POWER SYSTEM OPERATION AND CONTROL

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OVERVIEW

- Interconnected systems
- Generator scheduling/dispatching
- Load-generation balancing
- Area Control Error (ACE)
- Load following and regulation
- Unit and system ramping curves

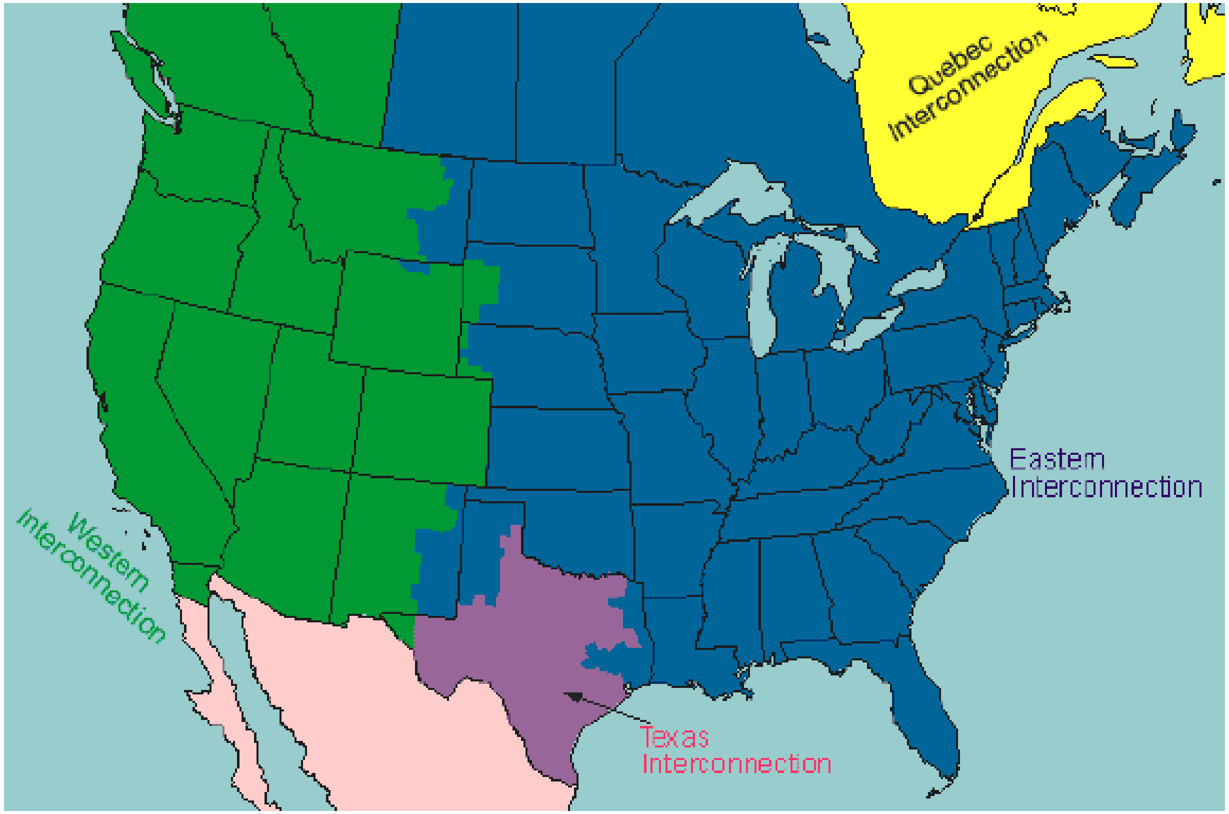
NORTH AMERICAN POWER GRID

- Utilities quickly learned the benefits in reliability and reduced operating reserves by connecting to neighboring systems.
- There are over 3,000 electric utilities in the US.
- Some provide service in multiple states.
- Over 1,700 non-utility power producers.
- Utilities are either investor-owned, publicly-owned, cooperatives, and Federal utilities.
- Electric utilities are regulated by local, State, and Federal authorities.

NORTH AMERICAN INTERCONNECTIONS

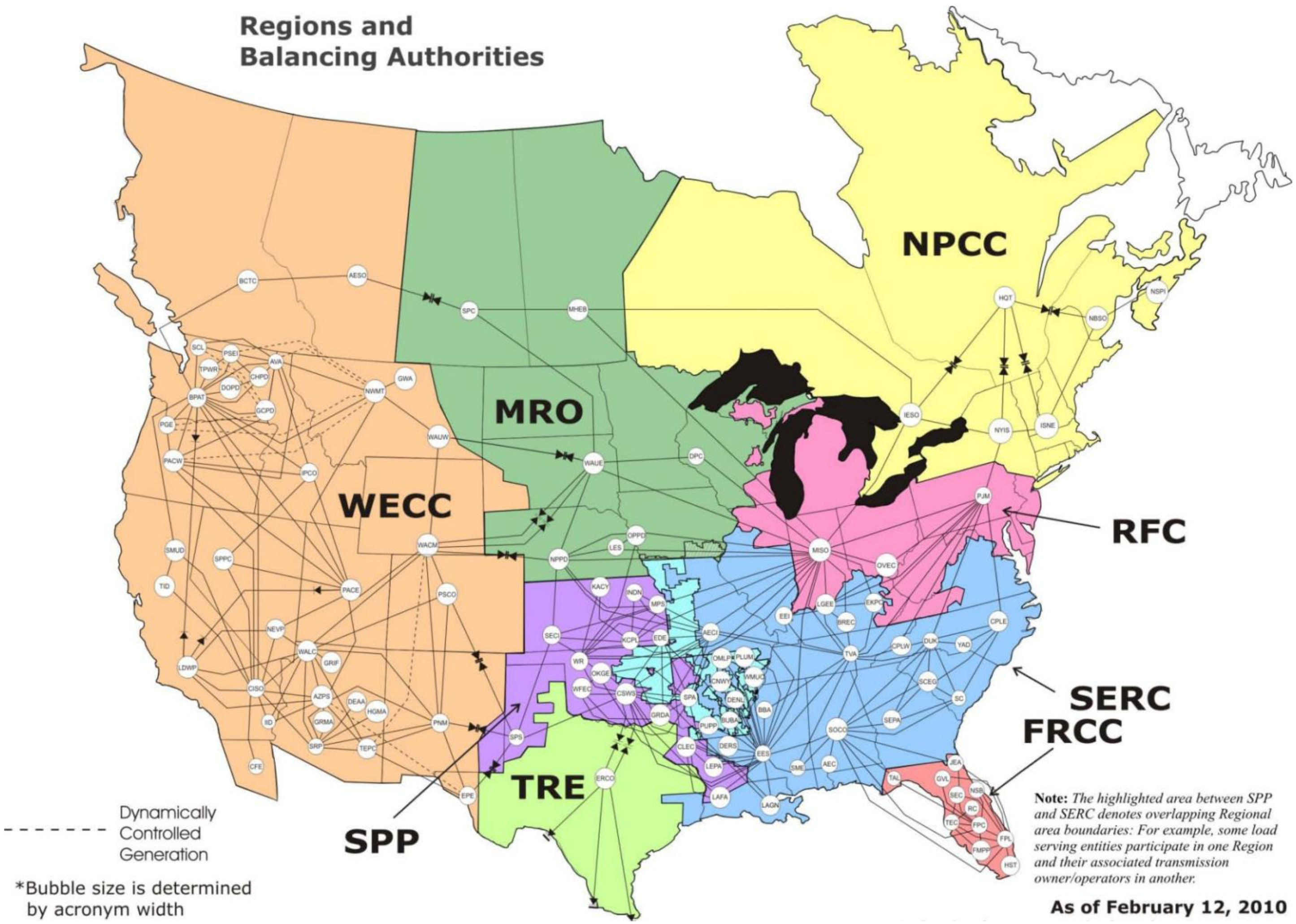
The power system of North America is divided into four major Interconnections which can be thought of as independent islands.

