



**Transmission Constraints and Congestion
in the Western and Eastern Interconnections,
2009-2012**

**United States Department of Energy
Washington, DC 20585
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Note to Reader

This document provides a summary of publicly available information regarding transmission constraints and congestion from 2009-2012. This is not the Department's third National Electric Transmission Congestion Study, which will be released separately. Providing relevant transmission data available to the public in a timely manner will aid the development of worthwhile public and private analyses on a range of electricity topics. The Department intends to release a stand-alone transmission data document annually, rather than combining it with the triennial congestion studies.

Acronyms and Abbreviations

AEP	American Electric Power	INDN	City of Independence Power and Light Department
BA	Balancing authority	IOU	Investor-owned Utility
BC	British Columbia	ISO	Independent System Operator
BEPM	Basin Electric Power Cooperative	ISO-NE	Independent System Operator – New England
BPA	Bonneville Power Administration	JOA	Joint Operating Agreement
CAISO	California Independent System Operator	LADWP	Los Angeles Department of Water and Power
CEC	California Energy Commission	LCA	Load capacity area
CME	Constraint Management Event	LMP	Locational marginal price
COI	California-Oregon Intertie	LTRA	Long-Term Reliability Assessment
ComEd	Commonwealth Edison	M2M	Market-to-market
CPUC	California Public Utilities Commission	MATS	EPA’s Mercury and Air Toxics Standards
DIR	MISO’s dispatchable intermittent resources	MISO	Midcontinent Independent System Operator
DLCO	Duquesne Light Company	MRTU	Market Redesign and Technology Update
DOE	U.S. Department of Energy	MTEP	Midwest Transmission Expansion Plan
DSIRE	Database of State Incentives for Renewables & Efficiency	MVP	Multi-value projects
EIA	Energy Information Administration	MW	Megawatt (1 million or 10 ⁶ watts)
EISPC	Eastern Interconnection States Planning Council	MWh	Megawatt-hour (1 million or 10 ⁶ watt-hours)
EPA	Environmental Protection Agency	NARUC	National Association of Regulatory Utility Commissioners
ERCOT	Electric Reliability Council of Texas	NDEX	North Dakota Export Limit
FERC	Federal Energy Regulatory Commission	NERC	North American Electric Reliability Corporation
FRCC	Florida Reliability Coordinating Council	NP-15	North of Path 15
GW	Gigawatt (1 billion or 10 ⁹ watts)	NYCA	New York Control Area
GWh	Gigawatt-hour (1 billion or 10 ⁹ watt-hours)		
ICTE	SPP’s Independent Coordinator of Transmission		

NYISO	New York Independent System Operator	The Department	U.S. Department of Energy
OASIS	Open Access Same-time Information System	TLR	Transmission Loading Relief
OTC	Once-through cooling	TrAIL	Trans-Allegheny Interstate Line
PDCI	Pacific DC Intertie	TVA	Tennessee Valley Authority
PG&E	Pacific Gas & Electric	U75	The percentage of time utilization was in excess of 75% of rated capability
PJM	Pennsylvania New Jersey Maryland Regional Transmission Organization	U90	The percentage of time utilization was in excess of 90% of rated capability
REZ	Renewable Energy Zone	UFM	Unscheduled Flow Mitigation
RGOS	MISO's Renewable Generation Outlet Study	UMTDI	Upper Midwest Transmission Development Initiative
RPS	Renewable Portfolio Standard	VACAR	The Virginia-Carolinas NERC sub-region
RTO	Regional Transmission Operator	VACS	VACAR South
SCE	Southern California Edison	WECC	Western Electricity Coordinating Council
SDG&E	San Diego Gas & Electric	WGA	Western Governors' Association
SEMA	Southeast Massachusetts	WREZ	Western Renewable Energy Zone
SERC	Southeast Reliability Corporation	WUMS	Wisconsin and Upper Michigan System
SOCO	Southern Company		
SONGS	San Onofre Nuclear Generating Station		
SPP	Southwest Power Pool		
TEPPC	WECC's Transmission Expansion Planning and Policy Committee		



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1. Introduction and Overview

Congestion occurs on the electric transmission system when flows of electricity across a portion of the system are restricted or constrained below desired levels. The term “transmission constraint”¹ refers either to a piece of equipment or an operational limit imposed to protect reliability that restricts these flows, or to a lack of adequate transmission capacity to deliver expected new sources of generation without violating reliability rules. Congestion in the transmission system can have undesirable consequences: it can limit the flow of low-cost power to meet demand, hamper the achievement of public policy goals, or even create reliability concerns.

Transmission constraints and congestion vary over time and location as a function of many factors, including changes in the patterns of electricity consumption, changes in the relative prices of the fuels used to generate electricity, and changes in the operational availability of specific grid-related assets (such as power plants or transmission lines).

This report presents data and information that were publicly available as of August 2012, with limited updates in December 2012, describing aspects of where transmission constraints and congestion typically occur across the eastern and western portions of the United States’ electric power system.²

The report is structured as follows. Chapter 2 presents conceptual and background information on transmission congestion and constraints, and describes three types of data and information that measure aspects of congestion and are publicly available in at least some regions of the country.

Chapters 3 through 5 report and summarize the data and information. Chapter 3 reports data and information on congestion management procedures. Chapter 4 reports data and information on resource-driven transmission constraints. Chapter 5 reports data and information on transmission system utilization. The chapters are subdivided by geographic region (West, Midwest, Northeast, Southeast) or other categories as appropriate for the data reported (e.g., economic congestion costs are reported by each organized market, because that type of data is available only for their regions).

The Department hopes that over time it will be possible to broaden the scope of the documents in this series and to provide useful data to readers on many aspects of the nation’s transmission assets. This initial document, however, will give particular attention to data on transmission constraints and congestion.

¹“Transmission constraint,” “transmission capacity constraint,” or simply “constraint” are typically used interchangeably in electricity literature, and are so used in this report.

²The Department of Energy does not endorse and has not independently validated the data and information reported here. DOE is unable to include data or information that could identify constraints or congestion in certain parts of the country, due to the lack of public sources.

This document provides data and information only through 2012. DOE will publish a follow-on document in 2014 focusing on calendar year 2013. It may also include additional material about calendar year 2012 beyond that provided here.

2. Transmission Constraints and Congestion: Concepts, Measurement, and Sources of Publicly Available Data

This chapter describes the types of data and information presented in this report. It begins by reviewing fundamental transmission constraint and congestion concepts. Next it describes the measures or indicators the Department has used to identify, characterize, and gauge the impacts of current transmission constraints and congestion. The Department has defined certain key terms based on typical industry practices. Instances where these terms have been used differently in particular industry sources relied on by the study are flagged when appropriate.

2.1. Transmission constraint and congestion concepts

The term “transmission constraint” may refer to:

- 1) An element of the transmission system (either an individual piece of equipment, such as a transformer, or a group of closely related pieces, such as the conductors that link one substation to another) that limits power flows;
- 2) An operational limit imposed on an element (or group of elements) to protect reliability; or
- 3) The lack of adequate transmission system capacity to deliver electricity from potential sources of generation (either from new sources or re-routed flows from existing sources when other plants are retired) without violating reliability rules.

Transmission constraints are set at a specific level or limit in order to comply with reliability rules and standards established to ensure that the grid is operated in a safe and secure manner. Reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC) specify how equipment or facility ratings should be calculated to avoid exceeding thermal, voltage, and stability limits following credible contingencies. Transmission operating limits, which constrain throughput on affected transmission elements, are created to comply with these rules and practices. Thus, although it is commonly thought that transmission constraints indicate reliability problems, in fact, constraints result from compliance with reliability rules. However, when constraints frequently limit desired flows, they may indicate reliability problems that warrant mitigation.

Transmission constraints can be relieved by increasing the electrical rating of an element, increasing the operating limit, or adding new equipment that increases transmission capacity to deliver additional electricity. However, relieving transmission constraints to increase transmission flows requires consideration of how the transmission network operates as a system. For example, while increasing the electrical rating of a particular element may relieve a particular constraint, doing so may only shift the location of the constraint to the next most

limiting element, and the net increase in transmission flow along the entire route may be only marginal.

Transmission constraints also can be relieved by changing generation dispatch, changing the operation of the transmission system, or by adding generation or reducing load on the “downstream” side of the constraint.

The term “congestion” refers to situations when transmission constraints limit transmission flows or throughput³ below levels desired by market participants or government policy (e.g., to comply with reliability rules). A high level of transmission system utilization alone does not necessarily mean congestion is occurring. Congestion can only arise when there is a desire to increase throughput across a transmission path, but such higher utilization is thwarted by one or more constraints. Transmission congestion has costs—they include higher costs incurred by consumers on the downstream side of the transmission constraint, difficulties achieving public policy goals such as increased renewable generation, and occasionally reliability problems where constraints limit access to reserves required for secure operations within a constrained area.

2.2. Measuring transmission constraints and congestion

This report provides data and information in three general categories: congestion management procedures, resource-driven transmission constraints and transmission system utilization. These categories are described below. These data are not available uniformly across the nation. Sources for each type of data in different regions in the country vary. See Table 2-1.

2.2.1. Congestion management procedures

Transmission owners and operators manage congestion with administrative procedures and with market-based or economic incentives. Data and information on the instances in which transmission operators have used these measures provides information about the presence of congestion or constraints. No single approach is used consistently across the nation.

³Throughout this study, the terms “transmission flows” and “transmission throughput” are used interchangeably to refer to the transport of electricity over transmission lines.

Table 2-1. Transmission Constraints and Congestion: Applicability and Availability of Major Sources of Data

	Congestion Management					Resource-Driven Transmission Constraints			Transmission System Utilization
	Administrative Procedures	Operationally Limiting Constraints	Economic Congestion Cost	Locational Marginal Prices	Wholesale Electricity Price Differentials	Local Reliability	Interconnection Queue	Renewable or Clean Energy Zone	%Utilization
West									
Non-RTO	WECC/TEPPC	Not applicable	Not applicable	Not applicable	FERC	NERC	WECC	WGA	WECC/TEPPC
CAISO	WECC/TEPPC	CAISO	CAISO	CAISO	FERC	NERC	WECC	WGA	WECC/TEPPC
Midwest									
MISO	NERC	MISO	MISO	MISO	FERC	NERC	MISO	Not available; in progress	Not available
SPP	NERC	SPP	SPP	SPP	FERC	NERC	SPP	Not available; in progress	Not available
PJM	NERC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
Non-RTO	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Not available from all utilities	Not available; in progress	Not available
Northeast									
ISO-NE	NERC	ISO-NE	ISO-NE	ISO-NE	FERC	NERC	ISO-NE	Not available; in progress	Not available
NYISO	NERC	NYISO	NYISO	NYISO	FERC	NERC	NYISO	Not available; in progress	Not available
PJM	NERC	PJM	PJM	PJM	FERC	NERC	PJM	Not available; in progress	Not available
Southeast									
SERC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Not available from all utilities	Not available; in progress	Not available
FRCC	NERC	Not applicable	Not applicable	Not applicable	FERC	NERC	Not available from all utilities	Not available; in progress	Not available

Note: Cells highlighted in green denote a parameter and source for which information has been gathered for this study

2.2.1.1. Administrative congestion management procedures

Both the Western and the Eastern Interconnections employ administrative congestion management procedures. In the Western Interconnection, the procedures are called Unscheduled Flow Mitigation (UFM). In the Eastern Interconnection, the procedures are called Transmission Load Relief (TLR). Both are NERC-approved operating procedures to limit flows if desired transmission flows exceed safe operating levels across particular grid elements. Publicly available data on their application in the Western Interconnection are less available than they are in the Eastern Interconnection.

UFM actions refer to a graduated series of initially pre-specified operational actions that modify transmission flows (via changes to the settings of equipment that controls the phase angle between points on the transmission system) and culminate in curtailment procedures. The Western Electricity Coordinating Council (WECC) collects but does not routinely release information on the deployment of these actions and procedures. However, the BPA website provides some public information on UFM actions and this information is routinely cited in WECC studies of historic transmission utilization.

This report presents publicly available information on UFM deployment in the Western Interconnection. The available information, however, offers no information on the economic impacts of UFM actions on market participants.

TLR actions refer to a graduated series of procedures that are used to ration requests for transmission service when available transmission is limited.⁴ TLRs are used less in regions of the Eastern Interconnection with centrally-organized wholesale electricity markets (which provide grid operators with another means for managing congestion). All TLR actions above a threshold level are recorded and reported to NERC.

This report presents trends in TLR actions over time where they are used. Public information from NERC on TLR deployment indicates the frequency, magnitude, and duration of curtailed or otherwise modified transactions. As with the UFM data, however, the information available on TLR deployment provides no information on the economic impacts of deployments on the affected market participants.

2.2.1.2. Market-based management of congestion

In the regions of the country served by the centrally-organized wholesale electricity markets operated by Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs), the interactions of wholesale buyers and sellers create localized, independently varying and transparent electricity prices. The resulting locational marginal price (LMP)⁵ differentials

⁴As noted earlier, TLRs are an example of a procedure whose purpose is to ensure that the transmission system can be operated safely. TLRs by themselves do not indicate that a transmission system is unreliable.

⁵A locational marginal price is the price of increasing or decreasing generation (or load) at a given location by one unit (typically, a megawatt-hour).

create incentives for market participants to manage or ration their utilization of the transmission system consistent with reliability limits. Thus within these market areas, the price mechanism itself helps to manage congestion and reveal transmission constraints.

Transmission systems have physical and administrative dividing lines or boundaries between and among the sub-regions or pricing zones within an RTO or ISO's footprint. When additional flows across a transmission line linking two zones are limited to protect reliability, the line is "constrained"; a constrained line that causes prices on either side to differ is called a "binding constraint." The price differentials created by constraints are an economic measure of transmission congestion.

This report observes that some operationally limiting constraints and the resulting impacts on LMPs and economic congestion cost occur at or near the seams between neighboring RTOs and ISOs, and that efforts are in progress to address those impacts that result from administrative and institutional differences in market rules and practices. Until efforts to resolve these differences are complete, it is not possible to determine the extent to which constraints and congestion have been created or exacerbated by these differences versus physical infrastructure limitations of the two transmission systems. Similarly, in the areas outside RTO- and ISO-managed wholesale electric markets, there is little data to determine the existence of constraints and congestion at the seams between sub-regions.

This report includes data and information related to the economic aspects of congestion, such as operationally limiting constraints, locational marginal prices, and economic congestion costs. Although every RTO and ISO calculates and reports on constraints, LMPs, and economic congestion costs, the markets differ with respect to the definitions, practices and conventions they use. As a result, constraints, LMPs, and the resulting annual congestion costs are generally not directly comparable between RTOs and ISOs. They may not even be comparable within a single area over time because RTOs and ISOs sometimes modify their footprints (as member companies move in or out of the market) or modify their market rules (e.g., a change in market design from one based on zonal to one based on nodal pricing). As a result, congestion metrics for a single market may not be comparable from year to year.

Locational Marginal Prices—Organized wholesale electricity markets typically report LMPs and differences among them that result when these constraints are binding, and the annual congestion costs that these constraints cause. In addition, commercial firms collect LMP data from RTO and ISO public websites; this report uses the Ventyx Velocity Suite LMP database, along with the gradient mapping tool, to display LMPs across broad areas and over time.

Operationally limiting constraints—The RTOs and ISOs and their market monitors track and report on congestion within their markets and identify the constraining elements within their transmission systems. Some RTOs and ISOs track how often a constraint is binding and the economic consequences of that constraint. This report presents RTO and ISO-provided information about the most significant constraints (e.g., the "top five constraints" by cost,

duration, or frequency), maps of constraint locations, trends in identified constraints over time, and commentary about specific constraints.

The methods and criteria used to identify and prioritize significant constraints vary and are not fully comparable between RTOs and ISOs and the planning entities operating in non-market areas.

Economic congestion costs—RTOs and ISOs or their market monitors use various methods to estimate congestion costs. This study presents RTOs’ or market monitors’ estimates of the congestion costs associated with particular constraints and annual congestion costs for an entire RTO or ISO. For perspective, these costs are considered in absolute magnitude and in the context of time, location and overall wholesale electricity market costs.⁶ In markets that rely on forward capacity prices, zonal differences in capacity prices also reflect the impact of transmission constraints and the economic cost of transmission congestion.

In presenting information about operationally limiting constraints, locational marginal prices, and economic congestion costs, some emphasis is placed on inter-market or seams-related congestion concerns. Examples include the following:

- Differences between scheduling and pricing methods inside neighboring markets and reliability coordinators can create price discontinuities and block transactions for electric energy.
- Uncontrolled or inadvertent loop flows across RTO boundaries when scheduled transactions (based often on contract path assumptions) do not match actual flows.
- Existing transmission reservation processes may not allow full use of firm transmission for energy and capacity sales.
- Many long-term firm transmission reservations are held by market participants who do not use them for capacity sales, with the result that regional transmission capacity is under-utilized.
- Current processes do not allow netting out energy and capacity commitments in opposite directions across seams.
- Interspersed control areas and regional footprints exacerbate seams problems.⁷

2.2.1.3. Indicators of congestion from bilateral market transactions

In areas that do not have organized wholesale electricity markets, and in trade across the boundaries between these areas and organized markets, wholesale electricity is either self-generated or bought from other producers through bilateral agreements. To support the latter

⁶This study does not present information on the net effect of various hedging mechanisms employed by RTO and ISOs; these hedges effectively recoup congestion costs to producers and consumers.

⁷Based on Newell, S.A., K. Spees (2011b). *Preliminary Issue Description: MISO-PJM Capacity Market Seam*. Cambridge, MA: The Brattle Group. December 2011, at

https://www.midwestiso.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Preliminary%20Brattle%20Report_MISO-PJM%20Capacity%20Seam%20Definition%20-%202011-12-06.pdf.

transactions, “pricing hubs” have been established as standard delivery points for wholesale trade within the transmission system. Wholesale electricity prices at these hubs are used as indices that establish the value of transactions conducted at or near these hubs.

Wholesale electricity price differentials—Electricity prices at adjacent hubs will differ if there are transmission constraints between the two hubs because the constraints prevent additional sales between the two hubs that would equalize prices. Comparison of electricity hub prices over time can reveal whether price differentials are occasional or persistent. Differentials in wholesale electricity hub prices are the only available indicator of electric congestion impacts in non-market regions of the nation and across the boundaries between market and non-market regions.

2.2.2. Resource-driven transmission constraints

The second set of measures provides information about how current and near-term changes in generation and transmission assets can affect transmission system usage.

2.2.2.1. Local reliability

Although grid reliability and transmission constraints are strongly interrelated, this report does not include generic reliability metrics such as “operating reserves percentage” or regional “reserve margin.” The report focuses on information about transmission constraints and congestion at sub-regional levels, rather than over broad regions. Operating reserve margins are usually calculated only for broad regions (e.g., for all of the Pacific Northwest or the New York ISO), and therefore do not provide information on transmission constraints and congestion at local levels. However, reliability issues pertaining to specific geographic or electrical areas are relevant for this report and are included where appropriate. Two principal drivers for local reliability concerns are generation retirements or pending needs for transmission infrastructure renovation/replacement.

2.2.2.2. Interconnection queues

Transmission interconnection queues reveal where generation developers want to site new power plants. A high concentration of proposed plants in a specific area can indicate that there is more demand at that location than there is transmission to serve it (notwithstanding the fact that much of the proposed new generation may never reach commercial viability). If a large number of projects are proposed for interconnection from a specific area, it sends an important signal about current perceptions of developers regarding the desirability and potential value of generation development in that area and invites consideration of whether that area merits greater transmission capacity to address current or expected deliverability problems. Thus, even though interconnection queues contain proposals that reach out many years into the future, and not all of the projects in a queue will mature, each interconnection queue reveals developers’ desires today and can serve as an indication of resource-driven transmission constraints.

Today, interconnection queues often contain generation resources that may be developed to support specific public policies favoring or directing a particular type of resource development (e.g., renewables to meet state RPS requirements). If there is insufficient transmission available to serve all of this policy-driven new generation development, then the lack of adequate transmission would constitute a constraint. Many such resources are in locations far from electric load centers. Where data permit, this study presents maps depicting the magnitude and types of planned new generation projects proposed for construction through 2020.

2.2.2.3. Renewable and clean energy zones

Formally identified clean or renewable energy zones indicate areas where resource experts have identified strong potential for the development of renewable or other sources of clean energy. Zone criteria can include physical characteristics of particular areas (e.g., good wind or solar availability) or other factors (e.g., avoidance of areas where development might be restricted). If areas identified as Renewable Energy Zones have little or no transmission service, this indicates a probable transmission constraint.

The states in the Western Interconnection have identified Renewable Energy Zones. This report includes the western zone maps and a few renewable development zones identified in the East.

2.2.3. Transmission system utilization

The final set of constraint and congestion measures is transmission system utilization. Transmission system utilization refers to the intensity with which specific elements of the transmission system are used over time. Transmission elements may be individual transmission lines, but often regional reliability entities or market operators calculate formal utilization metrics for “bundles” of lines. These bundles represent major pathways or “interfaces” between different parts of the transmission system. These interfaces have been defined previously by industry groups for various operational, administrative, and analytical purposes and were not developed by (or for) the Department.

Transmission system utilization metrics are developed for both hourly schedules for planned use of the transmission system and for actual hourly electricity flows. The basic measure of utilization is expressed as a percentage of the rated capacity of the transmission interface in question over a period of time (in this study, a single year, or 8,760 hours). Full utilization (i.e., 100%) is rarely achievable due to reliability or other considerations. Utilization of 90% is often considered a practical maximum and utilization above 75% is considered very high. The principal utilization metrics express the number of hours during which utilization was above a certain percentage over a given period of time (e.g., U90 = the percentage of time over a given year the line or element was loaded at or above 90% of its rated limit). Utilization metrics can be used to rank different interfaces by the number of hours utilization exceeds a certain percentage; to show increases or decreases in the utilization of a given interface over time; and to compare actual versus scheduled flows.

In the Western Interconnection, the major interfaces are called “rated paths.” The major interfaces generally coincide with the boundaries between balancing authorities (BAs).⁸ The WECC’s Transmission Expansion Planning and Policy Committee (TEPPC) routinely analyzes transmission schedules and actual flows and its analyses are included here.⁹

In the Eastern Interconnection, information and analysis of transmission system utilization is not publicly available on a consistent basis across the interconnection.

As noted earlier, high utilization alone is not a sufficient condition for congestion. There are many examples of highly utilized lines that operate exactly as designed (e.g., as a radial line connecting a dedicated source of generation to the grid), and would not be considered congested because there is no current demand to increase flows on them.

⁸Both the Eastern and Western Interconnections are subdivided into contiguous areas where utilities or other organizations, such as regional transmission organizations (RTOs) or independent system operators (ISOs), operate the transmission system as “balancing authorities” (BAs). A balancing authority is a NERC-registered entity that, within its footprint, is responsible for ensuring that bulk electricity supplies and bulk electricity demand are kept in near-perfect balance in real time. Maintaining this balance is essential to the reliability of the interconnected transmission system.

⁹See, for example, Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransPath_UtilizationStudy.pdf.

3. Congestion Management Procedures

This chapter presents data from congestion management procedures in place in different regions of the country. Congestion management procedures include administrative procedures, operationally limiting constraints, economic congestion costs, and wholesale electricity price differentials.

3.1. Administrative congestion management procedures

There are two types of administrative congestion management procedures used in the Western and Eastern Interconnections within the United States. These are unscheduled flow mitigation procedures and transmission loading relief procedures, and were described above in Chapter 2.

3.1.1. Unscheduled flow mitigation procedures

Operators in the Western Interconnection use unscheduled flow mitigation (UFM) procedures to manage loop flows. Initially, the procedures involve controlling phase shifters to manage power flows. When these procedures alone are not enough to mitigate loop flow, curtailments are invoked following protocols specified in NERC reliability rules. Table 3-1 reports unscheduled flow mitigation procedures for 2009, which were the most recent data publicly available as of 2012.

Table 3-1. Unscheduled Flow Mitigation Procedures, 2009¹⁰

Qualified Path Number	Qualified Path Name	Total Hours of Phase Shifter Control	Total Hours of Curtailment
22	SW of Four Corners	44	0
23	Four Corners Transformer	150	46
30	TOT 1A	99	5
31	TOT 2A	0	0
36	TOT 3	1	0
66	COI	61	23
	TOTAL	355	74

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, p. 40, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransPath_UtilizationStudy.pdf.

¹⁰There were an additional 77 hours of independent phase shifter use for TOT-2A to relieve congestion on that path. The table only reflected coordinated phase shifter use. Personal communication from K. Howard, WAPA, December 20, 2012.

The Four Corners Transformer was curtailed the most (albeit less than 0.5% of the hours of the year), followed by the California-Oregon Interface (COI) (less than 0.25% of the hours of the year).

3.1.2. Transmission loading relief procedures

3.1.2.1. Midwest

Transmission Loading Relief (TLR) procedures are used throughout the Midwest to manage congestion on flowgates. Figure 3-1 presents counts of TLR events from 2006 through 2011 separately for the level 3, 4, and 5 events.¹¹

Overall, 2011 continues a pattern of declining TLR events at all three levels across the Midwest. The decline in use of TLRs is most pronounced for SPP. In its first few years of operation, SPP made extensive use of TLR procedures to manage congestion. In 2010 SPP adopted the faster Constraint Management Event (CME) procedure (supplementing TLR use) to manage congested flowgates to deal with constraints created by market resources and schedules.¹² The CME process uses market operations, rather than administrative procedures, to redispatch resources around flowgate limits. Figure 3-1 shows that although the number of binding and breached event hours¹³ within SPP fell within the same ballpark in 2009 and 2010, the number of level 3 and 4 TLRs called in 2010 dropped compared with previous years (note that CME was only in use for 5 months of 2010). SPP observes that the TLR process was extensively over-reporting congestion in prior years.¹⁴

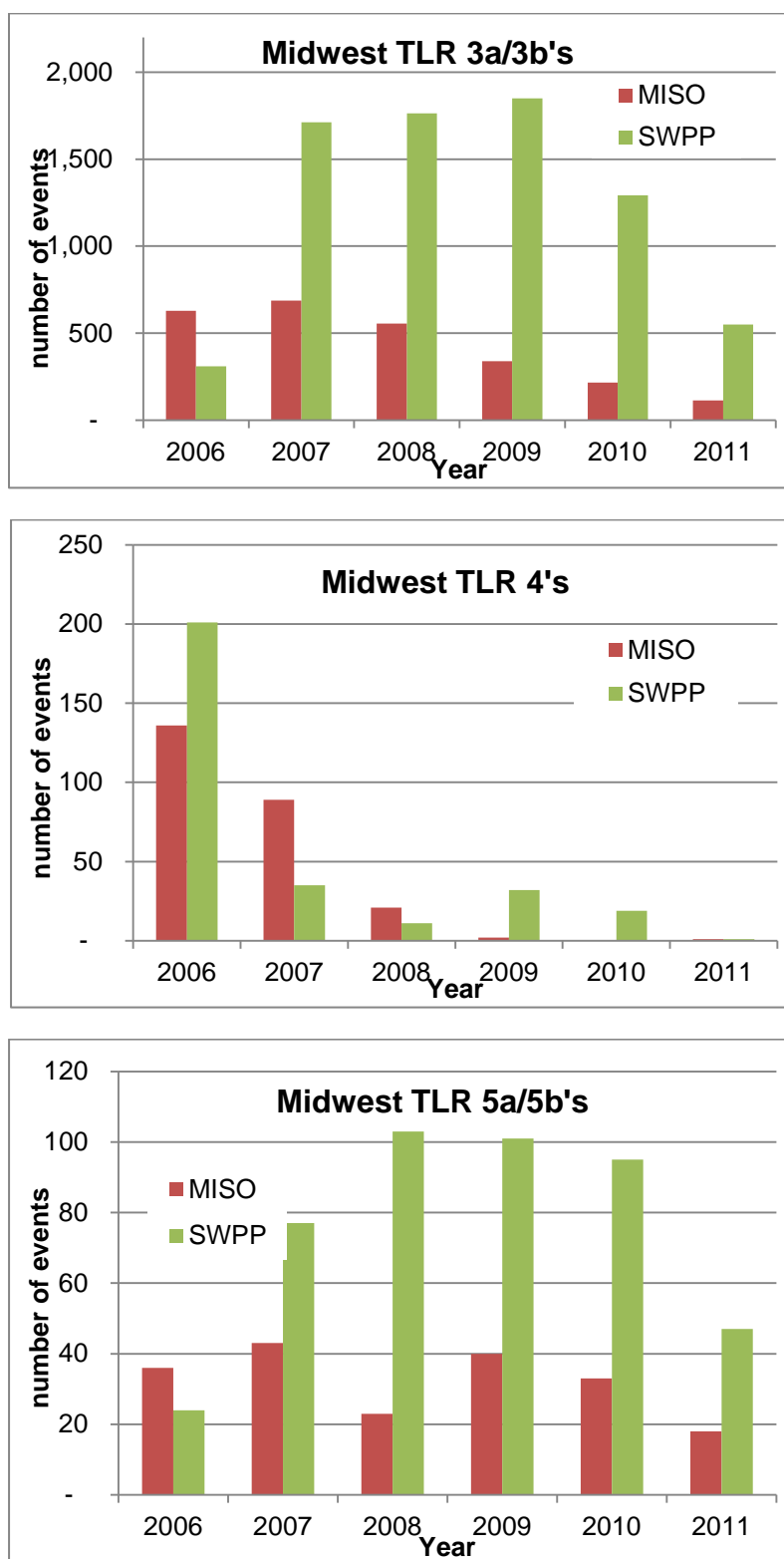
Table 3-2 also shows that while the use of CME appears to have reduced the number of TLRs called inside SPP's footprint, there were more TLRs called at flowgates outside SPP that affect operations inside SPP (called "external flowgates" in the table). SPP's use of TLRs and CMEs remained low in 2011 compared to prior years.

¹¹TLR levels 3, 4, and 5 refer to escalating levels of actions taken to ensure reliability. They all involve some level of curtailment or modification to transmission service requests.

¹²Southwest Power Pool (SPP) Market Monitoring Unit (2011c), *SPP 2010 State of the Market*, Little Rock, AR: SPP, Inc. May 10, 2011, <http://www.spp.org/publications/2010-State-of-the-Market-Report.pdf>, p. 97.

¹³SPP defines a breached event on a flowgate as one on which transmission flows exceed its rated level; a binding event occurs when the rated level of a flowgate serves as a hard limit that is preventing further throughput across the flowgate.

¹⁴Ibid.

Figure 3-1. Summary of TLR Level 3, 4, and 5 events in the Midwest

Source: NERC (2012f). "Transmission Loading Relief (TLR) Monthly Summaries." Data downloaded from NERC website. July, 2012, at <http://www.nerc.com/filez/Logs/monthlysummaries.htm>.

Table 3-2. Impacts of SPP use of TLRs and Congestion Management Event procedures in terms of hours of congestion events per year

	2009			2010		
	SPP Flowgates	External Flowgates	Total	SPP Flowgates	External Flowgates	Total
Total CME hours	0	0	0	4,234	0	4,234
TLR hours Level 3	17,039	983	18,022	11,948	1,325	13,273
TLR hours Level 4	4,107	95	4,202	281	222	503
TLR hours Level 5	790	103	893	632	438	1,070
Binding RTB hours	1,851	19	1,870	1,625	108	1,733
Breached RTB hours	90	21	111	83	32	115

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2011c), *SPP 2010 State of the Market*, Little Rock, AR: SPP, Inc., at <http://www.spp.org/publications/2010-State-of-the-Market-Report.pdf>, p. 98.

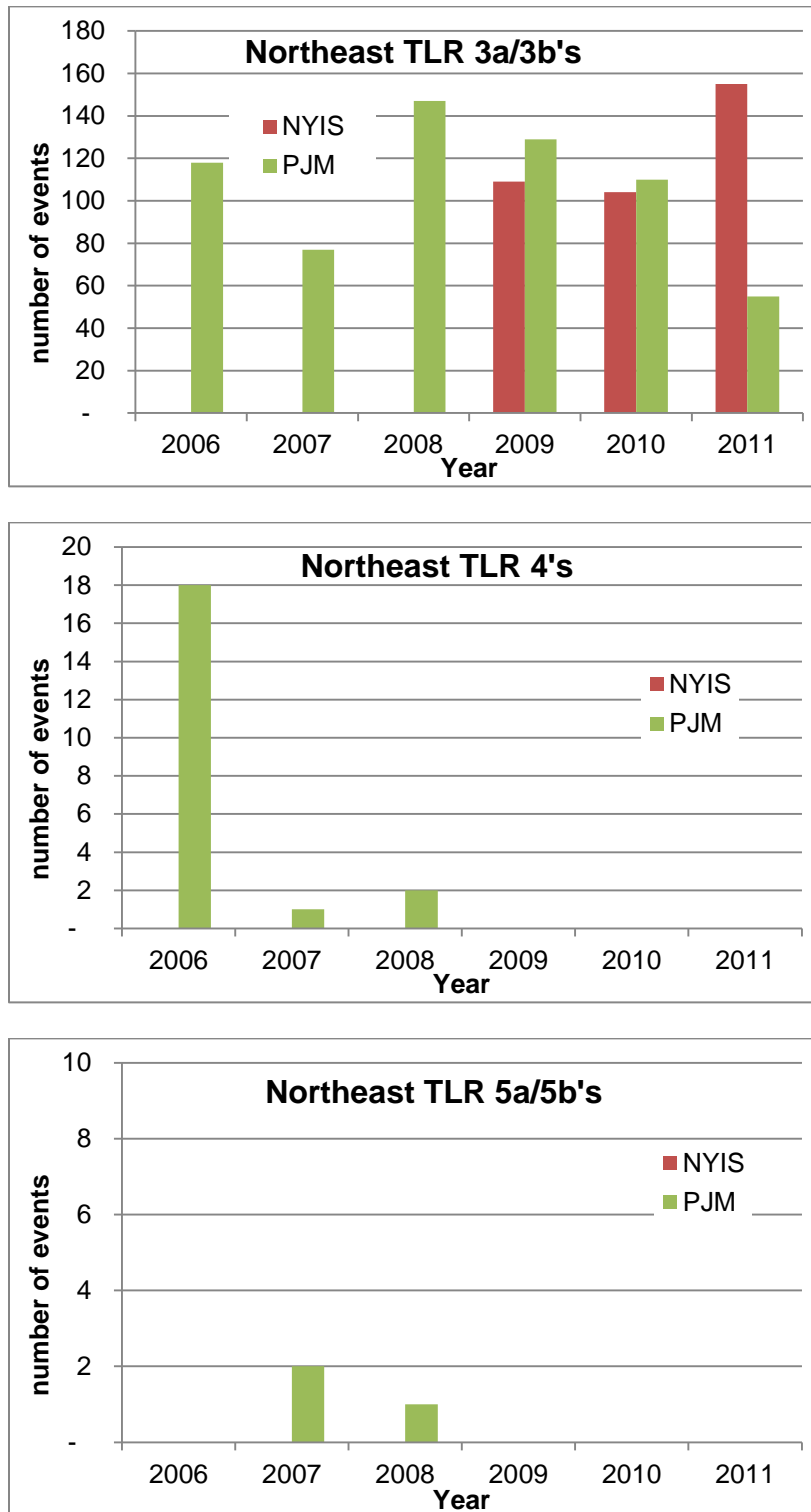
3.1.2.2. Northeast

Although market actors respond to locational market prices in ways that limit congestion, some of the RTOs and ISOs also use administrative measures (TLRs) to manage congestion in some situations. Both PJM and New York use TLRs (see Figure 3-2); New England does not use TLRs.

Overall, the frequency and severity of TLR events in the Northeast appears to be lower than it is in the Midwest. No TLR level 4 or 5 events have been called in the Northeast since 2008. The number of TLR level 3 events called is nearly an order of magnitude lower in the Northeast compared to the Midwest.

Consistent with the Midwest, the general trend in TLR events for PJM has been declining over time. New York only began using TLRs in 2009 (primarily to manage Lake Erie loop flows)¹⁵ and has only called TLR level 3 events, which affect only non-firm transactions. There are no clear trends in these data.

¹⁵Potomac Economics, NYISO's market monitor, writes that NYISO uses TLRs "to curtail transactions when loop flows contribute significantly to congestion on its internal flowgates. This NERC Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities. When a constraint is binding, the NYISO's real-time scheduling models manage its market flows over the constrained transmission facility by economically redispatching New York generation and by economically scheduling external transactions that source or sink in New York. If total loop flow accounts for a significant portion (i.e., more than 5%) of flow on a facility, the NYISO can invoke . . . the TLR procedure to ensure that external transactions that are not scheduled with the NYISO are curtailed to reduce flow over the constrained facility." Additionally, ". . . [M]ost external transactions that cause loop flows are not scheduled with the NYISO," so TLRs are the only mechanism NYISO has to manage these transactions. Source: Potomac Economics (2012c). *2011 State of the Market Report for the New York ISO Markets*. Prepared for Market Monitoring Unit for the New York ISO. April 2012, p. A-69.

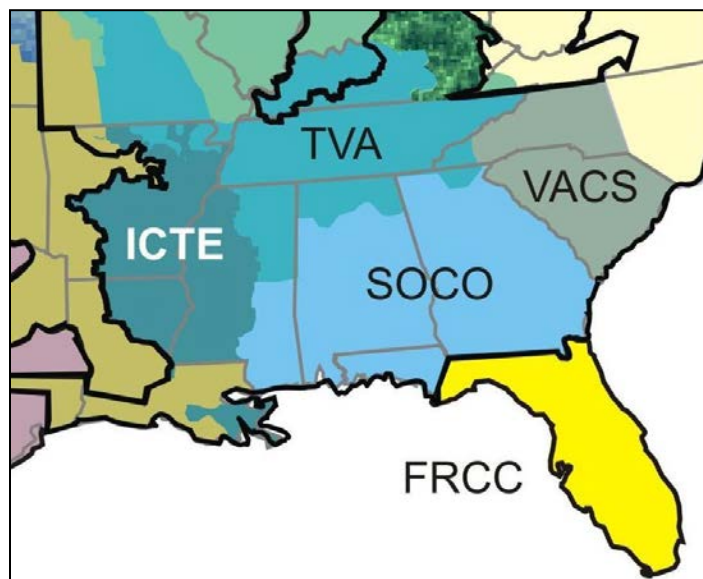
Figure 3-2. Summary of TLR Level 3, 4, and 5 events in the Northeast

Source: NERC (2012f). "Transmission Loading Relief (TLR) Monthly Summaries." Data downloaded from NERC website. July, 2012, at <http://www.nerc.com/filez/Logs/monthlysummaries.htm>.

3.1.2.3. Southeast

Once transmission is built to serve expected load and generation requirements, Transmission Loading Relief (TLR) procedures are used in the Southeast to manage congestion on flowgates when a contingency reliability problem arises. The reliability coordinators that manage TLRs in the Southeast are TVA, VACS, SOCO, ICTE (through early 2012), and FRCC, as shown in Figure 3-3.

Figure 3-3. Location of reliability coordinators managing TLRs in Southeast

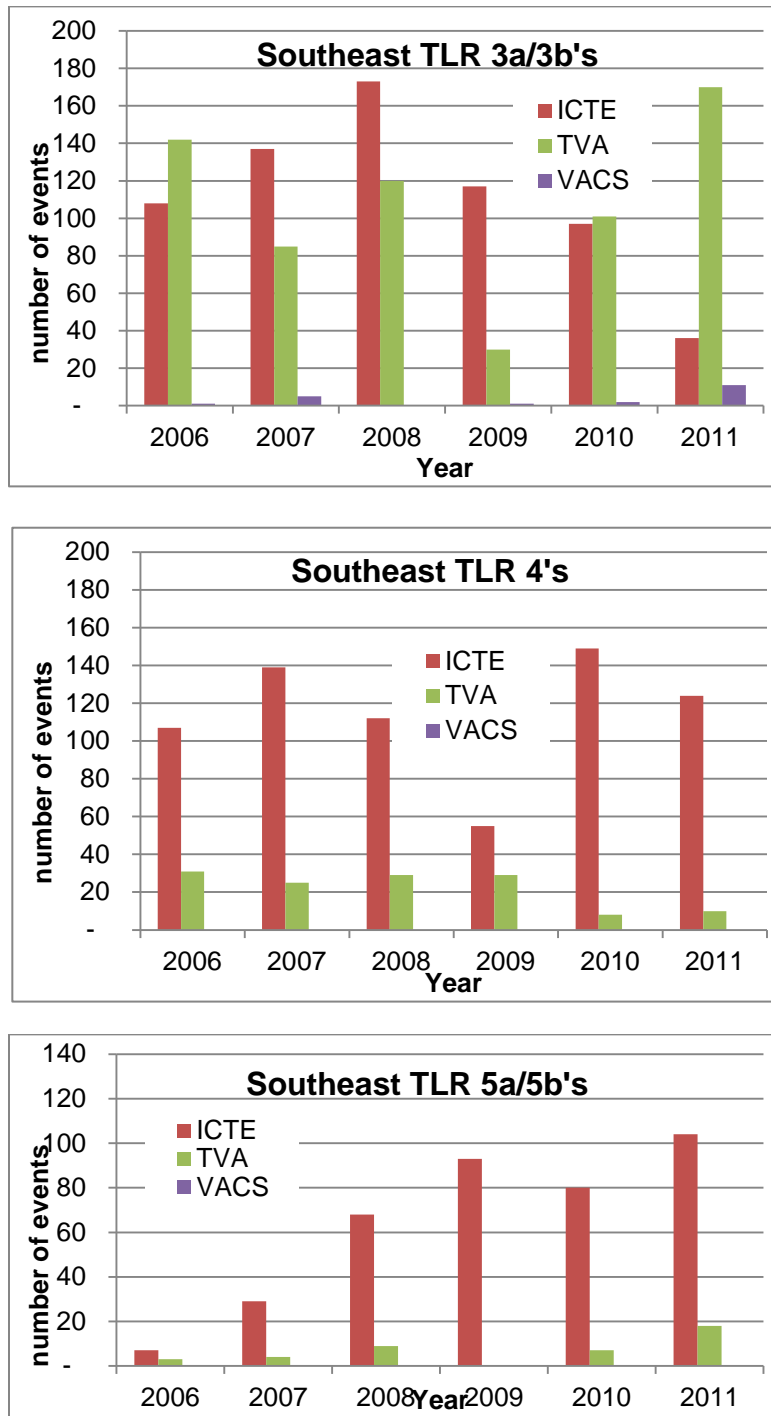


Source: NERC (2012c). "NERC Reliability Coordinators." *NERC website showing map of reliability coordinators*. July 2012, at <http://www.nerc.com/page.php?cid=5|67|206>.

Figure 3-4 presents counts of TLR events from 2006 through 2011 separately for the level 3, 4, and 5 events for ICTE, TVA, and VACS.¹⁶ SOCO and FRCC did not call any TLR events at level 3, 4, or 5 during this period.

TLRs are used extensively in the Entergy service area by operator ICTE (formerly Entergy Energy Services) and to a lesser extent by TVA. VACS uses TLRs less, and SOCO did not incur congestion requiring a TLR level 3, 4, or 5. In the areas that called TLRs, usage over the past several years does not exhibit any obvious trends with the exception of the increased use of TLR 5a/5b by ICTE.

