Introduction to Transmission Market Design in the US: Locational Marginal Pricing

NGInfra Academy
Electricity & CO_2 Markets Track

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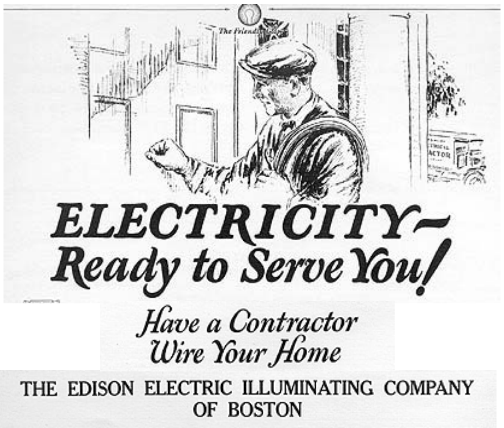
Outline



1. Some history
2. The "LMP" Philosophy
3. Calculation of LMPs: "Smart Auctions"
    a. Simple Linear Program
    b. DC Linearization of Load Flow
    c. Transmission Constrained LP
4. Examples of "Zonal" problems
5. Problems with LMPs
    a. Some left-behind λ's
    b. Market power

1. A Brief History of Regulation and Restructuring in the US

- 400 BC: Athens city regulates flute lyre girls
- 1978: Public Utilities Regulatory Act
- 1978: Schweppe’s “Power Systems 2000” article
- Federal:
  - 1992 US Energy Policy Act
  - FERC Orders 888, 2000
  - FERC “Standard Market Design”
- States:
  - California leads 1995; most states following
  - Response to California 2000-01: “Whoa!!”
  - Response to FERC SMD, Fuel price increases
    - ISO markets converging to LMP-type design
    - Other states keeping vertically integrated, regulated utilities

April 2003: “~~Standard Market Design~~” “Wholesale Power Market Platform”

FERC’s *mea culpa*:

> “The proposed rule was too prescriptive in substance and in implementation timetable, and did not sufficiently accommodate regional differences”
>
> “Specific features … infringe on state jurisdiction”

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Market Design Principles of "Platform"

- *Grid operation:*
  - Regional
  - Independent
  - Congestion pricing (*LMP*)
- *Grid planning:*
  - Regional
  - State and stakeholder led
- *Resource (= gen capacity) adequacy*
  - State led

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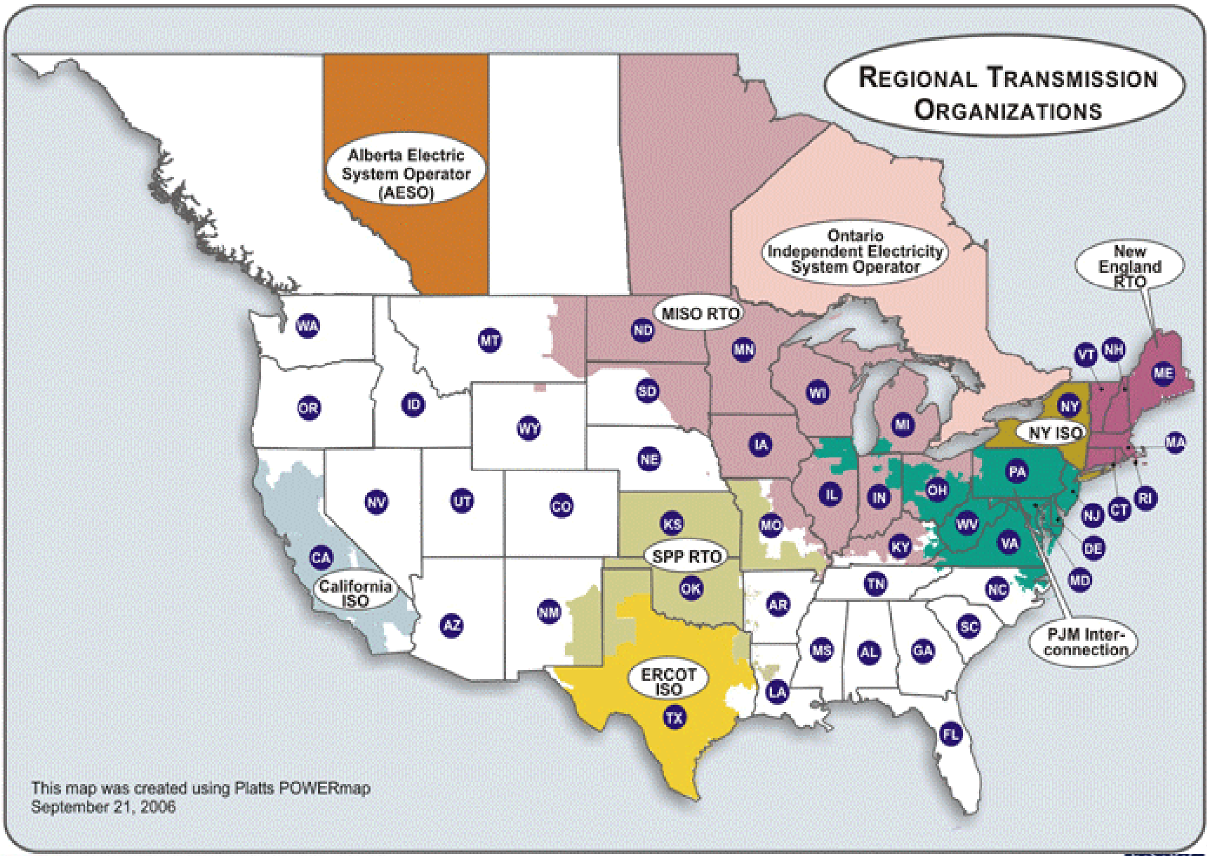
More Principles of "Platform"

- *Spot markets:*
  - Day ahead and balancing
  - Integrated energy, ancillary services, transmission
  - "Smart Auctions"
    - – Auctions solved by optimization models
- *Firm transmission rights*
  - Financial, not physical
  - Don't need to auction
    - – Allocation can protect participants from harm
- *Market power*
  - Market-wide and local mitigation
  - Monitoring



Source: FERC

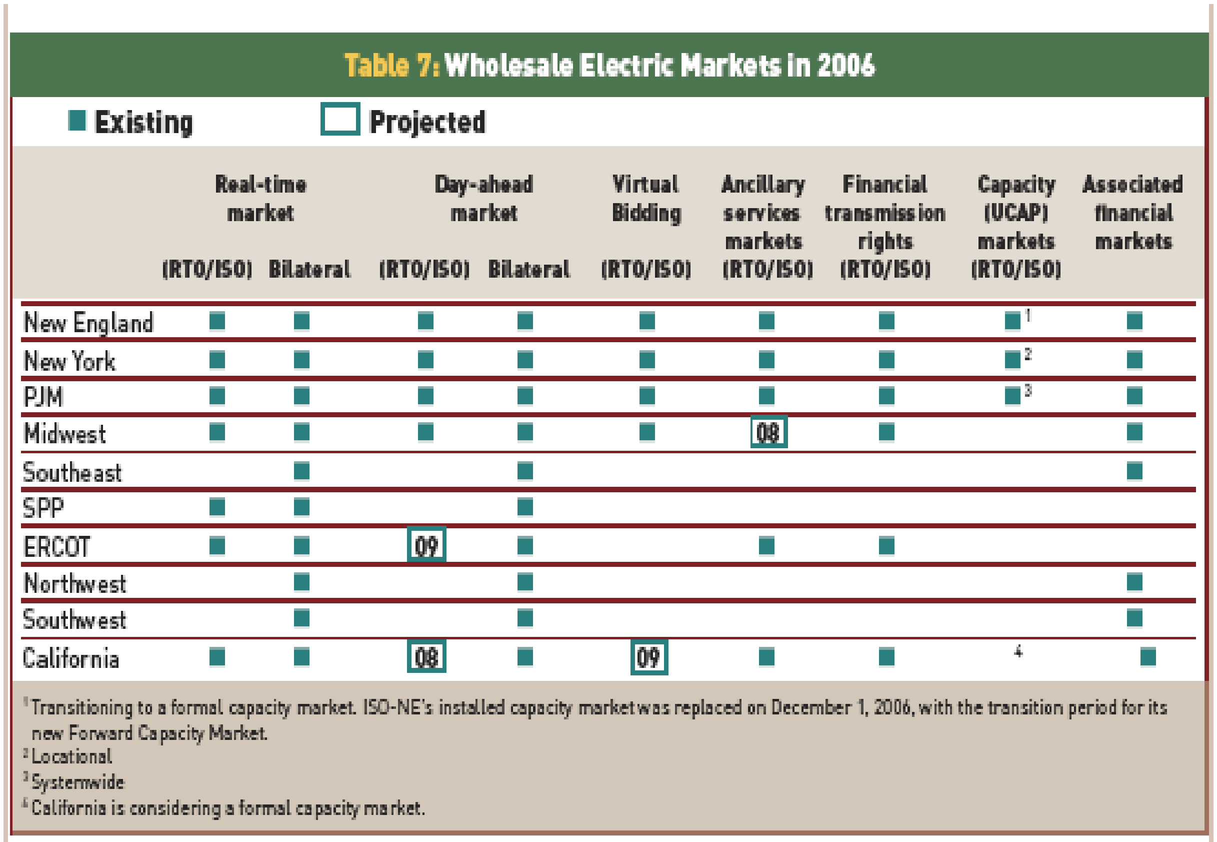


Table 7: Wholesale Electric Markets in 2006

■ Existing □ Projected

	Real-time market		Day-ahead market		Virtual Bidding	Ancillary services markets	Financial transmission rights	Capacity (UCAP) markets	Associated financial markets
	(RTO/ISO)	Bilateral	(RTO/ISO)	Bilateral	(RTO/ISO)	(RTO/ISO)	(RTO/ISO)	(RTO/ISO)	
New England	■	■	■	■	■	■	■	■[1]	■
New York	■	■	■	■	■	■	■	■[2]	■
PJM	■	■	■	■	■	■	■	■[3]	■
Midwest	■	■	■	■	■	□ 08	■		■
Southeast		■		■					■
SPP	■	■		■					
ERCOT	■	■	□ 09	■		■	■		
Northwest		■		■					■
Southwest		■		■					■
California	■	■	□ 08	■	□ 09	■	■	[4]	■

[1] Transitioning to a formal capacity market. ISO-NE's installed capacity market was replaced on December 1, 2006, with the transition period for its new Forward Capacity Market.