- **Western** – Generally everything west of the Rockies.
- **Texas** - Also known as Electric Reliability Council of Texas (ERCOT).
- **Eastern** – Generally everything east of the Rockies except Texas and Quebec.
- **Quebec**.



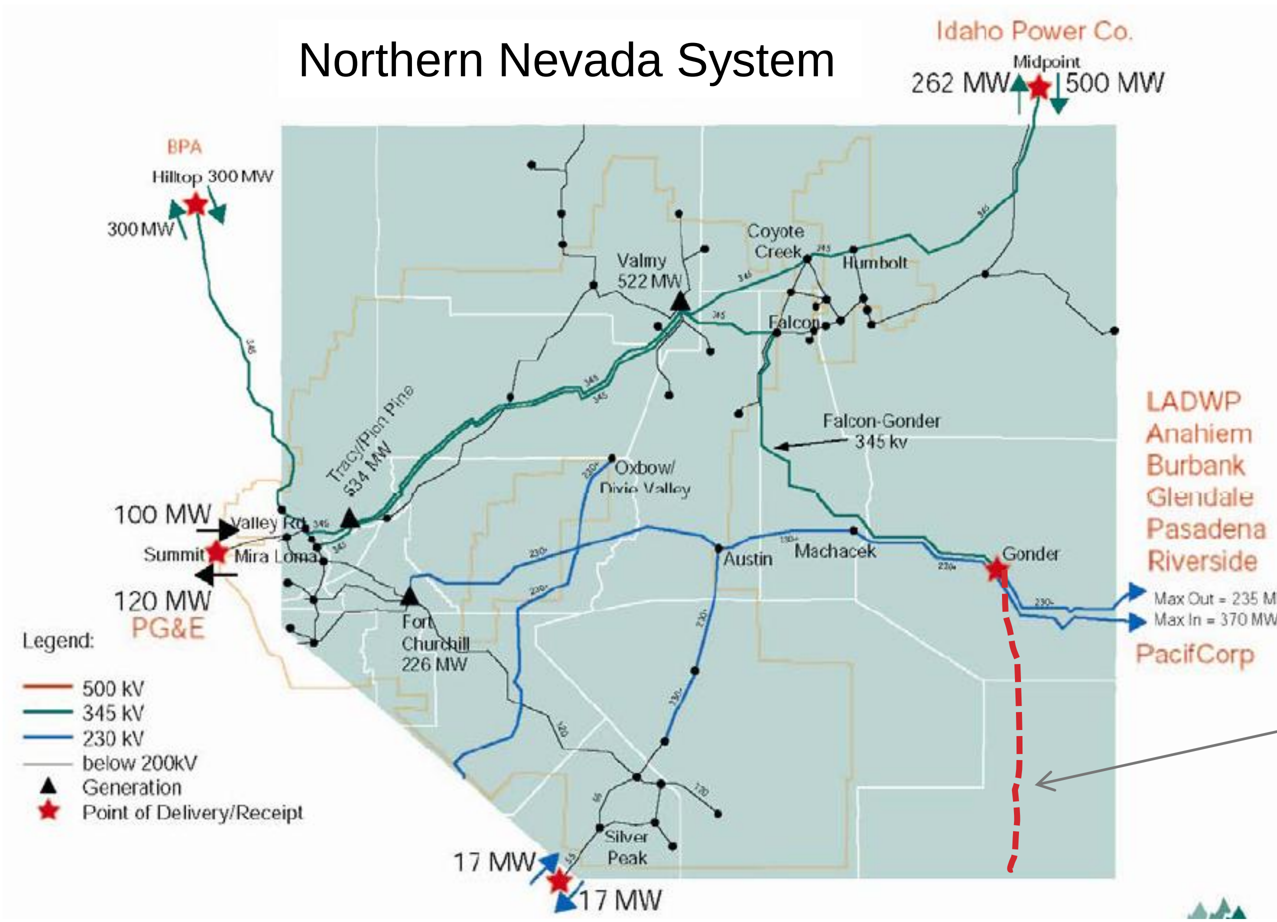
NORTH AMERICAN BALANCING AUTHORITIES

The actual operation of the Interconnections is handled by over 100 Balancing Authorities (BA's). The BA's dispatch generators in order to meet their individual needs. Some BA's also control load to maintain balance.



INTERCONNECTED OPERATION

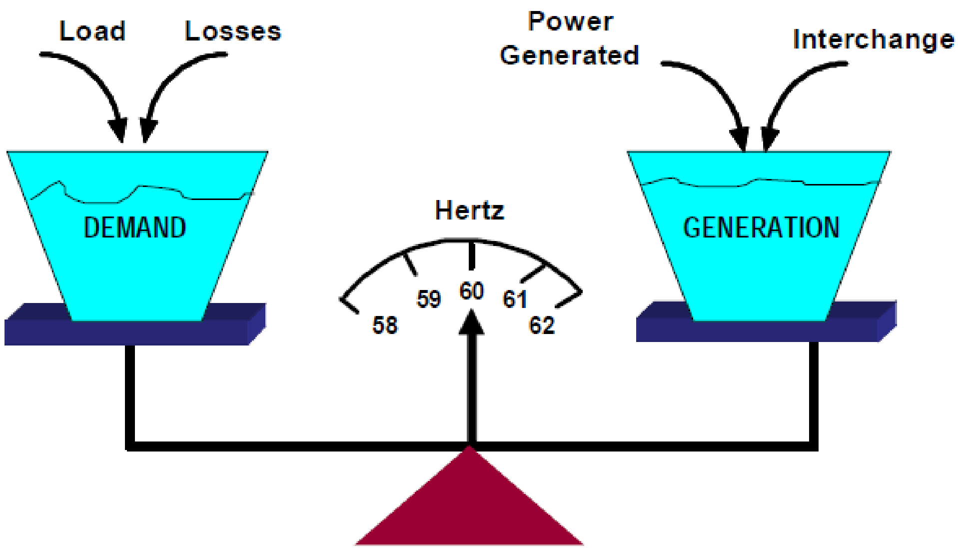
- Each BA in an Interconnection is connected via high voltage transmission lines (i.e., tie-lines) to neighboring Balancing Authorities.
- Overseeing the BA's are wide-area operators called Reliability Coordinators.
- The net power in/out of an area is the sum of the flow on its tie-lines.



