Power System Operations
Hands On Relay School
March 14, 2018
Rich Hydzik
Avista Utilities
What are we trying to do?

• Convert some form of energy into electric energy
• Transmit the energy from the generator to the load
• Deliver to the load as needed
• For an AC system
  – Spin a magnet in a coil of wire
  – Connect the wire to the load
  – Turn something on
AC System is a Rotating Machine

- Large mass
- Lots of inertia
- Frequency response / speed governors
System is Changing

- DC Inverters
- Different operating characteristics
- Distributed Energy Resources
- Still learning
Traditional Utility Model

• Integrated operations
• One owner/operator for
  – Generators
  – Transmission System
  – Distribution Systems
• Control Area Operator
  – Control from generator to retail customer
Traditional Utility Model

Control Areas
Today’s World

- NERC Functional Model – 1999 - 2004
- No single owner operator
- Markets have formed
- Reliability Coordinator established
- Control Area has been broken up into functions
  - Balancing Authority – Load resource balance, frequency control, generation dispatch
  - Transmission Operator – Voltage control, transmission scheduling, transmission switching
  - Generator Operator – Plant operations
  - Market Operators – Mishmash of BA, TOP, GOP functions
Functional Model
Balancing Authority

• The responsible entity that
  – Integrates resource plans ahead of time
  – Maintains load, interchange, generation balance within a Balancing Authority Area
  – Supports Interconnection frequency in real time

• Balancing Authority Area
  – The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority
  – Does not need to be contiguous – Pseudo Ties

• Balancing Authority is analogous to Control Area without control of transmission facilities
BA Operations Pre-Schedule

- Load Forecast
- Generation Schedule
- Net Scheduled Interchange (NSI)
  - Export is positive
  - Import is negative
- Load Forecast = Generation Schedule – NSI
- Contingency Reserves – Generators trip
  - MSSC or 3/3 percent of load/generation
- Operating Reserves – Regulation, forecast error
- This is the PLAN
BA Operations Pre-Schedule

• Net Scheduled Interchange
  – Sum of Scheduled Transactions

• Each transaction is an Electronic Tag / E-tag
  – Source BA
  – Transmission Path
  – Sink BA

• Sum of E-tags (transactions) is NSI
• NSI is verified with counterparties before operating hour
BA Operations Real-Time

• Area Control Error (ACE) – real-time measure of balancing

• ACE = NAI – NSI - 10B(Fa-Fs) – ME + ATEC
  – NAI – Net Actual Interchange
  – NSI – Net Schedule Interchange
  – Frequency Bias -MW/0.1Hz
  – ME – Meter Error
  – ATEC – Automatic Time Error Correction (WECC)

• ACE drives Automatic Generation Control (AGC)
  – Negative ACE, pulse units up
  – Positive ACE, pulse units down
Control Performance Standard 1 – CPS1

<table>
<thead>
<tr>
<th>ACE</th>
<th>Frequency</th>
<th>Good or Bad?</th>
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<tbody>
<tr>
<td>Positive</td>
<td>High</td>
<td>Bad</td>
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<tr>
<td>Positive</td>
<td>Low</td>
<td>Good</td>
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<td>Negative</td>
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- CPS1 is one-month and twelve-month measure
- Are we following the PLAN?
BA ACE Limit - BAAL

- Real-time measure
- Replaces CPS2 limits
BA Operations Real-Time

- Contingencies – Loss of Generation
- NAI decreases, driving ACE negative
- BAL-002 Disturbance Control Standard (DCS)
- ACE must be returned to pre-contingency ACE (or zero if ACE was positive) within 15 minutes
- Contingency reserves are used to recover
- Firm load shedding is not appropriate for DCS recovery
  - Interruptible load can be used as operating reserve
BA Operations Real-Time

Generator Trip and ACE Recovery
BA Operations Real-Time

• Frequency Bias Term in ACE – B MW/0.1Hz
  – Responds to off nominal frequency
  – High frequency raises ACE
  – Low frequency lowers ACE
  – AGC is slow acting – minutes, not seconds

• Governor Response
  – Instantaneous – seconds
  – Arrests frequency decline
  – Stabilizes system until AGC begins acting
BA Operations Real-Time

**FREQUENCY_ACTUAL**

AGC Response

Governor Response
BA Operations After-the-Fact

• Integrated values for the hour (Hour Ending xx)
• NAI – check out with adjacent BA’s
• Generation
• Load = Generation – NAI
• NERC Inadvertent = Inadvertent Interchange (II)
  – NAI – NSI
• Primary Inadvertent Interchange (PII) due to control error
  – $(1-Y) \times (I_{\text{actual}} - B \times \Delta T E/6)$
  – Accumulated PII is paid back over next three hours via ATEC
• Did we follow the PLAN?
Transmission Operator

• The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission Facilities

• Transmission Operator Area
  – The collection of Transmission assets over which the Transmission Operator is responsible for operating
Transmission Operator

- Outage coordination
- Real-time switching
- Voltage control
- Secure operations
- Forced outages and restoration
Reliable Operation