[2] Locational

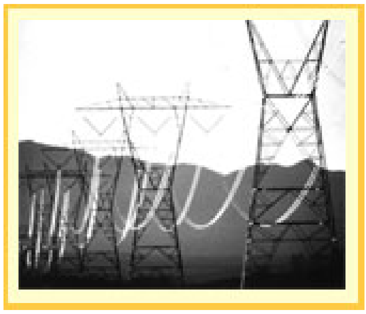
[3] Systemwide

[4] California is considering a formal capacity market.

Source: FERC

2. Locational Marginal Pricing Philosophy

- Price of energy (LMP) at bus i = Marginal cost of energy at bus
  - Most readily calculated as dual variable to energy balance (KCL) constraint for the bus in an Optimal Power Flow (OPF)
- General Statement of OPF
  - Objective *f*:
    - *If fixed demand:* MIN Cost = Σ Generator Costs
    - *If elastic demand:* MAX Net Benefits = Σ (Consumer Value - Generator Cost)
  - Decision variables *X*:
    - Generation
    - Accepted demand bids
    - Operating reserves
    - Real and reactive power flows
  - Constraints upon *X*:
    - Generator limits (including dynamic limits such as ramp rates)
    - Demand (net supply = load *L* at each bus for P,Q)
    - Load flow constraints (e.g., KCL, KVL)
    - Transmission limits & Reserve requirements



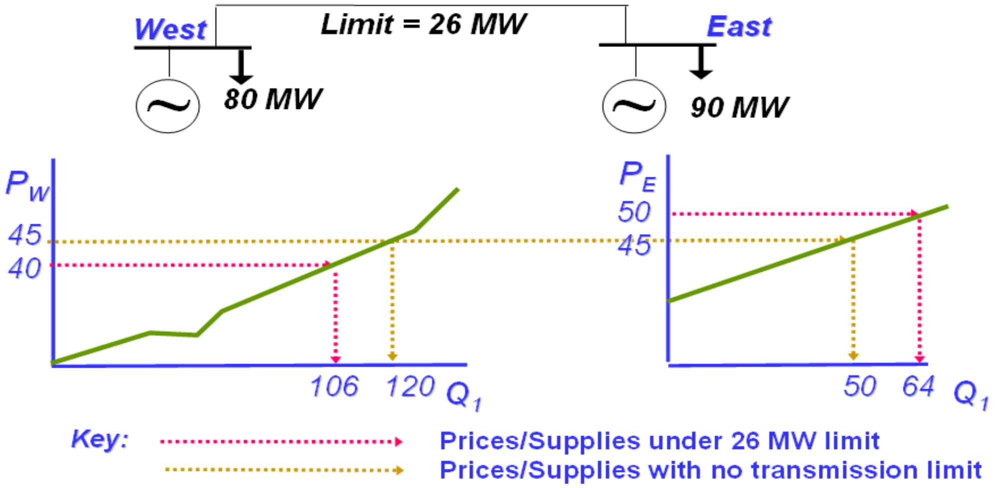
LMP Components

- LMP = Δ Cost resulting from unit change in load
  - d*f*/d*L*
  - Assumes:
    - No change in any integer {0,1} variables
    - No degeneracy (multiple dual solutions)
- Price at bus *i* equals the sum of:
  - *Energy:* Set equal to a "hub" price (e.g., "Moss Landing," or distributed bus)
  - *Loss:* Marginal losses (assuming supply comes from hub)
  - *Congestion:* LMP *minus* (Energy+Loss components)
    - In linear case = Weighted sum of λ's for transmission constraints $= \Sigma_k \text{PTDF}_{m \rightarrow \text{Hub},k}\ \lambda_k$
    - Where $\text{PTDF}_{m\rightarrow\text{Hub},k}$ = MW flow through line *k* resulting from 1 MW injection at node *m* and matching withdrawal at *Hub* node

- California ISO calculation of LMPs: Section 27.5 of the CAISO MRTU Tariff www.caiso.com/1798/1798ed4e31090.pdf, and F. Rahimi's testimony www.caiso.com/1798/1798f6c4709e0.pdf

LMP / Congestion Example

(Based on Presentation by Mark Reeder, NYISO, April 29, 2004)



- Marginal value of transmission = $10/MWh (=$50 – $40)
- Total congestion revenue = $10*26 = $260/hr
- Total redispatch cost = $130/hr
- Congestion cost to consumers: (40*106+50*64) – (45*170) = 7440 – 7650 = –$210/hr

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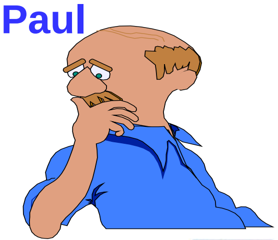
Theoretical Results

- Under certain assumptions (Schweppe et al., 1986):
  - Solution to OPF = Solution to competitive market
    - Dispatch of generation will be efficient (social welfare maximizing, including …)
    - Long run investment will be efficient
  - In other words: The LMPs “support” the optimal solution
    - If pay each generator the LMPs for energy and ancillary services at its bus ….
    - ….Then the OPF’s optimal solution X_j for each generating firm *j* is also profit maximizing for that firm
- This is an application of Nobel Prize winner Paul Samuelson’s principle:
  - Optimizing social net benefits (sum of surpluses)

    = outcome of a competitive market



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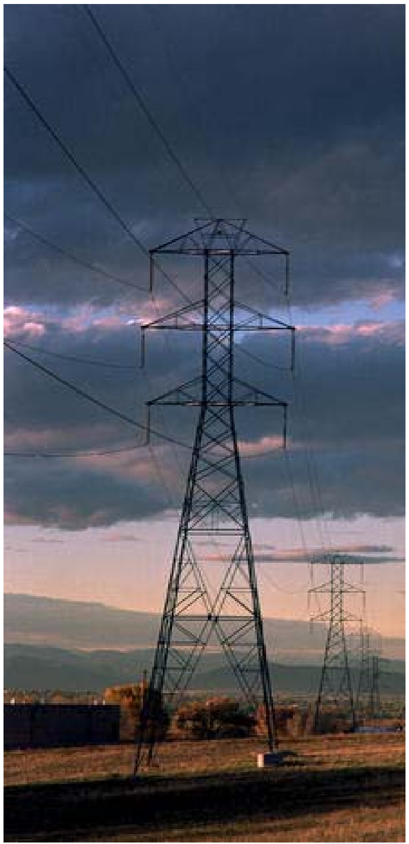
Assumptions

- No market power
- No price caps, etc.
- Perfect information
- Costs are convex
  - No unit commitment constraints
  - No lumpy investments or scale economies
- Constraints define convex set
  - E.g., AC load flow non convex
- Can compute the solution
  - ~10^4 buses, 10^3 generators



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3. Computing LMPs

a. *System Dispatch "Linear Program" sans Transmission*

- Basic model
  - *Cost minimization, pure thermal system, deterministic*

  In words:
  - *Choose level of operation of each generator (decision variable),*
  - *…to minimize total system cost (objective)*
  - *…subject to load, capacity limit (constraints)*
- Decision variable:

  y_{it} *= megawatt [MW] output of generating unit i (i=1,..,I) during period t (t=1,..,T)*
- Coefficients:

  CY_{it} *= variable operating cost [\$/MWh] for* y_{it}

  X_i *= MW capacity of generating unit i.*

  $LOAD_t$ *= MW demand to be met in period t*

  H_t *= length of period t [hours/yr]. (Note: in pure thermal system, periods do not need to be sequential)*

Operations LP: No Trans

MIN Variable Cost = $\Sigma_{i,t} H_t CY_{it} y_{it}$

subject to constraints:

Meet load:

$\Sigma_i y_{it} = LOAD_t \qquad \forall t$

Generation no more than capacity:

$y_{it} \leq X_i \qquad \forall i,t$

Nonnegativity:

$y_{it} \geq 0 \qquad \forall i,t$

This is a "Linear Program" (i.e., objective, constraints are linear in decision variables)

Operations LP Exercise

- Two generation types
  - A: Peak: 800 MW, MC = $70/MWh
  - B: Baseload: 1500 MW, MC = $25/MWh
- Load
  - Pk: Peak: 2200 MW, 760 hours/yr
  - OP: Offpeak: 1300 MW, 8000 hours/yr

What is the model?
What is the solution?
What are the prices in each period?

