



Effective Grid Utilization: A Technical Assessment and Application Guide

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S. Balser, S. Sankar, R. Miller, A. Rawlins,
M. Israel, T. Curry, T. Mason

*Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66201*

NREL Technical Monitor: Kara Clark
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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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Abbreviations

°C	degrees Celsius
AC	alternating current
ACCC	aluminum conductor carbon composite
ACCR	aluminum conductor composite reinforced
ACSR	aluminum conductor steel reinforced
ACSS	aluminum conductor steel supported
AEP	American Electric Power
ATC	available transfer capability
BPA	Bonneville Power Administration
CAES	compressed air energy storage
CAISO	California Independent System Operator
CBM	Capacity Benefit Margin
CFT	conditional firm transmission
CSC	convertible static compensator
DC	direct current
DOE	U. S. Department of Energy
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FACTS	flexible alternating current transmission system
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Administration
FRCC	Florida Reliability Coordinating Council
HTLS	high-temperature low-sag
HVDC	high-voltage direct current
Hz	hertz
IDC	Interchange Distribution Calculator
IEEE	Institute of Electrical and Electronics Engineers
IGBT	insulated gate bipolar transistor
IPFC	interline power flow controller

ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kWh	kilowatt-hours
kV	kilovolts
LMP	locational marginal price
m	meters
m/s	meters per second
mph	miles per hour
MISO	Midwest Independent System Operator
MRO	Midwest Reliability Organization
MVA	megavolt amperes
MVAR	megavolt-ampere reactive
MW	megawatts
NAESB	North American Energy Standard Board
NAPSIC	North American Power Systems Interconnection Committee
NERC	North American Electric Reliability Council (prior to January 1, 2007)
NERC	National Electric Reliability Corporation (after January 1, 2007)
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSRC	New York State Reliability Council
OASIS	Open Access Same-Time Information Systems
OATT	open access transmission tariff
PMU	phasor measurement unit
PUC	public utility commission
PURPA	Public Utility Regulatory Policy Act
PST	phase shifting transformer
RFC	Reliability First Corporation
RTO	Regional Transmission Organization
SIL	surge impedance loading
SPP	Southwest Power Pool
SSSC	series static synchronous compensator
STATCOM	static synchronous compensator

STEP	SPP Transmission Expansion Plan
SVC	static VAR compensator
TCSC	thyristor controlled series capacitor
TLR	Transmission Loading Relief
TOP	Transmission Operator
TPSC	thyristor protected series capacitor
TRM	Transmission Reliability Margin
TTC	total transfer capability
UPFC	unified power factor controller
VAR	volt-ampere reactive
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
Wh	watt-hour

Executive Summary

In order to more fully integrate renewable resources, such as wind and solar, into the transmission system, additional capacity must be realized in the short term using the installed transmission capacity that exists today. The U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory Transmission and Grid Integration Group supported this study to assemble the history of regulations and status of transmission technology to expand existing grid capacity.

This report compiles data on various transmission technology methods and upgrades for increased capacity utilization of the existing transmission system and transmission corridors. The report discusses the technical merit of each method and explains how the method could be applied within the current regulatory structure to increase existing transmission conductor and/or corridor capacity.

The history and current state of alternatives to new construction is presented for regulators, legislators, and other policy makers wrestling with issues surrounding integration of variable generation. Current regulations are assessed for opportunities to change them to promote grid expansion. To support consideration of these alternatives for expanding grid capacity, the report lists relevant rules, standards, and policy changes.

Background

Integrating significant levels of variable renewable generation into the nation's transmission system will require changes to utility operating procedures, energy market structures, and the conventional generation portfolio. It may require expansion of the existing transmission system, which is also strained by continued load growth. However, expanding the grid is no simple task. Lead times of 7–10 years are required to secure new rights-of-way and to permit, design, and construct new transmission. As a result, it will be very useful in the short run to improve transmission capability of the current transmission grid and develop methods for incremental capacity additions on existing rights-of-way.

U.S. Grid Interconnection Structure

The U.S. power grid is not a monolithic structure. It is a complex assembly of interconnections, regional entities, and balancing authorities. The electric power grid of the continental United States is divided into three asynchronous interconnections commonly known as the Eastern Interconnection, Western Interconnection, and Electric Reliability Council of Texas (ERCOT) Interconnection. To maintain reliability of the U.S. electrical system, eight regional entities as shown in Figure 1 work with the National Electric Reliability Corporation (NERC)¹—the electric reliability organization approved by the Federal Energy Regulatory Commission (FERC).² The regional entities are permitted to enact standards that are more stringent than those enacted by NERC, but they are not permitted to relax or enact standards less stringent than NERC standards.

¹NERC website: <http://www.nerc.com/>; NERC glossary: http://www.nerc.com/files/Glossary_of_Terms_2010April20.pdf

²FERC information: <http://www.ferc.gov/about/about.asp>;
<http://www.ferc.gov/legal/maj-ord-reg.asp>

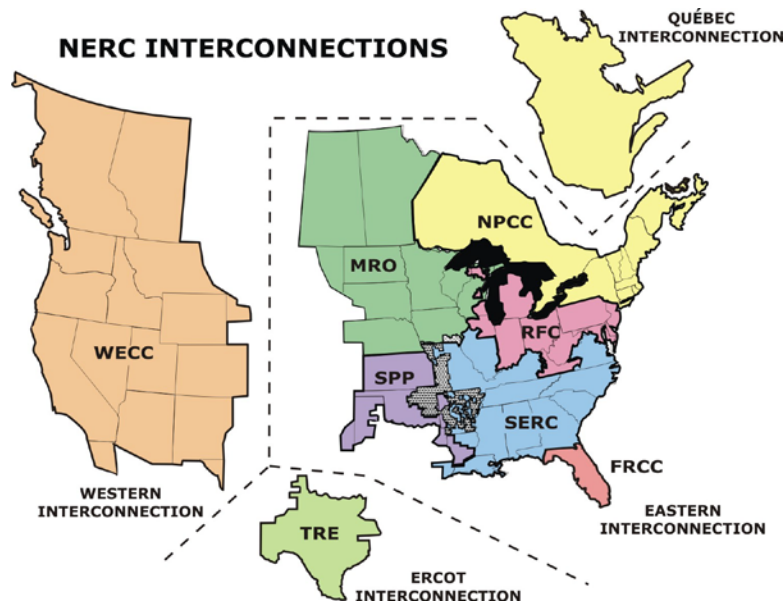


Figure 1. NERC interconnection³

Trends and Current Situation

A long history (detailed in Chapter 1) has brought the U.S. power system to its current set of operating procedures and regulations. Restructuring of the electricity market, mandatory reliability standards, replacing existing generation with renewable resources, and introducing competition have all served to change the way transmission is developed and operated in the United States. When conventional, dispatchable generation resources, such as coal and gas, are replaced by renewable resources, such as wind and solar energy, utilization of transmission capacity becomes more complicated. Often, these new generation resources are not at the same location as retired resources. Presently, transmission networks are fully or nearly fully subscribed in some parts of the grid, and are not fully subscribed in others. The variability of renewable resources further suggests that real-time dispatch of transmission capacity would be more efficient.⁴

Research has been conducted on methods to increase utilization of transmission resources by the Electric Power Research Institute⁵ (EPRI), Western Area Power Administration (WAPA), Western Governors Association,⁶ the State of Wyoming,⁷ west-wide Seams Steering Group – Western Interconnection,⁸ and the National Wind Coordinating Collaborative.

³ This image from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_Color_072512.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation. Accessed August 2012.

⁴ Independent Electricity System Operators (2010) "Integrating Renewable Resources – Design Principals," Ontario, Canada, http://www.ieso.ca/imoweb/pubs/consult/se91/se91-20101209-Renewables_Integration_Design_Principles.pdf. Accessed August 2012.

⁵ "Efficient Transmission Systems Program 172." (2012). 2012 Research Portfolio. Electric Power Research Institute, Palo Alto, CA. <http://portfolio.epri.com/ProgramTab.aspx?sId=PDU&rId=201&pId=6310>. Accessed August 2012.

⁶ Western Governors Association. (2006). "Clean Energy, a Strong Economy, and a Healthy Environment." <http://www.swenergy.org/news/news/documents/file/CDEAC06.pdf>. Accessed August 2012.

The results of these and other work discussed in this report lead to the following key findings.

Key Findings

Changes in Policy and Standards

- A relaxation of the separation distance that results in reduced ratings for parallel lines could increase the ratings of existing circuits. The Western Electricity Coordinating Council (WECC) that represents the Western Interconnect of North America has extended the NERC standards for multiple circuits to include those that are not on a common structure but are within a span length of each other.
- Replacing physical transmission rights with financial transmission rights could ensure efficient use of the transmission system during times of constraint due to congestion. FERC Order 2000 required Regional Transmission Organizations (RTOs) to establish market-based congestion management to improve the utilization of the grid and to allocate the cost of congestion to those users who were willing to pay the price.
- Implementing conditional firm transmission (CFT) and redispatch as a bridge between physical firm transmission and market-based transmission congestion management could increase utilization of the grid during certain periods. CFT provides transmission users access to selected transmission paths on a firm basis except during periodic constrained periods. Extending this practice allows increased use of the transmission system when conventional firm transmission is not available, but when the system is not actually constrained.
- Allowing redispatch (at some defined cost) when transmission paths are constrained could allow transmission customers to pay the cost of redispatch or forgo use of the transmission. Redispatch also provides a price signal that can be used to make economic decisions regarding the value of increasing transmission capability on selected paths. Redispatch provides many of the same benefits as market-based congestion management without having a formal congestion management system in place.
- Offering to redispatch the output of generators could provide long-term firm service to transmission customers and allow for new renewable energy projects to be financed. Providers could publish dynamic, real-time values for what they would charge to provide redispatch service, at specified congested locations within the transmission provider's system, and at specified flowgates at the border of the transmission provider's system.⁹ The flow is at a maximum level during a very small percentage of the time and varies over the course of a year.

⁷ State of Wyoming. (2004). "Rocky Mountain Area Transmission Study." <http://psc.state.wy.us/rmats/rmats.htm>. Accessed August 2012.

⁸ Western Governors Association. (2002). "Scope of SSG-WI Working Group." http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/ssg-wi_031902_scope.htm. Accessed August 2012.

⁹ Furman, Don and McIntire, Natalie. (undated). "New Transmission Projects Can Benefit Wind." National Wind Coordinating Collaborative. http://old.nationalwind.org/events/webinar/Webinar_Presentation.pdf. Accessed August 2012.

- Implementing transmission redispatch can increase transmission sales by reducing congestion, which otherwise would limit sales. Transmission redispatch resolves transmission congestion by changing generator output levels to reduce congestion. Redispatch is included as part of market-based congestion management, but in areas without markets, redispatch is often not implemented because it results in the reduction of selected generators that may impact revenue.
- Incorporating a redispatch process that includes a locational imbalance price reflects a congestion component that addresses the real-time imbalance market. An energy imbalance system would bridge the gap between a simple redispatch process and a full market-based congestion management system.
- Expanding the use of incentive rates to accommodate alternatives to building new transmission could be an important next step for FERC's incentive-based rate treatments for transmission of electric energy in interstate commerce. Including new technologies could also increase transmission capability without building new facilities.
- Establishing parity between generation resources and demand response would reduce energy costs and provide potential benefits to transmission. The magnitude of these benefits depends on the location of the demand response.
- Recognizing the benefits of new technologies in regulations could increase the capability of the existing grid without adding additional transmission lines. These technologies include energy storage, which could benefit the grid, including generation, transmission, and distribution. Incentives would require rule changes that recognize the unique operating characteristics and potential benefits of the new technologies. For example, a proposed rule recognizes the benefits of fast regulation services and allows for compensation of facilities capable of providing fast regulation service. Energy storage facilities can provide fast regulation as well as damping and stability, issues that often require transmission additions to mitigate.

Technology Innovations

The introduction of new technologies, particularly technologies with the advances in power electronics, has produced a variety of devices that can be used to overcome limitations in transmission capability. Some of these devices can be used to improve system damping and voltage support, which can limit the total transfer capability. Other technologies and enhanced engineering designs increase the power carrying capability of individual transmission lines.

- Replacing the use of static seasonal thermal ratings on critical constrained transmission lines with either real-time or dynamic monitoring of ambient conditions could increase line rating and therefore transmission capacity.¹⁰
- Replacing conventional transmission line conductors with high-temperature low-sag (HTLS) conductors on existing transmission lines could increase the thermal rating by up to 50%. The HTLS conductor imposes less physical loading than equivalent larger conductors that can require reinforcement of transmission tower structures.

¹⁰ Douglass, Dale A. (1998). "Upgrading Transmission Lines and Reducing Risk: Incremental upgrading methods can be used to increase thermal line ratings." *Transmission and Distribution World*, March 1, 1998.

- Increasing the operating voltage of the line and adopting compact line design principals can, under some conditions, mitigate thermal limits on transmission lines and help offset the added clearance requirements when the operating voltage is increased. Compact line design principles could offer some benefits during redesign, but overall costs to increase the operating voltage on a transmission line would be substantial. This option may be particularly attractive where compact line design principles could be applied to allow reconductoring of an existing line with minimal tower changes and within the existing right-of-way.

Increasing the capability of individual transmission lines can overcome thermal properties that limit power flow on individual circuits, but often the limitations are related more to system performance. These limitations are more effectively mitigated by adding devices to the system that enhance system damping and provide more effective voltage support through the use of power electronics. These devices are called flexible alternating current transmission system (FACTS) devices and are currently being used across the United States.

- Using static volt-ampere reactive (VAR) compensators (SVCs) can achieve more precise and quicker voltage support for both the steady-state and transient voltage stability of the transmission system than conventional methods. By controlling the reactive elements, system voltage profiles can be enhanced, and power transfer capabilities over individual lines, as well as groups of lines, can be accurately controlled, allowing better system performance and increased power transfer.
- Using static synchronous compensator (STATCOM) devices provides shunt-connected reactive-power compensation equipment capable of generating and/or absorbing reactive power. Both SVC and STATCOM devices provide voltage control (through reactive power support), allowing better system performance and increased power transfer.
- Employing series static synchronous compensators (SSSCs) provides an adjustable synchronous component series connected with a transmission line to vary the effective impedance of the transmission line. This increases power transmission capability, improves system stability, reduces system losses, reduces voltage drop, and optimizes (balanced) power flow along parallel lines.
- Using the unified power flow controller (UPFC) controls power flow for a single line. By directly controlling power flow, these devices increase line power transfer, improve voltage stability, and enhance rotor angle/system frequency stability.
- Using the interline power flow controller (IPFC) compensates and controls true power flow for multiple lines. These devices provide three of the system benefits including line increased power transfer, improved voltage stability, and enhanced rotor angle/system frequency stability.
- Using thyristor controlled series capacitor (TCSC) devices provides continuous and rapidly variable series compensation. Series compensation increases the power flow on a circuit by reducing the series impedance between the sending end and the receiving end. TCSCs also provide power flow control by altering the series impedance.

High-voltage direct current (HVDC), which can enhance the capability of existing transmission, has gained broad acceptance and is used in multiple locations in the United States and Canada.¹¹

- Using HVDC overhead transmission lines requires less right-of-way for the corridor than an alternating current (AC) transmission system of the same power transfer level. In some cases, it is feasible to convert an existing transmission line to HVDC to realize increased power flow for the same amount of right-of-way.
- Using HVDC in terminal equipment can overcome system stability issues to interconnect two AC systems. These back-to-back HVDC links can provide the required system damping to improve performance of the transmission system and allow higher levels of transfer between the two systems.
- Using HVDC lines for interconnecting two AC grids allows power to be scheduled over HVDC lines in much the same way that power can be scheduled from a generator. HVDC interties also can act as shock absorbers by injecting and extracting energy quickly from the connected AC grids, improving system performance and potentially allowing higher levels of power transfer over the grid.

Mechanical power devices have a history of providing improved system performance:

- Phase shifters, also known as phase shifting transformers (PSTs),¹² mechanically switched electromagnetic devices similar to conventional transformers, are introduced in an existing transmission line to allow the transmission operator to control the power flow through the line. The flow through heavily congested lines can be reduced and shifted to transmission lines with spare capacity. PSTs are less expensive than new transmission lines. They can often be placed in an existing substation, making them easier to permit.
- The maximum power transfer through an overhead transmission line is dependent on the line impedance, among other parameters. The impedance is inductive and can be reduced by connecting a capacitor in series. The capacitor can be installed in an existing substation or may be installed at a discreet point along the line. The localized nature of series capacitors and their modest cost is often preferred over building additional transmission.

Opportunities to increase overall utilization of the transmission system can result from better monitoring and control. Much of this could be categorized under the Smart Grid banner. Real-time monitoring provides a clearer picture of the state of the grid and allows operators to increase transfer across critical interfaces when stability and voltage margins are not compromised. This allows dynamic ratings for lines that are stability or voltage limited. While dynamic rating of the line may not increase firm transmission capacity, it may allow operators to schedule transmission circuits for non-firm transfer that might otherwise be subject to static limits.

Current efforts at real-time monitoring include the following:

¹¹ Bahrman, Michael. (2006). "Rapid City DC Tie," IEEE PSCE Atlanta. December 10, 2006. http://www.ieee.org/portal/cms_docs_pes/pes/subpages/meetings-folder/PSCE/PSCE06/panel18/Panel-18-6_The_Rapid_City_Tie.pdf. Accessed August 2012.

¹² "Power Flow Control with Phase Shifting Transformers." (2010). ABB. [http://www05.abb.com/global/scot/scot252.nsf/veritydisplay/023c7e3532a30cb885257776004a6992/\\$File/1ZDEAB.B1619_en_Phase_shifting_transformers.pdf](http://www05.abb.com/global/scot/scot252.nsf/veritydisplay/023c7e3532a30cb885257776004a6992/$File/1ZDEAB.B1619_en_Phase_shifting_transformers.pdf). Accessed August 2012.

- Real-time transmission temperature/sag to implement dynamic line rating
- Phasor measurement units (PMUs) to provide direct state measurements
- Improved supervisory control and data acquisition systems to accept and process real-time information flow from remote monitors.

Real-time monitoring provides system operators with an important tool to optimally dispatch the system and maximize the available transmission capacity. By using real-time system information, operators can balance the non-dispatchable nature of wind and solar resources with dispatchable resources to maximize the available transmission capacity.

Energy storage devices offer the potential to increase individual transmission capability; although, their primary emphasis has been to provide overall system benefits either through improved system dynamic performance or through energy price arbitrage. The range of capabilities and applications for energy storage facilities are based on their power rating and energy discharge capabilities.^{13,14}

Summary of Techniques

The techniques for effective grid utilization highlighted in this report are presented in Table 1. The top row of the table identifies the typical transmission limitation issues. The potential solutions are listed in the left column. The X marks potential approaches to address the limitation. The table can be used as a checklist for investigating the latest advances aimed at a particular issue.

¹³ “2020 Strategic Analysis of Energy Storage in California.” (2011) Public Interest Energy Research Program Final Project Report. Work performed by University of California, Berkeley School of Law; University of California, Los Angeles; University of California, San Diego. California Energy Commission: Sacramento, CA.

<http://www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-047.pdf> accessed August 2012.

¹⁴ Schainker, Robert. (2008). “Emerging Technologies to Increase the Penetration and Availability of Renewables.” Electric Power Research Institute: Palo Alto, CA http://www.energy.ca.gov/2008_energypolicy/documents/2008-07-31_workshop/presentations/Energy_Storage-Schainker.pdf. Accessed August 2012.

Table 1. Techniques for Improving Utilization of the Grid

	RIGHT OF WAY UTILIZATION	UNUSED CAPACITY	THERMAL	VOLTAGE	STABILITY
POLICIES					
Changes to WECC Reliability Criteria	X	X			
Financial Congestion Management		X			
Conditional Firm Transmission (CFT)		X			
Transmission Investment Rule	X	X			
Demand Resources (redispatch)			X	X	X
Dynamic/Real Time Rating		X			
TECHNOLOGIES					
High-Temp, Low-Sag (HTLS) Conductor			X		
Static VAR Compensator (SVC)				X	X
STATCOM				X	X
Series Static Synchronous Compensators (SSSC)		X		X	
Unified Power Factor Control (UPFC)		X		X	X
Independent Power Factor Controller (IPFC)		X		X	X
Thyristor Controlled Series Capacitor (TCSC)		X			
High Voltage Direct Current Transmission (HVDC)	X				X
Back to Back HVDC Link					X
System “shock absorbers”					X
Phase shifting transformer (PST)	X	X			
Series capacitors	X	X			
Real-time monitoring		X	X	X	X
Energy Storage	X		X	X	X

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1.0 Introduction

Continuing load growth and the integration of renewable energy sources is straining the U.S. transmission grid. Expanding the grid is costly and involves 7–10 years to secure new rights-of-way and to permit, design, and construct new transmission. Focused efforts toward improved utilization of the current transmission grid are under way and methods for incremental additions of capacity on existing rights-of-way are being explored.

This report presents information compiled from published reports, company and organizational websites, online seminars (i.e., webinars), conference proceedings, corporate operating manuals, and journal articles.

This chapter describes the regulatory history of the utility industry from 1910 through 2012. Chapter 2 lists rules, standards, and policy changes relevant to expanding existing transmission capacity. Chapter 3 explains the features of currently available technologies that offer alternatives to constructing new transmission. Chapter 4 presents some fundamental concepts about increase line capacity. Chapter 5 lists the results of recent analyses of the costs and benefits of policies and technologies to expand capacity on the existing grid. Chapter 6 lists organizations and projects exploring ways to expand grid capacity. Chapter 7 estimates the potential impact of various approaches. Appendices A and B provide detail on the U.S. power grid, its structure, and management.

1.1 Background

1.1.1 Regulation and Vertically Integrated Utilities

During the first three decades of the 20th century, utilities saw tremendous growth and were able to charge their expanding customer base for all of the services they provided. Utility generation and transmission expanded dramatically from 5.9 million kWh in 1907 to 75.4 million kWh in 1927. During this period, the delivered costs of electricity declined 55%. During the 1920s, utilities began to form holding companies that owned and controlled operating companies over large geographic regions. During this time, three holding companies controlled 45% of the U.S. electric utility industry. Under this interstate operating structure, holding companies were not subject to state-based regulatory commissions or federal oversight.¹⁵

In the 1930s, the federal government began to provide regulatory oversight and promote extending electricity to rural areas. The Public Utility Holding Company Act and the Federal Power Act were both passed in 1935 to regulate the industry at the state and federal level.¹⁶

Operating in a regulated, cost-based environment, utilities planned and built infrastructure to meet the needs of the customers they were obligated to serve. States regulated these companies because it was perceived as a lower cost approach to delivering electricity to customers than through market competition.¹⁷ Electric utilities were under state public utility commission (PUC)

¹⁵ “Powering a Generation of Change 1997-2012.” (2012). National Museum of American History, Smithsonian Institution. <http://www.americanhistory.si.edu/powering>. Accessed August 2012.

¹⁶ National Library for the Environment. (1999). “RS20015: Electricity Restructuring Background: Public Utility Holding Company Act of 1935 (PUHCA).” CRS Report for Congress, January 7, 1999. <http://www.cnle.org/nle/crsreports/energy/eng-47.cfm>. Accessed August 2012.

¹⁷ Concerning electric industry restructuring, see: Michaels, Robert J. (2006). “Vertical Integration and the Restructuring of the U. S. Electricity Industry.” CATO Institute, July 13, 2006.

oversight. They recovered their operating costs plus regulated profits (approximately 10%) through their approved service rates. As the demand for electricity grew, utilities could add to their system infrastructure with a guaranteed return on their investment. Utilities constructed generation facilities close to their customers to reduce costly system losses.

Electric utilities were primarily under state PUC control since their activities remained predominantly intrastate in nature. PUCs reviewed every aspect of utility operation, from siting to service requirements, through final rate development. Each utility operated a control area for the area of the country it served (i.e., Commonwealth Edison's control area was Chicago). Control areas matched electrical generation to load requirements and use.

1.1.2 1937–1964: Technology Improvements and Regional Interconnection

Improved technology allowed for larger, more efficient generating units. At the same time, transmission voltages increased to reduce system losses. Larger generating stations, located near their fuel supplies, were connected to high-voltage transmission lines and began replacing smaller generating stations connected to lower-voltage power sub-transmission/distribution lines.

The U.S. electric system changed from having many geographically small, locally operated grids to having interstate transmission lines interconnected to many different utility systems. This increased interconnectivity at much higher voltages offered higher reliability and improved system economics continuing to reduce the cost of electricity. Each utility served its customers either with its own generation or through purchases with neighboring utilities. The practice was called *wheeling* and used contract path pricing. The individual control areas still played an important role in electricity sales to neighboring utilities.

The Federal Power Act and individual state laws provided regulatory oversight. Reliability of the electric system was now both a regional and local concern.

1.1.3 1965–1969 Northeast Blackout and Regional Reliability

The great Northeast Blackout of 1965 uncovered a weakness in the U.S. and Canadian interconnected electric grid. One disturbance in one section of the grid caused a cascading effect that interrupted service over 80,000 square miles (eight states) in the Northeastern United States and in large parts of Canada. This blackout started with a single 345-kV transmission line relaying failure near Toronto, Canada. As a result, the NERC was formed under the Electric Power Reliability Act in 1967.¹⁸

Today, NERC is responsible for overall reliability, planning, and coordination of electricity supply in North America. NERC is a non-profit agency comprised of 10 regional councils. The regional councils represented smaller regions of North America. Through this model, the North

<http://www.cato.org/pubs/pas/pa572.pdf>. accessed August 2012. See also:
http://www.eia.gov/cneaf/electricity/page/fact_sheets/restructuring.html
<http://www1.eere.energy.gov/femp/pdfs/primer.pdf>

¹⁸ For a discussion of the impact of blackouts on reliability regulations see: Hilt, David W. (2003). "Northeast Blackout Impacts and Actions and the Energy Policy Act of 2005."
<http://www.nerc.com/docs/docs/blackout/ISPE%20Annual%20Conf%20-%20August%2014%20Blackout%20EPA%20of%202005.pdf>. Accessed August 2012.

American interconnected electric power system became the most reliable system of its kind in the world. This is essentially how utilities operated before deregulation legislation began.¹⁹

1.1.4 1970–1977: Environmental and Conservation Concerns; Department of Energy Organization Act

The electric utility industry experienced difficult times in the 1970s. Utilities owned and operated large, central-station generating plants and high-voltage or extra-high-voltage transmission lines to deliver reliable electricity. However, prices of electricity quadrupled between 1970 and 1985. The causes for this increase included operational responses to environmental and conservation concerns, poor U.S. economic performance, inflation, and response to occupational safety concerns.²⁰ In 1970, the Clean Air Act²¹ forced substantial reductions in allowable emission levels (sulfur dioxide) from coal-fired power plants because of acid rain concerns. This was followed by the Water Pollution Control Act of 1972.²² Utilities responded to the requirements of these acts by reducing the output of the existing generating stations, thereby reducing the generation reserve capacity available to the interconnected power system.

The Organization of the Petroleum Exporting Countries oil embargo of 1973 raised prices for oil used to generate electricity. The ensuing energy crisis also increased public awareness of conservation and energy efficiency issues in the United States. The Energy Supply & Environmental Coordination Act of 1974²³ required utilities to stop using natural gas or other petroleum-based products to generate electricity. The Resource Conservation & Recovery Act of 1976,²⁴ amendments to the 1970 Clean Air Act issued in 1977,²⁵ the Power Plant & Industrial Fuel Use Act of 1978,²⁶ and the National Energy Conservation Policy Act of 1978²⁷ all had the effect of reducing generating capacity at large power plants.

¹⁹ “NERC Operating Manual.” (2010). North American Electricity Reliability Corporation. New Jersey. http://www.nerc.com/files/opman_12-13Mar08.pdf. Accessed August 2012.

²⁰ “Powering a Generation of Change 1997-2012.” (2012). National Museum of American History, Smithsonian Institution. <http://www.americanhistory.si.edu/powering>. Accessed August 2012.

²¹ “History of the Clean Air Act, U. S. Environmental Protection Agency.” (2012). Environmental Protection Agency. http://www.epa.gov/air/caa/caa_history.html. Accessed August 2012.

²² “Water.” (undated). Environmental Protection Agency. <http://www.epa.gov/aboutepa/history/topics/fwpca/05.html>. Accessed August 2012.

²³ “Method of Collecting Energy Information ESECA.” (2011). U.S. Government Printing Office. <http://www.gpo.gov/fdsys/search/pagedetails.action?jsessionid=mNHYP6yDVQhgD40qTCvwxXq8zHkZ27fyvkvY YCBsLJNwJW1pRbTV!1599065783!258410883?browsePath=Title+10%2FChapter+II%2FSubchapter+A%2FPart+207%2FSubpart+A%2FSection+207.3&granuleId=CFR-2011-title10-vol3-sec207-3&packageId=CFR-2011-title10-vol3&collapse=true&fromBrowse=true>. Accessed August 2012.

²⁴ “Summary of the Resource Conservation and Recovery Act.” (1976). Environmental Protection Agency. <http://www.epa.gov/lawsregs/laws/rcra.html>. Accessed August 2012.

²⁵ “History of the Clean Air Act, U. S. Environmental Protection Agency.” (2012). Environmental Protection Agency. http://www.epa.gov/air/caa/caa_history.html. Accessed August 2012.

²⁶ Kubiszewski, Ida. (2006). “Power Plant and Industrial Fuel Use Act of 1978, United States.” The Encyclopedia of Earth. http://www.eoearth.org/article/Powerplant_and_Industrial_Fuel_Use_Act_of_1978_United_States. Accessed August 2012.

²⁷ “Power Plant and Industrial Fuel Use Act.” (undated). U.S. Office of Electricity Delivery and Energy Reliability. U.S. Department of Energy. <http://energy.gov/oe/electricity-policy-coordination-and-implementation/other-regulatory-efforts/power-plant-and>. Accessed August 2012.

In this environment, several federal agencies were created by the Department of Energy Organization Act in 1977,²⁸ including the DOE and FERC. FERC was given the jurisdictional authority assigned to the Federal Power Commission.

High inflation and economic recession resulted in very low or zero load growth for the utility sector. However, in response to earlier load growth projections, many large, central-station power plants were under construction. These coal and nuclear power plants were very costly and took years to build. The plant costs rose due to inflation, extended construction time due to occupational safety concerns, and meeting environmental regulatory requirements caused plant costs to rise. Once the plants were built, there was excess generation capacity reserve margins because loads had not increased as expected. The price of electricity increased dramatically between 1970 and 1985.²⁹

1.1.5 1978: Public Utility Regulatory Policies Act³⁰

The Public Utility Regulatory Policy Act³¹ (PURPA) was, in part, a response to high electric rates and perceived inefficiencies in the generation system. PURPA expanded participation of non-utility generators in the electricity market and demonstrated that electricity from non-utility generators could be integrated successfully with a utility's own supply. PURPA introduced FERC-approved, non-utility generation called *qualifying facilities*. Utilities were required to purchase generation from the qualifying facilities. The Fuel Use Act of 1978 (repealed in 1987)³² also helped qualifying facilities become established. Under the Fuel Use Act of 1978, utilities were not allowed to use natural gas to fuel new generating technologies, but qualifying facilities, which were by definition not utilities, were able to take advantage of abundant natural gas and abundant new technologies (such as combined-cycle). The new technologies lowered the financial threshold for entrance into the electricity generation business as well as shortened the lead time for constructing new plants. The additional capacity that the qualifying facilities supplied was relatively small due to limitations imposed upon them. Other PURPA provisions included the addition of sections 210, 211, and 212 to the Federal Power Administration (FPA), which gave FERC authority over qualifying facilities interconnections and transmission wheeling.

The PURPA provisions stimulated development of cheaper and cleaner generation technology and made it possible to add them to the power system via qualifying facilities and independent power producers. PURPA began the process of deregulating the highly regulated, monopoly generation sector. The natural gas sector was being deregulated under FERC's oversight, and some believed that the same deregulation could be applied to the generation sector. PURPA opened the wholesale power markets to non-utility producers of electricity, an activity which previous to that time was largely reserved for vertically integrated utilities. This allowed a certain degree of competition at the supply end of the electric power generation and delivery chain.

²⁸ "Department of Energy Organization Act." (1977). U.S. Department of the Interior, Bureau of Reclamation. <http://www.usbr.gov/power/legislation/doeorg.pdf>. Accessed August 2012.

²⁹ "History of the U.S. Electric Power Industry." (2000). U.S. Energy Information Administration. http://www.eia.gov/cneaf/electricity/chg_stru_update/appa.html. Accessed August 2012.

³⁰ PURPA and Amendments: http://www.naruc.org/Publications/PURPA_Manual_webversion.pdf.

³¹ Holy Cross Energy. (undated). "PURPA." <http://www.holycross.com/member-services/purpa>. Accessed August 2012.

³² "Repeal of the Powerplant and Industrial Fuel Act." (1987). U.S. Energy Information Administration. http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html. Accessed August 2012.

Responding to regulatory uncertainty, utilities began to reduce costs related to generation, transmission, and distribution infrastructure. They reduced the labor force through layoffs and early retirements. As a result, generation reserve margins and transmission capacity reserves began to decline.

Between 1978 and 1987, other regulated industries in the United States began to be deregulated. These other industries included the airline industry in 1978³³ and telecommunications (e.g., AT&T) in 1984.³⁴ Further deregulation efforts in the natural gas industry opened access to the pipelines and the spot market for price in 1986 and 1987.

1.1.6 1992: Energy Policies Act³⁵

The primary intent of the Energy Policies Act (EPAct) was to create open access to the transmission system for all generating companies, both utility and non-utility (qualifying facilities and independent power producers). While the act gave the FERC the power to order utilities to grant access to the transmission system, progress and the anticipated benefits were slow to be realized.³⁶ EPAct provided FERC with approval of exempt wholesale generators³⁷ and added Section 213 to the FPA.³⁸ Exempt wholesale generators were allowed to sell electricity to the bulk power market, and Section 213 extended FERC oversight to transmission access issues. As a result, transmission tariff structures changed and open access tariffs had to be filed (with FERC) before access to wheeling contracts would be granted by FERC. In 1992, for the first time, generation added by non-utility generators exceeded that added by traditional utilities.

FERC received reports through 1995 of discrimination by vertically integrated utilities for access to the transmission system.³⁹ In response, FERC issued several policy statements that transmission remained a natural monopoly and should be treated as such. These policy statements were the Comparability Standard,⁴⁰ Stranded Cost Notice of Proposed Rulemaking,⁴¹

³³ "Airline Deregulation." (undated). Avjobs, Inc. <http://www.avjobs.com/history/airline-deregulation.asp>. Accessed August 2012.

