NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

AUGUST 2006

U.S. Department of Energy

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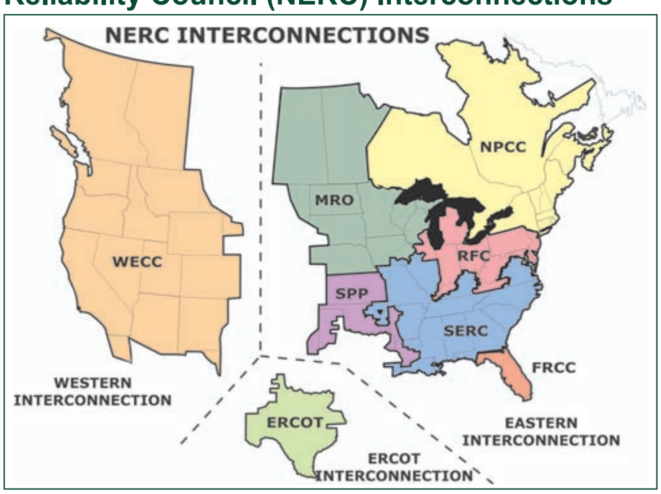
Executive Summary

Section 1221(a) of the Energy Policy Act of 2005 amended the Federal Power Act (FPA) by adding a new section 216 to that Act. FPA section 216(a) directed the Secretary of Energy to conduct a nationwide study of electric transmission congestion[1] by August 8, 2006. Based upon the congestion study, comments thereon, and considerations that include economics, reliability, fuel diversity, national energy policy, and national security, the Secretary may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor." The national congestion study is to be updated every three years.

This document is the Department of Energy's first congestion study in response to the law. It examines transmission congestion and constraints and identifies constrained transmission paths in many areas of the Nation, based on examination of historical studies of transmission conditions, existing studies of transmission expansion needs, and unprecedented region-wide modeling of both the Eastern and Western Interconnections. (See Figure ES-1 for a map showing these interconnections.)

Figure ES-1. Map of North American Electric Reliability Council (NERC) Interconnections



Source: NERC, 2006.

With the publication of this study, the Department of Energy (Department, or DOE) expects to open a dialogue with stakeholders in areas of the Nation where congestion is a matter of concern, focusing on ways in which congestion problems might be alleviated. Where appropriate in relation to these areas, the Department may designate national interest electric transmission corridors ("National Corridors" or "Corridors").

Transmission congestion occurs when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels—either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term "transmission constraint" may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability.

Power purchasers look for the least expensive energy available to ship across the grid to the areas where it will be used ("load centers"). When a transmission constraint limits the amount of energy that can be transferred safely to a load center from the most desirable source, the grid operator must find an alternative (and more expensive) source of generation that can be delivered safely, and re-instruct the owners of generators on how they should schedule electricity production at specific power plants. Further, if a large portion of the grid is very tightly constrained—as when demands are very high and local generation is limited—grid operators may have to curtail service to consumers in some areas to protect the reliability of the grid as a whole. All of these actions have adverse impacts on electricity consumers.

There are many ways to measure transmission congestion. This study developed congestion metrics related to the *magnitude and impact* of congestion (for example, the number of hours per year when a

[1]The law excludes the area covered by the Electric Reliability Council of Texas (ERCOT) from this requirement. In peforming the analysis reported on here, the Department also excluded Alaska and Hawaii because they are not part of the Eastern or Western Interconnections.

transmission constraint is loaded to its maximum safe operating level; and the number of hours when it is operated at or above 90% of the safe level) and the *cost of congestion* (such as the cost of the next MWh of energy if it could be sent across a facility already at its safe limit). Because no one metric captures all important aspects of congestion, the analysts identified the most constrained transmission paths according to several different congestion metrics and then identified those paths that were most constrained according to a combination of metrics.

The cost of congestion varies in real time according to changes in the levels and patterns of customers' demand (including their response to price changes), the availability of output from various generation sources, the cost of generation fuels, and the availability of transmission capacity. Transmission constraints occur in most areas of the Nation, and the cost of the congestion they cause is included to some degree in virtually every customer's electricity bill. Although congestion has costs, in many locations those costs are not large enough to justify making the investments needed to alleviate the congestion. In other locations, however, congestion costs can be very high, and eliminating one or more key constraints through some combination of new transmission construction, new generation close to a major load, and demand-side management can reduce overall electricity supply costs in the affected areas by millions of dollars per year and significantly improve grid reliability.

The Department finds that three classes of congestion areas merit further Federal attention:

- **Critical Congestion Areas.** These are areas of the country where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe. As shown in Figures ES-2 and ES-3, the Department has identified two such areas, each of which is large, densely populated, and economically vital to the Nation. They are:
  - The Atlantic coastal area from metropolitan New York southward through Northern Virginia, and
  - Southern California.
- **Congestion Areas of Concern.** These are areas where a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions. As shown in Figures ES-2 and ES-3, the Department has identified four Congestion Areas of Concern:
  - New England
  - The Phoenix – Tucson area
  - The Seattle – Portland area
  - The San Francisco Bay area.

Figure ES-2. Critical Congestion Area and Congestion Area of Concern in the Eastern Interconnection

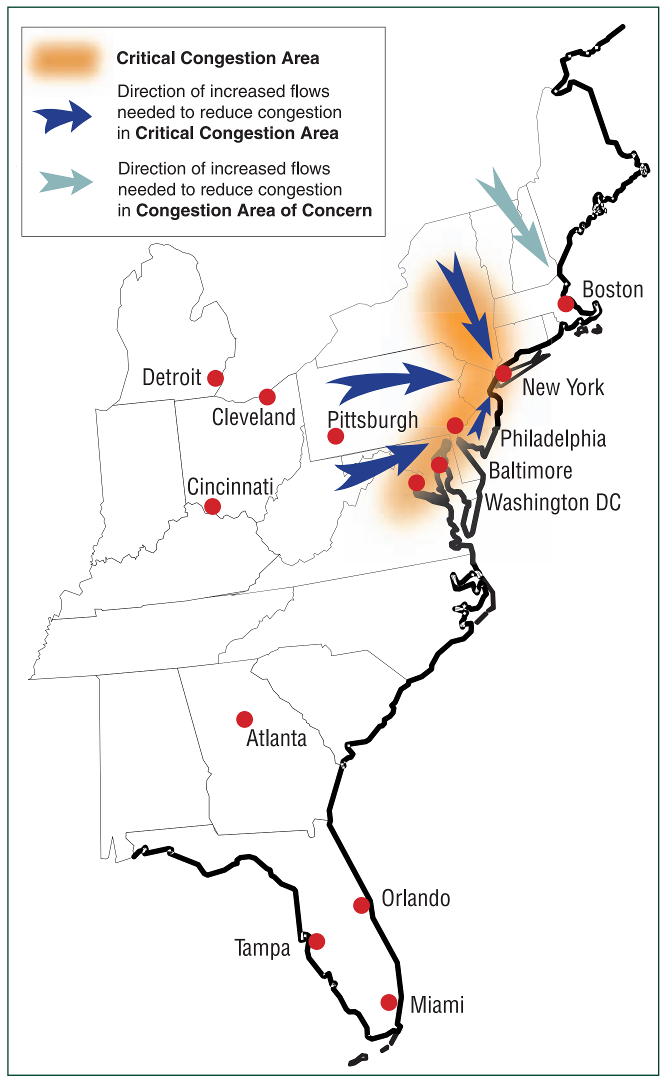
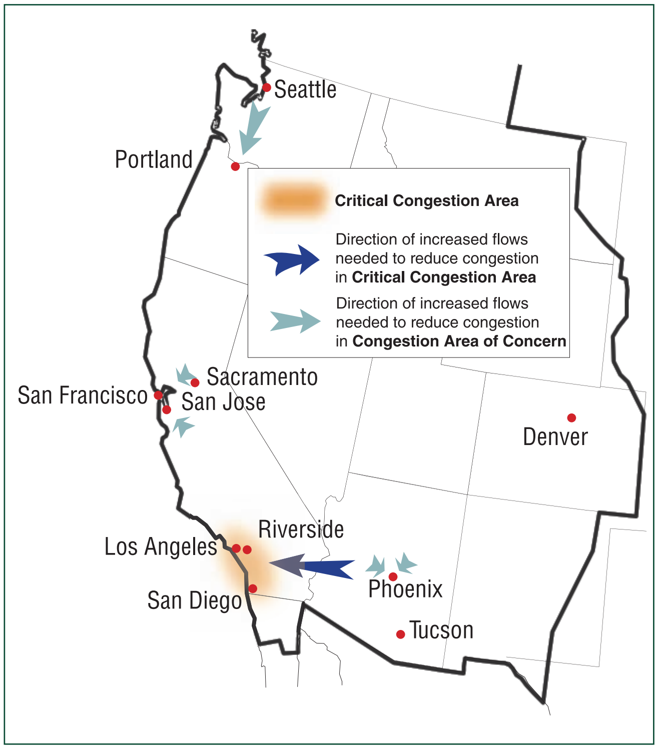


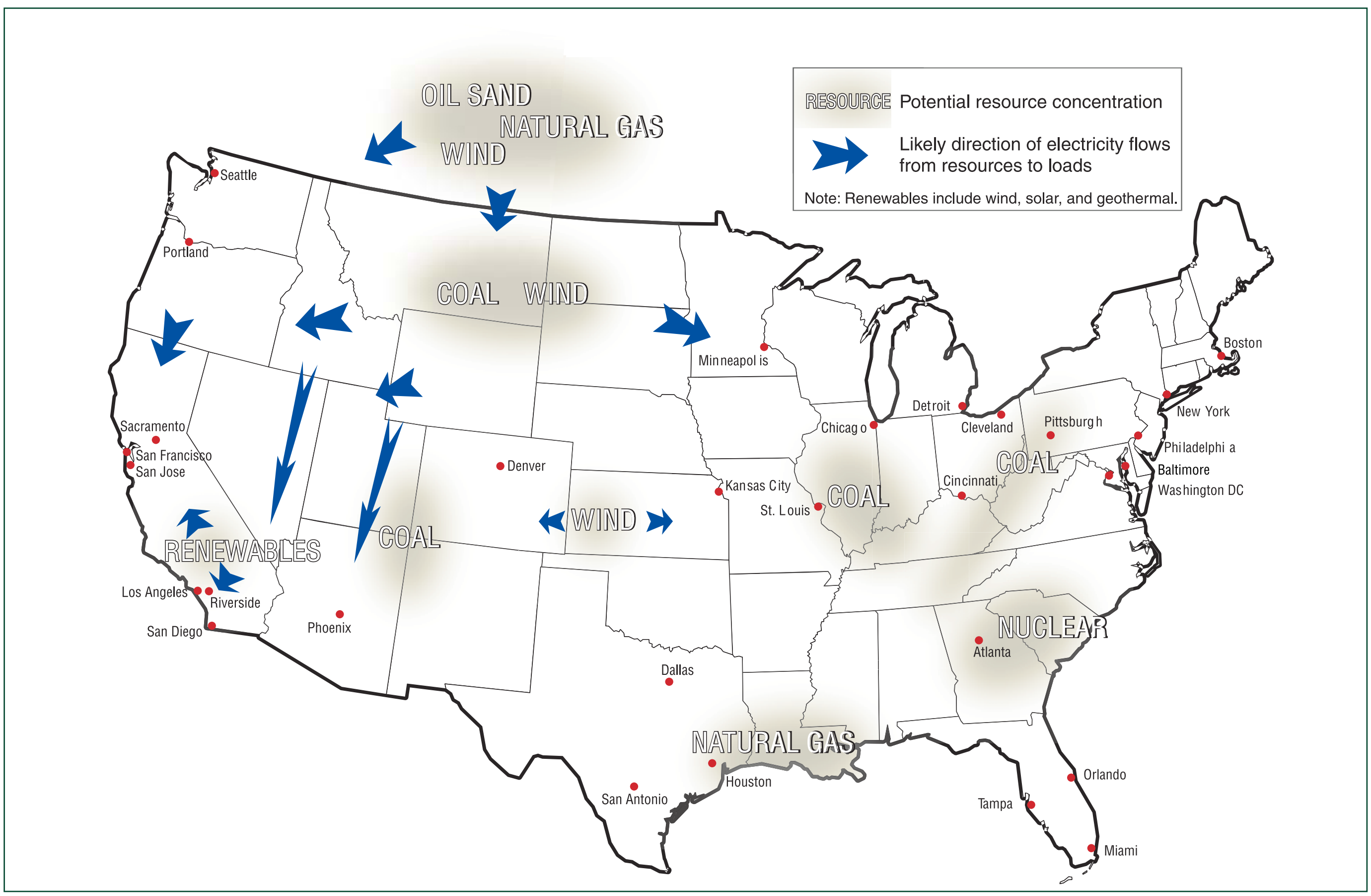
Figure ES-3. One Critical Congestion Area and Three Congestion Areas of Concern in the Western Interconnection



- **Conditional Congestion Areas.** These are areas where there is some transmission congestion at present, but significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity. As shown in Figure ES-4, these areas are potential locations for large-scale development of wind, coal and nuclear generation capacity to serve distant load centers. Some of the areas of principal interest are:
  - Montana-Wyoming (coal and wind)
  - Dakotas-Minnesota (wind)
  - Kansas-Oklahoma (wind)
  - Illinois, Indiana and Upper Appalachia (coal)
  - The Southeast (nuclear)

DOE believes that affirmative government and industry decisions will be needed in the next few years to begin development of some of these generation resources and the associated transmission facilities.

Figure ES-4. Conditional Constraint Areas



Next Steps

Notice of Intent to Consider Designation of National Corridors

For the two areas identified above as Critical Congestion Areas, the Department believes it may be appropriate to designate one or more National Corridors to facilitate relief of transmission congestion in these areas. The Department will also consider designating National Corridors to relieve constraints or congestion in Congestion Areas of Concern and Conditional Congestion Areas. The Department requests comments from stakeholders on three questions by October 10, 2006:

- Would designation of one or more National Corridors in relation to these areas be appropriate and in the public interest?
- How and where should DOE establish the geographic boundaries for a National Corridor?
- To the extent a commenter is focusing on a proposed transmission project, how would the costs of the facility be allocated? (Although the question of cost allocation for a transmission project is not directly related to the designation of a National Corridor, DOE recognizes the criticality of cost allocation issues and is interested in how they might be resolved.)

Chapter 6 provides additional discussion of these questions and information on where comments should be filed. After evaluating the comments received, the Department may proceed to designate some areas as National Corridors, seek additional information, or take other action.

Role of regional transmission planning organizations in finding solutions to congestion problems

DOE expects that regional transmission planning organizations will continue to show leadership in working with stakeholders and transmission experts to develop solutions to the congestion problems identified above in their respective areas. DOE expects these planning efforts to be inter-regional where appropriate, because many of the problems and likely solutions cross regional boundaries. In particular, the Department believes that these analyses should encompass both the congestion areas and the areas where additional generation and transmission capacity are likely to be developed. The Department will support these planning efforts, including convening meetings of working groups and working with the Federal Energy Regulatory Commission and congestion area stakeholders to facilitate agreements about cost allocation and cost recovery for transmission projects, demand-side solutions, and other subjects.

DOE anticipates that regional—and inter-regional, where appropriate—congestion solutions will be based on a thorough review of generation, transmission, distribution and demand-side options, and that such options will be evaluated against a range of scenarios concerning load growth, energy prices, and resource development patterns to ensure the robustness of the proposed solutions. Such analyses should be thorough, use sound analytical methods and publicly accessible data, and be made available to industry members, other stakeholders, and Federal and state agencies.

Annual congestion area progress reports

Each of the congestion areas identified above involves a somewhat different set of technical and policy concerns for the affected stakeholders. The Department will work with FERC, affected states, regional planning entities, companies, and others to identify specific problems, find appropriate solutions, and remove barriers to achieving those solutions.

The Department intends to monitor congestion and its impacts in these areas, and publish annual reports on progress made in finding and implementing solutions. The Department plans to issue its first progress report by approximately August 8, 2007, the second anniversary of the enactment of the Energy Policy Act of 2005.

Acronyms Used in This Report

AC	Alternating Current
AEP	American Electric Power
APS	Allegheny Power System
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CDEAC	Clean and Diversified Energy Advisory Committee (Western Governors Association)
CEC	California Energy Commission
ComEd	Commonwealth Edison
CRAI	CRA International (formerly Charles River Associates)
CREPC	Committee on Regional Electric Power Cooperation
CSP	Concentrating Solar Power
DC	Direct Current
DOE	U.S. Department of Energy
DR	Demand Response
DSM	Demand-Side Management
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPACT	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FRCC	Florida Reliability Coordinating Council
GE-MAPS	General Electric - Multi Area Production Simulation
Geo	Geothermal
GW	GigaWatt (one billion or 10^9 watts)
IRC	ISO-RTO Council
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
LGE	Louisville Gas & Electric
LGEE	Louisville Gas & Electric Energy
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
MISO	Midwest Independent System Operator
mmBtu	Million British thermal units
MMWG	Multiregional Modeling Working Group
MRO	Midwest Reliability Organization
MW	MegaWatt (one million or 10^6 watts)
MWh	MegaWatt-hours (one million or 10^6 watt-hours)
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Council
NIPS	Northern Indiana Public Service Company
NOI	Notice of Inquiry
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NTAC	Northwest Transmission Assessment Committee
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
OTC	Operating Transfer Capability
PEPCO	Potomac Electric Power Company
PHI	Pepco Holdings Inc.
PJM	PJM Interconnection
POEMS	Policy Office Electricity Modeling System
PV	Photovoltaic
RFC	Reliability*First* Corporation
RMATS	Rocky Mountain Area Transmission Study
RMR	Reliability-Must-Run

RRO	Regional Reliability Organization
RTO	Regional Transmission Operator
SCOPF	Security-Constrained Optimal Power Flow
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
SSG-WI	Seams Steering Group – Western Interconnection
STEP	Southwest Transmission Expansion Plan
SWAT	Southwest Area Transmission Planning Group
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
TWh	TeraWatt-hours (one trillion or 10^{12} Watt-hours)
VACAR	Virginia Carolina Reliability Group
WCATF	Western Congestion Assessment Task Force
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association

1. Introduction

FEDERAL POWER ACT

*** * * ***

Sec. 216. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES

(a) DESIGNATION OF NATIONAL INTEREST ELECTRIC TRANSMISSION CORRIDORS—(1) Not later than 1 year after the date of enactment of this section and every 3 years thereafter, the Secretary of Energy . . ., in consultation with affected States, shall conduct a study of electric transmission congestion.

(2) After considering alternatives and recommendations from interested parties (including an opportunity for comment from affected States), the Secretary shall issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.

*** * * ***

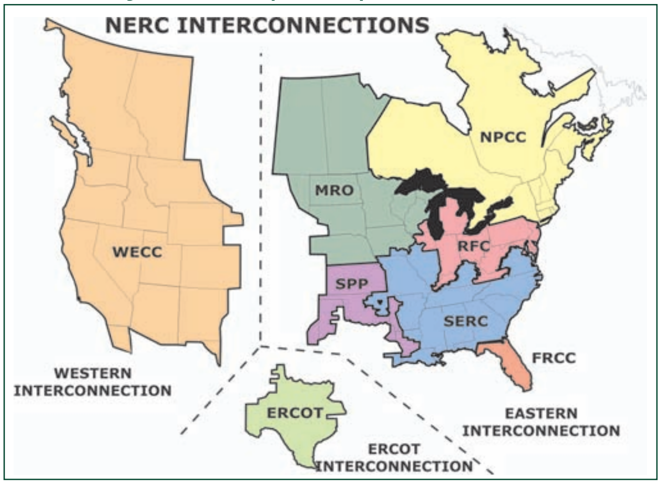
Section 1221(a) of the Energy Policy Act of 2005 added section 216 to the Federal Power Act (FPA), which directs the Secretary of Energy (the Secretary) to conduct a nationwide study of electric transmission congestion within one year after the date of enactment (i.e., by August 8, 2006) and every three years thereafter.[2]

The Secretary is also directed to issue a report based on the congestion study in which he may designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a national interest electric transmission corridor." As specified in FPA section 216(a)(4), the Secretary, in exercising his authority to designate a national interest electric transmission corridor ("National Corridor," or "Corridor"), may consider the economic vitality and development of the corridor and markets served, the economic growth of the corridor and its end markets, including supply diversification and expansion, the Nation's energy independence, national energy policy, and national defense and homeland security.

As directed in the law, this study examines congestion and transmission constraints in the U.S. portions of the Eastern and Western Interconnections, but does not address the Electric Reliability Council of Texas, which is a third interconnection. (See Figure 1-1 for a map of the three interconnections, which together comprise the bulk power system in the U.S., much of Canada, and a small portion of Mexico.) Although this analysis does not address congestion and constraints outside the U.S., data on Canadian electricity generation, transmission, demand, cross-border flows, etc. were incorporated into the modeling conducted for the study because

[2]See Appendix A for the full text of section 1221(a) and (b).

Figure 1-1. Map of North American Electric Reliability Council (NERC) Interconnections



Source: NERC, 2006.

in both the Eastern and Western Interconnections, the electricity grids and wholesale markets are highly integrated systems.

1.1. Organization of This Study

Chapter 1 defines transmission congestion, transmission constraints, and transmission paths, describes the team that conducted the study, and documents the public outreach and consultation process used to date. To minimize confusion, the term "corridor" will be used only in reference to National Corridors and to multipurpose energy corridors that Federal departments are to designate on Federal lands under section 368 of the Energy Policy Act of 2005.[3]

Chapter 2 describes the approach and methods used to conduct this study (i.e., review of existing studies, historical data, and simulations of future grid congestion). Chapter 2 also reviews the assumptions and procedures used for the congestion modeling and then outlines modeling processes and basic data specific to each interconnection.

Chapters 3 and 4 present the congestion study results. Chapter 3 reviews the historical transmission constraints of the Eastern Interconnection, and then presents the findings of congestion modeling for 2008 and 2011. Chapter 4 presents similar results for the Western Interconnection for 2008 and 2015.

Based on the findings of Chapters 3 and 4, Chapter 5 identifies **Critical Congestion Areas**—areas of the country where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe. Second, Chapter 5 identifies **Congestion Areas of Concern**, which are areas where a large-scale congestion problem exists or may be emerging, but more information and analysis is needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions. Third, the chapter identifies **Conditional Constraint Areas**—areas where significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity. DOE believes that affirmative government and corporate decisions

Comparison of This Study and DOE's 2002 *National Transmission Grid Study*

In May 2002, DOE published its *National Transmission Grid Study*, in response to direction provided by the Administration's *National Energy Policy*. The Grid Study presented an assessment of transmission congestion developed using the POEMS model, an electric system simulation tool. In several respects, findings from the Grid Study have been reconfirmed by the analysis presented in this report, including the economic importance of relieving severe congestion to benefit consumers and the basic geographic patterns of congestion. There are, however, important differences that preclude direct comparison of the results from the two studies. First, the results presented in the Grid Study are now four years old; some of the most severe problems flagged there have been or are being addressed and hence are no longer of interest in this study. Second, the current study uses modeling tools that focus more precisely on specific constraints and congested areas.

[3]See Appendix A for the text of section 368.

need to be made in the next few years to begin development of some of these generation resources and the associated transmission facilities.

Chapters 6 and 7 describe the next steps DOE envisions in working with stakeholders to address issues and concerns associated with the three kinds of congestion areas it has identified. Chapter 7 also discusses ways to improve and strengthen future congestion studies. This is the first congestion study DOE has conducted in response to its obligations under the Federal Power Act, as amended. It was done with extensive cooperation and support from regional transmission planning groups and organizations, states, and electric companies. DOE appreciates this support.

1.2. Definitions of Key Terms and Concepts

For the purposes of this study, DOE will use the definitions and concepts presented below. Also, see text box, next page, for additional information about the use of these terms.

Transmission congestion and constraints

Congestion occurs when actual or scheduled flows of electricity on a transmission line or a related piece of equipment are restricted below desired levels—either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The term *transmission constraint* may refer either to a piece of equipment that limits electricity flows in physical terms, or to an operational limit imposed to protect reliability. When a constraint prevents the delivery of a desired level of electricity across a line in real time, system operators must "redispatch" generation (that is, increase output from a generator on the customer's side of the constraint, and reduce generation on the other side), cut wholesale transactions previously planned to meet customers' energy demand at lower cost, or, as a last resort, reduce electricity deliveries to consumers. All of these actions have adverse impacts on electricity consumers.

Transmission constraints exist in many locations across the Nation. However, transmission congestion is highly variable, especially on an hour-to-hour or day-to-day basis. When longer periods of time are examined, recurrent patterns of congestion can be identified. A transmission facility's carrying capacity can vary according to ambient temperatures, the distribution of loads and generation across the grid, and the resulting patterns of electricity flows. The grid is not necessarily most congested (in terms of the volume or value of desired flows curtailed by constraints) during periods of peak demand, because under those conditions most low-cost generation capacity is being used to serve nearby customers and less output from such sources is available for export to more distant areas.

The cost of transmission congestion

Transmission congestion always has a cost—because when constraints prevent delivery of energy from less expensive sources, energy that is deliverable from more expensive sources must be used instead. It is not always cost-effective, however, to make the additional investments that would be required to alleviate congestion. Where transmission congestion occurs frequently because of a major constraint, the wholesale prices for electricity will differ on each side of the constraint; across a region, prices will usually vary in different locations as a function of the availability and costs of energy imports and local generation relative to load.

In an area with an organized wholesale electricity market and publicly posted information on minute-by-minute, location-specific wholesale energy prices, congestion costs can be accurately estimated by summing the value of low-cost transactions that cannot be completed due to transmission constraints, and comparing those to the more expensive value of the generation or imports forced by the constraint. ISOs and RTOs routinely publish monthly and annual congestion cost estimates, noting that the magnitude of those estimates is often driven by the cost of electricity (and underlying fuel costs) as much as by the magnitude of transmission constraints.[4] Similarly, ISOs and RTOs estimate the degree to which congestion in specific areas would be alleviated by transmission upgrades, because major reductions in congestion mean bill savings for electricity customers.[5] Congestion also occurs in areas where the grid is managed by individual integrated utilities rather than by regional grid operators; however, since transmission, generation and redispatch costs are less visible in these areas, the costs of congestion are not as readily identifiable.

Reliability

As the term is used here, reliability refers to the delivery of electricity to customers in the amounts desired and within accepted standards for the frequency, duration, and magnitude of outages and other adverse conditions or events. *Load pockets* are created when a major load center (such as a large city like San Francisco or New York) has too little local generation relative to load and must import much of its electricity via transmission from neighboring regions. For example, most of California is currently a generation-short load pocket; by contrast, transmission constraints cause Maine, which has far more generation than load, to be generation-rich. Because it is frequently difficult to site and build efficient new generation within a city, or to build additional transmission into a city, the resulting load pocket will often experience congestion—meaning it cannot import as much low-cost energy as it would like, and the city's electricity provider(s) must operate one or more existing power plants inside the city more intensively to ensure that all customer needs are met, although at higher cost. If electricity demand inside the load pocket grows quickly without being checked by energy efficiency and demand response, the load pocket may face a looming reliability problem, with too little supply (local generation plus transmission-enabled imports) relative to demand—whether in actual terms or according to accepted rules for safe grid operation. In such cases, it is necessary for the transmission owner(s) serving the load pocket to resolve the reliability problem as quickly as possible.

In the case of a load pocket, there are three primary ways to deal with a long-term congestion problem:

1. Build new central-station generation within the load pocket;
2. Build new or upgrade transmission capacity (some combination of lines and other equipment such as transformers and capacitors) to enable distant generators to serve a portion of the area's load; or
3. Reduce electricity demand (and net import needs) within the load pocket, through some combination of energy efficiency, demand response, and distributed generation.

The three options can be used singly or in combination to solve a transmission constraint problem flexibly and cost-effectively. Generation and transmission, however, are costly, time-consuming solutions that often face opposition. Demand-side options tend to be under-utilized because they have high transaction costs with results that may be less certain and less controllable. It should also be noted that there are a variety of transmission-only solutions to any specific transmission problem; not every transmission project (or combination of projects) will provide equal congestion relief, nor will it provide equal reliability or economic benefits to everyone in the affected region.

[4] See, for example, PJM's statement that congestion costs resulting from constraints in the Allegheny Mountain area totaled $747 million in 2005, with another $464 million on the Delaware River path that year. See http://www.pjm.com/contributions/news-releases/2006/20060307-national-interest-transmission-corridors.pdf for additional detail. Organized markets offer various hedging mechanisms to enable transmission purchasers to protect themselves and prevent the full cost of congestion from driving up their total delivered electricity costs.

[5] It is important to note that the purpose of this study was to identify areas experiencing significant congestion, as opposed to estimating the net value of actions to address the congestion. See, for example, the CAISO's estimate that transmission upgrades and operational improvements completed in 2005 reduced summer congestion costs by more than $54 million in just two months (http://www.caiso.com/docs/2005/10/19/2005101913044018437.pdf), and that three newly approved transmission projects will "reduce the costs of managing transmission bottlenecks and maintaining adequate generation for local reliability by $30 million per year" (http://www.caiso.com/17de/17de9de64cfa0.pdf).

Transmission Constraints, Paths, and Relief of Congestion

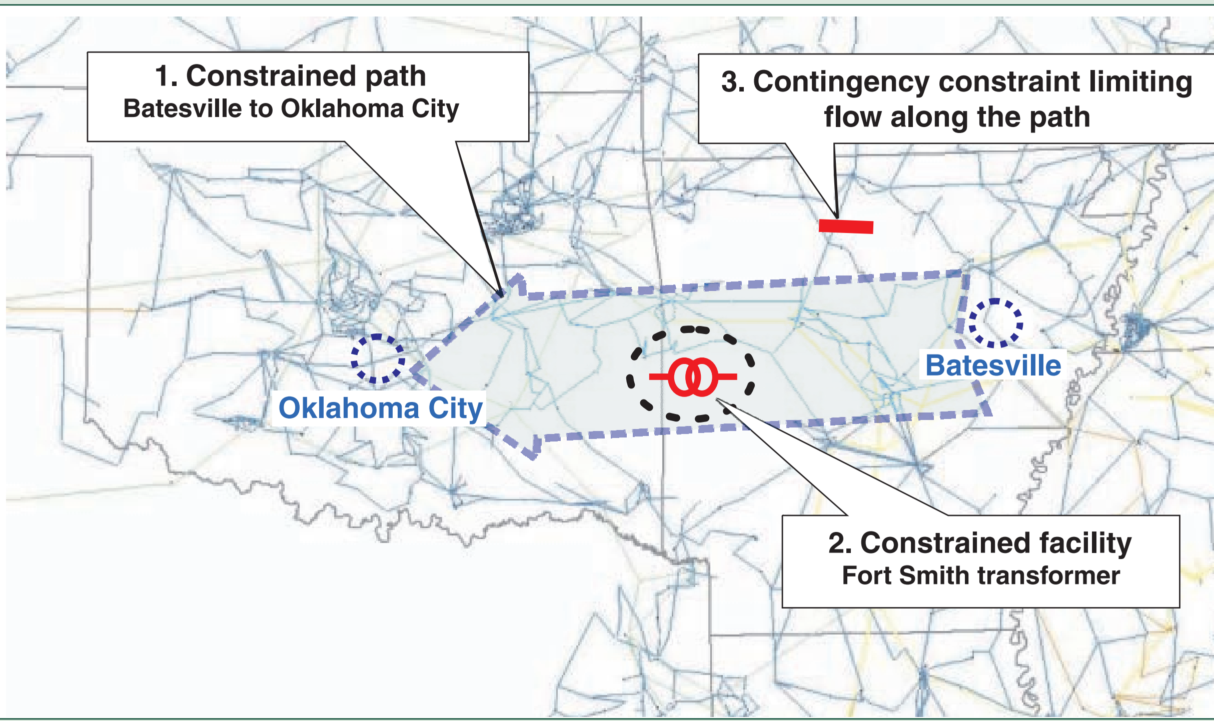
Grid operators strive in real time to serve "loads" (customers in a given geographic area) with output from the lowest cost combination of generation and demand-side resources then available. Transmission congestion arises when output from low-cost generation is available but cannot be delivered safely to loads due to transmission constraints. Transmission constraints limit the amount of generation that can be transported safely along a particular transmission *path*. A transmission path is a useful concept for visualizing a complex of related electric transmission lines and facilities that connect one or more generation sources to a load center. When one path into a load center (such as a city) is congested, additional demand in the load center must be served from alternate, higher-cost generation sources—either from another generation source closer to or within the load center, or from a distant generation source using another and less congested transmission path.

The figure below uses an example from Arkansas and Oklahoma to illustrate the relationship between a constraint and a path, and the complexities caused by the interconnected nature of the electric transmission network. In this example, a path connecting generation at or near Batesville, AR with loads in the vicinity of Oklahoma City, OK is constrained in the amount of power it can carry (label 1). The constraint is expressed by a limit placed on the amount of power allowed to flow through a transformer at Fort Smith (label 2).

Although flow along the path is *controlled operationally* by limiting the amount of power allowed to flow through this transformer, the transformer itself is not necessarily (and is probably not) being operated at its full capability. In this case, compliance with reliability rules has led regional grid operators to set a limit on the allowable loading for the transformer, based on the capability of all of the elements comprising the path. Existing studies have determined that a facility in northern Arkansas (label 3) is the most constraining element associated with the path.

Operational transmission limits are often set to ensure continued, reliable operation of the bulk power system should one or more key facilities fail unexpectedly. NERC's reliability rules require that the system be operated in such a way that if a single element (such as a power plant, transmission line, or transformer) fails suddenly, the

(continued on next page)



Transmission Constraints, Paths, and Relief of Congestion (continued)

operator will be able to restore the system to safe operating margins within 30 minutes. Therefore, grid operators conduct studies to understand what would happen if key facilities were lost through unforeseen events; each such loss is called a "contingency." In this case, the studies show that if power above a certain level is allowed to flow through the Fort Smith transformer *and* a contingency occurs (e.g., the Fort Smith transformer or some other element affecting the path fails), the ensuing instantaneous re-routing of power across the remaining elements of the path could cause an overload and lead to a forced outage for the entire path, or worse. Flows on the Fort Smith transformer are therefore held to a level calculated to ensure that in the event of a contingency, the entire system will continue to operate within safe limits (even though the transformer may be capable of handling greater flows).

This example illustrates that increasing the capability of the Fort Smith transformer alone would not relieve transmission congestion between Arkansas and Oklahoma – because the Fort Smith transformer is not the ultimately constraining facility. To increase permissible flows through the Fort Smith transformer, all facilities in the entire path would have to be re-evaluated, and the most limiting facility (or facilities) would have to be upgraded. The Fort Smith transformer might or might not have to be upgraded. A broad analysis of this kind is needed whenever planners seek to decide how best to relieve congestion in a given area.

Not all congestion is worth alleviating. There are many cases where it is not cost-effective to eliminate congestion by easing each transmission constraint.[6] New transmission, generation and demand-side management are costly and time-consuming to implement, so it may cost society and electric users less to pay for more expensive local generation—upon occasion—than to build a new transmission line or generator to alleviate a local transmission constraint. Utilities are obligated, however, to take action to address transmission constraints that clearly compromise grid reliability (as articulated in the standards set by the North American Electric Reliability Council). There is also a long tradition of utilities building new transmission to enable bulk power purchases that significantly reduce energy costs—this was the genesis of much of the backbone high voltage transmission system in the Western Interconnection.

