EE 5200 - Lecture 35 **Wednesday Nov 20, 2019**

Topics for Today:

- Announcements
  - ASPEN software - run off of MTU server via internet, see e-mail instructions.
  - Office: EERC 614.
  - Recommended problems & all solutions: Ch.13 solns (practice problems from old text) now posted.

Ongoing topics...

- Chapter 12 - Power system operation, AGC, economic dispatch
  - System Operation Basics
  - Paralleling of Generators, droop characteristics
  - Frequency biasing - β and B.
  - Constrained optimization methods - LaGrange multipliers
  - Optimal Dispatch, Generator Scheduling
    - Economics
    - Other constraints - environmental, contractual, availability
    - System load characteristics
  - Application to lossless system
  - System including losses - use [B] loss coefficient matrix

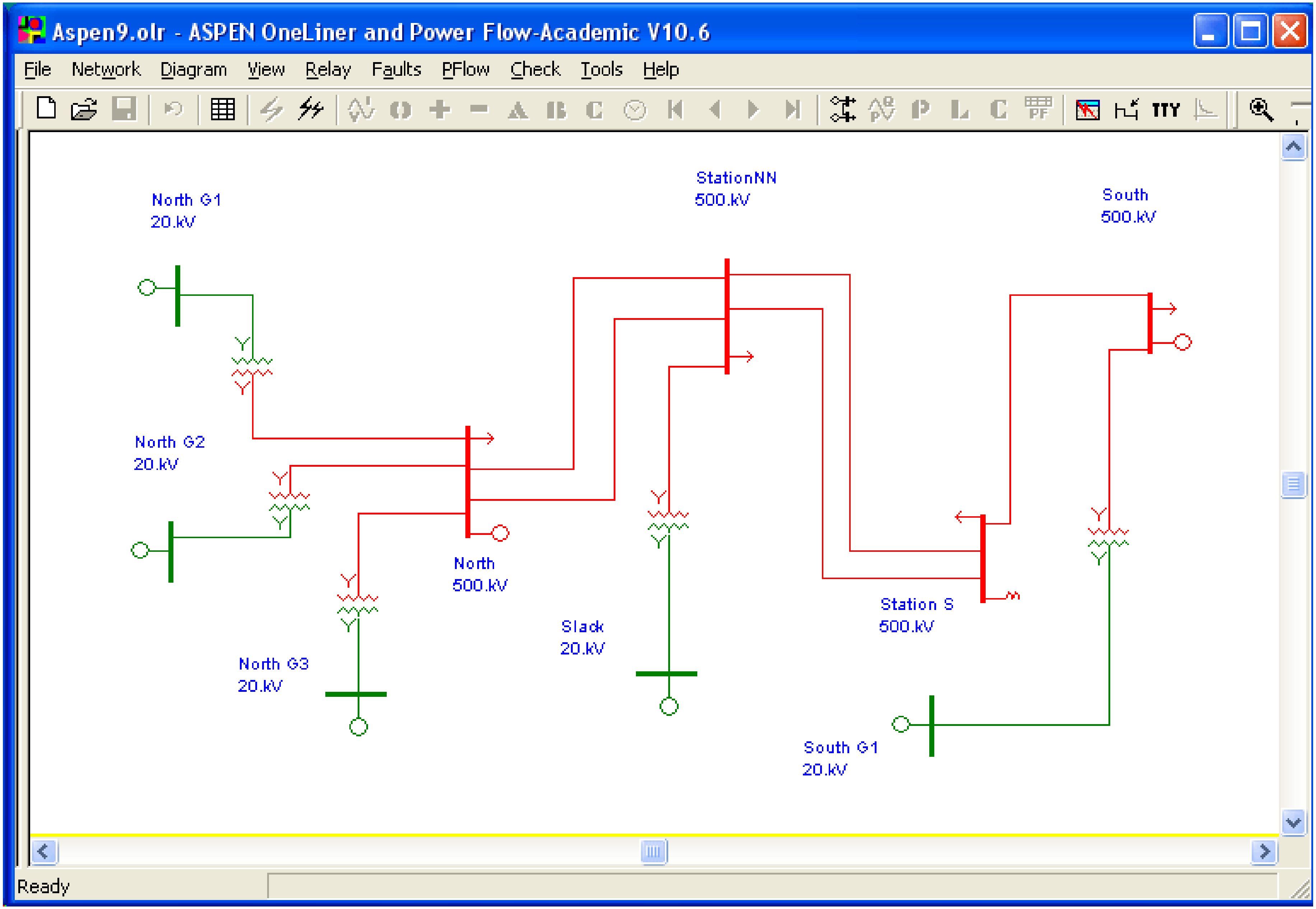
ASPEN Tutorial

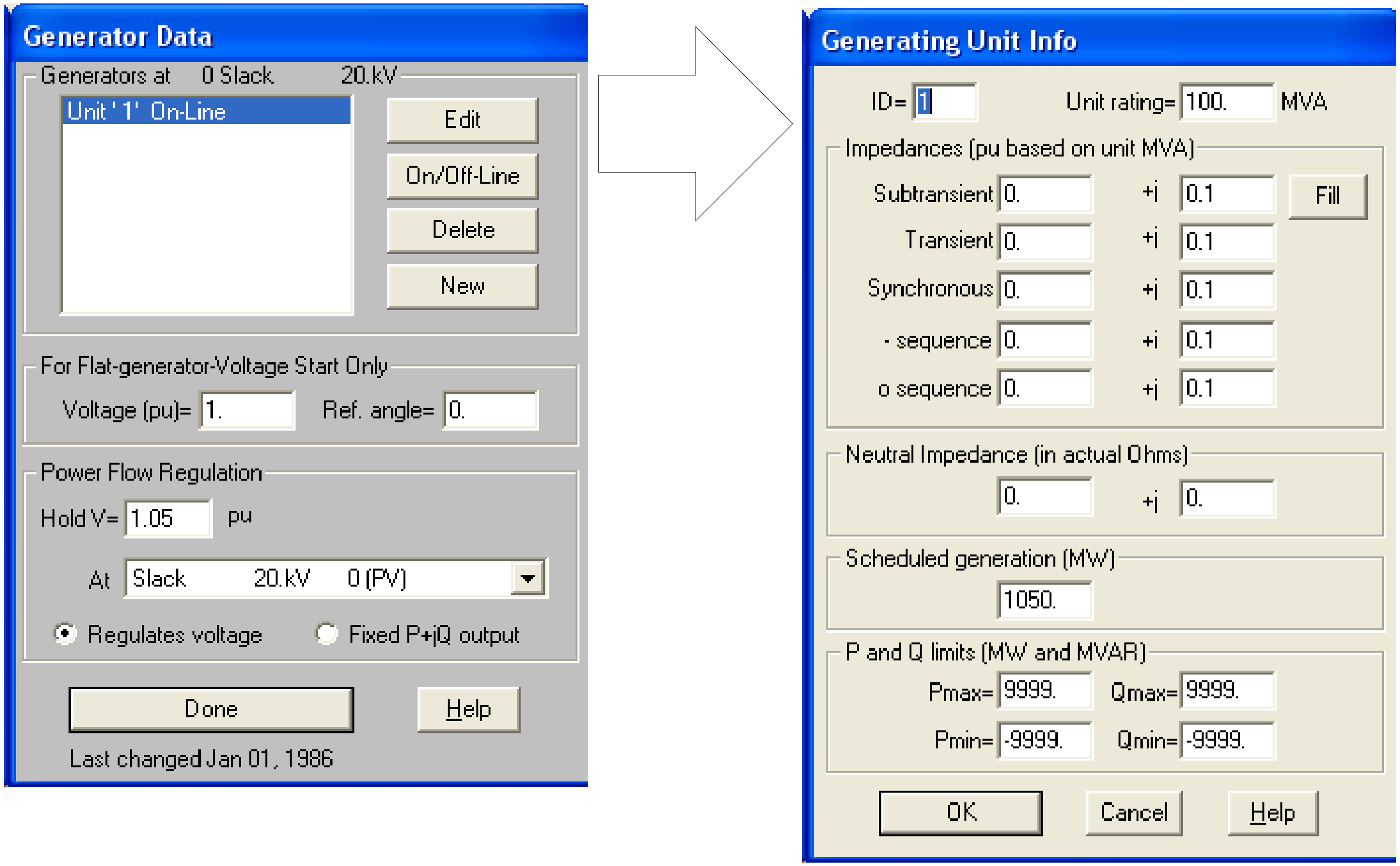
Intro to Software Capabilities

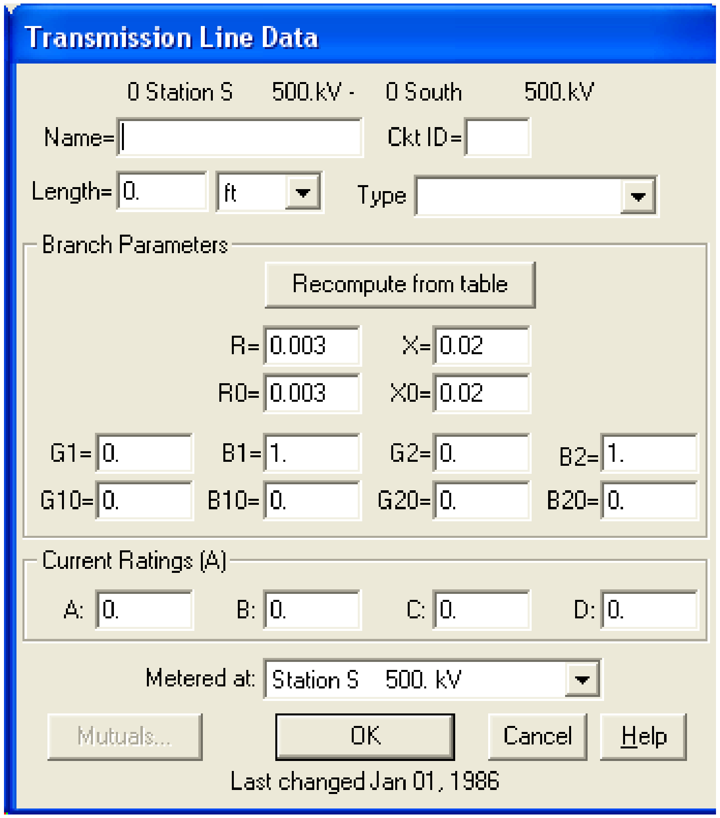
- Loadflow
- Short circuit, arc flash
- Relay application, coordination

