2004 STATE OF THE MARKET REPORT

SOUTHWEST POWER POOL, INC.

Prepared by:

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Independent Market Monitor
for the Southwest Power Pool, Inc.

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TABLE OF CONTENTS

<u>List of Figures</u>

List of Tables

EXECUTIVE SUMMARY

Purpose

The Independent Market Monitor (IMM) for the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) is required to provide an annual report on electricity market conditions to the SPP Board of Directors, the Federal Energy Regulatory Commission (FERC), the SPP Regional State Committee (RSC), and other appropriate state regulatory authorities.[1] The purpose of this 2004 State of the Market Report is to fulfill that requirement. Since SPP has not yet implemented new markets for the services it provides, this 2004 State of the Market Report is intended to describe current conditions in existing bilateral markets for electricity and in the market for transmission services. This report also quantifies some key measures of market activity that will serve as a baseline by which changes can be measured once markets for SPP's services are in full operation.

Electricity Supply and Demand

As an RTO, SPP provides services using the transmission systems of its members. SPP's members cover a 250,000 square mile region over all or part of eight states containing 4 million customers (this region is known as SPP's "footprint"). SPP currently has forty-five members, and its footprint includes seventeen separate control area operators that individually are responsible for matching electricity supply and demand within their territories.

SPP's members provide electricity to meet their customers' needs. The peak electric demand of these customers in the SPP footprint in 2004 was 38,767 MW. This 2004 peak demand was 1.5% higher than in 2003. Electric energy use in 2004 was 193.9 million MWh. Electricity use in SPP is seasonal and peaks during the summer, particularly in July and August. Customers within the five largest control areas in SPP account for 73.5% of total electric energy use in SPP. These five control areas and their shares of 2004 energy use are American Electric Power West (AEPW) with 22.8%, Oklahoma Gas and Electric (OKGE) with 14.5%, Westar Energy, Inc. (WERE) with 14.3%, Southwestern Public Service Company (SPS) with 13.9%, and Kansas City Power and Light (KCPL) with 8.0%.

Generating facilities supply the electricity that is used by the customers of SPP's members. At the end of 2004, the total generating capacity in SPP was 55,984 MW. In comparison to the peak demand of 38,767 MW during 2004, SPP has a significant resource margin (generation capacity in excess of peak demand) of 17,217 MW or 44.4%, presuming all generating capacity would be deliverable when the peak electricity demand occurs. Since 2000, there has been a surge in construction of new natural gas-fired generating plants, which contributed significantly to the 44.4% resource margin. Of the total generating capacity in SPP, 54.6% is natural gas-fired, and 90.9% of capacity in

[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.

SPP is either coal- or natural gas-fired. This substantial resource margin has important implications for both reliability and for mitigation of the potential exercise of market power within SPP.

Transmission Capability

Transmission systems are the "highways" that bridge the gap between suppliers and customers. As expected in any region, the number and capability of these highways vary across the SPP footprint. This is seen, for example, in the variation across control areas in the transmission import capacity per MW of peak load (as indicated by total tieline capacity between control areas). Within SPP, the nominal tieline transmission capacity for each control area in comparison to the peak load of each area varies from over twelve times the peak load to less than peak load. Variation in the transmission highways across SPP is also seen in the variation of the voltage levels of transmission facilities used throughout SPP. These variations can have implications for the competitiveness of the SPP markets.

The connectivity between the transmission system in the SPP footprint and the transmission systems in surrounding regions also varies. SPP's highest level of connectivity with a surrounding region is with the Southeast Electric Reliability Council (SERC). Most of SPP's link to SERC is with the Entergy and Associated Electric Cooperative, Inc. (AECI) control areas with approximately 40,000 MVA in total tieline capacity. However, over half of SPP's connectivity with Entergy is due to transmission lines connecting Entergy's control area in SERC and three control areas in SPP that are all relatively isolated from the rest of the SPP system. Direct transmission connectivity between SPP and the two other surrounding regions in the Eastern Interconnect (the Midwest Reliability Organization (MRO) and the Mid-America Interconnected Network, Inc. (MAIN)) is significantly less than SPP's direct connectivity with SERC.

In addition, SPP shares five high-voltage Direct Current (DC) ties with the Western Electricity Coordinating Council (WECC) and the Electric Reliability Council of Texas (ERCOT). These DC ties give 600 MW of transfer capability with WECC and 820 MW with ERCOT.

Transmission Service Requests and Transmission Congestion

SPP provides transmission service over the transmission systems of its members through a request process. Through this 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 that the capability of its members' transmission systems to move electricity is not exceeded. Fluctuations in request levels can be indicators of the relative level of supply and demand for transmission service within the SPP footprint.

While the overall level of transmission requests *approved* by SPP (and confirmed and used by third parties) remained fairly steady in SPP during 2003 and 2004, the *total* level of requests spiked during Summer 2003 and again in the second half of 2004. This increase in requests resulted in above normal levels of refused, withdrawn, and invalid requests for transmission service, particularly for shorter-term, non-firm transmission service. It appears that these additional requests for service during 2004 were largely for use of DC tie transfer capability to export power into ERCOT.

Since SPP approves requests for transmission service in advance of when the electricity will actually be moved across the transmission systems in SPP, another process is required to manage flows of electricity in real-time in the event that the capability of the systems to move electricity is exceeded because of outages or other events. Such transmission constraints in SPP are currently managed in real-time using the North American Electric Reliability Council (NERC) Transmission Loading Relief (TLR) process. Overall levels of TLR curtailments have increased in SPP during the past few years. This is due to an increase in *non-firm* service curtailment. *Firm* service curtailments were very minor compared to non-firm service curtailments and actually decreased in 2004 as compared to the prior two years. These TLR events occurred during both on- and off-peak hours in 2004, but spiked during off-peak hours. Major regions of congestion during 2004 occurred westward and southward out of eastern Kansas and southward along the eastern portion of the border between Oklahoma and Texas near the edge of the ERCOT region. The duration of constraints on transmission corridors ranged from 169 hours to 672 hours during 2004. The locations of congestion have also changed from year-to-year during the period from 2001 to 2004. This is in part due to the effect of transmission upgrades designed to solve existing congestion in the SPP region.

Bilateral Electricity 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. For the existing bilateral electricity power market in the SPP footprint, this report relies on prices reported by the trade press and others for short-term bilateral power sales. According to such price information, average on-peak prices in SPP increased by 21% from 2001 to 2004 (from $37.45/MWh in 2001 to $45.29/MWh in 2004.) Average off-peak prices increased by 28% (from $16.09/MWh in 2001 to $20.58/MWh in 2004.) In the 2001 to 2004 period, there were few significant price spikes. Prices rose above $100/MWh on only two occasions.

Rising natural gas prices are a driving force in the increase of on-peak electricity prices in the current bilateral electricity market in the SPP footprint. This is to be expected given the region's heavy dependence on natural gas for power generation, and a range of statistical tests confirms this result. Average daily natural gas prices in the SPP region increased by 41% from 2001 to 2004. The fact that on-peak electricity prices rose 21% while natural gas prices rose 41% during 2001 to 2004 may be due to the increased efficiency of new natural gas-fired facilities built in the SPP region during those years.

As to the level of prices, SPP's on-peak average price of $45.29/MWh tends to be in the lower end of the rather narrow range of average on-peak prices in the region, which are between $42.96/MWh and $50.79/MWh. Among the wider range of average off-peak prices, which are between $18.43/MWh and $35.45/MWh, SPP's average price of $20.58/MWh also tends to the lower end. The pricing points evaluated in WECC and ERCOT consistently had the highest and second highest, respectively, average on-peak and off-peak prices among SPP and its surrounding regions. Changes in electricity prices in SPP also are highly correlated with those in surrounding regions in the Eastern Interconnect, such as MRO and SERC. This means that the daily prices in these surrounding regions move at the same time and in the same direction as prices in SPP.

Transmission Expansion and New Generation Interconnection

SPP has active transmission expansion and generation interconnection processes in place to encourage increases in electricity supply availability. Under SPP's current transmission expansion plan, approximately $564 million will be invested in increasing the reliability of the transmission system in SPP between 2004 and 2010. In addition, as of the end of 2004, nearly $400 million in economic expansion projects were also being studied by SPP; much of this economic expansion is to accommodate new wind generation. The transmission expansion cost allocation methodology developed by the RSC, and recently approved by the FERC, helps ensure these expansions are built by facilitating cost allocation and cost recovery for these projects.

SPP's generation interconnection queue contains approximately 7,700 MW of active projects. Over half of this capacity is for new wind facilities located primarily in western SPP. The rest of the capacity is for coal- and natural gas-fired units mostly located in eastern SPP, particularly in eastern Kansas and western Missouri. If all of these active projects are built, generating capacity in SPP could increase by up to 14%. However, without the significant economic investment in new transmission infrastructure referenced above, the full output of new wind facilities will be unable to move out of western SPP.

New Markets and Market Power

SPP and its members are creating new markets for supplying services provided by SPP under its current Open Access Transmission Tariff (OATT). Initially, an energy imbalance service (EIS) market will be created. Currently, SPP provides EIS under Schedule 4 of its OATT. Under this schedule, SPP's customers can either arrange for energy imbalance service on their own or SPP will compensate for imbalance energy and pass the cost through to its customers with an imbalance. Under SPP's proposed EIS Market, the market will price imbalance energy throughout SPP for all of SPP's Transmission Customers. SPP anticipates filing with the FERC for approval of its EIS Market in June 2005. The EIS Market is scheduled to start no later than March 1, 2006. In later phases, development of an ancillary services market and market-based congestion management will be undertaken.

With respect to market power, absent transmission constraints, the SPP region has a workably competitive energy market. When a transmission constraint occurs in SPP and subdivides the market, generation owners in SPP may be able to exercise market power to raise electricity prices and increase their revenues. As a result, it is proposed that mitigation measures be imposed by SPP to block the exercise of market power in its proposed EIS Market. As part of the June 2005 filing at the FERC, the IMM will submit testimony detailing the proposed market mitigation measures and a market monitoring plan.

I. MARKET CHARACTERISTICS

A. Brief Overview of SPP

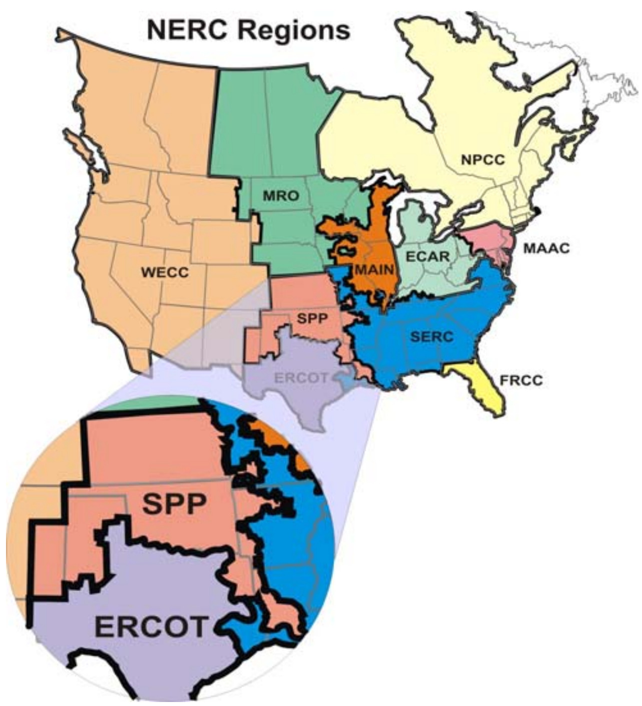
SPP is a NERC Regional Reliability Council and provides transmission service on the transmission facilities owned by its members. It is also creating new markets for imbalance energy, ancillary services, and congestion management as part of its fulfillment of its obligations as an RTO. SPP was granted RTO status by the FERC during 2004.

Location of SPP

The SPP RTO and Regional Reliability Council are located in the southwest corner of the Eastern Interconnect. It is bordered by the MRO, MAIN and SERC reliability councils in the Eastern Interconnect.[2] SPP also shares borders with the WECC and ERCOT reliability councils.

Figure I.1

MAP OF NERC RELIABILITY REGIONS AND SPP



SOURCE: NERC

The SPP footprint covers 250,000 square miles in part or all of eight states and 4 million customers. It covers all of Kansas and Oklahoma and parts of six other states

2 Prior to January 1, 2005, the MRO Regional Reliability Council was known as the Mid-Continent Area Power Pool (MAPP) Regional Reliability Council.

(Missouri, Arkansas, Texas, Louisiana, Mississippi, and New Mexico). The amount of territory covered by SPP in Mississippi is minimal.

The SPP region is centered on Oklahoma and Kansas. Spurs extend (a) southward into northwest Texas / Eastern New Mexico, (b) eastward into Arkansas, and (c) southward into Northeastern Texas and Western Louisiana.

SPP Membership

SPP has 45 members who serve load, provide generation supplies, and/or own transmission facilities. During 2004, SPP's member count fluctuated between 44 and 50. SPP's members include cooperatives, municipals, and state agencies in addition to investor-owned utilities (IOUs), independent power producers, and power marketers. A count of SPP members by category is shown in the table below.

Table I.1

SPP MEMBERS AS OF MARCH 2005

SPP Members	Number of Members
Investor-Owned Utilities	13
Cooperatives	8
Municipals	7
State Agencies	2
Independent Power Producers	3
Power Marketers	12
Total Members	45

SOURCE: SPP at http://www.spp.org/About_Members.asp

A list of SPP's members as of March 2005 is also attached to this report as an appendix.[3]

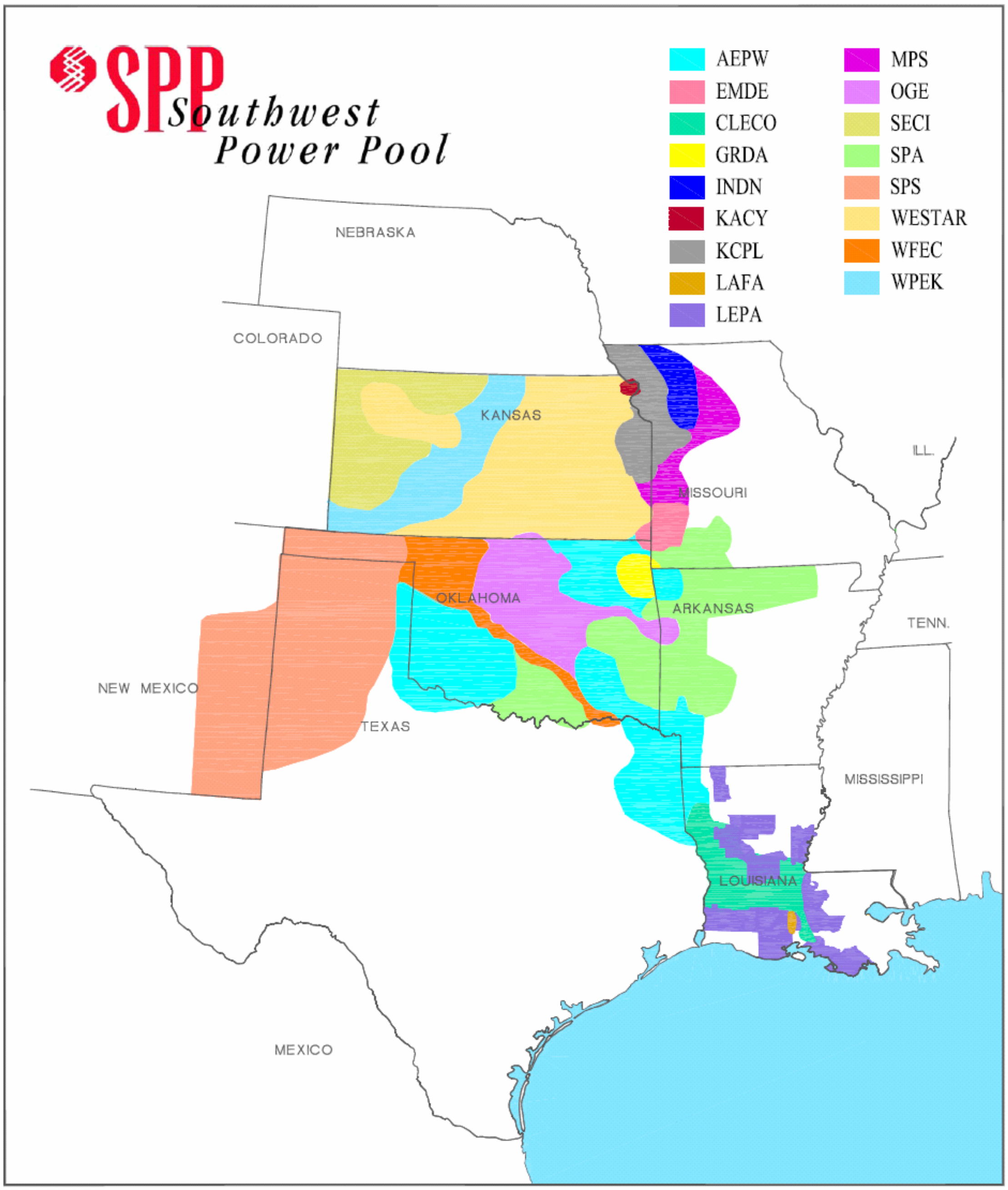
Control Areas in SPP

The SPP region is comprised of 17 control areas (including the Southwestern Power Administration (SWPA)), which are operated by IOUs, cooperatives, municipals, and state agencies. In essence, a control area is responsible for managing the supply/demand balance for electricity within its borders to assure reliability. A rough approximation of the locations of these control areas is shown in the figure below. SWPA withdrew from SPP on October 31, 2004, but SPP continues to sell transmission service in the SWPA control area under an interim agreement.

[3] Note that while all members are part of SPP as a regional reliability council, SPP does not provide reliability coordination services for all members, nor do all transmission-owning members have their facilities under SPP's regional tariff (the OATT). In addition, SPP provides reserve sharing service to nearby control areas that are not members of SPP, including AECI, Entergy, and Louisiana Generating.

Figure I.2

MAP OF SPP CONTROL AREAS



SOURCE: SPP
Note: The control areas titled CLECO, MPS, OGE, SECI, SPA, Westar, and WPEK in this map are called CLEC, Aquila-MPS, OKGE, SUNC, SWPA, WERE, and Aquila-WEPL elsewhere in this report.

B. Customers – The Demand for Electricity

Peak Demand and Energy Use by Month

Table I.2 shows that the peak demand in SPP was 38,767 MW in August 2004, which is consistent in magnitude and timing with previous years. The highest peaks typically occur in the late summer months as the demand for electricity is large due to cooling needs on the hottest days of the year. To emphasize this point, the peak in August 2004 was 72.4% higher than the peak in the lowest month, March.

Table I.2

MONTHLY PEAK ELECTRIC
ENERGY DEMAND (MW) FOR SPP

Month	2001	2002	2003	2004
January	25,213	26,732	27,813	27,727
February	24,055	26,225	26,550	26,794
March	21,802	26,226	24,355	22,489
April	23,142	26,187	25,728	23,010
May	29,432	31,118	30,699	32,042
June	31,675	34,179	35,210	34,350
July	36,898	37,817	37,044	37,695
August	36,518	38,200	38,196	38,767
September	30,118	35,646	30,868	34,076
October	21,786	30,726	24,523	24,955
November	24,613	24,088	23,867	26,040
December	22,769	26,122	24,844	28,621
Peak	36,898	38,200	38,196	38,767
Yearly Change	N/A	3.5%	0.0%	1.5%

SOURCE: FERC Form 714 and SPP OPS1
Note: The LAFA control area is not included in 2004 data.

Table I.3 displays electric energy use by month. In 2004, energy use was 193.9 million MWh. While energy use is highest in the summer, it does not peak as sharply as demand. The peak energy use in July was 42.9% higher than the lowest month, April. Total energy use increased by 3.8% in 2004 as compared to 2003. The load factor, which is the total electric energy use (193,931,300 MWh), divided by peak electric energy demand (38,767 MW) times the number of hours in the year (8,760), is 57.1% for SPP. The purpose of a load factor is to assess the amount of energy use consumed compared to maximum demand.