One Nevada Line

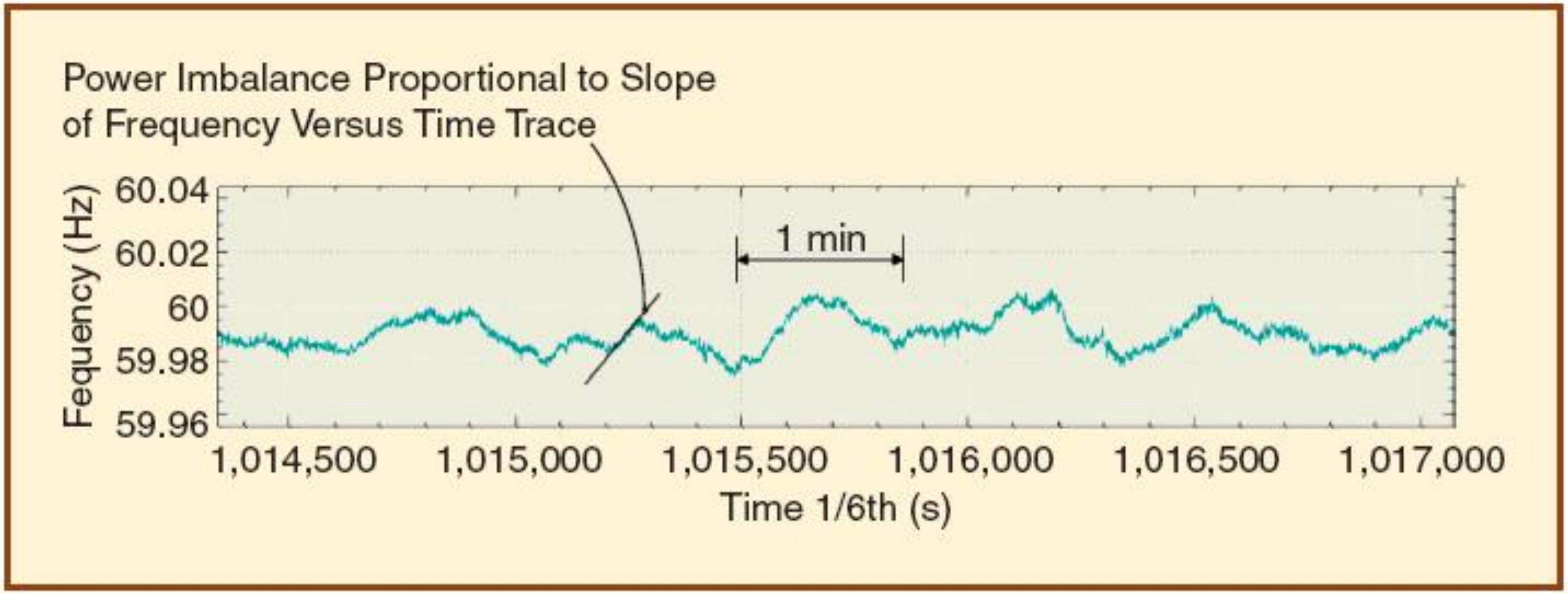
GENERATION-LOAD BALANCE

- As electricity itself cannot presently be stored on a large scale, changes in customer demand throughout the day and over the seasons are met by controlling conventional generation, using stored fuels to fire generation plants when needed.
  - The loads are not generally controlled directly, except for the case when there is insufficient generation available on peak days, at which point load may be reduced through DR programs.
- Frequency is maintained as long as there is a balance between resources and customer demand (plus losses). An imbalance causes a frequency deviation.
- The overall daily profile of load in a given area can be predicted reasonably well using forecasting tools.
- A day-ahead generating schedule can be developed based on the predicted next-day load profile.



FREQUENCY: THE HEARTBEAT OF A POWER SYSTEM

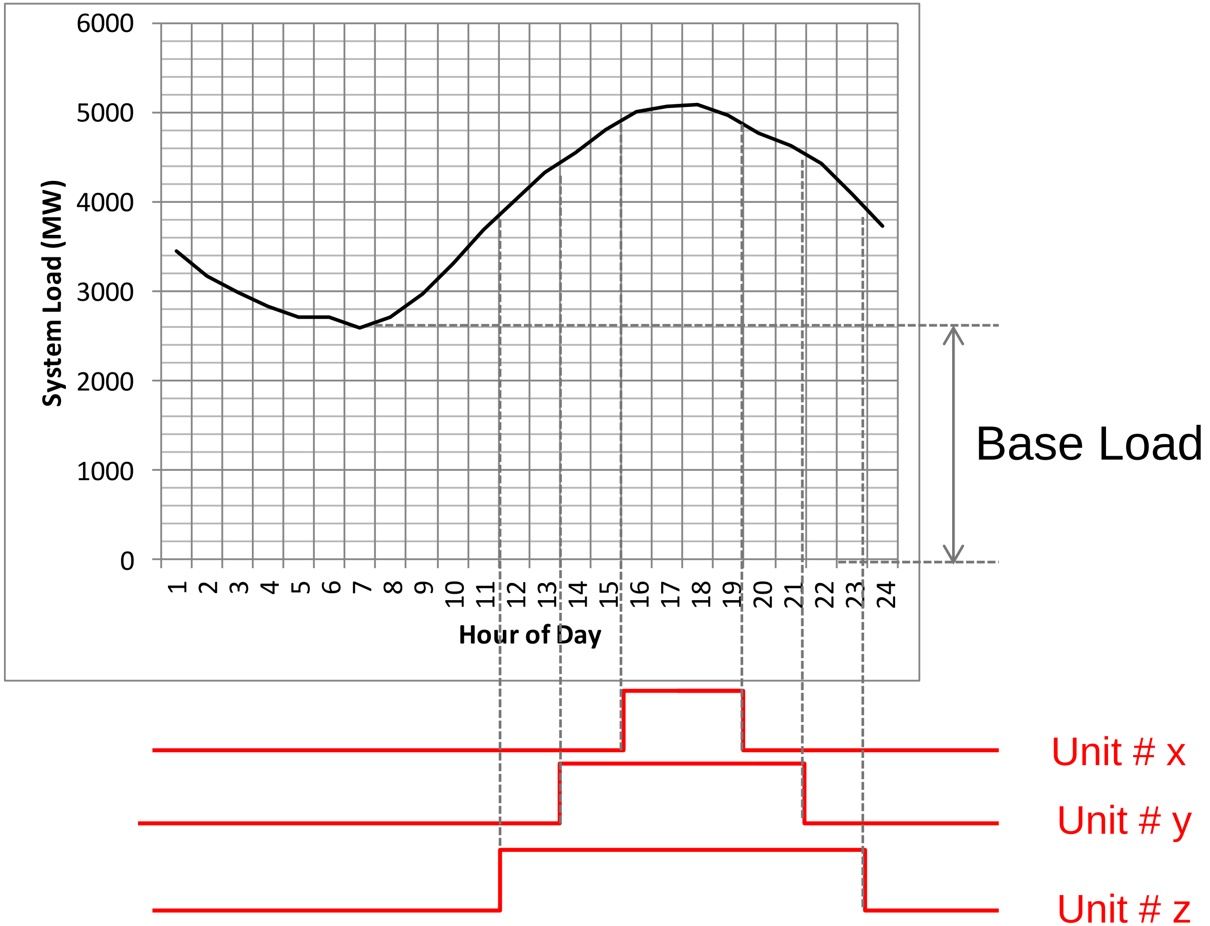
- The figure below shows a sample time history of the frequency on the grid in the western United States, sampled six times a second. The slope of the frequency trace is a measure of the overall imbalance of generation and load at any given moment.
- The actual grid frequency tends to oscillate slightly around 60 Hz. The frequency error from 60 Hz is used to fine-tune the generation level through regulation.



Source: Alec Brooks, Ed Lu,Dan Reicher, Charles Spirakis, and Bill Weihl,"Demand Dispatch" IEEE Power & Energy magazine, May/June 2010

OPTIMAL GENERATOR SCHEDULING

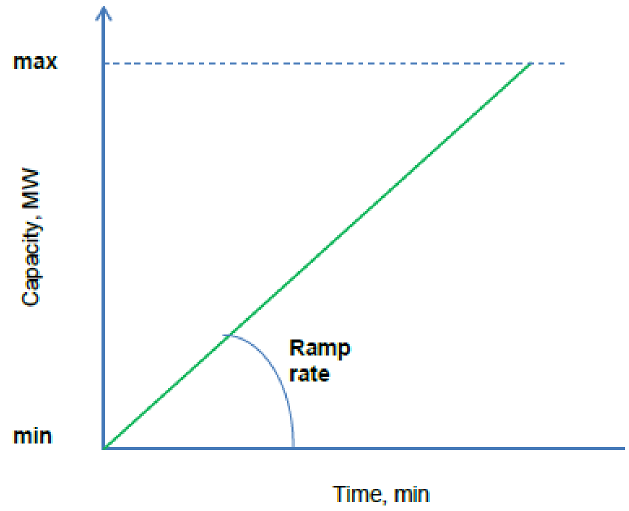
Given a power system with *n* generators, and a load forecast, the problem is to determine the optimal schedule of each generator (i.e., when to bring on-line and off-line) while recognizing generating unit limits and output capability.