³⁴ "Powering a Generation: Understanding Deregulation." (undated). Smithsonian Institution. <http://americanhistory.si.edu/powering/dereg/dereg3.htm>

³⁵ "Energy Policy Act 1992." (2009). U.S. Department of Energy, Energy Efficiency and Renewable Energy. <http://www1.eere.energy.gov/femp/regulations/epact1992.html>. Accessed August 2012.

³⁶ "Evolution of Markets and the Open Access Transmission Tariff." (2011). Edison Electric Institute. <http://www.eei.org/meetings/Meeting%20Documents/2011-08-01-TransmissionWholesaleMarketsSchool-Matt.pdf>. Accessed August 2012.

³⁷ "Examining the Impacts of the Energy Policy Act of 1992." (1994). National Rural Electric Cooperative Association. <http://www.thefreelibrary.com/Examining+the+impacts+of+the+Energy+Policy+Act+of+1992.-a016497478>. Accessed August 2012.

³⁸ "Order No. 889." (2010). Federal Energy Regulatory Commission. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp>. Accessed August 2012.

³⁹ Ibid.

⁴⁰ "Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act, Docket No. RM93-19-001." (1995). Federal Energy Regulatory Commission. http://www.ferc.gov/legal/maj-ord-reg/land-docs/71_FERC_61195.pdf. Accessed August 2012.

⁴¹ "Order No. 888 Final Rule." (1996). Federal Energy Regulatory Commission. <https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt>. Accessed August 2012.

Transmission Pricing Policy Statement, Pooling Notice of Inquiry,⁴² Regional Transmission Group Policy Statement,⁴³ and Merger Policy.⁴⁴

1.2 Deregulation and Restructuring

In 2012, the utility sector consists of a diverse group of entities. Some have preserved their identities as vertically integrated utilities, while other new players offer products and services that address parts of the electric power supply chain. Two primary factors for the move towards deregulation were large differences in the retail price of electricity and the need for technological advancement.⁴⁵ Deregulation efforts apply to the generation sector at the national level. The transmission sector will still be regulated, while the distribution sector will be deregulated on a state-by-state basis.

1.2.1 EPAct

The EPAct of 1992 opened the door for individual states to begin the process of deregulation, according to their own circumstances. Implementation guidelines were provided by FERC in Orders 888⁴⁶ and 889.⁴⁷ EPAct 2005 established the concept of a National Interest Electric Transmission Corridor in an effort to maintain momentum for siting new transmission. The act gave FERC limited siting authority for electric transmission facilities located in specific corridors designated by DOE.⁴⁸ These were sites where a state has either denied or delayed, for at least 1 year, an application to construct a transmission facility within the corridor.

1.2.2 FERC Order 888 (1996)

After passage of EPAct, FERC established rules by which open transmission would be achieved. Order 888 established standards of conduct concerning transmission access and treatment of transmission customers and rules to be followed to achieve open transmission objectives:

- Require all jurisdictional utilities (within the United States) to file an open access transmission tariff (OATT)
- Require investor-owned utilities to functionally unbundle wholesale generation and power marketing from transmission services
- Create non-profit Independent System Operators (ISOs) and operating guidelines

⁴² Hogan, William. (1995). "Electricity Transmission and Emerging Competition." Harvard University, Florida. <http://www.hks.harvard.edu/fs/whogan/purc0495.pdf>. Accessed August 2012.

⁴³ "FERC Laws and Orders." (undated). Basin Electric Power Cooperative, North Dakota. http://www.basinelectric.com/Electricity/Transmission/Regulation/FERC_Laws_and_Orders/index.html. Accessed August 2012.

⁴⁴ "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement ORDER NO. 592." (1996). Federal Energy Regulatory Commission. <http://www.ferc.gov/industries/electric/gen-info/mergers/rm96-6.pdf>. Accessed August 2012.

⁴⁵ "The Changing Structure of the Electric Power Industry: an Update" (1996). Energy Information Administration. <http://www.eia.gov/FTP/ROOT/electricity/056296.pdf>. Accessed August 2012.

⁴⁶ "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." (2006). Federal Energy Regulatory Commission. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp>. Accessed August 2012.

⁴⁷ "Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct" (2005). Federal Energy Regulatory Commission. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/order889.asp>. Accessed August 2012.

⁴⁸ "National Interest Electric Transmission Corridors and Congestion Study Documents." (undated). U.S. Department of Energy. <http://nietc.anl.gov/documents/index.cfm>. Accessed August 2012.

- Encourage reciprocity for non-jurisdictional (Canadian and Mexican) utilities
- Allow utilities to recover stranded costs
- Identify ancillary services and comparable services to properly operate the bulk power system
- Initiate Standards of Conduct

To meet these points, FERC required the functional separation of power schedulers and marketers and the transmission operations within vertically integrated utilities.

EPAct created a new category of electricity producer, the *exempt wholesale generator*, and mandated that FERC open up the national electricity transmission system to wholesale suppliers on a case-by-case basis. The EPAct created a competitive wholesale framework that opened transmission access to wholesale generators of power. Wholesale buyers of electricity, such as electric utilities, buy electricity at wholesale prices to sell it on a retail basis. Order 888 assured the exempt wholesale generators a way to transmit their power to their purchasers.

To support the deregulated operation of the generation sector, the transmission sector was restructured. Order 888 outlined 11 operational principles and guidelines for newly established, non-profit ISOs. Order 888 made ISOs responsible for operating the transmission system, Open Access Same-Time Information System (OASIS), generation dispatch (and queue), and certain control area power markets (generation and transmission). FERC asserted authority (upheld by the U.S. Supreme Court) over retail transmission service, including wholesale transmission (wheeling) and unbundled transmission as defined within Order 888.

1.2.3 FERC Order 889 (1996)

Order 889 further defined the independence of transmission by detailing how the newly emerging electricity markets should interact with transmission providers. Order 889 addressed the issue of access to transmission system information by all interested parties. It obliged transmission operators to implement OASIS, an internet-based system for obtaining transmission-related services, including the availability of transfer capacity on specific transmission paths in nearly real time. Order 889 made transmission system information previously held exclusively by vertically integrated utilities available to all interested parties.

1.2.4 FERC Order 2000 (2000)⁴⁹

After operating under the provisions of Order 888 for several years, barriers to functional deregulation were addressed by Order 2000. Order 2000 was issued primarily to improve transmission operational efficiency, expand the transmission system, and open access to the transmission system. Other goals were to lower electricity prices and reduce regulation. FERC addressed transmission on a regional, multi-state scale because all states within an interconnection are impacted by disturbances within it, as evidenced by the Western interconnection disturbances in the summer of 1996.⁵⁰

To ensure that ISOs extend beyond state boundaries, FERC created RTOs. RTOs operate the transmission facilities for the transmission owners in RTO control areas, but they are larger than their ISO predecessors. The RTO guidelines were designed to prevent transmission system

⁴⁹ FERC Order 2000. <http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf>

⁵⁰ "Disturbance Report" (1996). North American Energy Reliability Company. <http://www.nerc.com/docs/docs/pubs/AUG10FIN.pdf>. Accessed August 2012.

discrimination. FERC-approved RTOs must meet at least the four characteristics and eight functions FERC identifies as required for proper RTO operation.

1. *Independence*: The RTO must be independent of market participants. An RTO's independence is assured when none of its employees or non-stakeholder directors have a financial interest in any market participant.
2. *Sufficient Scope and Regional Footprint*: The RTO's region must be large enough to support efficient and nondiscriminatory power markets. This requirement is demonstrated when the organization meets nine criteria:
 - Has the ability to perform essential RTO functions
 - Operates with a footprint that is one contiguous geographic area
 - Operates a grid that is highly interconnected
 - Has the ability to deter market power
 - Recognizes existing trading patterns
 - Accommodates existing regional boundaries, such as the NERC regions
 - Encompasses existing regional transmission entities
 - Encompasses existing control areas
 - Respects international boundaries
3. *Operational Authority*: The RTO must have the authority to operate all of the transmission facilities under its control and must act as the security coordinator for the region.
4. *Near-term Reliability*: The RTO must have exclusive authority for maintaining the reliability of the transmission grid under its control up to the planning horizon.

In addition, the RTO must include the following services:

1. *Tariff Administration and Design*: The RTO will have sole responsibility over its own tariff and be the sole decision-making authority with respect to transmission services including new interconnections.
2. *Congestion Management*: The RTO will establish market mechanisms to manage transmission congestion. These mechanisms should provide price signals to transmission customers that reflect their transmission usage decisions.
3. *Parallel Path Flow*: The RTO must implement procedures to recognize and address the fact that power flows according to the laws of physics and power dispatched in one region may flow over the transmission grid into another region, potentially impacting the transmission capacity in the second region.
4. *Ancillary Services*: The RTO must ensure that the grid has sufficient ancillary services and must act as the provider of last resort, if necessary.
5. *OASIS and Capability Calculations*: The RTO should act as a single OASIS node in order to provide the necessary data so that transmission capability, whether calculated by the RTO or verified by the RTO, can be available to the transmission customers.

6. *Market Monitoring*: The RTO will submit to FERC a plan to ensure that the market is operating in a competitive fashion, that there are opportunities for efficiency improvements, and that there is sufficient oversight of the market participants.
7. *Planning and Expansion*: The RTO must develop a planning organization to oversee the grid development to ensure adequate capability and relieve congestion.
8. *Interregional Coordination*: The RTO will work with its neighbors to ensure reliable operating practices and efficient market interface among regions.

The ISOs already in operation also were required to prove they met the criteria to receive FERC approval. RTOs could be operated to earn a regulated profit for financing infrastructure expansion. FERC outlined a voluntary approach for transmission owners to hand over control of their facilities to an RTO of which they were a member. At or near this time, independent transmission companies began to appear. An independent transmission company is a collection of transmission owners combining to form one large transmission company (e.g., TRANSLink). FERC specified that independent transmission companies could participate within an RTO or form their own RTO. Therefore, an RTO could be a non-profit organization that was previously an ISO or it could be a regulated, for-profit transmission company.

Order 2000 requires transmission owners to state whether they belong to an RTO or if they intend to join an RTO. If they are not planning to join an RTO, they must explain why they are not participating and present plans and a timetable for future efforts. The order requires each public utility that is a member of a transmission entity and meets the requirements under FERC Order 888 to explain the extent to which the entity meets the minimum requirements and how it functions as an RTO. If the entity is not an RTO, the utility must explain how the entity plans to become an RTO or explain why that is not reasonable.

Under this scenario, FERC envisioned five RTOs for the entire U.S. transmission system—Northeast, Southeast, Midwest, Texas, and the entire Western Interconnection. Nine proposed RTOs were approved, each with its own operating rules. The result was a problem referred to as RTO boundaries or seams. Seams have problems, due to their different operating rules, related to scheduling and paying for electrical service between RTOs. As reported to FERC, seams issues allowed continued discrimination for open access and impediments to wholesale power competition. To correct this, FERC issued the Standard Market Design Notice of Proposed Rulemaking⁵¹ on July 31, 2002. Standard market design would eliminate seams issues by standardizing the way generation and transmission markets work and create a larger geographic region.

Standard market designs called for the introduction of independent transmission providers to replace RTOs. Independent transmission providers would retain many RTO responsibilities and add others. Under the standard market design proposal, jurisdictional utilities must file new transmission tariffs. Non-jurisdictional utilities would follow reciprocity guidelines established under Order 888. Locational marginal pricing and congestion revenue rights were introduced as new transmission pricing policies. FERC continued to assert its jurisdictional authority over bundled transmission, to oversee market power and, if required, to mitigate abuses of market

⁵¹ Woods, McGuire. (2008). "Detailed Summary of FERC's Standard Market Design NOPR." Thomson Reuters. <http://library.findlaw.com/2002/Jun/25/132372.html>. Accessed August 2012.

power. Finally, FERC proposed to develop resource adequacy guidelines and a regional planning process to sustain a viable electrical power system.

1.2.5 FERC Order 890 (2007)

To rectify continuing issues of effective planning and coordination, FERC issued Order 890,⁵² which required a more open, transparent, and inclusive planning process. It required all transmission providers to file a new attachment to their OATT that contained their transmission planning process. The planning process must follow nine transmission planning principles.

1. *Coordination*: The transmission provider must meet with all of its transmission customers and interconnect neighbors to develop a transmission plan. FERC did not specify the details of how that coordination was achieved (e.g., number and structure of meetings). It did suggest formation of permanent planning committees that included transmission providers as well as state authorities, customers, and other stakeholders.
2. *Openness*: The coordination process should include meetings that are open to all affected parties. That does not imply that the public is invited, but only direct stakeholders are part of the process. The size of the group is dependent on the nature of the agenda.
3. *Transparency*: The transmission provider is required to fully disclose to all stakeholders the basic criteria, assumptions, and data that form the foundation for its planning process. FERC expressed its expectation that even those transmission providers not under FERC jurisdiction would also follow the principles in Order 890. The clear methodology for available transmission (transfer) capability (ATC) and OASIS posting is an important component of transparency. FERC anticipated that NERC would play a role in developing the ATC methodologies.
4. *Information Exchange*: Order 890 also places requirements on transmission customers to submit information on projected loads, resources, and anticipated transmission requirements to better assist in the planning process. The transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.
5. *Comparability*: The transmission plan should meet the needs of transmission customers by accommodating their specific service requests and treating similar situations comparably. While this principle had been previously stated by FERC, there were continued concerns so that FERC felt it necessary to re-emphasize the requirement.
6. *Dispute Resolution*: There must be an established venue for dispute resolution to address both substantive and procedural planning disputes. FERC was careful to add that this requirement did not cover non-jurisdictional issues such as state siting issues.
7. *Regional Participation*: Transmission providers are required to coordinate with neighboring interconnected systems to share plans. Neighboring systems are to work together to ensure that plans are simultaneously feasible and to ensure that they address significant and persistent transmission congestion.
8. *Economic Planning*: Traditionally, planning primarily addressed reliability needs but FERC has added the requirement that “significant and recurring” congestion be

⁵² “Preventing Undue Discrimination and Preference in Transmission Service.” (2007). Federal Energy Regulatory Commission. <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>. Accessed August 2012.

addressed. While suboptimal dispatch and other economic transactions could be curtailed to maintain reliability, FERC requires that economic transmission expansion be part of the planning process.

9. *Cost Allocation:* Transmission providers and customers must develop a cost allocation method for new projects that represents a fair and equitable cost sharing based on benefit received. The cost allocation mechanism should provide incentives for new transmission and be supported by state authorities and regional participants.

In order to address perceived deficiencies in the way requests for firm point-to-point transmission service may be denied, FERC modified the pro forma OATT to include the “conditional firm” component. Specifically, FERC included the following in Order 890:

- FERC adopted the “conditional firm” component to provide additional long-term firm point-to-point service, requiring that transmission providers identify either defined system conditions or an annual number of hours during which service will be conditional, allowing transmission customers a choice.
- Transmission providers have an obligation to evaluate the provisions of redispatch from their own resources and provide customers with information on the capabilities of other generators to provide redispatch.
- The duration of both service options is limited to a time period during which service can be reasonably provided without impairing reliability.
- Transmission providers must post certain information monthly on the actual cost of redispatch services provided during that month.

Order 890 also addressed energy and generator imbalance penalties and rollover rights for transmission customers by increasing the minimum term of transmission contracts from 1–5 years.

1.2.6 FERC Order 717 (2008)

FERC issued Order 717⁵³ to clarify the rules previously promulgated under Order 2004⁵⁴ Standards of Conduct, which were widely perceived as interfering with efficient utility operations. Order 717 established a revised Standard of Conduct for employees of entities having both a “transmission function” and a “market function” by focusing on the day-to-day activities of employees. The order sought to more narrowly identify the scope of activities that constituted transmission activities and the scope of activities that constituted marketing activities.

Traditionally, transmission planning relied on information related to load growth, reliability, and generation expansion. Under the Standard of Conduct, however, generation planning is considered a market function. In that context, transmission planning has shortened its horizon to accommodate short-term needs because transmission planners no longer have a “window” into generation expansion.

⁵³ “Standards of Conduct for Transmission Providers.” (2008). Federal Energy Regulatory Commission. <http://www.ferc.gov/whats-new/comm-meet/2008/101608/M-1.pdf>. Accessed August 2012.

⁵⁴ “FERC Commission Orders” (2012). Federal Energy Regulatory Commission. <http://www.ferc.gov/legal/maj-ord-reg/stand-conduct/orders.asp>. Accessed August 2012.

1.2.7 FERC Order 1000 (2011)

FERC Order 1000⁵⁵ was adopted on July 21, 2011 to reform the transmission planning process to achieve the following outcomes:

- Require a regional transmission planning process
- Include procedures for the consideration of public policy requirements (e.g., renewable portfolio standards and other state clean energy requirements)
- Modify the right of first refusal for certain new transmission facilities
- Provide for additional coordination for planning and cost allocation, both within and among regions.

One of the key motivations was to enhance support for renewable project development and new transmission development by entities other than current public utility transmission owners.

1.3 Mandatory Reliability Standards

Reliability requirements for electric power systems have evolved from a voluntary agreement among utilities to mandates for minimum standards, with compliance audits to ensure enforcement. The history of reliability to a large extent mirrors the evolution of NERC. In response to the EPAct of 2005, FERC established the concept of a national Electric Reliability Organization (ERO) to develop and enforce mandatory reliability rules. As a result, NERC's role transformed from a voluntary organization to one that is certified by FERC to establish and enforce reliability standards for the bulk power system, including audit and financial penalty authority. NERC develops and enforces reliability standards; annually assesses adequacy; monitors the bulk power system; and is engaged in education, training, and certification of industry operating personnel.

The electric power grid of the continental United States is divided into three asynchronous interconnections commonly known as the Eastern Interconnection, Western Interconnection, and ERCOT Interconnection (see Figure 2). The eight regional entities are shown in Figure 3 work with NERC, the national electric reliability organization approved by FERC. The regional entities are permitted to enact standards that are more stringent than those enacted by NERC but are not permitted to relax or enact standards less stringent than NERC standards.

⁵⁵ "Order No. 1000 – Transmission Planning and Cost Allocation." (2012). Federal Energy Regulatory Commission. <http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>. Accessed August 2012.

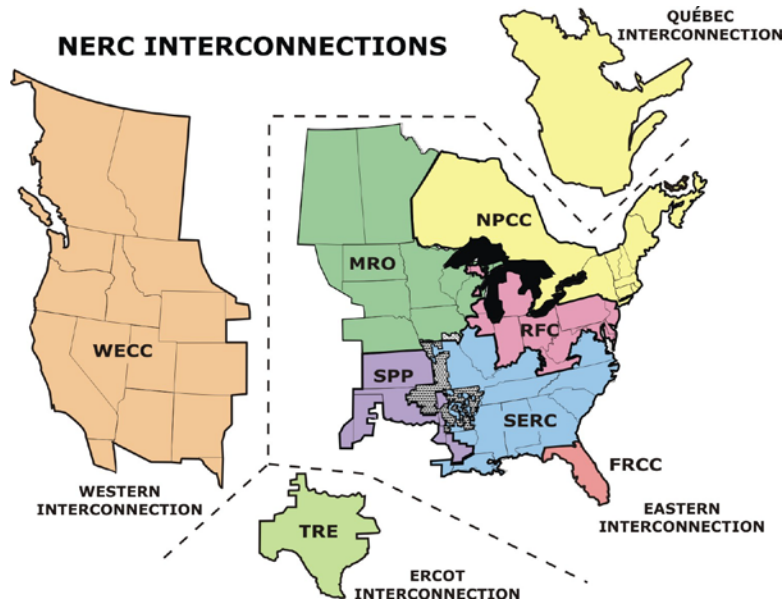


Figure 2. Interconnections of the U.S. Power Grid⁵⁶

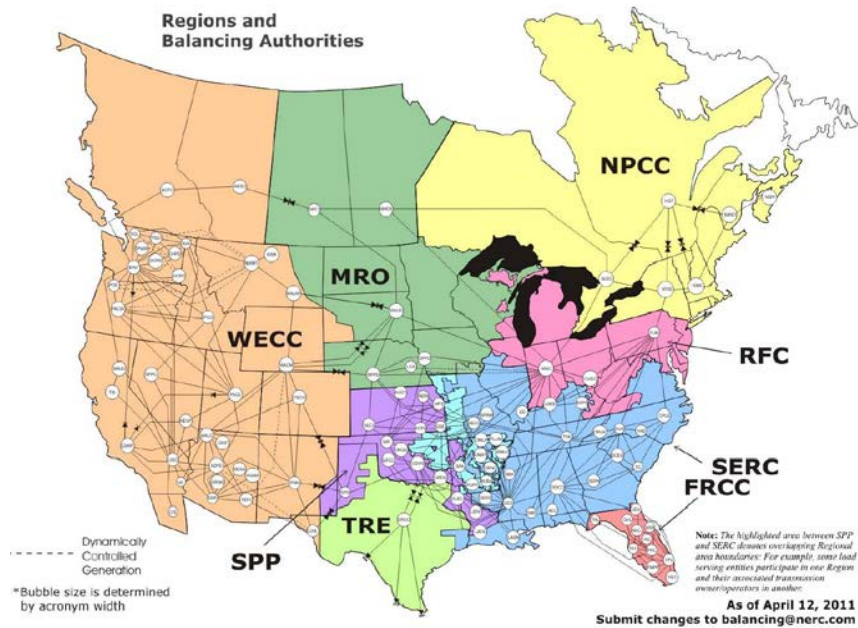


Figure 3. Regional entities and balancing authorities⁵⁷

⁵⁶ This image from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_Color_072512.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation. Accessed August 2012.

⁵⁷ This image from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/docs/oc/rs/BubbleMap_2011-04-12.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation. Accessed August 2012.

1.4 Trends and Current Situation

To a large extent, the need for increased transmission capacity is being driven not by an increase in demand, but more by a redistribution of generation. Replacing conventional dispatchable generation resources, such as coal and gas, with more efficient and/or cleaner renewable resources requires access to the transmission system. However, these new resources are often not at the same location as retired resources. Further complicating the issue of transmission capacity, the procedures and rules for accessing transmission service are being redefined by FERC. These orders are aimed at providing non-discriminatory service to potential users at a level comparable with that of the incumbent utility. FERC is also redefining the way transmission costs are allocated as they have in Order 1000.

For a more details on the current electric power grid structure in the United States, please refer to Appendix A: U.S. Electric Power Grid Structure.

2.0 Expanding Existing Transmission Capacity – Operations, Policy, Rules

Exploring opportunities to increase the transmission capacity of the existing systems requires understanding basic terminology and the structural operation of the grid. This chapter explains the features of the grid and its operation and outlines relevant policies and rules.

The carrying capacity of the transmission and distribution system is inextricably tied to reliability requirements. As outlined in Chapter 1, FERC has designated NERC as the ERO under EPCA 2005. NERC develops the minimum standards by which electric power transmission systems must be planned and operated. While other organizations may offer more stringent reliability rules, they may not set them below NERC standards. Activities to enhance the capabilities of existing transmission must be consistent with NERC standards.

2.1 Transmission Capability

When thinking about adding renewable generation to existing transmission lines, the concept of transmission *capabilities* is crucial. These transmission values are called *capabilities* (differentiating them from *capacities*) because they are dependent on the generation, customer demand, and transmission system conditions assumed during the analyzed time period. The electric industry generally uses the term *capacity* as a specific limit or rating of power system equipment. In transmission, *capacity* usually refers to the thermal limit or rating of a particular transmission element or component.

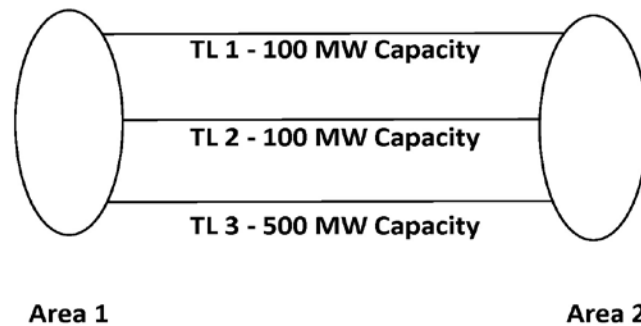
2.1.1 Total Transfer Capability

The ability of the interconnected electric systems to reliably move or transfer power from one *area* to another over all transmission lines (or paths) under specified system conditions is known as the *total transfer capability* (TTC). The units of transfer capability are defined in terms of electric power, generally expressed in megawatts. In this context, the area may be an individual electric system, an operating area, sub region, NERC region, or a portion of any of these.

When calculating TTC, the following features must be kept in mind:

- A transmission path (circuit) can be an individual transmission element or a combination of elements.
- TTC is directional. The transfer capability from Area A to Area B is not generally equal to the transfer capability from Area B to Area A.
- The ability of a single transmission line to transfer electric power, when operated as part of the interconnected network, is a function of the physical relationship of that line to the other elements of the transmission network.
- Individual transmission line capacities or ratings *cannot be added* to determine the transmission capability of a circuit or interface (transmission circuits between two or more areas within an electric system or between two or more systems).
- The actual transfer capability of a specific transmission interface between two areas of the network is less than the aggregated (added) capacity of the individual circuits of that interface. This is illustrated in Figure 4 where the sum of the individual line capacities that make up the only path between Area 1 and Area 2 is 700 MW. However, the

interface path capability is limited to 200 MW because the capability of the path must be maintained to meet the largest single contingency—the loss of the 500-MW line.



Contingency	Total Transfer Capability Between Area 1 and Area 2	TL 1	TL 2	TL 3
None	700 MW	IN	IN	IN
N-1	600 MW	OUT	IN	IN
N-1	600 MW	IN	OUT	IN
N-1	200 MW	IN	IN	OUT

Figure 4. Path rating and contingencies

Operating limits are also considered when estimating TTC. These limits are established based on a system's physical and electrical characteristics. The types of limits are as follows:

- *Thermal Limits:* Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.
- *Voltage Limits:* System voltages and changes in voltages must be maintained within acceptable minimum and maximum limits. For example, voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a partial or complete blackout of the interconnected network.
- *Stability Limits:* The transmission network must survive disturbances through transient (milliseconds) and dynamic (several minutes) time periods following the disturbance. All generators are connected to the AC (AC interconnected transmission systems are synchronized to operate at the same frequency, nominally 60 Hz). Immediately following a system disturbance, generators begin to oscillate relative to each other, causing

fluctuations in system frequency, line loadings, and system voltages. For the system to be stable, the oscillations must diminish as an electric system attains a new, stable operating point. If a new, stable operating point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric system may become unstable. Generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

Operating limits are developed based on thermal, voltage, and stability concerns according to industry reliability criteria (NERC and regional entities)⁵⁸ for transmission paths. All transfer capabilities ensure that power flows are within their respective operating limits, both pre-contingency and post-contingency. Different regional entities have various definitions.

Operating limits are typically calculated for the peak condition, which may occur only once during the year. In some cases, a separate TTC may be calculated for the peak condition for winter and summer. By calculating the rating under the most severe condition, the TTC for a particular path is lower than necessary for the remaining periods because system conditions would permit a higher capability. Even when the ATC is calculated hourly, the TTC remains constant for a particular series of calculations within the same season.

Recent evidence indicates that the NERC standards for calculating TTC (i.e., MOD-029-1a⁵⁹) could lead to unnecessarily low TTC values. Certain lines when modeled under the standard may cause the TTC to be limited by the modeling and not by historical evidence of TTC. This is particularly true when wind or other intermittent resources are being modeled.⁶⁰

The TTC could be expanded in at least two ways, thereby increasing the estimated transmission capacity available for new generation:

1. Calculating a path TTC under a wider range of conditions could lead to greater overall utilization of the path.
2. Evaluation and revision of NERC MOD-029-1a for calculating TTC could include historical evidence of TTC and avoid limits based on modeling artifacts.

2.1.2 Available Transfer Capability

ATC is less than TTC. It is the estimated or designated transmission capability remaining in the network over and above already committed uses. A complex mathematical calculation of ATC is made by each planning authority, using its own methodology. ATC is calculated by taking account of factors that reduce TTC such as the transmission reliability margin, existing transmission commitments, the capacity benefit margin, and other adjustments such as postbacks and counterflows.

⁵⁸ “NERC TPL and Top Standards.” (2012). North American Electric Reliability Company. <http://www.nerc.com/page.php?cid=2|20/>. Accessed August 2012.

⁵⁹ “Standard MOD-029-1a – Rated System Path Methodology.” (undated). North American Electric Reliability Company United States. <http://www.nerc.com/files/MOD-029-1a.pdf>. Accessed August 2012.

⁶⁰ Lew, Debbie and Milligan, Michael. (2007). “New Approaches to Deliver Wind Energy.” National Renewable Energy Laboratory: Boulder, CO. http://www.nrel.gov/wind/systemsintegration/pdfs/2007/lew_delivering_wind.pdf.

NERC requires that each transmission operator select one of the following three methodologies for calculating ATC:

1. The Area Interchange Methodology, MOD-028⁶¹
2. The Rated System Path Methodology, MOD-029
3. The Flowgate Methodology, MOD-030⁶²

While NERC defines all of these terms, each planning authority determines the exact methodology that it will use. The detailed calculation of ATC, particularly in the daily operation of the system, determines the ultimate utilization of the various transmission paths (circuits) on the grid.

2.1.2.1 Transmission Reliability Margin

The Transmission Reliability Margin (TRM) is a factor in the calculation of ATC that accounts for uncertainties and reduces ATC. NERC Standard MOD-008⁶³ lists the various factors that should be taken into consideration when calculating TRM:

- Aggregate load forecast
- Load distribution uncertainty
- Forecast uncertainty in transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages)
- Allowances for parallel path (loop flow) impacts
- Allowances for simultaneous path interactions
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages, and location of future generation)
- Short-term system operator response (operating reserve actions)
- Reserve-sharing requirements
- Inertial response and frequency bias

Uncertainties associated with TRM serve to reduce the ATC and therefore the capacity available for new generation. A more accurate estimate of each factor would reduce uncertainties and allow a more accurate (and potentially less conservative) estimate of ATC. Many transmission operators use a TRM of 0 (no effect) when calculating ATC, which results in a higher ATC than if these uncertainties were taken into account.

2.1.3 Capacity Benefit Margin

Another factor in the calculation of ATC, Capacity Benefit Margin (CBM) is the amount of firm transmission capability set aside by the transmission operator for use by the load serving entities.

⁶¹ “Standard MOD-028-2 – Area Interchange Methodology.” (2010). North American Electric Reliability Company. <http://www.nerc.com/files/MOD-028-2.pdf>. Accessed August 2012.

⁶² “Standard MOD-030-02 – Flowgate Methodology.” (2009). North American Electric Reliability Company. <http://www.nerc.com/files/MOD-030-2.pdf>. Accessed August 2012.

⁶³ “NERC Standard MOD-008-1 TRM Calculation Methodology” (2008). North American Electric Reliability Company. <http://www.nerc.com/files/MOD-008-1.pdf>. Accessed August 2012.

It is ignored in areas where load serving entities are required to secure their capacity requirements, including deliverability.

2.1.3.1 Other Adjustments

Each transmission provider may have adjustments specific to its system that would increase or decrease the ATC. NERC rules for calculating ATC permit these adjustments, as long as they are documented and applied consistently. The California Independent System Operator (CAISO), operating within the Western Interconnect of North America, for example, uses postbacks, which are temporary changes in transmission service for the particular period covered by the ATC calculation. The CAISO also uses counterflows, which are registered flows in opposition to the calculated ATC flow. These particular adjustments may actually increase the ATC.

2.1.4 Planning Versus Operating Horizon

Projected transmission needs are determined by planning studies. However, TTC can change over time as system conditions change and may be limited by either thermal limitations on individual facilities, voltage constraints, or stability limits, depending on existing conditions (see Figure 5). To gain maximum utilization of the grid, TTC calculations must be updated in real time to account for current conditions on the grid.

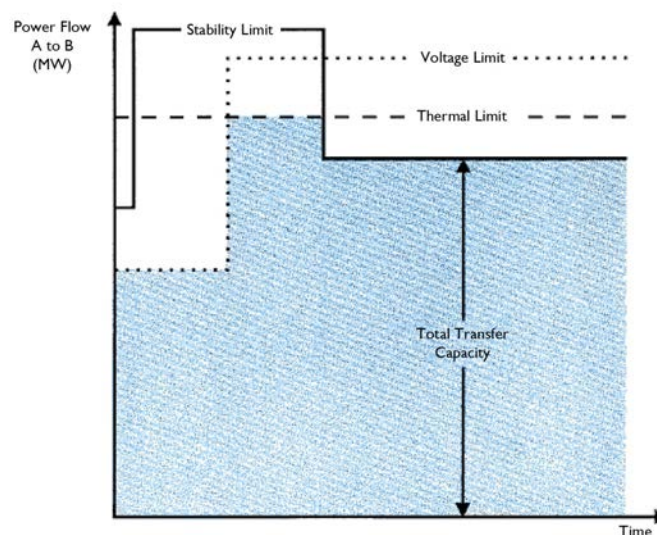


Figure 5. Total Transfer Capacity changes with time⁶⁴

Calculation of ATC takes account of the current TTC as well as the actual flows on the lines and not just the “reserved” flows, which may or may not materialize in real time. This is the difference between the prospective system, as used in planning systems, and the real-time conditions during actual operations, as illustrated in Figure 6. The figure introduces the concept of recallable and non-recallable capability. These are analogous to firm and non-firm capacity. The figure shows the additional capability that could be available by utilizing unscheduled, non-recallable capability. The unused (unscheduled) capability in the Operating Horizon could be made available in real time to increase overall transfer capability. Market-based congestion provides an opportunity to use all of the available capability and not unnecessarily reserving capability.

⁶⁴ Adapted from NERC website: www.NREC.com.

