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February 18, 2011

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Oklahoma Gas and Electric Company,
Docket No. ER11-___-000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") regulations,[2] Oklahoma Gas and Electric Company ("OG&E") respectfully requests Commission authorization to implement transmission rate incentives in accordance with FPA Section 219[3] and Order No. 679.[4] Specifically, OG&E requests authorization to include 100 percent of all prudently-incurred Construction Work in Progress ("CWIP") in rate base for five specific transmission projects to be constructed by OG&E within the Southwest Power Pool, Inc. ("SPP"). In addition, OG&E requests authorization to recover 100 percent of all prudently-incurred development and construction costs if one or more of the transmission projects identified and described herein are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. OG&E respectfully requests that the Commission approve these incentives to be effective March 1, 2011, without suspension or hearing.

The five transmission projects for which OG&E requests incentive rate treatment were previously evaluated by the Commission in *Oklahoma Gas and Electric Co*., 133 FERC ¶ 61,274 (2010) ("December 30 Order"). In the December 30 Order, the Commission considered OG&E's October 12, 2010 application for incentive rate treatment for eight transmission projects and found that "OG&E has adequately demonstrated that the Projects will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion, and therefore meet the requirements of FPA section 219 for incentive rate treatment."[5] However, the

[1] 16 U.S.C. § 824d (2006).

[2] 18 C.F.R. pt. 35 (2010).

[3] 16 U.S.C. § 824s (2006).

[4] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, Order No. 679-B, 119 FERC ¶ 61,062 (2007).

[5] December 30 Order at P 35.

Commission also found that a different applicant's filing in an unrelated docket "revealed the necessity to change Commission policy with respect to the application of the nexus test to groups of projects."[6] Applying this revised standard, the Commission concluded that OG&E satisfied the nexus requirement for two projects[7] and authorized the requested transmission incentive rates for those projects, but held that OG&E had failed to demonstrate the required nexus between the requested incentives and the remaining six projects.[8] This finding was "without prejudice to OG&E refiling to demonstrate how each of these six remaining projects meets the nexus requirement."[9]

Consistent with the guidance contained in the December 30 Order, OG&E, through this filing, demonstrates that the five transmission projects addressed herein satisfy fully the requirements for incentive rate treatment, including the requirement that OG&E demonstrate the required nexus between the requested transmission rate incentives and each of the five proposed transmission projects on a project-by-project basis.[10] Accordingly, for the reasons stated herein, OG&E respectfully requests that the Commission authorize incentive rate treatment for each of the five projects.

I. INTRODUCTION.

A. Oklahoma Gas and Electric Company.

OG&E is an electric public utility with plant, property, and other assets dedicated to the production, transmission, distribution, and sale of electric energy to wholesale and retail customers in Oklahoma and western Arkansas. OG&E serves more than 750,000 retail customers and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. OG&E owns and operates approximately 6,641 MWs of generation capacity comprising natural gas, low-sulfur coal, and wind generation facilities and also purchases power from third parties for resale. OG&E's transmission system includes approximately 4,500 miles of transmission lines plus 56 substations. OG&E is an Oklahoma corporation and a wholly-owned subsidiary of OGE Energy Corp.

OG&E is a member of SPP and SPP serves as the Transmission Provider for all new transmission transactions on the OG&E system. SPP administers a regional Open Access Transmission Tariff ("OATT"), which governs transmission service over the facilities of SPP's member transmission owners within the SPP region.[11] Each SPP member retains the unilateral

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6 *Id.* at P 39 (footnote omitted).

7 *Id*. at P 43.

8 *Id*. at PP 42, 44.

9 *Id*. at P 44.

10 OG&E's October filing requested incentives for a sixth project, the Anadarko (or Gracemont) substation. OG&E has elected not to request incentives for that project in this filing.

11 *See Southwest Power Pool, Inc.*, 82 FERC ¶ 61,267 (1998), *reh'g*, 85 FERC ¶ 61,031 (1998).

right to make an FPA Section 205 filing to change that member's rates or rate structure.[12] Although all new transmission service requests on OG&E's transmission facilities must be obtained through the SPP OATT, OG&E continues to serve two customers under existing long-term service agreements entered into under OG&E's OATT.

B. Transmission Projects for Which Incentives are Requested.

As explained in the Direct Testimony of Philip L. Crissup, appended hereto at Exhibit No. OGE-1, the transmission investments for which OG&E seeks incentives are the product of SPP's regional planning efforts, which were implemented to develop new transmission to meet applicable North American Reliability Corporation ("NERC") reliability standards, to relieve congestion, and to provide load across the SPP footprint with access to a broader generation resource portfolio.[13] Through its planning processes, SPP has identified the need for regional large-scale transmission projects to facilitate expansive renewable resource developments in the western portion of its system and for diverse resource options in load centers in the eastern portion of SPP and in neighboring balancing authority areas.[14] To this end, projects vetted and selected through SPP's planning processes, including the projects for which OG&E seeks FPA Section 219 incentives, as described below, are intended to strengthen the reliability of SPP's system and to provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service.[15]

As described in detail below, OG&E seeks approval to implement transmission incentives authorized by FPA Section 219 and Order No. 679 in connection with five major transmission projects to be constructed by OG&E in the SPP region (collectively, the "Projects"). These Projects are identified and described herein and in Mr. Crissup's testimony.

1. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012;

2. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to Westar Energy's ("WRGS") Rose Hill substation near Wichita, Kansas. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, will terminate at the interface with the WRGS segment at the Oklahoma-Kansas state line, is estimated to cost $57.8 million, and has an estimated in-service date of June 1, 2012;

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[12] *See Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 95 (2004).

[13] Crissup Testimony, Exhibit No. OGE-1 at 8-19, *citing* SPP OATT at Attachment O, Section VII.

[14] SPP OATT, Attachment O, Section IV; *see also*, Southwest Power Pool, Inc., May 17, 2010 Filing, Docket No. ER10-1269-000 at 4-7.

[15] *See* SPP OATT at Attachments O, J, and Z1.

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. This Project is estimated to cost $64 million and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013; and

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line to be constructed from OG&E's Woodward District Extra High Voltage substation to the Southwestern Public Service Company ("SPS") Tuco substation. The OG&E portion of the Tuco-Woodward Project is 72 miles in length and will terminate at a reactor station to be constructed at approximately the Oklahoma-Texas state border. The OG&E portion of the Project has an estimated cost of $120 million and an estimated in-service date of May 19, 2014.

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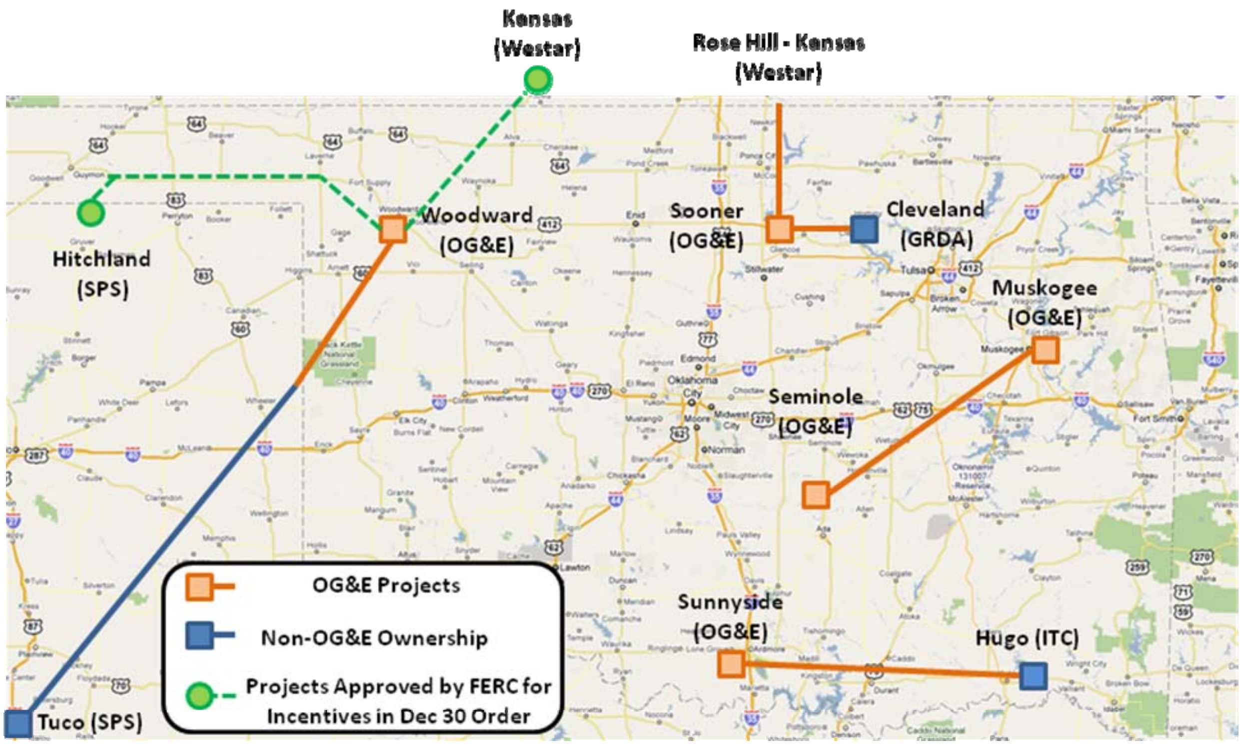
The location of each of the Projects is shown on the following map:[16]



Each of the Projects was included in the 2009 SPP Transmission Expansion Plan ("2009 STEP"),[17] and SPP has issued a "Notification To Construct" for each Project.[18] OG&E has accepted the SPP Notification to Construct for all five Projects. OG&E estimates that construction of the Projects will require between one and three and a half years, and that the annual construction costs will be as follows:

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16 A larger version of this map is included as Exhibit No. OGE-2. Additional maps showing more detail concerning the specific Projects and highlighting some of the risks and challenges associated with those Projects are included as Exhibit Nos. OGE-3 through OGE-9 and are further described in the Crissup testimony.

17 The STEP is an annual report issued by SPP that identifies planned transmission upgrades in the SPP region for a 20-year planning horizon. *See* SPP OATT, Attachment O. Exhibit No. OGE-10 includes excerpts of the relevant sections of the 2009 STEP Report. The report can be found in its entirety at: http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf.

18 Pursuant to the SPP OATT, after a new transmission project has been approved under the STEP, SPP, in writing, directs "the appropriate Transmission Owner(s) to begin implementation of the project." SPP OATT, Attachment O, Section VI.4. This written notification, called a "Notification to Construct," includes: "(1) the specifications of the project required by [SPP] and (2) a reasonable project schedule, including a project completion date." SPP OATT, Attachment O, Section VI.4.

Projected Budget for OG&E Transmission Projects
(Dollars in Millions)

Project	2010	2011	2012	2013	2014	Total
Sunnyside-Hugo	$25.105	$140.28	$21.904	$0	$0	$187.289
Sooner-Rose Hill	$10.858	$33.931	$13.045	$0	$0	$57.834
Sooner-Cleveland	$2.385	$19.074	$41.069	$1.536	$0	$64.064
Seminole-Muskogee	0	$11.1	$101	$67	$0	$179.1
Tuco-Woodward	0	$4.7	$23	$62.7	$29.6	$120
Total	$38.348	$209.085	$200.018	$131.236	$29.6	$608.287

The Projects represent an unprecedented level of new investment by OG&E in transmission infrastructure.[19] For example, the Projects will add approximately 393 miles of new 345-kV transmission facilities to the OG&E transmission system within the SPP region, a significant expansion of the 4,500 miles of high voltage transmission lines that currently compose OG&E's transmission system, of which only 910 miles are 345-kV lines. The cost projections for the combined Projects is approximately $608 million, which is equal to about 109 percent of OG&E's current net transmission plant of $558 million.[20]

C. The Transmission Projects are the Product of SPP's Regional Planning Process.

The Projects are components of a larger group of transmission facility investments to be constructed by a number of SPP member utilities as part of a regional program to enhance system reliability and reduce constraints and system congestion. As Mr. Crissup explains in his testimony, pursuant to SPP's Commission-approved regional transmission planning process set forth at Attachment O of the SPP OATT, each of the Projects was evaluated as part of a group of related projects under one of two SPP planning categories:

Transmission Service Upgrades. Transmission service upgrades, identified pursuant to the Aggregate Transmission Service Study Procedures set forth at Attachment Z1 of the SPP OATT, are determined by SPP to be necessary to alleviate constraints on the transmission system

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19 *See* Crissup Testimony, Exhibit No. OGE-1 at 7-8.

20 *Id*. The actual cost will depend on multiple factors such as the final routes for the proposed lines, and the costs of equipment, commodities and other construction elements.

and facilitate requests for transmission service.[21] This practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and to do so at the minimum total cost.[22]

Balanced Portfolio Projects. Balanced Portfolio projects are a cohesive group of economic transmission upgrades intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs" across the SPP region.[23] An SPP working group, with input from stakeholders, initially identified potential upgrades to be included in the portfolio, and, after conducting a cost/benefit analysis, SPP selected a specific cost beneficial grouping of projects with a project included from each SPP zone.[24]

II. DESCRIPTION OF FILING.

In addition to this transmittal letter, this filing contains the following materials:

- Attachment 1: Populated Formula Rate Template;
- Attachment 2: Prepared Direct Testimony and Exhibits of Philip L. Crissup;
- Attachment 3: Prepared Direct Testimony and Exhibits of Donald R. Rowlett; and
- Attachment 4: Attestation as required by 18 C.F.R. § 35.13(d)(6).

III. REQUEST FOR INCENTIVES.

The Projects that OG&E intends to construct are large-scale transmission investments with region-wide benefits and associated risks. These Projects are not routine for OG&E. As a result, OG&E seeks to implement a narrowly-focused set of transmission incentives to reduce the risks and challenges inherent in such investments. Specifically, OG&E respectfully requests that the Commission authorize OG&E: (a) to include 100 percent of prudently-incurred CWIP in rate base, and (b) to recover 100 percent of prudently-incurred costs of transmission facilities that are cancelled or abandoned, in whole or in part, for reasons beyond OG&E's control. These incentive rate treatments will apply only to the specific Projects identified and described herein.

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21 SPP OATT, Attachment Z1.

22 SPP OATT, Attachment Z1, Section I.

23 SPP Balanced Portfolio Report (last revised June 23, 2009), Exhibit No. OGE-16 at 3.

24 *See* SPP's description of the Balanced Portfolio at http://www.spp.org/section.asp?pageID=120 (last visited February 17, 2011); SPP OATT, Attachment O, Section IV.3.; SPP Balanced Portfolio Report, Exhibit No. OGE-16 at 6-8.

With regard to CWIP, OG&E will populate its formula rate template with the costs of CWIP for the Projects.[25] A populated version of OG&E's Formula Rate template illustrating the implementation of the CWIP incentive is included for informational purposes at Attachment 1. With regard to the recovery of abandoned plant costs, OG&E does not seek to recover any costs associated with abandoned plant at this time. In the event that some or all of the Projects are abandoned, in whole or in part, OG&E will make an FPA Section 205 filing to recover such costs at that time.

OG&E's request for incentives is consistent with FPA Section 219 and the Commission's regulations and should be approved. Section 219 of the FPA provides for the Commission to establish incentive-based rate treatment for qualifying transmission investments.[26] Under Order No. 679, the incentives a utility may request can include a return on equity ("ROE") sufficient to attract capital, recovery of CWIP and pre-commercial expenses, the use of a hypothetical capital structure, accelerated depreciation, and Abandoned Plant,[27] but this list is not exhaustive.[28] To qualify for any of these incentives, an entity must show that: (1) the facilities for which incentives are sought ensure reliability or reduce the costs of delivered power by reducing congestion; (2) the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project (*i.e.*, the "nexus" test); and (3) the resulting rates are just and reasonable.[29]

OG&E's limited request for the CWIP and Abandoned Plant incentives satisfies fully these requirements and the Commission should authorize OG&E's requested transmission incentives.

A. The Projects Qualify for the Rebuttable Presumption Under FPA Section 219.

Where transmission projects are the product of a fair and open regional planning process, or have received construction approval from a state authority, the Commission has adopted a rebuttable presumption that such projects will ensure reliability or reduce the costs of delivered power by reducing congestion, so long as the regional planning process "considered whether the project ensures reliability or reduce congestion."[30] In the December 30 Order, the Commission evaluated a group of projects that included each of the five Projects addressed herein and held

[25] The populated formula rate template included as Attachment 1 reflects the tariff changes accepted by the Commission in the December 30 Order. No additional tariff changes are required to implement the incentives requested herein.

[26] *See* 16 U.S.C. § 824s(a) ("the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting [*sic*] consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion").

[27] Order No. 679 at PP 85-193.

[28] *See id.* at P 55.

[29] *Id.* at P 76.

[30] Order No. 679-A at PP 5, 49-50.

that each of the Projects satisfied the requirements for the application of the rebuttable presumption:

> We find that OG&E has adequately demonstrated that the Projects will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion, and therefore meets the requirements of FPA section 219 for incentive rate treatment. As detailed above, each of the Projects has been identified as either a Priority Project, Balanced Portfolio project, or identified as a necessary upgrade for transmission service in the STEP 2009, which are components [of] SPP's regional planning process, as provided in Attachment O of the SPP OATT. Thus, OG&E has demonstrated that each of the Projects is eligible for the first of the rebuttable presumptions established in Order No. 679.[31]

While the Commission has already held that OG&E has satisfied the first element of the FPA Section 219 standard for transmission rate incentives for each of the Projects, for the convenience of the Commission and to ensure a complete record OG&E has included in this filing specific testimony and supporting exhibits demonstrating the Projects' eligibility for the rebuttable presumption. The following discussion, together with Mr. Crissup's testimony, demonstrates that the SPP planning processes through which each of the Projects was evaluated and approved determined that the Projects will enhance reliability and/or reduce congestion.

1. OG&E's Sunnyside-Hugo and Sooner-Rose Hill Projects Were Evaluated and Approved by SPP as Upgrades to Fulfill Requests for Transmission Service, and SPP Concluded that these Projects Would Relieve Congestion and/or Ensure Reliability.

Pursuant to SPP's Attachment Z1 procedures, SPP conducts an open season during which customers may make requests for long-term transmission service.[32] SPP then performs an Aggregate Facilities Study ("AFS") of the eligible requests for transmission service received during the open season. The AFSs relevant to the Projects are attached to this filing as Exhibit Nos. OGE-14 and OGE-15.[33] Determining which upgrades will relieve congestion on the system is a key objective of the AFS process: "[s]ystem constraints will be identified and appropriate upgrades determined."[34] SPP also is charged with determining "the upgrades required to reliably provide all of the requested service" and determining which "alternative solutions would reduce overall cost to customers."[35] This approach results in "a more efficient

[31] December 30 Order at P 35.

[32] SPP OATT, Attachment Z1, Section II; *see also*, Crissup Testimony, Exhibit No. OGE-1 at 13-15.

[33] Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers at 10-13 (September 16, 2008), Exhibit No. OGE-14 ("SPP September 2008 Study"); Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers at 11-13 (Revised March 19, 2009), Exhibit No. OGE-15 ("SPP March 2009 Study").

[34] SPP OATT, Attachment Z1, Section III.a.

[35] *Id*. The AFS methodology also is designed to ensure that NERC Reliability Standards are met. *See* SPP September 2008 Study, Exhibit No. OGE-14 at 10; SPP March 2009 Study, Exhibit No. OGE-15 at 10.

expansion of the transmission system."[36] Upgrades evaluated for transmission requests pursuant to Attachment Z1 are folded into the Attachment O integrated transmission planning study and analysis,[37] which incorporates NERC Reliability Standards, load and capacity forecasts, and congestion within SPP and between SPP and other regions.[38]

In the 2009 STEP Report, SPP identified Sunnyside-Hugo and Sooner-Rose Hill as two of the "[m]ajor 345 kV projects" currently proposed in SPP.[39] SPP has determined that Sunnyside-Hugo and Sooner-Rose Hill are necessary upgrades to alleviate congestion and thereby facilitate requests for transmission service in the region.[40] The Aggregate Facilities Studies relevant to the Sunnyside-Hugo line and the Sooner-Rose Hill line state "that limiting constraints exist in many areas of the regional transmission system"[41] and SPP found that Sunnyside-Hugo and Sooner-Rose Hill are among the upgrades needed to alleviate these constraints.[42] Subsequently, these Projects were included in the 2009 STEP Report, which was approved by the SPP Board of Directors. SPP has issued Notifications to Construct for Sunnyside-Hugo and Sooner-Rose Hill.[43]

2. OG&E's Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward Projects were Evaluated and Approved by SPP as Balanced Portfolio Network Upgrades, and SPP Concluded that the Projects Would Ensure Reliability and/or Relieve Congestion.

SPP's Balanced Portfolio projects are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[44] To select which projects would be included in the Balanced Portfolio, SPP's Cost Allocation Working Group ("CAWG"), with stakeholder input, identified "upgrades that would provide a balanced benefit

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36 SPP OATT, Attachment Z1, Section I.

37 *See* Crissup Testimony, Exhibit No. OGE-1 at 14-15; SPP OATT, Attachment O, Figure 1 and Sections III.3-III.5.

38 *See* SPP OATT, Attachment O, Section III.6.

39 2009 STEP, Exhibit No. OGE-10 at 7-8. These Projects are transmission service upgrades and are considered "part of the future expansion of the [SPP] Transmission System." *See also* SPP OATT, Second Revised Sheet No. 300.

40 SPP September 2008 Study, Exhibit No. OGE-14 at 18 and Table 3; SPP March 2009 Study, Exhibit No. OGE-15 at 18 and Table 3.

41 SPP September 2008 Study, Exhibit No. OGE-14 at 18; SPP March 2009 Study, Exhibit No. OGE-15 at 18.

42 In the 2009 STEP, SPP found that Sooner-Rose Hill may mitigate a constraint at one of SPP's top ten congested flowgates. The top ten congested flowgates are those with the highest "value of relieving the constraint measured in dollars." *See* 2009 STEP, Exhibit No. OGE-10 at 15-16.

43 Crissup Testimony, Exhibit No. OGE-1 at 15; SPP Notification to Construct, SPP-NTC-20017 (January 16, 2009), Exhibit No. OGE-11; SPP Notification to Construct, SPP-NTC-20055 (September 18, 2009), Exhibit No. OGE-12.

44 SPP Balanced Portfolio Report, Exhibit No. OGE-16 at 3; Crissup Testimony, Exhibit No. OGE-1 at 16.

to SPP members over a specified ten-year payback period."[45] Pursuant to Attachment O of the SPP OATT, the Balanced Portfolio must be (1) cost beneficial, meaning that "[t]he sum of the benefits [measured using an adjusted production cost metric] . . . must equal or exceed the sum of the costs [measured as the net present value of the revenue requirements];"[46] and (2) balanced, meaning that the benefits must also equal or exceed the costs for each SPP zone.[47] From an initial list compiled by the CAWG, SPP conducted an analysis of the adjusted production cost of each potential project.[48] The annual benefits of the potential projects were compared to the estimated engineering and construction costs, which were provided by transmission owners.[49] A potential project's benefit-to-cost ratio was used to determine potential groupings of projects.[50]

In the 2009 STEP Report, SPP identified Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward as three of the "[m]ajor 345 kV projects" currently proposed in SPP.[51] These three Projects are SPP Balanced Portfolio Network Upgrades and are included in the Portfolio 3E "Adjusted."[52] This final selection of projects was based on a grouping of projects that ensured that a project was included for each SPP zone "with the most beneficial project chosen in each zone."[53] Studies have demonstrated that the benefits of these projects outweigh their costs[54] and that these projects will relieve congestion by addressing "many of the top constraints in the SPP."[55] SPP also concluded that this reduction in congestion will result in demonstrable cost savings to customers.[56] Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward have been approved by the SPP Board of Directors. A Notification to Construct has been issued for all three Projects, and OG&E has accepted the Notification to Construct.[57]

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45 *See* SPP's description of the Balanced Portfolio at http://www.spp.org/section.asp?pageID=120 (last visited February 17, 2011).

46 SPP OATT, Attachment O, Section IV.3.

47 *Id.*

48 SPP Balanced Portfolio Report, Exhibit No. OGE-16 at 6.

49 *Id.* at 8.

50 *Id.*

51 *See* 2009 STEP, Exhibit No. OGE-10 at 6-7.

52 Crissup Testimony, Exhibit No. OGE-1 at 17-18.

53 SPP Balanced Portfolio Report, Exhibit No. OGE-16 at 9.

54 *See* SPP's description of the Balanced Portfolio at http://www.spp.org/section.asp?pageID=120 (last visited February 17, 2011).

55 2009 SPP Balanced Portfolio Report, Exhibit No. OGE-16 at 35. Moreover, in the 2009 STEP, SPP found that Seminole-Muskogee will mitigate in part constraints at two of SPP's top ten congested flowgates. The top ten congested flowgates are those with the highest "value of relieving the constraint measured in dollars." *See* 2009 STEP, Exhibit No. OGE-10 at 15-16.

56 *See* Crissup Testimony, Exhibit No. OGE-1 at 18. The net benefit to a typical residential customer is estimated to be $0.78/month. Balanced Portfolio Report, Exhibit No. OGE-16 at 3.

57 SPP Notification to Construct, SPP-NTC-20041 (June 19, 2009), Exhibit No. OGE-13.

B. The Projects Satisfy FPA Section 219's Nexus Requirement.

In order to meet the requirements for incentives under FPA Section 219 and Order No. 679, a party requesting incentives must show a nexus between the incentives being sought and the investments in transmission projects on a project-by-project basis.[58] The Commission has stated that the nexus required is not a "but for" test and that a party seeking incentives meets FPA Section 219's requirements by showing a rational relationship between the proposed incentives and the specific transmission projects.[59]

The nexus requirement is fact-specific and the Commission evaluates applications for incentives on a case-by-case basis.[60] In evaluating requests for incentives, the Commission has explained that it "will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project."[61] The Commission has found particularly relevant whether a project is "routine,"[62] as compared to "other transmission projects or upgrades that are constructed in the ordinary course of maintaining a utility's transmission system to provide safe and reliable service."[63] In determining whether a project is routine, the Commission will consider "all relevant factors," for example, "(i) the scope of the project (*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the effect of the project (*e.g.*, improving reliability or reducing congestion costs); and (iii) the challenges or risks faced by the project (*e.g.*, siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments)."[64] As the Commission noted in the December 30 Order: "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."[65]

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58 *See* December 30 Order at PP 39-44.

59 Order No. 679 at P 48.

60 *See, e.g.*, *Otter Tail Power Co.*, 129 FERC ¶ 61,287 at P 28 (2009) ("*Otter Tail*"); *Virginia Elec. & Power Co.*, 124 FERC ¶ 61,207 at P 47 (2008) ("*VEPCo*").

61 Order No. 679-A at P 27.

62 *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084 at P 48 (2007), *reh'g denied*, 122 FERC ¶ 61,034 (2008) ("*BG&E*").

63 *BG&E*, 120 FERC ¶ 61,084 at P 53; Order No. 679-A at P 60. To show a project is not routine, a utility may also compare its investment in the project "to some other aggregate measure of investment, such as total rate base or recent annual investment levels." *Pepco Holdings, Inc.*, 125 FERC ¶ 61,130 at P 54 (2008).

64 *BG&E*, 120 FERC ¶ 61,084 at P 52; *PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273 at P 43 (2010); *Public Service Electric and Gas Company*, 131 FERC ¶ 61,028 at P 19 (2010); *Great River Energy*, 130 FERC ¶ 61,001 at P 31 (2010).

65 December 30 Order at P 37 (quoting *BG&E*, 120 FERC ¶ 61,084 at P 54).

1. The Projects for which OG&E Seeks Incentives Represent a Dramatic Departure from OG&E's Routine Transmission Projects.

a. The Projects are designed and approved by SPP to address regional needs and to provide pool-wide benefits.

Pursuant to Attachment Z1 of the SPP OATT, SPP is responsible for determining which transmission upgrades are needed to accommodate requests for transmission service and "to develop a more efficient expansion of the transmission system."[66] After SPP conducts the necessary technical studies and determines the required upgrades, SPP then performs "a regional review of the required upgrades to determine if alternative solutions would reduce overall cost to customers."[67] Similarly, SPP selects the final package of Balanced Portfolio projects after conducting a cost-benefit analysis to determine the "overall portfolio benefits to the region."[68] Pursuant to Attachment O of the SPP OATT, SPP then must designate the appropriate transmission owner or owners to construct, own, and/or finance each project in the STEP, [69] which includes transmission service upgrades and Balanced Portfolio projects selected by SPP, as well as other projects that "impact future development of the SPP transmission grid."[70] It is only after SPP has determined which specific projects will best serve the needs of the pool that the Notification to Construct is issued, and a specific Transmission Owner agrees to finance and construct the relevant projects. [71]

OG&E's routine transmission investments are designed and built to meet localized needs of customers within OG&E's service territory.[72] In contrast to such routine projects, the Projects for which OG&E request incentives have been designed by SPP to address regional needs. SPP, in its 2010 Strategic Plan, recognized that "[h]istorically, the transmission system was designed primarily to serve local systems," but that historical design has hindered "optimal utilization" of generation assets.[73] Therefore, part of SPP's vision for the future of its transmission grid is that it will "be able to deliver increased value to members by facilitating the implementation of and managing a robust transmission system flexible enough to reliably accommodate any number of future scenarios."[74] To this end, within SPP, "[g]rid expansion will be required to add additional renewable and non-renewable resources into the generation mix."[75] SPP envisions that the

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66 SPP OATT, Attachment Z1, Section 1.

67 *Id.* at Section III.a.

68 Balanced Portfolio Report, Exhibit No. OGE-16, at 7; SPP OATT, Attachment O, Section IV.3.

69 SPP OATT, Attachment O, Section VI.1.

70 2009 STEP, Exhibit No. OGE-10 at 2.

71 Crissup Testimony, Exhibit No. OGE-1 at 9.

72 *Id.*at 21-22.

73 2010 Southwest Power Pool Strategic Plan at 10, *available at* http://www.spp.org/publications/2010_SPP_Strategic_Plan.pdf.

74 *Id.*

75 *Id.*

expansion of its regional grid should contain "an optimal mix of 'highways' (300 kV+) and byways (below 300 kV)" and should "minimize[] future transmission constraints without over-investing in transmission capacity."[76] SPP believes that "[a] robust system creates immense new value for SPP members and end users in the SPP region."[77] The five Projects at issue in this filing – all 345-kV transmission lines – thus will help realize SPP's vision of developing a robust, regional transmission system that includes transmission "highways" of 300 kV or more.

However, because each of the Projects is the product of SPP's regional planning process, these Projects are at risk that they may be modified, postponed, or terminated by subsequent SPP planning decisions. In *PPL*, the Commission acknowledged that RTO planning processes could result in transmission projects being canceled and found that an abandoned plaint incentive would help to ameliorate that risk.[78]

b. The Projects are not routine compared to OG&E's typical transmission projects.

Apart from SPP's characterization of the Projects, the Projects for which OG&E has requested incentive rate treatment are substantially different from the routine transmission projects undertaken by OG&E over the past several years. Several factors demonstrate that each of these Projects is anything but routine.

First, each of the Projects addressed in this filing is a 345-kV project. OG&E's typical transmission projects are constructed at 69 kV or 138 kV; OG&E has built only one 345-kV project in the past eight years.[79] 69-kV or 138-kV projects are smaller in stature, shorter in length and typically follow a standard construction design.[80] OG&E's transmission construction and maintenance programs are heavily weighted towards these types of small projects.[81] The proposed Projects total 393 miles of 345-kV transmission lines, a 43% increase in OG&E's 345-kV system. Such a substantial expansion of OG&E's 345-kV system is not routine.[82]

Second, unlike the Projects for which incentives are sought, the routine projects undertaken by OG&E are of limited scope and cost. From 2006 through 2009, OG&E's routine annual transmission capital investments averaged 24.6 miles of new transmission lines with an annual cost of $13.6 million.[83] These projects rarely impacted more than a single county and

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[76] *Id.*

[77] *Id.*

[78] *PPL Electric Utilities Corporation*, 123 FERC ¶ 61,068 at P 47 (2008), *reh'g denied*, 124 FERC ¶ 61,229 (2008).

[79] Crissup Testimony, Exhibit No. OGE-1 at 21.

[80] *Id.*

[81] *Id.*

[82] *Id.* at 21-22.

[83] *Id.* at 21.

were typically built in support of localized transmission needs.[84] In 2010, OG&E constructed its first 345-kV EHV project in eight years.[85] This project, the WindSpeed line, was 120 miles in length and cost approximately $165 million dollars.[86] This atypical project skewed OG&E's five-year average transmission investment metric. When the Windspeed Project is included, OG&E's five-year average transmission investment increases to 53.5 miles and $51.3 million per year.[87] Yet even when compared to this inflated average, the Projects for which OG&E requests incentives are larger in size and scope and are not comparable to OG&E's routine transmission projects. In contrast to OG&E's routine capital projects, the Projects addressed in this application range from 38 miles to 120 miles of 345-kV lines. Further, the least expensive of the Projects addressed in this application is expected to cost approximately $58 million, more than ten percent of OG&E's current net transmission plant in service, and the most expensive Project is expected to cost $187 million, approximately 35 percent of OG&E's current plant in service. Projects of this magnitude are not routine for OG&E.[88]

Third, unlike routine projects that are focused on OG&E's service to customers within its service territory, the Projects that are the subject of this filing were designed and evaluated based on regional factors and are being built to provide regional benefits. As noted above, each of these Projects was reviewed by SPP and ultimately approved based on an analysis of region-wide effects on system reliability, the ability of these Projects to reduce congestion, and the Projects' benefits to the entire SPP region. Projects of regional scope and effect are not routine.[89]

2. Each of the Projects is of Regional Scope and Effect and Faces Atypical Risks and Challenges, Factors which Show that Each Project is not Routine.

The following discussion addresses the specific transmission Projects for which OG&E seeks incentive rates on a project-by-project basis and demonstrates that each of the Projects is not routine and meets the nexus requirement under FPA Section 219 and Order No. 679.

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84 *Id.* at 21-22.

85 *Id.* at 22.

86 The Windspeed line was a Sponsored Upgrade under the SPP OATT. As such, the revenue requirement associated with the Windspeed line was directly assigned to OG&E. OG&E also received pre-approval for recovery of the costs of the WindSpeed line from the Oklahoma Corporation Commission and was able to ensure cost recovery from retail customers in Oklahoma. Therefore, OG&E did not need to seek FPA Section 219 incentives for construction of the Windspeed line.

87 Crissup Testimony, Exhibit No. OGE-1 at 22.

88 *Id.* at 21-22.

89 *Id.*

a. The Sunnyside-Hugo Project.

(1) **The Project's substantial scope and regional effect show that it is not routine.**

The Sunnyside-Hugo Project is significant in terms of cost, in terms of miles of new transmission facilities added to the current OG&E system, and in terms of its effect on the SPP region. It is not a routine transmission project for OG&E.

Sunnyside-Hugo is a 345-kV, 120-mile transmission line with associated upgrades to the Sunnyside substation. OG&E estimates that the Project will cost $187 million and will be placed into service on or about April 1, 2012.[90] The investment required to complete this new transmission line represents 33.5 percent of OG&E's current net transmission plant of $558 million. The line will stretch 120 miles across southern Oklahoma from the Sunnyside Substation near Lone Grove, Oklahoma, to the Western Farmers Electric Cooperative substation near Hugo and Fort Towson, Oklahoma.

The Project is intended to have region-wide effects. As part of its transmission service study procedures, SPP has determined that the Sunnyside-Hugo Project is necessary to alleviate constraints on the transmission system and to facilitate requests for transmission service in the region.[91] In the September 2008 Study, SPP evaluated 1,488 MW of long-term transmission service requests.[92] The purpose of the study was "to identify system problems and potential modifications necessary to facilitate" the requested service.[93] SPP analyzed the system impact of each requested service by using a "steady-state analysis" and the study identifies Sunnyside-Hugo as one of the facility upgrades that must be built in order to provide requested transmission service "while maintaining or improving system reliability[.]"[94] This includes meeting NERC Reliability Standards and SPP's own reliability criteria.[95]

Ultimately, the September 2008 Study concluded that service requests made by Arkansas Electric Cooperative Corporation ("AECC"),[96] American Electric Power West ("AEPM"),[97] and Oklahoma Municipal Power Authority ("OMPA")[98] each independently require the addition of

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90 *See* December 30 Order at P 43 (finding significant in scope two other OG&E projects with respective costs of $178 million and $135 million and with respective lengths of 82 miles and 80 miles); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 at P 32 (finding that a similarly sized proposed transmission line of 130 miles is substantial in scope).

91 Crissup Testimony, Exhibit No. OGE-1 at 23; SPP March 2009 Study, Exhibit No. OGE-15 at 18.

92 September 2008 Study, Exhibit No. OGE-14 at 3.

93 *Id.* at 3.

94 *Id.* at 10, 14-15 and Appendix A, Table 4.

95 *Id.* at 10.

96 *Id.* at Appendix A, Table 3, AECC Reservation No. 1161209.

97 *Id.* at Appendix A, Table 3, AEPM Reservation Nos. 1158760, 1158761, 1162214, and 1163062.

98 *Id.* at Appendix A, Table 3, OMPA Reservation No. 1159596.

the Sunnyside-Hugo Project. Combined, these requests constitute 1,436 MW, which is nearly the entire 1,488 MW of requests reviewed in the September 2008 Study.[99]

(2) **The Project faces significant risks and challenges, which demonstrate that it is not routine.**

Sunnyside Hugo presents multiple risks and challenges that distinguish the Project from routine transmission investments.

First, the Project faces risks and challenges associated with the need to coordinate the Project's construction with another utility. Unlike more routine projects, the Sunnyside-Hugo Project is a component of a larger regional transmission project and provides for OG&E to construct facilities that will connect with the Hugo Substation to be built by ITC Great Plains, LLC ("ITC"), an independent, transmission-only utility. OG&E has no control over the permitting or construction of the ITC portion of the project. Any delay in ITC's ability to construct and place into service the Hugo substation will delay OG&E's ability to place Sunnyside-Hugo into service.[100] The Commission has recognized that the need to coordinate with other utilities when planning transmission projects poses special challenges.[101]

Second, the Sunnyside-Hugo Project faces extraordinary challenges with regard to obtaining the required rights-of-way. While a right-of-way is required for even the most routine transmission projects, Sunnyside-Hugo will extend approximately 120 miles, a distance far greater than OG&E's routine projects.[102] The need to obtain such a substantial right-of-way presents a number of significant risks and challenges. These unique siting and routing issues show that the Project is not routine.

As Mr. Crissup explains in his testimony, Sunnyside-Hugo will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Carter, Marshall, Johnston, Bryan, and Choctaw counties.[103] Rights-of-way must be obtained for each individual landowner along the Project's proposed 120-mile route. This process can be lengthy and contentious. When landowners do not contract for the necessary rights-of-way voluntarily, the resulting proceedings can be time-consuming and can lead to substantial delays, increased project costs, or re-routing of a project.[104] In an extreme case, difficulties in obtaining or the failure to obtain a right-of-way could result in the abandonment of the project.[105]

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[99] *See* Crissup Testimony, Exhibit No. OGE-1 at 24; September 2008 Study, Exhibit No. OGE-14, Appendix A, Table 3, AECC Reservation No. 1161209, AEPM Reservation Nos. 1158760, 1158761, 1162214, and 1163062, and OMPA Reservation No. 1159596.

[100] Crissup Testimony, Exhibit No. OGE-1 at 24.

[101] *See*, *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 65 (2008); *VEPCo*, 124 FERC ¶ 61,207 at P 66.

[102] A map included as Exhibit No. OGE-4 details the length of the Sunnyside-Hugo project.

[103] Crissup Testimony, Exhibit No. OGE-1 at 25.

[104] *Id.* at 25-26.

[105] *Id.* at 25.

This risk has already materialized. To date, with respect to the Sunnyside-Hugo Project, approximately 100 condemnation cases have been filed covering approximately 150 separate parcels. While some of these cases may settle prior to going to trial, it is likely that the vast majority will not.[106] The volume of condemnation cases related to Sunnyside-Hugo is far from routine for OG&E.[107]

Moreover, the proposed route poses additional siting challenges because it requires OG&E to obtain rights-of-way across Chickasaw and Choctaw tribal lands.[108] Building transmission lines across tribal lands poses unusual risks because state eminent domain laws and procedures applicable to privately-owned property often do not apply to property held by or for the benefit of Native American tribes.[109] As a result, negotiations for rights-of-way on tribal lands are more complex and may result in significant delays, increased costs and potential re-routing issues. As Mr. Crissup explains, property owned by Native American Nations can be held by the tribal entities directly, by individuals, or by the U.S. Bureau of Indian Affairs in trust for a group or for specific individuals.[110] The myriad ways property can be owned by a Native American Nation or individual impacts the length of time it takes to acquire such property and the specific procedures that need to be followed.[111] This process can result in delays and potential cost increases and/or route changes.

Third, the Sunnyside-Hugo Project faces significant environmental risks and challenges, which could impact the siting of the Project and which could also delay its construction or lead to the Project's abandonment. These factors separate Sunnyside-Hugo from routine transmission projects. Like the OG&E projects approved by the Commission in the December 30 Order, Sunnyside-Hugo will cross the habitat of a protected species. In this instance, the Project's route is expected to cross through the habitat of the endangered American Burying Beetle.[112] A survey of the activities of the American Burying Beetle was performed along the Sunnyside-Hugo route in 2010, but was found deficient by the U.S. Fish and Wildlife Service ("USFWS"), and will have to be re-surveyed in 2011.[113] The survey cannot be performed again until the weather conditions are favorable to activity by the Beetle. The need to evaluate the potential impact of the Project on the Beetle may cause delays due to the need for analysis and surveys, the timing of which are dependent on weather conditions. Delays could result in re-routing or

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106 *Id.* at 26.

107 *Id.* at 27.

108 A map included as Exhibit No. OGE-3 shows the tribal lands that Sunnyside-Hugo's proposed route will cross.

109 Crissup Testimony, Exhibit No. OGE-1 at 27.

110 *Id.*

111 *Id.*

112 *Id.* at 27-29.

113 A map showing the historic range and current distribution of the American Burying Beetle is included as Exhibit No. OGE-5.

other potential mitigation requirements.[114] The siting of transmission facilities within endangered species habitats presents risks and challenges that support a determination that the Project qualifies for transmission incentives.[115] These issues are not routine. As Mr. Crissup notes, this Project is the first instance in which he has encountered the American Burying Beetle in 23 years of work on OG&E transmission projects.[116]

Finally, environmental assessments required by the National Environmental Policy Act ("NEPA") are being performed at this time in conjunction with the portion of the proposed route that crosses BIA lands. The results of these investigations are unknown at this time. Depending on the outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.[117]

b. The Sooner-Rose Hill Project.

(1) **The Project's substantial scope and regional effect show that it is not routine.**

The Sooner-Rose Hill Project is significant in terms of cost, in terms of miles of new transmission facilities added to the current OG&E system, and in terms of its effect on the SPP region. It is not a routine transmission project for OG&E.

Sooner-Rose Hill is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation, near Perry, Oklahoma, to the Rose Hill substation near Wichita, Kansas. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length. OG&E's investment required for completion of this new transmission line, estimated to cost $57.8 million, represents over ten percent of OG&E's current net transmission plant of $558 million. The Project has an estimated in-service date of June 1, 2012.

The Project is designed to provide regional benefits. As part of SPP's transmission service study procedures, SPP has determined that Sooner-Rose Hill is necessary to alleviate constraints on the regional transmission system and to facilitate requests for transmission service.[118] In the March 2009 Study, SPP evaluated 1,359 MW of long-term transmission service requests.[119] The purpose of the study was "to identify system problems and potential modifications necessary to facilitate" the requested service.[120] SPP analyzed the system impact

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114 Crissup Testimony, Exhibit No. OGE-1 at 28.

115 December 30 Order at PP 42-43; *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 72.

116 Crissup Testimony, Exhibit No. OGE-1 at 28-29.

117 *Id.* at 29.

118 *Id.* at 29-30; SPP March 2009 Study, Exhibit No. OGE-15 at 18.

119 SPP March 2009 Study, Exhibit No. OGE-15 at 3.

120 *Id.* at 10, 15.

of each requested service by using a "steady-state analysis" and the study identifies Sooner-Rose Hill as one of the facility upgrades that must be built in order to provide requested transmission service "while maintaining or improving system reliability[.]"[121] This includes meeting NERC Reliability Standards and SPP's own reliability criteria.[122]

Ultimately, the March 2009 Study concludes that service requests made by Kansas Power Pool ("KPP"),[123] Aquila Inc. dba Aquila Networks ("UCU"),[124] and WRGS[125] each independently require the addition of the Sooner-Rose Hill Project. Combined, these requests total 485 MW, which constitutes over one-third of the total 1,359 MW of requests reviewed in the March 2009 Study.[126] In addition, SPP in the 2009 STEP determined that the Sooner-Rose Hill Project was a "regional reliability upgrade" that could relieve the flowgate that monitors the 138 kV line from El Paso to Farber for the loss of the 345-kV line from Wichita to Woodring.[127]

(2) **The Project faces significant risks and challenges, which demonstrate that it is not routine.**

Sooner-Rose Hill presents several risks and challenges that separate the Project from routine transmission investments.

First, Sooner-Rose Hill faces risks and challenges associated with the need to coordinate the Project's construction with a different utility that will site, construct and place into service related facilities to be located in Kansas. As Mr. Crissup explains in his testimony, the OG&E portion of the Sooner-Rose Hill Project is only one part of a larger regional project to be built in Oklahoma and Kansas.[128] The transmission line and related facilities to be built by OG&E will be located wholly within Oklahoma and will interconnect with the remaining portion of the transmission line and related facilities to be constructed by WRGS in Kansas. OG&E has no role in the siting, permitting, or construction of the facilities to be located outside of Oklahoma, which face many of the same risks and challenges as the Oklahoma portion of the line. Any delay in the construction of the facilities to which OG&E will interconnect will delay OG&E's ability to complete its portion of the Project and place it into service, and WRGS' failure to build

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121 *Id.* at 3 and Appendix A, Table 4.

122 *Id.* at 10.

123 *Id.* at Appendix A, Table 3, KKP Reservation Nos. 1222644 and 1222932.

124 *Id.* at Appendix A, Table 3, UCU Reservation No. 1223093.

125 *Id.* at Appendix A, Table 3, WRGS Reservation No. 1197077.

126 *Id.* at Appendix A, Table 3, KKP Reservation Nos. 1222644 and 1222932, UCU Reservation No. 1223093, WRGS Reservation No. 1197077.

127 2009 STEP, Exhibit No. OGE-10 at 26. The 2009 STEP found that over a twelve month period, the percentage of total intervals breached or binding was 2.0% and that the average shadow price was $2.29. 2009 STEP, Exhibit No. OGE-10 at 70. The "shadow price" is the amount of value of relieving the constraint measured in dollars. 2009 STEP, Exhibit No. OGE-10 at 15.