Table I.3

TOTAL ELECTRIC ENERGY
USE (MWH) WITHIN SPP BY MONTH AND YEAR

Month	2001	2002	2003	2004
January	15,062,764	14,998,895	15,476,829	16,004,922
February	12,933,881	13,334,037	13,715,476	15,131,874
March	13,392,264	14,355,431	13,840,581	14,222,696
April	12,951,013	13,739,781	13,505,896	13,684,563
May	14,512,469	14,921,652	15,041,588	16,399,342
June	16,633,607	17,815,097	16,407,968	17,252,902
July	20,478,400	20,333,862	20,660,105	19,553,691
August	19,622,438	20,407,856	20,619,550	18,953,642
September	14,926,821	16,934,543	15,205,432	17,245,327
October	13,788,953	14,374,024	13,866,201	14,905,589
November	13,361,565	13,889,201	13,494,786	14,298,951
December	14,327,047	15,263,229	14,972,800	16,277,800
Total	181,991,222	190,367,608	186,807,212	193,931,300
Yearly Change	N/A	4.6%	-1.9%	3.8%

SOURCE: FERC Form 714 and SPP OPS1
Note: The LAFA control area is not included in 2004 data.

Demand by Control Area

Table I.4 displays peak demand and energy use in 2004 by control area. In SPP, AEPW is the control area with the most electric energy use with 22.8% of the SPP total in 2004. OKGE (14.5%), WERE (14.3%), SPS (13.9%), and KCPL (8.0%) are the next largest in terms of electric energy use. Together, these five largest control areas account for 73.5% of the SPP total. These same five control areas also had the highest peak demands, ranging from 9,106 for AEPW to 3,492 for KCPL.

Table I.4

CONTROL AREA DEMAND AND
ELECTRIC ENERGY USE IN 2004

Area	2004 MWh	Percent	Non-Coincident Peak
AEPW	44,310,512	22.8%	9,106
OKGE	28,072,370	14.5%	5,803
WERE	27,701,442	14.3%	5,851
SPS	26,997,353	13.9%	4,893
KCPL	15,539,244	8.0%	3,492
CLEC	10,753,917	5.5%	2,030
Aquila - MPS	7,912,438	4.1%	1,774
SWPA	6,593,275	3.4%	1,347
WFEC	6,207,889	3.2%	1,217
GRDA	4,985,125	2.6%	972
EMDE	4,963,273	2.6%	980
Aquila - WEPL	2,877,452	1.5%	592
KACY	2,554,686	1.3%	495
SUNC	2,216,153	1.1%	395
LEPA	1,148,137	0.6%	246
INDN	1,098,034	0.6%	288
SPP	193,931,300	100%	-

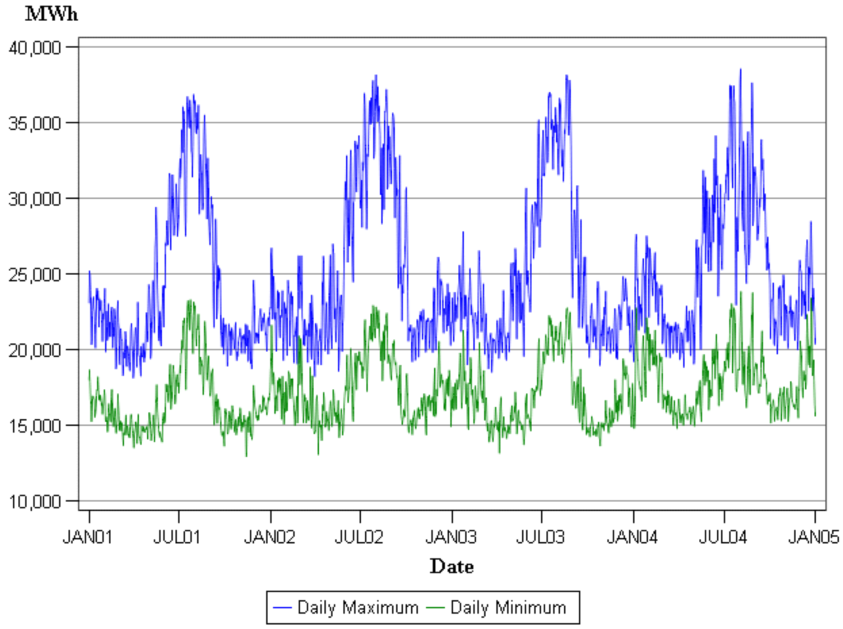
SOURCE: SPP OPS1
Note: The LAFA control area is not included in 2004 data.

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 discussion above, 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 use throughout the year. In addition, the difference between the maximum and minimum daily electric demand widens during the summer with a maximum swing over the four year span of 16,700 MW occurring in July 2002. This difference narrows during the rest of the year and reached the lowest daily minimum to maximum demand swing of 2,598 MW in March 2004. It is these swings across seasons and across the hours of the day, plus the fact that electricity cannot be stored in sizable quantities, that necessitate moment-by-moment balancing of supply and demand by control areas in SPP.

Figure I.3

SPP DAILY MAXIMUM AND MINIMUM
ELECTRIC ENERGY USE BY HOUR FROM 2001 TO 2004

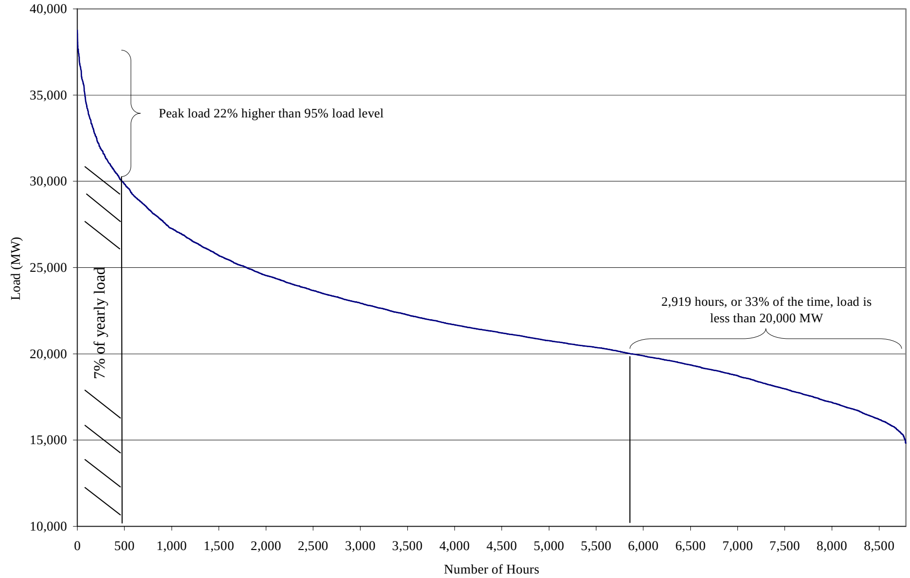


SOURCE: FERC Form 714 and SPP OPS1

A load duration curve, which is a distribution of hourly electric energy use by descending order rather than by chronological order, for the SPP region is shown in Figure I.4. It is designed to show the number of hours on the horizontal axis in which load exceeds the MW level on the vertical axis. This load duration curve for SPP shows that approximately 22% of the total generation called upon to serve load can be expected to run in only 5% of the hours. Also, the top 5% of the hours where load is greatest represent 7% of the yearly electric energy use. Finally, 33% of the time, load in SPP is less than 20,000 MW, and the SPP region requires no less than approximately 15,000 MW during all hours of the year in order to satisfy customers' needs for electricity.

Figure I.4

SPP ELECTRIC LOAD DURATION CURVE FOR 2004



SOURCE: SPP OPS1

C. Generation – The Supply of Electricity

Generation Capacity by Location

As seen in Table I.5, the total generating capacity within SPP's footprint is 55,984 MW; 39,858 MW of which, or 71%, is located in the following five control areas: AEPW, OKGE, WERE, SPS, and Cleco Power (CLEC).

Table I.5

CURRENT ON-LINE GENERATION CAPACITY BY CONTROL AREA

Control Area	Capacity (MW)
AEPW	14,782
OKGE	8,470
WERE	6,738
SPS	5,378
CLEC	4,490
KCPL	4,456
SWPA	3,286
Aquila-MPS	1,751
GRDA	1,532
EMDE	1,272
WFEC	1,263
KACY	643
SUNC	606
Aquila-WEPL	488
LAFA	326
INDN	292
LEPA	211
Total	55,984

SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and EIA 860
Note: OMPA generation was allocated as follows: 192 MW to OKGE, 7 MW to AEPW, and 6 MW to WFEC. The capacity of SPRM was added to the total of SWPA, and the capacity of MIDW was added to WERE's total. These allocations are based on SPP Summer-Peak 2005 Transmission Model – March 2004 series.

Resource Margin

As noted above, for 2004 SPP had a peak demand of 38,767 MW. Given 55,984 MW of generating capacity, this means that there is 17,217 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 resource margin in the SPP footprint would be 44.4% of peak load. This substantial resource margin has important ramifications for both reliability and for mitigation of the potential exercise of market power within SPP.

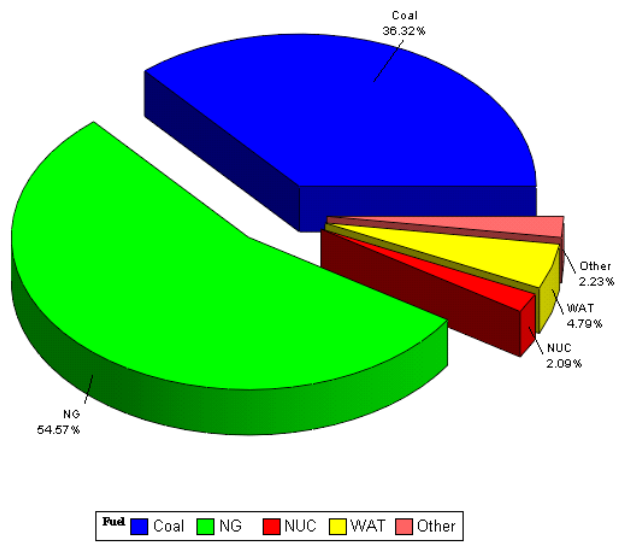
Generation Capacity by Fuel Type

As seen in Figure I.5, natural gas is the primary fuel for 55%, or 30,551 MW, of the total generating capacity in SPP. Of this natural gas-fired capacity, 36% can be found in the AEPW control area and 17% is located in the OKGE control area. Coal is the second-most prevalent fuel source for power generation in SPP representing 36%, or 20,330 MW. As noted previously in Figure I.4, load is less than 20,000 MW 33% of the time and approximately 15,000 MW of capacity operates in SPP during all hours of the year. Approximately 18% of the coal generation can be found in AEPW, while KCPL and WERE each have 15% in their control areas. While hydro generation capacity is just

5% of the total, 77% of the hydro generation is located in the SWPA control area. Wolf Creek is the only nuclear facility in SPP; it is located in WERE's control area and has a capacity of 1,170 MW.

Figure I.5

CURRENT ON-LINE GENERATION CAPACITY BY FUEL TYPE



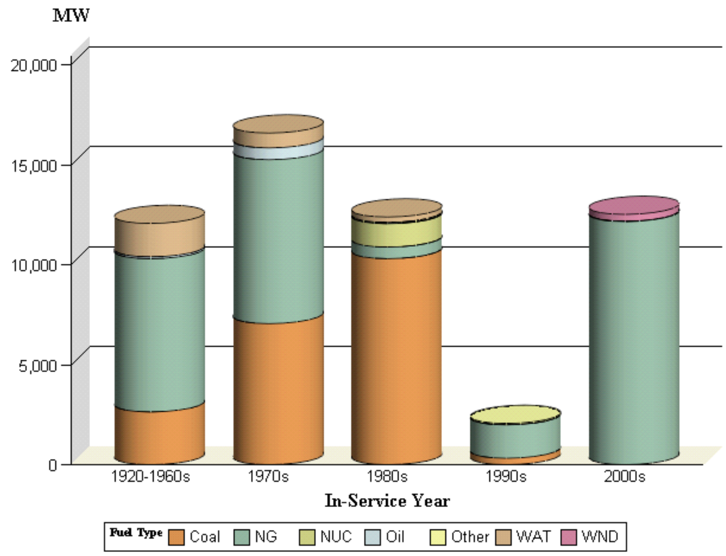
SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and EIA 860
Note: WAT stands for hydro generation.

Generation Capacity by In-Service Year

Figure I.6 reveals that 73% of the generation capacity currently operated in SPP was built prior to 1990. Nearly all of the coal units in SPP were built prior to 1990. The 1970s was the decade with the most construction, with over 16,602 MW built. Very little capacity was built in the 1990s, but there has been a surge through the 2000s. Most of these new generating units are natural gas-fired facilities and are primarily responsible for the substantial resource margin in SPP. There has also been an emergence of wind-powered generation in recent years. With the decade only half over, more generation has been built in the 2000s than during either the 1980s or 1990s. With the potential for new wind generation facilities in SPP, construction during the 2000s could approach the level seen during the 1970s.

Figure I.6

CURRENT ON-LINE GENERATION CAPACITY BY IN-SERVICE YEAR



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and EIA 860

The construction of generation since 2000 has been highly concentrated in three control areas: AEPW with 47%, OKGE with 18%, and CLEC with 15%, all of which are primarily in the southeastern portion of SPP.

Generation Capacity – Outages

Generating facilities are occasionally taken out of service for maintenance, and they also shut down from time to time due to equipment failures. Sudden outages due to equipment failures are called forced outages. Generation outages decrease the amount of electricity supply available to meet demand.

Table I.6 reports the extent of generation capacity outages that occurred on the same day as the monthly peak load in SPP during 2004. The table reveals an expected pattern. When peak load is at its highest (June to September), total outages as a percentage of peak load are at their lowest (3% to 8% of peak load).

This is in part due to the fact that planned maintenance outages are scheduled outside the summer peak period and coordinated by SPP. Outage data and peak load are displayed graphically in Figure I.7.

Table I.6

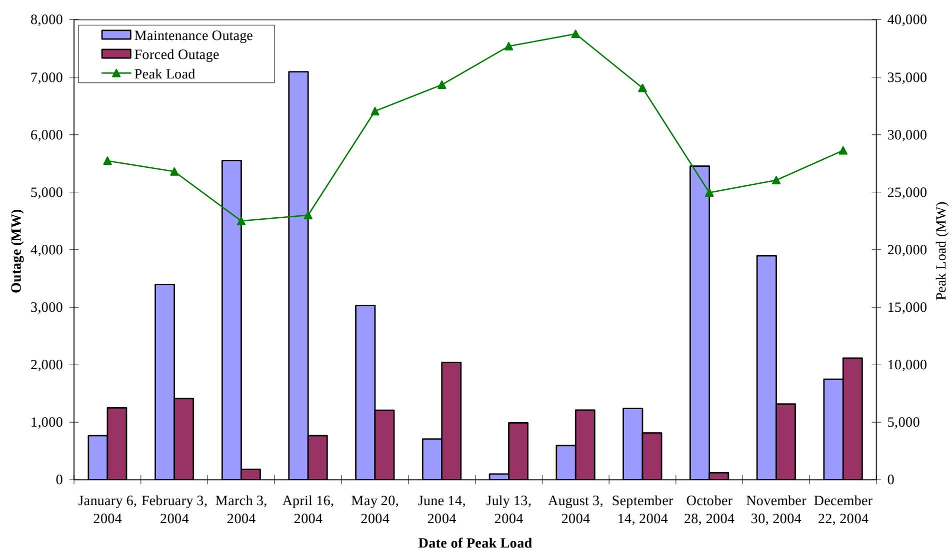
GENERATION OUTAGE DATA COINCIDENT
WITH PEAK LOAD BY MONTH FOR 2004

Date of Peak Load	Peak Load (MW)	Forced Outage (MW)	Maintenance Outage (MW)	Total Outage (MW)	Percentage of Peak Load
January 6, 2004	27,727	1,251	767	2,018	7.28
February 3, 2004	26,794	1,413	3,392	4,805	17.93
March 3, 2004	22,489	179	5,552	5,731	25.48
April 16, 2004	23,010	766	7,093	7,859	34.15
May 20, 2004	32,042	1,210	3,030	4,240	13.23
June 14, 2004	34,350	2,040	706	2,746	7.99
July 13, 2004	37,695	989	100	1,089	2.89
August 3, 2004	38,767	1,211	593	1,804	4.65
September 14, 2004	34,076	812	1,239	2,051	6.02
October 28, 2004	24,955	121	5,454	5,575	22.34
November 30, 2004	26,040	1,317	3,894	5,211	20.01
December 22, 2004	28,621	2,117	1,750	3,867	13.51

SOURCE: FERC Form 714 and SPP OPS1

Figure I.7

OUTAGE DATA COINCIDENT
WITH PEAK LOAD BY MONTH FOR 2004



SOURCE: FERC Form 714 and SPP OPS1

D. Transmission – The Bridge Between Supply and Demand

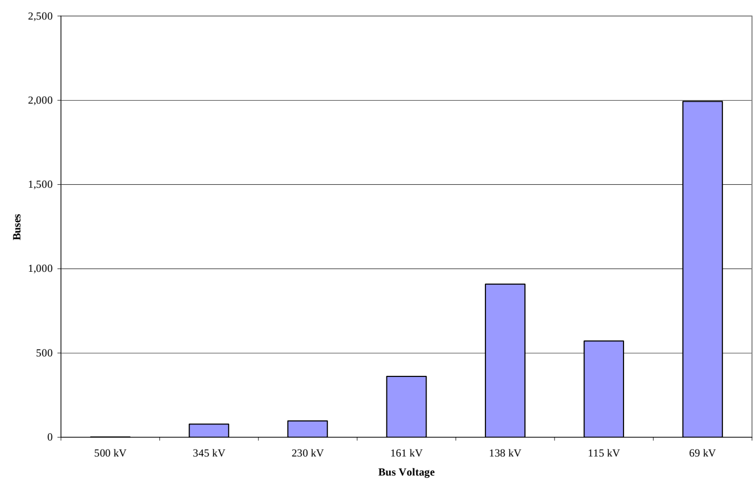
Composition of the Transmission System

Analysis of transmission buses in SPP is a useful way of evaluating the location and extent of transmission facilities and their interconnection throughout SPP. The number of transmission buses reflects the number of generation "injection points," "sinking points" for serving load, and facilities used for transforming power between differing voltage levels used in transmission systems throughout the SPP region.

There are primarily seven transmission voltages used in SPP: 500, 345, 230, 161, 138, 115, and 69 kV. The number of transmission buses in SPP at each voltage level is shown in the Figure I.8.

Figure I.8

SPP TRANSMISSION BUSES BY VOLTAGE



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series
Note: Transformers are removed from transmission bus data. Data is for voltage levels at 69 kV and above.

This figure indicates that the lowest voltage, 69 kV, is the most prevalent voltage level in use throughout SPP. Nearly half of the 4,009 transmission buses at 69 kV and above in SPP are at the 69 kV voltage level. Most of the transmission owners in the SPP region use 69 kV systems to deliver power to lower voltage transmission and distribution systems.[4]

[4] Modeling of 69 kV transmission facilities is incomplete in SPP's transmission models. Despite this the conclusions in this report based on this data are valid and have been generally confirmed by analysis of transmission line-miles from FERC Form 1 filings.

At the opposite end of the spectrum is the one 500 kV transmission bus in SPP. This single 500 kV bus in SPP is used to interconnect SPP (in the OKGE control area) with Entergy's 500 kV high-voltage system.

