2009 State of the Market Report

Southwest Power Pool, Inc.

May 26, 2010

Table of Contents

List of Figures

List of Tables

Disclaimer

The data and analysis in this report are provided for informational purposes only and shall not be considered or relied upon as market advice or market settlement data. Southwest Power Pool, Inc. ("SPP") and Boston Pacific Company, Inc. ("Boston Pacific") make no representations or warranties of any kind, express or implied, with respect to the accuracy or adequacy of the information contained herein. SPP and Boston Pacific shall have no liability to recipients of this information or third parties for the consequences arising from errors or discrepancies in this information, for recipients' or third parties' reliance upon such information, or for any claim, loss or damage of any kind or nature whatsoever arising out of or in connection with (i) the deficiency or inadequacy of this information for any purpose, whether or not known or disclosed to the authors, (ii) any error or discrepancy in this information, (iii) the use of this information, or (iv) any loss of business or other consequential loss or damage whether or not resulting from any of the foregoing.

Acknowledgments

SPP would like to acknowledge Boston Pacific's integral role as an advisor during the preparation of this report.

EXECUTIVE SUMMARY

A. Purpose

The Market Monitoring Unit (MMU), as the internal market monitor for the Southwest Power Pool (SPP) Regional Transmission Organization (RTO), has been asked to provide an annual report on electricity market conditions to the SPP Board of Directors (Board), the Federal Energy Regulatory Commission (FERC), the SPP Regional State Committee (RSC), and other appropriate state regulatory authorities.[1] The purpose of this *2009 State of the Market Report* is to fulfill that request.[2] The FERC requires *State of the Market Reports* from all RTOs and Independent System Operators (ISOs).

This report first provides an overview of supply and demand conditions in the SPP footprint. Next it provides an extensive report on SPP's energy market – the Energy Imbalance Service (EIS) Market. The EIS Market started on February 1, 2007 so this report is on its third year of operation. The report then begins a discussion of transmission services ("the Transmission Market"). Some broad recommendations based on analysis come next. Finally, it identifies a few market and regulatory events that are likely to affect SPP's markets in the coming years.

The MMU concludes that SPP performed as a healthy RTO in 2009. For the EIS Market, the signs of good health include robust participation, prices and price volatility which compare well to neighboring ISOs, successful expansion to include new balancing authorities, and the absence of structural market power. For the Transmission Market the clearest sign of good health is the substantial investment in the transmission system. Furthermore, in 2009, SPP created a new regional transmission planning process that will take effect in 2010.

Still, there are actions SPP should take to keep or improve its good health. First, SPP should move quickly to standardize categories that account for transmission outages. This categorization in a database must allow easy reporting on the causes and locations of transmission outages across the footprint. Second, SPP should monitor and report trends in transmission congestion and use of temporary flowgates. Third, congestion on temporary flowgates should be included in the calculation and activation of offer caps. This will require changes to the Market Protocols and the offer cap system. Fourth, SPP's should continue the expedient implementation of Future Market development in order to achieve consumer benefits as soon as possible.

B. Overview of the SPP Footprint

Electricity Supply and Demand

[1] *See* Order Granting RTO Status Subject to Fulfillment of Requirements, February 10, 2004, FERC Docket No. RT04-1-000 and ER04-48-000, at p. 56, fn. 222.
[2] Boston Pacific Company, Inc. provided substantial assistance in the development of this report, including providing the first draft of the report to the Board's Oversight Committee.

In 2009, SPP successfully expanded its footprint with the addition of the Nebraska Public Power District (NPPD), the Omaha Public Power District (OPPD), and the Lincoln Electric System (LES), also known as the Nebraska entities or balancing authorities. As expected, such an expansion has impacts on SPP. For example, in 2009, the addition of the Nebraska balancing authorities increased (a) peak demand by 14%, (b) electricity usage by 11%, and (c) the number of miles of transmission facilities by 16%. SPP's Regional Entity (RE) footprint plus the Nebraska entities, now includes nineteen separate balancing authority operators that, individually, are responsible for matching electricity supply and demand within their territories.[3]

In addition to adding the Nebraska Market Participants, two additional Market Participants were also added to the EIS Market footprint in 2009. These Market Participants are Missouri Public Service (MPS) and Independence Power & Light (INDN).[4] MPS and INDN were already a part of the broader SPP footprint, but joined the EIS Market in September and December, respectively. Given the fact that MPS and INDN joined so late in the year, 2010 will provide a better indication of the impact of MPS and INDN. The Market footprint now includes 15 separate Balancing Authorities.

SPP's members provide electricity to meet their customers' needs. In 2009, the peak electric demand of these customers in the SPP Market footprint, including the new balancing authorities, was 39,628 MW on July 14th. The RE peak was 46,482 MW on June 23rd. These peaks are higher than the 2008 peak demand for the Market footprint of 36,541 MW and the 2008 peak demand for the RE footprint of 42,891 MW. However, without the new balancing authorities, the 2009 Market peak demand was 34,043 MW, while the 2009 RE peak demand was 40,817 MW. When these peaks are compared to 2008, the Market peak declined 6.84% and the RE peak declined 4.8%.

Similar to peak demand, electric energy use increased relative to 2008 if the new balancing authorities are included in the totals, but decreased if they are not included. With the new balancing authorities, electric energy usage was 227.2 million MWh. However, without those new balancing authorities, usage was 204.2 million MWh, representing a decrease of 2% when compared to 2008. Two causes for the decline in peak demand and usage without the new balancing authorities are (a) the recession and (b) milder weather as indicated by a decrease in the number of heating and cooling degree days in 2009.

Generating facilities supply the electricity that is used by the customers of SPP's members. The total generating capacity in SPP was 65,796 MW.[5] In comparison to the peak demand of 46,482 MW during 2009, SPP has a significant resource margin (installed generation capacity in excess of peak demand) of 19,314 MW or 42%. However, in reality, this capacity includes some units that are not necessarily dedicated to serve load or, due to limited

[3] The Nebraska entities became members of SPP on December 1, 2008 and began participating in SPP on April 1, 2009 by placing their transmission facilities under the SPP Tariff and joining the EIS Market. However, the Nebraska entities are not yet a part of the SPP Regional Entity (RE) footprint. Currently, SPP is working with NERC and the Midwest Reliability Organization (MRO) to transfer the Nebraska entities' registrations to the SPP RE.

[4] MPS is now known as KCPL Greater Missouri Operations Company (KCPL-GMO), although for the purposes of this report we refer to it as MPS.

[5] This capacity figure represents the summer capability of SPP's generating units.

transmission capability, are not deliverable to meet all loads at all times. This healthy resource margin can have positive implications for both reliability and for mitigation of the potential exercise of market power within SPP.

Generation Interconnection

The initial examination of the amount of generation reveals a resource margin that would appear to allow for an increase in load without requiring construction of new generation to maintain reliability. However, the economics of electricity generation, not just growth in demand, drive interest in constructing new generation. The capacity in the generation interconnection queue rose sharply from roughly 31,000 MW at the end of 2007 to about 60,000 MW at the end of 2008. In 2009, the amount of capacity in the queue leveled off, and at the end of the year there was 60,768 MW in the queue. However, if we do not include the 4,556 MW that was transitioned into the SPP process as a result of the Nebraska entities joining SPP in 2009, there was actually a decline in the level of capacity in the queue.[6] Among the active generation interconnection requests, 86.3% of the capacity (in nominal terms) is for wind projects, while coal accounts for 2.3% and natural gas accounts for 11.0%.[7]

Generation and Transmission Outages

Generating facilities are occasionally taken out of service for planned maintenance, and they also shut down from time to time due to unexpected equipment failures (forced outages). Generation outages decrease the amount of electricity supply available to meet demand and, thereby, can affect market prices.

In 2009, generation outages in the SPP footprint followed an expected pattern. When peak load is usually at its highest (roughly June to August), total outages as a percentage of peak load are at their lowest. This is mostly due to the fact that planned maintenance outages are scheduled outside the summer peak period and approved by SPP.

Comparing 2009 to 2008, using a very conservative metric of total outages as a percentage of the monthly peak demand, the extent of generation outages were slightly higher in 2009 than in 2008 on average. For the year, outages as a percentage of peak load increased from an average of 13.1% in 2008 to 13.4% in 2009. Part of this increase may be attributed to nuclear maintenance schedules. Nuclear units are usually taken offline on an 18 month cycle, and the SPP nuclear units were in maintenance during 2009.

Transmission outages also impact deliverability and can affect market prices. Moreover, transmission outages can make transmission congestion more likely so that the SPP Market is segmented with prices varying by location. Transmission elements, like generating units, need to be removed from service for planned maintenance and for new construction. Transmission system components also fail from time to time and are impacted by weather, resulting in forced outages.

---

[6] This decline has continued since the end of 2009. As of April 8, 2010, there now is only 43,375 MW in the queue.
[7] Other fuel types account for the remaining 0.4% of capacity.

The pattern of transmission system outages for 2009 follows the same general pattern as that for generating units in that outages are at some of their lowest levels during the summer months. The extent of transmission system outages in each month was calculated by the length of time of each outage for each transmission facility and totaled for each month. Using this metric, transmission outages have increased each of the past three years – the addition of the new balancing authorities only adds to the increase in 2009. Even if we remove the new balancing authorities from the calculation, outages have increased 45% when compared to 2008's total. This increase follows increases of 39% from 2006 to 2007 and 5% from 2007 to 2008. This increasing trend concerns us. We believe that part of the reason for this increase is most likely due to legitimate reasons such as the increased amount of transmission investment that has resulted from SPP's Transmission Expansion Plan (STEP). However, given the current data set, we are unable to confirm this and other hypotheses. Given this, we recommend that a database that allows for easy accounting of transmission outages and their causes is created by the end of the 2010 calendar year.

C. EIS Market Results

Market Activity

As is the nature of an imbalance market, a *sale* is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled. Similarly, a *purchase* is made by a Market Participant when either (a) it generates less than it has scheduled and/or (b) its actual load is more than it has scheduled.

For 2009, EIS Market sales totaled 20.8 million MWh, with a total of $556 million paid to suppliers. To put the size of the EIS Market into context, overall EIS Market sales were roughly equal to 10.6% of total electricity consumption within the EIS Market footprint.

In comparison to 2008, MWh sales were up 38%, but sales revenue was down 35%. If we exclude the five new balancing authorities from the calculation, MWh sales increased by 9.6% and sales revenue decreased by 46%. Sales revenue was down significantly because of the decrease in the price of electricity discussed in the next section.

Market Prices

Electricity prices are a result of the supply and demand for electricity and the ability of the transmission "highways" to move electricity from the sources of supply to meet demand. We analyzed prices in the EIS Market from two perspectives.

The first perspective is to compare EIS Market prices to those in two neighboring, real-time energy markets: those operated by the Midwest Independent Transmission System Operator (MISO) and the Electric Reliability Council of Texas (ERCOT). We do not expect the prices in these markets to be identical to those in SPP because of differences in resource/fuel mix, patterns of demand, and other factors including inherent design aspects of each market.[8] However, prices in these two markets give us one measure of *competitive* market prices and, for that reason we

[8] For example, SPP and MISO are 'nodal' pricing markets, whereas ERCOT is presently a 'zonal' market.

expect EIS Market prices to be in-line with MISO and ERCOT real-time market prices. We take comfort in the fact that EIS prices were generally between prices in MISO and ERCOT. Specifically, the simple average price in the EIS Market was $27.50/MWh which is 9% below ERCOT's average price and 1% above that for MISO.

In comparison to 2008, SPP's simple average annual price fell dramatically from $53.21/MWh in 2008 to $27.50/MWh in 2009, representing a drop of 48%. MISO and ERCOT saw similar declines of 44% and 54%, respectively. We believe that decreases in natural gas prices are one reason we are seeing such a large decline in electricity prices. Average Panhandle natural gas prices decreased by about 54% from 2008 to 2009. This is important because (a) fuel cost accounts for a large portion of the variable cost of producing electricity and (b) natural gas-fired resources are at the margin (and therefore setting the price) 61% of the time in SPP. Given the importance of the link between natural gas prices and SPP's electricity prices, we discuss, in Section V, several factors that could have contributed to the decline in natural gas prices.

The second perspective taken on EIS Market prices is to assess how prices vary across the SPP EIS Market footprint. Prices vary across locations when there is transmission congestion which breaks the SPP-wide market into submarkets. Looking first at the locations represented by the balancing authority locations in the EIS Market footprint, we see that all of these have load-weighted average hourly prices which fall within a band of no more than 7.2% above and 18.1% below the SPP-wide *weighted* average hourly price of $28.69/MWh (note the weighted average price is higher than the SPP-wide *simple* average price of $27.50/MWh). SPS ($30.75/MWh) and NPPD ($23.51/MWh) had the highest and lowest prices, respectively.

Another look at the variation across locations takes a more granular view. In this view, we look at prices at every load price location – not aggregated to balancing authority locations – and for each five-minute dispatch interval – not the hourly prices. Here we see that 98.1% of these locational prices, by interval, fall within what can be seen as an expected range of zero to $100/MWh, in 2008 92.7% fell into this range.

Revenue Adequacy (Net Revenue Calculation)

Revenue Adequacy is a metric used by other RTOs and ISOs. The calculation determines whether revenue earned in 2009 in the EIS Market would have been adequate to cover the total annualized cost for new investment in generation. That is, the Revenue Adequacy metric determines whether EIS Market prices are signaling a need for new capacity with prices that equal or exceed the cost of new entry.

We performed a Revenue Adequacy calculation for the EIS Market in 2009. We found that, even assuming a perfect dispatch response throughout the year, the EIS Market would not yield sufficient revenue to warrant investment in new generation. This is true for both natural gas-fired peaking turbines and intermediate load combined cycle units. This is not surprising, given the relatively high installed resource margin described previously and the significant drop in electricity prices in 2009.

Fuel Type

We look at fuel type usage in two ways. First, we look at actual generation (output) by fuel type in the EIS Market footprint; that is, we trace each MWh back to the fuel used in its generation. Second, we look at which fuels are at the margin or, in other words, which fuels are setting EIS Market prices. Due to data limitations, some assumptions were necessary to calculate these statistics; therefore, these numbers should be seen as estimates rather than absolutes.

We found that coal was responsible for 64.0% of the electricity output in 2009 in the EIS Market footprint, while natural gas and nuclear were responsible for about 23.3% and 7.6% of the output, respectively. Renewables such as wind and hydro accounted for 4.2% and 0.9%, respectively, of the output in the EIS Market footprint. In comparing generation by fuel type to 2008, the most notable change was that nuclear generation increased by almost 3 percentage points. This is due to the Nebraska entities joining the EIS Market in April 2009, and bringing with them significant nuclear generation.

While coal was responsible for the most output, natural gas units were *at the margin* in SPP for the largest portion of the time. Natural gas was at the margin approximately 61% of the time, and coal was at the margin about 39% of the time.

Market Participation

Full participation in the EIS Market is voluntary. Therefore it is essential to determine the extent to which Market Participants are participating. We look at participation in three ways. The first is to determine the percentage of resources that are offered for dispatch in the EIS Market. In 2009, participation was consistently at a robust level; on average, 88% of installed resource capacity was made available for dispatch in the EIS Market.[9] This is equivalent to last year when participation was also 88%.

The second measure of market participation is what portion of the capacity of a resource was made available for dispatch. Most power plants have a minimum level of output that must be maintained (akin to a car sitting at idle) and some have a maximum that falls short of the full capacity of the resource (perhaps to reserve capacity to meet ancillary service needs). For example, say a 100 MW resource is made available to the market with a minimum of 30 MW and a maximum of 80 MW (to leave 20 MW for ancillary service reserves). In this example, the Market Participant has made 50 MW or 50% of the capacity available to the EIS Market. In reality, in 2009 the average portion of available capacity made available for dispatch (the average *dispatchable range*) was 44% (it was 46% last year). This decline concerns us, and as a result we are looking at this metric at the market participant level regularly.

[9] For the purposes of this calculation, we included only available and self-dispatched resources. If resources designated as manual were included in this calculation, the percentage of capacity made available to the market for 2009 would be approximately 77%. According to the Market Protocols, manual resources are those that cannot follow dispatch instructions or adhere to a schedule. This can be as a result of a unit (a) being an intermittent resource or (b) undergoing a resource test or being in startup or shutdown mode.

The third measure of market participation indicates how fast the resource can be dispatched up and down within its dispatchable range – this is termed "ramp rate" and is measured in MW per minute. The average ramp rate for 2009 was 2.8 MW/minute, the same level as in 2008. This level seems low, and is a concern of ours. The average ramp rate had increased in late 2008/early 2009, and we thought that the reason for that increase was a rule change made in October 2008. This rule change allowed a participant to break up its dispatchable range into as many as 10 segments and to provide a different up and down ramp rate for each segment. However, ramp rate has since declined, reaching a low of 2.6 MW/minute in December.

Market Power Measurement and Mitigation

The SPP Offer Cap is the most explicit market power mitigation tool imposed in the EIS Market. It is imposed only when there is transmission congestion. The SPP Offer Cap varies by resource and by location – it is lower (tighter) in areas with more transmission congestion. Moreover, since it reflects the cost of entering the EIS Market by building and operating a new combustion turbine power plant, it also is a measure of the competitive price level that we would not want to be exceeded routinely in the EIS Market. Given this, we look at how often a price offer is accepted near the SPP Offer Cap. If this is common, then the SPP Offer Cap is holding prices down just like a lid on a pot of boiling water. In contrast, if price offers are seldom accepted near the SPP Offer Cap, then we believe this indicates prices are comfortably below this one measure of a *competitive price level.* The bottom line is that price offers are not accepted near the SPP Offer Cap very often. In 2009, such offers were accepted a very small portion of the opportunities – less than six hundredths of one percent of the available resource intervals.

The FERC imposed a separate offer cap that applies at all times for all resources. The FERC Offer Cap is $1,000/MWh. Price offers were accepted near the FERC Offer Cap a very small portion of the opportunities – under four thousandths of one percent of the available resource intervals.

EIS Market results also can be used to develop traditional, structural measures of the potential for market power concerns. Two traditional measures are: the market shares of Market Participants and an antitrust measure called the Herfindahl-Hirschman Index (HHI) which is calculated as the sum of the squares of market shares.[10]

A high number of Market Participants with smaller market shares indicates competitiveness. For example, when judging when to grant a supplier the right to charge market-based (as opposed to cost-based) rates, the FERC uses a market share under 20% to support a rebuttable presumption that a supplier does not have the ability to exercise market power and, therefore, should be granted market-based rate authority. For 2009 in its entirety, no Market Participant had a market share at or above 20%. The highest market share was 14.8% (in 2008 it was 14.7%). Again, this is another indicator that the EIS Market is a competitive market.

[10] For example, if a market had ten suppliers, each with a 10% market share, the HHI would be 1,000.

A low HHI also indicates competitiveness. For example, the FERC and the U.S. Department of Justice use the same ranges of HHIs to judge the competitive effect of mergers and acquisitions: an HHI at or below 1,000 is something of a safe harbor, an HHI from 1,000 to 1,800 indicates moderate market concentration, and an HHI above 1,800 indicates high concentration. The FERC also uses a higher HHI threshold of 2,500 when judging whether or not to grant a competitor the right to charge market-based (as opposed to cost-based) rates. In calculating HHIs, we used an alternative way of looking at market shares. That is, we calculated the shares of capacity made available to the market, for each participant, *at the peak hour of each month*. For 2009, the peak capacity HHI for the year in total was 1,292 as measured by market shares of capacity made available to the EIS Market; this HHI is at the low end of the moderately concentrated range. In 2008, the HHI was 1,411.

Revenue Neutrality Uplift

SPP's Open Access Transmission Tariff (OATT or Tariff) requires that the EIS Market remain revenue neutral. This simply means that it cannot collect more money from Market Participants than it pays out and vice versa. If SPP either over collects or under collects, it must apply an uplift procedure to return to a revenue neutral state by either collecting additional money from Market Participants or returning money to Market Participants.

There are five components to Revenue Neutrality Uplift (RNU), which determine whether SPP over collects (RNU is negative) or under collects (RNU is positive): (i) EIS, (ii) self-provided losses, (iii) over-scheduling charges, (iv) under-scheduling charges, and (v) uninstructed deviation (UD) charges. The majority of RNU occurs as a result of the EIS component. The EIS component represents 73% of all RNU contribution (positive or negative) in 2009.

Because RNU ultimately affects how much participants pay, we calculated an all-in price, which represents the load-weighted SPP average price adjusted for net RNU divided by total EIS MWh (sales plus purchases). As discussed later, the RNU adjustment (a) allows congestion costs that were not effectively imposed on Market Participants through schedule adjustments to be accounted for and (b) allows over- and under-scheduling and UD charges to be accounted for. The largest positive RNU adjustment occurred in October and was \$0.90/MWh, which is 2.9% of the October average price. The largest negative RNU adjustment occurred in December; this adjustment was a negative \$0.38/MWh, which is 1.0% of the December average price.

D. Energy Delivery

Transmission systems are the "highways" that bridge suppliers to customers. As expected in any region, the number and capability of these "highways" vary across the SPP footprint.

Transmission Owner Revenue

Under its OATT, SPP grants transmission service over the transmission systems owned by its members. In return, SPP's transmission-owning members receive revenues for the service granted by SPP. The total revenue received by transmission owners in 2009 was approximately $486 million. Together, on average, the transmission owners received roughly $40 million of revenues each month in 2009. In 2008, the total revenue received by transmission owners was approximately $408 million.

Transmission Service Requests

Through a request process, parties who wish to move electricity over the transmission system request this service in advance. SPP will approve these requests if it can do so while ensuring reliability and simultaneous feasibility; that is, while assuring that the capability of the transmission systems of its members to move electricity is not exceeded. The total number of transmission service requests in SPP has declined in each of the past two years. The total number of transmission service requests in SPP decreased by 11% from 2007 to 2008 and 27% from 2008 to 2009. We recommend that SPP report on the causes of the decrease in transmission requests over the last two years. One positive trend is that SPP's approval rate, measured as a ratio of approved requests to the sum of approved and refused requests, increased from 54% in 2007 to 63% in 2008 to 74% in 2009.

Transmission Congestion

Transmission congestion on the SPP transmission system causes locational price divergence. In order to understand just how prevalent congestion has been over time, we looked to see how often there was at least one flowgate experiencing congestion in each five-minute dispatch interval over 2009. We found that there was at least some congestion 71% of the time; this is an increase from 2007 and 2008 when there was at least some congestion approximately 56% of the time. However, it should be noted that this could be an overly strict metric in the sense that it only takes problems at one flowgate, for one interval, to indicate congestion over all of SPP.

However, while the overall number of congestion instances (congested flowgate intervals) is up in 2009, the number of more serious instances of congestion (breached flowgate intervals) has decreased. This is important because breached flowgate intervals have the largest impact on the SPP system in terms of price. Therefore, although the incidence of congestion increased, the impact on prices went down during 2009.

Transmission Investment

This year is the 5th year SPP has used the STEP as the tool for regional planning. The 2009 STEP looks at transmission investments for the ten-year period from January 1, 2010 through December 31, 2019. It includes over 4,000 miles of upgrades or new line construction and over 80 new or upgraded transformers, totaling approximately $4.45 billion.[11] Of the $4.45 billion of total planned investment, approximately $2.4 billion is for Regional Reliability projects, while another $770 million is for a portfolio of economic upgrades known as the Balanced Portfolio. The two balancing authorities with the most planned investment over the next ten years are SPS and OKGE.

[11] *See 2009 SPP Transmission Expansion Plan, A Report of the SPP Regional Transmission Organization*, Approved by the SPP Board of Directors on January 26, 2010 ("STEP")."

Going forward, SPP will utilize a new planning process known as the Integrated Transmission Plan (ITP). This is an iterative, three-year process which was developed and approved by the Board of Directors on October 27, 2009. The ITP process will be used starting in 2010 and will include three major parts: (a) a 20-year assessment that will begin in year one of the three year cycle and be completed in year two, (b) a 10-year assessment that will begin during year two and be completed in year three, and (c) a near-term assessment that will be completed each year. In addition, SPP is also considering six Priority Projects, estimated at a cost of $1.1 billion.[12] These projects are high priority projects that are designed to capture near-term opportunities so that they are not lost in the transition to the new ITP process.

E. Recommendations

We thought it would be useful to step back from all the details presented so far and draw out some recommendations. We first look back at 2009 and make four recommendations based on that experience. We then look forward and recommend three issues that the Board will want to be watching as it anticipates events that could significantly affect prices and reliability in SPP.

Recommendations Looking Back

We draw out four recommendations based on our detailed look back at 2009. First, transmission outages have increased each of the past three years. This increasing trend in the number of transmission outages continues to concern us. The *2007* and *2008 State of the Market Reports* recommended that the SPP RTO report on the reasons for transmission outages. Given this, we recommend that the SPP RTO complete its new methodology for tracking standardized reasons for transmission outages and report on those by year end. In addition, we recommend that the SPP RTO develop additional metrics related to transmission outages that can be reported regularly to show the extent, the locations, and the reasons for the transmission outages across SPP's footprint.

Second, while the number of serious instances of congestion (breached flowgate intervals) has fallen in each of the past two years, the total number of congested flowgate intervals that include at least one breached or binding flowgate has increased. Nevertheless the effort to re-dispatch generation to match congestion has reduced from 2008 to 2009, resulting in a decrease in total flow gate shadow prices and less breached intervals in 2009. This indicates a decrease in total congestion cost and lower price impacts. Congestion intervals have increased in the Market Footprint for several important reasons. First, the addition of five new Market Participants in 2009 added many new flowgates, both temporary and permanent. Second, temporary flowgates were used to improve management of congestion in the Panhandle of Texas. Third, transmission upgrades in several specific areas required the use of more than expected temporary flowgates for longer than expected. We recommend that an enhanced methodology for tracking and monitoring congestion trends be implemented to ensure that the Market effectively contributes to the resolution of congestion.

[12] *See SPP Priority Projects Phase II Report Revision 1*, Published April 2, 2010 ("Priority Projects") at page 5.

Third, the market system currently imposes offer caps on resources that have the potential to wield market power when permanent flowgates are activated. The offer cap system also only uses congestion on permanent flowgates in calculating individual caps. The original design for the offer cap system did not include temporary flowgates because they represented a very small portion of the total number of flowgates and they had a very short life expectancy. Over time, temporary flowgates have become a significant source of congestion. To address this change in system operations, the reference to permanent flowgates in the market protocols should be removed and the offer cap system should be modified to include temporary as well as permanent flowgates. These changes would ensure that the offer cap system effectively caps offers over time regardless of the use of temporary flowgates.

Offer caps are imposed when a flowgate is activated. The current trigger for activating a flowgate is a TLR. SPP uses TLRs as a proxy for congestion. Historically TLRs have been a good proxy but proposed market rule changes would allow SPP to activate flowgates for extended periods without calling a TLR. SPP needs to develop a new trigger for imposing offer caps to reflect actual congestion before implementing any rule changes with regard TLRs.

Fourth, SPP is currently in the process of developing new markets. The major components of these new markets include: (a) a Day-Ahead Market with Transmission Congestion Rights (TCRs), (b) a Centralized Unit Commitment process, (c) a Real-Time Balancing Market, similar to today's EIS Market, and (d) a price-based Operating Reserves procurement. We have been participating in the design activities and based on efficiencies recognized in other markets believe expedient completion of the new markets would be of benefit to all Market Participants.

Recommendations Looking Forward

The Board also has to anticipate broad market and regulatory events that will affect the performance of SPP's markets. While a lengthy discussion in this report may not be appropriate, we would be remiss if we failed to at least identify the broad issues on the horizon. These events include (a) climate change policy, (b) clean air legislation, and (c) natural gas price changes.

Climate change policy has the potential to be a game changer in the electricity business. However, political progress on limiting greenhouse gas emissions at the national and international level has been slower than many have expected. Hopes were high for action at the United Nations conference in Copenhagen in December, especially after the Waxman-Markey climate change bill passed the U.S. House of Representatives in June. However, the last-minute deal that was reached in Copenhagen was only enough to keep negotiation towards a new international agreement moving forward in 2010. The deal did encourage countries to submit commitments to unilateral emissions reductions, which many did. As some countries move forward while the world cannot agree, similarly, in the U.S., some states are moving forward as regional groupings while the nation as a whole cannot agree. The Regional Greenhouse Gas Initiative (RGGI) in the Northeast and Mid-Atlantic region continues to put a limit on emissions from power plants, and to conduct auctions for allowances, though prices for allowances are very low. The Western Climate Initiative (WCI) in the Western U.S. and throughout Canada has a stated 2012 start date for an emissions cap that will eventually cover 90% of emissions in participating jurisdictions, but the WCI faces challenges. Finally, the Midwestern Greenhouse Gas Reduction Accord (MGGRA) faces tough political hurdles to move towards implementation.

With respect to non-green house gas emissions, there has been a flurry of activity in the last few years concerning limiting emissions of SO_2, NOx, and mercury. The U.S. Environmental Protection Agency (EPA) formulated the Clean Air Interstate Rule and the Clean Air Mercury Rule to regulate these emissions using cap-and-trade, but court action intervened. In response, the EPA has pursued other alternatives, including the revision of National Ambient Air Quality Standards (NAAQS) and promulgation of maximum achievable control technology (MACT) standards that would cap emissions in a "command and control" manner. The EPA has also been cooperating with legislators to draft the Clean Air Act Amendments of 2010, currently in committee, which would allow the EPA to pursue cap-and-trade style regulation for these emissions. Because SO_2, NOx, and mercury emissions in the electricity sector come mainly from coal-fired generation, compliance with these possible regulations could trigger widespread retrofitting and retirement of coal plants over the coming decade.

Finally, because natural gas is at the margin so often, EIS market prices rise and fall pretty much in tandem with natural gas prices. In 2009, both natural gas prices and EIS Market prices fell significantly.

I. OVERVIEW OF THE SPP FOOTPRINT

A. Brief Overview of SPP

The Southwest Power Pool (SPP) was granted Regional Transmission Organization (RTO) status by the Federal Energy Regulatory Commission (FERC) in October 2004.[13] SPP provides transmission service on the transmission facilities owned by its members under its Open Access Transmission Tariff (OATT or Tariff). In addition, SPP is one of eight North American Electric Reliability Corporation (NERC) Regional Entities (RE). As an RE, SPP enforces compliance with federal and regional reliability standards. The SPP RE area plus the Nebraska participants is usually what is referred to when discussing the SPP footprint,[14] and is the footprint discussed in this section (Section I).

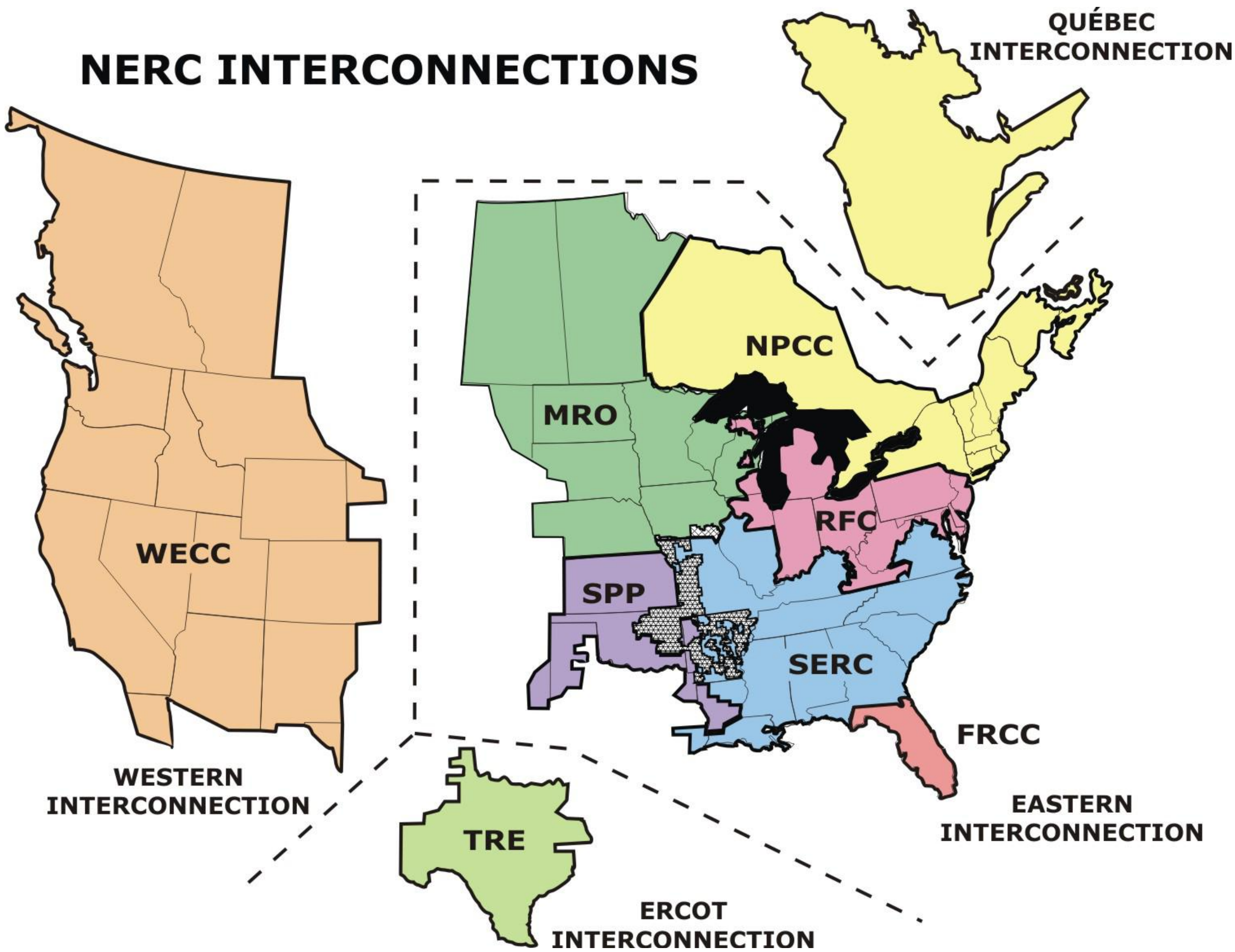
In February 2007, SPP launched its real-time Energy Imbalance Service (EIS) Market. The EIS Market does not cover the whole SPP footprint, and so this is referred to as the EIS Market footprint. SPP is also in the process of developing new markets. The major components of these new markets include: (a) a Day-Ahead Market with Transmission Congestion Rights (TCRs), (b) a Reliability Unit Commitment (RUC) process, (c) a Real-Time Balancing Market, similar to today's EIS Market, and (d) a price-based Operating Reserves procurement. These markets are tentatively scheduled to be launched in December 2013.