¹⁶TLR levels 3, 4, and 5 refer to escalating levels of actions that are taken to ensure reliability. They all involve some level of curtailment or modification to transmission service requests.

Figure 3-4. Summary of TLR Level 3, 4, and 5 events in the Southeast

Source: NERC (2012f). "Transmission Loading Relief (TLR) Monthly Summaries." NERC website. July 2012, at <http://www.nerc.com/filez/Logs/monthlysummaries.htm>.

The number of TLRs in the ICTE area indicates that congestion exists in that area (as the Department identified in the 2009 National Electric Transmission Congestion Study). Entergy has been addressing this congestion by building transmission; however, Entergy has historically

built transmission projects mainly for reliability reasons and not to lower delivered energy costs or interconnect third-party generators. Entergy redispatches existing generation to ease congestion.¹⁷ The increase of TLRs in 2011 in ITCE may be the result of actions and congestion mitigation elsewhere, in particular actions to relieve congestion in the Acadiana load pocket in Southern Louisiana, which is “across the seams” from Entergy.^{18 19}

3.2. Operationally limiting constraints

3.2.1. West

As described in Chapter 2, a constraint is a transmission element or combination of elements that limits power flow below what is desired. Because CAISO is the only area in the West that tracks trades and curtailments and makes this information public, this section does not include data or information from the rest of the West. This section discusses constraint and congestion information from CAISO for the year 2011 and earlier, prior to the San Onofre Nuclear Generating Station (SONGS) Units being taken off-line.

Congestion occurs on a constraint (a line, nomogram or branch group²⁰) in the CAISO day-ahead market when the constraint is scheduled to its capacity limit, and the day-ahead shadow price of that constraint is non-zero. The shadow price of a constraint is the marginal value of that constraint’s capacity. Specifically, it is the value that increasing the capacity of the constraint by one MW would bring to the overall market dispatch cost. For instance, if a constraint has a shadow price of \$200 per MWh, increasing the capacity of that constraint would decrease overall market dispatch cost by \$200 for an additional MWh of flow over the constraint.

3.2.1.1. CAISO intertie congestion

The CAISO market monitor reports the frequency of congestion on interties to other systems. The locations of intertie constraints identified for 2011 are shown in Figure 3-5.²¹

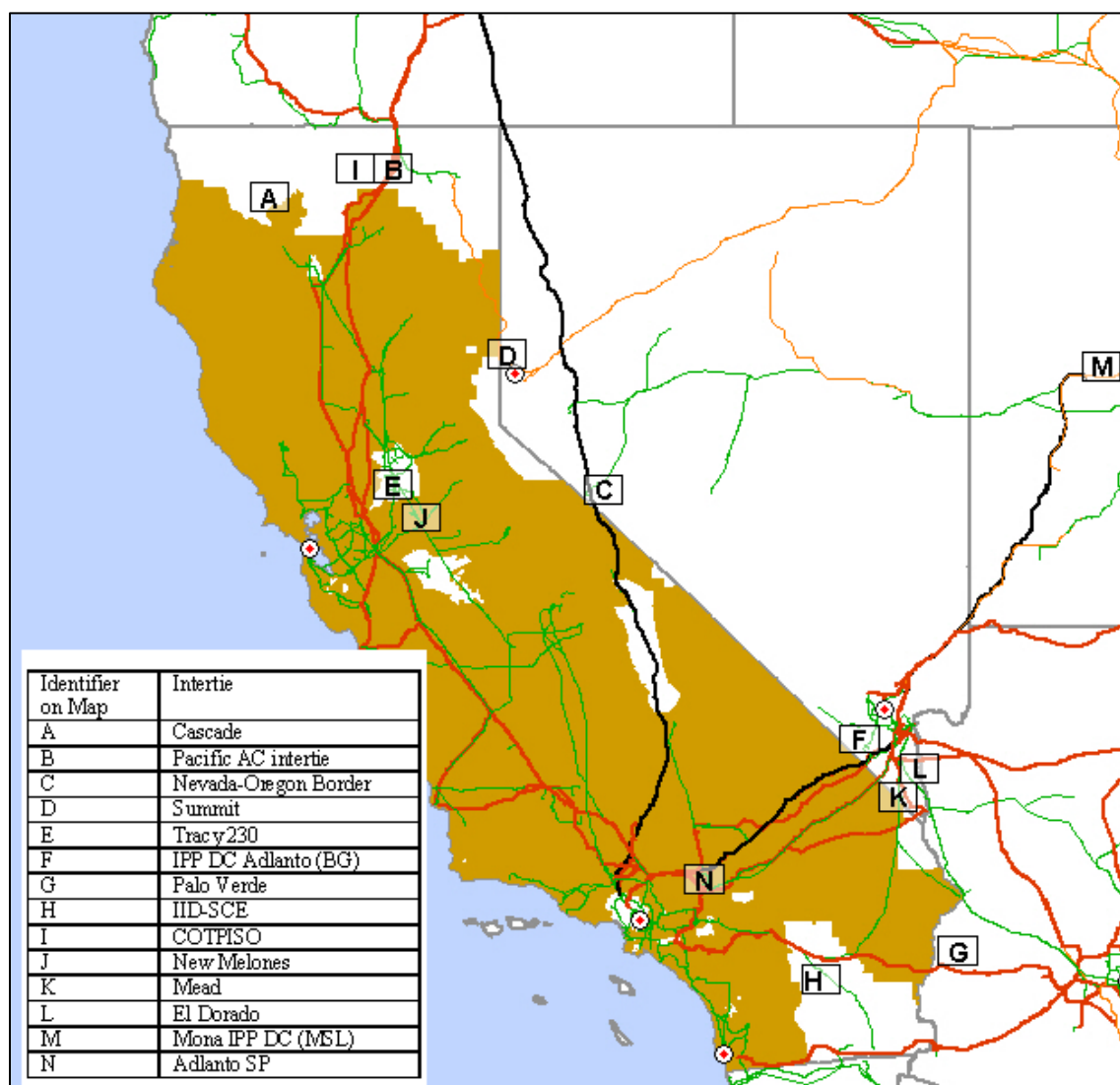
¹⁷Reeves, O. (Arkansas Commission) (2011). “Comments of Olan Reeves of the Arkansas Commission at the U.S. Department of Energy.” Excerpt taken from transcript at US DOE (2011e). National Electric Transmission Congestion Workshop, St. Louis, MO., December 8, 2011, at, <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf>, pg 32.

¹⁸*Ibid.*, p. 36.

¹⁹On October 12, 2012, the Federal Energy Regulatory Commission approved Entergy’s request to switch from using the Southwest Power Pool as its Independent Coordinator for Transmission, to use MISO in that role. When the process is completed, this will effectively give MISO functional control over Entergy’s transmission system assets.

²⁰A branch group is a group of lines that have a capacity limit on combined flow. A nomogram defines a limit on a transmission line or group of lines that depends on multiple variables, e.g., generation, load and voltage, and so cannot be implemented as a static capacity limit.

²¹These are the internal constraints identified by the CAISO market monitor in 2011. California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom,

Figure 3-5. Location of 2011 CAISO Intertie Constraints

Source: Ventyx (2012). "Ventyx Velocity Suite"; personal communication with CAISO staff August 10, 2012.

Figure 3-6 shows the frequency of import congestion as a percent of total hours in 2011. The frequency of congestion on most major interties increased in 2011, particularly on ties to the Northwest (California-Oregon Transmission Project, Cascade, and New Melones) because of high levels of low-cost wind and hydro availability.²² The market monitor attributes this congestion to planned outage and line maintenance.²³

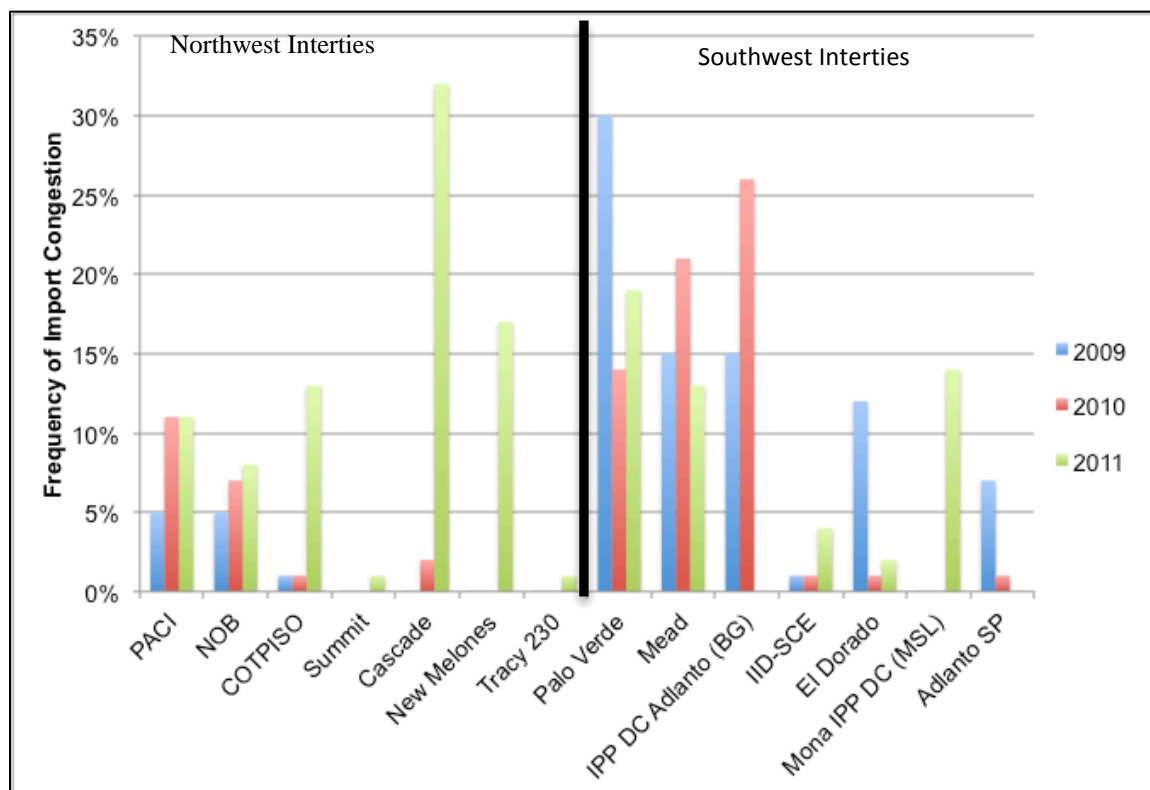
CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 131.

²²*Ibid.*, p. 131.

²³*Ibid.*, pp. 140-141.

Imports from the Southwest into CAISO, and in particular on the Palo Verde intertie, are among the highest. The increase in congestion frequency in 2011 on this intertie occurred mainly because the capacity limit was de-rated several times to accommodate transmission maintenance and upgrade work.²⁴

Figure 3-6. Frequency of import congestion on CAISO interties, 2009 to 2011



Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 133.

3.2.1.2. CAISO internal congestion

The CAISO market monitor also reports on internal constraints. These are typically sets of lines with interrelated capacity limits (e.g., branch groups and nomograms). The locations of internal constraints identified for 2011 are shown in Figure 3-7.²⁵ Hours of congestion in 2011 on these constraints are shown in Figure 3-8. A combination of forced and planned transmission outages in 2011 on other parts of the network accounted for congestion on constraints between SDG&E

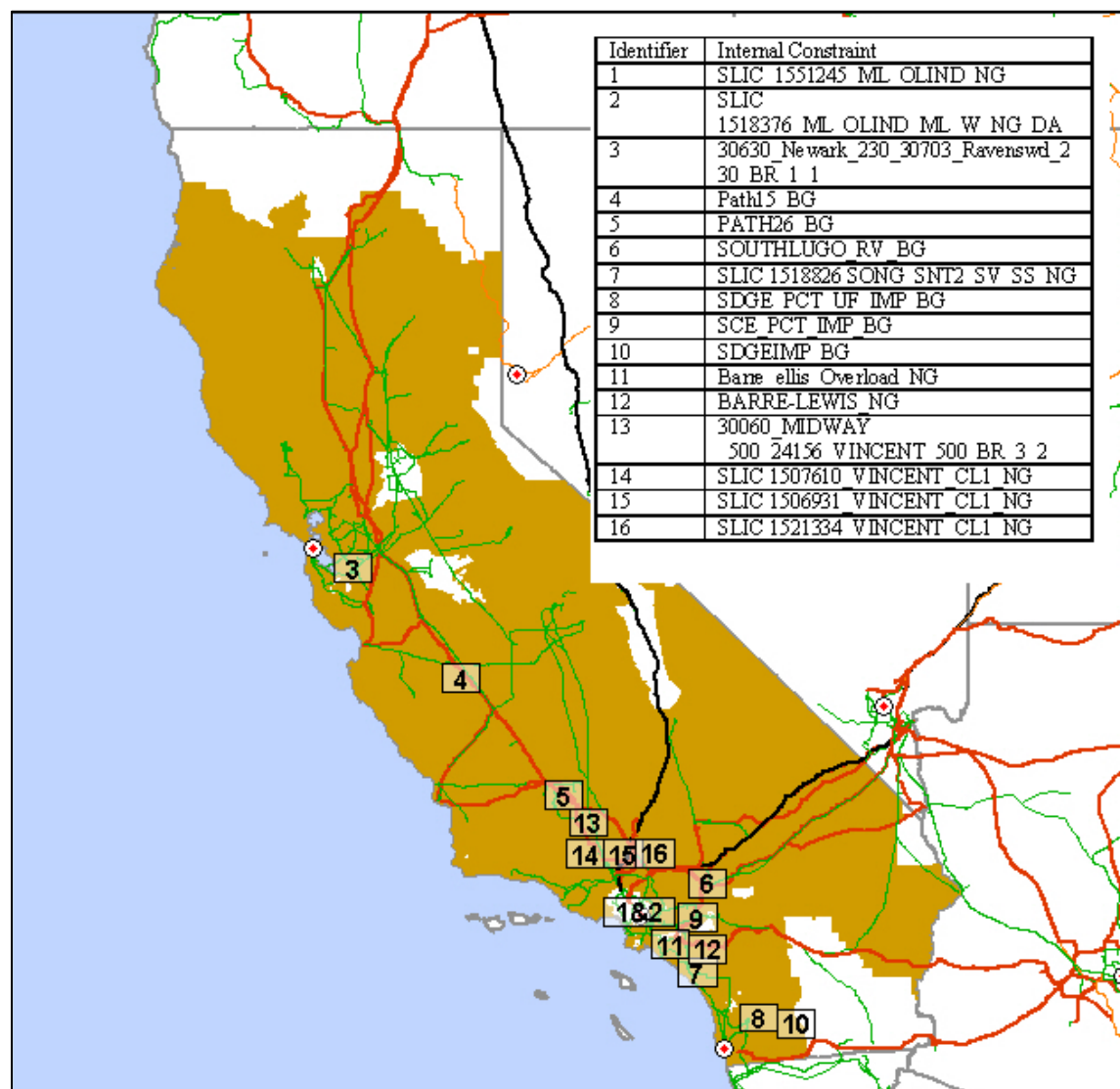
²⁴*Ibid.*, p. 133.

²⁵These are the internal constraints identified by the CAISO market monitor in 2011. California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, pp. 135-136.

and the Imperial Irrigation District (the two constraints on the very right of Figure 3-8), in the Midway-Vincent area, and on Path 26. Scheduled transmission maintenance accounted for congestion on Path 15.²⁶

The most frequent congestion in the graph below was on the SDG&E to Imperial branch group and was about 525 hours in the first two quarters of 2011 (12% of hours in those two quarters), due mainly to transmission outages.²⁷

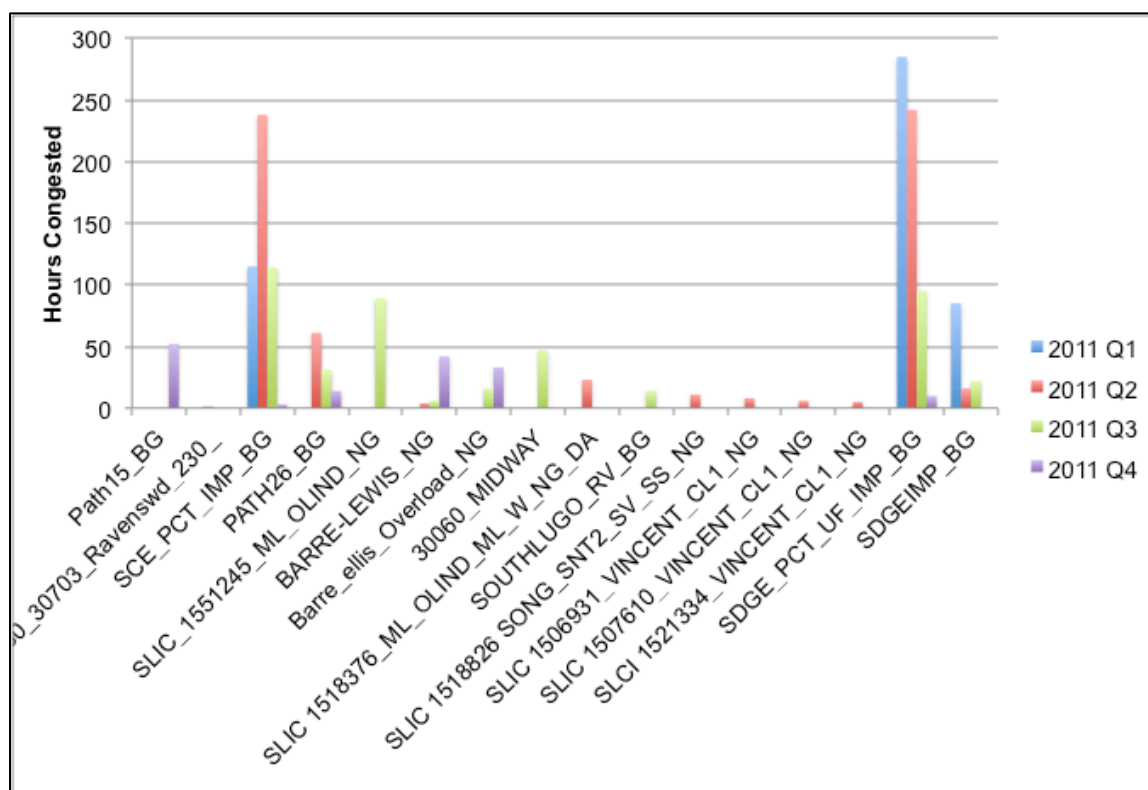
Figure 3-7. Location of 2011 CAISO Internal Constraints



Source: Ventyx (2012). "Ventyx Velocity Suite"; personal communication with CAISO, August 10, 2012.

²⁶*Ibid.*, pp. 135-136.

²⁷*Ibid.*, p. 135.

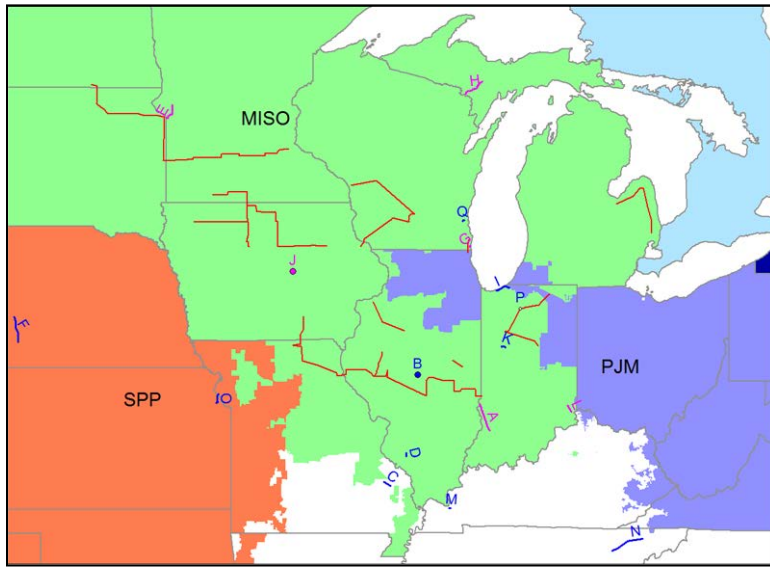
Figure 3-8. Number of congested hours on internal CAISO constraints, Feb-Dec 2011

Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 137.

3.2.2. Midwest

Constraints in the Midwest (and other parts of the east) are described in terms of flowgates, which represent groups of closely related (electrically speaking) transmission system elements at specific locations. When more transmission flow across a flowgate is requested than can be accommodated, and requests for utilization must be limited, it means that the flowgate has become constrained and is now operationally limiting.

Operations in the three RTOs in the Midwest region are geographically intermingled, as is illustrated in Figure 3-9. Transmission constraints inside one RTO often affect electricity flows inside a neighboring region. This phenomenon is common between MISO and SPP, SPP and Entergy and its eastern neighbors, and MISO and PJM.

Figure 3-9. MISO, PJM and SPP footprints overlap within the Midwest region

Source: Midwest ISO (2012f). “Top Congested Flowgate Study, System Planning Committee Presentation”, Presentation at MISO Board of Directors System Planning Committee Meeting, June 19, 2012, at <https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2012/20120619/20120619%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Top%20Congested%20Flowgate%20Study%20Overview.pdf>, pg. 4.

Much of the significant congestion within the Midwest region occurs at the interfaces between RTOs. This is shown in Figure 3-10, a map from the MISO-PJM-SPP-TVA Coordinated System Congested Flowgate Study Scope document developed in January 2010. This study looked at all of the flowgates at the seams between MISO, PJM, SPP and TVA that had “consistently negative cross-border impacts on the stakeholders in the past” and were projected to continue those adverse impacts in the future, based on historical binding flowgate hours and shadow prices.²⁸ As the figure shows, most of these cross-border interfaces are in the Lake Michigan area (PJM-MISO seams), Iowa-Nebraska (SPP seam) and Indiana-Kentucky (PJM-MISO seam).²⁹

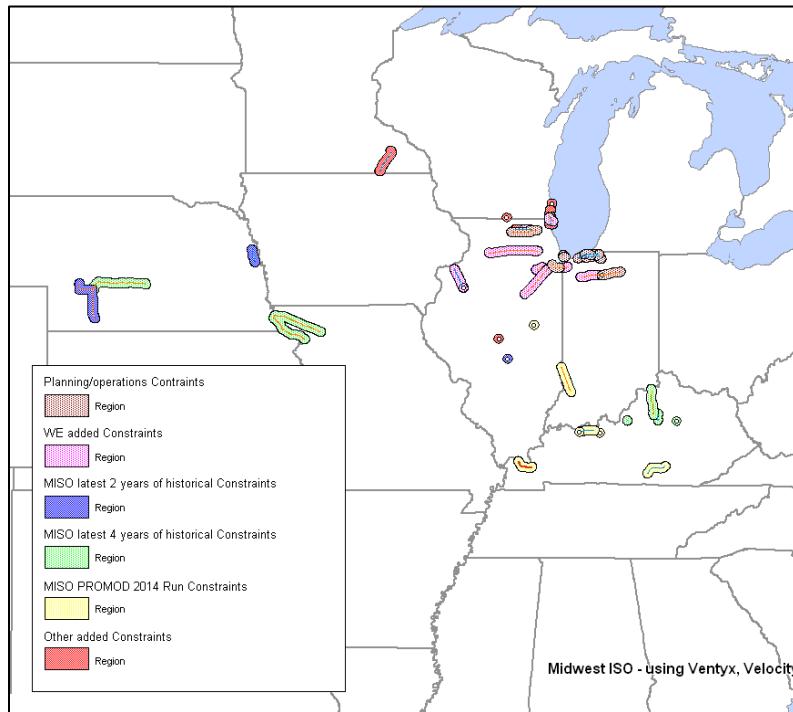
MISO identified all of the most congested flowgates in its service territory (see Figure 3-11) and evaluated each one to see whether it would be beneficial to remedy it by building more transmission. The planners found that few of the potential transmission solutions would be beneficial to MISO in terms of offering benefits in excess of the transmission costs beyond MISO’s planned Multi-Value Projects and reliability projects. One of the primary reasons for lack of sufficient benefits to MISO was that most of the constraints are located at the interfaces

²⁸ Midwest ISO (2010a). *Coordinated System Congested Flowgate Study Scope*, January 2010, at <https://www.pjm.com/~media/committees-groups/committees/teac/20100113/20100113-item-01-cross-border-congested-flowgate-study.ashx>, p. 1.

²⁹ *Ibid.*, p. 2.

between MISO to SPP and MISO to PJM; MISO found that most of the benefits of congestion reduction would accrue primarily to parties outside MISO.³⁰

Figure 3-10. Many top congested flowgates in the Midwest are at seams between RTOs

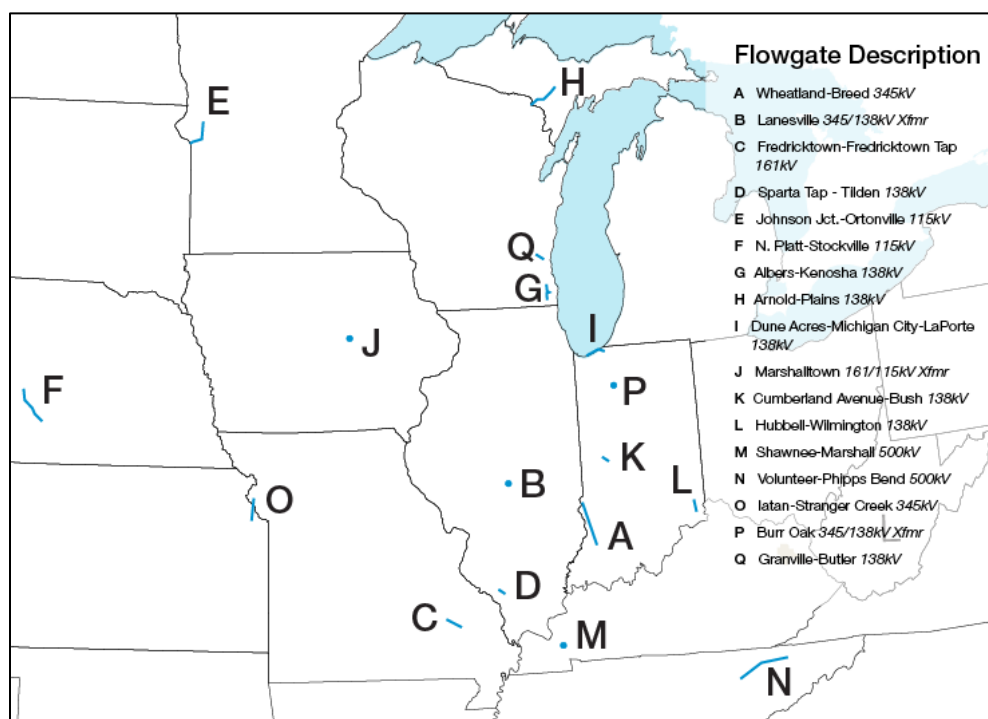


Source: Midwest ISO (2010a). *Coordinated System Congested Flowgate Study Scope*, January 2010, at <https://www.pjm.com/~media/committees-groups/committees/teac/20100113/20100113-item-01-cross-border-congested-flowgate-study.ashx>, Figure 1, p. 3, based on “MISO-PJM Cross-Border Study.”

There are also seams issues between MISO and SPP. In 2010, different rules and practices between the two markets caused “inequitable allocation of firm transmission service curtailments in the Kansas City area that resulted from cross-system loop flows.” Congestion was lower in the Kansas City area in 2011, but SPP asserts that the problem of cross-system loop flows has not yet been resolved.³¹ In SPP’s planned Nebraska City-Maryville-Sibley 345 kV transmission project will fix a longstanding seam issue between Omaha (in MISO) and Kansas City (in SPP).

³⁰Midwest ISO (2012f). “Top Congested Flowgate Study, System Planning Committee Presentation”, *Presentation at MISO Board of Directors System Planning Committee Meeting*, June 19, 2012, at <https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2012/20120619/20120619%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Top%20Congested%20Flowgate%20Study%20Overview.pdf>, p. 4.

³¹Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*, July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, pp. 94-95.

Figure 3-11. Top congested flowgates within and around MISO, 2011-12

Source: Midwest ISO (2012f). "Top Congested Flowgate Study, System Planning Committee Presentation", Presentation at MISO Board of Directors System Planning Committee Meeting, June 19, 2012, at <https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2012/20120619/20120619%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Top%20Congested%20Flowgate%20Study%20Overview.pdf>, p. 8.

SPP uses the percentage of dispatch intervals when a flowgate is breached (flow over the element has exceeded its allowable limit) or binding (flow over the element has reached but not exceeded its allowable limit) to identify its most congested flowgates. SPP's market monitoring routinely identifies the top ten most congested flowgates. See Table 3-3. SPP also notes:

In 2011, at least one flowgate was congested an average of 76% of the time. This is an increase from 2010 in which an average of 69% of all intervals had at least one congested flowgate. This level of congestion is not necessarily a concern, as congestion in the form of binding flowgates can indicate that the transmission system is being fully utilized. However, breached flowgates, or those that have exceeded their limit, can be problematic. In 2011, approximately 4.4% of all dispatch intervals included a breached flowgate. Since 2008, the percentage of breached flowgates has declined each year.

Breached flowgates lead to significant price differentials across the region and can adversely impact individual market participants.³²

Over the last two years the incidence of breached flowgates has decreased while the incidence of binding flowgates has increased. SPP concludes that it “is successfully managing the delicate balance of utilizing the grid to its fullest while minimizing severe congestion.”³³

Congestion within SPP is largely concentrated in a few select transmission corridors that correspond to macro power flows across the region. For instance, . . . the Texas Panhandle is heavily congested . . . due largely to overall flows from the rest of the system into this region. Congestion in the Kansas City area is driven principally by north to south flows that occur in the Nebraska/Kansas interface.”³⁴ SPP has approved transmission upgrades (e.g., reconductoring lines and adding new substations and transformers) that are expected to mitigate congestion at many of these flowgates as the new projects come into service between 2011 and 2018.³⁵

Table 3-3. Top ten congested flowgates in SPP: Those flowgates constrained the most hours in 2011

Region	Flowgate Name	Binding Intervals	Breached Intervals	Total Intervals	Percent of Time
Texas Panhandle	RANPALAMASWI	20,854	409	21,263	20.2%
	OSGCANBUSDEA	19,457	393	19,850	18.9%
Kansas City Area	IASCLKNASJHA	9,462	278	9,740	9.3%
	PENMUNSTRCRA	3,745	127	3,872	3.7%
	LAKALASTJHAW	1,482	541	2,023	1.9%
W Nebraska	GENTLMREDWIL	4,204	92	4,296	4.1%
Tulsa	OKMHENOKMKEL	2,400	92	2,492	2.4%
SW Kansas	HOLPLYHOLSPE	1,727	260	1,987	1.9%
Wichita	ELPFARWICWDR	1,771	68	1,839	1.7%
SW Missouri	BRKXF1BRKXF2	328	83	411	0.4%

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*, July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 85.

³²Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*, Little Rock, AR: SPP, Inc., July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 11.

³³*Ibid.*, p. 84.

³⁴*Ibid.*, p. 47.

³⁵Southwest Power Pool (SPP) Market Monitoring Unit (2012e). *2012 Transmission Expansion Plan (STEP) Report*, January 31, 2012, at <http://www.spp.org/publications/2012%20STEP%20Report.pdf>, pp. 21-22.

Table 3-4. Top ten constrained flowgates by price in SPP

Flowgate Name	Binding Shadowprice	Breached Shadowprice	Total Shadowprice
RANPALAMASWI	20,854	409	21,263
OSGCANBUSDEA	19,457	393	19,850
IASCLKNASJHA	9,462	278	9,740
PENMUNSTRORA	3,745	127	3,872
LAKALASTJHAW	1,482	541	2,023
GENTLMREDWIL	4,204	92	4,296
OKMHENOKMKEL	2,400	92	2,492
HOLPLYHOLSPE	1,727	260	1,987
ELPFARWICWDR	1,771	68	1,839
BRKXF1BRKXF2	328	83	411

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*, July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 84.

As described above, shadow prices represent the dollar value associated with relieving the congestion on the flowgate by one MW. The total shadow prices for the top two flowgates are high. SPP comments that “high levels of congestion with significant price impacts signal areas where additional transmission development is needed to eliminate bottlenecks and facilitate efficient transfer of low cost energy.”³⁶ Low shadow prices indicate that there may be a benefit to reducing congestion, but additional transmission investment might not be cost-effective;³⁷ since SPP reports that congestion in several of these areas are the consequence of seams issues more than physical constraints, continued work on inter-area market and schedule coordination could mitigate this congestion.

Figure 3-12 shows the most congested flowgates within SPP in 2008 and 2009; the flowgates with red circles were in the top ten flowgates in both years, those with blue circles were in the top ten for 2009 only, and those with clear circles were in the top ten in 2008 only. Comparing this map against the most congested flowgates in 2011, it appears that only a few of these earlier flowgates remain persistent and problematic—those within the Texas Panhandle, north of Kansas City, and in central Oklahoma.³⁸

³⁶*Ibid.*, p. 82.

³⁷Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*, Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 84.

³⁸Southwest Power Pool (SPP) Market Monitoring Unit (2010). *SPP 2009 Annual State of the Market Report*. AR: SPP Inc. June 2010, at <http://www.spp.org/publications/SPP-2009-ASOM-Report.pdf>, Figure III.5, p. 78.

Figure 3-12. Most congested flowgates within SPP for 2008 and 2009

Cities = green circle; red bullets with lines = flowgates that were in SPP's top ten most congested in both 2008 and 2009; blue bullets with lines = flowgates that were in top ten most congested for 2009 but not 2008; clear bullets with lines = flowgates that were in 2008's top ten most congested but not in 2009.



Source: Southwest Power Pool (SPP) Market Monitoring Unit (2010). *SPP 2009 Annual State of the Market Report*. AR: SPP Inc. June 2010, at <http://www.spp.org/publications/SPP-2009-ASOM-Report.pdf>, Figure III.5, p. 78.

3.2.3. Northeast

PJM

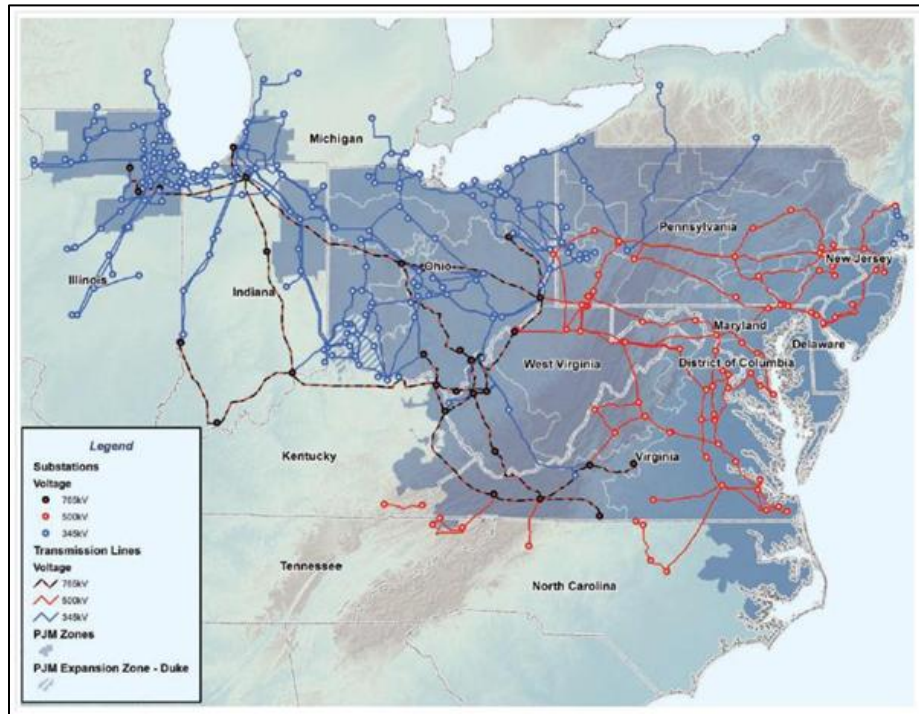
Figure 3-13 shows the high-voltage lines within the PJM Interconnection. These lines are a mix of 765, 500 and 345 kV lines and equipment, as well as underlying lower voltage facilities.

PJM routinely identifies the five most congested parts of the network. See Figure 3-14. Some of these are flowgates (collections of equipment that operate together electrically but span multiple lines) and others are single transmission elements (lines or transformers). The five most constrained points on the PJM system in 2011 were:³⁹

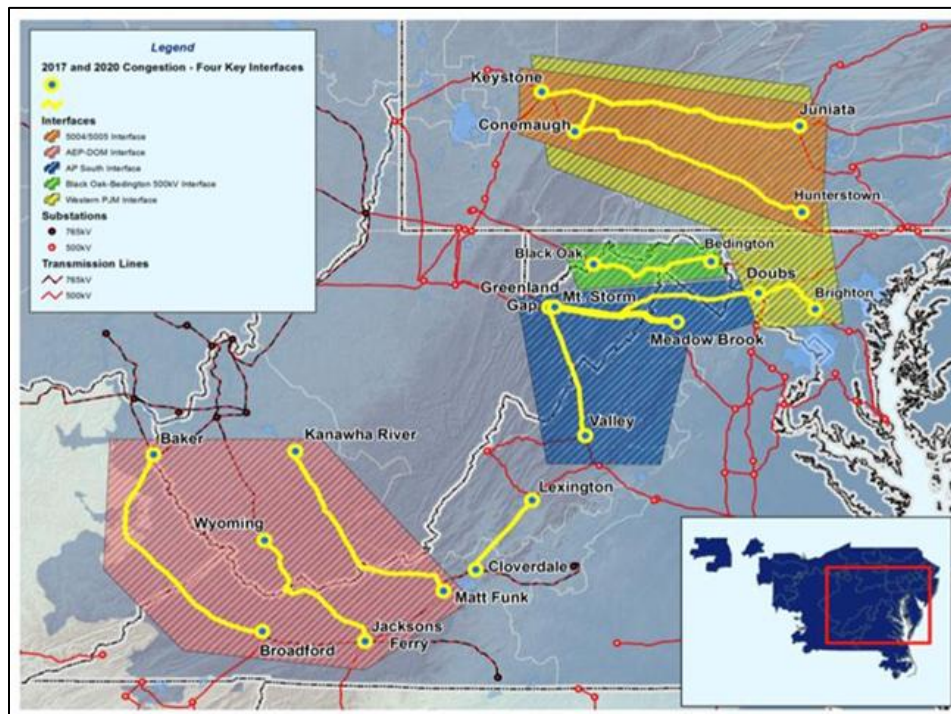
- AP South
- 5004-5005
- Western PJM
- Belmont transformer
- AEP-Dominion

Many of these constraints are in the mountains and limit the flow of low-cost western generation to highly populated coastal load centers.

³⁹Monitoring Analytics (2011b). *State of the Market Report for PJM: 2010*. Norristown, PA: PJM. March 2011, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml, p. 475.

Figure 3-13. Map of PJM high voltage transmission Lines

Source: PJM (2012b). *PJM 2011 Regional Transmission Expansion Plan*. Norristown, PA: PJM. February 2012, at <http://www.pjm.com/documents/reports/rtep-report.aspx>, Book 3 Baseline Results, p. ii.

Figure 3-14. PJM Top 5 historical congestion constraints

Source: PJM System Planning (2012). May 2012. *Email from Chuck Liebold, PJM System Planning*.

PJM's expansion to the west and south over the past decade has increased the scope of its transmission planning and its grid management challenges. Table 3-5 shows the most congested flowgates within PJM, by number of hours congested, between 2008 and 2011. Note that congestion moves around over time—specifically, points that were highly congested in 2008 and 2009 became less congestion as new transmission came into service in 2010 and 2011, and other points became more congested, possibly due to the change in electricity flows and institutional seams.

Table 3-5. Top PJM-identified congested flowgates by hours congested, 2008-2011

Constraint	2008	2009	2010	2011
South Mahwah-Waldwick	0	0	8	494
AP South	1,016	604	1,516	1,013
Belmont Transformer	*	76	203	497
Oak Grove-Galesburg	0	754	242	1,131
Crete-St Johns Tap	14	306	810	1,115
5004/5005 Interface	449	294	605	*
Cloverdale-Lexington	1,813	434	684	*
Kammer Transformer	1,628	1,328	*	*
Bedington-Black Oak	279	73	212	*
Pana North	640	318	*	*

*Denotes a year or adjacent year where the congested number of hours was not reported because it was not one of the top 25 constraints

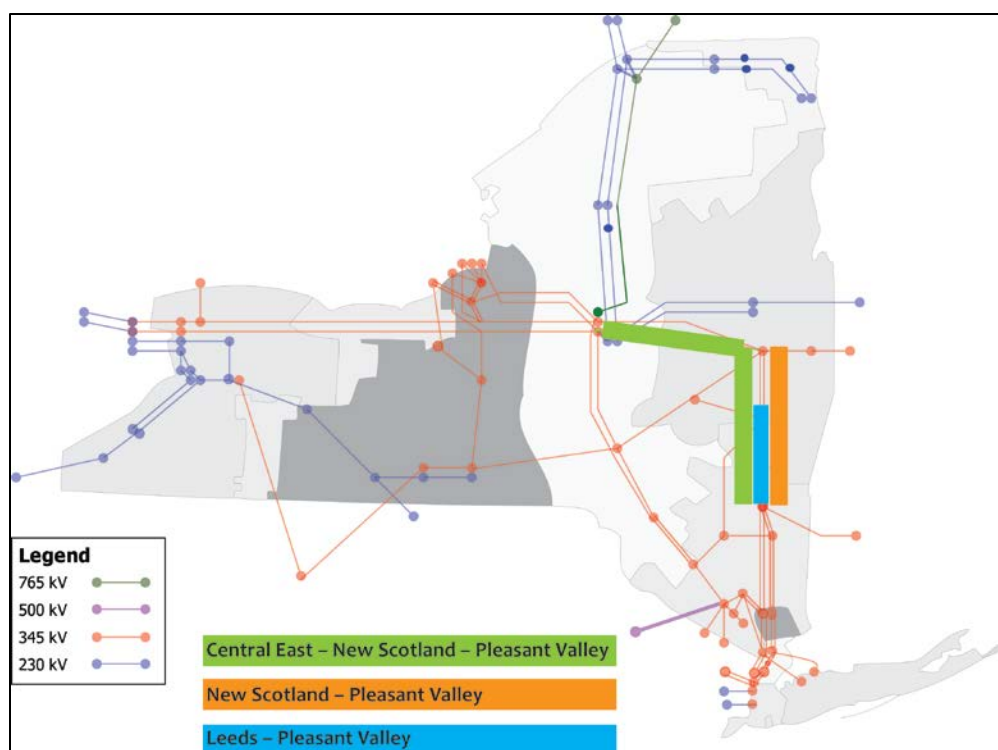
Source: Monitoring Analytics (2010). *State of the Market Report for PJM: 2009*. Norristown, PA: PJM. March 11, 2010, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2009.shtml, Table 7-9, p. 416; Monitoring Analytics (2011b). *State of the Market Report for PJM: 2010*. Norristown, PA: PJM. March 2011, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml, Table 7-11, p. 489.