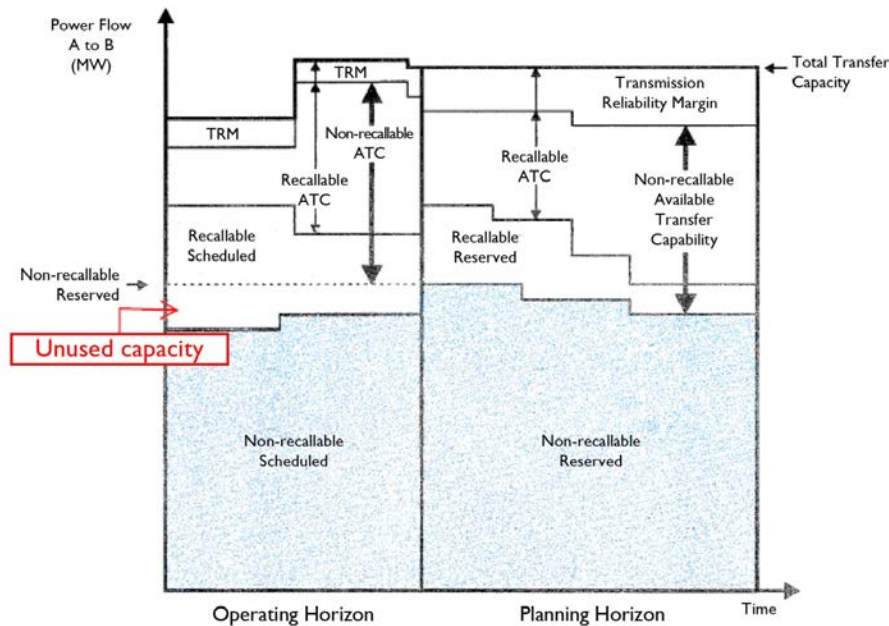


Figure 6. Available Transfer Capability operating versus planning horizon⁶⁵

2.2 Thermal Ratings and Estimated Capacity

Estimated transmission capacity is affected by ratings of lines and other equipment. Individual transmission owners may develop the rating of transmission lines (and other equipment) provided they follow certain general guidelines as noted in the excerpt from NERC standard FAC-08-3⁶⁶ below.

The methodology used to establish the equipment ratings that comprise the facility shall be consistent with at least one of the following⁶⁷:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems
- A practice that has been verified by testing, performance history, or engineering analysis

The effect of the assumptions used for thermal ratings is shown in the example below. A utility in the northeastern United States has calculated summer and winter ratings based on a set of conservative assumptions as follows:

- A summer maximum ambient temperature of 35°C and an average daily maximum of 30°C
- A winter maximum ambient temperature of 10°C and an average daily maximum of 5°C

⁶⁵ Adapted from NERC website: www.NREC.com.

⁶⁶ "NERC Facility Ratings." (undated) North American Electric Reliability Company. <http://www.nerc.com/files/FAC-008-3.pdf>. Accessed August 2012.

⁶⁷ Ibid Section 2.1

- Ambient wind speed of 3 feet per second for summer and winter
- All local thermodynamic equilibrium ratings are established assuming a maximum time period of 4 hours, but total no more than 300 hours over the life of the line
- All system thermodynamic equilibrium ratings are established assuming a maximum time period of 15 minutes, but total no more than 12.5 hours over the life of the line; a normal preload is also used in establishing the short-term emergency rating
- 40-year life is assumed for each line

The assumed ambient temperature plays an important role in determining the capacity of an individual line and presents an opportunity to increase utilization of line capacity. In the example, the actual average maximum monthly temperature in the utility's core area is 25.6°C, which is 4.4°C less than the assumption. Using the higher assumed temperature results in a reduced capacity for the line. Reducing the average maximum assumption closer to the recorded average could increase TTC and allow for added transfer of renewable generation.

Fine-tuning the timing of ratings could also increase TTC. The maximum temperature applies for a particular time period. This means that the line would be underutilized for all but the time when the ambient temperature was at its maximum. Dynamic line rating or real-time line rating can be used to reduce the conservatism built into the seasonal static ratings. By using actual conditions rather than assuming a static set of "worst case" conditions, the available transmission could be increased in real time for operational purposes.

Table 2 shows the relative sensitivities of the thermal line rating associated with the assumptions used in the calculations. This is based on IEEE Standard 738-1993.⁶⁸

Table 2. Impact of Assumptions on Thermal Line Rating⁶⁹

ASSUMPTIONS	IMPACT ON CALCULATED RATING
Solar heating during the day	<5%
Ambient air temperature	10% for a 10°C difference
Wind speed	10% - 20% within the range of 0 to 3 ft/sec
Wind direction	10 degree angle to conductor vs. perpendicular 2.8% reduction

NERC Standard FAC-08-3⁷⁰ permits a methodology that can be "verified by testing, performance history or engineering analysis." If implemented properly, dynamic line rating or adjustment of ratings criteria would increase TTC while maintaining reliability.

2.3 Common Corridor Definitions

A factor in the calculation of ATC is the reliability requirement adjustments for lines on a common corridor that share rights-of-way. NERC considers the reliability impact of lines on a common structure, whereas WECC has required that lines on a common corridor be evaluated

⁶⁸ "IEEE Standard for Calculating the Current-Temperature of Bare Conductors." (1993). IEEE. <http://standards.ieee.org/findstds/standard/738-1993.html/>. Accessed August 2012.

⁶⁹ Source: Increased Power Flow through Transmission Circuits: Overhead Line Case Studies and Quasi-Dynamic Rating. (2006). EPRI: Palo Alto, CA 2006.

⁷⁰ "NERC Facility Ratings." (undated) North American Electric Reliability Company. <http://www.nerc.com/files/FAC-008-3.pdf>. Accessed August 2012.

together when assessing the reliability of a transmission path. Revisions to the WECC reliability requirements for transmission lines that share a common corridor take effect April 2012. This change could allow for increased use of transmission corridors, improve the siting and permitting process for transmission expansion, and ensure that the current reliability levels of the Western Interconnection are not compromised.

A technical drafting team within WECC proposed refining the definition for Adjacent Transmission Circuits to incorporate separation language that was contained previously in the Common Corridor definition. It should be noted that the drafting team modified the distance between the structure center line separation from “less than the longest span length of the two transmission circuits at the point of separation or 500 feet” to “separation between their center lines less than or equal to 250 feet at the point of separation.” The 250-foot distance was selected because it is approximately the maximum height of a 500-kV tower with some margin. The changes were approved by the WECC Board of Directors and will take effect in April 2012.⁷¹ With this change, future transmission circuits may be placed in closer proximity, thereby potentially increasing the utilization of existing rights-of-way.

2.4 Congestion Management

2.4.1 Market-Based Congestion Management

Transmission is affected by allocation decisions of the line operators. Market-based congestion management allocates transmission either a day ahead or in real time to the highest bidders for transmission rights. Rather than holding physical transmission rights, participants hold financial transmission rights that form a hedge against congestion. FERC Order 2000 required RTOs to establish market-based congestion management.

With financial transmission rights, all market participants have access to the transmission capacity and are under constrained conditions. Those willing to pay the highest price for access to the limited capacity may use it. The holder of the financial transmission rights realizes the financial premium from the scarcity price of the transmission. This provides an efficient use of constrained transmission systems, minimizing unused capacity since all market participants have access to the grid.

Under a market-based congestion management system, generation is redispatched to relieve the congestion. The initial dispatch is determined by utilizing the most efficient generation to serve the load. The following figures and tables from a PJM Interconnection training manual⁷² illustrate how the process can work. Figure 7 shows a dispatch using the lowest cost generation to serve the load. In doing so, however, the maximum capacity of the indicated line is exceeded (253 MW of flow with a capacity of 230 MW). Note that the three most efficient generators are fully dispatched (Brighton, Alta, and Park City) and the balance of the load requirement is met

⁷¹ “WECC-0071 System Performance Criteria Approved.” (2012). Western Electricity Coordinating Council. <http://www.wecc.biz/Standards/Development/WECC-0071/Lists/SiteNews/DispForm.aspx?ID=4>. Accessed August 2012.

⁷² PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. Source for Figures 8, 9, and 10: “LMP FTR Training Manual.” (2011). PJM. PJM makes no representation, warranty or guarantee as to the accuracy or completeness of the information provided herein. <http://www.pjm.com/~media/training/core-curriculum/ip-lmp-101/lmp-ftr-101-training.ashx/>. Accessed August 2012.

by the fourth most efficient generator (Solitude). The least efficient generator (Sundance) is not dispatched at all.

Dispatch Solution Ignoring Thermal Limit

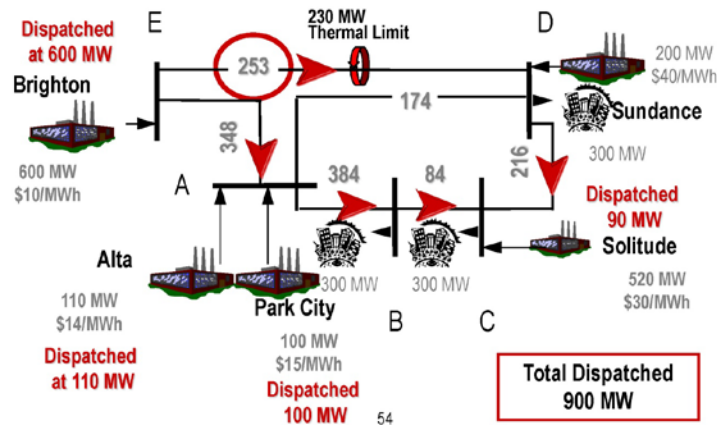


Figure 7. Dispatch and flows before congestion relief

To relieve the congestion on the overloaded line, redispatch of the generation from the lowest cost configuration is necessary, as shown in Figure 8. The redispatch reduces the output from Brighton (most efficient generator) by 90 MW and increases the output from Solitude (fourth most efficient generator) by 90 MW to compensate. This redispatch lowers the flow on the overloaded line to within its limit of 230 MW, but causes the overall cost of supplying the load to increase. In a market-based system, this is reflected in an increase in the locational marginal price and results in a higher cost of power. The difference in cost between the optimal dispatch and the redispatch is the congestion component of locational marginal price and is paid by customers.

Actual Dispatched Generation

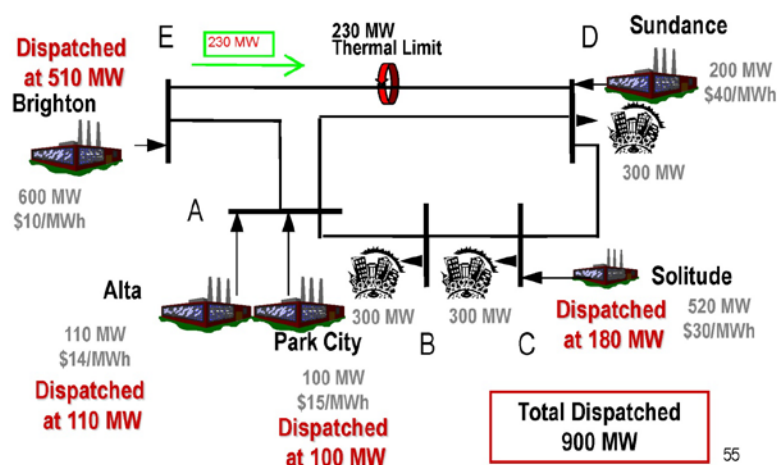


Figure 8. Dispatch and transmission flows after redispatch to relieve congestion

However, transmission customers can hedge against these congestion costs by securing the congestion revenue rights. Two primary methods are available for hedging congestion: the transmission congestion contract as used by the New York Independent System Operator (NYISO), a balancing area and electric power market operator for the state of New York within the Northeast Power Coordinating Council (NPCC) and the financial transmission rights as used by PJM Interconnection. PJM is an RTO with responsibility for all or a portion of 13 states and the District of Columbia. PJM manages the electric power grid and the wholesale electricity market within its footprint and is a balancing area within the regional entity Reliability First Corporation in the Eastern Interconnection. PJM began as a power pool and transitioned to an ISO in 1997 and became an RTO in 2001.

Both transmission congestion contracts and financial transmission rights provide a market-based, efficient method for allocating transmission capacity and minimizing unused capacity, particularly during periods of transmission shortage.

In areas without markets, it is not feasible to use redispatch as a means of congestion management. These areas must rely on physical transmission rights, which can leave unused capacity even during times of perceived transmission shortage. In the example above, transmission customers could only serve the load up to the limit of the line (230 MW) based on a preset dispatch. There would be no mechanism to allocate the cost of redispatch. Approximately 23 MW (253 MW minus 230 MW) would not be served because the capacity of the transmission could not be increased. If market-based congestion management were used, the cost of adding transmission would be weighed against the cost of redispatch.

When viewing the redispatch in terms of locational marginal price, as calculated in a market-based system (Table 3), the post redispatched and associated locational marginal prices are given in Figure 9. Prior to congestion, however, the locational marginal price in the system would have been the same and set by the marginal unit, which is Solitude's at \$30/MWh. Table 4 shows the impact on total cost to load, as a result of the congestion and redispatch. The cost of congestion to the loads is \$1,920.

Table 3. Locational Marginal Price Calculations

LMP Calculations - No Loss Component

How would 1 MW of energy be supplied to each bus from the two “marginal” units without violating the transmission constraint?

Bus	Sensitivity Factors (for 1 MWh of Load Supplied from)		Calculation (MWh) (Brighton Unit Price) + (MWh) (Solitude Unit Price) +	LMP
	Brighton @ \$10/MWh	Solitude @ \$30/MWh		
A	0.65 MWh	0.35 MWh	0.65 (\$10) + 0.35 (\$30)	\$17.00
B	0.18 MWh	0.82 MWh	0.18 (\$10) + 0.82 (\$30)	\$26.40
C	0.00 MWh	1.00 MWh	0.00 (\$10) + 1.00 (\$30)	\$30.00
D	-0.50 MWh	1.50 MWh	-0.50 (\$10) + 1.50 (\$30)	\$40.00
E	1.00 MWh	-0.00 MWh	1.00 (\$10) + 0.00 (\$30)	\$10.00

The sensitivity factors reflect the amount of cost effective generation required to supply 1 MW of load at each bus, without increasing the flow on the contingency

Table 4. Cost of Congestion to Loads

LOAD	MW	PRE-DISPATCH		POST DISPATCH		CONGESTION	
		LMP	COST	LMP	COST	COST/MW	COST
B	300	30	\$9,000.00	26.4	\$7,920.00	(\$3.60)	(\$1,080.00)
C	300	30	\$9,000.00	30	\$9,000.00	\$0.00	\$0.00
D	300	30	\$9,000.00	40	\$12,000.00	\$10.00	\$3,000.00
TOTAL			\$27,000.00		\$28,920.00		\$1,920.00

Example # 2 - 5 Bus Transmission Grid

LMPs - No Loss Component Included

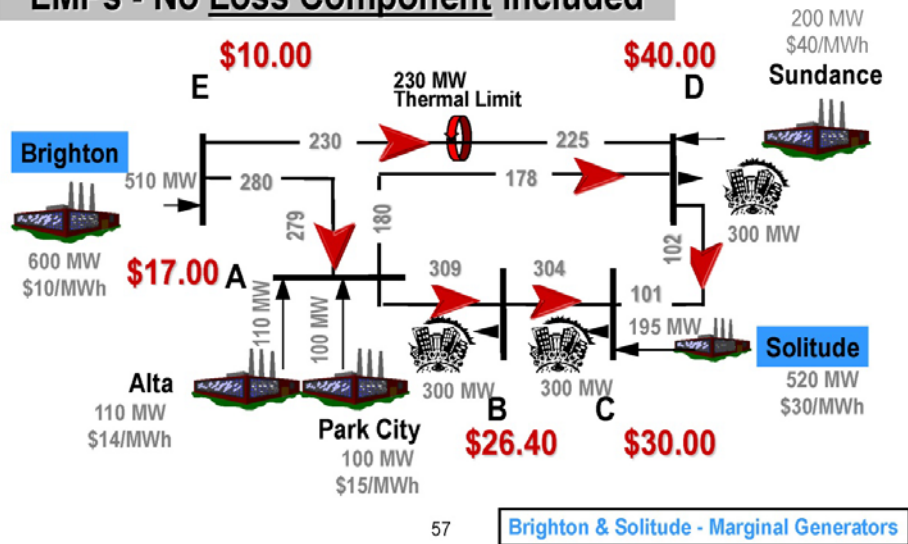


Figure 9. Post redispatch locational marginal prices

2.4.2 Conditional Firm Transmission

More of the existing transmission capacity has been made available, subject to voluntary risk of curtailment, through CFT. FERC provided for CFT in Order 890⁷³ to bridge the gap between management of the physical firm transmission and market-based transmission congestion. In situations where long-term firm transmission is not available because of periodic constraints, FERC recommended the issuing of CFTs to allow a limited number of users during constrained situations, but still provide transmission service at other times. Widespread use of CFTs would serve to increase the use of existing transmission capacity.

Transmission service providers have requested approval and implemented CFT service, as required in November 2007 under FERC Order 890.⁷⁴ These include: Bonneville Power Administration, Maine Public Service Company, PacifiCorp, Northwestern Energy, Western Area Power Administration, Southwest Power Pool, Nevada Power, and Florida Reliability Coordinating Council.

2.4.3 Redispatch

Another means to resolve transmission congestion is transmission *redispatch*, the changing of generator output levels. Redispatch can be used to enable additional transmission sales by reducing the congestion that otherwise would limit sales. Redispatch is included as part of market-based congestion management, but in areas without markets, redispatch is often not implemented because it results in the reduction of selected generators, which may impact their revenue.

⁷³ "Preventing Undue Discrimination and Preference in Transmission Service." (2007). Federal Energy Regulatory Commission. <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>. Accessed August 2012.

⁷⁴ "FERC Order 890: What Does it Mean for the West?" (2007). National Wind Coordinating Collaborative. <http://www.nationalwind.org/assets/publications/ferc890.pdf>. Accessed August 2012.

Where transmission lines are congested, adjusting the output of generators that produce congestion could be a lower-cost, faster solution to new transmission service than building new lines. It makes sense to use the lowest cost methods to resolve transmission congestion before turning to higher-cost methods.

2.4.3.1 Operation of Redispatch

Transmission providers could offer to redispatch generators to provide long-term firm service to transmission customers, which in turn would allow for new renewable energy projects to be financed. Providers could publish dynamic, real-time values for what they would charge to provide redispatch service, at specified congested locations within the transmission provider's system, and at specified flowgates at the border of the transmission provider's system. In non-market environments, these values can and will be cost-based. These costs are known to the entity performing dispatch. By making these costs more transparent, customers can assess redispatch options. As a result, participants might voluntarily offer redispatch solutions and be properly compensated for their efforts. The benefits are more renewable energy integrated onto the grid and lower total costs for consumers if transmission constraints are handled by redispatch instead of more costly measures.

The process of redispatch is very similar to that followed under market-based congestion management. Figure 7 shows the dispatch before adjusting for the overload on the line between Brighton and Sundance. The line is rated as 230 MW and the flow is 253 MW. To relieve the overload, the Brighton plant output is reduced 90 MW, and the Solitude Plant compensates by increasing output 90 MW, which reduces the flow to 230 MW, as shown in Figure 8.

2.4.3.2 Cost of Redispatch

All transmission providers regularly redispatch their systems to relieve congestion. The challenge is predicting future redispatch costs and providing cost certainty to customers. Redispatch service can be effective only where actual costs are assigned to customers requiring the service, and where such costs can be known with reasonable certainty at the time the customer decides whether or not to accept transmission service.

Costs are determined by the increased cost of output from one generator, and the decrease in output from another generator. Costs of redispatch must be determined and allocated to the customers requiring such service. Providing transparency of costs over time will help providers and market participants assess and predict redispatch costs. Table 5 shows the cost increase associated with redispatching the system shown in Figure 7 and Figure 8. The cost to accommodate the additional flow of 23 MW (253 MW minus 230 MW) between buses E and D without overloading any lines is \$1,800. The transmission customer must decide if it is willing to pay \$1,800 for redispatch to gain the additional 23 MW of transmission service.

Table 5. Cost of Redispatch

UNIT	RATING (MW)	COST	PRE-REDISPATCH		POST REDISPATCH	
			OUTPUT (MW)	COST	OUTPUT (MW)	COST
Brighton	600	\$10	600	\$6,000	510	\$5,100
Alta	110	\$14	110	\$1,540	110	\$1,540
Park City	100	\$15	100	\$1,500	100	\$1,500
Sundance	200	\$40	0	\$0	0	\$0
Solitude	520	\$30	90	\$2,700	180	\$5,400
TOTAL			900	\$11,740	900	\$13,540
TOTAL COST INCREASE						\$1,800

WECC, the organization representing the western Interconnect of North America is evaluating an energy imbalance system and associated toolkit⁷⁵ that would incorporate a redispatch process to relieve congestion and allocate the cost according to a locational imbalance price. The locational imbalance price includes a congestion component similar to locational marginal price, but it only addresses the real-time imbalance market. The energy imbalance system would bridge the gap between a simple redispatch process as described above and a full market-based congestion management system.

CAISO currently uses a market-based congestion management system employing locational marginal price and follows congestion management processes similar to other RTO/ISOs.

2.5 FERC Transmission Investment Rule

To help increase transmission capacity, the development of incentive-based rate treatments for the transmission of electric energy was ordered by EPAct 2005.⁷⁶ As a result, FERC issued Order 679,⁷⁷ which implemented the following incentive-based rate treatments:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies)
- Full recovery of prudently incurred construction work in progress
- Full recovery of prudently incurred pre-operations costs
- Full recovery of prudently incurred costs of abandoned facilities
- Use of hypothetical capital structures

⁷⁵ Western Electricity Coordinating Council. (2009). "Congestion and Balancing Toolkit." <http://www.wecc.biz/committees/BOD/120909/Technical%20Session/1/Congestion%20and%20Balancing%20Tool%20Kit.pdf>. Accessed August 2012.

⁷⁶ "Energy Policy Act of 2005." (2005). U.S. Department of Energy, Energy Efficiency and Renewable Energy. http://www.afdc.energy.gov/afdc/laws/epact_2005/. Accessed August 2012.

⁷⁷ Stevens, George. (2007). "Transmission Infrastructure Investments FERC Order 679." Indiana Utility Regulatory Commission. http://www.narucpartnerships.org/Documents/Transmission_Infrastructure_Investments_eng_George_Stevens.pdf. Accessed August 2012.

- Accumulated deferred income taxes for stand-alone transmission companies
- Adjustments to book value for stand-alone transmission company sales/purchases
- Accelerated depreciation
- Deferred cost recovery for utilities with retail rate freezes
- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) RTOs and ISOs.

All rates approved under the rules are subject to Federal Power Act rate filing standards. The rule allows transmission owners, on a case-by-case basis, to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide owners with greater regulatory certainty and facilitate the financing of projects. The rule became effective on September 29, 2006. FERC has made minor adjustments to the rule and issued a Notice of Inquiry on May 19, 2011⁷⁸ seeking comments to questions designed to determine the effectiveness of the rule.

Much of the rule was focused on new transmission; however, the incentive could also be applied to incremental improvement of existing transmission facilities. This was clearly stated in FERC's responses to the Notice of Inquiry as provided in Section 180 of the FERC discussion of the final rule.⁷⁹ FERC has not yet implemented any changes to the order in response to the Notice of Inquiry.

Since the issuance of Order 679, FERC has received more than 75 applications for transmission⁸⁰ incentives associated with more than an estimated \$50 billion in proposed investments from a variety of transmission developers. In one case, FERC granted incentive rates for transmission in Potomac Electric Power Company's (PEPCO's) Mid Atlantic Power Pathway. In another case, FERC granted incentive rates for the delivery of renewable energy in the Tehachapi Project to load centers in California.

A possible next step for FERC would be to expand the use of incentive rates to accommodate alternatives to building new transmission, including new technologies that increase transmission capability on existing lines.

2.6 Demand Response

Some benefits to transmission capacity have been attributed to *demand response*, the balancing of customers' need for electricity with the power company's output. Table 5 identifies qualitative benefits that demand response offers to transmission and distribution. Quantitative benefits are difficult to assess because demand response is spread across a large portion of the system. Any benefits to individual transmission facilities are dependent on the distribution of demand resources and the resulting flow changes on the transmission system brought about by reduced demand.

⁷⁸ Troutman Sanders, LLP. (2012). "FERC Releases NOI on Transmission Investment," Washington Energy Report. <http://www.troutmansandersenergyreport.com/2011/05/ferc-releases-noi-on-transmission-investment/>. Accessed August 2012.

⁷⁹ "Promoting Transmission Investment Through Pricing Reform: Final Rule" (2006). Federal Energy Regulatory Commission. <http://regulations.vlex.com/vid/part-ii-22122747/>. Accessed August 2012.

⁸⁰ Campbell, Richard. (2011). "Regulatory Incentives for Electricity Transmissions – Issues and Cost Concerns." Energy Legislation, United States, 2011. <http://energylegislation.blogspot.com/2011/11/regulatory-incentives-for-electricity.html>. Accessed August 2012.

Although the main benefit of demand response is reduced energy costs, there are also potential benefits to transmission. According to a presentation by Battle Group to U.S. DRCC Webinar, March 16, 2007, demand response can help avoid or defer costs although the benefits may be larger for distribution than for transmission.

In cases where specific and significant blocks of localized demand resources exist, FERC's effort to establish parity between generation resources and demand response suggests that demand response could schedule negative transmission reservations. To the extent that a particular load block has a corresponding resource and flow path with a transmission reservation, the load's willingness to curtail during specific peak times, would have the same effect as scheduling a negative transmission reservation. This could reduce peak demand on specific transmission paths and, therefore, be the equivalent of increasing the capability of the path for a non-curtailed load by the same amount. Future OATT could address this potential as a means of reducing peak transmission congestion.

2.7 Regulatory and Other Incentives to New Technologies

New technologies can increase the capability of the existing grid without adding additional transmission lines. Technologies, such as energy storage, offer benefits to multiple facets of the grid from generation to transmission and distribution.

Incentives and market rules can be designed to encourage and accommodate these technologies. FERC and the RTO/ISOs would need to implement rule changes that recognize the unique operating characteristics of the new technologies. For example, FERC's Notice of Proposed Rule Making RM 11-7 and AD10-11 recognized the benefits of fast transmission regulation services that have previously required additions to the transmission system. The rule will compensate storage facilities that can provide fast regulation, and other benefits to the grid related to damping and stability.⁸¹

2.8 Opportunities

As discussed in the previous sections of this chapter, changes in standards and policies can "stretch" the existing grid. The following list summarizes suggested changes in primary policies, rules, and procedures for determining transmission capabilities and some opportunities for modification to enhance transmission capabilities:

- Replace the practice of using static seasonal ratings on critical constrained transmission lines, with either real-time or dynamic monitoring of ambient conditions. Transmission capability that is currently restricted could be increased during much of the year because the line rating is fixed for the worst ambient conditions that rarely occur.
- Extend the NERC standards for multiple circuits to include those that are not on a common structure, but are within a span length of each other. This action by the WECC could increase utilization of existing rights-of-way.
- Establish market-based congestion management to improve the utilization of the grid and to allocate the cost of congestion to those users who were willing to pay the price. Extending this practice of replacing physical transmission rights with financial

⁸¹ Brown Rudnick LLP. (2011). "Comments of the Electricity Storage Association."
http://www.electricitystorage.org/images/uploads/static_content/advocacy/regulation/ESAFERCPCFPNOPR.pdf.
Accessed August 2012.

transmission rights ensures that the actual cost of using the transmission system is done in the most efficient and equitable use of the transmission system during times of constraint.

- Implement CFT and redispatch as a bridge between physical firm transmission and market-based transmission congestion management. CFT provides a mechanism for transmission users to have access to selected transmission paths on a firm basis except during periodic constrained periods. Extending this practice allows increased use of the transmission system when conventional firm transmission is not available, but when the system is not actually constrained. During periods when transmission paths are constrained, redispatch may relieve the constraints at some defined cost and allow transmission customers to decide whether to pay the cost of redispatch or forgo use of the transmission. Redispatch also provides a price signal, which can be used to make economic decisions regarding the value of increasing transmission capability on selected paths. Redispatch provides many of the same benefits as market-based congestion management with having a formal congestion management system in place.

3.0 Expanding Existing Transmission Capacity – Technology

Complex technology is necessary to increase the power flow capacity on existing power equipment (overhead lines and power transformers), power circuits (multiple power equipment elements in series), and power system interfaces (multiple parallel power circuits connecting power system regions). The following three issues are basic to all approaches:

1. For overhead lines, increase in power flow capacity is dependent on length, original design assumptions, environmental regulations, the condition of structures, and the type of conductors. Increase in a line's thermal rating could range from between 5% and 100%.
2. Overhead lines are only part of the transmission path (circuit). The lines are terminated at substations by air disconnects, circuit breakers, and line traps. The power flow through all of the circuit elements must be limited to avoid damaging the line or the terminating equipment. The maximum allowable power flow over this circuit may be limited by any one of the circuit elements. According to the current NERC rating methodology,⁸² a facility rating must be the minimum of all ratings between substations.
3. Increase in maximum allowable power flow through a component circuit or circuit element does not necessarily yield a higher rating for the complex interface, or from source to sink, when considered as part of a power system interface. This is because increased flow on an improved element may bump into another element's limits.

Transmission circuit ratings are often developed on a system basis, rather than on an individual line basis.⁸³ This is because the maximum power flow on the transmission system is a function of the overall system topology (transmission lines, transformers, generation, series and shunt compensation, and load). Many non-thermal system considerations (such as sag and voltage) can also limit the maximum power flow on a specific transmission circuit. The overall limit may be set between operating areas, irrespective of ownership or individual lines, and may change during a day based on system conditions. Increasing the capacity on a single line by 100% would not necessarily increase the system capacity by this amount. A separate, parallel facility may have a constraint after the flow increases by only 25%.

A variety of technologies is available to more fully leverage and expand the physical capability of an existing transmission system infrastructure and its assets (i.e., rights-of-way). These include the following:

- FACTS-based devices
- HVDC converters and transmission
- Enhanced system and equipment monitoring
- “Mature” (i.e., well-established, non-power electronics-based) technologies (e.g., phase shifting transformers, series capacitor line compensation)
- Next-generation conductors (i.e., high-capacity or superconductor cable)

⁸² “NERC FAC-008-1 Rating Methodology.” (2006). North American Electricity Reliability Company. <http://www.nerc.com/files/FAC-008-1.pdf>. Accessed August 2012.

⁸³ “Western Interconnection Path Flow Study.” (2007). Western Electricity Coordinating Council. http://www.wecc.biz/committees/BOD/TEPPC/External/070917_07_Report.doc. Accessed August 2012.

Although each of these technologies employs different methods to affect the operating parameters of the transmission system, they all facilitate a more stable and fully utilized electric power network. As with most technologies, however, there are tradeoffs between device size/capability and cost. In addition, a technology may work well to address one issue, but it may raise other issues. Accordingly, the selection of a technology is based on competing, though generally collaborative, interests (e.g., technical feasibility and applicability, cost, operations and maintenance, and proven commercial history).

The following sections discuss technologies available to enhance the existing transmission system infrastructure. Brief histories are provided for context and clarification. To achieve a structure for comparison, the grid parameter(s) affected by each technology are broadly classified into three categories:

1. Increased power transfer
2. Improved voltage stability
3. Enhanced system frequency stability

As with any *system* (defined in Webster's Dictionary as "a regularly interacting or interdependent group of items forming a unified whole"), these three specified categories of grid parameters are not isolated. Targeted improvements to one grid parameter can have ancillary and indirect benefits on another parameter. The three categories are used to identify the targeted system improvements provided by a particular technology.

3.1 Fundamentals of Power Transfer Limits

The following sections describe technical aspects of electric power transfer that will help those evaluating alternative strategies for increasing the transfer capability of the grid.

3.1.1 Surge Impedance Loading

The surge impedance loading (SIL) of a power transmission line is the nominal power flow capacity based on the design characteristics for the line and its operating voltage. SIL is governed more by the overall geometry of the line and its operating voltage and less by the conductor size. SIL is independent of the line length. SIL is not the maximum that a particular line can carry, but rather a benchmark that can be used to compare lines of different designs and voltage rating. SIL is a useful concept to compare different transmission lines.

For an overhead transmission line, typical surge impedance is around 300 ohms, compared to a cable, which may be 50 ohms or less. At 345 kV, the SIL of an overhead line is on the order of 400 MW. Short lines may be able to carry 800 MW or more. Long lines of the same construction may be limited to less than 400 MW by system considerations. Underground transmission cables always operate very far below SIL because of limitations on heat dissipation. As a result, underground transmission cables are a net source of reactive power (vars) to the system.

Reactive loading and losses can become a limiting problem if a significant number of the lines are loaded above their SIL. As loading increases appreciably above SIL for many lines in the system, the reactive losses will increase in relation to the square of the current and the line reactance. Adding high-capacity lines, instead of improving the power transfer capability of the system, could further increase the reactive losses and, consequently, further hamper power transfers.

3.1.2 Thermal Limits

Thermal limits are the maximum flows that can be permitted through a transmission circuit, either on a continuous basis or for a short duration, based on the circuit design. The design parameters include the conductor type, conductor bundles, ambient temperature, wind speed, ice loading, and span length. The thermal limitation is critical primarily in cases of lower voltage lines of 50 miles or less.

At extra-high voltage (345 kV and above), environmental considerations, such as corona discharge and field effects, dictate line designs and usually result in high thermal capabilities, which can exceed the realistic power transfer. For extra-high voltage transmission, line terminating equipment, such as wave traps and substations, impose a thermal limit rather than the line itself. Consequently, thermal limits are significant only for short lines at 138 kV and below.

The process of selecting a thermal rating for an overhead line can be fairly complex or simple. Ratings are published by conductor manufacturers for a range of conservative weather assumptions and conductor temperature limits. Ratings can also be determined from field measurements of sag, wind direction and strength, solar insolation, and other variables.

As power flow increases in a bare overhead power line, the conductors, connectors, and associated hardware are heated because of the ohmic losses. Typically, lines that are thermally limited are the shorter lines in the system and the economic cost of electrical losses may be tolerable. However, potential damage to conductor systems or safety concerns occasioned by violation of minimum clearances remains a concern.

Thermal ratings for overhead lines are defined in amperes or megavolt amperes (MVA) with an associated duration and, possibly, by frequency of occurrence. Consequently, one line may have a continuous thermal rating of 100 MVA; a 4-hour, long-time emergency rating of 115 MVA; and a 15-minute, short-time emergency rating of 130 MVA. The system operator would understand these ratings to mean that the power flow on this line could reach but not exceed 100 MVA indefinitely. Also, if the flow exceeds 100 MVA, but is less than 115 MVA, the operator must reduce the flow to below 100 MVA within the next 4 hours. If the flow exceeds 115 MVA, the operator must reduce it to below 100 MVA within 15 minutes. The temperature limits on these lines typically serve to limit the loss of conductor tensile strength to less than 10% over the life of the line. It may be possible to exceed the thermal limits of lines and accept some loss of life provided safe clearances are maintained especially for lines that are scheduled for replacement or upgrade in the near future.

3.1.3 System Limits

System limits are functions of transmission line reactance in relation to the overall power system. Series reactance, shunt admittance, and their combination can alter system transfer limits.

