PUBLIC SERVICE COMPANY OF OKLAHOMA

Integrated Resource Plan

Spring 2005

Including an *Addendum* Reflecting Continuing Analysis as Represented in Cause No. 200500516

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SECTION A -- NARRATIVE

1.0 IRP Process Overview

1.1 Introduction - Public Service Company of Oklahoma (PSO) is a wholly-owned subsidiary of American Electric Power Corporation (AEP). The total AEP System comprises eleven operating companies, operating in eleven states, and in, primarily, two different Regional Transmission Organizations (RTO's), as follow:

AEP West Zone – SPP:

- Public Service Oklahoma (PSO), serving portions of Oklahoma
- Southwestern Electric Power (SWEPCO), serving portions of Arkansas, Louisiana, and Texas

  Note: In addition, Texas North Company (TNC) serves portions of Texas within the SPP RTO. The TNC load and peak demand in the SPP zone is minimal (demand estimated at approximately 30 MW or, comparatively, well less than 1% of either the PSO or SWEPCO peak demand) and TNC owns no generation capability that is located in the SPP zone, instead relying on purchase transfers from ERCOT via DC ties. Therefore, TNC is not detailed in the planning analysis as described in this report.

AEP East Zone – PJM:

- Appalachian Power (APCo), serving portions of Virginia and West Virginia
- Columbus Southern Power (CSP), serving portions of Ohio
- Indiana Michigan Power (I&M), serving portions of Indiana and Michigan
- Kentucky Power (KP), serving portions of Kentucky
- Ohio Power (OPCo), serving portions of Ohio
- Kingsport Power (KgP), serving portions of Tennessee
- Wheeling Power (WP), serving portions of West Virginia

  Note: KgP and WP are affiliated, non-generating distribution companies. As such, neither would be considered for capacity resource ownership but, rather, each would continue to incur costs as part of its FERC wholesale cost-of-service tariff with its affiliated operating company – APCo and OPCo, respectively.

The operating companies in AEP's western zone located in the Southwest Power Pool ("SPP Companies") collectively serve a population of about 3.7 million (0.9 million retail customers) in a 36,000 square-mile area of Arkansas, Louisiana, Oklahoma, and Texas. AEP-SPP recently experienced its all-time peak internal demand of 8,480 MW on August 26, 2005 (SWEPCO recently established and all-time time demand of 4,724 on August, 23, 2005, and PSO likewise recently establishing an all-time demand of 4,047 MW on July 22, 2005).

1.2 Planning Objective - This report presents the results of an Integrated Resource Plan (IRP) analysis for the SPP Companies covering the period 2005-2014. The information presented with this IRP ("Plan") includes descriptions of assumptions, study parameters, methodologies, and results including the integration of supply-side resources and demand-side management approaches.

The objective of this planning process was to set forth a plan that would provide the AEP operating companies with capacity resources that will maintain the companies' long-term reliability and low cost profile to its customers, ensuring the flexibility necessary to promptly respond to the changes occurring in the electric utility industry. In that regard, *assumptions and plans are continually reviewed and modified as new information becomes available*. Such continuous analysis is required to ensure that changing markets, market structures, technical parameters, reliability and environmental requirements are constantly re-assessed.

1.3 Fundamental Steps and Planning Considerations - With the additional supply-side resources reflected in the Plan, SWEPCO and PSO, individually, are expected to have adequate resources to serve customers' requirements throughout the ten (10)-year (2005-2014) IRP period, while at the same time being positioned to be in compliance with known or anticipated economic/market conditions, technology advancements, changes in governing statutes/rules, including environmental requirements, all at the lowest reasonable cost to customers.

The resource planning process includes the following basic steps:

1. *Load Forecasting (Energy and Demand)* — Development of energy and peak demand forecast for native load, an estimation of demand side management opportunities, as well as an estimation of wholesale customer load and demand profiles. The latter intended to optimize the utilization of the available generating resources.
2. *Review / Assessment of Current Resources* — Evaluation of physical and economic factors - including environmental compliance requirements - that may affect the continued operation of any of the system's current generation resources.
3. *Reliability Analysis / Reserve Criteria* — Consideration of RTO and/or zonal requirements concerning sufficiency of capacity planning reserves.
4. *Determination of Adequacy of Current Resources / Need for Additional Resources* — Matching existing and currently planned resources against total requirements (load plus reserve requirements), to determine projected future capacity shortfalls / needs.
5. *Identification of Capacity Resource Options* — Consideration of various classes of potential resources: market purchases of firm capacity vs. generating unit additions vs. purchase of existing generating assets; available technology options; etc. Determination of the relevant assumptions for each of these options, as well as system-wide application assumptions.
6. *Determination of Optimal Resource Mix and Timing* — Consideration of the analytically optimal resource mix and timing of new capacity resources within the planning period under various modeling assumptions and risk factors.
7. *Implementation Considerations* — Consideration of technical and physical ability to implement, local (state/operating company) legal entity bidding and/or ownership issues and requirements, as well as siting and other practical technical and regulatory issues.

Further, the planning process includes the following process considerations discussed more fully below:

1. "Obligation to Serve" Load Requirements
2. Environmental Regulations
3. Existing Generating Unit Operating Considerations
4. Commodity Pricing Assessment
5. Supply Options: Build/Own vs. Buy
6. Transmission and RTO impacts
7. Optimal Resource Mix
8. Generation Technology Assessment
9. Risk Analysis

Obligation to Serve Load Requirements: Electric utility service in the four states the SPP Companies operate is fully regulated, with the exception Texas. As such, the long-term obligation to generate, transmit and distribute reliable power and energy is one of the chief considerations of the IRP process.

Environmental Regulations: Environmental regulatory uncertainty has been analyzed under various scenarios, including the guidelines recently established under the U.S. Environmental Protection Agency (EPA) Clean Air Interstate Rules (CAIR) and Clean Air Mercury Rules (CAMR).

> Note: Given both the generation mix and technology of the existing fleet of the SPP Companies (significant gas generation as well as either low-sulfur, Powder River Basin [PRB]-sourced coal and/or coal units with scrubbers), the relative impacts of CAIR and CAMR are limited. Further, certain states such as Oklahoma are generally not directly impacted by the requirements of CAIR.

Existing Generation Unit Operating Considerations: Planning necessitates the analysis of not only new generation resources to meet prospective load and demand growth, but also the analysis of the continued operation or potential retirement and/or re-powering of existing resources. Such analyses center on the economic viability of generating units within the context of the available capacity market "build versus buy" opportunities. Viability may also be impacted by decisions surrounding any plans to meet mandated emission regulations. However, other factors such as a unit's ability to alleviate local reliability constraints may impact day-to-day operational planning. In some situations, re-powering can be a viable alternative to retirement, but that decision depends heavily on site-specific considerations. The SPP Companies participation in the SPP RTO – and the processes and procedures that are then invoked -- also play a role in unit disposition decisions.

Commodity Pricing Assessment:: Any detemination of supply-side capacity and energy options must take into consideration the anticipated value of various commodity prices that have a direct bearing on generation assets – whether those assets are existing assets or are "new-build" assets being contemplated as part of the IRP process. Such commodity prices include natural gas, energy, delivered coal (by-type), emission allowances that are currently transacted within liquid markets, namely, SO_2, NOx and, to a lesser extent, CO_2. In addition, regional/RTO requirements surrounding capacity obligations have set forth the assessment of capacity prices as an important element within the capacity planning process. Clearly, such regional capacity availability and attendant pricing play a role in the fundamental "make versus buy" construct within capacity resource planning. However, recent volatility in the natural gas market has further focused specific attention on that commodity as being perhaps the most critical commodity element in this long-term process.

Supply Options: Build/Own vs. Buy: Load serving utilities typically have the option of building/supplying their own resources *or* buying energy and capacity from the wholesale market to meet future needs. Issues impacting these options that should ultimately be considered include but are not limited to:

- Investor credit-worthiness and ultimate impact on required cost of capital;
- Exposure to market risk and, with that, consideration of price certainty; and
- Regulatory/legal requirements that may dictate consideration of such options

To expand upon the final issue, utilities may be directed or encouraged by regulators to pursue more open procurement processes. The rules governing competitive procurement are not uniform as exemplified in the four state jurisdictions of the SPP Companies. For instance, certain rules may require states' utilities to initiate a formal Request for Proposal (RFP) process, and may provide for independent review of the utility's bid evaluation process. Even in cases where regulators allow utility self-build, they must frequently provide detailed information on the costs of any self-build options versus alternatives before approval. Further, FERC policies can also influence this build/own vs. buy decision. For example, "market power" considerations may limit the aggregate amount of generation resources a utility may own in a zone, thus limiting its ability to build and own additional resources itself or acquisition of competitive (e.g. IPP) resources.

The SPP Companies are developing self-build options as each has a regulatory "obligation to serve." These options will also serve as a backstop should market solicitations being established as part of the IRP implementation process not produce supply options that are lower cost or that are less robust than self-build options.

Transmission and RTO Impacts: Overall resource planning typically considers *all* resources, including transmission. In certain cases, transmission investment may be warranted purely for reliability purposes. Transmission can also enhance available generation resources when it opens access to nearby zones that may have generation capability deficiencies. In other cases, transmission is required to deliver the energy from new generation projects to loads, or to make local resources more economic through off-system sales or integration with more remote zones. Transmission considerations will also affect potential siting of new resources. Both the transmission system's ability to integrate a new resource, and specific interconnection requirements must be considered. Moreover, an RTO may have interconnection protocols, sometimes quite detailed, that must be complied with.

Utility memberships with RTOs have implications for the addition of generation resources to the transmission system. In the past, addition of regulated generation to ones' own transmission facilities involved limited coordination with neighboring systems. However, membership in an RTO now requires development of specific coordinated transmission plans, with the related potential cost responsibility to mitigate transmission impacts on neighboring systems resulting from the new generation. In addition, the proposed generation resources must be studied by the RTO to assess reliability consequences, connection requirements and cost responsibilities. The length of the SPP generation interconnection study process is not as well defined, but it could take as much as one year.

Optimal Resources Mix: The Plan must contemplate the optimal mix of generating asset types necessary to meet future load obligations. The comparison of different resources involves tradeoffs between available technologies with different generating profiles. In general, generating technologies with high fixed costs and low variable costs, such as most solid-fuel (coal, lignite) technologies, tend to be more economic when operated at high capacity factors. Technologies with low fixed, but high variable costs, such as gas-fired simple-cycle combustion turbines, are more economic at low capacity factors.

As discussed later in this report, incremental resources for the SPP Companies were considered reflecting a reasonable "mix" of generation types that comport to the inherent typical load shapes of the SPP Companies.

Generation Technology Assessment: Given the necessary long time horizons of most resource planning exercises, the capacity planning process must consider new or constantly evolving generating technologies, some of which may have potentially uncertain or unproven performance and cost parameters. Therefore, the modeling assessment of such generating technologies for the SPP Companies as part of this Plan considered an array of sources for such cost and performance estimates. Such sources included commonly cited public information, consortiums where AEP is actively engaged, vendor relationships, as well as AEP's own experience and expertise.

Risk Analysis: The future is inherently uncertain, and the "optimal" plan for one set of assumptions may not be optimal for a different set of assumptions. Different approaches to planning account for uncertainty in different ways. At a minimum, virtually all resource plans model several discrete scenarios that vary key drivers such as fuel prices, load growth, capacity build costs, and environmental regulation. More computationally intensive modeling processes characterize the distributions governing these drivers and their correlations, using sampling techniques to model wide ranges of possible scenarios. As described above, and for purposes of this Plan, the primary risk driver was considered to be the long-term price of natural gas.

1.4 Planning Horizon - Given the significant time period typically encompassed by the capacity planning process, both from the perspective of the ultimate cost exposure of these long-lived assets as well as from the perspective of the in-service "lead-time" requirement, the evaluations to be discussed in this document were performed over a 2005-2020 [1] detailed capacity resource "planning" period. As a result, in order to recognize the ultimate cost-based end-effects of any capacity option established in the latter years of that planning period, the economics were extended an additional ten (10) years, resulting in an overall 2005-2030 economic "study" period.

The optimal capacity resource plans identified in this document were performed utilizing the proprietary *Strategist* [2] resource optimization tool and were based on a traditional revenue requirements basis. In all scenarios the model seeks, as its ultimate objective function, to establish a *least-cost* (revenue requirement) Cumulative Present Worth (CPW) solution over the defined study period.

2.0 Demonstration of Need

2.1 Load and Demand Forecast - Internal load and peak demand forecasts were based on the AEP Economic Forecasting group's January, 2005 update to the approved 2005 AEP load forecast that was completed in the summer of 2004.

The electric energy and demand forecast is the accumulation of five specific forecast model processes as reflected in the chart below. The first two processes model the consumption of electricity at the aggregated customer level. These aggregated levels are the FERC revenue classifications of residential, commercial, industrial, other, and municipals and cooperatives. The first model process is the monthly short-term sales models and the second is the annual long-term sales models. The third process estimates energy losses in terms of transmission and distribution losses from the source to the customer premise. The fourth process blends short and long term results, aggregates the revenue class sales, and adds energy losses. This culminates in what is generally called net internal energy requirements. Net internal energy requirements are projected here in the units of monthly electricity production at the source. The final model process also distributes the monthly net internal energy requirements across the hours of the month resulting in the hourly demand forecast.

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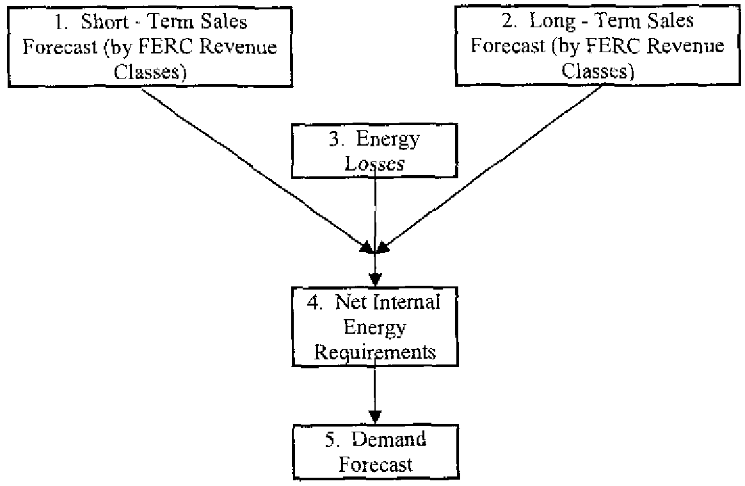
[1] Although the long-term modeling to be described assessed capacity needs through 2020, given the fact that the capacity resource planning evaluation for all "out-years" will be continually cycled going-forward *and* considering that the overall corporate long-term financial planning horizon is typically limited to ten years, the IRP results in this report represent a view of the AEP capacity resource requirements through the year 2014.

[2] As discussed in greater detail later in this document, *Strategist* is a long-term resource optimization tool widely used over the past two decades in the utility industry for resource planning activity. This proprietary application is under lease to AEP from New Energy Associated (NEA), Atlanta, GA.



The long-term forecasts are developed utilizing annual econometric models. The process starts with an economic forecast provided by *Economy.com* for the United States as a whole, each state, and regions within each state. These forecasts include forecasts of employment, population, and other demographic and financial variables. The long-term forecast incorporates the economic forecast and other inputs to produce a forecast of annual KWh sales. Other inputs include regional and national economic and demographic conditions (some of which are presented in the following table), energy prices, weather data, and customer-specific information.

		CPI	GDP (2000 $)	PPI
		Urban Consumer - All Items, (Index 1982-84=100)	2000 $	Index = 1982, United States
	1980	82.4	5,161.7	79.1
	1985	107.6	6,053.8	111.6
	1990	130.7	7,112.5	117.6
	1995	152.4	8,031.7	130.9
	2000	172.2	9,816.9	130.7
Actual Data	**2003**	184.0	10,398.0	141.1
Forecast Data	**2004**	188.0	10,888.9	143.3
	2005	190.2	11,268.9	145.5
	2010	212.1	13,301.0	150.0
	2015	236.7	15,122.2	159.0
	2020	264.2	16,899.2	169.3
	2025	294.9	18,683.1	180.2

AEP uses processes that take advantage of the relative strengths of each method. The regression models typically used in the shorter-term modeling use the latest available sales and weather information to represent the variation in sales on a monthly basis for short-term applications. While these models produce extremely accurate forecasts in the short run, without specific ties to economic factors, they are less capable of capturing the structural trends in the electricity consumption that are important for the longer term planning. The long-term process, with its explicit ties to economic and demographic factors, is appropriate for longer term decisions and the establishment of the most likely or "base"load and demand outcome over the forecast period.

2.1.1 (Peak) Demand Forecast -- The following table identifies the projected annual internal (peak) demand forecast of PSO that was utilized in this IRP process. As suggested in the methodology overview just addressed, this forecast represents the "base" projection of load and demand for PSO that has the highest probability of occurrence.

Given the obvious uncertainty surrounding weather, classical long-term load forecasting employs the prospect of weather normality. Moreover, the uncertainty surrounding the need for additional resources during periods of extreme weather temperatures near the tails of normally distributed weather experiences is one of the reasons NERC regions, RTOs, and their respective member companies, maintain reserve capacity thresholds in excess of their projected peak demands.

Public Service Company of Oklahoma

Annual Peak Internal Demand (MW)
1995 (Historical) - 2014 (Forecast)
("Historical Results are both "As Reported" and "Weather Normalized")

		PSO			
		"As Reported"		"Weather Normalized"	
	Year	MW	Annual Growth	MW	Annual Growth
Actual Data	1995	3,292		3,445	
	1996	3,360	2.1%	3,584	4.0%
	1997	3,474	3.4%	3,632	1.3%
	1998	3,683	6.0%	3,698	1.8%
	1999	3,811	3.5%	3,766	1.8%
	2000	3,823	0.3%	3,840	2.0%
	2001	3,785	-1.0%	3,794	-1.2%
	2002	3,786	0.0%	3,865	1.9%
	2003	3,879	2.5%	3,889	0.6%
	2004	3,773	-2.7%	3,930	1.1%
	2005 [(A)]	4,047	7.3%	N/Av	
	Average Annual Growth Rate (1995-2005 [(A)])		2.13%		1.48%
	Compound Annual Growth Rate (1995-2004/5 [(A)])		2.09%		1.47%
Forecast Data	2005			4,014	
	2006			4,093	2.0%
	2007			4,151	1.4%
	2008			4,216	1.6%
	2009			4,293	1.8%
	2010			4,354	1.4%
	2011			4,420	1.5%
	2012			4,478	1.3%
	2013			4,556	1.7%
	2014			4,627	1.6%
	Compound Annual Growth Rate (2005-2014)				1.60%

[(A)] Actuals through September 4, 2005.
Note that on 7/22/05 PSO achieved an actual (all-time) peak demand of 4,047 MW.
This would result in a 2006(F) v. 2005(A) increase of 1.13% for PSO

Note that this table also offers a comparative view of these forecasted demand levels versus a comparable (10-year) historical period. It would suggest that the projection of peak demand as reflected over the forecast period compares favorably to recent historical results, particular when those historical results are adjusted for normal weather. Specifically for PSO, it would suggest that the forecasted compound annual growth rate for the 10-year period of 1.60% is slightly above the weather normalized 10-year historical level of 1.47%.

2.2 Demand Side Management (DSM) - The economic purpose of a demand side management (DSM) program is to reduce customer load (peak demand, energy, or both) at less cost than would be incurred to serve that load. DSM programs' availability, economics, the utility's avoided energy and capacity costs, the allocation of the programs' costs and benefits, and the effect on customers are factors considered in DSM program analysis.

2.2.1 Current DSM Offerings – Following is a summary of the current DSM programs:

> "MarketChoice" (aka "ValueChoice") offers real-time pricing (RTP) options for participating customers. As represented on the table below and in Section B (CDR for PSO), based on historical responses, it is anticipated that **32 MW** of demand would be shifted annually during peak hours. In addition, PSO has two special contract industrial customer tariffs applicable to Weyerhauser and Elkem for which **16 MW** has been reflected in the PSO CDR for such anticipated annual load reductions.

The amount of DSM currently reflected in the IRP for PSO is as follows:

Public Service Company of Oklahoma

Annual Impact of Demand Side Management on Forecasted Peak Demand (MW)
2005-2014

	PSO		
Year	Active DSM [A]	Interruptible Tariffs [B]	*Sum*
2005	(32)	(16)	*(48)*
2006	(32)	(16)	*(48)*
2007	(32)	(16)	*(48)*
2008	(32)	(16)	*(48)*
2009	(32)	(16)	*(48)*
2010	(32)	(16)	*(48)*
2011	(32)	(16)	*(48)*
2012	(32)	(16)	*(48)*
2013	(32)	(16)	*(48)*
2014	(32)	(16)	*(48)*

[A] "MarketChoice (aka ValueChoice) program
[B] Two special interruptible contracts with Weyerhasuer and Elkem

2.2.2 Potential Future DSM - Over the past decade, low regional price levels of market energy and capacity have limited the opportunities for cost-effective DSM. However, it would be anticipated that capacity prices would begin to rise in coming years in conjunction with expected regional capacity addition requirements. Some DSM measures could prove cost-effective in this future environment. DSM implementation can require significant lead time (just as the implementation of supply resources), and such opportunities must be identified and acted on sufficiently in advance.

Given these circumstances, AEP recognizes the need to enhance its DSM planning process, and has begun initial steps to do so. The initial objectives are:

- √ Develop a comprehensive DSM planning approach that will enable AEP and its operating company subsidiaries to fully implement any cost-effective DSM measures that may be identified in a timely manner, and
- √ Develop an initial "order of magnitude" estimate of the amount of DSM that may ultimately prove to be cost effective, and the timing thereof. This estimate will be continually refined.

Further steps in AEP's enhanced DSM planning process over the relatively near-term will involve:

1. A continual review of the assumptions made regarding possible DSM measures identified as potentially cost-effective.
2. Inclusion of such DSM measures in combined supply / demand-side resource optimization profiles.
3. Inclusion of jurisdiction-specific DSM information and a "roadmap" of AEP's enhanced DSM planning process in regulatory IRP reports and getting feedback thereon.
4. Addition of a DSM participant analysis to assure that a reasonable sharing of DSM benefits can be arranged between participating customers and the system, looking at customer-specific tariffs, etc.

AEP has performed a series of preliminary, high-level economic screenings of various non-RTP-type DSM measures involving equipment at the customer premise. The following table offers a non-exhaustive listing of such measures for both residential and commercial appication. Based on estimates associated with the cost to implement such unique measures, the measures' effective potential load/demand impact, as well as potential customer saturation and sign-up percentages, it was determined that there was negligible opportunity to cost effectively initiate such DSM measures/programs over the next several years. However, by later this decade, the company believes there will be greater opportunity for certain of these measures – including combinations of measures aggregated into programs – to achieve a Rate Impact Measure ("RIM") or benefit–to-cost ratio greater than or equal to 1.0. These preliminary screenings suggest that based on today's technologies such potential demand reduction at peak for the combined SPP Companies would be approximately 10 MW by around 2010. However, as technologies advance and competition among DSM equipment/service providers grows, such benefits could escalate.

Sample Listing of DSM Technologies Involving Customer Premise Equipment (CPE)

Residential	Commercial
Ceiling Insulation (> R30)	CFL/Ballast-Replacement
Compact Fluorescent Lamps (CFL)	CFL-New
Direct Load Control AC Cycling	Energy Efficient AC
Energy Efficient Ballasts	Energy Efficient Condensing Heating
Energy Efficient Central AC	Energy Efficient Conv. Heaters
Floor/Basement Insulation	Energy Efficient Heat Pump
Geothermal Heat Pump	Exit Signs-Retrofit
Induction Cooktop	T5 Lighting
Load Control AC & WH	T8 Lighting
Load Control Water Heat	Variable Speed Drive Motors
Low Flow Fixtures	Window Film
Programmable Thermostat	
Remove 2nd Refrigerator	
Solar Water Heating	
Tank/Pipe Wrap	

2.3 Current Owned Capacity Portfolio – The following figures offer a summary of supply resources for the SPP Companies. Specifically, the current profile of supply sourced from owned generation facilities consists of:

Coal / Lignite	1,018 MW
Gas / Diesel	3,079 MW
Total AEP	**4,097 MW**

2.4 Unit Disposition –A review of selected PSO units was performed as part of the IRP evaluation process. That review revealed the following units were candidates for further study.

- Southwestern Units 1 & 2 ; and
- Tulsa Unit 3 (currently not operable,in stand-by status)

Although the review identified the above units for further examination, in general, economic viability of the existing AEP-SPP fleet of gas-fired generating units - and the decision to mothball or retire such units - can be simply stated as the net present value of the ongoing (largely fixed) costs to maintain the unit for reliable operation *versus* the replacement capacity cost of the unit. As will be described later, since PSOis projected to be substantially capacity-short over the planning period, and, thus, additional generating capacity is indicated, no unit can be taken out of service without a commensurate capacity replacement.

Following the premise that capacity replacement value is the primary metric of economic viability from a (capacity) resource planning perspective, the existing gas-fired generating units were evaluated against a proxy for capacity replacement cost based on a forecasted pure market capacity price used throughout this IRP process. When considering the removal from operation of multiple units, potentially constituting hundreds of megawatts, the market capacity price may become less indicative of the replacement cost, as the ability for the AEP-SPP control area to rely on incremental purchases becomes constrained, and other factors such as transmission network upgrade costs and new build options must ultimately be factored into the indicative replacement value.

Each unit previously identified was evaluated individually against its market capacity replacement cost. Given PSO's dependence on market purchases through 2007 (as will be set forth later in this document), as well as known transmission constraint issues removing anyl unit from service prior to that point would not be prudent.

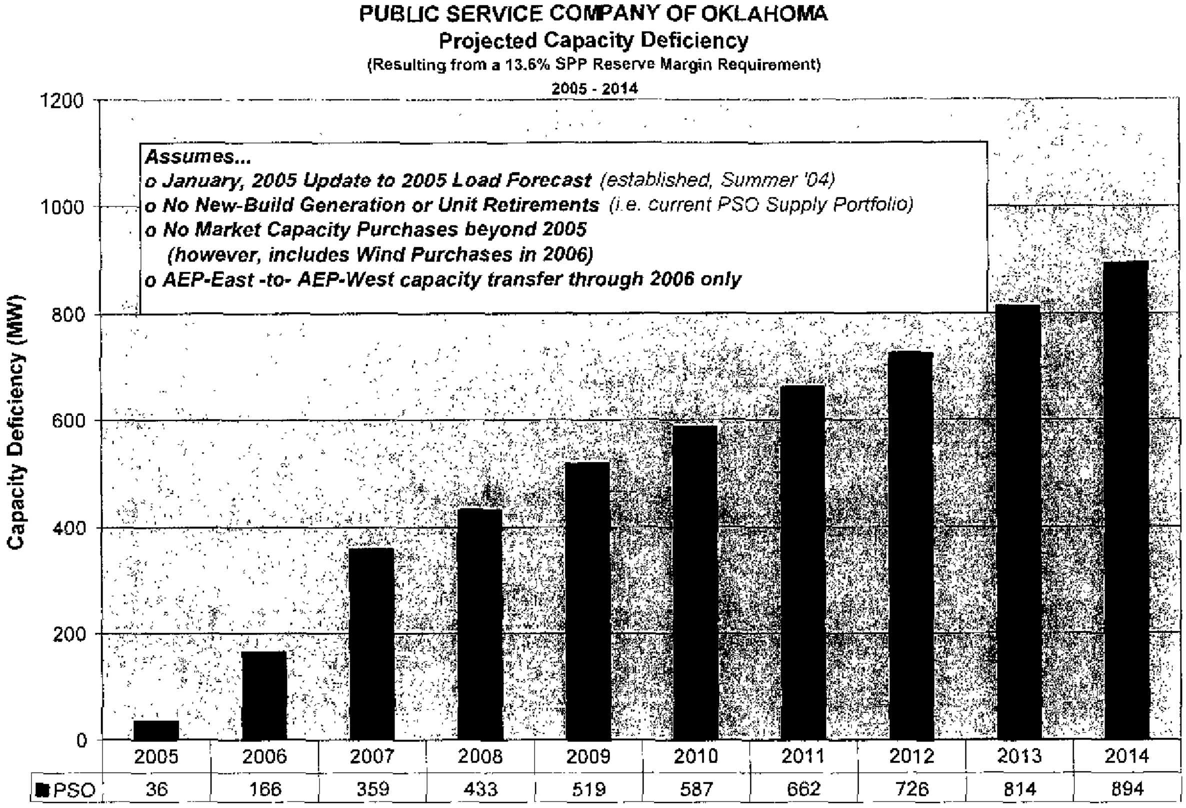
Even though continued operation of all but one of the units can be justified solely on their replacement capacity value, additional qualitative factors were considered including: (1) energy contribution, (2) operational history, (3) repowering opportunities, and (4) infrastructure impacts such as Reliability Must Run status, environmental, and safety issues. With the exception of Tulsa 3, *all* PSO units scored satisfactorily on these additional quantitative and qualitative factors.

The following represent the findings and recommendations of this unit disposition review process:

- No unit retirements or mothballing over the ten-year IRP period.
- Make necessary capital re-investment and perform necessary maintenance for Tulsa Unit 3 so as to ensure its safe and reliable start-up and operation by the 2006 summer season.
- Develop specific recommendations for any potential repowering of steam units that may be candidates.
- Continue the policy of frequent periodic review of the ongoing expected capital and O&M dollars necessary to maintain reliable and safe operation versus the capacity replacement cost of the units.

2.5 Capacity and Reserve Margin Requirement - A **13.6%** planning reserve margin (as a percent of annual peak demand, 12.0% as a percent of capacity) requirement as set forth by SPP has been used over the entire planning period. PSO and SWEPCO are assumed to meet this minimum requirement separately under the assumption that the inter-company available Transfer Capability (ATC) is insufficient to support large capacity commitments. Specifically, prior operational experience and internal assessments of company transmission capabilities suggest that, when considering a single contingency event, the present transfer limit is 200 MW for firm capability. Recognizing that loadings will increase over the planning period, this inter-company transfer limit was assumed to be zero for modeling purposes. However, as discussed later in this document, this constraint was relaxed in forming the final recommended resource plan to consider limited (up to 200 MW) of reserve sharing.

2.6 Projected Capacity / Reserve Margin Deficiencies – The chart below presents the MW capacity (reserve margin) deficiencies under the long-term forecast of peak demand and the current capacity supply portfolio for PSO.



As suggested above, PSO is anticipated to require 433 MW of capacity resources to achieve a 13.6% reserve margin requirement by 2008. That date is critical in that it demonstrates that the respective capacity needs at that time may far outweigh the ability to import potentially available (market) capacity due to known and anticipated transmission constraints to be discussed further in this report. That 2008 timeframe is also critical in that it represents the earliest summer season in which, as will also be discussed, new build capacity resources in the form of "peaking" capacity could be in-service.

2.7 Operating Agreements - The ultimate determination of the unique PSO and SWEPCO capacity requirements are also impacted by:

- The FERC-approved 1997 Restated and Amended Operating Agreement among Central Power and Light Company (aka Texas Central Company (TCC)), West Texas Utilities Company (aka Texas North Company (TNC), PSO, SWEPCO, and Central and Southwest Services, Inc. (CSW) ("CSW Operating Agreement").
- The 1998 System Integration Agreement among American Electric Power Service Corporation (AEPSC), as agent for eastern operating companies, and CSW, as agent for western operating companies ("SIA"). The SIA is designed to function as an umbrella agreement in addition to the CSW Operating Agreement and the 1951 AEP Interconnection Agreement that likewise governs the sharing of capacity, energy, and costs among the eastern operating companies.

Among other things, the CSW Operating Agreement sets forth requirements by which *each* operating company must seek to maintain adequate annual planning reserve margins in the form of a Planning Reserve Level of capacity. As discussed, in this Plan the Planning Reserve Level within the SPP Companies' region is **13.6%** when expressed as a function of its forecasted Company Load Responsibility (as defined in Section 2.12 of the CSW Operating Agreement).

Note: Subsequent to the 1997 CSW Operating Agreement, events in the state of Texas tied primarily to legislation requiring electric utility restructuring and customer choice, have resulted in nearly all of the generating capability previously owned by TCC and TNC and residing within the ERCOT region being divested, mothballed or retired in the interim. Given this, the focus of this IRP in AEP's western region was limited to the PSO and SWEPCO operating companies (SWEPCO being inclusive of a portion of its service territory located in the Texas that is a part of the SPP region.).

The SIA provides for the integration and coordination of AEP's East and West companies zone. Among other things, the SIA provides for the transfer of power and energy between AEP West zone and AEP East zone under certain conditions. AEP has continued to reserve **250 MW** of transmission capacity between the AEP East zone and AEP West zone. With that, this Plan continues to reflect the East -to- West transfer/purchase of 250 MW of capacity through the 2006 summer season since the AEP Eastern (PJM) zone is anticipated to have more than enough installed capacity ("ICAP") in the summer of 2006 to cover this transfer and be in keeping with the capacity reliability/reserve requirements of PJM. However, that position is anticipated to change beginning in 2007, whereby the continued transfer of capacity from AEP's East -to- West zones could then place the AEP-PJM zone in a capacity deficit position. Therefore, additional studies will need to occur going-forward to assess whether the continued transfer of capacity beyond 2006 is merited based on the SIA provisions.

3.0 Capacity Resource Planning -- Short Term Needs

3.1 Recent RFP Solicitations - Recognizing requisite "new-build" capacity addition lead-times of ~18-30 months (peaking); ~30-42 months (intermediate); ~60+ months (baseload); the following are summarizations of recent Request for Proposals (RFPs) that have been solicited to meet the nearer-term incremental capacity and energy needs of the SPP Companies:

2005 through 2009 Capacity Bid Solicitaions

- ✓ On December 14, 2004, an RFP was issued on behalf of PSO and SWEPCO for the purchase of peaking capacity for the summer of 2005 (PSO and SWEPCO) and 2006 (PSO only). As a result of that bid process, 150 MW of 2005 capacity purchases were awarded. This amount is reflected within this Plan.
- ✓ On April 15, 2005, an RFP was issued on behalf of PSO (250 MW) and SWEPCO (100 MW) for the purchase of peaking capacity for the years 2006 through 2009. Responses were received from three (3) bidders for the 2006 requirements only, with ultimate negotiations with two of those respondents leading to bids that included 2007 requirements. Currently these bids are being evaluated including the determination as to whether each would be qualified by SPP to receive firm network transmission capability. Therefore, such potential 2006 and 2007 capacity purchase amounts have not yet been reflected – by specific counterparty – within this IRP, but rather are classified within the capability category "Unknown Wholesale Purchases" line of the CDR that will be discussed later.

  (Note that RFPs for additional capacity will likely be solicited to meet remaining 2007 summer capacity requirements for the SPP Companies as well as, potentially, any incremental 2008 and 2009 requirments that may be established subsequent to the identification of any new-build capacity plans for those years.)

Renewable Capacity & Energy Bid Solicitaions

✓ On November 1, 2004, an RFP was issued on behalf of PSO and SWEPCO for the purchase of up to 250 MW (nameplate) of renewable energy generation facilties that would be placed into service by December 31, 2005. (Note: Such bid proposals could include either wind, solar, hydroelectric, geothermal, biomass, and biomass-based waster products, including landfill gas generation technologies.) This RFP culminated in a purchase agreement for PSO with a non-affiliate to purchase a total of 40 MW of wind nameplate capacity and energy from an extension of the Weatherford project.

(Note that an additional 151 MW of nameplate wind energy is being purchased by PSO as a result of on-going bilateral negotiations with another non-affiliate. This IRP incorporates these purchases although the amount of capacity assumed to be applicable to meet planning reserve requirements is limited to approximately 8% of nameplate, in recognition of SPP critieria and, fundamentally, the intermittent nature of this resource.)

3.2 Transmission Limitations Impacting Short-Term Requirements – As discussed, ATC constraints limit the ability to exercise inter-company capacity transfers between the SPP Companies. Further, the ability to schedule firm transmission with SPP due to capacity import limitations further constrains the level and timing by which a market solution can be utilized within the capacity resource plan. To reiterate a previous point from Section 3.1, above, PSO and SWEPCO received an initial response of three (3) offers from only 3 bidders - for 2006 *only* - for its April, 2005 bid solicitation for 2006 though 2009 capacity. This, in spite of the fact that, as will be reflected on the following table, the anticipated overall SPP reserve margin as reflected in that region's 2005 EIA-411 report, is anticipated to be as high as 29.7% -to- 23.6% over that same timeframe. Further, the responses to this most recent RFP for 2006 market capacity fell well short of the number of bids -- 20 offers (from 10 bidding entities) and 35 offers (from 8 bidders) – that were received from comparable market capacity RFPs made as recently as late-2003 and 2004, for the years 2004 and 2005, respectively.

SOUTHWEST POWER POOL PROJECTED CAPACITY AND DEMAND
As Shown in 2005 SPP EIA-411, Item 3.1, Summer
(in MW unless noted)

	Net Operable Capacity	Net Internal Demand	Reserve Capacity	Reserves Above Min Requirement	Reserve Margin (% of Net Internal Demand)	Capacity Margin (% of Net Operable Capacity)
2005	53,525	40,451	13,074	7,558	32.3%	24.4%
2006	53,525	41,262	12,263	6,637	29.7%	22.9%
2007	53,525	41,953	11,572	5,851	27.6%	21.6%
2008	53,525	42,499	11,026	5,231	25.9%	20.6%
2009	53,525	43,306	10,219	4,314	23.6%	19.1%
2010	53,525	44,271	9,254	3,217	20.9%	17.3%
2011	53,525	44,574	8,951	2,873	20.1%	16.7%
2012	53,525	44,988	8,537	2,402	19.0%	15.9%
2013	53,525	45,835	7,690	1,440	16.8%	14.4%
2014	53,525	46,650	6,875	514	14.7%	12.8%

4.0 Capacity Resource Planning – Long-Term Needs

4.1 Resource Planning Assumption & Issues

4.1.1 Commodity Prices -- Gas & Energy - One of the more critical commodity assumptions in the development of the IRP for the SPP Companies is the forecast of natural gas prices.

The natural gas prices are a forecast of cash prices (not NYMEX-based futures), based on a fundamental analysis of the natural gas market. In these long-term projections, it has been assumed that the underlying fundamental price movements of crude oil cause much of the price volatility in refined petroleum products with the balance of the refined product pricing then being a function of the product's unique anticipated supply/demand and inventory condition. Refined products in the form of residual (No. 6) and distillate (No. 2) oil have some direct substitutability with natural gas both in the short-term and the long-term. Additionally, the petroleum and natural gas markets behave in a directionally correlated manner when viewed over longer time periods. The initial forecasted price is for the Henry Hub geographical location, which is then translated into zonal forecasts. These zonal forecasts use fuel and variable costs for unconstrained transportation areas, and historical relationships for constrained areas. Historical shapes are used to determine monthly price factors, with a check to ensure adequate summer / winter spreads as an incentive to refill gas storage each year.

Market energy prices are strongly influenced by gas-fired generation which is on the margin during peak hours and seasons and, therefore, is closely coupled (via implied market heat rates) to natural gas prices. In order to achieve consistent commodity pricing between the gas and electricity, long-term energy prices employed for resource planning modeling represent the product of forecasted gas prices and the AEP Fundamental Analysis group's estimate of such implied (marginal) market heat rates.

The following represents the long-term forecast of average annual natural gas prices – including a High and Low range which was intended to proxy a +/- 2 standard deviation (90% probability range) – and energy prices, respectively, as established by the AEP Fundamental Analysis group in its February, 2005 forecast, and that were utilized in the IRP modeling of the SPP Companies.

4.1.2 Transmission Constraints Modeled - As previously suggested when reviewing the SPP Companies recent attempts to solicit bids for short-term capacity needs, an overall region such as the Southwest Power Pool may have sufficient capacity to cover its load responsibility with adequare reserve margins and still have participating entities/companies with specific resource need. Although the region may have capacity to serve its overall load, it may not be possible to get power from that capacity into certain areas due to transmission limitations. Such areas are defined as being "transmission constrained".

Although there are a number of unique contingency situations which may produce transmission constraints, an area is generally considered to be transmission constrained if the load in the area exceeds the sum of the generation available in the area plus the transmission import capability into the area. Solutions to such constraints may be to build additional transmission into the area, reduce the load in the area, or construct some type of additional generating capacity in the area.

Therefore, significant issues exist within the SPP region in terms of the ability to obtain firm transmission service for purchase of market capacity. The ability of either PSO or SWEPCO to rely on firm capacity purchases to achieve nearer-term (pre-2010) reserve requirements has increasingly become a greater concern. As a result, the capacity resource modeling was constrained to assume that a long-term (vs. short-term) option would be necessary by 2008 based on:

- AEP capacity purchases and, with that, attendant firm transmission requirements may be limited to as little as 200-300 MW in the relative near term summer seasons, and
- Anticipated lead-time to acquire long-term resources, specifically combustion turbines, suggests 2008 to be the *earliest* potential summer season to address a long-term solution for any such capacity deficiencies that would exceed that 200-300 MW firm transmission threshold.

4.1.2.1 ERCOT – SPP Ties

The interface between AEP-SPP and ERCOT consists of two HVDC ties, the North DC Tie (Oklaunion) in northern Texas connecting ERCOT to PSO and the East DC Tie (Welch) in northeastern Texas connecting ERCOT to SWEPCO. Since there are no synchronous connections between the Eastern Interconnection and ERCOT, the impacts of loop flows within the Eastern Interconnection are isolated from ERCOT, and vice versa. However, the impact of the real power flows through the 600 MW East DC Tie can have a dramatic effect upon voltage performance in the AEP-SPP (SWEPCo) Transmission System.

4.1.2.2 Unique Design Implications

The number of interconnections between the AEP-SPP Companies and neighboring systems, as well as the topology of the AEP-SPP Transmission System can significantly influence its performance of the latter. Facility outages, generation dispatch or load changes internal to AEP as well as on neighboring companies' systems, in combination with power transactions across the interconnected network, can have a significant effect on the power flows on the AEP-SPP transmission facilities.

Further, the generation in the AEP-SPP zone was planned primarily to meet individual operating company needs and located near load centers. The full deliverability of generation throughout the AEP-SPP zone was not a key driver in the planning of the generation or the transmission system. Over time, this has resulted in a transmission system in the AEP-SPP zone that is constrained when generation is dispatched in a manner inconsistent with the original design of utilizing local generation to serve local load.

Therefore, the AEP-SPP import capability would be constrained by the loading of the most limiting element in the transmission network. In addition, firm import capability is typically calculated on the basis of one contingency (any one network element out of service) and considers transmission reservations already in place throughout the region. These factors could severely reduce the AEP-SPP import capability, to the point that studies of individual transactions must be undertaken by SPP and may result in a finding that firm transmission service for significant import is either severely constrained or not available.

4.1.3 Commodity Prices – Capacity - Based on those SPP EIA-411 projections below, the fundamentals might initially suggests capacity reserve margins - inclusive of even anticipated merchant (IPP) capacity projects - point to generation asset "build" levels within the next 5 to 10 years in the AEP-SPP zone. However, as previously discussed in Section 3.2, in the AEP-SPP zone, long-term (supply) options may be required to be significantly accelerated, relative to overall SPP capacity needs, due to locational transmission constraint issues.

SOUTHWEST POWER POOL PROJECTED CAPACITY AND DEMAND
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2009	53,525	43,306	10,219	4,314	23.6%	19.1%
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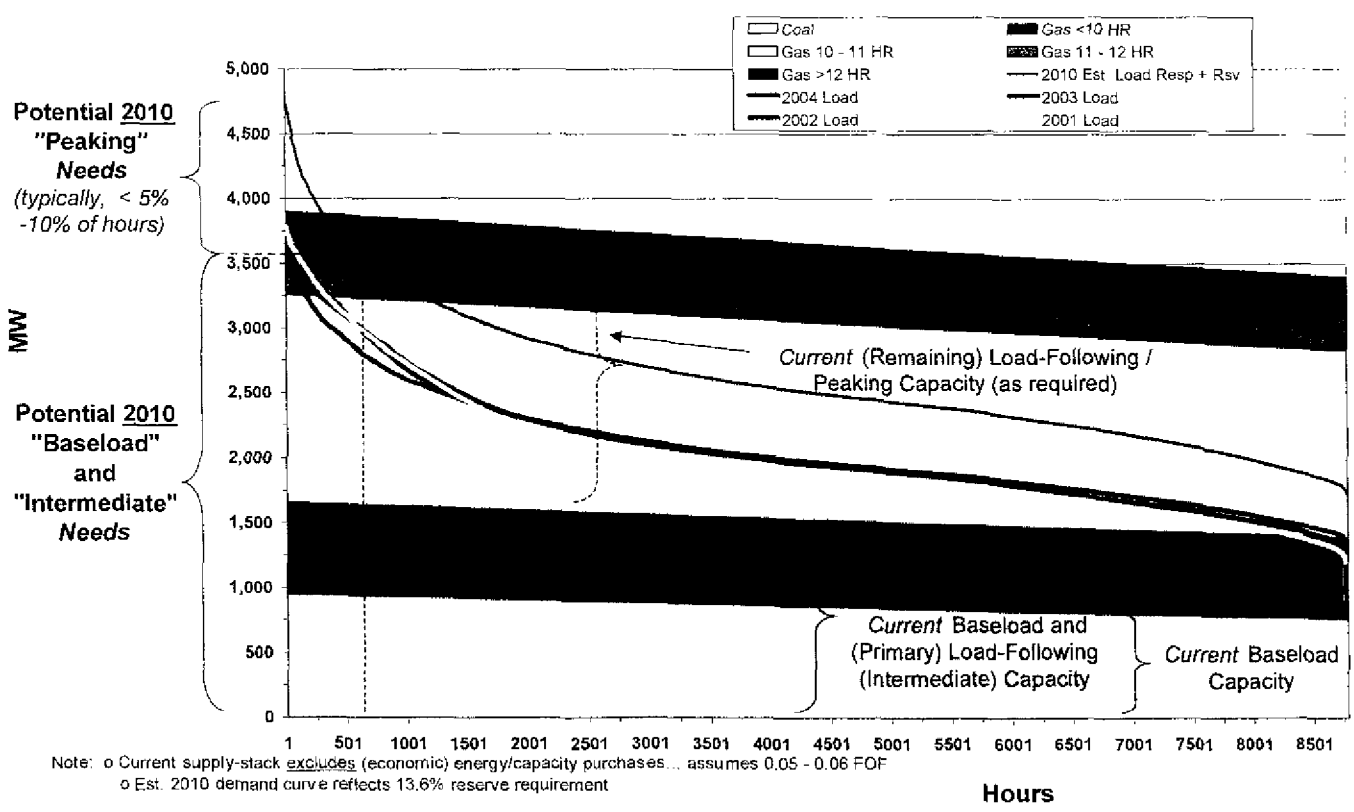
2011	53,525	44,574	8,951	2,873	20.1%	16.7%
2012	53,525	44,988	8,537	2,402	19.0%	15.9%
2013	53,525	45,835	7,690	1,440	16.8%	14.4%
2014	53,525	46,650	6,875	514	14.7%	12.8%

Based on that capability trending information, as well as known, potentially overriding AEP-SPP regional transmission constraints, the following table represents the long-term forecast of SPP zonal capacity prices as established by the AEP Fundamental Analysis group and utilized within the capacity resource modeling for the SPP Companies.

4.1.4 Capacity "Mix" Considerations - The following charts provide historical and projected (2010) load shapes for PSO. These curves were then overlayered against the current typical "stack" of currently available native generation sources. These overlays reflect "shaped" optical supply/demand relationships for PSO.

Note that, in addition to the identification of potential "peaking" requirements for both companies going-forward, the fact that relative higher heat-rate gas (steam) units make up such a large portion of the supply stack for both companies would suggests lower-cost "baseload" capacity is required for PSO.

Public Service Company of Oklahoma
Historical / Projected Load Duration Curve vs. (Native) Supply Stack



Note: o Current supply-stack excludes (economic) energy/capacity purchases... assumes 0.05 - 0.06 FOF
o Est. 2010 demand curve reflects 13.6% reserve requirement

4.2 Least-Cost Resource Planning Modeling Options

4.2.1 Modeling Objective - The objective of the IRP modeling effort was to recommend an optimum mix of incremental resources, not only from a least-cost perspective but also from the perspectives of risk, achievability, and affordability.

4.2.2 Capacity Supply (Build) Modeling Options - In addition to nearer-term (2005-2009) capacity market purchase options, new–build options were modeled to represent "peaking", "intermediate", and "baseload" capacity needs. To reduce the significant number of modeling permutations in *Strategist*, capacity "build" technologies were limited to certain representative unit-types. The options ultimately assumed to be available for modeling analyses for the SPP Companies as part of this IRP process are presented below:

AEP-SPP Zone	Type	Coal Source	Capability Avg. Nom.	Capability Summer	Approx. Avg. Ann. Heat Rate	Approx. "All-in" Installed Cost per Kw *
Baseload *(Coal-fired)*	Supercritical Pulv. Coal	*PRB*	600 **	594		
Intermediate *(Gas Combined Cycle)*	2x1 GE-7FA		500	479		
Peaking *(Gas Turbines, Simple Cycle)*	GE-7EA (80 MW)		*** *160 (2x80)*	*154*		

* *includes est. EPC, owner's costs, interconnection, and AFUDC*
** assumes only 75% (450 MW) would apply to PSO/SWEPCO capacity resource plan recognizing that certain non-affiliate 3rd-parties have ownership participation rights
*** represents minimum tranche modeled

However, it is important to note that alternative long-term supply technology options are currently under evaluation. Therefore, such alternative supply options having comparable cost and performance characteristics may ultimately be substituted should technological and/or market-based profiles surrounding those options warrant.

4.2.3 Technology Option Screening – The modeling options identified in Section 4.2.2, above were established after an initial review of numerous new-build generating technologies. This screening process was undertaken in an attempt to reduce the problem size within the comprehensive *Strategist* modeling application to be discussed below.

The economic screening process used to analyze and set forth the ultimate, respective "baseload", "intermediate", and "peaking" technology options was based on a quantitative comparison on a long-term levelized basis. The screening horizon covered a 40-year period, 2006 through 2045, reflecting the nominal lifetime of most capacity additions. These options were screened by comparing levelized annual "busbar" cost/capacity factor relationships in order to eliminate the more costly alternatives from further study, thus making the resource expansion "problem state" in *Strategist* more manageable. An example of the economic screening output that was performed to establish the peaking technology to be further modeled in *Strategist* can be seen below:

Note that each peaking technology assessed is represented by a line that shows the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at zero capacity factor represents the fixed costs, including carrying charges and fixed O&M, which would be incurred even if the unit produces no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced. Specifically, this chart displays the economic screening "best-in-class" by comparing the cost curves for various ("multiple-unit" combustion turbine and aero-derivative unit) peaking options. It reflects the cost relationships for various combustion turbine and aero-derivative (AD) peaking machines. It suggests that the GE 7EA and 7FA turbines are generally more economical than the various AD machines up to a capacity factor range of 20 to 30%. Given concerns over generation / emissions permitting limitations such output levels could create, AD units were not considered for further modeling in *Strategist*. Although the cost curves were very comparable, GE 7EA machines were screened ahead of GE 7FA models after consideration of other factors not included in the screening exercise such as relative "quick-start" capability, simplicity of design, potential broader availability, etc.

While the combination of these preliminary economic and technical screens served as the basis for the subsequent detailed modeling, it is important to reiterate that the generation technologies utilized within the *Strategist* long-term capacity resource modeling were intended to represent reasonable proxies for each technology "type" (baseload, intermediate, peaking). Subsequent substitution of specific technologies could occur in any ultimate build plan based on emerging economic or non-economic factors not yet identified

4.2.4 Modeling Approach -- The *Strategist* Model - The *Strategist* optimization model served as the underpinning from which these (AEP-SPP) zonal and operating company-specific capacity requirement perspectives were examined and, ultimately, recommendations made. As an objective function, *Strategist* determines the regulatory "least-cost" resource mix for the system being assessed. The solution is bounded by a user-defined set of resource technologies and prescribed sets of constraints and assumptions.

> Note: *Strategist* also offers the capability to address incremental transmission ("T") options that may be tied to evaluations of certain generating capacity resources alternatives.

Strategist develops a discrete "macro" (PSO and SWEPCO-specific, as described above) least-cost resource mix for a system by incorporating a wide variety of planning assumptions including:

- Characteristics (e.g. capital cost, construction period, life) of resource addition alternatives
- Operating parameters (e.g. capacity ratings, heat rates, outage rates, etc) of existing and new units
- Unit disposition (retirement / repowering)
- Delivered fuel prices
- Prices of external market energy and capacity as well as SO_2 and NO_x emission allowances
- Reliability constraints (in this study, minimum reserve margin targets)
- Emission limits and environmental compliance options

These assumptions, and others, are considered to develop an integrated plan that best fits the utility. Note that *Strategist* does <u>not</u> develop a full regulatory "cost of service" (COS) profile. Rather, it typically considers only COS that change from plan-to-plan, not fixed "embedded" costs associated with *existing* asset costs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to supply alternatives.

Specifically, *Strategist* includes and recognizes in its "incremental revenue requirement" output profile:

√ Fixed costs of capacity additions, i.e. carrying charges on new generating capacity additions and associated transmission (based on a weighted average AEP system cost of capital) and fixed O&M

√ Fixed costs of any capacity purchases

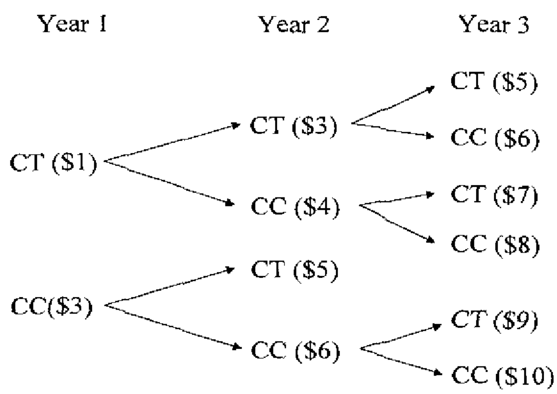
√ Variable costs associated with the <u>entire</u> fleet of added *and* existing generating units. This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs.

√ Market revenues from external energy transactions (e.g. off-system sales) are netted against these costs under this ratemaking/revenue requirement format.

As suggested, this is a holistic model in that existing units may operate differently under varying capacity addition scenarios modeled. Therefore, the model ultimately determines and reflects such unique going-forward costs from a system (i.e. AEP-SPP) operating perspective. Further, due to the "netting" of external energy transactions against variable costs, depending on the market spreads for energy, *Strategist* outcomes may represent relative "longer" or "shorter" (market) energy positions that can have bearing on the resulting net system cost.

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from hundreds of thousands of possible resource alternative combinations created by the module's chronological "dynamic programming" algorithm. On an annual basis, each capacity resource alternative combination that satisfies its least-cost objective function through various user-defined constraints (chief among them being a "minimum" on-going capacity reserve margin) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations as well as the number of feasible states increase approximately exponentially with the number of resource alternatives being considered.

The following diagram offers a very simplistic example of this algorithm. In it, the model has the choice of two capacity types (CT and CC) and must achieve its reserve requirement constraint through some combination of three (3) of these units – one per year -- over a three- year period. As is reflected, six unique plans that could meet such requirements are generated (and retained) by the model even after the elimination of one of the more expensive paths.



* Note: Path "CC (Yr. 1)" - to - "CT (Yr. .2)" path eliminated from further consideration in Yr. 3 as its cumulative cost ($5) is greater than a similar plan ... "CT (Yr. 1)" - to - "CC (Yr. 2)" costing $4.

4.2.5 Modeling Contraints - As demonstrated in this example, the potential for creating such a vast number of alternative combinations and feasible states can become an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist* model includes a number of input variables specifically designed to allow the user to *further* limit or constrain the size of the problem the model is attempting to solve. One of several of these variables focus on limiting the number of a particular resource alternative that can be considered by the model during the planning period. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs of the SPP Companies so as to reduce the problem size within the *Strategist* tool:

- ✓ SPP capacity purchases available in 100MW segments, from 2005 through 2009, with a cap of 300 MW beginning in 2008.
- ✓ *Peaking* capacity was modeled as blocks of four (4), 80MW GE-7EA combustion turbine units. (summer rating of 77 MW x 4 = 308 MW), available beginning in 2010.
- ✓ *Intermediate* capacity was modeled as single natural gas Combined Cycle units, each rated 500 MW. (479 MW summer) available beginning in 2010.

- ✓ *Baseload* capacity was represented by 75% (450 MW) ownership shares of 600 MW Supercritical PC units, available beginning in 2011, based on the assumption that certain non-affiliates would exercise some portion of previously-established participation rights tied to the CSW Operating Company construction of new generation.
- ✓ PSO-SWEPCO (inter-company) interconnection was set at 0 MW in *Strategist* for firm capacity, but allowed to approach ~200 MW in the final ("Hybrid") plan (in either direction) as discussed later. Energy transfers of up to 600 MW were allowed throughout the planning period to emulate current conditions.
- ✓ PSO and SWEPCO external interconnections were each constrained at 1,000 MW for non-firm energy sales; 600 MW for non-firm energy purchases.
- ✓ As discussed, given the limited East-West inter-company interconnection, *Strategist* modeled AEP East (PJM) and West (SPP) zones separately. In addition, the AEP-SPP zone was modeled uniquely for both PSO and SWEPCO due to the limited AEP-SPP inter-company interchange capability. Results from the independent PSO and SWEPCO model evaluations were, however, rolled-up into a final, overall AEP-SPP profile so as to reflect the inter-company energy transfer capabilities – and the attendant energy cost benefits that could be derived from such transfers – into a "final" set of PSO and SWEPCO CPW (total) revenue requirement / cost profiles.

4.2.6 Primary Modeling Framework & Drivers – As demonstrated earlier, recognizing the volatility of gas pricing, capacity plans were established optimizing around <u>each</u> level (Low, Base/Mid, High) of gas price range identified.

As part of an initial effort to establish a relative risk profile tied to such gas price volatility, each optimal (build) plan that was established for a certain level of gas price was locked-in and then "re-priced" in the model with the other (High-to-Low) gas prices. A matrix of resulting cost profiles was then established to determine relative exposure to such propective shifts in natural gas prices. This, as well as additional simulation analyses to be discussed, offers a validation to the notion that proforma assumptions around gas pricing play a critical role in the development of the capacity resource plan for the SPP Companies.

5.0 Review of Modeling Results

5.1 Results Based on Gas Price Scenarios — The following matrix for PSO facilitates a view of an "optimal" – or least cost – capacity build plan as measured by that planning profiles' unique "Total Cumulative Present Worth (CPW)". These least-cost determinations made by *Strategist* over the modeling study period were based on an "array" of natural gas prices described earlier. This afforded a means to then compare the relative impacts that natural gas pricing had on such build plans.

· *Representing <u>row</u> results: the respective optimal generation build plans created under the assumption that either the "Low", "Mid-Low" (arithmetic average of forecasted "Low" and "Base" gas pricing), "Base (Mid)", "Mid-High", or "High" gas prices would exist.*

· *Representing <u>columnar</u> results: the costs of these optimal build plans effectively "re-priced" under the notion that ultimate gas prices would deviate from that original plan/build view.*

PSO

Relative Impact on BUILD PLANS Based on a Range of Gas Prices

	New Capacity Additions 10-Year (2005-2014) #	New Capacity Additions 10-Year (2005-2014) MW	Full Period (2005-2020) #	Full Period (2005-2020) MW		Low Gas	MidLow Gas	Base Gas	MidHigh Gas	High Gas
Low Gas Optimal Plan										
CT	4	308	8	616	Total CPW-$B	8.19		10.40	11.21	12.96
CC	2	739	2	739	*Levelized $/MWh*	*43.26*		*53.18*	*56.78*	*64.67*
PC	0	0	0	0	Var, Net CPW-$B	6.63		8.87	9.68	11.38
					Levelized $/MWh	*29.72*		*39.76*	*43.42*	*51.02*
Total		1,047		1,355						
Mid-Low Gas Optimal Plan										
CT	4	308	4	308	Total CPW-$B		9.26	10.10		
CC	1	260	1	260	*Levelized $/MWh*		*48.05*	*51.83*		
PC	1	446	2	890	Var, Net CPW-$B		6.83	7.67		
					Levelized $/MWh		*30.63*	*34.41*		
Total		1,014		1,458						
Hybrid Plan										
CT	4	308	4	308	Total CPW-$B	8.44	9.26	10.13	10.79	12.08
CC	1	260	1	260	*Levelized $/MWh*	*44.39*	*48.09*	*51.97*	*54.94*	*60.73*
PC	1	446	2	890	Var, Net CPW-$B	6.05	6.90	7.77	8.44	9.67
					Levelized $/MWh	*27.13*	*30.95*	*34.84*	*37.86*	*43.38*
Total		1,014		1,458						
Base Gas Optimal Plan										
CT	4	308	4	308	Total CPW-$B	8.46		10.08	10.73	11.94
CC	1	260	1	260	*Levelized $/MWh*	*44.46*		*51.75*	*54.67*	*60.08*
PC	1	446	2	890	Var, Net CPW-$B	6.00		7.66	8.32	9.47
					Levelized $/MWh	*26.91*		*34.33*	*37.30*	*42.46*
Total		1,014		1,458						
Mid-High Gas Optimal Plan										
CT	4	308	4	308	Total CPW-$B	8.46		10.08	10.73	11.94
CC	1	260	1	260	*Levelized $/MWh*	*44.46*		*51.75*	*54.67*	*60.08*
PC	1	446	2	890	Var, Net CPW-$B	6.00		7.66	8.32	9.47
					Levelized $/MWh	*26.91*		*34.33*	*37.30*	*42.46*
Total		1,014		1,458						
High Gas Optimal Plan										
CT	0	0	0	0	Total CPW-$B	8.53		10.20	10.89	11.88
CC	2	739	2	739	*Levelized $/MWh*	*44.78*		*52.29*	*55.35*	*59.80*
PC	1	446	2	890	Var, Net CPW-$B	5.95		7.66	8.36	9.24
					Levelized $/MWh	*27.13*		*34.37*	*37.48*	*41.66*
Total		1,165		1,629						

Recommended Build Plan

Relative Impact on ESTABLISHED Build Plans based on a range of Gas Prices

Note: "Total CPW" represents cumulative present worth (CPW) over the full economic study period (2005-2030) of all generation "G"-related **fixed** costs (FOM & carrying charges) *including* incremental new build and environmental retrofit capital investment as well as market purchase of capacity *PLUS*: total (system) **variable** "G" costs (fuel, VOM, replacement emissions costs) *NET OF*: <revenues>/costs associated with non-affiliated off-system sale/purchase projections from the inherent energy profiling also performed in *Strategist*.

"Var(iable) CPW" represents cumulative present worth over the study period (2005-2030) of the total variable costs, net as described above.

5.2 Build Plans – Analysis Discussion Points

⇒ The optimal or *least-cost* build plan for PSO under each gas price scenario is that matrix cell highlighted in yellow on the previous tables that aligns with that pricing assumption. For example, under the PSO "Low Gas (pricing) Scenario", the lowest cost plan is that listed as "Low Gas Optimal Plan", with a CPW total cost of **$8.19 billion** over the full 26-year study period.

⇒ Looking across the gas scenarios for the PSO matrix results - the optimal plan costs of the AEP-SPP zone are very responsive to gas prices. This is largely a function of the large amount of existing gas-fired capacity.

- For example, looking across the row of the "Base Gas Optimal (Build) Plan" for PSO, study period costs range from **$8.46 billion** under the Low gas scenario to **$11.94 billion** under the High gas scenario (nearly 41% cost spread), almost all of which represents attendant fuel cost differences.

- However, the "Low Gas Optimal Plan" results suggest even wider-ranging costs across ultimate scenarios with, again for PSO, those figures ranging from **$8.19 billion -to- $12.96 billion** over the study period (approaching a *58%* spread)

- This responsiveness to gas prices causes the "High Gas Optimal Plan" to be quite different for PSO, *consisting of 890 MW of coal-fired capacity over the full planning period (2 x 445 MW-summer* units) with 479 MW of combined cycle capacity (excluding the proposed Lawton PPA). Contrastingly, the "Low Gas Optimal Plan" is an "all-gas" build plan with no solid-fuel units selected by the model.

⇒ Note that for PSO, the *same* build profile/mix was established for the "Mid-High" *and* "Base Gas" optimal plans. In an attempt to determine the approximate "trigger point" by which the model would optimally begin to select more gas generation versus coal, a "Mid-Low Optimal (Build) Plan" was introduced. As reflected on the PSO matrix, coal-fired generation continued to be selected by the model at that lowered gas pricing point in nearly like amounts over the planning period. Thus, for the AEP-SPP zone, this (Mid-Low) gas price is still above that gas (and correlating energy) pricing point at which coal-fired capacity becomes the more economical incremental build choice.⇒

⇒ Lawton Cogeneration facility: Development of a proposed PURPA combined cycle facility at Lawton, Oklahoma would result in PSO receiving firm capacity (260MW-summer rating) via a purchase power agreement (PPA). A June, 2005, ruling by the Oklahoma Supreme Court remanded the PPA back to the OCC on various issues including the issue of the appropriateness of the Avoided Energy Cost used in the PPA.

In conclusion, these results recognize:

1. the significant build alternative sensitivity and resulting cost exposure in the AEP-SPP Zone that correlates directly with gas prices;
2. the fact that the modeled solid-fuel optimal build plan outcomes are essentially the same between the "High" (~+2 std.dev.) and even the "Mid-Low" (~ -1 std.dev.) LT gas pricing scenarios;
3. the fact that there is potential for limited planning reserve sharing between the companies;
4. *Firm Transmission Limitations* -- as discussed previously, the fact that significant issues exist within the SPP region in terms of the ability to obtain firm network transmission service for purchases of market capacity, leading to a determination that a long-term (vs. short-tern market) solution would be necessary by 2008
5. *Distressed Generation* – it is recognized that should opportunities arise in the near future for the acquisition of any available (and technically/locationally-viable) "distressed" merchant generation assets, such opportunities should be actively explored, particularly if the break-even cost of such acquisition (vis-

à-vis the cost any subsequent of greenfield construction as outlined in this Plan) is greater than the potential purchase price.

The results and conclusions were compiled into an SPP Company view and a "Hybrid" Plan was set forth as the optimal plan for purposes of further risk analysis as well as assessment of corporate financial and (state / jurisdictional) regulatory recovery impacts. For PSO, this plan recommends the addition of: 1,198 MW (summer) of total generating capacity consisting of 308 MW (4) CT units, 0 MW CC unit, and 890 MW (2) Pulverized Coal units over the *full* 2005-2020 planning period.

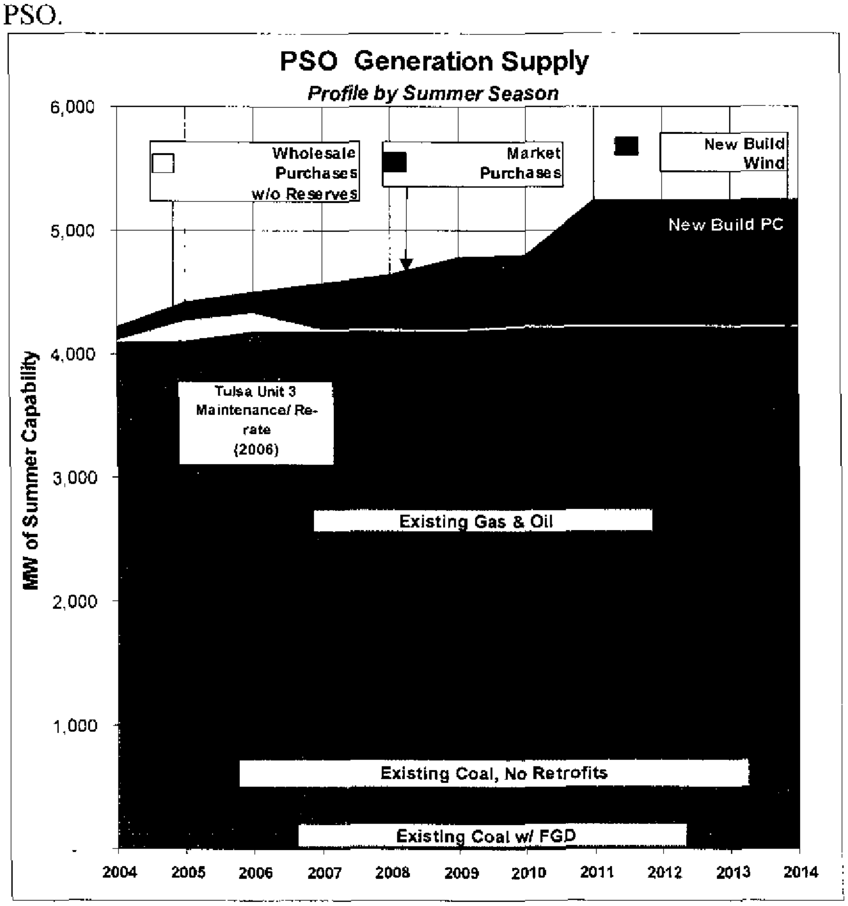
When viewed from the perspective of the *nearer-term* (10-year) financial planning period, the PSO Plan recommends **754 MW (summer) of long-term generating capacity*** consisting of:

PSO*

308 MW (4) CT units
446 MW (1) PC unit

* amounts above are in addition to the assumed 260 MW of summer capability stemming from the PSO-Lawton cogeneration PPA

The following chart provides a graphical profile of the annual progression of capacity mix as reflected in the Hybrid Plan for PSO.



5.3 Risk Assessment – To quantify and understand the potential risks inherent in the selected capacity build / expansion plans, AEP chose to include additional risk analyses as part of the process over-and-above the discrete gas price scenario modeling performed in *Strategist* and described earlier. The inclusion of risk in the evaluation process provides a fuller understanding of the impacts of each proposed capacity resource plan. AEP engaged Black & Veatch (B&V) to assist in this risk evaluation and to provide more rigorous risk profiling for the expansion plans under consideration.

In summary, this risk analysis involved more robust simulation profiling. The simulation approach used by B&V was built off of the output of selected optimal (build) scenarios from *Strategist* to evaluate the impacts from changes in modeling variables determined to be "key risk factors". The key risk factors evaluated and the magnitude (distributions) of their variability in the simulations performed by B&V are as follows:

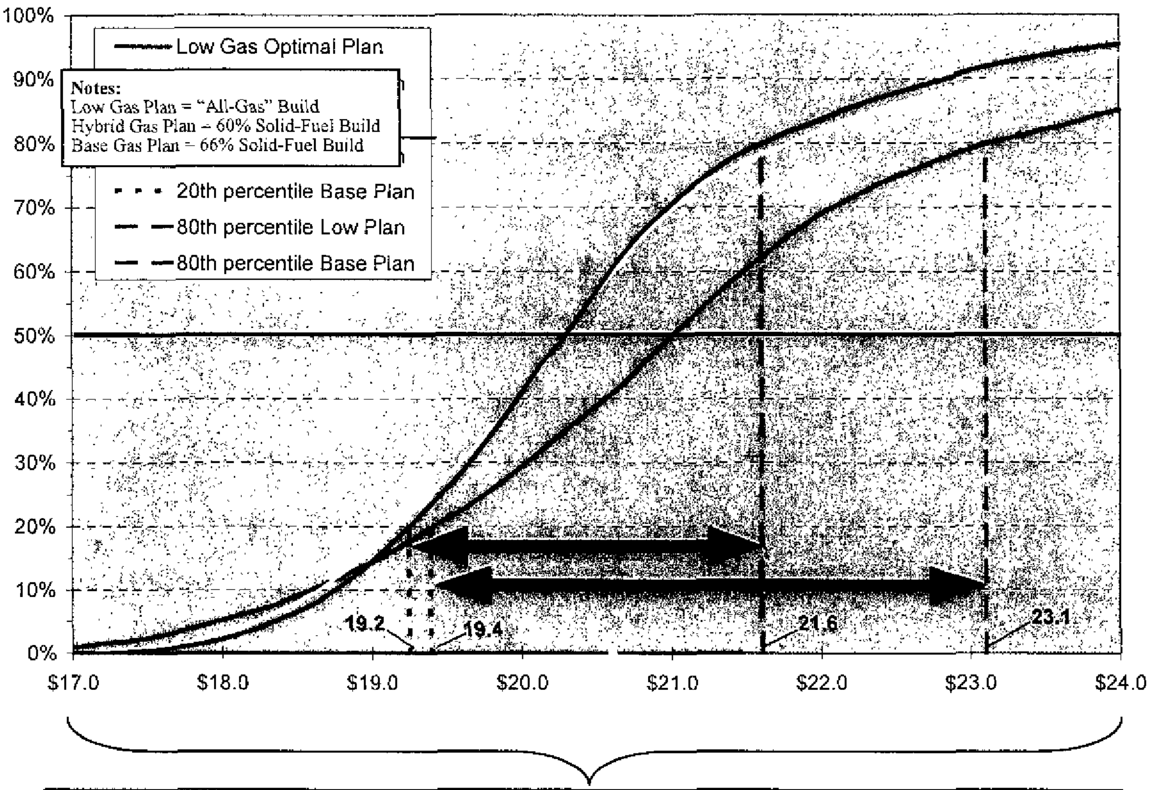
- Natural Gas (NG) Prices . . . *with ranges generally averaging +/- ~$2/MMBtu over the g period*
- SO_2 Allowance Prices. . . *with ranges of +40%; -20% by the end of the planning period as established by B&V*
- NOx Allowance Prices. . . *with ranges of +40%; -20% by the end of the planning period as established by B&V*
- Capital Cost of New Generation . . . *capital cost ranges established by B&V and used in simulation profiles as follows:*

Generation Type	LOW	HIGH
Supercritical PC	-15%	+20%
Combined Cycle (GE 2x1 7FA)	-10%	+20%
Simple Cycle Combustion Turbine (GE 7EA)	-10%	+15%

The simulation results were based on a B&V-developed Monte Carlo simulator program and was predicated upon 5,000 trials. For each trial, the simulator: 1) selects a value for each factor identified above from a probability distribution assigned to it by a risk add-in program ; then 2) re-calculates the plan profile CPW based on the relative change in the variables. Repeating the process for the desired number of trials, a probability distribution is established at the completion of the process.

5.3.1 Risk Profile Results - The following chart displays the comparable results of B&V's simulation analysis for the AEP-SPP zone by offering the following probability distribution of CPW cost profiles for the build plans tested:

Simulation Distribution for Varying AEP-SPP Build Plans
CPW ($Billions) 2005 - 2030



Note: X axis equal to +/- 15% of Base Plan distribution mean (mean value = approx. $20.4 B)

The simulation results show three unique risk profiles. The "Low "("All-Gas") build plan shows a significantly broader distribution range – as represented by the more gradual slope of the cumulative cost distribution curve - than either the "Hybrid" or "Base" ("60-66% Solid-Fuel") build plans. This is driven largely by the risk factor linked to gas pricing. While the Hybrid and Base Case build plans show some small potential (@ ~15%, intersection of the cumulative distribution curves) for a larger CPW cost / revenue requirement, given that the slope of the cost distribution curve is steeper, the *range* - and attendant economic risk - of the CPW costs are less than the All-Gas (Low) build plan.

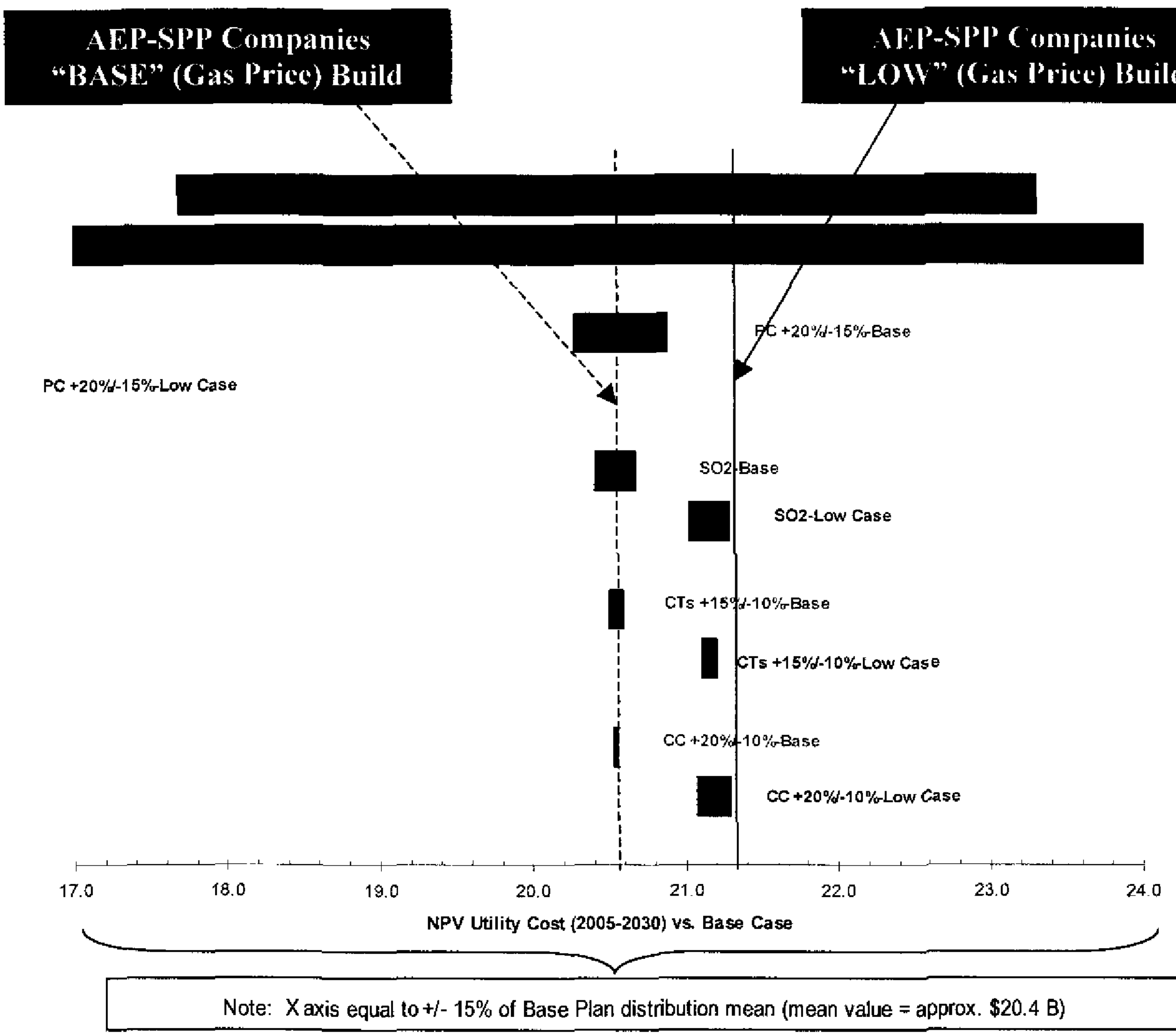
Further, as reflected graphically above, the following table indicates a probability of 60% that the results will be within +~ 5.6% and -~ 7.0% of the mean Hybrid Plan value of $20.6 billion. This distribution range of the Hybrid Plan simulated results compares favorably with the Low ("All Gas") plan.

Relative Simulation Distribution By Build Plan

Plan	20th Percentile ($000 NPV)	Average ($000 NPV)	80th Percentile ($000 NPV)	Percent from Mean 20th Percentile	Percent from Mean 80th Percentile
AEP-SPP Low	19,391,508	21,467,030	23,103,918	-9.67%	7.63%
AEP-SPP Base	19,248,170	20,373,469	21,605,538	-5.52%	6.05%
AEP-SPP Hybrid	19,175,524	20,623,933	21,779,618	-7.02%	5.60%

This further serves to validate the conclusion drawn from the discrete *Strategist* profiling for AEP-SPP discussed previously. In general, it would suggest that there is a tradeoff between the higher installed (fixed) cost of coal-fired capacity and its mitigating effect on higher natural gas (variable) costs.

Finally, the tornado diagram that follows highlights the unique impacts of each variable on simulated CPW for the AEP-SPP zone. It demonstrates the significant impact of natural gas prices, when comparing it to the relative impacts on total CPW for the other risk variables analyzed.



In summary, these risk assessments indicate that such (gas price) risk tolerance is not suited to the pursuit of an all-gas plan. (Recall also that these cost profiles do not reflect other cost factors that lie outside of traditional cost-of-service such as local, socio-economic factors, political factors, etc.) Risk tolerance of the Plan to gas price volatility would indicate preference to a generation capacity build plan that incorporates ample solid-fuel generating sources going forward.

The following statement was excerpted from B&V's engagement report:

> *"The risk tolerance of the region indicates an expansion plan that is* <u>*not*</u> *all natural gas is preferable. In addition, the risk profile for the expansion plans with coal technology shows a preferred expected revenue requirement CPW as well as greater certainty around the expected value when compared to the no coal technology expansion plan."*

The report goes on to conclude and recommend the following:

> *"Current natural gas price forecasts suggest a mixture of coal and natural gas technologies. As natural gas forecasts are influenced by current events, we recommend that the evaluation of expansion plans be continued and updated on a semi-annual basis. The frequency of updates may be adjusted to annual once the process is firmly established and key variable thresholds are defined. This will allow the incorporation of the latest information into the planning process. As uncertainty around various parameters is reduced, the change in risk can clearly be communicated.*
>
> *Current results in the west show large uncertainty with the all gas plan. This level of uncertainty is believed to be above the risk tolerance level for the region. In addition, the all gas plan has a less desirable expected revenue requirement CPW."*

6.0 Conclusions

Several conclusions can be drawn from this capacity resource planning / IRP process for the PSO:

- ✓ PSO has reasonably determined its needs for additional capacity resources over the ten-year IRP period;
- ✓ PSO has identified a reasonable approach for the further examination and inclusion, where warranted based on its economic cost-effectiveness, of additional DSM measures and programs;
- ✓ PSO will continually assess the economic viability of its older-vintaged, higher-cost units in its generating fleet;
- ✓ PSO has undertaken efforts to address short-term capacity resource requirements by way of market bid solicitation;
- ✓ concurrently, PSO recognizes and will actively engage the SPP RTO to address the transmission constraint issues impacting the ability to import capacity;
- ✓ given this constraint, however, PSO has undertaken steps to establish a least-cost long-term capacity resource planning process, including detailed analysis of key input parameters and, considering the significant capital investment at stake, robust modeling of relevant risk;

- ✓ based on those results PSO has set forth a reasonable IRP so as to ensure the reliable supply of generating capacity for years to come at a cost that will both be economically/competitively-driven and will be less subject to market volatilities; and

- ✓ PSO will seek to implement this Plan utilizing any prescribed processes established for that purpose.