128 Crissup Testimony, Exhibit No. OGE-1 at 29-30.

its portion of the Project could lead to the abandonment of the OG&E portion of the Project.[129] Such risks show that a project is not routine.[130]

Second, the Project faces unique challenges associated with acquiring the necessary right-of-way. Sooner-Rose Hill's proposed route is expected to cross Otoe-Missouria, Pawnee, Osage, and Chilocco tribal lands.[131] As detailed above, the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain authority in cases where the property is held in trust by the BIA. As of January 1, 2011, there are twenty tracts along the Sooner-Rose Hill route that have involvement of the BIA, which complicates the process of obtaining the necessary rights-of-way. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.[132]

Third, the proposed route for the Sooner-Rose Hill Project faces environmental risks and challenges. Environmental assessments required by NEPA are being performed at this time in conjunction with the portion of the proposed route that crosses BIA lands. The results of these investigations are unknown at this time. Depending on the outcome of the environmental assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.[133]

c. The Sooner-Cleveland Project.

(1) **The Project's substantial scope and regional effect show that it is not routine.**

The Sooner-Cleveland Project is significant in terms of cost, in terms of miles of new transmission line added, and in terms of its impact on the SPP region. It is not a routine project for OG&E.

Sooner-Cleveland is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. OG&E will construct the entire Sooner-Cleveland line. The investment required for the completion of this new transmission line, approximately $64 million, represents approximately 11.5 percent of OG&E's current net transmission plant of $558 million. The Project has an expected in-service date of March 31, 2013.

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129 *Id.* at 31-32.

130 *See Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 65; *VEPCo*, 124 FERC ¶ 61,207 at P 66..

131 *See* Tribal Jurisdictions, Exhibit No. OGE-3.

132 Crissup Testimony, Exhibit No. OGE-1 at 32.

133 *Id.* at 33.

The Project has region-wide effects. Sooner-Cleveland is part of SPP's Balanced Portfolio, a group of projects which is specifically intended to reduce congestion on the system and which benefits "the SPP region and beyond through congestion relief, utilization of the area's large renewable resources, and expansion of markets."[134] SPP has also found that these projects may provide benefits such as "increasing reliability and lowering required reserve margins, [and] deferring reliability upgrades," as well as "providing environmental benefits due to more efficient operation of assets."[135] Indeed, SPP has stated that the "balanced portfolio projects will enhance access to all types of generation, including the vast wind potential in the SPP region. These transmission upgrades will be the beginning of a wind-collector grid that will enable the collection, use, and possible export of renewable energy beyond SPP."[136] In the 2009 STEP, SPP included the Sooner-Cleveland Project as one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[137] Similarly, the 2009 STEP included the Sooner-Cleveland Project as addressing "many of the top SPP flowgates" and enabling "lower transfers of revenue requirements necessary to achieve balance."[138]

(2) The Project faces significant risks and challenges, which demonstrate that it is not routine.

The Sooner-Cleveland Project faces a number of risks and challenges, which show that the project is not routine.

First, Sooner-Cleveland faces significant risks and challenges associated with the need to coordinate the Project's construction with two different utilities, each in different states. As explained by Mr. Crissup, the Sooner-Cleveland Project must be coordinated with the permitting and construction of the improvements at the Sooner substation, which, in turn, is contingent on the completion of the Sooner-Rose Hill Project, which includes a portion to be built by WRGS in Kansas. In addition, Sooner-Cleveland is also dependent on the Grand River Dam Authority's ("GRDA") upgrade at the Cleveland substation. OG&E has no role in the siting, permitting, or construction of the facilities to be built by WRGS and GRDA. Any delay in the construction schedule of either project could result in a delay for the Sooner-Cleveland Project.[139] The Commission has recognized that the need to coordinate with other utilities when planning transmission projects poses special challenges.[140]

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134 SPP Integrated Transmission Planning, Process Document (last revised 10/29/09) at 6, *available at* http://www.spp.org/publications/ITP_Process_Final_20091029.pdf.

135 Balanced Portfolio Report (last revised June 23, 2009) at 3, Exhibit No. OGE-16.

136 SPP News Release, "Portfolio of New EHV Transmission Projects Approved: Benefits Will Be Balanced Across SPP Region" at 2 (April 29, 2009), *available at* http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf.

137 2009 STEP, Exhibit No. OGE-10 at 27.

138 *Id.*

139 Crissup Testimony, Exhibit No. OGE-1 at 34.

140 *See, e.g.*, *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 65.

Second, the Sooner-Cleveland Project faces risks and challenges associated with obtaining rights-of-way on tribal lands. Sooner-Cleveland's proposed route is expected to cross Otoe-Missouria, Pawnee, and Osage tribal lands, and rights-of-way will need to be obtained on those lands as well.[141] As detailed above, the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain in cases where the property is held in trust by the BIA. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.[142]

Third, the Sooner-Cleveland Project faces significant environmental risks and challenges, which could impact the siting of the Project and which could also delay its construction or lead to the Project's abandonment. These factors separate the Project from routine transmission projects. Sooner-Cleveland's proposed route will cross Sooner Lake and the Arkansas River, which will require OG&E to obtain various approvals from the U.S. Army Corps of Engineers.[143] This requirement may result in Project delays due to required environmental assessments pursuant to NEPA and may require environmental mitigation or potential route changes, which would lead to further delays and potential cost increases.[144]

In addition, the endangered American Burying Beetle inhabits several areas along Sooner-Cleveland's proposed route, and significant portions of the route will need to be surveyed.[145] The need to evaluate the potential impact of the Project on the American Burying Beetle may cause delays due to the need for analysis and surveys, the timing of which are dependent on weather conditions. Failure to complete the necessary permitting for the endangered species could cause delays or cancellation of the Project, and the required environmental impact analysis could require changes to the proposed route or other revisions to the Project. Moreover, some measures potentially will be required to mitigate the impact of the Project on the American Burying Beetle and its critical habitat.[146] The siting of transmission facilities within endangered species habitats presents risks and challenges that support a determination that the Project qualifies for transmission incentives.[147]

Further, Sooner-Cleveland's proposed route also includes areas of concern to the USFWS due to the presence of the American Bald Eagle and migratory waterfowl.[148] While the

[141] *See* Tribal Jurisdictions, Exhibit No. OGE-3.

[142] Crissup Testimony, Exhibit No. OGE-1 at 35.

[143] A map included as Exhibit No. OGE-6 shows the proposed route for Sooner-Cleveland as it relates to Sooner Lake and the Arkansas River.

[144] Crissup Testimony, Exhibit No. OGE-1 at 36-37.

[145] *Id.* at 37; *see also*, American Burying Beetle Historic Range and Current Distribution in Oklahoma, Exhibit No. OGE-5.

[146] Crissup Testimony, Exhibit No. OGE-1 at 37.

[147] December 30 Order at PP 42-43.

[148] Crissup Testimony, Exhibit No. OGE-1 at 36.

American Bald Eagle is no longer listed as an Endangered Species, it is still protected under the Bald and Golden Eagle Protection Act[149] and the Migratory Bird Treaty Act.[150] Both acts prohibit "taking" listed migratory birds, their eggs, feathers, and nests. Accordingly, the Sooner-Cleveland Project faces risks associated with avoiding harm to these protected species and their critical habitat.[151] For example, significant portions of the route will need to be surveyed, and some measures potentially will be required to mitigate the impact of the Project on one or more of these species. Delays could result in re-routing or other potential mitigation requirements.[152] 345-kV EHV transmission lines are taller than OG&E's typical 138-kV or 69-kV transmission projects and 345kV transmission requires a significantly wider rights-of-way footprint. Assessments due to the larger scale of the Sooner-Cleveland 345-kV Project are underway with USFWS and the Oklahoma Department of Wildlife. Final results including adjustments to routing or potential changes to the Project have yet to be determined.

Finally, environmental assessments required by NEPA are being performed for the portion of the proposed route that crosses BIA lands. Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project. [153]

Fourth, the Project faces risks and challenges associated with its significant lead times. Siting and construction of Sooner-Cleveland will not be completed until at least March of 2013. This lead time creates uncertainties, and costs may increase over time. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond OG&E's control. Further, large projects, such as Sooner-Cleveland, generate complex logistical and management issues that also increase the risk of delay or cost overruns.[154] The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project such as Sooner-Cleveland requires a substantial amount of material, and requires OG&E to hire outside contractors, which is not required for routine projects.[155]

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[149] 16 U.S.C. §§ 668-668d (2006).

[150] 16 U.S.C. §§ 703-712 (2006).

[151] Crissup Testimony, Exhibit No. OGE-1 at 36-38.

[152] *Id.* at 36

[153] *Id.* at 36-37.

[154] *Id.* at 38.

[155] *Id.*

d. The Seminole-Muskogee Project.

(1) **The project's substantial scope and regional effect show that it is not routine.**

The Seminole-Muskogee Project is significant in terms of cost, in terms of miles of new transmission line added, and in terms of its effect on the SPP region. It is not a routine transmission project for OG&E.

Seminole-Muskogee is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation and will include associated upgrades to both substations. The investment required for the completion of this new transmission line, approximately $179.1 million, represents over 32 percent of OG&E's current net transmission plant of $558 million.[156] Due to its scope, the Project has an estimated in-service date of December 31, 2013.[157]

The Project will have a regional impact. Seminole-Muskogee is part of SPP's Balanced Portfolio, a group of projects which is specifically intended to reduce congestion on the system and which benefits "the SPP region and beyond through congestion relief, utilization of the area's large renewable resources, and expansion of markets."[158] SPP has also found that these projects may provide benefits such as "increasing reliability and lowering required reserve margins, [and] deferring reliability upgrades," as well as "providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[159] Indeed, SPP has stated that the "balanced portfolio projects will enhance access to all types of generation, including the vast wind potential in the SPP region. These transmission upgrades will be the beginning of a wind-collector grid that will enable the collection, use, and possible export of renewable energy beyond SPP."[160] Similar to the Sooner-Cleveland Project, SPP determined in the 2009 STEP that Seminole-Muskogee was one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[161] Specifically, SPP has determined that Seminole-Muskogee could relieve congestion on the flowgate that monitors the 138 kV line

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[156] *See* December 30 Order at P 43 (finding significant in scope two other OG&E projects with respective costs of $178 million and $135 million and with respective lengths of 82 miles and 80 miles); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 at P 32 (finding that a similarly sized proposed transmission line of 130 miles is substantial in scope).

[157] A map showing the range and scope of the project is included as Exhibit No. OGE-7.

[158] Crissup Testimony, Exhibit No. OGE-1 at 38-39. SPP Integrated Transmission Planning, Process Document (last revised 10/29/09) at 6, *available at* http://www.spp.org/publications/ITP_Process_Final_20091029.pdf.

[159] Balanced Portfolio Report at 3, Exhibit No. OGE-16.

[160] SPP News Release, "Portfolio of New EHV Transmission Projects Approved: Benefits Will Be Balanced Across SPP Region" at 2 (April 29, 2009), *available at* http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf.

[161] Crissup Testimony, Exhibit No. OGE-1 at 39. 2009 STEP, Exhibit No. OGE-10 at 27.

from Okmulgee to Henryetta for the loss of Okmulgee to Kelco.[162] In the 2009 STEP, SPP found that over a twelve-month period, the percentage of total intervals breached or binding on the Okmulgee to Henryetta line was 1.9% with an average shadow price of $5.01.[163] SPP further determined that Seminole-Muskogee could relieve congestion on the flowgate monitoring the 138-kV line from Riverside Station to Okmulgee City for the loss of the 138-kV line from Riverside Station to Explorer Okmulgee.[164]

The Seminole-Muskogee transmission line also was part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system.[165] In 2007, SPP set the stage for regional extra high voltage transmission construction through the strategic SPP "EHV Overlay Project" report. In the report, SPP stated:

> This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs.[166]

(2) **The Project faces significant risks and challenges, which demonstrate that it is not routine.**

Seminole-Muskogee presents several risks and challenges that separate the Project from routine transmission investments.

First, the Seminole-Muskogee Project faces extraordinary challenges with regard to obtaining the required rights-of-way. While a right-of-way is required for even the most routine transmission project, Seminole-Muskogee will extend approximately 120 miles, a distance far greater than OG&E's routine projects.[167] The need to obtain such a substantial right-of-way presents a number of significant risks and challenges.[168] These unique siting and routing issues show that the project is not routine.

As Mr. Crissup explains in his testimony, Seminole-Muskogee will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Seminole, Hughes,

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162 2009 STEP, Exhibit No. OGE-10 at 22.

163 *Id.*

164 *Id.* at 25. This line, SPP determined, had a percentage of total intervals breached or binding of 0.9% over a twelve-month period and a shadow price of $2.30. 2009 STEP, Exhibit No. OGE-10 at 25.

165 Crissup Testimony, Exhibit No. OGE-1 at 40.

166 Southwest Power Pool, *Final Report on the Southwest Power Pool (SPP) EHV Overlay Project* (June 27, 2007), *available at* http://www.spp.org/publications/spp_ehv_study_final_report.pdf ("EHV Report").

167 Crissup Testimony, Exhibit No. OGE-1 at 40.

168 *Id.* at 41.

Okfuskee, McIntosh, Okmulgee, and Muskogee counties.[169] Rights-of-way must be obtained for each individual landowner along the Project's proposed 120-mile route. This process can be lengthy and contentious and, in cases where landowners do not contract for the necessary rights-of-way voluntarily, can lead to substantial delays, increased project costs, or re-routing of a project. In an extreme case, difficulties in obtaining or the failure to obtain a right-of-way could result in the abandonment of the Project. [170]

In addition, the Project faces risks and challenges associated with obtaining rights-of-way on tribal lands. Seminole-Muskogee requires OG&E to obtain rights-of-way for a 120-mile route that is expected to cross Seminole, Muscogee (Creek), and United Keetoowah Band of Cherokees tribal lands.[171] As detailed above, the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain in cases where the property is held in trust by the BIA. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.[172]

Second, the proposed route for the Seminole-Muskogee Project presents a number of environmental risks and challenges. The proposed route for Seminole-Muskogee will cross the Arkansas River. OG&E has identified five different possible routes for the line over the Arkansas River, and all of those possible routes have generated considerable local interest.[173] The route ultimately selected will require OG&E to obtain a permit from the Corps of Engineers, and will also require OG&E to negotiate an agreement with the Arkansas Riverbed Authority, a consortium of the Cherokee, Chickasaw, and Choctaw tribes that controls access to the Arkansas Riverbed. Delays or a denial of these required approvals could cause significant siting and construction delays, which could also cause increased costs.

In addition, environmental assessments required by NEPA may be required for tracts that cross BIA lands.[174] Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.[175]

Further, review and approval from the USFWS may also affect the selection of a final route and the timing of the Project's construction.[176] The endangered American Burying Beetle

[169] *Id.* at 40.

[170] *Id.* at 25.

[171] *Id.* at 40; *see also,* Tribal Jurisdictions, Exhibit No. OGE-3.

[172] Crissup Testimony, Exhibit No. OGE-1 at 41-42.

[173] A map included as Exhibit No. OGE-7 shows alternative routes for Seminole-Muskogee project as well as their relationship with the Arkansas River, the Deep Fork Wildlife Refuge, and Lake Eufaula.

[174] Crissup Testimony, Exhibit No. OGE-1 at 44.

[175] *Id.*

[176] *Id.* at 42.

inhabits several areas along Seminole-Muskogee's proposed route.[177] Significant portions of the route will need to be surveyed, and some measures potentially will be required to mitigate the impact of the Project on the American Burying Beetle.[178] The need to survey significant portions of the route and the possibility that some mitigation may be required raise the possibility of further siting and construction delays.

In addition, the USFWS has expressed concerns over routing the Seminole-Muskogee line near or through the Deep Fork Wildlife Refuge.[179] The Refuge protects wetlands along the Deep Fork River in eastern Oklahoma.[180] USFWS has determined that the Refuge provides sanctuary for several endangered species in addition to the American Burying Beetle, including the Interior Least Tern, the Whooping Crane, and the Piping Plover.[181] USFWS' concern over the routing of the line may affect the Project's ultimate route.[182] As the Commission has recognized, the existence of endangered species also creates potential risks for permitting and developing the Project.[183] Moreover, the U.S. Army Corps of Engineers also has expressed a preference for the line to cross over Lake Eufaula rather than traverse the Refuge.[184] While the alternative route could mitigate risks associated with crossing the Refuge, it would require OG&E to obtain a lake crossing permit from the Corps and would add uncertainty and risk to the Project's development.

Third, the Seminole-Muskogee Project faces risks and challenges associated with the Project's substantial lead time.[185] Seminole-Muskogee is much larger than routine transmission investments, calling for the construction of 120 miles of new 345-kV transmission lines.[186] Siting and construction of Seminole-Muskogee will not be completed until December of 2013.[187] This lead time creates uncertainties, and costs may increase over time. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and

[177] *Id.* at 42; *see also*, American Burying Beetle Historic Range and Current Distribution in Oklahoma, Exhibit No. OGE-5.

[178] Crissup Testimony, Exhibit No. OGE-1 at 44.

[179] *Id.*at 42-43.

[180] *See* "Deep Fork National Wildlife Refuge," http://www.fws.gov/southwest/refuges/oklahoma/Deep%20Fork/index.html (last visited on February 14, 2011).

[181] *See* Refuge Staff, Deep Fork National Wildlife Refuge, *Environmental Assessment: The Building of New Administrative Office and Visitor Contact Facilities On Deep Fork National Wildlife Refuge at 8* (January 14, 2010), *available at* http://www.fws.gov/southwest/refuges/oklahoma/Deep%20Fork/DFAdminOfficeFacilityEA.pdf.

[182] Crissup Testimony, Exhibit No. OGE-1 at 44.

[183] The siting of transmission facilities within endangered species habitats presents risks and challenges that support a determination that the project qualifies for transmission incentives. December 30 Order at P 42-43; *Pepco*, 124 FERC ¶ 61,176 at P 72.

[184] Included as Exhibit No. OGE-8 is a map that shows the relationship among the proposed route, the Deep Fork Wildlife Refuge, and Lake Eufaula.

[185] Crissup Testimony, Exhibit No. OGE-1 at 45.

[186] *Id.*

[187] *Id.*

the required regulatory approvals, could change for reasons beyond the control of OG&E.[188] The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project requires a large amount of material and involves reliance on outside contractors, which are not required for routine projects. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns.[189]

e. The Tuco-Woodward Project

(1) **The Project's substantial scope and regional effect show that it is not routine.**

The Tuco-Woodward Project is significant in terms of cost and in terms of miles of new transmission line to be added to the OG&E system. It is not a routine project for OG&E.

Tuco-Woodward is a multi-state 345-kV, 250-mile transmission line to be built from OG&E's Woodward District EHV substation to the SPS Tuco substation. Thus, the line will stretch across state lines from Woodward, Oklahoma to Hale County, Texas. The OG&E portion of the Tuco-Woodward Project is 72 miles extending from OG&E's Woodward substation to a reactor station to be constructed at approximately the Oklahoma-Texas state border. OG&E's portion of the Project has an estimated cost of $120 million and an estimated in-service date of May 19, 2014. OG&E's investment required for the completion of this new transmission line represents over 22 percent of OG&E's current net transmission plant of $558 million.[190]

The Project will have region-wide effects. Tuco-Woodward is part of SPP's Balanced Portfolio, a group of projects which is specifically intended to reduce congestion on the system and which benefits "the SPP region and beyond through congestion relief, utilization of the area's large renewable resources, and expansion of markets."[191] SPP has also found that these projects may provide benefits such as "increasing reliability and lowering required reserve margins, [and] deferring reliability upgrades," as well as "providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[192] Indeed, SPP has stated that the "balanced portfolio projects will enhance access to all types of generation, including the vast wind potential in the SPP region. These transmission upgrades will be the beginning of a wind-collector grid that will enable the collection, use, and possible

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188 *Id.*

189 *Id.*

190 *See* December 30 Order at P 43 (finding significant in scope two other OG&E projects with respective costs of $178 million and $135 million and with respective lengths of 82 miles and 80 miles); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 at P 32 (finding that a similarly sized proposed transmission line of 130 miles is substantial in scope).

191 Crissup Testimony, Exhibit No. OGE-1 at 16-18; SPP Integrated Transmission Planning, Process Document (last revised 10/29/09) at 6, *available at* http://www.spp.org/publications/ITP_Process_Final_20091029.pdf.

192 Balanced Portfolio Report at 3, Exhibit No. OGE-16.

export of renewable energy beyond SPP."[193] In the 2009 STEP, SPP determined that Tuco-Woodward was one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[194] Specifically, SPP has determined that Tuco-Woodward could relieve congestion on the flowgate that monitors the 115 kV transmission line from Randall County substation to Palo Duro for loss of the 230 kV line from Amarillo to Swisher.[195] In the 2009 STEP, SPP found that over a twelve-month period, the percentage of total intervals breached or binding was 20.4% with a shadow price of \$29.79.[196] A flowgate shadow price indicates the reduction to the cost of the market dispatch which would result from a small increase in the enforced loading limit, generally expressed in dollars per MW per hour of loading. The flowgate shadow prices are often applied as broad measures of the marginal costs of congestion within a market. Among the top 10 most congested flowgates monitored by SPP that are within SPP, \$29.79 was the highest average shadow price.[197]

The Tuco-Woodward transmission line is also part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system. In 2007, SPP set the stage for regional extra high voltage transmission construction through the strategic SPP "EHV Overlay Project" report. In the report, SPP stated:

> This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs.[198]

(2) **The Project faces significant risks and challenges, which demonstrate that it is not routine.**

Tuco-Woodward presents multiple risks and challenges that distinguish the Project from routine transmission investments.

First, the Project faces risks and challenges associated with the need to coordinate the Project's construction with another utility. Unlike more routine projects, the OG&E portion of

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[193] SPP News Release, "Portfolio of New EHV Transmission Projects Approved: Benefits Will Be Balanced Across SPP Region" (April 29, 2009), *available at* http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf.

[194] Crissup Testimony, Exhibit No. OGE-1 at 46; 2009 STEP, Exhibit No. OGE-10 at 71.

[195] 2009 STEP, Exhibit No. OGE-10 at 27.

[196] *Id.* at 17.

[197] *Id.*

[198] EHV Report at 4, *available at* http://www.spp.org/publications/spp_ehv_study_final_report.pdf; Crissup Testimony, Exhibit No. OGE-1 at 46-47.

the Tuco-Woodward Project is a component of a larger regional transmission project and provides for OG&E to construct facilities that will connect with the SPS transmission system located in Texas. The SPS portion of the Project will face risks and challenges associated with siting, permitting, and constructing the facilities in Texas that will equal or exceed those faced by OG&E. Any delay in SPS's ability to construct and place into service its portion of the lengthy transmission line – which constitutes approximately 175 miles of the 250-mile line – will delay OG&E's ability to place its portion of the Tuco-Woodward Project into service.[199] The Commission has recognized that the need to coordinate with other utilities when planning transmission projects poses special challenges.[200]

Second, the Tuco-Woodward Project faces substantial challenges in obtaining the required rights-of-way.[201] While a right-of-way is required for even the most routine transmission project, the proposed route for OG&E's portion of the line is approximately 72 miles long, a distance far greater than OG&E's routine projects. The need to obtain such a substantial right-of-way presents a number of significant risks and challenges. These unique siting and routing issues show that the Project is not routine.

As Mr. Crissup explains in his testimony, Tuco-Woodward will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Woodward, Dewey, Custer, Washita, Roger Mills, and Beckham counties.[202] Rights-of-way must be obtained for each individual landowner along the proposed 72-mile route.[203] This process can be lengthy and contentious. When landowners do not contract for the necessary rights-of-way voluntarily, the resulting proceedings can be time-consuming and can lead to substantial delays, increased project costs, or re-routing of a project. In an extreme case, difficulties in obtaining or the failure to obtain a right-of-way could result in the abandonment of the Project. [204]

In addition, the Project faces risks and challenges associated with obtaining rights-of-way on tribal lands.[205] Tuco-Woodward's proposed route is expected to cross Cheyenne-Arapahoe tribal lands.[206] As detailed above, the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain in cases where the property is held in trust by the BIA. Problems with

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[199] Crissup Testimony, Exhibit No. OGE-1 at 47.

[200] *See, e.g.*, *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 65.

[201] Crissup Testimony, Exhibit No. OGE-1 at 47-49.

[202] *Id.* at 47-48.

[203] *Id.* at 48.

[204] *Id.* at 25.

[205] *Id.* at 47-49.

[206] *See* Tribal Jurisdictions, Exhibit No. OGE-3.

obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.[207]

Third, the Project's proposed route presents a number of environmental risks and challenges. The federally protected Black Kettle National Grasslands lie along Tuco-Woodward's proposed route in Oklahoma. The Black Kettle National Grasslands encompass 31,300 acres, with 30,724 of those acres being located near Cheyenne, Oklahoma, and the remaining 576 acres in Texas.[208] Routing a large EHV transmission project through this area will pose significant challenges for OG&E, including potential federal permitting issues, and poses a risk of delays and significant cost increases if the proposed route is changed, or if additional environmental mitigation requirements are imposed. For example, mitigation could include adjusting the Woodward-Tuco route to avoid the Black Kettle National Grasslands altogether, potentially adding additional line miles and additional costs to the overall Project.[209]

Tuco-Woodward's proposed route also passes through the natural habitat of the Lesser Prairie Chicken.[210] The Lesser Prairie Chicken is a Candidate Species under the USFWS Endangered Species Act and, for the State of Oklahoma, is currently under the jurisdiction of the Oklahoma Department of Wildlife Conservation ("ODWC").[211] While there are no defined regulatory approvals that are required when interacting with Lesser Prairie Chicken Habitat in Oklahoma, ODWC and USFWS are providing active guidance to agricultural, wind farm development and transmission construction interests in order to limit the possibility of the Lesser Prairie Chicken moving from a Candidate Species to an Endangered Species.[212]

Finally, environmental assessments required by NEPA may be required for tracts that cross BIA lands.[213] Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.[214]

Fourth, the Tuco-Woodward Project faces risks and challenges associated with its substantial lead time. OG&E's portion of Tuco-Woodward is much larger than routine

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[207] Crissup Testimony, Exhibit No. OGE-1 at 48-49.

[208] *Id.* at 49 (*citing* http://www.fs.fed.us/r3/cibola/districts/black.shtml). Exhibit No. OGE-8 shows the location of the proposed route in relation to the Black Kettle National Grasslands.

[209] Crissup Testimony, Exhibit No. OGE-1 at 49.

[210] *Id.* at 49-50. Exhibit No. OGE-9 is a map showing the location of the proposed route in relation to concentrations of the Lesser Prairie Chicken.

[211] Selected pages of the USFWS Species Assessment and Listing Priority Assignment Form for the Lesser Prairie Chicken are included as Exhibit No. OGE-17. The entire assessment can be found at http://www.fws.gov/ecos/ajax/docs/candforms_pdf/r2/B0AZ_V01.pdf.

[212] Crissup Testimony, Exhibit No. OGE-1 at 50.

[213] *Id.*

[214] *Id.*

transmission investments, providing for the construction of 72 miles of a 250-mile, multi-state 345-kV transmission line to be constructed by OG&E in Oklahoma and SPS in Texas. Siting and construction of Tuco-Woodward will not be completed until May of 2014. This lead time creates uncertainties, and costs may increase over time.[215] The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could changes for reasons beyond the control of OG&E. The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project requires a large amount of material, and requires OG&E to utilize outside contractors, which are not required for routine projects. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns.[216]

3. The Projects Face Substantial Financial Risks and Challenges.

The size of the investment required for Projects – approximately $608 million – will present a number of financial risks and challenges for OG&E. Each of the Projects is significant and presents individually capital costs in excess of OG&E's average annual expenditures for all capital additions over the past five years, which has averaged approximately $53 million.[217] The least expensive of the five Projects, Sooner-Rose Hill, has an estimated cost of $58 million, more than ten percent of OG&E's current net transmission plant in service. The most expensive, Sunnyside-Hugo, is expected to cost $187 million, approximately 35 percent of OG&E's current net transmission plant in service. The financial risks and challenges associated with this unprecedented level of new capital investment are highlighted herein and addressed in Mr. Rowlett's testimony at Exhibit No. OGE-18, as well as the exhibits appended to Mr. Rowlett's testimony (*i.e.*, Exhibit Nos. OGE-19 – 23).

First, funding projects of this size and scope will require significant outlays of cash, decreasing OG&E's cash flow during the construction phase of the project. As Mr. Rowlett explains in his testimony, OG&E's annual budgeting process aggregates the cost of the five individual Projects for financing purposes and anticipates that the annual capital expenditures associated with these Projects will average over $120 million and will be approximately $209 million in 2011 and $200 million in 2012. Over the next four years, OG&E will face a negative cash flow position as a result of meeting this extensive level of capital expenditures. This is due to the fact that cash flows generated from operations will not be sufficient to cover these transmission Projects. The decreased cash flow will put stress on OG&E's credit metrics, increase the risk that the company may not be able to satisfy its financial obligations, and can harm its credit ratings. For example, Standard and Poor's ("S&P") has noted that cash flow support is crucial in maintaining credit quality during upswings in the capital expenditures.[218]

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215 *Id.* at 51.

216 *Id.* at 51.

217 Rowlett Testimony, Exhibit No. OGE-18 at 5.

218 Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-23 at 6.

Second, these expenditures will increase OG&E's debt and will burden OG&E's financial metrics, raising the risk of a credit downgrade.[219] As Mr. Rowlett explains, credit rating agencies rely largely on two financial ratios to determine if the company has a sufficient level of cash flow to satisfy its obligations: Funds From Operations to Interest Expense ("FFO/Interest") and the ratio of Funds From Operations to Total Debt ("FFO/Total Debt"). Funds From Operations is largely composed of net income and depreciation expense. The more debt and other fixed contractual obligations a company has, the higher the adjusted interest expense and total adjusted debt and the lower the cash flow coverage ratios. This problem is most acute during the construction cycle of large projects, at which time the denominator of both formulas increases while the numerator decreases.

OG&E has very recent experience in this regard.[220] On June 29, 2010, Fitch Ratings downgraded the Issuers Default Rating ("IDR") of OG&E from A+ to A. Fitch stated:

> The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The cap ex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period.[221]

Strong credit ratings are important to OG&E's ability to borrow money at a lower cost.[222] Lower credit ratings will increase OG&E's cost of debt, costs that will be passed on to customers. Credit ratings also affect a company's access to capital markets and define its overall risk profile.[223]

Third, internal competition for capital with other OG&E expenditures raises additional financing challenges.[224] OG&E has a number of additional capital expenditures that will compete with these five Projects for financing. OG&E is facing aging utility infrastructure that will require investments higher than historical levels several years into the future. Additionally, OG&E is investing in new Smart Grid technology over the next three years as well as additional obligations in renewable energy and environmental initiatives. OG&E's total projected base

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219 *See* Rowlett Testimony, Exhibit No. OGE-18 at 7.

220 *See id*. at 7-8.

221 Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" at 1 (June 28, 2010), Exhibit No. OGE-22.

222 *See* Rowlett Testimony, Exhibit No. OGE-18 at 9.

223 *Id.*

224 *See id*. at 9-10.

transmission, distribution, generation and other capital expenditures through year 2014, as well as the expenditures for the Projects addressed in this filing, will be over $3.2 billion. The sheer volume of these capital expenditures means that numerous capital projects will be competing with these and other projects in question for funding priority within OG&E.[225]

Fourth, the long lead times associated with some of the Projects raises further financing challenges.[226] Certain of the Projects will not be placed into service until the end of 2013 or 2014, even though OG&E will incur significant costs in connection with those Projects starting immediately.[227] These long lead times open the door to unexpected cost increases, construction delays and continually building carrying costs.[228]

4. The Total Package of Requested Incentives is Tailored to the Specific Risks and Challenges of the Projects.

Each of the Projects faces substantial risks and challenges. The requested incentives are necessary to mitigate these risks, will provide OG&E with up-front certainty, and will reduce the financial pressure on OG&E that would otherwise occur from the financing and construction of the Projects. The CWIP and Abandoned Plant incentives are tailored to the specific risks and challenges of the Projects. Notably, OG&E is not asking for a broad range of incentives from those identified in Order No. 679, most significantly an increased ROE, but instead is requesting to adopt a narrowly-focused pair of incentives that are designed around the Projects for which the incentives will apply. The Commission has previously relied on similar considerations to approve requested CWIP and Abandoned Plant incentives.[229]

With regard to CWIP, the Commission has recognized that inclusion of 100 percent of CWIP in rate base can promote transmission investment, provide up-front regulatory certainty to investors, stabilize rates, and improve cash flow.[230] The Commission has indicated that it will grant the CWIP incentive where the transmission investment is large or "where denying such an incentive would adversely affect the utility's ratings."[231] As discussed above and in the testimony of Donald R. Rowlett, the substantial level of investment OG&E will make in the Projects – approximately $608 million – as well as the long lead times associated with the

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225 *See id*.

226 *See id*. at 10.

227 *See id*.

228 *See id*.

229 *See Xcel Energy Services, Inc.*, 121 FERC ¶ 61,284 at PP 59, 63 (2007) ("*Xcel*"); *Otter Tail*, 129 FERC ¶ 61,287 at PP 31, 33 (2009); *Great River Energy*, 130 FERC ¶ 61,001 at PP 33, 35 (2010) ("*Great River*"); *Southern California Edison Company*, 133 FERC ¶ 61,107 at PP 75-76, 87-88 (2010), *reh'g denied*, 133 FERC ¶ 61,255 (2010); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at PP 64, 75 (2009), *clarified on denial of rehearing*, 130 FERC ¶ 61,044 (2010); *Northeast Utilities Service Company and National Grid USA*, 125 FERC ¶ 61,183 at PP 87-89, 93-94 (2008)

230 Order No. 679 at P 115. *See, e.g., Otter Tail*, 129 FERC ¶ 61,287 at P 32.

231 Order No. 679 at P 117.

Projects will place a major strain on OG&E's cash flow. This incentive provides even greater value if one or more of the Projects are delayed due to siting or permitting issues or the need to act to mitigate potential environmental impacts or address effects on endangered or protected species. The CWIP incentive will ease this strain by ensuring adequate cash flow during the construction phase of the Projects.[232] Exhibit No. OGE-19 demonstrates the difference in cash flow OG&E would experience between receiving the 100 percent CWIP incentive as compared to AFUDC treatment. This analysis shows that the CWIP incentive increases OG&E's cash flow by 36.5%, from $113.4 million to $154.8 million, which will mitigate substantially the stress placed by the Projects' costs on OG&E's finances.

Moreover, the CWIP incentive would reduce debt levels beginning in 2011 by an estimated $12.7 million and by 2014 by an estimated $41.4 million, and would decrease the total interest paid on debt by an estimated $6.75 million over the same four year period.[233] Also included as Exhibit No. OGE-20 is a summary of the cash flow to debt impact of CWIP in rate base, which is expressed as a percentage of funds generated from operations or FFO compared to debt levels. This exhibit demonstrates that without CWIP in rate base, it is more difficult for OG&E to pay the interest on its debt.

The improved cash flow provided by the CWIP incentive also will help OG&E maintain its credit ratings, which could be harmed by a negative cash flow.[234] The Fitch Report that addressed the potential challenges facing OG&E and which downgraded OG&E's IDR from A+ to A noted the positive effect of the requested CWIP incentive: "[o]ther favorable regulatory mechanisms if implemented, such as cash recovery of capital costs during construction work in progress, would be viewed as credit enhancing by Fitch."[235] As noted by Fitch, the CWIP incentive can prevent a possible credit downgrade by providing more stable cash flow and decreasing financial risk. Avoiding a credit rating downgrade is important because a downgrade would increase borrowing costs and thereby increase rates for customers.[236]

Because 100 percent CWIP recovery reduces downward pressure on OG&E's credit ratings, OG&E would be able to borrow money at a lower cost. Not having to finance AFUDC costs would also help OG&E to minimize the final amount of capital expenditures incurred to complete the Projects. The certainty of cost recovery provided by the CWIP incentive also will allow the Projects to compete effectively with other transmission projects for financing.

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232 *See* Rowlett Testimony, Exhibit No. OGE-18 at 11-12.

233 *See id.* at 14.

234 *See id.* at 8. *See also, e.g., PSE&G*, 129 FERC ¶ 61,300 at P 44 (2009); *Am. Elec. Power Serv. Corp.*, 116 FERC ¶ 61,059 at P 59 (2006), *order on reh'g*, 118 FERC ¶ 61,041 at P 27 (2007); *PPL*, 123 FERC ¶ 61,068 at P 43.

235 Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" at 1 (June 28, 2010), Exhibit No. OGE-22.

236 *See* Rowlett Testimony, Exhibit No. OGE-18 at 14.

Allowing OG&E to include CWIP in its rate base will also benefit customers through greater rate stability.[237] Absent including CWIP in rate base, transmission customers may experience rate shock when large-scale transmission projects are placed into service.[238] The CWIP incentive allows for a project's costs to be more gradually incorporated into rates over the course of the construction period.

Similarly, with regard to recovery of the future costs of Abandoned Plant, the Commission has recognized that allowing a utility to recover 100 percent of prudently incurred costs if a transmission project is abandoned for reasons outside the control of the utility's management is an "effective means to encourage transmission development by reducing the risk of non-recovery of costs."[239] The Projects face substantial risks that warrant approval of the Abandoned Plant incentive. There are a number of environmental and regulatory factors that may lead to the eventual abandonment of some or all of the Projects. For example, as discussed in detail above, OG&E must secure rights of way for the length of the Projects, as well as numerous state and federal regulatory approvals, and there is the potential that OG&E may not be able to secure all the necessary rights of way and regulatory approvals.[240] Further, all but one of the Projects will be interconnected to facilities to be constructed by other parties, often in other states. The failure of the related projects to move forward could cause OG&E to abandon one or more of the Projects. Each of the Projects also faces the risk that future SPP decisions could cancel or significantly alter the Project.[241]

As noted above, the Projects are not routine and face a number of legal, regulatory and financial uncertainties. Authorizing the Abandoned Plant incentive will shield OG&E from being forced to forfeit prudently-incurred costs should one or more of the Projects be terminated for reasons beyond OG&E's control. Mitigating the risk of being forced to bear these costs will also enhance OG&E's access to reasonably-priced capital by reducing financial uncertainty. Moreover, the Abandoned Plant incentive mitigates the unique risk that one or more of the Projects will be abandoned, risk that is not addressed by the CWIP incentive, which relates to the size and scope of the Projects and the potential for delay in the in-service date of the transmission investments.

In sum, the combination of CWIP recovery and the potential for future recovery of abandoned plant costs are closely tied to the risks and challenges associated with the Projects and adoption of the requested incentives will reduce these risks and challenges and remove potential obstacles to the construction of the Projects. This "package" of incentives is focused on

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[237] *Id*. at 14-15.

[238] *See, e.g., Duquesne Light Co.*, 125 FERC ¶ 61,028, at P 37 (2008); *Southern Indiana Gas & Elec. Co.*, 125 FERC ¶ 61,124, at P 42 (2008).

[239] Order No. 679 at P 163.

[240] *Southern California Edison Co.*, 121 FERC ¶ 61,168, at P 72 (2007), *reh'g denied*, 123FERC ¶ 61,293 (2008).

[241] *See, e.g., Green Power*, 127 FERC ¶ 61,031 at P 51; *PPL*, 123 FERC ¶ 61,068 at P 47.

responding to the risks faced by the Projects and reducing disincentives to their construction. The Commission itself has noted the linkage of these two incentives.[242]

C. The Resulting Rates are Just and Reasonable.

In Order No. 679, the Commission endorsed single-issue incentives filings.[243] The Commission stated that "applicants for single-issue ratemaking are only required to address cost and rate issues associated with the new investment and therefore are not obligated to justify the reasonableness of unchanged rates."[244]

In this case, the proposed incentive rates are just and reasonable. As the Commission has found, CWIP recovery "merely affects the timing of cost recovery, and not the level of cost recovery."[245] Further, as Mr. Rowlett explains, the CWIP incentive may serve to lower costs paid by OG&E's customers by preventing increases in OG&E's borrowing costs and by reducing financing expenses associated with AFUDC.[246]

Moreover, approval of the requested Abandoned Plant incentive will not affect OG&E's existing transmission rates because OG&E is not seeking to recover these costs currently.[247] In the event that OG&E seeks to recover abandoned plant costs, it will make an FPA Section 205 filing in which it will show that the costs to be recovered were prudently incurred and that the Projects were abandoned for reasons beyond OG&E's control.

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242 Order No. 679 at P 117.

243 *Id*. at P 191.

244 Order No. 679-A at P 98.

245 *Great River*, 130 FERC ¶ 61,001 at P 40; *see* Order No. 679-A at P 38.

246 *See* Rowlett Testimony, Exhibit No. OGE-18 at 12-14.

247 *See, e.g., Great River*, 130 FERC ¶ 61,001 at P 40 ("Great River's request for Abandoned Plant Recovery will not affect Great River's transmission rates because Great River is not currently seeking to recover any such abandoned plant cost associated with the projects").

IV. COMMUNICATIONS.

Communications with respect to this filing should be directed to:

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V. ADDITIONAL FILING REQUIREMENTS AND REQUEST FOR WAIVERS.

A. Advanced Technology Statement.

This section describes the advanced technologies that OG&E plans to employ with respect to the five Projects that are the subject of this application. Advanced technologies are defined as technologies "that increase[] the capacity, efficiency, or reliability of an existing or new transmission facility."[248] As discussed in Mr. Crissup's testimony, OG&E intends to employ certain advanced technologies in the Projects for which incentives are requested in order to maximize the capability and functionality of these transmission assets. Specifically:

- OG&E is installing SEL-421 relays for standard line protection on EHV transmission. These high-speed, digital relays are capable of transmitting synchro-phasor data, which are the line currents and voltages (magnitude and angle) synchronized to a GPS time standard. OG&E is planning synchro-phasor implementation for 14 substations and 25 relays within the OG&E Projects. The benefits to synchro-phasor implementation are advanced fault analysis, wide area disturbance recording, and monitoring or transmission system stability. Synchro-phasors will also allow OG&E to expand its ability to collect data from strategic locations across the transmission system for analysis, display and archival purposes in order to improve system efficiency and reliability. This technology also will provide the ability to import actual data for state estimation, measure line constraints, checkphasing of Current Transformers and Potential Transformers, and wide-area protection schemes.

[248] Energy Policy Act of 2005, Pub. L. No. 109-58, § 1223(a), 119 Stat. 594, 953 (2005).

- OG&E is installing fiber optic cable and related systems with these Projects to allow for faster, more reliable communication among the substations. Fiber optic cable is replacing existing carrier system technology involving signals sent through transmission wires themselves. In addition to being more reliable, fiber optic cable also allows for future potential applications to be developed through OG&E's Smart Grid program.

B. Additional Requirements Applicable to Requested CWIP Recovery.

1. Statement BM.

Section 35.13(h)(38) of the Commission's regulations requires an applicant seeking to include CWIP in rate base to submit a Statement BM in support of the CWIP request. OG&E witness Donald R. Rowlett has prepared a Statement BM in support of OG&E's CWIP request, and he describes the contents of the statement in his testimony.[249] The statement is included as Exhibit No. OGE-21, an attachment to Mr. Rowlett's testimony. This exhibit explains how the proposed Projects are prudent and consistent with a least-cost energy supply program, and describes how the SPP planning processes relevant to the Projects identify reliability and economic upgrades and how alternatives were considered to reduce costs to customers.

2. Accounting to Protect Against Double Recovery.

The Commission's regulations require that any utility that includes CWIP in rate base "must discontinue the capitalization of any AFUDC related to those amounts of CWIP i[n] rate base."[250] Additionally, the utility must propose accounting procedures to "[e]nsure that wholesale customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP proposed to be included in rate base . . . [or] for any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities."[251] To satisfy these requirements, OG&E will not accrue AFUDC in Account 107, Construction Work in Progress.[252] Moreover, OG&E will use the SAP plant accounting system to maintain its accounting records for CWIP electric plant assets during construction and after the Projects are placed into service. The SAP system includes the capability to identify specific work orders that should not be included in the calculation and capitalization of AFUDC. The work orders related to the Projects will be identified in SAP, and no AFUDC will be calculated on their balances. This will prevent a double-recovery of CWIP and capitalized AFUDC on the same rate base items. If OG&E is accorded different ratemaking treatment of CWIP by the OCC or APSC, any accrued AFUDC would be recorded in FERC Account 182.3 Other Regulatory Assets. The AFUDC regulatory asset would be amortized over the depreciable life of the Projects. The amortization amount would be debited to FERC

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[249] *See* Rowlett Testimony, Exhibit No. OGE-18 at 17.

[250] 18 C.F.R. § 35.25(e) (2010).

[251] 18 C.F.R. § 35.25(f) (2010).

[252] *See* Rowlett Testimony, Exhibit No. OGE-18 at 15-16.

Account 407.3 Regulatory Debits. The AFUDC regulatory asset and associated amortization would not be included in the rate charged to OG&E's wholesale transmission customers. In the December 30 Order, with respect to the two projects for which incentives were approved, the Commission found that these same proposed accounting procedures sufficiently demonstrated that OG&E has accounting procedures and internal controls in place to prevent recovery of AFUDC to the extent OG&E is allowed to include CWIP in rate base.[253]

3. Specific Accounting Treatment.

The Commission has noted that, where a utility proposes to recover a current return on CWIP, this cost is recovered in a different period than ordinarily would occur under the Uniform System of Accounts. Accordingly, to maintain the comparability of financial information among entities, the Commission has required utilities recovering a current return on CWIP to "debit through FERC Account 407.3, Regulatory Debits, and credit through FERC Account 254, Other Regulatory Liabilities, in accordance with the objectives of those accounts. Amounts recorded in FERC Account 254 related to return on the proposed Project[s] must be deducted from the rate base."[254] However, the Commission has granted waiver of that accounting treatment and permitted utilities to use footnote disclosures.[255] Consistent with this precedent, OG&E requests waiver of the specific accounting treatment and proposes instead to use footnote disclosures.[256] In the December 30 Order, with respect to the two projects for which incentives were approved, the Commission accepted OG&E's proposal to use footnote disclosures to provide comparability of financial information in its annual FERC Form No. 1 and its quarterly FERC Forms No. 3-Q to recognize the economic effects of having CWIP in rate base.[257] OG&E will conform these disclosures to the specific directions contained in the December 30 Order.[258]

4. Request for Waiver of 18 C.F.R. §§ 35.25(c)(4) and (g).

Section 35.25(c)(4) of the Commission's regulations requires that, to address the potential for anti-competitive effects resulting from CWIP recovery including the potential for prices squeeze and double whammy, an applicant seeking to include CWIP in rate base develop "forward looking allocation ratios reflecting the anticipated average annual use the wholesale customers will make of the system over the estimated service life of the project." The Commission has determined that this Section should be waived as to the double whammy

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[253] December 30 Order at P 58.

[254] *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 106 (2006), *order on reh'g*, 118 FERC ¶ 61,042 (2007).

[255] *See, e.g.*, *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 at P 80 (referencing *Am. Transmission Co. LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 at PP 16-17 (2004); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, *order on reh'g*, 121 FERC ¶ 61,009 (2007); and *Southern California Edison Co.*, 122 FERC ¶ 61,187 (2008)).

[256] *See* Rowlett Testimony, Exhibit No. OGE-18 at 16-17.

[257] December 30 Order at P 59.

