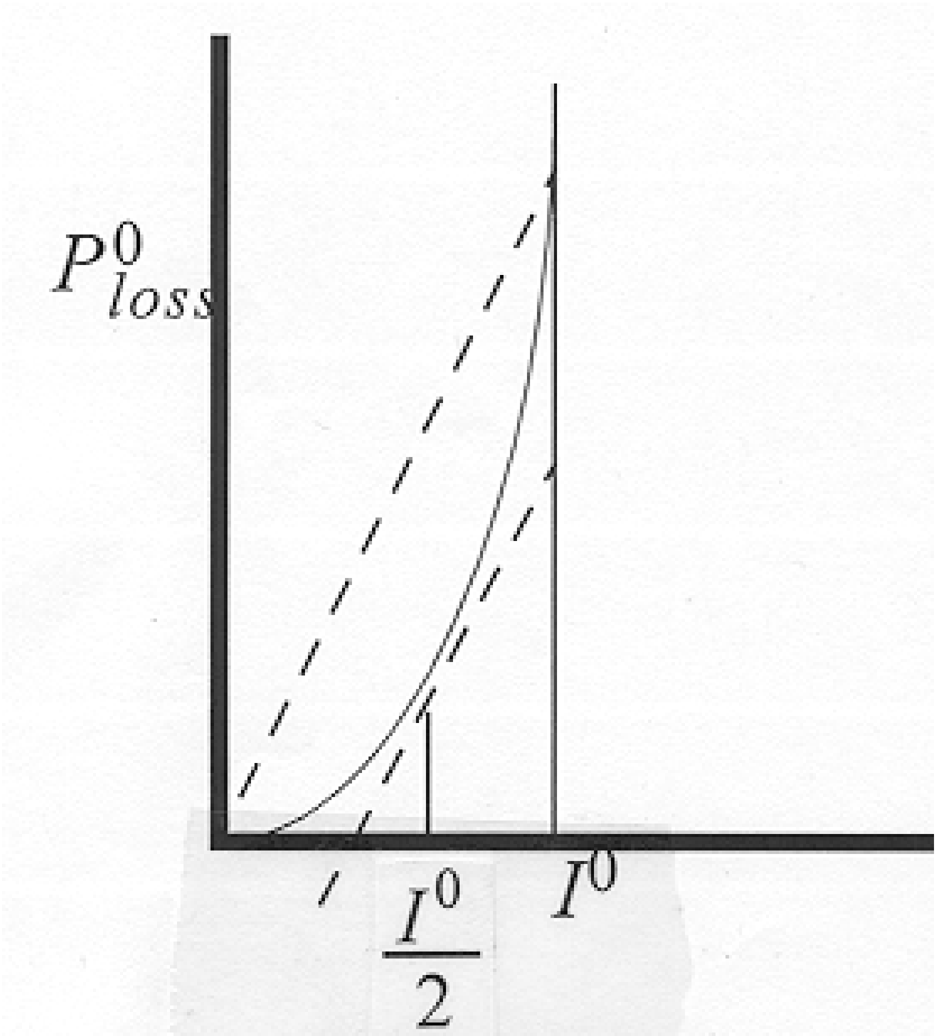
Basic Derivation

- Transaction $P_t(s) = s * P_{t-full}$
- Trapezoidal Integration Method: $Df \cong \left.\frac{\partial f}{\partial s}\right|_{s=\frac{1}{2}} Ds$

$$\frac{\partial f}{\partial s} = \frac{\partial f}{\partial q_1}\frac{\partial q_1(s)}{\partial s} + \frac{\partial f}{(\partial V_1/V_1)}\frac{(\partial V_1/V_1(s))}{\partial s} +$$

$$\ldots + \frac{\partial f}{\partial q_N}\frac{\partial q_N(s)}{\partial s} + \frac{\partial f}{(\partial V_N/V_N)}\frac{(\partial V_N/V_N(s))}{\partial s}$$