Operating Model Complications

1. Other objectives
   -- Max Profit? Min Emissions?
2. Energy storage
   -- Pumped storage, batteries, hydropower
3. Explicitly stochastic
   -- Usual assumption: forced outages are random and independent
4. Transmission constraints
5. Commitment variables
   -- E.g., start-up costs
6. Cogeneration

3b. "DC" Linearization of AC load flow

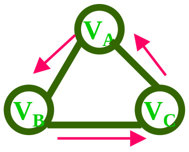
(e.g., F.C. Schweppe, M.C. Caramanis, R.E. Tabors, R.E. Bohn, Spot Pricing of Electricity, Kluwer, 1988)

Assumptions

- Assume reactance >> resistance
- Voltage amplitude same at all buses
- Changes in voltage angles θ_A-θ_B from one end of a line to another is small

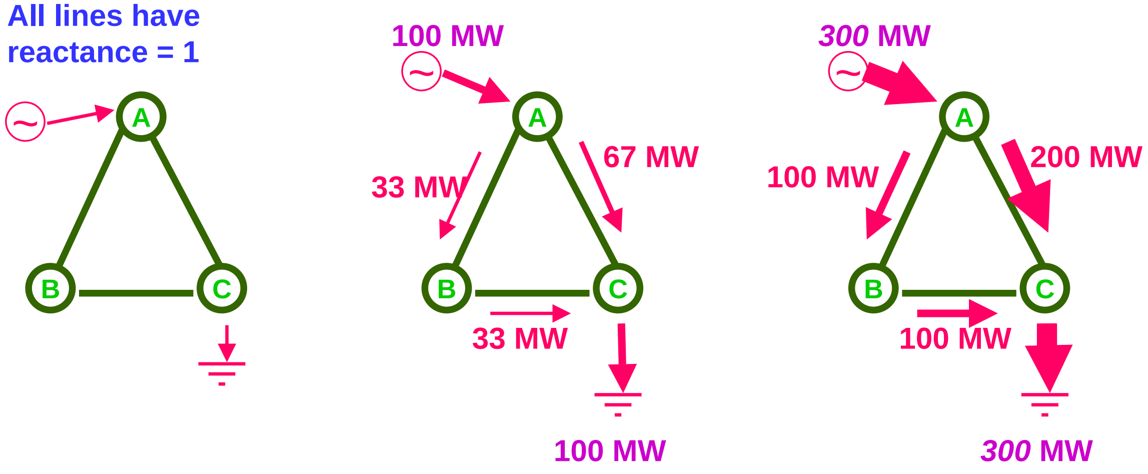
Results:

- Power flow f_{AB} (MW) proportional to:
  - current I_{AB}
  - difference in voltage angle θ_A-θ_B
- Analogies to Kirchhoff's Laws:
  - Current law at A: $\Sigma_i\, y_{iA} = \Sigma_{\text{neighboring } m}\; f_{Am} + \text{LOAD}_A$
  - Voltage law: $f_{AB}{*}R_{AB} + f_{BC}{*}R_{BC} + f_{CA}{*}R_{CA} = 0$
- Given power injections at buses, flows are unique



Example of “DC” Load Flow

All lines have reactance = 1



Kirchhoff’s Current Law at C:

+33 + 67 - 100 = 0

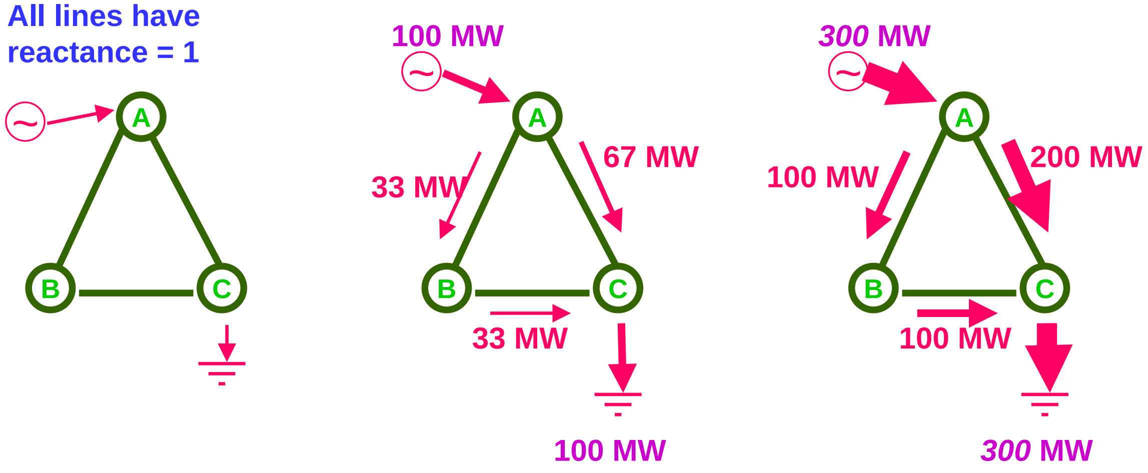
Kirchhoff’s Voltage Law:

1*33 + 1*33 + 1*(-67) = 0

Proportionality!

Proportionality means “Power Transmission Distribution Factors” can be used to calculate flows

All lines have reactance = 1

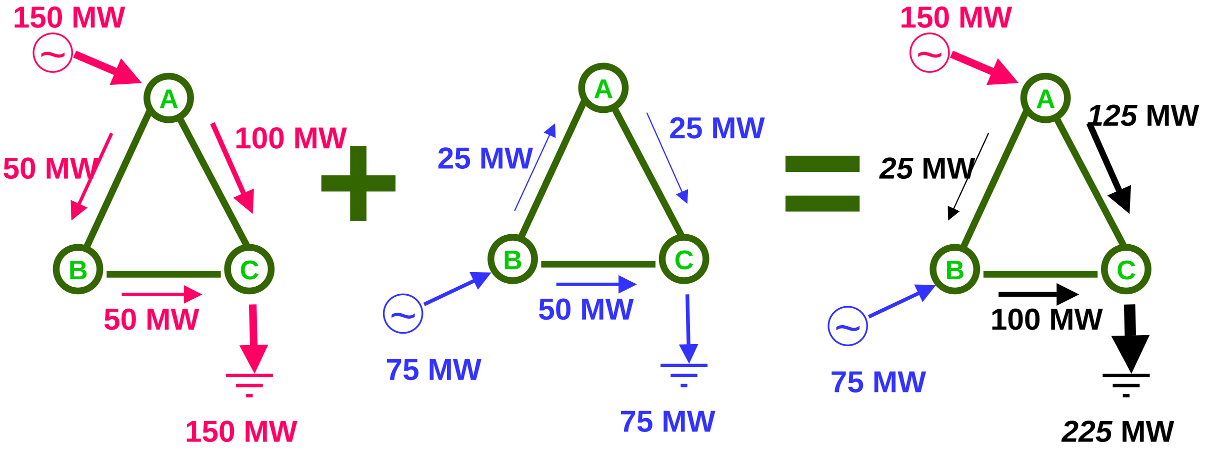


$PTDF_{m\rightarrow n,k}$ = the MW flowing on transmission element *k*, if 1 MW is injected at *m* and 1 MW is withdrawn at *n*

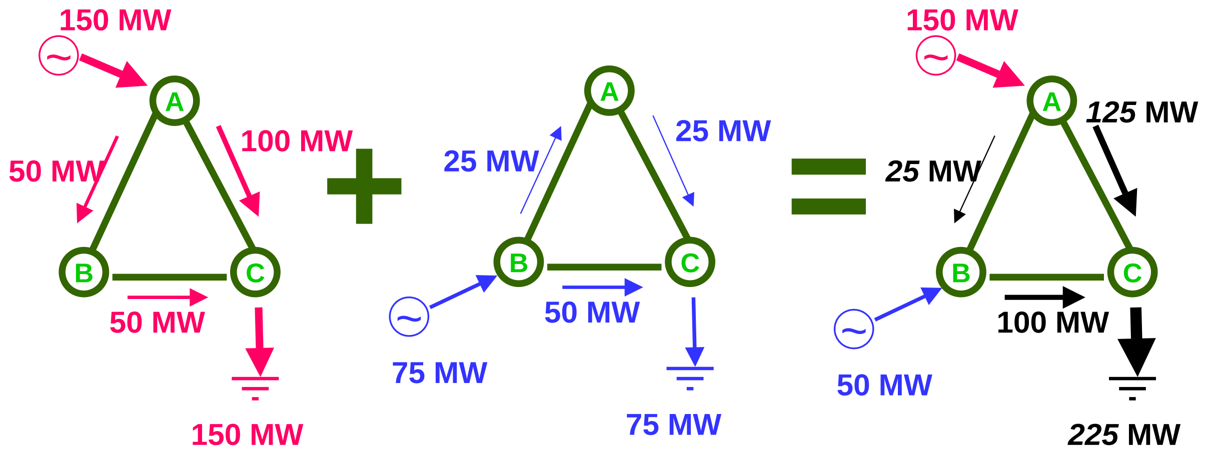
E.g., $PTDF_{A\rightarrow C,AB} = 0.33$

$= -PTDF_{C\rightarrow A,AB}$

Principle of Superposition



Using PTDFs to Calculate Total Flow

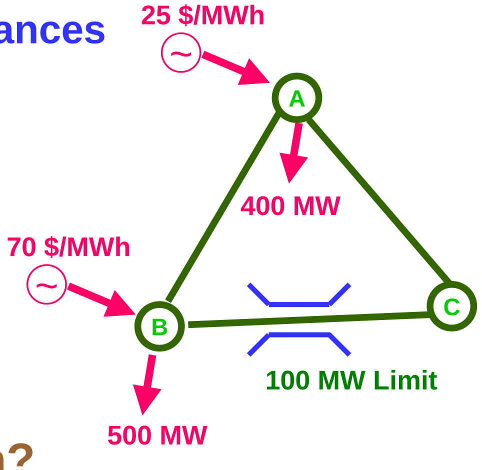


Total flow from B to C = $PTDF_{A \rightarrow C,BC}$*150 + $PTDF_{B \rightarrow C,BC}$*75

= 0.33*150 + 0.67*75 = 100 MW

Exercise in Transmission Modeling

- **Assumptions**
  - Triangle network, equal reactances
    - – Line from B to C: 100 MW limit
  - Two plants:
    - A: MC = 25 $/MWh
    - B: MC = 70 $/MWh
  - Load:
    - A: 400 MW
    - B: 500 MW



- **What's the optimal dispatch?**
  - Solve by inspection
  - What are the prices at each bus?