Transmission Paths and Nodes

For purposes of this congestion study, a transmission *path* is defined as a line (or a group of related transmission lines) linking two *nodes*. A node is a geographic area that has a significant amount of net generation or load, or in some cases both; to limit the scope of this analysis, no attempt is made to study or characterize conditions inside nodes. A transmission path may be a single major transmission line, or a collection of transmission facilities or elements (medium- and high-voltage lines and support equipment, such as substations, transformers, phase angle regulators, capacitor banks, and so on) that behave in an electrically related fashion and together deliver electricity from one node to another.[7]

1.3. Consultation with States and Regional Entities

The Department took the following steps in preparing this study:

- It initiated a series of conference calls in December 2005 and January 2006 with several electricity reliability organizations, regional transmission operators, electricity trade associations and their members, and the states to describe DOE's study plan and request parties' cooperation, comments, information, and suggestions.

[6]Relieving a single constraint usually reveals the next most limiting constraint, which tends to limit achievable flows by less than the full amount of change in the initial constraint.

[7]In some areas, certain important paths are called "flowgates" and given specific names. A flowgate is sometimes associated with a specific contingency, and flows on that path may be limited only if that contingency occurs. See H. Chao and S. Peck, "A Market Mechanism for Electric Power Transmission," *Journal of Regulatory Economics*, vol. 10, pp. 25-59, 1996.

- On February 2, 2006, the Department published a Notice of Inquiry (NOI) in the *Federal Register* (71 Fed. Reg. 5,660), "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," explaining the Department's intended approach for the congestion study and inviting public comment on several questions pertaining to corridor designation. In response to this inquiry, the Department received 111 comments from state government agencies, regional entities, and various stakeholders. The list of commenters can be found in Appendix B.

- On March 29, 2006, the Department held a public technical conference in Chicago, Illinois to address the questions presented in the NOI. The technical conference was advertised through publication of the NOI and through notices circulated to the members of electricity-related trade associations. The Department worked with many of the NOI respondents in putting together the conference agenda, which is included in Appendix C. A list of the attendees is shown in Appendix D. The conference was also accessible to remote participants through a conference call bridge. The Department invited attendees and others to offer additional post-conference comments; an additional 15 comments were received (see Appendix F).

- Throughout the preparation of the congestion study, the Department staff has sought to meet with parties requesting an opportunity to offer input. These outreach and input opportunities have included in-office meetings, visits to others' offices and meetings, speeches, conference call briefings for organizations, and other events. A number of state representatives (with the assistance of the National Association of Regulatory Utility Commissioners) took the opportunity to participate in the March technical conference, receive progress reports, offer input on the congestion study and corridor designation matters. Representatives of the regional transmission organizations and independent system operators have also been active participants in this process. Appendix G lists outreach and input opportunities the Department has made available on this subject since August, 2005.

- All documents issued or received by the Department to date pertaining to the congestion study or National Corridors have been posted for public access on the Department's website, http://www.oe.energy.gov/.

The Department invites public comment on this congestion study. Comments may address any element of the study method and its findings—recognizing, however, that this study addresses electric transmission congestion and is not intended to select or designate National Corridors. (See Chapter 6 for the Department's notice that it is considering designation of National Corridors, and particular questions the Department requests commenters to address.)

Comments on the study approach, methodology, data, and related matters must be submitted to the Department by October 10, 2006—if possible by e-mail to congestionstudy.comments@hq.doe.gov. The Department will take these comments into account in its future activities related to the geographic areas of particular interest identified in this study, and in the design and development of the next congestion study.

2. Study Approach and Methods

This chapter describes the process and methods used to study congestion in the Eastern and Western Interconnections. The process involved two parallel and coordinated analyses, one for each interconnection. The analyses of the Eastern and Western Interconnections are discussed separately.

The methods, which were common to both analyses, included:

1. Review of available information on historical congestion and previously documented transmission-related studies;
2. Simulation modeling to estimate future economic congestion, using common economic assumptions and analytical approaches; and
3. Comparison and assessment of the historical information with the simulation findings.

Although this study reports on transmission congestion in the United States, the analyses of the Eastern and Western Interconnections incorporated appropriate data concerning Canadian electricity generation, transmission, demand, cross-border flows, etc. into the simulations.

2.1. Review of Historical Transmission Studies

For each interconnection, analysts collected and reviewed recent regional transmission studies, which in most cases were transmission expansion plans and reliability assessments. The results of these reviews are discussed in Chapters 3 and 4. Using these studies and other information concerning recent grid transmission flows and curtailments, the analysts identified existing transmission constraints within the interconnection, as determined by other parties, and took into account upgrades already approved by regulators or under construction to alleviate specific constraints.

2.2. Simulations

The simulations of Eastern and Western Interconnection congestion used 2008 as the base year to estimate congestion on the transmission grid. Each analysis also simulated congestion for a later year, but because of differences in data availability, the eastern analysis focused on 2011 and the western analysis focused on 2015.

Both eastern and western modeling used simulation tools that use optimal power flow modeling on a decoupled network system (i.e., DC power flow with linear loss estimates) to minimize production costs across the grid while delivering all needed power from generators to loads in each hour of the model year. Each simulation model incorporated average system line losses. Each model conducts an internal reliability assessment, optimizing flows while respecting grid constraints that would limit flows within or between regions, and redispatching generation as necessary to ensure that load is served reliably. Each simulation calculated the location, duration and cost of congestion across the grid to identify those elements on the grid that are expected to experience the greatest congestion (as defined below). Thus, congestion in the simulations reflects underlying economic forces, constrained by the physical limits of the power systems.[8]

[8]Time series simulations based on optimal power flow models over a defined study period can estimate total system production costs for that period. These models can be used to compare production costs in base and change case simulations—the base case represents the transmission system as it exists today or in the near future, with known and quantifiable modifications. The change case represents discrete transmission enhancements that are being tested to determine their impact on production costs, reliability, or other performance indicators. The difference between the base and change cases yields a calculated basis for evaluating the economics of the transmission enhancement. It is important to note that the impact of a transmission enhancement cannot be assessed using measures of current congestion, such as congestion rent, that reflect only base case conditions. The simulation techniques used for this congestion study did not incorporate voltage stability limits, which require modeling using a full alternating current optimal power flow solution for each study interval; this adds significant complexity to the modeling process. Transient stability, another important physical constraint, may not be possible to model under unconstrained network dispatch.

2.3. Scenario Analyses and Economic Assumptions

Fuel prices

The Eastern and Western Interconnection simulations used similar fuel price forecasts for supply cost modeling, to determine the extent to which fuel costs affect electricity congestion levels and patterns. The congestion study used three fuel price scenarios, which can be generally stated as a $7/mmBtu price for natural gas for the base case, with low and high cases starting at $5 and $9/mmBtu, respectively. Fuel price assumptions are shown below in Figures 2-1 and 2-2 and Table 2-1.

- **Oil base case**—Base case prices were developed from the NYMEX futures prices for light sweet crude oil as of November 3, 2005. For 2010, crude oil prices were interpolated between the 2009 futures price and the Energy Information Administration's (EIA's) *Annual Energy Outlook 2006* reference case forecast price for 2011. For 2011 and beyond, the forecast used the EIA price forecast. Prices were adjusted regionally and monthly according to documented geographical and temporal patterns.
- **Oil high case**—The high case forecast for light, sweet crude oil was calculated by adding one standard deviation of the oil futures price to the base case price series.
- **Oil low case**—For crude oil, the EIA's *Annual Energy Outlook 2006* low price case forecast for 2008-2015 was used as the low case for all years.
- **Natural gas base case (east)**—The natural gas base price forecast reflects NYMEX futures as of

Figure 2-1. Crude Oil Prices: History and Basis Forecast

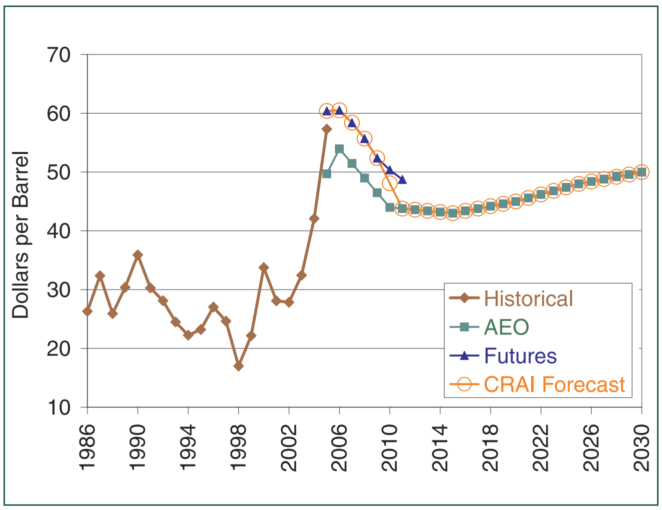


Figure 2-2. Natural Gas Spot Prices at Henry Hub: History and Basis Forecast

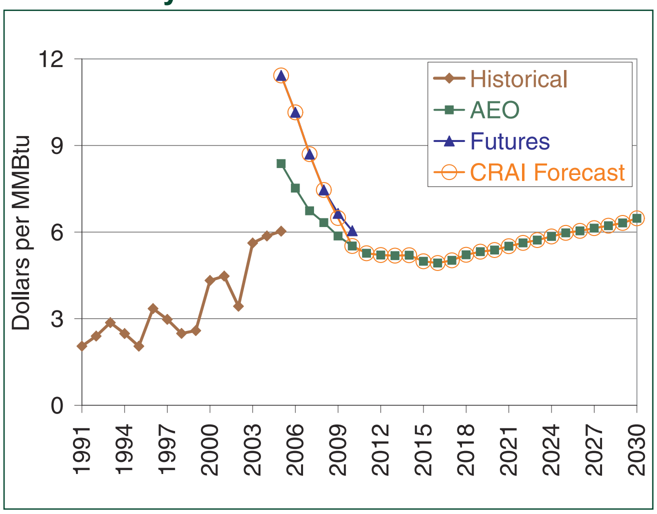


Table 2-1. Crude Oil and Natural Gas Price Forecasts: Base Case, High Case, and Low Case

	Light Sweet Crude Oil Forecast ($/Barrel)			Natural Gas Forecast ($/MMBtu)		
Year	Base Case	High Case	Low Case	Base Case	High Case	Low Case
2008	55.68	82.42	45.48	7.46	9.53	5.39
2009	52.37	83.18	41.23	6.49	8.29	5.17
2010	48.08	80.73	37.00	5.52	7.68	4.94
2011	43.78	77.02	35.23	5.27	7.80	4.62
2012	43.59	79.84	33.55	5.20	8.09	4.42
2013	43.39	82.37	31.96	5.18	8.40	4.30
2014	43.20	84.68	30.44	5.20	8.73	4.21
2015	43.00	86.80	28.99	4.99	8.65	3.99

November 3, 2005, for Henry Hub gas, through 2008; the Energy Information Administration's *Annual Energy Outlook 2006* reference case forecast prices for 2010 through 2030; and an interpolation between the two sources for the 2009 price. Regional basis differentials and monthly price variations were calculated for various delivery points within the Nation using regression models reflecting historical relationships for each delivery point relative to Henry Hub costs and NYMEX seasonal price patterns.

- **Natural gas high case (east)**—The high case for natural gas was created by determining the standard deviation for NYMEX gas futures prices in proportion to the base case, and defining the high price forecast as the base case price plus one standard deviation.
- **Natural gas low case (east)**—For the long term, the EIA's *Annual Energy Outlook 2006* low price case forecast for 2008-2015 was used as the low case for the congestion studies. For the near term, the low case used the base case price less one standard deviation of NYMEX gas futures prices.
- **Natural gas in the western analysis**—The western analysis used pre-determined gas price scenarios with $5/mmBtu gas in 2005 as the base case and high price scenarios of $7 and $9. Western gas market hub and burner-tip area price differentials were estimated using the NW Power and Conservation Council's methodology from its Fifth Power Plan. Fixed transportation costs (capacity charges) for gas delivery from regional hubs to consumption areas were calculated using the California Energy Commission's *Energy Policy Report 2005* data and method, and are included with other fixed costs of the scenario.
- **Coal**—For the eastern analysis, the EIA's *Annual Energy Outlook 2006* base price forecast was used for the coal price series for all scenarios, because coal is generally purchased under long-term contracts with less price variability than gas or oil, and because coal-fired generation usually operates as a baseload resource and rarely sets the marginal cost of electricity. For the West, coal prices are based on the EIA's 2005 Energy Outlook, and modified for each delivery area to reflect transportation costs specific to that area's combination of coal sources and destination distance.

Hydro availability

The western analysis assumed average hydro conditions and hydropower availability for both 2008 and 2015. Hydro conditions, however, significantly affect western power production patterns and costs.

Other assumptions

In the Eastern Interconnection analysis the load and generation assumptions were based on those reported by utilities in their Form 714 filings to FERC. As such no specific assumptions were made with regard to load growth, energy efficiency, and new wind or nuclear generation for the study period.

In the Western Interconnection analysis the following assumptions were made:

General Generation Resources. Existing resources are resources assumed to be online by 12/31/2008. These resources were identified through the Western Electricity Coordinating Council's (WECC) power flow case (HS2A PF) and the SSG-WI 2003, CEC, RMATS, and other data bases. Generating resource capacities are based on the power flow case. Thermal unit capacities are net of station service. Net-to-grid generation from cogeneration resources is not explicitly modeled except in Alberta. The power flow capacities used in the model are very similar to those in CEC, Platts, and other data sources.

Renewable Generation. Hourly wind shapes used to model all wind generating resources were supplied by the National Renewable Energy Laboratory (NREL), with the exception of CAISO's wind shapes for its areas based on actual data. Wind is treated as a fixed input to the model. Geothermal plants were modeled as base load plants as confirmed by the Clean and Diversified Energy Initiatives Geothermal Task Force. Data to model specific plants in California were provided by the CAISO. Solar production profiles were provided by NREL.

DSM/Energy Efficiency. Existing and some forecasted DSM and energy efficiency programs were embedded in the load forecast. These amounts were not explicitly identified by WECC. In addition, some new DSM programs were modeled as dispatchable resources in 2015 studies.

2015 simulation

In the western 2015 Reference Case, the following incremental resources were added, compared to the 2008 case (which included only existing/committed resources):

- DSM—680 MW
- Geothermal—1,362 MW
- Solar—1,323 MW
- Wind—14,526 MW
- Nuclear—0 MW

High Renewables case for 2015

The High Renewables case represents an aggressive development of western renewable resources based on the analyses of the Clean and Diversified Energy Advisory Committee's (CDEAC) Biomass Task Force, Geothermal Task Force, Solar Task Force, and Wind Task Force. The High Renewable scenario adds 42,812 MW of nameplate renewable capacity on top of the Reference Case incremental renewable generation 19,664 MW between 2004 and 2015. The resulting total renewable generation in 2015 is 68,436 MW of nameplate capacity in the Western Interconnection. The High Renewable generation additions were offset by removal of natural gas (12,381 MW) and coal (7,579 MW) generation resources.

High Coal case for 2015

The High Coal scenario adds new coal generation that includes some advanced coal technologies with lower emission rates. The High Coal scenario adds 11,300 MW of coal generation above the Reference Case, with 5,000 MW from advanced coal technologies. The High Coal scenario additions were offset by reduced natural gas (6,460 MW) generation resources.

See Table 2-2 for specific generation assumptions of the High Renewables and High Coal scenarios.

Transmission analysis

High Renewables. The High Renewables case required new transmission to support significant new renewable generation across the Western Interconnection including the Pacific Northwest, Wyoming, Montana, Nevada and New Mexico. Transmission for the High Renewables scenario consists of nine projects and about 3,578 miles of new lines at a cost of nearly $6.8 billion above the CDEAC Reference case.

High Coal. The High Coal case integrates significant new coal generation in the Western Interconnection including large concentrations in

Table 2-2. Generation Assumptions for Western Interconnection Reference 2015 Cases (Megawatts Nameplate Capacity)

	Natural Gas	Coal	Oil	Hydro	Nuclear	DSM/ DR	Other	Wind	Biomass	Geo	Solar CSP	Solar PV	Solar CSP & PV	Renew-ables	Total
Total Generation 2015															
SSG-WI Reference	106,084	48,490	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	**258,838**
CDEAC Scenarios:															
High Efficiency	99,785	42,440	1,703	66,017	9,637	16,068	561	17,933	2,187	4,021			1,483	25,624	**261,835**
High Renewables	93,703	40,911	1,703	66,017	9,637	724	561	43,457	9,326	8,243	2,677	3,250	7,410	68,436	**281,692**
High Coal	99,624	59,790	1,703	66,017	9,637	724	561	17,933	2,187	4,021			1,483	25,624	**263,680**
Incremental Generation 2004-2015															
SSG-WI Reference	30,412	9,608	-320	1,745	0	680	0	16,273	1,006	1,362			1,023	19,664	**61,786**
CDEAC Scenarios:															
High Efficiency	24,113	3,558	-320	1,745	0	16,024	0	16,273	1,006	1,362	0	0	1,023	19,664	**64,784**
High Renewables	18,031	2,029	-320	1,745	0	680	0	41,797	8,145	5,584	2,677	3,250	6,950	62,476	**84,641**
High Coal	23,952	20,908	-320	1,745	0	680	0	16,273	1,006	1,362	0	0	1,023	19,664	**66,629**
CDEAC Scenario Additions and Removals to SSG-WI Reference Case															
High Efficiency	-6,299	-6,050				15,344									**2,995**
High Renewables	-12,381	-7,579						25,524	7,139	4,222	2,677	3,250	5,927	42,812	**22,852**
High Coal	-6,460	11,300													**4,840**

Wyoming, Montana, Nevada and Utah. The Seams Steering Group – Western Interconnection (SSG-WI) Transmission Subgroup proposed 11 transmission projects and about 3,903 miles of new lines with costs of almost $7.0 billion.

Line losses

The energy lost in power delivery from the power plant to the customer's meter affects grid congestion and electricity costs. Both the eastern and western analyses used simulation models that assume average line losses in a decoupled network representation. The western analysis used one sensitivity case to determine the impact of generation commitment and dispatch based on marginal, rather than average, line loss calculations and found that line losses assumptions may have a significant effect upon congestion findings. This shows that further analysis is needed to better understand the implications of line losses for congestion.

Resource assumptions

The modeling results, including projected congestion, are very dependent upon assumptions about which specific new transmission elements and power plants are included in the projected grid and resource set. Analyses for near-term operational purposes are essentially snapshots of current conditions. They look ahead at most for a single year, and include only those resources currently operating or nearly operational.

By comparison, longer-term projections of the patterns and levels of future power flows and congestion can be strongly affected by assumptions about whether specific new transmission lines or major power plants are included in the base resource set—for example, whether major new coal resources are assumed on-line in the Powder River Basin, or new merchant DC cables in the New York and New England regions are assumed to be constructed. Such factors are not significant for the 2008 model year, for which transmission and generation resources can be predicted with relative confidence, but the impacts of assumed new transmission and generation resources are very important for the 2011 and 2015 analyses. A hypothesized new transmission line can "assume away" an otherwise significant new congestion problem.

2.4. Estimating and Evaluating Congestion

In order to assess the magnitude of congestion across the transmission paths modeled in the two interconnections, the congestion study team developed and applied five metrics. Those metrics are:

1. Binding hours: Number of hours (or % of time annually) that a constrained path is loaded to its limit.
2. U90: Number of hours (or % of time annually) that a constrained path is loaded above 90% of its limit.
3. All-hours shadow price:[9] Shadow price averaged over all hours in a year.
4. Binding hours shadow price: Average shadow price over only those hours during which the constraint was binding (shadow price is zero when constraint is not binding).
5. Congestion rent: Shadow price multiplied by flow summed over all hours the constraint is binding.

Usage metrics

Both the number of hours that a path is loaded to its limit (the binding hours metric) and the number of hours that it is loaded close to its limit (the U90 metric) indicate how heavily that path is used. A path that is highly loaded for much of the time is likely to result in significant, costly congestion. In addition, since the limit on each path is set by operational reliability considerations—thermal, transient stability or voltage limits, either singly or in combination with other paths and elements—a path that hits its usage limit has also reached its reliability limit.

Transmission path usage is described using a composite index such as U90. In each hour, the analysts identified the element that is the most limiting with respect to incremental transfer of power between end nodes of the path. The usage indicator (e.g. percent loading with respect to the flow limit) for the

[9] See Glossary for definition of "shadow price."

most limiting element is considered to be the loading of the path. Thus U90 for the path is the percent of time when that path's most limiting element is loaded at 90% or more of its safe capacity.

Economic metrics

The economic significance of congestion on a given path can be measured in several ways:

- The *shadow price* for a path equals the value of the change in all affected generation if one more MWh could flow across a constrained facility (i.e., the marginal cost of generation redispatch required to adhere to the transmission constraint). The shadow price for a given path is zero unless the path is loaded to its limit. For this study, the shadow price was averaged across all hours in the modeled year for each path to identify those that had the greatest marginal cost impact on generation costs.
- However, because transmission congestion varies across time, the cost imposed by a single constraint can vary widely as well. Therefore, the analysts also tabulated the economic cost of a constraint by documenting the average shadow price in only those hours when the constraint is binding.
- Last, the analysts summed the shadow price times flow over all the hours when the constraint is binding, and call this sum "congestion rent" for purposes of this study. This congestion rent is estimated for each constraint, and is used to indicate and rank the severity of transmission congestion at the various locations on the transmission system. This estimate should not be assumed to equal the benefits that might be achieved by expanding the transmission system to eliminate that constraint, and should not be compared to the cost of any such expansion.

For transmission paths, the analysts calculated economic congestion as the differential between simulated locational prices for end nodes defining the path—the higher the price differential, the higher the congestion. The price differential for a path reflects both the effect of each binding constraint limiting the flow across the path and the impact of the power transfer across the path on the constraint.

Absolute values versus relative ranking of congested paths

These metrics were tracked for each transmission element over every scenario analyzed for both interconnections, and used in various combinations to determine which grid elements were most congested. Given the uncertainties and complexities of these simulations, the relative rankings of constrained paths are more significant than the absolute values estimated for any specific path.

The next section of this chapter discusses the review of available information and the simulation modeling. The findings from the comparison and assessment of the historical information and the simulation results, applied to each interconnection, are discussed separately in Chapter 3.

2.5. The Eastern Interconnection

Review of historical information

The congestion study team collected two types of information on congestion in the Eastern Interconnection. First, over 65 documents from a variety of sources were reviewed, most of which were either reliability assessments or economic analyses. (See Appendixes H and I.) The reliability assessments identified transmission elements that limit flows under a range of load and generation conditions, identified constraints that would limit flows between and within regions as inter-regional transfers increase, and determined whether load can be served reliably. The economic analyses quantified the location, duration and cost of congestion. These documents were valuable both as sources of information on historical congestion and as input and benchmarking information for the simulation modeling.

Second, the team drew upon primary data from NERC and the ISOs and RTOs. The data were received in two forms: records of Transmission

Loading Relief (TLR) actions and congestion market information.[10] TLR actions are grid management procedures formally prescribed by NERC that are invoked by Eastern Interconnection grid operators when grid flow schedule inconsistencies or unplanned events necessitate short-term actions to curtail or redirect transactions to ensure secure power system operations.[11] Congestion market information refers to information on congestion costs within the eastern centralized wholesale markets. These markets rely on locational marginal prices (LMPs) to provide financial incentives to market participants to undertake congestion-relieving actions voluntarily.[12]

As with many analyses, the quality of the available input information affected the quality of the analytical effort and its findings. This congestion study is based upon two sets of information—historical studies (including transmission planning studies and NERC regional and inter-regional reliability assessments) and forward-looking modeling. Most of the Eastern Interconnection has been well documented by historical studies (conducted from 2003), and extensive, detailed grid flow and electricity cost data results from the operation of centralized real-time electricity markets.

As documented in studies by the Edison Electric Institute[13] the ISOs and RTOs in the Eastern Interconnection routinely conduct public and well-vetted transmission planning and reliability studies. These studies are informed by the availability of extensive information generated from the ISOs' and RTOs' centralized operation of the regional transmission grid and centralized electricity markets, which reveal transmission congestion occurrences and their costs to energy users. Thus, for the areas covered by these organizations there is extensive information available in the historical analyses to document past congestion, and extensive data is available for use in fine-tuning grid models to identify future transmission congestion and constraints.

There is significantly less publicly available information about transmission congestion and constraints in the Southeast and Florida. Other than the regional reliability councils' sections of NERC reliability assessments for these areas, no systematic analyses are available to the public concerning transmission flows and congestion within or across utility boundaries. Transmission expansion studies are conducted within individual utility footprints rather than for the broad region, so there is little public documentation of electricity flows and constraints within and between utilities and subregions. There is little public information about the locations and cost of transmission constraints between utilities or regions (for instance, between Southern Company and the Florida utilities). The unavailability of market and other data or formal regional transmission studies precluded independent assessment of the present study's findings for this region by comparing them with results from other studies.

Appendix I lists the studies that were available and reviewed for this analysis. This study uses only CRA International's (CRAI) proprietary data and that provided by the NERC MMWG 2005 Update Case as the basis for analysis of electricity flows and congestion in the Southeast; absent market and other data, or formal regional transmission studies, it is difficult to test the present study's findings for this region by comparing them with results from other sources.

Simulation modeling to estimate future congestion

Simulation modeling of the Eastern Interconnection for this study entailed several steps:

1. Preparation of input data for the 2008 and 2011 study years;
2. Use of the GE-MAPS study tool;

[10] Sources: ISO-NE, NYISO, PJM, and MISO.

[11] http://www.nerc.com/~filez/Logs/index.html.

[12] Lesieutre, B. and J. Eto. 2004. "When a Rose Is Not a Rose: Electricity Transmission Costs: A Review of Recent Reports." *The Electricity Journal*. Volume 17, No. 4, May, pp. 59-73. Lawrence Berkeley National Laboratory Report, LBNL-52739.

[13] Hirst, Eric, "U.S. Transmission Capacity: Present Status and Future Prospects." Edison Electric Institute and Department of Energy, August 2004; and Energy Security Analysis, Inc., "Meeting U.S. Transmission Needs," Edison Electric Institute, July 2005.

3. Development of analytical procedures to aggregate modeling results into constraint areas for analysis;
4. Specification of sensitivity studies; and,
5. Collecting and aggregating modeling results to estimate congestion.[14]

Base data

The Eastern Interconnection study used 2008 and 2011 as the base years for evaluation. Input data for these two study years came from two primary sources. The majority of input data were taken directly from CRAI's proprietary database of Eastern Interconnection generator production cost characteristics, transmission ratings, and electricity demands. This database has been developed over many years and is itself based on a variety of public (e.g., annual utility reports to FERC on Form 714) and private data sources. DOE also directed CRAI to collect information from transmission planning and regional/inter-regional reliability studies; in particular, the NERC Multiregional Modeling Working Group (MMWG) 2005 series load flow cases for the summer of 2007 and the summer of 2010 served as input data on the configuration and capabilities of generation and transmission in the Eastern Interconnection. In order to resolve particular questions and resolve any discrepancies between data sources, DOE directed CRAI to consult with industry representatives about projects under development or special cases such as the Cross-Sound and Neptune high voltage DC cables, which were added to the MMWG study case as resources for 2011.

GE-MAPS, a commercially available multi-area production cost simulation tool, was used to study future congestion in the Eastern Interconnection. Production cost simulation tools estimate the cost of serving the electrical load in a given area by calculating on an hour-by-hour basis the least-cost dispatch of a fleet of generation units, each with known fixed and variable costs of production. Multi-area production cost simulation tools conduct this least-cost dispatch for more than one area simultaneously while considering the capability of transmission lines connecting the areas to support imports and exports of power to further lower the overall total cost of production. GE-MAPS assesses the electrical capability of transmission lines to support such inter-regional transfers using a technical approach called decoupled power flow.

Development of nodes

CRAI's GE-MAPS tool represents the Eastern Interconnection as having approximately 46,000 distinct electrical elements (buses). Some of these elements represent points of load demand, some represent points where generators interconnect with the grid, and others represent transformers, phase shifters, substations and interconnections of transmission line segments. DOE directed CRAI to aggregate the load and generation buses in the Eastern Interconnection into a set of nodes, each of which represents significant concentrations of loads and/or generation within electrically and geographically contiguous areas. A total of 253 nodes were developed and analyzed.

The goal was to create nodes that have: (1) significant excess generating capability (exporting areas), (2) significant excess loads (importing areas), or (3) both significant generation and loads (such areas can shift between being importing and exporting areas). Transmission paths connect the nodes on the power grid. Each node is connected to one or more adjacent nodes via transmission paths, each with a known and limited capability. The nodes were designed to exclude—rather than contain—major transmission facilities, so as to make congestion visible between nodes rather than obscured within a node. Electric power system control areas[15] are not good proxies for nodes because they vary widely in size and electrical capacity, and congestion frequently occurs within control areas.

This approach to defining nodes varied by market:

- For markets administered by NYISO and ISO-NE, LMP zones were used as a proxy for nodes. This is because congestion typically occurs between these zones rather than within

[14] These steps involved the use of CRAI's in-house post-processing tools, TRANZER (a commercial product of Cambridge Energy Solutions) and PowerWorld Simulator (a commercial product of PowerWorld Corporation).

[15] See Glossary for definition of "control area."

these zones. An exception is NYISO Zone J (New York City), but Zone J was retained as a single node rather than divided.

- For all other markets, generation and load buses within the same control area were grouped into nodes using a clustering algorithm to reflect the impact of power injections and withdrawals at individual buses on major constrained paths. As noted above, some nodes were primarily generation sources, others were dominated by load rather than generation, and some had both load and generation.

The existing electrical links between pairs of nodes were the paths tested for congestion. The nodes for the Eastern Interconnection are shown in Figure 2-3.

Defining paths

For modeling purposes, a transmission path is defined as a complex of lines linking two nodes. Paths may be defined on two levels—at the aggregate level, a path is defined as one or more lines on the network between two nodes, while at a detailed level a path includes a number of related physical transmission elements connecting one node to another. A path may extend across transmission owners or control areas, and may contain one or more existing transmission system facilities.

Along a path, the model incorporates constraints that are most limiting for flows between generation nodes and load nodes. Constraints restrict the flow on a line, transformer, or a group of related elements, so that the flows do not exceed the appropriate thermal or stability-based reliability limit for the path.

For each hourly time-step in a year-long simulation, GE-MAPS calculates the least-cost dispatch from the portfolio of available generation to meet all loads, recognizing limits on the ability of the paths to support electrical transfers. The program then totals the amount and cost of each generator's production as well as the loading on each path over all hours in the study year. For every scenario run, the model tabulates the transmission congestion for each path over the hours and year, so that the congestion results can be compared within and across scenarios. These results are presented in Chapter 3.

2.6. The Western Interconnection

Review of historical information

Information on congestion in the Western Interconnection was received in two forms. First, over 35 documents from a variety of sources were reviewed; these documents are listed in Appendixes H and J. The majority of these documents were prepared by regional and sub-regional transmission planning study groups, including Western Governors' Association (WGA); Seams Steering Group – Western Interconnection (SSG-WI); Northwest Transmission Assessment Committee (NTAC); Rocky Mountain Area Transmission Study (RMATS); Southwest Transmission Expansion Plan (STEP); Southwest Area Transmission Planning Group (SWAT); and Western Electric Coordinating Council (WECC). One of these, the Western Governors' Association Transmission Task Force report in support of the CDEAC initiative, is notable because materials developed for that study were important inputs to this congestion study's western region modeling.[16]

Second, this study examined historically archived data collected by WECC, including hourly line flows. Access to this comprehensive set of historical information permitted direct calculation of actual grid congestion, including U90, for the transmission paths in the west.

The analysts conducting the Western Interconnection study used the same model and data sources as used for various recent WECC reliability assessments and other modeling and represent the same organizations (and in most cases are the same analysts) as those conducting other western modeling. Accordingly, the western team concluded that there was no need for fresh validation of its model and data against other sources.

[16] http://www.westgov.org/wga/initiatives/cdeac/index.htm.

Simulation modeling to estimate future congestion

The Western Interconnection congestion analysis simulated the years 2008 and 2015. As noted, input data for this study were taken in their entirety from a separate, recent study prepared in support of the WGA Clean and Diversified Energy Initiative. The basic model of the Western Interconnection used in the WGA study was developed previously by SSG-WI for 2008. The loads and resources included in the 2015 base case for the WGA study were derived from recent integrated resource plans prepared by western utilities. Hydro output is fixed based on average historical conditions. Wind output is also fixed based on the amount of expected capacity in 2015 and information on potential wind power production from the National Renewable Energy Laboratory.

The model

The western analysis used GridView, a commercially available multi-area production cost simulation tool developed by ABB, to study future congestion in the Western Interconnection. ABB GridView is similar to the GE-MAPS tool used to study congestion in the Eastern Interconnection. Both seek to minimize the total variable cost of

Figure 2-3. Nodes in Congestion Study Simulation of the Eastern Interconnection

production by dispatching a fixed fleet of generation to meet a known set of hourly electricity loads. Both also take into account limitations on the ability of the transmission system to support imports and exports of power within the interconnection.

Loads

The WECC 2005 Load and Resources forecast was the primary basis for load modeling. Existing and predicted demand-side management is embedded in area load forecasts, and transmission losses are included in the load forecast as a fixed percentage of each load. The Northwest Power and Conservation Council's models were used to determine loads for Oregon, Washington and parts of Idaho. The California Energy Commission's September 2005 load forecast was used to represent California loads. Load forecasts for Colorado, Montana, Utah, Wyoming, northern Nevada and parts of Idaho were based on the RMATS September 2004 study, escalated out to 2008 and 2015.

Transmission paths

The basic units of analysis for the study of congestion in the Western Interconnection are the existing catalogued major transmission paths defined by WECC. The system's historical patterns of power flow, and the long history of coordination and information sharing among western transmission planners and operators have led to the identification of 67 major transmission paths. A path can represent either a single transmission line or a combination of lines from one area or combination of areas to another area or combination of areas. A path may be between control areas or internal to a control area.[17] Interactions between the power flows on various transmission paths and resource output levels are described by technical nomogram[18] relationships.

[17] Recall that as directed by DOE, CRAI developed the functional equivalent of even more granular "paths" for the study of the Eastern Interconnection by applying heuristic and statistical methods, essentially in a bottom-up fashion. By contrast, in the Western Interconnection, the major transmission paths have already been defined on the basis of extensive planning studies and years of operating experience. They are well-documented through a formal WECC process.

[18] A nomogram is a graphic representation that depicts operating relationships between generation, load, voltage, or system stability in a defined network. On lines where the relationship between variables does not change, a nomogram can be represented simply as a single transmission interface limit; in many areas, the nomogram indicates that an increase in transfers into an area via one line will require a decrease in flows on another line.