Trapezoidal Integration Method



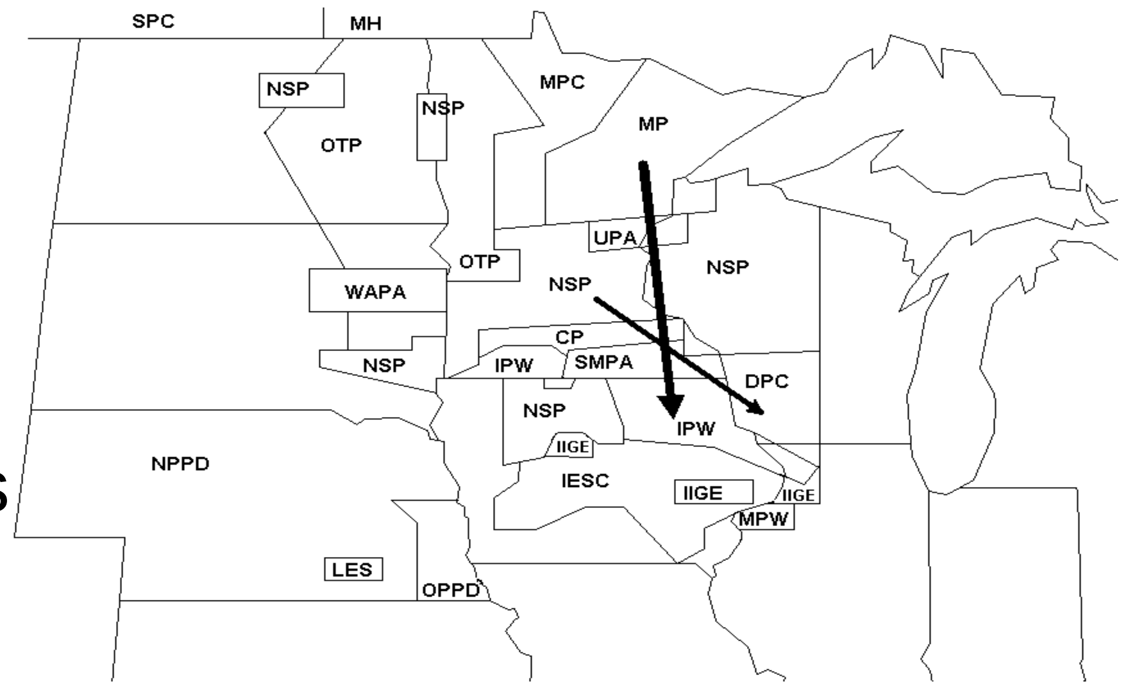
Basic Derivation

- Network state vector: $\underline{X} = (q_1, V_1, \ldots, q_N, V_N)$
- Set $\frac{\partial f}{\partial \underline{X}} = \left[\frac{\partial f}{\partial q_1} \quad \frac{\partial f}{(\partial V_1 / V_1)} \cdots \frac{\partial f}{\partial q_N} \quad \frac{\partial f}{(\partial V_N / V_N)} \right]$
- Then

$$Df \cong \left.\frac{\partial f}{\partial s}\right|_{s=\frac{1}{2}} Ds = \left.\left(\frac{\partial f}{\partial \underline{X}} \begin{bmatrix} \frac{\partial q_1(s)}{\partial s} \\ \frac{\partial V_1(s)}{\partial s} \\ \ldots \\ \frac{\partial q_N(s)}{\partial s} \\ \frac{\partial V_N(s)}{\partial s} \end{bmatrix} \right)\right|_{s=\frac{1}{2}} Ds$$

Numerical Studies

- MAPP power system model :
  - 3120 buses
  - 499 generators
  - 5257 branches
  - 24 control areas



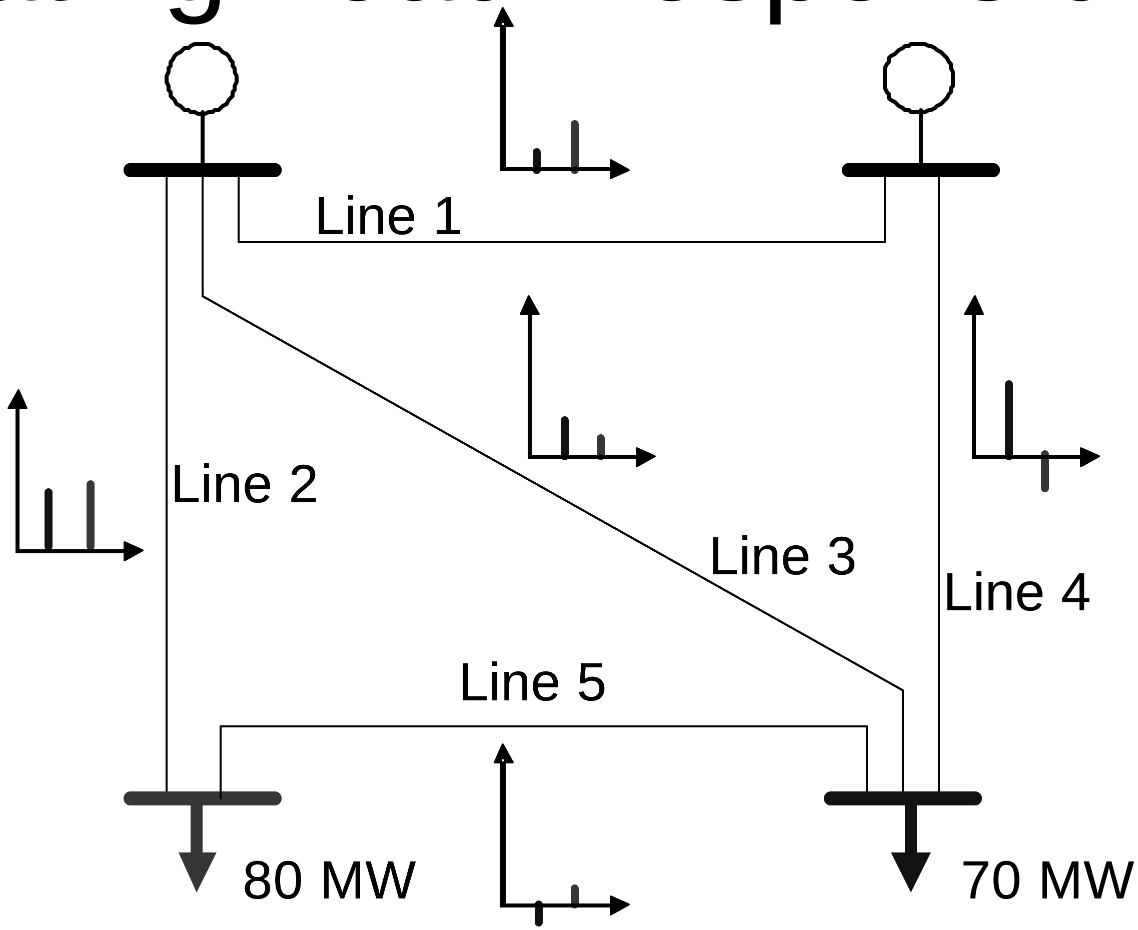
Allocation of Change in Branch MW & MVAR Flows to Transactions