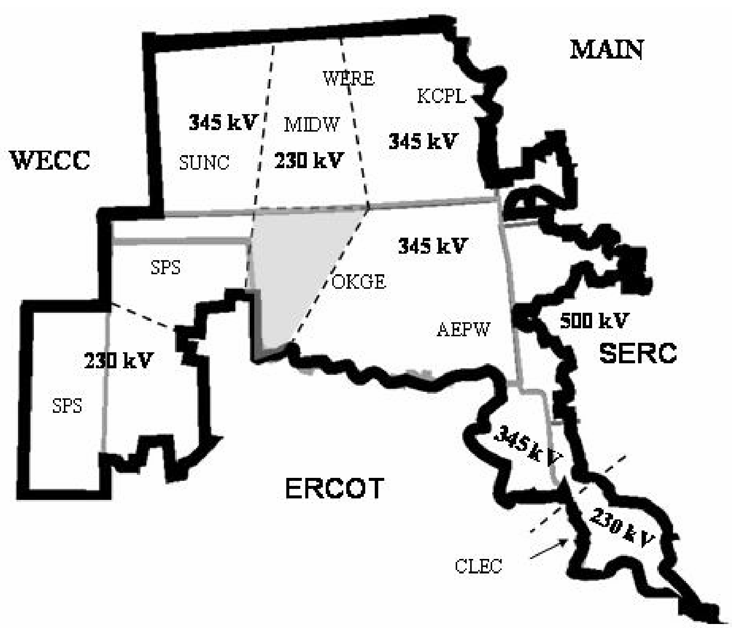
Transmission facilities at 345 kV form the backbone of the transmission system in SPP. This backbone primarily connects the transmission systems in the AEPW, OKGE, WERE and KCPL control areas in eastern SPP. Smaller control areas in eastern SPP, such as The Empire District Electric Co. (EMDE), Aquila - MPS, and Grand River Dam Authority (GRDA), also use 345 kV facilities to interconnect with the AEPW, OKGE, WERE and KCPL control areas.

Transmission facilities at 230 kV form a secondary backbone that is used in SPP primarily in the SPS, CLEC and WERE control areas. Smaller control areas nearby, such as Louisiana Energy & Power Authority (LEPA), City of Lafayette (LAFA), and Aquila - WEPL, also use 230 kV lines to interconnect with the CLEC and WERE control areas.

The figure below indicates the locations of the 500 kV, 345 kV, and 230 kV buses in the SPP region.

Figure I.9

REGIONS OF HIGH-VOLTAGE
(230+ KV) CONNECTIVITY IN SPP

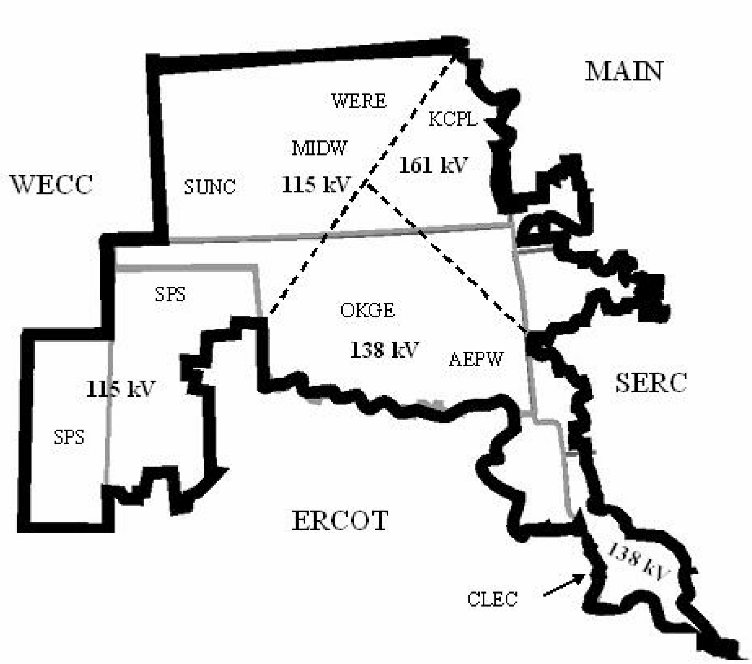


SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and NERC at http://www.nerc.com/regional/nercmapbw.jpg
Note: The shaded region does not contain transmission buses at 230 kV and above, except for a single 230 kV bus connecting the lower voltage AEPW system in western Oklahoma to the SPS control area in West Texas. The locations of the dotted lines shown above are approximate, and do not fully indicate the extent of overlaps between the 345 kV and 230 kV systems in SPP, particularly in the SPS and WERE control areas.

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. A review of transmission buses in SPP shows that 115 kV is typically used in western SPP, 138 kV in southern SPP, and 161 kV in northeastern SPP. This is indicated in the figure below.

Figure I.10

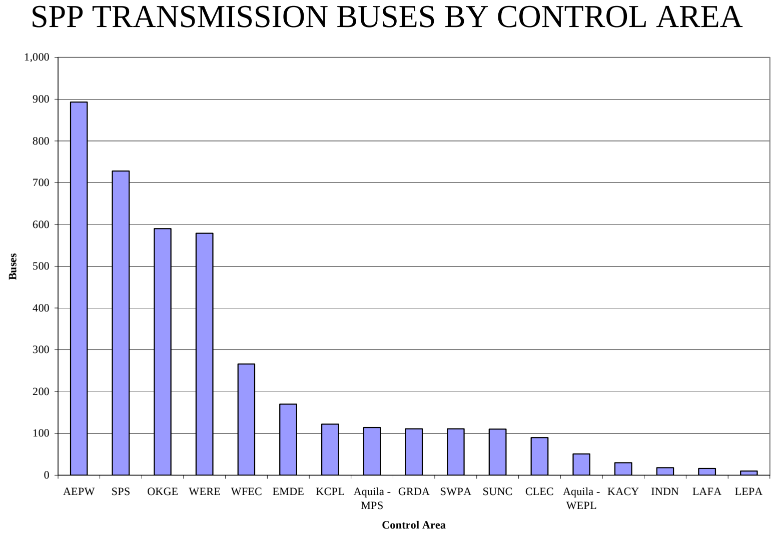
REGIONS OF MEDIUM-VOLTAGE
(115 KV TO 161 KV) CONNECTIVITY IN SPP



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and NERC at http://www.nerc.com/regional/nercmapbw.jpg
Note: The locations of the dotted lines shown above are approximate, and do not fully indicate the extent of overlaps between the 115 kV, 138 kV and 161 kV systems in SPP.

When analyzing the location of transmission buses in SPP, it is also useful to review the location of the buses by control area. The figure below shows the number of transmission buses in SPP by control area.

Figure I.11



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series
Note: Transformers are removed from transmission bus data. Data is for voltage levels at 69 kV and above.

About 76% of the transmission system in the SPP region, as measured by the number of transmission buses, is found in five control areas, which are: AEPW, SPS, OKGE, WERE and Western Farmers Electric Cooperative (WFEC). It is noteworthy that transmission systems in relatively rural areas, such as those in the SPS, WFEC and EMDE control areas, have moved up in this ranking in comparison to their ranking based on peak load (see Table I.4). This implies that these control areas have more transmission buses in comparison to their peak load than control areas covering more populated areas.

Recent Major Transmission Projects

The transmission system as discussed above includes the impacts of major transmission expansion projects.

In late 2004, OKGE added a new transformer to its Fort Smith interconnection with Entergy's 500 kV system in order to enhance connectivity with SERC. The timing of this upgrade was prompted by a recent proceeding at the FERC.[5]

Also in 2004, SPS built a new high-voltage DC tie, called the "Lamar" tie, between SPP and WECC in western Kansas in order to increase connectivity with

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[5] *See* Order Approving Contested Settlement Offer, Subject to the Commission's Modifications, and Authorizing Acquisition and Disposition of Jurisdictional Facilities, July 2, 2004, FERC Docket No. EC03-131-000, at pp. 5 to 6.

WECC. Similar to the Fort Smith upgrade, construction of this new facility was prompted by a FERC proceeding.[6]

During 2002, Kansas City Power & Light Company upgraded its LaCygne to Stilwell 345 kV line to remove significant constraints on north-to-south power flows in SPP. The capacity of this transmission line was increased from 1,251 MVA to 1,972 MVA, and the upgrade was performed "hot" without removing the LaCygne line from service.

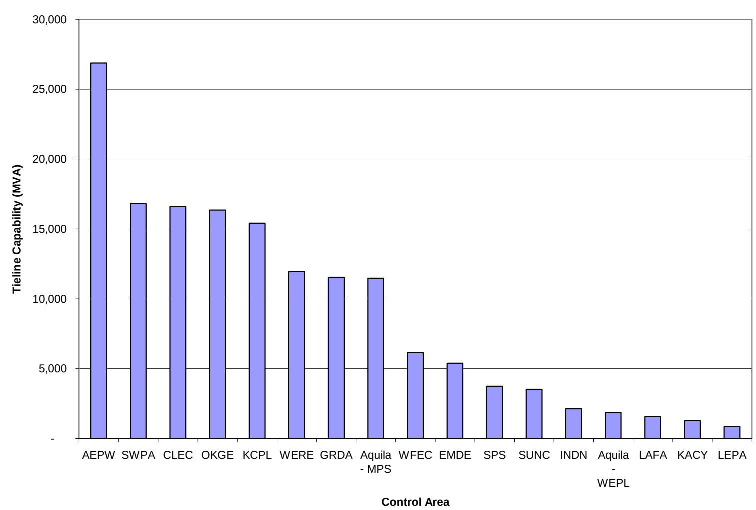
In 2001, the Finney to Potter County 345 kV line was built, providing a second 345 kV connection between SPS and the rest of SPP between western Kansas and West Texas. This 219-mile line was the first phase of the Lamar tie project.

Internal SPP Transmission Connectivity

Another useful measurement of the transmission system in SPP is to determine the total nominal transmission capacity of lines bordering each control area in SPP. These lines are also called "tielines". The following figure shows this tieline capacity by control area.[7]

Figure I.12

SPP NOMINAL TIELINE CAPACITY BY CONTROL AREA



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series

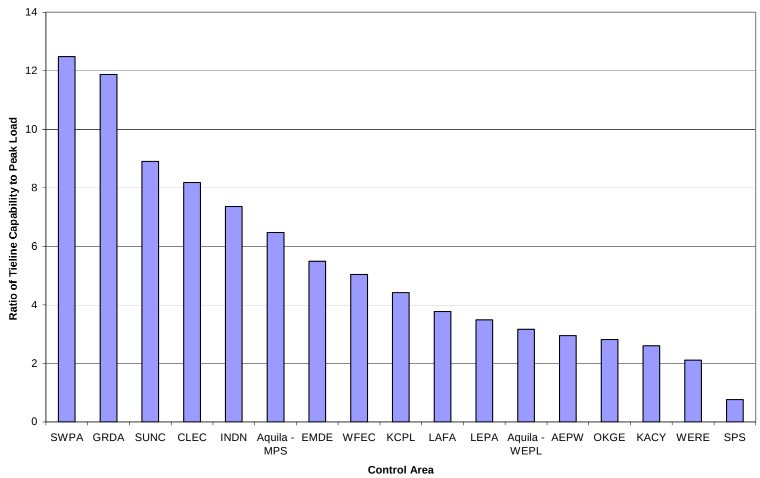
6 *See* Order Conditionally Approving Settlement and Conditionally Authorizing Proposed Merger, March 12, 1997, FERC Docket No. EC96-2-000.

7 Note that the nominal tieline capacity shown is not the same as Available Transfer Capability or Total Transfer Capability as defined by NERC. Further, it does not imply physical rights to transfer power over specific transmission facilities. The nominal tieline capacity is simply the sum of the power transfer capacity in MVA of each transmission line bordering a control area.

As expected, many of the largest control areas, as measured by peak load served, have the highest tieline capacity, such as AEPW, OKGE and KCPL. However, the WERE and SPS control areas have significantly less tieline capacity than might be expected given the size of the load served in each area. The table below shows the ratio of tieline capacity for each control area divided by the control area's peak load in MW.

Figure I.13

RATIO OF NOMINAL TIELINE CAPACITY TO PEAK LOAD



SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series and SPP OPS1

This analysis shows that while WERE and SPS are two of the five largest control areas in SPP in terms of peak load, they rank among the lowest of all SPP control areas for their ratio of total transmission tieline capacity to peak load. The SPS control area appears to be particularly isolated from the rest of the SPP system in terms of transmission connectivity. The other three of the five largest control areas in SPP in terms of peak load, AEPW, OKGE and KCPL, have transmission tieline capacity to peak load ratios between 2.8 and 4.4. Of the five largest control areas in SPP, KCPL has the highest ratio at 4.4. The medium and small sized control areas in SPP typically have higher ratios, ranging between 2.6 and 12.5, and averaging 6.6.

Seams with Adjacent Regions

The transmission system in the SPP region interconnects with those in adjacent regions in the Eastern Interconnect, Western Interconnect and ERCOT.

Eastern Interconnect

In the Eastern Interconnect, the SPP transmission system interconnects over Alternating Current (AC) transmission lines with systems in the MRO, MAIN and SERC reliability regions. The highest level of direct interconnection, based on transmission tieline capacity in MVA, is with the SERC region, as shown in the table below.

Table I.7

SPP TIELINE CAPACITY (MVA) WITH
ADJACENT RELIABILITY REGIONS

Adjacent Region	Tieline Capacity (MVA)
SERC	40,396
MRO	2,152
MAIN	1,779
Total	44,327

SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series

In the SERC and MRO regions, SPP's transmission system connects with the transmission systems of several control areas.[8] The table below shows the tieline capacities between SPP and each adjacent control area.

Table I.8

SPP TIELINE CAPACITY (MVA)
WITH ADJACENT CONTROL AREAS

Adjacent Control Area	Tieline Capacity (MVA)
Entergy (SERC)	19,158
AECI (SERC)	18,343
LAGN (SERC)	2,895
NPPD (MRO)	1,673
OPPD (MRO)	312
MEC (MRO)	167
AMRN (MAIN)	1,779
Total	44,327

SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series

Despite the information provided above, SPP may actually be more heavily interconnected with the MAIN region than indicated by these direct interconnection statistics. The reason for this is that the AECI control area forms a thin wedge between SPP and the Ameren Transmission (AMRN) control area in Missouri. Two 345 kV lines exiting SPP extend through AECI into the AMRN control area. In addition, AECI is

8 Despite the difference in reliability council participation, the Midwest ISO is the reliability coordinator for MRO and most utilities in MAIN.

heavily interconnected with both SPP and AMRN. While SPP has 18,343 MVA of tieline capacity with AECI, AECI has 10,304 MVA of tieline capacity with MAIN, and nearly 85% of that capacity (8,720 MVA) is with AMRN. Therefore, indirectly, it appears that SPP's interconnection with the AMRN control area in MAIN may actually be greater than indicated by the direct interconnection statistics shown above.

Seams Issues Between SPP, SERC and MAIN

As connectivity increases between adjacent regions, seams issues can occur. These seams issues can be exacerbated when parts of one region have more connectivity with an adjacent region than the rest of the region with which they are associated. In SPP, based on the transmission connectivity discussed above, the potential for seams issues exists between (a) SPP and SERC and (b) SPP and MAIN, albeit more indirectly with MAIN than with SERC.[9]

Within SPP, approximately 60% of the connectivity between Entergy and SPP is between Entergy and a single control area in SPP, which is CLEC. CLEC has nearly five times more direct connectivity with Entergy than it has with the rest of SPP. All connectivity between the Louisiana Generating, LLC (LAGN) control area and SPP is with CLEC.

Approximately 65% of the connectivity between AECI and SPP is between AECI and two control areas in SPP (SWPA and GRDA). SWPA has slightly more interconnection tieline capacity with SERC (AECI and Entergy combined) than it does with the rest of SPP, while GRDA has slightly more connectivity with the rest of SPP than it does with AECI. One other control area, Aquila – MPS, also has significant connectivity with AECI in comparison to its connectivity to the rest of SPP. In addition, Aquila - MPS also has significant connectivity with AMRN in MAIN, accounting for two-thirds of the total direct connectivity between SPP and AMRN.

The table below shows this seams-related connectivity (tieline capacity) by SPP control area.

Table I.9

SPP CONTROL AREA TIELINE CAPACITY (MVA) WITH SERC AND MAIN

SPP Control Area	AECI (SERC)	Entergy (SERC)	LAGN (SERC)	AMRN (MAIN)	SPP
CLEC	-	11,313	2,895	-	2,388
SWPA	7,110	2,607	-	248	6,857
GRDA	4,853	-	-	-	6,686
Aquila – MPS	2,224	-	-	1,177	6,950

SOURCE: SPP Summer Peak 2005 Transmission Model – March 2004 series

[9] SPP has developed or is developing agreements with adjacent regions to address potential seams issues. A detailed agreement between SPP and the Midwest ISO has been approved by FERC. SPP signed a transmission coordination agreement with AECI during August 2004.

CLEC's case appears to be one for further review for potential seams issues. CLEC, along with the LAFA and LEPA control areas, are connected to the rest of SPP by two transmission lines between CLEC and AEPW with a total transmission capacity of 1,085 MVA. In comparison, CLEC, LAFA and LEPA together have 15,330 MVA of transmission tieline capacity with the Entergy and LAGN control areas in SERC.[10]

ERCOT and WECC

A total of five 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 820 MW of transmission capability. On the SPP side, these ties are located in the AEPW control area, and they are owned and operated by AEPW.

Three DC ties, known as Eddy County, Blackwater and Lamar, connect SPP to WECC for 600 MW of transmission capability. These three ties are located in the SPS control area. The Eddy County tie is owned by El Paso Electric and Texas-New Mexico Power, but operated by SPS. The Blackwater tie is owned and operated by Public Service Company of New Mexico. The Lamar tie is owned and operated by Public Service Company of Colorado, an affiliate of SPS.

The transmission capability of each DC tie is shown in Table I.10 below.

Table I.10

DC TIE TRANSMISSION CAPABILITY

Name of DC Tie	Transmission Capability
ERCOT East (Welsh)	600 MW
ERCOT North (Oklaunion)	220 MW
Eddy County	200 MW
Blackwater	200 MW
Lamar	200 MW

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

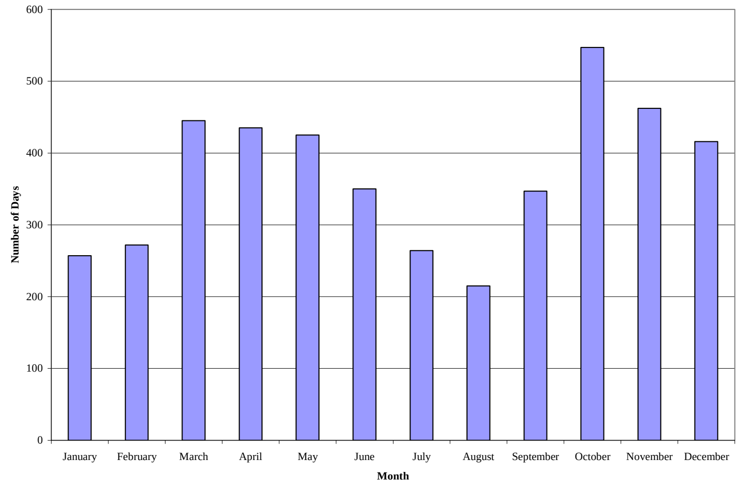
Transmission Outages

Transmission elements, just like generating units, need to be removed from service for occasional maintenance. 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 2004 follows the same general pattern as that for generating units by increasing during spring and fall months and decreasing during summer and winter months. However, in contrast to generation outages, only 1.2% of outages reported on the SPP transmission system are forced outages.