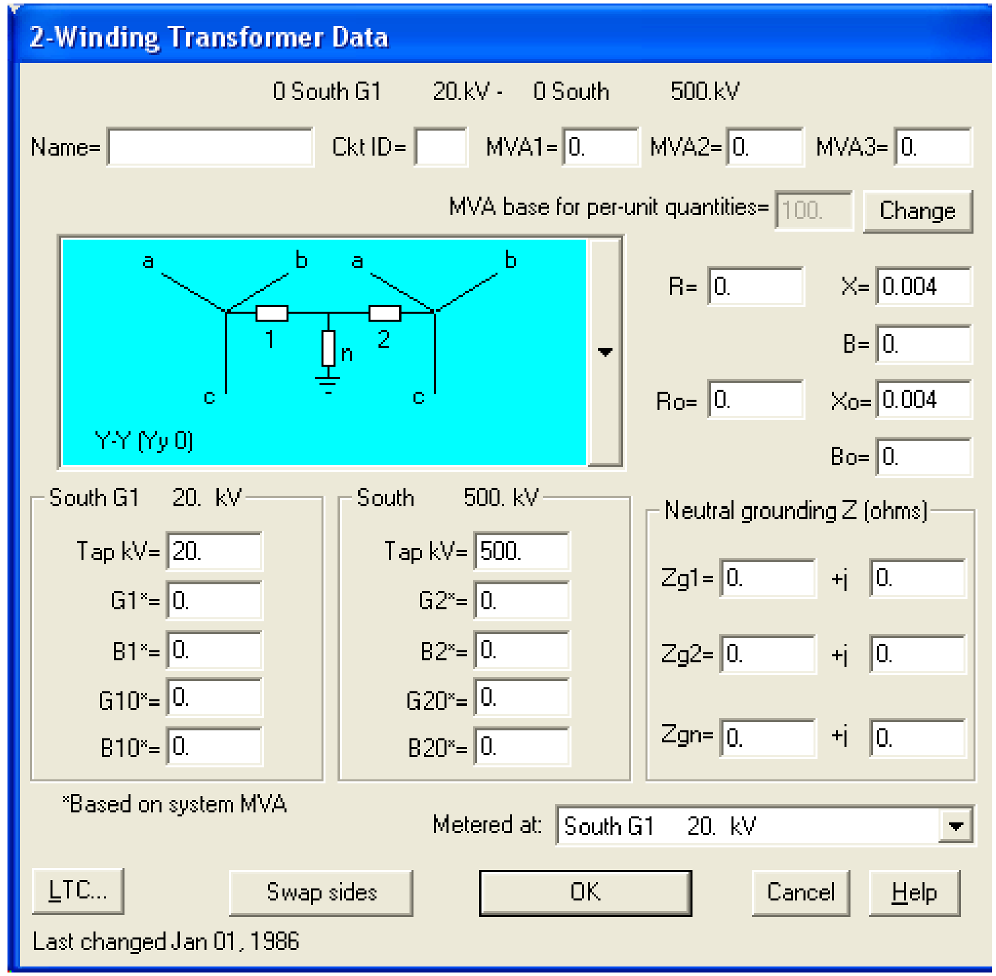
Basics of setting up a loadflow

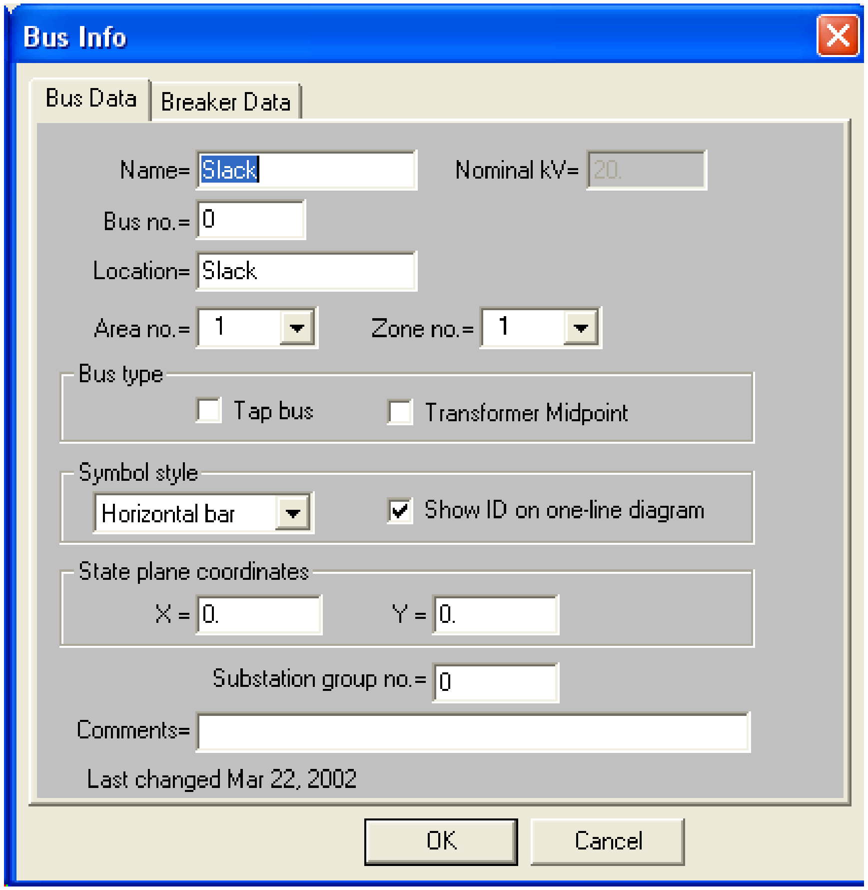
- Get the system data, parameters
- Basics of program
- Draw system configuration
- Parameters
  - Buses
  - Lines
  - Transformers
  - Generators
  - Loadflow configuration
- Output
- Remedial actions

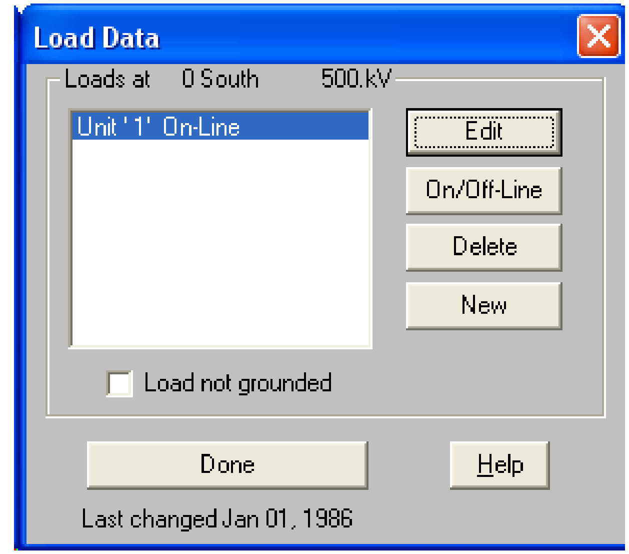

Aspen9.olr - ASPEN OneLiner and Power Flow-Academic V10.6
File Network Diagram View Relay Faults PFlow Check Tools Help
North G1
20.kV
StationNN
500.kV
South
500.kV
North G2
20.kV
North
500.kV
Slack
20.kV
Station S
500.kV
North G3
20.kV
South G1
20.kV
Ready

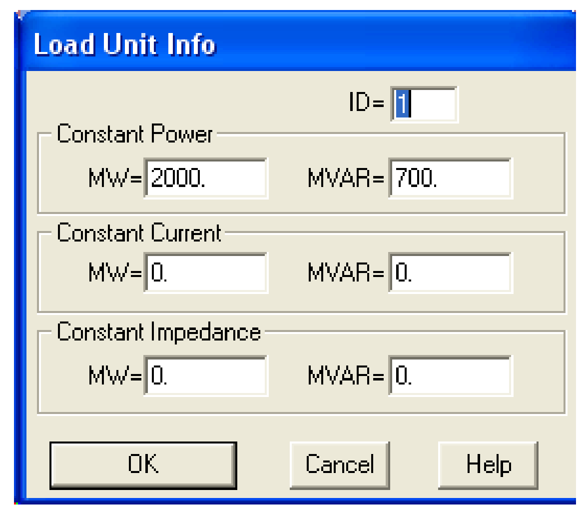

Generator Data
Generators at 0 Slack 20.kV
Unit '1' On-Line
Edit
On/Off-Line
Delete
New
For Flat-generator-Voltage Start Only
Voltage (pu)= 1.
Ref. angle= 0.
Power Flow Regulation
Hold V= 1.05 pu
At Slack 20.kV 0 (PV)
Regulates voltage
Fixed P+jQ output
Done
Help
Last changed Jan 01, 1986
Generating Unit Info
ID= 1
Unit rating= 100. MVA
Impedances (pu based on unit MVA)
Subtransient 0. +j 0.1
Fill
Transient 0. +j 0.1
Synchronous 0. +j 0.1
- sequence 0. +j 0.1
o sequence 0. +j 0.1
Neutral Impedance (in actual Ohms)
0. +j 0.
Scheduled generation (MW)
1050.
P and Q limits (MW and MVAR)
Pmax= 9999. Qmax= 9999.
Pmin= -9999. Qmin= -9999.
OK
Cancel
Help