3. Congestion and Constraints in the Eastern Interconnection

This chapter addresses the Eastern Interconnection, reviewing first the paths that have historically been constrained, and then presenting the simulation results for those parts of the grid that are expected to be constrained and congested in 2008 and 2011. This chapter offers general rather than detailed information on the constraints studied and the simulation modeling results, to avoid offering unnecessary detail about vulnerable elements of the Nation's critical energy infrastructure.[19]

3.1. Historical Transmission Constraints and Congestion Areas

Historical transmission constraints are locations on the grid where it has frequently been necessary to interrupt electric transactions or redirect electricity flows because the existing transmission capacity is insufficient to deliver the desired energy without compromising grid reliability. The constraints shown below were documented by the regional reliability councils or other major transmission entities in the Eastern Interconnection. As noted in Chapter 1, the amount and quality of the transmission studies—and therefore the available information about the grid—varies from region to region across the interconnection. A list of the studies reviewed is included in Appendix I.

Historical transmission constraints are presented below by region. (See maps in Figures 3-1 through 3-6.) In some cases, a constraint is shown as a point, which represents a load pocket with limited transmission into the area to serve its loads. In other cases, the constraint is shown as an arrow, indicating that electricity flows across that constraint tend to be directional, with the generation sources located toward the base of the arrow and the loads somewhere beyond its point. No attempt has been made to depict the magnitude of the transactions that were limited or the level of congestion caused by each constraint; therefore, the arrows do not reflect a magnitude (of electricity flow or economic value). The numbers do not represent a rank order, but correspond to the constraints listed below each map.

These constraints are generally known to transmission owners, planners, and wholesale electricity buyers across the Eastern Interconnection. In some cases, transmission upgrades or expansions are already being planned or are under construction to alleviate a significant reliability or economic problem caused by the constraint. Most of the constraints shown, however, require operational mitigation for day-to-day management, and no commitments for physical capital upgrades have been made.

The congested areas indicated on the graphics below may be affected by one or more local transmission constraints—for instance, the southwest Connecticut area is currently affected by six different transmission constraints. In many cases, the constraint closest to the indicated area is not the most limiting element on the path because some other constraint further "upstream" limits the path's flows to a greater degree.

Constraints in the New England region

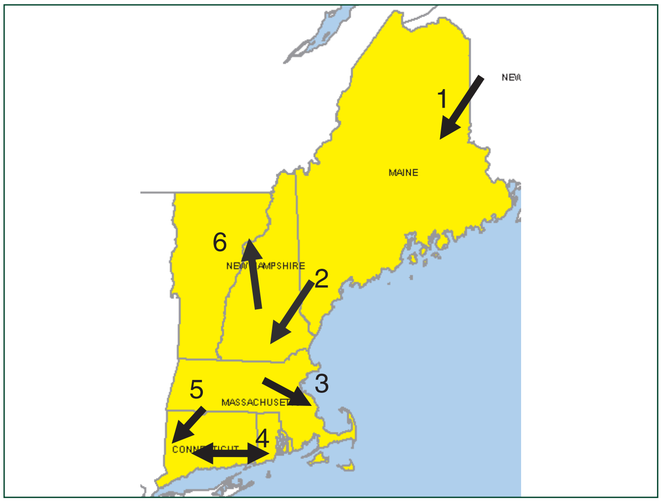
Figure 3-1 shows the following constraints in the New England region:

1. New Brunswick to Maine
2. Maine-New Hampshire Interface
3. Boston Import

[19] A reader seeking more detailed information should contact the transmission planning department of the relevant transmission owner or grid operator, or Department of Energy staff.

4. Southern New England East-West Flows
5. Southwest Connecticut
6. Northwestern Vermont from New Hampshire

Figure 3-1. Constraints in the New England Region (ISO-New England)



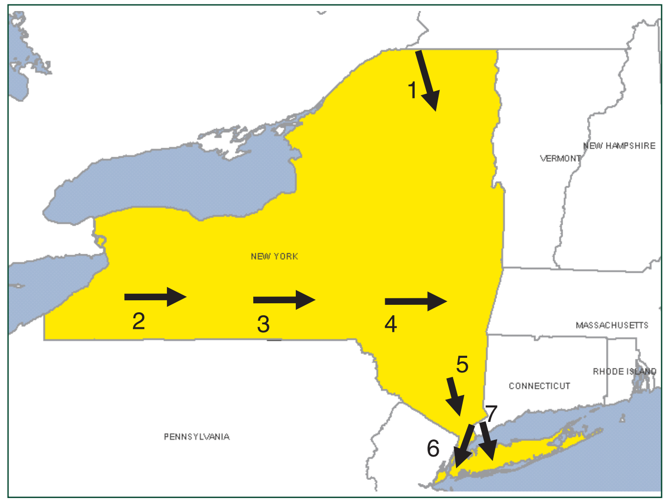
Many of the constraints identified in this region are expected to be eased by transmission projects that are either now under construction or approved by appropriate government officials for construction. Nonetheless, the New England region faces growing electricity supply challenges that new transmission could mitigate. New England has a growing load and many of its older power plants are close to retirement, so the region will need to consider new investments in some combination of local generation, transmission to bring new low-cost power into the area (e.g., hydropower from Quebec), and more energy efficiency and demand response to better manage loads. The area now depends to a substantial extent upon natural gas and oil as generation fuels, which in today's markets leads to high retail electricity prices.

Constraints in the New York region

Figure 3-2 shows the following constraints in the New York region:

1. Moses South Interface
2. Dysinger East Interface
3. West Central Interface
4. Central East and Total East Interface
5. UPNY-ConEd Interface
6. Westchester to New York City
7. Westchester to Long Island

Figure 3-2. Constraints in the New York Region (New York ISO)



All of New York's constrained transmission paths have a common characteristic—they move power from the west, south and north to the loads in and around New York City and Long Island. The New York metropolitan area is a major load pocket with significantly less generation than load, and is heavily import-dependent. The area's electricity rates are high, due in considerable part to the dependence of local generation on natural gas and oil fuels.

Constraints in the PJM region

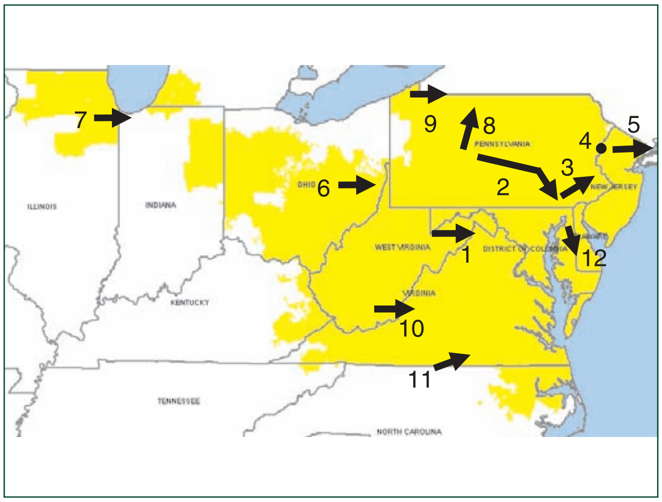
Figure 3-3 shows the following constraints in the PJM region:

1. From Allegheny Power System to PEPCO and Dominion
2. The Western Interface and Central Interfaces of "Classic PJM"[20]
3. The Eastern Interface of "Classic PJM"
4. Branchburg transformer
5. PJM to New York City

[20] PJM has expanded substantially in recent years. The term "Classic PJM" is used to refer to PJM's footprint before the expansion, when PJM's territory consisted of eastern Pennsylvania, New Jersey, much of Maryland, Delaware, and the District of Columbia.

6. American Electric Power and First Energy to APS transformers
7. Lines connecting ComEd to AEP along Lake Michigan—These lines also limit MISO flows
8. Homer City Transformer
9. Erie East – Erie
10. Kanawha – Mt. Funk
11. North Carolina to Southern Virginia
12. Constraints into Delmarva Peninsula

Figure 3-3. Constraints in the PJM Region



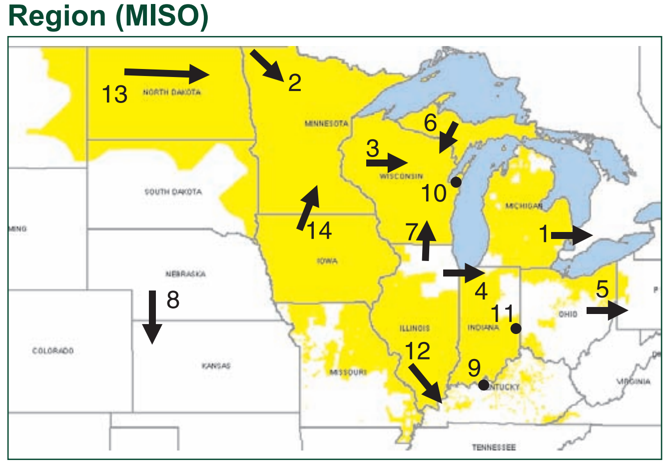
In much the same manner as the New York metropolitan area, eastern PJM is facing continuing load growth in combination with power plant retirements and limited new generation investment near loads. Transmission constraints are causing significant congestion in both western and eastern PJM, because there is more low-cost Midwest coal-based and nuclear power available for delivery eastward than the grid capacity can accommodate. Inside the region, load pockets around Washington DC, central Maryland, the Delmarva Peninsula and New Jersey all need major investments in new transmission, generation and demand management to improve reliability and reduce consumer costs. PJM is also the southern pathway for power flows to the New York metropolitan area, and New York wholesale buyers would like to buy more power through PJM than PJM can deliver, given the limitations of the existing transmission grid.

Constraints in the Midwest ISO region

Figure 3-4 shows the following constraints in the Midwest ISO region:

1. Michigan to Ontario
2. Manitoba to Minnesota and N. Dakota
3. Minnesota to Wisconsin (limits current flows and wind and coal development in the upper Midwest)
4. NIPS system impacts from ComEd to AEP flows
5. First Energy to APS
6. Upper Peninsula of MI into Wisconsin
7. Into Wisconsin from Illinois and Iowa
8. West Nebraska to west Kansas
9. LGE system
10. Inside Wisconsin
11. Miami Fort
12. Illinois to Kentucky
13. Western North Dakota to Eastern North Dakota (low cost coal and wind development cited in MISO MTEP 2005)
14. Iowa and Southern Minnesota (low cost coal and wind development cited in Iowa – Southern Minnesota Exploratory Study, 2005).

Figure 3-4. Constraints in the Midwest ISO Region (MISO)



Several of MISO's transmission constraints are reliability-oriented, such as the Minnesota to Wisconsin limits. However, most of the constraints reflect the desire of wholesale electricity buyers and potential generators to move more low-cost power from resource-rich areas to load centers. Significant additional transmission investments are likely to be required to enable increased flows of coal-fueled and nuclear power from the Midwest (Illinois, Ohio, Indiana and Kentucky) into PJM and New York, and to deliver wind power from the North Central Plains (the Dakotas) to Chicago and other Midwest markets.

Constraints in the Southwest Power Pool region

SPP reports the first six of the following constraints as having the most frequently refused firm transmission requests for the first 3 quarters of 2005 (see Figure 3-5):

1. Elk City Transformer
2. Redbud-Arcadia
3. Valliant-Lydia and Pittsburg-Seminole
4. Ft. Smith Transformer
5. Iatan-Stranger Creek
6. Nebraska to Kansas
7. Kansas Panhandle wind development (from SPP's "Summary of Congestion in SPP and Potential Economic Expansion Alternatives," 2006)

Three major congestion patterns are observable in SPP: East to west flows of electricity toward Oklahoma City, flows from Western Oklahoma into Western Texas, and flows from Nebraska and West Kansas into Central Kansas. As elsewhere, reliability requirements determine which constraints are binding, while the directions of the power flows reflect the underlying economics of the available power sources.

Constraints in the SERC Reliability Corporation region

Figure 3-6 shows the following constraints in the SERC Reliability Corporation region:

Entergy

1\. Southeast Missouri to Northeast Arkansas

2\. Central Arkansas to Southern Arkansas

3\. Ft. Smith

6\. Southeast Louisiana to Western Louisiana

5\. Flow into New Orleans

6\. McAdams Autotransformer

Figure 3-5. Constraints in the Southwest Power Pool Region (SPP)

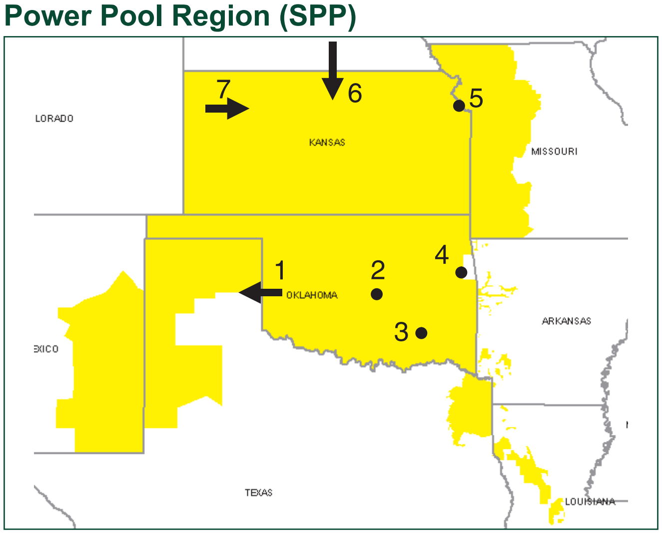
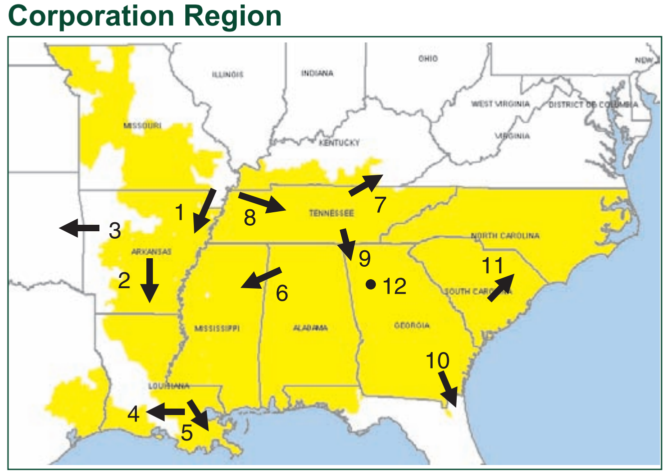


Figure 3-6. Constraints in the SERC Reliability Corporation Region



As shown in Figure 3-6, major constraints within the Entergy portion of the SERC[21] area are limiting flows from Missouri to Arkansas, Central to South Arkansas, flows into the SPP system (Arkansas to Oklahoma), flows from Alabama to Mississippi, and—until recently—flows into New Orleans.

Tennessee Valley Authority (TVA)

7. Volunteer Transformer Bank and Sullivan Transformer Bank (now upgraded)
8. Cumberland-Davidson and Johnsonville-Davidson
9. Tennessee to Georgia

In the TVA area, the most limited flow directions are Tennessee to Georgia (Chattanooga-Huntsville to Atlanta), West to Central Tennessee (flows between Cumberland Fossil Plant and Nashville) and Tennessee to Kentucky (mostly flows from Cumberland into the LGEE system in Kentucky).

Southern Company and VACAR (non-Dominion)

10. Southeast into Florida
11. Eastern South Carolina
12. Atlanta

Problems in the Southern area reflect import limitations into Atlanta and limited flows from Georgia to Florida (limited by constraints on the Florida end). Congestion problems in the VACAR (non-Dominion) portion of SERC are largely concentrated around Charleston, South Carolina.

3.2. Results from Simulations of the Eastern Interconnection

Interpreting the modeling results

Electric system simulation modeling is performed for many purposes, including valuation of existing or proposed generation or transmission assets, long-range system planning, forecasting of electricity prices or transmission congestion contracts, or cost-benefit studies to assess regulatory reforms or market re-design options. For all these purposes, it is necessary to validate the data, modeling assumptions and simulation algorithms. The validation approach varies depending on the goal or purpose of the modeling. In most cases, modelers focus on how realistically the simulation results reflect historically observed inter-regional flows of power and whether the simulated patterns of congestion are similar to those observed in real systems.

In this study, the process of model validation particularly focused on comparing simulated patterns of congestion against those historically observed. Thus, while the model calculates and optimizes electricity production costs subject to reliability constraints, it has been validated for transmission metrics—flows, limits, and congestion results—rather than power production costs. The congestion modeling process followed an iterative approach in which congestion results were benchmarked against validated data, the differences were closely examined, assumptions were revisited and input data verified until discrepancies were ultimately resolved or understood.

This is the first interconnection-wide study of eastern congestion. There are certain questions about data quality and modeling effectiveness—particularly with respect to reactive power, reliability limits and treatment of line losses—that merit further examination. With those uncertainties in mind, the absolute values of congestion metrics for each transmission path or constraint are less important than their relative weights. The goal here has been to identify those paths and areas that are especially congested, not to calibrate exactly how congested each area is now or may become. The Department of Energy is responsible for identifying areas where congestion is now or is likely to become especially severe, and if appropriate, facilitating mitigation of such problems through the designation of National Corridors. For that purpose, determining the relative rankings of the congestion associated with specific constraints is a very useful model result. By contrast, the estimates of power production costs should not be regarded as valid predictors for the

[21] The SERC Reliability Corporation (SERC) is the Regional Reliability Organization (RRO) responsible for promoting, coordinating and ensuring the reliability and adequacy of the bulk power supply systems in the Southeast, excluding Florida.

years modeled. Future electricity production costs are difficult to predict due to the variability and uncertainty of fuel costs, environmental costs, operating costs, and other factors.

Interconnection electricity demands and generation resources were held constant across all of the fuel price scenarios for a given year, as were the transmission system's physical and electrical characteristics. Thus, fuel prices—translated through the geographic distribution of power plants consuming those fuels—were the principal drivers of transmission congestion and costs as they varied between scenarios.

Identifying the most constrained paths

In running the three fuel price cases for 2008 and 2011, as directed by DOE, CRAI identified the highest-ranking hundred constraints for each of the four congestion metrics for each scenario, and for both model years:

- 100 highest binding hours; this identifies the constrained paths that are most consistently and heavily used, and most often require out-of-merit redispatch of generating units to prevent affected facilities from over-loading.
- 100 highest U90; these are the constrained paths that are most frequently within 10% of becoming binding.
- 100 highest shadow price; these constrained paths have the most persistently high shadow prices and cause price spikes in end-use markets.
- 100 highest congestion rent; these are the paths that raise delivered energy costs the most over the course of the year.

As one might expect, some constrained paths ranked high on more than one list. As directed by DOE, CRAI compiled a single list of 171 constrained paths as the most constrained for the 2008 base case; a similar process was followed to identify the most constrained paths for the other five scenarios (2008 high and low fuel price case, and 2011 base, high and low fuel price case). Then CRAI looked across all six scenarios to identify the paths that were near the top of the list in every scenario, and thus would be constrained under almost every year and fuel price; 118 paths fit this pattern. Last, CRAI sorted these top 118 paths by market area.

Figure 3-7 shows the most congested paths identified by the Eastern Interconnection modeling. A few observations:

- Many of the most congested paths are located within regional markets while others cross the boundaries between two markets.
- A significant number of the most congested paths appear on the tie lines between two control areas.
- Given load growth patterns and the size of transmission utility footprints, some of the most congested paths are located within individual control areas, particularly in the Southeast.

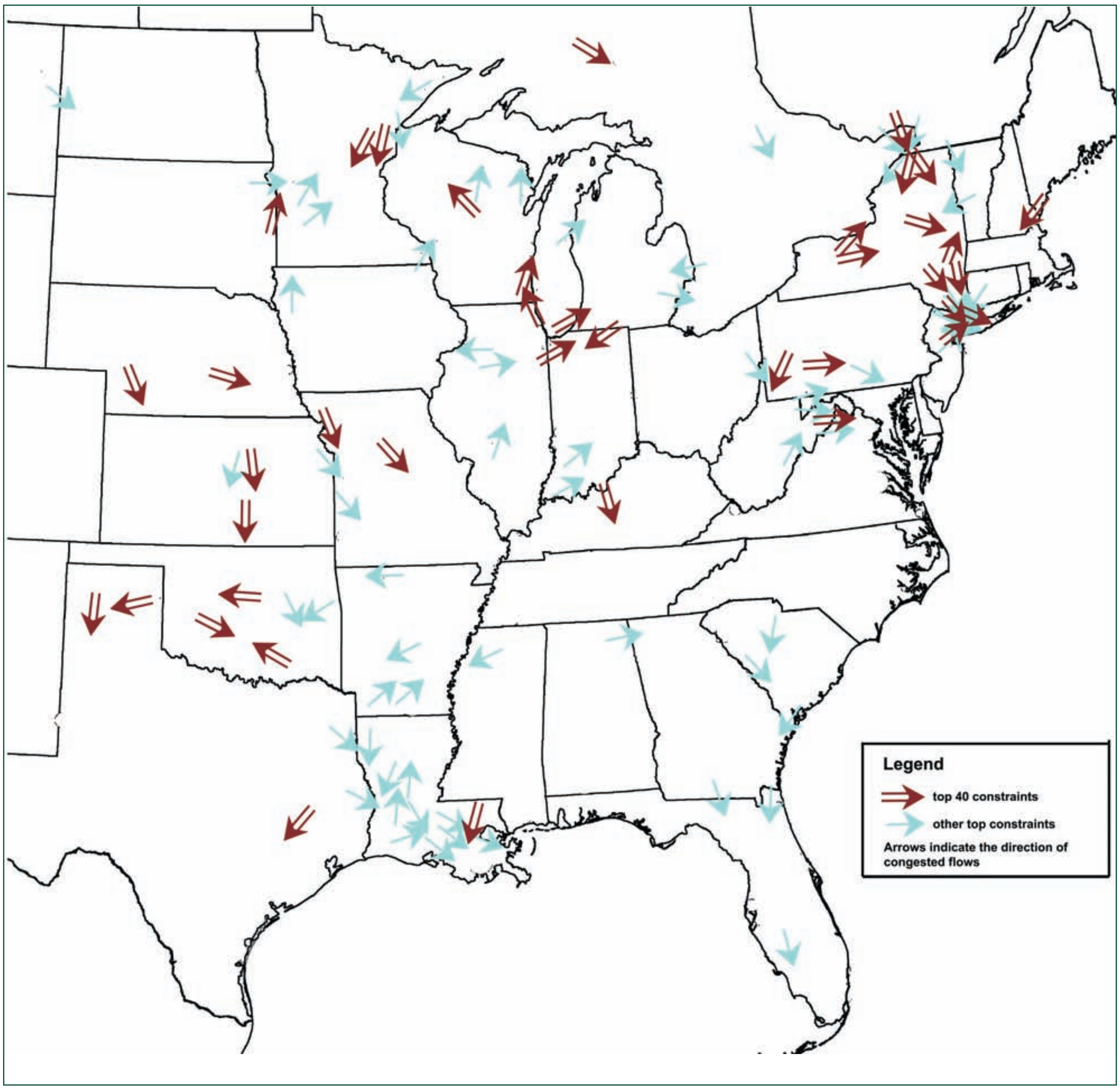
As shown in Figure 3-7, the simulation modeling for the Eastern Interconnection found patterns and locations of congestion and constraints that closely parallel the constraints known from historical patterns. Note that the areas where congestion is most highly concentrated are eastern PJM and the state of New York. Significant congestion is indicated in Louisiana, but this simulation used supply and demand data for the Gulf Coast region as it was prior to the 2005 hurricanes. Demand in this area is now much lower, which presumably reduces the congestion.

One area where the modeled results differed from those reported in existing regional analyses was Florida. DOE's analysis of the Eastern Interconnection showed a significant constraint at the border between Georgia and Florida, and other constraints within Florida. Although these constraints are not as high-ranking (in terms of U90 and congestion rent) as others in the interconnection, the DOE analysis showed higher line loadings and numbers of binding hours than are reflected in available regional analyses.

Officials at the Florida Reliability Coordinating Council (FRCC) suggest two possible reasons for these differences in analytic results. One is that the model used in DOE's analysis may not accurately reflect obstacles to trade in the Georgia-Florida border area, and the second is that dispatch in this area of Florida is based on marginal losses, but the model assumed dispatch on the basis of average losses.

Concerning the obstacles to trade, the model used here assumes economically efficient transactions will occur everywhere in the Eastern Interconnection, including the Georgia-Florida border area. This assumption is typical of simulation models. Deviating from that assumption in an analytically justifiable way is not feasible without more detailed information and data about the obstacles in question, so that they can be accurately portrayed in the model. Average retail electricity rates in Florida were 24% higher in 2004 than those in Georgia and 31% higher than those in Alabama;[22] this implies the existence of significant barriers to trade of some kind. The treatment of line losses will be considered in determining changes needed to improve future national, regional, and inter-regional congestion analyses. (See Chapter 7 for additional discussion.)

Figure 3-7. Most Congested Paths in the Eastern Interconnection, 2008 Simulation



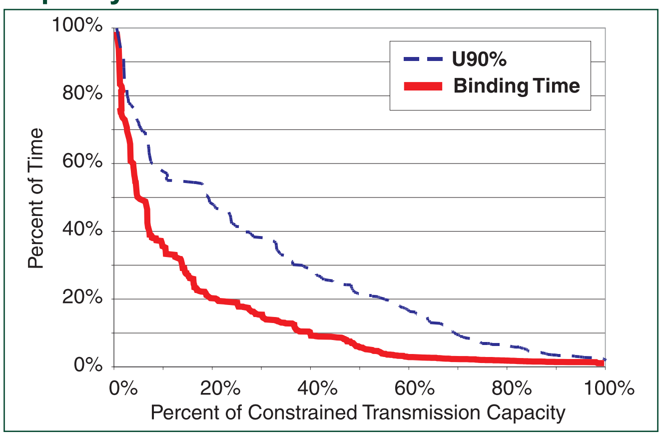
Note: Louisiana is shown as having significant congestion, but this simulation is based on the Gulf Area system as it was prior to the 2005 hurricanes. Electricity demand in the area is now significantly lower, and one would expect congestion to

[22] Energy Information Administration, *State Electricity Profiles 2004*, June 2006.

Other observations based on the congestion modeling

Figure 3-8 confirms expected relationships for those paths that are constrained. First, most constraints are heavily loaded in relatively few hours per year—for instance, 80% of constrained transmission capacity is at its binding limit less than 20% of the year. Second, many of the constraints that sometimes operate at or above 90% of their operating limits reach the binding level (100% of limit) much less frequently. For instance, the ten percent of transmission capacity most heavily used is at 90% usage in 56% of the year, but reaches binding levels only 34% of the time.

Figure 3-8. Time That Constraints Are Binding Relative to Level of Constrained Transmission Capacity

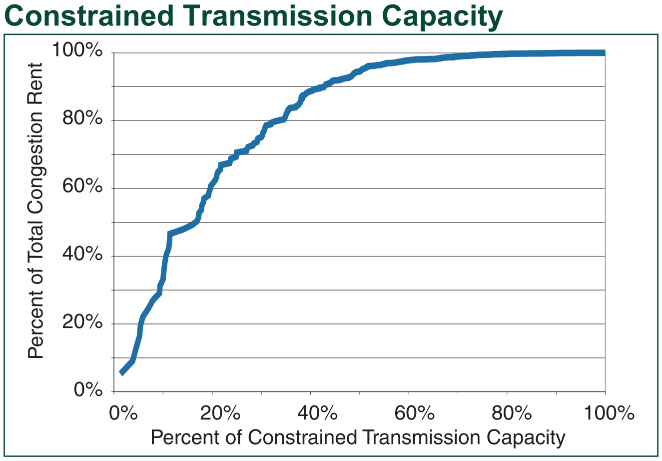


Source: Eastern Interconnection 2008 Base case.

Figures 3-9 and 3-10 confirm two more expected relationships. Figure 3-9 shows that total congestion rent[23] rises as the amount of constrained transmission capacity increases. Thus, 20% of constrained capacity accounts for 60% of congestion rent, and 50% accounts for nearly 95% of congestion rent. Congestion is not evenly spread around the system, and a relatively small portion of constrained transmission capacity causes the bulk of the congestion cost that is passed through to consumers. **This means that a relatively small number of selective additions to transmission capacity could lead to major economic benefits for many consumers.**

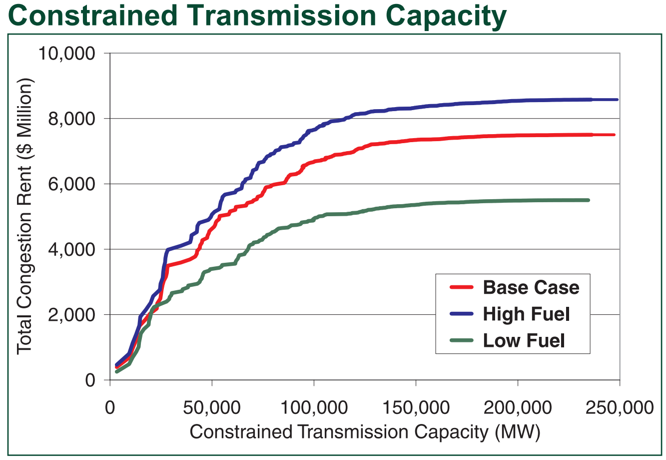
Figure 3-10 shows that the relative level of congestion rent tracks with relative fuel prices—as fuel prices rise, a given transmission constraint will impose higher and higher costs upon the customers located on the expensive, generation-short side of the constraint, because the shadow price of each constraint has fuel prices embedded in the underlying cost of power production foregone due to the constraint. In areas such as the Northeast, where the marginal generation close to loads tends to be older, less efficient oil- and gas-fired units, new transmission construction will enable the import of less expensive coal, nuclear, hydropower, or more

Figure 3-9. Congestion Rent Versus Constrained Transmission Capacity



Source: Eastern Interconnection 2008 Base case.

Figure 3-10. Congestion Rent Versus Constrained Transmission Capacity



Source: Eastern Interconnection 2008 Base case and Fuel Sensitivity case.

[23] Annual congestion rent is calculated by multiplying the marginal production cost of pushing one more MWh through a transmission constraint times the number of MWh that flow through the constraint, and summing the products for the hours during a year when that constraint is limiting.

efficient gas-fired generation, and create millions of dollars of savings in delivered electricity costs, while improving grid reliability.[24]

Congestion rent, as a fraction of total electricity cost, was found to be relatively low in the eastern modeling. For the 2008 base case, the total cost of served load was about $171 billion, and congestion rent totaled 4.7%; for the 2011 high case, the total cost of served load was about $202 billion, and congestion rent totaled 5.1%.

A few specifics about the congestion findings from the modeling:

- 46% of the constrained capacity had average shadow prices greater than $1.00/MWh in all hours.
- 10% of the constrained capacity showed all-hours congestion prices greater than $10/MWh.
- 20% of constrained capacity accounted for 60% of the congestion rent.
- 42% of the constrained capacity accounted for 90% of the congestion.

Reconciling congestion modeling and historical constraints

The top 118 constraints in the Eastern Interconnection identified through modeling and ranking were compared to the historical congestion areas and constraints to verify that the model was properly identifying problem areas on the grid. In most cases, the modeling results were consistent with the historical data.

- Almost every constraint shown as a critical historical constraint identified in the regional studies was identified in the modeling as affecting significant transmission paths.
- Six historical constraints were not confirmed in modeling as binding; upon investigation, it was determined that for five of those constraints, the NERC Multiregional Modeling Working Group (MMWG) load flow case includes transmission upgrades that relieve the historical constraint (for instance, modeled upgrades eliminate part of the Eau Claire-Arpin constraint from Minnesota to Wisconsin, as well as upgrades in Georgia that ease constrained flows into Atlanta). In the case of a constraint in northeast Kansas, as confirmed by SPP, the historical constraint causes primarily non-firm curtailments.
- The modeling identified many more constraints than the regional studies. Most of these did not affect any significant paths, either because the constraint has primarily a local impact, or because other constraints are more binding upon the path. For example, neither the Southwest Connecticut nor the Boston import constraints bind in the model, because upstream and downstream constraints limit flows into the congestion area more tightly.

The net result of this comparison is that the modeling for the Eastern Interconnection effectively identified the important grid congestion areas and transmission constraints.

[24] Economic congestion, as calculated and expressed here, is not intended to be a proxy for true production cost savings, even though reducing congestion does reduce overall electricity production costs.

4. Congestion and Constraints in the Western Interconnection

Chapter 4 has the same structure as Chapter 3—first it reviews the historical transmission constraints in the Western Interconnection, and then it presents the results of congestion simulation modeling. The logic and process of comparing the historical and modeled congestion results in the West was essentially parallel to that described in Chapter 3 for the Eastern Interconnection, so that process is not re-described here.

4.1. Historical Transmission Constraints in the Western Interconnection

The transmission constraints described below were identified by reviewing recent transmission studies, expansion plans and reliability assessments conducted by subregional groups of western utilities, the Western Electricity Coordinating Council (WECC), the Seams Steering Group – Western Interconnection (SSG-WI), and the California Independent System Operator (CAISO). The studies covered in this review are listed in Appendix J. Figure 4-1 shows some of the Western Interconnection's principal catalogued transmission paths and indicates those paths that were identified as congested in the historical studies.[25] A transmission constraint (or constraints) inhibiting flows on a transmission path is represented by a red bar across the path. The bar also crosses or touches all lines comprising the path.

The western analysis used significantly larger nodes (covering wider geographical spans with much larger generation and load weightings) than those used in the eastern modeling. The western path catalog includes 67 WECC paths, plus other monitored lines, as well as specific unscheduled flow paths, operating transfer capability group paths, and nomograms[26] that reflect the effect of other lines (including smaller lines) upon the modeled paths. Some of these paths are internal to nodes, and so were not identified by the modeling described here, although they are well-known and studied in sub-regional analyses.

In addition to reviewing existing studies by others, the western analysis team also examined data on actual transmission usage for the six-year period between 1999 and 2005. Below, Figure 4-2 shows the western transmission paths that were most heavily used. The usage metric shown is U75, the metric that reflects how many hours in a year the path was loaded at or above 75% of Operating Transfer Capability (OTC), the coordinated maximum flow limit set on actual path transfers reflecting system operating conditions at the time.[27] Consistent with other congestion results, this shows that the most heavily loaded lines include the Bridger West line, the Southwest of Four Corners-to-Cholla-to-Pinnacle Peak lines (built to deliver power from baseload plants to loads), Western Colorado to Utah, the lines from Wyoming to Colorado, and the southern New Mexico path to El Paso.

