NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

DECEMBER 2009

U.S. Department of Energy

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Note to Readers

As the Department of Energy (DOE) stated when it announced the beginning of its work on this study in May 2006, the 2009 Congestion Study focused on the identification of existing electric transmission-level congestion based on publicly available historic information and data related to transmission congestion. The information and data used by DOE in conducting the analysis in this study was that which was available through May 2009. As a result the study does not address the possible impacts of the recent recession on congestion, or any other recent events, reports, or other developments affecting congestion.

Consistent with the requirements of the Energy Policy Act of 2005, the Department invites public comment on this study. A 60-day comment period will begin shortly, with the publication of a notice of the availability of the study and the comment period in the *Federal Register*. DOE will post the opening and closing dates of the comment period on www.congestion09.anl.gov, which is a public website the Department maintains for congestion-related activities and materials. All comments received will be posted on this website.

Commenters may address any aspect of this study they consider appropriate. The Department intends to update, or issue an addendum to, this study in which it may consider the effect of the recession on congestion identified in the study, comments received on this version of the study, and the implications of additional data or information that has become available since May 2009. The Department invites commenters to direct it to data, publications, or other information that they believe relevant to this additional analysis.

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Executive Summary

In the Energy Policy Act of 2005 (EPAct), Congress directed the U.S. Department of Energy (DOE) to conduct a study every three years on electric transmission congestion and constraints within the Eastern and Western Interconnections. The American Reinvestment and Recovery Act of 2009 (Recovery Act) further directed the Secretary to include in the 2009 Congestion Study an analysis of significant potential sources of renewable energy that are constrained by lack of adequate transmission capacity. Based on this study, and comments concerning it from states and other stakeholders, the Secretary of Energy may designate any geographic area experiencing electric transmission capacity constraints or congestion as a national interest electric transmission corridor (National Corridor).

In August 2006, the Department published its first National Electric Transmission Congestion Study. In 2007, based on the findings of that study and after considering the comments of stakeholders, the Secretary designated two National Corridors, one in the Mid-Atlantic area and one covering Southern California and part of western Arizona.

This document identifies areas that are transmission-constrained, but as in 2006, this study does not make recommendations concerning existing or new National Corridor designations. The Department may or may not take additional steps concerning National Corridors at some future time.

Transmission Congestion

Congestion occurs on electric transmission facilities when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels. These restrictions may be imposed 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" can refer to a piece of equipment that restricts power flows, to an operational limit imposed to protect reliability, or to a lack of adequate transmission capacity to deliver potential sources of generation without violating reliability requirements. Because power purchasers typically try to buy the least expensive energy available, when transmission constraints limit the amount of energy that can be delivered into the desired load center or exported from a generation-rich area, these constraints (and the associated congestion) impose real economic costs upon energy consumers. In the instances where transmission constraints are so severe that they limit energy deliverability relative to consumers' electricity demand, such constraints can compromise grid reliability.

The 2009 study documents (to the extent publicly available data permit) where electricity congestion and transmission constraints occur across the eastern and western portions of the United States' bulk power system. Congestion varies over time and location as a function of many factors, including energy use and production patterns across the grid and changes in the availability of specific assets (such as power plants or transmission lines) over time. This analysis indicates general patterns of congestion—broad areas where the transmission congestion reflects imbalances between electric supply and demand that create significant costs, perhaps including adverse impacts on reliability.

Transmission congestion and the existence and impacts of transmission constraints can be measured according to three broad sets of metrics—high levels of transmission usage, the economic costs and electricity prices that result from transmission constraints, and, occasionally, the reliability consequences of transmission limits. These metrics and the results of their application are discussed in detail in Chapters 2, 4 and 5.

The 2009 study identifies regions of the country that are experiencing congestion, but refrains from addressing the issue of whether transmission expansion would be the most appropriate solution. In some cases, transmission expansion might simply move a constraint from one point on the grid to another without materially changing the overall costs of congestion. In other cases, the cost of building new facilities to remedy congestion over all affected lines may exceed the cost of the congestion itself, and, therefore, remedying the congestion would not be economic. In still other cases, alternatives other than transmission, such as increased local generation (including distributed generation), energy efficiency, energy storage and demand response may be more economic than transmission expansion in relieving congestion.

Thus, a finding that a transmission path or flowgate is frequently congested should lead to further study of the costs and impacts of that congestion, and to a careful regional study of a broad range of potential remedies to larger reliability and economic problems. Although congestion is a reflection of legitimate reliability or economic concerns, not all transmission congestion can or should be reduced or "solved."

Study Approach and Input

Chapter 2 presents the 2009 study's approach and methods. The 2009 study differs methodologically from the previous study in that in 2006 the Department worked with analysts and consultants to develop independent projections of future congestion in the Eastern and Western Interconnections. In planning for the 2009 study, the Department determined that it would not conduct or sponsor congestion projections specifically for the 2009 study, but would draw instead upon the many studies prepared by others through independent, credible planning entities and processes.

The Department conducted extensive public outreach and consultation relating to the 2009 study. Department staff reached out to stakeholders within state governors' offices, public utility regulators, electric utilities and grid operators, electricity producers, demand-side resource providers, environmental organizations, and the general public to invite input on transmission congestion and constraints, and their consequences. Department staff conducted seven regional and technical public workshops to collect information. The Department reviewed comments submitted in connection with the 2006 congestion study about the conduct of future studies, and reviewed more than 40 comments filed as inputs to the 2009 study. Department staff met or spoke with all stakeholders requesting such contact. All of these views have been considered carefully in preparing the analyses that follow.

For the 2009 study, the Department revisited each of the congestion areas identified in 2006 and reassessed the 2006 study's conclusions for each area in light of currently available information on present conditions and expected high-probability developments. The Department reviewed more than 325 documents, independent studies, and analyses containing relevant information, as well as analyses of both historical and projected grid conditions; all of those reference materials are listed in Appendix C.

Renewable Resource Development, Transmission Availability, and the Concept of a Conditional Constraint Area

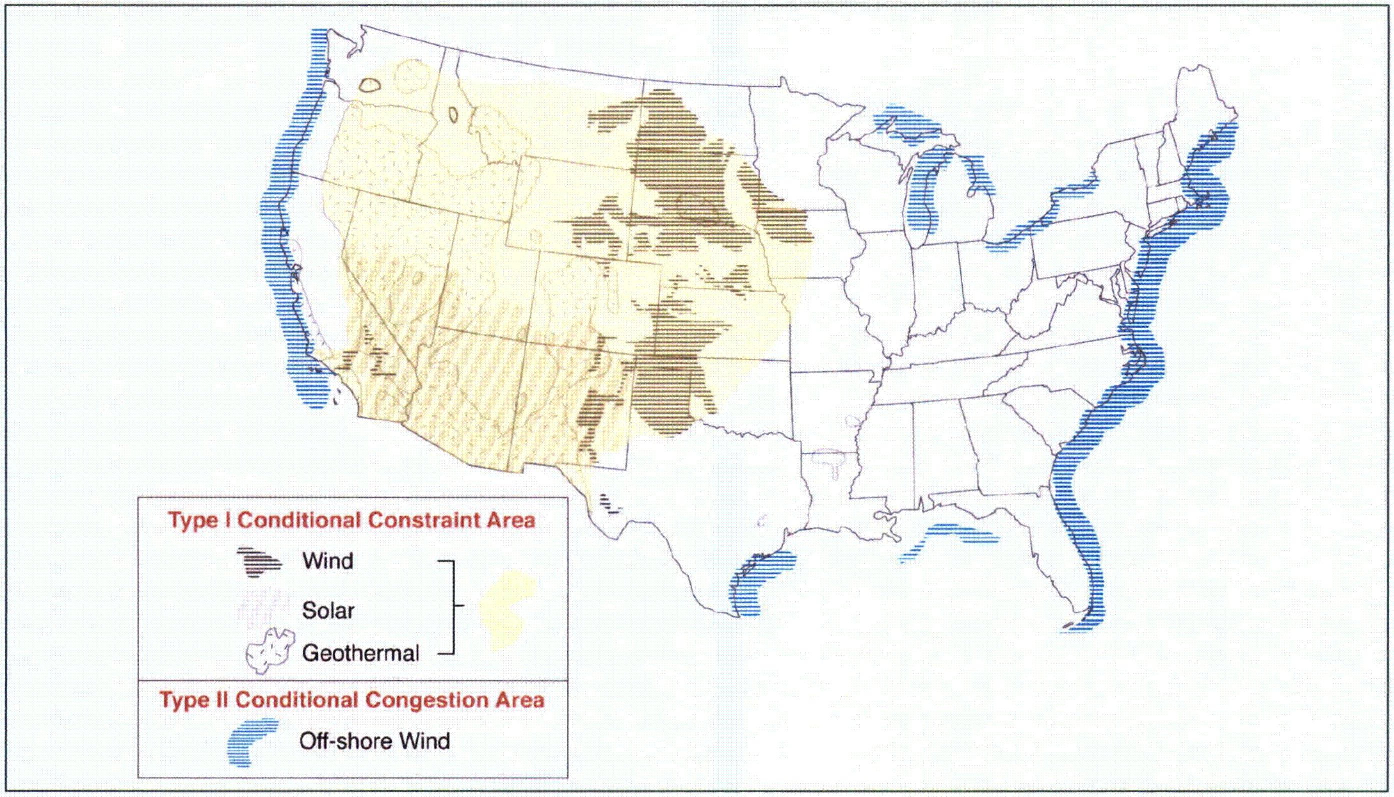
The Recovery Act expanded the scope of the 2009 Congestion Study by requiring the Department to include an analysis of the significant potential sources of renewable energy that are constrained in accessing appropriate market areas by lack of adequate transmission capacity, and explain why adequate transmission capacity has not been developed. Chapter 3 addresses these issues after reviewing the areas with the greatest potential for wind, solar and geothermal resource development as identified by the National Renewable Energy Laboratory (NREL).

In this study, the Department defines and identifies two types of Conditional Congestion Areas, Type I and Type II. A Type I Conditional Congestion Area is an area where large quantities of renewable resources could be developed economically using existing technology with known cost and performance characteristics—if transmission were available to serve them. Because many of the nation's rich onshore renewable resources are located in adjacent or overlapping areas, the Department has determined that it is appropriate to identify a single very large Type I area, rather than to call out technology-specific congestion areas (as was done in the 2006 study). By contrast, a Type II Conditional Congestion Area is an area with renewable resource potential that is not yet technologically mature but shows significant promise due to its quality, size, and location. If such resources become technologically mature (through additional R&D and sufficient experience with commercial-scale projects) they could then be limited chiefly by transmission availability, and if so the affected area would qualify for Type I status. A very large onshore Type I area and several offshore Type II areas are shown in Figure ES-1.

It is important to recognize that the economics of renewable resource development can vary widely from region to region, and that the characteristics of the resources are very location-specific. In many cases transmission access makes the difference between an economic and uneconomic project or development area; such economic and geographic granularity must also consider the cost of the transmission to access the resource, and cannot be determined or conveyed accurately in a national-scale study. Several states and regional organizations are conducting highly detailed analyses to identify preferred locations for development of renewable energy resources and their associated electric transmission needs—including efforts by the Western Governors' Association (WGA), Midwest Governors' Association, Southwest Area Transmission (SWAT) Forum, California, Arizona, and several other states. The Department recommends that resource development economic and policy decisions should be guided by these efforts. The Department also notes that there appears to be a wealth of commercially viable renewable resources outside the Type I Conditional Constraint Area; identification of the Area is not meant to suggest that it is not appropriate to develop additional transmission to serve new renewable (and other) resources elsewhere in the nation.

The Recovery Act also directed the Department to analyze the extent to which legal challenges filed at the State and Federal level are delaying the construction of transmission necessary to access renewable energy. Review of numerous transmission projects, including those intended to serve primarily renewable resources, suggests that most large-scale transmission projects are subject to legal challenge,

Figure ES-1. 2009 Type I and Type II Conditional Constraint Areas



regardless of any relationship to renewable resources; the Department concludes that while renewable-associated transmission projects face many challenges, they do not appear to suffer from legal challenge or delay to a greater or lesser extent than other transmission projects.

Transmission Congestion in the Eastern Interconnection

Because transmission congestion occurs when the flow of electricity from one point to another is limited below desired levels, transmission congestion can be evidenced in at least three ways—as heavy electrical usage of the equipment, as price differentials or economic cost differentials between different parts of the grid, and in extreme conditions, as a reliability problem that results from the inability to deliver enough electricity to meet consumers' electricity demand. Each of these measures can be expressed in quantitative metrics, discussed below, but the amounts of publicly available data to quantify and evaluate congestion are limited.

The Department hired a consulting firm to conduct a first-ever assessment of publicly available data on historical transmission congestion in the Eastern Interconnection.[1] The study was based solely on data for 2007. Information on actual electricity flows and on some aspects of scheduled flows in the Eastern Interconnection is not publicly available. Accordingly, the study collected and assessed information on three core elements that affect how transmission is managed—and how congestion can be measured with publicly available data—in the Eastern Interconnection: transmission reservations, transmission schedules, and real-time operations. The available data on 2007 historical transmission confirm the findings of the 2006 study with respect to the principal transmission congestion locations in the East. However, the Department concludes that the Eastern data—and more broadly, information on electric transmission usage generally in the U.S.—need significant improvement in scope and quality.

Reviewing the Congestion Areas identified in 2006, the Department concluded that the Mid-Atlantic Critical Congestion Area (extending from mid-state New York down to mid-Virginia) continues to experience high levels of transmission congestion. The region is making significant progress in reducing loads and improving reliability through the use of aggressive energy efficiency and demand response programs, and has added new generation since 2006. However, little new transmission has been built in the region in the past three years, although many new backbone and expansion projects are nearing construction; therefore it is likely to be several years before current congestion levels ease. This will lead to continued price differentials across the region and could compromise continued reliability in the Washington, Baltimore, New Jersey and New York City areas over the coming years. In addition, as long as New York's electric reliability and economics depend to a significant degree on electricity imports through New Jersey, Pennsylvania and neighboring states, tensions will remain over how to balance the needs and costs across the region. The Department finds that the Mid-Atlantic area continues to exhibit major transmission congestion problems and should continue to be identified as a Critical Congestion Area. This identification—as is the case with the others that follow in this document—is based on consideration of the totality of the various kinds of information presented, rather than on whether specific congestion metrics have been met or exceeded.

In 2006 the Department identified New England as a Congestion Area of Concern due to high electricity price differentials across the region and congestion-related reliability problems in Boston, southwest Connecticut, and other sub-areas. Over the past three years, however, transmission congestion within New England has fallen significantly. This is due to years of sustained effort and achievement on several fronts—new utility-scale and distributed, small-scale supply resources have come on-line, primarily in the locations where they were most needed and valuable; aggressive demand response programs have made load reduction into a geographically targeted resource that can be used to reduce peak loads and mitigate the effects of temporal transmission constraints; and energy efficiency is

[1]Open Access Technology International (OATI) (2009). *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, at http://www.congestion09.anl.gov/.

reducing total loads. Further, the area has a strong queue of new generation projects, as well as a diverse set of new reliability- and economics-oriented transmission projects completed or sitting in its interconnection and transmission system study queues. These developments have eased the significant reliability and economic differentials affecting the Boston metropolitan area and southwest Connecticut.

Although New England still faces a potential resource shortfall under extreme load conditions over the next few years, most of the significant transmission constraints have been eliminated by the region's multi-faceted approach. The region has shown that it can permit, site, finance, cost-allocate and build new generation and transmission, while encouraging new demand-side resources as well. New England faces some near-term reliability challenges, but is working aggressively to address them. For these reasons, the Department no longer identifies New England as a Congestion Area of Concern.

The Department also reviewed transmission congestion and grid conditions across the rest of the Eastern Interconnection and concludes that although there are numerous locations where transmission constraints cause economic congestion and occasional operational reliability problems, at present there are no other large areas that would justify formal identification as a congestion area.

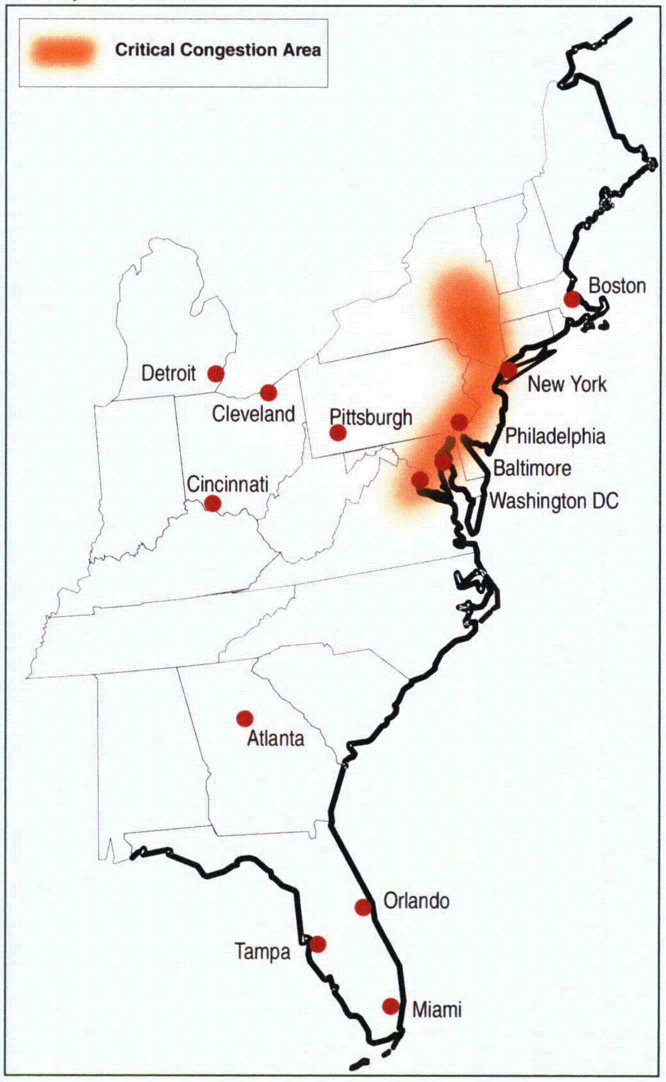
Figure ES-2 shows the Mid-Atlantic Critical Congestion Area, the only congestion area identified by the Department in the Eastern Interconnection in 2009.

Transmission Congestion in the Western Interconnection

For 2009, the Department examined congestion and constraints in the Western Interconnection in general and reviewed the status of the areas it identified in its 2006 study. The Transmission Expansion Planning and Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC) conducted both historical analysis of 2007 transmission data and forecasts of transmission needs for 2018. The TEPPC work found that although electricity flows vary from season to season and year to year as a function of changes in electricity demand, fuel costs and availability, new generation additions and losses, and other factors, the patterns reflected in this one-year snapshot still correspond generally to the broad patterns of past historical congestion. In fact, viewed with the same congestion metrics used in the 2006 Congestion Study, the grid congestion patterns for the 2007 data are consistent with the results of TEPPC's analysis of 2004 data (which was reported in the 2006 study).

The Western grid differs from the Eastern grid in that the Western grid system covers larger distances with a higher proportion of transmission lines linking distant generation sources to large, concentrated load centers. This means that Western system electricity data are more geographically aggregated and less granular—across physical geography and

Figure ES-2. Mid-Atlantic Critical Congestion Area, 2009



transmission assets and paths—than in the East. Another difference between West and East is that the West is dominated by vertically integrated utilities, with no centrally organized wholesale electric markets outside California; therefore, there are no data about the historic costs of congestion or electricity prices to measure the economic dimensions and consequences of transmission congestion in the (non-California) West.

The West has developed a strong, transparent regional transmission planning and analysis process over the past several years. This process is now yielding a wealth of proposals to build new backbone transmission across the interconnection, with at least 51 major projects being considered from British Columbia and Alberta down to southern California. Many of these projects are intended to enable concentrations of new renewable generation capacity in regions including southern California, Montana, Wyoming, Washington, and Oregon to deliver their output to coastal and southern load centers.

The Department's 2006 study identified Southern California (spanning the metropolitan areas of Los Angeles and San Diego) as a Critical Congestion Area, given the area's persistent transmission congestion problems, large population, and important economic role within the nation. Factors influencing the identification as a Critical Congestion Area included the area's growing electric demand, heavy dependence upon electricity imports, and difficulty in building new power plants and transmission lines.

In the 2009 study, the Department concludes that although the state of California has shown national leadership in moderating electric load growth and increasing distributed generation, the Southern California region remains challenged. New transmission and generation in Southern California have barely kept pace with load growth over the past few years. Although many promising generation and transmission projects are now in the planning or regulatory approval stages, experience shows that few such projects become operational on schedule in California. Slow development of new generation and transmission facilities could compromise near-term grid reliability in Southern California, despite growing demand response and smart grid capabilities. For these reasons, the Department concludes that Southern California remains congested, and that it should retain its status as a Critical Congestion Area.

In 2006 the Department identified the San Francisco Bay Area as a Congestion Area of Concern because of the reliability challenge posed by serving the area between San Jose and San Francisco with a single set of lines across the San Francisco Peninsula. The area had high local generation costs due to local high-cost reliability-must-run requirements, and little in-area generation. Instead—then and now—the San Francisco City and Peninsula depend upon import capabilities and the level of electricity demand and generation dispatch in the East Bay and South Bay.

A combination of supply and demand relief measures will be needed to reduce congestion and maintain reliability on the San Francisco Peninsula, but only a few of the needed measures will be completed over the near term. Until there is a clearer picture of how and when all the needed supply and demand-side elements will materialize, and materially improve conditions on the San Francisco Peninsula, the Department will continue to identify the San Francisco Peninsula as a Congestion Area of Concern.

The 2006 study identified the area from Seattle south to Portland as a Congestion Area of Concern with both reliability and economic implications. This reflected both high loading in winter and summer and increasing wind generation to the east, combined with new generation that had been built within the congestion path. Current development of rich wind resources to the east of the area is exacerbating the congestion problems over the near term, despite aggressive operational mitigation efforts by the local grid operator.

Several major backbone transmission projects are now being evaluated for the area; their completion would probably solve most of the Seattle-Portland congestion problems. Such completion, however, appears several years away. Until then, the Department will continue to identify the area as a Congestion Area of Concern.

Last, the 2006 study identified the Phoenix-Tucson region as a Congestion Area of Concern because this metropolitan region was experiencing explosive population and load growth with significant transmission loading and congestion. Numerous new transmission and generation projects have been given regulatory approval, however, and are now coming into service in the region, with the result that the existing and planned transmission systems appear adequate to meet the local energy reliability needs of the area for much of the coming decade. Although not all of the transmission and demand-side projects that will resolve current congestion problems have been completed, the recent history of transmission development in Arizona indicates that projects developed through the state's Biennial Transmission Assessment process receive swift regulatory approval and are built on schedule with limited complications or uncertainty due to permitting, routing or cost recovery. Therefore, the Department considers it likely that most of these projects will become operational by their scheduled dates in 2009 and 2010. Based on the progress in addressing congestion issues, the Department no longer identifies the Phoenix-Tucson area as a Congestion Area of Concern.

Figure ES-3 shows the 2009 Transmission Congestion Areas for the Western Interconnection.

A wealth of new backbone transmission is being considered for development in the Western Interconnection. This new transmission will affect western congestion patterns, as will efforts to develop new renewable resources to meet state renewable portfolio requirements and increased energy efficiency to meet resource and carbon emissions management goals. The Department will continue monitoring these developments, and the paths and congestion areas identified above, to determine whether levels of congestion and usage are becoming better or worse as load, generation and transmission infrastructure change over time.

Public Comments, Next Steps and Recommendations

The Department invites public comments on all aspects of this study. The comment period will be for 60 days, beginning with the day a notice of the availability of the study for public comment is published in the *Federal Register*. As soon as the closing date has been determined, the Department will post the closing date on its Congestion Study web site, congestion09@anl.gov. Comments must be submitted in writing to the Department no later than 5:00 p.m. EST on the closing date, if possible by e-mail to congestion09@anl.gov.

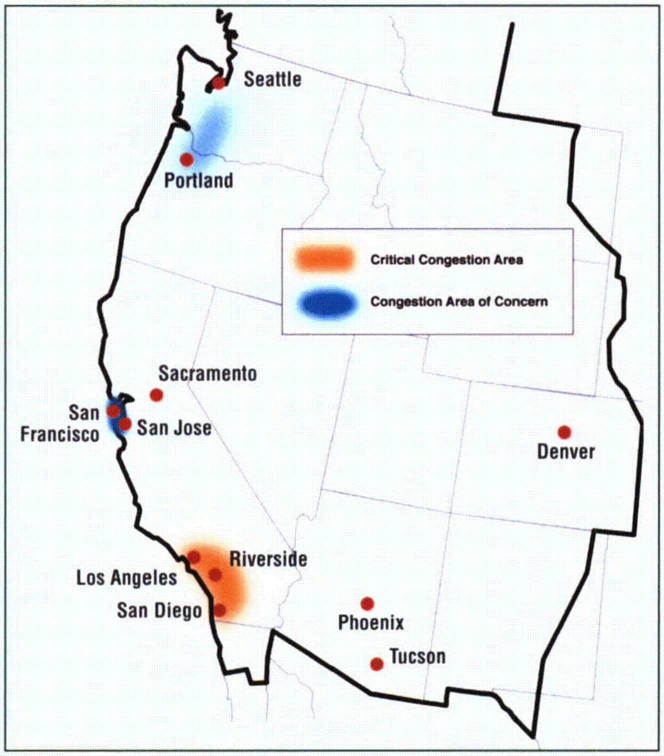
Comments may also be submitted by conventional mail to this address:

Comments on DOE 2009 Transmission Congestion Study
c/o Adriana Kocornik-Mina
Office of Electricity Delivery and Energy Reliability (OE)
U.S. Department of Energy
1000 Independence Avenue SW
Washington DC 20585

All comments received will be made publicly available on the website DOE has created for this study, www.congestion09.anl.gov. The Department will consider all comments received and take them into account in making decisions based in part on the findings of this study.

Several important activities and analyses are pending or already under way that are likely to show

Figure ES-3. 2009 Congestion Areas in the Western Interconnection



more clearly where the case for building additional transmission capacity is especially strong. The Recovery Act provided funds with which the Department intends to support these activities and analyses. These include:

1. *Stronger and more inclusive regional and interconnection-level transmission analysis and planning.* The Department believes that analytical entities in each of the Nation's interconnections should develop a broad portfolio of possible electricity supply futures, and identify their associated transmission requirements. These analyses will address, for example, the extent to which energy efficiency programs can reduce or forestall the need for additional transmission capacity, the merits of developing high-potential renewables in remote areas, as well as the merits of developing other renewable resources closer to load centers.

   After these analyses have been developed and made available for public review, transmission experts from the electricity industry, the states, federal agencies, and other stakeholder groups will collaborate in the development of interconnection-level transmission plans. Thus, to the extent feasible these plans will identify a coherent core set of transmission projects regarded by a diverse group of experts as needed under a wide range of futures.

2. *Designation by states of geographic zones* with concentrated, high-quality renewable resource potential, or other physical attributes especially relevant to reducing overall carbon emissions at reasonable cost. See, for example, *Western Renewable Energy Zones—Phase 1 Report,*[2] which identifies renewable resource "hubs." These hubs are the approximate centers of high-value resources areas that have also been screened to avoid park lands, wilderness areas, wetlands, military lands, steeply sloped areas, etc. DOE has announced that it seeks proposals from eastern state-based organizations to undertake similar analyses in the eastern United States. Identification of zones of particular interest for the development of additional low-carbon electric generating capacity will be very important as input to the long-term planning processes described in the preceding paragraph.

3. *Regional or sub-regional renewable integration studies.* The output from wind and solar generation sources is inherently variable, at least over shorter periods of time. Therefore, in a given region, transmission planners must determine how higher levels of renewable generation could be used in combination with other generation sources, demand-side resources, and storage facilities while maintaining grid reliability. Completion of these integration studies, along with careful transmission planning, is essential to enable planners to make informed decisions about how to integrate large amounts of new renewable generation effectively, economically and reliably.

Determining what will constitute future transmission "adequacy," however, is no simple matter. It is becoming technically feasible to drive transmission systems harder and obtain more services from them, without endangering reliability—provided certain critical conditions are met. These include:

1. The availability of detailed, near-real-time information about second-to-second changes in the operational state of the bulk power supply systems.
2. The availability of effective control devices that will respond extremely quickly to correct or avert potentially hazardous operating conditions.
3. The availability of appropriately trained workforces that will be able to design, build, operate, and maintain such complex systems.

The Department has plans to address these challenges, again through funds provided by the Recovery Act.

Given the rising importance of electric infrastructure planning, however, there is a clear need to facilitate better and more transparent planning and policy decisions by improving the quality and availability of data concerning the use of existing transmission facilities. More systematic and

[2]Western Governors' Association (WGA) and U.S. Department of Energy (DOE) (2009). "Western Renewable Energy Zones – Phase 1 Report," at http://www.westgov.org/wga/initiatives/wrez/.

consistent data are needed on several transmission subjects, such as:

1. The prices and quantities of short- and long-term transactions in wholesale electricity markets.
2. Scheduled and actual flows on the bulk power system. At present, Open Access Same-Time Information System (OASIS) data are scattered across many websites, are neither edited nor archived, and not presented in a consistent format. Clearer direction from the Federal Energy Regulatory Commission (FERC) on how such data are to be presented would be very helpful. Special attention is required to depict more clearly the flows across inter-regional seams.
3. The economic value of curtailed transactions.

The Department looks forward to being able to draw upon both improved data and the results of a wide range of relevant studies in its 2012 Congestion Study.

Acronyms and Abbreviations

AC	Alternating Current
ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy Efficient Economy
AEP	American Electric Power
AFC	Available Flowgate Capacity
AP	Allegheny Power
APS	Arizona Public Service
ATC	Available Transfer Capability
AWEA	American Wind Energy Association
BGE	Baltimore Gas & Electric
BLM	Bureau of Land Management
BPA	Bonneville Power Administration
BRA	Base Residual Auction
BTA	Biennial Transmission Assessment
CAISO	California Independent System Operator
CapX	Capacity Expansion
CEC	California Energy Commission
CPUC	California Public Utility Commission
CSP	Concentrating Solar Power
DC	Direct Current
DG	Distributed Generation
DOE	U.S. Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPAct	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
EWITS	Eastern Wind Integration and Transmission Study
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GW	GigaWatt (1 billion or 10^9 watts)
HAWG	WECC's Historical Analysis Working Group
HVDC	High Voltage Direct Current
ICTE Staff	Entergy's Transmission Manager
IDC	Interchange Distribution Calculator
IEPR	Integrated Energy Policy Report
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
LADWP	Los Angeles Department of Water and Power
LAGN	Lousiana Generating, LLC
LBNL	Lawrence Berkeley National Laboratory
LGEE	Louisville Gas and Electric Energy
LMP	Locational Marginal Price
LMPCCs	Congestion component of Locational Marginal Prices
MAPP	Midcontinent Area Power Pool
MAPP	Mid-Atlantic Power Pathway
MISO	Midwest Independent System Operator
MW	MegaWatt (one million or 10^6 watts)
MWh	MegaWatt-hours (1 million or 10^6 watt-hours)
NARUC	National Association of Regulatory Utility Commissioners
National Corridor	National interest electric transmission corridor
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYRI	New York Regional Interconnect
OASIS	Open Access Same-Time Information System

OATI	Open Access Technology International
PATH	Potomac-Appalachian Transmission Highline
PEPCO	Potomac Electric Power Company
PG&E	Pacific Gas & Electric
PJM	PJM Regional Transmission Organization
PSEG	Public Service Enterprise Group
Recovery Act	American Reinvestment and Recovery Act of 2009
RETI	California Renewable Energy Transmission Initiative
RMR	Reliability-Must-Run
RPS	Renewable Portfolio Standards
RRO	Regional Reliability Organization
RTEP	PJM's Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
SCE	Southern California Edison
SERC	Southeast Reliability Corporation
SDG&E	San Diego Gas & Electric
SPP	Southwest Power Pool
SWAT	Southwest Area Transmission
TEP	Tucson Electric Power
TEPPC	WECC's Transmission Expansion Planning and Policy Committee
The Department	U.S. Department of Energy
TrAIL	Trans-Allegheny Interstate Line
TCC	Transmission Congestion Contracts
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
WIRAB	Western Interconnection Regional Advisory Board
WOTAB	West of the Atchafalaya Basin
WREZ	Western Renewable Energy Zone
WUMS	Wisconsin Upper Michigan System

1. Overview

Congestion occurs on electric transmission facilities when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels. These restrictions may be imposed 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 restricts power flows, an operational limit imposed to protect reliability, or to a lack of adequate transmission capacity to deliver potential sources of generation without violating reliability requirements. Because power purchasers typically try to buy the least expensive energy available, when transmission constraints limit the amount of energy that can be delivered into the desired load center, these constraints (and the associated congestion) will impose real economic costs upon energy consumers. In the instances where transmission constraints are so severe that they limit energy deliverability relative to consumers' electricity demands, grid reliability can be compromised.

This study shows (to the extent publicly available data permit) where electricity congestion and transmission constraints occur across the eastern and western portions of the United States' bulk power system. Congestion varies over time and location as a function of many factors, including energy use and production patterns across the grid, and changes in the availability of specific assets (such as power plants or transmission lines) over time. This analysis indicates general patterns of congestion—broad areas where the transmission congestion reflects imbalances between electric supply and demand that create significant costs, perhaps including adverse impacts on reliability.

The costs of congestion may be measured in terms of economics or reliability, as discussed below for Critical Congestion Areas and Congestion Areas of Concern. But transmission congestion—up to and including a complete lack of transmission—can also limit development of new resource areas, as experienced over the past decade for renewable resources; in these cases, the congestion cost is a failure to achieve consumers' desires and government policy goals. Such areas may be identified below as part of a Conditional Constraint Area.