[258] *Id.*

concern.[259] Section 35.25(g) of the Commission's regulations requires additional information on the potential anti-competitive impacts of CWIP recovery. The required information includes:

> (i) The percentage of the proposed increase in the jurisdictional rate level attributable to non-pollution control/fuel conversion CWIP and the percentage of non-pollution control/fuel conversion CWIP supporting the proposed rate level; (ii) The percentage of non-pollution control/fuel conversion CWIP permitted by the state or local commission supporting the current retail rates of the public utility against which the relevant wholesale customers compete; and (iii) Individual earned rate of return analyses of each of the competing retail rates developed on a basis fully consistent with the wholesale cost of service for the same test period if the requested percentage of wholesale non-pollution control/fuel conversion CWIP exceeds that permitted by the relevant state or local authority to support the currently competing retail rates.[260]

OG&E respectfully requests waiver of Sections 35.25(c)(4) and (g). These regulations mainly address concerns about the potential for anti-competitive effects resulting from the inclusion of generation-related CWIP in rates. These concerns are less significant with respect to transmission-related CWIP, which is at issue in this filing. OG&E has included in this filing evidence showing the projected CWIP balances for the year 2011,[261] the estimated amount of CWIP to be included in rate base for years 2011 to 2014,[262] as well as a comparison of the rate impact on customers of the CWIP recovery versus the AFUDC approach.[263] OG&E believes this information, as well as the additional information included in this application, is sufficient to satisfy Sections 35.25(c)(4) and (g). To the extent it has not fulfilled these requirements, OG&E requests waiver of Sections 35.25(c)(4) and (g).

5. Annual Filing Requirement.

In Order No. 679, the Commission "determined that recovery of CWIP on a formulary basis is not permitted without prior Commission review. The Commission will allow public utilities to propose a method to limit their filing requirement related to CWIP to an annual filing."[264] Consistent with this policy, OG&E requests permission to satisfy the CWIP filing requirement through an annual submission of the FERC Form 730.[265] In the December 30 Order, with respect to the two cases for which incentives were approved, the Commission

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259 *See* Order No. 679 at P 109.

260 18 C.F.R. § 35.25(g) (2010).

261 *See* Attachment 1; Rowlett Testimony, Exhibit No. OGE-18 at 12.

262 Rowlett Testimony, Exhibit No. OGE-18 at 5 & 12.

263 *See* Exhibit No. OGE-19, Summary of Cash Flow and Interest Impact; Rowlett Testimony, Exhibit No. OGE-18 at 12-14.

264 Order No. 679 at P 121.

265 The Commission has permitted this approach in past cases. *See, e.g., Otter Tail*, 129 FERC ¶ 61,287 at P 34; *Xcel*, 121 FERC ¶ 61,284 at P 68.

approved OG&E's proposal to satisfy the annual filing requirement by the filing its form FERC-730 report.[266]

C. Request for Waiver of Cost of Service Statements.

OG&E respectfully requests waiver of Section 35.13 of the Commission's regulations, including the requirements to submit Period I and II data. The Commission has recognized that these cost of service statements are not necessary with respect to formula rates, which are based on a utility's actual costs.[267] In the December 30 Order, with respect to the two projects for which the Commission authorized the requested incentives, the Commission granted OG&E's request for waiver of section 35.13 of the Commissions' regulations.[268]

D. Proposed Effective Date.

OG&E respectfully requests waiver of Section 35.3 of the Commission's regulations to permit the requested incentives to be effective March 1, 2011. Good cause exists to grant this waiver. In the December 30 Order, the Commission denied OG&E's prior request for incentives for the Projects "without prejudice to OG&E refiling to demonstrate how each of [the] remaining projects meets the nexus requirement."[269] OG&E has acted expeditiously to re-file its request for incentives in compliance with the December 30 Order, and a March 1, 2011 effective date will mitigate the consequent delay in the implementation of these incentives. In addition, a proposed March 1, 2011 effective date is consistent with Commission policy and precedent. In general, the Commission will grant waiver of the 60-day prior notice requirement where a filing lowers or has no effect on rates.[270] OG&E's request to include 100 percent of CWIP in rate base for the Projects will benefit ratepayers by supporting OG&E's cash flow, reducing interest expenses, and avoiding rate shock.[271] Moreover, the abandoned plant incentive will have no effect on rates unless and until OG&E makes an additional FPA Section 205 filing to recover the abandoned plant costs and the Commission finds such costs to be prudent and outside of management's control.[272]

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[266] December 30 Order at P 60.

[267] *See, e.g.*, *Oklahoma Gas and Electric Co.*, 122 FERC ¶ 61,071 at P 41 (2008).

[268] December 30 Order at P 61.

[269] December 30 Order at P 44.

[270] *See Central Hudson*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089, at 61,337 (1992); *Midwest Energy, Inc.*, 75 FERC ¶ 61,224, at 61,743 (1996) (waiving notice where customer would "derive maximum benefit" from an earlier effective date for the rate change); *Southwestern Electric Power Co.*, 36 FERC ¶ 61,081 (1986), *reh'g denied*, 37 FERC ¶ 61,235 (1986) (waiving notice requirement for implementing CWIP since allowing a rate to decrease sooner would benefit the customer).

[271] *See above* Section III.B.4.

[272] *See* Order No. 679 at PP 163, 166.

E. Posting and Service.

Pursuant to Sections 35.1(a) and 35.2(e) of the Commission's regulations, an electronic copy of this filing is being served on SPP, the Oklahoma Corporation Commission, the Arkansas Public Service Commission, and all of SPP's and OG&E's OATT customers. In addition, a complete copy of this filing is available on the SPP and OG&E OASIS.

VI. CONCLUSION

For the foregoing reasons, OG&E respectfully requests that the Commission grant OG&E the CWIP and Abandoned Plant incentives with respect to the Projects discussed herein. OG&E requests that the proposed incentives be made effective on March 1, 2011.

Respectfully submitted,

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ATTACHMENT 1

POPULATED TEMPLATE

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

Oklahoma Gas and Electric Company

Index of Worksheets

1	Worksheet	Description
2	Attachment H - Addendum 2-A	Rate Formula Template Utilizing FERC Form 1 for the 12 months ended 12/31/2009 and "Actual Data"
3	Worksheet A	Account 454, Rent from Electric Property
4		Account 456, Other Electric Revenues
4		Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits
5		Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service
6	Worksheet B	Transmission Network Load (MW)
7	Worksheet C	Account 281, Accumulated Deferred Income Taxes - Accelerated Amortization Property
8		Account 282, Accumulated Deferred Income Taxes - Other Property
9		Account 283, Accumulated Deferred Income Taxes - Other
10		Account 190, Accumulated Deferred Income Taxes
11		Account 255, Accumulated Deferred Investment Tax Credits
12	Worksheet D	Account 928, Regulatory Commission Expense Allocations
13		Account 930.1, General Advertising Allocations (safety related only to trans.)
14		Account 930.2, Miscellaneous General Expenses
15		Transmission Lease Payments
16	Worksheet E	Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility
17	Worksheet F	Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase
18		Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase
19		Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives
20	Worksheet G	Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities
21	Worksheet H	Transmission Plant Adjustments
22	Worksheet I	Plant Held for Future Use
23	Worksheet J	Development of Composite State Income Tax Rates
24	Worksheet K	13 Month Balances for Plant & Accumulated Depreciation, Material & Stores and Debt & Equity
25		Account 165, Prepayments Calculation
26		Long Term Debt Cost Calculation
27	Worksheet L	True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation
28	Worksheet M	Depreciation Rates
29	Worksheet N	Unfunded Reserves Calculation
30	Worksheet O	Amortizations for Extraordinary O&M and Storm Costs
31	Worksheet P	Construction Work in Progress and Abandoned Plant Balances

Rate Formula Template
Utilizing FERC Form 1 for the 12 months ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

For rates effective January 1, 2011

Line No.					Transmission Amount
1	NET SPP OATT RELATED UPGRADES REV. REQ.	(Addendum 2-A, ln 17 - ln 18)			$ 20,940,944
2	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(Addendum 2-A, ln 21)			85,380,232
3	DIVISOR				
4	TO's Transmission Network Load	(Worksheet B, ln 14)			4,854,836
5	RATES				
6	Annual Cost ($/kW/Yr)	(ln 2 / ln 4)	17.587		
7	P-to-P Rate ($/kW/Mo)	(ln 6 / 12)	1.466		
			Peak		Off-Peak
8	Weekly P-To-P Rate ($/kW/Wk)	(ln 6 / 52; ln 6 / 52)	0.338		0.338
9	Daily P-To-P Rate ($/kW/Day)	(ln 8 / 5; ln 8 / 7)	0.068	Capped at weekly rate	0.048
10	Hourly P-To-P Rate ($/MWh)	(ln 9 / 16; ln 9 / 24 both x 1,000)	4.228	Capped at weekly & daily rate	2.013

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.			Total	Allocator		Transmission Amount
11	REVENUE REQUIREMENT (w/o incentives)	(ln 117)				$ 123,738,282
12	REVENUE CREDITS	(Note A)	Total	Allocator		
13						$ -
14	Other Transmission Revenue	(Worksheet A)	11,525,696	DA	1.00000	$ 11,525,696
15	Total Revenue Credits		11,525,696			$ 11,525,696
16	NET REVENUE REQUIREMENT (w/o incentives)	(ln 11 less ln 15)				$ 112,212,586
17	SPP OATT RELATED UPGRADES REVENUE REQUIREMENT	(Worksheet G & P) (Note X)				$ 21,258,506
18	SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP	(Worksheet L)				$ 317,562
19	PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST	(Worksheet L)				$ 5,256,287
20	ADDITIONAL REVENUE REQUIREMENT (w/ incentives)	(Note C) & (Worksheet F, ln 61)				$ -
21	OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3	(ln 16 - ln 17 - ln 18 - ln 19 + ln 20)				$ 85,380,232
22	NET PLANT CARRYING CHARGE (w/o incentives)	(Note B)				
23	Annual Rate	((ln 16 / ln 46) x 100)				20.52%
24	Monthly Rate	(ln 23 / 12)				1.71%
25	NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives)	(Note B)				
26	Annual Rate	(((ln 16 - ln 92) / ln 46) x 100)				16.95%
27	NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN	(Note B)				
28	Annual Rate	(((ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100)				2.63%

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) RATE BASE CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
29	GROSS PLANT IN SERVICE					
30	Production	(Worksheet K)	3,094,645,765	NA		
31	Transmission	(Worksheet K)	942,744,528	TP	0.93085	877,550,515
32	Distribution	(Worksheet K)	2,804,714,234	NA		
33	General Plant	(Worksheet K) (Note J)	221,648,326	W/S	0.05740	12,723,367
34	Intangible Plant	(Worksheet K) (Note V)	30,534,454	W/S	0.05740	1,752,781
35	TOTAL GROSS PLANT	(sum lns 30 to 34)	7,094,287,307			892,026,664
36	GROSS PLANT ALLOCATOR	(ln 35 - Col. 5 / Col. 3)		**GP=**	**0.125739**	
37	ACCUMULATED DEPRECIATION					
38	Production	(Worksheet K)	1,509,338,480	NA		
39	Transmission	(Worksheet K)	355,134,240	TP	0.93085	330,575,491
40	Distribution	(Worksheet K)	946,822,367	NA		
41	General Plant	(Worksheet K) (Note J)	84,528,061	W/S	0.05740	4,852,198
42	Intangible Plant	(Worksheet K) (Note V)	21,353,013	W/S	0.05740	1,225,735
43	TOTAL ACCUMULATED DEPRECIATION	(sum lns 38 to 42)	2,917,176,161			336,653,424
44	NET PLANT IN SERVICE					
45	Production	(ln 30 - ln 38)	1,585,307,285	NA		
46	Transmission	(ln 31 - ln 39)	587,610,288			546,975,024
47	Distribution	(ln 32 - ln 40)	1,857,891,867	NA		
48	General Plant	(ln 33 - ln 41)	137,120,265			7,871,169
49	Intangible Plant	(ln 34 - ln 42)	9,181,441			527,046
50	TOTAL NET PLANT IN SERVICE	(sum lns 45 to 49)	4,177,111,146			555,373,239
51	NET PLANT ALLOCATOR	(ln 50 - Col. 5 / Col. 3)		**NP=**	**0.132956**	
52	ADJUSTMENTS TO RATE BASE	(Note D)				
53	Account No. 281	(Worksheet C)	-			-
54	Account No. 282	(Worksheet C)	(805,926,447)			(97,127,482)
55	Account No. 283	(Worksheet C)	(107,025,154)			(2,330,707)
56	Account No. 190	(Worksheet C)	104,239,996			3,473,834
57	Account No. 255	(Worksheet C)	(15,213,997)			-
58	Unfunded Reserves	(Worksheet N)	(1,647,242)	DA	1.00000	(1,647,242)
59	TOTAL ADJUSTMENTS	(sum lns 53 to 57)	(825,572,844)			(97,631,596)
60	UNAMORTIZED ABANDONED PLANT	(Worksheet P) (Note R)	0	DA	1.00000	0
60a	Construction Work in Progress (CWIP)	(Worksheet P) (Note Z)	135,219,538	DA	1.00000	135,219,538
61	LAND HELD FOR FUTURE USE	(Worksheet I) (Note F)	780,532	TP	0.93085	726,556
62	WORKING CAPITAL	(Note G)				
63	CWC	(1/8 * ln 90)	12,564,069			2,160,973
64	Materials & Supplies -- Transmission Related	(Worksheet K) (Note S)	17,494,137	TP	0.93085	16,284,358
65	Prepayments (Account 165)	(Worksheet K)	8,244,622	GP	0.12574	1,036,668
66	TOTAL WORKING CAPITAL	(sum lns 63 to 65)	38,302,829			19,481,999
67	RATE BASE (sum lns 50, 59, 60, 61, 66)		3,390,621,663			613,169,736

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator		(5) Total Transmission
	OPERATION & MAINTENANCE EXPENSE					
68	Transmission	321.112.b	29,685,276			
68a	Less Extraordinary & Storm Cost Amortization	(Worksheet O)	-			
69	Less expenses for LSE cost responsibility	(Worksheet E, ln 14)	5,827,805			
70	Less Account 561 (Load Dispatching)	321.84-92.b (Note P & U)	9,773,191			
71	Less Account 565	321.96.b (Note I)	1,058,012			
72	Plus Acct 565 native load, zonal or pool	(Note I)	-			
73	Transmission Subtotal	(ln 68-ln 68a-ln 69-ln 70-ln 71+ln 72)	13,026,268	TP	0.93085	12,125,457
74	Administrative and General	323.197.b (Note J)	90,790,720	NA		
75	Less: Acct. 924, Property Insurance	323.185.b	1,651,034	NA		
76	Less: Acct. 928, Reg. Com. Exp.	323.189.b	4,522,890	NA		
77	Less: Acct. 930.1, Gen. Advert. Exp.	323.191.b	1,625	NA		
78	Less: Acct. 930.2, Misc. General Exp.	323.192.b	14,919,172			
79	Less: PBOP amount included in Line 74	(Note T)	11,100,000			
80	Balance of A & G	(ln 74 - sum ln 75 to ln 79)	58,595,999	W/S	0.05740	3,363,609
81	Plus: Acct. 924	(ln 75)	1,651,034	GP	0.12574	207,599
82	Plus: Acct. 928 - Transmission Direct Assigned	(Note K) (Worksheet D)	11,018	DA	1.00000	11,018
83	Plus: Acct. 928 - Transmission Allocated	(Note K) (Worksheet D)	18,152	DA	1.00000	18,152
84	Plus: Acct. 930.1 - Transmission Direct Assigned	(Note K) (Worksheet D)	-	DA	1.00000	-
85	Plus: Acct. 930.1 - Transmission Allocated	(Note K) (Worksheet D)	-	DA	1.00000	-
86	Plus: Acct. 930.2 - Adj. Misc. General Expenses	(Worksheet D)	14,810,084	W/S	0.05740	850,149
87	Plus: PBOP Amount	(Note T)	12,400,000	W/S	0.05740	711,802
88	A & G Subtotal	(sum lns 80 to 87)	87,486,287			5,162,329
89	Transmission Lease Payments	(Worksheet D)	-	DA	1.00000	-
90	TOTAL O & M EXPENSE	(ln 73 + ln 88 + ln 89)	100,512,555			17,287,786
91	DEPRECIATION AND AMORTIZATION EXPENSE					
92	Transmission	336.7.b	20,977,544	TP	0.93085	19,526,875
93	Plus: Extraordinary & Storm Cost O&M Amortization	(Worksheet O) (Note W)	10,464	TP	0.93085	9,741
94	Plus: Recovery of Abandoned Incentive Plant	(Worksheet P) (Note R)	0	DA	1.00000	0
95	General	336.10.b	12,995,380	W/S	0.05740	745,979
96	Intangible	336.1.f	4,216,474	W/S	0.05740	242,040
97	TOTAL DEPRECIATION AND AMORTIZATION	(sum lns 92 to 96)	38,199,862			20,524,634
98	TAXES OTHER THAN INCOME	(Note L)				
99	Labor Related					
100	Payroll	263.i	8,598,019	W/S	0.05740	493,556
101	Plant Related					
102	Property	263.i	56,728,987	GP	0.12574	7,133,031
103	Gross Receipts	263.i	-			
104	Other	263.i	111,689	GP	0.12574	14,044
105	TOTAL OTHER TAXES	ln 100 + (sum lns 102 to 104)	65,438,695			7,640,630
106	INCOME TAXES	(Note M)				
107	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		38.97%			
108	CIT=(T/1-T) * (1-(WCLTD/R)) =		43.53%			
109	where WCLTD=(ln 137) and R= (ln 140)					
110	and FIT, SIT & p are as given in Note M.					
111	1 / (1 - T) = (from ln 107)		1.6385			
112	Amortized Investment Tax Credit	266.8.f (enter negative)	(4,231,644)			
113	Income Tax Calculation	(ln 108 * ln 116)	132,838,164	NA		24,022,834
114	ITC adjustment	(ln 111 * ln 112)	(6,933,446)	NP	0.132956	(921,845)
115	TOTAL INCOME TAXES	(sum lns 113 to 114)	125,904,718			23,100,989
116	RETURN (Rate Base * Rate of Return)	(ln 67 * ln 140)	305,150,237	NA		55,184,243
117	REVENUE REQUIREMENT	(sum lns 90, 97, 105, 115, 116)	635,206,067			123,738,282

Rate Formula Template
Utilizing FERC Form 1 for the 12 months Ended 12/31/2009
(Enter whether "Projected Data" or "Actual Data") Projected Data

OKLAHOMA GAS AND ELECTRIC COMPANY

SUPPORTING CALCULATIONS

ln No.	(1)	(2)	(3)		(4)		(5)
	TRANSMISSION PLANT INCLUDED IN SPP TARIFF						
118	Total transmission plant	(ln 31)					942,744,528
119	Less transmission plant excluded from SPP Tariff	(Worksheet H) (Note N)					18,521,292
120	Less Production Related Transmission Facilities	(Worksheet H) (Note O)					46,672,721
121	Transmission plant included in SPP Tariff	(ln 118 - ln 119 - ln 120)					877,550,515
122	Percent of transmission plant in SPP Tariff	(ln 121 / ln 118)				**TP=**	**0.93085**
123	WAGES & SALARY ALLOCATOR (W/S)						
124	Production	354.20.b	51,909,552	NA			-
125	Transmission	354.21.b	7,237,937	TP	0.93085		6,737,409
126	Distribution	354.23.b	35,161,973	NA			-
127	Other (Excludes A&G)	354.24,25,26.b	23,060,052	NA			-
128	Total	(sum lns 124 to 127)	117,369,514				6,737,409
129	Transmission related amount	(ln 128 - Col. 5 / Col. 3)				**W/S=**	**0.05740**
130	RETURN (R)						
131	Preferred Dividends	(118.29.c) (positive number)	0				-
132	Development of Common Stock:						
133	Long Term Debt	(Worksheet K) (Note Q)			44.72%		1,545,303,846
134	Preferred Stock	(Worksheet K) (Note Q)			0.00%		-
135	Common Stock	(Worksheet K) (Note Q)			55.28%		1,910,285,534
136	Total	(sum lns 133 to 135)					3,455,589,381
			$	%	Cost (Note Q)		Weighted
137	Long Term Debt		1,545,303,846	44.72%	0.0640		0.0286
138	Preferred Stock	112.3.c	-	0.00%	0.0000		0.0000
139	Common Stock		1,910,285,534	55.28%	0.1110		0.0614
140	Total (sum lns 137 to 139)		3,455,589,381			**R**	**0.0900**

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes

General Notes: a) References to data from Form 1 are indicated as: page#.line#.col.#
b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above.

Note Letter

A The revenues credited shall include a) amounts received directly from the SPP for service under this tariff reflecting the TO's integrated transmission facilities and b) amounts from customers taking service under grandfathered agreements. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the definition of transmission facilities under this tariff shall not be included as revenue credits. Revenues from coincident peak loads included in the DIVISOR are also not included as revenue credits unless this revenue is offset by a corresponding expense. See Worksheet A for details.

B The annual and monthly net plant carrying charges on page 2 are to be used to compute the revenue requirement for directly assigned transmission facilities, Base Plan Upgrades, Transmission Service Upgrades, Sponsored, Economic Portfolio Upgrades and Generator Interconnection Facilities, etc. whose revenue requirement is calculated in Worksheet G and recoverd pursuant to Attachments J and Z, or successor attachments, of the SPP OATT.

C This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional revenue requirements for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the relevant year, and included here. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected.

D Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190 and 255 as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. Transmission allocations shall be shown on Worksheet C, including amounts excluded through direct assignment to incentive plant, as shown on separate workpapers.

E Reserved for future use.

F Identified as being only transmission related or functionally booked to transmission.

G Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 90. Prepayments are limited to electric related items.

H Reserved for future use

I Only include transmission costs paid to others by the TO for which the transmission customer under the tariff receives a benefit (such as the payment of Base Plan Charges allocated to the TO's zone and not otherwise recovered by SPP from customers). Charges related to Base Plan Upgrades under Attachment J, Future Roll-Ins under Attachment Z and replacement of Existing Facilities are to be included. Direct Assignment Facilities, Economic Upgrades, Requested Upgrades and generator related to Network Upgrades (as defined in Attachment J) are to be excluded.

J General Plant and Administrative and General expenses will be functionalized based on the indicated allocator on each line.

K Includes all Regulatory Commission expense itemized in FERC Form 1 at 351.h. Show in Worksheet D how these expense items are allocated to transmission. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Account 930.1 shall Include only safety-related advertising cost booked to the account.

L Includes only FICA, unemployment, highway, property and other assessments charged in the relevant year. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected. Gross receipts tax and taxes related to income are excluded.

M The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 112) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required:	FIT =	35.00%	
	SIT=	6.10%	(State Income Tax Rate or Composite SIT - Worksheet J)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

N Removes the dollars of plant booked to transmission plant that is excluded from the Tariff because it does not meet the Tariff's definition of Transmission Facilities or is otherwise not eligible to be recovered under this Tariff.

O Removes the dollars of plant booked to transmission (e.g. step-up transformers) that are included in the development of OATT ancillary services rates and not already removed in Note N above.

P Removes the dollars of expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.

Q Long Term Debt cost rate calculated in Section V of Worksheet K. Preferred Stock cost rate = preferred dividends (ln 131) / preferred outstanding (ln 138). Common Stock cost rate (ROE) = 11.10%, the rate accepted by FERC in Docket No. ER08-281 It includes an additional 50 basis points for the TO remaining a member of the SPP RTO. This rate shall not change until a new rate is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. The percentage of equity used in determining the weighted cost of equity for OG&E for purposes of the Settlement Formula Rate shall not exceed 56% ("Equity Cap") as accepted by FERC in Docket No. ER09-281 regardless of OG&E's actual percentage of equity. To the extent OG&E's actual percentage of equity exceeds the Equity Cap, such amount in excess of the Equity Cap shall be treated as Long-Term Debt for purposes of the Settlement Formula Rate. The Equity Cap shall not change until a new Equity Cap is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. Include in the interest on Debt from Associated Companies only the interest on Long-Term Debt.

R OG&E must make the appropriate filing at FERC before inputting or changing amounts on lines 60 & 94 (abandoned plant).

S The Formula Rate will functionalize Material and Supplies for Construction on the basis of a single-year usage ratio in accordance with the most recent FERC Form 1, and will true-up these costs based on the trued-up year's Form 1. M&S for Construction will utilize 13 month average balances as reflected in Worksheet K, Section II and exclude any M&S booked in Account 107.

T PBOP base amount, initially set at $12,400,000, shall not be changed absent a separate filing made with the FERC.

U Transmission Service Study and Generation Interconnection Study costs shall be recorded in FERC Accounts 561.6 and 561.7, respectively. Costs of studies performed by SPP on behalf of OG&E, costs of studies performed by OG&E at SPP's request, reimbursement of study costs from SPP for studies performed by OG&E at SPP's request and studies for OG&E's retail load shall be recorded in FERC Accounts 561.6 & 561.7. FERC Accounts 561.6 and 561.7 are excluded from the Formula Rate.

OKLAHOMA GAS AND ELECTRIC COMPANY

Notes - continued

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".

W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.

X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentive, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.

Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corportion Commission and the FERC. This amount should equal amount reflected on line 93.

Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

List of Allocators:

Direct Assigned	DA	1.000000
Gross Plant	GP	0.125739
Net Plant	NP	0.132956
Trans. Plant in SPP	TP	0.930847
Wages & Salaries	W/S	0.057403
No Allocator	NA	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet A

Line No.		Data Sources	2009 YE Balance	GP Allocator	Allocated to Transmission
	I. Account 454, Rent from Electric Property - Relevant Year = 2009 (Note 1)				
	(Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section V, Notes below)				
1	Rent from Electric Property	300.19.b	$1,285,452	12.5739%	$161,631
2					
3					
4	**Net Account 454 - Credited as transmission pole rentals =**				**$161,631**

II. Account 456, Other Electric Revenue - Relevant Year = 2009 (Notes 1 & 2)

(Other electric revenues including miscellaneous transmission revenues. Provide data sources and explanations in Section V, Notes below)

Line No.			(A) 2009 YE Balance	(B) Power Production	(C) Distribution	(D) Utility Commercial	(E) Utility A & G	(F) Miscellaneous	(G) Transmission (Load in Divisor)	(H) Other Transmission
5		300.21.b	$92,225,167							
6	Miscellaneous - McClain Adder									
7	Miscellaneous - Scrap Sales			$19,127						
8	Miscellaneous - OMPA Admin Fee			$120,801						
9	Miscellaneous			$72	$30,790			$9,269		
10	Miscellaneous - Honeywell Energy Management									
11	Miscellaneous - Sale of Residual Oil									
12	Reimbursed Payroll Costs			$1,253	$3,832	$2,832	$50			
13	Remuneration Sales Taxes Collection - OK & AR						$115,159			
14	Franchise & Privilege Tax Adjustment						$152			
15	Oil Lease & Royalties						$10,124			
16	Pace Payments									
17	Transmission Service Revenues - from OG&E LSE								$83,852,324	
18	Transmission Service Revenues - Unbundled OK & AR								$277,758	
19	Transmission Service Revenues - Direct Assigned Facilities									
20	Salvage Clearing			$2,880	$54,131	$1,748				
21	Off-System Sales Credit - Oklahoma							$1,715,839		
22	Discount on Purchased Wind Credits							$86,197		
23	Renewable Energy Certificate Sales - OK & AR						$612,037			
24	Base Plan Revenues - 2008 & 2009								$3,851,809	$1,456,983
25										
26	TOTALS (Sum lns 6 - 25)		$92,225,167	$144,133	$88,753	$4,580	$737,522	$1,811,305	$87,981,891	$1,456,983
27	**Net Account 454 - Credited as Transmission Revenues** [(A)-(B)-(C)-(D)-(E)-(F)-(G)] =									**$1,456,983**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet A

III. Account 456.1, Revenues from Transmission of Electricity of Others - Relevant Year = 2009 (Notes 1 & 3) 328-330.Total.n $17,615,928

(Provide data sources and any detailed explanations necessary in Section V, Notes below)

Ln			Transmission (Load in Divisor)	
	Less:			
28	TO's LSE Direct Assignment Revenue Credits			
29	TO's LSE Sponsored (Requested or Economic) Upgrade Revenue Credits			
30	TO's LSE Network Upgrades for Generation Interconnection - Credits			
31	TO's Point-To-Point Revenue for GFA's Associated with Load Included in the Divisor			
32	Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor		$6,980,799	
33	TO's Revenue Associated with Transmission Plant Excluded From SPP Tariff			
34	Wholesale Distribution charges		$311,758	
35	TO's LSE Revenue from Ancillary Services Provided			
36	Network Service Ancillary Revenues (Schedule 1) Associated With Load Included in the Divisor		$416,289	
37				
38				
39				
40	**Total Revenues Adjusted from Account 456.1 (Revenues retained by OG&E for load included in the divisor) =**	(Sum lns 28 thru 39)		$7,708,846
41	**Net Account 456.1 Included in Template (PTP revenues to be credited) =**	[(328-330.Total.n) - ln 40]		**$9,907,082**

IV. Revenue from Grandfathered Interzonal Transactions - Revelant Year = 2009 (Note 3)

(Provide data sources and any detailed explanations necessary in Section V, Notes below)

Ln			
42	Revenues from Grandfathered Interzonal Transactions	0	
43			
44	Revenues received from SPP for PTP service	0	
45			
46	**Sum of Parts I, II & III**	(Addendum 2-A, ln 14)	**$11,525,696**

V. Notes

(Provide data sources for Sections I, II, III and IV along with any detailed explanations necessary.)

47 1. When calculating the Baseline ATRR, the "Revelant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form 1.

48 2. Section II, Other Electric Revenues reflects revenues received from SPP for Directly Assigned Upgrades and Other Transmission Revenues to be credited to customers.
of this Attachment H - Addendum 2-A.

49 3. Section III, Net Account 456.1 reflects SPP Point-to-Point revenues to be credited to customers.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet B

I. Transmission Network Load (MW)

Line No.	Month, Day and Year[1]	Hour Ending[1]	OG&E Peak Load	WFEC Peak Load	OMPA Peak Load	AECI/KAMO Peak Load				TO's Transmission Peak Load[1]
1	15-Jan-09	1900	4,203	105	254	18				4,579
2	4-Feb-09	800	3,879	100	218	15				4,212
3	2-Mar-09	800	3,668	100	203	15				3,987
4	23-Apr-09	1500	3,626	71	245	8				3,950
5	31-May-09	1800	4,143	87	320	12				4,562
6	24-Jun-09	1700	5,728	114	452	16				6,311
7	13-Jul-09	1700	5,947	110	471	17				6,544
8	4-Aug-09	1700	5,570	113	439	15				6,137
9	9-Sep-09	1700	4,984	92	354	11				5,441
10	1-Oct-09	1500	3,684	75	238	8				4,005
11	16-Nov-09	1900	3,560	92	211	12				3,875
12	9-Dec-09	2000	4,274	108	259	16				4,656
13	Total		53,265	1,167	3,665	161				58,258
14	12-CP		4,439	97	305	13				4,855

II. Notes

1 These are the dates, hour ending and loads at the time of the TO's transmission peak, as reported in FERC Form 1, page 400. Peak Load for Point-to-Point services sold under the SPP Tariff are not reflected in the totals above. Revenues from Point-to-Point services are shared according to Attachment L of the SPP OATT and revenues received provide revenue credits to network customers.

2 "GFA PTP Scheduled Load" is the firm load in kW scheduled by Grandfathered Agreements' (GFA) customers taking firm point-to-point (PTP) service at the time of TO's monthly transmission peak load. Details are as follows:

Ln No.	Month, Day and Year	Hour ending								GFA PTP Scheduled Load
15	15-Jan-09	1900								0
16	4-Feb-09	800								0
17	2-Mar-09	800								0
18	23-Apr-09	1500								0
19	31-May-09	1800								0
20	24-Jun-09	1700								0
21	13-Jul-09	1700								0
22	4-Aug-09	1700								0
23	9-Sep-09	1700								0
24	1-Oct-09	1500								0
25	16-Nov-09	1900								0
26	9-Dec-09	2000								0

3 "GFA PTP Contract Demand" is the contract demand in kW for GFA customers taking firm PTP service at the time of TO's monthly peak load. Details are as follows:

Ln No.	Month, Day and Year	Hour ending								GFA PTP Contract Demand
27	15-Jan-09	1900								0
28	4-Feb-09	800								0
29	2-Mar-09	800								0
30	23-Apr-09	1500								0
31	31-May-09	1800								0
32	24-Jun-09	1700								0
33	13-Jul-09	1700								0
34	4-Aug-09	1700								0
35	9-Sep-09	1700								0
36	1-Oct-09	1500								0
37	16-Nov-09	1900								0
38	9-Dec-09	2000								0

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet B

II. Notes (cont.)

4 "Non-Firm Sales in TO's Zone" are non-firm loads in kW at the time of, and include in, TO's monthly transmission system peak load associated with sales to customers in TO's zone. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-Firm Sales in TO's Zone
39	15-Jan-09	1900								0
40	4-Feb-09	800								0
41	2-Mar-09	800								0
42	23-Apr-09	1500								0
43	31-May-09	1800								0
44	24-Jun-09	1700								0
45	13-Jul-09	1700								0
46	4-Aug-09	1700								0
47	9-Sep-09	1700								0
48	1-Oct-09	1500								0
49	16-Nov-09	1900								0
50	9-Dec-09	2000								0

5 "Non-TO Generation" in kW is load served by non-TO generators operating synchronously with the TO's transmission system. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-Firm Sales in TO's Zone
51	15-Jan-09	1900								0
52	4-Feb-09	800								0
53	2-Mar-09	800								0
54	23-Apr-09	1500								0
55	31-May-09	1800								0
56	24-Jun-09	1700								0
57	13-Jul-09	1700								0
58	4-Aug-09	1700								0
59	9-Sep-09	1700								0
60	1-Oct-09	1500								0
61	16-Nov-09	1900								0
62	9-Dec-09	2000								0

6 "Non-TO Load in TO's Zone" is load in kW for firm-service customers in TO's zone that is electronically transferred to other TO zones. Details are as follows:

Line No.	Month, Day and Year	Hour ending								Non-TO Load in TO's Zone
63	15-Jan-09	1900								0
64	4-Feb-09	800								0
65	2-Mar-09	800								0
66	23-Apr-09	1500								0
67	31-May-09	1800								0
68	24-Jun-09	1700								0
69	13-Jul-09	1700								0
70	4-Aug-09	1700								0
71	9-Sep-09	1700								0
72	1-Oct-09	1500								0
73	16-Nov-09	1900								0
74	9-Dec-09	2000								0

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

I. Account 281 - ADIT - Accelerated Amortization Property

Relevant Year = 2009 (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
1									
2	Net Total Property and Accumulated Depreciation	-	-	-	-	-	-	-	Accumulated deferred income taxes-Accelerated amortization property.
3	Other	-	-	-	-	-	-	-	
4		-	-	-	-	-	-	-	
5		-	-	-	-	-	-	-	
6		-	-	-	-	-	-	-	
7		-	-	-	-	-	-	-	
8		-	-	-	-	-	-	-	
9		-	-	-	-	-	-	-	
10		-	-	-	-	-	-	-	
11		-	-	-	-	-	-	-	
12		-	-	-	-	-	-	-	
13		-	-	-	-	-	-	-	
14		-	-	-	-	-	-	-	
15		-	-	-	-	-	-	-	
16		-	-	-	-	-	-	-	
17		-	-	-	-	-	-	-	
18		-	-	-	-	-	-	-	
19		-	-	-	-	-	-	-	
20		-	-	-	-	-	-	-	
21		-	-	-	-	-	-	-	
22		-	-	-	-	-	-	-	
23									
24	**Subtotal - Form 1, p273**	-	-	-	-	-	-		
25	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
26	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
27	**Total (ln 24 - ln 25 - ln 26)**	-	-	-	-	-	-		
28	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
29	**Total (ln 27 * ln 28)**		0	0	0	0	0	0	

II. Account 282 - ADIT - Other Property

Relevant Year = 2009 (Note 2)

Line No.	(A) Identification	Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
30									
31	Net Total Property and Accumulated Depreciation	(772,454,785)	-	-	-	(772,454,785)	-	(772,454,785)	Accumulated deferred income taxes-Other property.
32	Income Taxes Recoverable/Refundable, net	(33,471,662)	(33,471,662)	-	-	-	-	-	Deferred tax per SFAS 109 related to property and Retail S. Georgia.
33	Other		-	-	-	-	-	-	
34			-	-	-	-	-	-	
35			-	-	-	-	-	-	
36			-	-	-	-	-	-	
37			-	-	-	-	-	-	
38			-	-	-	-	-	-	
39			-	-	-	-	-	-	
40			-	-	-	-	-	-	
41			-	-	-	-	-	-	
42			-	-	-	-	-	-	
43			-	-	-	-	-	-	
44			-	-	-	-	-	-	
45			-	-	-	-	-	-	
46			-		-	-	-	-	
47			-	-	-	-	-	-	
48			-	-	-	-	-	-	
49			-	-	-	-	-	-	
50									
51	**Subtotal - Form 1, p275**	(805,926,447)	(33,471,662)	-	-	(772,454,785)	-		
52	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
53	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
54	**Total (ln 51 - ln 52 - ln 53)**	(805,926,447)	(33,471,662)	-	-	(772,454,785)	-		
55	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
56	**Total (ln 54 * ln 55)**		0	0	0	(97,127,482)	0	(97,127,482)	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

III. Account 283 - ADIT - Other **Relevant Year = 2009** (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
	Accumulated Deferred Income Tax:								
57									
58	Prepaid Expenses	(2,160,820)	-	-	-	(1,080,410)	(1,080,410)	(2,160,820)	Book accrual vs. actual payments for tax.
59	Pension Plans	(79,161,220)	(79,161,220)	-	-	-	-	-	ADIT related to Pre-paid Pension Expense.
60	Bond Redemption - Unamortized Call Premium Costs	(5,444,354)	-	-	-	(5,444,354)	-	(5,444,354)	Expenses amortized for books; deducted for tax prior years when incurred/paid.
61	Reg Asset - Deferred Excess 2007 Storm Expenses - OK	(11,444,010)	-	-	-	(11,444,010)	-	(11,444,010)	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
62	Reg Asset - Deferred McClain Plant Costs - OK	(1,205,143)	(1,205,143)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
63	Reg Asset - Deferred Red Rock Plant Costs - OK	(2,814,213)	(2,814,213)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
64	Reg Asset - Deferred Excess 2007 Storm Expenses - AR	(74,096)	-	-	-	(74,096)	-	(74,096)	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
65	Reg Asset - Deferred Excess Pension Expenses - OK	(2,491,900)	(2,491,900)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
66	Reg Asset - Deferred Excess Pension Expenses - AR	33,741	33,741	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
67	Deferred Other - Rate Case Consult/Expert Witness Costs	(235,369)	(235,369)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
68	Deferred Rate Case Expense - OK	(113,972)	(113,972)	-	-	-	-	-	Costs deducted for tax purposes, recorded as Regulatory Assets for book.
69	LIFO Inventory Adjustments - Fuels Stock	(1,913,799)	(1,913,799)	-	-	-	-	-	Full Adj charged to 2008 Book Income vs Taxable Income over 4 yrs per Sec 481.
70			-	-	-	-	-	-	
71			-	-	-	-	-	-	
72			-	-	-	-	-	-	
73			-	-	-	-	-	-	
74			-	-	-	-	-	-	
75			-	-	-	-	-	-	
76			-	-	-	-	-	-	
77			-	-	-	-	-	-	
78			-	-	-	-	-	-	
79			-	-	-	-	-	-	
80			-	-	-	-	-	-	
81			-	-	-	-	-	-	
82			-	-	-	-	-	-	
83			-	-	-	-	-	-	
84			-	-	-	-	-	-	
85			-	-	-	-	-	-	
86			-	-	-	-	-	-	
87			-	-	-	-	-	-	
88			-	-	-	-	-	-	
89			-	-	-	-	-	-	
90			-	-	-	-	-	-	
91			-	-	-	-	-	-	
92			-	-	-	-	-	-	
93			-	-	-	-	-	-	
94			-	-	-	-	-	-	
95			-	-	-	-	-	-	
96			-	-	-	-	-	-	
97			-	-	-	-	-	-	
98			-	-	-	-	-	-	
99			-	-	-	-	-	-	
100			-	-	-	-	-	-	
101			-	-	-	-	-	-	
102			-	-	-	-	-	-	
103			-	-	-	-	-	-	
104			-	-	-	-	-	-	
105			-	-	-	-	-	-	
106			-	-	-	-	-	-	
107			-	-	-	-	-	-	
108									
109	**Subtotal - Form 1, p277.9.k**	(107,025,154)	(87,901,875)	-	-	(18,042,870)	(1,080,410)		
110	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
111	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
112	**Total (ln 109 - ln 110 - ln 111)**	(107,025,154)	(87,901,875)	-	-	(18,042,870)	(1,080,410)		
113	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
114	**Total (ln 112 * ln 113)**		0	0	0	(2,268,687)	(62,019)	(2,330,707)	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

IV. Account 190 - ADIT **Relevant Year =** **2009** (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)	(I) Description / Justification
115	Accrued Vacation	4,202,206	-	-	-	-	4,202,206	4,202,206	Book accrual vs. actual payments for tax.
116	Derivative Instruments	129,259	129,259	-	-	-	-	-	Tax deduction for Mark-to-Market discount permitted by Section 465.
117	Bad Debts	883,243	883,243	-	-	-	-	-	Book accrual vs. actual payments for tax.
118	Accrued Interest	1,030,526	-	-	-	1,030,526	-	1,030,526	Book accrual vs. actual payments for tax.
119	Accrued Liability-Public Liability	724,556	-	-	-	362,278	362,278	724,556	Book accrual vs. actual payments for tax. Split 50% labor, 50% plant
120	Accrued Liability-Employee Related	590,758	-	-	-	-	590,758	590,758	Book accrual vs. actual payments for tax.
121	Regulatory Liabilities- Deferred Gains - Property Sales	6,397	6,397	-	-	-	-	-	Taxable gains recorded as Regulatory Liabilities for book.
122	Rate Refund Accrual	244,723	244,723	-	-		-	-	Deferred revenue accrual per books vs. actual revenue for tax purposes.
123	Income Taxes Recoverable, net (Pens & Medicare Part D)	6,442,710	-	-	-	-	6,442,710	6,442,710	Anticipated Medicare subsidy.
124	Post-Retirement Benefits	29,233,798	-	-	-	-	29,233,798	29,233,798	Book accrual vs. actual payments for tax purposes.
125	Consumer Loans	-	-						Income, losses and expenses recognized for tax but not for book.
126	Deferred Fed Investment Tax Credits	5,893,853	5,893,853						ADIT for Unamortized ITC balance. ITC utilized for tax purposes in prior years.
127	Tax Credit Carryover	33,296,514	33,296,514	-	-	-	-	-	ADIT for Tax Credit Carryover
128	Net Operating Loss	230,811	230,811	-	-	-	-	-	ADIT for Net Operating Loss carryover
129	Medicare Part D Subsidy	16,633,572	-	-	-	-	16,633,572	16,633,572	ADIT for Non-taxable government subsidy (IRC Section 139A) FAS 158
130	Other - Investments in Partnerships	72,491	72,491	-	-	-	-	-	ADIT for Book vs. Tax Partnership Income and Expense differences.
131	Kaw Water Storage Agreement Liability	3,137,726	3,137,726	-	-	-	-	-	ADIT for Book vs. Tax Differences due to differences in Imputed Interest Rates
132	Charitable Contributions Carryover	1,486,853	1,486,853	-	-	-	-	-	ADIT for Limited Charitable Contributions Carryover
133									
134									
135							-	-	
136									
137									
138				-	-	-	-	-	
139									
140									
141									
142									
143				-	-	-	-	-	
144			-	-	-	-	-	-	
145			-	-	-	-	-	-	
146			-	-	-	-	-	-	
147			-	-	-	-	-	-	
148			-	-	-	-	-	-	
149			-	-	-	-	-	-	
150									
151	**Subtotal - Form 1, p234.8.c**	104,239,996	45,381,870	-	-	1,392,804	57,465,323		
152	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-		
153	**Less FASB 106 Above if not separately removed**	-	-	-	-	-	-		
154	**Total (ln 151 - ln 152 - ln 153)**	104,239,996	45,381,870	-	-	1,392,804	57,465,323		
155	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%		
156	**Total (ln 154 * ln 155)**		0	0	0	175,129	3,298,705	3,473,834	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet C

V. Account 255 - Accumulated Deferred Investment Tax Credits

Relevant Year = 2009 (Note 2)

Line No.	(A) Identification	(B) Relevant Year Average of BOY and EOY Balance	(C) 100% Non-Transmission Related	(D) 100% Related to facilities excluded in Worksheet H	(E) 100% Transmission Related	(F) Plant Related	(G) Labor Related	(H) Total Included in Ratebase (E)+(F)+(G)
157	Accumulated Deferred Investment Tax Credits	(15,213,997)	(15,213,997)	-	-	-	-	-
158			-	-	-	-	-	-
159			-	-	-	-	-	-
160			-	-	-	-	-	-
161			-	-	-	-	-	-
162			-	-	-	-	-	-
163			-	-	-	-	-	-
164			-	-	-	-	-	-
165			-	-	-	-	-	-
166			-	-	-	-	-	-
167			-	-	-	-	-	-
168			-	-	-	-	-	-
169			-	-	-	-	-	-
170			-	-	-	-	-	-
171			-	-	-	-	-	-
172			-	-	-	-	-	-
173			-	-	-	-	-	-
174			-	-	-	-	-	-
175								
176	**Subtotal - Form 1, p267.8.h**	(15,213,997)	(15,213,997)	-	-	-	-	
177	**Less FASB 109 Above if not separately removed**	-	-	-	-	-	-	
178	**Less FASB 106 Above if not separately removed**	-	-					
179	**Less Post 1971 ITC Property Under F2 Option**	-	-	-	-	-	-	
180	**Total (ln 176 - ln 177 - ln 178 - ln 179)**	(15,213,997)	(15,213,997)	-	-	-	-	
181	**Transmission Allocator [GP or W/S]**		0.0000%	0.0000%	100.0000%	12.5739%	5.7403%	
182	**Total (ln 180 * ln 181)**		0	0	0	0	0	0

NOTE:

1. A worksheet will be provided to support the average of beginning and ending balances for items in ADIT Accounts 281, 282, 283, 190 & 255.
2. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form 1.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet D

I. Account 928 - Regulatory Comm. Expenses

Relevant Year = **2009**

(A) Item No.	(B) Description	(C) 2007 Expense	(D) Non-Transmission	(E) Transmission Allocation	(F) Transmission Direct Assigned	(G) Explanation
	Regulatory Commission Expenses:					
1	FERC Assessment for Annual Charges	1,510,964	1,510,964		-	
2	Arkansas Public Service Commission for Annual Charges	275,471	275,471	-	-	
3	Oklahoma Corporation Commission for Annual Charges	1,373,781	1,373,781	-	-	
4	Arkansas Rate Case (08-103-U)	122,601	122,601	-	-	
5	Arkansas Rate Review - 2010	57,995	57,995	-	-	
6	FERC Transmission Rate Case (ER08-281-000)	11,018	-	-	11,018	
7	OU Spirit (PUD 2009-167)	56,126	56,126	-	-	
8	Oklahoma Rate Case 2009 (PUD 2008-398)	933,872	933,872	-	-	
9	Oklahoma Fuel Audit (PUD 2008-299)	9,646	9,646	-	-	
10	2008 FCA Prudence (PUD 2008-398)	22,549	22,549	-	-	
11	Arkansas Energy Efficiency Programs (06-004-R)	4,508	4,508	-	-	
12	Security	19,973	17,462	2,511	-	Allocated based on gross plant
13	System Hardening Project	36,083	31,546	4,537	-	Allocated based on gross plant
14	Minor Items	88,303	77,200	11,103	-	Allocated based on gross plant
15			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
NOTE:	FERC Assessments are to be included in Column (D)		-	-	-	
	Total - Form I, pg 351.46.h+k	4,522,890	4,493,720	18,152	11,018	

II. Account 930.1 - General Advertising Expense

Relevant Year = **2009**

(A) Item No.	(B) Description	(C) 2007 Expense	(D) Non-Transmission	(E) Transmission Allocation	(F) Transmission Direct Assigned	(G) Explanation
1	General Advertising Expense	1,625	1,625	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
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			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
			-	-	-	
	Total - Form I, pg 323.191.b	1,625	1,625	-	-	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet D

III. Transmission Lease Payments

Relevant Year = 2009

(A) Item No.	(B) Description	(C) Expense

Total Transmission Lease Payments

IV. Account 930.2 - Misc. General Expenses

Relevant Year = 2009

Item No.	Description	Date Sources	TO Total	Explanation
1	Miscellaneous General Expenses	323.192.b	14,919,172	
2	Less: Industry Association Dues	335.1.b	626,487	
3	Plus: EEI Dues		511,399	
4	Plus: SPP Dues		6,000	
5	Adjusted Miscellaneous General Expenses	(ln 1-ln 2+ln 3+ln 4)	14,810,084	

NOTE:

1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form 1.
2. All Industry Assn. Dues shall be removed from Acct. 930.2 and the Formula Rate except for EEI and SPP.
3. In sections I and II, the explanation will include why the cost is related to transmission service as the basis for the allocation

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet E

Additional Revenue Requirement from
Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility

			Relevant Year
			2009
1	Other Expenses:		
2	Direct Assignment Charge		
3	Sponsored (Requested or Economic) Upgrades Charge		
4	Firm and Non-Firm Point-To-Point Charges		
5	Base Plan Charges		4,837,746
6	Schedule 9 Charges		935,695
7	SPP Schedule 1-A		
8	SPP Annual Assessment		
9	NERC Assessment		
10	Ancillary Services Expenses		54,364
11	Other		
12	Other		
13	Other		
14	Total	(Sum of lns 2 through 13)	$ 5,827,805

Notes:

1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Revelant Year" is the year of the most recent FERC Form No. 1.
2. Adjustment to charges that are booked to transmission accounts that are the responsibility of the TO's LSE.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

I. Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase.