7.0 PSO – Action Plan

The PSO Action Plan summarized below provides an action item for decisions that need to be made within the next 2 – 4 years. This decision window provides the necessary lead-time to implement necessarily long-lead time resource solutions. Resource decisions outside this time frame will be re-evaluated in subsequent IRPs.

This Action Plan will ensure PSO will continue to meet its obligation serve in a low cost, reliable manner, appropriately adapting to the changing industry environment.

Action Item	Resource Type	Timing	Size	Action
1	Peaking Capacity	Beginning Summer 2008	320 MW	Competitive solicitation for peaking capacity and energy for an in service date of June 1, 2008. File for used and useful determination under HB1910.
2	Baseload Capacity	Beginning Summer 2011	Up to 600 MW	Competitive solicitation for baseload capacity and energy for an in service date of June 1, 2011. File for used and useful determination under HB1910.
3	Transmission	Summer 2007	n/a	Complete Tulsa Area 345/138kV upgrade
4	Existing Steam Generation	2005 IRP (Fall Update)	n/a	Continue iteration of disposition evaluations of existing steam units including Southwestern 1 and 2 as well as Tulsa 3.
5	DSM	2005 IRP (Fall Update)	n/a	Continue assessment of viable, cost-effective measures
6	Intermediate	2009	300 MW	Develop contingency supply options for the Lawton Cogen plant for the event the COD is either accelerated or deferred from the assumed 2009.
7	Market Capacity Purchases	2006 – 2008		Bid solicitations as required

SECTION B – CAPABILITY, DEMAND AND RESERVES

OVERVIEW

The 2005 Capacity, Demand and Reserves (CDR) profile is a ten-year summary of the IRP for the PSO. All figures included in the CDR are expressed in megawatts and is comprised of three major sections:

1. A ***Capability*** section containing PSO's installed capacity less unavailable or derated capacity, less off-system capacity sales without reserves plus all purchases of capacity without reserves.
2. A ***Demand*** section containing PSO's forecast of on-system peak demand plus off-system sales with reserves less any purchases with reserves. Demand-side management (DSM) peak capacity impacts and SPP Operating Company peak diversity are included as appropriate.
3. A ***Reserves*** section details the amount that Capability exceeds Demand and the amount these reserves exceed the minimum required by the Southwest Power Pool (SPP).

Notes to the CDR

Demand

o Based on the 2005 Revised Load Forecast, completed in January, 2005.
o PSO interruptible load is Elkem Metals.

Capacity

o No unit retirements.
o Tulsa 3 restarts in 2006 at 68MW.
o The 250MW capacity transfer from the AEP-East Zone to the AEP-West Zone (per SIA) extends through 2006.
o Initial unit ratings are per 12/2003 internal assessment. Northeastern Unit 1 rating per 8/26/03 letter from W. L. Sigmon to the AEP Generation Pool & System Integration Agreement Committees.
o Derating for Environmental Compliance modeling:
Oklaunion, 0.4% in 2012 for FGD upgrade

o Capacity additions based on results of 2005 Q1 (Spring '05 IRP) Strategist modeling (updated).
o Lawton cogeneration PPA assumed in-sevice for summer 2009.
o Due to build lead-time constraints, first CT capacity available in 2008; first solid-fuel units in 2011.
o 95MW purchase from Tenaska for 2005 Summer.

Transactions

o Annual wholesale purchases and purchase from East are allocated on ratio of total purchases needed by each operating company.
o Capacity purchases from the market through 2008.

PUBLIC SERVICE OF OKLAHOMA
CAPABILITY, DEMAND AND RESERVES FORECAST
04 ACTUAL - 2014
BASE (SPRING 2005 IRP) PLAN

AEP PUBLIC SERVICE COMPANY OF OKLAHOMA

CAPABILITY

	Plant Capabilities	04 ACT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
10												
9	DIESEL UNITS @ PLANT LOCATIONS	25	25	25	25	25	25	25	25	25	25	25
8	OKLAUNION #1	108	108	108	108	108	108	108	108	108	108	108
7	COMANCHE # 1G1, 1G2, 1S	273	273	273	273	273	273	273	273	273	273	273
6	NORTHEASTERN # 1 & 2	899	899	899	899	899	899	899	899	899	899	899
5	NORTHEASTERN # 3 & 4	910	910	910	910	910	910	910	910	910	910	910
4	RIVERSIDE # 1 & 2	917	917	917	917	917	917	917	917	917	917	917
3	SOUTHWESTERN # 1, 2, 3	472	472	472	472	472	472	472	472	472	472	472
2	TULSA # 2, 3, 4	410	410	410	410	410	410	410	410	410	410	410
1	WELEETKA # 4, 5, 6	163	163	163	163	163	163	163	163	163	163	163
1	TOTAL	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177
	Adjustments to Plant Capability											
	NEW CTS					308	308	308	308	308	308	308
	TULSA #3 UNAVAILABLE	-80	-80	-12	-12	-12	-12	-12	-12	-12	-12	-12
	NEW COAL								446	446	446	446
	COMBINED CYCLE						260	260	260	260	260	260
2	TOTAL	-80	-80	-12	-12	296	556	556	1,002	1,002	1,002	1,002
3	**Net Plant Capability (1 + 2)**	4,097	4,097	4,165	4,165	4,473	4,733	4,733	5,179	5,179	5,179	5,179
	Off-System Sales Without Reserves											
	TRANSFER TO SWEPCO						49					97
	TRANSFER TO TNC							5	5	5	6	6
4	TOTAL	0	0	0	0	0	49	5	5	5	6	103
	Purchases Without Reserves											
	AEP EAST TO WEST CAPACITY TRANSFER		159	128								
	TENASKA		95									
	RFP WIND			17	17	17	17	42	42	42	42	42
	TRANSFER FROM SWEPCO											
	WEATHERFORD WIND		9	9	9	9	9	9	9	9	9	9
	OGDEN MARTIN COGEN	20	20	20	20	20	20	20	20	20	20	20
	ENTERGY KOCH	107										
	UNKNOWN WHOLESALE PURCHASE		36	166	359	125						
5	TOTAL	127	319	340	405	171	46	71	71	71	71	71
6	**Total Capability (3 - 4 + 5)**	4,224	4,416	4,505	4,570	4,644	4,730	4,799	5,245	5,245	5,244	5,147

DEMAND

		04 ACT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
A	**Peak Demand Before Passive DSM**	3,773	4,014	4,093	4,151	4,216	4,293	4,354	4,420	4,478	4,556	4,627
B	**Passive DSM**											
	NEW DSM PROGRAMS											
	TOTAL	0	0	0	0	0	0	0	0	0	0	0
C	**Peak Demand (A - B)**	3,773	4,014	4,093	4,151	4,216	4,293	4,354	4,420	4,478	4,556	4,627
D	**Active DSM**											
	VALUECHOICE		32	32	32	32	32	32	32	32	32	32
	INTERRUPTIBLE		16	16	16	16	16	16	16	16	16	16
	TOTAL	0	48	48	48	48	48	48	48	48	48	48
E	**Firm Demand (C - D)**	3,773	3,966	4,045	4,103	4,168	4,245	4,306	4,372	4,430	4,508	4,579
F	**Other Demand Adjustments**											
	DIVERSITY	13	40	41	41	42	43	43	44	44	45	46
	TOTAL	13	40	41	41	42	43	43	44	44	45	46
7	**Native Load Responsibility (E - F)**	3,760	3,926	4,005	4,062	4,127	4,202	4,262	4,329	4,385	4,462	4,533
	Off System Sales With Reserves											
8	TOTAL	0	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves											
	PSO - SWPA ENTITLEMENT	40	40	40	40	40	40	40	40	40	40	40
	AEP EAST TO WEST CAPACITY TRANSFER	179										
9	TOTAL	219	40	40	40	40	40	40	40	40	40	40
10	**Load Responsibility (7 + 8 - 9)**	3,541	3,886	3,965	4,022	4,087	4,162	4,222	4,289	4,345	4,422	4,493

RESERVES

		04 ACT	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	**Reserve Capacity (6 - 10)**	683	530	540	548	557	568	577	957	900	822	654
12	**% Reserve Margin ((11/10) * 100)**	19.3	13.6	13.6	13.6	13.6	13.6	13.7	22.3	20.7	18.6	14.6
13	**% Capacity Margin (11/(6) * 100)**	16.2	12.0	12.0	12.0	12.0	12.0	12.0	18.2	17.2	15.7	12.7
14	**Reserves Above Minimum 12% Capacity Margin**	200	0	0	0	0	0	1	372	308	219	42

SECTION C – ENERGY SUPPLY PLAN

OVERVIEW

The 2005 AEP-SPP Energy Supply Plan (ESP) is a ten-year production forecast performed in conjunction with the IRP for the SPP Companies. The ESP was generated using the PROMOD IV Analytical Probabilistic Dispatch (APD) module, a detailed production costing model produced by New Energy Associates. While generation and fuel consumption projections in the ESP are subject to uncertainties such as fuel price, load forecasts, and operational constraints, they were created using the most recent available data and assumptions. The ESP was developed using a multi-area model representing the AEP-SPP System. Assumptions and information sources represented in the ESP are listed below:

Fuel and Market Prices

- The natural gas, emission allowance, and power market price forecasts are provided by the AEP Fundamental Analysis group.
- Solid fuel price forecasts are provided by the AEP Fuel, Emission and Logistics group, and are consistent with contractual agreements and market forecasts.

Operational Characteristics

- The generating unit capacities and equivalent unplanned unavailability rates are provided by the AEP Generation Business Services group.
- Short-term planned maintenance outages and long-term outage cycles provided by the Asset and Outage Planning Department.

Transactions

- Firm off-system transactions for each operating company are modeled to represent contractual requirements.
- The off-system economy forecast is based on the economic dispatch of AEP unit generation against a forecast of market prices.

Load Forecast

- The peak and energy forecasts used in the ESP are consistent with the forecasts used to develop the 2005-2014 CDR.

AEP PUBLIC SERVICE COMPANY OF OKLAHOMA

	2005 Jul-Dec	2006	2007	2008	2009	2010	2011	2012	2013	2014
D & GENERATION - GWH										
System Load										
Net System Load (Incl Losses)	10,006	19,100	19,368	19,707	20,018	20,302	20,602	20,911	21,228	21,556
Off-System & Economy Sales	207	1,118	806	1,041	1,627	2,097	2,725	3,038	2,649	2,661
Off-System & Economy Purchases	-3,461	-6,521	-6,540	-6,097	-5,775	-5,352	-4,743	-4,023	-4,286	-4,435
Generation Required	6,752	13,696	13,633	14,651	15,871	17,047	18,585	19,926	19,592	19,782
Natural Gas Total	2,976	6,005	6,317	7,236	8,085	9,494	9,064	8,743	8,845	9,037
Coal Total	3,776	7,691	7,316	7,416	7,785	7,553	9,521	11,183	10,747	10,744
GENERATION TOTAL	6,752	13,696	13,633	14,651	15,871	17,047	18,585	19,926	19,592	19,782
CAPACITY FACTOR - PER CENT.										
COMPOSITE CAPACITY FACTOR	37.1%	37%	37 0%	36 7%	37.3%	40 0%	39.9%	42.7%	42.1%	42.5%
FUEL - MMBTU X 1000										
MMBTU X 1000 TOTAL	69,270	140,952	137,691	145,953	154,394	163,911	179,025	191,511	187,936	189,671
FUEL EXPENSE - $000										
$000 TOTAL	240,716	489,027	475,915	495,612	539,393	620,891	635,108	647,260	689,732	716,577
SALES TRANSACTIONS										
Total Sales GWH	207	1,118	806	1,041	1,627	2,097	2,725	3,038	2,649	2,661
Total Sales $000	8,124	57,207	38,180	49,177	82,994	111,511	141,517	153,824	141,593	143,975
PURCHASE TRANSACTIONS										
Total Purchased GWH	3,461	6,521	6,540	6,097	5,775	5,352	4,743	4,023	4,286	4,435
Total Purchase $000	139,628	246,175	241,576	218,030	206,140	195,124	169,601	141,801	154,269	163,620
EMISSION FEES & FUEL AUX COSTS										
Emission Fees & Fuel Aux. Costs	12,832	20,458	19,872	22,009	29,091	37,258	43,245	48,680	51,023	55,925
ADDITIONAL EXPENSES & REVENUES										
Net Adtnl. Exp. & Revenue	12,203	25,878	29,323	28,155	52,935	80,354	92,044	102,206	102,571	103,768
PRODUCTION COST - $000										
Total Fuel Expenses	240,716	489,027	475,915	495,612	539,393	620,891	635,108	647,260	689,732	716,577
Emission Fees & Fuel Aux. Costs	12,832	20,458	19,872	22,009	29,091	37,258	43,245	48,680	51,023	55,925
Net Adtnl. Exp. & Rev.	12,203	25,878	29,323	28,155	52,935	80,354	92,044	102,206	102,571	103,768
Off-System Sales Revenue	-8,124	-57,207	-38,180	-49,177	-82,994	-111,511	-141,517	-153,824	-141,593	-143,975
Off-System Purchase Expense	139,628	246,175	241,576	218,030	206,140	195,124	169,601	141,801	154,269	163,620
Net Production Cost	397,256	724,332	728,506	714,629	744,566	822,117	798,481	786,123	856,003	895,916

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PSO Spring 2005 IRP

Addendum

Subsequent to the development of the PSO Integrated Resource Plan in the Spring of 2005, certain planning elements and factors previously described have evolved. While it is critical to emphasize that the ultimate PSO IRP has not changed from that which has been identified in the preceding portion of this document, any reasonable planning process will continue to assess key variables that impact that process up to the point of plan implementation.

In that regard, following are several factors—discussed in the process outline order (and numbering) reflected in the prior pages—that have undergone such evolution over the balance of 2005 and into the year 2006. Each factor is being addressed by exception, which is intended to emphasize that the information in this Addendum is only intended to append, not replace, the formal PSO capacity resource planning set forth in the preceding Spring 2005 IRP documentation.

As will be ultimately discussed, such planning factor updates that have occurred in the period leading up to PSO's implementation of its nearer-term capacity resource plan will serve to confirm and validate that commitment.

SECTION A – NARRATIVE (*ADDENDUM*)

1.0-A IRP Process Overview

1.1-A Introduction - It is now anticipated that, by 2007, SWEPCO will be obligated to serve a relatively small number of retail customers (~30 MW of demand, or well less than 1% of SWEPCO's peak demand) residing in the SPP region of north Texas that have been the obligation of AEP affiliate, Texas North Company (TNC).

1.3-A Fundamental Steps and Planning Considerations

Environmental Regulations:
On June 15, 2005, the USEPA finalized amendments to the July 1999 regional haze rule. These amendments apply to the provisions of that rule—known as the Clean Air Visibility Rule (CAVR)—that require emission controls known as best available retrofit technology, or BART, for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. The pollutants that reduce visibility include fine particulate matter (e.g. PM2.5), and compounds which contribute to PM2.5 formation, such as NO_x, SO_2 and, under certain conditions, volatile organic compounds and ammonia. The requirements of CAVR are largely location-driven and must be considered in addition to the regional and state-specific pollutant remediation requirement impacts of CAIR and CAMR as previously discussed. Based on subsequent assessments, the possibility now exists that PSO's Northeastern 3 and 4 coal-fired units could be required to install flue gas desulfurization (FGD or "scrubbers") by the latter part (~2014) of this planning period.

2.0-A Demonstration of Need

2.1-A Load and Demand Forecast - Updates to the January 2005 load and demand forecasts utilized in the determination of PSO's capacity resource plan have been performed.

With that, as identified in the following table, updates to various projected annual national economic indicators used in the long-term econometric models previously described in Section 2.1 have been modified from those originally employed in the determination of the load and demand forecast update performed by AEP Economic Forecasting in January, 2005. However, the underlying long-term expected rate of growth of these indicators remains generally consistent.

		CPI	GDP	PPI
	Year	Consumer Price Index (Urban Consumer - All Items, Index 1982-84=100)	Gross Domestic Product (Bil. 2000 $)	Producer Price Index (All Commodities, Index = 1982)
Actual	1970	39	3,772	37
	1980	82	5,162	90
	1990	131	7,113	116
	2000	172	9,817	133
	2001	177	9,891	134
	2002	180	10,049	131
	2003	184	10,321	138
	2004	189	10,756	147
Forecast	2005	195	11,135	157
	2006	202	11,529	168
	2007	208	11,875	172
	2008	213	12,244	174
	2009	218	12,632	178
	2010	223	13,005	182
	2011	228	13,368	185
	2012	233	13,730	189
	2013	239	14,077	193
	2014	244	14,421	198
	2015	249	14,763	202
	2020	278	16,487	225
	2025	309	18,216	251
Compound Growth Rates				
Historical 20-Yr (1980-2000)		3.8%	3.3%	2.0%
Historical 10-Yr (1990-2000)		2.8%	3.3%	1.3%
Forecast 10-Yr (2005-2015)		2.5%	2.9%	2.5%
Forecast 10-Yr (2005-2015)		2.3%	2.5%	2.4%

Moreover, the long-term load forecasting methodology utilized by AEP Economic Forecasting has undergone some change in the interim period. That department subsequently incorporated Statistically Adjusted End-use (SAE) models for forecasting long-term Residential and Commercial kWh energy sales and, with that, attendant peak demand. SAE models are econometric models with features of end-use models included to specifically account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005 (EPAct 2005). SAE models start with the construction of structured end-use variables that embody end-use trends, including equipment saturation levels and efficiency. Factors are also included to account for changes in energy prices, household size, home size, income, and weather conditions. Regression models are still used, as before, to estimate the relationship between observed customer usage and the structured end-use variables. The result is a model that has implicit end-use structure, but is econometric in its model-fitting technique.

AEP Economic Forecasting's analysis would suggest that the SAE approach for residential and commercial load profiles explicitly accounts for energy efficiency which, in turn has served to slightly lower the forecast of PSO demand and energy in the outer forecast horizon (i.e. generally years beyound 2010) when such energy efficiency intiatives—such as those being envisioned by EPAct 2005—could begin to manifest more aggressively.

2.1.1-A (Peak) Demand Forecast - A review of the most recent PSO demand forecast in the following table would support that longer-term relative trending when comparing those SAE-influenced results to the prior long-term PSO demand forecast that did not utilize SAE techniques (specifically, the January 2005 forecast update utilized in PSO's Spring 2005 IRP profile).

Public Service Company of Oklahoma

Annual Peak Internal Demand (MW) -- UPDATE

1996 (Historical) - 2014 (Forecast)

(Historical Results are both "As Reported" and "Weather Normalized")

		PSO			
		"As Reported"		"Weather Normalized"	
	Year	MW	Annual Growth	MW	Annual Growth
Actual Data	1996	3,360	2.1%	3,584	4.0%
	1997	3,474	3.4%	3,632	1.3%
	1998	3,683	6.0%	3,698	1.8%
	1999	3,811	3.5%	3,766	1.8%
	2000	3,823	0.3%	3,840	2.0%
	2001	3,785	-1.0%	3,794	-1.2%
	2002	3,786	0.0%	3,865	1.9%
	2003	3,879	2.5%	3,889	0.6%
	2004	3,773	-2.7%	3,930	1.1%
	2005	4,047	7.3%	4,026	2.4%
	2006(A)	4,156	2.7%	N/Av	
	'10-Year' Compound Annual Growth Rate (1996-2006(A))		2.15%		
	'9-Year' Compound Annual Growth Rate (1996-2005)		2.09%		1.30%

		Spring 2005 IRP		2006 Load Forecast		2005 "Q4" / 2006 "Q1" Update [B]		2006 "Q2" Update [C]	
		(Jan '05 Update to "2005" Fcst performed Aug. '04)		("2006" Load & Demand Fcst performed Aug. '05)		(Nov. '05/Jan. '06 Update to "2006" Fcst performed Aug '05)		(May '06 Update to "2006" Fcst performed Aug '05)	
Forecast Data	2006	4,093	1.7%	4,039	0.3%	4,020	-0.2%	4,101	1.9%
	2007	4,151	1.4%	4,110	1.8%	4,040	0.5%	4,169	1.7%
	2008	4,216	1.6%	4,161	1.2%	4,084	1.1%	4,216	1.1%
	2009	4,293	1.8%	4,207	1.1%	4,155	1.7%	4,274	1.4%
	2010	4,354	1.4%	4,250	1.0%	4,224	1.7%	4,333	1.4%
	2011	4,420	1.5%	4,295	1.0%	4,289	1.5%	4,388	1.3%
	2012	4,478	1.3%	4,343	1.1%	4,337	1.1%	4,446	1.3%
	2013	4,556	1.7%	4,392	1.1%	4,386	1.1%	4,495	1.1%
	2014	4,627	1.6%	4,442	1.1%	4,436	1.1%	4,544	1.1%
	'9-Year' Compound Annual Growth Rate (2005(A) - 2014)		1.56%		1.10%		1.08%		1.35%

			Annual Variances from "Spring '05" IRP Forecast					
			2006 Load Forecast		2005 "Q4" / 2006 "Q1" Update		2006 "Q2" Update	
Forecast Data	2006	[redacted]	(54)	-1.3%	(73)	-1.8%	8	0.2%
	2007		(41)	-1.0%	(111)	-2.7%	18	0.4%
	2008		(55)	-1.3%	(132)	-3.1%	0	0.0%
	2009		(86)	-2.0%	(138)	-3.2%	(19)	-0.4%
	2010		(104)	-2.4%	(130)	-3.0%	(21)	-0.5%
	2011		(125)	-2.8%	(131)	-3.0%	(32)	-0.7%
	2012		(135)	-3.0%	(141)	-3.2%	(32)	-0.7%
	2013		(164)	-3.6%	(170)	-3.7%	(61)	-1.3%
	2014		(185)	-4.0%	(191)	-4.1%	(83)	-1.8%

[A] On 7/18/06 PSO achieved a (preliminary) actual all-time peak demand of 4,156 MW.

[B] The initial update to the 2006 Load Forecast was performed in November, 2005. It was subsquently re-affirmed in January, 2006.

[C] For comparative purposes, excludes potential new firm (cost-based) wholesale loads (<50MW) reflected in PSO CDR.

"N/Av" = data not available

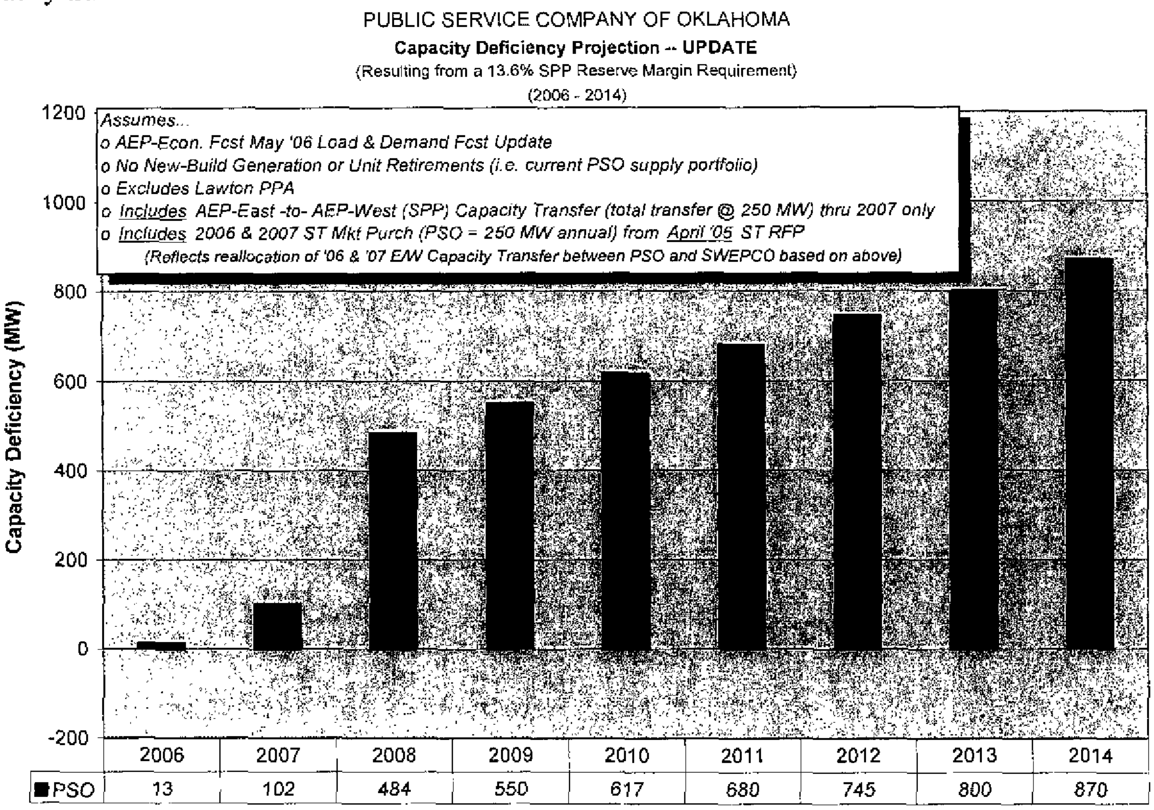
The table reflects three subsequent forecast views of PSO peak demand that would ultimately indicate only minor changes from the January 2005 forecast previously described and identified in the Spring 2005 IRP. The forecast and forecast updates to the "2006" PSO load and demand forecast (established in the summer of 2005) were performed by the AEP Economic Forecasting group in November 2005, January 2006 (which re-affirmed the November 2005 update), and May, 2006, respectively. It suggests that the most recent forecast for the updated 9-year forecast period through 2014 now indicates a PSO peak demand compound annual growth rate (CAGR) of 1.35%, versus the 1.56% level for the same period reflected in the "Spring 2005" IRP forecast performed in January, 2005. While that latest (May, 2006) update represents a slightly lower growth rate than that January, 2005 projection, it has increased from both the "2006" PSO Load and demand forecast performed in the summer of 2005, as well as the update performed as recently as January, 2006, which had indicated an even lower CAGR for PSO over the same period of only 1.10% and 1.08%, respectively. Further, this most recent update of the forecasted CAGR for PSO of 1.35% is slightly above the most recent available "weather normalized" *actual* 9-year (1996-2005) CAGR demand growth for PSO of 1.30%

AEP Economic Forecasting's analysis would suggest that the SAE approach to forecasting long-term load and demand previously decribed explicitly accounts for shifts in energy efficiency assumptions which, in turn, has served to contribute to the slightly lower forecast of PSO demand and energy in the outer forecast horizon (i.e. generally years beyond 2010 when such energy efficiency intiatives—such as those being envisioned by EPAct 2005—could indeed begin to more signifcantly manifest.) A review of the most recent PSO demand forecast in the table above would support that relative reduced out-year trending when comparing those SAE-influenced results to the prior long-term PSO demand forecast that did not utilize SAE techniques (specifically, the January 2005 forecast update utilized in PSO's Spring 2005 IRP profile).

Another driver of these recent PSO customer demand projection swings has been the aftermath of the September, 2005 hurricane events that impacted the Gulf Coast states. In the case of PSO there were, for instance, significant pricing implications to its retail customers due to the relative short-term increases in natural gas pricing. Due to PSO's particularly heavy reliance on natural gas-sourced power supply—both own generation and purchased energy—such increases in natural gas prices were originally assumed to have a longer-term affect on regional customer retention/growth as well as through usage elasticity impacts. Subsequent stabilization has occurred in those commodity markets, as reflected in a "quicker" return in PSO's long-term demand expectations to a level nearer to the January 2005 forecast level. As previously suggested, however, while such uncommon events that occurred last year in the Gulf States are impossible to predict, uncertainties surrounding such occurrences—and their aftermath—is something that the Company must contemplate when addressing risk as part of the capacity resource planning process.

2.4-A Unit Disposition -- At the time of the development of PSO's Spring 2005 IRP, Tulsa Unit 3 was not operable and in a standby mode. The Company, however, was in the process of performing the necessary upgrades and maintenance that would be required to ensure safe, reliable start-up and operation. With that, the Plan assumed that this unit would become operational. Such upgrades and repairs to Tulsa Unit 3 were performed and the unit is now able to achieve the 68 MW of generating capability that had been projected for purposes of PSO's resource planning beginning in 2006.

2.6-A Projected Capacity / Reserve Margin Deficiencies – The following table reflects PSO's updated projected capacity deficiencies assuming the most recent (May 2006) long-term forecast of peak demand and the current capacity supply portfolio. As defined in the legend text, these anticipated PSO capacity deficiency projections represent a "going-in" position in that no new capacity additions are reflected over-and-above known, firm capacity transactions.



	2006	2007	2008	2009	2010	2011	2012	2013	2014
■PSO	13	102	484	550	617	680	745	800	870

As indicated within the updated table above, PSO is now anticipated to require 550 MW of capacity resources to achieve a 13.6% reserve margin requirement by 2008. That date is critical in that it demonstrates that the capacity needs at that time may outweigh the ability to import potentially available (market) capacity due to known and anticipated transmission constraints previously discussed in the Spring 2005 IRP. That 2008 timeframe is also critical in that it represents the earliest summer season in which new build capacity resources in the form of peaking capacity could be in-service. Note that the PSO capacity deficiency grows to 870 MW by the end of the IRP period. This would suggest that the rate of growth in the capacity deficiency of PSO is largely a function of the 1.35 percent (50-60 MW) compound annual growth rate in the most recent update of forecasted peak demand.

2.7-A Operating Agreements - As identified, the AEP System Integration Agreement (SIA) provides for the integration and coordination of AEP's East and West companies zone. Among other things, the SIA provides for the transfer of power and energy between AEP West zone and AEP East zone under certain conditions. The Plan has been updated to reflect the transfer/purchase of 250 MW of capacity from the 2006 summer season into the 2007 summer season since the AEP Eastern (PJM) zone is now anticipated to have enough installed capacity ("ICAP") in the summer of 2007 to cover a comparable reserve requirement within PJM. As identified in the PSO capacity position chart above, that position, however, remains unknown beginning in 2008, as the continued transfer of capacity from AEP's East to West zones could place the AEP-PJM zone in a capacity deficit position.

3.0-A Capacity Resource Planning -- Short Term Needs

3.1-A Recent RFP Solicitations

- Previously, the 250 MW PSO assignment of the AEPSC purchases (from two counterparties) of 350 MW of annual peaking capacity and related energy for the years 2006 and 2007 that resulted from its April 15, 2005, soliciation was not yet assumed to have received firm network transmission service authorization from the SPP. As such, the capacity assigned to PSO continued to be reflected implicity as an "Unknown Wholesale Purchase" within the PSO Spring 2005 IRP Capacity, Demand, Reserve (CDR) profile. Subsequently, these capacity purchases were evaluated by SPP to determine whether each would be qualified to receive firm network transmission service. Such evaluations were completed and each of the transactions has now been qualified by SPP for such firm network transmission service subject to the potential re-dispatch of other generation. Therefore, these 2006 and 2007 capacity purchase amounts for PSO have now been reflected—by specific amounts, by counterparty—and have been included in both the previous addended chart of the Company's long-term capacity deficiency position as well as within the PSO CDR reflected in this IRP addendum.

- On December 8, 2005, AEPSC again as agent for PSO and SWEPCO—and in conjunction with the overall 2005 RFP solicitation for long-term PSO (and SWEPCO) capacity resources—issued an additional RFP for "Short-Term" capacity and related energy. This soliciation was made for a total of up to 200 MW for the year 2006 and up to 800 MW for each of the years 2007 through 2009 and that would be shared among the two companies based on their relative capacity positions. Based on both the ultimate anticipated need and the offers received, a determination was made to enter into negotiations for two purchase transactions. The first being for 225 MW of capacity for each of the years 2007 through 2009. The second, with a separate counterparty, for 200 MW for the years 2008 and 2009.

  As with the case of previous short-term capacity purchases, the Company does not yet know whether either transaction will quality for firm network transmission service by SPP. As a result, until such evaluations are completed by the SPP, PSO's ultimate allocated share of these capacity resource amounts for the years 2007 through 2009 have not yet been reflected as an offsetting capacity source in the summary of its *Capacity Deficiency Projection* in the previous chart. In addition, such capacity purchase amounts are reflected as part of the line item "Unknown Wholesale Purchase" within in the PSO CDR included in this IRP addendum.

- Renewable (wind power) capacity and energy acquisitions by PSO that were incorporated into PSO's Spring 2005 IRP had assumed that the MW that would be applicable to meet capacity planning reserve requirements would be limited to approximately 8 to 9 percent of capacity nameplate. That limitation was in recognition of the prior PSO experience that considered not only the SPP critieria surrounding the "firmness" of wind power, but also the respective locations and interconnections of these intermittent resources. Subsequently, it was determined by the SPP that the Blue Canyon I and II projects would not qualify for firm transmission capacity without fairly massive transmission interconnection upgrades. As such, while the Company is receiving energy associated with the transaction, 14 MW of previously assumed firm capacity is now not being reflected in PSO's capacity portfolio (CDR).

4.0-A Capacity Resource Planning – Long-Term Needs

4.1-A Resource Planning Assumption & Issues

4.1.1-A Commodity Prices -- Gas & Energy - The AEP Fundamental Analysis group has performed continuous updates to its forecasts of commodity prices, including natural gas. The following table offers a comparison of those updates of the average annual "Base" (or point-estimate) of projected Henry Hub natural gas prices versus those Base values previously reflected in the modeling to support the Spring 2005 IRP.

The three most recent AEP Fundamental Analysis updates of natural gas prices projections have incorporated the impact of the September 2005 Gulf Coast hurricanes as a significant relative driver in the nearer-term period (2006-2008), initially impacting average annual pricing by as much as $3-4 per MMBtu. Specifically, these near-term projections assumed that the ramification of those events on both drilling and pipeline infrastructure could cause supply pressures to exist, however, it was anticipated that those pressures will be largely mitigated by the 2008/2009 timeframe as indicated in each of these subsequent AEP Fundamental Analysis profiles .

In terms of the relative impact such increased pricing volatility may have on PSO's long-term capacity planning modeling, several points are evident. First, any upward pressure from the 2005 hurricane events inherently incorporated into the latest projections of natural gas prices will be relatively short-lived from a capacity planning perspective. In fact, annual pricing trends captured in the above table suggests that the "Base" natural gas prices from these five chronologically-distinct forecast views will converge in the 2010 timeframe—a period that generally aligns with the assumed start of new-build generation needs in the region. Second, as previously discussed with the projecting of future load and demand, is the notion that the potential to predict the timing of long-term (natural gas and attendant energy) pricing volatility due to similar such naturally occurring events in the future is impossible. That being said, it is reasonable to assume that such unpredictable events could periodically re-emerge going-forward that would have the potential to cause periodic havoc on commodity pricing. Finally, it is important to note that the nominal price of gas has been projected to remain above the $6 per MMBtu threshold throughout the forecast period. This is in spite of the anticipated increasing receipt of liquified natural gas (LNG) by over 2 Tcf per year by 2010 as well consideration of Alaskan pipeline deliveries from the north slope in the mid-to-latter part of the next decade.

The following table offers a comparison of both "HIGH" and "LOW" projected natural gas bandwidths versus those originally established in the February 2005 forecast and utilized in PSO's 2005 IRP. Further, this table compares these projection bandwidths across the same set of forecast updates from AEP Fundamental Analysis.

The forecasted natural gas pricing bandwidths depicted above continue to confirm even greater pricing volatility then that which was incorporated into the Spring 2005 IRP (February, 2005 projections). Specifically—beginning with the subsequent June, 2005 estimates and continuing with the November 2005 and, finally, affirmed in the March and June, 2006 AEP Fundamental Analysis updates—these total natural gas pricing bandwidths continue to exceed $5 per MMBtu and, as such, will likewise continue to validate PSO's approach in addressing such potential price volatility when it establishes its justification for solid-fuel capacity going-forward.

Additional Natural Gas Price Forecast Validation:
To support the AEP Fundemenal Analysis projected view of this critical commodity pricing, the following chart offers a recent view of projected average annual natural gas pricing from several industry sources.

The backwardation of nominal prices through the 2010 period as LNG imports begin to increase is the consensus among the sources depicted above. From 2006 through 2010, AEP's projection of nominal prices at the benchmark Henry Hub average $7.28/MMBtu.

Beyond 2010, AEP's nominal price projection averages $6.33/MMBtu through 2020 considering Alaska pipeline deliveries from the North Slope in 2018 and increasing LNG receipts all tempered by modest growth of lower 48 production and a possible reduction of net Canadian imports. Both EIA and (confidential and proprietary) Source 2 predict Alaska pipeline receipts by 2015 with less price impact than the AEP projection.

Ultimately, AEP Fundamental Analysis suggests the factor that will most likely shape the fundamentals of overall gas demand will be the growth of gas consumption for electricity generation. Gas demand growth from the power sector is inevitable as long as the economy grows and only a minimal amount of non-gas-fired generating capacity comes online in the Eastern Interconnect by 2010.

4.1.3-A Commodity Prices – Capacity - The following chart offers the long-term forecast of SPP zonal capacity prices as established by the AEP Fundamental Analysis group in its February 2005 forecast assumed for the Spring 2005 IRP as well as the group's most recent profile of regional capacity pricing performed in June, 2006.

Additional Capacity Price Forecast Validation:

To support the AEP Fundemenal Analysis projected view of market capacity price, the following chart compares the same AEP Fundamental Analysis annual projections of SPP capacity values, as reflected above, with the actual 2005-2009 bid responses to the short-term AEPSC market capacity solicitations made in December 2004, April 2005, and December 2005, that were previously described.

As reflected on the preceding chart, it would indicate that such recent market responses to these capacity RFPs are, in the short-term, generally tracking at or above these fundamental projections. Given the relative small amounts of capacity at issue (total AEP-SPP amounts of 150 MW in 2005, 350 MW in 2006, 575 MW (total) in 2007, and 425 MW in 2008 and 2009) it might also suggest that the projected capacity valuation trend may be conservative given the potential for (capacity) market depth issues brought on by the anticipated firm transmission constraints previously discussed.

4.2-A Least-Cost Resource Planning Modeling Options

4.2.2-A Capacity Supply (Build) Modeling Options - As reflected in the table below, updates were performed to the original (February, 2005) technology-specific cost and performance estimates used in the Spring 2005 IRP in both July 2005 and December 2005, respectively.

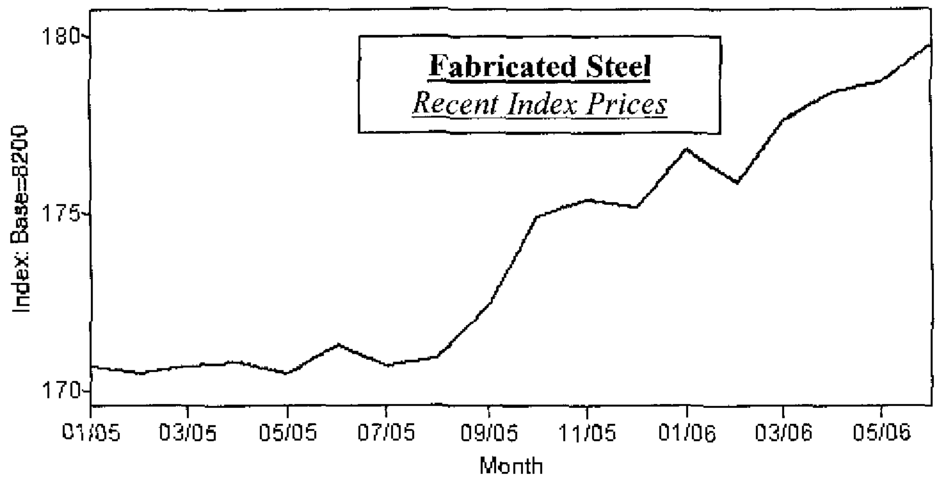
AEP-SPP Zone	Type	*Coal Source*	*Capability* Avg. Nom.	*Capability* Summer	*Approx. Avg. Ann. Heat Rate*	*Approx. "All-in" Installed Cost per Kw ** Excl. AFUDC	*Approx. "All-in" Installed Cost per Kw ** Incl. AFUDC
Baseload *(Coal-fired)*	Adv. Supercritical Pulv. Coal	*PRB*	**				
Spring 2005 IRP (AEP New Gen.Devel., 2005 v1.2) Dated: 2/24/05			600	594			
Update, 2005 v2.0 Dated: 7/5/05			600	594			
Latest Update, 2005 v3.0 Dated: 12/1/05			600	594			
Intermediate *(Gas Combined Cycle)*	2x1 GE-7FA						
Spring 2005 IRP (AEP New Gen Devel., 2005 v1.2) Dated: 2/24/05			500	479			
Update, 2005 v2.0 Dated: 7/5/05			500	479			
Latest Update, 2005 v3.0 Dated: 12/1/05			500	479			
Peaking *(Gas Turbines, Simple Cycle)*	GE-7EA (80 MW)		***				
Spring 2005 IRP (AEP New Gen.Devel., 2005 v1.2) Dated: 2/24/05			160 *(2x80)*	154			
Update, 2005 v2.0 Dated: 7/5/05			170 *(2x85)*	163			
Latest Update, 2005 v3.0 Dated: 12/1/05			160 *(2x80)*	163			

* includes est. EPC, owner's costs, and (generic) interconnection, per Corporate Technology Development forecast
** assumes only 75% (450MW) would apply to PSO capacity resource plan recongnizing that certain non-affiliate 3rd parties have ownership participation rights re: self-build options
*** represents minimum peaker tranche assumed

Focusing on those specific generating technology types originally modeled within the *Strategist* optimization in the Spring 2005 IRP process—Advanced Supercritical Pulverized Coal (PC) (*baseload*), Natural Gas Combined Cycle (NGCC), 2x1 GE-7FA (*intemediate*), and Natural Gas Combustion Turbine (NGCT), GE-7EA (*peaking*)—the updated profiles suggest generally consistent (or even improved) performance estimates, but increases in estimated installed costs.

Additional Generation Techology Installed Cost Increase Validation:

A major cost pressure impacting the installed costs of all generation types is the cost of various commodities, including the cost of steel. The following chart depicts the recent trend in the indexed price of fabricated structural steel. 2005 prices escalated by 8% over 2004 with, as suggested in the chart, most of that increase occurring in the latter four months of the year—a period coinciding with the hurricane events previously discussed. This trend is continuing in 2006, with indexed prices escalating another 3+% through YTD June.



Source: U.S. Department of Labor Statistics; PPI for Fabricated Steel (BLS Index Code: WPU107405); Dated: June 2006

Further, it is anticipated that the competing demands for various craft labor groups—electricians, pipefitters, welders, etc.—will also likely contribute to generation project cost pressures as more such new-build projects are announced and undertaken. In terms of the affects of these generation technology type cost changes on PSO's capacity resource plan, no impacts would be anticipated. As will be described, the relative mix and timing—the latter being largely affirmed based on the updated profiles of PSO demand previously discussed—remains unchanged from that of the Spring 2005 IRP.

5.0-A Review of Modeling Results

5.1-A Results Based on Gas Price Scenarios — An update to that model output matrix was performed in the fall of 2005 to reflect updates to certain modeling parameters previously described, namely:

- updated demand forecast from AEP Economic Forecasting's "2006" Load & Demand Forecast performed in August, 2005;
- updated long-term commodity price forecast from AEP Fundamental Analysis' June 2005 Forecast Update; and
- updated generation technology cost & performance parameters from AEP Generation Development's July, 2005 update.

As identified in the discrete modeling results found in the following cost matrix, the "Hybrid" Plan for PSO reflects the same amount and relative mix of Baseload, Intermediate (represented by the continued assumption of a Lawton PPA) and Peaking capacity resources as had been reflected in the Spring 2005 IRP.

Capacity Resource Modeling Results Based on an Array of Natural Gas Prices
(Update Perfomed Subsequent to the "Spring 2005" IRP)

PUBLIC SERVICE COMPANY OF OKLAHOMA

Modeling Update Reflects...
- o Updated Load & Demand Projections from AEP Economic Forecasting (August, 2005 Forecast)
- o Updated Commodity Pricing Forecast from AEP Fundamental Analysis (June, 2005 Update)
- o *Updated New Generation Technology Cost & Performance Parameters Matrix (2005 v2.0 dated: 7/8/05)*
- o No change in unit disposition profile (from Spring '05 IRP)

PSO

	New Capacity Additions: 10-Year (2005-2014) #	MW	Full Period (2005-2020) #	MW		Low Gas	MidLow Gas	Base Scenario	MidHigh Gas	High Gas
Low Gas Optimal Plan										
CT	8	648	12	972	Total CPW-$B	8.52	9.53	10.74	12.67	15.64
CC	1	260	1	260	*Levelized $/MWh*	*46.33*	*50.95*	*56.49*	*65.32*	*78.91*
PC	0	0	0	0	Var., Net CPW-$B	6.8	7.7	8.9	10.9	13.9
					Levelized $/MWh	*31.01*	*35.46*	*40.93*	*49.79*	*63.46*
Total		908		1,232						
MidLow Scenario Optimal Plan										
CT	8	648	12	972	Total CPW-$B	8.52	9.53	10.74	12.67	15.62
CC	1	260	1	260	*Levelized $/MWh*	*46.31*	*50.94*	*56.48*	*65.31*	*78.84*
PC	0	0	0	0	Var., Net CPW-$B	6.8	7.7	8.9	10.9	13.8
					Levelized $/MWh	*31.00*	*35.46*	*40.93*	*49.79*	*63.40*
Total		908		1,232						
Hybrid Plan										
CT	4	324	4	324	Total CPW-$B	8.83	9.63	10.48	12.01	14.38
CC	1	260	1	260	*Levelized $/MWh*	*48.21*	*51.40*	*55.32*	*62.31*	*73.06*
PC	1	445	2	890	Var., Net CPW-$B	6.1	6.8	7.6	9.1	11.6
					Levelized $/MWh	*28.00*	*30.97*	*34.81*	*41.83*	*52.67*
Total		**1,029**		**1,474**						
Base Scenario Optimal Plan										
CT	4	324	4	324	Total CPW-$B	8.88	9.60	10.48	12.03	14.41
CC	1	260	1	260	*Levelized $/MWh*	*48.00*	*51.27*	*55.28*	*62.38*	*73.30*
PC	1	445	2	890	Var., Net CPW-$B	6.2	6.8	7.7	9.3	11.7
					Levelized $/MWh	*28.24*	*31.30*	*35.24*	*42.36*	*53.37*
Total		1,029		1,474						
MidHigh Gas Optimal Plan										
CT	4	324	4	324	*Total CPW-$B*	*8.88*	*9.60*	*10.48*	*12.03*	*14.41*
CC	1	260	1	260	*Levelized $/MWh*	48.00	51.27	55.28	62.38	73.30
PC	1	445	2	890	Var., Net CPW-$B	6.2	6.8	7.7	9.3	11.7
					Levelized $/MWh	*28.24*	*31.30*	*35.24*	*42.36*	*53.37*
Total		1,029		1,474						
High Gas Optimal Plan										
CT	4	324	4	324	Total CPW-$B	8.88	9.60	10.48	12.03	14.41
CC	1	260	1	260	*Levelized $/MWh*	*48.00*	*51.27*	*55.28*	*62.38*	*73.30*
PC	1	445	2	890	Var., Net CPW-$B	6.2	6.8	7.7	9.3	11.7
					Levelized $/MWh	*28.24*	*31.30*	*35.24*	*42.36*	*53.37*
Total		1,029		1,474						

Recommended Build Plan

Therefore, these capacity resource modeling results identified in the cost matrix can continue to support the *planning conclusions and recommendations as set forth in the PSO Spring 2005 IRP.*

The only minor exception between this updated cost matrix and that which was originally established for the PSO's Spring 2005 IRP, can be found under the "Mid-Low" and "Low" natural gas price forecast profile. The discrete *Strategist* model updates performed in the fall of 2005 would opt to build additional peaking capacity (CTs) in lieu of: a) baseload, pulvierized coal under the "Mid-Low" case, and b) intermediate combined cycle capacity under the "Low" case. That being said, it is also important to point out that such a view of capacity resource mix would continue to create very significant ranges of CPW revenue requirements. Specifically, whereas this updated Hybrid Plan result would create a potential CPW revenue requirement variation or "swing" of as much as $5.4 billion based on the potential gas price bandwidth ($14.36 billion less $8.93 billion) over the full 30-year study period in that updated view, that potential revenue requirement exposure under that "Mid-Low" optimal build plan would now be *$7.1* billion ($15.62 billion less $8.52 billion), or as much as an 83 percent potential swing. No further capacity resource optimization profiles were performed.

Additional Modeling Validation:
The subsequent culmination of the 2005 IRP implementation process—the awarding of long-term capacity resource committments stemming from PSO's respective Peaking and Baseload Request for Proposals (RFP)—established the following:

- ✓ Award for the construction of a total of **four (4) Combustion Turbine peaking units** at PSO's Riverside and Southwestern Station facilities—for operation by June, 2008—based on offers received from AEPSC, acting as agent for PSO; and
- ✓ Award for the construction of an **ultra-supercritical pulverized coal unit** by Oklahoma Gas Electric (OG&E) at its Sooner Station site for operation by June, 2011. It has been announced that this unit—to built and operated by OG&E—would be jointly owned with PSO taking a 50 percent interest.

Based on this, an additional modeling exercise was performed within *Strategist* to offer a final validation of the 2005 capacity resource plan. Specifically, the pricing and performance parameters for the baseload unit stemming from the OG&E offer from the RFP process were used to replace the comparable "generic" or non-descript/non-site specific data within the original (and updated) planning modeling. The capacity resource profile was then re-run to reflect the relative impact of these offered cost and performance profiles on PSO's study period CPW. In addition, an opposing view was also modeled that sought to add a "generic" combined cycle unit (since no viable combined cycle alternative resulted from PSO's RFP process) *in lieu of* that coal unit for in-service in 2011.

This evaluation did not constitute an updated optimization profile for long-term PSO capacity resources. Rather it simply represented a method to compare the relative cost impact of the offered pulverized coal facility versus an alternative technology type in the form of a combined cycle unit.

As summarized on the following table, the results of this *Strategist* analysis that sought to validate the offered (OG&E) pulverized coal unit vis-à-vis a generic combined cycle unit, would suggest that under both an AEP Fundamental Analysis "High" and "Mid-High" gas price scenario, the view with the OG&E-offered solid-fuel, baseload unit in 2011 resulted in a lower total CPW over a 40-year "life-cycle" (i.e. through the RFP-emulated

2051) analysis period than a generic CC build. Under an AEP FA "Base" gas view, however, the generic CC was slightly (0.7%) less expensive over the study period from a Total CPW perspective, but 6.0% more expensive when considering potentially volatile variable costs (largely fuel) only.

Capacity Resource Modeling Results Based on an Array of Natural Gas Prices
(Update Perfomed Subsequent to the "Spring 2005" IRP and Dec. '05 RFP Process)

PUBLIC SERVICE COMPANY OF OKLAHOMA
"Baseload Substitution Analysis"
Based on RFP (Full Project Life-Cycle) Commercial Evaluation Period: 2006-2051

		Natural Gas Pricing Source: AEP Fundamental Analysis "Q1 (Mar.) 2006" Forecast		
		Base Gas Scenario	MidHigh Gas	High Gas
OG&E Pulverized Coal Unit in 2011				
	Total CPW-$B	13.35	14.87	16.07
	Levelized $/MWh	*68.42*	*75.40*	*80.91*
	Var., Net CPW-$B	9.66	11.00	12.17
	Levelized $/MWh	*44.21*	*50.37*	*55.71*
Substitution: **"Generic" Combined Cycle in 2011**				
	Total CPW-$B	13.25	14.91	16.29
	Levelized $/MWh	*67.96*	*75.56*	*81.88*
	Var., Net CPW-$B	10.24	11.72	13.05
	Levelized $/MWh	*46.89*	*53.64*	*59.72*
% Variance	Total CPW-$B	***-0.7%***	***0.2%***	***1.3%***
(Generic) CC vs. OG&E PC	Var., Net CPW-$B	***6.0%***	***6.5%***	***7.2%***

As an additional sensitivity on these RFP offer results for baseload resources, a view of forecasted natural gas prices from the Energy Information Administration (EIA) was applied. EIA is the statistical agency of the U.S. Department of Energy. EIA issues a wide range of weekly, monthly and annual reports on energy production, stocks, demand, imports, exports, and prices, and prepares analyses and special reports on topics of current interest. EIA's most recent (February 2006) long-term profiles of Henry Hub natural gas pricing are compared to AEP Fundamental Analysis' "Q1-2006" view as reflected in the table below:

Utilizing those long-term natural gas pricing views from EIA, the following table offers a like-comparative analysis (OG&E-offered supercritical pulverized coal unit versus a "generic" NG combined cycle unit in 2011).

		Natural Gas Pricing Source: EIA		
		Base Gas Scenario	[redacted]	High Gas
OG&E Pulverized Coal Unit in 2011				
	Total CPW-$B	13.29	[redacted]	15.86
	Levelized $/MWh	*68.16*	[redacted]	*79.92*
	Var., Net CPW-$B	9.27	[redacted]	11.23
	Levelized $/MWh	*42.42*	[redacted]	*51.39*
Substitution: **"Generic" Combined Cycle in 2011**				
	Total CPW-$B	13.25	[redacted]	16.07
	Levelized $/MWh	*67.96*	[redacted]	*80.88*
	Var., Net CPW-$B	9.88	[redacted]	12.12
	Levelized $/MWh	*45.24*	[redacted]	*55.48*
% Variance	Total CPW-$B	***-0.3%***		***1.3%***
(Generic) CC vs. OG&E PC	Var., Net CPW-$B	***6.6%***		***8.0%***

[redacted]

Notes:
o OG&E pulverized coal unit data sourced from *RFP bid response*
o Both views (PC and NGCC build) reflect:
-- (Bid) CT additions (324MW, summer) in 2008
-- Lawton PPA (260MW, CC) effective 2010
o EIA "Base" and "High" gas prices per:
-- Base: Report #: DOE/EIA-0383(2006), released February, 2006
-- High: *"Annual Energy Outlook 2006 with Projections to 2030" Report, released December, 2005*

In the EIA "High" natural gas price scenario, again, the view with the OG&E solid-fuel, baseload unit in 2011 resulted in a lower total CPW over a 40-year "life-cycle" (i.e. again, through 2051) study period than a generic CC build. While under the EIA "Base" gas view, however, the generic CC was cost was nearly identical with the generic NGCC unit being 0.3% less expensive over the same study period from a Total CPW perspective but, again, 6.6% more expensive when considering only variable costs.

6.0-A Conclusions

In conclusion:

- ✓ From a "needs assessment" perspective, the subsequent analysis of PSO long-term load and demand would suggest that the projected PSO MW obligation to serve remains as set forth in the 2005 IRP.
- ✓ From a "cost-driver" perspective:
    - subsequent assessment of natural gas pricing—one of the key cost drivers in the evaluation—would suggest that such longer-term pricing is consistent with that set forth in the 2005 IRP, with (High-to-Low) pricing bandwidths—and with that, the attendant exposure to natural gas pricing—being potentially broader; and
    - subsequent assessment of new generation techology cost and performance parameters have remained fairly consistent versus those set forth in the 2005 IRP with, however, cost pressures tied to both matieral and labor anticipated to impact all technology types.

✓ From an analytical/modeling perspective, the optimum (least-cost) peaking and baseload alternatives originally identified in the *2005 IRP* were emulated in an updated analysis that considered certain modifications/updates to various modeling parameters. Moreover, the results from the final one-off analysis decribed in this documentation would further suggest that this PSO capacity resource planning outcome resulting from the recent PSO RFP process was itself validated as being reasonable when compared to an "alternative" (but not offered via the RFP process) generation type—a "generic" natural gas combined cycle unit.

7.0-A PSO – Action Plan

The following PSO Action Plan reflected as part of the Spring 2005 IRP has now been augmented in the following table:

Action Item	Resource Type	Timing	Amount	Action
1	Peaking Capacity	Beginning Summer 2008	Up to 320 MW	Competitive RFP solicitation for peaking capacity and energy for an in service date of June 1, 2008. Offers received, evaluated and awarded to AEPSC, as agent for PSO, for two sites (Riverside Station (160MW) and Southwestern Station (160MW)) .Filed for used and useful determination under HB1910.
2	Baseload Capacity	Beginning Summer 2011	Up to 600 MW	Competitive RFP solicitation for baseload capacity and energy for an in service date of June 1, 2011. Offers received, evaluated and recently (7/18/06) awarded /announced to OG&E, for a pulverized coal facility at Sooner Station site w/ PSO taking a 50% interest. Contract negotiations for this joint venture proceding. Filed for used and useful determination under HB1910.
3	Transmission	Summer 2007	n/a	Complete Tulsa Area 345/138kV upgrade
4	Existing Steam Generation	2005 IRP (Fall Update)	n/a	Continue cycling of disposition evaluations of existing gas-steam units including, among others, Southwestern 1 and 2 as well as Tulsa 3.
5	DSM	2005 IRP (Fall Update)	n/a	Continue assessment of viable, cost-effective measures

6	Intermediate	2010 (delayed from 2009 due to uncertainty regarding timing of any final OCC order)	300 MW	Develop contingency supply options for the Lawton Cogeneration plant for the event the COD is either accelerated or deferred from the assumed date of 2010.
7	Market Capacity Purchases (AEPSC, as agent, and on behalf of PSO and SWEPCO)	2006 – 2009	Up to 200 MW (2006) to up to 800 MW (2007, 2008, and 2009) – total PSO and SWEPCO	Competitive RFP solicitation for market capacity and related energy for the years 2006-2009. Offers received, evaluated, and term negotiations underway for the possible acquisition of 225 MW (total PSO and SWEPCO) for 2007 and 425 MW (total) for 2008 and 2009. Company allocations to be determined.

SECTION B – CAPABILITY, DEMAND AND RESERVES

OVERVIEW *(ADDENDUM)*

The following 2005 Capacity, Demand and Reserves (CDR) profile represents a modified view of the ten-year IRP for PSO based on the paraemeters reviewed in this Plan addendum. All figures included in the CDR are expressed in megawatts.

PUBLIC SERVICE OF OKLAHOMA
CAPABILITY, DEMAND AND RESERVES FORECAST
05 ACTUAL - 2014
BASE (SPRING 2005 IRP) PLAN -- UPDATE

CAPABILITY

	Plant Capabilities	05 ACT	2006	2007	2008	2009	2010	2011	2012	2013	2014
10											
9	DIESEL UNITS @ PLANT LOCATIONS	25	25	25	25	25	25	25	25	25	25
8	OKLAUNION #1	108	108	108	108	108	108	108	108	108	108
7	COMANCHE #1G1, 1G2, 1S	273	273	273	273	273	273	273	273	273	273
6	NORTHEASTERN # 1 & 2	899	899	899	899	899	899	899	899	899	899
5	NORTHEASTERN # 3 & 4	910	910	910	910	910	910	910	910	910	910
4	RIVERSIDE #1 & 2	917	917	917	917	917	917	917	917	917	917
3	SOUTHWESTERN #1, 2, 3	472	472	472	472	472	472	472	472	472	472
2	TULSA #2, 3, 4	410	410	410	410	410	410	410	410	410	410
1	WELEETKA # 4, 5, 6	163	163	163	163	163	163	163	163	163	163
1	TOTAL	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177	4,177
	Adjustments to Plant Capability										
	NEW CTs				324	324	324	324	324	324	324
	NEW COAL							446	446	446	446
	TULSA #3 UNAVAILABLE	-80	-12	-12	-12	-12	-12	-12	-12	-12	-12
	NE 3&4 FGD RETROFIT										-15
	COMBINED CYCLE PPA						260	260	260	260	260
2	TOTAL	-80	-12	-12	312	312	572	1,018	1,018	1,018	1,003
3	Net Plant Capability (1 + 2)	4,097	4,165	4,165	4,489	4,489	4,749	5,195	5,195	5,195	5,180
	Off-System Sales Without Reserves										
	TRANSFER TO SWEPCO										124
4	TOTAL	0	0	0	0	0	0	0	0	0	124
	Purchases Without Reserves										
	RFP WIND FIRM CAPACITY		3	3	3	3	29	29	29	29	29
	TRANSFER FROM SWEPCO										
	WEATHERFORD I WIND	9	9	9	9	9	9	9	9	9	9
	OGDEN MARTIN COGEN	20	20	20							
	FIRM PURCHASES	101	250	250							
	UNKNOWN WHOLESALE PURCHASE		13	82	160	226	7				
5	TOTAL	130	295	364	172	238	45	38	38	38	38
6	Total Capability (3 - 4 + 5)	4,227	4,460	4,529	4,661	4,727	4,794	5,233	5,233	5,233	5,094

DEMAND		05 ACT	2006	2007	2008	2009	2010	2011	2012	2013	2014
A	Peak Demand Before Passive DSM	4,047	4,101	4,169	4,216	4,274	4,333	4,388	4,446	4,495	4,544
B	**Passive DSM**										
	NEW DSM PROGRAMS										
	TOTAL	0	0	0	0	0	0	0	0	0	0
C	Peak Demand (A - B)	4,047	4,101	4,169	4,216	4,274	4,333	4,388	4,446	4,495	4,544
D	**Active DSM**										
	VALUECHOICE		35	35	35	35	35	35	35	35	35
	INTERRUPTIBLE		16	16	16	16	16	16	16	16	16
	TOTAL	0	51	51	51	51	51	51	51	51	51
E	Firm Demand (C - D)	4,047	4,050	4,118	4,165	4,223	4,282	4,337	4,395	4,444	4,493
F	**Other Demand Adjustments**										
	DIVERSITY	218	19	22	23	23	23	24	24	24	24
	TOTAL	218	19	22	23	23	23	24	24	24	24
7	Native Load Responsibility (E - F)	3,829	4,030	4,096	4,142	4,200	4,259	4,314	4,371	4,420	4,468
	Off System Sales With Reserves										
8	TOTAL	0	0	0	0	0	0	0	0	0	0
	Purchases With Reserves										
	PSO - SWPA ENTITLEMENT	40	40	40	40	40	40	40	40	40	40
	AEP EAST TO WEST CAPACITY TRANSFER	129	65	70							
9	TOTAL	169	105	110	40	40	40	40	40	40	40
10	Load Responsibility (7 + 8 - 9)	3,660	3,925	3,986	4,102	4,160	4,219	4,274	4,331	4,380	4,428

RESERVES		05 ACT	2006	2007	2008	2009	2010	2011	2012	2013	2014
11	Reserve Capacity (6 - 10)	567	535	543	559	567	575	959	902	853	666
12	% Reserve Margin ((11/10) * 100)	15.5	13.6	13.6	13.6	13.6	13.6	22.4	20.8	19.5	15.0
13	% Capacity Margin (11/(6) * 100)	13.4	12.0	12.0	12.0	12.0	12.0	18.3	17.2	16.3	13.1
14	Reserves Above Minimum 12% Capacity Margin	68	0	0	0	0	0	376	311	256	62

This PSO 2005 IRP "CDR-Addendum" Updated to Reflect Effects of:

- o AEP Economic Forecasting May, 2006 Forecast Update, incl. DSM updates (vs. Jan. '05 Fcst. Update)
- o PSO share of East-to-West Capacity Transfer through 2007 (vs. 2006 only)
- o Delay of Lawton PPA In-Service until 2010 (vs. 2009 in-service)
- o Reduction of 14 MW of Wind Projects (Blue Canyon) that can offer Firm Capability
- o With network transmission service authorization from SPP, PSO share of 350MW (PSO assignment fixed @ 250MW) purchases in 2006 & 2007 now considered "Firm" (vs. "Unknown (Market) Wholesale Purchase")
- o PSO Northeastern Units 3&4 now assumed to incur derating of 15MW beginning in 2014 due to projected FGD installation resulting from CAVR
- o 2005 Actual data (vs. Forecast)

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF **ERNEST G. JOHNSON**, DIRECTOR OF THE PUBLIC UTILITY DIVISION, OKLAHOMA CORPORATION COMMISSION, TO REQUIRE PUBLIC SERVICE COMPANY OF OKLAHOMA TO INFORM THE COMMISSION REGARDING PLANNING OF ENERGY PROCUREMENT PRACTICES AND RISK MANAGEMENT STRATEGIES AND FOR A DETERMINATION AS TO APPROPRIATE METHODS TO LESSEN THE IMPACT OF ENERGY PRICE VOLATILITY UPON CONSUMERS.	)	CAUSE NO. PUD 200100096

FILED
MAY 15 2006
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

Public Service Company of Oklahoma's 2006 Fuel Supply Portfolio And Risk Management Plan

May 15, 2006

Table of Contents

I. Introduction

As a public utility company, PSO has an obligation to serve its customers at all times at all load levels, and those loads change on an instantaneous basis. To meet its constantly changing and uncertain load obligations, PSO uses all available resources, regardless of ownership, while taking into account fuel markets, environmental constraints, and regulatory requirements. This commitment is demonstrated, in part, by PSO's recent contracts, in 2004 and 2005, to purchase wind energy that provides not only a reasonable economic price, but also provides fuel diversity and environmental benefits to PSO and its customers. PSO routinely displaces its own generation with economic purchases from the competitive market and has established natural gas, coal, fuel oil, and transportation procurement processes that use competitive bidding and market offers.

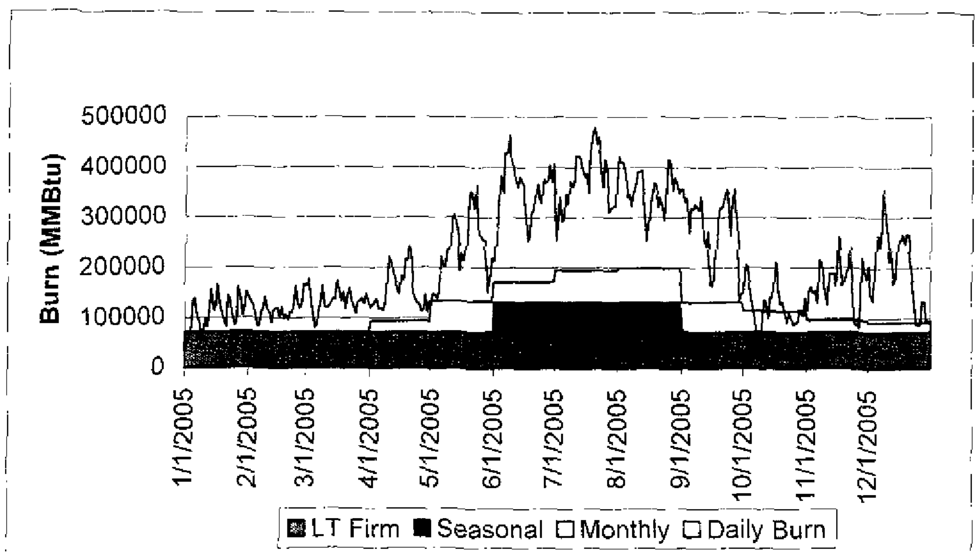
PSO's fuel procurement and risk management plan has as its primary focus concerns for: (1) reliability (to ensure fuel will be available), (2) adequacy (in sufficient quantities), (3) flexibility (to alter the portfolio to meet changing needs), and (4) price (to ensure reliable fuel supply at the lowest reasonable cost). In other words, PSO's fuel procurement activity is first and foremost focused on ensuring that all the electric power that its customers want is available when they want it.

A. Fuel Planning Qualifications

PSO's fuel planning and the foundation of PSO's fuel costs for 2006 and 2007 are based on existing fuel and fuel-related contracts and anticipated market prices for that fuel. While western coal costs are anticipated to remain relatively stable, natural gas prices can vary based on supply and demand realities in the natural gas market. PSO currently has 82,000 MMBtus per day of annual base load natural gas, or approximately 38 percent of its annual natural gas supply requirements (based on the prior year's generation), under contracts of one-year or longer having staggered terms. Since most natural gas suppliers are not willing to assume the market price risk, the pricing under those contracts is generally based on market indices. Natural gas suppliers typically demand a significant premium to assume the market price risk for fixed-price contracts which would increase the cost of fuel to PSO's customers. PSO considers and evaluates fixed-price natural gas contracts whenever market conditions indicate that such arrangements may provide an opportunity to minimize the overall fuel cost for PSO's customers without restricting operational flexibility for PSO's generating units. Presently, PSO has approximately 21 percent of its annual base load natural gas requirements secured under fixed-price contracts to mitigate price volatility.

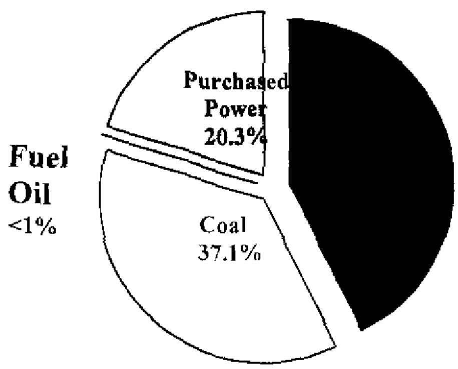
For supply reliability, PSO acquires its natural gas under annual, seasonal, and monthly firm arrangements, while using daily purchases to meet the varied requirements of PSO's natural gas-fired generation. Illustration 1 shows PSO's 2005 natural gas purchases by transaction type.

Illustration 1: PSO 2005 Natural Gas Purchases by Transaction Type



It is difficult to fully anticipate the availability and cost of purchased power for the upcoming year, and therefore it is difficult for PSO to anticipate its fuel and purchased power mix for 2006. Although historical amounts may not be reflective of future fuel and purchased power amounts for PSO, Illustration 2 provides a summary of the approximate distribution of total kilowatt-hours (kWh) by fuel source or purchased power for PSO in 2005.

Illustration 2: 2005 PSO Total kWhs by Fuel Source or Purchased Power



Despite the difficulty in projecting the amount and cost of purchased power opportunities that will be available during 2006 and 2007, the Company does make such projections. The process used to forecast purchased power is described below in Section II C.

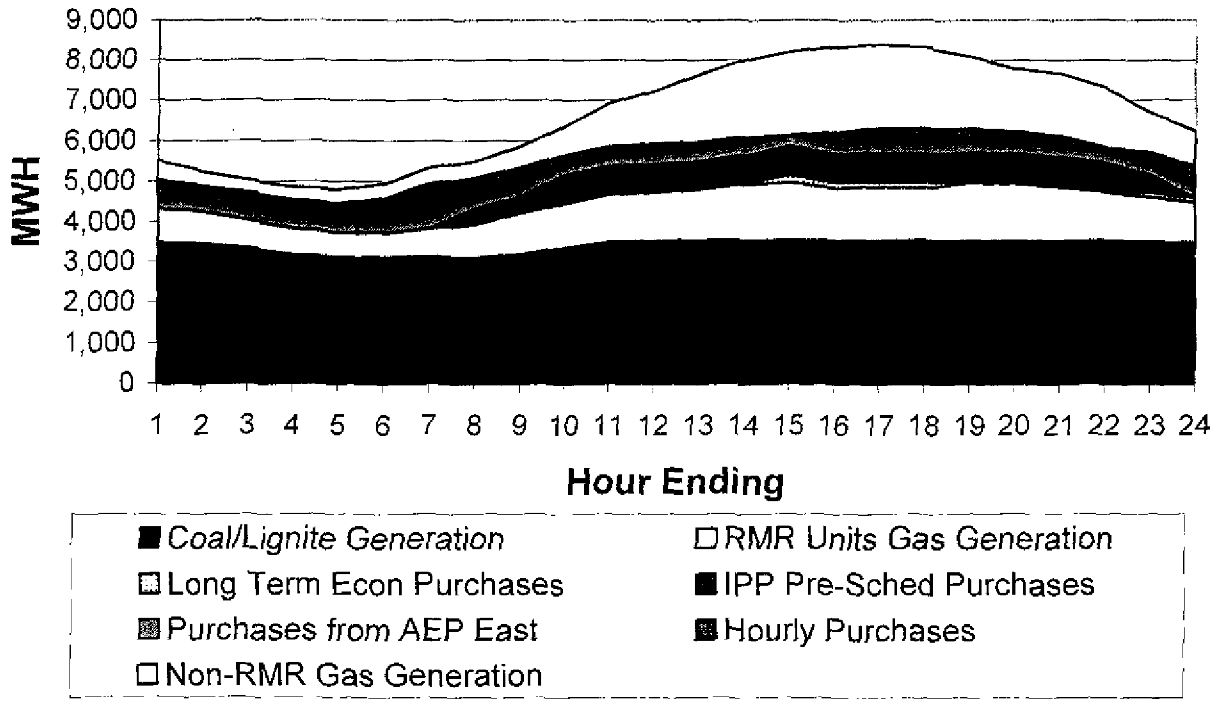
B. Fuel Planning Objectives

The Company's generation plants are fueled by either coal or natural gas, with some units capable of burning limited quantities of fuel oil. PSO's overall fuel strategy is to assure reliable, flexible, and competitively priced fossil fuel supplies and transportation resulting in the lowest reasonable cost to meet the generation requirements of the PSO system, recognizing the dynamic nature of fuel markets, environmental considerations, and regulatory requirements. To accomplish this objective, PSO maintains a portfolio of supply contracts with varying contract terms.

Typically, PSO meets its generation requirements by first using its lower–cost coal-fired units (and generation from SWEPCO's coal and lignite-fired units when available to PSO) to achieve the overall lowest reasonable fuel cost and by running its Reliability-Must-Run units (RMR) for system reliability purposes. PSO maintains a coal inventory to be both proactive and responsive to known and anticipated changes in operating, coal supply, and rail transportation conditions. In addition, PSO's coal inventory mitigates risk and allows the Company to take advantage of favorable and timely coal purchases.

Next, PSO's natural gas-fired units are compared to purchased power opportunities, based on each unit's efficiency, economics, and other relevant factors, to meet peak load demands, to replace coal capacity during scheduled maintenance and forced outages, to follow daily and hourly load swings, and for voltage support. Fuel oil is also burned in PSO's power plants when appropriate. Illustration 3 provides a graphical depiction of the hourly economic dispatch of available resources for a typical day.

Illustration 3: Typical Day Resource Economic Dispatch 2005



For 2006-2007, PSO also anticipates the delivery of wind energy which will generally displace energy from PSO's non-RMR natural gas-fired units.

Given PSO's combination of generation plants, PSO's average fuel cost from its own generation will be a weighted average of the delivered cost of coal and natural gas. Illustration 4 provides a graphic representation of PSO's fuel costs from its own generation for 2005 shown in $/MMBtu.

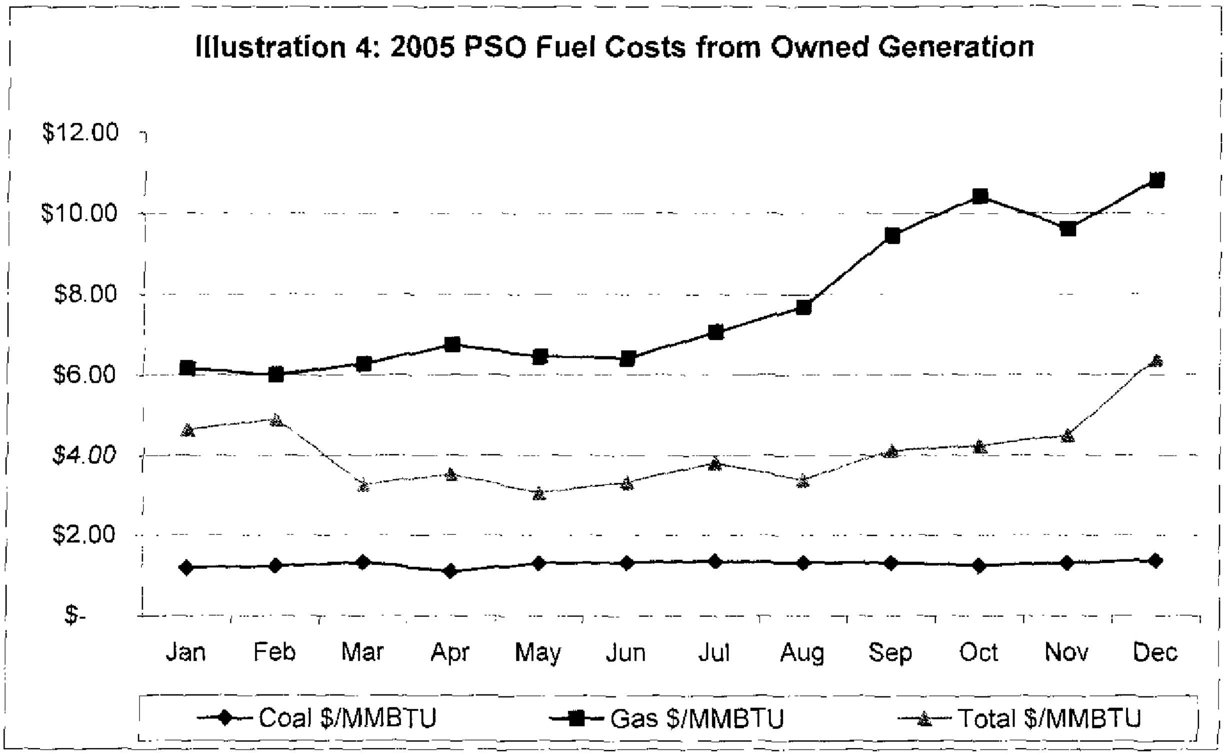
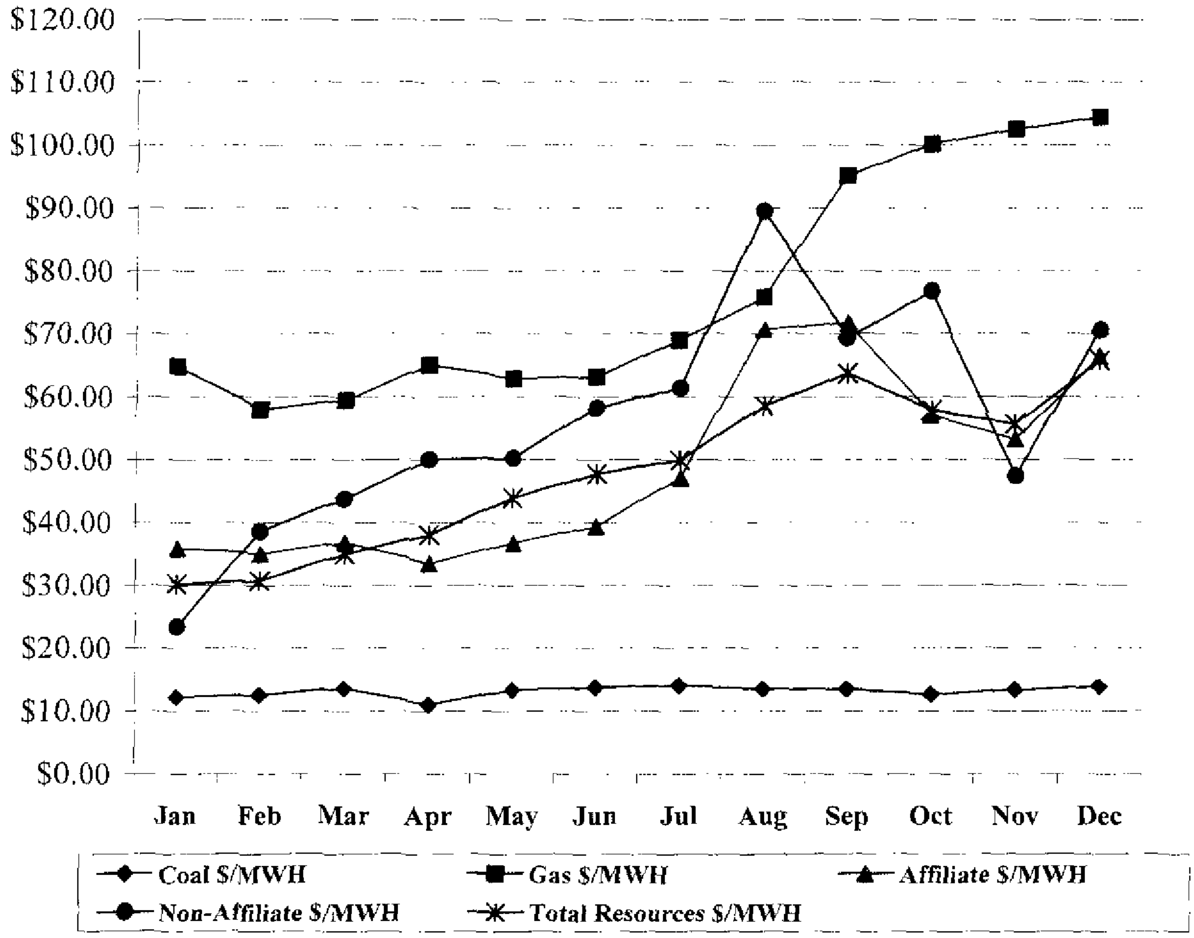


Illustration 5 shows PSO's total fuel costs, including the cost of purchased power, on a $/MWH basis. Note that the cost of affiliate power purchases is lower than non-affiliate purchases. This is due to the purchase of energy from SWEPCO's low-cost coal and lignite-fired units when they are available to PSO.

Illustration 5: 2005 PSO Fuel Costs and Purchased Power from Owned Generation



C. Prior Procurement Plan Feedback

The flexibility in PSO's fuel supply plan and the diversity of its generating fleet allow the Company to optimize the dispatch of generation to take advantage of lower spot market fuel and purchased power opportunities, while maintaining reliability of service to its customers. PSO's diversified generation and balanced fuel supply portfolio is the foundation of its risk management plan and provides an effective physical hedge to mitigate fuel cost volatility of any particular fuel cost component. By investing in and using generating plants with different fuel sources, PSO has, in effect, created a flexible portfolio of coal, natural gas, fuel oil and purchased power resources, including wind, which helps in the management of overall variable costs due to the potential price volatility of any one particular fuel source. PSO's ability to mitigate the potential price volatility of its overall fuel cost has been primarily attributable to management of its fuel mix, through maximum use of its coal generation, increased flexibility in fuel supply and transportation contracts, periodic use of fuel oil, and the use of purchased energy. As noted above, the effect of PSO's balanced fuel supply portfolio on its fuel cost during 2005, excluding purchased power, is evidenced in Illustration 4 where the total $/MMBtu is the resulting average of both natural gas and coal-related costs. Also, as shown above, Illustration 5 includes the impact of purchased power expense on PSO's total average fuel and purchased power cost.

In Cause No. PUD 20030076, OCC Staff Witness Dr. Kenneth R. Zimmerman recommended, "...that the Commission instruct PSO to work with Staff to identify annual average minimum gas burn as a first step toward acquiring at least a portion of this minimum gas requirement through fixed price gas supply contracts." In Cause No. PUD 200200754, OCC Staff Witness Zimmerman stated that, "...PSO could conceivably lower its cost of gas, provide some physical mitigation of potential gas price volatility and improve the reliability of its gas supply by purchasing between 15% and 20% of its annual gas supply requirement under fixed price terms, rather than at index prices." While fixed price contracts do not necessarily ensure lower fuel cost, PSO has responded to the Staff's suggestion and currently has approximately 21 percent of its annual base load natural gas required secured under fixed price contracts.