Location of SPP

SPP is located in the southwest portion of the Eastern Interconnection. It is bordered by the Midwest Reliability Organization (MRO) and the SERC Reliability Corporation (SERC) in the Eastern Interconnection. SPP also shares borders with the Western Electricity Coordinating Council (WECC) and the Texas Regional Entity (TRE). Figure I.1 shows the four NERC Interconnections and the eight Regional Entities. As seen in the figure, the SPP RE region is centered on Oklahoma and Kansas. Spurs extend (a) southward into northwest Texas/Eastern New Mexico, (b) eastward into Arkansas and Missouri, and (c) southward into northeastern Texas and Louisiana. While not shown in this figure, three new balancing authorities covering most of Nebraska were added to SPP in late 2008/early 2009. These entities, referred to in this report as the Nebraska entities, include Nebraska Public Power District (NPPD), Omaha Public Power District (OPPD), and Lincoln Electric System (LES). The Nebraska entities became SPP members on December 1, 2008 and began participating in SPP on April 1, 2009 by placing their transmission facilities under the SPP Tariff and joining the EIS Market. However, the Nebraska entities are not yet a part of the SPP RE footprint, which is the reason they are shown to be in the MRO in the figure below. Currently, SPP is working with NERC and the MRO to transfer the Nebraska entities' registrations to the SPP RE. For the purposes of this report we included the Nebraska entities as part of SPP starting on April 1, 2009.

[13] *See* Order on Compliance Filing, January 24, 2005, FERC Docket Nos. RT04-1-006 and ER04-48-006.
[14] *See* http://www.spp.org/publications/SPP_Footprints.pdf.

Figure I.1 NERC Interconnections



SOURCE: NERC website

SPP Membership

At the end of 2009, SPP had 54 members who serve load, provide generation, and/or own transmission facilities.[15] SPP's members include cooperatives, municipals, state agencies, independent transmission companies, investor-owned utilities (IOUs), independent power producers (IPPs), and power marketers. A count of SPP members by category is shown in the table below.

[15] Since the end of 2009, SPP has added two new investor-owned utilities (IOUs) to bring the total to 56 members. These two companies are AEP Oklahoma Transmission Company, Inc. and AEP Southwestern Transmission Company, Inc.

Table I.1 SPP Members as of December 31, 2009

SPP Members	Number of Members
Cooperatives	11
Independent Power Producers	5
Independent Transmission Companies	3
Investor-Owned Utilities	12
Power Marketers	10
Municipals	9
State Agencies	4
Total Members	54

SOURCE: http://www.spp.org/section.asp?pageID=4

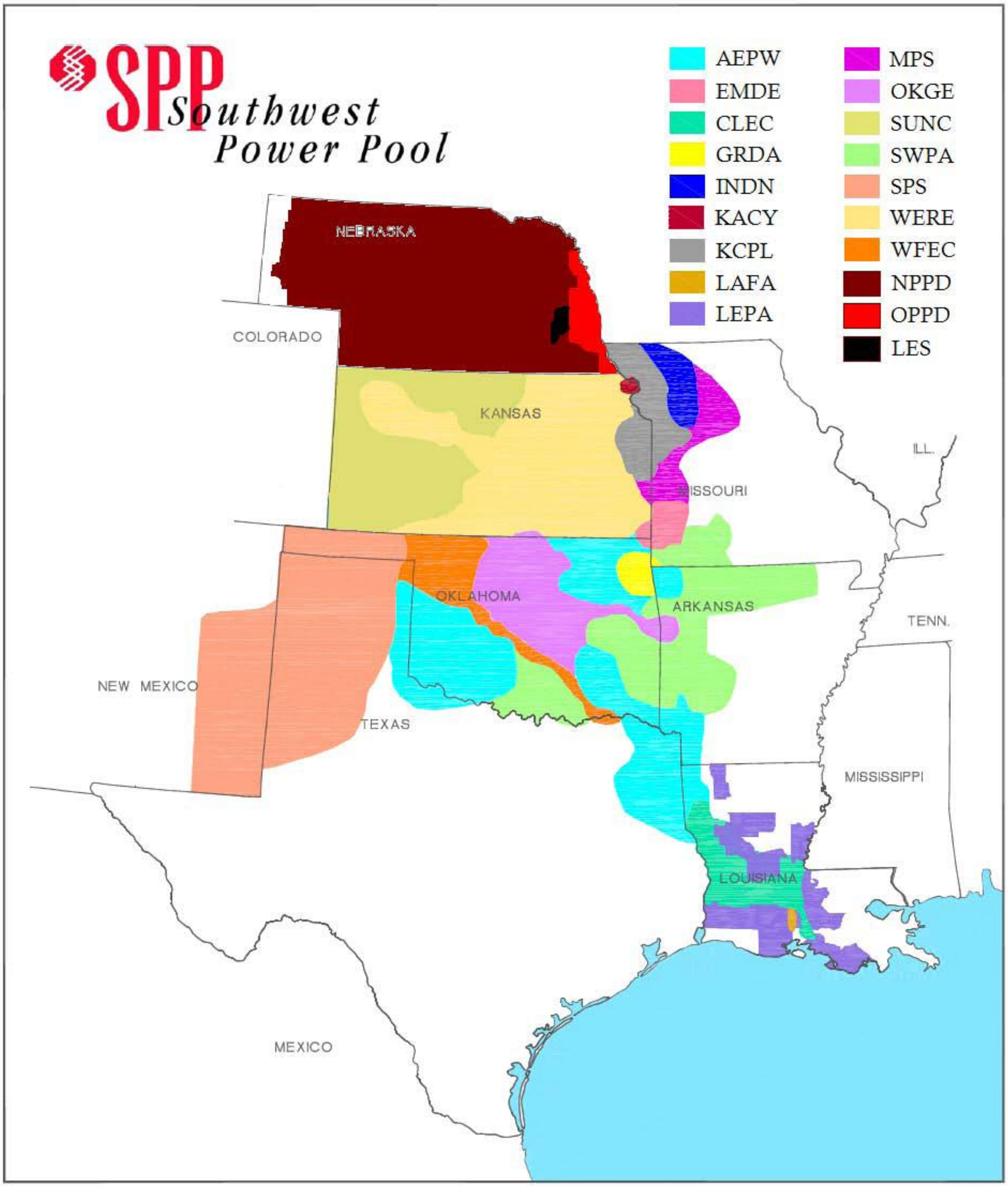
A list of SPP's members as of December 31, 2009 is also attached to this report as Appendix B.

Balancing Authorities in SPP

The SPP footprint is comprised of 19 balancing authorities (including the Southwestern Power Administration (SWPA) and the three Nebraska entities), which are operated by IOUs, cooperatives, municipals, and state agencies.[16] In essence, a balancing authority is responsible for managing the minute-to-minute supply/demand balance for electricity within its borders to assure reliability. A rough approximation of the locations of these balancing authorities is shown in Figure I.2.

[16] SWPA withdrew from SPP on October 31, 2004, but through a contractual agreement SPP sold transmission service in the SWPA balancing authority in 2009 (*See* Southwest Power Pool, Inc., OATT, at Attachment AD). SWPA is included in the count of balancing authorities.

Figure I.2 Map of SPP Balancing Authorities



SOURCE: SPP

Note: This map is meant only to show approximate locations of SPP's balancing authorities. In addition, Missouri Public Service (MPS) is now known as KCPL Greater Missouri Operations Company (KCPL-GMO), although for the purposes of this report we refer to it as MPS.

B. Customers – The Demand for Electricity

Peak Demand and Energy Usage by Month

As mentioned in the previous section, the Nebraska entities joined SPP in April 2009. As a result Table I.2, below, shows the 2009 monthly peaks with and without the Nebraska entities included.[17] We can see that this addition had an impact on SPP. That is, if we include the Nebraska entities the peak demand in SPP was 46,482 MW, while if we do not, the peak demand was 40,817 MW. Therefore the addition of the Nebraska entities increased peak demand in SPP by 14% in 2009. The peak with and without the new entities occurred in June 2009; the peak in previous years also occurred during the summer period. However, historically we have seen that the highest peaks typically occur in late summer months, July or August, when the demand for electricity is large due to cooling needs on the hottest days of the year. However, the peak occurs in June this year because of an unusually hot period in the last week of June.

In order to make a more accurate comparison of the growth or decline in peak since last year we must focus on the peak numbers without the Nebraska entities. As seen below, peak demand declined by about 4.8% from 42,891 MW to 40,817 MW. This reverses a trend of peak growth over the past few years. Two causes for the decline are most likely the recession and milder weather during the summer period of 2009 as indicated by the decrease in the number of cooling degree days in 2009. The lowest monthly peak in 2009 occurred in the fall, unlike last year when it occurred in the spring. There is a significant difference between the highest monthly peak and the lowest monthly peak. To document this point, note that the peak in June 2009 was 58.5% higher than the peak in the lowest month of the year, November. This illustrates the spread in peak load across the year.

[17] Because the Nebraska entities participated in SPP starting in April of 2009, most of this report provides data and analysis that includes the Nebraska entities. However, in sections where the addition of the Nebraska entities seems to have a notable impact or when making a comparison across years causes analytical problems, we have shown the statistics with and without the Nebraska entities to highlight "the Nebraska effect". For example, in Table I.2, if we compared the peak demand with the Nebraska entities in 2009 to the 2008 numbers, we would report an 8.4% increase in peak. This increase, however, would be a function of expanding the SPP footprint rather than an increase in demand relative to 2008.

Table I.2 Monthly Peak Electric Energy Demand (MW) for SPP

Month	2005	2006	2007	2008	2009 without NE	2009 with NE
January	27,513	26,220	29,576	30,265	31,253	31,253
February	25,659	27,530	31,127	28,882	29,480	29,480
March	24,916	25,104	25,263	27,019	27,723	27,723
April	25,087	30,036	26,369	25,369	26,131	29,856
May	33,093	35,600	31,538	33,614	30,053	33,818
June	38,906	37,263	34,970	36,675	40,817	46,482
July	40,187	42,284	38,404	40,930	39,968	45,641
August	39,654	41,781	42,594	42,891	39,696	45,312
September	37,157	32,736	35,782	31,786	31,791	36,244
October	32,643	33,464	32,815	26,067	25,849	29,050
November	26,524	29,183	25,675	25,894	25,756	29,856
December	30,686	29,868	28,435	31,522	31,588	36,326
Peak	40,187	42,284	42,594	42,891	40,817	46,482
Yearly Change	3.7%	5.2%	0.7%	0.7%	-4.8%	NA

SOURCE: SPP: eDNA[18]
Note: Due to data limitations, the LAFA balancing authority was not included in the 2004 data used to calculate the 2005 yearly change.

Table I.3 displays the total electric energy used each month for 2005 to 2009. In 2009, electricity usage was 204.2 million MWh without the Nebraska entities and 227.2 million MWh if they are included. Therefore, the addition of the new entities increased electricity usage in 2009 by 11%. Moreover, the Nebraska entities only joined SPP in April 2009 so we would expect this percentage to increase next year when they will be a part of SPP for the entire year.

Looking at the column in Table I.3 without the Nebraska entities, we can see that while energy use is highest in the summer, it does not peak as sharply as demand; the electricity used in July, the month with the highest total usage, was 43.4% higher than the lowest month, February. We can also see that total energy usage decreased by 2.0%, or 4.2 million MWh, in 2009 as compared to 2008. A comparison of the number of heating and cooling degree days, which serve as an indicator of the demand for electricity due to extreme weather, was made for two of SPP's largest load centers, Kansas City, Missouri and Oklahoma City, Oklahoma.[19] The

[18] For the years up to and including 2008, we used self-reported data and filled in any holes in the data with SPP's eDNA data. However, for 2009, we shifted to using only eDNA data, as it is now deemed more accurate. We do not believe this change causes significant differences in the statistics shown. This note also applies to Tables I.3 – I.4 and Figures I.3 – I.4.

[19] Heating degree days are the sum for each day of the difference between the average temperature and 65 degrees Fahrenheit. So for a given day, if the average temperature is 35 degrees Fahrenheit, the number of heating degree days for that day would be 30 (65-35=30). Conversely, the cooling degree days are calculated based on how much the average temperature is above 65 degrees.

total number of heating and cooling degree days decreased from 2008 to 2009 by 9.3% in Kansas City and 2.6% in Oklahoma City. As a result, we believe this decline is most likely caused by milder weather as indicated by the decline in heating and cooling degree days and the recession.

Over the last 5 years, SPP's total electric energy usage has increased, on average, by about 1% a year. This is higher than the national average annual increase of 0.2% over the same period according to the U.S. Energy Information Administration (EIA) data. Last year we noted that the EIA predicted a national decrease in electricity use of 1.7% in 2009.[20] This year they reported an actual decline of 3.1% nationally in 2009. SPP's 2.0% decline is in line with what the EIA reported nationwide. Going forward, the EIA is predicting an overall increase of 1.0% annually from 2009 to 2035. To put SPP's usage in perspective, the national usage in 2009 was around 3.75 billion MWh, meaning SPP's total usage this year, if we include the Nebraska entities, accounted for about 6.1% of all the electric energy consumed in the country.[21]

Including the Nebraska entities, the load factor was 55.8% for SPP as a whole in 2009. Load factor is the total electric energy usage (227,156,939 MWh), divided by the product of the peak electric energy demand (46,482 MW) and the number of hours in the year (8,760). This means that in SPP the 2009 average hourly demand was 55.8% of the annual peak demand. The purpose of a load factor is to assess the amount of energy consumed, in terms of an average demand level, compared to maximum demand.

Table I.3 Total Electric Energy Usage (MWh) Within by Month and Year

Month	2005	2006	2007	2008	2009 without NE	2009 with NE
January	16,210,874	15,666,000	17,513,926	17,916,956	17,667,795	17,667,795
February	13,801,101	14,913,897	15,538,645	16,130,713	14,519,057	14,519,057
March	14,770,780	15,032,395	14,980,855	15,868,522	15,533,985	15,533,985
April	13,842,032	14,927,189	14,687,552	15,082,027	14,702,153	16,777,585
May	16,137,831	17,066,150	16,271,308	16,628,534	15,949,108	18,156,693
June	19,207,696	19,302,281	18,129,631	19,473,562	19,744,249	22,229,086
July	21,137,988	22,110,340	20,672,797	21,910,456	20,820,626	23,951,369
August	21,129,901	22,267,479	23,105,995	20,922,453	20,589,527	23,606,686
September	18,491,054	16,137,026	17,931,945	16,627,506	16,441,934	18,766,591
October	15,504,518	15,332,150	16,184,560	15,439,553	15,136,538	17,460,954
November	14,775,515	14,794,643	15,187,854	14,752,400	14,749,346	17,205,015
December	17,074,178	16,479,557	17,086,857	17,595,617	18,314,184	21,282,122
Total	202,083,468	204,029,107	207,291,923	208,348,298	204,168,501	227,156,939
Yearly Change	4.2%	1.0%	1.6%	0.5%	-2.0%	NA

SOURCE: SPP: eDNA
Note: Due to data limitations, the LAFA balancing authority was not included in the 2004 data used to calculate the 2005 yearly change.

[20] *See* Energy Information Administration (EIA), *Annual Energy Outlook 2009, With Projections to 2030*, March 2009
[21] *See* EIA, *Annual Energy Outlook Early Release Overview*, December 14, 2009 at http://www.eia.doe.gov/oiaf/aeo/overview.html.

Demand by Balancing Authority

Table I.4 displays each balancing authority's peak demand and energy usage in 2009. In SPP, American Electric Power (AEPW) is the balancing authority with the most electric energy usage with 19.9% of the SPP total in 2009. Southwestern Public Service Company (SPS) (13.2%), Oklahoma Gas & Electric (OKGE) (12.8%), Westar Energy, Inc. (WERE) (12.4%), and Kansas City Power & Light (KCPL) (7.0%) are the next largest in terms of electric energy usage. Together, these five balancing authorities account for 65.3% of the SPP total in 2009. If we exclude the Nebraska entities, then these 5 balancing authorities account for 72.8% which is comparable to the 73.0% and 73.1% in 2007 and 2008, respectively. These same five balancing authorities also had the highest peak demands, ranging from 9,700 MW for AEPW to 3,567 MW for KCPL. The Nebraska entities account for 10.1% of the total usage in SPP in 2009. This will likely increase next year as they will have been in the market for a full year in 2010 rather than just from April to December as was the case in 2009.

Table I.4 Balancing Authority Demand and Electric Energy Usage in 2009

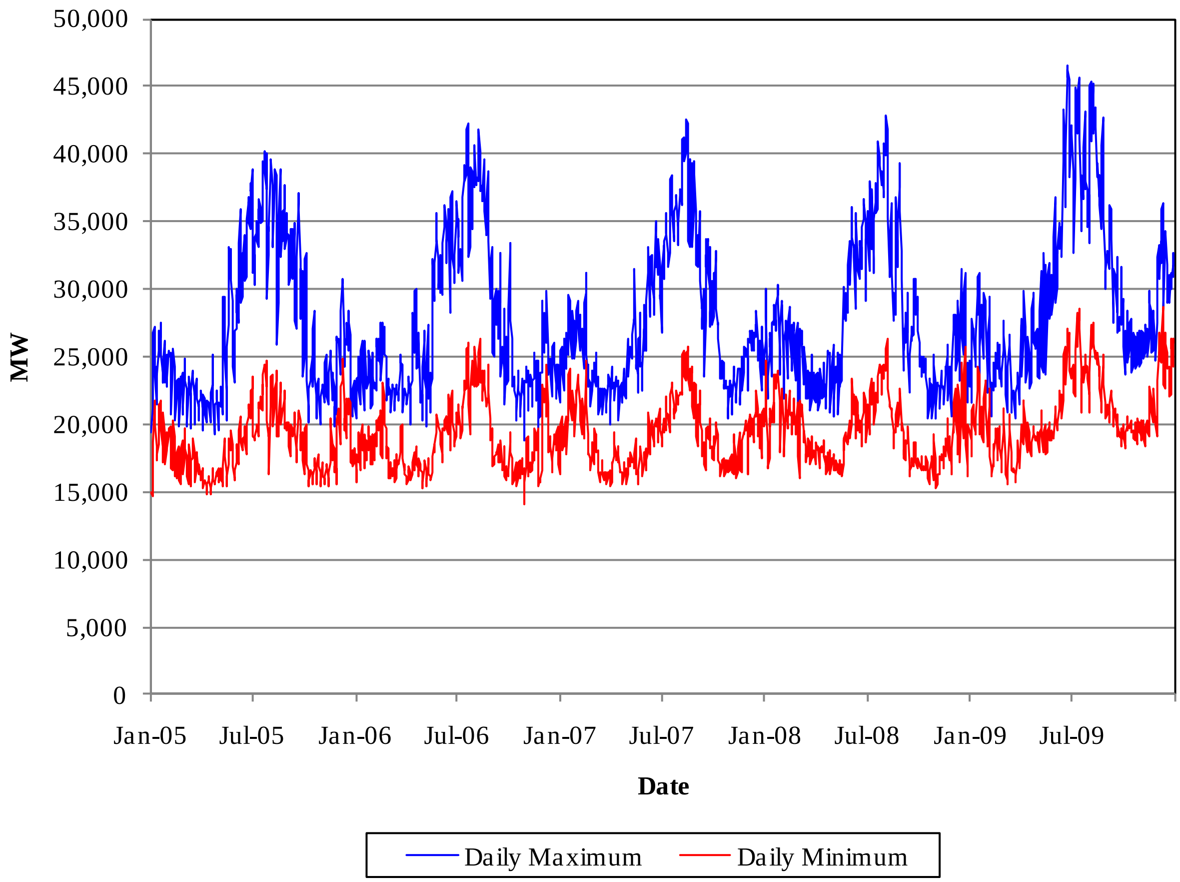
Area	2009 Usage (MWh)	Percent	Non-Coincident Peak (MW)
AEPW	45,251,076	19.9%	9,700
SPS	29,940,600	13.2%	5,455
OKGE	29,127,652	12.8%	6,346
WERE	28,220,090	12.4%	5,944
KCPL	16,007,422	7.0%	3,567
CLEC	11,205,002	4.9%	2,359
MPS	8,588,196	3.8%	1,943
WFEC	7,564,100	3.3%	1,459
SWPA	6,838,828	3.0%	1,504
EMDE	5,273,641	2.3%	1,085
SUNC	5,259,602	2.3%	982
GRDA	4,308,230	1.9%	856
KACY	2,431,394	1.1%	474
LAFA	2,071,651	0.9%	473
INDN	1,080,277	0.5%	293
LEPA	1,000,741	0.4%	228
NPPD	11,815,305	5.2%	2,966
OPPD	8,653,343	3.8%	2,498
LES	2,519,790	1.1%	745
SPP	227,156,939	100.0%	-

SOURCE: SPP: eDNA

Pattern of Demand

Figure I.3 provides a graph of the maximum and minimum hourly electricity demand per day. As could be expected from the earlier discussions, the daily maximum electric demand varies significantly across the seasons of the year. Similarly, the daily minimum electric demand varies by season in the same manner as the daily maximum electric energy demand throughout the year, just not to the same degree. Thus we see the difference between the maximum and minimum daily electric demand widen during the summer with a maximum swing over the five-year span of 21,289 MW, occurring in August 2009. This difference narrows during the rest of the year and reached the lowest daily demand swing of 2,590 MW in April 2007. The average daily difference for the five-year period is over 8,500 MW and almost 14,000 MW if we just include the summer months. It is these swings across seasons and across the hours of the day, plus the fact that electricity cannot be stored, that necessitate moment-by-moment balancing of supply and demand by balancing authorities in SPP. Looking at Figure I.3, we can see the demand jumped in April 2009 due to the inclusion of the Nebraska entities. This also explains why the summer numbers in 2009 look roughly 5,000 MW higher than in previous years.

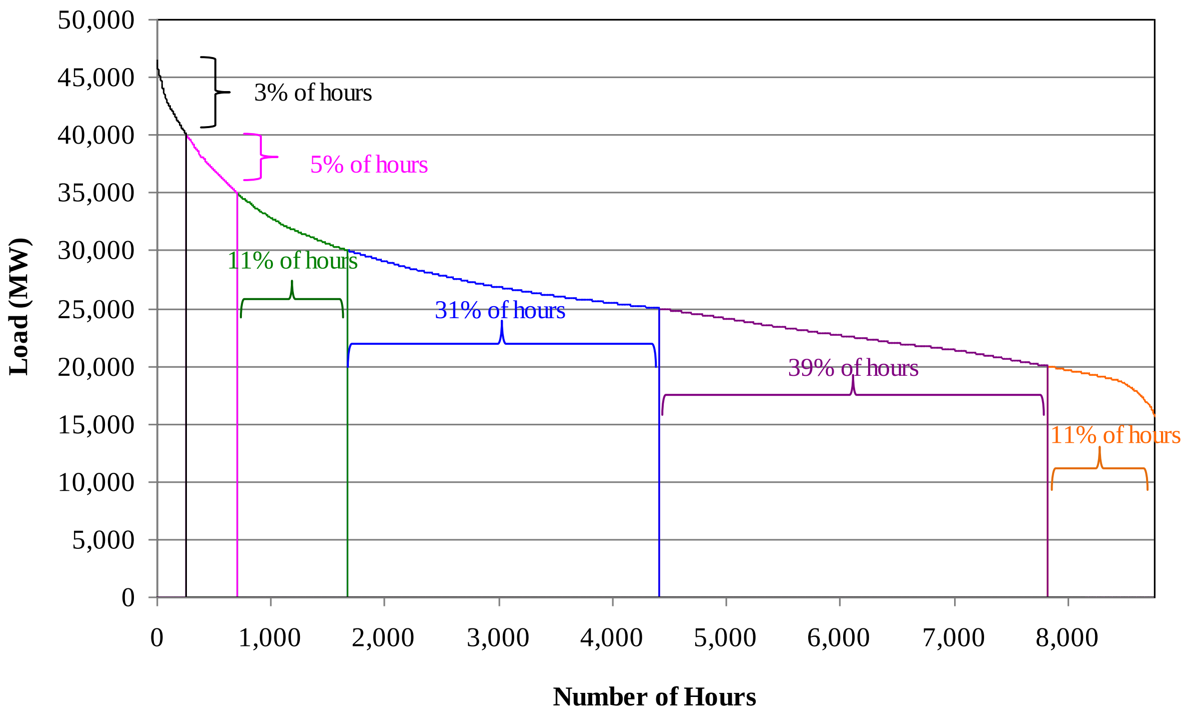
Figure I.3 Daily Maximum and Minimum Electric Energy Demand by Hour 2005-2009



SOURCE: SPP: eDNA

A load duration curve, which is a distribution of hourly electric energy demand by descending order rather than by chronological order, is shown in Figure I.4. It is designed to show the number of hours on the horizontal axis in which load is equal to or exceeds the MW level on the vertical axis. This load duration curve for SPP in 2009 shows that load ranged from a low of approximately 15,600 MW to a high (the peak) of 46,482 MW. In order to display how often the load is within certain MW ranges, we have broken the duration curve into colors for each 5,000 MW range. Looking at the figure, going from right to left, we can see that SPP's load was between 15,000 MW and 20,000 MW for about 11% of the hours in 2009. The next two parts of the curve flatten out significantly where we see 70% of the load between 20,000 and 30,000 MW. The remaining parts of the curve begin to display how demand reaches certain load levels for only a small number of hours in the year. This is important because SPP needs to have enough capacity (plus reserves) to meet these high demand levels even if they occur only a few hours a year. Looking again at the figure, we see that for 16% of the hours load is between 30,000 MW and 40,000 MW, and, for the top 3% of hours when load is at its greatest, we see a range from 40,000 MW to 46,482 MW.

Figure I.4 Electric Load Duration Curve for 2009



SOURCE: SPP: eDNA

C. Generation – The Supply of Electricity

Generation Capacity by Location

As seen in Table I.5, the total installed generating capacity within SPP's footprint is 65,796 MW; 39,832 MW of which, or 61%, is located in the following five balancing authorities: AEPW, OKGE, WERE, SPS, and CLEC.[22] The Nebraska balancing authorities are new to the list this year; they add 6,979 MW of capacity to the SPP footprint.

Table I.5 Current Installed Generation Capacity by Balancing Authority

Balancing Authority	Capacity (MW)
AEPW	14,269
OKGE	8,164
WERE	7,013
SPS	6,190
CLEC	4,196
KCPL	4,053
SWPA	3,247
GRDA	2,058
MPS	1,998
WFEC	1,557
EMDE	1,257
SUNC	1,190
OMPA	968
LAFA	755
KACY	752
INDN	448
CLWL	376
LEPA	293
YAZO	33
OPPD	3,382
NPPD	3,060
LES	537
Total	65,796

SOURCE: 2009 SPP EIA-411 Internal Report (Redacted Version) (Published August, 2009) and EIA-860. Note: Because the 2010 EIA-411 Report was not yet available, we used Item 3.1 (Projected Capacity and Demand for Ten Years, Summer 2009) from the 2009 EIA-411 Report. We used EIA-860 data to provide estimates for the Nebraska balancing authorities' capacity. These numbers are estimates rather than absolutes. OMPA, City of Clarksdale, MS (CLWL), and Public Service Commission of Yazoo City, MS (YAZO) are not balancing authorities but were broken out separately for the purposes of this table.

[22] This capacity figure represents the summer capability of SPP's generating units.

Resource Margin

As previously noted, in 2009, SPP had a peak demand of 46,482 MW. Given 65,796 MW of generating capacity, this means that there is 19,314 MW of generating capacity in excess of peak load within the SPP footprint. This excess generating capacity above peak load is called a resource margin. Expressed as a percentage, the installed resource margin in the SPP footprint is 42% of peak load. This is an increase over the 2008 resource margin of 35% of peak load.

It is important to note, however, that this capacity includes some generating units that are not necessarily dedicated to serve load or, due to finite transmission capability, are not deliverable to meet all loads at all times. This capacity presently consists primarily of IPP capacity which is not included within deliverability (transmission expansion) studies, and as such reflects 'less firm' deliverability to network load. A robust resource margin has important potential ramifications for both reliability, economic delivery, and for mitigation of the potential exercise of market power within SPP.

Generation Interconnection Process for Capacity Additions

The earlier examination of the amount of generation reveals, at the surface, a resource margin that would appear to allow for an increase in load without requiring the construction of new generation. However, the economics of electricity generation, not just a growth in demand, drive interest in constructing new generation. The capacity in the generation interconnection queue rose sharply from roughly 31,000 MW at the end of 2007 to about 60,000 MW at the end of 2008. In 2009, the amount of capacity in the queue leveled off, and at the end of the year there was 60,768 MW in the queue. However, if we do not include the 4,556 MW that was transitioned into the SPP process as a result of the Nebraska entities joining SPP in 2009, there was actually a decline in the level of capacity in the queue.[23] We believe that upward pressure on fuel costs and global warming concerns were prime contributors towards the surge in interest in new capacity in 2008, especially in the form of wind and more efficient natural gas generation. In addition, State Renewable Portfolio Standards (RPS) and the potential for a national RPS mandate could have also increased the interest in wind generation development in SPP. The decline since in the number of MW may be driven by (a) the economic downturn and (b) changes made to SPP's generation interconnection process described below.

The high demand for generation interconnection over the past several years placed an enormous amount of stress on the generation interconnection process causing longer process times for requests and, as a result, a backlog in the queue. Other RTOs and ISOs also faced similar problems, so much so that the FERC held a technical conference on interconnection queuing practices on December 11, 2007 in response to concerns about the effectiveness of queue management. Then, following the technical conference, on March 20, 2008, the FERC issued an order directing the RTOs and ISOs to work with their stakeholders to improve their interconnection processes. SPP formed the Generation Queuing Task Force (GQTF) to help reform their process. SPP then filed its proposed reform measures, and the FERC issued an Order conditionally accepting SPP's proposal, thus allowing them to implement the changes (effective June 2, 2009).

---

[23] This decline has continued since the end of 2009. As of April 8, 2010, there now is only 43,375 MW in the queue.

SPP's new generation interconnection process was designed to improve processing times and give precedence to more serious projects that are further along in the development process. To attain these goals, SPP now has three interconnection queues rather than just one. That is, interconnection customers now choose to begin in one of three queues: (a) the Feasibility Study Queue, (b) the Preliminary Interconnection System Impact Study (PISIS) Queue, and (c) the Definitive Interconnection System Impact Study (DISIS) Queue. The Feasibility Queue and the PISIS Queue are not required for projects seeking interconnection in SPP. Instead, they provide an avenue for projects to acquire information that will aid them in deciding whether to move forward with their projects. These two queues require lower deposits and less strict milestones. The DISIS Queue, on the other hand, is required by SPP, and requires that the customers meet stricter milestones regarding project size, project location, project site, and in some cases, a buyer for the power that would be generated. The fact that the DISIS Queue requires strict milestones to be met discourages projects that are more speculative in nature from clogging the queue and allows those further along to have priority. Once a customer passes through the DISIS Queue, the next step is to complete a Facility Study. This study consists of SPP or the Transmission Owner specifying and estimating the cost of equipment, engineering, and construction to implement the interconnection. Upon completion of the Facility Study, an applicant may proceed to execute a Generation Interconnection Agreement.[24]

We believe the reform measures implemented by SPP are constructive because they address the recommendation from last year regarding the generation interconnection process. Specifically, in the *2008 State of the Market Report,* Boston Pacific stated, "We recommend that instead of using a "first come, first served" method, SPP should allow advanced projects – projects that (a) have already secured a buyer for output or (b) have met certain milestones – to move past projects that are not as far along."[25]

Table I.6 shows that, at the end of 2009, 313 projects were currently active in the process or had executed an interconnection agreement, representing 60,768 MW of capacity.[26] This is a significant amount of capacity. To put this number in perspective, the peak demand in SPP in 2009 was only 46,482 MW. Of all the projects in the queue, 16,744 MW of capacity have fully executed an interconnection agreement. Historically, as would be expected, not all of the capacity that enters the interconnection process ends up being built. Going forward, we would expect that the capacity that is most likely to be withdrawn is that in the Feasibility Study Queue and the PISIS Queue as these queues are not required for interconnection and the requirements are less stringent than that of the DISIS Queue. We can see from the table below that 33,301 MW are in the Feasibility Study and PISIS Queues.

[24] *See* SPP's *Guidelines for Generation Interconnection Requests to SPP's Transmission System* for additional details.

[25] *See 2008 State of the Market Report, Southwest Power Pool, Inc.,* Prepared by Boston Pacific Company, Inc. (May 5, 2009) at page 92.

[26] That is, they have either successfully completed the interconnection process or are still in the process. This data only includes requests through December 30, 2009.