A. Determine "R" with hypothetical 100 basis point increase in ROE.

Line No.				
1	ROE w/o incentives (Addendum 2-A, ln 139)			11.10%
2	ROE with additional 100 basis point incentive			12.10%
3	Determine R (cost of long term debt, cost of preferred stock and percent is from Addendum 2-A, lns 137 through139)			
4		%	Cost	Weighted cost
5	Long Term Debt	44.72%	0.0640	0.0286
6	Preferred Stock	0.00%	0.0000	0.0000
7	Common Stock	55.28%	0.1210	0.0669
			R =	0.0955

B. Determine Return using "R" with hypothetical 100 basis point ROE increase.

8	Rate Base (Addendum 2-A, ln 67)	613,169,736
9	R (from A. above)	0.0955
10	Return (Rate Base x R)	58,573,909

C. Determine Income Taxes using Return with hypothetical 100 basis point ROE increase.

11	Return (from B. above)	58,573,909
12	CIT (Addendum 2-A, ln 108)	43.53%
13	Income Tax Calculation (Return x CIT)	25,498,425
14	ITC Adjustment (Addendum 2-A, ln 114)	(921,845)
15	Income Taxes	24,576,580

II. Calculate Net Plant Carrying Charge Rate (NPCC) with hypothetical 100 basis point ROE increase.

A. Determine Net Revenue Requirement less Return and Income Taxes.

16	Net Revenue Requirement (Addendum 2-A, ln 16)	112,212,586
17	Return (Addendum 2-A, ln 116)	55,184,243
18	Income Taxes (Addendum 2-A, ln 115)	23,100,989
19	Net Revenue Requirement, Less Return and Taxes	33,927,354

B. Determine Net Revenue Requirement with hypothetical 100 basis point increase in ROE.

20	Net Revenue Requirement, Less Return and Taxes	33,927,354
21	Return (from I.B. above)	58,573,909
22	Income Taxes (from I.C. above)	24,576,580
23	Net Revenue Requirement, with 100 Basis Point ROE increase	117,077,843
24	Transmission Plant Depreciation Expense (Addendum 2-A, lns 92)	19,526,875
25	Net Rev. Req, w/100 Basis Point ROE increase, less Depreciation	97,550,968

C. Determine NPCC with hypothetical 100 basis point ROE increase.

26	Net Transmission Plant (Addendum 2-A, lns 46)	546,975,024	
27	Net Revenue Requirement, with 100 Basis Point ROE increase	117,077,843	
28	NPCC with 100 Basis Point increase in ROE	21.40%	
29			
30	Net Rev. Req, w/100 Basis Point ROE increase, less Dep.	97,550,968	
31	NPCC with 100 Basis Point ROE increase, less Depreciation	17.83%	(use when no CIAC is associated with facilities receiving incentives)
32	NPCC w/o 100 Basis Point ROE increase, less Depreciation	16.95%	(Addendum 2-A, ln 26)
33	NPCC w/o Return, income taxes and Depreciation	2.63%	(use when CIAC is associated with facilities receiving incentives)
34	100 basis point ROE increase (line 31 - 32)	0.89%	

III. Calculation of Composite Depreciation Rate.

35	Transmission Plant @ Beginning of Period (p.206, ln 58, col. b)	789,771,070
36	Transmission Plant @ End of Period (p.207, ln 58, col. g)	860,448,242
37		1,650,219,312
38	Average Balance of Transmission Investment	825,109,656
39	Annual Depreciation (p.336, ln 7, col. f)	20,977,731
40	Composite Depreciation Rate	2.54%
41	Depreciable Life for Composite Depreciation Rate	39.33
42	Depreciable Life Rounded to Nearest Whole Year	39

NOTE:

Incentives shall not be included in the revenue requirement calculation unless approved by the FERC in a separate single issue filing.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

IV. Summary of Additional Revenue Requirements Detailed in Section V below.

Line No.	Proj. No.	Project Description Summary	In-Service	Investment	Additional Rev. Requirement
	SUMMARY OF ADDITIONAL REVENUE REQUIREMENT FOR FACILITIES RECEIVING INCENTIVES				
43	1				$ -
44	2				
45	3				
46	4				
47	5				
48	6				
49	7				
50	8				
51	9				
52	10				
53	11				
54	12				
55	13				
56	14				
57	15				
58	16				
59					
60					
61		TOTALS		$ -	$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet F

V. Determine the Additional Revenue Requirement for facilities receiving incentives.

A. Facilities receiving incentives

Project 1. Approved by FERC in Docket No. (e.g. ER05-925-000)

Line No.	Details			
62	Investment	-	Current Year	**2009**
63	Service Year (yyyy)	2009	ROE increase accepted by FERC (Basis Points)	50
64	Service Month (1-12)	6	NPCC w/o incentives, less depreciation	16.95%
65	Useful Life	39	NPCC w/incentives approved for these facilities, less dep.	17.39%
66	CIAC (Yes or No)	No	Annual Depreciation Expense (Investment / Useful Life)	-

Line No.		Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Additional Rev. Requirement
69	w/o incentives	2009	-	-	-	$ -	
70	w/incentives	2009	-	-	-	$ -	$ -
71	w/o incentives	2010	-	-	-	-	
72	w/incentives	2010	-	-	-	-	$ -
73	w/o incentives	2011	-	-	-	-	
74	w/incentives	2011	-	-	-	-	$ -
75	w/o incentives	2012	-	-	-	-	
76	w/incentives	2012	-	-	-	-	$ -
77	w/o incentives	2013	-	-	-	-	
78	w/incentives	2013	-	-	-	-	$ -
79	w/o incentives	2014	-	-	-	-	
80	w/incentives	2014	-	-	-	-	$ -
81	w/o incentives	2015	-	-	-	-	
82	w/incentives	2015	-	-	-	-	$ -
83	w/o incentives	2016	-	-	-	-	
84	w/incentives	2016	-	-	-	-	$ -
85	w/o incentives	2017	-	-	-	-	
86	w/incentives	2017	-	-	-	-	$ -
87	w/o incentives	2018	-	-	-	-	
88	w/incentives	2018	-	-	-	-	$ -
89	w/o incentives	2019	-	-	-	-	
90	w/incentives	2019	-	-	-	-	$ -
91	w/o incentives	2020	-	-	-	-	
92	w/incentives	2020	-	-	-	-	$ -
93	w/o incentives	2021	-	-	-	-	
94	w/incentives	2021	-	-	-	-	$ -
95	w/o incentives	2022	-	-	-	-	
96	w/incentives	2022	-	-	-	-	$ -
97	w/o incentives	2023	-	-	-	-	
98	w/incentives	2023	-	-	-	-	$ -
99	w/o incentives	2024	-	-	-	-	
100	w/incentives	2024	-	-	-	-	$ -
101	w/o incentives	2025	-	-	-	-	
102	w/incentives	2025	-	-	-	-	$ -
103	w/o incentives	2026	-	-	-	-	
104	w/incentives	2026	-	-	-	-	$ -
105	w/o incentives	2027	-	-	-	-	
106	w/incentives	2027	-	-	-	-	$ -
107	w/o incentives	2028	-	-	-	-	
108	w/incentives	2028	-	-	-	-	$ -
109	w/o incentives	2029	-	-	-	-	
110	w/incentives	2029	-	-	-	-	$ -
111	w/o incentives	2030	-	-	-	-	
112	w/incentives	2030	-	-	-	-	$ -
113	w/o incentives	2031	-	-	-	-	
114	w/incentives	2031	-	-	-	-	$ -
115	w/o incentives	2032	-	-	-	-	
116	w/incentives	2032	-	-	-	-	$ -
117	w/o incentives	2033	-	-	-	-	
118	w/incentives	2033	-	-	-	-	$ -
119	w/o incentives	2034	-	-	-	-	
120	w/incentives	2034	-	-	-	-	$ -
121	w/o incentives	2035	-	-	-	-	
122	w/incentives	2035	-	-	-	-	$ -
123	w/o incentives	2036	-	-	-	-	
124	w/incentives	2036	-	-	-	-	$ -
125	w/o incentives	2037	-	-	-	-	
126	w/incentives	2037	-	-	-	-	$ -
127	w/o incentives	2038	-	-	-	-	
128	w/incentives	2038	-	-	-	-	$ -
129	w/o incentives	2039	-	-	-	-	
130	w/incentives	2039	-	-	-	-	$ -
131	w/o incentives	....		....	.....	....	
132	w/incentives	....	....	.....	.....	....	....
133							$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

I. Project Summary

Proj. No.	A. BASE PLAN UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	**In-Service**	**Investment**	**ATRR**
1	Reno-Sunny Lane 69kV Line - replace wave trap & current transformer to allow 1200A limit	6/1/2006	$ 67,511	$ 11,685
2	Richards Tap-Richards 138kV Line - construct new 138kV line	6/1/2006	$ 2,765,703	$ 478,694
3	Van Buren AVEC-Van Buren Interconnect 69kV Line - replace wave trap and current transformer to allow 1200A limit	6/1/2006	$ 107,896	$ 18,675
4	Brown Explorer Tap 138kV Line - upgrade current transformer at Brown Substation	6/1/2006	$ 31,518	$ 5,455
5	NE Enid-Glenwood 138kV Line - construct new 138kV line	12/1/2006	$ 3,897,313	$ 683,245
6	Razorback-Short Mountain 69kV Line - construct new 69kV line	12/1/2006	$ 9,320,377	$ 1,633,971
7	Richards-Piedmont 138kV Line - construct new 138kV line	10/1/2007	$ 3,790,016	$ 678,518
8	OG&E Windfarm-WFEC Mooreland 138kV Line - upgrade conductor to 795AS33	6/1/2007	$ 85,105	$ 15,110
9	Ft. Smith-Colony 161kV Line - replace 1200A terminal equipment with 2000A terminal equipment	12/1/2008	$ 136,512	$ 25,150
10	Cedar Lane-Canadian 138kV Line - replace 800A wave trap to allow 1200A limit	6/1/2008	$ 23,213	$ 4,225
11	Bodle Substation - Install 138kV Circuit Breaker, Line Relaying, Wave Traps, CCVTs and Communications	6/1/2010	$ 726,650	$ 138,607
12	Ardmore - Rocky Point 69kV Line - rebuild and reconductor 0.82 miles of line with 477AS33	6/1/2011	$ 461,000	$ 51,395
13	Tiger Creek Substation - install 69kV, 9MVAR capacitor bank	2/1/2011	$ 266,000	$ 46,600
14				
15				
16				
17				
18				
19				
	BASE PLAN UPGRADE TOTALS		**$ 21,678,814**	**$ 3,791,329**

Proj. No.	B. TRANSMISSION SERVICE UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	**In-Service**	**Investment**	**ATRR**
1				
2				
3				
4				
5				
6				
7				
	TRANSMISSION SERVICE UPGRADE TOTALS			

Proj. No.	C. SPONSORED OR ECONOMIC PORTFOLIO UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	**In-Service**	**Investment**	**ATRR**
1				
2				
3				
4				
5				
6				
7				
	SPONSORED OR ECONOMIC PORTFOLIO UPGRADE TOTALS			

Proj. No.	D. GENERATOR INTERCONNECTION FACILITIES ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY			
	Project Description Summary	**In-Service**	**Investment**	**ATRR**
1				
2				
3				
4				
5				
6				
7				
	GENERATOR INTERCONNECTION FACILITIES TOTALS			

TOTAL SPP OATT RELATED UPGRADES REVENUE REQUIREMENT (Sum of Parts A, B, C & D above) **$ 3,791,329**

NOTES:

1. Base Plan Upgrades and Economic Portfolio revenue requirement are estimates and will be trued-up to actual amounts in the True-up Adjustment.
2. Base Plan and Economic Portfolio revenue requirements in the Summaries will be provided to SPP for their Cost Allocation calculations.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

II. Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities.

A. Base Plan facilities.

Project 1: Reno - Sunny Lane 69kV Line -- Replace wave trap and current transformers to allow 1200A limit. 2006-2016 STEP project.

The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
1	Investment	$ 67,511	Current Year			2011
2	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			16.95%
3	Service Month (1-12)	6				
4	Useful Life	39	Annual Depreciation Expense		(Investment / Useful Life)	$ 1,731
5	CIAC (Yes or No)	No				
6 7	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
8	2006	$ 67,511	$ 888	$ 66,623	$ 7,038	$ 7,038
9	2007	$ 66,623	$ 1,777	$ 64,846	$ 12,060	$ 12,060
10	2008	$ 64,846	$ 1,777	$ 63,070	$ 11,782	$ 11,782
11	2009	$ 63,070	$ 1,731	$ 61,339	$ 10,378	$ 10,378
12	2010	$ 61,339	$ 1,731	$ 59,608	$ 11,978	$ 11,978
13	2011	$ 59,608	$ 1,731	$ 57,877	$ 11,685	$ 11,685
14	2012	$ -	$ -	$ -	$ -	$ -
15	2013	$ -	$ -	$ -	$ -	$ -
16	2014	$ -	$ -	$ -	$ -	$ -
17	2015	$ -	$ -	$ -	$ -	$ -
18	2016	$ -	$ -	$ -	$ -	$ -
19	2017	$ -	$ -	$ -	$ -	$ -
20	2018	$ -	$ -	$ -	$ -	$ -
21	2019	$ -	$ -	$ -	$ -	$ -
22	2020	$ -	$ -	$ -	$ -	$ -
23	2021	$ -	$ -	$ -	$ -	$ -
24	2022	$ -	$ -	$ -	$ -	$ -
25	2023	$ -	$ -	$ -	$ -	$ -
26	2024	$ -	$ -	$ -	$ -	$ -
27	2025	$ -	$ -	$ -	$ -	$ -
28	2026	$ -	$ -	$ -	$ -	$ -
29	2027	$ -	$ -	$ -	$ -	$ -
30	2028	$ -	$ -	$ -	$ -	$ -
31	2029	$ -	$ -	$ -	$ -	$ -
32	2030	$ -	$ -	$ -	$ -	$ -
33	2031	$ -	$ -	$ -	$ -	$ -
34	2032	$ -	$ -	$ -	$ -	$ -
35	2033	$ -	$ -	$ -	$ -	$ -
36	2034	$ -	$ -	$ -	$ -	$ -
37	2035	$ -	$ -	$ -	$ -	$ -
38	2036	$ -	$ -	$ -	$ -	$ -
39	2037	$ -	$ -	$ -	$ -	$ -
40	2038	$ -	$ -	$ -	$ -	$ -
41	2039	$ -	$ -	$ -	$ -	$ -
42	2040	$ -	$ -	$ -	$ -	$ -
43	2041	$ -	$ -	$ -	$ -	$ -
44	2042	$ -	$ -	$ -	$ -	$ -
45	2043	$ -	$ -	$ -	$ -	$ -
46	2044	$ -	$ -	$ -	$ -	$ -
47	2045	$ -	$ -	$ -	$ -	$ -
48	2046	$ -	$ -	$ -	$ -	$ -
49	2047	$ -	$ -	$ -	$ -	$ -
50	2048	$ -	$ -	$ -	$ -	$ -
51	2049	$ -	$ -	$ -	$ -	$ -
52	2050	$ -	$ -	$ -	$ -	$ -
53						
54	Project Totals				$ 64,921	$ 64,921

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 2: Richards Tap-Richards 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
55	Investment	$ 2,765,703	Current Year		2011
56	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation		16.95%
57	Service Month (1-12)	6			
58	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 70,915
59	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
62	2006	$ 2,765,703	$ 36,391	$ 2,729,312	$ 288,312	$ 288,312
63	2007	$ 2,729,312	$ 72,782	$ 2,656,531	$ 494,074	$ 494,074
64	2008	$ 2,656,531	$ 72,782	$ 2,583,749	$ 482,687	$ 482,687
65	2009	$ 2,583,749	$ 70,915	$ 2,512,834	$ 425,166	$ 425,166
66	2010	$ 2,512,834	$ 70,915	$ 2,441,918	$ 490,710	$ 490,710
67	2011	$ 2,441,918	$ 70,915	$ 2,371,003	$ 478,694	$ 478,694
68	2012	$ -	$ -	$ -	$ -	$ -
69	2013	$ -	$ -	$ -	$ -	$ -
70	2014	$ -	$ -	$ -	$ -	$ -
71	2015	$ -	$ -	$ -	$ -	$ -
72	2016	$ -	$ -	$ -	$ -	$ -
73	2017	$ -	$ -	$ -	$ -	$ -
74	2018	$ -	$ -	$ -	$ -	$ -
75	2019	$ -	$ -	$ -	$ -	$ -
76	2020	$ -	$ -	$ -	$ -	$ -
77	2021	$ -	$ -	$ -	$ -	$ -
78	2022	$ -	$ -	$ -	$ -	$ -
79	2023	$ -	$ -	$ -	$ -	$ -
80	2024	$ -	$ -	$ -	$ -	$ -
81	2025	$ -	$ -	$ -	$ -	$ -
82	2026	$ -	$ -	$ -	$ -	$ -
83	2027	$ -	$ -	$ -	$ -	$ -
84	2028	$ -	$ -	$ -	$ -	$ -
85	2029	$ -	$ -	$ -	$ -	$ -
86	2030	$ -	$ -	$ -	$ -	$ -
87	2031	$ -	$ -	$ -	$ -	$ -
88	2032	$ -	$ -	$ -	$ -	$ -
89	2033	$ -	$ -	$ -	$ -	$ -
90	2034	$ -	$ -	$ -	$ -	$ -
91	2035	$ -	$ -	$ -	$ -	$ -
92	2036	$ -	$ -	$ -	$ -	$ -
93	2037	$ -	$ -	$ -	$ -	$ -
94	2038	$ -	$ -	$ -	$ -	$ -
95	2039	$ -	$ -	$ -	$ -	$ -
96	2040	$ -	$ -	$ -	$ -	$ -
97	2041	$ -	$ -	$ -	$ -	$ -
98	2042	$ -	$ -	$ -	$ -	$ -
99	2043	$ -	$ -	$ -	$ -	$ -
100	2044	$ -	$ -	$ -	$ -	$ -
101	2045	$ -	$ -	$ -	$ -	$ -
102	2046	$ -	$ -	$ -	$ -	$ -
103	2047	$ -	$ -	$ -	$ -	$ -
104	2048	$ -	$ -	$ -	$ -	$ -
105	2049	$ -	$ -	$ -	$ -	$ -
106	2050	$ -	$ -	$ -	$ -	$ -
107						
108	Project Totals				$ 2,659,643	$ 2,659,643

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 3: Van Buren AVEC - Van Buren Interconnect 69kV Line -- Wave trap and current transformer ratio work to increase limit to 1200A. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details										
109	Investment	$	107,896	Current Year							2011
110	Service Year (yyyy)		2006	NPCC w/o incentives, less depreciation							16.95%
111	Service Month (1-12)		6								
112	Useful Life		39	Annual Depreciation Expense		(Investment / Useful Life)				$	2,767
113	CIAC (Yes or No)		No								
114-115	**Investment Year**		**Beginning Balance**		**Depreciation Expense**		**Ending Balance**		**Revenue Requirement**		**Rev. Req. for SPP Allocation**
116	2006	$	107,896	$	1,420	$	106,477	$	11,248	$	11,248
117	2007	$	106,477	$	2,839	$	103,637	$	19,275	$	19,275
118	2008	$	103,637	$	2,839	$	100,798	$	18,831	$	18,831
119	2009	$	100,798	$	2,767	$	98,031	$	16,587	$	16,587
120	2010	$	98,031	$	2,767	$	95,265	$	19,144	$	19,144
121	2011	$	95,265	$	2,767	$	92,498	$	18,675	$	18,675
122	2012	$	-	$	-	$	-	$	-	$	-
123	2013	$	-	$	-	$	-	$	-	$	-
124	2014	$	-	$	-	$	-	$	-	$	-
125	2015	$	-	$	-	$	-	$	-	$	-
126	2016	$	-	$	-	$	-	$	-	$	-
127	2017	$	-	$	-	$	-	$	-	$	-
128	2018	$	-	$	-	$	-	$	-	$	-
129	2019	$	-	$	-	$	-	$	-	$	-
130	2020	$	-	$	-	$	-	$	-	$	-
131	2021	$	-	$	-	$	-	$	-	$	-
132	2022	$	-	$	-	$	-	$	-	$	-
133	2023	$	-	$	-	$	-	$	-	$	-
134	2024	$	-	$	-	$	-	$	-	$	-
135	2025	$	-	$	-	$	-	$	-	$	-
136	2026	$	-	$	-	$	-	$	-	$	-
137	2027	$	-	$	-	$	-	$	-	$	-
138	2028	$	-	$	-	$	-	$	-	$	-
139	2029	$	-	$	-	$	-	$	-	$	-
140	2030	$	-	$	-	$	-	$	-	$	-
141	2031	$	-	$	-	$	-	$	-	$	-
142	2032	$	-	$	-	$	-	$	-	$	-
143	2033	$	-	$	-	$	-	$	-	$	-
144	2034	$	-	$	-	$	-	$	-	$	-
145	2035	$	-	$	-	$	-	$	-	$	-
146	2036	$	-	$	-	$	-	$	-	$	-
147	2037	$	-	$	-	$	-	$	-	$	-
148	2038	$	-	$	-	$	-	$	-	$	-
149	2039	$	-	$	-	$	-	$	-	$	-
150	2040	$	-	$	-	$	-	$	-	$	-
151	2041	$	-	$	-	$	-	$	-	$	-
152	2042	$	-	$	-	$	-	$	-	$	-
153	2043	$	-	$	-	$	-	$	-	$	-
154	2044	$	-	$	-	$	-	$	-	$	-
155	2045	$	-	$	-	$	-	$	-	$	-
156	2046	$	-	$	-	$	-	$	-	$	-
157	2047	$	-	$	-	$	-	$	-	$	-
158	2048	$	-	$	-	$	-	$	-	$	-
159	2049	$	-	$	-	$	-	$	-	$	-
160	2050	$	-	$	-	$	-	$	-	$	-
161											
162	Project Totals							$	103,760	$	103,760

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 4: Brown Explorer Tap 138kV Line -- Upgrade current transformers at Brown Substation. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
163	Investment	$ 31,518	Current Year			2011
164	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			16.95%
165	Service Month (1-12)	6				
166	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 808
167	CIAC (Yes or No)	No				
168 169	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
170	2006	$ 31,518	$ 415	$ 31,103	$ 3,286	$ 3,286
171	2007	$ 31,103	$ 829	$ 30,274	$ 5,630	$ 5,630
172	2008	$ 30,274	$ 829	$ 29,444	$ 5,501	$ 5,501
173	2009	$ 29,444	$ 808	$ 28,636	$ 4,845	$ 4,845
174	2010	$ 28,636	$ 808	$ 27,828	$ 5,592	$ 5,592
175	2011	$ 27,828	$ 808	$ 27,020	$ 5,455	$ 5,455
176	2012	$ -	$ -	$ -	$ -	$ -
177	2013	$ -	$ -	$ -	$ -	$ -
178	2014	$ -	$ -	$ -	$ -	$ -
179	2015	$ -	$ -	$ -	$ -	$ -
180	2016	$ -	$ -	$ -	$ -	$ -
181	2017	$ -	$ -	$ -	$ -	$ -
182	2018	$ -	$ -	$ -	$ -	$ -
183	2019	$ -	$ -	$ -	$ -	$ -
184	2020	$ -	$ -	$ -	$ -	$ -
185	2021	$ -	$ -	$ -	$ -	$ -
186	2022	$ -	$ -	$ -	$ -	$ -
187	2023	$ -	$ -	$ -	$ -	$ -
188	2024	$ -	$ -	$ -	$ -	$ -
189	2025	$ -	$ -	$ -	$ -	$ -
190	2026	$ -	$ -	$ -	$ -	$ -
191	2027	$ -	$ -	$ -	$ -	$ -
192	2028	$ -	$ -	$ -	$ -	$ -
193	2029	$ -	$ -	$ -	$ -	$ -
194	2030	$ -	$ -	$ -	$ -	$ -
195	2031	$ -	$ -	$ -	$ -	$ -
196	2032	$ -	$ -	$ -	$ -	$ -
197	2033	$ -	$ -	$ -	$ -	$ -
198	2034	$ -	$ -	$ -	$ -	$ -
199	2035	$ -	$ -	$ -	$ -	$ -
200	2036	$ -	$ -	$ -	$ -	$ -
201	2037	$ -	$ -	$ -	$ -	$ -
202	2038	$ -	$ -	$ -	$ -	$ -
203	2039	$ -	$ -	$ -	$ -	$ -
204	2040	$ -	$ -	$ -	$ -	$ -
205	2041	$ -	$ -	$ -	$ -	$ -
206	2042	$ -	$ -	$ -	$ -	$ -
207	2043	$ -	$ -	$ -	$ -	$ -
208	2044	$ -	$ -	$ -	$ -	$ -
209	2045	$ -	$ -	$ -	$ -	$ -
210	2046	$ -	$ -	$ -	$ -	$ -
211	2047	$ -	$ -	$ -	$ -	$ -
212	2048	$ -	$ -	$ -	$ -	$ -
213	2049	$ -	$ -	$ -	$ -	$ -
214	2050	$ -	$ -	$ -	$ -	$ -
215						
216	Project Totals				$ 30,309	$ 30,309

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 5: NE Enid - Glenwood 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
217	Investment	$ 3,897,313	Current Year			2011
218	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation			16.95%
219	Service Month (1-12)	12				
220	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 99,931
221	CIAC (Yes or No)	No				
222–223	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
224	2006	$ 3,897,313	$ -	$ 3,897,313	$ 50,809	$ 50,809
225	2007	$ 3,897,313	$ 102,561	$ 3,794,752	$ 704,251	$ 704,251
226	2008	$ 3,794,752	$ 102,561	$ 3,692,191	$ 688,206	$ 688,206
227	2009	$ 3,692,191	$ 99,931	$ 3,592,260	$ 606,254	$ 606,254
228	2010	$ 3,592,260	$ 99,931	$ 3,492,329	$ 700,178	$ 700,178
229	2011	$ 3,492,329	$ 99,931	$ 3,392,398	$ 683,245	$ 683,245
230	2012	$ -	$ -	$ -	$ -	$ -
231	2013	$ -	$ -	$ -	$ -	$ -
232	2014	$ -	$ -	$ -	$ -	$ -
233	2015	$ -	$ -	$ -	$ -	$ -
234	2016	$ -	$ -	$ -	$ -	$ -
235	2017	$ -	$ -	$ -	$ -	$ -
236	2018	$ -	$ -	$ -	$ -	$ -
237	2019	$ -	$ -	$ -	$ -	$ -
238	2020	$ -	$ -	$ -	$ -	$ -
239	2021	$ -	$ -	$ -	$ -	$ -
240	2022	$ -	$ -	$ -	$ -	$ -
241	2023	$ -	$ -	$ -	$ -	$ -
242	2024	$ -	$ -	$ -	$ -	$ -
243	2025	$ -	$ -	$ -	$ -	$ -
244	2026	$ -	$ -	$ -	$ -	$ -
245	2027	$ -	$ -	$ -	$ -	$ -
246	2028	$ -	$ -	$ -	$ -	$ -
247	2029	$ -	$ -	$ -	$ -	$ -
248	2030	$ -	$ -	$ -	$ -	$ -
249	2031	$ -	$ -	$ -	$ -	$ -
250	2032	$ -	$ -	$ -	$ -	$ -
251	2033	$ -	$ -	$ -	$ -	$ -
252	2034	$ -	$ -	$ -	$ -	$ -
253	2035	$ -	$ -	$ -	$ -	$ -
254	2036	$ -	$ -	$ -	$ -	$ -
255	2037	$ -	$ -	$ -	$ -	$ -
256	2038	$ -	$ -	$ -	$ -	$ -
257	2039	$ -	$ -	$ -	$ -	$ -
258	2040	$ -	$ -	$ -	$ -	$ -
259	2041	$ -	$ -	$ -	$ -	$ -
260	2042	$ -	$ -	$ -	$ -	$ -
261	2043	$ -	$ -	$ -	$ -	$ -
262	2044	$ -	$ -	$ -	$ -	$ -
263	2045	$ -	$ -	$ -	$ -	$ -
264	2046	$ -	$ -	$ -	$ -	$ -
265	2047	$ -	$ -	$ -	$ -	$ -
266	2048	$ -	$ -	$ -	$ -	$ -
267	2049	$ -	$ -	$ -	$ -	$ -
268	2050	$ -	$ -	$ -	$ -	$ -
269						
270	Project Totals				$ 3,432,943	$ 3,432,943

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 6: Razorback - Short Mountain 69kV Line -- Construct new 69kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
271	Investment	$ 9,320,377	Current Year		2011
272	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation		16.95%
273	Service Month (1-12)	12			
274	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 238,984
275	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
278	2006	$ 9,320,377	$ -	$ 9,320,377	$ 121,510	$ 121,510
279	2007	$ 9,320,377	$ 245,273	$ 9,075,104	$ 1,684,207	$ 1,684,207
280	2008	$ 9,075,104	$ 245,273	$ 8,829,831	$ 1,645,835	$ 1,645,835
281	2009	$ 8,829,831	$ 238,984	$ 8,590,847	$ 1,449,850	$ 1,449,850
282	2010	$ 8,590,847	$ 238,984	$ 8,351,863	$ 1,674,467	$ 1,674,467
283	2011	$ 8,351,863	$ 238,984	$ 8,112,879	$ 1,633,971	$ 1,633,971
284	2012	$ -	$ -	$ -	$ -	$ -
285	2013	$ -	$ -	$ -	$ -	$ -
286	2014	$ -	$ -	$ -	$ -	$ -
287	2015	$ -	$ -	$ -	$ -	$ -
288	2016	$ -	$ -	$ -	$ -	$ -
289	2017	$ -	$ -	$ -	$ -	$ -
290	2018	$ -	$ -	$ -	$ -	$ -
291	2019	$ -	$ -	$ -	$ -	$ -
292	2020	$ -	$ -	$ -	$ -	$ -
293	2021	$ -	$ -	$ -	$ -	$ -
294	2022	$ -	$ -	$ -	$ -	$ -
295	2023	$ -	$ -	$ -	$ -	$ -
296	2024	$ -	$ -	$ -	$ -	$ -
297	2025	$ -	$ -	$ -	$ -	$ -
298	2026	$ -	$ -	$ -	$ -	$ -
299	2027	$ -	$ -	$ -	$ -	$ -
300	2028	$ -	$ -	$ -	$ -	$ -
301	2029	$ -	$ -	$ -	$ -	$ -
302	2030	$ -	$ -	$ -	$ -	$ -
303	2031	$ -	$ -	$ -	$ -	$ -
304	2032	$ -	$ -	$ -	$ -	$ -
305	2033	$ -	$ -	$ -	$ -	$ -
306	2034	$ -	$ -	$ -	$ -	$ -
307	2035	$ -	$ -	$ -	$ -	$ -
308	2036	$ -	$ -	$ -	$ -	$ -
309	2037	$ -	$ -	$ -	$ -	$ -
310	2038	$ -	$ -	$ -	$ -	$ -
311	2039	$ -	$ -	$ -	$ -	$ -
312	2040	$ -	$ -	$ -	$ -	$ -
313	2041	$ -	$ -	$ -	$ -	$ -
314	2042	$ -	$ -	$ -	$ -	$ -
315	2043	$ -	$ -	$ -	$ -	$ -
316	2044	$ -	$ -	$ -	$ -	$ -
317	2045	$ -	$ -	$ -	$ -	$ -
318	2046	$ -	$ -	$ -	$ -	$ -
319	2047	$ -	$ -	$ -	$ -	$ -
320	2048	$ -	$ -	$ -	$ -	$ -
321	2049	$ -	$ -	$ -	$ -	$ -
322	2050	$ -	$ -	$ -	$ -	$ -
323						
324	Project Totals				$ 8,209,841	$ 8,209,841

$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 7: Richards - Piedmont 138kV Line -- Construct new 138kV line. 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
325	Investment	$ 3,790,016	Current Year			2011
326	Service Year (yyyy)	2007	NPCC w/o incentives, less depreciation			16.95%
327	Service Month (1-12)	10				
328	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 97,180
329	CIAC (Yes or No)	No				
330/331	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
332	2007	$ 3,790,016	$ 16,623	$ 3,773,393	$ 165,505	$ 165,505
333	2008	$ 3,773,393	$ 99,737	$ 3,673,656	$ 682,261	$ 682,261
334	2009	$ 3,673,656	$ 97,180	$ 3,576,476	$ 601,118	$ 601,118
335	2010	$ 3,576,476	$ 97,180	$ 3,479,296	$ 694,985	$ 694,985
336	2011	$ 3,479,296	$ 97,180	$ 3,382,116	$ 678,518	$ 678,518
337	2012	$ -	$ -	$ -	$ -	$ -
338	2013	$ -	$ -	$ -	$ -	$ -
339	2014	$ -	$ -	$ -	$ -	$ -
340	2015	$ -	$ -	$ -	$ -	$ -
341	2016	$ -	$ -	$ -	$ -	$ -
342	2017	$ -	$ -	$ -	$ -	$ -
343	2018	$ -	$ -	$ -	$ -	$ -
344	2019	$ -	$ -	$ -	$ -	$ -
345	2020	$ -	$ -	$ -	$ -	$ -
346	2021	$ -	$ -	$ -	$ -	$ -
347	2022	$ -	$ -	$ -	$ -	$ -
348	2023	$ -	$ -	$ -	$ -	$ -
349	2024	$ -	$ -	$ -	$ -	$ -
350	2025	$ -	$ -	$ -	$ -	$ -
351	2026	$ -	$ -	$ -	$ -	$ -
352	2027	$ -	$ -	$ -	$ -	$ -
353	2028	$ -	$ -	$ -	$ -	$ -
354	2029	$ -	$ -	$ -	$ -	$ -
355	2030	$ -	$ -	$ -	$ -	$ -
356	2031	$ -	$ -	$ -	$ -	$ -
357	2032	$ -	$ -	$ -	$ -	$ -
358	2033	$ -	$ -	$ -	$ -	$ -
359	2034	$ -	$ -	$ -	$ -	$ -
360	2035	$ -	$ -	$ -	$ -	$ -
361	2036	$ -	$ -	$ -	$ -	$ -
362	2037	$ -	$ -	$ -	$ -	$ -
363	2038	$ -	$ -	$ -	$ -	$ -
364	2039	$ -	$ -	$ -	$ -	$ -
365	2040	$ -	$ -	$ -	$ -	$ -
366	2041	$ -	$ -	$ -	$ -	$ -
367	2042	$ -	$ -	$ -	$ -	$ -
368	2043	$ -	$ -	$ -	$ -	$ -
369	2044	$ -	$ -	$ -	$ -	$ -
370	2045	$ -	$ -	$ -	$ -	$ -
371	2046	$ -	$ -	$ -	$ -	$ -
372	2047	$ -	$ -	$ -	$ -	$ -
373	2048	$ -	$ -	$ -	$ -	$ -
374	2049	$ -	$ -	$ -	$ -	$ -
375	2050	$ -	$ -	$ -	$ -	$ -
376	2051	$ -	$ -	$ -	$ -	$ -
377						
378	Project Totals				$ 2,822,387	$ 2,822,387

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 8: OG&E Windfarm - WFEC Mooreland 138kV Line -- Upgrade conductor to 795AS33. 2006 Aggregate Study 1 and 2006 - 2016 STEP project.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
379	Investment	$ 85,105	Current Year			2011
380	Service Year (yyyy)	2007	NPCC w/o incentives, less depreciation			16.95%
381	Service Month (1-12)	6				
382	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 2,182
383	CIAC (Yes or No)	No				
384-385	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
386	2007	$ 85,105	$ 1,120	$ 83,985	$ 8,872	$ 8,872
387	2008	$ 83,985	$ 2,240	$ 81,746	$ 15,203	$ 15,203
388	2009	$ 81,746	$ 2,182	$ 79,564	$ 13,394	$ 13,394
389	2010	$ 79,564	$ 2,182	$ 77,382	$ 15,479	$ 15,479
390	2011	$ 77,382	$ 2,182	$ 75,199	$ 15,110	$ 15,110
391	2012	$ -	$ -	$ -	$ -	$ -
392	2013	$ -	$ -	$ -	$ -	$ -
393	2014	$ -	$ -	$ -	$ -	$ -
394	2015	$ -	$ -	$ -	$ -	$ -
395	2016	$ -	$ -	$ -	$ -	$ -
396	2017	$ -	$ -	$ -	$ -	$ -
397	2018	$ -	$ -	$ -	$ -	$ -
398	2019	$ -	$ -	$ -	$ -	$ -
399	2020	$ -	$ -	$ -	$ -	$ -
400	2021	$ -	$ -	$ -	$ -	$ -
401	2022	$ -	$ -	$ -	$ -	$ -
402	2023	$ -	$ -	$ -	$ -	$ -
403	2024	$ -	$ -	$ -	$ -	$ -
404	2025	$ -	$ -	$ -	$ -	$ -
405	2026	$ -	$ -	$ -	$ -	$ -
406	2027	$ -	$ -	$ -	$ -	$ -
407	2028	$ -	$ -	$ -	$ -	$ -
408	2029	$ -	$ -	$ -	$ -	$ -
409	2030	$ -	$ -	$ -	$ -	$ -
410	2031	$ -	$ -	$ -	$ -	$ -
411	2032	$ -	$ -	$ -	$ -	$ -
412	2033	$ -	$ -	$ -	$ -	$ -
413	2034	$ -	$ -	$ -	$ -	$ -
414	2035	$ -	$ -	$ -	$ -	$ -
415	2036	$ -	$ -	$ -	$ -	$ -
416	2037	$ -	$ -	$ -	$ -	$ -
417	2038	$ -	$ -	$ -	$ -	$ -
418	2039	$ -	$ -	$ -	$ -	$ -
419	2040	$ -	$ -	$ -	$ -	$ -
420	2041	$ -	$ -	$ -	$ -	$ -
421	2042	$ -	$ -	$ -	$ -	$ -
422	2043	$ -	$ -	$ -	$ -	$ -
423	2044	$ -	$ -	$ -	$ -	$ -
424	2045	$ -	$ -	$ -	$ -	$ -
425	2046	$ -	$ -	$ -	$ -	$ -
426	2047	$ -	$ -	$ -	$ -	$ -
427	2048	$ -	$ -	$ -	$ -	$ -
428	2049	$ -	$ -	$ -	$ -	$ -
429	2050	$ -	$ -	$ -	$ -	$ -
430	2051	$ -	$ -	$ -	$ -	$ -
431						
432	Project Totals				$ 68,058	$ 68,058

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 9: Ft. Smith - Colony 161kV Line - Replace 1200A terminal equipment with 2000A equipment to utilize line rating.

