TRANSMISSION OPERATIONS
WORKSHOP

for
Afghanistan, Tajikistan, Turkmenistan and Uzbekistan

ISTANBUL, TURKEY

July 22–25
2008

USAID FROM THE AMERICAN PEOPLE
USEA United States Energy Association
BONNEVILLE POWER ADMINISTRATION
SMUD SACRAMENTO MUNICIPAL UTILITY DISTRICT The Power To Do More.®

TRANSMISSION OPERATIONS WORKSHOP

FOR

AFGHANISTAN, TAJIKISTAN,

TURKMENISTAN AND UZBEKISTAN

ISTANBUL, TURKEY
July 22-25, 2008

Managed by
UNITED STATES ENERGY ASSOCIATION (USEA)

Funded by
THE U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT (USAID)

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TRANSMISSION OPERATIONS WORKSHOP FOR
AFGHANISTAN, TAJIKISTAN,TURKMENISTAN AND UZBEKISTAN

Section 1
Workshop Agenda

AGENDA

FOR THE

TRANSMISSION OPERATIONS WORKSHOP

FOR

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Purpose: To provide a forum for the for US and ATTU system operators to identify, review, evaluate and discuss transmission and dispatch system operation standards, practices, equipment, communications and training programs.

Participants:

Afghanistan

His Excellency, Dr. M.J. Shams; Minister of Economy; Chairman of the Inter-Ministerial Commission for Energy (ICE); Chairman of the DABS Board of Directors, and Chief Executive Officer (CEO) of Da Afghanistan Breshna Shirkat (DABS), jpsjams@bluewin.ch

Engineer Nahida Akbari, Manger of Power Plant, Da Afghanistan Breshna Moassessa
Engineer Najmia Amini, Da Afghanistan Breshna Moassessa
Engineer Habibulah Hamdard, K.E.D.
Attaulhaq Shams, Conference Interpreter, mirwais_atta@yahoo.com
Abdul Rasool, USAID/Afghanistan, rwardak@usaid.gov

Tajikistan

Farrukh Jumaev, Deputy Head of Department of International Economic Relations, Barki Tojik, Jumaevbarkitojik@bk.ru
Sergey Tkachenko, Deputy Head of Central Dispatch Service, Barki Tojik, Sirojidin@mail.ru

Turkmenistan

Erkin Astanov, Chief of Relay Protection and Automation Service, Turkmenenergo
Kerimkuli Nuryagdyev, Director of the Abadan State Power Station, Turkmenenergo

Uzbekistan

Umar Karimov, CDC "Energy", Karimov@udc.uz
Bakhtiyor Mukhiddinov, National Dispatch Center
Abasskhon Nimatullayev, Chief of Operation Network Department, Uzbekenergo, sjsc@uzpak.uz

United States

Peggy Olds, Manger, Technical Operations, Bonneville Power Administration (BPA), paolds@bpa.gov
Keith Hartley, Principal Operations Engineer, Sacramento Municipal Utility District (SMUD), Khartle@smud.org
Sharon Hsu. Energy Team, Office of Infrastructure and Engineering, USAID/EGAT, shsu@usaid.gov
Nadja Ruzica, Afghan Desk Officer, USAID/Washington, nruzica@usaid.gov

USEA Coordination:

John Hammond, Program Manager, JHammond@usea.org
Jason Hancock, Senior Program Coordinator, JHancock@usea.org

United States Energy Association
1300 Pennsylvania Avenue, NW
Suite 550, Mailbox 142
Washington, DC 20004
Phone: 202-312-1230, Fax: 202-682-1682

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Tiyatro Cd No:25 Beyazit 34126 Istanbul - Turkey
Telephone: (+90 212) 516 69 80
Fax: (+90 212) 516 69 98
e-mail: info@thepresidenthotel.com

MONDAY, JULY 21st

19.00 USEA hosted Welcome Dinner (*Hotel Restaurant)*

TUESDAY, JULY 22nd

9.00-9.30 OVERVIEW OF WORKSHOP- *JOHN HAMMOND, PROGRAM MANAGER, USEA*

9.30-11.30 PRESENTATIONS ON TRANSMISSION SYSTEMS IN AFGHANISTAN, TAJIKISTAN, TURKMENISTAN, UZBEKISTAN AND TURKEY - PRESENTATIONS BY PARTICIPATING AND DISCUSSION

- Afghanistan
- Tajikistan
- Turkmenistan
- Uzbekistan
- Turkey

11.30-11.45 OVERVIEW OF BONNEVILLE POWER ADMINISTRATION

- Overview of US system
- Overview of WECC
- BPA system overview
  - Geographic location of BPA within US
  - General Description
  - Unique issues
    - Wind and Water

11.45-12.00 OVERVIEW OF SACRAMENTO MUNICIPAL UTILITY DISTRICT

- Location (in US and in respect to BPA)
- Area – Description of Sacramento valley
- Size – Distribution and Control Area
- Control Area development and changes (History)
- Load description – Variations from Winter to Summer;
- Monitor and Control of various voltage levels
- Unique Features – Geography of the Distribution System and Hydro Plants
- Energy Sources – Thermal, Hydro, Wind, and Photovoltaic

12.00-13.00 LUNCH

13.00-15.00 **POWER SYSTEM OPERATING DESCRIPTIONS**

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS
SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- System Description
  - Unique Features of System
  - Seasonal Issues
  - Topography
- Operational Description
- Maintenance/Repair Description
- Outage Planning
  - Planned vs. Unplanned
  - California ISO outage coordination
  - NW Power Pool 45 Day Outage Coordination process

15.00-15.20 **Tea break**

15.20-17.00 **OPERATIONAL PLANNING**

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- Planning Process
- Study Process
- RAS Schemes
- Emergency Operations
  - Load and generation imbalance
  - Restoration Practices
  - Emergency Standards

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Planning Process
- Study Process
- RAS Schemes
- Business Side
- Emergency Operations
  - Load and generation are out of balance
  - Restoration Practices
  - Emergency Standards

19:00 USEA hosted dinner (*location to be determined*)

WEDNESDAY, JULY 23

9.00-10.30 **OPERATING REQUIREMENTS**

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- Organizational structure
- Operations and Controls
- Training and Tools

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Organizational structure
- Operations and Controls
- Training and Tools

10.30-10.50 **Tea break**

10.50-12.30 **Inter-connected Operations and Organizational Requirements**

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- Reliability: Standards-FERC,NERC requirements
- Treaty Obligations and other legal issues
- Economic operations: TX rates, marketing, agreements, contracts
- Coordination Issues with other utilities

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Environmental
- Coordination Issues
- Congestion

12.30-13.30 **Lunch**

13.30-15.30 INTER –AREA COORDINATION

General Coordination

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- Types
- Legal issues
- US organizations that manage Inter-regional coordination
- Benefits/Issues

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Managing information exchanges
- Planning
- Interchanges and inter-ties
- Benefits/Issues

15.30-15.50 Tea break

15.50-17.00 INTER –AREA COORDINATION

Specific Applications and Methods

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- WECC example
- NWPP 45 Day Outage coordination process
- Treaty Issues and "One utility Operation" approach
- Hourly Coordination-FCRPS

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Technological solutions
- Financial issues

THURSDAY, JULY 24

9.00-10.30 SYSTEM OPERATION EXAMPLES

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS:

- Wind generation integration issues

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER:

- Normal outage incident

10.30-10.50 Tea break

10.50-12.0 SYSTEM OPERATION EXAMPLES (continued)

SMUD SYSTEM, KEITH HARTLEY, PRINCIPAL SYSTEMS ENGINEER

- Fire Control Issues

BPA SYSTEM, PEGGY OLDS, MANAGER, TECHNICAL OPERATIONS

- Vegetation Management/ 1996 outage

12.00-13.30 Lunch

13.30-15.30 Open for Participant Question and Answer

15.30-15.50 Tea break

15.50-17.00 ROUND TABLE DISCUSSION

- Wrap-up Discussion
- Discussion of Future Activities

19:00 USEA hosted Farewell Dinner

FRIDAY, JULY 25

All Day SITE VISITS (locations to be determined)

Section 2
Biographical Data

Peggy A. Olds

Manager, Technical Operations,
Transmission Services
Bonneville Power Administration (BPA)
PO Box 491 TOT/Ditt-2 *(360)418-2856*
Vancouver, WA 98663 *paolds@bpa.gov*

Professional Profile

2003-Present	Manager, Technical Operations, Dittmer Control Center, Bonneville Power Admin.
2000-2003	Project Lead, RTO West, Multi-Utility Regional Transmission Organization, BPA
1996-2000	Team Lead, California Integration Team, Transmission Business Line, BPA
1992-1996	Policy Analyst (various division, Power and Generation Management Business Lines
1981-1992	District Conservationist, Manager, US Dept. of Agriculture, Soil Conservation Service
1976-1981	U.S. Department of Agriculture, Soil Conservation Service
1975	U.S. Department of Agriculture, Forest Service

Accomplishments

1987	Graduate Business Scholar, Portland State University, Portland OR
1990	Federal Employee of the year, Federal Executive Board, Portland OR
1995	Special Act Award, BPA MSS Re-engineering Team
1999	Corporate Acknowledgement, Norwegian Trade Council/Norwegian Utilities Association
Various	BPA Quality Step Increases, Special Act, Success Share, Gain Share, Performance Awards

Educational/Professional Training

1976 University of Nebraska-Omaha, Bachelors of Science, BS with honors

1987 Portland State University, Masters in Business Administration, MBA, with honors

Keith A. Hartley, P.E.
11548 Forty Niner Circle
Gold River, CA 95670
(916) 732-6582 (day)
(916) 861-0811 (evening)

OBJECTIVE: A position supporting generation or power system operations providing technical assistance and coordination as required through implementation of applications and engineering functions.

CAREER SUMMARY: Twenty seven of years experience with generation construction, generation design engineering, and utility operations; project management required for operation; design modifications for improvements in safety, reliability, and efficient operation of generation facilities and the electric system; and providing technical direction and guidance to project personnel. Ability to provide a unique interface, in a competitive environment, between the complex requirements of daily electric system operations and generation operations.

EXPERIENCE:

Sacramento Municipal Utility District

January 2001 - Present

Principal Electrical Engineer

Worked in the Operations Engineering area in support of the Operations control room. Principal activities include assisting and providing required or desired changes to the EMS; on-call requirements; AGC support; and disturbance and operational support. I was involved in the formation of the SMUD Control Area and two Control Area expansions.

California Independent System Operator (CAISO)

December 1998 – January 2001

Manager – Operational Applications, Operations Systems Department

Under the general direction of the Director of Operations Systems, coordinate the development of new or existing applications or systems to provide enhancements, benefits, or new functionality to the end users of Grid Operations and Operations Engineering as well as Operations Systems support personnel.

Responsibilities include:

- Provide direction to Operational Applications staff by coordinating assignments, providing technical guidance, and resolving problem situations that lead to the successful completion of projects and tasks.
- Establish goals used for financial strategies in the development of O&M and capital budget details for the Operational Applications section.
- Communicate with other business units to maintain an understanding of processes in support of changes to interconnected systems.
- Understand corporate decisions to provide direction in support of the development of emerging business strategies.
- Provide specifications for RFIs, RFPs (e.g., EMS Replacement), or bid proposals to implement changes to development, test and production environments.

October 1997 – December 1998

Senior EMS/SCADA Engineer

Worked and provided direction in a four-member team responsible for the startup activities of the CAISO on the Energy Management System. Activities included:

- Database implementation;
- System and application checkout (AGC, Resource Scheduler, Interchange Scheduler, ICCP, Data Acquisition)
- System and database builds;
- Functional checkout and implementation of the Backup EMS;
- Assisting vendor in troubleshooting network problems;
- Writing Operational and EMS contingency procedures;
- Preparation of area budget

Sacramento Municipal Utility District
October 1982 – October 1997
Principal Electrical Engineer

Energy Operations Department - Operations Management System (OMS) (From November 1988)
Primary responsibilities include:
- Provide guidance as required to operations dispatchers to resolve system problems and technical issues.
- Building and modifying the Energy Management System (EMS) SCADA databases and operator interfaces to facilitate field changes and correction of problems.
- Coordinate with field crews and dispatchers for generation and substation modification checkout.
- Diagnose field equipment, RTU, and system operational problems;
- Provide lead technical guidance to electrical engineering positions and hardware technician staff.
- Provide engineering support to energy control dispatch staff for effective use of generation facilities.
- Provide project management and technical support for the migration of the EMS and the energy scheduling and accounting applications.
- Develop and maintain the real time sequence (state estimator, external estimator, security analysis, and load flows).

Other responsibilities include support for the power system supplying the EMS by analyzing and correcting problems, producing design documentation for system modifications, and assuring proper maintenance for critical support equipment.

Engineering Department - Generation Engineering (November 1984 to November 1988)
Activities involved:
- Making changes and adding new features to electrical systems at existing generating facilities.
- Analysis of plant controls to provide improvements in operation and efficiency.
- Providing required changes to drawings for plant modifications.
- Writing test procedures.
- Procuring materials and equipment.
- Coordinating installations.

Also provided bid specifications and technical proposals as well as evaluated bids and vendor submittals. Provided field direction and coordinated craft personnel and technicians during construction and startup, in order to meet operational deadlines.

Nuclear Engineering Department - Electrical Design (prior to November 1984)
Project management and electrical design for modifications to the Rancho Seco Nuclear Generating Station to improve performance, reliability, safety, and to ensure that designs met the latest NRC standards.

BECHTEL POWER CORPORATION
January 1980 - October 1981
Field Engineer
Palo Verde Nuclear Generating Station

Duties included interpretation of drawings, material take-offs, initiating requisitions, and inspecting installations. Developed as-built drawings and field designs. Documented and corrected any deviations occurring between field drawings and actual installations.

EDUCATION:
B.S. Electrical Engineering (specialization in Power Systems) – December 1979.
New Mexico State University
Las Cruces, New Mexico

Section 3
Definitions

Definitions

Area Control Error (ACE): The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC): A stand-alone subsystem that regulates the power output of electric generators within a prescribed area in response to changes in system frequency, tie-line loading, and the relation of these to each other. This maintains the scheduled system frequency and established interchange with other areas within predetermined limits.

Balancing Authority: Same as Control Area; new naming convention based on entity function.

Control Area: The entity responsible for balancing load and generation in real time in its Balancing Authority area. A Balancing Authority area is an electric system bounded by interconnection metering and telemetry, which measure the current, voltage, power flow, and status of transmission equipment.

Distributed Control System (DCS): A computer-based control system where several sections within the plants have their own processors, linked together to provide both information dissemination and manufacturing coordination.

Energy Management System (EMS): A computer control system used by electric utility dispatchers to monitor the real-time performance of various elements of an electric system and to control generation and transmission facilities.

Inter-Control Center Communications Protocol (ICCP): An international standard for real-time data communication between the EMS control centers, utilities, power pools, regional control centers, and non-utility generators. ICCP defines a set of objects and services for data exchanging.

Independent System Operator (ISO): An entity approved by the Commission -

(a) to exercise operational or functional control of facilities used for the transmission of electric energy in interstate commerce;
(b) and, to ensure nondiscriminatory access to the facilities.

North American Electric Reliability Council (NERC): A not-for-profit company formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of nine Regional Reliability Councils and one Affiliate, whose members account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja-California-Norte-Mexico. The members of these regional councils are from all segments of the electricity supply industry: investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers. The NERC Regions are: East Central Area Reliability Coordination Agreement (ECAR); Electric Reliability Council of Texas (ERCOT); Mid-Atlantic Area Council (MAAC); Mid-America Interconnected Network (MAIN); Mid-Continent Area Power Pool (MAPP); Northeast Power Coordinating Council (NPCC); Southeastern Electric Reliability Council (SERC); Southwest Power Pool (SPP); Western Systems Coordinating Council (WSCC); and Alaskan Systems Coordination Council (ASCC, Affiliate). NERC has developed the Version 0 reliability standards. NERC System Data Exchange (NERC SDX): Provides a central repository of all scheduled and on-going branch, generator, and transformer outages throughout the Eastern Interconnection. This data is made available to NERC-approved users, who have agreed to the terms of the NERC Data Confidentiality Agreement.

<u>Remote Telemetry Unit (RTU):</u> A device that collects data at a remote location and transmits it to a central station. RTUs are commonly used in SCADA systems.

<u>Supervisory Control and Data Acquisition (SCADA):</u> A computer system for gathering and analyzing real time data. SCADA systems are used to monitor and control a plant or equipment.

<u>Security Analysis:</u> Use of computer software to analyze system contingencies to ensure that power can be delivered from generation to load within the operating limits of transmission equipment and without loss of continuity of supply or widespread failure for the most likely contingencies.

<u>State Estimator:</u> Computer software package that takes redundant measurements of quantities related to system state as input and provides an estimate of the system state. It is used to confirm that the monitored electric power system is operating in a secure state by simulating the system both at the present time and one step ahead, for a particular network topology and loading condition. With the use of a state estimator and its associated contingency analysis software, system operators can review each critical contingency to determine whether each possible future state is within reliability limits.

<u>Supervisory Control and Data Acquisition (SCADA):</u> A system of remote control and telemetry used to monitor and control the electric system. SCADA is also used in other industries, including chemical plants and water treatment facilities.

<u>WECC</u>: Western Systems Coordinating Council (WSCC) was formed with the signing of the WSCC Agreement on August 14, 1967 by 40 electric power systems. Those "charter members" represented the electric power systems engaged in bulk power generation and/or transmission serving all or part of the 14 Western States and British Columbia, Canada.

The Western Electricity Coordinating Council (WECC) was formed on April 18, 2002, by the merger of WSCC, Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA). The formation of WECC was accomplished over a four-year period through the cooperative efforts of WSCC, SWRTA, WRTA, and other regional organizations in the West. WECC's interconnection-wide focus is intended to complement current efforts to form Regional Transmission Organizations (RTO) in various parts of the West.

WECC continues to be responsible for coordinating and promoting electric system reliability as had been done by WSCC since its formation. In addition to promoting a reliable electric power system in the Western Interconnection, WECC will support efficient competitive power markets, assure open and non-discriminatory transmission access among members, provide a forum for resolving transmission access disputes, and provide an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the eight regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources. WECC and the nine other regional reliability councils were formed due to national concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization.

Due to the vastness and diverse characteristics of the region, WECC's members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable and affordable electric service to more than 71 million people in WECC's service territory.

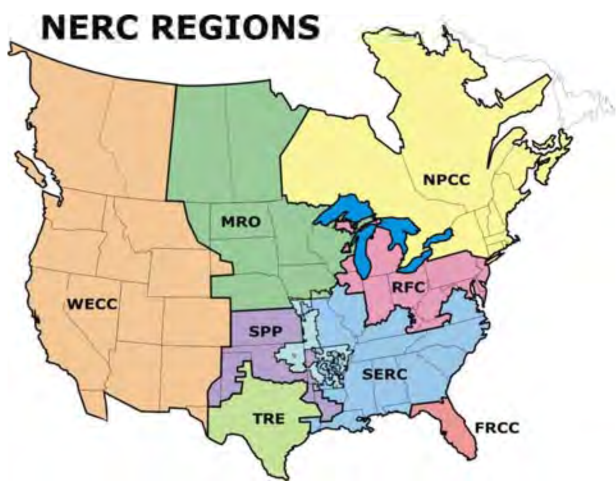
Section 4

OVERVIEW OF U.S. ELECTRICAL SYSTEMS & BPA

A General Description of the U.S. Systems
and the
Bonneville Power Administration (BPA)
Transmission System

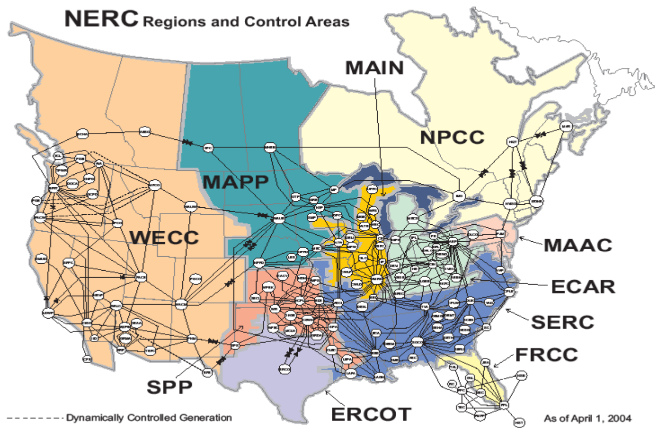
1

North American Electric Reliability Council (NERC)



2

NERC -- Interconnections



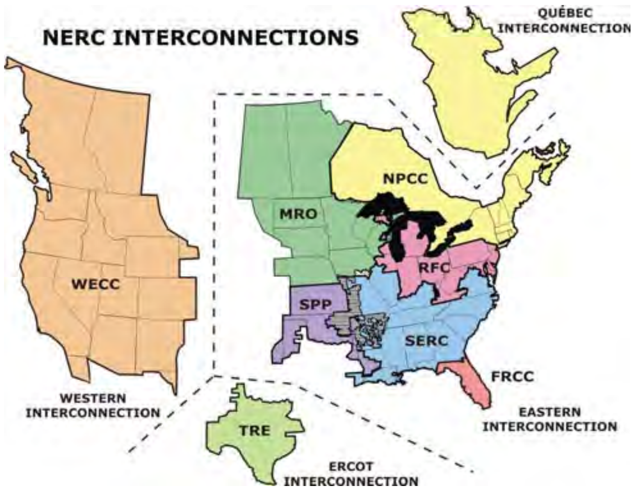
3

NERC Statistics
Electrical Bulk Power System

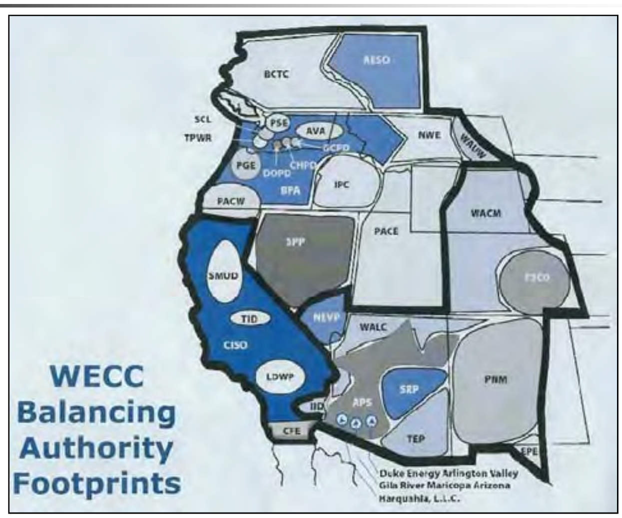
- Total People Served: 334 Million
- Total Demand: 830 Giga-Watts
- Over 530,000 Km of Transmission lines over 230 KV
- Total Km (Miles)
  - 230 KV AC 270,000 Km (170,000 Miles)
  - 345 KV AC 130,000 Km (80,000 Miles)
  - 500 KV AC 90,000 Km (55,000 Miles)
  - 765 KV AC 30,000 Km (17,000 Miles)
  - Direct Current (DC) 14,000 Km (9,000 Miles)

4

Actual System Interconnections



Western Electricity Coordinating Council (WECC) and Members



WECC Statistics: Member Transmission Systems

- Total Transmission Length, for 115 KV and above: 118,000 miles or 190,000 km
- Total Annual Energy Demand: 831,570 Giga-Watt-Hours.
- Winter Peak: 128,934 Mega-Watts.
- Summer Peak: 149,147 Mega-Watts.

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WECC: Topology and Size

- Covers 3 Nations
- Crosses Mountains, Deserts, and Forests.
- Two Time zones.
- Largest Region in US

8

Bonneville Power Administration

WHAT IS BPA?

- **Self-financed, federal power marketing agency within the Department of Energy (DOE)**
- **Markets power at cost from 31 federal dams and 1 nuclear plant –**
- **Markets transmission services – owns 75% (15,440 miles) of the high-voltage lines in Pacific Northwest**
- **Protects, mitigates & enhances fish & wildlife.**
- **300,000 square mile service area**
- **$3.3 billion in annual revenues**

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BPA General Information

BPA established	1937
Pacific Northwest population	11,950,509
Transmission line Circuit miles)	15,442
BPA-owned substations	237
Employees (staff years)	2,923
Supplies 35% of power in Northwest	

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BPA Organization

- BPA is organized into three business units:
  - **Power Business Services**: Approximately 250 employees. BPA markets the power generated at 31 Federal dams, one non-Federal nuclear plant at Hanford, Washington, and some non-Federal power plants, such as wind projects.
  - **Transmission Business Services:** Approximately 1,600 employees. BPA owns and operates 75 percent of the Pacific Northwest's high-voltage electric grid. The grid includes more that 15,000 circuit-miles of transmission line and 235 substations. It carries a peak load of about 30,000 megawatts of electricity and produces about $700 million a year in transmission revenues.
  - **Corporate:** Approximately 1,100 employees. Includes Finance; Environment, Fish and Wildlife; Energy Efficiency; Customer Support Services; General Counsel; Planning and Governance; and Risk Management.

BPA: 1930s

- The Bonneville Project Act, signed into law, August 1937
- BPA's first Power rate was approximately 2 mills per kilowatt-hour (stayed this way for 27 years.)
- In 1938, BPA energized its first transmission line, a single direct current line from Bonneville Dam to Cascade Locks, 3.5 miles away.
- In 1938, BPA energized the 238-mile Bonneville-Grand Coulee line, setting the stage for a high-voltage transmission grid that would grow to encompass over 15,000 circuit miles and over 8500 corridor miles.

BPA: 1940s

- BPA rose to new challenges during the war years of 1941 to 1945, delivering more electricity than all of the other power systems in the region combined in the preceding 50 years.
- By 1945, BPA's high voltage transmission system was the second largest power grid in the nation. The load shift to support war efforts required many changes in the construction of lines radiating from the main grid.

In 1942, crews strung the Grand Coulee-Covington line from eastern Washington to Puget Sound.

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BPA: 1950s

- BPA developed the nation's first microwave system for communicating signals to the relays to trigger equipment protection devices.
- BPA engineers also succeeded in developing a program for calculating power flows with digital computers, which proved to be faster, more accurate and more flexible than previous analog approaches. Many BPA inventions and developments went on to become standards for the rest of the industry

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BPA: 1960s

- An era of interconnection with other regions began thanks to a historic treaty with Canada and development of the interties that connect the Northwest with the Southwest regions of the United States.
- These interties, the largest transmission projects ever undertaken in the United States at the time, were hailed as engineering marvels.
- They took advantage of the fact that the Northwest and Southwest traditionally had different peaking times, winter and summer respectively, which allowed for the exchange of power and minimized each region’s need to build resources

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BPA: 1970s

- With a burgeoning Northwest population, it was clear that hydropower alone could not meet future needs. This led to the Hydro-Thermal Power Program and the construction of nuclear power plants, intended to augment federal hydropower with nonfederal thermal power.
- Concerns about an energy shortage and other issues set the stage for development of the Northwest Power Act.
- It was also the decade when BPA began real-time control with digital computer support for day-to-day system operations replacing the analog-supported manual system, thus enhancing operational decisions.
- In 1974, BPA became a self-financing agency through the Columbia River Transmission Act.

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BPA: 1980s and 1990s

- The 1980's passage of the Northwest Power Act brought new responsibilities to BPA, particularly in the areas of energy conservation and fish and wildlife protection.
- In this decade, BPA became a national leader in energy efficiency and changed the image of conservation from curtailment to one of preserving all the amenities by using energy more efficiently.
- In the 1990's wholesale deregulation came to the electrical energy industry through the Energy Policy Act and FERC mandates.
- For the first time BPA faced competition as new independent energy marketers attracted BPA customers with lower prices. BPA responded with its Competitiveness Project. The project's themes were "market driven, customer focused, cost conscious and results oriented."

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Questions ?