1.1. Legislative Requirements for This Study

The Energy Policy Act of 2005 (EPAct) added section 216(a) to the Federal Power Act (FPA), directing the Secretary of Energy to conduct a study of electric transmission congestion by August 2006, and every three years thereafter. The FPA section 216(a) congestion study for 2009 identifies transmission congestion and constraints in the Eastern and Western Interconnections; the Electric Reliability Council of Texas (ERCOT) is statutorily excluded from it. Based on the study, and comments from states and other stakeholders, the Secretary shall issue a report, which may designate any geographic area experiencing electricity transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor (National Corridor). In determining whether to designate a National Corridor the Secretary may consider the effects of congestion on the area's economic vitality and development, on its fuel diversity, and on energy independence, national energy policy and national security.[3] Designation of an area as a National Corridor is one of several preconditions required for possible exercise by the Federal Energy Regulatory Commission (FERC) of "backstop" authority to approve the siting of transmission facilities in that area.

[3] Federal Power Act, section 216(h), 16 U.S.C. 824p(h).

In August 2006, the U.S. Department of Energy (DOE) issued the *2006 National Electric Transmission Congestion Study*.[4] That study identified two Critical Congestion Areas (the Mid-Atlantic, extending from New York down into Virginia, and Southern California), four Congestion Areas of Concern (Seattle-Portland, the San Francisco Bay Area, Phoenix-Tucson, and New England), and several Conditional Congestion Areas where significant congestion would result if large amounts of new renewable, coal or nuclear generation were developed without simultaneous development of associated transmission capacity (Montana-Wyoming, Dakotas-Minnesota, Kansas-Oklahoma, Illinois-Indiana-Upper Appalachia, and the Southeast). It explained the rationale for identifying these areas, including both historic and projected data about electricity production and use.

Based on the findings of the 2006 study, and subsequent study and input, the Department issued a report and order designating two National Corridors in October 2007.[5]

The present document identifies areas that are transmission-constrained, but it does not make recommendations concerning existing or new National Corridor designations. The Department may or may not take additional steps concerning National Corridors at some future time.

This study fulfills the requirements of FPA section 216(a). It also fulfills new analytical requirements added by Section 409 of the American Recovery and Reinvestment Act (Recovery Act), which stipulated that the 2009 Congestion Study is to include:

1) An analysis of the significant potential sources of renewable energy that are constrained in accessing appropriate market areas by lack of adequate transmission capacity;
2) An analysis of the reasons for failure to develop the adequate transmission capacity;
3) Recommendations for achieving adequate transmission capacity;
4) An analysis of the extent to which legal challenges filed at the State and Federal level are delaying the construction of transmission necessary to access renewable energy; and
5) An explanation of assumptions and projections made in the study, including
   a) Assumptions and projections relating to energy efficiency improvements in each load center;
   b) Assumptions and projections regarding the location and type of projected new generation capacity; and
   c) Assumptions and projections regarding projected deployment of distributed generation infrastructure.

1.2. Outline of This Study

This study revisits the Congestion Areas identified in the 2006 study to assess whether they remain congested in light of recent trends and actions concerning energy use and infrastructure development. As directed by the Recovery Act, it also looks in depth at the potential for domestic renewable energy development and where additional transmission capacity is needed to enable such development. As in the 2006 study, this study addresses the Eastern and Western Interconnections but it does not include ERCOT (per statutory direction).

Chapter 2 presents the study's approach and methods.

Chapter 3 addresses the issues related to renewable energy development and transmission availability, including Recovery Act requirements, and identifies Type I and Type II Conditional Constraint Areas.

Chapter 4 reviews congestion and constraints in the Eastern Interconnection. It also looks at the Congestion Areas identified in the 2006 study and

[4]The *2006 National Electric Transmission Congestion Study* can be accessed at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf/.

[5]The Department's *National Electric Transmission Congestion Report and Order* designating the Mid-Atlantic Area National Interest Electric Transmission Corridor (Docket No. 2007-OE-01) and the Southwest Area National Interest Electric Transmission Corridor (Docket No. 2007-OE-02) can be accessed at http://nietc.anl.gov/documents/docs/FR_Notice_of_5_Oct_07.pdf.

reevaluates the level of congestion in each area. Similarly, Chapter 5 examines congestion and constraints in the Western Interconnection and updates the status of the areas identified in 2006. Chapter 6 provides information about how to file comments on the study and discusses some of the Department's concerns and plans regarding the achievement of future transmission adequacy.

2. 2009 National Electric Transmission Congestion Study—Study Approach and Methods

2.1. Study Process

Like the *2006 National Electric Transmission Congestion Study*, the 2009 study looks at a variety of historic and projected information about transmission congestion across the nation's two major electric grids. Also like the 2006 study, the 2009 study examines congestion using a number of metrics, including—for existing lines—information on line usage, transaction service denials, and electricity price differentials between locations within a single market area.

The 2009 study differs methodologically from the previous study in that in 2006 the Department worked with analysts and consultants to develop independent projections of congestion in the Eastern and Western Interconnections. The 2006 projections were used to provide context to three additional information sources for each region—indicators of congestion derived from historic data on the use of existing lines, independent reports of existing congestion issues prepared by industry or stakeholder commentators about the regions studied, and independent projections of future conditions in the regions prepared by industry members and stakeholders (for purposes other than the Department's use). In planning for the 2009 study, the Department determined that it would not conduct or sponsor congestion projections specifically for the 2009 study, but would draw instead upon the many studies prepared by others through independent, credible planning entities and processes.

2.2. Information Collection and Public Consultation

As in the 2006 study, the Department conducted an extensive public outreach and consultation process. This process began in 2006, following publication of the 2006 study, with a request for public comment on the 2006 study and suggestions of additional topics that should be addressed in the 2009 study.

In 2008, the Department issued a request for information and documents that it should take notice of in preparing the 2009 study. This request was sent to the governors' offices in the 48 contiguous states, to the chairs of the 48 contiguous states' utility regulatory commissions, to members of the electric industry through their trade associations, and to electric reliability entities.[6] The Department received a total of 41 responses directing attention to numerous documents. The respondents are listed in Appendix A, and the actual responses have been posted on DOE's website for the study.[7]

The Department conducted six public regional workshops and one public technical conference to seek stakeholder information and views for the study. These meetings were announced through notices in the *Federal Register*, letters to many stakeholders, and requests to many specific stakeholders to participate as speakers. The meeting dates and locations were:

- Regional Workshops:
  - San Francisco, CA (June 11, 2008)
  - Oklahoma City, OK (June 18, 2008)
  - Hartford, CT (July 9, 2008)
  - Atlanta, GA (July 29, 2008)
  - Las Vegas, NV (August 6, 2008)
  - Chicago, IL (September 17, 2008)

[6]The Edison Electric Institute, National Rural Electric Cooperative Association, American Public Power Association, Electric Power Supply Association, National Association of Regulatory Utility Commissioners, and the Working Group for Investment in Reliable and Economic Electric Systems.

[7]See http://congestion09.anl.gov/index.cfm.

- Technical Conference:
  - Chicago, IL (March 25-26, 2009)

Detailed information about these meetings was posted on-line beforehand, and each meeting was broadcast in real-time using webcasting capabilities for those who could not attend the meeting in person. Transcripts and presentations from each meeting were posted afterward.[8] The agendas and a list of the organizations participating in these meetings are shown in Appendix B.

Department staff also invited direct consultation about transmission congestion and the 2006 and 2009 studies, and met with stakeholders and members of the public to hear their views.

2.3. Transmission Congestion, Congestion Metrics, and Cautions

Transmission congestion occurs when actual or scheduled flows of electricity on a transmission line or across a piece of transmission equipment are restricted below the level that grid users desire (for instance, to bring low-cost electricity into a load center or move electricity out from a generation point to customers). The Transmission Expansion Planning and Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC) says, for example, that "Path congestion implies that capacity is not available when needed by the market or to serve native load."[9] Those restrictions could be caused by limited physical or electrical capacity of the line, or by operational restrictions created to protect grid reliability. The term "transmission constraint" may refer to either a piece of equipment that creates a physical limit to the amount of electricity that can flow across it, an operational limit imposed to protect reliability, or to a lack of adequate transmission capacity to serve potential sources of generation without violating reliability requirements.

When congestion limits flows between two points, a dispatcher may have to redispatch generation (usually at higher cost) on the side of the constraint where additional generation is needed to ensure that sufficient electricity is available to meet loads; if the dispatcher is unable to redispatch sufficient generation, he or she may have to curtail delivery to certain loads to maintain the system's overall operational balance and reliability.

Because transmission congestion occurs when insufficient electricity can flow from one point to another, transmission congestion can be evidenced in at least three ways—as electrical usage of the equipment up to or near its safe limits, as price differentials or economic cost differentials between different parts of the grid, and in extreme conditions, as a reliability problem that results from the inability to deliver enough electricity to meet customer's electricity demands. Each of these measures can be expressed in quantitative metrics, discussed below. However, as Chapters 4 and 5 will discuss, there are limited amounts of publicly available data to quantify and evaluate congestion.

Transmission Usage Metrics

This study evaluates historical congestion using congestion metrics similar to those developed for the 2006 study. Specifically, these metrics quantify the percentage of time when the electricity flow across a particular path or flowgate[10] exceeded 75%, 90% or 99% of its operating transfer capability. These metrics quantify how heavily the path or flowgate is loaded (i.e., 99% loading means the line is essentially operating at full capacity); this can affect both the physical and economic dimensions of congestion.

Specific transmission usage measures can reflect differing aspects of usage, and yield differing results:

[8] Transcripts and presentations for these meetings can be found at http://www.congestion09.anl.gov/pubschedule/index.cfm and http://congestion09.anl.gov/techws/index.cfm.

[9] TEPPC Historical Analysis Work Group (2009). *2008 Annual Report of the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee, Part 3—Western Interconnection Transmission Path Utilization Study*, at http://congestion09.anl.gov/, p. 27.

[10] In the Western Interconnection, a "path" often refers to several transmission lines that are closely related; in the East, no such paths have been formally identified, but the important constraints have been identified as "flowgates."

- Actual electricity flows are a direct measure of the level of utilization.
- Net schedules are a measure of expected utilization developed shortly before the time of actual utilization, based on contractual commitments to deliver electricity.
- Curtailments are measures of changes to scheduled utilization that are made during the course of real-time operations.
- Requests for transmission service are a measure of reservations for future utilization, made in advance of and often as a pre-requisite for, scheduling contractual commitments to deliver electricity.

If sufficient high-quality data exist for various transmission paths or flowgates, the transmission data can be sorted and ranked according to considerations including directional flows or schedules, seasonal usage, heavy and lightly loaded hours.

The fact that a line is heavily loaded does not necessarily mean that it is congested, since congestion is defined to mean an inability to serve all transmission users' requests. Often, there is no supporting information available on transmission requests that could not be fulfilled and there is no information on transmission requests that were not made because it was known in advance that the request could not be fulfilled. Similarly, heavy line loading does not necessarily represent a reliability problem. North American Electric Reliability Corporation (NERC) rules place strict limits on line loadings to ensure that lines can be operated to these limits reliably at all times, so a heavily loaded line is still operating within pre-established safe operating limits. Finally, continuous heavy loading of certain lines within these limits (especially radial lines designed to transport the output of dedicated power plants), may neither reflect congestion nor pose a threat to reliability if there is no additional generation seeking to transport power over these lines.

Transmission Reliability Metrics

In operational terms, a principal indicator of transmission reliability problems is the inability to deliver enough electricity to loads to keep supply and demand in balance in real time; this is a particular problem for areas that constitute "load pockets," where energy demand can approach and occasionally exceed the combined capability of in-area generation plus transmission-enabled energy imports. In planning terms, transmission reliability reflects whether transmission assets can be operated within safe system operating limits and reliability standards, as determined by NERC- and FERC-approved requirements. For the purposes of this study, these reliability limits are assumed to determine the operational limits of the transmission system; in other words, the reliability-related operating limit for a flowgate sets its maximum allowed use, and desired use above that flow level constitutes congestion.

For this study, a transmission loading relief (TLR) event is the relevant reliability metric indicating that transmission congestion exists. As explained in Chapter 4, a transmission operator calls a TLR when flow over one or more flowgates threatens to violate operating limits; the TLR requires limiting flows and transactions on one or more lines to avoid the potential violation. TLRs are often associated with specific grid events such as storms and equipment maintenance events that can render particular generation and transmission assets unavailable and change the pattern of electricity flows across the grid. Chapter 4 reviews the distribution of TLR events in the Eastern Interconnection.

Economic Congestion Metrics

The PJM Regional Transmission Organization (PJM) Market Monitor explains that:

> Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy to some loads. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load. The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation .... Congestion reflects the underlying characteristics of the power system

including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints.[11]

Several metrics are useful for describing and quantifying economic congestion. These can be calculated from actual transactions within areas that operate centrally-organized spot electric markets (the Northeast, Midwest and California) or derived from simulations using production cost models:

- Shadow prices represent the value of a one-MW increase in flow across a transmission path as a function of a change in the path's capacity.
- Nodal prices (called locational marginal prices or LMPs within organized wholesale electric markets) represent the change in the price of electricity at a particular location as a function of an incremental change in load or generation; the existence of significant variations between LMP levels within an area indicates the impact of transmission congestion between the nodes.
- Congestion rent for a particular point (flowgate or path) on the grid equals the shadow price times the path's total flow or limit; this indicates the increased cost that customers or the system as a whole are paying due to the existence of the transmission constraint (absent hedging mechanisms such as Financial Transmission Rights).

Because economic measures of actual congestion are only available within regions that operate centrally organized wholesale electric markets, they are discussed principally in Chapter 4 for the Eastern Interconnection, and in Chapter 5 with respect to Southern California.

Cautions—What Should Be Done About Congestion?

This study identifies regions of the country that are experiencing congestion. Even if a transmission path is congested, however, this does not necessarily mean that transmission expansion is warranted to reduce congestion or its impacts for an affected region. In some cases, transmission expansion could shift the constraint from one point on the grid to another without materially changing the overall costs of congestion. In other cases, the cost to build new facilities to remedy congestion more comprehensively over all affected lines may exceed the cost of the congestion itself; therefore, remedying the congestion would not be economic. In still other cases, alternatives other than transmission, such as increased local generation (including distributed generation), energy efficiency, energy storage and demand response may be more economic than transmission expansion in relieving congestion.

Thus, finding that a path or flowgate is congested should lead to further study of the costs and impacts of that congestion, as well as a careful regional study of a broad range of potential remedies to larger reliability and economic problems. Although congestion is a reflection of legitimate reliability or economic concerns, not all transmission congestion can or should be reduced or "solved." The purpose of this study is to identify congestion, not make determinations on whether or how it should be mitigated.

2.4. Historical Data and Analysis

One of the important inputs to the Department's assessment of electric transmission congestion in the Eastern and Western Interconnections in this study is historical information on the actual utilization of the transmission system in calendar year 2007. Independent technical analyses of historical transmission system utilization were conducted for each Interconnection. Through the Lawrence Berkeley National Laboratory (LBNL), the Department funded Open Access Technology International (OATI) to study the Eastern Interconnection. Similarly, it funded TEPPC to perform the Western Interconnection analysis. The OATI findings for 2007 historical congestion in the Eastern Interconnection

[11] Monitoring Analytics, LLC (2009a). *2008 State of the Market Report for PJM*. (Vol. 1- Introduction), at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml, p. 50.

are discussed below and in Chapter 4; the TEPPC findings for 2007 historical congestion in the Western Interconnection are reviewed below and in Chapter 5. Market structures and reliability management practices vary from region to region, affecting how each region manages grid operations and measures transmission congestion. Table 2-1 shows in summary form the wide disparities in data availability across the nation with respect to transmission congestion metrics.

Eastern Interconnection Historical Data and Analysis

The Department contracted with OATI to conduct a first-ever assessment of publicly available historical data on transmission congestion in the Eastern Interconnection.[12] The study was based solely on data for 2007. Information on actual electricity flows and on some aspects of scheduled flows in the Eastern Interconnection is not publicly available. Accordingly, OATI collected and assessed information on three core transmission procedural elements that affect how transmission is managed—and how congestion can be measured with publicly available data—in the Eastern Interconnection: transmission reservations, transmission schedules, and real-time operations. Distinct metrics were calculated for each of the three procedures, as explained in Chapter 4.

Western Interconnection Historical Data and Analysis

The Department also supported work by TEPPC to analyze historical congestion on the Western grid,

Table 2-1. Publicly Available 2007 Data and Metrics on Transmission Utilization, Eastern and Western Interconnections

	WECC	ISO-NE	NYISO	PJM	MISO	MAPP	SPP	SERC (VACAR, TVA, Southern, Entergy)	FRCC
Operational and Reliability Metrics									
Transmission Reservations	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
Transmission Schedules	Yes 2007 data for 23 major paths only	Yes	Yes	No	No	No	No	No	No
Actual Flows (U75, U90, U99)	Yes 2007 data for 23 major paths only	No	No	No	No	No	No	No	No
Transmission Loading Relief Actions	No TLRs are not used in WECC	No (Resolved through market re-dispatch)	No (Resolved through market re-dispatch)	Yes	Yes	Yes	Yes	Yes	Yes
Economic Metrics									
Market Organization	No organized spot market outside California; only economic data from WECC modeled forecasts	Organized spot markets	Organized spot market	Organized spot market	Organized spot market	No organized spot market	Organized spot market (day-of only)	No organized spot market	No organized spot market
Locational Marginal Prices	No	Yes	Yes	Yes	Yes	No	Yes (for second half of 2007)	No	No
Shadow Prices for Binding Constraints	No	Yes	Yes	Yes	Yes	No	No	No	No

[12] Open Access Technology International (OATI) (2009). *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, at http://www.congestion09.anl.gov/.

using data for the period November 1, 2006 through October 31, 2007.[13] TEPPC has long-standing agreements with WECC members that allow it to collect and analyze information on actual electricity flows in addition to public information on transmission schedules. Accordingly, metrics calculated from this information can quantify transmission utilization as the percentage of time when the electricity flow across a particular path exceeds 75%, 90% or 99% of its operating transfer capability. This is the same data source and analytical approach used in the 2006 study to gauge historical congestion in the Western Interconnection.

Although electricity flows vary from season to season and year to year as a function of electricity demands, fuel costs and availability, new generation additions and losses, and other factors, the patterns reflected in this one-year snapshot correspond generally to broader patterns of past historical congestion. In fact, viewed with the same congestion metrics used in the 2006 study, the grid congestion patterns for the 2007 data are consistent with the results of TEPPC's analysis of 2004 data, as reported in the 2006 study. The TEPPC analysis is reported in WECC's "2008 TEPPC Annual Report, Part 3."[14]

2.5. Future Conditions and Congestion Across the Grid

As noted in Chapter 1, for the 2009 study the Department did not conduct independent analysis of future grid conditions to forecast transmission congestion. Instead, the Department reviewed an extensive body of studies and analyses on current and future market and reliability conditions conducted by other entities—state agencies, independent system operators (ISOs) and regional transmission organizations (RTOs), NERC, regional reliability organizations (RROs), regional market monitors, trade associations, and consulting firms. Many of these materials were provided to the Department by stakeholders and public commenters.[15]

For the 2009 study, the Department revisited each of the congestion areas identified in the 2006 study and reassessed the 2006 conclusions in light of currently available information on present conditions and expected, high-probability new facilities or congestion-reducing programs. Each of these congestion area reassessments entailed detailed review of the various studies and information sources discussed above; the sources reviewed for this study are listed in Appendix C, which includes more than 325 entries.

2.6. Assumptions Made in the Study

The Recovery Act requires the Department to explain the "assumptions and projections made in the Study, including—(A) assumptions and projections relating to energy efficiency improvements in each load center; (B) assumptions and projections regarding the location and type of projected new generation capacity; and (C) assumptions and projections regarding projected deployment of distributed generation infrastructure."[16]

As explained above, the Department did not conduct independent modeling analyses or forecasts of future transmission congestion in either interconnection, but examined a variety of analyses and studies for each region of the nation. These studies developed by others reflect differing goals, analytical methods, data sources, and underlying assumptions and projections. The Department has not attempted a systematic review to identify and explain the assumptions and projections used in these studies.

[13] TEPPC Historical Analysis Work Group (2009). *2008 Annual Report of the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee, Part 3—Western Interconnection Transmission Path Utilization Study*, at http://congestion09.anl.gov/.

[14] *Ibid.*

[15] These materials are posted at http://www.congestion09.anl.gov/.

[16] 111th US Congress (2009). *American Recovery and Reinvestment Act (ARRA) of 2009, Section 409*, at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf.

3. Renewable Energy Development and Transmission Availability

The Recovery Act directed the Department of Energy to include the following elements in the *2009 National Electric Transmission Congestion Study*:

(1) An analysis of the significant potential sources of renewable energy that are constrained in accessing appropriate market areas by lack of adequate transmission capacity;

(2) An analysis of the reasons for failure to develop the adequate transmission capacity;

(3) Recommendations for achieving adequate transmission capacity; and

(4) An analysis of the extent to which legal challenges filed at the State and Federal level are delaying the construction of transmission necessary to access renewable energy.[17]

These issues are addressed in this chapter, which identifies a large Conditional Constraint Area relating to renewable energy.

3.1. Background

3.1.1. Conditional Congestion Areas Identified in the 2006 Study

The Department's *2006 National Electric Transmission Congestion Study* presented the concept of a Conditional Congestion Area, described as an "area where . . . significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity . . . . [T]hese areas are potential locations for large-scale development of . . . generation capacity to serve distant load centers."[18] The 2006 study identified the areas shown in Figure 3.1 as Conditional Congestion Areas, and commented that "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."[19]

The 2006 study included Conditional Congestion Areas for fossil and nuclear resource development. The current study does not identify resource-specific Conditional Congestion Areas, as explained later in this chapter.

In the 2006 study, the Department further commented:

> 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 . . . .
>
> . . . [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.[20]

3.1.2. Recent Developments

Much has happened to advance development of renewable energy resources and related transmission since the 2006 study was issued, including:

[17] 111th US Congress (2009). *American Recovery and Reinvestment Act (ARRA) of 2009, Section 409*, at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_bills&docid=f:h1enr.pdf.

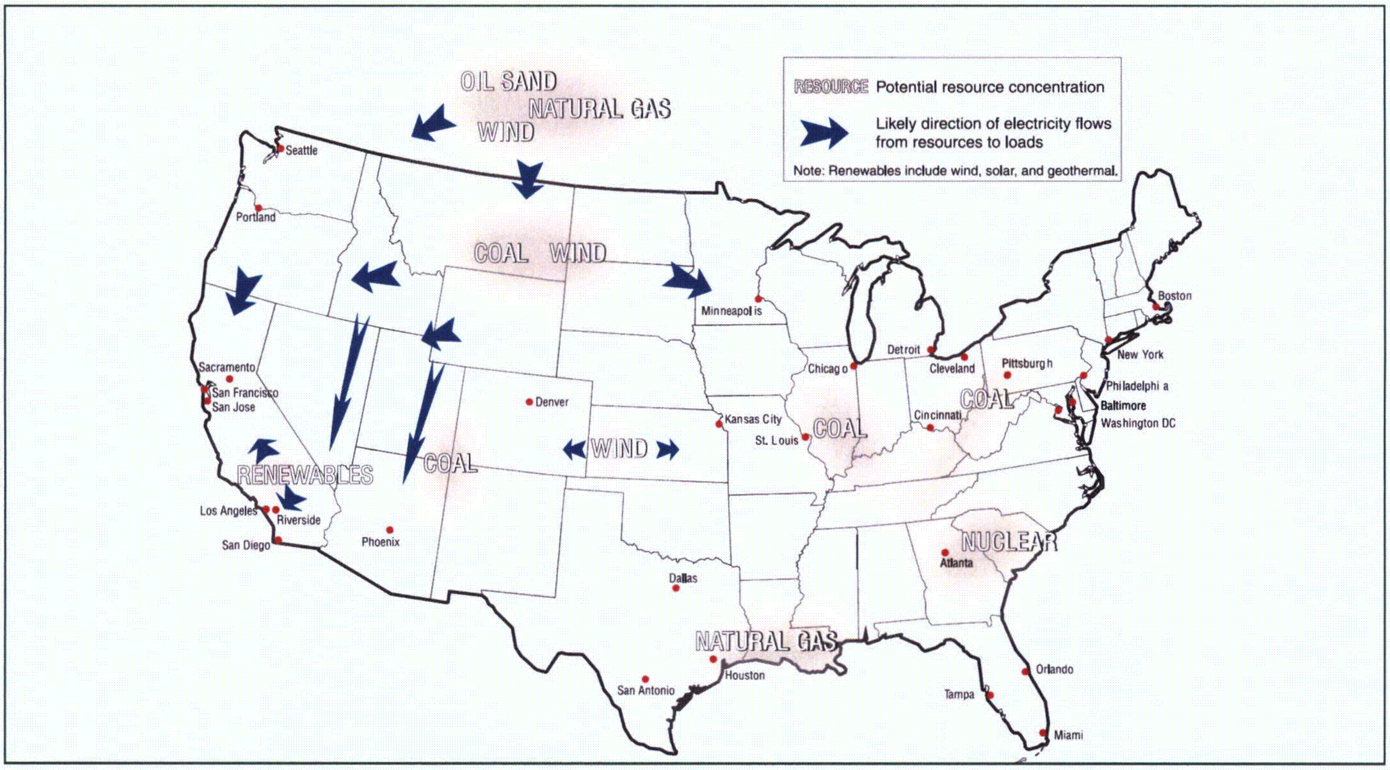
[18] U.S. Department of Energy (DOE) (2006a). *National Electric Transmission Congestion Study*, at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf, p. ix.

[19] *Ibid.*

[20] *Ibid.*, p. 40.

- A greater commitment to inclusive, transparent, and systematic regional planning across the nation, spurred by the issuance of Order 890 by FERC.
- Advances in the commercial availability and competitiveness of wind and solar technologies, leading to the interconnection of over 15,000 MW of new wind generation and 3,668 MW of solar thermal and photovoltaic plants across the country during 2006, 2007 and 2008.[21]
- Adoption of Renewable Portfolio Standards requiring substantial and increasing amounts of renewable energy purchases in 34 states and the District of Columbia.[22]
- Increases in the cost and price volatility of oil, coal and natural gas,[23] which made renewable energy sources more desirable as a price hedge and as a domestic contributor to national energy security.

Figure 3-1. 2006 Conditional Congestion Areas



Source: U.S. Department of Energy (DOE) (2006a). *National Electric Transmission Congestion Study*, at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf, p. ix.

[21] Wind data from Energy Information Administration (EIA) (2007a). "Form EIA-860 Database Annual Electric Generator Report," at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html, Table 4; and American Wind Energy Association (AWEA) (2008). *Annual Wind Industry Report, Year Ending 2008*, at http://www.awea.org/publications/reports/AWEA-Annual-Wind-Report-2009.pdf; solar data from Solar Energy Industries Association (SEIA) (2009). *U.S. Solar Industry Year in Review 2008*, at http://www.seia.org/galleries/pdf/2008_Year_in_Review-small.pdf, p. 2.

[22] Database of State Incentives for Renewables & Efficiency (DSIRE) (2009). *Rules, Regulations and Policies for Renewable Energy*, at http://www.dsireusa.org/summarytables/rrpre.cfm.

[23] Energy prices in general have been notably more volatile since 2005, as noted in sources including the *Wall Street Journal* (Gordon Brown and Nicolas Sarkozy, "Oil Prices Need Government Supervision," July 8, 2009: "For two years the price of oil has been dangerously volatile, seemingly defying the accepted rules of economics"); the *New York Times* (Jad Mouawad, "Swings in Price of Oil Hobble Forecasting," July 5, 2009: "Volatility in the oil markets in the last year has reached levels not recorded since the energy shocks of the late 1970s and early 1980s . . ."); and the Center for American Progress (Amanda Logan and Christian Weller, "Signals on the Fritz: Energy Price Volatility Impedes Investment by Creating Uncertainty," June 2009: "Energy prices in general and gasoline prices in particular have gone from red hot to stone cold to red hot again in the span of a few months in recent years.") These observations are validated by the price histories of natural gas and oil from sources such as the Bureau of Labor Statistics, International Monetary Fund and TFC Commodity Charts.

- A greater national concern with the possible impacts of climate change and global warming, with uncertainty about carbon and greenhouse mitigation strategies making non-polluting renewable generation sources more attractive relative to fossil-fueled sources.
- Greater recognition of the value of renewable generation (particularly wind) for rural economic development and job creation in the renewable sector.
- Numerous studies examining the potential for and value of renewable development in different regions, spanning detailed transmission planning, as in the case of the Midwest Independent System Operator (MISO) and ERCOT; and broad analyses and policy recommendations, such as the DOE–American Wind Energy Association (AWEA)–National Renewable Energy Laboratory (NREL) study, *20 Percent Wind by 2020*, and popularized recommendations by T. Boone Pickens and former Vice President Al Gore.

The combined impact of these developments has been to create a significantly more favorable environment for the development of new renewable energy resources, and associated infrastructure requirements, including additional transmission capacity. These changes have also stimulated interest in clarifying federal energy policy through legislation in several key areas, including climate change, carbon regulation, and regulatory matters pertaining to the development of new transmission capacity.

Utility investment in new transmission has increased significantly over the past five years, and much of that new investment has interconnected new wind and solar resources. The Edison Electric Institute (EEI) reports that its members' total recent and planned investment in transmission to support renewable resource integration (for renewable projects exceeding $20 million per project) exceeds $21 billion as of early 2009.[24] However, EEI points out that there are challenges in building transmission for renewables—"While fossil resources have some flexibility to site in close proximity to the existing transmission grid, siting of renewable resources is largely dictated by nature, due to the location of the resource and the inability to transport the fuel source."[25] EEI further cautions:

> [G]iven the nature of power flows and grid design on alternating current (AC) transmission systems, a transmission project cannot be dedicated to a specific renewable resource project or limited to transmitting renewable energy . . . . Most [transmission] projects . . . are multi-faceted; that is, they are not in development solely to integrate renewable resources. In most cases, transmission projects address an array of purposes and deliver a number of benefits, such as congestion relief, enhanced regional reliability, and reduced system losses.[26]

The Department will issue grants in 2009 under the Recovery Act to improve the information base planners need and establish long-term self-sustaining infrastructure for interconnection-wide planning in the Eastern, Western, and ERCOT interconnections.

3.2. Potential Sources of Significant Renewable Energy Constrained by Lack of Adequate Transmission Capacity

The Recovery Act stipulated that this study should identify significant potential domestic sources of renewable energy that are constrained by lack of adequate transmission capacity. In responding to this assignment, the Department has drawn upon existing analyses to identify those geographic areas with high renewable resource potential, technology by technology, and offers commentary on their likely development path and the status of their transmission requirements.

[24] Edison Electric Institute (2009). *Transmission Projects Supporting Renewable Resources*, at http://www.eei.org/ourissues/ElectricityTransmission/Documents/TransprojRenew_web.pdf, p. iv.
[25] *Ibid*, p. iii.
[26] *Ibid*, pp. iii-iv.

As described more fully below, the need for project interconnection and the lack of adequate transmission capacity are frequently a major obstacle to the development of large scale renewable energy projects. While some progress has been made, much more work is needed to address the challenges to new transmission projects to support a build-out of renewable energy. Major obstacles preventing prompt build-out of transmission capacity include: (i) need for more systematic regional and interregional analyses and planning of future transmission requirements; (ii) complications relating to appropriate cost allocation for new transmission capacity; (iii) complications relating to permitting across multiple jurisdictions, combined with the recent judicial curtailment of FERC's existing backstop siting authority;[27] and (iv) shortcomings in the queuing processes used to interconnect renewable energy electricity generation to the electric grid and the related construction of new transmission facilities. For many potential renewables projects, the issues of whether such transmission capacity will ever become available, and if so when, are at least as important as the likely cost of the transmission facilities and how the cost will be allocated. If it is necessary to wait five to fifteen years while new transmission is being planned, routed, reviewed by regulators, cost-allocated, and built, such delay and uncertainty can pose a more serious threat to project success than the actual cost of the transmission.[28] It will be necessary to address these challenges on an urgent basis to help facilitate the integration of greater renewable resources into the electricity supply.

A number of additional analyses are now under way to identify and geographically delineate renewable energy zones that contain significant amounts of high-quality renewable resources that could be commercially developed today or in the near future. These analyses require detailed information to determine the quality of the renewable resource and the level of generation commercially likely given suitable transmission infrastructure; they are also using environmental suitability analyses and detailed geographic tools to exclude areas that by law, regulation or terrain are precluded from development. These analyses and other efforts include:

- The Western Renewable Energy Zone (WREZ) analysis, sponsored jointly by the Western Governors' Association (WGA) and the Department. This work was begun in 2008[29] and is discussed further below.
- The California Renewable Energy Transmission Initiative (RETI), begun in 2007, is identifying areas where renewable energy can be developed in the most cost-effective and environmentally benign manner, and the transmission corridors needed to access those areas.[30] Phase 1 of the RETI process estimated the amount of renewable energy that California would need to meet its future energy goals and conducted environmental and economic assessments of high-quality in-state renewable resource areas to identify the major electric transmission projects needed to access the renewable energy and deliver it to consumers.[31] Phase 2 is developing a conceptual transmission plan to serve the renewable energy zones and Phase 3 will develop detailed plans for transmission service.[32]
- Working with the MISO, the Midwest Governors have supported the *Regional Generation Outlet Study* and wind development scenarios in the *2008 Midwest Transmission Expansion Plan*. MISO recently worked with the Southwest Power Pool (SPP), Tennessee Valley Authority (TVA), and PJM to conduct the *2008-09 Joint*

[27] In *Piedmont Environmental v. Federal Energy Regulatory Commission*, 558 F.3d 304 (4th Cir. 2009), the Court significantly limited FERC's authority to site transmission lines in National Corridors designated by the Department of Energy.

[28] A recent study by LBNL found that, based on a review of transmission planning studies, the median projected cost of transmission to access wind generation is about $300/kW, which is about 15% of the cost of building a new wind generating unit. Mills, A., R. Wiser, and K. Porter (2009), *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*. Lawrence Berkeley National Laboratory report LBNL-1417E, at http://eetd.lbl.gov/EA/EMP/re-pubs.html.

[29] See http://www.westgov.org/wga/initiatives/wrez/.

[30] See http://www.energy.ca.gov/reti/index.html.

[31] California Renewable Energy Transmission Initiative (RETI) (2009). *Renewable Energy Transmission Initiative (RETI). Phase 1B, Final Report*, RETI-1000-2008-003-F, at http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF.