3.c. Linearized Transmission Constraints in Operations Optimization Problem (OPF)

y_{im} = MW from plant i, at bus m

MIN Variable Cost = $\Sigma_m \Sigma_i CY_i \, y_{im}$

subject to:

Energy balance: $\Sigma_{i,m} y_{im} - \Sigma_m LOAD_m = 0$

GenCap: $y_{im} \le X_{im} \quad \forall i,m$

Transmission: $-T_k \le \Sigma_m PTDF_{m \rightarrow Hub,k} (\Sigma_{i,m} y_{im} - \Sigma_m LOAD_m) \le T_k \quad \forall k$

Nonnegativity: $y_{im} \ge 0 \quad \forall i,m$

- Note: Simplify PTDF's by assuming a single "hub" bus where all injections sink
- EXERCISE:
  1. Formulate for 3 node problem (assume A is the "hub")
  2. Solve in EXCEL and get solution

Linearized Transmission Constraints in Operations LP: Exercise Example

MIN Variable Cost = $25y_A + 70y_B$

subject to:

Energy Balance: $y_A + y_B = 900$

Transmission:

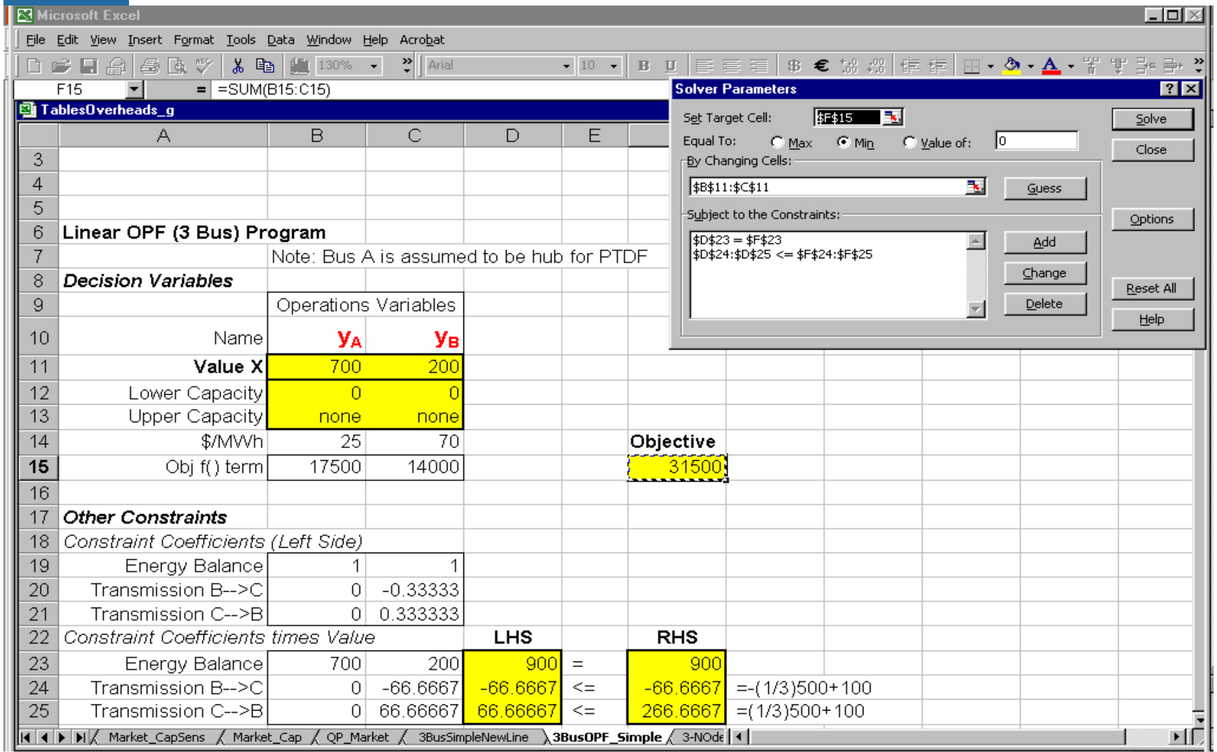
$$-100 \leq [\, 0.0(y_A - 400) - 0.33\,(y_B - 500)] \leq +100$$

Nonnegativity: $y_A, y_B \geq 0$

Note: In calculating PTDFs, I assume that all injections “sink” at hub node A

- **E.g., injection z_B at B is assumed to be accompanied by an equal withdrawal $-z_B$ at A**

EXCEL SOLVER ® Solution to 3 Bus Linearized OPF



F15 = =SUM(B15:C15)

	A	B	C	D	E		
3							
4							
5							
6	**Linear OPF (3 Bus) Program**						
7		Note: Bus A is assumed to be hub for PTDF					
8	***Decision Variables***						
9		Operations Variables					
10	Name	y_A	y_B				
11	**Value X**	700	200				
12	Lower Capacity	0	0				
13	Upper Capacity	none	none				
14	$/MWh	25	70			**Objective**	
15	Obj f( ) term	17500	14000			31500	
16							
17	***Other Constraints***						
18	*Constraint Coefficients (Left Side)*						
19	Energy Balance	1	1				
20	Transmission B-->C	0	-0.33333				
21	Transmission C-->B	0	0.333333				
22	*Constraint Coefficients times Value*			**LHS**		**RHS**	
23	Energy Balance	700	200	900	=	900	
24	Transmission B-->C	0	-66.6667	-66.6667	<=	-66.6667	=-(1/3)500+100
25	Transmission C-->B	0	66.66667	66.66667	<=	266.6667	=(1/3)500+100

Solver Parameters

Set Target Cell: $F$15

Equal To: ○ Max ● Min ○ Value of: 0

By Changing Cells: $B$11:$C$11

Subject to the Constraints:

$D$23 = $F$23
$D$24:$D$25 <= $F$24:$F$25

Augmented Linearized (OPF): Add Flows/KCL to Get LMPs

f_k = MW flowing through component k

y_{im} = MW from plant i, at bus m

z_{mt} = Net MW injection at bus m

MIN Variable Cost = $\Sigma_m \Sigma_i \text{CY}_i\, y_{im}$

subject to:

Energy Balance (KCL): $\Sigma_i\, y_{im} - \text{LOAD}_m = z_m \quad \forall m$

Energy Balance (Total): $\Sigma_m\, z_m = 0 \quad \forall m$

GenCap: $y_{im} \le X_{im} \quad \forall i,m$

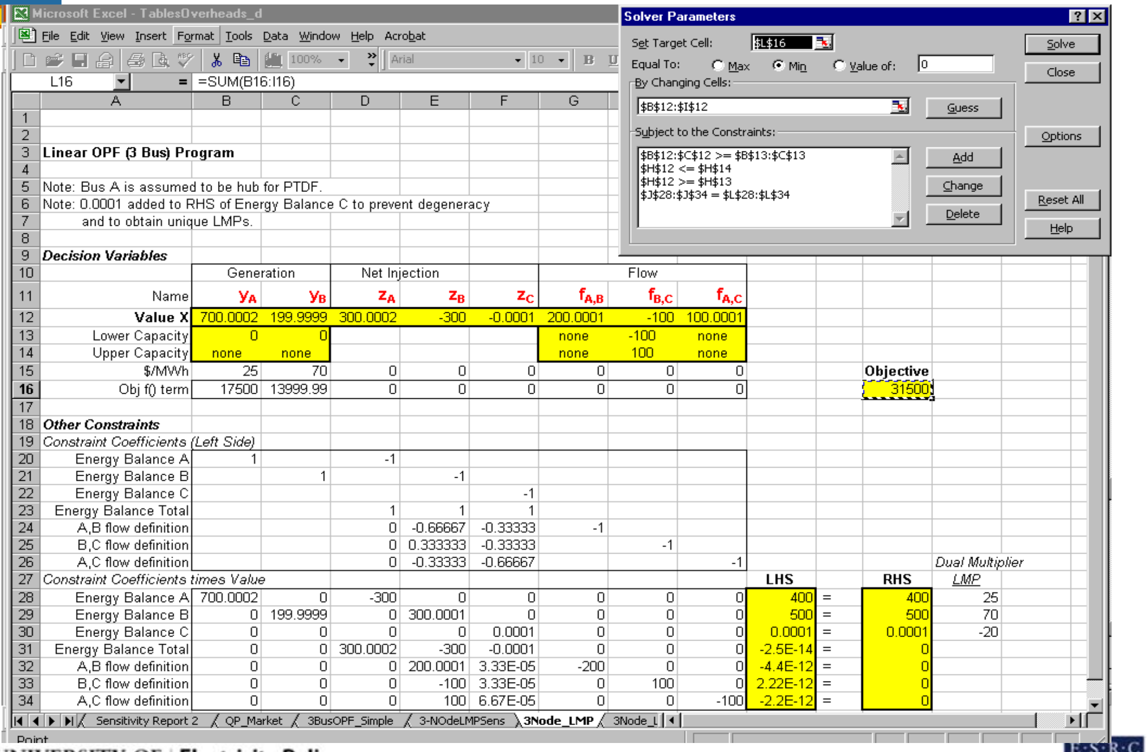
Transmission: $f_k - [\Sigma_m \text{PTDF}_{\text{Hub}\to m,k}\, z_{mt}] = 0 \quad \forall k$