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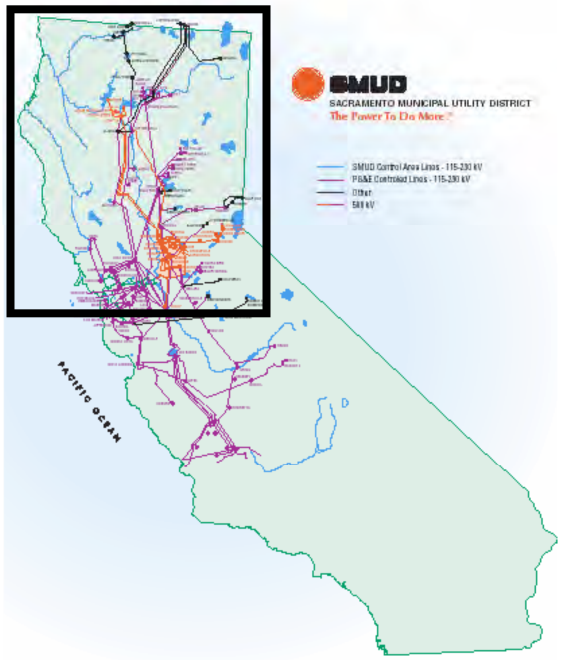
List of Terms

- AGC = Automatic generator Control
- aMWh = Average Mega Watt Hour
- BA = Balancing Authority
- BPA = Bonneville Power Administration
- EMS = Energy Management System
- FERC = Federal Energy Regulatory Commission
- FY = Fiscal Year
- GWh = Giga Watt Hour
- NERC = North American Electric Reliability Council
- NWPP = Northwest Power Pool
- OTC = Operational Transfer Capacity
- PNW = Pacific Northwest
- PP = Power Pool
- RAS = Remedial Action Scheme
- RTO =Regional Transmission Organization
- SCADA= Supervisory Control And Data Acquisition
- WECC = Western Electric Coordinating Council
- 24/7 = 24 Hours a day 7 days a week.

Overview of Sacramento Municipal Utility District (SMUD)

Location of SMUD

- In north-central California on the west coast of the US
- Entirely within a valley between 2 mountain ranges
- Hot and dry in the summer – no rainfall
- Cool and wet in the winter – rain in the valley, snow in the mountains



Northern California

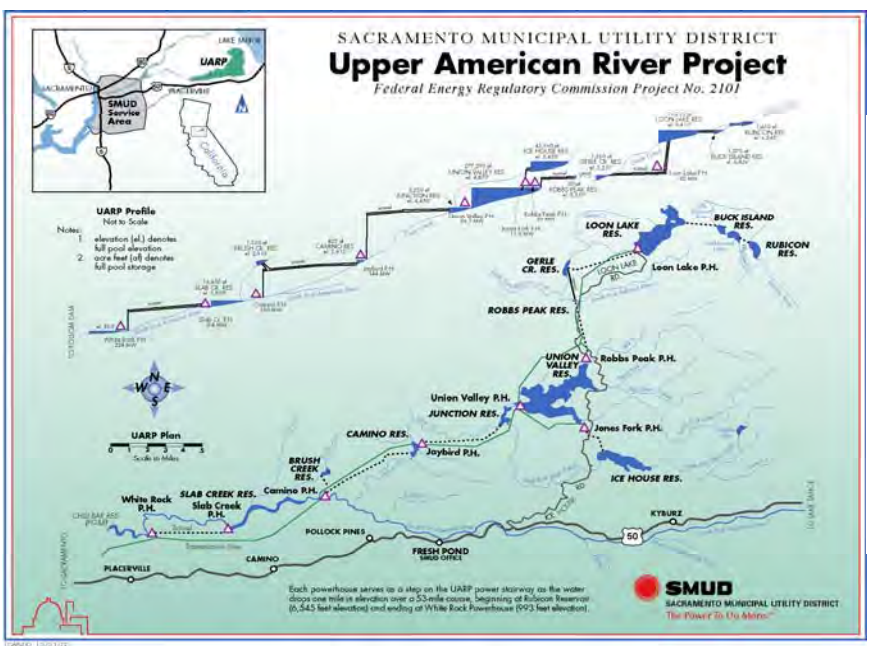
Distribution System Data

- Service area population: 1.4 million
- Service area (in square miles): 900
- Total number of customers: 589,599 (522,228 residential, 67,361 commercial)
- Employees: 2,161
- Transmission lines (in circuit miles): 473
- Distribution lines (in circuit miles) : 9,784
- Peak demand: 3,299 megawatts (July 24, 2006)

In the beginning…

Generation

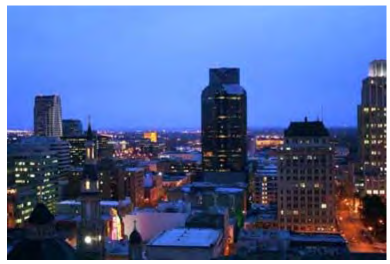
- Hydroelectric (hydro)
- Gas turbines (GT)
- Wind generators
- Photovoltaic [picture]



The completion of Union Valley Reservoir

Facilities

- SMUD stated with one building; and continued to grow along with Sacramento -



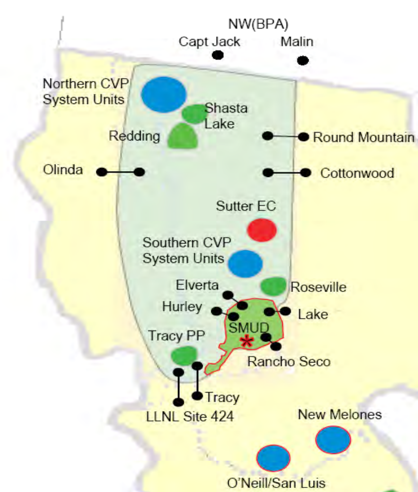
Facilities Now

- Headquarters (left) and Customer Service Center

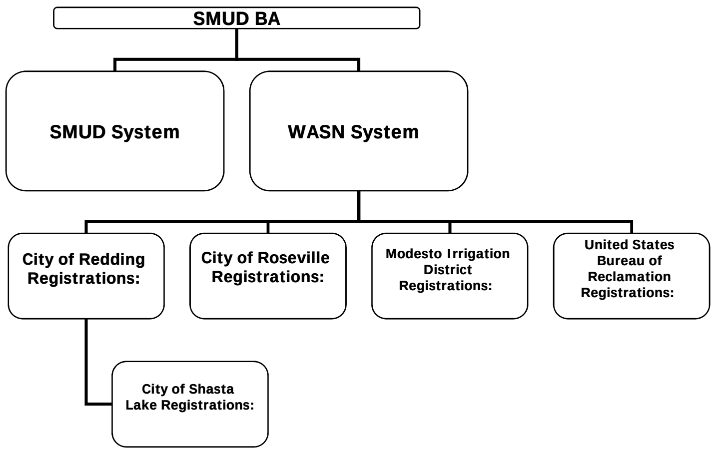
SMUD Control Area

- Responsible for balancing load and generation through entire area and provide reliable operations
- Provide assistance to other entities that are part of the Control Area
- Other Areas – WAPA (Federal water agency) and MID (Small Local Utility)
- Responsibility to Regional and Federal Agencies for reporting and operations – Western Electricity Coordinating Council (WECC), North American Reliability Corporation (NERC), and Federal Energy Regulatory Commission (FERC)

SMUD Control Area



SMUD Control Area Organizational Structure



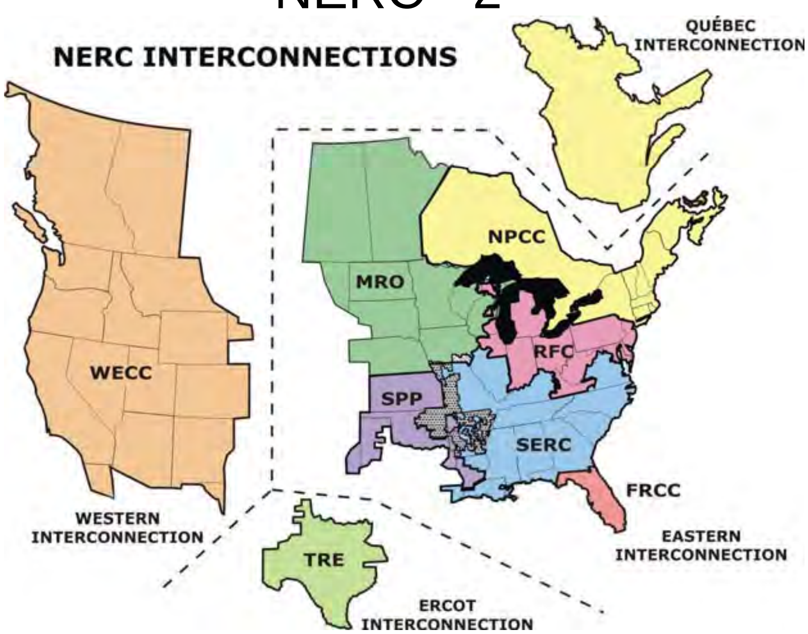
Reliability Regulation

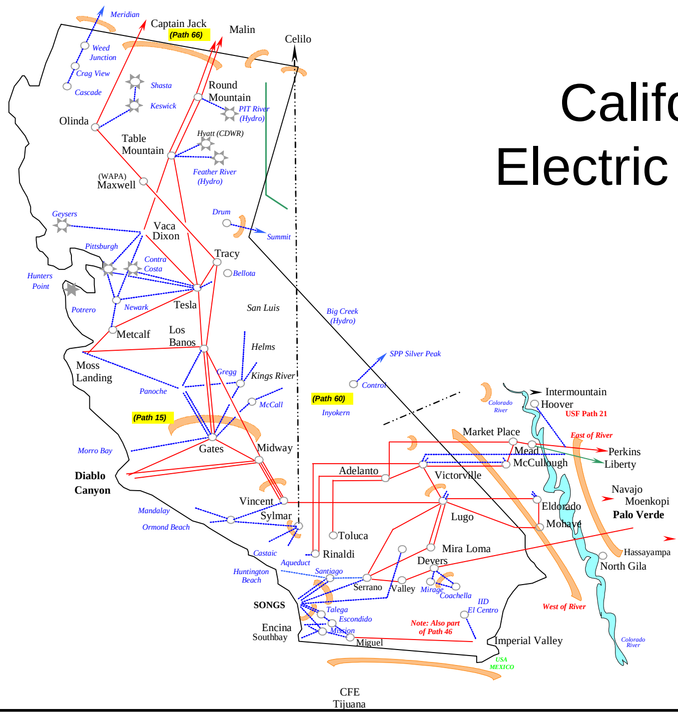
- On August 8, 2005, President Bush signed H.R. 6, *The Energy Policy Act (EPA) of 2005*, into law.
- The Federal Energy Regulatory Commission (FERC) enforces *The EPA of 2005*.
- The law contains provisions that make compliance with the Reliability Standards mandatory and enforceable.

Western Electricity Coordinating Council (WECC)

- Largest and most diverse of the NERC regions
- 35 Balancing Authorities
- 71 million people in WECC service territory
- ~150,000 MW / ~123,000 MW peak summer/winter load

NERC - 2





California Electric Grid

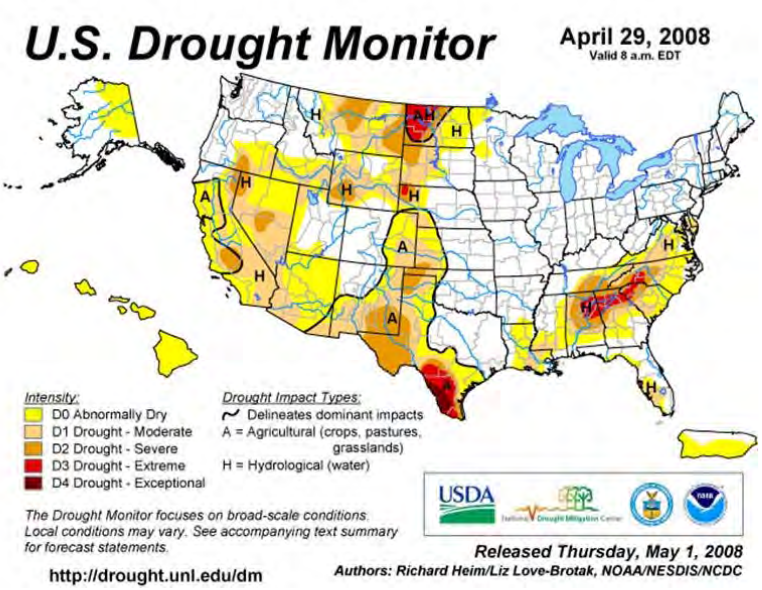
2008 Summer Operations

- SMUD Control Area Load:
  ~4600-4700 MW
- SMUD Load:
  ~3000-3100 MW
- WAPA Load:
  ~1600 MW

Fire Information

- Preliminary Fire Season Outlook:
  - Northern California – Expected to be Normal
    - Earlier start to the season due to drier than normal March-April period caused annual grasses to cure earlier than average
    - First half of fire season might be a little windier than average
  - Southern California – Expected to be Above Normal
    - Greater amount of growth due to early winter rains
    - Recent drying trends have allowed annual grasses to dry rapidly creating flammable materials
    - Increased likelihood of greater than normal number of large fires during May-July period

Weather Information*



Reservoir Information

- Dry Winter
- Snowmelt inflow to SMUD Hydro reservoirs peak at about May 17, which is slightly earlier than average. The 2008 forecast for water storage 320 TAF (thousand acre feet) out of a of 380 TAF capacity.
- Rainfall in the valley during winter was 57% of average.
- After the summer, the Hydros will be operated so that end of year storage is about 230 TAF. This is being done to conserve water for use in summer 2009 in the event of a third dry year.

Questions/Discussion

Section 5

POWER SYSTEM OPERATING DESCRIPTION – BPA Transmission System

A Detailed Look at BPA's Transmission and Power System Operations

1

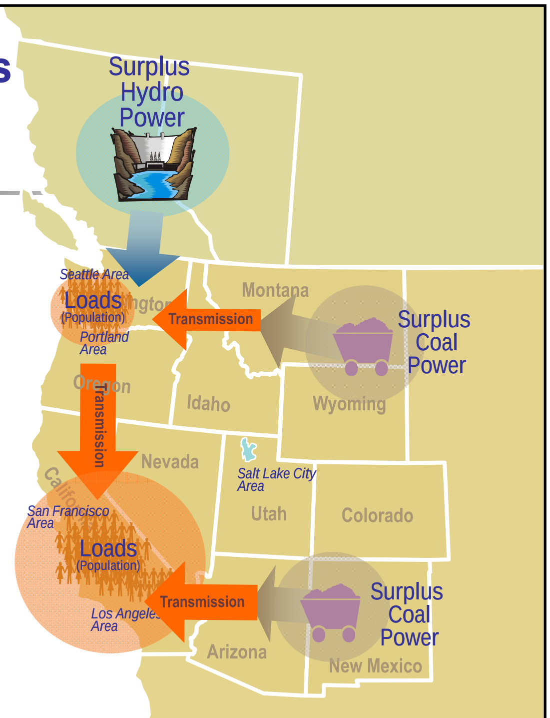
System Description: WECC

- Issues
  - Large Area
  - Many Different Transmission Operators, Loads, Power Suppliers, and Distribution Entities.
  - Low Density of lines.
  - Loads isolated from generation by large distances.
  - Congestion.

2

WECC Loads and Generation

- Largest WECC loads are in California.
- Surplus coal power from the Southwest and the Great Plains, and surplus hydro power from British Columbia is available to supply California.
- Intertie transmission to California is limited.
- Pacific Northwest generation and loads lie between these surplus power supplies and California loads.



System Description: BPA Transmission System

- BPA owns and operates 75% of the Pacific Northwest's high voltage electrical transmission system.
- The system includes more than 15,000 miles of transmission line and more than 200 substations.
- The system networks across 300,000 square miles in Oregon, Washington, Idaho, Montana and sections of Wyoming, Nevada, Utah and California.
- The system enables a peak loading of about 30,000 megawatts and generates about $579 million a year in revenues from transmission services.
- BPA's Transmission Services operate under an Open Access Transmission Tariff based on FERC's pro forma tariff as a non-jurisdictional entity.

4

System Description: BPA Transmission System

Number of Miles of Transmission line

1,000 kV (DC Line)	264
500 kV	4,734
345 kV	570
287 kV	227
230 kV	5,300
161 kV	119
138 kV	50
115 kV	3,557
below 115 kV	367
Total	**15,190**

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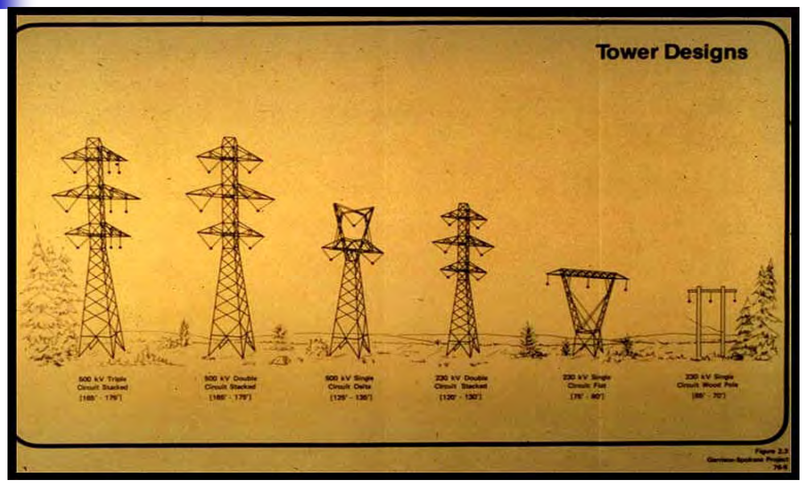
Unique Features : AC - DC Converter

Northern end of the 846 mile 1 million volt direct current power line to N. Los Angeles

6

Unique Features : Tower Design



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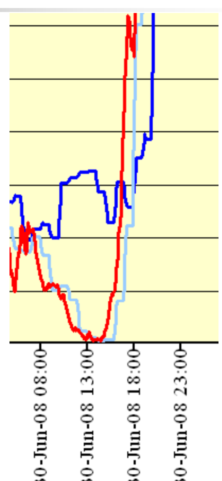
Unique Features:
Wind Generation Integration

- With close to 5000 MW of wind potential, predicting the wind pattern is of utmost importance.
  - Dark Blue is the Base point Forecast Method
  - Light Blue is the Persistence Forecast
  - Red is the Actual Wind Gen



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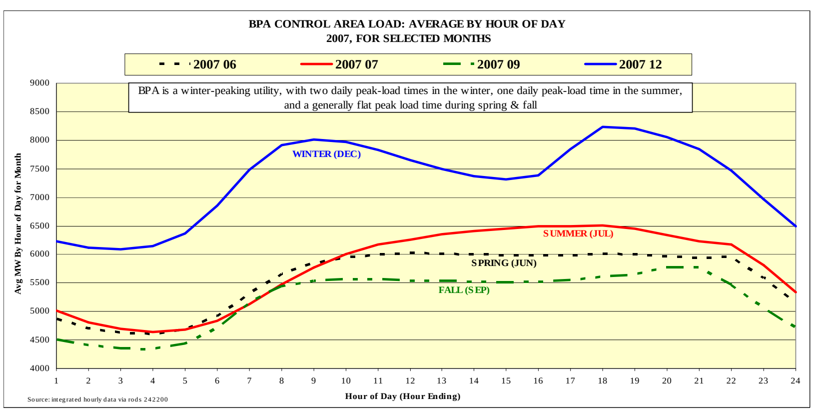
Seasonal Issues

- **Spring**
  - Winter Snow melt
  - Fish management
- **Summer**
  - Heavy North South Power flows
  - Ever increasing summer loads
- **Fall**
  - Lower Water Conditions
- **Winter**
  - BPA's Load is a Winter peaking system
  - Heavy East West power flows.
  - Wind/Rain storms on the Coast
  - Snow and Ice

9

Seasonal Issues: Seasonal Load Patterns



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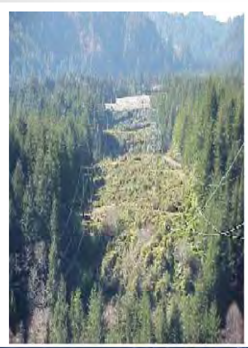
Topography of the BPA Region

- Large geographic footprint
- Low density of load
- Predominantly interlinked hydro,with base-loaded thermal resources
- Hydro generation output is controlled by water storage releases

11

Topography of the Region



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Topography: The Columbia River Gorge

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Topography: Hells Canyon

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Topography: High Elevation

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Topography: High Desert

16

Topography: Mountains

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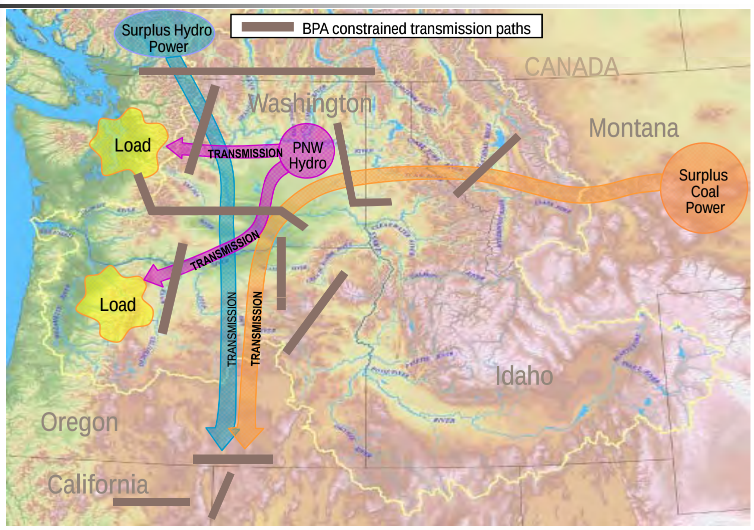
Operational Description: BPA Power Flows



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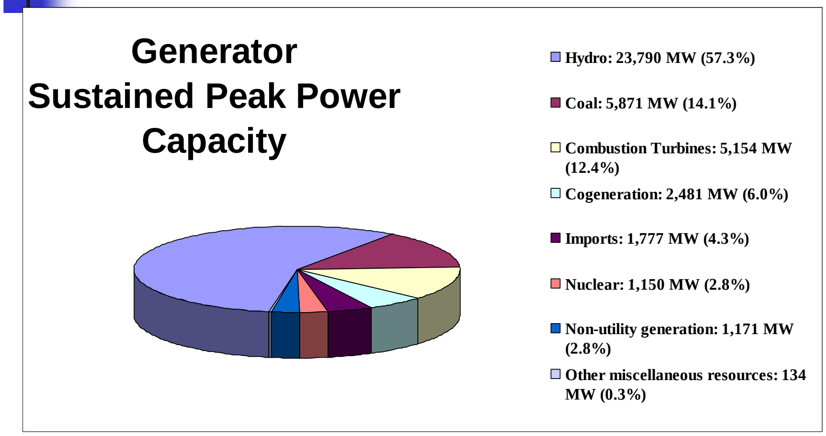
Operations Description: Total Generation Capability



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Operations Description: Dams and Generation

20

Columbia River Hydrological Data

- Range of project capacity: 1.5 MW at Boise Diversion to 7,000 MW at Grand Coulee
- The median age of FCRPS hydro projects is 31 years.
- Average runoff is 103 million acre feet (MAF) January through July.
- The historical range of January through July runoff is 54 to 156 MAF.
- Annual Federal hydro generation ranges from 6,840 average megawatts (aMW) to 10,300 aMW, averaging 8,700 aMW.
- The system can store 20.5 MAF in the U.S., plus 5 MAF at Libby Dam and 15.5 MAF in Canada under the Columbia River Treaty, plus 2.25 MAF Non-Treaty Storage in Canada; it is a *storage-limited system.*
- FCRPS storage can hold 25% of the average annual runoff; the Colorado or Missouri systems can store 400% of their annual runoff.
- The Columbia River system was developed and is operated for flood control, navigation, irrigation, municipal and industrial water supply, recreation, fish and wildlife, and power production.
- Major drivers of system operations are flood control and Endangered Species Act operations to protect salmon runs.
- Generation is largely driven by the need to move water for non-power purposes.
- Individual hydro projects are interdependent, affecting downstream projects.

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Operations Description: Hydrological Coordination

There is a high value in coordinated generation operation.
- Hydro-thermal coordination creates firm power and can displace capital investments.

Parties cannot coordinate simply on short-term price signals.
- Hydro projects are interdependent resources.
- River coordination spans multiple plants and long time periods.
- Long-term system thinking dominates operational strategy.

Unplanned obligations or supply shortage can disrupt coordination.
- Many non-power constraints affect hydro production.
- Hydro is not necessarily responsive to short-term price or “must run” orders.
- Short-term cost is opportunity cost relative to long-term use.

Hydro-thermal coordination may cause transmission flow issues.
- Base loading coal allows using and recharging hydro storage.
- Requires broad, flexible transmission rights.