New York

Figure 3-15 shows New York state's high voltage transmission system. Since most of New York's population and 30% of its load are concentrated in and around New York City, most of the electricity flows toward that area, as shown in Figure 3-16. NYISO's market monitor explains that, "[s]upply resources in Eastern New York are generally more expensive than those in Western New York, while the majority of the load is located in Eastern New York. Hence, the transmission lines that move power from the low-cost to high-cost parts of the state provide

considerable value. Consequently, transmission bottlenecks arise as power flows from Western New York to Eastern New York, leading to significant congestion-related price differences between regions.”⁴⁰ The NYISO explains that 39% of the state’s generation and 51% of its annual demand are located in the lower Westchester, New York City and Long Island zones (at the southeast tip of the state); and 61% of its generation and the other half of its load are located in the rest of the state.⁴¹ New York’s in-state reliability requirement totaled 38,622 MW and its in-state generation totaled 39,570 MW as of spring 2012;⁴² the remainder of its resources are imported (primarily from Quebec, New England or PJM) or in-state demand-side resources such as demand response. Locational capacity requirements encourage resources to be located where needed.

Figure 3-15. NYISO high-voltage transmission system and transmission congestion corridors



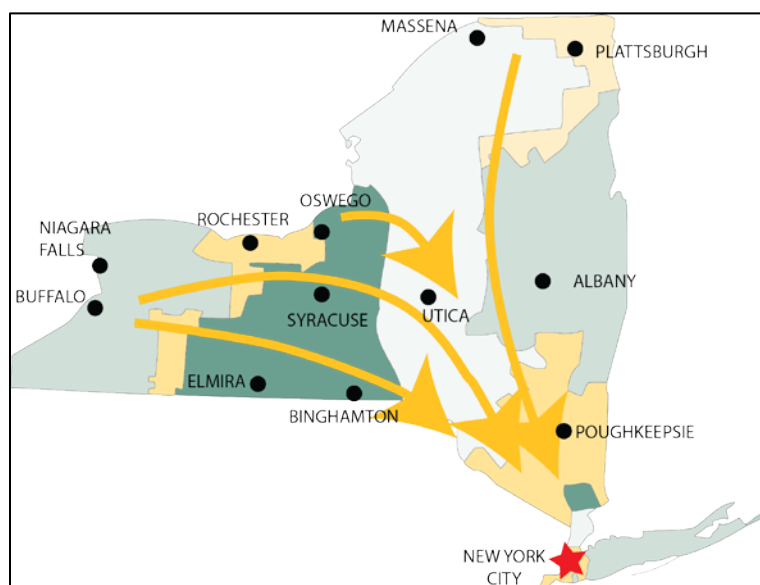
Source: NYISO (2012e). *Power Trends 2012: State of the Grid*, May 10, 2012, at http://www.nyiso.com/public/webdocs/newsroom/power_trends/power_trends_2012_final.pdf, Figure 17, p. 31.

⁴⁰Potomac Economics (2012c). 2011 State of the Market Report for the New York ISO Markets.

Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012. p. A-57.

⁴¹NYISO (2012e). *Power Trends 2012: State of the Grid*, May 10, 2012, at http://www.nyiso.com/public/webdocs/newsroom/power_trends/power_trends_2012_final.pdf, p. 34.

⁴²*Ibid.*, p. 14.

Figure 3-16. New York electricity flows

Source: Buechler, J. (NYISO) (2011). "NYISO Update for the 2012 National Electric Transmission Congestion Study," Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops," at <http://energy.gov/sites/prod/files/Presentation%20by%20John%20Buechler%2C%20NYISO.pdf>, p. 14.

The New York ISO reports that transmission congestion peaked in 2008 and has been declining since then.⁴³ Table 3-6 shows the most congested transmission constraints as a function of most congested hours over four years, as identified by NYISO. The magnitude of congestion is highest consistently over time at several of these constraints.

Most electricity transactions in New York are scheduled in the day-ahead market rather than the balancing (real-time) market, so much of New York's congestion is related to day-ahead transactions. Congestion pricing differences arise between regions when "scheduling between regions reaches the limits of the transmission network."⁴⁴ Figure 3-17 shows both the frequency and value of transmission congestion within New York's day-ahead market in 2010 and 2011 by sub-regions; the upper graph of the percentage of hours during which congestion occurs by sub-region indicates that the lines on Long Island and into and inside New York City load pockets were congested close to or well over 50% of each year. For both years, lines in the Central to East and external interfaces (New York's links to Quebec, New England, and PJM) were congested over a quarter of the time.

⁴³ *Ibid.*, p. 4.

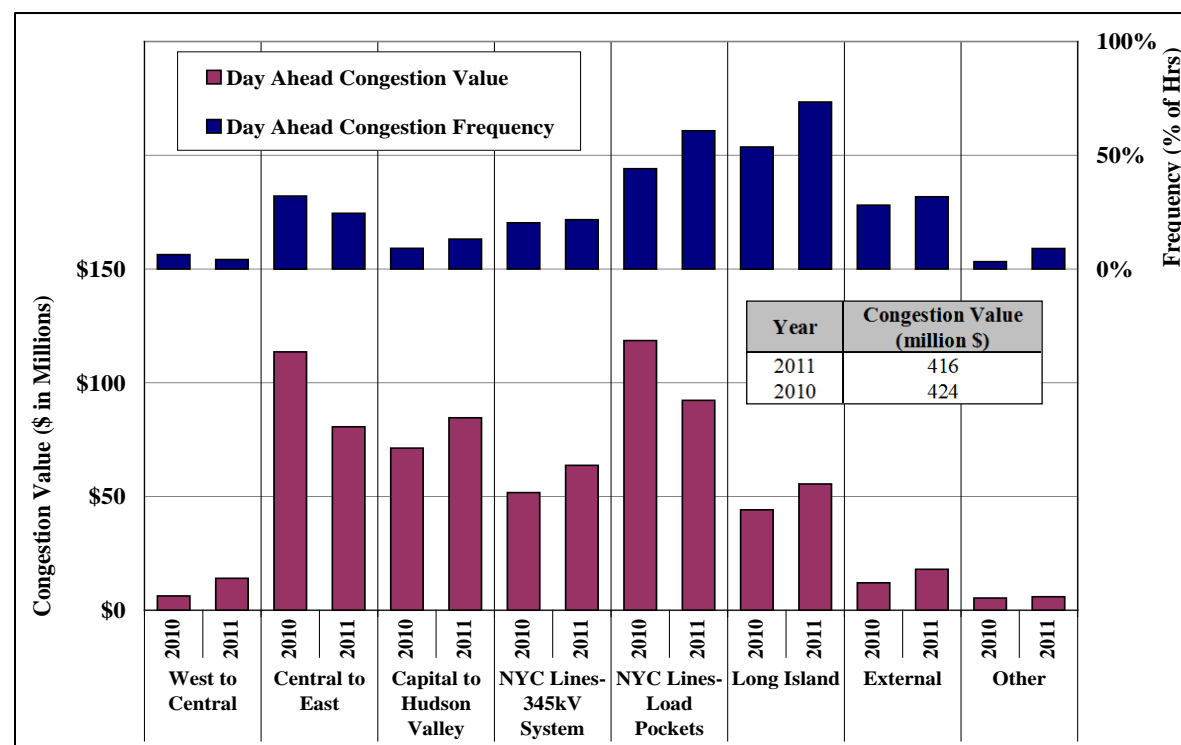
⁴⁴ Potomac Economics (2012c). 2011 State of the Market Report for the New York ISO Markets. Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012, http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_Report-Final_41812.pdf, at p. A-57.

Table 3-6. NYISO—Number of congested hours by constraint, 2008-2011

Constraint	2008	2009	2010	2011 (Projected)	2011 (% of year congested)
Dunwoodie-Shore Rd	4,469	5,240	4,292	7,820	83%
Goethals-Gowanus 345	329	121	460	2,801	32%
Greenwood Lines	4,741	4,330	4,317	4,382	50%
Central East	5,182	4,788	2,964	1,889	22%
Leeds-Pleasant Valley	1,083	725	673	1,830	9%
Astoria 138 HG5_138	0	0	0	1,361	16%
West Central	2,120	296	1	118	1%

Source: NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study, Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at

http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, p. 47.

Figure 3-17. Day-ahead congestion by transmission path, New York ISO, 2010-2011

Source: Potomac Economics (2012a). *2011 State of the Market Report for the New York ISO Markets*.

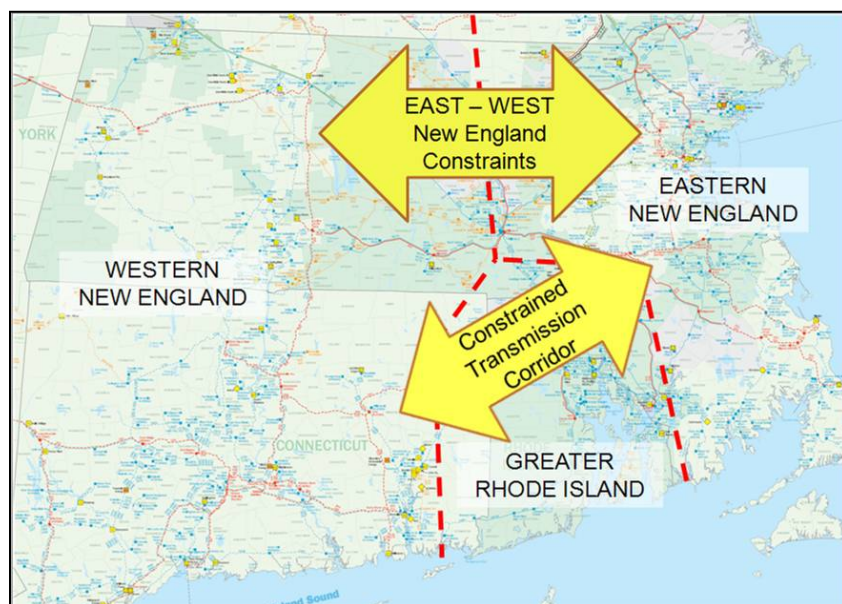
Prepared for Market Monitoring Unit for the New York ISO. April 2012, at

http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_Report-Final_41812.pdf, Figure A-44, pg. A-58.

New England

Broad transmission flows within New England are relatively predictable (see Figure 3-18). ISO-NE and its market monitor report that there currently are few consistently binding transmission constraints within the region. The former Boston load pocket is now also well-served with both local generation and transmission upgrades and many areas that once had voltage problems and needed out-of-merit generation have been addressed.⁴⁵

Figure 3-18. Overall congestion patterns in southern New England



Source: ISO-NE, (2011b). *2011 Regional System Plan*. Holyoke, MA: ISO-NE. October 2011, at http://iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc.

New England imports a significant amount of its energy. The region imports low cost electricity from Quebec (1,546 MW on average net imports per peak hour in 2011) and New Brunswick (average net imports of 87 MW during peak hours in 2011), and has been a net exporter to New York (exporting on average 397 MW per peak hour across the Cross Sound Cable and importing net 59 MW on the Roseton interface in 2011).⁴⁶

Inter-regional

As new transmission construction, lower loads and lower fuel prices combine to reduce transmission congestion across the Northeast, more of the congestion that remains is due to

⁴⁵ISO-NE (2011b). *2011 Regional System Plan*. Holyoke, MA: ISO-NE. October 2011, at http://iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc.

⁴⁶Potomac Economics (2012a). *2011 Assessment of the ISO New England Electricity Markets*, June 2012, at http://www.potomaceconomics.com/uploads/isonereports/ISONE_2011_EMMU_Report_Final_June_2012.pdf, pp. 47-49.

institutional seams issues rather than classic infrastructure constraints. According to a Brattle Group study, the consequences of the “artificial, rule-based barriers” can be significant:

- For the last 5 planning years, PJM capacity prices were about \$30/kW-yr greater than MISO prices. “But although the transmission system could reliably transfer 5,300-6,300 MW of capacity in the 2014-15 planning year, only 400 MW of capacity sales from MISO to PJM exist today”.
- 4,300 MW more transmission flow could be possible between MISO and Commonwealth Edison
- 2,000 MW more transmission flow could be possible between MISO and the rest of PJM
- Resolution of the barriers could create potential total capacity cost reductions of \$1.5 billion per year.⁴⁷

However, PJM takes issue with Brattle’s analysis and conclusions, noting that much higher levels of MISO generation capacity have been bid into PJM’s capacity markets and fills the available firm transmission capacity from west to east.⁴⁸

Although the eastern RTOs have made great progress at building new transmission inside their footprints to mitigate constraints and reduce congestion within their respective footprints, less transmission has been built that spans states and RTO seams.

As noted in Section 3.2.2 above, the eastern RTOs and ISOs are working with MISO to identify the causes of these market inefficiencies and mis-matches and find ways to reduce and eliminate them. Market-to-Market and seams coordination efforts include:

- Flowgate allocation and coordination to recognize impacts of each region on other’s flowgates and flows;
- Better communication, market-to-market scheduling and dispatch and congestion management; and
- Operations planning and market model coordination.

As the result of analysis conducted in the Broader Regional Markets Initiative the New York ISO and its neighbors developed the Interface Pricing Initiative to modify pricing methods and models that create incentives that have been exacerbating Lake Erie loop flows. New York

⁴⁷Newell, S.A., K. Spees (2011b). *Preliminary Issue Description: MISO-PJM Capacity Market Seam*. December 2011, at https://www.midwestiso.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Preliminary%20Brattle%20Report_MISO-PJM%20Capacity%20Seam%20Definition%20-%202011-12-06.pdf.

⁴⁸PJM (2011f). “Initial PJM Comments on Brattle/MISO Capacity Market Seam Report,” December 15, 2011, at <http://pjm.com/~media/documents/reports/20111215-initial-pjm-comments-on-brattle-miso-capacity-market-seam-report.ashx>.

proposed these revisions in a filing at FERC⁴⁹ but during the timeframe of this report, that issue has not yet been fully resolved in a final FERC ruling.⁵⁰

Another example is scheduling across the interface between New England and New York. Because of latency issues and differences in the dispatch and pricing systems, it is not possible to ensure that energy consistently flows between the two systems from the area of lower cost to the area of higher cost. New England's market monitor estimates that on the northern AC lines between NYISO and ISO-NE, "power only flow[ed] in the apparent "right" direction about half the time"⁵¹ during 2009, 2010 and 2011. If these transmission interfaces had been scheduled efficiently, "the total production cost of meeting demand in the two regions (combined) would have been lower by a cumulative \$77 million from 2006 through 2010."⁵² FERC approved tariff revisions in April 2012 to allow Coordinated Transaction Scheduling for NYISO and ISO-NE that are expected to remedy this problem.⁵³

New York and PJM have worked to improve the efficiency of transaction scheduling across their joint interface. To improve price convergence with better use of the interface, the two regions moved to scheduling transactions every 15 minutes (rather than only hourly scheduling). They are discussing the use of Coordinated Transaction Scheduling, initially based on the concept developed by New York and New England. They are also working on shared models and flow calculations across their joint transmission interfaces. These new market-to-market software and processes are scheduled to begin operations in early 2013.⁵⁴ To enhance system efficiency and reliability across broader regional markets, the New York ISO has committed to complete Coordinated Transaction Scheduling and Market to Market Coordination with ISO-New England, deploy Coordinated Transaction Scheduling with PJM, and Intra-hour Transaction Scheduling with Ontario.⁵⁵

⁴⁹FERC Docket No. ER08-1281-010.

⁵⁰Boshart, G. (2012). "FERC signs off on one Lake Erie loop flow fix, but not another." *SNL Energy*. March 15, 2012, at <http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=14450575>.

⁵¹ISO-NE (2012a). *2011 Annual Markets Report*. May 15, 2012, at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf, p. 21.

⁵²*Ibid.*, p. 21, citing to ISO-NE white paper, "Inter-regional Interchange Scheduling (IRIS) Analysis and Options," January 5, 2011.

⁵³Rivera-Linares, C. (2012a). "FERC approves tariff revisions for NYISO, ISO New England." *Transmission Hub*. April 19, 2012.

⁵⁴NYISO (2012f). "PJM Interconnection and New York ISO Boards commit to broader regional markets initiative," *press release*, October 17, 2012, at http://www.nyiso.com/public/webdocs/newsroom/press_releases/2012/20121017-PJM-NYISO-news-release.pdf.

⁵⁵NYISO (2012g). "2013-2017 Strategic Plan", December 2012, p. 6; NYISO (2012h). "Business Plan Highlights," December 2012, p. 3.

3.2.4. Southeast

Currently there is limited transfer capability between the Entergy system and SPP⁵⁶ and between Entergy and TVA. The Entergy system has transferred operational oversight of its transmission system from SPP to MISO.⁵⁷ This change may produce unintended congestion or reliability issues in neighboring regions such as TVA.⁵⁸ Flows in the Entergy region are also affected by changes in other regions. Seams create difficulties in determining the cost of transmission projects and allocation of those costs.⁵⁹

In this area of the country, few reports identify specific transmission constraints. The NERC Long Term Reliability Assessment contains some information on constraints, analyzing five sub-regions in the southeast: SERC-E, SERC-N, SERC-SE, SERC-W (largely coincident with Entergy) and FRCC. These areas are shown in Figure 3-19. Daily and monthly operational constraints for specific facilities are posted on the utilities' OASIS sites.

3.3. Economic congestion costs

Public information on economic aspects of congestion management is only available for the operation of organized wholesale electricity markets with congestion pricing. In the US, these markets are CAISO, MISO, PJM, NYISO and ISO-NE. Congestion and constraints impose real costs outside these markets, but those costs are not consistently made publicly available outside the market footprints.

⁵⁶Powell, D. (Entergy) (2011). "U.S. Department of Energy Pre-Congestion Study Regional Workshop for the 2012 National Electric Congestion Study." Presentation by Doug Powell of Entergy System at the US DOE (2011e) Regional Congestion Study Workshop. St. Louis, MO., December 8, 2011, at <http://energy.gov/sites/prod/files/Presentation%20by%20Doug%20Powell%2C%20Entergy.pdf>, slide 2.

⁵⁷Reeves, O. (Arkansas Commission) (2011). "Comments of Olan Reeves of the Arkansas Commission." Presented at the US DOE (2011e) Regional Workshop for the 2012 National Electric Congestion Study, St. Louis, MO., December 8, 2011, at, <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf>, pg. 31; Entergy (2012b). "LPSC Approves Entergy's Proposed Move to MISO." *Entergy press release*. May 23, 2012, at http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=2445.

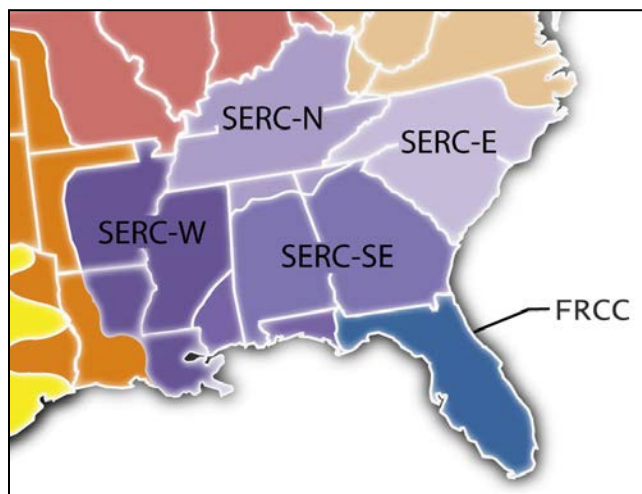
⁵⁸Till, D. (Tennessee Valley Authority) (2011). "Comments of D. Till of the Tennessee Valley Authority." Presented at the Regional Workshop for the 2012 National Electric Congestion Study." Excerpt from transcript of the U.S. Department of Energy (2011e), Regional Congestion Study Workshop, St. Louis, MO., December 8, 2011, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf>, p. 118.

⁵⁹Reeves, O. (Arkansas Commission) (2011). "Comments of Olan Reeves of the Arkansas Commission." Presented at the U.S. Department of Energy (2011e), National Electric Transmission Congestion Workshop, St. Louis, MO., December 8, 2011, at, <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf>, pg. 68.

3.3.1. CAISO

Congestion costs in CAISO are reported below for years 2006 to 2011. Because the congestion management systems and the way congestion was calculated differed between the CAISO market design that was in place before the 2009 Market Redesign and Technology Upgrade (MRTU) (referred to as “pre-MRTU”) and the redesigned MRTU markets in place in 2009, they are not directly comparable, and are reported on separate lines.⁶⁰

Figure 3-19. Map of NERC long-term reliability assessment sub-regions in the Southeast



Source: NERC (2011c). *2011 Long-Term Reliability Assessment*. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, p. x.

Table 3-7. CAISO congestion costs, 2006-2011 (\$M)

	2006	2007	2008	2009	2010	2011
CAISO: pre-MRTU ⁶¹	\$263	\$181	\$350			
CAISO: MRTU, Day Ahead Energy and Congestion				\$128	\$110	\$219

Source pre-MRTU: California ISO (CAISO) (2008). *2007 Annual Report on Market Issues & Performance*. Folsom, CA: CAISO. April 2008, at <http://www.caiso.com/Documents/2008AnnualReportonMarketIssuesandPerformance.pdf>, pp. 3, 4, 17, and 5.1; California ISO (CAISO) (2009). *2008 Annual Report on Market Issues & Performance*. Folsom, CA: CAISO. April 2009, at <http://www.caiso.com/Documents/2009AnnualReportonMarketIssuesandPerformance.pdf>, pp. 4, 5.1, and 6.5.

Source MRTU: unofficial estimates provided via personal communication with CAISO, August 1, 2012.

CAISO has several major interties, or transmission lines, that connect its system to surrounding areas. Congestion costs on interties were generally lower in 2011 than in 2009 and 2010. The exception is for the Pacific AC Intertie (COI) and Nevada-Oregon Border (PDCI). Above in Table

⁶⁰The MRTU percentages are unofficial estimates.

⁶¹Pre-MRTU percentage is intrazonal plus inter-zonal congestion as percent of total wholesale Energy and Ancillary Services cost. The Ancillary Services cost is a small percent of total cost.

3-7 these interties were shown to have only slightly more frequent congestion in 2011. This suggests that while congestion did not happen more frequently, when it did occur it was more costly. Again, according to the market monitor, this congestion is due “primarily” to planned outage and line maintenance.⁶²

The state of California has a population of over 37 million people and had a total energy load of roughly 259,000 GWh in 2010⁶³; this represents roughly 35% of the Western Interconnection load.⁶⁴ In 2011 CAISO imported 29% of its power over a few interties.⁶⁵ Generation outside of California has tended to be lower cost than in-state generation because of the technologies used: more coal, hydro, and nuclear are located out-of-state (although trends in the Southwest indicate this cost differential might be closing).⁶⁶ This cost differential, in combination with the limited number of intertie points and the cost and losses associated with long-distance transport of electricity, make the average cost of electricity inside California higher than the average outside California even before the impact of internal CAISO constraints. It also makes California vulnerable to reliability issues and cost spikes if and when intertie availability is compromised.

Figure 3-20 shows congestion costs associated with usage of interties from 2009 to 2011. Total day-ahead congestion charges for transmission over the interties in 2011 was \$127 million⁶⁷ (or slightly more than \$3 that year for each of the more than 37 million Californians who are served by CAISO).⁶⁸

The pattern of congestion costs has changed over time, apart from the general cost reduction in 2011 due to increased hydro production and low-cost imports, as well as moderate demand.⁶⁹ As mentioned above, imports were higher from the Pacific Northwest, due to increased wind

⁶²California ISO (CAISO) (2012b). *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 140-141

⁶³US Census Bureau (2012). “State & County Quick Facts: California,” at <http://quickfacts.census.gov/qfd/states/06000.html>; Energy Information Administration (EIA) (2011). *State Historical Tables for 2010, Retail Sales of Electricity to Ultimate Customers: by End-Use Sector by State by Provider*, at http://www.eia.gov/electricity/data/state/sales_annual.xls.

⁶⁴California ISO (CAISO) (2012). “The ISO grid,” at <http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx>.

⁶⁵California ISO (CAISO) (2012b). *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 33.

⁶⁶*Ibid.*

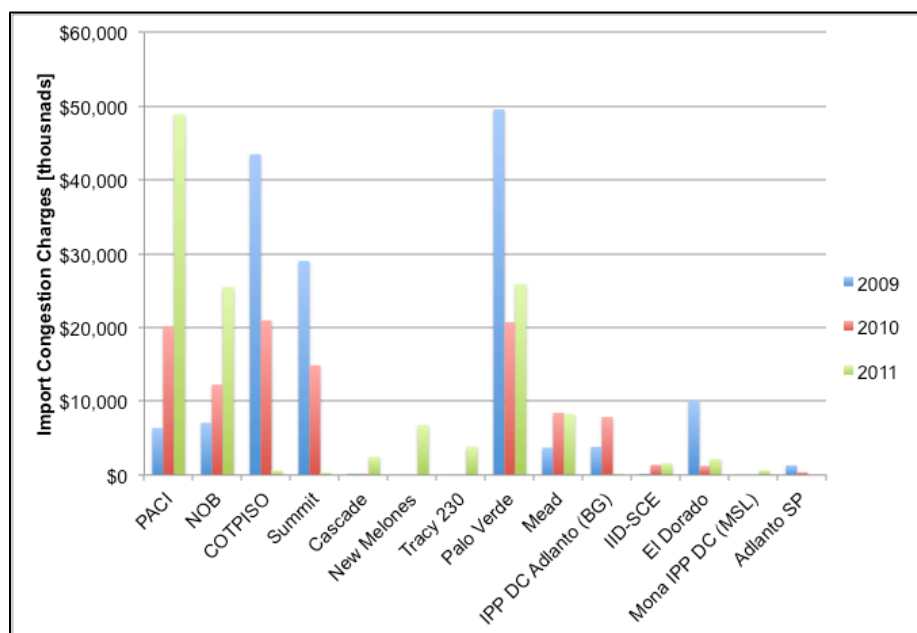
⁶⁷Intertie congestion charge is based on the shadow price of the intertie times the intertie limit in the day-ahead market. The shadow price of a constraint, described above in section 4.3.1, is only non-zero when the inter-tie is fully loaded. *Ibid.*, p. 132).

⁶⁸California ISO (CAISO) (2011b). *California ISO Company Information and Facts: Shaping a Renewed Future*. Folsom, CA: CAISO. May 2011, at http://www.caiso.com/Documents/CompanyInformation_Facts.pdf, p. 1.

⁶⁹California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 1.

and hydro in that region, and lower from the Southwest, because of decreased price differentials, in 2011 compared with 2009 and 2010.

Figure 3-20. Congestion charges on CAISO interties, 2009 to 2011



Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 133.

3.3.2. MISO

MISO's market monitor explains that:

. . . [C]ongestion costs arise when transmission line flow limits prevent lower-cost generation on the unconstrained side of a transmission interface from replacing higher-cost generation on the constrained side of the interface. This results in diverging LMPs that reflect the value of transmission When congestion arises, the price difference across an interface represents the marginal value of transmission capability between the two areas. When the power transferred across the interface or constraint reaches its limit, the cost of the resulting congestion is equal to the marginal value of the constraint . . . multiplied by the total flow over the constraint.⁷⁰

⁷⁰Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A-72.

For 2011, MISO's market monitor reports that:

The value of real-time congestion totaled \$1.24 billion, a 20% increase from 2010.⁷¹ The largest regional rise in congestion occurred in the Central region (up 44%), where market-to-market (M2M) constraints bound more frequently than in prior years. Congestion persisted in a west-to-east pattern, partly as a result of continued growth in wind output in the West. Wind output increased 30% to 3.0 GW. The introduction of the DIR [dispatchable intermittent resource] type in June 2011 has made congestion there more manageable.⁷²

Congestion costs within an RTO can also vary from year to year due to changes in its footprint—as a utility moves into or out of the control zone for an RTO, that change affects which flows occur within the RTO's boundaries and where the seams occur between RTOs. Total congestion costs for MISO in 2013 will not be comparable to those in 2011 and 2012 due to the addition of Entergy's transmission facilities into the MISO market.

Inside MISO, 2011 real-time congestion reflected a greater number of low-voltage constraints that it could not manage effectively.⁷³ A significant amount of the congestion costs were incurred in the North WUMS (Wisconsin and Upper Michigan) area, which MISO's market monitor calls the most congested area within MISO in 2011.⁷⁴

MISO tracks binding constraints that limit flows on transmission elements so that they will not exceed operating reliability limits. The region's market monitor explains that "constraints are violated, or considered "unmanageable," when the real-time market is unable to redispatch its resources quickly enough (or lacks sufficient redispatch capability) to relieve the constraint."⁷⁵ The market monitor further notes that the largest single factor causing short-term constraint violations was "unforeseen changes in network flows."⁷⁶ However, MISO's market monitor estimates that about \$245 million of 2011's congestion value (19% of the year's total) was unpriced in 2011 due to a "constraint relaxation algorithm" used as an operational practice—in other words, had MISO not used this algorithm, calculated congestion would have been \$245 million higher in 2011. Thirty percent of MISO's "unmanageable congestion" (\$140 million, or 19% of MISO's total annual congestion) was the result of a market practice called a "transmission deadband" that causes constraints to "appear to be violated," or bind at levels

⁷¹MISO's "gross annual market charges" in 2011 totaled \$23.6 billion, serving 38.9 million people across its service area. From "MISO Corporate Information," at <https://www.midwestiso.org/Library/Repository/Communication%20Material/Corporate/Corporate%20Fact%20Sheet.pdf>, p. 1.

⁷²Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. ii.

⁷³*Ibid.*, p. 43.

⁷⁴*Ibid.*, p. 9.

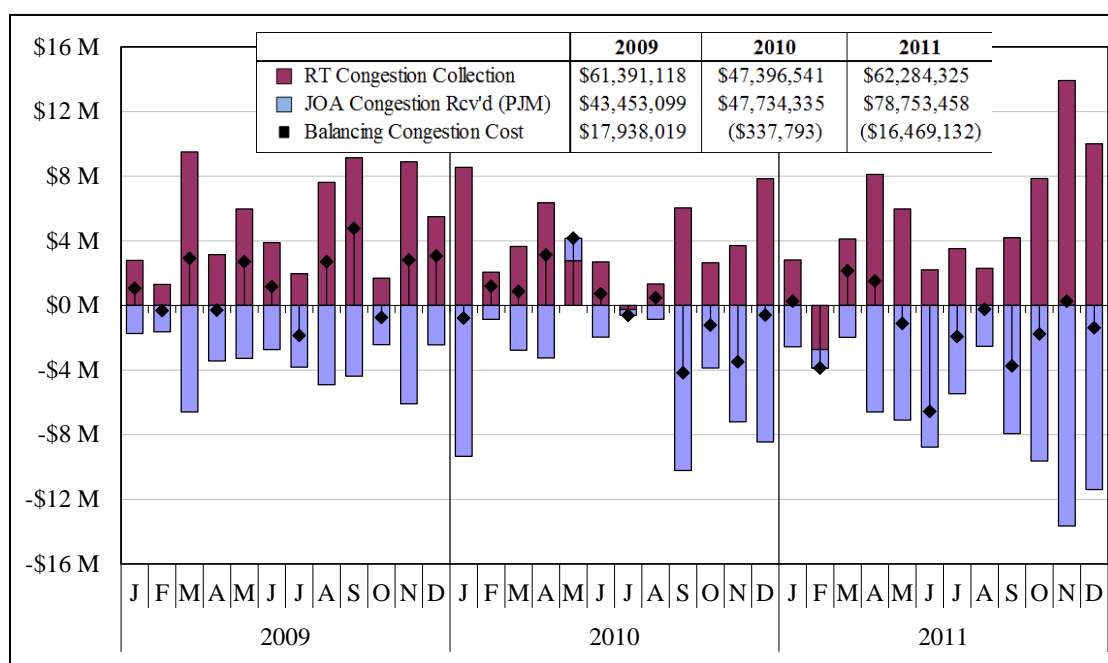
⁷⁵*Ibid.*, p. 44.

⁷⁶*Ibid.*, p. 44.

below their physical capability.⁷⁷ Thus, at least 38% of MISO's total annual congestion in 2011 was attributable to operational and administrative causes rather than actual physical transmission constraints.

Figure 3-21, from MISO's market monitoring report, shows the real-time congestion cost component of MISO's congestion costs. The negative costs shown indicate payments from PJM to MISO under the Joint Operating Agreement (JOA) to cover MISO redispatch to manage transmission congestion. Congestion revenues collected through the markets were much lower than the value of real-time congestion "due to loop flows that don't pay MISO for use of the network and PJM's entitlements on MISO's system."⁷⁸

Figure 3-21. Elements of real-time congestion costs in MISO, 2009-2011



Source: Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A-74.

MISO is a net importer during all hours and seasons, to meet its market's energy and capacity needs.⁷⁹ PJM is MISO's most extensive interface.⁸⁰ Data from the MISO market monitor indicate that a third of these imports flow across the interface with PJM.⁸¹

⁷⁷ *Ibid.*, p. 43-44.

⁷⁸ *Ibid.*

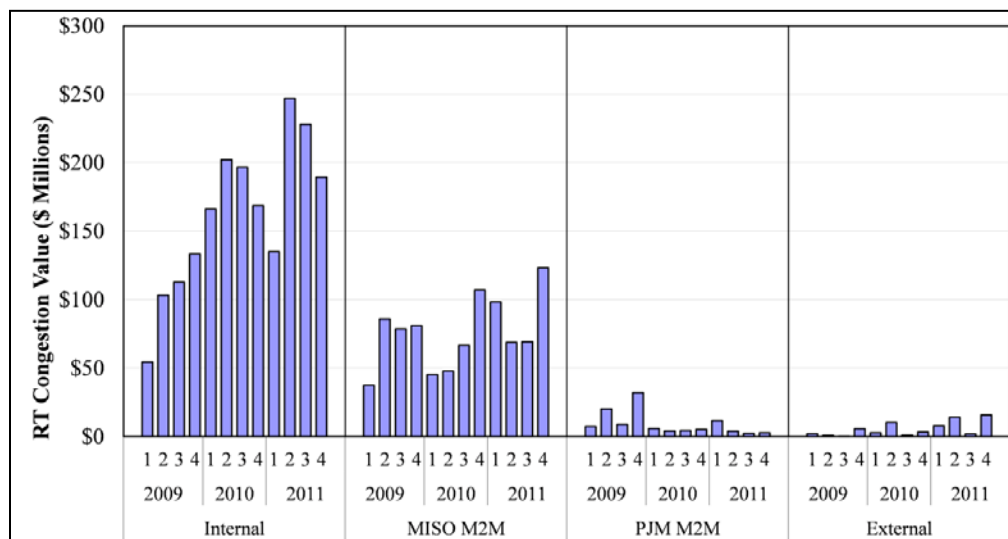
⁷⁹ *Ibid.*, p. A103.

⁸⁰ *Ibid.*, p. A106.

⁸¹ *Ibid.*, p. 47.

Figure 3-22 shows the four types of constraints MISO tracks—internal transmission constraints, MISO-coordinated Market-to-Market (M2M) constraints (much dominated by generation within the Commonwealth Edison footprint, which is part of PJM but located within the MISO boundaries), PJM-coordinated M2M constraints that affect MISO, and external constraints on other systems that MISO helps to manage using TLRs. As the figure shows, two-thirds of MISO’s congestion costs are caused by internal constraints, but the other third is caused by constraints within MISO that affect PJM.

Figure 3-22. Value of real-time congestion by type of constraint

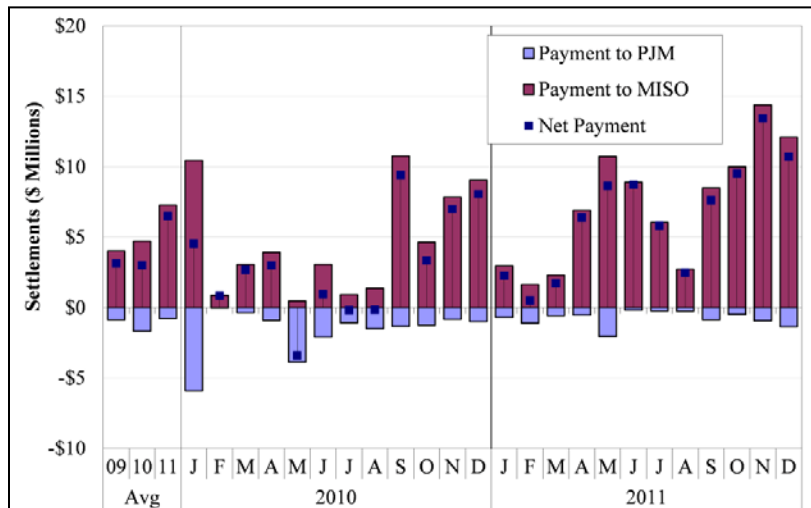


Source: Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, Figure A58, p. A-84.

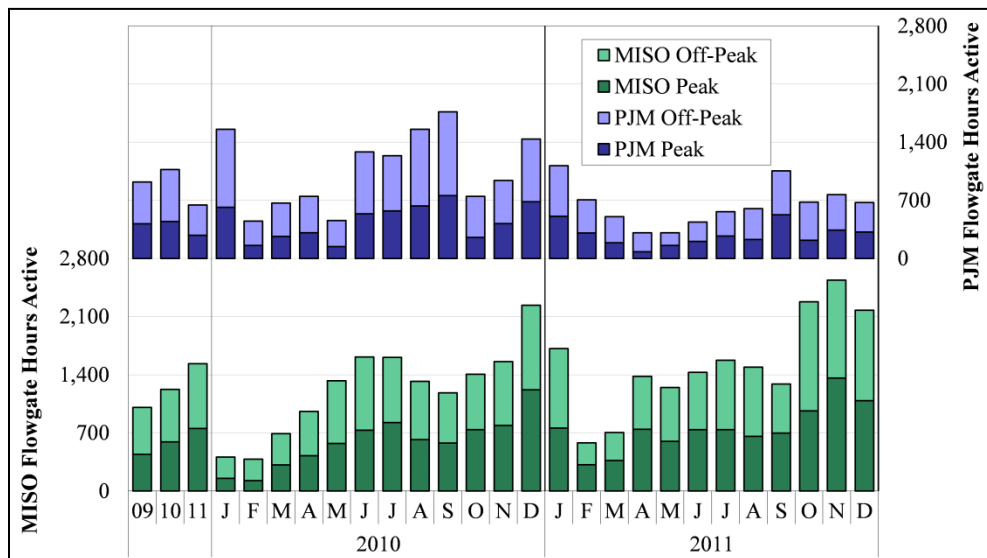
MISO and PJM have a Joint Operating Agreement (JOA) to manage constraints that affect both RTOs. The JOA “allows each RTO to more efficiently relieve congestion on its constraints with re-dispatch from the other RTO’s resources if it is less costly for them to do so.”⁸² In principle, each RTO is compensated for excess flows from the other RTO. As Figure 3-23 shows, between late 2009 and the end of 2011, M2M congestion increased on the transmission constraints inside MISO but declined inside PJM.

Figure 3-24, from MISO’s market monitor, shows the number of hours when constraints within MISO and PJM were binding and limited electricity flow between the two RTOs (or when a constraint within one RTO limited flows within the other RTO). Jointly coordinated flowgates within MISO (bottom half of the graph) constrained operations within PJM in far more hours than the coordinated flowgates within PJM; but more of the constraint hours for the PJM-coordinated flowgates occurred in off-peak hours than on-peak.

⁸²Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. 45.

Figure 3-23. Market-to-Market settlements between PJM and MISO, 2009-2011

Source: Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. 45.

Figure 3-24. Hours when flowgates within MISO and PJM created Market-to-Market congestion events, 2010-2011

Source: Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A89, Figure A71.

MISO'S market monitor annually reports on the five most frequently constrained points that PJM and MISO coordinate to manage congestion. For the year 2011, these were as follows⁸³:

PJM-coordinated M2M Constraints

1. Crete – St. John's
2. E. Frankfort – Crete
3. Mareng – Pleasant Valley
4. Nelson – Electric Junction
5. Burnham – Munster

MISO-coordinated M2M Constraints

1. Oak Grove – Galesburg
2. Michigan City – LaPorte
3. Kenosha – Lakeview
4. Lakeview – Zion
5. Prairie – Mt. Vernon

Several of these constraints are included within the most congested flowgates identified in Figure 3-24 above.

3.3.3. PJM

Within PJM, PJM's market monitor reports that total congestion costs equaled \$998 million in 2011, down 30% from \$1.42 billion from 2010.⁸⁴

Some specifics about congestion within PJM include:

- The top 20 congested elements account for 76% of PJM congestion.
- The top 3 most expensive congestion points are at interfaces with other RTOs, which cost \$455 million in 2011, down 36% from 2010; the most congested points are AP South, the 5004/5005, and West (see Table 3-8 below).
- Line congestion costs totaled \$333M in 2011, down 32% from 2010. The most congested lines in PJM were Electric Junction-Nelson, Dickerson-Quince Orchard, and Graceton-Raphael Road, accounting for 18% in congestion line costs.
- Congestion due to transformers cost \$186M in 2011, down 3% from 2010, with Belmont, Clover, and Susquehanna creating the most congestion.⁸⁵

⁸³Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p.A-104, Figures A77 and A78.

⁸⁴Monitoring Analytics (2012a). *State of the Market Report for PJM: 2011*, March 15, 2012, Vol. 2, p. 275, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml.

Table 3-8 tracks the congestion cost caused by each of the top PJM transmission constraints for 2008 through 2011. It shows that the trend over time has been for congestion costs to decline at most of PJM's top constraints. Although total PJM congestion costs rose in 2010, 2010 costs were lower than annual total PJM congestion charges in 2005, 2006, 2007 and 2008, despite the region's growth in size and load;⁸⁶ the 2009 congestion costs were extraordinarily low because average hourly MWh loads fell by 4.4% and average LMPs fell by 45% relative to 2008.⁸⁷

Table 3-8. Top PJM constraints by congestion cost (million \$)

Constraint	2008	2009	2010	2011
AP South	\$558	\$207	\$420	\$239
Cloverdale-Lexington	\$229	\$16	\$29	\$6
Mt Storm-Pruntytown	\$224	\$21	\$24	*
Bedington-Black Oak	\$165	\$20	\$105	\$30
West	\$106	\$44	\$22	\$59
Kammer	\$76	\$34	*	*
5004/5005 Interface	\$43	\$44	\$92	\$76
Pleasant Valley-Belvedere	*	\$34	\$16	*
Doubs	*	\$25	\$64	*
AEP-Dominion	*	\$9	\$62	\$38
Belmont	*	*	\$27	\$54
Branchburg-Readington	\$31	*	\$12	*
East	\$40	*	*	\$18
Total PJM Congestion Cost[^]	\$2,117	\$719	\$1,424	\$998

*Denotes years or adjacent years where the congested number of hours was not reported because it was not in the Top 25.

[^] The total represents all constraints, and is therefore not the sum of the column, as row entries shown here are only for the top congested paths.