System planners have long recognized this relationship, particularly where there are prospects of changing the line surge impedance, either by adding equipment (e.g., series capacitors) or by modifying the line itself (e.g., reconductoring, voltage uprating). Transmission line series inductive reactance is determined by conductor size, phase spacing, number of conductors, relative phasing (double-circuit lines), and line configuration. In long high-voltage overhead transmission lines, the series reactance is larger than the series resistance and is dominant in a first-order explanation of system behavior. For this reason, simple reconductoring of many long transmission lines, with no change to structure geometry, results in only minor changes in system power flows.

However, for shorter lines, the thermal capacity of the conductors or the characteristics of the system in which the line operates impose the power limits of that line. System limits can result from factors such as voltage drop, possibility of voltage collapse, and system stability, both steady state and transient.

3.2 Increasing Thermal Limits

The thermal limits of the conductor are a key limiting factor in the capabilities of transmission lines. As electricity flows through a transmission line, heat is produced due to the flow of current through the resistance of the conductor. As the current flowing through the conductor increases, additional heat is produced, which causes the temperature of the conductor to increase. The temperature is a function of the electrical current and the environmental conditions (temperature, humidity, and windspeed). If the conductor becomes too hot, one of two problems may result.

1. First, excessive heat may permanently damage the conductor. Each transmission line has a maximum amount of power that can flow over it without damage.
2. Second, the increasing temperature may cause the line to physically sag below design levels, resulting in increased risk of injury and damage, as well as line outages. The line must not touch anything including the ground. Physical sag of the line can be reduced by using certain conductors.

Other important constraints are the level of electric and magnetic fields produced (e.g., electric fields increase as the conductor gets closer to the ground), the maximum structure loads during occasional high wind and ice loads, and the maximum temperature at which the energized conductors are allowed to operate.

Given standard worst-case weather conditions, the thermal rating of an existing line is determined by the maximum allowable conductor temperature. Thus, uprating (pushing more electricity) such lines, without reconductoring, normally requires finding ways to maintain electrical clearances above the ground while operating at a higher conductor temperature.

To protect against problems resulting from thermal overloads on transmission lines, utilities install relays. A relay senses the amount of power flowing through a transmission line, and operates a circuit breaker to interrupt the power flow on the line, if it exceeds the thermal limit of the line. The power will then flow through parallel paths. The increased loading along the parallel paths creates the potential for an overload condition on other transmission lines. If the system is not properly designed, operated, and maintained, thermal overloads can lead to cascading outages of transmission lines and system breakup.

Transmission line capacity can be increased through improvements in transmission tower design (to compensate for physical sag) and increases to conductor current capabilities (to withstand more heat). The ability to accurately determine the conductor thermal condition at any point in time is also helpful in maintaining the line.

3.2.1 Improved Transmission Structures

Adaptations can be made to accommodate physical sag resulting from increased transmission capacity on existing lines. Ground clearance on specific spans can be increased by installing additional structures mid-span, if the ground contours and permitting restrictions allow.

Clearance can also be increased by modifying the existing structures to raise the conductor attachment points. Alternatively, existing structures can be replaced with taller structures. These methods do not increase conductor tension, minimizing the need to replace angle and dead-end

structures. Increasing ground clearance typically results in only modest increases in allowable ampacity (electricity through the line) before cost becomes prohibitive.

3.2.2 Reconductoring

To increase the current capability of lines, a thermal balance calculation must be performed to determine if the conductor, as well as all the connectors and hardware, can withstand the resulting higher temperatures. The rating of the line is limited by the following:

- The properties of the conductor material
- The environmental conditions surrounding the conductor
- The ground clearance of the line

Today, most overhead transmission lines are aluminum conductor steel reinforced (ACSR) transmission. Steel can withstand temperatures up to 200°C with no changes in its properties. Aluminum, however, experiences deterioration in mechanical properties when the temperature is higher than 90°C. The temperature is a function of the electrical current and the environmental conditions. On a continuous basis, ACSR may be operated at temperatures up to 100°C and, for limited time emergencies, at temperatures as high as 125°C without any significant change in the physical properties.

To increase the nation's transmission capability to handle new generation, transmission systems could achieve higher current densities in existing transmission lines. Several approaches have been proposed to achieve this increase:

- Increase the maximum allowable operating temperature of the conductor to 100°C. For example, if the line is limited to a modest temperature of 50°C to 75°C and the electrical clearance above the ground is sufficient to allow an increase in physical sag for operation at a higher temperature, then the thermal rating of the line can be increased. If sufficient clearance does not exist in all spans, then conductor attachment points on tower structures may be raised, the conductor tension increased, or other mechanical methods applied to obtain the necessary clearance at the higher temperature.
- Use dynamic ratings or less-conservative weather conditions relating to wind speed and ambient temperatures. For example, if the existing line is already rated at a temperature near 100°C, and a modest increase of 5% to 15% is desired, then condition monitors can be installed and the higher ratings used when wind speed is higher than the standard 0.6 m/s and the ambient temperature is lower than 40°C.
- Replace the conductor with a larger one or with one capable of continuous operation above 100°C (reconductoring).

Reconductoring, the replacement of transmission lines with conductors that withstand more electricity transfer, is the most common method of attaining significant increases in allowable ampacity. Although the physical characteristics of the new line may allow more electricity to be transferred, it imposes more weight on support structures. Horizontal wind pressure on wires causes most of the stress on tangent structures. Because most transmission structures are already near their structural limit, just replacing wires with larger diameter wires is usually not economically viable.

Traditional conductors (e.g., ACSR, all-aluminum) used on most transmission lines are composed of aluminum strands or a steel core surrounded by aluminum strands. Aluminum expands faster than steel does when it is heated; therefore, conductors with high proportions of aluminum sag more than those with low proportions of aluminum. The strength of aluminum starts to degrade under sustained usage above 95°C, thereby limiting the maximum operating temperature of traditional conductors.

Aluminum conductor steel supported (ACSS) conductors have been used for reconductoring. The aluminum strands that surround the steel core on an ACSS conductor are fully annealed so that they are too soft to carry wire tension. Because the steel carries all the tension, ACSS conductors do not sag as much as comparatively sized traditional conductors. Additionally, ACSS conductors can operate at much higher temperatures than traditional conductors without a loss of strength. The sag and tension characteristics of ACSS conductors can usually be matched to existing structure capacities such that a significant ampacity increase is realized with few or no structural modifications.

Composite conductors are a relatively new option in the industry, but have generally been used with great success. The two primary options are the aluminum conductor composite reinforced (ACCR) cable and the aluminum conductor carbon composite (ACCC). Each cable uses a special lightweight, high-strength core to carry the tension, surrounded by aluminum wire to carry the current. The ACCR cable uses a fiber reinforced aluminum matrix core surrounded by aluminum-zirconium strands. The ACCC cable uses a high-strength carbon and glass fiber core, embedded in a high-performance thermoset resin matrix, surrounded by fully annealed aluminum wire. When compared to the ACSS conductor, the primary advantage of each cable is the low thermal expansion characteristics of its core, which allows the cable temperature to increase greatly with little increase in sag. Although the material cost of these products can be high, structure modifications are minimized, resulting in cost-effective installation.

The thermal rating of an existing line can be increased by approximately 50% by using a replacement conductor that has twice the aluminum area of the original conductor. The larger conductors can double the original strain structure tension loads and increase transverse wind/ice conductor loads on suspension structures by approximately 40%. Such large load increases typically would require structure reinforcement or replacement. This drawback to the use of a larger conductor may be avoided by using the HTLS conductor, which can be operated at temperatures above 100°C while exhibiting stable tensile strength and creep elongation properties.

Practical temperature limits of up to 200°C have been specified for some conductors. Using the HTLS conductor, which has the same diameter as the original, at 180°C can increase the line rating by 50%, often without any significant change in structure loads. If the replacement conductor has a lower thermal elongation rate than the original, then the structures will not have to be raised. Although the use of a larger conductor provides a reduction in losses over the life of the line while operating temperatures remain at a modest level, the use of the HTLS conductor reduces capital investment by minimizing structure modifications.

Conductors are constructed from helically stranded combinations of individual wires. Galvanized steel wires are used for mechanical reinforcement, aluminum wires for the conduction of electricity, and hard-drawn aluminum for both mechanical and electrical purposes.

Desirable properties for reinforcing core-wire material include a high elastic modulus, a high ratio of tensile strength to weight, the retention of tensile strength at high temperatures, a low plastic and thermal elongation, a low corrosion rate in the presence of aluminum, and a relatively high electrical conductivity. The material must be easy to fabricate into wire for stranding.

Choices available for HTLS conductors include the following:

- ACSS and ACSS/twisted annealed aluminum strands over a conventional steel stranded core; operation to 200°C
- Gap type heat resistant aluminum alloy conductor steel reinforced high-temperature aluminum, grease-filled gap between core/inner layer; operation to 150°C; gap type super heat resistant aluminum alloy conductor steel reinforced
- ACCR high-temperature alloy aluminum over a composite core made from alumina fibers embedded in a matrix of pure aluminum; operation to 210°C
- Composite reinforced aluminum conductor annealed aluminum over fiberglass/thermoplastic composite segmented core; probable operation to 150°C
- Aluminum conductor composite carbon fiber reinforced annealed or high-temperature aluminum alloy over a core of strands with carbon fiber material in a matrix of aluminum; probable operation to 210°C

Table 6 illustrates the capacity increases and relative cost of reconductoring an existing ACSR transmission line with various conductors of equal diameter.

Table 6. Relative Cost of Reconductoring

CONDUCTOR	DIAMETER (IN)	ALUM AREA (KCMIL)	WEIGHT (LB/KFT)	AC RESISTANCE - 75°C		AMPACITY RATINGS			RELATIVE COST (APPROX.)
				(ohm/kft)	Δ%	75[°C]	100[°C]	200[°C]	
Drake ACSR	1.108	795	1093	0.0266		905	1115	---	1
Drake ACSS	1.108	795	1093	0.0258	-3.0%	919	1132	1660	1.2
Suwannee ACSS/TW	1.108	960	1317	0.0216	-18.8%	1010	1245	1831	1.3
Suwannee ACCR/TW	1.108	958	1075	0.0211	-20.5%			1812	5
Drake ACCC/TW	1.108	1020	1043	0.0206	-22.6%	1029	1267	1861	2.5
Suwannee ACSR/TW	1.108	960	1317	0.0218	-18.0%	1000	1233	---	1.1
Note: 1. Conductors with an overall diameter equal to the standard ACSR conductor allow reconductoring without major structure reinforcement. 2. Ambient Temperature 25°C, wind speed 2 ft/sec., full sun. 3. Costs are relative estimates and costs for newer composite core conductor may decrease with higher volume.									

Superconductors have received press coverage over the last several years and may be applicable in very specific applications.⁸⁴

⁸⁴ American Superconductor, "New Transmission Options – Case Study Super Conductor Cables," Transmission Policy Institute, Colorado, 2011. <http://www.narucmeetings.org/Presentations/MCCALL%20NARUC%204-2011.pdf>. Accessed August 2012.

3.2.3 Dynamic Circuit Ratings

The actual thermal capacity of a transmission circuit is determined by the conductor temperature at each point in time. This conductor temperature is dependent on the magnitude of current flow, conductor resistance, and ambient weather conditions (temperature, humidity, wind). While the current flow can be accurately measured and the conductor resistance is known, the ambient weather conditions along the length of the transmission line are difficult to monitor. To be on the safe side, thermal ratings of lines are calculated assuming the most adverse seasonal weather condition. If actual conditions were known, the line could be allowed to carry more power than the worst case ambient conditions allow.

Various schemes are available to more accurately determine the true thermal limits of a transmission circuit based on real-time monitoring. With these measurements, thermal limits of the line could be calculated on a real-time basis. While systems that employ remote measurements may hold the most promise to accurately determine conductor temperature, they require power and communications, which can limit their effectiveness and increase their cost. The EPRI has developed the Dynamic Thermal Circuit Rating program⁸⁵ for dynamic rating of transmission line equipment and various manufacturers offer systems as well. Four types of real-time monitors have been used in the industry for this purpose:

1. Weather data monitors measure ambient temperature, wind speed, wind direction, and solar heating. When combined with line current data, the conductor temperature and sag can be calculated and compared to the allowable sag.
2. Conductor temperature monitors consist of a thermocouple clamped to the conductor. The sag in the conductor can then be calculated and compared to the allowable sag.
3. Tension monitors consist of a load cell placed between a dead-end insulator string and the structure. The sag in the conductor can then be calculated and compared to the allowable sag.
4. Sag monitors use laser surveying technology to measure sag directly. They can be configured to take measurements at preset intervals or on demand.

Monitors are installed at multiple locations because conductor temperature can vary when the geographical orientation of the line (e.g., N-S or E-W) changes significantly. Some segments are more prone to the effects of wind and sun than are others.

The data from each monitor is relayed to the utility's operations center where software calculates a dynamic circuit rating. The benefits of dynamic rating are dependent on the level of conservatism used in the original static circuit rating. Under peak loading conditions, the increased rating of the circuit through the use of real-time monitors is typically low when compared to increases achieved through other means. However, the cost is lower as well. Real-time monitoring can also be an appropriate solution when reconductoring and/or structure upgrades are not practical due to permitting or outage concerns. Typical of these types of system is the one employed in ERCOT.⁸⁶

⁸⁵ Electric Power Research Institute. (2007). "DTCR 4.1." http://mydocs.epri.com/docs/ApplyingResults/Ready_Now/PDU/2007_Application_Plan_for_P164-001_DTCR_4-1.pdf. Accessed August 2012.

⁸⁶ Johnson, Justin "Smart Grid Demonstration Project – Dynamic Line Rating," Oncor Electric Delivery Company, 2010.

In some cases, the capacity of existing transmission circuits is limited by the thermal rating of terminal equipment. In some cases, involving equipment such as switches, wave traps, and other relatively inexpensive devices, direct replacement is sometimes possible. For more expensive equipment, such as transformers, dynamic rating may be possible using software to calculate internal temperatures that allow increased power flow at certain times. EPRI has released Power Transformer Loading software designed to calculate real-time ratings of transformers.⁸⁷

3.2.4 Voltage Upgrading

Thermal limits on transmission lines are determined by the current flow and not directly by the power transfer. Power flow is proportional to the product of the voltage and current. By increasing the applied voltage (voltage upgrading), power transfer can be increased without a corresponding increase in current. Unfortunately, voltage upgrading introduces other issues, such as insulation strength and clearances, corona, electromagnetic fields, and radio frequency interference.

Increasing the applied voltage on a transmission circuit will require replacement of the insulators, possible modification to the tower design to maintain adequate clearances, and /or changes to terminal equipment. It may also impact conductor selection to mitigate the issues created at the higher voltages. While small temporary voltage increases could be tolerated on transmission lines (a few percent), significant increases in voltage will require redesign of the line. Voltage increases could also require widening the right-of-way. Voltage upgrading may be attractive where compact line design principles can be applied. These allow reconductoring of an existing line with minimal tower changes and within the existing right-of-way.

Transmission line conductors are rated by ampacity, not voltage. Upgrading the voltage on an existing transmission line results in a proportional increase in its transfer MVA capacity. The required replacement of the insulators with longer ones can create clearance problems as follows:

- Conductors supported by insulators that hang vertically (e.g., I-Strings and V-Strings) have reduced ground clearance and may have reduced clearance between phases. When subjected to wind, the insulators swing further horizontally, which can result in clearance violations to the structure or come close to facilities at the edge of the right-of-way.
- Insulators mounted horizontally (e.g., Line Posts) put higher stresses on the structures and may result in inadequate clearance between phases or to come to close to facilities at the edge of the right-of-way.

If these issues can be overcome without the need for extensive structure modifications, then upgrading the voltage on a transmission line may be a viable option. However, the substation facilities at each end must be expanded, if not completely rebuilt, and construction for voltage improvements typically requires extended outages and may result in unacceptable impacts to other entities.

http://www.ercot.com/content/meetings/ros/keydocs/2010/0625/05_OncorDynamicLineRatingProject06252010_pp#363.1.Smart. Accessed August 2012.

⁸⁷ Electric Power Research Institute. (2008). "Development of Algorithms to Include New Research Data on Loss of Life."

http://mydocs.epri.com/docs/ApplyingResults/Ready_Now/PDU/2008/2008%20Application%20Plan%20for%20P37-002%20PTLOAD-%20Development%20of%20algorithms%20to.pdf. Accessed August 2012.

As long as those issues can be mitigated, voltage uprating can provide a substantial increase to the transfer capacity of a transmission line. Live line uprating offers a means of reducing outage time on critical transmission lines.

4.0 Increasing System Limits

4.1 Voltage and Stability Control

Voltages throughout the system must remain within an acceptable range at all times for system reliability. When power flows through a transmission line, the voltage drops. Voltage at the receiving end of a line is lower than at the sending end. If large amounts of power are transferred over long distances, the bulk transmission system must maintain adequate voltage at the receiving end. Voltage can also drop as a result of outages of critical facilities. If a sudden outage of a transmission line occurs, power will continue to flow at the same level, but on less efficient, alternative parallel paths. As a result, the voltage drop in the transmission system increases, and there will be an abrupt change in the voltage at the receiving end. Voltage drops or voltage fluctuations at the customer end reflect reduced system reliability.

4.1.1 Stability Constraints

Normally, all generators on an interconnected system operate in synchronism. That is, each generator operates at precisely the same frequency (60 Hz in North America). System disturbances, such as load changes or facility outages, will cause the speed (frequency) of one or more generators to change relative to other generators. In addition, the magnitude of other frequency-dependent items, such as the load, also changes and causes imbalances in the system. Generator controls sense such changes and change the power output of the affected generators to synchronize the system.

This stability is compromised under two types of conditions: steady-state instability and transient instability.

- *Steady-state instability* occurs when the system cannot return to synchronous operation because of excessive power flows. The speed of some generators changes relative to others, causing system separation, a break-up of the transmission system, or a blackout.
- *Transient instability* occurs when a major disturbance (such as a short circuit on a transmission line or the loss of a large generating unit) is experienced, causing generators to oscillate relative to each other. If the system cannot damp the oscillations quickly, for example, by changing the output of generators, the oscillations will increase, causing large fluctuations in line loadings and system voltages. The result is the same as for steady-state instability: system separation, a break-up of the transmission system, or a blackout.

These events are not common in modern transmission networks, primarily because of the planning and coordinated operations.

If power flows exceed dynamic limits over wide areas, the grid can exhibit unstable behavior. If not controlled, this can trigger large-scale outages. Dynamic grid stability is a critical issue for power system management. To maintain reliability, potential instabilities must be sensed and responded to quickly.

While transmission lines have a designed power handling capacity based on thermal limits, instabilities frequently limit maximum transmitted power to levels significantly less. In particular, this limits both the amount of power that can be imported from outside a region and amounts that can be transferred from one region to another. The addition of significant remote

generating facilities, much of it with low inertia, may have undesirable effects by reducing the overall system damping under sudden energy imbalance, such as generation trips.

Addressing stability limits requires study to identify the source of the problem. Operating procedures or altered protective systems may be implemented to eliminate or mitigate stability problems and increase the power transfer capability of the existing grid.

4.1.2 FACTS Devices

FACTS technology refers to power electronic devices used to enhance the operation and control of the electric power grid. FACTS devices use power electronic components and conventional equipment in different configurations for switching or controlling reactive power for active power conversion or control.

FACTS technology increases the value of the transmission system by facilitating a greater utilization of the system's assets. FACTS technology increases the steady-state or transient stability (or both) operating regions of the system. To do this, FACTS devices apply strategies to influence the operating parameters of the transmission system. These methods are categorized as follows:

- Voltage controller
- Line impedance controller
- Power flow controller

Several FACTS devices are currently in operation in United States, and they are applied in various configurations. Table 7 lists the EPRI sponsored FACTS devices installed in United States.

Table 7. EPRI-sponsored FACTS installations⁸⁸

EPRI SPONSORED FACTS INSTALLATIONS			
DEVICE	DESCRIPTION	LOCATION	HOST UTILITY
Unified Power Flow Controller (UPFC)	+/- 160 MVA Shunt; +/-160 MVA Series'	Inez Substation, Kentucky	AEP
Thyristor Controlled Series Capacitor (TCSC)	Line Impedance Controller 208 MVAR	Slatt Substation; Oregon	BPA
Back-to-Back HVDC Tie	36 MW	Eagle Pass, Texas	CSW
Static Synchronous Compensator (STATCOM)	Voltage Controller +/- MVAR	Sullivan Substation, Tennessee	TVA
Convertible Static Compensator (CSC)	Flexible Multifunctional Compensator +/- 200 MVAR	Marcy Substation, New York	NYPA

4.1.2.1 Static VAR Compensator

An important type of FACTS in use today is the static VAR compensator (SVC). An SVC is a shunt-connected, static generator and/or absorber of reactive power, in which the output is varied

⁸⁸ "Efficient Transmission Systems Program 172." (2012). 2012 Research Portfolio. Electric Power Research Institute, Palo Alto, CA. <http://portfolio.epri.com/ProgramTab.aspx?sId=PDU&rId=201&pId=6310/>. Accessed August 2012.

to maintain or control specific parameters of an electrical power system.⁸⁹ SVCs are used mainly to regulate system voltages; these devices combine thyristor-based power electronics with inductors and/or capacitors to rapidly and accurately produce or consume reactive power. Producing (out of the SVC) reactive power at a bus will raise the bus voltage; similarly, consuming (into the SVC) reactive power will lower the bus voltage.

SVCs were one of the first technologies classified as a FACTS device, shown in Figure 10 as a second-generation controlled device.

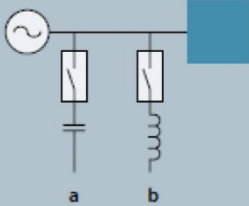
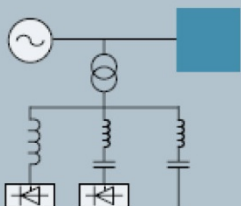
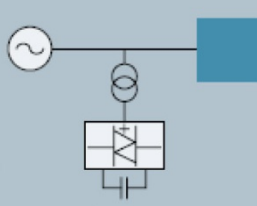
Switchgear Capacitors Reactors	Thyristor Valve (s) Control & Protection Transformer Capacitors Reactors	IGBT (GTO) Valves Control & Protection Transformer DC Capacitors
$52 \leq \text{kV} \leq 765$ $\sim 50 \leq \text{MVar} < 500$	$52 \leq \text{kV} \leq 765$ Control range : $\sim 50 \leq \text{MVar} \leq 1000$	$52 \leq \text{kV} \leq 765$ Control range: $\sim 50 \leq \text{MVar} \leq 500$
		
MSC/MSR Mechanically Switched Capacitors/ Reactors	SVC Static VAR Compensator	SVC PLUS® (STATCOM) Static Compensator

Figure 10. FACTS devices⁹⁰

SVCs have several features that require attention. Due to the nature of power electronic switching, SVCs (and FACTS equipment in general) generate harmonics (i.e., multiples of the fundamental voltage/current frequency), which can have adverse affects on power system quality. To counter these effects, filters must be employed. In addition, SVCs experience a marked decrease in their capacity to generate/absorb reactive power when system voltages are low (in the same manner as conventionally switched reactor or capacitor banks). Finally, because SVCs use conventional AC reactors and capacitors, the overall footprint of the equipment is larger than a comparatively capable STATCOM device (from a reactive power generation/absorption perspective).

SVCs are voltage control devices and can enhance both the steady-state and transient voltage stability of the transmission system. Improved system voltage profiles can enhance power

⁸⁹ Mathur, R., Mohan, and Varma, Rajiv K. (2002). "Thyristor-Based FACTS Controllers and Electrical Transmission Systems," New York, NY: Wiley-IEEE Press.

⁹⁰ Adapted from Siemens "Discover the World of FACTS Technology Technical Compendium." (2011). http://www.energy.siemens.com/hq/pool/hq/power-transmission/FACTS/FACTS_Technology_.pdf. Accessed August 2012.

transfer capabilities, and the absorption/generation of reactive power can improve rotor angle/system frequency transient stability (via power system damping). These improvements are not always directly controllable by an SVC device, and thus are indirect system benefits.

Hundreds of SVCs have been installed all over the world. One of the largest SVCs in the United States is in Devers, California. Southern California Edison and CAISO identified voltage stability constraints from increasing the power imported into California from Arizona.⁹¹ Southern California Edison installed a 440-MVAR SVC at Devers in 2006, which subsequently increased the California import. Similarly, Entergy installed a 300-MVAR SVC in Porter near New Orleans to increase the power import capability into New Orleans area.

4.1.2.2 Static Synchronous Compensator

Like SVCs, STATCOM devices are also shunt-connected, reactive-power compensation equipment capable of generating and/or absorbing reactive power. The output can be varied to control the specific parameters of an electric power system. Unlike SVCs, STATCOM devices use voltage source converters—generally comprised of gate turn off thyristors or Insulated Gate Bipolar Transistors (IGBTs)—and a direct current (DC) voltage source to generate a set of three-phase AC output voltages. Because of this, STATCOMs appear as an adjustable voltage source behind a reactance, and as such do not require capacitor or reactor banks to generate/absorb reactive power. As a result, a STATCOM is more compact, has a smaller footprint, and generates less noise/magnetic impact (as compared to an SVC).

As with SVCs, STATCOMs produce harmonics as a result of power electronic switching. To resolve these undesired effects, STATCOMs can employ filters. However, their robust switching capability also enables them to employ strategies to simply mitigate (as much as possible) harmonic production. Although STATCOM devices provide a measure of capability beyond SVCs, the fundamental intent of these devices is to provide voltage control (through reactive power support) to the system. A summary of the characteristics of SVCs versus STATCOMs is provided in Table 8.

⁹¹ Kowalski, J et.al. “Application of Static VAR Compensation on the SCE System,” IEEE PES PSCE, 2006.

Table 8. SVCs versus STATCOMs⁹²

ISSUE	STATCOM	SVC
V/I characteristic	Good undervoltage performance Current Source	Good overvoltage performance Impedance
Control range	Symmetrical otherwise Hybrid solutions	Freely adjustable to any range by TCR/TSR/TSC branches
Modularity	Same converter usable for various applications (STATCOM, UPFC, CSC, B2B etc.) Redundancy no degraded mode	TCR/TSR/TSC branches used in SVC and TCSC/TPSC Redundancy Degraded mode operation
Response time	1 to 2 cycle	2 to 3 cycle
Transient behavior	Self protecting at critical system faults	Available before, during, and after critical system conditions
Space requirement	40% to 50%	100%
Availability	96% to 98%	>99%
Investment costs	120% to 150%	100%

Similar to an SVC, the STATCOM can be classified as a voltage controller and it is used primarily to improve the voltage stability of the transmission system. Here again, indirect system benefits are also applicable, as with the SVC. However, these improvements are not necessarily directly attributable to the STATCOM device. Unlike the SVC, the voltage source converter technology used in STATCOM devices allows independent control of output current over the entire inductive/capacitive range, irrespective of the system voltage. This means that the STATCOM can provide voltage support during periods of low system voltage (i.e., faults), and in other situations where system voltage collapse is of concern.

Several STATCOMs are installed in United States. An early project sponsored by EPRI at Sullivan substation in Tennessee began operation in 1995. The STATCOM enabled Tennessee Valley Authority to defer capital expenditures for an additional substation transformer, or an additional 161-kV line. A recent installation at Stony Hill, Connecticut, employed an 8-MVAR STATCOM together with switched capacitors to increase the power import into Southwest Connecticut by 100 MW.⁹³ Another recent STATCOM installation at Essex, Vermont, provided voltage stability in response to significant load growth. The 7-MVAR STATCOM provided the needed stability control and was compact.

4.1.2.3 Series Static Synchronous Compensator

Like the STATCOM, the SSSC appears (to the system) as an adjustable synchronous voltage source; unlike the STATCOM (and as the name implies), the SSSC is connected in series with a transmission line (see Figure 11). This connection enables the device to vary the effective impedance of the transmission line (by injecting a voltage containing an appropriate phase angle in relation to the line current). The system enhancements available from an SSSC mirror those offered by a conventional series capacitor used to compensate transmission lines, including

⁹² Adapted from: Tyll, H.K. (2004). "FACTS Technology for Reactive Power Compensation and System Control," Transmission and Distribution Conference and Exposition: Latin America, 2004 IEEE/PES, Sao Paulo.

⁹³ M. Henderson, et.al. (2010). "Planning HVDC and FACTS in New England."
<http://ieeexplore.ieee.org/xpl/mostRecentIssue.jsp?punumber=5479080>.

increased power transmission capability, improved system stability, reduced system losses, reduced voltage drop, and optimized (balanced) power flow along parallel lines.

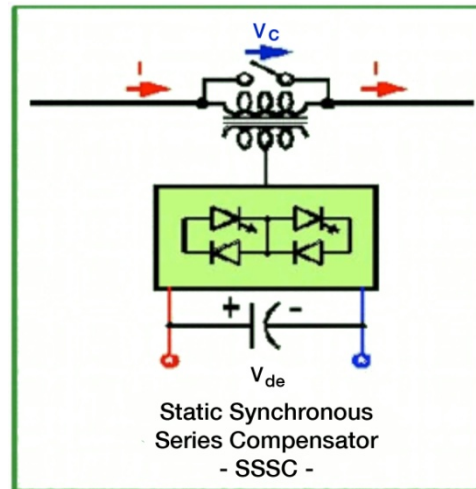


Figure 11. SSSC electrical diagram⁹⁴

As with SVCs/STATCOMS, SSSC devices can introduce harmonics due to the nature of the power electronic switching. Compensation techniques are similar to those previously identified for the STATCOM.

The manner in which the SSSC performs (particularly improvements to system stability) provides the transmission system with a powerful device capable of quickly responding to a variety of abnormal conditions and performing as a line impedance controller.

When the power system is disturbed (e.g., during a fault), the connected synchronous machines may accelerate or decelerate, and system frequency may rise or fall above the nominal value (60 Hz). While these occurrences are not unexpected, they are not desired. Rather, it is advantageous to return the system to a steady state condition (generally as quickly as possible). In these situations, the line impedance controller enables the SSSC device to either increase or decrease the amount of power transmitted from a generator (helping to counter the machine acceleration or deceleration) by increasing or decreasing the inductive/capacitive reactance of the line; this helps to damp the power swing oscillations and facilitates a quicker return of the system to steady state.

SSSC devices can also be used to increase (or decrease) current flow on a line, and even balance the current flows in parallel lines. In both instances, the effective line impedance is varied according to the implemented control scheme (and its desired outcomes). The result is a change in flow corresponding to the increase or decrease of the effective line impedance. While the SSSC is able to control power flows indirectly (by varying the line impedance), it does not provide complete power flow control capability (provided by devices offering phase angle shifting capability).

An SSSC device does not introduce a physical capacitor into the transmission line and hence it does not cause sub-synchronous resonance.

⁹⁴ Adapted from: Chow, Joe H. "Voltage-Sourced Converter Based FACTS Controller Seminar," NSF US-Africa Research and Education Collaboration Workshop, December 15, 2004.

4.1.2.4 Unified Power Flow Controller / Interline Power Flow Controller

The UPFC and IPFC are the most versatile FACTS-based devices thus far developed. The key distinction between the UPFC and IPFC is that the UPFC is designed to perform its control functions on only one line, whereas the IPFC is intended to compensate and manage power flows for multiple lines. The methods and control strategies implemented by each device, however, are quite similar.

Both the UPFC and IPFC are combinations of the STATCOM and SSSC devices. Accordingly, both offer all three FACTS controller capabilities (i.e., voltage controller, line impedance controller, and power flow controller).

Of particular note is the true power flow control nature of the UPFC/IPFC, as compared to the SSSC. Whereas the SSSC affects power flow by modifying the effective line impedance, the UPFC/IPFC can control power flow quantity and direction by regulating bus voltage phase angles (i.e., phase angle shifting). By facilitating the control of each of the aforementioned parameters, these devices directly provide all three of the system benefits identified (i.e. increased power transfer, improved voltage stability, and enhanced rotor angle/system frequency stability). These increased capabilities are accompanied by increased cost, but the overall contribution of the UPFC or IPFC device to the transmission system can be of significant value.

Two EPRI-sponsored UPFC projects are operating in the United States. The Inez UPFC was the first of its kind in the world and was placed into service in 1998. The other UPFC project in the United States is the convertible static compensator (CSC) at the Marcy substation on the New York Power Authority (NYPA) transmission system. Two of the New York State system's major interfaces are the Total East interface and the Central East interface. Before application of the CSC device, the transfer across these interfaces was limited to 6150 MW and 2880 MW, respectively. These limits were imposed due to voltage collapse and power system damping concerns that could occur under critical contingencies.

Extensive studies performed by NYPA and EPRI identified the need for both voltage support and power flow management capabilities.⁹⁵ The CSC device provides a readily customizable FACTS-based solution, which can be adjusted depending upon the needs of the system. As such, it provides all of the following capabilities: STATCOM, SSSC, UPFC, and IPFC. These various capabilities are available in two +/- 100 MVAR rated units.

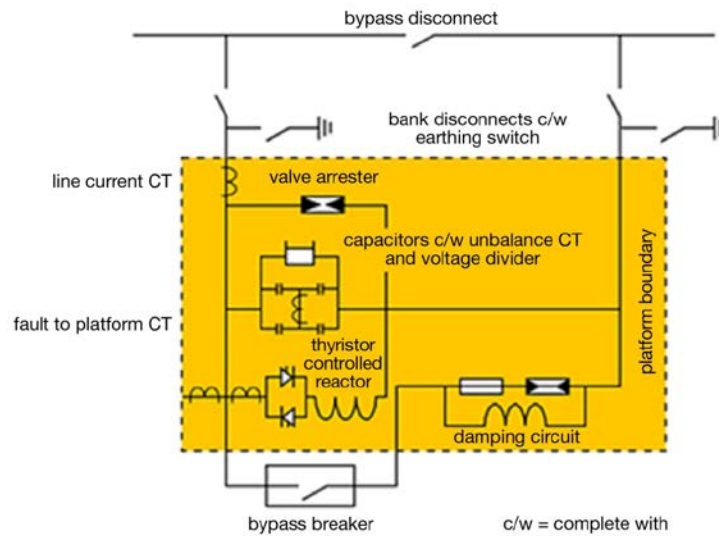
Results from system operations demonstrated increased power transfers of 114 MW on the Total East interface, and 65 MW on the Central East interface.⁹⁶ In addition to a greater utilization of the existing transmission infrastructure, other benefits provided by this equipment include relieved power transfer bottlenecks, improved voltage control, and reduced system losses.