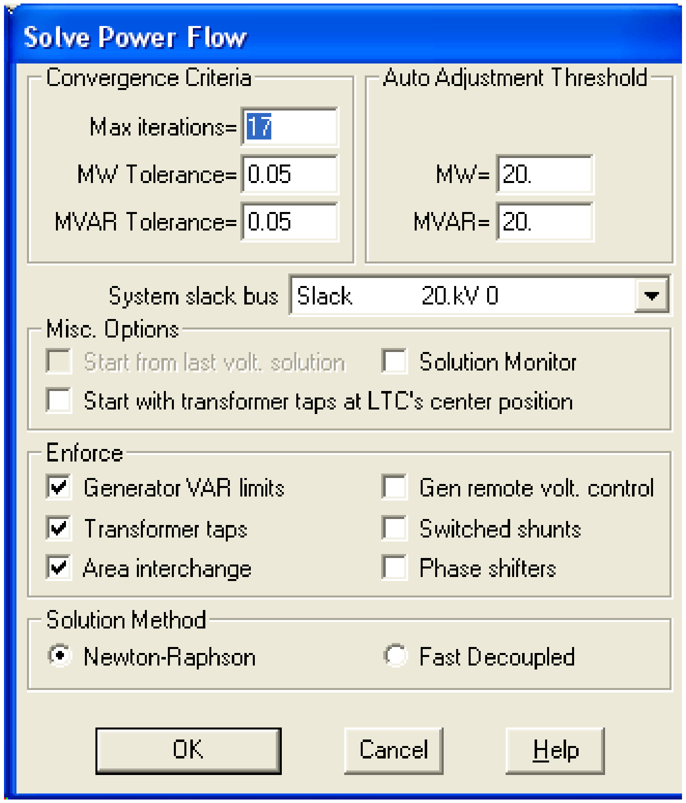

Transmission Line Data
0 Station S 500.kV - 0 South 500.kV
Name=
Ckt ID=
Length= 0.
ft
Type
Branch Parameters
Recompute from table
R= 0.003
X= 0.02
R0= 0.003
X0= 0.02
G1= 0.
B1= 1.
G2= 0.
B2= 1.
G10= 0.
B10= 0.
G20= 0.
B20= 0.
Current Ratings (A)
A: 0.
B: 0.
C: 0.
D: 0.
Metered at: Station S 500. kV
Mutuals...
OK
Cancel
Help
Last changed Jan 01, 1986


2-Winding Transformer Data
0 South G1 20.kV - 0 South 500.kV
Name=
Ckt ID=
MVA1= 0.
MVA2= 0.
MVA3= 0.
MVA base for per-unit quantities= 100.
Change
a
b
a
b
1
n
2
c
c
Y-Y (Yy 0)
R= 0.
X= 0.004
B= 0.
Ro= 0.
Xo= 0.004
Bo= 0.
South G1 20. kV
Tap kV= 20.
G1*= 0.
B1*= 0.
G10*= 0.
B10*= 0.
South 500. kV
Tap kV= 500.
G2*= 0.
B2*= 0.
G20*= 0.
B20*= 0.
Neutral grounding Z (ohms)
Zg1= 0. +j 0.
Zg2= 0. +j 0.
Zgn= 0. +j 0.
*Based on system MVA
Metered at: South G1 20. kV
LTC...
Swap sides
OK
Cancel
Help
Last changed Jan 01, 1986


Bus Info
Bus Data
Breaker Data
Name= Slack
Nominal kV= 20.
Bus no.= 0
Location= Slack
Area no.= 1
Zone no.= 1
Bus type
Tap bus
Transformer Midpoint
Symbol style
Horizontal bar
Show ID on one-line diagram
State plane coordinates
X = 0.
Y = 0.
Substation group no.= 0
Comments=
Last changed Mar 22, 2002
OK
Cancel


Load Data
Loads at 0 South 500.kV
Unit '1' On-Line
Edit
On/Off-Line
Delete
New
Load not grounded
Done
Help
Last changed Jan 01, 1986


Load Unit Info
ID= 1
Constant Power
MW= 2000.
MVAR= 700.
Constant Current
MW= 0.
MVAR= 0.
Constant Impedance
MW= 0.
MVAR= 0.
OK
Cancel
Help


Solve Power Flow
Convergence Criteria
Max iterations= 17
MW Tolerance= 0.05
MVAR Tolerance= 0.05
Auto Adjustment Threshold
MW= 20.
MVAR= 20.
System slack bus Slack 20.kV 0
Misc. Options
Start from last volt. solution
Solution Monitor
Start with transformer taps at LTC's center position
Enforce
Generator VAR limits
Transformer taps
Area interchange
Gen remote volt. control
Switched shunts
Phase shifters
Solution Method
Newton-Raphson
Fast Decoupled
OK
Cancel
Help

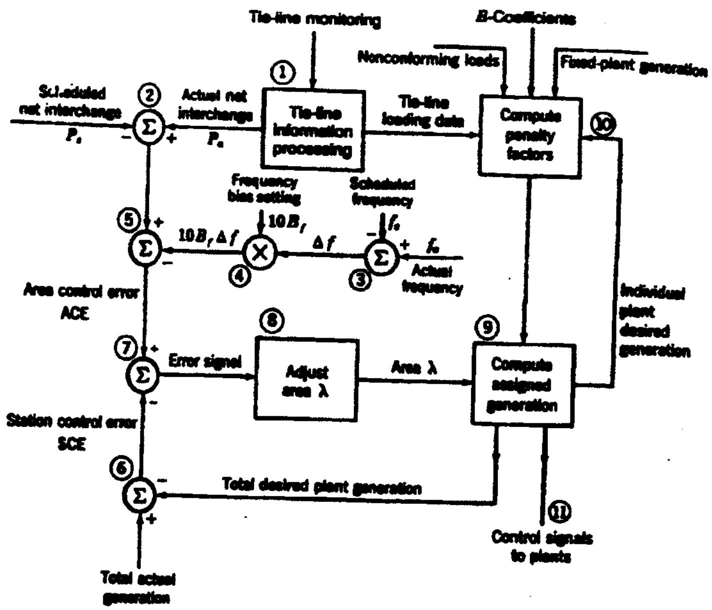


FIGURE 13.8
Block diagram illustrating the computer-controlled operation of a particular area.

symbols × or Σ indicate points of multiplication or algebraic summation of incoming signals.