GENERATION FLEET CHARACTERISTICS

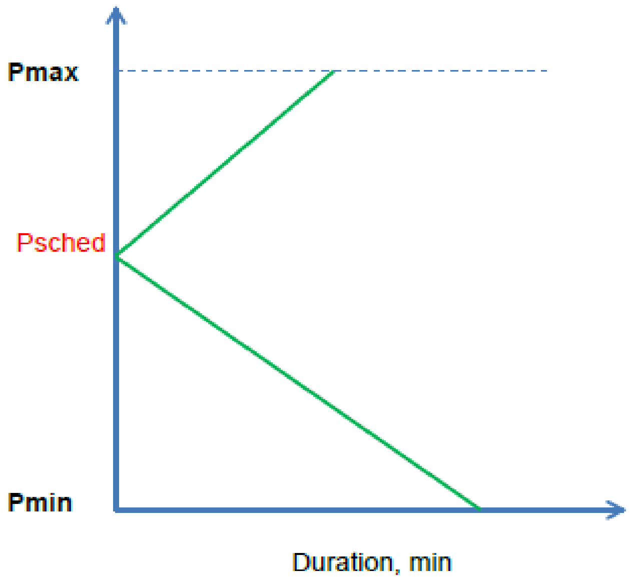
Each generating unit has specific (fixed) physical characteristics that determine the capability of each unit to respond to changes in system load in the up or down direction:

- Minimum generation – P_{min} (MW)
- Maximum generation – P_{max} (MW)
- Maximum ramp rate – R (MW/min)



Time-specific characteristics are:

- Scheduled operating point - P_{sched} (MW)
- Regulation reserve (MW)
- Load following reserve (MW)
- Contingency reserve – P_{cont} (MW)

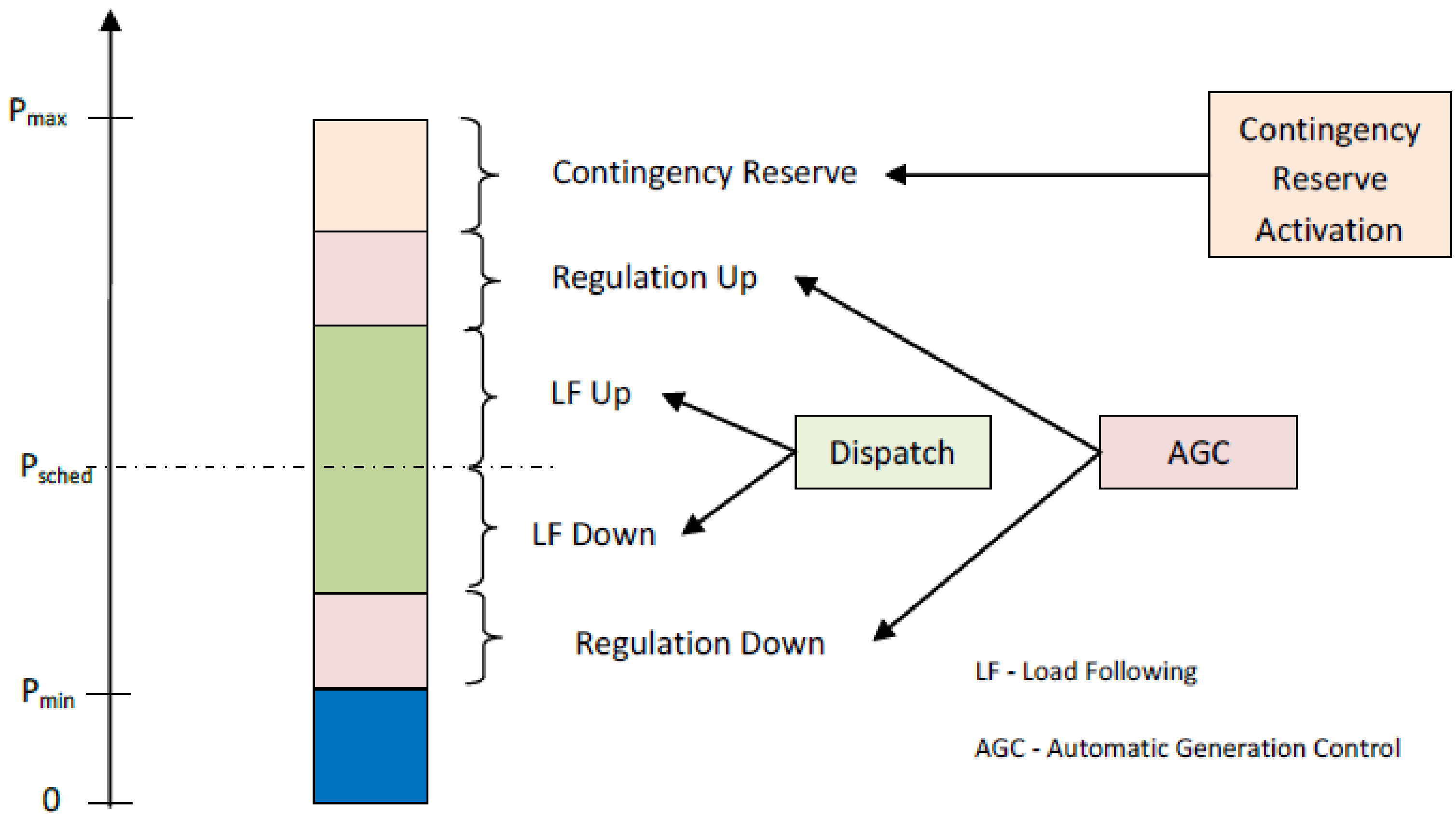


OPERATING RESERVE REQUIREMENTS

BA's are required to maintain the following types of reserves to provide for regulation, balance against the load forecasting error and equipment forced and scheduled outages, and to maintain local area reliability (typically 10-15% of peak load):

- **Spinning Reserve –** Unloaded generation that is synchronized, automatically responsive to frequency deviations, and ready to serve an additional demand. It consists of regulating reserve and contingency reserve.
    - **Regulating Reserve** – An amount of reserve responsive to automatic generation control (AGC), that is sufficient to provide normal regulating margin.
    - **Contingency Reserve** – The capacity available to be deployed by a balancing authority (BA) to meet the North America Electric Reliability Corporation (NERC) and WECC contingency reserve requirements.
- **Non-Spinning Reserve –** (1) The generating reserve, which is not connected to the system but capable of serving the demand within a specified time from its activation; and (2) loads that can be removed from the system in a specified time.

RESERVE ALLOCATION IN SCHEDULING PROCESS



OPTIMAL GENERATOR DISPATCH (SUB-PROBLEM)

- **Optimal Power Flow/Economic dispatch**: Given a forecasted load on the system at a particular hour, determine the optimal power production from each generator that is committed such that operating cost is minimized, while meeting numerous constraints.

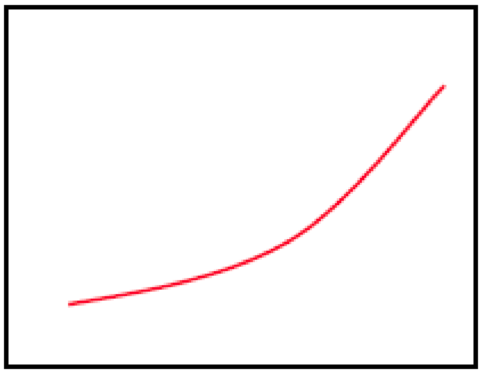
  → Conventional generators are dispatchable. On the other hand, renewable resources are not dispatchable, hence cannot be scheduled.

