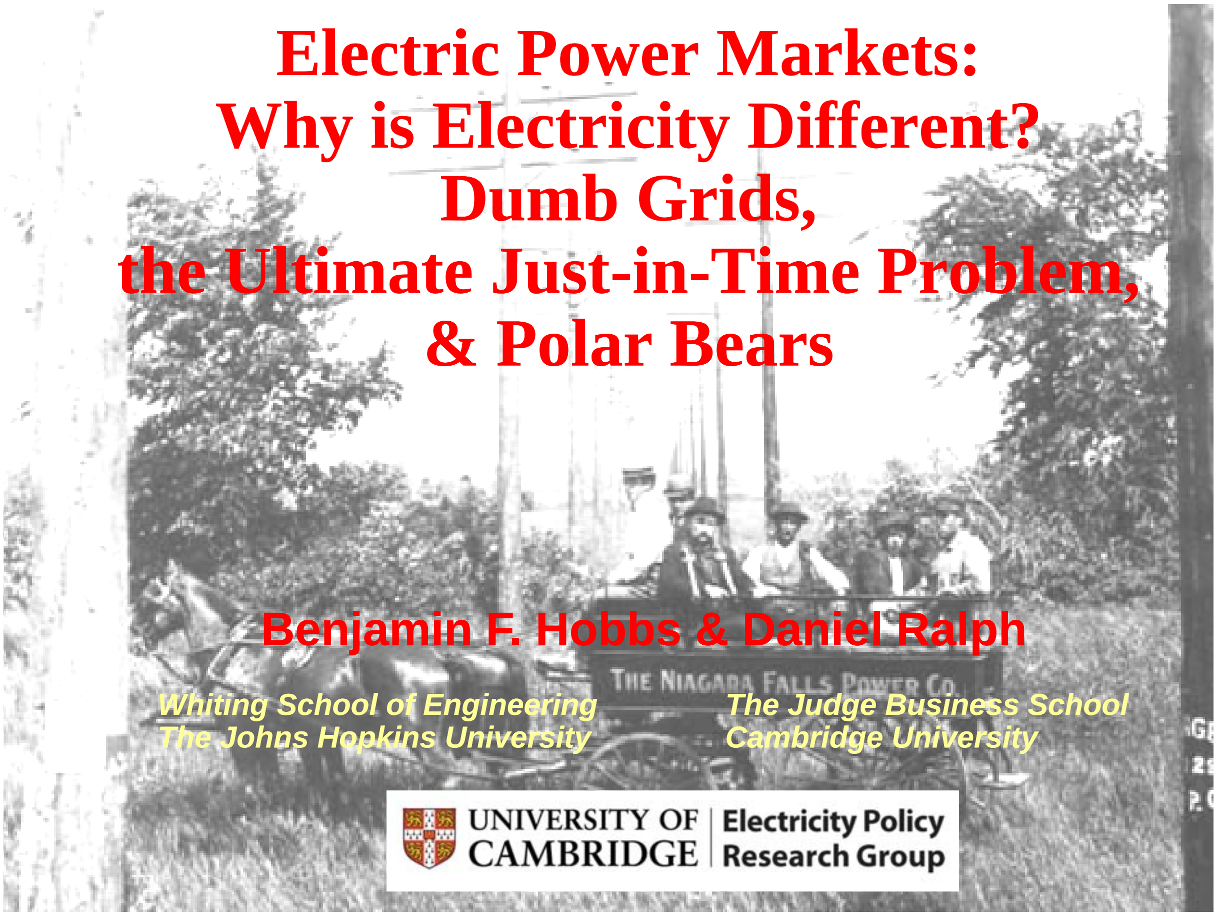
Electric Power Markets: Why is Electricity Different? Dumb Grids, the Ultimate Just-in-Time Problem, & Polar Bears



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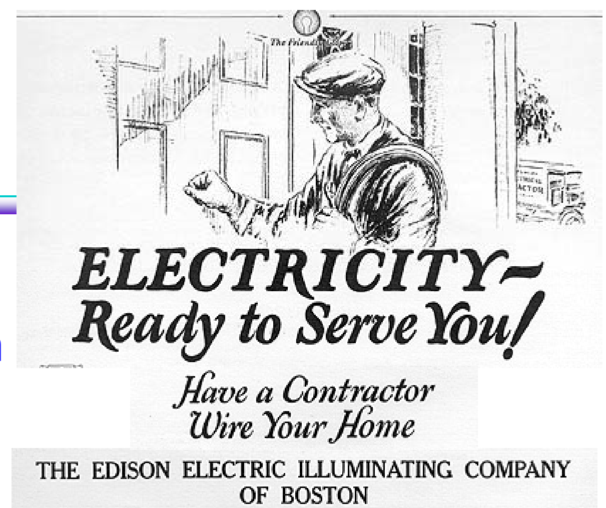
Outline

- I. Why power?
- II. Model definition
- III. Model uses
- IV. The basics
  - A. Supply Dispatch
  - B. Demand Bidding
  - C. Commitment
  - D. Transmission
  - E. Investment