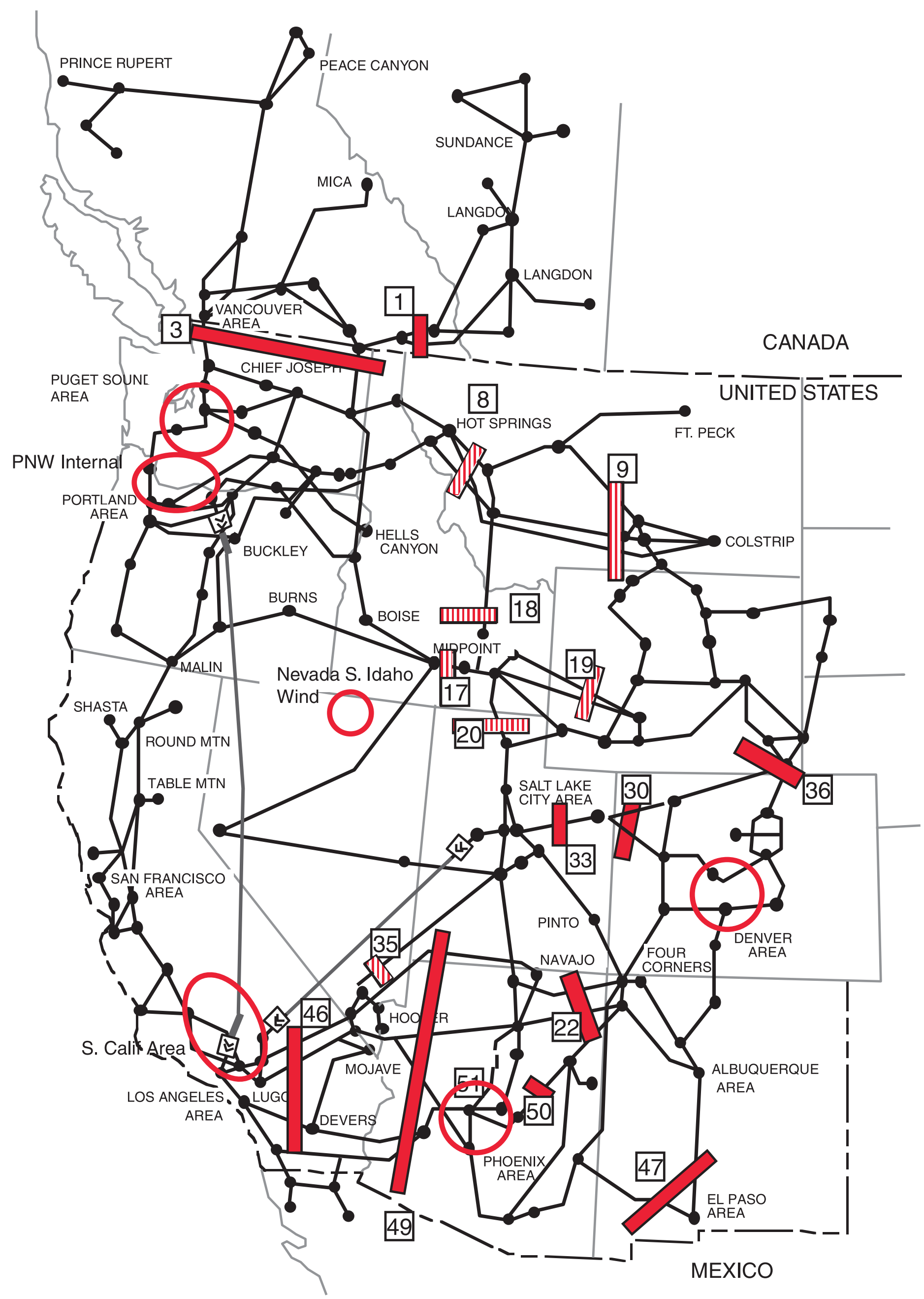
Figure 4-3 shows how heavily various paths within the West have been used over a recent 18-month period. Based on the U90 metric (which is the percentage of time a path is loaded at or above 90% of its limit), this figure shows that only five lines were at U90 or above for more than 10% of the hours in this time period. Of the most heavily loaded lines, note that the Bridger West line is dedicated to delivering electricity from the Bridger coal-fired power plants to loads in Utah and Oregon; this is one-way flow

[25] Appendix K lists WECC's 67 paths.

[26] A "nomogram" is a graphic representation that depicts operating relationships between generation, load, voltage, or system stability in a defined network. (See Glossary.)

[27] WECC, *Operating Transfer Capability Policy Committee Handbook*, May 2006 (http://www.wecc.biz/documents/library/OTC/OTCPC_HANDBOOK_05-19-06.pdf).

Figure 4-1. Congestion on Western Transmission Paths



Congested Transmission Paths

Transmission line (or lines). Solid red or hashed bars "bundle" the lines they cross or touch into a numbered transmission path.

\# The number alongside each bar is the WECC number for that path.

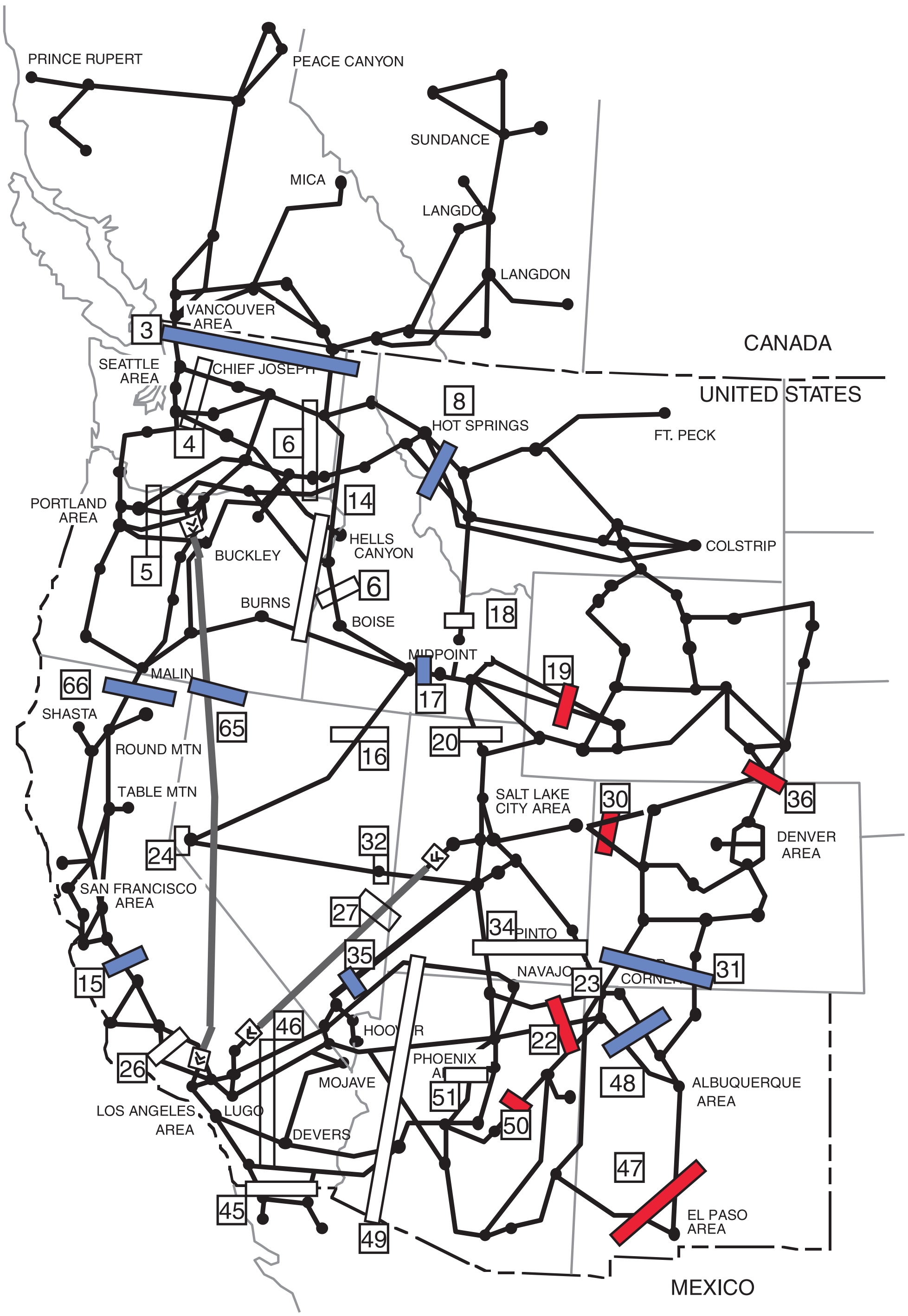
Congestion on the path, based on current or near-term conditions.

Subregional areas with significant existing congestion.

Congestion that would result from future development of generation capacity in the Rocky Mountain area.

Based on historical and existing modeling studies. Not all of WECC's 67 catalogued paths are shown.

Figure 4-2. Actual Transmission Congestion, 1999-2005



Transmission line (or lines). White or colored bars "bundle" the lines they cross or touch into a numbered transmission path.

— The number alongside each bar is the WECC number for that path.

Actual Flow > 75% of OTC greater than 50% of time on path

Actual Flow > 75% of OTC between 25% and 50 % of time on path

Actual Flow > 75% of OTC between 0% and 25% of time on path

Based on most heavily loaded season for each path during the 6-year period.

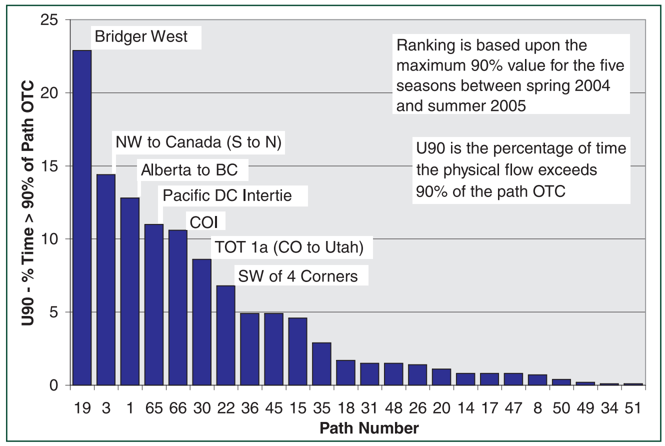
on a line designed specifically for delivery of the plants' output to loads, so high loading for this line demonstrates desirable asset utilization, not undesirably high congestion. Many of the most heavily loaded lines in this period were other major tie-lines similarly designed to facilitate high-volume bulk power trades (Northwest to Canada northbound, Alberta west to British Columbia, the Pacific Direct Current Intertie, the California-Oregon AC Intertie, and the westbound line from Four Corners.

4.2. Congestion Findings From Modeling for the Western Interconnection

Figure 4-4 shows how projected relative congestion patterns vary as a function of fuel prices. This graph orders the most heavily used transmission paths (as measured by U90, the number of hours when usage equals or exceeds 90% of the line's limit), at the base case price for gas ($7/mmBtu). For each path, the graph also shows projected U90 hours for low- and high-case fuel prices as well. The shifts in usage between paths as fuel prices change reflects how electricity flows change with fuel prices—when gas prices are low, long-distance coal-by-wire imports are somewhat less competitive, but when gas prices rise, load-serving entities buy more coal, nuclear and hydropower (to the degree that they are available) and reduce purchases from gas-fired power plants. The shifts in relative congestion associated with fuel price changes would be even more pronounced in a low-hydro scenario.

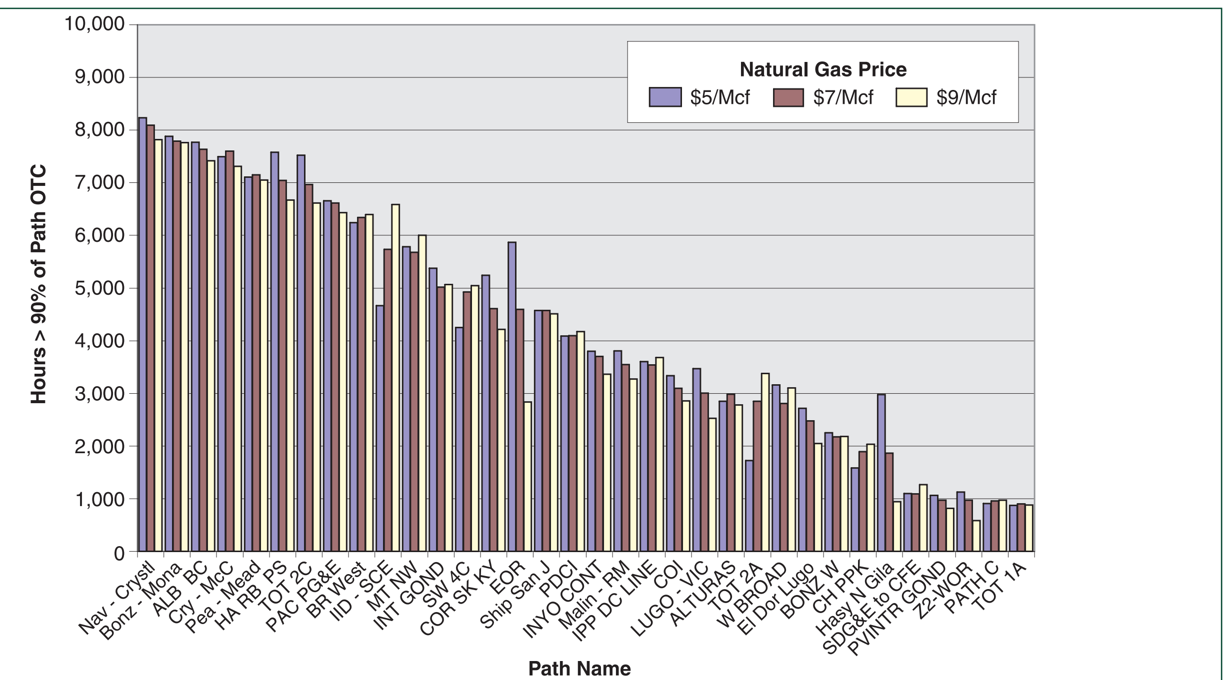
In its modeling, the western analysis sorted the congested paths by a number of methods to identify those that were most congested. Using an averaging method that combined both usage and economic impact, they found the following paths were the

Figure 4-3. Most Heavily Loaded Transmission Paths in 2004-2005



Based on values for U90.

Figure 4-4. Projected Congestion on Western Transmission Paths, 2008



U90 values at alternative natural gas prices.

most likely to be the most heavily congested in 2008:

- Arizona to Southern Nevada and Southern California
- North and Eastern Arizona
- In the Rocky Mountains, the Bridger West line from Wyoming to Utah
- Montana to Washington and Oregon
- Colorado to Utah
- Colorado to New Mexico
- Utah to Northern and Central Nevada
- The Pacific Northwest south to California
- Pacific Northwest flows northward to Canada
- In Southern California, from the Imperial Irrigation District to Southern California Edison.

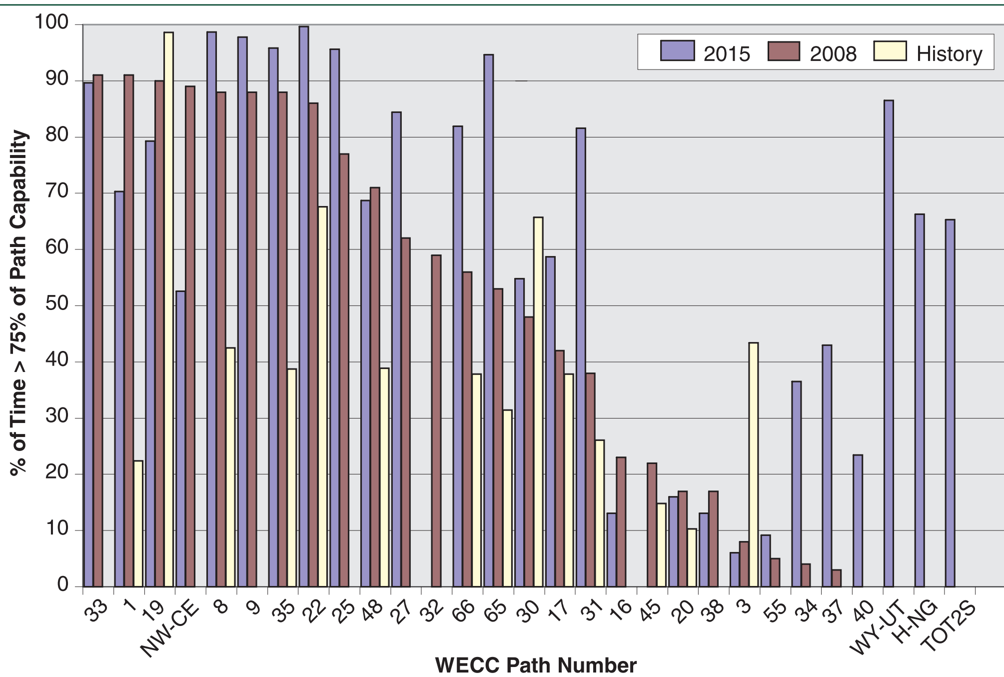
These findings match well with the results from other recent studies (compare to Figure 4-1).

Figure 4-5 (next page) shows congestion on western transmission paths for the 2015 case. The resource assumptions in this case reflect utilities' integrated resource plans and state renewable portfolio standards, as well as certain planned transmission lines that would support those developments. Thus the resource case for 2015 includes both new generation and the transmission that would be required to deliver that production to load; without that transmission, the new generation would be trapped behind the constraints imposed by today's transmission grid, and very likely the new generation itself would not be built.[28] Beyond these specific transmission additions, however, the 2015 case deliberately does not add significant new transmission, so as to expose remaining transmission problems and identify where congestion will occur. As a result, the 2015 case finds that during many time periods, the full output of low-cost generators will not be deliverable to loads without further transmission expansion beyond that assumed in the scenario. It also shows transmission congestion as continuing in many of the same areas where it exists today.

This case illustrates the importance of planning new generation and transmission jointly when seeking to develop new generation capacity distant from loads; without such joint planning and coordination between generation and transmission developers, needed new generation is not likely to be built when needed or in the most suitable locations.

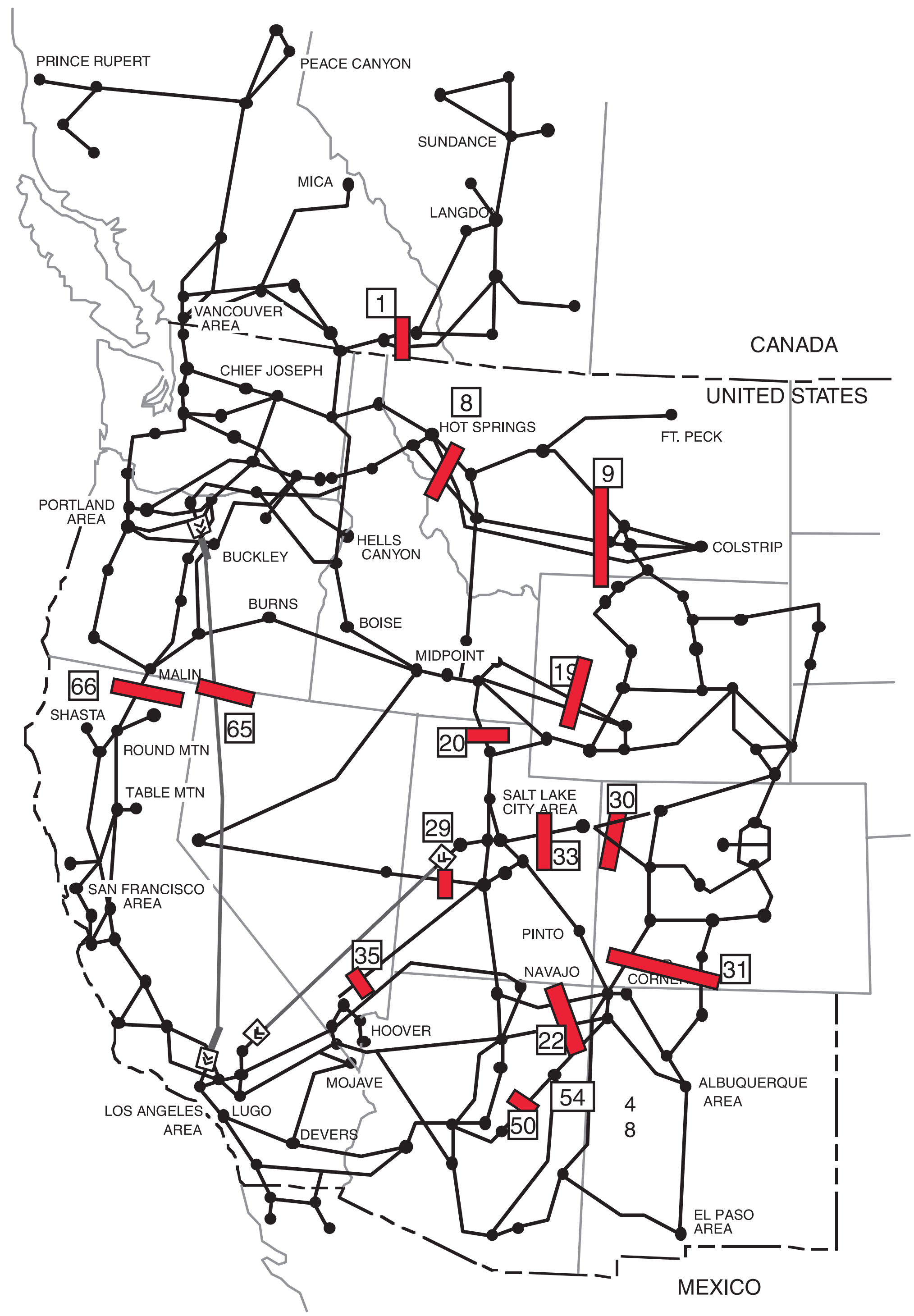
Figure 4-6 compares historical congestion patterns on western paths against modeled congestion for 2008 and 2015, using U75 (the percentage of time

Figure 4-6. Comparison of Historical and Modeled Congestion on Western Paths



[28] For details on the new transmission capacity assumed in the 2015 case, see WCATF's report, posted on the WECC website, http://www.wecc.biz/index.php?module=pagesetter&func=viewpub&tid=5&pid=42.

Figure 4-5. Projected Congestion on Western Transmission Paths, 2015



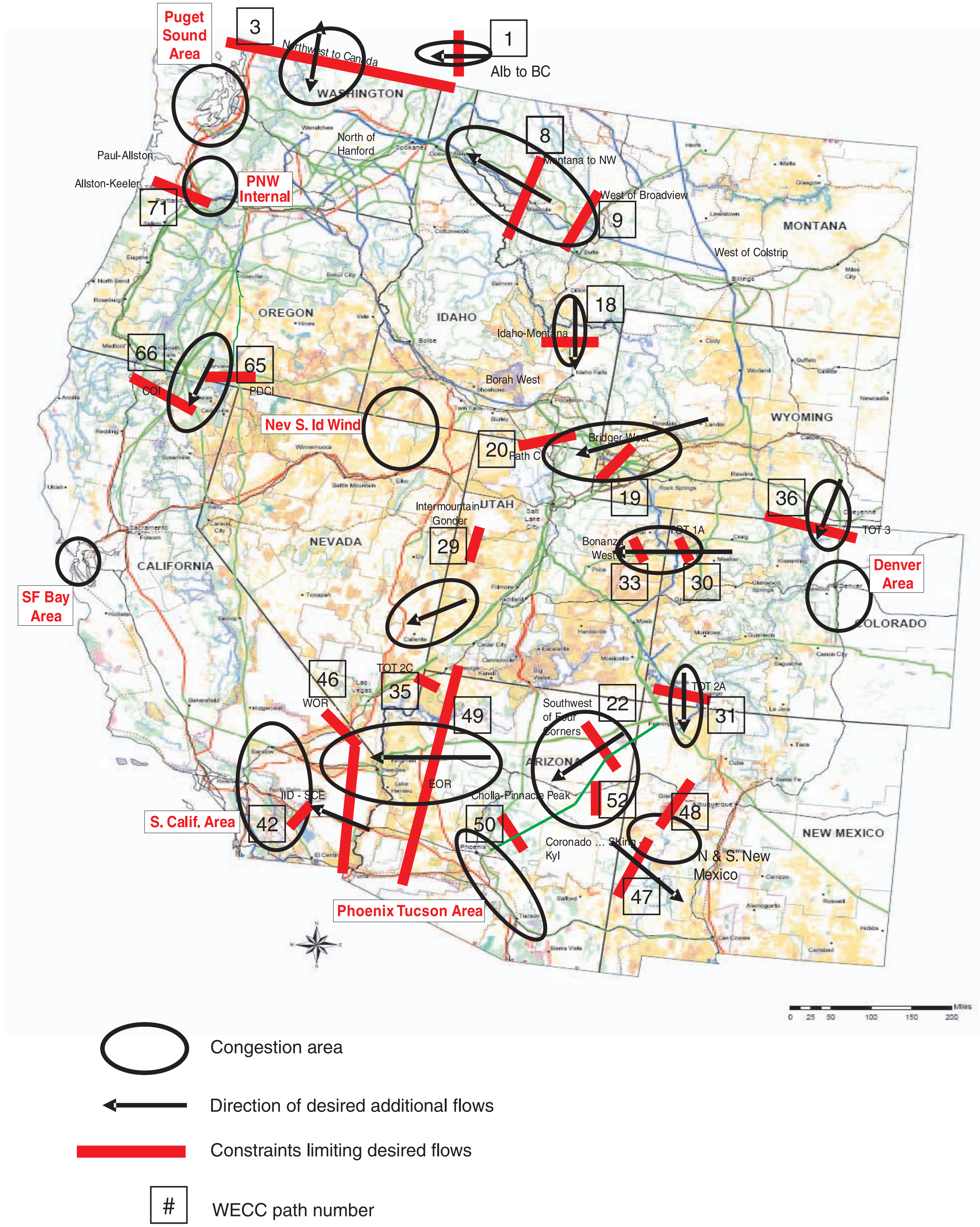
Transmission line (or lines). Solid red bars "bundle" the lines they cross or touch into a numbered transmission path.

\# The number alongside each bar is the WECC number for that path.

Congested path in 2015 simulation. Results are affected by assumptions about future resource development.

Based on most heavily loaded season for each path during the 6-year period.

Figure 4-7. Existing and Projected Major Transmission Constraints in the Western Interconnection



Based on existing studies, usage data, and projections for 2008 and 2015.

when path loading is at or above 75% of the path's reliability limit). For the paths that exist today (shown in Figure 4-6 with both blue and red bars, as distinguished from the lines that were created to connect new generation in 2015, with a blue bar only), there is a high correlation between current and projected transmission congestion. It is important to note, however, that more paths are heavily loaded in the 2015 case because the case assumes higher loads and higher generation outputs but did not increase transmission capacity correspondingly across the interconnection. Thus, path usage levels increase broadly across the grid, not just on the new facilities built into the 2015 case specifically to serve associated new generating capacity.

Figure 4-7 (previous page) displays the principal results of the western analysis in a single graphic. It shows the principal existing and projected constraints in the Western Interconnection, based on existing studies, usage data, and projections for 2008 and 2015.

5. Critical Congestion Areas, Congestion Areas of Concern, and Conditional Congestion Areas

5.1. Overview

Chapters 3 and 4 have described the Department's analyses to identify the most significant congestion areas in the Eastern and Western Interconnections. Building on these results, this chapter identifies certain geographic areas that merit further Federal attention. The Department has grouped these areas into three classes: (1) those where near-term action is especially needed; (2) those where additional analysis and information appear to be needed to better understand the scope and relative urgency of the problem; and (3) those where congestion would become a major problem if new generation were to be developed without sufficient attention to the need for associated new transmission. These classes and the relevant geographic areas are discussed below.

In identifying these areas, the Department considered the size of the affected population and the likely impacts of existing and/or emerging transmission problems on the areas' electric reliability, supply diversity, and economic vitality and growth. It is important to recognize that for each of these congestion areas, appropriate transmission solutions may extend well beyond the boundaries of the congestion area. Although this study identifies a number of congestion areas that merit further Federal attention, DOE may or may not designate National Corridors in relation to these areas.

Critical Congestion Areas. These are areas where DOE finds that it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe. This may be because the affected population is very large, because the economic costs of the congestion are very high, because of a growing reliability problem, because the consequences of grid failure could be very severe for the Nation, or a combination of these considerations. The problems in these areas should be addressed promptly with planning and policy efforts to develop and implement appropriate transmission, generation and demand-side solutions. This study identifies two densely populated and economically vital Critical Congestion Areas:

- The Atlantic coastal area from Metropolitan New York southward through northern Virginia, and
- Southern California.

These areas are identified in Figures 5-1 and 5-2 with orange shading. The dark blue arrows indicate the directions additional low-cost electricity would flow if more transmission capacity were available. In Chapter 6, the Department states that it is focusing attention on, and preliminarily believes it may

Three Classes of Congestion Areas

Critical Congestion Areas: Areas where it is critically important to remedy existing or growing congestion problems because the current and/or projected effects of the congestion are severe.

Congestion Areas of Concern: Areas where this study and other information suggests that a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission and other solutions.

Conditional Congestion Areas: Areas where future congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity.

be most appropriate to consider designation of one or more National Corridors in, these areas.

Congestion Areas of Concern. These are areas where a large-scale congestion problem exists or may be emerging, but more information and analysis is needed to determine the magnitude of the problem and the likely relevance of transmission and other solutions. The congestion in these areas may be significant, but it does not appear to be of critical importance at this time. These areas are shown in Figures 5-1 and 5-2 by light blue arrows. The arrows also indicate where some possible transmission solutions have been suggested and the direction of the additional electricity flows that would result.[29]

This study identifies four Congestion Areas of Concern:

- New England
- The Phoenix-Tucson area
- The San Francisco Bay area
- The Seattle-Portland area

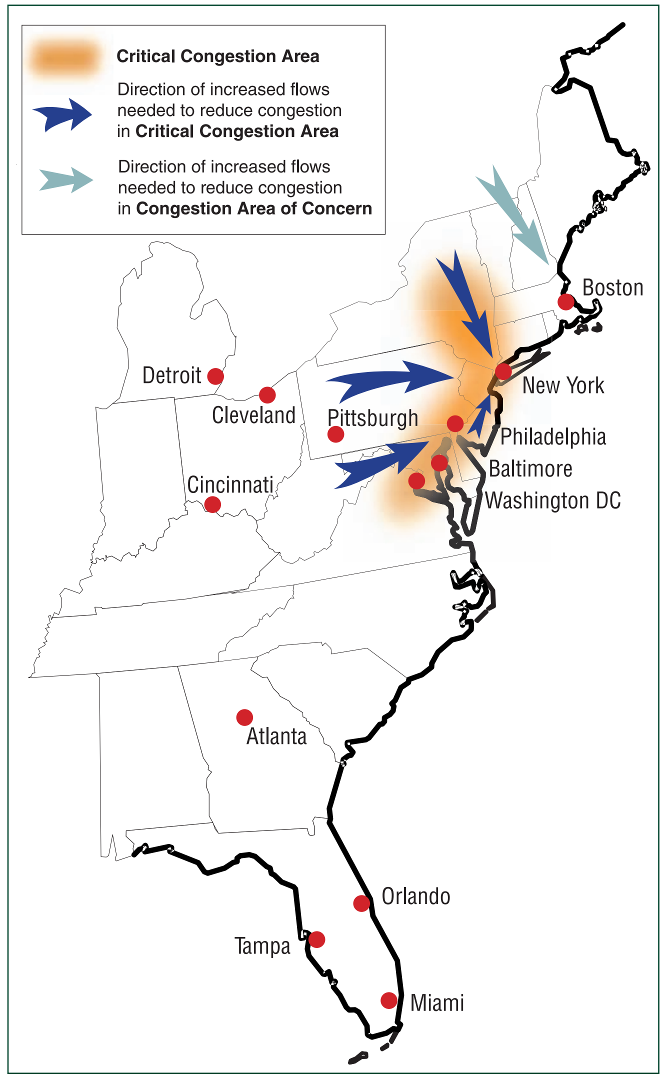
Conditional Congestion Areas. These are areas where significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity. These areas are shown in Figure 5-5, and they are known to be of considerable interest for possible development of wind, nuclear, or coal-fired generation to serve distant load centers. Timely development of integrated generation and transmission projects in these areas will occur only if states, regional organizations, Federal agencies, and companies collaborate to bring these facilities into existence.

Some of the areas of principal interest are:

- Montana-Wyoming (coal and wind)
- Dakotas-Minnesota (wind)
- Kansas-Oklahoma (wind)
- Illinois, Indiana and Upper Appalachia (coal)
- The Southeast (nuclear)

All of these congestion areas are discussed below. In all cases, it appears that a combination of broad regional planning and more detailed local planning are essential to develop a set of preferred transmission, generation and demand-side solutions—to meet regionally-perceived needs, and to build adequate regional support and consensus around those solutions. The likelihood of successful outcomes, with or without designation of National Corridors, will be enhanced if the parties involved in the regional planning also address cost allocation and cost recovery for desired solutions.

Figure 5-1. Critical Congestion Area and Congestion Area of Concern in the Eastern Interconnection



[29] See comments by PJM, Allegheny Power, American Electric Power, and the California Energy Commission in response to DOE's Notice of Inquiry of February 2, 2006.

5.2. Congestion Areas in the Eastern Interconnection

Metropolitan New York – Mid-Atlantic Critical Congestion Area

The area from greater New York City south along the coast to northern Virginia is one continuous congestion area, covering part or all of the states of New York, Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and the District of Columbia. This area requires billions of dollars of investment in new transmission, generation, and demand-side resources over the next decade to protect grid reliability and ensure the area's economic vitality. Planning for the siting, financing, and construction of these facilities is urgent.

Indicators of this area's importance as a population and economic center include:

- 55 million people (19% of the Nation's 2005 population)[30]
- $2.3 trillion dollars of gross state product (18% of the 2005 gross national product)[31]
- 561 terawatt-hours of electricity consumption (16% of the national total in 2004)[32]
- 547 terawatt-hours of electricity generation (14% of the national total in 2004)[33]
- 140 gigawatts of generation capacity (15% of the Nation's 2004 total).[34]

The region also includes the Nation's capital and the world's leading financial and communications centers, and many other facilities critical to national security and defense. Electricity demand in this area is growing: PJM, for example, says that "weather-normalized summer peak in the PJM region is forecast to increase at an average rate of 1.7% per year over the next ten years"[35] (through 2015), ranging from 1.1 to 2.5% among utilities. Inability of the grid to sustain reliable, affordable electricity deliveries to the area would compromise the safety and well-being of the Nation as well as the millions who live and work in the region.

Transmission congestion problems are worsening across this area:

- **In southeastern New York**, metropolitan New York City and Long Island face 1.7% annual load growth, and require continuing additional generation (possibly as early as 2008).[36] Although a growth rate of 1.7% might not be considered high in some areas, in absolute terms here it means satisfying substantial quantities of new demand each year in an area that is already very densely developed. The New York City Building Congress recently estimated that the City will need to add (or gain access to) between 6,000 and 7,000 MW of electricity resources over the next two decades.[37] The City's population is expected to reach 9 million by 2030.[38]
- **Southeastern New York** also needs improved voltage support that will require transmission reinforcements in the Lower Hudson Valley, more generation and demand-side management as early as 2008, and as much as 2,250 MW of new capacity or load reduction by 2015.[39] Even with such improvements, southeast New York state will remain substantially dependent upon the transmission system to meet its capacity and energy needs. Several specific transmission, generation and demand-side measures have been

[30] Source: U.S. Census Bureau, Population Estimates Program, http://factfinder.census.gov/servlet/GCTTable?_bm=y&-geo_id=&-ds_name=PEP_2005_EST&-_lang=en&-_caller=geoselect&-redoLog=false&-format=US-19&-mt_name=PEP_2005_EST_GCTT1_US9.