- Constraints include:
  - Minimum transmission losses
  - Generator limits (regulation, load following and contingency reserves)
  - Voltage limits at all system nodes

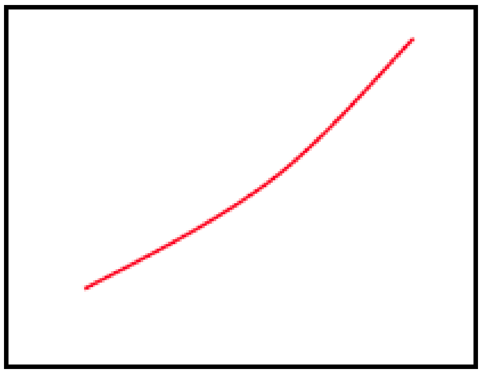
Operating Costs

- **Generator heat rate curves lead to the fuel cost curves**

Heat-Rate Curve



Fuel-Cost Curve



  - The fuel cost is commonly express as a quadratic function

$$C_i = \alpha_i + \beta_i P_i + \gamma_i P_i^2$$

  - The derivative is known as the incremental fuel cost

$$dC_i \big/ dP_i = \beta_i + 2\gamma_i P_i$$

MATHEMATICAL FORMULATION

- Cost function to minimize

$$C_{total} = \sum_{i=1}^{n_{gen}} C_i = \sum_{i=1}^{n_{gen}} \alpha_i + \beta_i P_i + \gamma_i P_i^2$$

- Generator limits

$$P_{i(\min)} < P_i < P_{i(\max)}$$

- Power flow constraints

$$P_i = \sum_{j=1}^{n} |Y_{ij}||V_j||V_i|\cos(\theta_{ij} + \delta_j - \delta_i)$$

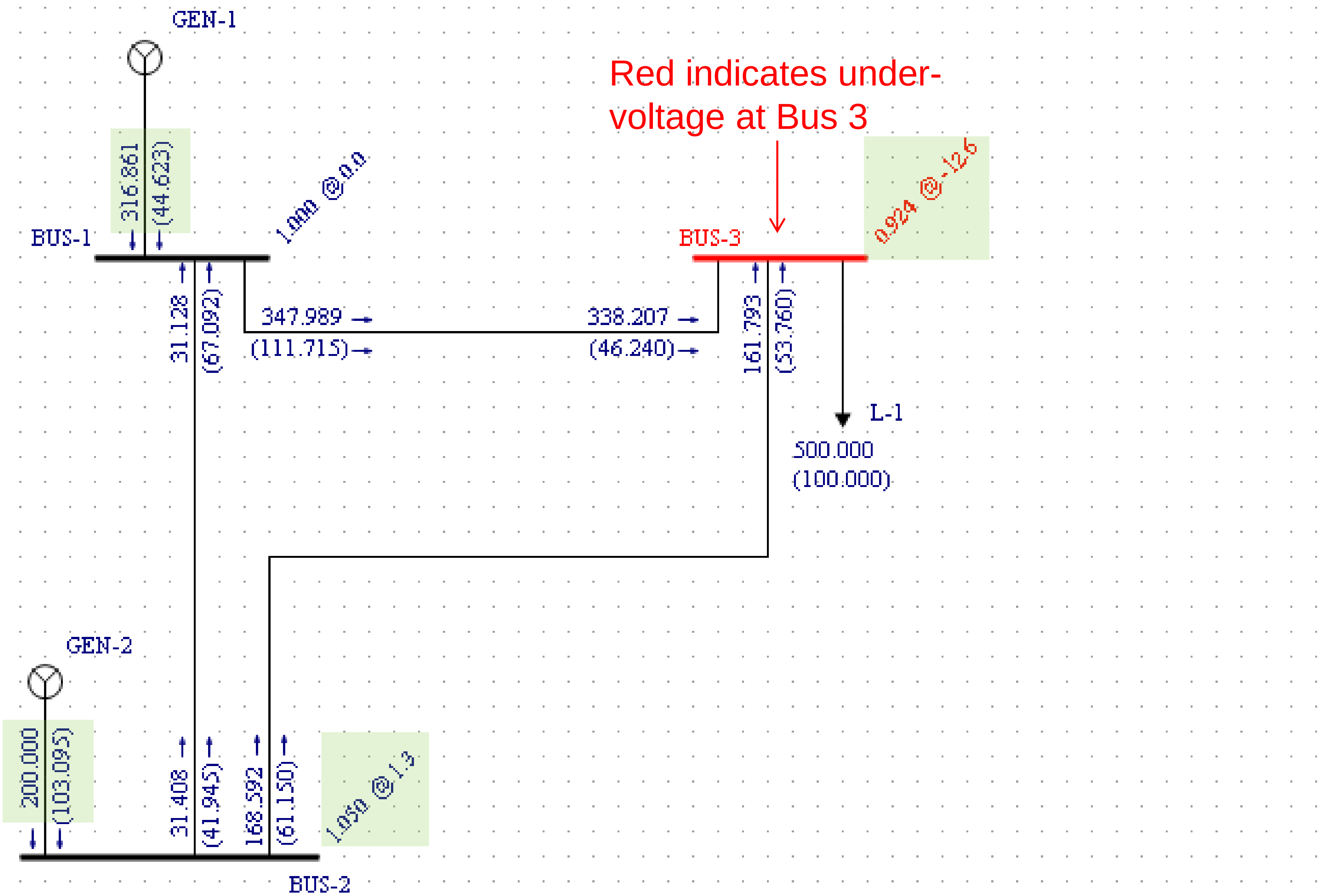
$$Q_i = -\sum_{j=1}^{n} |Y_{ij}||V_j||V_i|\sin(\theta_{ij} + \delta_j - \delta_i)$$

- Voltage constraints

$$0.95 \leq |V_i| \leq 1.05$$

- Electric utilities use commercial software packages to solve the problem.

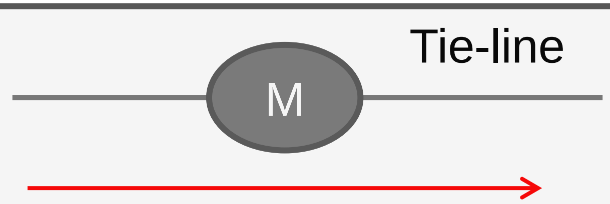
EXAMPLE OF POWER FLOW SOLUTION



INTERCHANGE ERROR

Customer demand and generation are constantly changing within all BA's.
→ BA's will have some unintentional outflow or inflow at any given instant.

- A Balancing Authority's internal obligations is to control an instantaneous value called the **Area Control Error (ACE)** by keeping it within acceptable limit that is proportional to the BA size (44 MW for NV Energy South?). ACE consists of the following:
  - **Interchange Error**, which is the net outflow or inflow compared to what it is scheduled to be imported or exported.
  - **Frequency Bias**, which is the Balancing Authority's obligation to stabilize frequency: For example, if frequency goes low, each BA is asked to contribute a small amount of extra generation in proportion to its size.
- Conceptually, ACE is to a Balancing Authority what frequency is to the Interconnection. For example, over-generation makes ACE go positive and puts upward pressure on Interconnection frequency.