$f_k \ge -T_k\, ;\ f_k \le T_k \quad \forall k$

Nonnegativity: $y_{im} \ge 0 \quad \forall i,m$

- LMPs are duals to Energy Balance at each bus

Three Node Example: OPF With Additional Variables and Constraints to Obtain LMPs: SOLVER® Solution



Microsoft Excel - TablesOverheads_d

L16 = =SUM(B16:I16)

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3	**Linear OPF (3 Bus) Program**												
4													
5	Note: Bus A is assumed to be hub for PTDF.												
6	Note: 0.0001 added to RHS of Energy Balance C to prevent degeneracy												
7	and to obtain unique LMPs.												
8													
9	***Decision Variables***												
10		Generation		Net Injection			Flow						
11	Name	y_A	y_B	z_A	z_B	z_C	$f_{A,B}$	$f_{B,C}$	$f_{A,C}$				
12	**Value X**	700.0002	199.9999	300.0002	-300	-0.0001	200.0001	-100	100.0001				
13	Lower Capacity	0	0				none	-100	none				
14	Upper Capacity	none	none				none	100	none				
15	$/MWh	25	70	0	0	0	0	0	0			**Objective**	
16	Obj f() term	17500	13999.99	0	0	0	0	0	0			31500	
17													
18	***Other Constraints***												
19	*Constraint Coefficients (Left Side)*												
20	Energy Balance A	1		-1									
21	Energy Balance B		1		-1								
22	Energy Balance C					-1							
23	Energy Balance Total			1	1	1							
24	A,B flow definition			0	-0.66667	-0.33333	-1						
25	B,C flow definition			0	0.333333	-0.33333		-1					
26	A,C flow definition			0	-0.33333	-0.66667			-1				*Dual Multiplier*
27	*Constraint Coefficients times Value*									**LHS**		**RHS**	*LMP*
28	Energy Balance A	700.0002	0	-300	0	0	0	0	0	400	=	400	25
29	Energy Balance B	0	199.9999	0	300.0001	0	0	0	0	500	=	500	70
30	Energy Balance C	0	0	0	0	0.0001	0	0	0	0.0001	=	0.0001	-20
31	Energy Balance Total	0	0	300.0002	-300	-0.0001	0	0	0	-2.5E-14	=	0	
32	A,B flow definition	0	0	0	200.0001	3.33E-05	-200	0	0	-4.4E-12	=	0	
33	B,C flow definition	0	0	0	-100	3.33E-05	0	100	0	2.22E-12	=	0	
34	A,C flow definition	0	0	0	100	6.67E-05	0	0	-100	-2.2E-12	=	0	