10 The LAGN control area is embedded in the Entergy control area.

Figure I.14

DAYS OF TRANSMISSION OUTAGES BY MONTH FOR 2004



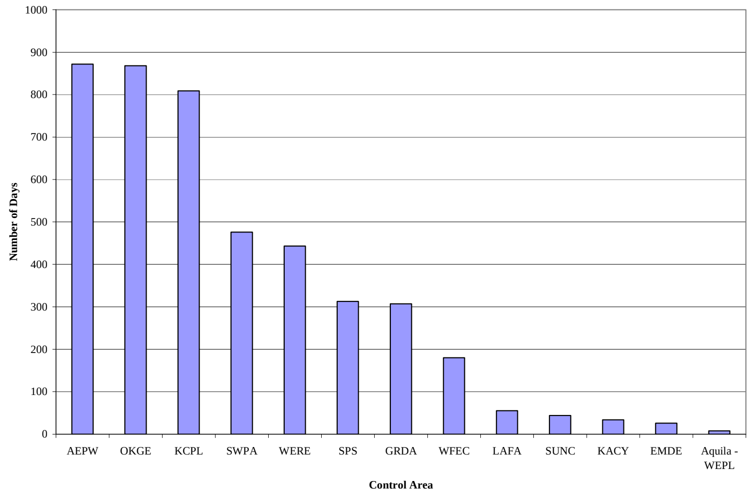
SOURCE: SPP OPS1
Note: Transmission outage data covers 100+ kV transmission components in SPP.

Figure I.14 above shows the extent of transmission system outages in each month of 2004, calculated by the length of outage in days for each outage and totaled for each month. For example, 100 transmission lines out of service for three days equal 300 outage days in the figure above.

The location of transmission outages in SPP during 2004 are shown in Figure I.15 below by control area. The AEPW, OKGE and KCPL control areas all experienced over 800 days of transmission facility outages during 2004.

Figure I.15

DAYS OF TRANSMISSION
OUTAGES BY CONTROL AREA FOR 2004



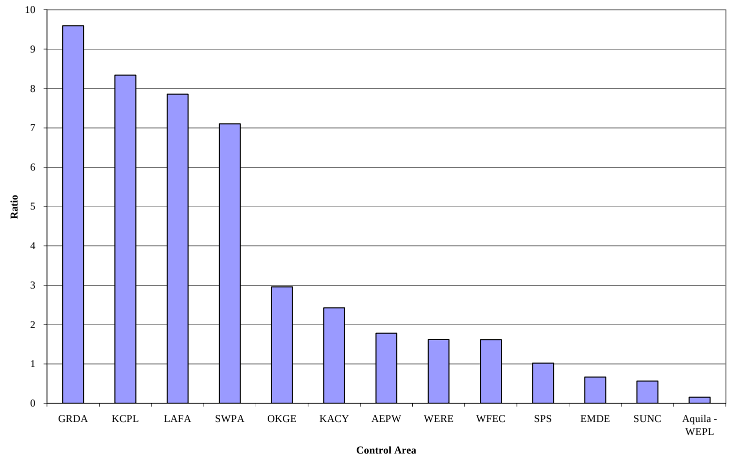
SOURCE: SPP OPS1

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

However, in comparison to the number of transmission buses at 100kV or greater voltage levels, the GRDA, SWPA, KCPL, and LAFA control areas have the highest level of outage duration per transmission bus. Figure I.16 below shows the ratio of days of transmission outages to the number of transmission buses at 100+ kV for each control area shown in Figure I.15.

Figure I.16

RATIO OF DAYS OF TRANSMISSION OUTAGES TO
NUMBER OF TRANSMISSION BUSES BY CONTROL AREA FOR 2004



SOURCE: SPP OPS1

II. 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, 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 supply and demand for transmission service within the SPP footprint.

Flowgates and Flowgate Limits

SPP primarily grants access to the transmission systems of its members based on flowgates designated by SPP and its members.[11] Flowgates are combinations of critical transmission elements that represent a proxy of the transmission system. Transmission elements are designated as flowgates because they have 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 limiting element and a contingent element. The limiting element is at either the same or a lower voltage level than the contingent element. The amount of power flow permitted over a flowgate, that is, its transfer capability, is based on the amount of power the limiting element could handle if the contingent element experienced a sudden outage. In certain cases, flowgates are made up of one or more transmission elements that are limiting individually or in conjunction, and no contingent element is included.

Since SPP is responsible primarily for managing access to transmission service based on flowgates, SPP's transmission owning members are responsible for managing constraints on all other transmission elements under their control unless an emergency situation occurs. Aside from requests for yearly transmission service or emergency conditions, overloads on critical transmission elements not designated as flowgates cannot be used to deny access to the transmission service provided by SPP.

Flowgates have separate limits for firm and non-firm transmission service. Non-firm service can be sold up to the total transfer capability limit of a flowgate. Firm service can be sold up to a level equal to the flowgate limit less the transmission reliability margin (TRM) for the flowgate. TRM levels are established based on SPP's

[11] In addition to granting transmission service based on available transfer capability on flowgates, SPP also 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).

resource sharing requirements, which account for potential generator outages or "contingencies."[12]

TRM levels are substantial portions of the total limit for certain flowgates in SPP. During 2004, the highest TRM levels, as a percentage of the total flowgate limit, were found on flowgates in the following areas: (a) the border between the SPS control area and the rest of SPP, (b) Fort Smith between the OKGE and Entergy control areas (which was upgraded during 2004), (c) the border between Kansas and Oklahoma, and (d) the eastern border between Oklahoma and Texas in the AEPW control area. The flowgates in SPP with the highest TRM levels, as a percentage of the total flowgate limit, during 2004 are shown in the following Table II.1.

Table II.1

HIGHEST TRANSMISSION RELIABILITY MARGINS BY PERCENTAGE OF SUMMER EMERGENCY LIMIT DURING 2004

Flowgate	Summer Emergency Limit (MW)	TRM (MW)	Summer Emergency Limit Less TRM (MW)	TRM as Percentage of Summer Emergency Limit
SPP to SPS Ties	899	540	359	60%
Fort Smith-Arkansas Nuclear One	335	190	145	57%
Kildare-Creswell Woodring-Wichita	171	71	100	42%
Lone Oak-Sardis Pittsburg-Valliant	107	28	79	26%
Fort Smith Transformer 500 - 345	480	125	355	26%
South Philips-West McPherson Summit-East McPherson	148	38	110	26%
Craig Junction-Ashdown West Valliant-Lydia	235	59	176	25%
Valliant-Lydia Eldorado-Longwood	956	233	723	24%
Southwestern Station-Ft. Cobb Oklaunion-Tuco	151	36	115	24%
South Coffeyville-Dearing Delaware-Neosho	210	49	161	23%

SOURCE: SPP OASIS at https://sppoasis.spp.org/documents/flowgates/flowgate.xls

Transmission Service Requests

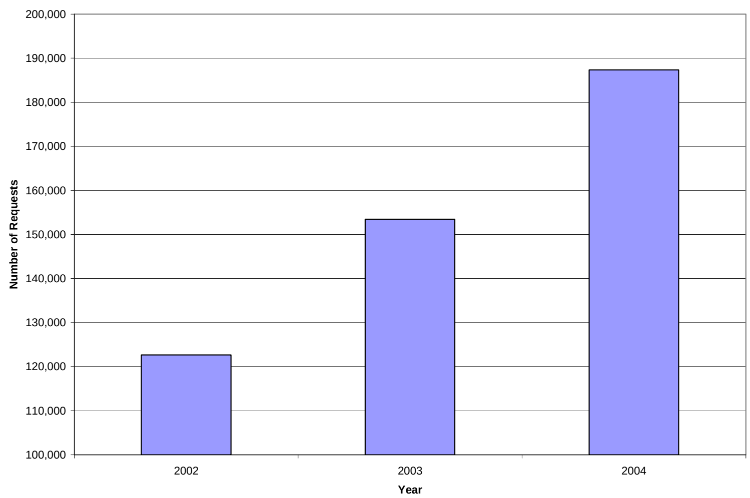
Transmission service requests can be a measure of both the demand for access to the transmission system in the SPP region and SPP's ability to grant access. The demand for service can be measured by the total number of transmission service requests

[12] Transmission owners may request that SPP base TRM levels on factors other than just reserve sharing requirements for generator outages. However, our understanding is that this is not typical of most flowgate TRM levels in SPP.

submitted. SPP's ability to provide service can be measured by the number of service requests it approves and that requestors confirm. The total number of transmission service requests, shown in Figure II.1, in SPP has steadily increased during the period from 2002 to 2004, indicating an increased demand for service on the transmission system in the SPP region. During 2002, 122,661 requests for service were submitted, and 153,460 and 187,348 were submitted in 2003 and 2004, respectively, resulting in an overall 52.7% increase in annual requests for transmission service during the 2002 to 2004 period.

Figure II.1

ANNUAL SPP TRANSMISSION SERVICE REQUESTS

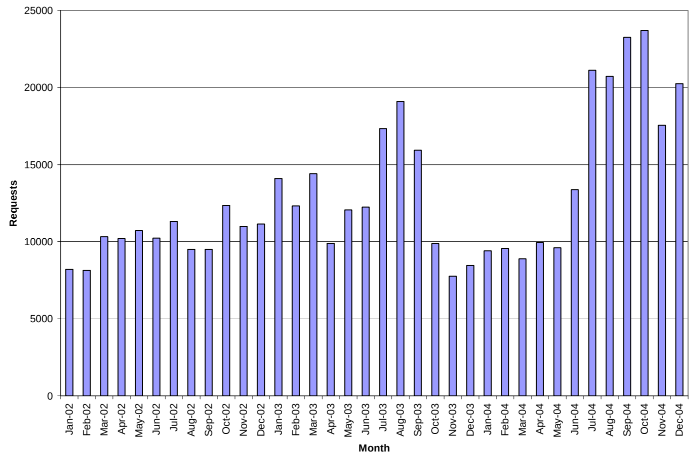


SOURCE: SPP OASIS

On average, 10,222 requests occurred per month in 2002, 12,788 requests per month in 2003, and 15,612 per month during 2004. The following figure shows the actual number of requests per month during 2002 to 2004. Aside from surges in requests during 2003 and the second half of 2004, the minimum level of requests appears to be less than 10,000 per month for each year. Figure II.2 shows that the surge in requests during Summer 2003 and the second half of 2004 was particularly strong.

Figure II.2

MONTHLY SPP TRANSMISSION
SERVICE REQUESTS FROM 2002 TO 2004

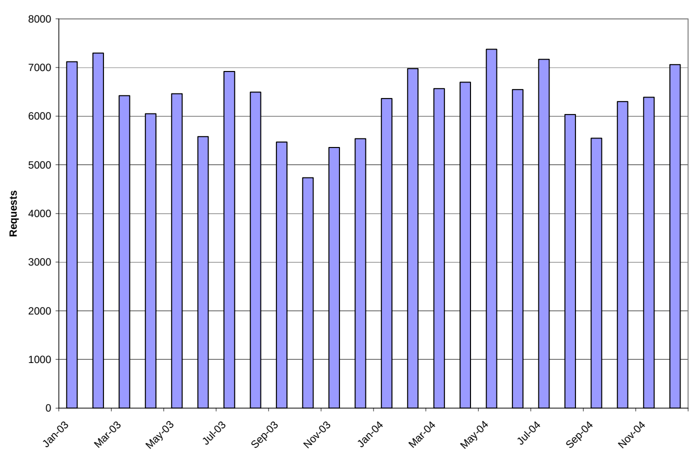


SOURCE: SPP OASIS

However, the trend in requests approved by SPP and confirmed by requestors did not follow the same pattern as overall requests during 2003 and 2004. These confirmed requests remained fairly steady during the two-year period, dropping off slightly during early fall in both years. There were 73,431 requests confirmed in 2003 and 79,023 in 2004. In terms of monthly averages, in 2003 there were 6,119 requests confirmed per month and 6,585 in 2004. Figure II.3 below shows the trend of confirmed requests.

Figure II.3

MONTHLY SPP CONFIRMED TRANSMISSION
SERVICE REQUESTS FROM 2003 TO 2004

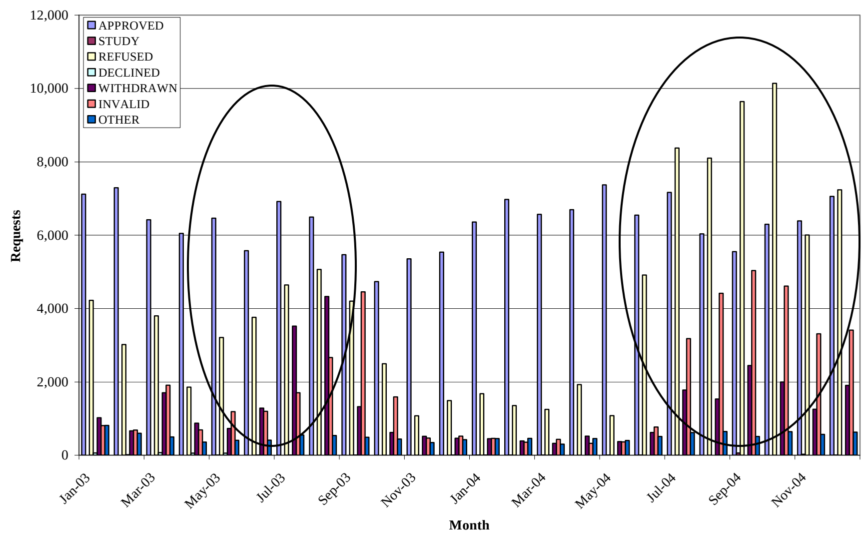


SOURCE: SPP OASIS

Instead of impacting the level of confirmed requests, the overall increase in transmission service requests led to substantial increases in refused, withdrawn, and invalid requests during Summer 2003 and the second half of 2004 as shown in the figure below. Refused requests were denied by SPP due to a lack of transmission transfer capability, withdrawn requests were removed from the request process by the party that submitted the request, and invalid requests could not be accepted by SPP for processing due to an error in the request. The primary surges in these three request types in both years are circled on Figure II.4.

Figure II.4

MONTHLY SPP TRANSMISSION SERVICE
REQUESTS BY STATUS FROM 2003 TO 2004

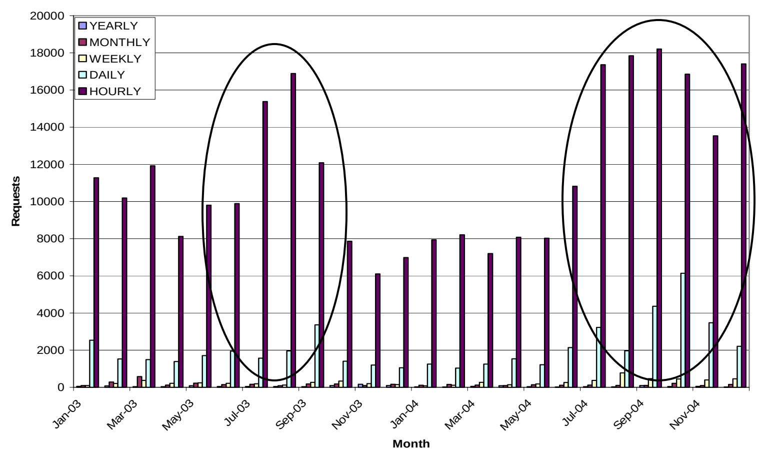


SOURCE: SPP OASIS

The increase in transmission service requests that occurred during Summer 2003 and the second half of 2004 was for shorter-term requests; primarily in hourly and daily requests, but also some in weekly service requests. Little or no increase was seen in the longer-term requests for transmission service lasting for a month or more. This is shown in the Figure II.5 below. The primary surges in these three reservation duration types in both years are circled on the figure.

Figure II.5

TRANSMISSION SERVICE REQUESTS
BY DURATION FROM 2003 TO 2004



SOURCE: SPP OASIS

In total, 74,888 refused, withdrawn, and invalid transmission service requests were submitted during the second half of 2004 (June to December) in excess of the average level of such requests submitted during the first half of the year (January to May).[13] In total, 101,972 service requests were refused, withdrawn and invalid during 2004.

Transmission Service Requests for DC Ties

Upon review of the transmission service requests submitted in 2004, it appears that much of the overall increase in requests during the second half of 2004 may have been due to requests submitted for use of SPP's DC ties with ERCOT. During 2004, 71,324 requests for transferring power over SPP's DC ties with ERCOT and WECC were not approved by SPP. Of these requests, 62,276 were for exporting power out of SPP over the ERCOT East tie and 6,951 were for exporting power out of SPP over the ERCOT North tie. In comparison, only 2,097 unconfirmed requests were made for transmission service (a) over the DC ties between SPP and WECC and (b) for importing power into SPP over the ERCOT DC ties.[14]

Approximately 90% of all requests for exports over SPP's ERCOT East DC tie involved a Point of Receipt in the following control areas: SPS, AMRN, KCPL, Omaha

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[13] The average level of such requests was 2,257 per month during January 2004 to May 2004. If this pattern had continued for the rest of 2004, there would have been 27,084 refused, withdrawn and invalid requests during 2004.

[14] When a request for transmission service includes a DC tie as both the point of receipt and the point of delivery, it is counted as an import request and an export request, respectively, despite the fact that only a single service request was submitted.

Public Power District (OPPD), Aquila – MPS, Aquila – WEPL, and WERE. Similarly, nearly 90% of all requests for exports over the ERCOT North DC tie involved a Point of Receipt in the same control areas, but included AEPW, instead of SPS.

During December 2004, SPP notified the FERC of what it viewed as excessive transmission service requests and proposed a limit on the number of requests that could be submitted.[15] The FERC approved SPP's proposal, and our understanding is that the number of refused, withdrawn and invalid requests submitted for the ERCOT DC ties has decreased as a result.[16] However, it does appear that the large number of requests experienced by SPP for exports over the DC ties to ERCOT is a potential indicator of the demand for such service.

From the perspective of confirmed transmission service requests over the DC ties, specific patterns of service requests are noticeable. During 2004, confirmed requests for exports to ERCOT over the ERCOT ties outweighed confirmed import requests to SPP by a significant margin. For the ties between SPP and WECC, confirmed requests for the Eddy County tie were for exports to WECC, confirmed requests over the Blackwater tie were for imports into SPP, and no requests were confirmed over the Lamar tie. Table II.2 shows the number of confirmed requests in each direction over the DC ties.

Table II.2

CONFIRMED TRANSMISSION SERVICE REQUESTS ON DC TIES

DC Tie	Confirmed Export Requests	Confirmed Import Requests
ERCOT East	3,819	798
ERCOT North	736	46
Eddy County	42	-
Blackwater	-	307
Lamar	-	-

SOURCE: SPP OASIS
Note: In this table the term "export" refers to transfers of power out of SPP and the term "import" refers to transfers of power into SPP.

B. Transmission Congestion

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

15 *See* Submission of Proposed Revisions to Attachments J and P of Tariff. December 13, 2004. FERC Docket No. ER05-326 at p. 3.

16 *See* Order Accepting Tariff Filing. February 11, 2005. FERC Docket No. ER05-326.

Role of SPP Flowgates in Congestion Management

As discussed above, flowgates are sets of transmission lines designated by SPP and its members annually for purposes of providing transmission service. As a result, SPP also manages congestion over those flowgates. The number of defined flowgates varies from year to year, but there were approximately 80 flowgates defined within SPP during 2004. 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.