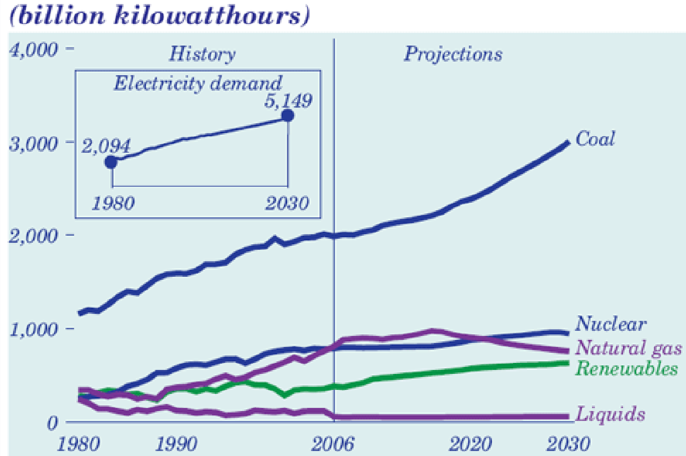
I. Why Power?
(1) Lynchpin of the Economy

- Economic impact
  - ~$1000/person/y in US (~oil)
    - 2.5% of GDP (10x water sector)
  - ~50% of US energy use
  - Most capital intensive
- Consequences when broken
  - 1970s UK coal strikes
  - 2000-2001 California crisis
  - Chronic third-world shortages
- Ongoing economic restructuring
  - Margaret & Fred
  - Vertical disintegration
    - generation, transmission, distribution
    - Access to transmission
  - Spot & forward markets
  - Horizontal disintegration, mergers

Why Power?
(2) Polar Bears

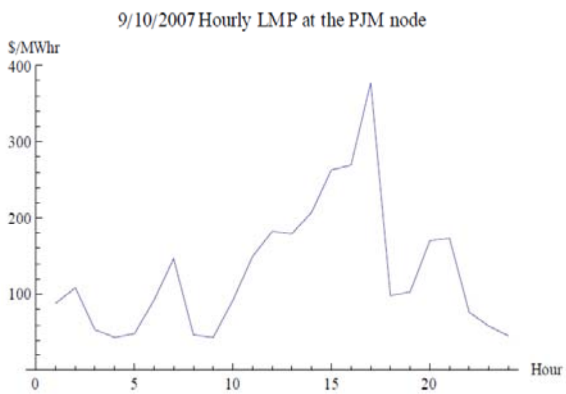
- Environmental impact
  - Transmission lines & landscapes
  - ‘Conventional’ air pollution: 3/4 US SO_2, 1/3 NO_x
  - 3/8 of CO_2 in US; CO_2 increasing

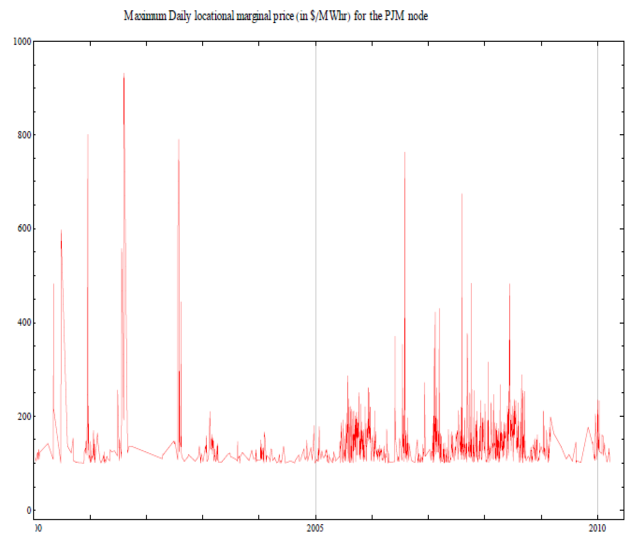
Figure 4. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



Why Power?
(3) The Ultimate Just-In-Time Product

- <u>Little storage/buffering</u>
  - Must balance supply & demand in real time
- ⇒ Huge price volatility





Why Power?
(4) Dumb Grids

- Physics of networks
  - North America consists of 3 synchronized machines
  - What you do affects everyone else ⇒ must carefully control to maintain security.
    - E.g., parallel flows due to Kirchhoff`s laws
- Valveless networks
- Saint Fred's dream remains just that
  - Broken demand-side of market

II. Definition of Electric Power Models

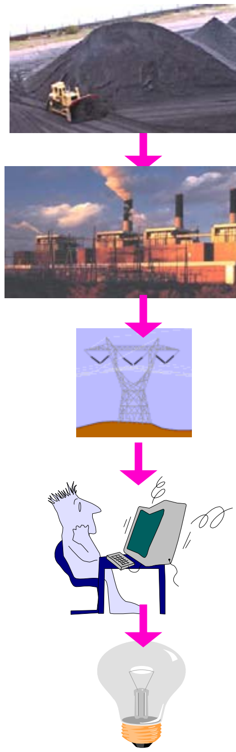
- *Models that:*
  - simulate or optimize …
  - operation of & investment in …
  - generation, transmission & use of electric power …
  - and their economic, environmental & other impacts …
  - using mathematics &, perhaps, computers
- *Focus here: "bottom-up" or "process" engineering economic models*
  - Technical & behavioral components
  - Used for:
    - firm-level decisions
      - MIN costs, MAX profits
    - policy-analysis
      - simulate reaction of market to policy

Process Optimization Models

Elements:

- *Decision variables. E.g.,*
  - Design: MW of new combustion turbine capacity
  - Operation: MWh from existing coal units
- *Objective(s). E.g.,*
  - MAX profit or MIN total cost
- *Constraints. E.g.,*
  - Σ Generation = Demand
  - Capacity limits
  - Environmental rules
  - Build enough capacity to maintain reliability