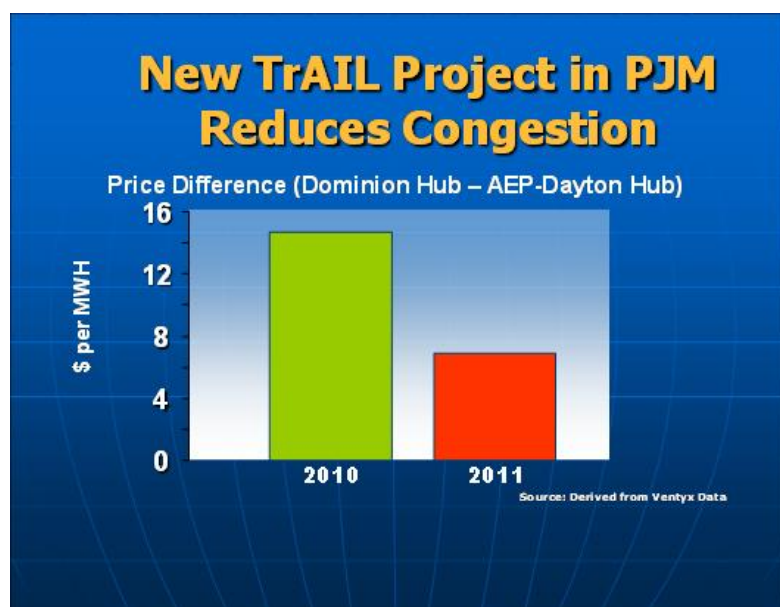
Source: Monitoring Analytics (2012a). *State of the Market Report for PJM: 2011*, March 15, 2012, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml, Section 10, Table 10-14, p. 274 and Table 10-25, p. 280.

Major new transmission projects in PJM have had significant impacts upon congestion costs. Figure 3-25 shows the impact of the TrAIL (Trans-Allegheny Interstate Line) project on the LMP differential between the line's endpoints (AEP-Ohio and Dominion in Virginia)—the new line created enough new transmission capacity to help narrow the price differential by over 50% within a year.

⁸⁵ *Ibid.*, p. 277.

⁸⁶ Bowring, J. (Monitoring Analytics) (2011). "2010 Year in Review, presentation at PJM Annual Meeting." May 17, 2011, slide 10.

⁸⁷ *Ibid.*, slides 7-8.

Figure 3-25. TrAIL project helped lower LMP differential by over 50% in 2011

Source: FERC (2011d). *State of the Markets*. April 2011, at <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2011.pdf>, slide 14.

PJM's market monitor reports that non-transmission factors drive PJM congestion cost increases—particularly increased load, higher gas/fuel costs, and generation additions in the western part of the system (particularly new wind)⁸⁸ which cannot reach eastern loads by the transmission constraints noted above. New resources in eastern PJM, where the loads are, are being procured that lower congestion costs. Five new generators cleared PJM's May 2012 forward capacity auction, including three in New Jersey, one in Delaware and one in Maryland; these are scheduled to come on line no later than June 1, 2015.⁸⁹ The auction also procured 14,833 MW of demand response,⁹⁰ much of which will lower peak load demand in eastern PJM.

Table 3-9 shows congestion costs within PJM by control zone (which generally track utility service footprints). These are raw total dollar costs that are not normalized by the amount of load served. Positive congestion costs mean that congestion caused delivered energy costs to be higher to the customers receiving wholesale electricity within that area; negative congestion costs mean that due to transmission constraints, new energy production in these areas lowers congestion. The table shows that the costs were uniformly the highest in 2008. The highest

⁸⁸PJM (2012b). *PJM 2011 Regional Transmission Expansion Plan*. Norristown, PA: PJM. February 2012, at <http://www.pjm.com/documents/reports/rtep-report.aspx>, p. 77.

⁸⁹PJM (2012d). "PJM capacity auction secures record amounts of new generation, demand response, energy efficiency; auction maintains reliable power supplies for consumers," *Press release*, May 18, 2012, at <http://www.pjm.com/~media/about-pjm/newsroom/2012-releases/20120518-pjm-capacity-auction-secures-record-amounts-of-new-generation-demand-response-energy-efficiency.ashx>; Rivera-Linares, C. (2012l). PJM: "Recommendation to remove PATH, MAPP partly due to reduced load growth." *Transmission Hub Morning Report*, August 9, 2012, at http://www.wiresgroup.com/docs/TransHub_Path_081012.pdf.

⁹⁰*Ibid.*

costs have been declining over time in the eastern zones, while costs have been somewhat more constant over time in the western zones. While there has been some volatility (in 2010), the trend has been toward lower costs.

Table 3-9. PJM Congestion costs by control zones (million \$)

Control Zone	2008	2009	2010	2011
EASTERN ZONES				
AECO	\$58	\$15	\$28	\$29
AP	\$487	\$95	\$283	\$144
ATSI	n/a	n/a	n/a	-\$3
BGE	\$92	\$34	\$92	\$51
DLCO	\$20	\$16	\$31	\$20
DPL	\$96	\$31	\$47	\$39
Dominion	\$323	\$113	\$286	\$139
External	-\$75	-\$1	-\$15	-\$35
JCPL	\$189	\$31	\$51	\$46
Met-Ed	\$16	\$1	\$8	-\$2
PECO	-\$64	-\$24	-\$15	\$9
PENELEC	\$166	\$33	\$107	\$59
PPL	-\$9	-\$6	-\$8	\$1
PSEG	\$73	\$11	\$4	-\$5
Pepco	\$216	\$58	\$98	\$71
RECO	\$10	\$2	\$4	\$2
TOTAL EAST	\$1,598	\$409	\$1,001	\$565
WESTERN ZONES				
ComEd	\$284	\$220	\$263	\$239
AEP	\$224	\$83	\$155	\$195
Dayton	\$12	\$8	\$10	\$3
TOTAL WEST	\$520	\$311	\$428	\$437

Source: Monitoring Analytics (2012a). *State of the Market Report for PJM–2011*, March 15, 2012, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml. Appendix G, Table G-6, p. 394.

3.3.4. NYISO

New York measures congestion costs in terms of “Bid Production Cost,” which measures the total economic benefit of reducing congestion—it represents the total generating cost of producing power to serve load and includes generator fuel cost, variable operations and maintenance costs, emissions costs and start-up costs;⁹¹ congestion costs represent the estimated additional cost that customers paid given system constraints over what they would have paid under perfect dispatch with an unconstrained transmission system (estimated using a production cost model of the New York system).

Calculated congestion within New York was highest in 2008, and has been declining since that time as electricity costs declined. Figure 3-26 shows that congestion costs were double or more in 2008 relative to congestion costs in subsequent years. Lower natural gas prices, lower load forecasts and new generation and transmission in southeast New York have reduced current and projected congestion;⁹² New York’s market monitor reports that “[a]verage electricity prices at the zone level in New York fell 6 to 8 percent from 2010 to 2011,” with natural gas prices down an average of 8 percent in 2011 and more than one gigawatt of new gas-fired generating capacity installed in the Capital Zone (September 2010) and New York City (July 2011).⁹³

Table 3-10 lists historic congestion across New York’s most constrained transmission paths for the period 2006 through 2010, as determined by the NYISO. The top four constraints create persistent congestion within the New York system. New York’s market monitor notes that congestion into Long Island became more significant in 2011 “due to several significant outages of the transmission lines that bring imports from Upstate New York and from PJM.”⁹⁴ It also observes that day-ahead congestion revenues are highest in winter months (when natural gas prices are higher so more low-cost energy tries to flow from west to eastern New York, where more generation is gas-fired) and in the summer (when loads are higher and, to deal with more frequent Thunderstorm Alerts, the ISO lowers real-time transfer capability into Southeast New York to reposition available generation capacity closer to loads, increasing congestion into Southeast New York, New York City and Long Island).⁹⁵

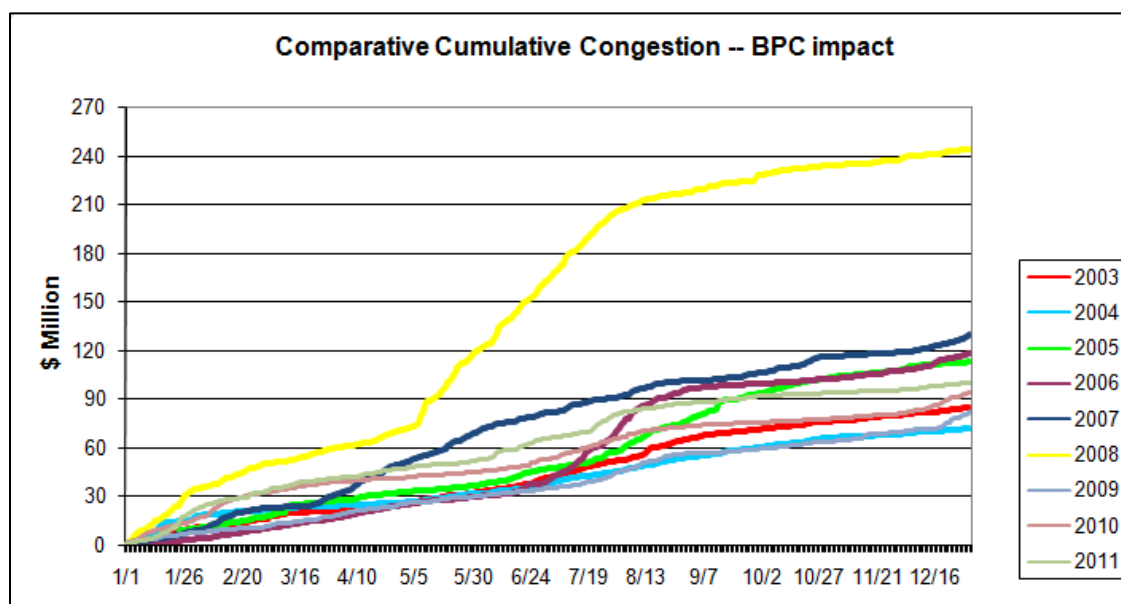
⁹¹Buechler, J. (NYISO) (2011). “NYISO Update for the 2012 National Electric Transmission Congestion Study,” Presentation at the US DOE (2011b) Regional Workshop, Philadelphia, PA. December 6, 2011, at <http://energy.gov/sites/prod/files/Presentation%20by%20John%20Buechler%2C%20NYISO.pdf>, p. 9; Comments of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., DOE NETCS Comments, 1/31/12, p. 4.

⁹²NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study, Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, pp. 7-8.

⁹³Potomac Economics (2012c). *2011 State of the Market Report for the New York ISO Markets*. Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012, p. 1.

⁹⁴Potomac Economics (2012c). *op. cit.*, p. 6.

⁹⁵*Ibid.*, pp. 20 and 26.

Figure 3-26. Cumulative congestion costs in New York, 2003-2011

Source: NYISO, "Comparative Cumulative Congestion – BPC Impact, Annual Historic Congestion Report," at http://www.nyiso.com/public/webdocs/services/planning/congestion_costs/congested/2011_Annual.zip.

Table 3-10. NYISO historic Demand\$ (millions) congestion by constrained path 2006-2010

Constrained Path *	2006	2007	2008	2009	2010	Total
CENTRAL EAST	195	572	1,199	435	491	2,892
LEEDS_PLSNTVLY 345	452	435	667	149	232	1,935
DUNWOODIE_SHORRD_345	492	260	187	118	155	1,212
GREENWOOD LINES	119	90	113	87	132	541
WEST CENTRAL-OP	2	51	55	1	0	109
ASTORIAW138_HG5_138	1	2	1	0	0	5
GOTHLS S_ GOWANUS_ 345	0	0	0	0	0	1

*Ranking is based on absolute values

Source: NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study, Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, pp. 7, 43.

Table 3-11, also from the NYISO, lists New York's most constrained transmission facilities in 2010 and the impact of each on 2010 congestion costs—together these seven transmission constraints reportedly caused 90.5% of New York State's calculated congestion in 2010. The high-congestion Central East point is the substation through which much of New York's generation in the western and northern portions of the state must pass to reach loads in the

southeastern portion. The New York ISO reports that average price differentials between generation-rich western and load-heavy eastern New York were 36 to 37% in 2009 and 2010.⁹⁶

Table 3-11. New York transmission constraints, impact on 2010 and 2011 total congestion

Monitored Facility	% of annual total congestion		Cumulative % of total annual congestion	
	2010	2011	2010	2011
Central East – VC	45.2	33.2	45.2	33.2
Pleasant Valley 345 Leeds	22.8	15.0	68.0	*
Dunwoodie 345 – Shore Rd 345	14.5	20.0	82.5	*
Leeds 345 – New Scotland 345	3.1	19.1	87.6	87.3
Springbrook 345 – E. Garden Center 345	1.9	1.5	87.6	*
Greenwood 138 – Vernon 138	1.7	0.3	89.2	*
Motthaven 345 – Dunwoodie 345	1.3	1.3	90.5	*

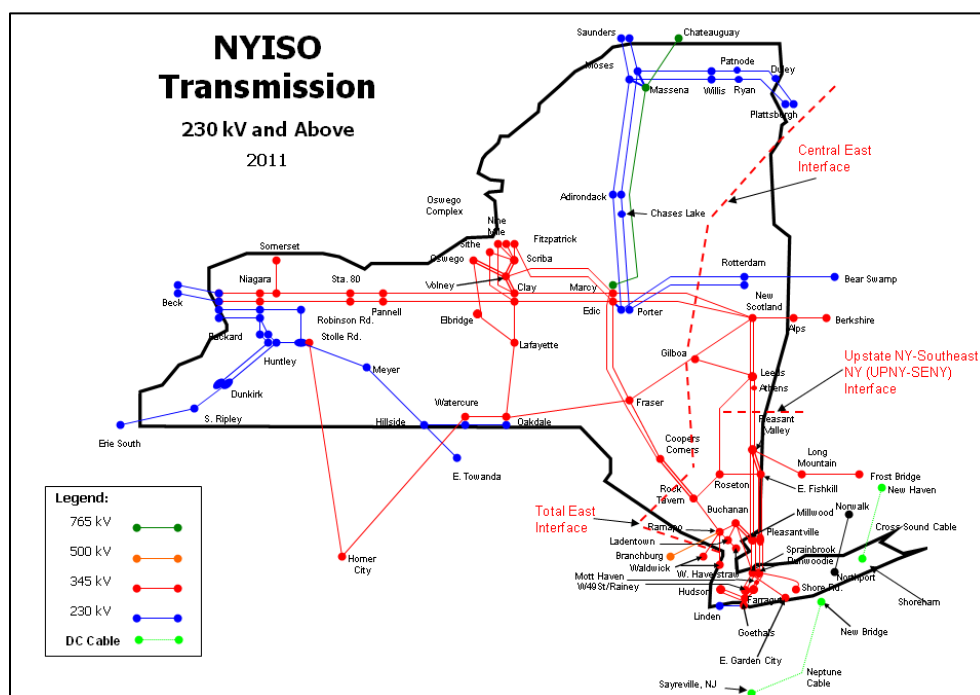
* in the Cumulative % of total annual congestion for 2011 means that the calculation is inappropriate because the facilities do not maintain the same congestion contribution order given.

Source: Buechler, J. (NYISO) (2011). “NYISO Update for the 2012 National Electric Transmission Congestion Study,” Presented at the United States Department of Energy (2011a). “Material Submitted: Pre-Congestion Study Regional Workshops”, at [http://energy.gov/sites/prod/files/Presentation by John Buechler, NYISO.pdf](http://energy.gov/sites/prod/files/Presentation%20by%20John%20Buechler,%20NYISO.pdf), p. 12; NYISO, “Annual Constraint Summary,” 2012, at http://www.nyiso.com/public/webdocs/services/planning/congestion_costs/congested/2011_Annual.zip.

Figure 3-27 shows New York’s transmission system, to identify the locations of these constrained paths.

NYISO projections of future congestion under several scenarios indicate that the above paths will continue to act as constraints that create on-going congestion, as shown in Table 3-12. Like Table 3-10, this projection measures future congestion in terms of “Demand\$ congestion”, defined as the congestion component of load payments, which equals zonal load times the constraint shadow price times the load zone shift factor (which is not the same as congestion payments by load).

⁹⁶Potomac Economics (2011b). *2010 State of the Market Report for the New York ISO Markets*, July 2011, at http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2010_Final.pdf, p. 24.

Figure 3-27. New York transmission system

Source: NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study, Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, p. C-6.

Table 3-12. Projection of future congestion (Demand\$ million) in New York by constrained path

Nominal Value (\$M)	2011	2012	2013	2014	2015	Total
CENTRAL EAST	268	226	229	209	212	1,144
LEEDS_PLSNTVLY 345	228	199	206	187	205	1,025
DUNWOODIE_SHORRD_345	41	46	49	54	57	247
GREENWOOD LINES	10	10	11	12	12	55
GOTHLSS_GOWANUSS_345	5	4	4	4	5	22

* Reported numbers represent absolute values.

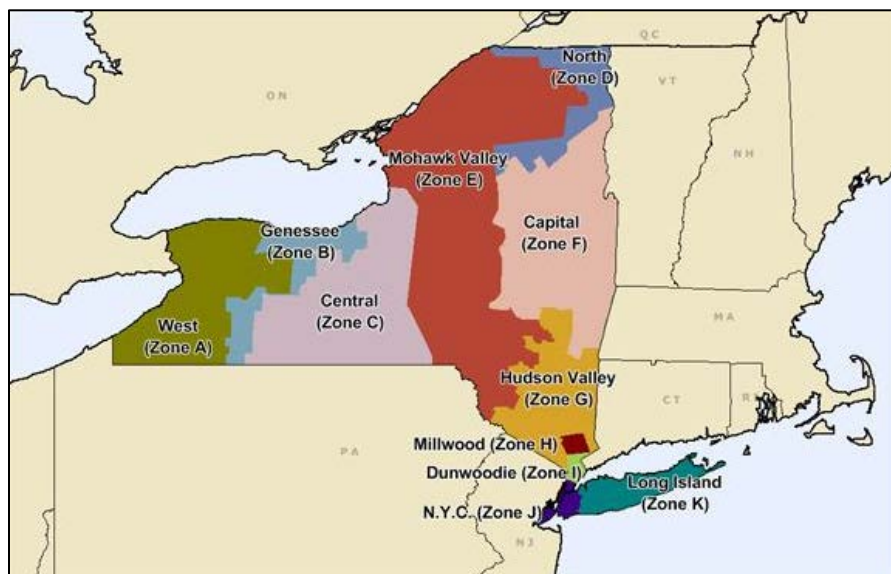
Source: NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study, Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, p. 46.

New York's market monitor offers several observations about congestion within the state:

- Transmission congestion costs increase with higher natural gas prices, which increase the cost of redispatching resources.
- Natural gas is the primary fuel in eastern New York—in southeastern New York, natural gas-fired generation is on the margin over 90% of the time⁹⁷—so increases in natural gas prices tend to increase flows from western New York, which is less reliant on natural gas.
- Although congestion costs increased in 2010, west-to-east congestion was less frequent because imports from neighboring areas into Western New York decreased (which reduced the overall flow from West to East) and clockwise loop flows around Lake Erie (that tend to load the west-to-east transmission interfaces in New York) decreased notably in 2010.⁹⁸

Figure 3-28 shows New York's eleven load zones.

Figure 3-28. Map of NYISO location-based marginal pricing zones



Source: FERC (2012d). *New York ISO: Market Overview and Focal Points*. May 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/new-york.asp>, slide 1.

⁹⁷ Miller, R. (Edison Company) (2012), "Comments of Consolidated Edison [sic] Company of New York, Inc. and Orange And Rockland Utilities, Inc.," Comments submitted to U.S. DOE for the 2012 Congestion Study, January 31, 2012, at <http://energy.gov/sites/prod/files/Consolidated%20Edison%20Company%20of%20New%20York%20and%20Orange%20and%20Rockland%20Utilities%20-%20Comments%20to%20the%202012%20Congestion%20Study.pdf>, p. 2.

⁹⁸ Potomac Economics (2011b). *2010 State of the Market Report for the New York ISO Markets*. Prepared by Potomac Economics for the Independent Market Monitor for the New York ISO. July 2011, at http://www.potomaceconomics.com/uploads/nyiso_reports/NYISO_2010_Final.pdf, at pp. iv & v.

Table 3-13, from NYISO, compares total annual congestion costs across the load zones from 2006 through 2010 and shows that costs have been consistently highest in the New York City and Long Island zones, with the Hudson Valley a distant third.

Figure 3-29 shows day-ahead congestion costs by transmission path within New York for 2010 and 2011. It shows that congestion costs varied across groups of paths between 2010 and 2011, and that the four zones in the southeast (labeled Central to East, Capital to Hudson Valley, NYC Lines—345 kV system, and NYC Lines in Load Pockets) together accounted for much of the congestion cost. New York's market monitor calculates the value of congestion as the marginal cost of relieving the constraint (shadow price) multiplied by the scheduled flows across the line or interface, and collects this amount in revenues to fund Transmission Congestion Cost payments to transmission customers.⁹⁹

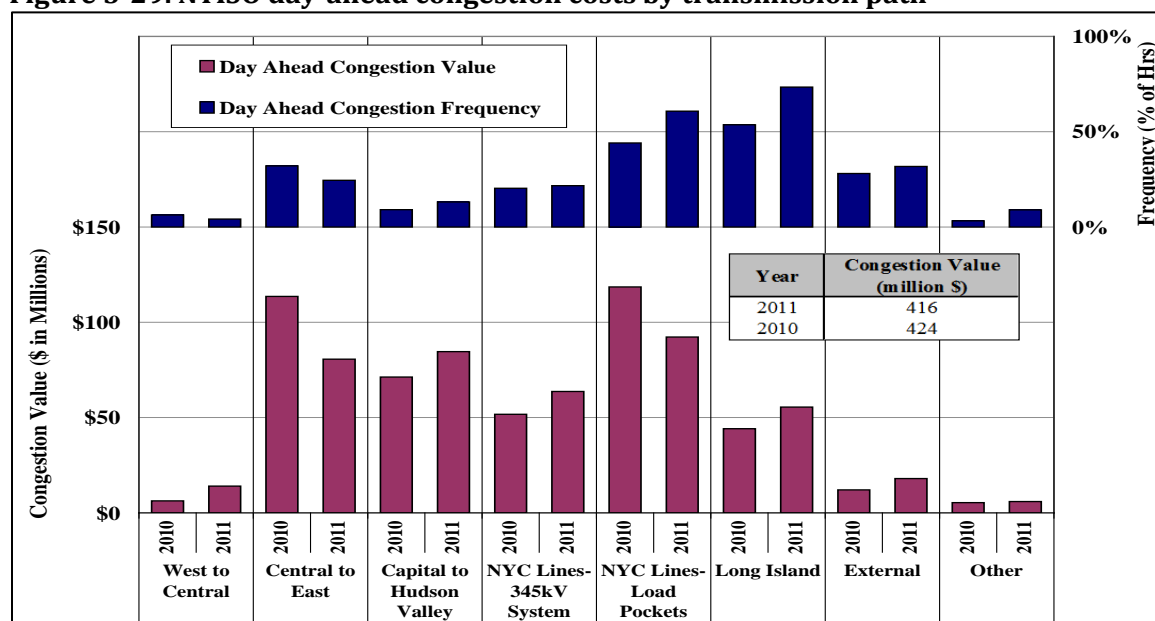
Table 3-13. Historic NYISO congestion costs by zone 2006-2010 (nominal \$M)

Zone	2006	2007	2008	2009	2010
West	1	(14)	(25)	(14)	(1)
Genesee	2	(14)	(9)	4	6
Central	4	9	18	8	11
North	0	0	(2)	(3)	(1)
Mohawk Valley	2	5	10	4	5
Capital	27	74	143	53	62
Hudson Valley	54	87	175	57	73
Millwood	27	31	78	16	23
Dunwoodie	44	56	124	41	49
NY City	673	700	1403	503	560
Long Island	708	518	624	274	350
NYCA Total	1,542	1,508	2,613	977	1,141

Notes: The reported values do not deduct TCCs. NYCA totals represent the sum of absolute values. Athens SPS in service 2008-2010 (and 2011). DAM data include Virtual Bidding & Transmission planned outages.

Source: NYISO (2012a). *2011 Congestion Assessment & Resource Integration Study Phase 1*. Rensselaer, NY: NYISO. March 20, 2012, at http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report_3-20-12.pdf, p. 43.

⁹⁹Potomac Economics (2011b). *2011 State of the Market Report for the New York ISO Markets*. Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012, p. A-57 & A-58.

Figure 3-29. NYISO day-ahead congestion costs by transmission path

Source: Potomac Economics (2012c). *2011 State of the Market Report for the New York ISO Markets*. Prepared for Market Monitoring Unit for the New York ISO. April 2012, Figure A-44, p. A-58.

New York's market monitor also notes that changes in some operational and modeling practices will lower congestion costs in the future. For instance, in 2011 the NYISO corrected an inconsistency built into the economic model of Transmission Congestion Contract auctions relative to the day-ahead markets; this model correction could reduce congestion shortfalls by almost \$16 million per year.^{100 101}

3.3.5. ISO-NE

In 2011, total New England "system-wide congestion-related costs totaled approximately \$37 million, and payments for generators in "must-run" situations that provided second-contingency coverage and voltage support totaled \$9 million. These represent significant reductions from 2008 when congestion totaled \$273 million and generator payments for "must-run" situations totaled \$212 million."¹⁰²

¹⁰⁰*Ibid.*, at pp. 26 and A-60.

¹⁰¹Additionally, NYISO "introduced Interface Pricing reforms in February 2012 that should improve the accuracy of prices in the day-ahead and real-time market models that are associated with external transactions and generation dispatch. These reforms should better align flows in the NYISO market models with actual power flows" and thus reduce artificial congestion. (*Ibid.*, p. 30.)

¹⁰²ISO New England, Internal Market Monitor (2012). "2011 Annual Markets Report," http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf, p. 9.

3.4. Wholesale electricity price differentials

3.4.1. Western Interconnection

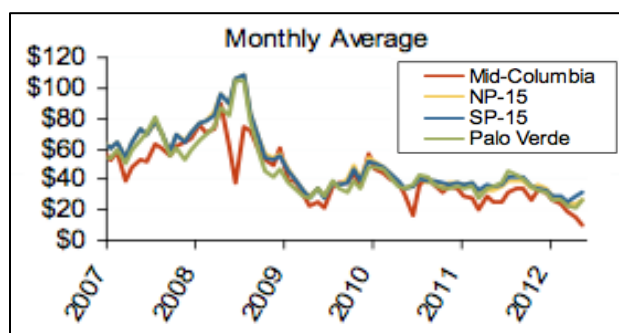
3.4.1.1. West-wide electricity price differentials

Daily index prices are available for some key trading points in the west.¹⁰³ Figures 3-30 through 3-32 show day-ahead on-peak index prices from 2007 to May 2012 for several hubs in California (north of Path 15 (NP-15), and south of Path 15 (SP-15)), the Pacific Northwest (Mid-Columbia, California-Oregon Border) and the Southwest (Palo Verde, Four Corners). In general, prices overall have decreased and stayed low since 2008, and there is not much price separation between the hubs since 2009. Mid-Columbia, located in the Pacific Northwest on the Washington-Oregon border, tends to be lower than the California and other hubs.¹⁰⁴

3.4.1.2. CAISO electricity price differentials

The CAISO also reports economic impacts for internal constraints. Figure 3-33 and Figure 3-34 show the impact constraint congestion has on the prices within the main three utility load areas (PG&E, SCE and SDG&E).

Figure 3-30. Western daily index day-ahead on-peak prices (in \$/MWh)

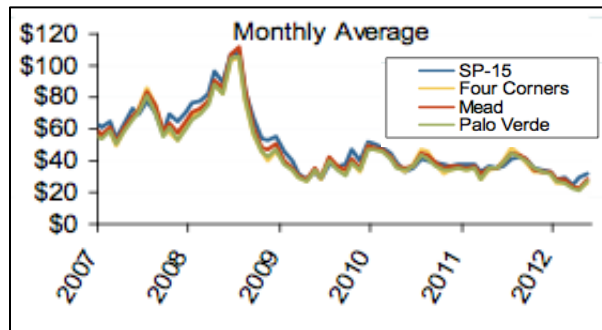


Source: Federal Energy Regulatory Commission (FERC) (2012a). *California Independent System Operator: Overview and Focal Points*. May 2012, at <http://ferc.gov/market-oversight/mkt-electric/california/2012/07-2012-elec-ca-archive.pdf>.

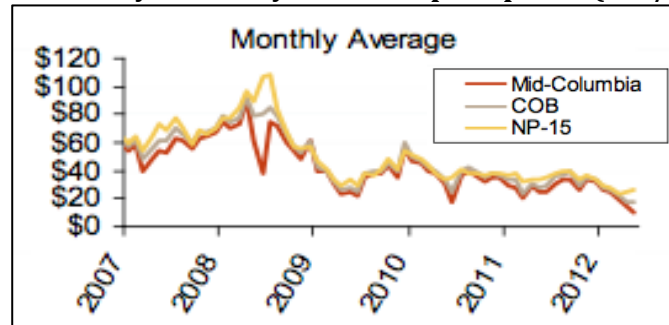
¹⁰³These index prices are calculated by Platts based on deal and trade prices self-reported by market participants (including utilities, service providers, and traders). Platts (2012). "Methodology and Specifications Guide: North American Electricity," at

http://www.platts.com/IM.Platts.Content/methodologyreferences/methodologyspecs/na_power_method.pdf.

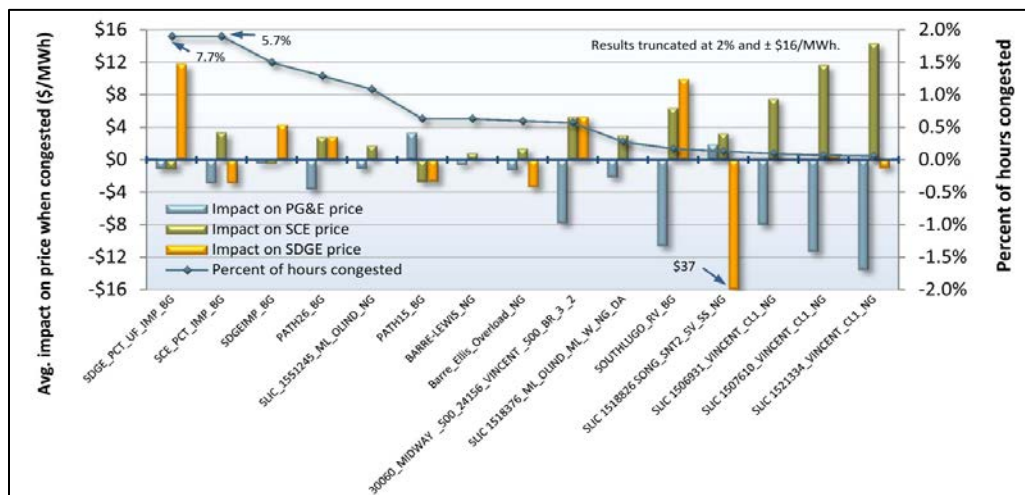
¹⁰⁴Westerners have studied the usage and potential for upgrading the main transmission route connecting the Pacific Northwest and Northern California, Path 66 or the California-Oregon Intertie. These studies found that upgrading the path by 2,000 MW would cost \$4 billion, and thus far have not been found to be economic under existing system and other conditions. (Metague, S. (Pacific Gas & Electric) (2011). "Comments of Steve Metague." Provided at the United States Department of Energy (2011a). *National Electric Transmission Congestion Study Workshop*. Portland, Oregon, December 13, 2011, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Portland%20Workshop.pdf>, pp. 75-77).

Figure 3-31. Southwestern daily index day-ahead on-peak prices (in \$/MWh)

Source: Federal Energy Regulatory Commission (FERC) (2012a). *California Independent System Operator: Overview and Focal Points*. May 2012, at <http://ferc.gov/market-oversight/mkt-electric/california/2012/07-2012-elec-ca-archive.pdf>.

Figure 3-32. Northwestern daily index day-ahead on-peak prices (in \$/MWh)

Source: Federal Energy Regulatory Commission (FERC) (2012a). *California Independent System Operator: Overview and Focal Points*. May 2012, at <http://ferc.gov/market-oversight/mkt-electric/california/2012/07-2012-elec-ca-archive.pdf>.

Figure 3-33. Frequency and cost impact of congestion on internal constraints (February-December 2011)

Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 136.

The vertical bars in Figure 3-33 show for each constraint the magnitude of average price impact in 2011 on the load areas averaged during times the constraint was congested. For the most part, constraints caused lower prices for PG&E (located in Northern California). That means when congestion occurred, Northern California was generally on the generation or supply side of the constraint and not all the available low cost power could flow south due to transmission constraints.¹⁰⁵

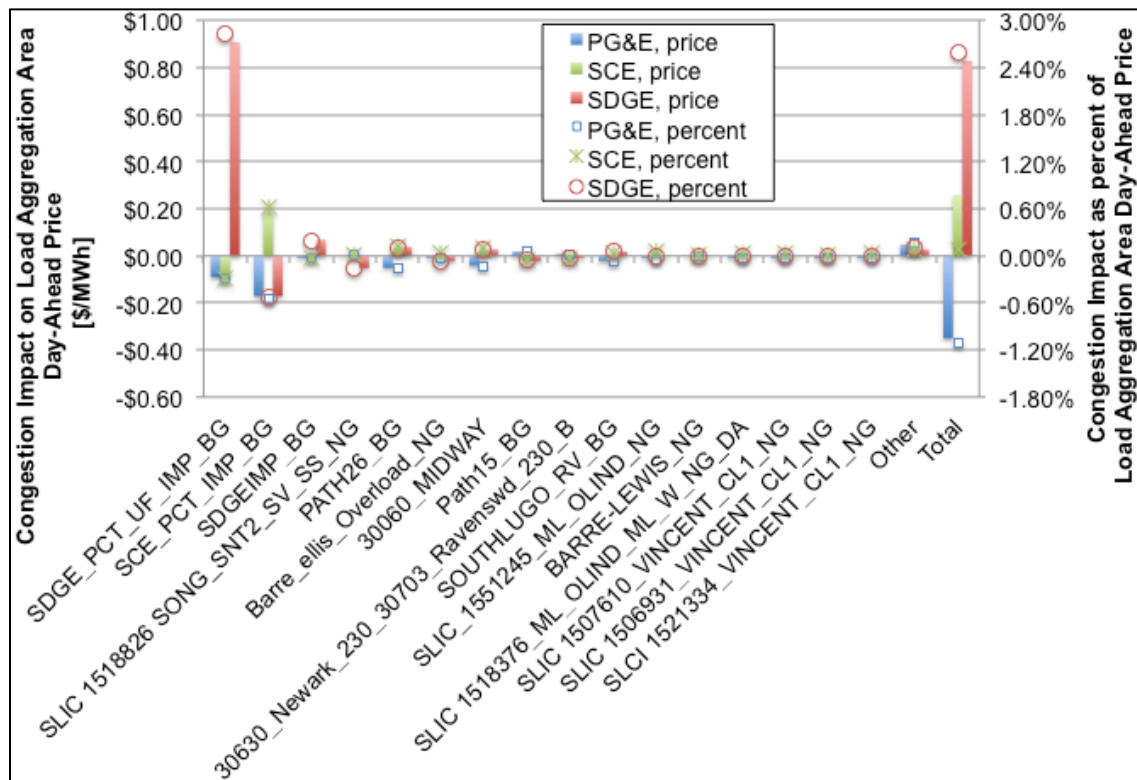
Figure 3-34 shows the overall impact (not just during times of congestion) of constraint congestion on average day-ahead prices in PG&E, SCE and SDG&E pricing zones during 2011. The overall price impact was negative for PG&E (-1.1%), and positive for SCE (0.8%) and SDG&E (2.6%), indicating price deviations from an unconstrained scenario. The SDG&E-Imperial branch group had the largest impact on load-zone day-ahead price of all constraints.

The base average prices in PG&E, SCE and SDG&E were \$31.26/MWh, \$31.36/MWh, and \$32.09/MWh, respectively. The most frequently congested constraint, the SDG&E to Imperial branch group that raised prices by \$12/MWh, or about one third, during hours of congestion, only raised prices by \$0.90/MWh, or 3%, during all hours. The greatest price impact—a decrease of \$37/MWh in SDG&E price forced by an internal nomogram related to the San Onofre power plant—is greater than the average base power price, but it only occurred in 40 hours (less than 0.5% of the year).

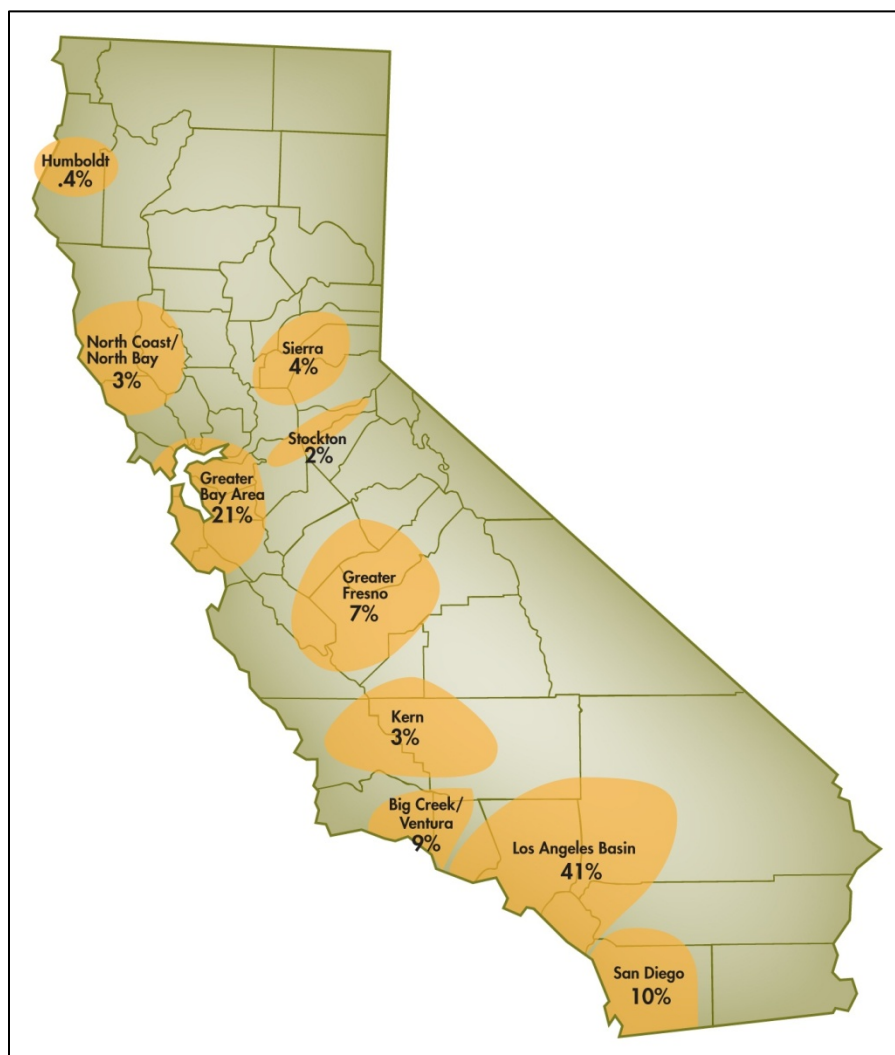
The CAISO market monitor also reports economic congestion impact for each Load Capacity Area (LCA).¹⁰⁶ Figure 3-35 maps California's LCAs and Figure 3-36 shows average day-ahead congestion components for these LCAs. This figure indicates that LCAs in PG&E have lower prices (negative average congestion), except in the Humboldt area. SCE LCAs experienced positive congestion costs (higher prices) in 2010 and 2011. The San Diego LCA experienced negative congestion costs (savings from excess generation relative to load) in 2010 and positive congestion costs in 2011.

¹⁰⁵The Central California transmission system, which separates the large load and resource centers in Northern and Southern California, is currently facing complex usage issues, including reliability of the Fresno area, integration and delivery of renewable resources, operation of the Helms pump storage facility and integration with other hydro resources, and large changes in flow direction over the year. (California ISO (CAISO) (2012a). *2011-2012 Transmission Plan*. Prepared by Infrastructure Development. March 23, 2012, at <http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf>, pp. 41-42, 55-56, 118-125). Because of all these issues, CAISO is conducting a special study to look at the possibility of upgrading the transmission system in the Central California region as part of its 2012/2013 transmission planning activities. Preliminary results from this activity are expected in the fall of 2012. (California ISO (CAISO) (2012d). *Addendum to: 2012/2013 Transmission Planning Process Unified Planning Assumptions and Study Plan: Central California Study Scope*. Folsom, CA: CAISO. May 24, 2012, at http://www.caiso.com/Documents/CentralCalifornia_StudyScope.pdf.

¹⁰⁶An LCA is a region recognized by CAISO as being at least somewhat dependent on imports of power from surrounding regions to meet load.

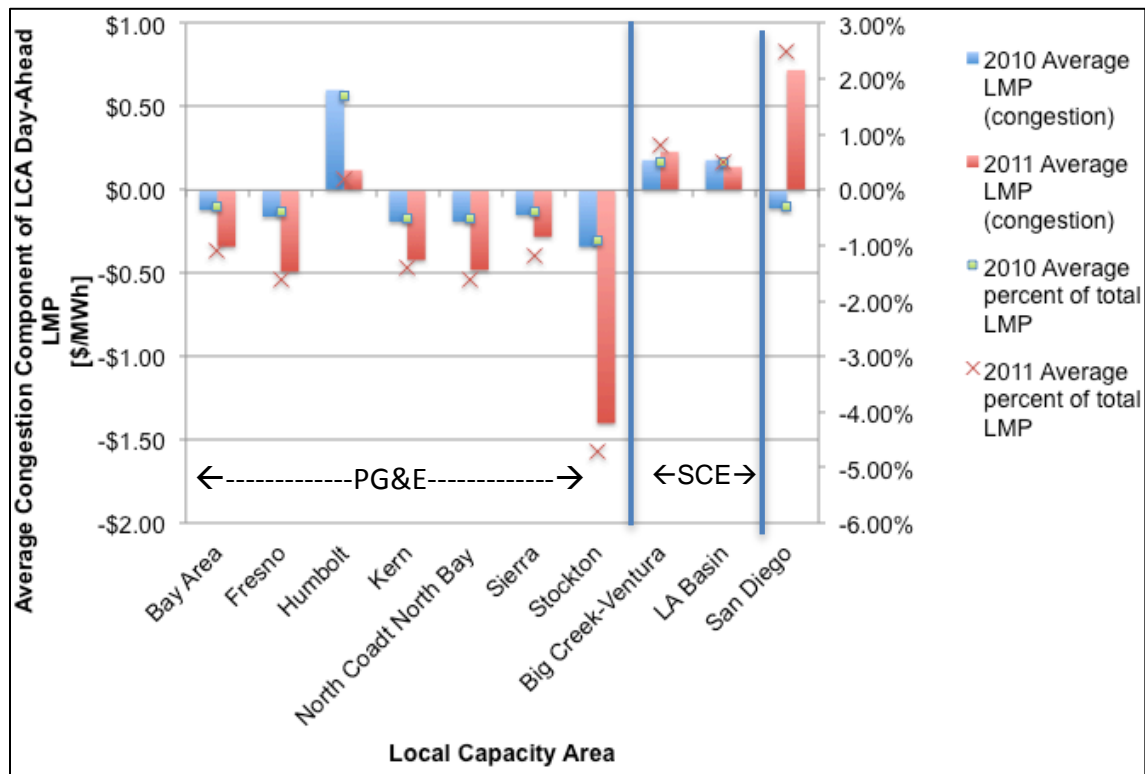
Figure 3-34. Impact of constraint congestion on average day-ahead load price, Feb-Dec 2011

Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 138.