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Operations Description: Management Issues

- Competing Interests
  - Flood Control
  - Hydropower
  - Navigation
  - Irrigation
  - Recreation
  - Fish and Wildlife enhancement
- BPA
  - Transmission and Power Services
- COE
  - Reservoir Control Center

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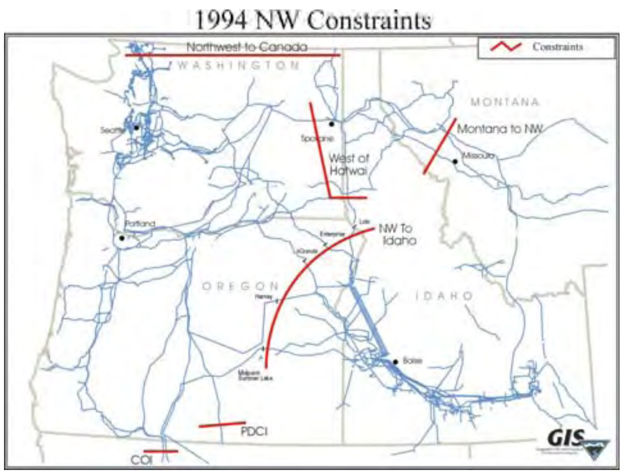
Operations Description: Columbia River Basin

24

Operations Description: Constrained Paths - 1994



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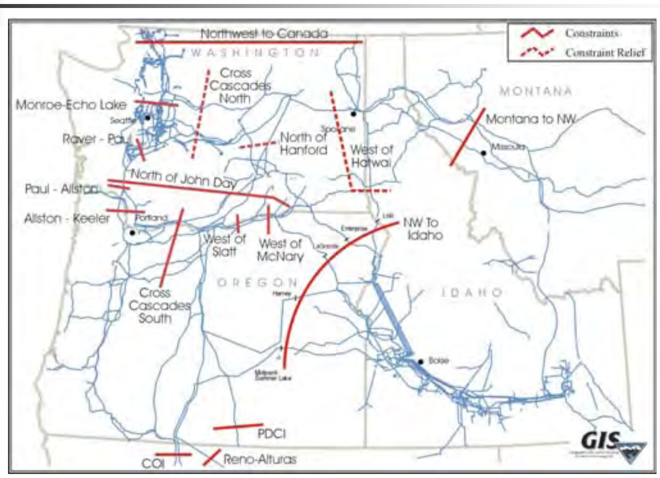
Operations Description: Constrained Paths - 2008



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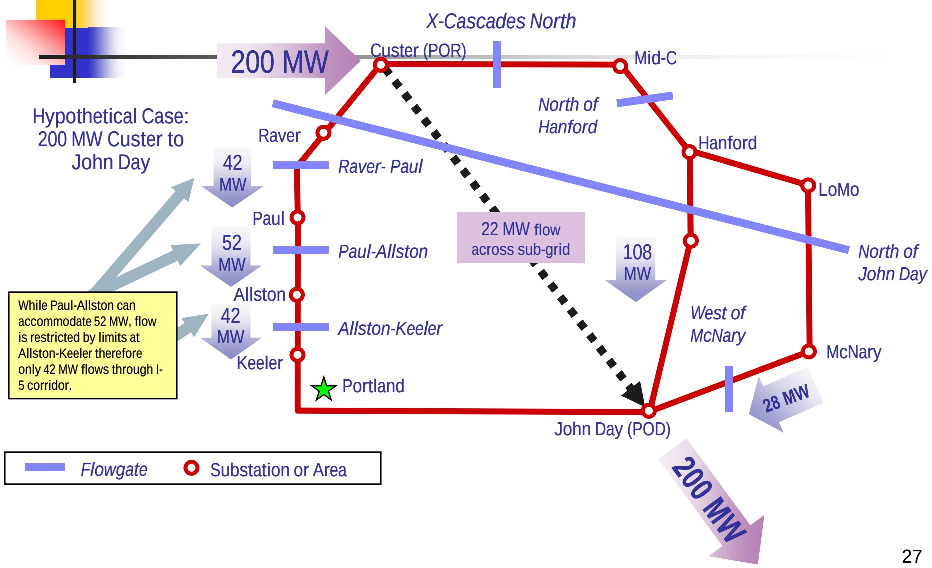
Operations Description: System Operating Limits



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Maintenance Issues: Terrain and Weather

28

Mechanical Issues

Maintenance Issues: Vandalism

Outage Process: Three Types of Outages

1. Construction outages
   - Project energization important
     May often be contract work and scheduled prior to outage requests
   - Often requires multiple outages
2. Maintenance outages
   - Older system requires more maintenance
3. Emergency Repair
   - Failures or imminent failures

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Outage Process: Why Outage Coordination is Important

- Planned outages - taken when they create the least impact on the transmission system
  - Historically we look at transmission loading and try to take outages when loading is lower to minimize risks
  - Spring and Fall are the usually the preferred months to take outages
  - Outages that require work outside --
    - summer is best time for work conditions
    - often the worst time due to higher transmission loading
    - higher temperatures - increased A/C & irrigation load and reduced thermal capacity of equipment

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Outage Process: Why Outage Coordination is Important (continued)

- Combine work that can be done in one outage instead of multiple outages
  - e.g.. Line maintenance combined with line PCB maintenance
  - Caution: clearance boundaries, clearance holders
- Adequate study time to make sure outages do not create a reliability problem
  - An outage in Montana may not seem like it would have an impact in Washington but the transmission system responds to changes in impedances that may not be geographically close in distance
- Adequate notice of transfer capability impacts created by an outage so the market has time to respond
  - NWPP process is two weeks prior to outage week

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Outage Process: Northwest Power Pool Outage Planning

- Long Term
  - Coordinates outages up to a year in advance.
- Short Term: 45 day process
  - Provides adequate time for studies, coordination to minimize impacts, and market notification.
  - Affects **ALL** Significant Equipment
  - Deadline for Outage Requests

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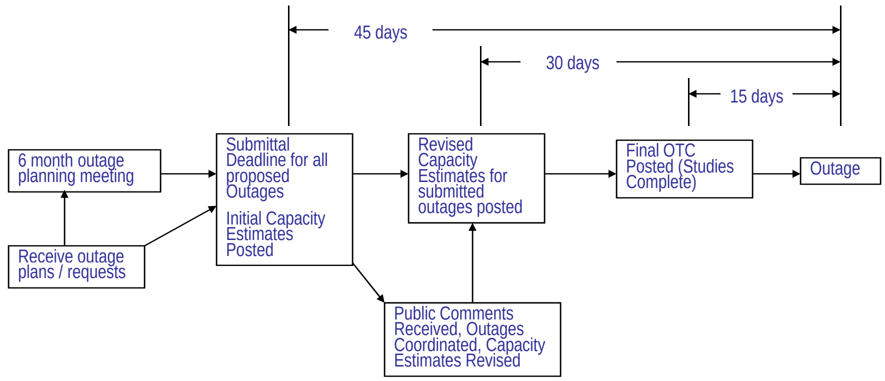
Outage Process: NWPP 45 day Outage Planning Process



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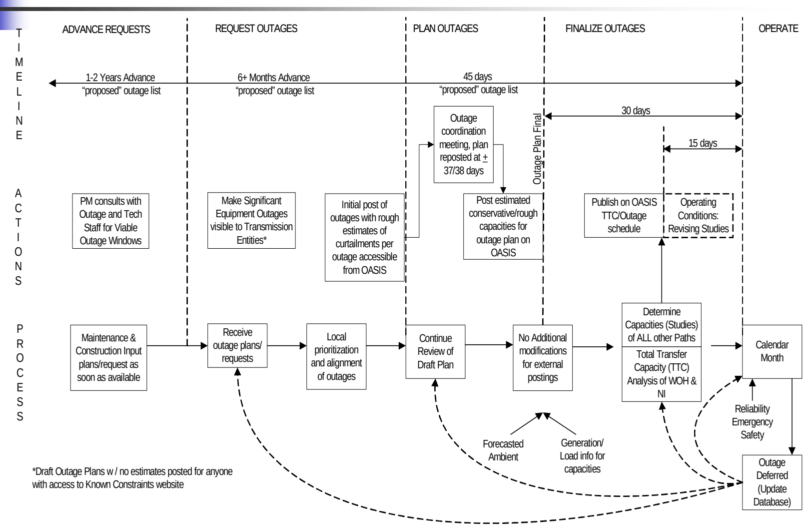
Outage Process: Detailed Outage Process



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Questions ???

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SMUD POWER SYSTEM OPERATING DESCRIPTION

1

Overview

- System Description
- Operational Description
- Maintenance and Repair
- Outage Planning
  - Transmission System
  - Generation

2

SMUD System

- Distribution System:
  - Service area in km^2 ($miles^2$): 2331 km^2 (900 $miles^2$)
  - Total number of customers: 589,599 (522,228 residential, 67,361 commercial)
  - Transmission lines: 761km (473 miles)
  - Distribution lines: 15746 km (9,784 miles)
  - Number of breakers: 145 (> 69kv)
  - Generation: 1659 MW (1006 Thermal, 653 Hydro)

3

SMUD Control Area

SMUD Control Area – Includes SMUD + WASN

- WAPA Sierra Nevada (WASN):
  - Service to an additional 650,000
  - Power to the area north of SMUD
  - Controls generation serviced by US Bureau of Reclamation (USBR)
  - Transmission lines: 1423 km (884 miles)
  - Distribution lines: None
  - Generation: 32 units; 2125 MW (all hydro)

4

SMUD Control Area

- CA Functions:
  - Reliability Reporting
  - Interchange Scheduling
  - Balancing Services (Load following, AGC, Operating Reserves, Operating Reserve Requirements, etc.)
  - Transfer Limit Adjustments
  - Import Limitations
  - Constraint Mitigation
  - OASIS Administration (Transmission line capacity market)

5

SMUD Control Area Customer Loads

- SMUD (~3,300 MW)
- WASN (and Federal entities) – (~1,650 MW)
  - USBR (~80 MW - Pump load)
  - Modesto Irrigation District - MID (~700 MW)
  - Roseville (~345 MW)
  - Redding (~245 MW)
  - Shasta Lake (~31 MW)

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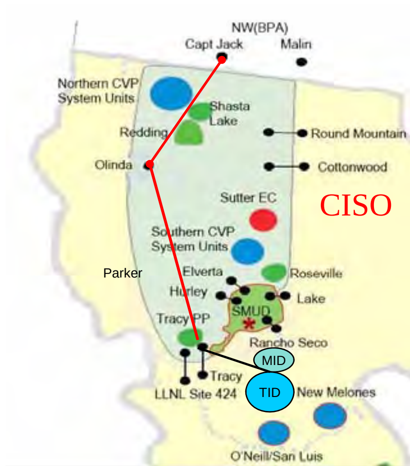
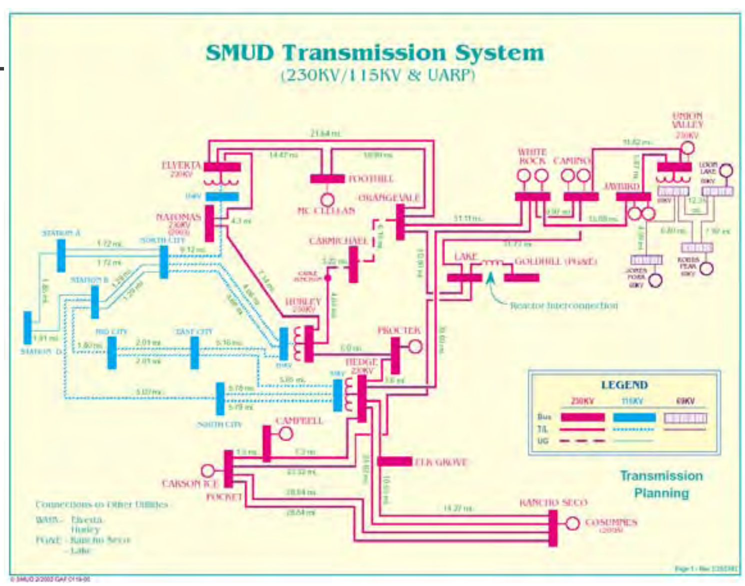
Current SMUD BA





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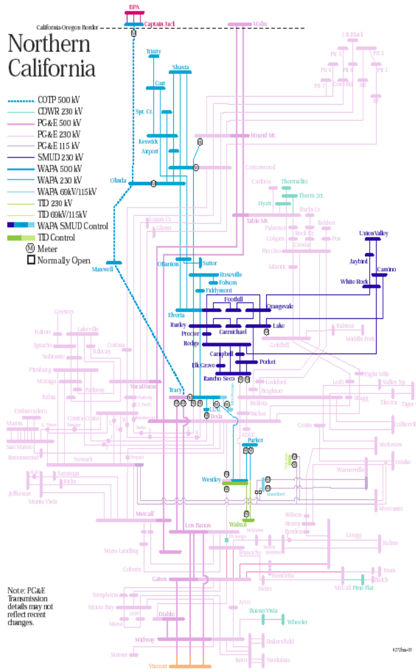
WASN Transmission



Seasonal Problems

- Winter
  - Storm damage
  - Customer outages
  - Lower loads
- Summer
  - High temperatures: + 40° C
  - Highest loads
  - Fires under transmission lines

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Finally the storm is over!!

Diverse Topology

- Valley
  - Sacramento
  - Customer load
  - Thermal and Wind generation
  - Transmission lines – 12 kV to 500 kV
- Mountains
  - Hydro generation
  - Transmission lines – 69kV and 230 kV

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Operational Description

Control Room Operations

- SMUD has 4 desks – Scheduling, Transmission, Generation/Gas, and Shift Senior
  - Scheduling – checks out all scheduling issues – new, changed, curtailed; approves all e-tags
  - Transmission – monitors activity on all major lines in the Control Area; electronic systems provide assistance to determine limit violations through warning and alarms
  - Generation/Gas – determines generation and reserve requirements based on the next hours schedules; remotely starts units (Hydros) or calls Plant Operators (Thermals) as required to meet expected changes in Schedule and Load demands; operates gas system to thermal plants

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Operational Description

Control Room Operations

- Shift Senior has over-view of all positions and checks, monitors, and answers questions; this position contacts other entities as needed

- Procedures: used (and required) for most control room activities; typically this is backup for training and not referenced on a daily basis
- WECC and NERC policy also determines decisions; Policy books are available in the control room
- Operator Independence: WECC and NERC require a document that gives authority to the Operators to take whatever action is required to maintain grid reliability. This document is signed by the General Manager and hangs on the wall. Authority to drop customer load if needed without prior approval.

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Operational Description

EMS and SCADA

- EMS functions include:
  - SCADA
  - AGC – Automatic Generation Control
  - Reserve Monitor
  - Load Shed
  - Capacitor Control
  - Alarm Processing; Sequence of Events
  - Energy Accounting

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Operational Description

EMS and SCADA

- External Applications:
  - ICCP: Inter Control-center Communication Protocol - Standard protocol for data exchange
  - Historical Data Storage: SMUD uses the PI system from OSI
  - Interchange Scheduling – SMUD contracts with OATI in Minneapolis for scheduling services

32

Operational Description

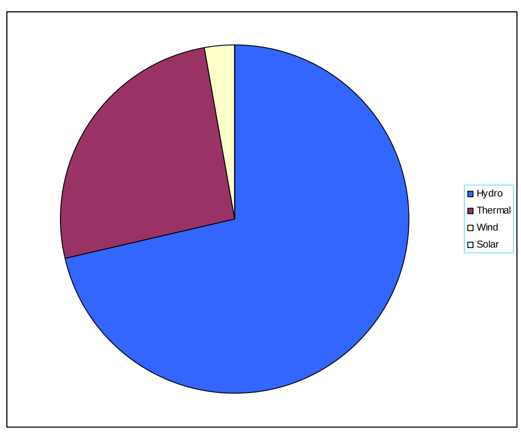
Generation operation

- Hydro generation is operated via SCADA from the Control Center
- Generation can be manually or automatically operated:
  - Auto is through AGC;
  - Manual control - Through the EMS for the Hydros and Phone call to the Operator at the Thermal Plants
- SMUD owns hydro generation (~650 MW)

33

Operational Description

Generation



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Operational Description

Transmission operation

- Operates 115 and 230 kV system
- Switching performed from Control Center
- Monitor the 500 kV system; WAPA is responsible for all switching activities, coordinating through SMUD

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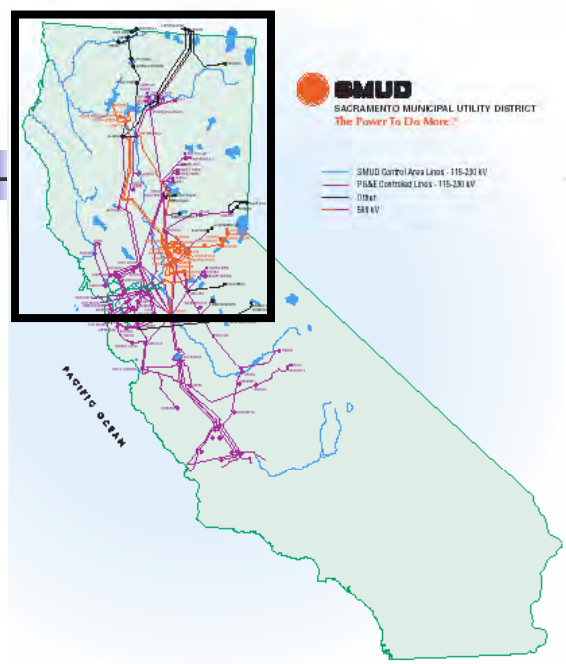
Northern California Electric Grid



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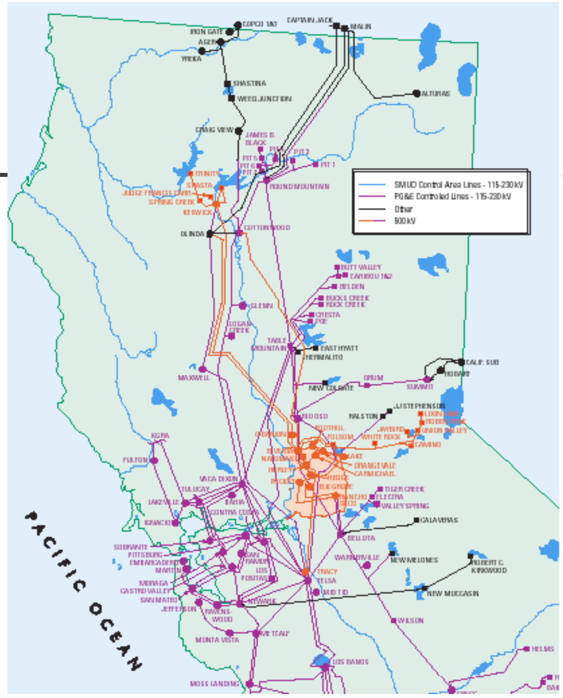
Northern California Electric Grid



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Maintenance and Repair

- Cost
- Distribution Department does all work

42

SMUD Managers timing periodic maintenance items

43

Maintenance Costs

Proposed O&M Budget for 2009

WBS		2008 Budget	Proposed 2009	Variance	Comments
E/TM/O/CL	Corrective Maintenance Trans Line	$425,156	$457,148	$31,992	
E/TM/O/CS/CME	Corrective Maintenance- Expected	$5,825	$17,819	$11,994	
E/TM/O/CS/CMU	Corrective Maintenance- UnExpected	$291,266	$363,950	$72,684	
E/TM/O/PL	Preventive Maintenance Trans Line	$548,143	$631,555	$83,412	
E/TM/O/PS/CDM	Preventive Maintenance - Condition Directed Maint	$1,119,224	$908,312	($210,912)	
E/TM/O/PS/CMT	Preventive Maintenance - Condition Monitoring Tasks	$1,695,143	$1,987,186	$292,043	
E/TM/O/CN	Preventive Maintenance - Network (underground line)	$252,360	$73,534	($178,826)	
E/TM/O/PN	Preventive Maintenance - Network (underground line)	$265,328	$476,745	$211,417	
E/TM/O/TT	Trim Trees Trans Lines/ Substation	$538,024	$545,325	$7,301	
E/TO/O/OT	Operate Transmission Substation	$398,131	$1,220,000	$821,869	Increase to accommodate NERC testing and upgrade to Modify the UARP Relay communications from Microwave to Fiber.
E/TO/O/PT/1	Plan Transmission Operations	$1,373,329	$1,373,329	$0	Lets talk about this number…
E/TO/O/PT/2	Orangevale(formally Hedge) Bus Configuration Study	$108,844	$100,000	($8,844)	
E/TO/O/PT/5	Pocket (formally Elverta) Sub Bus Config Upgrade Study	$107,552	$100,000	($7,552)	
	Total:	**$7,128,325**	**$8,254,903**	**$1,126,578**	

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SMUD Distribution

- Distribution Operator
  - Operates 69 kV, 21 kV, 12 kV, 4 kV
  - All lower voltage switching
  - Distribution system monitoring
  - Outage restoration
  - Emergency response (downed lines, car-pole accidents)
  - Storm response (storm damage, poles down, trees blown into lines)

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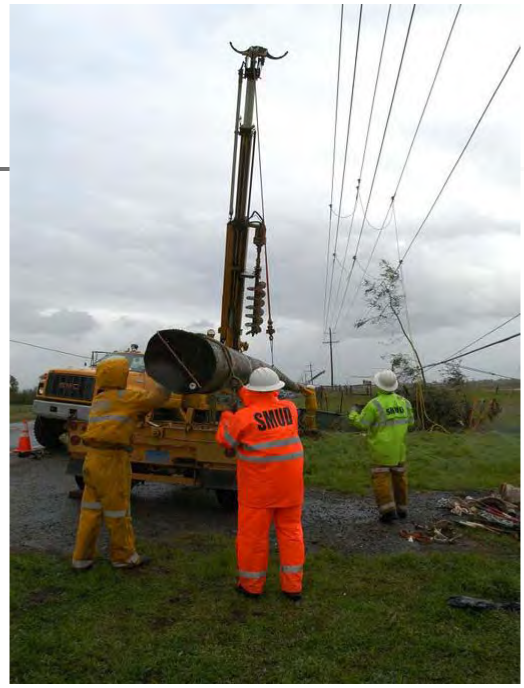

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Outage Planning

- Planned outages through the Transmission Outage Application (TOA)
  - Major outages require power system study
- Unplanned
  - Higher cost
  - Greater system disturbance

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Outage Planning

- Transmission Outage Application (TOA) communicates automatically with the California ISO to update their outage information
- Generation outages are also sent to the Regional Reliability Coordinator (Part of WECC)

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Questions/Discussion

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Section 6

SMUD OPERATIONAL PLANNING

1

Overview

- Planning Process
- Study Process – seasonal
- Remedial Action Schemes
- Business Applications
- Emergency Operations

2

Planning
(System and Long Term)

System Pre-Schedulers

- Forecast loads for pre-schedule
- Arranges for procurement of energy (internal and external) and operating reserves
- Abides by import limitations for SMUD as provided by Power Operations Engineering
- Load forecasting tools assist to accurately determine Load for different time frames – next week, next day, next hour, within hour

3

Planning
(System and Long Term)

- Long term planning
  - Future infrastructure requirements
  - Based on studies in future years
  - Based on load growth
  - Budget planning

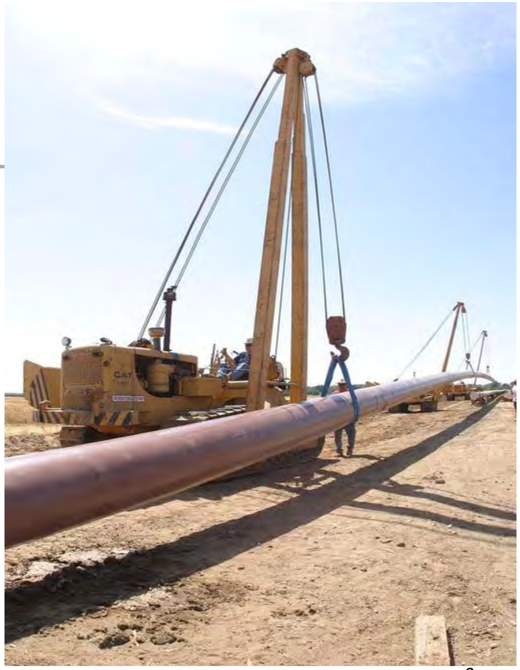
4

Infrastructure

- New generation
  - Wind
  - Combustion Turbine / Co-gen
- Generator maintenance
- Other improvements

5

New gas pipeline installation



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Transformer at a new plant installation

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Wind Turbine construction at the existing Solano Wind Farm

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Study Process

- Seasonal
  - Summer:
    - Highest loads
    - Largest MW imports
    - High probability of fires tripping lines
  - Studies
    - Determine maximum import capability
    - Contingency studies for system weakness
    - Determine solutions for contingency events
    - Line loading problems

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Study Process

- Seasonal
  - Winter:
    - Lowest loads
    - Minimal MW imports
    - Storm damage creates system problems
  - Studies
    - Contingency studies for system weakness (long line damage, tripping)
    - Determine solutions for contingency events

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RAS

- Resolve line loading problems
- Safeguard during high load conditions when import limits are reached – Direct load tripping if a contingency develops

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Business Aspects

- Processes bring business changes:
  - Financing requirements – Bonds, Low interest loans, rate increases
  - Infrastructure Projects are high cost – require Board approval, special financing, shared financing (Federal, other utilities, formation of entities – Transmission Agency of Northern California)

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Emergency Operations

Operations

- Typically during high load conditions
- Possible load shed
- Low media visibility (unless load shedding is required)
- Emergency drill is conducted yearly with various departments that are affected

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Emergency Operations

Interconnected Operations Issues

- Schedules for all power deliveries – imports and exports (Electronic tags or "e-Tags")
- Generation and load balanced to remain "on Schedule"
- "Off Schedule" results in +/- ACE; negative = under-generating; positive = over-generating
- All entities within WECC must assist for under-frequency conditions – frequency bias
- Emergency assistance typically from adjacent utility/Control Area

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Emergency Operations

Load and Generation – out of balance

- Causes:
  - Problems with AGC
  - Generator not responding to AGC
  - Scheduling problem
  - System disturbance
  - Inadequate reserves (not enough generation – spin and quick start)
- Minimum results:
  - Inadvertent energy across ties

A. Introduction

1. **Title:** **Automatic Generation Control**
2. **Number:** BAL-005-0
3. **Purpose:**
   This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Generator Operators
   - **4.3.** Transmission Operators
   - **4.4.** Load Serving Entities
5. **Effective Date:** April 1, 2005

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE

calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

R7. The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.

R8. The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.

R8.1. Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R9. The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.

R9.1. Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R10. The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.

R11. Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.

R12. Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.

R12.1. Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R12.2. Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.

R12.3. Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.

R13. Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

R14. The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.

Standard BAL-005-0 — Automatic Generation Control

R15. The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be

Adopted by NERC Board of Trustees: February 8, 2005 3 of 5
Effective Date: April 1, 2005

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Emergency Operations

Load and Generation – out of balance

- Maximum consequences:
  - RAS operations
  - Imports overload lines
  - Low frequency
  - System blackout (worst case)
- Controlled by:
  - Maintaining adequate reserves
  - Request energy assistance from adjacent area
  - Cutting export schedules
  - Shedding load

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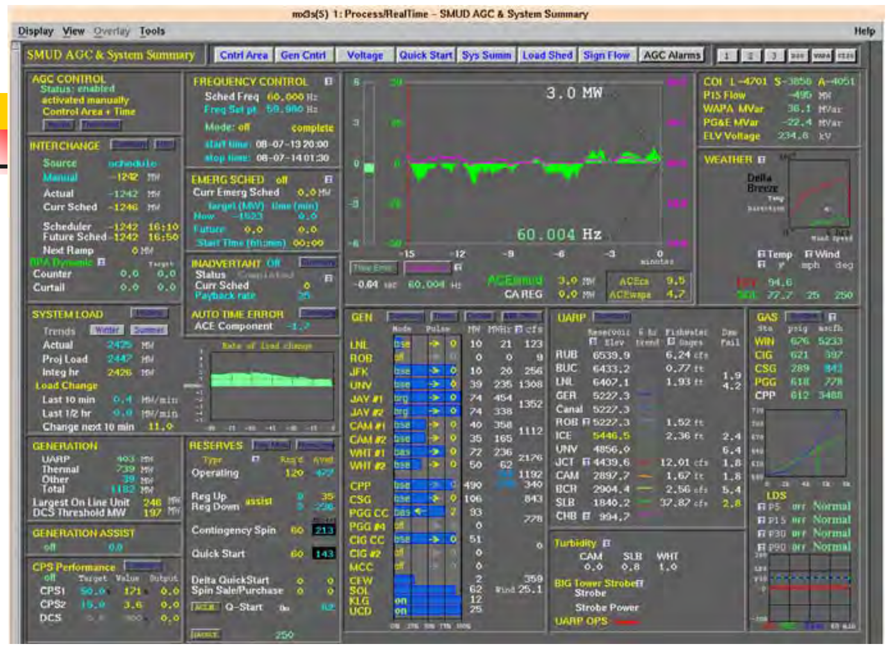

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Emergency Operations

Restoration - System Blackout

- Reliability Coordinator (WECC) directs operations
- Black start procedures used
- Black start generators are equipped with standby generators to provide plant power
- Local grid is restored until the system is able to be paralleled with an adjacent system

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Emergency Operations

Standards

- WECC and NERC standards govern all emergency operations
- Localized problems result in a required report within a specified time
- Widespread problem is investigated by a team selected by NERC and a report is then issued; conclusions result in changes to standards and audits

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Questions/Discussion

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BPA OPERATIONAL PLANNING

A brief overview of
BPA Operational Planning

1

System Operations and Planning

- Planning process
- Operations Study Process
- Remedial Action Schemes (RAS)
- Emergency Operations

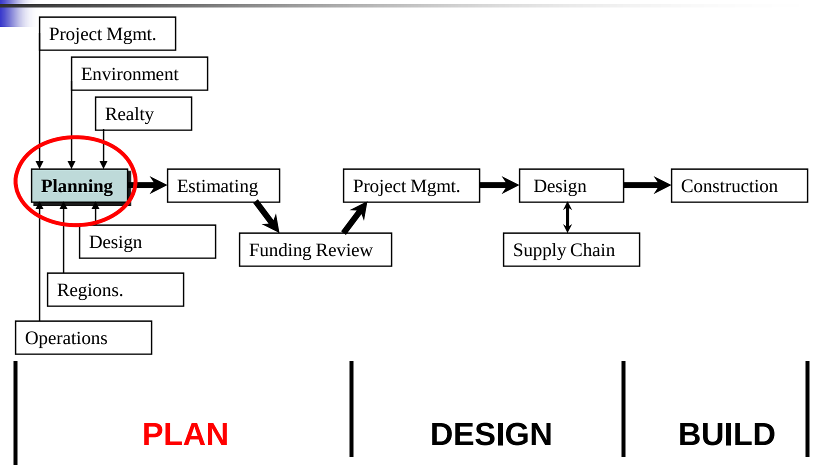
2

Transmission Planning

- Develop Plans of Service for Expansion, Modifications and Replacements to BPA's Transmission System & Equipment to:
  - Provide Reliable Load Service
  - Integrate New Generation/Lines and Loads
  - Accommodate Transmission Requests
  - Maintain Desired Transfers/Intertie Ratings
  - Relieve Congested Paths
  - Improve Operability and Maintainability
- Provide Technical Expertise in Power System Analysis and Knowledge of BPA's Main Grid
- Support WECC/NERC Subcommittees/Workgroups
- Provide Engineering Support to Account Executives
- Coordinate Research & Development Projects for Planning

3

Planning: Overall Process



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Planning: Methodology

Run detailed studies for the feasible alternatives

- Investigate the scope of the problem
- Run Sensitivity Studies for the problem area to determine the worst season and pattern (for generation, transfers, etc.)
- Identify the date the project is needed for operational use from the detailed studies
- Evaluate the technical performance of each alternative and how well they fit in with the long-range transmission plan for the area

5

Planning: Risk & Business Case

- What Risks are associated with the project?
- What are the Probabilities and Consequences?
- In Planning, a detailed Risk Assessment is completed, prior to issuing the final design, for alternatives with costs above a threshold consistent with Agency guidelines.
- Planning provides input to the development of Business Cases. This is an Agency requirement and includes both cost and risk analysis components.
- BPA also uses an Agency Decision Framework (ADF) for complex, politically-sensitive projects.