[31] Source: Bureau of Economic Analysis, National Economic Accounts, http://www.bea.gov/bea/dn/home/gdp.htm.

[32] Energy Information Administration, *Electric Power Annual 2004*, Data Tables, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

[33] *Ibid*.

[34] *Ibid*.

[35] See PJM comments in response to DOE's February 2, 2006 Notice of Inquiry.

[36] Lynch, Mark S., "ISO Power Trends 2005," April 20, 2005 presentation.

[37] See comments by the City of New York in response to DOE's February 2, 2006 Notice of Inquiry.

[38] See demographic projections reported in the *New York Times* at section 1, p. 33, February 19, 2006; cited in comments by City of New York.

[39] NYISO, "The NYISO Issues Reliability Needs Assessment," September 21, 2005.

proposed to address these problems, including a new line (or lines) to bring additional power (principally hydro) down from Canada.

- **As a whole, New York state** depends on high-cost oil and gas for about 35% of its power production; the U.S. average is about 21%.[40] Accordingly, New Yorkers would benefit from improved access to low-cost power. Power moves across the state—whether for reliability or economics—from the northwest to the southeast, and all flows from the west and north must pass through a central set of transmission facilities located between western and downstate New York.
- **In New Jersey**, transmission constraints limit imports from the west and south, causing most of the state to face some of the highest electricity prices in the mid-Atlantic area. Several old, inefficient power plants have been retired recently, reducing local generation and degrading reliability. Major transmission upgrades are needed within 8 years, to bring in power for both reliability and cost reduction. A new merchant transmission line (the Neptune line) will go into service in 2007, and will move electricity from New Jersey into Long Island; the line will ease Long Island's supply needs, but it may exacerbate New Jersey's local reliability and supply problems. Further, some New York parties are looking to the New Jersey – New York interface (and the PJM network beyond it) as a possible means of accessing low-cost generators in the Midwest to support New York City. This could increase wholesale power prices in New Jersey and elsewhere in eastern PJM.
- **The Delaware River path**, an important conduit from Wilmington and Philadelphia north to upper New Jersey, faces numerous projected violations of reliability criteria on the transmission lines that supply densely populated areas of New Jersey in every year from 2005 through 2010.
- **PJM estimates that congestion costs** caused by transmission constraints in the Allegheny Mountain area alone have totaled more than $1.3 billion over the past three years.[41] Further, PJM says that "more than 9400 MW of new generation, of which approximately 6700 MW are coal-fired units located in western Pennsylvania, western Maryland, eastern Kentucky, Ohio, and West Virginia, are pending in PJM's interconnection queue, with commercial operation dates of 2006-2012."[42] Addition of this generation capacity, though needed, will create additional congestion unless new transmission is also developed.
- **Retirements of generation are up sharply** in the mid-Atlantic area. PJM says that over 1700 MW of capacity were retired between January 1, 2003 and late June 2005, and almost another 1700 MW are now proposed for retirement. More than 45% of these units are or were more than 40 years old.[43] Several older, high-polluting power plants are suitable for retirement but are being kept on-line to protect urban voltages. As in other parts of the Mid-Atlantic region, few efficient new power plants have been built close to the load centers in the past decade.
- **The Delmarva Peninsula** has long been a load pocket with significantly higher power prices and lower reliability than the adjoining areas.[44] Although the Delmarva area is not densely populated, it is now experiencing rapid population and load growth. Recent small-scale transmission upgrades have been helpful but will not be sufficient to meet the peninsula's future needs. Recently Pepco Holdings, Inc. proposed a new transmission line that would bring new capacity and energy to the peninsula from the south by crossing the Chesapeake Bay.
- **In the Baltimore – Washington, DC area**, PJM finds that without transmission upgrades, critically important loads in the Washington, DC –

[40] Energy Information Administration, *Electric Power Annual 2004*.

[41] PJM comments in response to DOE's February 2, 2006 Notice of Inquiry.

[42] *Ibid.*

[43] *Ibid.*

[44] *Ibid*. PJM says . . . "load growth in the Delmarva Peninsula is projected to be 2.7% per year or an increase of 573MW, over the next five years, but planned generation additions are minimal. Only 60MW were added to the peninsula in 2004 and only another 150MW are being studied in PJM's interconnection process. Longer term forecasts indicate continuing, significant load growth in this area."

Baltimore area will face numerous violations of reliability criteria over the next 15 years.[45]

There are no easy solutions to these problems. Old, inefficient power plants should be retired or upgraded, and there is often opposition to retaining existing or building new generation within urban areas where it is often needed to support local voltage and grid reliability. Air pollution regulations sometimes limit when and at what output levels existing or new central station and distributed generation can operate. In principle, additional transmission capacity would enable delivery of enough bulk power to meet customers' demands. New transmission lines, however, would go through many communities that may oppose the construction of new overhead high-voltage power lines, while utilities and their customers oppose incurring high costs to make such lines less intrusive aesthetically by putting them underground. Energy efficiency, demand response, and other demand-side measures can reduce loads and improve the balance between supply and demand, but those measures must be pursued over extended periods in order for their impacts to grow to transmission- or power plant-equivalent quantities. As planners in PJM, NYISO, and ISO-NE have recognized, all of these measures should be pursued on an integrated basis to ensure an adequate response to the economic and reliability challenges ahead.

Electricity supply and transmission planners in the Mid-Atlantic area are looking west, particularly to West Virginia, Kentucky, Ohio and Indiana, where there are extensive coal resources and the willingness to host power plants as a means of fostering economic development. West Virginia and western Pennsylvania also have significant potential wind resources. In addition, the Midwest has comfortable reserves of generation for the near term, particularly low-cost, base-load nuclear and coal generation. Nonetheless, major transmission upgrades will be needed in parts of Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia, and perhaps Ohio to enable delivery of enough Midwestern generation to the Mid-Atlantic area to meet that area's growing reliability and economic needs.

Several new high-voltage transmission lines have been proposed to address these needs, but to date no region-wide analysis has been published confirming that the proposed lines would provide the facilities the region needs to strengthen its overall system and facilitate greater imports. As the entity responsible under FERC oversight for transmission planning within its broad footprint, PJM is the appropriate entity to respond to this analytic challenge.

New York City's electricity supply problems are especially complex and difficult. Building new generation capacity within the city is extremely challenging because of air quality restrictions, high real estate values, fuel supply problems, and local opposition to power plants. Some additional generation is being added north of the city to serve the city's requirements. Adding major new transmission lines to the north and northwest would increase the options available to the city for power. During the summer the city could be served by excess, relatively inexpensive hydropower from Canada. The flexibility provided by new transmission could also enable the city to tap recently proposed in-state wind power and clean coal generating capacity, if they are developed. An alternative is to supply a portion of the city's needs by strengthening ties to PJM and using the PJM network to access coal-fired generation in western PJM, but this would affect electricity supplies and costs within PJM.

The organizations directly responsible (under FERC oversight) for transmission planning across this area are PJM and NYISO. They perform and publish analyses for their respective areas on an ongoing basis, coordinate their activities, and seek to extend the time horizons of their respective analyses farther into the future. All of these efforts are important, and continuation of them is vital.

Additional efforts are needed, however, at the inter-regional level. The electric systems of the Mid-Atlantic states and New York have become so highly interdependent that it is not possible to address the Mid-Atlantic problems without affecting New York's electric system, and vice versa.

[45] *Ibid.*

Similarly, because of close import ties and multiple electrical interfaces, significant changes in transmission or generation capacity or flows in New York or the Mid-Atlantic will also affect system operations in New England, Ontario, Michigan, and the upper Midwest. This interdependence will continue to grow. Given that the economy of the Nation and the well-being of its citizens depend heavily upon a strong, reliable, electricity infrastructure for this area, the Department believes it is advisable to develop an inter-regional, long-term approach to dealing with the area's challenges.

The Department recommends that transmission planners, regulators and stakeholders from PJM, NYISO, ISO-NE, MISO, Quebec and Ontario work jointly to analyze the long-term inter-regional challenges and to identify and support solutions that will meet the needs of the wider area as a whole, as well as its components. The Department does not intend that any of the RTO-level initiatives and analyses now under way should be put on hold or delayed while a new level of inter-regional analysis is conducted. The challenge is to find an appropriate balance between the upgrades and other actions that are needed urgently in the near term, and the need to develop realistic concepts for what this critical portion of the Eastern Interconnection should look like twenty and thirty years from now. This long-term effort will be hampered by many uncertainties, and it will be important to ensure that near-term initiatives are robust "no regrets" projects, suitable to a wide range of possible futures.

New England Congestion Area of Concern

Chapter 3 showed that several locations in New England today face significant transmission congestion, but the problems in most of these areas are being addressed through planned transmission projects. These areas include the Maine generation pocket (where too little transmission capacity is available to send more low-cost generation south), the Boston load pocket (where more local generation, more import capacity, more demand reduction, or some combination are needed), southwest Connecticut (where the local grid is very weak), and northern Vermont (where demand has been growing rapidly). ISO-NE and the transmission owners in the region have pursued a systematic reliability assessment and transmission planning process over the past several years, and new transmission projects and other efforts are now under way that are intended to substantially ease these problems.

Beyond these projects, ISO-NE has recently begun analysis of a possible new 345 kV transmission project linking Rhode Island, southern Massachusetts, and central Connecticut. This project could ease reliability concerns in Rhode Island and Massachusetts by strengthening the network, while enabling delivery of needed additional electricity supplies into western Connecticut.[46]

Looking 10-15 years ahead, however, the New England region faces growing electricity supply challenges that new transmission could help to mitigate. New England has a growing load and many of its older power plants are close to retirement, so the region will need to undertake new investments in local generation, transmission to bring new low-cost power into the area (for instance, hydropower from Quebec), and more energy efficiency and demand response to better manage loads. The area now depends to a substantial extent upon natural gas and oil as generation fuels, leading (in today's markets) to high retail electricity prices.

5.3. Congestion Areas in the Western Interconnection

In contrast to the East, congestion in the West is more tightly focused geographically, and in some areas more contingent upon the development of

[46] See National Grid's comments to DOE's February 2, 2006 Notice of Inquiry. National Grid says that "the transmission system in southern New England experiences transmission constraints in Rhode Island, Connecticut, and the Springfield, Massachusetts areas. Limitations on Connecticut import capability that currently result in out-of-merit generation costs are projected to become a reliability issue by 2009 at which time available generation and transmission will no longer be adequate to meet resource adequacy requirements. The ISO-NE RSP05 indicates that the . . . area would benefit from transmission reinforcements that better integrate the load serving and generation within Massachusetts, Rhode Island, and Connecticut, and enhance the grid's ability to move power from east-to-west and vice versa."

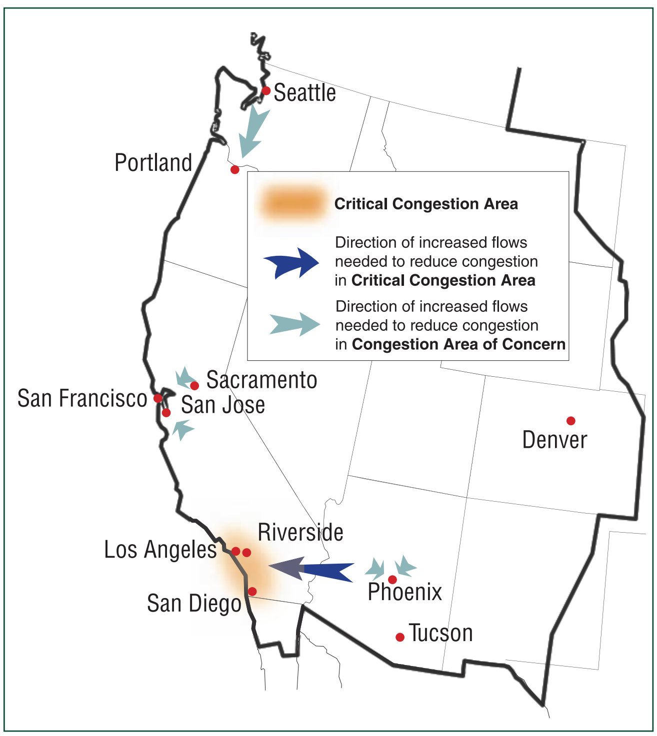
new generation resources. Figure 5-2 shows one area that the Department regards as a Critical Congestion Area (Southern California). Three others are shown as Congestion Areas of Concern (the Seattle – Portland area, the San Francisco Bay area, and the Phoenix – Tucson area).

Southern California Critical Congestion Area

The state of California is the sixth largest economy in the world, and had an estimated population in 2005 of over 36 million persons.[47] About two-thirds of California residents live in Southern California, which faces rapidly growing electric demand. The area contains important economic, manufacturing, military and communications centers—in total, an infrastructure that affects the economic health of the U.S. and the world.

Electrically, this is the area south of WECC transmission path 26, or SP26. (See map in Figure 5-3.)

Figure 5-2. One Critical Congestion Area and Three Congestion Areas of Concern in the Western Interconnection



In 2005, actual peak demand in SP26 reached 98% of the forecasted peak, which was notable because temperatures across the area at the time were moderate and well below 10-year average or 10-year maximum levels. Available generation capacity in the area varies significantly in real time due to changes in planned and forced outages, operational decisions by non-utility generators, hydropower availability, and air emissions and other environmental constraints. Imports are also variable, reflecting transmission limits as well as price variability. Despite recent transmission upgrades on the South of Lugo path, the Mission-Miguel #2 line, and series capacitor upgrades on the Palo Verde-Devers and Southwest Power Link lines, import capability into SP26 is still below desired levels. According to the California ISO, various combinations of extreme peak demand, high generation unavailability, or critical transmission losses could cause the SP26 area to be short on local generation capacity and require the ISO to cut non-firm and firm loads to maintain grid reliability.[48]

Southern California needs new transmission capacity to reach generation sources outside the region for reliability, economics, and compliance with the state's renewable portfolio standard. The California Energy Commission's November 2005 *Strategic Plan* identifies four major projects related to Southern California as needed in the near term:[49]

- Palo Verde – Devers No. 2 500kV Project
- Sunrise Powerlink 500kV Project
- Tehachapi Transmission Plan Phase I – Antelope Transmission Project
- Imperial Valley Transmission Upgrade

San Diego Gas & Electric reports that San Diego is the Nation's seventh largest city, that demand in this area is served by a combination of internal capacity and imported power, and that virtually all of the imports are delivered through two points of interconnection. Neither of these points of interconnection is capable of meeting the peak load import requirements of the area if the other is out of

[47] U.S. Census Bureau, California QuickFacts, July 2006, http://quickfacts.census.gov/qfd/states/06000.html.

[48] CAISO, "2006 Summer Loads and Resources Operational Assessment," April 10, 2006, and CAISO, "Summer 2006 Operating Plan: Focusing on the CAISO South," Darius Shirmohammadi, May 2006.

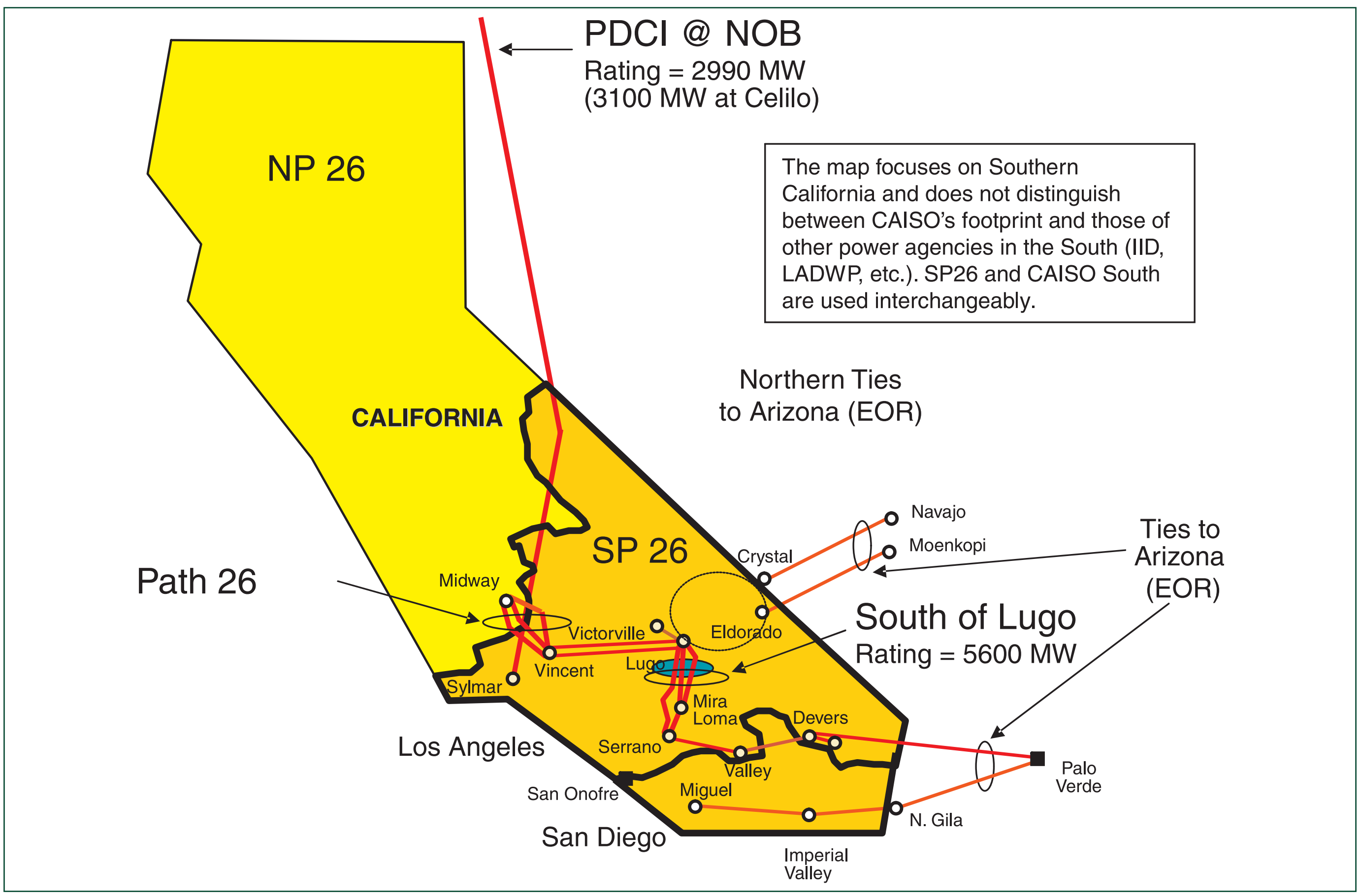
[49] Cited in California Energy Commission's comments (Joe Desmond) in response to DOE's February 2, 2006 Notice of Inquiry.

service.[50] The California Energy Commission, in its "2005 Integrated Energy Policy Report," said "the San Diego region's transmission problems are acute and graphically illustrate the importance of adequate transmission . . . . SDG&E's transmission situation is very precarious."[51]

Given local opposition to new power plants and the limited new plant construction over the past decade, it is questionable whether enough new generation will be built within the region soon enough to meet reliability requirements. Thus, imports are likely to be needed to ensure adequate capacity resources for area reliability. Imports could also provide economic benefits: access to lower-cost generation coal, nuclear, hydroelectric, wind, and efficient gas-fired units could reduce and stabilize the cost of supplying electricity to consumers.

The CAISO has been working with other entities in the Western Electricity Coordinating Council to identify transmission and generation solutions for Southern California and other areas. The CAISO has approved several new transmission upgrades that are under consideration at the Public Utility Commission; other possible components of the area's economics and reliability solutions are tied up in regional discussions about potential development of new generation in the Southwest and Powder River Basin (see the discussion below on Conditional Constraint Areas). Although progress is being made in expanding California's energy infrastructure, Southern California's economic and strategic significance to the Nation is so large that the Department finds it to be a Critical Congestion Area. The Department urges continued cooperative analysis and planning within the Western

Figure 5-3. Southern California: Major Transmission into SP26



Source: California Independent System Operator.

[50] Comments by San Diego Gas & Electric in response to DOE's February 2, 2006 Notice of Inquiry.
[51] Quoted in San Diego comments (*op. cit.*).

Interconnection, and a strong commitment to identify and implement sound solutions as quickly as possible.

Seattle – Portland Congestion Area of Concern

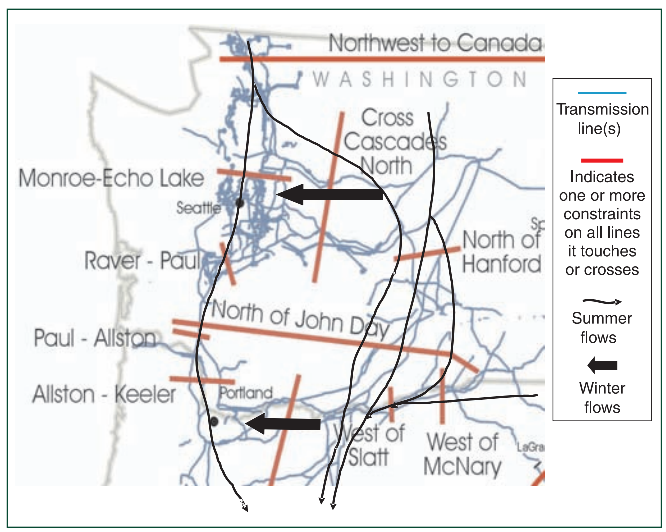
Electricity flows in the area near Highway I-5 from Seattle south toward Portland have become increasingly congested over the past two years, and there is reason to believe that without attention, the problem will grow worse. The Department highlights this area as a matter of concern because these flows represent a growing reliability problem for grid operators, and an emerging economics problem for the Northwest region.

Until recently, the states of Washington and Oregon were winter-peaking—that is, electricity usage was highest in the winter, due to a combination of electricity-based home heating and a high proportion of electricity-intensive industries. In recent years, however, rapid population growth has led to higher summer air conditioning loads, and economic trends have shifted away from manufacturing and toward a more service-based economy. As a result, the region's peak electricity demand now occurs in the summer months. In the 1980s, western power flows followed a predictable seasonal pattern—in the summer, the Pacific Northwest delivered surplus hydropower south to serve California's peak loads, while in the winter electricity producers in California used their surplus generating capacity to make electricity for shipment north to support Oregon and Washington's winter peak load. Today, however, with the shift to summer peak loads, the Pacific Northwest faces a growing need for more transmission capacity to support market transactions and protect system reliability.[52]

In terms of real-time operations, some of the most congested and problematic paths in the Northwest cross the Washington-Oregon border. (See Figure 5-4.) The most serious problems occur in the summer, when loads are highest and transmission operating limits are lower.[53] When these lines are loaded above their limits—as occurred at least 29 times in August 2005—action is required to reduce flow on the path, by redispatching production between power plants until the overload is resolved.[54] NERC requirements for system security require that such overloads be remedied within 30 minutes or less. The magnitude of the overloads and the limited range of solutions available to grid operators make it increasingly challenging to operate the system safely. In addition to thermal overloads, this congestion could exacerbate voltage and transient stability concerns.

At present, operators manage the congestion primarily by adjusting generation output from Federal hydro facilities at various locations north and south of the Oregon-Washington border. However, if more generation is built north of the border, southbound flows will increase, making congestion worse; unless the new generation is built south of the border, or new transmission is built, operators will eventually have to cut non-federal generation or even black out some consumers to protect reliability. Such actions would also cause somewhat

Figure 5-4. Congested Paths and Seasonal Power Flows in the Pacific Northwest



[52] See comments by Seattle City Light, March 6, 2006, in response to DOE's Notice of Inquiry of February 2, 2006.

[53] When electricity flows through a line, some of the electricity is converted to heat; as ambient air temperatures rise, the line grows hotter because less of the heat is dissipated into the air; as load on a transmission line increases, more electricity is converted to heat, the temperature of the line increases, and the line sags lower. As a result, it is necessary to reduce permissible line loadings as ambient temperatures rise.

[54] Bonneville Power Administration (BPA), "Challenge for the Northwest: Protecting and Managing an Increasingly Congested Transmission System," April 2006; BPA, "Congestion Schedule Management," February 7, 2006.

higher electricity costs in Washington, Oregon and California.

This congestion problem was not identified in either the review of existing historical analyses or the modeling conducted for this study, for two reasons. First, to make the task manageable, the historical review addressed only analyses pertaining to the 67 catalogued transmission paths in the Western Interconnection, and this congestion does not occur on one of those paths. Second, based on information from regional sources, the 2008 scenario assumed that thousands of MW of new generation would be built in Oregon, which would alleviate much of the congestion. However, if less of that generation is built, or some of it is built in Washington north of the transmission constraint, then the congestion is likely to continue and grow more serious.

Given that summer loads in Washington, Oregon and California will continue to grow (even with demand-side programs), it is likely that without focused remediation, this congestion will worsen and compromise reliability in this vital region. The stakeholders in Washington and Oregon have begun studying the problem and are working to find solutions. The Department believes that the parties should continue these efforts to ensure that appropriate solutions, perhaps including new transmission facilities, are identified and implemented to protect regional reliability and reduce consumers' costs.

San Francisco Bay Area Congestion Area of Concern

In Northern California, the biggest reliability challenges are in the area between San Jose and the San Francisco peninsula. The peninsula, home to San Francisco and important technology, financial and medical institutions, has very little local generation and is served by long radial transmission feeder lines. The Bay Area cities of Alameda, Palo Alto, and Santa Clara state, for example, that in 2004 the Greater Bay Area had to rely upon 4300 MW of local high-cost reliability-must-run (RMR) generating capacity to meet the area's total requirements of about 9000 MW. Annual RMR costs for the Pacific Gas & Electric portion alone of the Greater Bay Area were estimated at more than $187 million.[55] San Francisco has experienced numerous large outages, including those in 1998, 2003 and 2005. Farther south in San Jose, a large population and manufacturing economy has high loads served with little local generation, heavy dependence on two substations, and a 115 kV system. As with the other Congestion Areas of Concern, the Bay Area needs new transmission and generation to improve reliability and reduce the local delivered cost of electricity.

Various transmission options have been proposed, but as yet no broad suite of solutions has been proposed and approved to address these problems. Until this objective is met, the Department will view the Bay Area as a Congestion Area of Concern.

Phoenix – Tucson Congestion Area of Concern

Phoenix is the sixth-largest city in the United States; almost 4 million people live in the Phoenix metropolitan area. The region has seen explosive growth, with population increasing by a third between 1990 and 2000. Both population and energy demand continue to grow. About 110 miles to the southeast, the Tucson metro area has almost a million people and is also growing rapidly. Both cities have a significant concentration of economically important high-technology businesses, including manufacturing and research. Arizona Public Service Company states that "annual system load growth throughout the Southwest is 3-5%, which is approximately three times the national average."[56]

Historical studies of path utilization in central and south Arizona show transmission to be heavily loaded today, and congestion is projected to grow rapidly under every future scenario studied. One major transmission path in the area operates at U75 for 40% or more hours in the summer, while the other paths are forecast to have very high shadow

[55] See Comments of Bay Area Municipal Transmission Group in response to DOE's February 2, 2006 Notice of Inquiry (including attachment dated September 17, 2004).

[56] See comments of Arizona Public Service Company (APS), a subsidiary of Pinnacle West Capital Group, in response to DOE's February 2, 2006 Notice of Inquiry.

prices during binding hours in 2008 and 2015. Some of the high transmission loading is driven by the two metro areas' reliability needs, but some is caused by the recent proliferation of new generation capacity in Arizona built to serve California loads.

Transmission planners have identified a set of transmission solutions that should help address the Arizona problems and manage new generation interconnection and flows more effectively. However, until there is more certainty with respect to approval for these new lines, generation construction, and long-term procurement contracting between wholesale purchasers and producers, transmission adequacy in the Phoenix – Tucson area will merit continued attention from the Department of Energy.

5.4. Enabling New Resource Development: Conditional Constraint Areas

One of the principal benefits of new transmission is to enable the development of new supply resources in remote area to serve urban load centers. A variety of companies are refining proposals to develop large concentrations of new generation in specific areas—such as wind in the Dakotas and Western Kansas, mine-mouth coal in the Powder River Basin and Appalachia, and nuclear power in the Southeast. If this concentrated generation capacity were to be developed without associated transmission facilities, its output could not be delivered to loads because the existing grid would not be able to accommodate the flows. Significant investments in new backbone transmission will be needed to enable the commercial success of such generation development projects.

The congestion study analysts used two alternative generation development scenarios to assess their impacts on transmission congestion. The Eastern Interconnection scenario assumed substantial new wind development in the Northern Great Plains and Western Kansas, and the Western Interconnection analysis used a scenario projecting new wind development in Southern California and Wyoming and new coal development in Wyoming and Montana. In both scenarios, it is clear that only a limited amount of output from new generation capacity could be delivered from the source nodes to markets using existing transmission facilities without causing new congestion problems. This conclusion should not be surprising. The transmission networks in these areas were designed to accommodate existing or projected local and sub-regional requirements, as opposed to major increases in the volume of electricity produced for export. In some areas upgrades are already needed to meet nearby requirements.

Concerns about energy security and the need for greater diversification in electricity supplies are leading to increased emphasis on development of domestic energy resources. Federal and state policies will greatly affect which areas are developed and when. Some of these policy decisions have already been made: twenty-two states, representing more than 40% of U.S. electricity sales, have adopted some type of renewable portfolio requirement. Wind power is expected to constitute the bulk of new renewable purchases (i.e., non-hydro) and for the foreseeable future wind is expected to be the dominant renewable capacity investment.[57]

The U.S. has vast reserves of coal, most of which is located far from load centers. Although historically most coal has been delivered by rail to power plants sited near load centers (as opposed to mine-mouth generation and delivery of electricity to load centers by wire), railroad capacity is also constrained and it has become about as difficult and expensive to build new rail as it is to build new transmission. Thus, many proposals to build new coal-fired generation contemplate building an associated high-voltage or ultra-high voltage line to deliver the coal to distant load centers.

As discussed previously, the degree of congestion projected in a simulation model is determined in large part by the assumptions made—for example, if one were to design a 2015 western case with 2,000 MW of new coal-fired power plants on-line in Wyoming, and add major new lines to deliver that

[57] Nonetheless, sizeable amounts of potential commercial-scale geothermal, solar, and biomass generation capacity were identified as possible by 2015 in the report of the Clean and Diversified Energy Advisory Committee (CDEAC) to the Western Governors, June 2006. Much of this non-wind renewables capacity would also require development of new transmission capacity.

energy from Wyoming to Utah, Arizona and California, the new generation would cause little new congestion because the congestion solution—appropriately located new transmission—would already be assumed and incorporated into the simulation.

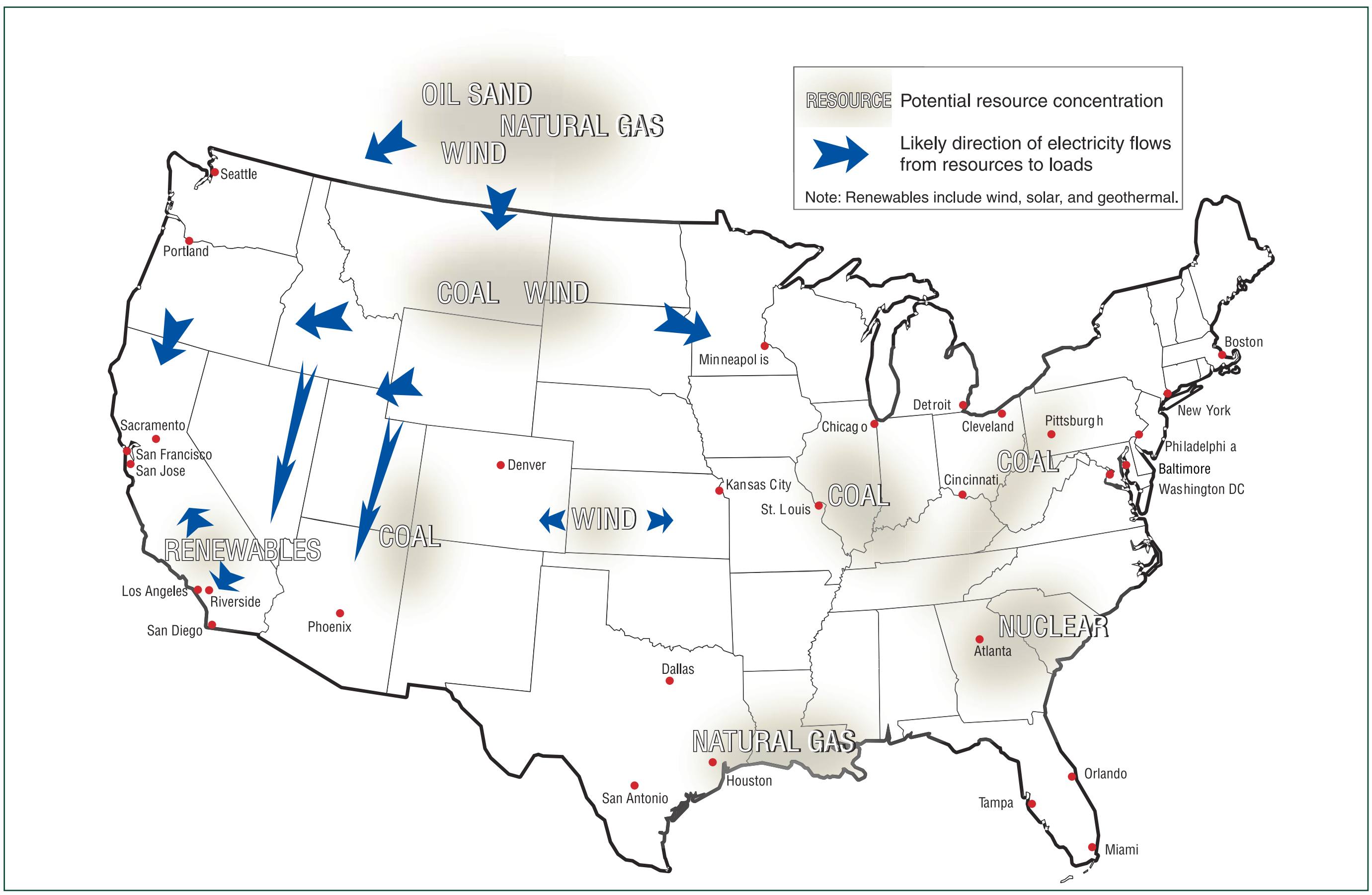
This congestion study does not address in detail when and where concentrated development of new generation resources would cause transmission congestion. We are confident, however, that the grid as built today cannot sustain major development and use of new domestic coal, wind, or nuclear plants without significant congestion and deliverability problems—and that the associated transmission requirements must be addressed in combination with the planning of the new generation facilities. At the same time, the additional transmission capacity would be able to both deliver the new generation and support other flows as well, often reducing overall delivered energy costs and improving reliability elsewhere in the Interconnection.

Because of the chicken-and-egg relationship between new generation capacity and new transmission capacity in these areas, future congestion studies will require a set of carefully-designed assumptions and scenarios to better understand the dynamics and impacts of alternative patterns of developing these facilities. For the near term, the Department has identified the source areas where possible new generation might be concentrated as Conditional Constraint Areas, to highlight their relevance for likely future development. (See Figure 5-5 below.)