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
433	Investment	$ 136,512	Current Year			2011
434	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			16.95%
435	Service Month (1-12)	12				
436	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 3,500
437	CIAC (Yes or No)	No				
438-439	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
440	2008	$ 136,512	$ -	$ 136,512	$ 1,780	$ 1,780
441	2009	$ 136,512	$ 3,500	$ 133,012	$ 22,234	$ 22,234
442	2010	$ 133,012	$ 3,500	$ 129,511	$ 25,743	$ 25,743
443	2011	$ 129,511	$ 3,500	$ 126,011	$ 25,150	$ 25,150
444	2012	$ -	$ -	$ -	$ -	$ -
445	2013	$ -	$ -	$ -	$ -	$ -
446	2014	$ -	$ -	$ -	$ -	$ -
447	2015	$ -	$ -	$ -	$ -	$ -
448	2016	$ -	$ -	$ -	$ -	$ -
449	2017	$ -	$ -	$ -	$ -	$ -
450	2018	$ -	$ -	$ -	$ -	$ -
451	2019	$ -	$ -	$ -	$ -	$ -
452	2020	$ -	$ -	$ -	$ -	$ -
453	2021	$ -	$ -	$ -	$ -	$ -
454	2022	$ -	$ -	$ -	$ -	$ -
455	2023	$ -	$ -	$ -	$ -	$ -
456	2024	$ -	$ -	$ -	$ -	$ -
457	2025	$ -	$ -	$ -	$ -	$ -
458	2026	$ -	$ -	$ -	$ -	$ -
459	2027	$ -	$ -	$ -	$ -	$ -
460	2028	$ -	$ -	$ -	$ -	$ -
461	2029	$ -	$ -	$ -	$ -	$ -
462	2030	$ -	$ -	$ -	$ -	$ -
463	2031	$ -	$ -	$ -	$ -	$ -
464	2032	$ -	$ -	$ -	$ -	$ -
465	2033	$ -	$ -	$ -	$ -	$ -
466	2034	$ -	$ -	$ -	$ -	$ -
467	2035	$ -	$ -	$ -	$ -	$ -
468	2036	$ -	$ -	$ -	$ -	$ -
469	2037	$ -	$ -	$ -	$ -	$ -
470	2038	$ -	$ -	$ -	$ -	$ -
471	2039	$ -	$ -	$ -	$ -	$ -
472	2040	$ -	$ -	$ -	$ -	$ -
473	2041	$ -	$ -	$ -	$ -	$ -
474	2042	$ -	$ -	$ -	$ -	$ -
475	2043	$ -	$ -	$ -	$ -	$ -
476	2044	$ -	$ -	$ -	$ -	$ -
477	2045	$ -	$ -	$ -	$ -	$ -
478	2046	$ -	$ -	$ -	$ -	$ -
479	2047	$ -	$ -	$ -	$ -	$ -
480	2048	$ -	$ -	$ -	$ -	$ -
481	2049	$ -	$ -	$ -	$ -	$ -
482	2050	$ -	$ -	$ -	$ -	$ -
483	2051	$ -	$ -	$ -	$ -	$ -
484	2052	$ -	$ -	$ -	$ -	$ -
485						
486	Project Totals				$ 74,907	$ 74,907

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 10: Cedar Lane - Canadian 138kV Line - Replace 800A wave trap at Cedar Lane

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
487	Investment	$ 23,213	Current Year			2011
488	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			16.95%
489	Service Month (1-12)	6				
490	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 595
491	CIAC (Yes or No)	No				
492 493	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
494	2008	$ 23,213	$ 305	$ 22,908	$ 2,420	$ 2,420
495	2009	$ 22,908	$ 595	$ 22,313	$ 3,738	$ 3,738
496	2010	$ 22,313	$ 595	$ 21,718	$ 4,326	$ 4,326
497	2011	$ 21,718	$ 595	$ 21,122	$ 4,225	$ 4,225
498	2012	$ -	$ -	$ -	$ -	$ -
499	2013	$ -	$ -	$ -	$ -	$ -
500	2014	$ -	$ -	$ -	$ -	$ -
501	2015	$ -	$ -	$ -	$ -	$ -
502	2016	$ -	$ -	$ -	$ -	$ -
503	2017	$ -	$ -	$ -	$ -	$ -
504	2018	$ -	$ -	$ -	$ -	$ -
505	2019	$ -	$ -	$ -	$ -	$ -
506	2020	$ -	$ -	$ -	$ -	$ -
507	2021	$ -	$ -	$ -	$ -	$ -
508	2022	$ -	$ -	$ -	$ -	$ -
509	2023	$ -	$ -	$ -	$ -	$ -
510	2024	$ -	$ -	$ -	$ -	$ -
511	2025	$ -	$ -	$ -	$ -	$ -
512	2026	$ -	$ -	$ -	$ -	$ -
513	2027	$ -	$ -	$ -	$ -	$ -
514	2028	$ -	$ -	$ -	$ -	$ -
515	2029	$ -	$ -	$ -	$ -	$ -
516	2030	$ -	$ -	$ -	$ -	$ -
517	2031	$ -	$ -	$ -	$ -	$ -
518	2032	$ -	$ -	$ -	$ -	$ -
519	2033	$ -	$ -	$ -	$ -	$ -
520	2034	$ -	$ -	$ -	$ -	$ -
521	2035	$ -	$ -	$ -	$ -	$ -
522	2036	$ -	$ -	$ -	$ -	$ -
523	2037	$ -	$ -	$ -	$ -	$ -
524	2038	$ -	$ -	$ -	$ -	$ -
525	2039	$ -	$ -	$ -	$ -	$ -
526	2040	$ -	$ -	$ -	$ -	$ -
527	2041	$ -	$ -	$ -	$ -	$ -
528	2042	$ -	$ -	$ -	$ -	$ -
529	2043	$ -	$ -	$ -	$ -	$ -
530	2044	$ -	$ -	$ -	$ -	$ -
531	2045	$ -	$ -	$ -	$ -	$ -
532	2046	$ -	$ -	$ -	$ -	$ -
533	2047	$ -	$ -	$ -	$ -	$ -
534	2048	$ -	$ -	$ -	$ -	$ -
535	2049	$ -	$ -	$ -	$ -	$ -
536	2050	$ -	$ -	$ -	$ -	$ -
537	2051	$ -	$ -	$ -	$ -	$ -
538	2052	$ -	$ -	$ -	$ -	$ -
539						
540	Project Totals				$ 14,709	$ 14,709

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 11: Bodle Substation - Install 138kV Circuit Breaker, Line Relaying, Wave Traps, CCVTs and Communications

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
541	Investment	$ 726,650	Current Year			2011
542	Service Year (yyyy)	2010	NPCC w/o incentives, less depreciation			16.95%
543	Service Month (1-12)	6				
544	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)		$ 18,632
545	CIAC (Yes or No)	No				
546	**Investment**	**Beginning**	**Depreciation**	**Ending**	**Revenue**	**Rev. Req. for**
547	**Year**	**Balance**	**Expense**	**Balance**	**Requirement**	**SPP Allocation**
548	2010	$ 726,650	$ 9,316	$ 717,334	$ 81,011	$ 81,011
549	2011	$ 717,334	$ 18,632	$ 698,702	$ 138,607	$ 138,607
550	2012	$ -	$ -	$ -	$ -	$ -
551	2013	$ -	$ -	$ -	$ -	$ -
552	2014	$ -	$ -	$ -	$ -	$ -
553	2015	$ -	$ -	$ -	$ -	$ -
554	2016	$ -	$ -	$ -	$ -	$ -
555	2017	$ -	$ -	$ -	$ -	$ -
556	2018	$ -	$ -	$ -	$ -	$ -
557	2019	$ -	$ -	$ -	$ -	$ -
558	2020	$ -	$ -	$ -	$ -	$ -
559	2021	$ -	$ -	$ -	$ -	$ -
560	2022	$ -	$ -	$ -	$ -	$ -
561	2023	$ -	$ -	$ -	$ -	$ -
562	2024	$ -	$ -	$ -	$ -	$ -
563	2025	$ -	$ -	$ -	$ -	$ -
564	2026	$ -	$ -	$ -	$ -	$ -
565	2027	$ -	$ -	$ -	$ -	$ -
566	2028	$ -	$ -	$ -	$ -	$ -
567	2029	$ -	$ -	$ -	$ -	$ -
568	2030	$ -	$ -	$ -	$ -	$ -
569	2031	$ -	$ -	$ -	$ -	$ -
570	2032	$ -	$ -	$ -	$ -	$ -
571	2033	$ -	$ -	$ -	$ -	$ -
572	2034	$ -	$ -	$ -	$ -	$ -
573	2035	$ -	$ -	$ -	$ -	$ -
574	2036	$ -	$ -	$ -	$ -	$ -
575	2037	$ -	$ -	$ -	$ -	$ -
576	2038	$ -	$ -	$ -	$ -	$ -
577	2039	$ -	$ -	$ -	$ -	$ -
578	2040	$ -	$ -	$ -	$ -	$ -
579	2041	$ -	$ -	$ -	$ -	$ -
580	2042	$ -	$ -	$ -	$ -	$ -
581	2043	$ -	$ -	$ -	$ -	$ -
582	2044	$ -	$ -	$ -	$ -	$ -
583	2045	$ -	$ -	$ -	$ -	$ -
584	2046	$ -	$ -	$ -	$ -	$ -
585	2047	$ -	$ -	$ -	$ -	$ -
586	2048	$ -	$ -	$ -	$ -	$ -
587	2049	$ -	$ -	$ -	$ -	$ -
588	2050	$ -	$ -	$ -	$ -	$ -
589	2051	$ -	$ -	$ -	$ -	$ -
590	2052	$ -	$ -	$ -	$ -	$ -
591	2053	$ -	$ -	$ -	$ -	$ -
592	2054	$ -	$ -	$ -	$ -	$ -
593						
594	Project Totals				$ 219,618	$ 219,618

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 12: Ardmore - Rocky Point 69kV Line - rebuild and reconductor 0.82 miles of line with 477AS33

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
595	Investment	$ 461,000	Current Year		2011
596	Service Year (yyyy)	2011	NPCC w/o incentives, less depreciation		16.95%
597	Service Month (1-12)	6			
598	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 11,821
599	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
600-601	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
602	2011	$ 461,000	$ 5,910	$ 455,090	$ 51,395	$ 51,395
603	2012	$ -	$ -	$ -	$ -	$ -
604	2013	$ -	$ -	$ -	$ -	$ -
605	2014	$ -	$ -	$ -	$ -	$ -
606	2015	$ -	$ -	$ -	$ -	$ -
607	2016	$ -	$ -	$ -	$ -	$ -
608	2017	$ -	$ -	$ -	$ -	$ -
609	2018	$ -	$ -	$ -	$ -	$ -
610	2019	$ -	$ -	$ -	$ -	$ -
611	2020	$ -	$ -	$ -	$ -	$ -
612	2021	$ -	$ -	$ -	$ -	$ -
613	2022	$ -	$ -	$ -	$ -	$ -
614	2023	$ -	$ -	$ -	$ -	$ -
615	2024	$ -	$ -	$ -	$ -	$ -
616	2025	$ -	$ -	$ -	$ -	$ -
617	2026	$ -	$ -	$ -	$ -	$ -
618	2027	$ -	$ -	$ -	$ -	$ -
619	2028	$ -	$ -	$ -	$ -	$ -
620	2029	$ -	$ -	$ -	$ -	$ -
621	2030	$ -	$ -	$ -	$ -	$ -
622	2031	$ -	$ -	$ -	$ -	$ -
623	2032	$ -	$ -	$ -	$ -	$ -
624	2033	$ -	$ -	$ -	$ -	$ -
625	2034	$ -	$ -	$ -	$ -	$ -
626	2035	$ -	$ -	$ -	$ -	$ -
627	2036	$ -	$ -	$ -	$ -	$ -
628	2037	$ -	$ -	$ -	$ -	$ -
629	2038	$ -	$ -	$ -	$ -	$ -
630	2039	$ -	$ -	$ -	$ -	$ -
631	2040	$ -	$ -	$ -	$ -	$ -
632	2041	$ -	$ -	$ -	$ -	$ -
633	2042	$ -	$ -	$ -	$ -	$ -
634	2043	$ -	$ -	$ -	$ -	$ -
635	2044	$ -	$ -	$ -	$ -	$ -
636	2045	$ -	$ -	$ -	$ -	$ -
637	2046	$ -	$ -	$ -	$ -	$ -
638	2047	$ -	$ -	$ -	$ -	$ -
639	2048	$ -	$ -	$ -	$ -	$ -
640	2049	$ -	$ -	$ -	$ -	$ -
641	2050	$ -	$ -	$ -	$ -	$ -
642	2051	$ -	$ -	$ -	$ -	$ -
643	2052	$ -	$ -	$ -	$ -	$ -
644	2053	$ -	$ -	$ -	$ -	$ -
645	2054	$ -	$ -	$ -	$ -	$ -
646	2055	$ -	$ -	$ -	$ -	$ -
647						
648	Project Totals				$ 51,395	$ 51,395

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 13: Tiger Creek Substation - install 69kV, 9MVAR capacitor bank

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details				
649	Investment	$ 266,000	Current Year		2011
650	Service Year (yyyy)	2011	NPCC w/o incentives, less depreciation		16.95%
651	Service Month (1-12)	2			
652	Useful Life	39	Annual Depreciation Expense	(Investment / Useful Life)	$ 6,821
653	CIAC (Yes or No)	No			

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
654-655						
656	2011	$ 266,000	$ 5,684	$ 260,316	$ 46,600	$ 46,600
657	2012	$ -	$ -	$ -	$ -	$ -
658	2013	$ -	$ -	$ -	$ -	$ -
659	2014	$ -	$ -	$ -	$ -	$ -
660	2015	$ -	$ -	$ -	$ -	$ -
661	2016	$ -	$ -	$ -	$ -	$ -
662	2017	$ -	$ -	$ -	$ -	$ -
663	2018	$ -	$ -	$ -	$ -	$ -
664	2019	$ -	$ -	$ -	$ -	$ -
665	2020	$ -	$ -	$ -	$ -	$ -
666	2021	$ -	$ -	$ -	$ -	$ -
667	2022	$ -	$ -	$ -	$ -	$ -
668	2023	$ -	$ -	$ -	$ -	$ -
669	2024	$ -	$ -	$ -	$ -	$ -
670	2025	$ -	$ -	$ -	$ -	$ -
671	2026	$ -	$ -	$ -	$ -	$ -
672	2027	$ -	$ -	$ -	$ -	$ -
673	2028	$ -	$ -	$ -	$ -	$ -
674	2029	$ -	$ -	$ -	$ -	$ -
675	2030	$ -	$ -	$ -	$ -	$ -
676	2031	$ -	$ -	$ -	$ -	$ -
677	2032	$ -	$ -	$ -	$ -	$ -
678	2033	$ -	$ -	$ -	$ -	$ -
679	2034	$ -	$ -	$ -	$ -	$ -
680	2035	$ -	$ -	$ -	$ -	$ -
681	2036	$ -	$ -	$ -	$ -	$ -
682	2037	$ -	$ -	$ -	$ -	$ -
683	2038	$ -	$ -	$ -	$ -	$ -
684	2039	$ -	$ -	$ -	$ -	$ -
685	2040	$ -	$ -	$ -	$ -	$ -
686	2041	$ -	$ -	$ -	$ -	$ -
687	2042	$ -	$ -	$ -	$ -	$ -
688	2043	$ -	$ -	$ -	$ -	$ -
689	2044	$ -	$ -	$ -	$ -	$ -
690	2045	$ -	$ -	$ -	$ -	$ -
691	2046	$ -	$ -	$ -	$ -	$ -
692	2047	$ -	$ -	$ -	$ -	$ -
693	2048	$ -	$ -	$ -	$ -	$ -
694	2049	$ -	$ -	$ -	$ -	$ -
695	2050	$ -	$ -	$ -	$ -	$ -
696	2051	$ -	$ -	$ -	$ -	$ -
697	2052	$ -	$ -	$ -	$ -	$ -
698	2053	$ -	$ -	$ -	$ -	$ -
699	2054	$ -	$ -	$ -	$ -	$ -
700	2055	$ -	$ -	$ -	$ -	$ -
701						
702	Project Totals				$ 46,600	$ 46,600

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

Project 14:

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details					
703	Investment		Current Year			2011
704	Service Year (yyyy)	2008	NPCC w/o incentives, less depreciation			16.95%
705	Service Month (1-12)					
706	Useful Life	39	Annual Depreciation Expense		(Investment / Useful Life)	$ -
707	CIAC (Yes or No)	No				
708/709	**Investment Year**	**Beginning Balance**	**Depreciation Expense**	**Ending Balance**	**Revenue Requirement**	**Rev. Req. for SPP Allocation**
710	2008	$ -	$ -	$ -	$ -	$ -
711	2009	$ -	$ -	$ -	$ -	$ -
712	2010	$ -	$ -	$ -	$ -	$ -
713	2011	$ -	$ -	$ -	$ -	$ -
714	2012	$ -	$ -	$ -	$ -	$ -
715	2013	$ -	$ -	$ -	$ -	$ -
716	2014	$ -	$ -	$ -	$ -	$ -
717	2015	$ -	$ -	$ -	$ -	$ -
718	2016	$ -	$ -	$ -	$ -	$ -
719	2017	$ -	$ -	$ -	$ -	$ -
720	2018	$ -	$ -	$ -	$ -	$ -
721	2019	$ -	$ -	$ -	$ -	$ -
722	2020	$ -	$ -	$ -	$ -	$ -
723	2021	$ -	$ -	$ -	$ -	$ -
724	2022	$ -	$ -	$ -	$ -	$ -
725	2023	$ -	$ -	$ -	$ -	$ -
726	2024	$ -	$ -	$ -	$ -	$ -
727	2025	$ -	$ -	$ -	$ -	$ -
728	2026	$ -	$ -	$ -	$ -	$ -
729	2027	$ -	$ -	$ -	$ -	$ -
730	2028	$ -	$ -	$ -	$ -	$ -
731	2029	$ -	$ -	$ -	$ -	$ -
732	2030	$ -	$ -	$ -	$ -	$ -
733	2031	$ -	$ -	$ -	$ -	$ -
734	2032	$ -	$ -	$ -	$ -	$ -
735	2033	$ -	$ -	$ -	$ -	$ -
736	2034	$ -	$ -	$ -	$ -	$ -
737	2035	$ -	$ -	$ -	$ -	$ -
738	2036	$ -	$ -	$ -	$ -	$ -
739	2037	$ -	$ -	$ -	$ -	$ -
740	2038	$ -	$ -	$ -	$ -	$ -
741	2039	$ -	$ -	$ -	$ -	$ -
742	2040	$ -	$ -	$ -	$ -	$ -
743	2041	$ -	$ -	$ -	$ -	$ -
744	2042	$ -	$ -	$ -	$ -	$ -
745	2043	$ -	$ -	$ -	$ -	$ -
746	2044	$ -	$ -	$ -	$ -	$ -
747	2045	$ -	$ -	$ -	$ -	$ -
748	2046	$ -	$ -	$ -	$ -	$ -
749	2047	$ -	$ -	$ -	$ -	$ -
750	2048	$ -	$ -	$ -	$ -	$ -
751	2049	$ -	$ -	$ -	$ -	$ -
752	2050	$ -	$ -	$ -	$ -	$ -
753	2051	$ -	$ -	$ -	$ -	$ -
754	2052	$ -	$ -	$ -	$ -	$ -
755						
756	Project Totals				$ -	$ -

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

B. Transmission Service Upgrades.

Project 1, (Describe)

The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
757	Investment	-	Current Year	2011
758	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation	16.95%
759	Service Month (1-12)	-	Rev. Req. allocated to TO's Identified Customers	100.00%
760	Useful Life	50	Annual Depreciation Expense (Investment / Useful Life)	-
761	CIAC (Yes or No)	no		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
764	2006	-	-	-	$ -	$ -
765	2007	-	-	-	-	$ -
766	2008	-	-	-	-	$ -
767	2009	-	-	-	-	$ -
768	2010	-	-	-	-	$ -
769	2011	-	-	-	-	$ -
770	2012	-	-	-	-	$ -
771	2013	-	-	-	-	$ -
772	2014	-	-	-	-	$ -
773	2015	-	-	-	-	$ -
774	2016	-	-	-	-	$ -
775	2017	-	-	-	-	$ -
776	2018	-	-	-	-	$ -
777	2019	-	-	-	-	$ -
778	2020	-	-	-	-	$ -
779	2021	-	-	-	-	$ -
780	2022	-	-	-	-	$ -
781	2023	-	-	-	-	$ -
782	2024	-	-	-	-	$ -
783	2025	-	-	-	-	$ -
784	2026	-	-	-	-	$ -
785	2027	-	-	-	-	$ -
786	2028	-	-	-	-	$ -
787	2029	-	-	-	-	$ -
788	2030	-	-	-	-	$ -
789	2031	-	-	-	-	$ -
790	2032	-	-	-	-	$ -
791	2033	-	-	-	-	$ -
792	2034	-	-	-	-	$ -
793	2035	-	-	-	-	$ -
794	2036	-	-	-	-	$ -
795	2037	-	-	-	-	$ -
796	2038	-	-	-	-	$ -
797	2039	-	-	-	-	$ -
798	2040	-	-	-	-	$ -
799	2041	-	-	-	-	$ -
800	2042	-	-	-	-	$ -
801	2043	-	-	-	-	$ -
802	2044	-	-	-	-	$ -
803	2045	-	-	-	-	$ -
804	2046	-	-	-	-	$ -
805	2047	-	-	-	-	$ -
806	2048	-	-	-	-	$ -
807	2049	-	-	-	-	$ -
808	2050	-	-	-	-	$ -
809	2051	-	-	-	-	$ -
810	2052	-	-	-	-	$ -
811	2053	-	-	-	-	$ -
812	2054	-	-	-	-	$ -
813	2055	-	-	-	-	$ -
814	2056	-	-	-	-	$ -
815	....	....	.....	.....	....	....
816						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

C. Sponsored or Economic Portfolio Upgrades.

Project 1, (Describe)

The calculated Rev. Req. from Sponsor and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
817	Investment	-	Current Year	2011
818	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation	16.95%
819	Service Month (1-12)	-	Rev. Req. allocated to Sponsoring Entity	100.00%
820	Useful Life	50	Annual Depreciation Expense (Investment / Useful Life)	-
821	CIAC (Yes or No)	no		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
822-823						
824	2006	-	-	-	$ -	$ -
825	2007	-	-	-	-	$ -
826	2008	-	-	-	-	$ -
827	2009	-	-	-	-	$ -
828	2010	-	-	-	-	$ -
829	2011	-	-	-	-	$ -
830	2012	-	-	-	-	$ -
831	2013	-	-	-	-	$ -
832	2014	-	-	-	-	$ -
833	2015	-	-	-	-	$ -
834	2016	-	-	-	-	$ -
835	2017	-	-	-	-	$ -
836	2018	-	-	-	-	$ -
837	2019	-	-	-	-	$ -
838	2020	-	-	-	-	$ -
839	2021	-	-	-	-	$ -
840	2022	-	-	-	-	$ -
841	2023	-	-	-	-	$ -
842	2024	-	-	-	-	$ -
843	2025	-	-	-	-	$ -
844	2026	-	-	-	-	$ -
845	2027	-	-	-	-	$ -
846	2028	-	-	-	-	$ -
847	2029	-	-	-	-	$ -
848	2030	-	-	-	-	$ -
849	2031	-	-	-	-	$ -
850	2032	-	-	-	-	$ -
851	2033	-	-	-	-	$ -
852	2034	-	-	-	-	$ -
853	2035	-	-	-	-	$ -
854	2036	-	-	-	-	$ -
855	2037	-	-	-	-	$ -
856	2038	-	-	-	-	$ -
857	2039	-	-	-	-	$ -
858	2040	-	-	-	-	$ -
859	2041	-	-	-	-	$ -
860	2042	-	-	-	-	$ -
861	2043	-	-	-	-	$ -
862	2044	-	-	-	-	$ -
863	2045	-	-	-	-	$ -
864	2046	-	-	-	-	$ -
865	2047	-	-	-	-	$ -
866	2048	-	-	-	-	$ -
867	2049	-	-	-	-	$ -
868	2050	-	-	-	-	$ -
869	2051	-	-	-	-	$ -
870	2052	-	-	-	-	$ -
871	2053	-	-	-	-	$ -
872	2054	-	-	-	-	$ -
873	2055	-	-	-	-	$ -
874	2056	-	-	-	-	$ -
875	....	....	.....	.....	....	....
876						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet G

D. Generator Interconnect Upgrades.

i. Project 1, (Describe)

The calculated Rev. Req. from Generator and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.

Line No.	Details			
877	Investment	-	Current Year	**2011**
878	Service Year (yyyy)	2006	NPCC w/o incentives, less depreciation	16.95%
879	Service Month (1-12)	-	Rev. Req. allocated to TO's Zone	100.00%
880	Useful Life	50	Annual Depreciation Expense (Investment / Useful Life)	-
881	CIAC (Yes or No)	no		

Line No.	Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Revenue Requirement	Rev. Req. for SPP Allocation
884	2006	-	-	-	$ -	$ -
885	2007	-	-	-	-	$ -
886	2008	-	-	-	-	$ -
887	2009	-	-	-	-	$ -
888	2010	-	-	-	-	$ -
889	2011	-	-	-	-	$ -
890	2012	-	-	-	-	$ -
891	2013	-	-	-	-	$ -
892	2014	-	-	-	-	$ -
893	2015	-	-	-	-	$ -
894	2016	-	-	-	-	$ -
895	2017	-	-	-	-	$ -
896	2018	-	-	-	-	$ -
897	2019	-	-	-	-	$ -
898	2020	-	-	-	-	$ -
899	2021	-	-	-	-	$ -
900	2022	-	-	-	-	$ -
901	2023	-	-	-	-	$ -
902	2024	-	-	-	-	$ -
903	2025	-	-	-	-	$ -
904	2026	-	-	-	-	$ -
905	2027	-	-	-	-	$ -
906	2028	-	-	-	-	$ -
907	2029	-	-	-	-	$ -
908	2030	-	-	-	-	$ -
909	2031	-	-	-	-	$ -
910	2032	-	-	-	-	$ -
911	2033	-	-	-	-	$ -
912	2034	-	-	-	-	$ -
913	2035	-	-	-	-	$ -
914	2036	-	-	-	-	$ -
915	2037	-	-	-	-	$ -
916	2038	-	-	-	-	$ -
917	2039	-	-	-	-	$ -
918	2040	-	-	-	-	$ -
919	2041	-	-	-	-	$ -
920	2042	-	-	-	-	$ -
921	2043	-	-	-	-	$ -
922	2044	-	-	-	-	$ -
923	2045	-	-	-	-	$ -
924	2046	-	-	-	-	$ -
925	2047	-	-	-	-	$ -
926	2048	-	-	-	-	$ -
927	2049	-	-	-	-	$ -
928	2050	-	-	-	-	$ -
929	2051	-	-	-	-	$ -
930	2052	-	-	-	-	$ -
931	2053	-	-	-	-	$ -
932	2054	-	-	-	-	$ -
933	2055	-	-	-	-	$ -
934	2056	-	-	-	-	$ -
935	....	....	.....	.....	....	....
936						

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet H - Transmission Plant Adjustments

I. Transmission Plant Adjusted for SPP Tariff

Line No.	(A) Plant Description		(B) Amount
1	Radial Lines		$ 18,521,292
2			
3	Other Adjustments - Transfers:		
4	Distribution Assets Reclassified as Transmission Assets		-
5	Transmission Assets Reclassified as Distribution Assets		-
6			
7	Plant Transfers Excluded from SPP Tariff	(line 119)	**$ 18,521,292**
8			
9			

II. Production Related Transmission Facilities

Line No.	(A) Plant Description		(B) Amount
10	Generation Radial Ties (Centennial)		$ 12,586,522
11	Generation Step Up Transformers (GSU's) and Related Equipment		34,086,199
12			
13	Total	(line 120)	**$ 46,672,721**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet I - Account 105 - Electric Plant Held for Use

Form I - Page 214 Detail

I. Non-Transmission

Line No.	LOC CODE &/OR REG	PLANT NAME	ACQUISITION DATE	ACQUISITION VALUE	ACCUM DEPR	AVG BOY and EOY	EST. YEAR IN SERVICE	COMMENT
1	9114-D	Johnson Sub	1974	42,059.21		42,059.21	2013	
2	9114-D	Johnson Sub	1974	364.80		364.80	2013	
3	9335-D	Mountainburg Sub	1966	8,823.55		8,823.55	2012	
4	9335-D	Mountainburg Sub	1966	375.40		375.40	2012	
5	9216-D	Central Sub	2006	362,717.38		362,717.38	2014	
6	5110-D	Springdale Sub	1972	11,372.48		11,372.48	2018	
7	7322-D	Sacred Heart Sub	1973	2,631.89		2,631.89	2020	
8	7507-D	Seran Sub	1974	12,051.45		12,051.45	2020	
9	3336-D	Taft Sub	1973	5,236.53		5,236.53	2020	
10	8411-D	Acorn Sub	1969	5,907.07		5,907.07	2015	
11	8482-D	Aluma Sub	1970	10,303.87		10,303.87	2018	
12	8615-D	Anderson Road Sub	1965	5,543.15		5,543.15	2015	
13	7104-D	Bellcow Sub	2008	53,795.46		53,795.46	2010	
14	8210-D	Freeway Sub	1970	28,049.14		28,049.14	2011	
15	8493-D	Kelley Ave Sub	1962	11,055.26		11,055.26	2015	
16	8592-D	Post Road Sub	1970	18,589.47		18,589.47	2015	
17	8531-D	Ridgeview Sub	1967	16,928.49		16,928.49	2020	
18	8415-D	State Center Sub	1971	4,308.46		4,308.46	2015	
19	8164-D	SW 29th Street Sub	1974	22,359.07		22,359.07	2018	
20	8716-D	Midwest Blvd Sub	1987	5,281.72		5,281.72	2015	
21	8111-D	Newcastle Sub	1987	10,487.68		10,487.68	2011	
22	4152-D	Banner Sub	1969	9,576.66		9,576.66	2015	
23	8109-D	Canadian River Sub	1966	5,899.99		5,899.99	2018	
24	4319-D	Lovell Sub	1968	3,269.47		3,269.47	2018	
25	4117-D	Purdue Sub	1972	7,272.86		7,272.86	2018	
26	8165-D	Rancho Sub	1974	28,181.47		28,181.47	2016	
27	8699-D	S E 134th Sub	1967	5,231.43		5,231.43	2018	
28	8718-D	Sooner Road Sub	1967	10,167.51		10,167.51	2015	
29	8159-D	Wheatland Sub	1973	17,388.43		17,388.43	2020	
30	3610-D	Shady Grove Sub	2002	68,833.80		68,833.80	2018	
31	3216-D	Sahoma Lake Sub	2002	102,519.25		102,519.25	2018	
32	8359-D	Yukon Sub	2007	136,027.43		136,027.43	2015	
33	8133-D	Will Rogers Sub	2006	320,944.78		320,944.78	2014	
34	4229-D	Oil Sands Sub	2007	36,209.65		36,209.65	2015	
35	8135-D	Racer Sub	2007	7,543		7,543	2010	
36								
37								
38								
39								
40		**TOTAL ARKANSAS**		414,340		414,340		
41		**TOTAL OKLAHOMA**		982,968		982,968		
42		**TOTAL ALL**		1,397,308		1,397,308		
43								
44								
45		**NON TRANSMISSION TOTAL**		1,397,308				

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet I - Account 105 - Electric Plant Held for Use

II. Transmission

Line No.	LOC CODE &/OR REG	PLANT NAME	ACQUISITION DATE	ACQUISITION VALUE	ACCUM DEPR	AVG BOY and EOY	EST. YEAR IN SERVICE	COMMENT
46	34501-H	345 KV H-Frame -	1983	54,656.25		54,656.25	2018	
47		W. Ft. Smith Loop						
48	16101-H	161 KV H-Frame -	1989	37,601.73		37,601.73	2018	
49		W. Ft. Smith Loop						
50	34501-T	345 KV Tower -	1983 & 1989	164,719.48		164,719.48	2018	
51		W. Ft. Smith Loop						
52	13802-S	138 KV Piedmont-Haymaker	2004	149,208.47		149,208.47	2015	
53	3609-T	Garrison Sub	1978	140,076.15		140,076.15	2017	
54	7707-T	Jaycee Sub	1974	30,196.68		30,196.68	2016	
55	7210-T	Diamond Sub	1971	6,336.16		6,336.16	2018	
56	7120-T	Lincoln County Sub	1972	4,126.09		4,126.09	2012	
57	4160-T	Breckenridge Sub	1984	36,881		36,881	2016	
58	8329-T	Matthewson Sub	2009	156,729.95		156,729.95	2017	
59								
60								
61								
62								
63								
64								
65								
66								
67								
68								
69								
70								
71		**TOTAL ARKANSAS**		256,977		256,977		
72		**TOTAL OKLAHOMA**		523,555		523,555		
73		**TOTAL ALL**		780,532		780,532		
74								
75								
76		**TRANSMISSION ONLY**	(line 61)	**780,532**				
77								
78		**TOTAL COMPANY**	Form I, p.214	2,177,840				
79								

NOTE:

1. To be included in transmission rate base, the land held for future use must be estimated to be in service within 10 years
2. When calculating the Baseline ATRR, use data from the year being trued-up to calculate "AVG BOY and EOY"; when calculating the Projected ATRR, use data from the most recent FERC Form 1 to calculate the "AVG BOY and EOY."

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet J - Tax Apportionments by State

I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES

Line No.		For Tax Year 2008		
1	State Income Tax Rate - Oklahoma	Note 1	6.00%	
2	Apportionment Factor	Note 2	93.7%	
3	Oklahoma State Income Tax Rate	(ln 1 * ln 2)		5.6223%
4	State Income Tax Rate - Arkansas		6.50%	
5	Apportionment Factor	Note 2	7.41%	
6	Arkansas State Income Tax Rate	(ln 4 * ln 5)		0.4818%
7	Total State Income Tax Rate	(sum ln 3 & ln 6)		6.1041%

Note 1: The Oklahoma State Income Tax Rate of 6% can be reduced to 5.66% in years where credits are not available or offset tax. In 2008, a tax rate of 6% applies since all tax due was offset by credits. A deduction of Oklahoma State Income Taxes on the State Income Tax return cannot be taken when tax is not due because of offsetting credits.

Note 2: Apportionment Factors are to be based on most recent annual income tax filings as calculated in Parts II. & III. below

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet J - Tax Apportionments by State

II. Calculation of Oklahoma Apportionment Factor

		Column A Total Within Oklahoma	Column B Without Oklahoma	A divided by B Percentage Within Oklahoma
1.	Value of real and tangible personal property used in the unitary business (by averaging the value at the beginning and ending of the tax period).			
	(a) Owned property (at original cost):			
	(I) Inventories	113,871,954	115,004,314	
	(II) Depreciable property	5,490,850,182	5,767,977,552	
	(III) Land			
	(IV) Total of section 1(a)	5,604,722,136	5,882,981,866	
	(b) Rented property (capitalize at 8 times net rental paid)	5,396,024	5,663,920	
	(c) TOTAL (sum of 1(a) and 1(b))	5,610,118,160	5,888,645,786	95.2701%
2.	(a) Payroll	148,628,887	153,755,794	
	(b) Less: Officers salaries	1,882,975	1,882,975	
	(c) TOTAL (subtract 2(b) from 2(a))	146,745,912	151,872,819	96.6242%
3.	Sales:			
	(a) Sales delivered or shipped to Oklahoma purchasers:			
	(I) Shipped from outside Oklahoma	-		
	(II) Shipped from within Oklahoma	1,771,270,832		
	(b) Sales shipped from Oklahoma to:			
	(I) The United States Government	-		
	(II) Purchasers in a state or country where the corporation is not taxable (i.e. under Public Law 85-272)	-		
	(c) TOTAL (sum of 3(a) and 3(b))	1,771,270,832	1,985,257,004	89.2212%
	TOTAL PERCENTAGES (sum of items 1(c), 2(c) and 3(c))			281.1155%
	Average of TOTAL PERCENTAGES (1/3 of total percent)			**93.7052%**

III. Calculation of Arkansas Apportionment Factor

		(A) Amounts in Arkansas	(B) Total Amounts	(C) Percentage (A) / (B)
1.	Property Used in Business:			
	(a) Tangible Assets Used in Business and Inventories Less Construction in Progress:			
	1. Amount Beginning of Year:	246,765,867	5,395,467,851	
	2. Amount End of Year	309,753,593	6,370,495,880	
	3. Total: (sum of 1(a) 1 and 1(a) 2)	556,519,460	11,765,963,731	
	4. Average Tangible Assets: (divide 1(a) 3 by 2)	278,259,730	5,882,981,866	
	(b) Rental Property: (8 times annual rent)	267,896	5,663,920	
	(c) Average Value of Intangible Property:	-	-	
	(d) TOTAL PROPERTY (sum of lines 1(a) 4, 1(b) and 1(c))	278,527,626	5,888,645,786	4.729910%
2.	Salaries, Wages, Commissions and Other Compensation Related to the Production of Business Income:	5,126,907	153,755,794	3.334448%
3.	Sales/Receipts:			
	(a) Destination Shipped From Within Arkansas:	213,986,172		
	(b) Destination Shipped From Without Arkansas	-		
	(c) Origin Shipped From Within Arkansas to U.S. Govt:	-		
	(d) Origin Shipped From Within Arkansas to Other Non-taxable Jurisdictions:	-		
	(e) Other Gross Receipts:	261,781		
	(f) TOTAL SALES / RECEIPTS: (sum of lines 3(a) to 3(e))	214,247,953	1,985,167,032	10.792440%
	(g) DOUBLE WEIGHTED (Applies to tax years beginning on or after January 1, 1995) (Column C, Line 3(f) times 2)			21.584880%
4.	TOTAL PERCENTAGES: (Column C sum of lines 1(d), 2 and 3(g))			29.649238%
5.	Average of TOTAL PERCENTAGES (Column C, Line 4 divided 4)			**7.412310%**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K - 13 Month Average Balances and Long Term Debt Costs

I. Plant Additions & Accumulated Depreciation Balances

Gross Plant (Note 1)

Line No.		End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
1	Intangible	28,034,452	28,451,119	28,867,786	29,284,453	29,701,120	30,117,787	30,534,454	30,951,121	31,367,788	31,784,455	32,201,122	32,617,789	33,034,456	30,534,454
2	Production-Redbud	526,109,692	526,193,025	526,276,358	526,359,691	526,443,024	526,526,357	526,609,690	526,693,023	526,776,356	526,859,689	526,943,022	527,026,355	527,109,688	526,609,690
3	Production	2,523,266,846	2,525,600,179	2,527,933,512	2,530,266,845	2,532,600,178	2,534,933,511	2,537,266,844	2,539,600,177	2,541,933,510	2,544,266,843	2,546,600,176	2,548,933,509	2,951,266,842	2,568,036,075
4	Transmission	900,705,107	902,134,690	903,830,273	905,259,856	907,489,439	910,619,022	963,185,605	964,615,188	966,044,771	967,474,354	968,903,937	996,993,520	998,423,107	942,744,528
5	Distribution	2,754,714,236	2,763,047,569	2,771,380,902	2,779,714,235	2,788,047,568	2,796,380,901	2,804,714,234	2,813,047,567	2,821,380,900	2,829,714,233	2,838,047,566	2,846,380,899	2,854,714,232	2,804,714,234
6	General Plant	218,148,328	218,731,661	219,314,994	219,898,327	220,481,660	221,064,993	221,648,326	222,231,659	222,814,992	223,398,325	223,981,658	224,564,991	225,148,324	221,648,326
7	Total	6,950,978,661	6,964,158,243	6,977,603,825	6,990,783,407	7,004,762,989	7,019,642,571	7,083,959,153	7,097,138,735	7,110,318,317	7,123,497,899	7,136,677,481	7,176,517,063	7,589,696,649	7,094,287,307

Accumulated Depreciation and Amortization (Note 2)

Line No.		End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
8	Intangible	21,053,013	21,103,013	21,153,013	21,203,013	21,253,013	21,303,013	21,353,013	21,403,013	21,453,013	21,503,013	21,553,013	21,603,013	21,653,013	21,353,013
9	Production-Redbud	90,500,149	91,700,149	92,900,149	94,100,149	95,300,149	96,500,149	97,700,149	98,900,149	100,100,149	101,300,149	102,500,149	103,700,149	104,900,149	97,700,149
10	Production	1,395,533,767	1,398,200,767	1,400,867,767	1,403,534,767	1,406,201,767	1,408,868,767	1,411,535,767	1,414,202,767	1,416,869,767	1,419,536,767	1,422,203,767	1,424,870,767	1,428,871,100	1,411,638,331
11	Transmission	346,648,213	348,051,144	349,454,620	350,857,550	352,262,121	353,668,537	355,176,298	356,579,229	357,982,159	359,385,090	360,788,021	362,245,604	363,646,535	355,134,240
12	Distribution	922,822,367	926,822,367	930,822,367	934,822,367	938,822,367	942,822,367	946,822,367	950,822,367	954,822,367	958,822,367	962,822,367	966,822,367	970,822,367	946,822,367
13	General Plant	82,028,059	82,444,726	82,861,393	83,278,060	83,694,727	84,111,394	84,528,061	84,944,728	85,361,395	85,778,062	86,194,729	86,611,396	87,028,063	84,528,061
14	Total	2,858,585,568	2,868,322,166	2,878,059,309	2,887,795,906	2,897,534,144	2,907,274,227	2,917,115,655	2,926,852,253	2,936,588,850	2,946,325,448	2,956,062,046	2,965,853,296	2,976,921,227	2,917,176,161

Net Plant (Gross Plant less Accumulated Depreciation and Amortization)

Line No.		End. Balance Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	End. Balance Dec-11	13 Months Avg Balance
15	Intangible	6,981,439	7,348,106	7,714,773	8,081,440	8,448,107	8,814,774	9,181,441	9,548,108	9,914,775	10,281,442	10,648,109	11,014,776	11,381,443	9,181,441
16	Production-Redbud	435,609,543	434,492,876	433,376,209	432,259,542	431,142,875	430,026,208	428,909,541	427,792,874	426,676,207	425,559,540	424,442,873	423,326,206	422,209,539	428,909,541
17	Production	1,127,733,079	1,127,399,412	1,127,065,745	1,126,732,078	1,126,398,411	1,126,064,744	1,125,731,077	1,125,397,410	1,125,063,743	1,124,730,076	1,124,396,409	1,124,062,742	1,522,395,742	1,156,397,744
18	Transmission	554,056,894	554,083,546	554,375,653	554,402,306	555,227,318	556,950,485	608,009,307	608,035,959	608,062,612	608,089,264	608,115,916	634,747,916	634,776,572	587,610,288
19	Distribution	1,831,891,869	1,836,225,202	1,840,558,535	1,844,891,868	1,849,225,201	1,853,558,534	1,857,891,867	1,862,225,200	1,866,558,533	1,870,891,866	1,875,225,199	1,879,558,532	1,883,891,865	1,857,891,867
20	General Plant	136,120,269	136,286,935	136,453,601	136,620,267	136,786,933	136,953,599	137,120,265	137,286,931	137,453,597	137,620,263	137,786,929	137,953,595	138,120,261	137,120,265
21	Total	4,092,393,093	4,095,836,077	4,099,544,516	4,102,987,501	4,107,228,845	4,112,368,344	4,166,843,498	4,170,286,482	4,173,729,467	4,177,172,451	4,180,615,435	4,210,663,767	4,612,775,422	4,177,111,146

Notes:
1. When calculating the Baseline ATRR, use the actual 13 month account balancees for the year being trued-up. When calculating the Projected ATRR, the values for "Gross Plant" shall include net plant additions.
2. When calculating the Projected ATRR, the values for Accumulated Depreciation and Amortization shall include both accumulated depreciation and amortization on new plant projected to be in service as well as the accumulated depreciation and amortization on existing plant through the end of the projected year.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K

II. Material and Supplies for Construction Balances

		End Balance Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	End Balance Dec-09	13 Months Avg. Balance
22	Production O&M	20,946,297	21,890,004	22,057,074	22,343,192	22,498,214	21,570,345	21,741,347	22,277,664	22,585,545	22,316,660	19,401,217	20,070,271	20,648,180	21,565,078
23	Transmission O&M	232,238	392,235	364,535	294,968	207,590	204,595	279,286	278,618	208,949	253,127	248,948	295,280	299,184	273,812
24	Distribution O&M	1,765,006	1,743,269	1,913,807	1,720,647	1,556,926	1,483,317	1,843,289	1,950,324	2,037,250	1,974,392	2,041,372	2,017,744	2,144,149	1,860,884
25	Prod. Construction	874,641	114,423	70,809	78,475	85,819	49,726	43,570	53,595	49,798	42,483	3,098,165	2,961,943	2,957,833	806,252
26	Trans. Construction	7,277,133	11,381,130	11,484,437	16,986,607	21,191,225	21,668,847	22,466,470	21,333,642	19,956,404	18,396,045	17,593,723	17,099,832	17,028,736	17,220,325
27	Dist. Construction	36,298,511	30,065,084	31,804,054	30,159,124	28,941,789	27,792,114	31,268,210	32,160,947	30,034,588	30,001,864	29,905,528	29,800,419	30,391,859	30,663,392
28	Total	67,393,826	65,586,145	67,694,716	71,583,013	74,481,563	72,768,944	77,642,172	78,054,790	74,872,534	72,984,571	72,288,953	72,245,489	73,469,941	72,389,743

Notes:
1. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.
2. Transmission O&M (ln 23) and Transmission Construction (ln 26) are summed and reflected on page 3 of 6, line 64 of the Attachment H - Addendum 2-A.

III. Debt and Equity Balances

		End Balance Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	End Balance Dec-09	13 Months Avg. Balance
29	Long Term Debt (Face Value)	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,250,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,350,000	1,545,303,846
30	Propriety Capital	1,824,359,077	1,827,756,872	1,826,247,396	1,825,702,797	1,829,794,350	1,842,807,212	1,882,073,082	1,928,238,799	1,979,560,371	2,005,311,703	2,018,773,223	2,018,331,303	2,024,389,844	1,910,257,387
31	Less: Acct. 204	-													-
32	Less: Acct. 216.1	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,502	102,871	102,530
33	Less: Acct. 219	-	-	-	-	-	-	-	(260,501)	(572,565)	54,963	(147,910)	(363,514)	(409,287)	(130,678)
34	Common Stock	1,824,256,575	1,827,654,370	1,826,144,894	1,825,600,295	1,829,691,848	1,842,704,710	1,881,970,580	1,928,396,798	1,980,030,434	2,005,154,238	2,018,818,631	2,018,592,315	2,024,696,260	1,910,285,534
35	LTD / (LTD + Common Stock)	45.9%	45.8%	45.8%	45.8%	45.8%	45.6%	45.1%	44.5%	43.8%	43.5%	43.4%	43.4%	43.3%	44.7%

Notes:
1. Outstanding Long Term Debt are reported in Accts. 221-224 (112.18-21.c & d) and the calculation shall include only current period costs and shall not include any deferred costs, (except as authorized by FERC), interest rate hedging costs/gains/losses, or credit facility expenses related to short-term indebtedness. Remove the value of any hedge contracts from Accts. 222-224 (257.h) for this purpose.
2. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet K

IV. Account 165 - Prepayments

		BOY Balance Relevant Year	EOY Balance Relevant Year	Average Balance
36		(111.57.d)	(111.57.c)	
37	Prepayments	8,022,198	8,467,046	8,244,622

Notes:
1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form No. 1.

V. Long-Term Debt Costs

	Accounts	Reference	Calculation	Comments / Explanations
38	Acct 427 - Long-term interest expense	(117.62.c)	$ 96,574,200	
39	Acct. 428 - Amortization of debt discount and expense	(117.63.c)	$ 1,194,630	
40	Acct. 428.1 - Amortization of loss on reacquired debt	(117.64.c)	$ 1,186,698	
41	Acct. 430 - Interest on Long-term debt to Associated Companies in Acct. 223 (112.20.c)	(117.67.c)	$ -	(per note on pg 450.1 for pg 256, col. i)
42	Less: Acct. 429 - Premium on debt discount	(117.65.c) (enter negative)	$ -	
43	Less: Acct. 429.1 - Amortization of gain on reacquired debt	(117.66.c) (enter negative)	$ -	
44	**Total Long Term Interest**	(sum lns 38 to 43)	**$ 98,955,528**	
45	Average of the 13 month balances outstanding long-term debt	(ln 29)	$ 1,545,303,846	
46	**LONG TERM DEBT COST**	(ln 44 / ln 45)	**6.404%**	

Notes:
1. Unless approved in a Section 205 filing by FERC, gains and losses on interest rate hedging on long term debt shall not be flowed through interest expense; and the value of hedge contracts shall not be included in long term debt balances.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L - True-Up Adjustment with interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation.

Line No.

I. Prior Year True-Up with Interest Calculation

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year.

Line No.			Rate Year
1	Projected Revenue Requirement	$ 85,301,630	2009
2	Baseline Revenue Requirement	$ 80,372,300	2009
3	True Up Adjustment Without Interest (TUA)	**$ 4,929,330**	
4	Average Interest Rate on Amount of Refunds or Surcharges		
5	calculated per Section V below	**0.2708%**	

Line No.	Year		[A] Amount	[B] Interest Rate	[C] Months	[D] Interest cols [A] x [B] x [C]	[E] Refund / (Surcharge) cols [A] + [D]
6	2009	6 months interest	$ 4,929,330	0.2708%	6	$ 80,102	$ 5,009,431
7	2010	12 months interest	$ 5,009,431	0.2708%	12	$ 162,807	$ 5,172,238
8	2011	6 months interest	$ 5,172,238	0.2708%	6	$ 84,049	$ 5,256,287

II. Prior Period Correction True-Up with Interest Calculation

This section will calculate the interest on the True-up Adjustment (refund or surcharge) on a correction made in a Prior Period.