Solver Parameters

Set Target Cell: $L$16

Equal To: ○ Max ● Min ○ Value of: 0

By Changing Cells: $B$12:$I$12

Subject to the Constraints:

```
$B$12:$C$12 >= $B$13:$C$13
$H$12 <= $H$14
$H$12 >= $H$13
$J$28:$J$34 = $L$28:$L$34
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Counterintuitive Behavior of LMPs

- *Prices can be negative*
  - Because consumption at a bus can relieve congestion that otherwise bottles up cheap generation
  - See Bus C in previous example

- *Prices at two buses connected by an uncongested line can differ*
  - Compare LMPs at buses A and B

- *Power can flow from a high price bus to a low price bus*
  - See flow from A to C

4. Failed "Zonal" Pricing: Learning the Hard Way

- California 2004
- PJM 1997
- New England 1998
- UK 2020?

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The “DEC” Game in Zonal Markets

- “System Redispatch Model”
  - ISO ignores congestion day ahead
  - ISO pays to resolve congestion in real time.
- Clear zonal market day ahead (DA):
  - All generator bids used to create supply curve in zone
  - Clear supply against zonal load
  - All accepted bids paid DA price
- In real-time, “intrazonal congestion” arises—constraint violations must be eliminated
  - “INC” needed generation (e.g., in load pockets) that wasn’t taken DA
    - Pay them > DA price
  - “DEC” unneeded generation (e.g., in gen pockets) that can’t be used
    - Allow generator to pay back < DA price

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Problems arising from “DEC” Games

- Problem 1: Congestion worsens
  - The generators you want won’t enter the DA market
  - The generators you *don’t* want will
  - Real-time congestion worsens
- Problem 2: Encourages DA bilateral contracts with “cheap” DEC’ed generation
  - Destroyed PJM zonal market in 1997
- Problem 3: DEC game is a money machine
  - Gen pocket generators bid cheaply, knowing they’ll be taken and can buy back at low price
    - E.g., P_{DA} = \$70/MWh, P_{DEC} = \$30
    - You make \$40 for doing nothing
  - Market power not needed for game (but can make it worse)
  - E.g., California 2004

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Problems arising from “DEC” Games

- Problem 4: Short Run Inefficiencies
  - If DEC’ed generators are started up & then shut down
  - If INC’ed generation is needed at short notice
- Problem 5: Encourages siting in wrong places
  - Complex rules required to correct disincentive to site where power is needed
  - E.g., New England 1998, UK late 1990s

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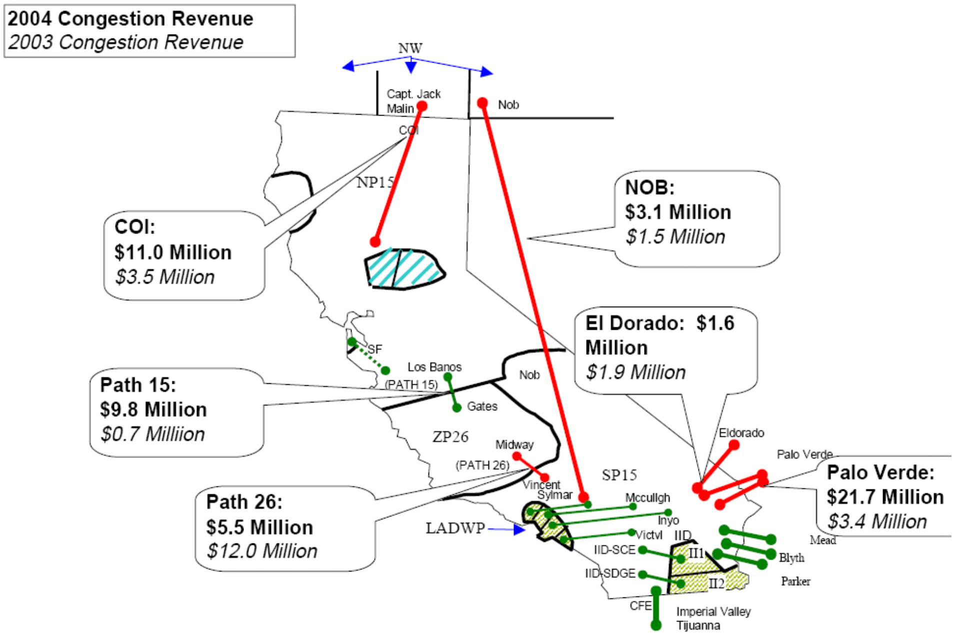
Example 1: Cost of DEC Game in California

- Three zones in 1995 market design
- Cost of Interzonal-Congestion Management:
  - $56M (2006), $55.8 (2004) $26.1 (2003)



2004 Congestion Revenue
2003 Congestion Revenue

COI:
$11.0 Million
$3.5 Million

NOB:
$3.1 Million
$1.5 Million

El Dorado: $1.6 Million
$1.9 Million

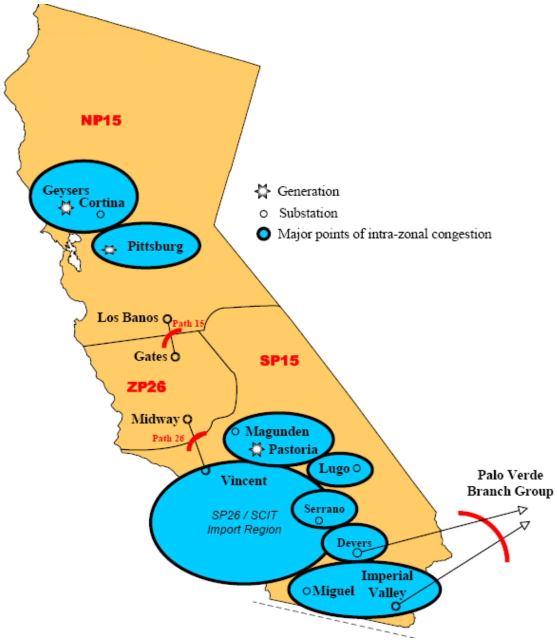
Path 15:
$9.8 Million
$0.7 Milliion

Path 26:
$5.5 Million
$12.0 Million

Palo Verde:
$21.7 Million
$3.4 Million

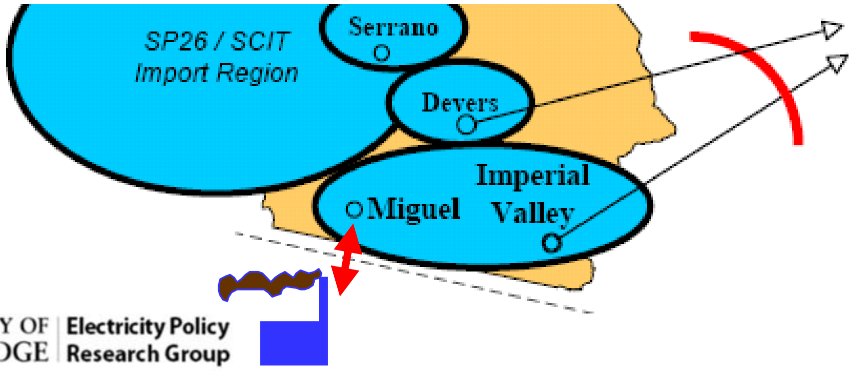
Intrazonal Congestion in California (Real-Time Only)

- $207M (2006), $426M (2004), $151M (2005)
- Mostly transmission within load pockets
- Managed by:
  - Dispatching "Reliability Must Run" and "minimum load" units
  - INC's and DEC's
- Three components (2004):
  1. *Minimum load compensation costs—required to be on line but lose money ($274M)*
  2. *RMR unit dispatch ($49M)* (Total RMR costs $649M)
  3. INC's/DEC's (*$103M*):
     - Mean INC price = $67.33/MWh
     - Mean DEC price = $39.20/MWh



Miguel Substation Congestion

- 3 new units in north Mexico (1070 MW), in Southern California zone
- Miguel substation congestion limits imports to Southern California
  - INC San Diego units
  - DEC Mexican units or Palo Verde imports
- Mexican generation can submit very low DEC bids
  - In anticipation, CAISO Amendment 50 March 2003 mitigated DEC bids
- Nevertheless, until Miguel was upgraded (2005), Miguel congestion management costs ~ $3-$4M/month even with mitigation
  - Value to Mexican generators: ~$5/MW/hr



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Example 2: PJM Zonal Collapse

- New (1997) PJM market had zonal day-ahead market
  - Congestion would be cleared by “INC’s” and “DEC’s” in real-time
  - Congestion costs uplifted
- Generators had two options:
  - Bid into zonal market
  - Bilaterals (sign contract with load, submit fixed schedule)
- Hogan’s generator intelligence test:
  - You have three possible sources of power
    - Day ahead: zonal $30/MWh
    - Bilateral with west (cheap) zone: $12/MWh
    - Bilateral with east (costly) zone: $89/MWh
  - Result: HUGE number of infeasible bilaterals with western generation
  - PJM emergency restrictions June 1997
- PJM requested LMP and FERC approved; operational in April 1998
  - The important issue is not the total cost of transmission -- it’s the incentives when congestion occurs

(Source: W. Hogan, Restructuring the Electricity Market: Institutions for Network Systems, April 1999)

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Example 3:
Perverse Siting Incentives in New England

- Before restructuring, New England’s power pool (NEPOOL) had a single zone and energy price