II. Forecasting

A summary of PSO's Load and Demand, Fuel, and Purchased Power forecasting process is described below.

A. Load and Demand Forecasting

PSO has historically used two distinct methods for forecasting its annual kWh and will continue to do so for 2006. First, PSO uses regression models with time series error terms to forecast short-term kWh sales up to 18 months ahead. These models use the most recent customer count, kWh sales data, weather data (in the form of degree days), and indicator variables where needed. The models used are estimated and evaluated in an iterative process.

Second, the long-term kWh forecast uses econometric models incorporating an economic forecast to produce a forecast of annual kWh sales. The long-term process starts with an economic forecast provided by Economy.com for the United States as a whole, each state, and regions within each state. These forecasts include forecasts of employment, population, and income. Inputs such as regional and national economic and demographic conditions, energy prices, weather data, customer-specific information and informed judgment are all used in producing these forecasts.

To forecast peak and hourly kW loads, PSO uses a series of algorithms for distributing the monthly kWh sales to hourly demand. The inputs into forecasting hourly demand are kWh sales, transmission and distribution losses, weather, hourly load profiles, and calendar information. The output from the model includes hourly loads for PSO for the entire forecast period.

B. Fuel Forecasting

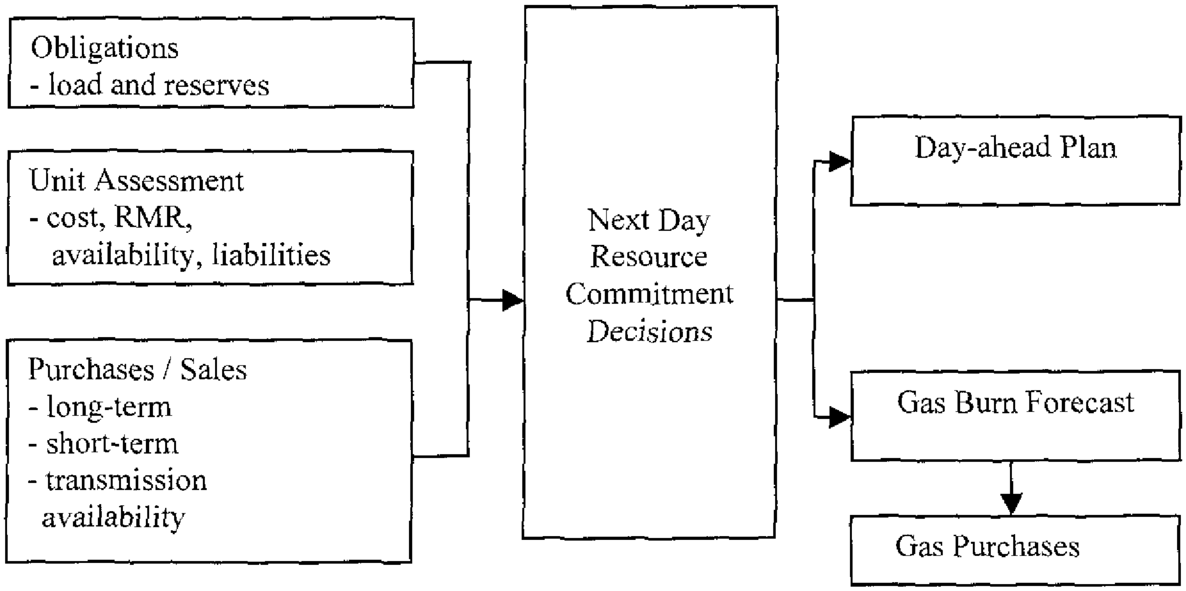
The fuel cost for each of PSO's generating plants is different and is based on the cost of fuel and related transportation costs to deliver the fuel to the plant. Coal prices are based upon the contractual pricing provisions contained in the coal supply and transportation contracts, with replacement and supplemental coal costs based on projected spot market prices for coal.

Natural gas projections are based upon the contractual pricing provisions contained in the varied term supply and transportation contracts and the trading prices of natural gas futures contracts from the New York Mercantile Exchange (NYMEX) for delivery at the Henry Hub, adjusted for transportation basis differentials applicable to PSO's geographic region and delivery points. PSO monitors the fuel markets daily and considers industry standard forecasts published by analysts such as Cambridge Energy Research Associates, Inc. (CERA), PIRA Energy Group, and the United States Energy Information Administration. Based on the Commission-approved settlement in PSO's most recent rate case, Case No. PUD 200300076, PSO's Fuel Adjustment Clause is provided to the OCC Staff on an annual basis.

C. Purchased Power Forecasting

American Electric Power Service Corporation (AEPSC), acting as agent for PSO forecasts hourly, daily, monthly, and annual loads for PSO. When making these forecasts, AEPSC uses historical load data for similar weather days in like seasons and adjusts the load forecast for subsequent changes in the magnitude and type of load served and current specific weather patterns. The load information and other data such as fuel prices, market power prices, scheduled generating unit outages, etc. are used to develop projections of fuel burn and power purchases for PSO. These projections are part of the day-ahead resource commitment process used for PSO, which is presented below in Illustration 6. While the day-ahead process must plan to meet peak demand for the day, PSO also uses that process to purchase and schedule energy to displace its own generation.

Illustration 6: Day-Ahead Resource Commitment Process

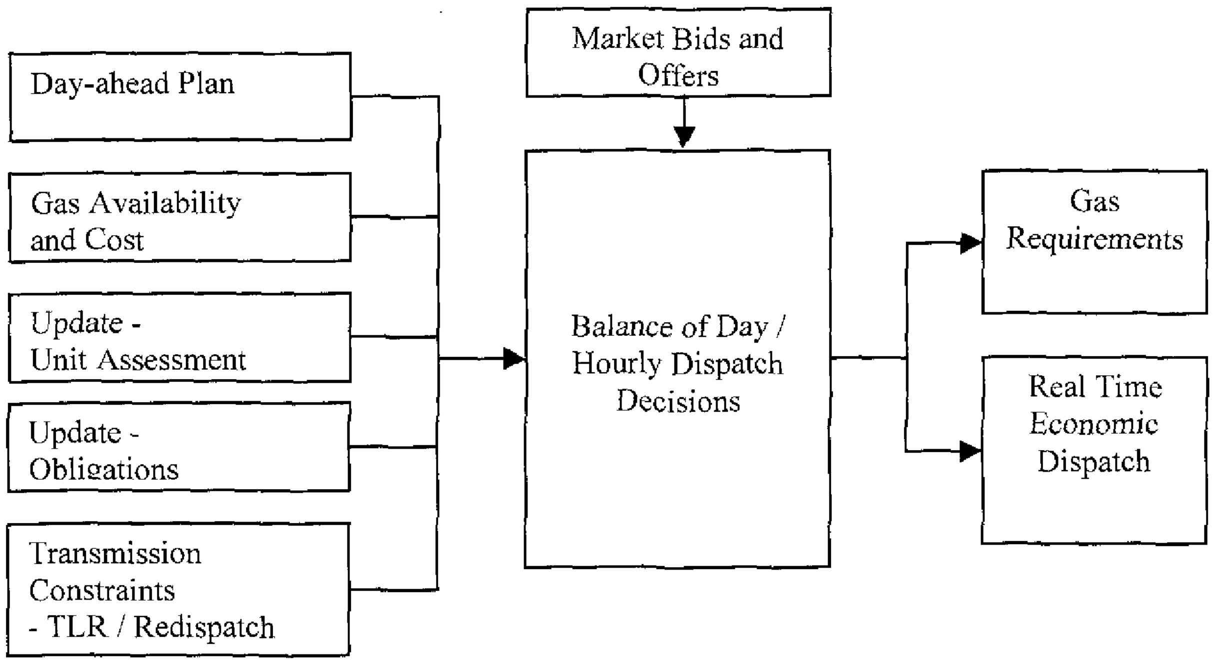


AEPSC uses a resource optimization program called GenTrader from Power Cost Incorporated (PCI) for weekly and daily optimization studies. AEPSC has received training for GenTrader from PCI during the installation and following any updates to the program. In addition, AEPSC has participated in a user group meeting sponsored by PCI.

This program uses plant heat rate curves, fuel costs, emissions costs, and load forecasts to predict an optimal hourly dispatch profile. By using the marginal cost output from this program, AEPSC can compare the cost of generating a block of energy to the cost of purchasing the energy from the market. The PCI forecasting program, as well as other decision support tools, is augmented by AEPSC knowledge and activity in the market and the arrangement of hourly, daily, weekly, monthly, and longer-term sales and purchases of energy.

In the intra-day market (real time), AEPSC hourly marketers, and generation dispatchers work closely to optimize the PSO system by taking into consideration opportunities to purchase energy in the market. If AEPSC has an offer from a reliable source of energy capable of being delivered to PSO's system at a price that is below the forecasted marginal generation (dispatch) cost, AEPSC purchases this economic energy whenever possible. Such purchases are part of the hourly and balance of day resource dispatch process outlined in Illustration 7 below.

Illustration 7: Hourly and Balance of Day Resource Dispatch Process



As a result of the active purchasing practices by AEPSC, energy purchases constituted 20.3 percent of PSO's energy supply (kWh) for the year 2005. These energy purchases benefited PSO customers because PSO was able to displace energy from its own higher cost natural gas-fired units. As the forecasted time period decreases, long-term to near-term, so too does the potential variability of load and uncertainty in fuel prices. Consequently, hourly energy purchases can be made with more certainty that they will be below PSO's marginal generation cost than can longer-term purchases of energy. As the time frame into the future increases, a wider range of load and fuel price projections must be taken into consideration when making energy purchase decisions.

The structure of any long-term energy purchases must be considered to continue to reflect the dynamic nature of PSO's system, reliability requirements and PSO's continuously changing load requirements. Purchased power for the peak days of Monday through Friday, other than hourly purchases, is typically under a flat schedule - offered and purchased on a standard 16-hour time frame for some period (daily, weekly, monthly, etc.). Also, variable weather leads to load variability on a daily basis. Forecasting inaccuracies, including unanticipated load changes, unexpected generation outages, and abnormal weather patterns, may lead to drastically different system costs over long periods of time, thereby increasing the possibility that energy cost associated with longer-term periods could be above PSO's hourly marginal generation cost.

III. PSO Generating Resources and System Capabilities

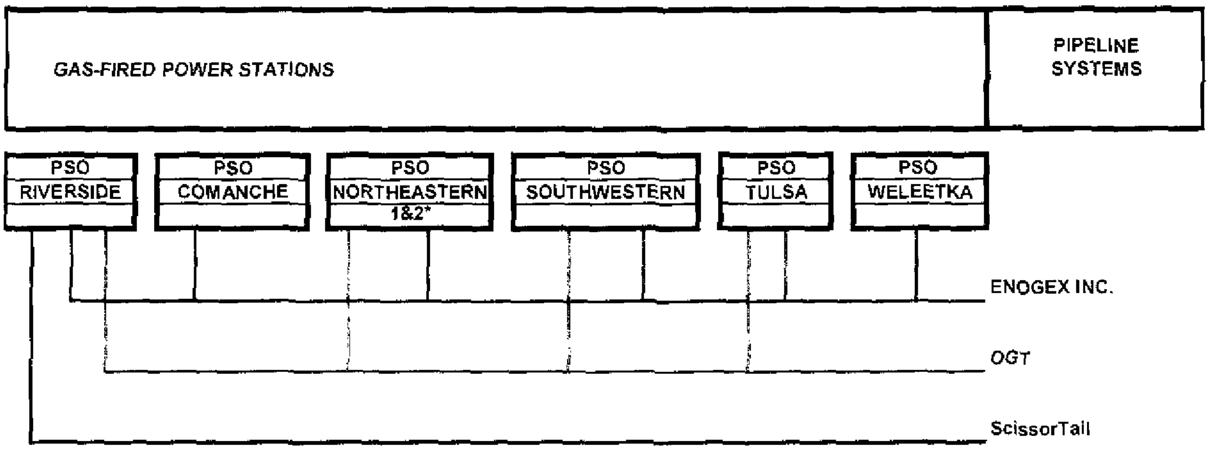
PSO's generating fleet is composed of two coal-fired power plants and six natural gas-fired power plants. These plants and their production capacity are as follows:

Power Plant	Fuel Type	Production Capacity (MW)
Comanche	Natural Gas	268
Riverside	Natural Gas	893
Southwestern	Natural Gas	449
Tulsa	Natural Gas	409
Weleetka	Natural Gas	167
Northeastern 1 & 2	Natural Gas	890
Northeastern 3 & 4	Coal	910
Oklaunion	Coal	108
Total		4,094

In addition, certain generating units at Riverside, Northeastern and Southwestern can also use fuel oil to generate electricity, and PSO maintains a limited quantity of fuel oil at these plants as an emergency back-up fuel supply. PSO can also burn natural gas at Northeastern 3 and 4 in the event of coal curtailments or coal-related equipment outages.

With the exception of Comanche and Weleetka, each of PSO's natural gas-fired plants is connected to at least two different pipeline systems, with Riverside being connected to three pipelines. These multiple natural gas pipeline connections provide the Company with access to reliable, flexible, and competitively priced natural gas supplies. The natural gas pipeline interconnections to each of PSO's natural gas-fired plants are shown below in Illustration 8.

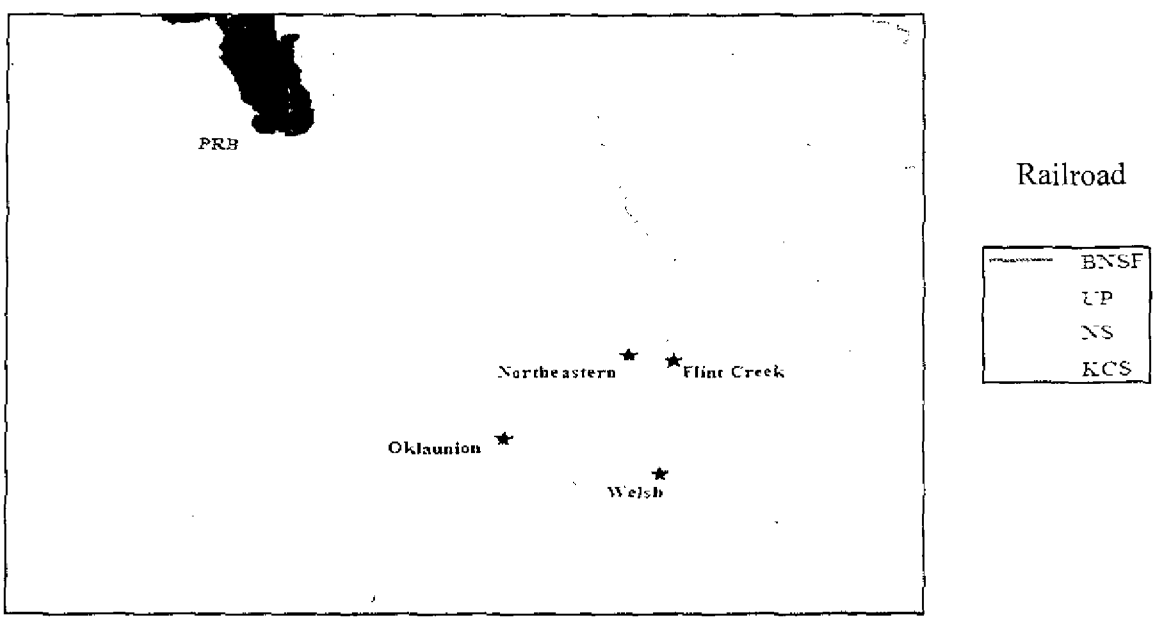
Illustration 8: Existing Natural Gas Pipeline Interconnections to PSO



* Includes gas for NE3-4 should it be needed.

Similarly, the Northeastern 3 and 4 coal units have access to two competing rail carriers for coal deliveries. The location of PSO's and SWEPCO's coal-fired generating plants relative to the coal supply region and rail transportation routes is provided in Illustration 9.

Illustration 9: Location of PSO & SWEPCO Coal Plants



IV. Comparison Between Available Alternatives

A. Methodology Discussion

Some of the various supply options potentially available to PSO are listed below. This list is intended to be comprehensive, yet it is not exhaustive.

1. Coal Procurement and Transportation Alternatives

- PSO could purchase all of its coal through long-term supply contracts, through spot market purchases, or through a combination of both.
- PSO's alternatives for coal transportation savings continue to include negotiating more economically favorable coal transportation contracts, and arbitrating or litigating adverse coal transportation contracts to provide greater flexibility to take advantage of lower priced base and spot coal.

2. Natural Gas Procurement and Transportation Alternatives

- PSO could purchase all of its natural gas requirements through fixed-price supply contracts for terms of one year or greater if there were suppliers willing to sell all volumes at a fixed price.
- PSO could purchase all of its natural gas requirements on the daily spot market if ample supplies were available.
- PSO could purchase its natural gas under index-priced supply contracts if suppliers were willing to commit to sales of natural gas, but not at a fixed price.
- PSO could purchase its natural gas requirements from a combination of fixed-price supply contracts having a term of one year or greater and daily spot market purchases.

- PSO could negotiate to have all its natural gas transportation requirements provided through firm service, which would guarantee that all of its requirements would be met at all times, if sufficient firm transportation capacity were available.
- PSO could secure interruptible service to meet its entire transportation needs if sufficient interruptible transportation capacity were available.
- PSO could purchase natural gas storage capacity if it were available in storage facilities connected to pipelines capable of delivery to PSO's generating plants.
- PSO could burn fuel oil as an alternative to natural gas in selected units, but would probably experience reduced generation output and peaking capability. Environmental issues may also arise if fuel oil is burned for an extensive period of time.
- PSO could co-fire the Northeastern 3 and 4 coal units with natural gas.

3. Risk Management

- PSO could use a diverse generation portfolio.
- PSO could hedge natural gas prices (including purchasing at a fixed price) to mitigate price volatility. Hedging does not, however, ensure a lower fuel cost and may increase the cost.
- PSO could provide customer choices that allow varying payments and varying power prices for customers.

B. Scenarios Relevance – Discussion

1. Coal Procurement and Transportation

- Purchasing all of PSO's coal through long-term, fixed-price supply contracts could result in suppliers demanding an economic premium, which could result in higher prices for PSO's customers. It would also prohibit PSO from taking advantage of coal spot market opportunities for any portion of its coal requirements.
- PSO could elect to purchase all of its coal on the spot market, but it would face the risk and uncertainty of not knowing whether it would have coal available to fulfill its commitment to provide adequate, reliable generation capacity to meet its customers' requirements.

2. Natural Gas Procurement and Transportation

- Purchasing all of PSO's natural gas through fixed-price supply contracts could result in suppliers demanding an economic premium to ensure a fixed price over a long period due to uncertainty in the market. This could result in higher prices for PSO's customers. At this time, even though PSO has requested fixed-price bids, some natural gas suppliers will not offer fixed-price contracts. The suppliers who will offer fixed prices require significant premiums for doing so. Also, because of changing market conditions, weather patterns, unit outages, power purchase opportunities, etc., it would be difficult for PSO to predict its long-term needs with precise accuracy. As shown previously in Illustration 1, PSO has significant variability in its daily natural gas burns.
- PSO could elect to purchase all of its natural gas on the daily spot market, and though these prices could be lower than purchases made on a longer-term basis, PSO would face the uncertainty of not knowing whether sufficient natural gas would be available

to fulfill its commitment to provide adequate, reliable generation capability to meet its customers' requirements.

- PSO could negotiate to have all its natural gas transportation requirements provided through firm service, which would guarantee that all of its requirements would be met at all times, but the price for such firm service would be prohibitive.
- Alternatively, PSO could secure interruptible service to meet its entire natural gas transportation needs, if sufficient transportation capacity were available. However, service reliability could be severely impacted, as the transporter would be able to curtail gas delivery to PSO at its discretion.
- PSO could purchase natural gas storage, if available, to meet its natural gas peaking requirements. However, prior evaluations have indicated that, due to the difficulty in anticipating peak hourly and daily requirements, it would be difficult for PSO to nominate its natural gas withdrawals in advance, and this has not evolved as a viable operational or economic alternative. Storage injections and withdrawals must be accomplished at a steady flow rate and are not responsive to the peaking demands of natural gas-fired electric generators.
- PSO could use fuel oil on a limited basis in some of its natural gas-fired generating units. However, fuel oil is generally a higher-priced alternative to natural gas and could decrease the flexibility and efficiency of plant operations. There are also environmental issues that need to be considered when fuel oil is burned for an extended period.
- PSO's Northeastern 3 and 4 are coal-fired units that have natural gas burning capability. PSO can co-fire with natural gas in these two units. However, in most, if

not all, instances, burning natural gas instead of coal would result in higher fuel costs for PSO's customers.

3. Risk Management

- PSO could and does use a diverse portfolio of generating assets, including economic energy purchases, as an effective physical hedge to ensure the lowest, reasonable fuel cost.
- PSO could use forward contracts and futures contracts (including fixed price contracts, if available) to hedge the cost of natural gas. Hedging is not, however, expected to reduce the cost of natural gas and may increase the cost.

V. Discussion of Fuel Resource Plan Selected

PSO's generation portfolio includes coal-fired, natural gas-fired and fuel-oil generation, as well as economic energy purchases. Additionally, PSO has entered into long-term wind energy purchases for fuel diversity and economic energy purposes. PSO optimizes available generation resources by first dispatching its lower cost coal units (and solid fuel units from SWEPCO when available to PSO), in addition to its Reliability-Must-Run units. PSO then uses natural gas-fired generation, along with purchased energy, to meet any base-load requirements which exceed coal-fired generation capabilities, to meet peak electrical demands, to replace coal capability during scheduled maintenance and forced outages, and to meet load-following and voltage-support requirements.

PSO (through AEPSC) forecasts hourly, daily, monthly, and annual loads to anticipate both its fuel and purchased power requirements. It then uses an algorithmic optimization model called GenTrader which uses heat rate curves, fuel costs, and load forecasts to predict dispatch costs. The output from this model, along with market price projections, is then used to optimize the PSO system and to identify opportunities in the purchased energy market.

A. Coal

PSO has an established coal and transportation procurement process that uses competitive bidding and market offers. The majority of the coal used as boiler fuel on PSO's system is obtained through long-term supply and transportation contracts, with the remaining portion of PSO's coal requirements purchased in the spot market. As it has done in the past, PSO will continue to evaluate its contracts and attempt to negotiate the most favorable terms whenever possible.

PSO maintains a coal inventory to be both proactive and responsive to known and anticipated changes in operating, coal supply, and rail transportation conditions. In addition, PSO's coal inventory mitigates risk and allows the Company to take advantage of favorable and timely coal purchases.

To further reduce coal costs, PSO will also continue to pursue efforts to reduce its coal transportation costs through its rail contract negotiations.

B. Natural Gas

PSO procures all of its natural gas supplies by competitive bids or competitive market offers. PSO uses a combination of annual, seasonal, and monthly base load supply contracts, and monthly and daily competitive bidding, to locate and optimize its natural gas purchase requirements. The types of natural gas purchases are identified in the table below.

Type of Purchase	Term	Bid Type	2005 Annual Requirement
Annual base-load	1 year or greater	Competitive Bid	38%
Seasonal firm	Greater than 1 month, less than 1 year	Competitive Bid	9%
Monthly base-load	1 month	Competitive Bid	21%
Daily incremental (next day, same day and no-notice)	Daily	Market Offer	32%

Actual weather, generating unit availability, and economic purchase power opportunities will impact these percentages for 2006. PSO's diversity in the types of purchases it makes reduces its exposure to potential daily price volatility and secures a reliable supply of natural gas. PSO is active in the daily natural gas markets and stays abreast of current market changes, including any new potential natural gas suppliers that can be solicited.

PSO currently intends to purchase its annual base load natural gas requirements, or approximately 38 percent of its natural gas (based on 2005 generation), under contracts having a term of one year or greater and the remainder of its requirements, 62 percent, on spot supply arrangements which would include seasonal, monthly base load, next-day, no-notice, and same-day natural gas, as needed. The amount of base load natural gas was determined by taking the average minimum daily burn (82,000 MMBtus/day) multiplied by 365 days (annual base load requirements) and then dividing by the total annual burn for calendar year 2005. PSO's natural gas purchases by transaction type for 2005 were previously provided in Illustration 1.

Historically, for the summer peak period of June through August, PSO entered into some seasonal, base load supply contracts to ensure deliveries of natural gas as a hedge against a shortage of supply rather than against a change in prices. For the summer of 2006, and in addition to its annual base load natural gas requirement of 82,000 MMBtus/day, PSO has obtained seasonal base load supply of 70,000MMBtu/day for the summer months of June, July, and August. PSO also obtained 5,000 MMBtu/day of short-term base load supply for the months of April, May, September, and October. PSO has historically obtained incremental daily call natural gas for June through August to ensure supply availability on projected high volume burn days, however, due to pricing considerations, PSO has not entered into arrangements for incremental call gas for the Plan Year (6/2006 thru 5/2007), although it still could do so should prices become more favorable. The reservation fees and adders to index for daily call gas proposals received from suppliers were excessive when compared to historical summer call gas transactions and the adders PSO is currently realizing in the daily gas market. PSO expects to secure less expensive gas supplies in the spot market.

PSO's plan for the winter of 2006-2007 is to start each month with a minimum of 82,000 MMBtus/day of annual base load natural gas and supplement that with monthly base load natural gas purchases obtained by competitive bid to meet forecasted minimum monthly requirements. PSO currently has approximately 21 percent of its annual base load natural gas requirements secured under fixed-price contracts to mitigate price volatility. Daily natural gas will be purchased on a competitive basis to follow projected changes in daily load.

PSO typically uses pricing based on the following natural gas price indices:

Monthly:	*Inside FERC* PEPL	Daily:	*Gas Daily* PEPL
	Inside FERC ANR		*Gas Daily* ANR
	Inside FERC OGT		*Gas Daily* OGT

In general, PSO cannot purchase natural gas below the index price. The index price plus the current market adder represents the market price for natural gas. PSO has seen a significant increase in market adders since the storms that occurred during the 2005 hurricane season and the increase of independent power producer natural gas use in Oklahoma, causing increased competition for the available natural gas. On occasion, PSO might have an opportunity to purchase a small package of natural gas below market. However, this is rare and would probably involve a distressed seller who needs to quickly dispose of a specific natural gas package.

Wherever possible, PSO uses competitive bidding and competitive market offers for natural gas transportation services. PSO negotiates transportation arrangements with connecting pipelines for swing service beyond its daily nominations to meet its peak hourly and daily demands. PSO currently has a firm transportation agreement with Enogex and interruptible transportation agreements with Enogex and OGT. PSO also has a direct connection with Scissortail Energy at the Riverside Power Station.

A schematic that reflects the various pipelines interconnected to each of PSO's power plants was provided earlier in Illustration 8. As the result of a competitive Request For Proposals, PSO and Enogex executed a long-term firm transportation contract effective January 1, 2003. In conjunction with the firm transportation agreement, an interruptible transportation agreement was negotiated at the same time to complement the provisions of the firm agreement.

PSO does not currently have any natural gas storage arrangements. Based on a prior Request for Proposal, PSO has determined that firm natural gas storage arrangements would cost approximately $1.00 per MMBtu above the commodity cost of the natural gas and the related transportation. Natural gas storage arrangements require withdrawals to be nominated in advance, and because PSO cannot anticipate its peak hourly and daily natural gas requirements, it is difficult for PSO to nominate its withdrawals in advance. In addition, the mechanics of the storage operations require a steady flow rate for withdrawals that is not responsive to the dynamic peaking requirements of PSO's natural gas-fired generating units. PSO's firm natural gas transportation contract allows for over- or under-burn quantities at a cost that is significantly below the cost of storage. PSO monitors the Oklahoma natural gas market on a daily basis, and will continue to monitor the storage issues and cost, especially if there are any indications of supply reliability issues. Through recent discussions with suppliers, PSO has confirmed that storage still does not represent an economical option for PSO.

C. Fuel Oil

During periods of high volatility in natural gas prices, PSO does daily comparisons between natural gas and fuel oil prices to determine the most favorable fuel price option and burns fuel oil when so indicated. Because fuel oil is not used as a primary fuel supply for PSO's power plants, PSO will continue to purchase its fuel oil requirements on the spot market, by competitive bid, on an as-needed basis. PSO procures its fuel oil through requests for written bids (or oral bids in emergency situations) from its fuel oil suppliers which are then reviewed and the lowest cost bid, with acceptable quality and delivery conditions, is selected.

PSO maintains fuel oil inventories at Riverside, Southwestern, and Northeastern for reliability purposes. The target inventory levels are:

Riverside Units 1 & 2:	80,000 barrels or 3½ days supply at 60% load
Southwestern Unit 3:	42,500 barrels or 3½ days supply at 100% load
Northeastern Unit 2:	23,500 barrels or 2½ days supply at 100% load

The Riverside plant is also connected to a pipeline capable of delivering fuel oil.

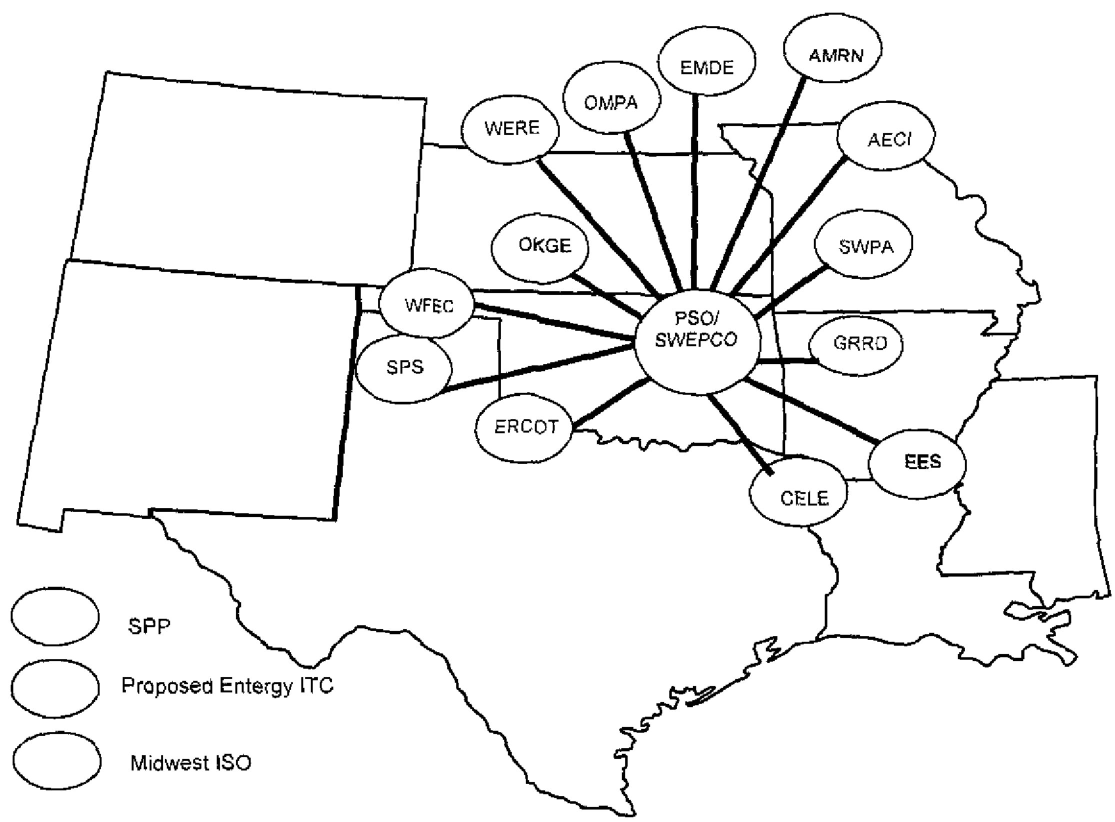
D. Purchased Energy

AEPSC, as agent for PSO, is engaged to trade with creditworthy energy companies that buy and sell over-the-counter electricity in SPP. AEPSC's production optimization group and trading group contact and use market offers from other utilities in the area, independent power producers, and marketing companies with generation assets in the region, and other marketing companies with a trading presence in the Midwest.

AEPSC has developed strong relationships with the SPP utilities, and has leveraged on the relationships with other utilities in the eastern interconnect. These relationships provide AEPSC and PSO with opportunities for commercial transactions that on occasion have provided flexibility in the scheduling process.

AEPSC has a wide coverage of the Midwestern section of the eastern interconnect and *the Electric Reliability Council of Texas (ERCOT) market which allows for numerous market* opportunities to purchase power. Illustration 10 provides the external control area ties to PSO.

Illustration 10: PSO/SWEPCO External Control Areas Ties



As previously discussed, as part of its day-ahead resource commitment process and its hourly and balance of the day resource dispatch process (Illustrations 6 and 7), PSO routinely purchases energy on an economic basis and displaces energy from its own natural gas-fired generation when it is able to economically and reliably able to do so.

E. Customer Programs

PSO has offered several programs to assist customers in managing their price volatility risk, including an average monthly payment plan and its Real Time Pricing tariffs which provide customers with choices in how to best use electric energy.

VI. Bill Projections and Comparisons

The tables below provide monthly bill projections for Summer 2006, and Winter 2006, as well as the previous year's information.

Winter Bill

Customer *Class and* Usage	**Bill* 2005**	**Actual Price–¢/kWh 2005**	**Estimated Bill* 2006**	**Estimated Price–¢/kWh 2006**	**Projected % Increase Per kWh**
Residential-1070 kWh	$ 75.12	7.02	$86.69	8.10	15.4%
Small Commercial-1760 kWh	$129.54	7.36	$148.73	8.45	14.8%

Summer Bill

Customer Class and Usage	**Bill* 2005**	**Actual Price–¢/kWh 2005**	**Estimated Bill* 2006**	**Estimated Price–¢/kWh 2006**	**Projected % Increase Per kWh**
Residential-1070 kWh	$84.09	7.86	$96.83	9.05	15.1%
Small Commercial-1760 kWh	$151.42	8.60	$172.51	9.80	14%

* Actual and estimated bill amounts include Base Service Charge, Energy Charge, FAC, IRCA Rider, Merger Savings Credit Rider (discontinued on 12/31/05), and Franchise Fee.

VII. Final Comments

As stated previously, any fuel procurement, and risk management plan must have multiple concerns or considerations for: *reliability, adequacy, flexibility, and price.* The foundation of PSO's risk management plan has been to have a diversified generation and supply portfolio, which includes coal-fired generation, natural gas-fired generation, fuel-oil generation, and wholesale energy purchases. Each of these commodities is procured under a competitive bidding and competitive market offer process. This includes energy purchases to displace energy from PSO's own-generation when it is able to do so, both economically and reliably. PSO's fuel supply plan and portfolio are balanced, yet flexible, which allows PSO to appropriately respond to changes in the fuel supply and purchased energy markets, thereby ensuring a reliable fuel supply at the lowest reasonable cost. As markets develop and change, PSO will review its fuel procurement activities, and modify them as appropriate, to ensure that any fuel procurement and risk management plan continues to meet the standards of reliability, adequacy, flexibility, and reasonable cost.

VIII. Contact Information

For questions or additional information, please contact:

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The Southwest Power Pool ("SPP") has the responsibility for assessing the adequacy of the regional transmission system, and PSO's transmission planning staff fully participates with SPP in their transmission planning activities. The 2006 SPP Regional Expansion plan has not been published as of this date but the scope of the Plan is described in Attachment A. The SPP 2006 plan applies to a ten-year planning horizon, from 2006 to 2016.

The 2005 SPP Expansion plan is included as Attachment B. It covers the period from 2005 through 2010, but does give consideration to conditions for a ten-year period.

In addition to the SPP regional planning process, PSO's transmission planning group independently assesses the transmission system and produces a report. The report is confidential, contains market-sensitive information and is not publicly available. The report will be provided upon request under the terms of a protective order.

PSO's proposed transmission lines and substation projects for the years 2007 through 2014 are listed in Attachment C. The locations of these facilities have been redacted. The locations will be provided under the terms of a protective order.

ATTACHMENT A

Southwest Power Pool (SPP) Expansion Plan
2006 Proposed Scope

Introduction
The main objective of the SPP RTO Expansion Plan is to create an effective long-range plan for the SPP footprint which identifies NERC, SPP and local planning criteria violations and develops appropriate mitigation plans to meet the reliability needs of the SPP region. In addition, projects which may produce an economic benefit to the stakeholders in the SPP footprint are also evaluated. This process consists of the following steps:

1. Identification of the reliability based problems (NERC, SPP and local criteria violations)
2. Comprehensive assessment of known mitigation plans, and
3. Development of additional mitigation plans to meet the needs of the region and maintain NERC, SPP and Local reliability/planning standards, and
4. Identification of other projects that may provide economic benefit to the system.

The process is an open process and allows for stakeholder input. All study results through the planning process are being coordinated with other entities/regions responsible for transmission needs assessment/planning.

Expansion Plan Objectives
Reliability Planning

- SPP shall plan the SPP Transmission System to meet:
  - NERC Reliability Standards
  - SPP Criteria
  - Local Planning Criteria as requested by Transmission Owner(TO)
- Address additional needs of the region
- Assess mitigation plans proposed by TO (Operating guides and/or new facilities)
- SPP shall track planned system upgrades to ensure reliability projects are built in time to meet the needs of the system. This will be accomplished through the SPP Project Tracking process.
- SPP shall coordinate regional transmission plans with neighboring entities, regions and RTO's.

Market Need & Economic Benefit Screening

- SPP shall identify projects for potential system reinforcements that may provide an economic benefit to the system.

Assumptions for Reliability Assessment

Load Flow Models

- SPP shall use the SPP MDWG 2005 Series 2007 Summer Peak, 2007/8 Winter Peak, 2011 Summer Peak, 2011/12 Winter Peak and 2016 Summer Peak cases with updates from nearby regions and entities. The cases shall be modified as follows to create the Base Cases for the Expansion Plan:
    - Treatment of transmission owner -Initiated Projects
        - SPP shall remove transmission owner initiated projects within SPP that have a start of construction date beyond January 1, 2008. In the event that there is a question from the initiating transmission owner regarding the January 1, 2008 cutoff date for removal of projects, SPP staff will approve exceptions.
        - All Proposed and Exploratory projects shall be removed from the models
    - Treatment of previous SPP RTO Expansion Plan Projects
        - SPP staff shall remove previous SPP RTO Expansion Plan projects that have a start of construction date beyond January 1, 2008. In the event that there is a question regarding the January 1, 2008 cutoff date for removal of projects, SPP staff will approve exceptions.
    - Treatment of SPP Aggregate Study (Attachment Z) Projects
        - SPP staff shall remove SPP Aggregate Study Projects that have a required start of construction date beyond January 1, 2008. In the event that there is a question regarding the January 1, 2008 cutoff date for removal of projects, SPP staff will approve exceptions.
        - SPP staff shall include all SPP Aggregate Study Projects that have signed contracts and have an in-service date prior to January 1, 2008.

Stability Models

- SPP Staff shall use the SPP 2005 Series MDWG 2007 Winter Peak stability model.
    - Remove Proposed and Exploratory projects
    - Include all SPP Aggregate Study Projects that have signed contracts and have a completion date prior to January 1, 2008.

Methodology for Reliability Assessment

Steady State Analysis

- Monitoring of Facilities
    - SPP staff shall monitor all facilities in the SPP footprint 69 kV and above.
    - With the exception of Entergy (EES) and Associated Electric (AECI), SPP staff shall monitor all facilities in first tier control areas 230 kV and above. Within EES and AECI, facilities shall be monitored at 100 kV and above.
- The 2007 Summer Peak case and 2007/8 Winter Peak case shall be used to help time projects prior to 2011

- Summer Peak Analysis – Contingency analysis shall be performed on the 2011 Summer Peak case (including all transaction cases) and the 2016 Summer Peak case (including all transaction cases).
  - All NERC Reliability Standard for transmission planning, Table 1 category B contingencies 69 kV and above in SPP will be evaluated. These contingencies do not include manual transfer of load or manual switching.
  - All NERC Reliability Standard for transmission planning, Table 1 category B contingencies 100 kV and above in EES and AECI will be evaluated.
  - For other first tier areas, all NERC Reliability Standard for transmission planning, Table 1 category B 230 kV and above contingencies will be evaluated.
  - SPP will verify that all violations identified have reinforcement plans
  - SPP will verify that all category A and B violations identified have reinforcement plans
- Winter Peak Analysis – Contingency analysis shall be performed on the 2011/12 Winter Peak case (including all transaction cases
  - All NERC Reliability Standard for transmission planning, Table 1 category B contingencies 69 kV and above in SPP will be evaluated. These contingencies do not include manual transfer of load or manual switching.
  - All NERC Reliability Standard for transmission planning, Table 1 category B contingencies 100 kV and above in EES and AECI will be evaluated.
  - For other first tier areas, all NERC Reliability Standards for transmission planning, Table 1 category B 230 kV and above contingencies will be evaluated.
  - Within SPP, automatic bus outages for 345 kV and above buses (Bus section C-1) will be conducted TO will verify if the contingency is valid.
  - Within SPP, automatic double lines outages from 345 kV buses (Breaker failure C-2) will be conducted. TO will verify if the contingency is valid category C and D contingency list which shall also include tower outages.
  - SPP will verify that all category A, B and C violations identified have reinforcement plans

Stability Analysis

- SPP staff shall provide a list of past studies to stakeholders to determine what contingencies to evaluate.
- Stakeholders shall provide SPP staff a priority list of category B, C and D contingencies to evaluate.
- Based on recommendations from stakeholders, SPP staff and TWG shall determine the appropriate contingencies to evaluate.
- The 2007/08 Winter Peak stability case shall be used to evaluate the stability of the system

Voltage Stability Analysis

- Stakeholders shall provide input to SPP staff regarding potential voltage stability problems.
- SPP staff will screen for stability problems by reviewing load flow results for low voltage, non-converged cases, and voltage deviations of 5%.
- SPP staff and TWG will determine what contingencies to evaluate using either a PV or QV analysis.
- SPP staff will perform a reactive margin/reserve study
    - Use 2011 Summer Peak base case, and list VAR reserves in each control area.
    - Use 2011 Summer Peak base case and produce additional cases by removing the largest unit in significant load areas.
    - SPP staff will screen the above cases for potential voltage stability problem by running 230 kV and above contingencies for all facilities in the SPP footprint.
    - SPP staff will identify generators that are at their var limits.
    - SPP staff will perform a P-V analysis on selected contingencies, as identified by the screening analysis.

Use of Operating Guides

- The Steady State analysis will identify all violations without the use of operating guides/directives.
- Operating guides/directives may be used as alternatives to planned projects. Load flow analysis will be performed to determine the effectiveness of the operating guide in alleviating the violation(s).
- SPP staff will determine all reinforcements that are needed to eliminate operating guides/directives used in alleviating violation(s). A list of reinforcements that are no longer required due to operating guides will be included in the report.

Market Need & Economic Benefit Screening

- Solicit stakeholder input
- Conduct preliminary screen of projects
- Post results
- Additional investigation and study will be conducted once interest has been expressed (willingness to build)

ATTACHMENT B

Southwest Power Pool

SPP RTO Expansion Plan 2005-2010

Prepared by SPP Staff
SPP Engineering Planning

As approved by TWG: September 14, 2005

Table of Contents

History

Southwest Power Pool, Inc. (SPP) has been involved in regional planning for decades. SPP did not wait for Regional Transmission Organization (RTO) designation to formalize a more comprehensive, open and transparent planning process to address transmission expansion needs within the SPP footprint. The SPP Open Access Transmission Tariff (OATT) contains procedures in Attachment O describing the coordinated planning process.

The Transmission Working Group (TWG) has been assigned primary responsibility for the regional planning process. The TWG consists of both transmission owning and non-transmission owning members. Meetings are open and agendas are posted on the SPP web site (www.spp.org). SPP stakeholders are encouraged to actively participate in the regional planning process to ensure that the recommended expansion plans are the best solutions in and around the SPP footprint.

SPP, as a regional reliability council, has coordinated planning for many years. SPP staff has historically performed regional assessments of the transmission system and coordinated studies for SPP transmission owners. This process was included in the Tariff upon the addition of long-term transmission service on April 1, 1999.

SPP has performed or participated in many recent regional expansion studies. During 2000, SPP began a Bulk Extra High Voltage (EHV) Transmission Study. This study identified potential upgrades to relieve known constraints in the SPP region. The Bulk EHV Transmission Study was completed in two phases during 2001. SPP then followed up that study by participating in the Midwest ISO Transmission Expansion Plan (MTEP) during 2002 and 2003. Up until the MISO-SPP merger termination in early 2003, SPP staff and resources in Little Rock provided leadership and significant support to the MTEP effort. The initial MISO study was completed in June of 2003 with SPP considered as a sub-region. SPP continues to support model building efforts and inter-regional studies with neighboring North American Energy Reliability Council (NERC) regions and other entities responsible for the planning and operations of the bulk electric transmission system.

It is important to note that SPP's planning process has been effective in planning and expanding the transmission system in the past several years. SPP has maintained a reliable transmission system through active review and engineering assessment. SPP has upgraded 45 transmission facilities through the regional Tariff in the five years this process has been in place. A prime example of the effectiveness in regional planning was SPP's ability to upgrade the LaCygne-Stilwell 345 kV line. In only 27 months, the project went from concept to completion and full cost-recovery without impact to retail or wholesale customers. This line was identified as one of the key constraints in the Eastern Interconnection in the Federal Energy Regulatory Commission (FERC) 2001: *Electric Transmission Constraint Study,* Division of Market Development. LaCygne-Stilwell was the only SPP facility identified as a limit in the study. SPP transmission owners, through the regional planning process, reached agreement on benefit and cost support to upgrade this key limitation [FERC Docket ER03-547-000]. An innovative transmission upgrade approach was used, and construction was completed ahead of schedule, providing for increased SPP reliability and transmission system capacity for 2003 and beyond. The LaCygne-Stilwell upgrade would not have occurred without a functioning regional planning process.

SPP as an RTO is responsible for planning and for directing or arranging necessary transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service. It also coordinates such efforts with appropriate state authorities. SPP has been proactive in its transmission expansion planning efforts which continue to evolve over time. In November 2003, SPP formally kicked off its new, expanded process at the first SPP Regional Planning Summit.

SPP, through the TWG, has designed a formal process for planning and expansion that encourages open participation for market-motivated solutions to relieve congestion. SPP staff is responsible for development of the SPP RTO Expansion Plan. SPP continues to work with state regulatory agencies and legislators to ensure that the regional planning process addresses all needs. With time, the Regional State Committee (RSC) is more involved in the transmission expansion planning process at SPP. The SPP planning and expansion process will be coordinated and integrated with programs of existing regional transmission groups.

SPP has a history of coordination with existing regional transmission groups through its efforts with coordination agreements and information exchange, and SPP will continue these activities as an RTO. This coordination is demonstrated by SPP's past and continuing participation with the MTEP as well as with Southeastern Electric Reliability Council's VST model building efforts. The SPP RTO Expansion Plan includes all transmission facility expansion in the region and attempt to assess the combined effect on loop flows and reliability of all existing and planned facilities.

In early 2004, SPP initiated a special study of transmission expansion plans for the Kansas/Panhandle sub-region of SPP. SPP staff continues to evaluate the benefits of several EHV transmission expansion projects to improve imports/exports for the Kansas/Panhandle sub-region which has significant potential to provide demand and energy from wind farm developments. SPP is expanding its capabilities with the recent installation/training of PowerWorld and Global Energy's MarketSym tools for evaluating the market and commercial benefits of system expansion alternatives.

Much has happened recently regarding planning at SPP. In fact, FERC in their initial order regarding SPP's RTO filing was supportive of SPP's planning efforts (Dockets RT04-1-00 and ER04-48-00). The FERC order in paragraph 185 states:

> *We commend SPP for its efforts in updating its transmission planning and expansion process. SPP is currently reviewing this function with an eye toward making the process more open and participatory and is evaluating a two-year planning cycle with the first year's focus on reliability and the second year's focus on market needs. The current draft of this cycle calls for approval of the transmission plan on September of the second year.*

> *We believe SPP's efforts here are a critical first step toward a regional assessment of transmission needs and strongly support its proactive efforts.*

The SPP RTO expansion planning process will continue to evolve as SPP moves forward as an RTO. SPP has created a dedicated webpage at http://www.spp.org/Objects/Engineer.cfm to post numerous public documents regarding the SPP RTO Expansion Plan and analysis results. All stakeholders are required to fill out a stakeholder ID form, sign a confidentiality agreement and return the forms to SPP to obtain access to the regional planning models and project data that are shared on SPP's E-Room.

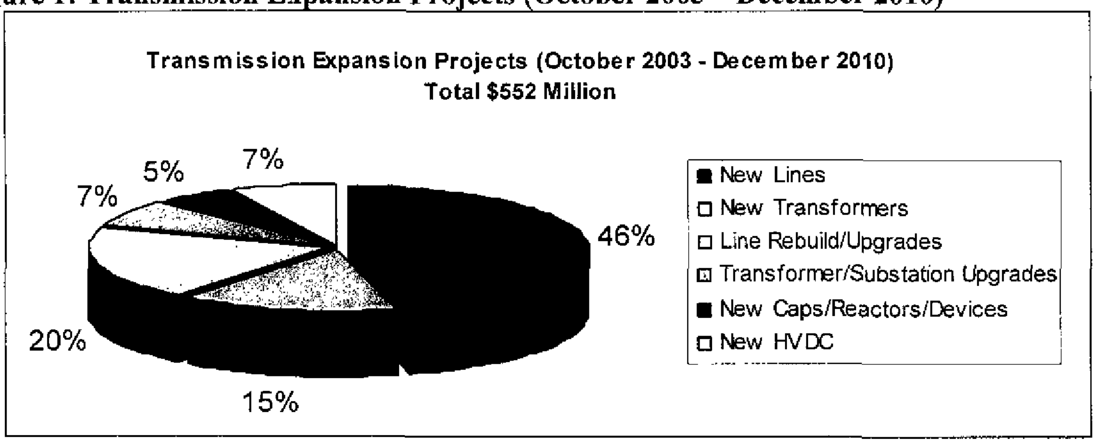
SPP management has stated that a key RTO objective is transmission expansion opportunities. System expansion that is needed to address reliability requirements, as well as provide economic benefits, will be developed and implemented in an efficient and effective manner as a result of the SPP RTO Expansion Plan.

Executive Summary

SPP began the initial RTO expansion planning process in late 2003. The SPP RTO expansion planning process is open and collaborative using regional planning summits to present the process, discuss results and collect feedback. The regional planning summits were well attended by a variety of attendees including: regulators, SPP transmission owners, transmission owners from other regions, members of the Wind Coalition, load serving entities, consulting firms and independent system operators.

Phase I of this report, titled *SPP RTO Expansion* Plan, SPP addressed reliability violations and recommended projects to meet planning standards. The projects identified in Phase I span October 2003 through December 2010, and the SPP system requires an investment totaling $552 million. The estimated line mileage for new transmission lines for this period totaled 634 miles, while rebuilds/upgrades totaled 646 miles. The project types are illustrated in Figure 1.

Figure 1: Transmission Expansion Projects (October 2003 – December 2010)



The major 345 kV projects over the study period are as follows:

- 105 mile Finney-Lamar 345 kV line and high voltage direct current (HVDC) tie – December 2004
- Oklahoma Gas and Electric Company (OGE) Draper 345/138 kV transformer – June 2005
- American Electric Power (AEP) 14 mile Chamber Springs-Tontitown 345 kV line – June 2007
- AEP 22 mile Flint Creek-East Centerton 345 kV line – June 2010

Only 100 kV and above contingencies were evaluated; as a result, the $552 million project cost does not include all 69 kV projects required to meet the planning standards. New or advanced projects identified by the SPP RTO Expansion Plan process equal $172 million of the $552 million.

A market assessment was conducted during Phase II of the SPP RTO Expansion Plan to determine potential projects for system reinforcement. Potential projects were identified from a variety of resources including stakeholder feedback, review of past transmission line loading relief, refused long-term transmission reservations and suggestions from summit participants during the Planning Summit III. Thirty three projects were screened to determine the top four projects with the best cost to benefit ratio. These projects were further studied by doing complete seasonal economic runs for 2005 and 2010. The top four projects are as follows:

- Tulsa East Switching Station
- Sooner-Cleveland 345 kV line
- Rose Hill-Sooner 345 kV line
- Tolk-Potter 345 kV line

Detailed analysis of the four projects showed that the projects each have approximately 10-year return on investment. The Sooner-Cleveland 345 kV line had the best cost to benefit ratio. Summit participants showed interest in all four projects. A proposed economic upgrade process was presented at the Regional Planning Summit IV.

At Summit IV, it was recommended that an Economic Modeling and Methods Task Force be formed. This task force will review basic model assumptions, solution techniques, etc. and make recommendations for improvements to future economic planning analyses.

SPP intends to publish the SPP RTO Expansion Plan after receiving approval from the Board of Directors during the fourth quarter of 2005. Through the collaborative process, the Transmission Working Group (TWG) has overseen the development of the plan and will present a draft to the SPP Markets and Operations Policy Committee (MOPC). After review by the MOPC, the plan will be presented to the Board for approval. The Board approved Phase I of the SPP RTO Expansion Plan in April, 2005.

After initial review of Phase I, SPP recommended changing the two year planning cycle to 18-months. Figure 50 shows the proposed 18-month SPP RTO planning cycle. Under the new process, the SPP Board would approve the reliability projects within one year from the study start date. Another key item of the new 18-month cycle is the first cycle will be in sync with the SPP Model Development Working Group (MDWG) model building effort, whereas the second cycle will use Models on Demand (MOD).

Appendix A of this report contains a list of all projects. The projects are divided into three categories including Board approved projects (Phase 1 – April 2005), approved out of cycle projects and out of cycle projects pending evaluation. The project lists will be revised quarterly to include project updates.

Phase 1: Reliability

Introduction and Scope of Analysis

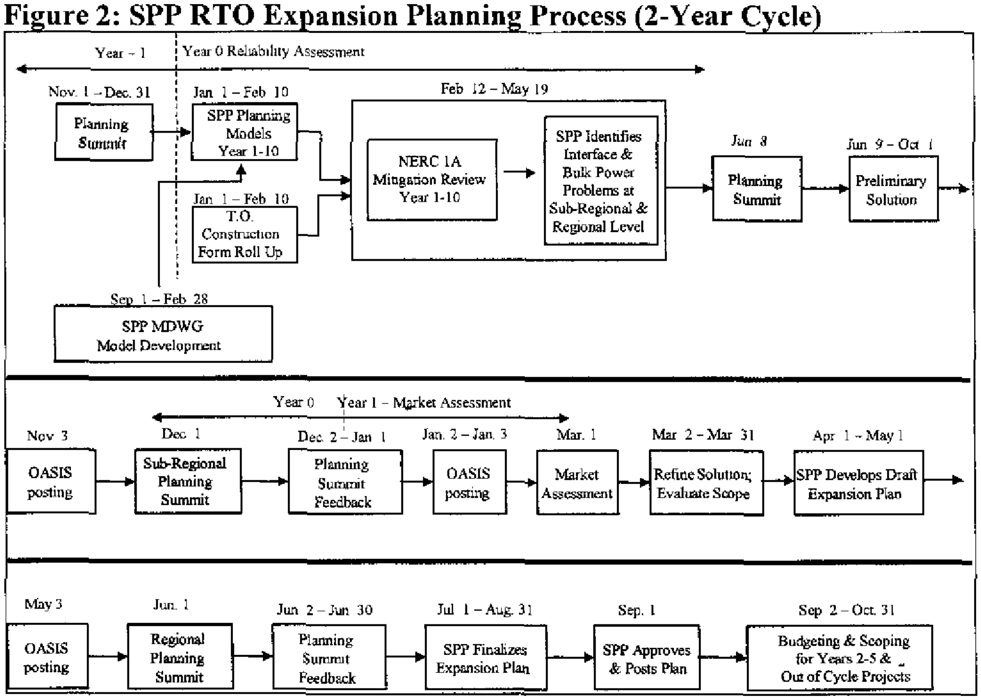
Introduction

SPP adopted a two-year planning cycle. The planning cycle and important milestones are illustrated on Figure 2. SPP intends to shorten the planning cycle as the planning process matures.

The SPP expansion planning process is open and participatory, and stakeholder inputs are welcomed. The basic premise of the expansion planning process is to ensure transmission system reliability through compliance with planning criteria while creating an effective long-range plan. The long-range plan includes a comprehensive assessment of mitigation plans to maintain planning standards.

The SPP RTO Expansion Plan is divided into two phases. Phase I of the SPP RTO Expansion Plan focuses on reliability needs, and Phase II weighs market needs related to an economic expansion plan. All study results are being coordinated with other entities responsible for transmission needs assessment and planning.

Figure 2: SPP RTO Expansion Planning Process (2-Year Cycle)



Models and data created for the planning process are stored in SPP's non-public E-Room. SPP members are bound by SPP Bylaws, Membership Agreement and Code of Conduct. Non-members are required to sign a Non-Disclosure Agreement to receive study models and results. Non-members are also required to fill out an identification form to access the data and models.

Scope

Phase 1 is intended to provide an independent assessment of expansion plans required by SPP in order to meet NERC, regional and local planning standards. The study will review the summer peak conditions for 2005 through 2010. Major projects recommended through the reliability assessment are also being evaluated for 2013 summer peak conditions to verify the long-term effectiveness of these projects.

Model updates are performed at the beginning of the planning process. SPP members provide model updates through the SPP MDWG model-building process. The SPP MDWG 2004 models (update two) were used as the starting load flow model. Outside regions provided model updates to SPP. Updates were made to both the stability and load flow models. In addition to the base models for 2005 and 2010 summer peak, SPP created additional load flow models that include long-term firm, confirmed reservations plus rollovers that are not usually modeled in the base models. If these transactions were scheduled they cause a bias across the SPP region. Many of these transactions cross the SPP interfaces. Three scenarios were created for each test year, first being transaction case one (T1) which simulates a west to east bias flow, second being transaction case two (T2) which simulates an east to west bias flow and third being transaction case three (T3) which is a hybrid flow that consists of west to east bias and Southwestern Public Service (SPS) importing.

A consistent treatment of projects within the SPP footprint and neighboring systems was required before performing a reliability needs assessment. Three project categories were proposed by SPP staff – planned, proposed and exploratory.

- Planned – A planned project is driven by system needs and is the recommended solution among all evaluated projects. Planned projects are commitments that have little, if any, outstanding issues that could delay implementation past the expected in-service date. Planned projects should be included in load flow as part of the baseline. Typically, planned projects would not require pending approvals such as budget, permitting, site or regulatory. In addition, equipment procurement and installation are not of concern.

- Proposed – A proposed project is one for which a need has been identified and is the best-known alternative but has not yet received adequate approvals. A proposed project would not be included in the baseline load flow but would be considered when evaluating solutions to identified problems. Such projects have been identified as preferred solutions but have yet to receive budgetary, siting, permitting, regulatory or other necessary approvals. Equipment procurement and installation are not a concern for proposed projects.

- Exploratory – An exploratory project is one for which a system need has been identified but alternatives and details have not been fully investigated. Exploratory projects would not be included in the baseline load flow but would be considered when evaluating solutions to identified problems. Exploratory projects are conceptual in nature. They are typically visionary EHV transmission projects for addressing potential system needs. These projects have little, if any, approvals. Despite these unknowns, procurement and installation of the project by the target need date should not cause concern.

All of the proposed and exploratory projects that were in the model and part of the model update process were removed. This was done to test the system and determine the appropriate reinforcement. The proposed and exploratory projects, as well as other projects recommended by stakeholders and SPP staff, provided a pool of possible solutions to the identified problems. Expected system reinforcements that met the definition of planned projects were incorporated into neighboring regions' MMWG models to create a consistent baseline topology for SPP's reliability assessment.

Contingency Simulations

Transmission facilities in the SPP footprint along with first tier companies were tested using NERC Table 1A guidelines. Updates to the contingency list were received from SPP members and first tier companies. NERC defines system outages in four different categories:

Category A: System intact, no disturbance
Category B: Loss of a single element
Category C: Loss of two or more elements (normal clearing, manual system adjustments between events), bus fault, single line to ground (SLG) fault with breaker failure, etc.
Category D: Extreme events, loss of two or more elements, three-phase fault with breaker failure, loss of tower with three ore more circuits, loss of all generation in a station, etc.

SPP uses the most restrictive criteria for contingency analysis. If a transmission owner has more restrictive criteria than the SPP or NERC criteria, SPP will perform the analysis using the transmission owner's criteria. For example, SPP's voltage criteria requires load serving bus voltages to be in the range of ±10% of nominal voltage for Category B outages, while Kansas City Power and Light (KCPL) has requested SPP monitor KCPL's buses for ±5% of nominal voltage for a Category B outage. However, Westar requested that SPP use the SPP criteria rather than Westar's more restrictive criteria because this was a regional study.

Contingency analyses were performed for facilities above 100 kV, all generators in SPP, Associated Electric Cooperative, Inc. (AECI) and Entergy. Contingency analyses were also performed for facilities above 230 kV in SPP's first tier control areas as well as other first tier companies. Modeled facilities 69 kV and above were monitored for overloads and voltage violations in SPP. SPP monitored Entergy and AECI facilities above 100 kV plus other first-tier companies with 230 kV and above.

Stability Simulations

SPP solicited input from stakeholders and transmission owners to list potential stability simulations. Stability analyses were performed on the more severe Categories C and D outages. Knowing that stability analysis requires a great deal of time and resources, SPP staff requested the help of SPP stakeholders at TWG meetings to prioritize the list of stability simulations.

Fault Study

A basic three-phase fault study was performed on locations where system improvements were proposed. Results were shared with transmission owners to determine whether further fault studies are required. It is important to note that breaker replacements, due to an increase in fault currents, have not been included in the final list of SPP expansion projects.

Findings

The results in this section reflect the findings discovered using 2005 summer case and 2010 summer case peak load simulations. No attempt was made to identify when reliability violations would occur between 2005 and 2010. Project timing was determined in the solutions phase of the planning process.

Stability Findings

SPP reviewed the list of past studies completed by transmission owners and other reliability organizations. SPP also assessed the list of requested Categories C and D contingencies provided by stakeholders. After reviewing this information, SPP determined nine contingencies to be evaluated in more detail. Eight of the contingencies are to be evaluated for dynamics stability and one for voltage stability. Six of the contingencies were NERC Category C events and three were NERC Category D events. The stability simulations show that one of the Category C and one of the Category D contingencies would be unstable. It was determined that the unstable Category C would be stable with the use of an operating procedure. For the unstable Category D contingency, it was determined that due to the low probability of the event occurring and the fact that it posed no regional security problem, no action was recommended.

Summary of Load Flow Findings

SPP evaluated 7,775 contingencies in the load flow study. This study identified numerous criteria violations. Figures 3-10 summarize the results of the contingency simulations. Note: for Category A, facilities are monitored against Rate A while buses are monitored with voltage criteria of 0.95-1.05 per unit. For Category B, C and D outages, facilities are monitored against Rate B while buses are monitored with voltage criteria of 0.90-1.10 per unit. Incremental overloads and voltage violations due to transaction cases are also summarized.

Figure 3: NERC Category A Overload Summary – shows the number of NERC Category A overloads violation by voltage for the base and transaction cases.

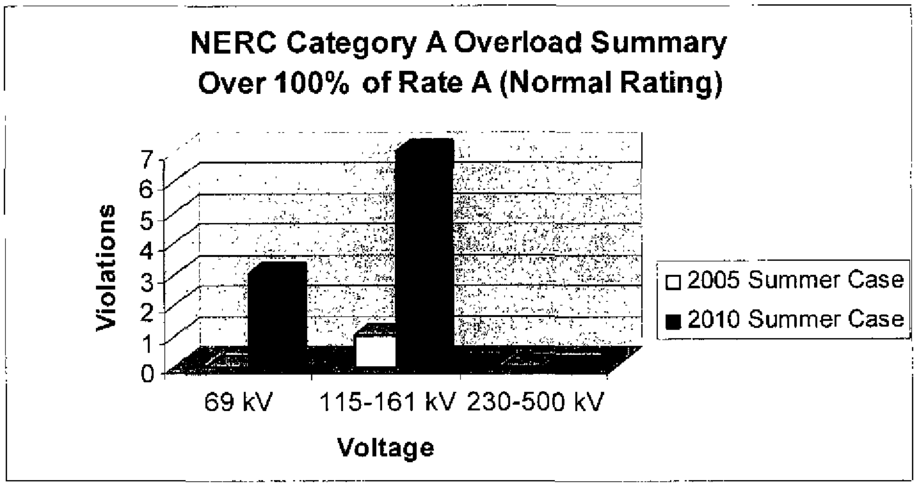


Figure 4: NERC Category A Voltage Violations Summary – shows the NERC Category A voltage violations for the base case and transaction cases for 2005 and 2010 summer cases.

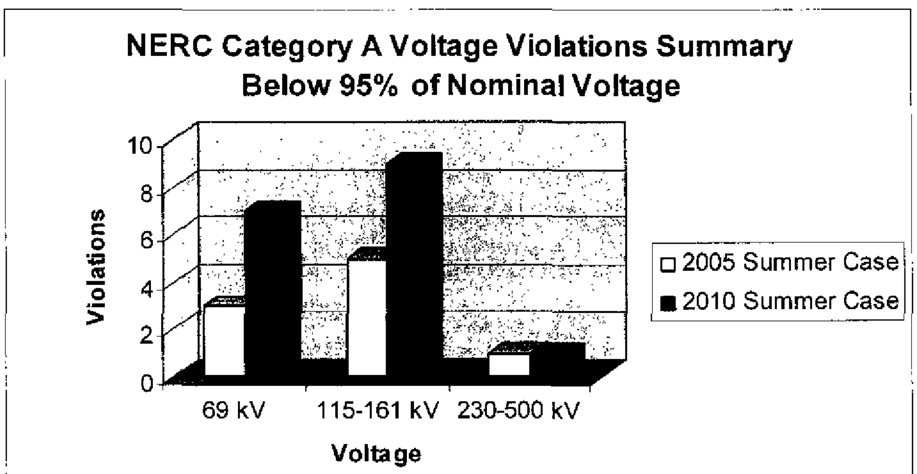


Figure 5: NERC Category B Overload Summary – depicts the NERC Category B overload violations (n-1 contingencies) for the base case and transaction cases. As illustrated in Figure 5, the number of violations increases with time and the greatest number of violations occurs at the 69 kV voltage level.

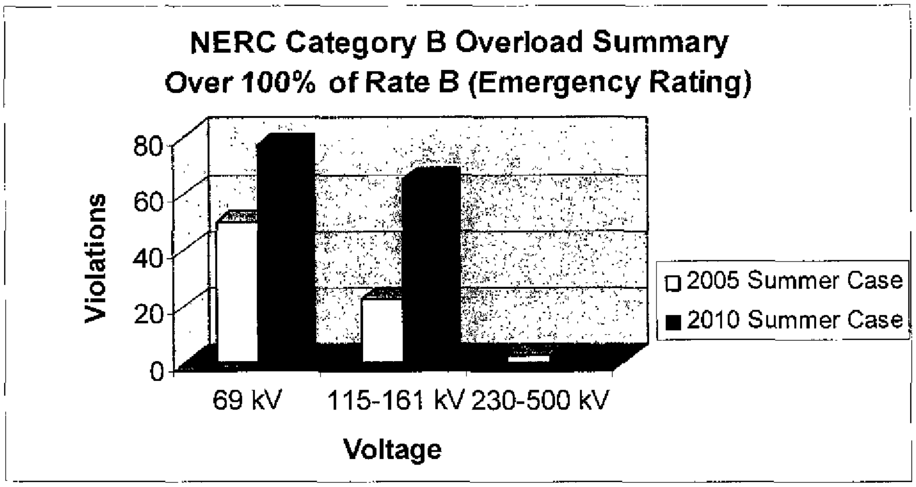


Figure 6: NERC Category B Voltage Violations Summary – shows the NERC Category B voltage violations for 2005 summer case and 2010 summer case for the base case and transaction cases. More violations are identified in 2010 than in 2005.

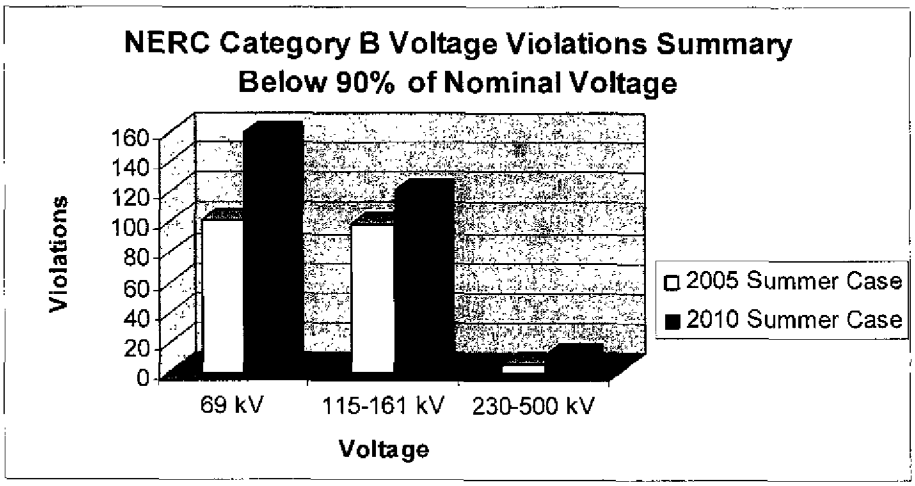


Figure 7 and Figure 8 show the number of NERC Categories A and B incremental violations that were identified by transaction cases not identified by the base cases. The x-axis identifies the case and the NERC category. For example, 2005_A indicates it was 2005 case and NERC Category A. As expected, the transaction cases did increase the number of criteria violations; however, the numbers of additional violations were not as great as anticipated. Several of the violations identified simply advance the need for future projects.

Figure 7: NERC Categories A and B Incremental Overloads

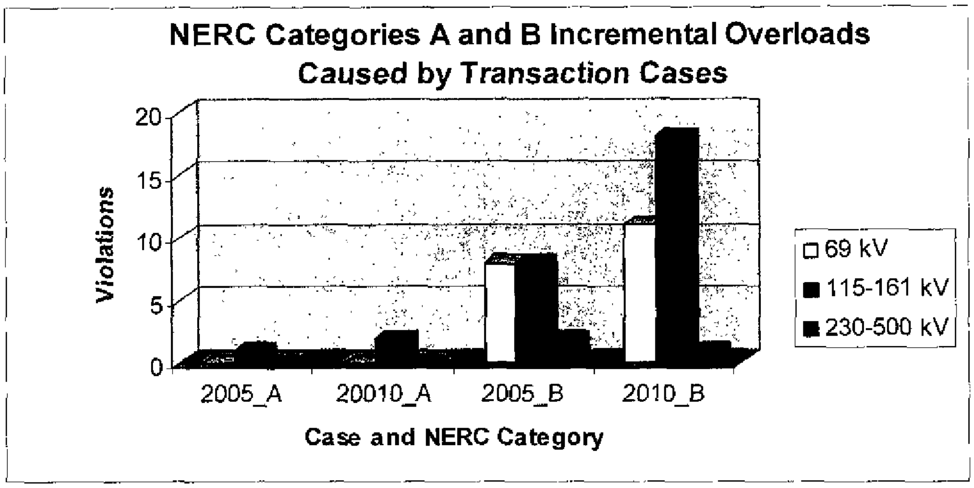


Figure 8: NERC Categories A and B Incremental Voltage Violations

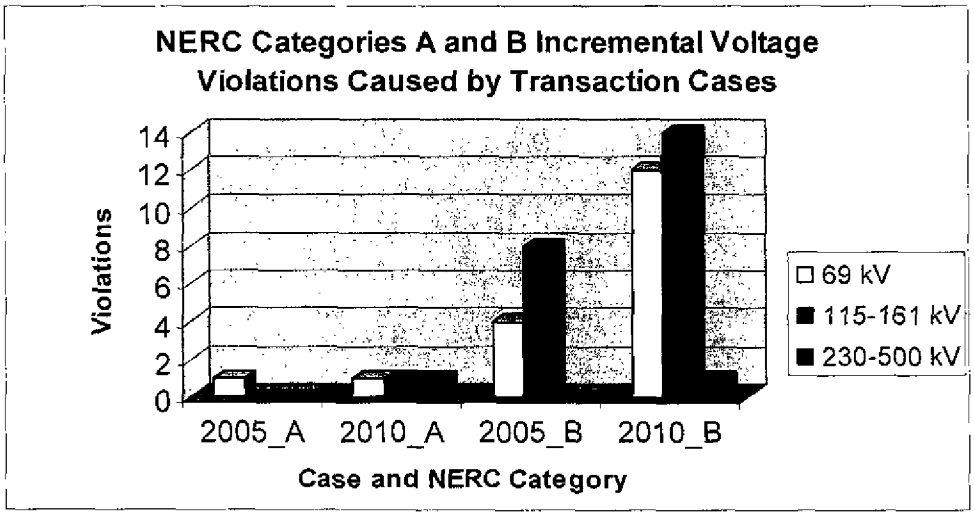


Figure 9: NERC Categories C and D Overload Summary – depicts the number of NERC Categories C and D contingency overloads for the base case and transaction cases. As can be seen by the graph, the majority of the violations were in the 115 kV to 161 kV range.

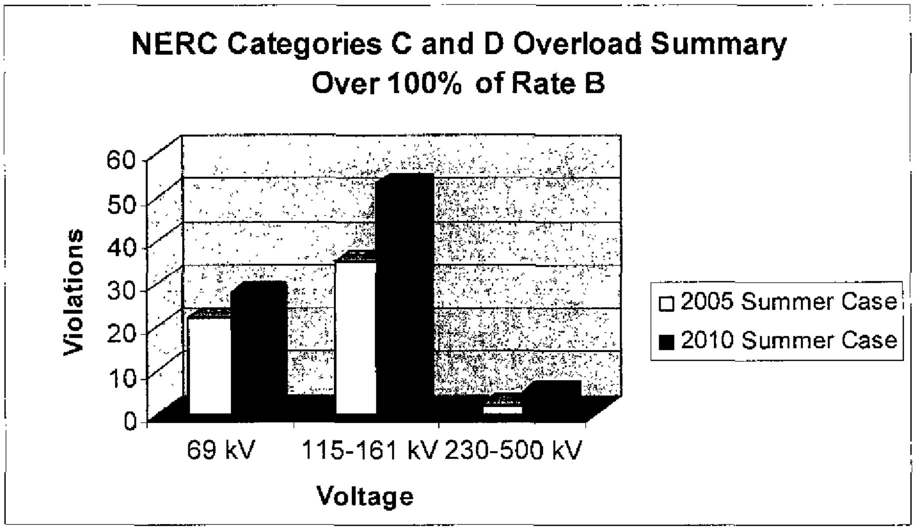
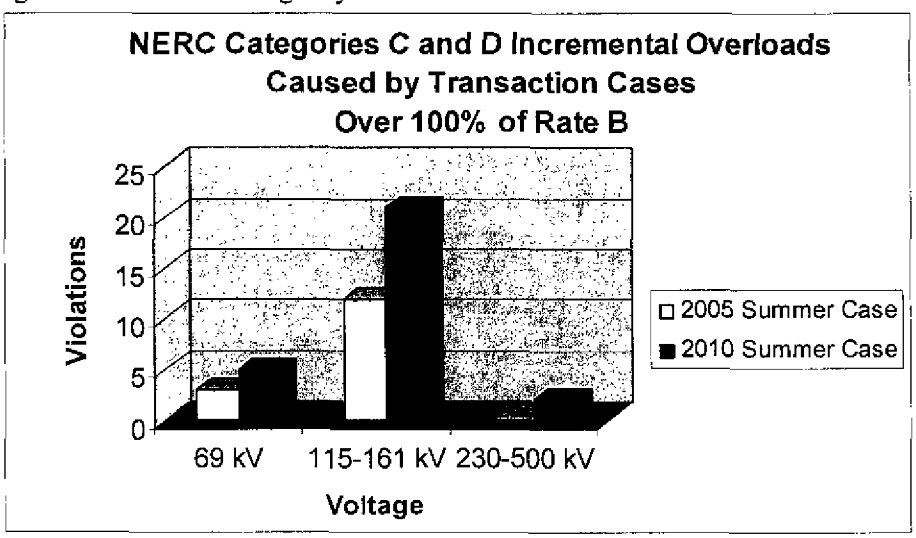


Figure 10: NERC Categories C and D Incremental Overloads – shows the incremental NERC Categories C and D contingency overloads identified in the transaction cases.



Violations and Major Problem

The maps showing criteria violations above 100 kV within the SPP footprint can be found in Appendix B. Violations are grouped by state for map purposes. Contingencies are not discussed in this report due to security concerns.

Recommendations

Major Projects

The identified criteria violations were shared during Planning Summit II so SPP could solicit stakeholder suggestions for projects to address identified violations. A pool of solutions was created by using inputs received from stakeholders, proposed and exploratory projects provided by transmission owners and alternative solutions by SPP staff. SPP staff independently evaluated the alternatives and then makes recommendations from this pool of solutions. The solutions, identified in this report, correct all SPP violations identified with the exception of a few NERC Category C and Category D type contingencies still under evaluation. In the next planning cycle, SPP staff will work with affected transmission owners to resolve any outstanding issues regarding NERC Categories C and D.

The timing of projects was determined from the load flow results of the 2005 summer case and 2010 summer case simulations. For the complete list of expansion projects and details regarding each project, refer to Appendix A. The projects are divided into three categories including Board approved projects (Phase 1 – April 2005), approved out of cycle projects and out of cycle projects pending evaluation. The project lists will be revised quarterly to include project updates.

Figures 13-23 show the zone maps with the recommended projects of 100 kV and above facilities. For the purpose of this report, the SPP region was split into eleven zones. Figure 11 shows the complete SPP region, and Figure 12 shows how the region was divided into zones. Project descriptions along with estimated in-service dates for 100 kV and above projects are shown in the project description tables on page 18-20.