Line No.			Correction Rate Year
9	Baseline Revenue Requirement	$ -	0
10	Revised Baseline Revenue Requirement	$ -	0
11	True Up Adjustment Without Interest (TUA)	**$ -**	
12	Average Interest Rate on Amount of Refunds or Surcharges		
13	calculated per Section V below	**0.0284%**	

Line No.	Year		[A] Amount	[B] Interest Rate	[C] Months	[D] Interest cols [A] x [B] x [C]	[E] Refund / (Surcharge) cols [A] + [D]
14		6 months interest	$ -	0.0284%	6	$ -	$ -
15		months interest	$ -	0.0284%		$ -	$ -
16		6 months interest	$ -	0.0284%	6	$ -	$ -

17	**TOTAL PRIOR YEAR TRUE-UP ADJUSTMENT**	(ln 8[E] + ln 16[E])	**$ 5,256,287**

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

III. Base Plan Upgrade True-Up Calculations

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

	Proj. No.		Projected ATRR - Prior Year (1)	Baseline ATRR - Prior Year (2)	True-Up Adjustment Without Interest	Refund / (Surcharge) 2009	Refund / (Surcharge) 2010	Refund / (Surcharge) 2011
19	1	Reno-Sunny Lane 69kV Line	$ 11,444	$ 10,378	$ 1,066	$ 1,084	$ 1,119	$ 1,137
20	2	Richards Tap-Richards 138kV Line	$ 468,836	$ 425,166	$ 43,670	$ 44,379	$ 45,822	$ 46,566
21	3	Van Buren AVEC-Van Buren Interconnect 69kV Line	$ 18,290	$ 16,587	$ 1,703	$ 1,731	$ 1,787	$ 1,816
22	4	Brown Explorer Tap 138kV Line	$ 5,343	$ 4,845	$ 498	$ 506	$ 522	$ 531
23	5	NE Enid-Glenwood 138kV Line	$ 668,242	$ 606,254	$ 61,988	$ 62,995	$ 65,042	$ 66,099
24	6	Razorback-Short Mountain 69kV Line	$ 1,598,092	$ 1,449,850	$ 148,242	$ 150,651	$ 155,547	$ 158,075
25	7	Richards-Piedmont 138kV Line	$ 662,125	$ 601,118	$ 61,007	$ 61,999	$ 64,014	$ 65,054
26	8	OG&E Windfarm-WFEC Mooreland 138kV Line	$ 14,758	$ 13,394	$ 1,364	$ 1,386	$ 1,431	$ 1,454
27	9	Ft. Smith-Colony 161kV Line	$ 1,681	$ 22,234	$ (20,553)	$ (20,588)	$ (20,659)	$ (20,694)
28	10	Cedar Lane-Canadian 138kV Line	$ 1,278	$ 3,738	$ (2,460)	$ (2,464)	$ (2,472)	$ (2,477)

29 **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** (sum ln 19 thru ln 28) **$ 317,562**

NOTE: (1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page

(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

IV. Calculation of Optional Prepayment and Prepayment Credit

			"Customer 1"	"Customer 2"	"Customer 3"	"Customer 4"
30	Prepayment Amount					
31	TUA with first year's interest	Line 6[E] above	$ 5,009,431	$ 5,009,431	$ 5,009,431	$ 5,009,431
32	Line 31 plus 6 Months of year 2 Interest	(6 x Interest Rate on Line 7[B]+1) * Line 31	$ 5,090,835	$ 5,090,835	$ 5,090,835	$ 5,090,835
33	Customer's Load in year preceeding the current Rate Year	(MW)				
34	System Load in year preceeding the current Rate Year	(MW)				
35	Amount of Prepayment	Line 32 x (Line 33 / Line 34)	$0	$0	$0	$0
36	Prepayment Adjustment (Note 1)					
37	Customer's Load applicable in the current Rate Year	(MW)				
38	System Load applicable in the current Rate Year	(MW)				
39	Prepayment Adjustment	[(Line 37 / Line 38) / (Line 33 / Line 34) - 1] x Line 35	$0.00	$0.00	$0.00	$0.00
40	Line 39 plus 6 Months Interest	(6 x Interest Rate on Line 7[B]+1) * Line 39	$0.00	$0.00	$0.00	$0.00
41	Prepayment Credit					
42	Total TUA with interest	Line 8[E] above	$ 5,256,287	$ 5,256,287	$ 5,256,287	$ 5,256,287
43	Monthly Prepayment Credit	[Line 42 x (Line 33 / Line 34) / 12]	$0	$0	$0	$0

Note;

1. The Prepayment Adjustment is made to reflect any difference between the Network Customer's load ratio share percentage used to determine the Prepayment and the actual load ratio share percentage applicable in the Rate Year during which the True-Up Adjustment would otherwise have been collected.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet L

V. Average Interest Rate / Debt Cost Calculations

	Quarter	Year	[A] FERC Quarterly Interest Rate	[B] OG&E Short Term Debt Rate	[C] Rate for Surcharges (lesser of A or B)	[D] Rate for Refunds (column A)
44	3rd	2009	3.25%	0.39%	0.39%	3.25%
45	4th	2009	3.25%	0.39%	0.39%	3.25%
46	1st	2010	3.25%	0.25%	0.25%	3.25%
47	2nd	2010	3.25%	0.34%	0.34%	3.25%

48	Average Interest Rate Applicable to Surcharges from column [C]	0.34%
49	Average Interest Rate Applicable to Refunds from column [D]	3.25%

NOTE: (1) The FERC Quarterly Interest Rate in column [A] is the interest applicable to the quarter indicated.
(2) The OG&E Short Term Debt Rate in column [B] is the weighted average Short Term Debt cost applicable to the quarter indicated.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet M - Depreciation Rates

Source: 2006 Form I, page 337.1 & 337.2, column (e)

Transmission Plant Account	Account Description	Rate
350	Land and Land Rights	1.56%
352	Structures and Improvements	0.92%
353	Station Equipment	1.79%
354	Towers and Fixtures	1.81%
355	Poles and Fixtures	3.65%
356	Overhead Conductors and Devices	3.13%
358	Underground Conductors and Devices	

General Plant Account	Account Description	Rate
389	Land and Land Rights	2.19%
390	Structures and Improvements	3.19%
391	Office Furniture and Equipment	5.01%
392	Transportation Equipment	10.99%
393	Stores Equipment	2.89%
394	Tools, Shop and Garage Equipment	5.32%
395	Laboratory Equipment	9.77%
396	Power Operated Equipment	1.78%
397	Communication Equipment	5.34%
398	Miscellaneous Equipment	3.50%
Intangibles		10.28%

Note: These rates are fixed and will be changed only by a separate FPA 205 filing.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet N - Unfunded Reserves

I. Labor Related

Line No.	Account No.	Account Title		Beginning Balance		Ending Balance		Average
1	228.2	Accumulated Provision for Injuries and Damages	$	2,216,375	$	1,414,000	$	1,815,188
2	242	Severance	$	-	$	-	$	-
3	242	Accrued Vacation Pay	$	13,048,848	$	13,681,770	$	13,365,309
4	242	Workers Compensation	$	1,702,233	$	1,946,698	$	1,824,466
5	242	Post Retirement Life Insurance	$	999,006	$	92,967	$	545,987
6	242	Incentive Compensation	$	7,835,045	$	12,688,443	$	10,261,744
7	242	Public Liability	$	285,000	$	114,000	$	199,500
8	242	Miscellaneous	$	403,441	$	963,955	$	683,698
9	xxx	Reserved for future					$	-
10		Sub-Total	$	26,489,948	$	30,901,833	$	28,695,891
11		Wage & Salary Allocator						0.057403
12		Total Labor Related Reserves (ln 10 times ln 11)					$	1,647,242

II. Plant Related

Line No.	Account No.	Account Title		Beginning Balance		Ending Balance		Average
13	xxx	Reserved for future	$	-	$	-	$	-
14	xxx	Reserved for future	$	-	$	-	$	-
15	xxx	Reserved for future	$	-	$	-	$	-
16		Sub-Total	$	-	$	-	$	-
17		Gross Plant Allocator						0.125739
18		Total Labor Related Reserves (ln 16 times ln 17)					$	-
19		**TOTAL REDUCTION TO RATE BASE (negative of ln 12 plus ln 18]**					**$**	**(1,647,242)**

Note:

The average of the beginning and ending balances of reserves that are unfunded (i.e. not set aside in an escrow) and whose balances have been included in the expenses recovered under the formula, will be deducted from rate base. This total will be represented as a negative amount on Line 58 of the Data tab.

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet O - Amortizations

I. Extraordinary O&M Amortization

Line No.	Justification	FERC Docket No	Effective Year	Amortization Term (yrs)	Beginning O&M Expense	Annual Amortization	Annual Year End Balance
1						$ -	$ -
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12	Total Extraordinary O&M Amortization					$ -	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet O - Amortizations

II. Storm Cost Amortization

	Justification	FERC Docket No	Effective Year	Amortization Term (yrs)	Beginning O&M Expense	Annual Amortization	Annual Year End Balance
13	2007 Ice Storm expenses		2008	5	$ 52,321	$ 10,464	$ 41,857
14			2009			$ 10,464	$ 31,393
15			2010			$ 10,464	$ 20,929
16			2011			$ 10,464	$ 10,465
17			2012			$ 10,464	$ 1
18							
19							
20							
21							
22							
23							
24							
25							
26	Total Storm Costs Amortization					$ 10,464	
27	**TOTAL AMORTIZATIONS**	(entered in Data tab on ln 93)	(sum of lns 12 and 26)			**$ 10,464**	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

I. Project Summary

Proj. No.	A. CWIP Annual Transmission Revenue Requirements Project Description	ATRR
1	Sooner - Rose Hill 345kV Line (Base Plan Upgrade)	$ 3,881,603
2	Sooner - Cleveland 345kV Line (Balanced Portfolio Upgrage)	$ 1,049,419
3	Woodward District EHV - Tuco 345kV Line (Balanced Portfolio Upgrage)	$ 235,499
4	Seminole - Muskogee 345kV Line (Balanced Portfolio Upgrade)	$ 473,581
5	Sunnyside - Hugo 345kV Line (Base Plan Upgrade)	$ 11,827,076
6		$ -
7		
8		
9		
10		
11		
	CWIP Totals	**$ 17,467,177**

Proj. No.	B. Abandoned Plant Annual Transmission Revenue Requirements Project Description	ATRR
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
	Abandoned Plant Totals	

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant Balances

II. Construction Work in Progress (CWIP) Balances

Line No.	Month	Year	Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
			Sooner-Rose Hill 345kV Line	Sooner-Cleveland 345kV Line	Woodward District EHV-Tuco 345kV Line	Seminole-Muskogee 345kV Line	Sunnyside-Hugo 345kV Line						
1	**December**	2010	$ 10,858,000	$ 2,385,000	$ -	$ -	$ 25,105,000						$ 38,348,000
2	**January**	2011	$ 11,154,000	$ 2,888,000	$ 200,000	$ 20,000	$ 28,255,000						$ 42,517,000
3	**February**	2011	$ 16,323,000	$ 3,388,000	$ 400,000	$ 40,000	$ 36,776,000						$ 56,927,000
4	**March**	2011	$ 21,388,000	$ 4,384,000	$ 700,000	$ 500,000	$ 48,827,000						$ 75,799,000
5	**April**	2011	$ 25,629,000	$ 4,873,000	$ 1,000,000	$ 1,000,000	$ 62,293,000						$ 94,795,000
6	**May**	2011	$ 29,784,000	$ 5,358,000	$ 1,300,000	$ 1,500,000	$ 76,218,000						$ 114,160,000
7	**June**	2011	$ 31,905,000	$ 6,339,000	$ 1,600,000	$ 2,000,000	$ 90,932,000						$ 132,776,000
8	**July**	2011	$ 34,593,000	$ 7,303,000	$ 1,900,000	$ 2,700,000	$ 107,096,000						$ 153,592,000
9	**August**	2011	$ 37,707,000	$ 8,661,000	$ 2,300,000	$ 4,200,000	$ 121,282,000						$ 174,150,000
10	**September**	2011	$ 40,797,000	$ 10,009,000	$ 2,700,000	$ 6,000,000	$ 132,757,000						$ 192,263,000
11	**October**	2011	$ 42,100,000	$ 12,548,000	$ 3,200,000	$ 8,200,000	$ 143,233,000						$ 209,281,000
12	**November**	2011	$ 43,608,000	$ 16,016,000	$ 3,700,000	$ 10,400,000	$ 152,089,000						$ 225,813,000
13	**December**	2011	$ 44,789,000	$ 21,459,000	$ 4,700,000	$ 11,100,000	$ 165,385,000						$ 247,433,000
14	**Average Balances**		$ 30,048,846	$ 8,123,923	$ 1,823,077	$ 3,666,154	$ 91,557,538	$ -	$ -	$ -			$ 135,219,538
15	**Return**	(Data Ln 140 * Ln 14)	$ 2,704,346	$ 731,139	$ 164,074	$ 329,948	$ 8,240,024	$ -	$ -	$ -			$ 12,169,531
16	**Taxes**	(Data Ln 108 * Ln 15)	$ 1,177,257	$ 318,280	$ 71,425	$ 143,633	$ 3,587,052	$ -	$ -	$ -			$ 5,297,647
17	**ATRR**	(Ln 15 + Ln 16)	$ 3,881,603	$ 1,049,419	$ 235,499	$ 473,581	$ 11,827,076	$ -	$ -	$ -			$ 17,467,177

OKLAHOMA GAS AND ELECTRIC COMPANY

Worksheet P - Construction Work in Progress and Abandoned Plant

III. Abandoned Plant

Line No.			Project 1	Project 2	Project 3	Project 4	Project 5	Project 6	Project 7	Project 8	Project 9	Project 10	Total
18	**Abandoned Plant Balance**												
19	**Amortization Period (months)**												
20	**Monthly Amortization Amount**												
	Month	Year											
21	**December**	2010											
22	**January**	2011											
23	**February**	2011											
24	**March**	2011											
25	**April**	2011											
26	**May**	2011											
27	**June**	2011											
28	**July**	2011											
29	**August**	2011											
30	**September**	2011											
31	**October**	2011											
32	**November**	2011											
33	**December**	2011											
34	**Average Balances**		-										
35	**Return**	(Data Ln 140 * Ln 34)	0										
36	**Taxes**	(Data Ln 108 * Ln 35)	0										
37	**Amortization Abandoned Plant** (Beg. Bal. less End. Bal.)		0										
38	**ATRR**	(Ln 35 + Ln 36 + Ln 37)	0	-	-	-	-	-					

ATTACHMENT 2

DIRECT TESTIMONY AND EXHIBITS OF PHILIP L. CRISSUP

EXHIBIT NO. OGE-1

Exhibit No. OGE-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER11-___-000

DIRECT TESTIMONY AND EXHIBITS OF
PHILIP L. CRISSUP

February 18, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER11-___-000

<u>DIRECT TESTIMONY AND EXHIBITS OF PHILIP L. CRISSUP</u>

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Philip L. Crissup. My business address is 321 N. Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101. I am Director of Regional Transmission Affairs of Oklahoma Gas and Electric Company ("OG&E").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. As Director of Regional Transmission Affairs, my areas of responsibility include the coordination of Transmission Planning and Transmission Policy activities at OG&E and in coordination with the Southwest Power Pool, Inc. ("SPP").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I received a Bachelor of Science degree in Electrical Engineering from the University of Oklahoma in 1983. Upon graduation, I began my career at OG&E at the Northern Region Engineering office in Enid, Oklahoma as a Distribution Engineer. I was promoted to Design Engineer in the Transmission Design section of Corporate Engineering in 1987, and then to Senior Engineer in the same department in 1994. I moved to the Engineering Planning section in 1997, and became Manager of the Transmission Planning group in 2002. In 2006, I became Director of Regional Transmission Affairs. I am a Licensed Professional Engineer in the State of Oklahoma.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR BEFORE A STATE REGULATORY AGENCY?

A. Yes. At the Federal Energy Regulatory Commission ("Commission" or "FERC"), I submitted testimony in 2008 in support of a Federal Power Act Section 205 filing by Tallgrass Transmission LLC in Docket No. ER09-35-000. Further, I submitted testimony in 2008 in connection with a Federal Power Act Section 203 filing by OG&E and Redbud Energy LP in Docket No. EC08-58-000. Most recently, I submitted testimony in 2010 in support of OG&E's request for transmission rate incentives in Docket No. ER11-112-000.

I also have filed testimony in proceedings before the Oklahoma Corporation Commission ("OCC") in a 2008 proceeding concerning International Transmission Corporation's application to be classified and regulated by the OCC as a transmission-only utility, as well as in an OCC filing for recovery of OG&E's costs associated with the WindSpeed 345-kV transmission line.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS TESTIMONY.

A. On October 12, 2010, OG&E submitted to FERC an FPA Section 205 filing requesting approval of certain transmission incentives for eight transmission projects to be constructed within the Southwest Power Pool ("SPP"). On December 30, 2010, FERC issued an order which granted this request for two projects but denied the request for transmission incentives for the remaining six projects.[1] In the December 30 Order, FERC found that "OG&E has adequately demonstrated that the Projects will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion, and therefore meet the requirements of FPA section 219 for incentive rate treatment."[2] However, it also found that a different applicant's filing in an unrelated docket "revealed the necessity to change Commission policy with respect to the application of the nexus test to groups of projects."[3] Applying this revised standard, FERC held that OG&E had failed to demonstrate the required nexus between the requested incentives and the specific investments being made with regard to the remaining six projects.[4] This finding was "without prejudice to OG&E refiling to demonstrate how each of these six remaining projects meets the nexus requirement."[5]

In response to the December 30 Order, OG&E, through the filing which includes this testimony, is requesting FERC authorization to recover two specific transmission rate incentives in connection with five of the specific transmission projects that were previously included in OG&E's October 12, 2010 filing. The incentives OG&E requests are: (1) inclusion of 100 percent of construction work in progress, or "CWIP," in rate base, and (2) recovery of 100 percent of prudently

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[1] *Oklahoma Gas and Electric Co*., 133 FERC ¶ 61,274 (2010) ("December 30 Order").

[2] December 30 Order at P 35.

[3] *Id.* at P 39 (footnote omitted).

[4] *Id*. at PP 42, 44.

[5] *Id*. at P 44.

incurred expenses should the projects be abandoned for reasons outside OG&E's control, or "Abandoned Plant." My testimony identifies and describes the five transmission projects that are the subject of OG&E's request for transmission rate incentives (collectively, "the Projects"). I also will address the relevant SPP planning processes and the status of the Projects with respect to those processes; the benefits and costs of the Projects; and the non-financial risks and challenges that OG&E faces in completing the Projects.

OG&E is presenting one other witness in support of its filing. Donald R. Rowlett, OG&E's Director of Regulatory Policy and Compliance, describes the Projects' financial risks and challenges and the benefits of the requested incentives.[6] Mr. Rowlett further describes the CWIP-related accounting procedures that OG&E plans to implement in accordance with the Commission's regulations.

II. THE PROJECTS

Q. PLEASE DESCRIBE OG&E.

A. OG&E is an electric public utility with plant, property, and other assets dedicated to the production, transmission, distribution, and sale of electric energy to wholesale and retail customers in Oklahoma and western Arkansas. OG&E serves more than 750,000 retail customers and sells electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives, and other market participants. OG&E owns and operates approximately 6,641 MWs of generation capacity composed of natural gas, low-sulfur coal, and wind

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6 *See* Direct Testimony of Donald R. Rowlett, Exhibit No. OGE-18.

generation facilities, and also purchases power from third parties for resale. OG&E's transmission system includes approximately 4,500 miles of transmission lines plus 56 substations, not including the two projects authorized for incentive treatment in the December 30 Order. OG&E is an Oklahoma corporation and a wholly owned subsidiary of OGE Energy Corp. OG&E is a member of SPP.

Q. PLEASE DESCRIBE THE PROJECTS.

A. The Projects are a set of additions to the SPP transmission system that will help meet the region's growing transmission needs and provide significant benefits, as I will detail later in my testimony. The Projects consist of five specific transmission facility additions:

1. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012;

2. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to an interface with a Westar Energy line segment at the Oklahoma-Kansas state line. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, is estimated to cost $57.8 million, and has an estimated in-service date of June 1, 2012;

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand

River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. This Project is estimated to cost $64 million and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013; and

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV to Southwestern Public Service Company's ("SPS") Tuco substation. The OG&E portion of the Tuco-Woodward Project is 72 miles in length and will terminate at a reactor station to be constructed near the Oklahoma-Texas state border. The Project has an estimated cost of $120 million with an estimated in-service date of May 19, 2014.

A map that depicts each of the Projects for which OG&E requests incentive rate treatment is appended as Exhibit No. OGE-2 to this application. Additional maps that are project-specific or risk-specific also are included as Exhibit Nos. OGE-3 through OGE-9. I will reference specific maps throughout this testimony.

Q. WHAT ARE THE KEY DRIVERS OF THESE INVESTMENTS?

A. The key drivers of these investments are derived from SPP's regional planning efforts, which were implemented to develop new transmission to meet applicable

North American Reliability Corporation ("NERC") reliability standards, to relieve congestion, and to access remote renewable resources.[7] In tailoring its planning processes, SPP has reiterated the need for new large-scale transmission projects to facilitate expansive renewable resource developments in the western portion of its system and for diverse resource options in load centers in the eastern portion and in neighboring systems.[8] To this end, projects vetted and selected through SPP's planning processes generally strengthen the reliability of SPP's system and provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service.[9]

Q. DO THE PROJECTS REPRESENT A SIGNIFICANT EXPANSION OF THE OG&E TRANSMISSION SYSTEM?

A. Yes. The Projects will add approximately 393 miles of new transmission facilities to the OG&E system within the SPP region, compared to 4,500 miles of high voltage transmission lines, and 910 miles specifically of 345-kV lines, currently comprising OG&E's transmission system. The current cost projection for the combined Projects is approximately $608 million. The actual cost will depend on multiple factors such as the final routes for the proposed lines, and the costs of equipment, commodities, and other construction elements. The projected investment is equal to about 109 percent of OG&E's current net transmission plant of $558 million. The average annual capital investment in the Projects over

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7 SPP Open Access Transmission Tariff ("OATT") at Attachment O, Section VII.

8 SPP OATT at Attachment O, Section IV; *see also*, SPP May 17, 2010 Filing, Docket No. ER10-1269-000 at 4-7.

9 *See* SPP OATT at Attachments O, J, and Z1; SPP May 17, 2010 Filing, Docket No. ER10-1269-000 at 4-7.

the next 5 years will equal approximately $122 million, representing more than twice OG&E's previous average annual capital investment of $53 million.

OG&E estimates that the annual construction costs will be as follows:

<u>Projected Budget for these Five OG&E Transmission Projects</u>
(Dollars in Millions)

Project	2010	2011	2012	2013	2014	Total
Sunnyside-Hugo	$25.105	$140.28	$21.904	$0	$0	$187.289
Sooner-Rose Hill	$10.858	$33.931	$13.045	$0	$0	$57.834
Sooner-Cleveland	$2.385	$19.074	$41.069	$1.536	$0	$64.064
Seminole-Muskogee	0	$11.1	$101	$67	$0	$179.1
Tuco-Woodward	0	$4.7	$23	$62.7	$29.6	$120
Total	$38.348	$209.085	$200.018	$131.236	$29.6	$608.287

III. SPP REGIONAL PLANNING PROCESSES

Q. HAVE THE PROJECTS BEEN INCLUDED IN ANY REGIONAL PLANNING PROCESSES?

A. Yes. SPP recently completed its 2009 SPP Transmission Expansion Plan ("STEP")[10] pursuant to the planning processes set forth at Attachment O of the SPP Open Access Transmission Tariff ("OATT"). Each of the Projects was evaluated and approved by SPP through regional planning processes and subsequently included in the 2009 STEP. The SPP Board of Directors has

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[10] *See* 2009 STEP, Exhibit No. OGE-10. Exhibit No. OGE-10 includes excerpts of the relevant sections of the 2009 STEP Report. The report, in its entirety, can be found at http://www.spp.org/publications/2009%20SPP%20Transmission%20Expansion%20Plan%20(Redacted%20Version).pdf.

approved each of the Projects, and SPP has issued a Notification to Construct for each Project.[11]

Q. WHAT IS A NOTIFICATION TO CONSTRUCT?

A. Pursuant to the SPP OATT, "[a]fter a new transmission project is (i) approved under the SPP Transmission Expansion Plan or (ii) required pursuant to a Service Agreement or (iii) required by a generation interconnection agreement to be constructed by a Transmission Owner(s) other than the Transmission Owner that is a party to the generation interconnection agreement, [SPP] shall [in writing] direct the appropriate Transmission Owner(s) to begin implementation of the project[.]"[12] The Transmission Owner(s) designated to construct the project are referred to as the "Designated Transmission Owner(s)." The written notification includes: "(1) the specifications of the project required by the Transmission Provider and (2) a reasonable project schedule, including a project completion date ("Notification to Construct")."[13] As of September 28, 2010, OG&E has accepted the SPP Notification to Construct for all five Projects.

Q. AT WHAT PHASE DOES SPP ISSUE A NOTIFICATION TO CONSTRUCT?

A. SPP only issues a Notification to Construct after it has determined which specific projects will best serve the needs of the SPP system.

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[11] *See* SPP Notification to Construct, SPP-NTC-20017 (January 16, 2009), Exhibit No. OGE-11; SPP Notification to Construct, SPP-NTC-20055 (September 18, 2009), Exhibit No. OGE-12; SPP Notification to Construct, SPP-NTC-20041 (June 19, 2009), Exhibit No. OGE-13.

[12] SPP OATT, Attachment O, Section VI.4.

[13] *Id*.

Q. WHAT IS THE 2009 SPP TRANSMISSION EXPANSION PLAN?

A. SPP's planning processes are outlined in Attachment O of SPP's OATT, and include the requirement for SPP to produce an annual STEP that addresses SPP's transmission expansion needs over a 20 year planning horizon.[14] The 2009 STEP includes a regional reliability assessment for the period of 2010 to 2019 and identifies needed transmission upgrades and possible problems in both normal and contingency conditions.[15] The 2009 STEP also highlights the region's top congested flowgates and identifies priority projects that will lower production costs and relieve congestion.[16]

Q. WERE THE PROJECTS EVALUATED IN THE 2009 STEP?

A. Yes. Within its overall transmission planning process, SPP uses several distinct evaluation and approval processes to determine the need for new transmission infrastructure. Each of the relevant processes is described in the STEP Report. Each Project was vetted through processes that considered reliability needs and congestion relief before being approved and included in the STEP.[17]

First, SPP conducts tariff studies to identify, among other things, transmission expansion projects needed to address the reliability and/or congestion concerns created by new requests for transmission service. Accordingly, SPP combines all requests for transmission service that it has received during an open season, identifies all system constraints, and then

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14 SPP OATT, Attachment O, Sections I and V.

15 2009 STEP, Exhibit No. OGE-10 at 3.

16 *Id.* at 3-4.

17 *See, e.g.*, SPP OATT, Attachment O, Sections III.3 to III.6.

determines "the upgrades required to reliably provide all of the requested service."[18] This practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and do so at the minimum total cost to beneficiaries.[19] As an additional component to this process, SPP conducts a regional review to determine if alternative solutions would reduce overall cost to customers (*i.e.*, through congestion reduction, greater efficiencies, *etc*.).[20] Through this process, SPP identified the need for Sunnyside-Hugo and Sooner-Rose Hill.

Second, SPP's Balanced Portfolio process identifies projects "intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[21] Sooner-Cleveland, Seminole-Muskogee and Tuco-Woodward are each Balanced Portfolio upgrades.

SPP must designate the appropriate Transmission Owner or Owners to construct, own, and/or finance each project in the STEP.

Q. PLEASE DISCUSS HOW THE PROJECTS FIT INTO SPP'S VISION FOR THE FUTURE OF ITS TRANSMISSION SYSTEM.

A. SPP, in its 2010 Strategic Plan, recognized that "[h]istorically, the transmission system was designed primarily to serve local systems," but that historical design

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18 *See* SPP OATT, Attachment Z1, Sections I, III.a.

19 *See* SPP OATT, Attachment Z1, Section I.

20 *See* SPP OATT, Attachment Z1, Sections III.a.

21 *See* 2009 STEP, Exhibit No. OGE-10 at 23.

has hindered "optimal utilization" of generation assets.[22] Therefore, part of SPP's vision for the future of its transmission grid is that it will "be able to deliver increased value to members by facilitating the implementation of and managing a robust transmission system flexible enough to reliably accommodate any number of future scenarios."[23] To this end, within SPP, "[g]rid expansion will be required to add additional renewable and non-renewable resources into the generation mix."[24] SPP envisions that the expansion of its regional grid should contain "an optimal mix of 'highways' (300 kV+) and byways (below 300 kV)" and should "minimize[] future transmission constraints without over-investing in transmission capacity."[25] SPP believes that "[a] robust system creates immense new value for SPP members and end users in the SPP region."[26] The five Projects at issue in this filing – as 345-kV transmission lines – thus will help realize SPP's vision of developing a robust, regional transmission system that includes transmission "highways" of 300 kV or more.

Q. PLEASE DESCRIBE HOW SPP EVALUATES TRANSMISSION PROJECTS REQUIRED TO MEET TRANSMISSION SERVICE REQUESTS.

A. Pursuant to the Aggregate Transmission Service Study Procedures set forth at Attachment Z1 of the SPP OATT, SPP conducts an open season during which

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[22] 2010 Southwest Power Pool Strategic Plan at 10, available at http://www.spp.org/publications/2010_SPP_Strategic_Plan.pdf.

[23] *Id.*

[24] *Id.*

[25] *Id.*

[26] *Id.*

customers may make requests for long-term transmission service. SPP then conducts an Aggregate Facilities Study ("AFS") of the eligible requests for transmission service received during the open season. During the AFS, "[s]ystem constraints will be identified and appropriate upgrades determined."[27] SPP is charged with determining "the upgrades required to reliably provide all of the requested service" and with performing "a regional review of the required upgrades to determine if alternative solutions would reduce overall cost to customers."[28] SPP conducts a system impact analysis to determine the steady-state impact of the aggregate transmission service requests on the SPP system, as well as on first tier non-SPP control areas. This analysis ensures that SPP's criteria and the NERC Reliability Standards are met.[29] To determine the impact of transmission service requests on the transmission system, SPP uses several seasonal models to study the aggregate transfer of the total requested service over a variety of requested service periods.[30] A transfer analysis is completed using the Power System Simulator for Engineering ("PSS/E") AC Contingency Calculation ("ACCC").[31] This analysis screens for potential loading violations

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[27] SPP OATT, Attachment Z1, Section III.a.

[28] *Id*.

[29] *See*, *e.g.*, Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers (September 16, 2008), Exhibit No. OGE-14 at 10-14 ("SPP September 2008 Study"); Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers (Revised March 19, 2009), Exhibit No. OGE-15 at 10-14 ("SPP March 2009 Study").

[30] SPP September 2008 Study, Exhibit No. OGE-14 at 10; SPP March 2009 Study, Exhibit No. OGE-15 at 10.

[31] *See*, *e.g.*, SPP September 2008 Study, Exhibit No. OGE-14 at 13; SPP March 2009 Study, Exhibit No. OGE-15 at 13.

under contingency conditions. Curtailment and redispatch are considered as alternatives to assigning new network upgrades.[32]

Q. WHAT IS THE PURPOSE OF EVALUATING TRANSMISSION SERVICE REQUESTS ON AN AGGREGATE BASIS?

A. SPP studies transmission service requests on an aggregate basis in order "to develop a more efficient expansion of the transmission system that provides the necessary ATC [*i.e.*, available transfer capability] to accommodate all such requests at the minimum total cost."[33] As stated above, this practice is intended to allow SPP and participating stakeholders to "develop a more efficient expansion of the transmission system" that will provide the necessary capacity to resolve congestion and reliability problems and do so at the minimum total cost to beneficiaries.[34] Upgrades evaluated for transmission requests pursuant to Attachment Z1 are folded into the Attachment O integrated transmission planning study and analysis,[35] which incorporates NERC Reliability Standards, load and capacity forecasts, and congestion within SPP and between SPP and other regions.[36] Projects vetted by this process are then reviewed together with projects from other studies such as high priority studies and the "Balanced Portfolio." In short, SPP's evaluation of upgrades pursuant to Attachments Z1 and O are

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[32] *See, e.g.*, SPP September 2008 Study, Exhibit No. OGE-14 at 13-14; SPP March 2009 Study, Exhibit No. OGE-15 at 13-14.

[33] SPP OATT, Attachment Z1, Section I.

[34] *See id*.

[35] See SPP OATT, Attachment O, Figure 1; *see also*, Attachment O, Sections III.3 to III.5.

[36] *See* SPP OATT, Attachment O, Section III.6.

reviewed against system-wide constraints and needs in order to ensure that the projects selected enhance reliability and/or reduce congestion.

Q. WERE THE OG&E PROJECTS EVALUATED BY SPP IN THIS PROCESS?

A. Yes. Sunnyside-Hugo was evaluated in Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers, issued on September 16, 2008. Sooner-Rose Hill was evaluated in Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers, issued on December 10, 2008 and revised on March 19, 2009. These studies are included in this filing at Exhibit Nos. OGE-14 and OGE-15. Through the Aggregate Transmission Service Study Procedures, SPP determined that the Sunnyside-Hugo and Sooner-Rose Hill Projects were among the projects needed to accommodate the aggregate transmission service requests.[37] Subsequently, these Projects were included in the 2009 STEP Report, which was approved by the SPP Board of Directors. Notifications to Construct also have been issued for these two Projects.[38]

Q. WHAT FINDINGS DID SPP MAKE IN CONNECTION WITH ITS EVALUATION OF THESE PROJECTS?

A. SPP found that limiting constraints exist on SPP's system that would prevent the requests for transmission service from being granted unless upgrades are made to

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[37] SPP September 2008 Study, Exhibit No. OGE-14 at 14-15 and Table 3; SPP March 2009 Study, Exhibit No. OGE-15 at 15 and Table 3.

[38] SPP Notification to Construct, SPP-NTC-20017, Exhibit No. OGE-11; SPP Notification to Construct, SPP-NTC-20055, Exhibit No. OGE-12.

the transmission system. These necessary upgrades include Sunnyside-Hugo and Sooner-Rose Hill.[39]

Q. PLEASE DESCRIBE FURTHER HOW SPP EVALUATES TRANSMISSION PROJECTS THAT ARE PART OF A BALANCED PORTFOLIO.

A. The Balanced Portfolio is an SPP initiative to select a cohesive group of economic transmission upgrades to benefit the SPP region as a whole.[40] The Balanced Portfolio projects are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs," and the sum of the benefits must exceed the sum of the costs.[41] SPP has stated that the Balanced Portfolio benefits "the SPP region and beyond through congestion relief, utilization of the area's large renewable resources, and expansion of markets."[42]

Q. HOW WERE THE OG&E PROJECTS EVALUATED BY SPP IN THIS PROCESS?

A. SPP's Cost Allocation Working Group ("CAWG"), with stakeholder input, identified "upgrades that will provide a balanced benefit to customers over the specified ten-year payback period."[43] Pursuant to Attachment O of the SPP OATT, the Balanced Portfolio must be (1) cost beneficial, meaning that "[t]he

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39 SPP September 2008 Study, Exhibit No. OGE-14 at 18 and Table 3; SPP March 2009 Study, Exhibit No. OGE-15 at 18 and Table 3.

40 SPP Balanced Portfolio Report (last revised June 23, 2009), Exhibit No. OGE-16 at 3 ("Balanced Portfolio Report").

41 *Id*.

42 SPP Integrated Transmission Planning, Process Document (last revised 10/29/09) at 6, *available at* http://www.spp.org/publication/ITP_Process_Final_20091029.pdf.

43 Balanced Portfolio Report, Exhibit No. OGE-16 at 3.

sum of the benefits [measured using an adjusted production cost metric] . . . must equal or exceed the sum of the costs [measured as the net present value of the revenue requirements];" and (2) balanced, meaning that the benefits must also equal or exceed the costs for each SPP zone.[44] From an initial list compiled by the CAWG, SPP conducted an analysis of the adjusted production cost of each potential project.[45] The annual benefits of the potential projects were compared to the estimated engineering and construction costs, which were provided by transmission owners.[46] A potential project's benefit-to-cost ratio was used to determine potential groupings of projects.[47] The final selection of projects was based on a grouping of projects that ensured that a project was included for each SPP zone "with the most beneficial project chosen in each zone."[48] This group of transmission projects was referred to by SPP as Portfolio 3E "Adjusted."

Q. WHAT IS PORTFOLIO 3E "ADJUSTED"?

A. Portfolio 3E "Adjusted" is the group of five 345-kV transmission line projects and two transmission substation projects selected to fulfill the Balanced Portfolio objectives. The projects have an estimated total cost of $692 million.[49] This group of projects includes, but is not limited to, the Sooner-Cleveland, Seminole-Muskogee and Tuco-Woodward Projects. Portfolio 3E "Adjusted" has been

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[44] SPP OATT, Attachment O, Section IV.3.e.

[45] Balanced Portfolio Report, Exhibit No. OGE-16 at 6.

[46] *Id*. at 8.

[47] *Id*.

[48] *Id*. at 9.

[49] *Id*. at 3.

approved by the SPP Board of Directors, and a Notification to Construct has been issued for all projects, including Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward.[50]

Q. WHAT IS THE PRIMARY BENEFIT OF THE PROJECTS INCLUDED IN PORTFOLIO 3E "ADJUSTED"?

A. Portfolio 3E "Adjusted" will alleviate several of the most congested flowgates in SPP, benefiting the entire region through reduced congestion and cost savings.[51] SPP estimates that Portfolio 3E "Adjusted" will provide a net benefit of $0.78 per month to the typical monthly residential customer whose current bill is $7.58 monthly.[52]

Q. WHAT OTHER BENEFITS WILL PORTFOLIO 3E "ADJUSTED" PROVIDE?

A. The Balanced Portfolio projects can provide increased reliability and lower required reserve margins, thus deferring reliability upgrades, and "environmental benefits due to more efficient operation of assets and greater utilization of renewable resources."[53] For example, SPP estimates that the Portfolio 3E "Adjusted" projects will save SPP Transmission Owners over $25 million in deferred reliability project costs, providing a net reliability benefit of over $9 million in the region, and over $2 million overall.[54] SPP has stated that the

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50 SPP Notification to Construct, SPP-NTC-20041, Exhibit No. OGE-13.

51 Balanced Portfolio Report, Exhibit No. OGE-16 at 3.

52 *Id.*

53 *Id.*

54 *Id.* at 42.

Balanced Portfolio projects "will enhance access to all types of generation, including the vast wind potential in the SPP region. These transmission upgrades will be the beginning of a wind-collector grid that will enable the collection, use and possible export of renewable energy beyond SPP."[55]

IV. USE OF ADVANCED TECHNOLOGIES

Q. DID OG&E CONSIDER THE USE OF ANY ADVANCED TECHNOLOGIES FOR THE PROJECTS?

A. Yes. OG&E has begun to install advanced technologies in the OG&E Projects to maximize the capability and functionality of these transmission assets.

Q. PLEASE DESCRIBE THESE ADVANCED TECHNOLOGIES.

A. The Projects will use certain technologies that are considered "advanced transmission technologies" under Section 1223 of the Energy Policy Act of 2005[56] which defines advanced transmission technology as "technology that increases the capacity, efficiency, or reliability of an existing or new transmission facility."

OG&E is installing SEL-421 relays for standard line protection on EHV transmission. These high-speed, digital relays are capable of transmitting synchro-phasor data, which are the line currents and voltages (magnitude and angle) synchronized to a GPS time standard. OG&E is planning synchro-phasor implementation for 14 substations and 25 relays within the OG&E Projects. The benefits to synchro-phasor implementation are advanced fault analysis, wide area

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55 SPP News Release, "Portfolio of New EHV Transmission Projects Approved: Benefits Will Be Balanced Across SPP Region" (April 29, 2009), *available at* http://www.spp.org/publications/Transmission_Project_Portfolio_Approved_4_29_09.pdf

56 42 U.S.C § 16422(a) (2006).

disturbance recording, and monitoring of transmission system stability. Synchrophasors will also allow OG&E to expand its ability to collect data from strategic locations across the transmission system for analysis, display and archival purposes in order to improve system efficiency and reliability. This technology will also provide the ability to import actual data for state estimation, measure line constraints, checkphasing of Current Transformers and Potential Transformers, and wide-area protection schemes.

OG&E also is installing fiber optic cable and related systems with these Projects to allow for faster, more reliable communication among the substations. Fiber optic cable is replacing existing carrier system technology involving signals sent through transmission wires themselves. In addition to being more reliable, fiber optic cable also allows for future potential applications to be developed through OG&E's Smart Grid program. In addition to these technologies, and where appropriate in the design and construction process, OG&E will incorporate tubular steel structures rather than lattice-type structures.

V. RISKS AND CHALLENGES ASSOCIATED WITH THE PROJECTS

Q. HOW IS THIS PORTION OF YOUR TESTIMONY ORGANIZED?

A. In the December 30 Order, FERC noted that when an applicant has adequately demonstrated that a project is "not routine," that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive. FERC explained that it was changing its policy with regard to the evidence required to evaluate requests for transmission rate incentives that involved groups of projects. Under FERC's new approach, applicants must identify and describe the specific risks and challenges associated with each individual project, rather than addressing the group of projects collectively. Accordingly, this portion of my testimony addresses each of the five Projects separately and identifies and describes the specific non-financial risks and challenges associated with each of the Projects. I will begin by explaining why these Projects are not routine in terms of their regional benefits and in terms of OG&E's historic investments in transmission. Mr. Rowlett's testimony will address the financial risks and challenges associated with the Projects.

Q. ARE THE PROJECTS ROUTINE COMPARED TO OG&E'S TYPICAL TRANSMISSION PROJECTS IN TERMS OF SIZE?

A. No, the Projects are extraordinary compared to OG&E's routine transmission investments.

Q. PLEASE DESCRIBE WHAT CHARACTERIZES OG&E'S ROUTINE TRANSMISSION INVESTMENTS.

A. OG&E's typical transmission projects are constructed at 69 or 138 kV; OG&E has only built one 345-kV project over the last eight years. 69-kV or 138-kV projects are smaller in stature, shorter in length, and typically follow a standard construction design. OG&E's transmission construction and maintenance programs are heavily weighted towards these types of small projects.

Moreover, OG&E's routine transmission projects are of limited scope and cost. From 2006 through 2009, OG&E's routine annual transmission capital investments averaged 24.6 miles of new transmission lines, with an annual cost of $13.6 million. These projects rarely impacted more than a single county and were typically built in support of localized transmission needs. In 2010, OG&E constructed its first 345-kV EHV project in eight years. This project, the WindSpeed line, was 120 miles in length and cost approximately $165 million dollars.[57] This atypical project skewed OG&E's five-year average transmission investment metric. Prior to the construction of the WindSpeed line, it had been over twenty-five years since OG&E attempted to build projects of the size and scope included in this filing. When the WindSpeed Project is included, OG&E's five-year average transmission investment increases to 53.5 miles and $51.3 million per year. Even when compared to this inflated average, the Projects for which OG&E requests incentives are larger in size and scope and are not comparable to OG&E's routine transmission projects. In contrast to OG&E's routine capital projects, the current Projects addressed in my testimony range from 38 miles to 120 miles of 345-kV lines, and the least expensive of the Projects is expected to cost approximately $58 million, or more than ten percent of OG&E's current net transmission plant in service.

Finally, routine projects are focused on OG&E's service to its customers, rather than regional factors.

The map included as Exhibit OGE-2 shows the relationship in scope and effect between the two projects approved for incentive rate treatment by the Commission in December 30, 2010 order (shown on the map as dotted lines), and the Projects at issue in the instant application.

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[57] The Windspeed line was a Sponsored Upgrade under the SPP OATT. As such, the revenue requirement associated with the Windspeed line was directly assigned to OG&E. OG&E also received pre-approval for recovery of the costs of the WindSpeed line from the Oklahoma Corporation Commission and was able to ensure cost recovery from retail customers in Oklahoma. Therefore, OG&E did not need to seek FPA Section 219 incentives for construction of the Windspeed line.

A. SUNNYSIDE-HUGO

Q. PLEASE DESCRIBE THE SUNNYSIDE-HUGO PROJECT.

A. Sunnyside-Hugo is a 120-mile, 345-kV transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the Sunnyside substation. As part of its transmission service study procedures, SPP has determined that Sunnyside-Hugo is necessary to alleviate constraints on the transmission system and to facilitate requests for transmission service in the region. The Project is expected to be placed into service on April 1, 2012. The length of this line and the amount of capital required to fund its construction makes it a non-routine project for OG&E.

Q. PLEASE FURTHER DESCRIBE THE FINDINGS OF THE TRANSMISSION SERVICE STUDY THAT FOUND SUNNYSIDE-HUGO IS NECESSARY TO ALLEVIATE CONSTRAINTS ON THE SPP TRANSMISSION SYSTEM.

A. In Aggregate Facility Study SPP-2006-AG3-AFS-11 For Transmission Service Requested by Aggregate Transmission Customers, SPP evaluated 1,488 MW of long-term transmission service requests.[58] The purpose of the study was "to identify system problems and potential modifications necessary to facilitate" the requested service.[59] SPP analyzed the system impact of each requested service by using a "steady-state analysis" and the study identifies Sunnyside-Hugo as one of

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[58] SPP September 2008 Study, Exhibit No. OGE-14 at 3.

[59] *Id*.

the facility upgrades that must be build in order to provide the requested transmission service "while maintaining or improving system reliability[.]"[60] This includes meeting NERC Reliability Standards and SPP's own reliability criteria.[61]

Ultimately, the study concluded that service requests made by Arkansas Electric Cooperative Corporation ("AECC"),[62] American Electric Power West ("AEPM"),[63] and Oklahoma Municipal Power Authority ("OMPA")[64] each independently require the addition of the Sunnyside-Hugo Project. Combined, these requests constitute 1,436 MW, which is nearly the entire 1,488 MW of requests reviewed in the study.[65]

Q. DOES SUNNYSIDE-HUGO REQUIRE OG&E TO COORDINATE WITH ANOTHER UTILITY?

A. Yes, it does. OG&E's Sunnyside-Hugo Project will connect with the Hugo Substation to be constructed by ITC Great Plains, LLC ("ITC"), an independent, transmission-only utility. OG&E has no control over the siting, permitting, or construction of the ITC portion of the Project. Any delay in ITC's construction of the Hugo substation will delay OG&E's ability to place Sunnyside-Hugo into service. For this reason, the Sunnyside-Hugo Project is not routine for OG&E.

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60 *Id*. at 3 and Table 4.

61 *Id*. at 10.

62 *Id*. at Table 3, AECC Reservation No. 1161209.

63 *Id.* at Table 3, AEPM Reservation Nos. 1158760, 1158761, 1162214, and 1163062.

64 *Id.* at Table 3, OMPA Reservation No. 1159596.

65 *Id.* at Table 3, AECC Reservation No. 1161209, AEPM Reservation Nos. 1158760, 1158761, 1162214, and 1163062, and OMPA Reservation No. 1159596.

Q. WILL OG&E NEED TO OBTAIN RIGHTS-OF-WAY FOR THIS PROJECT?

A. Yes. Sunnyside-Hugo is a large Project, extending 120 miles from the Sunnyside Substation near Lone Grove, Oklahoma, to the Western Farmers Electric Cooperative substation near Hugo and Fort Towson, Oklahoma. The Project will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Carter, Marshall, Johnston, Bryan and Choctaw counties. In addition, Sunnyside-Hugo's proposed route is expected to cross Chickasaw and Choctaw tribal lands, and rights-of-way will need to be obtained on those lands as well. The map included as Exhibit No. OGE-3 shows the tribal lands that Sunnyside-Hugo's proposed route will cross. In addition, the map included as Exhibit No. OGE-4 provides a more detailed view of the proposed route and a sense of the large number of rights-of-way at issue.

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE NEED TO OBTAIN RIGHTS-OF-WAY FROM PRIVATE LANDOWNERS IN SEVERAL COUNTIES?

A. Rights-of-way for the Sunnyside-Hugo Project must be obtained for each individual landowner along the Project's proposed 120-mile route. This process can be lengthy and contentious. When landowners do not contract for the necessary rights-of-way voluntarily, the resulting proceedings can be time-consuming and can lead to substantial delays, increased project costs, or re-routing of a project. In an extreme case, difficulties in obtaining or the failure to obtain rights-of-way could result in the abandonment of the Project.

The right-of-way acquisition process begins with negotiations between OG&E and individual landowners regarding the fair value of the right-of-way easement being sought by OG&E. With a project of the size and scope of Sunnyside-Hugo, there are hundreds of affected landowners. In each instance, OG&E seeks to make every reasonable effort to reach a negotiated agreement with respect to the relevant rights-of-way.

If good faith negotiations fail, OG&E then has the right to acquire real property through eminent domain proceedings pursuant to Oklahoma state law. In each instance, OG&E is required to institute a condemnation action by filing a Petition for Condemnation for each affected property. These proceedings give landowners a forum to challenge OG&E's right to condemn the property and, separately, to contest OG&E's valuation of the easement right. Unless a settlement is reached, contested condemnation proceedings result in a case-by-case determination by the district court. This process is applicable for every parcel sought to be condemned for the length of a transmission line route and this transmission line involves hundreds of parcels.

Q. DOES OG&E ANTICIPATE NEEDING TO INITIATE MANY CONDEMNATION PROCEEDINGS FOR THE SUNNYSIDE-HUGO PROJECT?

A. Yes. To date, approximately 100 condemnation cases have been filed covering approximately 150 separate parcels. While some of these cases will settle prior to going to trial it is likely that a significant number will proceed to finality. The volume of condemnation cases related to Sunnyside-Hugo is far from routine for OG&E.

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY ON TRIBAL LANDS?

A. Negotiations for rights-of-way on tribal lands are more complex and may result in significant delays, increased costs and potential re-routing issues. Building transmission lines across tribal lands is challenging because state eminent domain laws and procedures may not apply, depending on how a particular piece of property is held. In some instances, real estate belonging to a Native American Nation is held in trust by the U.S. Department of the Interior's Bureau of Indian Affairs ("BIA") for the benefit of the Nation. In other cases, a Nation may own real property in its own name and not in trust. In addition, individual members of a Nation may own real property, which in some instances can be held in trust by the BIA for the benefit of the individual. Access rights to tribal lands must be negotiated either through the BIA for property held in trust or directly with the Nation or individual for property not held in trust. The myriad ways property can be owned by a Nation or individual impacts the length of time it takes to acquire such property and the specific procedures that need to be followed.