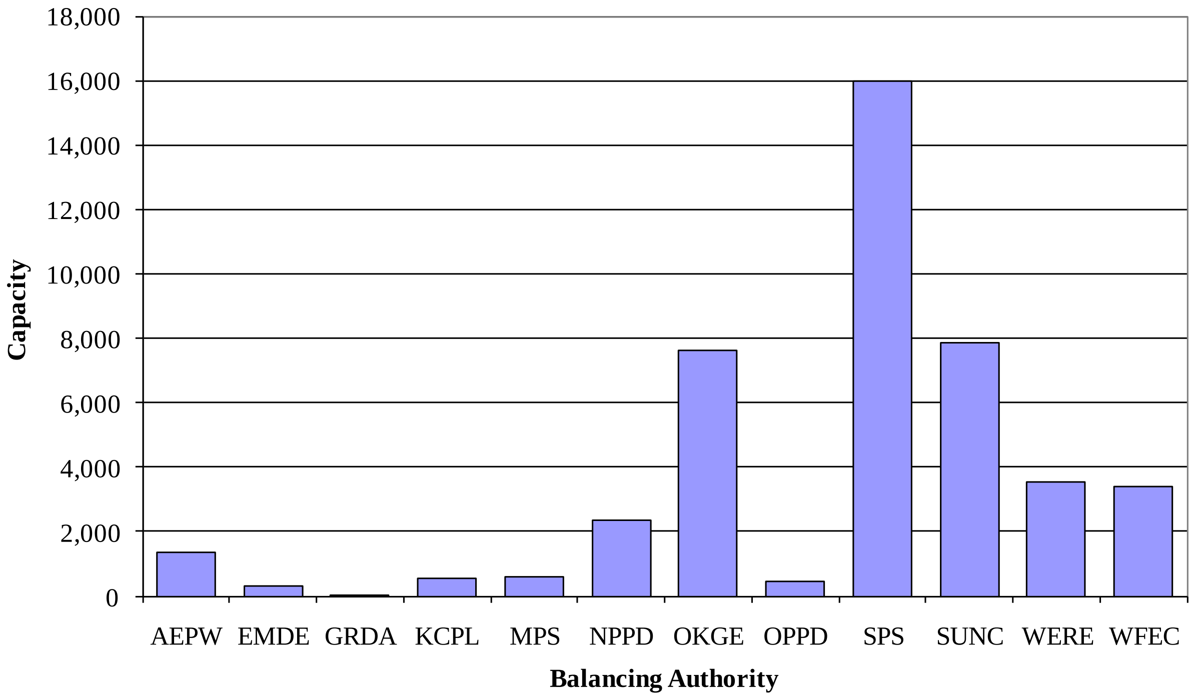
Table I.6 Status and Capacity of Generation Interconnection Requests

Study	Status of Study	Number of Projects	Total Capacity
Feasibility Study	Feasibility Study Queue	51	9,569
	Completed	69	15,732
System Impact Study	PISIS Queue	37	8,000
	DISIS Queue	24	3,169
	Completed	1	200
Facility Study	In Progress/Requested	28	6,367
	Completed	1	30
Interconnection Agreement	Pending	10	959
	Fully Executed/On Suspension	19	4,349
	Fully Executed/On Schedule	23	5,209
	Fully Executed/Commercial Operation	50	7,187
Total		313	60,768

SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, December 30, 2009.

Figure I.5 illustrates that, of the capacity that is active (projects with a fully executed interconnection agreement are not included) in the generation interconnection process, the largest share is in SPS. More specifically, about one-third of the requested capacity is in the SPS area.

Figure I.5 Active Requests for Generation Interconnection: Capacity by Balancing Authority



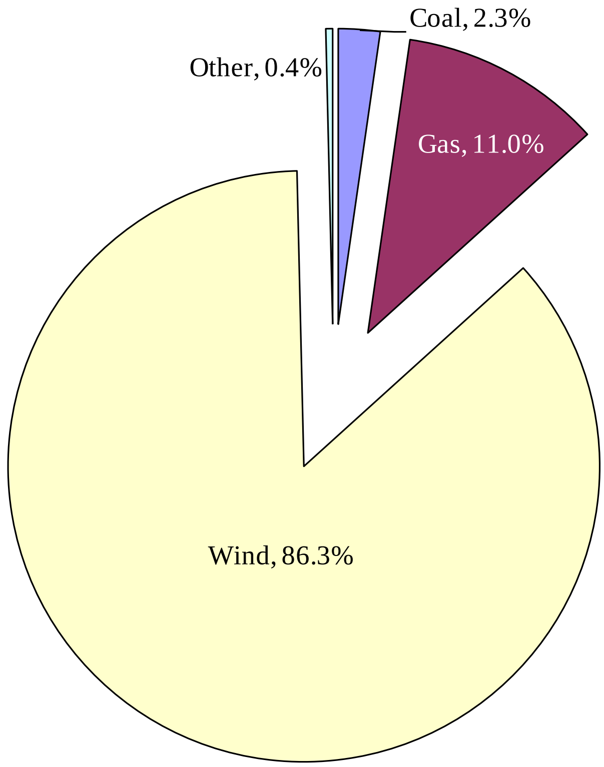
SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, December 30, 2009.

As seen in Figure I.6, among active interconnection requests (projects with a fully executed interconnection agreement are not included), 86.3% of the capacity is for wind projects, while natural gas and coal represent 11.0% and 2.3%, respectively.[27]

---

[27] Note that, here, wind capacity is stated in nominal terms.

Figure I.6 Type of Active Generation Interconnection Requests



SOURCE: SPP OASIS, Generation Interconnection Queue at
https://studies.spp.org/SPPGeneration/GI_Summary.cfm, December 30, 2009.
Note: Wind capacity, here, is stated in nominal terms.

Generation Capacity – Outages

Generating facilities are occasionally taken out of service for maintenance (maintenance outages), and they are also shut down from time to time due to equipment failures. These sudden outages due to equipment failures are called forced outages. Generation outages decrease the amount of electricity supply available to meet demand. Therefore, the reason we look at generation outages is to make sure that participants are not Physically Withholding generation, especially during peak periods, which could cause prices to increase.

Table I.7 reports the extent of generation capacity outages that occurred on the same day as the monthly peak load in SPP during 2009. The table reveals an expected pattern. During the summer period (June to August) when peak load reaches its highest, maintenance outages are at their lowest levels. This is mostly due to the fact that planned maintenance outages are scheduled outside the summer peak period and coordinated by SPP in order to maximize available capacity during the periods it is needed most. As seen below, the average total outage (average of the 12 monthly entries) as a percentage of average peak load (average of the 12 monthly entries) for 2009 was 13.4%, only slightly higher than last year when it was 13.1%.

Table I.7 Generation Outage Data Coincident with Peak Load by Month for 2009

Date of Peak Load	Peak Load (MW)	Forced Outage (MW)	Maintenance Outage (MW)	Total Outage (MW)	Percentage of Peak Load
January 16, 2009	31,253	1,120	1,198	2,318	7.4%
February 4, 2009	29,480	708	2,112	2,820	9.6%
March 2, 2009	27,723	339	6,510	6,849	24.7%
April 7, 2009	29,856	2,964	7,496	10,460	35.0%
May 31, 2009	33,818	1,408	4,025	5,433	16.1%
June 23, 2009	46,482	1,629	606	2,235	4.8%
July 14, 2009	45,641	683	595	1,278	2.8%
August 4, 2009	45,312	754	1,006	1,760	3.9%
September 8, 2009	36,244	1,159	1,139	2,298	6.3%
October 1, 2009	29,050	1,158	4,857	6,015	20.7%
November 16, 2009	29,856	1,870	7,551	9,421	31.6%
December 10, 2009	36,326	1,734	3,811	5,545	15.3%
Average Peak Load	35,087	1,294	3,409	4,703	13.4%

SOURCE: SPP OPS1

D. Transmission – The Bridge between Supply and Demand

Composition of the Transmission System

There are primarily six transmission voltages used in SPP: 345, 230, 161, 138, 115, and 69 kV.

The 69 kV voltage is the most prevalent voltage level in use throughout SPP. Most of the Transmission Owners in the SPP region use 69 kV systems to deliver power to lower voltage transmission and distribution systems.

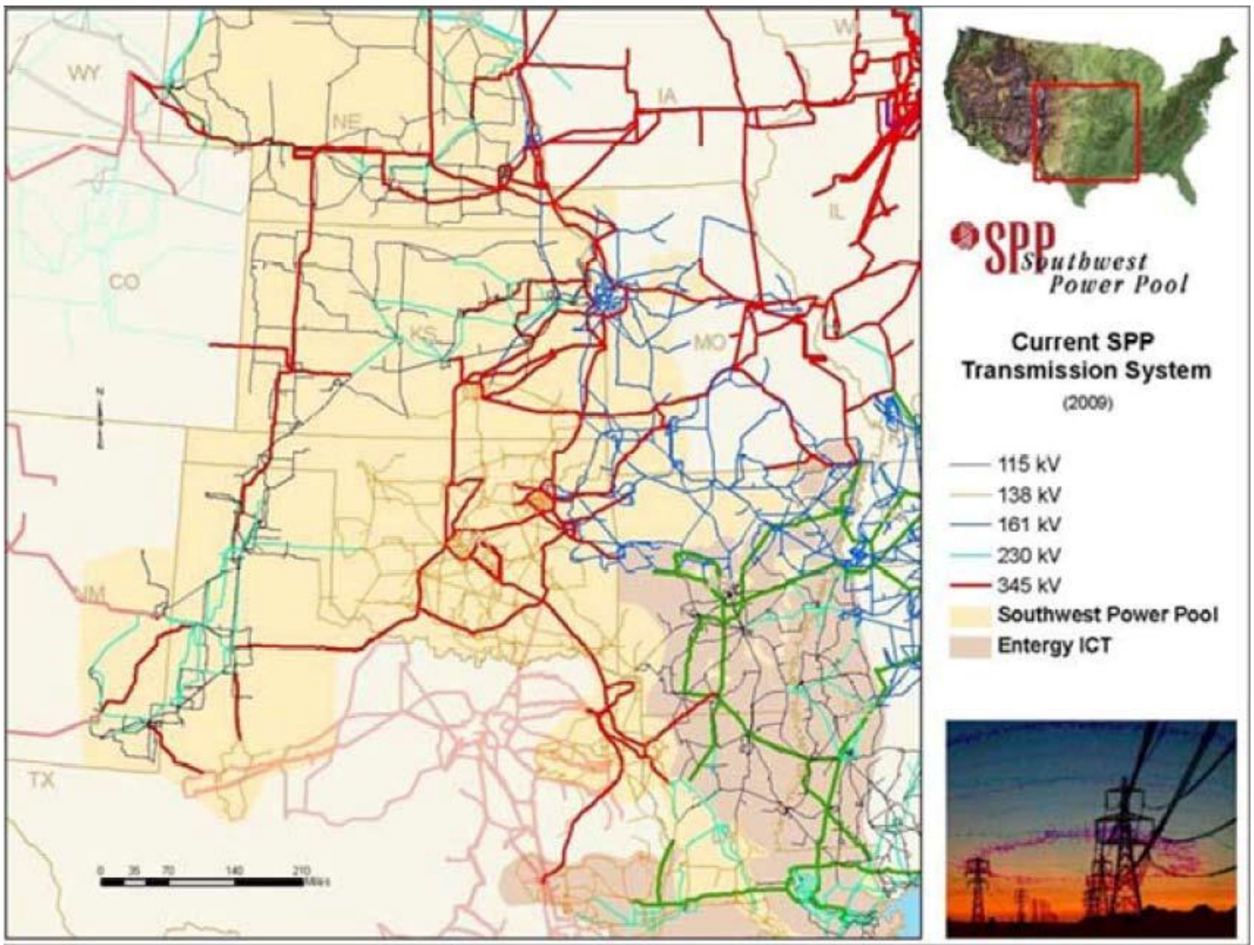
At the opposite end of the spectrum, transmission facilities at 345 kV form the backbone of the transmission system in much of SPP. This backbone primarily connects the transmission systems in the AEPW, KCPL, OKGE, and WERE balancing authorities in eastern SPP. Certain balancing authorities in eastern SPP, such as MPS and Grand River Dam Authority (GRDA), also use 345 kV facilities to interconnect with the AEPW, KCPL, OKGE, and WERE balancing authorities.

Transmission facilities at 230 kV form a secondary backbone that is used in SPP primarily in the SPS, Cleco Power LLC (CLEC), and WERE balancing authorities. Other balancing authorities nearby, such as Louisiana Energy & Power Authority (LEPA) and City of Lafayette (LAFA), also use 230 kV lines to interconnect with the CLEC balancing authority.

Between the 230 kV and 69 kV voltage systems, there are three voltages used in SPP: 115 kV, 138 kV, and 161 kV. These three voltage levels serve a mid-level power transfer function in SPP, and typically only one of these three voltage levels is used in any specific location. As seen in the figure, 115 kV is typically used in western SPP, 138 kV in southern SPP, and 161 kV in northeastern SPP.

The figure below indicates the locations of medium- and high-voltage systems (115 kV to 345 kV) in the SPP region.

Figure I.7 Transmission System by Voltage



SOURCE: SPP

SPP Transmission Connectivity with ERCOT and WECC

A total of seven Direct Current (DC) ties connect SPP to ERCOT and WECC. Two DC ties, known as ERCOT East and ERCOT North, or Welsh and Oklaunion, respectively, connect SPP to ERCOT for 810 MW of transmission capability. On the SPP side, these ties are located in the AEPW balancing authority, and they are owned and operated by AEPW.

Three DC ties, known as Eddy County, Blackwater, and Lamar, connect SPP to WECC for 610 MW of transmission capability. The Eddy County tie is owned by El Paso Electric

(EPE) and Texas - New Mexico Power (TNP), but operated by SPS. The Blackwater tie is owned and operated by the Public Service Company of New Mexico (PNM). The Lamar tie is owned and operated by Public Service Company of Colorado (PSCO), an affiliate of Xcel Energy.

Finally, two DC ties located in Nebraska, known as Sidney and Stegall, connect SPP to WECC for an additional 400 MW of transmission capability. The Sidney tie is owned and operated by the Western Area Power Administration (WAPA). The Stegall tie is owned and operated the by Tri-State Generation and Transmission Association. These two DC ties are new to this list this year as a result of the addition of the Nebraska entities in April 2009. The transmission capability of each DC tie is shown in Table I.8.

Table I.8 DC Tie Transmission Capability

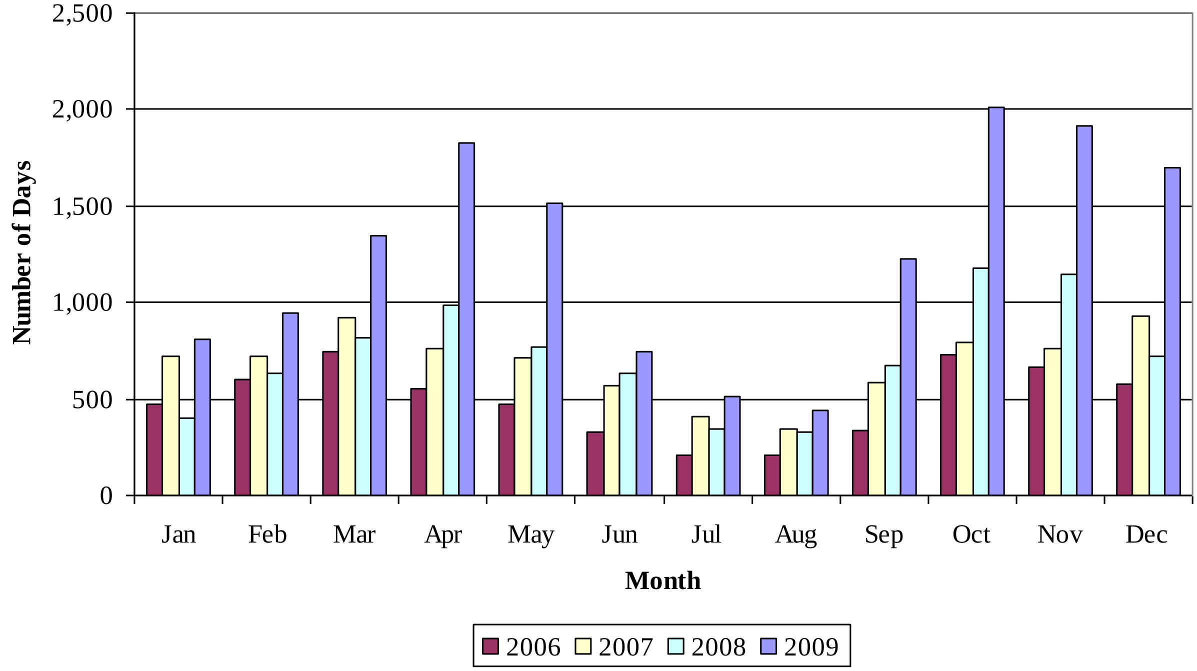
Name of DC Tie	Transmission Capability (MW)
ERCOT East (Welsh)	600
ERCOT North (Oklaunion)	210
Lamar	210
Eddy County	200
Blackwater	200
Sidney	200
Stegall	200

SOURCE: SPP OASIS at http://sppoasis.spp.org/documents/flowgates/FlowGates.cfm

Transmission Outages

Transmission outages can impact deliverability and affect market prices. Moreover, transmission outages can make transmission congestion more likely so that the SPP Market is segmented with prices varying by location. Transmission elements, like generating units, need to be removed from service for occasional maintenance and for new construction. Transmission system components also fail from time to time, resulting in forced outages. The following figure shows that the pattern of transmission system outages for 2009 follows the same general pattern as that for generating units in that outages were at some of their lowest levels during the summer months. Only 1.4% of outage days in 2009 on the SPP transmission system were forced outages.

Figure I.8 Days of Transmission Outages by Month for 2006 to 2009



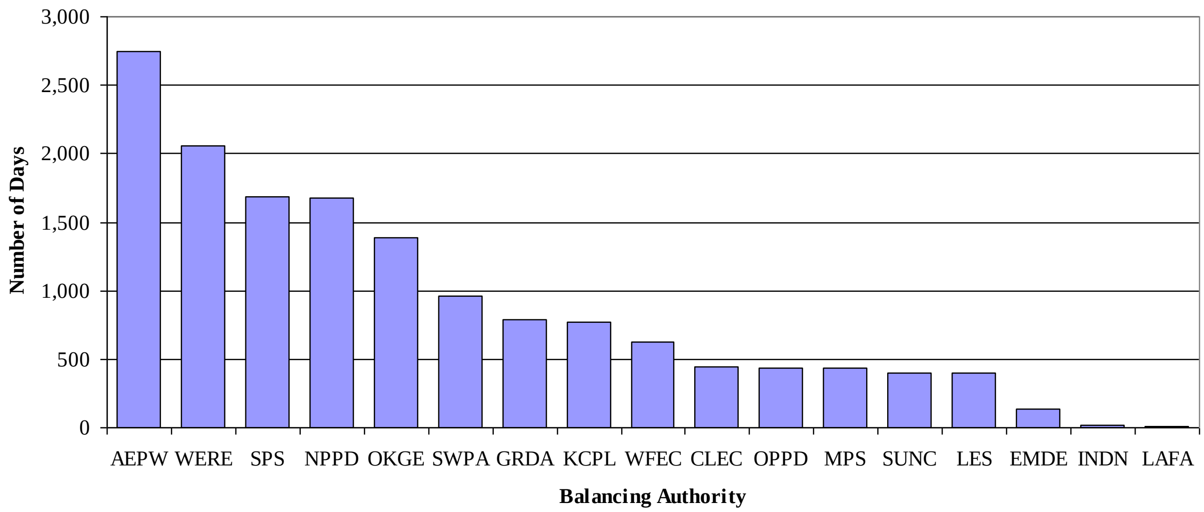
SOURCE: SPP OPS1
Note: Transmission outage data covers 100+ kV transmission components in SPP.

Figure I.8 above shows the extent of transmission system outages for each month from 2006 to 2009, calculated by the length of time of each outage. For example, if 12 lines were out for two hours each, that would count as 1 outage day in the metric above. If one line was out for 48 hours, then that would count as 2 outage days. As we can see in the figure above, outages have increased in each of the past three years. The addition of the Nebraska entities makes this increase even larger in 2009. This can be seen in the figure by looking at the large difference in the 2008 bars and 2009 bars starting in April when the Nebraska entities joined SPP. However, even if we remove the Nebraska entities from the calculation, transmission outages increased 45% when compared to the 2008 total. This increase follows on top of a 39% increase from 2006 to 2007 and a 5% increase from 2007 to 2008. If we include the Nebraska entities in 2009, transmission outages increased 74% over last year's total.

This increasing trend in the number of transmission outages over the past several years continues to concern us. Boston Pacific recommended in both the *2007* and *2008 State of the Market Reports* that SPP report on the reasons for increasing transmission outages. The increases could be a result of legitimate reasons such as: (a) having to take lines out of service for construction as a result of an increase in the amount of transmission investment from SPP's Transmission Expansion Plan, (b) more accurate reporting, or (c) weather. However, given the current data set, we are unable to confirm or refute these hypotheses. At a minimum, reporting on this would alleviate any concerns of market power abuse through forced or maintenance outages. Given this, we recommend that the SPP RTO complete its new methodology for tracking standardized reasons for transmission outages and report on those by year end.

The location of transmission outages in SPP during 2009 are shown below in Figure I.9, by balancing authority. The AEPW, WERE, SPS, and NPPD balancing authorities all experienced over 1,500 days of transmission facility outages during 2009, accounting for 54% of all outages. In comparison to 2008, the SPS and GRDA balancing authorities experienced particularly large increases from 699 days to 1,689 days and 203 days to 792 days, respectively. The SWPA balancing authority, on the other hand, actually saw a decline in number of outages by about 3%.

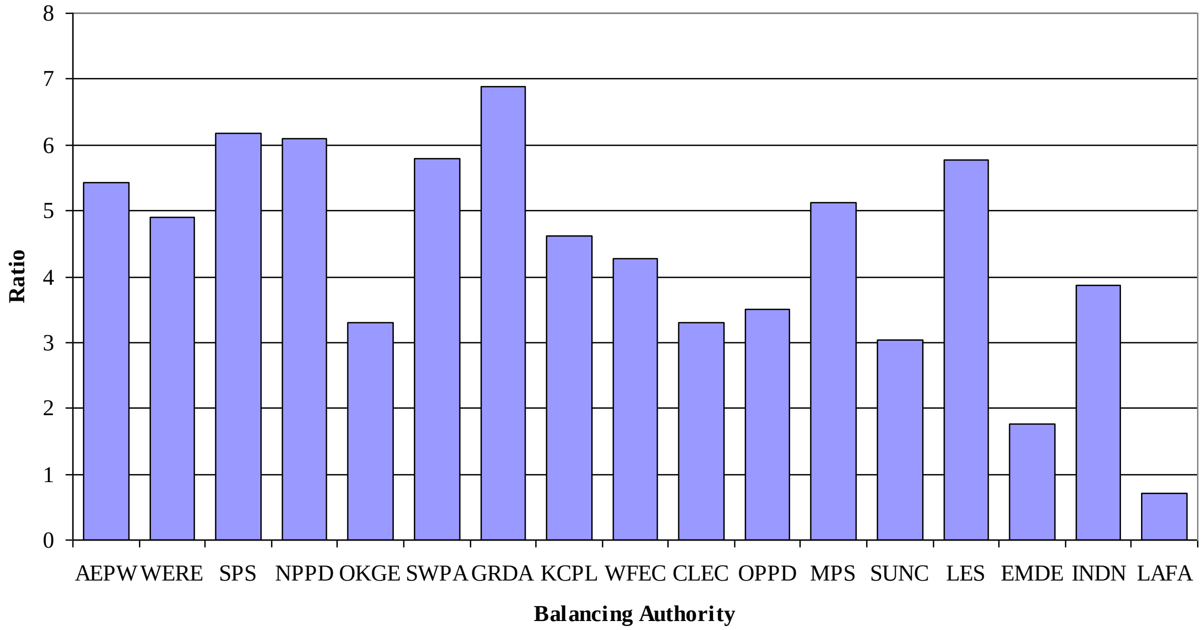
Figure I.9 Days of Transmission Outages by Balancing Authority for 2009



SOURCE: SPP OPS1
Note: Transmission outage data covers 100+ kV transmission facilities in SPP.

Figure I.10 shows the ratio of days of transmission outages to the number of transmission facilities at 100+ kV for each balancing authority shown in Figure I.9. This figure helps put in perspective the number of outages. That is, one balancing authority may have more outages than another simply because it is a larger balancing authority. The GRDA balancing authority had the highest level of outage duration per transmission line. Again, as mentioned previously, only 1.4% of outage days in SPP were as a result of forced outages. Therefore, we do not see this as a reliability issue, but the reasons for the increases should be transparently reported by SPP.

Figure I.10 Ratio of Days of Transmission Facility Outages to Number of Transmission Facilities by Balancing Authority for 2009



SOURCE: SPP OPS1

II. EIS MARKET RESULTS

A. Brief Overview of the EIS Market

SPP launched its Real-Time Energy Imbalance Service (EIS) Market on February 1, 2007; therefore, 2009 is the third year of EIS Market operation. The EIS Market footprint, which contains 15 balancing authorities, is a subset of SPP's footprint.[28] The EIS Market is an imbalance market in which all resource and load imbalances are settled. SPP is also in the process of developing new markets. The major components of these new markets include: (a) a Day-Ahead Market with Transmission Congestion Rights (TCRs), (b) a Reliability Unit Commitment (RUC) process, (c) a Real-Time Balancing Market, similar to today's EIS Market, and (d) a price-based Operating Reserves procurement. These markets are tentatively scheduled to be launched in December of 2013. As these markets are yet to be in operation, this section focuses on the EIS Market. To give an overview of the 2009 results, we report on seven topics: (i) Market Activity, (ii) Market Prices, (iii) Revenue Adequacy (Net Revenue Calculation), (iv) Fuel Type, (v) Market Participation, (vi) Market Power Measurement and Mitigation, and (vii) Revenue Neutrality Uplift (RNU).

B. Market Activity

The EIS Market is *mandatory* in the sense that all resource and load imbalances must be settled in the EIS Market. However, the market is *voluntary* in the sense that a Market Participant can decide for itself whether to (a) self-dispatch its resources or (b) participate fully by making its resources available for SPP to dispatch in the EIS Market.

Tables II.1 and II.2 show, for 2007, 2008, and 2009, the volume of sales and purchases in the market and the dollars received and paid by Market Participants for those transactions. A *sale* is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled. Similarly, a *purchase* is made by a Market Participant when either (a) it generates less than it has scheduled and/or (b) its actual load is more than it has scheduled.

For example, say a Market Participant schedules and offers 100 MWh of generation from a power plant; by scheduling <u>and</u> offering, this power plant becomes dispatchable by the EIS Market. If the power plant is dispatched at 125 MWh, it made a 25 MWh sale to the EIS Market. In contrast, if it is dispatched at only 70 MWh, it made a 30 MWh purchase from the EIS Market. If it was dispatched at 100 MWh, then no MWh would be considered to be bought or sold in the EIS Market since the resource's actual production was equal to its schedule. On the load side, if a Market Participant schedules 100 MWh of load, but actually uses 125 MWh, it has purchased 25 MWh; if its actual use is only 70 MWh, it sold 30 MWh to the EIS Market.

[28] The EIS Market footprint balancing authorities include: AEPW, The Empire District Electric Co. (EMDE), GRDA, KACY, KCPL, OKGE, SPS, Sunflower Electric Power Corporation (SUNC), WERE, and Western Farmers Electric Cooperative (WFEC). In addition, during 2009, 5 more balancing authorities joined the EIS Market: the three Nebraska entities, OPPD, NPPD, and LES joined in April, while MPS and INDN joined in September and December, respectively.

Table II.1 and Table II.2 show that there were about 20.8 million MWh both sold and purchased in the EIS Market in 2009. This compares to 15.1 million MWh sold and purchased in 2008 and a little over 13 million MWh sold and purchased in 2007. In comparison to 2008, the increase from 15.1 million MWh to 20.8 million MWh represents a 38% increase. However, it is important to note that 5 new balancing authorities joined the EIS Market during 2009, so we must account for this in order to make a more accurate comparison to 2008. If we take the market sales without these new balancing authorities, sales increased by 9.6% from 2008 to 2009.

In 2007 and 2008 sales volume was at its highest in the three summer months (June, July, and August). However, in 2009, sales volume was at its highest in April through July, with May and June having the largest monthly sales figures. One possible cause for the surge in sales during this timeframe is if one or more participants chose not to schedule any generation, and yet its generation was bid to be dispatched. This would result in more MWh being settled in the market because the actual values for generation would be much higher than the zero MWh that were scheduled.

To put EIS sales and purchases in context, note that we estimate a total of approximately 197 million MWh were used (total load) in the EIS Market footprint in 2009.[29] EIS Market sales (at 20.8 million MWh) were equal to roughly 10.6% of total load within the EIS Market footprint, which shows an increase over both 2007 and 2008 when the sales as a percentage of total load was approximately 8.3% and 8.5%, respectively. Across 2009, sales as a percentage of load ranged from a low of 8.0% in February to a high of 14.8% in May, while in 2008, the low was 6.7% in February and the high was 9.5% in April. The increase in market penetration can at least in part be attributed to the new entities. If we exclude them from the calculation, EIS sales as a percentage of load drops from 10.6% to 9.6%. This, however, is still an increase over 2008.

For 2009, the dollars received by Market Participants for their sales was approximately $556 million, and the dollars paid by Market Participants for their purchases was roughly $541 million. In 2008, the dollars received for sales and paid for purchases by Market Participants was approximately $858 million and $860 million, respectively. If we just look at the dollars received for sales, we see a decrease of about 35% from 2008 to 2009. However, we once again need to make an adjustment for the fact that five new balancing authorities joined the EIS Market at different points during 2009. After making this adjustment, the dollars received by Market Participants for sales actually decreased by 45.9% from 2008 to 2009. This notable decrease in sales revenues stems mostly from the fact that EIS prices dropped by about 50% from 2008 to 2009; we will discuss prices in detail in the next section.

Clearly, settlement of the EIS Market involves a substantial amount of money. Moreover, because the market is only an imbalance energy market, these tables most likely understate the scale of the market. For example, say a Market Participant chooses to make a 100 MW resource available to the market; that is, the Market Participant schedules and offers 100

[29] The total load here is the load in the EIS Market footprint, which does not include CLEC, LAFA, LEPA, and SWPA. These balancing authorities are included in SPP's RE footprint. This also does not include MPS for the first 8 months of the year and INDN for the first 11 months of the year as they were not in the EIS Market at that point.

MWh. At that point, the full 100 MWh is open to competition – if another Market Participant offers a better price for all 100 MWh than that offered by the original Market Participant, then the full 100 MWh would be settled in the EIS Market. If, however, the original Market Participant's price cannot be beaten or can be beaten for only a fraction of the 100 MWh, that should not diminish the fact that the full 100 MWh was decided in the EIS Market.

The implied price from sales is calculated by dividing the dollars received by Market Participants by the total MWh sold. The implied price for 2007 and 2008 was $50.98/MWh and $56.72/MWh, respectively. In 2009, the implied price was $26.68/MWh. This decline of roughly 50% from previous years is consistent with the decline in the SPP-wide price in 2009. Furthermore, the implied price is in line with the SPP-wide simple average price of $27.50/MWh and the load-weighted SPP-wide price of $28.69/MWh.

Table II.1 Electricity Sales in the EIS Market by Month

Month	2007		2008		2009	
	MWh Sold by Market Participants	Dollars Received by Market Participants	MWh Sold by Market Participants	Dollars Received by Market Participants	MWh Sold by Market Participants	Dollars Received by Market Participants
January	NA	NA	1,039,772	$56,216,109	1,185,553	$38,989,054
February	982,439	$52,552,411	909,783	$47,669,552	1,072,096	$25,688,072
March	1,084,657	$49,846,702	1,103,011	$69,336,696	1,490,880	$40,667,461
April	1,052,692	$52,640,111	1,219,830	$86,486,507	2,049,867	$44,530,637
May	1,103,790	$52,296,674	1,255,460	$75,968,700	2,296,007	$53,030,607
June	1,413,136	$83,835,716	1,524,363	$122,337,024	2,581,722	$67,535,973
July	1,515,464	$79,063,516	1,700,883	$141,401,971	2,163,603	$58,871,708
August	1,717,694	$99,278,662	1,607,292	$98,461,189	1,750,833	$44,084,898
September	1,236,895	$56,661,578	1,243,061	$42,733,924	1,543,249	$35,475,405
October	998,315	$49,455,937	1,156,163	$33,988,429	1,437,650	$41,562,783
November	1,042,553	$48,699,623	1,170,629	$40,589,763	1,524,504	$40,376,086
December	1,064,088	$49,144,201	1,188,272	$42,388,959	1,731,930	$64,834,942
Total	13,211,723	$673,475,131	15,118,519	$857,578,823	20,827,894	$555,647,625

SOURCE: SPP DSS

Table II.2 Electricity Purchases in the EIS Market by Month

Month	2007		2008		2009	
	MWh Purchased by Market Participants	Dollars Paid by Market Participants	MWh Purchased by Market Participants	Dollars Paid by Market Participants	MWh Purchased by Market Participants	Dollars Paid by Market Participants
January	NA	NA	1,043,455	$57,354,271	1,188,142	$37,568,499
February	1,005,583	$51,164,242	922,467	$48,964,975	1,057,879	$25,060,083
March	1,099,568	$45,836,392	1,138,038	$74,067,497	1,493,862	$37,093,444
April	1,052,875	$53,053,948	1,238,066	$89,959,155	2,041,624	$44,342,376
May	1,119,682	$52,665,570	1,270,867	$77,930,131	2,275,774	$50,994,468
June	1,415,285	$77,641,662	1,541,808	$124,170,580	2,600,313	$65,719,895
July	1,525,948	$81,019,780	1,694,465	$137,776,627	2,185,067	$57,732,361
August	1,737,670	$97,611,473	1,601,390	$97,151,969	1,755,053	$43,324,776
September	1,238,007	$55,701,933	1,220,809	$42,364,155	1,523,855	$34,424,749
October	980,889	$50,036,336	1,130,682	$32,395,775	1,370,937	$38,801,489
November	1,031,906	$50,076,946	1,150,690	$36,295,802	1,518,169	$40,595,067
December	1,085,549	$51,879,158	1,165,153	$41,737,051	1,750,441	$65,758,329
Total	13,292,962	$666,687,440	15,117,890	$860,167,988	20,761,115	$541,415,536

SOURCE: SPP DSS

C. Market Prices

Each year in the *State of the Market Report*, we compare SPP EIS prices to neighboring markets to put the prices in perspective. In comparing SPP prices to these other markets, the Midwest Independent Transmission System Operator (MISO) and ERCOT, we are looking to see if SPP prices are in the same ballpark as the other prices. It is not reasonable to expect that they will perfectly mirror each other as different regions have differences in resource/fuel mix, patterns of demand, and other factors including inherent design aspects of each market.[30] However, we do expect to see similar prices and trends among the regions. After comparing SPP market prices to those of its neighbors, we then look within SPP to compare prices across balancing authorities in the EIS Market.