	Transaction 1			Transaction 2			Sum of Allocated Values			Actual Totals	
Branch Index	ΔMW Flow	ΔMW DC Power Flow	ΔMVAR Flow	ΔMW Flow	ΔMW DC Power Flow	ΔMVAR Flow	ΔMW Flow	ΔMW DC Power Flow	ΔMVAR Flow	ΔMW Flow	ΔMVAR Flow
1	0.02	0.00	-20.10	-497.26	-500.00	44.35	-497.24	-500.00	24.24	-497.24	24.17
2	-497.02	-500.00	13.78	0.00	0.00	-2.43	-497.02	-500.00	11.34	-497.02	11.32
3	-135.66	-139.78	56.34	-0.79	-0.65	0.57	-136.45	-140.44	56.91	-136.43	56.84
4	-183.73	-190.18	16.07	0.88	0.77	-2.28	-182.84	-189.41	13.80	-182.85	13.82
5	-240.62	-240.11	31.17	27.00	26.75	-6.14	-213.62	-213.36	25.03	-213.61	25.78
6	-138.55	-150.77	42.69	-34.60	-34.84	-6.24	-173.15	-185.61	36.44	-173.14	36.42
7	43.47	48.44	40.87	138.29	139.10	-3.12	181.76	187.54	37.76	181.75	37.91
8	-141.80	-161.89	10.03	-133.65	-143.75	16.84	-275.45	-305.63	26.87	-275.55	27.27
9	241.09	245.32	72.08	-16.29	-16.98	28.57	224.80	228.34	100.65	224.77	100.77
10	79.91	91.64	9.34	127.92	131.17	20.78	207.83	222.81	30.12	207.81	30.09

Allocation of Change in Area MW & MVAR Losses to Transactions

	Transaction 1		Transaction 2		Sum of Allocated Values		Actual Totals	
Area Index	ΔMW Loss	ΔMVAR Loss	ΔMW Loss	ΔMVAR Loss	ΔMW Loss	ΔMVAR Loss	ΔMW Loss	ΔMVAR Loss
1	-0.03	-0.26	-0.01	-0.08	-0.04	-0.34	-0.04	-0.34
2	0.02	-0.07	0.02	0.04	0.03	-0.03	0.04	-0.04
3	0.06	0.66	0.04	0.47	0.10	1.13	0.10	1.14
4	-0.03	2.98	-0.14	-0.20	-0.17	2.78	-0.17	2.86
5	-0.13	-0.28	-0.07	-0.16	-0.20	-0.45	-0.19	-0.45
6	-0.08	2.15	-0.22	-1.06	-0.29	1.09	-0.29	1.12
7	0.33	5.91	-0.68	-3.89	-0.35	2.02	-0.35	1.79
8	-0.31	0.29	-0.06	0.04	-0.38	0.33	-0.38	0.33
9	0.64	3.02	0.24	1.13	0.87	4.14	0.87	4.12
10	0.83	7.98	0.19	2.58	1.01	10.56	1.03	10.74
11	0.40	2.45	0.86	5.29	1.25	7.75	1.26	7.77
12	1.69	5.87	0.06	-2.92	1.75	2.95	1.75	3.00
13	2.53	27.87	-0.75	7.02	1.78	34.89	1.77	35.40
14	1.35	13.31	0.59	6.30	1.94	19.61	1.94	19.61
15	8.70	42.80	-5.49	-55.40	3.21	-12.60	3.21	-12.77
16	3.32	26.87	2.00	14.30	5.33	41.17	5.34	41.31
17	4.31	39.40	1.49	12.97	5.80	52.36	5.81	52.58
18	4.78	87.44	1.49	20.95	6.27	108.38	6.28	108.61
19	39.97	487.60	2.17	25.09	42.14	512.69	42.16	512.41
20	40.18	378.87	41.26	554.24	81.44	933.12	81.44	932.94
Total	108.52	1134.87	42.99	586.71	151.51	1721.58	151.54	1722.13

Allocating Load Responsibilities



Generators are identical

Two companies sharing one transmission system

- Each company operates independently
- Each company dispatches generation to meet its own load and its allocation of losses (calculated by integration method)
- Each company's dispatch affects the other through the losses on the transmission system

Pareto Optima

$$Min \qquad a CostA + (1 - a) CostB$$

- Subject to:

$$P_2 + P_8 = Load_A + Loss_A$$

$$P_3 + P_6 = Load_B + Loss_B$$

Nash Equilibrium

- Simultaneous Solution of:

$$Min \quad CostA$$

- *Subject to*

$$P_2 + P_8 = Load_A + Loss_A$$

$$Min \quad CostB$$

subject to

$$P_3 + P_6 = Load_B + Loss_B$$

Two Independent Companies Trading between them

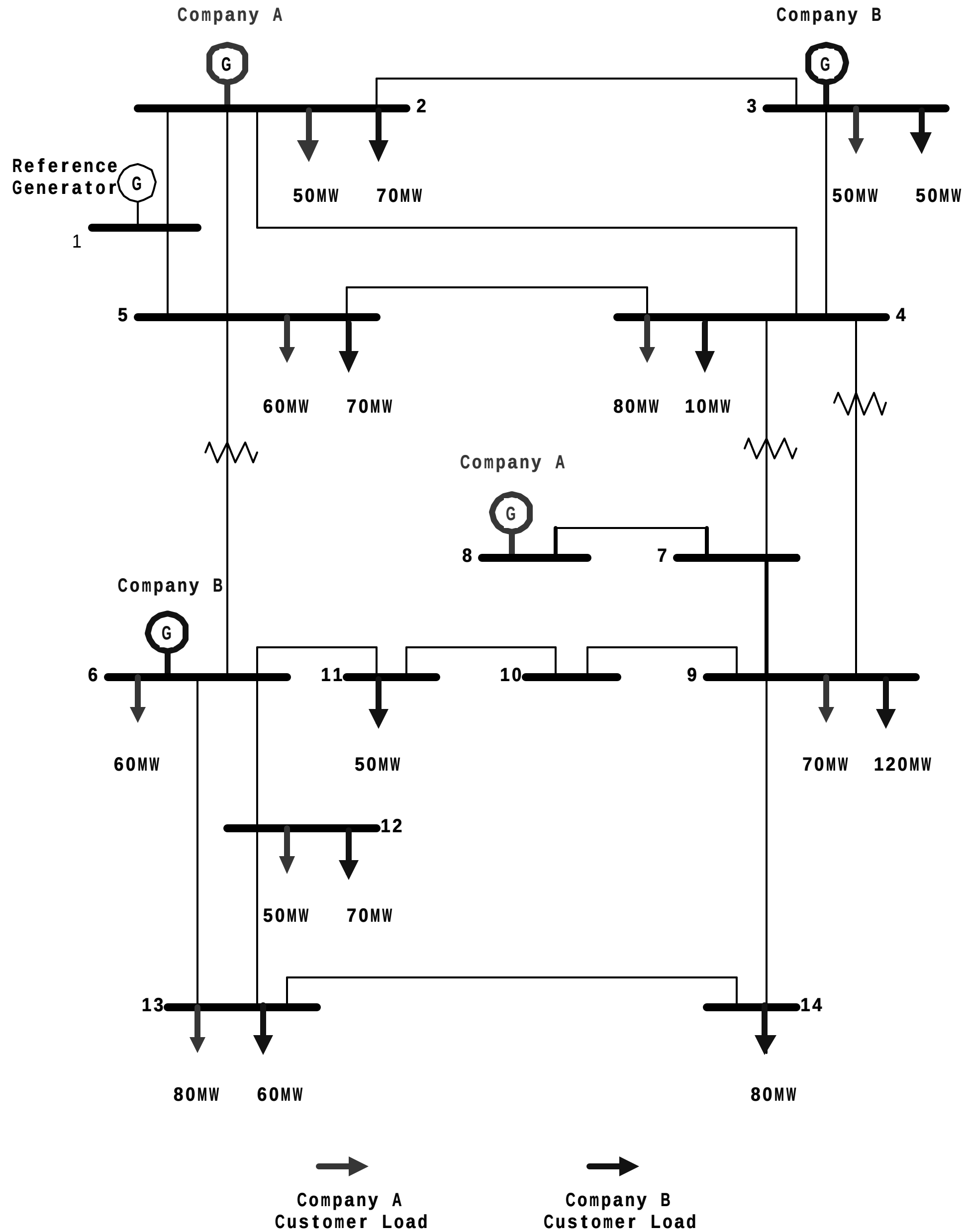
$$Min \qquad CostA + CostB$$

- Subject to

$$P_2 + P_8 + P_3 + P_6 = Load_A + Loss_A + Load_B + Loss_B$$

- This is the same as a pool dispatch where all generators are treated as one company