Figure 3-35. CAISO local capacity areas, with percent of total load

Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 25.

Figure 3-36. Average congestion component of local capacity area day-ahead prices, Jan-Dec 2011

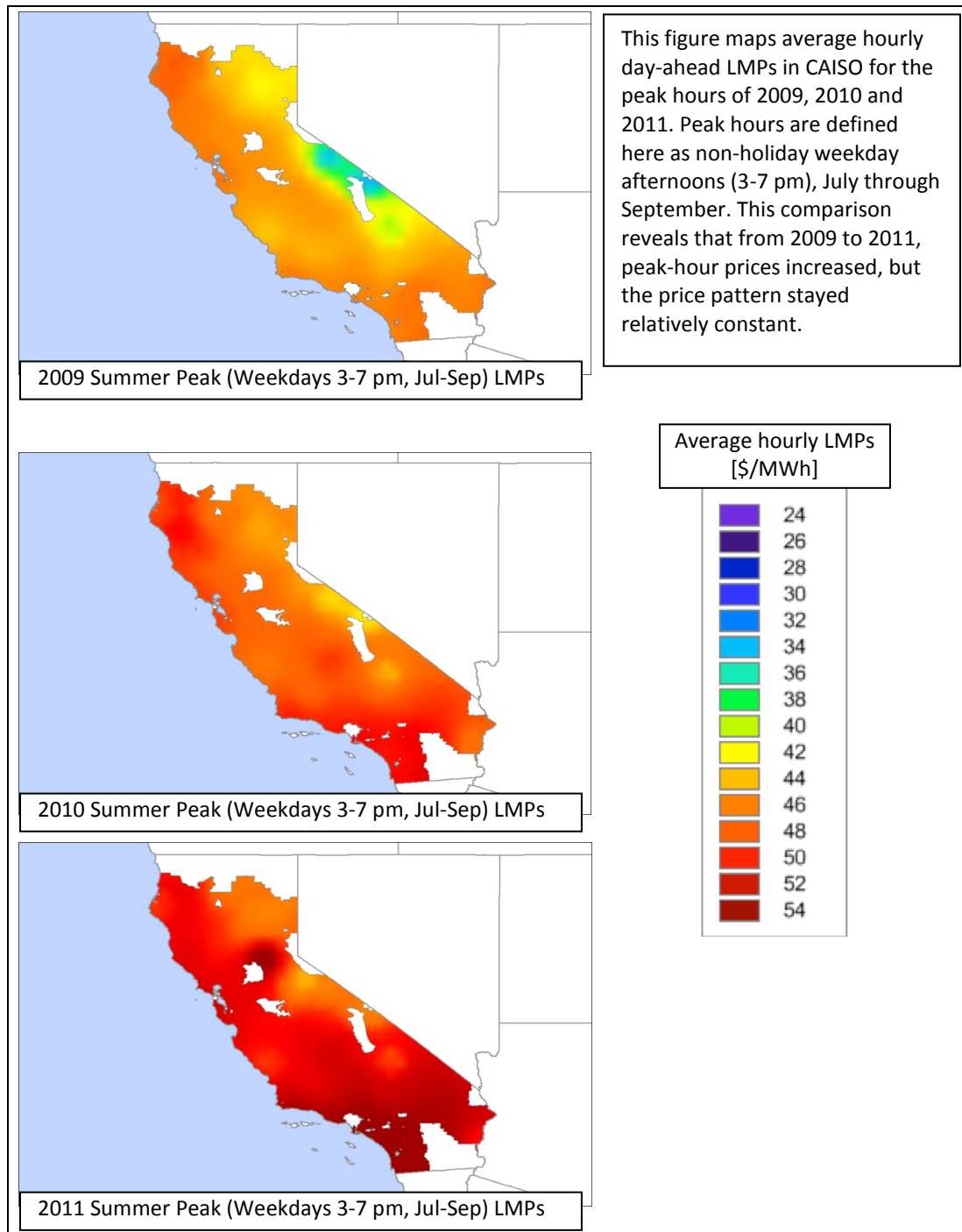


Source: California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, p. 139.

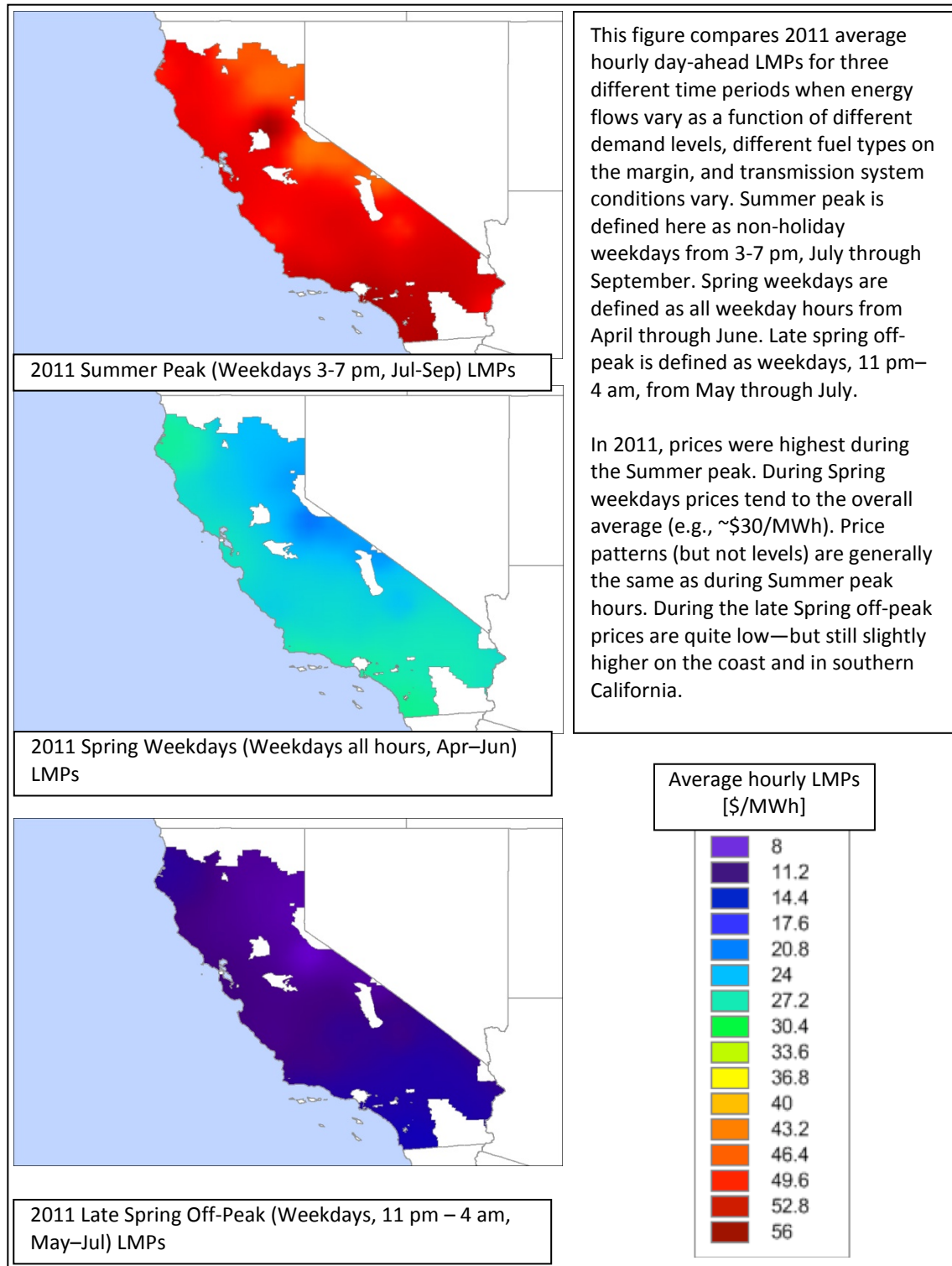
3.4.1.3. CAISO locational marginal prices

Locational marginal prices (LMP) only exist within organized electricity markets where nodal prices are used in the operations and settlements. In the West, CAISO is the only region that has LMPs.

Figure 3-37 and Figure 3-38 map CAISO average hourly day-ahead LMPs for two different sets of time periods, to compare energy price patterns across years and during different fuel dominant periods.

Figure 3-37. Summer Peak LMPs for 2009, 2010, and 2011 (\$/MWh)

Source: Ventyx (2012). "Ventyx Velocity Suite"

Figure 3-38. Seasonal LMPs for 2011 (\$/MWh)

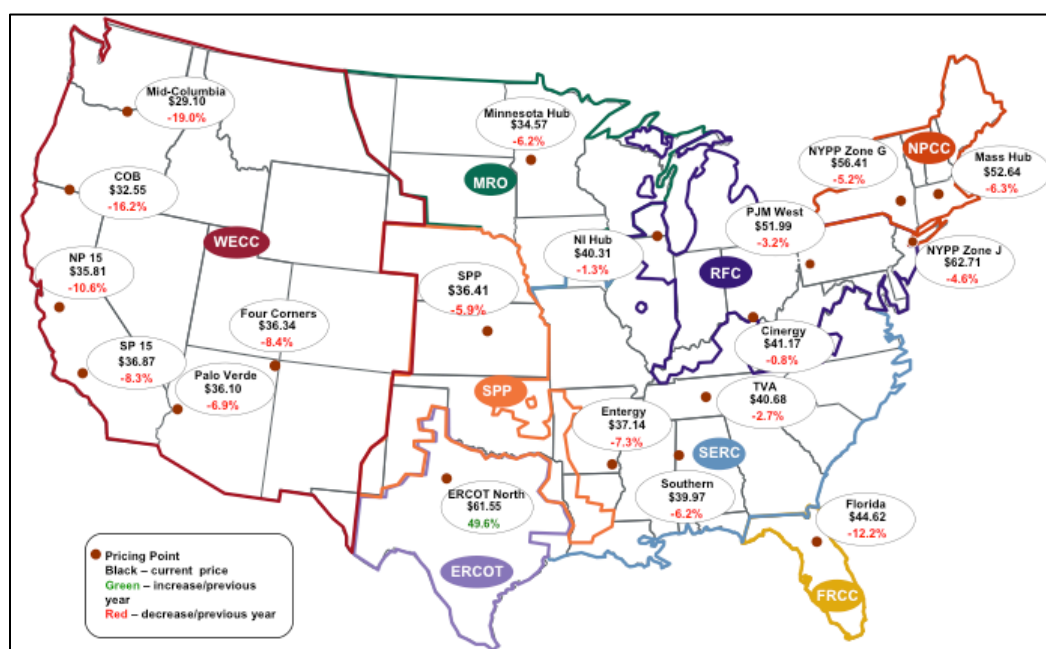
Source: Ventyx (2012). "Ventyx Velocity Suite."

3.4.2. Eastern Interconnection

This section describes electricity price patterns across the entire Eastern Interconnection. Prices are influenced by a number of factors, including fuel price and relative fuel prices influencing the order of dispatching resources; seasonal variations in load and resource availability; location of load centers; and transmission availability connecting load centers to generation. Price changes tend to vary similarly across the interconnection (e.g., when prices rise, all prices rise), but some differences do exist, which may be attributable to congestion.

Figure 3-39 compares average on-peak electric spot market prices for all peak hours in 2011, at pricing hubs across the nation. This figure shows that in 2011 prices in the Eastern Interconnection were higher than in the Western Interconnection, and that within the Eastern Interconnection they were lower in the Midwest and higher in the Atlantic coastal states.

Figure 3-39. 2011 Average on-peak electric spot prices (\$/MWh)



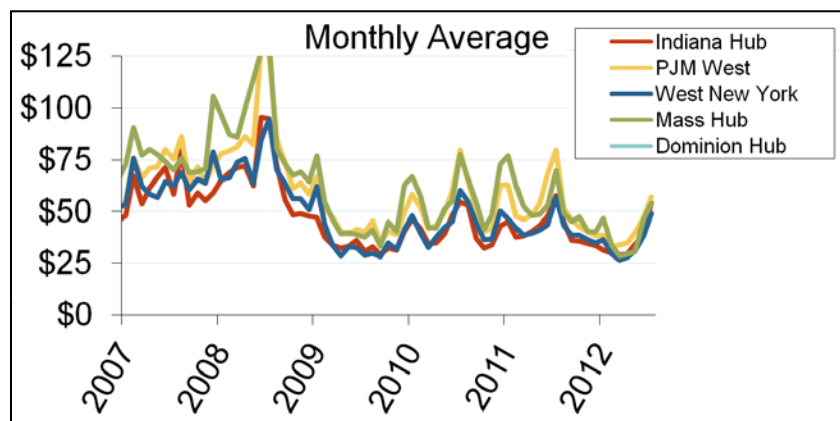
Source: FERC (2012b). *Electric Power Markets: National Overview*. On-peak electric spot prices,” March 12, 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/overview/elec-ovr-on-pk-elec-pr.pdf>.

Figure 3-40 shows monthly day-ahead spot market prices in the eastern organized spot markets. It shows that the same patterns prevailed over the bulk of the last six years—spot prices are consistently higher at the east coast hubs (Massachusetts and Dominion) than prices to the west (Indiana and Western New York. Year-to-year energy price fluctuations are in part driven by changes in fuel prices, because fuel costs determine marginal electricity production costs. Within MISO, coal-fired resources set the energy price in 93% of intervals, particularly in

off-peak hours, and coal prices rose by 6 to 10% in 2011 even as natural gas prices dropped.¹⁰⁷ Within PJM, coal-fired resources set the marginal electricity price in 69% of the intervals.¹⁰⁸

MISO notes that energy prices declined slightly after 2010 due to declines in average load, increased generation by intermittent resources, and a 1.5 GW increase in average net imports.¹⁰⁹ Overall, since 2009 the average prices between the five hubs track each other fairly closely.

Figure 3-40. Eastern monthly day-ahead on-peak prices



Source: FERC (2012d). *Market Oversight: Electric Market Overview and Focal Points*. May 2012, p. 12 at <http://www.ferc.gov/market-oversight/mkt-snp-sht/2012/05-2012-snapshot-ne.pdf>.

Figures 3-41 to 3-43 illustrate how the magnitude and intensity of transmission congestion change over time, as revealed in locational marginal prices (LMPs) of electricity.

The following figures show that price and congestion patterns within the RTOs and ISOs in the eastern interconnection that calculate LMPs in day ahead markets vary markedly from year to year (Figure 3-41), vary as a function of season reflecting dominant fuel and load-driven transmission patterns (Figure 3-42), and vary by season and time of day, which in turn reflect both load levels and marginal fuel (Figure 3-43). All of these figures suggest the same basic price pattern—electricity prices are highest in the Mid-Atlantic coastal population centers and lowest to the west.

¹⁰⁷ Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at <https://www.midwestiso.org/Library/Repository/Report/IMM/2011%20State%20of%20the%20Market%20Report.pdf>, p.3.

¹⁰⁸ Monitoring Analytics, LLC (2012). *State of the Market Report for PJM: 2011*, March 2012, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml, Section 2, pg. 31.

¹⁰⁹ Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at <https://www.midwestiso.org/Library/Repository/Report/IMM/2011%20State%20of%20the%20Market%20Report.pdf>, p.4.

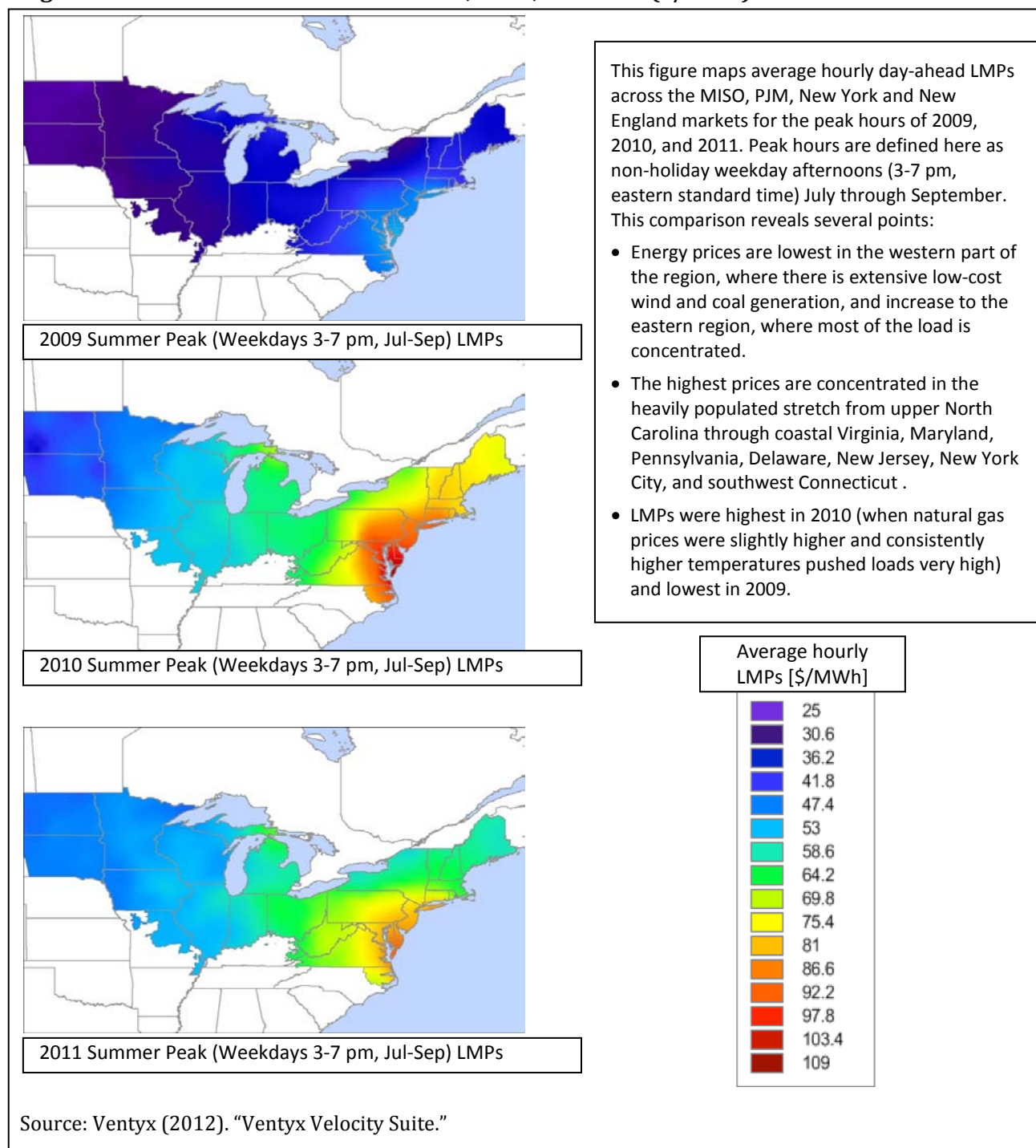
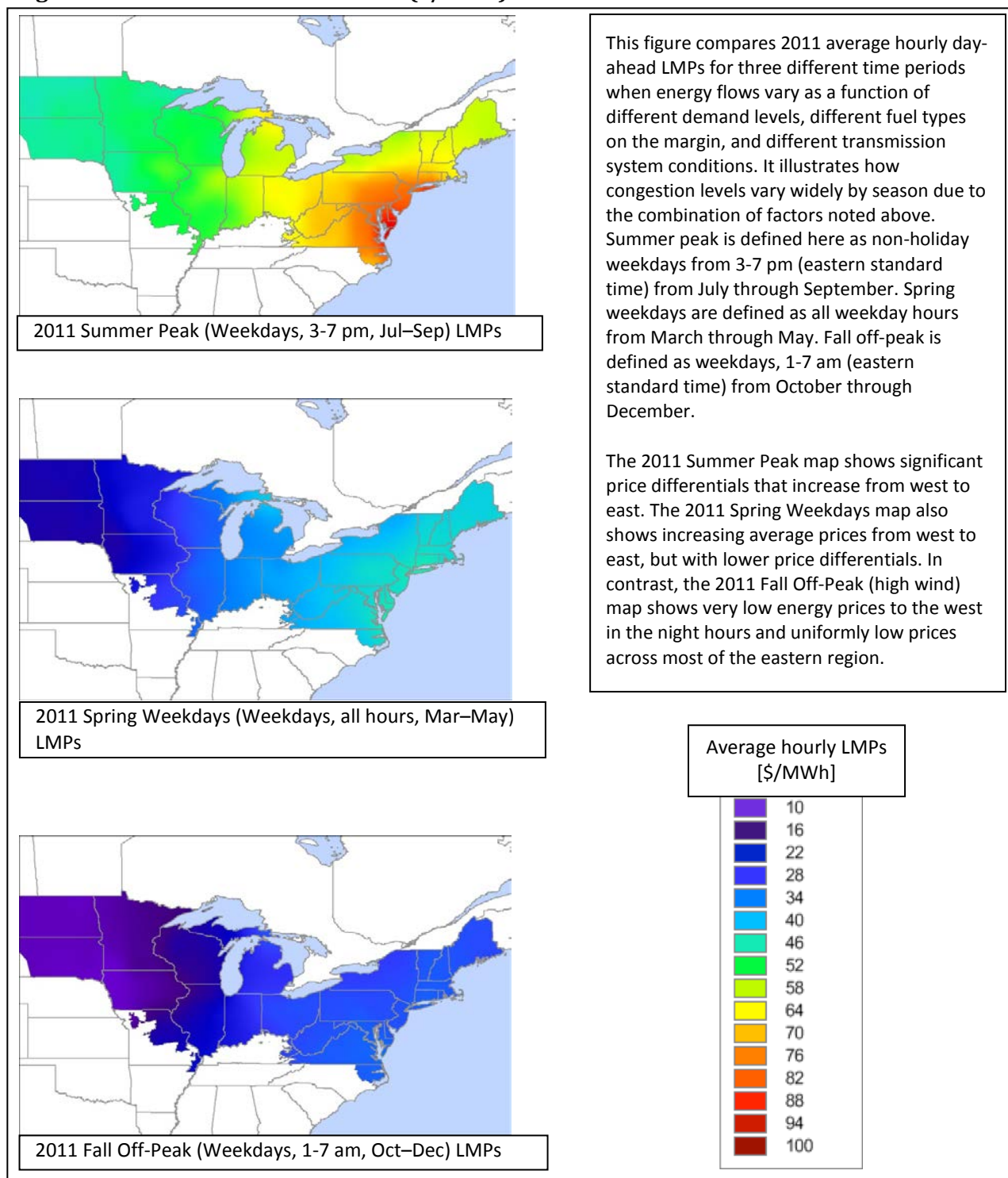
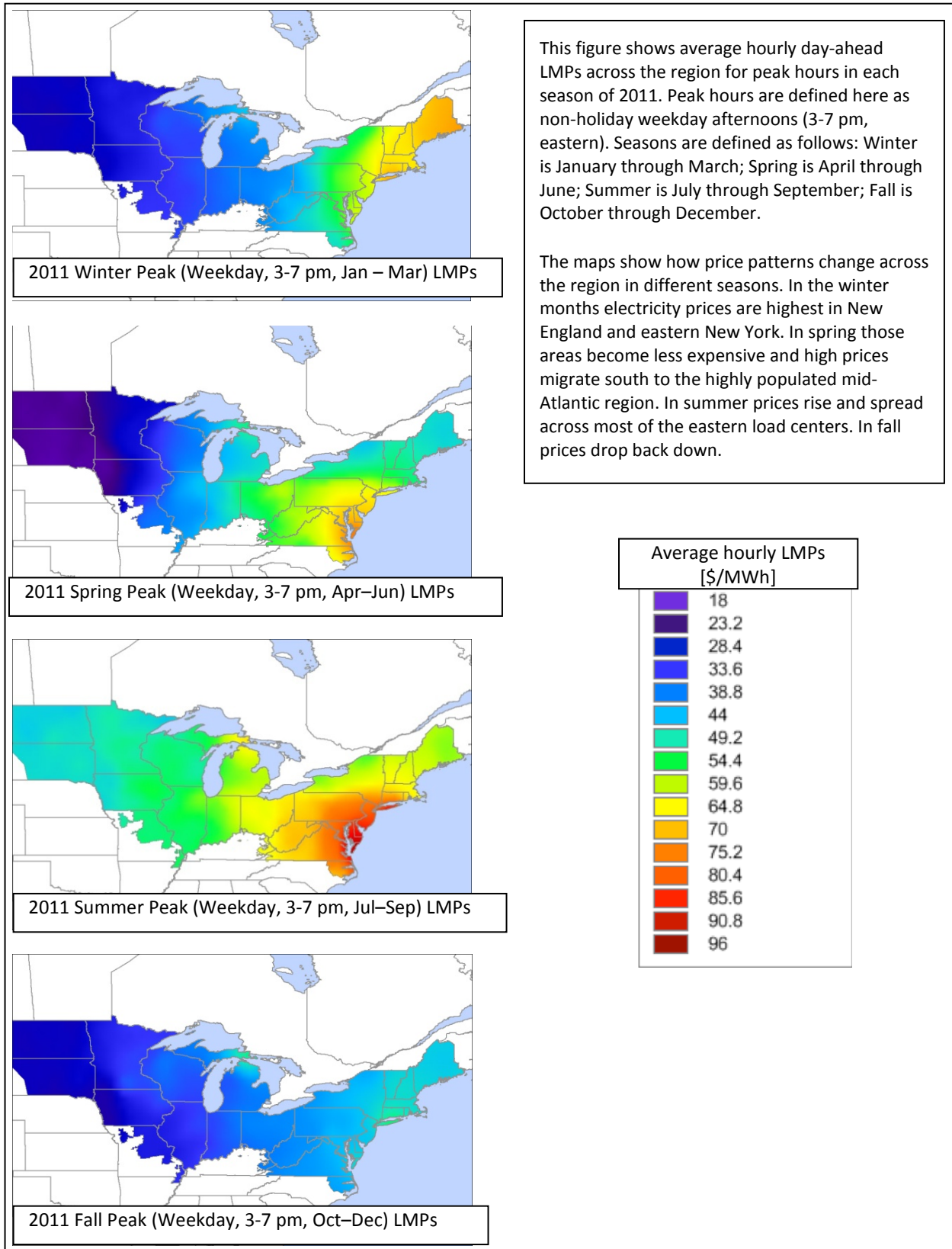
Figure 3-41. Summer Peak LMPs for 2009, 2010, and 2011 (\$/MWh)

Figure 3-42. Seasonal LMPs for 2011 (\$/MWh)

Source: Ventyx (2012). "Ventyx Velocity Suite."

Figure 3-43. Seasonal Peak LMPs for 2011 (\$/MWh)

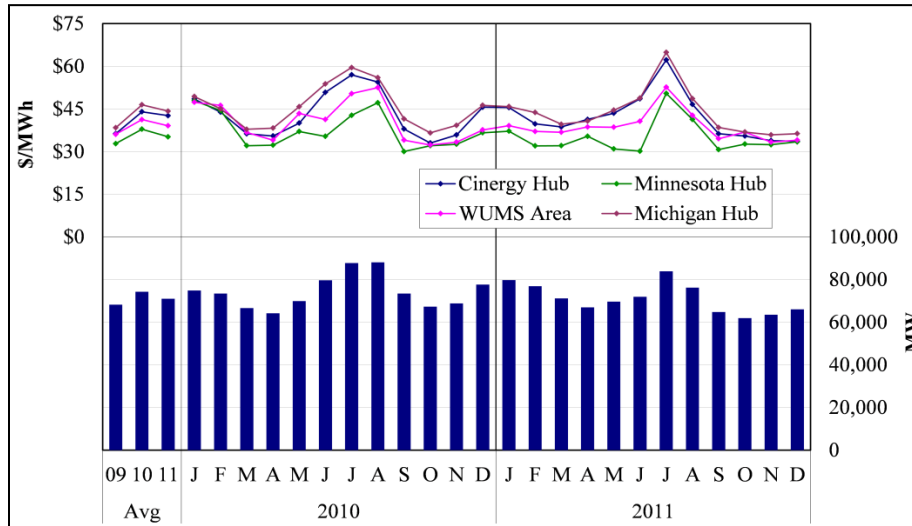
Source: Ventyx (2012). "Ventyx Velocity Suite."

3.4.3. Midwest

Data from the MISO market monitor indicate that wholesale electricity price differences between regions tend to be greatest during peak hours.

Figure 3-44 shows day-ahead hub energy prices at the four hubs within MISO. Prices in Michigan and Minnesota are consistently lowest, while prices to the east are higher.

Figure 3-44. Day-ahead hub prices and load, peak hours, 2010-11

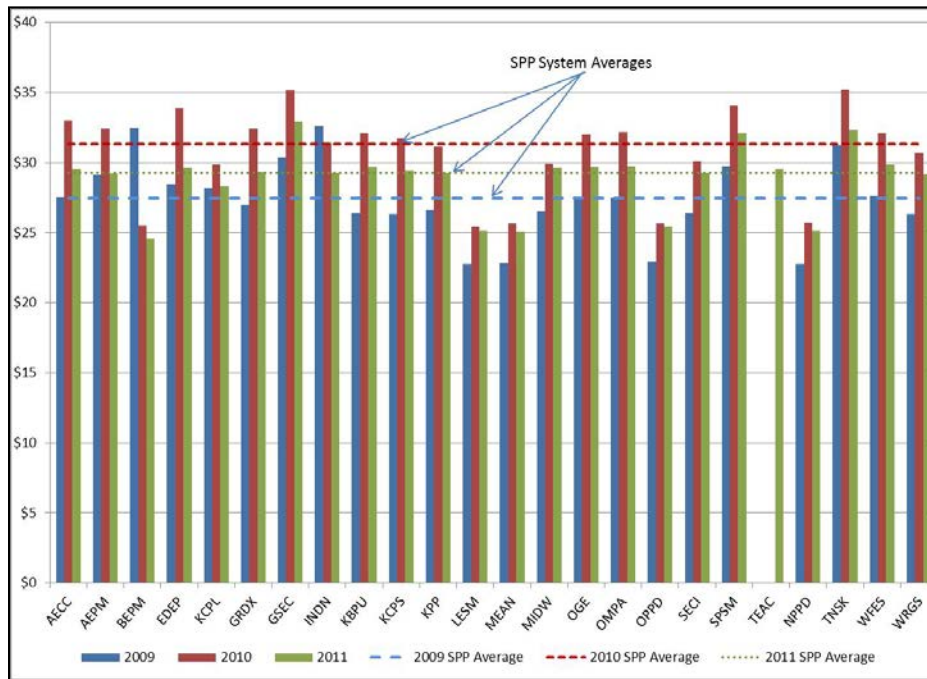


Source: Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A-24.

SPP calculates Energy Imbalance Prices (similar to LMPs) that represent location-specific marginal market-clearing prices for electricity traded in the organized spot market. Within SPP, the annual average prices associated with each balancing authority show noticeable but not wide variations between zones for a given year, as shown in Figure 3-45. The highest price paid in 2011 (\$32.22) was 10% higher than the mean price of \$29.28, while the lowest price (\$25.87) was 15% lower than the mean; these price divergences were created primarily by congestion.^{110 111}

¹¹⁰Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 41.

¹¹¹Because spot market prices in SPP closely track natural gas costs, average and zonal prices for a given year track relatively consistently over time. SPP's market monitoring unit concludes that where average prices drop significantly from 2009 to 2011 for specific market participants, as for BEPM (Blue Canyon Windpower) and INDN (City of Independence), this reflects a change in transmission infrastructure or generation operation that affected congestion and prices in subsequent years.

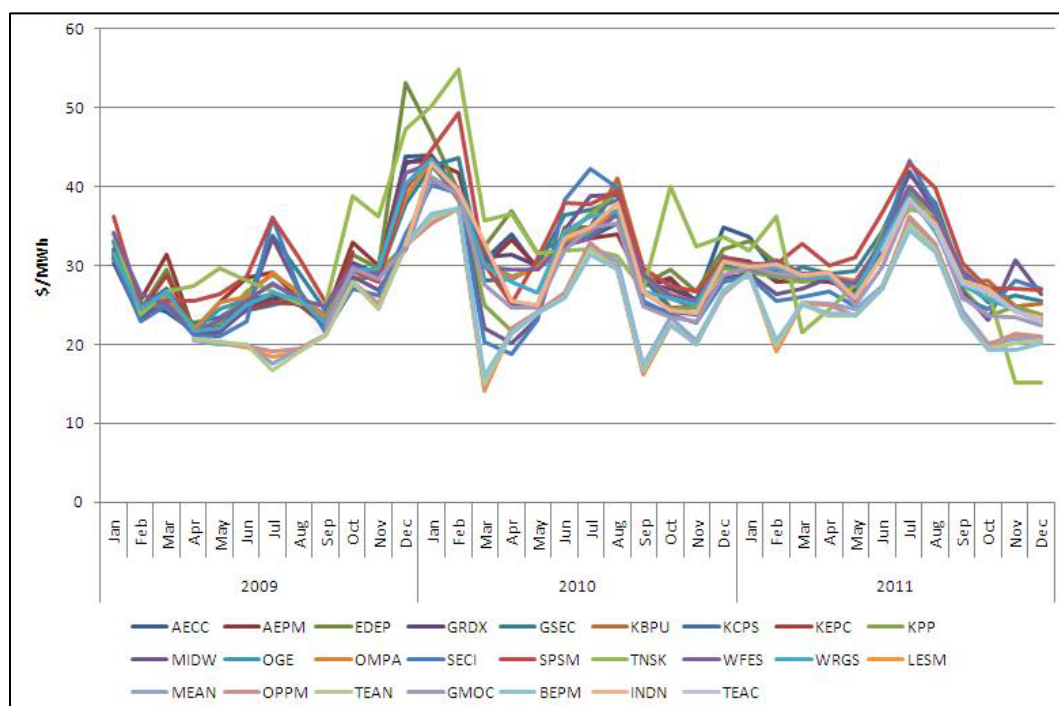
Figure 3-45. Prices between SPP market participant zones , 2009-2011

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, Figure II.10, pg 41.

Figure 3-46 compares average monthly prices by participant within SPP. Price divergences reflect differing generation fleets and congested areas; “congestion usually drives up prices in one area of the SPP market and down in another unless the congestion is at the seam with another market.”¹¹²

SPP also compares its energy prices to its neighbors to determine whether price differentials reveal any significant competitive disadvantage for the region. Figure 3-47, prepared by SPP’s market monitoring unit, compares annual average prices for peak and off-peak periods for SPP, MISO and ERCOT, and indicate that SPP’s prices were on average below MISO’s during on-peak hours, and relatively close to MISO’s in the off-peak.

¹¹²Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 44.

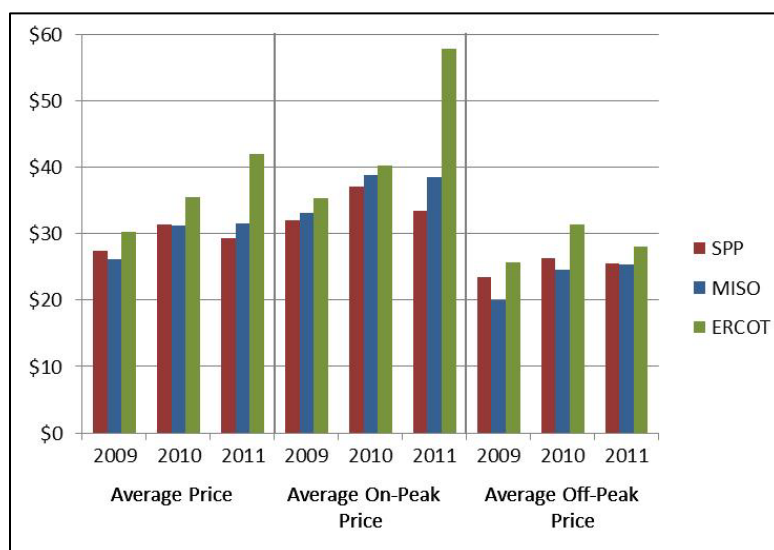
Figure 3-46. Average monthly energy price by SPP market participant, 2009-2011

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, Figure II.13, p. 44.

SPP price differentials between 2010 and 2011 should be viewed with caution, because market operations changed in 2011 with the implementation of a new Congestion Management Event process (in late 2010) and a step Violation Relaxation Limit function (in early 2011), that together enabled more low-cost power to flow and contributed to market price declines for reasons that have nothing to do with changed grid assets or changes in relative fuel costs.^{113 114}

¹¹³Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 10.

¹¹⁴SPP notes that more congestion during off-peak hours is “usually caused by less overall system dispatch flexibility during those time periods.”¹¹⁴ To remedy this, SPP has proposed amendments to its FERC-approved OATT “to allow automated and systematic curtailment instructions to be sent to non-dispatchable resources during congestion periods” to increase system flexibility. (Rivera-Linares, C. (2012h). “SPP seeks amendments to its OATT in light of increase in non-dispatchable resources,” *Transmission Trends*, July 30, 2012, p. 20.)

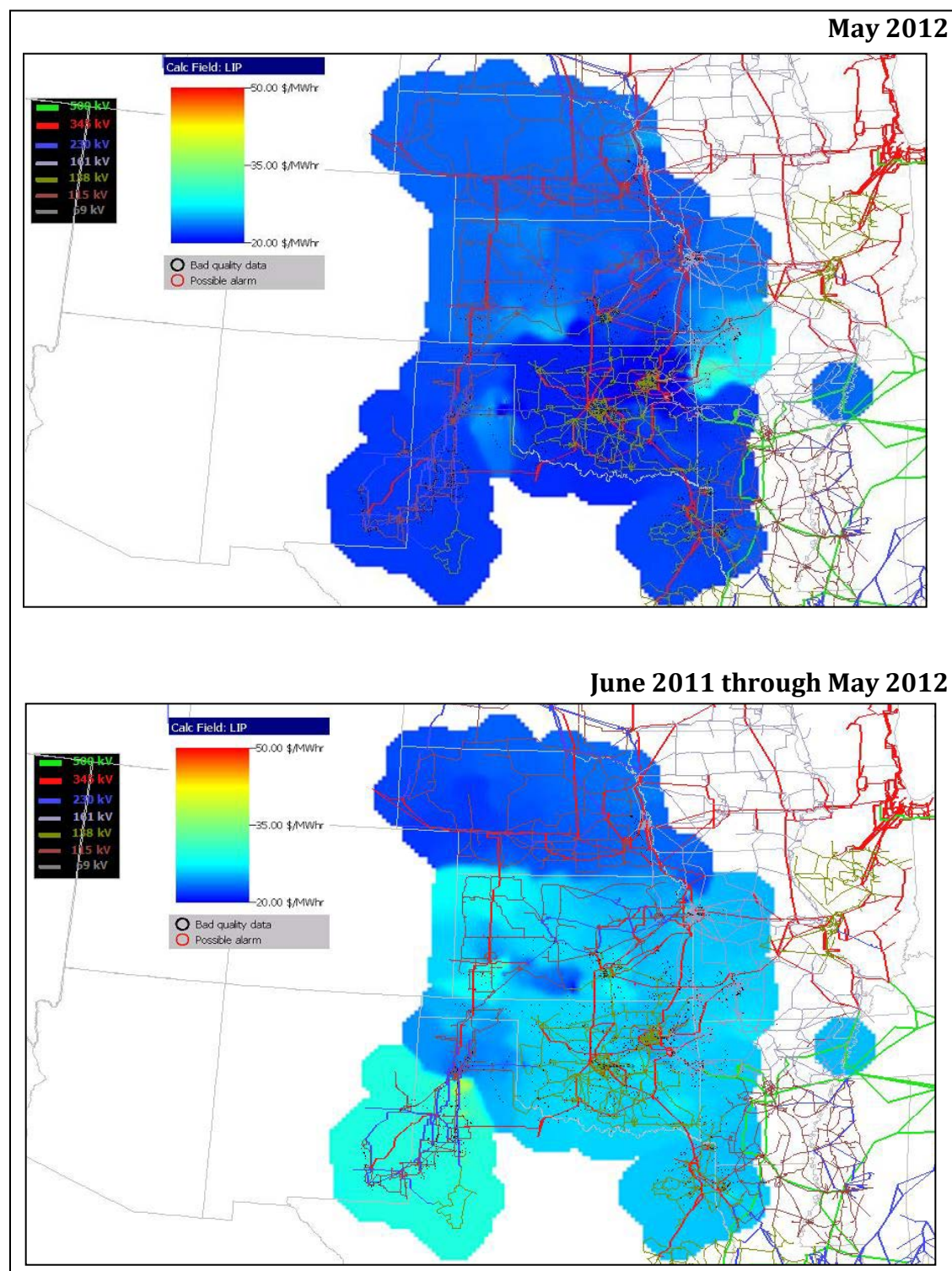
Figure 3-47. SPP and MISO average energy prices

Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, Figure II.5, pg. 36.

Figure 3-48 shows the pattern of average locational electricity prices within the SPP footprint in May 2012, as well as for the full year (June 2011-May 2012). It shows congestion in northeast Oklahoma, the Texas Panhandle, NW Arkansas-SW Missouri and south central Kansas; SPP reports that some of this is related to transmission system outages for maintenance, as well as high temperatures and associated higher loads.¹¹⁵

¹¹⁵ Southwest Power Pool (SPP) Market Monitoring Unit (2012d). *SPP Monthly State of the Market Report May 2012*, Little Rock, AR: SPP Inc., June 2012, at <http://www.spp.org/publications/SPP%20MSOM%20Report%20201205.pdf>, p. 2.

Figure 3-48. SPP Energy Imbalance Service Locational Imbalance Prices contour map, May 2012 and June 2011 through May 2012



Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012d). *SPP Monthly State of the Market Report May 2012*, Little Rock, AR: SPP Inc., June 2012, at <http://www.spp.org/publications/SPP%20MSOM%20Report%20201205.pdf>, p. 3.

3.4.4. Northeast

Table 3-14 compares on-peak bilateral electricity prices (i.e., not LMPs from the ISO/RTO centralized wholesale markets). The table shows that between 2007 and 2011, prices have been consistently highest in eastern New York (Zone J (New York City) and Zone G (the Hudson Valley)), and lowest in New York Zone A (far west New York) and at PJM West.