Scheduled net flow: 350 MW
Actual net flow: 340 MW
(due to load reduction)
→ ACE goes positive
Frequency goes up
→ Reduce generation

AREA CONTROL ERROR (ACE)

$$ACE = (NI_A - NI_S) - 10ß\,(F_A - F_S) - I_{ME}$$

NI_A is Actual Net Interchange

NI_S is Scheduled Net Interchange

ß is Balancing Authority Bias

F_A is Actual Frequency

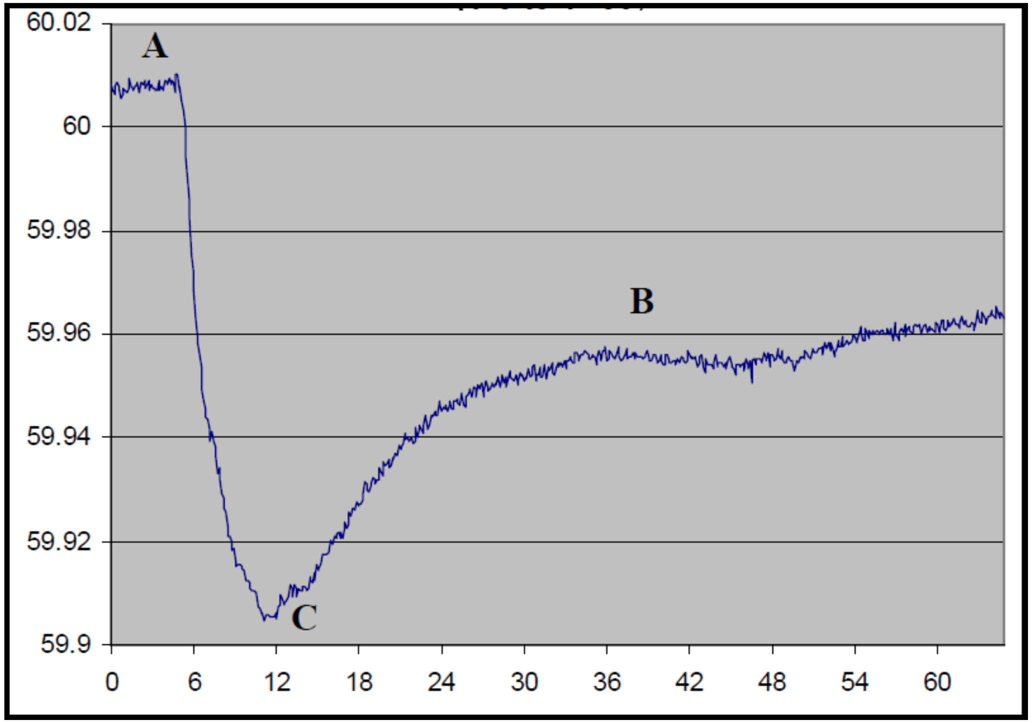
F_S is Scheduled Frequency

I_{ME} is Interchange (tie line) Metering Error

- $(NI_A - NI_S)$ represents the ACE associated with meeting schedules.
- 10ß $(F_A - F_S)$ is the BA's obligation to support frequency. ß is in MW/0.1Hz (ß = -1,480 MW/.1 Hz for WSCC)
- I_{ME} is a correction factor for meter error. Normally this number very small or zero.

INITIAL RESPONSE TO A DISTURBANCE: PRIMARY CONTROL

Primary Control (also known as Frequency Response) occurs within the first few seconds following a disturbance, and it is provided by fast-acting generator governor actions (similar to cruise control on a car). They sense a change in speed and adjust the energy input into the generators' prime mover. Primary control is provided by spinning reserves.



Typical WSCC frequency response due to loss of a generator
(Source: NERC Report on Balancing and Frequency Control, July 5,2009)

FOLLOWING RESPONSES: SECONDARY AND TERTIARY CONTROL

- **Secondary Control** maintains the minute-to-minute balance throughout the day to restore frequency. This is accomplished using the BA's Automatic Generation and Control (AGC) system and manual dispatch actions to maintain balance.
  - NERC Control Performance Standards:
    - CPS1 assigns each Control Area a slice of the responsibility for control of Interconnection frequency. CPS1 is a yearly standard that measures impact on frequency error - based on a specific formula.
    - CPS2 is a monthly standard intended to limit unscheduled flows – also based on a specific formula.
    - NERC does not mandate generation and load to be balanced 100% of the time. Each Balancing Authority shall operate such that its average ACE for at least 90% of its ten-minute periods over a calendar month is within a specific limit (L)

$$AVG_{10\text{-minute}}(ACE_i) < L$$

- **Tertiary Control** involves the generally manual actions taken by operators in response to disturbances. It includes the initial deployment of reserves and the actions taken to expeditiously restore reserves such that the system is able to withstand the next contingency.

POWER SYSTEM OPERATION – REAL TIME

- In real time, the level of generation is adjusted to meet differences between actual loads and the hourly schedules. This real-time adjustment, can be separated into "load following" (within-hour resource dispatching) and "regulation" (sub-minute adjustments of generation) processes according to their respective time scales.
  - **Load following** typically requires adjustments every 5-15 minutes. This is accomplished through a re-dispatch of on-line generation via automatic adjustments by computerized control systems. Load following and regulation require sufficient capacity and ramp rates, upward and downward, to respond to changes in load.
  - **Regulation**, in turn, is effected by making sub-minute output adjustments exclusively through an automatic generation control (AGC) system.
- During real time operation, generators under AGC are adjusted every 2 or 4 seconds (although their actual responses are slower) to keep the ACE close to zero.

POWER SYSTEM OPERATION – REAL TIME

- The hourly day-ahead schedules (based on load forecast) are comprised of hourly energy blocks with 20-minute ramps between hours; the ramping process begins 10 minutes before the end of each hour.
- Hour-ahead adjustments are made to account for forecact errors
- Additional adjustments are conducted over regular intervals (5-15 minutes) to track changes in actual load, i.e., load following.
- Finally, adjustments are made at the sub-minute level to reduce the difference between the actual load and the real-time generation schedule . This must be matched by AGC to maintain system frequency.