• N – 1 Criterion
• System must be able to suffer any credible contingency
  – No cascading outages
  – Stable – voltage and transient
  – No System Operating Limit (SOL) exceedances (WECC)
• Definition of “credible” contingency is open to some interpretation
  – Transmission Operator defines “credible” contingency
  – Varies depending on time horizon
  – Any single outage – generator, transformer, line – 3P fault
  – Credible multiple (N-2) – double circuit tower, breaker failure
  – LG fault
System Studies

- **Thermal and voltage**
  - Thermal overloading
  - High/low voltage

- **Transient stability**
  - Power system swings
  - Model fault impedance, relay times, breaker times
  - 3P faults for N-1
  - 1LG faults for N-2

- **Voltage stability**
  - Reactive margin
  - Voltage collapse
  - Does reactive switching help or not?
Operating Horizons - Seasonal

- Next peak season – Summer, Winter
- Studies based on worst case conditions
  - Peak loads
  - Peak generation – runoff in Northwest
  - Off peak
- Outage conditions studied to update procedures
  - Major transmission facilities, generators, etc
- Reliable operating points for outage conditions
- Usually conservative – guaranteed safe operating point
- Thermal/voltage, transient stability, voltage stability
Operating Horizons
Weeks, Next-Day, Real-Time

• Weeks Ahead
  – Outage coordination
  – Check thermal/voltage and voltage stability based on procedure limits

• Next-Day
  – Check thermal/voltage and voltage stability based on procedure limits

• Real-Time
  – State Estimation (SE) – Set powerflow model based on actuals
  – Real-Time Contingency Analysis (RTCA)
  – Check thermal/voltage, some voltage stability
N – 1 Criterion

• N-1 Criterion is based on present system
• When outage occurs (N-1), system then must perform for next outage (N-1-1)
• This is difficult – system is designed for N-1
• Rely on SE/RTCA to identify next problem
• N-1-1 does not equal N-2
N-1-1 In Action

- N-0 All facilities in service – All is OK
N-1-1 In Action

- N-1 Loss of 230/115 transformer – All is OK
N-1-1 In Action

• N-1-1 Loss of 115 circuit - All is NOT OK
N-1-1 In Action

• SOL exceedance is NOT acceptable post-contingency
• Pre-contingency mitigation is required
• Available actions
  – Radialize system if possible
    • We do this often to manage outages
  – Load shedding before the contingency occurs
    • This has been done, definitely to be avoided if possible
  – Change generation dispatch
N-1-1 In Action

• System is designed to absorb ONE credible contingency – Planning Scenario
  – N-1 – Category B
    • No post-contingency SOL exceedances allowed
    • Limited mitigating actions
  – N-2 or N-1-1 Category C
    • Post-contingency SOL exceedances allowed with mitigation
    • Load shedding, other actions permissible to mitigate

• System is operated with something always out of service – Operating Scenario
N-1-1 In Action

• Before March 2014 (WECC)
• N-1-1 SOL exceedances were handled with post-contingency action
  – Manual actions
  – Load shedding or loss acceptable
  – No cascading allowed

• N-1-1 Operations After March 2014 (WECC)
  – Same performance requirement as Planning Category B N-1
  – NO SOL exceedances are allowed post-contingency
N-1-1 In Action

- Reveals any weak links in the system
- This changes the system design philosophy
- Requires significant excess capacity or reduced planned outages
- Limits outage windows
  - Construction
  - Maintenance
  - Lots of spring and fall outages
  - Fewer summer outages
  - Fewer winter outages
Variable Generation Resources
Variable Generation Resources
Variable Generation – BA Operations

- 100% known
  - Conventional generation dispatch
  - Net Scheduled Interchange
- 97% known
  - Load – forecasts are very good 24 hours out
- Not quite known
  - Wind generation
  - Forecasts are good, but get worse further out (two hours)
  - Can significantly increase regulating reserve required
Variable Generation – Not always there when it is needed
Variable Generation

BPA Balancing Authority Load 8. Total Wind, Hydro, and Thermal Generation, Last 7 days
11Jan2016 - 18Jan2016 (last updated 17Jan2016 15:12:07)

- Load
- Wind
- Hydro
- Thermal

Based on 5-min readings from the BPA SCADA system for points 45593, 79687, 79682, and 79685
Balancing Authority Load in Red, Wind Gen. in Green, Hydro Gen. in Blue, and Thermal Gen. in Brown
Click chart for installed capacity info
BPA Technical Operations (TOT-OpInfo@bpa.gov)
Variable Generation Growth

WIND GENERATION CAPACITY IN THE BPA BALANCING AUTHORITY AREA

Last update: 12/14/2017. Chart displays sequential changes in wind generation capacity in the BPA BA, based on date when actual generation first exceeded 50% of nameplate. Note that movements of wind generation facilities out of the BPA BA are shown as negative increments to capacity.
Essential Reliability Services