Q. ARE THERE POTENTIAL ENVIRONMENTAL IMPACTS THAT MAY AFFECT THE PROJECT?

A. Yes. The Project's route is expected to cross through the habitat of the endangered American Burying Beetle. A survey of the activities of the American Burying Beetle was performed along the Sunnyside-Hugo route in 2010, but was found deficient by the United States Fish and Wildlife Service ("USFWS"), and will have to be re-surveyed in 2011. The survey cannot be performed until the weather conditions are favorable to activity by the beetle. Since 1989, the USFWS has listed the American Burying Beetle as an Endangered Species.[66] USFWS recently reviewed and confirmed the beetles' endangered status,[67] identifying eastern Oklahoma as one of the beetles' few remaining habitats.[68] A map of the historical range of the American Burying Beetle is included as Exhibit No. OGE-5.

The Endangered Species Act prohibits any action that causes a "taking" of any listed species of endangered fish or wildlife.[69] Depending on the results of the new survey in the spring, the Sunnyside-Hugo Project could require permitting and/or a Habitat Conservation Plan to offset any potential harmful effects that the proposed activity might have on the beetle.[70] Alternatively, OG&E could be required to reroute the Project in order to avoid the occurrences of the beetle and its critical habitat. Studying the beetles' occurrences and establishing mitigation strategies add risk for OG&E and potentially could delay the Project. This is the first time that I have encountered the American Burying Beetle on a transmission project in the twenty-three years that I have worked at

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66 *Determination of the Endangered Status for the American Burying Beetle*, 54 Fed. Reg. 29,652 (July 13, 1989).

67 *The 5-Year Review of the American Burying Beetle* § 3.1 (2008), *available at* http://ecos.fws.gov/docs/five_year_review/doc1968.pdf (last visited February 11, 2011).

68 FWS Fact Sheet on American Burying Beetle at 2, www.fws.gov/southwest/es/oklahoma/beetle1.htm. (last visited on February 13, 2011).

69 Endangered Species Act § 9(a)(1)(B), 16 U.S.C. § 1538(a)(1)(B) (2006).

70 *See, e.g.*, FWS Habitat Conservation Planning and Incidental Take Permit Processing Handbook at 1-1- 1-3 (November 4, 1996), *available at* http://www.nmfs.noaa.gov/pr/pdfs/laws/hcp_handbook.pdf.

OG&E. Accordingly, the presence of the American Burying Beetle along the line route is not a routine occurrence for OG&E.

In addition, environmental assessments required by the National Environmental Policy Act ("NEPA") are being performed in conjunction with the tracts that cross BIA lands. The results of these investigations are unknown at this time.

Q. WHAT RISKS DO THESE ISSUES POSE TO THE SITING, CONSTRUCTION, AND OPERATION OF THE PROJECT?

A. The need to evaluate the potential impact of the Project on the American Burying Beetle may cause delays due to the need for analysis and surveys, the timing of which are dependent on weather conditions. Delays could result in cost increases, and the need for regulatory approvals could result in re-routing or other potential mitigation requirements.

Depending on the outcome of the environmental assessments required by NEPA, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.

B. SOONER-ROSE HILL

Q. PLEASE DESCRIBE THE SOONER-ROSE HILL PROJECT.

A. Sooner-Rose Hill is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to an interface with a Westar Energy line segment at the Oklahoma-Kansas state line. As part of its transmission service study procedures, SPP has determined that Sooner-Rose Hill is necessary to alleviate constraints on the transmission system and to facilitate requests for transmission service in the region. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length and has an estimated in-service date of June 1, 2012.

Q. PLEASE FURTHER DESCRIBE THE FINDINGS OF THE TRANSMISSION SERVICE STUDY THAT FOUND SUNNYSIDE-HUGO IS NECESSARY TO ALLEVIATE CONSTRAINTS ON THE SPP TRANSMISSION SYSTEM.

A. In Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers, SPP evaluated 1,359 MW of long-term transmission service requests.[71] The purpose of the study was to "identify system problems and potential modifications necessary to facilitate" the requested service.[72] SPP analyzed the system impact of each requested service by using a "steady-state analysis" and the study identifies Sooner-Rose Hill as one of the facility upgrades that must be built in order to provide requested transmission service "while maintaining or improving system reliability[.]"[73] This includes meeting NERC Reliability Standards and SPP's own reliability criteria.[74]

Ultimately, the study concludes that service requests made by Kansas Power Pool ("KPP"),[75] Aquila Inc. dba Aquila Networks ("UCU"),[76] and Westar

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71 SPP March 2009 Study, Exhibit No. OGE-15 at 3.

72 *Id*.

73 *Id*. at 3 and Table 4.

74 *Id*. at 10.

75 *Id*. at Table 3, KPP Reservation Nos. 1222644 and 1222932.

(WRGS)[77] each independently require the addition of the Sooner-Rose Hill Project. Combined, these requests total 485 MW, which constitutes over one-third of the total 1,359 MW of requests reviewed in the study.[78] In addition, SPP determined that Sooner-Rose Hill was a "regional reliability upgrade" that could relieve the flowgate that monitors the 138-kV line from El Paso to Farber for the loss of the 345-kV line from Wichita to Woodring.[79]

Q. WILL OG&E BE REQUIRED TO COORDINATE WITH ANOTHER UTILITY TO CONSTRUCT THE SOONER-ROSE HILL PROJECT?

A. Yes. The OG&E portion of the Sooner-Rose Hill line, to be located wholly within Oklahoma, is only a portion of a larger regional project to be built in Oklahoma and Kansas. Because this line connects with another utility headquartered in a different state and because the line also crosses state lines, this Project is non-routine for OG&E. The OG&E portion will interconnect with the remaining portion of the transmission line and related facilities to be constructed by Westar Energy in Kansas.[80] OG&E has no role in the siting, permitting, or construction of the facilities to be located outside of Oklahoma. The Westar portion of the Project faces many of the same risks and challenges as the

(continued…)

76 *Id*. at Table 3, UCU Reservation No. 1223093.

77 *Id*. at Table 3, WRGS Reservation No. 1197077.

78 *Id*. at Table 3 KPP Reservation Nos. 1222644 and 1222932, UCU Reservation No. 1223093, and WRGS Reservation No. 1197077.

79 2009 STEP, Exhibit No. OGE-10 at 26. The 2009 STEP found that over a twelve month period, the percentage of total intervals breached or biding was 2.0% and that the average shadow price was $2.29. *Id.* The "shadow price" is the amount of value of relieving the constraint measured in dollars. *Id.* at 15.

80 *See* OG&E Projects, Exhibit No. OGE-3.

Oklahoma portion of the line. Any delay in the construction of the facilities to which OG&E will interconnect will delay OG&E's ability to complete the Project and place it into service. Moreover, if Westar is unable to build its portion of the Project in Kansas, OG&E could be forced to abandon its portion of the Project in Oklahoma.

Q. WILL OG&E NEED TO OBTAIN RIGHTS-OF-WAY FOR THIS PROJECT?

A. Yes. The routing of this Project is particularly complex. The proposed route of the Sooner-Rose Hill will cross privately-owned property as well as tribal lands, each of which presents unique and challenging requirements and risks. The Project will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Noble and Kay counties. In addition, Sooner-Rose Hill's proposed route is expected to cross Otoe-Missouria, Pawnee, Osage, and Chilocco tribal lands, and rights-of-way will need to be obtained on those lands as well.[81]

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY ON TRIBAL LANDS?

A. As detailed previously in my testimony with respect to the Sunnyside-Hugo Project, *supra*, Section V.A, the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain rights in cases where the property is held in trust by the BIA. As of January 1, 2011, there are twenty tracts along the Sooner-Rose Hill route that have involvement of the BIA, which

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81 *See* Tribal Jurisdictions in Oklahoma, Exhibit No. OGE-3.

complicates the process of obtaining the necessary rights-of-way and makes this Project not routine for OG&E. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.

Q. ARE THERE POTENTIAL ENVIRONMENTAL IMPACTS THAT MAY AFFECT THE PROJECT?

A. Environmental assessments required by NEPA are being performed at this time in conjunction with the tracts that cross BIA lands. The results of these investigations are unknown at this time.

Q. WHAT RISKS DO THESE ISSUES POSE TO THE SITING, CONSTRUCTION, AND OPERATION OF THE PROJECT?

A. Depending on the outcome of the environmental assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors could also result in abandonment of the Project.

C. SOONER-CLEVELAND

Q. PLEASE DESCRIBE THE SOONER-CLEVELAND PROJECT.

A. The Sooner-Cleveland Project is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's ("GRDA") Cleveland substation, plus associated upgrades to the Sooner substation. A map included as Exhibit No. OGE-6 details the proposed route for the Project. Sooner-Cleveland is part of SPP's Balanced Portfolio, a group of projects specifically intended to reduce congestion on the system. In the 2009

STEP, SPP included Sooner-Cleveland as one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[82] Similarly, the 2009 STEP included the Sooner-Cleveland Project as addressing "many of the top SPP flowgates" and enabling "lower transfers of revenue requirements necessary to achieve balance."[83] The Project is expected to be placed into service on March 31, 2013.

Q. DOES SOONER-CLEVELAND REQUIRE OG&E TO COORDINATE WITH ANOTHER UTILITY?

A. Yes. OG&E must coordinate the Project's permitting and construction with two additional projects by two other utilities, Westar and Grand River Dam Authority.[84] Specifically, OG&E's completion of improvements at Sooner substation is contingent on the completion of the Sooner-Rose Hill Project, a significant portion of which Westar is responsible for constructing. Similarly, the Sooner-Cleveland Project is dependent on the Grand River Dam Authority's upgrade at the Cleveland substation. OG&E has no role in the siting, permitting, or construction of the facilities that Westar and GRDA are planning to build. A delay in the construction schedule of either project can result in a delay for the Sooner-Cleveland Project. Failure of either of these utilities to perform will create substantial risks that could lead to an abandonment of the Project.

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[82] 2009 STEP, Exhibit No. OGE-10 at 27.

[83] *Id.*

[84] *See* OG&E Projects, Exhibit No. OGE-2.

Q. WILL OG&E NEED TO OBTAIN RIGHTS-OF-WAY FOR THIS PROJECT?

A. Yes. Sooner-Cleveland's path crosses Oklahoma's Noble, Pawnee, and Osage counties.[85] In addition, Sooner-Cleveland's proposed route will cross Otoe-Missouria, Pawnee, and Osage tribal lands, and rights-of-way will need to be obtained on those lands as well.[86]

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY ON TRIBAL LANDS?

A. As detailed previously in my testimony with respect to the Sunnyside-Hugo Project, *supra*, Section V.A., the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain rights in cases where the property is held in trust by the BIA. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs. While the Project likely will cross multiple tracts, OG&E will not know the exact number of tracts until the route gets finalized, thus creating an additional layer of uncertainty and risk for this Project. These issues do not arise with OG&E's routine projects.

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85 See Sooner to Cleveland Routing, Exhibit No. OGE-6.

86 *See* Tribal Jurisdiction in Oklahoma, Exhibit No. OGE-3.

Q. ARE THERE OTHER PERMITTING AND REGULATORY REQUIREMENTS APPLICABLE TO THIS PROJECT?

A. Yes. The Project's proposed route will cross Sooner Lake and the Arkansas River, which will require OG&E to obtain various approvals from the U.S. Army Corps of Engineers.[87] This requirement may result in project delays due to required environmental assessments pursuant to NEPA and may require environmental mitigation or potential route changes, which would lead to further delays and potential cost increases.

Q. ARE THERE POTENTIAL ENVIRONMENTAL IMPACTS THAT MAY AFFECT THE PROJECT?

A. Yes. The current route for Sooner-Cleveland includes areas of concern to the USFWS due to the presence of the American Bald Eagle and migratory waterfowl. While the American Bald Eagle no longer is listed as an Endangered Species, it is still protected under the Bald and Golden Eagle Protection Act[88] and the Migratory Bird Treaty Act.[89] 345-kV EHV transmission lines are taller than OG&E's typical 138-kV or 69-kV transmission projects and 345-kV transmission requires a significantly wider rights-of-way footprint. Assessments due to the larger scale of the Sooner-Cleveland 345-kV Project are underway with USFWS and Oklahoma Department of Wildlife. Final results including adjustments to routing or potential changes to the Project have yet to be determined.

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87 *See* Sooner to Cleveland Routing, Exhibit No. OGE-6.

88 16 U.S.C. §§ 668-668d (2006).

89 16 U.S.C. §§ 703-712 (2006).

Additionally, the endangered American Burying Beetle inhabits several areas along Sooner-Cleveland's proposed route, and significant portions of the route will need to be surveyed.[90] As detailed previously in my testimony with respect to the Sunnyside-Hugo Project, *supra*, Section V.A., some measures potentially will be required to mitigate the impact of the Project on the American Burying Beetle and its critical habitat. The need to survey significant portions of the route and the potential for required mitigation raise risks that the Project will face siting and construction delays.

Finally, environmental assessments required by NEPA are being performed in conjunction with the tracts that cross BIA lands. The results of these investigations are unknown at this time.

Q. WHAT RISKS DO THESE ISSUES POSE TO THE SITING, CONSTRUCTION, AND OPERATION OF THE PROJECT?

A. Failure to complete the necessary permitting for the described species could cause delays or cancellation of the Project. Moreover, significant portions of the route will need to be surveyed to identify the potential presence of these Endangered Species, and some measures likely will be required to mitigate the impact of the Project on one or more of these species. The need to survey significant portions of the route and the likely possibility that some mitigation may be required raise the possibility of further siting and construction delays, which could also cause further increased costs. Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental

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[90] *See* American Burying Beetle Historic Range and Current Distribution in Oklahoma, Exhibit No. OGE-5.

impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors are not routine and could also result in abandonment of the Project.

Q. DOES THE SOONER-CLEVELAND PROJECT PRESENT ANY OTHER SPECIAL CHALLENGES FOR THE FACILITY'S CONSTRUCTION?

A. Yes. Siting and construction of the Project will not be completed until March of 2013. This lead time creates uncertainties, and costs may increase over time. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond the control of OG&E and make the Project unfeasible. The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project requires a large amount of material, and requires OG&E to use outside contractors, which is not required for routine projects. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns.

D. SEMINOLE-MUSKOGEE

Q. PLEASE DESCRIBE THE SEMINOLE-MUSKOGEE PROJECT.

A. The Seminole-Muskogee Project is a 345-kV, 120-mile transmission line built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both substations. A map included as Exhibit No. OGE-7 details the proposed route for the Project. Seminole-Muskogee is part of SPP's Balanced Portfolio, a group of projects specifically intended to reduce congestion on the system. SPP determined that Seminole-Muskogee was one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[91] Specifically, SPP has determined that Seminole-Muskogee could relieve congestion on the flowgate that monitors the 138-kV line from Okmulgee to Henryetta for the loss of Okmulgee to Kelco.[92] SPP also found that over a twelve-month period, the percentage of total intervals breached or binding on the Okmulgee to Henryetta line was 1.9% with an average shadow price of $5.01.[93] A flowgate shadow price indicates the reduction to the cost of the market dispatch which would result from a small increase in the enforced loading limit, generally expressed in dollars per MW per hour of loading. The flowgate shadow prices are often applied as broad measures of the marginal costs of congestion within a market. SPP further determined that Seminole-Muskogee could relieve congestion on the flowgate monitoring the 138-kV line from Riverside Station to Okmulgee City for the loss of the 138-kV line from Riverside Station to Explorer Okmulgee.[94] The Project is expected to be placed into service on December 31, 2013.

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[91] 2009 STEP, Exhibit No. OGE-10 at 27.

[92] *Id.* at 22.

[93] *Id.*

[94] *Id.* at 25. This line, SPP determined, had a percentage of total intervals breached or binding of 0.9% over a twelve-month period and a shadow price of $2.30. *Id.*

Q. HOW DOES THE SEMINOLE-MUSKOGEE PROJECT FIT INTO THE SPP'S EXTRA HIGH VOLTAGE OVERLAY PROJECT?

A. Prior to being included in the Balanced Portfolio, the Seminole Muskogee line was also part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system. In 2007, SPP set the stage for regional extra high voltage transmission construction through the strategic SPP "EHV Overlay Project" report. In the report, SPP stated:

> This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs.[95]

Q. WILL OG&E NEED TO OBTAIN RIGHTS-OF-WAY FOR THIS PROJECT?

A. Yes. Seminole-Muskogee is a large project, extending 120 miles form Seminole County to Muskogee County, Oklahoma. The Project will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Seminole, Hughes, Okfuskee, McIntosh, Okmulgee, and Muskogee counties.[96] In addition, Seminole-Muskogee's proposed route is expected to cross Seminole, Muscogee (Creek), and United Keetoowah Band of Cherokees tribal lands and rights-of-way will need to be obtained on those lands as well.[97]

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95 Southwest Power Pool, Final Report on the Southwest Power Pool (SPP) EHV Overlay Project (June 27, 2007), *available at* http://www.spp.org/publications/spp_ehv_study_final_report.pdf) ("EHV Report").

96 *See* Seminole to Muskogee Alternative Segments, Exhibit No. OGE-7.

97 *See* Tribal Jurisdictions in Oklahoma, Exhibit No. OGE-3.

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY FROM PRIVATE LANDOWNERS IN SEVERAL COUNTIES?

A. As I explained in connection with the Sunnyside-Hugo Project, the process for obtaining rights-of-way from landowners can be cumbersome and time-consuming, particularly when OG&E is unable to reach agreement with affected landowners and must initiate condemnation proceedings. The need to obtain rights-of-way across both private and tribal lands (and the need to resolve multiple eminent domain disputes) creates a significant risk of delay and cost increases. This risk will be greater if OG&E is compelled to revisit the Project's proposed route or if costs associated with the project increase significantly over budget. This Project requires OG&E to obtain rights-of-way for a 120-mile route, which will include negotiations and potential condemnation proceedings for hundreds of individual landowners. A right-of-way of this length is not routine for OG&E.

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY ON TRIBAL LANDS?

A. As detailed previously in my testimony with respect to the Sunnyside-Hugo Project, *supra*, Section V.A., the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain rights in cases where the property is held in trust by the BIA. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs. While the Project likely will cross hundreds of tracts, OG&E will not know the exact number of tracts until the route is finalized, thus creating an additional layer of uncertainty and risk for this Project.

Q. ARE THERE POTENTIAL ENVIRONMENTAL IMPACTS THAT MAY AFFECT THE PROJECT?

A. Yes. Again, review and approval from USFWS may affect the selection of a final route and the timing of the Project's construction. The endangered American Burying Beetle inhabits several areas along Seminole-Muskogee's proposed route.[98] Significant portions of the route will need to be surveyed, and some measures potentially will be required to mitigate the impact of the Project on the American Burying Beetle and its critical habitat. Again, the need to survey significant portions of the route and the potential for required mitigation create risks of siting and construction delays.

In addition, during preliminary meetings with the USFWS, the agency expressed concerns over routing the Seminole-Muskogee line near or through the Deep Fork Wildlife Refuge. A map included as Exhibit No. OGE-8 shows the relationship between the proposed route, the Deep Fork Wildlife Refuge, and Lake Eufaula.[99] The Deep Fork Wildlife Refuge protects wetlands along the Deep Fork River in eastern Oklahoma and was added to the National Wildlife

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98 *See* American Burying Beetle Historic Range and Current Distribution in Oklahoma, Exhibit No. OGE-5.

99 *See also*, Seminole to Muskogee Alternative Segments, Exhibit No. OGE-7 (showing a alternative routes that cross either the Deep Fork Wildlife Refuge or Lake Eufaula).

Refuge System in 1993.[100] According to the USFWS, at least 147 species of birds, including a wide variety of migrating and wintering waterfowl, fifty-one species of mammals, fifty-four species of reptiles and thirty-eight species of amphibians, inhabit the bottomland forest and associated wetlands.[101] USFWS recently completed an Environmental Assessment to construct a headquarters and visitors center in the Refuge, and determined that the Refuge provide sanctuary for several Endangered Species in addition to the American Burying Beetle, including the Interior Least Tern, the Whooping Crane, and the Piping Plover.[102] As stated earlier, the existence of Endangered Species along the proposed transmission route creates potential risks for permitting and developing the Project pursuant to USFWS rules and regulations.

Moreover, the U.S. Army Corps of Engineers ("the Corps") also has expressed a preference for the line to cross over Lake Eufaula rather than traverse through the Refuge. While the alternative route could mitigate risks associated with crossing the Refuge, it would require OG&E to obtain a lake crossing permit from the Corps and would add uncertainty and risk to the Project's development.

The proposed route for Seminole-Muskogee also will cross the Arkansas River, which would raise several challenges. This river crossing would require OG&E to obtain an additional permit from the Corps. OG&E also must negotiate

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[100] *See* http://www.fws.gov/southwest/refuges/oklahoma/Deep%20Fork/index.html (last visited on February 16, 2011).

[101] U.S. Fish and Wildlife Service, *Deep Fork NWR seeks comments on Environmental Assessment for new Administrative Office*, Press Release (February 12, 2010), *available at* http://www.fws.gov/southwest/refuges/oklahoma/Deep%20Fork/DFAdministrativeBldgeaPRfinal.pdf.

[102] Deep Fork National Wildlife Refuge, *The Building of New Administrative Office and Visitor Contact Facilities On Deep Fork National Wildlife Refuge* at 8 (January 14, 2010), *available at* http://www.fws.gov/southwest/refuges/oklahoma/Deep%20Fork/DFAdminOfficeFacilityEA.pdf.

an agreement with the Arkansas Riverbed Authority, a consortium of the Cherokee, Chickasaw, and Choctaw tribes that control access to the Arkansas Riverbed. OG&E has identified five different possible routes for the line over the Arkansas River, and all of those possible routes have generated considerable local interest and unrest. OG&E also plans to hold discussions with the Corps regarding a possible route across Camp Gruber on the east side of the Arkansas River near Braggs. This level of interaction with the Corps is not routine for OG&E.

Finally, environmental assessments required by NEPA may be required in conjunction with the tracts that cross BIA lands. The number and scope of required NEPA assessments are unknown at this time.

Q. WHAT RISKS DO THESE ISSUES POSE TO THE SITING, CONSTRUCTION, AND OPERATION OF THE PROJECT?

A. Denial of a permit by either the Corps or USFWS could require the line to be re-routed and cause significant siting and construction delays, which could also cause increased costs. With respect to the American Burying Beetle, the need to survey significant portions of the route and the possibility that some mitigation may be required raise the possibility of further siting and construction delays. Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors also could result in abandonment of the Project.

Q. DOES THE PROJECT PRESENT ANY OTHER SPECIAL CHALLENGES FOR THE FACILITY'S CONSTRUCTION?

A. Yes. Seminole-Muskogee is much larger than routine transmission investments, calling for the construction of 120 miles of new 345-kV transmission lines. Siting and construction of the Seminole-Muskogee Project will not be completed until December of 2013, and therefore, the Project faces risks and challenges associated with this lead time of nearly three years. This lead time creates uncertainties. For example, the longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond OG&E's control. Moreover, the costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. Such risks are compounded by the fact that a large project requires a large amount of material and involves reliance on outside contractors. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns. A line of this length and cost is not routine for OG&E.

E. TUCO-WOODWARD

Q. PLEASE DESCRIBE THE TUCO-WOODWARD PROJECT.

A. Tuco-Woodward is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV substation to the Southwestern Public Service Company ("SPS") Tuco substation. The OG&E portion of the Project is 72 miles in length. Tuco-Woodward is part of SPP's Balanced Portfolio, a group of projects specifically intended to reduce congestion on the system. SPP determined that Tuco-Woodward was one of seven upgrades that, by reducing congestion, would result "in savings in generation production costs," and would provide "significant benefit versus cost to the SPP region."[103] Specifically, SPP has determined that Tuco-Woodward could relieve congestion on the flowgate that monitors the 115-kV line from Randall County substation to Palo Duro for loss of the 230-kV line from Amarillo to Swisher.[104] SPP also found that over a twelve-month period, the percentage of total intervals breached or binding was 20.4% with a shadow price of $29.79.[105] SPP further determined that Seminole-Muskogee could relieve congestion on the flowgate monitoring the 138-kV line from Riverside Station to Okmulgee City for the loss of the 138-kV line from Riverside Station to Explorer Okmulgee.[106] The Project is expected to be placed into service on May 19, 2014.

Q. HOW DOES THE TUCO-WOODWARD PROJECT FIT INTO THE SPP'S EXTRA HIGH VOLTAGE OVERLAY PROJECT?

A. Prior to being included in the Balanced Portfolio, the Tuco-Woodward line was also part of a series of extra high voltage transmission projects designed by SPP as a regional "overlay" to the existing transmission system. In 2007, SPP set the

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[103] 2009 STEP, Exhibit No. OGE-10 at 27.

[104] *Id.* at 17.

[105] *Id.*

[106] *Id.* at 25. This line, SPP determined, had a percentage of total intervals breached or bidning of 0.9% over a twelve-month period and a shadow price of $2.30. *Id.*

stage for regional extra high voltage transmission construction through the strategic SPP "EHV Overlay Project" report. In the report, SPP stated:

> This project provided a long-range strategic assessment regarding long-term reliability and capacity needs through the use of a 345 kV, 500 kV, and 765 kV or higher transmission system to overlay the SPP footprint, to assess the potential integration with neighboring systems, to address future transmission needs required by SPP and to ensure an efficient and optimal transmission system to address long-term future transmission needs.[107]

Q. DOES TUCO-WOODWARD REQUIRE OG&E TO COORDINATE WITH ANOTHER UTILITY?

A. Yes. Unlike more routine projects, the OG&E portion of the Tuco-Woodward Project is a component of a larger regional transmission project and provides for OG&E to construct facilities that will connect with the SPS transmission system located in Texas.[108] The SPS portion of the Project will face risks and challenges associated with siting, permitting, and constructing the facilities in Texas that will equal or exceed those faced by OG&E. Any delay in SPS's ability to construct and place into service its portion of the lengthy transmission line—which constitutes 175 miles of the 250-mile line—will delay OG&E's ability to place its portion of the Tuco-Woodward Project into service. The fact that OG&E must coordinate with another utility headquartered in another state is not routine for OG&E.

Q. WILL OG&E NEED TO OBTAIN RIGHTS-OF-WAY FOR THIS PROJECT?

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[107] EHV Report at 4.

[108] *See* OG&E Projects, Exhibit No. OGE-2.

A. Yes. Tuco-Woodward is a large project, extending 250 miles from SPS's Tuco substation in Hale County, Texas to OG&E's Woodward District EHV substation near Woodward, Oklahoma. The Project will require OG&E to acquire rights-of-way from private landowners in each of Oklahoma's Woodward, Dewey, Custer, Washita, Roger Mills, and Beckham counties. In addition, Tuco-Woodward's proposed route is expected to cross Cheyenne-Arapahoe tribal lands, and rights-of-way will need to be obtained on those lands as well.[109]

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY FROM PRIVATE LANDOWNERS IN SEVERAL COUNTIES?

A. As I explained in connection with the Sunnyside-Hugo Project, the process for obtaining rights-of-way from landowners can be cumbersome and time-consuming, particularly when OG&E is unable to reach agreement with affected landowners and must initiate condemnation proceedings. The need to obtain rights-of-way across both private and tribal lands (and the need to resolve multiple eminent domain disputes) creates a significant risk of delay and cost increases. This risk will be greater if OG&E is compelled to revisit the Project's proposed route. This Project requires OG&E to obtain rights-of-way for a 72-mile route, which will include negotiations and potential condemnation proceedings for scores of individual landowners.

Q. WHAT SPECIFIC CHALLENGES ARE RAISED BY THE PROCESS TO OBTAIN RIGHTS-OF-WAY ON TRIBAL LANDS?

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109 *See* Tribal Jurisdictions in Oklahoma, Exhibit No. OGE-3.

A. As detailed previously in my testimony with respect to the Sunnyside-Hugo Project, *supra*, Section V.A., the process for obtaining rights-of-way on tribal lands is complex and time-consuming due to the different ways in which such property is held and by the lack of eminent domain rights in cases where the property is held in trust by the BIA. Problems with obtaining rights-of-way for the Project's proposed route could lead to delays and/or changes in the Project's proposed route, with associated increases in costs.

Q. ARE THERE POTENTIAL ENVIRONMENTAL IMPACTS THAT MAY AFFECT THE PROJECT?

A. Yes. The federally protected Black Kettle National Grasslands lies along Tuco-Woodward's proposed route in Oklahoma. A map showing the location of the Project's proposed route in relation to the Black Kettle National Grasslands is included as Exhibit No. OGE-8. The Grasslands contains 31,300 acres with 30,724 acres located near Cheyenne, Oklahoma, and the remaining 576 acres located near Canadian, Texas.[110] The area was purchased and rehabilitated by the federal government after the devastation of the 1930s "Dust Bowl," and Congress designated a protected National Grasslands in the 1960s.[111] Routing the Project through this area will pose significant challenges for OG&E including potential federal permitting issues, delays and significant costs. For example, mitigation could include adjusting the Woodward-Tuco route to avoid the Black Kettle

[110] http://www.fs.fed.us/r3/cibola/districts/black.shtml (last visited February 16, 2011).

[111] Johnson, David, *A Short History of the Grasslands* at 5-6 (February 3, 2006), available at http://www.fs.fed.us/r3/cibola/plan-revision/national_grasslands/backdocs/Grasslands_History_2-3-06.pdf.

National Grasslands altogether, potentially adding additional line miles and additional costs to the overall Project.

Tuco-Woodward's proposed route also passes through areas which some regard as the natural habitat of the Lesser Prairie Chicken, a species of bird that is classified as a candidate for future listing as a Threatened Species by the USFWS.[112] While there are no defined regulatory approvals that are required when interacting with Lesser Prairie Chicken Habitat in Oklahoma, the Oklahoma Department of Wildlife Conservation ("ODWC") and USFWS are providing active guidance to agricultural, wind farm development and transmission construction interests in order to limit the possibility of the Lesser Prairie Chicken moving from a Candidate Species to an Endangered Species. The Lesser Prairie Chicken may be listed by the USFWS as an Endangered Species prior to the completion of this Project, which increases the risk of delay and abandonment of the Project. Building a line in the vicinity of the habitat of the Lesser Prairie Chicken is not routine for OG&E. A map showing the location of the Project's proposed route in relation to concentrations of the Lesser Prairie Chicken is included as Exhibit No. OGE-9.

Finally, environmental assessment required by NEPA may be required in conjunction with the tracts that cross BIA lands. The number and scope of required NEPA assessments are unknown at this time. Depending on the number and outcome of the NEPA assessments, OG&E could be required to mitigate

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[112] Selected pages of the USFWS Species Assessment and Listing Priority Assignment Form for the Lesser Prairie Chicken are included as Exhibit No. OGE-17. The entire assessment can be found at http://www.fws.gov/ecos/ajax/docs/candforms_pdf/r2/B0AZ_V01.pdf.

potential environmental impacts, which could lead to additional costs, changes in the Project's proposed route, or delays in construction. Such factors also could result in abandonment of the Project.

Q. DOES THE TUCO-WOODWARD PROJECT PRESENT ANY OTHER SPECIAL CHALLENGES FOR THE FACILITY'S CONSTRUCTION?

A. Yes. The Project involves the construction of 250 miles of new 345-kV transmission lines. The participation in the construction of a 250 mile transmission line is not routine for OG&E. Siting and construction of the Project will not be completed until May of 2014. This lead time creates uncertainties, and costs may increase over time. The longer the lead time for a project, the more likely it is that circumstances, such as the projected cost of a project and the required regulatory approvals, could change for reasons beyond the control of OG&E and make the Project unfeasible. The costs of materials can increase significantly in a short time period, and OG&E may encounter shortages or delays in the availability of certain materials. This risk is compounded by the fact that a large project requires a large amount of material and requires OG&E to use outside contractors, which is not required for routine projects. Moreover, a large project generates complex logistical and management issues that also increase the risk of delay or cost overruns.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT NO. OGE-2

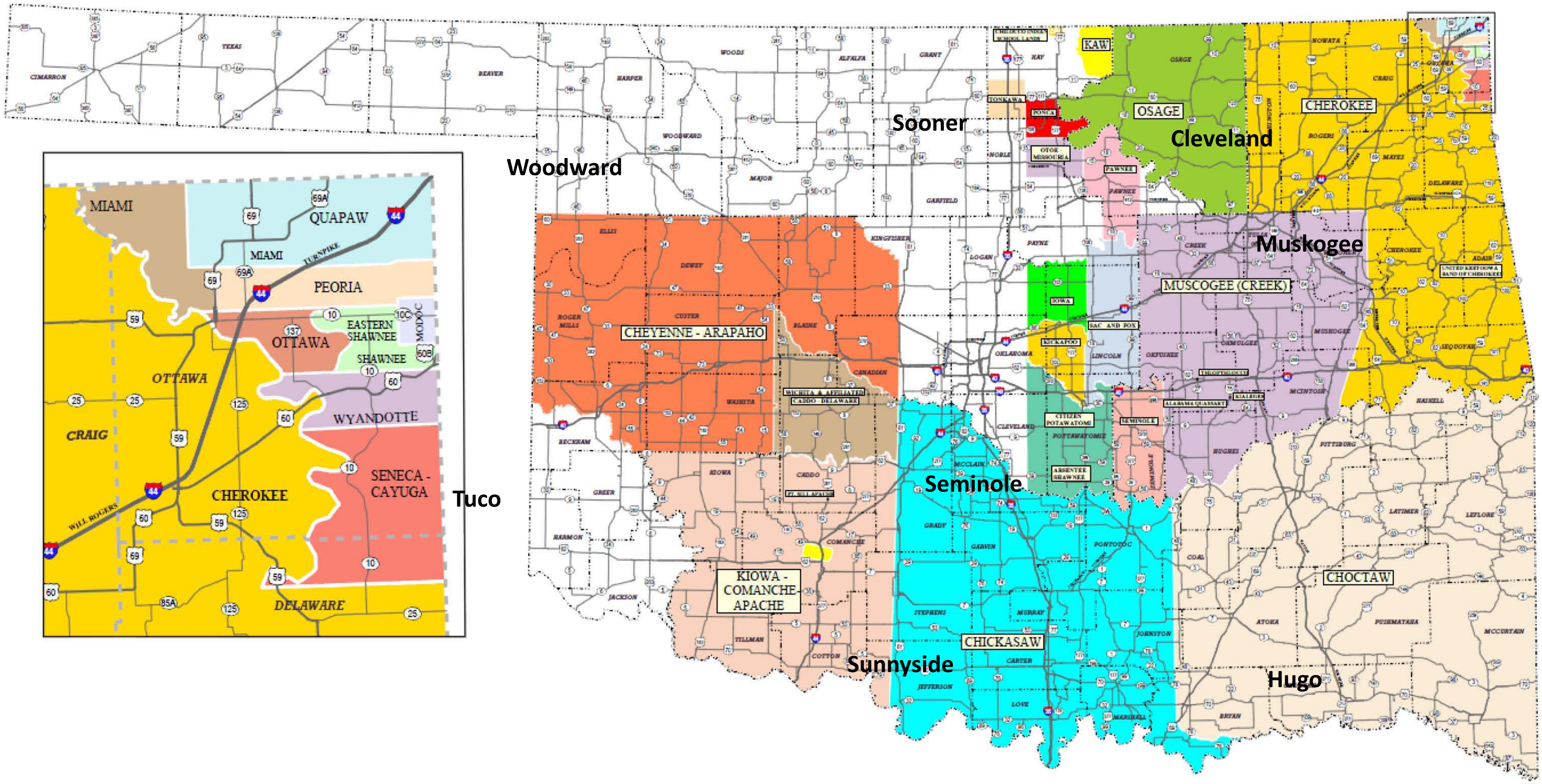
OG&E Projects

Kansas
(Westar)

Rose Hill - Kansas
(Westar)

EXHIBIT NO. OGE-3

TRIBAL JURISDICTIONS IN OKLAHOMA



37 FEDERALLY RECOGNIZED TRIBES (Tribal Boundaries provided by the Bureau of Land Management)

ABSENTEE SHAWNEE TRIBE	CHOCTAW NATION	KAW NATION	OSAGE NATION	SAC AND FOX NATION	WYANDOTTE NATION
ALABAMA QUASSARTE TRIBAL TOWN	CITIZEN POTAWATOMI TRIBE	KIALEGEE TRIBAL TOWN	OTOE - MISSOURIA TRIBE	SEMINOLE NATION	UNITED KEETOOWAH BAND OF CHEROKEES
APACHE TRIBE	COMANCHE NATION	KICKAPOO TRIBE	OTTAWA TRIBE	SENECA - CAYUGA TRIBE	
CADDO TRIBE	DELAWARE NATION	KIOWA TRIBE	PAWNEE NATION	SHAWNEE TRIBE	
CHEROKEE NATION	EASTERN SHAWNEE TRIBE	MIAMI NATION	PEORIA TRIBE	THLOPTHLOCCO TRIBAL TOWN	
CHEYENNE - ARAPAHO TRIBES	FT. SILL APACHE	MODOC TRIBE	PONCA NATION	TONKAWA TRIBE	
CHICKASAW NATION	IOWA TRIBE	MUSCOGEE (CREEK) NATION	QUAPAW TRIBE	WICHITA & AFFILIATED TRIBE	

EXHIBIT NO. OGE-4

Exhibit No. OGE-4
Page 1 of 1

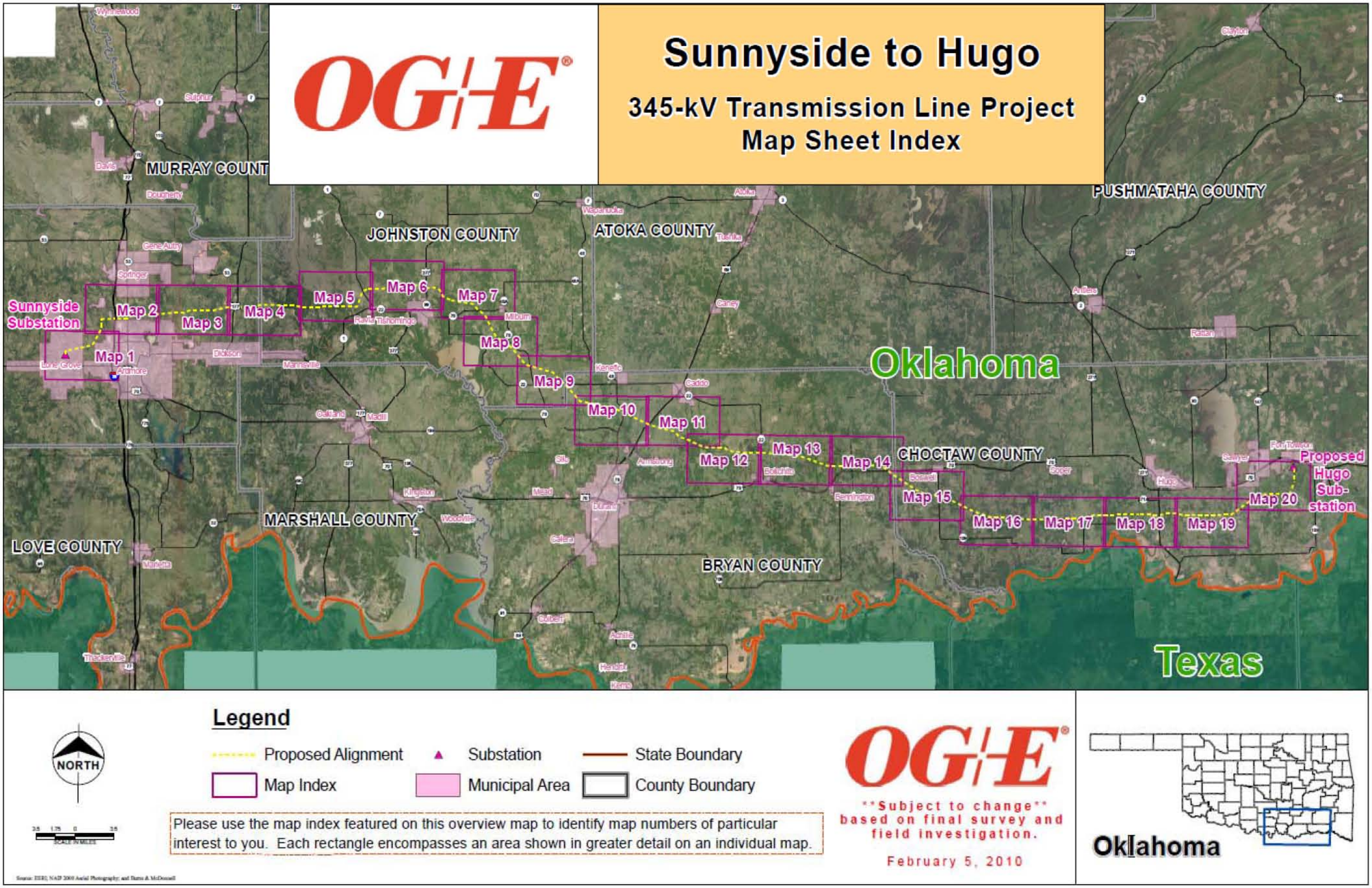
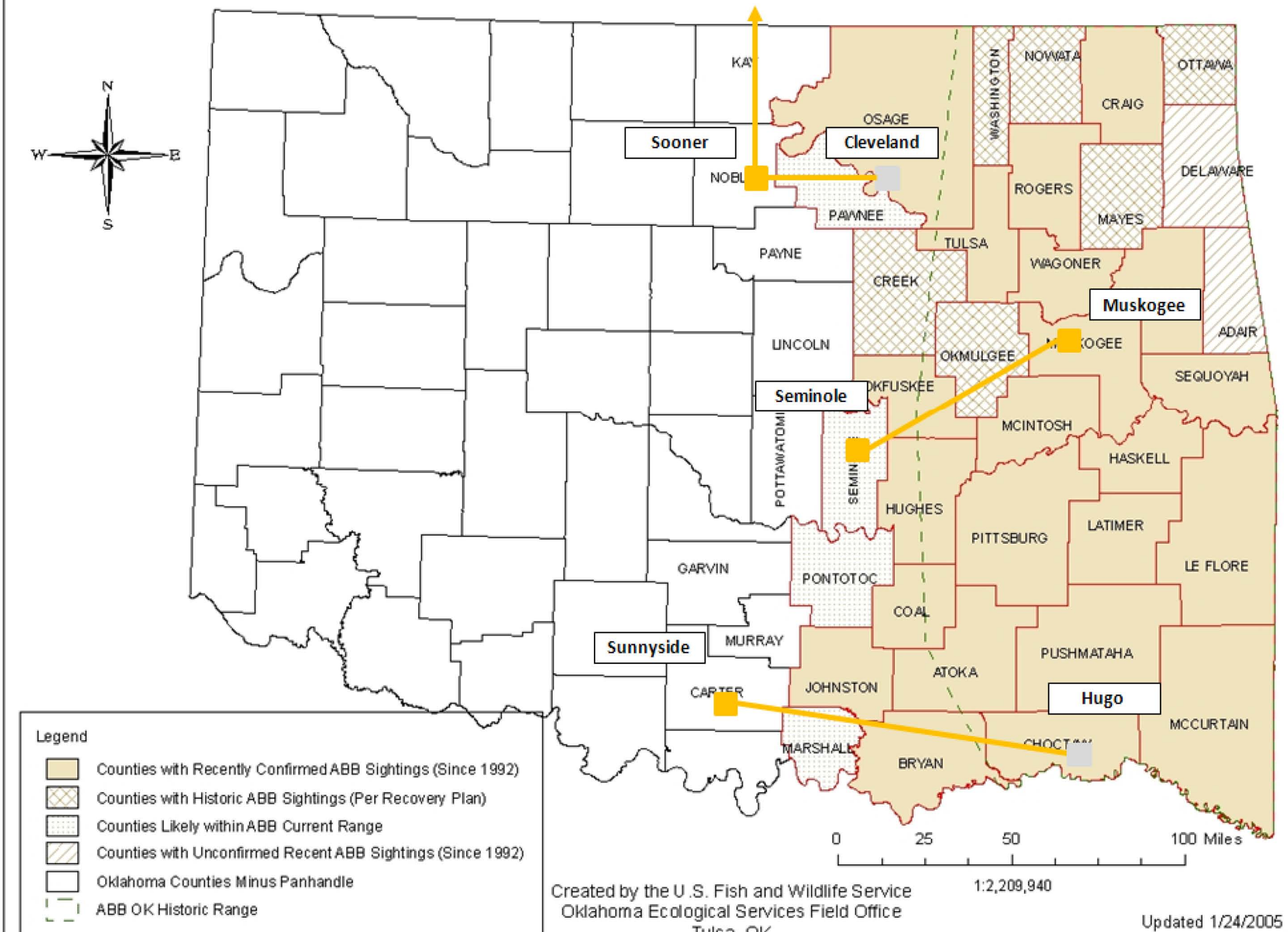


EXHIBIT NO. OGE-5

American Burying Beetle Historic Range and Current Distribution in Oklahoma



Created by the U.S. Fish and Wildlife Service
Oklahoma Ecological Services Field Office
Tulsa, OK

Updated 1/24/2005

EXHIBIT NO. OGE-6

Sooner to Cleveland Routing

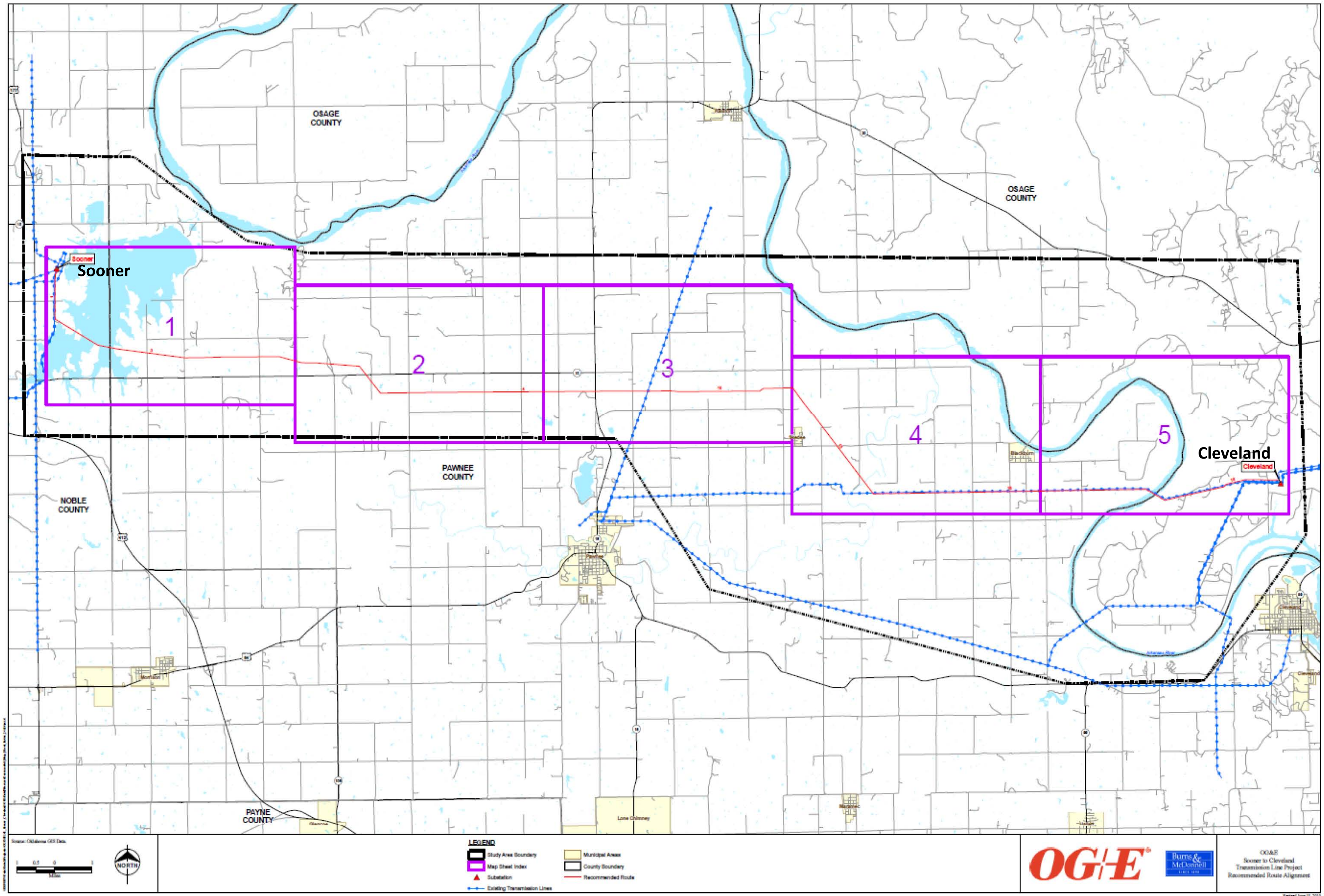


EXHIBIT NO. OGE-7

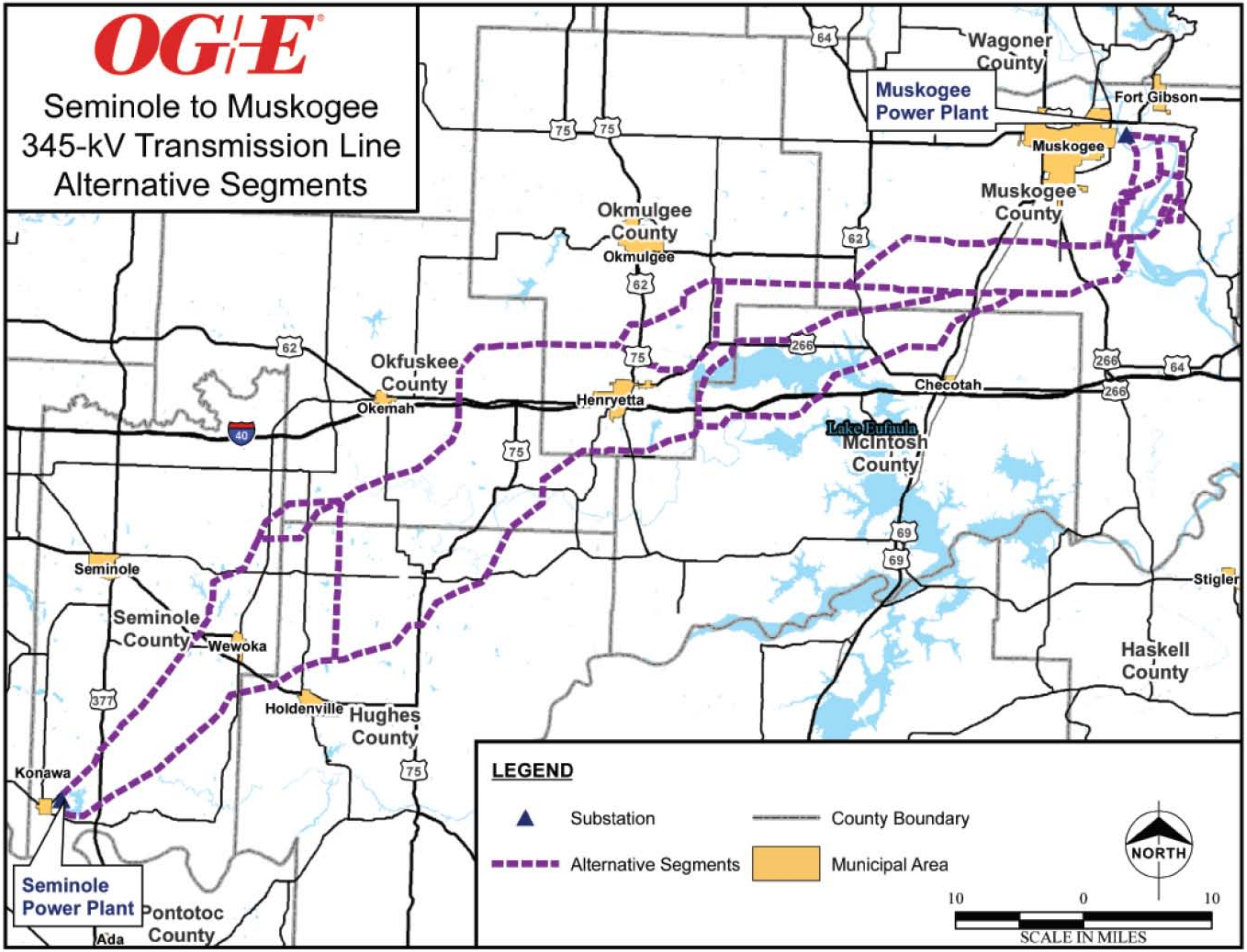

OG+E
Seminole to Muskogee
345-kV Transmission Line
Alternative Segments
Muskogee Power Plant
Wagoner County
Fort Gibson
Muskogee
Muskogee County
Okmulgee County
Okmulgee
Okfuskee County
Okemah
Henryetta
Checotah
Lake Eufaula
McIntosh County
Haskell County
Stigler
Seminole
Seminole County
Wewoka
Holdenville
Hughes County
Konawa
Seminole Power Plant
Pontotoc County
Ada
LEGEND
Substation
County Boundary
Alternative Segments
Municipal Area
NORTH
10
0
10
SCALE IN MILES

EXHIBIT NO. OGE-8

Oklahoma Natural Resources: Wind, Wildlife, Untilled Landscapes, and Protected Areas

The Nature Conservancy
SAVING THE LAST GREAT PLACES ON EARTH
Oklahoma Chapter August 2005

This map depicts general areas of conservation sensitivity and is intended to provide general guidance for wildlife appropriate siting of wind farms, transmission lines and other landscape-altering structures.