Table 3-14. New York on-peak prices compared to PJM West and the ISO-New England Hub (annual average bilateral prices, day-ahead on-peak \$/MWh)

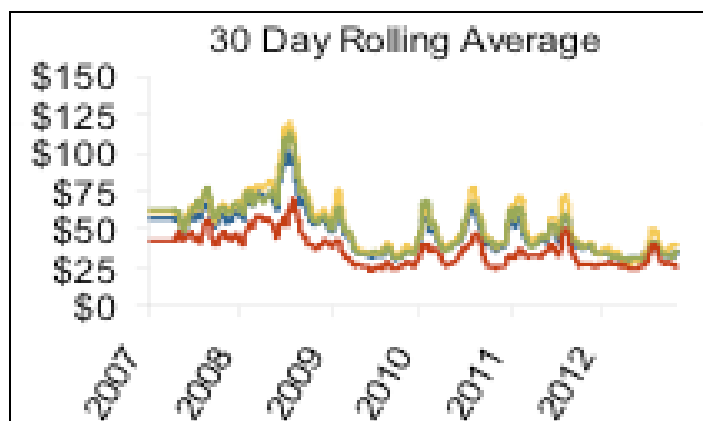
	2007	2008	2009	2010	2011	5-Yr Avg
ISO-NE hub	\$77.39	\$91.55	\$46.24	\$56.18	\$52.64	\$64.80
NY Zone G	\$83.51	\$100.99	\$49.80	\$59.48	\$56.41	\$70.04
NY Zone J	\$94.15	\$112.63	\$55.77	\$65.76	\$62.71	\$78.20
NY Zone A	\$64.02	\$68.34	\$35.54	\$43.89	\$41.52	\$50.66
PJM West	\$71.15	\$83.70	\$44.60	\$53.68	\$51.99	\$61.02

Source: FERC (2012d). *New York ISO: Market Overview and Focal Points*. May 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/new-york/2012/11-2012-elec-ny-archive.pdf>, slide 2.

PJM

Figure 3-49 compares day-ahead daily average prices at hubs spanning PJM. It shows that prices have moved together relatively consistently over time, and that Illinois prices remain consistently lower than prices at the eastern hubs.

Figure 3-49. Daily average of PJM day-ahead prices, all hours



Source: FERC (2012e). *PJM Electric Market: Market Overview and Focal Points*. November 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/pjm/2012/11-2012-elec-pjm-archive.pdf>, slide 3.

Table 3-15 presents the real-time, load-weighted average energy prices (LMP) and their components (energy, congestion, and line losses) by zone in PJM for the years 2010 and 2011. The zones with lower LMPs (Allegheny Power, ComEd, AEP, Dayton, DLCO, and Penelec) are

western control zones on the generation-rich side of the AP South constraint, and thus have negative congestion cost components.

Table 3-15. Annual real-time, load-weighted average LMPs and components for PJM load zones the years 2010 and 2011 (\$/MWh)

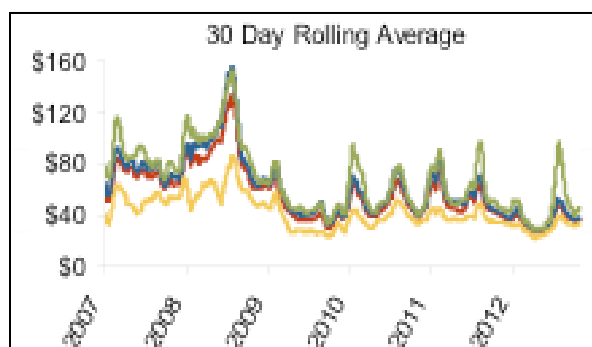
	2010				2011			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	\$57.03	\$49.69	\$3.87	\$3.47	\$57.81	\$50.11	\$4.95	\$2.75
AEP	\$40.35	\$47.45	(\$4.67)	(\$2.43)	\$42.97	\$48.64	(\$3.99)	(\$1.68)
AP	\$47.08	\$47.42	(\$0.05)	(\$0.28)	\$48.57	\$48.99	(\$0.22)	(\$0.20)
ATSI	NA	NA	NA	NA	\$46.88	\$51.24	(\$3.85)	(\$0.51)
BGE	\$59.19	\$48.69	\$8.04	\$2.46	\$58.74	\$49.82	\$6.62	\$2.30
ComEd	\$36.21	\$47.95	(\$8.85)	(\$2.90)	\$38.97	\$49.12	(\$7.32)	(\$2.83)
DAY	\$40.51	\$48.10	(\$6.66)	(\$0.93)	\$43.90	\$49.40	(\$4.57)	(\$0.93)
DLCO	\$39.41	\$47.89	(\$6.68)	(\$1.79)	\$43.30	\$49.12	(\$4.15)	(\$1.67)
Dominion	\$56.08	\$48.86	\$6.30	\$0.92	\$54.47	\$49.83	\$4.04	\$0.60
DPL	\$56.51	\$49.07	\$4.59	\$2.85	\$56.76	\$49.95	\$3.82	\$2.99
JCPL	\$56.00	\$49.58	\$3.92	\$2.51	\$58.09	\$50.73	\$4.62	\$2.74
Met-Ed	\$53.47	\$48.20	\$4.22	\$1.05	\$53.64	\$49.22	\$3.42	\$1.00
PECO	\$53.60	\$48.36	\$3.54	\$1.70	\$55.19	\$49.47	\$3.82	\$1.90
PENELEC	\$45.17	\$47.19	(\$1.73)	(\$0.28)	\$48.18	\$48.27	(\$0.46)	\$0.37
Pepco	\$58.16	\$48.70	\$7.94	\$1.51	\$55.71	\$49.82	\$4.63	\$1.26
PPL	\$51.50	\$47.90	\$2.84	\$0.76	\$53.76	\$48.95	\$3.85	\$0.96
PSEG	\$55.78	\$48.58	\$4.73	\$2.47	\$57.16	\$49.71	\$4.78	\$2.67
RECO	\$54.85	\$49.48	\$3.20	\$2.17	\$53.17	\$50.88	(\$0.15)	\$2.44
PJM	\$48.35	\$48.23	\$0.08	\$0.04	\$49.48	\$49.40	\$0.05	\$0.03

Source: Monitoring Analytics (2012). *State of the Market Report for PJM—2011*, March 15, 2012, at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml. Vol. 2, Table 10-3, p. 268.

New York

Figure 3-50 compares average energy prices at four points within New York state from 2007 through 2011. It shows that the prices move up and down in very similar patterns.

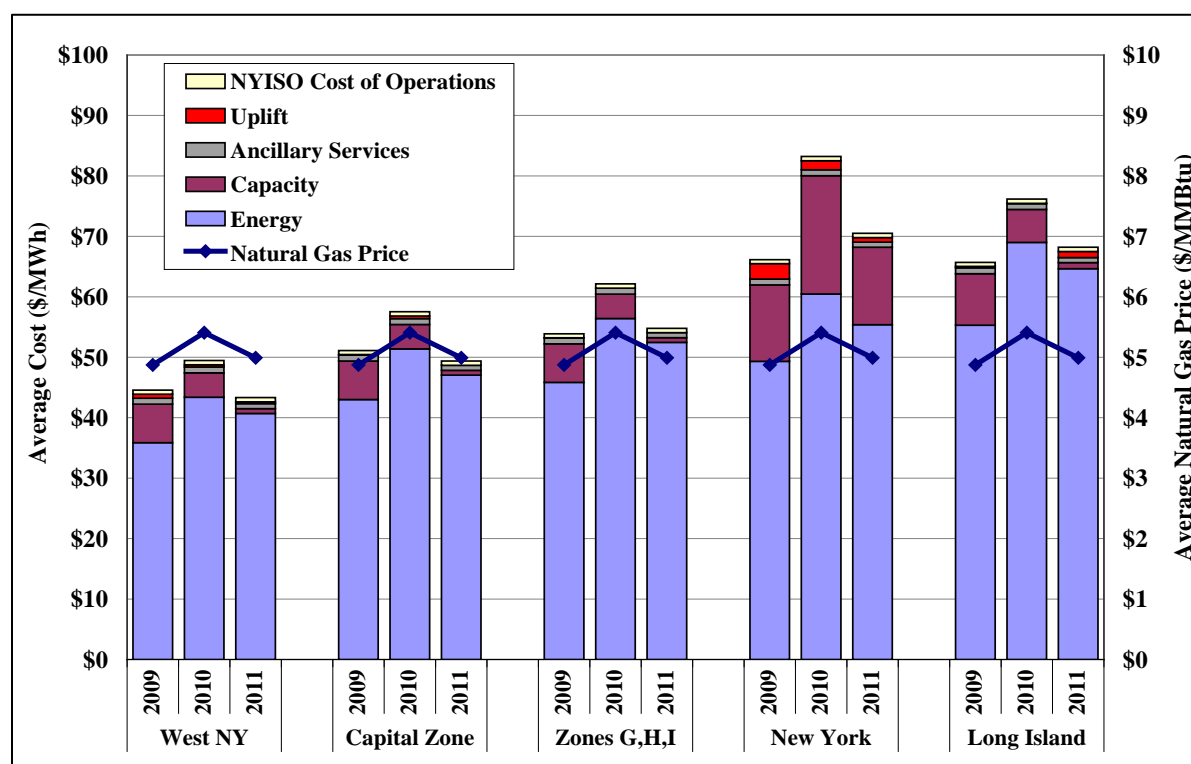
Figure 3-50. Rolling average on-peak day-ahead electricity prices in New York, 2007 through 2012



Source: FERC (2012d). *New York ISO: Market Overview and Focal Points*. May 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/new-york/elec-ny-rto-pr.pdf>.

New York's market monitor also offers a comparison of the "all-in price for [wholesale] electricity, which reflects the average cost of serving load from the New York markets."¹¹⁶ This is shown in Figure 3-51. The existence of average cost differentials between regions ranging from about \$43 in West New York to \$71/MWh in New York City (for 2011) illustrate the impacts of differentials in transmission delivery capabilities and relative loads and generation across the state

Figure 3-51. All-in wholesale market price by region, New York state, 2009-11



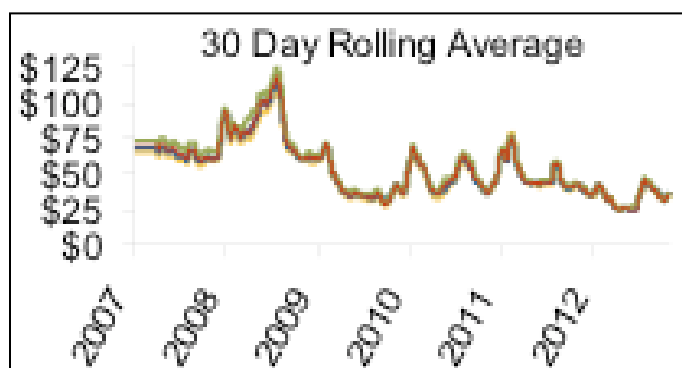
Source: Potomac Economics (2011b). *2011 State of the Market Report for the New York ISO Markets*. Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012, p. 3.

New England

In contrast to the PJM and New York zone index prices over time, prices within New England are notable because all of the hub prices moved in near-lockstep from 2009 through early 2012, with minimal differentials between zones. This is shown in Figure 3-52, which supports the point made above that there are no significant transmission constraints remaining within New England to cause price differentials.¹¹⁷

¹¹⁶Potomac Economics (2011b). *2011 State of the Market Report for the New York ISO Markets*. Prepared by Potomac Economics for Market Monitoring Unit for the New York ISO. April 2012, p. 3.

¹¹⁷Completion of major transmission projects in Connecticut and Boston are credited with alleviating costly congestion within those load pockets, flattening the LMP differentials between the New England load zones

Figure 3-52. Daily average of ISO-NE day-ahead prices, all hours

Source: FERC (2012b). *New England Electric Market: Last Month's RTO Prices*. November 2, 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/new-england/elec-ne-rto-mth-pr.pdf>.

The price spike in 2008 reflects a 10% increase in natural gas prices over the 2007 cost. Average real-time electricity prices rose 20% in 2010 over 2009, driven by increases of 3% in energy and 8% in peak load within the region.¹¹⁸

Very small differences between delivered electricity prices in New England's eight load zones (Figure 3-53) can be seen in Table 3-16. This table compares average day-ahead electricity prices for three years to the ISO-NE Hub price (an average of system pricing locations that is meant to represent a congestion-free price)¹¹⁹ and shows how the average annual price in each of the New England states varies from that Hub price. It shows that prices in Maine have been consistently lowest relative to the Hub price, while Connecticut prices run highest—but all fall on average within less than 5 percent above or below the Hub price. For most of the zones, the cost impact of line losses exceeds the impact of transmission congestion.¹²⁰ ISO-NE's market monitor comments that "price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion primarily was restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service."¹²¹

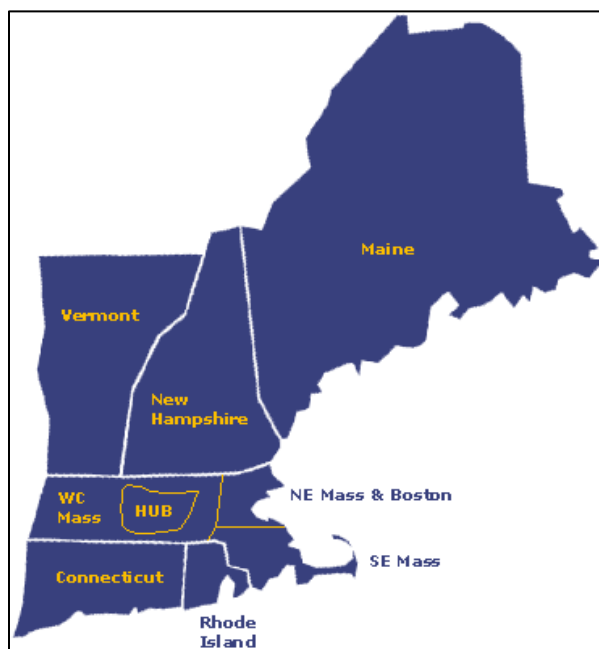
(Figure 3-52), and lowering overall congestion within the region. [New England States Committee on Electricity (2012). "Comments to the 2012 Congestion Study," at <http://energy.gov/sites/prod/files/New%20England%20States%20Committee%20on%20Electricity%20-%20Comments%20to%20the%202012%20Congestion%20Study.pdf>].

¹¹⁸Potomac Economics (2011b). *2010 Assessment of the ISO New England Electricity Markets*. Prepared by Potomac Economics for the ISO-NE. June 2011, at http://www.potomaceconomics.com/uploads/isone_reports/ISONE_2010_IMMUN_Report_Draft_Final_June-11.pdf, p. ix.

¹¹⁹*Ibid.*, Figure 10, p. 6.

¹²⁰*Ibid.*, p. 98.

¹²¹Potomac Economics (2012a). *2011 Assessment of the ISO New England Electricity Markets*. Prepared by Potomac Economics for the ISO-NE. June 2012, at http://www.potomaceconomics.com/uploads/isone_reports/ISONE_2011_EMMU_Report_Final_June_2012.pdf, p. 6.

Figure 3-53. New England load zones

Source: ISO New England (2012b), "Locational Marginal Pricing," at http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/lmp/index-p3.html.

Table 3-16. Simple average day-ahead electricity prices for the New England Hub and load zone differences from the Hub price (\$/MWh, 2009 through 2011)

Location (load zone)	2009	2010	2011
New England Hub price	\$41.54	\$48.89	\$46.38
Maine	-\$1.93	-\$2.19	-\$0.80
New Hampshire	-\$0.67	-\$0.87	-\$0.45
Vermont	\$0.05	\$0.68	\$0.28
Connecticut	\$1.21	\$1.87	\$1.09
Rhode Island	-\$0.39	-\$0.79	-\$0.61
Southeast Massachusetts	\$0.17	-\$0.56	-\$0.20
Western Central Massachusetts	\$0.36	\$0.63	\$0.53
Northeast Massachusetts	-\$0.09	-\$0.67	-\$0.24

Source: ISO New England, Internal Market Monitor, "2011 Annual Markets Report," http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf, Table 3-1, p.39.

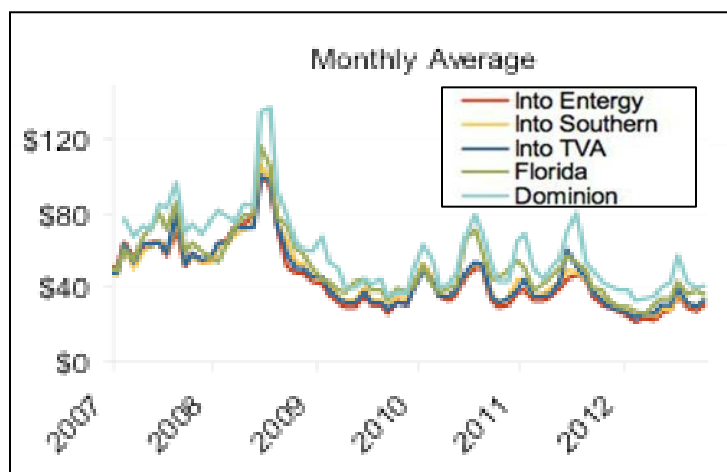
In the years before the data shown in this table, the price differential changed for the Southeast Massachusetts (SEMA) load zone—in 2008, the average congestion price difference between the Hub and Lower SEMA was about \$10/MWh in 2008; fell to less than \$1/MWh in 2009; and fell to negative \$0.56 per MWh in 2010. This reduction in congestion was attributed to

transmission upgrades into Lower SEMA that went into service in July 2009, increasing the thermal transfer capability of that interface.¹²²

3.4.5. Southeast

Daily hub index prices are available for some points in the Southeast (see Figure 3-54).¹²³ These prices indicate some price separation between regions, but it is not possible to determine the cause. Average electricity prices in the region decreased from 2009 to 2012.

Figure 3-54. Average day-ahead bilateral prices in the Southeast



Source: FERC (2012f). *Southeast Electric Market: Overview and Focal Points*. November 2012, at <http://www.ferc.gov/market-oversight/mkt-electric/southeast/2012/11-2012-elec-se-archive.pdf>, p. 5.

¹²²*Ibid.*

¹²³These index prices are calculated by Platt's based on deal and trade prices self-reported by market participants (including utilities, service providers, and traders). Source: Platt's (2012). *Methodology and Specifications Guide: North American Electricity*. January 2012, at http://www.platts.com/IM.Platts.Content/methodologyreferences/methodologyspecs/na_power_method.pdf.

4. Resource-Driven Transmission Constraints

Some congestion is caused by resource availability, resource location, and related policy issues rather than by immediate demands for transmission service that exceed existing capacity. This section explores these resource-driven congestion issues, including local reliability, interconnection queues, clean or renewable energy zones and the impact of renewable development, and environmental regulations in more detail.

4.1. Local reliability

This subsection presents information about local reliability issues in the West, Midwest and Southeast; no public data were identified on local reliability issues in the Northeast.

4.1.1. West

The unexpected outage of the San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 in early 2012 placed the Los Angeles and San Diego areas in a tight operating position for the 2012 peak summer season, with concerns about possible reliability issues under high loading conditions.¹²⁴ ¹²⁵ The two SONGS nuclear units (shown in shown in Figure 4-1) had a capacity of 2,240 MW. Before Sunrise Powerlink was energized, and with all facilities in operation including SONGS, import capability into the area was 2,850 MW. The exact import capability without SONGS is not publicly available.¹²⁶

Without the SONGS units, Los Angeles was expected to be short approximately 240 MW and San Diego was expected to be short 337 MW under heavy loading conditions.¹²⁷

¹²⁴The SONGS outage highlights Southern California's tight resource situation, where the loss of one major generating source or transmission link can threaten serious local reliability problems. The September 8, 2011 Arizona-Southern California Outage is another example of how the outage of one system element can lead to major reliability problems and, in this case, cause widespread power outages. Recommendations from the FERC-NERC analysis focus more on operations planning and situational awareness than on infrastructure investment, highlighting that there are many ways to maintain reliability. (Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC) (2012). *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*. April 2012, at http://www.nerc.com/files/AZOutage_Report_01MAY12.pdf.)

¹²⁵As of December 2012, the time frame of this report, it was not know whether SONGS would re-open. In June 2013 Southern California Edison announced it would be closing SONGS permanently, raising some short- and long-term issues grid planners and regulators are actively addressing, and which will be re-examined in the annual update to this document.

¹²⁶California ISO (CAISO) (2012a) *2011-2012 Transmission Plan*. Prepared by Infrastructure Development. March 23, 2012, at <http://www.caiso.com/Documents/Board-approvedISO2011-2012-TransmissionPlan.pdf>. pg 185.

¹²⁷Millar, N. (2012). "Briefing on Summer 2012 Operations Preparedness." On behalf of CAISO. Board of Governors Meeting. March 22-23, 2012, at <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf>; POWERnews (2012). "Tube Wear at San Onofre May Stem from Multiple Causes, NRC Head Says." April 12, 2012, at http://www.powermag.com/POWERnews/4531.html?hq_e=el&hq_m=2422484&hq_l=4&hq_v=fd675fc2f8.

Figure 4-1. Location of San Onofre Nuclear Generating Station (SONGS) in relation to load centers in Los Angeles Basin and San Diego



Source: Millar, N. (2012). "Briefing on Summer 2012 Operations Preparedness." On behalf of CAISO. Board of Governors Meeting. March 22-23, 2012, at <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf>, p. 2.

The early completion in June 2012 of the Sunrise Powerlink, with its initial 800 MW import capability, helps to mitigate reliability issues in San Diego because it allows for more imports into the area. This benefit of the Sunrise Powerlink was not anticipated and was not used as a justification for building the line; it had been developed as a way to increase imports of renewable power. According to officials at the CAISO, this transmission line is "more valuable today than when it was conceived because of the significant reliability benefits it brings helping to compensate for the loss of power from the San Onofre power plant this summer."¹²⁸

Table 4-1 examines expected summer 2012 reserve margins for the San Diego area in light of the SONGS outage. Operational measures to mitigate the local reliability concerns due to loss of SONGS included the following:

- Restart of Huntington Beach units (452 MW of local generating capacity, which also enables 350 MW of imports into the San Diego load pocket);
- Acceleration of the Barre-Ellis transmission upgrade;

¹²⁸San Diego Gas & Electric (SDG&E) (2012). "SDG&E Energizes Sunrise Powerlink." San Diego, Ca. June 18, 2012, at <http://regarchive.sdge.com/sunrisepowerlink/release26.html>.

- Fully deployment of demand response, Flex Alerts, CPUC 20/20 program, and seeking additional demand response from military and public agency customers.¹²⁹

Table 4-1. San Diego Reserve calculation with SONGS outage, with and without Huntington Beach units 3 & 4 (all values in MW)

Load	Mild Conditions	Heavy Load		Mild Conditions	Heavy Load
	4438	4882		4438	4882
Total gen	3048	3048		3048	3048
Import capability	2100	2100	➡	2450	2450
Load can be served	5148	5148		5498	5498
Reserves available	710	266		1060	616
Reserve requirement	603	603		603	603
Reserve margin	107	-337	➡	457	13

Huntington Beach units 3 & 4
increase import capability to
San Diego.

Source: Millar, N. (2012). "Briefing on Summer 2012 Operations Preparedness." On behalf of CAISO. Board of Governors Meeting. March 22-23, 2012, at <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf>, p. 3.

4.1.2. Midwest

Although the Midwest region has a great deal of generation capacity, several issues discussed below affect grid reliability across the region. Within MISO, the forecast for 2012 indicated that MISO could be short of operating reserves—down to 4.8% operating reserves, including load curtailments and demand response—during peak demand conditions if temperatures reached MISO's extreme weather case.¹³⁰ MISO also noted that its generation fleet could be affected by abnormally dry weather conditions and a severe drought in the Northern Plains and Upper Midwest, which would limit availability of water to cool power plants.¹³¹

SPP does not report any significant reliability issues related to resource-driven transmission constraints.

¹²⁹ Millar, N. (2012). "Briefing on Summer 2012 Operations Preparedness." On behalf of CAISO. Board of Governors Meeting. March 22-23, 2012, at <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf>.

¹³⁰ Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A-19.

¹³¹ Lum, R. (2012e). "MISO: Resources should meet demand, unless peak occurs in June," *Transmission Hub*. June 8, 2012.

4.1.3. Southeast

Transmission owners in this region are said to be able to build adequate transmission to accommodate load and generation, in part because of the vertically-integrated regulatory structure in the region.¹³² The Southeastern region “is planned and built to provide safe and reliable power deliveries from generation resources to customer loads while enabling the economic dispatch of generation with minimal congestion.”¹³³ Across the Southeast, the utilities coordinate with regulators and load-serving entities to build new generation and transmission proactively to address potential reliability or transmission congestion concerns. Utilities in this region seek to “plan our system to be able to deliver designated network resources to our loads. . . . [W]e don’t have congestion by virtue of how we do our planning process.”¹³⁴

According to NERC existing generation capacity is projected to be sufficient to cover load for the next several years. Load in this region is projected to grow, but at a slow rate given the broader economic environment.¹³⁵ Loads across the region fell in 2008 with the economic recession, and have begun rising again. FRCC observes that “[e]xtreme weather in 2010 masked the continued downward trend in energy consumption which continued into 2011.”¹³⁶

NERC noted that the persistent drought in the Southeast represents a potential reliability problem, warning before the summer of 2012 that:

Persistent drought conditions are also affecting the southeast states of Alabama, Georgia, and South Carolina Within these three states, approximately 19,000 MW of generation within the drought-affected areas require open-loop cooling Additionally, just over 4,000 MW of on-peak hydro capacity is also in this area. Significant derates and/or complete unit outages due to a lack of cooling water could expose the southeastern areas to capacity shortages in extreme scenarios; however,

¹³²Finley, E. (North Carolina Public Utility Commission) (2011). “Comments of Chairman Ed Finley, North Carolina Public Utility Commission.” Presented at the U.S. Department of Energy, National Electric Transmission Congestion Workshop, December 6, 2011, transcript, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20Philadelphia%20Workshop.pdf>, p.

16.

¹³³Southern Company, “Congestion Considerations in Southeast Physical Markets,” submission to U.S. Dept of Energy, p. 1, October 9, 2012.

¹³⁴Till, D. (Tennessee Valley Authority) (2011). “Comments by D. Till of the Tennessee Valley Authority.” Presented at the U.S. Department of Energy, National Electric Transmission Congestion Workshop.” Excerpt from transcript of Regional Congestion Study Workshop, St. Louis, MO, December 8, 2011, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20St%20Louis%20Workshop.pdf>, p. 133-34.

¹³⁵NERC (2011c). *2011 Long-Term Reliability Assessment*. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, pp. 185, 188.

¹³⁶FRCC (2012). “2012 Ten-Year Site Plan Workshop,” FRCC Presentation by Dochoda, Stacy & John Odom to the Florida Public Service Commission, August 13, 2012, http://www.psc.state.fl.us/utilities/electricgas/docs/FRCC_08_13_2012.pdf, slide 7.

reserve margins in these areas are more than sufficient to provide system operators with alternative resources should reservoir water levels fall significantly.¹³⁷

4.2. Interconnection queues

Interconnection queues reveal where developers want to locate new generation and thus suggest where new transmission may be needed. The process for new generation to move into an interconnection queue, and which entities manage those queues and how, varies across the nation.

4.2.1. West

The CAISO interconnection queue is publicly available through its website. Other utilities' and transmission providers' interconnection queues are also available on their Open Access Same-time Information System (OASIS) or company websites. However, some entities, especially public power entities, do not post queues publicly. Thus it is difficult to compile a comprehensive list of interconnection queues across the West.

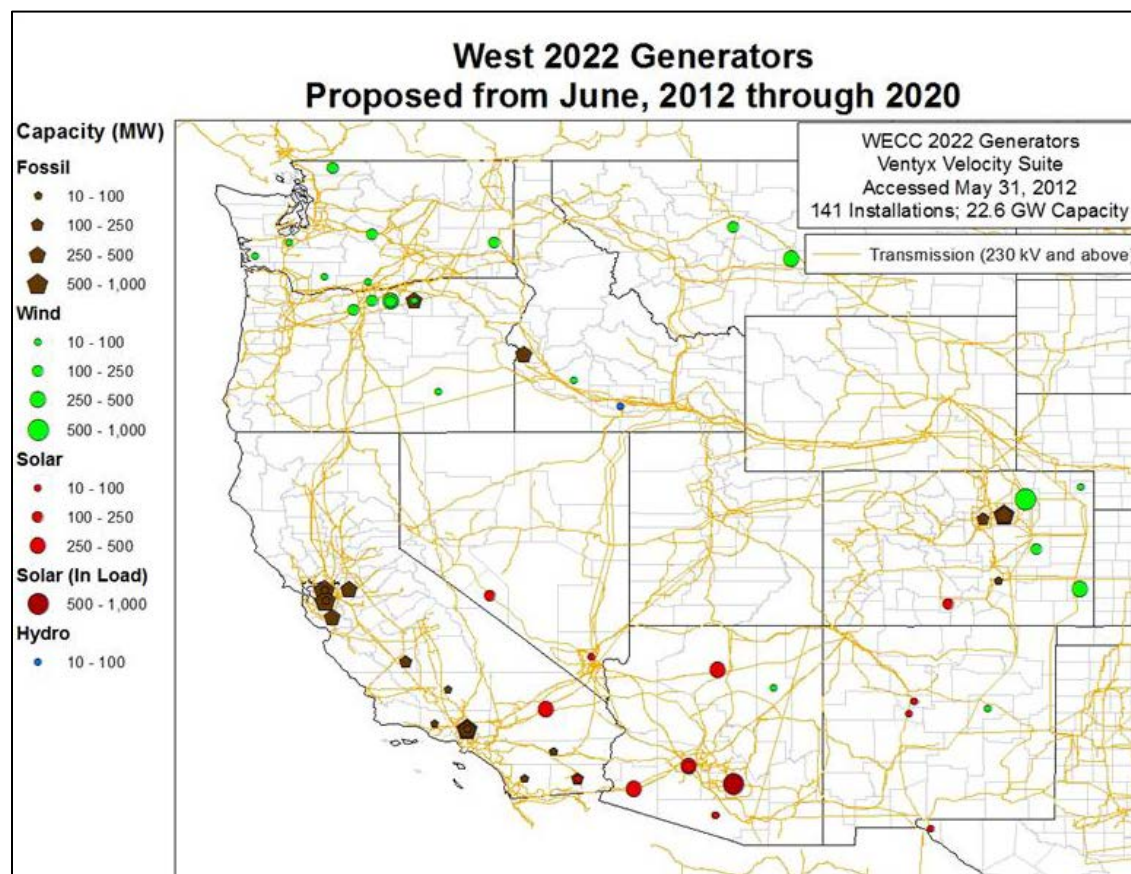
As a proxy for an interconnection-wide queue, for the purposes of this study, the Department has relied on the WECC Common Case resources list, a listing of expected generator developments prepared for use in the WECC ten-year transmission planning study. WECC/TEPPC developed a dataset that includes the minimum set of generation likely to be built and in place over the next ten years, based on a review of current utility integrated resource plans and the judgment of resource planners and other stakeholders.¹³⁸ It thus reflects current stakeholder thinking about trends in resource-driven congestion. This list includes some but not all of the generation now in the Western Interconnection queues that can use current or

¹³⁷NERC (2012d). *Summer Reliability Assessment 2012*. Princeton, NJ: NERC. May 2012, at <http://www.nerc.com/files/2012SRA.pdf>, p. 18.

¹³⁸To build the dataset, WECC uses submissions from the Load and Resource Subcommittee (LRS), research on utility Integrated Resource Plans (IRPs), and input from resource planners and other work group participants. All generation included in the list must meet the resource criteria for existing, under-construction, and planned resources. (Western Electricity Coordinating Council (WECC) (2012a). *WECC Data Collection Manual*. Salt Lake City, UT: WECC. January 2012, at <http://www.wecc.biz/committees/StandingCommittees/PCC/LRS/Shared%20Documents/WECC%20DATA%20COLLECTION%20MANUAL/LAR2012.pdf>.) In cases where the planning reserve margin is not initially met, enough "planned" and "future" generation is included (on top of existing generation) to satisfy the reserve margin. Renewable generation areas identified by the Western Renewable Energy Zone (WREZ) tool is used to create generic resources that close the gap in the event that states do not meet their RPS requirements. (Western Electricity Coordinating Council (WECC) (2011e). *WECC 10-Year Regional Transmission Plan: Plan Summary*. Salt Lake City, UT: WECC. September 2011, at http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf; WECC 2011 Plan Summary, Pacini, H. (2011). *TEPPC 2022 Common Case—Conventional and Renewable Resource Assumptions, on behalf of WECC*. February 10, 2011, at http://www.wecc.biz/committees/BOD/TEPPC/20120106/Lists/Presentations/1/120210_2022CCGenerationAssumptions_RTEPWebinar.pdf.

anticipated transmission for grid and load access. The WECC Common Case resources are mapped in Figure 4-2.

Figure 4-2. WECC 2022 Common Case resources

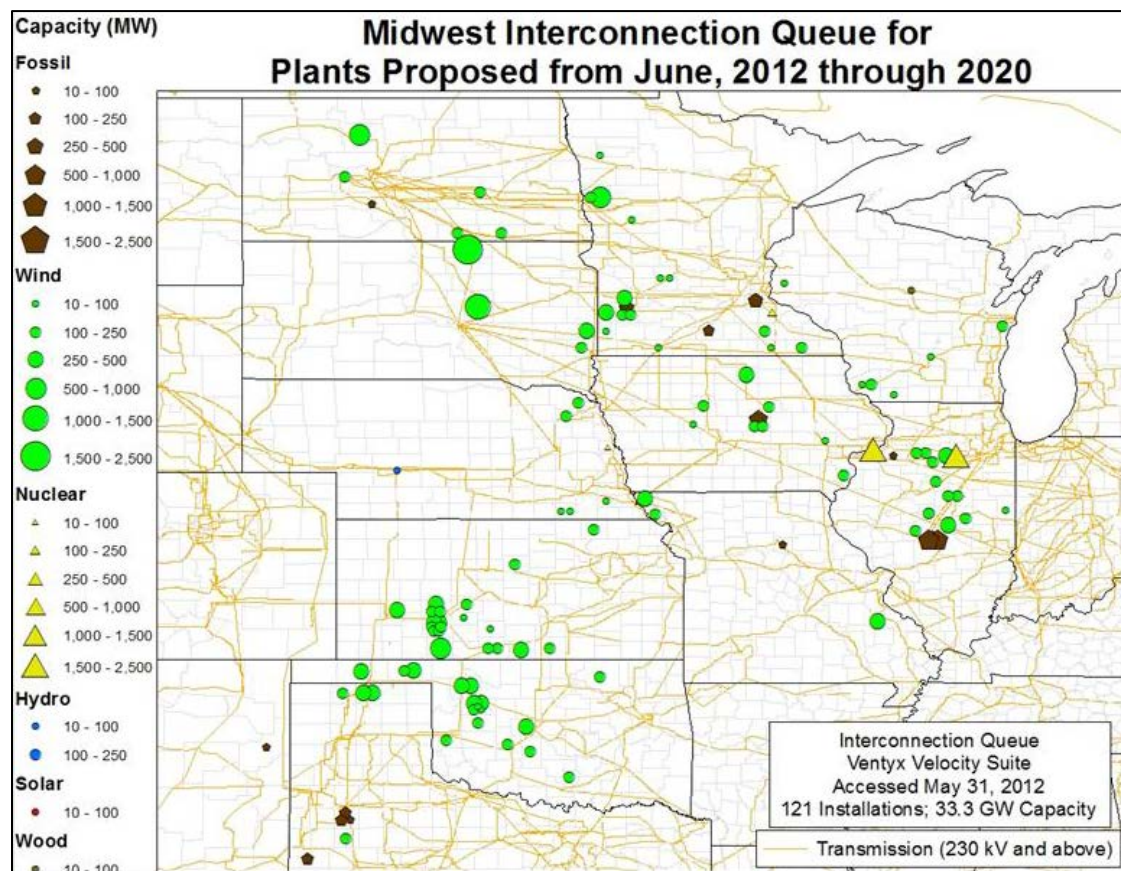


Source: Ventyx (2012). "Ventyx Velocity Suite."

4.2.2. Midwest

Figure 4-3 shows all of the generation siting requests spanning MISO, SPP and PJM-West, for all plants indicating an intended in-service date between summer 2012 and the end of 2020. Most of the proposed new generation is wind-based.

Figure 4-3. Interconnection queue for the Midwest, by plant size and technology

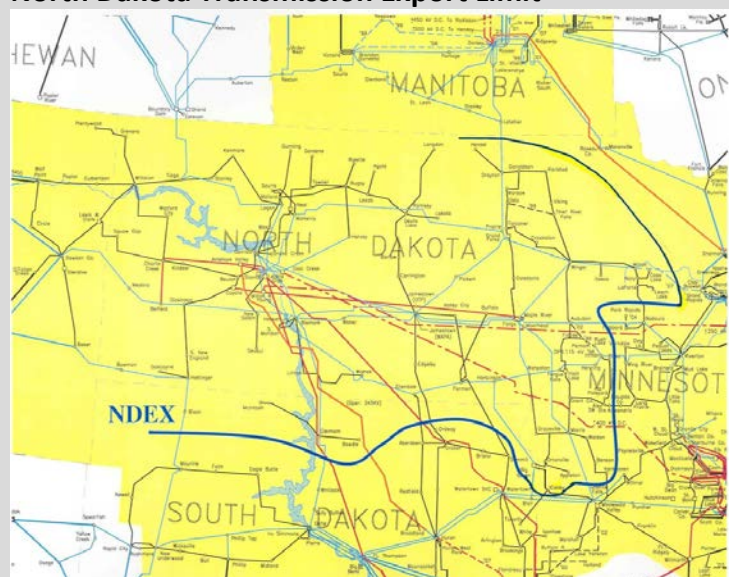


Source: Ventyx (2012). "Ventyx Velocity Suite."

Case study on regional resource development and congestion: The North Dakota Export Line

North Dakota offers an example of how the lack of transmission and the inability to interconnect hampers regional development. In the northern plains recent interconnection requests totaled 9,083 MW from Minnesota, 2,882 MW from South Dakota and 2,638 MW from North Dakota (with a total of 6,000 MW of potential wind generation projects permitted or announced within the state). Despite new transmission construction in Minnesota, there will not be enough transmission capacity to allow all of this generation to interconnect and deliver the potential energy to loads, and MISO estimates that it will be years before additional transmission capacity is available.¹

The figure below shows the transmission constraint that currently limits further generation development inside North Dakota for export to eastern and southern load centers. Known as the North Dakota Export Limit (NDEX), it is a stability-based operating constraint that limits exports to about 1,950 MW. The North Dakota Public Service Commission asserts that “additional new transmission is needed for the upper Great Plains region to provide clean, long-term and low-cost domestic energy . . . to contribute to national energy supply.”² Several transmission improvements are under consideration that if built would enable greater exports from North Dakota. In addition, discussions are under way among MISO, the Western Area Power Administration (Western) and others about reciprocal arrangements to enable more efficient usage of their aggregate transmission facilities (including additional export), while providing appropriate compensation to transmission owners for the use of their assets.

North Dakota Transmission Export Limit

Source: Lein, J. (North Dakota Public Service Commission) (2011). “U.S. Department of Energy National Electric Transmission Congestion Study Workshop.” Presented at the United States Department of Energy (2011a). “Material Submitted: Pre-Congestion Study Regional Workshops”, at <http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/national/2012>, p. 8.

¹Lein, J. (North Dakota Public Service Commission) (2011). “Comments of Jerry Lein.” Provided at the United States Department of Energy (2011e). *National Electric Transmission Congestion Study Workshop*. St. Louis, MO. December 8, 2011, at

<http://energy.gov/sites/prod/files/Presentation%20by%20Jerry%20Lein%2C%20ND%20PSC.pdf>, p. 7.

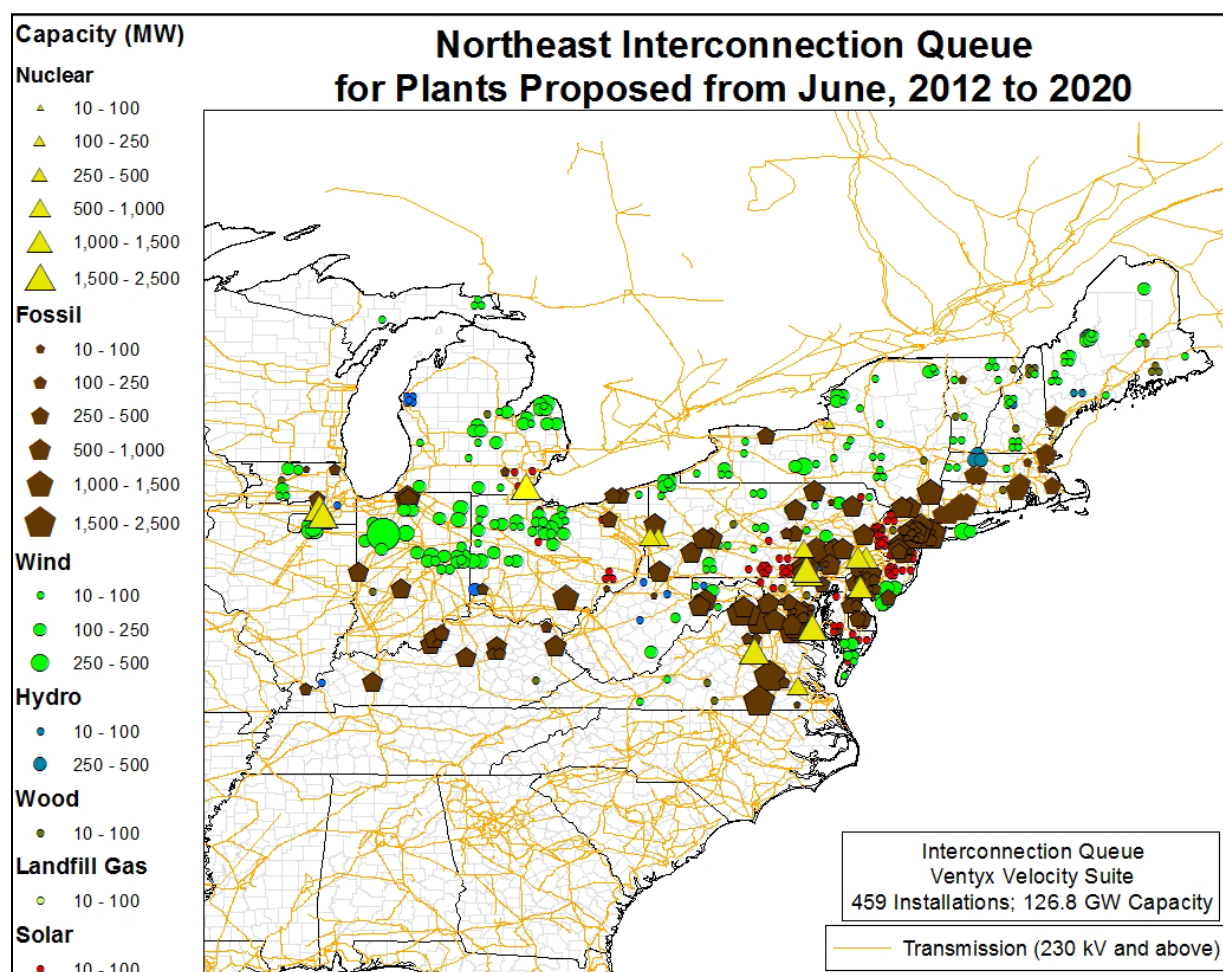
² *Ibid.*, p. 11.