Figure 11: SPP Region

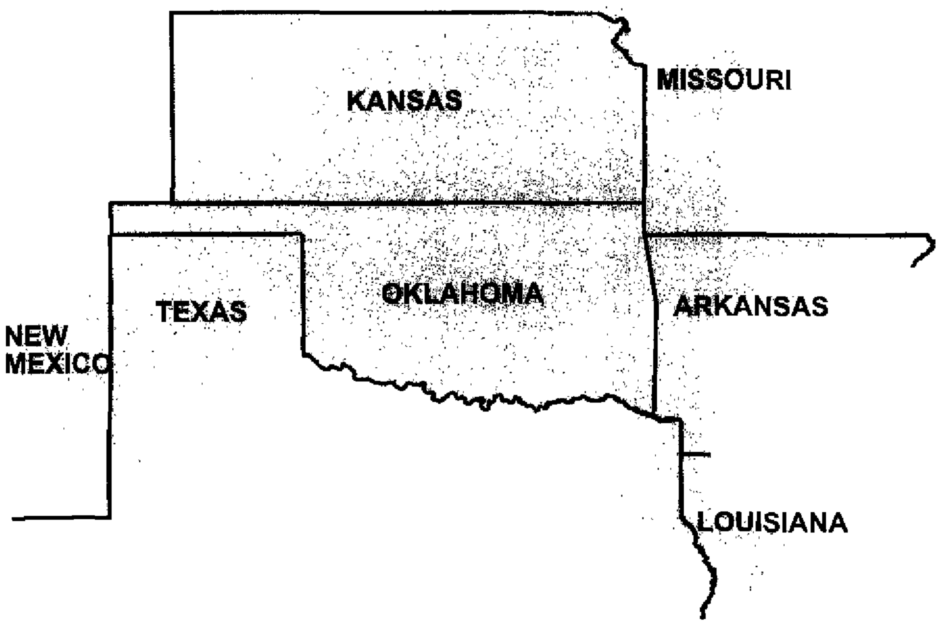
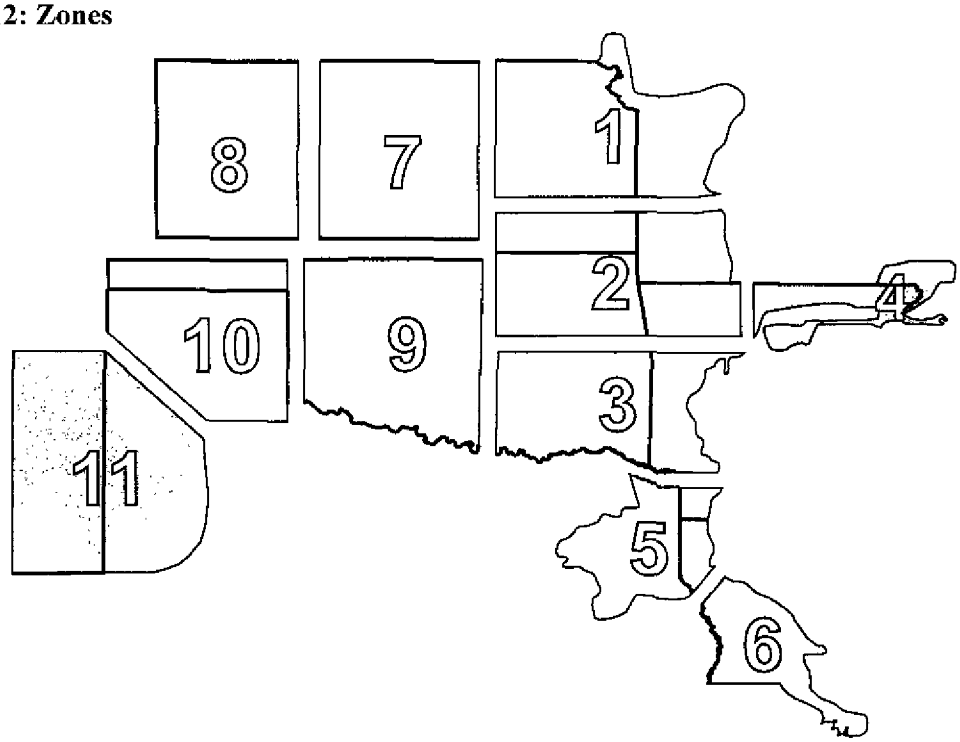


Figure 12: Zones



Project Description (100 kV and Above Projects)	Estimated In-Service Date
Zone 1	
Install 5.5 miles of 161 kV line from Turner Road-Belton South	Jun-04
Rebuild 15.1 miles of 115 kV line from Kereford-NW Leavenworth	Jun-04
Reconductor 5.5 miles of 161 kV line from Avondale-Randolph-Hawthorn	Jun-04
Convert 28.5 miles of 115 kV line to 230 kV original design from McDowell Creek-Morris Co.	Jun-05
Install 230/115 kV 280/308 MVA transformer at McDowell Creek	Jun-05
Install 50 Mvar 161 kV capacitor at Paola	Jun-05
Install 8.5 miles of new 115 kV line from Prairie-Lang	Jun-05
Install 9 miles of 161 kV line from West Gardner-Cedar Niles	Jun-05
Install new 230/115 kV 280/308 MVA transformer at Auburn	Jun-05
Replace 4.6 miles of double circuit 115 kV line with single circuit from Auburn-South Gage	Jun-05
Install 4 miles of 161 kV line from Greenwood-Lone Jack	Jun-06
Install 8.8 miles of 161 kV line from Cedar Niles-Quarry	Jun-06
Convert 36 miles 161 kV line to 115 kV from Tecumseh-Midland	Jun-07
Install 2 miles of 161 kV line from Crosstown-Boulevard	Jun-07
Install 50 Mvar 161 kV capacitor at Craig	Jun-07
Reconductor 4.5 miles of 161 kV line from Stilwell-Antioch	Jun-07
Install 345/161 kV 400/440 MVA transformer at Paola	Jun-08
Install 7.6 miles of 161 kV line from Cedar Niles-Hillsdale	Jun-08
Rebuild 6.4 miles of 115 kV line from Jarbalo-166 Street	Jun-08
Reconductor 1.7 miles of 161 kV line from North Kansas City to Northeast	Jun-08
Install 12 miles of 161 kV line from Hillsdale-Lackman	Jun-09
Reconductor 5 miles of 161 kV line from Greenwood-Merriam and replace line switches and wavetrap at Merriam and Greenwood	Jun-09
Replace a 161 kV wave trap at Blue Valley	Jun-09
Replace circuit switcher at Lenexa on the Lenexa-Craig terminal	Jun-09
Install 27 miles of 161 kV line from North Louisburg-Middle Creek-Paola	Jun-10
Zone 2	
Rebuild 6.8 miles of 161 kV line from Tontitown-Dyess	Apr-04
Convert 4.4 miles 69 kV line to 161 kV from Lowell-Rogers	Jun-04
Install 10.4 miles of 161 kV line from Tontitown-Lowell	Jun-04
Install 4.7 miles of 161 kV line from Rogers-East Rogers	Jun-04
Rebuild 25 miles of 138 kV line from Riverside-Okmulgee	Jun-04
Increase current transformer at Five Tribes Substation on the Pecan Creek-Five Tribes 161 kV	Apr-05
Replace Bartlesville SE wavetrap	May-05
Increase CTR to 2000A at Muskogee.	May-05
Replace jumper and switch at South Springdale on the Dyess-S. Springdale line	Jun-05
Upgrade CT and Wavetrap at Bristow, and line relays at Bristow, Rock Creek & Horseshoe Lake	Jan-06
Install 19 miles of 161 kV line from Tahlequah-Stilwell	May-06
Replace three switches at Tulsa SE on the Tulsa SE-53 & Garnett N Tap 138 kV line	Jun-06
Install 14 miles of 345 kV line from Chamber Springs-Tontitown	May-07
Install 345/161 kV 675 MVA transformer at Tontitown	May-07
Install 7.5 miles of 161 kV line from Siloam Springs-Chamber Springs	May-07
Convert 12 miles of 69 kV line to 161 kV from Dyess-N Fayettville-Fayetteville-S Fayetteville	Jun-07
Install 4.2 miles of 161 kV line from Reinmiller-Tipton Ford	Jun-07
Rebuild 1.5 miles of 161 kV Tontitown-Elm Springs REC line and replace switch and bus at Elm Springs REC	Jun-07
Replace Jumper, Switch, Breaker at Dyess and replace switch at Elm Springs REC	Jun-08
Upgrade the main and transfer buses and bus work within bay at Springfield. Replace disconnect switches at Springfield. Reconductor 2 miles 161 kV line from Brookline-Springfield	Jun-08

Project Description (100 kV and Above Projects)	Estimated In-Service Date
Install 15 miles of 161 kV line from Monett-Chesapeake	Jun-09
Install 275 MW generator at Springfield SWPS 2	Jun-09
Install 345/161 kV 675 MVA transformer at East Centerton	Jun-10
Zone 3	
Wavetrap and CT at Seminole	Nov-04
Install 5.5 miles of 161 kV line from Clarksville-Little Spadra	Dec-04
Install 28.4 Mvar 69 kV capacitor at Red Oak	Jun-05
Install 45 Mvar 161 kV capacitor at Fort Smith	Jun-05
Install 18 Mvar 69 kV capacitor at VBI	Oct-05
Replace wavetraps, switches and reset relays at Valliant.	Oct-05
Install 2 miles of 161 kV line from 3rd Street Tap-Massard	Jun-06
Convert/rebuild 35.5 miles of 69 kV line to 161 kV from Branch-Short Mountain-Razorback tap-IGO-Little Spadra	Jun-10
Convert/rebuild 4.7 miles of 69 kV line to 161 kV from Fitzhugh-Helberg	Jun-10
Relay upgrade at Park Lane	Jun-10
Replace substation conductor at Hope substation on the Hope-Fulton 161 kV line	Jun-10
Zone 4	
Remove wavetraps at Idalia and Asherville, also reconductor 22 miles of 161 kV line from Idalia-Asherville	Jun-09
Zone 5	
Lone Star South replace CT on the Lone Star South-Pittsburg 138 kV line	Dec-04
Rebuild 16.4 miles of 138 kV line from Knox Lee-Rock Hill	May-05
Rebuild 26.3 miles of 138 kV line from IPC Jefferson-Lieberman	May-05
Install 20 miles of 138 kV line from Pittsburg-Winnsboro	Jun-06
Reconductor 9.5 miles of 138 kV line from Rockhill-Carthage REC. This project was advanced from the original timing because a three terminal line contingency was identified late in the study process.	Jun-06
Replace relay, wavetrap and switch at Knox Lee and switch at Oak Hill on the Knox Lee-Oak Hill 138 kV line	Jun-06
Install 25 miles of 138 kV from Winnsboro-North Mineola	Jun-07
Reconductor 2.3 miles of 138 kV line from Carthage REC-Cartage Tap. This project was advanced from the original timing due to a three terminal line contingency not initially identified.	Jun-07
Lone Star South replace CT on the Lone Star South-Wilkes 138 kV line	Jun-09
Replace wavetrap at South Shreveport on the South Shreveport-SW Shreveport 138 kV line	Jun-10
Zone 6	
Reconductor 5.9 miles of 138 kV line from Many-Fisher	Oct-03
Install 22 MVAR 138 kV capacitor at Marksville	Jun-04
Zone 7	
Install three 10 Mvar capacitors and 8 Mvar statcom at Plainville 115 kV	Jun-05
Install 11 miles of 138 kV line from Evans South-17th Street	Jun-08
Install 20 Mvar 138 kV capacitor at Harper	Jun-10
Zone 8	
Install 26 miles of 115 kV line from Pioneer-Hugoton-Walkemeyer	Dec-04
Install 105 miles of 345 kV line from Lamar-Finney and 210 MW HDVC Station which provides a 3rd DC tie to WECC at Lamar	Jan-05
Install 115 kV 33.2 Mvar Capacitor at East Liberal	Jan-05
Install 12 Mvar 115 kV capacitor at Ruleton	Dec-06
+/- 8 Mvar DVAR and 15 Mvar capacitor at Rhoades 115 kV	Jun-07
Rebuild 25 miles of 115 kV line from Holcomb-Plymell-Pioneer Tap	Jun-08
Rebuild 46 miles of 115 kV line from Scott City-Manning tap-Dighton-Beeler-Ness City	Jun-08
Install +/- 8 Mvar Dvar and 15 Mvar capacitor at Mingo 115 kV	Dec-08

Project Description (100 kV and Above Projects)	Estimated In-Service Date
Zone 9	
Install 23.4 Mvar 138 kV capacitor at Sunnyside	Jun-04
Raise 4 or 5 structures on Comanche tap-Duncan OMPA 138 kV line to increase clearance	Jun-04
Install 6.5 miles of 138 kV line from Glenwood-NE Enid	Dec-04
Install 8.5 miles of 138 kV line from Haymaker-Piedmont	Dec-04
Install two 25 Mvar 345 kV reactors at Arcadia	Mar-05
Reconductor 1.9 miles of 138 kV line from Stillwater-McElroy	Apr-05
Replace free standing metering CT at Elk City	Apr-05
Replace terminal equipment and wavetrap at Division Substation on the Division-Silver Lake 138 kV line	Apr-05
Increase CTR to 2000A at Sunnyside	Apr-05
Reconductor 1.7 miles of 138 kV line from Memorial-Skyline and increase terminal equipment	May-05
Upgrade wavetrap at Franklin SW on the Franklin SW-Midwest Tap	May-05
Install 10 Mvar 138 kV capacitor at Marietta	Jun-05
Install 345/138 kV 493 MVA transformer at Draper	Jun-05
Replace the Cornville wavetrap	Jul-05
Replace Southwestern Station wavetrap & Anardarko wavetrap	Aug-05
Install 18 Mvar 69 kV capacitor at Woodard District	Oct-05
Relocate 2.5 miles of 138 kV line from NE 10th-Glendal new substation	Jun-06
Install 6.5 miles 138 kV line from Glenwood-NE Enid	Jun-06
Zone 10	
Install two taps on the Nichols-Swisher 230 kV line and open between the taps. Install 5.5 miles of double circuit 230 kV line from each line tap to the Amarillo South substation. Install new Amarillo South substation with 230/115 kV 225/259 MVA transformer	Apr-05
Install 14.4 Mvar 115 kV capacitor at Dallam	Jun-05
Upgrade transformer 1 and 2 at Nichols with two 230/115 kV 225/259 MVA transformers	Dec-10
Zone 11	
Install 2.9 miles of 230 kV line from Lubbock South-LP South Interchange	Jun-04
Install 28.8 Mvar 115 kV capacitor at Seven Rivers	Dec-04
Install 230/115 kV 150 MVA transformer at Seven Rivers	Feb-05
Install 24.5 miles of 230 kV line from Eddy County-Seven Rivers	Feb-05
Install 6 miles of new 115 kV line from Amerada Hess-Doss	Mar-05
Install 14.4 Mvar 69 kV capacitor at Doss	Jun-05
Install 50 Mvar 230 kV capacitor at Chaves	Jun-05
Install 24.5 miles of 115 kV line from Floyd-Floyd Tap	Dec-05
Install 26 miles of 115 kV line from Lubbock East-Crosby	Dec-05
Install 6 miles of 115 kV line from Floyd-Cox	Jun-06
Install 230/115 150 MVA transformer at Pecos	Apr-08
Install 31.5 miles of 230 kV line from Seven Rivers-Pecos-Potash Junction	Apr-08
Install 230/115 kV 252/298.8 MVA transformer #2 at Lubbock South	Jun-09

Figure 13: Zone 1

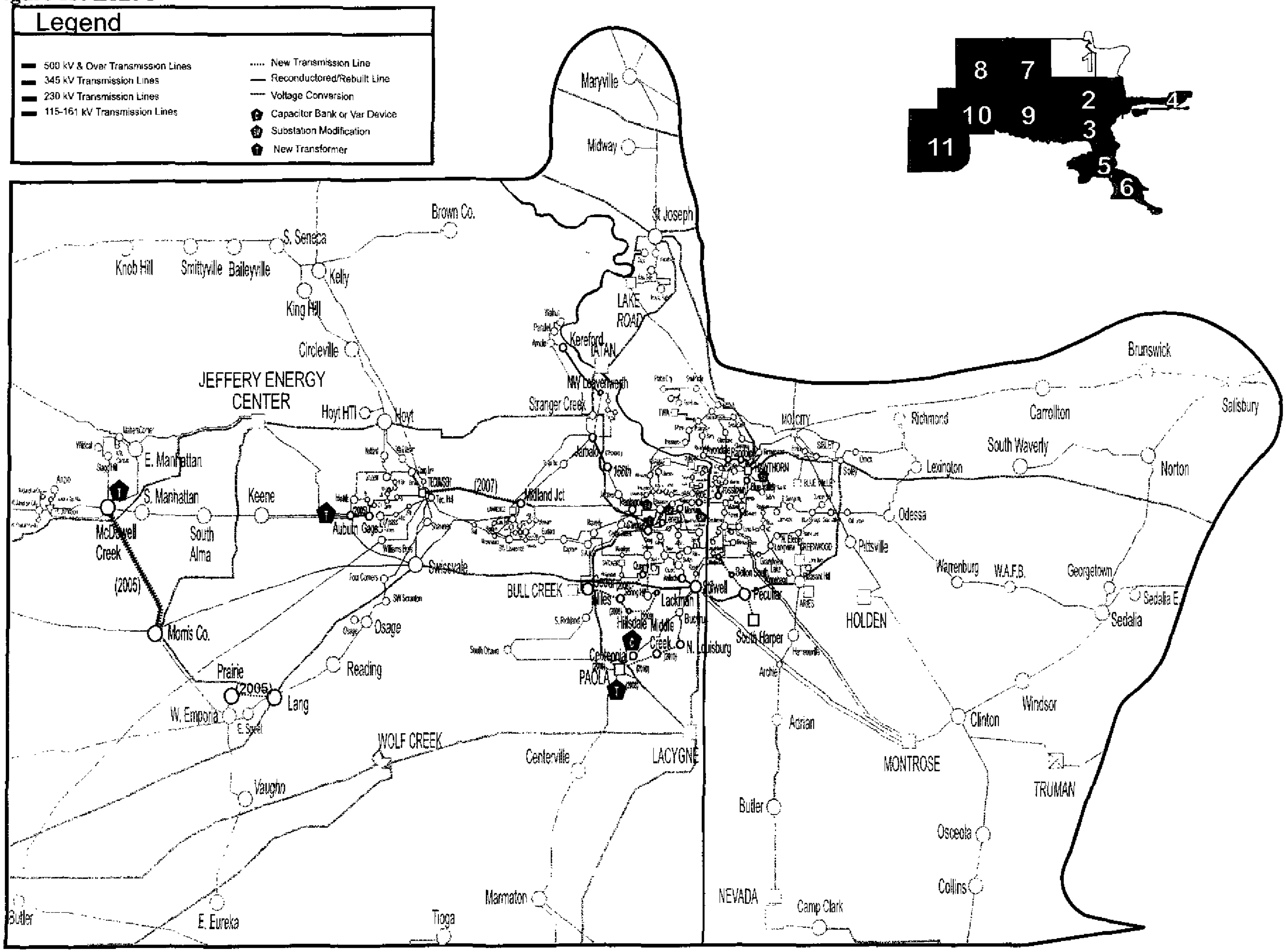


Figure 14: Zone 2

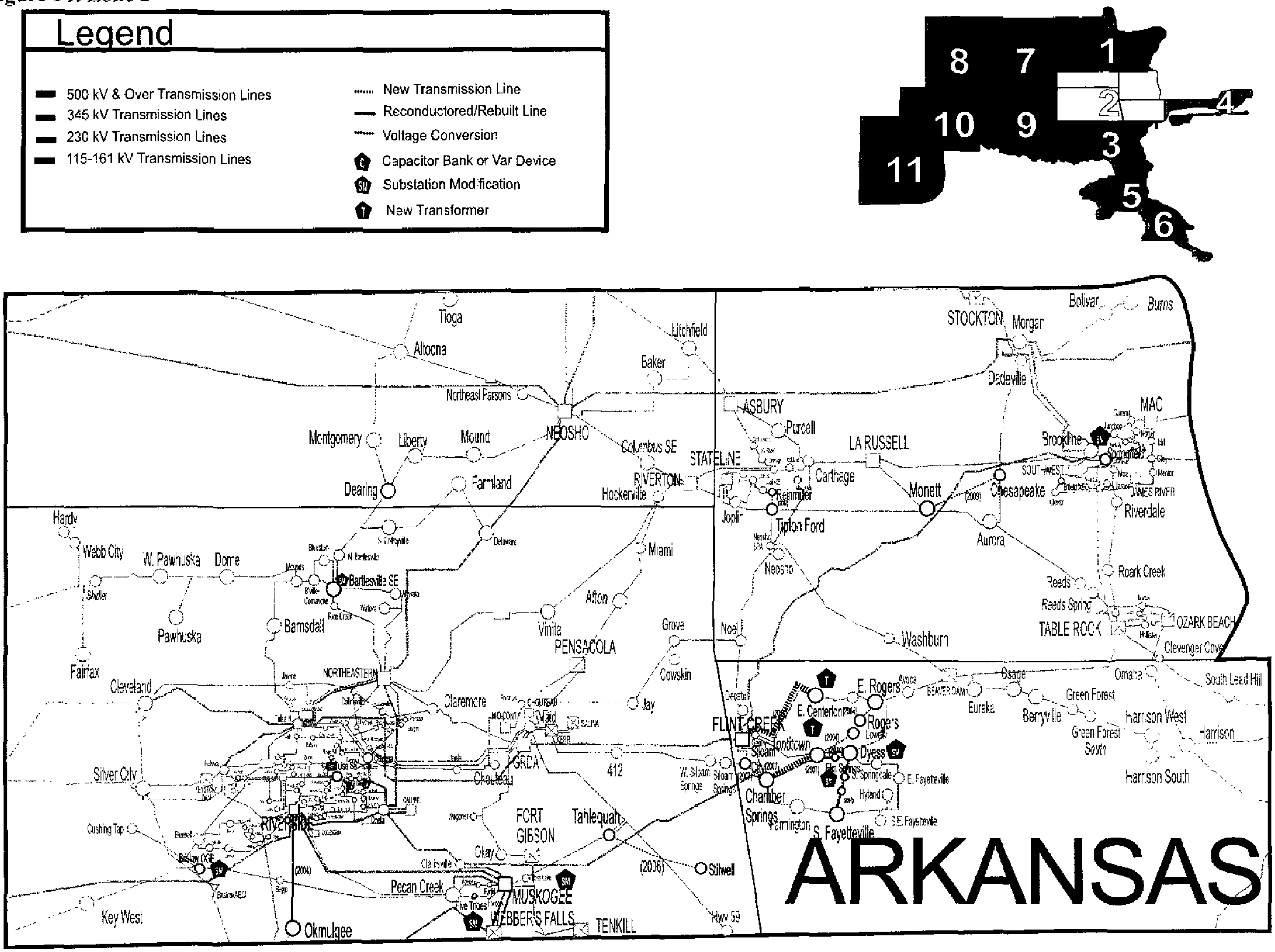


Figure 15: Zone 3

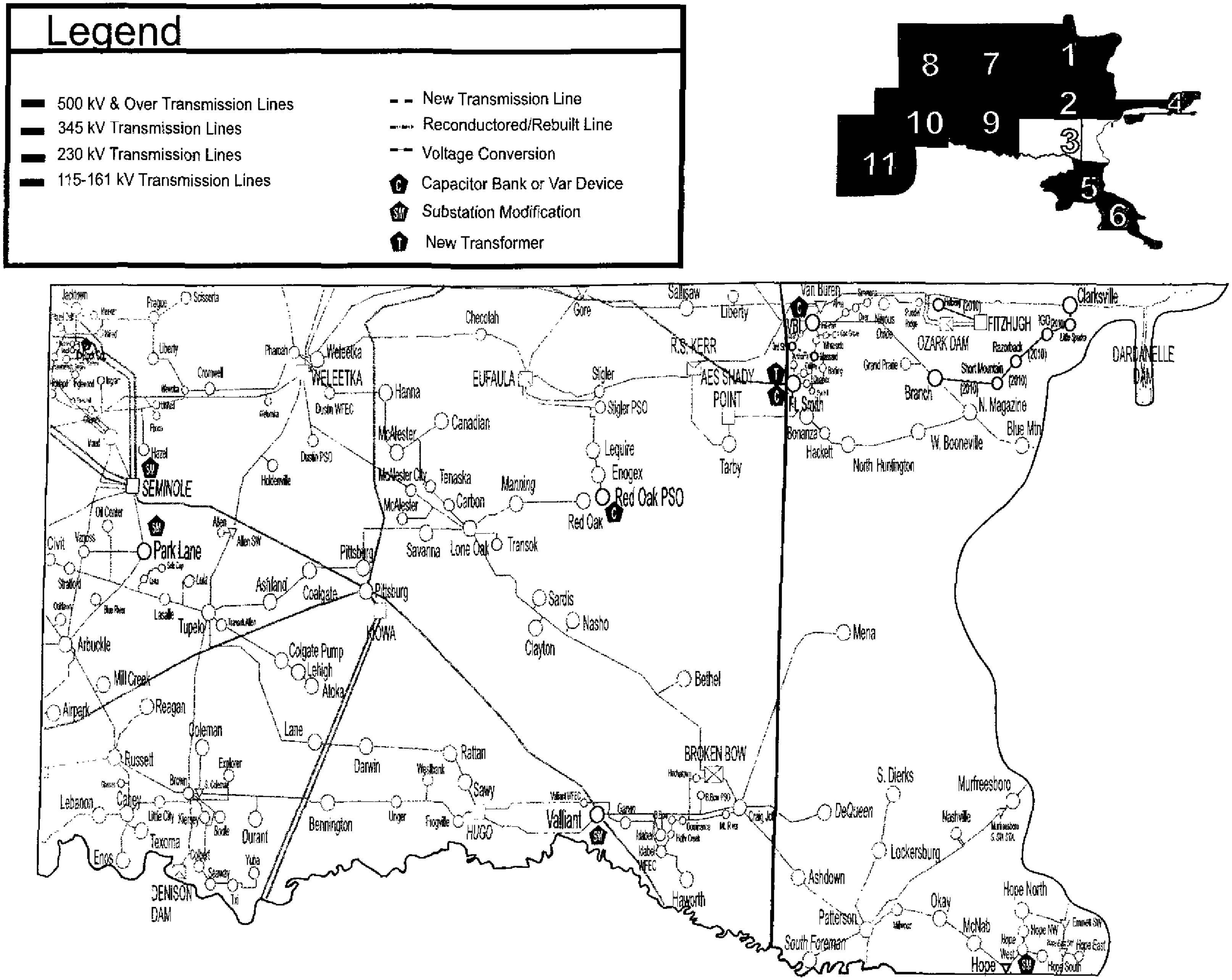


Figure 16: Zone 4

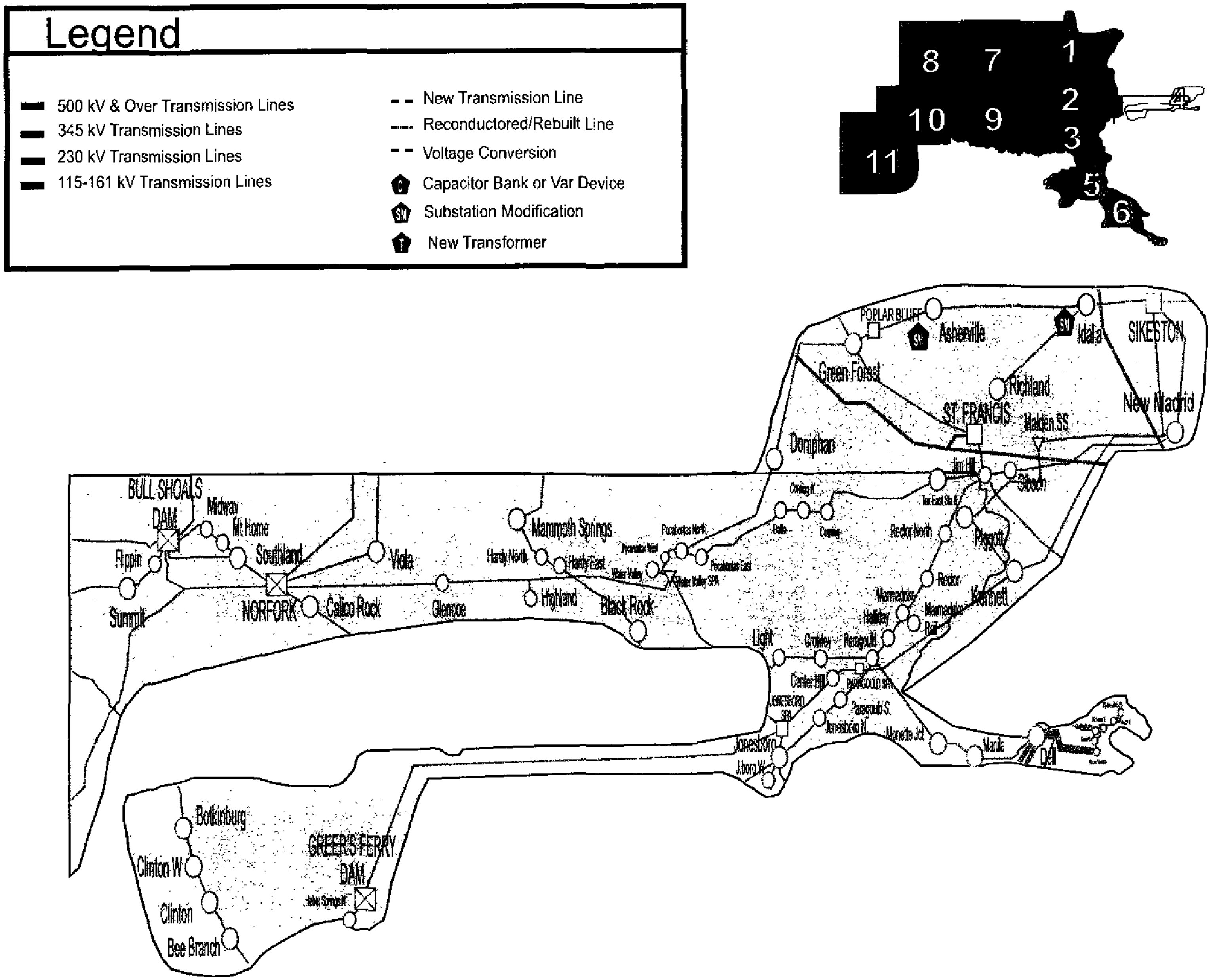


Figure 17: Zone 5

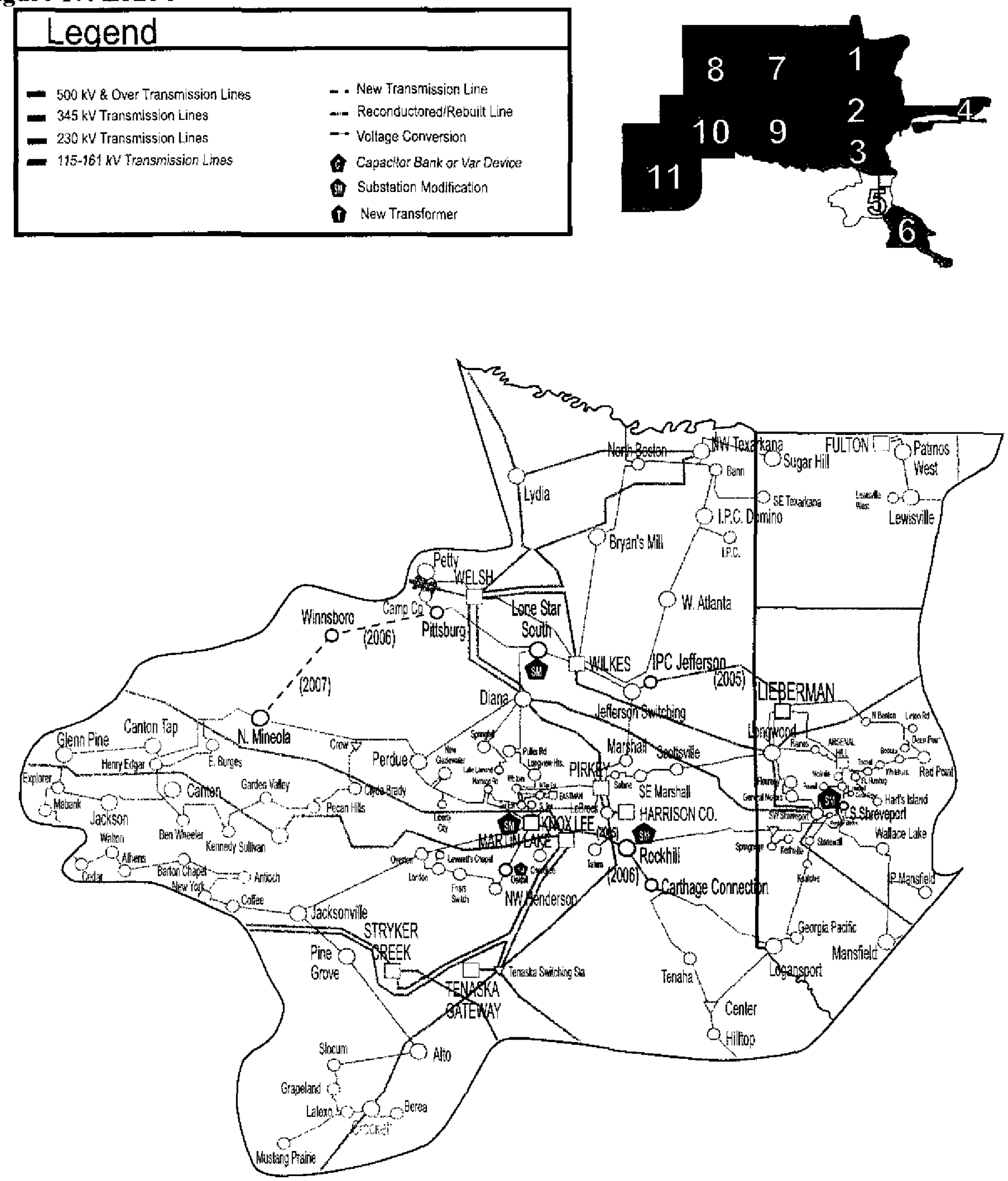


Figure 18: Zone 6

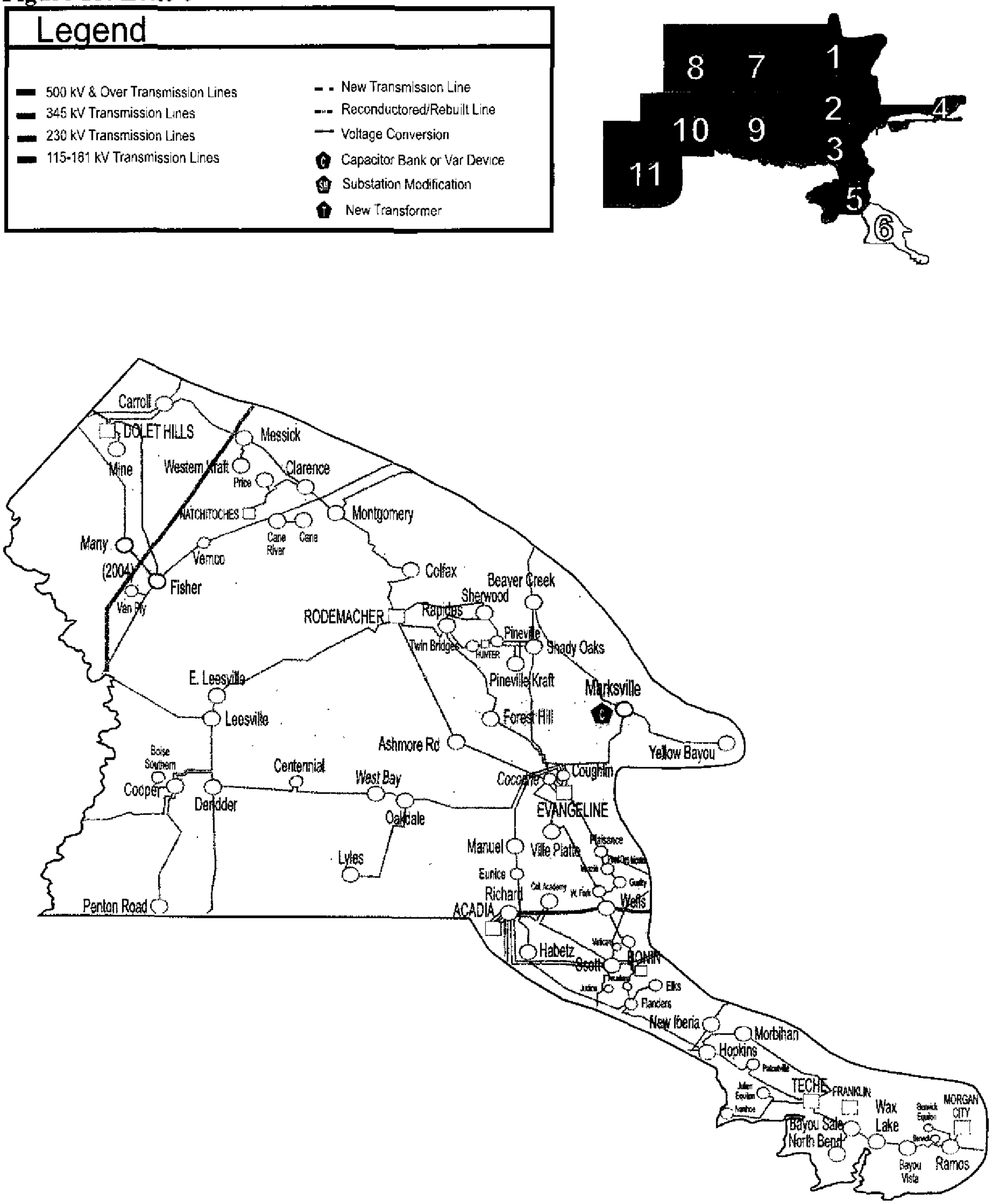


Figure 19: Zone 7

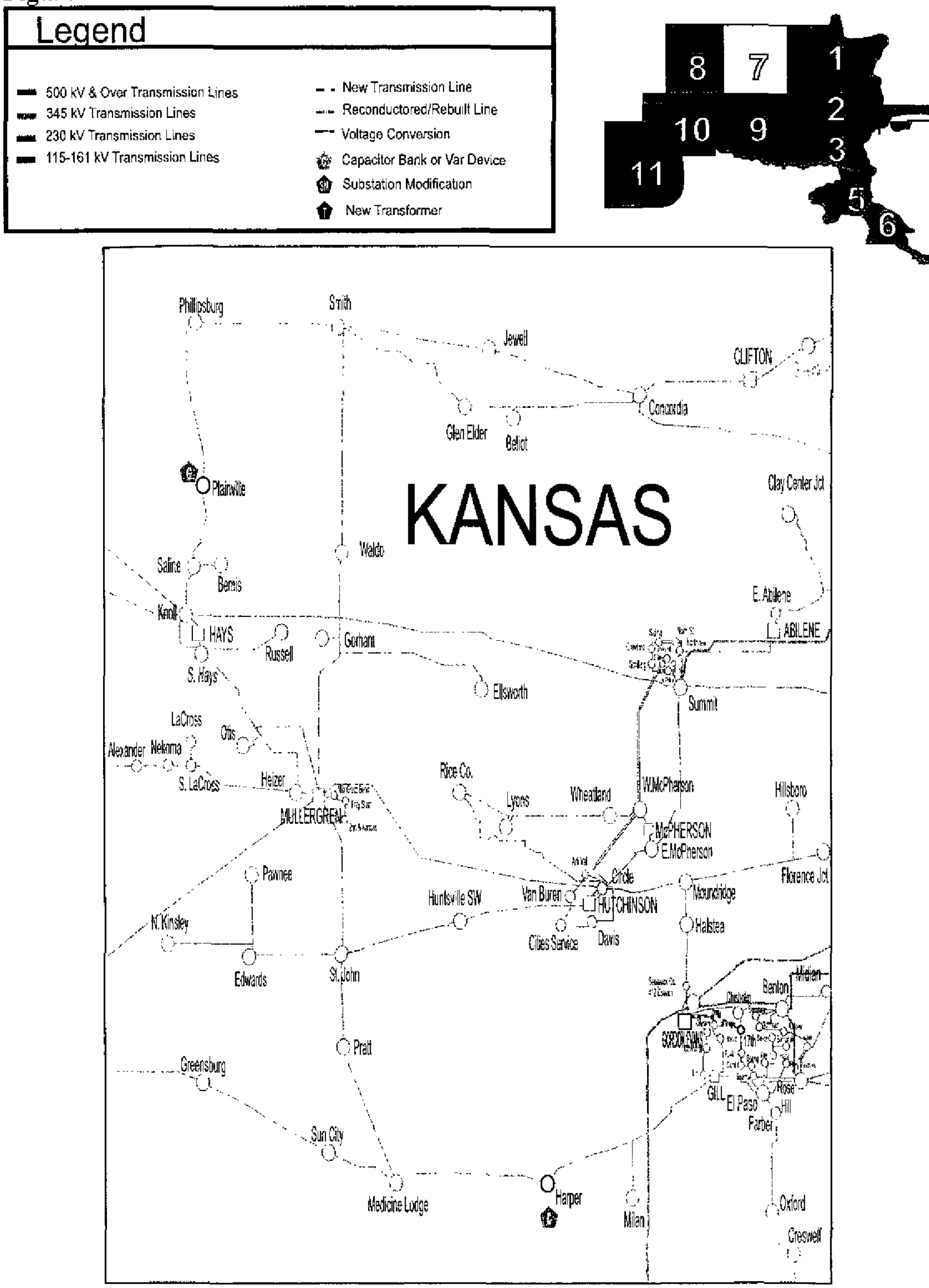


Figure 20: Zone 8

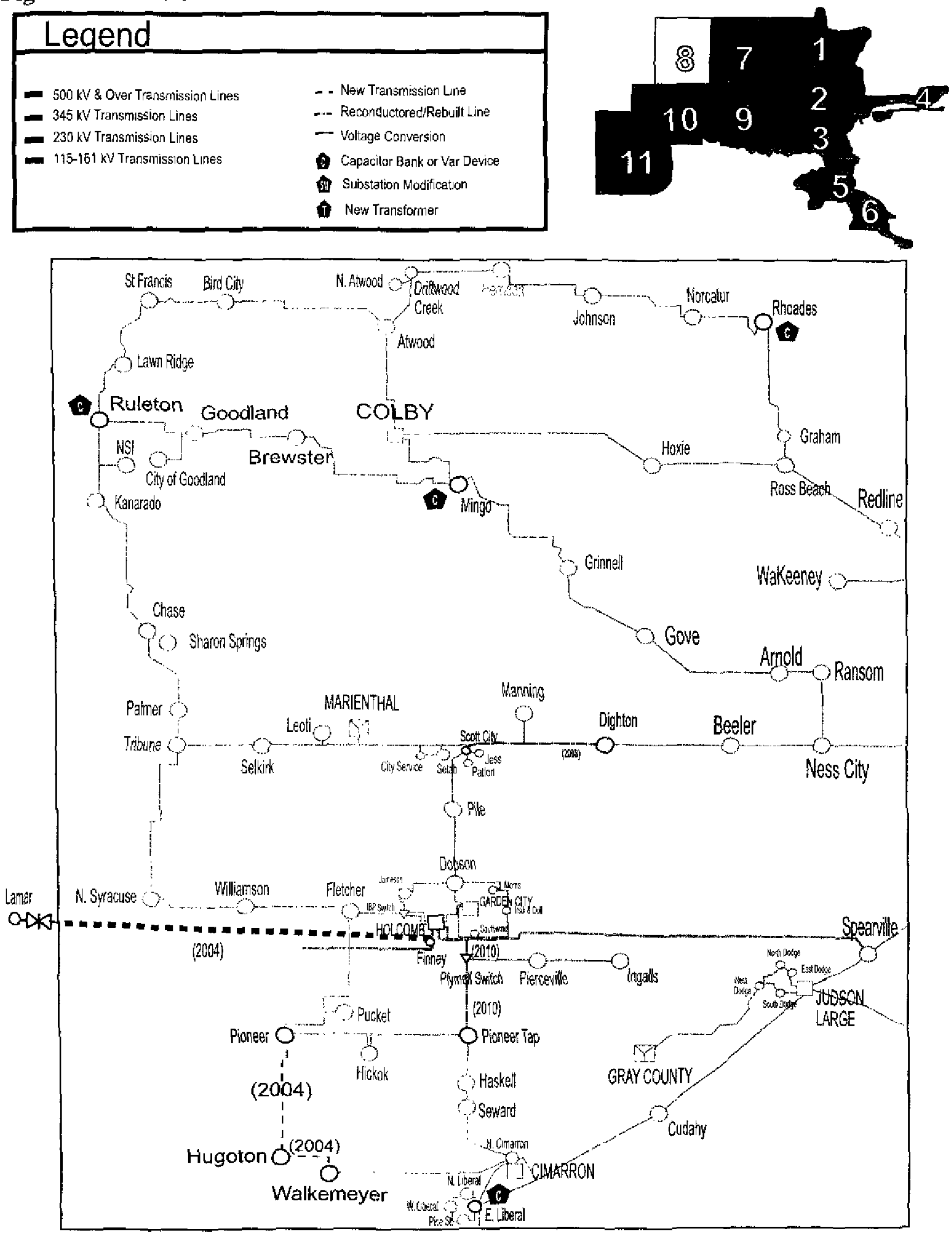


Figure 21: Zone 9

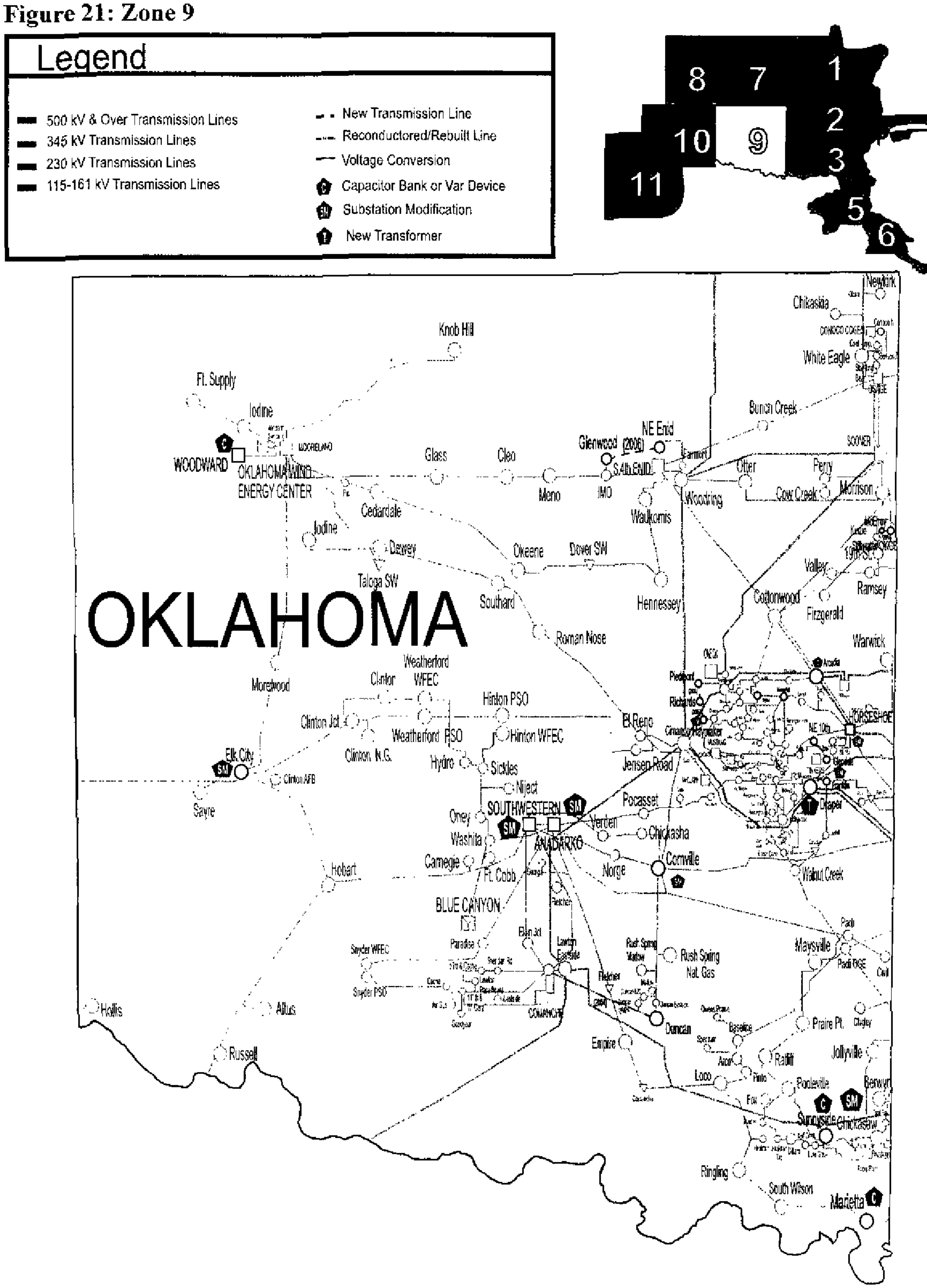


Figure 22: Zone 10

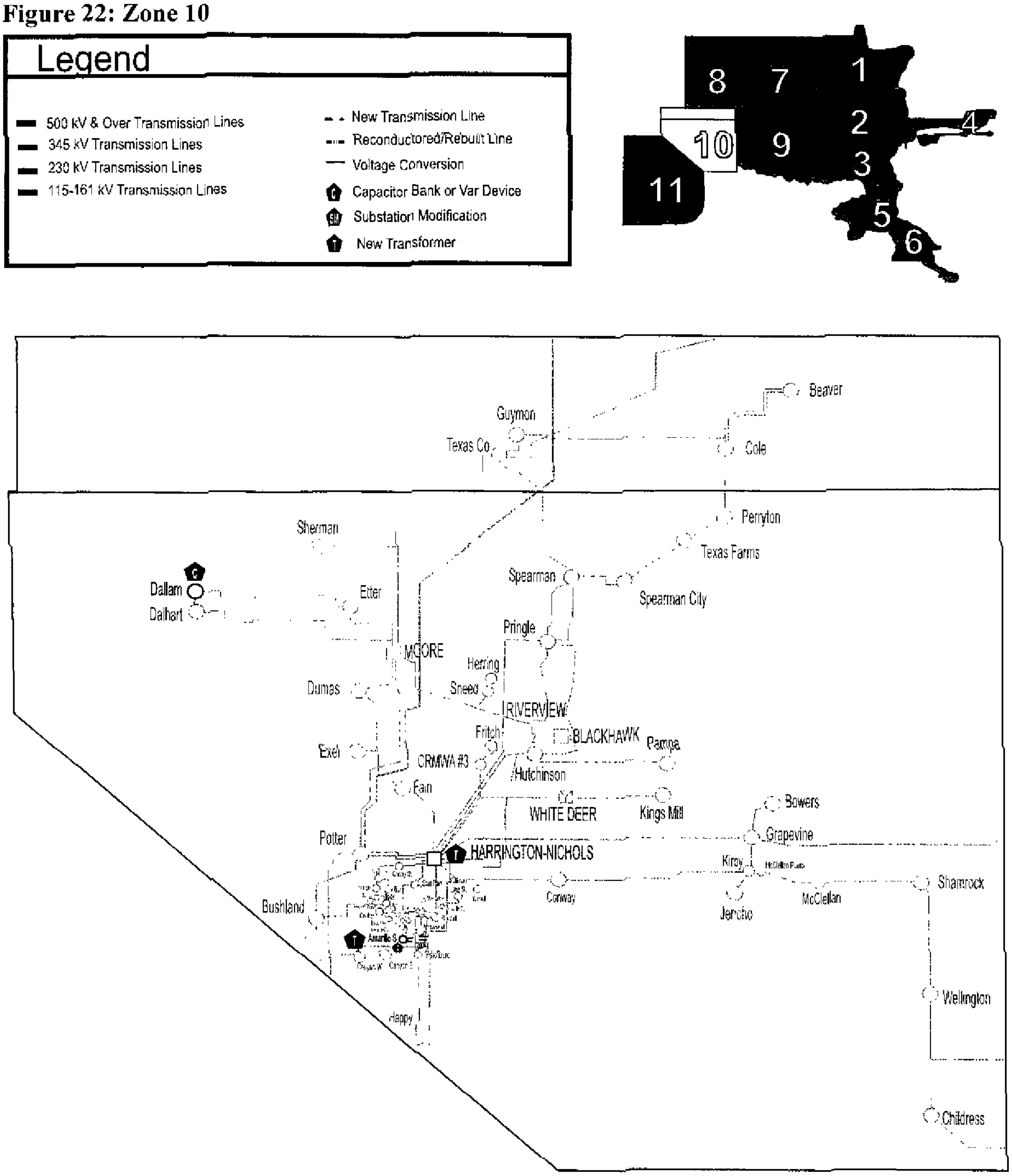
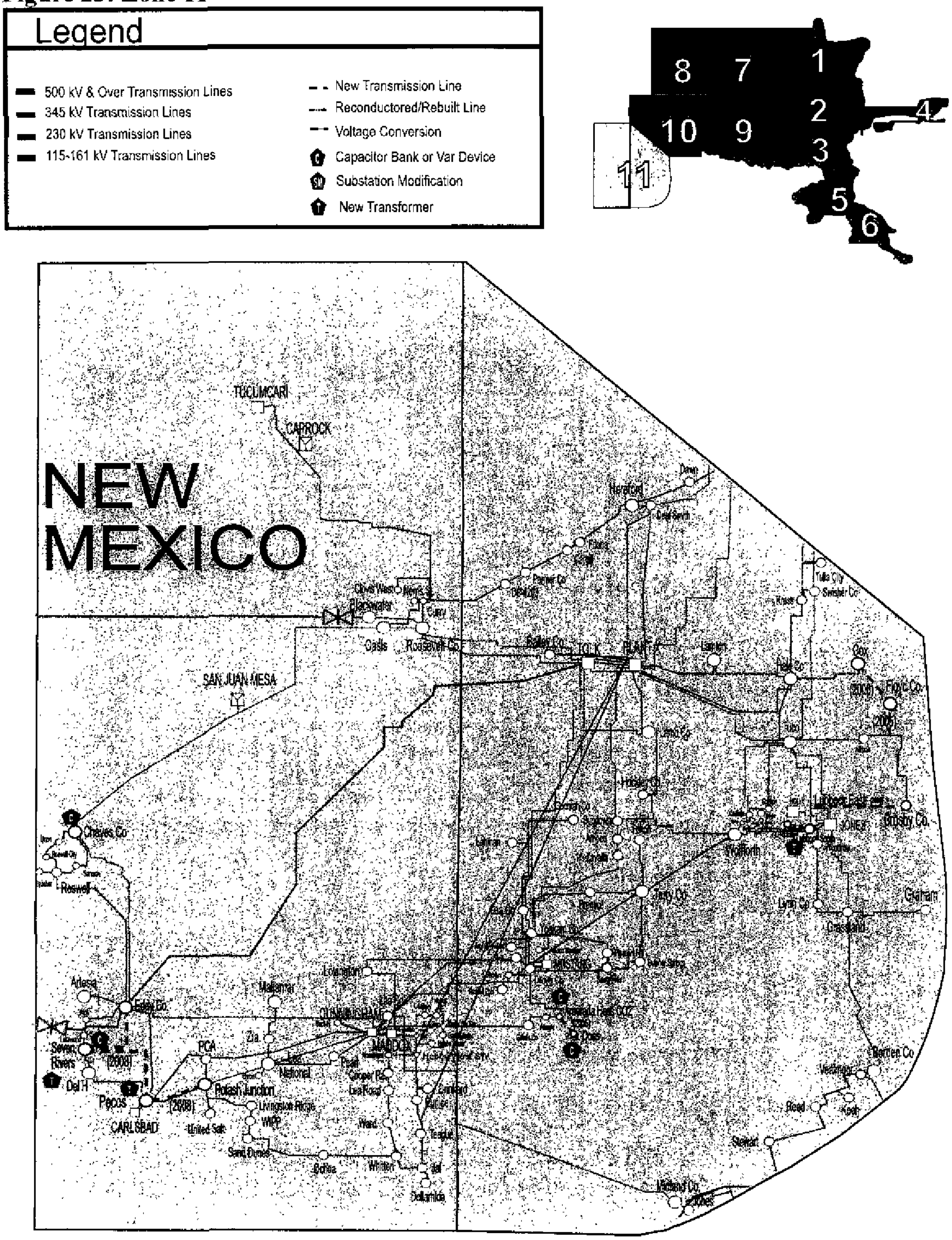


Figure 23: Zone 11



Summary of Projects

Figures 11-14 summarize the projects recommended for the SPP RTO Expansion Plan. Estimated line mileage for new transmission lines for October 2003 to December 2010 totaled 634 miles, and rebuilds/upgrades totaled 646 miles. Figure 28 shows the breakdown of projects by type.

Figure 24: Estimated Cost of Transmission Line Projects

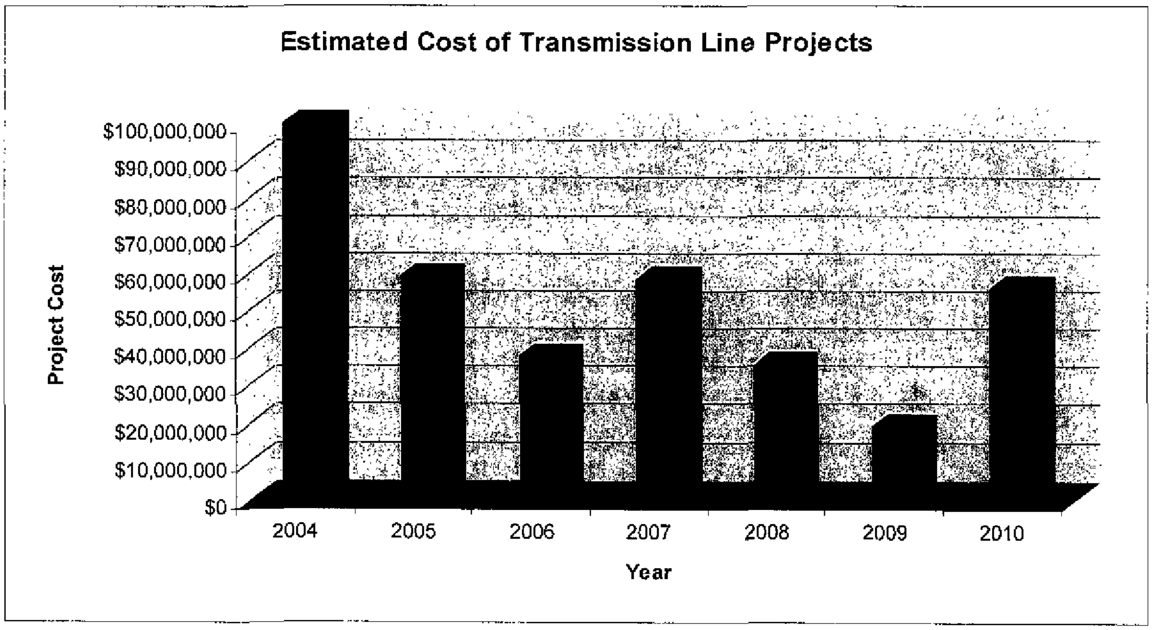


Figure 25: Estimated Line Mileage for Transmission Line Projects

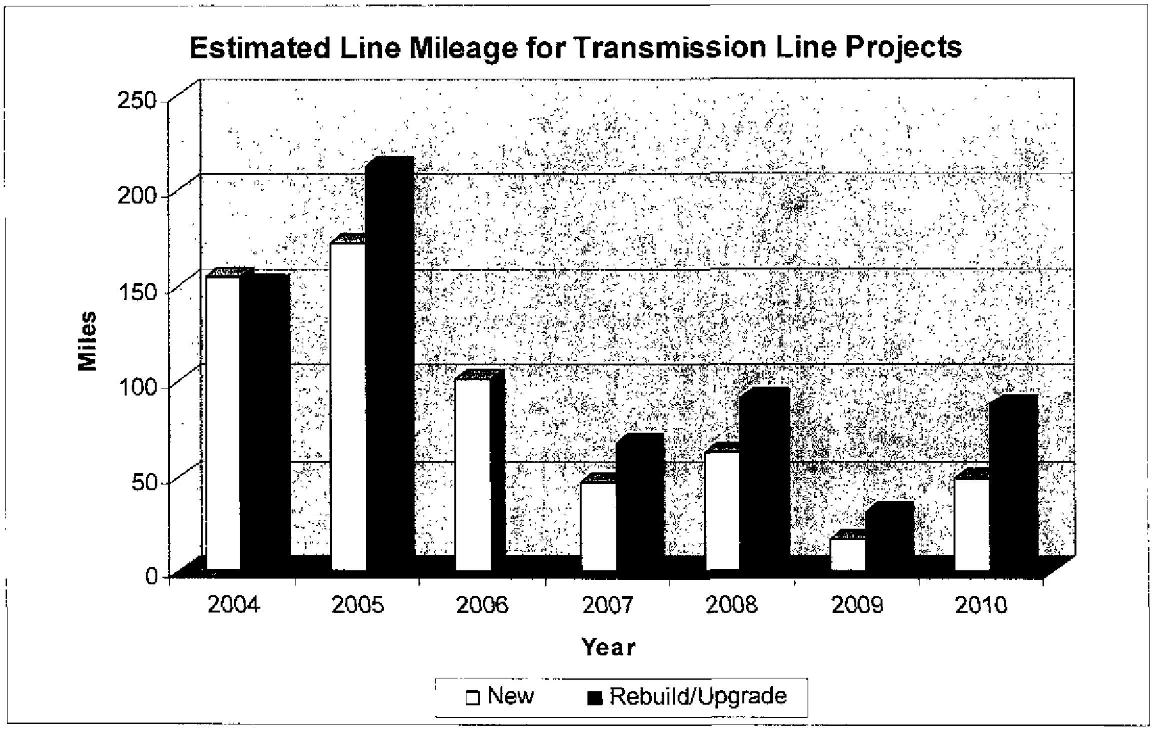


Figure 266: Estimated Cost of Transformer Projects

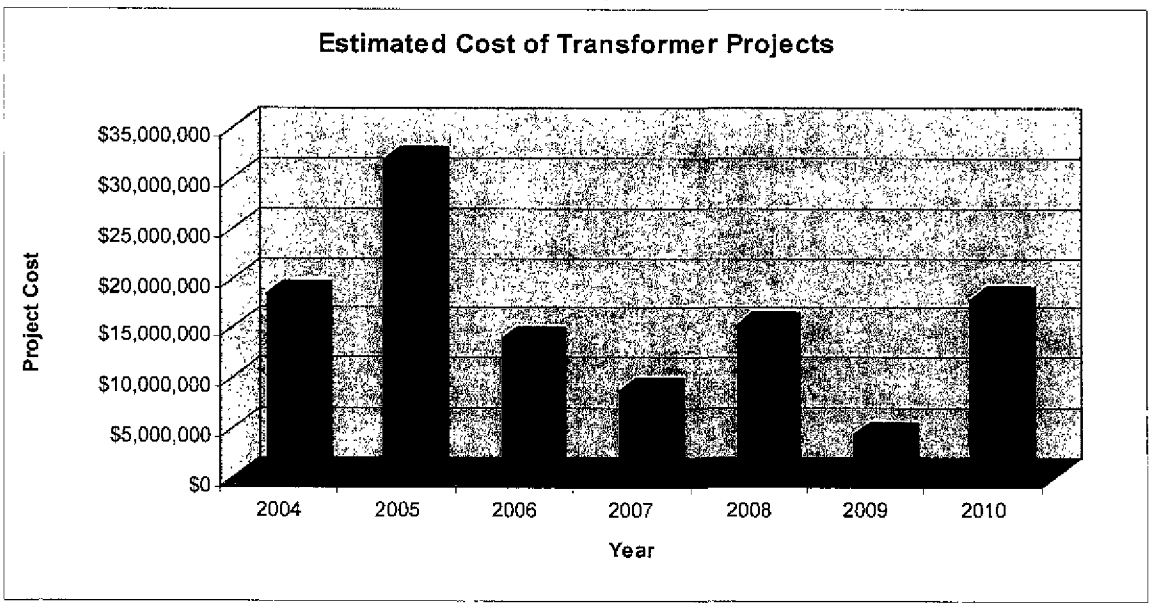


Figure 277: Estimated Number of Transformer Projects

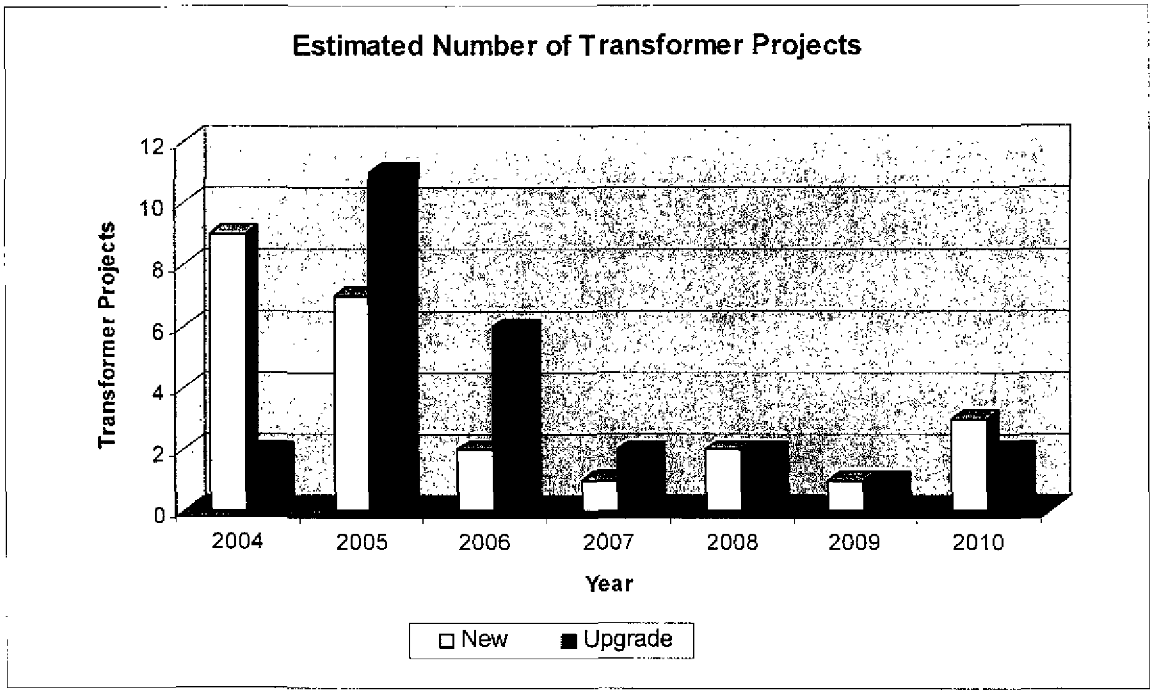
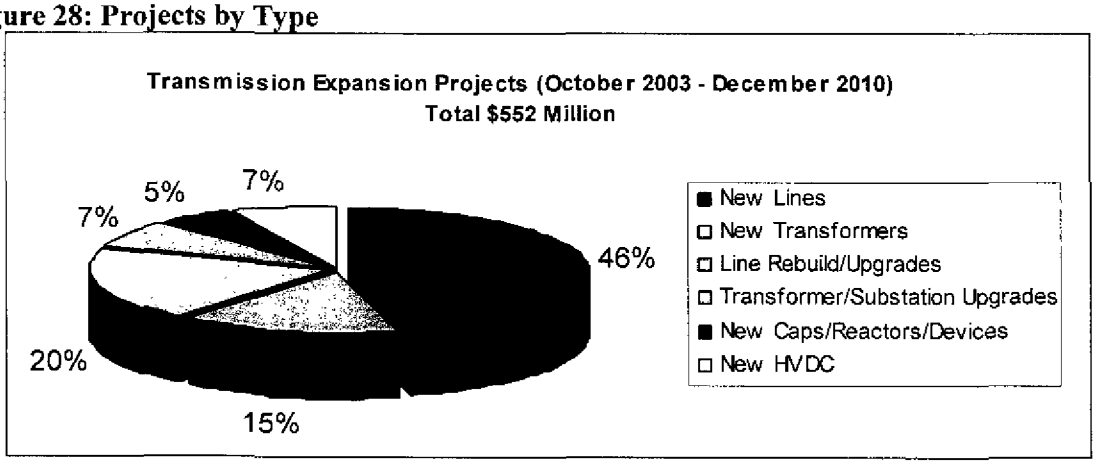


Figure 28: Projects by Type



Complete List of Recommended Projects

The complete list of recommended SPP RTO Expansion Plan projects can be found in Appendix A.

Out of Cycle Projects – Project Tracking

"Out of Cycle" projects are those that have been announced or developed after the SPP RTO Expansion Plan. These projects may include new load service, new generator interconnections (signed interconnection agreement or firm commitment) or new transmission interconnections. The projects had unknown status at the time of the analysis for the SPP RTO Expansion Plan. Out of cycle projects can also include reliability projects that the transmission owner committed to build and may include site purchase only. The out of cycle projects also include projects that may be on the "fast track" for various reasons. New projects submitted through the MDWG model building process will be reviewed for potential out of cycle projects.

SPP expects that members will help support the plan and communicate any system changes. To provide data for a dynamically changing transmission system, the following is proposed:

- When a new project is announced, developed or studied by the transmission owner and it can have a significant impact on the current models, the project should be reported to SPP as soon as discovered. The data will be reported using Forms 1-3 with an appropriate entry made for the project. The in-service data should be shown as well as any other pertinent information. If the project is confidential to the transmission owner or the customer, a column is provided to flag it as "Customer Confidential." SPP staff will not share any details regarding "Customer Confidential" projects until authorized. SPP will track and report the number of "Customer Confidential" projects in routine postings.
- Data should be sent to SPP on a continuous basis throughout the year, not accumulated and sent in a grouping. Studies require accurate models.
- On a quarterly, each entity responsible for a project would update the in-service dates on the Forms 1-3 Updating should be done for all projects that entity has construction responsibility for.
- On an immediate basis, each entity should notify SPP if there is a change in project schedule or in-service date that impacts the project construction around or of a flowgate element or 230 kV or higher transmission project. This notification should occur as soon as the information is known, not on a quarterly basis.

Likewise, SPP will provide on the same basis to the construction entities information on any changes in required construction because of transmission service sold. This notification allows the responsible entity to get the item on Forms1-3 and seek the approvals necessary for going forward. The proposed process is for SPP to send out Forms 1-3 quarterly.

Over the year, the projects required for sold service should transfer to Forms 1-3 along with the necessary project information. The list of Out-Of-Cycle projects is included in Appendix A.

Operating Guides/Directives

Operating guides/directives have been used for many years in the SPP region to mitigate system constraints such as line overloads and low voltages. Operating guides/directives provide the system operator with actions that may alleviate the system problem during emergency situations.

Some companies within the SPP region use operating guides/directives to solve system violations identified in the planning process. Operating guides/directives were tested to see whether the full implementation correct the problem. Checking of line overloads and voltage violations were performed only before and after the implementation. Issues such as relay tripping and equipment failures during the implementation of the operating guides/directives were not tested. Transmission owners perform a more detailed analysis during the operating horizon.

SPP used operating guide/directive solutions recommended by the transmission owners. All operating guides/directives used in the SPP RTO Expansion Plan were tested to ensure that full implementation of the guides/directives do correct the system problem. SPP staff was concerned that some of the operating horizon recommendations could not be implemented in time due to highly overloaded facilities. These facilities may trip before the operating guides/directives could be fully implemented. To address this concern, additional testing was done on facilities loaded greater than 110% of long term emergency rating post contingency. SPP staff gathered additional information on short-term ratings for these facilities to make sure the facilities could withstand the high overloads until the guides/directives were implemented.

Future SPP RTO Expansion Plan studies will not initially include operating guide/directives. System reinforcement will be determined for all violations. Operating guides/directives will be considered as alternatives to the reinforcements.

Figure 29: Operating Guides/Directives Used (Facilities Above 100 kV)

Area No	Area	Thermal	Voltage
502	Cleco Power LLC (CELE)	1	
523	Grand River Dam Authority (GRDA)/Associated Electric Cooperative, Inc. (AECI)	1	
536	Westar (WERE)	7	1
541	KCPL	1	
	Total	9	1

CELE Dolet Hills Operating Guide
GRDA/AECI Chouteau Operating Guide
WERE (Directive 400) Outage of Jeffrey Energy Center-Hoyt 345 kV Line
(Directive 618) Outage of Auburn Road 230/115 kV Transformer
(Directive 633) Outage of East Manhattan 230/115 kV Transformer
(Directive 803) Outage of Hoyt-Stranger 345 kV Line
(Directive 900) Outage of Jeffrey Energy Center-East Manhattan 230 kV Line
(Directive 1105) Outage of the Moundridge-Halstead or Gordon Evans-Halstead 138 kV Lines
(Directive 1205) Outage of Circle-Davis 115 kV Line
(Directive 1213) Outage of the Circle to Hutchinson Energy Center 115 kV Line

KCPL Operating Letter #132 Close Sprint Bus

Phase II: Market Assessment

Objective

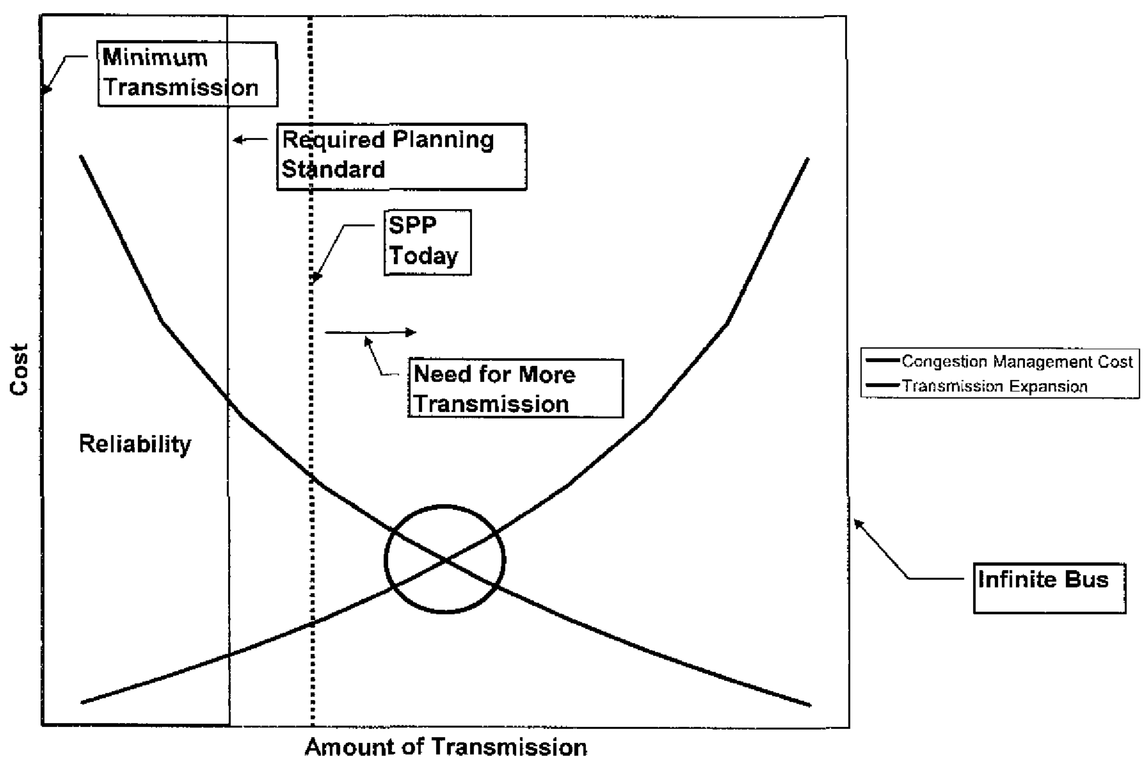
Some transmission projects may be justified not for purely reliability reasons but rather on their ability to improve the system in an economic manner. Phase II of the SPP RTO Expansion Plan addressed potential transmission projects that may be justified based on the expected economic benefits.

The market assessment is intended to provide an independent market evaluation of potential transmission expansion projects that offer the greatest return on investment.

Economic Planning

The costs of congestion management and transmission construction are inversely proportional as demonstrated by Figure 30. SPP plans the system to meet planning standard; as a result, SPP is beyond the required planning standards requirement. SPP would like to have additional transmission installed to achieve the most cost effective point of operation (i.e., where the costs of transmission and congestion management intersect).

Figure 30: Supply and Demand



Economic Modeling Assumptions

SPP used the Global Energy MarketSym package, which utilizes the PowerWorld load flow program, to perform detailed analysis of the transmission projects in Phase II.

- Henwood MarketSym
  - Coordination of overall simulation process and case/data management
  - ProSym is the engine for initial unit commitment and dispatch
  - Multi-regional database for load/generator/cost characteristics
- PowerWorld Simulator
  - Dispatch optimization using alternating current-optimal power flow (AC-OPF)
  - Computes nodal prices and economic costs of constraints

Key Assumptions Used in the Economic Model
SPP region is modeled as 19 transmission areas encompassing the 17 tariff control areas
Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SOEP) are dispatched as a single control area (AEPW)
Oklahoma Municipal Power Authority (OMPA) loads are distributed within Oklahoma Gas and Electric (OGE), PSO/AEPW and Western Farmers Electric Coop (WFEC) transmission areas
Arkansas Electric Cooperative Corporation loads are aggregated with other loads at buses within Entergy , SOEP and SWPA systems
A portion of Grand River Dam Authority (GRDA) loads are embedded in the Associated Electric Cooperative, Incorporated (AECI) system
Simulation of every other hour in a typical week to represent a month
Control area peak load forecast based on SPP Energy Information Administration (EIA) 411 report and other information analyzed and documented by Henwood staff
Peak loads are modeled based on total internal demand as reported by utilities
Hourly load shapes are based on 'typical year' representation derived by Henwood from multiple years of historical data
Interruptible loads reported in EIA 411 are modeled as dispatchable resources in ProSym
More than 95% of total generation capacity of the optimal power flow (OPF) area is explicitly identified and mapped
Thermal generator forced outage rates and equivalent schedule outage rates are estimated for classes of generators from NERC Generating Availability Data System (GADS) data reported through the year 1999
The ProSym 'Converged Monte-Carlo' technique is used for forced outage rate
Natural gas price estimates are generally tied to Henry Hub price
Fuel oil prices are generally tied to NYMEX future prices
Unit commitment/dispatch by ProSym

Unit commitment by control area
Spinning reserve requirement - 2% of load
Regulation and load following - 3% of load
Non-spinning requirement – 2% of load
Must-run units modeled in SPS
Additional must-run units will be modeled as information becomes available
AC optimal power flow (AC is used to incorporate losses and VAR flows)
Calculates nodal prices
Monitor branches > 100 kV
Monitor all flowgates > 100%
Flowgate operating range for violation cost 0-2% (Penalty of $45 per MW per hour)
Flowgate operating range for violation cost > 2% (Penalty of $90 per MW per hour)
Branches or transformers above normal rated capacity (Penalty of $30 per MW per hour)
Hurdle rates • Between SPP areas - $2 • Between SPP and First Tier - $5
$4 added to offer curves for independent power producers

For the evaluation of economic projects, SPP used an 8% discount rate and evaluated the benefits over a 10-year period using a two-step process. The first step determines if the dispatch cost plus violation cost savings over the studied period paid for the project. If the project is determined to be of benefit to the OPF study area then the cost of the project was allocated to the beneficiaries.

The allocation of the project has two parts: direct and indirect. The direct costs are referred to as the generator redispatch savings and the indirect impact is referred to as the load benefits.

Equations 1 and 2 show how the calculations are made. When benefits are calculated, there are winners and losers. The objective is to levelize cost across the region. In the allocation process only positive impacts are used. The indirect benefits portion is still being discussed. In this report, SPP used the allocation of 10% of unhedged indirect benefits and also without the indirect benefits (i.e, all the load is hedged).

Equation 1: Direct – Generator Redispatch Benefits

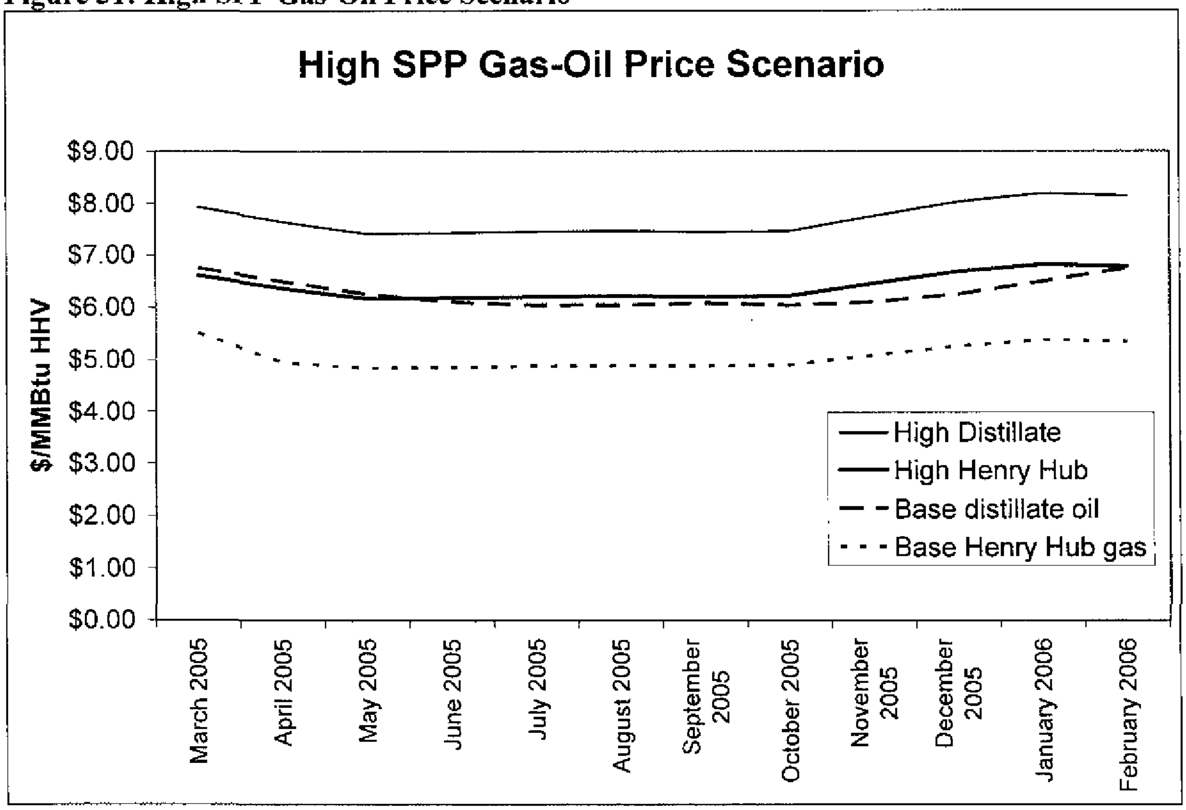
$$\sum_{\substack{\text{All}\\\text{Hours}}} \sum_{\substack{\text{Back}\\\text{Area}}} \sum_{\substack{\text{Gen}\\\text{with}\\\Delta\,MW}} [\,(\Delta\ MW \times \text{Nodal price}) - \Delta\ \text{Dispatch cost}\,]$$

Equation 2: Indirect – Load Impact Benefits

$$\sum_{\substack{\text{All}\\\text{Hours}}} \sum_{\substack{\text{Back}\\\text{Area}}} [\,\Delta\ \text{Load weighted price} \times \text{Load} \times (\text{Pct “unhedged” load})\,]$$

During the economic analysis, a sensitivity evaluation is made to fuel cost. Figure 31 shows the fuel cost used for the base fuel and high cost scenarios.

Figure 31: High SPP Gas-Oil Price Scenario



Project Screening

Phase II of the SPP RTO Expansion Plan was originally scheduled for completion by March 1, 2005. However, due to the time constraint of performing market analysis for economic upgrades, only three or four projects were evaluated in detail. SPP and stakeholders developed a list of potential transmission projects to be evaluated, and only 100 kV and above projects were considered. The projects include proposed and exploratory transmission projects provided by transmission owners and not used in Phase I, projects proposed by stakeholders, projects from breakout groups at the Planning Summit III, projects developed after reviewing transmission line loading relief history and projects after reviewing rejected transmission service. Thirty-three projects were included in the screening process.

The steps for the screening process include:

1) Rank the list of potential transmission projects
2) Used a typical week from July 2005 to run ProSym
3) Base MarketSym run made for 2005 with the OPF area including SPP and first tier companies
4) Change case created for each project on the list of potential transmission projects
5) MarketSym run made for each change case
6) Comparing the base case to the change case, the total dispatch savings (dispatch cost plus violation cost) extracted
7) 10-year savings estimated by calculating the savings over the summer period and assuming the yearly savings is twice the summer savings
8) Present worth of the future savings over a 10-year period calculated using an eight percent discount rate
9) Estimated cost developed for each project
10) Ratio number calculated by dividing the estimated dispatch savings by the cost of the project
11) Projects ranked by the ratio (Note: the ranking method used was solely for screening purposes)
12) List of projects presented in an open SPP TWG meeting for comments (List of screened projects can be found in Appendix C)

Based on project ranking, SPP staff recommends the top four that yield the highest ratio. The four projects selected for detailed analysis are:

1) 345 kV Tulsa East switching station to tie PSO's Northeastern-Oneta and GRDA's GRDA1-Tulsa N lines
2) Rose Hill-Sooner 345 kV
3) Sooner-Cleveland 345 kV
4) Tolk-Potter 345 kV

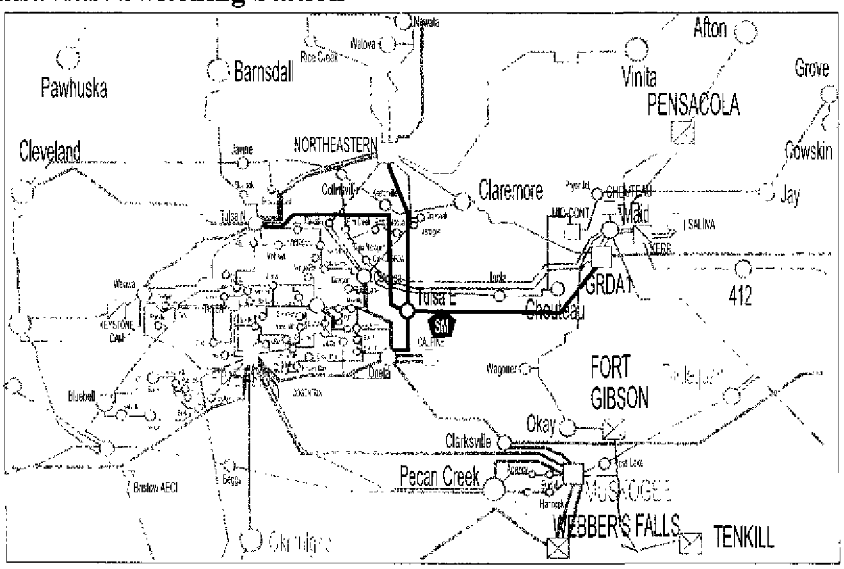
Detailed Analysis

Detailed analyses were performed on the four selected projects. Seasonal MarketSym runs were created for 2005 and 2010. Each change case was compared to the base case. The production cost savings (i.e. dispatch savings plus violations cost savings) was calculated for a 10-year period using seasonal data. The production was used to determine if savings over 10 years would pay for the project. Generation revenues and load savings were calculated to determine the allocation of the benefits.