The Supply Chain & the “Deciders”



Fuel extractors

Power plant owners (GENCOs)

Transmission operators (TSOs)

Distribution companies (DISCOs)

Retail suppliers, Energy service companies (ESCOs)

Consumers

III. Process Model Uses Company Level Decisions

Real time operations:

- **Automatic protection (<1 second): auto. generator control (AGC) methods to protect equipment, prevent service interruptions.**
  - ***TSO***
- **Dispatch (1-10 minutes): MIN fuel cost, s.t. voltage, frequency constraints**
  - ***TSO or GENCOs***

Operations Planning:

- **Unit commitment (8-168 hours). Which generators to be on line to MIN cost, s.t. “operating reserve” constraints**
  - ***TSO or GENCOs***
- **Maintenance & production scheduling (1-5 yrs): fuel deliveries, maintenance outages**
  - ***GENCOs***

Company Decisions Made Using Process Models, Continued

Investment Planning

- Demand-side planning (3-15 yrs): Modify consumer demands to lower costs
  - *consumers, ESCOs, DISCOs*
- Transmission & distribution planning (5-15 yrs): add circuits to maintain reliability and minimize cost
  - *TSO, DISCOs*
- Resource planning (10 - 40 yrs): most profitable mix of supplies, D-S programs under projected prices, demands, fuel prices
  - *GENCOs*

Company Decisions Made Using Process Models, Continued

Pricing Decisions

- Bidding (1 day - 5 yrs): optimize offers to provide power to MAX profit, s.t. fuel & power price risks
  - *GENCOs*
- Market clearing price determination (0.5- 168 hours): MAX social surplus/match offers
  - *TSOs, traders*

Policy Uses of Process Models

- **Use models of *firm*'s decisions to simulate *market***
- **Approaches**
  - **Via single optimization (Paul Samuelson):**

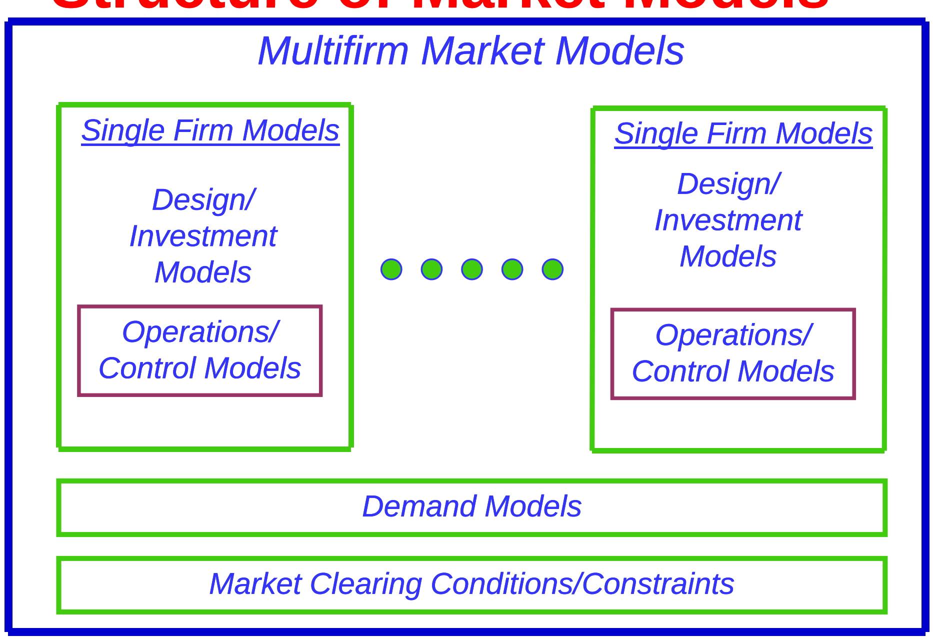
    MAX {consumer + producer surplus}

    ⇔ Marginal Cost Supply = Marg. Benefit Consumption

    ⇔ Competitive market outcome

    Other formulations for imperfect markets
  - **Attack equilibrium conditions directly**
- **Use**
  - **Effects of environmental policies / market design / structural reforms upon …**
  - **… market outcomes of interest (costs, prices, emissions & impacts, income distribution)**

Structure of Market Models



- ***If each firm assumes it can't affect price → competitive model***
- ***If each assumes others won't change sales → Nash-Cournot oligopoly model***
  - ***What did John Nash's father do for a living?***

All Models are Wrong … Some are Useful

- *Very small models*
  - Quick insights in policy debates
  - Need:
    - transparent models to convincingly communicate implications of assumptions
    - general conclusions
- *Very large models*
  - Actual grid operations and planning
  - Need:
    - Implementable numerical solutions
    - policy conclusions for specific systems
- *In-between models*
  - Forecasting and impact analyses of policies
  - Need:
    - ability to simulate many scenarios
    - but still represent "texture" of actual system

IV.A. Operations Model: System Dispatch Linear Program

- In words:
  - Choose level of operation g of each generator to minimize total system cost *subject to* demand level
- Decision variable:

  g_{it} = megawatt [MW] output of generating unit i during period t
- Coefficients:

  CG_{it} = variable operating cost [$/MWh] for g_{it}

  H_t = length of period t [h/yr].