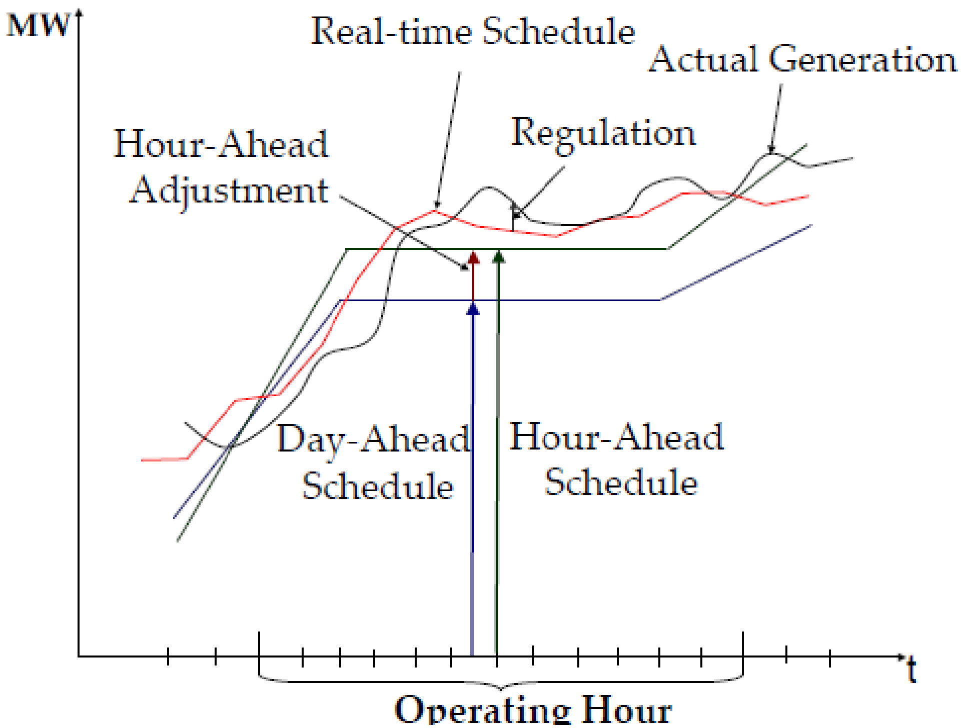
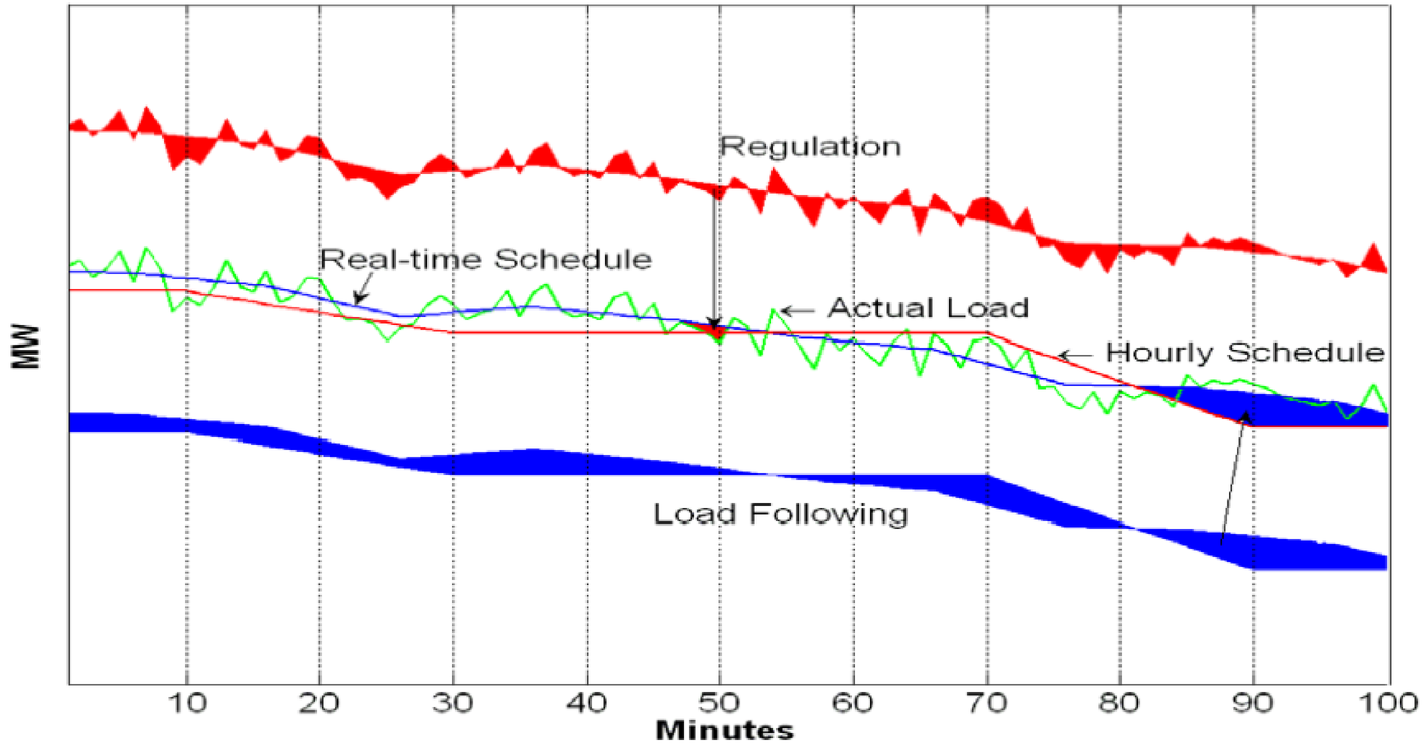


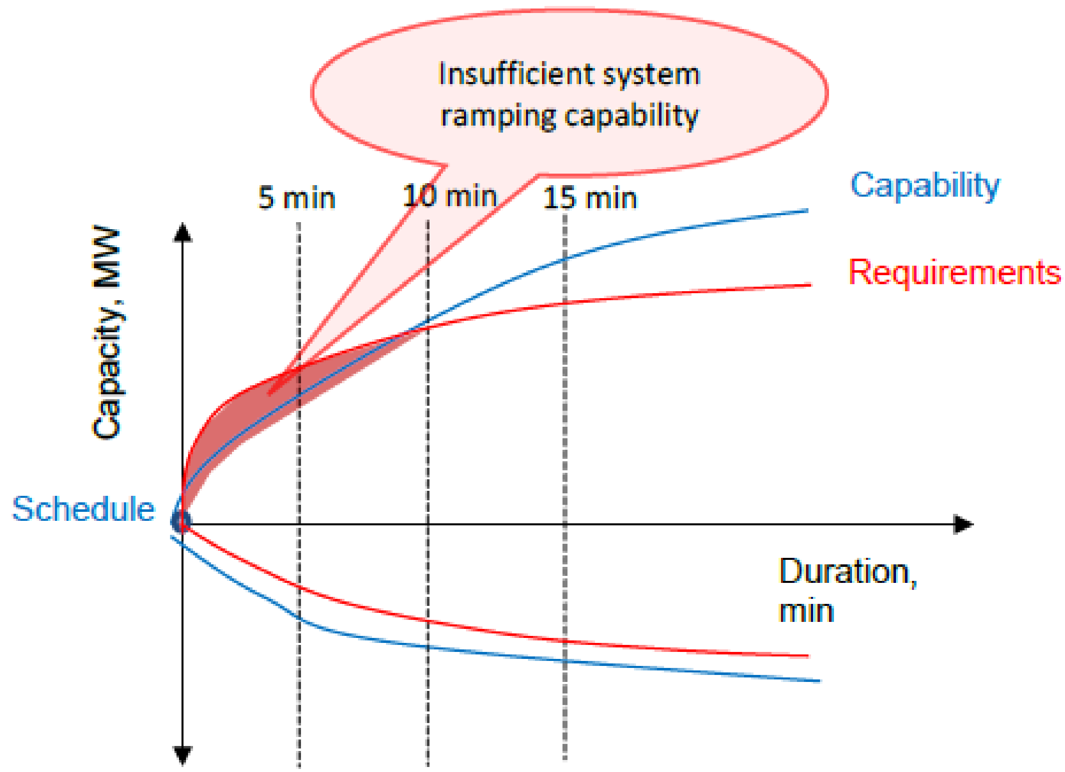
ILLUSTRATION OF REGULATION AND LOAD FOLLOWING

- Load following is the difference between 10-minute interval average and 60-minute average (both with ramps) of load, depicting the variation of load within the hour at a 10-minute time scale.
  - Load Following = [real-time schedule] – [hourly schedule]
  - Regulation = [actual load] – [real-time schedule]
- Note that the regulation ramps (i.e. slopes) are significantly higher than those of load following