Comparison to MISO and ERCOT

Table II.3 shows the average real-time prices for SPP, MISO, and ERCOT for 2009. We calculated the average price by taking the hourly prices for each market and taking a simple average of those prices. As shown in the table below, SPP's average price is between MISO's and ERCOT's prices; the SPP price is about 1% above MISO's and 9% below ERCOT's.

We used the simple average price for SPP's hourly price so it would give us a value more comparable to the MISO and ERCOT averages. We also calculated the load weighted average for SPP. The weighted average price was $28.69/MWh, and this number also falls in between the prices from the other two markets.

[30] For example, SPP and MISO are 'nodal' pricing markets, whereas ERCOT is presently a 'zonal' market.

The coefficient of variation is a measure of the volatility of market prices; it is calculated as the average hourly difference in price divided by the overall simple average price (i.e. the standard deviation divided by the mean). Therefore, a higher volatility is represented by a higher percentage. The volatility for SPP is lower than the other markets (55% vs. 63% and 146%), this means the SPP market has less variation in prices than the other two markets. In addition, SPP's volatility decreased slightly from 2008 when it was 62%.

Table II.3 Electricity Prices Compared with Neighboring Regions for 2009

Region	Average Price	Max. Price	Min. Price	Median Price	Volatility
SPP	$27.50	$422.18	-$45.27	$24.65	55%
MISO	$27.11	$287.85	-$95.25	$24.05	63%
ERCOT	$30.19	$1,033.63	-$46.23	$24.04	146%

SOURCE: SPP DSS and MISO website at
http://www.midwestmarket.org/home/Market%20Reports/?type=rt_lmp&list=month
and ERCOT website at http://www.ercot.com/mktinfo/services/bal/index.html

Table II.4 shows prices by year for each of the three markets. Average prices in all three markets declined precipitously in 2009. SPP's simple average annual price fell from $53.21/MWh in 2008 to $27.50/MWh in 2009, representing a drop of 48%. These declines are similar to those seen in MISO and ERCOT where prices declined 44% and 54%, respectively. SPP on-peak and off-peak prices also dropped substantially in 2009; prices for on-peak dropped by 51%, while off-peak fell by 44%. Also important to draw out is the fact that the SPP average price is once again between that of MISO and ERCOT as was the case in both 2007 and 2008. This gives us further comfort that SPP's 2009 annual prices are reasonable and in line with average prices from the other two markets.

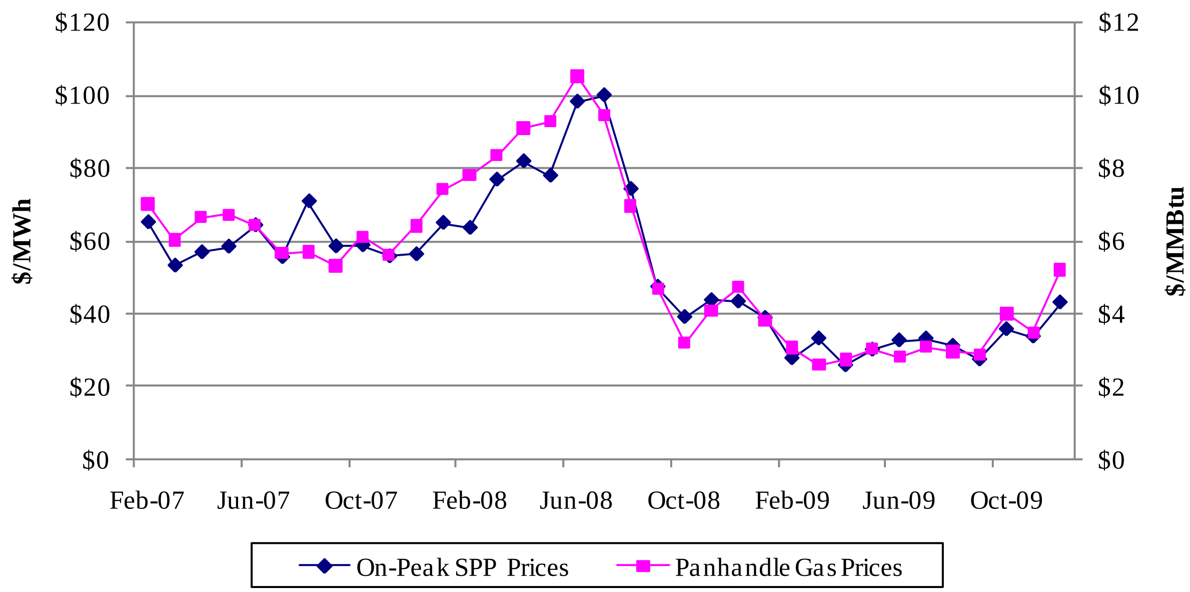
Table II.4 Electricity Prices Compared with Neighboring Regions

Region	Average Price			Average On-Peak Price			Average Off-Peak Price		
	2007	2008	2009	2007	2008	2009	2007	2008	2009
SPP	$49.18	$53.21	$27.50	$58.30	$66.16	$32.11	$41.25	$41.89	$23.47
MISO	$47.37	$48.08	$27.11	$63.37	$64.86	$34.15	$33.45	$33.34	$20.92
ERCOT	$53.00	$65.64	$30.19	$60.74	$80.88	$35.25	$46.26	$52.31	$25.74

SOURCE: SPP DSS and MISO website at
http://www.midwestmarket.org/home/Market%20Reports/?type=rt_lmp&list=month
and ERCOT website at http://www.ercot.com/mktinfo/services/bal/index.html

We believe that the drop in natural gas prices is the primary reason we are seeing such a large decline in electricity prices. Panhandle natural gas prices decreased by about 54% from 2008 to 2009. This is important because in SPP, natural gas-fired resources are at the margin (and therefore setting the price) 61% of the time. Natural gas prices have an even larger impact on *on-peak* prices in SPP. In 2009, natural gas was at the margin about 77% of the time during *on-peak* periods, while only 47% of the time during *off-peak* periods. The figure below shows a visual comparison of prices for Panhandle natural gas and SPP on-peak electricity prices. This figure shows that the prices usually move in the same direction, and natural gas and electricity prices usually hit peaks and valleys at the same times. This figure shows the step-for-step movement of electricity and natural gas prices in 2007 through 2009 and helps to verify the significance of the relationship between natural gas and on-peak electricity prices. Given the importance of natural gas prices to SPP's prices, in Section V, we discuss in detail several factors that could have contributed to the decline in natural gas prices. These factors include: (a) the recession, (b) the increase in worldwide liquefied natural gas (LNG) facilities, and (c) innovative, new drilling techniques for unconventional gas.

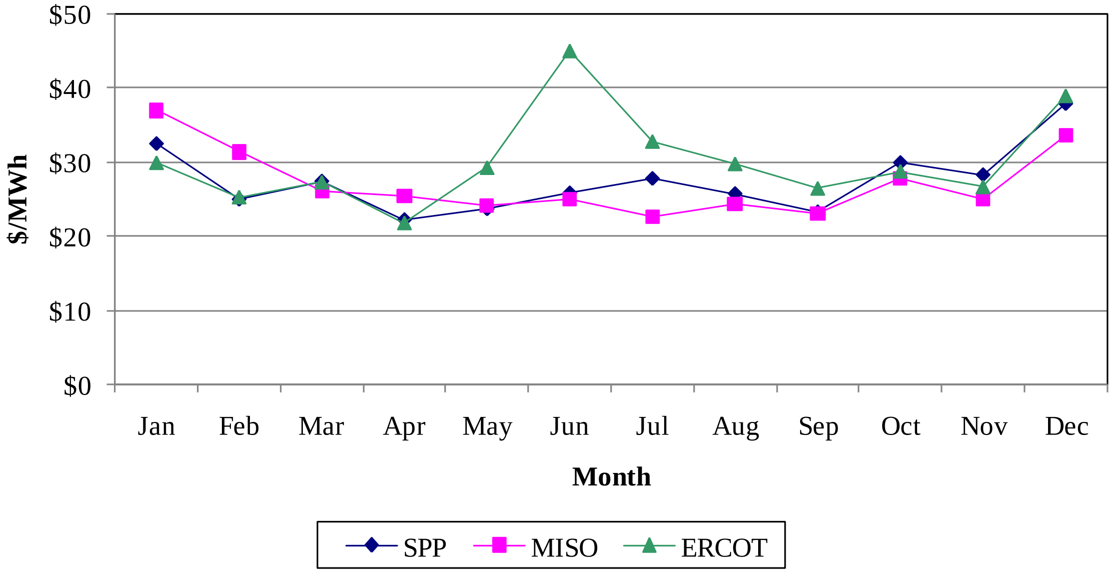
Figure II.1 Comparison of Average Monthly On-Peak SPP Electricity Prices and Panhandle Natural Gas Prices



SOURCE: SPP DSS and for Panhandle data: https://www.theice.com/marketdata/reportcenter/reports.htm
Note: The average on-peak electricity prices in this figure are load-weighted prices.

The average prices over the whole year is one way to compare the SPP market to its neighboring markets, but it can mask possible differences in the SPP market across the months. Therefore, we also looked at month-by-month price data. Figure II.2 shows prices at the monthly level in SPP, MISO, and ERCOT. For the most part, SPP's monthly prices fell between those of MISO and ERCOT, just as the average price for the year did. The largest monthly price difference occurred in June when SPP's simple average price was below ERCOT's by more than $19/MWh; however, SPP's price was in line with MISO's June price. For a few months SPP's price did exceed both MISO and ERCOT prices, but they were within a couple of dollars/MWh of the other regions.

Figure II.2 SPP, MISO & ERCOT-Wide Hourly Average Prices by Month for 2009

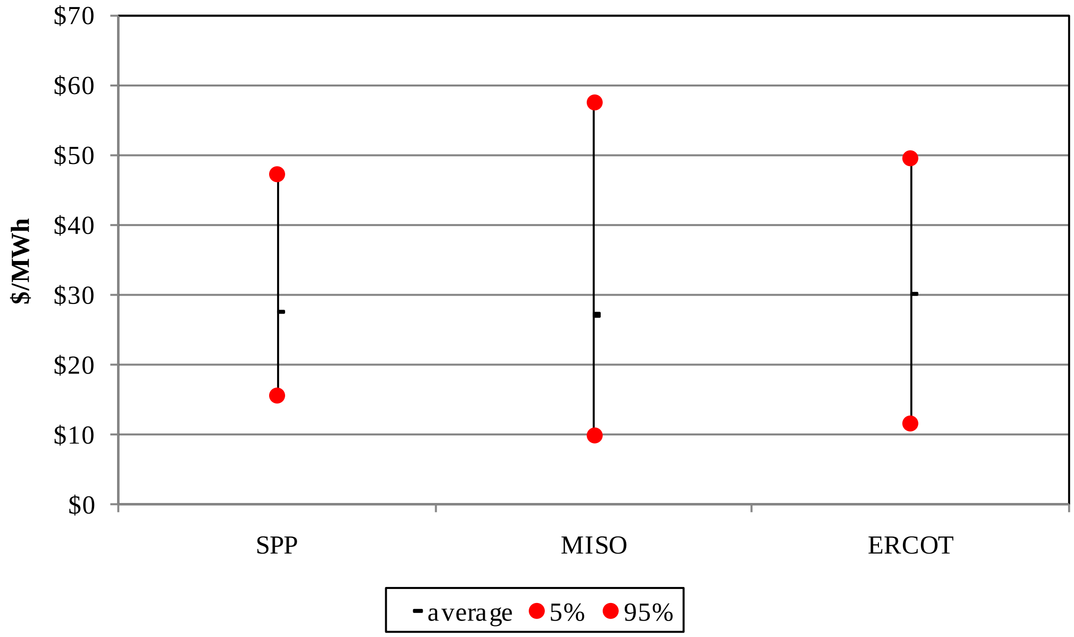


SOURCE: SPP DSS and MISO website at
http://www.midwestmarket.org/home/Market%20Reports/?type=rt_lmp&list=month
and ERCOT website at http://www.ercot.com/mktinfo/services/bal/index.html

Figure II.3 makes an even more granular comparison by showing the distribution of *hourly prices* for the three markets. The idea here is to see if the majority of the price points for each market are comparable to each other. We do this by looking at the hourly prices that fall between the 5th and 95th percentiles; that is, the lowest 5% of prices and the highest 5% of prices were excluded, leaving the middle 90%. The figure shows that there is significant overlap in prices with SPP's 5th and 95th percentile prices falling within the 5th and 95th percentiles of both MISO and ERCOT. This again demonstrates that SPP prices are comparable to market prices in the neighboring markets even at the hourly level.

In analyzing this figure we did notice that even though ERCOT's volatility is significantly higher than MISO's (as seen in Table II.3), MISO has the greatest 5th to 95th percentile range of hourly prices. The reason for this phenomenon is that ERCOT has a small number of very large prices that drive its volatility up, but are not included in Figure II.3 because they are in the top 5% of prices, which are not included. To document this point, we note that while SPP and MISO had only 0.6% and 0.5% of their hourly prices above $100, ERCOT had 1.8% of its hourly prices above $100. This shows that ERCOT's volatility is driven by more extreme prices, and that when these prices are excluded MISO actually has a greater range for the majority of hours.

Figure II.3 SPP, MISO & ERCOT Hourly prices for 2009



SOURCE: SPP DSS and MISO website at
http://www.midwestmarket.org/home/Market%20Reports/?type=rt_lmp&list=month
and ERCOT website at http://www.ercot.com/mktinfo/services/bal/index.html

Comparison Across Locations Within SPP

We are also interested in the difference in price across the SPP EIS Market footprint. As with comparisons to MISO and ERCOT, we want to watch for any significant differences in prices across locations, which could be cause for concern. We first look at the level of prices for the load settlement location(s) in each of SPP's balancing authorities. As we did with the SPP-wide prices, we will progress from a broad view of prices to a more narrow view.

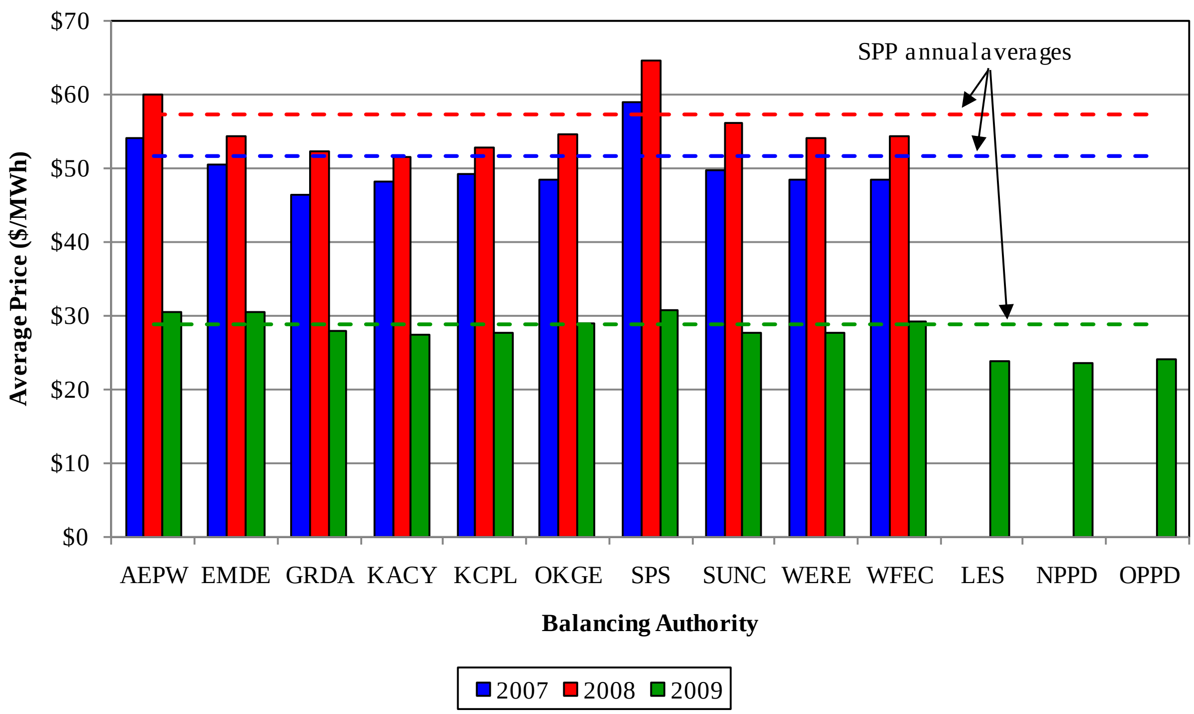
Figure II.4 shows the weighted average of hourly prices for each balancing authority during the period compared to the SPP-weighted average price of $28.69/MWh.[31] SPS has the highest price of all the balancing authorities with an average price of $30.75/MWh, which is (a) 7.2% above the SPP weighted average, (b) $0.21/MWh higher than the next highest price, and (c) more than $7/MWh higher than the lowest price. In 2007 and 2008, we also saw SPS having the highest price and AEPW having the next highest. However, while in 2007 and 2008 SPS and AEPW were the only balancing authorities with prices above the SPP average, this year EMDE, OKGE, and WFEC also have prices above the SPP average. Two factors seem to be driving this change. First, the SPS average price was not as high relative to the other balancing authorities as it has been in the past. Second, the Nebraska entities joined the EIS Market in April 2009, and brought with them a lot of cheap nuclear and coal generation that in turn can lead to low average

[31] We used the simple average for SPP to compare against neighboring regions since we did not have their load data and wanted to make the comparison as valid as possible. However, since we do have the Locational Imbalance Price (LIP) and load data for the balancing authorities we are now using a weighted average. We believe this number is more representative of the average price.

prices. The Nebraska balancing authorities' average prices ranged from $23.51/MWh to $24.00/MWh, while the other balancing authorities had average prices that ranged from a minimum of $27.40/MWh to a maximum of $30.75/MWh. Thus, these lower prices could bring the SPP average price down resulting in additional balancing authorities having average prices higher than the SPP-wide average.

Note that two additional balancing authorities, MPS and INDN, joined the EIS Market in September and December, respectively, but are not shown in this figure. We chose not to display these two balancing authorities in this figure or any of the other tables or figures that breaks out market statistics by balancing authority. The reason for doing this is that these two balancing authorities only had price data for the last few months of the year when prices were higher. This results in average annual prices for these two balancing authorities appearing to be higher than the other balancing authorities when in reality they are not. However, while we did not show MPS and INDN prices individually in these table and figures, we did include their prices in the calculation of the SPP-wide prices that are reported.

Figure II.4 Average Annual Price by Balancing Authority



SOURCE: SPP DSS

We now turn to a comparison of price volatility across locations within SPP. Table II.5 below displays the volatility of hourly prices, as measured by the coefficient of variation, for each balancing authority. The volatilities (on the top line of Table II.5) range from a low of 59% in GRDA to a high of 96% in LES. The three new Nebraska balancing authorities actually have the three highest volatilities, which is surprising given they have the lowest average prices. In 2008, SPS had the highest volatility (104%), and it also had the highest average price. Another notable point is that the exclusion of the top 1% of each balancing authority's prices (as seen on the bottom line of Table II.5) reduces the volatility significantly for all of the balancing authorities except for the Nebraska balancing authorities. The Nebraska balancing authorities' volatility without the top 1% ranged from 82% to 86%, while the other balancing authorities volatilities ranged from 39% to 55%. The Nebraska price volatility is principally due to congestion issues around transfers from Nebraska to the South and issues in MISO and PJM related to Chicago and wind generation.

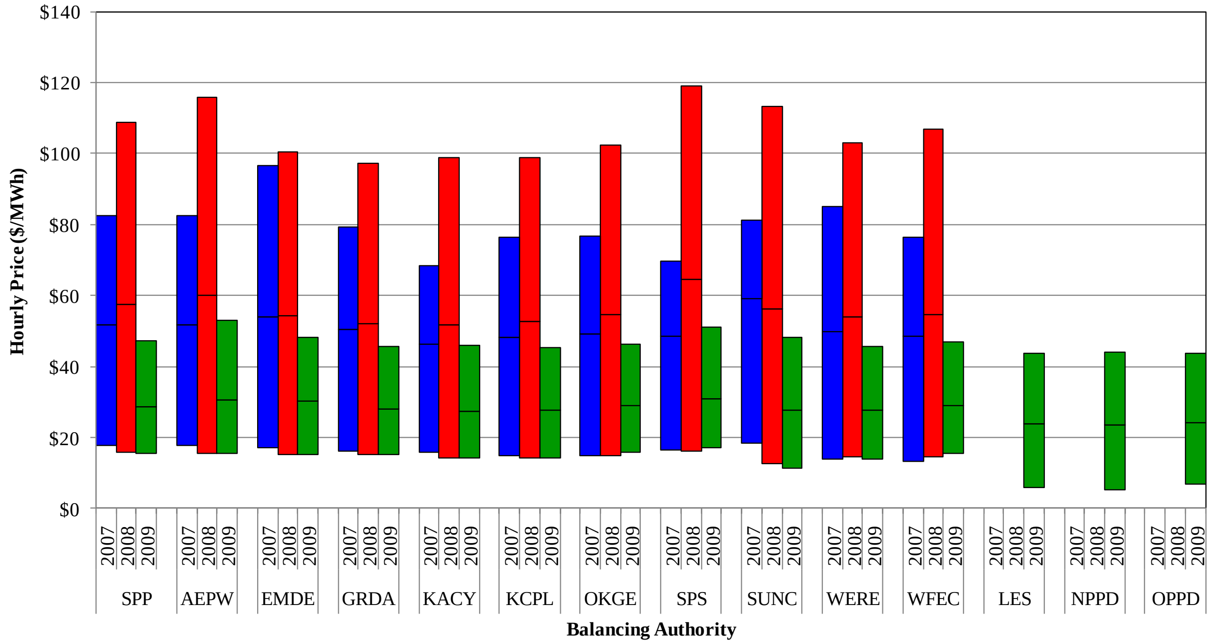
Table II.5 Volatility by Balancing Authority for 2009

Balancing Authority	LES	OPPD	NPPD	EMDE	SUNC	SPS	AEPW	KACY	KCPL	WFEC	WERE	OKGE	GRDA	SPP
Volatility	96%	93%	93%	81%	79%	75%	72%	63%	63%	62%	62%	61%	59%	55%
Volatility Without Top 1%	86%	83%	82%	47%	55%	43%	46%	42%	42%	40%	42%	39%	39%	39%

SOURCE: SPP DSS

Figure II.5 displays the *hourly price* distribution for each balancing authority. Once again, we do this by showing the hourly prices from the 5th to the 95th percentile (the line in the middle of each bar represents the load weighted average price). The middle 90% of prices illustrates significant overlap in hourly prices across SPP's balancing authorities with the exception being the Nebraska balancing authorities. The Nebraska balancing authorities have a 5th percentile in the $5/MWh to $6/MWh range, while the other balancing authorities' 5th percentile values range from $11.27/MWh to $17.21/MWh. In comparing 2009 to previous years, we see that prices in 2009 for each of the balancing authorities have a much tighter range. The lower end of the range is relatively consistent with previous years, while the higher end drops dramatically. The 2009 95th percentiles fall not only below the 2008 95th percentiles, but also below the 2008 averages. This once again illustrates the significant decline in prices in 2009.

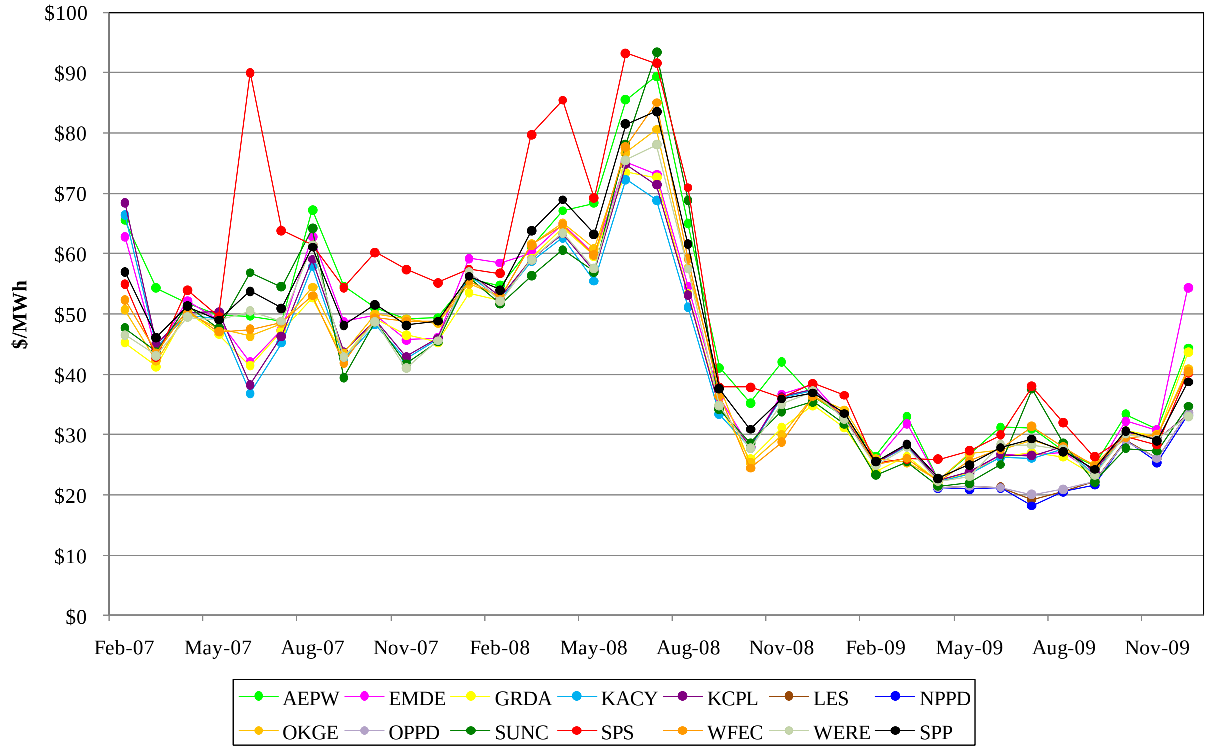
Figure II.5 Annual Price Range by Balancing Authority



SOURCE: SPP DSS

Figure II.6 shows that from month to month the balancing authorities' average prices, in general, stay relatively close to each other. For example, the price range was about $3/MWh in February, and less than $10/MWh in seven other months in 2009. December had the largest range with over $21/MWh separating the highest balancing authority average price from the lowest. Every balancing authority, except SUNC, reached a maximum 2009 average price in December. All balancing authorities except the Nebraska entities and SPS reached average lows in April.

Figure II.6 Average Monthly Price by Balancing Authority



SOURCE: SPP DSS

The most granular view of prices across SPP's EIS Market footprint is at the dispatch interval level. Prices are calculated for each five minute interval at various locations across the SPP EIS Market footprint, and are termed Locational Imbalance Prices (LIPs). Because these are the most granular price data, it is important to see how prevalent price extremes are in SPP. With this in mind, we took all of SPP's LIPs (for load settlement locations) for the year, and separated them into four categories: (i) less than $0/MWh, (ii) between $0/MWh and $100/MWh, (iii) between $100/MWh and $400/MWh, and (iv) above $400/MWh.

Table II.6 shows the percentage of these prices that fall into each category. (The $400/MWh price reflects the FERC's bid cap for the first three months of EIS Market operations in early 2007. While the FERC cap has since been increased to $1,000/MWh, we felt that $400/MWh was still a good break point.) We see that the vast majority (98.1%) of the prices were in the range of $0/MWh to $100/MWh, 1.0% were below $0/MWh, and less than 1% were above $100/MWh. These percentages for 2009 are closer to the those seen in 2007, when 97.1% of prices fell between $0/MWh and $100/MWh, than in 2008, when only 92.7% were in that range. The low 2008 number was due to high prices seen in June and July where we saw over 25% of interval prices exceeded $100/MWh. This increase was in part due to the increase in natural gas prices in the summer of 2008 when average daily natural gas prices for June were about $10.50/MMBtu and about $9.50/MMBtu in July. With significantly lower natural gas prices in 2009, interval prices rarely exceeded $100/MWh.

Table II.6 Flagged Interval Prices Beyond Thresholds for 2009

Month	Percent of Observations Less Than $0	Percent of Observations Between $0 and $100	Percent of Observations Between $100 and $400	Percent of Observations Great Than $400
January	0.2%	98.4%	1.3%	0.1%
February	0.4%	99.2%	0.3%	0.1%
March	0.4%	98.3%	1.1%	0.2%
April	0.6%	99.0%	0.3%	0.1%
May	1.7%	97.4%	0.8%	0.1%
June	1.3%	97.9%	0.7%	0.1%
July	1.6%	97.5%	0.9%	0.1%
August	1.5%	97.9%	0.6%	0.0%
September	1.1%	98.4%	0.5%	0.1%
October	1.0%	98.1%	0.6%	0.3%
November	0.8%	98.5%	0.4%	0.2%
December	0.9%	97.6%	1.3%	0.2%
Total	1.0%	98.1%	0.7%	0.1%

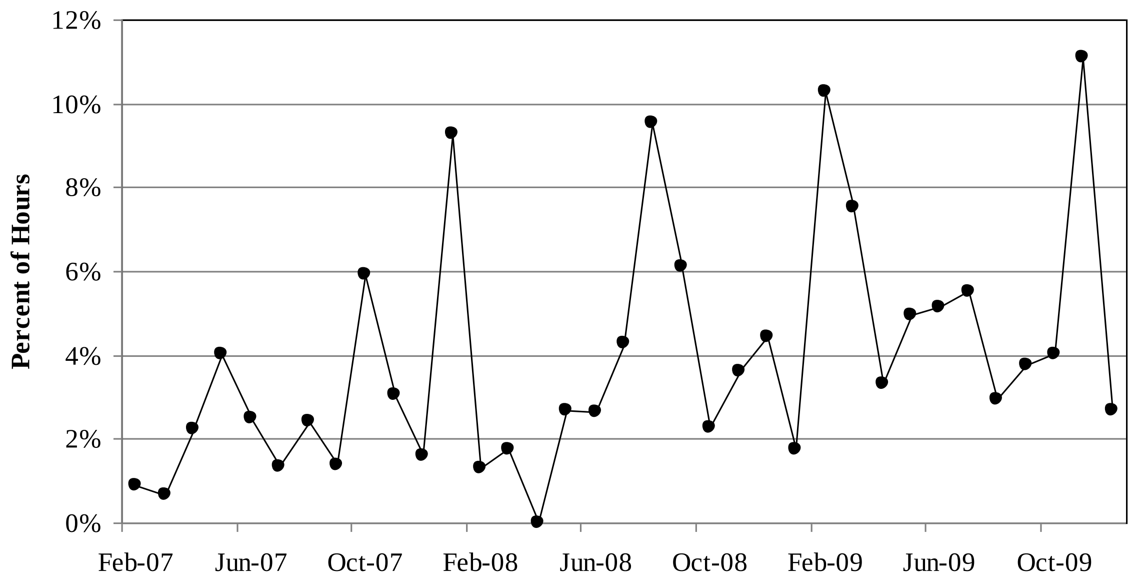
SOURCE: SPP DSS
Note: This table only includes prices at load settlement locations.

LIP Re-pricing

The SPP Market Protocols allows for re-pricing of LIPs if it is determined that there were market software or data input errors.[32] This determination must occur within five days of the effected date. Figure II.7, below, shows how often re-pricing has occurred from 2007 to 2009. That is, it shows the percentage of hours in each month that were re-priced. We can see that re-pricing occurred in a little over 5% of the hours in 2009; this is up from 4% of the hours in 2008 and 2.4% of the hours in 2007. In order to put this in perspective, we wanted to see to what extent these re-priced hours actually affected average market prices. We calculate that taking account of re-pricing caused the SPP average price to go up $0.07/MWh in 2009. Thus, while, there may be some hours in which re-pricing changed market prices (either by increasing or decreasing them) by $10/MWh or even $100/MWh in a few rare cases, the impact on an annual basis seems to be quite small.

[32] *See* Southwest Power Pool, Inc, Market Protocols, Revision 14.0 at Section 11.6.3.

Figure II.7 Percent of Repriced Hours by Month



D. Revenue Adequacy (Net Revenue Calculation)

Akin in some ways to the logic of the SPP Offer Cap, other RTOs and ISOs, in their *State of the Market Reports*, estimate whether market prices over the past year would have been sufficient to cover the annualized cost of building a new power plant and, therefore, indicate whether such an investment would be justified. Not only is investment in a new natural gas-fired peaking combustion turbine plant assessed – the type of plant reflected in the SPP Offer Cap – but investments in natural gas-fired combined cycle plants, new pulverized coal plants, and even new nuclear plants are sometimes included.

This assessment is termed a Net Revenue Calculation because the calculation is meant to determine if market prices – such as hourly EIS Market prices – would be adequate to cover fuel and other variable operating costs and, still, *net of those operating costs*, yield revenue sufficient to cover the annualized fixed investment costs and fixed operating cost of a new power plant. Of course, as with any metric, the Net Revenue Calculation has to be put in perspective. First, it reflects only one year – an investor would have to have evidence that he or she could cover the full annualized cost of a new plant over many years before he or she would move forward with an investment. Second, whether Net Revenue *should be expected* to justify a new investment will depend on market balance – we would expect it to be less than sufficient when there is excess power plant capacity and more than sufficient when there is a shortage. Third, fuel prices can provide an economic justification even if there is surplus capacity – for example, high natural gas prices might mean Net Revenue is sufficient to justify new wind, coal, and nuclear capacity. Fourth, the cost of building and financing a new power plant is site specific.

With this perspective in mind, a Net Revenue Calculation was completed for SPP's *2009 State of the Market Report*. In this section we describe the inputs to and the results of the Net Revenue Calculation for two technologies: a natural gas-fired combined cycle power plant and a combustion turbine peaking plant. The bottom line result is that the revenues in the EIS Market in 2009 were not adequate to cover the first-year annualized cost of either a combined cycle plant or a combustion turbine.

The key cost assumptions for the two technologies are summarized in Table II.7. We used the same assumptions in Table II.7 as Boston Pacific did last year. We do not believe there have been significant changes in the cost of these plants, and that modest changes would not make a difference in our conclusions.