[32] See additional RETI information at http://www.energy.ca.gov/reti/documents/index.html.

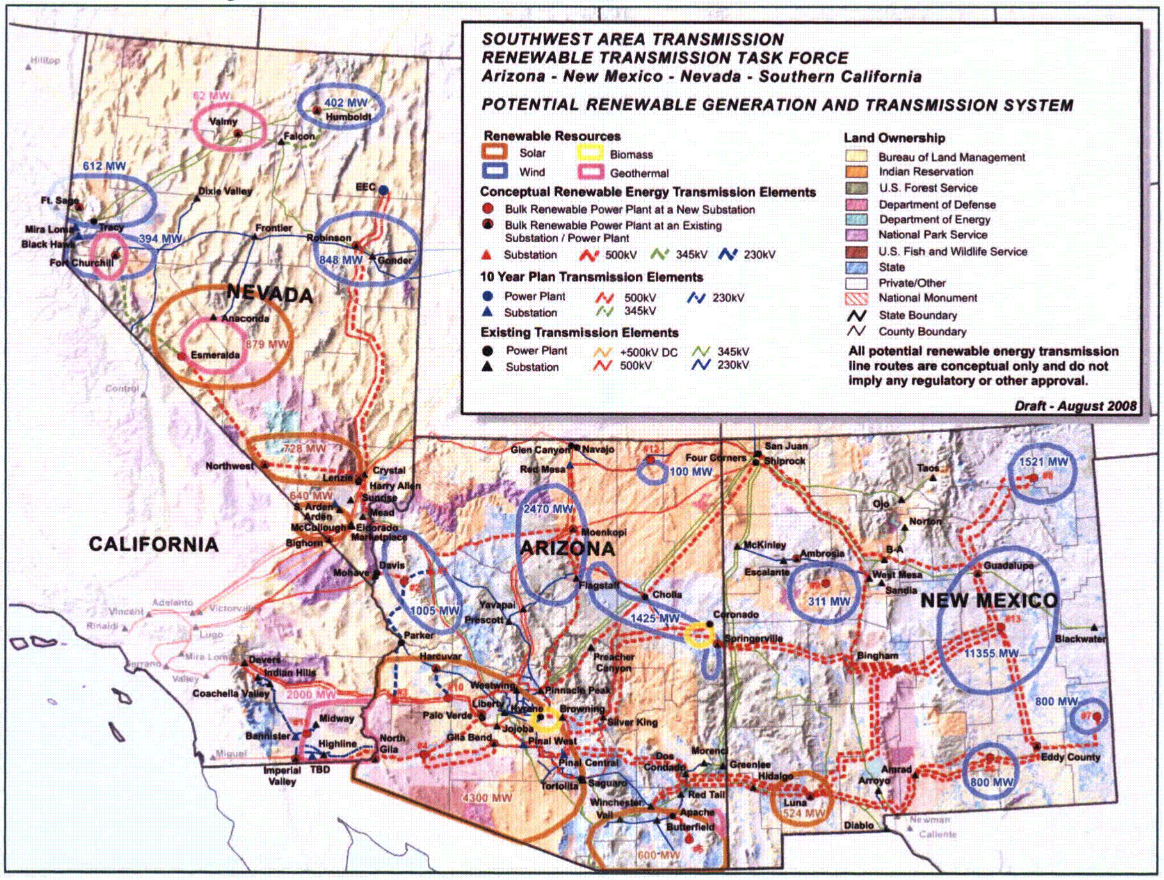
Coordinated System Plan to explore the transmission requirements associated with 5% and 20% wind development scenarios for the Eastern Interconnection.

- Individual states, including Texas, Arizona, Colorado, Utah, Michigan, Oregon and Hawaii, are also conducting or have completed analyses to identify specific renewable energy zones suitable for commercial renewable generation development with dedicated transmission facilities.

One example of such analysis is a work product from the Southwest Area Transmission (SWAT) Renewable Transmission Task Force, which has been studying Arizona, New Mexico, Nevada and Southern California. As Figure 3-2 shows, this regional task force has identified potential renewable generation locations by technology, mapped them against land ownership, and identified current and conceptual electric transmission elements that could deliver this new generation to load centers in the study area.

The WREZ analysis is similar in purpose but covers a much larger area. In June 2009, the WGA and the DOE announced the preliminary identification of WREZs, as "areas . . . that feature the potential for large scale development of renewable resources in areas with low environmental impacts, subject to resource-specific permitting processes."[33] The WREZ project has also created a modeling tool to estimate the delivered cost of renewables from specific source areas to load centers, including the costs of generation and transmission. The minimum size of a WREZ resource area is 1,500 MW for wind and solar energy within a 100-mile radius of the

Figure 3-2. SWAT Renewable Energy Zones and Current and Potential Transmission System



Source: Kondziolka, R. (2009). "Western Interconnection Subregional Planning and Development," Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://congestion09.anl.gov/techws/index.cfm/, slide 17.

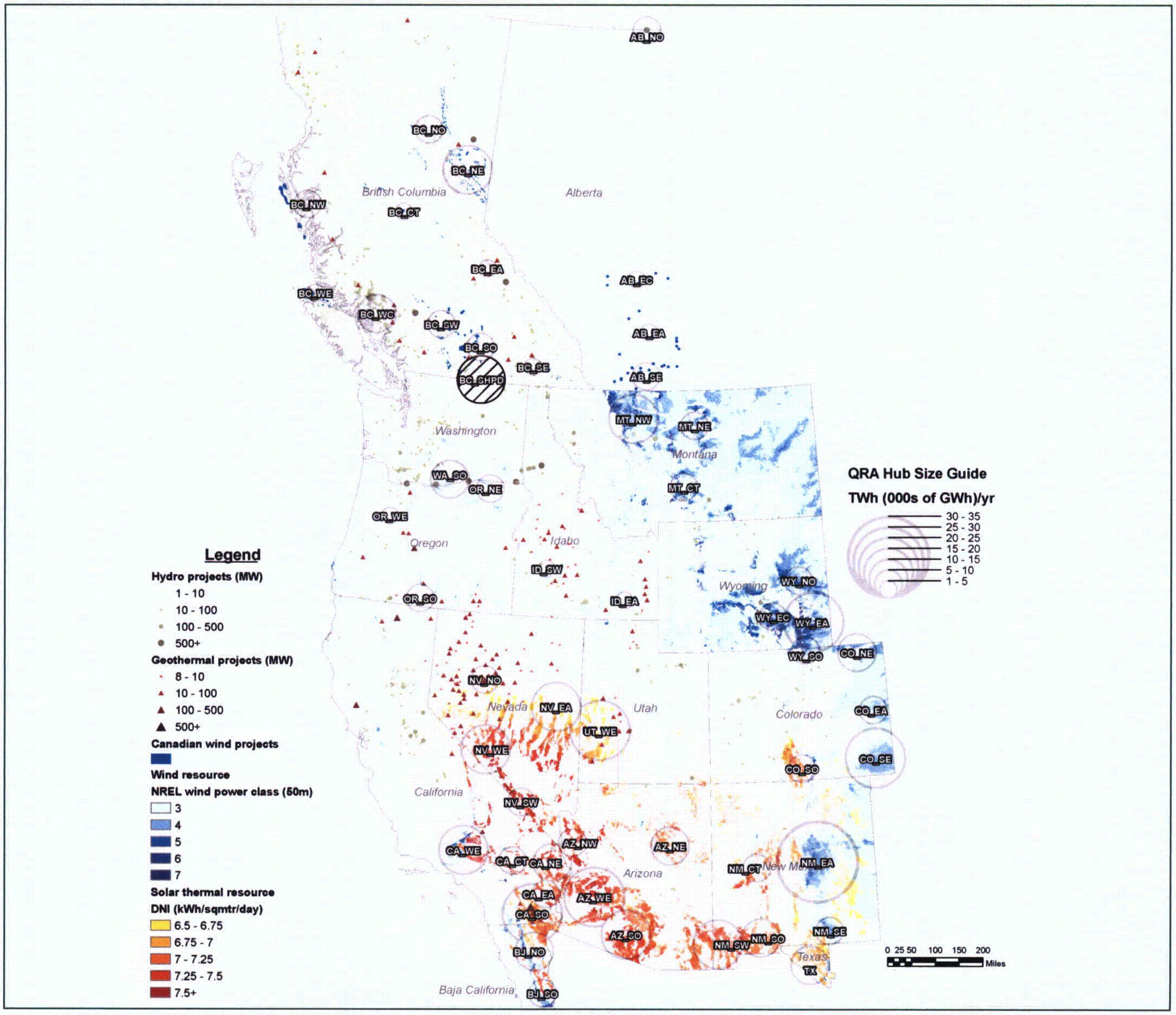
[33] Western Governors' Association (WGA) and U.S. Department of Energy (DOE) (2009). "Western Renewable Energy Zones – Phase 1 Report," at http://www.westgov.org/wga/initiatives/wrez/, p. 2.

center. The screening process excludes lands where energy development is prohibited, such as national parks, or is unsuitable for other reasons. The WREZ areas are shown in Figure 3-3. The estimated total generation capacity located within the U.S. WREZ areas is about 163,000 GW of capacity, with potential annual energy production of about 450,000 GWh per year,[34] or about 11% of total U.S. generation in 2008.

The WREZ report also identifies renewable resources outside WREZ areas, which are commercially viable renewable sources that may not need access to high-voltage transmission and may be dispersed and close to load; these can include biomass, landfill gas, small hydro, and a variety of decentralized renewables.[35]

Outside Texas and the Southwest, few of these renewable energy zone analyses are complete. The next stage in the WREZ project, for example, is to facilitate the matching of wholesale electricity buyers with prospective developers of renewable generation; until this is done, it will not be clear

Figure 3-3. WREZ Renewable Energy Zones: WREZ Initiative Hub Map



Source: Western Governors' Association (WGA) and U.S. Department of Energy (DOE) (2009). "Western Renewable Energy Zones – Phase 1 Report," at http://www.westgov.org/wga/initiatives/wrez/, p. 12.

[34] *Ibid.*, pp. 23-24.

[35] *Ibid.*, p. 17.

where new transmission capacity is needed. In the absence of more detailed information, this congestion study looks broadly at wide areas with rich renewable resource bases to identify geographic areas where renewable energy could be developed if it were served by sufficient transmission infrastructure. These areas will be identified in Section 3.3 below.

The rest of this section reviews the geographic locations of the nation's principal renewable generation resources, including wind, solar photovoltaic, solar thermal and concentrating solar, geothermal, and biomass.

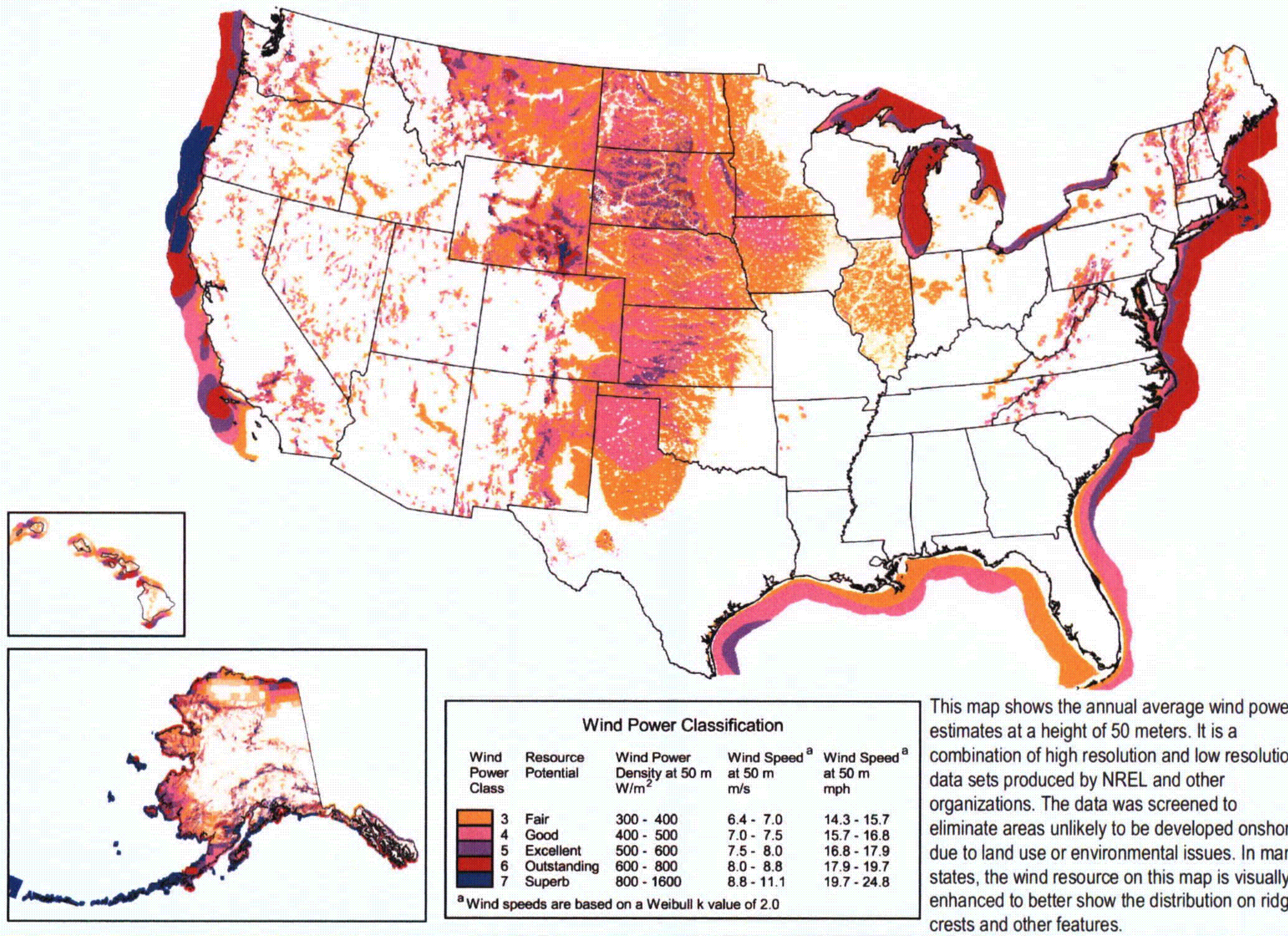
3.2.1. Wind Generation Resource Locations

The *2006 National Electric Transmission Congestion Study* identified promising areas in the Dakotas and Minnesota, Wyoming and Montana, and Kansas and Nebraska as areas where there are many proposals to develop commercial wind generation but insufficient transmission to support such generation development. However, the Recovery Act calls for an analysis of where there are significant potential renewable energy resources that could be developed given new transmission construction, not where there is strong development interest.

Figure 3-4 shows the location of significant on-shore and off-shore wind resources in the United States.

While the 2006 study identified areas with good terrestrial (on-shore) wind development potential, Figure 3-4 shows that much of the nation's greatest wind resource potential lies off-shore. To date some off-shore wind generation projects have been

Figure 3-4. Domestic Wind Resources Map



Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

This map shows the annual average wind power estimates at a height of 50 meters. It is a combination of high resolution and low resolution data sets produced by NREL and other organizations. The data was screened to eliminate areas unlikely to be developed onshore due to land use or environmental issues. In many states, the wind resource on this map is visually enhanced to better show the distribution on ridge crests and other features.

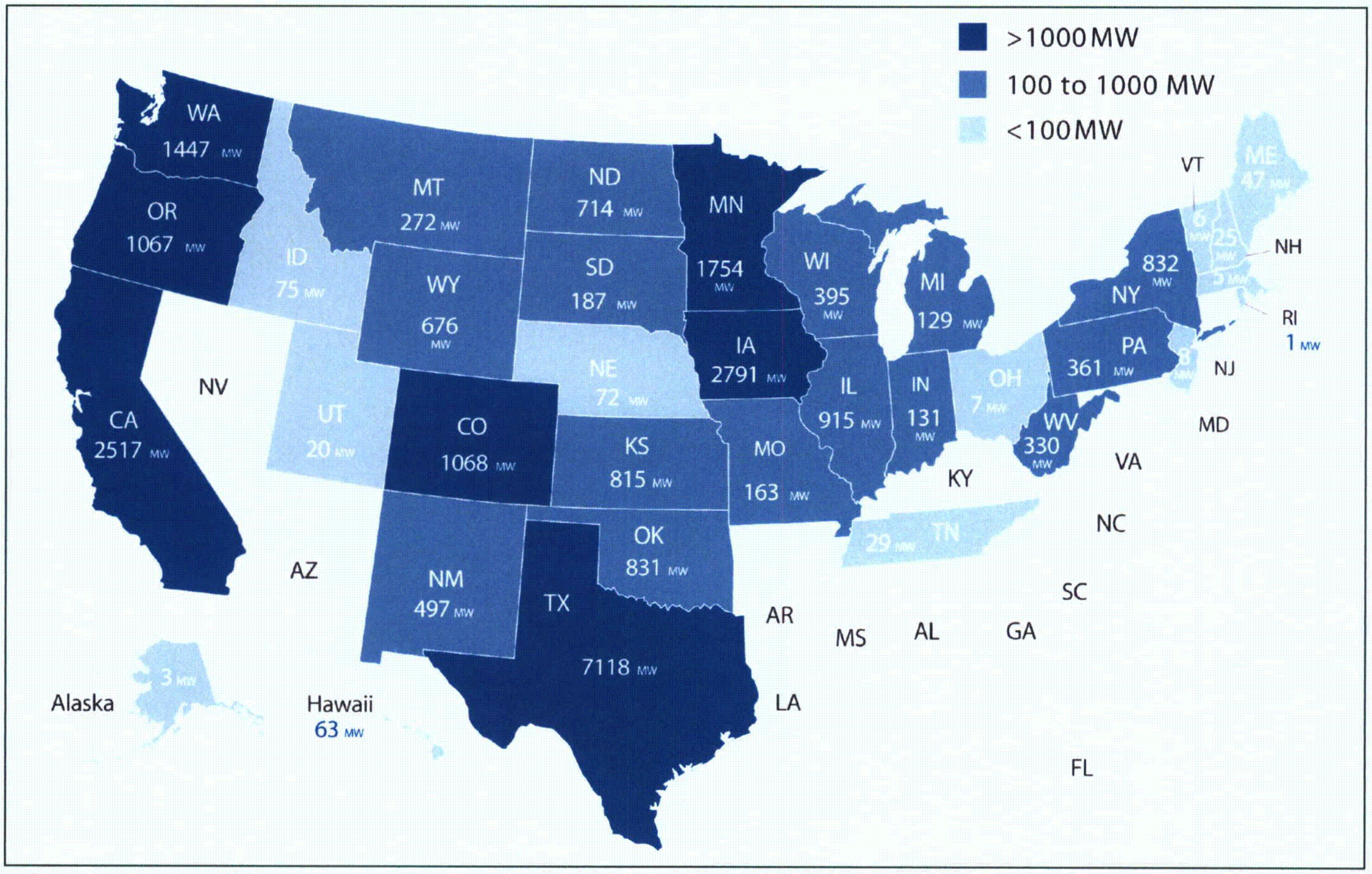
Source: National Renewable Energy Laboratory (NREL) (2009). "United States Wind Resource Map," at http://www.windpoweringamerica.gov/pdfs/wind_maps/us_windmap.pdf.

proposed (off the coasts of Rhode Island, New Jersey, Delaware, Massachusetts, New York, Ohio, Georgia and Texas), but as yet none have been built in these waters. The challenges to off-shore wind development include public opposition, regulatory uncertainties, higher costs and greater uncertainties associated with building and operating generation and transmission in a harsh off-shore environment, and fluctuating prices for competing fuels that can affect project economics.

Figure 3-5 shows where significant wind development has already occurred in the nation (as of 2008). The match between actual wind development and strong wind resources has occurred primarily where there has been adequate transmission capacity to interconnect the new wind generators and deliver their electricity to loads, or in areas in which there is a willingness to build new transmission capacity quickly without charging the full cost to new wind producers (as in ERCOT and California). Where there is high wind resource potential but little new wind development, those gaps occur principally because there is neither adequate transmission capacity to deliver wind generation, nor an expeditious way to build new transmission for that purpose. However, in the past few years utilities have proposed and regulators have approved a significant quantity of new transmission to connect new wind projects to loads. These transmission projects will enable significant amounts of new wind generation development in the next few years.

In 2008, 8,545 MW of new net wind generation capacity was brought on line, bringing total domestic wind capacity to 25,369 MW.[36] But 300,000 more MW wind capacity was waiting in interconnection

Figure 3-5. Wind Power Development in the United States, 2008 (Megwatts Installed by State)



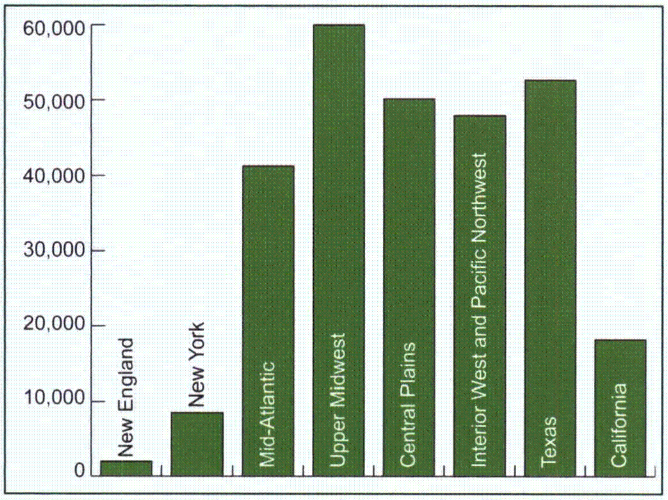
Source: American Wind Energy Association (AWEA) (2008). *Annual Wind Industry Report, Year Ending 2008*, at http://www.awea.org/publications/reports/AWEA-Annual-Wind-Report-2009.pdf, p. 9.

[36] American Wind Energy Association (AWEA) (2008). *Annual Wind Industry Report, Year Ending 2008*, p. 4.

queues across the nation at the end of 2008, as shown in Figure 3-6. As the American Wind Energy Association comments, "The proposed wind projects in these queues have applied for interconnection to the grid, but most of these wind plants cannot be built because there is insufficient transmission capacity to carry the electricity they would produce. While not all of these wind projects will ultimately be built, it is still clear that wind power development is outpacing the expansion and modernization of our electric grid."[37]

Several important policy developments have facilitated wind interconnection. In February 2007, FERC issued Order 890, which improved the ability of wind generation to access transmission by adopting cost-based energy imbalance calculation methods, requiring transmission providers to develop redispatch and conditional firm service methods, and requiring all transmission providers to participate in local and regional transmission planning processes. Later that year, FERC approved a new transmission cost allocation method proposed by the California Independent System Operator (CAISO) for location-constrained resources (such as Tehachapi wind generation).

Figure 3-6. MW Wind in Regional Interconnection Queues



Source: American Wind Energy Association (AWEA) (2008). *Annual Wind Industry Report, Year Ending 2008*, at http://www.awea.org/publications/reports/AWEA-Annual-Wind-Report-2009.pdf, p. 5.

Development of an initial group of off-shore wind projects in the U.S. could begin soon. U.S. Interior Secretary Ken Salazar indicates that the Department of Interior expects "as many as a dozen proposals for offshore wind-energy projects in the coming months under a new federal program to expedite construction of renewable energy projects on federal land and in coastal waters."[38] It further expects "federal permit applications to be submitted for 10 to 12 projects over the next few months, . . . each capable of generating at least 350 MW of electricity"[39] and estimates that wind energy on the U.S. outer continental shelf has the potential to generate 900,000 MW of power.[40] Officials in many eastern states are interested in developing off-shore wind close to metropolitan load centers, as an alternative or supplement to long-distance transmission from Midwestern and Canadian wind resource areas.

3.2.2. Solar Photovoltaic Resource Locations

The nation's best solar resources are found in the southwestern United States, as illustrated in Figure 3-7; these areas are where most utility-scale (one megawatt and larger plants) photovoltaic generation is expected to develop. However, as photovoltaic technologies improve and costs fall while incentives spread, distributed small-scale photovoltaics are being installed in many areas of the nation, with photovoltaic initiatives as far north as Wisconsin, Michigan, Massachusetts, Oregon and New York.[41]

Most of the utility-scale solar photovoltaic projects that are now installed, under development, or proposed are located in the desert southwest, including the 550 MW Topaz Solar Farm and the 250 MW California Valley Solar Ranch in southern California.

[37] *Ibid*, p. 5.

[38] Tita, B. (2009). "Interior Secretary Salazar Expecting Surge in Offshore Wind Farms." *Wall Street Journal*.

[39] *Ibid*.

[40] *Ibid*.

[41] U.S. DOE Office of Energy Efficiency and Renewable Energy (EERE), Solar Energy Technologies Program (2009). "Solar America Initiative," at http://www1.eere.energy.gov/solar/solar_america/. Since distributed solar photovoltaics are small-scale generation sources that tend to be located at customer load centers, as with rooftop photovoltaic units, they do not require electric transmission and will not be discussed further in this study.

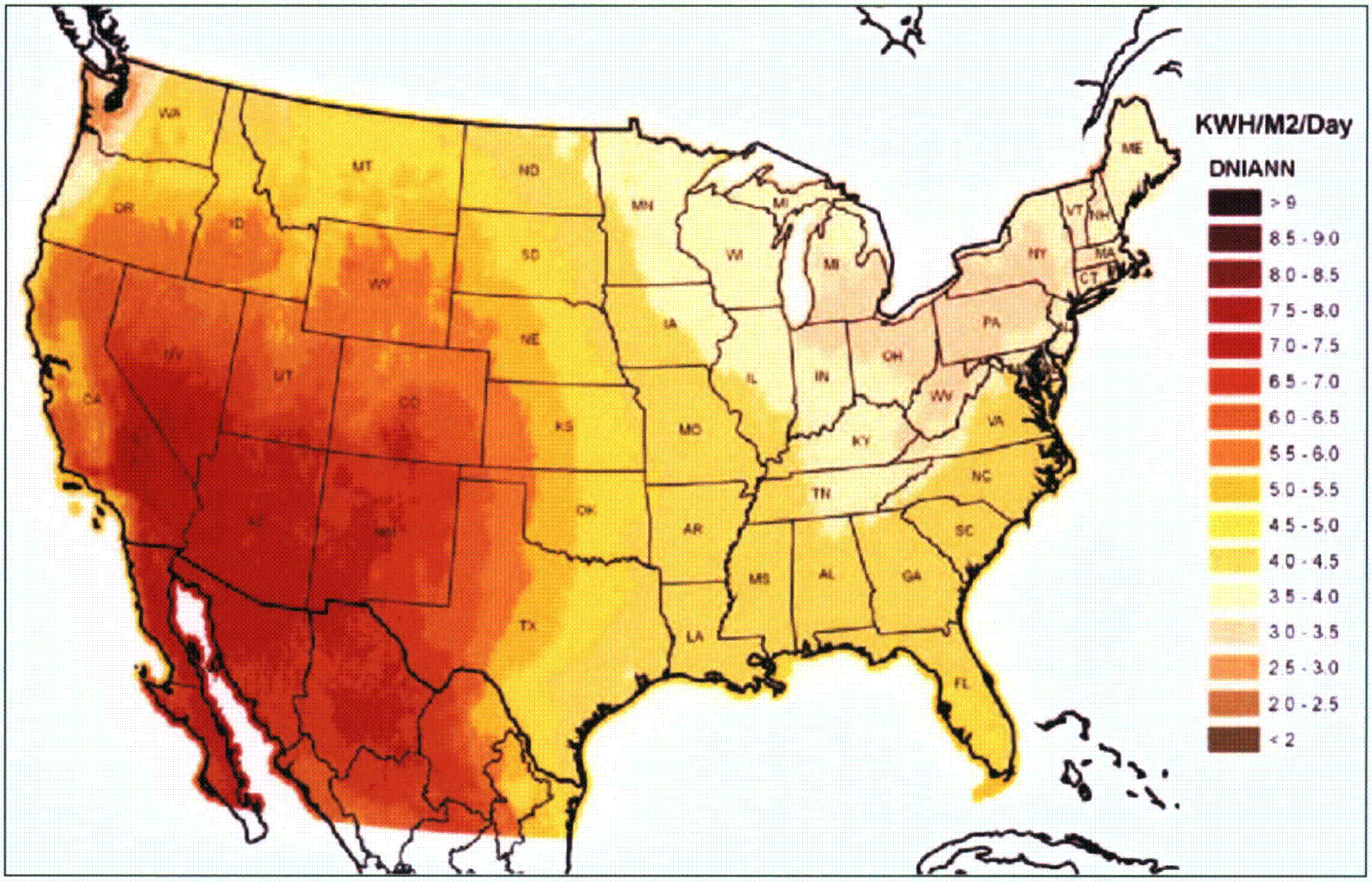
3.2.3. Concentrating Solar Power and Solar Thermal Resources

Concentrating solar power (CSP) plants require large tracts of land with good solar resources; the Department estimates that a 250-MW plant with 6 hours of storage would require nearly 3 square miles of land.[42] A model developed at NREL for concentrating solar plants using the parabolic trough Rankine cycle technology estimates that given land availability, storage costs, and solar availability, as much as 55 GW of CSP technology could be developed in the southern regions of California, Arizona and New Mexico, as shown in Figure 3-8 below. Current development of CSP projects is occurring in these regions, facilitated by utility power purchase contracts. The Solar Energy Industries Association indicates that dozens of concentrating solar plants, representing thousands of MW of capacity, are moving toward installation, mostly in the deserts of California, Nevada, and Arizona, and in Florida.[43]

3.2.4. Geothermal Resource Potential

Electricity is produced from geothermal energy by tapping hot underground rock, water, or steam through deep wells and using heated fluids or steam to drive turbines. Geothermal resources include hot water and rock at relatively shallow levels or miles below the surface, and can even include molten magma. In some cases geothermally heated fluids are piped directly to end-use facilities (e.g., district heating of community buildings, greenhouses, domestic or process hot water) rather than used to raise steam in boilers. The best domestic geothermal

Figure 3-7. National Solar Radiation Map, May 2007 Data



Source: Renne, D. (2008). "2008 Solar Annual Review Meeting, Solar Resource Characterization." National Renewable Energy Laboratory, at http://www1.eere.energy.gov/solar/review_meeting/pdfs/prm2008_renne_nrel.pdf, slide 4.

[42] U.S. DOE Office of Energy Efficiency and Renewable Energy (EERE), Solar Energy Technologies Program (2008). "Concentrating Solar Power." National Renewable Energy Laboratory, at http://www1.eere.energy.gov/solar/pdfs/43685.pdf, p. 2.

[43] Solar Energy Industries Association (SEIA) (2009). *U.S. Solar Industry Year in Review 2008*, at http://www.seia.org/galleries/pdf/2008_Year_in_Review-small.pdf, pp. 6-7.

resources are located in the western states (as shown in Figure 3-9), Alaska and Hawaii.

A new analysis by the Department indicates that 126 geothermal projects are now in consideration or under development that could add 3,600 to 5,600 MW of new geothermal electric generation capacity over the next few years.[44] The Department cites two studies that suggest that geothermal energy could contribute as much as 100,000 to 517,800 MW to domestic electric supply, and that "geothermal energy, once restricted to naturally occurring hydrothermal fields in remote areas, could someday be operating in more locations and in greater proximity to large end-use markets."[45]

3.2.5. Biomass Resources

Unlike wind, solar, geothermal and hydro resources, biomass is diverse and less location-constrained than other renewable resources. Biomass-based renewables use agricultural feedstocks —wood wastes, agricultural wastes, dedicated crops and landfill or wastewater methane—as a fuel for direct combustion, gasified for combustion, or in a biochemical conversion to make a distilled fuel such as diesel or ethanol.

Because biomass can be widely grown and transported (whether as an input feedstock or as a converted end product), it is not essential for

Figure 3-8. Projected Concentrating Solar Power Capacity (MW) by Region in 2050

Source: Blair, N. (no date). "Concentrating Solar Deployment Systems (CSDS)—A New Model for Estimating U.S. Concentrating Solar Power Potential." National Renewable Energy Laboratory, at http://www1.eere.energy.gov/solar/review_meeting/pdfs/p_55_blair_nrel.pdf, p.2.

[44] U.S. DOE Office of Energy Efficiency and Renewable Energy (EERE), Geothermal Technologies Program (2009). *National Geothermal Action Plan: Preliminary Draft*, p. 16.

[45] *Ibid*, p. 2.

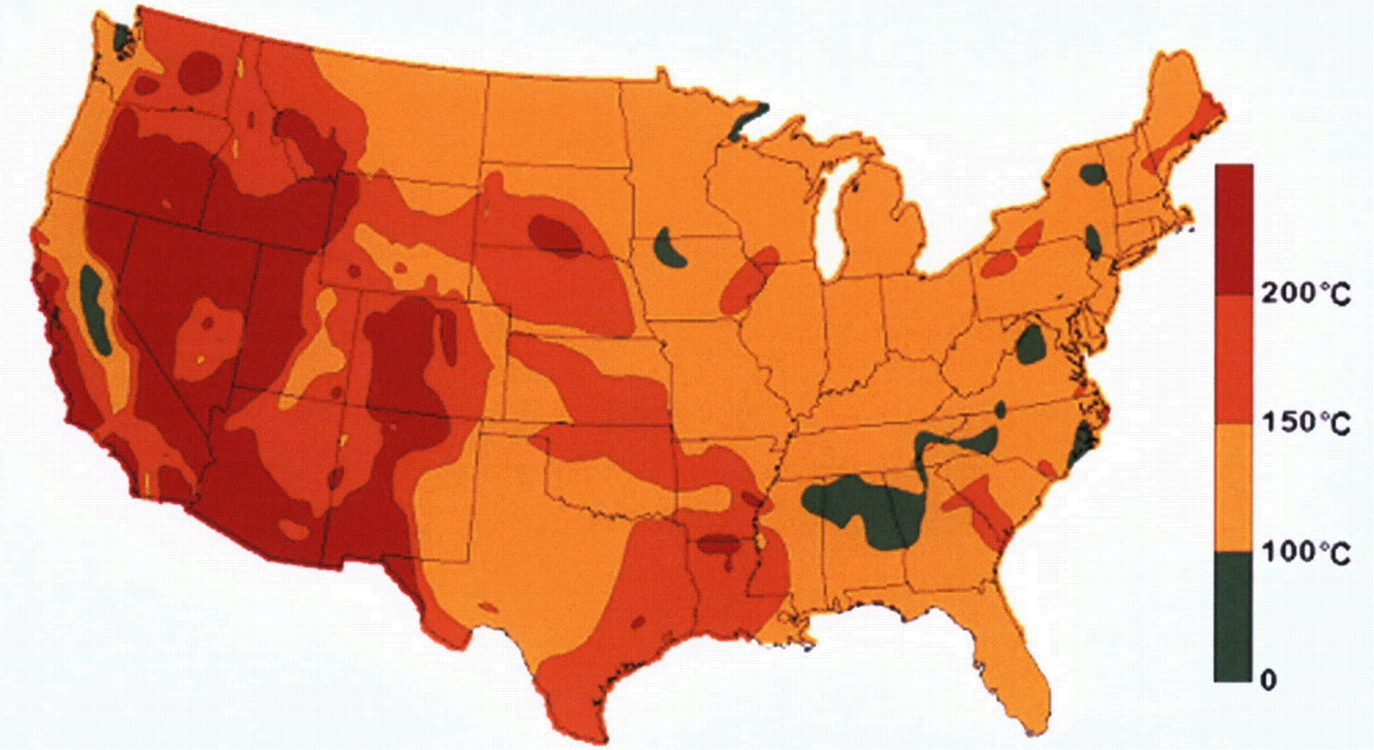
biomass-fueled electricity generation to occur at the point of fuel creation, nor does it necessarily require dedicated transmission, as is the case with wind, solar or geothermal generation. Further, because biomass resources that could be used as fuel for electric generation are located in many areas across much of the nation, there do not appear to be concentrated areas that are more obviously suitable for biomass development than others. Therefore, biomass resources will not be discussed further in this study.