The Secretary, now or in the future, may designate one or more National Corridors in relation to a Conditional Constraint Area, if appropriate. Decisions on National Corridors in these areas would depend on the availability and quality of information in response to questions such as:

1. Is there a clear regional or multi-state commitment to develop substantial new generation resources in the area?

Figure 5-5. Conditional Constraint Areas



2. Is there strong commercial interest from generation companies that would develop the resources, and from load-serving entities that would purchase the output?
3. Has sufficient analysis been done to determine the amount and approximate locations of the required new transmission facilities?
4. Are the overall public benefits associated with the development of the new generation and transmission complex sufficiently large to merit National Corridor designation?

In this context, section 368 of the Energy Policy Act of 2005 requires the Secretaries of Energy, Agriculture, Commerce, Interior, and Defense to identify areas on Federal Lands in the West that are suitable for designation as multipurpose energy corridors. The law requires designation of these corridors by August 2007. Such corridors in the rest of the country must be identified and designated by August 2009. On June 23, 2006, the Departments named above released a preliminary map of potential energy corridors they are considering for designation in the West under section 368 (see Figure 5-6). For more detailed state-level maps of these potential corridors, see the website listed in the footnote below.[58] DOE recognizes the need to coordinate the designation of National Corridors and the designation of multipurpose energy corridors under section 368.

Montana – Wyoming Conditional Constraint Area

This area is rich in coal and wind resources that, if developed, could provide important sources of low-cost energy and fuel diversity while improving domestic energy self-sufficiency and enhancing the economic development in the resource areas. This resource development scenario has been thoroughly explored in analyses sponsored by the Western Governors Association.[59] Several new transmission lines have been proposed[60] to deliver this energy westward to distant load centers in Washington, Oregon and California, and southward to Arizona and Nevada. Other new lines would support these flows, such as the new capacity discussed above for the Seattle – Portland area.

Further, much of western Canada is rich in coal, natural gas, wind, and oil sands. If the Canadian provinces choose to develop these resources to increase their energy exports to the United States, much of the generation in Alberta would be transmitted south by way of British Columbia, or by building new lines directly into the Northern Great Plains. These lines would then link up with the new lines proposed to support expansion and shipment of Montana-Wyoming generation.

Development of these generation resources and distribution of their economic and reliability benefits across much of the Western Interconnection will not occur without a corresponding commitment to build the transmission lines needed to deliver the generation to distant loads. This will require a long-term Federal and state policy commitment to site and develop the resources, including support for long-term power purchase contracts and some agreement on how to allocate the costs of the new transmission in a fair, mutually-accepted fashion. Several of the extra-high voltage lines conceived in this scenario could be sited in the energy corridors on Federal lands now being identified under section 368. (See Figure 5-6.)

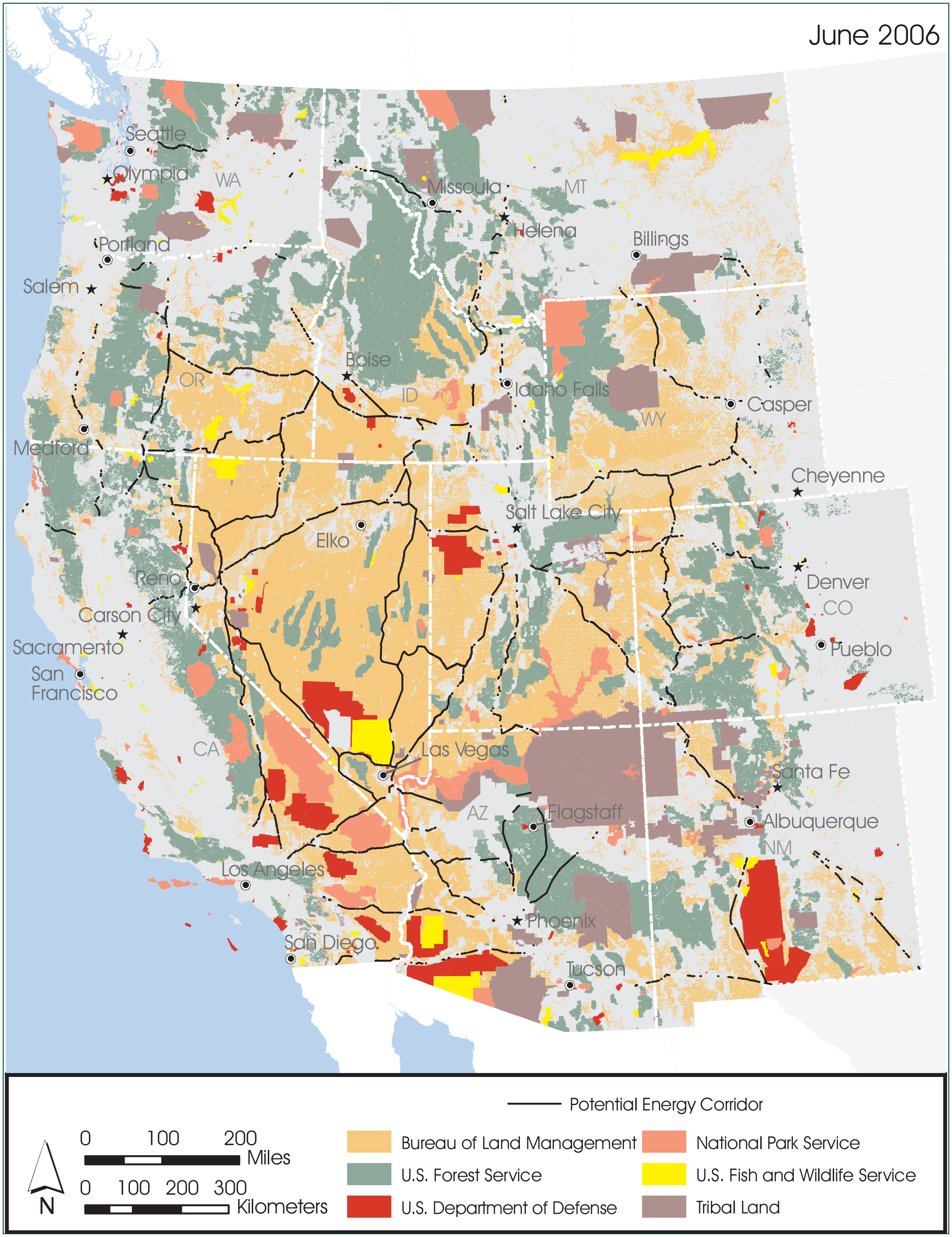
Figure 5-7 shows key results from the Western Governors Association's Clean and Diversified Energy Advisory Committee's (CDEAC) projection of a high coal generation future. The figure shows the probable locations and quantities for new coal generation in 2015 across Montana, Wyoming, Nevada and Utah, plus (in red) the associated new transmission lines that would be needed. Figure 5-8 presents a comparable projection for a future emphasizing new renewable resource development, spanning the above states plus the Pacific Northwest. As shown in both figures, the CDEAC

[58] For more information about implementation of section 368, see http://corridoreis.anl.gov.

[59] See especially the "Report of the Transmission Task Force, May 2006, Western Governors' Association Clean and Diversified Energy Initiative," at http://www.westgov.org/wga/initiatives/cdeac/TransmissionReport-final.pdf, and the broader CDEAC report at http://www.westgov.org/wga/meetings/am2006/CDEAC06.pdf.

[60] These proposals include the Frontier line from Wyoming through Utah and Nevada to California, Northern Lights from Montana to Nevada, and the TransWest Express from Idaho to Arizona.

Figure 5-6. Potential Corridors on Federal Lands in the West



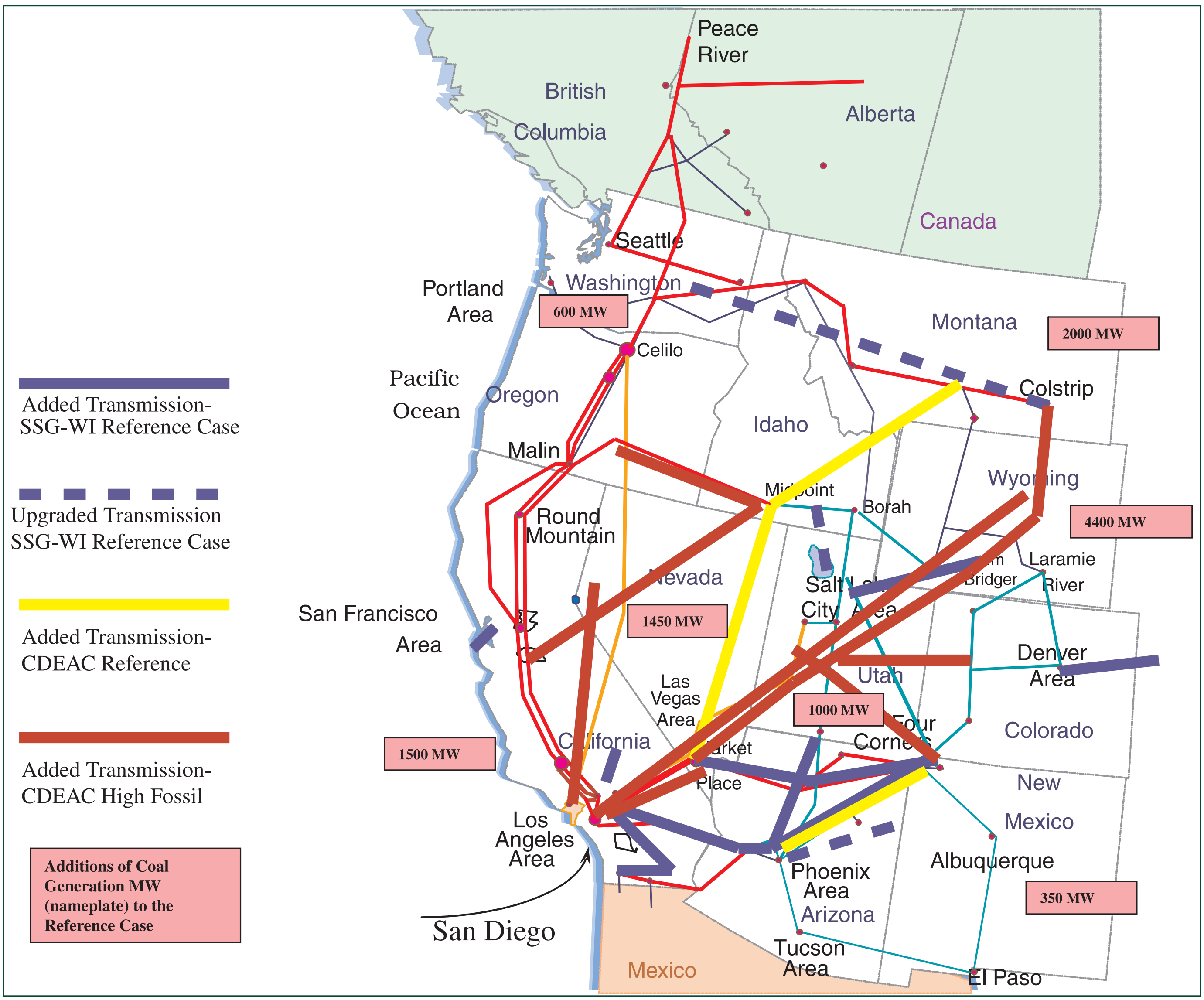
Note: These corridors are under consideration for designation as part of the implementation of section 368 of the Energy Policy Act of 2005.

Reference Transmission Case, which includes a mix of new generation capacity, projects a need for 21 transmission additions and upgrades with about 3,956 miles of new lines, at a cost of nearly $8.4 billion. In addition, CDEAC concluded that there is "considerable overlap in the transmission recommendations between the High Coal and High Renewables scenarios," finding that "the two scenarios share five common projects covering approximately 2,021 miles of new lines for a cost of nearly $3.6 billion."[61] Thus, under a diverse range of generation futures, the Western Interconnection needs large additions to its transmission network.

Dakotas – Minnesota Conditional Constraint Area

Across North Dakota, South Dakota, Minnesota and Wisconsin, there is over 300 GW of potential wind generation capacity.[62] Figure 5-9 illustrates the potential locations for wind development in the Dakotas and Minnesota. Tapping this potential would be very beneficial for the Great Plains economy, and enhance the Nation's energy security and fuel diversity. The transmission needed to deliver this generation to Midwestern markets, however, will require contractual purchase commitments

Figure 5-7. CDEAC 2015 High Coal Generation and Associated New Transmission Lines



[61] CDEAC Report, pp. 8 and 9.

[62] "Midwest Wind Power Development—Transmission Planning in the Midwest IV," presentation by Mat Schuerger, February 11, 2004, Wind on the Wires.

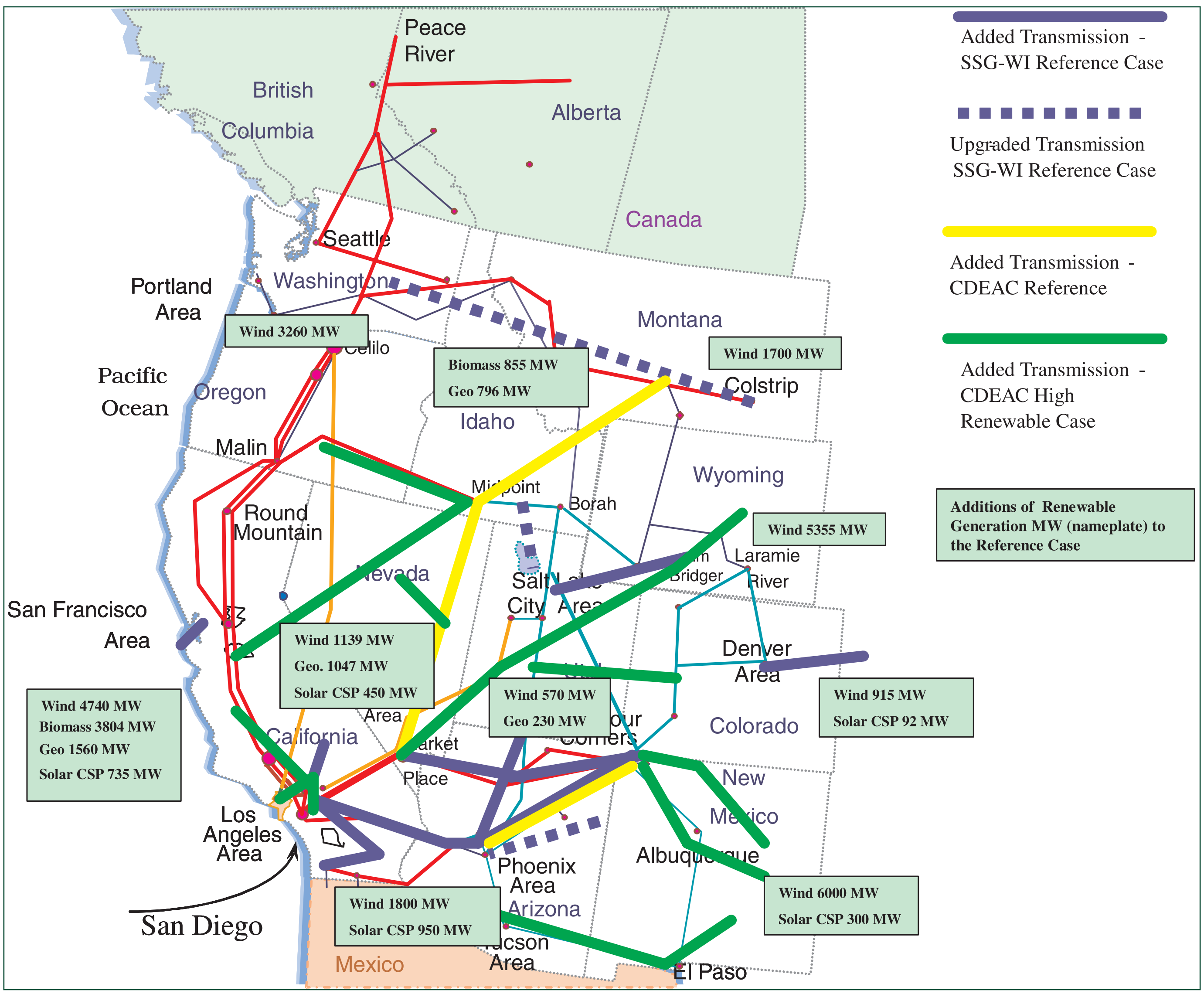
from buyers, significant financial investments, and a means of definitively allocating the costs of the new transmission.

The states and wind advocates within MISO's footprint have made a firm commitment to wind development, projecting the development of 10,000 MW of new wind power across much of the Midwest.[63] Concerted discussion and planning toward this goal over the past four years has led to significant progress. In June 2006 a consortium of electric cooperatives, municipals and investor-owned utilities called CapX 2020 announced that its members would invest several billion dollars in three 345 kV transmission lines spanning 550 miles, linking South Dakota, North Dakota, and various points in Minnesota and Wisconsin.[64] If successful, these projects will provide a significant portion of the new transmission needed to make the vision of Northern Great Plains wind development a reality.

Kansas – Oklahoma Conditional Constraint Area

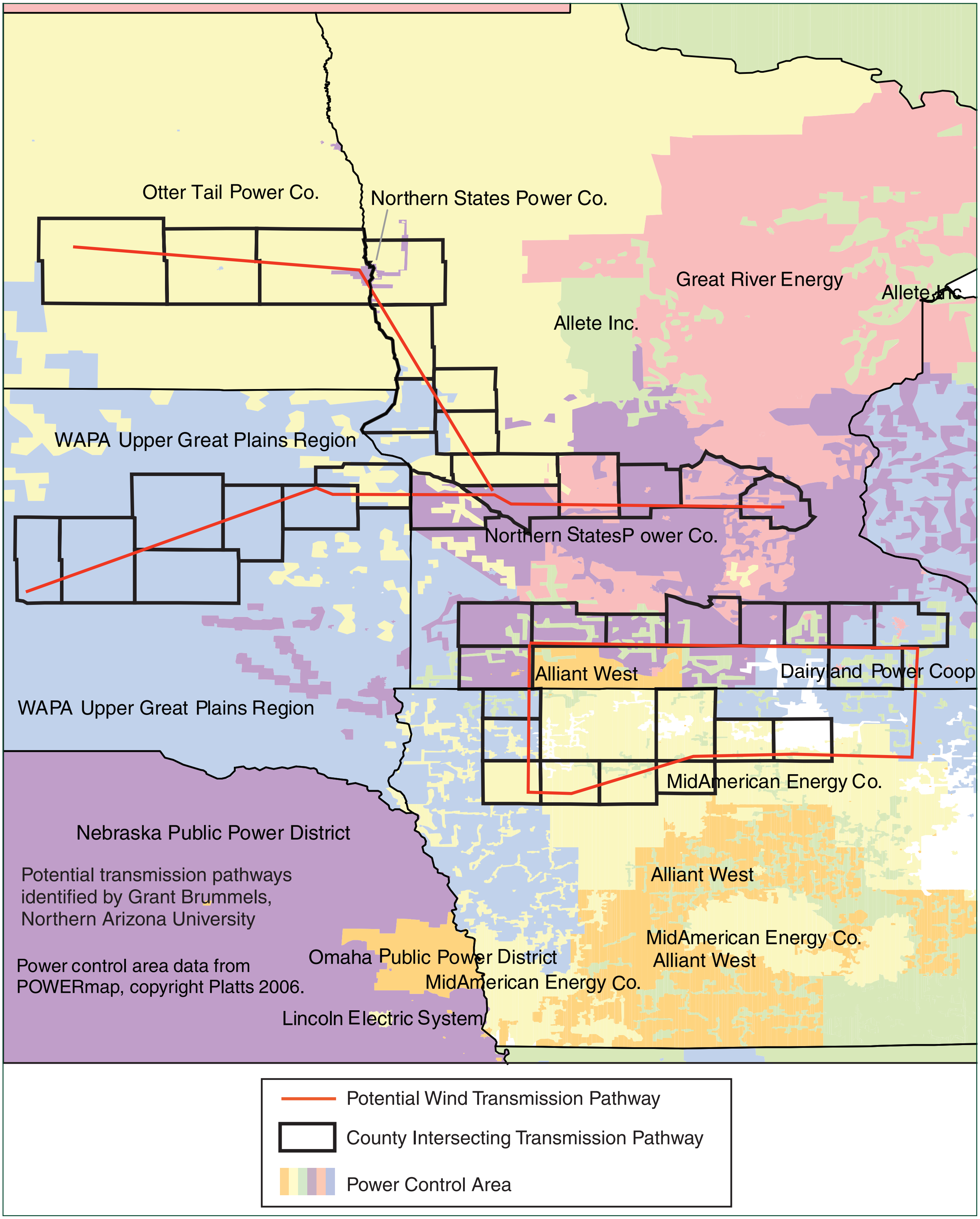
The Central Great Plains—western Kansas and Oklahoma—have significant potential wind generation that, if developed, could greatly improve the economic vitality of this rural area while bringing

Figure 5-8. CDEAC 2015 High Renewables Generation and Associated New Transmission Lines



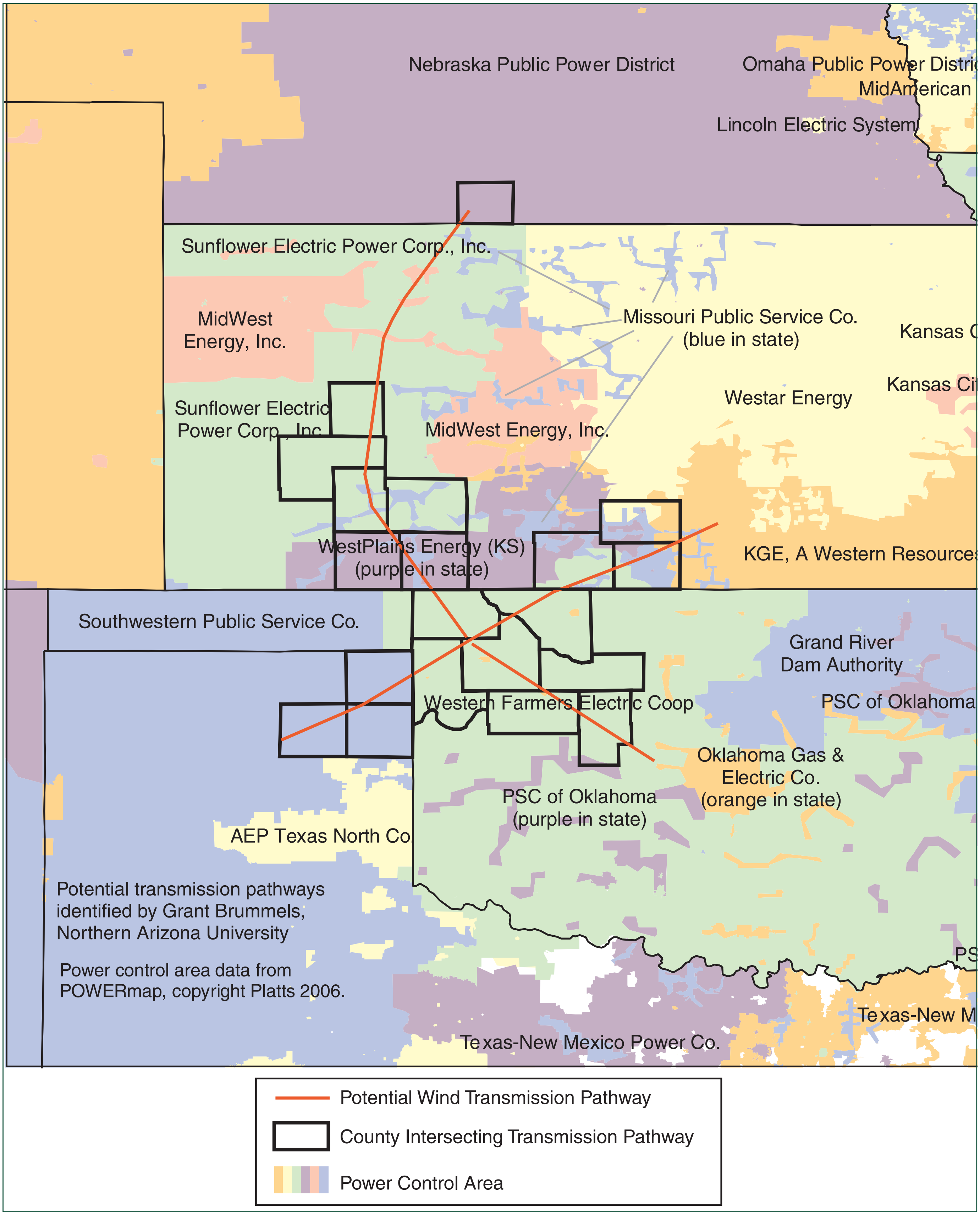
[63] See http://www.capx2020.com.
[64] *Ibid.*

Figure 5-9. Potential Wind Development and Associated Transmission Requirements in Northern Great Plains Area



Source: National Renewable Energy Laboratory.

Figure 5-10. Potential Wind Development and Associated Transmission Requirements in Central Great Plains Area



Source: National Renewable Energy Laboratory.

moderate cost renewable energy to Midwest and Colorado loads. As with wind energy in the Upper Great Plains, development of these domestic energy resources would improve the Nation's energy security by reducing dependence on imported fuels and reducing the price volatility of electric power.

As shown in Figure 5-10, development of these wind resources will require significant investment in new transmission facilities reaching from Nebraska to Oklahoma. This new transmission would also improve reliability in western Kansas and reduce delivered electricity costs for all of western Kansas and Oklahoma. Given that development of these renewable energy resources is consistent with Federal energy policy, promotes national energy security, and would reduce energy costs in several states, the Department believes that electricity-related developments in this potential congestion area should be tracked closely.

Illinois-Indiana and Upper Appalachian Conditional Constraint Areas

Development of major amounts of new coal-fired generation in Illinois, Indiana, Ohio, West Virginia and Kentucky would require development of associated new transmission capacity in order to deliver the electricity to load centers. It is not yet clear, however, how much additional transmission capacity might be needed beyond the substantial enhancements now being discussed for the eastern PJM states.

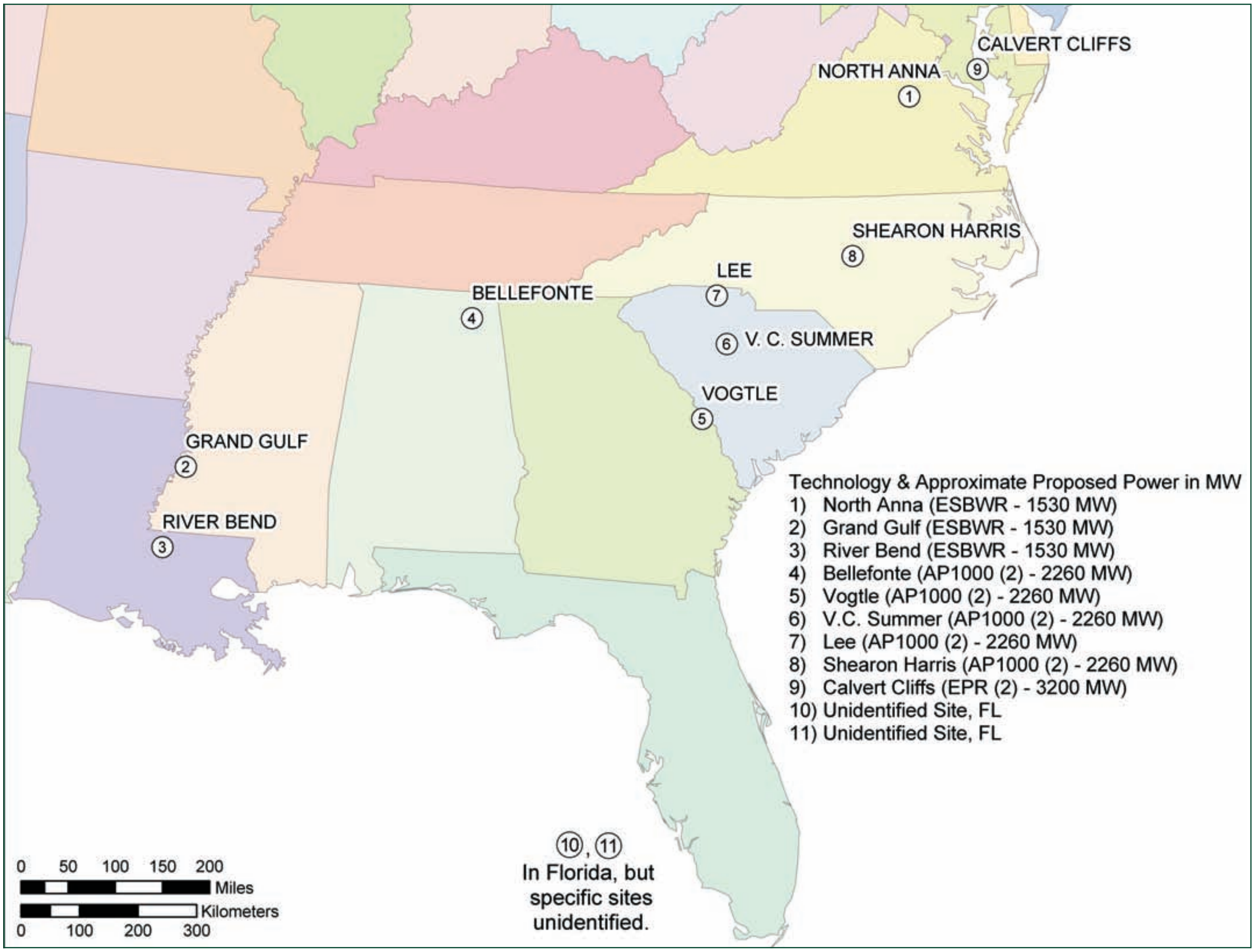
Southeastern Conditional Constraint Area

There is growing interest in developing a new generation of nuclear power plants in the Nation as sources of low-cost base-load electricity without air emissions. To date most of the applications for new nuclear power plants involve locations in the southeastern United States. (See Figure 5-11.) Any one new nuclear power plant is likely to require interconnection and some system upgrades; a large regional concentration of new nuclear capacity would require regional or inter-regional transmission planning to determine what new transmission facilities would be required to move large amounts of electricity to potential buyers over a wide geographic area.

5.5. Conclusion

The Department will monitor developments in all of the above congestion and constraint areas. It will offer assistance and policy support for more detailed transmission analysis and planning, with the expectation that most of these areas are so large that no one entity can or should carry the full burden of determining how to meet these challenges. The Department will document progress in these efforts through annual reports, and it will examine conditions in both Interconnections in aggregate terms in the next congestion study (August 2009). For additional details, see Chapter 7.

Figure 5-11. Locations of Proposed New Nuclear Generation Capacity in the Southeastern United States



Source: U.S. Department of Energy, Office of Nuclear Energy, 2006.

6. Request for Comments on Designation of National Corridors and on This Study

6.1. Request for Comments Concerning Designation of National Corridors

The Department is considering designation of National Corridors to facilitate relief of transmission congestion. The Department is focusing its attention on, and preliminarily believes it may be most appropriate to consider designation of one or more National Corridors to help relieve transmission capacity constraints or congestion in, two Critical Congestion Areas—the Mid-Atlantic coastal area from metropolitan New York southward to northern Virginia, and Southern California.[65] However, the Department also will consider designating National Corridors to relieve constraints or congestion in the Congestion Areas of Concern and Conditional Congestion Areas identified in Chapter 5 of this study. Interested parties are invited to offer comments on alternatives and recommendations. After evaluating the comments received, the Department will issue a report in which it may designate National Corridors, seek additional information, or take other action.

In determining whether and where to designate National Corridors, the Department will not be exercising transmission planning functions. In order to make sound decisions, however, DOE will need many kinds of information, including transmission planning information pertinent to affected geographic areas. Accordingly, the Department seeks responses to the questions set forth below from the public, affected state energy planning agencies, public utility commissions, regional transmission organizations (RTOs), independent system operators (ISOs), regional reliability councils, utilities, environmental organizations, citizen groups, business organizations, and any other interested parties.

In evaluating where to set the geographic boundaries for a National Corridor, DOE will seek to balance the relevant interests. Among other things, a National Corridor must be tailored to the transmission constraints or congestion giving rise to the designation while also being large enough so as not to unduly restrict the choice of solutions, or unduly constrain potential siting and permitting activities by FERC under section 216(b).

While comments are invited on any and all aspects of the study and the potential designation of National Corridors, DOE particularly requests that commenters respond to the following three basic questions:

1. **Would designation of one or more National Corridors in these areas be appropriate and in the public interest?** In answering this question, commenters should address the following:

   A. *Does a major transmission congestion problem exist?* Commenters should provide additional details and analysis concerning congestion in the particular Critical Congestion Areas, Congestion Areas of Concern, or Conditional Congestion Areas identified in Chapter 5. Describe the population and economy affected by the congestion problem today and explain the future impacts of the congestion and transmission constraints (e.g., with year-specific and scenario projections) if the constraints are not remedied in a timely fashion. Describe the current and projected reliability and economic impacts of the transmission constraints.

[65] The Department notes that Critical Congestion Areas may not be the only areas for which it will be appropriate to designate National Corridors. The Department is focusing on the Critical Congestion Areas at this time because it regards actions to address their needs as especially urgent, given the long lead-times typically associated with transmission projects and the social and economic adversities associated with inadequate transmission capacity.

B. *Are key transmission constraints creating the transmission congestion?* Commenters should identify the approximate locations (geography and equipment) of current and expected transmission constraints creating the congestion problem. (Note: The Department will consider requests to treat such information as non-public and security-sensitive.)

C. *What is the magnitude of the problem?* Why (or why not) is the problem of such magnitude and implications that it merits federal attention, as distinguished from that of state and regional entities?

D. *What are the relevant transmission or non-transmission solutions?* Commenters are requested to explain what the proposed solutions are and how they were determined. More broadly, commenters should explain and document the range of transmission, generation and demand-side solutions that were considered to address the congestion and reliability problems, and the reasons why a proposed solution is favored. The Department invites comments on all possible alternatives and recommendations.

2. **How and where should DOE establish the geographic boundaries for a National Corridor?** Section 216(a) of the Federal Power Act states that a National Corridor is a "geographic area" but otherwise does not define the term "national interest electric transmission corridor." Therefore, the Department has broad discretion in interpreting what this term means and what geographic area should be included within any particular National Corridor. The Department believes, however, that a Corridor must be a "geographic area," and therefore does not intend, as some parties have suggested, to entertain suggestions that it designate "conceptual" Corridors that do not have specific geographic boundaries.

   The Department expects that some parties supporting designation of a particular Corridor will have done sufficient engineering and planning analyses to enable the parties to identify one or more potential transmission solutions to the underlying problem. The Department expects that the proponent will be able, in electrical terms, to identify a project path that would begin at some specific substation or other facility, pass through appropriate and specified intermediate facilities, and terminate at another specific location. These analyses will enable the proponent of the Corridor to identify an approximate centerline for the proposed Corridor, and to propose and explain the rationale for territorial bands of some specified width on each side of the centerline. (In some situations it could be appropriate to make the bands asymmetric—i.e., wider on one side of the centerline than on the other.) Comments of this type may be particularly helpful to DOE in deciding whether and where to designate a Corridor.