At position 1 processing of information about power flow on tie lines to other control areas is indicated. The *actual* net interchange P_a is positive when net power is out of the area. The *scheduled* net interchange is P_s. At position 2 the scheduled net interchange is subtracted from the actual net interchange.[3] We shall discuss the condition where both actual and scheduled net interchange are out of the system and therefore positive.

Position 3 on the diagram indicates the subtraction of the scheduled frequency f_s (for instance, 60 Hz) from the actual frequency f_a to obtain Δf, the frequency deviation. Position 4 on the diagram indicates that the frequency bias setting B_f, a factor with a *negative sign* and the units MW/0.1 Hz, is multiplied by $10\ \Delta f$ to obtain a value of megawatts called the *frequency bias* $(10\ B_f \Delta f)$.

The frequency bias, which is positive when the actual frequency is less than the scheduled frequency, is subtracted from $(P_a - P_s)$ at position 5 to obtain the ACE, which may be positive or negative. As an equation

$$\text{ACE} = (P_a - P_s) - 10B_f(f_a - f_s)\ \text{MW} \tag{13.68}$$

A negative ACE means that the area is not generating enough power to send the desired amount out of the area. There is a deficiency in net power output. Without frequency bias, the indicated deficiency would be less because there would be no positive offset $(10\ B_f \Delta f)$ added to P_s (subtracted from P_a) when actual frequency is less than scheduled frequency and the ACE would be less. The area would produce sufficient generation to supply its own load and the prearranged interchange but would not provide the additional output to assist neighboring interconnected areas to raise the frequency.

Station control error (SCE) is the amount of actual generation of all the area plants minus the desired generation, as indicated at position 6 of the diagram. This SCE is negative when desired generation is greater than existing generation.

The key to the whole control operation is the comparison of ACE and SCE. Their difference is an error signal, as indicated at position 7 of the diagram. If both ACE and SCE are negative and equal, the deficiency in the output from the area equals the excess of the desired generation over the actual generation and no error signal is produced. However, this excess of desired generation will cause a signal, indicated at position 11, to go to the plants to increase their generation and to reduce the magnitude of the SCE; the resulting increase in output from the area will reduce the magnitude of the ACE at the same time.

If ACE is more negative than SCE, there will be an error signal to increase the λ of the area, and this increase will in turn cause the desired plant generation to increase (position 9). Each plant will receive a signal to increase its output as determined by the principles of economic dispatch.

This discussion has considered specifically only the case of scheduled net interchange out of the area (positive scheduled net interchange) that is greater than actual net interchange with ACE equal to or more negative than SCE. The reader should be able to extend the discussion to the other possibilities by referring to Fig. 13.8.

Position 10 on the diagram indicates the computation of penalty factors for each plant. Here the *B*-coefficients are stored to calculate $\partial P_L / \partial P_{gi}$ and the penalty factors. The penalty factors are transmitted to the section (position 9), which establishes the individual plant outputs for economic dispatch and the total desired plant generation.

[3] Subtraction of standard or reference value from actual value to obtain the error is the accepted convention of power system engineers and is the negative of the definition of control error found in the literature of control theory.

From Gross, 2nd Ed.

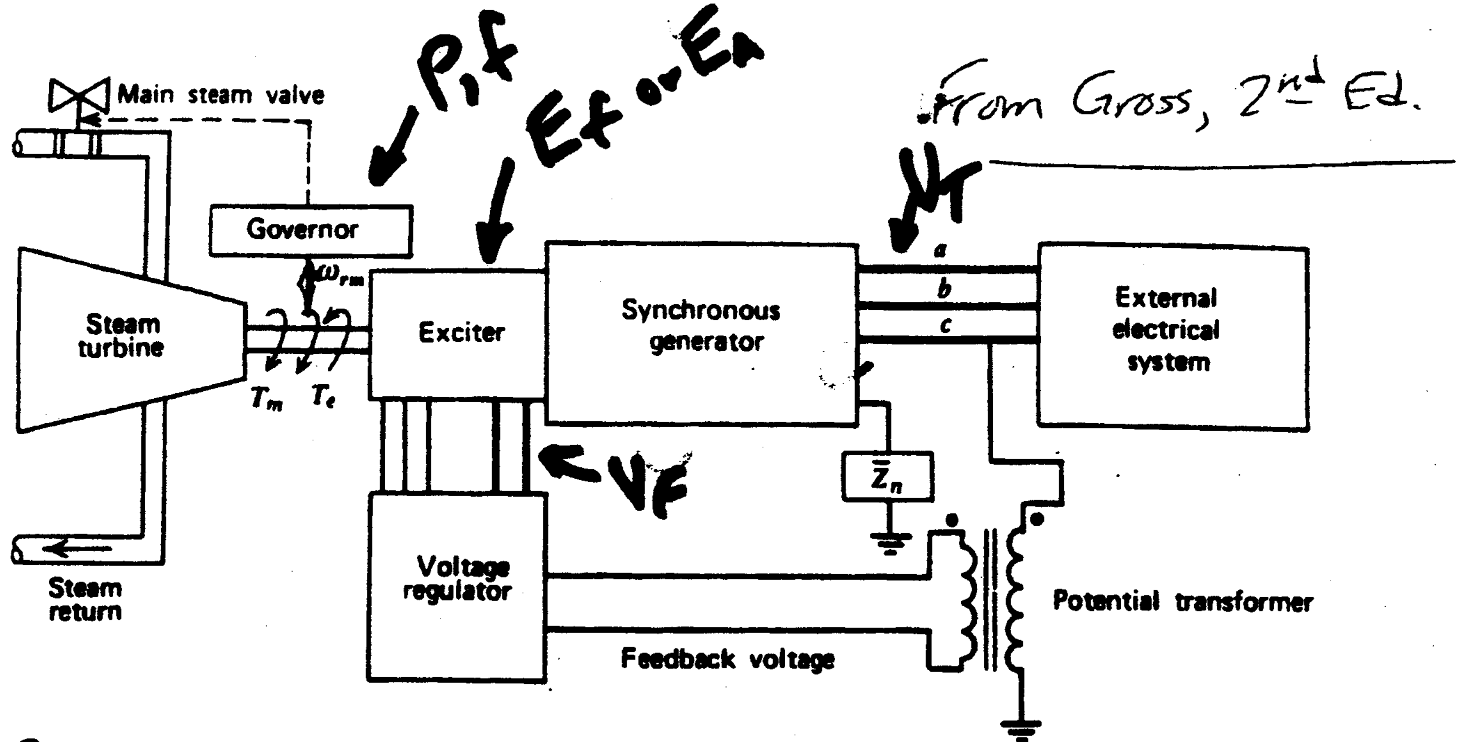
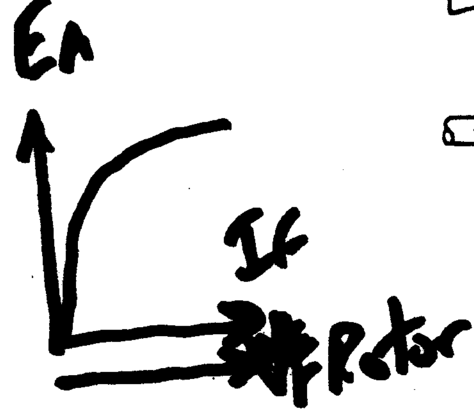
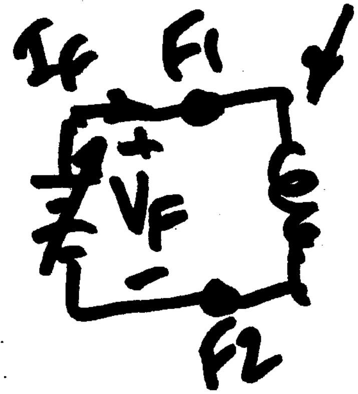