3.3. 2009 Conditional Constraint Areas

In this study, the Department defines and identifies two types of Conditional Congestion Areas, Type I and Type II. A Type I area is one where it appears that the development of significant additional generation—using existing technology with known cost and performance characteristics—is limited primarily by the availability of transmission capacity. By contrast, a Type II area is one with renewable resource potential that is not yet technologically mature but shows significant promise due to its quality, size, and location. If such resources become technologically mature (through additional R&D and experience with commercial-scale projects that would make their cost and performance parameters predictable), they might then be limited chiefly by transmission availability. If so, the affected area would then qualify for Type I status.

This study identifies a large Type I Conditional Constraint Area (Figure 3-10) where construction of major new transmission projects would enable development of thousands of MW of new renewable generation. Parts of this area have large

Figure 3-9. U.S. Geothermal Resource Map



Source: U.S. DOE Office of Energy Efficiency and Renewable Energy (EERE), Geothermal Technologies Program (2006). "U.S. Geothermal Resource Map," at http://www1.eere.energy.gov/geothermal/geomap.html.

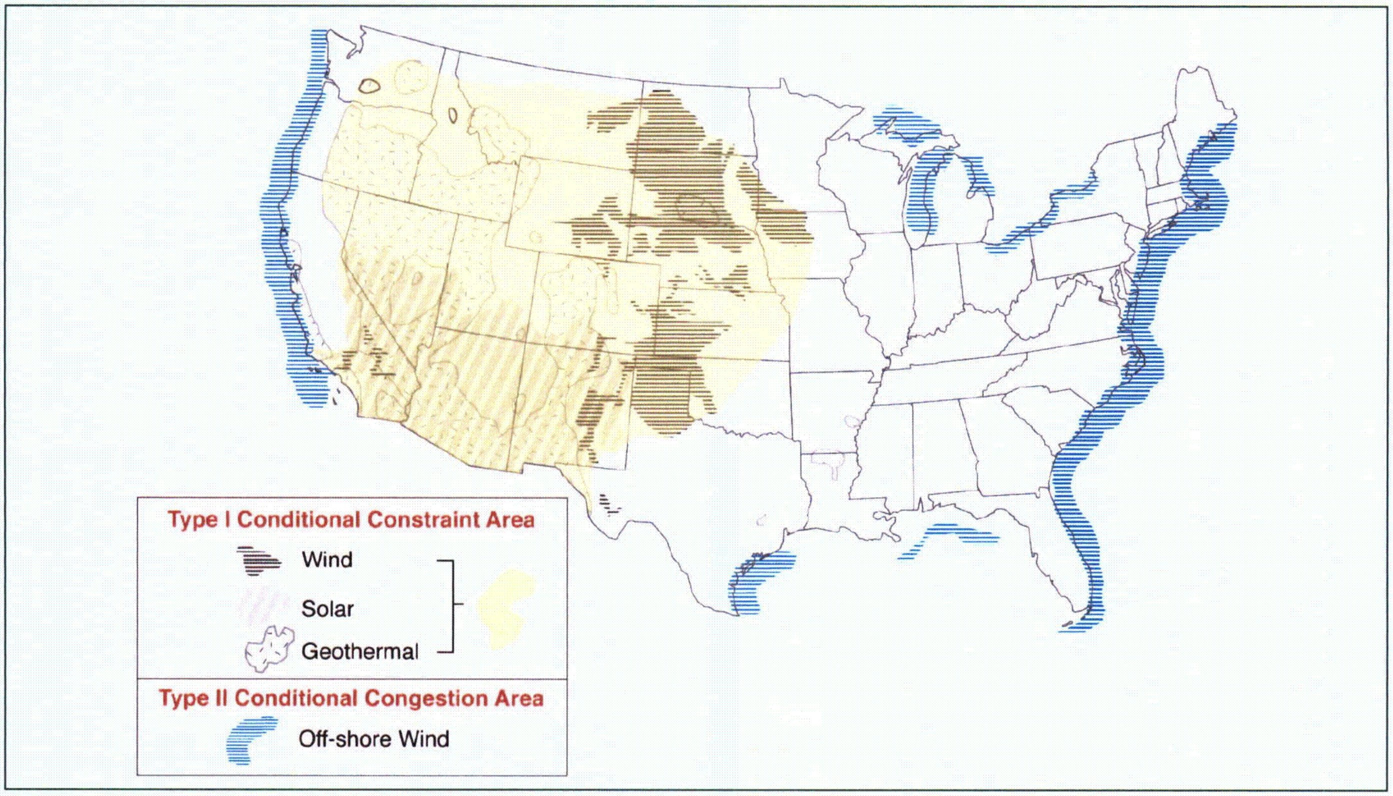
numbers of generation proposals sitting in transmission access queues, where they have been delayed for years because the existing transmission network is not sufficient to deliver additional electricity from these points to load centers. Even though not all of the generation projects sitting in these queues will be economically competitive, and not all of them will be successfully completed (much less survive the transmission queue), the fact that these areas' queues are so large demonstrates the appropriateness of including the areas within the Type I Conditional Constraint Area.[46] Figure 3-10 also identifies several offshore Type II areas that have promising wind potential.

In the 2006 study, the Department identified several Conditional Congestion Areas specifically because of their potential for wind development. In this study, building upon the review above of all of the significant renewable resources available for development, the Department takes a somewhat different approach:

1. When all of the areas identified by NREL as having strong resource development potential for wind, geothermal and photovoltaic energy are combined into a single map, as shown in Figure 3-10, it is clear that significant portions of the western states and much of the eastern coastal region could host renewable resource development. Further, many western areas could host more than one kind of renewable energy development.

2. The Department concludes that it is appropriate to consider the on-shore resource areas shown

Figure 3-10. 2009 Type I and Type II Conditional Constraint Areas



[46] In March 2008, the Bonneville Power Administration (BPA), in order to identify the more speculative projects in its transmission queue, initiated a Network Open Season (NOS). Under the NOS, those seeking transmission capacity were asked to sign Precedent Transmission Service Agreements, which committed them to take service at a specified time and under specified terms. The NOS improves management of BPA's long-term transmission queue and provides a better understanding of market dynamics and what new infrastructure might be needed to support the evolving electrical needs of the region. At the close of the 2008 NOS, BPA had 153 requests from 28 customers for 6,410 MW of new long-term firm transmission service. Almost three-quarters of those requests are associated with wind generation, reflecting the region's momentum toward rapid development of renewable resources and the need to comply with state Renewable Portfolio Standards.

in the West and the upper Midwest as one very large Type I Conditional Constraint Area.[47]

3. The Department also concludes that off-shore wind resources, though promising, still face many technological and economic hurdles and that the affected areas should be identified as Type II Conditional Constraint Areas.

At the same time, it is clear from current renewable development activities that many economically viable renewable resources exist outside the areas identified as having the best resource development potential. Some areas (such as Pennsylvania and West Virginia for wind and northern California for geothermal) are showing that they can develop substantial amounts of new renewable capacity in areas that NREL has not recognized as having high resource potential, without waiting for dedicated new transmission lines. Further, small-scale distributed renewables are being developed in some communities today, such as rooftop photovoltaics in Chicago and community wind in Minnesota, without need for new enabling transmission. The Department does not wish to imply that omission of an area from the Type I Conditional Constraint Area means that the omitted area has low quality or insufficient renewable resources, or that it would not be appropriate to build new transmission to facilitate major renewable resource development in those areas.

It is important to recognize that the economics of renewable resource development can vary widely, and that they are very location-specific. In many cases transmission access can make the difference between an economic and uneconomic project or development area. Such economic and geographic granularity must also consider the cost of transmission to access the resource,[48] and cannot be determined or conveyed in a national-scale study.[49]

Much of the Type I Conditional Constraint Area also has potential for development of additional non-renewable generation as well as renewables—or instance, there are extensive coal and gas reserves in Montana and Wyoming near the wind resources, and natural gas lines can deliver fuel to power plants in most locations in the lower 48 states. A transmission project developed to open up new renewable resource areas could also be used to transmit non-renewable generation. A transmission line developed primarily to serve power from one source or area will probably carry electricity generated by various sources. One of the major benefits of a robust transmission network is that it enables grid operators to adjust the generation mix they are using in response to the intermittent nature of renewable electricity generation, as well as to other unanticipated events or conditions.

3.4. Reasons for the Failure to Develop Adequate Transmission for Renewables

In response to the Recovery Act, section 409, the Department finds a number of reasons why adequate transmission capacity has not been developed in some areas with large amounts of potential renewable resources:

- Until recently, new utility-scale renewable generation was rarely economically competitive with conventional fossil generation alternatives, particularly given the added cost of long-distance transmission. As a result, the transmission capacity we have now was usually built for other purposes.

[47] Although Texas and specifically the region that makes up ERCOT is shown on the NREL maps as having significant renewable resource potential, this study does not include ERCOT within the Conditional Constraint Area, because the EPAct specifically excludes ERCOT from consideration in the study. ERCOT and the state of Texas are already doing a commendable job developing new transmission to facilitate renewable resource development.

[48] A recent study by LBNL found that, based on a review of transmission planning studies, the median projected cost of transmission to access wind generation is about $300/kW, which is about 15% of the cost of building a new wind generating unit. Mills, A., R. Wiser, and K. Porter (2009), *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*. Lawrence Berkeley National Laboratory report LBNL-1417E, at http://eetd.lbl.gov/EA/EMP/re-pubs.html.

[49] It should be noted that the Department has not attempted to use any screen for economics or competitiveness to narrow down the resource-rich regions of the country. As discussed earlier in this chapter, the current renewable energy development zone analyses under way in Colorado, California, Arizona and elsewhere show that such screening depends on highly localized economic and engineering data and assumptions that are beyond the scope of a national study.

- Renewable projects in particular have been subject to the "chicken and egg" timing problem—new transmission will not be built unless there is specific generation to deliver from and specific customers to deliver to, but remote renewables cannot be developed unless the transmission is there to serve them.
- Developers need to be sure there is a clear, predictable process for transmission project cost allocation and cost recovery, particularly if that project crosses more than one utility's footprint and would serve a wider area; until recently, there have been few regional cost allocation schemes to recover the cost of large backbone transmission projects or portfolios of such projects.
- Until the past few years, transmission planning within the interconnections has been relatively localized rather than regional or interconnection-wide, so there was little analysis to support the idea of building regional and interregional high voltage transmission to open up large new renewable resource areas. Transmission planning requires broad scenario analyses that consider reliability and economic evaluations as well as detailed technical and engineering analyses, so it is a lengthy process to move from the concept of new transmission to a widely accepted transmission plan and from there through permitting and financing to actual construction.
- Because long-distance transmission is expensive, large transmission projects are very costly and difficult to finance and build for individual, independent renewable project developers. Until recently, only renewable projects developed by utility owners were able to ensure that required new transmission would be built.
- Because many significant renewable resource areas are far from loads, the transmission lines needed to serve them may cross multiple states and federal lands, requiring lengthy, costly, and potentially contentious and litigious environmental and regulatory permitting processes.
- The siting process can be hindered if state siting authorities do not address the multistate nature of many of the high-voltage electric transmission lines needed to transport renewable energy to population centers. Under EPAct Congress gave FERC backstop authority to site transmission facilities in National Corridors, provided certain specific conditions had been met. FERC's authority was severely curtailed, however, by a recent decision by the U.S. Court of Appeals for the Fourth Circuit. In *Piedmont Environmental v. Federal Energy Regulatory Commission*, 558 F.3d 304 (4th Cir. 2009), the Court significantly limited FERC's ability to site transmission lines in National Corridors designated by the Department.

In *Piedmont*, the Court of Appeals struck down a FERC rule designed to implement its "backstop" transmission line siting authority granted under FPA § 216(b). The Court ruling significantly limits FERC's authority to issue construction permits for interstate transmission lines located in National Corridors. This limitation on FERC's transmission line siting authority could adversely impact efforts to site transmission across broad regional areas, such as will be needed for providing access to remotely located renewable energy resources. Moreover, the reach of the decision in this case appears to extend beyond the Fourth Circuit, because both the Public Service Commission of the State of New York and the Minnesota Public Utilities Commission were parties to the case.

3.5. Legal Challenges Delaying Transmission for Renewable Energy

The Recovery Act directs the Department to analyze and report on the extent to which legal challenges filed at the State and Federal level are delaying the construction of transmission necessary to access renewable energy. To research this issue, the Department conducted an informal inquiry with officials in various state energy offices, regional planning organizations, transmission companies and electric trade associations, and reviewed a decade of electric trade news coverage of proposed transmission project developments.

The Department interpreted "legal challenges filed at the State and Federal level" broadly, to encompass regulatory challenges before state utility regulatory and permitting or siting agencies and similar challenges before state and federal environmental agencies, as well as court cases. The Department interpreted "transmission necessary to access renewable energy" to mean projects that would open up renewable resource-rich areas that were not previously served by transmission, rather than transmission projects that would serve a variety of generation sources including some renewables. Last, the Department interpreted "delaying the construction of transmission" broadly to include the permitting as well as the construction process, because legal challenges would more likely be raised to delay or deny permit issuance than they would during the construction phase, after a permit has been issued.

There are examples where transmission projects serving non-renewable resources have been delayed through lengthy permitting processes—such as American Electric Power's (AEP) 765 kV line through West Virginia and Virginia, which was delayed for over ten years by factors that included environmental challenges to land use agency approval processes. More recently, proponents of the Trans-Allegheny Interstate Line (TrAIL) 500kV line project through Pennsylvania had to deal with lawsuits from property owners challenging the use of old right-of-way agreements. There are also examples where regulatory processes led to permit denials for proposed transmission projects, as with the Arizona Public Utility Commission's denial of Southern California Edison's (SCE) proposed Devers-Palo Verde 2 transmission line. All of these projects, however, were designed primarily to deliver generation from non-renewable sources.

The New York Regional Interconnect (NYRI) is the closest example found of a project that could serve renewable energy sources that was delayed (and possibly terminated) due to legal challenges. The NYRI project was a merchant direct current (DC) line proposed for construction from upstate New York, where it could pick up hydro generation and new wind projects planned in northern New York, off-shore in Lake Ontario, or elsewhere in Canada, and deliver it to load centers in down-state New York, tying to the electric distribution system serving Manhattan and northern New Jersey.[50] NYRI has ceased its participation in the New York Public Service Commission's siting process because it concluded that the New York Independent System Operator's (NYISO) transmission tariffs, approved by FERC, would compromise its ability to recover the full costs of the transmission line.[51] However, it is not clear that this result is due to legal challenges so much as to a failure by the project's planners to identify an adequate, low-risk cost recovery mechanism.

Through the research described above, the Department has not found examples where legal challenges filed at the state and federal level are clearly delaying construction of transmission needed to access renewable energy. Among the cases where new transmission is now being built to open up new renewable resource-rich areas (as in Minnesota, California and Texas), the transmission projects worked through a deliberative but not hostile regulatory and permitting process that addressed grid engineering, siting, permitting, environmental, and cost allocation and cost recovery issues. None of these projects appears to have suffered inordinate legal challenges or delays in comparison to transmission projects targeted to serve non-renewable generation.

It is useful, however, to review several specific transmission and generation projects that, while not strictly meeting the statutory description of a transmission project serving renewable generation that has been delayed by legal challenges, are still relevant to the broader theme of developing transmission to serve renewables:

- The Cape Wind project, a proposed 454 MW wind generation project that would site 130 turbines in Nantucket Sound, has experienced extended delays from legal challenges filed before federal and state environmental and permitting agencies. Most of these legal challenges addressed the issue of developing the wind turbines offshore (with a variety of environmental issues

[50] Breslin, M. (2008). "New York's HVDC Line Takes a Step Forward." *Renewable Energy Transmission*, at http://nyri.us/pdfs/News/NYRI_Article-RenewableEnergyMagazine.pdf, p. 10.

[51] Thompson, C. (2009). "Letter from Chris Thompson, President of NYRI," at http://nyri.us/.

raised before the federal Minerals Management Service and state Division of Fisheries & Wildlife), but in 2008 the Cape Cod Commission denied siting of the 18-mile, 115 kV transmission line that would bring the wind power onto shore.

The Massachusetts Energy Facilities Siting Board then took review jurisdiction and overturned the denial, and the City of Barnstable filed suit challenging that review. Subsequently, the Barnstable Superior Court dismissed the suit[52] and the City of Barnstable is preparing an appeal to the Massachusetts Supreme Judicial Court.[53] Opposition to the transmission line appears to be an alternate way to fight the off-shore generation project, rather than a challenge to transmission for its own sake.

- San Diego Gas & Electric's (SDG&E) Sunrise Powerlink transmission project is intended to deliver renewable energy 150 miles from the Imperial Valley to San Diego. SDG&E filed its initial request for approval to build the line at the California Public Utility Commission (CPUC) in 2005 and filed a new set of documents in August 2006; the CPUC approved the project in December 2008. The federal Bureau of Land Management (BLM) granted approval for the project to use federal lands in January 2009. The Utility Consumers' Action Network currently has an application pending before the CPUC requesting the Commission to reconsider its approval of the project, and intends to seek appellate court review of any adverse decision.[54] The project was hotly contested before the CPUC and the BLM on environmental grounds, including both land use and environmental impacts, and some critics questioned whether the line is justified on either reliability or economic grounds.

- The Montana-Alberta Tie Line, a proposed 214-mile, 230 kV, 300 MW line between Lethbridge, Alberta and Great Falls, Montana would enable development and delivery of wind generation in Montana. The regulatory approval process included scrutiny by the Montana Department of Environmental Quality, WECC, FERC, Canada's National Energy Board, and the Alberta Energy and Utilities Board.[55] Environmentalists' challenges in these proceedings reflected the concern that the line could transport electricity generated from Montana coal as well as wind generation,[56] as well as more specific issues relating to siting the line and its and environmental impacts.

- The CapX 2020 project (spearheaded by Xcel Energy with 11 other utilities) is a $2 billion project building over 700 miles in three 345 kV lines to link wind farms in North and South Dakota to load centers in southern Minnesota and eastern Wisconsin. Press reports indicate that the lines are opposed by some environmental groups "questioning whether such a large project is necessary in light of new programs aimed at curtailing customer demand for electricity through energy efficiency and other programs."[57] Concerns about both need and environmental impact surfaced in routine agency regulatory proceedings rather than through the courts.

- A $1.5 billion, 600-mile transmission project proposed by the Transmission Agency of Northern California (TANC), called the TANC Transmission Project (TTP), was terminated in mid-July 2009. TANC consists of 15 publicly-owned utilities in northern California that collectively serve more than one million customers. The line was intended, among other things, to enable the

[52] Town of Barnstable v. Mass. Energy Facilities Siting Board, 25 Mass. L. Rep. 375, 2009 Mass. Super. LEXIS 108.

[53] Ouellette, J. (2009). "Commission, Barnstable pursue Cape Wind lawsuits," *Wicked Local Yarmouth*, at http//www.wickedlocal.com/yarmouth/news/x1438501070/Commission-Barnstable-pursue-Cape-Wind-lawsuits.

[54] Utility Consumers' Action Network (UCAN) (2009). "UCAN Files First (of Many) Appeals to Reverse CPUC's Sunrise PowerLink Approval," *UCAN News*, at http://www.ucan.org/energy/electricity/sunrise_powerlink/court_appeal_expected_fight_stop_sunrise_powerlink.

[55] Tonbridge Power, Inc. (2008). "Tonbridge Power Receives Final DOE Permit to Construct MATL Transmission Line," at http://www.tonbridgepower.com/News/2008%2017%2011%20TBZ%20Receives%20Final%20MATL%20Permit(1).pdf.

[56] Brown, M. (2007). "Ill Winds for Montana Wind Power Project as Developer Eyes Different Site in California." Associated Press.

[57] Cusick, D (2008). "Project That Could Boost Midwest 'Wind Belt' Faces Enviro Opposition." *Greenwire*.

delivery of renewable-based electricity. Three of TANC's major members withdrew their support for the line for a variety of reported reasons, including the potential for litigation by opponents of the line. Their withdrawal made the project financially infeasible for its remaining supporters. Although a range of alternative routes were under study, the line faced intense opposition from potentially affected local communities and landowners. Some homeowners asserted that just being included within the study areas reduced their property values.

In conclusion, while it appears that no new transmission project goes unchallenged, there is little evidence to date to suggest that transmission lines serving primarily renewable sources have experienced a different level of opposition or delay relative to lines for non-renewable generation. The cases reviewed suggest that transmission-related projects can be compromised or even killed by protracted regulatory proceedings and in some instances the apparent lack of an effective way to bring such proceedings to closure.[58]

[58] See www.tanc.us, esp. TANC Transmission Project—Frequently Asked Questions, June 2009; also, *Transmission & Distribution World*, "TANC Commission Votes to Terminate TANC Transmission Project," July 22, 2009, at http://tdworld.com/newsletters/.

4. Transmission Congestion in the Eastern Interconnection

4.1. Introduction

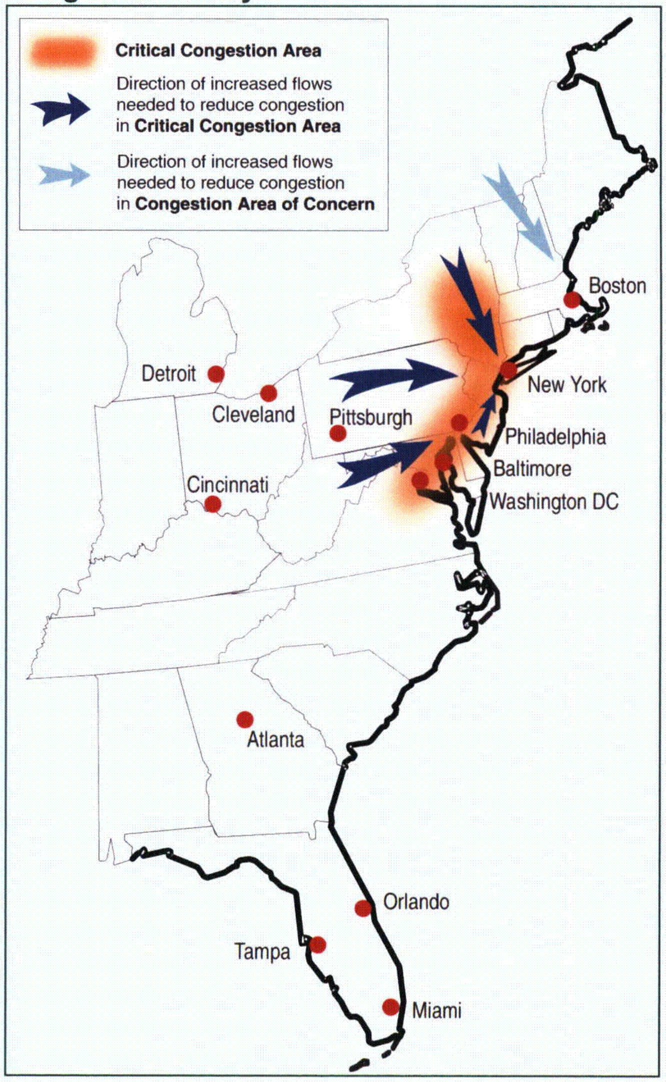
The *2006 National Electric Transmission Congestion Study* identified two congestion areas in the Eastern Interconnection—the Mid-Atlantic Critical Congestion Area and the New England Congestion Area of Concern. These are shown in Figure 4-1. This chapter reviews developments in these areas since 2006 and determines whether these identifications are still appropriate, and whether new areas should be identified.

This chapter begins by discussing the metrics used to evaluate recent transmission congestion in the Eastern Interconnection, and then reviews congestion in 2007 across the interconnection. This section draws upon an analysis of historic congestion in the Eastern Interconnection conducted by OATI under contract to the Department's LBNL.[59] It also examines the Mid-Atlantic and New England areas today, comparing current and projected conditions against the problems identified in the 2006 study, to determine whether they continue to exhibit congestion problems. Chapter 4 concludes with a review of the Conditional Congestion Areas identified in 2006 for potential coal and nuclear power development, and discusses whether any new congestion areas should be identified in the Eastern Interconnection.

4.2. Congestion Metrics Overview

This section provides an overview of three complementary elements that affect how transmission is managed and how congestion is measured in the Eastern Interconnection. The three elements examined are Transmission Reservations, Transmission Schedules, and Real-Time Operations. This section discusses the temporal relationships among the elements, the ways in which the Eastern transmission operators differ in their implementation of these elements, the data that are publicly (and not publicly) available to calculate metrics pertaining to these practices, and finally, the interpretation and significance of the metrics in understanding congestion in the Eastern Interconnection.

Figure 4-1. Eastern Critical Congestion Area and Congestion Area of Concern Identified in the *2006 National Electric Transmission Congestion Study*



[59] OATI's analysis and conclusions are published in a report, *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, available at http://www.congestion09.anl.gov/.

4.2.1. Transmission Reservations

As a result of FERC Orders 888 and 889, all transmission operators are required to make timely information publicly accessible about the availability of transmission service on their systems. This information is posted on OASIS websites. The posted information provides the basis for reservations of transmission service. Reservations may be made for varying time horizons, ranging from an hour to a year, and may be for either firm or non-firm service. In portions of the Eastern Interconnection, available capacity is posted for flowgates (available flowgate capacity or AFC), which represent combinations of electrically related transmission elements along a defined path. In other portions of the Eastern Interconnection, available capacity is posted for contract paths (Available Transfer Capability or ATC), which represent the transfer capability available between adjacent zones or balancing areas.

OATI collected posted AFC and ATC data from all OASIS sites in the Eastern Interconnection. OATI used the absence of available transmission capacity (that is, ATC or AFC = 0) as the principal metric for congestion using the transmission reservation data. The logic for this interpretation is that if ATC or AFC = 0, then either the flowgate or the path it is on is already fully subscribed.

Flowgates and Contract Paths

In the Eastern Interconnection, analysts in some areas refer to transmission congestion occurring on a "contract path"; analysts in other areas refer to congestion occurring on a "flowgate." This distinction arises because transmission capabilities in the Eastern Interconnection are described in two different ways. In some areas transmission is characterized as flowing between a source (point of generation) and a sink (point of delivery) along a contract path; in other areas transmission is characterized as flowing over intermediate, electrically related transmission facilities between a source and sink, called flowgates.

Although electricity flows according to the laws of physics (which means that an AC electrical flow may occur on many power lines across multiple utilities, not on a specific line between the source and sink), the contract path concept assumes that the electricity flows along the most direct electrical path from source to sink. Contract paths represent the transfer capability between adjacent "balancing authorities." (Under reliability requirements approved by FERC, a balancing authority is responsible for ensuring in real time that electricity demand and available electricity supplies are very nearly equivalent; because electricity demand is constantly changing, an exact match is not feasible, but the balancing authority is required to keep imbalances within a very narrow range.) Contract path descriptions essentially aggregate a group of transmission facilities (lines and transformers) and routes into a single "path" between the source and sink (or two balancing authorities) and simplify some aspects of the electrical properties of the individual links between points within balancing authorities.

By contrast, a flowgate is made up of one or more transmission facilities (lines, transformers, and other equipment) that behave in closely related fashion with respect to the flow of electricity and transfer capability between adjacent zones. Flowgates are more numerous than contract paths, as power may flow over several flowgates between adjacent balancing authorities. Flowgates are monitored constantly for reliability purposes and become the focal point for curtailments when such actions are required in real-time operations. There are thousands of flowgates in the Eastern Interconnection.

There are millions of individual transmission elements (line segments, transformers, substations, capacitors, breakers, etc.) in the East. Aggregating these elements into functional groups that are closely related electrically, such as a path between two balancing areas or a flowgate, makes it easier to understand and talk about transmission facilities according to their purpose and location. Reliability or economic congestion concepts and measurement techniques are the same whether the congestion is measured on flowgates or on contract paths.

There are several limitations associated with this metric as a measure of congestion. First, while reservations are often a prerequisite for scheduling transmission, they are not always a necessary prerequisite; transmission is sometimes scheduled over a flowgate or path without first having a reservation in place, as some of the schedules are based on grandfathered agreements and/or are for native load service and do not require reservations. Second, the unavailability of transmission service for reservation does not provide any indication of whether a reservation might have been sought and subsequently denied.[60] Third, the availability of transmission service is affected by scheduled outages, which might lead to congestion during the time of the outage, but would not necessarily indicate congestion under non-outage conditions.

4.2.2. Transmission Schedules

Transmission schedules are determined by transmission system operators during day-ahead and day-of operations, using established procedures for both security-constrained unit commitment (day-ahead time frame) and security-constrained economic dispatch (day-of time frame). These procedures lead to the identification of congestion, defined as situations in which not all requested transactions can be accommodated and generating units must be re-dispatched to operate the transmission system within established reliability limits (i.e., production levels from plants across the area must be readjusted so as to meet local load requirements by substituting local generation for supplies that cannot be imported because of the transmission congestion).

There are significant differences in the way these schedules are determined by different transmission system operators. RTOs or ISOs that operate formal, centralized markets develop their schedules based on competitive offers submitted by generators, plus flows dictated by bilateral contracts. Outside of centralized electricity markets, transmission system operators develop schedules based on flows under bilateral agreements between purchasers, generators and marketers. OATI did not examine the resulting schedules, regardless of how they were developed, because OATI focused instead on transmission reservations, which place an upper limit on acceptable flows.[61]

Aspects of the schedules developed by RTOs and ISOs are publicly available and this information provides economic insights into congestion within their markets. The information includes shadow prices[62] of binding constraints, and the congestion component of LMPs. OATI collected lists of binding constraints (and in most cases the shadow prices of these constraints) and the congestion component of LMPs from MISO, New York Independent System Operator (NYISO), PJM, and Independent System Operator New England (ISO-NE). OATI used the magnitudes of these prices as indicators of significant congestion and computed the market metrics accordingly.

As with AFC and ATC limitations, high market prices are only a partial measure of congestion. First, as noted, prices are only established and posted in formal wholesale markets; they are not applicable to or available for transmission systems that are not in or do not operate such markets. Second, prices alone do not indicate the magnitude of congestion, which depends also on the flow of power over congested paths. As noted, scheduled and actual flow information is not universally publicly available. Third, prices (even if flow information could be combined with them) do not, by themselves, provide a reliable indication of the level of grid operators' efforts to relieve congestion. They are simply economic scalars that enable comparison within a given market of congestion costs in one location with such costs in other locations.

[60] OATI also examined denied requests for reservations, but found them to be insignificant and did not review them further. Denied requests have uncertain value as a measure of desired but unconsummated transactions because they represent only requests that were actually made; they do not reflect desired transactions that were not pursued because the parties knew in advance that the requests were likely to be denied.

[61] FERC Order 889 requires that schedules in the bilateral markets be posted after the fact for all transmission reservations. This information is available on many, but not all of the OASIS sites. Scheduled flow information is not posted publicly in the organized markets operated by RTOs and ISOs.

[62] The shadow price of a constraint measures the incremental change in operating costs that would result from an incremental 1-MW change in the constraint limit.

4.2.3. Real-Time Operations

In real-time (or day-of) operations, transmission schedules are sometimes modified through Transmission Loading Relief (TLR) operating procedures developed by NERC. TLRs curtail scheduled transactions in order to modify power flows that might otherwise lead to violations of reliability criteria. These procedures are invoked typically when there are scheduling inconsistencies and/or where there are unplanned outages.[63] In some areas, such as SPP, TLRs are used as an alternative to LMPs for managing congestion. In these areas, a high frequency of TLRs indicates that the grid is being used heavily and does not, by itself, imply the existence of major reliability problems.

TLRs identify one or more specific flowgates and the amount of power that must be curtailed. Protocols have been established that determine how the curtailments are to be allocated among the various classes of affected energy transactions (e.g., firm vs. non-firm service). TLR information is recorded and maintained by NERC's Interchange Distribution Calculator Working Group, which made the data available for OATI's study. OATI evaluated the frequency and duration of TLR actions on particular flowgates as a measure of congestion. Frequency indicates how often scheduled transactions were curtailed and duration indicates the length of time transactions were curtailed. As was the case with the other two elements, TLRs are only partial measures of congestion, as no information on the commercial value of the curtailed transactions is recorded by NERC.

For centralized markets, real-time constraints are managed primarily by real-time market re-dispatch, not through TLRs. This information is captured in the shadow price for the binding constraints and was documented by OATI for some of the markets.