   The Department recognizes, however, that its role under FPA section 216 is not to site specific transmission lines or facilities. Rather, the Department's role is to designate geographic area experiencing transmission congestion or constraints so that parties can work with appropriate state permitting authorities and the FERC to site, construct, and operate any needed transmission facilities. Therefore, the Department will consider the designation of broader geographic areas as National Corridors that are not focused on a single transmission line or facility. In such cases, the Department requests comment on how, where, and on what basis to establish the boundaries for particular Corridors.

3. **How would the costs of a proposed transmission facility be allocated?** Although cost allocation issues are not directly related to the designation of a National Corridor, proposed transmission facilities crossing utility, state and regional boundaries have sometimes foundered because the proponents were not able to devise a cost allocation method that would satisfy critical regulatory and policy requirements. Given that many of the congestion problems addressed in this study could require combined transmission and generation solutions spanning several states or regions, and could affect people in some geographic areas—both positively and negatively—more than others, DOE is interested in cost allocation issues and how they

might be resolved. Accordingly, the Department requests that respondents focusing on proposed transmission projects or facilities also discuss how they expect the costs of such projects to be allocated, and particular obstacles that remain to be resolved.

Additional guidance for commenters

1. **Criteria.** The Secretary of Energy will exercise his sound discretion in deciding whether and where to designate National Corridors. In making these decisions, DOE may apply, among other considerations, the criteria listed below.

   A. Reliability

      1. Is the end market (or load center) that would be served through a potential Corridor currently experiencing reliability problems?
      2. Are future violations of North American Electric Reliability Council (NERC) standards likely in the absence of transmission enhancements?
      3. How large is the population of the affected area?
      4. What is the likely economic impact of potential grid failures in the affected region? Could transmission solutions mitigate those impacts?

   B. Reduced Electricity Supply Costs

      1. Would transmission enhancements reduce electricity supply costs in the affected area, and lead to net economic benefits for electricity consumers?
      2. Would the benefits come about through improved access to low-cost resources, lower market concentration among suppliers, reduced price volatility, or other means?

   C. Diversification of Generation Sources and/or Generation Fuels

      1. Would transmission enhancements diversify an area's generation sources and moderate overdependence upon particular generation fuels?
      2. What would be the likely magnitude of these changes for energy security, energy price volatility, and improved energy supply in the event of an emergency?

   D. National Energy Policy and National Security

      Would transmission enhancements further national energy policy or national security in ways not identified under the preceding criteria?

2. **Sound and verifiable information.** The Department is particularly interested in receiving analyses and information that exhibit the following characteristics:

   A. Use of state-of-the-art, verifiable, quantitative methods, and publicly accessible data.

   B. Developed through a publicly accessible process, with on-going stakeholder input and involvement.

   C. Encompassing a geographic and electrical span covering both the area where the congestion occurs and areas that are proposed as part of generation and/or transmission solutions to the problem.

3. **Availability of supporting data and analyses.** The Department expects that supporting analyses and source material will be submitted and/or made available (through attachments, footnotes, web links, etc.) for the Department's technical review. To the maximum extent practicable, the Department intends to make all analyses and underlying data provided in response to the Department available for public review.

4. **What will happen after DOE designates a National Corridor?** As a matter of national energy policy, DOE wishes to work cooperatively with other parties to facilitate timely solutions to major transmission capacity constraints and congestion, especially those that have led DOE to designate a National Corridor. For example, DOE may participate in regional meetings or regulatory proceedings related to the identification or consideration of such solutions, host

meetings among relevant parties, support key technical analyses, etc.

The designation of a National Corridor will not, in itself, entitle a project developer to proceed with construction and operation of an electric transmission facility in the National Corridor. Designation of a National Corridor is a finding that it is in the national interest to mitigate electric energy transmission capacity constraints or congestion in a specified area or areas to relieve adverse impacts on consumers, and that designation of the Corridor will facilitate such relief. DOE expects that transmission developers will come forward with formal applications to build new or expand existing transmission facilities to alleviate problems leading to the designation of National Corridors. Such applications will be reviewed and possibly approved by appropriate state and federal agencies under their respective siting and permitting authorities.

5. **Duration of a National Corridor designation.** FPA section 216 is silent on the issue of whether National Corridors should have an expiration date, and if they should expire, whether the expiration should occur on a date certain or should be pegged to the occurrence of a particular event or circumstance. Interested persons are invited to comment on whether, if DOE designates one or more National Corridors, the Corridors should be permanent or whether DOE should set an expiration date. If a Corridor should expire at some point, commenters should identify when and/or upon the occurrence of what event or action. For example, should the Corridor designation be effective for a fixed period of years, or should it be effective only until appropriate mitigation of the identified congestion or constraint is in place?

6. **Comment period and address for filing comments.** Comments on the possible designation of National Corridors in the Critical Congestion Areas, Congestion Areas of Concern, and Conditional Congestion Areas must be submitted to the Department by October 10, 2006—if possible by e-mail to EPACT1221@hq.doe.gov. The Department will take these comments into account in its decisions on the possible designation of National Corridors.

6.2. General Request for Comments on the Congestion Study

The Department invites all public comments on this study. Comments may address any element of the study method and its findings. Comments will be particularly useful if they address the following questions concerning improvements for this or future congestion studies:

1. Did this study accurately identify appropriate areas as National Interest Congestion Areas, Congestion Areas of Concern, and Conditional Congestion Areas? Are there additional areas that should have been so identified?
2. How should the method and approach for analyzing historical and future congestion on the grid be improved?
3. Are there better ways to define, identify and measure "congestion" and "transmission constraints"?
4. How should additional data to improve the quality of the congestion analysis be obtained?
5. What is the appropriate level of "granularity" for analyzing the Eastern and Western Interconnections? That is, what level of detail is appropriate in terms of geographic and electrical specificity?
6. Is it necessary or appropriate to use the same analytical tools to examine congestion in the Eastern and Western Interconnections?
7. Would it be useful, for both transmission planning purposes and DOE's congestion analyses, to develop a "path catalog" for the Eastern Interconnection similar to that used in the Western Interconnection?

Comment period and address for filing comments. Comments on the approach, methodology, data, and related matters concerning this study must be submitted to the Department by October 10, 2006—if possible by e-mail to congestionstudy.comments@hq.doe.gov. The Department will take the comments into account in its decisions concerning the geographic areas of particular interest identified in this study, and in the design and development of the next congestion study.

7. Next Steps Regarding Congestion Areas and Considerations for Future Congestion Studies

As the first congestion study conducted under section 1221(a) of the Energy Policy Act of 2005, this analysis has identified significant amounts of congestion and projected congestion on the Nation's transmission networks. (See Chapter 5.) Chapter 6 provides details on DOE's request for comments concerning possible designation of National Corridors to help ease congestion in two Critical Congestion Areas. This chapter discusses next steps for DOE and others related to alleviating congestion elsewhere and improving the value of future congestion studies.

7.1. Next Steps Regarding Congestion Areas

Role of regional transmission planning organizations in finding solutions to congestion problems

DOE expects that regional transmission planning organizations will take the lead in working with stakeholders and industry transmission experts to develop solutions to the congestion problems identified above in their respective areas. DOE expects these planning efforts to be inter-regional where appropriate, because many of the problems and likely solutions cross regional boundaries. In particular, the Department believes that these analyses should encompass both the congestion areas and the areas where additional generation and transmission capacity are likely to be developed. The Department will support these planning efforts, including convening meetings of working groups and working with the Federal Energy Regulatory Commission and congestion area stakeholders to facilitate agreements about cost allocation and cost recovery for transmission projects, demand-side solutions, and other subjects.

DOE anticipates that regional—and where appropriate, inter-regional—congestion solutions will be based on a thorough review of generation, transmission, distribution and demand-side options, and that such options will be evaluated against a range of scenarios concerning load growth, energy prices, and resource development patterns to ensure the robustness of the proposed solutions. Such analysis should be thorough, use state-of-the-art analytical methods and publicly accessible data, and be made available to industry members, other stakeholders, and regulators.

Congestion area progress reports

Each of the congestion areas identified above involves a somewhat different set of technical and policy concerns for the affected stakeholders. The Department will work with FERC, affected states, regional planning entities, companies, and others to identify specific problems, find appropriate solutions, and remove barriers to achieving those solutions.

Having identified certain areas as Critical Congestion Areas, Congestion Areas of Concern, and Conditional Congestion Areas, the Department intends to monitor congestion and its impacts in these areas, and publish annual reports on progress made in finding and implementing solutions. The first progress report will be issued on August 8, 2007, the second anniversary of the enactment of the Energy Policy Act.

In these reports the Department will note progress in commitments and/or construction of new transmission facilities, generation capacity, and expansion of energy efficiency and demand response efforts to alleviate or moderate the congestion problems identified, and the parties responsible for such progress. In the four Congestion Areas of Concern (New England, the Seattle – Portland area, the San Francisco Bay area, and the Phoenix – Tucson area), more information and analysis are needed to assess the magnitude of the congestion and the merits of possible solutions. DOE expects that appropriate regional entities will conduct and report on additional analyses during the year, so that the first Congestion Area Progress Report will be able to determine whether these areas should continue receive Federal monitoring and attention.

Similarly, DOE will monitor congestion trends, corporate commitments, state or multi-state announcements, and other events related to resource development in Conditional Congestion Areas, and discuss their implications in the progress reports.

7.2. Considerations for Future Congestion Studies

The information collected for this congestion study from existing primary analyses of historical data and new simulation studies of future congestion is in aggregate the largest, most comprehensive and detailed body of information assembled to date on congestion in the Eastern and Western Interconnections. This effort builds upon the prior work of virtually every major transmission planning organization in North America.

FERC's recent Notice of Proposed Rulemaking concerning revisions to its Order 888[66] gives significant emphasis to improving regional transmission planning and the availability of data on transmission usage. If FERC includes such provisions in a final rule, it is likely that future studies of congestion in the Eastern Interconnection will be better informed by systematic analysis of information from OASIS sites on actual transmission use. The recent analysis of such data for the Western Interconnection may be an appropriate model for eastern analyses. Additional work is already under way in the Western Interconnection to complement these assessments with information on scheduling, which will help to distinguish between physical and contractual congestion.

Future studies of prospective congestion in the Eastern Interconnection will also be improved by greater involvement and more formal participation by transmission planning organizations and entities within the Interconnection. Data access and forum openness issues will have to be resolved for these efforts to succeed. Planners in both interconnections need to find ways to deal with the inescapable uncertainties associated with the pace, location, and technologies for new generation.

Below, we outline some additional concerns and topics for consideration in future national, regional and multi-regional studies.

Strengthening regional planning efforts

The West has a well-coordinated, interconnection-wide process with four sub-regional detailed planning efforts, but to date efforts have focused on identification of congestion and reliability problems. This work should be continued and extended to include independent (i.e., non-corporate) assessment of possible solutions in regional or sub-regional terms. The Northeast and Midwest have relatively mature, detailed and independent regional transmission planning processes that stop at regional boundaries, and there is a need for inter-regional analyses of some critical problems. The Department intends to engage the various planning entities, stakeholders, regulators and FERC in a discussion of how these various planning efforts can be improved to better address congestion challenges and solutions.

As noted in previous chapters, there is no coordinated, publicly accessible planning process in the Southeast. The Florida Reliability Coordinating Council (FRCC) and utilities have no publicly available transmission planning documents available at this time, and the Department has not gained access to any studies of the reliability or economic impacts of congestion in this area. The Department believes it would be worthwhile for the FRCC, Florida regulators, and stakeholders to work with SERC to conduct a publicly accessible regional analysis for the entire Southeast to determine whether the transmission congestion pattern found in this study is substantiated by additional information and analysis.

[66] Federal Energy Regulatory Commission, "Preventing Undue Discrimination and Preference in Transmission Service, Notice of Proposed Rulemaking," FERC Docket Nos. RM05-25-000 and RM05-17-000, May 18, 2006.

Refining congestion metrics

As indicated in this study, there are no standard metrics for measuring congestion and its impacts; perhaps the only thing that is clear is that no single metric is sufficient to capture all relevant aspects of congestion. The metrics used here were developed specifically for this study, and as with most tools, they are subject to future refinement. The Department welcomes further dialogue about congestion metrics with the industry, regional transmission planners, market monitors, and the academic community.

Data collection and improvements

As this and previous studies have shown,[67] there is very little systematic data available on existing and planned transmission facilities and investments. Transmission congestion within ISO and RTO areas is closely measured and tracked, but little comparable data is collected outside the boundaries of the ISOs and RTOs. DOE will work with EIA, FERC, NERC and industry members to determine whether data collection requirements should be modified. By making its data base and analytic assumptions publicly available, the Western Congestion Assessment Task Force (WCATF) has set important precedents in this area that the Department hopes will be continued in the West and adopted in the East.

Granularity versus aggregation

In the West, transmission expansion planning and reliability analyses have been conducted chiefly by sub-regional groups, and the results have been rolled up at the west-wide level. West-wide regional planning occurs at a very general analytical level, compared to the more granular level modeled in the East. Future western analyses may need to examine whether it is possible and useful to develop a more detailed set of models and data, to better understand the nuances of congestion, reliability and cost variations occurring within the zones connected by the West's 67 major transmission paths. This would allow western regional planners to more consistently model and address significant congestion problems that are now buried inside very large western nodes. Two examples of such granularity problems are the congestion on the Seattle-to-Portland transmission path, and the question of how to provide transmission for wind generation out of the Tehachapi Mountains in southern California.

Modeling improvements

One of the important technical challenges to congestion modeling is that the current DC models do not address voltage problems. Determining the effects of a proposed transmission enhancement on such problems requires separate analysis with an AC model, to ensure that voltage and transient stability are properly addressed. As a related issue, more work is needed to model effectively marginal, rather than average transmission system losses. Marginal losses more closely parallel actual power system physics, but average losses are easier to simulate.

Much of the congestion seen today results from the practice of adhering to reliability limits imposed so as to be prepared to withstand contingencies. Without questioning the need for such adherence, there are nonetheless legitimate questions about whether we have adequate tools to represent and analyze the complex relationship between contingencies and congestion. This relationship needs to be more fully understood. Similarly, some congestion and flow restrictions are due to scheduling practices and transmission rights rather than reliability and operational capabilities *per se*.

DOE will consult with those who performed analyses related to this study and with other modeling experts, analysts, and sources of data to determine what refinements are feasible before undertaking modeling for the next congestion study.

In the East, as discussed on the preceding page, there is a need for more systematic and coordinated analyses and responses regarding congestion problems that cross regional boundaries.

[67] Energy Information Administration, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, December, 2004; Hirst, Eric, "U.S. Transmission Capacity: Present Status and Future Prospects," Edison Electric Institute and U.S. Department of Energy, August 2004; and Energy Security Analysis, Inc., "Meeting U.S. Transmission Needs," Edison Electric Institute, June 2005.

Glossary

Available transfer capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin.

Binding hours: Those hours when a transmission element is operating at its maximum operating safe limit; as a congestion metric, the % of time annually that the element is loaded to its limit.

Binding hours shadow price: A congestion metric that equals the average value of the shadow prices in those hours when a transmission element operates at its limit; the shadow price equals zero when the element is below its limit.

CAISO: California Independent System Operator, serving most of the state of California.

Congestion: The condition that occurs when transmission capacity is not sufficient to enable safe delivery of all scheduled or desired wholesale electricity transfers simultaneously.

Congestion rent: As used in this report, congestion rent equals the shadow price per MWh times the MWh flowing through a transmission element, summed over all the hours when that element is operating at its maximum (binding) limit.

Constrained facility: A transmission facility (line, transformer, breaker, etc.) that is approaching, at, or beyond its System Operating Limit or Interconnection Reliability Operating Limit.

Contingency: An unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Control area: A geographic and electrical area managed by a transmission or integrated utility, ISO or RTO, the manager of which is responsible for ensuring a continuous real-time balance of electrical supply and demand.

Curtailment: A reduction in service required when all demand cannot be served because a generating unit, transmission line, or other facility is not functioning due to maintenance, breakdown, or emergency conditions.

Demand: The physical rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

Demand response: Demand response programs are used to reduce consumers' use of electricity during times of peak demand, with incentives to curtail electricity demand and reduce load during peak periods in response to system reliability or market conditions. Customers reduce their load by reducing specific energy uses, by the utility curtailing the customer's use, or by using distributed generation in place of utility-delivered energy. Demand response can respond to price signals or directions from distribution utilities or system operators.

Demand-side management: Activities or programs undertaken by a retail electricity provider, utility, energy service company, or energy end users to influence the amount or timing of electricity they use.

EIA: Energy Information Administration, an organization within the U.S. Department of Energy.

Element: An electrical device with terminals that may be connected to other electrical devices, such as generators, transformers, circuit breakers, bus sections, or transmission lines; an element may be comprised of one or more components.

Energy: A capacity for doing work; electrical energy is measured in watt-hours (kilowatt-hours, megawatt-hours or gigawatt-hours).

ERCOT: Electric Reliability Council of Texas, an ISO serving 80% of Texas' load.

Facility rating: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Flowgate: An individual or a group of transmission facilities (e.g., transmission lines, transformers) that are known or anticipated to be limiting elements in providing transmission service. This term is used principally in the Eastern Interconnection.

Generation: The process of transforming existing stored energy into electricity; also, an amount of electric energy produced, expressed in kilowatt-hours (kWh) or megawatt-hours (mWh).

Interconnection: When capitalized, any one of the three major alternating current (AC) electric system networks in North America (Eastern, Western, and ERCOT).

ISO: Independent System Operator, an independent, federally regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system within its footprint and in coordination with neighboring entities.

ISO-NE: Independent System Operator for New England, covering the states of Maine, Vermont, New Hampshire, Connecticut, Rhode Island and Massachusetts.

Limiting element: An electrical element that is either 1) operating at its appropriate maximum rating, or 2) would be operating at its maximum rating following a limiting contingency; a limiting element establishes a system limit.

LMP: Locational Marginal Price, a method for pricing wholesale power based on actual grid conditions. The LMP at a specific point on the grid reflects the full cost of supplying the next MWh of electricity at that location, including the marginal cost of generating the electricity, the cost of delivering it across the grid, and the value of energy lost in delivery. Differences at a given time in LMPs at different locations reflect the impact of transmission congestion—LMPs at two points will be the same when the congestion they face is the same, but diverge if transmission congestion obstructs delivery of less expensive energy to one of them, raising LMP in the constrained area by the cost of the congestion.

Load: An end-use device (or a customer operating such device) that receives power from the electric system.

Load flow model: A detailed model, also referred to as a power flow model, that represents the interdependencies of energy flow along different paths in the system.

Load pocket: A load center (such as a large metropolitan area) that has little local generation relative to the size of the load, and must import much of its electricity via transmission from neighboring areas.

MISO: The Midwest ISO, the Regional Transmission Operator serving all or portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Minnesota, Montana, Nebraska, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, Wisconsin, and West Virginia.

MMWG: NERC's Multi-regional Modeling Working Group, which develops a dataset of information about grid elements (power plants and transmission facilities) and their ratings for use in regional reliability modeling.

Node: A node is used in simulation modeling to represent an aggregation of significant amounts of electrical demand and/or supply, to simplify the modeling calculations (relative to modeling each power plant or load center individually). Each Interconnection is broken down into a set of nodes connected to each other by transmission paths.

Nomogram: A graphic representation that depicts operating relationships between generation, load, voltage, or system stability in a defined network. On lines where the relationship between variables does not change, a nomogram can be represented simply as a single transmission interface limit; in many areas, the nomogram indicates that an increase in transfers into an area across one line will require a decrease in flows on another line.

NYISO: New York Independent System Operator, serving New York State.

Operating transfer capability (OTC): The amount of power that can be transferred in a reliable manner, meeting all NERC contingency requirements, considering the current or projected operational state of the system. OTC is sometimes referred to as TTC, or Total Transfer Capability.

Outage: A period during which a generating unit, transmission line, or other facility is out of service.

Peak demand: Maximum electric load during a specified period of time.

PJM: The RTO serving parts or all of the states of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Rating: The safe operational limits of a transmission system element under a set of specified conditions.

Redispatch: When transmission constraints or reliability requirements indicate that specific levels of generation across a set of power plants cannot be maintained reliably, the grid operator redispatches (changes the dispatch or operating instructions) for one or more power plants (increasing generation on one side of the constraint and reducing generation on the other side) to restore a safe operational pattern across the grid.

Reliability: Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply customers' aggregate electric demand and energy requirements at all times, taking account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability can be measured by the frequency, duration and magnitude of adverse effects on electricity delivery to customers.

RTO: Regional Transmission Operator, an independent, federally regulated entity that coordinates regional transmission in a non-discriminatory manner and ensures the safety and reliability of the electric system.

Shadow price: The shadow price equals the value of the change in all affected generation if one more MWh could flow across a constrained facility then loaded to its maximum limit; the marginal cost of generation redispatch required to obey the transmission constraint.

SPP: The Southwest Power Pool, serving portions of Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.

Stability limit: The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

System: A combination of generation, transmission, and distribution components.

System operating limit: The value (such as MW, MVar, amperes, frequency, or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to, pre- and post-contingency ratings for facilities, transient stability, voltage stability, and system voltage.

System operator: An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

Thermal rating: The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or sags to the point that it violates public safety requirements.

TLR: Transmission loading relief, a procedure used in the Eastern Interconnection to deal with a situation where a transmission facility or path is at its operating limit. In a TLR, the grid operator can redispatch generation, reconfigure transmission, or curtail loads to restore the system to secure operating conditions.

Transfer capability: The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: An interconnected group of lines and associated equipment for moving electric energy at high voltage between points of supply and points at which it is delivered to other electric systems or transformed to a lower voltage for delivery to customers.

Transmission constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

Transmission path: A transmission path may consist of one or more parallel transmission elements. The transfer capability of the transmission path is the maximum amount of actual power that can flow over the path without violating reliability criteria. The net scheduled power flow over the transmission path must not exceed the path's transfer capability or operating nomogram limits at any time, even during periods when the actual flow on the path is less than the path's transfer capability.

U90: The number of hours or percentage of a year when a transmission path is operated at or above 90% of its safe operating limit.

U75: The number of hours or percentage of a year when a transmission path is operated at or above 75% of its safe operating limit.

Voltage: Voltage is the difference in electrical potential between two points of an electrical network, expressed in volts. The North American grid is operated using alternating current at 120 volts and 60 Herz frequency.

WECC: Western Electric Coordinating Council, the reliability coordinator serving the western interconnection.

Appendixes

Appendix A
Sections 368 and 1221(a) and (b) of the Energy Policy Act of 2005

SEC. 368. ENERGY RIGHT-OF-WAY CORRIDORS ON FEDERAL LAND.

(a) Western States- Not later than 2 years after the date of enactment of this Act, the Secretary of Agriculture, the Secretary of Commerce, the Secretary of Defense, the Secretary of Energy, and the Secretary of the Interior (in this section referred to collectively as `the Secretaries'), in consultation with the Federal Energy Regulatory Commission, States, tribal or local units of governments as appropriate, affected utility industries, and other interested persons, shall consult with each other and shall--

(1) designate, under their respective authorities, corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on Federal land in the eleven contiguous Western States (as defined in section 103(o) of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702(o));

(2) perform any environmental reviews that may be required to complete the designation of such corridors; and

(3) incorporate the designated corridors into the relevant agency land use and resource management plans or equivalent plans.

(b) Other States- Not later than 4 years after the date of enactment of this Act, the Secretaries, in consultation with the Federal Energy Regulatory Commission, affected utility industries, and other interested persons, shall jointly--

(1) identify corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on Federal land in States other than those described in subsection (a); and

(2) schedule prompt action to identify, designate, and incorporate the corridors into the applicable land use plans.

(c) Ongoing Responsibilities- The Secretaries, in consultation with the Federal Energy Regulatory Commission, affected utility industries, and other interested parties, shall establish procedures under their respective authorities that--

(1) ensure that additional corridors for oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities on Federal land are promptly identified and designated as necessary; and

(2) expedite applications to construct or modify oil, gas, and hydrogen pipelines and electricity transmission and distribution facilities within such corridors, taking into account prior analyses and environmental reviews undertaken during the designation of such corridors.

(d) Considerations- In carrying out this section, the Secretaries shall take into account the need for upgraded and new electricity transmission and distribution facilities to--

(1) improve reliability;

(2) relieve congestion; and

(3) enhance the capability of the national grid to deliver electricity.

(e) Specifications of Corridor- A corridor designated under this section shall, at a minimum, specify the centerline, width, and compatible uses of the corridor.

SEC. 1221. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES.

(a) In General- Part II of the Federal Power Act (16 U.S.C. 824 et seq.) is amended by adding at the end the following:

`SEC. 216. SITING OF INTERSTATE ELECTRIC TRANSMISSION FACILITIES.

`(a) Designation of National Interest Electric Transmission Corridors- (1) Not later than 1 year after the date of enactment of this section and every 3 years thereafter, the Secretary of Energy (referred to in this section as the `Secretary'), in consultation with affected States, shall conduct a study of electric transmission congestion.

`(2) After considering alternatives and recommendations from interested parties (including an opportunity for comment from affected States), the Secretary shall issue a report, based on the study, which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor.

`(3) The Secretary shall conduct the study and issue the report in consultation with any appropriate regional entity referred to in section 215.

`(4) In determining whether to designate a national interest electric transmission corridor under paragraph (2), the Secretary may consider whether--

> `(A) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
>
> `(B)(i) economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and
>
> `(ii) a diversification of supply is warranted;
>
> `(C) the energy independence of the United States would be served by the designation;
>
> `(D) the designation would be in the interest of national energy policy; and
>
> `(E) the designation would enhance national defense and homeland security.

`(b) Construction Permit- Except as provided in subsection (i), the Commission may, after notice and an opportunity for hearing, issue one or more permits for the construction or modification of electric transmission facilities in a national interest electric transmission corridor designated by the Secretary under subsection (a) if the Commission finds that--

> `(1)(A) a State in which the transmission facilities are to be constructed or modified does not have authority to--
>
> > `(i) approve the siting of the facilities; or
> >
> > `(ii) consider the interstate benefits expected to be achieved by the proposed construction or modification of transmission facilities in the State;

`(B) the applicant for a permit is a transmitting utility under this Act but does not qualify to apply for a permit or siting approval for the proposed project in a State because the applicant does not serve end-use customers in the State; or

`(C) a State commission or other entity that has authority to approve the siting of the facilities has--

> `(i) withheld approval for more than 1 year after the filing of an application seeking approval pursuant to applicable law or 1 year after the designation of the relevant national interest electric transmission corridor, whichever is later; or
>
> `(ii) conditioned its approval in such a manner that the proposed construction or modification will not significantly reduce transmission congestion in interstate commerce or is not economically feasible;

`(2) the facilities to be authorized by the permit will be used for the transmission of electric energy in interstate commerce;

`(3) the proposed construction or modification is consistent with the public interest;

`(4) the proposed construction or modification will significantly reduce transmission congestion in interstate commerce and protects or benefits consumers;

`(5) the proposed construction or modification is consistent with sound national energy policy and will enhance energy independence; and

`(6) the proposed modification will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.

Appendix B

Parties Responding to the Department of Energy's February 2, 2006 Notice of Inquiry on "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors"

3M Company

ABB

Allegheny Energy

American Corn Growers Foundation

American Electric Power

American Public Power Association

American Transmission Company LLC

American Wind Energy Association

APS, A Subsidiary of Pinnacle West Capital Corporation

Baugher, Lisa

Bay Area Municipal Transmission Group

Beard, Laura

Bonneville Power Administration

British Columbia Transmission Corporation

California Energy Commission

California Public Utilities Commission

Canadian Electricity Association

Cimarron County of Oklahoma

City of Fayetteville, North Carolina, Public Works Commission

City of New York

Clark, Rolan O.

Edison Electric Institute

Electric Power Supply Association

Great River Energy

Horizon Wind Energy

Hydro-Québec TransÉnergie

Innovation Investment

International Transmission Company

ISO/RTO Council

Kansas Electric Transmission Authority

Kansas House of Representatives House Committee on Utilities

Kentucky Public Service Commission

Lassen (Calif.) Municipal Utility District

Louisiana Energy and Power Authority and Lafayette Utilities System

McQuillen, Mary

Michael Strategic Analysis

Montana Governor Brian Schweitzer

Montana Legislature

Montana-Dakota Utilities Co.

National Association of Regulatory Utility Commissioners

National Electrical Manufacturers Association

National Grid

National Rural Electric Cooperative Association

Nevada State Office of Energy

New Jersey Board of Public Utilities

New York Designated Transmission Owners

New York Regional Interconnection, Inc.

New York State Public Service Commission

North American Electric Reliability Council

North Dakota Industrial Commission

Northeast Power Coordinating Council

Northwest Independent Power Producers Coalition

NorthWestern Energy

Ohio Consumers' Counsel
Oklahoma Municipal Power Authority
Old Dominion Electric Cooperative
Ontario Independent Electricity System Operator
Optimal Technologies (USA) Inc.
Oregon Department of Energy
Organization of MISO States
Pacific Gas & Electric Company
Pacific NorthWest Economic Region
Pennsylvania Department of Environmental Protection
Pennsylvania Environmental Council
Pennsylvania Public Utility Commission
Pepco Holdings Inc. (on behalf of PHI Companies)
PJM Interconnection L.L.C.
Powerex
PPL Companies
PSEG Companies
Public Power Council
Public Utilities Commission of Ohio
Reliant
Salt River Project
San Diego Gas & Electric Company
Scherer, Donald
Seattle City Light
Seminole Electric Cooperative, Inc.
Sierra Nevada Region of the Western Area Power Administration
Sierra Pacific Power and Nevada Power Company
Southern California Edison
Southern Company
Stevens County [Kansas] Economic Development Board
Tennessee Valley Authority
Tompkins Renewable Energy Education Alliance
Trans-Elect, Inc.
Transmission Access Policy Study Group
U.S. Environmental Protection Agency
United States Congressman Todd Russell Platts (19th District, Pennsylvania)
United States Senator Craig Thomas
Upper Great Plains Transmission Coalition
Utah Clean Energy
Utah Energy Advisor to Governor Jon Huntsman, Jr.
Washington State Energy Facility Site Evaluation Council
Western Electricity Coordinating Council
Western Interstate Energy Board and the Committee on Regional Electric Power Cooperation (Joint Comments)
Wisconsin Public Power Inc.
Work Group Members of the Western Business Roundtable
Work Group Members of the Western Congestion Analysis Task Force (WCATF)
Wyoming Governor Dave Freudenthal
Wyoming Infrastructure Authority
Xcel Energy

Note: As of June 30, 2006, the U.S. Department of Energy had received approximately 120 additional comments pertaining directly to the New York Regional Interconnection Inc.'s March 6, 2006, request for early designation of a National Interest Electric Transmission Corridor (NIETC).

Appendix C

Agenda for DOE's March 29, 2006 Technical Conference on National Interest Electric Transmission Corridors

Public Technical Conference on DOE Congestion Study and Criteria for Designation of National Interest Electric Transmission Corridors

AGENDA

March 29, 2006 — 8:30 am – 3:00 pm CST

7:30 - 8:30 am	Registration Check-in and Continental Breakfast
8:30 -10:00 am	SESSION 1: Welcome and Opening Statements by U.S. Department of Energy
8:30 am	Welcome *Kevin Kolevar*, Director, Office of Electricity Delivery and Energy Reliability
8:45 am	Update on Congestion Study *Poonum Agrawal*, Manager, Markets & Technical Integration, Office of Electricity Delivery and Energy Reliability
9:00 am	Discussion of Process Questions Concerning Designation of National Corridors *David Meyer*, Acting Assistant Director, Division of Permitting, Siting, and Analysis, Office of Electricity Delivery and Energy Reliability
9:30 am	Question & Answer Period Facilitated by: *Jody Erikson*, Keystone Center
10:00 – 10:15 am	Break
10:15 – 12:00 pm	SESSION 2: How Can the Designation of Transmission Constraint Areas and National Corridors Add Value to Existing Planning and Siting Processes? Panelists: *Ricky Bittle*, Vice President of Planning, Rates & Dispatching, Arkansas Electric Cooperative Corp. *Joe Desmond*, Chairman, California Energy Commission *Laurence Chaset*, California Public Utilities Commission *Sandra Hochstetter*, Chairman, Arkansas Public Service Commission *Rob Kondziolka*, Salt River Project and Chairman, Western Congestion Assessment Task Force *Michael B. Robinson*, Project Manager, Transmission Planning, Southern Company Services, Inc. *William Whitehead*, Manager of Transmission Planning Policy, PJM Interconnection Facilitated by: *Jody Erikson, Keystone Center*

March 29, 2006 — 8:30 am – 3:00 pm CST

Each panelist will make a 5-minute presentation responding to one or more of the following questions:

What weight should DOE give to analyses conducted by regional transmission planning processes in the identification of constraint areas and designation of National Corridors?

What aspects of regional planning processes should be considered in assessing these analyses, such as the extent to which they are open to all parties and not overly influenced by a single interest group; are coordinated with state and load serving entities' resource plans; consider wires and non-wires alternatives; consider access to distant future resources, such as wind and coal, and produce well-documented and transparent analyses?

In the absence of an established regional transmission planning process, how should regional, state, and local considerations be addressed in the identification of constraint areas and designation of National Corridors?

What additional complementary or supporting actions by DOE (or others) should be triggered by the identification of constraint areas or the designation of National Corridors? For example, should DOE foster federal/state teams to encourage development and expeditious reviews of proposals to mitigate congestion in constraint areas? Should priority be placed on designating corridors on federal lands under Section 368 that could be used for projects to relieve constraint areas?

After the round of opening statements, DOE will ask the panelists a series of follow-up questions. After this round of questions, the facilitator will open the discussion to comments and questions from the audience.

12:00 – 1:00 pm Lunch

An informal lunch will be provided at the meeting site.

1:00 – 2:45 pm SESSION 3: How should Criteria Be Applied in the Identification of Constraint Areas and the Designation of National Corridors?

Overview of Comments on Criteria and Metrics

Poonum Agrawal, U.S. Department of Energy

Panelists:

Mary Ellen Paravalos, Director of Regulatory Policy, National Grid

David Till, Transmission Planning Department Manager, Tennessee Valley Authority

Michael Heyeck, Vice President, Transmission, American Electric Power

Kevin Wright, Commissioner, Illinois Commerce Commission

Ed Tatum, Assistant Vice President, Rates & Regulations, Old Dominion Electric Cooperative

Wayne Walker, Director of Project Development, Horizon Wind Energy

Wayne Snowdon, Vice Chair, Canadian Electricity Association Transmission Council; Vice President, Transmission, NB Power

Facilitated by: *Jody Erikson, Keystone Center*

March 29, 2006 — 8:30 am – 3:00 pm CST

	Each panelist will make a 5-minute presentation responding to one or more of the following questions: How broadly (or narrowly) should constraint areas and corridors be defined? Should thresholds be established in applying criteria for constraint area and National Corridor designations? If so, what should they be for the eight draft criteria proposed by DOE? Should constraint area or National Corridor designations expire after some fixed period? If so, what should the period be? How should the designation of constraint areas and National Corridors be coordinated with the planning and siting processes used in Canada, ERCOT, and Mexico? After the round of opening statements, DOE will ask the panelists a series of follow-up questions. After this round of questions, the facilitator will open the discussion to comments and questions from the public audience.
2:45 pm	Summary, Next Steps, and Closing Remarks Discussion led by: *Poonum Agrawal, U.S. Department of Energy*
3:00 pm	Adjourn

Appendix D

On-Site Participants in DOE's March 29, 2006 Technical Conference on National Interest Electric Transmission Corridors

Poonum Agrawal, U.S. Department of Energy

Parveen Baig, Iowa Utilities Board

Derek Bandera, Reliant Energy, Inc.