Figure 6.10. Turbine–generator–exciter system





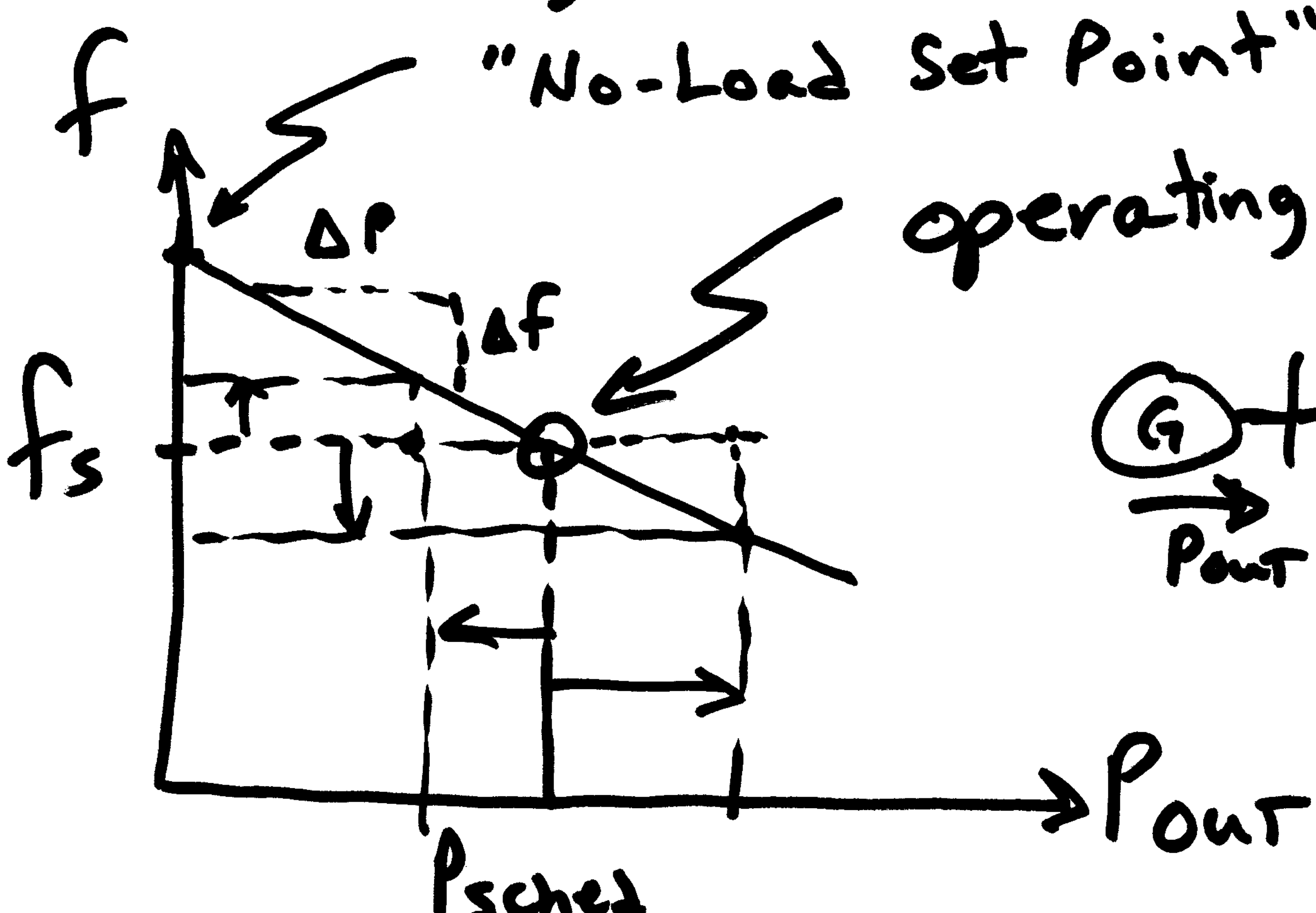
$$P = \frac{E_f V_T}{X_s} \sin\delta$$

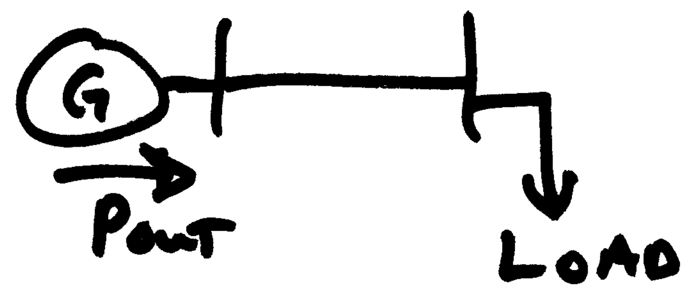
$$Q = \frac{E_f V_T}{X_s} \cos\delta - \frac{V_T^2}{X_s}$$

"Droop Characteristic" of Gen.