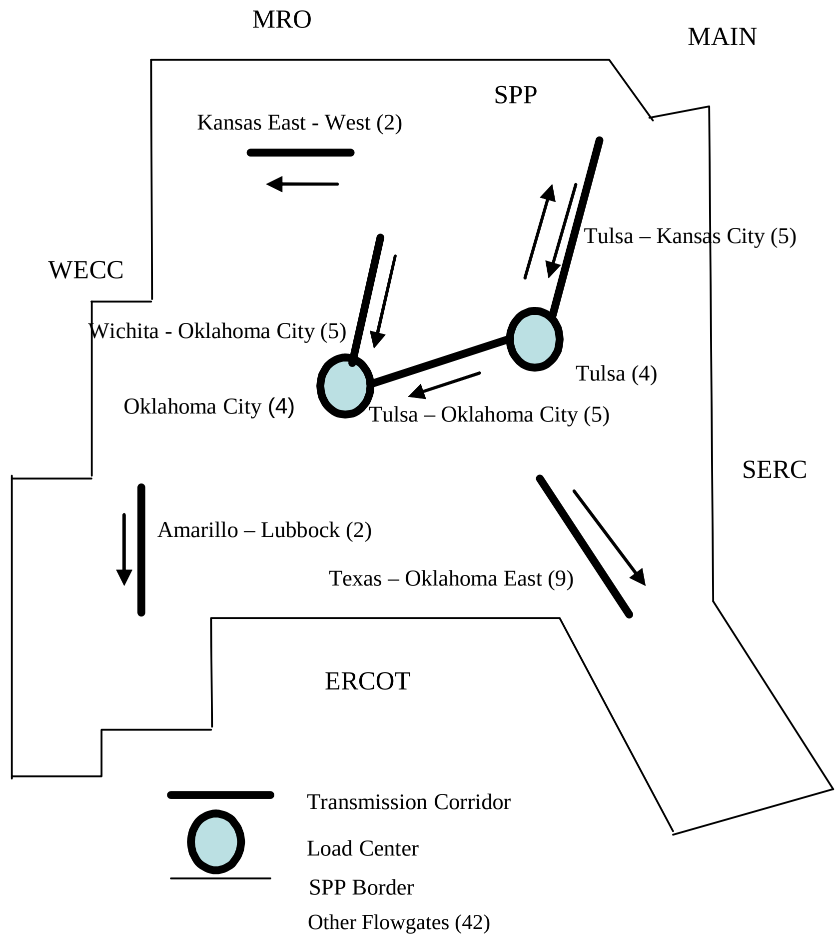
Many flowgates in SPP occur in (a) transmission corridors typically located between major load centers and (b) major load centers. The transmission corridors that contain a significant number of flowgates are:

a. Amarillo – Lubbock
b. Kansas East – West
c. Texas – Oklahoma East
d. Tulsa – Kansas City
e. Tulsa – Oklahoma City
f. Wichita – Oklahoma City

The major concentrations of flowgates in load centers are found in Tulsa and Oklahoma City. Figure II.6 below illustrates the locations of these eight transmission corridors and load centers, including the number of flowgates for each, which is provided after the name of each transmission corridor or load center.

Figure II.6

LOCATION OF MAJOR TRANSMISSION CORRIDORS AND LOAD CENTERS



SOURCE: SPP OASIS at https://sppoasis.spp.org/documents/flowgates/flowgate.xls
Note: The number in parentheses reflects the number of permanent flowgates defined in 2004 for each transmission corridor or load center. The arrows indicate the primary direction(s) of constrained power flows in a transmission corridor during 2004.

Congestion Management Method – NERC TLRs

SPP uses the NERC procedure for TLR on defined flowgates to relieve congestion between control areas.[17] The TLR procedure enables SPP to (a) respect transmission service priorities, and (b) mitigate potential or actual system operating limit (SOL) and interconnection reliability operating limit (IROL) violations on any

[17] The congestion managed by SPP is only part of the total congestion that occurs in the SPP region. Congestion in locations other than flowgates is managed by the transmission owners prior to or during TLR events through voluntary redispatch and system reconfiguration.

transmission facility modeled in the Interchange Distribution Calculator (IDC).[18] There are seven distinct TLR levels, which can be seen in Table II.3.

Table II.3

ACTIONS TAKEN DURING TLR LEVELS

TLR Level	Reliability Coordinator Action
1	**Notify** Reliability Coordinators of potential System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations
2	**Hold** transfers at present level to prevent SOL or IROL violations
3a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service
3b	**Curtail** Interchange Transactions using Non-firm Transmission Service Arrangements to mitigate an SOL or IROL Violation
4	**Reconfigure** transmission
5a	**Reallocation** of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service
5b	**Curtail** Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL Violation
6	**Emergency Procedures**
0	**TLR concluded**

SOURCE: NERC Operating Manual, Attachment 1-IRO-006-0

Transactions are curtailed based upon a specified Curtailment Threshold and Transmission Service Priority. SPP uses the standard NERC Curtailment Threshold of 5%, which means that only transactions with a Transfer Distribution Factor (TDF) greater than 5% over a flowgate can be cut during a TLR event. That is, curtailment is only performed when 5% or more of the total power transfer of a transaction passes over the flowgate. The purpose of this threshold is to prevent curtailment of transactions that have an insignificant impact on the flowgate.

Transmission Service Priorities for energy schedules range from zero to seven with lower numbers equivalent to lower priorities. Firm transmission service receives the highest priority, and the rest of the priority levels are for non-firm service of various durations, such as monthly, daily, and hourly. When curtailments occur, transactions are curtailed from lowest to highest priority. It should be noted that the actual amount of MW of relief for a given flowgate is only a fraction of the amount of MW curtailed (i.e., perhaps 10 MW of relief over a flowgate from a curtailment of 100 MW from a generating resource).

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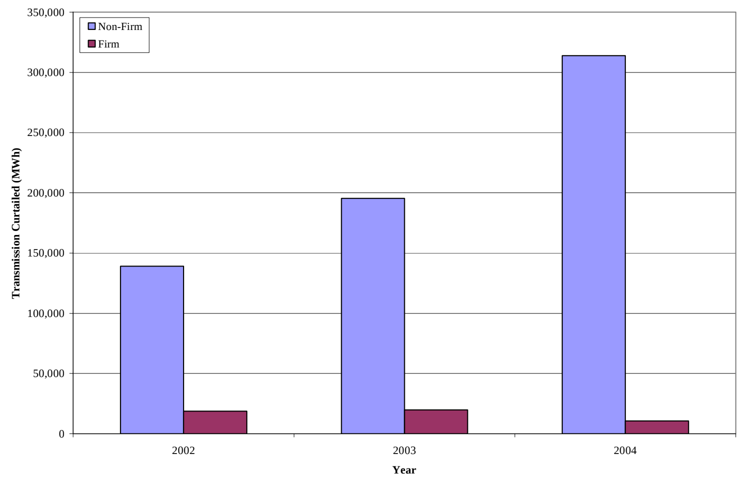
[18] The IDC is used by Reliability Coordinators to calculate TDFs, which are the percentage impact of scheduled power flows over defined flowgates. It is also used to determine which transactions to curtail given the current system status and the priorities of new transactions.

Analysis of SPP Congestion Management

As seen in Figure II.7 below there were approximately 324,583 MWh curtailed in 2004 (both non-firm and firm). Approximately 97% of that amount was for non-firm curtailment. This is due to SPP's less conservative analyses for selling non-firm transmission service as compared to firm service in order to maximize transmission service revenue. Conversely, SPP uses more conservative analyses for selling firm service as compared to non-firm service in order to ensure reliable operation of the transmission system. Therefore, in SPP, non-firm service is more likely to be curtailed than firm service.

Figure II.7

TOTAL TRANSMISSION SERVICE
CURTAILED (MWH) BY YEAR AND TYPE



SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

As for the locations of these curtailments, shown in Table II.4, the transmission corridors and load centers with a concentration of flowgates account for approximately 96% of the total electricity (in MWh) curtailed.

Table II.4

CURTAILMENTS (MWH) FOR
TRANSMISSION CORRIDORS AND LOAD CENTERS FOR 2004

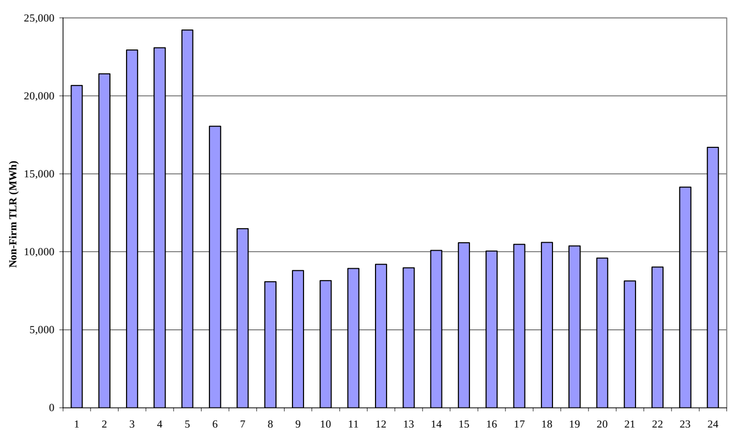
Transmission Corridor/ Load Center	Total Curtailment	Non-Firm	Firm
Texas - Oklahoma East	135,440	134,931	509
Wichita - Oklahoma City	118,510	110,202	8,308
Tulsa - Kansas City	42,658	41,908	750
Kansas East - West	12,744	11,896	848
Tulsa	3,671	3,603	68
Oklahoma City	1,084	984	100
Amarillo - Lubbock	869	829	40
Tulsa - Oklahoma City	-	-	-
Total	314,976	304,353	10,623

SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

Non-firm transmission service curtailments were larger during off-peak hours (10 p.m. through 6 a.m.) than on-peak hours in 2004, as seen in Figure II.8 below. The level of firm curtailments, shown in Figure II.9, did not vary significantly between on-peak and off-peak hours, but did peak slightly at 8 a.m. and 9 a.m.

Figure II.8

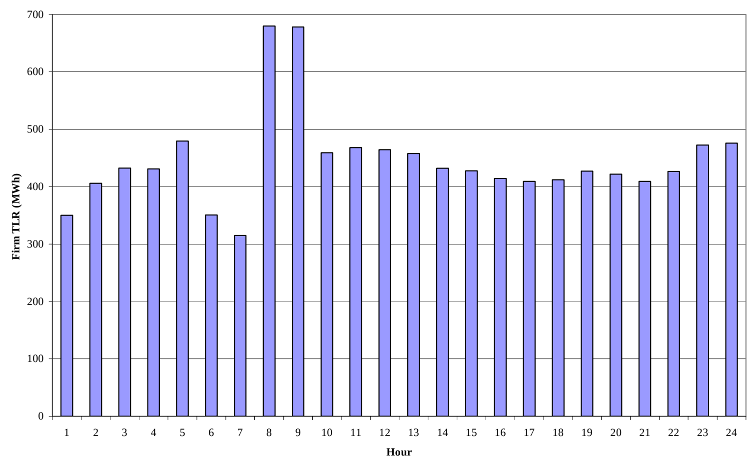
NON-FIRM CURTAILMENTS BY HOUR OF DAY FOR 2004



SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

Figure II.9

FIRM CURTAILMENTS BY HOUR OF DAY FOR 2004



SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

It is also useful to survey transmission congestion by examining particular flowgates that are commonly constrained. Table II.5 below lists the eight flowgates in SPP with the most hours of constraint, the relevant transmission corridor or load center in which the flowgate is located, and the direction of constrained flow.

Table II.5

LOCATION AND DIRECTION OF FLOW
FOR MOST-CONSTRAINED FLOWGATES

Flowgate	Corridor / Load Center	Direction
Hugo - Valliant	Texas - Oklahoma East	North - South
Creswell - Kildare	Wichita - Oklahoma City	North - South
Bartlesville - North Bartlesville	Tulsa - Kansas City	South - North
Northeast Station - Oneta	Tulsa - Kansas City	North - South
El Paso - Farber	Wichita - Oklahoma City	North - South
South Philips - West McPherson	Kansas East - West	East - West
Lone Oak - Sardis	Texas - Oklahoma East	North - South
Catoosa - Lynn Lane	Tulsa	North - South

SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

Tables II.6 and II.7 show the amount of MWh curtailed during 2003 and 2004 over those flowgates by period (on-peak vs. off-peak) and month, respectively. As expected from Figures II.8 and II.9, many of the constraints in the transmission corridors and load centers were most active during off-peak hours. This can be seen from the hourly average data for on-peak periods in the table. It is important to review hourly average data for this information because on-peak periods last for 16 hours while off-peak periods last for 8 hours. The constraints were also more active in the summer months during 2004 as seen in Table II.7. Constraints in the Wichita – Oklahoma City and Texas – Oklahoma East corridors in particular followed this pattern. The flows in both these corridors were also constrained in the north-to-south direction.

The Kansas East – West corridor was constrained on flows in the east-to-west direction across Kansas. These constraints occurred fairly evenly across all hours of the day, but peaked slightly during off-peak hours. Constraints on this corridor also peaked during March, but occurred throughout the period from March to September as seen in Table II.7.

Constraints in the Tulsa – Kansas City corridor were most active during summer months. This corridor experienced constraints in both north-to-south and south-to-north flows. The north-to-south flows were mostly constrained during off-peak hours and south-to-north flows were mostly constrained during on-peak hours. Similarly, constraints in the Tulsa load center occurred primarily during on-peak hours in the summer to early fall period.

Table II.6

FIRM AND NON-FIRM CURTAILMENTS (MWH)
FOR MOST-CONSTRAINED FLOWGATES FOR 2003 AND 2004

Flowgate	Total MWh			Hourly Average	
	On- and Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Hugo - Valliant	58,606	28,942	29,664	1,809	3,708
Creswell - Kildare	51,155	18,085	33,070	1,130	4,134
Bartlesville - North Bartlesville	27,130	27,130	-	1,696	-
Northeast Station - Oneta	26,733	14,841	11,892	928	1,487
El Paso - Farber	23,021	12,115	10,906	757	1,363
South Philips - West McPherson	11,743	7,375	4,368	461	546
Lone Oak - Sardis	10,830	10,309	521	644	65
Catoosa - Lynn Lane	3,671	3,148	523	197	65

SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

Table II.7

CURTAILMENTS (MWH) BY MONTH FOR
MOST-CONSTRAINED FLOWGATES FOR 2003 AND 2004

Flowgate	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Hugo - Valliant	-	-	-	1,776	3,841	200	2,592	1,564	4,508	17,521	23,194	3,410
Creswell - Kildare	194	5,995	-	-	384	4,291	4,610	4,224	8,312	10,097	1,520	11,528
Bartlesville - North Bartlesville	4,207	190	-	-	-	929	14,009	7,795	-	-	-	-
Northeast Station - Oneta	421	-	-	-	8,301	2,169	12,325	3,517	-	-	-	-
El Paso - Farber	-	-	-	-	2,021	12,517	1,597	3,546	3,159	181	-	-
South Philips - West McPherson	-	-	6,009	1,797	-	2,015	764	928	330	-	-	-
Lone Oak - Sardis	-	-	-	535	6,960	-	100	-	1,068	2,167	-	-
Catoosa - Lynn Lane	-	-	-	-	-	2,360	103	-	1,208	-	-	-
Total	4,822	6,185	6,009	4,108	21,507	24,481	36,100	21,574	18,585	29,966	24,714	14,938

SOURCE: SPP OASIS TLR Report at https://sppoasis.spp.org/documents/tlr/LLR Report.xls

Analysis by Total Number of Hours

It is also useful to examine transmission congestion by the number of hours each region or flowgate is constrained. In 2004, the greatest number of constraints occurred in the following transmission corridors or load centers, shown in Table II.8. These hours take into account overlapping hours of constraint, i.e. when two flowgates in the same transmission corridor or load center were constrained simultaneously.

Table II.8

HOURS OF CONSTRAINT BY TRANSMISSION
CORRIDOR AND LOAD CENTER DURING 2004

Transmission Corridor/ Load Center	Hours
Texas - Oklahoma East	672
Wichita - Oklahoma City	602
Kansas East - West	558
Tulsa - Kansas City	283
Tulsa	169
Oklahoma City	34
Amarillo - Lubbock	11
Tulsa - Oklahoma City	10

SOURCE: NERC TLR Monthly Summaries at
http://www.nerc.com/~filez/Logs/monthlysummaries.htm

The Fort Smith area between SPP and Entergy also was historically a significant constraint for the SPP region (156 total hours of constraint in 2003). However, the transmission system was upgraded in this area during the fall of 2004, and the hours of constraint have dropped considerably.[19]

Changes in Location of Congestion over Time

As seen in Figure II.7 earlier, total non-firm TLR events have increased steadily in SPP during the past few years. The locations of major constraints in SPP also changed from year to year. Figure II.10 shows the top four constrained flowgates for each of the past three years. There is very little overlap between years for any particular flowgate. The two most persistently constrained flowgates were South Philips – W. McPherson and Creswell – Kildare. These two flowgates were among the top constraints in multiple years and have been increasing over time. The South Philips – W. McPherson flowgate is in the Kansas East – West transmission corridor, and the Creswell – Kildare flowgate is in the Wichita – Oklahoma City transmission corridor. Congestion on these flowgates constrain power flows out of eastern Kansas, and more specifically, out of the WERE control area.

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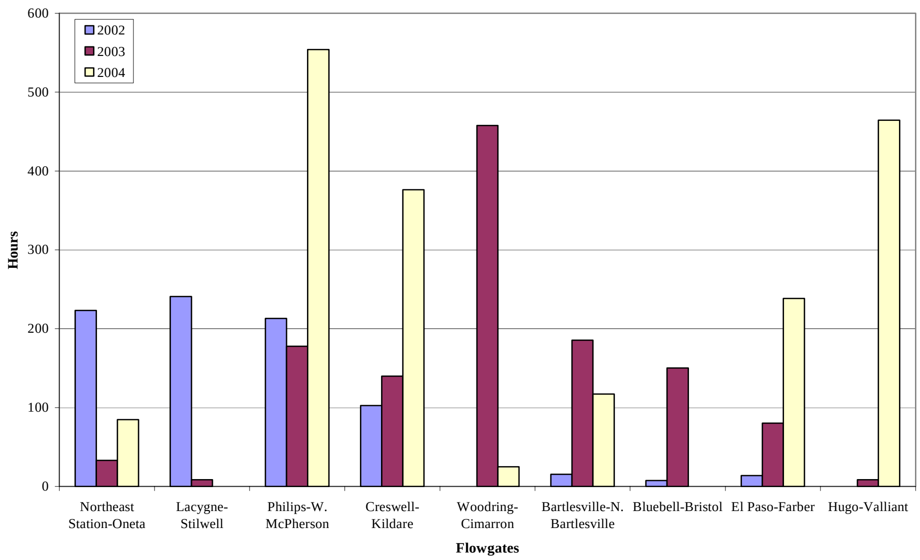
[19] *See* Order Approving Contested Settlement Offer, Subject to the Commission's Modifications, and Authorizing Acquisition and Disposition of Jurisdictional Facilities, July 2, 2004, FERC Docket No. EC03-131-000, at pp. 5 to 6.

However, the pattern of congestion in the area of the LaCygne-Stilwell line since 2002 indicates that some of the congestion previously seen on LaCygne-Stilwell prior to the upgrade moved to nearby flowgates after the upgrade. As mentioned in Section I.D., the LaCygne – Stilwell flowgate was upgraded in 2002, and consequently, power flows over it have not been constrained since.

Figure II.10

TLR HOURS FOR MOST-CONSTRAINED FLOWGATES BY YEAR



SOURCE: NERC TLR Monthly Summaries at
http://www.nerc.com/~filez/Logs/monthlysummaries.htm

III. MARKET RESULTS – WHOLESALE ELECTRICITY PRICES

A. Wholesale Electricity Prices in SPP

Electricity prices are a result of the supply and demand for electricity and the ability of the transmission "highway" to move electricity from the sources of supply to meet demand.

The Bilateral Market for Electricity in SPP

In evaluating electricity prices in SPP, it is useful to gauge the extent of the bilateral electricity market in SPP today. While there is no complete record, FERC Form 1 filings give an indication of sales and purchases for the companies required to file them. Table III.1 shows that, in 2003, nine of the larger utilities in SPP (a) sold over 37 million MWh of electricity and (b) purchased over 33 million MWh. These are not limited to purchases or sales within the SPP footprint, but they give a useful indication of the level of such transactions by large participants that are in SPP in whole or in part.