  CAP_i = MW capacity of generating unit i.

  CF_i = maximum capacity factor [ ] for unit i

  D_t = MW demand to be met in period t

Operations Linear Program (LP)

MIN Variable Cost = $\Sigma_{i,t} H_t \, CG_{it} \, g_{it}$

subject to:

$\Sigma_i \, g_{it} = D_t \quad \forall t$

$g_{it} \leq CAP_i \quad \forall i,t$

$\Sigma_t \, H_t \, g_{it} \leq CF_i \, 8760 \, CAP_i \quad \forall i$

$g_{it} \geq 0 \quad \forall i,t$

Operations LP Exercise

- Two generators
  - A: Peak: 800 MW, MC = \$70/MWh
  - B: Baseload: 1500 MW, MC = \$25/MWh
- Demand
  - Pk: Peak: 2200 MW, 760 hours/yr
  - OP: Offpeak: 1300 MW, 8000 hours/yr
- Assignment:
  - Write down LP
  - What is best solution (by inspection?)
- What if a hydro plant?
  - 100 MW
  - But can only produce 200,000 MWh/yr?

Operations LP Answer: Model Formulation

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

subject to:

Meet load:

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

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

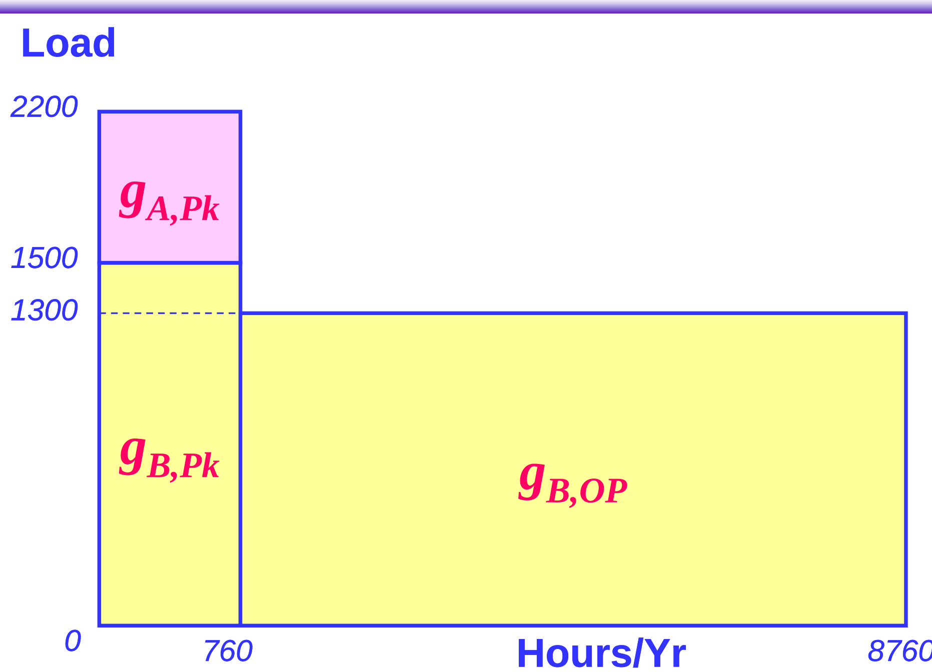
Generation ≤ capacity:

$$g_{A,Pk} \le 800;\ g_{A,OP} \le 800$$

$$g_{B,Pk} \le 1500;\ g_{B,OP} \le 1500$$

Nonnegativity: $g_{A,Pk}, g_{A,OP}, g_{B,Pk}, g_{B,OP} \ge 0$

Operations LP Answer: Load Duration Curve



Operations LP Answer: Model Formulation with Hydro

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

s.t.:

Meet load: $g_{A,Pk} + g_{B,Pk} + g_{HYD,Pk} = 2200$

$g_{A,OP} + g_{B,OP} + g_{HYD,OP} = 1300$

Generation ≤ capacity:

$g_{A,Pk} \le 800;\ g_{A,OP} \le 800$

$g_{B,Pk} \le 1500;\ g_{B,OP} \le 1500$

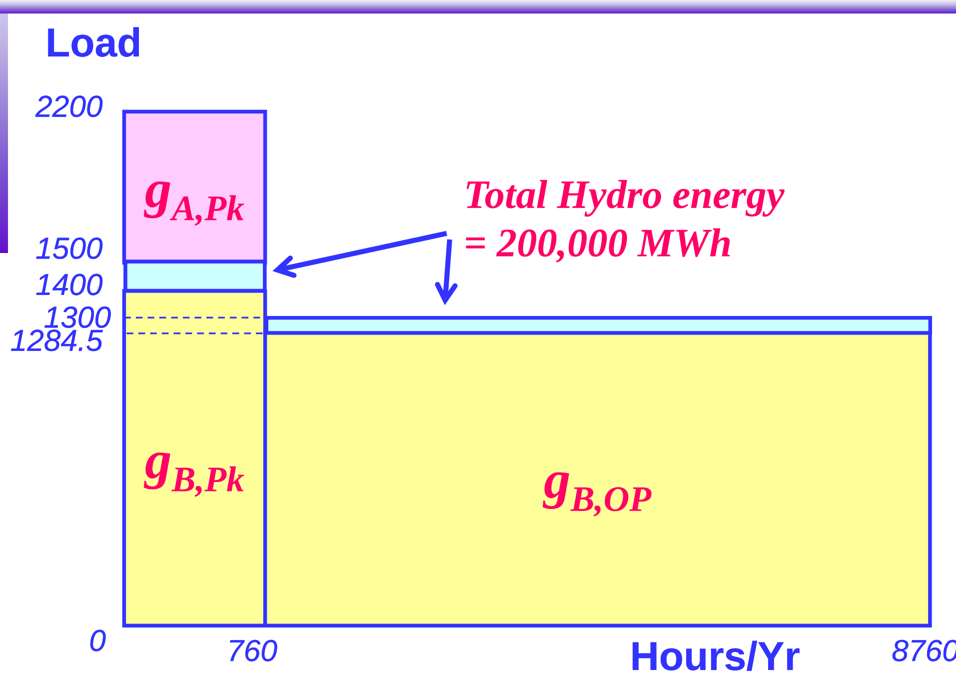
$g_{HYD,Pk} \le 100;\ g_{HYD,OP} \le 100$