Table II.7 Cost Assumptions Used for Net Revenue Calculations in 2009 Dollars

Cost Item	Combined Cycle	Combustion Turbine	Units
Installed Capital Cost[a]	$1,100.00	$950.00	$/kW
Annualized Capital Cost[b]	$127.63	$110.17	$/kW-yr
Heat Rate[c]	7.1	9.3	MMBtu/MWh
Variable O&M Cost[d]	$1.50	$4.00	$/MWh
Fixed O&M Cost[d]	$36.00	$30.00	$/kW-yr

a) Boston Pacific created assumptions for the cost of a combined cycle and combustion turbine for Testimony submitted to the Minnesota Public Utilities Commission in October 2008. Given our thorough review of the costs, we use those estimates here. We also wanted to note that the technology used for the combustion turbine (CT) was a GE LMS 100. This is a more expensive technology to build, but it operates more efficiently than a conventional CT, in addition, many times this is the technology Boston Pacific has seen being built in recent years.

b) This is the first-year capacity price; the capacity price would increase with inflation thereafter. The following assumptions about project finance were made: (1) 50%/50% debt/equity shares; (2) debt with 15 year term and 7.5% interest rate; (3) A 1.5 minimum debt service coverage ratio; (4) a 12.5% return on project equity; and (5) 35% federal tax rate and 3% state tax rate.

c) The heat rates were based on Boston Pacific's industry experience and they are also very similar to numbers from the Public Service Company of New Mexico's September 2008 Electric Integrated Resource Plan for the Period 2008-2027.

d) The variable and fixed Operation and Maintenance (O&M) cost were created based on Boston Pacific's judgment after review of wide ranging IRP estimates.

The methodology for the Net Revenue Calculation has three steps.

- First, the variable cost of electricity generated by the technology is estimated for each day. The variable cost is the sum of the energy cost and the variable O&M cost per MWh. The energy cost is the heat rate – the number of MMBtu of natural gas fuel needed to generate one MWh – times the daily natural gas price in dollars per MMBtu (as reported for the Panhandle).[33]

- Second, variable cost for each day is compared to each of the hourly prices for that day in the SPP EIS Market.[34] If the variable cost is lower than the hourly SPP EIS Market price, that power plant is assumed to be run (dispatched). The hours in which the power plant is found to be dispatched are the hours in which the power plant earns revenue.

- Third, the total revenue earned is calculated and the variable costs are netted out. If the remaining revenue is larger than the annualized capital cost plus the fixed O&M costs, then the revenue is said to be adequate to cover the first-year cost of a new plant.

As already noted, net revenues in 2009 were not adequate to cover the fixed costs of either a combined cycle or a combustion turbine power plant. As seen in Table II.8, the combined cycle plant would have been run (dispatched) in about 55% of all hours, and net revenue would have covered about 29% of the first-year fixed costs. The combustion turbine power plant would have run about 17% of all hours, and net revenue would have covered about 13% of the first-year fixed costs. "Net Revenue as % of AFC" has dropped by about half from 2008 in large part because of the lower electricity prices making the margins tighter when the plants were run. So, while a combined cycle would still have run around 55% it no longer covered 60% of the fixed cost as it did in 2008, but rather less than 30%.

Table II.8 Summary of 2009 Net Revenue Calculations

Calculation Category	Combined Cycle	Combustion Turbine
Annual Fixed Cost (AFC)	$163.63/kW-yr	$140.17/kW-yr
Net Revenue as % of AFC	29%	13%
% of Time Dispatched	55%	17%

In addition to testing revenue adequacy using SPP-wide hourly prices, we also wanted test whether prices in certain areas of SPP might be high enough to justify investment. To test this possibility, Tables II.9 and II.10 provide a Net Revenue calculation for two of the balancing authorities with the highest prices according to Figure II.4 as those balancing authorities are most likely to show the need for new plants. Looking at the results below, we conclude that the net revenue, even in these areas, was not adequate to cover the fixed costs of either a combined cycle or a combustion turbine power plant. Last year, for a combined cycle, SPS's "Net Revenue as % of AFC" was 93%, while this year it fell to 38%. This decline can be attributed at least in part to (a) lower electricity prices and (b) the fact that a new combined cycle came online in SPS in the latter half of 2008.

[33] Prices used were the average price of all trades during the previous day, i.e., the price used for the fuel costs for the entire day of June 2nd was the average trade price on June 1st. Weekend natural gas prices used the average trade price from the previous Friday. Data is available at www.theice.com.

[34] Prices used were the weighted averages estimated across all load areas.

Table II.9 Summary of Combined Cycle Net Revenue Calculations for Selected Balancing Authorities

Calculation Category	SPP-Wide	AEPW	SPS
Net Revenue as % of AFC	29%	36%	38%
% of Time Dispatched	55%	56%	64%

Table II.10 Summary of Combustion Turbine Net Revenue Calculations for Selected Balancing Authorities

Calculation Category	SPP-Wide	AEPW	SPS
Net Revenue as % of AFC	13%	20%	20%
% of Time Dispatched	17%	18%	21%

In summary, we did not find EIS Market prices to be sufficient to justify new investment in either of these natural gas fueled power plants. This is not surprising given the high resource margin calculated for the past year. This raises the question as to why generation is still being built in SPP. First, as indicated by the interconnection queue, much of the planned new generation is wind. The justification for wind comes from government mandates for renewables and significant tax incentives, not just EIS prices. Second, even for conventional technologies, justification does not rely solely on EIS prices. For example, reliability may require the addition of new capacity in a specific location. In this context, we note that the Revenue Adequacy calculations therein are for SPP in total, or specific balancing authorities, not local pockets of need.

E. Fuel Type

In this section, we assess fuel type from two perspectives. The first is to simply ask what fuels were used to generate all the electricity in the EIS Market footprint.[35] The second perspective is to ask which fuels are *at the margin* and, thereby, which fuels determined Locational Imbalance Prices (LIPs) in the EIS Market.[36] At the outset, we should say that the data are not easy to come by and the estimates rely on several data sources that must be mapped onto one another. However, we believe the estimates here are reasonable.

As expected, we found in Table II.11 that coal-fired resources generated the most electricity in the EIS Market footprint. Specifically, coal accounted for 64.0% of the electricity generation and natural gas accounted for 23.3%. Nuclear accounted for 7.6% of the generation. It is important to note that wind and hydro accounted for 4.2% and 0.9%, respectively. Combined, this is over 5%, and it might be viewed as the renewable energy's share of supply.

[35] For the calculation of generation by fuel type we included output from all resource designations (available, self-dispatch, manual, supplemental, and unavailable).
[36] For the purposes of this report, a marginal resource was defined as a resource that was available to the market, had an offer price within $0.20/MWh of its administered price, and had positive ramp available.

In comparing generation by fuel type to 2008, the most notable change was that nuclear generation increased by almost 3 percentage points. This is due to the Nebraska entities joining the EIS Market in April 2009, and bringing with them significant nuclear generation. From April to December, the three Nebraska entities had about 26.2% of their generation coming from nuclear resources, while the rest of SPP had only 4.6%. Wind production also increased from 3.4% of generation in 2008 to 4.2% in 2009. We would expect wind generation to continue to increase as mandates and incentives from Congress and individual states encourage the development of additional renewable generation. Furthermore, there is a tremendous amount of wind in SPP's generation interconnection queue, and if even part of this gets built, it could dramatically increase wind generation in SPP.

Table II.11 Generation by Fuel Type for 2009

Fuel Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	2008 Total	2007 Total
Coal	69%	64%	57%	62%	63%	59%	60%	60%	64%	71%	73%	67%	64.0%	65.5%	64.0%
Natural Gas	21%	23%	30%	20%	21%	27%	28%	28%	23%	19%	17%	20%	23.3%	25.4%	26.0%
Nuclear	6%	6%	7%	11%	11%	9%	9%	8%	9%	4%	3%	8%	7.6%	4.7%	5.8%
Wind	4%	5%	6%	5%	4%	3%	3%	3%	3%	5%	5%	4%	4.2%	3.4%	2.6%
Hydro	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0.9%	0.8%	0.9%
Other	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0.1%	0.2%	0.8%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100.0%	100.0%	100.0%

SOURCE: SPP DSS

Table II.12 displays which fuels are at the margin in SPP, and thus setting market prices. LIPs in the EIS Market are calculated as the price to meet the *next* MW needed at any location. Under EIS Market Protocols, in order to influence LIPs a resource must meet the following criteria: (a) it must be made available for SPP dispatch, (b) the resource must be deployed by SPP, and (c) the resource is not limited in its ability to follow SPP dispatch (i.e. the resource is not at its maximum or minimum nor does it have ramp rate limitations).[37]

As expected, we see that coal and natural gas flip their respective positions when we look at fuels at the margin. That is, as seen in Table II.12, natural gas is at the margin about 61.0% of the time and coal is at the margin for about 39.0% of the time. Comparing these results to those from 2007 and 2008, we see that natural gas is at the margin less in 2009. Natural gas was the marginal fuel 82.0% and 70.1% of the time in 2007 and 2008, respectively. This drop in natural gas at the margin from 2007 to 2008 was partly due to a change in method used in the calculation, and partly due to changes in market conditions. The further drop in natural gas at the margin from 2008 to 2009 appears to be partly due to the addition of the Nebraska entities. The reason the Nebraska entities have caused somewhat of a shift to coal on the margin is because they have additional nuclear generation; this displaces some natural gas generation causing coal to be at the margin more often. In addition, lower demand across the footprint could result in more coal at the margin as SPP dispatch does not have to go as high up the supply curve to meet demand.

[37] Due to limitations of the data, we were not able to use the exact same criteria for determining which resources were at the margin. Instead, for this report, a resource was determined to be *at the margin* if (a) it was made available to the market, (b) its offer price was within $0.20/MWh of its relevant LIP, and (c) it had positive ramp available. While this is not exact, we believe this provides a reasonable proxy for resources at the margin.

Table II.12 Generation at the Margin for 2009

Fuel Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	2008 Total	2007 Total
Natural Gas	63.8%	62.6%	67.0%	54.6%	51.8%	57.4%	64.0%	68.1%	55.6%	59.4%	60.1%	67.1%	61.0%	70.1%	82.0%
Coal	36.2%	37.2%	33.0%	45.3%	48.2%	42.3%	36.0%	31.8%	44.3%	40.6%	39.9%	32.8%	39.0%	29.8%	16.5%
Other	0.0%	0.1%	0.0%	0.0%	0.0%	0.2%	0.0%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	1.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

SOURCE: SPP DSS

F. Market Participation

As already noted, while all imbalances must be settled in the EIS Market, full participation in the SPP EIS Market is voluntary. Market Participants can decide whether to self-dispatch their units or make them available for SPP dispatch in the EIS Market. We take a look at participation in three different ways: (a) the percentage of capacity made available to the market, (b) the dispatchable range of available units, and (c) the ramp rates of available units. Starting in the latter part of 2009, a significant change in the way nuclear resources were offered into the EIS market affected these three metrics. Before the change, nuclear resources were submitted in self-dispatched status; self-dispatched resources are dispatched to the sum of their schedules. However, during times of congestion these schedules were subject to being curtailed. Being self-dispatched, the nuclear resources were instructed to ramp down to meet their new schedules. However, nuclear units were not able to follow these instructions, which caused the EIS Market to respond inappropriately. Since the change, nuclear resources are now submitted in available status, but with very limited dispatchable ranges and very low ramp rates. Although technically considered as “available” resources, they are truly unavailable to be dispatched to any significant degree. To eliminate the adverse impacts of this new use of “available” status, and to make the 2009 numbers comparable to those in 2007 and 2008, we are treating nuclear resources as “self-dispatched” resources for the purposes of these metrics.

As part of their resource plans, Market Participants designate their units as self-dispatched or available for EIS Market dispatch.[38] For self-dispatched resources, SPP assumes those units will be at their scheduled level. For available resources, SPP determines the desired level of operation through security constrained economic dispatch. The first check for the level of participation in the EIS Market is what percentage of capacity is being made available to SPP for economic dispatch. To calculate this we divide the available capacity by the sum of available and self-dispatched capacity. In 2007, participation started out at 77% and gradually increased to 85% by December. Participation continued to increase during 2008, and has maintained roughly an 88% average over 2008 and 2009. The initial upward trend shows that Market Participants became more comfortable with the market and, as a result, made a higher percentage of their capacity available. Participation at 88% is a very robust level.[39] This can be seen in Table II.13.

[38] Note that a resource can also be designated manual, supplemental, or unavailable. For the purposes of this section, we focus on just those resources that are available or self-dispatched.

[39] If resources designated as manual were included in this calculation, the percentage of capacity made available to the market for the year would be approximately 77%, which is in line with last year when it was 78%. According to the Market Protocols, manual resources are those that cannot follow dispatch instructions or adhere to a schedule. This can be as a result of a unit (a) being an intermittent resource or (b) undergoing a resource test or being in startup or shutdown mode.

Table II.13 Percent of Total Capacity Made Available to the EIS Market by Month

Month	% SPP-Wide Availability in 2007	% SPP-Wide Availability in 2008	% SPP-Wide Availability in 2009
January	NA	87%	89%
February	77%	86%	88%
March	78%	87%	89%
April	80%	92%	84%
May	79%	90%	84%
June	81%	89%	87%
July	82%	89%	86%
August	81%	88%	85%
September	82%	87%	84%
October	84%	88%	91%
November	85%	88%	93%
December	85%	88%	90%
Average*	81%	88%	88%

* Average is weighted by the number of days in each month

SOURCE: SPP DSS

There are two ways a resource can limit its participation in the market, even when it has been made available to the market. First, a resource can limit its dispatchable range; that is, the portion of the capacity that can be moved up and down as customer need varies. Most power plants have a minimum level of operation that must be maintained (akin to a car sitting at idle) and some have a maximum that falls short of the full capacity of the resource (perhaps to reserve capacity to meet ancillary service needs).

For example, say a 100 MW resource is made available to the market with a minimum of 30 MW and a maximum of 80 MW (to leave 20 MW for ancillary service reserves). In this example, the Market Participant has made 50 MW or 50% of the capacity available to the EIS Market. As seen in Table II.14, the dispatchable range for 2009 was 44%, last year it was slightly higher at 46%. We have some concerns over the fact that this metric appears to be trending downwards over the latter part of 2008 and into 2009. As a result, we also regularly monitor dispatchable range at the market participant level.

Table II.14 Dispatchable Range of Capacity Made Available to the EIS Market by Month

Month	Percent of Capacity Dispatchable in 2007	Percent of Capacity Dispatchable in 2008	Percent of Capacity Dispatchable in 2009
January	NA	46%	45%
February	50%	47%	44%
March	47%	48%	46%
April	47%	47%	43%
May	46%	46%	44%
June	47%	49%	45%
July	48%	50%	45%
August	49%	48%	46%
September	46%	46%	43%
October	46%	43%	41%
November	46%	44%	41%
December	47%	45%	42%
Average*	47%	46%	44%

* Average is weighted by the number of days in each month

SOURCE: SPP DSS

Note: In the SPP MMU's Monthly Reports, the available capacity is adjusted for Ancillary Services. In the table above we used the full capacity for the calculation.

Providing a low ramp rate is a second way a participant could limit the level of participation of one of its available units. The ramp rate dictates how fast a power plant can be moved from one level of operation to the next. Ramp rates are provided as part of a Market Participant's resource plan, and are provided in MW per minute. At the broadest level, we are concerned whether enough ramp is available to meet changes in need across the SPP system. One way to determine this is to look at the number of market ramp rate violations each month. A market ramp rate violation can occur when there is not enough ramp provided by available resources in total to rebalance generation and load.

As seen in Table II.15, there were market ramp rate violations in only 0.41% of the intervals. The month with the lowest percentage of ramp rate violations was July (0.03%) and the month with the highest percentage of violations was May (1.00%). May was the only month in which there was a market ramp violation in at least 1% of the intervals. In 2007 and 2008, the average for the year was higher at 0.96% and 0.69% of intervals, respectively. Therefore, although this did not seem to be a major problem in 2007 or 2008, there seems to be continued improvements in 2009. In this sense the ramp rates being provided appear adequate.

Table II.15 Market Ramp Rate Violations

Month	% of Intervals with Market Ramp Rate Violations in 2007	% of Intervals with Market Ramp Rate Violations in 2008	% of Intervals with Market Ramp Rate Violations in 2009
January	NA	1.24%	0.63%
February	1.30%	0.81%	0.29%
March	1.10%	0.95%	0.36%
April	0.94%	0.53%	0.44%
May	0.90%	0.86%	1.00%
June	0.82%	0.72%	0.49%
July	0.71%	0.26%	0.03%
August	0.44%	0.31%	0.13%
September	0.66%	0.59%	0.19%
October	1.24%	0.77%	0.41%
November	1.50%	0.66%	0.55%
December	1.01%	0.60%	0.39%
Average*	0.96%	0.69%	0.41%

* Average is weighted by the number of days in each month

SOURCE: SPP MMU December 2009 Monthly State of the Market Report

However, in Table II.16, we see that the average ramp rate provided by available resources is approximately 2.8 MW/minute.[40] This level seems low, and is a concern of the MMU. Last year Boston Pacific noted that the implementation of Protocol Revision Request (PRR) 113 in late October 2008 could result in an increase in available ramp going forward. As background, before this PRR was implemented, a single ramp rate for a unit was used for all generation levels whether ramping up or down. PRR 113 allows a participant to break up its dispatchable range into as many as 10 segments and to provide a different up and down ramp rate for each segment. This provides participants more flexibility with the units they offer into the market. While offered ramp seemed to increase during the latter part of 2008 and into early 2009 after PRR 113 was implemented, this trend was not maintained, and the average for 2009 was 2.8 MW/minute, the same as it was in 2008.

[40] Average ramp rate offered is calculated for available resources using the lesser of a resource's ramp rate across a five-minute dispatch interval and its dispatchable range.

Table II.16 Average Ramp Rate of Capacity Made Available to the EIS Market by Month

Month	Average Ramp Rate Offered in 2007 (MW/min)	Average Ramp Rate Offered in 2008 (MW/min)	Average Ramp Rate Offered in 2009 (MW/min)
January	NA	2.7	3.2
February	2.3	2.6	3.1
March	2.4	2.6	3.1
April	2.7	2.7	2.7
May	2.6	2.5	2.7
June	2.7	2.6	2.9
July	2.6	2.6	2.9
August	2.6	2.7	2.8
September	2.4	2.8	2.6
October	2.2	2.9	2.8
November	2.2	3.0	2.7
December	2.5	3.4	2.6
Average*	2.5	2.8	2.8

* Average is weighted by the number of days in each month

SOURCE: SPP MMU December 2009 Monthly State of the Market Report

G. Market Power Measurement and Mitigation

Locational Imbalance Prices in SPP are calculated using, among other things, Market Participant offer curves. Because these offers are a major driver of prices, there is a potential concern with market power through submission of higher than appropriate offer prices. The FERC refers to this as Economic Withholding. To mitigate this, SPP has in place two different FERC-approved offer caps. These caps do not put a cap on prices, but rather, limit how high of an offer a Market Participant can submit.

The offer cap that we term the "FERC Cap" is a hard offer cap. What we mean by this is it (a) is set at a constant level, (b) applies to all resources, and (c) applies at all times. The FERC Cap is considered to be a "safety net" against extreme cases of economic withholding. For the first three months of the EIS Market, the FERC Cap was set at $400/MWh. Since May 2007, the FERC Cap has been increased to $1,000/MWh. The cap was set at a tighter level for the first three months of market operation because of the uncertainty surrounding the start of the market.

SPP's other offer cap is termed the "SPP Cap." Unlike the FERC Cap, the level of this cap (a) is resource specific and (b) varies depending upon market conditions. The SPP Cap is designed to balance mitigation and reliability; that is, it limits price spikes resulting from market power, but, at the same time, is set at a level high enough not to discourage new investment.

The following three characteristics of the SPP Cap illustrate how this is accomplished. First, the SPP Cap is levied only during times of transmission congestion, because absent congestion the SPP Market is structurally competitive. Second, it is only imposed on those resources that have the potential to wield market power; that is, it applies only to resources with a Generator to Load Distribution Factor (GLDF) of negative 5% or larger (more negative) and on other resources with negative GLDFs owned by that same company. Third, the SPP Cap is set at a level that will not discourage new investment. The SPP Cap reflects the total annual fixed and variable costs of a new peaking power plant with the fixed costs spread over the hours of congestion. Therefore, the more hours of congestion the tighter the cap becomes.

We assessed how much of an effect the offer caps are having on prices in the EIS Market. In other words, we asked whether these offer caps are, in effect, holding prices down much like a lid on a pot of boiling water. One indication of a significant effect would be if price offers that were being accepted (dispatched) are at or near the offer caps. Table II.17 shows that, in this sense, the effect of these caps has been negligible. The column entitled “Percent of Available Resource Intervals Dispatched with Offer Near FERC Cap” illustrates that offers were accepted near (within 5%) the FERC Cap in only 0.0035% of all opportunities (all “available resource intervals”). The table also shows that the effect of the SPP Cap has been negligible. The SPP Cap was imposed in 26.53% of available resource intervals; however, offers were accepted near that cap in only 0.0599% of available resource intervals. These numbers are generally in line with those from last year. The only notable difference was that the “Percent of Available Resource Intervals with SPP Cap Imposed and Dispatched Near SPP Cap” declined from 0.3514% in 2008 to 0.0599% in 2009. Again, however, in both years the effect seems to be negligible.

Table II.17 Effect of FERC and SPP Offer Caps in 2009

Month	Percent of Available Resource Intervals Dispatched with Offer Near FERC Cap	Percent of Available Resource Intervals with SPP Cap Imposed	Percent of Available Resource Intervals with SPP Cap Imposed and Dispatched Near SPP Cap
Jan	0.0003%	8.99%	0.0000%
Feb	0.0000%	12.95%	0.0000%
Mar	0.0000%	14.75%	0.1732%
Apr	0.0000%	10.83%	0.0128%
May	0.0070%	17.52%	0.1177%
Jun	0.0061%	27.69%	0.0826%
Jul	0.0034%	39.50%	0.1561%
Aug	0.0110%	32.29%	0.0402%
Sep	0.0021%	30.98%	0.0593%
Oct	0.0023%	32.37%	0.0035%
Nov	0.0006%	36.34%	0.0004%
Dec	0.0036%	34.36%	0.0397%
Total	0.0035%	26.53%	0.0599%

SOURCE: SPP DSS

We also assessed the competitiveness of the EIS Market using traditional structural measures. For example, we calculated the market shares in the EIS Market. A standard for judging market share comes from a FERC standard for granting the right for a supplier to sell at market-based prices (as opposed to regulated cost-based rates). In one of two FERC threshold tests for granting the right to sell at market-based prices, the FERC asks that the supplier have no more than a 20% share of the market. If the market share is 20% or less, it is presumed the supplier cannot exercise market power. If the market share exceeds 20%, the supplier can conduct an additional test or point to mitigation for market power, such as the mitigation measures and monitoring of SPP's MMU; that is, the 20% is not a hard and fast limit to market-based rate authority. We view market shares in two ways: (a) market shares of EIS Market sales and (b) market shares of capacity made available to the market. By looking at market shares of EIS Market sales we are able to see if any participants have a large share of what is actually sold in the market. Alternatively, we look at market shares of capacity made available to see whether any participants have a large portion of the capacity made available for SPP dispatch.

Table II.18 shows, by anonymous Market Participant, market shares of EIS Market sales for 2009. No Market Participant had a market share greater than 20% for the year. The highest market share for 2009 for any one Market Participant was 14.8%. Last year, the highest market share for the year in total was about the same at 14.7%. Overall, this table indicates by this metric that the EIS Market is competitive.

Table II.18 Shares of EIS Market Sales for Market Participants (Anonymously Ranked) 2009

Market Participant	Total
1	14.8%
2	11.4%
3	11.1%
4	10.8%
5	10.2%
6	7.8%
7	6.7%
8	4.0%
9	3.5%
10	2.3%
11	1.9%
12	1.8%
13	1.7%
14	1.7%
15	1.6%
16	1.3%
17	1.2%
18	0.9%

Market Participant	Total
19	0.9%
20	0.8%
21	0.7%
22	0.6%
23	0.5%
24	0.4%
25	0.4%
26	0.3%
27	0.2%
28	0.2%
29	0.1%
30	0.1%
31	0.0%
32	0.0%
33	0.0%
34	0.0%
35	0.0%

SOURCE: SPP DSS

An alternative way to look at market shares is to look at percentage shares of capacity made available to the market. The next table shows the shares of capacity made available by each participant *at the peak hour of each month*. The peak for the year occurred in June. Participant 1 was the only participant with a share consistently above the 20% mark, with shares ranging from 17.1% in December to 26.1% in March.

The Herfindahl-Hirschman Index (HHI) is a measure of competitiveness closely related to market shares. Some background on the HHI standard is useful. The U.S. Department of Justice has a three-part standard for HHIs when judging the competitive effect of mergers and acquisitions. An HHI at or under 1,000 is a 'safe harbor' of sorts because the market is said to be unconcentrated. If, after a merger or acquisition, the HHI is at or below 1,000, it is generally thought that there is no competitive harm from the merger or acquisition; that is, the merger or acquisition does not make the exercise of market power more likely. An HHI between 1,000 and 1,800 is said to indicate moderate concentration. An HHI over 1,800 is said to indicate a highly concentrated market. The FERC uses these same standards when it assesses mergers and acquisitions. However, for market-based rate authority, the FERC uses a threshold of 2,500 for the HHI in one of its standards.

The HHIs, shown at the bottom of Table II.19, ranged from 1,106 in December to 1,604 in March. The peak capacity HHI for the year in total was 1,292, lower than that in 2008 (1,411). All of these HHI statistics fall within the moderately concentrated range, with the peak for year falling at the lower end of this range.[41]

Table II.19 Shares of Capacity Made Available During the Peak Hour of the Month for All Market Participants (Anonymously Ranked) for 2009

Market Participant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Period
1	22.8%	24.3%	26.1%	19.7%	23.5%	23.0%	23.4%	23.9%	20.8%	21.8%	18.4%	17.1%	23.4%
2	19.6%	18.0%	19.8%	19.8%	17.3%	18.3%	17.2%	19.0%	18.2%	14.2%	15.0%	17.9%	17.2%
3	16.6%	16.9%	15.2%	13.0%	13.0%	14.6%	13.3%	13.7%	13.0%	11.9%	13.6%	13.5%	13.3%
4	13.7%	17.2%	15.2%	14.0%	14.9%	11.0%	13.2%	12.0%	13.6%	11.7%	13.8%	12.5%	13.2%
5	6.4%	5.7%	4.7%	7.5%	8.9%	5.8%	5.9%	6.7%	6.0%	9.5%	8.9%	7.2%	5.9%
6	0.0%	0.0%	0.0%	3.6%	2.8%	3.2%	3.2%	3.3%	3.1%	6.6%	6.7%	4.6%	3.2%
7	4.2%	1.2%	2.5%	2.6%	2.0%	3.2%	3.2%	3.3%	3.6%	2.3%	0.0%	1.9%	3.2%
8	0.0%	0.0%	0.0%	6.3%	3.0%	4.6%	3.0%	1.1%	3.0%	6.0%	6.0%	5.8%	3.0%
9	3.8%	4.0%	3.5%	3.3%	2.2%	2.7%	2.7%	3.0%	2.6%	3.4%	1.3%	2.7%	2.7%
10	1.9%	2.2%	2.3%	2.2%	2.3%	2.1%	2.6%	2.5%	2.1%	1.9%	2.3%	1.6%	2.6%
11	3.0%	3.9%	3.7%	2.4%	2.0%	1.5%	2.2%	2.3%	2.6%	1.1%	2.2%	2.8%	2.2%
12	0.8%	0.0%	2.0%	2.1%	1.7%	0.9%	1.8%	2.0%	1.7%	1.9%	1.8%	0.8%	1.8%
13	0.9%	1.1%	1.1%	0.0%	1.0%	1.7%	1.7%	1.3%	0.9%	0.0%	0.0%	0.0%	1.7%
14	2.5%	2.9%	1.2%	1.9%	1.1%	2.1%	1.6%	1.7%	2.0%	0.0%	1.0%	2.0%	1.6%
15	0.0%	0.0%	0.0%	0.0%	1.0%	1.5%	1.6%	0.8%	0.9%	1.0%	1.0%	0.9%	1.6%
16	1.7%	0.0%	0.0%	0.0%	1.8%	1.3%	1.4%	1.5%	1.6%	2.0%	3.7%	3.1%	1.4%
17	0.9%	1.5%	1.4%	0.8%	1.1%	1.2%	1.3%	0.6%	1.2%	1.5%	0.7%	1.4%	1.3%
18	0.0%	0.0%	0.0%	0.4%	0.2%	0.4%	0.4%	0.5%	0.3%	0.4%	0.4%	0.3%	0.4%
19	0.0%	0.0%	0.1%	0.1%	0.0%	0.1%	0.2%	0.3%	0.1%	0.1%	0.1%	0.1%	0.2%
20	1.1%	1.3%	1.2%	0.4%	0.3%	0.8%	0.1%	0.8%	0.2%	1.1%	0.0%	1.0%	0.1%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	1.4%	3.0%	2.9%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
HHI	1,467	1,577	1,604	1,288	1,367	1,299	1,292	1,364	1,221	1,165	1,142	1,106	1,292

SOURCE: SPP DSS

H. Revenue Neutrality Uplift (RNU)

The Tariff requires that SPP remain revenue neutral for every hour of the settlement process. This means that the money received by SPP from Market Participants (receivables) must equal the money paid by SPP to Market Participants (payables). If SPP has paid out more money than it has received it must apply an uplift procedure in order to acquire sufficient funds to remain revenue neutral. Similarly, if SPP collects more money than it pays out in an operating hour it must return additional funds to the Market Participants in order to remain revenue neutral.

[41] By no means do we want this to be interpreted that, if a Market Participant has a large resource base, it is a bad thing to offer resources into the EIS Market. The opposite is more likely to be true. Withholding resources might raise the concern of market power for that large Market Participant.

There are five components to Revenue Neutrality Uplift (RNU), which determine whether SPP over collects (RNU is negative) or under collects (RNU is positive): (i) energy imbalance service (EIS), (ii) self-provided losses (SP loss), (iii) over-scheduling charges (O/S), (iv) under-scheduling charges (U/S), and (v) uninstructed deviation (UD) charges. For the first two components SPP both pays money and collects money. Therefore, in any given hour, this component can be positive (SPP has under collected) or negative (SPP has over collected). The last three components are always payments to SPP by Market Participants and thus are always negative. They are levied against Market Participants when they do not follow explicit guidelines in the Tariff. To understand RNU, we provide a detailed look into how SPP calculates each of these five components.

Energy Imbalance Service Payments

EIS payments are calculated as EIS volume multiplied by the appropriate LIP. EIS volume is calculated each interval for every resource and load settlement location. It represents the difference between the actual or metered MW level and the scheduled MW level. EIS volume can result in a sale or a purchase. A *sale* is made by a Market Participant when either (a) it generates more than it has scheduled and/or (b) its actual load is less than it has scheduled. Similarly, a *purchase* is made by a Market Participant when either (a) it generates less than it has scheduled and/or (b) its actual load is more than it has scheduled.

As mentioned, EIS payments are calculated as EIS volume multiplied by the LIP. The LIP used is the appropriate settlement location LIP. For example, if one resource had a 30 MW purchase and its LIP was $100/MWh, its EIS payment would be $3,000. That is, SPP would collect $3,000 dollars from that participant for its purchase.

Therefore, for a given operating hour, the EIS component is the net of all sales and purchases revenue. If SPP collects less revenue from Market Participant purchases than it paid out for Market Participant sales, then the EIS component of RNU is positive, meaning SPP has a revenue shortfall. If SPP collects more revenue from Market Participants than it paid out, the EIS component of RNU is negative and SPP has a surplus of revenue.

Self-Provided Losses

The SPP Tariff requires that all transmission loss energy must be replaced by Transmission Customers. There are four types of transmission transactions: (i) Into (Source (start) from outside of SPP and Sink (end) inside of SPP), (ii) Within (Source and Sink inside of SPP), (iii) Through (Source and Sink outside of SPP, but flows through SPP), and (iv) Out (Source in SPP and Sink outside of SPP). Losses associated with the first two types of transactions, Into and Within, are priced with the operation and settlement of the EIS Market. The other two types of transactions, Through and Out, are subject to loss charges in the EIS Market. Therefore Through and Out transactions are the only types of transactions that can show up in RNU.

Market Participants have the option of Self-Providing their losses or financially settling their losses related to Through and Out transactions. If they choose to financially settle their losses, the Market Participant is charged the sum of the costs incurred by all Transmission Owners as a result of the transaction. Therefore, there is no need for RNU.

However, if a Market Participant chooses to Self-Provide its losses, there can be the need for RNU. In this case, the Market Participant assigns a Designated Balancing Authority (DBA), which is billed a charge that is equal to the loss MW times its LIP. The Transmission Owners will be compensated for the costs incurred as a result of the transaction based on their own LIP prices and the Transmission Owner Loss Matrix which is posted on the Open Access Same-time Information System (OASIS). Therefore, if these amounts are not equal, RNU is required. If the SPP collects more money from the DBA than it pays out to the Transmission Owners, RNU will be negative. If SPP collects less money from the DBA than it pays to the Transmission Owners, RNU will be positive.

Over and Under Scheduling

During the collaborative design phase of SPP's EIS Market, Market Participants raised the concern that participants would be able to profit from locational price differences by over- or under-scheduling their generation and load. These profits would result in an increased uplift (Revenue Neutrality Uplift) to the market. In order to mitigate these arbitrage opportunities, SPP developed a method for disgorging revenue accumulated from over- and under-scheduling, and the method was subsequently approved by the FERC.

To give a more detailed explanation of the concern and the mitigation measure in place, we first provide a simplified hypothetical example of how a participant could profit by under-scheduling, and then explain how SPP's mitigation tool nullifies the benefits gained by the participant. Assume a Market Participant schedules 30 MWh of generation and 30 MWh of load. However, its actual load and generation end up being 55 MWh – that is, the Market Participant under-scheduled. Assume further that the LIP at the load location is $20/MWh, and the LIP at the generation location is $40/MWh. In this instance, the participant has an imbalance at both generation and load. The participant *will be paid* $40/MWh for the 25 MWh of extra generation it produced over and above its schedule, but it *will pay* only $20/MWh for the additional 25 MWh of load over and above its schedule. Therefore, by under-scheduling, the Market Participant has profited by the number of MWh of imbalance times the difference in LIPs at generation and load [25 MWh of imbalance multiplied by ($40 minus $20)]. This yields $500 of profit for the Market Participant.