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Planning: Types of Projects

- Main Grid Reinforcement (500 kV & 345 kV)
- Area Service Reinforcement (230 kV & 115 kV)
- Customer Service (115 & 69 kV system)
- Generation / Line & Load Interconnection Requests
- Point-to-Point Transmission Requests
- Interties (COI, PDCI, NW-Canada)
- Congested Paths (e.g. NJD, WOM, SOA)
- Reactive Additions (Capacitors, Reactors)
- Remedial Action Schemes (RAS)
- Technology Innovation (TI) Projects
- Equipment Replacement (e.g. breakers, capacitors)

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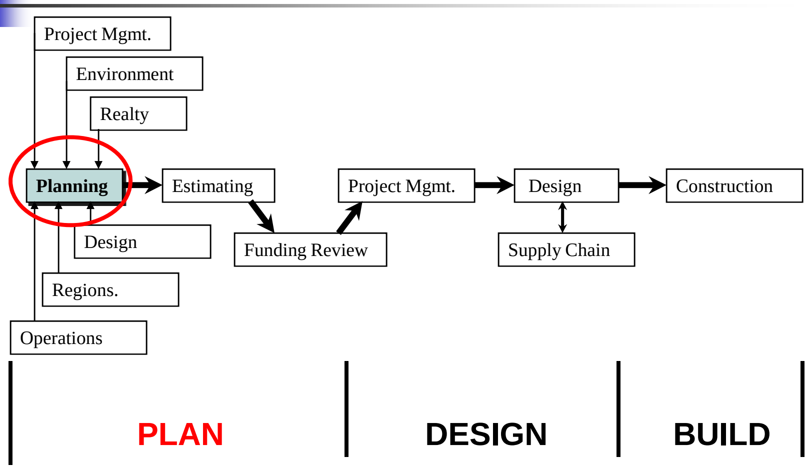
Planning: Overall Process



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Operating Studies at BPA

- System Operating Studies
  - Offline
    - Powerflow (Thermal and Voltage)
    - Voltage Stability (PV, VQ)
    - Transient Stability
  - Online
    - State Estimator
    - Contingency Analysis
- Operating Criteria
- Modeling Issues

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Studies: Offline

- Vendors
  - GE, PowerWorld
- Purpose
  - To determine the boundary of reliable operation
  - Meet Regional Operating Criteria
  - Set System Operating Limits (SOLs)

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Studies: Operating Limits

- How is the WECC criteria used to determine system Operating Limits?
  - Each criteria has a level of margin associated with it.
    - Transient : Voltage Dip
    - Reactive : Power Test
    - Thermal : 30 minute rating

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Studies: WECC Operating Criteria

NERC and WECC Categories	Category Definition	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
A	No Contingency (All facilities in service)	Nothing in addition to NERC		
B	Event resulting in the loss of a single element.	Not to exceed 25% at load busses or 30% at non-load busses. Not to exceed 20% for more than 20 cycles at load busses	Not below 59.6 Hz for 6 cycles or more at a load bus.	Not to exceed 5% at any bus
C	An event resulting in the loss of multiple elements	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load busses	Not below 59.0 Hz for 6 cycles or more at a load bus.	Not to exceed 10% at any bus
D	Extreme Event resulting in the cascading loss of multiple elements	Nothing in addition to NERC		

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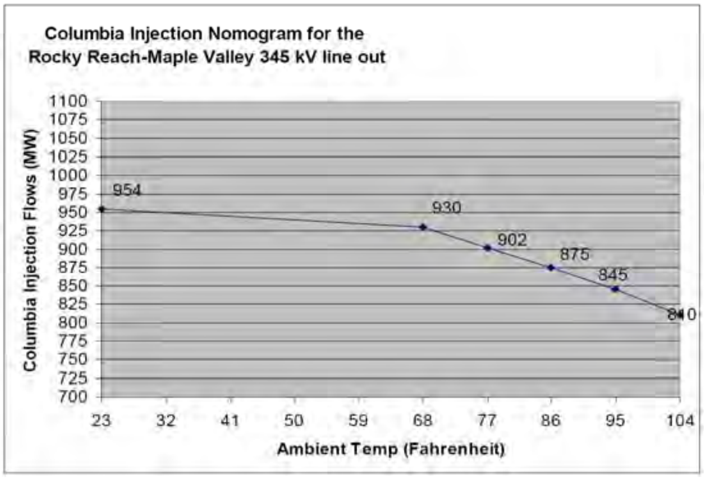
Studies: Typical Operating Nomogram



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Studies: Finding the Boundaries

- What methods are used to find the boundary of stability?
  - PV / QV / Transient / Thermal
- WECC criteria is used to translate the stability boundary into the region of operation.
- How can we determine the boundary?
  - Evaluate and quantify how the system responds to changes.
  - Begin with a representation of operating conditions, and stress the system by introducing stressful conditions in a series of tests.

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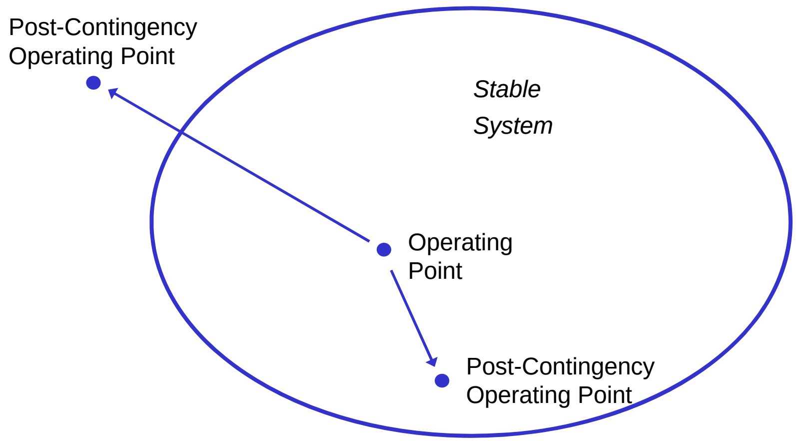
Studies: Result of a Contingency



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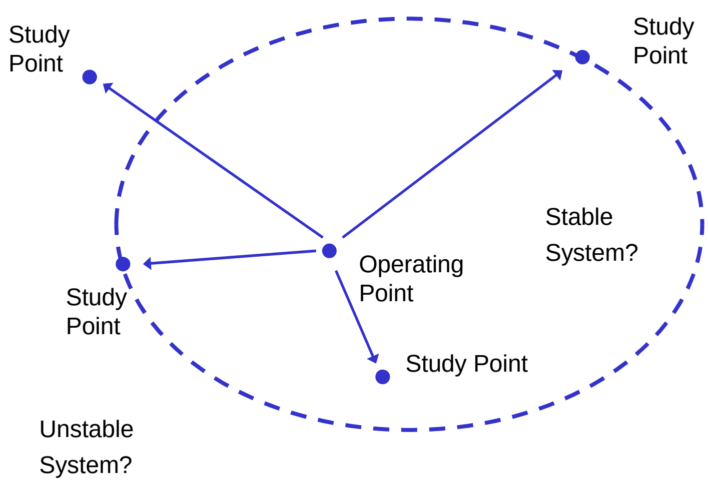
Studies: Finding the Boundaries



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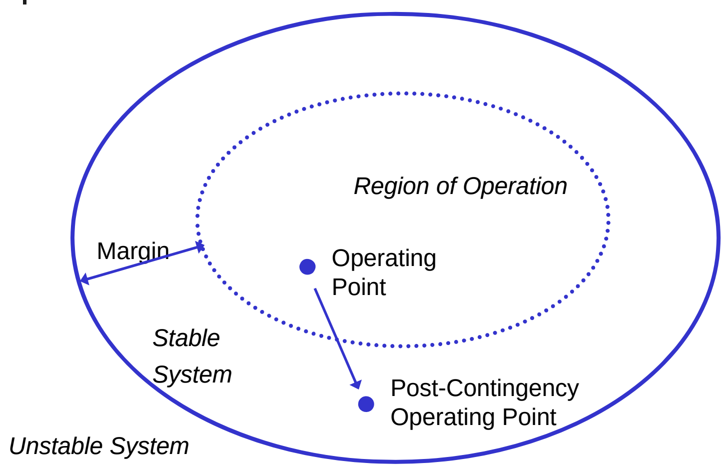
Studies: Defining the Operating Region



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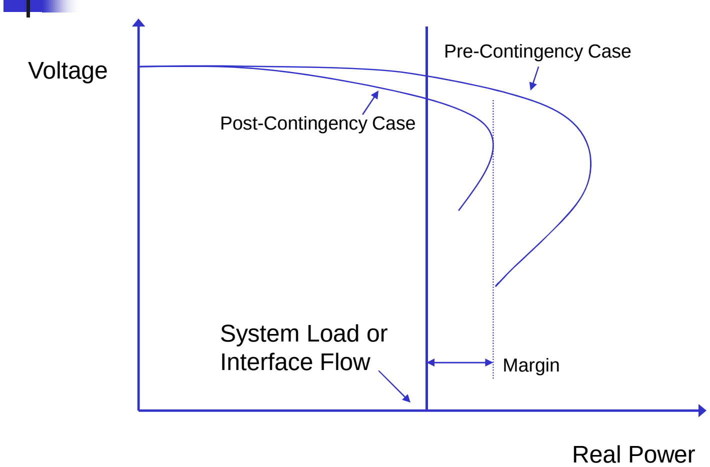
Studies: PV Method



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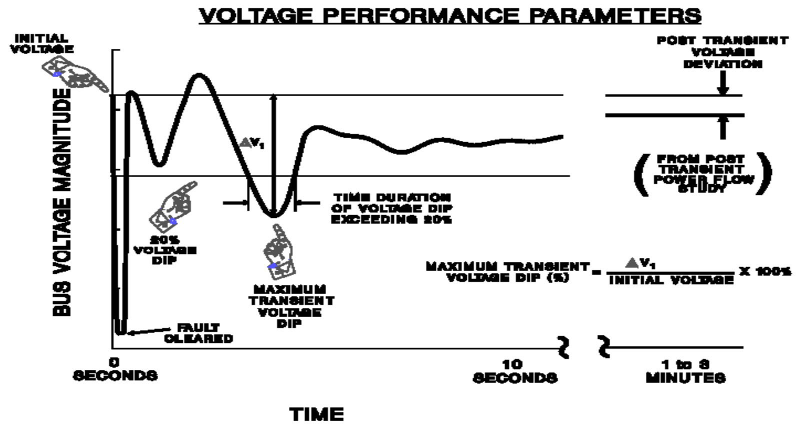
Studies: Transient



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Studies: Modeling Issues

- Load Modeling
  - Motor loads
- Generator Modeling
  - Governor / plant response
- Level of Detail
  - More detail does not always result in a better model

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Remedial Action Scheme (RAS)

- Equivalent Meanings
  - RAS = Remedial Action Scheme (WECC)
  - SPS = Special Protection Scheme (NERC)
  - SIPS = System Integrity Protection Scheme (IEEE)
- Text Book Definition
  - Fast Automatic Control Scheme designed to mitigate a power system disturbance.
- BPA's Remedial Action Schemes are designed to relieve 3 types of power system problems.
  - Thermal
  - Voltage Stability
  - Transient Stability
- A typical RAS composition Inputs
  - Controller
  - Outputs
  - Monitoring

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RAS: Inputs

- Inputs are received from:
  - Line Loss Logic
  - Generation Loss Logic
  - Power Rate Relays
  - Other RAS

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RAS: Inputs

- Inputs are received at Dittmer and Munro Control Centers. The control centers are located over 250 miles apart.

RAS: Controller

- Programmable Logic Controller
  - Triple Redundant
  - Fault Tolerant
  - Parallel Systems
  - No single points of failure

RAS: Outputs

- Generation Dropping – AC RAS
  - Canadian (Shrum, Mica, Revelstoke)
  - Federal Plants (Grand Coulee, Chief Joe, etc)
  - COI Capacity owners (Mid Columbia Plants)
  - Combustion turbines (Goldendale Energy Center, Coyote Springs 2, Calpine)
  - Wind (Leaning Juniper, Klondike IV, Biglow Canyon, White Creek, etc)

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RAS: Other Outputs

- Chief Joseph Brake (1400 MW Braking resistor)
- Reactive Switching
- Load Tripping
  - DSI's
  - PSE Light Industrial/Residential Load
- Intertie Separation

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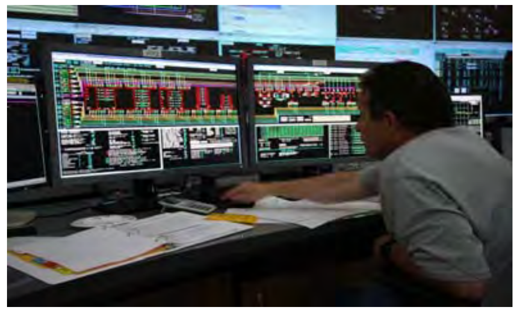
RAS: BPA RAS Dispatcher

- RAS Dispatcher at Dittmer Control Center.
- This desk is staffed 24/365.



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Why do we have RAS?

- To Increase Path Capacity (MW-$) without putting more wire in the air.

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RAS: Where would BPA exports be without them?

Path	RAS Available (MW)	No RAS (MW)
California-Oregon-Intertie (N-S)	4800	500
HVDC (N-S)	3100	1300
Northern Intertie (S-N)	2000	500

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Emergency Operations:

30

Emergency Operations: BPA Unique Role

- The Bonneville Power Administration (BPA) occupies a unique position within the Northwest Power Pool (NWPP).
- Due to its extensive involvement in the operation of the 500 kV bulk transmission grid and Federally-owned generating resources (primarily located in Washington, Oregon, Idaho, and Montana), it is an absolute necessity that BPA assume responsibility for the initial restoration of a **base power grid** in the event a major blackout occurs in the geographic area of the northwest.

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Emergency Operations: Balancing Authority

- Before any system switching or service restoration efforts can begin the following states need to be known.
  - System Status
  - Generation
  - Transmission Grid
  - Identify Cause of Disturbance

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Emergency Operations: BA Duties During Restoration

- Internal Stabilization
- Only after assessment has been made and reliability can be assured, the Balancing Authority may connect or tie to other Balancing Authority Areas upon PNSC approval.
- Tie to Neighbor System
- The Balancing Authority shall comply with PNSC directives unless such actions would violate safety, equipment, regulatory, or statutory requirements.

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Emergency Operations: Black Start Part A

- SYSTEM ASSESSMENT
  - Consult status
    - with Reliability Coordinator
    - with Neighbor Utilities
  - Establish plan of action
- BUILD GENERATION-LOAD ISLANDS
  - Clear dead busses
  - Separate from other utilities
  - Restart Generation
  - Charge base grid transmission
  - Restore base system loads

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Emergency Operations: Black Start Part B

- BUILD A BASE TRANSMISSION GRID
  - Synchronize generation-load islands
- RESTORE/SYNCHRONIZE MAJOR TIES
  - *With concurrence of the Reliability Coordinator*
- RESTORE and SYNCHRONIZE NW UTILITIES TO BASE TRANSMISSION GRID
  - *With concurrence of the Reliability Coordinator*
- RESTORE ASSOCIATED SYSTEM LOADS
  - Coordinate LOAD PICKUP

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Questions?

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Section 7

SMUD OPERATING REQUIREMENTS

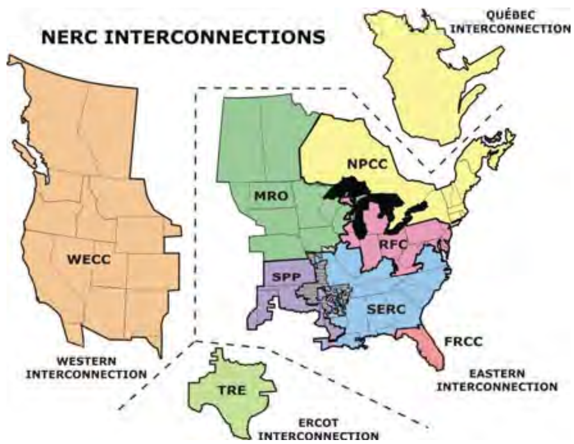
1

Overview

- Organization
  - WECC / SMUD - SMUD is 1 of the 5 Control Areas within the California Reliability Area
  - SMUD – System Operations and Reliability, Distribution Services
- Operations and Control
  - EMS / SCADA
  - Operators
  - Distribution System
  - Line and Substation maintenance
  - Distribution System monitor and control
- Training and Tools

2

SMUD within WECC



System Operations and Reliability

Operations Organization and Description

- Power Operations Engineering – Supports PSO through system studies, assisting with daily operational issues, provide reports internally and externally
- System Protection and Control – Provide all relay settings; install, maintain, and replace substation and line relays; trip and malfunction reports
- Power System Assessments (Planning) – Long term planning of the transmission system; recommendations to Management on new infrastructure requirements

Operations Organization and Description

Continued:

- Operations Management Systems (EMS) – Operate and maintain the EMS and peripheral software applications
- Power System Operations (PSO) – Operate the EMS to control and monitor the transmission grid, generation, and scheduled power transactions

7

Operations Organization and Description

Distribution Services

- Distribution System Operators (DSO) - Operates 69 kV, 21 kV, 12 kV, 4 kV
- Separate from Power System Operators
- Line maintenance and repair is managed by Distribution Services and <u>directed</u> by PSO

8

Operations Organization and Description

Distribution Services

- Switching below 69kV
- Distribution outage restoration
- Emergency response (storms, auto accidents)
- Metering

9

Operations Organization and Description

Distribution Services

- Distribution Operators - use the same EMS as Power system Operators; direct field crews for problems
- Troubleshooters – directed by DSO; on-call 7X24 to check on dist system problems; will repair minor problems
- Lineman – directed by DSO to repair "large" problems (lines down, poles down); substation and line maintenance / repair; new construction
- Service Desk - receive outage calls; direct initial response to Troubleshooters with problem/location

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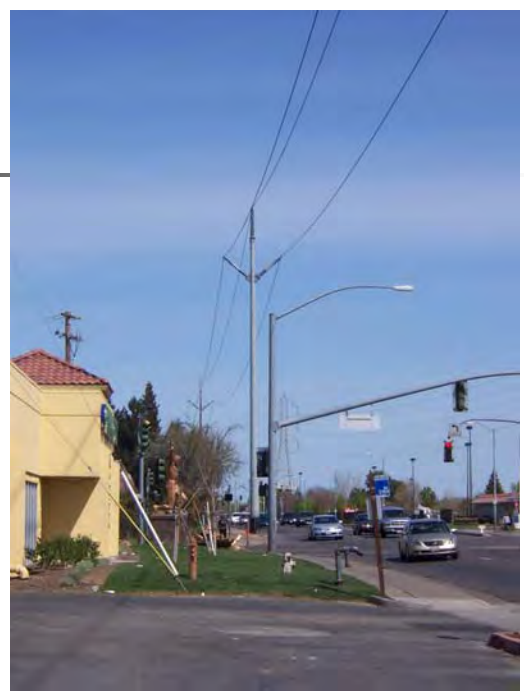
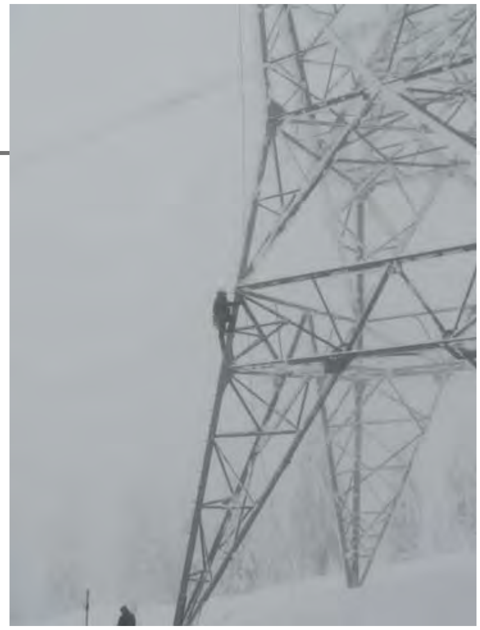
Ingersoll-Rand


RIBALDI


Ingersoll-Rand






OVERSIZE LOAD

Maintenance Costs

Proposed O&M Budget for 2009

WBS		2008 Budget	Proposed 2009	Variance	Comments
E/TM/O/CL	Corrective Maintenance Trans Line	$425,156	$457,148	$31,992	
E/TM/O/CS/CME	Corrective Maintenance- Expected	$5,825	$17,819	$11,994	
E/TM/O/CS/CMU	Corrective Maintenance- UnExpected	$291,266	$363,950	$72,684	
E/TM/O/PL	Preventive Maintenance Trans Line	$548,143	$631,555	$83,412	
E/TM/O/PS/CDM	Preventive Maintenance - Condition Directed Maint	$1,119,224	$908,312	($210,912)	
E/TM/O/PS/CMT	Preventive Maintenance - Condition Monitoring Tasks	$1,695,143	$1,987,186	$292,043	
E/TM/O/CN	Preventive Maintenance - Network (underground line)	$252,360	$73,534	($178,826)	
E/TM/O/PN	Preventive Maintenance - Network (underground line)	$265,328	$476,745	$211,417	
E/TM/O/TT	Trim Trees Trans Lines/ Substation	$538,024	$545,325	$7,301	
E/TO/O/OT	Operate Transmission Substation	$398,131	$1,220,000	$821,869	Increase to accommodate NERC testing and upgrade to Modify the UARP Relay communications from Microwave to Fiber.
E/TO/O/PT/1	Plan Transmission Operations	$1,373,329	$1,373,329	$0	Lets talk about this number…
E/TO/O/PT/2	Orangevale(formally Hedge) Bus Configuration Study	$108,844	$100,000	($8,844)	
E/TO/O/PT/5	Pocket (formally Elverta) Sub Bus Config Upgrade Study	$107,552	$100,000	($7,552)	
	Total:	$7,128,325	$8,254,903	$1,126,578	

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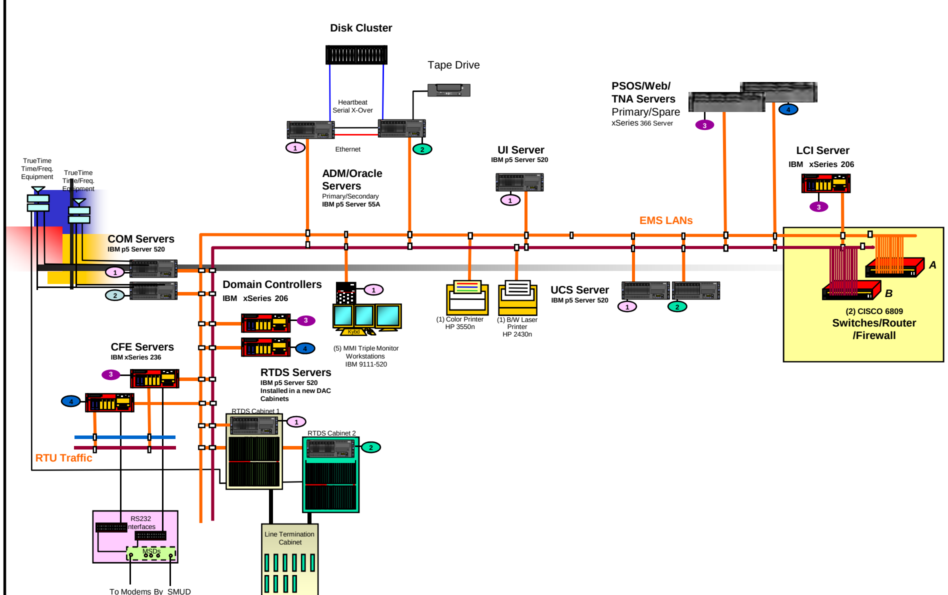
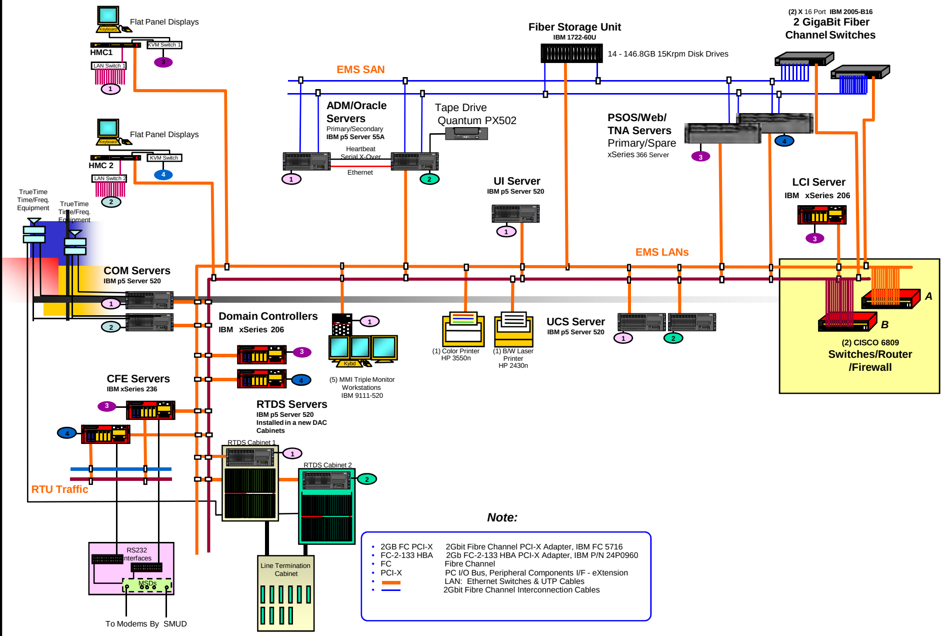
EMS and SCADA

- EMS functions include:
  - SCADA; AGC; Reserve Monitor; Energy Accounting; Alarm Processing; Sequence of Events; Load Shed; and Capacitor Control
  - Both Primary and Backup systems are dual / redundant
  - Primary and Backup systems are continuously synchronized
  - EMS network is separate from SMUD general network
  - Access is limited to “as-needed” basis
  - EMS data is provided to other areas through the PI system (OSI – Oil Systems Industries is the supplier of the system)



Primary Control Center



Backup Control Center

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Training and Tools

- Train new operators
- On-the-Job training
- Provide training classes to existing Operators to maintain WECC and NERC Certification
- Maintain training records of all Operators

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Standard PER-002-0 — Operating Personnel Training

A. Introduction

1. **Title:** **Operating Personnel Training**
2. **Number:** PER-002-0
3. **Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operatio
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall be staffed with adequately operating personnel.