Hydro Energy Limit:

$760 g_{HYD,Pk} + 8000 g_{HYD,OP} \le 200{,}000$

Nonnegativity: $g_{A,Pk}, g_{A,OP}, g_{B,Pk}, g_{B,OP} \ge 0$

Operations LP with Hydro Answer: Load Duration Curve



IV.B. Towards a Smart Grid: Price Responsive Demand in an Operations LP

MAX Net Benefits from Market =

$$\Sigma_t H_t \int_0^{d_t} P_t(x)dx - \Sigma_{i,t} H_t CG_{it} g_{it}$$

subject to:

$\Sigma_i g_{it} - d_t = 0 \quad \forall t$

$g_{it} \leq CAP_i \quad \forall i,t$

$\Sigma_t H_t g_{it} \leq CF_i \, 8760 \, CAP_i \quad \forall i$

$g_{it} \geq 0 \quad \forall i,t$

IV.C Unit Commitment: A Mixed Integer Program

- Define:
  - u_{it} = 1 if unit i is committed in t (0 o.w.)
  - CU_i = fixed running cost of i if committed
  - MR_i = "must run" (minimum MW) if committed
  - Periods t =1,..,T are consecutive, and H_t=1
  - RR_i = Max allowed hourly change in output
- MIN $\Sigma_{i,t} CG_{it} g_{it} + \Sigma_{i,t} CU_i u_{it}$

s.t. $\Sigma_i g_{it} = D_t \quad \forall t$

$MR_i u_{it} \leq g_{it} \leq CAP_i u_{it} \quad \forall i,t$

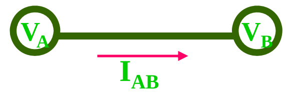
$-RR_i \leq (g_{it} - g_{i,t-1}) \leq RR_i \quad \forall i,t$

$\Sigma_t g_{it} \leq CF_i T X_i \quad \forall i$

$g_{it} \geq 0 \quad \forall i,t; \; u_{it} \in \{0,1\} \quad \forall i,t$

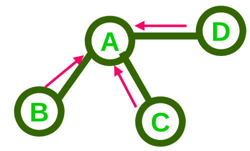
IV.D Transmission-Constrained Models
Review of DC Circuit Laws

- *Ohm's Law:*

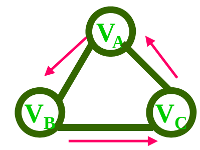


  - $V_A - V_B = I_{AB} * R_{AB}$
  - *Voltage difference proportional to current * resistance*

- *Kirchhoff's Current Law:*



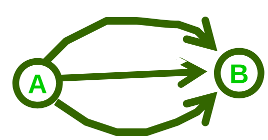
  - *No net current inflow to a node*
  - $\Sigma_n \; I_{A,n} = 0$



- *Kirchhoff's Voltage Law:*
  - *Sum of voltage differences around any loop = 0*
  - $(V_A - V_B) + (V_B - V_C) + (V_C - V_A) = 0$
  - *Sub in Ohm's Law:* $I_{AB} * R_{AB} + I_{BC} * R_{BC} + I_{CA} * R_{CA} = 0$

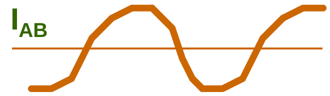
Implications of Laws

- *Use laws to calculate flows*
  - *If you know generation and load at every "bus" except the "swing bus", then ...*
  - *..The "load flow" (currents in each line, voltages at each bus) is uniquely determined by Kirchhoff's two laws!*
  - *= The "load flow" problem*



- *Some odd byproducts of laws:*
  - *Can't "route" flow: "Unvalved network"*
  - *Power follows many paths: "Parallel flows"*
  - *Power from different sources intermingled. What you do affects everyone else:*
    - *1 sells to 2 -- but this transaction congests 3's lines, increasing 3's costs*
    - *One line owner can restrict capacity & affect entire system*
  - *Adding a line can worsen transmission capacity of system*