4.3. Historical Congestion in the Eastern Interconnection

Through LBNL, the Department hired OATI to analyze publicly available historical data on transmission congestion in the Eastern Interconnection. The available data are limited, and vary in content and quality across the interconnection. Such an effort has not been undertaken previously in the East (unlike in the West), so the Department and LBNL asked OATI to study data for 2007 only. This is the first time such a broad transmission data collection and analysis effort has been undertaken, and the most important finding from the effort may be the understanding of how uneven the publicly available data are, and how difficult it is to interpret the data consistently across the interconnection. Although the Department was aware that market operations affect congestion management practices, and that public reporting across the grid varies widely, it is nonetheless concerned to find major variations in data granularity and quality from region to region, and to learn how inconsistencies, such as those between the Interchange Distribution Calculator (IDC) and OASIS in how they name and map flowgates, sometimes make it difficult to determine precisely how transmission is being utilized across the interconnection.[64]

Transmission congestion management practices differ widely across the Eastern Interconnection, reflecting region-to-region differences in philosophy, grid operations and market structure from region to region. Table 4-1 summarizes the variations in these practices and the available data. In the Northeast (NYISO, ISO-NE, and PJM), where centralized power markets have existed for many years, grid operators manage transmission flows and reliability over the short term primarily using price signals generated through the wholesale power market. In

[63] For instance, PJM called 150 TLRs in 2008, an increase of 87% over 2007, with most of the increase attributed to transmission line outages caused by storms and tornadoes. See Monitoring Analytics, LLC (2009). *2008 State of the Market Report for PJM.* (Vol. 1- Introduction), at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml, p. 22.

[64] Common and more rigorous conventions for naming transmission facilities in the Eastern Interconnection would make it easier to track transmission activities and conditions, particularly when more than one data source is involved.

the Midwest (MISO and SPP), they manage transmission congestion over the short term using TLR curtailments (although this may change over time with greater market experience). In the Southeast (SERC Reliability Corporation (SERC), Florida Reliability Coordinating Council (FRCC), TVA and Entergy), where there are no centralized power markets, all utilities are vertically integrated, and there is limited information on transmission congestion because the utilities manage available transmission capacity and reservations in ways that limit the amount of transmission service that might otherwise have to be curtailed. Over the long term, all of the regions look explicitly at where transmission congestion occurs and what supply- and demand-side measures could alleviate it.

Notwithstanding the data challenges and the wide variety of practices employed by eastern operating entities to manage and document congestion on and among their systems, OATI's analysis offers several insights into the patterns, causes, and trends in congestion within the Eastern Interconnection. While it is relatively straightforward to draw conclusions about individual areas and about the areas where organized markets operate, it is harder to draw broad conclusions across the entire interconnection.

4.3.1. Transmission Reservations

The availability of reservations for transmission service is not a complete measure of transmission

Table 4-1. 2007 Transmission Congestion Data Provided to OATI for Study of the Eastern Interconnection

	Entergy	FRCC	ISO-NE	MISO	MAPP	NYISO	PJM	Southern Company	SPP	TVA	VACAR
						Operational and Reliability Metrics					
Transmission Reservations	Yes Reserva-tions confirmed or refused	Yes Reserva-tions and trans-mission service offers	No OASIS not utilized by ISO-NE	Yes Flowgate AFC, reserva-tions confirmed or refused	Yes Flowgate AFC, reserva-tions confirmed or refused	N/A OASIS not utilized by NYISO	Yes Confirmed reserva-tions over interfaces	Yes Reserva-tions and ATC	Yes Flowgate AFC, reserva-tions confirmed or refused	Yes Reserva-tions and transmissi on services offers	Yes Reserva-tions and trans-mission service offers
Transmission Schedules	No	No	Yes Net schedules for flows over interfaces and interface TTC data	No	No	Yes Day ahead and real time schedules over interfaces	No	No	No	No	No
Actual Flows	No	No	No	No	No	No	No	No	No	No	No
Transmission Loading Relief Actions	Yes (ICTE)	Yes	No Resolved through market re-dispatch	Yes	Yes Included in MISO reliability footprint	No Resolved through market re-dispatch	Yes	Yes	Yes	Yes	Yes
					Economic Metrics						
Market Organization	No organized spot market	No organized spot market			No organized spot market			No organized spot market		No organized spot market	No organized spot market
Locational Marginal Prices	No	No	Yes	Yes	No	Yes	Yes	No	Yes For second half of 2007	No	No
Shadow Prices for Binding Constraints	No	No	Yes	Yes	No	Yes	Yes	No	No LMPs did not have constraints and shadow prices available	No	No

congestion. OATI's hypothesis was that fully subscribed lines (i.e., zero availability of either firm or non-firm reservations) means that there is no room available to handle additional requests; however, this does not say much about actual flows or the availability of room for additional flows. While it measures the extent to which a contract path or flowgate has been subscribed, it does not measure the potential unmet demand for additional transmission usage, nor does it measure the actual usage of a contract path or flowgate. OATI could not identify congestion based on actual utilization of transmission paths or flowgates because scheduling is performed through the use of e-Tags; neither e-Tags nor actual flows are publicly available consistently throughout the Eastern Interconnection.[65]

Generally speaking, OATI found that firm reservations were more fully subscribed than non-firm reservations as measured by the total MWh subscribed. However, for some reservations sinking into the organized markets (such as PJM), non-firm reservations were sometimes subscribed more fully than firm reservations. OATI believes that this may reflect sellers' desire to secure non-firm, rather than firm, transmission service opportunistically in response to prices available within these markets. It may also reflect a higher amount of merchant and intermittent generation selling into those markets.

Overall, the general pattern of firm reservations was from the north (Canada) toward the south (MISO) and from west (PJM-West) to the east (PJM-East). However the general pattern of non-firm reservations was from the east (MISO and PJM) to the west [Midcontinent Area Power Pool (MAPP)] and to the south [Entergy (EES) and TVA]. OATI found that the greatest amount of firm reservations subscribed (measured in MWh) sourced from PJM-West and Canada and sank into MISO. (See Figure 4-2). The greatest amount of non-firm reservations sank into MAPP and EES, followed by TVA. The source of these non-firm reservations was primarily from MISO, followed by PJM. (See Figure 4-3). In these figures, a positive (greater than zero) flow indicates that the flows originate in the zone indicated; a negative (less than zero) flow indicates that the net flows sink in (are delivered to) the zone shown.

According to OATI's analysis, the interface between SERC and Florida is fully subscribed (i.e., all available transmission capacity is being used in most hours of the year).

Information on transmission reservations is not relevant for assessing transmission activities within ISO-NE, NYISO, and PJM, as these entities rely on offers and bids cleared through nodal pricing in their centralized electricity markets to ration the availability and allocate the provision of transmission services.

4.3.2. Transmission Loading Relief Actions

The need for and hence use of TLRs varies across the Eastern Interconnection. Where they are used,[66] a Reliability Coordinator initiates a TLR procedure when a transmission line is loaded to the point that there is a potential or actual security limit violation. The TLR usually entails cutting one or more transmission contract flows (in priority order, first cutting non-firm transmission and then firm transmission schedules) and redispatching generation on either side of the limiting line to reduce line loading. The Reliability Coordinator initiating the TLR identifies the transactions and native and network load curtailments that will be used to gain loading relief and uses the NERC IDC to calculate the impact of the load relief across specific flowgates.[67] There are five levels of TLRs, ranging in severity from Level 1 (notification that an operating limit is reached) through Level 3 (curtailing non-firm point-to-point service) to Level 5 (curtailing firm transmission service). Once a TLR is initiated, it is

[65] OATI recommends that the Department try to acquire records of scheduled and actual flows for future analysis (as is routinely performed in the Western Interconnection through TEPPC's long-standing analyses of historic congestion).

[66] TLRs are used in SPP, PJM and the southeast.

[67] On an AC transmission system, electricity flows follow the path of lowest impedance, so cutting generation at one plant will affect flows across numerous flowgates in addition to the specific point that is being targeted for loading relief. Note that this means that more than one transaction may have to be modified or disrupted in order to achieve the desired relief at a particular location.

tracked in the TLR log maintained by the NERC IDC working group.

As noted previously, within NYISO and ISO-NE (and to a lesser extent PJM), TLR procedures are supplanted by market operations relying primarily on real-time re-dispatch based on market offers and so are not useful in describing this aspect of transmission congestion within the footprints of these organizations.

Table 4-2 shows statistics on TLRs by region, as compiled by OATI based on IDC information—column 2 shows the number of TLR curtailments, column 3 shows the number of hours covered by those curtailments, and columns 4 and 5 show the amount of non-firm and firm energy curtailed by region. The table confirms that more non-firm MWh were curtailed than firm MWhs (as is intended by the design of the TLR procedures). Table 4-2 indicates that the highest number of curtailments, and the highest number of hours of curtailments, occurred within SPP. According to SPP, many of these curtailments were due to weather-related outages in 2007. Despite the high number and duration of curtailments in SPP, far more MWh of non-firm and firm energy were curtailed in the adjacent MISO and Entergy regions than in SPP.

While OATI found limited evidence suggesting a correlation between these curtailments and earlier findings on non-firm transmission reservation metrics, OATI found no evidence of a correlation between firm curtailments and the firm transmission reservation metrics reported above. Both of these findings are consistent with the experience of the industry experts who provided suggestions to OATI on accessing and assembling the public information OATI relied upon to prepare its report.

The highest number of non-firm curtailments occurred in the MISO region, followed by those in SPP and Entergy. The constraints generally limited flows of power seeking to move from north to south and from west to east. In particular, the combination of curtailments and net reservations show that constraints limited the flow of electricity from Canada south through Minnesota and Wisconsin in 2007.

Figure 4-2. Net Firm Reservations for All Eastern Zones, 2007

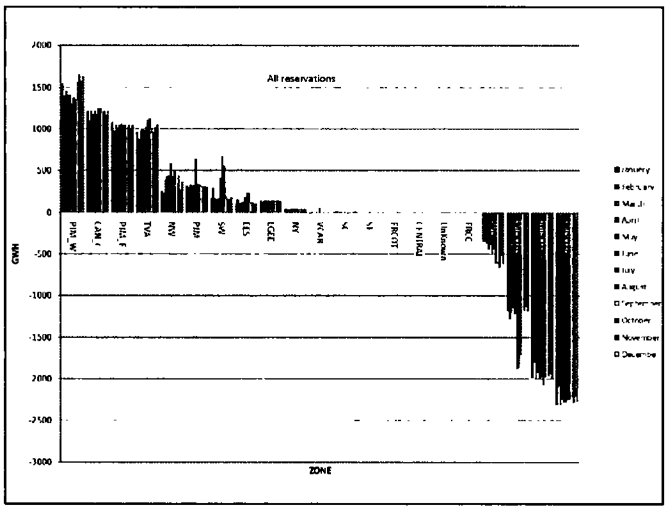
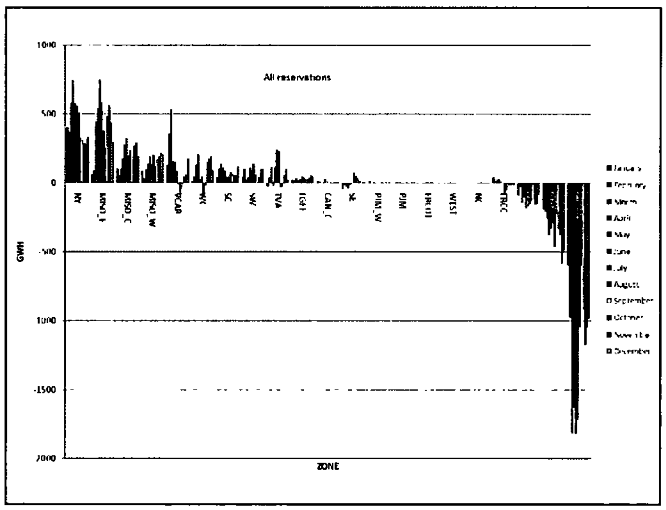


Figure 4-3. Net Non-Firm Reservations for All Eastern Zones, 2007



Notes: CAN_C = Central Canada; CENTRAL = Midwest ISO Central Region; EES = Entergy; FRCC = Florida Reliability Coordinating Council; LGEE = Louisville Gas and Electric Energy; MISO_C = Midwest ISO Central Region; MISO_E = Midwest ISO Eastern Region; MISO_W = Midwest ISO Western Region; NC = North Carolina; NW = Northwest Region of MAPP (Mid-Continent Area Power Pool); NY = New York; PJM = Pennsylvania-Jersey-Maryland; PJM_E = Pennsylvania-Jersey-Maryland = East; PJM_W = Pennsylvania-Jersey-Maryland = West; SC = South Central Region; SE = South East Region; SW = South West Region; TVA = Tennessee Valley Authority; VACAR = Virginia-Carolinas Sub Region; WC = West Central Part of MAPP; WEST = West Region of MAPP.

Sources: Open Access Technology International (OATI) (2009). *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, at http://www.congestion09.anl.gov/, Figure 72, p. 106, and Figure 73, p. 107.

MISO reports that it completed significant transmission additions in 2007 and 2008 that have addressed the underlying physical basis for many of the 2007 TLR actions in Wisconsin and Minnesota, so the number and severity of TLR actions going forward is expected to be lower. There are also constraints in the flow from west to east through Iowa and in Nebraska affecting southbound flows. But these historic transmission curtailment patterns are expected to be modified going forward due to recent operational changes within MISO—in January 2009, MISO launched an ancillary services market that began operating as the region's overall balancing authority, working with existing member entities as local balancing authorities.[68] Both developments should reduce the need for transmission curtailments.

The largest amount of firm MWhs curtailed was in the Entergy region. OATI's discussions with ICTE staff (Entergy's transmission manager) indicated that because pricing for firm and non-firm service is similar or identical, power marketers and independent generators moving electricity in that region tend to take comparatively more firm service than they might if firm service were priced higher (as it tends to be in other regions). Hence, curtailments affect firm service to a greater degree than might be observed in other regions because there are comparatively fewer non-firm transactions.

4.3.3. Cost of Congestion

Information on transmission reservations and TLR actions does not capture the economic significance of transmission congestion. In the East, this information is only available at present for the organized markets (ISO-NE, MISO, NYISO, PJM, and SPP), which rely on formal market processes to manage transmission congestion and make this information publicly available. (See Figure 4-4, which displays the geographic areas covered by these markets.) In the Southeast and lower Midwest, comparable information on the economic significance of transmission congestion is not available.

OATI used the shadow prices for binding transmission constraints and the congestion component of Locational Marginal Prices (LMPCCs) as market metrics for congestion. Shadow prices directly assess the magnitude and direction of congestion on transmission paths.[69] LMPCCs characterize specific constrained areas (either generation or load pockets). OATI found that shadow prices for binding constraints in 2007 were more reliable indicators of congestion than were LMPCCs. Changes in the sign and magnitude of shadow prices could be

Table 4-2. Transmission Loading Relief in the U.S. Portion of the Eastern Interconnection 2007 Data

Reliability Coordinator	Number of TLR Curtailments (Level 3 and Above TLRs)	Number of Hours in TLR (for Level 3 and Above)	Non-Firm MWh Curtailed (TLR Level 3)	Firm MWh Curtailed (TLR Level 5 and Above)
Southwest Power Pool	14,817	14,895	42,1401	1,355
Midwest ISO	7,494	12,552	103,4746	25,474
Independent Coordinator Transmission (Entergy)	2,519	3,809	40,4781	53,687
Tennessee Valley Authority	692	852	82,258	1,582
PJM	502	1,692	106,573	2,088
Virginia-Carolinas-South Reliability Coordinator	21	51	0	0

Source: Open Access Technology International (OATI) (2009). *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, at http://www.congestion09.anl.gov, Table 7, p. 109.

[68] Midwest ISO (2008b). "Midwest ISO to Begin Accepting Offers for Ancillary Services Market," Midwest ISO Press release, at http://www.midwestmarket.org/publish/Document/1d44c3_11e1d03fcc5_-7dc30a48324a/2008-12-22%20Midwest%20ISO%20Begins%20Accepting%20ASM%20Offers.pdf?action=download&_property=Attachment.

[69] The shadow price of a transmission constraint on a path or interface is a direct indicator of congestion on that path. The positive or negative signs associated with individual shadow prices reflect only conventions adopted to indicate the direction of constrained flows; it is the absolute value of a shadow price that reflects the economic significance of the constraint.

readily related to seasonal and time-of-use (peak/off-peak) market flow patterns. In contrast, LMPCC values in 2007 were often volatile, exhibiting frequent and less explicable changes in sign (positive and negative)[70] than binding transmission constraint shadow prices. OATI speculated that LMPCCs might be more volatile because they sometimes reflect the collective effect of several simultaneously binding transmission constraints, some of which may be on facilities supplying power into an area while others are on facilities supplying power out of the same area at the same time. LMPCC metrics complement shadow price metrics in illustrating economic congestion—LMPCC helps to identify load or generation pockets, while shadow prices reflect the value of relieving constrained lines.

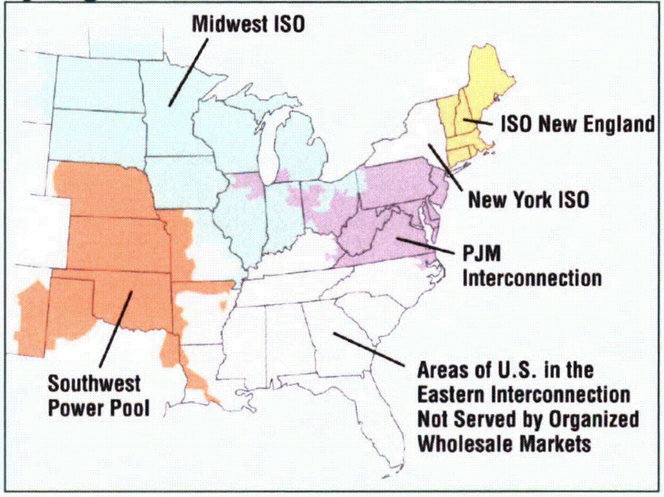
Before OATI could compare prices across the organized markets, it first had to determine whether the data from different markets were sufficiently comparable. OATI collected real-time price data for MISO congestion, while PJM and NYISO price data are from day-ahead markets.[71] Several factors led OATI to conclude that the market-based data are comparable despite these differences between the markets and the data available from them:

- Across the eastern markets, virtual bidding allows market participants to arbitrage away systematic differences effectively between the day-ahead and real-time markets within a given market area. In ISO-NE, where real-time and day-ahead congestion data could be readily compared, OATI determined that the differences due to reliance on day-ahead versus real-time data in calculating metrics were insignificant. Therefore OATI concluded that the congestion data and results are comparable between the markets despite the time-frame difference.
- OATI also believes that market participants arbitrage away systematic differences among the markets with respect to variations in market rules or timelines. This arbitrage is assisted, in part, because all of the markets analyzed have relatively similar uplift payment mechanisms to cover the situations when market prices (LMPs) are not sufficient to cover offer prices.

OATI reported several findings about eastern congestion, as measured by economic metrics:

- Counting the number of congested paths with high magnitude and frequency of non-zero shadow prices, MISO and PJM (the largest RTOs) experienced greater congestion than did either NYISO or ISO-NE in 2007.
- MISO and PJM experienced the greatest amount of economic congestion in 2007. Both regions had a significant number of transmission constraints with shadow prices exceeding \$500/MWh. In contrast, shadow prices within NYISO rarely exceeded \$200/MWh and within ISO-NE never exceeded \$200/MWh. The general pattern of congestion within and across MISO and PJM was one of increasing intensity from west to east. (See Figure 4-5.)
- For 2007, the ISO-NE network was the least congested among the Eastern markets analyzed. While there was some congestion across ISO-NE

Figure 4-4. Areas in the Eastern Interconnection Served/Not Served by Organized Wholesale Markets



[70] A positive LMP congestion cost indicates that the area is a load pocket, and transmission constraints limit the ability to import electricity in; a negative LMPCC indicates that the area has an excess of generation and transmission constraints limit the ability to export all of the generation produced.

[71] OATI collected both real-time and day-ahead congestion data from ISO-NE. Congestion data from SPP were only available for a portion of 2007 and were not analyzed.

interties, there was far less congestion within ISO-NE than existed within the other organized markets. Still, some LMPCCs exceeded $100/MWh; OATI attributed this in part to areas with sparse transmission.

- Congestion within the NYISO was dominated by flows from upstate toward New York City and Long Island. Few shadow prices averaged above $200/MWh. Although New York LMPCCs rarely exceeded $100/MWh, the pattern of LMPCCs formed a series of load pockets from New York's East Central zone down the Hudson Valley to New York City and onto Long Island.

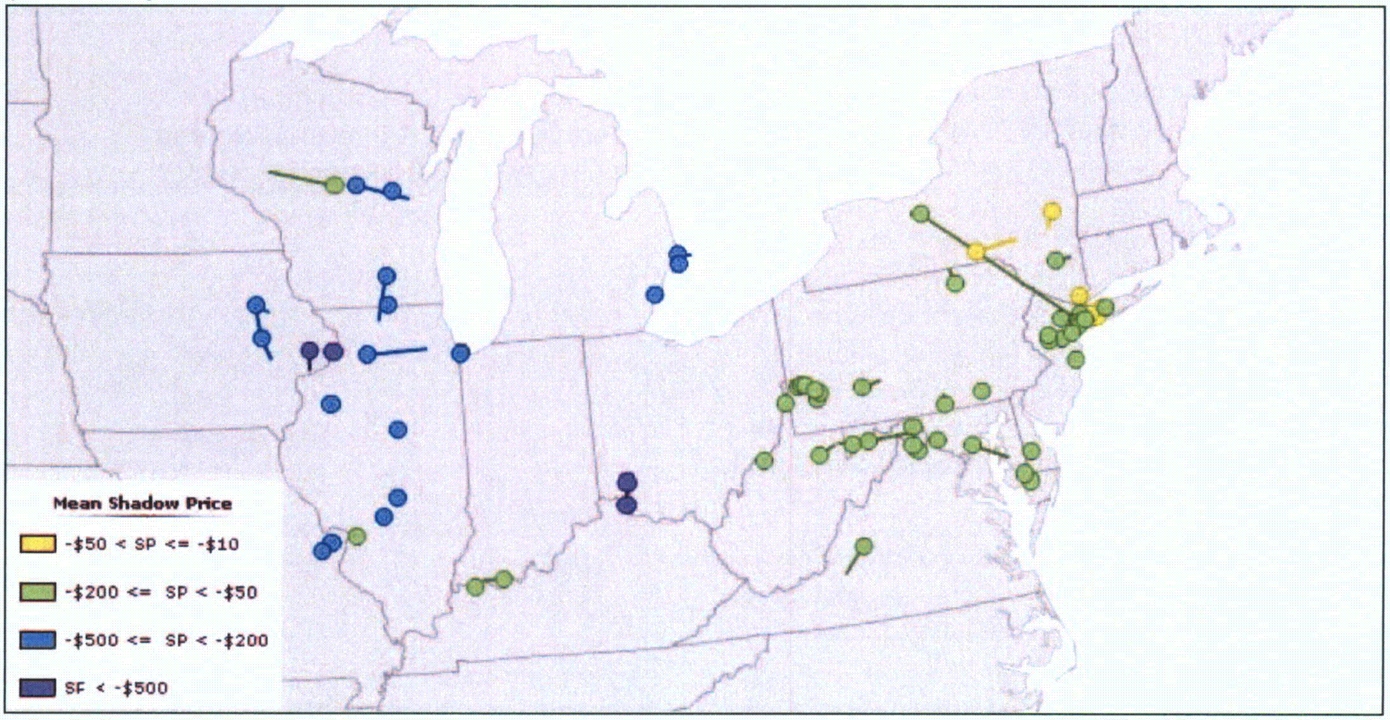
4.4. Mid-Atlantic Critical Congestion Area

In the 2006 study, the Department identified the mid-Atlantic area, from mid-state New York south along the Atlantic coastal plain to northern Virginia and west through eastern Pennsylvania, as a Critical Congestion Area. The Department made this identification because of the area's importance as a population and economic center and because of the many known transmission constraints and challenges to building new transmission and managing load growth.

The Department cited a number of congestion-related issues in this area in the 2006 study:

- The high electricity consumption and load growth of metropolitan New York City and Long Island, both of which are generation-short and face high electricity prices,
- The need for voltage support in southeastern New York,
- The region's high dependence upon costly (and price-volatile) oil- and gas-fired generation,
- Transmission constraints, reliability violations, and limited local generation in New Jersey, which may nonetheless be pressed to serve as a

Figure 4-5. Combined MISO-PJM-NYISO Binding Constraints Metric: Annual Mean Shadow Prices (All Hours)



Notes: For each of the top ranking transmission constraints, the "from" and "to" terminals of the path in question are located and joined by a straight line, using approximate geographical latitude and longitude coordinates. Where the from/to geographical locations are so close that they would not be discernible on the map, a circle is shown instead of a line. The color of the line or circle indicates the relative magnitude of the shadow price (see legend).

Source: Open Access Technology International (OATI) (2009). *Assessment of Historical Transmission Congestion in the Eastern Interconnection*, at http://www.congestion09.anl.gov/, Figure 120, p. 169.

Data Issues Hamper Analysis of Historical Congestion in the Eastern Interconnection

The lack of consistent, publicly accessible data on transmission flows and electricity costs across the Eastern Interconnection limited the Department's ability to analyze historic congestion across the region.

The OATI study could not identify congestion based on actual utilization of transmission paths or flowgates, as scheduling is done using "e-Tags" and these data are not publicly available. OATI recommended looking for a way to acquire scheduled and actual flows for future analysis (comparable to the analysis of historic congestion in the Western Interconnection that has been routinely conducted by WECC for a number of years).

One goal of the OATI study was to determine if there is a correlation among the various measures of congestion as identified through analysis of OASIS, market and IDC data. Lack of naming standards made it difficult to correlate the information available from the three sources.

Another goal of the OATI study was to present results on an electronic geographic map to facilitate further analysis. This proved to be a challenge as the geographic location of data was not readily available on a consistent basis for use in the study. The Department suggests that the regional planning entities should work together to develop such information on a consistent basis across the Eastern Interconnection, with suitable access restrictions for security-sensitive information.

NERC-provided IDC data were used to determine the number and magnitude of curtailments on the system. The flowgates were rated according to the number and size of the constraints. OATI could not determine the correlation between the refused reservations and curtailments on a flowgate because IDC does not report historic distribution factors.

Two sets of metrics used market data from ISO-NE, MISO, NYISO, and PJM: (1) binding congestion constraint shadow price statistics, and (2) LMP congestion component statistics. Data availability varied widely:

- There are no organized electricity markets in the southeastern region (the areas managed by SERC, TVA, Entergy/ICTE and Florida) and the grid managers do not share electricity cost information or much transmission flow information beyond the minimum required by current federal reporting requirements.
- SPP did not have full year market data for 2007.
- Constraint shadow prices were publicly available for all centralized markets except SPP. For ISO-NE they were made available for the study for a subset of constraints (interfaces).
- The data needed for congestion rent computation were either unavailable or considered commercially sensitive. A surrogate (sum of constraint shadow prices) was used instead, when these data were publicly available.
- The LMP congestion component data were available for all markets except SPP, and except January through May 2007 for PJM. In consultation with PJM project advisors, OATI devised a procedure to back-compute an approximation of the PJM LMPCCs for January through May 2007.

The Energy Information Administration's 2004 report, *Electricity Transmission in a Restructured Industry: Data Needs for Public Policy Analysis*, offers a detailed discussion of the data then—and now—collected on electricity production, market operations, pricing and flows. The report provides commentary on where these data and existing data collection vehicles fall short in allowing policy officials and analysts to understand key dimensions of grid operations and markets. Although several orders from the FERC have increased the scope, depth and transparency of regional electric system planning, major improvements are needed to collect data on many aspects of grid operations and make them publicly available.

pathway for new transmission and additional electricity flows to serve New York City,

- High congestion costs caused by transmission constraints that limit eastbound flows across the Allegheny Mountains,
- High retirements of older fossil generators, and
- Expensive, generation-deficit load pockets on the Delmarva Peninsula and the Baltimore-Washington metropolitan area.

This section reviews recent developments in the Mid-Atlantic region, including notable changes in load, energy efficiency, demand response, and distributed generation, as well as supply-side progress in transmission and generation development, and considers the net effect of these changes upon transmission congestion.

As many stakeholders have observed, the Mid-Atlantic region illustrates several key points about transmission congestion and changes to the bulk power system:

- It would not be economic to eliminate all transmission congestion; however congestion that creates significant reliability risks or increases in economic costs to consumers should be addressed.
- Making improvements to reduce transmission bottlenecks in one part of grid may only move congestion to other parts of the grid and make other bottlenecks more problematic.
- Changes in location of generation and patterns of loads will affect the timing and magnitude of transmission congestion and hence its economic and reliability impacts.
- In many cases, not addressing economic congestion today may lead to reliability-eroding congestion in the future.
- There are a number of ways to mitigate transmission congestion, including adding large and small generation, developing demand-side resources, and building additional transmission; these options should be regarded as a portfolio from which planners should make appropriate use of every tool available.
- All of these efforts take time for analysis, planning, siting, regulatory review and approval, and implementation or construction.
- Joint, inter-regional planning and cost allocation are needed to solve grid reliability and cost problems that cross market and state borders.[72]

The single greatest challenge in the Mid-Atlantic region is how southeastern New York will meet its electricity needs in the years ahead—with what combination of in-state resource development and efficiency, imports from New England and Canada to the north and east, and imports from the Midwest and south carried on cables through New Jersey and Pennsylvania. This issue lies at the heart of the Mid-Atlantic's future. As framed by a New Jersey public utility commissioner:

> Not only are we the most congested state in the country . . . , but we're at the edge of PJM. And therefore we have another problem, and that is the seams issue between us and the New York guys . . . . There are at least 3,000 MW of projected projects that will take power out of New Jersey and run them across the Hudson River or the northernmost boundary or cross the water into Long Island out of New Jersey and out of PJM into New York . . . . And there are very few rules that indicate how New York has to make up for that deficit.[73]

Similarly, according to PJM, "We are as concerned as New Jersey that as we continue to try to solve and

[72] Extracted from comments by Messrs. Michael Kormos (PJM), Dan Cleverdon (DCPUC), Ed Tatum (Old Dominion Electric Cooperative), Steve Naumann (Exelon), Paul Napoli (PSE&G), Jim Haney (Allegheny Power), Ms. Lisa Barton (American Electric Power), and Commissioners Frederick Butler (New Jersey), Doug Nazarian (Maryland), and Sherman Elliott (Illinois). See U.S. DOE Office of Electricity Delivery and Energy Reliability (2008). "Materials Submitted & Transcripts: Pre-Congestion Study Regional Workshops," at http://www.congestion09.anl.gov/pubschedule/index.cfm.

[73] Butler, F. (2008). "Comment of Frederick Butler Commissioner of the New Jersey Board of Public Utilities" Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Chicago, Illinois. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 6.

fix our problems, [those solutions should not be] simply used and leveraged by New York at an unfair arrangement."[74] The tension between New York and its neighbors, combined with the closely related question of how all the eastern states will meet their renewable portfolio standard requirements, highlights the growing importance of interregional, interconnection-wide scenario analysis and system planning across the East.

4.4.1. Changes in Load and Demand-Side Resources

New York has a projected peak demand of 33,452 MW in 2009, down from its record peak 33,939 MW in 2006[75] during record heat waves. Although load in New York was growing at an average annual rate of 1.23%, the recent economic slowdown and aggressive energy efficiency efforts have reduced forecast growth rates, which now are projected at 0.68% increase per year rather than the 1.31% expected previously.[76] Electricity consumption in New York fell from 167,208 GWh in 2005 to 165,613 GWh in 2008.[77]

Recent commitments by the New York Governor and the state's Department of Public Service have mandated a 15% reduction in electricity use by 2015, so the state's utilities are investing in aggressive energy efficiency programs to achieve these goals. The NYISO reports that if current efficiency program funding levels are maintained, they expect peak consumption to be reduced by approximately 5% of 2007 forecasted levels by 2015. Absent energy efficiency programs, New York's peak electricity demand would be 2,126 MW higher by 2018.[78]

In New York's capacity resource program, demand-side resources can compete to supply operating reserves and regulation services in the day-ahead and real-time markets. For 2009, New York will have 2,138 MW of registered Special Case Resources (demand response), up 761 MW from 2008,[79] and 364 MW of Emergency Demand Response Program resources.[80] In August 2006, NYISO demand response programs reduced electric peak demand by almost 1,000 MW when the system hit record peak levels.[81]

To facilitate more effective demand response and customer energy efficiency choices, most of the New York utilities are installing advanced metering systems designed to deliver transparent, market-based prices to all consumers.[82]

It appears that the combined impacts of New York's energy efficiency policies and programs, increased demand response from customers registering as Special Case Resources, and increases in expected generation and transmission availability are improving the state's reliability outlook. These changes allow the NYISO to conclude that "the forecasted baseline system meets applicable reliability criteria for the next 10 years, from 2009 through 2018, without any additional resource needs."[83] The ISO cautions, however, that the New York system could need resources as soon as 2010

[74] Kormos, M. (2008). "Comment of Michael J. Kormos, Senior Vice President-Operations PJM Interconnection, L.L.C." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Chicago, Illinois. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 9.

[75] New York ISO (NYISO) (2009d). "2009 Summer Outlook," at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_2009_Summer_Outlook__05212009_(2).pdf, p. 4.

[76] NYISO (2009b). *Power Trends 2009*, at http://www.nyiso.com/public/webdocs/newsroom/current_issues/nyiso_powertrends2009_final.pdf, p. 19, and New York ISO (NYISO) (2009d). "2009 Summer Outlook," p. 9.

[77] NYISO (2009a). *2009 Load and Capacity Data 'Gold Book,'* at http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC.pdf, Section 1.

[78] NYISO (2009e). *Reliability Summary 2009-2018*, at http://www.nyiso.com/public/webdocs/newsroom/current_issues/rna2009_final.pdf, p. 8.

[79] *Ibid.*, p. 6.

[80] NYISO (2009d). "2009 Summer Outlook," pp. 12-13.

[81] NYISO (2009e). *Reliability Summary 2009-2018*, p. 10.

[82] NYISO (2009b). *Power Trends 2009*, p. 26.