R2. Each Transmission Operator and Balancing Authority shall have a training program for operating personnel that are in:

R2.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Electric System.

R2.2. Positions directly responsible for complying with NERC standards.

R3. For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:

R3.1. A set of training program objectives must be defined, based on NERC and Re Reliability Organization standards, entity operating procedures, and applicabl regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements normal, emergency, and restoration conditions for the Transmission Operator Balancing Authority operating positions.

R3.2. The training program must include a plan for the initial and continuing trainin Transmission Operator and Balancing Authority operating personnel. That pl address knowledge and competencies required for reliable system operations.

R3.3. The training program must include training time for all Transmission Operato Balancing Authority operating personnel to ensure their operating proficiency.

R3.4. Training staff must be identified, and the staff must be competent in both kno of system operations and instructional capabilities.

R4. For personnel identified in Requirement R2, each Transmission Operator and Balancin Authority shall provide its operating personnel at least five days per year of training an using realistic simulations of system emergencies, in addition to other training required maintain qualified operating personnel.

C. Measures

M1. The Transmission Operator and Balancing Authority operating personnel training prog shall be reviewed to ensure that it is designed to promote reliable system operations.

Adopted by NERC Board of Trustees: February 8, 2005
Effective Date: April 1, 2005

Standard PER-002-0 — Operating Personnel Training

D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. **Levels of Non-Compliance**

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Proposed Effective Date	Errata

Adopted by NERC Board of Trustees: February 8, 2005 2 of 2
Effective Date: April 1, 2005

Training and Tools

- Operator Training Simulator: same as the EMS – one-lines, controls, alarms, changes to system changes power flows
- EMS - Siemens Spectrum 3.X
  - Current Version 3.9
  - Primary and Backup systems
  - The primary system and control room is located at the main SMUD campus
  - The Backup system and control room is located 40km from the primary
  - RTU communications are also duplicated

28

Questions/Discussion

29

BPA Operating Requirements

A Focus on Organization and
People

1

Operations Overview

- Organizational structure
- Operations and Control
- Training and Tools

2

Organizational Design

BPA is organized into three business units:

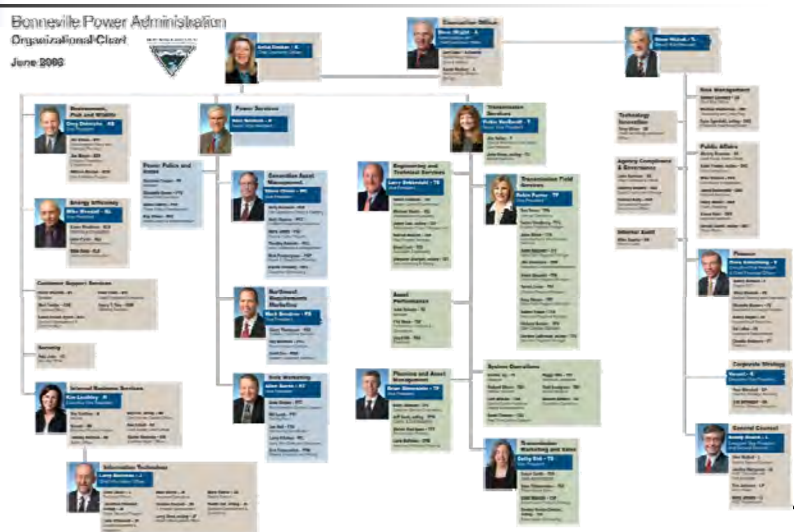
Power Business Services: Approximately 250 employees. BPA markets the power generated at 31 Federal dams, one non-Federal nuclear plant at Hanford, Washington, and some non-Federal power plants, such as wind projects.

Transmission Business Services: Approximately 1,600 employees. BPA owns and operates 75 percent of the Pacific Northwest's high-voltage electric grid. The grid includes more that 15,000 circuit-miles of transmission line and 235 substations. It carries a peak load of about 30,000 megawatts of electricity and produces about $700 million a year in transmission revenues.

Corporate: Approximately 1,100 employees. Includes Finance; Environment, Fish and Wildlife; Energy Efficiency; Customer Support Services; General Counsel; Planning and Governance; and Risk Management.

3

Organizational Design: Organizational Chart



4

Organizational Design: Transmission Org. Chart

Larry Bekkedahl – TE
Vice President
Engineering and Technical Services

Vickie VanZandt – T
Senior Vice President
Transmission Services

Cathy Ehli – TS
Vice President
Transmission Marketing & Sales

Robin Furrer - TF
Vice President
Transmission Field Services

Brian Silverstein – TP
Vice President
Planning & Asset Management

John Quinata - TG
Manager
Asset Performance

Hardev Juj – TO
Manager
System Operations

Bonneville Power Administration
Transmission Executive Team

5

Operations: Transmission Dispatch & Scheduling

- System Operations Dispatch – (NERC Certified System Operators)
  - 14 Senior Dispatchers – Shift supervisors
  - 10 Generation Dispatchers – Balancing Authority (BA)
  - 26 System Dispatchers
    - Dispatcher Training – 1 Training Coordinator / 3 full-time Dispatch trainers
    - Outage Offices – 2 Senior Outage; 4 Outage Dispatchers
- Transmission Scheduling
  - 6 Real-time Lead Schedulers
  - 20 Real-time Duty Schedulers
  - 4 Pre-Schedulers

6

Operations: System Dispatch

- Dittmer Dispatch
  - Five consoles manned 24/7
    - Senior Dispatcher – shift supervisor
    - Generation Dispatcher – AGC
    - Generations Dispatcher – RAS
    - System Dispatcher – West Main Grid
    - System Dispatcher – East Main Grid
    - 8 hour shifts – five person rotation / five week – built in relief week for training
    - All shift dispatchers (including Outage office) NERC Certified System Operators
  - Non-certified employees
    - Compliance/Governance Specialist
    - Interchange (numbers) clerk
    - Dispatch clerical staff
    - Manager Dittmer Dispatch – NERC certified system operator reliability

7

Operations: System Dispatch-Transmission

- The System Dispatcher performs duties in accordance with established system dispatching procedures, policies of the Administration, government regulations, and the Bonneville Power Administration (BPA) safety rules.
- Operate the BPA power System in a safe reliable manner
- Responsible for maintaining voltage schedules
- Responsible for maintaining reactive reserve margins
- Control switching and Clearance procedures for all high voltage switching on BPA system
- Directs real-time actions during normal, planned, and emergency conditions
- Adheres to all NERC/WECC Reliability standards
- Monitors alarms via SCADA/EMS and responds appropriately
- Curtailing/dropping load when needed.
- Authority to trip generation or interconnections to maintain the reliability of the BPA or WECC Interconnected system
- Authority to resolve unexpected or ongoing BPA transmission situations and/or to keep system operations within reliable operating limits

8

Operations: System Dispatch – Generation

- Generation Dispatchers monitor, operate, and coordinate the loading of Federal generation plants in the Pacific Northwest and the power interchange with interconnected utilities; monitor restricted transmission paths; monitor nomograms and set up the remedial action schemes as necessary to maintain a secure and reliable transmission system. The Generation Dispatcher performs duties in accordance with established system dispatching procedures, policies of the Administration, government regulations, and the Bonneville Power Administration (BPA) safety rules.
- Generation Dispatcher function is divided into two consoles
  - AGC control
  - RAS console

9

Operations: Automatic Generation Control (AGC)

- Operates Automatic Generation Control (AGC) computer systems, which control loading of Federal generation plants.
- Follows scheduled generation patterns and interchange schedules, except as necessary to do the following:
  - Adjusts tie-line interchange schedules when required by BPA or an interconnected utility.
  - Responds to emergency requests for operating reserves.
  - Takes appropriate action for emergency outages of generating units at Federal generation plants and informs PBL.
  - Provides for the emergency power requirements of customers when possible.
  - Authorizes power purchases from available sources to meet BPA's load requirements in emergencies.
  - Any other action necessary to maintain the security or reliability of the power system. This includes, but is not limited to, the loss of a facility, unscheduled flow, abnormal voltage responses, etc.

10

Operations: AGC Control Continued

- In cooperation with dispatchers of other utilities, incorporates their systems into BPA's Control Area.
- Approves removal from service of generating units at Federal generation plants.
- Monitors and maintains adequate operating reserves (both spinning and non-spinning) in conformance with BPA and other specified requirements.
- Maintains necessary records, calculates Inadvertent Interchange and Regulating Margin, and determines accuracy of telemetered quantities each hour.

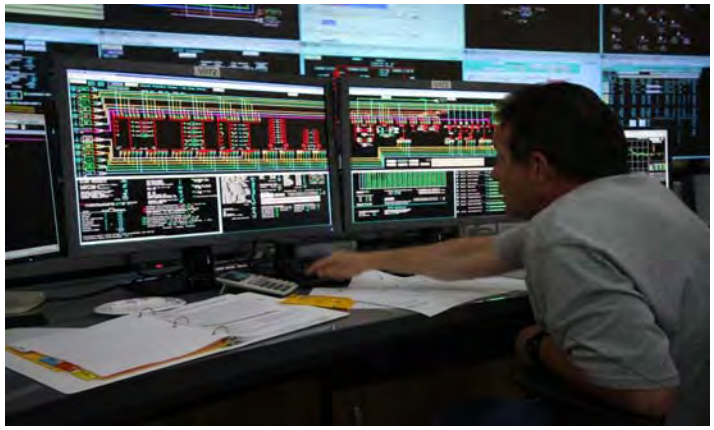
11

Operations: RAS Console

- Monitors various transmission lines and paths for loading and other conditions which require Remedial Action schemes (RAS) to be armed or disarmed, and takes appropriate action.
- Monitors various transmission lines and paths and responds as necessary to keep flows below, or restore flows to be below, the Operational Transfer Capability (OTC).
- Monitors the transmission system and establishes new OTCs as system conditions require.
- Monitors and coordinates removal of telemetering, and control and RAS circuits from the AGC computer system to ensure continuity of operation. Notifies appropriate maintenance personnel if repairs are needed.
- Monitors/Implements WECCnet messaging system

12

Operations: RAS Console



Operations: Senior Dispatcher

- Senior System Dispatchers are in charge and direct the work of all dispatching personnel on shift with them.
- Senior System Dispatchers are operational representatives of the Bonneville Power Administration and exercise broad discretionary powers in maintaining the safety, reliability, efficiency and integrity of the large interconnected transmission system.
- The Senior System Dispatcher is responsible for operating and controlling that part of the Bonneville Transmission System assigned by the Vice President of Transmission Services. This includes real-time operation of Federal generation and that part of the transmission system assigned to the control center (Dittmer/Munro), coordinating BPA system operation with interconnected utilities and ensuring compliance with applicable national and regional reliability criteria.

Operations: Senior Dispatcher

- The Senior is responsible for the safe, efficient and reliable operation and control of BPA's 1000kv HVDC, 500kv HVAC Main Grid transmission system including all associated power system equipment, 345kv, 230kv and below Sub Grid transmission system including all associated power system equipment, relaying and remedial action schemes.
- If necessary, the Senior System Dispatcher can assume jurisdiction of the entire BPA power system to provide limited AGC and complete transmission facilities backup in the event of failure at either of the BPA control centers.
- The Senior System Dispatcher has the responsibility to comply with NERC Standards and during emergency conditions has the authority to take or direct timely and appropriate real-time actions, up to and including shedding of firm load to prevent or alleviate Operating Security Limit violations. Authority for such actions is delegated from the Vice President for Transmission Services.
- The Senior System Dispatcher will be a key player in the coordination of restoration of the WECC Grid in the event of a major disturbance.

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Tools: Energy Management Tools

- Energy Management Tools
  - Mapboard
    - System Overview
    - Big picture view of switching, etc.
  - Supervisory Control & Data Acquisition (SCADA)
    - Real-time data (analog MW, kV, etc., and alarms)
  - Data Archiving Tool (PI)
    - Summary Information
    - Trending

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Tools: Dittmer Dispatch Floor


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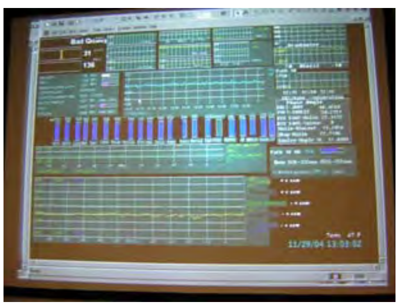
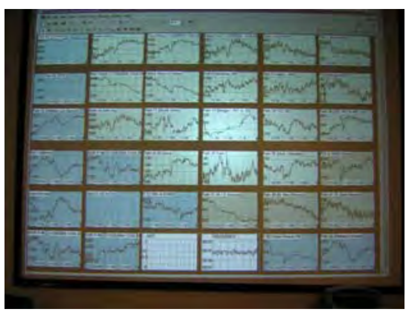
Tools: PI

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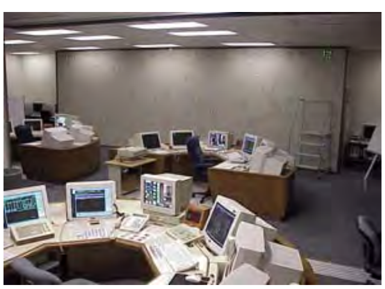
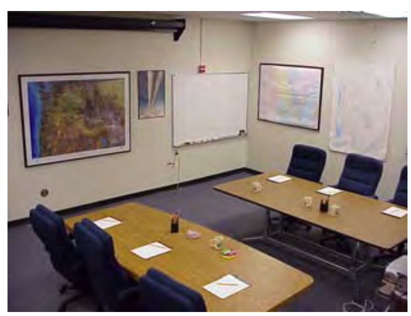
Dispatcher Training at Bonneville Power Administration

Training: Dispatch Training Facility





Training: What do we use it for?

- Restoration
- Emergency Operations
- Local Area Problems
- Voltage Collapse
- AGC training
- Timely Operation Issues

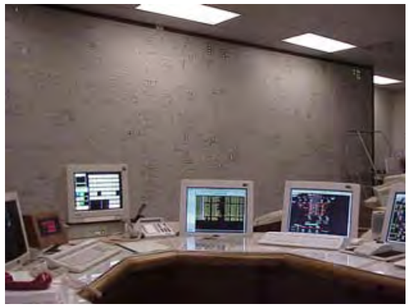
21

Training: Instructors

- Operate the simulator
  - Pause, Replay
- Monitor trainee progress
- Give feedback to trainees
- Role Playing
- Add unexpected events

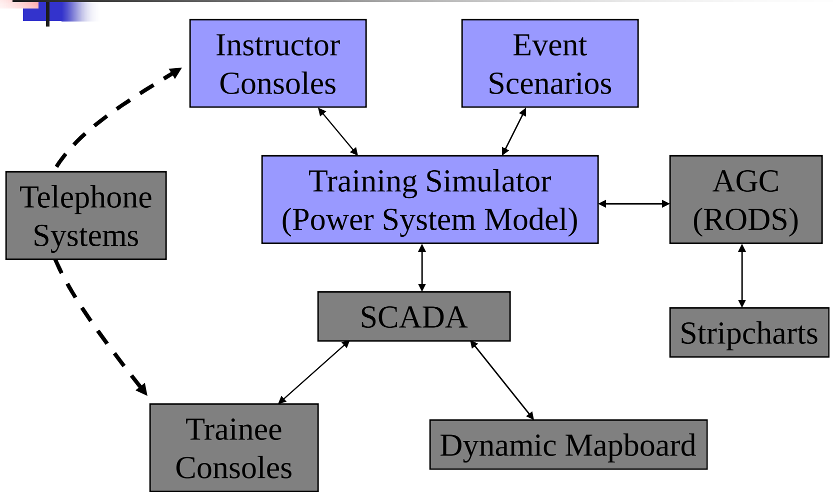
22

Training: Trainees



- Same tools they use real-time
  - SCADA displays
  - AVTEC Communications
  - Console configuration
  - Dynamic Mapboard

Training: EPRI OTS connects to BPA tools



Training: BPA Training Facility Objectives

- Realistic Environment
  - Same tools and displays
    - SCADA
    - State Estimator / Contingency Analysis
    - Historical Data / Stripcharts
    - RAS
  - Communications
- Training Tools capable of illustrating concepts
  - Voltage Collapse
  - Restoration
  - Detailed Model
  - System Dynamics / WECC wide behavior

25

Training: Training Experience

- Regular BPA session training
  - Each dispatcher provided 3 days of training, twice a year
    - 60 dispatchers split between 2 control centers
  - Each session typically runs 10-12 weeks.
- Individual Training
  - New hires
  - New Procedures
- Training Exercises
  - Emphasize communication, coordination, and an applied understanding of system theory

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Training: Typical Training Session

- Tuesday
  - Lectures on AGC, NERC/WECC policy, RAS
  - Blackstart Restoration Simulation
- Wednesday
  - Lectures on Voltage Control, Load Shedding (Automatic and Manual)
  - Local Area Problem Simulation
  - Manual Load Shedding Simulation
- Thursday
  - Lectures on Intertie Issues, Recent Disturbance Review
  - Workshop on Using PI tools
  - Disturbance Simulation

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Training: Creating a Training Session

- Idea (scenario)
- Identify Learning Objectives
- What is the best way to make sure trainees meet the objectives?
  - Integrate with Lecture
  - Student Participation
  - Discussion
- People
  - Communication is vital for realism. Role playing is essential.

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Questions?

29

Section 8

SMUD
INTER-CONNECTED OPERATIONS AND ORGANIZATIONAL REQUIREMENTS

1

Overview

- Environmental Issues
- Coordination
  - Emergency Standards
    - Prudent Utility Practices
    - WECC and NERC standards
    - Procedures
  - System Restoration
    - Procedures and Training
- Congestion

2

Environmental

- Sacramento Air Quality Board
  - Limitations on emissions from thermal power plants (total output)
  - Pollution offsets required for new thermal generators
- Hydro re-licensing
  - Hydro plants built on Federal land under 50 year lease (license) agreement
  - New operating license in final phases of negotiation

3

Environmental

- New construction
  - Environmental impact Report (EIR)
  - Public meetings
  - Board approval
- Emergency generators
  - Facilities
  - Constrained by air quality issues
  - License to test for limited hours each year

4

Coordination

Standards based

- Prudent Utility Practices
  - "common sense" operating practices
  - keep the lights ON
- WECC
  - over 1100 pages of standards
  - covered in 13 sections
  - Can be viewed on internet –www.wecc.biz
  - WECC funds "Reliability Coordinators" throughout region (electric grid police and fire department)

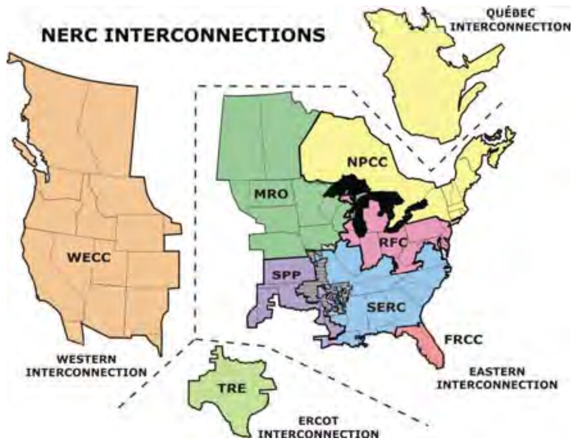
5

Coordination

- NERC
  - Standards – at a higher level; applicable to all North American interconnected entities
  - WECC standards are written for "local" conditions; variations in operating conditions north to south, east to west
- WECC maintains "Reliability Coordinators" for it's Region

6

WECC and NERC (again)



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Coordination

- Procedures Coordinate Operations
  - Based on WECC and NERC standards
  - Required documentation on all aspects of system operation
  - Most important - Emergency Operations (Black start) and Grid Reliability (Load-Gen balance, Reserves)
  - Inter-operation procedures provided to adjacent entity

8

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-2
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities
   - **4.2.** Reliability Coordinators
   - **4.3.** Load-Serving Entities
5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

- **R6.1.** Loading all available generating capacity.
- **R6.2.** Deploying all available operating reserve.
- **R6.3.** Interrupting interruptible load and exports.
- **R6.4.** Requesting emergency assistance from other Balancing Authorities.
- **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and

- **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

- **R7.1.** Manually shed firm load without delay to return its ACE to zero; and
- **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff (See Attachment 1-IRO-006-0 "Transmission Loading Relief Procedure" for explanation of Transmission Service Priorities):

- **R9.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.
- **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.
- **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.
- **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency

conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 Energy Emergency Alert Levels.

M5. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Timeframe

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 4 and 5 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for a Reliability Coordinator:**

- **2.1. Level 1:** Did not submit the report to NERC as required in R9.2.
- **2.2. Level 2:** Not applicable.
- **2.3. Level 3:** Not applicable.
- **2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
  - **2.4.1** One or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate. (R2)
  - **2.4.2** There is no evidence an Emergency Alert was issued as specified in R8
  - **2.4.3** Failed to comply with R9.3 or R9.4
  - **2.4.4** Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.

3. **Levels of Non-Compliance for a Balancing Authority:**

- **3.1. Level 1:** Not applicable.
- **3.2. Level 2:** Did not provide evidence that it has the responsibility and clear decision-making authority in accordance with R1.
- **3.3. Level 3:** Not applicable.

Coordination

Restoration

- Distribution
  - local outages affecting a single utility
  - Storm related (lightning, wind, flooding)
- Extreme
  - Cascading event
  - Wide area outage (NE blackout affected US and Canada - Aug 14, 2003)

11

Coordination

- Blackout
  - Black start procedures
  - Generation capable of self-starting
  - Procedures in place
  - Training on procedures
- Assistance
  - Adjacent areas may be able to provide assistance for local problems
  - Contracts typically established that define the terms
  - Reliability Coordinators will direct emergency operations for widespread grid problems

12

Congestion

- Congestion Model operated by California Independent System Operator (CAISO)
- Controls electric prices in California
- Managed by all Control Areas
- BPA, SMUD and CAISO manage the north-south path between Oregon and California

13

Questions/Discussion

14

BPA Inter-Connected Operations and Organizational Requirements

1

Topics

- Reliability: Standards and Organizations
  - NERC
  - FERC
  - WECC
  - NWPP
- Treaties
- Hydro Coordination Issues
- Economic Operations

2

Reliability: North American Electrical Reliability Corporation (NERC)

- *"NERC's mission is to improve the reliability and security of the bulk power system in the United States, Canada and part of Mexico. The organization aims to do that not only by enforcing compliance with mandatory Reliability Standards, but also by acting as a "force for good" -- a catalyst for positive change whose role includes shedding light on system weaknesses, helping industry participants operate and plan to the highest possible level, and communicating Examples of Excellence throughout the industry. "* NERC

3

Reliability: What is NERC?

- Formed by regional reliability councils in 1968 in response to the 1965 Northeast U.S. blackout
- A self-regulatory organization relying on reciprocity & mutual self-interest
- Involves all entities whose operations affect the bulk power system
- Mission: to ensure that the North American bulk power system is reliable, adequate & secure

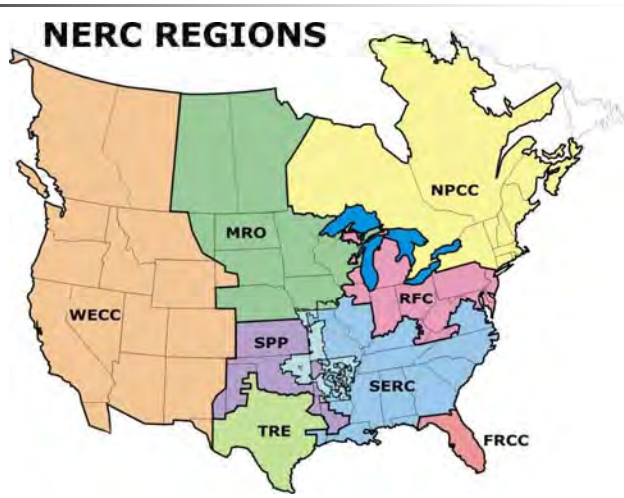
4

Reliability: What Does NERC Do?

- Sets reliability standards for bulk power system
- Monitors & assesses compliance with standards
- Provides education & training resources
- Conducts reliability assessments
- Analyzes disturbances
- Facilitates information exchange & coordination
- Supports reliable system operation & planning
- Certifies reliability organizations & personnel
- Coordinates physical & cyber security
- Administers conflict resolution procedures

5

Reliability: US Electrical System Regions



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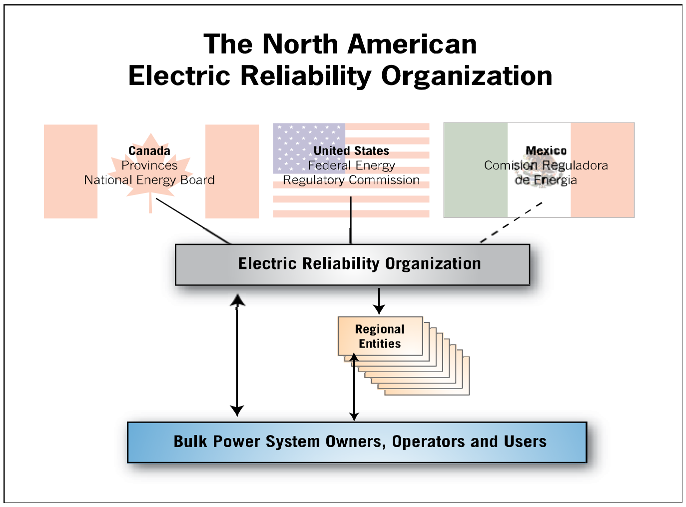
Reliability: Relationship Between Entities



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Reliability: Regional Reliability Standards

- Regions may develop regional standards subject to defined criteria (next slide)
- <u>All</u> enforceable reliability standards must be approved by the Electric Reliability Organization (ERO) and FERC
- Regions may use ERO procedure to develop regional standards
- Regions may use their own ERO-approved standards development procedure

8

Reliability: Regional Standards Criteria

- Standards proposals from Interconnection-wide regions (e.g., WECC and ERCOT) get rebuttable presumption at ERO that they meet the "just & reasonable" test
- ERO reviews for:
  - Fair and open process
  - No adverse impacts on other Interconnections
  - No threat to public health, safety, welfare, or national security
  - No undue impact on competition
- Other regions have burden of proof to show:
  - Just and reasonable
  - Justifiable difference, e.g., arising from different electrical system (physical) characteristics
- Goal: greater consistency across North America

9

Reliability: Penalties and Sanctions

Violation Risk Factor	Violator Size & Time Horizon Limits	Violation Severity Level			
		Lower	Moderate	High	Severe
Lower	Base Penalty	$1,000	$3,000	$6,000	$10,000
	Lower	$1,000	$1,000	$1,500	$2,000
	Upper	$2,000	$6,000	$12,000	$20,000
Medium	Base Penalty	$5,000	$15,000	$25,000	$40,000
	Lower	$2,000	$3,000	$5,000	$8,000
	Upper	$10,000	$30,000	$50,000	$80,000
High	Base Penalty	$35,000	$50,000	$70,000	$100,000
	Lower	$7,000	$10,000	$14,000	$20,000
	Upper	$70,000	$100,000	$140,000	$200,000

Statutory limit: $1,000,000 per day

Non-financial sanctions allowed

Penalty funds may be used to offset following year's assessment

Other factors (aggravating and mitigating) for consideration:

- **Repeat infractions**
- **Prior warnings**
- **Deliberate violations**
- **Self-reporting and self-correction**
- **Quality of entity compliance program**
- **Overall performance**

10

Reliability: NERC Reliability Blocks

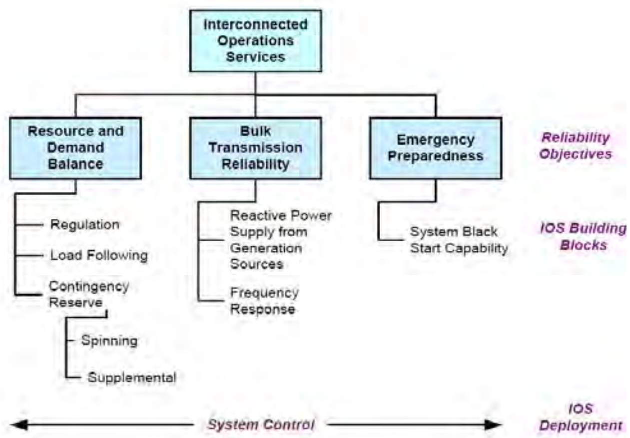


Figure 1 – IOS as Reliability Building Blocks

11

Reliability: NERC Balancing

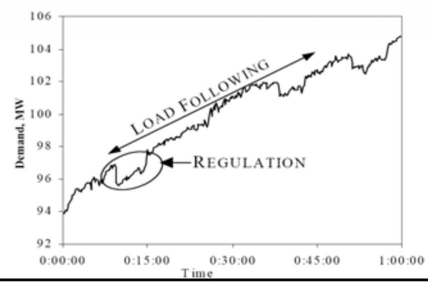
Table 1 – Overview of Resource and Demand Balancing IOS Objectives

IOS		Reliability Objective	
		Normal operating state	Post-contingency
REGULATION		Follow minute-to-minute differences between resources and demand.	
LOAD FOLLOWING		Follow resource and demand imbalances occurring within a scheduling period.	
FREQUENCY RESPONSE[4]			Arrest deviation from scheduled frequency.
CONTINGENCY RESERVES	SPINNING		Restore resource and demand balance, usually after a contingency.
	SUPPLEMENTAL		Restore resource and demand balance after a contingency

12

Reliability: NERC Deployment

	Deployment Period		
Continuous	Seconds	Minutes	Hours
Regulation			
Load Following			
Post Contingency			
Frequency Response			
Contingency Reserve - Spinning			
Contingency Reserve - Non-Spinning			



13

Reliability: FERC -- Federal Energy Regulatory Commission

- FERC is responsible for:
  - Regulating the interstate transmission of natural gas, oil, and electricity.
  - Regulating the wholesale sale of electricity (individual states regulate retail sales).
  - Licensing and inspecting hydroelectric projects.
  - Approving the construction of interstate natural gas pipelines, storage facilities, and Liquefied Natural Gas (LNG) terminals.
  - Monitoring and Investigating Energy Markets.