Tulsa East Switching Station

By installing a switching station, the Tulsa East Switching Station project ties PSO's Northeastern-Oneta 345 kV line and GRDA's GRDA 1-Tulsa North 345 kV lines. Figure 32 shows the location of the Tulsa East Switching Station.

Figure 32: Tulsa East Switching Station



The estimated cost for the Tulsa East Switching Station is $8 million. The calculated economic savings for this project over 10-years is approximately $8 million dollars using an eight percent discount rate, as shown in Figure 33. The savings indicates that the project could be beneficial to interested parties.

Figure 33: Tulsa East Switching Station 10-Year Savings

	Dispatch Cost Savings + Violation Costs Tulsa East 2005	 Tulsa East 2010
Spring	$230,268	$318,501
Summer	$580,340	$641,818
Fall	$181,508	$182,609
Winter	$62,592	$184,838
Total	$1,054,708	$1,327,766
Estimated 10-Year Savings	$7,819,177	

Figure 34 shows the annual generator dispatch benefits and load impacts/load benefits for the Tulsa East Switching Station.

Figure 34: Tulsa East Switching Station Annual Savings for 2005 and 2010

	Year 2005 Generator Redispatch Savings	Year 2005 10% load Benefit Normalized	Year 2010 Generator Redispatch Savings	Year 2010 10% load Benefit Normalized
CELE	(485)	(6,826)	424	(13,074)
EMDE	8,540	(52,204)	4,686	(32,156)
GRRD	826	(41,285)	104	(16,792)
INDN	1,527	(1,292)	370	(3,009)
KACP	8,632	(33,876)	31	(45,558)
KACY	615	(4,628)	(19)	(5,324)
LAFA	145	(714)	52	(2,677)
LEPA	28	(274)	20	(1,069)
MIDW	0	(273)	0	(229)
MIPU	858	(11,748)	1,379	(25,401)
OKGE	3,256	195,648	3,462	178,047
PSOK	88,217	297,795	69,870	309,439
SOEP	(20,932)	(47,922)	(2,085)	(10,396)
SPPIPP	2,191	0	4,752	0
SPRM	2,123	(31,868)	682	(21,776)
SUNC	(234)	1,355	(2,299)	3,990
SWPA	(83)	(12,709)	20	(11,613)
SWPS	(277)	126,027	538	124,975
WEPL	51	817	(306)	398
WERE	10,724	(56,545)	5,774	(40,534)
WFEC	1,885	46,304	3,993	41,433
Subtotals	107,606	365,783	91,448	428,673
AECI	46,811	(27,250)	21,289	(24,353)
IOWA	19,712	(10,332)	15,571	(37,185)
MAINS	4,165	(126,623)	122	(102,474)
NEBR	(46)	7,725	793	(69,399)
EES	(3,075)	(29,092)	(4,326)	(23,247)
EESIPP	5,021	0	4,924	0
Subtotals	72,587	(185,572)	38,373	(256,659)
Totals	**180,193**	**209,303**	**129,821**	**172,015**

Annual Production Cost Savings for 2005

Violation Costs Savings	257,395
Dispatch Savings	797,313
Dispatch + Violation Savings	1,054,708

Annual Production Cost Savings for 2010

Violation Costs Savings	572,217
Dispatch Savings	755,549
Dispatch + Violation Savings	1,327,766

Tulsa East Annual Savings

Figure 35 shows allocation of benefits for the Tulsa East Switching Station using only positive benefits of both generation and load. Negative savings were not included in the allocation. The allocation is shown using two scenarios: 1) generator redispatch savings plus 10% of the load benefits and 2) generator redispatch savings.

Figure 35: Allocation Tulsa East Benefits Based on 10-Year Savings

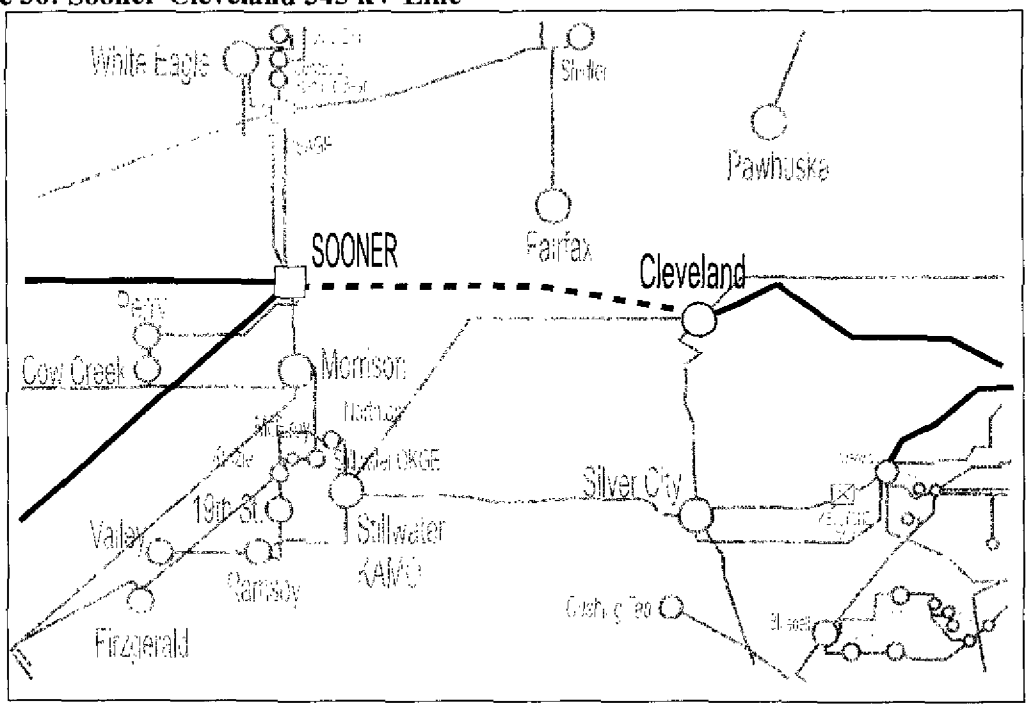
	Allocation Generator Redispatch Savings + 10% Load Benefits	Allocation Generator Redispatch Savings
CELE	0%	0%
EMDE	1%	4%
GRRD	0%	0%
INDN	0%	1%
KACP	1%	3%
KACY	0%	0%
LAFA	0%	0%
LEPA	0%	0%
MIDW	0%	0%
MIPU	0%	1%
OKGE	23%	2%
PSOK	45%	45%
SOEP	0%	0%
SPPIPP	0%	2%
SPRM	0%	1%
SUNC	0%	0%
SWPA	0%	0%
SWPS	15%	0%
WEPL	0%	0%
WERE	1%	5%
WFEC	6%	2%
AECI	4%	20%
IOWA	2%	10%
MAINS	0%	1%
NEBR	1%	0%
EES	0%	0%
EESIPP	1%	3%
Totals	100%	100%

AEP announced a new $48 million project in the Tulsa area. This project completes the 345 kV loop from Wekiwa-Riverside by converting an existing 138 kV line. A sensitivity run was made to determine the impact of this project. The sensitivity runs show that with the project in place, only half of the benefits of the Tulsa East Switching Station project would be realized

Sooner-Cleveland 345 kV Line

The Sooner-Cleveland 345 kV line is a 32-mile transmission line connecting OGE's Sooner generating station to GRDA's Cleveland substation station. Figure 36 shows the location of the Sooner-Cleveland 345 kV line.

Figure 36: Sooner-Cleveland 345 kV Line



The estimated cost of the Sooner-Cleveland 345 kV line is $18 million. The calculated economic savings for this project over a 10-year period is approximately $25 million using an eight percent discount rate, as shown in Figure 37. The savings indicates that the project could benefit interested parties.

Figure 37: Sooner-Cleveland 345 kV Line 10-Year Savings

	Dispatch Cost Savings + Violation Costs	
	Sooner-Cleveland 2005	Sooner-Cleveland 2010
Spring	$1,173,381	$988,535
Summer	$1,245,334	$1,082,592
Fall	$963,488	$635,359
Winter	$718,855	$632,127
Total	$4,101,058	$3,338,613
Estimated 10-Year Savings	$25,446,587	

Figure 38 shows the annual generator redispatch benefits and load impacts/load benefits for the Sooner-Cleveland 345 kV line.

Figure 38: Sooner-Cleveland 345 kV Line Annual Savings for 2005 and 2010

	Year 2005 Generator Redispatch Savings	Year 2005 10% load Benefit Normalized	Year 2010 Generator Redispatch Savings	Year 2010 10% load Benefit Normalized
CELE	7,380	57,355	1,468	23,664
EMDE	15,156	(128,415)	15,184	(120,116)
GRRD	6	(17,088)	(17)	(29,764)
INDN	13,611	(42,528)	7,265	(29,184)
KACP	23,627	(686,442)	11,668	(444,348)
KACY	7,476	(105,794)	5,537	(70,347)
LAFA	54	13,227	(48)	3,452
LEPA	(1)	6,257	23	1,578
MIDW	0	(36,186)	0	(20,931)
MIPU	9,169	(261,019)	11,732	(198,955)
OKGE	93,936	2,307,668	89,677	1,560,565
PSOK	65,986	863,662	58,557	539,376
SOEP	39,328	434,532	33,770	237,843
SPPIPP	3,624	0	5,073	0
SPRM	7,499	(107,293)	7,292	(106,216)
SUNC	541	(23,043)	(641)	(3,314)
SWPA	2,867	(42,112)	2,209	(40,428)
SWPS	23,472	1,049,980	26,408	891,198
WEPL	(65)	(96,976)	(227)	(56,605)
WERE	203,690	(2,012,380)	102,845	(1,376,921)
WFEC	62,137	515,698	44,963	329,443
Subtotals	579,493	1,689,103	422,739	1,089,991
AECI	15,008	(200,247)	12,507	(169,101)
IOWA	4,115	(421,972)	(4,419)	(229,930)
MAINS	5,454	(909,397)	(1,962)	(549,673)
NEBR	5,499	(544,109)	2,859	(413,769)
EES	(47,030)	89,646	(33,443)	(71,897)
EESIPP	10,169	0	(108)	0
Subtotals	(6,785)	(1,986,080)	(24,565)	(1,434,369)
Totals	**572,708**	**(296,976)**	**398,174**	**(344,379)**

Annual Production Cost Savings for 2005

Violation Costs Savings	1,957,912
Dispatch Savings	2,163,146
Dispatch + Violation Savings	4,121,058

Annual Production Cost Savings for 2010

Violation Costs Savings	948,046
Dispatch Savings	2,390,569
Dispatch + Violation Savings	3,338,615

Figure 39 shows allocation of benefits for the Sooner-Cleveland 345 kV line. The allocation of benefits used only positive benefits of both generation and load. Negative savings were not included in the allocation. The allocation is shown using two scenarios: 1) generator redispatch savings plus 10% of the load benefits and 2) generator redispatch savings.

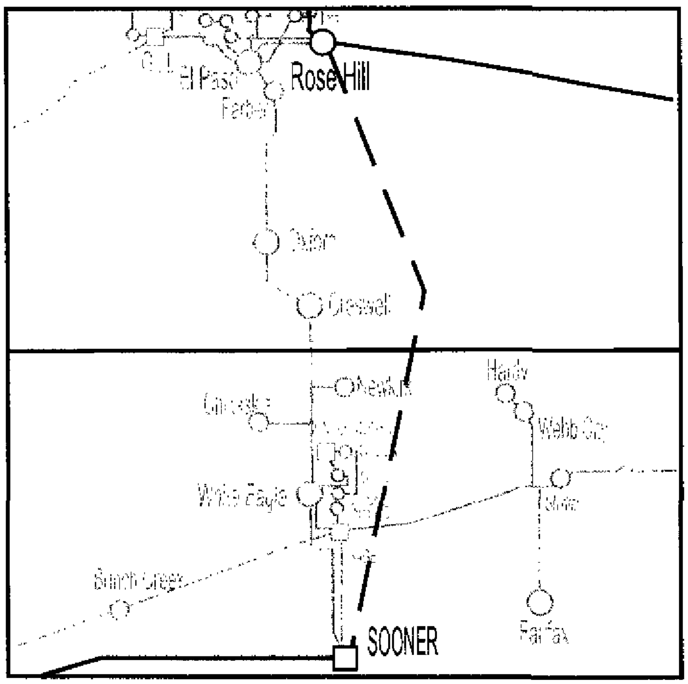
Figure 39: Allocation Sooner-Cleveland 345 kV Based on 10-Year Savings

	Allocation Generator Redispatch Savings + 10% Load Benefits	Allocation Generator Redispatch Savings
CELE	1%	1%
EMDE	0%	3%
GRRD	0%	0%
INDN	0%	2%
KACP	0%	3%
KACY	0%	1%
LAFA	0%	0%
LEPA	0%	0%
MIDW	0%	0%
MIPU	0%	2%
OKGE	41%	17%
PSOK	15%	12%
SOEP	8%	7%
SPPIPP	0%	1%
SPRM	0%	1%
SUNC	0%	0%
SWPA	0%	0%
SWPS	20%	5%
WEPL	0%	0%
WERE	3%	30%
WFEC	10%	10%
AECI	0%	3%
IOWA	0%	0%
MAINS	0%	1%
NEBR	0%	1%
EES	1%	0%
EESIPP	0%	1%
Totals	100%	100%

Rose Hill-Sooner 345 kV Line

The Rose Hill-Sooner 345 kV line is an 83-mile transmission line connecting Westar Energy's Rose Hill substation and OGE's Sooner generating station. Figure 40 shows the location of the Rose Hill-Sooner 345 kV line.

Figure 40: Rose Hill-Sooner 345 kV Line



The estimated construction cost of the Rose Hill-Sooner 345 kV line is $44 million. The calculated economic savings for this project over a 10-year period is approximately $42 million using an eight percent discount rate, as shown in Figure 41. The savings would indicate the project could benefit interested parties who would request additional study; however, the payback period may exceed 10-years.

Figure 41: Rose Hill-Sooner 345 kV Line 10-Year Savings

	Dispatch Cost Savings + Violation Costs	
	Rose Hill-Sooner 2005	Rose Hill-Sooner 2010
Spring	$1,961,617	$1,630,577
Summer	$1,905,147	$1,705,158
Fall	$1,775,775	$1,187,216
Winter	$1,143,109	$904,225
Total	$6,785,648	$5,427,176
Estimated 10-Year Savings	$41,840,778	

Figure 42 shows the annual generator redispatch benefits and load impacts or load benefits for the Rose Hill-Sooner 345 kV line.

Figure 42: Rose Hill-Sooner 345 kV Line Annual Savings for 2005 and 2010

	Year 2005	Year 2005	Year 2010	Year 2010
	Generator Redispatch Savings	10% load Benefit Normalized	Generator Redispatch Savings	10% load Benefit Normalized
CELE	13,822	110,432	5,289	69,743
EMDE	17,670	(28,231)	16,747	(6,449)
GRRD	(0)	146,195	3	94,818
INDN	28,572	(66,117)	13,828	(51,699)
KACP	50,440	(986,490)	45,025	(671,235)
KACY	21,102	(161,633)	16,358	(113,499)
LAFA	(39)	31,531	115	17,340
LEPA	31	12,914	0	8,149
MIDW	0	(53,106)	0	(27,309)
MIPU	26,049	(403,430)	28,505	(323,414)
OKGE	159,202	2,943,603	163,543	1,770,614
PSOK	56,683	1,366,973	47,200	913,138
SOEP	71,260	743,026	52,244	465,385
SPPIPP	2,349	0	2,275	0
SPRM	10,476	(62,056)	6,497	(40,276)
SUNC	587	(47,009)	(435)	(10,405)
SWPA	2,636	(17,543)	2,093	(10,325)
SWPS	52,183	1,432,390	44,454	1,098,007
WEPL	(828)	(148,765)	(448)	(73,178)
WERE	475,208	(3,291,564)	252,411	(2,145,724)
WFEC	149,851	642,156	80,762	374,022
Subtotals	1,137,252	2,163,275	776,466	1,337,703
AECI	17,878	(114,962)	13,042	(100,575)
IOWA	7,221	(453,634)	1,071	(221,292)
MAINS	7,467	(1,017,516)	2,028	(647,631)
NEBR	8,775	(730,772)	3,805	(472,843)
EES	(79,011)	720,296	(33,393)	499,115
EESIPP	5,001	0	1,802	0
Subtotals	(32,669)	(1,596,587)	(11,645)	(943,225)
Totals	**1,104,583**	**566,688**	**764,820**	**394,478**

Annual Production Cost Savings for 2005

Violation Costs Savings	2,664,830
Dispatch Savings	4,120,817
Dispatch + Violation Savings	6,785,647

Annual Production Cost Savings for 2010

Violation Costs Savings	1,278,927
Dispatch Savings	4,148,248
Dispatch + Violation Savings	5,427,175

Figure 43 shows allocation of benefits for the Rose Hill-Sooner 345 kV line. The allocation of benefits used only positive benefits of both generation and load. Negative savings were not included in the allocation. The allocation is shown using two scenarios: 1) generator redispatch savings plus 10% of the load benefits and 2) generator redispatch savings.

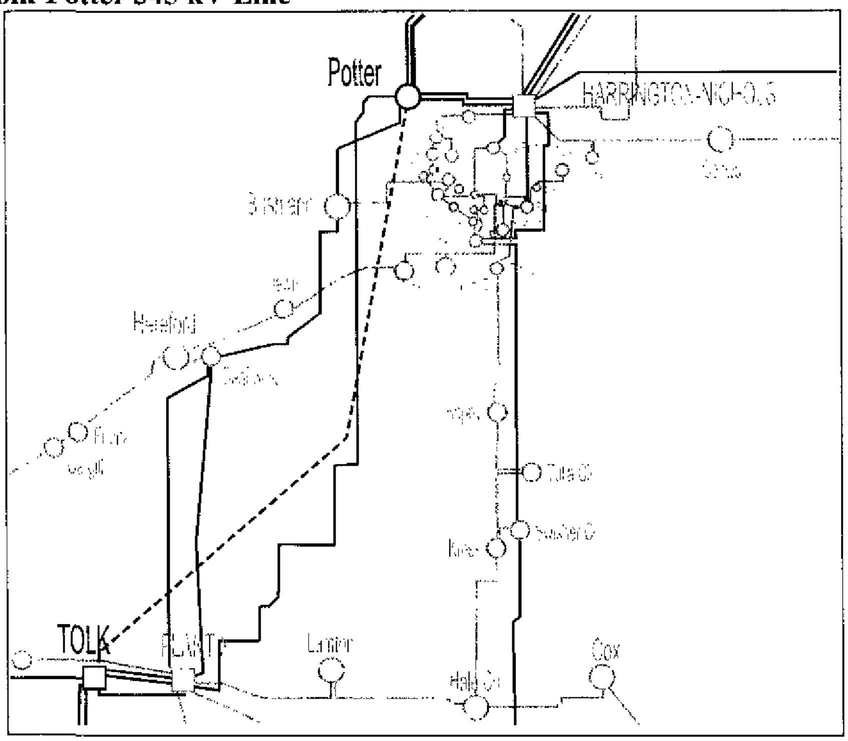
Figure 43: Allocation Rose Hill-Sooner 345 kV Line Based on 10-Year Savings

	Allocation Generator Redispatch Savings + 10% Load Benefits	Allocation Generator Redispatch Savings
CELE	4%	3%
EMDE	0%	2%
GRRD	2%	0%
INDN	0%	2%
KACP	1%	5%
KACY	0%	2%
LAFA	0%	0%
LEPA	0%	0%
MIDW	0%	0%
MIPU	0%	3%
OKGE	31%	20%
PSOK	15%	6%
SOEP	8%	6%
SPPIPP	0%	0%
SPRM	0%	1%
SUNC	0%	0%
SWPA	0%	0%
SWPS	18%	5%
WEPL	0%	0%
WERE	4%	31%
WFEC	7%	10%
AECI	0%	2%
IOWA	0%	0%
MAINS	0%	0%
NEBR	0%	0%
EES	8%	0%
EESIPP	0%	0%
Totals	100%	100%

Tolk-Potter 345 kV Line

The Tolk-Potter 345 kV line is a 55-mile transmission line connecting the SPS Potter substation and SPS Tolk generating station. Figure 44 shows the location of the Tolk-Potter 345 kV line.

Figure 44: Tolk-Potter 345 kV Line



The estimated construction cost of the Tolk-Potter 345 kV line is $30 million. The calculated economic savings for this project over a 10-year period is approximately $35 million using an eight percent discount rate, as shown in Figure 45. The savings indicates the project could be beneficial to the interested parties who would request additional study.

Figure 45: Tolk-Potter 345 kV Line 10-Year Savings

	Dispatch Cost Savings + Violation Costs	
	Tolk-Potter 2005	Tolk-Potter 2010
Spring	$1,819,161	$1,818,469
Summer	$1,385,254	$1,034,012
Fall	$1,330,766	$1,329,091
Winter	$610,566	$1,019,690
Total	$5,145,747	$5,201,262
Estimated 10-Year Savings	$34,679,236	

Figure 46 shows the annual generator redispatch benefits and load impacts or load benefits for the Tolk-Potter 345 kV line.

Figure 46: Tolk-Potter 345 kV Line Annual Savings for 2005 and 2010

	Year 2005 Generator Redispatch Savings	Year 2005 10% load Benefit Normalized	Year 2010 Generator Redispatch Savings	Year 2010 10% load Benefit Normalized
CELE	5,713	(4,821)	3,717	(36,997)
EMDE	1,928	(16,131)	4,326	(33,049)
GRRD	(15)	4,789	79	(17,162)
INDN	4,445	(12,202)	2,240	(11,628)
KACP	3,789	(197,767)	4,922	(165,233)
KACY	1,620	(34,294)	2,208	(28,948)
LAFA	49	1,020	282	(9,399)
LEPA	18	124	1	(5,256)
MIDW	0	(109,426)	0	(108,988)
MIPU	3,404	(72,016)	3,925	(67,985)
OKGE	13,233	361,315	6,963	69,722
PSOK	621	69,708	1,895	(75,645)
SOEP	8,265	57,749	18,551	(115,970)
SPPIPP	1,764	0	602	0
SPRM	3,513	(12,947)	2,335	(26,025)
SUNC	2,404	(359,375)	1,177	(341,000)
SWPA	1,972	(6,799)	1,820	(24,476)
SWPS	2,071,338	2,320,275	1,888,549	2,389,331
WEPL	(121)	(306,876)	66	(305,386)
WERE	31,148	(702,684)	23,728	(552,106)
WFEC	3,135	27,325	4,959	(27,690)
Subtotals	2,158,223	1,006,968	1,972,346	506,109
				0
AECI	4,020	(32,594)	3,680	(61,409)
IOWA	4,921	44,164	2,818	14,678
MAINS	1,976	(244,914)	(1,896)	(199,580)
NEBR	4,227	201,064	11,114	(81,543)
EES	(17,978)	46,707	(11,636)	(466,367)
EESIPP	5,202	0	1,753	0
Subtotals	2,369	14,428	5,832	(794,221)
Totals	**2,160,592**	**1,021,396**	**1,978,178**	**(288,112)**

Annual Production Cost Savings for 2005

Violation Costs Savings	(1,733,704)
Dispatch Savings	6,879,452
Dispatch + Violation Savings	5,145,748

Annual Production Cost Savings for 2010

Violation Costs Savings	(2,001,377)
Dispatch Savings	7,202,639
Dispatch + Violation Savings	5,201,262

Figure 47 shows allocation of benefits for the Tolk-Potter 345 kV line. The allocation of benefits used only positive benefits of both generation and load. Negative savings were not included in the allocation. The allocation is shown using two scenarios: 1) generator redispatch savings plus 10% of the load benefits and 2) generator redispatch savings.

Figure 47: Allocation Tolk-Potter 345 kV Line Based on 10-Year Savings

	Allocation Generator Redispatch Savings + 10% Load Benefits	Allocation Generator Redispatch Savings
CELE	0%	0%
EMDE	0%	0%
GRRD	0%	0%
INDN	0%	0%
KACP	0%	0%
KACY	0%	0%
LAFA	0%	0%
LEPA	0%	0%
MIDW	0%	0%
MIPU	0%	0%
OKGE	5%	1%
PSOK	1%	0%
SOEP	1%	1%
SPPIPP	0%	0%
SPRM	0%	0%
SUNC	0%	0%
SWPA	0%	0%
SWPS	87%	95%
WEPL	0%	0%
WERE	1%	1%
WFEC	0%	0%
AECI	0%	0%
IOWA	1%	0%
MAINS	0%	0%
NEBR	3%	0%
EES	1%	0%
EESIPP	0%	0%
Totals	100%	100%

Project Comparison/Sensitivity Analysis

Figure 48 shows the cost benefit ratio for the four projects based on the calculated 10-year savings. The Sooner-Cleveland 345 kV line has the highest benefit cost ratio, followed by Tolk-Potter 345 kV line. The ratios for the other two projects were slightly less than 100% for a 10-year period. This does not conclude that they are not good economic projects. This analysis did not consider other benefits that may even reduce the payback time to less than 10 years.

Figure 48: Benefit Cost Ratio Based on 10-Year Savings

	Cost Millions	10-Year Savings	Ratio
Tulsa East	$8.0	$7,819,177	98%
Sooner-Cleveland	$18.0	$25,446,587	141%
Rose Hill-Sooner	$43.5	$41,840,778	96%
Tolk-Potter	$29.5	$34,679,236	118%

A sensitivity analysis was conducted to determine how the cost benefit variance related to the sequence of the four project installations. The sensitivity runs revealed the order yielding the greatest benefit is Sooner-Cleveland 345 kV line, Tolk-Potter 345 kV line, Tulsa East Switching Station and Rose Hill-Sooner 345 kV line. The sensitivity runs also show that the savings gained by all projects stacked together were less than the savings realized by the four projects conducted individually.

A sensitivity analysis was also made to study the impact of high fuel cost. The Economic Planning section of this report describes the high fuel scenario. High fuel scenario results:

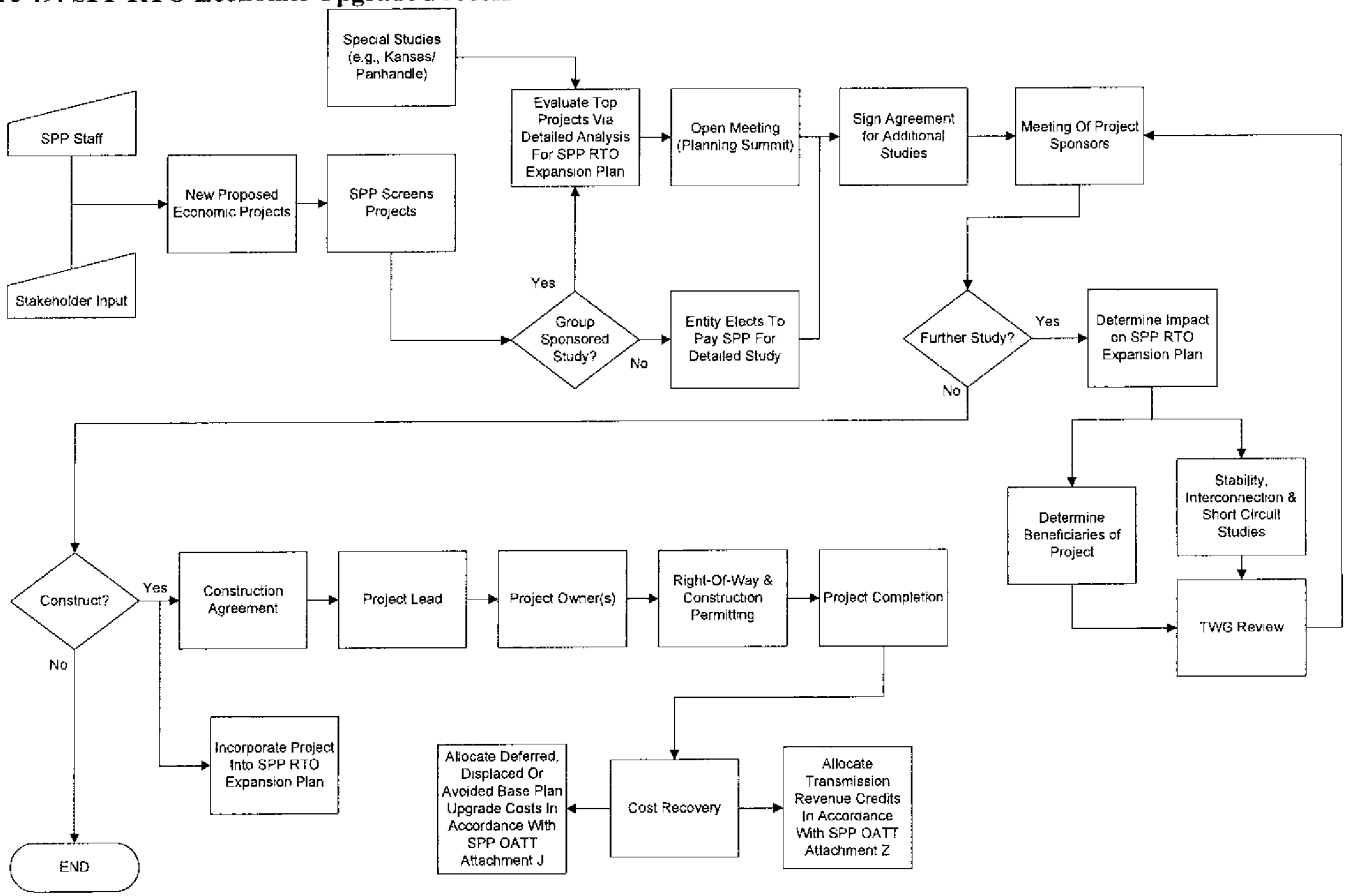
- Tulsa East Switching Station – benefit increased 5%
- Sooner to Cleveland 345 kV Line – benefit increased 56%
- Rose Hill-Sooner 345 kV Line – benefit increased 20%
- Tolk-Potter 345 kV Line – benefit increased 23%

Economic Upgrades

Funding of economic projects is voluntary. The four economic projects were presented at SPP Planning Summit IV. Participants have shown some initial interest in pursuing all four projects.

At the SPP Planning Summit IV, SPP presented a proposed flow chart that outlines the Economic Upgrade Process. Few changes have been made to the flowchart since incorporating comments from stakeholders. Figure 49 shows the proposed flow chart for SPP economic upgrades.

Figure 49: SPP RTO Economic Upgrade Process



Next SPP RTO Planning Cycle

SPP held its fourth planning summit on June 1, 2005 in Dallas/Fort Worth. Results of the Phase II assessment, along with approved Phase I, were shared with summit participants. One of the outcomes of Summit IV was the formation of the Economic Modeling and Methods Task Force. The task force will review the economic planning process used by SPP staff and offer proposals for the improvement of the process.

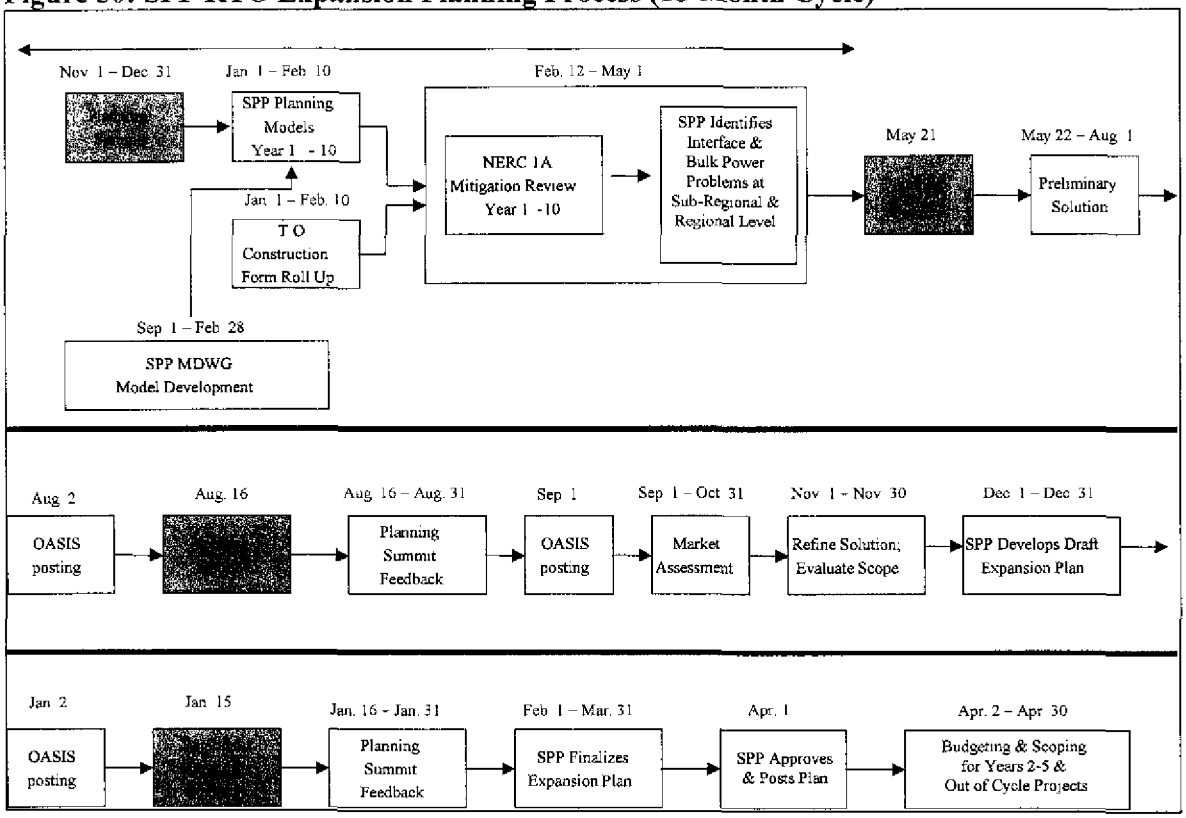
The task force will address the following:

- Determine the necessary data required to model, study and evaluate economic alternatives using MarketSym and PowerWorld
- Review the solution techniques used in the prior expansion plans and provide recommendations for improvement and/or alternatives
- Define as necessary any terms used in the economic planning process, data or assumptions that provides clear understanding
- Review and revise as appropriate the economic assumptions to be used in the development of the economic phase of the expansion plan
- Review and modify if appropriate the methodologies for overall quantification and break-out of economic impacts

After initial review of Phase I, SPP recommended changing the two year planning cycle to 18-months. Figure 50 shows the proposed 18-month SPP RTO planning cycle. Under the new process, the SPP Board would approve the reliability projects within one year from the study start date. Another key item of the new 18-month cycle is the first cycle will be in sync with the SPP MDWG model building effort, whereas the second cycle will use Model On Demand (MOD).

Appendix A of the SPP RTO Expansion Plan contains a list of all projects. The projects are divided into three categories including Board approved projects (Phase I - April 2005), approved out of cycle projects and out of cycle projects pending evaluation. The project lists will be revised quarterly to include project updates.

Figure 50: SPP RTO Expansion Planning Process (18-Month Cycle)



Appendix A: List of Projects

Project Identification

Forms 1-3 contain a list of the projects addressed in the SPP Expansion Plan. Figure 51 shows the area number identifying the owner building the project. SPP transmission owners conduct future planning; and, consequently, many projects listed by SPP were already identified and planned by the transmission owner.

Forms 1-3 identified projects using 'PL,' 'X' and 'OOC.' Projects planned by the transmission owners are indicated with 'PL.' An 'X' indicates the project was identified through the SPP RTO Expansion Plan process and therefore not previously recognized or planned by a transmission owner. 'OOC' shows that the project is an out of cycle project.

The projects are also divided into three categories: projects approved by the Board (Phase I, April 2005); out of cycle projects evaluated and being presented in this report; and out of cycle projects still to be evaluated. Forms 1-3 do not contain all 69 kV and below projects, because the total 69 kV system was not evaluated. The transmission owners independently planned the majority of the 69 kV system.

Figure 51: Owner Area Identification

Area Number	**Owner Building the Project**	
502	CELE	Central Louisiana Electric Company, Incorporated
503	LAFA	City of Lafayette
504	LEPA	Louisiana Energy & Power Authority
515	SWPA	Southwestern Power Administration
520	AEPW	American Electric Power System West
523	GRDA	Grand River Dam Authority
524	OKGE	Oklahoma Gas and Electric Company
525	WFEC	Western Farmers Electric Cooperative
526	SWPS	Southwestern Public Service Company
527	OMPA	Oklahoma Municipal Power Authority
531	MIDW	Midwest Energy, Incorporated
534	SUNC	Sunflower Electric Power Corporation
536	WERE	Westar Energy, Incorporated
539	WEPL	West Plains Energy
540	MIPU	Missouri Public Service Company
541	KCPL	Kansas City Power and Light Company
542	KACY	Board of Public Utilities, Kansas City, KS
544	EMDE	Empire District Electric Company
545	INDN	City Power & Light, Independence, Missouri
546	SPRM	City Utilities, Springfield Missouri

Forms 1 – Transmission Lines and Transformers

9/15/2005

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	From Location	[illegible]	To Location	[illegible]	[illegible]	Line Mile Estimates [illegible]	Line Mile Estimates [illegible]	Line Mile Estimates [illegible]	Ratings [illegible]	[illegible]	Project Description / Comments
SPP BOD APPROVED (4/1/05)															
2004 Spring															
	10/31/03	PL	502	50120	Many	50057	Fisher	1	138	5.9		5.9	249	$300,000	Reconductor an existing line with 795 Drake conductor
	06/01/03	PL	524	54702	Breckenridge Tap	54769	NE Enid	1	138		6.5	6.5	268/287	$1,800,000	
	12/31/03	PL	524	54769	NE Enid	54732	NE Enid	1	138/69		X		123/134	$2,200,000	
	12/31/03	PL	524	55256	Muldrow	55307	Third St	1	69		9.0	9.0	48/48	$1,700,000	
	10/31/03	PL	526	50694	Riverview	50693	Riverview	2	115/69	X			40/40	$250,000	Transformer moved to Carlsbad
	04/01/04	PL	526	52310	Carlsbad	52309	Carlsbad	2	115/69	X			40/40		
	04/01/04	PL	526	51041	Amarillo South	51040	Amarillo South	1	230/115		X		225/259	$12,000,000	
	04/01/04	PL	526	51041	Amarillo South	50915	Nichols	1	230		5.5	5.5	452/497		
	04/01/04	PL	526	51041	Amarillo South	51321	Swisher	1	230		5.5	5.5	452/497		A new interchange is intercepting the Nichols to Swisher 230 kV ckt.
	04/01/04	PL	526	51040	Amarillo South	51026	Farmers	1	115		0.5	0.5	146/161		
	04/01/04	PL	526	51040	Amarillo South	51036	Arrow Head	1	115		0.5	0.5	146/161		A new interchange is intercepting the Arrow Head to Owens Corning 115 kV ckt.
	04/01/04	PL	526	51040	Amarillo South	51038	Owens Corning	1	115	0.5	0.5	1.0	246/271		1/2 mile of new ckt.
	04/01/04	PL	526	51888	LE-Plains	52444	LE-Plains	1	115/69		X		61.6/61.6	$1,000,000	
	04/01/04	PL	526	52354	LE-Lovington	52442	LE-Lovington	1	115/69		X		100/100	$1,500,000	
Completed	01/01/04	PL	541	58656	Maywood North	58722	Maywood South	1	161		0.1	0.1	558	$0	New BPU Maywood South sub and cut-in
Completed	01/01/04	PL	541	58722	Maywood South	58742	Metropolitan	1	161		4.6	4.6	293	$0	New BPU Maywood South sub and cut-in
2004 Summer Peak															
	06/01/04	PL	520	53144	Lowell	53152	Rogers	1	161	4.4		4.4	393/413	$4,890,000	Convert line to 161 kV
	06/01/04	PL	520	53152	Rogers	53135	East Rogers	1	161		4.7	4.7	393/413	$2,902,000	New 161 kV Line
	04/01/04	PL	520	53170	Tontitown	53144	Lowell	1	161		10.4	10.4	393/413	$7,034,000	New 161 kV Line
	04/01/04	PL	520	53170	Tontitown	53131	Dyess	1	161	6.8		6.8	446/446	$490,000	Rebuild 161 kV Line
	06/01/04	PL	520	53795	Riverside	54030	Explorer Okmulgee	1	138	25.0		25.0	265/309	$4,473,000	Rebuild line
	06/01/04	PL	520	54023	Okmulgee	54030	Explorer Okmulgee	1	138	5.0		5.0	265/309	$1,327,000	Rebuild line
	06/01/04	PL	520	54157	Comanche Tap	56204	OMPA Duncan	1	138	17.7		17.7	109/163	$50,000	Raise 4 to 5 structure
	06/01/04	PL	526	50518	LP&L South Interchange	50517	LP&L South Interchange	1	230/69		X		112/112	$1,000,000	4th Interconnection to LP&L
	09/17/04	PL	526	51465	Lamb	51531	Tuco	1	69	29.3		29.3	88/88	$1,700,000	Reconductor Circuit
	06/01/04	PL	526	51661	Lubbock South	50518	LP&L South Interchange	1	230		2.9	2.9	492/541	$575,000	Use SPS ratings for now
	03/01/04	PL	526	51804	Lynn County	51803	Lynn County	2	115/69		X		40/40	$1,500,000	Add 2nd Auto at Lynn
12/01/04	06/01/04	PL	536	57151	Auburn	57179	South Gage	1	115	4.6		4.6	223/245	$1,800,000	Replace double circuit w/larger single circuit / In service 12/2004 - Emergency rating is CT limit
12/01/04	06/01/04	PL	536	57218	Kereford	57259	NW Leavenworth	1	115	15.1		15.1	223/245	$3,400,000	Rebuild / In service 12/2004 - Emergency rating is CT limit
	06/01/04	PL	536	57543	Creswell	57548	Paris	1	69	5.7		5.7	100/100	$1,300,000	Rebuild / Limit is substation bus at Creswell
07/01/04	06/01/04	PL	536	57745	Newton	57733	Gatz	1	69	3.3		3.3	72/72	$900,000	Rebuild / In service 7/2004 - Rating is CT limit
	06/01/04	PL	540	59210	Martin City	59259	Turner Road	1	161		3.3	3.3	223/245	$1,320,000	
	06/01/04	PL	540	59259	Turner Road	59340	Belton South	1	161		5.5	5.5	223/245	$2,200,000	
	06/01/04	PL	540	59296	Harrisonville sw	59297	Harrisonville N tap	1	69	1.8		1.8	100/107	$500,000	
	06/01/04	PL	540	59340	Belton South	59290	Belton South	1	161/69		X		100/125	$1,250,000	
Completed	06/01/04	PL	541	57973	Hawthorn	58027	Randolph	1	161	2.0		2.0	558	$402,000	Reconductor Hawthorn-Randolph 161 kV Line
Completed	06/01/04	PL	541	58027	Randolph	58015	Avondale	1	161	3.5		3.5	558	$700,000	Reconductor Randolph-Avondale 161 kV Line
Completed	06/01/04	PL	544	59540	SUB 152 - Monett	59591	SUB 383 - Monett	1	69	0.0			65	$425,000	Rebuild 69KV Bus Monett Sub #152

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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	From Location	[illegible]	To Location	[illegible]	[illegible]	Line Mile Estimates			Ratings	[illegible]	Project Description / Comments
Completed	06/01/04	PL	544	59596	SUB 393 - Reinmiller	59538	SUB 131 - Diamond	1	69	10.8		10.8	92	$1,200,000	Reconductor 69KV LINE FROM REINMILLER
	06/01/04	PL	548	59907	Sunset	59834	Seminole	1	69	1.2		1.2	103/108	$400,000	Line Feed for new Seminole Substation
2004 Winter Peak															
	12/31/04	PL	503	50305	Bonin	50308	St George	1	69	2.1		2.1	195/235	$700,000	Reconductoring
	11/01/04	PL	520	53802	Catoosa	53783	Lynn Lane East	1	138	X			262/262	$0	Strain bus and jumpers rerated at Catoosa
	11/16/04	PL	523	54470	Walmart Tap	54482	Walmart	1	69		3.0	3.0	57/65	$1,100,000	Build new 69kV line
	11/16/04	PL	523	54482	Walmart	53941	Ramona	1	69		3.0	3.0	57/65	$1,100,000	Build new 69/13.8kV substation
	06/01/04	PL	524	54934	Draper	54933	Draper	1	345/138		X		493/493	$8,000	Upgrade CT
	10/01/04	PL	524	55300	Fort Smith	55305	Fort Smith	1	500/161		X		440/480	$7,500,000	entered by KG form IDEV submitted
	11/01/04	PL	524	54033	Pittsburg	55045	Seminole	1	345	X			956/956	$25,000	Wavetrap and CT at Seminole
	12/31/04	PL	524	55319	Little Spadra	55320	Little Spadra	1	161/69		X		123/134	$1,300,000	
	12/31/04	PL	524	55319	Little Spadra	52714	SPA Clarksville	1	161		5.5	5.5	223/223	$2,000,000	
	12/31/04	PL	526	50858	Finney	59998	Lamar	1	345		105.0	105.0		$45,000,000	Includes substation estimates
04/26/05	12/31/04	PL	534	56391	Pioneer	56481	Hugoton	1	115		13.0	13.0	165/198	$5,500,000	New Pioneer-Hugoton 115 Line
01/25/05	12/31/04	PL	534	56481	Hugoton	56405	Walkemeyer	1	115		13.0	13.0	165/198		New Pioneer-Hugoton 115 Line
06/01/05	09/01/04	PL	540	59205	Blue Springs East	59226	Grain Valley	1	161	3.4	0.3	3.6	223/245	$720,000	
06/01/05	09/01/04	PL	540	59226	Grain Valley	59227	Oak Grove	1	161	3.4	0.3	3.6	223/245	$720,000	
2005 Spring															
	03/01/05	PL	520	53526	Crockett	53525	Crockett	1	345/138	X			330/330	$12,000	Reset metering CT
	02/01/05	PL	526	52293	Seven Rivers	52294	Seven Rivers	1	230/115		X		150/150	$6,615,000	
	02/01/05	PL	526	52293	Seven Rivers	52185	Eddy County	1	230		24.5	24.5	492/541		
12/31/2005	03/01/05	PL	526	51996	Amerada Hess	52036	Doss	1	115		6.0	6.0	157/173	$4,200,000	
12/31/2005	03/01/05	PL	526	52036	Doss	52035	Doss	1	115/69		X		75/75		
2005 Summer Peak															
08/30/05	06/01/05	X	515	52694	Springfield	52692	Springfield	2	161/69	X			70/70	$700,000	Replace transformer
	06/01/05	X	520	53131	Dyess	53159	South Springdale	1	161	X			305/354	$100,000	Replace Jumper and Switch at South Springdale
06/01/07	06/01/05	X	520	53319	SE Texarkana	53329	Texarkana	1	69	X			90/121	$100,000	Replace riser and jumper at Texarkana
	05/01/05	PL	520	53548	*IPC Jefferson*	53420	Lieberman	1	138	26.3		26.3	160/160	$4,936,000	Rebuild 138 kV Line
05/13/05	05/01/05	PL	520	53557	Knox Lee	53622	Cherokee	1	138	3.3		3.3	214/287	$309,000	Rebuild 138 kV Line
05/13/05	05/01/05	PL	520	53611	Tatum	53522	Cherokee	1	138	6.5		6.5	214/287	$610,000	Rebuild 138 kV Line
05/13/05	05/01/05	PL	520	53611	Tatum	53598	Rock Hill	1	138	6.6		6.6	214/268	$620,000	Rebuild 138 kV Line
06/01/05	05/01/05	PL	520	53811	Catoosa	53802	Catoosa	1	138/69	X			93/103	$1,274,000	Replace Auto
05/01/05	04/01/05	PL	520	54028	Weleetka	54029	Weleetka	1	138/69	X			50/55	$990,000	Replace Auto
	06/01/05	X	520	54125	Hedrick	54138	Snyder	1	69	X			72/72	$50,000	Replace wave trap
No Date	06/01/05	X	523	54428	Pensacola	54465	Gray Tap	1	69	4.4		4.4	99/113	$800,000	Rebuild of Pensacola - Jayline (not owned by GRDA -- have tried to convince owner)
04/29/05	05/31/05	PL	524	54835	Memorial	54850	Skyline	1	138	1.7		1.7	478/478	$1,600,000	Increase Terminal equipment and reconductor to 2000A.
Completed	04/30/05	PL	524	54853	Division	54852	Silver Lake	1	138	2.5		2.5	268/308	$125,000	Replace terminal equipment and trap at Division Substation to 2000A.
02/12/05	05/31/05	PL	524	54861	Mustang	54896	Morgan	1	138	X			388/444	$15,000	Increase CTR to 2000A at Mustang.
04/27/05	06/01/05	PL	524	54934	Draper	54933	Draper	3	345/138		X		493/493	$9,500,000	
	05/31/05	PL	524	54937	Horseshoe Lake	54841	Hammett	1	69	X			52/66	$15,000	Increase CTR to 600A.
	06/01/05	X	524	54996	Elowah	55052	Tribbey	1	69	X			52/66	$0	Close NO switch of Elowah-Tribbey NOTE: Overloads Midwest - Franklin so it must take place after the Midwest - Franklin project is complete
06/01/06	04/30/05	X	524	55011	Stillwater	55009	McElroy	1	138	1.9		1.9	478/478	$800,000	Reconductor 1.91 miles of 477AS33 to 795AS33

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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	From Location	[illegible]	To Location	[illegible]	[illegible]	Line Mile Estimates [illegible]	[illegible]	[illegible]	Ratings [illegible]	[illegible]	Project Description / Comments
	04/30/05	PL	524	55138	Sunnyside	54033	Pittsburg	1	345	X			800/800	$10,000	Increase CTR to 2000A at Sunnyside. Next limit is 1339A Relay setting at AEP's Pittsburg.
	06/01/05	X	524	55177	Park Lane	55187	Ahloso Tap	1	69	X			96/96	$50,000	Replacement of Switch (800->1200A)
	05/31/05	PL	524	55224	Muskogee	53794	Riverside	1	345	X			1052/1052	$15,000	Increase CTR to 2000A at Muskogee. New limit is 1760A AEP Trap
	05/31/05	PL	524	55224	Muskogee	53756	Clarksville	1	345	X			901/985	$15,000	Increase CTR to 2000A at Muskogee.
06/01/06	06/31/05	PL	524	54855	Richars Tap	54862	Richards	1	138		3.5	3.5	268/308	$1,000,000	
04/20/05	04/30/05	X	524	55228	Five Tribes	55234	Pecan Creek	1	161	X			272/312	$15,000	Increase CTR to 1200A at Five Tribes Substation.
	08/01/05	X	525	54122	Elk City	55897	Elk City	1	69	1.9		1.9	47/61	$380,000	Reconductor line
	06/01/05	PL	525	54946	Midwest Tap	55917	Franklin SW	1	138	X			286/286	$24,000	Upgrade Wave Trap (800->2000A) - Line is tie line between OGE & WFEC. Replace 800 amp wavetrap with 2000 amp wavetrap at Franklin Switch and 795ACSR jumpers with 1590ACSR, connectors. Next limit is two breakers and disconnect switches at Franklin.
	06/01/05	X	525	56043	Russell	56042	Russell	1	138/69	X			62/62	$620,000	Replace 25MVA XF at Russell with 62MVA
02/01/05	02/08/05	PL	536	53972	S Coffeyville	57002	Dearing	1	138	X			215/215	$10,000	Replace wavetrap at Dearing. Rating is WERE sag limit of conductor.
12/1/2006	06/01/05	X	536	56862	McDowell	57335	McDowell	1	230/115		X		280/308	$3,300,000	New transformer
12/1/2006	06/01/05	X	536	56863	Morris	56862	McDowell	1	230	28.5		28.5	363/363	$1,100,000	Originally built for 230kV, operated 115kV
No Date	06/01/05	X	536	56991	Weaver	57604	Weaver		138/69		X		100/110	$1,200,000	New transformer #2 at Weaver
10/01/05	06/01/05	X	536	57307	Prairie	57304	Lang	1	115		8.0	8.0	179/179	$2,200,000	New construction, 795 kcmil ACSR, 100 degree C rating will be implemented upon review of terminal equipment
12/01/05	06/01/05	X	540	59209	Sedalia	59271	Sedalia North	1	161/69	X			100/125	$700,000	Transformer Upgrade
No Date	06/01/05	X	540	59239	Harrisonville	59295	Harrisonville	1	161/69	X			100/125	$2,100,000	Removed due to Out-of-cycle projects
	06/01/05	X	540	59242	Clinton	59303	Clinton	2	161/69	X			100/125	$2,070,000	Transformer Upgrade
12/01/05	06/01/05	PL	541	58054	Cedar Niles	57966	West Gardner	1	161		9.0	9.0	293	$2,500,103	New Cedar Niles-West Gardner 161 kV Line
07/01/05	06/01/05	PL	544	59548	SUB 221 - Billings Northeast	59560	SUB 359 - Republic East	1	69	6.1		6.1	92	$800,000	Reconductor 69KV line
2005 Winter Peak															
05/01/05	08/01/05	PL	520	54044	Valiant	54014	Hugo Tap	1	138	X			195/227	$47,000	Replace wavetrap at Valiant.
05/01/05	10/01/05	PL	520	54037	Valiant	53277	Lydia	1	345	X			1011/1176	$99,000	Replace switches and reset relays at Valiant.
	08/10/05	PL	520	54140	Southwestern Station	55814	Anadarko	1	138	X			202/235	$47,000	Replace Southwestern Station wavetrap & Anardarko wavetrap
05/01/05	10/01/05	PL	520	55948	Hugo Power Plant	54044	Valiant	1	138	X			315/315	$142,000	Replace switches at Valiant. New limits would be the WFEC conductor at 315 mva.
04/01/05	07/01/05	PL	520	54153	Elk City	54121	Elk City	1	230/138	X			260/287	$80,000	Replace free standing metering CT.
04/01/05	07/01/05	PL	520	54112	Cornville	55867	Cornville Tap	1	138	X			118/143	$47,000	Replace the Cornville wavetrap.
06/01/05	07/01/05	PL	520	53940	Bartlesville Southeast	53835	N.Bartlesville	1	138	X			202/235	$47,000	Replace Bartlesville SE wavetrap. New limits would be the 795 ACSR line conductor for the SP and BSE CT setting for the WP
	10/31/05	PL	524	55068	Shawnee	55070	Mission Hill	1	69	X			72/72	$10,000	Increase CTR to 600A.
	01/01/06	PL	524	55035	Bristow	55048	Keystone West	1	138	X			267/267	$350,000	Upgrade CT and Wavetrap at Bristow, and line relays at Bristow, Rock Creek & Horseshoe Lake.
06/01/05	09/01/05	PL	526	50938	Northwest Interchange	50937	Northwest Interchange	1	115/69		X		84/84	$650,000	
	09/01/05	X	526	50956	East Plant	50956	East Plant	1&2	115/69	X			84/96.6	$2,050,000	Upgrade both existing transformer
	09/01/05	PL	526	50996	34th St	51002	Coulter	1	115	1.0		1.0	146/161	$2,200,000	
	09/01/05	PL	526	50996	34th St	51008	Georgia	1	115	3.3		3.3	146/161		

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										Line Mile Estimates			Ratings		
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	From Location	[illegible]	To Location	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	Project Description / Comments
09/01/05	12/31/05	PL	526	51559	Floyd Tap	51518	Floyd	1	115		6.0	6.0	146/146	$9,500,000	
09/01/05	12/31/05	PL	526	51564	Crosby	51688	Lubbock East	1	115		26.0	26.0	157/173		
2006 Summer Peak															
	06/01/06	X	515	52650	Norfork	52648	Norfork	1	161/69	X			50	$800,000	Replace transformer with rebuilt 37 MVA XF
12/31/04	06/01/06	X	520	53276	Lone Star South	53311	Pittsburg	1	138	X			230/268	$50,000	Replace CT
	06/01/06	PL	520	53311	Pittsburg	53337	Winnsboro	1	138		20.0	20.0	303/354	$9,630,000	New 138 kV Line
06/01/07	06/01/06	X	520	53557	Knox Lee	53586	Oak Hill #2	1	138	X			251/287	$100,000	Replace relay, wave trap at Knoxlee
06/01/07	06/01/06	X	520	53774	53rd & Garnett N. Tap	53823	Tulsa Southeast	1	138	X			235/278	$63,000	Replace 3 switches
	06/01/06	X	520	53598	Rock Hill	53519	Carthage REC	1	138	9.5		9.5	246/287	$2,425,000	Reconductor with 1272 ACSR. In Rock Hill sub Replace 755 ACSR and CT
	06/01/06	X	520	53519	Carthage REC	53529	Carthage T	1	138	2.3		2.3	280/287	$690,000	Reconductor line with 1272 ACSR
05/30/05	05/30/06	PL	523	54455	Tahlequah	54504	Stilwell	1	161		19.0	19.0	230/264	$4,800,000	Build new 161kV line from Tahlequah to Stilwell
05/30/05	05/30/06	PL	523	54504	Stilwell	54521	Stilwell City	1	161/69	X			70/78	$1,800,000	Install 161/69kV autotransformer at Stilwell
12/31/04	06/30/06	PL	524	54769	NE Enid	54734	Glenwood	1	138		6.5	6.5	268/287	$2,500,000	
06/01/05	06/01/06	PL	524	54984	NE10th	54986	Glendale	1	138	2.5		2.5	268/287	$750,000	Related to the new construction of Glendale
	06/01/06	X	524	54972	Reno	54980	Sunny Lane	1	69	X			134/154	$100,000	Replace Wave Trap and CT -- new limit 1200A
	06/01/06	PL	524	55298	Van Buren AVEC	55336	VBI	1	69	X			134/143	$50,000	Trap & CTR work increase to 1200A.
	06/01/06	X	524	55326	3rd Street Tap	55342	Massard	1	161		2.0	2.0	72/72	$450,000	New tap on 3rd street and new line from 3rd Tap - Massarc
12/31/06	06/01/06	PL	524	55331	Razorback	55312	Short Mountain	1	69		13.5	13.5	134/143	$4,800,000	
06/01/10	06/01/06	PL	524	55338	Razorback Tap	55331	Razorback	1	69		9.5	9.5	134/143	$2,800,000	
06/30/06	05/31/06	PL	524	54862	Richards	54864	Piedmont	1	138		5.0	5.0	268/308	$2,031,693	
	06/01/06	X	526	51241	Bailey Co	51242	Bailey Co	1&2	115/69	X			84/84	$2,200,000	Upgrade both existing transformer
	06/01/06	X	526	51315	Kress	51316	Kress	1	115/69	X			84/84	$1,250,000	Upgrade both existing transformer
06/01/10	06/01/06	PL	526	51360	Cox	51518	Floyd	1	115		24.5	24.5	157/173	$7,150,000	
	06/01/06	X	526	51959	Denver City	51962	Denver City	1&2	115/69	X			84/84	$2,200,000	Upgrade both existing transformer
06/01/14	06/01/06	X	536	56851	Auburn	57151	Auburn	2	230/115		X		280/308	3,080,000	New transformer #2 at Auburn
06/01/05	06/01/06	X	540	59209	Sedalia	59271	Sedalia South	1	161/69	X			100/125	$700,000	Transformer Upgrade
	06/01/06	PL	540	59313	Lone Jack	59218	Greenwood	1	161		4.0	4.0	223/245	$1,600,000	Radial Line From Greenwood to New Lone Jack 161KV Sut
	06/01/06	PL	541	57991	Terrace		Boulevard	1	161		1.0	1.0	293	$5,088,000	New Boulevard sub and new 161kV line
06/01/08	06/01/06	PL	541	58030	Waldron	58656	Maywood	1	161		8.2	8.2	293	$1,323,000	New Waldron sub cut-in
06/01/08	06/01/06	PL	541	58030	Waldron	58017	Weatherby	1	161		6.2	6.2	273	$0	New Waldron sub cut-in
06/01/07	06/01/06	PL	541	58064	Cedar Niles	58037	Quarry	1	161		8.8	8.8	293	$6,168,000	New Cedar Niles-Quarry 161 kV Line
2006 Winter Peak															
	12/01/06	X	526	51597	Hockley	51598	Hockley	1&2	115/69	X			84/96.6	$2,200,000	Upgrade both existing transformer
2007 Summer Peak															
06/01/08	06/01/07	X	520	53138	Fayetteville	53146	N Fayetteville	1	161	4.0		4.0	354/413		Convert 69 KV line to 161 kV
06/01/08	06/01/07	X	520	53146	N Fayetteville	53131	Dyess	1	161	6.0		6.0	354/413	$7,940,000	Convert 69 KV line to 161 kV
06/01/08	06/01/07	X	520	53157	S Fayetteville	53138	Fayetteville	1	161	2.0		2.0	354/413		Convert 69 KV line to 161 kV
	05/01/07	X	520	53155	Chamber Springs	53176	Tontitown	1	345		14.0	14.0	1011/1176	$14,405,000	Install new 345 kV line, ROW and terminal equipment at Chamber Springs
	05/01/07	PL	520	53158	Siloam Springs	53154	Chamber Springs	1	161		7.5	7.5	354/413	$6,627,225	New 161 line. Terminal equipment at Chamber Spring and Siloam Springs
	05/01/07	X	520	53170	Tontitown	53194	Elm Springs REC	1	161	1.5		1.5	422/492	$640,000	Rebuild line with 2-397 ACSR. Replace 1200 A switch 1045, and bus Elm Springs.
	05/01/07	X	520	53176	Tontitown	53170	Tontitown		345/161		X		675/675	$4,278,100	Install new 345/161 kV Auto and install terminal equipment at

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					From Location		To Location			Line Mile Estimates			Ratings		Project Description / Comments
	06/01/07	X	520	53337	Winnsboro	53581	North Minneola	1	138		25.0	25.0	303/354	$9,056,000	New 138 kV Line
05/30/13	05/30/07	PL	523	54451	Claremore	54479	Claremore	3	161/69		X		75/84	$1,800,000	Install 3rd 161/69kV autotransformer at Claremore
05/30/09	05/30/07	PL	523	54455	Tahlequah	54504	Tahlequah	3	161/69	X			70/78	$1,800,000	Install 3rd 161/69kV autotransformer at Tahlequah
05/30/10	05/30/07	PL	523	54516	Kansas	54515	Kansas	2	161/69	X			86/95	$1,800,000	Install 2nd 161/69kV autotransformer at Kansas
	06/01/07	X	526	51829	Terry Co	51830	Terry Co	1&2	115/69	X			84/84	$2,200,000	Upgrade both existing transformer
06/01/11	06/01/07	X	536	57180	Tecumseh	57252	Midland	1	115	36.0		36.0	117/117	$9,000,000	Convert line from 161kV to 115 kV
	06/01/07	PL	541	57969	Stilwell	58050	Antioch	1	161	4.5		4.5	553	$1,561,000	Reconductor 161kV line
	06/01/07	PL	541	57990	Crosstown		Boulevard	1	161		2.0	2.0	293	$4,542,940	New 161kV line
	06/01/07	PL	541	58077	Pleasant Valley	58066	South Ottawa	1	161		16.0	16.0	293	$1,885,000	New South Richland sub and cut-in
	06/01/07	PL	541	58077	Pleasant Valley	57966	West Gardner	1	161		11.0	11.0	293	$0	New South Richland sub and cut-in
06/01/08	06/01/07	PL	541	58126	Lackman	57969	Stilwell	1	161		8.0	8.0	293	$164,000	New Lackman sub cut-in
06/01/08	06/01/07	PL	541	58126	Lackman	58042	Springhill	1	161		3.0	3.0	293	$0	New Lackman sub cut-in
	06/01/07	X	544	59500	ReinMiller	59472	Tipton Ford	1	161		4.2	4.2		$3,215,000	Install new 161 kV line from 292 to 393 Build 4.2 miles Terminal at both
2007 Winter Peak															
	12/01/07	X	526	51401	Hale Co	51402	Hale Co	1&2	115/69	X			84/96.6	$2,350,000	Upgrade both existing transformer
2008 Summer Peak															
	06/01/08	X	515	52692	Springfield	59969	Brookline	1	161	2.0		2.0	380/380	$640,000	Upgrade the main and transfer buses and bus work within bay at Springfield to 1800 amps($250,00). Replace disconnect switches at Springfield.Reconductor 2 miles 161 kV line $390,000 1272 ACSR
06/01/09	06/01/08	X	520	53131	Dyess	53194	Elm Springs REC	1	161	X			305/353	$186,000	Replace Jumper, Switch, Breaker at Dyess and replace switch at Elm Springs
10/01/05	06/01/08	X	520	53249	Bann	53269	Kings Highway	?	69	X			90/105	$50,000	Replace Switch in King Hwy substatior
02/01/08	04/01/08	PL	526	52313	Pecos	52314	Pecos	1	230/115	X			150/150		Cost to relocate Chaves Transformer
	04/01/08	PL	526	52313	Pecos	52253	Potash Junction	1	230		14.0	14.0		$9,000,000	
	04/01/08	PL	526	52313	Pecos	52293	Seven Rivers	1	230		17.5	17.5			
	06/01/08	X	526	51687	Lubbock East	51688	Lubbock East	1&2	115/69	X			84/96.6	$2,200,000	Upgrade both existing transformer
	04/01/08	PL	526	52314	Pecos	52308	Fiesta	1	115		0.5	0.5	146/146	$200,000	Move 115 kV circuit from Carlsbad to Pecos
	06/01/08	PL	534	56359	Beeler	56456	Ness City	1	115	11.9		11.9	165	$1,264,000	Scott City to Ness City Rebuild
	06/01/08	PL	534	56360	Dighton Tap	56359	Beeler	1	115	20.9		20.9	165	$2,220,000	Scott City to Ness City Rebuild
	06/01/08	PL	534	56362	Manning Tap	56360	Dighton Tap	1	115	13.7		13.7	165	$1,455,000	Scott City to Ness City Rebuild
	06/01/08	PL	534	56393	Plymell	56392	Pioneer Tap	1	115	14.0		14.0	165	$2,016,000	Holcomb to Pioneer Tap Rebuild
	06/01/08	PL	534	56433	Scott City	56362	Manning Tap	1	115	10.0		10.0	165	$1,062,000	Scott City to Ness City Rebuild
	06/01/08	PL	534	56448	Holcomb	56393	Plymell	1	115	11.0		11.0	165	$1,584,000	Holcomb to Pioneer Tap Rebuild
	06/01/08	X	536	57041	Evans South	57064	17th Street	1	138		11.0	11.0	464/478	$6,204,000	New Line from Evans-17th Street
	06/01/08	X	536	57064	17th Street	57840	17th Street	2	138/69		X		150/165		New transformer #2 at 17th Street
06/01/13	06/01/08	X	536	57244	Jarbalo	57233	166th Street	1	115	6.4		6.4	223/240	$1,600,000	Rebuild Line
No Date	06/01/08	PL	541	57985	Northeast	58018	North Kansas City	1	161	1.7		1.7	553	$438,700	Reconductor 161kV Line
	06/01/08	PL	541	58121	Hillsdale	58054	Cedar Niles	1	161		7.6	7.6	293	$5,812,000	New Hillsdale-Cedar Niles 161 kV Line and Cedar Niles ring bus
	06/01/08	PL	541		Paola	58069	Paola	1	345/161		X		400/440	$12,650,000	New 345/161kV transformer and 345kV line cut-in
2009 Summer Peak															
	06/01/09	X	515	52634	Idalia	96056	Asherville	1	161	22.0		22.0	237/237	$4,400,000	Remove wave traps at Idalia and Asherville Reconductor Idalia-Asherville line.
12/31/04	06/01/09	X	520	53276	Lone Star South	53819	Wilkes	1	138	X			359/394	$50,000	Change CT Ratio
No Date	06/01/09	X	520	53532	Forest Hills	53596	Quitman	1	69	X			72/72	$100,000	Replace Bus & reset relays at Quitman substatior

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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	From Location	[illegible]	To Location	[illegible]	[illegible]	Line Mile Estimates			Ratings	[illegible]	Project Description / Comments
	06/01/09	X	524	55073	Earlsboro	55077	Fixico	1	69	X			76/76	$50,000	Replace CT & Trip to 1200A
	06/01/09	X	526	51680	Lubbock South	51681	Lubbock South	2	230/115		X		252/298.8	$2,300,000	New transformer
	09/01/09	X	526	51709	Cochran	51710	Cochran	1&2	115/69	X			84/84	$2,200,000	Upgrade both existing transformer
	06/01/09	X	541	57978	Craig	58038	Lenexa	1	161	X			513/513	$98,000	Replace Lenexa Circuit Switcher R1-4 with 2000 Amp Breaker
	06/01/09	X	541	58000	Blue Valley	58010	Winchester Jct	1	161	X			293/293	$13,000	upgrade wavetrap to 1200 amp, increase line rating to 293 Mva
	06/01/09	X	541	58031	Greenwood	58010	Merriam	1	161	5.0		5.0	558/558	$1,256,000	Reconductor Merriam Greenwood with 1192 ACSS for 2000 amp capability, Uprate Line Switches and Wavetraps at Merriam and Greenwood
06/01/08	06/01/09	PL	541	58121	Hillsdale	58126	Lackman	1	161		12.0	12.0	293	$6,966,000	New Hillsdale-Lackman 161 kV Line
	06/01/09	PL	541		Sunflower		West Gardner	1	161		2.0	2.0	293	$1,641,000	New Sunflower sub and cut-in
	06/01/09	X	544	59480	Monett	59499	Chesapeake	1	161		15.0	15.0		$8,000,000	Install New 161 line from Monett to Chesapeake.
06/01/08	06/01/09	PL	546	59954	SWPS Bus	59893	SWPS #2	1	161		X		300	$2,000,000	Step-Up Transformer for
2010 Summer Peak															
06/01/11	06/01/10	X	520	53140	Flint Creek	53172	East Centerton	1	345		22.0	22.0	1011/1178	$23,685,000	New 345 kV Line
06/01/11	06/01/10	X	520	53172	East Centerton	53133	East Centerton	1	345/161		X		675/675	$7,425,000	New 345/161 kV Auto
No Date	06/05/10	X	520	53383	Hope	53374	Fulton	1	115	X			217/239	$100,000	Replace conductor in Hope Substation
05/01/07	06/05/10	X	520	53448	South Shreveport	53455	SW Shreveport 'T'	1	138	X			230/246	$130,000	Replace wavetrap at South Shreveport
06/01/11	06/01/10	X	520	53540	Gregtton	53562	Lake Lamond	1	69	2.7		2.7	136/136	$1,496,000	Reconductor line with 1272 ACSR
	06/01/10	X	520	54104	Altus Junction	56245	Ompa Altus Park	1	69	X			52/69	$100,000	Altus Junction replace jumpers & wavetrap
	06/01/10	PL	524	53208	Fitzhugh	55327	Helberg	1	161	4.7		4.7	313/359	$1,416,000	Conversion from 69kV to 161kV
	06/01/10	X	524	55177	Park Lane	55187	Ahloso Tap	1	69	X			97/111	$50,000	Relay upgrade
	06/01/10	PL	524	55312	Short Mountain	55316	Branch	1	161	10.8		10.8	134/143	$3,231,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55319	Little Spadra	55338	Razorback Tap	1	161	7.0		7.0	226/259	$2,112,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55321	Noark	55323	Great Lakes Carbon	1	161	1.7		1.7	134/143	$522,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55323	Great Lakes Carbon	55330	Altus	1	161	1.8		1.8	134/143	$543,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55328	Igo	55321	Noark	1	161	10.0		10.0	134/143	$2,994,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55330	Altus	53208	Fitzhugh	1	161	2.2		2.2	134/143	$660,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55331	Razorback	55312	Short Mountain	1	161	13.5		13.5	134/143	$4,050,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55338	Razorback Tap	55331	Razorback	1	161	9.5		9.5	134/143	$2,850,000	Conversion from 69kV to 161kV
	06/01/10	PL	524	55338	Razorback Tap	55328	Igo	1	161	9.9		9.9	134/143	$2,973,000	Conversion from 69kV to 161kV
	06/01/10	X	526	51094	NE Hereford	51095	NE Hereford	2	115/69		X		84/84	$2,000,000	New transformer
09/01/05	06/01/10	X	526	51517	Floyd Co	51518	Floyd Co	1&2	115/69	X			84/84	$2,200,000	Upgrade both existing transformer
	06/01/10	PL	541	58058	North Louisburg		Middle Creek	1	161		12.0	12.0	293	$3,650,000	New North Louisburg-Middle Creek 161kV line
	06/01/10	PL	541	58069	Paola		Middle Creek	1	161		15.0	15.0	293	$4,732,000	New Middle Creek sub and Paola-Middle Creek 161kV line
	06/01/10	X	544	59400	Monett City South	59402	Monett City East	1	69	1.2		1.2	54/65	$240,000	Reconductor 1.2 MILES with 335.4 ACSR
2010 Winter Peak															
	12/01/10	X	526	50914	Nichols	50915	Nichols	1&2	230/115		X		225/259	$4,100,000	New transformer
	12/01/10	X	526	52153	Artesia	52154	Artesia	1&2	115/69	X			84/96.6	$2,200,000	Upgrade both existing transformer
OUT OF CYCLE - EVALUATED															
05/27/05		OOC	502	50220	Wells Reactor	98109	Wells	1	500/230		X		560/560	$25,000,000	CLEC/EES Wells Substation
12/31/06		OOC	515	99696	SPA Hilltop	99696	EES Hilltop	1	161		X			$5,300,000	Interconnection with EES
06/01/06		OOC	523	53937	Barnsdahl	96165	Tallant	1	138		2.5	2.5	245/245	$1,000,000	Interconnection with AECI
06/01/06		OOC	130	96165	Tallant	97005	Tallant	1	138/69		X				Interconnection
[illegible]		OOC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	2	[illegible]	X			[illegible]	[illegible]	

9/16/2005

New In-Service Date as of 9/16/05 (m/d/y)	Planned In-Service Date as of 4/1/05 (m/d/y)	Project Type	SPP Area	"From" Bus Number used in SPP MDWG	From Location	"To" Bus Number used in SPP MDWG	To Location	Circuit #	Voltage(s) (kV)	Line Mile Estimates: # of Rebuild or Upgrade	Line Mile Estimates: # of New	Line Mile Estimates: Total Miles	Ratings: Summer Rating Normal/ Emergency	Estimated cost of Project	Project Description / Comments
06/01/06		OOC	524	54842	Chitwood	56172	Garber	1	138		5.5	5.5	268/308	$1,811,674	New Tie-OMPA-Garber to OG&E Chitwood, complete loop 138kV, Arcadia-Memo Tp
12/01/06		OOC	524	54785	Woodward Dist.	54796	Iodine	1	138		22.0	22.0	268/308	$4,400,000	New Line- Build tie line between Wordward District and Iodine, relieve OL on WFEC foe outage of WindFarm to Mooreland
06/01/05		OOC	540	59341	South Harper 161	59165	South Harper #1 18	1	161/18		X		100/125	$5,000,000	South Harper Peaking
06/01/05		OOC	540	59341	South Harper 161	59166	South Harper #2 18	1	161/18		X		100/125	$5,000,000	South Harper Peaking
06/01/05		OOC	540	59341	South Harper 161	59167	South Harper #3 18	1	161/18		X		100/125	$5,000,000	South Harper Peaking
06/01/05		OOC	540	59342	Peculiar 161	59341	South Harper 161	1	161	5.0		5.0	465/564	$1,500,000	161kV Line From South Harper Peaking to Peculiar 345
06/01/05		OOC	540	59198	Peculiar 345	59342	Peculiar 161	1	345/161		X		400/500	$5,000,000	345/161kV Transformer Tapping P-Hill to Stillwell 345kV line @ Peculiar
06/01/05		OOC	540	59198	Peculiar 345	57968	Stilwell 345	1	345	9.6	0.4	10.0	717/717	$5,000,000	Tap P-Hill to Stillwell 345kV line @ Peculiar
06/01/05		OOC	540	59198	Peculiar 345	59200	P Hill 345	1	345	11.5	0.4	11.9	956/956	$6,000,000	Tap P-Hill to Stillwell 345kV line @ Peculiar
06/01/05		OOC	540	59343	South Harper 69	59342	South Harper 161	1	69/161		X		50/63	$5,000,000	161/69kV Transformer @ S Harper Tapping Peculiar to Freeman 69kV
12/31/05		OOC	540	59342	Peculiar 161	59340	Belton South 161	1	161	4.1		4.1	465/564	$5,500,000	161kV Line From Peculiar to Belton South
01/01/06		OOC	540	96555	Gravois Mills	59314	North Warsaw 161	1	161	31.0		31.0	223	$500,000	New 161/69kV Sub Tapping AECI Gravious Mill to Truman Line
01/02/06		OOC	540	52702	Truman	59314	North Warsaw 161	1	161	2.0		2.0	223	$500,000	New 161/69kV Sub Tapping AECI Gravious Mill to Truman Line
12/31/05		OOC	540	59277	Warsaw 69	59315	North Warsaw 69	1	69		X		72/78	$300,000	New 69kV line connecting Warsaw to North Warsaw
12/31/05		OOC	540	59315	North Warsaw 69	59314	North Warsaw 161	1	161/69		X		50/63	$1,500,000	161/69kV Transformer @ North Warsaw
06/01/07		OOC	540	59224	Longview 161	59345	Sampson 161	1	161	3.0	0.4	3.4	223/245	$1,250,000	161kV Tap of Longview to Grandview East
06/01/07		OOC	540	59345	Sampson 161	59223	Grandview East 161	1	161	3.0	0.4	3.4	223/245	$1,250,000	161kV Tap of Longview to Grandview East
06/01/10		OOC	540	59215	Hallmark 161	59346	Ritchfield 161	1	161	1.8		1.8	223/245	$1,250,000	161kV Tap of Hallmark to Sibley
06/01/10		OOC	540	59346	Ritchfield 161	59202	Sibley 161	1	161	14.9		14.9	223/245	$1,250,000	161kV Tap of Hallmark to Sibley
OUT OF CYCLE - PENDING EVALUATION															
06/01/07		OOC	539	58794	Spearville	58871	Judson Large	2	115		14.2	14.2		$3,550,000	
06/01/06		OOC	541	58035	Tomahawk	57992	Bendix	1	161	2.0		2.0	293	$528,600	Reconductor line with 1192 acsr
06/01/08		OOC	541	58035	Tomahawk	58076	Mission Junction	1	161	2.4		2.4	293	$630,000	Reconductor line with 1192 acsr
06/01/08		OOC	541	58076	Mission Junction	58034	Kenilworth	1	161	2.4		2.4	293	$624,000	Reconductor line with 1192 acsr
12/31/05		OOC	536	57597	Midian	57583	Butler	1	69	3.0		3.0		$600,000	New load and new substation requires this rebuild
12/31/05		OOC	536	57597	Skelly	57602	Butler	1	69	0.7		0.7		$140,000	New load and new substation requires this rebuild
11/01/06		OOC	536	56990	Midian	57597	Midian	2	138-69		X		100/110	$1,100,000	New load requires this transformer addition
12/31/05		OOC	536	57505	New Cities Service	57527	3rd & VanBuren	1	69	3.2		3.2		$640,000	Construct at 115 kV, Operate at 69 kV until Fall 2008
12/31/06		OOC	536	57513	HEC	57512	43rd & Lorraine	1	69	2.7		2.7		$540,000	Construct at 115 kV, Operate at 69 kV until Fall 2008
12/31/06		OOC	536	57512	43rd & Lorraine	57524	Tower 33	1	69	2.5		2.5		$500,000	Construct at 115 kV, Operate at 69 kV until Fall 2008
06/30/06		OOC	536	57165	HTI Junction	57152	Circleville	1	115	15.5		15.5	223/245	$2,360,000	
06/30/06		OOC	536	57478	Midwest Solvent Junction 1	57473	Atchison Junction 2	1	69	0.3		0.3	108	$35,000	Rebuild
06/30/06		OOC	536	57413	Circle	57419	HEC	1	115	0.4		0.4	223/245	$220,000	Rebuild
12/31/06		OOC	520	53414	Hart's Island	53486	Port Robson	1	138		7.0	7.0	368/512	$16,379,600	AEP is planning to build a new 1590 ACSR, 138 kV line, approximately 7 miles long, that will be radial (at least initially) from AEP's existing Hart's Island station in Shreveport, Louisiana.
															Rebuild / Line not rebuilt. Uprated to 100 degree C operation

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New In-Service Date as of 9/1/05 (m/d/y)	Planned In-Service Date as of 4/1/05 (m/d/y)	Project Type	SPP Area	"From" Bus Number used in SPP MDWG	From Location	"To" Bus Number used in SPP MDWG	To Location	Circuit #	Voltage(s) (kV)	Line Mile Estimates: # of Rebuild or Upgrade	Line Mile Estimates: # of New	Line Mile Estimates: Total Miles	Ratings: Summer Rating Normal/ Emergency	Estimated cost of Project	Project Description / Comments
02/01/05	06/01/04	OOC	540	59296	Harrisonville sw	59295	Harrisonville 161	1	69	1.8		1.8	100/107	$360,000	Rebuild
12/31/04	06/01/05	OOC	540	59308	Nevada 161	59309	Metz	1	69	3.6		3.6	100/107	$720,000	Rebuild
06/01/07		OOC	520	53794	Riverside Station (345 kV)	53785	Riverside Station T1 138 k	1	345/138	X	X		675/675		Replace transformer at Riverside Station
06/01/07		OOC	520	53785	Riverside Station T1 138 kV	53795	Riverside Station (138 kV)	1	138	1.0		1.0	892/956		Rebuild 138 kV line to Riverside Station 138 kV
06/01/07		OOC	520	53794	Riverside Station (345 kV)	53891	Riverside Station T2 138 k	1	345/138		X		675/675		New 2nd tranformer at Riverside Station
06/01/07		OOC	520	53891	Riverside Station T2 138 kV	53795	Riverside Station (138 kV)	1	138		1.0	1.0	892/956		New 138 kV line to Riverside Station 138 kV
06/01/07		OOC	520	53794	Riverside Station	53885	Sapulpa	1	345		X		901/1055		Conversion from 138 kV to 345 kV. (Line is already built for 345 kV.)
06/01/07		OOC	520	53885	Sapulpa	53767	Wekiwa	1	345		X		901/1055	$48,000,000	Conversion from 138 kV to 345 kV. (Line is already built for 345 kV.)
06/01/07		OOC	520	53885	Sapulpa	53886	Sapulpa	1	345/138		X		560/616		New transformer at Sapulpa
06/01/07		OOC	520	53886	Sapulpa	53771	Jenks	1	138		5.0	5.0	202/235		New 138 kV line to loop into Sapulpa 138 kV station
06/01/07		OOC	520	53886	Sapulpa	53826	52Dclwt4	1	138		5.0	5.0	202/235		New 138 kV line to loop into Sapulpa 138 kV station
06/01/07		OOC	520	53886	Sapulpa	53827	S.S	1	138		5.0	5.0	161/187		New 138 kV line to loop into Sapulpa 138 kV station
06/01/07		OOC	520	53886	Sapulpa	53862	Oakswlp4	1	138		5.0	5.0	161/187		New 138 kV line to loop into Sapulpa 138 kV station
06/01/07		OOC	520	53818	Oneta Station	53781	Broken Arrow 81st St	1	138	8.1		8.1	368/478		Rebuild Line
06/01/07		OOC	520	53818	Oneta Station	53797	Broken Arrow North Tap	1	138	10.9		10.9	368/478		Rebuild Line
12/31/05		OOC	540	59255	P Hill 161kV	59316	Harris Rd 161kV	1	161	3.0		3.0	466/558	$1,250,000	161kV Tap of P Hill to Greenwood
12/31/05		OOC	540	59316	Harris Rd 161kV	59218	Greenwood 161kV	1	161	1.7		1.7	466/558	$1,250,000	161kV Tap of P Hill to Greenwood