[83] NYISO (2009c). *2009 Reliability Needs Assessment: Comprehensive System Planning Process*, at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/RNA_2009_Final_1_13_09.pdf, p. i.

if it experiences both high load growth and extreme hot weather.[84]

Within PJM, 2009 summer peak load is projected to exceed 134,000 MW, with the region's Mid-Atlantic load expected at 59,621 MW. Summer peak load across the entire PJM region (which is larger than the area within the Mid-Atlantic region of concern here) is expected to grow at an average of 1.7% over the next 10 years.[85]

Several of the Mid-Atlantic states have developed ambitious energy efficiency programs:

- Maryland's goal, set by gubernatorial order and confirmed by the EmPOWER Energy Efficiency Act of 2008, is to use energy efficiency to reduce per capita electricity consumption and peak demand by 15% by 2015.
- Pennsylvania's Act 129 of 2008 requires electric distribution companies to adopt and implement cost-effective energy efficiency and conservation plans to reduce energy demand and use.
- Washington DC's Clean and Affordable Energy Act of 2008 requires the District's utilities to reduce per capita energy consumption.
- New Jersey has a goal of reducing energy consumption by at least 205 MW by 2020, with peak demand reductions of 5,700 MW by 2020.
- Delaware has enacted legislation seeking a 30% average reduction in annual energy usage for its citizens by the end of 2015.

The American Council for an Energy Efficient Economy (ACEEE) has recognized several of the Mid-Atlantic states as leaders in delivering energy efficiency—ACEEE's State Energy Efficiency Scorecard ranked New York as 5th, New Jersey 10th, Maryland 12th, and Pennsylvania 15th among the nation's best for efficiency policies and programs.[86]

Recent market changes within PJM allow demand response and energy efficiency to be bid as forward capacity resources. PJM has 5,925 MW of load management and demand response in place to meet summer 2009 load.[87] PJM acquires firm capacity through its Reliability Pricing Model Base Residual Auction (BRA) process. Its latest BRA, held in spring 2009, acquired a total of 136,143 MW of capacity including 7,047 MW of demand response and 569 MW of energy efficiency for the years 2012-2013; 67% of this demand response will be located in PJM's most constrained areas.[88] Before the latest BRA, PJM had about 1,400 MW of demand response capacity. However, there is not yet enough of a track record with new demand-side resources to be sure that they will materialize on the schedules called for under the BRA commitments.

Several states have aggressive goals for distributed generation and photovoltaics. One of the most aggressive is New Jersey. Since 2001, New Jersey has built more than 60 MW of solar projects, assisted by Clean Energy Program solar energy rebates (now phased out) and Solar Renewable Energy Credits. The state's current goal is to install enough solar capacity (1,800 MW) to get 2,120 GWh of energy from solar by 2020. The state is also developing community-based solar programs for distributed, aggregated resources and commercial grid-connected projects.[89]

[84] *Ibid.*, p. ii.

[85] PJM (2009e). *PJM Load Forecast Report*, at http://www.pjm.com/~/media/documents/reports/2009-pjm-load-report.ashx, p. 1.

[86] Eldridge, M., et al. (2008) *The 2008 State Energy Efficiency Scorecard*, ACEEE Report Number E086, at http://www.aceee.org/pubs/e086_es.pdf, p. 4.

[87] PJM (2009f). "Region Ready for Hot Weather Power Demand," PJM Press release, at http://www.pjm.com/media/about-pjm/newsroom/2009-releases/20090506-pre-seasonal-forecast.pdf.

[88] PJM (2009g). "Table 1 – RPM Base Residual Auction Resource Clearing Price Results in the RTO," *2012/2013 RPM Base Residual Auction Results*. PJM Docs #540109, at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx, p. 5.

[89] State of New Jersey (2008). *NJ Energy Master Plan*, at http://www.state.nj.us/emp/docs/pdf/081022_emp.pdf, pp. 69-70.

4.4.2. Changes in Generation and Transmission

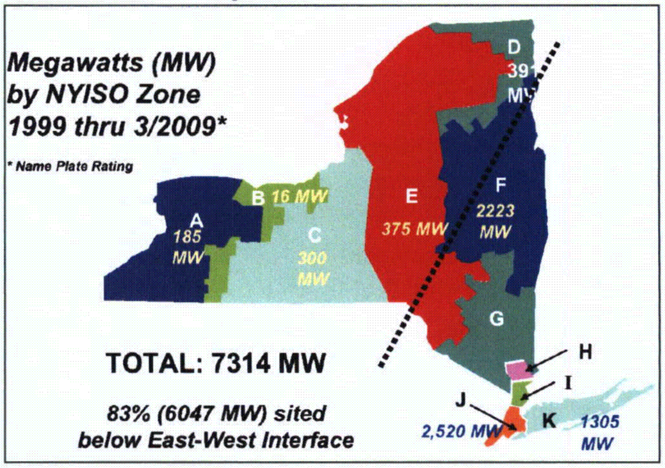
Changes in Generation

New York has 38,547 MW of installed generation in place to meet load in the summer of 2009.[90] Independent generators have added over 2,400 MW of new generation between January 2006 and May 2009[91] (including additional renewable resources that bring total wind generation to 1,275 MW[92]), and generator availability has increased by 7%. NYISO reports that 83% of the 7,300 MW added since 1999 has been sited in New York City, Long Island and the Hudson Valley, where the need for new generation was greatest.[93] (See Figure 4-6.) The addition of new generation capacity in Astoria East and West in New York City in 2006 has substantially reduced congestion within the City.[94]

Additional planned new market-based generation and merchant transmission projects are moving through the planning and permitting process, although four generation projects anticipated on-line in 2010-2011 are now experiencing delays.[95] The ISO reports that over the past year, "NYISO's markets have provided the incentive for approximately 1,700 MW of proposed generating capacity."[96] At the same time, however, retirements of existing power plants representing over 1,200 MW of capacity are projected over the coming decade.[97]

Changes in the types and locations of generation can have a significant effect on congestion in the future. New York adopted a renewable portfolio standard in 2004 that requires 25% of the state's electricity to be generated from renewable resources by 2013; achieving this goal will require development of both new generation and transmission. Around 8,000 MW of wind generation alone (not counting other renewables) are proposed for development across western New York. Currently 1,275 MW of wind generation is on-line; an additional 1,000 MW is expected to come on-line in 2009; and another 6,500 MW is in the interconnection queue.[98] New York also has the ability to access additional hydro and wind generation imported from Quebec, off-shore in Lake Erie, and off-shore in Long Island Sound and the Atlantic Ocean. As more of this wind generation is added to the system,

Figure 4-6. Generation Added in New York State, 1999–Early 2009



Source: Buechler, J. (NYISO) (2009). "Inter-Regional Planning in the Northeast." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slide 11.

[90] NYISO (2009f). "NYISO Anticipates Sufficient Electricity Supply for Summer 2009," NYISO Press release, at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/NYISO_Anticipates_Sufficient_Electricity_Supply_for__Summer_2009_05212009.pdf.

[91] Derived from NYISO (2009a). *2009 Load and Capacity Data 'Gold Book'*. "Table III-2," pp. 30-57.

[92] NYISO (2009f). "NYISO Anticipates Sufficient Electricity Supply for Summer 2009," NYISO Press Release.

[93] Buechler, J. (NYISO) (2009). "Inter-Regional Planning in the Northeast." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slide 10.

[94] Patton, D. and P. Lee VanSchaick (2008). *2007 State of the Market Report. New York ISO.* Prepared by Potomac Economics, Ltd. Independent Market Advisor to the New York ISO, at http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf, p. 37.

[95] NYISO (2009c). *2009 Reliability Needs Assessment: Comprehensive System Planning Process.* Table 2-1, pp. 2-7.

[96] NYISO (2009e). *Reliability Summary 2009-2018*, p. 5.

[97] NYISO (2009b). *Power Trends 2009*, p. 15 and NYISO (2009e). *Reliability Summary 2009-2018*, p. 6.

[98] Buechler, J. (NYISO) (2009). "Inter-Regional Planning in the Northeast." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slide 35.

the grid's dynamics and transmission and generation needs could change markedly in ways that this Congestion Study cannot predict or address.

A significant amount of new generation is proposed in PJM. At the end of 2008, PJM's interconnection queue had 32,965 MW of active projects, of which 30 MW had come in service and 83 MW was under construction. By the end of 2008, however, 5,990 MW of generation capacity within PJM had retired, with another 1,651 MW pending retirement;[99] the net result of these retirements, weighed against the new generation additions and continued load growth, meant that PJM faced possible near-term reliability criteria violations in many areas.[100]

Development of new wind generation is likely to have a significant effect on bulk system power flows across the region; but with many potential wind development sites across the Mid-Atlantic, from the Appalachian Mountains to large wind developments off the shores of New Jersey, the likely flow patterns and impacts are not yet fully understood and will require further analysis. At the start of 2009:

- PJM had about 1,800 MW of wind generation connected to its system, with another 1,800 MW under construction and over 46,000 MW of wind generation capacity (250 project requests) in its interconnection queue.[101]
- New Jersey is evaluating at least 3,000 MW of potential off-shore wind development by 2020 (some projects with in-service dates of 2013), with a complementary goal of producing 2,120 GWh from solar energy by 2020.
- New York had 1,274 MW of wind plant capacity in operation as of April 2009, and 8,017 MW in its interconnection queue.[102] Con Edison and the Long Island Power Authority have joint plans to evaluate transmission needed to develop off-shore wind in increments of 350 MW.

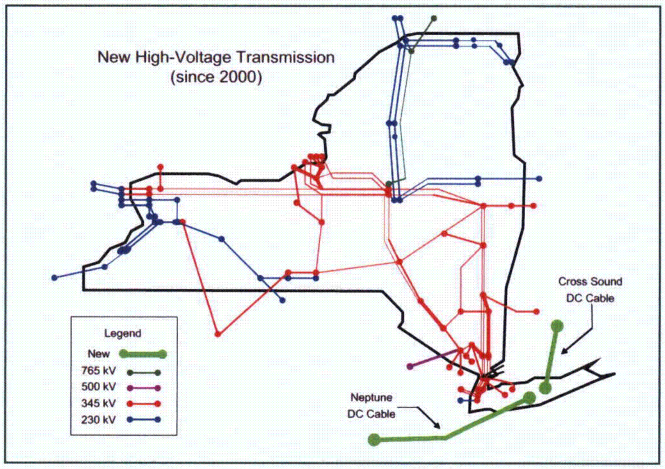
The Department is supporting the work of NREL and the Eastern Interconnection system planning organizations on the Eastern Wind Integration and Transmission Study (EWITS), to better understand how significant increases in variable generation can be incorporated reliably into the Eastern grid.

Changes in Transmission

Figure 4-7 shows recent transmission built in New York. One of the most notable transmission additions in New York was the completion of the merchant Neptune project in 2007, an under-sea 230 kV cable from PJM to Long Island that added 660 MW of eastbound import capability. Although flows on the cable can be bi-directional, in 2008 all power flows went from PJM to New York, with average hourly east-bound flows at 572 MW.[103]

Figure 4-8 illustrates why new transmission such as the Neptune project is needed. Most of the electricity flows in upstate New York are either west-to-east or north-to-south, and all move electricity toward the New York City area. Because transmission capacity into this area is limited, New York City is

Figure 4-7. New Transmission Built in New York Area



Source: NYISO (2009b). *Power Trends 2009*, at http://www.nyiso.com/public/webdocs/newsroom/current_issues/nyiso_powertrends2009_final.pdf, p. 6.

[99] PJM (2009h). *2008 Regional Transmission Expansion Plan (RTEP)*, at http://www.pjm.com/documents/reports/rtep-report.aspx?sc_lang=en, p. 31.

[100] *Ibid.*

[101] ISO-NE, NYISO and PJM (2009). *2008 Northeast Coordinated Electric System Plan: ISO New England, New York ISO and PJM*, at http://www.interiso.com/public/document/NCSP_2008_20090327.pdf, p. 31.

[102] NYISO (2009g). "Wind Power Growing in New York," NYISO Press release, at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/Wind_Power_Growing_In_NY_04222009.pdf.

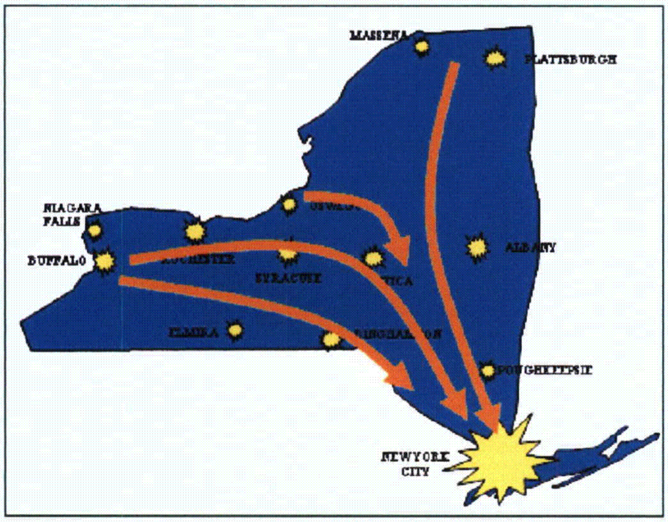
[103] Monitoring Analytics, LLC (2009a). *2008 State of the Market Report for PJM*. (Vol. 1- Introduction), p. 24.

an epicenter of transmission congestion and its delivered energy prices are higher than in other eastern load centers.

New York's Market Monitor explains that:

> The primary transmission constraints in New York occur at the following locations:
>
> - The Central-East interface that separates eastern and western New York;
> - The transmission paths connecting the Capital region to the Hudson Valley;
> - The transmission interfaces into load pockets inside New York City; and
> - The interfaces into Long Island.
>
> As a result of transmission congestion and losses, there was considerable variation in clearing prices across the system. In the day-ahead market, eastern up-state prices were 27% higher than average prices in western New York, New York City prices were 8% higher than average prices in the eastern up-state region, and Long Island prices were 22% higher than average prices in the eastern up-state region.
>
> Total congestion costs declined from $770 million in 2006 to $740 million in 2007. The reduced congestion costs in 2007 were largely due to: a) mild summer weather, which reduced the frequency of shortage conditions; and b) the installation of 660 MW of new transmission capacity from New Jersey to Long Island, which reduced congestion on the interface between up-state New York and Long Island.[104]

Figure 4-8. Bulk Power Flows in New York State



Source: Buechler, J. (NYISO) (2009). "Inter-Regional Planning in the Northeast." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slide 20.

The effect of the Neptune cable, activated in July 2007, was to reduce average prices in east New York by 3%.[105]

The NYISO reports several recent changes in congestion patterns in the state:

- Congestion into southeast New York (Long Island and New York City) has declined over the past two years due to the availability of the Cross Sound Cable (2006), the Neptune Cable (2007), and improved system modeling of the New York City load pockets;
- Higher net imports into western New York from Hydro Quebec, Ontario and PJM have increased congestion on the Central-East interface (responsible for 39% of 2007 congestion costs, with the adjoining Pleasantville-Leeds and Dunwoodie-Shore facilities responsible for another 48% of those costs[106]);
- Weather alerts and reserve shortages have increased congestion from Albany through the Hudson Valley;
- Congestion-reducing benefits of new transmission have been offset by higher fossil fuel prices.[107]

[104] Patton, D. and P. Lee VanSchaick (2008). *2007 State of the Market Report. New York ISO*, p. vi.

[105] *Ibid.*

[106] NYISO (2009c). *2009 Reliability Needs Assessment: Comprehensive System Planning Process*, p. 6-2.

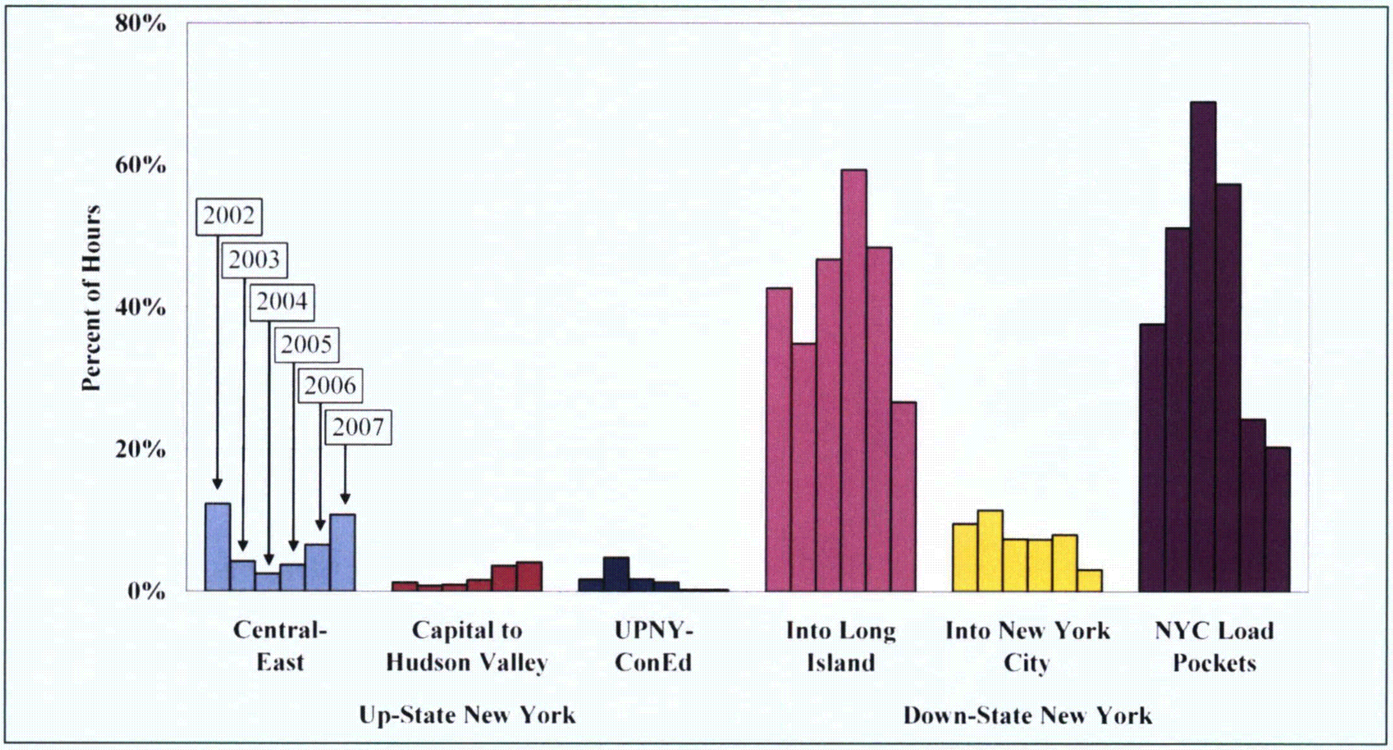
[107] Buechler, J. (NYISO, 2008). "Comments of the New York ISO." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study, Hartford, Connecticut. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 6.

Transmission congestion affects New York's day-ahead and real-time markets, preventing customers from buying power from the least expensive producers. Market operations software calculates the LMP or market-clearing price of serving load at each location; a higher LMP at a given point in time reflects the fact that transmission congestion and line losses limit deliverability of less expensive energy to that location. Transactions in the day-ahead market are based on predicted transmission capacity, and congestion costs are priced at the calculated congestion component of the LMP. However, "market participants can hedge congestion charges in the day-ahead market by owning Transmission Congestion Contracts (TCCs), which entitle the holder to payments corresponding to the congestion charges between two locations. Excepting losses, a participant can perfectly hedge its bilateral contract if it owns a TCC between the same two points over which it has scheduled the bilateral contract."[108] Day-ahead congestion costs in 2007 were over $750 million, offset by $680 million in day-ahead congestion rents; balancing congestion costs (incurred when forecast day-ahead transmission flows exceed actual real-time availability on a particular line, and the ISO must redispatch generation to keep the constraint in balance) equaled $159 million in 2007.[109]

The decline of real-time congestion on New York's major interfaces is shown in Figure 4-9, which shows that congestion has declined markedly since its peak in 2004. However, congestion was still problematic in 2007, affecting the Central-East interface in 10% of the hours of the year, into New York City 5% of the time, into Long Island 25% of the hours, and into City load pockets 20% of the year.[110] The cost of down-state congestion in New York reached $280 million in 2007.

PJM has experienced annual congestion costs of about $1.6-$1.8 billion per year since 2005, and doesn't expect those costs to decline significantly

Figure 4-9. Frequency of Real-Time Congestion on Major Interfaces 2002-2007



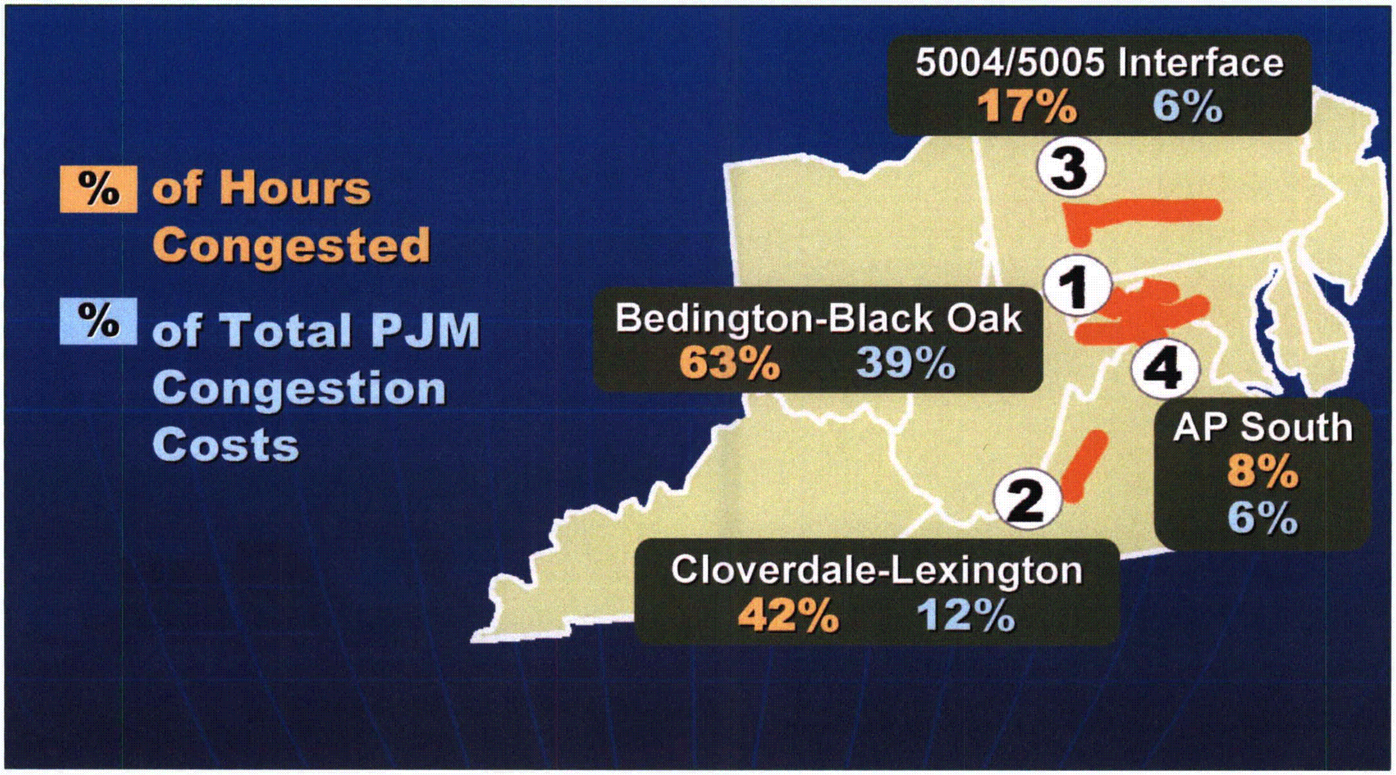
Source: Patton, D. and P. Lee VanSchaick (2008). *2007 State of the Market Report. New York ISO.* Prepared by Potomac Economics, Ltd., Independent Market Advisor to the New York ISO, at http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf, Figure 35, p. 68.

[108] Patton, D. and P. Lee VanSchaick (2008). *2007 State of the Market Report. New York ISO*, p. 66.
[109] *Ibid.*, pp. 67-74.
[110] *Ibid.*, p. 68.

until major new transmission projects are completed. Congestion costs increased to $2.12 billion PJM-wide in 2008, amounting to approximately 6% of total electricity billings.[111] "Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the Allegheny Power (AP) South interface. This interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones."[112] PJM reports that in 2007 its top 20 congestion-causing constraints were responsible for 87% of PJM's total congestion costs in that year; one particular constraint caused half a billion dollars of congestion annually. (See Figure 4-10.)

Total congestion is less important than its local or zonal impacts. The impacts of PJM's congestion on electricity producers and users differ as a function of the location of each relative to the constraints. Table 4-3 summarizes congestion costs across PJM by control area for 2008 in total dollars paid by, or credited to, electricity users and producers. Note that AP and Dominion customers paid the highest net total for congestion (as one would expect given the location of the key PJM transmission constraints shown in Figure 4-10), while generators on the eastern side of the constraints [e.g., those in the Baltimore Gas & Electric (BGE), Potomac Electric Power Company (PEPCO) and New Jersey's Public Service Enterprise Group (PSEG)] all earned high congestion credits in PJM's day-ahead market.[113]

Figure 4-10. Major Points of Congestion in PJM, 2007



Source: Federal Energy Regulatory Commission (FERC) (2008a). "2008 Summer Market Forecast." Office of Enforcement, http://www.ferc.gov/market-oversight/mkt-views/2008/05-15-08.pdf, slide 10.

[111] Monitoring Analytics, LLC (2009a). *2008 State of the Market Report for PJM.* (Vol. 1- Introduction), p. 50.

[112] *Ibid.*, p. 51.

[113] PJM and other organized wholesale markets have financial hedging mechanisms so electricity buyers and sellers can offset the costs of congestion. In PJM these mechanisms are tradable Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR), made available to the firm loads that pay for the cost of the transmission system. "While the transmission system, and therefore ARRs/FTRs, are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial hedge to the cost of congestion to firm load." See Monitoring Analytics, LLC (2009a). *2008 State of the Market Report for PJM.* (Vol. 1- Introduction), p. 50.

These observations support the concerns raised in the 2006 study about the continuing impacts of transmission congestion upon the metropolitan area stretching from Washington DC north through eastern Maryland, Pennsylvania and New Jersey.

New transmission projects and upgrades designed and approved through PJM's Regional Transmission Expansion Plans (RTEPs) target each of these transmission constraints; these projects have in-service dates ranging from mid-2008 out through 2012. Using simulations developed for the RTEP, PJM estimates that annual congestion costs of $1,800 million in 2007 could be reduced to $250 million by 2012.[114]

As noted earlier, however, PJM warns that "transmission [congestion] is more of a network issue than an individual constraint," i.e., it is a major west-to-east problem on the Mid-Atlantic transmission grid, and a broad program of improvement is required. If only a single key constraint is eased, another will emerge—for instance, as Bedington-Black Oak becomes less problematic, there will be more frequent congestion on the Cloverdale-Lexington 500 kV line in West Virginia.[115] As the major new transmission projects such as the Trans-Allegheny Interstate Line (TrAIL) and the Potomac-Appalachian Transmission Highline (PATH) are brought into service, they could significantly change the electricity flow and congestion patterns at these constrained interfaces and elsewhere across the Mid-Atlantic.

New York offers a similar observation—since two-thirds of the state's load is located in the southeast (around New York City and Long Island), while most of its lower-cost generation is in the north, the state's physical and economic transmission constraints "just walk down the Hudson River."[116] New York's transmission constraints showed a similar pattern to PJM's in that only a few constraints accounted for the bulk of the transmission congestion cost (on a bid production cost basis) is

Table 4-3. PJM Congestion Cost Summary by Control Zone, Calendar Year 2008 (Million Dollars)

	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$111.1	$31.8	$1.2	**$80.5**	($12.9)	$8.1	($2.0)	($23.0)	**$57.5**
AEP	($367.1)	($671.0)	$15.7	**$319.6**	($85.2)	$4.0	($6.9)	($96.1)	**$223.6**
AP	$124.4	($391.6)	$38.7	**$554.7**	($13.6)	$21.5	($32.6)	($67.7)	**$487.1**
BGE	$314.3	$245.3	$3.2	**$72.2**	$10.1	($14.2)	($4.5)	$19.8	**$92.0**
ComEd	($480.9)	($820.9)	$4.8	**$344.8**	($54.9)	$0.4	($5.2)	($60.6)	**$284.2**
DAY	($45.5)	($56.5)	$0.2	**$11.1**	$3.5	$2.6	($0.3)	$0.6	**$11.8**
DLCO	($159.2)	($249.2)	$1.1	**$91.2**	($49.4)	$22.2	$0.3	($71.3)	**$19.9**
Dominion	$337.2	$5.2	$33.0	**$364.9**	($9.3)	($0.9)	($33.9)	($42.3)	**$322.6**
DPL	$149.5	$54.1	$1.1	**$96.5**	$8.0	$6.2	($1.8)	($0.1)	**$96.4**
External	($59.5)	($51.5)	$35.6	**$27.5**	($31.6)	($36.4)	($107.5)	($102.7)	**($75.2)**
JCPL	$260.6	$72.1	$9.1	**$197.6**	($0.0)	($0.4)	($8.9)	($8.5)	**$189.0**
Met-Ed	$104.9	$104.5	$3.3	**$3.8**	$2.3	$0.8	$10.4	$12.0	**$15.7**
PECO	$70.9	$118.1	$0.5	**($46.8)**	($0.5)	$15.5	($0.7)	($16.8)	**($63.5)**
PENELEC	($43.2)	($224.3)	$4.8	**$186.0**	($4.8)	$13.6	($1.4)	($19.9)	**$166.1**
Pepco	$642.4	$436.2	$8.4	**$214.7**	$6.6	($3.7)	($9.1)	$1.2	**$215.9**
PPL	$29.0	$39.9	$12.7	**$1.8**	$0.2	$5.6	($5.2)	($10.6)	**($8.8)**
PSEG	$287.3	$190.9	$33.3	**$129.7**	$5.2	$34.5	($27.9)	($57.3)	**$72.5**
RECO	$10.0	$0.1	$1.5	**$11.4**	$0.5	($0.2)	($2.2)	($1.5)	**$9.9**
Total	**$1,286.1**	**($1,166.7)**	**$208.4**	**$2,661.2**	**($225.9)**	**$79.2**	**($239.5)**	**($544.6)**	**$2,116.6**

Source: Monitoring Analytics, LLC (2009a). *2008 State of the Market Report for PJM.* (Vol. 1- Introduction), at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2008.shtml, Table 6, p. 53.

[114] Herling, S. (PJM) (2009). "Congestion and the PJM Regional Transmission Plan." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slides 3-12, and remarks at that workshop.

[115] Kormos, M. (2008). "Comment of Michael J. Kormos Senior Vice President-Operations PJM Interconnection, L.L.C.," p. 4.

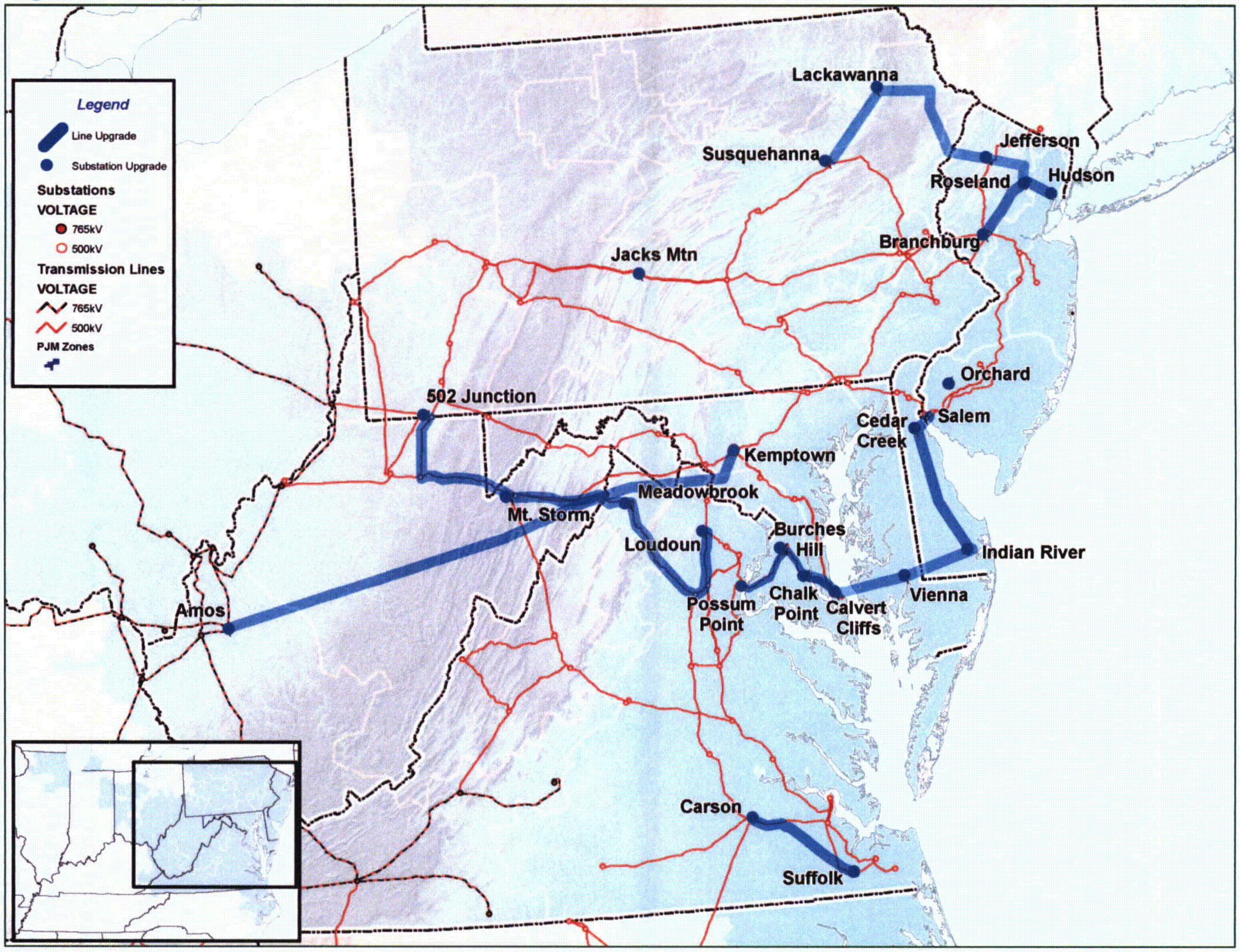
[116] Private communication between Diane Barney, New York State Public Service Commission, and Joe Eto, Lawrence Berkeley National Laboratory, March 27, 2009.

due to three transmission constraints—the Central East voltage constraint, the Leeds to Pleasant Valley line, and the Dunwoodie to Shore Road line.[117] Eliminating upstate bottlenecks will not relieve the fact that the Dunwoodie interface still limits flows into New York City.[118] But under New York's cost allocation rules, transmission projects that significantly reduce congestion and prices downstate generally increase prices for upstate consumers without creating large net benefits overall.[119]

One recent analysis suggests that it would be more economical to relieve in-City congestion by increasing local energy efficiency and in-city generation than to build new major transmission facilities down from upstate.[120]

PJM now has five major new transmission projects approved and under development, as shown in Figure 4-11. They are:

Figure 4-11. Approved New Backbone Transmission in PJM



Source: Herling, S. (PJM) (2009). "Congestion and the PJM Regional Transmission Plan." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slide 7.