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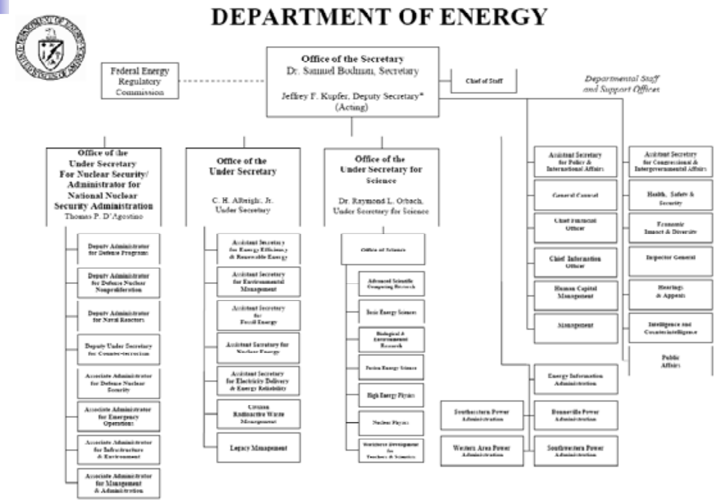
Reliability: FERC



15

Treaty Issues: LBJ & Pearson at the Peace Arch on 16 September 1964

ATIONAL ANTHEMS—Speakers and guests at the ceremony for the signing of e Columbia River Treaty stand at attention during the playing of both countries' tional anthems. Three bands played the music: the Bellingham High School and, the Fort Lewis Army band and a Canadian Navy band. From left to right e Washington Gov. Albert D. Rosellini, President Johnson, Vermont Sen. George Aiken, ranking Republican on the Senate Foreign Relations Committee, Arkansas Sen. James W. Fulbright, chairman of the Senate Foreign Relations Committee (white raincoat), Arthur Laing, Canada's Minister of Northern Affairs, Canadian Prime Minister Lester Pearson and British Columbia Premier W.A.C. Bennett. —Herald photo.

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Treaty Issues: Columbia River Treaty

- On September 16, 1964 U.S. President Lyndon Johnson and Canadian Prime Minister Lester Pearson met at the Peace Arch in Blaine, Washington (U.S.A) to proclaim and sign the Columbia River treaty.
- The treaty and a series of international agreements set the stage for west coast wide electric energy generation and flood control.
- Negotiations led to land mark agreements that delivered the Canadian share of the power from Canada (Canadian entitlement) to the Pacific Northwest area, for 30 years.

17

g1

Treaty Issues: Columbia River Treaty

- President Lyndon Johnson:

" This system is also the proof of the power of cooperation and unity. You have proved that if we turn away from division, if we just ignore dissention and distrust, there is no limit to our achievement."

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Slide 18

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g1 gdb5351, 7/11/2008

Economic Operations

- BPA sets separate transmission and power rates.
- Rates are based on the "cost" of operating the BPA transmission and power system.
- Rates for "surplus" power, when available, are marked based.
- Power and transmission capacity sold in a product mix
  - Long/short term
  - Firm/non-firm

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Economic Operations

- Transmission rates: Network Point to Point based.
- BPA "markets" transmission on a transparent web-interface system called "OASIS"
- BPA sells surplus power thru a trading floor.
- Legally-binding contracts are developed for:
  - Integrating new generations (interconnection agreements)
  - Serving new loads.
  - Providing transmission services

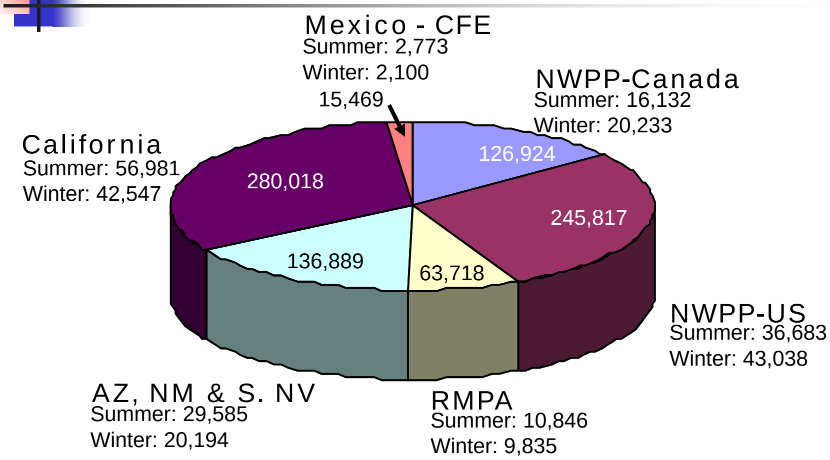
20

Economic: Business Operations

- How does BPA Load Area compare?
- Who are BPA's Customers?
- Where does the income come from?
- How effective is BPA at delivering affordable power?
- Maintenance Costs
- Efficiency goals and results.

21

Economic: Comparison of Load Size



Annual GWh with Summer & Winter Peaks

22

Economic: BPA Customers

- **Publicly Owned Utilities** - Bonneville's principal customer base consist of Northwest regional public utilities and municipalities, plus cooperatives; referred to as "preference customers" because they are entitled to a statutory preference and priority in the purchase of available Federal power. Preference customers are eligible to purchase power at Bonneville's PF rate for most of their loads.
- **Investor Owned Utilities** - consists of six regional IOU's that Bonneville provides firm power to under contracts other than long-term firm requirements power sales contracts. Bonneville also sells substantial peaking capacity to these regional IOU's. Recently Bonneville has entered into agreements with these utilities in settlement of Bonneville's statutory obligation to provide benefits under the Residential Exchange Program, for specified periods beginning 10/1/2001.
- **Direct Service Industries** - primarily consists of aluminum smelters (95%) plus some other industries. Under the Northwest Power Act, Bonneville signed long-term contracts with the DSI's in 1981- these contracts expired in 2001. Since 2001, Bonneville has had varying contractual relationships with the DSI's; currently Bonneville serves some DSI load.
- **Customers Outside the Northwest** – consists of public and investor owned utilities in the Southwest and California. Bonneville sells and exchanges power via the Intertie to these customers. These sales and exchanges are composed of firm power and non-firm energy surplus to Bonneville's regional requirements.

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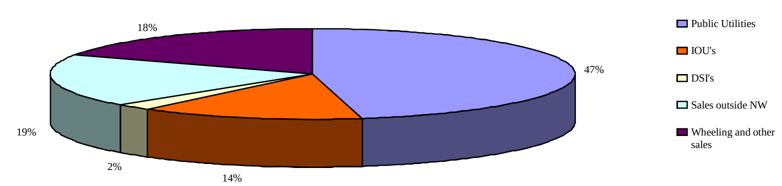
Economic: Revenues by Customer Group 2006

FY 2006 Revenues by Customer Group*



1. **Publicly Owned Utilities ($1,712M)**
   Northwest Regional Municipalities, Public Utility Districts
   And Cooperatives
2. **Investor- Owned Utilities ($503M)**
   Includes PGE, Puget, Pacificorp, and other smaller IOU's
3. **Direct Service Industries ($80M)**
   Aluminum Smelters
   Chemical, Paper, and other metal industries
4. **Sales outside the Northwest ($692M)**
   Public and investor owned utilities in the Southwest and California

5.. **Wheeling and other sales ($654M)**

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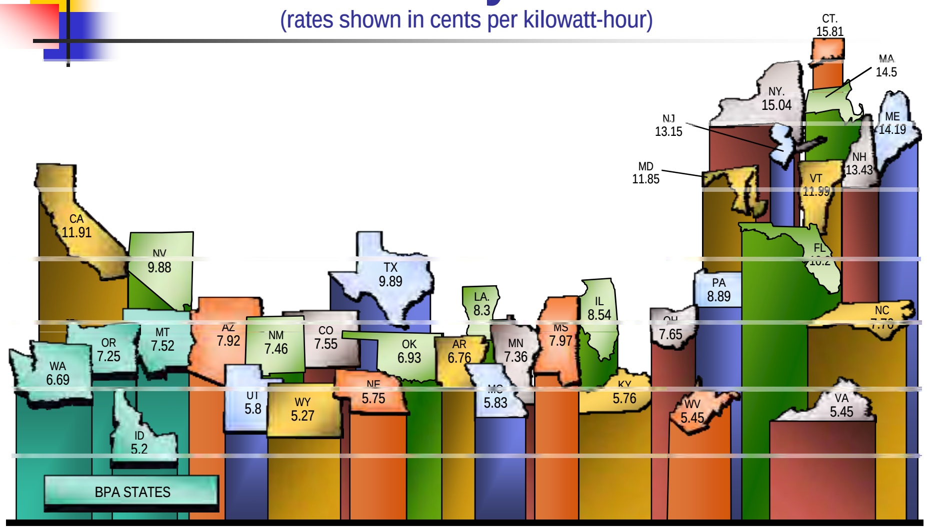
Economic: Ranking of Average Retail Electricity Rates

(rates shown in cents per kilowatt-hour)

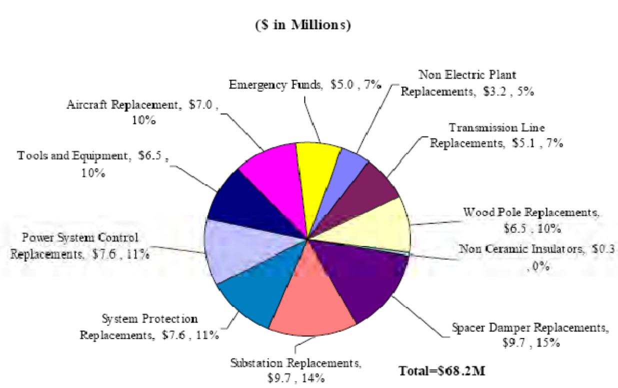


2007

25

Economic: Maintenance Costs

System Replacements Average 2008-2009



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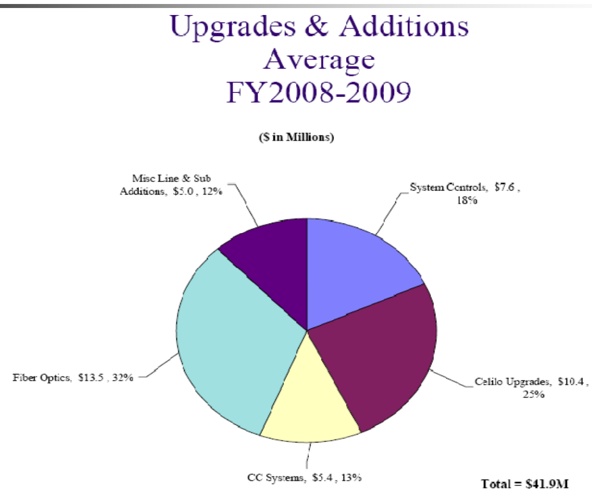
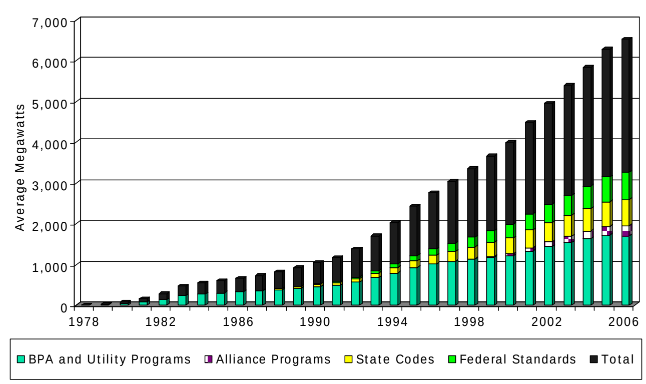
Economic: Maintenance Costs



27

Economic: PNW Energy Efficiency Achievements 1978 – 2006



Northwest Power and Conservation Council

Since 1978 Utility & BPA Programs, Energy Codes & Federal Efficiency Standards Have Produced *Nearly* 3,300 aMW of Savings.

28

Coordination: The Need for Coordination in the PNW

- Agreements - Columbia River Treaty, PNCA, MCHC
- Coordination creates certainty for a variable resource (like hydro), maximizes generation output of limited fuel, and helps "shape" resources to meet load.
- Provides participants with protection from changes to anticipated upstream storage releases.
- Columbia River Treaty (with Canada) assumes that PNW resources are coordinated.

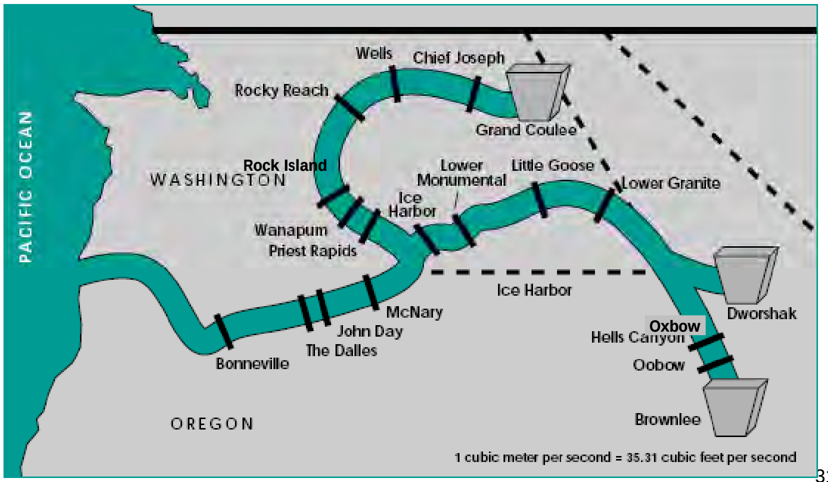
29

Coordination: Pacific Northwest Coordination Agreement

- Enables the optimized operation of the US projects to meet both power and nonpower River demands
- 17 party agreement, signed in 1964
- Took 8 years to renegotiate (1997)
- 29% of Treaty returns come from the non-Federal owners of the Mid-C projects

30

Coordination: Hourly Coordination Problem



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Section 9

SMUD
INTER-AREA COORDINATION:
GENERAL

1

Overview

- Information Exchange
  - Proprietary data
  - Operating information
  - Communication methods
  - Non-disclosure agreements
- Planning (Power)
- Interchange Schedules and Inter-ties
  - Scheduling – e-tag, contract with OATI
  - Coordinated schedules – approved tags
  - Hourly schedule checkout – before hour, after hour, spreadsheet tool
  - ACE issues
  - Problems – Inadvertent flows, System stability
- Benefits and Issues

2

Information Exchange

- Proprietary data
  - Data is typically proprietary since the start of de-regulated markets
  - Agreements for data sharing
- Operating information
  - Certain data must be exchanged in order to operate effectively – tie points, line flows, breaker positions
  - Events affecting other Control Areas
- Communication methods
  - Usually ICCP
  - Phone – land line; cell phone backup; satellite phone
  - WECC-net: computer based messaging system through WECC
- Non-disclosure agreements
  - Contract stating data obtained will not be sent to another entity

Information Exchange - other methods

Planning

- Load forecasting
  - EMS – next 10 minutes
  - hourly, next day, next week, yearly peak prediction
- Forecast tools – software, weather
  - same day – load average of days with same temperature
  - time of year – date based
  - equivalent load – based on load forecast
  - SMUD has contracts with 3 different weather forecasters
- Power Flow analysis
  - Analysis of the electric system for varying extreme conditions of load, temperature and outages
- Contingency Analysis
  - Network application for real-time analysis of possible events based on the current condition of the electric system

5

Interchange Schedules and Inter-ties

Key Issues Affecting Operations

- Area Control Error – ACE [= Scheduled interchange MW – Actual Interchange MW]
- Voltage / Frequency [maintain 230kv / 60Hz]
- Grid Reliability
- WECC and NERC Policy (Reliability)
- Customers
- Load / Weather
- Outages – Planned, Forced
- System limitations – Imports, Generation
- Coordinated Operations – Adjacent Control Areas, Power Contracts, Power Schedules
- Grid Control – EMS / SCADA, equipment malfunction
- Infrastructure damage due to storms, theft, etc

6

Interchange Schedules and Inter-ties

Interconnected Operations

- Schedules for all power deliveries – imports and exports (Electronic tags or “e-Tags”)
- Generation and load balanced to remain “on Schedule”
- “Off Schedule” results in +/- ACE; negative = under-generating; positive = over-generating
- All entities within WECC must assist for under-frequency conditions – frequency bias
- Emergency assistance typically from adjacent utility/Control Area

7

A. Introduction

1. **Title:** **Real Power Balancing Control Performance**
2. **Number:** BAL-001-0
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:**
   4.1. Balancing Authorities
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ε_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \text{ or } \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

R2. Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10\text{-}minute}(ACE_i) \le L_{10}$$

where:

$$L_{10} = 1.65\,\epsilon_{10}\sqrt{(-10B_i)(-10B_s)}$$

ε_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3. Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.

R4. Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

M1. Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPS1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12\text{-}month}}{(\epsilon_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-}month}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{clock\text{-}minute} = \frac{\left(\frac{\sum ACE_{sampling\ cycles\ in\ clock\text{-}minute}}{n_{sampling\ cycles\ in\ clock\text{-}minute}}\right)}{-10B}$$

$$\Delta F_{clock\text{-}minute} = \frac{\sum \Delta F_{sampling\ cycles\ in\ clock\text{-}minute}}{n_{sampling\ cycles\ in\ clock\text{-}minute}}$$

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The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{clock\text{-}minute} = \left[\left(\frac{ACE}{-10B} \right)_{clock\text{-}minute} * \Delta F_{clock\text{-}minute} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{clock\text{-}hour} = \frac{\sum CF_{clock\text{-}minute}}{n_{clock\text{-}minute\ samples\ in\ hour}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{clock\text{-}hour\ average\text{-}month} = \frac{\sum_{days\text{-}in\text{-}month} [(CF_{clock\text{-}hour})(n_{one\text{-}minute\ samples\ in\ clock\text{-}hour})]}{\sum_{days\text{-}in\text{-}month} [n_{one\text{-}minute\ samples\ in\ clock\text{-}hour}]}$$

$$CF_{month} = \frac{\sum_{hours\text{-}in\text{-}day} [(CF_{clock\text{-}hour\ average\text{-}month})(n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages})]}{\sum_{hours\text{-}in\text{-}day} [n_{one\text{-}minute\ samples\ in\ clock\text{-}hour\ averages}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-}month} = \frac{\sum_{i=1}^{12} (CF_{month\text{-}i})(n_{(one\text{-}minute\ samples\ in\ month)\text{-}i})]}{\sum_{i=1}^{12} [n_{(one\text{-}minute\ samples\ in\ month)\text{-}i}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

M2. Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{Violations_{month}}{(Total\ Periods_{month} - Unavailable\ Periods_{month})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if } \left| \frac{\sum ACE}{n_{samples\ in\ 10\text{-}minutes}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{samples\ in\ 10\text{-}minutes}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Attachment 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-0
3. **Purpose:**

   The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**

   4.1. Balancing Authorities

   4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

   4.3. Regional Reliability Organizations
5. **Effective Date:** April 1, 2005

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently

than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

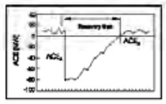
For loss of generation:

if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

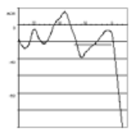


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

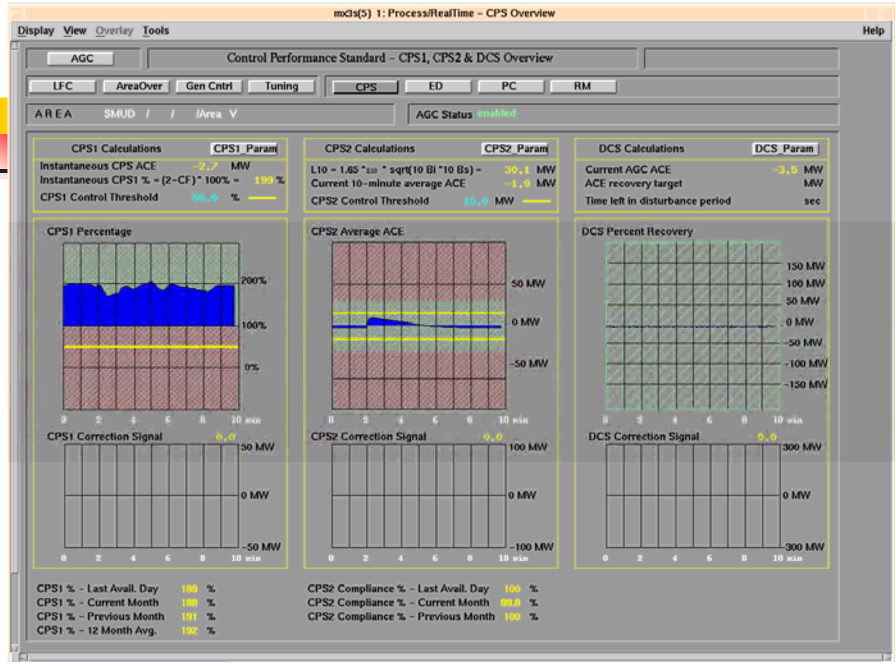
Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Interchange Schedules and Inter-ties

Interconnected Operations

- Each hour – energy (kWh) must agree at all tie points with adjacent Control Areas; If not, problem must be discovered
- For a generator that trips off-line, recovery (ACE = 0) must be within 15 minutes
- Largest generator = MSSC (Most Severe Single Contingency)
- There must be reserves to cover the MSSC – 50% from Spinning reserves; 50% from Quick Start reserves
- Frequency bias is built into each Control Area's ACE equation to provide immediate assistance by ALL to return frequency to 60 Hz
- Special considerations for Wind Power



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Interchange Schedules and Inter-ties

- Metering
  - MW / MWH
  - Generation
  - Ties to adjacent Control Areas
  - Maintenance issues:
    - Maintaining calibration
    - Yearly coordinated inspection and calibration
    - Expense

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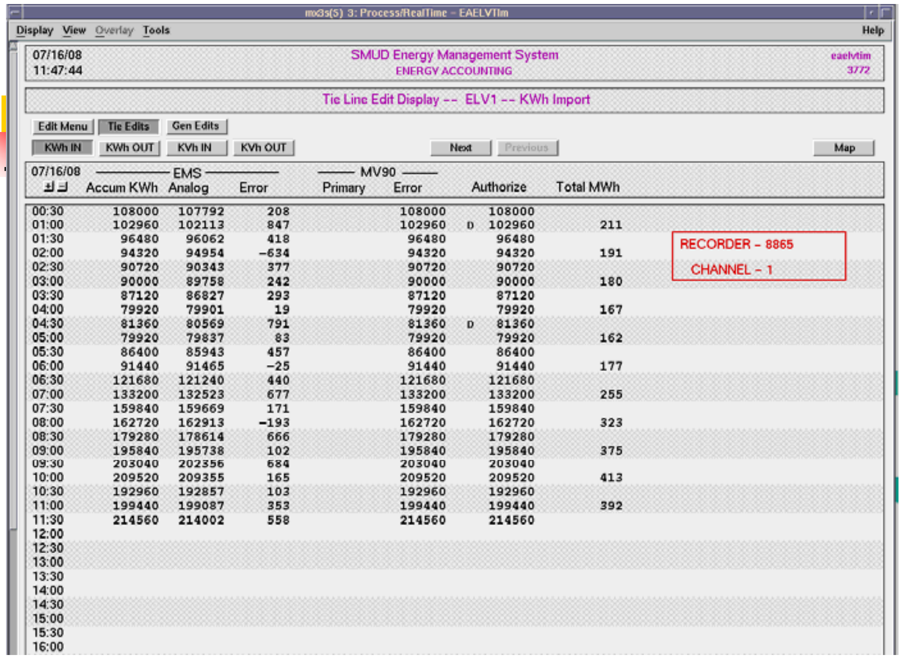

mx3s(5) 3: Process/RealTime – EAELVTIm

Display View Overlay Tools Help

07/16/08
11:47:44

SMUD Energy Management System
ENERGY ACCOUNTING

eaelvtim
3772

Tie Line Edit Display -- ELV1 -- KWh Import

Edit Menu | Tie Edits | Gen Edits

KWh IN | KWh OUT | KVh IN | KVh OUT | Next | Previous | Map

07/16/08	EMS			MV90			
	Accum KWh	Analog	Error	Primary	Error	Authorize	Total MWh
00:30	108000	107792	208	108000		108000	
01:00	102960	102113	847	102960	D	102960	211
01:30	96480	96062	418	96480		96480	
02:00	94320	94954	-634	94320		94320	191
02:30	90720	90343	377	90720		90720	
03:00	90000	89758	242	90000		90000	180
03:30	87120	86827	293	87120		87120	
04:00	79920	79901	19	79920		79920	167
04:30	81360	80569	791	81360	D	81360	
05:00	79920	79837	83	79920		79920	162
05:30	86400	85943	457	86400		86400	
06:00	91440	91465	-25	91440		91440	177
06:30	121680	121240	440	121680		121680	
07:00	133200	132523	677	133200		133200	255
07:30	159840	159669	171	159840		159840	
08:00	162720	162913	-193	162720		162720	323
08:30	179280	178614	666	179280		179280	
09:00	195840	195738	102	195840		195840	375
09:30	203040	202356	684	203040		203040	
10:00	209520	209355	165	209520		209520	413
10:30	192960	192857	103	192960		192960	
11:00	199440	199087	353	199440		199440	392
11:30	214560	214002	558	214560		214560	
12:00							
12:30							
13:00							
13:30							
14:00							
14:30							
15:00							
15:30							
16:00							