Makes possible

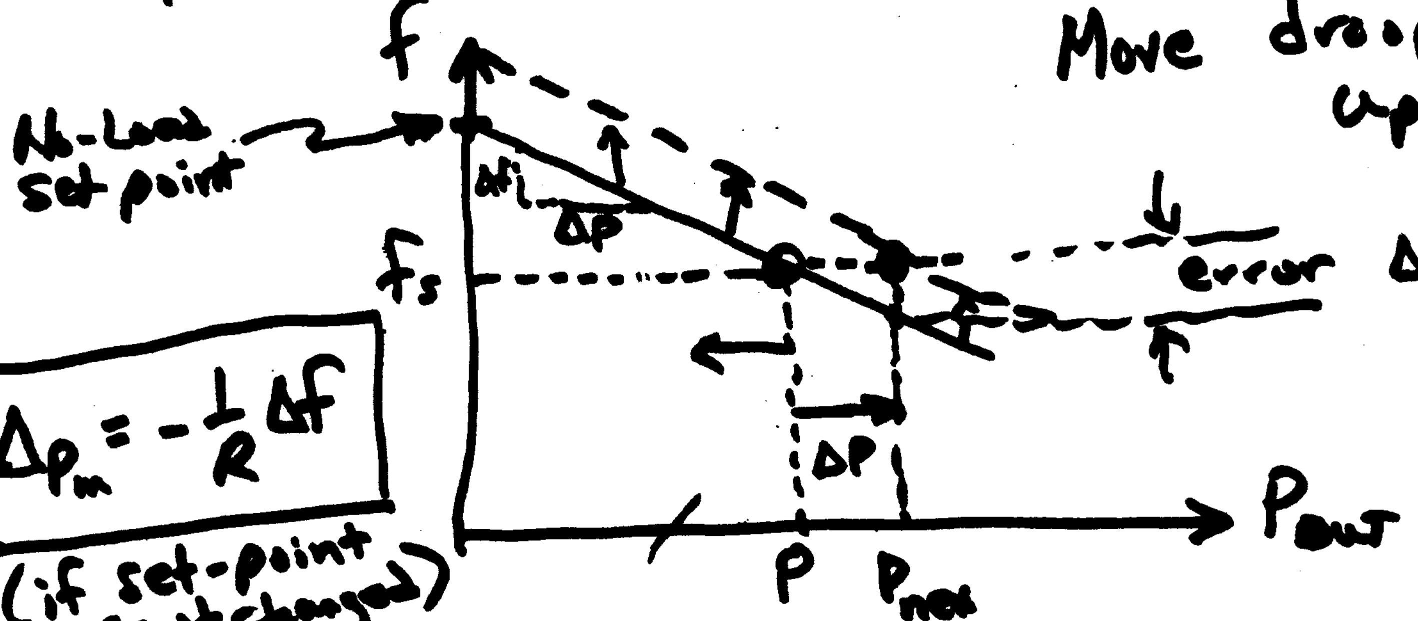
- Maintaining 60 Hz.
- Sheduled Gen
- Min System loss ("economic dispatch")





Droop Characteristic (Refer to AGC Notes) 1

Move droop char. upward.



$$\boxed{\Delta p_m = -\frac{1}{R}\Delta f}$$

(if set-point isn't changed)

"<u>Slope</u>": $R = -\dfrac{\Delta f}{\Delta P}$ neg, pos R always positive.

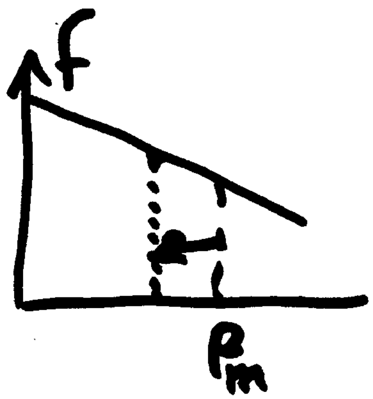
[Can track f either in Hz or p.u.
P is typically tracked in p.u. (although text examples are in MW).

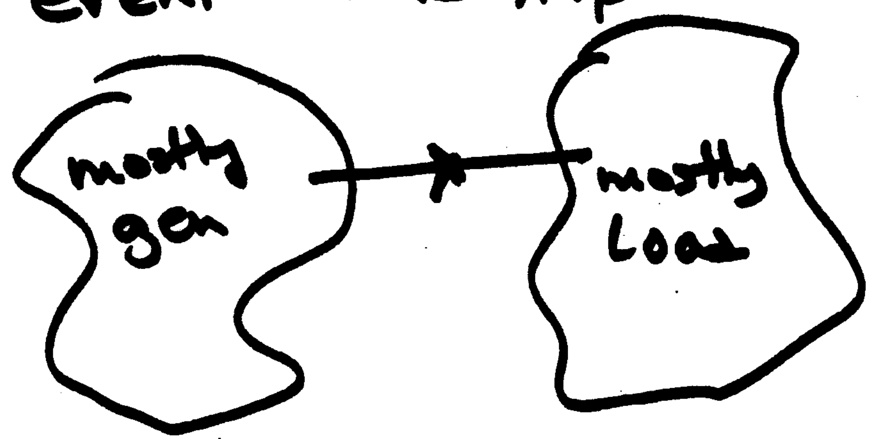
Two scenarios:

- 1) Controlled change in P_{SCHED}.
  - Change $f_{no\text{-}load}$, let gov "do its thing."