AC Load Flow is More Complex

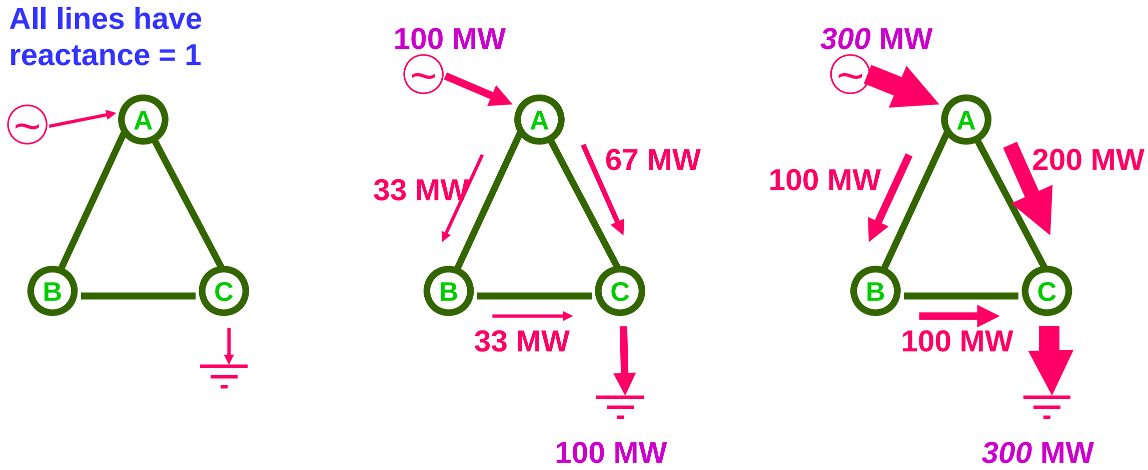


- *Sinusoidal voltage at each bus (with RMS amplitude and phase angle), as are line currents*
- *“Reactive” (vs. “real” power) a result of “reactance” (capacitance and inductance)*
  - *power stored and released in magnetic fields of capacitors and inductors as the current changes direction*
- *Although reactive power doesn’t do useful work, it causes resistance losses & uses up capacity*

“DC” Linearization of AC load flow

- ***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 are small***
- ***Results:***
  - ***Power flow t_{AB} proportional to:***
    - ***current I_{AB}***
    - ***difference in voltage angle θ_A-θ_B***
  - ***Linear analogies to Kirchhoff’s Laws:***
    - ***Current law at A: $\Sigma_i g_{iA} = \Sigma_{neighboring\ n}\ t_{An} + LOAD_A$***
    - ***Voltage law: $t_{AB}*R_{AB} + t_{BC}*R_{BC} + t_{CA}*R_{CA} = 0$***
  - ***Given power injections at each bus, flows are unique***

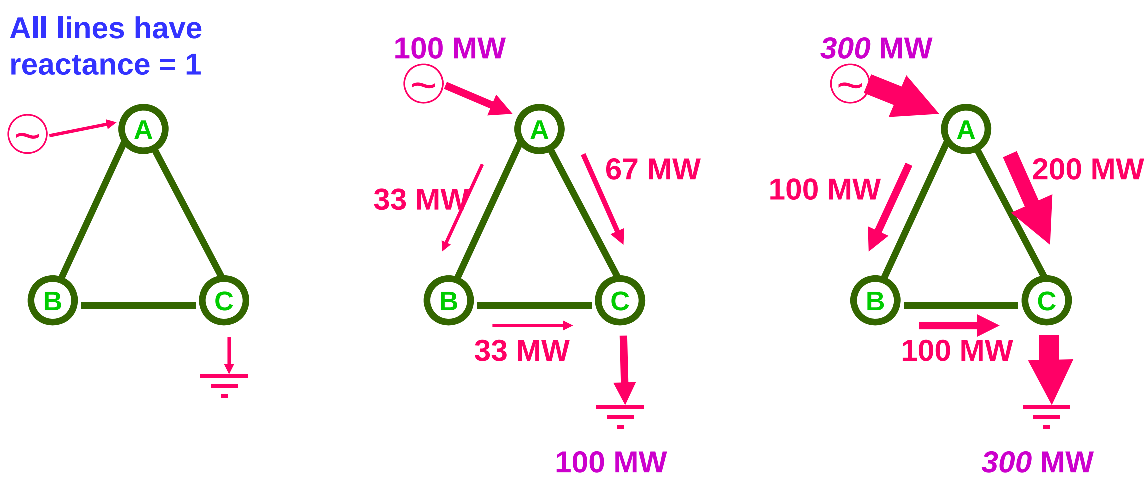
Example of “DC” Load Flow



<u>Kirchhoff’s Current Law at C:</u>
+33 + 67 - 100 = 0
<u>Kirchhoff’s Voltage Law:</u>
1*33 + 1*33 + 1*(-67) = 0

Proportionality!