Diane Barney, New York Dept. of Public Service

Joel Bearden, Cargill Power Markets, LLC

Michael Bednarz, US Department of Energy - Midwest Regional Office

Mark Bennett, Electric Power Supply Association

Bradley Bentley, Sempra Energy Utility

Heather Bergman, The Keystone Center

Ricky Bittle, Arkansas Electric Cooperative Corporation

Grant Brummels, Sustainable Energy Solutions

John Buechler, NYISO

Shelton Cannon, Federal Energy Regulatory Commission

Henry Chao, ABB Inc.

Laurence Chaset, California Public Utilities Commission

Kevin Coates, Composite Technology Corp.

Kurt Conger, EXS Inc.

Lot Cooke, U.S. Department of Energy

Randell Corbin, Ohio Consumers' Counsel

Robert Cupina, Federal Energy Regulatory Commission

Keith Daniel, Georgia Transmission Corporation

Lex Davidson, Areva T&D Inc.

Joe Desmond, California Energy Commission

Michael Desselle, AEP

David Dworzak, Edison Electric Institute

Sherman Elliott, Midwest ISO

Kimberly Erickson, Xcel Energy

Christine Ericson, Illinois Commerce Commission

Jody Erikson, The Keystone Center

Joseph Eto, Lawrence Berkeley Natl Lab

Tim Fagan, PSEG

Philip Fedora, Northeast Power Coordinating Council

Lynn Ferry, Southern California Edison

Betty Gallagher, ComEd

Kenneth Gates, PHI

Lauren Giles, Energetics Incorporated

Craig Glazer, PJM Interconnection, L.L.C.

Kenneth Glick, California Energy Commission

Matthew Goldberg, ISO New England Inc.

Rob Gramlich, American Wind Energy Association

John Guidinger, Commonwealth Associates Inc.

James Haney, Allegheny Power

Steve Henderson, CRA

Scott Henry, Duke Power

Michael Heyeck, American Electric Power

Sandra Hochstetter, Arkansas Public Service Commission

Raymond Kershaw, International Transmission Company

Mohan Kondragunta, SCE

Robert Kondziolka, SRP

Klaus Lembeck, PUCO

Doug Larson, Western Interstate Energy Board

Jay Loock, WECC

King Look, Consolidated Edison

Ellen Lutz, U.S. Department of Energy

Paul McCoy, Trans-Elect, Inc.

Michael McDiarmid, NM Energy Office

Robert McKee, American Transmission Company

M. Andrew McLain, U.S. Department of Energy

Will McNamara, Sempra Energy

David Meyer, U.S. Department of Energy

Joe Miller, JAM Enterprises

Pamela Mills, San Diego Gas & Electric

Jeffrey Mitchell, ReliabilityFirst Corp.

Eric Mortenson, Exelon

Jodi Moskowitz, PSEG

Jim Musial, DTE Energy

Steven Naumann, Exelon

David Neumayer, Western Area Power Administration

Roberto Paliza, Paliza Consulting, LLC.

Mary Ellen Paravalos, National Grid

Carl Patka, New York Independent System Operator

Jerry Pell, U.S. Department of Energy

Les Pereira, Northern California Power Agency

Jay Porter, American Transmission Company

Kathleen Quasey, Chicago Solar Partnership

Raj Rana, American Electric Power

Marion Rawson, Energetics Incorporated

Robert Reynolds, Peabody Energy

Randy Rismiller, Illinois Commerce Commission

Michael Robinson, Southern Company

Jay Ruberto, Allegheny Power

Lawrence Salomone, Washington Savannah River Company

David Sapper, Public Service Commission of Wisconsin

Allen Schindler, Northeast Utilities Service Co.

Robert Schlueter, Intellcon

John Schnagl, Federal Energy Regulatory Commission

Richard Schultz, ITC Transmission

Russell Schussler, Georgia Transmission Corporation

Alison Silverstein, Alison Silverstein Consulting

William Smith, Organization of MISO States

Wayne Snowdon, Canadian Electricity Association Transmission Council

Julia Souder, U.S. Department of Energy

Jennifer Sterling, Exelon

Mark Stout, Tri-State G&T

Edward Tatum, Old Dominion Electric Cooperative

Christine Tezak, Stanford WRG

Robert Thomas, Cornell University

David Till, Tennessee Valley Authority

Dale Trott, Burns & McDonnell

Charles Tyson, Midwest ISO

Julie Voeck, American Transmission Company

Steve Waddington, Wyoming Infrastructure Authority

Wayne Walker, Horizon Wind Energy

Kim Warren, Independent Electricity System Operator

Stephen Waslo, U.S. Department of Energy

Keith White, Calif. Public Utilities Comm.

Bill Whitehead, PJM

James Whitehead, Tennessee Valley Authority

Greg Williams, Bracewell & Giuliani LLP

Lawrence Willick, LS Power Development, LLC

Jeffrey Wilson, Midwest ISO

Kevin Wright, Illinois Commerce Commission

Robert Young, PA Public Utility Commission

Appendix E

On-Line Participants in DOE's March 29, 2006 Technical Conference on National Interest Electric Transmission Corridors

Ram Adapa, EPRI

Rahul Advani, Energy Capital Partners

Syed Ahmad, FERC

John Ahr, Allegheny Power

Lauren Andersen, PJM

Grace Anderson, California Energy Commission

Christy Appleby, PA Office of Consumer Advocate

Paul Bautista, Discovery Insights LLC

Alan Bax, MO Public Service Commission

David Beam, North Carolina Electric Membership Corporation

Joel Bearden, Cargill Power Markets, LLC

Candace Beery, MT PSC

William Bokram, Michigan Public Service Commission

Rich Bonnifield, PSEG

Donald Brookhyser, Alcantar & Kahl

Kenneth Brown, (organization not provided)

Brenda Buchan, Florida Public Service Commission

Jack Cadogan, Department of Energy - Wind

Greg Cagle, Progress Energy Carolinas, Inc.

Mary Cain, FERC

Richard Campbell, PPL

James Carnahan, Southwestern Power Administration

Janice Carney, ElectriCities

Thomas Carr, Western Interstate Energy Board

Phillip Cave, KY Public Service Commission

Ed Chang, Flynn Resource Consultants Inc.

Carol Chinn, FERC

Raj Chintapalli, Customized Energy Solutions

Amy Christensen, Iowa Utilities Board

Paul Ciampoli, NGI

Marcus Cole, Energy Capital Partners

Perry Cole, Energy Capital Partners

Anthony Como, Department of Energy

Stephen Conant, Anbaric Power

Jeffrey Conopask, D.C. Public Service Commission

Harold Cook, Booth & Associates, Inc.

Duane Dahlquist, Blue Ridge Power Agency

Edward Davis, Entergy Services, Inc

George Dawe, Duke Energy Corporation

Michael Delaney, City of New York

Christian DeLuca, IM-43

Rachel Dibble, Salt River Project

Sedina Eric, FERC

Bryce Freeman, Wyoming Infrastructure Authority

Roger Fujihara, DC Public Service Commission

Mark Futrell, Florida Public Service Commission

David Gaige, Burns & McDonnell

Alan Gale, City of Tallahassee

Judy Grau, California Energy Commission

Jack Halpern, Louis Berger Group, Inc

Damase Hebert, New Jersey Board of Public Utilities

James Hebson, PSEG

Donna Heimiller, National Renewable Energy Lab

Michael Held, MidAmerican Energy

Paul Herndon, APS

Terron Hill, National Grid

Raymond Hinkle, URS Corp.

Carolyn Holmes, 3M

Larre Hozempa, Allegheny Power

Margaret Hunt, Edison Electric Institute

Verne Ingersoll, Progress Energy

Eve Jasmin, Natural Resources Canada

Jeff Johnson, KY Public Service Commission

Margarett Jolly, Consolidated Edison of New York, Inc.

Sean Jones, Investor

Ahmad Khan, IIT

Neil Kirby, AREVA T&D Inc

Brendan Kirby, Oak Ridge National Laboratory

Ed Kirschner, Cinergy

Paul Klebe, ND Public Service Commission

Michael Kormos, PJM Interconnection

Rich Kosch, Lincoln Electric System

Bob Lawrence, Bob Lawrence & Associates, Inc.

Barry Lawson, NRECA

Michael Lee, Exeter Associates

Kathryn Lewis, Florida Public Service Commission

River Luo, ISO New England

Thomas Lyle, Vermont Public Service Board

Bill Malcolm, MISO

Marsha Manning, Progress Energy

Larry Mansueti, Department of Energy

Richard Marinelli, PSE&G

Jayme Martin, Cargill Power & Gas Markets

CV Mathai, Arizona Public Service Company

Joel McAllister, California Energy Commission

Richard McCain, Frederick County Government

Nina McLaurin, Progress Energy

Israel Melendez, Constellation Energy Commodities

Eileen Merrigan, FERC

Mary Meyers, Pepco Holdings, Inc.

Don Morrow, American Transmission Company

Jeff Mueller, PSEG Services Corp.

David Nick, DTE Energy

Christopher Norton, American Municipal Power - Ohio, Inc.

Beth O'Donnell, KY Public Service Commission

Gloria Ogenyi, Conectiv

Matthew Olearczyk, EPRI

Steve Oxley, Wyoming Public Svc Commission

Lee Paden, Law Offices of Lee W. Paden, P.C.

Anantha Pai, University of Illinois

Randall Palmer, Allegheny Power

Lopa Parikh, DC Office of the People's Counsel

Greta Paulsen, Montana-Dakota Utilities

Sheila Pendleton, VCALL

Marjorie Perlman, Rochester Gas and Electric Corporation

Denise Phipps, Self

Mark Plank, USDA

Kevin Porter, Exeter Associates

Nick Pratley, National Grid USA

Tom Pruitt, Duke Energy

Dennis Ray, PSERC

Charles Redell, Energy Prospects

Mark Ringhausen, Old Dominion Electric Cooperative

Dean Robinson, Tennessee Valley Authority

Hal Romanowitz, Oak Creek Energy Systems

Elliot Roseman, ICF Consulting

Gregory Rowland, Duke Energy

Morteza Sabet, WAPA/SNR

Bruce Sailers, Cinergy

James Salo, Colorado River Commission of Nevada

Antonio Sammut, International Transmission

Jeffrey Sanders, FERC

Michael Schmidt, Platts Inside Energy

Marsha Smith, Idaho Public Utilities Commission

Grace Soderberg, NARUC

Ryan Stanley, Pacific Gas and Electric Company

David Steele, WEST Associates

William Steeley, EPRI

Edward Stein, FirstEnergy Solutions

Curtis Stepanek, Ameren Services

John Sterling, Arizona Public Service Company

Tracey Stewart, Southwestern Power Administration

Pam Stonier, VT PSB

Jeff Taylor, New Mexico Attorney General

Dina Thompson, PacifiCorp

Michael Thompson, Wright & Talisman, P.C.

Sebastian Tiger, FERC

William VanderLaan, Illinois Commerce Commission

Jack VanKuiken, Argonne National Laboratory

Pat vanMidde, vanMidde Consulting

James Viikinsalo, Southern Company Services, Inc.

Sandra Waldstein, Vermont Public Service Board

Carol White, FERC

Patsy White, FPSC

Robert Williams, Florida Municipal Power Agency

Rick Woodlee, Tennessee Valley Authority

Jeff Wright, FERC

Ellen Young, Stuntz, Davis & Staffier, PC

Joni Zenger, Utah Division of Public Utilities

Darrell Zlomke, Wyoming Public Service Commission

Appendix F

Organizations Providing Formal Comments to DOE's March 29, 2006 Technical Conference on National Interest Electric Transmission Corridors

The following 13 organizations provided formal comments to the U.S. Department of Energy on the plan presented at the March 29, 2006, Technical Conference:

Allegheny Power

American Electric Power

American Transmission Company

California Public Utilities Commission

Committee on Regional Electric Power Cooperation

Edison Electric Institute

ISO/RTO Council

National Association of Regulatory Utility Commissioners

Northeast Power Coordinating Council

Northern California Power Agency

Old Dominion Electric Cooperative

PSEG Services Corporation

Xcel Energy

Appendix G

Outreach Meetings Held Regarding the Congestion Study

Organization/Event	Outreach Type	Location	Date
National Conference of State Legislatures (NCSL)	Presentation at NCSL National Conference	Seattle, WA	August 18, 2005
Southern States Energy Board	Presentation at Utility Restructuring Task Force	Atlanta, GA	August 27, 2005
Midwest State Energy Office	Presentation for Web Cast	Web Cast	August 31, 2005
National Association of State Energy Officials (NASEO)	Presentation at NASEO 2005 Annual Meeting	New York, NY	September 12, 2005
Hunton & Williams	Presentation at Seminar	Washington, D.C.	September 19, 2005
Committee on Regional Electric Power Cooperation (CREPC)	Presentation	San Diego, CA	September 20, 2005
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	September 26, 2005
Western Electricity Coordinating Committee (WECC)	Presentation at Joint Committee Meetings	Phoenix, AZ	September 29, 2005
Imperial (Calif.) Irrigation District	Meeting	Washington, D.C.	October 3, 2005
National Council on Electricity Policy Annual Meeting	Presentation	Chicago, IL	October 4, 2005
Bonneville Power Administration (BPA)	Meeting	Washington, D.C.	October 27, 2005
Transmission Access Policy Group (TAPS)	Presentation	Washington, D.C.	November 7, 2005
American Public Power Association (APPA)	Presentation at APPA's Energy Policy Act of 2005 Seminar	Washington, D.C.	November 10, 2005
National Wind Coordinating Committee (NWCC)	Presentation at Transmission and Wind Strategy: Issues and Opportunities conference	Conference call	November 10, 2005
National Association of Regulatory Utility Commissioners (NARUC)	Presentation at NARUC Annual Convention	Palm Springs, CA	November 14, 2005
New York State Public Service Commission	Meeting	Albany, NY	December 20, 2005
North American Electric Reliability Council (NERC)	Conference call	Conference call	December 22, 2005
ISO-RTO Council	Conference call	Conference call	January 10, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Conference call	Conference call	January 11, 2006
ISO-New England (ISO-NE)	Conference call	Conference call	January 12, 2006
Law Firm of Bracewell & Giuliani	Meeting	Washington, D.C.	January 17, 2006
American Electric Power (AEP)	Meeting	Washington, D.C.	January 31, 2006
Upper Great Plains Transmission Coalition (UGPTC)	Conference call	Conference call	January 31, 2006
Energy Policy Act of 2005: Electric Transmission and Distribution Future R&D Needs (DOE conference)	Presentation at conference	Tallahassee, FL	February 1, 2006
National Association of State Energy Officials (NASEO)	Presentation at NASEO Energy Outlook Conference	Washington, D.C.	February 7, 2006

Organization/Event	Outreach Type	Location	Date
National Independent Power Producers Coalition (NIPPC)	Conference call	Conference call	February 8, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Presentation NARUC Winter Meeting	Washington, D.C.	February 14, 2006
Western Electricity Coordinating Council	Presentation	Salt Lake City, Utah	February 15, 2006
National Electricity Delivery Forum	Presentation	Washington, D.C.	February 15-16, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Presentation at NARUC Meeting	Washington, D.C.	February 22, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	February 28, 2006
Canadian Electricity Association Power Marketer's Council	Presentation	Washington, D.C.	March 1, 2006
U.S.-Canada Forum	Presentation at the Forum at the Woodrow Wilson Center	Washington, D.C.	March 2, 2006
PJM Interconnection	Meeting	Washington, D.C.	March 3, 2006
Federal Energy Regulatory Commission (FERC)	Meeting with FERC staff	Washington, D.C.	March 9, 2006
Infocast Transmission Summit (conference)	Presentation	Washington, D.C.	March 14, 2006
North American Electricity Working Group	Presentation	La Jolla, CA	March 22, 2006
Innovation Investments, ICF Consulting	Meeting	Washington, D.C.	March 27, 2006
Public Technical Conference and Web Cast on DOE Congestion Study and Criteria for Designation of National Interest Electric Transmission Corridors	Presentations	Chicago, IL	March 29, 2006
Federal Energy Regulatory Commission (FERC), PJM Interconnection	Meeting with FERC staff and PJM Interconnection	Washington, D.C.	April 3, 2006
Committee on Regional Electric Power Cooperation (CREPC)	Presentation at CREPC meeting	Portland, OR	April 4, 2006
ABB	Meeting	Washington, D.C.	April 7, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	April 10, 2006
Burns & McDonnell Transmission Line Symposium	Presentation	Kansas City, MO	April 27, 2006
North American Electric Reliability Council (NERC) Stakeholders Meeting	Presentation	Arlington, VA	May 1, 2006
U.S. DOE Wind Program	Meetings with staff	Washington, D.C.	May 2006
PJM Interconnection	Meeting	Washington, D.C.	May 4, 2006
American Transmission Company	Meeting	Washington, D.C.	May 11, 2006
Edison Electric Institute (EEI)	Meeting	Washington, D.C.	May 11, 2006
Organization of MISO States (OMS) Board	Conference call	Conference call	May 11, 2006
Southern Company	Meeting	Birmingham, AL	May 22, 2006
Electric Power Supply Association (EPSA)	Meeting	Washington, D.C.	May 30, 2006
U.S. DOE Nuclear NP2010 Program	Conference calls with staff	Conference call	May, June 2006
Community Power Alliance	Presentation at the Community Power Alliance Breakfast	Washington, D.C.	June 6, 2006
Platt's Infrastructure Investment Conference	Presentation	Washington, D.C.	June 6, 2006
Florida Public Service Commission (FPSC)	Meeting	Tallahassee, FL	June 15, 2006

Organization/Event	Outreach Type	Location	Date
Florida Reliability Coordinating Council (FRCC)	Meeting	Tallahassee, FL	June 15, 2006
National Association of Regulatory Utility Commissioners (NARUC)	Conference call with Electricity Committee	Conference call	June 16, 2006
ISO-New England (ISO-NE)	Meeting	Holyoke, MA	June 19, 2006
Edison Electric Institute (EEI)	Presentation at EEI Annual Convention	Washington, D.C.	June 20, 2006
Allegheny Power, ICF Consulting	Meeting	Washington, D.C.	June 21, 2006
National Grid	Meeting	Washington, D.C.	July 28, 2006

Appendix H

General Documents or Data Reviewed for the Congestion Study

1. Electricity Advisory Board, Electric Resources Capitalization Subcommittee, U.S. Department of Energy, "Competitive Wholesale Electricity Generation: A Report of the Benefits, Regulatory Uncertainty, and Remedies to Encourage Full Realization Across All Markets," September 2002.
2. Electric Transmission Constraint Study, FERC OMOI, December 2003.
3. Electricity Advisory Board, U.S. Department of Energy, "Transmission Grid Solutions Report," September 2002.
4. Federal Energy Regulatory Commission, "Testimony of Karl Pfirrmann, President, PJM Western Region, PJM Interconnection, L.L.C.," Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources—Docket No. AD05-3-000.
5. Federal Energy Regulatory Commission, "Remarks of Audrey Zibelman, Executive Vice President, PJM Western Region, PJM Interconnection, L.L.C.," Transmission Independence and Investment—Docket No. AD05-5-000 and Pricing Policy for Efficient Operation and Expansion of the Transmission Grid—Docket No. PL03-1-000.
6. National Commission on Energy Policy, "Siting Critical Energy Infrastructure, An Overview of Needs and Challenges, A White Paper Prepared by the Staff of the National Commission on Energy Policy," June 2006.
7. U.S. Department of Energy, "National Transmission Grid Study," May 2002.
8. U.S. Department of Energy, "Comments to the Designation of National Interest Electric Transmission Bottlenecks (NIETB) Notice of Inquiry," Appended 10/15/04.

Appendix I

Documents or Data Reviewed for the Eastern Interconnection Analysis

1. 2004 State of the Market Report—New York ISO, Potomac Economics.
2. 2005 Minnesota Biennial Transmission Report.
3. 2005 Triennial Review of Resource Adequacy, March 2006, NYISO.
4. APPA Issue Brief: Joint Ownership of Transmission, January 2006.
5. Big Stone Certificate of Need and Route Permit.
6. Buffalo Ridge Incremental Generation Outlet Transmission Study (BRIGO Study).
7. Cambridge Energy Research Associates Study (2004) "Grounded in Reality: Eastern Interconnection."[68]
8. CAPX 2020 Vision Study – CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs. (Minnesota 2005).
9. Electric Transmission Constraint Study (December 19, 2001) posted on the FERC website.
10. FERC Form 715s.
11. Florida-Southern Interface Study for 2005 Summer & 2005-06 Winter Bulk Electric Supply Conditions (October 2004).
12. Impacts of Lincoln – Circle 230kV in Kansas, May 2005, SPP Engineering Department, Planning Section.
13. Iowa/Southern Minnesota Exploratory Study.
14. ISO New England 2004 Annual Markets Report.
15. ISO New England Regional System Plan 2005 (October 2005).
16. Maryland Public Service Commission, "Reply Comments of the Staff of the Maryland Public Service Commission in the Matter of the Inquiry Into Locational Marginal Prices in Central Maryland During the Summer of 2005"—Case No. 9047.
17. MEN 2002 Interregional Transmission System Reliability Assessment.
18. Michigan Exploratory Study Preliminary Study Report (Draft), October 2005, MISO.
19. Michigan Public Service Commission, "Final Staff Report of the Capacity Need Forum," January 3, 2006.
20. Midwest Transmission Expansion Plan (MTEP) of the Midwest ISO. (The Northwest Exploratory Study and Midwest ISO West RSG Consolidated Study included in the MTEP should be reviewed for possible NIETC designations.)
21. MISO 2003 Transmission Expansion Plan.
22. MISO Transmission Expansion Plan 2005 (June 2005).
23. NERC 2005 Long-Term Reliability Assessment.
24. NERC 2005 Summer Assessment.
25. NERC 2005/2006 Winter Assessment.
26. NERC TLR Data.
27. New England 2005 Triennial Review of Resource Adequacy, ISO New England, November 2005.
28. Northeastern Coordinated System Plan.

[68] Reviewed but considered confidential, so not used.

29. NPCC 2004 Report of the CP–10 Working Group Under the Task Force on Coordinated Planning.

30. NPCC Reliability Assessment for Summer 2005.

31. NYISO 2004 Intermediate Area Transmission Review of the New York State.

32. NYISO 2005 Load & Capacity Data.

33. NYISO Comprehensive Reliability Planning Process (CRPP) Reliability Needs Assessment (December 2005).

34. NYISO Comprehensive Reliability Planning Process Supporting Document and Appendices For The Draft Reliability Needs Assessment (December 2005).

35. NYISO Comprehensive Transmission Plan.

36. NYISO Electric System Planning Process, Initial Planning Report (October 6, 2004).

37. NYISO Operating Study Winter 2004-05 (November 2004).

38. NYISO Transmission Performance Report (August 2005).

39. PJM Regional Transmission Expansion Plan 2005 (September 2005).

40. PJM, MISO, NYISO, and ISO-NE Realtime and Day-ahead Constraint Data.

41. PJM Interconnection, L.L.C., "Comments of PJM in Response to the MD PSC Notice of Inquiry"—Case Number 9047.

42. Project Mountaineer, Work Group Meeting, Sheraton Four Points Hotel, Baltimore, MD, August 3, 2005.

43. Reports produced by MAIN and ECAR (provided to U.S. Department of Energy by EEI).

44. SERC Reliability Review Subcommittee's 2005 Report to the SERC Engineering Committee (June 2005).

45. SPP RTO Expansion Plan 2005–2010 (September 2005).

46. Southwest Minnesota Twin Cities 345 kV EHV Development Study.

47. Southwest Power Pool's Kansas/Panhandle Sub-Regional Transmission Study, January 26, 2006.

48. Southwest Power Pool Intra-Regional Appraisal and Study Observation—2005 Summer Peak Transmission Assessment, May 2005, SPP Engineering Department, Planning Section.

49. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2005/06 Winter Peak Transmission Assessment—Draft, Nov 2005, SPP Engineering Department, Planning Section.

50. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2005/06 Winter Peak Transmission Assessment—Nov 2005, SPP Engineering Department, Planning Section.

51. Southwest Power Pool Intra-Regional Appraisal and Study Observation 2014 Summer Peak Transmission Assessment, Nov 2005, SPP Engineering Department, Planning Section.

52. System Reliability Assurance Study (SRAS) prepared by Consolidated Edison Company of New York in December 2005.

53. Trans-Allegheny Interstate Line Project, A 500 kV Transmission Line Through the AP Zone; Published February 28, 2006 by Allegheny Power.

54. U.S. Department of Energy, "National Transmission Grid Study," May 2002.

55. U.S. Department of Energy Transmission Bottleneck Project Report, Consortium for Electric Reliability Technology Solutions (CERTS), March 2003.

56. VACAR 2004-2005 Winter Stability Study Report (March 2004)

57. VACAR 2005 Summer Reliability Study Report (April 2004).

58. VACAR 2007 Summer Reliability Study Report (February 2002).

59. VASTE 2005 Summer Reliability Study Report (May 2005).

60. VASTE 2005-06 Winter Study Report (November 2005).

61. VEM 2004 Summer Reliability Study Report (May 2004).

62. VEM 2004-2005 Winter Reliability Study Report (November 2004).

63. VST(E) 2011 Summer Study Report (November 2004).

64. VSTE 2008 Summer Study Report (November 2005).

65. Western Area Power Administration's Dakota Wind Study (2005).

Appendix J

Documents or Data Reviewed for the Western Interconnection Analysis

1. Available on the WECC Web site—http://www.wecc.biz. Open "Congestion Study" under the Main Menu of the home page:

a. "Framework for Expansion of the Western Interconnection Transmission System, October 2003."

b. "Western Interconnection Transmission Path Flow Study"—February 2003.

c. "Northwestern Consortia to Study the Regional Wind Development Benefits of Upgrades to Nevada Transmission Systems"—May 10, 2005.

d. "Conceptual Plan for Electricity Transmission in the West"—August 2001.

e. "Proposed Criteria for Evaluation of Transmission and Alternative Resources"—October 2005.

2. Available on State of Wyoming Web site at http://psc.state.wy.us/htdocs/subregional/Reports.htm: "Rocky Mountain Area Transmission Study"—September 2004.

3. Available on California Energy Commission Web site at http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CTF.PDF: "Committee Final Strategic Transmission Investment Plan (Committee Final Strategic Plan), California Energy Commission, November 2005."

4. Available on the Public Service Company of Colorado Web site at http://www.rmao.com/wtpp/PSCO_Studies.html: "Colorado Long Range Transmission Planning Study"—April 27, 2004.

5. Available from WECC (Phase 3 Accepted Path Rating Study Report)—Call (801) 582–0353: "Southwest Power link and Palo Verde–Devers 500kV Series Capacitor Upgrade Project"—dated December 2, 2004.

6. California Energy Commission 2005 Integrated Energy Policy Report, November 2005.

7. CAISO testimony to the CPUC for the Palo Verde–Devers #2 Project http://www.caiso.com/14cf/14cf82f921c90.pdf.

8. Documents on the CAISO Controlled Grid Study,[69] http://www.caiso.com/docs/2002/12/02/200212021600259660.html.

9. Documents on the CAISO's Policies, Standards, and Processes, http://www.caiso.com/docs/2001/06/04/2001060418221123496.html.

10. Documents on the Generator Interconnection Process, http://www.caiso.com/docs/2002/06/11/2002061110300427214.html.

11. Documents on the Northwest/California Subregional Group, http://www.caiso.com/docs/2003/07/22/20030722133104582.html.

12. Documents on the Palo Verde–Devers #2 project http://www.caiso.com/docs/2005/01/19/2005011914572217739.html.

13. Fifth Northwest Electric Power and Conservation Plan. Document 2005-7. The Northwest Power Planning Council May, 2005.

14. Information on the CAISO Transmission Economic Assessment Methodology (TEAM) http://www.caiso.com/docs/2003/03/18/2003031815303519270.html.

15. Information on the Southwest Transmission Expansion Plan (STEP) http://www.caiso.com/docs/2002/11/04/2002110417450022131.html.

[69] Information for the CAISO documents listed was incorporated indirectly in the study through participation on the WCATF by representatives of the CAISO.

16. Montana Department of Environmental Quality 1996. Draft Environmental Assessment of the Beartooth Pipeline Billings, Montana to Elk Basin, Wyoming. Helena, Montana.[70]

17. Montana Department of Natural Resources and Conservation 1976. Draft Environmental Impact Statement on Anaconda-Hamilton 161 KV Transmission Line. Energy Planning Division. Helena, Montana.

18. Montana Department of Natural Resources and Conservation 1976. Draft Environmental Impact Statement on Clyde Park - Dillon 161 Kilovolt and 69 Kilovolt Transmission Lines. Energy Planning Division. Helena, Montana.

19. Montana Department of Natural Resources and Conservation 1979. Draft Environmental Impact Statement on the Proposed Northern Tier Pipeline System. Helena, Montana.

20. Montana Department of Natural Resources and Conservation 1981. Report on Alternative Northern Tier Pipeline Routes Between Weeksville and Helmville, A report to the Northern Tier Pipeline Company. Facility Siting Division. Helena, Montana.

21. Montana Department of Natural Resources and Conservation 1983. Draft Report Preferred and Alternate Routes: BPA 500 - Kilovolt Line From Garrison -West. Energy Division. Helena, Montana.

22. "Montana – Pacific Northwest Transmission Upgrade Study" http://www.nwpp.org/ntac/pdf/, click on 25-Oct-2005 file "MT-NW Study Report 2005-Oct.zip."

23. Montana State Department of Natural Resources and Conservation 1974. Draft Environmental Impact Statement on Colstrip Electric Generating Units 3&4, 500 Kilovolt Transmission Lines and Associated Facilities, Volume Four, Transmission Lines. Energy Planning Division. Helena, Montana.

24. Montana (State of), USDA-Forest Service, and USDI-Bureau of Land Management 1981. Utility-Transportation Corridor Study for Montana, The Existing Situation and Options for Future Corridor Selection.

25. Northwest Power Pool report http://www.nwpp.org/ntac/pdf/Selected%20Transmission%20Siting%20Constraints.pdf.

26. "Puget Sound Area Upgrade Study Report"—November 2004 http://www.nwpp.org/ntac/pdf/PSASG%20Final%20Draft.pdf.

27. Report of the BPA Infrastructure Technical Review Committee 2001-2004.

28. "Report of the Phase I Study of the Central Arizona Transmission System" http://www.azpower.org/cats/default.asp#phase1.

29. "Report of the Phase II Study of the Central Arizona Transmission System" http://www.azpower.org/cats/default.asp#phase2.

30. "Report of the Phase III Study of the Central Arizona Transmission System" http://www.azpower.org/cats/default.asp#phase3.

31. Report of the Tehachapi Collaborative Study Group, March 16, 2005.

32. The Potential for More Efficient Electricity Use in the Western U.S.: Energy Efficiency Task Force Draft Report to the Clean and Diversified Energy Advisory Committee of the Western Governor's Association, Draft Report for Peer Review and Public Comment. Western Governor's Association. September 15, 2005.

33. The Report of the Imperial Valley Study Group, September 30, 2005.

34. Transmission studies available in consultation with WECC and the Wyoming Infrastructure Authority.

[70] Information for the State of Montana documents listed was incorporated indirectly in the study. No State of Montana representative participated in the Western Congestion Assessment Task Force (WCATF) study; however, there was participation by representatives of the Northwestern Energy Company (a Montana utility). Note that the documents listed are all corridor-specific reports and the WCATF study was a higher level, non-corridor-specific study.

35. U.S. Department of Energy 1982. Draft Environmental Impact Statement Garrison-Spokane 500 kV Transmission Project. Bonneville Power Administration. Portland, Oregon.[71]

36. U.S. Department of Energy 1983. Draft Environmental Impact Statement, Conrad – Shelby Transmission Line Project, Montana, Appendix A. Western Area Power Administration. Billings, Montana.[72]

37. U.S. Department of Energy 1983. Draft Environmental Impact Statement, Great Falls–Conrad Transmission Line Project, Montana, Appendix A. Western Area Power Administration. Billings, Montana.[73]

38. WECC 2006 Existing Generation and Significant Additions and Changes to System Facilities.

[71] Information was incorporated indirectly in the study through participation on the WCATF by representatives of BPA. Note that this document is corridor-specific and the WCATF study was a higher level, non-corridor-specific study.

[72] Information was incorporated indirectly through participation on the WCATF by a representative of the Western Area Power Administration (WAPA). Note that this document is corridor-specific and the WCATF study was a higher-level study.

[73] Information was incorporated indirectly through participation on the WCATF by a representative of WAPA. Note that this document is corridor-specific and the WCATF study was a higher-level study.

Appendix K

List of WECC Paths[74]

Path Number	Path Name	Path Number	Path Name
1	Alberta - British Columbia	39	TOT 5
2	Alberta - Saskatchewan	40	TOT 7
3	Northwest - Canada	41	Sylmar to SCE
4	West of Cascades - North	42	IID - SCE
5	West of Cascades - South	43	North of San Onofre
6	West of Hatwai	44	South of San Onofre
8	Montana to Northwest	45	SDG&E - CFE
9	West of Broadview	46	West of Colorado River
10	West of Colstrip	47	Southern New Mexico
11	West of Crossover	48	Northern New Mexico
14	Idaho to Northwest	49	East of Colorado River
15	Midway - Los Banos	50	Cholla - Pinnacle Peak
16	Idaho - Sierra	51	Southern Navajo
17	Borah - West	52	Silver Peak - Control 55kV
18	Idaho - Northwest	54	Coronado West
19	Bridger West	55	Brownlee East
20	Path C	58	Eldorado - Mead 230 kV
21	Arizona to California	59	WALC Blythe 161 kV Sub
22	SW of Four Corners	60	Inyo - Control 115 kV Tie
23	Four Corners 345/500 kV Tx.	61	Lugo - Victorville 500 kV line
24	PG&E - Sierra	62	Eldorado - McCullough 500 kV line
25	Pacificorp - PG&E 115 kV	63	Perkins-Mead-Marketplace 500 kV line
26	Northern - Southern California	64	Marketplace - Adelanto
27	IPP DC Line	65	Pacific DC Intertie
28	Intermountain - Mona 345 kV	66	COI
29	Intermountain - Gonder 230 kV	71	South of Allston
30	TOT 1A	73	North of John Day
31	TOT 2A	75	Midpoint - Summer Lake
32	Pavant - Gonder 230 kV	76	Alturas Project
33	Bonanza West	77	Crystal - Allen
35	TOT 2C	78	TOT 2B1
36	TOT 3	79	TOT 2B2
37	TOT 4A	80	Montana Southeast
38	TOT 4B		

[74] Refer to WECC Path Rating Catalog for path details.