Forms 2 – Devices and Loads

Need-In-Service Date as of 8/1/05 (m/d/y)	Planned In Service Date as of 4/1/05 (m/d/y)	Project Type	SPP Area	Type Description	Bus Number Used in SPP MDWG Model	Location	Voltage(s) (kV)	Summer Peak Rating (various Units)	Estimated cost of Project	Project Description/ Comments
SPP BOD APPROVED (4/1/05)										
2004 Spring										
	12/31/03	PL	502	Capacitor Bank	50123	Marksville	138	22 Mvar	$200,000	Adding a 22 Mvar capacitor bank at the Marksville Substation to improve the voltage under single contingency conditions.
	12/31/03	PL	524	Emer Capacitors	55017	Chandler	69	9.6 Mvar	$200,000	
	04/01/04	PL	526	Capacitor Bank	51038	Owens Corning	115	14.4 Mvar	$800,000	Part of Amarillo South Project
2004 Summer Peak										
	06/01/04	PL	524	Emer Capacitors	55135	Sunnyside	138	23.4 Mvar	$63,000	
12/31/05	06/01/04	PL	536	Capacitor	57767	Mulbery	69	10 Mvar	$525,000	Install switched capacitor bank
	06/01/04	PL	546	New Load Substation	59934	Seminole Substation	69	70 Mvar	$3,400,000	
2004 Fall										
	11/16/04	PL	523	Capacitor and Reactor	54482	Walmert	69	14.2 Mvar	$500,000	Voltage support
2004 Winter Peak										
	12/31/04	PL	526	HVDC	59998	Lamar	345	210 MW	$40,000,000	HVDC
	12/31/04	PL	526	Reactor	50858	Finney	345	50 Mvar	$1,000,000	Finney-Lamar Project
	12/31/04	PL	526	Reactor	59998	Lamar	345	50 Mvar	$1,000,000	Finney-Lamar Project
	12/31/04	PL	526	Capacitor Bank	52294	Seven Rivers	115	28.8 Mvar	$550,000	
2005 Spring										
	03/31/05	PL	524	Reactor	55703	Arcadia	14	25 Mvar	$325,000	Install 25Mvar reactor on the 13.8kV tertiary winding of the 345/138 kV bus
	03/31/05	PL	524	Reactor	55704	Arcadia	14	25 Mvar	$325,000	Install 25Mvar reactor on the 13.8kV tertiary winding of the 345/138 kV bus
2005 Summer Peak										
06/01/05	05/01/05	PL	520	Capacitor Bank	54278	Clarendon	69	3.6 Mvar	$550,000	Install switched cap
06/01/05	05/01/05	PL	520	Capacitor Bank	54282	Memphis	69	3.6 Mvar	$550,000	Install switched cap
	06/01/05	PL	520	Capacitor Bank	54026	Red Oak	69	28.4 Mvar	$585,000	Install switched cap
No Date	06/01/05	X	520	Capacitor Bank	53162	Waldron	69	6 Mvar	$550,000	Install switched cap
10/01/05	06/01/05	PL	524	Capacitor Bank	55300	Ft. Smith	161	45 Mvar	$370,000	Install switched cap.
	06/01/05	X	525	Capacitor Bank	55878	Carter Jct	69	12 Mvar	$162,000	Install switched cap
	06/01/05	X	525	Capacitor Bank	55988	Marietta	138	10 MVar	$180,000	Install switched cap
	06/01/05	PL	526	Capacitor Bank	50644	Dallam Sub	115	14.4 Mvar	$850,000	
	06/01/05	X	526	Capacitor Bank	52035	Doss	69	14.4Mvar	$300,000	Install 2 7.2 Mvar caps
	06/01/05	X	526	Capacitor Bank	51986	Amerada Hess	115	14.4 Mvar	$250,000	14.4 Mvar caps proposed for the Amerada 115 kV bus
	06/01/05	X	526	Capacitor Bank	52073	Chaves	230	50 Mvar	$1,000,000	50 Mvar caps proposed at 230 kV bus
	06/01/05	PL	539	Capacitor Bank	58772	East Liberal	115	33.2 Mvar	$600,000	
06/01/09	06/01/06	X	539	Capacitor Bank	58766	Plainville	115	38 Mvar	$3,500,000	8Mvar Statcom at 34.5 kV bus, and three 10 Mvar blocks at 115 kV bus
	06/01/06	X	540	Capacitor Bank	59277	Warsaw 269.0	69	10 Mvar	$250,000	
12/01/05	06/01/05	PL	541	Capacitor Bank	58069	Paola 161kV	161	50 Mvar	$550,000	New Paola 50Mvar cap bank
	06/01/05	X	544	Capacitor Bank	59404	Purdy	69	6 Mvar	$106,000	Install 6 Mvar Cap at Purdy
2005 Winter Peak										
	09/30/05	PL	524	Capacitor Bank	55342	Massard	69	6 Mvar	$30,000	Increase existing cap size to 18 Mvar

New In-Service Date as of 8/1/05 (m/d/y)	Planned In-Service Date as of 1/1/05 (m/d/y)	Project Type	SPP Area	Type Description	Bus Number (used in SPP MDWG Model)	Location	Voltage(s) (kV)	Summer Peak Rating (Nominal Units)	Estimated cost of project	Project Description/ Comments
	10/31/05	PL	524	Capacitor Bank	54782	Woodward District	69	18 Mvar	$100,000	Install Switched 69kV cap
	10/31/05	PL	524	Capacitor Bank	55336	VBI	69	18 Mvar	$200,000	Install Switched 69kV cap
2006 Summer Peak										
No Date	06/01/06	X	520	Capacitor Bank	53730	Coweta	69	8 Mvar	$550,000	Install switched cap
	06/01/06	X	525	Capacitor Bank	55881	Dover	69	5 Mvar	$90,000	Install switched cap
2006 Winter Peak										
	12/31/06	PL	534	Capacitor Bank	56357	Ruleton3	115	12 Mvar	$500,000	
2007 Summer Peak										
	06/01/07	PL	534	DVAR	56373	Rhoades3	115	+/-8 /24Mvar	$1,300,000	+- 8 Mvar DVAR and 15 Mvar Cap Bank
06/01/06	06/01/07	PL	541	Capacitor Bank	57978	Craig 161kV	161	50Mvar	$706,000	New Craig 50Mvar cap bank
2008 Summer Peak										
		X	526	Load Relocation	51175	Curry	69	10.4 MW	$0	Relocate Load to Curry 115 kV bus (51176)
		X	526	Load Relocation	50661	Moore	69	14.4 MW	$0	Relocate Load to Moore 115 kV bus (50664)
2008 Winter Peak										
	12/31/08	PL	534	DVAR	56429	Mingo3	115	+/-8 /24Mvar	$1,800,000	+- 8 Mvar DVAR and 15 Mvar Cap Bank
2010 Summer Peak										
	06/01/10	X	539	Capacitor Bank	58768	Harper	138	20 Mvar	$1,500,000	20 Mvar cap bank at Harper
	06/01/10	X	544	Capacitor Bank	59425	Hermitage	69	2 Mvar	$36,000	Install 2 Mvar of Caps at Hermitage
	06/01/10	PL	546	New Load Substation	59963	Mentor Substation	161	28 MVA	$3,500,000	
OUT OF CYCLE - EVALUATED										
06/01/06		OOC	520	Capacitor Bank	53802	Catoosa	138	50.4 Mvar	$394,000	Install switched capacitor bank
06/01/06		OOC	520	Capacitor Bank	53386	Arsenal Hill	138	50.4 Mvar	$432,000	Install switched capacitor bank
06/01/05		OOC	502	Reactor	50220	Wells	230	36 ohm	Part of $25M	Reactor to limit flows on transformer
10/31/05		OOC	524	Capacitor Bank	55120	Russett	138	18 Mvar	$261,700	Install Switched 138kV cap
OUT OF CYCLE - PENDING EVALUATION										
06/01/07		OOC	541	Capacitor Bank	58063	South Waverly	161	50 Mvar	$706,000	Reliability project to eliminate voltage violations for contingencies
06/30/06		OOC	536	Capacitor Bank	53730	Clearwater	138	15 Mvar	$1,000,000	Install switched capacitor bank
06/30/08		OOC	536	Capacitor Bank	57005	NE Parsons	138	15 Mvar	$1,000,000	Install switched capacitor bank
06/30/06		OOC	536	Capacitor Bank	57481	Nortonville	69	15 Mvar	$564,000	Install switched capacitor bank
06/30/06		OOC	536	Capacitor Bank	57704	Parsons	69	10 Mvar	$525,000	Install switched capacitor bank
06/30/06	06/01/04	OOC	536	Capacitor	57559	UDALL 2	69	10 Mvar	$525,000	Install switched capacitor bank
06/01/07		OOC	520	Capacitor Bank	53795	Riverside Station	138	50 Mvar	Part of the Tulsa EHV $48 M	Install switched capacitor bank
06/01/07		OOC	520	Capacitor Bank	53795	Riverside Station	138	50 Mvar		Install switched capacitor bank
06/01/07		OOC	520	Capacitor Bank	53800	Tulsa Power Station	138	50 Mvar		Install switched capacitor bank
06/01/07		OOC	520	Capacitor Bank	53800	Tulsa Power Station	138	50 Mvar		Install switched capacitor bank

Forms 3 – Generators

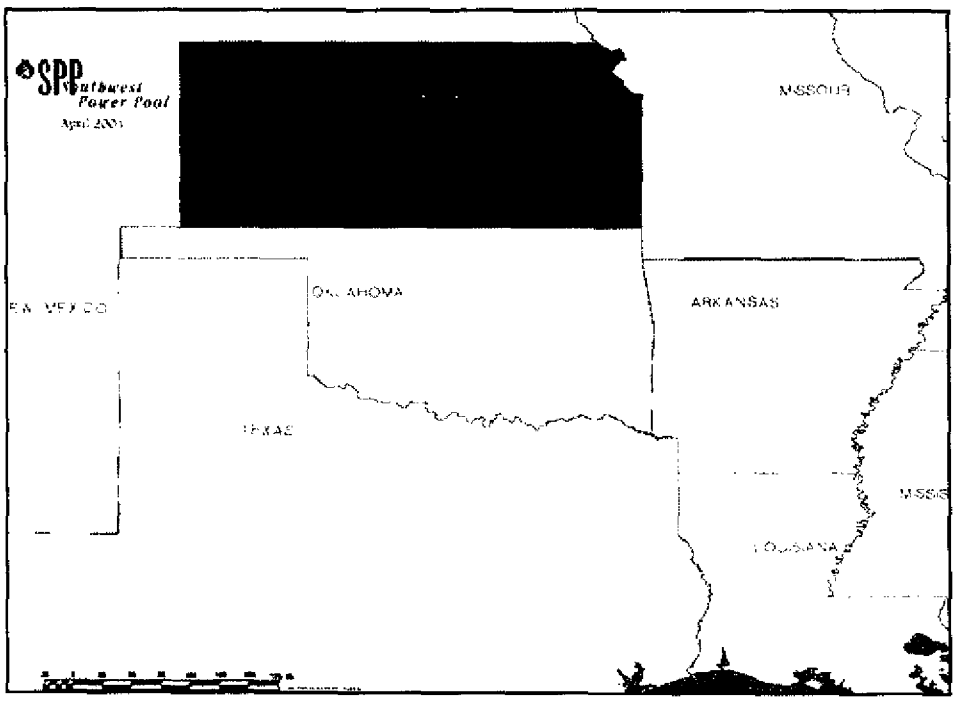
New In-Service Date as of [illegible] (m/d/y)	Planned In-Service Date as of 4/1/05 (m/d/y)	Project Type	SPP Area	Bus Number used in SPP MDWG Model	Name	Location	Comments	Grid Injection Voltage (KV)	Generator Summer Peak Rating (MW)	Estimated cost of Project
SPP BOD APPROVED (4/1/05)										
2010 Summer Peak										
	06/01/09	PL	546	59893	SWPS #2	Springfield, MO	Coal	161	275	$578,500,000
OUT OF CYCLE - PENDING EVALUATION										
6/1/2005		OOC	540		South Harper		CTs		315	
6/1/2005		OOC	504		Renauld		CTs		90	
12/31/2005		OOC	526		Wildorado, TX		Wind Farms		160	
12/31/2005		OOC	526		San Juan Mesa, NM		Wind Farms		120	
12/31/2005		OOC	536		Elk River, KS		Wind Farms		150	
12/31/2005		OOC	524		Weatherford, OK		Wind Farms		106	
12/31/2005		OOC	525		Blue Canyon II, OK		Wind Farms		120	
12/31/2005		OOC	534		Marienthal, KS		Wind Farms		30	
6/1/2006		OOC	502		Elk		CTs		90	
6/1/2009		OOC	541		Iatan 2		Coal		900	

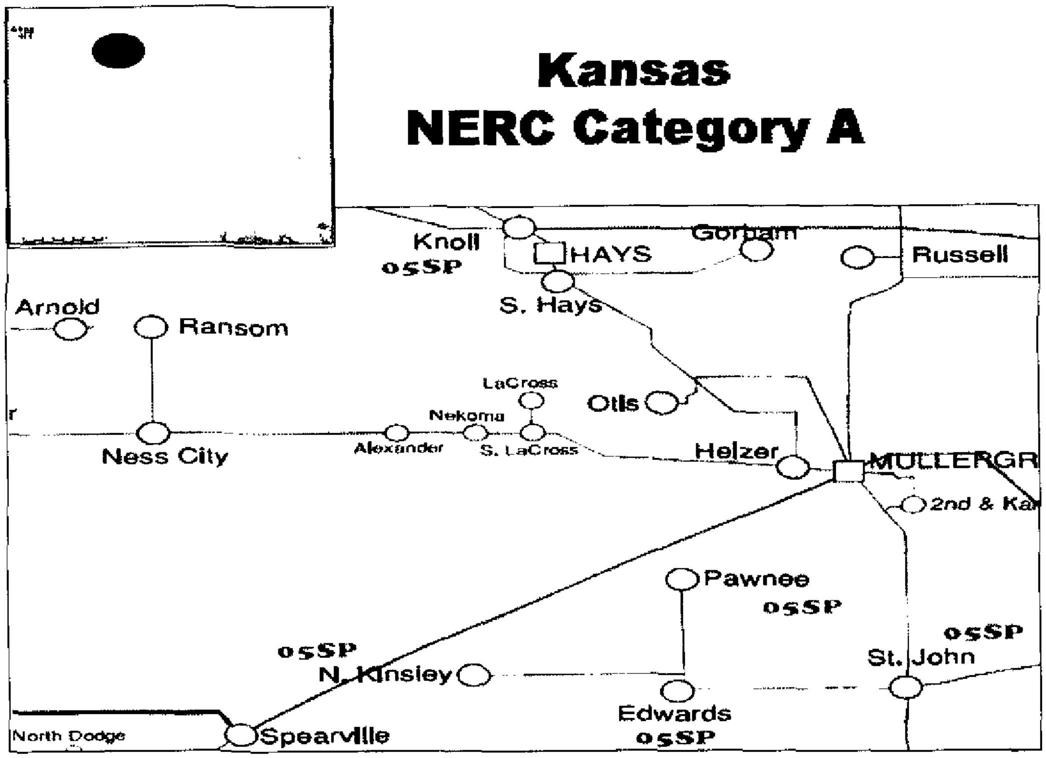
Appendix B: Maps with Criteria Violations above 100 kV

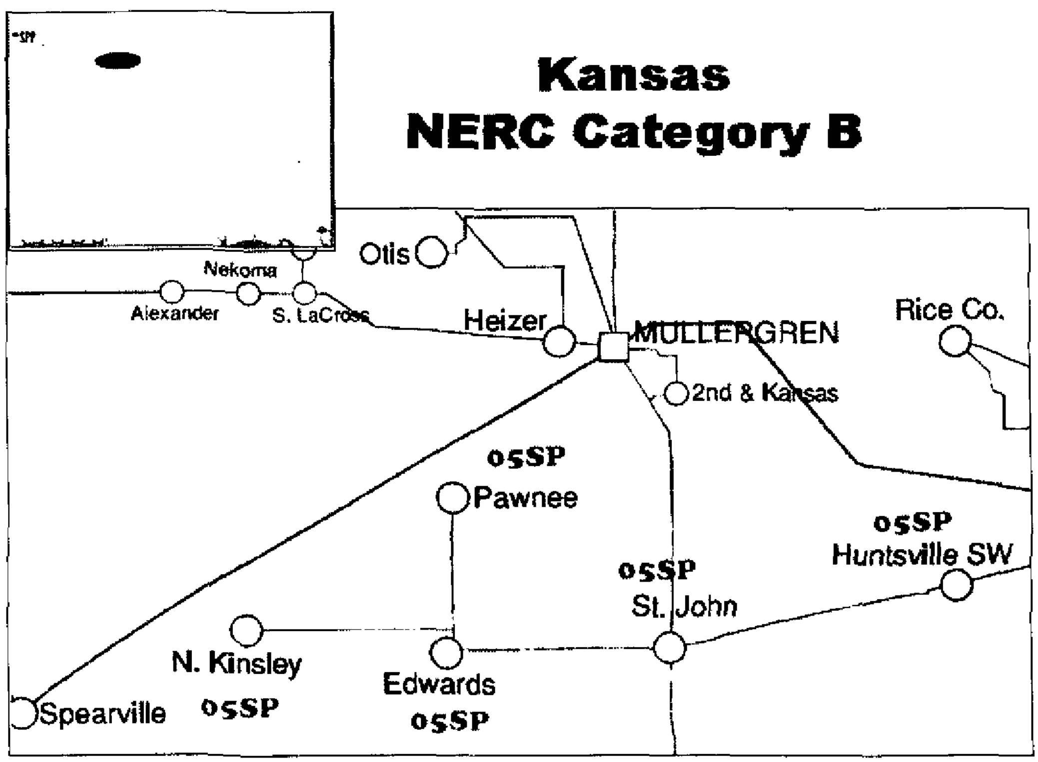
Following are maps showing criteria violations above 100 kV within the SPP footprint. Violations are grouped by state for map purposes. Contingencies are not discussed in this report due to security concerns.

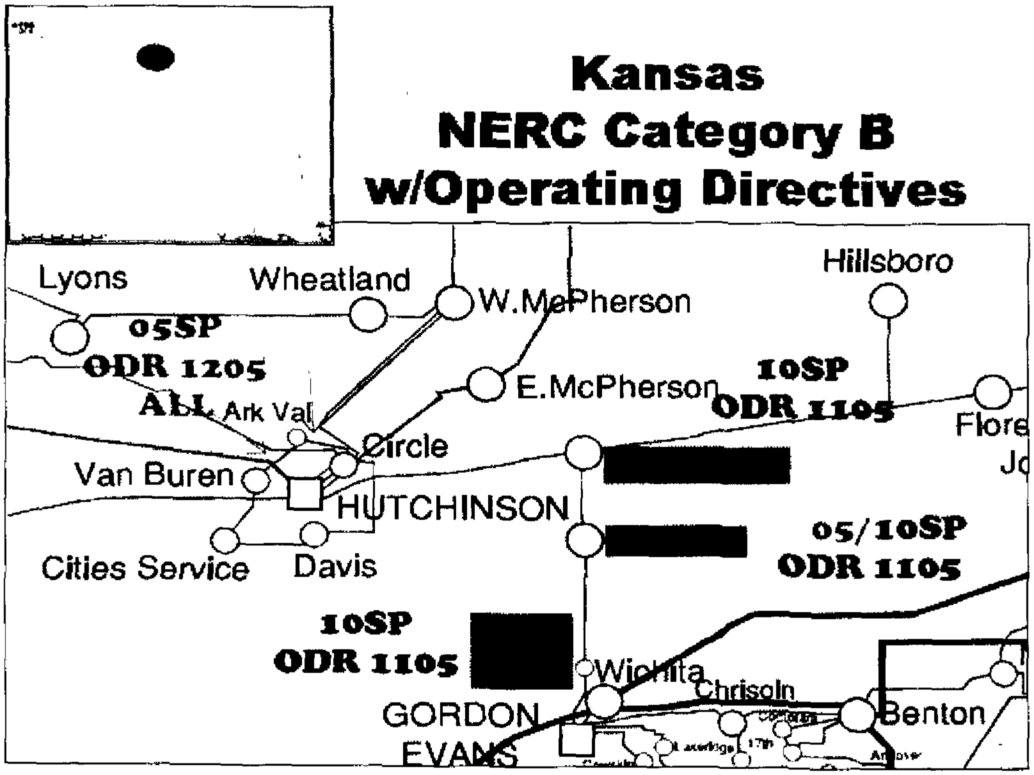
Map Legends:
05SP – 2005 Summer Peak
10SP – 2010 Summer Peak
ODR – Operating Directive
Location name highlighted indicates voltage violation
Line highlighted between two locations indicates an overloaded line
Yellow/Orange 2005 violation
Purple 2010 violation
B – Base Case
T1 – West to East transaction case
T2 – East to West transaction case
T3 – Hybrid transaction case (West to East with SPS importing)
ALL – Base Case, T1, T2, and T3
Voltage violations are highlighted and do not identify the type of load flow case (base or transaction case)

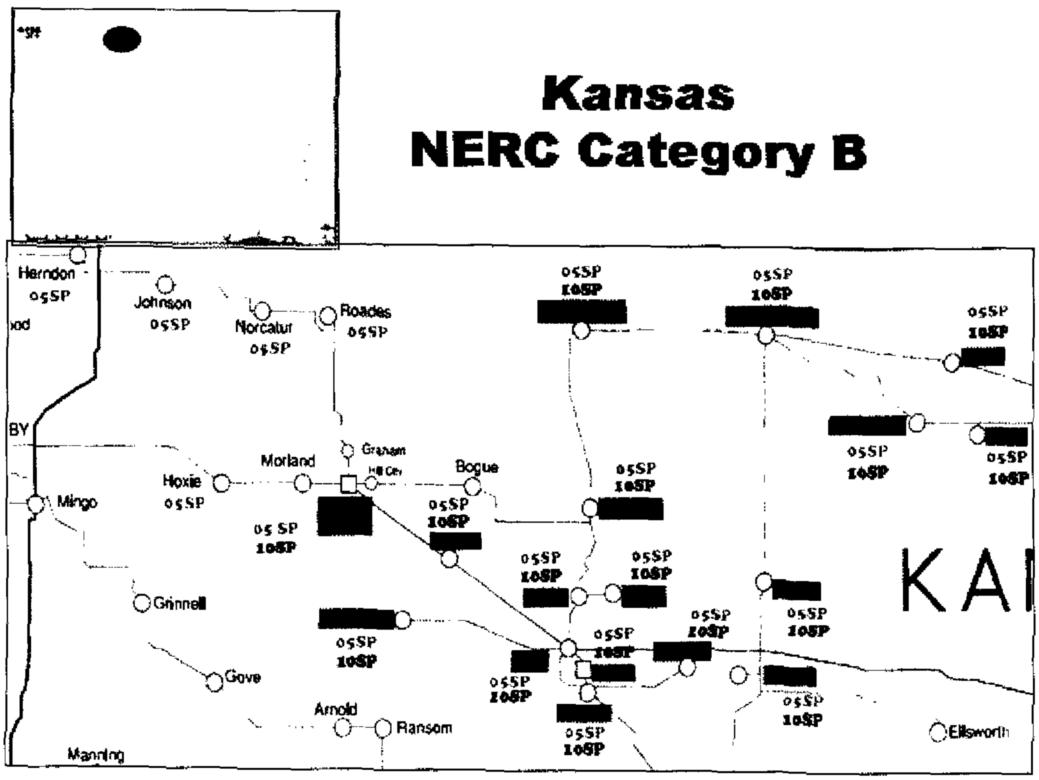
Kansas

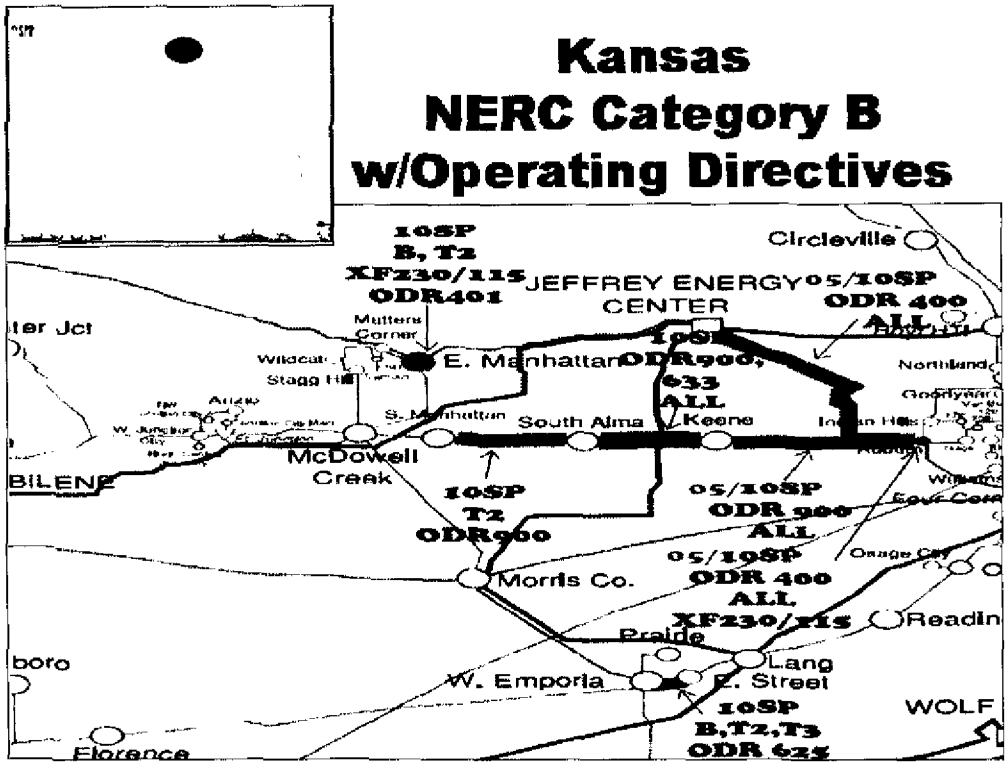


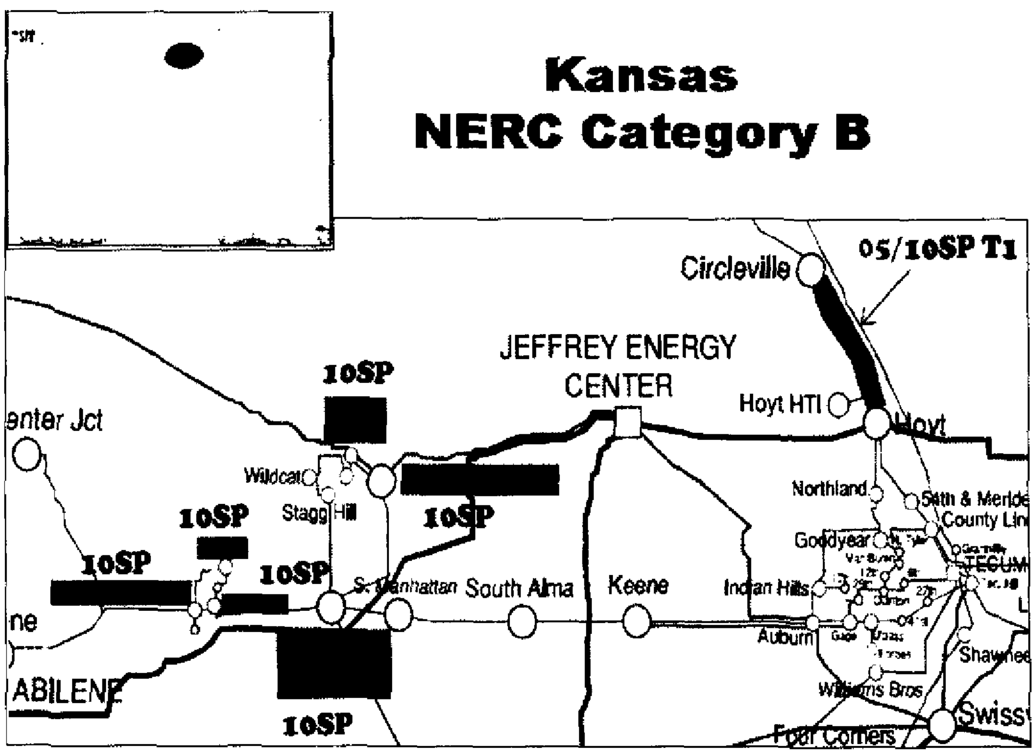

Kansas
NERC Category A
Knoll
05SP
HAYS
Gorham
Russell
Arnold
Ransom
S. Hays
LaCross
Otis
Nekoma
Ness City
Alexander
S. LaCross
Helzer
MULLERGR
2nd & Ka
Pawnee
05SP
05SP
05SP
N. Kinsley
St. John
Edwards
05SP
North Dodge
Spearville

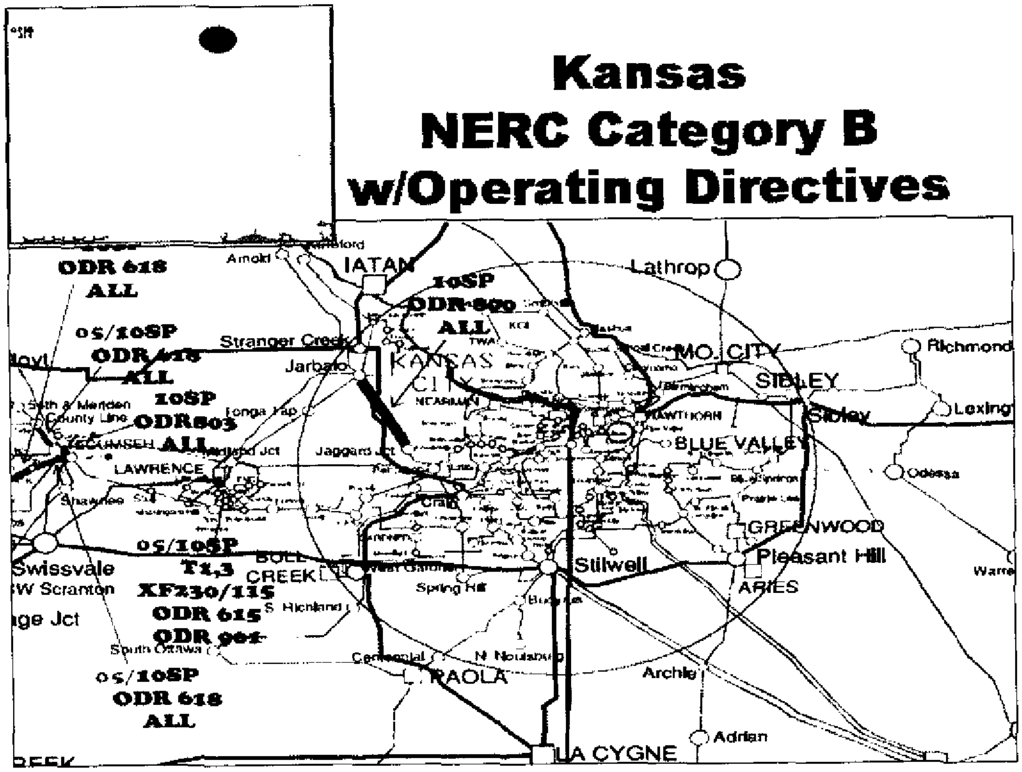

Kansas
NERC Category B
Otis
Nekoma
Alexander
S. LaCross
Heizer
MULLERGREN
Rice Co.
2nd & Kansas
05SP
Pawnee
05SP
Huntsville SW
05SP
St. John
N. Kinsley
Edwards
Spearville
05SP
05SP

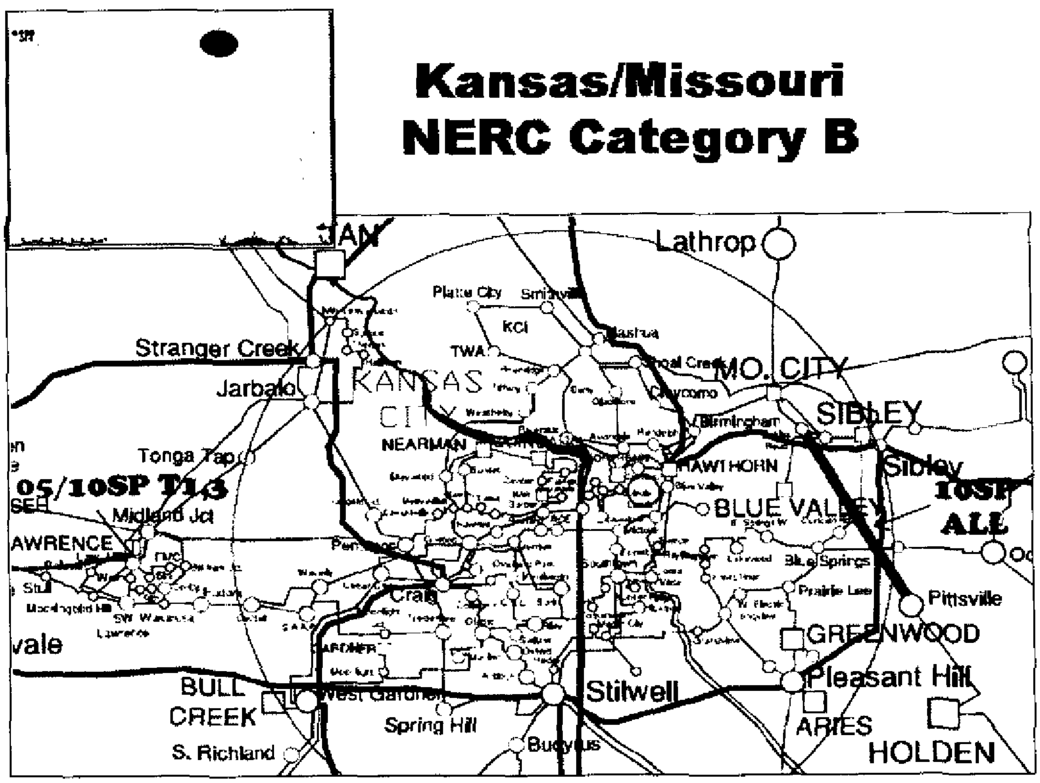

Kansas
NERC Category B
w/Operating Directives
Lyons
Wheatland
W.McPherson
Hillsboro
05SP
ODR 1205
ALL
Ark Val
E.McPherson
10SP
ODR 1105
Circle
Van Buren
HUTCHINSON
[redacted]
[redacted]
05/10SP
ODR 1105
Cities Service
Davis
10SP
ODR 1105
[redacted]
Wichita
Chrisoln
GORDON
Benton
EVANS


Kansas
NERC Category B
Herndon
05SP
Johnson
05SP
Norcatur
05SP
Roades
05SP
05SP
10SP
Morland
Hoxie
05SP
Mingo
Bogue
05 SP
10SP
Grinnell
Gove
Arnold
Ransom
Manning
Ellsworth
KA

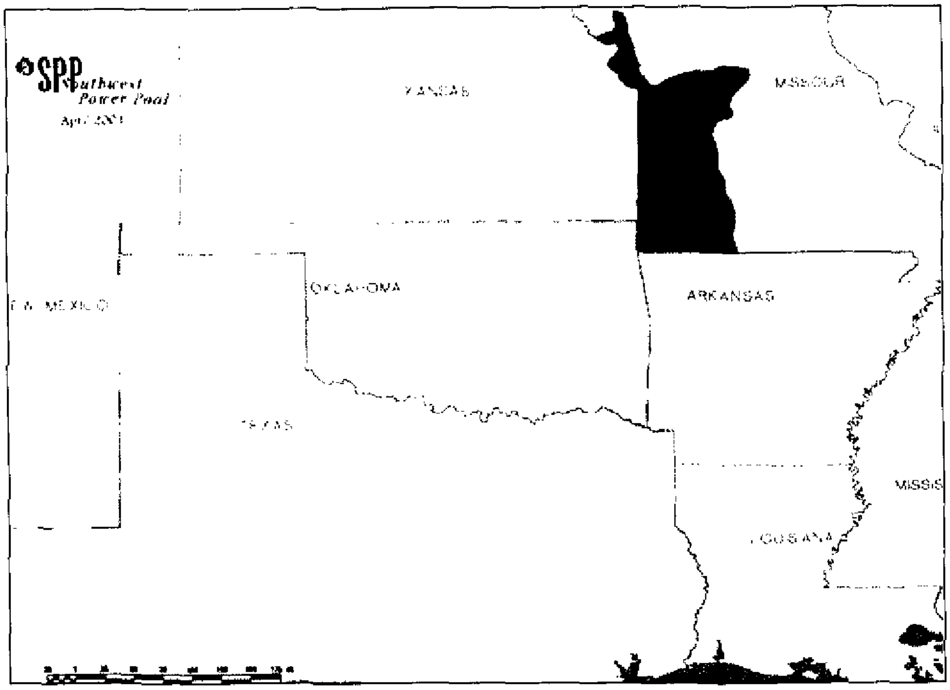

Kansas
NERC Category B
w/Operating Directives
10SP
B, T2
XF230/115
ODR401
JEFFREY ENERGY
CENTER
05/10SP
ODR 400
ALL
Circleville
Mutters Corner
Wildcat
Stagg Hill
E. Manhattan
ODR900,
633
ALL
South Alma
Keene
McDowell
Creek
10SP
T2
ODR900
05/10SP
ODR 900
ALL
05/10SP
ODR 400
ALL
XF230/115
Morris Co.
Prairie
Lang
E. Street
10SP
B,T2,T3
ODR 625
W. Emporia
Reading
WOLF
Florence
Northland
Goodyear

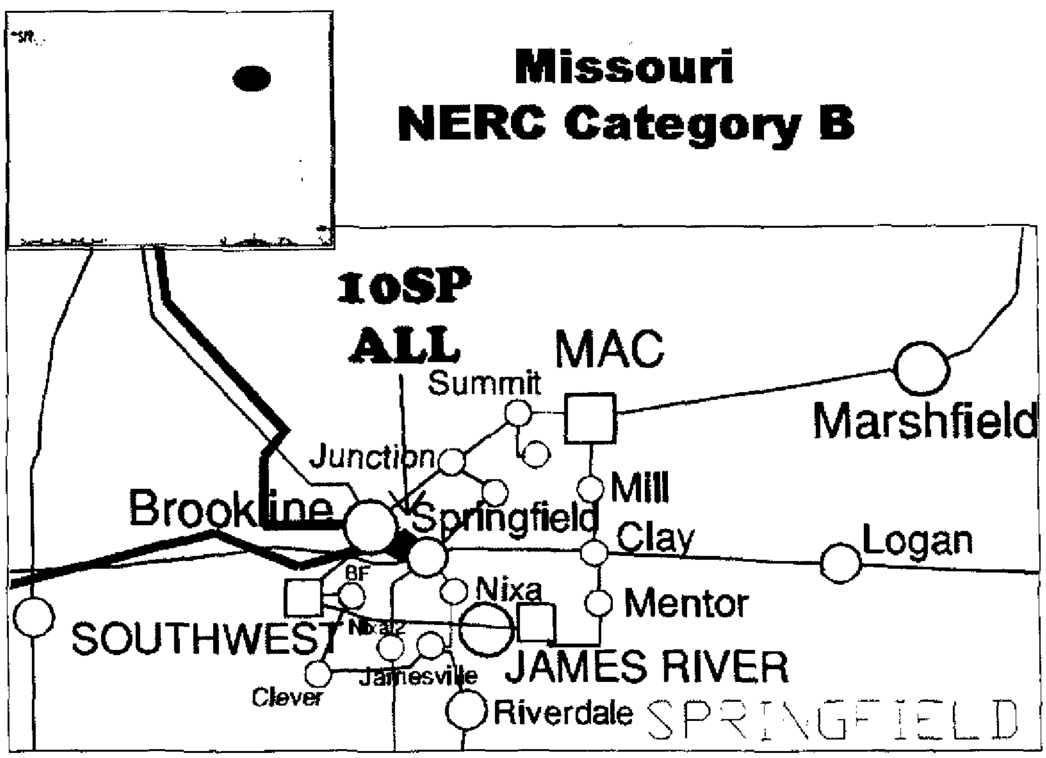

Kansas
NERC Category B
05/10SP T1
Circleville
JEFFREY ENERGY
CENTER
Hoyt HTI
Hoyt
10SP
10SP
10SP
10SP
10SP
10SP
Wildcat
Stagg Hill
S. Manhattan
South Alma
Keene
Indian Hills
Northland
Goodyear
Auburn
Williams Bros
Four Corners
Swiss
Shawnee
ABILENE


Kansas
NERC Category B
w/Operating Directives
ODR 618
ALL
05/10SP
ODR 618
ALL
10SP
ODR803
ALL
10SP
ODR 800
ALL
05/10SP
T1,3
XF230/115
ODR 615
ODR 901
05/10SP
ODR 618
ALL
IATAN
Lathrop
Richmond
Stranger Creek
Jarbalo
KANSAS CITY
MO. CITY
SIBLEY
Sibley
Lexing
BLUE VALLEY
HAWTHORN
LAWRENCE
Odessa
GREENWOOD
Pleasant Hill
ARIES
Swissvale
W Scranton
CREEK
Stilwell
Spring Hill
PAOLA
Archie
Adrian
LA CYGNE

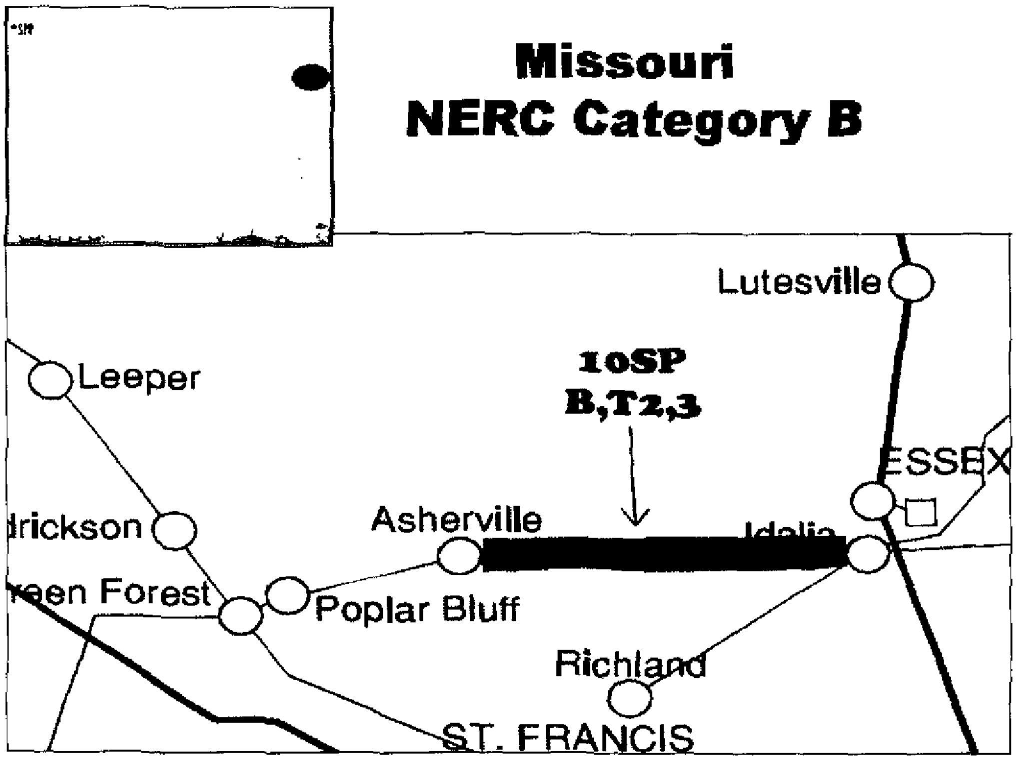

Kansas/Missouri
NERC Category B
Lathrop
Platte City
KCI
TWA
Nashua
Stranger Creek
Jarbalo
KANSAS CITY
MO. CITY
SIBLEY
Sibley
10SP
ALL
Tonga Tap
05/10SP T1,3
Midland Jct
NEARMAN
HAWTHORN
BLUE VALLEY
AWRENCE
Blue Springs
Pittsville
Prairie Lee
GREENWOOD
GARDNER
Pleasant Hill
BULL
CREEK
West Gardner
Stilwell
Spring Hill
S. Richland
Bucyrus
ARIES
HOLDEN

Missouri

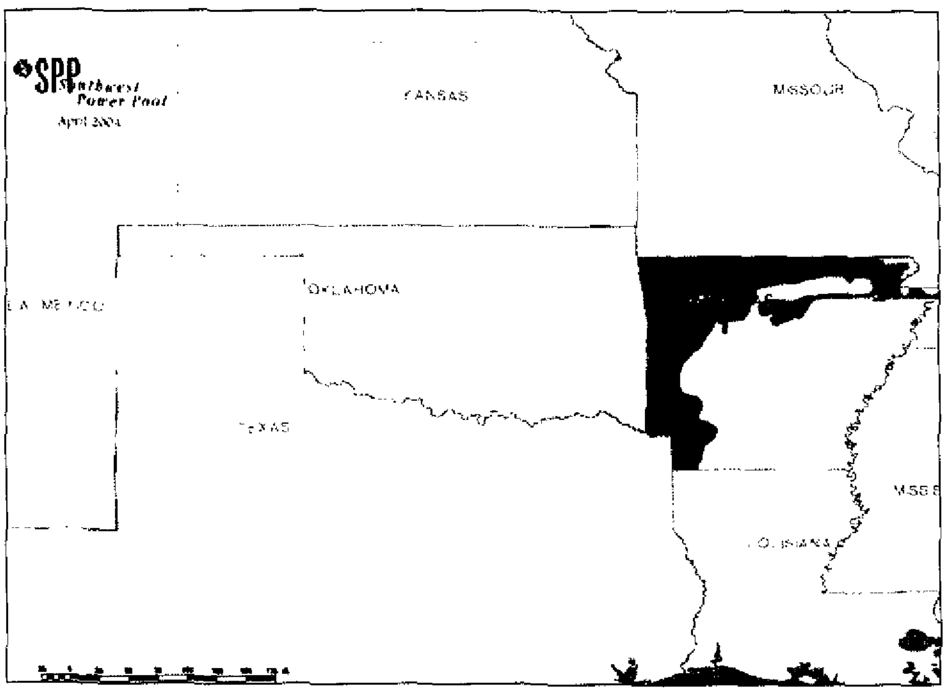

ARKANSAS

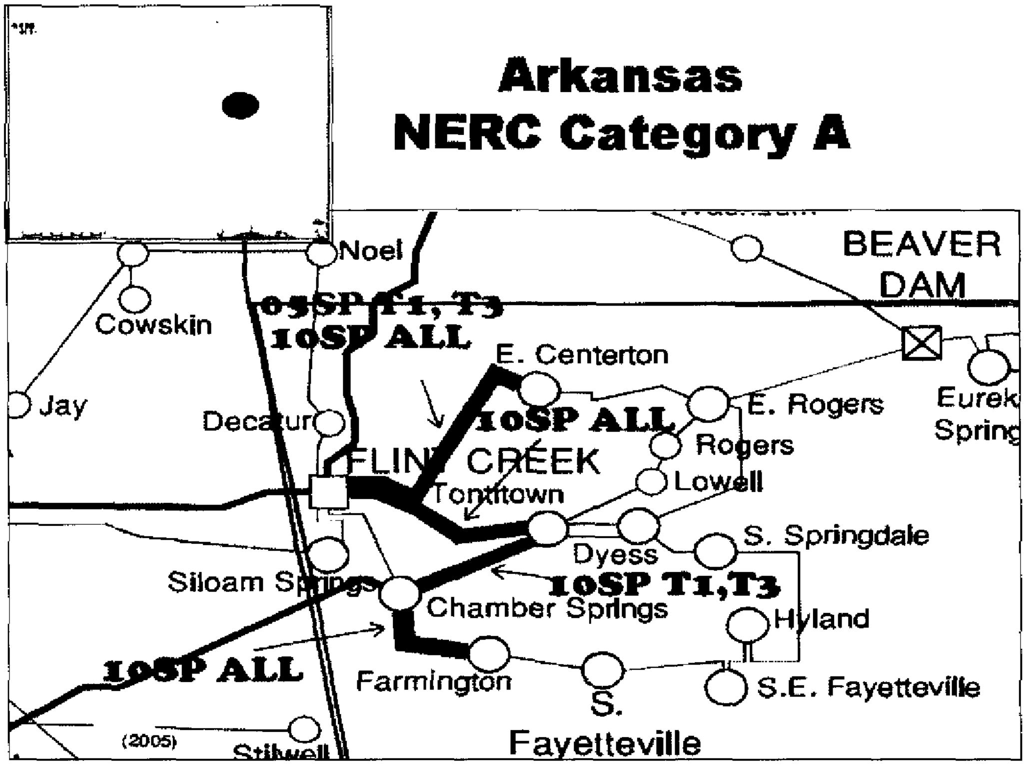

Missouri
NERC Category B
10SP
ALL
MAC
Summit
Marshfield
Junction
Brookline
Springfield
Mill
Clay
Logan
BF
Nixa
Mentor
SOUTHWEST
JAMES RIVER
Jamesville
Clever
Riverdale
SPRINGFIELD

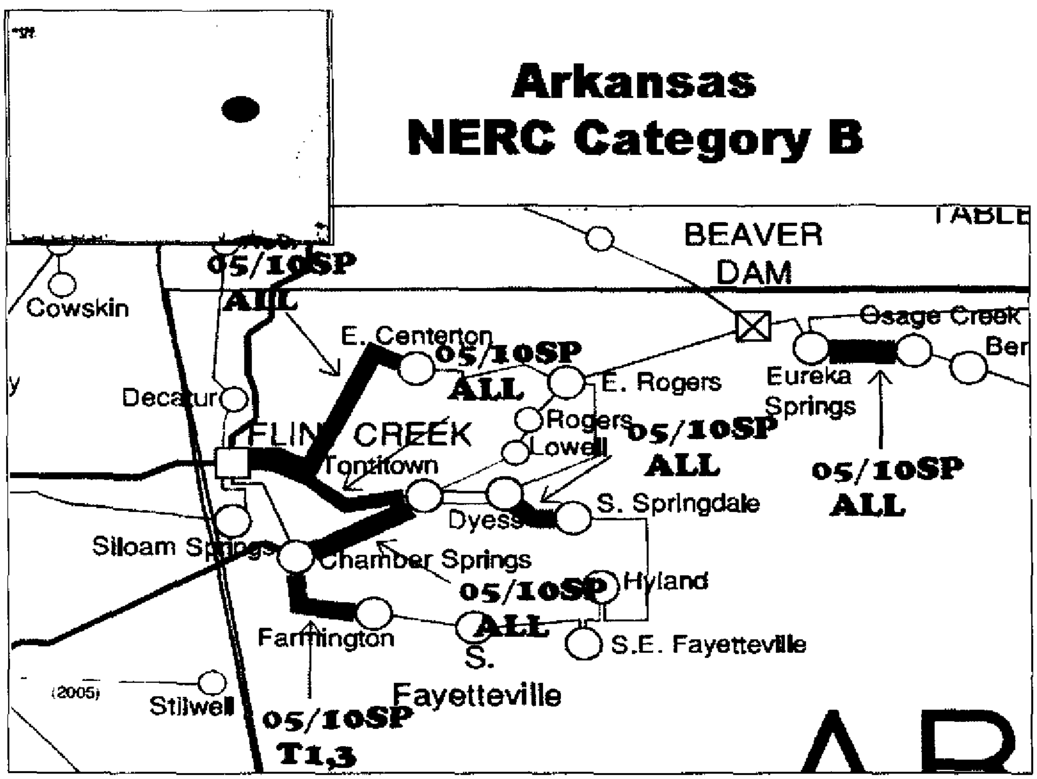
Missouri
NERC Category B

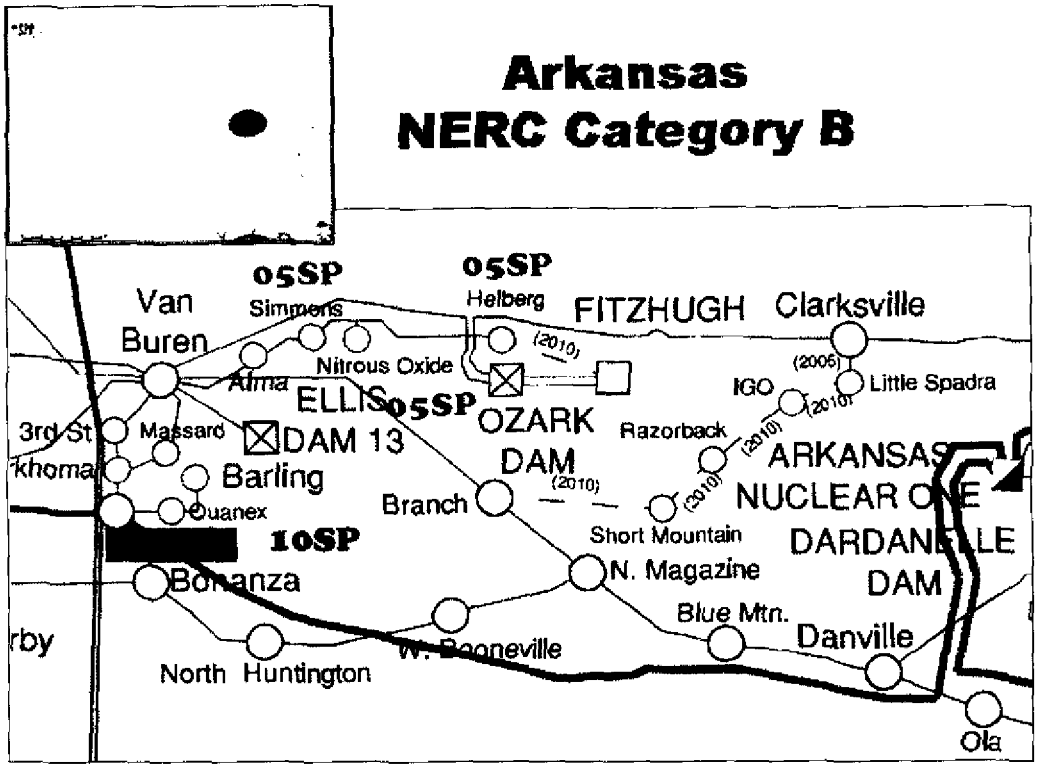


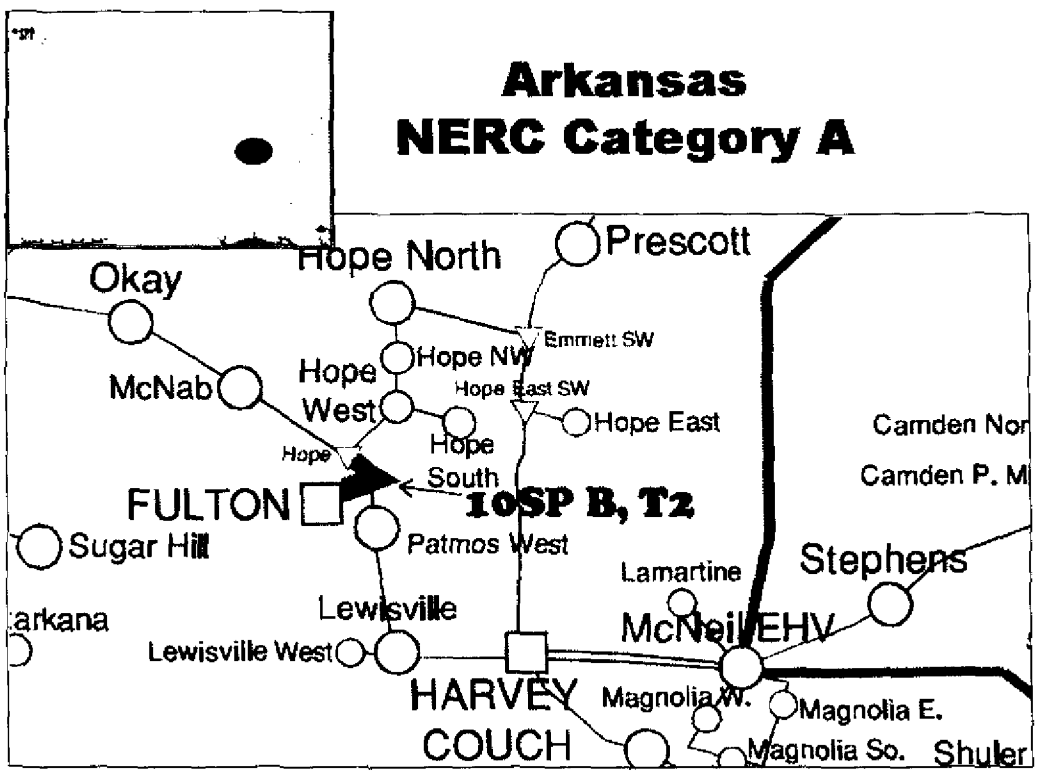
Arkansas



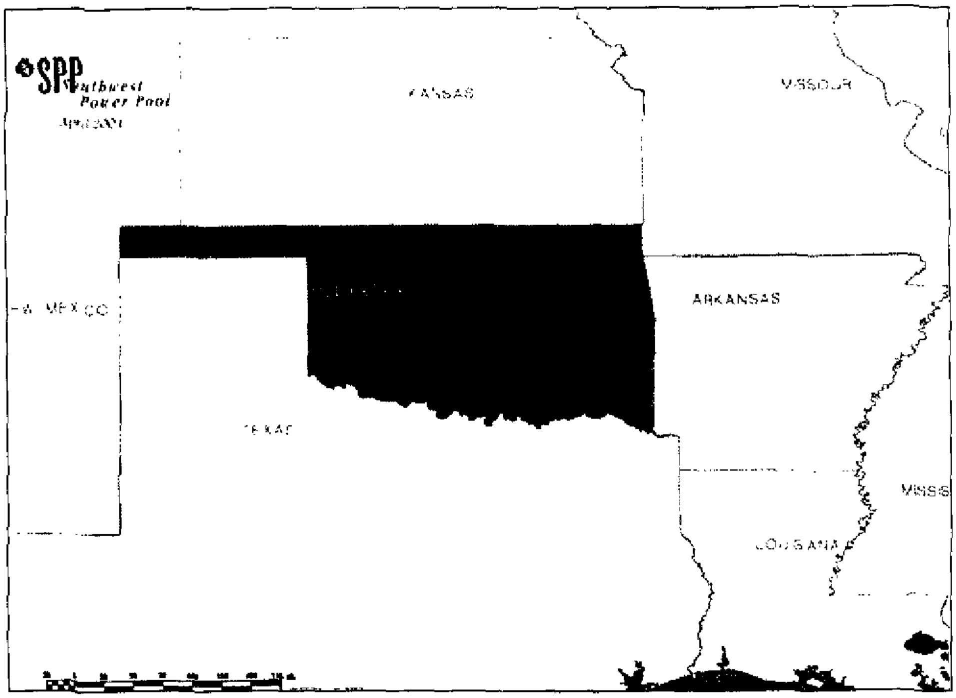

Arkansas
NERC Category A
Noel
BEAVER DAM
05SP T1, T3
10SP ALL
Cowskin
E. Centerton
Jay
Decatur
10SP ALL
E. Rogers
Eureka Springs
FLINT CREEK
Rogers
Lowell
Tontitown
S. Springdale
Dyess
Siloam Springs
10SP T1,T3
Chamber Springs
Hyland
10SP ALL
Farmington
S.E. Fayetteville
S. Fayetteville
(2005)
Stilwell

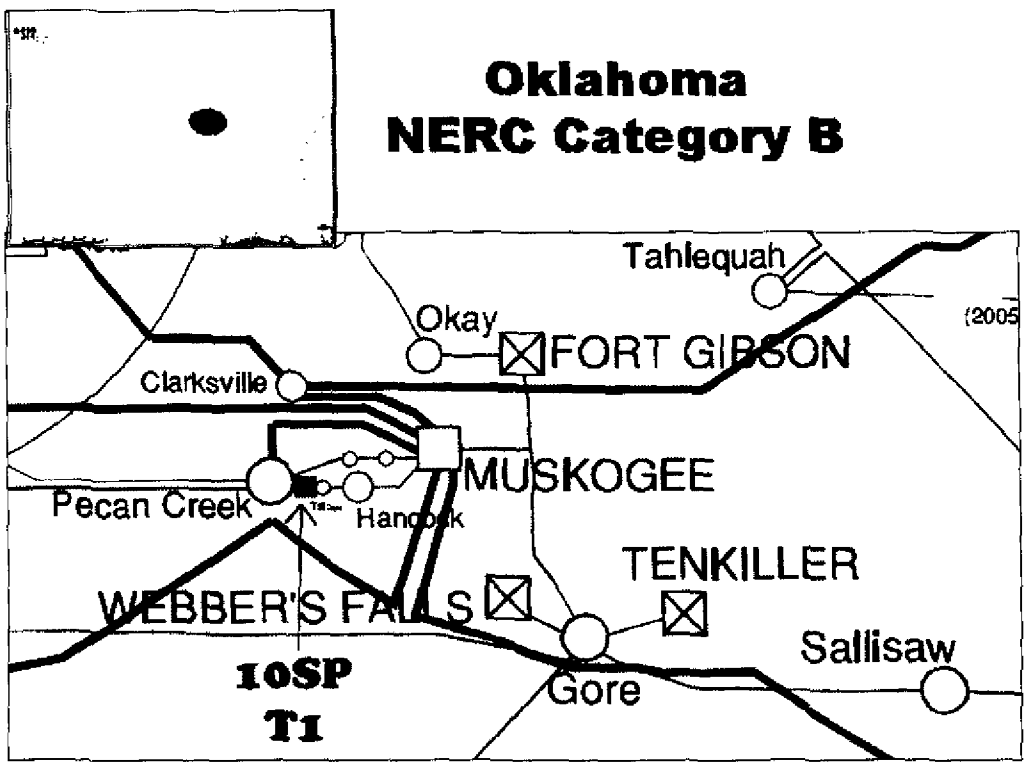

Arkansas
NERC Category B
BEAVER DAM
05/10SP ALL
Cowskin
Osage Creek
E. Centerton
05/10SP ALL
E. Rogers
Eureka Springs
Decatur
Rogers
05/10SP ALL
FLINT CREEK
Lowell
Tontitown
05/10SP ALL
S. Springdale
Dyess
Siloam Springs
Chamber Springs
05/10SP ALL
Hyland
Farmington
S. Fayetteville
S.E. Fayetteville
(2005)
Stilwell
05/10SP T1,3
AR


Arkansas
NERC Category B
05SP
05SP
Van Buren
Simmons
Helberg
FITZHUGH
Clarksville
(2010)
Nitrous Oxide
(2006)
Alma
IGO
Little Spadra
ELLIS
05SP
OZARK DAM
3rd St
Massard
DAM 13
Razorback
ARKANSAS NUCLEAR ONE
Barling
(2010)
Branch
Quanex
Short Mountain
10SP
DARDANELLE DAM
Bonanza
N. Magazine
Blue Mtn.
Danville
W. Booneville
North Huntington
Ola


Arkansas
NERC Category A
Hope North
Prescott
Okay
Emmett SW
Hope NW
McNab
Hope West
Hope East SW
Hope East
Camden
Hope
Hope South
FULTON
10SP B, T2
Sugar Hill
Patmos West
Lamartine
Stephens
Lewisville
McNeil EHV
Lewisville West
HARVEY COUCH
Magnolia W.
Magnolia E.
Magnolia So.
Shuler

Oklahoma


KANSAS
MISSOURI
ARKANSAS
TEXAS
MISSIS
LOUISIANA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Pecan Creek
Hancock
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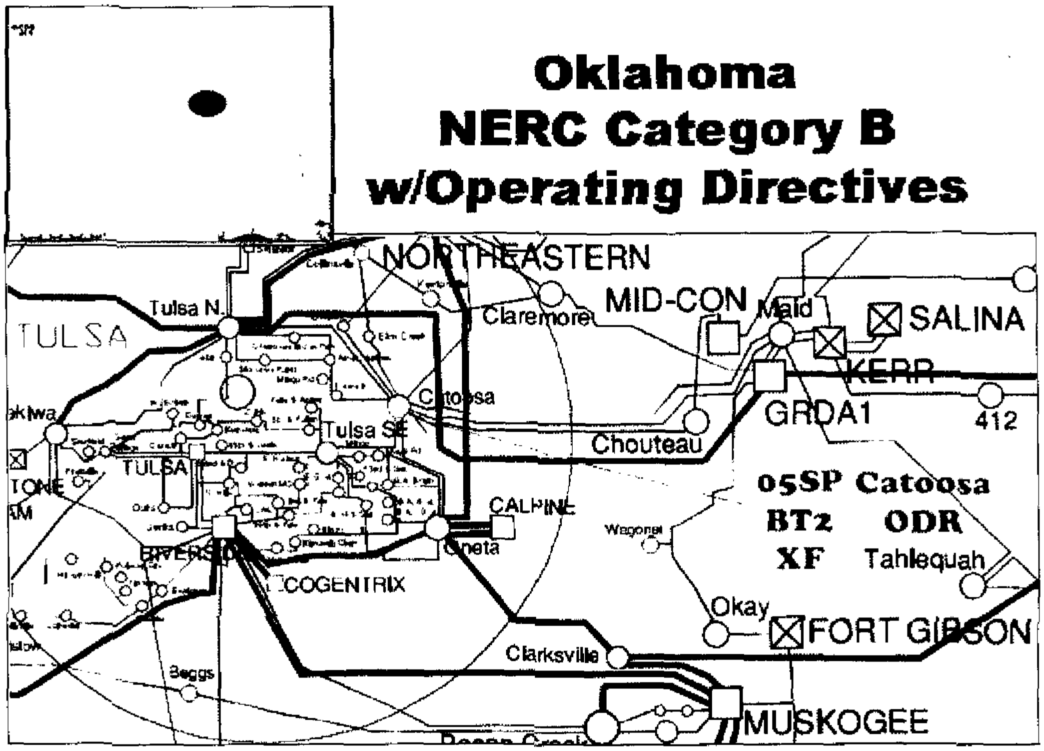
Gore
Sallisaw
10SP
T1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Maid
SALINA
Tulsa N.
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Claremore
KERR
Catoosa
GRDA1
412
Tulsa SE
Chouteau
TULSA
05SP Catoosa
BT2 ODR
XF
CALPINE
Wagoner
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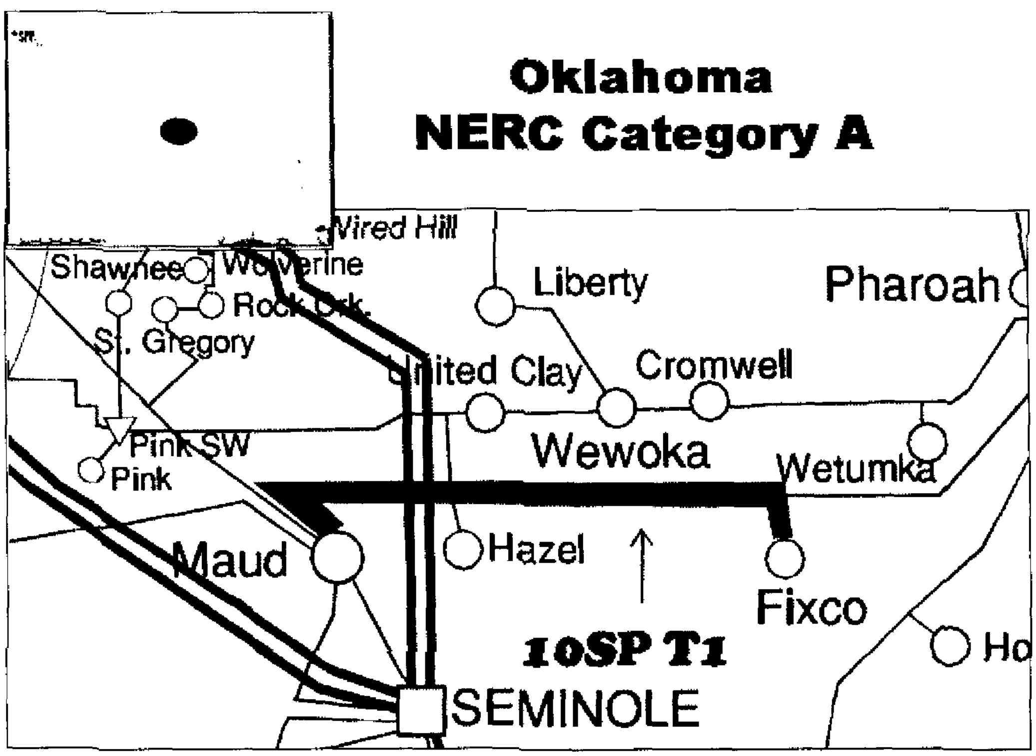
Beggs
MUSKOGEE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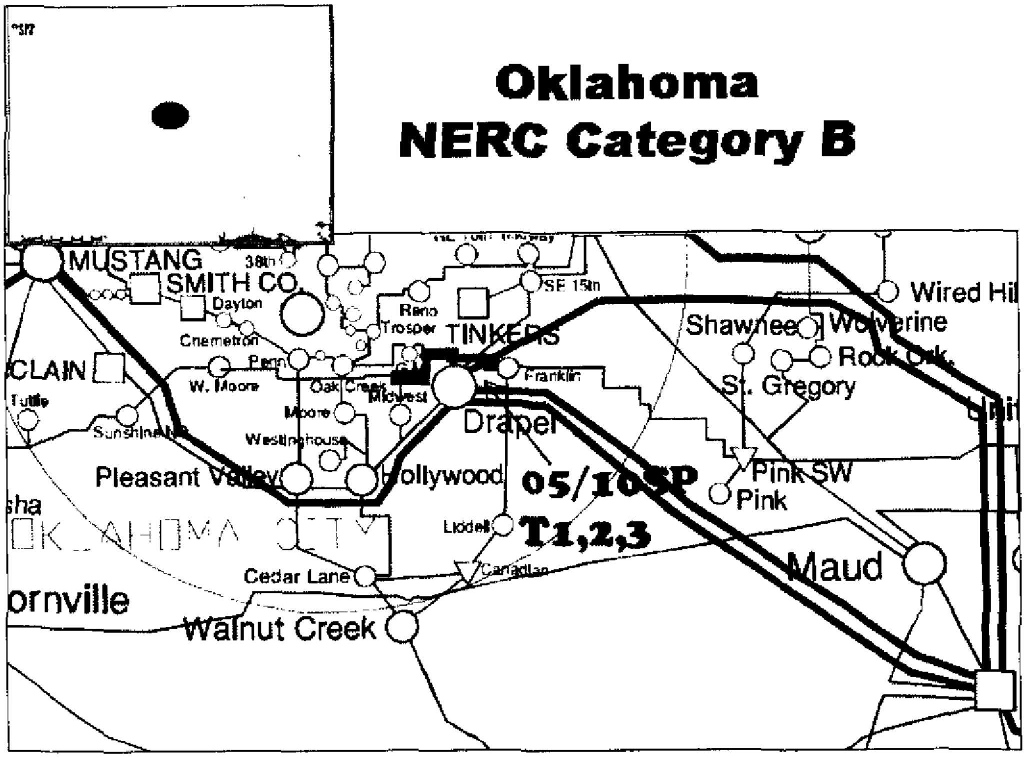
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Moore
Midwest
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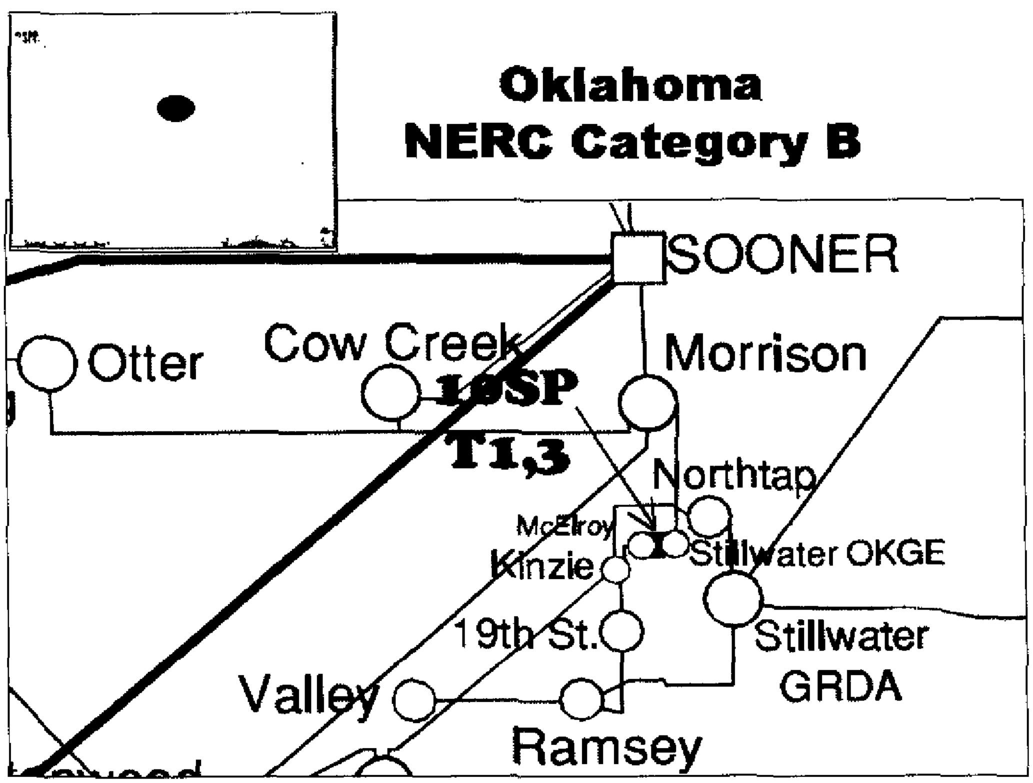
TINKERS
SE 15th
Franklin
Draper
CLAIN
Tuttle
Sunshine
Pleasant Valley
Hollywood
05/10SP
T1,2,3
Liddell
Canadian
Cedar Lane
Walnut Creek
ornville
Shawnee
Wolverine
Rock Crk.
St. Gregory
Wired Hi
Pink SW
Pink
Maud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SOONER
Otter
Cow Creek
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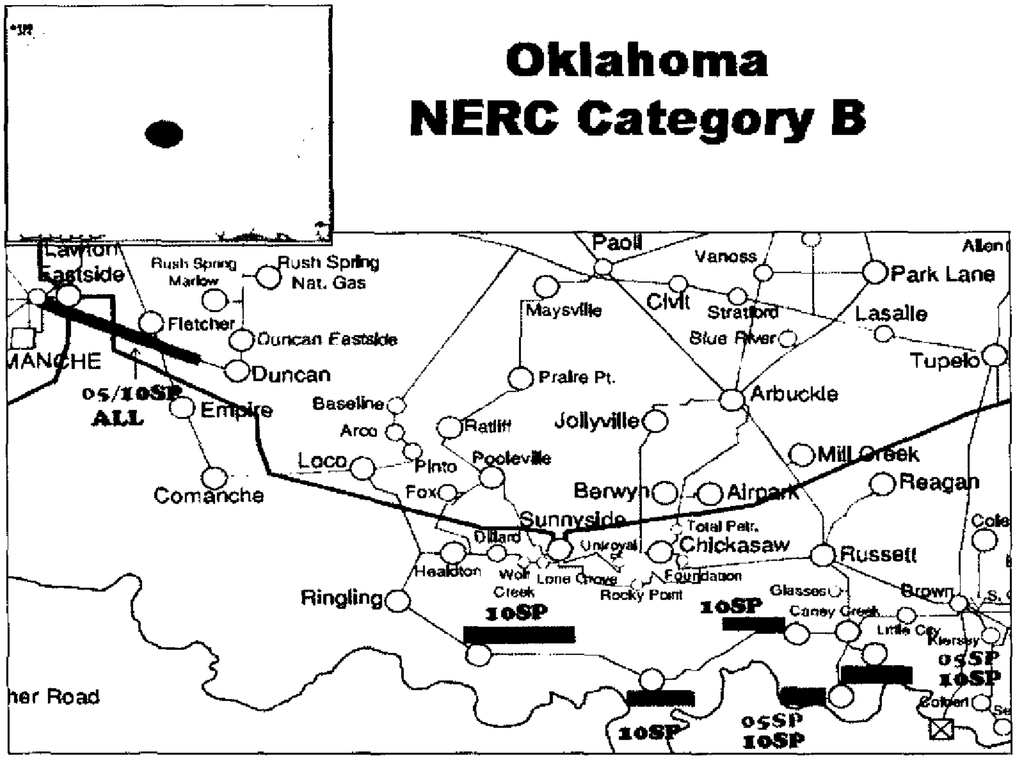
T1,3
Morrison
Northtap
McElroy
Kinzie
Stillwater OKGE
Stillwater
GRDA
19th St.
Valley
Ramsey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Rush Spring Marlow
Rush Spring Nat. Gas
Fletcher
Duncan Eastside
Duncan
05/10SP ALL
Empire
Comanche
Baseline
Arco
Loco
Pinto
Fox
Ratliff
Pooleville
Maysville
Praire Pt.
Jollyville
Paoli
Vanoss
Civit
Stratford
Blue River
Park Lane
Lasalle
Tupelo
Allen
Arbuckle
Mill Creek
Reagan
Berwyn
Airpark
Sunnyside
Dillard
Total Petr.
Chickasaw
Russett
Healdton
Wolf Creek
Lone Grove
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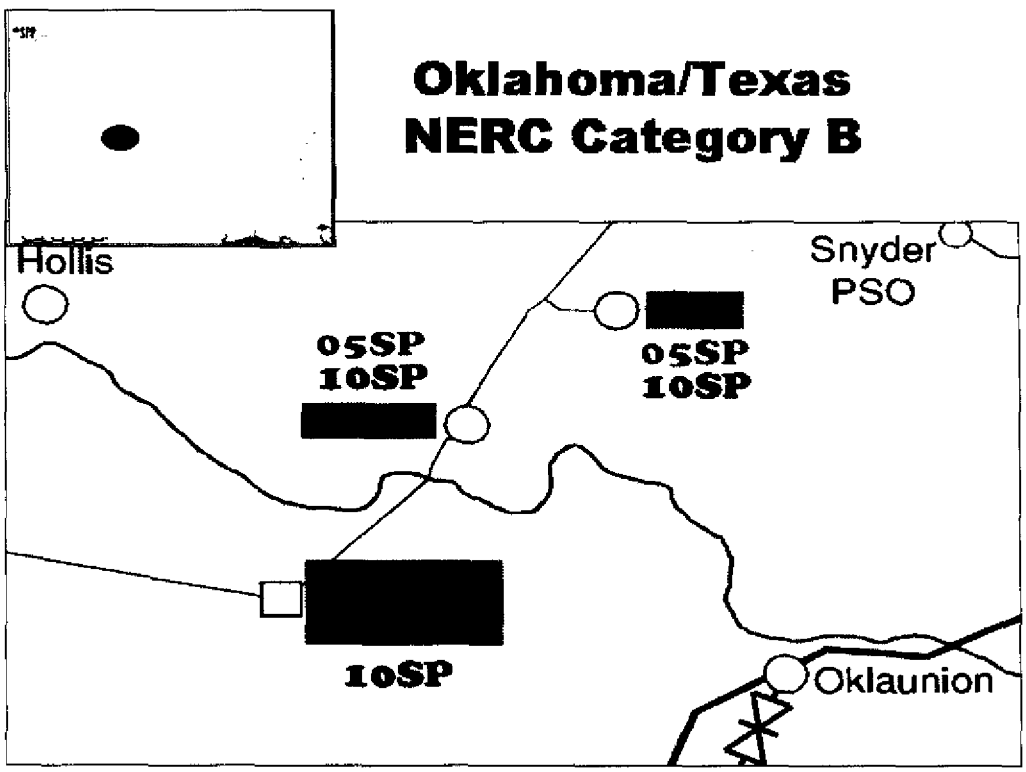
10SP
05SP
10SP
her Road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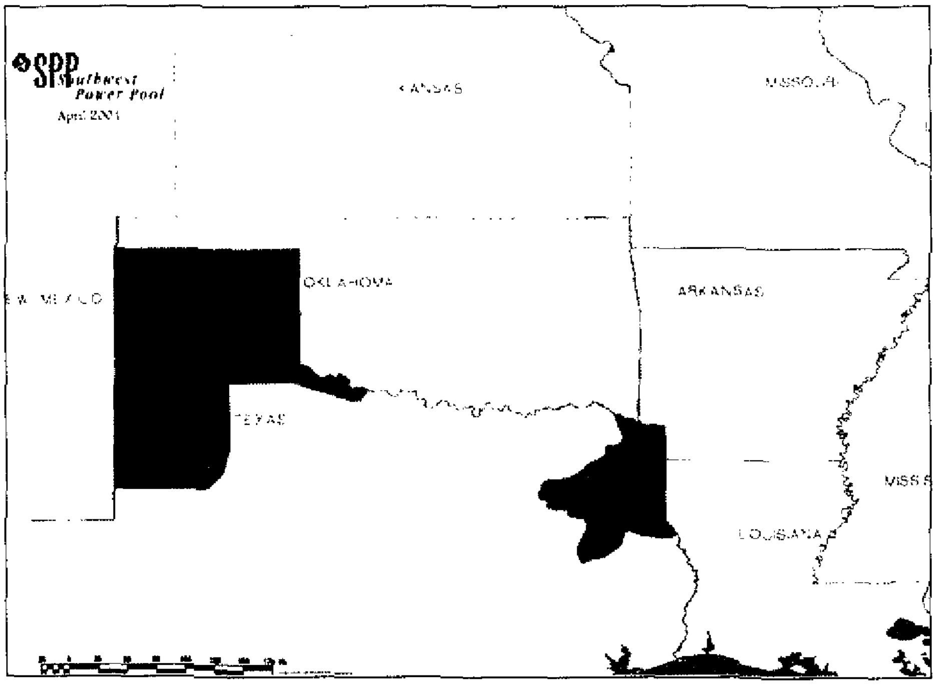
10SP
10SP
Oklaunion