4.1.2.5 Thyristor Controlled Series Capacitors

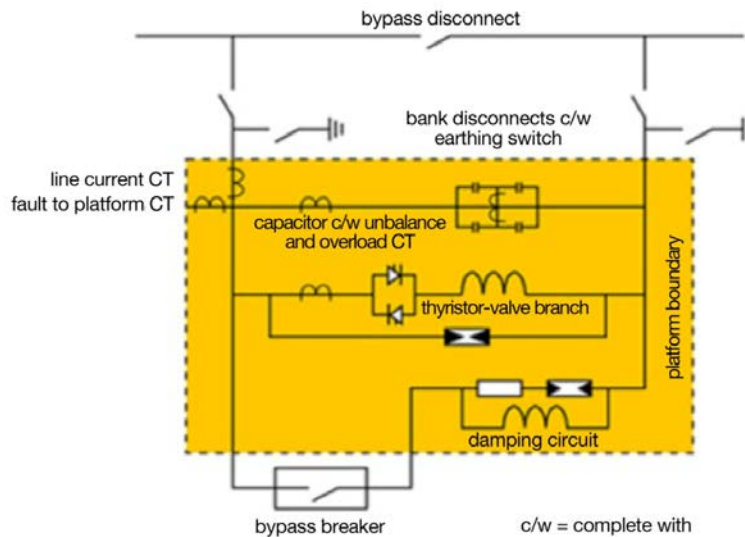
A TCSC is an extension of conventional series capacitors by adding a thyristor controlled reactor. Placing a controlled reactor in parallel to the series capacitor provides a continuous and rapidly variable series compensation system. In some applications, thyristors are used just to protect the series capacitor, rather than controlling the series compensation, and they are called thyristor protected series capacitors (TPSCs). Figure 12 compares the two devices.

⁹⁵ Edris, A. (1999). "FACTS Technology Development: An Update." IEEE Power Tech Conference, Budapest, Hungary.

⁹⁶ Fradanesh, B. and Schuff, A. (2003). "Dynamic Studies of the NYS Transmission System With the Marcy CSC in the UPFC and IPFC Configurations." Transmission and Distribution Conference and Exposition, IEEE PES.



Thyristor Controlled Series Capacitor



Thyristor Protected Series Capacitor

Figure 12. TCSC and TPSC⁹⁷

Series compensation increases the power flow on a circuit by reducing the series impedance between the sending end and the receiving end. The TCSC, in addition to providing the benefit of a fixed series capacitor, offers the advantage of power flow control by altering the series impedance. Power flow control helps either increase the flow when the load requires it or reduce when transmission congestion occurs.

⁹⁷Adapted from <http://www.energy.siemens.com/co/en/power-transmission/facts/series-capacitor/-content=Applications>

The first-ever TCSC was installed in WAPA system at Kayenta, Arizona, in 1992. This was installed to increase the power transfer capacity between Shiprock substation in New Mexico and Glen Canyon substation in Arizona.⁹⁸ Another TCSC is in operation at Slatt substation in Oregon.

4.1.2.6 Comparing FACTS Devices

Table 9 summarizes how each of the FACTS devices provides benefits. Some devices provide indirect benefits to system parameters as a result of their direct (i.e., targeted) improvements. Accordingly, the table below indicates which system improvements (generally) are directly attributable to the capabilities offered by each device.

Table 9. Comparison of FACTS Devices

FACTS DEVICE	INCREASED POWER TRANSFER	IMPROVED VOLTAGE STABILITY	ENHANCED ROTOR ANGLE/SYSTEM FREQUENCY STABILITY
SVC	Indirect	Direct	Indirect
STATCOM	Indirect	Direct	Indirect
TCSC / SSSC	Direct	Indirect	Direct
UPFC/IPFC	Direct	Direct	Direct

Table 10 provides a relative comparison of the benefits for different applications for each of the FACTS devices.

Table 10. Relative Comparison of Benefits

FACTS DEVICE	LOAD FLOW CONTROL	VOLTAGE CONTROL	TRANSIENT STABILITY	DYNAMIC STABILITY
SVC	X	XXX	X	XX
STATCOM	X	XXX	XX	XX
TCSC	XX	X	XXX	XX
UPFC	XXX	XXX	XX	XX

Installation cost of a particular FACTS device depends on various factors such as redundancy, ambient conditions, and location. Voltage stability can be enhanced using the FACTS devices listed, and their application can often be used in place of building additional transmission.

4.2 Power Flow Control

In addition to the described technologies, power flow controlling devices can increase the transfer capacity of lines. In contrast to the situation described in the previous examples, these devices allow for active control of the flow in the line. A well-known technology for controlling line flow are PSTs.

⁹⁸ Christi, N., Hedin, R., Johnson, R., Krause, P., Montoya, A. (1991). "Power System Studies and Modelling for the Kayenta 230 kV Substation Advanced Series Compensation." IEEE 5th International Conference on AC and DC Transmission.

4.2.1 FACTS Devices

In addition to controlling voltage and stability, FACTS devices can directly control power flow. By controlling power flow, localized overloads can be mitigated by diverting power from the over loaded circuit to other parallel paths. A more detailed discussion of FACTS devices is presented in the previous sections.

4.2.2 High-Voltage Direct Current Lines

HVDC devices have a long (and evolving) history of application in electrical power systems. Although most transmission is provided via AC, DC applications can provide economic and technical benefits to more fully utilize the existing transmission system infrastructure. In addition to the classic application of long distance, point-to-point transmission or long lengths of cable, HVDC can provide important technical benefits when interconnecting large AC networks where only weak AC interconnections exist. The three major U. S. interconnections use HVDC links.

In an HVDC transmission system, AC voltage is converted to high-voltage DC using power electronic devices, such as thyristors or high power transistors. The systems that use thyristors are known as classic HVDC / Line Commutated Converters / Current Source Converters. The DC systems that use high-power transistors, such as IGBTs, are called Voltage Source Converters as well as specific manufacturer trade names.

HVDC transmission systems are used in long-distance overhead transmission applications, primarily for economic reasons and stability considerations, and in underground/underwater applications, as the only technically viable alternative in certain instances. HVDC cables do not have a charging current effect like AC cables, which make DC cable transmission superior to AC beyond a certain length.

Since the first HVDC system was placed in service in Gotland, Sweden, in 1954,⁹⁹ HVDC technology has progressed in both size and implementation. The Gotland project connected two AC systems via a submarine cable link, utilizing mercury arc valves to convert AC to DC. The project was rated at 20 MW and 100 kV. Today, depending on the selected converter technology (i.e., line commutated or voltage-source), the ratings of HVDC systems can reach 2000 MW and 800 kV, for line-commutated or thyristor-based converters, and 400 MW and 300 kV, for voltage-source or IGBT-based converters. Accordingly, a variety of proven HVDC technologies can be designed and implemented to help improve an assortment of transmission system limitations and constraints.

Generally, HVDC overhead line towers are much more compact than equivalent AC transmission line towers. Therefore, HVDC transmission systems require less right-of-way, as compared to an AC transmission system of the same power transfer level. In other words, HVDC transmission systems can deliver more power than an AC transmission system for the same amount of right-of-way. For example, an 8000-kV AC line has a capacity of 2000 MW and requires 75-m right-of-way. In contrast, a 500-kV DC line has a capacity of 3000 MW and only requires 50-m right-of-way.¹⁰⁰ By using advanced control techniques, HVDC lines can provide

⁹⁹ "The Gotland HVDC Link" (2012). ABB Power Technologies.
<http://www.abb.com/industries/ap/db0003db004333/8e63373c2cdc1cdac125774a0032c5ed.aspx>. Accessed August 2012.

¹⁰⁰ Weimers, Lars. (undated). "Bulk Power Transmission at Extra High Voltages, a Comparison Between Transmission Lines for HVDC at Voltages Above 600 kv dc and 800 kv ac," ABB Power Technologies.
[http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/56aef360ec16ff59c1256fda004aeaec/\\$file/04mp0274%20rev.%2000.pdf](http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/56aef360ec16ff59c1256fda004aeaec/$file/04mp0274%20rev.%2000.pdf). Accessed August 2012.

system damping, which can help to improve stability and potentially improve overall system transfer capability in the connected system.

4.2.2.1 HVDC Back-to-Back Systems

In back-to-back applications, the fundamental building blocks for all HVDC systems, the power converters, are co-located and separated by a short run of interconnecting DC bus work (see Figure 13). These devices have a solid history of use in interconnecting asynchronous AC transmission systems throughout the world.

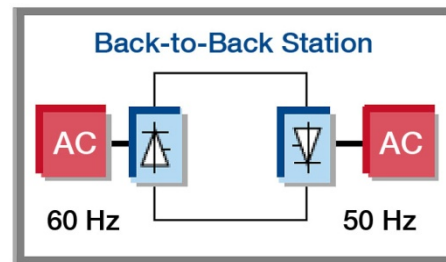


Figure 13. Back-to-back HVDC system configuration¹⁰¹

Back-to-back HVDC systems are particularly suited to connect two asynchronous AC systems, such as between WECC and the Eastern Interconnect or between ERCOT and the Eastern Interconnect. Figure 14 shows the back-to-back and the long-distance HVDC transmission systems that are currently in operation in North America. By using appropriate control strategies, a back-to-back HVDC link can provide the required system damping that improves the overall performance of both the transmission systems to which it is connected and allow higher levels of transfer between the two systems.

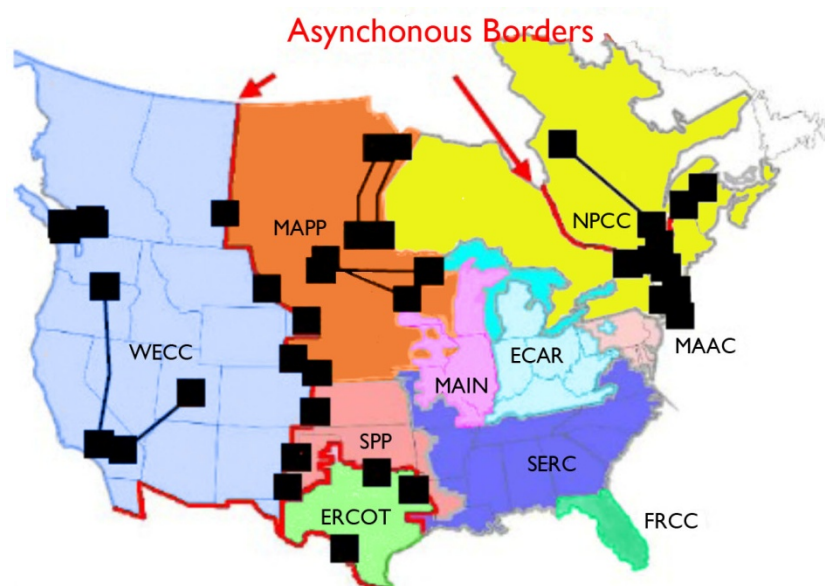


Figure 14. HVDC systems in North America¹⁰²

¹⁰¹ Adapted from Siemens "HVDC Classic," United States. <http://www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-classic/>. Accessed August 2012.

HVDC systems are customized for each application, and the technology is changing rapidly so it is difficult to find general cost data.¹⁰³

4.2.2.2 *Segmentation and Grid Shock Absorbers*

HVDC is particularly effective for interconnecting two AC grids when conventional AC interconnection is not feasible for technical reasons. The current grid configuration consists of a tight network of AC lines with some HVDC links employed for special conditions. Advances in HVDC technologies have presented other opportunities for the application of HVDC technologies in an overall structural way. The grid in the United States has pockets of AC that would benefit from having the weak AC interties replaced with HVDC interties.

The advantage of HVDC interties is that power can be scheduled over the HVDC lines in much the same way that power can be scheduled from a generator. Another advantage of HVDC interties is their control capabilities to act as shock absorbers, by injecting and extracting energy more quickly and precisely from the connected AC grids than conventional AC controls. Typical HVDC response to a disturbance includes the following:

- During normal conditions, each HVDC tie is operated in a conventional manner with power flow held at scheduled levels on each tie until a disturbance is sensed on either side of the HVDC link.
- The disturbance is indicated by changes in frequency beyond a small threshold. Power transfer is automatically changed to support a falling frequency or limit a rising frequency.
- Power flows can be increased up to the ratings of the HVDC ties or to the thermal or voltage limits imposed by adjacent ac systems on either side of the HVDC ties.
- Without the protection assured by grid segmentation, disturbances can propagate without bounds, causing tie power flows to increase to levels exceeding thermal limits, and eventually violating voltage and angular stability limits, triggering cascading.
- With HVDC ties, power transfers are limited to safe levels that will often be beyond the stability limits of AC ties.
- Unlike unsegmented grids where the possibility of any one AC tie reaching a thermal or voltage limit requires constraining the loading of other parallel ties to levels substantially below their thermal capabilities, and which are thus underutilized, each HVDC tie can operate up to its local thermal or voltage limit.
- The ability to control power flows at the perimeter of an area (AC sector) allows adjustment of power flows to counter disturbances and internal problems that could otherwise result in intra-area cascading.
- Centralized control and coordination of power flows over the HVDC ties will be limited to normal dispatching of inter-area power flows and remedial adjustments to limit or reduce power flow in weakened areas within a sector. (The latter capability is generally

¹⁰² Adapted from Bahrman, Mike "Overview of HVDC Transmission," IEEE PSEC Conference, Georgia, November 1, 2006. http://www.ieee.org/portal/cms_docs_pes/pes/subpages/meetings-folder/PSCE/PSCE06/panel2/Panel-02-1_Overview_of_HVDC_Transmission.pdf. Accessed August 2012.

¹⁰³ For a discussion of cost data available in 2006, see the presentation of Mike Bahrman (referenced above).

available for today's grids only from phase angle regulators in AC ties.) This degree of flow controllability is much faster and more manageable with HVDC ties.

- Inter-area support (traditionally provided by synchronizing power with its problematic lack of control) is provided by what is effectively a governor control on each HVDC tie that responds to frequency differences between asynchronous areas. When a disturbance in one area triggers increased power flow from adjacent AC systems via these controls, the frequency change in the adjacent systems will cause increased support from more remote AC systems.
- A major disturbance that causes frequency to drop in an area may load HVDC ties to their local power transfer limits. The first result is cascading avoidance. The second result is the activation of the spinning reserve in the affected system, as frequency is allowed to drop. Between increased tie flows and greater intra-area generator production from spinning reserve, the frequency drop may be arrested. If it is not, under-frequency load shedding that normally responds after a grid breakup will occur and arrest the frequency decay with a relatively lesser loss of customers.

4.2.3 Improved Real-Time Monitoring and Dispatch

Real-time monitoring within power systems is being actively pursued in the United States. Much of this activity could be categorized under the Smart Grid banner. Real-time monitoring provides a clearer picture of the state of the grid and allows operators to increase transfer across critical interfaces when stability and voltage margins are not compromised. This allows dynamic ratings for lines that are stability or voltage limited. While dynamic rating of the line may not increase firm transmission capacity, it may allow operators to schedule transmission circuits for non-firm transfer that have static limits.

Current efforts at real-time monitoring include the following.

- Real-time transmission temperature/sag to implement dynamic line rating
- PMUs to provide direct state measurements—a number of utilities have implemented programs to equip their systems with advanced real-time monitoring systems, including PMUs. The NYISO has recently announced installation of 39 PMUs as part of its Smart Grid initiative,¹⁰⁴ and WAPA has initiated a similar project totaling \$108 million.¹⁰⁵ DOE funded approximately 50% of the Western synchrophaser project.
- Improved supervisory control and data acquisition systems to accept and process real-time information flow from remote monitors

Real-time monitoring requires real-time communications consistent with the speed of the monitoring equipment. The Power Line Carrier has been used for many years for relaying purposes. Increased data rates require more robust systems with higher capacity, such as fiber optic links. Fiber optic communication channels are commonly embedded in transmission ground wires and retrofitting existing transmission lines that do not have optical ground wire

¹⁰⁴ Electric Power Research Institute. (2010). "Synchrophasor Enabled Smart Applications." http://www.nyiso.com/public/webdocs/Issues_and_Trends/smart_grid/EPRI_Presentation_2010.pdf. Accessed August 2012.

¹⁰⁵ IEEE, "Phasor Measurements: Systems and Applications." http://www.ieee.org/portal/cms_docs_pes/pes/subpages/meetings-folder/T_D_2005_2006/wednesday/pn22/05TD0297.pdf. Accessed August 2012.

provides an economic method for using existing transmission facilities to enhance real-time monitoring.

Expansion and improvement of communication channels for transmission of real-time data includes fiber optic and improved Power Line Carrier.

Real-time monitoring provides system operators with an important tool to optimally dispatch the system to maximize the available transmission capacity. By using real-time system information, operators can balance the non-dispatchable nature of wind and solar resources with dispatchable resources to maximize the available transmission capacity.

4.2.4 Phase Shifting Transformer

PSTs are electro-magnetic devices, similar to conventional transformers that are introduced in an existing transmission line. A PST contains two sets of windings, one in series and the other in parallel. It controls the power flow by adjusting the phase angle between the sending and the receiving ends of the PST and injecting voltage through the series windings.

A PST allows the transmission operator to control the power flow through a transmission line. Using this device, the flow through heavily congested lines can be reduced and shifted to transmission lines with spare capacity. This means that the transfer capacities rise as congestion diminishes. Furthermore, PSTs are relatively inexpensive devices, when compared to new transmission lines, and can often be placed in an existing substation. They have been less subject to public opposition due to environmental, political, or other concerns. As a result, the permitting process for a PST may be relatively problem free.

A PST, however, has some drawbacks. First, it adds an extra series element in the grid, which is subject to failure. Second, it generally increases the losses in the system as it distorts the natural flows in the power system. Third, the effects of power flow control are not necessarily positive for all parties involved. The effect of shifting the power flow is not local, and an increase in one place can induce a decrease in the other. A final disadvantage is that, in the case of multiple power flow controlling devices, they must be used in a coordinated way to avoid inefficient grid use. When multiple power flow controlling devices are installed in the transmission grid, local control can cause suboptimal or inefficient use of the available power system.

When employing PSTs, analysis is often performed to develop strategies and circuit configurations that minimize the frequency of operation of the phase shifting mechanism since this leads to higher maintenance and potentially shortened life of the unit. Strategies such as the following have been investigated by at least one western utility:

1. *Control by power flow:* Set power flow on the 230-kV circuit at a predefined level for overall system economic operation. During contingent situations or other changes in the system, adjust the phase shifter to maintain the predefined power flow on the circuit. This form of control implies automatic and continuous control.
2. *Control by phase angle:* Set the phase shifter at a fixed tap (angle) position during normal conditions. Change the tap position according to some predefined setting for contingent cases. This form of control implies non-continuous control by remote supervision.
3. *Bypass control:* The phase shifter is bypassed for maintenance or for specific conditions such as loss of 500-kV supply, or for economic operation under suitable system conditions.

4. *Control for remedial action:* A few remedial action schemes address events such as cable overload protection, over-voltage protection and under-frequency load shedding. The phase shifter control needs to be coordinated with the existing remedial action schemes and new remedial action schemes to be added in future.

4.2.5 Fixed Series Capacitors

Fixed series capacitors reduce the line impedance in long lines, increasing maximum power transfer. Greater the line impedance means lower the power transfer capability of the line. Unlike the shunt (parallel) capacitors, these series capacitors are not meant to supply reactive power. Hence, their power rating is relatively small. However, their voltage rating is higher than a shunt capacitor, and they are installed on elevated insulated platforms.

The cost of installing a series capacitor is approximately 10% of the cost of the overhead line on which it is applied. The increase in power transfer capacity could be approximately 10% to 30% depending on the network topology.

Many series capacitors are in operation in United States, and many more are in planning stages. One of the recent projects was the replacement of older series capacitors at Eldorado substation in Nevada.¹⁰⁶ New series capacitors were placed in service in 2006 on 500-kV lines at Eldorado substation by Southern California Edison to increase the power transfer between Arizona/Nevada and Southern California.

4.3 Energy Storage

Energy storage devices offer the potential to increase individual transmission path transfer capability, although their primary emphasis has been to provide overall system benefits either through improved system dynamic performance or through energy price arbitrage. One of the primary distinguishing characteristics between the various types of energy storage devices is their energy storage capacity, which is the key determinant for whether a device can be effective in increasing transmission path transfer capability. Other features include cost, location, and efficiency.

Table 11 lists the most common types of energy storage devices and a comparison of their cost.

¹⁰⁶ Siemens Power Transmission and Distribution. (2006). "Eldorado Series Capacitor Upgrade Project," Highlights & Innovations in Transmission and Distribution. HVDC/FACTS Highlights. <http://www.ptd.siemens.de/artikel0602.pdf>. Accessed August 2012.

Table 11. Present Worth of 10-year Operation in Year 1 (\$/kW)¹⁰⁷

TECHNOLOGY/ USE	ADVANCED LEAD-ACID BATTERY	Na/S (7.2 hr)	Zn/Br	V- REDOX	LEAD-ACID BATTER WITH CARBON- ENHANCED ELECTRODES	Li-ION	CAES (8 hrs)	PUMPED HYDRO (8 hrs)	HIGH- SPEED FLYWHEEL (15 min)	SUPERCAP (1 MIN)
Long-duration storage, frequent discharge	2839.26	2527.97	2518.03	3279.34	2017.87	2899.41	1470.10	2399.90		
Long-duration storage, infrequent discharge	1620.37	2438.97	1817.82	2701.41	1559.57	2442.79				
Short-duration storage, frequent discharge	1299.70		905.53	1459.85	669.85	1409.99			965.73	834.62
Short-duration storage, infrequent discharge	704.18		697.78	999.78	625.57	960.48			922.87	793.02

Applying storage technologies to transmission systems requires sufficient energy and power capacity to be meaningful.

¹⁰⁷Schoenung, Susan. (2011). *Energy Storage Systems Cost Update a Study for the DOE Energy Storage Systems Program*, Sandia Laboratory Report: Albuquerque, NM, SAND2011-2730. <http://prod.sandia.gov/techlib/access-control.cgi/2011/112730.pdf>. Accessed September 2012.

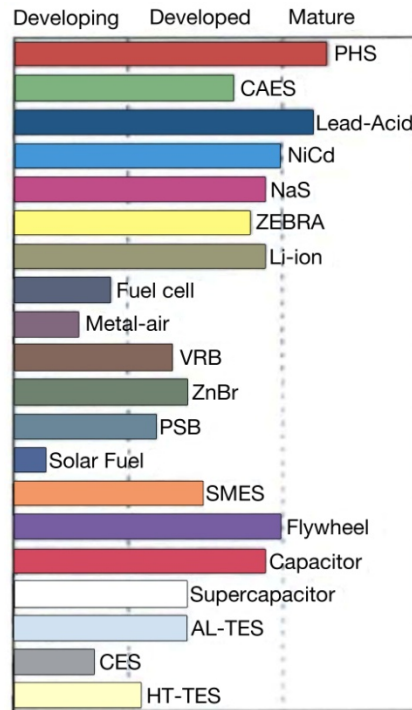


Figure 15. Maturity of energy storage technologies¹⁰⁸

While a variety of energy storage technologies are under development, only a few have reached the stage where efficiency and cycling life time are viable.¹⁰⁹

4.3.1 Battery Systems

Significant development is underway in storage technologies, including batteries and battery technologies. Some of these technologies are being used commercially, including for grid support. They provide many benefits for electric power utilities, transmission companies, electricity generators, and consumers. Some of the benefits are load leveling, spinning reserve, absence of emissions, and deferral of investment for new generation and transmission equipment. Some of the batteries used in grid applications are as follows:

- *Lead Acid Batteries:* Lead acid is one of the oldest and most developed battery technologies. These batteries are much cheaper when compared to other battery technologies. The major disadvantage is that they use lead, which is toxic and needs to be recycled.
- *Sodium Sulphur Batteries:* Sodium sulphur batteries are high temperature batteries. They have operating temperatures of 300 °C to 350°C. They have relatively high energy and power density, high electrical efficiency, long life, a small footprint, instantaneous response, and reliable operation. The sodium sulphur batteries are the most commercially advanced of several emerging energy storage devices for peak shaving and power quality solutions.

¹⁰⁸ Adapted from Ibid.

¹⁰⁹ Electricity Storage Association. (2003). "Technologies & Applications, Technology Comparisons," ESA: Morgan Hill, CA. http://energystorage.org/tech/technologies_comparisons_lifefefficiency.htm/. Accessed August 2012.

- *Zinc Bromine Batteries:* The Zinc Bromine flow battery is an attractive technology for utility-energy storage. The battery has high specific energy and energy efficiency. 100% depth of discharge does not damage the battery but improves it. Zinc/bromine batteries are attractive candidates for load-leveling applications because they offer two to three times the specific energy of lead-acid batteries, have sufficient power, operate at near room temperature, are recyclable, are low cost to build, and have the potential for long life.
- *Vanadium Redox Batteries:* Vanadium Redox Batteries are a particularly clean technology, with high availability and a long lifecycle. Their energy density is rather low, approximately 40 Wh per kilogram. The role for vanadium redox is high-level power storage. Vanadium Redox Batteries can be fully discharged without reducing life expectancy. Some applications are for utility supply energy levels, which can be as high as 350 MW and more.
- *Lithium Ion Batteries:* The lithium ion battery market has grown tremendously in the last two decades. They have a high specific energy,¹¹⁰ high energy density and high charge/discharge efficiencies. Larger-scale production due to emerging electric vehicle applications is expected to bring down their cost significantly.

While batteries offer the potential for relieving transmission congestion, applications have typically centered on on-peak and off-peak energy price arbitrage.

4.3.2 Pumped Storage Hydro

Pumped storage hydro is a mature technology with many installations in the United States and around the world. A pumped storage facility consists of an upper reservoir and lower reservoir and a generator/pump in between. During periods of high electricity demand, water is allowed to flow from the upper reservoir to the lower reservoir passing through the turbine/generator and generating electricity. During periods of low demand, the process is reversed and the water is pumped from the lower reservoir to the upper reservoir where it is stored until the next period of high demand.

Similar to batteries, pumped storage hydro facilities offer the potential to be used to reduce transmission congestion, but their primary application is to hedge on- and off-peak energy price arbitrage. Pumped storage hydro facilities are limited by the geography suitable for building the two reservoirs, which limits their application in relieving transmission constraints.

4.3.3 Flywheel Energy Storage

Flywheels are devices capable of storing energy in a rotating mass driven by a motor/generator arrangement. They allow electrical energy to be removed from the connected electrical grid and stored in the rotating mass of the flywheel and then removed from the rotating mass of the flywheel and returned to the electrical grid as electrical energy. Solid state electronic converters and controls permit this process of removal, storage, and retrieval to occur very rapidly within the operating range of the device.

Current applications of flywheels for grid size installations have been limited to providing frequency regulation services with installations rated in the 20-MW/5-MW-hr size in operation. Typical size of a single unit is 100 kW; a 20-MW plant would require 200 individual flywheels.

¹¹⁰ National Renewable Energy Laboratory. (2009). "Energy Storage," NREL: Golden, CO. http://www.nrel.gov/vehiclesandfuels/energystorage/battery_types.html/. Accessed August 2012.

While the current application has been restricted to frequency regulation, technical papers have been written that demonstrate the potential for large flywheel installations (50 MW)¹¹¹ to provide stability damping on grids, one of the limiting factors for power transfers across transmission paths and interfaces. Installed costs for flywheels can be relatively expensive per kilowatt-hour. However, because of their high efficiency, they compare favorably to other forms of energy storage but over a longer operating period, as noted in Table 12.

4.3.4 Compressed Air Energy Storage

Compressed air energy storage (CAES) uses compressed air as the storage medium. It is released during periods of high electricity demand to power turbine/generators, and replenished during periods of low electricity demand using pumps. Different configurations have been developed to achieve better efficiencies and lower costs, and one early configuration is in commercial operation in Alabama. CAES installations depend on the availability of a suitable storage cavern and, therefore, their application for relieving transmission constraints is also somewhat limited.

4.3.5 Energy Storage Devices for Transmission Constraint Relief

Energy storage devices have the potential to alter transmission flow patterns that may relieve transmission constraints under some conditions. Energy storage devices have been used on transmission systems to arbitrage energy prices between peak and off-peak. They store energy during periods when energy prices are low and release energy during periods when energy prices are high. Cost recovery is dependent on the price differential between peak and off-peak periods. Additional revenue can sometimes be realized in earning capacity payments and supplying ancillary services.

One study has quantified the potential benefit of locating energy storage facilities in such a way that transmission utilization is increased.¹¹² The National Electric Transmission Congestion Study, published by DOE in December 2009, concludes that this benefit may be limited for energy storage technologies with particular geographic requirements. However, there may be instances where energy storage can be located to impact transmission capability. For example, locating an energy storage facility coincident with wind generation could reduce the peak loading on the transmission facility. During periods of high wind generation, a portion of the energy is stored to reduce the peak loading on the transmission facility. During periods of reduced wind generation, energy is released to take advantage of available transmission capacity.

However, by coordinating the energy storage with the wind generation rather than with the price of energy, the overall economics of energy storage is potentially reduced. The question is whether the reduced cost of increasing the transmission capacity is sufficient to compensate for the potential loss of energy revenue. Determining whether the economics favor co-locating energy storage with wind or other non-dispatchable resources is very dependent on a number of factors. Critical parameters include the following:

- Price differential between peak and off-peak energy
- Time correlation between generation production and energy prices

¹¹¹ Rici, M.R. and Fiske, O.J. (2006). "Third Generation Flywheels for High Power Electricity Storage," LaunchPoint Technologies, Inc, CA. http://www.launchpnt.com/portals/53140/docs/002_Fiske_PowerRing.pdf. Accessed August 2012.

¹¹² U.S. Department of Energy, (2009). "National Electric Transmission Congestion Study" http://energy.gov/sites/prod/files/Congestion_Study_2009.pdf. Accessed August 2012.

- Amount of reduced transmission capacity and cost savings
- Relative size of energy storage compared to peak generation capacity
- Potential for realizing additional revenue from an energy storage facility, in capacity payments, ancillary services, and non-dispatchable resource integration services

The congestion study lays out many of the considerations and issues and includes sample analyses for three different geographic locations and energy markets. As the paper points out, the potential benefits of using the energy storage to benefit transmission capability is very much location-specific and it is difficult to generalize the results.

4.4 Conceptual Benefits and Constraints of Increasing Transmission Capability

The cost to upgrade the capacity of an existing transmission line is difficult to estimate without a full understanding of all the constraints. Constraints that need to be considered are as follows:

- Right-of-way constraints including the width of the right-of-way, easement restrictions, permitting restrictions, and physical constraints along the corridor
- Capacity, age, condition, and degree of structural data available for existing structures
- Ability of the system to handle the increased capacity
- Outage constraints, including the ability of the system to withstand the short or long outages needed to accomplish the upgrade

4.4.1 Right-of-Way Widths

The right of way widths for transmission lines are difficult to increase and desirable to decrease. Line characteristics that affect transfer capacity also potentially affect right-of-way widths that must accommodate increased sag or electromagnetic fields. The National Electrical Safety Code¹¹³ does not dictate the required width of a right-of-way, only that transmission lines must be constructed to keep the public safe. The most common method of determining right-of-way width assumes that a tall building could (some day) be built just outside the right-of-way at mid-span between two structures. The National Electrical Safety Code requires that all wires maintain a set clearance from said building during 48-mph wind. Additionally, many utilities maintain a set clearance to the edge of the right-of-way under high-wind conditions.

In areas with very high land prices, some utilities choose much narrower right-of-way corridors by regularly examining land use at the edge of the right-of-way and mitigating inadequate clearances. As an example, a building constructed adjacent to a structure might not require any mitigation while a building built near mid-span might be mitigated by adding an additional structure. However, this level of risk is intolerable for most utilities.

Table 12 contains representative right-of-way widths for common nominal transmission voltages. The actual width used by a utility will vary dependent upon span length, structure configuration, conductor type, metrological conditions, and tolerance for risk.

¹¹³ “National Electric Safety Code,” (2012). IEEE. <http://standards.ieee.org/about/nesc/>. Accessed August 2012.

Table 12. Right-of-Way Width

TRANSMISSION VOLTAGE (KV)	TYPICAL ROW WIDTH (FT)
12.0	40
34.5	60
69.0	90
115.0	110
230.0	140
345.0	170
500.0	200

4.4.2 Transmission Line Capacity and Cost

Table 13 contains representative single circuit transmission line capacities and costs by voltage. The actual capacities vary by conductor size, geographic location, and circuit rating methodology. The actual costs vary by line length, terrain, geologic conditions, access, land cost, structure type, structure configuration, conductor type, meteorological conditions, and span length.

Table 13. Typical Single Circuit Transmission Costs

TRANSMISSION VOLTAGE (KV)	TYPICAL CAPACITY (MW)	TYPICAL COST (\$/MILE)
12	10	300,000
34.5	25	400,000
69	100	600,000
115	175	700,000
230	450	1,000,000
345	1000	1,500,000
500	1500	1,900,000

Double circuit costs are usually approximately 1.6 times the cost of a single circuit line. The cost of an underground transmission line varies by cable type, construction standards, line length, land use/congestion, terrain, and geologic conditions. The relative cost is typically 3–10 times the cost of an equivalent overhead line with the same capacity. Generally, this ratio increases with voltage.

5.0 Research Efforts

The industry continues to investigate technology and regulatory policies to increase the utilization of transmission resources. Some of the active organizations and their focus are presented below.

5.1 EPRI Transmission Efficiency Initiative

EPRI has initiated a program with a number of leading utility organizations to identify needs and gaps in technology that could lead to lower losses and more efficient utilization of transmission systems.¹¹⁴ The technologies and overall objectives are identified below.

1. Reduction of system losses
 - Voltage upgrade / extra-high voltage AC / HVDC
 - Coordination voltage VAR control
 - Loss minimization optimization
2. Reduce line and equipment losses
 - Advanced conductors and superconductors
 - Low-loss leadership in energy environmental design substation equipment and transformers
3. Increase line and system utilization
 - Dynamic rating
 - SMART transmission

5.2 Western Area Power Administration

WAPA undertook a study in 2009 to examine transmission expansion options in the Montana-Dakota region to accommodate development of generation options.¹¹⁵ As part of that effort, a review of methods and technologies with the potential to enhance the existing grid was conducted. The study identified the following potential enhancements:

- Reconductor transmission lines and replace terminal equipment
- Voltage upgrades
- Conversion of single circuit to double circuit
- Series compensation
- Shunt compensation (switched and static VAR compensators)
- PSTs
- Dynamic line rating

¹¹⁴ “Efficient Transmission Systems Program 172.” (2012). 2012 Research Portfolio. Electric Power Research Institute, Palo Alto, CA. <http://portfolio.epri.com/ProgramTab.aspx?sId=PDU&rId=201&pId=6310/>. Accessed August 2012.