  - Complex planning process required transmission investment along with generation to minimize impact of new generators on older units
- In response to market opening, approximately 30 GW new plant construction was announced in late 1990s (doubling capacity)
  - To deal with perverse siting incentives, NEPOOL proposed complex rules for new generators, requiring extensive studies of system impacts and expensive investments in the transmission system.
  - Rules would increase costs for entry and delay it, protecting existing generators from competition
- October 1998, FERC struck down rules as discriminatory and anticompetitive responses to the defective congestion management system
  - ISO-NE submitted a LMP proposal in 1999 which was accepted

(See W. Hogan, *ibid.*)

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Example 4: UK in 2020?

- UK system's congestion costs have fallen drastically
  - System sized to allow all generators to serve load during the peak
- Can't sustain if add large amounts of intermittent generation
  - If 25% wind, reserve margin ~40%
  - Uneconomic to size transmission to meet peak load from all possible sources
  - ⇒ Congestion would grow
- E.g., two node system:
  - Cheap generation + wind in North
  - High loads and expensive generation in South
  - If all wind available, huge N-S link needed to avoid congestion
- Prompting UK rethinking of NETA congestion management

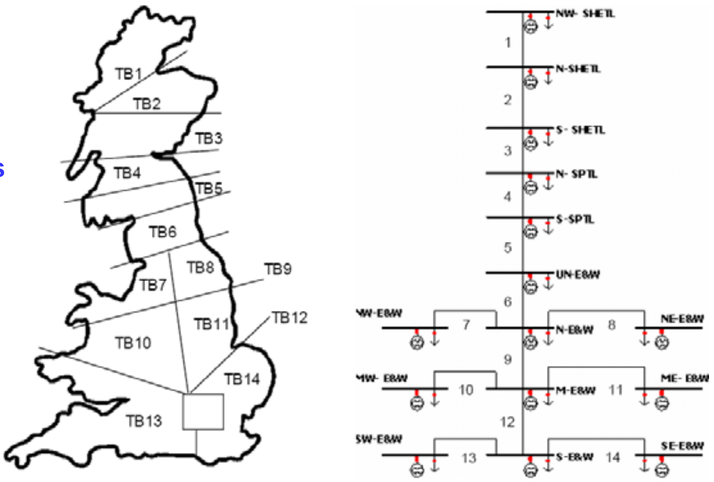

Figure 1: Simplified Great Britain (GB) transmission system

(Source: G. Strbac, C. Ramsay, D. Pudjianto, Centre for Distributed Generation and Sustainable Electrical Energy, "Framework for development of enduring UK transmission access arrangements," July 2007

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Other Ways to Manage Intrazonal Congestion

R. Hakvoort, D. Harris, J. Meeuwsen, S. Hesmondhalgh, A system for congestion management in the Netherlands Assessment of the options, The Brattle Group and DCision, Zwolle, June 5, 2009

- Market Agent Approach
  - Curtail bilateral transactions across congested interface on prorated basis
  - Market parties arrange for replacement energy
- System Redispatch with All Costs Reallocated to Generation in Constrained-Off Area
- Market Redispatch
  - Generators in Constrained-Off Area bid for Transmission Rights
  - Highest bids accepted and operate
  - Rejected bids curtailed, have to contract for replacement energy themselves

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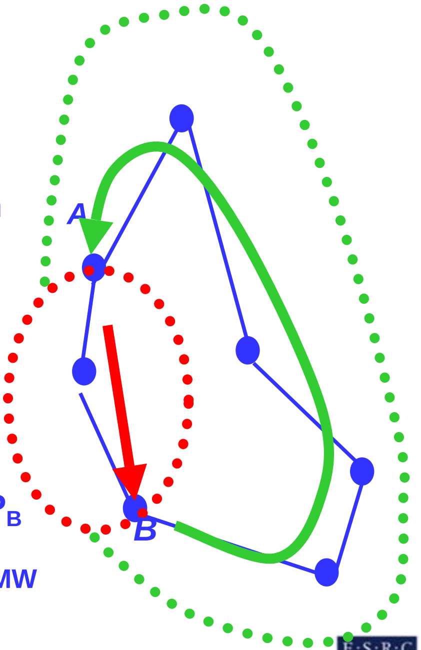
5. Remaining Problems of LMP:
a. Left-behind λ's

- Ideally, LMPs should reflect all constraints
- Spatial λ's left behind:
  - "The seams issue" – interconnected systems with different congestion management systems
    - Can lead to "Death Star"-type games ("money machines")
- Temporal λ's left behind:
  - Ramp rates not considered in real-time LMPs
    - Distorts incentives for investment in flexible generation
- Interacting commodity (ancillary services) λ's left behind:
  - Operator constraints not priced
    - Can systematically depress energy prices
- The problem of nonconvex costs
  - Unit commitment (min run, start up costs)
    - Marginal costs ambiguous

Spatial λ's left behind

- Green and Red systems interconnect at A and B. They manage congestion differently:
  - Green: LMP-based
  - Red: Path-based



- Power from A to B follows all paths and can cause congestion in both systems: there is one correct P for each, and one correct transmission charge
  - But Green ignores Red's constraints and miscalculates LMPs
- If Red's charge from A to B is less than P_A-P_B for Green…
  - *Enron's "Death Star"Money machine!* Red 1000 MW transaction from A to B, and Green 1000 MW back from B to A

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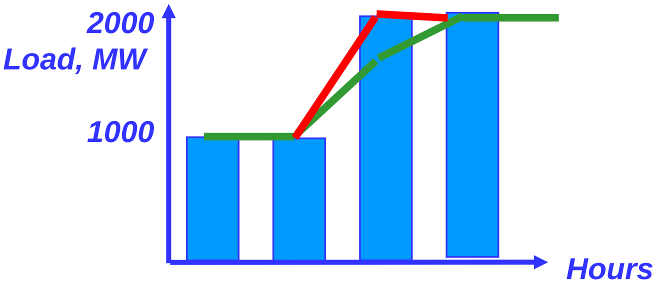
Temporal λ's left behind

- Some ISOs price real-time LMPs considering only constraints active in that time interval ("static optimization")
  - This skews LMPs by ignoring binding dynamic constraints in other intervals
- E.g.: a system with two types of generation:
  - 🟩 2100 MW of slow thermal @ $30/MWh, with max ramping = 600 MW/hr
  - 🟥 1000 MW of quick start peakers @ $70/MWh
- Morning ramp up and resulting generation:



Depresses LMP volatility – under values flexible generation

True LMP:	*30*	*-10*	*70*	*30*
"Static LMP"	*30*	*30*	*30*	*30*

Kudos to Shmuel Oren for pointing this out

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Other Commodities' λ's left behind

- Operators often call generators "OOM" ("out of merit order") to ensure that important contingency & other constraints met
  - to some extent inevitable
- But if done frequently and predictably, these are constraints that should be priced in the market. Else:
  - Depresses prices for other generators whose output or capacity is helping to meet that constraint
  - Inflates prices for generators that worsen that constraint
  - Could skew investment
- Has been identified as a chronic problem in some U.S. markets by market monitors

Nonconvex Costs: What are the Right λ's?

- Common situation:
  - Cheap thermal units can continuously vary output
  - Costly peakers are either "on" or "off"
  - ⇒ Even during high loads, LMP set by cheap generators