North & East Texas



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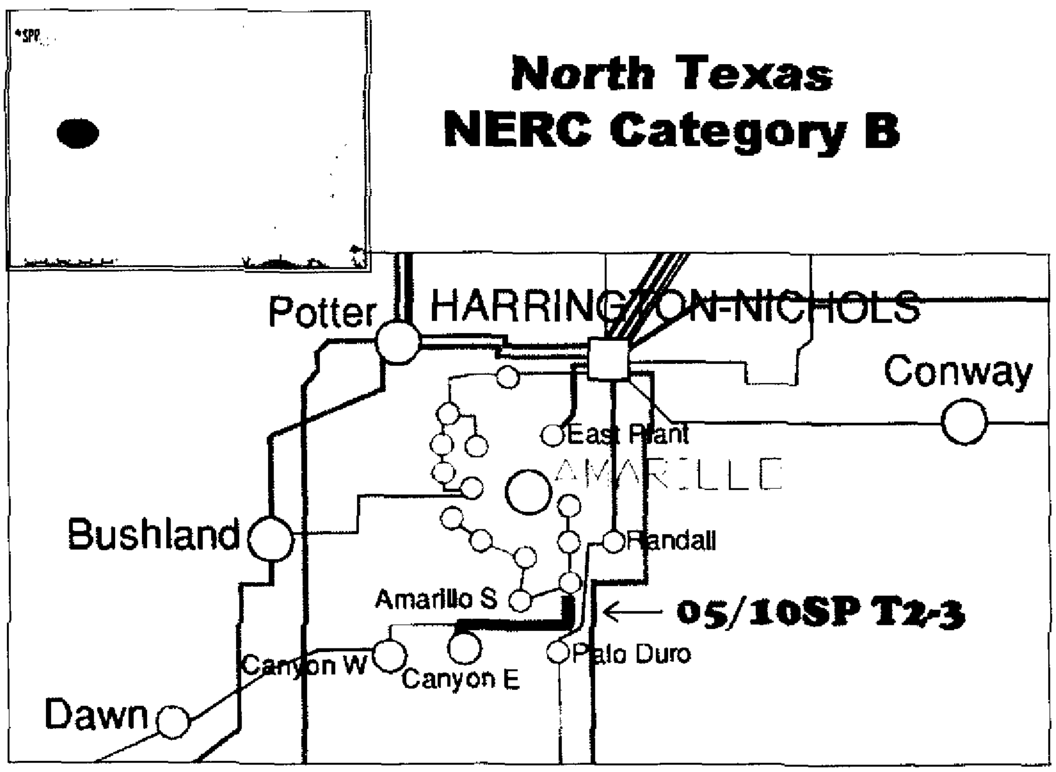

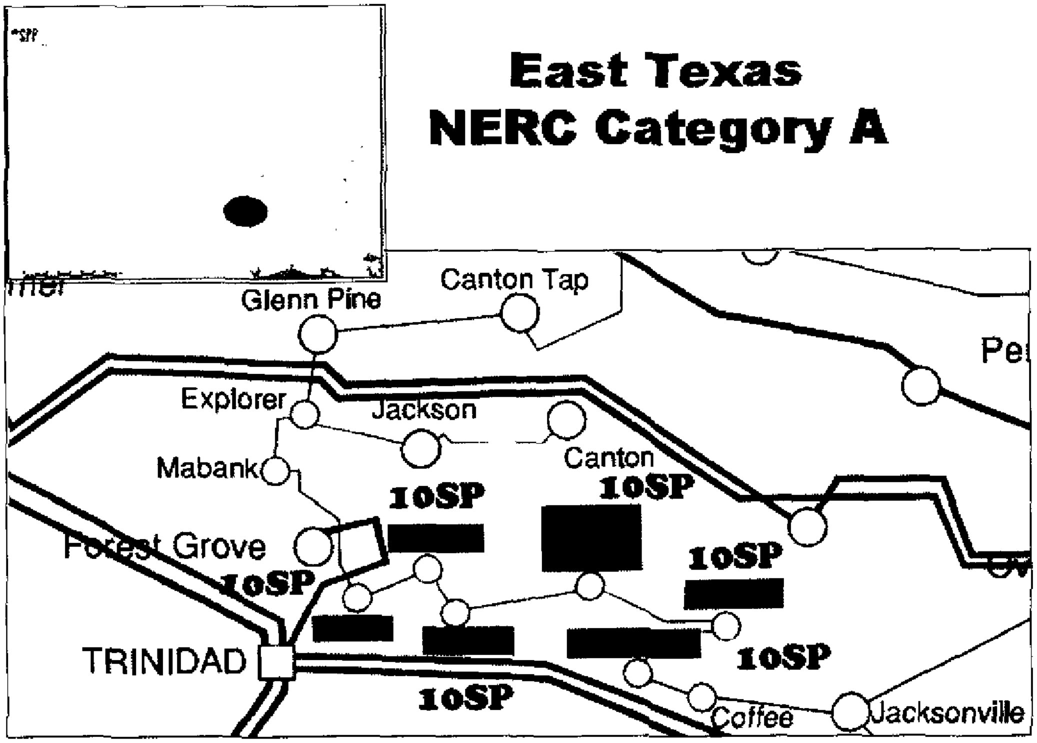
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Glenn Pine
Explorer
Jackson
Mabank
Canton
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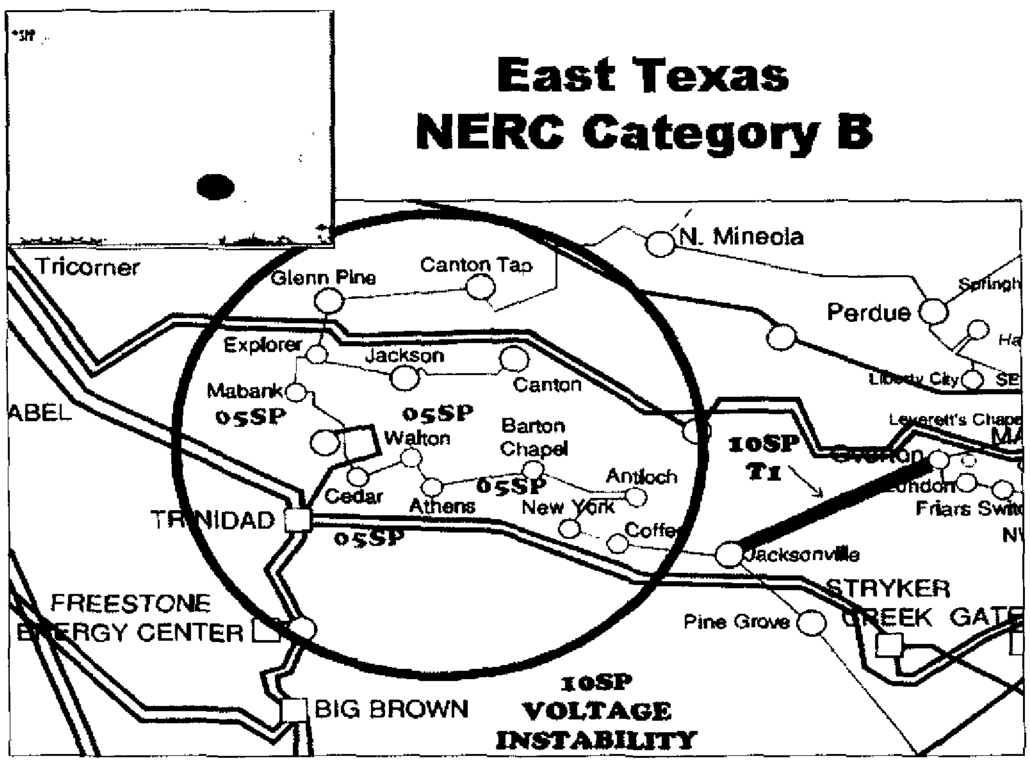
10SP
Forest Grove
10SP
10SP
10SP
TRINIDAD
10SP
10SP
Coffee
Jacksonville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Tricorner
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Canton
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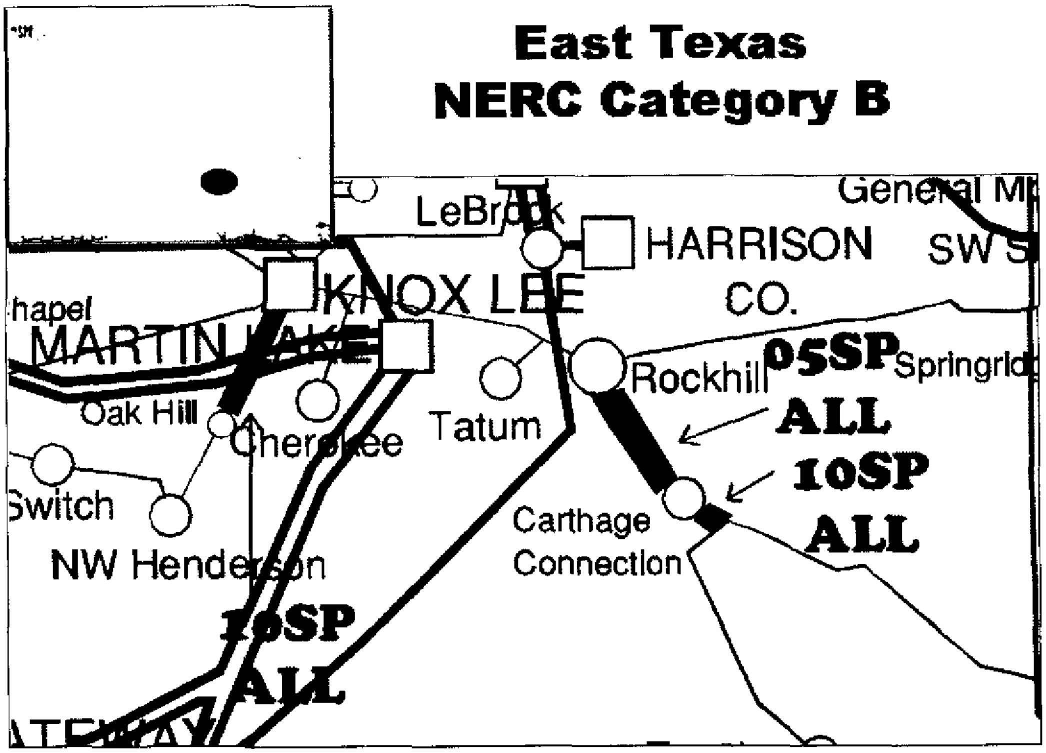
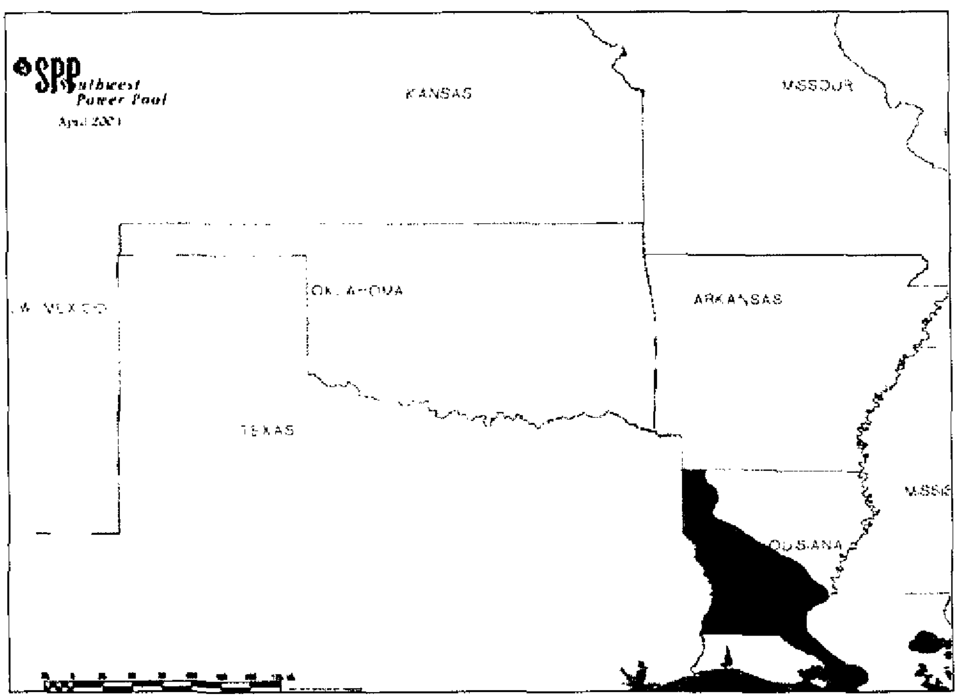
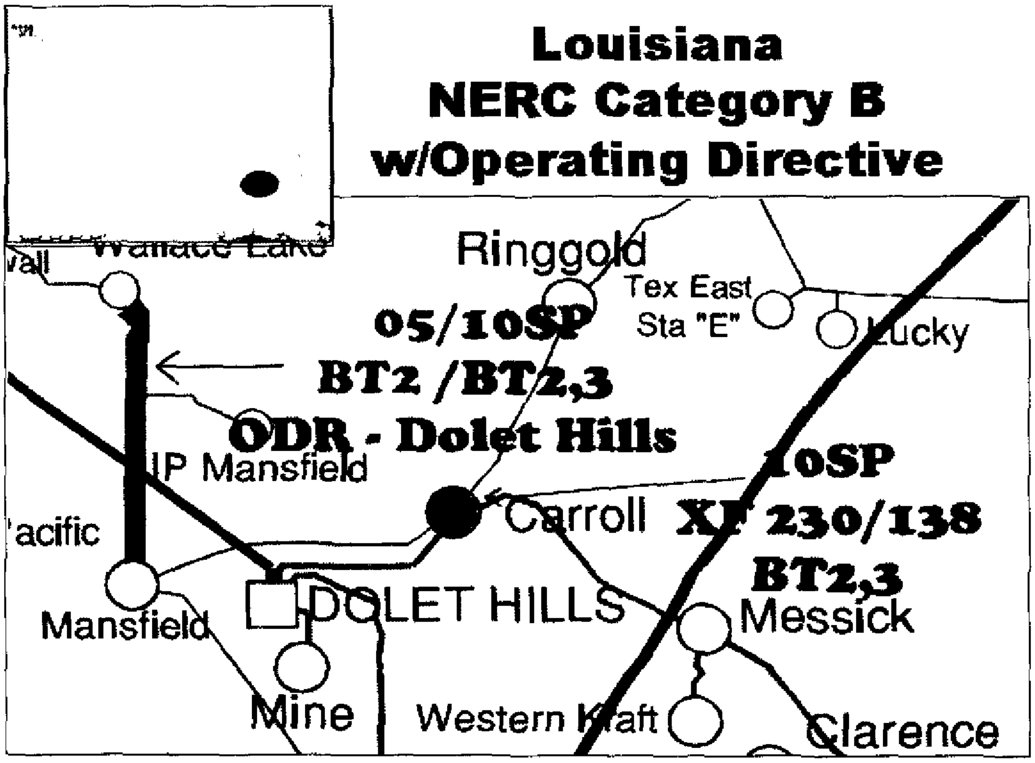
Barton Chapel
10SP
T1
Antioch
Cedar
Athens
05SP
New York
Friars
TRINIDAD
05SP
Coffee
Jacksonville
STRYKER
FREESTONE ENERGY CENTER
Pine Grove
BIG BROWN
10SP
VOLTAGE INSTABILITY

East Texas
NERC Category B



Louisiana




Louisiana
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w/Operating Directive
Ringgold
Tex East
Sta "E"
Lucky
05/10SP
BT2 /BT2,3
ODR - Dolet Hills
IP Mansfield
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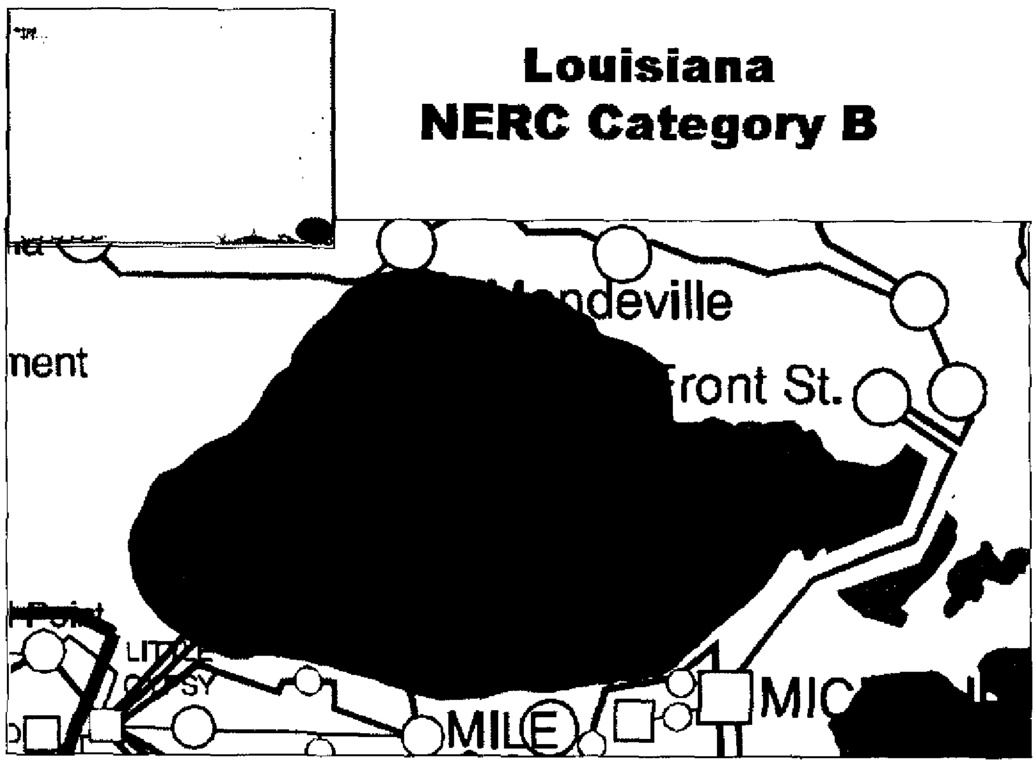
Carroll
XF 230/138
BT2,3
acific
Mansfield
DOLET HILLS
Messick
Mine
Western Kraft
Clarence


Louisiana
NERC Category B
deville
nent
ront St.
MILE
MIC

Appendix C: List of Screened Projects and Ranking

Project Ranking			
Project Name	Project Cost ($ Million)	Dispatch Savings (10 Year Estimate Cost Savings)	Ratio x 100
Tulsa East 345 kV Switching Stations	8.0	9.4	117.5
Tolk-Potter 345 kV	29.5	25.0	84.7
Cleveland-Sooner 345 kV	18.0	14.6	80.9
Tuco-Tolk-Potter 345 kV	44.5	25.2	56.7
Rose Hill-Sooner 345 kV	43.5	19.7	45.2
SWPS-Battlefield 161 kV	3.0	1.0	34.9
Fair Port-Sibley 345 kV	32.0	9.9	31.0
Potter-Clovis 345 kV	98.5	27.5	27.9
Super X-Plan 345 kV	493.5	136.9	27.7
Pauline-Knoll-Spearville-XF 345 kV	119.0	32.2	27.1
Modified X-Plan 345 kV	449.0	120.0	26.7
Pauline-Knoll-Spearville 345 kV	114.0	29.7	26.1
JEC-Swisvalle 345 kV	27.0	6.3	23.3
Valliant Tie 138 kV	3.3	0.7	21.6
Original X-Plan 345 kV (Plan-A)	419.0	84.4	20.1
Original X-Plan 345 kV (Plan-B)	410.0	81.9	20.0
Swisvalle-JEC-Moore 345 kV	86.5	14.7	17.0
Flint Creek-ISES 345 kV	126.0	20.7	16.4
Tuco-Tolk 345 kV	17.0	2.5	14.8
S.Dierks-Murfressboro 138 kV	7.3	0.9	12.6
S.Fayetteville-Osage 161 kV	17.3	1.9	10.7
JEC-Moore 345 kV	59.5	5.9	9.9
NW Texarkana-McNeil 345 kV	28.0	2.7	9.6
Chaves 230/115 kV Transformer 2	7.0	0.7	9.5
Wolf Creek-Lang 345 kV	22.0	1.3	6.0
NW Texarkana-McNeil-Dolet Hills 345 kV	52.3	3.0	5.6
Lacyne-Montrose-Callaway 345 kV	105.0	4.0	3.8
Moore-Pringle 230 kV	20.0	0.7	3.5
SPS 115kV Lines & Transformers	35.0	0.9	2.7
Potter-Northwest 345 kV	132.0	2.0	1.5
Muskogee-VBI 345 kV	38.3	0.4	1.0
Dolet Hills 345 kV Tie	24.3	0.1	0.2
HaleCounty-PlantX 230 kV	27.0	0.0	0.1

ATTACHMENT C

Proposed Transmission Lines For Years 2007 through 2014

Line Ownership	Terminal From	Terminal To	Line Length MI	Expected Service Date	Nominal Voltage KV Oper	Nominal Voltage KV Design	Estimated Costs ($)
PSO Project TL-A	[redacted]		5.0 miles	Jun-07	138	138	4,825,000
PSO Project TL-A			5.0 miles	Jun-07	138	138	6,139,000
PSO Project TL-B			1.06 miles	Jun-07	138	138	1,905,000
PSO Project TL-C			4.3 mi reconductor	Jun-07	138	138	2,721,000
PSO Project TL- D			3.75 miles	Dec-07	138	138	3,899,258
PSO Project TL-E			27.0 miles	Dec-08	138	138	11,937,000
PSO Project TL-F			10.0 miles	Dec-08	138	138	8,860,000
PSO Project TL-G			2.0 miles	Dec-08	138	138	2,160,000
PSO Project TL-H			6.4 miles	Jun-09	138	138	8,227,000
PSO Project TL-I			24.7 mi reconductor	Jun-09	138	138	9,900,000
PSO Project TL-J			4.31 mi reconductor	Jun-09	138	138	4,200,000
PSO Project TL-K			4.79 mi reconductor	Jun-10	138	138	2,887,569
PSO Project TL-L			2.0 miles	Dec-10	138	138	3,280,380

Proposed Substations For Years 2007 through 2014

Line Ownership	Terminal	Line Length MI	Expected Service Date	Nominal Voltage KV Oper	Nominal Voltage KV Design	Estimated Costs ($)
PSO Project S-A	[redacted]		Jun-07			86,000
PSO Project S-B			Jun-07			523,000
PSO Project S-C			Jun-07			169,000
PSO Proejct S-D			Jun-07			9,065,000
PSO Project S-E			Jun-07			302,000
PSO Project S-F			Jun-07			7,444,000
PSO Project S-G			Jun-07			3,033,000
PSO Project S-H			Jun-07			1,191,000
PSO Project S-I			Jun-07			139,000
PSO Project S-J			Jun-07			235,000
PSO Project S-K			Jun-07			200,000
PSO Project S-L			Jun-07			96,000

PSO Project S-M	[redacted]		Jun-07			7,650,000
PSO Project S-N	[redacted]		Dec-07			3,624,000
PSO Project S-O	[redacted]		Jun-08			790,000
PSO Project S-O	[redacted]		Jun-08			332,000
PSO Project S-P	[redacted]		Jun-08			448,000
PSO Project S-Q	[redacted]		Jun-08			571,000
PSO Project S-Q	[redacted]		Jun-08			338,000
PSO Project S-R	[redacted]		Jun-08			523,000
PSO Project S-S	[redacted]		Jun-08			2,093,000
PSO Project S-T	[redacted]		Jun-08			2,204,000
PSO Project S-U	[redacted]		Jun-08			168,000
PSO Project S-V	[redacted]		Jun-08			360,000
PSO Project S-W	[redacted]		Dec-08			593,000
PSO Project S-X	[redacted]		Jun-09			2,900,000
PSO Project S-Y	[redacted]		Dec-10			660,000
PSO Project S-Z	[redacted]		Dec-10			359,000
PSO Project S-AA	[redacted]		Dec-10			798,000
PSO Project S-AB	[redacted]		Dec-10			116,000

Public Service Company of Oklahoma

Request For Proposal

for
Peaking Capacity and Energy Resources

November 2005

PUBLIC SERVICE
COMPANY OF
OKLAHOMA

A unit of American Electric Power

Table of Contents

NOTICE

In the event that a Bidder perceives a conflict between this RFP and other posted information (e.g., answers to questions), this RFP document, as amended, shall prevail.

If corrections or clarifications to the RFP documents are required, PSO will issue a "RFP Amendment" on its RFP website located at:

www.PSOklahoma.com/go/rfp

Potential Bidders should check this RFP website regularly. It is the sole responsibility of the Bidder to keep up with any RFP document changes as discussed above.

SECTION 1 - GENERAL INFORMATION

1.1 Introduction

The purpose of this document is to prescribe the process by which Public Service Company of Oklahoma ("PSO" or the "Company") will request and evaluate Proposals through a competitive procurement process which Company deems, in its sole discretion, to provide the most reasonable cost and reliable resources to fulfill a portion of its supply-side resource need consistent with Company's resource planning requirements. The scope of this Request For Proposal ("RFP"), subject to the limitations described herein, is focused on a supply-side resource capable of delivering peaking capacity and associated energy in or to the Company's transmission system (see Section 3.6) and that is capable of fulfilling the planning reserve requirements of the Southwest Power Pool ("SPP").

The Company is soliciting binding Proposals from bidders (Bidders) in the form of Power Purchase Agreements (PPA) and/or the acquisition of existing generation facilities for up to 500 megawatts (MW) of Peaking Resources with a Commercial Operation Date of June 1, 2008 ("COD"). The Company prefers to ultimately own and operate the generation facilities providing the capacity and associated energy proposed under the terms of this RFP, and, therefore, Bidders who propose a PPA will be encouraged to propose terms that allow the Company to acquire the generation facility during the contract term. The Company values the Bidder's flexibility in terms of adjusting the COD. Proposals shall be submitted by Bidders in the form of the RFP Response Package attached as Appendix E.

Proposals shall be binding upon the successful Bidder(s) until August 31, 2006.

The general schedule for the RFP process is shown below. A more detailed schedule follows in Section 4.3.

Draft RFP Issued	09/12/05
Issue Final RFP	11/01/05
Binding Peaking Proposals Due	12/20/05
Selection of Award Group	03/16/06
Execute Final Contract(s)	05/15/06

The Company seeks Proposals from any Bidder who is capable of meeting the conditions of this RFP. Bidders should note that the Company and its agents will be able to, and should be expected to, respond to this RFP. As described in more detail below, the Company has put in place prudent safeguards to avoid undue preference to its self-build Proposals. Any Bidder who has a question with respect to such safeguards is instructed to contact the Independent Monitor (IM) as described in Section 1.2 below.

PSO, based in Tulsa, Oklahoma, is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP). PSO is an operating electric public utility engaged in the generation, transmission, distribution, purchase and sale of electric energy in

Oklahoma. PSO provides wholesale and retail electric service to more than 509,000 customers in a service area covering approximately 30,000 square miles. PSO's retail electric rates and services are regulated by the Oklahoma Corporation Commission ("OCC" or the "Commission"). PSO's wholesale power and transmission rates and services are regulated by the Federal Energy Regulatory Commission ("FERC").

PSO will be using its Affiliate, American Electric Power Service Corporation (AEPSC) as its agent for the RFP process.

For capitalized terms not defined in the main text of this RFP, please refer to Section 8, Glossary of Terms.

1.2 Independent Monitor

PSO is committed to a fair solicitation process. The evaluation criteria and process are designed to ensure a fair solicitation process and to provide Bidders with information on how the Proposals will be evaluated and what the Company deems as important aspects of a Proposal. Merrimack Energy Group, Inc. will act as the Independent Monitor for this solicitation. The IM will monitor the RFP process and will review and track the Company's conduct of the RFP to ascertain that no undue preference is given to PSO's self-build Proposals. This will include, to the extent necessary, reviewing the draft RFP and the Company's evaluation of Proposals; monitoring communications (and communications protocols) with market participants; monitoring adherence to codes of conduct; validation of the models, input assumptions; risk assessments; and monitoring contract negotiations.

A more detailed evaluation of the IM's Scope of Work is attached as Appendix A. Among other responsibilities noted in the Scope of Work, the IM will address Bidders' questions, issues, and concerns during the RFP process, and, as needed, communicate those issues and concerns to the appropriate parties, including PSO and OCC Staff.

Contact information for the IM is:

Wayne Oliver
Merrimack Energy Group, Inc.
727 Lafayette Road
P O Box 2955
Seabrook, NH 03874
Phone: (603) 474-3385
Cell: 781-856-0007
Fax: 603-474-3384
E-mail: waynejoliver@aol.com

1.3 Self-Build Procedures

Procedures for this RFP call for objective, arm's-length dealing with respect to agents of the Company who are developing self-build Proposals ("Self-Build Team"). Appropriate procedures and a Code of Conduct are in place to safeguard against the Self-Build Team receiving undue preferential treatment and preferential access to information. Additional procedural provisions require PSO to protect the confidentiality of Proposals and Bidder information and to ensure such information is not improperly used by PSO or its Affiliates (see Procedures Manual in Appendix K).

Specifically prohibited is the communication, directly or indirectly, of material non-public information about or derived from PSO selectively to the Self-Build Team, as well as any preference by PSO expressed in any way whatsoever for self-build Proposals per se. Accordingly, in this RFP there is pre-established operational independence between PSO and the Self-Build Team to ensure that any Proposals submitted by the Self-Build Team will not have any material advantage in the selection process versus Proposals submitted by third-party Bidders.

SECTION 2 - SECTION NOT USED

SECTION 3 - 2005 PEAKING RESOURCES RFP

3.1 Overview of RFP

The Company's Integrated Resource Plan ("IRP") has identified that additional capacity must be added to the PSO system over the next 10 years in order for it to maintain adequate capacity reserves. The IRP process has shown that the most economic solution for meeting PSO's future capacity reserve needs is the addition of peaking capacity and associated energy by the summer of 2008 and baseload capacity and associated energy by the summer of 2011.

In order to meet its future resource needs, PSO will issue two separate RFPs, this RFP for peaking resources and a separate RFP for baseload resources. In this peaking resource RFP, PSO seeks Proposals for capacity and associated energy for up to 500 MW of peaking resources with a COD of June 1, 2008. PSO's baseload resource RFP will seek Proposals for firm capacity and associated energy for up to 600 MW of baseload resources with a COD of June 1, 2011.

PSO is interested in Proposals that are in the form of PPAs and/or the acquisition of existing generation facilities (Asset Purchase Proposal or APP). PSO prefers to own and operate the generation facilities providing the peaking capacity and associated energy proposed under the terms of this RFP. Therefore, Bidders who submit PPA Proposals will be requested to propose terms that give PSO the option to acquire the Bidder's interest in the designated generation facility at various points during the contract term.

Appendix H contains the Model Power Purchase and Sale Agreement ("Model PPA") and Appendix I contains the Model Purchase and Sale Agreement ("Model PSA"). The Model PPA and Model PSA together are referred to as the Model Contracts.
In addition to Proposals from third parties, it is anticipated that PSO will submit self-build Proposals.

PSO's objective for this RFP is to encourage a broad range of Proposals and to secure those resources that provide the greatest benefit to its customers. PSO reserves the right to reject any and all Proposals, in its sole discretion, if they are not in the best interest of PSO. The level of flexibility and creativity offered by the Bidder in its Proposal will be recognized in the evaluation process. PSO is interested in Proposals that:

(i) provide flexibility in terms of the COD, including the ability to defer or accelerate the COD by one year;
(ii) offer other options which minimize risk and costs to PSO and its customers;
(iii) provide PSO with the ability to acquire the generation assets used to supply the capacity and energy for a PPA Proposal;
(iv) offer creative pricing and technical options either as part of its Base Proposal or as an Alternative; and
(v) offer fuel and fuel transportation flexibility.

3.2 Basic Requirements for Firm Peaking Capacity and Energy Proposals

The Company is seeking Proposals for firm capacity and associated energy for a minimum of 320 MW and up to 500 MW of peaking resources with a COD of June 1, 2008. Firm capacity will be defined as Net Dependable Summer Capability. The minimum bid size is 40 MW of Net Dependable Summer Capability.

Bidders who propose PPAs are required to conform to a contract term of 20, 25 or 30 years.

In addition to PPA Proposals, PSO will also consider Asset Purchase Proposals for the acquisition of a Bidder's existing generation facilities or interests therein. Asset Purchase Proposals must meet the same minimum size and COD that are defined for PPA Proposals. Asset Purchase Proposals shall be for a fixed dollar amount, inclusive of all monetary consideration for the generation asset. Any contractual obligations (e.g., fuel supply and transportation, maintenance agreements, etc.) related to the generation asset proposed for sale should be clearly defined by the Bidder in its Proposal. PSO prefers Proposals in which it will acquire the majority interest and/or the operational control of the generation facilities.

PSO prefers Proposals with points of delivery tied directly to PSO's transmission system as shown in Appendix C. All Proposals, regardless of the location of the generation resource, will be judged based upon their impact on PSO's transmission facilities, including the cost of any required system upgrades, and to the extent they can be determined, on neighboring transmission systems.

Bidders are encouraged to provide PSO with Base Proposals and alternatives that reflect what they believe to be their best pricing Proposal.

3.2.1 Base Proposal

The Base Proposal is the preferred Proposal of the Bidder and shall be comprised of the information provided by the Bidder in the RFP Response Package.

PSO will determine the Proposals to be included on the short list based on its evaluation of the Base Proposals. Therefore, Bidders are advised to present their best Proposal as the Base Proposal. At no point in the evaluation process will Bidders have the opportunity to unilaterally change their Proposal.

3.2.2 Alternative Proposals

In addition to the Base Proposal, Bidders may submit up to two alternatives to the Base Proposal (Appendix E Tab 15 of the RFP Response Package) under the Proposal Submittal Fees, (see Section 4.1) although these Alternatives will not be considered until the portfolio evaluation phase (see Section 5). Alternatives could include different project size(s) or structure(s), alternative financial arrangements, alternative PPA terms and conditions, alternative APP terms and conditions, and other pricing provisions that differ from the Base Proposal. Proposals with different sites, technologies, fuel supply arrangements, etc. from the Base Proposal must be submitted as separate Proposals, and must include an additional Proposal Submittal Fee.

PSO's objective for alternative Proposals is to allow the Bidder the flexibility of phasing in a Project, offering a different project size, proposing alternate pricing options and PPA terms and conditions, etc. which could be considered in a portfolio with other Proposals. This will allow PSO to optimize the benefits from the solicitation by combining Proposals with different characteristics.

Bidders should clearly label and describe the alternatives in Tabs 3 and 15 of the RFP Response Package, including appropriate pricing schedules. Alternatives will only be considered if they add value to the resource procurement process and can provide the flexibility deemed important by PSO.

3.3 Power Purchase Proposals

The Company seeks Proposals that have clear and definable pricing characteristics. Proposals containing a fixed price, throughout the term of the Proposal for capacity charges (stated in $/kW-year) are preferred. Bidders shall not offer Proposals with indexed pricing (e.g., Producer Price Index, Consumer Price Index, interest rates, etc.) for the capacity component of the price (see RFP Response Package Tab 3.) PSO seeks peaking Proposals based upon unit heat rates and fuel index pricing.

Bidders proposing PPA products are responsible for all costs to deliver those products to PSO, including, but not limited to: costs of transmission service, upgrades and new construction of transmission facilities located outside of the AEP SPP control area; costs of transmission congestion; costs of ancillary services; and any fees or taxes, present and future, over the term of the Proposal. This must be expressly confirmed in Bidders' Proposals.

Bidder generation resources interconnected to PSO's transmission system within the AEP SPP control area near PSO's large load centers are preferred.

In addition, PSO is interested in Proposals giving it the option to purchase the generation assets that are used to supply the capacity and energy under the PPA. Bidders are encouraged to propose purchase pricing for those generation assets at various points during the contract term. (Appendix E Tab 3)

Peaking products should be proposed in quantity blocks ranging from a minimum size of 40 MW to a maximum size of 500 MW.

PSO prefers products that provide scheduling flexibility commensurate with the operating characteristics of the proposed generation assets. PSO reserves the right to dispatch these products at any load level within the source generator's operating limits, and to start and stop as needed to serve PSO's operational needs.

Requirements of the PPA may be met through a slice of system, existing generation facilities, or proposed new generating facilities.

3.3.1 System Products

Company encourages the Bidder to submit RFP Proposals for Peaking products supported by a single generating facility or by a system of generating facilities. Such slice-of-system ("System") Proposals should meet the Peaking product criteria stated above and elsewhere in this RFP. Because the characteristics of a System are not defined by reference to the capabilities of a particular generating unit, the Bidder should specify with particularity the capabilities of its System product. The Bidder should modify its RFP Response Package to the extent necessary to include this information. The Bidder should include an overview of its System and information on the particular generating facilities supporting its System Proposal.

In order to assist Bidders wishing to propose System products, Company is providing the following non-exhaustive list of the capabilities that should be described in such Proposals. Where appropriate, Company has specified minimum standards that must be met by a System product.

(i) Quality: Company prefers System products that are Firm with liquidated damages. The Bidder should specify the level of firmness of its System product and state any excuses from performance with particularity (i.e., the number of units or percentage of system that must be off-line prior to any diminishment in System product service).

(ii) Scheduling: The Bidder should specify any minimum notice times prior to scheduling and dispatch of the System product by Company. In particular, the Bidder should specify if its System product must be scheduled on a day-ahead basis, and the extent to which its System may be scheduled on an hour-ahead or shorter basis. For a Peaking Product, Company should have rights to dispatch the unit on an hourly basis at a minimum.

(iii) Scheduling Limits: The Bidder should state any minimum or maximum loading constraints, as well as the rate at which Company may change the loading of the System over a given time period.

(iv) Starts: The Bidder should state the number of "starts" – the scheduling of at least minimum load after the System has been scheduled to zero – over a given time, any mandatory downtime or uptime, and the cost, if any, of starting the System.

(v) Delivery Point: The Bidder should specify the Delivery Point for energy and ancillary services from the System and, if more than one point, any information necessary to determine the allocation of energy and ancillary services among those points.

(vi) Ancillary Services: The Bidder should specify the ancillary services that Company will have the right to utilize from the System and, if such ancillary services are not under the direct dispatch and control of Company, the manner in which aggregate System revenues from those services will be determined and allocated to Company.

3.4 Asset Purchase Proposals

Bidders may submit Proposals to sell existing generation assets that have a proven operating history. In such case, a Bidder shall offer to sell (i) 100% of the ownership of a generation asset having a minimum Net Dependable Summer Capability that matches the products outlined in Section 3.3 or (ii) its ownership interest in a generation asset in which the Bidder's share of the output is no less than the minimum Net Dependable Summer Capacity that matches the products outlined in Section 3.3. PSO prefers generation assets that do not have any restrictions or limitations imposed on them as a result of other assets at that site.

Asset Purchase Proposals shall be priced at a fixed dollar amount inclusive of all monetary consideration for the generation assets. APPs may include or exclude related arrangements for fuel commodities and transportation of them and the presence or absence of this factor shall not adversely affect the conforming status of a Proposal. Any material contract obligations that are associated with the proposed asset sale should be clearly defined (e.g., fuel storage, fuel transportation).

Any and all costs that would be incurred by PSO for the delivery of power from a generation asset, including, but not limited to costs of transmission service, upgrades and new construction; costs of transmission congestion; costs of ancillary services; and any fees or taxes, present and future, over the term of the Proposal, will be considered in evaluating the Proposal.

All Asset Purchase Proposals shall provide the information required in the RFP Response Package. Such information shall not preclude the Company from conducting its own due diligence.

3.5 Fuel Considerations

3.5.1 Power Purchase Agreement

PPA Proposals should have fuel supply and transportation flexibility commensurate with the Proposal's operational and dispatch flexibility. The Bidder shall clearly describe the flexibility of its fuel supply and transportation arrangements serving its generation units. The Company's analysis will be weighted to reflect the value such fuel supply and transportation flexibility affords Company operations.

With respect to the energy and ancillaries price component of PPA Proposals for natural gas generating facilities, Company's preference is for a heat rate priced Proposal tied to the *Gas Daily* daily midpoint price index, which methodology is included in the Model PPA. If Bidder desires to utilize a different energy and ancillaries pricing methodology, Bidder should include the description of any index used, whether the pricing is daily or monthly, as well as any escalation factors or other costs to the Company which should be considered.

Regardless of the specific fuel used by the generating facilities or system that Bidder relies on in its Proposal, Bidder shall explain its proposed fuel supply plan in detail (Appendix E, Tab 5,) including its proposed primary fuel supply and transportation and its backup alternatives. The Bidder is encouraged to suggest as part of its Proposal terms and conditions for inclusion in the PPA under which Company would be able to lock-in the variable fuel price component of the energy and ancillaries charges from time to time during the term of the PPA.

Preference will be given to Proposals that provide maximum flexibility and secondary source(s) of fuel supply and transportation arrangements. Bidders shall clearly identify any fuel-related constraints and/or limitations associated with their Proposals, including, but not limited to, operational flexibility or reliability of its fuel supply and/or transportation which might affect the ability to dispatch the generation and/or Company's ability to utilize the resource for operating reserves.

In the event that a new fuel supply or transportation arrangement is required to enable Bidder to meet its delivery obligation to Company, all relevant information with respect to such proposed arrangements should be provided as part of Bidder's Proposal in sufficient detail to allow its feasibility to be evaluated by the Company's evaluation team.

3.5.2 Purchase of Existing Peaking Generation Facilities

PSO requests Proposals for the purchase of existing peaking generation facilities which address not only the Company's desire for peaking generation capacity, but also its requirements for dispatchable operations with maximum fuel and transportation flexibility. Such flexibility is an integral part of the evaluation of any such Proposal.

Bidders shall identify the any existing fuel supply and transportation agreements currently serving the generation facility being offered. They shall also identify the general commercial terms of such agreements, including, but not limited to, term, quantity obligation, pricing, any other applicable fees, or costs of such commitments, etc. Bidders should also state whether such commitments are assignable under the terms of the existing fuel supply and transportation agreements.

Should the disclosure of such information be subject to a confidentiality provision in Bidder's existing contracts the Company is willing to enter into a confidentiality agreement to ensure that such information is used solely for the evaluation of the Proposal.

Bidders shall also identify any other natural gas transporters within 10 miles of the subject generation facility.

Preference will be given to Proposals that provide maximum flexibility and secondary source of fuel supply and transportation arrangements. Bidders shall identify if the generation facility is capable of operating on any alternative fuels, and if so, shall identify the type and availability of such fuel, the existence of any long-term contracts for the supply and/or transportation of such fuel, and the assignability of such contracts. Secondary fuel supply and/or transportation options are valuable considerations for any Proposal.

Proposals shall also clearly describe any fuel-related constraints associated with the Proposal including, but not limited to, operational flexibility or reliability of its fuel supply and/or transportation that might affect dispatch of the generation facility and/or the Company's ability to utilize the resource for operating reserves.

The Company's analysis will be weighted to reflect the value that any such fuel and/or transportation flexibility provides to the Company's operation of the generation facility.

3.6 Reliable Delivery

Bidders are required to deliver firm capacity, energy and associated electric products to the AEP SPP Control Area. PSO expects to use Network Integrated Transmission Service under the SPP Open Access Transmission Tariff ("OATT") from resources within the SPP RTO footprint. Approval of transmission service by SPP for requests where the resources are located on PSO's transmission system are expected to require fewer transmission upgrades than resources located elsewhere.

Proposals for products originating outside the SPP RTO footprint shall specify the Bidder's obligation to reserve, provide for, and pay for firm transmission service to the

SPP RTO footprint. Such Proposals shall specify all pertinent details of proposed firm transmission paths, services and arrangements and shall specify all-inclusive pricing to the SPP RTO footprint, including all transmission costs and agreements in place to deliver such firm capacity, energy and associated electric products.

Each Bidder offering firm capacity, energy and associated electric products originating outside the SPP RTO footprint must provide the factual basis for its assumption that a firm transmission reservation can be obtained to deliver power into PSO's transmission system.

Prior to short-listing Proposals, PSO will undertake its own analysis for delivery of capacity, energy and associated electrical products and use the results in the Proposal evaluation phase. A Bidder, at its sole option and liability, can contract with applicable transmission provider(s) and pay for any studies it wishes to provide PSO prior to evaluation of Proposals.

Once Proposals are short-listed, PSO will perform more detailed studies at its own expense to estimate the cost of any required transmission upgrades. These transmission studies will be done in a manner similar to the transmission studies required by SPP. Company will use the best available information and data to perform these studies, however, there is no expectation that the study results will precisely match studies that will be ultimately performed by SPP to approve PSO's request for Network Integration Transmission Service.

After the Award Group is determined and negotiations are completed, Company will request Network Integration Transmission Service under the SPP OATT. Bidders sourcing their offer outside the SPP will be expected to make similar arrangements with transmission providers outside the SPP at that time.

SECTION 4 - INSTRUCTIONS TO BIDDERS

4.1 Proposal Submittal Fees

Bidders shall pay a non-refundable $5,000 Proposal Submittal Fee per Proposal from a single generation resource and a non-refundable Proposal Submittal Fee of $500 each for up to two alternatives as outlined in Section 3.2.2 from that same generation resource. Checks for the Proposal Submittal Fees should be made payable to Public Service Company of Oklahoma.

4.2 Confidential Information and Confidentiality Agreements

The Company, its agents, and the IM will treat as confidential all Proposals submitted by Bidders. Bidders shall submit their Proposals, with the knowledge and understanding that regardless of confidentiality any information submitted by them, such information is subject to disclosure to the Commission or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. In the event that the Company, in its sole judgment and discretion, determines that information contained in any question, response, or other communication between it and a Bidder that is not contained in the Bidder's Proposal, requires confidential treatment, a Confidentiality Agreement (Appendix B) will be submitted to the Bidder. The Company will ensure that all Bidders have access to the same information from the Company and that no Bidder will have selective or otherwise preferential access to market sensitive information from the Company through this RFP.

4.3 RFP Schedule

The schedule for the RFP is shown below. As circumstances warrant, the Company, in its sole judgment and discretion, may change this schedule, and in that event, PSO will inform all participants as far in advance as reasonably possible and the information will be posted on the RFP website located at www.PSOklahoma.com/go/rfp. The Company will consult with the IM prior to announcing any significant change to the schedule shown below.

Draft RFP Issued	09/12/05
Technical Conference	10/05/05
Posting Deadline for all Questions	10/07/05
Comments Due	10/21/05
Issue Final RFP	11/01/05
Notice of Intent to Submit Proposal Form Due	11/15/05
Pre-Bid Conference Registration Due	11/16/05
Pre-Bid Conference	11/21/05
Self-Build Proposals Due	12/19/05
Proposals Due	12/20/05
Short List Identified	01/30/06
Selection of Award Group	03/16/06
Execute Final Contracts	05/15/06

4.4 Modification or Cancellation of the RFP

In addition to modifying the proposed schedule, PSO reserves the right, in its sole judgment and discretion, but subject to prior consultation with the IM and Commission, to modify or cancel this RFP. PSO will post a notice on its RFP website and make a reasonable attempt to notify directly all participants who have filed a timely Notice of Intent to Submit Proposal (Appendix G) of any such changes, cancellations, or schedule changes. Notwithstanding, PSO shall not have responsibility for making any such notification.

4.5 Question, Comment and Response Process

All questions and comments submitted by Bidders, as well as PSO's responses to such questions, will be posted on the RFP website located at www.PSOklahoma.com/go/rfp. The official response to questions submitted by Bidders is the written response posted to the website. PSO's objective in posting these questions, comments and responses is to ensure all Bidders have equal access to information that may be potentially relevant to their Proposals.

Requests for access to the website Question and Answer section should be sent via e-mail to PSOPeakRFP@AEP.com. Requests should include: (1) contact name, (2) company, (3) mailing address, (4) phone number, and (5) e-mail address. A user ID and password will be issued and communicated through a return message to the requester's e-mail address.

Any Bidder who does not comply with the Notice of Intent to Submit Proposal in Section 4.10 will lose access to the Question and Answer section of the webpage.

Any unsolicited contact by Bidder with any PSO or its Affiliates personnel concerning this RFP is not permitted and may constitute grounds for disqualification.

4.6 Technical Conference

PSO will conduct a Technical Conference for any person interested in this RFP, at 1:00 p.m. CPT on October 5, 2005 at the PSO headquarters located at 212 E. 6th Street, Tulsa, Oklahoma. The primary purpose of this conference will be to review the RFP and to afford interested persons the opportunity to ask questions and make suggestions. Questions on the RFP website posted at least five days prior to the Technical Conference will be addressed during the Conference. Potential Bidders are encouraged, but not required, to attend and actively participate. Following the Technical Conference, PSO's complete presentation at the conference will be posted on its RFP website.

4.7 Additional Questions and Comment Submission

Following the Technical Conference, Bidders have until 5:00 p.m. CPT on October 7, 2005 to submit final questions. The Company will respond to all questions by October 15, 2005.

Comments on the RFP must be submitted to the Company by 5:00 p.m. CPT on October 21, 2005. Comments may be submitted through e-mail to PSOPeakRFP@AEP.com or by mail to the address specified in Section 4.12.

Following issuance of the Final RFP, Bidders are encouraged to continue to send questions related to the substance of the RFP to the Company RFP website. All questions should be submitted no later than 5:00 p.m. CPT December 2, 2005. After that time, the website will be closed for further questions. Questions submitted at least five days in advance of the Pre-bid Conference will be addressed during the Conference. PSO will answer all questions submitted to its RFP website, and will post the answers on the website by December 9, 2005.

4.8 Pre-Bid Conference

On November 21, 2005 the Company will hold a Pre-Bid Conference at its headquarters in Tulsa, Oklahoma. Interested parties are requested to return a Pre-Bid Conference Registration Form (Appendix D). *Completed Forms should be sent via e-mail to* PSOPeakRFP@AEP.com. The purpose of this meeting will be to answer any remaining technical and commercial questions.

After the Pre-Bid Conference, if Bidders have any unresolved concerns or questions, they may send them to the IM. Any and all addenda to the RFP will be posted on the RFP website by December 9, 2005.

4.9 Transmission Contacts

Any inquiries related to PSO's transmission system or services must be directed to the SPP.

4.10 Notice of Intent to Submit Proposal

Bidders shall submit a Notice of Intent to Submit Proposal on the form attached as Appendix G no later than 5:00 p.m. CPT, November 15, 2005. Notices should be submitted by e-mail to PSOPeakRFP@AEP.com. Confirmation of receipt by Company shall be the responsibility of the prospective Bidder. Submitting a Notice of Intent to Submit a Proposal does not commit a prospective Bidder to submit a Proposal. However, Bidders who do not submit a Notice of Intent to Submit Proposal will not be sent any further notices regarding this RFP and will lose their access rights to the Question and Answer section of the RFP website.

4.11 Joint Proposals

No Bidder may act through a partnership, joint venture, consortium, or other association or otherwise act in concert with any other person unless as part of its Proposal it provides written notification to PSO and fully identifies all partners, joint venturers, members or other entities or persons thereof.

4.12 Self-Build Options

Self-Build Proposals will submit information according the PPA new build requirements of the RFP and RFP Response Package.

Self-Build Proposals shall be submitted no later than 3:00 p.m. CPT, December 19, 2005.

4.13 Submission of Proposals

Proposals will be accepted no later than 3:00 p.m., CPT, December 20, 2005. Any Proposals received later than the applicable due date and time will be considered non-conforming and will be rejected.

Proposals must be signed by an officer, or other agent of the Bidder duly authorized to make such Proposals.

All Proposal terms and conditions shall be specified in detail in the RFP Response Package.

Proposal provisions including, but not limited to, term and pricing, shall remain in effect until August 31, 2006.

All Proposals, along with the appropriate Proposal Submittal Fee, must be delivered by hand or by express, certified or registered mail to:

Public Service Company of Oklahoma
Attention: Peaking RFP
c/o Steven Fate
212 E. 6th Street
Tulsa, Oklahoma 74119-1295
Telephone : 918-599-2369

In order to facilitate an objective, impartial, and effective RFP evaluation, PSO's IM will oversee opening all Proposals.

All Proposals must be submitted in accordance with the instructions and on the form(s) provided in the RFP Response Package. All Proposals must include ten bound paper copies of the Proposal, with one bearing original signature(s), as well as two CD-ROM's containing electronic copies which must be submitted with all text portions of the Proposal in Microsoft® Word and all spreadsheets in Microsoft Excel®.

Faxed Proposals or Proposals submitted via e-mail or the Internet will be considered non-conforming and will be rejected.

Each Proposal must be submitted separately in a sealed package with the following information shown on the exterior of the package:

PSO 2005 – RFP for Peaking Capacity and Energy Resources ____________________ **Name of Bidder**

Proposals submitted in response to this RFP will not be returned to Bidders. At the conclusion of the RFP, all Proposals will be archived by PSO until at least the conclusion of the RFP process and of any other related regulatory review and approval periods.

SECTION 5 - PROPOSAL EVALUATION

5.1 Receipt and Opening of Proposals

The IM and PSO's Designated Representative will document and monitor the process of opening all Proposals, including the order in which they are opened, and will ensure that all Proposal documents are housed in a secure location that is accessible only to designated RFP personnel and the IM.

5.2 Screening for Conformance with RFP Submittal Requirements

The Company, subject to the oversight of the IM, will thoroughly review and assess all Proposals to ensure that each:

(i) is received on time with all forms completed in their entirety;
(ii) is signed by a duly authorized officer or agent of the Bidder;
(ii) includes Proposal Submittal Fees for each Proposal and alternative Proposals; and
(iv) meets the informational requirements and other conditions specified in the RFP Response Package.

Proposals that meet the requirements of the RFP shall be considered conforming.

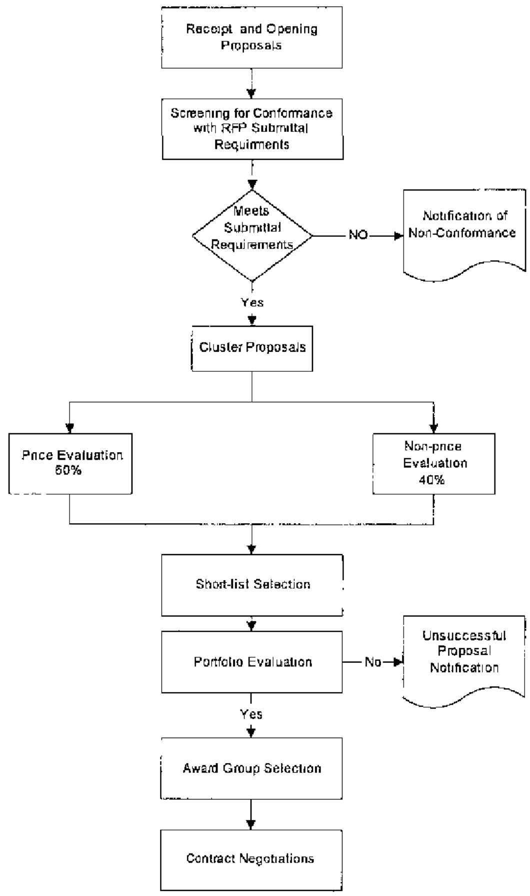
Proposals may be deemed non-conforming if they do not meet the requirements specified in the RFP Response Package Appendix E. Except for Proposals not received on time, at PSO's sole judgment and discretion, in consultation with the IM, Proposals that are non-conforming may be given three business days to remedy their non-conformity. PSO reserves the right, in consultation with the IM, not to consider any Proposal that is non-conforming.

During the initial screening process, PSO reserves the right to contact Bidders to clarify Proposal terms or to request additional information. The IM shall monitor all such contacts.

5.3 Description of the Evaluation Process

The Company will use a multi-stage evaluation process to review Proposals and to select the preferred resources or portfolio of resources. To proceed through each stage of the evaluation process, a Proposal must meet certain threshold requirements and criteria relative to other Proposals. Figure 5.3 illustrates the Proposal evaluation processes from receipt of the Proposals to the selection of the Award Group and contract negotiations.

Figure 5.3



The exact evaluation process followed will depend upon the number of Proposals received and changes in economic conditions that may have occurred from the time the Proposals were submitted until the particular stage of the evaluation. For example, while PSO prefers to conduct a price and non-price evaluation of all Proposals based on a 60/40 weighting between price/non-price factors, if a large number of Proposals are received, PSO may conduct an initial price screen prior to the non-price evaluation. Each phase of the evaluation process is described in more detail in subsequent sections.

Both the price and non-price characteristics of conforming Proposals will be evaluated by the Company. Proposals will be evaluated relative to one another and relative to their impact on PSO's system. The objective of the evaluation process is to select the Proposal(s) that provides the highest value consistent with PSO's stated objectives and requirements. The preferred Proposal(s) does not necessarily have to be the lowest cost option(s) or highest scoring Proposal(s) from a price and non-price perspective. PSO is interested in Proposals which provide the most desirable combination of operational flexibility and reliability, fuel supply and transportation diversity, limited risk and low cost.

5.3.1 Eligibility Requirements and Threshold Requirements Screening

The first step in the evaluation process will be to review each Proposal to ensure that it satisfies all of the applicable Eligibility Requirements specified in Section 5.2 and Threshold Requirements specified in Section 5.4. In this stage of the evaluation, PSO will determine whether the Proposal meets the Eligibility Requirements specified, the Proposal is consistent with all requirements outlined in the RFP and the Response Package and the Proposal conforms to the Threshold Requirements.

Proposals that provide inaccurate or incomplete information will be deemed to be non-conforming and may be rejected. The Company may, in its sole discretion, provide Bidders the opportunity to correct or clarify their Proposals to conform to the requirements of the RFP provided the competitive position of Proposals is not affected. If the Company seeks clarification, Bidders will be given three business days (or as otherwise stated by the Company in its request) to clarify their Proposal. Failure to timely conform to the requirements will result in rejection of the Proposal. Proposals that pass this initial screen will proceed to the next stage of the evaluation.

5.3.2 Categorize/Cluster Proposals

All Proposals that meet the Eligibility and Threshold Requirements Screening will be categorized or clustered by type of Proposal (PPA or APP), and resource type in preparation for the price and non-price analysis. This process will ensure that the highest ranking Proposals in each category can be distinguished and that a diversity of options are considered throughout the evaluation process. The Company reserves the right to determine, at its sole discretion, appropriate clusters from the Proposals that it receives and the placement of Proposals into clusters.

5.3.3 Price and Non-Price Analysis

The third step of the evaluation process will include a price and non-price evaluation for all Base Proposals that pass the Eligibility and Threshold Screening. The result of the 60/40 weighted price and non-price analysis will be a relative ranking and scoring of Base Proposals in each cluster. Base Proposals of the same type of contract and contract term will be evaluated relative to similar Proposals at this stage of the evaluation.

The Company may, in its discretion, use screening curves and/or detailed production cost analysis to calculate the total cost impacts of each Proposal on PSO's system. Proposals within each cluster will be assigned price rankings based on their impact on PSO's total system cost. Each Proposal will be evaluated using the price factors contained in the Proposal. Where appropriate, generation expansion and production cost models will be used to determine and evaluate the impact on the net present worth of the Company's revenue requirement.

5.3.4 Selection of the Short List

PSO will select a short list of Proposals from the various clusters based on the results of the price and non-price analysis. The objective of the ranking system is to differentiate Proposals relative to one another rather than selecting a fixed number of Proposals or megawatts of capacity. The Company's objectives for selecting the short list are to select (i) an amount of capacity in excess of the Company's requirements to ensure a viable competitive process is followed; and (ii) a diversity of options and contract types which meet PSO's RFP objectives and future generation needs while providing diversity and flexibility of its generation portfolio as well as it fuel supply and fuel transportation arrangements.

5.3.5 Portfolio Evaluation

In this stage of the evaluation process, short-listed Proposals from each cluster will be combined into various portfolios and compared and evaluated against each other. The Company may evaluate the Bidders' alternative Proposals that were submitted with their Base Proposal. The Company will also consider the benefits of flexibility options proposed by the Bidder relative to its Base Proposal. The Company will evaluate in more detail the impacts of other important PPA provisions.

In addition, the Company will assess the transmission impact of each Proposal to determine what, if any, transmission system improvements must be made and the estimated cost of those improvements. The Company will assess the Proposal's transmission system impact using SPP's reliability criteria and the SPP study methodology. Final transmission system impacts and related costs will be determined by SPP in accordance with the SPP OATT.

In this phase of the evaluation, the Company will conduct sensitivity analysis of important price and economic assumptions to determine how robust the various Proposals and/or portfolios of Proposals are to various assumptions. The Company may develop high and low fuel price cases as part of this portfolio evaluation process. Other sensitivities will include economic and environmental factors. The Company will also assess any unique non-price or flexibility provisions offered by Proposals or portfolio of Proposals that may result in a preferred portfolio of resources.

5.3.6 Award Group Selection and Contract Negotiations

Based upon the portfolio evaluation results, the Company will select a group of Proposals (Award Group) for contract negotiations.

The Company will negotiate first with the highest ranking Proposals sufficient to fill the resource needs. If negotiations with higher ranked Bidders indicate that the Company is unlikely to negotiate acceptable terms with the Bidders, the Company may terminate negotiations with those Bidders and commence negotiations with Bidders having lower ranked Proposals.

At this point in the process, an Award Group member may be required to provide evidence of its ability to post Acceptable Credit Support as outlined in Section 5.5.3 (ii) below. Such evidence may include, but will not be limited to, unrestricted cash on the Bidder's or Credit Support Provider's Balance Sheet, bank statements, existing credit facilities and/or expected future credit facilities as confirmed by Bidder's or Credit Support Provider's lender. PSO reserves the right to determine precisely what is considered to constitute sufficient evidence at the time of contract negotiation.

The basis for contract negotiations will be to discuss requested modifications to the relevant Model Contract identified by the Bidder in its Proposal. If no modification to the relevant Model Contract has been requested as a part of the Bidder's Proposal, the Bidder will be expected to execute a contract in substantially the form of the relevant Model Contract. Bidders that request material changes to the relevant Model Contract at this stage of the evaluation process that were not reflected in Bidders' exceptions to the contract identified in their Proposal will be subject to having their Proposal re-ranked by the Company. A Bidder's inclusion in the Award Group does not obligate the Company to accept any change to the relevant Model Contract that has been proposed by the Bidder. Contracts may be subject to approval by the appropriate regulatory agencies.

5.4 Threshold Requirements

5.4.1 Credit Threshold

Each Bidder must complete and submit with their Proposal the Bidder Profile Form (Appendix F Form 1).

Each Bidder must also provide proof of a minimum tangible net worth of $500 million U.S. dollars, as reflected on the Bidder's most recent audited balance sheet, where tangible net worth is defined as total assets less the sum of intangible assets, goodwill, and total liabilities.

5.4.2 Accounting Threshold

The Company is unwilling to be subject to accounting and tax treatment that results from Variable Interest Entity treatment as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 as issued and amended from time to time by FASB.

All PPA Proposals will be assessed by PSO for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with all the information requested in the RFP Response Package necessary to make such assessments. Moreover, each Bidder must also agree to make available at any point in the Proposal evaluation process any and all financial data associated with the Bidder, the generation resource and the PPA proposed that PSO requires to verify the expected treatment under FASB Interpretation No. 46. Such information may include, but is not limited to, data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's Proposal.

5.4.3 Siting

For a generation facility to be constructed, or being constructed, for a PPA Proposal (Project), the Bidder shall have identified a site and shall have taken the appropriate steps to acquire or secure use of the site by holding a purchase option or a binding letter of intent from the site owner(s).

5.5 Description of Non-Price Related Evaluation Criteria

As noted, Company anticipates that all Proposals will be evaluated relative to non-price and risk related criteria deemed to be important to Company. The Company is interested in PPA Proposals that offer operating flexibility and diversity and are likely to operate consistent with PPA requirements throughout the term of the PPA. Company expects to consider the non-price and risk related attributes of a Proposal in the screening phase and detailed evaluation phase of the evaluation process. This may be particularly important if a portfolio of Proposals is selected and various portfolios have similar prices.

Table 5.2 lists each of the Project non-price and/or risk-related criteria.

Table 5.2
Non-Price Criteria

Criterion	Weighting*
Flexibility (i) COD Flexibility (ii) Expansion Capability (iii) Contract Term	5%
Development Feasibility (i) Siting Status (ii) Environmental Permitting (iii) Project Schedule (iv) Engineering and Technology Maturity (iv) Fuel Supply and Transportation Arrangements (vi) Project Management Experience (vii) Rights-of-Way Acquisition (viii) Water Supply/Resource Availability (ix) Non-Owned Transmission System Impact	41%
Project Operational Viability (i) Operation and Maintenance Plan (ii) Financial Strength (iii) Environmental Compliance (iv) Environmental Impact (v) Fuel Reliability and Flexibility	27%
Quality of Output (i) Dispatchability/Scheduling (ii) Coordination of Maintenance (iii) Operating Profile/Characteristics	19%
Model Contracts (i) Model PPA (ii) Model PSA	8%

* Represents the major non-price criteria category weightings which combined represent 40% of the overall price and non-price score.

A detailed list and description of each non-price criteria for Proposals and Company's objectives relative to such criteria follows.

5.5.1 Flexibility

The Company is interested in Proposals that provide flexibility in terms of the COD in its acceleration option, Project size considerations, or the willingness of a Bidder to defer the COD in its deferral option. Company will incorporate the values presented in its analysis as well as qualitatively assess the level of flexibility offered by each Proposal. If Proposals are similarly ranked, the Proposal deemed to offer the greatest level of flexibility at the lowest cost will be preferred. Company views the following commitments to offer value to Company.

(i) COD Flexibility This criterion is important for Company due to uncertainty around the regulatory approval process. Company values Proposals that express a willingness to conform the COD at Company's request or can phase-in the Project to meet changes in the requirements.

(ii). Expansion Capability PPA Proposals with the capability to expand at the same site or offer volume and term flexibility will be viewed more favorably.

(iii) Contract Term When procuring resources to meet its identified needs, one of the Company's objectives for acquiring power resources is to achieve an appropriate portfolio mix of resources. The Company prefers longer term contracts that best meet its need for reliability, price risk management and flexibility for dispatchable operations.

5.5.2 Development Feasibility

This category is designed to assess the likelihood of a Project coming into fruition based on various factors critical to successful project development. The status of development as well as the likelihood for Project completion will be considered. The objectives of the criteria within this category are to provide an indication of the feasibility of each Project being developed as well as the likelihood of it being developed on schedule.

(i) Siting Status This criterion considers the Project site location and physical attributes. It also evaluates the Bidder's ability to demonstrate evidence that the site is committed for the full term of the PPA.

(ii) Environmental Permitting This criterion considers the degree of certainty offered by the Bidder in securing the necessary environmental permits. Projects in the early stages of development will be evaluated based on the Bidder's plan for securing permits, the reasonableness of the Project schedule relative to the proposed COD, prior experience, and BACT or LAER requirements. Projects which exhibit a thorough understanding of the environmental permitting process (or have secured permits) and who present a reasonable plan will be preferred. Projects which have made greater progress in environmental permitting or which do not require major permits are preferred. Projects with permits in place are more highly valued.

Proposals should include a list of required permits to build and/or operate the source. If permits are to be obtained in the future, it should include a timeline for obtaining the permits.

(iii) Project Schedule This criterion requests Bidders to provide a detailed Project schedule (critical path including milestone dates) for the Project that encompasses the period from the notice of selection of the Award Group to COD. The COD reflects the combination of a number of Project development factors necessary for successful Project development. Company will review and evaluate the Project schedule and critical path to ensure the Bidder has developed a reasonable schedule for meeting the proposed COD as outlined in Section 3.

(iv) Engineering and Technology Maturity This criterion considers questions pertinent to the engineering design and project technology. Bidders should provide information about the specific technology and/or equipment including the track record of the technology and equipment.

The electricity generation process proposed for the Project must have reached a proven level of technological maturity and the strategic generation equipment (e.g., turbine, generator) must be commercially available. The general specifications of the proposed equipment shall be provided.

Electricity generation processes are considered technologically mature if they are in use in at least two generation facilities that have been delivering electricity on a commercial basis to a utility for at least two years. Generation facilities still in the demonstration phase for new generation processes will not be considered. Strategic equipment used in generating electricity is not admissible for purposes of this RFP if it is not commercially available from a known equipment manufacturer or if it relies on a new operating principle or on one that has not yet been proven. This requirement is not meant to eliminate offers using equipment that constitutes an advanced version of proven equipment (e.g., LMS100 combustion turbine, etc.).

The Company reserves the right to require the Bidder to demonstrate that the proposed technology and strategic equipment used in the generation of energy are proven. The Company further reserves the right to commission an independent expert of its choice in order to establish the technological maturity.

(v) Fuel Supply and Transportation Arrangements This criterion refers to the quality and availability of the fuel supply and transportation arrangements of the Project relative to the technology proposed. Company prefers Proposals with fuel supply and transportation arrangements with reputable and creditworthy suppliers for a term sufficient to conform to the requirements for project financing. The Company also prefers fuel supply and transportation contracts with fixed or index-based prices with provisions that minimize risk to Company and its customers.

If the Project is in the early stages of development, Company requires a fuel supply procurement plan that demonstrates that the fuel supply arrangements adequately conform to the type and technology (e.g., combustion turbine unit, combined cycle unit, etc.) of the Project proposed consistent with the security and reliability required by Company. Company will evaluate the fuel supply and transportation status of each Project relative to the type of Project and technology proposed.

(vi) Project Management Experience This criterion requires Bidders to demonstrate project experience and management capability to successfully develop and operate the Project as proposed. PSO is particularly interested in a project team that has demonstrated success in at least one power project of a similar nature, type, size and technology and can demonstrate an ability to effectively work together to bring the Project to COD.

(vii) Rights-of-Way Acquisition Acquisition of rights-of-way and construction of other facilities (such as water pipelines, rail spurs, etc.) can be important elements of project development. Projects that do not require construction of other facilities and rights-of-way acquisition are preferred.

(viii) Water Supply/Resource Availability This criterion considers the degree of certainty offered by the Bidder in securing the necessary water supply required by the Project. The evaluation will be based on the Bidder's plan for securing water contracts/rights for the Project and the reasonableness of the plan relative to the Project type and schedule.

(ix) Non-Owned Transmission System Impact This criterion considers the transmission upgrades that may be required to transmission systems other than those owned by PSO. Projects which do not require construction of new transmission and other facilities are preferred.

5.5.3 Project Operational Viability

Project operational viability characteristics provide a means of evaluating whether Bidders will provide reliable service to Company and its customers over the term of the PPA. In addition, this criterion is designed to assure that the Bidder will be able to efficiently meet the terms and conditions of the PPA. The following factors will be considered:

(i) Operation and Maintenance Plan This factor evaluates the operation and maintenance (O&M) plan of the Bidder, as to the reasonableness of the maintenance funding levels and arrangements, the willingness of a Bidder to execute a long-term contract with a reputable operation and maintenance provider, and the previous experience of the Bidder in operating and maintaining similar facilities. Company prefers Projects that demonstrate that the Bidder has developed a solid plan and adequate funding to properly maintain the generation facility throughout the contract term. The plan should demonstrate that NERC, SPP, and other applicable Regional Reliability Council guidelines for operating the generation facility are to be followed.

(ii) Financial Strength PSO will evaluate the ability of Bidders to perform under the terms of their Proposals by reviewing credit ratings by Moody's and S&P, financial information as outlined in RFP Response Package and credit information published about Bidders (or their Credit Support Provider) by third parties, which will include, but not be limited to:

- Senior Unsecured, or Corporate credit ratings issued by Standard & Poor's
- Senior Unsecured, or Issuer credit rating(s) issued by Moody's; and
- SEC form 10-K, form 10-Q, and form 8-K filings.

In addition, PSO will perform its own internal credit evaluation of Bidders (or their Credit Support Providers) through the use on an internal credit scoring process, which will evaluate, at a minimum, the following factors:

(i) Revenue and earnings growth;
(ii) Historical tangible net worth;
(iii) Historical measures of cash flow adequacy;
(iv) Historical measures of leverage and
(v) Other credit risk and financial considerations, including, but not limited to, the status of ongoing court, regulatory, or other governmental processes or proceedings or significant contract negotiations or renegotiations.

Unsecured Credit or credit supported by a Parent Guarantor will be issued at the following limits, as listed in Table 5.3, based on the lowest of S&P, Moody's Credit Rating or PSO internal credit rating for Bidder or Bidder's Credit Support Provider. This shall be the aggregate unsecured credit limit extended to the Bidder, covering all contracts entered into between Bidder and PSO and its Affiliates.

Table 5.3 – Unsecured Credit Limits

Credit Rating	Dollar Credit Limit
AA- to AAA	$75,000,000
A+ and A	$60,000,000
A-	$50,000,000
BBB+	$35,000,000
BBB	$25,000,000
BBB-	$25,000,000
BB+ and below	$0

As part of this process, PSO reserves the right to request further financial information from Bidders (or their Credit Support Providers) and PSO will consider entering into a Confidentiality Agreement with such Bidders to protect such information, as appropriate. PSO may require successful Bidder (or its Credit Support Provider) to post a form of Acceptable Credit Support to ensure the Bidder's performance under the terms of the Proposal. The amount of Acceptable Credit Support, if required, will be in an amount determined by PSO's evaluation of the Bidder's credit condition in conjunction with a determination of the financial and performance obligations of the Bidder under the terms of the Proposal. In determining the financial and performance obligations component of a long-term PPA, PSO will estimate the costs to replace such PPA. These costs will relate to capacity and energy and will cover an 18 month period, which is the minimum period that PSO estimates it will take to obtain and have governmental and regulatory approval of an equivalent replacement contract.

Credit Support related to capacity charges will be based on 50% of the value of the estimated future capacity cost, covering the aforementioned period of 18 months. Credit Support related to energy charges will be based on the expected incremental replacement cost of such energy, given a 50% market move, over the 18-month period. However, if Bidder's capacity and/or energy prices exceed PSO's estimated market prices used in the preceding calculation, then the Credit Support calculation will employ Bidder's price(s) instead of PSO's estimated price(s) and still assume the 50% market move described above.

Table 5.4 illustrates the expected Credit Support Amounts for Bidders submitting PPA Proposals based upon the Bidders' assigned credit rating, and submitted in $/kW form. Bidders will be expected to post security in an amount determined by their (or their Credit Support Provider's) credit rating as represented in Table 5.4 and the number of MW Proposed. For other details regarding Credit Support posting requirements, refer to Article 8 of the Model PPA.

Further, Bidders should note that Company reserves the right to protect itself against counterparty credit concentration risk, and as such, may require Bidder to post Acceptable Credit Support in the form of cash or an Irrevocable Standby Letter of Credit in amounts in excess of those amounts listed in Table 5.4 to maintain compliance with AEP's credit policies.

Table 5.4 – Credit Support Amounts

Peaking Credit Rating	$/kW
AAA	-
AA+	-
AA	-
AA-	-
A+	-
A	-
A-	-
BBB+	-
BBB	-
BBB-	-
BB+	$7.05
BB	$9.25
BB-	$13.95
B+	$16.95
B	$19.40
B-	$21.95
CCC	$28.10

Bidders submitting an Asset Purchase Proposal will be subject to the same creditworthiness scrutiny as described above. However, the amount of Credit Support required will be based upon the Bidder's obligations and liabilities under an executed PSA.

(iii) Environmental Compliance This criterion addresses the ability of generation facilities supporting a PPA Proposal to remain in environmental compliance. Company will assess whether Proposals can demonstrate, through a credible plan, the ability to remain in compliance. Options to meet requirements of developing regulations for increased control of currently regulated air emissions and mercury should be considered. Also, the ability of a Bidder to secure the necessary Emission Allowances for a Project can influence Project costs. Bidders are required to prepare and submit a plan outlining its strategy for securing the necessary Emission Allowances to meet Project requirements.

(iv) Environmental Impact An important criterion for evaluating Proposals will be the Project's environmental impacts. The Project's overall plan to minimize air emissions will be an important aspect of this review. In addition, site impacts such as water use, land use, property value issues, and aesthetics will be considered in the Proposal evaluation.

(v) Fuel Reliability and Flexibility This criterion addresses the ability of a Proposal to provide flexibility of fuel supply and fuel transportation while meeting the reliability needs of Company. For example, having multiple natural gas pipelines or railroads serving a generation facility would be highly desirable. The ability to convert to an alternate fuel (e.g. gas to fuel oil, coal to gas) when economically or operationally beneficial would also be considered an attractive option.

Company prefers Proposals that can demonstrate that a reliable and secure supply of fuel and fuel transportation resources will be available to the generating facility. To assess reliability, the Company will consider accessibility to supply options, availability and firmness of transportation resources (e.g., number and nature of pipeline systems or rail transportation), history of pipeline operations in the relevant area, tariff terms and conditions, experience with operational flow orders and curtailments, etc. which protect the interests of the Company and its customers, and allow for maximum dispatchability of the generation.

5.5.4 Quality of Output

Quality of output evaluation criteria are designed to evaluate the system impacts associated with each Proposal relative to the level of operating flexibility and consistency with Company's objectives regarding enhancement to system generation, reliability and operations. Scheduling of generation facilities will be considered in the dispatching criteria as noted below. While the factors considered may, to some degree, be incorporated into the cost analysis and therefore influence the economics of each Proposal, it is not likely that the cost implications capture the full benefit to Company. Therefore, it is important to incorporate these criteria separately as part of the non-price related criteria in the analysis.

(i) Dispatchability/Scheduling This criterion refers to the extent to which the subject generation facilities will be dispatchable and the flexibility offered in scheduling energy. Dispatchability is defined as the ability of the Company to require delivery of power and energy at a Company determined level (including no output) for a specified period. Generation facilities that are not fully dispatchable will be evaluated based on the level of operating flexibility and control offered to Company.

(ii) Coordination of Maintenance This criterion addresses the willingness and flexibility of a Bidder to coordinate the maintenance schedules of the subject generation facilities in conjunction with Company's maintenance schedules for its own generation facilities.

(iii) Operating Profile/Characteristics This criterion refers to the ability of the subject generation facilities to meet load requirements (real and reactive) quickly and provide the operating flexibility deemed valuable to Company. Characteristics of importance include load following capability, minimum start-up capability, ability to cycle the unit, cold start time, ramping capability, and voltage support capability. Company will evaluate the operating profile of the subject generation facilities relative to its implications to the PSO system.

5.5.5 Model Contracts

(i) Model PPA Appendix H contains the Model Power Purchase Agreement. Bidders submitting PPA Proposals are required to include with their Proposal a red-line version of the PPA which clearly identifies any proposed changes to the Model PPA. Bidder's proposed changes to the Model PPA will be a part of *the non-price evaluation of the Proposal.*

(II) Model PSA Appendix I contains the Model Purchase and Sale Agreement (Model PSA). Bidders submitting Asset Purchase Proposals are required to include with their Proposal a red-lined version of the Model PSA which clearly identifies any proposed changes thereto. Bidders' proposed changes to the Model PSA will be considered by the Company in its evaluation of the Proposal.

5.6 Description of Price Related Evaluation Criteria

All Proposals will be evaluated on the basis of their price and operational performance factors in the price and portfolio evaluation through the simulation of the impact of the Proposal on the overall costs to the PSO system. Company will consider the impacts of the Proposal on PSO and its customers. Company will also include other criteria in its analysis, including operational characteristics and flexibility provisions that allow Company to minimize risk and uncertainty. Company's objective in selecting resources, therefore, involves a combination of rate implications and risk minimization options to arrive at the preferred portfolio of resources.

Company proposes to conduct a detailed cost analysis that incorporates all of the costs attributed to each Proposal including, but not limited to:

(i) Capacity Charge
(ii) Fixed O&M Charge
(iii) Energy Charge
(iv) Fuel Transportation Charge
(v) Variable O&M Charge
(vi) Start-Up Charge
(vii) Emissions Charge
(viii) Ancillary Services Charge

(ix) Transmission System Impact
(x) Debt Equivalence

A description of each component is presented below.

5.6.1 Capacity Charge

The Capacity Charge reflects the payment that Company will make to the Bidder for having the generating capacity available to Company to operate at the proposed committed capacity level. All Proposals will be evaluated at the target equivalent availability specified by the Bidder unless the target equivalent availability is deemed to be unrealistic for the proposed technology or facility design. Bidders may propose to bid a fixed price or fixed escalation Capacity Charge arrangement at the time of Proposal submission that locks in the Capacity Charge from the COD for the term of the PPA. Bidders are prohibited from submitting a Proposal price that includes escalation provisions tied to a variable and uncertain index (e.g., inflation, interest rates, etc.).

As noted in the Model PPA, the Bidder will be paid Capacity Charges based on the product of the Capacity Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

5.6.2 Fixed O&M Charge

The Fixed O&M Charge reflects the payments that Company would make to the Bidder to cover the Fixed O&M costs associated with their Proposal. This may include such items as fixed labor or staff expenses, property taxes, insurance, fixed maintenance expenses and other fixed operating expenses. Fixed natural gas pipeline and other fuel transportation charges, such as demand charges, should be reflected as a separate Fixed Fuel Transportation Charge. These payments will be calculated based on the initial base period charge and the escalation rate selected by the Bidder.

As noted in the Model PPA, the Bidder will be paid Fixed O&M Charge based on the product of the Fixed O&M Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

5.6.3 Energy Charge

This factor will account for the amount and cost of energy delivered by the Bidder. Such an analysis requires the incorporation of operating characteristics that influence the performance of the subject generation facilities. This includes the level of dispatchability proposed, the level of availability, and other operational constraints.

5.6.4 Fuel Transportation Charge

This Factor will account for the fixed and variable charges for recovery of Bidders fuel transportation cost. Fixed fuel charges, such as demand charges or reservation payments, should be recovered through a Fixed Fuel Transportation Charge.

As noted in the Model PPA, the Bidder will be paid Fuel Transportation Charges subject to the adjustment for the applicable month of the year and the ration of actual availability to target availability within the perimeters in the RFP and PPA.

5.6.5 Variable O&M Charge

The Variable O&M Charge reflects the payments that Company would make to the Bidder to cover the Variable O&M costs associated with their Proposal. The Variable O&M Charge may take into consideration non-fuel variable expenses related to operation of the Bidders generation facility. Variable natural gas pipeline and other fuel transportation charges, such as transportation charges for natural gas actually delivered, should be reflected as a separate Variable Fuel Transportation Charge. These payments will be calculated based on the initial base period charge and the escalation indices selected by the Bidder.