¹¹⁵ “Transmission Enhancement Technology Report.” (2002) Power Systems Engineering Research Center. http://www.pserc.wisc.edu/document_search.aspx/. Accessed August 2012.

- Conductor replacement from ASCR to ACCR
- FACTS devices
- Improved substation monitoring

5.3 Western Governors Clean and Diversified Energy Advisory Committee

The Western Governors Clean and Diversified Advisory Committee presented a report in 2006¹¹⁶ that identified the following steps to enhance the utilization of transmission:

FERC actions:

- Promote conditional-firm, priority non-firm, and other transmission service products
- Encourage transparent review and assessment of ATC
- Eliminate rate pancaking across control areas
- Promote control-area consolidation, wherever possible
- Encourage congestion management systems subject to reliability security constraints
- Encourage common websites for OASIS to facilitate transmission transactions
- Clarify the code of conduct for transmission owners/operators to allow transmission planners and resource planners of a vertically integrated utilities to participate in joint transparent discussions to better coordinate transmission planning with future and existing resources
- Convene a technical conference to develop needed reforms of interconnection and transmission queuing processes

Western Governors actions:

- Ensure resources to enable state participation in regional transmission planning
- Encourage the electric power industry to make the existing proactive, transparent interconnection-wide, and sub-regional transmission planning process a priority
- Review state laws, and if necessary, amend state laws requiring PUCs and public power boards to consider regional transmission needs
- Support the goal of a regional planning capability that can yield critical information for stakeholders and regulators to allow rigorous evaluation of large, long-term investments in transmission
- Bring together stakeholders and forge solutions to regional transmission needs, cost allocation, and siting where RTOs or ISOs do not exist, and ensure state participation in such activities by existing RTOs/ISOs
- Promote use of an open season process by project developers as a means of demonstrating demand for, and value of, new transmission projects and expand project participation

¹¹⁶ Western Governors Association. (2006). "Clean Energy, a Strong Economy, and a Healthy Environment." <http://www.swenergy.org/news/news/documents/file/CDEAC06.pdf>. Accessed August 2012.

- Urge FERC and PUCs to form joint panels on transmission cost recovery that would explicitly consider risks and needs for incentives, such as forms of preapproval, higher rates of return on transmission investments, and quicker cost recovery of transmission investments
- Encourage states to consider adopting funding mechanisms to support research, development, and demonstration of advanced technologies in the public interest
- Urge transmission operators to develop workable agreements at seams between ISO and non-ISO systems to enable effective grid operations
- Ensure that there are resources and political commitments to successfully implement the Western Governors' Association Transmission Permitting Protocol and the Midwest Electric Transmission Protocol for new interstate transmission proposals
- Evaluate the option of forming an interstate compact for the creation of a regional siting agency pursuant to Section 1221 of the EPAct 2005 and encourage consistent siting processes within their states through the use of standardized applications, joint data and studies, coordinated schedules and deadlines and other mechanisms, where possible.

State PUC actions:

- Establish tiered standards of review for prudence and application of transmission incentives for transmission expansion costs featuring a lower standard for screening studies and planning, a moderate standard for permitting and the acquisition of rights-of-way, and a higher standard for construction costs.
- For states with mandatory renewable portfolio standards, regulatory commissions should make public interest findings associated with cost-effective transmission projects that will enable states to attain energy policy goals.
- Expand transmission in advance of generation to enable the modular development of location-constrained, clean, and diversified resource areas to meet cost-effective Renewable Portfolio Standard, integrated resource plan, and state goals, similar to Texas and Minnesota legislation for new transmission and the renewable trunk line (Tehachapi Project) model for new transmission.
- Provide a coordinated, multi-state review of transmission projects by developing common principles for cost allocation and cost recovery, and adopt a common Western procedural process that would identify and coordinate the applications, forms, analyses, and deadlines.
- Promote cost-effective transmission expansion by accommodating both non-dispatchable and dispatchable resources.

Federal Agency actions:

- Commit state resources to participate in federal effort and identify contiguous corridors on adjacent state lands.
- Urge Congress to fund federal land management agency corridor planning efforts.
- Foster designation of corridors of lands not owned by the federal government or the states to ensure continuity in corridors.

Western Electric Power Industry actions:

- Synchronize regional transmission planning efforts to resource acquisition plans of load-serving entities and plans of generators
- Support and collaborate with state infrastructure authorities that have been created to facilitate transmission expansion
- Ensure institutional homes for regional transmission planning

5.4 Rocky Mountain Area Transmission Study

The Rocky Mountain Area Transmission Study provides a comprehensive view of the transmission needs covering the states of Colorado, Idaho, Montana, Utah, and Wyoming.¹¹⁷ The charter for the study includes the following:

- Work together for effective solutions in a balanced, open, and inclusive public process
- Conduct analysis of generation and transmission alternatives based on data, assumptions, and scenarios developed by participating stakeholders
- Consider every need, generation technology, and location option that is appropriate for the region
- Evaluate all potential transmission alternatives within the region
- Identify the costs and benefits of generation and transmission options for serving the electricity needs of consumers that make operational, economic, and environmental sense for the region
- Cooperate and coordinate with the west-wide Seams Steering Group – Western Interconnection planning effort¹¹⁸ and other sub-regional planning efforts and with WECC to ensure maintaining or improving system reliability.

The report provides a range of alternatives to conventional transmission expansion, with comparisons of the relative effectiveness of each.

¹¹⁷ State of Wyoming. (2004). “Rocky Mountain Area Transmission Study.” <http://psc.state.wy.us/rmats/rmats.htm/>. Accessed August 2012.

¹¹⁸ Western Governors Association. (2002). “Scope of SSG-WI Working Group.” http://www.westgov.org/wieb/meetings/crepcsprg2002/briefing%20materials/ssg-wi_031902_scope.htm/. Accessed August 2012.

6.0 Implementing Increased Line Ratings

Implementing increased transmission ratings or expanding transfer capability with new facilities can be a complex and time-consuming process. Critical review includes a comprehensive series of technical studies to verify that proposed changes will achieve the project objectives without compromising the surrounding interconnected system or reducing the ratings of other facilities (“do no harm” philosophy). NERC sets the fundamental reliability requirements for determining ratings, but the specific steps are determined by other authorities. ISOs or RTOs have standard planning and/or an interconnection processes that govern how transmission facilities are rated and integrated into the existing system in their areas. Areas not under the control of an ISO or RTO usually have less centralized, but equally complete, processes for increasing the rating of existing facilities.

6.1 ISO/RTO Rating Process

ISOs and RTOs normally have a formal expansion process that reviews transmission needs on an annual basis and studies the impact of a group of transmission changes. The ISO/RTO recommends transmission changes based on the studies, and issues a formal expansion plan for approval by the Board of Directors. Once approved, individual transmission owners implement the plan. Recommendations for individual transmission additions can come either from the ISO/RTO based on their planning studies or from the member transmission owners themselves. Merchant transmission expansion follows a similar path when requesting transmission additions or when expanding the capabilities of existing facilities. Figure 16 is the process followed by PJM and is representative of other ISO/RTOs.

PJM follows a three-step study process, whereby each step imposes a financial obligation on the requester and establishes PJM milestone responsibilities:¹¹⁹

1. *Transmission Interconnection Feasibility Study*: Project sponsor submits an interconnection request using the Interconnection Feasibility Study Agreement, along with a study deposit and preliminary project data. PJM conducts the study, and the sponsor is responsible for the full cost of the study. The study assesses the practicality and cost of incorporating the project. The project sponsor must decide whether or not to carry the project to the next step.
2. *System Impact Study*: If the project sponsor elects to pursue the project, the sponsor must execute a System Impact Study Agreement along with a study deposit to PJM. The sponsor must also provide more comprehensive project data. PJM schedules and performs a more comprehensive determination of the impact of the proposed project on both the local network and the overall system. The study refines the system upgrades necessary to accommodate the proposed project and the costs of the upgrades. PJM also estimates which party is responsible for the costs of the upgrades and the lead times for the upgrades. Similar to the Interconnection Feasibility Study, the project sponsor decides whether or not to proceed based on the more definitive costs and schedule.
3. *Transmission Interconnection Facilities Study*: If the project sponsor elects to proceed, the sponsor must execute a Transmission Interconnection Facilities Study Agreement, with a study deposit. When completed, the Facilities Study will document the engineering

¹¹⁹ “PJM Manual 14A, Generation and Transmission Interconnection Process.” (2012). PJM <http://www.pjm.com/~media/documents/manuals/m14a.ashx/>. Accessed August 2012.

design work necessary to begin construction of any required transmission facilities to support the project. It will also provide a good-faith estimate of the cost to be charged to the applicant for attachment facilities, local and network upgrades, and an estimate of the time required to complete a detailed design and construction of the facilities and upgrades.

Details of the responsibilities for the requester and PJM are detailed in the PJM OATT¹²⁰ and PJM Interconnection Manual M-14-B.¹²¹

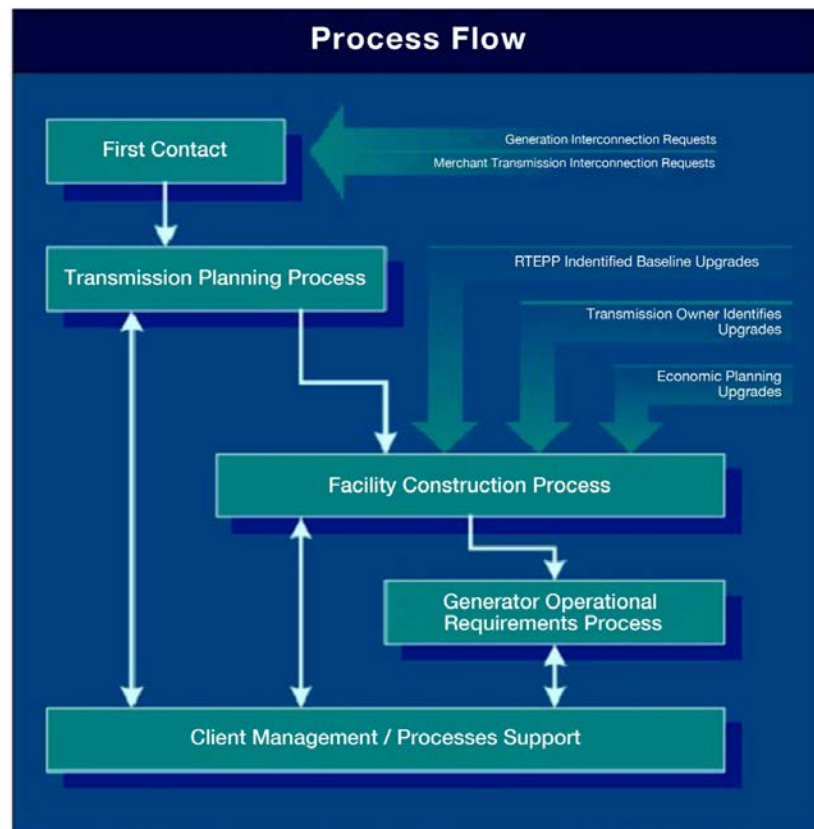


Figure 16. PJM Interconnection planning process¹²²

The PJM process described here is similar to the ones used by other ISO/RTOs. In most, if not all, ISO/RTO processes, the studies are conducted by the ISO/RTO and are often incorporated into the overall planning process and schedule that the ISO/RTO routinely conducts.

6.2 Non-ISO/RTO Rating Processes

Transmission expansion in areas not included in ISO/RTOs follow a variety of processes to ensure that transmission rating changes do not compromise overall system reliability. As an

¹²⁰ “PJM Open Access Transmission Tariff.” (2012). PJM.
<http://www.pjm.com/~media/documents/agreements/tariff.ashx/>. Accessed August 2012.

¹²¹ “PJM Regional Transmission Planning Process Manual.” (2012). PJM.
<http://www.pjm.com/~media/documents/manuals/m14b.ashx/>. Accessed August 2012.

¹²² Adapted from PJM “Manual 14 A Generation and Transmission Interconnection Process” (2012).
<http://www.pjm.com/~media/documents/manuals/m14a.ashx/>. Accessed August 2012.

example, WECC has a well-defined rating process that is shown in Figure 17¹²³ Similar to the process followed in areas within an ISO/RTO, WECC follows a three-stage study process for rating new transmission or changing the rating of an existing facility:

- *Phase 1:* Phase 1 involves a project description and results of initial studies that demonstrate that the proposed project meets minimum reliability standards under normal conditions. The material is submitted either through the WECC Progress Report process or via letter to the WECC Technical Studies Subcommittee (TSS). WECC will grant a Planned Rating if the project meets the necessary requirements under Phase 1.
- *Phase 2:* Phase 2 includes more comprehensive studies demonstrating that the proposed project meets reliability requirements under stressed conditions. A Project Review Group comprised of interested WECC members, normally members from utilities and other parties, who could be impacted by the proposed project, review the results. The project sponsor then submits the Project Review Group Phase 2 Rating Report to WECC.¹²⁴ Upon acceptance by WECC, the project is granted an Accepted Rating.
- *Phase 3:* In Phase 3, final implementation and construction of the project is monitored to ensure that all conditions are met under the Accepted Rating. This phase is completed when the project is placed in service.

¹²³ “Overview of Policies and Procedures for Regional Planning Product Review, Project Rating Review, and Progress Reports.” (2012). Western Electricity Coordinating Council.
http://www.wecc.biz/library/WECC%20Documents/Miscellaneous%20Operating%20and%20Planning%20Policies%20and%20Procedures/Overview%20Policies%20Procedures%20RegionalPlanning%20ProjectReview%20ProjectRating%20ProgressReports_07-05.pdf. Accessed August 2012.

¹²⁴ Ibid.

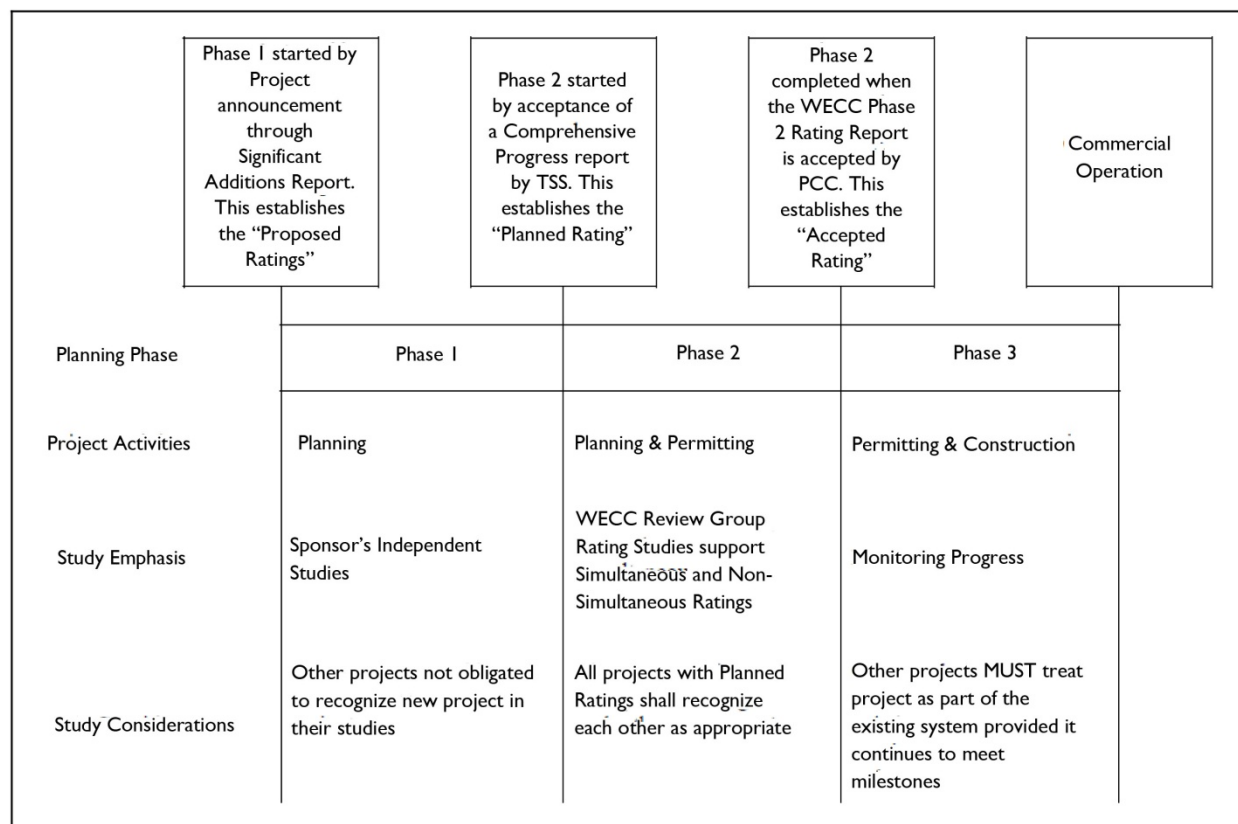


Figure 17. WECC rating process¹²⁵

In addition to the studies necessary under the rating process, it may be necessary to undertake an interconnection process with other entities that own facilities connecting with the project. That process will often involve additional studies as prescribed by the impacted system owner and is normally governed by the OATT of the impacted system.

¹²⁵ Adapted from "Overview of Policies and Procedures for Regional Planning Product Review, Project Rating Review, and Progress Reports," (2012). WECC.
http://www.wecc.biz/library/WECC%20Documents/Miscellaneous%20Operating%20and%20Planning%20Policies%20and%20Procedures/Overview%20Policies%20Procedures%20RegionalPlanning%20ProjectReview%20ProjectRating%20ProgressReports_07-05.pdf. Accessed August 2012.

7.0 Summary of Results

New renewable generation must be integrated into the existing electric power system. The way this system of transmission is developed and operated in the United States today has been affected by restructuring, the evolution of mandatory reliability, replacement of existing generation to accommodate renewable resources, and the process of introducing competition. Because changes have come relatively recently, traditional transmission planning (10 and 20+ years) has been disrupted. The consequence is that short-term transmission planning (5–10 years) has become the norm. Construction of new transmission lines takes 7–10 years, so 10-year planning is not adequate for the life span of transmission facilities (40+ years). The existing transmission grid must be utilized to its maximum potential until new transmission is built. That will require enhancements in operating procedures and the application of new technologies to enable current infrastructure to carry more power.

The research and analysis presented in the previous chapters identified the following opportunities to increase the available capability of the electric transmission grid.

7.1 Changes in Policy and Standards

The transfer capability of the existing grid can be increased by changes in the standards and policies guiding line rating, such as the following:

- Replacing the practice of using static seasonal ratings on critical constrained transmission lines, with either real-time or dynamic monitoring of ambient conditions that could increase transmission during much of the year.
- WECC has extended the NERC Transmission Planning Standards for multiple circuits to include those that are not on a common structure, but are within a span's length of each other. WECC has approved changing the distance between two circuits from a span length to a tower height, thereby eliminating reduced ratings on some parallel lines due to their proximity to other lines. While it is not clear how many lines are affected by this, a number of heavily used corridors in the west have lines that are forced into close proximity. A relaxation of the separation distance could increase the rating of existing parallel circuits.
- FERC Order 2000 required RTOs to establish market-based congestion management to improve the utilization of the grid and to allocate the cost of congestion to those users who were willing to pay the price. Replacing physical transmission rights with financial transmission rights ensures that the transmission system is allocated in the most efficient and equitable manner during times of constraint.
- CFT and redispatch were provided for by FERC Order 890 as a bridge between physical firm transmission and market-based transmission congestion management. CFT provides a mechanism for transmission users to have access to selected transmission paths on a firm basis except during periodic constrained periods. Extending this practice allows increased use of the transmission system when conventional firm transmission would not be available, but when the system is not actually constrained. During periods where transmission paths are constrained, redispatch may relieve the constraints at some defined cost and allows transmission customers to decide whether to pay the cost of redispatch or forgo use of the transmission. Redispatch also provides a price signal that can be used to make economic decisions regarding the value of increasing transmission capability on

selected paths. Redispatch provides many of the same benefits as market-based congestion management without having a formal congestion management market in place.

- Other changes offer the potential to increase existing transmission and/or allow better utilization of existing rights-of-way. These include reviewing, and possibly relaxing, transmission capability indices, expanding transmission investment rules to include new technologies, and fully integrating demand resources into transmission reservation and operation processes.

7.2 Technology

New technology, particularly power electronics, can help overcome limitations in transmission capability. Some of these devices can be used to improve system damping and voltage support. Other technologies and enhanced engineering designs increase the power carrying capability of individual transmission lines as described below:

- Conventional transmission line conductors can be replaced by HTLS conductors on existing transmission line to increase the thermal rating by up to 50%. The HTLS conductor overcomes the increased loading and other factors that can lead to the need to reinforce transmission structures, if existing conductors are simply replaced by larger conductors.
- Under some conditions, thermal limits on transmission lines can be mitigated by increasing the operating voltage of the line and adopting compact line design principals to help offset the added clearance requirements when the operating voltage is increased. Compact line design principles could offer some benefits during redesign, but overall costs to increase the operating voltage on a transmission line would be substantial. This option may be particularly attractive where compact line design principles could be applied to allow reconductoring of an existing line with minimal tower changes and within the existing right-of-way.

Increasing the capability of individual transmission lines can overcome thermal limitations, which limit power flow on individual circuits, but often the limitations are related more to system performance. These limitations are more effectively mitigated by adding devices to the system that enhance system damping and provide more effective voltage support through the use of power electronics. These devices are often lumped together under the term *FACTS devices*:

- The need for more precise and quicker voltage support can be satisfied through the use of SVCs. SVCs are voltage control devices that directly provide benefit for both the steady-state and transient voltage stability of the transmission system by electronically switching shunt inductors and capacitors to achieve a highly precise amount of reactive power support. By controlling the reactive elements, system voltage profiles can be enhanced and power transfer capabilities over individual lines, as well as groups of lines, can be accurately controlled, allowing better system performance and increased power transfer.
- Similar to SVCs, the STATCOM devices also act as shunt-connected, reactive-power compensation equipment capable of generating and/or absorbing reactive power, but STATCOM devices utilize different power control. The technology used in the STATCOMs eliminates the need for capacitor or reactor banks to generate/absorb reactive power. As a result, a STATCOM has a more compact design, a smaller footprint,

and lower noise/magnetic impact (as compared to an SVC). Although STATCOM devices provide a measure of capability beyond that of SVCs, the fundamental intent of these devices is to provide voltage control (through reactive power support) to the system.

- Employing similar technology to the STATCOM, the SSSC appears (to the system) as an adjustable synchronous component series connected in with a transmission line. This connection enables the device to vary the effective impedance of the transmission line, which leads to increased power transmission capability, improved system stability, reduced system losses, reduced voltage drop, and optimized (balanced) power flow along parallel lines.
- The UPFC and IPFC have similar technology and are one of the most versatile FACTS devices thus far developed. The key distinction between the UPFC and IPFC is that the UPFC is designed to perform its control functions on only one line, whereas the IPFC is intended to compensate and manage power flows for multiple lines. The methods and control strategies implemented by each device, however, are quite similar. Both the UPFC and IPFC are combinations of the STATCOM and SSSC devices with some important differences. In particular, the UPFC and IPFC have true power flow control, as compared to the SSSC. Whereas the SSSC affects power flow by modifying the effective line impedance, the UPFC/IPFC can directly control the magnitude and direction of power flow. By directly controlling power flow, these devices provide all three of the system benefits identified (i.e., line increased power transfer, improved voltage stability, and enhanced rotor angle/system frequency stability).
- The TCSC is an enhanced conventional series capacitor that uses a thyristor controlled reactor to provide a continuous and rapidly variable series compensation system. Series compensation, in general, increases the power flow on a circuit by reducing the series impedance between the sending end and the receiving end. In addition to providing the benefit of a fixed series capacitor, TCSC also provides an additional advantage of power flow control by altering the series impedance.

Other devices that can enhance the capability of existing transmission have a longer history of being used in power systems. While these employ power electronics, they are not commonly referred to as FACTS devices:

- HVDC transmission has a long (and evolving) history of application in electrical power systems. Although the overwhelming amount of transmission is provided via AC, DC applications can provide a variety of economical and technical benefits that may be used to more fully utilize the existing transmission system infrastructure. Generally, HVDC overhead transmission lines are much more compact than equivalent AC transmission lines. The HVDC transmission system requires less right-of-way as compared to an AC transmission system for the same power transfer level. In some cases, it is feasible to convert an existing transmission line to HVDC to realize increased power flow for the same amount of right-of-way.
- Applying the technology employed in HVDC terminal equipment, but eliminating the actual transmission line, is sometimes employed to interconnect two AC systems that would otherwise be impossible due to system stability concerns. These applications are called *back-to-back* and use the fundamental building blocks for all HVDC systems—the

power converters. However, they are co-located and separated by a very short run of interconnecting DC bus work. By using appropriate control strategies, a back-to-back HVDC link can provide the required system damping that improves the overall performance of both transmission systems to which it is connected and allow higher levels of transfer between the two systems.

- Extending the application of HVDC technology, a more system-wide approach to improving the overall efficiency of the transmission system may be achievable. The current grid configuration consists of a tight network of AC lines, with some HVDC links employed for special conditions. Advances in HVDC technologies have presented other opportunities for application in an overall structural way. HVDC is particularly effective for interconnecting two AC grids where conventional AC interconnection is not feasible for technical reasons. The grid in the United States has pockets of AC that would benefit from having the weak AC interties replaced with HVDC interties. HVDC interties' advantage is that power can be scheduled over the HVDC lines in much the same way that power can be scheduled from a generator. HVDC interties also have the advantage of using their control capabilities to act as shock absorbers, by injecting and extracting energy more quickly and precisely from the connected AC grids than conventional AC controls do. Therefore, HVDC interties improve system performance and potentially allow higher levels of power transfer over the grid.

While devices employing power electronics can react to system conditions much more quickly than mechanically controlled devices, more conventional power devices have a good history of providing improved system performance:

- A Phase Shifter, also known as PST, is a mechanical switch, electro-magnetic device, similar to a conventional transformer that is introduced in an existing transmission line. It allows the transmission operator to control the power flow through a transmission line. Using this device, the flow through heavily congested lines can be reduced and shifted to transmission lines with spare capacity. The transfer capacities rise as congestion diminishes. Furthermore, PSTs are relatively inexpensive devices, when compared to new transmission lines, and can often be placed in an existing substation. As a result, the permitting process for a PST may be relatively problem free.
- The maximum power transfer through an overhead transmission line, among other parameters, is dependent on the line impedance. The impedance is inductive and can be reduced by connecting a capacitor in series. The capacitor can be installed in an existing substation or may be installed at a discreet point along the line. The localized nature of the series capacitors and its modest cost is often preferable to building additional transmission.

The addition of energy storage facilities on transmission grids has received increasing interest in recent years, driven to a large extent by the addition of large blocks of non-dispatchable resources such as wind and solar. The ability to store a surplus of low cost, non-dispatchable resources during periods of low demand, and then release that energy during periods of high demand, can have both economic and technical benefits. Technology improvements have been particularly strong in battery storage by increasing energy storage density and charging/discharging rates. A number of energy storage technologies have reached the level of commercialization including batteries, flywheels, pumped storage hydro, and CAES.

In addition to the benefits of single devices, opportunities exist to increase the overall utilization of the current transmission system through better monitoring and subsequent control. Much of this could be categorized under the Smart Grid banner. Real-time monitoring provides a clear picture of the state of the grid and allows operators to increase transfer across critical interfaces when stability and voltage margins are not compromised. This allows dynamic ratings for lines that are stability or voltage limited. While dynamic rating of the line may not increase firm transmission capacity, it may allow operators to schedule transmission circuits for non-firm transfer that otherwise are limited by static limits.

Current efforts at real-time monitoring include the following:

- Real-time transmission temperature/sag to implement dynamic line rating
- PMUs to provide direct state measurements
- Improved supervisory control and data acquisition systems to accept and process real-time information flow from remote monitors.

Real-time monitoring provides system operators with an important tool to optimally dispatch the system to maximize the available transmission capacity. By utilizing real-time system information, operators can balance the non-dispatchable nature of wind and solar resources, with dispatchable resources, to maximize the available transmission capacity.

7.3 Overview of Techniques

Table 14 presents the policy and technology approaches for improved utilization of the existing grid.

Table 14. Summary of Benefits

	RIGHT OF WAY UTILIZATION	UNUSED CAPACITY	THERMAL	VOLTAGE	STABILITY
POLICIES					
Changes to WECC Reliability Criteria	X	X			
Financial Congestion Management		X			
Conditional Firm Transmission (CFT)		X			
Transmission Investment Rule	X	X			
Demand Resources (redispatch)			X	X	X
Dynamic/Real Time Rating		X			
TECHNOLOGIES					
High Temp, Low Sag (HTLS) Conductor			X		
Static VAR Compensator (SVC)				X	X
STATCOM				X	X
Series Static Synchronous Compensators (SSSC)		X		X	
Unified Power Factor Control (UPFC)		X		X	X
Independent Power Factor Controller (IPFC)		X		X	X
Thyristor Controlled Series Capacitor (TCSC)		X			
High Voltage Direct Current Transmission (HVDC)	X				X
Back to Back HVDC Link					X
System "shock absorbers"					X
Phase shifting transformer (PST)	X	X			
Series capacitors	X	X			
Real-time monitoring		X	X	X	X
Energy Storage	X		X	X	X

Appendix A: U.S. Electric Power Grid Structure

Interconnection and Regulatory Structures

The electric power grid of the continental United States is divided into three asynchronous interconnections commonly known as the Eastern Interconnection, the Western Interconnection, and the ERCOT Interconnection.

Eight regional entities, which work with NERC to improve reliability, overlay the three interconnections. The regional entities are responsible for the following tasks:

- Developing and implementing reliability standards
- Enforcing compliance with those standards
- Providing seasonal and long-term assessments of the bulk power system's ability to meet demand for electricity
- Providing an appeals and dispute resolution process

The regional entities are permitted to enact standards that are more stringent than those enacted by NERC (e.g., the FERC-approved electricity reliability organization), but they are not permitted to relax nor enact standards less stringent than electricity reliability organization standards.

Within the three interconnections, there are also sub-groups called balancing authorities, which have certain operating responsibilities relative to the efficient and reliable operations of the grid. The balancing authority structure of the United States relative to the regional entities and interconnections is shown in Figure 18.

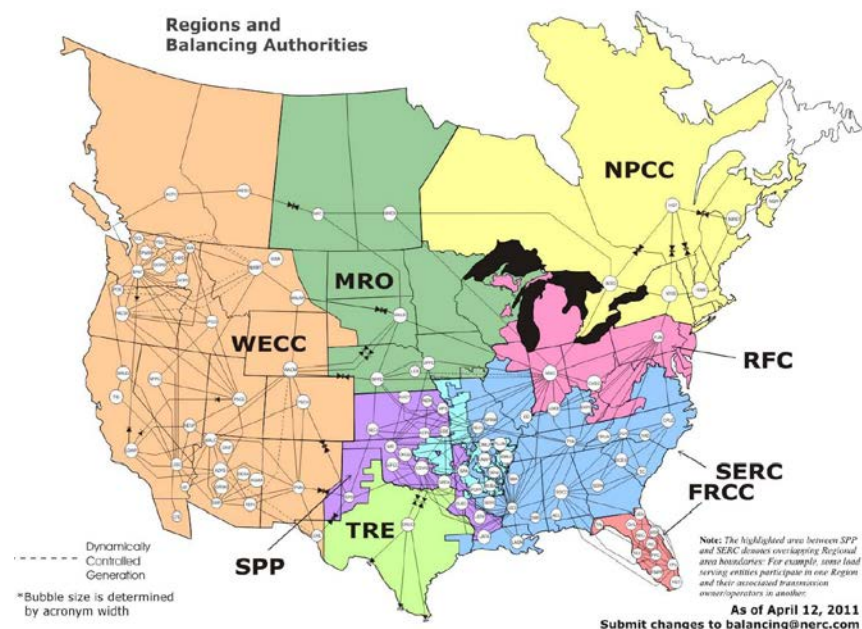


Figure 18. Regional entities and balancing authorities¹²⁶

¹²⁶ This image from the North American Electric Reliability Corporation's website is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/docs/oc/rs/BubbleMap_2011-04-

The structure of the three interconnections is described below relative to the various balancing authorities and ISO/RTOs within their footprint. In regions where there are organized markets, there are RTOs and ISOs, which operate the generation dispatch markets, market mitigation, and the system, and play varying roles in transmission planning.

NERC and Regional Entities

A reliability standard defines certain requirements of entities that own, operate, plan, and use the bulk power systems of North America. NERC, which was certified by FERC as the ERO for North America, works with all stakeholder segments of the electric industry to develop standards for the reliable planning and operation of the bulk power systems. Since ERCOT is not currently under FERC's jurisdiction, it is included separately in the discussion of standards and rules.

NERC

NERC has been certified by FERC to be the national ERO and has moved from being a voluntary, industry-sponsored organization to being a statutory entity with specific authority, compliance, and enforcement power.

NERC History

Historically, the vertically integrated utility industry used NERC, which is a bottom-up, electric-utility-dominated, volunteer organization, to establish reliability rules and monitor compliance. NERC was formed in 1968 in the aftermath of the 1965 Northeast Blackout and in response to the 1967 U.S. Federal Power Commission report on that blackout recommending the formation of an industry-based, national reliability organization.

While efforts were undertaken in the 1990s to require adherence to NERC reliability policies and guidelines, mandatory reliability standards were not adopted in the United States until Congress passed EPAct 2005. That act required FERC to certify an independent ERO, with the job of developing and enforcing mandatory reliability standards. Renewed efforts to adopt mandatory reliability standards came in response to the Northeastern blackout of August 14, 2003.

Subsequently, recommendations were made in a report prepared by a joint United States and Canadian task force that reviewed the causes of the blackout. Based on EPAct 2005, FERC certified NERC as the ERO on July 20, 2006. At that time, NERC changed its name from the North American Electric Reliability Council to the National Electric Reliability Corporation, but retained the same acronym. Under the procedures adopted by FERC, NERC is permitted to delegate a portion of its responsibilities for enforcement and for the development of regional standards applicable to regional entities. NERC oversees the activities of these Regional Reliability Organizations. A chronology of NERC history is given in Table 15.

[12.jpg](#). This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation. Accessed August 2012.