RECORDER – 8865
CHANNEL – 1

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Interchange Schedules and Inter-ties

- Metering
  - Operations
    - Values on the EMS (Energy Accounting)
    - Hourly checkout with adjacent CA
    - Data archive
    - Data retention for disputes
- Procedures for Inter-area operations

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Interchange Schedules and Inter-ties

- Scheduling – e-tag, contract with OATI
  - Electronic tag required for all energy transactions (one exception);
  - Must be approved by all affected entities in the path
  - SMUD has a contract with OATI to provide this and other services (reduction in staff, hardware)
- Coordinated schedules
  - ALL approved tags affecting an entity are provided as a net value
  - Schedules are coordinated through the e-tagging system
  - Hourly schedule checkout – before hour, after hour, spreadsht tool
  - ACE issues

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Interchange Schedules and Inter-ties

- Hourly schedule checkout – before hour, after hour, spreadsheet tool
  - Phone call to all adjacent Control Areas to confirm last hour accumulator values (at ties) and next hour schedule
  - SMUD also uses a spreadsheet to summarize schedule data, generator schedules, and other data
- ACE issues
  - Meters at tie points (summed) are used to compare real energy flow against scheduled (net) energy flow
  - Instantaneous deviations (MW) affect ACE
  - Hourly deviations (MWH) contribute to accumulated inadvertent

Balancing Authority Desk

Tuesday, July 15, 2008

Create Next Day | Create CMRC | Reload Next Day | Refresh Today | Highlight Cells

Predicted Temps: High 91 Low 61

Nomogram Selection: SMUD 2-1, SMUD 2-1b, SMUD 2-2, SMUD 2-2b, SMUD 2-2c, SMUD 2-2d, SMUD 2-3, SMUD 2-3b, SMUD 2-4, SMUD 2-4b, SMUD 2-4c, SMUD 2-5, SMUD 2-6, SMUD 2-6b, SMUD 2-6c

SMUD System

Load Forecast	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Pre-Schedule	1209	1114	1062	1034	1049	1107	1177	1277	1375	1480	1583	1688	1777	1919	2071	2224	2330	2387	2294	2121	1950	1820	1591	1375	39014
RT Schedule	1186	1105	1045	1020	1043	1112	1176	1266	1348	1418	1498	1569	1620	1744	1825	1936	2032	2065	2004	1859	1730	1631	1443	1258	35933
Yesterday	1307	1198	1136	1102	1121	1193	1257	1347	1453	1559	1689	1825	1994	2152	2291	2395	2443	2409	2261	2039	1848	1733	1524	1322	40598
Today	1186	1105	1045	1020	1043	1112	1176	1266	1348	1418	1498	1569	1620	1744	1825	1936	2032	2065	2004	1859	1730	1631	1443	1258	35933
Comparable Day																									0
PSO Forecast	1186	1105	1045	1020	1043	1112	1176	1266	1348	1418	1498	1569	1620	1744	1825	1936	2032	2065	2004	1859	1730	1631	1443	1258	35933
Load Change		-141	-60	-25	23	69	64	90	82	70	80	71	51	124	81	111	96	33	-61	-145	-129	-99	-188	-185	

Generation	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
UARP	39	33	1	0	1	6	137	115	128	198	118	92	133	225	213	309	322	323	351	303	208	212	21	6	3494
Cosumnes	490	494	483	500	500	500	487	497	501	498	500	498	499	501	497	496	494	494	495	497	500	505	501	499	11926
Campbells Soup	111	111	107	98	100	110	115	145	144	140	140	141	138	141	141	140	138	140	140	139	141	140	124	124	3108
Procter CC	76	77	77	76	78	76	87	101	97	88	89	87	81	89	88	88	89	89	88	88	90	89	82	84	2054
Procter Peaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carson Ice CC	50	52	45	39	45	49	44	50	51	51	51	53	50	51	51	51	51	50	51	50	51	50	42	42	1170
Carson Ice Peaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
McClellan Peaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Keifer LFG	15	13	15	15	16	15	13	14	12	12	12	13	11	14	13	15	15	12	14	15	14	14	15	15	332
UC Davis	9	9	8	7	9	9	9	10	11	11	11	14	24	23	25	24	24	24	24	23	23	21	9	9	370
Other	0	0	0	0	0	0	0	0	1	0	1	1	1	2	1	1	1	0	2	0	0	0	0	0	11
Total Generation	790	789	736	735	749	765	892	932	945	998	922	899	937	1046	1029	1124	1134	1132	1165	1115	1027	1031	794	779	22465
Net Interchange	-398	-310	-310	-285	-292	-351	-274	-332	-408	-413	-580	-675	-679	-693	-801	-807	-899	-938	-837	-746	-708	-591	-658	-472	-13457
Interchange Ramp		-88	0	-25	7	59	-77	58	76	5	167	95	4	14	108	6	92	39	-101	-91	-38	-117	67	-186	
SMUD System Balance	2	-6	1	0	-2	4	-10	-2	5	-7	4	5	-4	-5	5	-5	1	5	-2	2	5	-9	9	-7	-11

Reserves	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Excess Spin	186	191	182	91	80	247	200	195	184	108	202	205	190	80	86	85	163	210	181	227	307	301	409	331	4581
Spin Sales/Purch	0	0	0	0	0	0	0	0	0	21	0	30	0	48	50	50	50	0	0	0	0	0	0	0	249
Excess Total	677	682	731	731	720	709	587	548	524	460	556	559	539	434	435	347	346	399	373	414	492	478	696	699	13,016
QS Sales/Purch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reg Up Required	4	35	0	9	23	1	30	27	32	27	24	24	55	27	53	32	11	20	27	44	9	47	0	78	639
Reg Down Required	27	30	8	0	6	29	7	38	34	43	38	25	8	40	37	27	38	20	48	46	33	128	62	0	772

WASN System

WASN System	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Load Forecast	788	735	697	673	666	682	722	753	814	884	951	1017	1083	1154	1215	1279	1316	1315	1284	1225	1153	1080	961	855	23,302
Net Interchange	-220	-235	-231	-225	-222	-205	-172	-150	-26	67	18	80	178	146	230	272	269	274	217	204	247	282	180	73	1,051
Generation	515	455	435	430	430	430	515	554	746	902	925	1076	1225	1261	1403	1513	1513	1511	1415	1324	1320	1281	1054	784	23,017
System Balance	-53	-45	-31	-18	-14	-47	-35	-49	-42	-49	-44	-21	-36	-39	-42	-38	-72	-78	-86	-105	-80	-81	-87	-144	-1,336

Reserves	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
Excess Spin	137	137	137	137	137	137	137	102	102	102	102	102	102	102	102	52	52	52	102	102	87	104	137	111	2574
Excess Total	76	76	76	76	76	76	76	9	9	9	9	9	9	9	9	9	9	9	9	9	9	77	76	76	887
Reg Up Required	0	0	0	1	12	24	17	73	59	0	42	60	0	53	32	5	3	0	0	10	6	0	0	0	397
Reg Down Required	16	4	1	0	0	0	0	0	0	13	0	0	4	0	0	0	0	33	16	0	0	79	71	0	237

Benefits and Issues

- Data from other areas used in system studies
- Greater reliability through increased system detail of other areas
- Information on outages for power scheduling
- Accurate interchange data reduces exchange (power) issues and billing disputes
- Hourly checkout provides preliminary agreement of power exchanges
- In US, market aspects prevent additional data exchanges from occurring

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Questions/Discussion

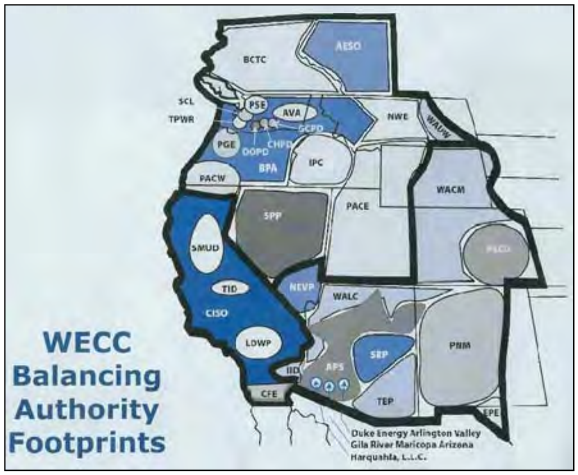
22

BPA INTER-AREA COORDINATION - GENERAL

Inter-Area Coordination: Types

- Western Interconnection (WECC)
- International Coordination (Canada, Mexico, U.S. government)
- Regional - Northwest Power Pool (NWPP)
- BPA and Adjacent utilities

Inter-Area Coordination: WECC Balancing Authorities



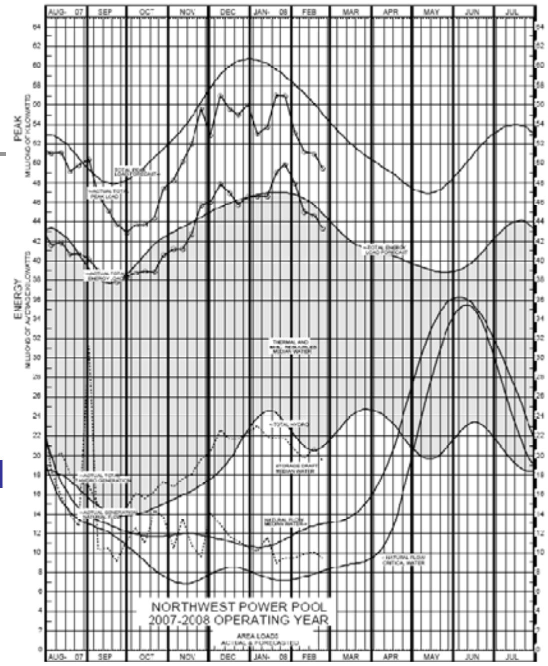
3

Regional: NorthWest Power Pool (NWPP)

- NORTHWEST POWER POOL (NWPP) serves as a forum in the electrical industry for reliability and operational adequacy issues in the Northwest, through both the transition period of restructuring and the future. NWPP promotes cooperation among its members in order to achieve reliable operation of the electrical power system, coordinate power system planning, and assist in transmission planning in the Northwest Interconnected Area.
- It is a voluntary organization comprised of major generating utilities serving the Northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating utilities in the region participate indirectly through the member system with which they are interconnected.
- The Pool was originally formed in 1942, when the federal government directed utilities to coordinate operations in support of wartime production. NWPP activities are largely determined by major committees - the Operating Committee, the PNCA Coordinating Group, and the Transmission Planning Committee.

4

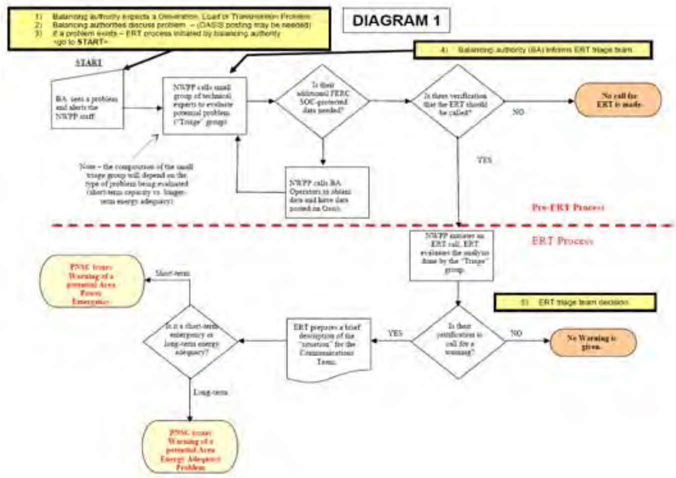
Inter-Area Coordination: NWPP Load and Generation actual vs. predicted



Regional: NWPP Load Shedding Agreement

Load Shedding			
Block #	***Hertz***	***Block%***	***Load%***
Block 1	59.3 Hz	5.6 %	5.6 %
Block 2	59.2 Hz	5.6 %	11.2%
Block 3	59.0 Hz	5.6 %	16.8%
Block 4	58.8 Hz	5.6 %	22.4%
Block 5	58.6 Hz	5.6 %	28.0%

Regional: NWPP Emergency Coordination Process



International Coordination: US and Canada

Bellingham Herald, Thursday, September 17, 1964

TREATY PACT AGREEMENT SIGNED—In the picture on the left, President Johnson goes through the formality of signing the treaty pact agreement for the Columbia River Treaty. The kibitzers looking over his shoulder are Washington Gov. Albert D. Rosellini and Sen. Henry Jackson. On the right a Canadian official hands Prime Minister Pearson the document while British Columbia Premier W.A.C. Bennett sits beside him ready to blot his signature.—Herald photo.

International Coordination: Columbia River Treaty

- Canada built three large storage reservoirs in SE British Columbia. The US built Libby Dam in Montana; its reservoir extends into Canada
- Storage increased from 5 MAF to over 20 MAF
- Operated for flood control and power only

9

Inter-Area Coordination: Organizations

- NERC
- WECC
- NW Power Pool
- Balancing Authorities: BPA SMUD
- Individual Utilities
- Other
  - Contracts
  - Operating agreements
  - Treaties
  - Procedures

10

Inter-Area Coordination: Benefits/Issues

- Benefits
  - Increases Transmission capacity and availability
  - Reduces Costs
  - Distributes benefits to wider markets
  - Maximizes efficiency and use of assets
  - Diversifies resources in markets

- Issues
  - Complex negotiations
  - Can take extended time to finalize
  - Documents must be clearly written to avoid misinterpretation.
  - Changes are difficult to make.
  - Requires commitment to work to solve common problems

11

Questions?

12

Section 10

SMUD
INTER-AREA COORDINATION:
SPECIFIC APPLICATIONS AND METHODS

1

Inter-area Coordination

Specific applications and Methods

- Technological solutions
  - DC Lines
  - Phase shifting transformers
  - Power electronics
  - Series Reactors
  - Series Capacitors
  - Metering
- Financial issues
  - Transaction agreements

2

Inter-area Coordination

- DC Lines
  - Control flows
  - Connect to other systems with different frequency
  - Asynchronous tie
- Phase shifting transformers
  - Limit power transfers
  - Power flow control
  - Maintenance requirements
  - Purchase expense
  - Maintenance expense
- Power Electronics
  - Accurate control of power flows
  - Maintain limitations
  - Purchase expense
  - Maintenance expense

3

Inter-area Coordination

- Series Reactors and Series Capacitors
  - Controlled by switching
  - Provides limitations on flows
- Metering
  - Accuracy (MWH)
  - Instantaneous (MW) – hourly integrated can be compared to MWH for accuracy check

4

Inter-area Coordination

- Transaction agreements
  - Long term contracts - energy (cost stability)
  - Short term contracts - energy (daily)
  - Operational contracts – maintenance, generation, reserves (cost stability)

5

Questions/Discussion

6

BPA Inter-Area Coordination: Specific Applications and Methods

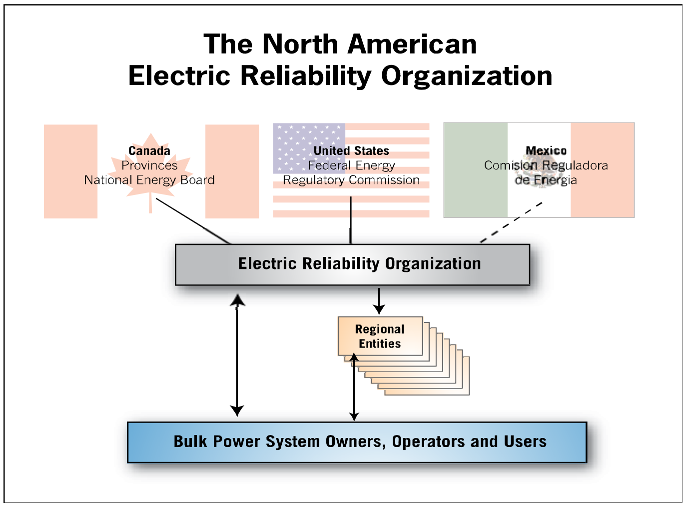
1

Inter-Area Coordination

- WECC example
- NWPP 45 day outage process
- Treaty issues
- Hourly Coordination

2

Inter-Area Coordination: Relationship Between Entities



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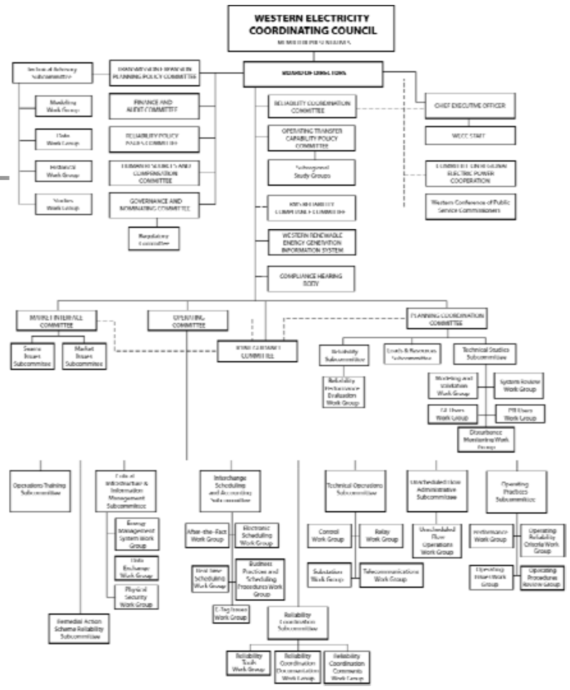
Inter-Area Coordination: WECC Example

- WECC operates through a series of committees, subcommittees, task forces groups, or work groups.
- Committee members represent utilities that are WECC members.
- Committees are assigned specific technical issues, problems or standards to work on and resolve.
- Example: WECC System Disturbance Rules.

4

Inter-Area Coordination: WECC Organizational Chart



Inter-Area Coordination: WECC Transmission Standards

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[e] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating [a] (A/R)	Applicable Rating [a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Single Single Single Single	A/R A/R A/R A/R	A/R A/R A/R A/R	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No [b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled [d] Planned/Controlled [d]	No No
	SLG or 3Ø Fault, with Normal Clearing [f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled [d]	No
	Bipolar Block, with Normal Clearing [f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [f]: 5. Any two circuits of a multiple Circuit towerline [g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled [d] Planned/Controlled [d]	No No
	SLG Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 6. Generator 7. Transmission Circuit 8. Transformer 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled [d] Planned/Controlled [d]	No No

6

Inter-Area Coordination: WECC System Disturbance Rules

WECC DISTURBANCE-PERFORMANCE TABLE
OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

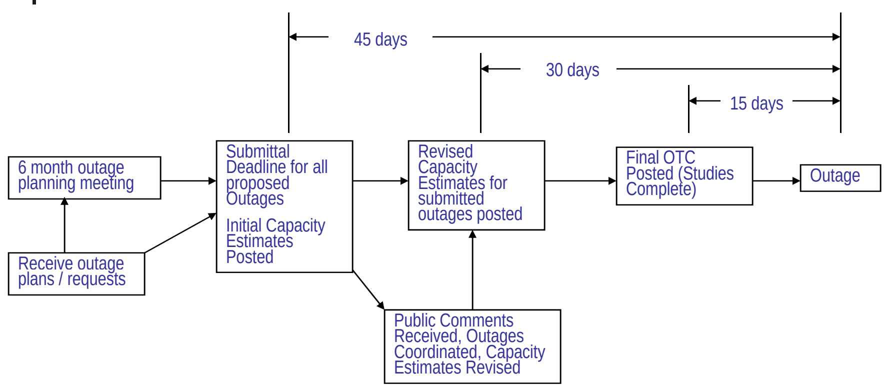
7

Inter-Area Coordination: NWPP 45 day Process

- NWPP Planning Process.
  - Coordinate outages up to a year in advance.
- 45 day process
  - Provides adequate time for studies, coordination to minimize impacts, and market notification.
  - Affects ALL Significant Equipment
  - Deadline for Outage Requests

8

Outage Process: Pacific Northwest Power Pool 45 day Outage Planning Process



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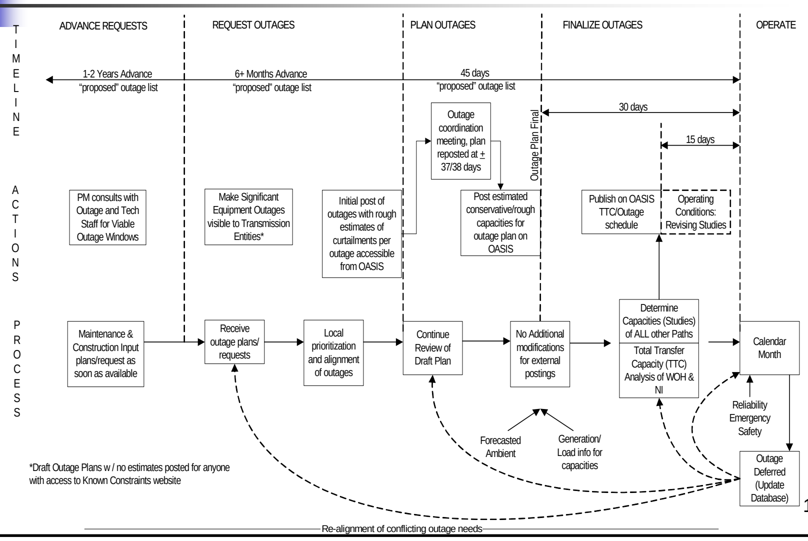
Outage Process: Detailed Outage Process



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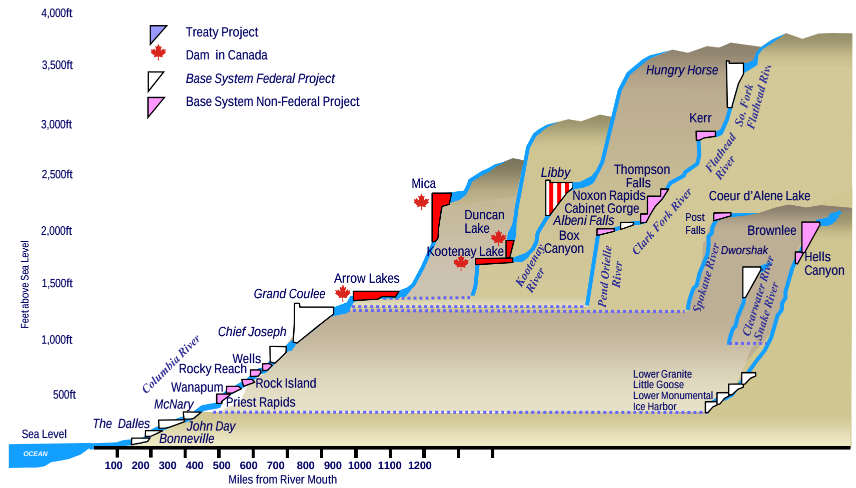
Inter-Area Coordination: Treaty Issues

- Treaty Planning is done on a rolling 6 year basis for power and flood control
- Outage coordination by the Northwest Power Pool is done on a rolling 24 month basis (includes both hydro & thermal units)
- Northwest Power Pool also looks at ability to meet forecasted load

Inter-Area Coordination: Treaty Issues (Cont.)

- The coordinated operation of the Canadian and US storage projects adds 2400 MW of capacity and 9.2 TWh of energy to the system’s annual production
- So current Entitlement returns to Canada are 1200 MW and 4.6 TWh

United States / Canada Treaty and Columbia River Base System Projects



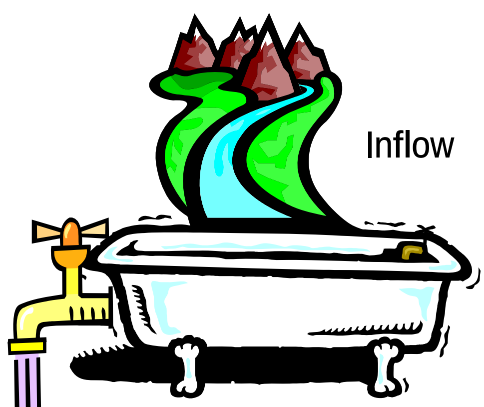
Inter-Area Coordination: Mid-Columbia Hourly Coordination Agreement

- Optimizes the hydraulic operation Grand Coulee, Chief Joseph, Wells, Rocky Reach, Rock Island, Wanapum, & Priest Rapids
- Energy deliveries are made within – hour between the generation projects, not to load
- Waiver for current agreement has been pending at FERC for some time

Inter-Area Coordination: A Broad View

15

Inter-Area Coordination: The Reservoir



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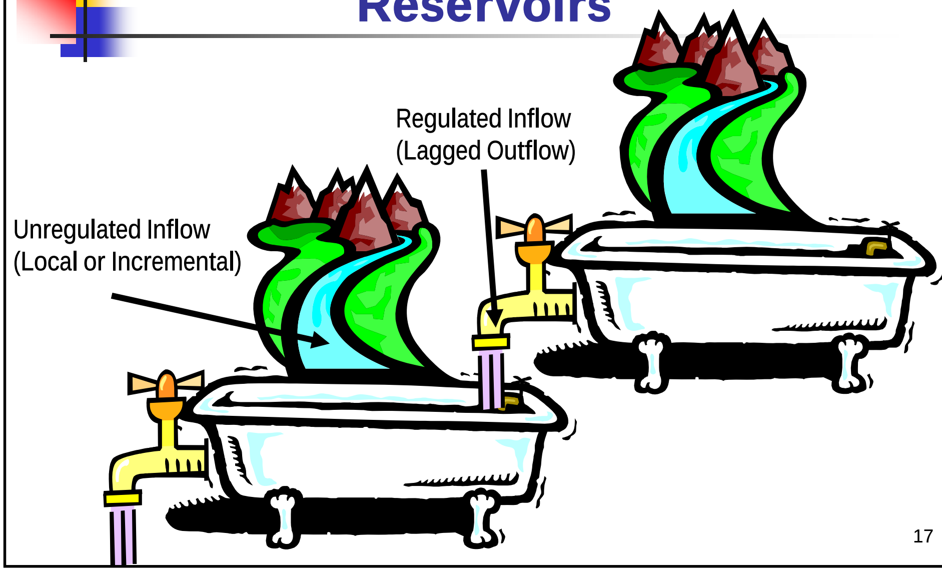
Inter-Area Coordination: Two Reservoirs



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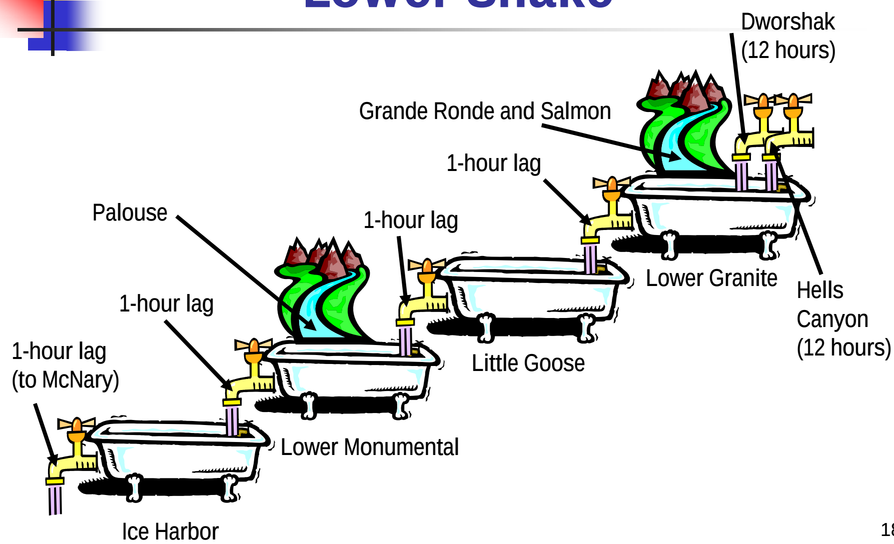
Inter-Area Coordination: Lower Snake



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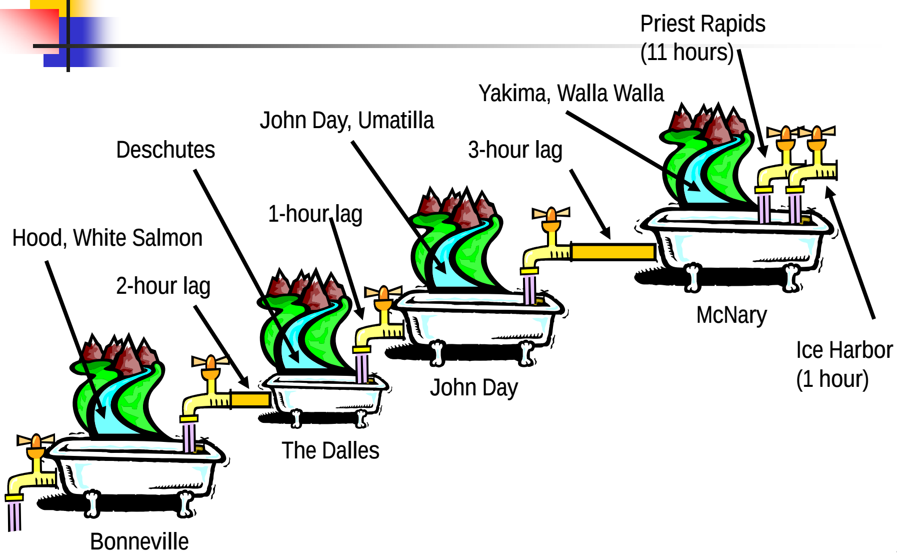
Coordination: Lower Columbia



Questions ?