IEEE 14 Bus Power System

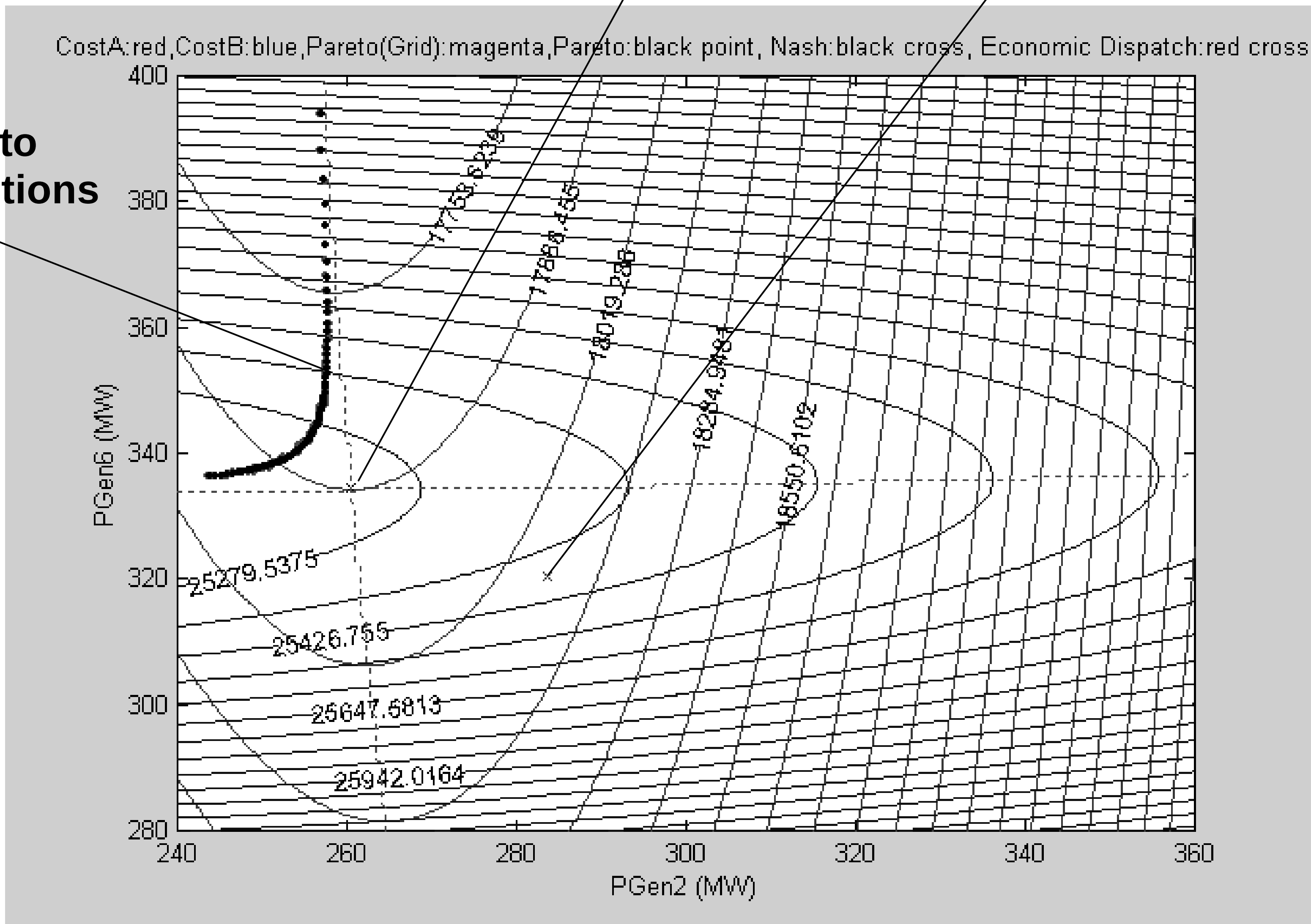


Solutions

Nash Solution

Pool ED

Pareto Solutions



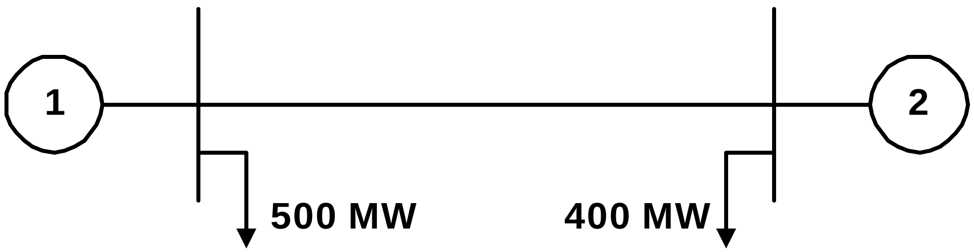
Central Market Designs

- PJM and NYISO are central markets based on Locational Marginal Price
- No identification of individual transactions
- Each generator and each load bids to sell (buy) from a central exchange.
- Central exchange calculates the bus LMP's which determine payments and transmission charges

Locational Marginal Price (LMP)

- Requires a Security Constrained Optimal Power Flow
- Usually coupled with Unit Commitment (SCUC)
- The only transmission management scheme now in use that uses full AC network model

CASE 1



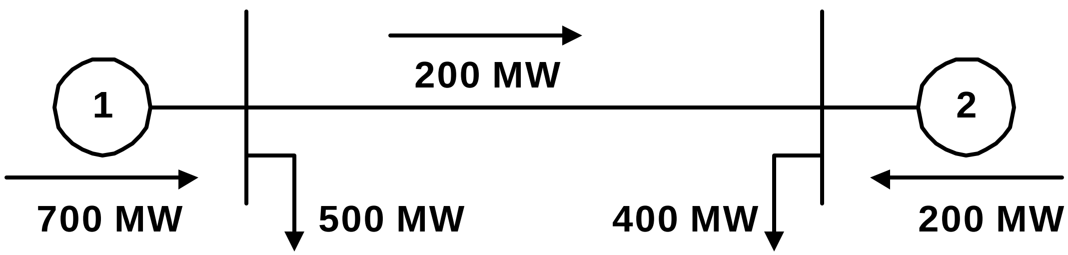
Generator 1		
Asks	MW	Price
A	400	5.00
B	400	7.50

	Generator 2	
Asks	MW	Price
C	200	6.50
D	200	8.00

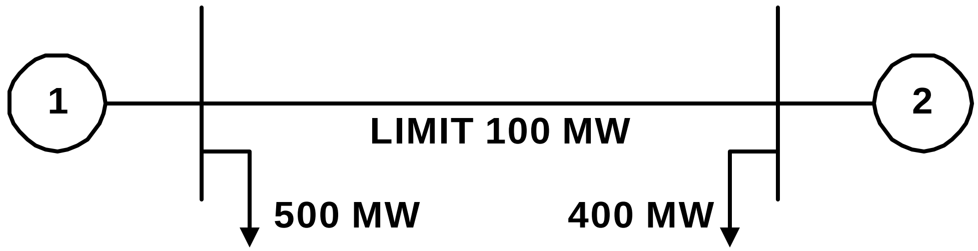
CASE 1 (cont)

Schedule of generation:

Ask	MW	Price
A	400	5.00
C	200	6.50
B	300	7.50 clearing price (same for both buses)



CASE 2



Generator 1

Ask	MW	Price
A	400	5.0
B	200	7.50

Generator 2

Ask	MW	Price
C	200	6.50
D	100	8.00

CASE 2 (cont)

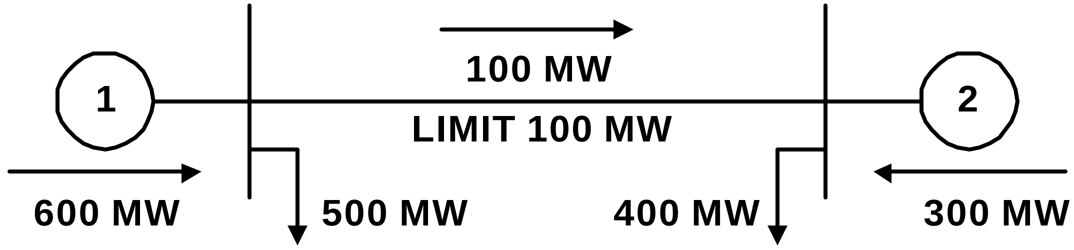
clearing price at bus 1 = 7.50
clearing price at bus 2 = 8.00

Bus 1 generation schedule

Ask	MW	Price
A	400	5.0
B	200	7.50 clearing price

Bus 2 generation schedue

Ask	MW	Price
C	200	6.50
D	100	8.00 clearing



Case 1 Accounting

Revenue Collected from Loads	Revenue paid to generators and Transmission Owners
Load 1: 500 x 7.50 = 3750	Gen 1: 700 x 7.50 = 5250
Load 2: 400 x 7.50 = 3000	Gen 2: 200 x 7.50 = 1500
	Transmission = 0
Total: 6750	Total: 6750

Case 2 Accounting

Revenue Collected from Loads	Revenue paid to generators and Transmission Owners
Load 1: 500 x 7.50 = 3750	Gen 1: 600 x 7.50 = 4500
Load 2: 400 x 8.00 = 3200	Gen 2: 300 x 8.00 = 2400
	Transmission 100(8.00-7.50)= 50
Total: 6950	Total: 6950