5.6.6 Start-Up Charge

The Start-Up Charge reflects the payments Company will make each time a generation facility, which specifies such payments, successfully starts its generating facility when called upon by Company to operate. Costs to start-up the generation facility after planned and unplanned maintenance or forced outages will not be included as Start-Up Charges. Company will estimate how many times it expects the generation facility to be required to start-up, and will include the proposed Start-Up Charge in conducting the evaluation. Bidders are encouraged to describe any constraints or unique characteristics of their Proposals which could influence the Company's analysis.

5.6.7 Emissions Charges

Company will evaluate the implications of a Proposal on overall system emission levels to assess how it will impact Company's Emission Allowances and the impact it will have on Company's position in the emission allowance market and any costs or savings associated with a particular Proposal. Company will estimate the SO_2 , NOx, and mercury emissions from its system as a result of each Proposal. To estimate the impacts associated with each Proposal, Company will calculate the dollar impacts as the net emission impacts of the project times the estimated market value of the emission over the term of the PPA.

5.6.8 Ancillary Services Charge

Ancillary Services that may be provided by generators are:

(i) Reactive Supply and Voltage Control;
(ii) Regulation and Frequency Response;
(iii) Energy Imbalance;
(iv) Operating Reserves – Spinning;
(v) Operating Reserves – Supplemental.

Bidder shall identify in their Proposal any explicit ancillary service charges related to delivering power and energy to Company under their Proposal. In addition, Bidder needs to describe in detail the relationship between Bidder's Proposal generation facility, Company and SPP RTO market operations. The details shall include responsibilities associated with scheduling, asset registration, resource bidding and ancillary service provision.

5.6.9 Transmission System Impact

This criterion considers the upgrades and attendant costs that may be required to PSO's transmission system. Company will use its computer modeling capability (e.g., power flow program) to verify and quantify the Transmission system impacts, based on the specific data contained in Bidder's Proposal.

5.6.10 Debt Equivalence

Evaluation of PPA Proposals will include the imputed cost (revenue requirement) of common equity for any additional amounts of common equity required to maintain the Company's current debt-equity ratio. Should the PPA be determined to be treated as a capital lease under EITF 01-08 and SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio based on the amount of the debt or capital lease liability anticipated to consolidate onto the Company's balance sheet. Should the PPA be determined to be treated as an operating lease under EITF 01-08 and SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio using Standard and Poor's (S&P) published guidelines as a basis of the equity imputation and its cost. Key parameters for the calculations will include ROE (pre-tax) based on the Company's authorized return and NPV discount factor and debt cost at the Company's weighted average cost of debt. If the PPA is not a lease, sensitivities will be calculated at a 30% and a 50% risk factor that will be applied to the fixed charge NPV to calculate the imputed debt. The cost of additional equity will be included as a revenue requirement to all applicable PPA Proposals.

As stated in the Threshold Requirements, the Company will not accept any Proposals with contract terms that would require balance sheet consolidation of a Variable Interest Entity (VIE) per FASB Interpretation No. 46R. Through information gathered from Bidders, the Company will determine whether it will be subject to VIE consolidation treatment at any time during the contract period. Failure in this provision will be considered a disqualification of the Proposal.

5.7 Notification of Evaluation Results and Negotiations

Upon completion of the screening to determine those Proposals that meet the Credit Threshold and Accounting Threshold, PSO will notify all Bidders on the status of their Proposal. Proposals meeting the thresholds will be separated and grouped as described in Section 5.3.2. For Bidders whose Proposal fails the threshold screening, Company will provide an explanation of the requirements that were not met.

Upon completion of Proposal evaluation, Bidders will be notified of the status of their Proposal and whether additional discussions or negotiations are warranted. Negotiations will commence as soon as practicable after selected Bidders are notified.

Upon conclusion of negotiations, if successful, PSO will work with the Bidders to develop definitive agreements for submission to the Commission. PSO will retain written documentation of its decision-making process for Proposals that are selected or rejected, including the reasons for its decisions.

Upon selection of Proposals for negotiation, PSO will contact each Bidder to notify it of the status of its Proposal and whether additional discussions or negotiations are warranted. Negotiations will commence as soon as practicable after selected Bidders are notified.

SECTION 6 – REGULATORY APPROVALS

Generally, the results of the RFP will be subject to regulatory approvals. Any contractual arrangements between PSO and prospective Bidders may be conditioned upon prior Commission authorization that is satisfactory in form and substance to PSO in its sole judgment and discretion. The Company reserves the right to reject any proposed contracts that result from the RFP if subsequently issued regulatory approvals or authorizations are subject to conditions, including ratemaking treatments, which are unacceptable to PSO in its sole judgment and discretion.

Other than the prior authorization from the Commission, for which PSO shall apply, a Bidder whose Proposal is selected will be solely responsible financially, legally and otherwise, as applicable, for acquiring and maintaining all necessary governmental (e.g. FERC), creditor, and other third party authorizations and consents necessary or appropriate to facilitate effectuation of the selected Proposal, including all authorizations, permits, licenses, consents, and approvals associated with a selected Proposal, as well as compliance with any and all governmental rules and regulations for the construction and operation of the Project identified in the Proposal.

SECTION 7 – RESERVATION OF RIGHTS

Bidder's Proposal will be deemed accepted only when PSO and the successful Bidder have executed definitive agreements. Company has no obligation to accept any

Proposal, whether or not the stated price in such Proposal is the lowest price offered, and PSO may reject any Proposal in its sole judgment and discretion and without any obligation to disclose the reason or reasons for rejection.

BY PARTICIPATING IN THE RFP PROCESS, EACH BIDDER AGREES THAT (A) EXCEPT TO THE EXTENT OF ANY REPRESENTATIONS AND WARRANTIES CONTAINED IN A DEFINITIVE AGREEMENT WITH THE COMPANY, ANY AND ALL INFORMATION FURNISHED BY OR ON BEHALF OF THE COMPANY IN CONNECTION WITH THE RFP IS OR WILL BE PROVIDED WITHOUT ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AS TO THE USEFULNESS, ACCURACY, OR COMPLETENESS OF SUCH INFORMATION, AND (B) EXCEPT AS OTHERWISE PROVIDED IN A DEFINITIVE AGREEMENT WITH THE COMPANY, NEITHER PSO, ITS AFFILIATES NOR ANY OF THEIR PERSONNEL OR REPRESENTATIVES SHALL HAVE ANY LIABILITY TO ANY BIDDER OR ITS PERSONNEL OR REPRESENTATIVES RELATING TO OR ARISING FROM THE USE OF OR RELIANCE UPON ANY SUCH INFORMATION OR ANY ERRORS OR OMISSIONS THEREIN.

Each Bidder is solely responsible to pay any and all costs incurred by the Bidder in the preparation of a Proposal in response to this RFP, or to contract for any products or services proposed by any Bidder. PSO reserves the right to modify or withdraw this RFP, to negotiate with any and all qualified Bidders to resolve any and all technical or contractual issues, or to reject any or all Proposals and to terminate negotiations with any Bidder at any time. PSO reserves the right, at any time and from time to time, without prior notice and without specifying any reason and, within its sole judgment and discretion, to:

1. Cancel, modify or withdraw this RFP, reject any and all responses, and terminate negotiations at any time during the RFP process;
2. Discuss with a Bidder and its advisors the terms of any Proposal submitted by the Bidder and obtain clarification from the Bidder and its advisors concerning the Proposal;
3. Consider all Proposals to be the property of PSO, subject to the provisions of this RFP relating to confidentiality and any confidentiality agreement that may be executed in connection with this RFP, and destroy or archive any information or materials developed by or submitted to PSO in this RFP;
4. Request from a Bidder information that is not explicitly detailed in this RFP, but which may be useful for evaluation of that Bidder's Proposal;
5. Determine which Proposals to accept, favor, pursue, or reject;
6. Reject any Proposals that are not complete or contain irregularities, or waive irregularities in any Proposal that is submitted;
7. Accept Proposals that do not provide the lowest evaluated cost;
8. Determine which Bidders to allow to participate in the RFP, including disqualifying a Bidder due to a change in the qualifications of the Bidder or in the event that PSO determines that the Bidder's participation in the RFP has failed to conform to the requirements of the RFP;

9. Conduct negotiations with any or all Bidders or other persons or with no Bidders or other persons; and
10. Execute one or more definitive agreements with any Bidder that submits a Proposal or with any other person or with no one.

If at any time the Company determines that there is a defect in the RFP process or a deviation from the requirements of the RFP or that collusive or fraudulent bidding has occurred or appears to have occurred, the Company, in consultation with the IM, may suspend the RFP in whole or in part as to any Bidder or Bidders so involved.

Under all circumstances, each Bidder is responsible for all costs and expenses it incurs in connection with the RFP. Under no circumstances, including the Company's termination of the RFP at any time, will the Company or any of its representatives be responsible for any costs or expenses of any Bidder incurred in connection with the RFP.

SECTION 8 – GLOSSARY OF TERMS

1.) Acceptable Credit Support. Acceptable Credit Support shall mean, but shall not be limited to, one or more of the following: (i) an irrevocable, transferable standby Letter of Credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank have a credit rating of at least A- from S&P or A3 from Moody's in a form as outlined in Appendix F Form 3, or (ii) a cash deposit.

2.) Affiliate: Is any person directly or indirectly controlling or controlled by or under direct or indirect common control with such person or any person that directly or indirectly (through one or more intermediaries) controls or is controlled by or is under common control with the person. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with"), as used with respect to any person, shall mean the direct or indirect ownership or control of, or the possession, directly or indirectly, of the power to vote, five percent (5%) or more of the outstanding voting securities of such person, or the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such person, whether through the ownership of voting securities, by agreement, or otherwise.

3.) Commercial Operation Date: The date upon which the seller's delivery obligations commence under a PPA

4.) Control Area: AEP SPP electric system bounded by interconnection metering and telemetry capable of controlling owned and contracted generation to maintain interchange schedules with other control areas. In this document, the term, "control area," is used interchangeably with the term, "transmission system."

5.) Credit Support Provider: An entity that has issued a guaranty to cover the obligations of the Bidder.

6.) Net Dependable Summer Capability: The net demonstrated summer capability of a generating unit established in accordance with the testing procedures defined in Section 12 of SPP Criteria--Electrical Facility Ratings.

7.) SPP RTO: The Southwest Power Pool Regional Transmission Organization. Major services provided by the SPP RTO to members include independent reliability coordination and tariff administration, regional engineering model development, planning and operating studies, reliability assessment studies, a computer-based telecommunications network, and operating reserve sharing. SPP provides regional transaction scheduling and is in the process of implementing market settlement functionality as required by FERC Order 2000.

8.) Peaking Capacity and Energy Resource: A firm generating resource that can be placed on-line or be made available for dispatch in a relatively short period of time. From an economic perspective a primary characteristic is that the resource's fixed cost profile (capital recovery and fixed operation and maintenance cost, etc.) would be sufficiently low so as to allow the asset to be economically justified to operate at potentially very low capacity factors.

Public Service Company of Oklahoma

Request For Proposal

for

Baseload Capacity and Energy Resources

December 2005

AEP
PUBLIC SERVICE COMPANY OF OKLAHOMA
A unit of American Electric Power

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NOTICE

In the event that a Bidder perceives a conflict between this RFP and other posted information (e.g., answers to questions), this RFP document, as amended, shall prevail.

If corrections or clarifications to the RFP documents are required, PSO will issue a "RFP Amendment" on its RFP website located at:

www.PSOklahoma.com/go/rfp

Potential Bidders should check this RFP website regularly. It is the sole responsibility of the Bidder to keep up with any RFP document changes as discussed above.

SECTION 1 - GENERAL INFORMATION

1.1 Introduction

The purpose of this document is to prescribe the process by which Public Service Company of Oklahoma ("PSO" or the "Company") will request and evaluate Proposals through a competitive procurement process which Company deems, in its sole discretion, to provide the most reasonable cost and reliable resources to fulfill a portion of its supply-side resource need consistent with Company's resource planning requirements. The scope of this Request For Proposal ("RFP"), subject to the limitations described herein, is focused on a supply-side resource capable of delivering baseload capacity and associated energy in or to the Company's transmission system (see Section 3.6) and that is capable of fulfilling the planning reserve requirements of the Southwest Power Pool ("SPP").

The Company is soliciting binding Proposals from bidders ("Bidders") in the form of Power Purchase Agreements ("PPA") and/or the acquisition of existing generation facilities for up to 600 megawatts ("MW") of baseload resources with a Commercial Operation Date of June 1, 2011 ("COD"). The Company prefers to ultimately own and operate the generation facilities providing the capacity and associated energy proposed under the terms of this RFP and, therefore, Bidders who propose a PPA will be encouraged to propose terms that allow the Company to acquire the generation facility during the contract term. The Company values the Bidder's flexibility in terms of adjusting the COD. Proposals shall be submitted by Bidders in the form of the RFP Response Package attached as Appendix E.

Proposals shall be binding upon the successful Bidder until November 30, 2006.

The general schedule for the RFP process is shown below. A more detailed schedule follows in Section 4.3 of this RFP.

Draft RFP Issued	10/10/05
Issue Final RFP	12/04/05
Binding Baseload Proposals Due	02/16/06
Selection of Award Group	06/12/06
Execute Final Contract(s)	08/31/06

The Company seeks Proposals from any Bidder who is capable of meeting the conditions of this RFP. Bidders should note that the Company and its agents will be able to, and should be expected to, respond to this RFP. As described in more detail below, the Company has put in place prudent safeguards to avoid undue preference to its self-build Proposals. Any Bidder who has a question with respect to such safeguards is instructed to contact the Independent Monitor ("IM") as described in Section 1.2 below.

PSO, based in Tulsa, Oklahoma, is a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"). PSO is an operating electric public utility engaged in the generation, transmission, distribution, purchase and sale of electric energy in

Oklahoma. PSO provides wholesale and retail electric service to more than 509,000 customers in a service area covering approximately 30,000 square miles. PSO's retail electric rates and services are regulated by the Oklahoma Corporation Commission ("OCC" or "the Commission"). PSO's wholesale power and transmission rates and services are regulated by the Federal Energy Regulatory Commission ("FERC").

PSO will be using its Affiliate, American Electric Power Service Corporation ("AEPSC"), as its agent for the RFP process.

For capitalized terms not defined in the main text of this RFP, please refer to Section 8, Glossary of Terms.

1.2 Independent Monitor

PSO is committed to a fair solicitation process. The evaluation criteria and process are designed to ensure a fair solicitation process and to provide Bidders with information on how the Proposals will be evaluated and what the Company deems as important aspects of a Proposal. Merrimack Energy Group, Inc. will act as the IM for this solicitation. The IM will monitor the RFP process and will review and track the Company's conduct of the RFP to ascertain that no undue preference is given to PSO's self-build Proposals. This will include, to the extent necessary, reviewing the draft RFP and the Company's evaluation of Proposals; monitoring communications (and communications protocols) with market participants; monitoring adherence to codes of conduct; validation of the models, input assumptions; risk assessments; and monitoring contract negotiations.

A more detailed evaluation of the IM's Scope of Work is attached as Appendix A. Among other responsibilities noted in the Scope of Work, the IM will address Bidders' questions, issues, and concerns during the RFP process, and, as needed, communicate those issues and concerns to the appropriate parties, including PSO and OCC Staff.

Contact information for the IM is:

Wayne Oliver
Merrimack Energy Group, Inc.
727 Lafayette Road
P O Box 2955
Seabrook, NH 03874
Phone: (603) 474-3385
Cell: 781-856-0007
Fax: 603-474-3384
E-mail: waynejoliver@aol.com

1.3 Self-Build Procedures

Procedures for this RFP call for objective, arm's-length dealing with respect to agents of the Company who are developing self-build Proposals ("Self-Build Team"). Appropriate procedures and a Code of Conduct are in place to safeguard against the Self-Build Team receiving undue preferential treatment and preferential access to information. Additional procedural provisions require PSO to protect the confidentiality of Proposals and Bidder information and to ensure such information is not improperly used by PSO or its Affiliates (see Procedures Manual in Appendix K).

Specifically prohibited is the communication, directly or indirectly, of material non-public information about or derived from PSO selectively to the Self-Build Team, as well as any preference by PSO expressed in any way whatsoever for self-build Proposals per se. Accordingly, in this RFP there is pre-established operational independence between PSO and the Self-Build Team to ensure that any Proposals submitted by the Self-Build Team will not have any material advantage in the selection process versus Proposals submitted by third-party Bidders.

SECTION 2 - SECTION NOT USED

SECTION 3 - 2005 BASELOAD RESOURCES RFP

3.1 Overview of RFP

The Company's Integrated Resource Plan ("IRP") has identified that additional capacity must be added to the PSO system over the next 10 years in order for it to maintain adequate capacity reserves. The IRP process has shown that the most economic solution for meeting PSO's future capacity reserve needs is the addition of peaking capacity and associated energy by the summer of 2008 and baseload capacity and associated energy by the summer of 2011.

In order to meet its future resource needs, PSO issued an RFP for 500 MW of Peaking Capacity and Energy Resources on September 12, 2005 and is issuing this RFP for baseload resources in which PSO seeks Proposals for firm capacity and associated energy for up to 600 MW of baseload resources with a COD of June 1, 2011.

PSO is interested in Proposals that are in the form of PPAs and/or the acquisition of existing generation facilities ("Asset Purchase Proposal" or "APP"). PSO prefers to own and operate the generation facilities providing the baseload capacity and associated energy proposed under the terms of this RFP. Therefore, Bidders who submit PPA Proposals will be requested to propose terms that give PSO the option to acquire the Bidder's interest in the designated generation facility at various points during the contract term.

Appendix H contains the Model Power Purchase and Sale Agreement ("Model PPA") and Appendix I contains the Model Purchase and Sale Agreement ("Model PSA"). The Model

PPA and Model PSA together are referred to as the Model Contracts. In addition to Proposals from third-parties, it is anticipated that PSO will submit self-build Proposals.

PSO's objective for this RFP is to encourage a broad range of Proposals and to secure those resources that provide the greatest benefit to its customers. PSO reserves the right to reject any and all Proposals, in its sole discretion, if they are not in the best interest of PSO. The level of flexibility and creativity offered by the Bidder in its Proposal will be recognized in the evaluation process. PSO is interested in Proposals that:

(i) provide flexibility in terms of the COD, including the ability to defer or accelerate the COD by one year;
(ii) offer other options which minimize risk and costs to PSO and its customers;
(iii) provide PSO with the ability to acquire the generation assets used to supply the capacity and energy for a PPA Proposal;
(iv) offer creative pricing and technical options either as part of its Base Proposal or as an Alternative; and
(v) offer fuel and fuel transportation flexibility

3.2 Basic Requirements for Firm Baseload Capacity and Energy Proposals

The Company is seeking Proposals for firm capacity and associated energy for a minimum of 450 MW and up to 600 MW of baseload resources with a COD of June 1, 2011. Firm capacity will be defined as Net Dependable Summer Capability. The minimum bid size is 100 MW of Net Dependable Summer Capability.

Bidders who propose PPAs are required to conform to a contract term of 30, 35 or 40 years.

In addition to PPA Proposals, PSO will also consider Asset Purchase Proposals for the acquisition of a Bidder's existing generation facilities or interests therein. Asset Purchase Proposals must meet the same minimum size and COD that are defined for PPA Proposals. Asset Purchase Proposals shall be for a fixed dollar amount, inclusive of all monetary consideration for the generation asset. Any contractual obligations (e.g., fuel supply and transportation, maintenance agreements, etc.) related to the generation asset proposed for sale should be clearly defined by the Bidder in its Proposal. PSO prefers Proposals in which it will acquire the majority interest and/or the operational control of the generation facilities.

PSO prefers Proposals with points of delivery connected directly to PSO's transmission system as shown in Appendix C. All Proposals, regardless of the location of the generation resource, will be judged based upon their impact on PSO's transmission facilities, including the cost of any required system upgrades, and to the extent they can be determined, on neighboring transmission systems.

Bidders are encouraged to provide PSO with Base Proposals and Alternatives that reflect what they believe to be their best pricing Proposal.

3.2.1 Base Proposal

The Base Proposal is the preferred Proposal of the Bidder and shall be comprised of the information provided by the Bidder in the RFP Response Package.

PSO will determine the Proposals to be included on the short-list based on its evaluation of the Base Proposals. Therefore, Bidders are advised to present their best Proposal as the Base Proposal. At no point in the evaluation process will Bidders have the opportunity to unilaterally change their Proposal.

3.2.2 Alternative Proposals

In addition to the Base Proposal, Bidders may submit up to two Alternatives to the Base Proposal (Appendix E Tab 15 of the RFP Response Package) under the Proposal Submittal Fees, (see Section 4.1) although these Alternatives will not be considered until the portfolio evaluation phase (see Section 5). Alternatives could include different project size(s) or structure(s), alternative financial arrangements, alternative PPA terms and conditions, alternative APP terms and conditions, and other pricing provisions that differ from the Base Proposal. Proposals with different sites, technologies, fuel supply arrangements, etc. from the Base Proposal must be submitted as separate Proposals and must include an additional Proposal Submittal Fee.

PSO's objective for Alternative Proposals is to allow the Bidder the flexibility of phasing in a Project, offering a different project size, proposing alternate pricing options and PPA terms and conditions, etc. which could be considered in a portfolio with other Proposals. This will allow PSO to optimize the benefits from the solicitation by combining Proposals with different characteristics.

Bidders should clearly label and describe its Alternatives in Tabs 3 and 15 of the RFP Response Package, including appropriate pricing schedules. Alternatives will only be considered if they add value to the resource procurement process and can provide the flexibility deemed important by PSO.

3.3 <u>Power Purchase Proposals</u>

The Company seeks Proposals that have clear and definable pricing characteristics. Proposals containing a fixed price throughout the term of the Proposal for capacity charges (stated in $/kW-year) are preferred. PSO seeks Proposals with heat rate pricing using an industry recognized index charge, such as *Coal Daily*, or fixed energy pricing with an escalator based on United States Department of Labor forecasts (see RFP Response Package Schedule 3-4). Proposals should also specify fixed and variable transportation costs for which they are requesting recovery on Schedule 3-6 of the RFP Response Package.

In recognition that Bidders whose Proposals rely on Greenfield or Brownfield construction may be experiencing historically high uncertainty for the cost of key commodities and construction labor, PSO will accept Proposals that index part of the construction cost via the Capacity Charge. In Schedule 3-1C of the RFP Response Package (Appendix E) the Bidder may specify which portion(s) of the Capacity Charge as defined in Section 5.6.1 of this RFP are tied to approved indices contained in Appendix J. The labor and material indices may be used to escalate the actual Capacity Charge from June 1, 2006 to COD. Beyond COD, the Bidders shall not offer Proposals with indexed pricing for the Capacity Charge. The Company prefers Proposals that have clear and definable pricing characteristics and do not index significant portions of the Capacity Charge.

Bidders proposing PPA products are responsible for all costs to deliver those products to PSO including, but not limited to: costs of transmission service, upgrades and new construction of transmission facilities located outside of the SPP footprint, costs of transmission congestion; costs of ancillary services, and any fees or taxes, present and future, over the term of the Proposal. This must be expressly confirmed in Bidder's Proposals.

Bidder generation resources interconnected to PSO's transmission system within the AEP SPP control area near PSO's large load centers are preferred.

In addition, PSO is interested in Proposals giving it the option to purchase the generation assets that are used to supply the capacity and energy under the PPA. Bidders are encouraged to propose purchase pricing for those generation assets at various points during the contract term. (Appendix E Tab 3)

Baseload products should be proposed in quantity blocks ranging from a minimum size of 100 MW to a maximum size of 600 MW.

PSO prefers products that provide scheduling flexibility commensurate with the operating characteristics of the proposed generation assets. PSO reserves the right to dispatch these products at any load level within the source generator's operating limits, and to start and stop as needed to serve PSO's operational needs.

Requirements of the PPA may be met through a slice-of-system, existing generation facilities or proposed new generating facilities.

3.3.1 System Products

Company encourages the Bidder to submit RFP Proposals for baseload products supported by a single generating facility or by a system of generating facilities. Such slice-of-system ("System") Proposals should meet the baseload product criteria stated above and elsewhere in this RFP. Because the characteristics of a System are not defined by reference to the capabilities of a particular generating unit, the Bidder should specify with particularity the capabilities of its System product. The Bidder should modify its RFP Response Package to the extent necessary to include this information. The Bidder should include an overview of its System and information on the particular generating facilities supporting its System Proposal.

In order to assist Bidders wishing to propose System products, Company is providing the following non-exhaustive list of the capabilities that should be described in such Proposals. Where appropriate, Company has specified minimum standards that must be met by a System product.

(i) Quality: Company prefers System products that are Firm with liquidated damages. The Bidder should specify the level of firmness of its System product and state any excuses from performance with particularity (i.e., the number of units or percentage of system that must be off-line prior to any diminishment in System product service).

(ii) Scheduling: The Bidder should specify any minimum notice times prior to scheduling and dispatch of the System product by Company. In particular, the Bidder should specify if its System product must be scheduled on a day-ahead basis and the extent to which its System may be scheduled on an hour-ahead or shorter basis.

(iii) Scheduling Limits: The Bidder should state any minimum or maximum loading constraints as well as the rate at which Company may change the loading of the System over a given time period.

(iv) Starts: The Bidder should state the number of "starts" – the scheduling of at least minimum load after the System has been scheduled to zero – over a given time, any mandatory downtime or uptime, and the cost, if any, of starting the System.

(v) Delivery Point: The Bidder should specify the Delivery Point for energy and ancillary services from the System and, if more than one point, any information necessary to determine the allocation of energy and ancillary services among those points.

(vi) Ancillary Services: The Bidder should specify the ancillary services that Company will have the right to utilize from the System and, if such ancillary services are not under the direct dispatch and control of Company, the manner in which aggregate System revenues from those services will be determined and allocated to Company.

3.4 Asset Purchase Proposals

Bidders may submit Proposals to sell existing generation assets that have a proven operating history. In such case, a Bidder shall offer to sell (i) 100% of the ownership of a generation asset having a minimum Net Dependable Summer Capability that matches the products outlined in Section 3.3 of this RFP or (ii) its ownership interest in a generation asset in which the Bidder's share of the output is no less than the minimum Net Dependable Summer Capacity that matches the products outlined in Section 3.3 of this RFP. PSO prefers generation assets that do not have any restrictions or limitations imposed on them as a result of other assets at that site.

Asset Purchase Proposals shall be priced at a fixed dollar amount inclusive of all monetary consideration for the generation assets. APPs may include or exclude related arrangements for fuel commodities and transportation of them and the presence or absence of this factor shall not adversely affect the conforming status of a Proposal. Any material contract obligations that are associated with the proposed asset sale should be clearly defined (e.g., fuel storage, fuel transportation).

Any and all costs that would be incurred by PSO for the delivery of power from a generation asset including, but not limited to, costs of transmission service, upgrades and new construction, costs of transmission congestion, costs of ancillary services, and any fees or taxes, present and future, over the term of the Proposal, will be considered in evaluating the Proposal.

All Asset Purchase Proposals shall provide the information required in the RFP Response Package. Such information shall not preclude the Company from conducting its own due diligence.

3.5 Fuel Considerations

3.5.1 Power Purchase Agreement

PPA Proposals should have fuel supply and transportation flexibility commensurate with the Proposal's operational and dispatch flexibility. The Bidder shall clearly describe the flexibility of its fuel supply and transportation arrangements serving its generation units. The Company's analysis will be weighted to reflect the value such fuel supply and transportation flexibility affords Company's operations.

Regardless of the specific fuel used by the generating facilities or system that Bidder relies on in its Proposal, Bidder shall explain its proposed fuel supply plan in detail (Appendix E, Tab 5) including its proposed primary fuel supply and transportation and its backup alternatives.

Preference will be given to Proposals that provide maximum flexibility and secondary source(s) of fuel supply and transportation arrangements. Bidders shall clearly identify any fuel-related constraints and/or limitations associated with their Proposals including, but not limited to, operational flexibility or reliability of its fuel supply and/or transportation which might affect the ability to dispatch the generation and/or Company's ability to utilize the resource for operating reserves.

In the event that a new fuel supply or transportation arrangement is required to enable Bidder to meet its delivery obligation to Company, all relevant information with respect to such proposed arrangements should be provided as part of Bidder's Proposal in sufficient detail to allow its feasibility to be evaluated by the Company's RFP evaluation teams.

3.5.2 Purchase of Existing Baseload Generation Facilities

PSO requests Proposals for the purchase of existing baseload generation facilities which address not only the Company's desire for low-cost baseload generation capacity but also its requirements for dispatchable operations with maximum fuel and transportation flexibility. Such flexibility is an integral part of the evaluation of any such Proposal.

Bidders shall identify any existing fuel supply and transportation agreements currently serving the generation facility being offered. They shall also identify the general commercial terms of such agreements including, but not limited to: term, quantity obligation, pricing, any other applicable fees or costs of such commitments, etc. Bidders should also state whether such commitments are assignable under the terms of the existing fuel supply and transportation agreements.

Should the disclosure of such information be subject to a confidentiality provision in Bidder's existing contracts, the Company is willing to enter into a confidentiality agreement to ensure that such information is used solely for the evaluation of the Proposal.

Preference will be given to Proposals that provide maximum flexibility and secondary source of fuel supply and transportation arrangements. Bidders shall identify if the generation facility is capable of operating on any alternative fuels and, if so, shall identify the type and availability of such fuel, the existence of any long-term contracts for the supply and/or transportation of such fuel and the assignability of such contracts. Secondary fuel supply and/or transportation options are valuable considerations for any Proposal. Bidders shall also identify any other fuel supply and transportation options available to the Proposal generation facility.

Proposals shall also clearly describe any fuel-related constraints associated with the Proposal including, but not limited to, operational flexibility or reliability of its fuel supply and/or transportation that might affect dispatch of the generation facility and/or the Company's ability to utilize the resource for operating reserves.

The Company's analysis will be weighted to reflect the value that any such fuel and/or transportation flexibility provides to the Company's operation of the generation facility.

3.6 <u>Reliable Delivery</u>

Bidders are required to deliver firm capacity, energy and associated electric products to the AEP SPP Control Area. PSO expects to use Network Integrated Transmision Service under the SPP Open Access Transmission Tariff ("OATT") from resources within the SPP RTO footprint. Approval of transmission service by SPP for requests where the resources are located on PSO's transmission system are expected to require fewer transmission upgrades than resources located elsewhere.

Proposals for products originating outside the SPP RTO footprint shall specify the Bidder's obligation to reserve, provide for, and pay for firm transmission service to the SPP RTO footprint. Such Proposals shall specify all pertinent details of proposed firm transmission paths, services and arrangements and shall specify all-inclusive pricing to the SPP RTO footprint, including all transmission costs and agreements in place to deliver such firm capacity, energy and associated electric products.

Each Bidder offering firm capacity, energy and associated electric products originating outside the SPP RTO footprint must provide the factual basis for its assumption that a firm transmission reservation can be obtained to deliver power into PSO's transmission system.

Prior to short-listing Proposals, PSO will undertake its own analysis for delivery of capacity, energy and associated electrical products and use the results in the Proposal evaluation phase. A Bidder, at its sole option and liability, can contract with applicable transmission provider(s) and pay for any studies it wishes to provide PSO prior to evaluation of Proposals.

Once Proposals are short-listed, PSO will perform more detailed studies at its own expense to estimate the cost of any required transmission upgrades. These transmission studies will be done in a manner similar to the transmission studies required by SPP. Company will use the best available information and data to perform these studies, however, there is no expectation that the study results will precisely match studies that will be ultimately performed by SPP to approve PSO's request for Network Integration Transmission Service.

After the Award Group is determined and negotiations are completed, Company will request Network Integration Transmission Service under the SPP OATT. Bidders sourcing their offer outside the SPP will be expected to make similar firm transmission service arrangements with transmission providers outside the SPP at that time.

SECTION 4 - INSTRUCTIONS TO BIDDERS

4.1 Proposal Submittal Fees

Bidders shall pay a non-refundable $5,000 Proposal Submittal Fee per Proposal from a single generation resource and a non-refundable Proposal Submittal Fee of $500 each for up to two alternatives as outlined in Section 3.2.2 if this RFP from that same generation resource. Checks for the Proposal Submittal Fees should be made payable to Public Service Company of Oklahoma.

4.2 Confidential Information and Confidentiality Agreements

The Company, its agents, and the IM will treat as confidential all Proposals submitted by Bidders. Bidders shall submit their Proposals with the knowledge and understanding that regardless of confidentiality any information submitted by them is subject to disclosure to the Commission or any other governmental authority or judicial body with jurisdiction relating to these matters and may be subject to legal discovery. In the event that the Company, in its sole judgment and discretion, determines that information contained in any question, response, or other communication between it and a Bidder that is not contained in the Bidder's Proposal requires confidential treatment, a Confidentiality Agreement (Appendix B) will be submitted to the Bidder. The Company will ensure that all Bidders have access to the same information from the Company and that no Bidder will have selective or otherwise preferential access to market sensitive information from the Company through this RFP.

4.3 RFP Schedule

The schedule for the RFP is shown below. As circumstances warrant, the Company, in its sole judgment and discretion, may change this schedule and in that event PSO will inform all participants as far in advance as reasonably possible and the information will be posted on the RFP website located at www.PSOklahoma.com/go/rfp. The Company will consult with the IM prior to announcing any significant change to the schedule shown below.

Draft RFP Issued	10/10/05
Technical Conference	11/04/05
Posting Deadline for all Questions	11/09/05
Comments Due	11/23/05
Issue Final RFP	12/04/05
Notice of Intent to Submit Proposal Form Due	12/12/05
Pre-Bid Conference Registration Due	12/13/05
Pre-Bid Conference	12/16/05
Self-Build Proposals Due	02/15/06
Binding Baseload Proposals Due	02/16/06
Short-list Identified	04/13/06
Selection of Award Group	06/12/06
Execute Final Contracts	08/31/06

4.4 Modification or Cancellation of the RFP

In addition to modifying the proposed schedule, PSO reserves the right, in its sole judgment and discretion, but subject to prior consultation with the IM and Commission, to modify or cancel this RFP. PSO will post a notice on its RFP website and make a reasonable attempt to notify directly all participants who have filed a timely Notice of Intent to Submit Proposal (Appendix G) of any such changes, cancellations, or schedule changes. Notwithstanding, PSO shall not have responsibility for making any such notification.

4.5 Question, Comment and Response Process

All questions and comments submitted by Bidders, as well as PSO's responses to such questions, will be posted on the RFP website located at www.PSOklahoma.com/go/rfp. The official response to questions submitted by Bidders is the written response posted to the website. PSO's objective in posting these questions, comments and responses is to ensure all Bidders have equal access to information that may be potentially relevant to their respective Proposals.

Requests for access to the website Question and Answer section should be sent via e-mail to PSOBaseloadRFP@AEP.com. Requests should include: (1) contact name, (2) company, (3) mailing address, (4) phone number and (5) e-mail address. A user ID and password will be issued and communicated through a return message to the requester's e-mail address.

Any Bidder who does not comply with the Notice of Intent to Submit Proposal discussed in Section 4.10 of this RFP will lose access to the Question and Answer section of the webpage.

Any unsolicited contact by Bidder with any PSO or its Affiliates personnel concerning this RFP is not permitted and may constitute grounds for disqualification.

4.6 Technical Conference

PSO conducted a Technical Conference for persons interested in this RFP on November 4, 2005 at the PSO headquarters located at 212 E. 6th Street, Tulsa, Oklahoma. The primary purpose of this conference was to review the RFP and to afford interested persons the opportunity to ask questions and make suggestions. Potential Bidders were encouraged, but not required, to attend and actively participate. Following the Technical Conference, PSO's complete presentation and the Questions and Answers were posted on its RFP website. The official response to questions submitted by Bidders is the written response posted to the website.

4.7 Additional Questions and Comment Submission

Following the Technical Conference, Bidders had until 5:00 p.m. CPT on November 9, 2005 to submit final questions. The Company responded to all questions by November 16, 2005.

Comments on the RFP were to be submitted to the Company by 5:00 p.m. CPT on November 23, 2005. No comments were received.

Following issuance of the Final RFP, Bidders are encouraged to continue to send questions related to the substance of the RFP to the Company RFP website. All questions should be submitted no later than 5:00 p.m. CPT December 29, 2005. After that time, the website will be closed for further questions. Questions submitted at least five days in advance of the Pre-bid Conference will be addressed during the Conference. PSO will answer all questions submitted to its RFP website, and will post the answers on the website by January 8, 2006.

4.8 Pre-Bid Conference

On December 16, 2005 the Company will hold a Pre-Bid Conference via teleconference. Interested parties are requested to return a Pre-Bid Conference

Registration Form (Appendix D). Completed Forms should be sent via e-mail to PSOBaseloadRFP@AEP.com. The purpose of this meeting will be to answer any remaining technical and commercial questions. The dial-in information for the teleconference will be provided to Bidders via e-mail.

After the Pre-Bid Conference, if Bidders have any unresolved concerns or questions, they may send them to the IM. Any and all addenda to the RFP will be posted on the RFP website by January 8, 2006.

4.9 *Transmission Contacts*

Any inquiries related to PSO's transmission system or services must be directed to the SPP.

4.10 Notice of Intent to Submit Proposal

Bidders shall submit a Notice of Intent to Submit Proposal on the form attached as Appendix G no later than 5:00 p.m. CPT, December 12, 2005. Notices should be submitted by e-mail to PSOBaseloadRFP@AEP.com. Confirmation of receipt by Company shall be the responsibility of the prospective Bidder. Submitting a Notice of Intent to Submit a Proposal does not commit a prospective Bidder to submit a Proposal. However, Bidders who do not submit a Notice of Intent to Submit Proposal will not be sent any further notices regarding this RFP and will lose their access rights to the Question and Answer section of the RFP website.

4.11 Joint Proposals

No Bidder may act through a partnership, joint venture, consortium, or other association or otherwise act in concert with any other person unless, as part of its Proposal, it provides written notification to PSO and fully identifies all partners, joint venturers, members or other entities or persons thereof.

4.12 Self-Build Options

Self-Build Proposals will submit information according the PPA new build requirements of the RFP and RFP Response Package.

Self-build Proposals shall be submitted no later than 3:00 p.m. CPT, February 15, 2006.

4.13 Submission of Proposals

Proposals will be accepted no later than 3:00 p.m., CPT, February 16, 2006. Any Proposals received later than the applicable due date and time will be considered non-conforming and will be rejected.

Proposals must be signed by an officer or other agent of the Bidder duly authorized to make such Proposals by the Bidder's board of directors or similar governing body.

Proposals must certify in writing that all Proposal terms, including pricing, have been approved by the Bidder's board of directors or other governing authority.

All Proposal terms and conditions shall be specified in detail in the RFP Response Package.

Proposal provisions including, but not limited to, term and pricing, shall remain in effect until November 30, 2006.

All Proposals, along with the appropriate Proposal Submittal Fee, must be delivered by hand or by express, certified or registered mail to:

Public Service Company of Oklahoma
Attention: Baseload RFP
c/o Steve Fate
212 E. 6th Street
Tulsa, Oklahoma 74119-1295
Telephone : 918-599-2369

In order to facilitate an objective, impartial and effective RFP evaluation, PSO's IM will oversee the opening of all Proposals.

All Proposals must be submitted in accordance with the instructions and on the form(s) provided in the RFP Response Package. All Proposals must include ten bound paper copies of the Proposal, with one bearing original signature(s), as well as two CD-ROM's containing electronic copies which must be submitted with all text portions of the Proposal in Microsoft® Word and all spreadsheets in Microsoft Excel.

Faxed Proposals or Proposals submitted via e-mail or the Internet will be considered non-conforming and will be rejected.

Each Proposal must be submitted separately in a sealed package with the following information shown on the exterior of the package:

PSO
2005 – RFP for Baseload Capacity and Energy Resources

____

Name of Bidder

Proposals submitted in response to this RFP will not be returned to Bidders. At the conclusion of the RFP, all Proposals will be archived by PSO until at least the conclusion of the RFP process and of any other related regulatory review and approval periods.

SECTION 5 - PROPOSAL EVALUATION

5.1 Receipt and Opening of Proposals

The IM and PSO's Designated Representative will document and monitor the process of opening all Proposals, including the order in which they are opened, and will ensure that all Proposal documents are housed in a secure location that is accessible only to designated RFP evaluation team members and the IM.

5.2 Screening for Conformance with RFP Submittal Requirements

The Company, subject to the oversight of the IM, will thoroughly review and assess all Proposals to ensure that each:

(i) is received on time with all forms completed in their entirety;
(ii) is signed by a duly authorized officer or agent of the Bidder;
(iii) includes Proposal Submittal Fees for each Proposal and Alternative Proposals; and
(iv) meets the informational requirements and other conditions specified in the RFP Response Package.

Proposals that meet the requirements of the RFP shall be considered conforming.

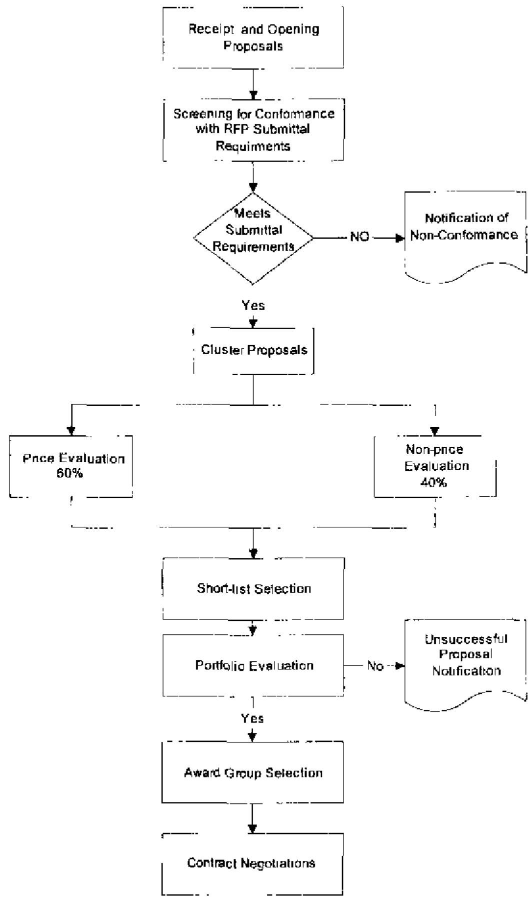
Proposals may be deemed non-conforming if they do not meet the requirements specified in the RFP Response Package, Appendix E. Except for Proposals not received on time, at PSO's sole judgment and discretion, in consultation with the IM, Proposals that are non-conforming may be given three business days to remedy their non-conformity. PSO reserves the right, in consultation with the IM, not to consider any Proposal that is non-conforming.

During the initial screening process, PSO reserves the right to contact Bidder(s) to clarify Proposal terms or to request additional information. The IM shall monitor all such contacts.

5.3 Description of the Evaluation Process

The Company will use a multi-stage evaluation process to review Proposals and to select the preferred resources or portfolio of resources. To proceed through each stage of the evaluation process, a Proposal must meet certain threshold requirements and criteria relative to other Proposals. Figure 5.3 illustrates the Proposal evaluation processes from receipt of the Proposals to the selection of the Award Group and contract negotiations.

Figure 5.3



The exact evaluation process followed will depend upon the number of Proposals received and changes in economic conditions that may have occurred from the time the Proposals were submitted until the particular stage of the evaluation. For example, while PSO prefers to conduct a price and non-price evaluation of all Proposals based on a 60/40 weighting between price/non-price factors, if a large number of Proposals are received, PSO may conduct an initial price screen prior to the non-price evaluation. Each phase of the evaluation process is described in more detail in subsequent sections.

Both the price and non-price characteristics of conforming Proposals will be evaluated by the Company. Proposals will be evaluated relative to one another and relative to their impact on PSO's system. The objective of the evaluation process is to select the Proposal(s) that provides the highest value consistent with PSO's stated objectives and requirements. The preferred Proposal(s) does not necessarily have to be the lowest cost option(s) or highest scoring Proposal(s) from a price and non-price perspective. PSO is interested in Proposals which provide the most desirable combination of operational flexibility and reliability, fuel supply and transportation diversity, limited risk and low cost.

5.3.1 Eligibility Requirements and Threshold Requirements Screening

The first step in the evaluation process will be to review each Proposal to ensure that it satisfies all of the applicable Eligibility Requirements specified in Section 5.2 of this RFP and Threshold Requirements specified in Section 5.4 of this RFP. In this stage of the evaluation PSO will determine whether the Proposal meets the Eligibility Requirements specified, the Proposal is consistent with all requirements outlined in the RFP and the Response Package and the Proposal conforms to the Threshold Requirements.

Proposals that provide inaccurate or incomplete information will be deemed to be non-conforming and may be rejected. The Company may, in its sole discretion, provide Bidders the opportunity to correct or clarify their Proposals to conform to the requirements of the RFP provided the competitive position of Proposals is not affected. If the Company seeks clarification, Bidders will be given three business days (or as otherwise stated by the Company in its request) to clarify their Proposal. Failure to timely conform to the requirements will result in rejection of the Proposal. Proposals that pass this initial screen will proceed to the next stage of the evaluation.

5.3.2 Categorize/Cluster Proposals

All Proposals that meet the Eligibility and Threshold Requirements Screening will be categorized or clustered by type of Proposal (PPA or APP) and resource type in preparation for the price and non-price analysis. This process will ensure that the highest ranking Proposals in each category can be distinguished and that a diversity of options is considered throughout the evaluation process. The Company reserves the right to determine, at its sole discretion, appropriate clusters from the Proposals that it receives and the placement of Proposals into clusters.

5.3.3 Price and Non-Price Analysis

The third step of the evaluation process will include a price and non-price evaluation for all Base Proposals that pass the Eligibility and Threshold Screening. The result of the 60/40 weighted price and non-price analysis will be a relative ranking and scoring of Base Proposals in each cluster. Base Proposals of the same type of contract and contract term will be evaluated relative to similar Proposals at this stage of the evaluation.

The Company may, in its sole discretion, use screening curves and/or detailed production cost analysis to calculate the total cost impacts of each Proposal on PSO's system. Proposals within each cluster will be assigned price rankings based on their impact on PSO's total system cost. Each Proposal will be evaluated using the price factors contained in the Proposal. Where appropriate, generation expansion and production cost models will be used to determine and evaluate the impact on the Company's net present worth of the revenue requirement.

5.3.4 Selection of the Short-list

PSO will select a short-list of Proposals from the various clusters based on the results of the price and non-price analysis. The objective of the ranking system is to differentiate Proposals relative to one another rather than selecting a fixed number of Proposals or megawatts of capacity. The Company's objectives for selecting the short-list are to select (i) an amount of capacity in excess of the Company's requirements to ensure a viable competitive process is followed and (ii) a diversity of options and contract types which meet PSO's RFP objectives and future generation needs while providing diversity and flexibility of its generation portfolio as well as its fuel supply and fuel transportation arrangements.

At this point in the process, a short-list member may be required to provide evidence of its ability to post Acceptable Credit Support as outlined in Section 5.5.3 (ii) below. Such evidence may include, but will not be limited to, unrestricted cash on the Bidder's or Credit Support Provider's Balance Sheet, bank statements, availability of credit under existing credit facilities and/or expected future credit facilities as confirmed by Bidder's or Credit Support Provider's lender. PSO reserves the right to determine precisely what is considered to constitute sufficient evidence and to evaluate the Bidder's ability to post Acceptable Credit Support at the time the short-list is determined.

5.3.5 Portfolio Evaluation

In this stage of the evaluation process short-listed Proposals from each cluster will be combined into various portfolios and compared and evaluated against each other. The Company may evaluate the Bidder's Alternative Proposals that were submitted with its Base Proposal. The Company will also consider the benefits of flexibility options proposed by the Bidder relative to its Base Proposal. The Company will evaluate in more detail the impacts of other important PPA provisions (e.g., COD deferral and acceleration options) offered by the Proposal.

In addition, the Company will assess the transmission impact of each Proposal to determine what, if any, transmission system improvements must be made and the estimated cost of those improvements. The Company will assess the Proposal's transmission system impact using SPP's reliability criteria and the SPP study methodology. Final transmission system impacts and related costs will be determined by the SPP in accordance with the SPP OATT.

In this phase of the evaluation, the Company will conduct sensitivity analysis of important price and economic assumptions to determine how robust the various Proposals and/or portfolios of Proposals are to various assumptions. The Company may develop high and low fuel price cases as part of this portfolio evaluation process. Other sensitivities will include economic and environmental factors. The Company will also assess any unique non-price or flexibility provisions offered by Proposals or portfolio of Proposals that may result in a preferred portfolio of resources.

5.3.6 Award Group Selection and Contract Negotiations

Based upon the portfolio evaluation results, the Company will select a group of Proposals (Award Group) for contract negotiations.

The Company will negotiate first with the highest ranking Proposals sufficient to fill the resource needs. If negotiations with higher ranked Bidder(s) indicate that the Company is unlikely to negotiate acceptable terms with the Bidder(s), the Company may terminate negotiations with those Bidder(s) and commence negotiations with Bidders having lower ranked Proposals.

The basis for contract negotiations will be to discuss requested modifications to the relevant Model Contract identified by the Bidder in its Proposal. If no modification to the relevant Model Contract has been requested as a part of the Bidder's Proposal, the Bidder will be expected to execute a contract in substantially the form of the relevant Model Contract. Bidders that request material changes to the relevant Model Contract at this stage of the evaluation process that were not reflected in Bidder's exceptions to the contract identified in its Proposal will be subject to having its Proposal re-ranked by the Company. A Bidder's inclusion in the Award Group does not obligate the Company to accept any change to the relevant Model Contract that has been proposed by the Bidder. Contracts may be subject to approval by the appropriate regulatory agencies.

5.4 Threshold Requirements

5.4.1 Credit Threshold

Each Bidder must complete and submit with their Proposal the Bidder Profile Form (Appendix F, Form 1). Each Bidder or Bidder's Credit Support Provider must also provide proof of a minimum tangible net worth of $500 million U.S. dollars, as reflected on the Bidder's (or Bidder's Credit Support Provider's) most recent audited balance sheet, where tangible net worth is defined as total assets less the sum of intangible assets, goodwill, and total liabilities.

5.4.2 Accounting Threshold

The Company is unwilling to be subject to accounting and tax treatment that results from Variable Interest Entity treatment as set forth in Financial Accounting Standards Board (FASB) Interpretation No. 46 as issued and amended from time to time by FASB.

All PPA Proposals will be assessed by PSO for appropriate accounting and/or tax treatment. Bidders shall be required to supply the Company with all the information requested in the RFP Response Package necessary to make such assessments. Moreover, each Bidder must also agree to make available at any point in the Proposal evaluation process any and all financial data associated with the Bidder, the generation resource and the PPA proposed that PSO requires to verify the expected treatment under FASB Interpretation No. 46. Such information may include, but is not limited to, data supporting the economic life (both initial and remaining), the fair market value, executory costs, nonexecutory costs, and investment tax credits or other costs (including debt specific to the asset being proposed) associated with the Bidder's Proposal.

5.4.3 Siting

For a generation facility to be constructed, or being constructed, for a PPA Proposal (Project), the Bidder shall have identified a site and shall have taken the appropriate steps to acquire or secure use of the site by holding a purchase option or a binding letter of intent from the site owner(s).

5.5 Description of Non-Price Related Evaluation Criteria

As noted, Company anticipates that all Proposals will be evaluated relative to non-price and risk related criteria deemed to be important to Company. The Company is interested in PPA Proposals that offer operating flexibility and diversity and are likely to operate consistent with PPA requirements throughout the term of the PPA. Company expects to consider the non-price and risk related attributes of a Proposal in the screening phase and detailed evaluation phase of the evaluation process. This may be particularly important if a portfolio of Proposals is selected and various portfolios have similar prices.

Table 5.2 lists each of the Project non-price and/or risk-related criteria.

Table 5.2
Non-Price Criteria

Criterion	Weighting For PPA*	Weighting For PSA*
Flexibility (i) COD Flexibility (ii) Expansion Capability (iii) Contract Term (iv) Environmental Compliance	10%	10%
Development Feasibility (i) Siting Status (ii) Environmental Permitting (iii) Project Schedule (iv) Engineering and Technology Maturity (v) Fuel Supply and Transportation Arrangements (vi) Project Management Experience (vii) Rights-of-Way Acquisition (viii) Water Supply/Resource Availability *(ix) Non-OwnedTransmission System* Impact	43%	41%
Project Operational Viability (i) Operation and Maintenance Plan (ii) Financial Strength (iii) Environmental Compliance (iv) Environmental Impact (v) Fuel Reliability and Flexibility	25%	25%
Quality of Output (i) Dispatchability/Scheduling (ii) Coordination of Maintenance (iii) Operating Profile/Characteristics	18%	17%
Model Contracts (i) Model PPA (ii) Model PSA	4%	7%

* Represents the major non-price criteria category weightings which combined represent *40% of the overall price and non-price score.*

A detailed list and description of each non-price criteria for Proposals and Company's objectives relative to such criteria follows.

5.5.1 Flexibility

The Company is interested in Proposals that provide flexibility in terms of the COD in its acceleration option, Project size considerations, or the willingness of a Bidder to defer the COD in its deferral option. Company will incorporate the values presented in its analysis as well as qualitatively assess the level of flexibility offered by each Proposal. If Proposals are similarly ranked, the Proposal deemed to offer the greatest level of flexibility at the lowest cost will be preferred. The Company views the following commitments to offer value to Company.

(i) COD Flexibility. This criterion is important for Company due to uncertainty around the regulatory approval process. Company values Proposals that express a willingness to conform the COD at Company's request or can phase-in the Project to meet changes in the requirements.

(ii) Expansion Capability. PPA Proposals with the capability to expand at the same site or offer volume and term flexibility will be viewed more favorably.

(iv) Contract Term. When procuring resources to meet its identified needs, one of the Company's objectives for acquiring power resources is to achieve an appropriate portfolio mix of resources. The Company prefers longer term contracts that best meet its need for reliability, price risk management and flexibility for dispatchable operations.

(v) Environmental Compliance. For Asset Purchase Proposals, the Company prefers Proposals that address the ability to meet potential future emission compliance requirements for CO_2. Recognizing the increasing role that coal will play in meeting future electricity supply needs, advanced technologies that utilize coal for power generation in a clean and efficient manner comprise a key element of a portfolio of technology options. International, national and state policy activities all indicate the high likelihood of future legal requirements to reduce greenhouse gas emissions, including CO_2. While the prospects for enactment of greenhouse gas control legislation in the United States are not imminent in the near term, there is growing evidence that emission control requirements will be mandated within the next several years. While the timing and substance of the regulations are uncertain, it is expected that the compliance regime will build on the emissions cap-and-trade market-based systems put in place for reducing SO_2, NOx and Hg from fossil-fueled power plants. There is likely to be a market for CO_2 emission allowances and a value associated with CO_2 emission reductions or offsets at power plants.

5.5.2 Development Feasibility

This category is designed to assess the likelihood of a Project coming into fruition based on various factors critical to successful project development. The status of development as well as the likelihood for Project completion will be considered. The objectives of the criteria within this category are to provide an indication of the feasibility of each Project being developed as well as the likelihood of it being developed on schedule.

(i) Siting Status. This criterion considers the Project site location and physical attributes. It also evaluates the Bidder's ability to demonstrate evidence that the site is committed for the full term of the PPA.

(ii) Environmental Permitting. This criterion considers the degree of certainty offered by the Bidder in securing the necessary environmental permits. Projects in the early stages of development will be evaluated based on the Bidder's plan for securing permits, the reasonableness of the Project schedule relative to the proposed COD, prior experience, and BACT or LAER requirements. Projects which exhibit a thorough understanding of the environmental permitting process (or have secured permits) and who present a reasonable plan will be preferred. Projects which have made greater progress in environmental permitting or which do not require major permits are preferred. Projects with permits in place are more highly valued.

Proposals should include a list of required permits to build and/or operate the source. If permits are to be obtained in the future, it should include a timeline for obtaining the permits.

(iii) Project Schedule. This criterion requests Bidders to provide a detailed Project schedule (critical path including milestone dates) for the Project that encompasses the period from the notice of selection of the Award Group to COD. The COD reflects the combination of a number of Project development factors necessary for successful Project development. Company will review and evaluate the Project schedule and critical path to ensure the Bidder has developed a reasonable schedule for meeting the proposed COD as outlined in Section 3 of this RFP.

(iv) Engineering and Technology Maturity. This criterion considers questions pertinent to the engineering design and project technology. Bidders should provide information about the specific technology and/or equipment including the track record of the technology and equipment.

The electricity generation process proposed for the Project must have reached a proven level of technological maturity and the strategic generation equipment (e.g., turbine, generator) must be commercially available. The general specifications of the proposed equipment shall be provided.

Electricity generation processes are considered technologically mature if they are in use in at least two generation facilities that have been delivering electricity on a commercial basis to a utility for at least two consecutive years.

Generation facilities still in the demonstration phase for new generation processes will not be considered. Strategic equipment used in generating electricity is not admissible for purposes of this RFP if it is not commercially available from a known equipment manufacturer or if it relies on a new operating principle or on one that has not yet been proven. This requirement is not meant to eliminate offers using equipment that constitutes an advanced version of proven equipment (e.g., large scale CFB boiler design, advanced supercritical steam cycles, etc.).

The Company reserves the right to require the Bidder to demonstrate that the proposed technology and strategic equipment used in the generation of energy are proven. The Company further reserves the right to commission an independent expert of its choice in order to establish the technological maturity.

(v) Fuel Supply and Transportation Arrangements. This criterion refers to the quality and availability of the fuel supply and transportation arrangements of the Project relative to the technology proposed. Company prefers Proposals with fuel supply and transportation arrangements with reputable and creditworthy suppliers for a term sufficient to conform to the requirements for project financing. The Company also prefers fuel supply and transportation contracts with fixed or index-based prices with provisions that minimize risk to Company and its customers.

If the Project is in the early stages of development, Company requires a fuel supply procurement plan that demonstrates that the fuel supply arrangements adequately conform to the type and technology of the Project proposed consistent with the security and reliability required by Company. Company will evaluate the fuel supply and transportation status of each Project relative to the type of Project and technology proposed.

(vi) Project Management Experience. This criterion requires Bidders to demonstrate project experience and management capability to successfully develop and operate the Project as proposed. PSO is particularly interested in a project team that has demonstrated success in at least one power project of a similar nature, type, size and technology and can demonstrate an ability to effectively work together to bring the Project to COD.

(vii) Rights-of-Way Acquisition. Acquisition of rights-of-way and construction of other facilities (such as water pipelines, rail spurs, etc.) can be important elements of project development. Projects that do not require construction of other facilities and rights-of-way acquisition are preferred.

(viii) Water Supply/Resource Availability. This criterion considers the degree of certainty offered by the Bidder in securing the necessary water supply required by the Project. The evaluation will be based on the Bidder's plan for securing water contracts/rights for the Project and the reasonableness of the plan relative to the Project type and schedule.

(ix) Non-owned Transmission System Impact. This criterion considers the transmission upgrades that may be required to transmission systems other than those owned by PSO. Project that do not require construction of new transmission and other facilities are preferred.

5.5.3 Project Operational Viability

Project operational viability characteristics provide a means of evaluating whether Bidders will provide reliable service to Company and its customers over the term of the PPA. In addition, this criterion is designed to assure that the Bidder will be able to efficiently meet the terms and conditions of the PPA. The following factors will be considered:

(i) Operation and Maintenance Plan. This factor evaluates the operation and maintenance (O&M) plan of the Bidder as to the reasonableness of the maintenance funding levels and arrangements, the willingness of a Bidder to execute a long-term contract with a reputable operation and maintenance provider and the previous experience of the Bidder in operating and maintaining similar facilities. Company prefers Projects that demonstrate that the Bidder has developed a solid plan and adequate funding to properly maintain the generation facility throughout the contract term. The plan should demonstrate that NERC, SPP, and other applicable Regional Reliability Council guidelines for operating the generation facility are to be followed.

(ii) Financial Strength. PSO will evaluate the ability of Bidders to perform under the terms of their Proposals by reviewing credit ratings by Moody's and S&P, financial information as outlined in RFP Response Package and credit information published about Bidder (or its Credit Support Provider) by third-parties which will include, but not be limited to (a) Senior Unsecured, or Corporate credit ratings issued by Standard & Poor's, (b) Senior Unsecured, or Issuer credit rating(s) issued by Moody's and (c) SEC Form 10-K, Form 10-Q, and Form 8-K filings.

In addition, PSO will perform its own internal credit evaluation of Bidders (or their Credit Support Providers) through the use on an internal credit scoring process, which will evaluate, at a minimum, the following factors:

- *Revenue and earnings growth*
- Historical tangible net worth
- Historical measures of cash flow adequacy
- Historical measures of leverage
- Other credit risk and financial considerations, including, but not limited to, the status of ongoing court, regulatory, or other governmental processes or proceedings or significant contract negotiations or renegotiations.

Unsecured Credit or credit supported by a Parent Guarantor (see Appendix F, Form 2 for the required Corporate Guaranty format) will be issued at the following limits, as listed in Table 5.3, based on the lowest of S&P, Moody's or PSO's internal Credit Rating for Bidder or Bidder's Credit Support Provider. *This shall be the aggregate unsecured credit limit extended to the Bidder,* covering all contracts entered into between Bidder and PSO and its Affiliates.

Table 5.3 – Unsecured Credit Limit

Credit Rating	Dollar Credit Limit
AA- to AAA	$75,000,000
A+ and A	$60,000,000
A-	$50,000,000
BBB+	$35,000,000
BBB	$25,000,000
BBB-	$25,000,000
BB+ and below	$0

As part of this process, PSO reserves the right to request further financial information from Bidder(s) or its Credit Support Providers and PSO will consider entering into a Confidentiality Agreement (Appendix B) with such Bidder to protect such information, as appropriate. PSO may require successful Bidder (or its Credit Support Provider) to post a form of Acceptable Credit Support to ensure the Bidder's performance under the terms of the Proposal. The amount of Acceptable Credit Support, if required, will be in an amount determined by PSO's evaluation of the Bidder's credit condition in conjunction with a determination of the financial and performance obligations of the Bidder under the terms of the Proposal. In determining the financial and performance obligations component of a long-term PPA, PSO will estimate the costs to replace such PPA. These costs will relate to capacity and energy and will cover an 18-month period, which is the minimum period that PSO estimates it will take to obtain and have governmental and regulatory approval of an equivalent replacement contract.

Credit Support related to capacity charges will be based on 50% of the value of the estimated future capacity cost, covering the aforementioned period of 18 months. Credit Support related to energy charges will be based on the expected incremental replacement cost of such energy given a 50% market move, over the 18-month period. However, if Bidder's capacity and/or energy prices exceed PSO's estimated market prices used in the preceding calculation, then the Credit Support calculation will employ

Bidder's price(s) instead of PSO's estimated price(s) and still assume the 50% market move described above.

Table 5.4 illustrates the expected Credit Support Amounts for Bidders submitting PPA Proposals based upon the Bidders' assigned credit ratings, in $/kW form. Bidders will be expected to post Acceptable Credit Support in an amount determined by their (or their Credit Support Provider's) credit rating as represented in Table 5.4 and the number of MW proposed. For other details regarding Credit Support posting requirements, refer to Article 7 of the Model PPA.

Further, Bidders should note that Company reserves the right to protect itself against counterparty credit concentration risk, and as such, may require Bidder to post Acceptable Credit Support in the form of cash or an Irrevocable Standby Letter of Credit in amounts in excess of those amounts listed in Table 5.4 to maintain compliance with AEP's credit policies.

Table 5.4 – Credit Support Amounts

Baseload	
Credit Rating	$/kW
AAA	
AA+	
AA	
AA-	
A+	
A	
A-	
BBB+	
BBB	
BBB-	
BB+	$ 46.15
BB	$ 60.65
BB-	$ 91.65
B+	$ 111.50
B	$ 127.60
B-	$ 144.15
CCC	$ 184.70

Bidders submitting an Asset Purchase Proposal will be subject to the same creditworthiness scrutiny as described above. However, the amount of Credit Support required will be based upon the Bidder's obligations and liabilities under an executed Purchase and Sale Agreement.

(iii) Environmental Compliance. This criterion addresses the ability of generation facilities supporting a PPA Proposal to remain in environmental compliance. Company will assess whether Proposals can demonstrate, through a credible plan, the ability to remain in compliance. Options to meet requirements of developing regulations for increased control of currently regulated air emissions and mercury should be considered. Also, the ability of a Bidder to secure the necessary Emission Allowances for a Project can influence Project costs. Bidders are required to prepare and submit a plan outlining its strategy for securing the necessary Emission Allowances to meet Project requirements.

(iv) Environmental Impact. An important criterion for evaluating Proposals will be the Project's environmental impacts. The Project's overall plan to minimize air emissions will be an important aspect of this review. In addition, site impacts such as water use, land use, property value issues, and aesthetics will be considered in the Proposal evaluation.

(v) Fuel Reliability and Flexibility. This criterion addresses the ability of a Proposal to provide flexibility of fuel supply and fuel transportation while meeting the reliability needs of Company. For example, having multiple natural gas pipelines or railroads serving a generation facility would be highly desirable. The ability to convert to an alternate fuel (e.g., gas to fuel oil, coal to gas) when economically or operationally beneficial would also be considered an attractive option.

Company prefers Proposals that can demonstrate that a reliable and secure supply of fuel and fuel transportation resources will be available to the generating facility. To assess reliability, the Company will consider accessibility to supply options, availability and firmness of transportation resources (e.g., number and nature of pipeline systems or rail transportation), history of pipeline operations in the relevant area, tariff terms and conditions, experience with operational flow orders and curtailments, etc. which protect the interests of the Company and its customers, and allow for maximum dispatchability of the generation.

5.5.4 Quality of Output

Quality of output evaluation criteria are designed to evaluate the system impacts associated with each Proposal relative to the level of operating flexibility and consistency with Company's objectives regarding enhancement to system generation, reliability and operations. Scheduling of generation facilities will be considered in the dispatching criteria as noted below. While the factors considered may to some degree be incorporated into the cost analysis and therefore influence the economics of each Proposal, it is not likely that the cost implications capture the full benefit to Company. Therefore, it is important to incorporate these criteria separately as part of the non-price related criteria in the analysis.

(i) Dispatchability/Scheduling. This criterion refers to the extent to which the subject generation facilities will be dispatchable and the flexibility offered in scheduling energy. Dispatchability is defined as the ability of the Company to require delivery of power and energy at a Company determined level (including no output) for a specified period. Generation facilities that are not fully dispatchable will be evaluated based on the level of operating flexibility and control offered to Company.

(ii) Coordination of Maintenance. This criterion addresses the willingness and flexibility of a Bidder to coordinate the maintenance schedules of the subject generation facilities in conjunction with Company's maintenance schedules for its own generation facilities.

(iii) Operating Profile/Characteristics. This criterion refers to the ability of the subject generation facilities to meet load requirements (real and reactive) quickly and provide the operating flexibility deemed valuable to Company. Characteristics of importance include load following capability, minimum start-up capability, ability to cycle the unit, cold start time, ramping capability, and voltage support capability. Company will evaluate the operating profile of the subject generation facilities relative to its implications to the PSO system.

5.5.5 Model Contracts

(i) Model PPA. Appendix H contains the Model PPA. Bidders submitting PPA Proposals are required to include with their Proposal a red-line version of the PPA which clearly identifies any proposed changes to the Model PPA. Bidder's proposed changes to the Model PPA will be a part of the non-price evaluation of the Proposal.

(ii) Model PSA. Appendix I contains the Model PSA. Bidders submitting Asset Purchase Proposals are required to include with their Proposal a red-lined version of the Model PSA which clearly identifies any proposed changes thereto. Bidders' proposed changes to the Model PSA will be considered by the Company in its evaluation of the Proposal.

5.6 Description of Price Related Evaluation Criteria

All Proposals will be evaluated on the basis of price and operational performance factors in the price and portfolio evaluation through the simulation of the impact of the Proposal on the overall costs to the PSO system. Company will consider the impacts of each Proposal on PSO and its customers. Company will also include other criteria in its analysis, including operational characteristics and flexibility provisions that allow Company to minimize risk and uncertainty. Company's objective in selecting resources, therefore, involves a combination of rate implications and risk minimization options to arrive at the preferred portfolio of resources.

Company proposes to conduct a detailed cost analysis that incorporates all of the costs attributed to each Proposal including, but not limited to:

- Capacity Charge
- Fixed O&M Charge
- Energy Charge
- Variable O&M Charge
- Start-Up Charge
- Emissions Charge
- Ancillary Services Charge
- Transmission System Impact
- Debt Equivalence

A description of each component is presented below.

5.6.1 Capacity Charge

The Capacity Charge reflects the payment that Company will make to the Bidder for having the generating capacity available to Company to operate at the proposed committed capacity level. All Proposals will be evaluated at the target equivalent availability specified by the Bidder unless the target equivalent availability is deemed to be unrealistic for the proposed technology or facility design. Bidders may propose a fixed price or pre-specified escalation Capacity Charge arrangement at the time of Proposal submission that locks in the Capacity Charge from the COD for the term of the PPA. Additionally, Bidders may propose a Capacity Charge in which parts, as indicated in Schedule 3-1 of the RFP Response Package, are indexed to known indices found in Appendix J. Capacity Charge payments made by PSO during the contract term of the PPA will be based on the actual total Capacity Charge that is effective on the COD and these pre-specified escalation rates.

As noted in the Model PPA, the winning Bidder(s) will be paid Capacity Charges based on the product of the Capacity Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

5.6.2 Fixed O&M Charge

The Fixed O&M Charge reflects the payments that Company would make to the Bidder to cover the Fixed O&M costs associated with their Proposal. This may include such items as fixed labor or staff expenses, property taxes, insurance, fixed maintenance expenses and other fixed operating expenses. Fixed natural gas pipeline and other fuel transportation charges, such as demand charges, should be reflected as a separate Fixed Fuel Transportation Charge. These payments will be calculated based on the initial base period charge and the escalation rate selected by the Bidder.

As noted in the Model PPA, the Bidder will be paid Fixed O&M Charge based on the product of the Fixed O&M Charge, Contract Capacity, an allocation factor for the applicable month of the year and the availability adjustment specified in the RFP and PPA.

5.6.3 Energy Charge

This factor will account for the amount and cost of energy delivered by the Bidder. Such an analysis requires the incorporation of operating characteristics that influence the *performance of the subject generation facilities. Bidders are fully responsible for all fuel* related expenses, which should be accounted for as specified in Sections 3.4.4 and 3.4.6 of the RFP Response Package.

5.6.4 Variable O&M Charge

The Variable O&M Charge reflects the payments that Company would make to the Bidder to cover the Variable O&M costs associated with their Proposal. The Variable O&M Charge may take into consideration non-fuel variable expenses related to operation of the Bidders generation facility. These payments will be calculated based on the initial base period charge and the escalation indices selected by the Bidder.

5.6.5 Start-Up Charge

The Start-Up Charge reflects the payments Company will make each time a generation facility, which specifies such payments, successfully starts its generating facility when called upon by Company to operate. Costs to start-up the generation facility after planned and unplanned maintenance or forced outages will not be included as Start-Up Charges. Company will estimate how many times it expects the generation facility to be required to start-up, and will include the proposed Start-Up Charge in conducting the evaluation. Bidders are encouraged to describe any constraints or unique characteristics of their Proposals which could influence the Company's analysis.

5.6.6 Emissions Charges

Company will evaluate the implications of a Proposal on overall system emission levels to assess how it will impact Company's Emission Allowances and the impact it will have on Company's position in the emission allowance market and any costs or savings associated with a particular Proposal. Company will estimate the SO_2, NOx, and mercury emissions from its system as a result of each Proposal. To estimate the impacts associated with each Proposal, Company will calculate the dollar impacts as the net emission impacts of the project times the estimated market value of the emission over the term of the PPA.

PSO previously retained a third-party to provide a range of CO_2 prices reflecting possible future CO_2 emission reduction scenarios. The range of CO_2 allowance prices reflect the potential stringency and timing of possible future legislation. The upper range of costs is associated with plants that capture 90% of the CO_2 emissions and then compress the gas and inject it into geologic formations near the plant.

Proposal evaluations will incorporate assumptions regarding the probabilities and future cost, if any, associated with tax assessment(s) or other impositions based on the quantity of CO_2 emissions produced from the combustion of fuel by a Proposal generation facility. If a Bidder proposes an arrangement wherein a specific facility is not identified (such as may be the case with a System PPA), the resulting contract shall explicitly state that PSO shall not be liable for any CO_2-related expenses, and the Bidder will be required to enter into an Indemnity Agreement which indemnifies Company from any incremental costs associated with or arising from any change in law related to CO_2 emissions. For Proposals with a specified facility, the potential CO_2 related expenses are to be provided by the Bidder in accordance with Tab 4 of the RFP Response Package. This data will be included in the Company's evaluation. The Proposal evaluation process will incorporate the assumption that the Bidder does not contractually absorb the liability associated with potential future incremental costs associated with or arising from any change in law related to CO_2 emissions. As such, Bidders are directed to submit Proposals that incorporate the assumption that Bidders will pass through any costs associated with meeting future CO_2 emissions control requirements.

5.6.7 Ancillary Services Charge

Ancillary Services that may be provided by generators are:

- Reactive Supply and Voltage Control
- Regulation and Frequency Response
- Energy Imbalance
- Operating Reserves – Spinning
- Operating Reserves – Supplemental

Bidder shall identify in their Proposal any explicit ancillary service charges related to delivering power and energy to Company under their Proposal. In addition, Bidder needs to describe in detail the relationship between Bidder's Proposal generation facility, Company and SPP RTO market operations. The details shall include responsibilities associated with scheduling, asset registration, resource bidding and ancillary service provision.

5.6.8 Transmission System Impact

This criterion considers the upgrades and attendant costs that may be required to PSO's transmission system, and to the extent they can be determined, on neighboring transmission systems. Company will use its computer modeling capability (e.g., power flow program) to verify and quantify the transmission system impacts, based on the specific data contained in Bidder's Proposal.

5.6.9 Debt Equivalence

Evaluation of PPA Proposals will include the imputed cost (revenue requirement) for any additional common equity required to maintain the Company's current debt-equity ratio. Should the PPA be determined to be treated as a capital lease under EITF 01-08 and

SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio based on the amount of the debt or capital lease liability anticipated to consolidate onto the Company's balance sheet. Should the PPA be determined to be treated as an operating lease under EITF 01-08 and SFAS 13, equity will be assumed to be added to maintain the current total debt to equity ratio using Standard and Poor's (S&P) published guidelines as a basis of the equity imputation and its cost. Key parameters for the calculations will include ROE (pre-tax) based on the Company's authorized return and net present value ("NPV") discount factor and debt cost at the Company's weighted average cost of debt. If the PPA is not a lease, sensitivities will be calculated at a 30% and a 50% risk factor that will be applied to the fixed charge NPV to calculate the imputed debt. The cost of additional equity will be included as part of the revenue requirement to all applicable PPA Proposals.

As stated in the Threshold Requirements, the Company will not accept any Proposals with contract terms that would require balance sheet consolidation of a Variable Interest Entity ("VIE") per FASB Interpretation No. 46R. Through information gathered from Bidders, the Company will determine whether it will be subject to VIE consolidation treatment at any time during the contract period. Failure in this provision will be considered a disqualification of Proposal.

5.7 Notification of Evaluation Results and Negotiations

Upon completion of the screening to determine those Proposals that meet the Credit Threshold and Accounting Threshold, PSO will notify all Bidders on the status of their Proposal. Proposals meeting the thresholds will be separated and grouped as described in Section 5.3.2. For Bidders whose Proposal fails the threshold screening, Company will provide an explanation of the requirements that were not met. Upon completion of Proposal evaluation, Bidders will be notified of the status of their Proposal and whether additional discussions or negotiations are warranted. Negotiations will commence as soon as practicable after selected Bidders are notified.

Upon conclusion of negotiations, if successful, PSO will work with the Bidders to develop definitive agreements for submission to the Commission. PSO will retain written documentation of its decision-making process for Proposals that are selected or rejected, including the reasons for its decisions.

SECTION 6 – REGULATORY APPROVALS

Generally, the results of the RFP will be subject to regulatory approvals. Any contractual arrangements between PSO and prospective Bidders may be conditioned upon prior Commission authorization that is satisfactory in form and substance to PSO in its sole judgment and discretion. The Company reserves the right to reject any proposed contracts that result from the RFP if subsequently issued regulatory approvals or authorizations are subject to conditions, including ratemaking treatments, which are unacceptable to PSO in its sole judgment and discretion.

Other than the prior authorization from the Commission for which PSO shall apply, a Bidder whose Proposal is selected will be solely responsible financially, legally and otherwise, as applicable, for acquiring and maintaining all necessary governmental (e.g., FERC), creditor, and other third-party authorizations and consents necessary or appropriate to facilitate effectuation of the selected Proposal, including all authorizations, permits, licenses, consents, and approvals associated with a selected Proposal, as well as compliance with any and all governmental rules and regulations for the construction and operation of the Project identified in the Proposal.

SECTION 7 – RESERVATION OF RIGHTS

A Bidder's Proposal will be deemed accepted only when PSO and the successful Bidder have executed definitive agreements. Company has no obligation to accept any Proposal, whether or not the stated price in such Proposal is the lowest price offered, and PSO may reject any Proposal in its sole judgment and discretion and without any obligation to disclose the reason or reasons for rejection.

BY PARTICIPATING IN THE RFP PROCESS, EACH BIDDER AGREES THAT (A) EXCEPT TO THE EXTENT OF ANY REPRESENTATIONS AND WARRANTIES CONTAINED IN A DEFINITIVE AGREEMENT WITH THE COMPANY, ANY AND ALL INFORMATION FURNISHED BY OR ON BEHALF OF THE COMPANY IN CONNECTION WITH THE RFP IS OR WILL BE PROVIDED WITHOUT ANY REPRESENTATION OR WARRANTY, EXPRESS OR IMPLIED, AS TO THE USEFULNESS, ACCURACY, OR COMPLETENESS OF SUCH INFORMATION, AND (B) EXCEPT AS OTHERWISE PROVIDED IN A DEFINITIVE AGREEMENT WITH THE COMPANY, NEITHER PSO, ITS AFFILIATES NOR ANY OF THEIR PERSONNEL OR REPRESENTATIVES SHALL HAVE ANY LIABILITY TO ANY BIDDER OR ITS PERSONNEL OR REPRESENTATIVES RELATING TO OR ARISING FROM THE USE OF OR RELIANCE UPON ANY SUCH INFORMATION OR ANY ERRORS OR OMISSIONS THEREIN.

Each Bidder is solely responsible to pay any and all costs incurred by the Bidder in the preparation of a Proposal in response to this RFP, or to contract for any products or services proposed by any Bidder. PSO reserves the right to modify or withdraw this RFP, to negotiate with any and all qualified Bidders to resolve any and all technical or contractual issues, or to reject any or all Proposals and to terminate negotiations with any Bidder at any time. PSO reserves the right, at any time and from time to time, without prior notice and without specifying any reason and, within its sole judgment and discretion, to:

- Cancel, modify or withdraw this RFP, reject any and all responses, and terminate negotiations at any time during the RFP process
- Discuss with a Bidder and its advisors the terms of any Proposal submitted by the Bidder and obtain clarification from the Bidder and its advisors concerning the Proposal.
- Consider all Proposals to be the property of PSO, subject to the provisions of this RFP relating to confidentiality and any confidentiality agreement that may

be executed in connection with this RFP, and destroy or archive any information or materials developed by or submitted to PSO in this RFP.

- Request from a Bidder information that is not explicitly detailed in this RFP, but which may be useful for evaluation of that Bidder's Proposal.
- Determine which Proposals to accept, favor, pursue or reject.
- Reject any Proposals that are not complete or contain irregularities, or waive irregularities in any Proposal that is submitted.
- Accept Proposals that do not provide the lowest evaluated cost.
- Determine which Bidders to allow to participate in the RFP, including disqualifying a Bidder due to a change in the qualifications of the Bidder or in the event that PSO determines that the Bidder's participation in the RFP has failed to conform to the requirements of the RFP.
- Conduct negotiations with any or all Bidders or other persons or with no Bidders or other persons.
- Execute one or more definitive agreements with any Bidder that submits a Proposal or with any other person or with no one.

If at any time the Company determines that there is a defect in the RFP process or a deviation from the requirements of the RFP or that collusive or fraudulent bidding has occurred or appears to have occurred, the Company, in consultation with the IM, may suspend the RFP in whole or in part as to any Bidder or Bidders so involved.

Under all circumstances, each Bidder is responsible for all costs and expenses it incurs in connection with the RFP. Under no circumstances, including the Company's termination of the RFP at any time, will the Company or any of its representatives be responsible for any costs or expenses of any Bidder incurred in connection with the RFP.

SECTION 8 – GLOSSARY OF TERMS

1. Acceptable Credit Support: Shall mean, but shall not be limited to, one or more of the following: (i) an irrevocable, transferable standby Letter of Credit issued by a U.S. commercial bank or a foreign bank with a U.S. branch with such bank have a credit rating of at least A- from S&P or A3 from Moody's in a form as outlined in Appendix F Form 3, or (ii) a cash deposit.

2. Affiliate: Is any person directly or indirectly controlling or controlled by or under direct or indirect common control with such person or any person that directly or indirectly (through one or more intermediaries) controls or is controlled by or is under common control with the person. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with"), as used with respect to any person, shall mean the direct or indirect ownership or control of, or the possession, directly or indirectly, of the power to vote, five percent (5%) or more of the outstanding voting securities of such person, or the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such person, whether through the ownership of voting securities, by agreement, or otherwise.

3. Commercial Operation Date: The date upon which the seller's delivery obligations commence under a PPA.

4. Control Area: AEP SPP electric system bounded by interconnection metering and telemetry capable of controlling owned and contracted generation to maintain interchange schedules with other control areas. In this document, the term, "control area," is used interchangeably with the term, "transmission system".

5. Credit Support Provider: An entity that has issued a guaranty to cover the obligations of the Bidder.

6. Net Dependable Summer Capability: The net demonstrated summer capability of a generating unit established in accordance with the testing procedures defined in Section 12 of SPP Criteria--Electrical Facility Ratings.

7. SPP RTO: The Southwest Power Pool Regional Transmission Organization. Major services provided by the SPP RTO to members include independent reliability coordination and tariff administration, regional engineering model development, planning and operating studies, reliability assessment studies, a computer-based telecommunications network, and operating reserve sharing. SPP provides regional transaction scheduling and is in the process of implementing market settlement functionality as required by FERC Order 2000.

8. Baseload Capacity and Energy Resource: A firm generating resource that is economically dispatched at a high capacity factor. Primary characteristics are the resource's high fixed cost profile (capital recovery and fixed operation and maintenance cost, etc.) would be relatively high but is economically justified due to its very low variable and incremental operating cost.