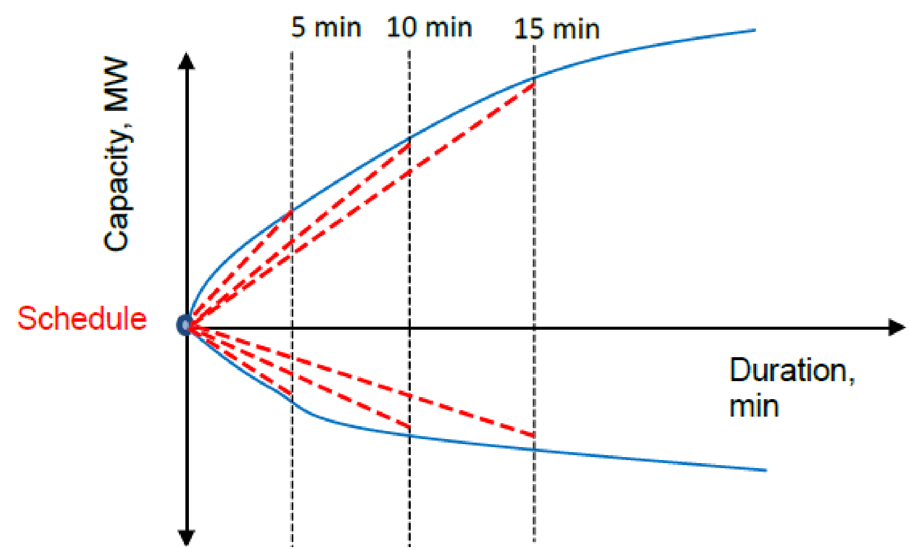
ASSESSING ADEQUACY OF RAMPING CAPABILITY

- Insufficient ramping capability is identified when the ramp requirements exceed generation fleet ramping limits.
- The figure below illustrates how such a deficiency could occur: the area in red highlights the magnitude and duration of the interval when regulation ramp requirements exceed fleet capability.
- More units and capacity are needed if composite unit ramping capability is insufficient,

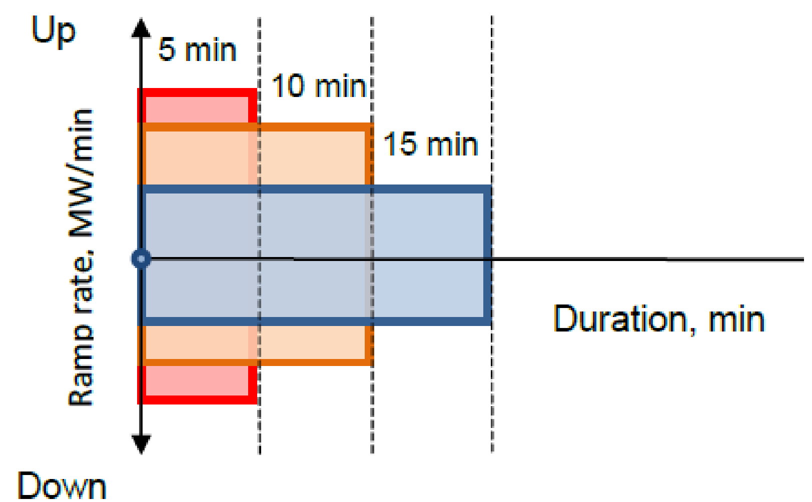


GENERATION FLEET RAMPING CAPABILITY

The individual ramping capability of each unit can be combined to calculate total ramping capability of the entire generation fleet. The top figure illustrates the composite ramping capability of the entire generation fleet.



The maximum available system ramping capability versus duration is derived from the angles of the red dotted line and time axis. The result is illustrated in the bottom figure.

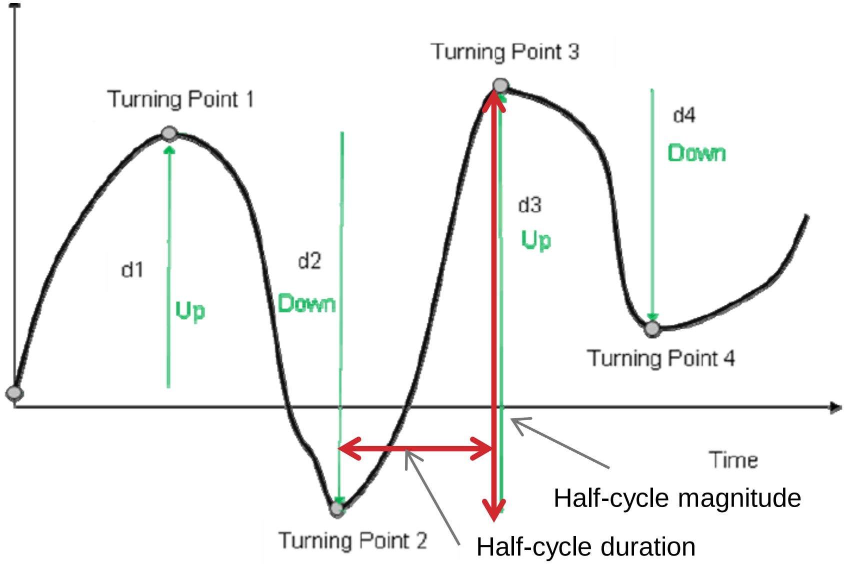


GENERATOR CYCLING AND MOVEMENTS

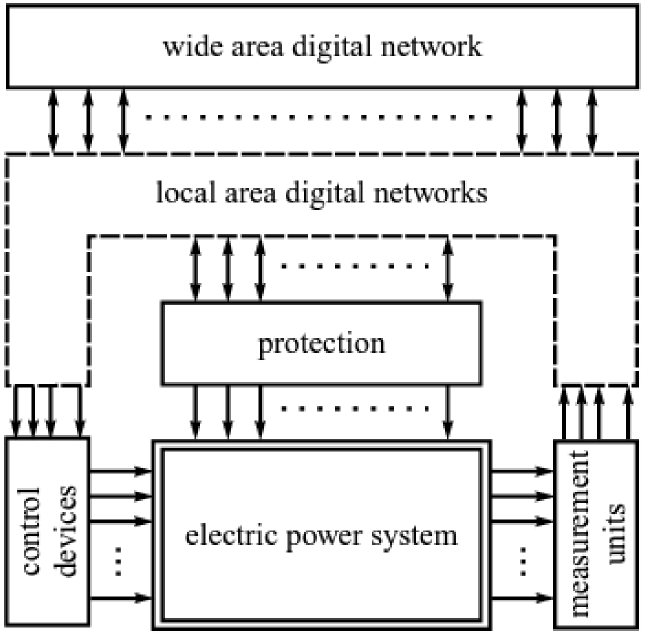
Generators providing load following and regulation services need to move up or down frequently to balance load with generation.

Two effective metrics* that have been proposed to quantitatively evaluate the cycling and movements (i.e., wear and tear) of conventional generators for providing balancing services include

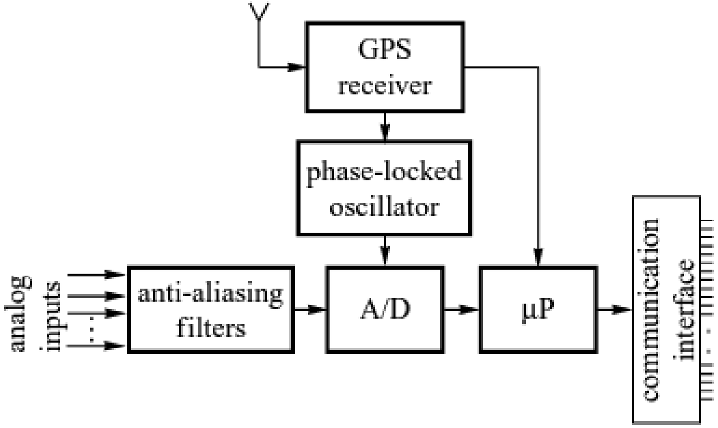
1. Mileage (MW) and number of direction changes in balancing service (load following and regulation);
2. Ramp (or half-cycle) analysis: Half-cycle ramp rate = ratio between half-cycle magnitude and half-cycle duration



SYSTEM MONITORING & CONTROL



Structure of a WAMPAC



Structure of a PMU

The possibility of measuring synchronized voltage and current phasors using GPS/GIS has led to new innovative ways of monitoring, protecting, and controlling power systems.

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