Section 11

SMUD
SYSTEM OPERATION EXAMPLES:
FIRE CONTROL

1

SMUD Distribution

- NERC requirements for vegetation management
- Reliability
- Forest management
  - Maintain clearance
  - lines contacting trees are the largest problem in heavily forested areas
- Problems result in:
  - line outages
  - forest fire

2

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**
2. **Number:** FAC-003-1
3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).
4. **Applicability:**
   - **4.1.** Transmission Owner.
   - **4.2.** Regional Reliability Organization.
   - **4.3.** This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.
5. **Effective Dates:**
   - **5.1.** One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.
   - **5.2.** Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Monitoring Responsibility**
     RRO
     NERC
   - **1.2. Compliance Monitoring Period and Reset**
     One calendar Year
   - **1.3. Data Retention**
     Five Years
   - **1.4. Additional Compliance Information**
     The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.
2. **Levels of Non-Compliance**
   - **2.1. Level 1:**
     - **2.1.1.** The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;
     - **2.1.2.** Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;
     - **2.1.3.** The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.
   - **2.2. Level 2:**
     - **2.2.1.** The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;
     - **2.2.2.** The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.
     - **2.2.3.** The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

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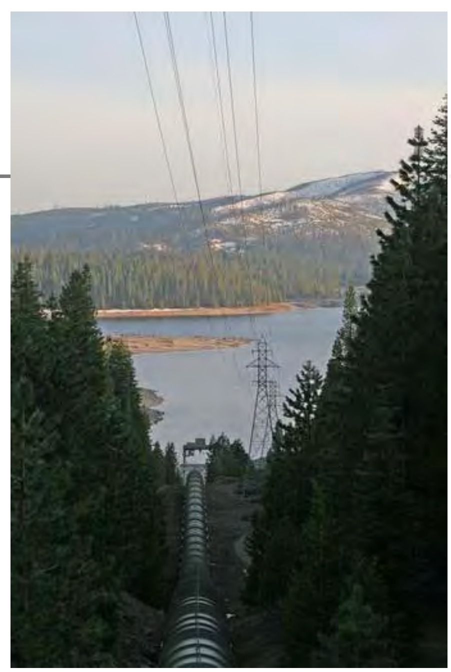

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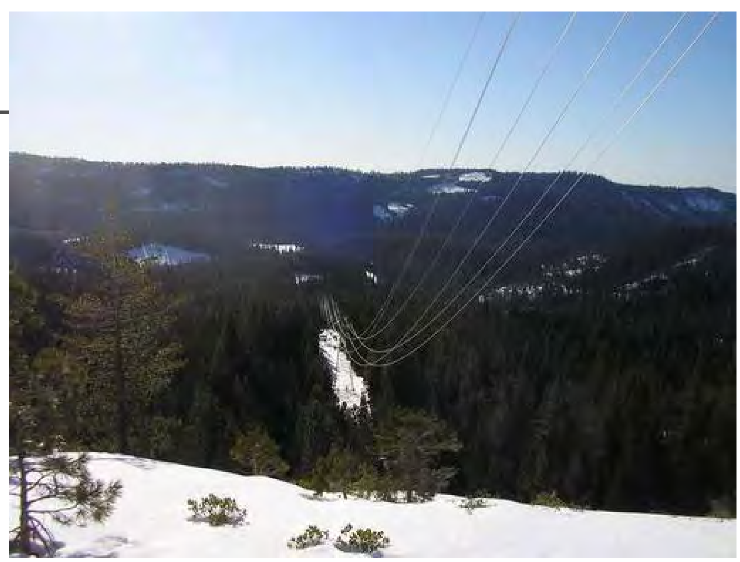

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12

Questions/Discussion

13

BLACKOUT RECOVERY & PREVENTION

Peggy A. Olds, Manager
Technical Operations
Bonneville Power Administration
USEA/USAID Presentation July, 2008

1

What Happened on August 14

- At 1:31 pm, FirstEnergy lost the Eastlake 5 power plant, an important source of reactive power for the Cleveland-Akron Area.
- Starting at 3:05 pm EDT, three 345 kV lines in FirstEnergy's system failed due to contacts with overgrown trees.

2

What Happened on August 14

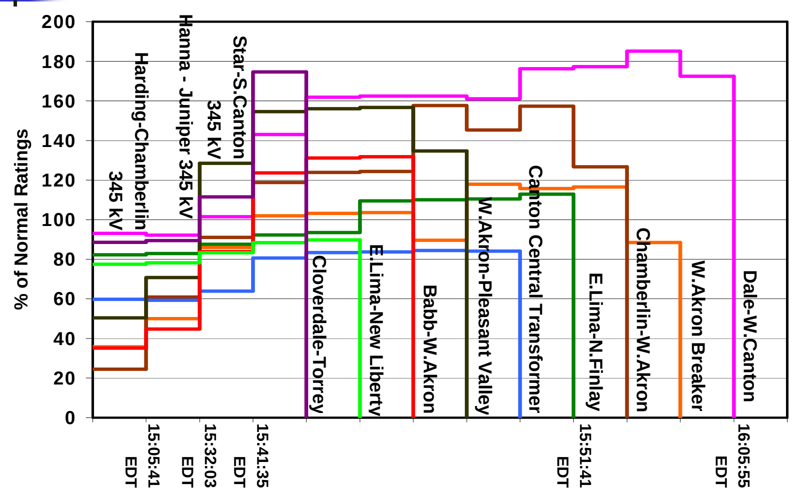
3

What Happened -- Ohio

- After the 345 kV lines were lost, at 3:39 pm FirstEnergy's 138 kV lines around Akron began to overload and fail.
  - 16 lines overloaded and tripped out of service

4

What Happened -- Ohio



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What Happened -- Ohio

- At 4:05 pm, FirstEnergy's Sammis-Star 345 kV line failed due to severe overload.

6

What Happened -- Cascade

- Before the loss of Sammis-Star, the blackout was only a local problem in Ohio
- After Sammis-Star tripped at 4:05:57, northern Ohio’s load was shut off from its usual supply sources to the south and east, and the resulting overloads on the broader grid began an unstoppable cascade that surged across the northeast, with many lines overloading and tripping out of service.

7

What Happened -- Cascade

1) 4:06

2) 4:08:57

3) 4:10:37

4) 4:10:38.6

8

What Happened -- Cascade

5) 4:10:39

6) 4:10:44

7) 4:10:45

8) 4:13

9

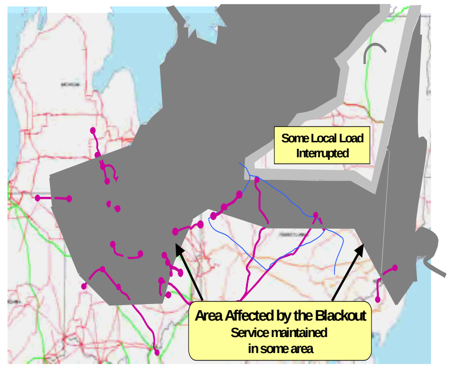
Power Plants Affected

- The blackout shut down 263 power plants (531 units) in the US and Canada, most from the cascade after 4:10:44 pm – but none suffered significant damage

10

Affected Areas

- When the cascade was over at 4:13pm, over 50 million people in the northeast US and the province of Ontario were out of power.



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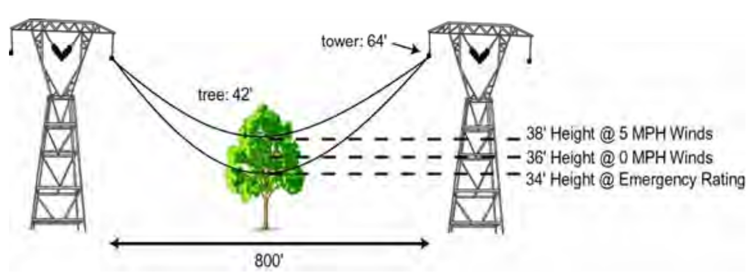
What Happened -- Ohio

- Why did so many trees contact power lines?
  - The trees were overgrown and rights-of-way hadn't been properly maintained
  - Lines sag lower in summer with heat and low winds



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What Caused the Blackout?

Three Root Causes:

- Inadequate Situational Awareness at FirstEnergy
- FirstEnergy's Failure to Manage Vegetation Growth in Its Transmission Rights-of-Way
- Failure of the Interconnected Grid's Reliability Organizations to Provide Effective Diagnostic Support

13

What Didn't Cause the Blackout?

- High power flow patterns across Ohio
- System frequency variations
- Low voltages low and declining
- Independent power producers and reactive power
- Unanticipated availability or absence of generation and transmission
- Peak temperatures or loads in the Midwest and Canada
- Master Blaster computer virus or malicious cyber attack

14

Cinergy -- Customer Property looking Northeast 8-14-03

15

Cinergy -- Customer Property looking Northeast

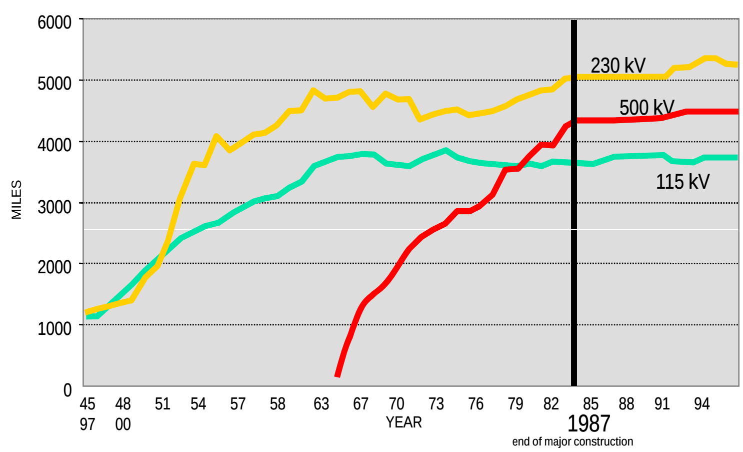
16

Could it Happen Again? What Others are Saying

- *We are way ahead of the game compared with the East Coast. We've already had our shock.* – Steve Weiss, NW Energy Coalition
- *What we learned in '96 is that we are getting really close to the edge.* – Wally Gibson, Northwest Power Planning and Conservation Council
- *We've got to look at improving infrastructure* – Oregon Congressman Peter DeFazio

17

TBL Operating Circuit Miles



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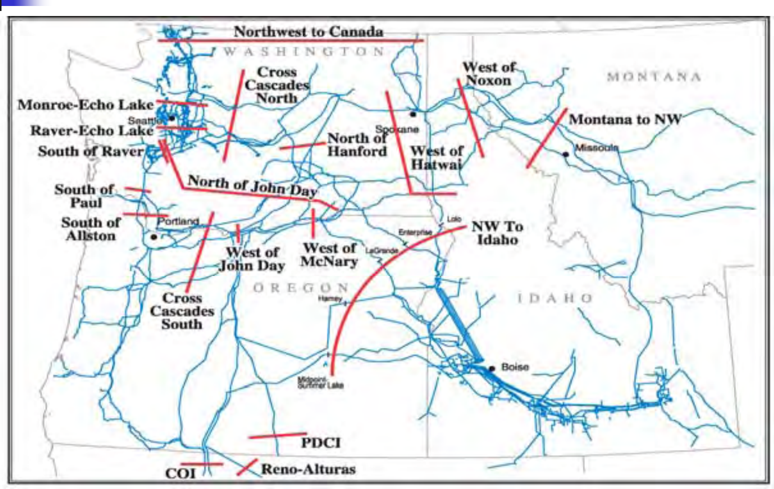
Reactive Support Additions

[redacted]

19

NW Constrained Paths



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Reliability?

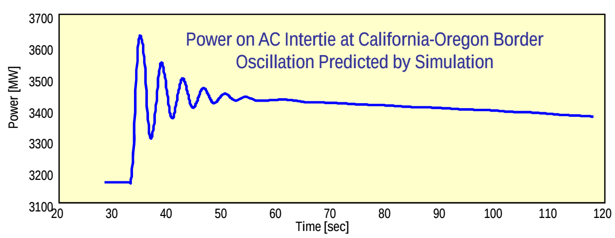
- Enough Generation to Meet Load is One Measure of Reliability
- Resiliency – The Ability of the System to Withstand and Recover from Problems Without Cascading Electrical Outages – is Another Measure
  - Lightning Strikes, Equipment Outages or Failures Cause Bumps on the System
  - The Western Transmission System is Not Very Resilient (Well-Damped) Anymore
    - Like a Car With Worn Out Shocks going Over a Bump

21

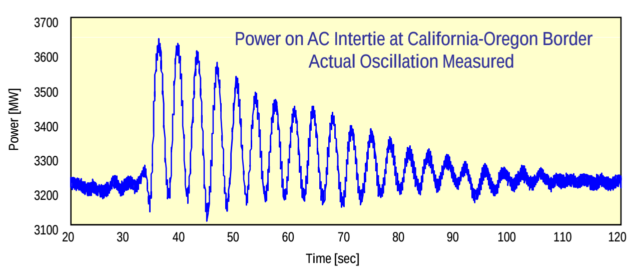
Simulation Reliability?

This Is What We Thought Would Happen

(Simulation)



This Is What Actually Happened
August 4, 2000 Oscillation - Alberta Separation



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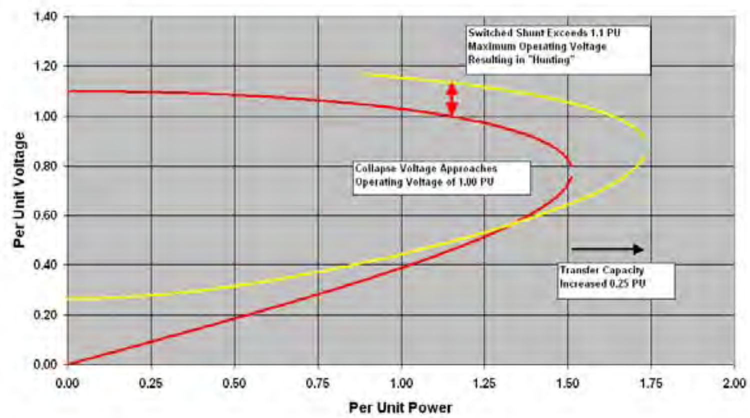
Shunt Capacity & Reliability

Figure 4. Excessive Use of Shunt Compensation to Extend Capacity



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The Need for Transmission

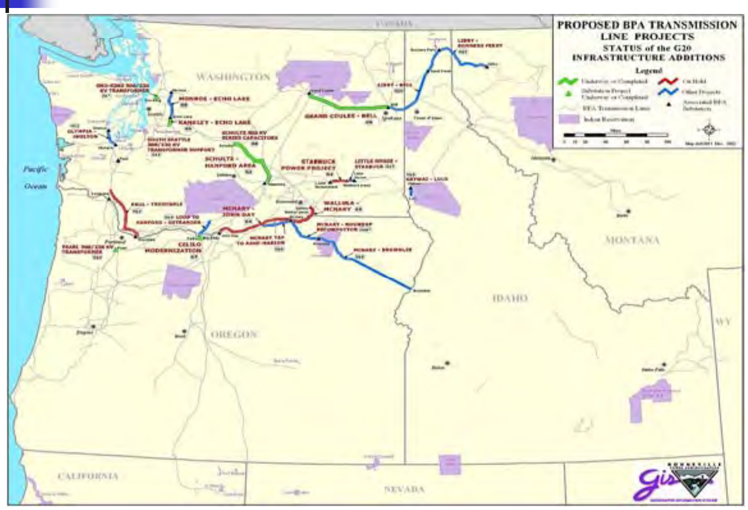
- Infrastructure Plans
  - Reinforces Load Centers
  - Integrates Needed Generation Resources
  - Relieves Crippling Congestion
    - We Don't Want Our Own Path 15 (Constraint in Central California)
  - Puts A Little Reliability Margin Back Into the Grid
    - To Reduce Exposure to Cascading Electrical Outages with Big Impacts
    - Needed For A Competitive Wholesale Market To Work
    - So We Can Meet Regional Load During Outages
    - So We Can Meet Load and Move Power When Large Load Shuts Down
    - So We Can Actually Do Some Maintenance Without Harming the Market
    - So any RTO Wouldn't Start with the Regional Grid heavily congested.

24

Future Reliability Issue?

25

Future Projects



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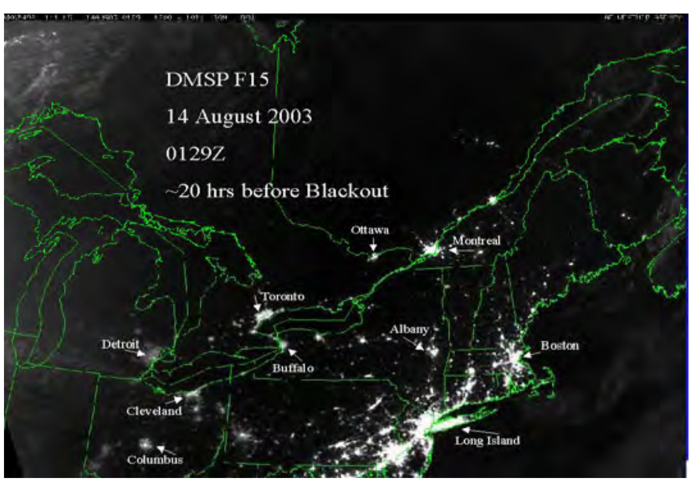
What Should The U.S. Do to Prevent Blackouts?

- Infrastructure investment.
- Nation needs mandatory reliability standards with teeth.
- One utility regional planning – full range of alternatives including non-construction solutions.
- Operate carefully!!

27

Before the Black Out



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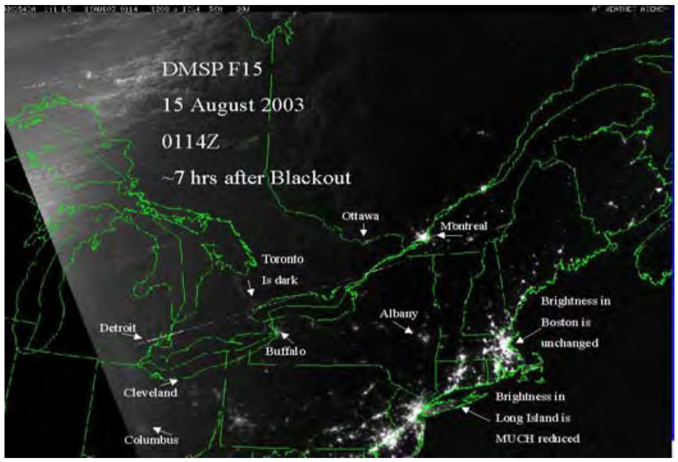
After the Black Out



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- **Questions?**

30

SMUD
SYSTEM OPERATION EXAMPLE:
OUTAGE INCIDENT

1

SMUD Distribution Line

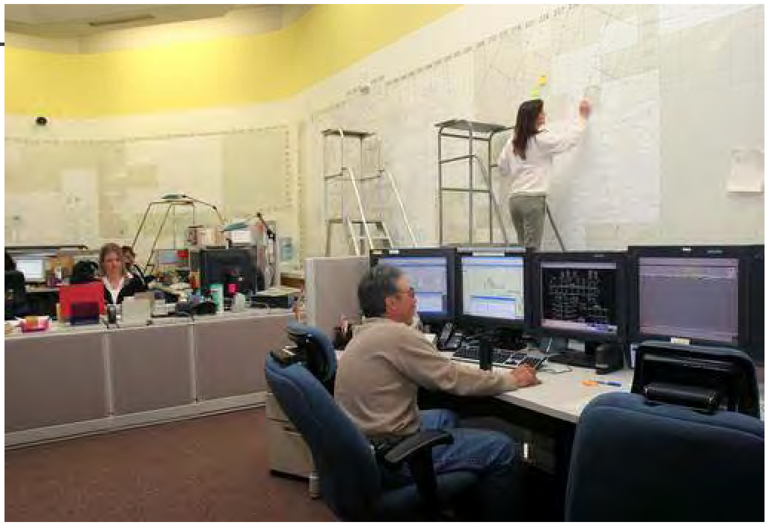
- Distribution Operator
  - Outage restoration
  - Emergency response (downed lines, car-pole accidents)
  - Storm response (storm damage, poles down, trees blown into lines)

2

The early days – no technology here!

3

Finally in the 21st Century!



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Seasonal Problems

- Winter
  - Storm damage
  - Customer outages
- Summer
  - Fires under transmission lines

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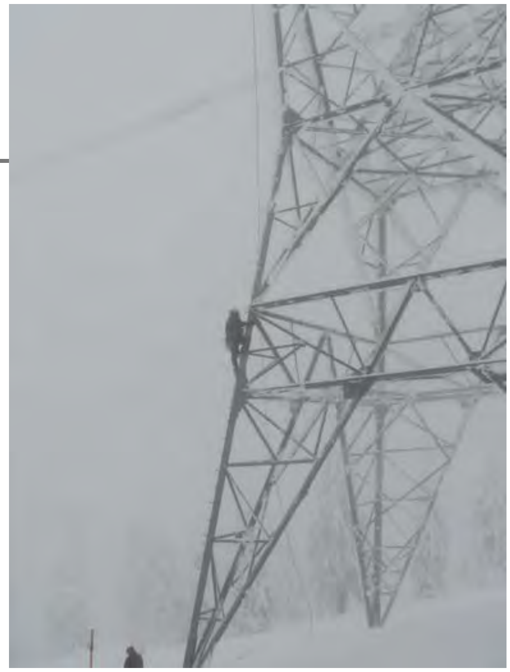
Emergency Operations

Regional

- Large scale system destruction
- Damage to the Utility system is too great to repair in a reasonable time frame
- Utilities in different areas of the North American system will provide parts, equipment and personnel to assist

17

18



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Emergency Operations

Distribution

- Typically during winter storm conditions
- Storm operations in effect – additional personnel and equipment
- Involve customer load outages
- High media visibility

20

Questions/Discussion

21

Wind Generation Integration Issues

Peggy A. Olds, Manager

Technical Operations

Bonneville Power Administration

USEA/USAID Presentation July, 2008

1

Wind Generation Integration Issues

- Green Power/Renewable Energy is an increasingly popular resource
- BPA is forecasting thousands of additional MWs of wind generation integration in the next decade
- Special provisions needed for operations: operating reserves

2

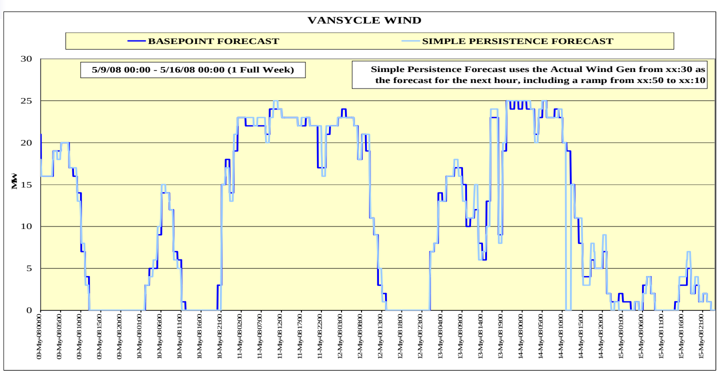
Wind Generation Integration Issues

BPA CONTROL AREA (BA) LOAD & TOTAL WIND GENERATION JAN 1 - APR 30, 2008 Transmission Technical Operations/TOT/5May08						
Month	CONTROL AREA LOAD SUM (MWH)	WIND GENERATION SUM (MWH)	CONTROL AREA LOAD HOURLY AVG (MWH)	WIND GENERATION HOURLY AVG (MWH)	Wind Gen as % of Control Area Load (FULL MONTH)	Wind Gen as % of Control Area Load (SINGLE HOUR MAX)
1/1/2008	5,781,167	300,922	7770.4	404.5	5.2%	17.9%
2/1/2008	4,829,541	292,353	6939.0	420.0	6.1%	19.6%
3/1/2008	5,028,249	381,650	6767.5	513.7	7.6%	20.2%
4/1/2008	4,818,787	414,542	6692.8	575.8	8.6%	22.1%
4-month total	20,457,744	1,389,467	7047.1	478.6	6.8%	22.1%

Source: Integrated hourly data via SCADA points 45583 & 79687

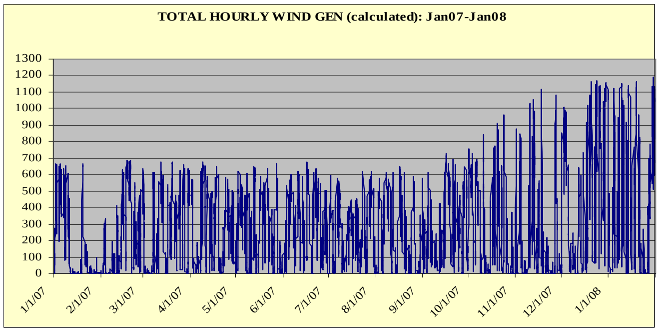
- Increasing penetration of wind generation as a percentage of control area load.

Wind Generation Integration Issues



- Forecasting wind generation output is a challenge.
- The data for the BasePoint Forecast vs. the Simple Persistence Forecast for the week. The generator is using a simple persistence forecasting methodology similar to a Persistence Model BPA is testing. It appears to forecast better than any other operator's basepoint forecast methodology.

Wind Generation Integration Issues



- BPA has experienced a significant increase in total hourly wind generation within the last year. A doubling of the generation in a 12 month period.

5

Wind Generation Integration Issues

- Forecasting
- Operational complexity in forecasting amount of and real time supply of needed operating reserves
- Non-traditional supplier/operator issues
- Market driven; resource constrained
- High public visibility and awareness

6

Questions ?

7