- 2) Uncontrolled event: line trip

P_{out} suddenly decreases, $f \uparrow$

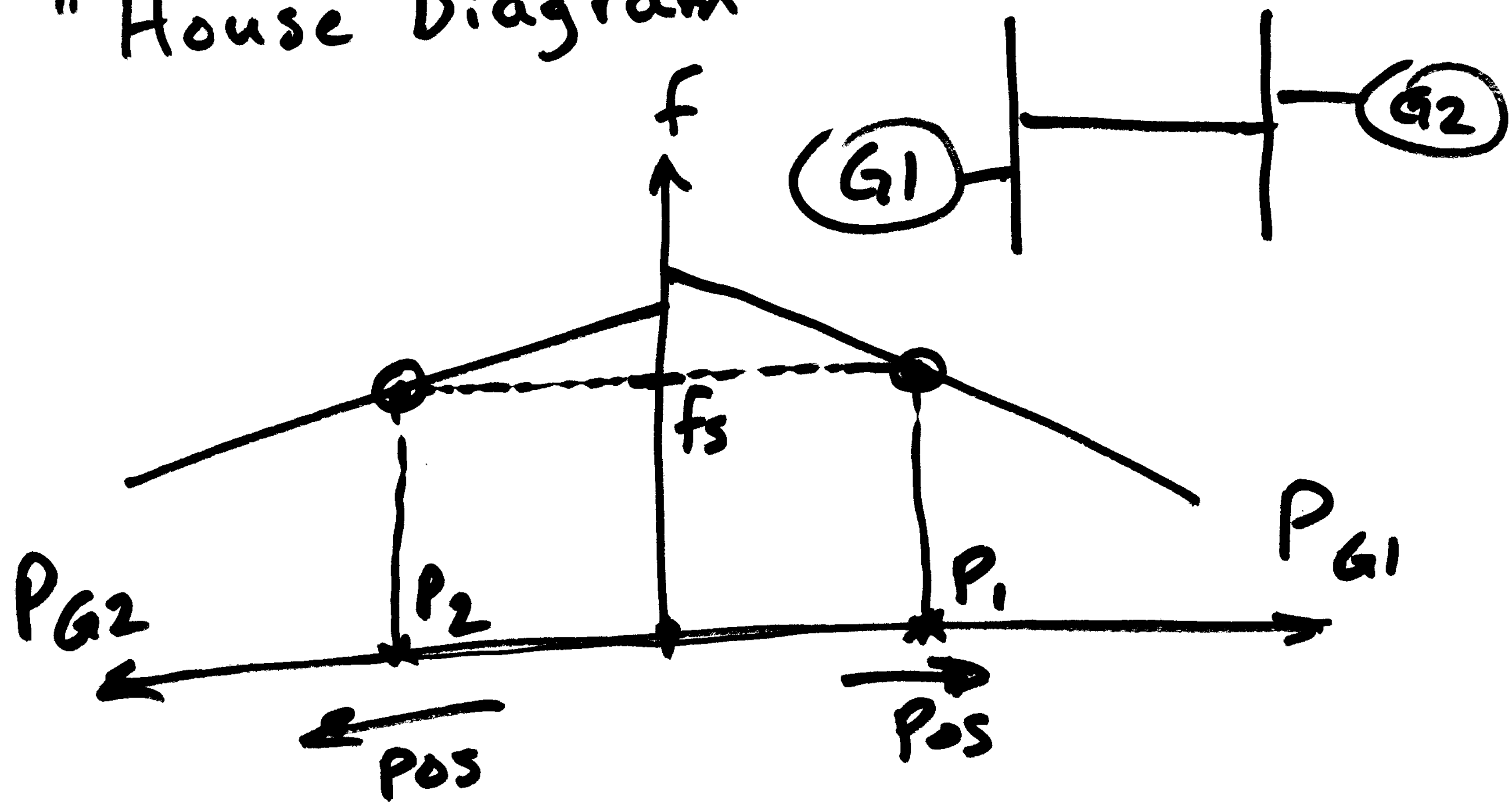


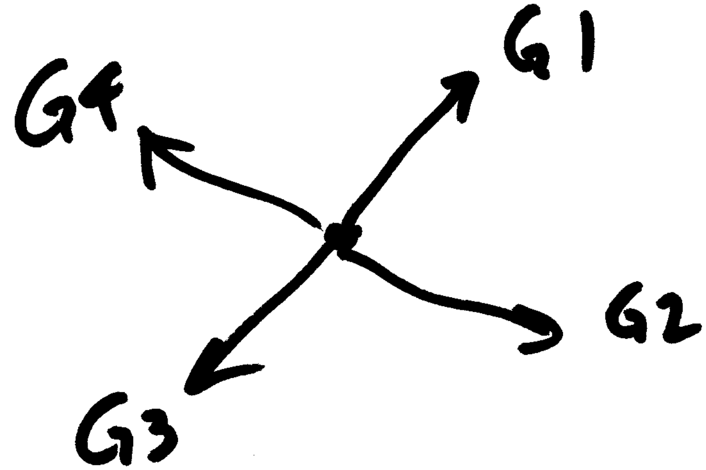


$$\Delta P_m = -\frac{1}{R}\Delta f$$

(See p. 2a, AGC Notes)

"House Diagram"

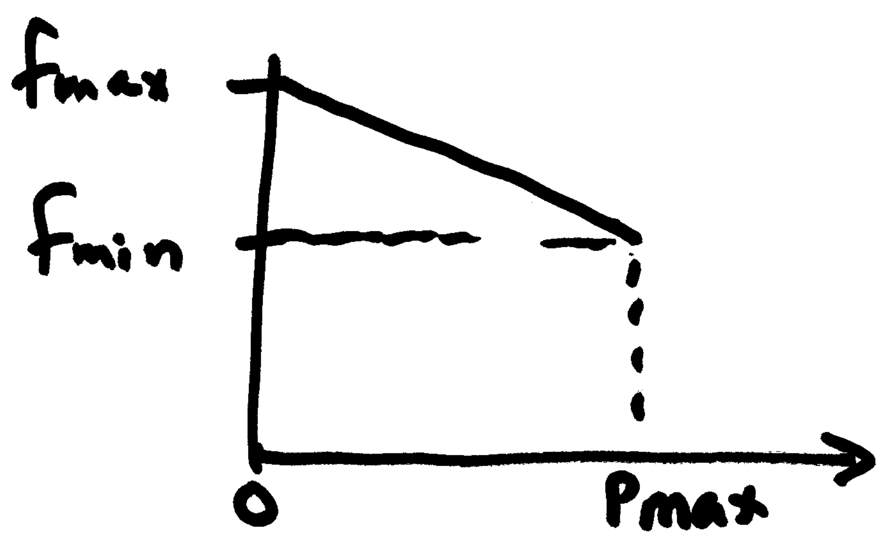




Typical Speed Droop ≈ 4-5% on <u>Gen Base</u>.

$$R = -\frac{\Delta f}{\Delta P} = -\frac{f - f_s}{P - P_0}$$

$$R = -\frac{(f - f_s)/f_s}{(P - P_0)/P_{\text{BASE of Generator}}}$$



Calculating for 2 or more generators...

<u>Ref. notes:</u> p.4.

- Mult gens.
- β is aggregate freq response of an Area.