4.2.3. Northeast

There are 451 projects representing 127 GW of proposed generation seeking grid interconnection across the Northeast between now and the end of 2020. Most of these projects are wind, but there are a large proportion of fossil plants as well.

Figure 4-4 shows the locations of this proposed generation. Some of the proposed projects sitting in interconnection queues may no longer be feasible given low fuel prices and competition from other plants for transmission access.

Figure 4-4. Northeast interconnection queue map (June 2012 through 2020)



Source: Ventyx (2012). "Ventyx Velocity Suite" and <http://www.oasis.oati.com/tva/tvadocs/CurrentQ.pdf>

A recent study anticipates that most of the Northeast states could fall short of their RPS requirements by 2020 due to transmission issues. IHS CERA estimates that RPS-induced demand for renewables will outstrip available resources, and that transmission constraints

could reduce deliverable renewable energy into PJM and New York load centers.¹³⁹ New York and New England disagree with this conclusion; there are significant wind resources within and close to New York and the New England states, and New York and New England have completed renewables integration studies that conclude that transmission congestion will not hamper wind development in particular.¹⁴⁰

4.2.4. Southeast

Interconnection queue information is available from transmission owners in the Southeast region, posted on the companies' websites.¹⁴¹ The map below in Figure 4-5 does not contain a complete set of all of the proposed power plants requesting interconnection across the Southeast. Nevertheless, this map shows most generation development in fossil technologies in Florida and Georgia. A few off-shore wind projects are in the queue off the coast of North Carolina, close to load centers and the existing (on-shore) transmission system.

There is extensive off-shore wind potential off the coast of North Carolina, South Carolina, Georgia and Virginia.¹⁴² According to studies by the North Carolina Transmission Planning Collaborative, the transmission to connect 5,000 MW of off-shore wind would cost up to \$1.3 billion.¹⁴³ The Southern Alliance for Clean Energy says that South Carolina could install 35 gigawatts of offshore wind generation.¹⁴⁴

According to the National Renewable Energy Laboratory, most of the southeastern states have strong technical potential for rooftop photovoltaic generation, including Florida (49 GW), Georgia (25 GW) and North Carolina (23GW).¹⁴⁵ To date, actual photovoltaic development in this area has been limited—there was a total of 55 MW of photovoltaics installed in North Carolina, with much less installed in the other southeastern states at the end of 2011,¹⁴⁶ but the Blue Ridge Mt. Electric Membership Corp, in Georgia, and Fayetteville Public Utilities in

¹³⁹IHS Emerging Energy Research (2012). *U.S. Wind O&M Strategies, 2012-2025*. June 2012, at <http://www.emerging-energy.com/uploadDocs/USWindOandMStrategies2012.pdf>, pp. 2-28, 2-29.

¹⁴⁰See NYISO (2010b). *Growing Wind—Final Report of the NYISO 2010 Wind Generation Study*, at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf, "Final Report – New England Wind Integration Study," December 2010, at http://www.uwig.org/newis_es.pdf.

¹⁴¹Interconnection queues were found for Associated Electric Cooperative Inc., CLECO Louisiana, Duke Carolinas, EKCP Kentucky, Florida Power and Light, Georgia Transmission Corp, LGE, Progress Energy Florida, Southern Company, and Tennessee Valley Authority.

¹⁴²Lopez, A., B. Roberts, et al. (2012). "U.S. Renewable Energy Technology Potentials: A GIS-Based Analysis." National Renewable Energy Lab, NREL/TP-6A20-51946. July 2012, at <http://www.nrel.gov/docs/fy12osti/51946.pdf>, p. 15.

¹⁴³Rivera-Linares, C. (2012m). "N.C. panel: 'Significant' transmission upgrades needed for high levels of offshore wind generation," *Transmission Hub*, February 10, 2012.

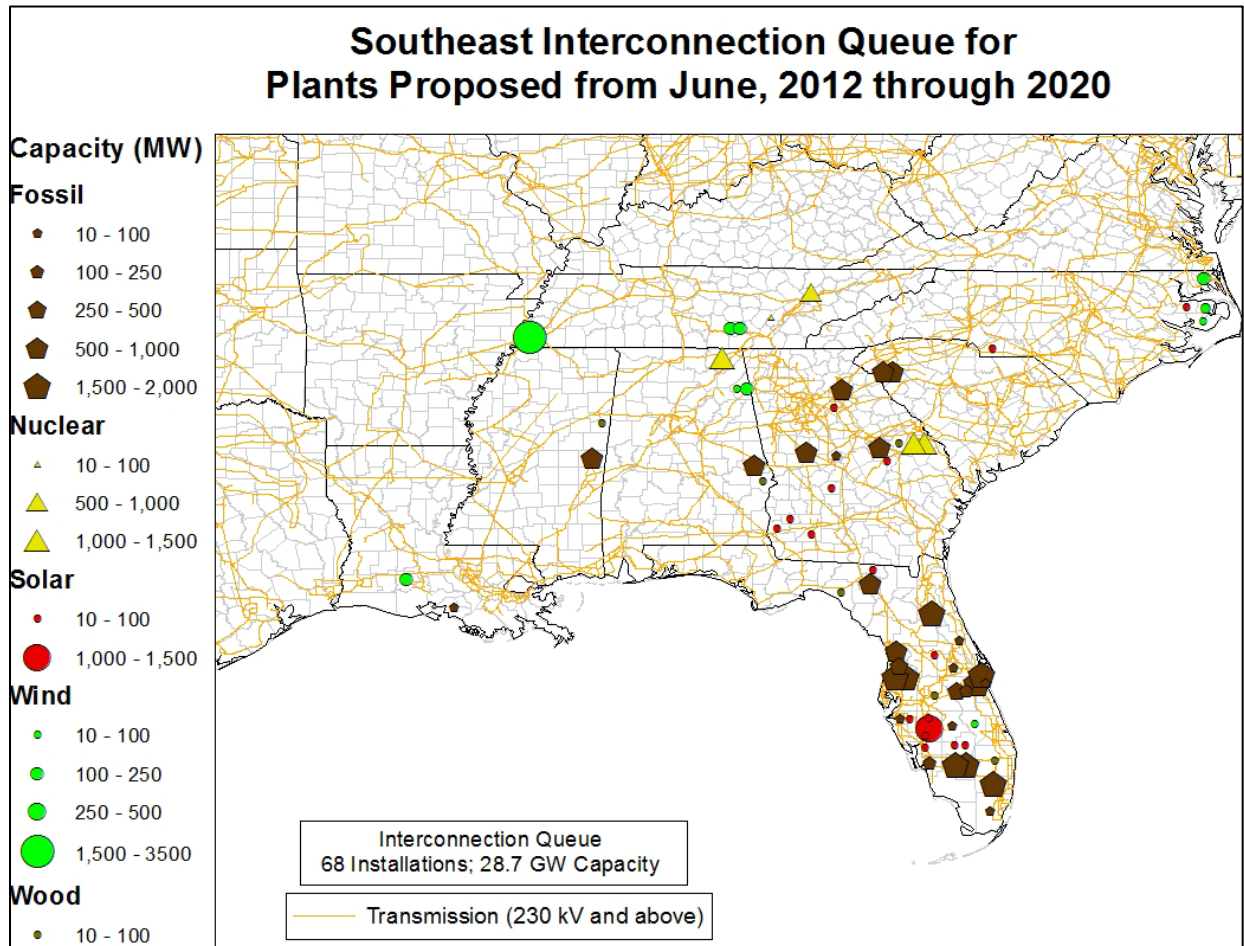
¹⁴⁴Smith, B. (2012b). "Fracking, economy slow developing SC offshore wind," *Associated Press*, Charleston SC, September 13, 2012, at <http://finance.yahoo.com/news/fracking-economy-slow-developing-sc-155831053.html>.

¹⁴⁵Lopez, A., B. Roberts, et al. (2012). "U.S. Renewable Energy Technology Potentials: A GIS-Based Analysis." National Renewable Energy Lab, July 2012, p. 12.

¹⁴⁶Solar Energy Industries Association and GTM Research (2012). "U.S. Solar Market Insight Report; 2011 Year-in-Review," 2012, p. 8.

Tennessee were ranked second and third among the nation's utilities in annual installed solar watts per customer in 2011.^{147 148}

Figure 4-5. Southeast interconnection queue map (June 2012 through 2020)



Sources: [http://www.oatioasis.com/AECI/AECIdocs/AECI Interconnection System Impact Study Queue For Posting -2012-4-16.pdf](http://www.oatioasis.com/AECI/AECIdocs/AECI%20Interconnection%20System%20Impact%20Study%20Queue%20For%20Posting%202012-4-16.pdf)

<http://www.oatioasis.com/clec/index.html>

<http://www.oatioasis.com/DUK/DUKdocs/studies.html#Generation>

Study Summary: [http://www.oatioasis.com/EKPC/EKPCdocs/EKPC Generation Interconnection Queue.pdf](http://www.oatioasis.com/EKPC/EKPCdocs/EKPC%20Generation%20Interconnection%20Queue.pdf)

<http://www.oatioasis.com/fpl/index.html>

[http://www.oatioasis.com/FPC/FPCdocs/GIS Queue Table 061212.mht](http://www.oatioasis.com/FPC/FPCdocs/GIS%20Queue%20Table%20061212.mht)

<http://www.oatioasis.com/gtc/index.html>

<https://www.weboasis.com/OASIS/SOCO/Interconnection/Active-Gen-IC-Requests.pdf>

http://lgeestudies.spp.org/SPPGeneration/GI_ActiveRequests.cfm

<http://www.oasis.oati.com/tva/tvadocs/CurrentQ.pdf>

¹⁴⁷Solar Electric Power Association (2012). "Fifth Annual 2011 SEPA Utility Solar Rankings," May 2012, at <http://www.solarelectricpower.org/sepa-utility-solar-rankings.aspx>, p. 3.

¹⁴⁸There has been much activity recently in the Southeast with respect to solar resources, which will be examined in the annual update to this document.

4.3. Clean or renewable energy zones

Identification of clean or renewable energy zones also help to reveal where new transmission could be needed to open up resource-rich areas for generation development. This is particularly relevant where new renewable resources must be built to meet state renewable portfolio standards (RPS). RPSs require utilities to satisfy a certain amount of demand with renewable resources. As of 2012, 29 states plus the District of Columbia had RPSs, and eight additional states had renewable portfolio goals.¹⁴⁹

4.3.1. West

Several states in the West have conducted their own renewable resource evaluations.¹⁵⁰ The Western Governors Association (WGA) called for the Western Renewable Energy Zone (WREZ) analysis, a multi-phase initiative to identify clean energy zones across the West,¹⁵¹ to inform the Western interconnection planning activities, for example, in estimating resource quality and site-specific costs for developing resources.

The WGA WREZ Phase 1 effort, completed in June 2009, identified 54 areas in the West with high renewable resource potential that also met other screening criteria.¹⁵² (Figure 4-6).

The WREZ Phase 3 report surveyed utilities and state regulators about their interest in WREZ areas and the potential for collaboration in developing areas of identified mutual interest.¹⁵³ Sixteen WREZ areas are of interest to utilities that together serve multiple states. The survey found that utilities are focused on developing renewable resources in or close to their service areas, but that utilities are not generally interested in more distant resource areas unless transmission is already in place or there is a high degree of certainty for the timely completion of transmission to the area. Additionally, the survey found that utility procurement decisions reflect a preference for in-state renewable development to promote energy self-sufficiency, local reliability, and local economic benefits such as jobs. This local preference also reflects

¹⁴⁹DSIRE (2012). "DSIRE Solar RPS Policies map." *DSIRE website*. Raleigh, NC: NC Solar Center, NC State University. June 2012, at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

¹⁵⁰These include California, Colorado, Arizona, New Mexico, Nevada, and Utah. (Western Governors' Association (WGA) & United States Department of Energy (2009). *Western Renewable Energy Zones – Phase 1 Report*. Denver, CO: (WGA). June 2009, at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf, p. 18.)

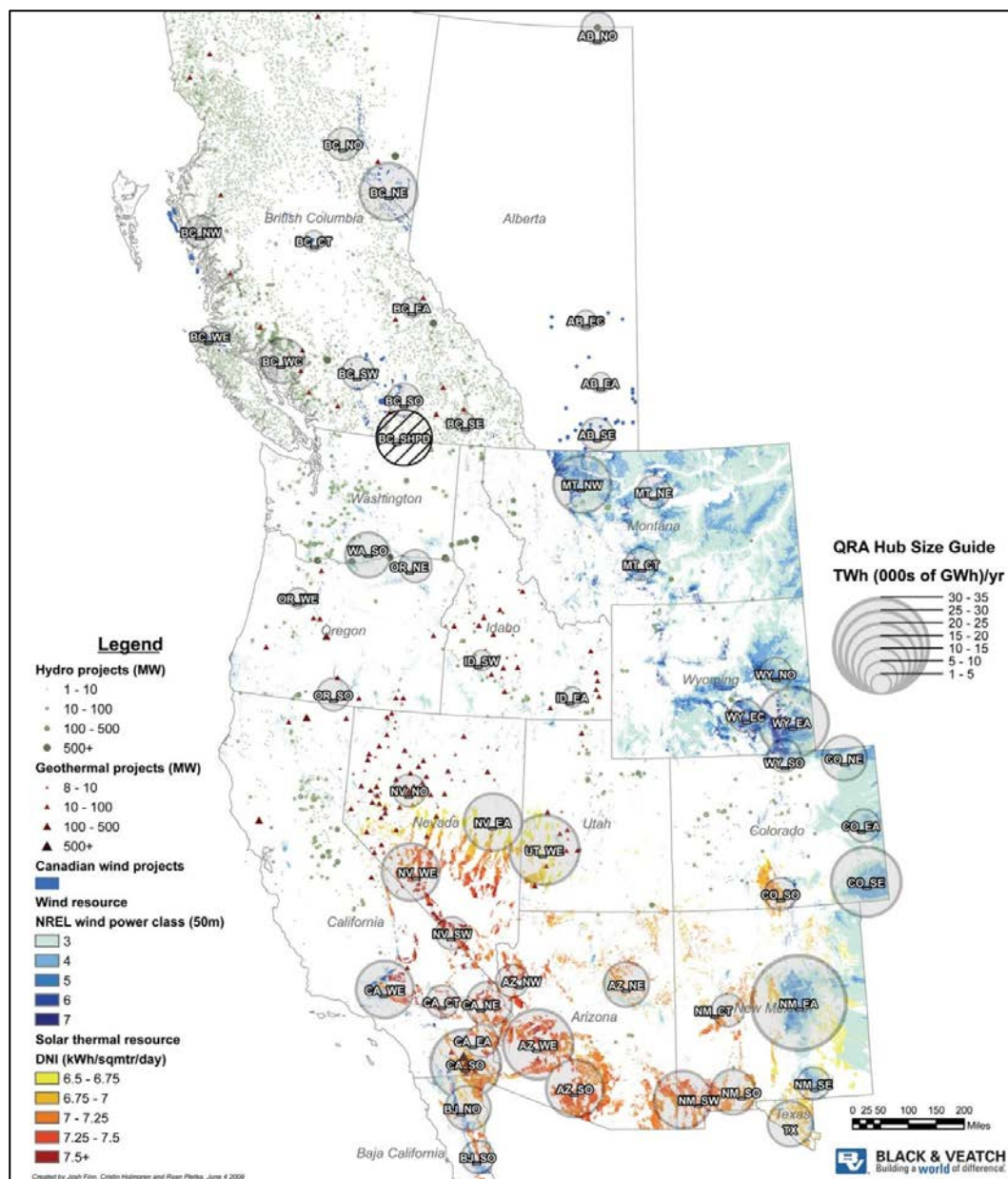
¹⁵¹This analysis was planned in four phases. The goals of these phases are as follows: Phase 1 is identification of renewable energy zones, although the actual outcome of Phase 1 was "Qualified Resource Areas", which are not officially renewable energy zones. Phase 2 is development of a tool to estimate the cost of delivering power from the REZs, and is being used in WECC transmission planning activities. Phase 3 is analysis and recommendations for the best ways to develop commercial generation within the REZs. Phase 4 focuses on improving coordination between industry stakeholders to facilitate permitting and cost allocation issues of multi-area transmission lines. *Ibid.*, pp. 18-19.)

¹⁵²The Phase I report identified "Qualified Resource Areas" or hubs, not renewable energy zones. These areas need to be subject to public evaluation and review, in particular related to wildlife and input from load serving entities, before determining the locations of renewable energy zone. *Ibid.*, p. 5.

¹⁵³Schwartz, L. et al. (2012) *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zones Initiative*. Prepared by Regulatory Assistance Project for Western Governors' Association, March 2012, http://www.westgov.org/component/joomdoc/doc_download/1555-wrez-3-full-report-2012.

awareness of the multiple cost dimensions of building, accessing and integrating renewable resources and enabling transmission relative to the benefits of geographic diversity and low-cost, stable-priced renewable generation.¹⁵⁴

Figure 4-6. WREZ Qualified Resource Areas Hub Map, from WGA WREZ Phase 1 report



Source: Western Governors' Association (WGA) & United States Department of Energy (2009). *Western Renewable Energy Zones – Phase 1 Report*. Denver, CO: (WGA). June 2009, at http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf.

¹⁵⁴ Western Governors' Association (WGA) (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*. Regulatory Assistance Project. Denver, CO: WGA. June 10, 2012 at http://www.westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=1610, pp. 8, 54-67.

4.3.1.1. Western RPSs and results from WECC renewables studies

RPS requirements across the West are shown in Table 4-2.

Table 4-2. Western state RPS requirements

State	RPS requirement ¹⁵⁵	Mandatory or Goal ¹⁵⁶	Incremental RPS Energy Requirement, 2010-2020 (as % of total incremental energy in West) ¹⁵⁷	Incremental RPS Energy Requirement, total 2010-2020 [GWh] ¹⁵⁸
California	33% by 2020	Mandatory	66%	59,165
Colorado	30% by 2020 (IOUs) 10% by 2020 (co-ops and munis)	Mandatory	10%	8,964
Washington	15% by 2020	Mandatory	7%	6,275
Arizona	15% by 2025	Mandatory	5%	4,482
Nevada	25% by 2025	Mandatory	4%	3,586
Oregon	25% by 2025 (large utilities) 5-10% by 2025 (smaller utilities)	Mandatory	3%	2,689
Utah	20% by 2025	Goal	3%	2,689
New Mexico	20% by 2020 (IOUs) 10% by 2020 (co-ops)	Mandatory	2%	1,793
Montana	15% by 2015	Mandatory	1%	896

¹⁵⁵ DSIRE (2012) "RPS Policies," at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

¹⁵⁶ *Ibid.*

¹⁵⁷ Western Electricity Coordinating Council (WECC) (2011e). *WECC 10-Year Regional Transmission Plan: Plan Summary*. Salt Lake City, UT: WECC. September 2011, at http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf, p. 27.

¹⁵⁸ Calculated based on *ibid.*, p. 27.

The incremental energy requirements between 2010 and 2020 by state in Table 4-2 are based on WECC analysis of the location and amount of existing renewable resources and assumptions about the operating conditions those existing renewable resources, whether those renewable resources will be used to meet in-state RPS requirements or be transported to other states, and load levels in 2020.¹⁵⁹

Case Study: Meeting the California RPS

California has the most ambitious RPS requirement in the West, requiring 33% of total retail sales of electricity to be met with output from eligible renewable generation by 2020. Based on a WECC analysis, California's aggressive renewable resource requirement in combination with the state's high load (proportional to the rest of the West) represents 66% of all new renewable resources needed to meet all state RPSs in the West.¹ For this reason, renewable development across the West may in part depend on where California utilities contract for supply to meet the RPS.

California's RPS is expected to drive utility contracts for between 75,000 and 90,000 GWh by 2020, of which at least roughly half will come from resources that need to be built.² Total renewable resource capacity required by 2020 is estimated to be between 16.8 and 17.7 GW,³ and as of 2012 there were enough renewable projects in the CAISO generator interconnection queue to meet this need.⁴ However, not all projects in the queue will be built, and some existing contracts may fall through.

There is no prohibition against using out-of-state generation to meet the California RPS, although state regulators have established rules for resource eligibility and requirements that favor in-state generation sources.⁵

¹Western Electricity Coordinating Council (WECC) (2011e). *WECC 10-Year Regional Transmission Plan: Plan Summary*. Salt Lake City, UT: WECC. September 2011, at http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf, p. 27.

²California Energy Commission (CEC) (2011b). *Renewable Power in California: Status and Issues*. Sacramento, CA. December 2011, <http://www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF-REV1.pdf>, p. 6.

³California Public Utilities Commission (CPUC) and California Energy Commission (CEC) (2012). "Revised Base Case and Alternative Scenarios for CAISO 2012-2013 Transmission Planning Process." Letter to Steve Berberich, CAISO. May 16, 2012, at http://www.caiso.com/Documents/2012-2013-FinalRenewableGenerationPortfoliosRecommended_CPUC-CEC.pdf.

⁴Wang, X., (California ISO) (2011). "Comments of Xiaobo Wang." Provided at the United States Department of Energy (2011b). *National Electric Transmission Congestion Study Workshop*. San Diego, CA. December 15, 2011, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20San%20Diego%20Workshop.pdf>, p. 95; Strack, J., (San Diego Gas & Electric) (2011). "Comments of Jan Strack." Provided at the United States Department of Energy (2011b). *National Electric Transmission Congestion Study Workshop*. San Diego, CA. December 15, 2011, at <http://energy.gov/sites/prod/files/Transcript%20-%202012%20National%20Electric%20Transmission%20Congestion%20Study%20San%20Diego%20Workshop.pdf>, p. 76.

⁵California Public Utilities Commission (CPUC) and California Energy Commission (CEC) (2012). "Revised Base Case and Alternative Scenarios for CAISO 2012-2013 Transmission Planning Process." Letter to Steve Berberich, CAISO. May 16, 2012, at http://www.caiso.com/Documents/2012-2013-FinalRenewableGenerationPortfoliosRecommended_CPUC-CEC.pdf.

¹⁵⁹*Ibid.*, p. 27.

WECC's 2019 ten-year transmission study analyzed the future implications of locating substantial amounts of renewable resources (12,000 GWh) in different parts of the West for delivery into California.⁶ Results of this analysis suggest the annual levelized capital cost of investing in renewable resources in these different locations ranged from \$1.8 billion/year to locate them in California or the Pacific Northwest, to \$0.8 billion/year to locate them in Wyoming. Variable production costs for the different scenarios were very similar.⁷

The WECC renewable resource scenarios explore “dump energy”—the amount of energy that could be produced but is not used to serve load. Often dump energy indicates areas where there is not sufficient transmission capacity to deliver the power; in other words, areas of transmission congestion. Dump energy was highest by two orders of magnitude in the Northern Nevada- and Montana-dominant renewable future scenarios. Another indicator of local transmission congestion due to inadequate transmission is the drop in WECC renewable percentage to 14.7% in the Northern Nevada scenario, compared with 15% in the other scenarios. This drop occurred because renewable generation was unable to flow to load due to inadequate transmission capacity.⁸

⁶Western Electricity Coordinating Council (2011b). *2019 TEPPC Study Report*. Salt Lake City, UT: WECC. September 2011, at <http://www.wecc.biz/library/StudyReport/Documents/2019%20Study%20Report.pdf>, p.10.

⁷The capital and product costs reported here only include the cost of resources, not transmission. The analysis that led to these results did not assume any bulk transmission upgrades, other than those deemed likely to be built by 2019; these were included in the input assumptions for all resource reallocation cases reported here. *Ibid.*, pp. 12, 34.

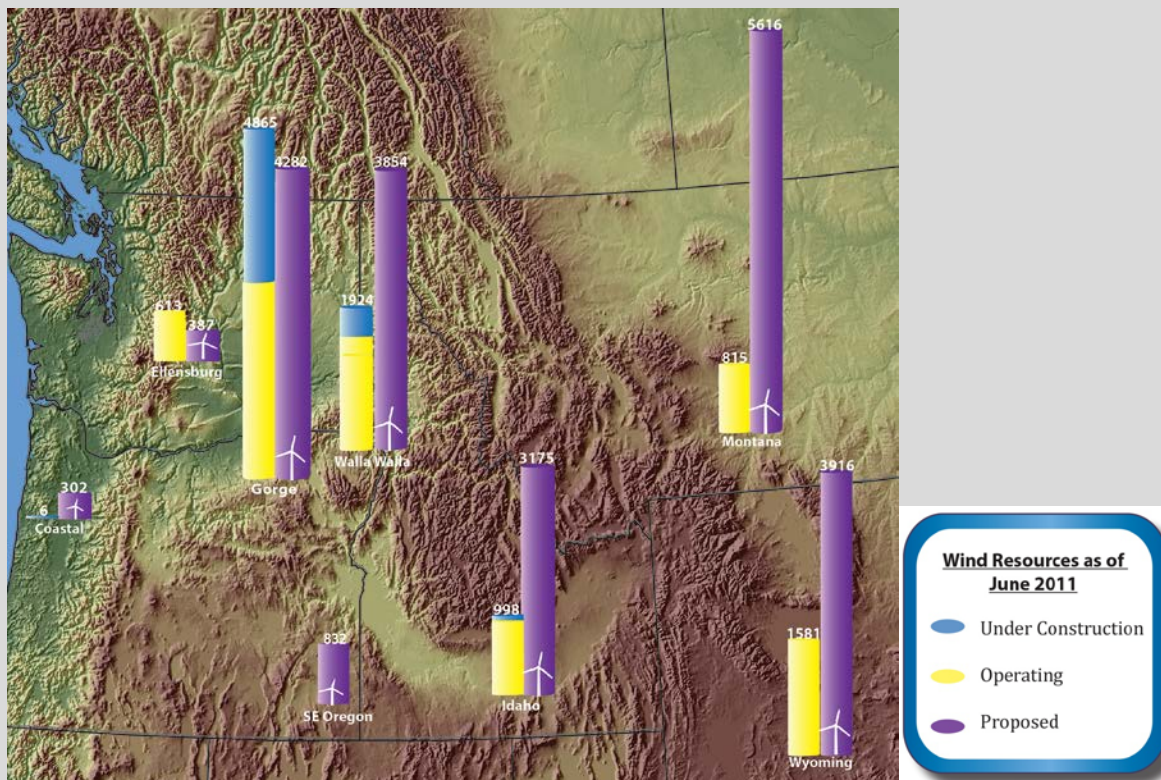
⁸*Ibid.*, p. 12.

**Case Study on uncertainty in resources and transmission:
Renewables in the Northwest**

Renewable generation development in the Northwest illustrates how anticipating transmission needs can be complicated by uncertainty about location or resources, transmission and plant retirements.

There is desire (political as well as economic) to pursue renewable, specifically wind, development at the state level, but there is uncertainty about where the production from new renewable generation will be delivered or what transmission must be built for this purpose. The map below shows that the amount of wind generation under construction is less than the amount of wind currently operating in the area, which suggests there may be a slowing of development in the near future.¹ As stated by ColumbiaGrid, the resource potential exists, especially in more remote locations in Idaho, Montana and Wyoming, but what transmission might connect it to load in the Pacific Northwest has not been determined.²

Existing and proposed wind capacity in the North



Source: ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan*. Portland, OR: ColumbiaGrid. February 15, 2012, at <http://www.columbiagrid.org/download.cfm?DVID=2563>, p. 15.

¹Capacity factors for wind differ across this region, with wind in the more “remote” eastern states having higher capacity factors than “local” wind closer to load centers in the west. However, the improved capacity factor needs to be weighed against the increase in transmission cost to connect these resources. Variability and fast-ramping were found to be similar in both remote and local wind resources, but this variability can be reduced if geographically diverse wind is developed (e.g., both local and remote wind). (Wind Integration Study Team (WIST) (2011). *Relative Northwest Benefits of Local vs. Remote Wind Generation*. January 2011, at [http://www.nwcouncil.org/energy/wind/meetings/2011/06/PEFA_WIST_WISTReportFinalJanuary2011\[1\].docx](http://www.nwcouncil.org/energy/wind/meetings/2011/06/PEFA_WIST_WISTReportFinalJanuary2011[1].docx).)

²ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan*. Portland, OR: ColumbiaGrid. February 15, 2012, at <http://www.columbiagrid.org/download.cfm?DVID=2563>, p. 44.

Renewables development is complicating use of the West of Cascades paths in Washington and Oregon. These paths are traditionally heavily loaded during cold winter weather. But they may soon need to accommodate large amounts of wind development if the wind is balanced with west-side gas resources, which could create some voltage stability issues. Planners are studying several potential transmission projects to deal with this problem.³ This is complicated by the pending retirement of units at the Centralia plant in 2020 and 2025, located on the high-load west-side of the paths, which will affect transmission flows and voltage stability in the area. The location of replacement generation will create different challenges—if replacement generation is built on the east side of the West of Cascades paths there may be an increased dependence on the Cascade paths to deliver power to loads; if replacement generation is located on the west side of those paths there may be further need to manage generation dispatch and curtail renewable resources (including wind).⁴

³ ColumbiaGrid (2012b). *Cross Cascades North Study Team Report*. Portland, OR: ColumbiaGrid. April 2012, at <http://www.columbiagrid.org/download.cfm?DVID=2628>, p. 2-3; ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan*. Portland, OR: ColumbiaGrid. February 15, 2012, at <http://www.columbiagrid.org/download.cfm?DVID=2563>, p. 39.

⁴ ColumbiaGrid (2012a). *2012 Update to the 2011 Biennial Transmission Expansion Plan*. Portland, OR: ColumbiaGrid. February 15, 2012, at <http://www.columbiagrid.org/download.cfm?DVID=2563>, p. 18-19.

4.3.2. Midwest

Although the Midwest region is rich in renewable energy and coal resources—and newly identified oil and gas developable with hydraulic fracturing technology—until recently there was little work done on an interconnection-wide basis to recognize renewable energy zones or clean energy zones comparable to those developed in the West and in ERCOT (within Texas). An effort to develop a tool that could allow this type of analysis is now under way under the auspices of the Eastern Interconnection States Planning Council: EISPC is working with the national laboratories to develop web-based geographic information system database that will allow stakeholders to identify areas that could be suitable for developing clean energy resources or determining Clean Energy Zones. There have, however, been several sub-regional efforts.

In 2009, at the direction of the state legislature, Michigan identified four regions of the state (Figure 4-7) with high wind energy potential, based on wind resources, land availability and exclusion of inappropriate uses, and energy production potential relative to other areas of the state.¹⁶⁰ The Michigan analysis estimates that these areas could host over 6,000 MW of wind generation capacity and produce almost 18 GWh of annual electricity.¹⁶¹

¹⁶⁰ Public Sector Consultants Inc. (2009). *Final Report of the Michigan Wind Energy Resource Zone Board*, October 15, 2009, p. 22.

¹⁶¹ *Ibid.*, p. 5.

Figure 4-7. Michigan regions with the highest wind energy production potential

Source: Public Sector Consultants Inc. (2009). *Final Report of the Michigan Wind Energy Resource Zone Board*, October 15, 2009, Exhibit 2, p. 4.

Similarly, the Governors of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin created the Upper Midwest Transmission Development Initiative to identify and “prioritize renewable generation zones sufficient to meet the needs of five states, identify transmission needed to deliver energy to load, and address cost allocation.”¹⁶² In 2010 the final UMTDI report identified 20 renewable energy zones and six renewable energy transmission corridors that could connect more than 15,000 MW of wind generation across the five states.¹⁶³

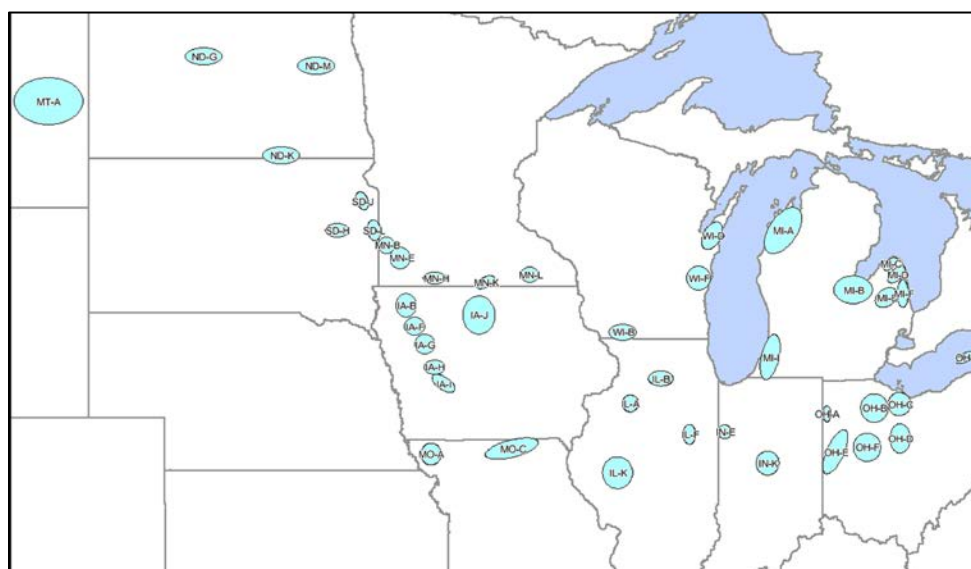
MISO’s Renewable Generation Outlet Study was an effort to develop a set of transmission portfolios that could meet its member states’ renewable energy requirements. This effort identified the areas where renewable resources were most likely to be developed, and designed potential transmission expansion plans that would facilitate alternative levels of high-value renewable development in those areas at reasonable transmission cost. MISO began its analysis by looking at all of the planned wind projects in the Midwestern and northeast

¹⁶²Boyd, D. (2009). “Upper Midwest Transmission Development Initiative,” *Presentation of Minnesota Public Utilities Commission at the NARUC Electricity Committee Meeting*, February 16, 2009, slide 3.

¹⁶³Wisconsin Public Service Commission (2010). “Upper Midwest Transmission Development Initiative releases report on the region’s renewable energy transmission corridors,” September 30, 2010.

interconnection queues in July 2008, including 67,000 MW within MISO's footprint (as shown in Figure 4-8 below) spread across renewable energy zones recognized by the Midwest Governors Association.¹⁶⁴ This analysis identified several alternative transmission plans to serve those zones, and narrowed those into a set of "candidate Multi-Value Projects" (see Figure 4-9).¹⁶⁵ A number of the transmission projects identified in the RGOS have moved forward within the MISO planning process as regionally coordinated transmission projects that were recognized as Multi-Value Projects in the MISO MTEP (Midwest Transmission Expansion Plan) 2011, and were approved by the MISO board in December 2011. MISO reports that the 17 Multi-Value Projects will "resolve reliability violations on approximately 650 elements, . . . enable 41 million MWh of wind energy per year to meet renewable energy mandates and goals, . . . and support a variety of generation policies by using a set of energy zones which support wind, natural gas and other fuel sources."¹⁶⁶

Figure 4-8. Midwest renewable energy zone locations identified by the Upper Midwest Transmission Development Initiative and other state agencies, 2010

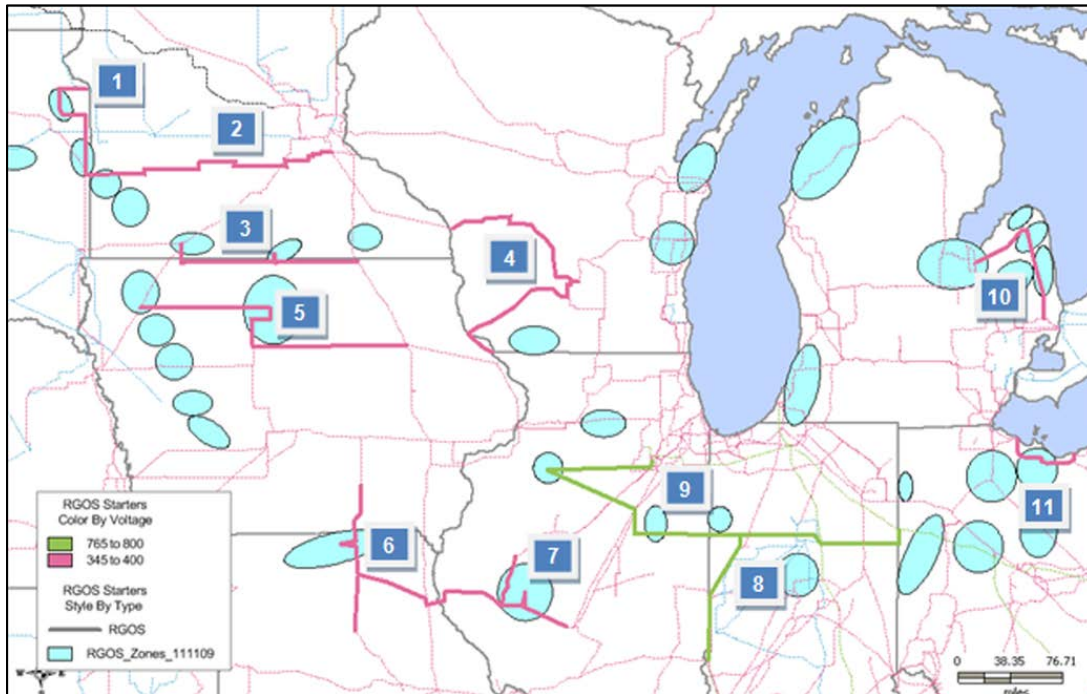


Source: Midwest ISO (2010b), *Regional Generation Outlet Study*, November 19, 2010, Figure 2.3-1 at <https://www.midwestiso.org/library/repository/study/rgos/regional%20generation%20outlet%20study.pdf>, p. 18.

¹⁶⁴ Gregerson, M. (2008). "Summary of MISO Studies to Help Determine Transmission Needed to Achieve Governors/Premiers' Renewable Energy Goals," Midwest Governors Association, September 25, 2008; Midwest ISO (2010b), *MISO Regional Generation Outlet Study*. Carmel, IN: MISO. November 19, 2010, at <https://www.midwestiso.org/Planning/Pages/RegionalGenerationOutletStudy.aspx>.

¹⁶⁵ Midwest ISO (2010b), *MISO Regional Generation Outlet Study*. Carmel, IN: MISO. November 19, 2010, at <https://www.midwestiso.org/Library/Repository/Study/RGOS/Regional%20Generation%20Outlet%20Study.pdf>.

¹⁶⁶ Midwest (2011e). *MISO 2011 Transmission Expansion Planning (MTEP) report*. Carmel, IN: MISO. December 2011, at <https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP11.aspx>, p. 42.

Figure 4-9. MISO RGOS-identified Candidate Multi-Value transmission projects

Source: Midwest ISO (2010b), *Regional Generation Outlet Study*, November 19, 2010, Figure 1.3-2, p. 13, at <https://www.midwestiso.org/library/repository/study/rgos/regional%20generation%20outlet%20study.pdf>.

Renewable development in this region is also increasing. At the end of 2011, MISO's wind generation represented 7.1% of installed capacity and 5.2% of generation. In 2010 MISO created the Dispatchable Intermittent Resource (DIR) generation category to improve control over wind resources, allowing wind to respond to dispatch instructions. This "reduced the need for manual curtailments to manage congestion or over-generation conditions by 33% in 2011. By December 2011, over 3 GW of wind units were DIRs and much of the remaining wind resources are anticipated to convert by June 2013, which should greatly reduce manual curtailments."¹⁶⁷ Figure 4-10 shows the variability of MISO wind generation. As the system is currently constructed and operated, this creates challenges with respect to real-time operating reserves management, supply forecasting and the provision of ancillary services MISO gives wind resources a 14.9% capacity credit for Planning Year 2012-2013.¹⁶⁸

Wind generation in SPP has also increased, as shown in Figure 4-11. SPP's market monitor reports that this is causing some localized congestion, particularly in the Texas Panhandle, which has been SPP's most congested region for the last five years.¹⁶⁹ As wind generation increases in the western side of SPP, congestion will continue until adequate transmission is in

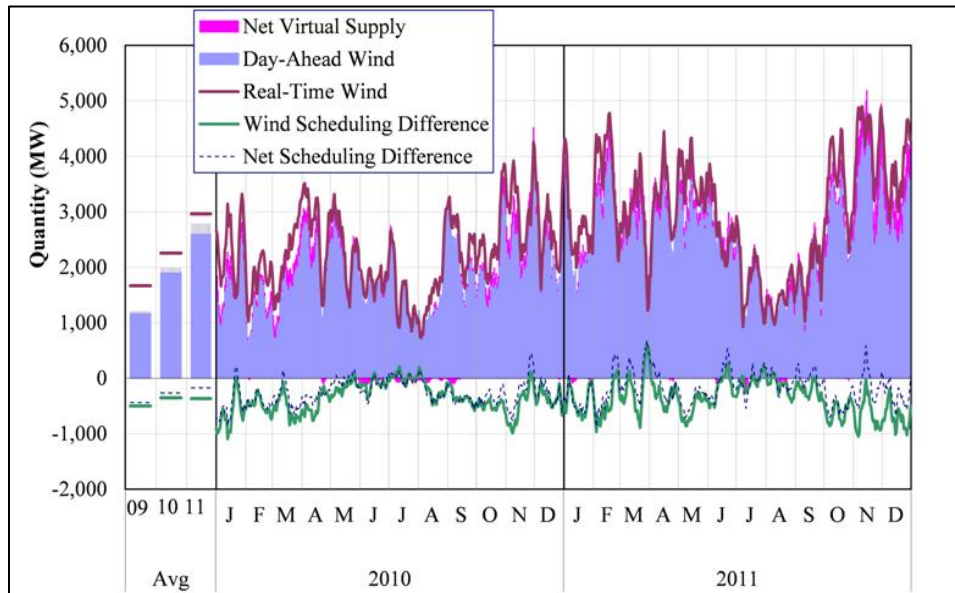
¹⁶⁷Potomac Economics (2012b), *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. 36.

¹⁶⁸*Ibid.*, p. 38.

¹⁶⁹Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc. July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, p. 11.