To mitigate this under-scheduling, SPP's computer software searches for parties that meet two criteria: (a) a party has actual load in excess of its scheduled load by the greater of 4% or 2 MW and (b) the party has a LIP at the location of its load which is *less than* the LIP at the location of its generation. When these two criteria are met, the settlement software automatically calculates the revenue that must be disgorged.

For over-scheduling, everything is simply reversed. First, the Market Participant schedules more load and generation than is actually needed, and secondly, the LIP at load is *higher than* the LIP at generation. This time the computer software searches for parties that (a) have load scheduled in excess of its actual load by the greater of 4% or 2 MW and (b) have a LIP at the location of its load which is *higher than* the LIP at the location of its generation. When these two criteria are met, the settlement software automatically calculates the revenue that must be disgorged.[42] The money collected by SPP from over- and under-scheduling has a negative RNU sign; that is, it serves to lower the RNU number.

Uninstructed Deviation Charge

Uninstructed Deviation (UD) is the difference between the Dispatch Instruction and the real time operating level of a resource as monitored by SPP. UD charges are equation-based penalties meant to keep resources operating at their dispatched levels.

Each market participant has an expected output level based on dispatch instructions for each 5-minute interval. UD charges are assessed when a resource is operating outside of an acceptable tolerance limit from these instructions. Determining whether a resource is subject to UD charges is a two step process: (i) calculating the tolerance limit (range) for each resource for each operating interval and (ii) calculating UD charges on MW that are above or below this tolerance limit for each operating hour.[43]

Calculating the Tolerance Limit for each Dispatch Interval

The tolerance limit is set at 10% above and below the dispatch instruction with a minimum of 5 MW and a maximum of 25 MW.[44] That is, if the dispatch instruction times 10% is calculated to be less than 5 MW, the tolerance limit is set at 5 MW. Similarly, if the dispatch instruction times 10% is calculated to be greater than 25 MW, the tolerance limit is set at 25 MW. For example if a resource was given a 500 MW dispatch instruction its tolerance limit would be set at 25 MW because 500 MW times 10% is 50 MW, which is greater than the 25 MW ceiling. Therefore, this resource could operate anywhere between 475 MW (500 MW - 25 MW) and 525 MW (500 MW + 25 MW) without incurring any UD charges.

Calculating the UD Charges for each Operating Hour

Once the tolerance limit has been established for a resource, UD charges are levied on each MW that is actually produced above or below this tolerance range or limit. These MW are called UD MW. For example, assume a resource is given a dispatch instruction of 100 MW; therefore, its tolerance limit is calculated to be 10 MW (100 MW * 10%). In other words, the resource can operate at a level between 90 MW and 110 MW without incurring UD charges. Assume further, that the resource actually produced at a level of 140 MW. For that interval, there would be 30 MW [140 MW minus 110 MW] of UD that would be subject to UD charges.

For each operating hour, the Hourly UD MW is calculated as the average of the absolute value of the interval UD MW calculated for each of the 12 dispatch intervals. This number is

---

[42] For a more detailed explanation of how the disgorgement tool works, please see the SPP Market Protocols v 14.0.
[43] Intermittent (i.e., non-dispatchable) resources such as wind generators are exempt from UD charges.
[44] The tolerance level is further adjusted for any Regulation Up and Regulation Down services being maintained on the resource. *See* SPP OATT for Service Offered by Southwest Power Pool at Attachment AE at Sections 4.1 (d) and 5.5.

then input into the UD equation to determine the UD charge for that operating hour. The equation for calculating UD charges has two tiers or steps; one equation for the first 25 MW of deviation and another equation for any remaining MW of deviation beyond 25 MW.[45]

1. Zero to 25 MW of deviation: UD $MW_{0\text{-}25}$ * 10% * $LIP_{Resource}$
2. Deviation MW beyond 25 MW: UD $MW_{>25}$ * 25% * $LIP_{Resource}$

For example, if a resource's hourly UD MW for a given hour was 30 MW and the LIP at the resource was $20/MWh, it would be penalized $75 [(25 MW * 10% * $20/MWh) + (5 MW * 25% * $20/MWh)] for that operating hour.[46] As is the case for over- and under-scheduling, the revenue collected by SPP from UD charges has a negative RNU sign, which means it lowers the RNU number.

RNU Analysis

Figure II.7 shows the impact of each component on RNU. The EIS component represents the vast majority of RNU contribution. The EIS component represents approximately 73% of all RNU contribution (whether positive or negative), 5% less than the past two years. Again, a positive contribution to RNU will result in SPP applying an uplift procedure to collect additional money to remain revenue neutral, and a negative contribution to RNU will result in SPP distributing excess money to Market Participants to remain revenue neutral.

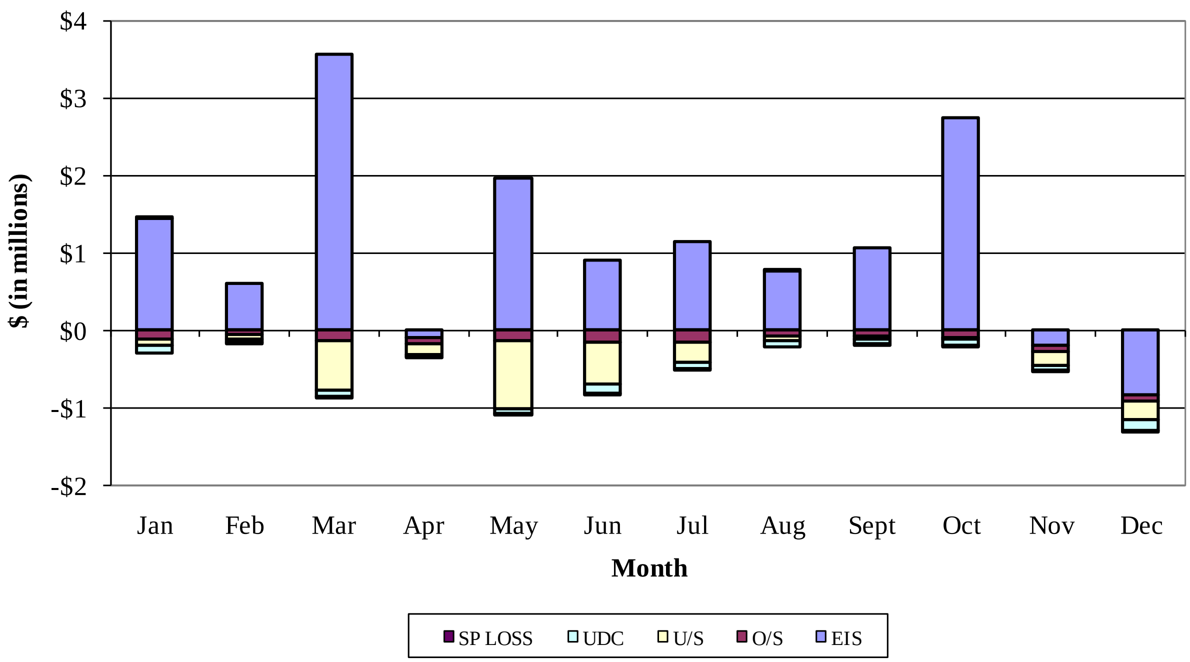
We see in Figure II.8, that EIS and Self-Provided Losses are sometimes positive and sometimes negative. On the other hand, Over- and Under-Scheduling and Uninstructed Deviation are always negative. The highest negative RNU occurred in December mostly due to a high negative EIS component. In this month, there was a total of $0.83 million of over collection of EIS payments. Once charges for the other components were also accounted for, there was $1.32 million of over collection in December.

The highest positive uplift occurred in March due to congestion, which caused price separation. In order to explain how congestion can cause high RNU, we look at the following example. Say there is a constraint moving west to east, and as a result the LIP on the un-constrained (west) side of the flowgate is $10/MWh, the LIP on the constrained side is $200/MWh, and the LIP at the load is $100/MWh. Furthermore, say that the resource on the un-constrained side, Resource A, scheduled 80 MW of generation, but was dispatched down to 50 MW in order to help relieve the constraint. The resource on the constrained side, Resource B, scheduled 10 MW, but was dispatched up to 40 MW to make up for the decrease of the other resource. The load, Load A, was scheduled at 90 MW and used 90 MW. As a result of these movements, Resource A has now purchased 30 MW from the EIS Market (80 MW schedule – 50 MW actual), Resource B has sold 30 MW to the EIS Market (40 MW actual – 10 MW schedule), and Load A has no imbalance (90 MW schedule – 90 MW used). In this instance Resource A will pay SPP $300 ($10 LIP times 30 MW imbalance) for its purchase, Resource B will receive $6,000 ($200 LIP times 30 MW imbalance) for its sale, and Load A pays $0 because it has no

[45] The resource LIP used in the equation is the absolute value of the LIP.
[46] Resources that are intermittent, starting up or shutting down, derated, or receive dispatch instructions beyond its reported capabilities can, in certain circumstances, be exempt from paying UD charges.

imbalance. This results in SPP receiving less than it paid out, causing a revenue shortfall that must be solved through RNU. Therefore, a positive $5,700 ($6,000 paid by SPP minus $300 received by SPP) will be included in RNU. The high RNU reflects that the hedge instruments (schedules) in excess of the simultaneous feasibility capability of the flowgate were left in place. This results in the full cost of the congestion not being accounted for, and as a result, the revenue needed to maintain revenue neutrality must be collected from Market Participants through RNU. High RNU numbers resulting from situations like this can be somewhat mitigated through curtailing schedules that impact the constraint. This causes those impacting the constraint to assume more of the financial burden associated with the constraint, which reduces the amount collected through RNU.

Figure II.8 Components of RNU by Month for 2009



SOURCE: SPP Website

Table II.20 displays the All-In price for SPP by month. This represents the load weighted SPP average price adjusted for net RNU divided by total EIS MWh (sales plus purchases). The RNU adjustment (a) allows congestion costs that were not effectively imposed on Market Participants through schedule adjustments to be accounted for and (b) allows over- and under-scheduling and UD charges to be accounted for. As seen below, this adjustment can be either positive or negative. The largest positive adjustment occurred in October and was $0.90/MWh, which is 2.9% of the October average price. The largest negative adjustment occurred in December. It was calculated to be negative $0.38/MWh which is 1.0% of the December average price.

Table II.20 All-In Price by Month for 2009

Month	Energy (LIP)	+	RNU	=	All-In Price
January	33.49		$0.48		$33.97
February	25.50		$0.21		$25.70
March	28.40		$0.89		$29.29
April	22.74		($0.09)		$22.66
May	24.97		$0.19		$25.16
June	27.83		$0.01		$27.85
July	29.23		$0.14		$29.38
August	27.17		$0.16		$27.32
September	24.19		$0.28		$24.47
October	30.57		$0.90		$31.47
November	28.97		($0.17)		$28.80
December	38.69		($0.38)		$38.31

SOURCE: SPP DSS and SPP website

III. ENERGY DELIVERY

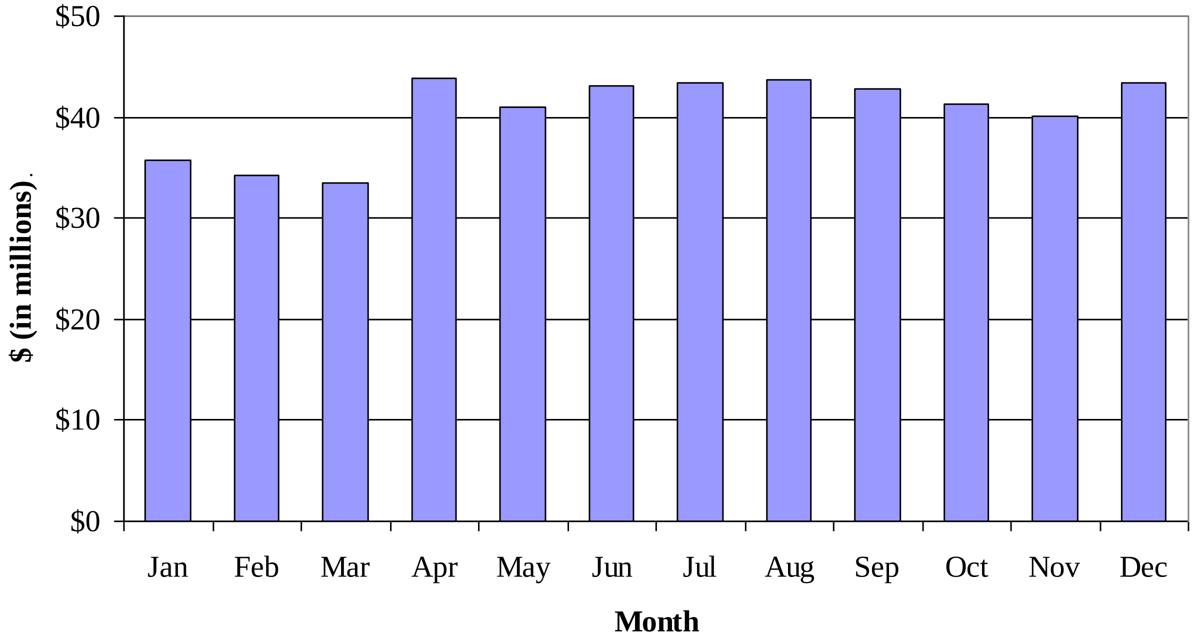
A. Transmission Service

Under its OATT, SPP grants transmission service over the transmission systems owned by its members. In return, SPP's transmission-owning members receive revenues for the service granted by SPP. Through a request process, parties who wish to move electricity over these transmission systems request this service in advance. SPP will approve these requests if it can do so while ensuring reliability and simultaneous feasibility; that is, while assuring that the capability of the transmission systems of its members to move electricity is not exceeded. Fluctuations in request levels can be indicators of the relative level of demand for transmission service within the SPP footprint.

Transmission Owner Revenue

As mentioned, the transmission-owning members receive revenues for the usage of their transmission facilities. Figure III.1 shows, by month, the revenues received by SPP's transmission owners for the usage of their transmission systems. The total for 2009 was approximately $486 million. This compares to $408 million in 2008. On average, the transmission owners received roughly $40 million of revenues each month in 2009. Therefore, to put this number in perspective, we can compare it to the revenues received for market sales by Market Participants in the EIS Market. The total dollars received for sales in the EIS Market was about $556 million, so the revenues in the Transmission Market were roughly 87% of those in the EIS Market in 2009. The jump in transmission revenues seen in the figure starting in April is a result of the addition of three new transmission owners to SPP.

Figure III.1 Transmission Owner Revenue for 2009



SOURCE: SPP OASIS at
http://sppoasis.spp.org/documents/swpp/tariff/TRANSMISSION_OWNER_REVENUE_ALL_SERVICES.htm

Flowgates and Flowgate Limits

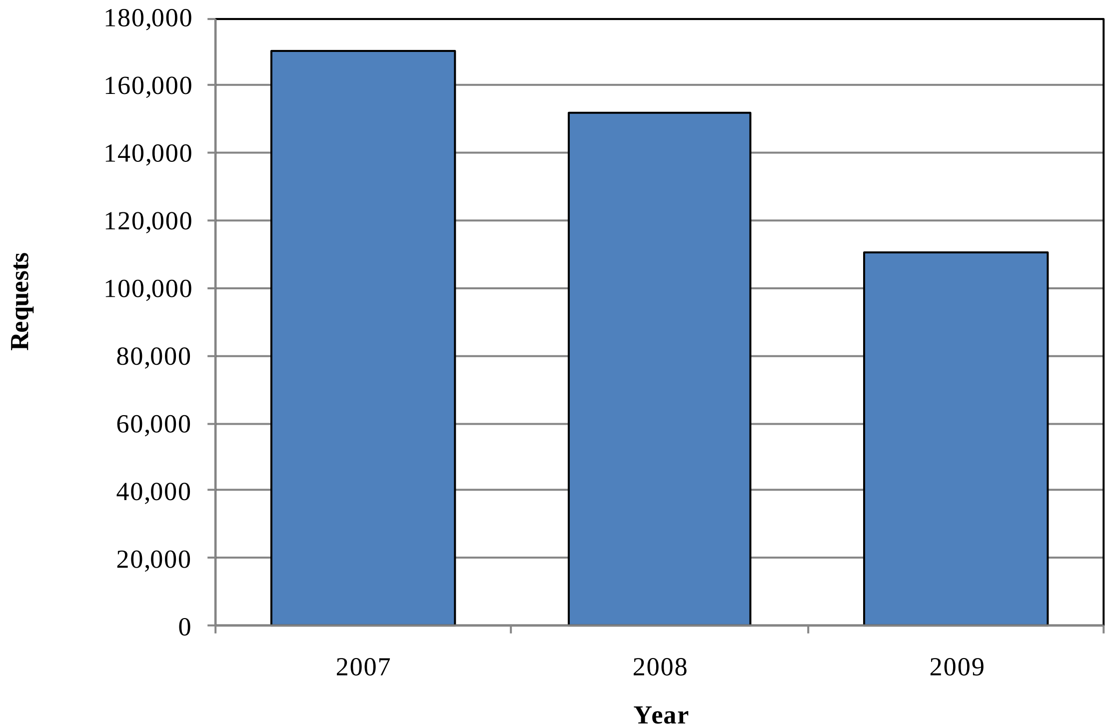
SPP primarily grants access to the transmission systems of its members based on assessments of flowgates designated by SPP and its members.[47] Flowgates are combinations of critical transmission elements that represent a proxy of the transmission system. Transmission elements are designated as flowgates if they have a history of being overloaded or show the potential to become overloaded due to power flows on the transmission system. Typically, a flowgate is a pair of transmission lines that includes a monitored facility and a contingency facility. The amount of power flow permitted over a flowgate is based on the amount of power the monitored facility could handle if the contingency facility experienced a sudden outage. This is based on NERC criteria that the transmission system remains secure (within loading limits) when experiencing the outage of any individual element. In certain cases, flowgates are made up of one or more transmission elements that are limiting individually or in conjunction, and no contingency facility is included.

[47] In addition to granting transmission service based on available transfer capability on flowgates, SPP uses a full single contingency (N-1) analysis of the transmission system for granting requests for transmission service equal to or greater than one year in length (yearly service).

Transmission Service Requests

Transmission service requests and their rate of confirmation can be a measure of both the demand for access to the transmission system in the SPP region and SPP's ability to grant access. The demand for service can be measured by the total number of transmission service requests submitted. SPP's ability to provide service can be measured by the number of service requests it approves. The total number of transmission service requests in SPP, shown in Figure III.2, has declined in each of the past two years. The number of requests dropped from 170,169 requests in 2007 to 151,878 in 2008, and then dropped further to 110,797 requests in 2009. This represents a 27% decrease from 2008 to 2009, and a 35% decrease from 2007 to 2009. We recommend that SPP report on the causes of the decrease in transmission requests over the last two years.

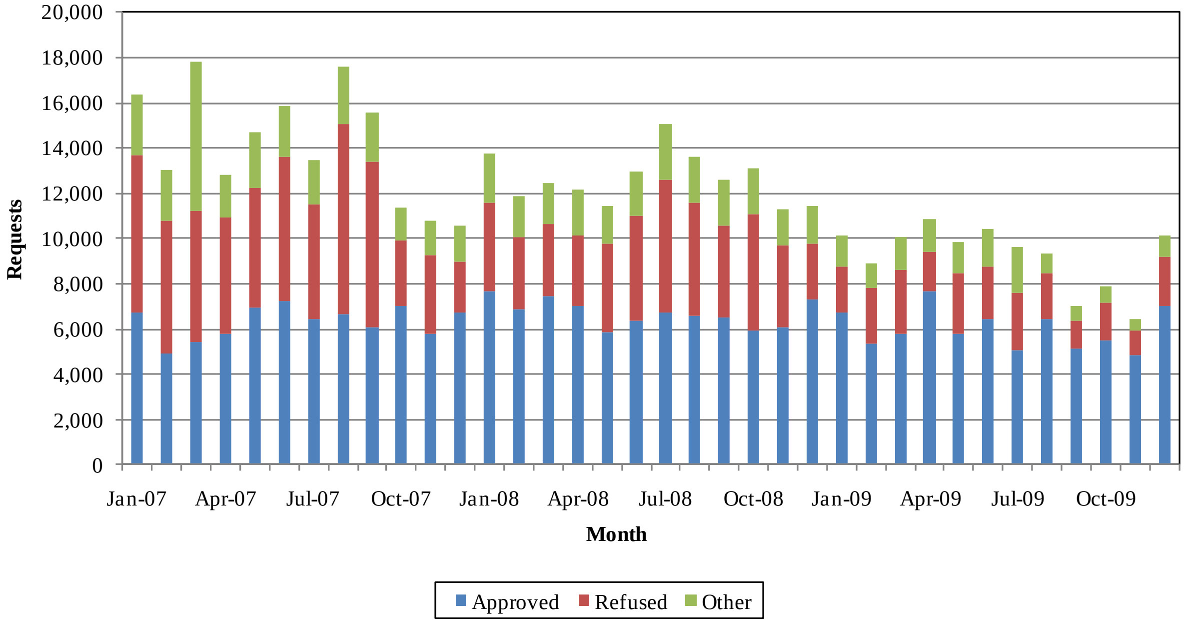
Figure III.2 Annual SPP Transmission Service Requests



SOURCE: SPP OASIS

On average, there were 14,181, 12,657, and 9,233 requests per month during 2007, 2008, and 2009, respectively. Figure III.3 shows the actual number of requests per month from 2007 to 2009. There were fewer requests in 2009 than in the two previous years; however, "other" requests accounted for only 12.8% of all requests in 2009, whereas in 2008 they accounted for 15.3% of all requests and in 2007 the percentage was 17.3%. "Other" requests include those requests that were designated as invalid, withdrawn, study, or declined.

Figure III.3 Monthly SPP Transmission Service Requests by Status from 2007 to 2009

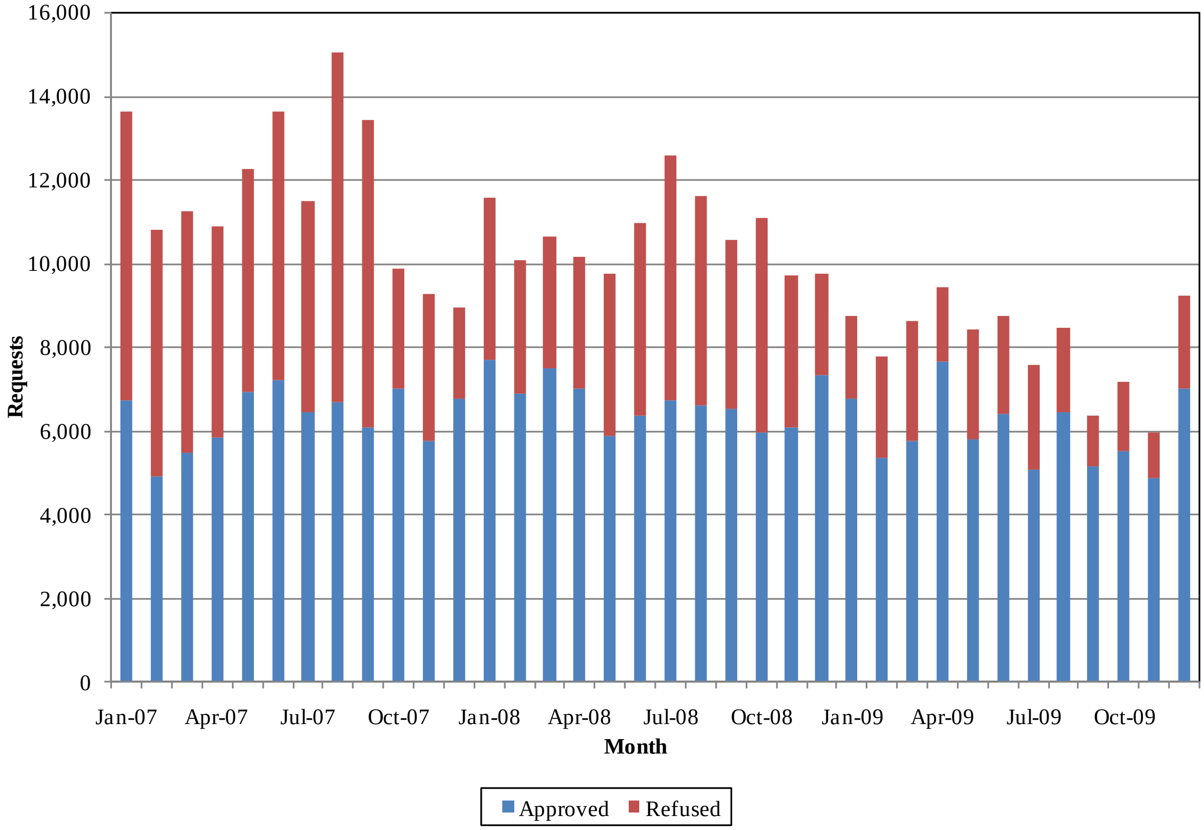


SOURCE: SPP OASIS

The trend in the number of requests approved by SPP and confirmed by requestors from 2007 to 2009 is shown in Figure III.4. The number of approved requests are represented by the blue bars in the figure. While the number of approvals went up from 2007 to 2008, they fell in 2009. There were 71,925 requests approved in 2009, compared to 80,641 in 2008 and 75,883 in 2007. In terms of monthly averages, in 2009 there were 5,994 requests approved per month, down from 6,720 approved in 2008 and 6,324 approved in 2007.

SPP's approval rates, measured as a ratio of approved requests to the sum of approved and refused requests, has steadily increased from 2007 to 2009. Figure III.4 shows the number of approved and refused reservation requests for each month from 2007 to 2009. Counting only approved and refused reservations, there was an annual approval rate of 54% in 2007, 63% in 2008, and 74% in 2009.

Figure III.4 Monthly Approved and Refused Transmission Service Requests 2007 to 2009



SOURCE: SPP OASIS

B. Transmission Congestion

Since SPP approves requests for transmission service in advance of when the electricity will actually be moved across the transmission system in SPP, a separate process is required to manage real-time flows of electricity in the event that the system's capability of moving electricity is exceeded because of outages, unforeseen power flows, or other events.

Role of SPP Flowgates in Congestion Management

Flowgates are sets of transmission lines designated by SPP and its members as those with a notable risk of congestion; and, therefore, a need to be closely monitored. SPP manages congestion over those flowgates and the number of flowgates varies from year to year. SPP reliability personnel also define additional, temporary flowgates to manage congestion that arises from unforeseen situations. For example, temporary flowgates may be used to prevent overloading in the event of a series of weather-related outages. Temporary flowgates are also used to assist with curtailing power flows over an existing flowgate or to address a need for congestion management in an area of SPP without flowgates.

Congestion Analysis

With a third year of EIS Market data, we can start to get a better understanding of how prevalent congestion is and what areas of SPP experience the most congestion. Table III.1 shows the percentage of all intervals in which there was at least one congested flowgate.[48] For 2007 and 2008, there was at least one flowgate congested on the transmission system in approximately 56% of the five-minute intervals. However, in 2009 this number increased notably to 71%. That equates to approximately 259 days in 2009 of transmission congestion out of a possible 365 days. Therefore, by this one strict metric, congestion in the SPP footprint seems to have increased in 2009.

The heaviest month of congestion occurred in March, during which at least one flowgate was congested for 94% of the intervals, representing a record high for any one month since the start of the EIS Market. The Cherry Creek to Boyd temporary flowgate, alone, was congested for 83% of the intervals, or 7,381 of the 8,916 intervals in March.[49] This temporary flowgate is located just south of Oklahoma City, and was created due to the outage of the South Gate to W. Moore 138 kV line. The low for the year occurred in January when only 35% of the intervals experienced congestion. The flowgate with the largest number of congested intervals in this month was the Plant X to Sundown temporary flowgate in SPS, which was congested for 12.4% of the intervals, or 1,104 intervals. The Kress to Hale Co. temporary flowgate was the second most congested flowgate during that month and was congested for just 6.2% of the intervals. We also see here that there is, on average, a little more congestion during the off-peak periods than the on-peak periods. The opposite was true in 2007 and 2008, when there was a little more congestion during the on-peak periods.

[48] A flowgate is congested during an interval if it is either binding or breached. Binding intervals occur when the flowgate is at its loading limit and breached intervals occur when the flowgate exceeds its loading limit.
[49] Due to the time change, March has 12 less intervals, which brings the total number of intervals down from 8,928 to 8,916.

Table III.1 Percent of Five-Minute Intervals with at Least One Flowgate Congested

Month	2007			2008			2009		
	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total	On-Peak	Off-Peak	Total
January	NA	NA	NA	30%	25%	28%	33%	37%	35%
February	61%	38%	49%	28%	25%	26%	76%	64%	70%
March	52%	45%	49%	81%	68%	74%	91%	97%	94%
April	40%	40%	40%	74%	73%	74%	67%	81%	74%
May	30%	20%	25%	49%	54%	52%	92%	87%	89%
June	90%	83%	86%	77%	70%	73%	88%	85%	86%
July	69%	63%	65%	87%	73%	80%	86%	94%	90%
August	69%	65%	67%	82%	64%	72%	77%	90%	84%
September	71%	64%	67%	55%	37%	45%	43%	67%	56%
October	72%	51%	61%	54%	47%	51%	48%	59%	54%
November	54%	69%	62%	71%	66%	68%	40%	69%	56%
December	38%	50%	45%	24%	30%	27%	50%	73%	62%
Total	59%	54%	56%	59%	53%	56%	66%	75%	71%

SOURCE: SPP DSS

Transmission Congestion's Impact on Locational Imbalance Prices

While all congestion (both binding and breached flowgates) causes price separation and thus increases in prices, breaches can have a much greater impact on Locational Imbalance Prices (LIPs). Breaches are usually to blame for extreme prices in SPP; however, binding constraints occur more often and thus can also notably increase prices.[50] To explain how this occurs, it is essential to first understand the formulas used to calculate LIPs in the market. The formula is provided below with a discussion of each of the elements after that.

LIP = System Marginal Price + (Shift Factor * Shadow Price)

System Marginal Price (SMP): it is the cost of serving the next MWh of load *in the SPP footprint* given the transmission constraint. If there are no transmission constraints, the LIP is simply equal to the SMP.

Shadow Price and Shift Factors: The second component of the LIP reflects the marginal cost of the transmission constraint; or more precisely the value of relieving the constraint by some small amount. The value of relieving the constraint is generally that lower-priced power can be used – so the value is reflected in the difference in LIPs on either side of the constraint. This value is called the "shadow price" of the constraint. The portion of the shadow price included in a LIP for a Resource at a particular location depends on the extent to which that Resource impacts the constrained flowgate. The measure of that impact is called a "shift factor." If a Resource delivers 10 MWh to the

[50] A flowgate is considered binding when the flowgate is at its effective limit, and a flowgate is considered breached when the flowgate has exceeded its effective limit.

market and 5 MWh of that impacts the relevant transmission facilities (the flowgate), then the shift factor is 50%.

In summary, a LIP at any one location equals (a) the SMP plus (b) the shift factor times the shadow price of each congested constraint. When a constraint is breached in SPP, the Shadow Price component of the LIP is generally much higher than when the constraint is just binding, which can result in broad price differentials within the market footprint. The table below shows the average shadow prices associated with flowgates in SPP when the flowgate (a) is not congested, (b) is binding, and (c) is breached. When there is no congestion on the system the shadow price is zero dollars. The average shadow price for binding constraints in SPP is roughly negative \$89/MW.[51] The average shadow price for breached constraints in SPP is significantly higher at approximately negative \$1,645/MW. Both are slightly lower than last year, when the average shadow price was negative \$130/MW and negative \$1,665/MW for binding and breached constraints, respectively.

Table III.2 Shadow Prices in 2009

Transmission Status	Average Administered Shadow Price
No Congestion	\$ -
Binding Constraint	\$ (89.38)
Breached Constraint	\$ (1,644.54)

SOURCE: SPP DSS

It is useful to show in detail how transmission congestion affects prices – the LIPs in the EIS Market. Let's start with the high, negative shadow prices in the table above which indicates that, by relieving the constraint, the market could save money because cheaper power could flow. But how does a high, negative shadow price turn into a high, positive LIP? The key is to recognize that the high, negative shadow price will be multiplied by a negative shift factor – the shift factor is negative because increasing generation on the constrained side of the flowgate will ease congestion on that flowgate. Since we have multiplied two negative numbers, we get a positive number. For example, take the shadow price of negative \$1,645 per MWh shown in the table above and assume the shift factor is a negative 20%; with these numbers, the shadow price times shift factor would add \$329/MWh to the hourly price (\$1,645 times 0.2). A high, positive price in the constrained area sends the appropriate price signal – we want to encourage more generation and less consumption in the congested area.[52]

---

[51] By mathematical convention, shadow prices in the EIS Market are quantified as negative numbers (some SPP market reports show them as positive numbers for simplification of presentation).

[52] There can be a lot more to this story. In a highly congested area, the SMP can also be very high. In addition, note that, with a breached flowgate, the raw shadow price is dictated by what used to be called a Penalty Factor and now are called Violation Relaxation Limits (VRLs); note that the VRL for a transmission constraint is set by SPP and was \$2,000/MW in 2009. However, starting on March 8, 2010, FERC has approved the VRL for transmission constraints to be reduced to \$1,500/MW. This will result in a lower average shadow price for breached constraints in 2010 as the VRL value effectively puts a cap on the shadow price. For an even more detailed discussion of the effects of transmission congestion on prices, please see Boston Pacific Company, Inc. *An Assessment of Price Volatility in Recent Deployment Tests for the SPP EIS Market* (October 19, 2006).