Table 15. NERC History¹²⁷

HISTORY	
1962–1963	The electricity industry created an informal, voluntary organization of operating personnel to facilitate coordination of the bulk power system in the United States and Canada. Four interconnected transmission systems were connected to three more systems, forming the largest electricity grid in the world.
1960s	Electricity industry operations followed: (a) criteria and guides for reliable operations, developed by the North American Power Systems Interconnection Committee (NAPSIC), a utility organization; and (b) reliability planning guides in some regions.
November 9, 1965	The largest blackout to this date in history occurred when 30 million people lost power in the northeastern United States and southeastern Ontario, Canada. New York City and Toronto were among the affected cities. Some customers were without power for 13 hours.
1967	Legislation (U.S. Electric Power Reliability Act of 1967) proposed the creation of a council on power coordination. Although not enacted, the proposed legislation stimulated the development of an industry reliability council.
1967–1968	The Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) recommended the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information and to review, discuss, and assist in resolving interregional coordination matters.
1967–1968	The Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) recommended the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information and to review, discuss, and assist in resolving interregional coordination matters.
June 1, 1968	NERC was established by the electric utility industry, in response to the 1965 blackout. Nine regional reliability organizations were formalized under NERC. Regional planning coordination guides, which NERC maintained, were also formalized. NAPSIC operations criteria and guides continued to be maintained and practiced voluntarily.
1975	NERC was incorporated as a non-profit corporation in New Jersey.
July 13–14, 1977	A blackout occurred in New York City. This led to the first, limited reliability provision in federal legislation. The legislation enabled the federal government to propose voluntary standards, an authority never exercised.
1980	NAPSIC became part of NERC, bringing the reliability roles of operations and planning together in one organization. NERC adopted NAPSIC operations criteria and guides.
1981	NERC changed its name to the North American Electric Reliability Council in recognition of Canada's participation.
1987	NERC updated its operations criteria and guides, renamed them as operating policies, and added requirement statements ("shall do this") and guideline statements ("should do this").

¹²⁷ Source: North American Electric Reliability Corporation. "History." (2007). <http://www.nerc.com/page.php?cid=1%7C7%7C11/>. Accessed August 2012.

HISTORY	
1987	NERC formed a committee to address terrorism and sabotage of the electricity supply system, at the urging of the U.S. National Security Council and DOE.
1992	NERC Board of Trustees stated for the first time that conformance to NERC and regional reliability policies, criteria, and guides should be mandatory to ensure reliability, in one of six Agreements in Principle adopted by the Board. (NERC still had no authority to enforce compliance with the policies, criteria, and guides.)
1993	Building on the Agreements in Principle, NERC published “NERC 2000,” a four-part action plan for the future, which recommended mandatory compliance with NERC policies, criteria, and guides; and a process for addressing violations. NERC 2000 encompassed policies for interconnected systems operation, planning reliable bulk electric systems, membership recommendations, and dispute resolution.
1995	NERC led on addressing the planning and operating reliability aspects of FERC’s Notice of Proposed Rulemaking on a more competitive wholesale electric power market.
1996	Two major blackouts in the Western United States prompted some Western Systems Coordinating Council members to enter into agreements to pay fines if they violated certain reliability standards. (The Western Systems Coordinating Council, a regional reliability organization, is now the WECC.)
1997	The Electric System Reliability Task Force established by the DOE and an independent “blue ribbon” panel formed by NERC determined that grid reliability rules must be mandatory and enforceable in an increasingly competitive marketplace. Both groups recommended the creation of an independent, self-regulatory, electric reliability organization to develop and enforce reliability standards throughout North America. Both groups concluded that federal legislation in the United States was necessary to accomplish this.
1997	NERC set out to implement the blue-ribbon panel’s recommendation of a self-regulatory reliability organization. NERC began work to convert its planning guides into planning standards.
1998	NERC led the effort to assess the electric industry’s readiness for Y2K, at the request of DOE.
1999	Nine independent directors were added to the NERC Board, joining the president and 37 industry stakeholder interests, in anticipation of NERC becoming a self-regulatory organization.
2000	NERC was appointed as the electric utility industry’s primary point of contact with the U.S. government for national security and critical infrastructure protection issues.
2001	NERC governance changed. The NERC Board was replaced with the 10-member independent board. The Stakeholders Committee was created (today, the Stakeholders Committee is called the Member Representative Committee).
May 1, 2002	NERC operating policies and planning standards became mandatory and enforceable in Ontario, Canada.
August 14, 2003	North America experienced its worst blackout ever, as 50 million people lost power in the northeastern and Midwestern United States and Ontario, Canada.

HISTORY	
April 5, 2004	The final report of the U.S.-Canada Power System Outage Task Force on the 2003 blackout concluded the single most important recommendation for preventing future blackouts, and reducing the scope of those that occur, is for the U.S. government to make reliability standards mandatory and enforceable.
Summer 2004	The Bilateral Electric Reliability Oversight Group was established as a forum for identifying and resolving reliability issues in an international, government-to-government context. The Bilateral Electric Reliability Oversight Group grew out of the United States – Canada Power System Outage Task Force.
November 12, 2004	NERC translated its operating policies, planning standards, and compliance requirements into an integrated and comprehensive set of 90 measurable standards called “Version 0 Reliability Standards.”
February 8, 2005	The NERC Board of Trustees adopted the Version 0 standards. Stakeholders overwhelmingly supported the standards.
April 1, 2005	Version 0 Reliability Standards became effective. Voluntary compliance was expected as a matter of good utility practice.
August 8, 2005	EPAAct 2005 authorized the creation of a self-regulatory “electric reliability organization” that would span North America, with FERC oversight in the United States. The legislation stated that compliance with reliability standards would be mandatory and enforceable.
April 4, 2006	<p>NERC filed an application with FERC to become the “electric reliability organization” in the United States.</p> <p>NERC filed with FERC 102 reliability standards, the 90 Version 0 standards plus 12 additional standards developed in the interim.</p> <p>NERC filed the same information with the Canadian provincial authorities in Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Quebec, and Saskatchewan, and with the National Energy Board of Canada, for recognition as the “electric reliability organization” in Canada.</p>
July 20, 2006	FERC certified NERC as the “electric reliability organization” for the United States.
September–December 2006	NERC signed Memorandums of Understanding with Ontario, Quebec, Nova Scotia, and the National Energy Board of Canada.
January 1, 2007	The North American Electric Reliability Council became the North American Electric Reliability Corporation. The new entity has a large membership base representing a cross-section of the industry.
March 15, 2007	FERC approved 83 NERC reliability standards, the first set of legally enforceable standards for the U.S. bulk power system, effective June 4, 2007. FERC stated that voluntary compliance with NERC’s additional standards should continue as good utility practice.
April 19, 2007	FERC approved eight delegation agreements by which NERC will delegate its authority to monitor and enforce compliance with NERC reliability standards in the United States to eight regional entities, with NERC continuing in an oversight role.
June 18, 2007	Compliance with approved NERC reliability standards becomes mandatory and enforceable in the United States.

NERC Structure

NERC is funded by 10 regional councils, which adapt NERC rules to meet the needs of their regions. In 1994, the regional councils opened their membership to independent power producers, power marketers, and electricity brokers. In 1996, NERC opened its board and committees to voting participation by independent power producers and power marketers (NERC 2001a). NERC and the regional councils have largely succeeded in maintaining a high degree of transmission-grid reliability throughout North America. However, the organization is dominated by representatives of the supply side (generators and transmission providers), even though the organization's purpose is to ensure the reliability of supply to the consumer. NERC replaced its 47-member combined stakeholder/independent board with a 10-member independent board in March 2001. Members of the independent board are selected by a stakeholder committee rather than being appointed or elected through a political process. NERC's role became more formalized when FERC 672 selected it as the national ERO in 2006.¹²⁸

NERC has provided delegated authority to eight regional entities in the United States and Canada—each has primary authority for enforcement in the regions shown in Figure 18. The eight regional entities operating under delegated authority from NERC are FRCC, Midwest Reliability Organization, NPCC, ReliabilityFirst Corporation, SERC Reliability Corporation, SPP, Texas Reliability Entity, and WECC.

Currently, there are more than 1900 registered entities subject to the reliability standards (a number of entities are counted more than once because they are registered under more than one category). The categories of registered entities are set out in the NERC registration process.¹²⁹ Registered entities are required to report the occurrence of defined bulk power system disturbances and unusual occurrences to the appropriate regional entity and to NERC. The regional entity and/or NERC, in turn, undertakes various levels of analysis to determine the causes of the events, assure tracking of corrective actions to prevent recurrence, gathers information needed to assess compliance, and provides lessons learned to the industry. The event analysis process also provides input for training and education, reliability trend analysis efforts and reliability standards development, all of which support continued reliability improvement. Under NERC's field trial of its event analysis program, the 2011 Southwest Cold Weather Events on February 2 and February 3¹³⁰ were classified as Category 4 due to the overall significance and impact of the event (loss of more than 5,000 MW but less than 10,000 MW of load or generation). Based on the scope of the needed analysis, and the fact that it impacted multiple regions, NERC determined that the event review should be coordinated at the NERC level.

¹²⁸ Troutman, Sanders, "Brief History of Mandatory Reliability Standard." (2009). <http://www.troutmansanders.com/tmapril2009-04/>. Accessed August 2012.

¹²⁹ (NERC) North American Electric Reliability Corporation "Updated Request to Identify Entities Responsible for Implementing Version 0 Standards," New Jersey, 2004. http://www.nerc.com/docs/standards/sar/Updated%20Req_to_Register_Entities_11-5-04.pdf. Accessed August 2012.

¹³⁰ (NERC) North American Electric Reliability Corporation Outages and Curtailments During the Southwest Cold Weather Event," New Jersey, 2011. http://www.nerc.com/files/SW_Cold_Weather_Event_Final_Report.pdf. Accessed August 2012.

NERC Rules and Standards

The electric power grid is used and relied on by all users and owners of the system. All users (generators and customers/loads) share the benefits of interconnected system operation. Reliability rules were established to assure that the activities of one user or control area do not adversely impact system reliability for other users or control areas.

Reliability rules require that control areas maintain a balance between generation and load, and they help maintain interconnection frequency. NERC's Control Performance Standards 1 and 2¹³¹ establish requirements for maintaining generation and load balance under normal conditions. The Disturbance Control Standard requires that control areas reestablish the generation-to-load balance within 15 minutes of the unexpected failure of a generator or transmission line. NERC also requires voltages to be maintained throughout the power system under normal and contingency conditions. For this purpose, NERC requires that control areas have reserves (extra generation, extra transmission capacity, and/or responsive load) ready to respond immediately when the need arises. These reserves can be obtained through markets, but they must be responsive to system operator commands.

The capacity available on the existing transmission system is governed by these reliability rules and the manner in which the grid is used to satisfy the growing and diverse demands placed on it. NERC has defined two primary levels of transmission service, firm and non-firm. *Firm* is defined as the highest quality (priority) service offered to customers under a field rate schedule. Firm customers expect to be treated on the same basis as other firm customers, including the native load of the transmission owner. *Non-firm* is defined as transmission service that is reserved on an as-available basis and is subject to curtailment or interruption. The designations and rules governing firm and non-firm transmission are contained in FERC's pro-forma OATT. As the name implies, entities scheduling power under firm transmission are given priority over those scheduled under non-firm transmission. During system events requiring curtailment of power schedules, non-firm transmission schedules are curtailed before those scheduled over firm transmission. If curtailment must be extended to firm transmission, NERC defines the criteria for curtailing firm transmission. In situations where interconnection-wide events require large-scale curtailment, NERC standards define the process.

To determine the priority within each category of service on the transmission system, transactions are identified by a tag, which uniquely identifies the transaction in terms of owner, time of schedule, source, and sink. These tags are used as input into NERC's Interchange Distribution Calculator (IDC),¹³² which serves to keep track of each transaction and determine, through sensitivity factors, effects on parallel paths from source to sink. These are used differently in the Eastern Interconnection, ERCOT, and WECC. Tags are initiated and processed in accordance with the North American Energy Standard Board (NAESB) business practice standards. Tags in the Eastern Interconnection are delivered to the IDC where they are used to

¹³¹ (NERC) North American Electric Reliability Corporation "Control Performance Standards," New Jersey. <http://www.nerc.com/docs/oc/ps/tutorcps.pdf>. Accessed August 2012.

¹³² (OATI) Open Access Technology International "Congestion Management." http://www.oatiinc.com/transmission_congestion_management.aspx/. Accessed August 2012.

implement the interconnection-wide Transmission Loading Relief (TLR) procedures specified in NERC’s standard IRO-006¹³³ and the NAESB business practice WEQ-008.¹³⁴

WECC, instead of using the IDC tool, uses the WECC Interchange Tool as the Tagging Authority Service for the Western Interconnection. The Texas Reliability Entity, areas in Texas use their own methodology based on ERCOT Operating Procedures.¹³⁵ A comparison of transmission scheduling is provided in Table 16.

Table 16. Comparison of Transmission Scheduling

TRANSMISSION SCHEDULING		
East	WECC	Texas (TRE, ERCOT)
e-Tag	e-Tag	e-Tag
IDC	WECC Interchange Tool	ERCOT Protocols
TLR	WECC Interchange Tool	ERCOT Protocols

Eastern Interconnection Transmission Loading Relief

During an event requiring execution of a TLR, NERC Standard IRO-006-EAST-1¹³⁶ provides for the following major actions:

- Inter-area redispatch of generation
- Intra-area redispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., demand-side management)
- Controlled load reductions (e.g., load shedding)

WECC Unscheduled Flow Mitigation

Similar to the TLR in the Eastern Interconnection, NERC has outlined a list of actions to be followed as provided in Table 17.

¹³³ (NERC) North American Electric Reliability Corporation “Standard IRO-006-3 — Reliability Coordination — Transmission Loading Relief,” New Jersey, 2006. <http://www.nerc.com/files/IRO-006-3.pdf>. Accessed August 2012.

¹³⁴ (NAESB) North American Energy Standards Board “Transmission Loading Relief – Eastern Interconnection,” United States, 2005. http://www.naesb.org/pdf2/weq_bklet_011505_tlr_numbering.pdf. Accessed August 2012.

¹³⁵ Texas Reliability Entity “Standards,” Texas, 2011. http://texasre.org/standards_rules/Pages/Default.aspx/. Accessed August 2012.

¹³⁶ (NERC) North American Electric Reliability Corporation “Standard IRO-006-EAST-1 — TLR Procedure for the Eastern Interconnection,” New Jersey, 2010. <http://www.nerc.com/files/IRO-006-EAST-1.pdf>. Accessed August 2012.

Table 17. WECC Actions under Unscheduled Flow Mitigation

STEP	ACTION DESCRIPTION	UNSCHEDULED FLOW ACCOMMODATION ACROSS PATH (First Contract Year / Second Contract Year / Third and Subsequent Contract Years)	EQUIVALENT PERCENT CURTAILMENT REQUIRED IN CONTRIBUTING SCHEDULE (Based on Amount of Unscheduled Flow across Path)				
			10–14%	15–19%	20–29%	30–49%	50+%
1	Operate controllable devices in path	N/A					
2	Accommodation	50 MW or 5% of maximum transfer limit					
3	Coordinated operation of qualified controllable devices	50 MW or 5% of maximum transfer limit					
4	First-level curtailment	50 MW or 5% of maximum transfer limit				10%	20%
5	Second-level curtailment	50 MW or 5% of maximum transfer limit			10%	15%	25%
6	Accommodation	75 MW or 6% of maximum transfer limit			10%	15%	25%
7	Third-level curtailment	50 MW or 5% of maximum transfer limit		10%	15%	20%	30%
8	Accommodation	100 MW or 7% of maximum transfer limit		10%	15%	20%	30%

Regional Entities

The NERC structure includes eight regional entities to allow a more local focus in improving the reliability of the grid. Membership in the regional entities is diverse and includes a wide range of participation, including investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal, and provincial utilities; independent power producers, power marketers, and end-user customers. The regional entities collectively account for virtually all of the electricity supplied in the United States, Canada, and part of Mexico.

Eastern Interconnection

The Eastern Interconnection covers the eastern half of the United States. There are six regional entities within the Eastern Interconnection. Each regional entity has multiple balancing authorities within its jurisdiction that are responsible for maintaining local reliability within their boundaries. In organized markets where ISO/RTOs are present, they often take on the responsibility of the balancing authorities, but not in all cases.

Northeast Power Coordinating Council

The NPCC covers New York and the six New England states, plus the Canadian provinces of Ontario, Quebec, New Brunswick, and Nova Scotia. It covers an area of nearly 1.2 million square miles with a population of more than 55 million people.¹³⁷ Within the NPCC, there are five balancing authorities, including the NYISO and the New England Independent System Operator (ISO-NE). The remaining three balancing authorities are Canadian.

¹³⁷ (NPCC) Northeast Power Coordinating Council “About NPCC,” New York, 2011. <https://www.npcc.org/About/default.aspx/>. Accessed August 2012.

NPCC Directories are currently being developed to demonstrate that NPCC regional criteria and standards are consistent with NERC reliability standards. The Directories will provide a consistent and comprehensive set of reliability requirements for the NPCC region to replace the current system of A, B, and C documents.¹³⁸ The development of the Directories will be shared with other regional entities that participate in an open and inclusive process for developing and reviewing the criteria documents.

Midwest Reliability Organization

The Midwest Reliability Organization (MRO) covers approximately 1 million square miles and 20 million people including the states of North Dakota, Minnesota, Nebraska and the majority of the states of South Dakota, Iowa, and Wisconsin and the Canadian provinces of Saskatchewan and Manitoba.¹³⁹ Within the MRO, there are 17 balancing authorities located in the United States, none of which are ISO/RTOs. The balancing authorities are a mix of investor-owned and publicly owned utilities including some regional power districts.

The MRO has approved a number of regional standards, but these standards have not yet been approved by NERC and FERC and are not mandatory at this point in time. Once approved by the regional entities, however, they are considered good utility practice and are often cited in contractual arrangements within the regional entities footprint. There are currently no MRO-approved standards that address renewable resources specifically.

Reliability First Corporation

The Reliability First Corporation (RFC) covers the upper middle eastern part of the United States with 13 balancing areas, including the Midwest Independent System Operator (MISO) and the PJM RTO. It includes the service territories of the load serving entities within the states of New Jersey; Delaware; Pennsylvania; Maryland; District of Columbia; West Virginia; Ohio; Indiana; Lower Michigan; and portions of Upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee, and Virginia. Similar to the MRO, the balancing areas in the RFC are a combination of investor-owned and publicly owned utilities.

RFC currently has one fully approved and mandatory standard (BAL-RFC-02)¹⁴⁰ addressing Resource Adequacy. BAL-RFC-02 requires that the modeling characteristics of “energy limited resources such as wind” are submitted to the RFC. RFC also has one standard that addresses renewable resources, with specific operating requirements (MOD-25-RFC-01)¹⁴¹ and another with reporting requirements (MOD-24-01_1).¹⁴²

¹³⁸ (NPCC) Northeast Power Coordinating Council “Directory Development and Revision Manual,” New York, 2011.

<https://www.npcc.org/Standards/Directories/NPCC%20Directory%20Development%20Manual%20Final%20%20Nov%208%202011%20GJD.pdf>. Accessed August 2012.

¹³⁹ (MRO) Midwest Reliability Organization “MRO Manual,” United States.

http://www.midwestreliability.org/01_about_mro/overview/mro_manual/1_Introduction.pdf. Accessed August 2012.

¹⁴⁰ Reliability First “Standards,” Ohio, 2011. <https://rfirst.org/standards/Pages/ApprovedStandards.aspx/>. Accessed August 2012.

¹⁴¹ Ibid.

¹⁴² Ibid.

SERC Reliability Corporation

SERC Reliability Corporation¹⁴³ is responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states. The SERC Region covers approximately 560,000 square miles and occupies the southeastern portion of the United States (excluding Florida), with 30 separate balancing authorities in its footprint. The balancing authorities represent a combination of investor-owned and publicly owned utilities, but no ISOs/RTOs exist within SERC.

SERC currently has one standard addressing automatic under frequency load shedding (PRC-006-SERC-01)¹⁴⁴ in the internal approval process. This draft standard does not address renewables specifically.

Florida Reliability Coordinating Council

The FRCC includes the regional entities for the State of Florida only and is comprised of 11 separate balancing authorities. No ISOs/RTOs exist within the footprint of FRCC. Many of the balancing authorities are publicly owned, but there are a few investor-owned utilities.

FRC currently has no standards approved by NERC and FERC, and it has no standards currently active within the standards approval process.

Southwest Power Pool

The Southwest Power Pool is both a regional reliability organization and an ISO, but unlike most ISOs, it does not act as the balancing authority for the region. There are 17 separate balancing authorities within the SPP footprint, representing a combination of investor-owned and publicly owned utilities. SPP provides reliability, tariff administration OATT, and scheduling for its members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP also provides transmission expansion planning and market operation for energy imbalance service.

SPP currently has one standard under development (PRC-006-SPP-01)¹⁴⁵ for under frequency load shedding.

Western Electricity Coordinating Council

WECC is unique among NERC regions in that it is substantially larger, including all or portions of 14 U.S. states as well as portions of Western Canada and northern Baja del Norte, Mexico, within the entire synchronous interconnection. This assessment considers the operation and interconnection processes only within in the U.S. portion of WECC, ignoring Canada and Mexico. While these regions are operationally a portion of WECC, the transmission interconnection and ratemaking processes are different than those in the United States.

Whereas in other NERC regions, policies are implemented directly by the regional entities, in WECC, many of the operations policies are implemented on a sub-regional basis through six sub-regional reliability councils. These sub-regional councils depicted in Figure 18. Within WECC and the sub-regional areas, most of the balancing authorities are large, vertically

¹⁴³ (SERC) Southeast Reliability Corporation “Welcome to SERC,” United States. <http://serc1.org/Application/HomePageView.aspx/>. Accessed August 2012.

¹⁴⁴ (SERC) Southeast Reliability Corporation “Standards,” United States, 2011. <https://serc.centraldesktop.com/standardhomepage/doc/10285789/w-SercRegionalStandards/>. Accessed August 2012.

¹⁴⁵ (SPP) Southwest Power Pool “Regional Standard Under Development: PRC-006-SPP-01 - Under Frequency Load Shedding,” United States, 2012. <http://www.spp.org/section.asp?pageID=101/>. Accessed August 2012.

integrated utilities, with only one ISO, the CAISO operating within the WECC in the United States.

This assessment reviews the transmission, operation, and interconnection processes for the WECC as a whole, with the notable exception of California. California will be considered independently from the WECC for several reasons. As already mentioned, California is unique insofar as it has an ISO controlling its transmission operation for investor-owned utilities in the state: Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. The ISO does not extend to the publicly owned utilities in the state, primarily the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District and Imperial Irrigation District, which represent approximately 40% of the state's energy demand and requirements.

In addition to having the only ISO in WECC, California is a major driver for transmission development in the WECC. It is a major load sink for both conventional and renewable generation, importing vast quantities of energy from throughout the Western United States. Since it imports much of its energy requirements, proposed transmission in the West is often geared to deliver energy to California. Finally, California's demand for renewable energy has drawn a large number of projects seeking to interconnect to the WECC grid and deliver energy to California.

Texas Regional Entity

Texas Reliability Entity is authorized by NERC to develop, monitor, assess, and enforce compliance with NERC Reliability Standards within the geographic boundaries of the ERCOT region. In addition, Texas Reliability Entity has been authorized by the Public Utility Commission of Texas to maintain Texas State reliability requirements. Texas Reliability Entity is independent of all users, owners, and operators of the bulk power system.

The regional entity functions and protocol compliance were previously performed by Texas Regional Entity, a functionally independent division of the ERCOT. Texas Reliability Entity took over all responsibilities of Texas Regional Entity on July 1, 2010. Texas Reliability Entity¹⁴⁶ performs the regional entity functions described in Section 215 of the EPCRA 2005 for the ERCOT region, as mandated by the FERC-approved delegation agreement with NERC. Texas Reliability Entity is a non-profit corporation with voluntary membership consisting of owners, users, and operators of the Bulk Electric System. Texas Reliability Entity members have membership in one of six industry sectors: System Coordination and Planning, Transmission and Distribution, Cooperative Utility, Municipal Utility, Generation, or Load-Serving and Marketing.

Enforcement

Because the Texas Reliability Entity is authorized by NERC to enforce compliance with NERC reliability standards, possible NERC standard violations may be identified by the entity itself by self-reports, exception reports, or as part of a self-certification or periodic data submission. NERC standard violations may also be discovered by Texas Reliability Entity during an audit or spot check, or during the course of a compliance violation investigation. Others may report a NERC standard violation through an incident report.

In addition, Texas Reliability Entity is permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides, working with Texas PUC staff regarding any potential

¹⁴⁶ Texas Reliability Entity (2012) Texas 2012. <http://www.texasre.org/Pages/Default.aspx/>. Accessed August 2012.

protocol violations. Possible violations of the ERCOT Protocols and/or Operating Guides may be reported by the entity itself during a self-certification or periodic data submission, discovered by Texas Reliability Entity during an audit or investigation, or reported through a complaint.

Texas Reliability Entity validates all alleged violations of NERC standards and/or ERCOT Protocols and Operating Guides. Texas Reliability Entity conducts an internal, independent review of the evidence before deciding on a course of action.

Enforcement of NERC Reliability Standards

After Texas Reliability Entity issues a “Notice of Possible Violation” to a NERC-registered entity, the entity has 30 days to submit a mitigation plan. Submitting a mitigation plan is not considered to be an admittance of guilt. The entity should preserve all relevant documentation, and the process is considered to be confidential.

When Texas Reliability Entity issues a “Notice of Alleged Violation,” Texas Regional Entity includes a penalty, which may be monetary or non-monetary, and which may include remedial actions to be taken. The entity may accept or contest the penalty; if contested, the entity may attempt to reach a settlement with Texas Regional Entity at any time.

A “Notice of Confirmed Violation,” or NOCV, is issued if the entity has not responded to the NAVAPS within 30 days, if the entity has accepted the violation and penalty, or if the entity has completed the appeals process with NERC. A “Notice of Penalty” is then issued, filed by NERC with the FERC, and posted on the NERC site.

Enforcement of ERCOT Protocols

Texas Reliability Entity has been authorized by the Texas PUC to investigate compliance with the ERCOT Protocols and Operating Guides, working with Texas PUC staff regarding any potential protocol violations. The Texas PUC oversees the enforcement process.

When Texas Reliability Entity issues an “ERCOT Protocol Compliance Violation” or an “ERCOT Operating Guide Compliance Violation,” a market participant has 10 days to contest, accept, or supply additional information, and 30 days to supply a mitigation plan to Texas Reliability Entity. After reviewing, Texas Reliability Entity will accept or deny the mitigation plan, and Texas Reliability Entity will also confirm that the mitigation plan has been completed. The Texas PUC determines a penalty, if necessary.

Redispatch ISOs and RTOs

In areas where there are organized markets, ISOs and RTOs have formed.

New York Independent System Operator

The NYISO¹⁴⁷ is the balancing and electric power market operator for the state of New York. It performs a central economic dispatch for New York and operates the transmission system within the state. The NYISO is a balancing authority within NPCC.

The NYISO is responsible for the reliable operation of the New York electric system. It does not issue reliability standards. Rather, regional reliability rules for New York are developed and maintained by the New York State Reliability Council (NYSRC). The NYSRC also monitors compliance in conjunction with the NYISO and, when necessary, ensures compliance through a

¹⁴⁷ New York Independent System Operator, “NYISO,” New York 2012. <http://www.nyiso.com/public/index.jsp/>. Accessed August 2012.

dispute resolution procedure as part of its agreement with the NYISO. The reliability rules developed by NYSRC are more stringent than NPCC and NERC standards and criteria.

The NYISO has adopted procedures for both reliability transmission planning and economic transmission planning.¹⁴⁸ The NYISO Comprehensive Reliability Planning process¹⁴⁹ begins with input from the Local Transmission Owner Planning Process, which assesses each of the eight utility transmission owners in the state on a 2-year cycle and adheres to the applicable criteria of NERC, NPCC, and NYSRC. The economic planning process (Congestion Assessment and Resource Integration Study)¹⁵⁰ issued its first report in 2010. The Congestion Assessment and Resource Integration Study is a two-phase process in which Phase 1 assesses the historic and future congestion on the New York State bulk power transmission system over a 10-year horizon and provides an analysis of the potential costs and benefits of relieving that congestion. In Phase 2, developers can propose transmission projects for evaluation of their potential economic benefits in relieving congestion. The NYISO analyzes each proposal to determine benefits and whether the proposed transmission project should proceed through a stakeholder voting process and have its costs recovered through the NYSIO Tariff.

PJM Interconnection

PJM is an RTO with responsibility for all or a portion of 13 states and the District of Columbia. PJM manages the electric power grid and the wholesale electricity market within its footprint and is a balancing within RFC. PJM began as a power pool and transitioned to an ISO in 1997 and became an RTO in 2001.

PJM has implemented a Regional Transmission Expansion Plan process that identifies transmission system upgrades and enhancements to provide for the operational, economic, and reliability requirements of the PJM system. The process considers generation and load response projects as part of the overall transmission needs over a 15-year planning horizon. Transmission upgrades to mitigate identified reliability criteria violations are evaluated for feasibility, impact, and cost over the entire PJM footprint. PJM has a separate process for evaluating Merchant Transmission as outlined in PJM Manual M-14C.¹⁵¹

New England Independent System Operator

ISO-NE¹⁵² is an RTO, but maintains its ISO name. It is responsible for a six-state area covering New England, with the responsibility for operation of the transmission system and wholesale electric power market within its footprint. ISO-NE is registered as a balancing authority under NERC. ISO-NE is responsible for transmission planning and issues an annual report (CELT),¹⁵³

¹⁴⁸ New York Independent System Operator, “Planning Studies,” New York, 2012.

http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp/. Accessed August 2012.

¹⁴⁹ New York Independent System Operator, “Comprehensive Reliability Planning Process Manual,” New York, 2007. <http://www.nyiso.com/public/webdocs/documents/manuals/planning/CRPPManual120707.pdf>. Accessed August 2012.

¹⁵⁰ New York Independent System Operator, “Initial Manual Congestion Assessment And Resource Integration Study,” New York, 2010. http://www.nyiso.com/public/webdocs/committees/bic/meeting_materials/2010-07-14/Agenda_10_Initial_CARIS_Manual_07_14_2010_BIC.pdf. Accessed August 2012.

¹⁵¹ PJM “PJM Manual 14C Generation and Transmission Interconnection Facility Construction,” United States, 2012. <http://www.pjm.com/~media/documents/manuals/m14c.ashx/>. Accessed August 2012.

¹⁵² (ISO NE) Independent System Operator New England, 2012. <http://www.iso-ne.com/>. Accessed August 2012.

¹⁵³ (ISO NE) Independent System Operator New England, “CELT,” New England, 2012. <http://www.iso-ne.com/trans/ceLT/>. Accessed August 2012.

which identifies capacity and transmission requirements within its footprint. ISO-NE has a somewhat de-centralized planning process. The generation and transmission additions or changes are submitted to ISO-NE under a formal Proposed Plan Application for review by the ISO Reliability Committee. The ISO supplies the Reliability Committee with a statement of its recommendation or the recommendation of any applicable task force. The Reliability Committee may defer action, recommend approval by the ISO, or recommend disapproval by the ISO. Applications are to be submitted no more than 5 years prior to the in-service date, without mitigating circumstances.

Midwest Independent Transmission System Operator

The MISO¹⁵⁴ is an RTO serving all or parts of 13 states and the Canadian province of Manitoba. The MISO operates the grid and power markets within its footprint. This includes reliability coordination and regional planning services. MISO handles generation interconnection, maintenance coordination, market monitoring, and dispute resolution. The MISO acts as the regional balancing authority, instructing local balancing authorities on operation of resources. The MISO develops an annual MISO Transmission Expansion Planning report, which identifies regional transmission expansion needs and operates an OASIS for long-term transmission reservations time. The MISO may experience a large addition in membership with the addition of the Entergy companies, who announced their intention to join MISO and become integrated by the end of 2013. If the Entergy companies join MISO, MISO may form MISO South to accommodate Entergy.

Southwest Power Pool

SPP¹⁵⁵ is both a regional entity and an ISO, but unlike most ISOs, it does not act as the balancing authority for the region. There are 17 separate balancing authorities within the SPP footprint, representing a combination of investor-owned and publicly owned utilities. SPP provides reliability, tariff administration OATT, and scheduling for its members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. SPP also provides transmission expansion planning and market operation for energy imbalance service and is in the process of implementing a full market structure.

SPP currently has one standard under development (PRC-006-SPP-01)¹⁵⁶ for under frequency load shedding. It does not specifically address renewable resources.

SPP has recently developed the Integrated Transmission Plan,¹⁵⁷ which is a reliability-based plan for incremental transmission additions and a strategic 20-year plan. As part of the initial start of the plan, SPP will develop a 10-year and a near-term transmission needs assessment. The driver for the Integrated Transmission Plan process is the SPP Transmission Expansion Plan (STEP),¹⁵⁸

¹⁵⁴ MISO Energy “Midwest Independent System Operator,” United States, 2012.

<https://www.misoenergy.org/Pages/Home.aspx/>. Accessed August 2012.

¹⁵⁵ (SPP) Southwest Power Pool, United States, 2012. <http://www.spp.org/>. Accessed August 2012.

¹⁵⁶ (SPP) Southwest Power Pool “Regional Standard Under Development: PRC-006-SPP-01 Under Frequency Load Shedding,” United States, 2012. <http://www.spp.org/section.asp?pageID=101/>. Accessed August 2012.

¹⁵⁷ (SPP) Southwest Power Pool “Integrated Transmission Planning,” United States, 2012.

<http://www.spp.org/section.asp?pageID=129/>. Accessed August 2012.

¹⁵⁸ (SPP) Southwest Power Pool “SPP Transmission Expansion Plan Report,” United States, 2012.

http://www.spp.org/publications/2012-01-18_2012%20STEP%20Report%20Filing_07-00390-UT.pdf. Accessed August 2012.

which summarizes activities that impact future development. Core areas addressed by STEP are as follows:

- Regional reliability
- Tariff studies to meet Transmission Service Requests
- Sub-regional and local area planning
- Transmission congestion and the ten most constraining flowgates
- Interregional coordination
- Integrated transmission planning and priority projects
- Project tracking

The STEP process is independent of SPPs duties as a regional entity of the North American Electric Reliability Corporation.

California Independent System Operator

The CAISO is responsible for the reliability of the transmission grid for the transmission owners for the investor owned utilities within California. The CAISO controls approximately 60% of the total California grid, while the remaining grid and energy deliveries are managed by municipal balancing authorities, such as the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District. The CAISO does not own any transmission and is not responsible for interconnecting into the investor-owned utility distribution system, or the operation of the distribution system. The CAISO is responsible for the interconnection of renewable resources to the transmission system within its jurisdiction.