  - ⇒ Too little incentive to reduce load
  - ⇒ Peakers don't cover their costs ("uplift" required)
  - ⇒ Cheap units may get inadequate incentive to invest
- California, New York solutions:
  - *If* peaking units are small relative to variation in load,
  - … *then* set LMP = average fuel cost of peaker, if peakers running
  - Note: LMP doesn't "support" thermal unit dispatch, so must constrain output
- Alternative: "Supporting prices" in mixed integer programming
  - Calculated from LP that constrains {0,1} variable to optimal level
  - Results in separate prices for supply (thermal plant MC) and demand (higher LMP), and uplifts to peakers
  - Source: R. O'Neill, P. Sotkiewicz, B. Hobbs, M. Rothkopf, and W. Stewart, "Efficient Market-Clearing Prices in Markets with Nonconvexities," Euro. J. Operational Research, 164(1), July 1, 2005, 269-285

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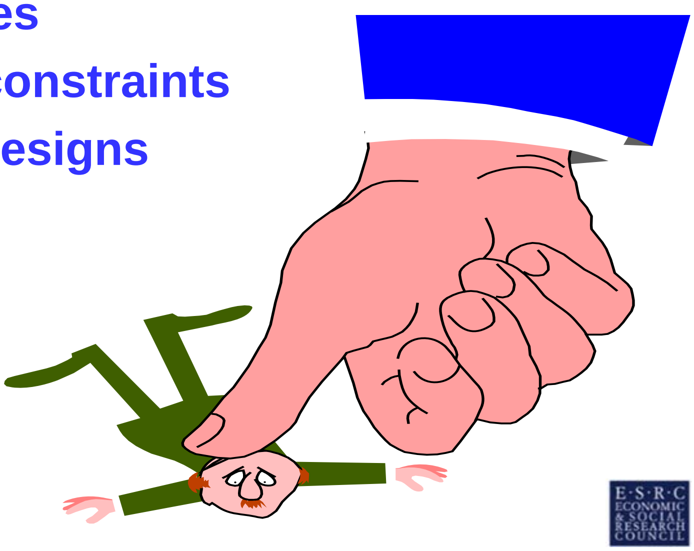
5. Remaining Problems:
b. Dealing With Market Power

Arises from:

- Inelastic demand / inefficient pricing
- Scale economies
- Transmission constraints
- Dumb market designs



Mark Twain:

"The researches of many commentators have already thrown much darkness on the subject and it is probable that, if they continue, we shall soon know nothing at all about it"

(thanks to Dick O'Neill for the quote)

How to Respond?
Local Market Power Mitigation Questions

- Who is eligible for mitigation?
- What triggers mitigation?
- How much Q is mitigated?
- What is the mitigated bid?
- How are locational marginal prices (LMPs) calculated?
- What is the bidder paid?
- What if the bidder doesn't cover its fixed costs?

Various Answers

- *Who is <u>eligible</u> for mitigation?*
  - Everyone
  - Congested areas / load pockets only. How to define?

- *What <u>triggers</u> mitigation?*
  - **Pivotal bidder** (CAISO MSC [Wolak], Rothkopf)
  - **Out-of-merit order** (PJM)
  - **Automated Mitigation Procedure** (NYISO, NEISO, MISO)
    - Conduct threshold (e.g., 200% over baseline bid)
    - Impact threshold (e.g., raise market price by 50%)

- *How much <u>Q</u> is mitigated?*
  - **Entire capacity** (PJM)
  - **Only pivotal/out-of-merit order quantity** (California proposals)

- *What is the <u>mitigated bid</u>?*
  - **Baseline** (mean bid during competitive period, plus negotiated "hockey stick") (MISO)
  - **Estimated variable cost** (fuel only? maintenance?) (CAISO, PJM)
  - **Combustion turbine proxy** (NEISO)

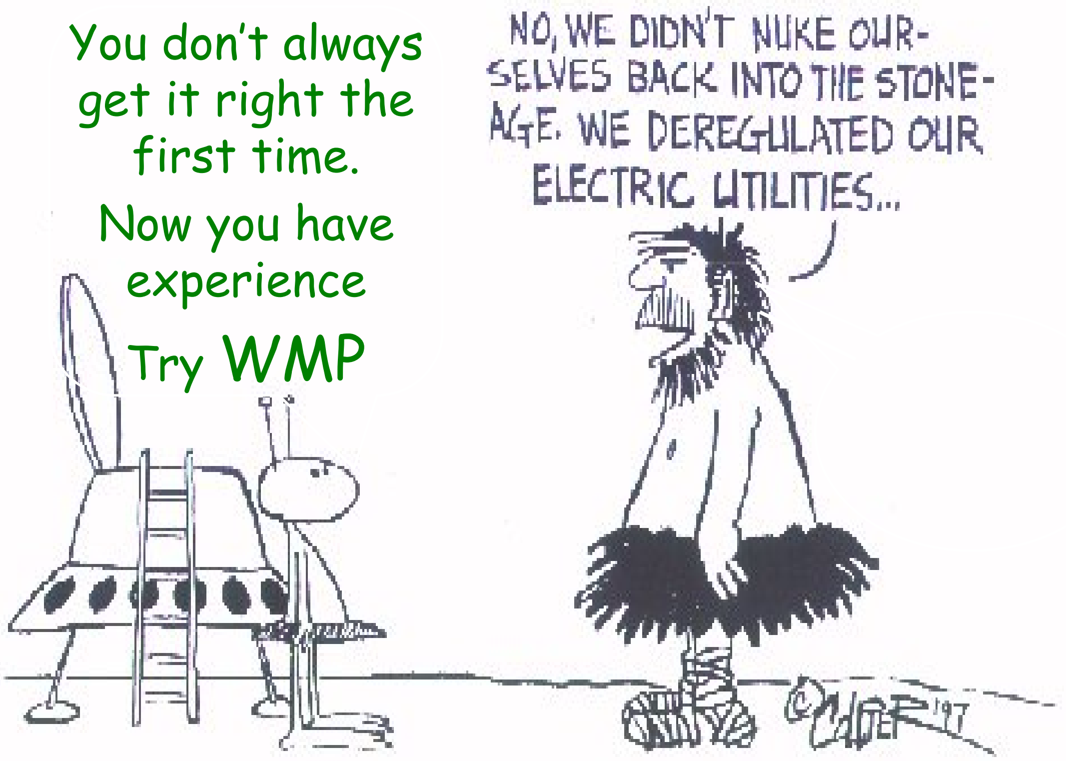
- **How are LMPs calculated?**
  - Include mitigated bid in locational marginal pricing calculations (PJM, CAISO)
  - Exclude mitigated bid (put mitigated Q in as price-taker) (Wolak)
- **What is the bidder paid?**
  - LMP or MAX(LMP, Variable Cost)
- **What if the bidder doesn't cover its fixed costs?**
  - File for "Cost of Service" contract (ISO may refuse)

Conclusion

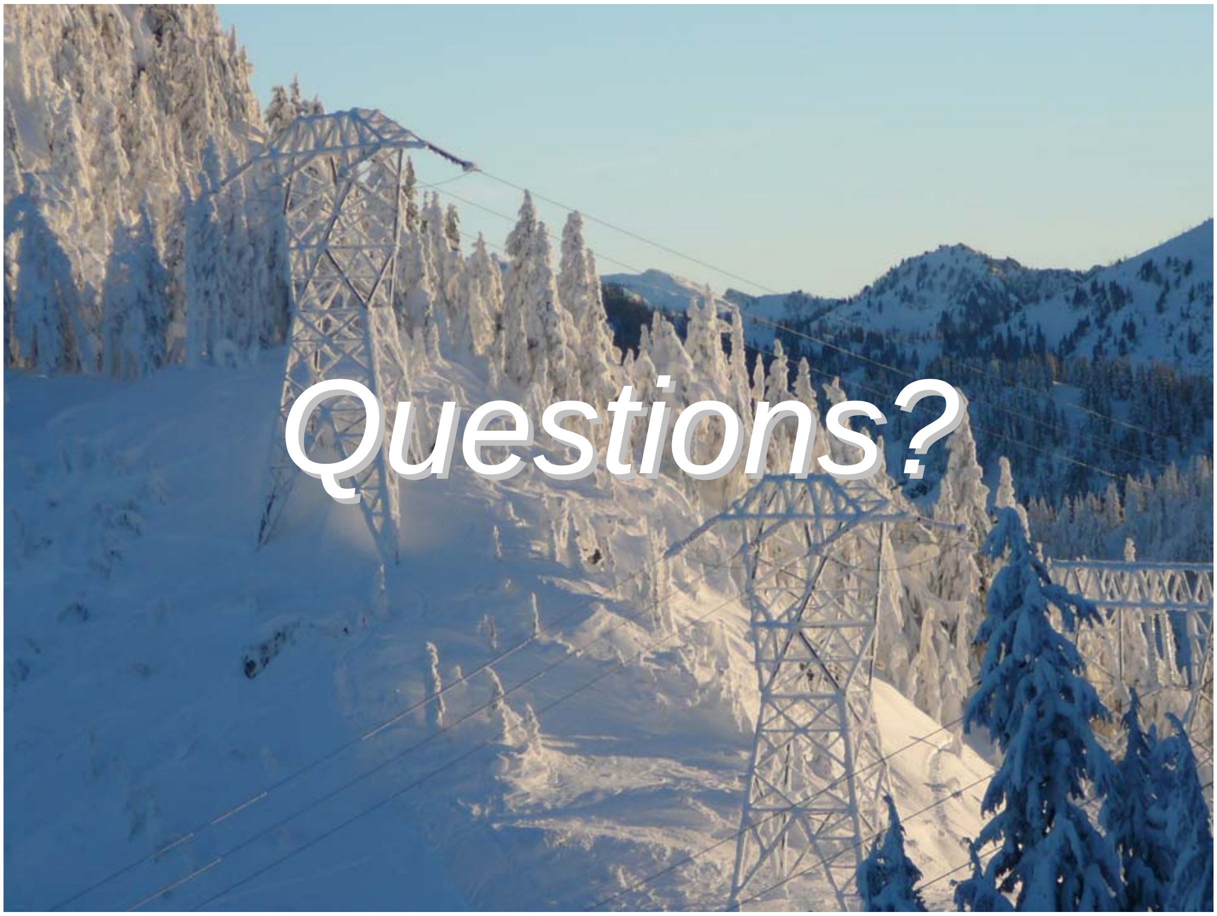
You don't always get it right the first time.

Now you have experience

Try WMP



Thanks to Dick O'Neill, FERC



Questions?

ISO LMP Training Materials

CAISO MRTU training
Locational Marginal Pricing (LMP) 101 Course Overview of Locational Marginal Pricing
http://www.caiso.com/1824/18249c7b59690.html
http://www.caiso.com/20a6/20a690af67c80.html   slides only

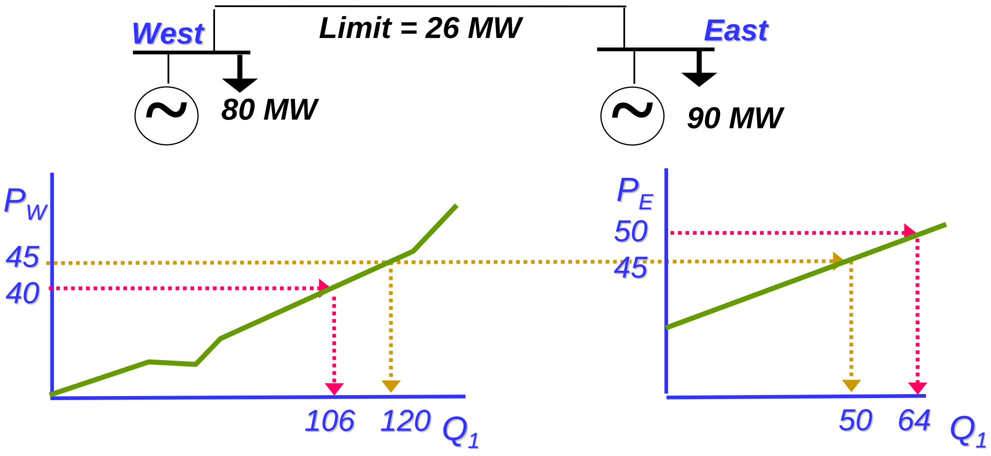
New England
http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index.html

PJM Training Curriculum
http://www.pjm.com/sitecore/content/Globals/Training/Courses/ol-lmp-101.aspx?sc_lang=en
http://www.pjm.com/~/media/training/core-curriculum/ip-lmp-101/lmp-101-training.ashx
http://www.pjm.com/~/media/training/core-curriculum/ip-gen-101/20050713-gen-101-lmp-overview.ashx
https://admin.acrobat.com/_a16103949/p20016248/ with audio accompaniment

Answers

LMP / Congestion Example

(Based on Presentation by Mark Reeder, NYISO, April 29, 2004)



Key: ··········▶ Prices/Supplies under 26 MW limit
··········▶ Prices/Supplies with no transmission limit

- Marginal value of transmission = \$10/MWh (=\$50 – \$40)
- Total congestion revenue = \$10*26 = \$260/hr = Cust payments – Gen revenue
- Total redispatch cost = \$130/hr
- Congestion cost to consumers: (40*106+50*64) – (45*170) = 7440 – 7650 = –\$210/hr

Operations LP Answer: Model Formulation

$$\text{MIN} \quad 760(70\, y_{A,Pk} + 25\, y_{B,Pk}) + 8000(70\, y_{A,OP} + 25\, y_{B,OP})$$

subject to:

Meet load:

$$y_{A,Pk} + y_{B,Pk} = 2200$$

$$y_{A,OP} + y_{B,OP} = 1300$$

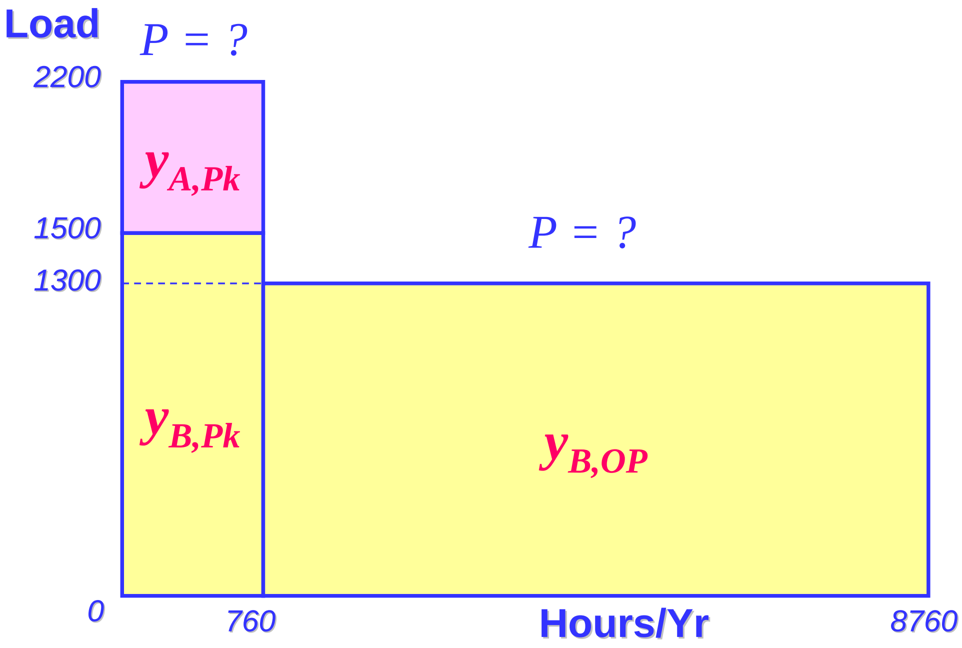
Generation $\leq$ capacity:

$$y_{A,Pk} \leq 800;\ y_{A,OP} \leq 800$$

$$y_{B,Pk} \leq 1500;\ y_{B,OP} \leq 1500$$

Nonnegativity: $y_{A,Pk}, y_{A,OP}, y_{B,Pk}, y_{B,OP} \geq 0$

Operations LP Answer: Load Duration Curve

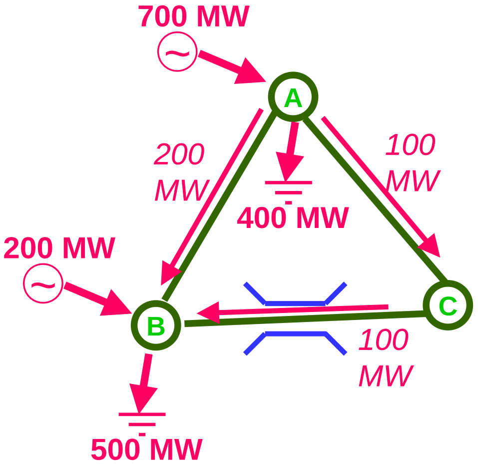


Exercise in Transmission Modeling: Answer

- **Optimal Dispatch**
  - **Two plants:**
    - **A: Meet load at A (400 MW) plus inject maximum amount that transmission limit allows (100 MW/PTDF = 100/.33 = 300 MW)**

      = 700 MW
    - **B: Serve the load at B not served by A (= 500 MW-300 MW)**

      = 200 MW



- **Marginal Costs ("LMP") to Load:**
  - **A: The cost of Plant A ($25)**
  - **B: The cost of Plant B ($70)**
  - **C: More complex! To bring 1 MW to C, can generate 2 MW at A and backoff 1 MW at B:**

    = 2*$25 + -1*$70 = -$20