Financial Transmission Right (FTR)

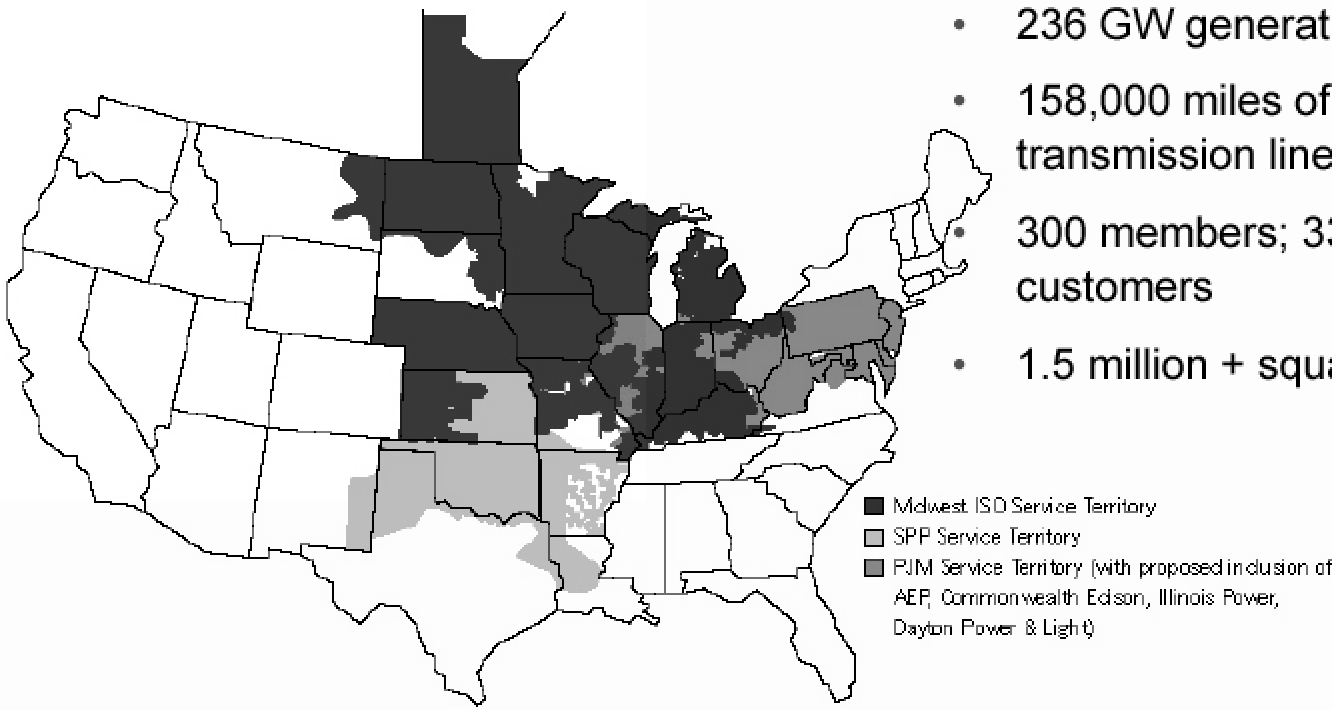
- Transmission charge in an LPM market is:
  - (LPMi-LMPj)*MWflow
- Holder of FTR receives credit of:
  - (LPMi-LMPj)*MWflow
  - Where MWflow is the “amount” purchased
- Holder can transfer the amount of the FTR from location i to j at no charge (credit cancels transmission charge)

FERC Standard Market Design

- FERC's proposal mirrors the PJM and NY ISO market designs
- Key elements of SMD
  - LMP based congestion management
  - Financial Transmission Rights
  - Financially binding day-ahead energy markets
  - Real time balancing markets
  - Capacity markets (initial reluctance, gradual acceptance)
  - Market power mitigation