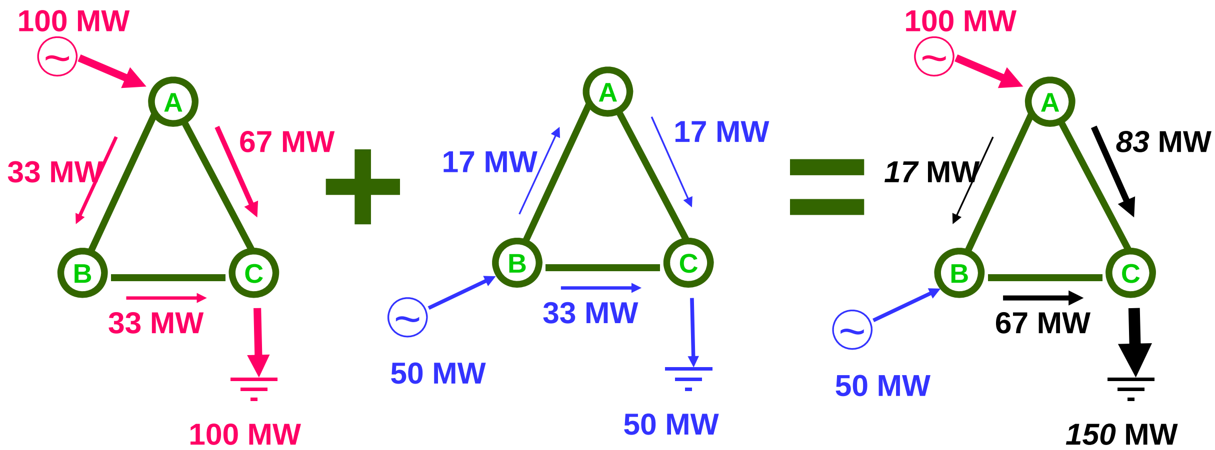
Proportionality means “Power Transmission Distribution Factors” can be used to calculate flows



$PTDF_{mn,jk}$ = the MW flowing from *j* to *k*, if 1 MW is injected at *m* and 1 MW is removed at *n*

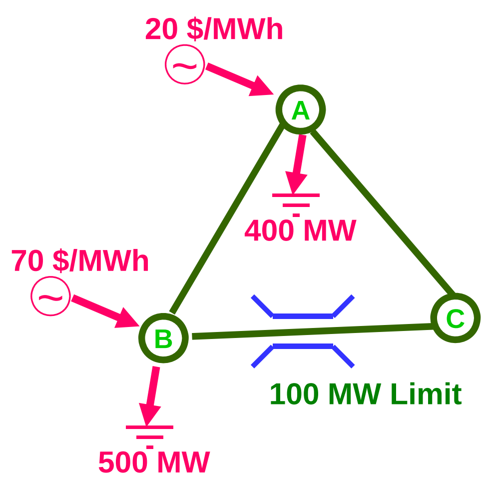
E.g., $PTDF_{AC,AB}$ = 0.33 (= $-PTDF_{CA,AB}$)

Principle of Superposition



Exercise in Transmission Modeling

- Assumptions
  - Equal reactances
    - – Line from B to C: 100 MW limit
  - Two plants:
    - A: MC = 20 $/MWh
    - B: MC = 70 $/MWh
  - Load:
    - A: 400 MW
    - B: 500 MW



- What's the optimal dispatch?
- What are the prices?
  - Dual variables (Lagrange multipliers) at each node

Linearized Transmission Constraints in Operations LP

g_{int} = *MW from plant* i, *at node* n, *during* t

z_{nt} = *Net MW injection at node n, during t*

MIN Variable Cost = $\Sigma_n \Sigma_{i,t} H_t CG_{int}\, g_{int}$

subject to:

Net Injection: $\Sigma_i g_{int} - D_{tn} = z_{nt}$ $\forall$t,n

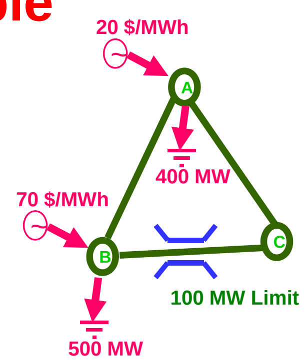
Hub Balance: $\Sigma_n z_{nt} = 0$ $\forall$t

GenCap: $g_{int} \le CAP_{in}$ $\forall$i,n,t

Transmission: $T_{k-} \le [\Sigma_n PTDF_{nk}\, z_{nt}] \le T_{k+}$ $\forall$k,t

$g_{int} \ge 0$ $\forall$i,n,t

Linearized Transmission Constraints in Operations LP: Example



MIN Variable Cost = $20g_A + 70g_B$

subject to:

Net Injection: $g_A - 400 = z_A$

$g_B - 500 = z_B$

Hub balance: $z_A + z_B = 0$

Transmiss'n C→B: $-100 \le [\, 0.33z_A + 0.0\, z_B] \le +100$

Nonnegativity: $g_A, g_B \ge 0$

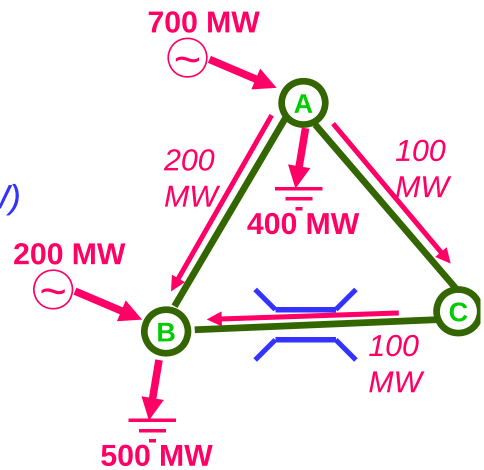
Note: In calculating PTDFs, I assume that all injections "sink" at node B (= "Hub")

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

Exercise in Transmission Modeling: Answer

Optimal Dispatch

- *Two plants:*
  - *A: Meet load at A (400 MW) plus 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
  - *Total cost = $28,000/hr*



Marginal Costs ("LMP") to Load:

A: A's marginal cost ($20)
B: Plant B's MC ($70)
C: To bring 1 MW to C, can back off 1 MW at B & expand 2 MW at A:
*= -$70 + 2*$20 = -$30 (Negative price)*