• Concern about changing generation fleet
  • Large coal fired power plants are being retired
  • Renewables and variable generation are increasing
  • Large synchronous generators inherently provide Essential Reliability Services

• Essential Reliability Services – ERSTF formed September 2014
  • Generation Ramping – ability to adjust to meet changing loads
  • Frequency Control
    • Inertia – object in motion tends to stay in motion
    • Primary frequency control – automatic response compensating for the loss of a large generator - fast
    • Secondary frequency control – Automatic generation control (AGC) to 60 Hz - slow
  • Voltage control – maintain within limits

• Reliability Effects
  • How does reliability change with newer resources?
Generation Ramping

- Variable resources are variable
- Generating resources must accommodate load and variable generation
- Load is very predictable hour to hour – 3% or so 24 hours out
- Solar generation has a very predictable pattern
  - Fast ramp up in morning
  - Large down up in evening
- Wind is more variable
  - Continuous changes
Generation Ramping

Actual net-load lower than originally estimated due to increased amount of renewable resources including DER

Typical Spring Day

- 2012 (actual)
- 2013 (actual)
- 2014
- 2015
- 2016
- 2017
- 2018
- 2019
- 2020

- ramp need ~13,000 MW in three hours
- Actual 3-hour ramp 10,892 MW on February 1, 2016

- over generation risk
- Net Load 11,663 MW on May 15, 2016

CAISO load profile – NERC DER Workshop Presentation 8/3/2016
Generation Ramping

- 9/25/2016 CAISO Renewable Generation
- Evening solar ramp out must be made up by other generation
- 10,000 MW over three hours
- CAISO has 5,000 MW of distribution connected (DER) solar that is not counted in this
- BA Load = Generation – Interchange
  - DER is not counted in generation
  - DER decreases BA load
Primary Frequency Control

- Responds in seconds to change in frequency (speed control)
  - Steam turbines response quickest
  - Gas turbines are almost as fast
  - Hydro is slower
- Governor responding according to droop characteristic (3-5%)
- Automatic response
- Each generator increases output a little – adds up fast
- If not enough generators respond
  - Torque out exceeds torque in
  - System slows down and stops
Primary Frequency Control

01/21/2016 01:08:56 Colstrip 3 and 4 – 1500 MW
Primary Frequency Response

- Inertia – object in motion tends to stay in motion – 3600 rpm
- Inertia determines Rate of Change of Frequency (ROCOF)
- More inertia, slower frequency decline
  - More time for governors to respond
- Less inertia, faster frequency decline
  - Less time for governors to respond
- How much is enough?
  - WECC and Eastern Interconnection – don’t know
  - ERCOT – They know and plan and operate to it
- Renewables have little or no inertia
- Renewables can have fast frequency response (synthetic inertia)
  - FFR can mitigate effects of low inertia and high ROCOF
Secondary Frequency Control

- **Automatic Generation Control (AGC)**
  - Slow acting – follows Area Control Error (ACE)
  - ACE measures schedule error and frequency error

- **Contingency Reserve**
  - Deployed following loss of a generator within ten minutes
  - 50% must be spinning – This may change very soon

- **Load Following Reserve**
  - Generation brought online to meet load variations within the hour

- **Regulating Reserve**
  - Generation controlled by AGC automatically responding to ACE changes
  - Avista generally carries +/- 25 MW going into each hour
Voltage Control

• Synchronous machines provide the voltage source
  ▪ Adjust voltage in real-time - regulators

• Capacitors and inductors store and release energy each cycle
  ▪ Capacitors release energy when inductors store energy and vice versa
  ▪ AC systems take advantage of this
    o Power factor correction
    o Series compensation

• Most inverters are current sources clocking off of system voltage
  ▪ Not an independent voltage source
  ▪ Inverters can supply and consume vars
  ▪ Type 3 and 4 Wind Turbines can supply vars

• Voltage pushes and pulls current (AC)
Voltage Control

• Voltage must be maintained near ratings under all conditions
  ▪ Generally 95% to 105% of nameplate rating
  ▪ Equipment guarantee to operate correctly, does not apply when voltage limit is exceeded

• Heavy load
  ▪ Tends to depress voltage
  ▪ Capacitors are used to compensate – produce vars

• Light load
  ▪ Voltage tends to rise
  ▪ Reactors are used to compensate – consume vars

• Contingencies
  ▪ 95% to 105% limit post-contingency
Distributed Energy Resources (DER)

DER on distribution system – From NERC DER Report 2017
Distributed Energy Resources (DER)

- DER penetration is growing in the west - California
- DER generation is approaching 6000 MW each day (2017)
  - This is equivalent to six nuclear or large coal plants
- How does this affect operation of the Bulk Power System?
  - This is connected directly to distribution load – houses, businesses, etc
  - Offsets BA load – utility generates less due to less system load
  - Changes load patterns
    - Much less load during mid-day
    - Large changes at sunrise and sunset – ramping issue startup and shutdown
- Is there a reliability issue to the bulk power system?
  - Voltage and frequency ride through is a concern
  - We don’t know but we need to know
Questions?