Renewable Integration and Planning

With California having the most aggressive renewable portfolio standard in the United States, there are many challenges the CAISO faces with respect to the integration of renewables. Many of the state's base load generation are anticipated to be replaced by renewables by 2020.

As the tax incentives in the United States made wind and solar more affordable and created a policy-driven influx of interconnection resources, the CAISO has run into even more issues with integration. On a 33% target, only approximately 25% of the projects within the CAISO queue are required to meet 33%. Designing a system to facilitate more than 70,000 MW of generation can cause substantial issues, and changes the current nature of energy flows within the state. If all of the generation in the queue were to be interconnected, California would substantially exceed its load, and be forced to either curtail or export excess generation.

To study and design the current transmission system for the impending influx of generation, the CAISO has worked with the state utilities and stakeholders to develop a transmission plan that would facilitate the 33% renewables goal, while maintaining reliable operation of the transmission system. There are currently 33 transmission network upgrades approved by the CAISO based on studies implemented by the Renewable Energy Transmission Initiative and the California Transmission Planning Group. Even with these studies, the CAISO is continuing to study impacts of new projects and the renewable resource mix anticipated in the future, which could take advantage of energy storage and co-location of renewable resources.

Interconnection of Renewables

FERC mandates that transmission cannot be overbuilt for anticipated generation, so every interconnection studied by the CAISO prior to 2008 was done serially. This resulted in a slower process and a backlog of projects anticipating network upgrades to allow for delivery of the project. In 2008, the CAISO moved forward in implementing a cluster study to study the impact of multiple projects within a specific area. This process would allow for the CAISO to assign the cost of substantial network upgrades to multiple projects to facilitate the delivery of generation resources within the state.

There are numerous maps in each of the investor-owned utilities depicting information on locating renewables more effectively due to available transmission capacity. Transmission ranking cost reports released by each investor-owned utility show the available transmission capacity at large delivery substations. These maps allow renewable resources to utilize the existing transmission capacity more efficiently. These maps and transmission ranking cost reports can be found at the following websites for the following investor-owned utilities:

- Pacific Gas & Electric
 - Map: <http://www.pge.com/b2b/energysupply/wholesaleelectricssolicitation/PVRFO/pvmap/>
 - Transmission ranking cost reports: http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricssolicitation/RPS/RenewablePortfolioStdsOIR-III-Admin_Other-Doc_PGE_20100120-01%5B1%5D.pdf
- Southern California Edison
 - Map: <http://www.sce.com/EnergyProcurement/renewables/spvp-ipp/spvp-ipp.htm>
 - Transmission ranking cost reports: http://asset.sce.com/Documents/Shared/2011_SCERFPSCE_s_TransmissionRankingCostReport.pdf
- San Diego Gas & Electric
 - Map: <http://sdge.com/builderservices/dgmap/>
 - Transmission ranking cost reports: <http://www.sdge.com/regulatory/documents/r-06-05-027/svcTRCRFiling.pdf>

Transmission Access

To sell power to the market, there are many options for renewable resources. There are programs specifically for the Renewable Portfolio Standards within the investor-owned utilities to gain a power purchase agreement, as well as congestion revenue rights that can be purchased to gain transmission access in the CAISO market.

There are multiple programs for transmission access within each of the California investor-owned utilities. Each of them has Rule 21 Interconnection procedures, such as the Southern California Edison Crest Program¹⁵⁹ and the Pacific Gas & Electric Solar Photovoltaic Power Purchase Agreement Program.¹⁶⁰ There are also Renewable Portfolio Standard Request for

¹⁵⁹ (SCE) Southern California Edison “Renewable and Alternative Power – CREST Program,” California, 2012. <http://www.sce.com/EnergyProcurement/renewables/crest.htm/>. Accessed August 2012.

¹⁶⁰ (PG&E) Pacific Gas & Electric Program “2011 Solar Photovoltaic Program,” 2011. <http://www.pge.com/b2b/energysupply/wholesaleelectricssolicitation/PVRFO/>. Accessed August 2012.

Offers for wholesale generation. Each of the investor-owned utilities has a Renewable Portfolio Standard Request for Offers for 2011.^{161, 162}

Available Transfer Capacity Rating Methodology

NERC requires that each Transmission Operator (TOP) select one of the following three methodologies for calculating ATC:

- The Area Interchange Methodology, MOD-028¹⁶³
- The Rated System Path Methodology, MOD-029¹⁶⁴
- The Flowgate Methodology, MOD-030¹⁶⁵

The CAISO uses the Rated System Path Methodology (MOD-029) for all ATC paths within its area.

Balancing Authorities Not Under RTO/ISO Jurisdiction

The Western Interconnection is substantially different than the Eastern Interconnection, as it does not have many ISOs or RTOs. The majority of the utilities are also their own balancing authority. Each of these balancing authorities has its own standards and operates differently, but still adheres to FERC regulations.

The Los Angeles Department of Water and Power is one of the larger municipal utilities in California, serving customers in the Los Angeles Basin. It acts as its own balancing authority, and imports its power from utilities such as Southern California Edison and San Diego Gas & Electric. Although it is not part of the CAISO, it is directly affected by changes to transmission within the CAISO.

BPA is a federal utility that operates a substantial amount of wind and hydro in the Northwest United States. One important difference with the BPA is that it has “environmental curtailment,” which allows it to curtail generation (specifically wind) due to dams overflowing and hydro needing to be used. The policies surrounding the environmental dispatch have been debated recently,¹⁶⁶ as a substantial quantity of wind generation was curtailed for this very reason. In times of curtailment, there may be other ways to plan system dispatch and overflowing of dams in heavy rain or snow melt periods, as well as enable various resource mixes to firm and shape intermittent generation to facilitate the full utilization of existing transmission.

¹⁶¹ (PG&E) Pacific Gas & Electric Program “2011 Renewables,” 2011.

<http://www.pge.com/b2b/energysupply/wholesaleelectricssuppliersolicitation/renewables2011/index.shtml/>. Accessed August 2012.

¹⁶² San Diego Gas and Electric Company “2011 Renewables Portfolio Standards Solicitation,” California, 2011. <http://www.sdge.com/rfo/renewable2011/index.shtml/>. Accessed August 2012.

¹⁶³ (NERC) North American Energy Reliability Corporation “Standard MOD-028-2 — Area Interchange Methodology,” New Jersey, 2012. <http://www.nerc.com/files/MOD-028-2.pdf>. Accessed August 2012.

¹⁶⁴ (NERC) North American Energy Reliability Corporation “Standard MOD-029-1a — Rated System Path Methodology,” New Jersey. <http://www.nerc.com/files/MOD-029-1a.pdf>. Accessed August 2012.

¹⁶⁵ (NERC) North American Energy Reliability Corporation “Standard MOD-030-02 — Flowgate Methodology,” New Jersey, 2009. <http://www.nerc.com/files/MOD-030-2.pdf>. Accessed August 2012.

¹⁶⁶ BPA Transmission Services Business Practices “Environmental Redispatch Version 3,” 2011. http://transmission.bpa.gov/ts_business_practices/Content/9_Redispatch_and_Curtailment/Environmental_Redispatch.htm/. Accessed August 2012.

Methods to Utilize Current Capacity

As there are many different programs and interconnection standards across the WECC, questions on how to reliably utilize the existing transmission system without substantial transmission expansion are posed.

First, current planning methodologies may need to be updated to fully appreciate resource diversity. Within the CAISO, there are many microclimates that may make it difficult to fully understand peak load situations. For instance, in the middle of August, it may be extremely hot in southern California, but temperatures remain lower in parts of Pacific Gas & Electric territory. To assume peak loads, at times in Pacific Gas & Electric that may see heavy fog, can be incorrect. Also, wind profiles and solar profiles can be extremely different at 3:00 p.m. on a hot summer day, as the wind does not typically blow during these times, but solar is at peak. In California, some wind tends to peak later in the evening, which makes co-location of resources extremely attractive. Is it fair then, to assume full capacity at summer peak for both of these resources? Is this “gold plating” the transmission system? With California being a key leader in renewable resource development and having aggressive Renewable Portfolio Standard targets, it behooves the industry to fully understand the implication. Currently, all of the investor-owned utilities within California have signed power purchase agreements to meet the 33% goal. To reach this goal, it is estimated that approximately 30 GW of renewable resources are required. Within the CAISO queue and investor-owned utilities wholesale distribution access generator interconnection queues, approximately 100 GW of generation is proposed to interconnect within the next 7 years. The majority of this is renewable generation. This results in more than 50% of these projects not getting built, but currently the transmission system is being designed to facilitate the full 100 GW of new generation. Looking into specific areas of the state, it may be pertinent to understand the amount of project failure within each area of interconnection study (clustering). If a multiplier, of sorts, was assigned to specific resource types based on capacity factors and project failure, a more realistic picture can be painted, and only imperative transmission projects would be proposed to offer reliability.

Second, FERC requires that transmission projects be “used and useful.” This requirement ties the hands of the utilities to be able to reliably interconnect generation projects. Certain projects may not be necessary if utilities could loop existing transmission into “trunk lines” or large generation tie lines to facilitate the delivery of large quantities of generation (an example of this is the Tehachapi Project). Doing this would allow utilities to fully utilize existing transmission and reliably integrate renewables where there is substantial base load or even hydro to offset off-peak generation.

Third, there are currently no incentives to promote energy storage for generator interconnection projects. If there were incentives for renewable energy projects to install and utilize energy storage devices in times of over-generation or shoulder peak, transmission could be utilized more fully, and utilities could redispatch more cost-effective solutions during peak time, while also fully utilizing the transmission system to transmit power to serve load.

Comparison of ISO/RTO

As the various ISOs and RTOs have matured, they have tended to offer similar features and services. This is due in part with the fact that FERC has played a significant role in defining the necessary components for a reliable grid and efficient and competitive markets. Table 18 compares the various functions played by the eight ISO/RTOs with respect to transmission planning and NERC functionality.

Table 18. ISO/RTO Comparison

			NERC			RELIABILITY	ECONOMIC
	Multi-state	FERC	Regional	Regional	NERC	Planning	Planning
ISO/RTO		Jurisdictional	Region	Location	Classifications	Process	Process
NYISO	No	Yes	No	NPCC	BA, IA, PA, RC, RP, TP, TOP, TSP	Yes	Yes
PJM	Yes	Yes	No	RFC, SERC	BA, IA, PA, RC, RP, TP, TOP, TSP	Yes	Yes
ISO-NE	Yes	Yes	No	NPCC	BA, IA, PA, RC, RP, TP, TOP, TSP	Yes	No
MISO	Yes	Yes	No	MRO, RFC, SERC	BA, IA, PA, RC, TSP, CFR	Yes	Yes
SPP	Yes	Yes	Yes	MRO, SERC, SPP	IA, PA, RC, RSG, TP, TSP	Yes	No
CAISO	No	Yes	No	WECC	BA, PA, TOP, TSP	Yes	Yes
ERCOT	No	No	Yes	ERCOT	BA, IA, PA, RS, RP, TOP, TSP	Yes	Yes

Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing area, and supports Interconnection
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid balanced interchange schedules between BA areas, and ensures communication of Interchange information for reliability assessment purposes
Planning Authority	PA	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become an RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PA area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

Appendix B: Additional Policy Details

In 1992 the EPAct¹⁶⁷ gave FERC “wheeling authority” and created a new category of electricity manufacturer: exempt wholesale producers. Additional details of U.S. regulations relevant to the transmission system are included in this appendix.

Congestion Management

NERC reliability standards¹⁶⁸ require the establishment of operating plans, monitoring of the system, and mitigation of limit violations through operational actions. These may include implementing redispatch of system resources and facilities. The ERCOT Nodal¹⁶⁹ electricity market construct provides for meeting reliability requirements through a robust system of operating actions that use ancillary services in dispatch actions by the ERCOT ISO. Ancillary services are procured and deployed through a comprehensive market system to ensure reliable operations in accordance with the NERC reliability standards, as well as with ERCOT’s Protocols¹⁷⁰ and Nodal Operating Guides.¹⁷¹ ERCOT uses a centralized energy dispatch process and applies Equipment Operating Ratings and Limits, described in the Protocols.

ERCOT market dispatch is done using the energy dispatch process according to the Protocols. Market-based congestion management techniques are embedded in a Security Constrained Economic Dispatch process.

Situations where the market system fails to reach a solution are considered failure(s) of the Security Constrained Economic Dispatch process and a reason for an Emergency Notice. Typically, actions taken for transmission loading relief, which are subject to this standard, are within the context of an Emergency Notice. Such actions may include: (1) system reconfiguration (pre- and post-contingency); (2) non-synchronous transfer of load to other systems not within the ERCOT Interconnection; and (3) a reduction of interruptible or firm loads.

System Assessment and Transmission Planning

Long-Term System Assessment 10-year view

ERCOT conducts a Long-Term System Assessment that does not provide specific recommendations. It is intended to inform the 5-year planning process by providing a longer term view of system reliability and indicates system needs that require solutions that will take longer than 5 years to implement. The study consists of two parts: (1) an analysis of the reliability needs of the system based on peak load system conditions and (2) an evaluation using scenario analysis of the cost-effectiveness of potential economic projects to improve system efficiency.

¹⁶⁷ U.S. Department of Energy “Energy Policy Act of 1992,” United States, 2009.

<http://www1.eere.energy.gov/femp/regulations/epact1992.html/>. Accessed August 2012.

¹⁶⁸ (NERC) North American Energy Reliability Corporation “Reliability Standards,” Washington, D.C., 2012. <http://www.nerc.com/page.php?cid=2%7C20/>. Accessed August 2012.

¹⁶⁹ (ERCOT) Electric Reliability Council of Texas “About Texas Nodal,” Texas, 2008. <http://nodal.ercot.com/about/index.html/>. Accessed August 2012.

¹⁷⁰ (ERCOT) Electric Reliability Council of Texas “Current Protocols – Zonal,” Texas, 2010. <http://www.ercot.com/mktrules/protocols/current/>. Accessed August 2012.

¹⁷¹ (ERCOT) Electric Reliability Council of Texas “Nodal Operating Guides,” Texas, 2011. <http://www.ercot.com/mktrules/guides/noperating/>. Accessed August 2012.

Transmission Planning Process

As the transmission planning authority for the region, ERCOT works with the region's transmission and distribution providers and other stakeholders to identify the need for new transmission facilities based on engineering analysis of operational results, load forecasting, generation interconnections, and transmission and system studies. As part of the planning process, ERCOT seeks input from all market participants and stakeholders about options and possible solutions through the ERCOT-led Regional Planning Group. Major projects must also be endorsed by the ERCOT Board of Directors.

To provide transmission customers with more information and clarity on the workings of a transmission provider's system, all transmission providers must include a coordinated regional planning process plan as Attachment K to the revised OATT. The planning process may vary depending on the region, but must include all nine FERC-mandated principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

Available Transfer Capability

In Order No. 888, FERC did not prescribe a calculation for ATC. Under Order No. 890, FERC now requires that the calculations and procedures used to determine ATC be transparent and consistent to reduce opportunities for undue discrimination. Transmission providers will need to include, as Attachment C in all OATT filings, the NERC methodology used to calculate ATC (i.e., contract path, network ATC, or network AFC),¹⁷² a process flow diagram that describes the various steps in performing the ATC calculation, and a definition and explanation of each ATC component (i.e., Total Transfer / Flowgate Capabilities), Existing Transmission Commitments, Capacity Benefit Margin, and Transmission Reserve Margin). The algorithm used to determine ATC must be provided on the transmission provider's website.

Creditworthiness

FERC found that a transmission provider's credit standards significantly affect transmission service. Therefore, each transmission provider must include the qualitative and quantitative criteria used to determine the level of secured and unsecured credit required from customers in a new OATT Attachment L.¹⁷³ Attachment L must include: (1) a summary of procedures for determining the level of secured and unsecured credit; (2) a list of acceptable types of collateral/security; (3) procedures for providing customers with reasonable notice of changes in credit levels and collateral requirements; (4) procedures for providing upon request a written explanation for any change in credit levels or collateral requirements; (5) reasonable opportunities to contest determinations of credit levels or collateral requirements; and (6) reasonable opportunities to post additional collateral, including curing any non-creditworthy determinations.

Energy and Generator Imbalances

Finding previous imbalance charges "excessive, too varied, and otherwise unrelated to the cost of providing the service," FERC adopted the following tiered charges for energy and generator imbalances:

¹⁷² (NERC) "Standard MOD-001-0 — Documentation of TTC and ATC Calculation Methodologies," New Jersey, 2005. <http://www.nerc.com/files/MOD-001-0.pdf>. Accessed August 2012.

¹⁷³ (FERC) Federal Energy Regulatory Commission "FERC Order 890-A Preventing Undue Discrimination and Preference in Transmission Service," United States, 2007. <http://www.ferc.gov/whats-new/comm-meet/2007/122007/E-1.pdf>. Accessed August 2012.

- *Tier 1 – Imbalances of less than or equal to 1.5% of scheduled transmission (or 2 MW, whichever is larger):* 100% of transmission provider’s incremental cost for under-scheduling imbalances or decremental cost for over-scheduling imbalances
- *Tier 2 – Imbalances greater than 1.5% and up to 7.5% of scheduled transmission:* Charges of 90% of a transmission provider’s decremental cost for over-scheduling imbalances; 110% of incremental cost for under-scheduling imbalances
- *Tier 3 – Imbalances above 7.5% of scheduled transmission:* Charges of 75% of a transmission provider’s decremental cost for over-scheduling imbalances; 125% of incremental cost for under-scheduling imbalances.

FERC exempted intermittent resources from the highest deviation band (Tier 3) to not unduly penalize these resources. FERC declined to modify intra-hour netting procedures, but limited its use to Tier 1 imbalances only. FERC also declined to abrogate existing generator imbalance agreements, but invited any party desiring an amendment to “exercise whatever rights it may have under the agreement or FPA section 206.”

In a change from Order No. 888, unreserved use and imbalance penalty revenue is to be distributed to all non-offending transmission customers, including affiliated customers. Transmission providers are to determine a nondiscriminatory payment mechanism to the extent the unreserved use penalty revenue accrues above the transmission provider’s base firm point-to-point transmission service charge or the imbalance penalty revenue accrues above the provider’s incremental cost.

Transmission Credits for Integrated Facilities

While keeping the general transmission credits structure the same, FERC eliminated the requirement that transmission facilities funded by network customers must be part of a provider’s “joint planning” process to be eligible for credits. The joint planning requirement created a disincentive for transmission providers to coordinate planning of facilities. Now, facilities need only be integrated with a transmission provider’s system to be eligible for credits. Facilities are presumed integrated if they are: (1) owned by the provider and (2) eligible for rate recovery by such provider. This standard applies only to transmission facilities added after the effective date of Order 890.

Transmission Capacity Reassignment

FERC lifted the price cap on the reassignment of point-to point service for all customers to eliminate what it considers an unnecessary impediment to the resale of transmission capacity. FERC declined to retain the price cap for a transmission provider’s merchant function and affiliates as originally proposed in Order 890’s Notice of Proposed Rulemaking. Any such reassignments must be reported on OASIS before the effective date of such assignment and aggregated in a quarterly report made by the transmission provider to FERC. The transmission assignee must execute a service agreement with the original transmission provider that will govern the service being assigned.

Changes to Long-Term Firm Point-to-Point Service – Redispatch and Conditional Firm

FERC concluded in Order 890 that the existing methodologies for evaluating requests for long-term, firm, point-to-point services are “no longer just, reasonable and not unduly discriminatory.” Therefore, FERC requires that when transmission requests cannot be met with

existing capacity, the transmission provider must offer customers either planning redispatch or conditional firm service. This is a deviation from FERC's original position in the notice of proposed rulemaking that only one of these options would be required. With planning redispatch, FERC wanted to make redispatch "of greater use to transmission customers and more consistent with reliability planning and operation of the system."¹⁷⁴ Although FERC declined to require planning redispatch for third-party resources, transmission providers must identify any third-party resources that could relieve system congestion in the system impact study process. Also, there is no requirement to cap redispatch prices over the term of the service at the costs of expanding the system. Redispatch pricing will be either: (1) the higher of the (a) actual incremental costs of redispatch or (b) applicable embedded cost transmission rate (monthly), or (2) a negotiated fixed rate subject to a cap representing the total fixed and variable costs of the resources expected to provide the redispatching service.

Conditional, firm, point-to-point service is long-term firm service, with periods of less than firm service during: (1) a defined number of hours or (2) defined system conditions. This allows firm service when an otherwise economic agreement would be denied because the resource might not be deliverable for a few hours out of the entire service agreement term. Notably, network resource designations may still be supported by conditional firm service because conditional service is not interruptible for economic reasons. Neither planning, redispatch, nor conditional firm service is required when it would impair system reliability.

Rollovers

Under FERC Order 890-B, the rollover term requirement of OATT § 2.2 has been extended so that only service agreements for 5 years and longer are eligible.¹⁷⁵ The notice period has also been extended from 60 days to 1 year, and customers must match any competing requests as to term and rate to retain their priority in the service request queue. All current contracts will roll over under previous rollover standards until the contracts are renewed following the acceptance of the transmission provider's planning process. Once the transmission provider's planning process is accepted by FERC, the new rollover provisions become effective and only service contracts of 5 years or longer in duration may roll over. Notably, customers will retain their rollover rights even if they redirect to other service providers.

Network Resources / Secondary Network Service

FERC is requiring that all network customers attest in each application for network service that: (1) the customer owns or is committed to purchasing the designated network resource and (2) the network resource fulfills the requirements of a designated resource.¹⁷⁶ Network resources must

¹⁷⁴ Stoel Rives, LLP "Energy Law Alert: Order No. 890: FERC Creates New Transmission Service Rules for Wind Energy; 'Prying Open The Black Box,'" United States, 2007. <http://www.stoel.com/showalert.aspx?Show=2302/>. Accessed August 2012.

¹⁷⁵ Troutman Sanders, LLP "Regulatory Alert Bulletin," Washington, D.C. 2008. <http://www.troutmansanders.com/files/FileControl/984289c3-6168-49a6-a830-48cdadbb0344/7483b893-e478-44a4-8fed-f49aa917d8cf/Presentation/File/Troutman%20Sanders%20Order%20No.%20890-B%20Summary.pdf>. Accessed August 2012.

¹⁷⁶ Order No. 890 requires that all designated network resources requests be accompanied by an attestation stating that the request meets the requirements of section 29.2 and 30.2 of the *pro forma* OATT. Order No. 890-A requires that the attestation be provided in the customer comment section of the OASIS at the time of confirmation (or at the time of submittal if the request is pre-confirmed), and that the language of the *pro forma* OATT sections 29.2(vii) and 30.2 be included in the attestation. Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 919; (FERC) "Order Accepting Compliance Filing, Subject to Further Compliance Filing, Granting Limited Waiver Request and

be undesignated as network resources to sell third-party firm service. Power purchase agreements with liquidated damage “make whole” provisions are the only agreements with liquidated damage provisions that may be considered a network resource. Agreements with fixed damages or damage caps are not eligible. FERC declined to limit secondary network service, and instead retained the rule that this service may be used to deliver economy energy to network loads.

Integration of NERC and NAESB Standards

OASIS NERC and NAESB have been tasked by FERC to integrate a number of new functionalities into OASIS to increase transmission system transparency and reduce undue discrimination. These new functionalities include the amount of unused transfer capability associated with transmission reservations; underlying load forecast assumptions for all ATC calculations; number of rejected affiliate versus non-affiliate requests for transmission service; and the total number of affiliate versus non-affiliate requests for transmission service and quarterly performance metrics for processing transmission delivery service requests.

Enforcement

FERC staff has been tasked with performing compliance audits of OATTs.¹⁷⁷ The most severe consequences will be determined on a case-by-case basis and include civil penalties, a revocation of market-based rates (if there is a factual nexus between the violation and the market-based rates), and findings of market manipulation under Section 222 of the Federal Power Act. In general, however, operational penalties will be used to enforce OATT rules and regulations. Examples of such operational penalties include the following unreserved use penalties (if included in the OATT):

- Penalties for use of transmission service that was not reserved must not be greater than twice the firm point-to-point rate for the period of unreserved use. In a change from Order 888, unreserved use penalty revenue is to be distributed to all non-offending transmission customers (including affiliated customers) to the extent the revenue accrues above the transmission provider’s base firm point-to-point transmission service charge.
- Penalties for a failure to meet the 60-day deadline to finish system impact and facilities studies: After failing to meet the 60-day compliance deadline for a system impact or facilities study, a transmission provider must notify the FERC. In the 120 days after such notification, if the transmission provider does not finish 90% of its studies within each study’s 60-day deadline, then penalties begin accruing (assessed each quarter) of \$500 per day per late study until a quarter occurs when 90% of all studies are completed within 60-days of receipt of the customer’s request.

FERC Order 1000

FERC has placed an increasing role in reliability and the rules and standards governing reliability. Most recently in this area is Order 1000 on transmission planning and cost allocation.¹⁷⁸ Order 1000 is intended to apply to new transmission facilities. The requirements of

Granting Clarification Request,” United States, 2009. <https://www.ferc.gov/EventCalendar/files/20090603154917-0a08-75-000.pdf>. Accessed August 2012.

¹⁷⁷ (FERC) Federal Energy Regulatory Commission “How Audits are Conducted,” United States, 2010. <http://www.ferc.gov/enforcement/audits/conducted.asp/>. Accessed August 2012.

¹⁷⁸ (FERC) Federal Energy Regulatory Commission “Order No. 1000 - Transmission Planning and Cost Allocation,” United States, 2012. <http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp/>. Accessed August 2012.

Order 1000 apply to the evaluation or reevaluation of any transmission facility that occurs after the effective date of the public utility transmission provider's filing adopting the reforms required by Order 1000. The Commission-directed public utility transmission providers must explain in their compliance filings how they would determine which facilities would be subject to the requirements of Order 1000. Based on an initial summary, Order 1000 establishes the following requirements.

There are three requirements for transmission planning:

- Each public utility transmission provider must participate in a regional transmission planning process, which produces a single regional transmission plan and satisfies the principles under Order 890.
- Each transmission planning process at the local and regional level must consider transmission needs driven by federal or state laws or regulations.
- Public utility transmission providers in neighboring transmission planning regions must coordinate concerning more efficient or cost-effective solutions.

There are three requirements for transmission cost allocation:

- Each public utility transmission provider must participate in a regional transmission planning process, which has a regional cost allocation method for new transmission facilities that satisfies six regional cost allocation principles.
- Public utility transmission providers in neighboring planning regions must have a common interregional cost allocation method for new interregional transmission facilities, which satisfies six regional cost allocation principles.
- Participant funding of new transmission facilities is permitted but not as part of the regional or interregional cost allocation method.

Federal Rights of First Refusal must be removed from Commission-approved tariffs and agreements are subject to four limitations:

- The requirement would not apply to a transmission facility not selected in a regional transmission plan for purposes of cost allocation.
- The requirement would not apply to upgrades to transmission facilities (i.e., tower change outs or reconductoring).
- The rule would allow, but not require, competitive bidding to solicit transmission projects or developers.
- Nothing in this requirement impacts state or local laws concerning construction of transmission facilities, including siting or permitting.

One additional requirement is that each public utility transmission provider must add a tariff provision that requires the provider to reevaluate the regional transmission plan to determine if alternative solutions need to be evaluated when there is a delay in the development of a transmission facility. Such alternative solutions can include those proposed by the incumbent.

All public utility transmission providers are required to make a compliance filing within 12 months of the effective date of the final rule; compliance filings for the regional planning and cost allocation requirements are due in 18 months.

FERC and the States

The U.S. has adopted a federalist system for regulating the electricity industry. FERC has an important role, and state regulators have an important role. Table 19 illustrates these roles.¹⁷⁹

Table 19. Federal Regulation and State Regulation for the Electricity Industry

FEDERAL REGULATION	STATE REGULATION
<ul style="list-style-type: none"> • Wholesale transactions (sales of energy for resale) • Interstate transmission (transfers of power across state lines) • Rates charged for transmission of oil • Hydroelectric licenses • Licensing of nonfederal hydroelectric projects • Inspection of hydroelectric projects for safety issues • Regulating the interstate transportation of natural gas, oil, and electricity • Approving the construction of interstate natural gas pipelines, storage facilities, and Liquefied Natural Gas terminals • Monitoring energy markets and companies to protect customers from market manipulation and higher prices • Resolving disputes between energy companies, other organizations, and the public • Overseeing mergers • Reviewing rates set by the Bonneville Power Administration and federal power marketing administrations • Certifying co-generators which use energy for both productions of electricity and industrial processes 	<ul style="list-style-type: none"> • Retail sales (sales of energy to users) • Intrastate transmission (transfers of power within state boundaries) • Certification for new electric generation and electric transmission facilities • Certification for oil pipelines • Develop retail franchise areas • Enforce service and quality standards • Set retail tariffs • Approve planning of transmission and generation facilities • Approve construction of non-hydro generation and transmission facilities

However, FERC does not regulate the following:

- The physical siting of electrical generation, transmission, or distribution facilities, except for hydroelectric projects and under certain circumstances transmission lines
- Activities of municipal power systems, the Tennessee Valley Authority, and most rural electric cooperatives

¹⁷⁹ (FERC) Federal Energy Regulatory Commission “What FERC Does,” United States, 2012. <http://www.ferc.gov/about/ferc-does.asp/>. Accessed August 2012.

ERCOT Protocols and Guides

For the ERCOT region, Texas Reliability Entity develops, through its own FERC-approved processes, separate regional reliability standards that go beyond, add detail to, or implement NERC reliability standards, or that cover matters not addressed in NERC reliability standards. Any entity (organization, company, government agency, individual) that is directly and materially affected by the reliability of the ERCOT bulk power systems may request an ERCOT-specific regional reliability standard to be developed, modified, or withdrawn by sending a Standard Authorization Request Form to the Reliability Standards Manager. The Reliability Standards Committee reviews and recommends action on ERCOT-specific reliability standards and regional variances to NERC standards.

In the ERCOT region, in addition to NERC reliability standards, ERCOT Protocols and Operating Guides outline the procedures and processes used by the ERCOT ISO and market participants for the orderly functioning of the ERCOT system and market. These ERCOT market rules are approved through a stakeholder process that is facilitated by ERCOT staff. Texas Reliability Entity has been authorized by the Texas PUC and is permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides. Texas Reliability Entity does not develop, revise, or modify the ERCOT Protocols or Operating Guides.

Additional Resources

Western Electric Coordinating Council (WECC) <http://www.wecc.biz/Pages/Default.aspx>

Northeast Power Coordinating Council (NPCC) <https://www.npcc.org/default.aspx>

Midwest Reliability (MRO) <http://www.midwestreliability.org>

Reliability First Corporation (RFC) <https://rfirst.org/Pages/Rfirst.aspx>

Southwest Power Pool (SPP) <http://www.spp.org>

SERC Reliability Corporation (SERC) <http://serc1.org/Application/HomePageView.aspx>

Florida Reliability Coordinating Council (FRCC) <https://www.frcc.com/default.aspx>

Electric Reliability Council of Texas (ERCOT) <http://www.ercot.com>

NERC Regional Entities (RE) <http://www.nerc.com/page.php?cid=1|9|119>

Transmission Capability Indices (ATC etc.) <http://www.westgov.org/wieb/wind/06-96NERCatc.pdf>

WECC Common Corridor Standard

<http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=71&Source=/Standards/Development>

Financial congestion management (PJM Training)

<http://www.pjm.com/~media/training/core-curriculum/ip-lmp-101/lmp-101-training.ashx>

Conditional Firm Transmission

http://old.nationalwind.org/events/webinar/Webinar_Presentation.pdf

<http://www.nationalwind.org/assets/publications/ferc890.pdf>

http://www.epsa.org/forms/uploadFiles/715D00000064.filename.EPSA_-_Redispatch_and_CFS_Bare_Essentials.pdf

http://www.nationalwind.org/assets/blog/WGA_NWCC_Redispatch_Factsheet.pdf

FERC transmission incentive rates

<http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp>

<http://www.ferc.gov/industries/electric/indus-act/trans-invest/2009.asp>

<http://www.whitecase.com/files/Uploads/Documents/alert-FERC-Extends-Transmission-Rate.pdf>

Available Transmission Capability (ATC) definitions and methodology

<http://www.nerc.com/docs/docs/pubs/atcfinal.pdf>

ACCR Conductors

http://solutions.3m.com/wps/portal/3M/en_US/EMD_ACCR/ACCR_Home/?WT.mc_id=www.3m.com/ACCR

ACCC Conductors <http://www.ctccable.com/pdf/ACCCOverview.pdf>

SyncroPhasor Measurements www.naspi.org

NYPA Convertible Static Compensator (CSC)

http://tdworld.com/mag/power_reinforcing_td_infrastructure

Upgrading thermal conductor ratings

http://tdworld.com/mag/power_uprating_transmission_lines/index.html

Conductor thermal rating

<http://www.southwire.com/transmission/OCM.htm>

IEEE Standard 738

<http://standards.ieee.org/findstds/standard/738-1993.html>

FACTS Devices

<http://www.energy.siemens.com/hq/en/power-transmission/facts>

<http://www.abb.com/facts>

<http://www.meppi.com/pages/results.aspx?k=statcom&cs=This%20Site&u=http%3A%2F%2Fwww.meppi.com>

HVDC

<http://www.energy.siemens.com/hq/en/power-transmission/hvdc>

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Series Capacitors

<http://www.abb.com/search.aspx?q=series%20capacitor%20banks&abbcontext=products>

Rocky Mountain Area Transmission Study on expanding existing transmission.

<http://psc.state.wy.us/rmats/rmats.htm>

EPRI report on transmission technology

<http://mydocs.epri.com/docs/CorporateDocuments/SectorPages/PDU/TransmissionEfficiencyInitiative/index.html>

DOE Technology Brief

<http://www.scribd.com/doc/6630240/Tech-Briefs>

U. S grid structure

<http://www.isorto.org/site/c.jhKQIZPBImE/b.2603295/k.BEAD/Home.htm>

U. S. ISOs and RTOs

<http://www.caiso.com/Pages/default.aspx>

<http://www.ercot.com>

<http://www.iso-ne.com>

<https://www.misoenergy.org/Pages/Home.aspx>

<http://www.nyiso.com/public/index.jsp>

<http://www.pjm.com>

<http://www.spp.org>

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<https://rfirst.org/Pages/Rfirst.aspx>

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<http://www.spp.org>

<http://www.wecc.biz/awareness/Reliability/Pages/default.aspx>

NERC glossary

http://www.nerc.com/files/Glossary_of_Terms_2010April20.pdf

Additional Policy Details

<http://www.ferc.gov/about/about.asp>

<http://www.ferc.gov/legal/maj-ord-reg.asp>