[117] Buechler, J. (NYISO, 2009). "Inter-Regional Planning in the Northeast," slide 23, and Workshop Transcript, p. 10.

[118] Russo, C.J., R.B. Niemann et al. (2009). *A Master Electrical Transmission Plan for New York City.* Draft prepared for the New York City Economic Development Corporation. CRA International Project No. D13536, at http://www.crai.com/uploadedFiles/Publications/a-master-electrical-transmission-plan-for-new-york-city.pdf, p. 29.

[119] *Ibid.*, p. 21.

[120] *Ibid.*, pp. 24-29.

- TrAIL is a 210-mile, 500 kV line from West Virginia, Maryland and Virginia, that will relieve expected overloads in the Washington DC area.
- A 130-mile, 500 kV circuit from Susquehanna, Pennsylvania to Roseland, New Jersey, will link generation from northeastern and north-central Pennsylvania into New Jersey.
- PATH will be a 244-mile 765 kv line from Amos, WV to Bedington, MD and a 92-mile, 500 kV line from Bedington to Kemptown, MD and is expected to relieve congestion around Washington DC and Baltimore.
- The Mid-Atlantic Power Pathway (MAPP) will be a 190-mile 500 kV line from Possum Point, Virginia, to Salem, New Jersey, with a direct current (DC) line crossing the Chesapeake Bay.
- The Branchburg to Roseland to Hudson (all in New Jersey) 500 kV line will resolve a number of thermal and reactive voltage reliability violations.[121]

These projects, and continuing upgrades to the system, will significantly alter the magnitude and location of congestion in the region in the future. PJM estimates that the transmission projects listed above, once completed, will eliminate 90% of the region's total congestion cost.[122]

There is a large merchant transmission queue in PJM, as shown in Figure 4-12. The fact that so many merchant transmission projects are competing in the region indicates market confidence that PJM's market rules and regulatory environment offer good prospects for financial and market success with sustainable long-term cost recovery.

In New York, comparable transmission projects include the addition of a Variable Frequency Transformer to the Goethals 345 kV line and two proposed transmission projects across the Hudson River (660 MW and 550 MW), to support downstate New York, and a proposed new line from Canadian Niagara Power to import energy downstate from Canada.[123] As noted in Chapter 3, the proposed NYRI High Voltage Direct Current (HVDC) project was recently withdrawn.

4.4.3. Other Evidence of Congestion

Figures 4-13 and 4-14 show daily bilateral on-peak locational marginal prices averaged at hubs in the Mid-Atlantic, for a recent 15-month period and for the past four years. Both graphics show clear patterns of significant, sustained price differentials.

Figures 4-13 and 4-14 demonstrate three other points. First, they illustrate that congestion impacts (as reflected in differences between wholesale electric prices at area pricing hubs) are generally higher at eastern locations than western. For instance, although the average real-time energy price across PJM was $66.29/MWh for all of 2008, the average real-time LMP in Commonwealth Edison's service territory was $49.38/MWh, $74.70 to $79.14/MWh for New Jersey's utilities, and $80.45 for PEPCO.[124] This is what one would expect, given that Mid-Atlantic load-serving entities import electricity across constrained interfaces from lower-cost sources located to their west. Second, they show that overall prices have gone down over the past year, which reflects the decline in fuel costs and some recent transmission improvements reducing congestion. Third, there is less volatility in recent price differentials between regions; this too may reflect the impact of transmission upgrades that went into service in 2008.

4.4.4. Conclusions for the Mid-Atlantic Region

The above information leads the Department of Energy to several conclusions pertinent to past and future transmission congestion within the Mid-Atlantic region:

[121] North American Electric Reliability Corporation (NERC) (2008). *2008 Long-Term Reliability Assessment, 2008-2017*, at http://www.nerc.com/files/LTRA2008v1_2.pdf, p. 165, and PJM (2009h). *2008 Regional Transmission Expansion Plan (RTEP)*, pp. 2 and 5.

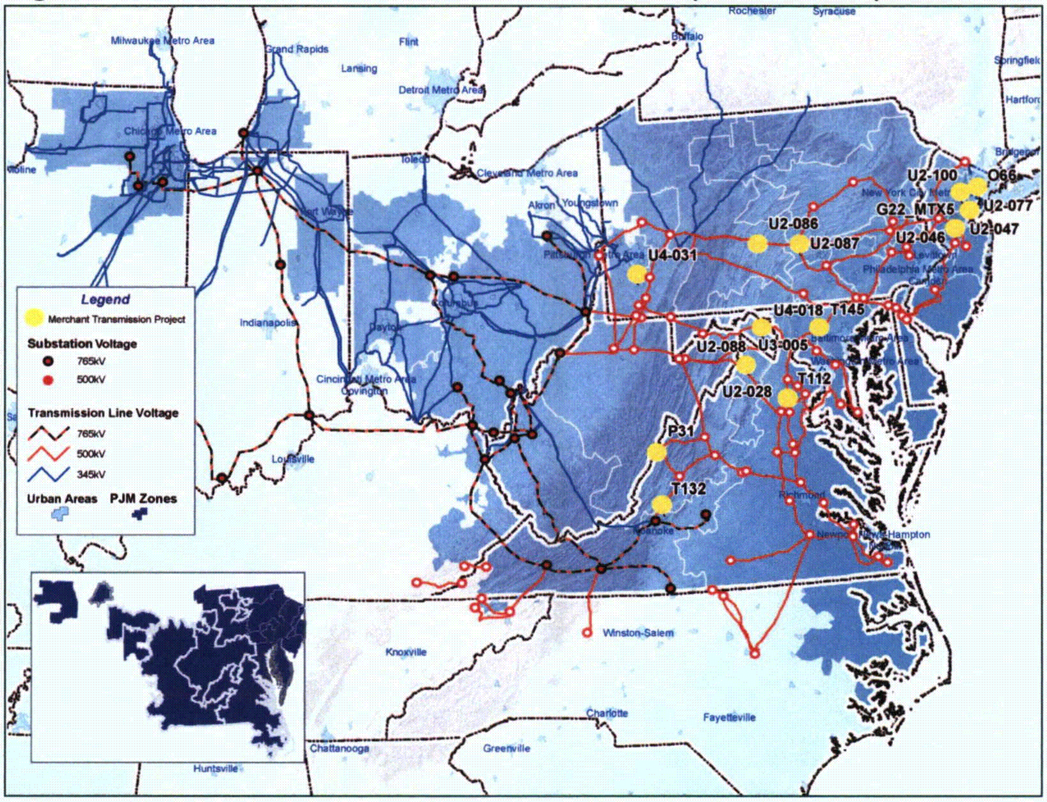
[122] PJM (2009h). *2008 Regional Transmission Expansion Plan (RTEP)*, p. 7.

[123] NYISO (2009a). *2009 Load and Capacity Data 'Gold Book,'* p. 117.

[124] Monitoring Analytics (2009b). "State of the PJM Market, Quarter 1, 2009." Presentation to PJM Members Committee, at http://www.pjm.org/Media/committees-groups/committees/mc/20090507/20090507-item-11-market-monitor-report.pdf, p. 34.

- The load centers continue to experience the impacts of significant levels of transmission congestion, measured in terms of economic cost and reliability. Much of that congestion limits west-to-east flows toward coastal load centers.
- The region is making significant progress in reducing loads and improving reliability through the use of aggressive energy efficiency and demand response programs.
- Although there are many projects in the NYISO and PJM generation interconnection queues, new generation is slow to come on-line and is often offset by retirement of older generation capacity.
- Although the planning entities (PJM and NYISO) have strong analytical planning processes with good stakeholder involvement, it takes years to bring needed large-scale, multi-state transmission projects from analysis to plan to reality.
- While PJM is making important progress toward significant transmission system upgrades and transmission expansion, it will be several years before these projects have a significant impact on current transmission congestion levels.
- Much less new transmission has been built in New York, although its market mechanism is causing more generation and demand-side resources to be built close to southeast load centers. Until New York has better load and resource balance from sources within and close to New York City, Long Island and Westchester County, there will continue to be tension between New York's needs and PJM's, and significant price differentials across the region.
- Slow development of new generation and new backbone transmission facilities (notwithstanding the growth in demand-side resources to moderate load growth and assist operational reliability) could compromise continued reliability in the Washington, Baltimore, New Jersey and New York City areas.
- Aggressive state renewable portfolio standards, large queues of proposed wind generation projects, and uncertainty about the potential for lower use of fossil plants due to carbon emissions

Figure 4-12. PJM Merchant Transmission Queue (as of 1/31/09)



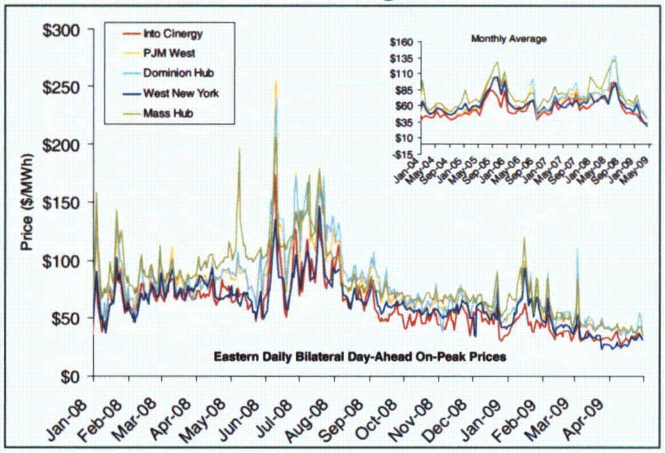
Source: PJM (2009h). *2008 Regional Transmission Expansion Plan (RTEP)*, at http://www.pjm.com/documents/reports/ rtep-report.aspx?sc_lang=en), p. 33.

limits make it difficult for planners to determine what future transmission projects will be needed to link generation to loads.

- The pace of economic activity in the Mid-Atlantic region has slowed as a result of the recession that began in 2008. Although the slowdown has tended to reduce transmission congestion in the area, this is likely to be a short-term effect that will be eroded as the regional economy revives. As such, it does not imply that the overall area's congestion problems have been resolved. The slowdown may, however, provide additional time for the various congestion-reducing measures discussed above to work. DOE invites commenters on this study to address the relationship between the recession and transmission congestion.

For these reasons, the Department finds that the Mid-Atlantic region continues to exhibit major transmission congestion problems and should be continue to be identified as a Critical Congestion Area. This identification—as is the case with the others that follow in this document—is based on consideration of the totality of the various kinds of information presented, rather than on whether specific congestion metrics have been met or exceeded.

Figure 4-13. Sustained Price Differentials Across the Mid-Atlantic Region



Source: Federal Energy Regulatory Commission (FERC) (2009b). "OE Energy Market Snapshot: Northeast States Version—April 2009 Data." Office of Enforcement, at http://www.ferc.gov/market-oversight/mkt-snp-sht/2009/06-2009-snapshot-ne.pdf, p. 11.

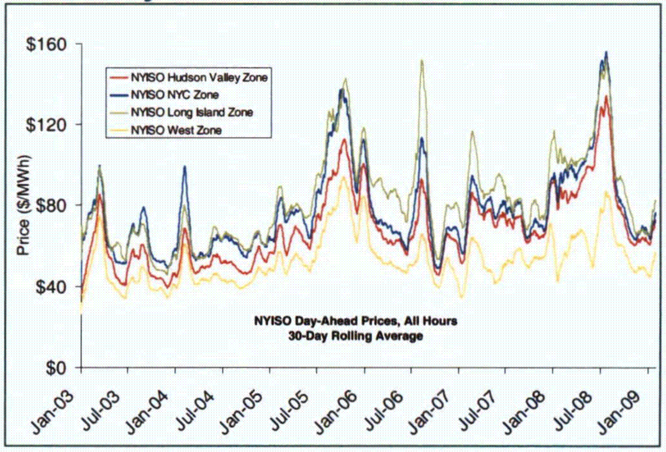
4.5. New England Congestion Area of Concern

The Department's 2006 study identified New England as a Congestion Area of Concern, reflecting the transmission constraints and significant congestion in the Southwest Connecticut and Boston area load pockets and the surplus of generation trapped behind transmission constraints in Maine. Conditions in New England have changed markedly over the past three years, as reviewed below.

4.5.1. Changes in Load and Demand-Side Resources

Peak load in New England equaled 26,545 MW in 2005, and 27,765 MW in 2008;[125] the peak hit 28,130 MW in 2006 under extremely hot weather conditions. The current load forecast anticipates peak demand of 28,480 MW in 2009, given normal weather.[126] ISO-NE reports that although load was growing at an annual compound rate of 1.2%, the combined effects of the economic slowdown and energy efficiency have slowed the rate of load growth.[127] Some areas have been growing disproportionately faster than others; for instance the

Figure 4-14. Significant Price Divergence Between Zones in NYISO—Daily Average of NYISO Day-Ahead Prices, All Hours



Source: Federal Energy Regulatory Commission (FERC) (2009b). "OE Energy Market Snapshot: Northeast States Version—April 2009 Data," Office of Enforcement, at http://www.ferc.gov/market-oversight/mkt-snp-sht/2009/06-2009-snapshot-ne.pdf, slide 10.

[125] ISO New England (ISO-NE) (2008d). *2008 Regional System Plan*, at http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf, Table 3-3, p. 25.

[126] *Ibid*., p. 23.

[127] *Ibid*., p. 25.

Boston metro area, Cape Cod and northwestern Vermont have experienced higher load growth.[128]

Most of the New England states have energy efficiency resource goals:

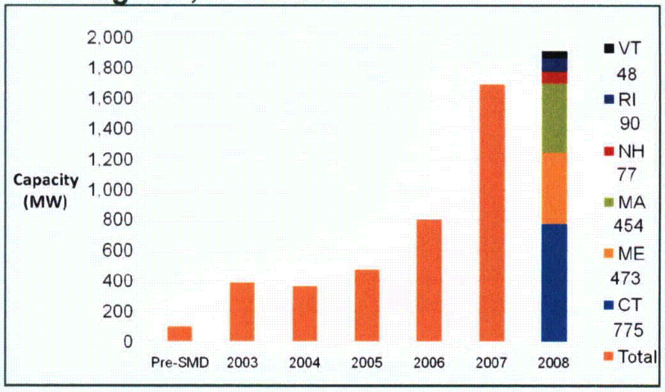
- Connecticut has set goals of 1.5% annual savings from 2009 through 2019, using all cost-effective energy efficiency;
- Maine seeks a 10% energy efficiency load reduction by 2017, using demand response and energy efficiency as priority resources;
- Massachusetts seeks a 25% cut in electric capacity needs and energy use by 2020 using energy efficiency, demand response, load management and distributed generation;
- Rhode Island calls for a 10% reduction of 2006 electric sales by 2022; and
- Vermont set goals for 2009-2011 of 2% annual efficiency savings, with programs administered by the statewide Efficiency Vermont program.[129]

New England states rank among the nation's leaders in energy efficiency policy and program accomplishments. The ACEEE ranks Connecticut 3rd, Vermont 4th, Massachusetts 7th, Rhode Island 11th, and New Hampshire 18th among all states in its "2008 State Energy Efficiency Scorecard."[130]

New England has achieved impressive growth in demand response resources, particularly since adoption of its Forward Capacity Market (FCM) auction process to procure new location-specific resources. In New England's first FCM, over 2,500 MW of demand response resources cleared the auction;[131] those resources are due on line in 2010-2011. In the second FCM, in 2008, over 2,900 MW of demand response cleared the auction, spread broadly across the region, as shown in Figure 4-15; those resources are due on line in 2012. As of April, 2009, New England reports a total of 3,276 assets ready to contribute 2,032 MW of demand response, with another 56 MW in the registration process; 40% of these demand response resources are concentrated in Connecticut, with another large percentage in Massachusetts load centers.[132] New England's demand response programs include critical peak pricing, emergency generation, and seasonal peak demand response.[133]

With the adoption of the FCM, New England has begun valuing energy efficiency and demand response as location-based, long-term reliability resources equivalent to supply-side resources. Under the FCM, "ISO New England projects the needs of the power system three years in advance and then holds an annual auction to purchase the power system resources that will satisfy the future regional requirements."[134] In its system planning, the region

Figure 4-15. Growth of Demand Resources in New England, 2003-2008



Source: Chadalavada, V. (2009b). "Roadmap to Renewable and Demand Resource Integration in New England." Presented at the New England Conference of Public Utilities Commissioners Symposium, Newport, Rhode Island, at http://www.iso-ne.com/pubs/pubcomm/pres_spchs/index.html, slide 4.

[128]NEEA (2007). "Electricity Transmission Infrastructure Development in New England: Value through Reliability, Economic and Environmental Benefits," at http://www.newenglandenergyalliance.org/downloads/New%20England%20Transmission%20Paper.pdf, pp. 20-22.

[129]FERC (2008b). "Electric Efficiency Resource Standards (EERS) and Goals." Office of Market Oversight, at http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-eeps.pdf.

[130]*Ibid*., p. iv.

[131]ISO-NE (2008a). *2007 Annual Markets Report*, at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2007/amr07_final_20080606.pdf, p. 77.

[132]Chadalavada, V. (2009a). "NEPOOL Participants Committee Meeting, COO Report." Presentation at NEPOOL Participants Committee Meeting, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2009/may12009/coo_npc_report_may_1_2009.pdf, slide 30.

[133]ISO-NE (2008d). *2008 Regional System Plan*, p. 49.

[134]ISO-NE (2009c). *ISO New England Outlook*, at http://www.iso-ne.com/nwsiss/nwltrs/outlook/2009/outlook_jan_2009.pdf, p. 3.

therefore reports energy efficiency, demand response, distributed generation and load management procured through the FCM as resources rather than as load offsets.

4.5.2. Changes in Generation and Transmission

New Generation

New England anticipates that it will have 33,700 MW of resources available to meet demand of 27,875 MW in the summer of 2009, with local generation accounting for 31,225 MW, energy efficiency providing 500 MW, and demand response accounting for 1,900 MW.[135]

A total of 42,777 MW of resources qualified to participate in New England's second FCM auction; of that amount, 33,988 MW of supply-side resources were selected, of which 1,157 MW are new generation.[136]

New England has 101 new generation projects in its interconnection queue, representing approximately 13,700 MW. These projects are spread broadly across the region, reflecting the locational signals established by the area's FCM location-specific pricing—a majority of the proposed projects are located in Connecticut and Massachusetts, the zones that offer the highest future capacity payments.[137] It is also worth noting that 31% of the generation in the queue is peaking capacity, which offers high value for maintaining grid reliability and balancing variable renewable generation.[138] These resources are committed to be in service by 2012.

New England is transmission-constrained for the Maine generation pocket. It requires local reliability support for the Boston, North Shore, southeast Massachusetts, Springfield, and western Massachusetts areas and for much of Connecticut.[139]

Despite these bright prospects for generation development several years out, New England faces some near-term challenges. The ISO's projections report that under reference or extreme load conditions, the region will have less operable capacity available than it will need to meet expected summer peaks in 2009 and 2010. If this situation materializes, operating plans to address it include calling on all interruptible and demand response resources reducing operating reserves, implementing voltage reductions, and even calling for voluntary customer load reductions in real-time,[140] to gain as much as 1,730 MW of load relief if extreme heat and loads occur. The region's 2008 Regional System Plan projects that this operable capacity deficit could continue through 2017.[141] Note, however, that this is a projected deficit in resource availability that is distinct from issues related to transmission congestion.

All six New England states have a renewable portfolio standard or renewable goal. These will change electricity flow patterns as a function of where the new renewables are built (or imported from). It is likely that much of the new renewable capacity will require new or upgraded transmission facilities, as well as new or increased fast-start generation in load centers.

New Transmission

The New England utilities have brought a significant amount of new transmission projects into service since 2005, as listed in Table 4-4. Most of these projects were planned and built to improve reliability, and have helped to remedy several of New England's most problematic reliability and economic congestion problems. These and other projects now under construction are shown in Figure 4-16. Several of New England's prior congestion and reliability problems have been alleviated with these new lines—for instance, the new projects have added

[135] ISO-NE (2009b). "ISO New England Forecasts Adequate Resources to Meet Summer Electricity Demand; Economic Conditions Are Expected to Keep Peak Demand Flat." ISO-NE Press release, at http://www.reuters.com/article/pressRelease/idUS166672+29-Apr-2009+BW20090429.

[136] ISO-NE (2009c). *ISO New England Outlook*, p. 3.

[137] Chadalavada, V. (2009a). "NEPOOL Participants Committee Meeting, COO Report," slide 34.

[138] *Ibid.*, slide 36.

[139] ISO-NE (2008d). *2008 Regional System Plan*, p. 143.

[140] Chadalavada, V. (2009a). "NEPOOL Participants Committee Meeting, COO Report," slides 83-87.

[141] ISO-NE (2008d). *2008 Regional System Plan*, Table 4-3, p. 36.

1,000 MW of additional import capacity into the Boston metro area, improved imports into critical load pockets like Southwest Connecticut (including the Connecticut-Long Island undersea cable) and strengthened the system in areas that have experienced major load growth, such as Northwest Vermont. A new 345 kV line from New Brunswick into Maine improves import capabilities from Canada.

ISO-NE reports that its transmission planning process has "identified the need for more than $6 billion of additional transmission investment over the next decade to ensure the region meets reliability standards."[142] That planning process has extensive stakeholder participation, including market participants and government representatives, including those from neighboring Canadian provinces. ISO-NE planners also coordinate with the NYISO and PJM planning activities, and expect to participate in upcoming interconnection-wide inter-regional planning efforts.

4.5.3. Other Evidence of Congestion

One way to assess congestion is to look at how price levels vary across the study area. Examination of real-time and day-ahead LMPs across New England for the past year shows that prices vary relatively little across the 9 zones. This is illustrated in Figure 4-17, which shows 13 months of monthly average real-time LMPs across all hours. A similar pattern holds for on-peak hours and in the day-ahead and real-time markets. ISO-NE's analyses of LMPs also show relatively small variations between LMPs across zones.[143]

Several factors suggest that the work New England has been doing to build new transmission and add new generation and demand-side resources is having a substantial impact in reducing total transmission congestion. First, the most persistent nodal LMP variations in New England trend from north to south, as shown in Figure 4-18. ISO-NE reports that

Table 4-4. New Transmission Projects Brought In-Service in New England, 2005-2009

Subregion	Transmission Project Name	In-Service Date
Boston	NSTAR 345 kV Transmission Reliability Project (Stage 1)	Nov-06
Boston	NSTAR 345 kV Transmission Reliability Project (Stage 2)	Dec-08
Southwest Connecticut	Southwest Connecticut (Bethel - Norwalk) Project	Dec-06
Southwest Connecticut	Southwest Connecticut (Middletown - Norwalk) Project	Dec-08
Southwest Connecticut	Norwalk - Glenbrook Cable Project	Nov-08
Southwest Connecticut	Norwalk - Northport 1385 upgrade	July 08
Vermont	Northern Loop Project	Dec-05
Vermont	Portions of Northwest Vermont Reliability Project	Apr-09
New Hampshire	Tioga Project	Jun-05
New Hampshire	Scobie Pond to Hudson Reinforcement Project	May-08
Northeast Massachusetts	North Shore Project	Jul-06
Central Massachusetts	Central Massachusetts Reinforcements	Dec-06
Connecticut	Killingly Project	Dec-06
Connecticut	Haddam / Middletown Reliability Project	Nov-05
Rhode Island	Southwest Rhode Island Project	Dec-08
Maine	Northeast Reliability Interconnect Project	Dec-07
Maine	Maguire Road Project	Aug-08

Source: Information modified from material provided by Michael Henderson, ISO-New England system planning.

[142] Rourke, S. (ISO-NE) (2008). "Remarks of Stephen J. Rourke, Vice President, System Planning, ISO New England." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Hartford, Connecticut. See Materials Submitted at the Meeting at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 3.

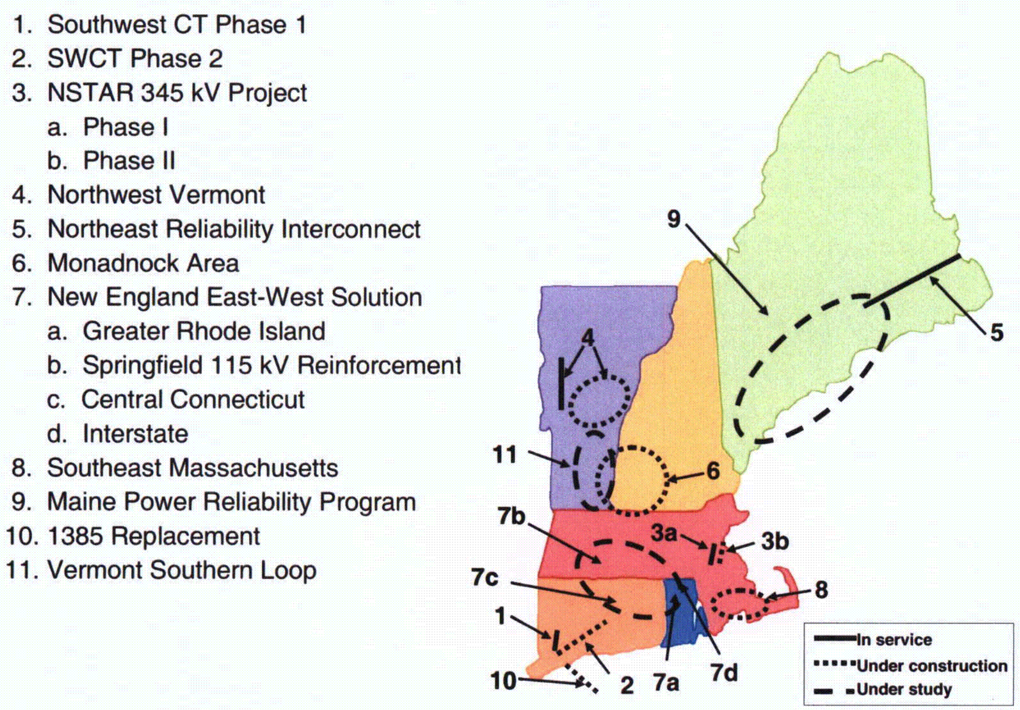
[143] See, for example, ISO-NE (2009a). *2008 Fourth Quarter Markets Report*, at http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/2008/2008_q4_quarterly.pdf, p. 24.

the lower prices in Maine (blue on the map, at $54/mWh) reflect transmission losses on imports coming into New England, while the higher prices in western Connecticut reflect transmission losses on exports to New York.[144] However, the variation between the highest and lowest locational prices is not extreme—a high of $64 and a low of $54, indicating that while some transmission congestion exists, it is not creating disproportionately price large differentials across the region. Second, the hourly average LMP differences between New England zones are small.[145] Third, not only are the variations in total price relatively small across the New England zones, as shown in Figure 4-19, the magnitude of those differentials has declined consistently across all of the zones over the past four years.[146] ISO-NE and others conclude that much of the price differentials remaining are due to line losses from generation distant from loads, that there appears to be little congestion on the New England system as a whole, and that what congestion remains is centered in the Connecticut sub-areas, rather than affecting many areas across the region.[147]

4.5.4. Conclusion for New England

Over the past three years, transmission congestion within New England has fallen significantly. This is due to years of sustained effort and achievement on several fronts—new utility-scale and distributed, small-scale supply resources have come on line, primarily in the locations where they are most needed

Figure 4-16. Map of New and Recent Transmission Projects in New England



Note: This map was developed in 2008. Many of the projects shown as under construction are now in service, and some of those shown as under study have now been approved.

Source: ISO New England (ISO-NE) (2008d). *2008 Regional System Plan*, at http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf, p. 147.

[144] ISO-NE (2009a), *2008 Fourth Quarter Markets Report*, p. 20.

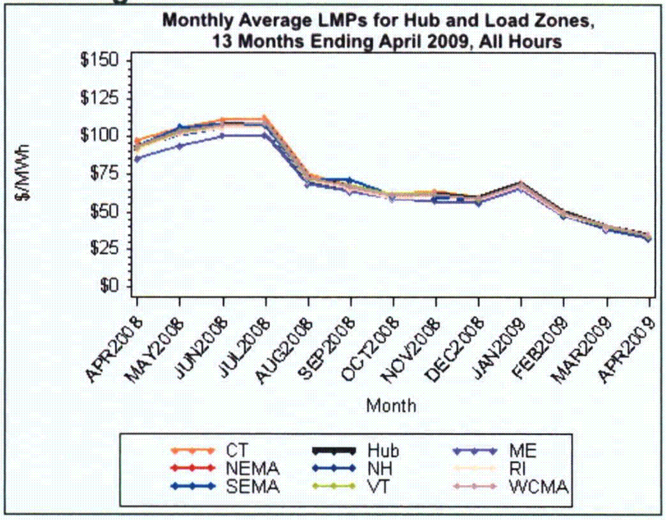
[145] *Ibid.*, p. 22.

[146] Ehrlich, D. (2009). "RSP09, 2008 Historical Market Data: Locational Margin Prices – Interfaces, MW Flows." Draft, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/a_lmp_interface.pdf, slides 4-9.

[147] *Ibid.*, slide 63.

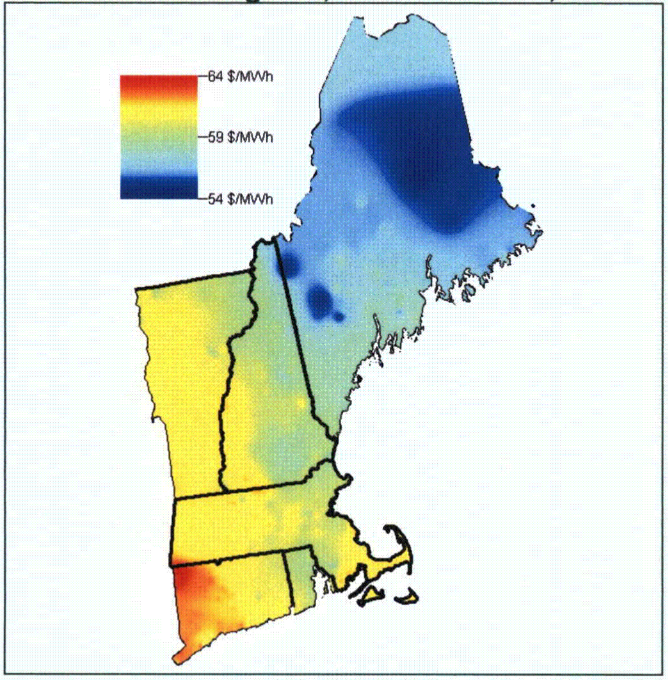
and valuable; aggressive demand response programs have made load reduction into a geographically targeted resource that can be used to reduce peak loads and mitigate the effects of temporal transmission constraints; and energy efficiency is

Figure 4-17. Average Real-time Prices in New England



Source: ISO-NE (2009d). "Monthly Market Operations Report, April 2009." Market Analysis and Settlements, at http://www.iso-ne.com/markets/mkt_anlys_rpts/mnly_mktops_rpts/2009/2009_04_monthly_market_report.pdf, p. 8.

Figure 4-18. Average Nodal Locational Market Prices in New England, Fourth Quarter, 2008



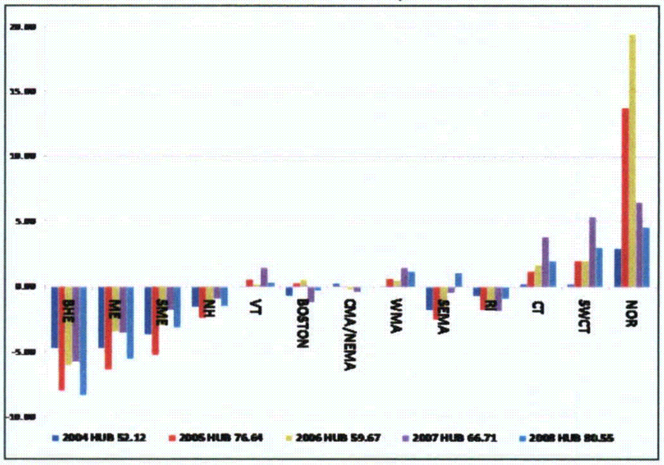
Source: ISO-NE (2009d). "Monthly Market Operations Report, April 2009," Figure 17, p. 20.

[148] ISO-NE (2008d). *2008 Regional System Plan*, pp. 35-36.

reducing total loads. Further, the area has a strong queue of new generation projects, as well as a diverse set of new reliability- and economics-oriented transmission projects completed or sitting in its interconnection and transmission system study queues. This combination of developments has, over several years, eased the significant reliability and economic differentials affecting the Boston metropolitan area and Southwest Connecticut that factored in the Department's identification of New England as a Congestion Area of Concern in 2006. These results reflect the steady efforts of the utilities, ISO, independent generators, regulators, legislators, energy service companies, and customers who have worked together to develop and implement a comprehensive and consistent set of policy, pricing and planning tools.