IV.E Investment Analysis: LP Snap Shot Analysis

- **Let generation capacity cap_i now be a variable, with:**
  - **(annualized) cost CRF [1/yr] $CCAP_i$ [$/MW]**

- **MIN** $\Sigma_{i,t} H_t CG_{it}\, g_{it} + \Sigma_i \text{CRF } CCAP_i\, cap_i$

s.t. $\Sigma_i g_{it} = LOAD_t \quad \forall t$

$g_{it} - cap_i \le 0 \quad \forall i,t$

$\Sigma_t H_t g_{it} - CF_i\, 8760\, cap_i \le 0 \quad \forall i$

$\Sigma_i cap_i \ge D_{PEAK}(1+M)$ **("reserve margin" constraint)**

$g_{it} \ge 0 \quad \forall i,t; \qquad cap_i \ge 0 \quad \forall i$

Planning LP Exercise

- Two generation types
  - A: Peak:
    - Operating Cost = \$70/MWh
    - Capital Cost = \$70,000 / MW/yr
  - B: Baseload:
    - Operating Cost = \$25/MWh
    - Capital Cost = \$120,000 / MW/yr
- Load
  - Peak: 2200 MW, 760 hours/yr
  - Offpeak: 1300 MW, 8000 hours/yr
  - Reserve Margin: 15%
- Assignment:
  - Write down LP
  - What is best solution (by inspection?)

Planning LP Answer: Model Formulation

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

$+ 70{,}000\,cap_A + 120{,}000\,cap_B$

subject to:

Meet load: $g_{A,Pk} + g_{B,Pk} = 2200$

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

Generation ≤ capacity:

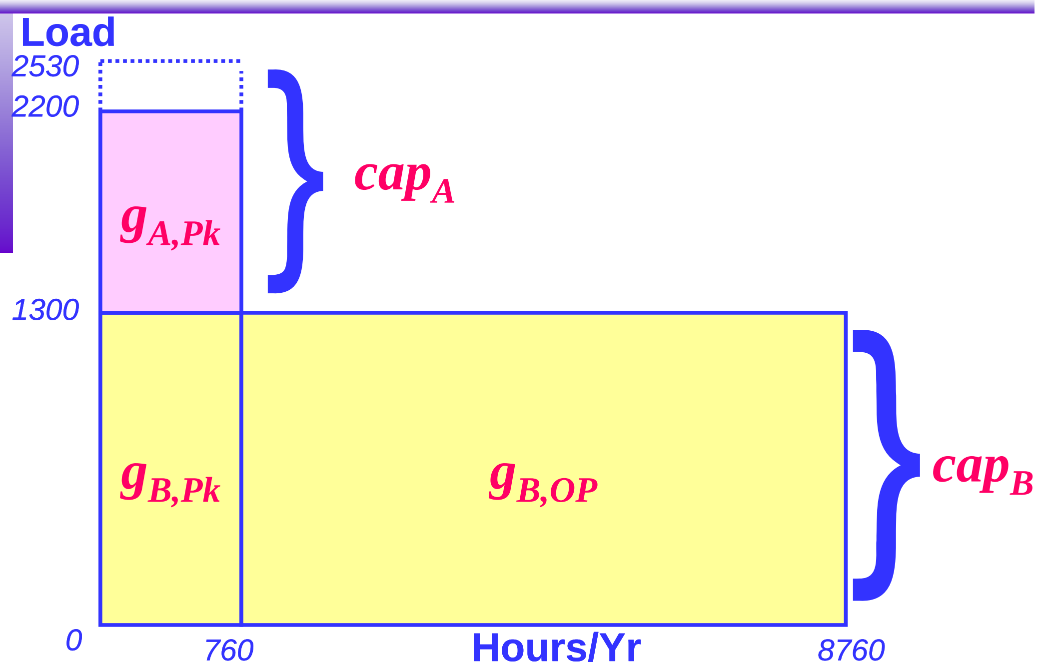
$g_{A,Pk} - cap_A \le 0;\ g_{A,OP} - cap_A \le 0$

$g_{B,Pk} - cap_B \le 0;\ g_{B,OP} - cap_B \le 0$

Reserve: $cap_A + cap_B \ge 1.15 \cdot 2200$

Nonnegativity: $g_{A,Pk}, g_{A,OP}, g_{B,Pk}, g_{B,OP} \ge 0$

Planning LP Answer: Load Duration Curve



A Complication: Uncertain future (demands, fuels,…)

- Math programming with recourse
  - scenarios s=1,2,..,S, each with probability PR^s
  - Considers how the system is operated in each realization.
- Simplest: Assume 2 decision stages:
  1. Choices made "here and now" before future is known
     - *E.g.,* long-lead time plants (nuclear, hydro).
     - These are x^1
  2. "Wait and see" choices, which are made after the future s is known.
     - *E.g.,* dispatch/operations, short-lead time plants (combustion turbines).
     - These are x^{2s} (one set defined for each scenario s)
- Model:

$$\begin{aligned} \text{MIN} \quad & C^1(x^1) + \Sigma_s PR^s C^{2s}(x^{2s}) \\ \text{s.t.} \quad & A^1(x^1) = B^1 \\ & A^{2s}(x^1, x^{2s}) = B^{2s} \qquad \forall s \end{aligned}$$