Given that breached constraints have a much larger price impact than binding constraints, we are interested to see what portion of the total number of congestion instances (congested flowgate intervals) are binding and what portion are breached. Furthermore, we are interested to see how these totals compare from year to year. Table III.3 shows, for 2007 to 2009, (a) the number of binding flowgate intervals, (b) the number of breached flowgate intervals, and (c) the number of congested (binding plus breached) flowgate intervals. We can draw two conclusions from this data.

First, the number of binding flowgate intervals, and, as a result, the number of total congested flowgate intervals (binding plus breached) has increased. This is not surprising given our prior discussion that showed that the percentage of time there was at least one flowgate congested increased from 56% in 2008 to 71% in 2009. In analyzing the underlying data, the main driver for the increase in total congested flowgate intervals is an increase in congestion on temporary flowgates. In fact, of the 118,864 congested flowgate intervals in 2009, 67% were on temporary flowgates. In 2008, only 12% of the 85,204 total congested flowgate intervals were on temporary flowgates. We recommend that SPP provide an explanation of the reasons for the increase in temporary flowgates.

The second conclusion that can be drawn from Table III.3 is that the number of breached flowgate intervals has dropped in each of the past two years. From 2008 to 2009, the number of breached flowgate intervals fell 18%. This is important because breached flowgate intervals have the largest impact on the SPP system in terms of price. Although the incidence of congested intervals has increased, the impact on price decreased in 2009.

Table III.3 Number of Binding and Breached Flowgate Intervals 2007-2009

Congestion Type	2007	2008	2009
Number of Binding Flowgate Intervals	63,615	77,130	112,268
Number of Breached Flowgate Intervals	8,992	8,074	6,596
Total Congested Flowgate Intervals	72,607	85,204	118,864

SOURCE: SPP DSS
Note that because the EIS Market was launched in February 2007, 2007 only has 11 months of data.

Because of the price impact of flowgate congestion, we are also interested in the specific flowgates that have been most problematic in SPP. Table III.4 displays the top ten flowgates with the highest aggregate shadow prices. This is calculated as the sum of the shadow prices for a particular flowgate for the year. This value can be seen in the far right column of the table below. Randall County to Palo Duro and Osage Switch to Canyon East had the highest aggregate shadow prices. Also seen in the table, these two flowgates were congested in 20.4% and 13.2% of all intervals in 2009, respectively. Both of these flowgates are located in SPS, and are in close proximity to each other. They were created to control high north to south flow between Amarillo and Lubbock – partly due to wind resources north of these flowgates. It appears that during the first half of the year the Randall County to Palo Duro flowgate was congested as a result, and during the second half of the year the Osage Switch to Canyon East temporary flowgate was congested. Together, one of these two flowgates was congested in 33.6% of all intervals over the year.

Table III.4 2009 Top 10 Congested Flowgates by Aggregate Shadow Price

Location	Flowgate Name	Voltage (kV)	Balancing Authority	% of Total Intervals Congested	Average Hourly Shadow Price ($/MWh)	Aggregate Shadow Price $/MW
Randall County to Palo Duro	RANPALAMASWI	115	SPS	20.4%	(29.79)	(260,925)
Osage Switch to Canyon East	TEMP01_15940	115	SPS	13.2%	(18.40)	(161,218)
Lake Road to Alabama	LAKALAIATSTR	161	MPS	2.6%	(14.27)	(124,981)
Neosho to Columbus	TEMP06_16094	161	AEPW	1.7%	(9.15)	(80,152)
Hugo Power Plant to Valliant	HPPVALPITVAL	138	WFEC-AEPW	5.5%	(7.60)	(66,576)
Longwood to Noram	TEMP05_15882	138	AEPW	0.7%	(7.37)	(64,537)
Gentleman to Red Willow	GENTLMREDWIL	345	NPPD	4.2%	(6.00)	(52,574)
Kress to Hale Co.	TEMP07_15765	115	SPS	5.1%	(5.74)	(50,247)
Okmulgee to Henryetta	OKMHENOKMKEL	138	AEPW	1.7%	(4.70)	(41,211)
Longwood Transformer	TEMP02_15679	345/138	AEPW	0.5%	(4.43)	(38,777)

SOURCE: SPP DSS

Comparing the top 10 congested flowgates from 2009 to those from 2008 can also be informative. It allows us to see if it is the same flowgates that are most problematic or if new flowgates have emerged. Figure III.5 displays the geographical location of the top 10 flowgates from 2008 and 2009. In the figure, notable cities and towns are denoted with large, green circles, while the flowgates are depicted by lines with bullet points at each end.[53] The flowgates with clear (transparent) bullets are flowgates that were in 2008's top 10, but are not in the 2009 top 10. Conversely, the flowgates with blue bullets are flowgates that were in the top 10 for 2009 but not in 2008. Finally, the flowgates with red bullets represents those flowgates that were in the top 10 in both 2008 and 2009.

[53] The SPS North-South flowgate is made up of 5 monitored lines and the SPP to SPS Ties flowgate is made up of 6 monitored lines. The lines for these flowgates shown in the figure do not represent the physical location for all of these lines.

Figure III.5 Transmission Congestion Map Summary by Flowgate

SOURCE: SPP DSS

From the figure we can draw several conclusions. First, it appears that flows have changed somewhat in 2009 when compared to previous years. For example, two flowgates, South Philips to West McPherson and Lone Oak to Sardis, that had been in the list of top congested flowgates since 2004 are no longer in the top 10. Lone Oak to Sardis dropped to number 12 on the list in 2009, while the South Philips to West McPherson flowgate was not congested in 2009 – most likely due to some upgrades in the WERE area. In addition, there appears to be two new congested flowgates in Missouri in 2009: (a) Lake Road to Alabama and (b) Neosho to Columbus. The Lake Road to Alabama flowgate was congested consistently from April through the end of 2009, while the Neosho to Columbus flowgate was heavily congested at the end of 2009.

Second, three of the top congested flowgates from 2008 are also on the list in 2009. They are: (a) Gentleman to Red Willow, (b) Okmulgee to Henryetta, and (c) Hugo Power Plant to Valliant. Given that these flowgates have shown persistent congestion, we looked at SPP’s 2009

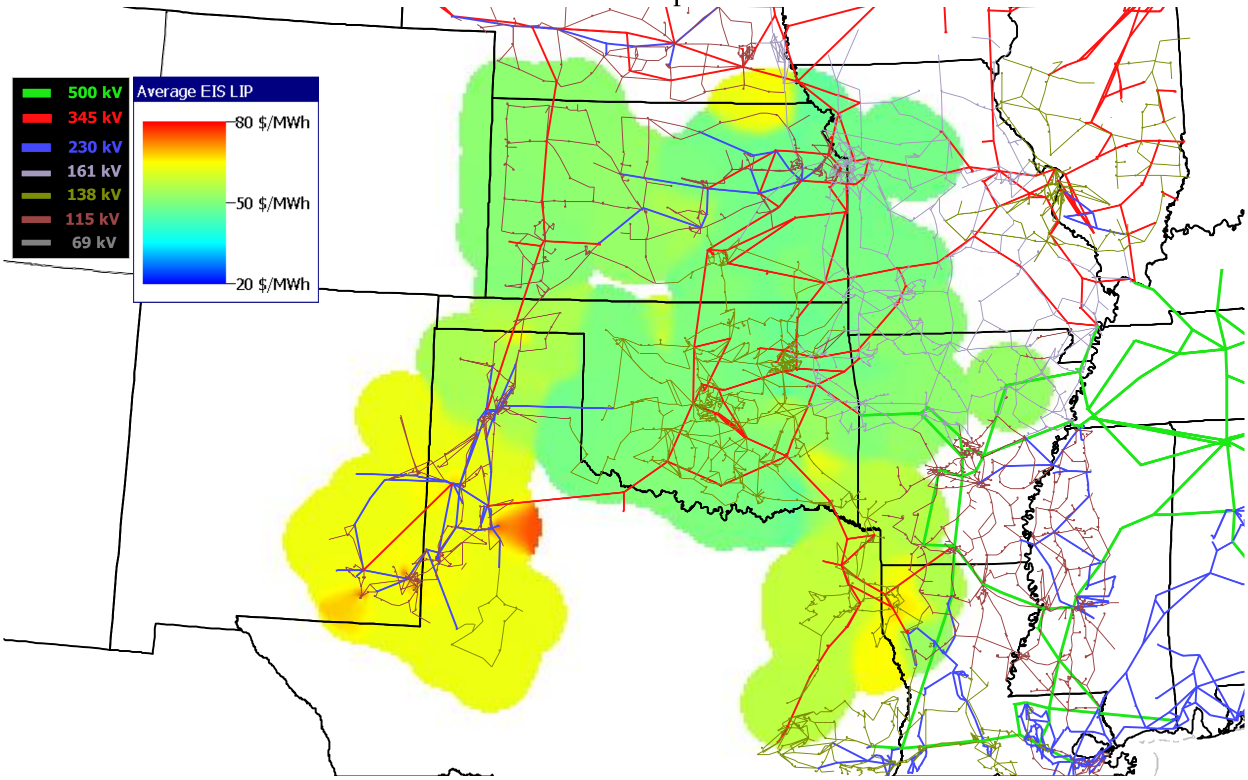
Transmission Expansion Plan to see if there were planned transmission upgrades that will help relieve these flowgates. From our review, there is indeed future investment planned which will at least partially mitigate these constraints. A 345 kV line that is part of the Balanced Portfolio from Spearville to Axtell to Knoll will potentially help relieve the congestion on the Gentleman to Red Willow flowgate. This project is expected to be in-service in June of 2013. Another Balanced Portfolio approved 345 kV line from Seminole to Muskogee could help the congestion on the Okmulgee to Henryetta flowgate. This project has an expected in-service date of April 2012. Finally, a planned 345 kV line from Hugo to Valliant, scheduled for 2012, will alleviate the congestion on the Hugo Power Plant to Valliant flowgate.

Third, there appears to be continued congestion in the Texas panhandle and northwest Louisiana areas but on different flowgates than a year ago. Last year, in the Texas panhandle, the SPP to SPS Ties and the SPS North-South flowgates were in the top 10, while this year the Osage Switch to Canyon East, Randall County to Palo Duro, and Kress to Hale Co. flowgates were in the top 10. These flowgates are congested due to high north to south flows. We understand that one reason for the shift in congestion in the panhandle of Texas is that SPP Operations changed the flowgates it monitored in SPS. Looking now at the northwest Louisiana area, last year the Southwest Shreveport Transformer was heavily congested. However, an upgrade to the transformer was completed in 2009, which has helped to alleviate congestion on this flowgate. Now there has been congestion on the Longwood Transformer and the Longwood to Noram flowgate.

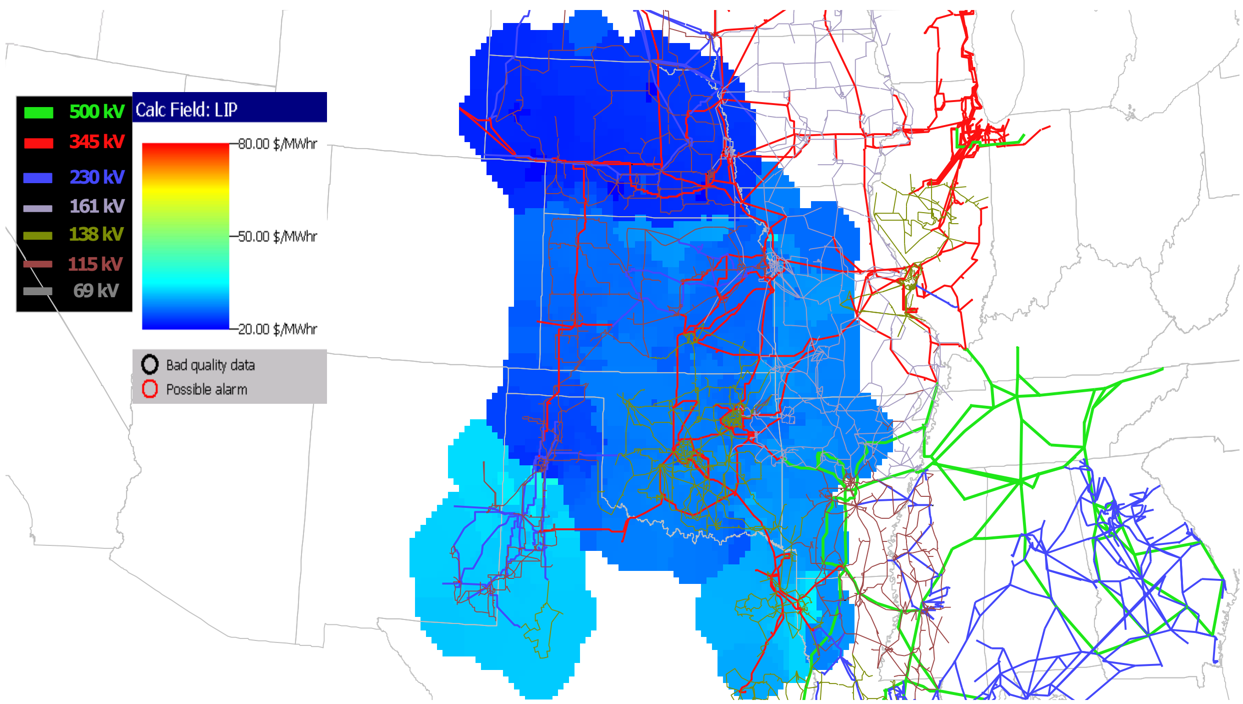
Figure III.6 takes the relationship of congestion to LIPs one step further than reporting average shadow prices. Two maps are shown below, one for 2008 and one for 2009. These maps provide a picture of the average annual LIPs by load settlement location in SPP. As can be seen in the figure’s legend, higher prices are shown as red and yellow and lower prices are shown as dark blue. Looking at these maps, we see that the highest areas of prices are the same for both 2008 and 2009. These areas are the southwest part of SPP, in the SPS territory, and the southeast part of SPP, in the northwest Louisiana area. The higher costs in these parts of SPP results from the congestion in these areas described above.

Figure III.6 SPP 2008 and 2009 EIS Price Contour Maps

2008 Map



2009 Map



SOURCE: SPP MMU

C. Transmission Investment

In order to maintain reliability and bolster competitiveness in the SPP footprint transmission investment is essential. Transmission system expansion not only increases capacity within the footprint, but also allows more electricity from outside the footprint to service SPP load. To achieve continued reliability and increased competitiveness, SPP relies on a regional expansion planning process. Although SPP has used regional planning for decades, this is the fifth year in which the SPP Transmission Expansion Plan (STEP) has been used as the tool for regional planning.

While the STEP has been used for the past five years, SPP will utilize a new planning process starting in 2010. Before going into detail on the contents of the 2009 STEP, we first provide an overview of how SPP's new planning process was developed and what it will entail. The new process is known as the Integrated Transmission Plan (ITP), and its development was driven by the Synergistic Planning Project Team (SPPT). As background, in January 2009, the SPP Board of Directors created the SPPT, which was comprised of a representative from the transmission owning utilities, a representative from the transmission dependent utilities, a representative from the marketing segment, two state regulatory commission chairs, a senior SPP staff member, a representative from the investment sector, and a consultant/facilitator. The SPPT was charged with "reviewing all strategic issues concerning transmission service, generator interconnection, Extra High Voltage (EHV) inter-regional transmission, and wind integration."[54] The SPPT published its final report in April 2009, and recommended that, "SPP should implement an [Integrated Planning Process] to facilitate the creation of a robust, flexible, and cost-effective transmission network in the SPP footprint."[55] As a result, an iterative, three-year process known as the ITP was developed and approved by the Board of Directors at its meeting on October 27, 2009. The ITP process will be used starting in 2010 and will include three major parts: (a) a 20-year assessment that will begin in year one of the three year cycle and be completed in year two, (b) a 10-year assessment that will begin during year two and be completed in year three, and (c) a near-term assessment that will be completed each year. The purpose of the 20-year assessment is to develop an EHV backbone network, while the purpose of the 10-year assessment is to identify 100 kV and above transmission solutions that are not addressed in the 20-year assessment. Finally, the near-term assessment, that will be completed annually, will be a reliability assessment that provides solutions to violations of NERC reliability standards and individual transmission owner planning requirements. In addition, separately, SPP is also considering six Priority Projects, estimated at a cost of $1.1 billion.[56] These projects are high priority projects that are designed to capture near-term opportunities so that they are not lost in the transition to the new ITP process.

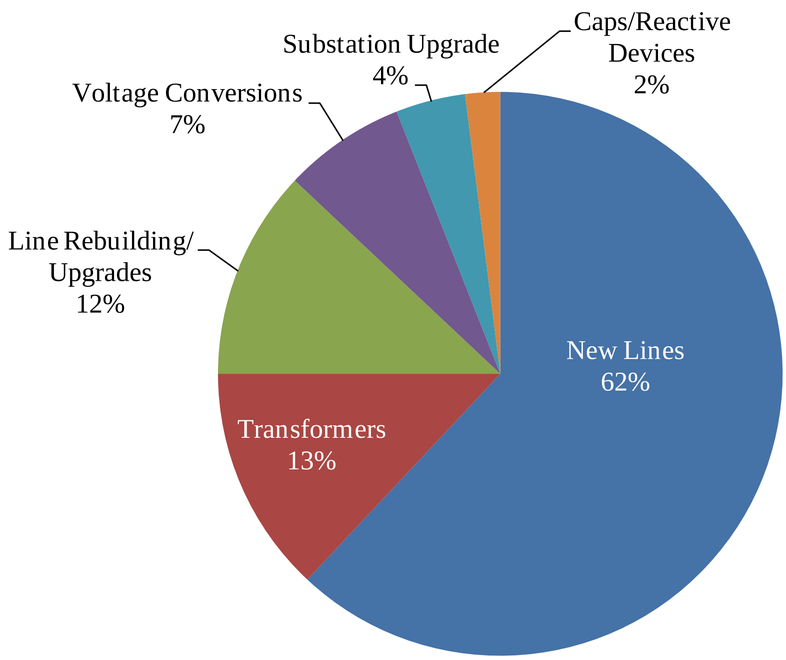
As previously mentioned, the STEP process was used for the 2009 planning year, and the rest of this section provides detail on the contents of the STEP. This year's STEP looks at transmission investments for the ten-year period from January 1, 2010 through December 31, 2019. This expansion encompasses over 4,000 miles of upgrades or new line construction and

---

[54] *See* Southwest Power Pool, *Report of the Synergistic Planning Project*, April 30, 2009 ("SPPT Report").
[55] *See* SPPT Report at page 6.
[56] *See SPP Priority Projects Phase II Report Revision 1*, Published April 2, 2010 ("Priority Projects") at page 5.

over 80 new or upgraded transformers, totaling approximately $4.45 billion.[57] This is approximately 65% more than the total (approximately $2.7 billion) planned investment included in last year's STEP. The figure below shows the percentage of dollars to be spent by project type. Approximately 74% of the investment is planned for building new transmission lines or upgrading existing lines.

Figure III.7 2010 to 2019 Cost by Network Upgrade Type



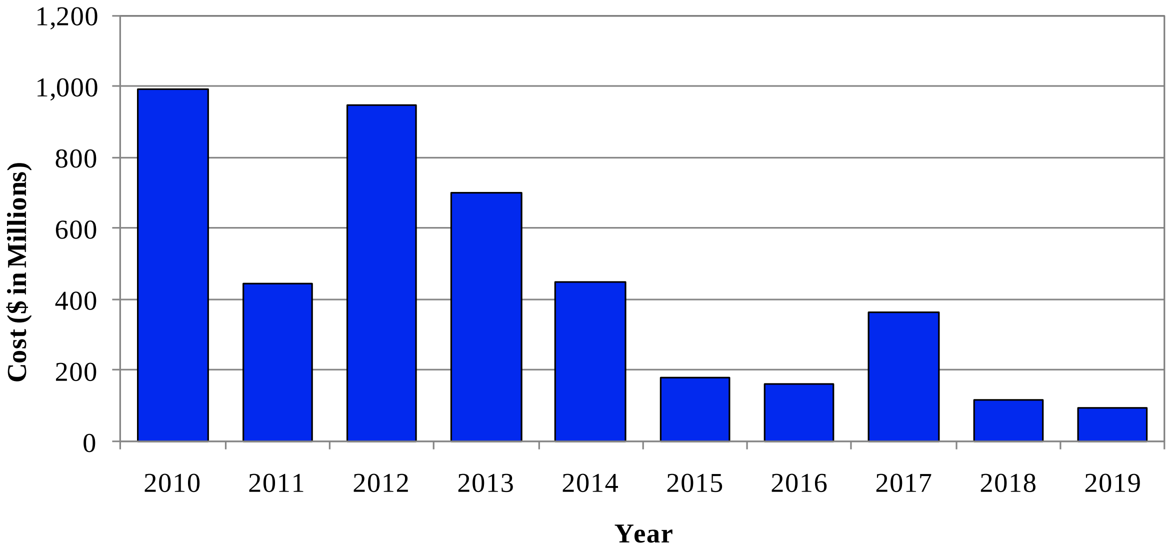
SOURCE: SPP Transmission Expansion Plan[58]

In total, there were roughly $4.45 billion of transmission projects included in the planning horizon from 2010-2019. Figure III.8 shows the costs of transmission projects currently planned by year from 2010 through 2019. Almost $1 billion of transmission projects were planned for 2010, accounting for over one-fifth of the total planned spending.

---

[57] *See 2009 SPP Transmission Expansion Plan, A Report of the SPP Regional Transmission Organization*, Approved by the SPP Board of Directors on January 26, 2010 ("STEP") at page 30.
[58] *See* STEP at page 5.

Figure III.8 Cost of Transmission Expansion Projects Needed 2010-2019



SOURCE: Appendix A of the SPP Transmission Expansion Plan

Transmission Project Distribution

Each of the projects incorporated in SPP's Transmission Expansion Plan comes from one of nine project types.[59] These project types reflect, among other things, the project's purpose. The following table summarizes how projects are classified in the expansion plan.

Table III.5 Project Classification

Project Type	Description
Generation Interconnect	Projects associated with a FERC-filed Generation Interconnection Agreement
Inter-Regional	Projects developed with neighboring Transmission Providers
Regional Reliability	Projects needed to meet the reliability of the region
Regional Reliability – non OATT	Projects to maintain reliability for SPP members not participating under the SPP OATT
Transmission Service	Projects associated with a FERC-filed Service Agreement
Zonal Reliability	Projects identified to meet more stringent local Transmission Owner criteria
Zonal – Sponsored	Projects sponsored by facility owner with no Project Sponsor Agreement
Balanced Portfolio	Projects identified through the Balanced Portfolio process
Sponsored	Projects with an executed Project Sponsor Agreement or that have previously been identified as an economic project to receive transmission revenue credits under the OATT attachment Z2

SOURCE: SPP Transmission Expansion Plan

Figure III.9 shows how the projects are allocated among the nine project types in the ten-year planning horizon. In the figure, we see $994 million expected to be spent in 2010. This 2010 total can be broken down into the following categories: (a) $520 million for Regional Reliability; (b) $319 million for Sponsored projects; (c) $55 million for Transmission Services; (d) $45 million for Zonal – Sponsored projects; (e) $44 million for Generation Interconnection; (f) $7 million for Regional Reliability – non OATT; and (g) $5 million for Zonal Reliability.[60]

A large part of the $520 million in Regional Reliability upgrades in 2010 stems from a $150 million project in NPPD, which includes building 79 miles of 345 kV transmission lines going from Shell Creek to Columbus East to NW 68 & Holdrege. Other balancing authorities also have large Regional Reliability upgrades planned for 2010. SPS has $146 million of upgrades planned; $125 million are from just seven projects, all over $10 million. WFEC and WERE also have significant dollar amounts of Regional Reliability upgrades planned with $60 million and $77 million, respectively. The $319 million in Sponsored projects comes from just two projects. First, a $218 million project, which includes building 120 miles of transmission lines in OKGE, would connect Northwest to Woodward. Second, a $100 million project in the WERE balancing authority is planned to install a new line from Reno County to Summit in central Kansas.

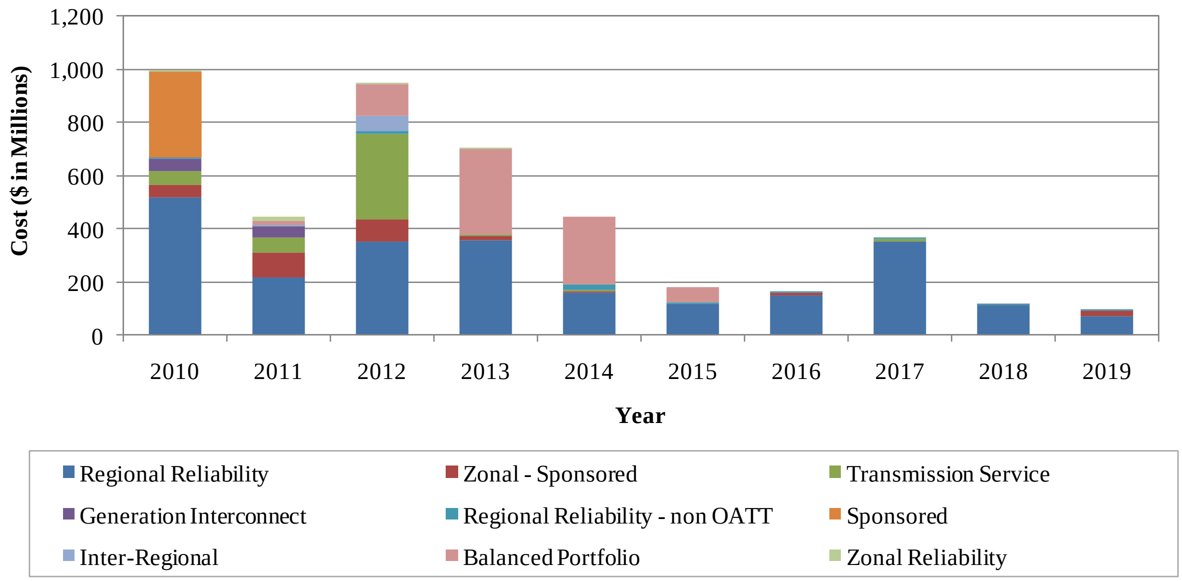
---

[59] *See* STEP at page 8.

[60] Both the Balanced Portfolio and the Inter-Regional categories were listed at $0 for 2010.

If we look at the full 10-year planning horizon, the Regional Reliability projects account for $2.4 billion of the total $4.45 billion of planned transmission investment. This $2.4 billion includes over 400 projects, which are required for NERC or SPP reliability standards. Thus it is not surprising that this is the largest of the nine project types. The largest Regional Reliability project not planned for 2010 is one in SPS scheduled for 2013. This project, estimated to cost $146, is for 130 miles of a new 345 kV line from Potter County Interchange to the new Frio-Draw substation in western Texas. The largest non Regional Reliability project beyond 2010 is a $200 million Transmission Service project in OKGE that would add a 120 mile 345 kV line from Hugo to Sunnyside. This project is scheduled to be completed in 2012.

Figure III.9 Cost of Transmission Expansion Projects Needed 2010-2019 by Project Source

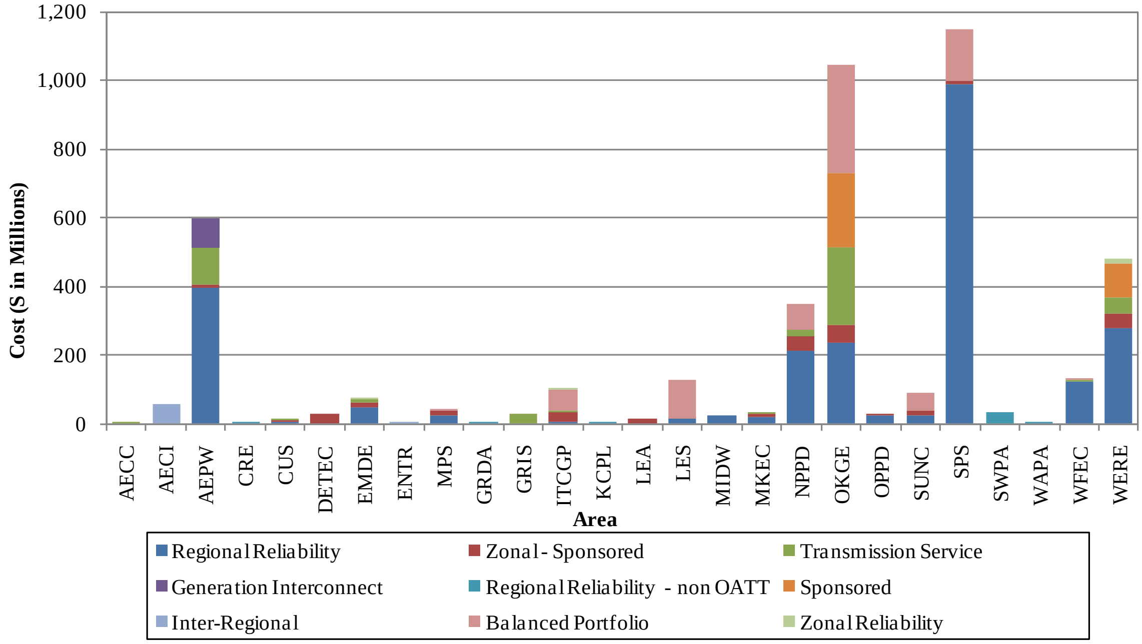


SOURCE: Appendix A of the SPP Transmission Expansion Plan

Using the same classification system, Figure III.10 was created to show (a) the area in which the project is intended and (b) to which category the planned project belongs.

As can be seen in Figure III.10, the costs of the projects planned for the full ten-year planning horizon were highest in SPS, OKGE, and AEPW. Of the total, 26% of the planned transmission expansion is located in the SPS area alone. This includes three planned projects estimated to cost over $100 million dollars each and over 100 projects in total.

Figure III.10 Tentative Cost of Transmission Expansion Projects Planned 2010-2019 by Area



SOURCE: Appendix A of the SPP Transmission Expansion Plan

IV. RECOMMENDATIONS

We thought it would be useful to step back from all the details presented and draw out some broader implications. Four such implications can be summarized as follows:

A. Transmission Outage Database

Transmission outages have increased each of the past three years. This increasing trend in the number of transmission outages continues to concern us. Boston Pacific recommended in both the *2007* and *2008 State of the Market Reports* that SPP report on the reasons for increasing transmission outages. The increases could be a result of legitimate reasons such as: (a) having to take lines out of service for construction as a result of an increase in the amount of transmission investment from SPP's Transmission Expansion Plan, (b) more accurate reporting, or (c) weather. However, given the current data set, we are unable to confirm or refute these hypotheses. At a minimum, reporting on this would alleviate any concerns of market power abuse through forced or maintenance outages. We recommend that SPP standardize the categorization of outage reasons and collect data to support reporting by year end. In addition, we recommend that SPP develop additional metrics related to transmission outages that can be reported regularly to show the extent, the locations, and the reasons for the transmission outages across SPP's footprint.

B. Transmission Congestion and Temporary Flowgates

While the number of serious instances of congestion (breached flowgate intervals) has fallen in each of the past two years, the total number of intervals in which at least one flowgate was either breached or binding has increased. We have seen a significant increase in congestion occurring on temporary flowgates. In fact, 67% of the breached or binding intervals in 2009 were associated with temporary flowgates. This is up from 13% and 12% in 2007 and 2008, respectively. Congestion intervals have increased in the Market Footprint for several important reasons. First, the addition of five new Market Participants in 2009 added many new flowgates, both temporary and permanent. Second, temporary flowgates were used to improve management of congestion in the Panhandle of Texas. Third, transmission upgrades in several specific areas required the use of more than expected temporary flowgates for longer than expected. We recommend that an enhanced methodology for tracking and monitoring congestion trends be implemented to ensure that the Market effectively contributes to the resolution of congestion.

C. Offer Cap

The market system currently imposes offer caps on resources that have the potential to wield market power when permanent flowgates are activated. The offer cap system also only uses congestion on permanent flowgates in calculating individual caps. The original design for the offer cap system did not include temporary flowgates because they represented a very small portion of the total number of flowgates and they had a very short life expectancy. Over time, temporary flowgates have become a significant source of congestion. To address this change in system operations, the reference to permanent flowgates in the market protocols should be removed and the offer cap system should be modified to include temporary as well as permanent flowgates. These changes would ensure that the offer cap system effectively caps offers over time regardless of the use of temporary flowgates.

Offer caps are imposed when a flowgate is activated. The current trigger for activating a flowgate is a TLR. SPP uses TLRs as a proxy for congestion. Historically TLRs have been a good proxy but proposed market rule changes would allow SPP to activate flowgates for extended periods without calling a TLR. SPP needs to develop a new trigger for imposing offer caps to reflect actual congestion before implementing any rule changes with regard TLRs.

D. EIS Market and New Markets

SPP launched its EIS Market on February 1, 2007. We not only believe that the EIS Market has been successful, but we also believe the process by which it was developed was successful. The RSC and the Board decided to endorse the actual development of the EIS Market because of the potential consumer benefits associated with it. As shown in a separate report, actual market data indicate that there were trade benefits (production cost savings) over $100 million in the first year of EIS Market operation.[61] Put simply, this is the result of the EIS Market dispatching up more efficient, lower-priced units and dispatching down higher-priced, less efficient units. Also, prices are now transparently calculated and reported in a spot market; this can provide liquidity for new generation investment by companies such as independent power producers and others responding to State competitive procurements.

SPP is currently in the process of developing new markets. The major components of these new markets include: (a) a Day-Ahead Market with Transmission Congestion Rights (TCRs), (b) a Centralized Unit Commitment process, (c) a Real-Time Balancing Market, similar to today's EIS Market, and (d) a price-based Operating Reserves procurement. Given the success of the EIS Market, we recommend that SPP implement the new markets as expediently as possible in order to realize the potential consumer benefits of the new markets.

[61] *See* Southwest Power Pool, Inc. Market Monitoring Unit and External Market Advisor Report to SPP Board of Directors/Members Committee April 22, 2008, *Estimation of Net Trade Benefits from EIS Market.*

V. BROADER ISSUES ON THE HORIZON

The Board also has to anticipate broad market and regulatory events that will affect the performance of SPP's markets. While a lengthy discussion in this report may not be appropriate, we would be remiss if we failed to at least identify the broad issues on the horizon. These events include (a) climate change policy, (b) clean air legislation, and (c) natural gas price changes.