Table III.1

2003 SALES AND PURCHASES BY SELECTED LARGE UTILITIES

	Sales (MWh)		Purchases (MWh)
Utility	Sales for Resale (RQ)	Sales for Resale (Non-RQ)	Purchased Power
AEP West	5,241,688	2,781,142	7,748,381
Southwestern Public Service Co	9,952,254	123,124	5,391,969
Cleco Power	651,833	609,099	5,327,000
Aquila, Inc.	331,714	811,991	4,596,154
Oklahoma Gas and Electric	1,552,434	113,860	4,526,599
Empire District Electric	308,573	324,656	2,112,879
Kansas City Power and Light	132,966	5,644,528	1,235,778
Midwest Energy Inc.	925	116,531	1,128,012
Westar	1,114,684	7,551,524	1,108,177
Total	19,287,071	18,076,455	33,174,949

SOURCE: 2003 FERC Form 1 Filings at Sales for Resale
Note: AEP West includes Public Service Company of Oklahoma and Southwestern Electric Power Company. Westar includes Westar Energy and Kansas Gas and Electric Company. Aquila includes all of its subsidiaries.

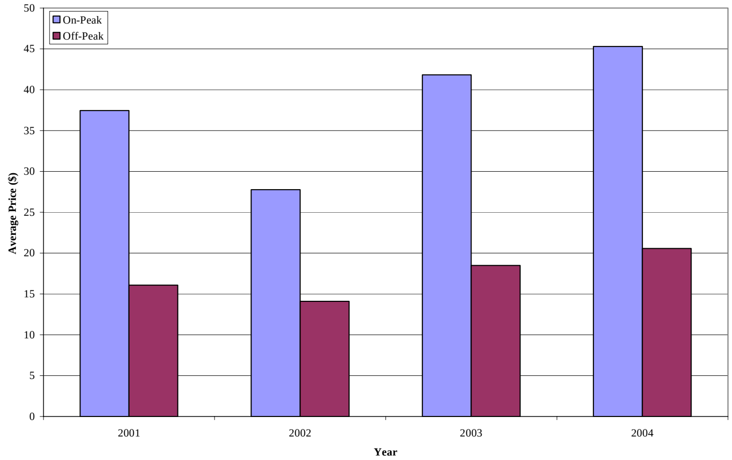
Electricity Prices in SPP

Annual average electricity prices in SPP are shown in Figure III.1 for 2001 through 2004. Average prices have increased between 2001 and 2004 for both on-peak and off-peak hours.[20] The average annual on-peak price increased from $37.45/MWh in 2001 to $45.29/MWh in 2004, a 21% increase. The average off-peak price increased from $16.09/MWh in 2001 to $20.58/MWh in 2004, a 28% increase.

[20] On-peak hours are the 16 hours between 6 a.m. and 10 p.m. Off-peak hours are weekends, holidays, and the 8 hours between 10 p.m. and 6 a.m.

Figure III.1

AVERAGE ELECTRICITY PRICES IN SPP BY YEAR AND TYPE

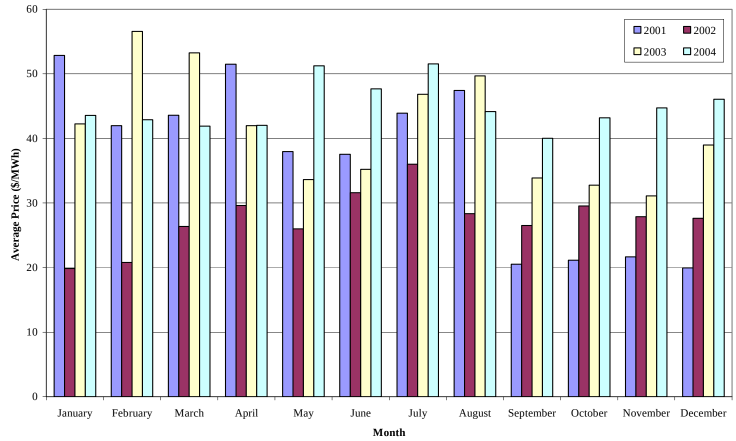


SOURCE: *Megawatt Daily*

Figure III.2 displays the monthly averages of daily on-peak prices for the 2001 to 2004 period. This figure shows that the comparison of monthly prices from 2001 to 2004 does not reveal a uniform seasonal trend from year to year, particularly during the first half of each year, although prices do trend higher during the summer period. At times, prices during the late winter and early spring months were as high as prices during the summer months of the same year. In contrast to the annual pattern of prices, monthly average peak prices during the first four months of the year were higher in 2001 and 2003 than in 2004. However, monthly average prices during 2004 were higher than in earlier years during May to December, except for August.

Figure III.2

SPP AVERAGE MONTHLY ELECTRICITY PRICES
FOR ON-PEAK HOURS FROM 2001 TO 2004

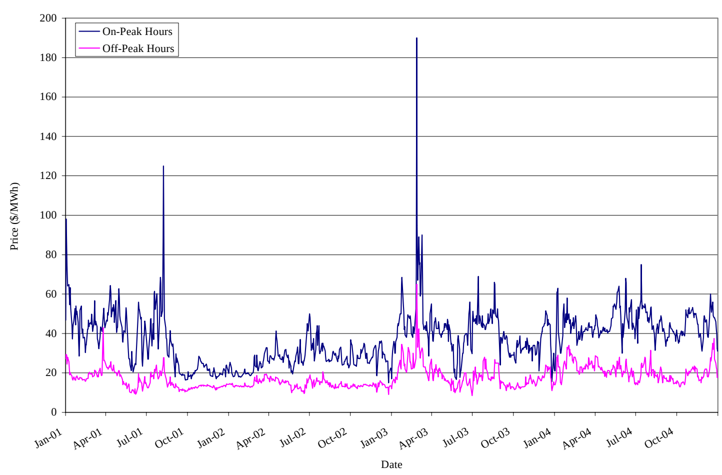


SOURCE: *Megawatt Daily*

While the previous two figures show the average annual on-peak and off-peak and monthly on-peak electricity prices in SPP, Figure III.3 below shows the daily on-peak and off-peak prices in SPP for 2001 to 2004. Most notably, there were three spikes in daily on-peak prices that are not clearly reflected on the annual and monthly price figures.

Figure III.3

SPP ON-PEAK AND OFF-PEAK
WEEKDAY PRICES FROM 2001 TO 2004



SOURCE: *Megawatt Daily*

Price volatility also is an important indication of market performance. It is a measure of the risk faced by market participants. A statistic called coefficient of variation (COV) is one good measure of volatility, and it is calculated by dividing the standard deviation by the mean (average) of a series of data. This statistic is expressed as a percentage; a higher percentage indicates more volatility. Table III.2 shows the COV calculated for each year for both on- and off-peak prices and shows that the COV varied from 15.7% to 43.0% for on-peak prices, and from 13.7% to 35.9% for off-peak prices. For on-peak prices, there appears to be a downward trend in volatility, although 2003 is an exception. No clear trend is seen for off-peak prices since volatility statistics decreased and increased in alternating years.

Table III.2

INDICATION OF ELECTRICITY PRICE VOLATILITY

On-Peak Hours					
	Mean ($/MWh)	Maximum ($/MWh)	Minimum ($/MWh)	Standard Deviation ($/MWh)	Coefficient of Variation (%)
2001	37.45	125.00	16.33	16.10	42.99
2002	27.76	50.00	17.77	5.85	21.06
2003	41.83	190.00	16.00	14.69	35.12
2004	45.29	75.00	21.00	7.11	15.70

Off-Peak Hours					
	Mean ($/MWh)	Maximum ($/MWh)	Minimum ($/MWh)	Standard Deviation ($/MWh)	Coefficient of Variation (%)
2001	16.09	43.00	9.23	4.37	27.13
2002	14.11	20.50	9.00	1.93	13.66
2003	18.48	65.00	7.00	6.64	35.94
2004	20.58	37.50	12.00	4.78	23.20

SOURCE: *Megawatt Daily*

As noted above, this report is meant in part to serve as a baseline and quantify key measures to be used for comparison when SPP fully implements its markets. At that time, effort will be needed to assure an "apples-to-apples" comparison. For example, SPP will establish a real-time imbalance energy market that yields hourly electricity prices. In this report, by necessity, we use price data for blocks of power. For example, *Megawatt Daily* reports on-peak prices for a financially firm 16-hour block of power. This will have to be accounted for when comparing price levels and volatility once the new SPP markets open.

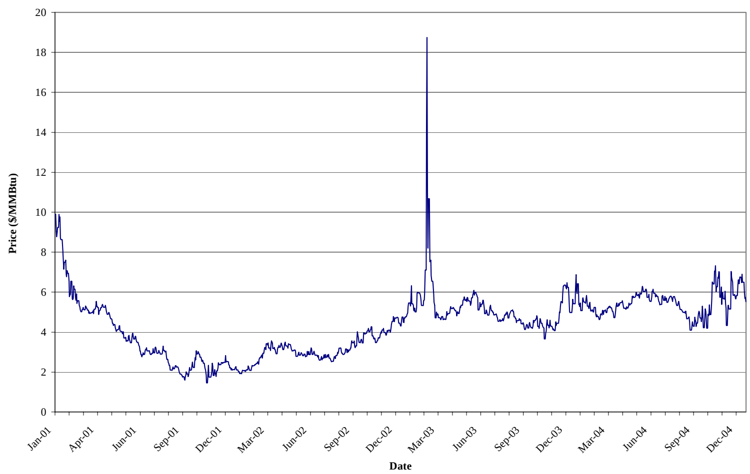
Natural Gas Prices

Because so much of the generating capacity in SPP runs on natural gas, the price of natural gas is expected to be an important determinant of the price of electricity.

For our analysis of daily natural gas prices, data for a pricing point denoted as Panhandle Eastern Pipe Line, Texas-Oklahoma (PEPL–OK) was used. This pricing point was chosen due to its geographical location within the SPP footprint and a slightly higher correlation (as compared to other pricing points) in recent years with SPP electricity prices.[21] Figure III.4 shows that after nearly reaching $10/MMBtu in January 2001, gas prices declined to a low of around $2/MMBtu in late 2001. Since then, prices have steadily increased, including a spike to nearly $20/MMBtu in February 2003. The price increase at PEPL–OK reflects the rising prices paid for natural gas throughout the United States during this time period due to evolving market conditions.

Figure III.4

PEPL–OK DAILY GAS PRICES FROM 2001 TO 2004



SOURCE: *Gas Daily*

As with electricity prices, volatility is an important measure of performance for natural gas markets too. The volatility of natural gas prices as indicated by the COV are shown in Table III.3. This measure of volatility is in the same range as those shown earlier for electricity prices in SPP. As with on-peak electricity prices, there appears to be a downward trend for natural gas price volatility with the COV decreasing from 46.8% in 2001 to 11.2% in 2004.

Table III.3

PEPL–OK GAS PRICE STATISTICS BY YEAR

	Mean ($/MMBtu)	Maximum ($/MMBtu)	Minimum ($/MMBtu)	Standard Deviation ($/MMBtu)	Coefficient of Variation (%)
2001	3.86	9.90	1.46	1.81	46.81
2002	3.15	4.78	1.91	0.68	21.62
2003	5.16	18.75	3.66	1.21	23.51
2004	5.45	7.33	4.11	0.61	11.18

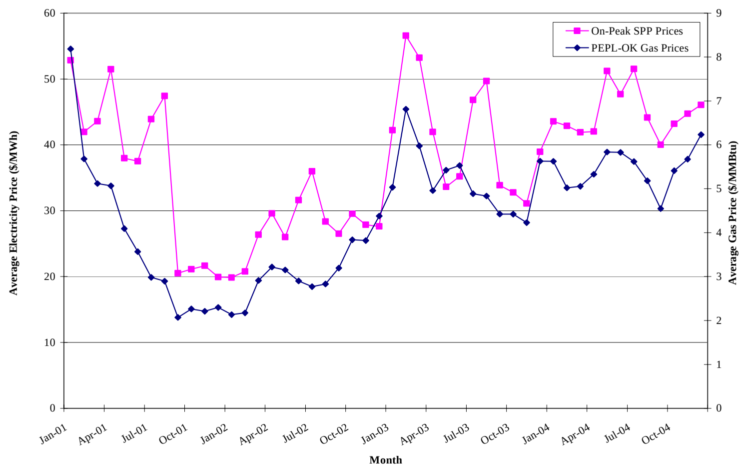
SOURCE: *Gas Daily*

[21] Daily natural gas prices for 2001 to 2004 were obtained from Platts for three pricing points: (a) PEPL–OK, (b) ANR Pipeline, Oklahoma (ANR–OK), and (c) Henry Hub.

A visual comparison of monthly average daily gas and on-peak period electricity prices from 2001 to 2004, seen in Figure III.5, 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 helps to verify the significance of the relationship between natural gas and on-peak electricity prices.

Figure III.5

COMPARISON OF AVERAGE MONTHLY ON-PEAK
ELECTRICITY PRICES AND PEPL–OK GAS PRICES FROM 2001 TO 2004



SOURCE: *Gas Daily*

A more thorough econometric analysis confirms that natural gas prices have a significant effect on on-peak electricity prices. By estimating a regression line between electricity prices, gas prices, and load through a multivariate analysis, the impact can be measured more precisely.[22]

As expected, the impact of daily natural gas prices is significant for prices reported for 16-hour blocks of on-peak power. The results show that a $1/MMBtu increase in natural gas prices would increase electricity prices by $7.21/MWh during on-peak periods, as revealed by the gas price coefficient. The $7.21 increase in electricity for each $1 dollar gas price increase is close to what would be expected if combined-cycle natural gas plants are the marginal units. The intuition behind this hypothesis is that a 7,210 Btu/kWh heat rate means the fuel cost of producing electricity increases by $7.21/kWh for each $1 of natural gas price increase.

At the same time, a $1/MMBtu increase in natural gas prices would increase electricity prices by $2.62 during the off-peak period. One possible explanation is that the share of natural gas fuel is relatively smaller during off-peak periods and, therefore, fluctuations in natural gas prices have smaller impacts on the electricity prices. A 1 GW

22 Please see Appendix C for a description of the regression methodology.

increase in load yields a $0.24 increase in off-peak electricity prices and $0.33 increase in on-peak prices.[23] Other factors, not studied here, that may affect electricity prices are coal prices and the resource margin.

Implied Heat Rates

In situations where natural gas-fired generation is expected to determine on-peak electricity prices, market analysts often calculate an implied heat rate. An implied heat rate is calculated by dividing the daily on-peak electricity price by the daily gas price, and then multiplying by 1,000 to calculate a heat rate in Btu/kWh. Table III.4 reveals that the implied average annual heat rates in SPP have fallen from 10,182 Btu/kWh in 2001 to 8,270 Btu/kWh in 2004. It is likely that this drop in implied heat rate (and the increased fuel efficiency it indicates) reflects the presence of new, more efficient, natural gas-fired combined-cycle generation in SPP.

Table III.4

ESTIMATED YEARLY AVERAGE HEAT RATE IN SPP

Year	On-Peak Heat Rate (Btu/kWh)
2001	10,182
2002	9,117
2003	8,047
2004	8,270

SOURCE: *Gas Daily* and *Megawatt Daily*

B. Electricity Price Comparison with Surrounding Regions

In addition to analyzing the electricity prices within SPP and the factors that contribute to those prices, it is also important to compare electricity prices in SPP with those in surrounding regions. For this analysis, 2004 data was used in two types of comparisons. The first is a comparison of average annual on-peak and off-peak prices for SPP and five surrounding regions. The second analysis is a comparison of the movements of daily on-peak and off-peak prices between SPP and two other regions, Entergy and MRO South.[24]

Electricity Price Comparison between SPP and Surrounding Areas

In evaluating electricity prices, it is useful to look at a regional comparison of average annual on-peak and off-peak electricity prices for 2004. Figure III.6 shows pricing points at SPP, Four Corners in WECC, MRO South, MAIN South, Entergy, and ERCOT.

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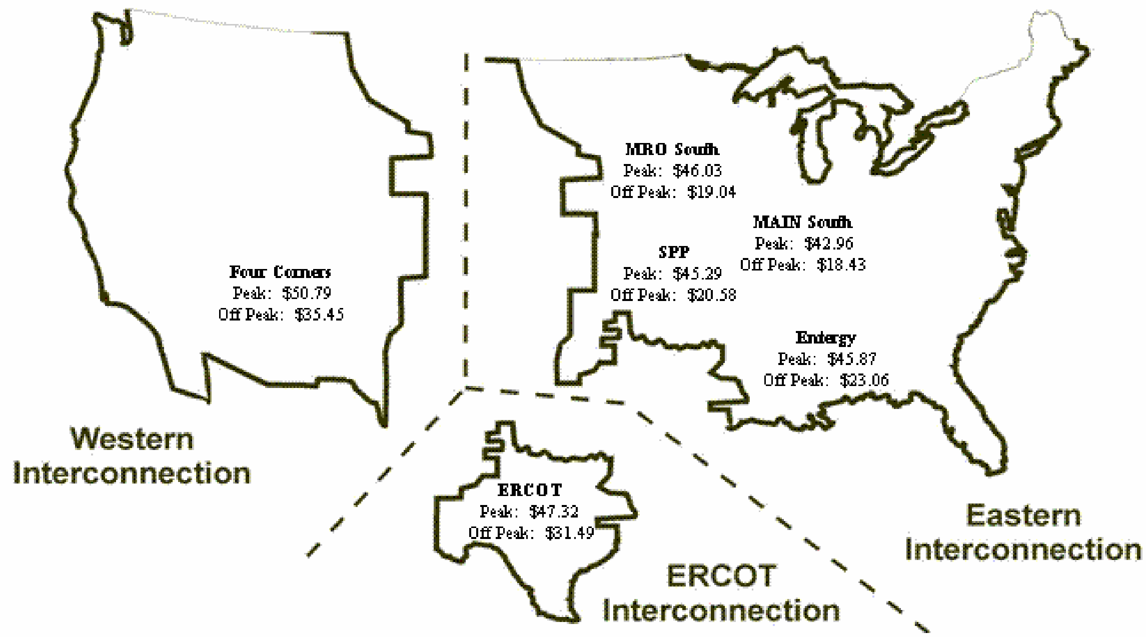
[23] Both variables (prices and load) are statistically different from zero at a 0.01% significance level.

[24] Despite the fact that MAPP has changed its name to MRO, *Megawatt Daily* continues to use the term MAPP for its pricing points.

Figure III.6

REGIONAL COMPARISON OF 2004 AVERAGE ELECTRICITY PRICES



SOURCE: NERC at http://www.nerc.com/regional/NERC_Interconnections_BW.jpg and *Megawatt Daily*

For these six regions, including SPP, annual average on-peak prices for 2004 range from a low of $42.96/MWh in MAIN South to a high of $50.79/MWh in Four Corners. Similarly, annual average off-peak prices for 2004 range from a low of $18.43/MWh in MAIN South to $35.45/MWh in Four Corners. In addition to MAIN South having both the lowest average prices and Four Corners having the highest average prices, during 2004, ERCOT had the second highest average on- and off-peak electricity prices.

The three remaining regions, SPP, MRO South and Entergy vary in the rankings of annual average on-peak and off-peak electricity prices. During 2004, SPP had the second lowest annual average on-peak price of $45.29/MWh with MAIN South as the only cheaper region. For off-peak prices, SPP had the third lowest price of $20.58/MWh falling behind both MRO South and MAIN South. While Entergy's annual average on-peak and off-peak electricity prices were higher than those in SPP during 2004, Entergy's on-peak price was lower than that of MRO South.

It is also significant to note that while both Four Corners in WECC and ERCOT had higher annual average prices than the four regional prices analyzed for the Eastern Interconnect, including SPP, there is a significant price clustering effect that occurs for off-peak prices. That is, while the off-peak prices for the four regions shown in the Eastern Interconnect range from $18.43/MWh to $23.06/MWh, which is a $4.63/MWh range, ERCOT's off-peak annual average price is $8.43/MWh higher at $31.49/MWh, and Four Corners' off-peak price is $12.39/MWh higher at $35.45/MWh.