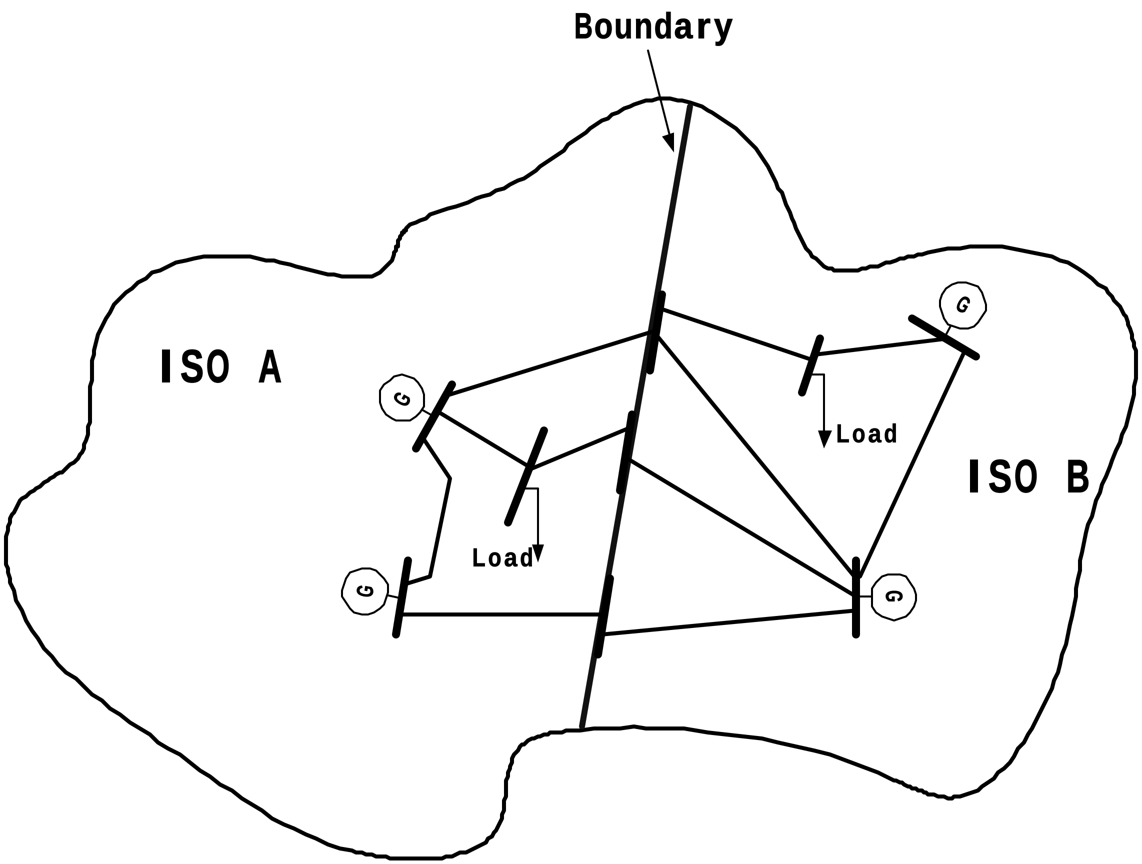
US Markets

- 213 GW peak load
- 236 GW generating capacity
- 158,000 miles of transmission lines
- 300 members; 33 million customers
- 1.5 million + square miles



Roberto Paliza, MISO

Seams Problem



Both regions A and B operate by LPM calculations.

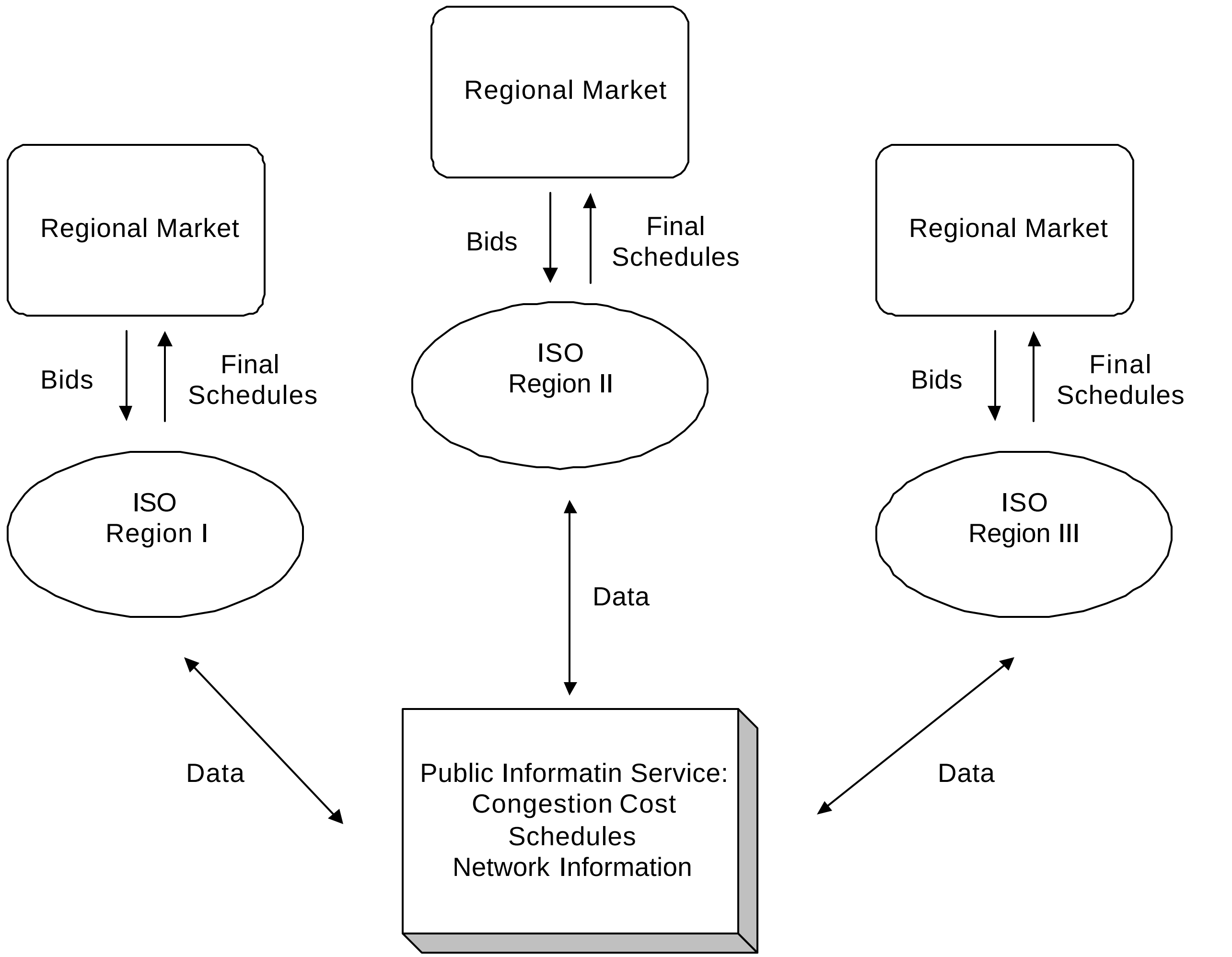
They will get different costs along the boundary o seam between them

If both A and B were operated as one market with one LMP calculation – there would be no such difference

Problems with Seams

- Trading across the seam is difficult due to price differences that are only due to regional OPF solutions