A. Climate Change Policy

Legislation and/or regulation to address concerns about global climate change has the potential to be a fundamental game changer for the electricity business in terms of the mix of supply- and demand-side resources needed to serve homes and factories and the price charged for service. For this reason, the SPP Board of Directors should be kept up to date on the subject and that is the purpose of our brief status report. This section provides an update on four related topics: (a) Copenhagen negotiations; (b) Federal legislation or regulation; (c) State and regional actions; and (d) the impact of the recession on emission prices.

Copenhagen Negotiations

The big event for global climate change in 2009 was meant to be the United Nations (UN) climate change negotiations in Copenhagen in December. There were high expectations for a global agreement in Copenhagen; the 12 days of negotiations themselves involved Presidents and Prime Ministers. In the end, however, no formal agreement was reached. Tensions remained between developed countries, the U.S. in particular, who do not want to act without a guarantee that large developing countries will also act. In response, developing countries say they do not want to impose additional costs on the energy they need to grow when developed countries are responsible for the vast majority of historical emissions. Support for negotiations was also hurt in some countries, in part, by reports of some factual errors in recent Intergovernmental Panel on Climate Change reports, as well as by emails (stolen from some prominent researchers at the University of East Anglia in the United Kingdom) which were said to reveal bias.

The result at Copenhagen was a 3-page political accord that was "recognized" by participating countries, but not formally adopted. The accord does take several steps that prevent the UN-based process from collapsing entirely, allowing for negotiations to continue in the future. The Copenhagen accord:

- Reiterates previous commitments to limit global warming to 2 degrees centigrade and maintains the "common but differentiated responsibilities" from the Kyoto Protocol, whereby developed countries are bound to specific emission reduction targets, but developing countries are not;
- Achieved agreement from developing countries to measure, report and verify their emissions internationally and agreement from some developing countries, including China, to limits on their emissions, though without penalties for non-compliance;
- Established a near-term $30 billion Copenhagen Green Fund for 2010-2012 for emissions mitigation and adaptation measures in developing countries, with a medium-term account

beginning in 2020 worth $100 billion annually, funded by public monies and "alternative sources" (markets).

Finally, the accord also contained a January 31, 2010 deadline for countries to amend the accord with unilateral emissions mitigation measures. The European Union and 14 other developed countries, as well as 35 developing countries, submitted unilateral emissions mitigation measures.[62] The U.S. submission stated that the U.S. would cut emissions in line with the Waxman-Markey proposal.[63]

Federal Legislation or Regulation

Of course the big event in U.S. energy policy in 2009 was the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey) legislation that passed the U.S. House of Representatives in June. It was hoped by its backers that the Senate would pass a similar bill and the U.S. would go to Copenhagen with completed climate change legislation. Recall, briefly, that Waxman-Markey would set a cap on greenhouse gas emissions in the United States covering 85% of U.S. emissions. Compared to 2005 emission levels, this cap would decline over time to reduce emissions 3% by 2012, 20% by 2020 and eventually 83% below 2005 levels by 2050. This legislation also had a federal renewable portfolio standard of 6% by 2012, rising to 20% by 2020, and an energy efficiency standard of 15% by 2020 for electric utilities. Waxman-Markey legislation was not passed in the Senate and now appears to have been eclipsed by other efforts.

In the Senate, there have been at least two significant alternative approaches. Recently, senators Kerry, Graham, and Lieberman have laid out a framework for a sectoral approach that would (a) set significant greenhouse gas emission reduction targets, (b) encourage nuclear production, clean coal, and carbon capture and storage, and (c) support manufacturing and provide price protection to low- and middle-income consumers. By "sectoral," it is meant that different approaches would be taken for different sectors of carbon dioxide emitters. A recent article by *The Economist*, for example, speculates that cap-and-trade would apply to only electric utilities to start, taxes or fees would be used for transportation, and emission regulation would be used for other industries.[64] The overall goal for emissions reduction would remain in the same range as the Waxman-Markey approach.[65] This proposal is also said to include a price band for emissions ranging from $10 to $30 per ton, increasing over time.

[62] *Appendix I – Qualified economy-wide emissions targets for 2020* for developed countries is available at http://unfccc.int/home/items/5264.php. The *Appendix II – Nationally appropriate mitigation actions of developing country Parties* is available at http://unfccc.int/home/items/5265.php.
[63] The U.S. submission to the Appendix I of the Copenhagen Accord at http://unfccc.int/files/meetings/application/pdf/unitedstatescphaccord_app.1.pdf.
[64] "Cap-and-trade's last hurrah" The Economist, March 20, 2010 at page 32.
[65] "As Senate Trio Advances Climate Measure, Energy-Only Bill Remains a Possibility", New York Times ClimateWire, March 18, 2010 at http://www.nytimes.com/cwire/2010/03/18/18climatewire-as-senate-trio-advances-climate-measure-ener-84418.html.

In December 2009 Senator Cantwell proposed a cap-and-dividend approach which would impose a cap on emissions very similar to the ACES cap, but is substantially different in that it auctions 100% of the allowances, and returns 75% of the revenue to U.S. residents.[66]

The time left for this Congress to act on climate change legislation is limited. Other, pressing matters and the 2010 elections may push the debate into the future. Obviously, the Congress has been busy with health insurance reform and discussions over the economy and financial regulation reform. That Congress has not completed climate legislation may be a simple reflection of the relative priority Americans place on other issues. For example, in a December Gallup poll Americans favored the U.S. signing the Copenhagen Accord, (55% to 38%) but when given the choice between "Improve the Economy" and "Reduce Global Warming" they chose the economy (85% to 12%).[67] Additionally, a March Gallup poll shows that Americans' attitudes about the cause of global warming have changed since 2008. Americans are now evenly split on whether increases in the Earth's temperature are due to human activities or natural causes (50% to 46% in favor of human activities in 2010 polling versus 58% to 38% in favor of the human activities in 2008 polling).[68]

President Obama still says that he wants a "comprehensive" energy bill this year, meaning a bill that limits national greenhouse gas emissions rather than an energy bill that only promotes or regulates specific energy sectors.[69] While work on a bill continues in Congress, the closer the 2010 elections in November get, the lower are the chances of any major legislation being passed.

However, even in the absence of Congressional action, the U.S. EPA could regulate greenhouse gas emissions. Following the 2007 U.S. Supreme Court ruling in *EPA v. Massachusetts*, the EPA under the Obama Administration has taken several steps in preparation of regulating greenhouse gas emissions.[70] Most importantly, on December 7, 2009 EPA released its Final Rule on the Greenhouse Gas Endangerment and Cause or Contribute Finding.[71] This opens the way for a final ruling which could require regulating greenhouse gases from stationary sources.

This threat of EPA regulation has given greater impetus to Congressional action, according to many in Congress and in business. However, the most striking Congressional response has been to seek legislation to prevent EPA from regulating emissions.[72] In an attempt

---

[66] *See* the CLEAR Act side by side with Waxman-Markey, H.R. 2454, at http://cantwell.senate.gov/issues/CLEAR%20Act%20Side-by-Side%20with%20ACES.pdf.
[67] "Americans Favor U.S. Signature on Copenhagen Treaty", December 15, 2009 at http://www.gallup.com/poll/124712/Americans-Favor-Signature-Copenhagen-Treaty.aspx.
[68] "Americans' Global Warming Concerns Continue to Drop", Gallup, March 11, 2010 at http://www.gallup.com/poll/126560/Americans-Global-Warming-Concerns-Continue-Drop.aspx.
[69] "New 'gang' gathering on energy?" Politico, March 10, 2010 at http://www.politico.com/news/stories/0310/34161.html.
[70] *See EPA Climate Change – Regulatory Initiatives*, accessed March 19, 2010, at http://www.epa.gov/climatechange/initiatives/index.html.
[71] EPA's finding *Greenhouse Gas Endangerment and Cause or Contribute Findings* was signed by Administrator Jackson on December 7, 2009. *See* http://www.epa.gov/climatechange/endangerment.html.
[72] Senator Lisa Murkowski of Alaska has been most prominent in these efforts. *See*, for example, "Murkowski CO2 Amendment Could Have Broad Reach", New York Times, September 22, 2009, at

to pre-empt such legislation, EPA Administrator Jackson sent a letter to Senators explaining that EPA regulations are not imminent.[73] The letter clarified that no stationary sources will be subject to EPA regulation of greenhouse gas emissions in 2010. Furthermore, in the first half of 2011 only sources required to get a Clean Air Act permit for other emissions will need to address their greenhouse gas emissions. Before 2014, only the largest sources (a threshold substantially higher than 25,000-ton per year of greenhouse gas emissions) will have to apply for permits. The smallest sources subject to the Clean Air Act will not be subject to greenhouse gas emissions until 2016 or later.

State and Regional Actions

Though it may be some time before the Federal Government acts, States have and will continue to take action in parts of the country. In addition to the 29 States with renewable portfolio standards requiring some percentage of electricity be created from renewable resources, there are three regional greenhouse gas emission cap-and-trade programs in the U.S. that continue to make progress.

First, the Regional Greenhouse Gas Initiative (RGGI) went into action in ten Mid-Atlantic and Northeast States with a first compliance period beginning in 2009. RGGI covers greenhouse gas emissions in power plants only. By 2018 the cap on covered emissions is 10% lower than the 2009 cap. However, because the 2009 cap was set years in advance based on projections from 2005 emissions figures, it does not capture the effects of the recent recession, which lowered emissions. Given the fact the cap is above actual emissions, allowance prices have recently been at or near the auction floor price of $1.86.[74]

Second, the Western Climate Initiative (WCI) is a proposed cap-and-trade program with participants across seven Western U.S. States and four Canadian Provinces. WCI will cover more than power plants and is moving forward to implementation in 2012. By 2015, when transportation within the participating jurisdictions will be covered, roughly 90% of the carbon emissions in participating jurisdictions will be covered under the cap. However, although the Governors of these jurisdictions have agreed to join this regional organization, the necessary legislative approvals have not necessarily been forthcoming. Some partners are on pace to join in 2012 (California and New Mexico and some of the four Canadian provinces), while other participants have not implemented the necessary legislative steps and would have to join WCI later, if at all (Arizona, Montana, Oregon, Utah, and Washington).

Third, the proposed Midwestern Greenhouse Gas Reduction Accord (MGGRA), has members across six Midwestern U.S. States and the Canadian Province of Manitoba. This program was scheduled to launch in 2012 but, like the WCI, Governors of member states and Provinces have either pulled back due to political pressure or have been unable to receive the necessary legislative approval. This, in part, is due to upcoming gubernatorial elections in all six

---

http://www.nytimes.com/cwire/2009/09/22/22climatewire-murkowski-co2-amendment-could-have-broad-reac-8171.html.

[73] "Letter from EPA Administrator on GHG Permitting Plans", February 22, 2010, at http://epa.gov/oar/pdfs/LPJ_letter.pdf.

[74] *RGGI Auction Results*, accessed March 19, 2010, at http://www.rggi.org/co2-auctions/results.

participating states. MGGRA is now likely to miss its scheduled 2012 launch, and if several states decide not to join MGGRA, it may not have the critical mass to be implemented at all.[75]

The Impact of the Recession on Emissions Prices

The recent financial crisis and recession has had the expected effect of reducing energy use and related greenhouse gas emissions. In fact, these emissions have declined dramatically in 2008 and 2009. In 2008, U.S. CO_2 emissions from the use of fossil fuels, which have historically increased somewhat faster than total greenhouse gas emissions, decreased by 2.8% as compared to 2007. In 2009 CO_2 emissions decreased another 6.4%. These declines compare to average annual increases in U.S. CO_2 emissions from fossil fuels of 1.2% annually from 1990 to 2007. The size of these declines, due to the credit crisis and recession, appear to be enough to reduce gross U.S. greenhouse emissions to levels similar to those from the mid 1990s.[76]

Carbon markets have responded to the recession-driven drop in emissions exactly as expected, with lower prices for emissions allowances. In RGGI, fourth quarter auction prices for allowances for the 2009-2011 compliance period have dropped by 33% to 42% from the initial price in the third quarter of 2008 of $3.07 and from the high price of $3.51 in the first quarter of 2009.[77] In Europe, which has also suffered from the credit crisis and recession, allowance prices were at about €14 at the end of 2009, down from a high of €30 in 2008.[78]

B. Clean Air Legislation

There have been a number of recent actions taken by the EPA under the authority granted by the Clean Air Act to cap or reduce emissions in electric generation. These include a recent modification of the National Ambient Air Quality Standards (NAAQS), developments surrounding the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), and potential new legislation granting the EPA the ability to regulate air pollutants including SO_2, NOx, and mercury to an unprecedented level.

NAAQS

In March 2008, the EPA revised the NAAQS – air quality standards delineated by geographic areas in order to promote public health – and lowered the primary ozone standards to 0.075 parts per million (ppm) from 0.08 ppm. They have also noted that they continue to review

---

[75] *See*, for example, "Midwest Regional Carbon Pact Faces Delays and Rising Partisanship", New York Times Climate Wire, February 19, 2010 at http://www.nytimes.com/cwire/2010/02/19/19climatewire-midwest-regional-carbon-pact-faces-delays-an-40140.html.

[76] 2008 U.S. gross Greenhouse Gas Emissions were 6,946 million metric tons of CO_2 equivalent. A 6.4% drop in this figure would be 6,501 million metric tons of CO_2 equivalent. This level is roughly equal to the 1995 U.S. gross Greenhouse Gas Emissions were 6,480 million metric tons of CO_2 equivalent. *See* the EPA 2010 Draft U.S. Greenhouse Gas Inventory Report, Executive Summary at http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010-Chapter-Executive-Summary.pdf.

[77] *RGGI Auction Results*, accessed March 19, 2010, at http://www.rggi.org/co2-auctions/results.

[78] *See* Bloomberg New Energy Finance, *Week in Review* email of March 9, 2010.

and reconsider these standards. The new ozone standard could require retrofitting on current generation in non-attainment areas to reduce NOx emissions.

CAIR and CAMR

The CAIR and CAMR rules were promulgated by the EPA in order to significantly reduce industrial emissions of SO_2 and NOx, as well as mercury emissions from coal-fired power plants.

In CAIR, the EPA found that SO_2 and NOx emissions from 25 states and the District of Columbia contribute to unhealthy levels of fine particles in downwind states. In addition, NOx emissions in 25 eastern states and the District of Columbia contribute to unhealthy levels of 8-hour ozone in other downwind states. Emissions caps in 28 states were to be initially implemented in 2009 for NOx, beginning at 1.5 million tons, and in 2010 for SO_2, beginning at 3.6 million tons. Emissions caps would be lowered to 1.3 million tons for NOx and to 2.5 million tons for SO_2 in 2018.[79]

In CAMR, findings from CAIR were extended to mercury. The aim was to establish performance standards limiting mercury emissions from coal-fired power plants from 48 tons per year to 38 tons in 2010, and then to 15 tons in 2015.[80]

All of these emissions caps would be managed under a cap-and-trade system similar to what is currently being done successfully under the Acid Rain program that began in 1995.[81] However, in 2008, the DC Court of Appeals ruled that these rules were inconsistent with the Clean Air Act legislation. The Court vacated CAMR and remanded CAIR back to the EPA in order to develop a replacement rule consistent with the Court's finding. The CAIR implementation plans, including the cap-and-trade system, remain in place until a replacement rule is finalized, which the EPA stated in 2008 could take two years.[82]

Section 112 of the Clean Air Act

It appears that, in response to the vacatur of CAMR, the EPA intends to regulate mercury emissions as a hazardous air pollutant (HAP) by proposing air toxics standards for coal-and oil-fired generating units through "maximum achievable control technology" (MACT) provided in Section 112 of the Clean Air Act. In contrast to the cap-and-trade system, which aims to allocate emissions allowances in the most cost-efficient way, this sort of "command and control" regulation would require that existing emissions sources achieve better than the "average emission limitation achieved by the best performing 12 percent of the existing sources…"[83] The

[79] http://www.epa.gov/cair/charts_files/cair_emissions_costs.pdf.
[80] http://www.epa.gov/air/mercuryrule/basic.htm.
[81] *See* http://www.epa.gov/airmarkets/progsregs/arp/basic.html.
[82] The DC Court originally vacated both rules, but upon rehearing, allowed CAIR to remain in place while a replacement rule was developed. *See* http://www.epa.gov/air/interstateairquality/basic.html and http://www.epa.gov/air/mercuryrule/.
[83] Section 112(d)(3)(A), http://www.epa.gov/ttn/atw/112dpg.html.

EPA intends to finalize a rule by November 16, 2011.[84] Existing sources would have three years to comply after the issuance of the rules, or November 2014 according to the EPA schedule.[85]

The Clean Air Act Amendments of 2010

The EPA has been working with Senators Carper and Alexander to promote a bill currently in Senate Committee hearings that would effectively replace CAIR and mandate mercury regulation using MACT standards, tightening emissions controls beyond what has been proposed up to this point. The bill would amend the Clean Air Act for the first time since 1990, aim to reduce mercury emissions by at least 90% by 2015 using MACT standards, and use a three-step phase-in of NOx and SO_2 emissions caps according to the table below.

Table V.1 Emissions Caps Proposed by the Clean Air Act Amendments of 2010 (millions of tons)[86]

Emissions Type	2012	2015	2018+
SO_2	3.5	2	1.5
NOx	1.39	1.3	1.3

NOx and SO_2 emissions would be subject to a cap-and-trade system similar to what was attempted through CAIR.

Impact of these Actions

There have been a number of concerns expressed by electric utilities over this new string of regulations. John McManus of AEP recently expressed in committee hearings a number of issues with the new legislation.[87] Among these are concerns with the timing of the legislation, notably that implementation may be too fast (the first emissions caps will be implemented in 2012) and that a scramble by electric generators to comply with the caps would be immensely costly and have adverse impacts to grid reliability, since many coal plants would have to shut down to install control equipment. Mr. McManus estimates that by full implementation, all current coal-generating units will be retrofitted or retired. Another concern is that a 90% reduction on mercury emissions using MACT may be unachievable given current control technologies, which have not been shown to reach this level of reductions over extended periods.

The major concern mentioned appears to be the lack of coordination between various emissions restrictions being considered by the EPA, something that has been echoed elsewhere. CIBO has noted that “The plethora of rules may make it impossible for any one unit to meet all of the rules simultaneously.”[88] With staggered emissions caps, MACT rules scheduled for 2011,

[84] Ibid.
[85] Section 112(i)(3)(A), http://www.epa.gov/ttn/atw/112ipg.html.
[86] Senate Bill 2995: Clean Air Act Amendments of 2010 at Sections 3 and 4.
[87] *See* Testimony of John M. McManus for American Electric Power before the Senate Environment and Public Works Committee and Subcommittee on Clean Air and Nuclear Safety Joint Hearing, March 3, 2010.
[88] CIBO August 2009 conference workshop summary at http://www.cibo.org/emissions/2009/cd/workshop.htm.

with potentially more stringent MACT standards in possible legislation for 2015, and the EPA considering future regulation of non-mercury HAPs as well as revised NAAQS standards, many generators may face several rounds of outages for compliance and may incur significant expense for emissions control equipment that could be optimized with well coordinated standards across all types of emissions. The EPA has mentioned in testimony that they expect the new legislation to result in a 1.5% to 2.5% increase in the retail cost of power between now and 2025.[89]

C. Natural Gas Prices

Because natural gas is at the margin so often, EIS market prices rise and fall pretty much in tandem with natural gas prices. To wit, the 48% decline in average EIS Market prices from 2008 to 2009 appears to be driven in large part by the significant decline in natural gas prices. In 2009, the simple average price for natural gas at Panhandle was $3.32 per MMBtu which is a 54% drop from the average price of $7.14 in 2008.[90]

The link between EIS Market prices and natural gas prices is revealed in more detail back in Figure II.1. It shows that changes in the monthly average EIS Market price in peak periods tracks quite well with the changes in the monthly average natural gas prices at Panhandle. Also shown there is the major price spike in the summer of 2008. In 2008, the daily natural gas price varied from a high of $11.60 per MMBtu on June 24th to a low of $1.71 per MMBtu on October 3rd. Just for comparison, in 2009 the low price at Panhandle was $1.87 per MMBtu on September 4th and the high price was $5.96 per MMBtu on December 29th.

Because of this link between EIS Market prices and natural gas, it is important to look at the apparent causes of the natural gas price decreases in 2009. It seems that the standard answer is a good starting point – the prices were driven down by changes in demand and supply. As to more specific explanations, we doubt that many forecasters predicted the peak or the trough of natural gas prices over the past two years. Still, three of the most likely explanations are (a) the recession, (b) the increase in worldwide liquefied natural gas (LNG) facilities, and (c) innovative, new drilling techniques for unconventional gas.

The most direct effect of the recession would be reduced demand. Looking nationwide, U.S. consumption of natural gas in 2009 was 1.4% lower than in 2008.[91] And 2008 consumption was slightly above that in 2007 – by about 0.3%. Based on these nationwide consumption figures, there was no dramatic decline in natural gas use in the last two years. (We will note that, while U.S. consumption fell a bit, U.S. natural gas market supply increase in 2009 by 3.7% which should have put downward pressure on prices.[92])

---

[89] Regina McCarthy, Assistant Administrator of the EPA, in live testimony before the Senate and Public Works Committee, March 3, 2010 at http://epw.senate.gov/public/index.cfm?FuseAction=Hearings.Hearing&Hearing_ID=0780a976-802a-23ad-42f3-03e35b75a30a.

[90] *See* https://www.theice.com/marketdata/reports/ReportCenter.shtml.

[91] Short-**T**erm Energy Outlook", Figure entitled "**U.S. Total Natural Gas Consumption**", Forecast & Analysis. EIA independent Statistics and Analysis, **April 2010**. Web. **April 12, 2010** at http://www.eia.doe.gov/emeu/steo/pub/gifs/Fig17.gif.

[92] EIA, Page 5, "Short-term Energy Outlook", Forecast & Analysis. EIA independent Statistics and Analysis, January 12, 2010. Web. March 30 2010. http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/jan10.pdf.

As to LNG, just a few years ago it was thought that the U.S. would turn inevitably to LNG on the world market as U.S. production declined. LNG was thought to be an important fuel for Europe and Asia, too. With this view in mind, significant LNG import facilities were added in the U.S. and worldwide and, there now is a surplus of LNG which is driving down its price. The U.S. EIA stated that "LNG import capacity is expected to be more than six times greater in 2009 than it was at the beginning of the decade."[93]

As to unconventional gas supply, note that in its biennial report for 2008, the Potential Gas Committee declared that natural gas reserves in the U.S. increased by 39% as compared to the estimated reserves just two years earlier in 2006.[94] The reason for this increase in reserves, in turn, was a breakthrough in drilling technology for shale-gas deposits which are found throughout the U.S., with notable reserves in Texas as well as in Pennsylvania and New York.[95] The new technology combined new techniques for drilling horizontally with techniques for hydraulic fracturing.[96] The Potential Gas Committee stated that "Most of the increase [in reserves] from the previous assessment arose from re-evaluation of shale-gas plays in the Appalachian basin and in the Mid-Continent, Gulf Coast and Rocky Mountain areas."[97] To put further emphasis on shale-gas, the Committee stated "The growing importance of shale gas is substantiated by the fact that, of the 1,836 Tcf of total potential resources, shale-gas accounts for 616 Tcf (33%)."[98] Some credible sources are calling this increase in shale-gas reserves and other unconventional natural gas supplies "the biggest energy innovation of the decade" or even an energy "revolution."[99]

Well, given this revolution, what is the expectation for the price of natural gas in the near-term? Using current futures prices as the measure, it is clear that the market does not currently see prices staying in the $3-$4 range per MMBtu that was seen in 2009. For example, as displayed in Table V.2, the current NYMEX futures prices (Trade Date of March 17, 2010) for 2011 through 2015 range from $5.52 to $6.77 per MMBtu. However, while the level of prices are expected to rise above last year, prices would be much higher had unconventional supply potential not increased. Supporting this point is data showing expectations for future

---

[93] EIA, energy in brief, "What role does liquefied natural gas (LNG) play as an energy source in the United States." December 11, 2009. Web. March 30, 2010. http://tonto.eia.doe.gov/energy_in_brief/liquefied_natural_gas_lng.cfm.

[94] Press Release, Page 5, Potential Gas Committee, "Potential Gas Committee reports unprecedented increase in magnitude of U.S natural gas resource base." June 18, 2009. Dr. John B. Curtis, Potential Gas Agency. Web. March 30, 2010. http://www.energyindepth.org/wp-content/uploads/2009/03/potential-gas-committee-reports-unprecedented-increase-in.pdf.

[95] EIA. Maps, "Shale Gas Plays," Natural Gas. EIA Independent Statistics and Analysis, May 28, 2009. Web. March 31, 2010. http://www.eia.doe.gov/oil_gas/rpd/shale_gas.pdf.

[96] *See* Daniel Yergin and Robert Ineson, "America's Natural Gas Revolution", The Wall Street Journal, November 2, 2009 ("Yergin").

[97] Press Release, Page 1, Potential Gas Committee, "Potential Gas Committee reports unprecedented increase in magnitude of U.S natural gas resource base." June 18, 2009. Dr. John B. Curtis, Potential Gas Agency. Web. March 30, 2010. http://www.energyindepth.org/wp-content/uploads/2009/03/potential-gas-committee-reports-unprecedented-increase-in.pdf.

[98] Press Release, Page 2, Potential Gas Committee, "Potential Gas Committee reports unprecedented increase in magnitude of U.S natural gas resource base." June 18, 2009. Dr. John B. Curtis, Potential Gas Agency. Web. March 30, 2010. http://www.energyindepth.org/wp-content/uploads/2009/03/potential-gas-committee-reports-unprecedented-increase-in.pdf.

[99] *See* Yergin.

natural gas prices as reflected by futures prices back in 2008. Table V.2 shows that, at the time of the price spike in summer 2008, prices in the 2011 to 2015 time frame were expected to be in the $10 to $11 per MMBtu range.

Table V.2 Sample of NYMEX Natural Gas Prices at Different Trade Dates

Trade Date	Future Prices by Year ($/MMBtu)				
	2011	2012	2013	2014	2015
June 23, 2008	$10.60	$10.59	$10.77	$10.99	$11.23
March 17, 2010	$5.52	$5.96	$6.26	$6.53	$6.77

SOURCE: NYMEX for Henry Hub

To many forecasters, the competition between foreign LNG and U.S. unconventional supply will have a great influence on the future path for natural gas prices. One major threshold question is whether unconventional supply in the U.S. will be enough to hold foreign LNG at bay. One worry about using foreign LNG is that its price would be tied to the price of oil. It is thought that, if unconventional supply in the U.S. is sufficient to hold LNG at bay, we can avoid the influence of volatile oil prices on the price of natural gas in the U.S.

However, the sufficiency of shale-gas resources is uncertain for at least two reasons. The first is the uncertainty over how much shale-gas there is and how rapidly production depletes after it starts. The second is uncertainty over environmental regulation and opposition. There already is vocal concern about the potential for damage to water supplies from hydraulic fracturing. For example the State of New York has put a moratorium on new wells in some areas.[100]

The uncertainty over natural gas prices caused by uncertainty over the need to import LNG and by uncertainty over the extent of shale resources, simply adds to the uncertainty created by a number of other factors such as weather; for example, the number of hot and cold days influence demand and the number of hurricanes can cut supply. Public policy also adds considerable uncertainty. Global climate change policy and Renewable Portfolio Standards both can affect the demand for natural gas.

In the face of this uncertainty, the range of reasonable price forecasts is very wide. The mitigation for this natural gas price uncertainty could come in the form of fixed-price contracts by gas suppliers; this is especially true if the natural gas suppliers want to win business in power generation away from coal. But such contracts would take a new mind set for natural gas producers and for the financial institutions that finance them, and that new mindset is only beginning to be seen.

[100] See “An Unconventional Glut”, The Economist, March 11, 2010.

APPENDIX A

List of Acronyms

Acronym	Full Term
ACES	American Clean Energy and Security Act of 2009
AECC	Arkansas Electric Cooperative Corporation
AECI	Associated Electric Cooperative Inc.
AEPW	American Electric Power
AFC	Annual Fixed Cost
ARRA	American Recovery and Reinvestment Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CLEC	Cleco Power LLC
CLWL	City of Clarksdale, Mississippi
CT	Combustion Turbine
DBA	Designated Balancing Authority
DC	Direct Current
DETEC	Deep East Texas Electric Cooperative
DISIS	Definitive Interconnection System Impact Study
DOE	Department of Energy
DSS	Decision Support System
EHV	Extra High Voltage
EIA	Energy Information Administration
EIS	Energy Imbalance Service
EMDE	Empire District Electric Co. (The)
ENTR	Entergy, Incorporated
EPA	Environmental Protection Agency
EPE	El Paso Electric
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GLDF	Generator to Load Distribution Factor
GQTF	Generation Queuing Task Force
GRDA	Grand River Dam Authority
HAP	Hazardous Air Pollutant
HHI	Herfindahl-Hirschman Index
INDN	City Power & Light, Independence, Missouri
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITP	Integrated Transmission Plan
KACY	Board of Public Utilities, Kansas City, Kansas
KCPL	Kansas City Power & Light
KCPL-GMO	KCPL Greater Missouri Operations Company

kV	Kilovolt (1,000 volts)
LAFA	City of Lafayette, Louisiana
LEPA	Louisiana Energy & Power Authority
LES	Lincoln Electric System
LIP	Locational Imbalance Price
LNG	Liquefied Natural Gas
MACT	Maximum Achievable Control Technology
MGGRA	Midwestern Greenhouse Gas Reduction Accord
MIDW	Midwest Energy, Inc.
MISO	Midwest Independent Transmission System Operator
MKEC	Mid-Kansas Electric Company
MMBtu	Thousand Thousand British Thermal Units (1,000,000 Btu)
MMU	Market Monitoring Unit
MPS	Missouri Public Service
MRO	Midwest Reliability Organization
MW	Megawatt (1,000,000 watts)
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_X	Nitrogen Oxide
NPCC	Northeast Power Coordinating Council
NPPD	Nebraska Public Power District
O&M	Operation and Maintenance
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
O/S	Over-Scheduling
OKGE	Oklahoma Gas & Electric
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
PISIS	Preliminary Interconnection System Impact Study
PNM	Public Service Company of New Mexico
Ppm	Parts per Million
PRR	Protocol Revision Request
PSCO	Public Service Company of Colorado
RE	Regional Entity
RFC	ReliabilityFirst Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RNU	Revenue Neutrality Uplift
RPS	Renewable Portfolio Standards
RSC	Regional State Committee
RTO	Regional Transmission Organization
RUC	Reliability Unit Commitment
SERC	SERC Reliability Corporation
SMP	System Marginal Price

SO_2	Sulfur Dioxide
SP Loss	Self-Provided Losses
SPP	Southwest Power Pool, Inc.
SPS	Southwestern Public Service Company
SPPT	Synergistic Planning Project Team
STEP	SPP Transmission Expansion Plan
SUNC	Sunflower Electric Power Corporation
SWPA	Southwestern Power Administration
Tcf	Trillion cubic feet
TCR	Transmission Congestion Rights
TNP	Texas – New Mexico Power
TRE	Texas Regional Entity
UD	Uninstructed Deviation
UN	United Nations
U/S	Under-Scheduling
VRL	Violation Relaxation Limit
WAPA	Western Area Power Administration
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WERE	Westar Energy, Inc.
WFEC	Western Farmers Electric Cooperative
YAZO	Public Service Commission of Yazoo City, Mississippi

APPENDIX B

List of SPP Members as of December 31, 2009

Cooperatives

Arkansas Electric Cooperative Corporation
East Texas Electric Cooperative, Inc.
Golden Spread Electric Cooperative
Kansas Electric Power Cooperative
Mid-Kansas Electric Company
Midwest Energy, Inc.
Northeast Texas Electric Cooperative
Rayburn Country Electric Cooperative
Sunflower Electric Power Corporation
Tex-La Cooperative of Texas, Inc.
Western Farmers Electric Cooperative

Independent Power Producer

Acciona Wind Energy
Calpine Energy Services, L.P.
Dogwood Energy, LLC
Entergy Power Ventures, LP
Tenaska Power Services Company

Independent Transmission Companies

Hunt Transmission Services, LLC
ITC Great Plains
Trans-Elect Development Company, LLC

Investor-Owned Utilities[101]

American Electric Power
    Public Service Company of Oklahoma
    Southwestern Electric Power Company
Cleco Power, LLC
Empire District Electric Company
Entergy Services, Inc.
Exelon Power Team
Kansas City Power & Light Company
    KCP&L Greater Missouri Operations Company[102]

---

[101] Since the end of 2009, SPP has added two new IOUs. These two companies are AEP Oklahoma Transmission Company, Inc. and AEP Southwestern Transmission Company, Inc.

OG&E Electric Services
Westar Energy, Inc.
    Kansas Gas and Electric Company
Xcel Energy
    Southwestern Public Service Company

Marketers

Cargill Power Markets, LLC
Constellation Energy Commodities Group, Inc.
Duke Energy Americas, LLC
Dynegy Power Marketing, Inc.
Edison Mission Marketing & Trading, Inc.
El Paso Merchant Energy, L.P.
Luminant Energy Company, LLC
NRG Power Marketing, Inc.
Shell Energy North America (IS), L.P.
Williams Power Company, Inc.

Municipals

Board of Public Utilities, Kansas City, Kansas
City of Clarksdale, Mississippi
City of Lafayette, Louisiana
City Power & Light, Independence, Missouri
City Utilities of Springfield, Missouri
Kansas Municipal Energy Agency
Lincoln Electric System
Oklahoma Municipal Power Authority
Public Service Commission of Yazoo City, Mississippi

State Agencies

Grand River Dam Authority
Louisiana Energy & Power Authority
Nebraska Public Power District
Omaha Public Power District

SPP Contract Participants

Southwestern Power Administration

---

[102] Aquila, Inc. (Missouri Public Service and St. Joseph Power & Light Company) was acquired by Kansas City Power & Light Company ("KCPL") and became KCPL Greater Missouri Operations Company ("KCPL GMO"). Although KCPL GMO is now a subsidiary of KCPL, it is still a voting (IOU) member of SPP.