Since the annual average electricity prices in Four Corners and ERCOT are above those in the SPP region, particularly for off-peak prices, it appears that market participants in the SPP region would have an economic incentive to export power to the Four Corners and ERCOT regions. Conversely, there is also an incentive to buying power from MRO South and MAIN South during off-peak periods and from MAIN South during on-peak periods. The slight differences in prices between SPP, MAIN South and MRO South may not be enough to cause significant power purchase levels due to the cost to move power from those regions to SPP. However, the significant differences in power prices between SPP, Four Corners and ERCOT should provide incentives for exports from SPP even after costs to move power are taken into account.

Correlation Between SPP and Surrounding Areas

In addition to analyzing annual average on-peak and off-peak prices, it can be important to understand whether regions with similar prices actually have similar pricing patterns or if the similarity in prices is simply happenstance. To determine whether price movement in SPP electricity prices occurs at the same time and in the same direction as movement in electricity prices in other regions, a statistic called the "correlation coefficient" is used. A correlation coefficient is a measure of the strength of the linear relationship between two sets of prices, and it ranges between -1 and 1. A positive value near 1 indicates that the two sets of prices being analyzed move in the same direction at the same time. A negative value near -1 indicates that the prices move in opposite directions at the same time. Finally, a value near zero means that the prices do not consistently move in either the same or the opposite direction at the same time.[25] The resulting correlation coefficients, as seen in Table III.5, reveal that SPP's electricity prices tend to move in the same direction at the same time as those of Entergy and MRO South for on-peak periods. This correlation has occurred as well for off-peak periods, though not as strongly with Entergy during 2002.[26]

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[25] A value of 1 indicates a perfectly positive linear relationship, -1 indicates a perfectly negative linear relationship, and 0 indicates no relationship between the variables.

[26] It is important to note that the natural log of the variables was taken prior to calculating the correlation coefficient. Therefore, the correlation coefficient reflects the percentage change in one price due to a one percent change in the other price.

Table III.5

CORRELATION COEFFICIENTS, BY YEAR,
FOR ELECTRICITY PRICES IN SPP, ENTERGY AND MRO SOUTH

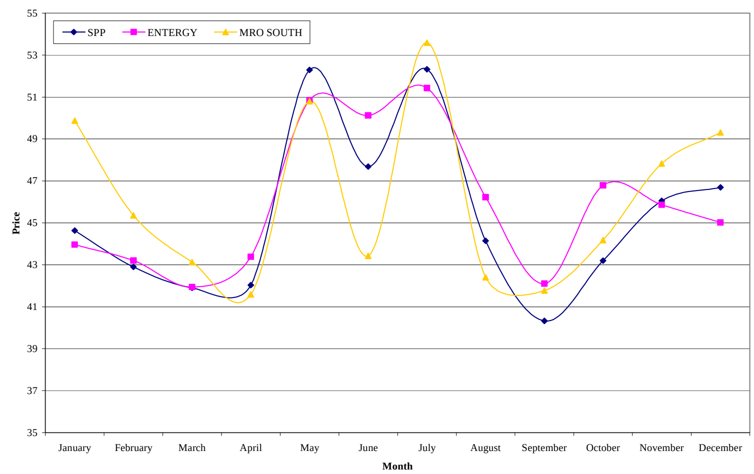
	On-Peak		Off-Peak	
	Entergy	MRO South	Entergy	MRO South
2002	0.903	0.868	0.575	0.854
2003	0.888	0.925	0.836	0.902
2004	0.853	0.793	0.713	0.852

SOURCE: *Megawatt Daily*

Figures III.7 and III.8 show line plots of the average electricity prices by month for SPP, Entergy, and MRO South for 2004. The first figure shows on-peak prices while the second shows off-peak prices. As indicated by the correlation coefficients, all three lines move in a similar manner despite regional differences in price levels and significant changes in the seasonal pattern of prices.

Figure III.7

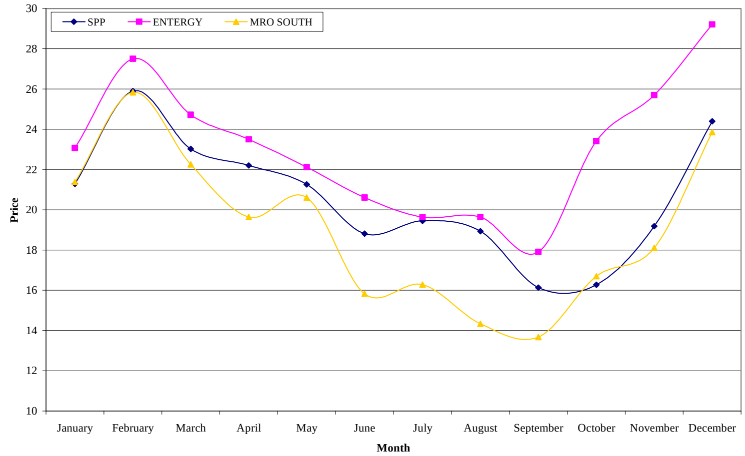
AVERAGE ON-PEAK ELECTRICITY PRICES BY MONTH FOR 2004



SOURCE: *Megawatt Daily*

Figure III.8

AVERAGE OFF-PEAK ELECTRICITY PRICES BY MONTH FOR 2004



SOURCE: *Megawatt Daily*

IV. ENHANCED ACCESS AND NEW ENTRY – SPP'S TRANSMISSION PLANNING AND GENERATOR INTERCONNECTION PROCESSES

Improving transmission access and providing new suppliers with the opportunity to enter the marketplace are important steps for maintaining the reliability and improving the competitiveness of SPP's transmission system. Transmission system expansion increases the amount of generation, both internal and external to SPP, that can reach a given area or load. SPP relies on an extensive transmission expansion planning process for modeling, evaluating, and recommending transmission expansion plans. This process has received recognition from the FERC for including ample opportunity for interested parties to participate.[27] Generation interconnection provides the opportunity for new plants to access the transmission system and begin serving load throughout SPP. SPP has guidelines that direct the review and study of requests for generation interconnection.

A. Transmission Planning Process

The main principles employed by SPP for transmission planning are to ensure transmission system reliability through compliance with planning criteria and to incorporate stakeholder input throughout the process. The regional planning process is conducted on a two-year cycle, divided into two equal parts. Part I entails developing an expansion plan based on reliability needs, and Part II entails assessing the system to determine market needs based on economic expansion plans. SPP completed Part I of its current planning cycle at the end of 2004.

SPP's reliability assessment provided an independent assessment of expansion plans required to meet NERC, regional, and local planning standards. The SPP transmission system was tested using NERC's category A, B, C and D type contingencies to identify system problems. For reference, the NERC definitions used by SPP are as follows:

- Category A – system intact, no disturbance;
- Category B – loss of a single element (N-1);
- Category C – loss of two or more elements (normal clearing, manual system adjustments between events), bus fault, Single Line Ground fault with breaker failure;
- Category D – extreme events, loss of two or more elements, 3 phase fault with breaker failure, loss of tower with three or more circuits, loss of all generation in a station, etc.

Table IV.1 shows the number of overload and voltage violations identified through SPP's reliability assessment for both 2005 and 2010.

[27] *See* Order on Proposed Tariff Revisions, April 22, 2005, FERC Docket No. ER05-652-000.

Table IV.1

OVERLOAD AND VOLTAGE VIOLATIONS

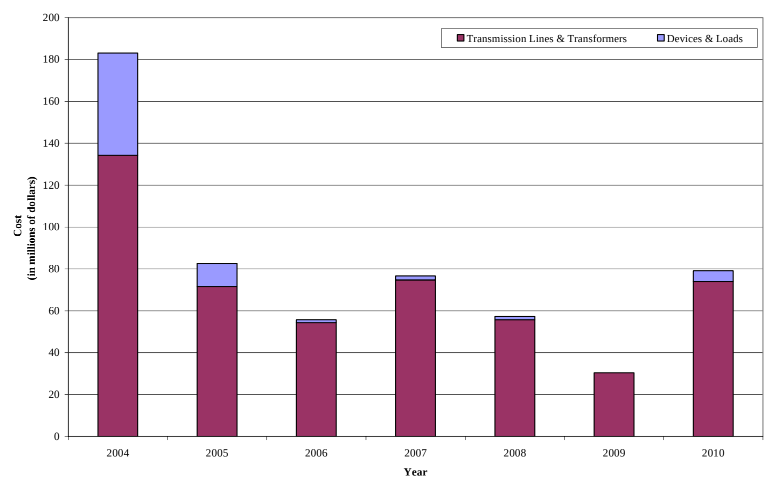
Violation Category	69 kV		115-161 kV		230-500 kV	
	2005	2010	2005	2010	2005	2010
Category A Overload Violations	0	3	1	7	0	0
Category A Voltage Violations	3	7	5	9	1	1
Category B Overload Violations	50	77	23	65	3	2
Category B Voltage Violations	101	159	99	121	6	12
Category C&D Overload Violations	22	28	35	53	2	5

SOURCE: "Reliability Study Criteria and Results" presented by Bob Lux at the SPP Regional Transmission Planning Summit III. December 1, 2004.

In early 2005, SPP completed its transmission expansion plan indicating the estimated costs for projects needed to address the above violations through the year 2010 shown in Table IV.1. The highest expenditures and number of projects occur in 2004 and 2005 with costs estimated at approximately $266 million, as seen in Figures IV.1 and IV.2. In 2004, spending is estimated at over $183 million for 69 projects. These figures include approximately $87 million for the Lamar DC tie project discussed in Section I.D. For 2005, SPP estimates transmission expansion costs to be approximately $83 million for 74 projects. Total expenditures for 2004-2010 are estimated to exceed $564 million.

Figure IV.1

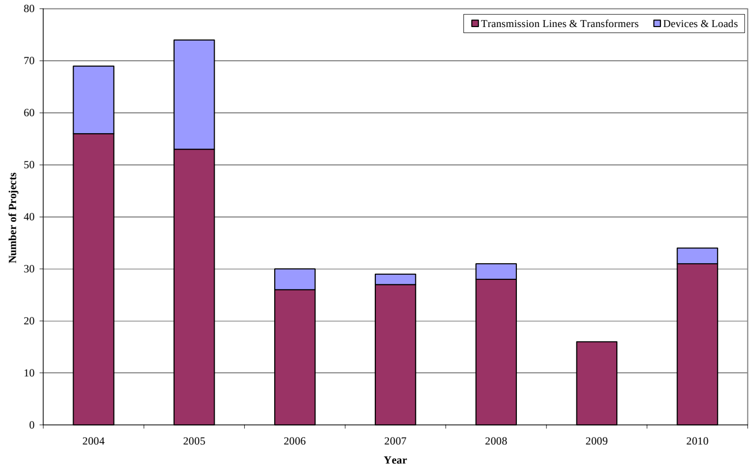
COST OF TRANSMISSION EXPANSION
PROJECTS NEEDED FROM 2004 TO 2010 BY TYPE



SOURCE: SPP Expansion Plan Projects

Figure IV.2

NUMBER OF TRANSMISSION EXPANSION
PROJECTS NEEDED FROM 2004 TO 2010 BY TYPE

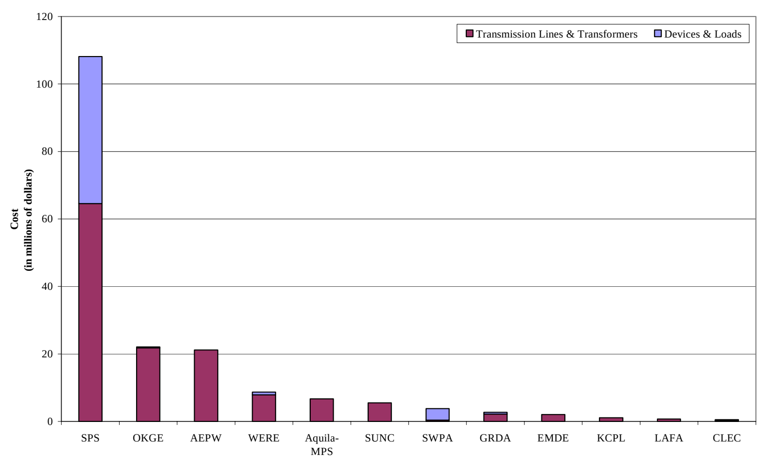


SOURCE: SPP Expansion Plan Projects

In 2004, nearly 83% of the total estimated costs of transmission expansion projects occurred in the OKGE, AEPW, and SPS control areas, with 59% of total costs in SPS alone. This can be seen in Figure IV.3. This is as expected since, as shown earlier, these three control areas have the most significant transmission capability in SPP as measured by number of buses.

Figure IV.3

COST OF TRANSMISSION EXPANSION
PROJECTS PLANNED IN 2004 BY CONTROL AREA



SOURCE: SPP Expansion Plan Projects

Beyond those shown so far, major transmission expansion projects may be needed to connect the eastern and western sections of SPP. Such connection will allow new wind capacity in western SPP to reach the entire SPP transmission system. SPP developed three proposed scenarios for the "Kansas/Panhandle" expansions, each with an estimated cost around $400 million.[28] After completing import and export analyses, the proposed scenarios have been limited to two options.

Transmission Cost Allocation

Since SPP began providing regional transmission service in 1997, limited transmission expansion has occurred within the SPP region. Aside from those built as a result of proceedings at the FERC, no new facilities have been constructed despite over 400 studies performed by SPP for long-term transmission service requests. The transmission expansion that has occurred has consisted of upgrades of existing facilities for the long-term requests.[29]

An important step in assuring transmission expansion is agreeing on the parties responsible for funding such expansion. To this end, SPP filed tariff revisions with the FERC that outline a regional cost allocation plan for transmission system improvements that was developed by the SPP Regional State Committee (RSC). These revisions were approved by the FERC and became effective on May 5, 2005.[30]

The regional transmission cost allocation plan was developed by the RSC through an open process that included opportunities for members and interested parties to participate. The tariff revisions creating this cost allocation plan divide new transmission expansion projects into four categories: (1) SPP Base Plan facilities, (2) economic upgrades, (3) generation interconnection facilities, and (4) facilities required to respond to transmission requests. Base Plan facilities or upgrades with estimated costs of $100,000 or more are eligible for regional cost allocation. One-third of the revenue requirement will be allocated to the SPP region on a postage stamp basis; the remaining two-thirds will be allocated to local zones based on each zone's share of the incremental MW-mile benefits. Costs for economic upgrades will be allocated in accordance with agreements reached with project sponsors. Costs for generation interconnection facilities and other facilities required to respond to transmission requests will be allocated according to SPP's tariff, although some upgrades to designated network resources may be treated the same as Base Plan projects.

In addition to the transmission cost allocation plan, the FERC allowed SPP to implement an experimental process during 2004 to address upgrades necessary to improve short-term transmission service. This process, called Attachment AA after the section of SPP OATT under which it is authorized, provides for prepayment of transmission service for use in upgrading transmission constraints that limit requests for

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28 These estimated costs do not include costs for underlying upgrades.

29 *See* Direct Testimony of Bruce Rew on Behalf of Southwest Power Pool, Inc., FERC Docket No. ER05-652, Exhibit No. SPP-1, at p. 4.

30 *See* Order on Proposed Tariff Revisions, April 22, 2005, FERC Docket No. ER05-652-000.

short-term service. SPP has authorized construction of at least ten facilities under the Attachment AA process that will provide improvements in SPP transmission system power transfer capability.[31]

B. Generation Interconnection Process

SPP's *Guidelines for Generation Interconnection Requests* outlines the procedure and process for applicants to request generation interconnection. In order to execute a Generation Interconnection Agreement three studies must be completed. A Feasibility Study assesses the practicality and costs involved to incorporate the proposed generating unit(s) into the SPP Transmission System. The results of this study may be a list of proposed system upgrades needed along with initial cost estimates. A System Impact Study is a refinement of the Feasibility Study including (1) load flow analysis, (2) short circuit/breaker rating analysis, and (3) transient stability analysis. Finally, a Facility 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.

Table IV.2 shows that between 2000 and 2004, 124 projects entered SPP's Generation Interconnection Queue, representing 41,265 MW of capacity. Of these, 39 projects are currently active,[32] representing 7,727 MW of capacity, and the remaining projects were withdrawn at some stage of the request process. Only 1,748 MW of active capacity in the Queue has fully executed an interconnection agreement. If all 39 active projects do become interconnected with the transmission system, this will increase the total capacity in SPP by approximately 14%.

Table IV.2

GENERATION INTERCONNECTION REQUESTS
BY STATUS AND CAPACITY FROM 2000 TO 2004

Status	Number of Projects	Total Capacity
Interconnection Agreement Fully Executed	11	1,748
Interconnection Agreement Pending	9	1,214
Facility Study in Progress	7	2,133
Impact Study Revision in Progress	1	900
Impact Study Set to Begin	7	977
Feasibility Study in Progress	3	555
Feasibility Study Requested	1	201
Withdrawn	85	33,538
Active Projects	39	7,727
Total	124	41,265

SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, April 4, 2005.

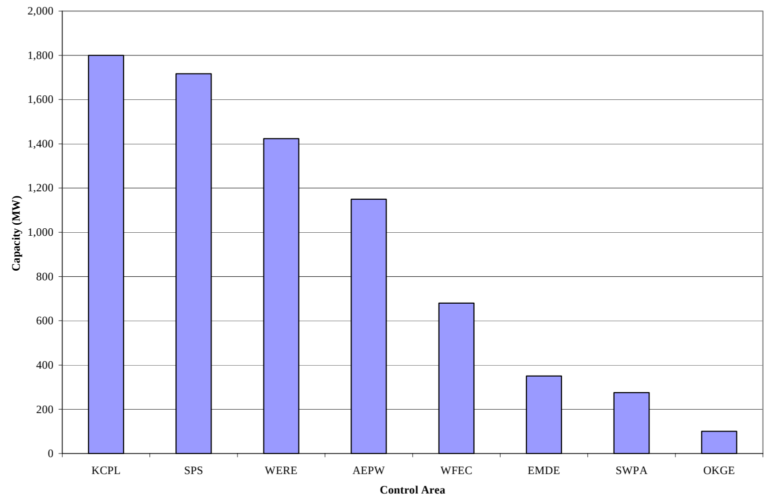
31 *See* Direct Testimony of Bruce Rew on Behalf of Southwest Power Pool, Inc., FERC Docket No. ER05-652, Exhibit No. SPP-1, at p. 3.

32 That is, they have either successfully completed the interconnection process or are still in the process.

Figure IV.4 illustrates that the largest amount of capacity requesting generation interconnection is located in Eastern Kansas (KCPL and WERE) and Southwestern SPP (SPS).

Figure IV.4

ACTIVE REQUESTS FOR GENERATION INTERCONNECTION:
CAPACITY BY CONTROL AREA FROM 2000 TO 2004

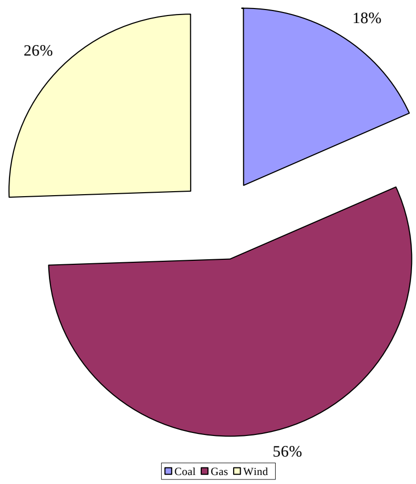


SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, April 4, 2005.

Between 2000 and 2004, 56% of the capacity entering the Generation Interconnection Queue was from gas-fired projects; 26% and 18% of capacity was from wind and coal projects, respectively. This is demonstrated in Figure IV.5.