Nevertheless, New England's most recent system plan indicates that the region could experience a negative operating reserve margin of as much as 750 MW as early as 2009 under an extreme (high load, 10% probability) load forecast or 2010 under a base (50%-50% probability) load forecast.[148] If this occurs, the region would need to use various load relief measures, including calling all demand response measures, calling for customer conservation, and possibly rotating load cuts.

Figure 4-19. Average Locational Marginal Prices Across New England Zones, Calculated as Differences from the Hub, for 2004-2008



Source: Ehrlich, D. (2009). "RSP09, 2008 Historical Market Data: Locational Margin Prices—Interfaces, MW Flows," Draft, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/a_lmp_interface.pdf, slide 8.

Does the threat of a reliability problem indicate transmission congestion? On the one hand, the potential inability to meet loads indicates that the lack of more transmission is limiting imports that might solve the problem; on the other hand, the reliability problem could also be solved by acquiring more generation or demand-side resources. It appears that New England is taking a broad, balanced approach to this reliability challenge by making a reasoned assessment of the risks and costs of new generation and transmission construction relative to load-shedding, and has concluded that concerns about the costs and feasibility of new generation and transmission over the short-term outweigh their benefits. Many of the individuals offering their views to the Department recommended this type of economic evaluation, in preference to an automatic assumption that congestion should be eliminated exclusively or primarily through construction of new transmission.

The Department finds that while some transmission congestion remains in New England, most of the significant transmission constraints have been eliminated by the region's multi-faceted approach. The region has shown that it can permit, site, finance, cost-allocate and build new generation and transmission, while encouraging new demand-side resources as well. New England faces some near-term reliability challenges, but is working aggressively to address them. For these reasons, the Department no longer identifies New England as a Congestion Area of Concern.

4.6. Congestion in the Midwest

4.6.1. Midwest ISO

The OATI analysis of congestion in 2007 found that the most congested high-voltage constraints affecting MISO were Black Oak-Bedington in Virginia (located in PJM, not MISO), Tekamah to Raun in Iowa, and Eau Claire-Arpin and Ellington-Hintz to N. Appleton 345 kV, both in Wisconsin. These interfaces were among the most congested measured in terms of either the number of hours congested, the frequency of high real-time shadow prices, or the sum of shadow prices. Much Midwest congestion was one-way, in that it consistently reflected the direction of flows and the existence of persistent transmission-limiting load or generation pockets.

MISO staff recommend caution in interpreting OATI's 2007 results, for reasons that include the potential for variation between AFC (forecast) and TLR (real-time) results, the fact that generation and transmission outages affect congestion, and that schedules (tags) better reflect actual transmission usage than planned usage.[149] Several of the most notable constraints affecting MISO in 2007 (including those outside MISO, such as Black Oak-Bedington, that affect it nonetheless) will be mitigated by now-completed or planned transmission upgrades (such as those at Eau Clair-Arpin and in central Indiana).

MISO's 2008 Transmission Expansion Plan found that congestion charges within the region are relatively low. Examination of the 29 most congested flowgates (in terms of number of binding hours) within the MISO footprint against MISO's expansion plans revealed that approved expansion projects to relieve reliability problems will resolve congestion at 20 of these flowgates.[150] These improvements will mitigate the Midwest's most persistent and well-known congestion area, spanning the Wisconsin Upper Michigan System (WUMS) and northern WUMS. Congestion in an area at the intersection of southeast Minnesota, northern Iowa and southwestern Wisconsin is also expected to be alleviated by planned and approved transmission expansion.

[149] Walsh, M. (2009). "Historic Congestion in the Eastern Interconnection, MISO Overview and Comments." Presented at the U.S. DOE Office of Electricity Delivery and Energy Reliability Spring 2009 Technical Workshop in Support of DOE 2009 Congestion Study, at http://www.congestion09.anl.gov/techws/index.cfm, slides 8-11.

[150] Midwest ISO (2009c). *MTEP 08: The Midwest ISO Transmission Expansion Plan*, at http://www.midwestiso.org/publish/Document/279a04_11db4d152b9_-7d8d0a48324a/2008-11_MTEP08_Report.pdf?action=download&_property=Attachment, p. 10. MISO observes that "The fact that most of the heaviest constrained flowgates are eventually being addressed by reliability based upgrades points to the linked nature of reliability and congestion or economic issues: it's often a matter of timing. For example, a transmission solution which is driven solely by perceived economic benefits in the short term may be required to address reliability concerns over time" (p. 11).

Several large transmission projects, comprising a group called the Capacity Expansion (CapX) 2020 Project, are being planned to enable development of wind resources in North Dakota, South Dakota, Minnesota and Iowa. The first phase of this project—consisting of three 345 kV lines—has been approved as a reliability project for cost allocation under MISO's 2008 Transmission Expansion Plan and granted Certificates of Need by the Minnesota Public Utilities Commission.[151] Other large projects have been proposed to serve renewables, including the Green Power Express, a merchant transmission proposal to move 12,000 MW of power from the Dakotas, Minnesota and Iowa to load centers including Chicago, southeastern Wisconsin and Minneapolis.[152] Further, the Midwest ISO is working with the other eastern system planning organizations to study alternative renewable energy development scenarios and associated transmission plans.

4.6.2. Southwest Power Pool

As noted previously in this chapter, SPP uses TLRs as a grid management tool. SPP's planning director commented that "the increases in TLRs in SPP represent a more effective use of the transmission system to provide lower-cost wholesale energy to buyers. It doesn't necessarily mean that we're in trouble or that the system is more congested. We're just pushing the system harder."[153]

In the Southwest Power Pool, congestion impacts do not occur over large areas (as in the Mid-Atlantic region); they are more localized—"what we have is the economic opportunities that are not being maximized or realized because we don't have the transmission to move generation [from] fossil, nuclear or renewable from our state into the region, much less to load centers" in other parts of the country.[154]

Within SPP, the areas of greatest economic congestion are known and SPP's system planners look at both reliability and economic congestion in devising appropriate solutions. In 2008, SPP experienced congestion particularly in northeastern Kansas and southeastern Nebraska on several constraining flowgates; in northwestern Louisiana, at the Southwest Shreveport transformer. SPP's market monitor reports that in 2008, 75% of SPP's congestion occurred on just 10 flowgates (out of more than 200 flowgates in SPP).[155]

SPP planners note that "as wind farms in the Panhandle of Texas, Oklahoma, and western Kansas continue to develop, the congestion in that region will increase"[156]; the area already had moderate congestion in 2008. These and other points of congestion are identified in monthly market monitoring reports and in SPP's annual Transmission Expansion Plan, where they are evaluated as either reliability or economic expansion projects. Many of SPP's most congested flowgates (whether identified in terms in terms of the number of five-minute periods when the flowgate operating limit is breached, or in terms of shadow price impact) are being addressed by scheduled transmission network upgrades, including a series of high-voltage lines intended to move wind generation out of western Kansas and Oklahoma.[157]

The Missouri Public Utility Commission observes that average monthly prices of electricity in SPP and MISO track closely, with a maximum difference of only \$3/MWh between the markets in 2007. This suggests that there is little congestion

[151] Midwest ISO (2009c). *MTEP 08: The Midwest ISO Transmission Expansion Plan*, and CapX (2009). "CapX2020 Granted Certificate of Need for 345-kilovolt Projects in Minnesota," at http://www.capx2020.com/Regulatory/State/Minnesota/pdf/PUC_Decision_on_345_CON_press_release_4-16-2009_final.pdf.

[152] ITC (2009). "ITC Holdings Corp. Unveils Green Power Express." ITC Press release, at http://investor.itc-holdings.com/releasedetail.cfm?ReleaseID=364150.

[153] Caspary, J. (SPP) (2008). "Comments of Jay Caspari." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Oklahoma City, Oklahoma. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 20.

[154] Sloan, T. (Kansas) (2008). "Comments of Representative Tom Sloan." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Oklahoma City, Oklahoma. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, pp. 9-10.

[155] Roach, C.R., S. Rein, and K. Gottshall (2009). *2008 State of the Market Report: Southwest Power Pool, Inc*, at http://www.spp.org/publications/SPP%202008%20State%20of%20the%20Market%20Report.pdf, p. 10.

[156] SPP (2009). *2008 SPP Transmission Expansion Plan*. Approved April 29, 2009, at http://www.spp.org/publications/2008_Approved_STEP_Report_Redacted.pdf, p. 35.

[157] *Ibid.*, pp. 5-6.

hampering flow between the two markets[158] (although it might also reflect similar generation mixes).

Much of SPP lies within the Midwestern portion of the large 2009 Conditional Constraint Area for renewable resources (see Chapter 3), where substantial new transmission development will be required to enable development of large potential wind energy resources. SPP is active in inter-regional planning efforts, where it works with other planning organizations to study potential high voltage and extra-high voltage overlay options to export wind to other U.S. markets. If renewable energy development were to become a high priority for the nation, a North Dakota Public Utility Commissioner recommended that the wind-rich, transmission-sparse region of the Dakotas and Minnesota should be declared a National Interest Electric Transmission Corridor to ensure expedited transmission siting and development.[159]

Although congestion within SPP can be problematic, at present it does not rise to a level that would merit formal Departmental action.

4.7. Congestion in the Southeast

4.7.1. SERC

The SERC region covers all or portions of 16 states in the southeast and south central portion of the U.S., from Arkansas east to Virginia, south to Georgia and west to Louisiana, and serving over 70 million people.

The SERC region has a large reserve margin of generation in excess of load—both historically and into the future—plus additional merchant generation capacity that is not counted in the reserve margin because those plants do not have firm transmission capacity contracts. Most of the states require their utilities to conduct integrated resource planning studies on a 2- or 3-year planning cycle, with the clear expectation that the utilities will continue to be proactive in forecasting loads and building ahead to avoid congestion and assure resource and facility redundancy in the face of natural disasters.[160] The SERC states and utilities coordinate and share their system expansion studies.[161]

The SERC region has a unique philosophy with respect to electric system planning and construction:

> The transmission system within SERC has been planned, designed and is operated such that the utilities' generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC Reliability Standards to meet project customer demands and provide contracted transmission services.[162]

This approach works well for the electric utilities within SERC (all of which are traditionally vertically integrated and regulated, with no central organized bulk electricity wholesale market). The region has a number of proposed major new nuclear

[158] Missouri Public Service Commission (2008). "Comments of the Missouri Public Service Commission." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Oklahoma City, Oklahoma. See Materials Submitted at the Meeting at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 9, citing analysis by Potomac Economics (SPP's Market Monitor).

[159] Wefald, S. (North Dakota Public Utilities Commission) (2008). "Comments of North Dakota Public Utilities Commissioner." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Oklahoma City, Oklahoma. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p.9, and "Comments from the Organization of MISO States to DOE regarding draft National Interest Electric Transmission Corridor designations," July 6, 2007.

[160] Sullivan, J. (Alabama Public Utility Commission) (2008). "Comments of Commissioner Jim Sullivan." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 18, and Wise, S. (Georgia Public Service Commission) (2008). "Comments of Commissioner Stan Wise." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 3.

[161] Bartlett, G. (Entergy Services) (2008). "Comments of George Bartlett." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 21.

[162] NERC (2009a). *2009 Summer Reliability Assessment*, at http://www.nerc.com/files/summer2009.pdf, p. 131.

and coal generators under utility ownership, and has already completed most of the planning necessary to ensure that sufficient transmission will be available when those plants come on-line.[163] Independent power producers that want to sign a long-term firm transmission contract are reportedly able to get service,[164] although those that want non-firm service may not be able find adequate ATC to accommodate their requests.

The concept of building to serve firm transmission requirements may make it difficult for the region to develop profitable variable-output renewable resources, since such plants generally use only non-firm transmission service. As of mid-2009, only two of the states in SERC (North Carolina and Virginia) have a renewable portfolio standard that will require significant renewable generation development. However, the Southeast does not appear to have strong on-shore wind development potential.

SERC reports that "there are no transmission constraints that could significantly impact reliability of the utilities in the SERC region"[165] in the summer of 2009, and that there are no limits to transfers between areas with the sole exception of the interface between the Delta subregion and SPP.[166] The utilities within SERC do not depend on purchases or imports into SERC to meet loads.[167] Because the southeastern utilities build aggressively in advance of load, there is little economic or reliability congestion within the region. The Department's 2006 study identified two historical constraints in the Southern Company's footprint, affecting flows from the north into Atlanta and from TVA into Southern; Southern reports that new transmission lines have been placed into service to address each constraint, and is repowering a coal plant in the Atlanta area as well.[168]

The TVA region sits at the center of the Eastern Interconnection, at the northwest edge of the SERC region. TVA says it is "less concerned with congestion . . . than with having enough transmission that we get economic dispatch of our designated native-network resources to our native loads."[169] The utility recognizes that congestion costs its customers money, but its managers build the system "to get the best dispatch of the resources for the load internally and then we're accommodating the market to the degree that we can or to the degree that the market is willing to invest."[170] TVA intends to use its regional planning process to clear up congestion that is an economic concern to the market. Over the near term, TVA sets its path ratings aggressively to avoid calling TLRs, and seeks to create enough real-time transmission capacity to allow post-contingency redispatch of resources.[171]

TVA plans to build several new nuclear generating facilities over the coming decade. All of these new units would be located at existing nuclear sites, so TVA anticipates being able to put the transmission in place needed to avoid any congestion that would limit the nuclear plants' ability to deliver to loads.[172]

4.7.2. Entergy

Through subsidiaries, Entergy serves customers in Louisiana, Texas, Arkansas and Mississippi. The Entergy region contains a number of significant transmission constraints that limit electricity flows, as evidenced by the high number of TLRs mentioned in Section 4.3.2 above. By design, these

[163] Wise, S. (Georgia Public Service Commission) (2008). "Comments of Commissioner Stan Wise," p 4, and Terreni, C. (Public Service Commission of South Carolina) (2008). "Comments of Charles Terreni." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 6.

[164] Sullivan, J. (Alabama Public Utility Commission) (2008). "Comments of Commissioner Jim Sullivan," p. 12.

[165] NERC (2009a). *2009 Summer Reliability Assessment*, p. 128.

[166] *Ibid.*

[167] *Ibid.*, p. 127.

[168] Carlsen, R. (Southern Company) (2008). "Comments of Ron Carlsen." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm p. 29.

[169] Till, D. (Tennesee Valley Authority) (2008). "Comments of David Till." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 17.

[170] *Ibid.*

[171] *Ibid.*, pp. 18-19.

[172] *Ibid.*, pp. 10-11.

TLRs interrupt non-firm transactions (primarily from independent power producers and merchant generators) and firm transmission (often from merchant generators).[173]

The number of TLRs in Louisiana has increased since 2006. Although the Department's 2006 study speculated that historic congestion levels in the state would go down because of lower load following Hurricane Katrina in 2005, in fact the opposite has occurred.[174] Where there are high levels of congestion and transmission bottlenecks, transmission-dependent utilities and merchant generators have been asked to fund costly transmission upgrades to secure firm (un-curtailed) transmission service—for instance, the Lafayette Utility System reports that to secure five-year firm transmission service for 25 MW, the utility would have to pay between $85 million and $284 million to grant the 25 MW request,[175] NRG Power Marketing was told that its request for 100 MW of yearly network service within the Louisiana Generating, LLC (LAGN) control area would cost between $70 million and $105 million, and Westar Energy Generation & Marketing's request for 15 MW of firm service from Entergy into Ameren for one year would require upgrades costing between $44 and $50 million.[176] Entergy's Transmission Coordinator recognizes that the system needs to be expanded but points out that Entergy does not yet have an effective cost allocation method to finance upgrades to resolve economic congestion rather than reliability needs.

Entergy responds that these are economic issues that its independent transmission coordinator must deal with, driven by:

> . . . about 15,000 MW of independent power producer facilities on the system with cheaper energy than some of the designated network resources, and the fact that entities are all trying to avail themselves of that energy, it creates flows on the system for which it wasn't originally designed. And we have no control over that . . . . TLRs are an indication in real time of what happens when the operators are trying to deal with these . . . problems . . . .[177]

One reason the number of TLRs has increased in the Entergy region is that in the past, Entergy would voluntarily redispatch its units to manage around a congestion problem, but now uses TLRs instead.[178]

Several load pockets exist on the Entergy system—in Acadiana, Amite South, and WOTAB (West of the Atchafalaya Basin), and the McAdams flowgate (the interface between Entergy and TVA) have traditionally been among Entergy's most congested facilities. Entergy Louisiana and Entergy Gulf States Louisiana recently completed three transmission projects in south Louisiana; two of the lines, the Amite II and III 230 kV expansion and upgrade projects, increase import capacity into the Amite South area by 350 MW.[179] This may reduce the number of TLRs in the Entergy region in years ahead. There is also limited transfer capability in the Ozarks between Entergy and SPP.[180] SPP, Entergy's independent transmission coordinator, is studying the need for transmission upgrades across the Entergy system, as illustrated in Figure 4-20.

Although the amount of congestion on the Entergy system appears high, it is hard to determine the cost

[173] Vosburg, J. (NRG Energy) (2008). "Comments of Jennifer Vosburg." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, pp. 30-31.

[174] Huval, T. (Lafayette Utility System) (2008). "Comments of Terry Huval" Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm pp. 26-27; and SPP (2008c). "Independent Coordinator of Transmission (ICT) for Entergy – Annual Performance Report, November 17, 2007 to November 17, 2008," submitted to FERC on February 11, 2009, p. 14.

[175] *Ibid.*, p. 27.

[176] *Ibid.*, p. 14.

[177] Bartlett, G. (Entergy Services) (2008). "Comments of George Bartlett." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, p. 34.

[178] Vosburg, J. (NRG Energy) (2008). "Comments of Jennifer Vosburg," p. 35.

[179] Entergy Louisiana, LLC (2009). "Entergy's Louisiana Utilities Announce Completion of Three Transmission Projects," Entergy Louisiana, LLC and Entergy Gulf States Louisiana, LLC Press release, at http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=1494.

[180] Southwest Power Pool, Inc. (SPP) (2007c). *ICT Strategic Transmission Expansion Plan (ISTEP) Report*, at http://oasis.e-terrasolutions.com/documents/EES/Strategic%20Plan%20Report%20Phase%201_Dec_07.pdf.

of that congestion because there are no clear economic or market-based congestion metrics in the region. The Department will continue to monitor developments in the area.

4.7.3. Florida

Sitting at the corner of the Eastern Interconnection, Florida has only limited interconnections through interfaces with Georgia. The state's electric utilities coordinate their planning through the FRCC and the Florida Public Utility Commission, which runs a ten-year planning process that addresses generation and transmission needs against load forecasts and aggressive energy efficiency programs.

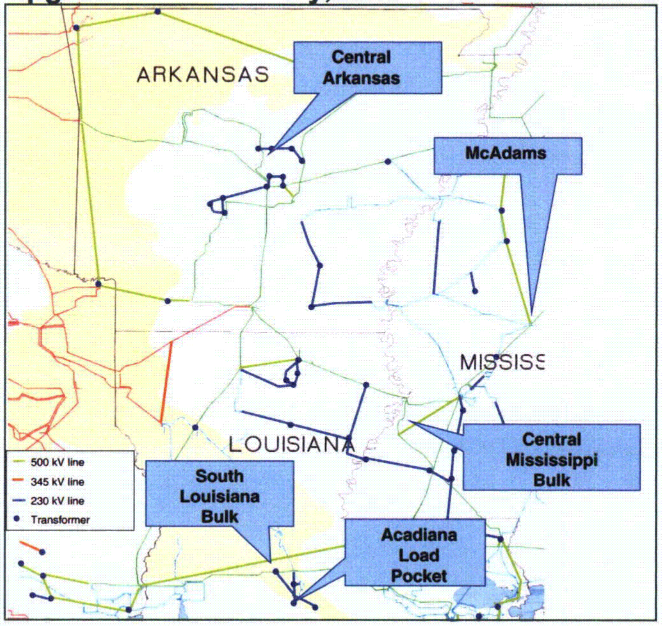
Most of Florida's power needs are met from in-state generation; summer generation capacity is predicted at 52,162 MW to serve internal demand of 45,531 MW (net of energy efficiency and demand response).[181] NERC reports that the FRCC has 2,377 MW of generation under firm contract for import into FRCC from the southeastern sub-region of NERC, with firm transmission service for deliverability.[182] Joint studies of the Florida-Southeastern interface show that there is a summer import capability of 3,600 MW flowing southbound and an export capability northbound of 1,000 MW.[183] The 2006 study's simulation analysis identified congestion that limited imports at the Georgia to Florida interface; as the discussion of 2007 transmission congestion indicates, there are little publicly available data to illuminate current conditions other than the fact that the available capacity is fully subscribed.

FRCC has identified transmission constraints in Central Florida that could require remedial actions in summer 2009 if west-to-east flow levels increase across the Central Florida metro load areas. Although transmission rebuild and expansion efforts are reported underway to alleviate this congestion, in the near term remedial operating strategies will be used as needed to mitigate thermal loadings and protect reliability.[184] FRCC explains that transmission constraints may be triggered in Northwest Florida under conditions of high imports into Florida from SERC; when necessary these too are mitigated by a special operating procedure.[185] FRCC does not identify other transmission constraints.

Florida does not participate in any organized power market, so there is no public pricing record to determine whether economic congestion occurs within the state or the magnitude of its impact.

Florida utilities are planning the possible construction of four new nuclear plants with a cumulative capacity of 4,400 MW. As in the SERC region, these plants are far enough out on the planning horizon that the utilities and the Florida Commission can plan and execute the needed transmission expansion and facilities upgrades to effectively integrate all of the new nuclear capacity as it becomes

Figure 4-20. Entergy Region Transmission Upgrades Under Study, 2009



Source: Southwest Power Pool, Inc. (SPP) (2008b). *ICT Strategic Transmission Expansion Plan (ISTEP) Phase II Report, Rev. 1*, at http://www.spp.org/publications/ISTEP_Phase_2_report.pdf, p. 4.

[181] NERC (2009a). *2009 Summer Reliability Assessment*, pp. 38-39.
[182] *Ibid.*, p. 40.
[183] *Ibid.*, p. 44.
[184] *Ibid.*, p. 41.
[185] *Ibid.*

available.[186] FRCC conducts regional studies to ensure "that all dedicated firm resources are deliverable to loads under forecast conditions."[187]

4.8. Nuclear Power Development and the Need for New Transmission

The desire for generation sources that do not emit greenhouse gases has given new vigor to advocates of nuclear power, with aggressive nuclear construction programs now underway in China, Russia, India and South Korea. The EPAct included significant incentives for new nuclear plant design, licensing, financing and construction. These have sparked a potential nuclear boom in the United States, beginning with the resumption of construction at the TVA's Watts Bar nuclear plant in 2007. By the end of 2008, 17 license applications had been submitted to the Nuclear Regulatory Commission for 26 new nuclear reactors, and more plants are reportedly under consideration.[188] However, recent news reports suggest that some of the proposed reactors may be delayed or cancelled because the sponsoring utilities do not have confidence that they can afford the high costs and risks involved in nuclear plant construction.[189]

Figure 4-21 shows the locations of proposed nuclear plants. As the map shows, most of these plants are proposed in the southeastern states, in an arc from eastern Texas through most of the Southeast up through Maryland. Although the Department identified a Conditional Congestion Area in the Southeast in the 2006 Congestion Study, it does not extend that identification here.

After further consideration, the Department believes that Conditional Constraint Area[190] identification should be applied only to areas that meet three conditions:

1) Important potential generation resources in the area are locationally restricted (i.e., the generation source cannot be moved to another location);
2) The potential resources are located relatively close together in such a way that a large new transmission project could serve thousands of MW of potential generation; and
3) The resources are unlikely to be developed on a large scale and in a coherent fashion unless new transmission is designed and built to serve a broad area.

Nuclear power development in the Southeast does not meet these conditions. Nuclear power is not locationally restricted; it is not limited by the vagaries of where nature put resources, but chiefly by the siting choices of the potential developers and communities. As Figure 4-21 shows, these proposed plant sites are widely dispersed, and their capacity would be added to the grid in increments of 1,000 to 2,000 MW per site; thus, building one or two new large transmission projects will not help bring many thousands of new nuclear capacity on-line. Last, the Department understands that the pending nuclear projects have been proposed by sponsors that plan to secure the needed transmission to interconnect the generator to the grid, so reactor development will not be contingent primarily upon transmission availability. For these reasons, the Department is not identifying any area as a Conditional Constraint Area specific to nuclear power development.

[186] Miller, C. and S. Garl (Florida Public Service Commission) (2008). "Comments of Cindy Miller and Steve Garl." Provided at the U.S. Department of Energy Workshop on 2009 Congestion Study. Atlanta, Georgia. See Workshop Transcript at http://www.congestion09.anl.gov/pubschedule/index.cfm, pp. 9-10.

[187] NERC (2009a). *2009 Summer Reliability Assessment*, pp. 42-43.

[188] Nuclear Energy Institute (2008). "Fact Sheet – New Nuclear Plants Create Opportunities for Expanding U.S. Manufacturing," at http://www.nei.org/keyissues/newnuclearplants/factsheets/.

[189] Williams, M. (AP) (2009). "Nuclear plants face major funding crisis." *Seattle Daily Journal of Commerce*, at http://www.nwbuildingpermits.com/news/co/12005472.html?cgi=yes.

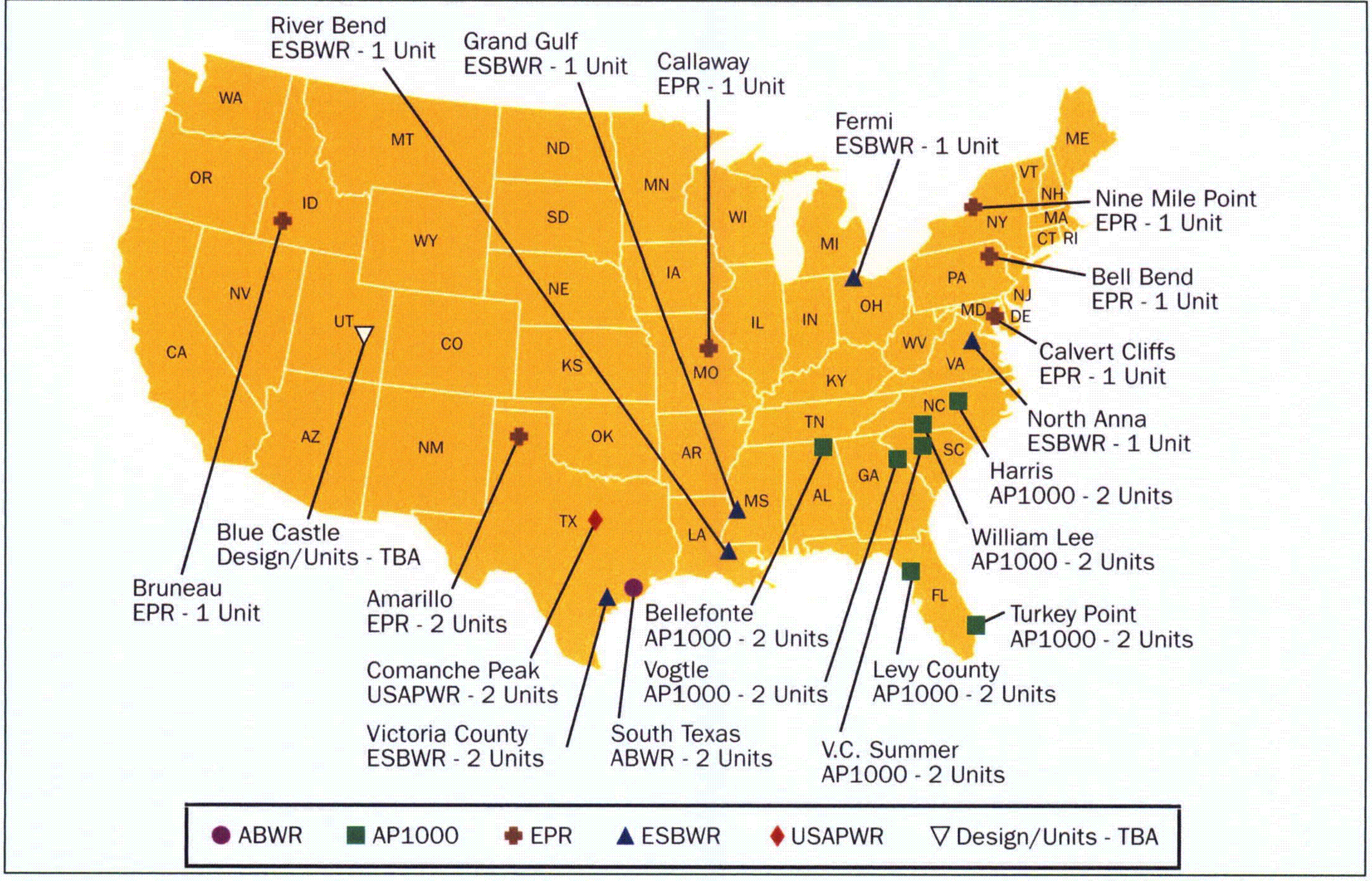
[190] In the present report, the Department has replaced the term "Conditional Congestion Area" with "Conditional Constraint Area." See Chapter 3 for a discussion of the reasons for the change.

4.9. Coal Development and the Need for New Transmission

The *2006 National Electric Transmission Congestion Study* identified two Conditional Congestion Areas in the Eastern Interconnection for potential coal development, one in Illinois and one in West Virginia and Pennsylvania. In the present study, the Department does not extend that identification for four reasons:

- Although there are significant coal reserves available in each area, it appears that a lack of transmission is not the principal impediment to new coal development in these areas. Rather, a review of PJM's transmission interconnection queue (and others) indicates that there are few coal plants in the queue; this suggests that the lack of new coal construction is driven by financial and political uncertainty surrounding future carbon regulation and strong legislative and regulatory preferences for renewable and low-carbon generation sources.
- Unlike the renewable resource areas identified in Chapter 3, these coal reserves are not under-served by existing transmission, nor are they new frontiers for the transmission grid. Although it is possible to develop a significant amount of additional coal-fired generation in each area, each area is already well-served by transmission infrastructure. Establishing transmission access for new coal generation capacity would not require extensive new transmission development (beyond that already in development or under study in the PJM transmission planning process).
- Like nuclear plants, coal-fired power plants are not locationally restricted. Although it has often been advantageous to develop coal-fired plants at the mine-mouth, there are many examples of coal shipments to plants developed at distant sites

Figure 4-21. Proposed New Nuclear Power Plants



Source: Nuclear Regulatory Commission (2008). "Location of Proposed New Nuclear Power Reactors," at http://www.nrc.gov/reactors/new-reactors/col/new-reactor-map.html.

with better transmission or other locational advantages (such as economic incentives).

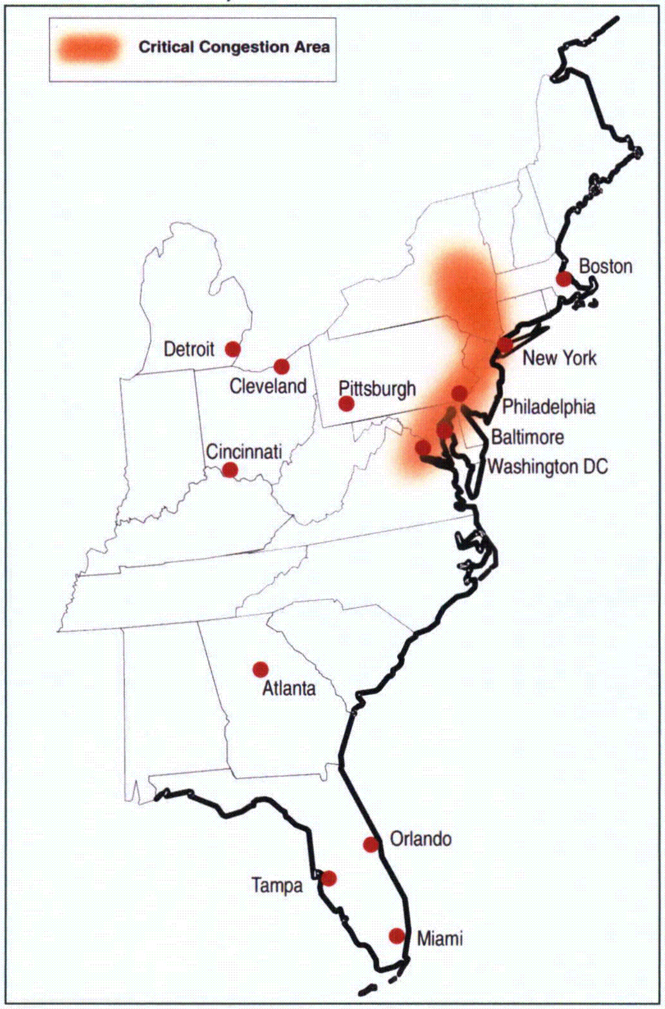
- Further, domestic coal development is not dependent upon power grid access alone—coal can be converted to a product similar to natural gas rather than to electricity,[191] and much coal is delivered directly to industrial consumers to serve fuel boilers without passing through an electric power plant.

For these reasons, the Department finds that the Illinois and Northern Appalachian coal fields should not be identified as Conditional Constraint Areas.

4.10. Congestion Areas in the Eastern Interconnection

The Department concludes that there is only one nationally significant congestion area in the Eastern Interconnection based on the evidence reviewed above. As shown in Figure 4-22, that is the Mid-Atlantic Critical Congestion Area, which continues to experience high and costly levels of congestion that affect a significant portion of the nation's population, reaching from south of Washington DC to north of New York City. While transmission constraints and congestion exist elsewhere in the interconnection, they occur over smaller geographic areas affecting fewer customers with lower costs. Although it may be challenging to build new transmission in many parts of the country, in parts of the Midwest and Southeast new transmission is being built to anticipate or mitigate transmission congestion before it imposes broad economic or reliability costs. As discussed above and in Chapter 3, the Department has not identified distinct, resource-specific Conditional Constraint Areas in the eastern United States.

Figure 4-22. Congestion Area in the Eastern Interconnection, 2009



[191] For example, see, Peabody Energy (2008). "ConocoPhillips and Peabody Energy Select Site in Muhlenberg County, KY, to Develop Coal-to-Gas Facility." Peabody Energy News release, at http://phx.corporate-ir.net/phoenix.zhtml?c=129849&p=irol-newsArticle&ID=1236657&highlight=#splash.