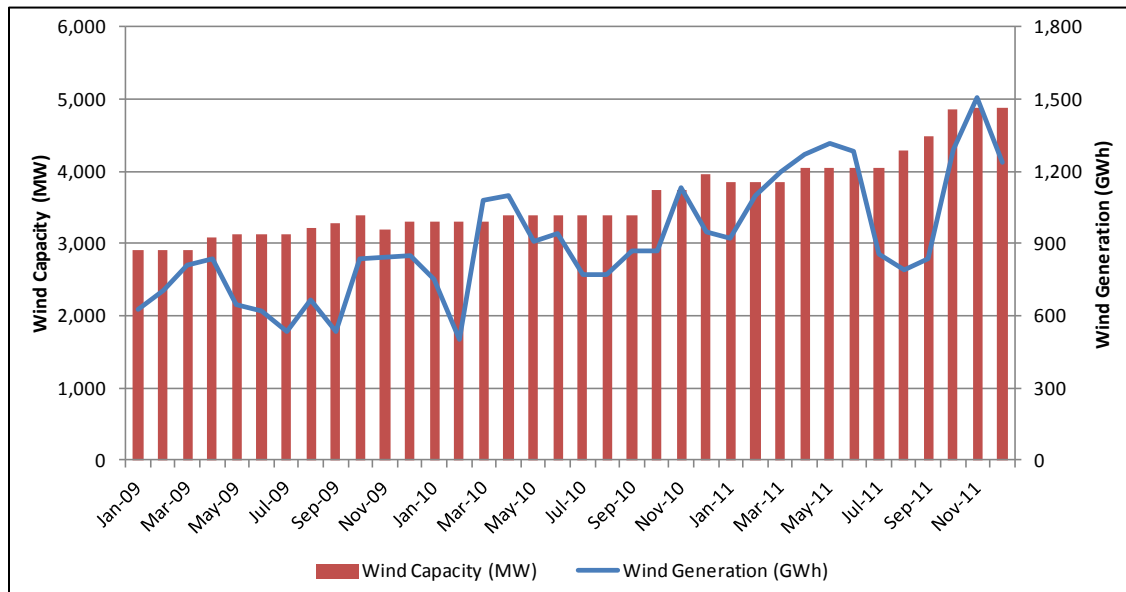
place to deliver the wind energy to loads. SPP's proposed automatic curtailment procedures for renewables, if approved by FERC, should diminish the localized congestion in the short term.

Figure 4-10. Day-ahead scheduling versus real-time wind generation in MISO, 2009-2011



Source: Potomac Economics (2012b), *2011 State of the Market Report for the MISO Electricity Markets*, Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p. A-70.

Figure 4-11. Wind capacity and generation in SPP, 2009-11



Source: Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc., July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, Figure II.26, p. 58.

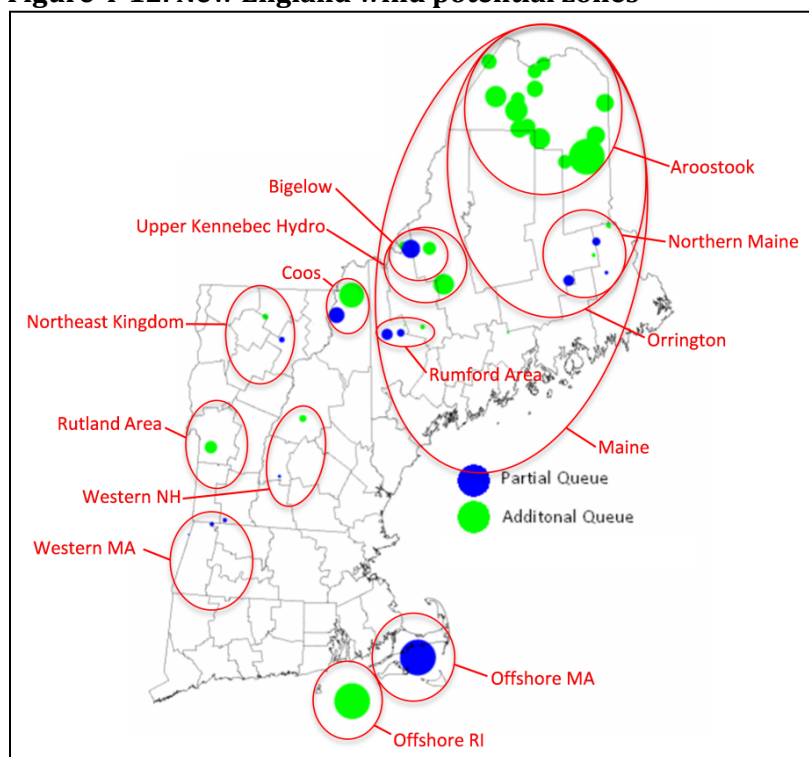
4.3.3. Northeast

No formally recognized clean energy zones exist yet in the northeast region. The Eastern Interconnection States Planning Council Energy Zone activity, mentioned above, will provide information on resource availability and other relevant issues (e.g., environmental considerations), tools and support for states to define energy zones.

All of the states within New England have renewable energy procurement requirements for their utilities. These state targets will amount to over 20% of the area's total projected energy use by 2020.¹⁷⁰ To achieve this goal, however, the region will need to add more system flexibility, more operating reserve and regulation resources, and more transmission to interconnect all the new generation and deliver it to load.

Figure 4-12 indicates potential wind development areas; actual development will be affected by a variety of considerations, including relative economics of wind and other generation technologies and fuels and the availability of transmission capacity to deliver generation to loads.

Figure 4-12. New England wind potential zones



Source: ISO-NE (2011b). *2011 Regional System Plan*. Holyoke, MA: ISO-NE. October 2011, at http://iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc; Henderson, M. (ISO-NE) (2011). "ISO New England Comments on the National Electric Transmission Congestion Study." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops", at <http://energy.gov/sites/prod/files/Presentation%20by%20Mike%20Henderson%2C%20ISO-NE.pdf>, slide 5.

¹⁷⁰ISO-NE, (2011b). *2012 Regional System Plan*. Holyoke, MA: ISO-NE. November 2012, at http://iso-ne.com/trans/rsp/2012/rsp11_final_110212.docx, p. 138.

The New England Wind Integration Study identified a number of areas with good wind potential where new wind generation development is likely, and hypothesized a transmission overlay to bypass or overcome the transmission constraints between these locations and New England loads.¹⁷¹

4.3.4. Southeast

No clean energy zones have been designated yet in the Southeast region. Southeastern states are participating in the EISPC Energy Zone process, which will not by itself define clean energy zones in the East but will provide information, tools and support for states that may seek to identify such zones in the future. There have been no state or regional efforts to formally identify the location of potential clean energy resources for utility or private transmission or siting purposes.

4.4. Changes in generation portfolios

There are a variety of drivers creating changes in regional generation portfolios. The most significant are federal and state environmental regulations, and trends in fuel prices.

Many of the new environmental regulations being promulgated by the Environmental Protection Agency (EPA) are still under development and their final impacts on power plants are unclear. Industry analyses based on early assumptions about the nature of new environmental requirements hypothesized a wide range of plant retrofits and retirements, particularly within the coal-fired fleet. But to date, the low price of natural gas relative to coal has been reducing the prospects for coal-fired generation¹⁷² more than anticipated environmental regulations, as discussed below.

4.4.1. West

New federal environmental regulations will require many existing power plants to modify cooling systems, air pollution treatment, and make other decisions related to pollution abatement. No transmission planning studies specifically examining the implications of these EPA regulations in the West were found during preparation of this report.

¹⁷¹GE Energy, Enernex AWS Truepower (2010). *Final Report: New England Wind Integration Study*. Prepared for ISO-NE, December 5, 2010, at http://www.uwig.org/newis_es.pdf.

¹⁷²For instance, PJM's market monitor reports that in the months of January through August 2012, coal-fired production across PJM totaled 41.9% of total PJM generation, compared to 48.0% for the same months in 2011; natural gas-fired generation as a percent of total PJM generation rose from 13.9% in 2011 to 19.3% in 2012 for the same months. (Monitoring Analytics (2012), "2012 Market Update for PJM: January through August," Presentation by J. Bowring to PJM Members Committee, September 24, 2012, Table 2-2, p. 4.)

In California, state-level once-through cooling (OTC) regulations will require generating units that use OTC systems to invest in new closed loop cooling systems, repower, or retire by 2020 (with slightly delayed implementation date for nuclear plants). Over 17 GW of capacity is estimated to be facing this decision, almost 15 GW of which is gas-fired.¹⁷³ There is still uncertainty about how California generators will choose to comply with the OTC requirements. Table 4-3 tabulates the California capacity, as of 2011, that will be affected by OTC rules.¹⁷⁴

Table 4-3. California generation capacity facing once-through cooling regulation, by region

Local Capacity Area	MW
Los Angeles Basin	4,940
San Diego	950
Big Creek/Ventura	1,947
Bay Area	1,303
LADWP	985
SUBTOTAL	10,124
Outside of LCA	3,180
TOTAL	13,304

Source: California Energy Commission (CEC) (2012a). *2011 Integrated Energy Policy Report*. Sacramento, CA. February, 2012, at <http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf>, p. 129.

4.4.2. Midwest

Load flows over the next several years may change along with changes in the generation portfolio. The low price of gas is causing gas-fired generation to displace some coal and oil generation in the dispatch order and is leading to the retirement of some coal generation.¹⁷⁵ ¹⁷⁶ New environmental regulations will also prompt the retirement and retrofits

¹⁷³California ISO (CAISO) (2012c). *2012 Summer Loads and Resources Assessment*. Folsom, CA: CAISO. March 15, 2012. at http://www.caiso.com/Documents/Briefing_SummerLoads_ResourcesOperationsPreparednessAssessment-Report-MAR2012.pdf, p. 6; California Energy Commission (CEC) (2012a). *2011 Integrated Energy Policy Report*. Sacramento, CA. February, 2012, at <http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf>, p. 127.

¹⁷⁴Capacity from the San Onofre Nuclear Generating Station units is included in this table.

¹⁷⁵Tierney, S. (2012). "Why Coal Plants Retire: Power Market Fundamentals as of 2012." *Coal Power Magazine*. July 30, 2012, at http://www.coalpowermag.com/ops_and_maintenance/400.html.

¹⁷⁶For example, "Historically cheap natural gas prices drove down coal-fired generation in 2011 in the Midwest Independent System Operator region, and at Consumers Energy, and are expected to do so again . . . said Consumers Energy official Richard Blumenstock . . . The primary driver for these depressed electricity prices was

of coal plants. Increased penetration of wind resources and new EPA regulations will put substantial downward pressure on capacity margins in MISO over the short-term to mid-term time horizons. MISO's 2012 analysis suggests that up to 12 GW of coal-fired capacity in MISO would be at risk of retirement due to the compliance costs of these regulations. Subsequent analysis by MISO indicates that higher levels of capacity could be at risk if the prevailing low natural gas prices continue for the long term because electricity prices are too low to make new gas-fired power plants profitable—in other words, investors expect that prices will stay so low that they cannot recover the costs of keeping inefficient fossil plants open nor earn enough return to justify building many new high-efficiency fossil generators. MISO surveys of market participants' compliance plans indicate substantial amounts of potential retirements and long-term outages related to environmental retrofits.

As of 2012 MISO had 71 GW of coal-fired capacity in service, providing 56.7% of its total generating capacity. Based on 2011 and early 2012 expectations about air emission regulation levels, coal plants representing 49 to 63 GW of that capacity were expected to install at least one environmental retrofit by 2016; MISO expected as much as 12 to 19 GW of the coal-fired fleet to be retired rather than retrofitted.¹⁷⁷ A study conducted by the Brattle Group for MISO estimated that in order to comply with the EPA's Mercury and Air Toxics (MATS) rule by Fall 2015 (assuming one-year compliance extensions), MISO would have to schedule approximately 45% more MW of coal-fired outages per season.¹⁷⁸

SPP has 25 GW of coal-fired capacity.¹⁷⁹ As of mid-2012, coal-fired generation produced about 60% of monthly electric generation within SPP and coal was the marginal fuel source in 46% of the hours between April 2011 and April 2012.¹⁸⁰

the low price for natural gas, he added Industry analysts attribute the price drop to a recent growth in natural gas production resulting from shale gas plays With such low fuel costs, gas-fired generators have incremental and average costs below generators having coal or oil as fuel sources. This results in MISO . . . committing and dispatching lower cost natural gas-fueled generators before higher cost coal-fueled and oil-fueled generators Consumers Energy intends to shut down coal units for extended periods when electricity prices in the Midwest Energy Market are forecasted to be well below the cost of production for a [coal] unit." Source: Cassell, B. (2012c). "Consumers backs down coal due to cheap gas, alters coal supply." *Generation Hub*. March 5, 2012. And independent power producer Dynegy's 2011 10-K reported that, "[profitable operation of Dynegy's coal-fired facilities is highly dependent on coal prices and coal transportation rates" Dynegy's gross margin from its coal generation segment decreased by 33% from 2010 to 2011 due to lower electricity prices, lower coal plant dispatch, and lower energy revenues in 2011. Source: Cassell, B. (2012b). "Dynegy retires Vermilion coal plant, mothballs other capacity." *Generation Hub*. March 8, 2012.

¹⁷⁷Celebi, M., K. Spees, Q. Liao, and S. Eisenhart. (2012). *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*. Prepared by The Brattle Group, May 2012, at <http://www.brattle.com/documents/UploadLibrary/Upload1039.pdf>, p. 5.

¹⁷⁸*Ibid.*, p. 3.

¹⁷⁹Southwest Power Pool (SPP) Market Monitoring Unit (2012c). *SPP 2011 State of the Market*. Little Rock, AR: SPP, Inc., July 9, 2012, at <http://www.spp.org/publications/2011-State-of-the-Market-Report.pdf>, Table II.24, pg. 56.

¹⁸⁰Southwest Power Pool (SPP) Market Monitoring Unit (2012g). *Monthly State of the Market Report April 2012*. Little Rock, AR: SPP, Inc. May, 2012, at <http://www.spp.org/publications/SPP%20MSOM%20Report%20201204.pdf>, pp. 12, 14.

4.4.3. Northeast

PJM

PJM's 2011 Regional Transmission Expansion Plan indicates that PJM had over 78,600 MW of coal-fired generation capacity as of June 2011. In this region there have been numerous coal plant retirement announcements, including American Electric Power's decision to retire more than 4,100 MW of coal-fired capacity in Ohio, Kentucky, Virginia, Indiana and West Virginia,¹⁸¹ Dominion's retirement of 334 MW in Virginia, and Exelon's shut-down of four older coal units in Pennsylvania.¹⁸²

PJM explains that "coal-fired units more than 40 years old and less than 400 MW are less efficient, run less frequently on average, and accordingly, have seen their capacity factors and net energy revenues decline since 2007. They also do not encompass economies of scale in retrofit costs that larger units possess. These older, smaller units, therefore, are likely candidates for retirement should they require substantial environmental retrofits and are considered at risk for deactivation."¹⁸³

Recently PJM announced that there is over one gigawatt of nameplate photovoltaic generation capacity installed within its service territory.¹⁸⁴ Much of this new solar power (Figure 4-13) is concentrated in the most populous parts of PJM.

New York

Compliance with environmental regulations is expected to affect the installed generation in New York State. The NERC 2011 LTRA estimated that New York could experience some retirement of coal and gas-fired generation.¹⁸⁵

New England

ISO-New England has also studied the potential impacts of environmental regulations and estimated that fossil fuel and nuclear capacity may be subject to cooling water intake requirements, the Air Toxics rule or the MATS rule.¹⁸⁶¹⁸⁷ The NERC 2011 LTRA estimated that environmental regulations could result in retirement of coal and gas-fired capacity.¹⁸⁸

¹⁸¹AEP (2012). "AEP notifies Reliability Organizations of planned plant retirements." *AEP press release*. March 23, 2012, at <http://www.aep.com/newsroom/newsreleases/?ID=1754>.

¹⁸²Cassell, B. (2012g). "Dominion, Exelon lead coal retirements." *EnergyBiz*. July 10, 2012.

¹⁸³PJM (2012b). *PJM 2011 Regional Transmission Expansion Plan*. Norristown, PA: PJM. February 2012, at <http://www.pjm.com/documents/reports/rtep-report.aspx>, Book 1, p. 62.

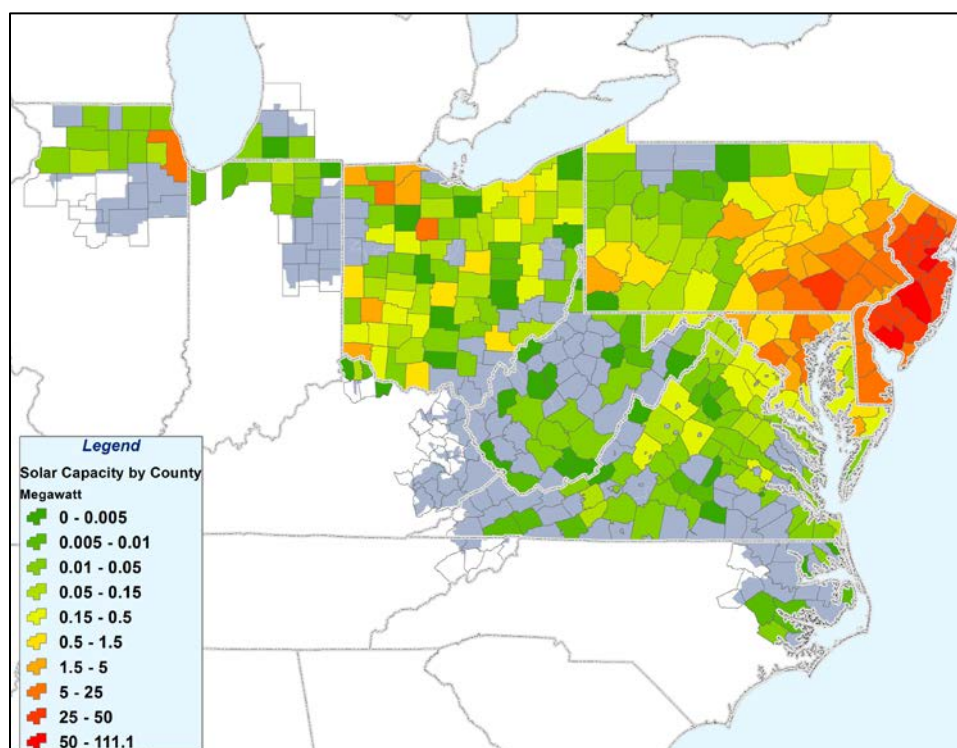
¹⁸⁴PJM (2012c). "PJM region shines with one gigawatt of solar power." *Press release*. May 15, 2012, at <http://www.pjm.com/~media/about-pjm/newsroom/2012-releases/20120515-pjm-region-shines-with-one-gw-solar-power.ashx>.

¹⁸⁵NERC (2011c). *2011 Long-Term Reliability Assessment*. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, Table 34, p. 146.

¹⁸⁶ISO-NE, (2011b). *2011 Regional System Plan*. Holyoke, MA: ISO-NE. October 2011, at http://iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc, p. 15.

¹⁸⁷*Ibid.*

¹⁸⁸NERC (2011c). *2011 Long-Term Reliability Assessment*. Princeton, NJ: NERC. November 2011, at http://www.nerc.com/files/2011%20LTRA_Final.pdf, Table 34, p. 146.

Figure 4-13. New solar capacity installed in PJM by county

Source: PJM (2012c). "PJM region shines with one gigawatt of solar power." *Press release*. May 15, 2012, at <http://www.pjm.com/~media/about-pjm/newsroom/2012-releases/20120515-pjm-region-shines-with-one-gw-solar-power.ashx>.

4.4.4. Southeast

In the Southeast, as in the rest of the nation, there is uncertainty over current and future environmental requirements and their implications for the current coal generation fleet. Falling gas and rising coal prices have been cited, and add a complicating factor.¹⁸⁹

Southeastern generators, led by the Southern Company, have voiced concern about the implementation timing of the pending EPA regulations.¹⁹⁰ The concern is that the compliance

¹⁸⁹Gulf Power Company (2012). *Ten Year Site Plan, 2012-2021, for electric generating facilities and associated transmission facilities*. Report submitted to the Florida Public Service Commission, April 2012, at <http://www.psc.state.fl.us/library/filings/12/01935-12/01935-12.pdf>, pp. 49-52.

¹⁹⁰See, for instance, Busbin, J. (Southern Company) (2011). "Comments of Jim Busbin of Southern Company." Presented at the U.S. Department of Energy, National Electric Transmission Congestion Workshop, Philadelphia, PA, December 6, 2011, and Georgia Power's integrated resource plan filing with the Georgia Public Service Commission, about which the company said, "These federal environmental regulations proposed by the U.S. Environmental Protection Agency (EPA) over the last several months would significantly expand the scope of regulations governing air emissions, water intake, and waste management at power plants. The regulations have the greatest impact on coal- and oil-fired plants, and if finalized as proposed would significantly increase the cost of electric power generation. In addition, some of the proposed rules would set unrealistically short compliance

timeline may lead to congestion or reliability problems, because scheduling plant outages for retrofitting equipment will interfere with meeting load, or that retrofits will not be able to be finished within the compliance window and plants will be forced to shut down.

deadlines that could impact electricity reliability beginning in 2015.” (Southern Company press release, “Georgia Power Files Updated Energy Plan; Highlights uncertainty of environmental regulations,” August 4, 2011.)

5. Transmission System Utilization

This chapter discusses publicly available data on transmission system utilization. The only interconnection of the country for which such data are available consistently is the Western Interconnection; thus this chapter only discusses the West. The discussion is based on WECC analysis of actual and scheduled flows from 2009, which are the most recent data available. Data on 2010 and 2011 usage was released in late 2013 and will be included in future updates to this study.¹⁹¹

Figure 5-1 shows all the major transmission paths in the West. The numbers in boxes indicate the major paths (collections of transmission elements) that WECC views as the dominant transmission delivery paths and points within the Western system. The black rectangles or cross-bars span a collection of lines and transformers that together make up a monitored path. WECC analyzes these paths and assigns a capacity rating to each such collection that makes up an individual path (which is named in the lists on the sides of the map).

These paths reflect some dominant historical practices—many large power plants were built in locations distant from loads, and long lines were built across great distances to deliver power from the plants to population centers. Many of these plants and lines were built decades ago under cooperative, multi-utility ownership and planning agreements. Examples include the California-Oregon Transmission Project and the Palo Verde and Four Corners power plants.

West-wide path analysis

The 2009 WECC transmission path utilization study analyzed 2009 historic schedule and flow information on 25 paths¹⁹² (see Figure 5-2). WECC determined which paths were the most heavily used based on directional and net schedules, and actual flows. Directional scheduled flow is the amount of power scheduled to flow in each direction on the paths; schedules can be made in either direction on a single path. Net scheduled flow is the summation of these directional flows on each path. Actual flow is the recorded amount of power that actually did flow. Net schedule and actual flows can be different because of loop-flow or changes in real-time system conditions. For directional schedules, net schedules and actual flows, WECC calculated the percent hours of the year each of these paths were at or above 75%, 90% and 99% of the hourly path operating transfer capability.^{193 194} These metrics are called U75, U90 and U99, respectively. A line loaded with actual flow at or above 75% is considered heavily used

¹⁹¹The TEPPC Path Utilization Study is not an annual report. Data on 2010 and 2011 usage had not been released as of 2012.

¹⁹²Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TrasnsPath_UtilizationStudy.pdf, p. 3.

¹⁹³Operating Transfer Capability – the megawatt capacity limitation of a path, which can vary hourly with changing operating conditions.

¹⁹⁴When operating transfer capability data in the WECC PI database was not available, total transfer capability (TTC) limits from the WECC Path Rating Catalog were used to represent the path limits.

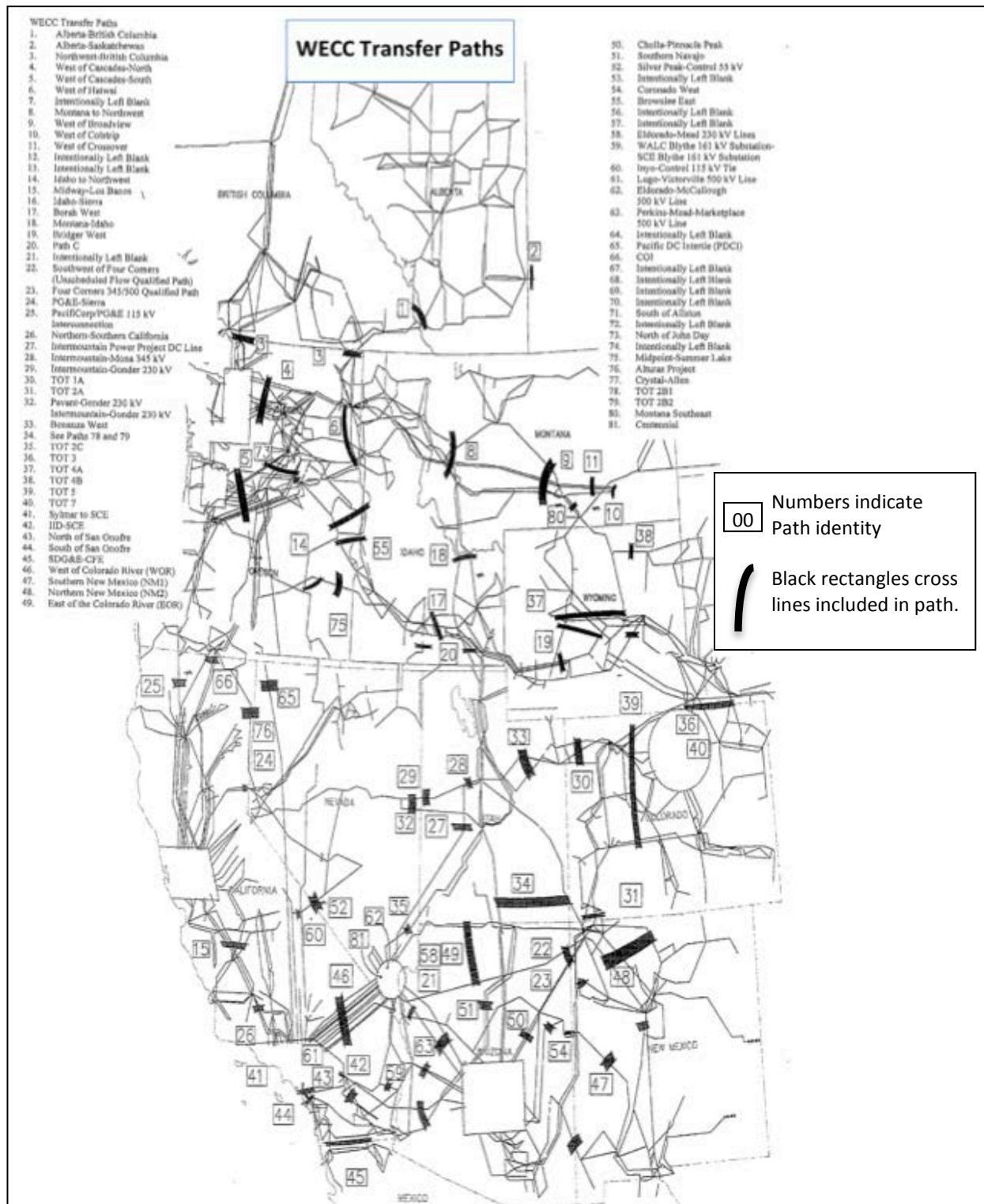
by market participants.¹⁹⁵ Ninety percent loading is often considered to be the maximum practical loading level.

Table 5-1 shows WECC's list of the most highly used paths based on actual flow and net schedule, and include the U75 and U90 measures for each. The actual flow on Path 27 in 2009, for instance, was at or above 1,800 MW (compared to a maximum path rating of 2,400 MW) for 74.6% of the year, or 6,535 hours.

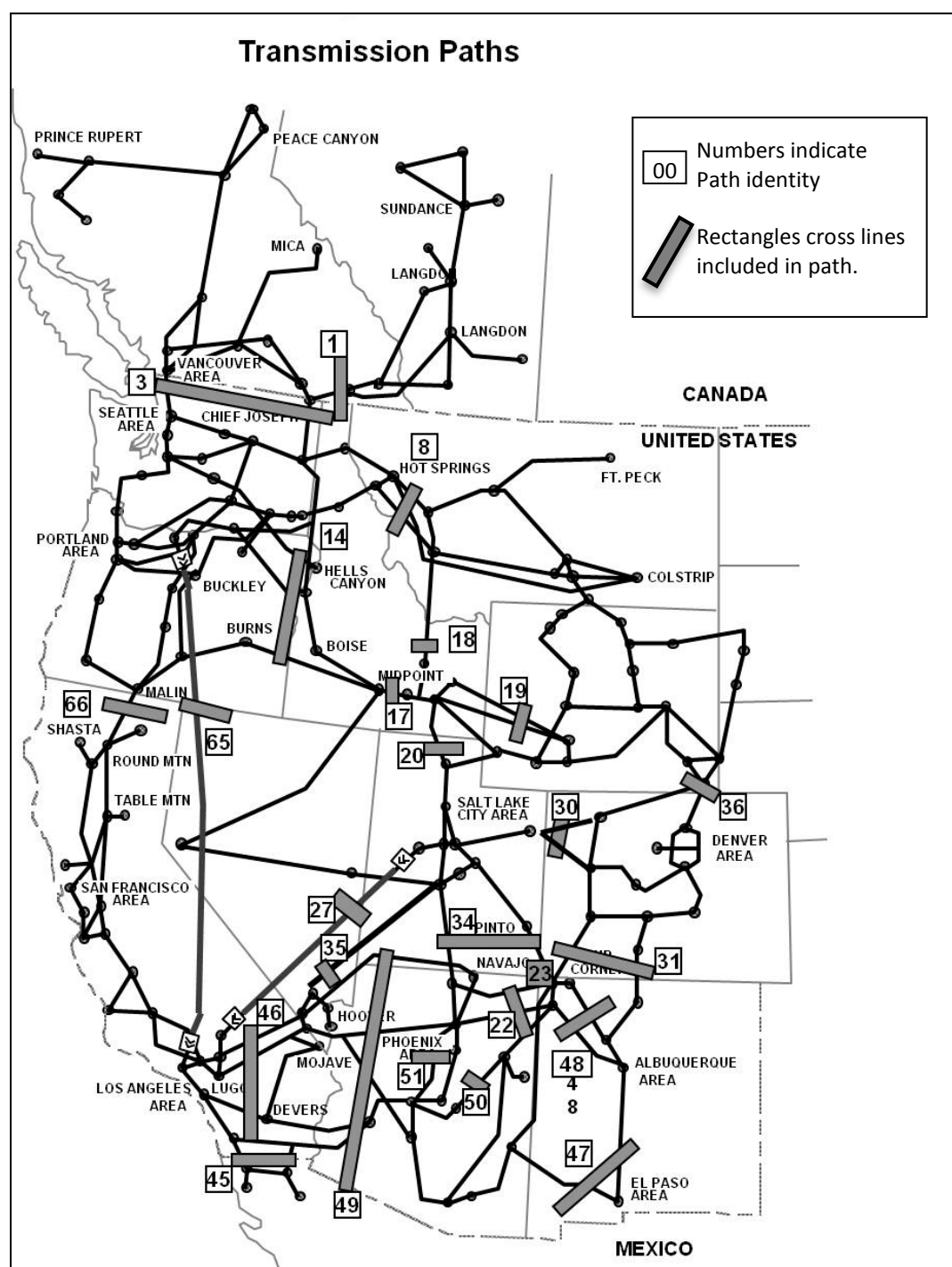
Table 5-2 shows WECC's list of the most highly used lines in the West, based on actual flow, for 2009, 2007 and for a period from winter 1998 through summer 2005.¹⁹⁶ For 2007 and before, WECC only reported the top six heavily used paths. This shows that the top-ranked lines change over time, as sorted by the amount of time the line was at 75% of rated capacity or more.

¹⁹⁵Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransnsPath_UtilizationStudy.pdf, p. 3.

¹⁹⁶For Winter 1995-Summer 2005, a path is included in this list if it experiences a seasonal loading exceeding 75% of capacity for more than half of the time in any season of years between 1995 and 2005.

Figure 5-1. Major high-voltage transmission in the West, and WECC rated paths

Source: Western Electric Coordinating Council (WECC), (2012b) *WECC Transfer Paths*, at www.wecc.biz/committees/BOD/TEPPC/TAS/01252011/Lists/Minutes/1/WECC Path Map.pdf.

Figure 5-2. WECC paths for 2009 data historic flow and schedule analysis

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransPath_UtilizationStudy.pdf, p. iii.

Table 5-1. Top ten heavily used WECC Paths based on actual 2009 flow and net schedule and percent of hours/year path is used above 75% or 90% of path rating

Rank	Actual Flow	U75	U90	Net Schedule	U75	U90
1	Path 27: IPP DC Line (Intermountain generator in Utah to S. CA)	74.6	33.2	Path 19: Bridger West (Jim Bridger Generating station in S Wyoming to S Idaho)	86.5	71.1
2	Path 19: Bridger West (Jim Bridger Generating station in S Wyoming to S Idaho)	67.9	28.9	Path 27: IPP DC Line (Intermountain generator in Utah to S. CA)	74.7	33.2
3	Path 22: SW of Four Corners (crosses NE Arizona)	43.4	4.7	Path 17: West of Borah (SE Idaho)	62.9	25.6
4	Path 49: East of River (crosses W Arizona)	24.0	2.0	Path 22: SW of Four Corners (crosses NE Arizona)	48.6	10.5
5	Path 8: Montana to NW (main Montana export path)	21.2	2.5	Path 49: East of River (crosses W Arizona)	24.5	1.5
6	Path 1: Alberta to BC	16.7	1.9	Path 20: Path C (N Utah and S Idaho)	22.9	9.6
7	Path 48: Northern New Mexico	16.5	0.6	Path 1: Alberta to BC	22.8	19.0
8	Path 3: NW to Canada (spans northern border of Washington state)	14.2	5.6	Path 8: Montana to NW (main Montana export path)	18.3	0.3
9	Path 50: Cholla-Pinnacle Peak (E Arizona)	12.8	1.4	Path 50: Cholla-Pinnacle Peak (E Arizona)	12.3	1.4
10	Path 35: TOT 2C (SW Utah to SE Nevada)	12.3	1.3	Path 14: Idaho to NW (SW and N Idaho, E Oregon and E Washington)	10.9	1.9

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransPath_UtilizationStudy.pdf, pp. 22-25.

Table 5-2. Most heavily used paths based on actual flow, 2009, 2007 and winter 1995 through summer 2005

Rank	2009	2007	Winter 1998 to Summer 2005
1	Path 27: IPP DC Line (Intermountain generator in Utah to S. CA)	Path 19: Bridger West (Jim Bridger Generating station in S Wyoming to S Idaho)	Path 19: Bridger West (Jim Bridger Generating station in S Wyoming to S Idaho)
2	Path 19: Bridger West (Jim Bridger Generating station in S Wyoming to S Idaho)	Path 8: Montana to NW (main Montana export path)	Path 50: Cholla-Pinnacle Peak (E Arizona)
3	Path 22: SW of Four Corners (crosses NE Arizona)	Path 22: SW of Four Corners (crosses NE Arizona)	Path 22: SW of Four Corners (crosses NE Arizona)
4	Path 49: East of River (crosses W Arizona)	Path 66: COI (Oregon to N California)	Path 47: Southern New Mexico
5	Path 8: Montana to NW (main Montana export path)	Path 35: TOT 2C (SW Utah to SE Nevada)	Path 30: TOT 1A (NW Colorado)
6	Path 1: Alberta to BC	Path 17: West of Borah (SE Idaho)	Path 36: TOT 3 (NE Colorado – SE Wyoming)
7	Path 48: Northern New Mexico	Path 47: Southern New Mexico	Path 27: IPP DC Line (Intermountain generator in Utah to S. CA)
8	Path 3: NW to Canada (spans northern border of Washington state)	Path 31: TOT 2A (SW Colorado)	
9	Path 50: Cholla-Pinnacle Peak (E Arizona)		
10	Path 35: TOT 2C (SW Utah to SE Nevada)		

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TrasnsPath_UtilizationStudy.pdf; Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2009). *2008 Annual Report of the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee, Part 3: Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. April 2009, at http://www.wecc.biz/committees/BOD/TEPPC/External/08_WI_TrasnsPath_UtilizationStudy.pdf; Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2007). *Western Interconnection Transmission Path Flow Study*, September 2007, at http://www.wecc.biz/committees/BOD/TEPPC/External/07_WI_TrasnsPath_UtilizationStudy.pdf.

In some cases high usage of a path is persistent by design. Several of the paths with high usage were built as dedicated lines to move power from one or a group of well-defined power sources to loads (e.g., IPP DC Line, Bridger West). These lines are heavily used because they were designed to be; high usage indicates intended asset utilization.¹⁹⁷ Southwest of Four Corners has also been consistently heavily loaded because it moves New Mexico and Arizona generation to owners and buyers in Southern California.¹⁹⁸

The composition of the high usage list and the rank order of heavily used paths vary over time, (for instance the inclusion and rank of the Montana to NW and Southern New Mexico paths).

CAISO

The only path internal to California in the WECC Path Utilization study is Path 46; the only interface paths from the CAISO to the rest of the West are paths 27 (Intermountain Power Project DC line), 45 (SDG&E-CFE), 65 (Pacific DC Intertie), and 66 (COI). Of these, only path 27 was highly used in 2009. Figure 5-3 shows the WECC paths that were analyzed in WECC's study of 2009 historic path usage that are in or near California. Table 5-3 reports the percentage of time each California path was loaded at or above 75% or 90% of capacity (respectively, for U75 and U90) during 2009, 2007 and winter 1998 through summer 2005. None of the high loading on these lines was very persistent. For example, in 2009 Path 65 was loaded at or above 2,325 MW (or 75% of 3100 MW total capacity) for 9.6% of the time, or 841 hours.

Information from CAISO indicates that California's net imports *increased* overall by 10% in 2011. Low-priced hydro and wind imports from the Northwest increased 60% from 2010, and there was an 8% decrease of imports from Southwest over 2010, likely due to decreased price differentials for natural gas between California and the Southwest.¹⁹⁹

¹⁹⁷Western Governors' Association (WGA) (2011). Findings from Pre-Meeting Webinar 4: Industry Response to WECC's 10-year Plan Recommendations on Montana to Northwest (Path 8) and Pacific Intertie (Paths 65/66). October 2011, at <http://www.westgov.org/sptsc/meetings/October%202011/briefing/present/path-webinar.pdf>.

¹⁹⁸Cholla-Pinnacle Peak accommodates similar flows, but it has not been as consistently heavily used as Southwest of 4C. (Western Electricity Coordinating Council (WECC) (2011f). *WECC 10-Year Regional Transmission Plan: WECC Path Reports*. Salt Lake City, UT: WECC. September 2011, at http://www.wecc.biz/library/StudyReport/Documents/Path_WriteUps.pdf).

¹⁹⁹California ISO (CAISO) (2012b) *2011 Annual Report on Market Issues & Performance*. Prepared by the Department of Market Monitoring. Folsom, CA: CAISO. May 10, 2012, at <http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf>, pp. 21, 37.

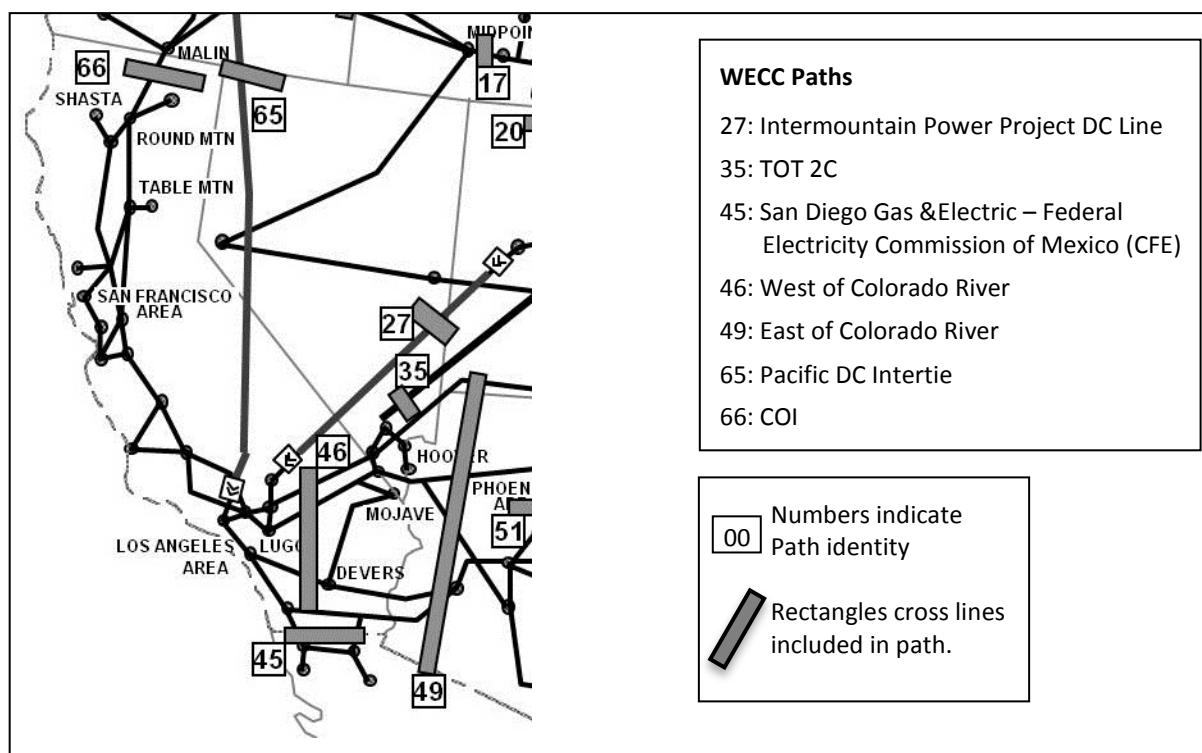
Table 5-3. Percent of hours/year California WECC path actual flow is above 75% or 90% of path rating

	2009 Data		2007 Data		1998-2005 Data	
	All Hours U75	All Hours U90	All Hours U75	All Hours U90	All Hours U75 ²⁰⁰	All Hours U90 ²⁰¹
Path 27: IPP DC Line (Intermountain generator in Utah to S. CA)	74.6	33.2	Not analyzed	Not analyzed	Not analyzed	Not analyzed
Path 45: SDG&E-CFE	3.2	0.7	0.3	0	~15	~5
Path 46: West of Colorado River (Southern California)	1.3	0	0.7	0	Not analyzed	Not analyzed
Path 65: Pacific DC Intertie	9.6	2.9	17	7.2	~31	~11
Path 66: California-Oregon Intertie	9.0	1.1	24.1	2.6	~38	~10.5

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TrasnsPath_UtilizationStudy.pdf, p. 20; Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2009). *2008 Annual Report of the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee, Part 3: Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. April 2009, at http://www.wecc.biz/committees/BOD/TEPPC/External/08_WI_TrasnsPath_UtilizationStudy.pdf, p. 16; Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2007). *Western Interconnection Transmission Path Flow Study*, September 2007, at http://www.wecc.biz/committees/BOD/TEPPC/External/07_WI_TrasnsPath_UtilizationStudy.pdf, pp. 12-13.

²⁰⁰Data reported for the maximum seasonal value between Winter of 1998 and Summer of 2005. Values are approximate.

²⁰¹Data reported for the maximum seasonal value between Winter of 1998 and Summer of 2005. Values are approximate.

Figure 5-3. WECC paths with historic flow analysis in or at border of California

Source: Transmission Expansion Planning Policy Committee (TEPPC) Historical Analysis Working Group (2010). *2009 Western Interconnection Transmission Path Utilization Study*. Salt Lake City, UT. June 2010, at http://www.wecc.biz/committees/BOD/TEPPC/External/09_WI_TransPath_UtilizationStudy.pdf, p. 6.

6. Summary and Next Steps

This report presented data and information on constraints and congestion in the Eastern and Western Interconnections in the U.S. All data and information included in this report is publicly available.

The Department intends to make this the first in a series of annual reports on the state of the U.S. transmission system based on publicly available data.

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