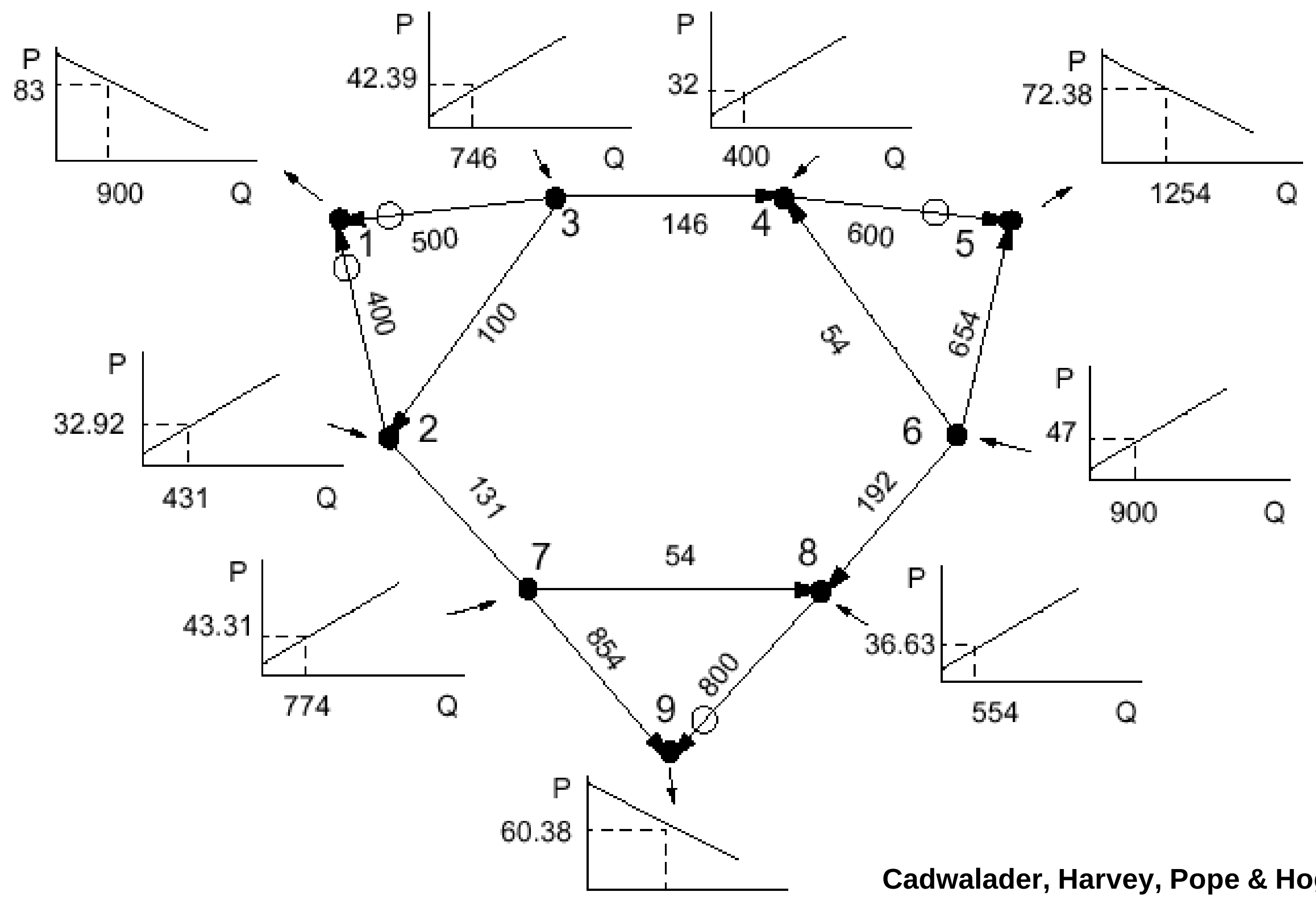
Solution to the “Seams” Problem



Information Exchanged

- All regions have the same network model covering all regions
- After the solution of each region's OPF:
  - exchange power injections, LMP's for each bus
  - exchange binding transmission constraint lambdas
- Each region now recalculates with a penalty term for its effect on other region's constraints
- Usually converges in three iteration for linear case

Constrained Market Solution



Cadwalader, Harvey, Pope & Hogan
Harvard University 1999

Iterative Solution to the Constrained Market

Region Bus No.		Start Iteration	1st Iteration	2nd Iteration	3rd Iteration	Final Iteration
1	Price ($/MW)	50	82.30	82.95	83.00	83.00
	Load (MW)	2000	923	900	900	900
2	Price ($/MW)	50	33.62	32.63	32.90	32.90
	Load (MW)	-1000	-454	-421	-430	-430
3	Price ($/MW)	50	42.24	42.75	42.38	42.38
	Load (MW)	-1000	-741	-758	-746	-746
4	Price ($/MW)	50	31.43	31.95	32.00	32.00
	Load (MW)	-1000	-381	-398	-400	-400
5	Price ($/MW)	50	71.32	72.43	72.38	72.38
	Load (MW)	2000	1289	1252	1254	1254
6	Price ($/MW)	50	47.93	46.97	47.00.	47.00
	Load (MW)	-1000	-931	-899	-900	-900
7	Price ($/MW)	50	44.03	43.27	43.29	43.30
	Load (MW)	-1000	-801	-776	-776	-777
8	Price ($/MW)	50	36.91	36.64	36.64	36.65
	Load (MW)	-1000	-564	-555	-555	-555
9	Price ($/MW)	50	60.23	60.43	60.40	60.40
	Load (MW)	2000	1659	1652	1653	1654

Congestion Constraints

Branch l No.	1	2	3	4	5	6	7	8	9	10	11	12
From Bus	1	1	2	2	3	4	4	5	6	7	7	8
To Bus	2	3	3	7	4	5	6	6	8	8	9	9
Lambda	-69.98	-20.79	0.00	0.00	0.00	65.73	0.00	0.00	0.00	0.00	0.00	40.78

Research Challenge for Seams Problem

- Do all of the OPF matching using an AC network model, an AC OPF and AC security analysis
- This presents a great problem wrt convergence and stability of solutions
- Added complexity: solve the seams problem within a SCUC