Figure IV.5

ALL GENERATION INTERCONNECTION REQUESTS:
CAPACITY (%) BY FUEL TYPE FROM 2000 TO 2004

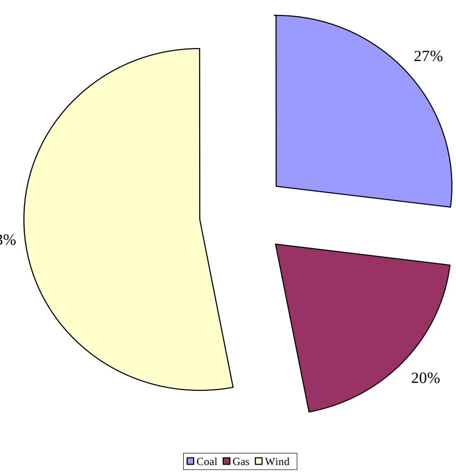


SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, April 4, 2005.

Among active requests, however, 53% of the capacity in the Queue is for wind projects, while coal and gas represent 27% and 20%, respectively, as seen in Figure IV.6.

Figure IV.6

ACTIVE REQUESTS FOR GENERATION INTERCONNECTION:
CAPACITY (%) BY FUEL TYPE FROM 2000 TO 2004



SOURCE: SPP OASIS, Generation Interconnection Queue at https://studies.spp.org/SPPGeneration/GI_Summary.cfm, April 4, 2005.

V. NEW MARKETS AND MARKET POWER

As an RTO, SPP is required by FERC Order No. 2000 to implement markets for its services. SPP is pursuing a phased approach to market development. Three separate phases are being pursued:

- Energy Imbalance Service (EIS) market (OATT Schedule 4)
- Ancillary Services market (OATT Schedules 3, 5 and 6)
- Market-based Congestion Management

A. Energy Imbalance Service Market

In June 2005, SPP will file with the FERC for approval of its proposed EIS Market for start-up by March 1, 2006. Currently, SPP provides EIS under Schedule 4 of its OATT. Under this schedule, SPP's customers can either arrange for energy imbalance service on their own, or SPP will compensate for imbalance energy and pass the cost through to its customers with an imbalance. Under SPP's proposed EIS Market, the market will price imbalance energy throughout SPP for all Transmission Customers.

The proposed EIS Market will provide locational (nodal) pricing signals. This will increase the transparency of prices and the actual cost of providing EIS in comparison to the current OATT Schedule 4. The EIS Market will introduce a bidding (offer) system for generation output and an RTO-wide security constrained economic dispatch (SCED) to determine the prices for each transmission node.

As with SPP's existing OATT Schedule 4, energy imbalances will be based on the difference between (a) actual generation and load and (b) transmission service schedules. Schedules will continue to be based on SPP's existing transmission reservation and scheduling process, which is a physical transmission rights process rather than a financial transmission rights process found in markets in some other regions of the U.S. While all energy imbalances will be settled in the EIS Market, market participants can elect whether or not to bid their generating units into the EIS Market to set the price and be dispatched by SPP. This feature allows flexible participation by SPP's members to meet their business and regulatory needs.

Transmission congestion in the EIS Market will be managed by a combination of the existing NERC TLR process and SPP's SCED of generating units offered into the EIS Market. Self-dispatched units (those generating resources not bidding into the EIS Market) will follow curtailments of their schedules from the TLR process while units offered into the EIS Market will follow SPP's dispatch signal for redispatch purposes.

B. Future Markets for SPP Services

Markets for the provision of Ancillary Services and Congestion Management are under consideration by SPP for future phases of market development. The Ancillary

Services market would provide market-based prices for services currently provided by SPP under three OATT schedules:

- Regulation and Frequency Response service (OATT Schedule 3); and
- Operating Reserves service – Spinning and Supplemental (OATT Schedules 5 and 6)

An Ancillary Services market may reveal a need for a day-ahead capacity market to determine generation resource commitment. SPP's proposed EIS Market involves pricing generation dispatch, not pricing of generation commitment.

As a threshold matter, developing market based congestion management is likely to involve determining whether it is necessary to move from SPP's existing physical transmission rights to financial, market-based, tradable transmission rights.

C. Energy Market Power

As part of the 2005 filing by SPP, the Independent Market Monitor (IMM) has prepared two testimonies. The first proposes market power mitigation measures and the second proposes a market monitoring plan; both of these elements are required by the FERC. The testimony on mitigation measures sets the context for the proposed mitigation measures by assessing the competitive structure of SPP and by explaining, often through simplified, quantitative examples, how the EIS Market will work.

In summary, the testimony concludes that in the absence of binding transmission constraints, the energy market in SPP is workably competitive. This is supported by two different analyses: (1) the Herfindahl-Hirschman Index (HHI) and (2) the Pivotal Supplier Analysis (PSA).[33] An HHI is one quantitative measure commonly relied on by the FERC to test for the potential for market power. It is the sum of the squares of the market shares of all suppliers in a marketplace. For example, if there are ten suppliers, each with a 10% market share, then the HHI would be 1,000 (10×10^2). The HHI threshold for concern commonly used is 1,000. That is, if the HHI is below 1,000, the market is presumed to be competitive. In the absence of transmission constraints, SPP has a HHI of 705, well below the threshold of 1,000.[34]

Since the HHI relies on market share, it can also be helpful to look more simply at the market shares of the larger SPP Companies. AEP West is the largest with a 15% share of the installed capacity. OG&E and Westar have shares of installed capacity of around 10%, and three other suppliers have shares between 5% and 10%. The HHI performed can be seen in Appendix D.

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[33] A more detailed discussion of this can be found in the *Direct Testimony of Craig R. Roach, Ph.D. Concerning SPP's Market Power Mitigation Measures*. Docket No. RT04-01-00_ and ER04-48-00_ at www.bostonpacific.com.

[34] There are three caveats to note about the test performed: 1) no imports were included in SPP for the analysis, 2) contractual commitments were not traced, and 3) installed capacity was used rather than economic capacity.

The main shortcoming of the HHI analysis is that it does not incorporate electricity demand. For this a PSA can be used. The PSA evaluates a market in terms of market supply and electricity demand. It identifies suppliers that are necessary ("pivotal") to satisfy peak load. If a single supplier controls more generation than the resource margin, it is considered to be pivotal. (Put another way, the PSA asks whether the peak load could still be served if that supplier withheld all of its generating capacity.) In the absence of transmission constraints, SPP does not have any pivotal suppliers. This is determined by taking the total peak capacity in 2004 of 55,984 MW minus total peak load of 38,767 MW, leaving the resource margin of 17,217 MW. AEP West is the largest generation owner and has only 8,644 MW. Consequently, no supplier is necessary to meet peak load. Again, this PSA does not take into account transmission capability and is only for an unconstrained market.

The testimony proposes two core mitigation measures: an offer cap and a scheduling requirement. The following bullet points give a quick overview of the offer cap proposed.

- The offer cap for the EIS Market is imposed only for periods of binding transmission constraints;
- It is imposed on generation resources within a constrained area with a negative 5% or higher Generation Shift Factor;
- The offer cap level is set equal to the full annual cost of a new combustion turbine spread over the hours of constraint. That is, it reflects the cost of new entry;
- Exceptions to the offer cap may be requested before the fact based on opportunity cost, risk, or operating costs; and
- Suppliers will know before the fact to whom the cap applies and the level of the cap.

The scheduling requirement is meant to extract additional congestion-related payments from other participants in the SPP EIS market. Again, the scheduling requirement only applies during times of binding transmission constraints. If a transmission constraint prevails, market participants that fail to schedule within a 4% band of actual load are singled out for further assessment. Specifically, it is determined whether these market participants gain revenue because the locational prices at generation and load diverge. If so, the revenue earned by virtue of that difference in locational prices must be disgorged.

The testimony also addresses transmission market power and resource adequacy. As the RTO, SPP is the primary mitigation for the exercise of transmission (vertical) market power in the SPP region. An Initial Assessment of transmission procedures and practices is proposed to identify any remaining opportunities for the abuse of vertical market power. Going forward, the market monitors will focus on these remaining opportunities and, when necessary, approach the FERC to request sanctions or penalties.

Assuring resource adequacy is crucial to the mitigation of both horizontal and vertical market power. Infrastructure shortages create opportunities for market power abuse. The IMM has proposed that the SPP Board and RSC jointly sponsor a Reliability Summit to address the impact of the EIS Market on reliability. The Summit can also serve as part of an early warning system for possible infrastructure shortages.

APPENDIX A

List of Acronyms

Acronym	Full Term
AC	Alternating Current
AECI	Associated Electric Cooperative Inc.
AEPW	American Electric Power West
AMRN	Ameren Transmission
ANR-OK	ANR Pipeline, Oklahoma
Aquila-MPS	Aquila Networks-Missouri Public Service
Aquila-WEPL	Aquila Networks-WestPlains Energy
Btu	British Thermal Unit
CLEC	Cleco Power LLC
COV	Coefficient of Variation
DC	Direct Current
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration
EIS	Energy Imbalance Service
EMDE	Empire District Electric Co. (The)
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GLS	Generalized Least Squares
GRDA	Grand River Dam Authority
GW	Gigawatt (1,000,000,000 watts)
HHI	Herfindahl-Hirshman Index
IDC	Interchange Distribution Calculator
IMM	Independent Market Monitor
INDN	City Power & Light, Independence, Missouri
IOU	Investor-Owned Utility
ISO	Independent Transmission System Operator
KACY	The Board of Public Utilities, Kansas City, Kansas
KCPL	Kansas City Power & Light
kV	Kilovolt (1,000 volts)
kWh	Kilowatt-hour
LAFA	City of Lafayette, Louisiana
LAGN	Louisiana Generating, LLC
LEPA	Louisiana Energy & Power Authority
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEC	MidAmerican Energy Company
MIDW	Midwest Energy, Inc.
MMBtu	Thousand Thousand British Thermal Units (1,000,000 Btu)
MRO	Midwest Reliability Organization

MVA	Megavolt Ampere
MW	Megawatt (1,000,000 watts)
MWh	Megawatt Hour
NERC	North American Electric Reliability Council
NG	Natural Gas
NPCC	Northeast Power Coordinating Council
NPPD	Nebraska Public Power District
NUC	Nuclear
OASIS	Open Access Same-time Information System
OATT	Open Access Transmission Tariff
OKGE	Oklahoma Gas & Electric
OLS	Ordinary Least Squares
OMPA	Oklahoma Municipal Power Authority
OPPD	Omaha Public Power District
PEPL-OK	Panhandle Eastern Pipe Line, Texas-Oklahoma
PSA	Pivotal Supplier Analysis
RQ	Requirements Service
RSC	Regional State Committee
RTO	Regional Transmission Organization
SCED	Security Constrained Economic Dispatch
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
SPRM	City Utilities, Springfield, Missouri
SPS	Southwestern Public Service Company
SUNC	Sunflower Electric Power Corporation
SWPA	Southwestern Power Administration
TLR	Transmission Loading Relief
TRM	Transmission Reliability Margin
WAT	Hydroelectric (Water)
WECC	Western Electricity Coordinating Council
WERE	Westar Energy, Inc.
WFEC	Western Farmers Electric Cooperative
WND	Wind

APPENDIX B

List of SPP Members as of March 2005

Investor-Owned Utilities

American Electric Power
- Public Service Company of Oklahoma
- Southwestern Electric Power Company

Aquila, Inc.
- Missouri Public Service
- St. Joseph Light & Power
- WestPlains Energy

Cleco Power LLC
Entergy Services, Inc.
Exelon Power Team
Kansas City Power & Light Company
OG&E Electric Services
Southwestern Public Service Company
The Empire District Electric Company
Westar Energy, Inc.
- Kansas Gas and Electric Company

Cooperatives

Arkansas Electric Cooperative Corporation
East Texas Electric Cooperative, Inc.
Kansas Electric Power Cooperative
Midwest Energy, Inc.
Northeast Texas Electric Cooperative
Sunflower Electric Power Corporation
Tex-La Cooperative of Texas, Inc.
Western Farmers Electric Cooperative

Municipals

City of Clarksdale, Mississippi
City of Lafayette, Louisiana
City Power & Light, Independence, Missouri
City Utilities, Springfield, Missouri
Oklahoma Municipal Power Authority
Public Service Commission of Yazoo City, Mississippi
The Board of Public Utilities, Kansas City, Kansas

State Agencies

Grand River Dam Authority
Louisiana Energy & Power Authority

Independent Power Producer

Calpine Energy Services, L.P.
Redbud Energy, L.P.
Tenaska Power Services Company

Marketers

Aquila Power – Aquila, Inc.
Cargill Power Markets, LLC
Cinergy Corporation
Constellation Energy Commodities Group, Inc.
Coral Power LLC
Dynegy Marketing & Trade
Duke Energy Trading & Marketing
Edison Mission Marketing & Trading, Inc.
El Paso Merchant Energy, L.P.
NRG Power Marketing, Inc.
TXU Energy Trading Company
Williams Power Company, Inc.

APPENDIX C

Regression Methodology

The first step of this analysis is to begin with the Ordinary Least Squares (OLS) method of estimating the regression equations for both on-peak and off-peak electricity prices. The multivariate regression equation takes the following general form:

$$Electricity\_Price_t = a_1 * Gas\_Price_t + a_2 * Load_t + e_t$$

where,

$Electricity\_Price_t$ is a generalized variable referred to as either
$Off\text{-}Peak_t$ – a time series of off-peak electricity prices[35] or
$On\text{-}Peak_t$ – a time series of on-peak electricity prices;

Gas_Price_t – a time series of daily natural gas prices;

$Load_t$ – a times series of daily peak load;

$a_{1,}\ a_2$ are linear regression coefficients; and

e_t is a statistical error term.

However, visual inspection of the SPP on-peak and off-peak weekday prices showed the presence of seasonality in the electricity prices. As a result, the OLS coefficients would underestimate the standard error, which would lead to incorrect decisions in hypothesis testing. Formally, the presence of autocorrelation was revealed by a Durbin-Watson test. This autocorrelation occurs when errors are not independent, and there is a relationship between the error terms across observations. The autocorrelation of errors can be corrected with a Generalized Least Squares (GLS) model by applying the Cochrane-Orcutt iterations method. This method uses a sequence of regressions to estimate a lagged error term coefficient. In the estimated generalized model the problem of autocorrelation is eliminated, and the problem of autocorrelation is explained by the lagged error term. The results of GLS regressions are summarized below.

$$On\text{-}Peak_t = \underset{(***)^{36}}{7.21 \times Gas\_Price_t} + \underset{(***)}{0.33 \times Load_t} + e_t + 0.76 e_{t-1} + v_t \qquad R^2 = 0.70$$

$$Off\text{-}Peak_t = \underset{(***)}{2.62 \times Gas\_Price_t} + \underset{(***)}{0.24 \times Load_t} + e_t + 0.84 e_{t-1} + v_t \qquad R^2 = 0.65$$

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[35] The times series consisted of 2001-2004 daily data for SPP electricity prices ($/MWh), PEPL-OK gas prices ($/MMBtu) and SPP load data (GW), obtained from Platts and SPP.

[36] The (***) symbol implies that coefficient above is statistically different from zero at 0.01% significance level.

GLS estimations show the presence of strong positive autocorrelation of errors in both regressions. This implies that expectations about a price increase, perhaps precipitated by forecasts for a hot summer, are followed by an additional increase in price. This also can be explained by the strategic bidding of generators that anticipate price increases. In addition, the error term includes all the significant variables not included into the regression, such as coal prices. The high multiple regression correlation coefficient R^2 in both regressions, implies that the regression equation fits actual data on electricity prices relatively well.

The multivariate regression confirms what was suggested by the more rudimentary analyses. Gas prices, as suggested by the heat rate analysis, are an important determinant of on-peak electricity prices.

APPENDIX D

Market Power Analysis: Initial HHI Assessment of SPP Whole Market Imports and Contracts Excluded

Parent Company	SPP Total		HHI
	Summer Peak Capacity (MW)	Percent	
AEP	8,644.11	15.44%	238.40
OGE	6,025.16	10.76%	115.83
Westar	5,781.74	10.33%	106.66
Xcel	4,428.00	7.91%	62.56
KCP&L	4,058.90	7.25%	52.56
CLECO	2,911.50	5.20%	27.05
Aquila	2,418.36	4.32%	18.66
Calpine	2,310.61	4.13%	17.03
Tenaska	2,285.03	4.08%	16.66
USCE	2,108.60	3.77%	14.19
Empire District	1,352.40	2.42%	5.84
GRDA	1,331.80	2.38%	5.66
WFEC	1,263.00	2.26%	5.09
Intergen	1,200.00	2.14%	4.59
Cogentrix	894.00	1.60%	2.55
Springfield City of	793.00	1.42%	2.01
Lafayette City of	646.50	1.15%	1.33
Kansas City City of	643.00	1.15%	1.32
AECC	618.00	1.10%	1.22
Sunflower Electric Power Corp	606.00	1.08%	1.17
Entergy	487.90	0.87%	0.76
Eastex CoGeneration LP	485.01	0.87%	0.75
Golden Spread EC	444.00	0.79%	0.63
OMPA	418.15	0.75%	0.56
ONEOK	336.00	0.60%	0.36
AES	320.00	0.57%	0.33
Independence City of	291.80	0.52%	0.27
Northeast Texas Elec Coop Inc	285.28	0.51%	0.26
McPherson City of	259.00	0.46%	0.21
Lubbock City of	251.58	0.45%	0.20
Sikeston City of	235.00	0.42%	0.18
Borger Energy Associates LP	220.00	0.39%	0.15
KAMO Electric Coop Inc	200.20	0.36%	0.13
Alexandria City of	156.30	0.28%	0.08
LEPA	111.00	0.20%	0.04

Smith Cogen	110.00	0.20%	0.04
Chanute City of	98.70	0.18%	0.03
Terrebonne Parish Consol Gov't	84.00	0.15%	0.02
KEPC	90.20	0.16%	0.03
Morgan City City of	68.00	0.12%	0.01
Jonesboro City of	63.00	0.11%	0.01
Tinker AFB	62.00	0.11%	0.01
Winfield City of	45.58	0.08%	0.01
Plaquemine City of	44.00	0.08%	0.01
Wellington City of	39.50	0.07%	0.00
Iola City of	37.63	0.07%	0.00
Higginsville City of	36.00	0.06%	0.00
Getty	35.00	0.06%	0.00
Carthage City of	32.00	0.06%	0.00
Vulcan Materials Co	30.00	0.05%	0.00
Kennett City of	29.00	0.05%	0.00
Midwest Energy Inc	25.00	0.04%	0.00
Erie City of	24.11	0.04%	0.00
Sid Richardson Carbon Ltd	20.00	0.04%	0.00
Engineered Carbons Inc	20.00	0.04%	0.00
Augusta City of	19.74	0.04%	0.00
Paragould Light & Water Comm	17.50	0.03%	0.00
Malden City of	17.00	0.03%	0.00
Poplar Bluff City of	13.00	0.02%	0.00
Gardner City of	11.00	0.02%	0.00
Girard City of	10.57	0.02%	0.00
Fredonia City of	6.13	0.01%	0.00
Burlington City of	9.24	0.02%	0.00
New Roads City of	9.00	0.02%	0.00
Kingfisher City of	8.00	0.01%	0.00
Piggott City of	7.50	0.01%	0.00
Neodesha City of	7.36	0.01%	0.00
Rayne City of	6.00	0.01%	0.00
Mangum City of	6.00	0.01%	0.00
Mulvane City of	5.67	0.01%	0.00
Oxford City of	5.05	0.01%	0.00
Norit Americas Inc	5.00	0.01%	0.00
Brownfield City of	2.68	0.00%	0.00
Tulia City of	1.11	0.00%	0.00
Bowersock Mills Power Co, The	1.00	0.00%	0.00
Floydada City of	0.63	0.00%	0.00
Total	**55,983.83**	**100.00%**	**705.49**