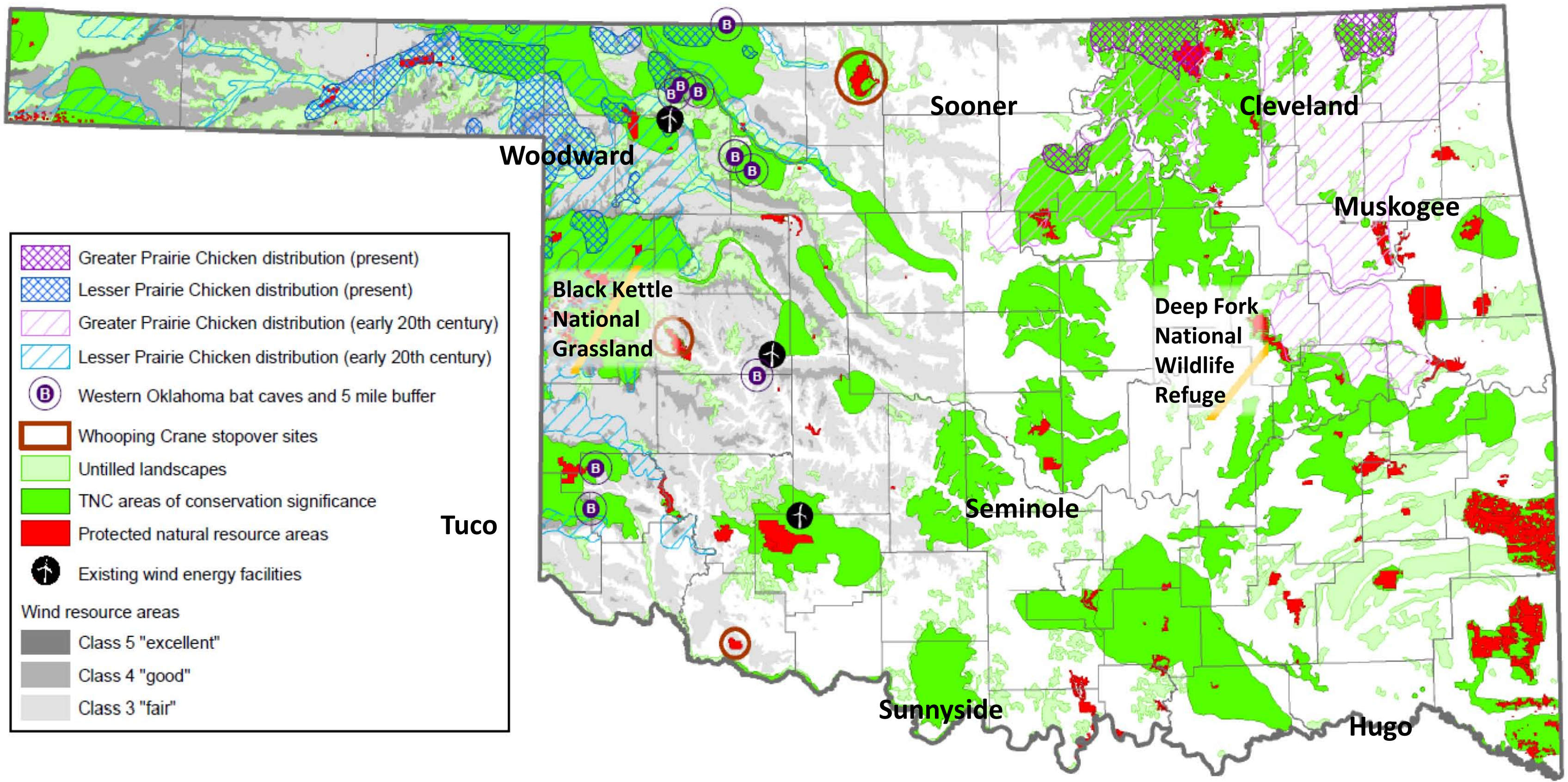


EXHIBIT NO. OGE-9

Lesser Prairie Chicken (LPC) and Transmission
Source: Oklahoma Department of Wildlife & Conservation and OGE

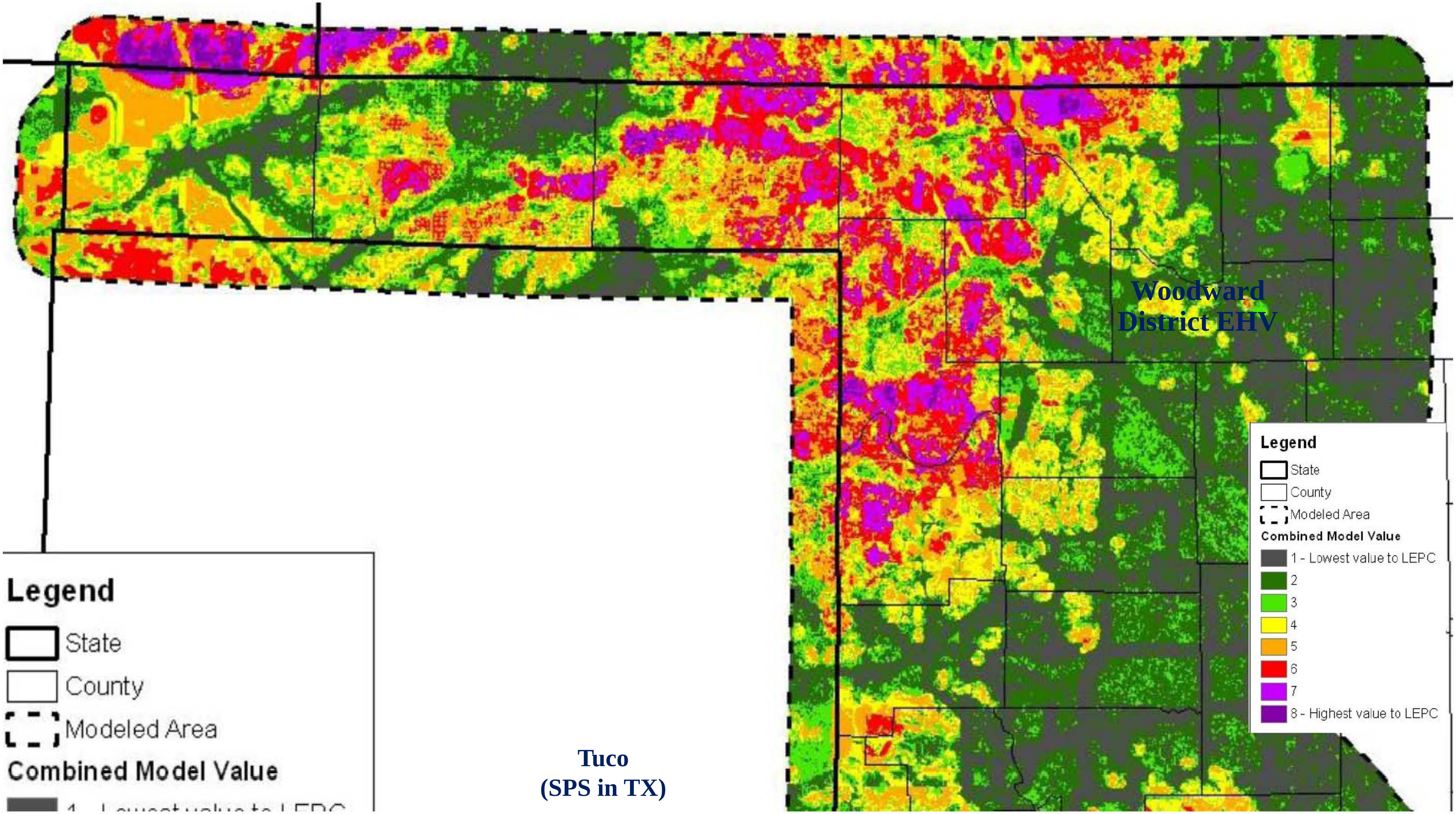
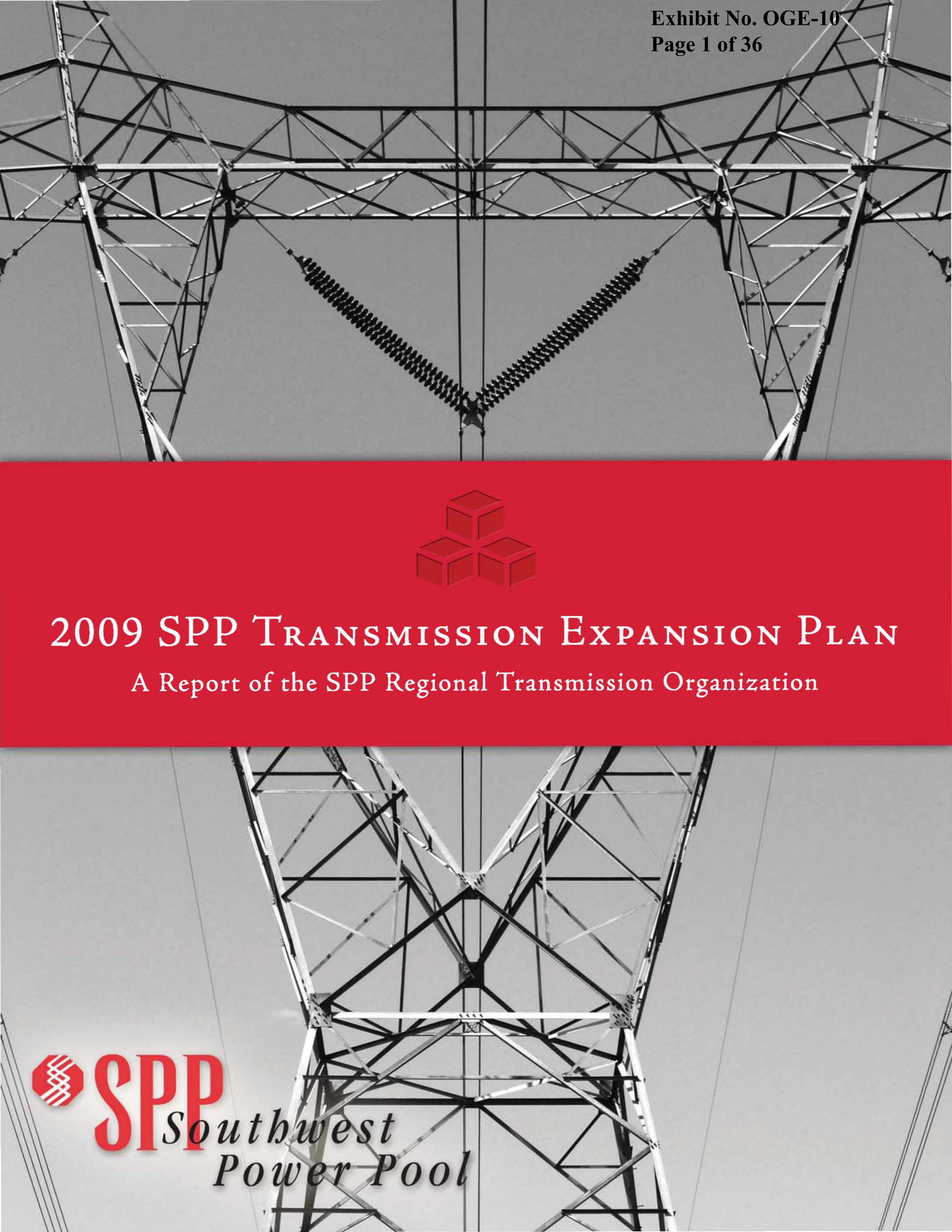


EXHIBIT NO. OGE-10



2009 SPP Transmission Expansion Plan

A Report of the SPP Regional Transmission Organization

SPP Southwest Power Pool

Table of Contents

1. Executive Summary

1.1 What is the 2009 SPP Transmission Expansion Plan?

The 2009 Southwest Power Pool, Inc. (SPP) Transmission Expansion Plan (STEP) summarizes 2009 activities that impact future development of the SPP transmission grid. Seven key topics are included that are critical to meeting mandates of either the SPP strategic plan or the nine planning principles in FERC Order 890. As a Regional Transmission Organization (RTO) of the Federal Energy Regulatory Commission (FERC), SPP must meet requirements of FERC and the SPP Open Access Transmission Tariff (OATT or Tariff).

1. **Synergistic Planning Project**: In January 2009 a Synergistic Planning Project Team (SPPT) was created to look for innovative and forward-thinking solutions to gaps and conflicts between SPP's transmission planning processes. The SPPT report, released in April, recommended that SPP adopt a new set of planning principles and transition the EHV Overlay, Balanced Portfolio, and reliability assessment processes to a new Integrated Transmission Plan (ITP). The ITP was approved by the SPP Board of Directors (BOD) in October; it is an iterative three-year process that includes 20-Year, 10-Year, and Near-Term assessments. The SPPT also recommended that SPP identify and evaluate a set of priority transmission projects to keep the momentum of transmission construction while transitioning to the ITP. In October the BOD approved six Priority Projects for further analysis.

2. **Regional reliability assessment 2010-2019**: This assessment, which was developed with extensive stakeholder review and input, creates a long-range transmission expansion plan for the SPP region, identifying needed transmission upgrades and possible problems in both normal and contingency conditions. The assessment identified approximately $2.8 billion in needed reliability projects and $4.45 billion for all upgrades, including economic and sponsored projects. Several issues impacted this year's assessment, including the addition of three Nebraska organizations to the footprint, major load increases in the Southwestern Public Service Company region, and some load decreases due to the economic downturn.

3. **Tariff studies**: In 2009 transmission expansion projects identified as needed to meet Transmission Service Requests totaled $455 million, and projects needed to meet Generation Interconnection requests totaled $81 million. During 2009, changes were made to the Tariff to improve the Aggregate Study and Generation Interconnection processes, and to create a new cost allocation methodology for wind projects. A Wind Integration Study will be issued in January 2010 to assess the operational and reliability impacts of integrating large amounts of wind into the SPP system.

4. **Sub-regional and local area planning**: Each year SPP holds a series of local planning meetings to address local needs in five sub-regions. In 2009 SPP studied the impact of additional load from 29 planned TransCanada oil pipelines across the footprint; 12 new reliability projects were identified and incorporated into the STEP.

5. **High priority economic studies**: In April 2009 the BOD approved a group of economic transmission expansion projects totaling almost $700 million, to be funded by a "postage stamp" rate to Transmission Owners across the SPP footprint. The project group is called the Balanced Portfolio because both costs and benefits are balanced across the region. The projects are

intended to lower production costs and reduce congestion. SPP monitors congestion on the transmission grid and in the STEP identifies the region's top 10 congested flowgates.

6. **Interregional coordination**: In addition to regional planning, SPP conducts interregional planning with neighboring systems. In 2009 the Entergy/SPP Regional Planning Process was created to share system plans and identify solutions to congestion between Entergy and SPP. SPP also participated in the Eastern Interconnection Wind Integration Transmission Study, which evaluates the power system impacts and needed transmission associated with increasing wind penetration to 20-30% for most of the Eastern Interconnection.

7. **Project tracking**: After the BOD approves expansion projects, SPP issues Notification To Construct (NTC) letters to relevant Transmission Owners. In 2009, 43 NTCs were issued with estimated construction costs of $1.85 billion. SPP actively monitors the progress of expansion projects by soliciting feedback from Transmission Owners. By the end of 2009, 124 projects were scheduled to be completed.

The SPP RTO acts independently of any single member, customer, market participant, or class of participants. It has sufficient scope and configuration to maintain electric reliability; effectively perform its functions, including Tariff administration and transmission planning; and support efficient and non-discriminatory power markets.

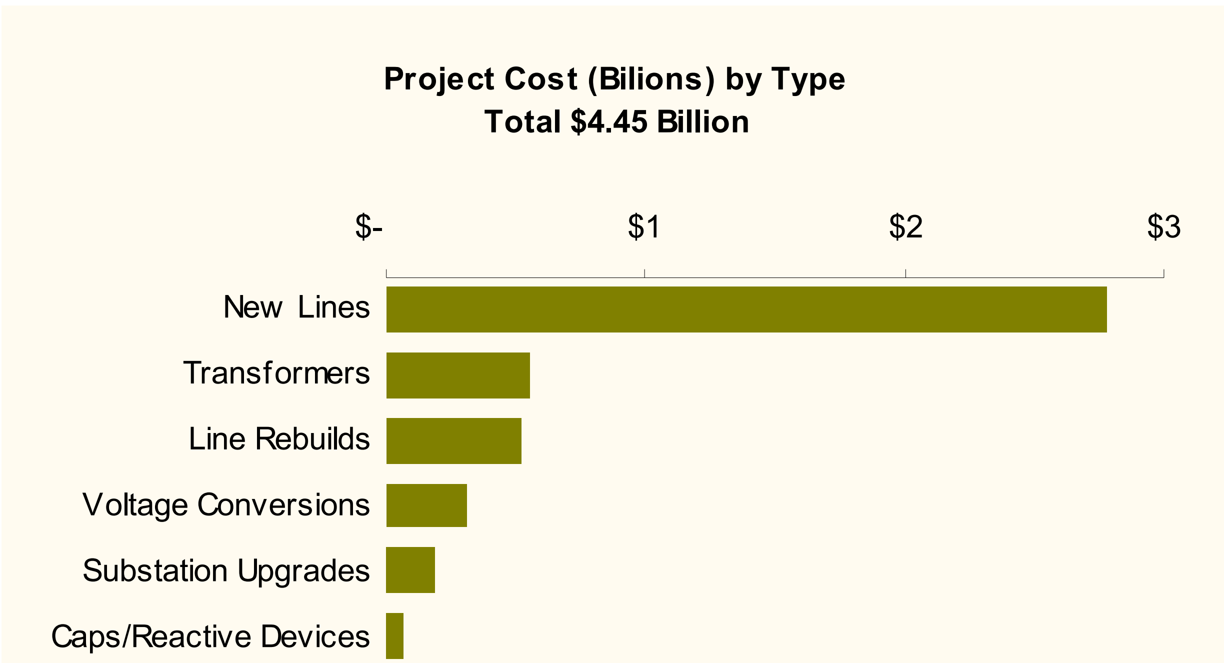
SPP's transmission planning process incorporates all of the organization's value propositions:

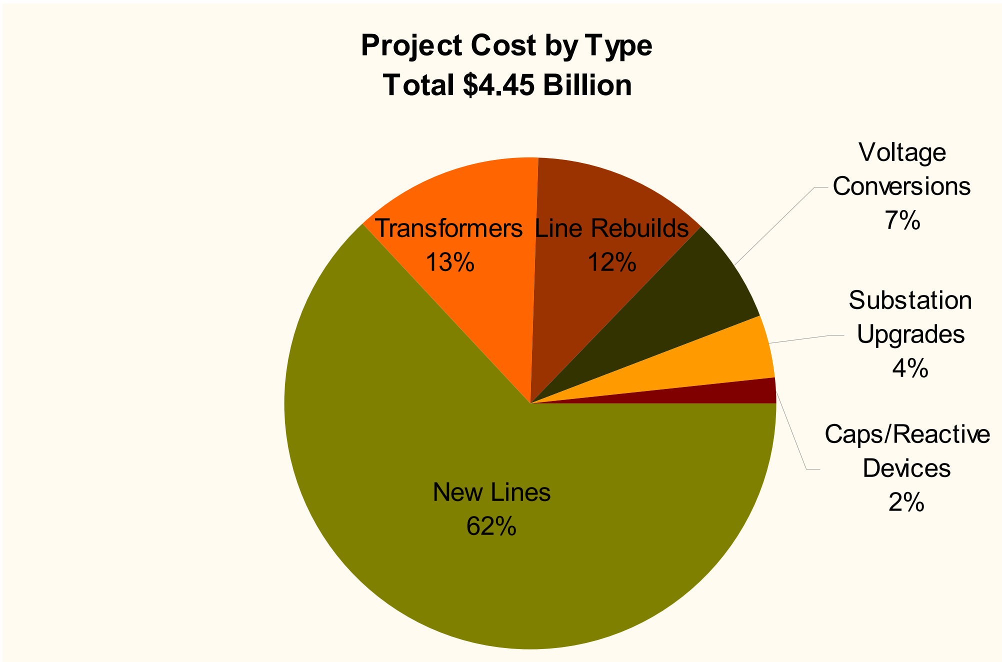
- Relationship-based
- Member-driven
- Independence through diversity
- Evolutionary vs. revolutionary
- Reliability and economics are inseparable

While SPP also serves as a Regional Entity (RE) under the North American Electric Reliability Corporation, the STEP functions are separate from the SPP RE.

1.2 Summary of 2010-2019 Network Upgrades

The 2009 STEP identifies approximately $4.45 billion of transmission Network Upgrades. This summary includes Network Upgrades required for NERC Reliability Standards or SPP criteria; Zonal Reliability Upgrades (compliance to Transmission Owner company-specific planning criteria); requests for Transmission Service under the Tariff with a FERC-filed Service Agreement; Generation Interconnections with a FERC-filed interconnection agreement; and Balanced Portfolio upgrades.




Project Cost by Type
Total $4.45 Billion
Voltage Conversions 7%
Transformers 13%
Line Rebuilds 12%
Substation Upgrades 4%
Caps/Reactive Devices 2%
New Lines 62%

The following table of project categories for the 2009 STEP is a cost summary and comparison with the 2007 and 2008 STEP:

2009 STEP (Nearest 10 Million)	2008 STEP (Nearest 10 Million)	2007 STEP (Nearest 10 Million)	Upgrade Type
$540	$320	$290	Transmission Service Request and Generation Interconnection Service Agreements
$1,690	$880	$720	Reliability - Base Plan
$1,070	$800	$640	Reliability - Other
$320	$620	$460	Sponsored Upgrades
$770			Balanced Portfolio
$60	$60	$90	Interregional Coordinated Upgrades
$4.45B	$2.7B	$2.2B	Appendix A - TOTAL

Has filed Service Agreement or is BOD-approved
(APPENDIX A includes a breakdown of projects in the 10-year horizon)

Major 345 kV projects in various stages of approval or sponsorship that were studied during the 2009 STEP process:

- American Electric Power to construct 33 miles of 345 kV transmission line from Turk in southwest Arkansas to Northwest Texarkana in northeast Texas
- American Electric Power to construct 18 miles of 345 kV transmission line from Flint Creek to Shipe Road in northwest Arkansas
- American Electric Power to construct 55 miles of 345 kV transmission line from Shipe Road to Osage Creek (passing near East Rogers) in northwest Arkansas
- Associated Electric Cooperative to construct 113 miles of 345 kV transmission line from Blackberry in southwestern Missouri to Sportsman to GRDA 1 in northeastern Oklahoma
- ITC Great Plains to construct 19 miles of 345 kV transmission line from Hugo Power Station to Valliant in southeastern Oklahoma
- Kansas City Power and Light to construct 30 miles of 345 kV transmission line from Iatan to Nashua in northwest Missouri
- Nebraska Public Power District to construct 79 miles of 345 kV transmission line from Shell Creek to Columbus East to NW 68 and Holdrege in east central Nebraska
- Oklahoma Gas and Electric to construct 120 miles of 345 kV transmission line from Northwest to Woodward District EHV in western Oklahoma

- Oklahoma Gas and Electric to construct 53 miles and Westar Energy to construct 53 miles of 345 kV transmission line from Rose Hill in central Kansas to Sooner in central Oklahoma

- Oklahoma Gas and Electric to construct 36 miles of 345 kV transmission line from Sooner to Cleveland in central Oklahoma

- Oklahoma Gas and Electric to construct 120 miles of 345 kV transmission line from Hugo to Sunnyside in southern Oklahoma

- Oklahoma Gas and Electric to construct 100 miles of 345 kV transmission line from Seminole to Muskogee in central Oklahoma

- Oklahoma Gas and Electric and Southwestern Public Service Company to construct 250 miles of 345 kV transmission line from Woodward District EHV in western Oklahoma to Oklahoma/Texas Stateline to Tuco in northwestern Texas

- Westar Energy to construct 51 miles of 345 kV transmission line from Reno County to Summit in central Kansas

- Construct 90 miles of 345 kV transmission line from Spearville to Wolf (Knoll) in western Kansas

- Construct 125 miles of 345 kV transmission line from Wolf in western Kansas to Axtell in southern Nebraska

- Convert from 230 kV to 345 kV transmission line from Hobbs Interchange to Midland in western Texas

- Construct 130 miles of 345 kV transmission line from Potter County Interchange to Frio-Draw in western Texas

- Construct 100 miles of 345 kV transmission line from Oklahoma/Texas Stateline to Gracemont in western Oklahoma

- Construct 215 miles of 345 kV transmission line from Potter County Interchange to Oklahoma/Texas Stateline in northwestern Texas

- Construct 30 miles of 345 kV transmission line from Tuco to Jones in western Texas

1.2.1 Appendices A and B

Appendix A includes a comprehensive listing of transmission projects identified by the SPP RTO. Not all projects in Appendix A have been approved by the SPP Board of Directors (BOD), but all BOD-approved projects are included in the list. Appendix A also includes Tariff study projects, economic projects, zonal projects and associated interregional projects.

Appendix B lists proposed transmission projects for which sponsors or RTO staff requested 1st quarter 2010 action by the BOD and were approved for construction. The original Appendix B list presented to the BOD by RTO staff was shortened from a 4-year to a 2-year financial window by the BOD. The Appendix B list includes projects specifically needed for regional reliability that have a financial commitment lead-time inside the 2010-2011 two-year commitment window. Appendix B includes more than regional reliability upgrades and Zonal Reliability Upgrades in which BOD approval is being requested. It also includes projects for which withdrawals are being sought.

Projects in appendices A and B are categorized in the column labeled "Project Type Exp" by the following designations:

Generation Interconnect – Projects associated with a FERC-filed Generation Interconnection Agreement

Interregional – Projects developed with neighboring Transmission Providers (Appendix A only)

Regional reliability – Projects needed to meet the reliability of the region

Regional reliability – non-OATT – Projects to maintain reliability for SPP members not participating under the SPP OATT (Appendix A only)

Transmission service – Projects associated with a FERC-filed Service Agreement

Zonal Reliability – Projects identified to meet more stringent local Transmission Owner criteria

Zonal – sponsored – Projects sponsored by facility owner with no Project Sponsor Agreement

Balanced Portfolio – Projects identified through the Balanced Portfolio process

Sponsored – Projects with an executed Project Sponsor Agreement or that have previously been identified as an economic projects to receive transmission revenue credits under the OATT attachment Z2.

As transmission usage changes, proposed and approved projects are subject to evaluation. Appendix A projects can be reevaluated by the SPP RTO for "best" regional and/or local area solutions. Even though many are approved, Network Upgrades listed in Appendix A are not considered beyond the scope of reevaluation. Transmission Network Upgrades approved for construction have the opportunity for additional review on a case-by-case basis. The goal of reevaluation is to investigate viable alternatives considering new information and then determine if a more regionally-beneficial solution exists. This also takes into account long-term strategy and regional reliability needs.

Appendix B includes only new proposed transmission projects that have SPP RTO support and for which sponsors or RTO staff are requesting action by the BOD. This appendix does not include Network Upgrades identified by the SPP OATT Attachment Z Transmission Service Procedure or Attachment V Generation Interconnections. If approved, these Network Upgrades will be included in the SPP OATT Transmission Service study models. Transmission Network Upgrades authorized for construction have the opportunity for additional review on a case-by-case basis. The goal of such reevaluation is to evaluate and compare viable alternatives and then determine a cost-effective transmission solution while taking into consideration long-term strategy and regional reliability needs.

SPP is committed to performing necessary analysis to determine needs, costs, and benefits, while supporting its members' state regulatory requirements necessary to substantiate funding of identified Network Upgrade costs.

Included in Appendix B are withdrawal requests for projects that have been previously issued a Notification to Construct (NTC). These projects are identified in the "BOD Action" column as "NTC – withdraw". The reasons listed below explain why these projects are no longer required:

- Network Upgrade no longer required due alternate solution
- Network Upgrade no longer required due to new load forecast
- Network Upgrade no longer required due to model correction
- Network Upgrade no longer required due to new generation

3.2 Load Forecast

The load forecast used in the reliability analysis study models was developed by each Load Serving Entity which is provided to SPP during the model building process, and the aggregated load represents SPP total load. Reliability analysis models had a total growth of 14.4 % for Summer 2010 through Summer 2019, or approximately 1.5% per year.

SPS had major increases in its load forecast in the 2009 STEP. The 2009 STEP's 2019 case increased approximately 900 MW compared to the to the 2008 STEP's 2018 case. Also, due to the economic downturn, updated load forecasts were incorporated into the load flow models in June 2009, which required additional analysis to be completed.

Overall growth for the 2009 STEP is about the same as the 2008 STEP, which had a growth rate of 1.6% per year. Although the SPP total growth rate slowed slightly, the large increase in the SPS area created the need for several new projects in the SPS area.

3.2.1 Transmission Service Commitments

Only Long-Term Firm Service commitments with FERC-filed Service Agreements were included in the study model, with two exceptions:

1) Generation that has a high probability of going into service and getting a FERC-filed interconnection agreement

2) Shortfall transactions to make generation and load match

SPP used five transaction scenarios to capture the effects of the Transmission Service. SPP built scenario models to minimize counter-balancing Transmission Service. The scope of the regional reliability assessment provides additional information on these scenario cases.

Proxy flowgates were used to determine which transmission service requests (TSR) to include in the scenarios. Proxy flowgates used to determine scenarios were selected based on greatest historic and present firm megawatts curtailed by NERC Transmission Loading Relief (TLR).

Guidelines for including service from new generation that has a high probability of going into service and getting a FERC-filed interconnection agreement:

- A formal request is sent to SPP requesting the generation capacity be included in the study model
- It must have a FERC-filed interconnection agreement (IA) that is not on suspension
- Funding for major equipment must be acquired
- It must be in an Aggregate Transmission Service Study and completed Facilities Study waiting for results without third-party impacts (this eliminates generators that may drop out

as result of changes in study results)

- Where applicable, air and environmental permits must be acquired
- Construction must be started, with major equipment awarded

A list of the Long-Term Firm Transmission Service, including study models, is available on the SPP password-protected file server TrueShare. Access may be requested by emailing questions@spp.org.

3.2.2 Generation

Generation Interconnection facilities were included in the regional reliability assessment load flow models when an interconnection agreement was executed and not on suspension.

The following new generation was included in the regional reliability assessment models:

Generation Capacity with an Executed Transmission Service Agreement			
Model Area	**Plant Name**	**Net Summer Capacity (MW)**	**In-Service Date**
American Electric Power	Mattison	320	In-Service
American Electric Power	Stall	455	6/1/2010
American Electric Power	Turk	618	4/1/2012
City Utilities, Springfield Missouri	Southwest 2	278	12/1/2010
Empire District Electric Company	Meridian Way Wind Farm (Cloud County)	100	In-Service
Kansas City Power and Light Company	Iatan # 2	848	6/1/2010
Oklahoma Gas and Electric Company	Redbud	150	In-Service
Omaha Public Power District	Nebraska City 2	682	In-Service
Nebraska Public Power District	Petersburg Wind Farm	80	11/1/2010
Nebraska Public Power District	Broken Bow Wind Farm	80	11/1/2010
Nebraska Public Power District	Whelan Energy Center 2	220	6/1/2012
Nebraska Public Power District	Elkhorn Wind Farm	81	In-Service
Nebraska Public Power District	Ainsworth Wind Farm	60	In-Service

Generation Capacity without an Executed Transmission Service Agreement			
Model Area	**Plant Name**	**Net Summer Capacity (MW)**	**In-Service Date**
Oklahoma Gas and Electric Company	Redbud Power Plant	610	In-Service

In later years of the STEP analysis when there is a shortfall between interchange, generation, and load, the following process was used:

1. Exhaust the generation of the network customer
2. Exhaust the Independent Power Producers (IPP) in the same model area
3. Exhaust IPPs in SPP outside the model area
4. After the above generation was exhausted, the remaining unused generation was dispatched on a pro rata basis

The following table lists the IPP generation used for generation shortfall:

IPP Generation Capacity Used to Meet Shortfall of Generation and Interchange			
Model Area	**Units used for shortfall**	**MW available for Shortfall**	**In-Service Date**
American Electric Power	Green Country Energy LLC	778	In-Service
American Electric Power	Kiamichi Energy Facility	310	In-Service
American Electric Power	Oneta Energy Center	1077	In-Service
American Electric Power	Eastman Cogeneration Facility	402	In-Service
American Electric Power	Harrison County Power Project	570	In-Service
KCP&L Greater Missouri Operations Company	Dogwood	481	In-Service
Oklahoma Gas and Electric Company	Redbud Power Plant	420	In-Service

3.2.3 Criteria

NERC Reliability Standards, SPP criteria, and local Transmission Owner planning criteria were utilized in this analysis (whichever is most stringent). If a project is identified by a more stringent local Transmission Owner's planning criteria, these projects were identified as Zonal Reliability Upgrades.

SPP Criteria is available on SPP.org:
http://www.spp.org/publications/Criteria07282009-with%20AppendicesCurrent.pdf

Transmission Owners' planning criteria is available through SPP.org:
http://www.oatioasis.com/SWPP/index.html → Select "Planning", then "Local Area Planning Criteria" on the left.

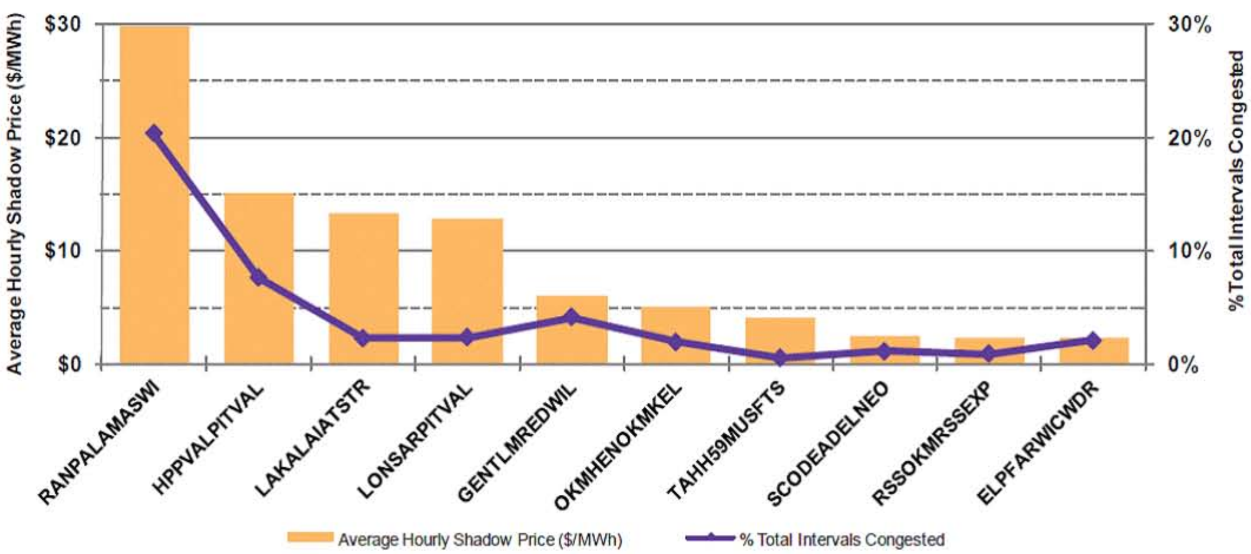
3.2.4 Demand Response

Transmission Owners with demand response programs have incorporated them into their load forecasts. SPP has not finalized the process for incorporating demand response into the planning process.

6.2 SPP Top Ten Flowgates

SPP monitors over 200 flowgates; 140 of the flowgates are located in SPP. From these, the annual top ten by "shadow price" are analyzed to determine potential solutions for these constraints, as shown in the table below. Shadow price is the amount of value of relieving the constraint measured in dollars. The noted upgrades were planned to provide one or more benefits, such as reliability or economic enhancements, but not necessarily to directly solve all congestion on the particular flowgate listed. This table has been updated for the STEP based on stakeholder feedback.

The below chart from the September 2009 SPP Monthly State of the Market Report plots the percent of intervals constrained and the average hourly shadow price for the annual top ten flowgates as of September 2009:



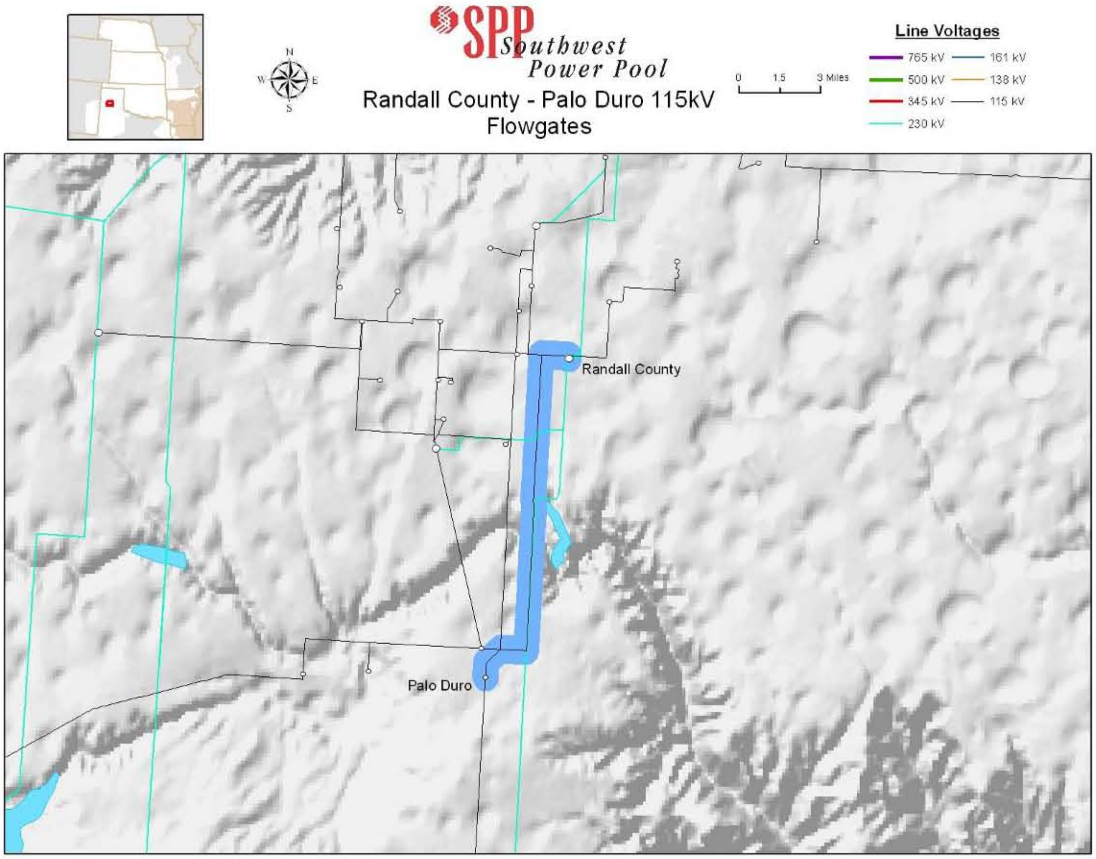
Flowgate Name	Flowgate Location (kV)	Control Area	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Possible Solutions [estimated completion date]
RANPALAMASWI	Randall County - Palo Duro (115) ftlo Amarillo – Swisher (230)	SPS	$ 29.79	20.4%	Mitigated to a large extent (95%) by new Potter to Tolk 345 kV line. [4/1/2012]
HPPVALPITVAL	Hugo -Valliant (138) ftlo Pittsburg – Valiant (345)	WFEC-CSWS	$ 15.00	7.6%	New 19 mile Hugo to Valliant 345 kV line with 138/345 kV XF at Hugo PP will address these constraints in southeastern OK. [4/1/2012]

Flowgate Name	Flowgate Location (kV)	Control Area	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Possible Solutions [estimated completion date]
LAKALAIATSTR	Lake Road – Alabama (161) ftlo Iatan to Stranger Creek (345)	MPS-KCPL	$ 13.30	2.2%	Pending upgrade projects are the 161 kV Tap of the Platte City to Stranger Creek line and the Iatan 345/161 kV substation. Both projects are under construction and have an expected In-Service Date of [12/31/09].
LONSARPITVAL	Lone Oak to Sardis (138) ftlo Pittsburg – Valiant 345	CSWS	$ 12.87	2.3%	New 19 mile Hugo to Valliant 345 kV line as stated above.
GENTLMREDWIL	Gentleman to Redwillow (345)	NPPD	$ 6.03	4.1%	New Axtell-Knoll-Spearville 345 kV line project will address the north –south flow from Nebraska. This project has an expected In-Service Date of [6/1/2013].
OKMHENOKMKEL	Okmulgee - Henryetta (138) ftlo Okmulgee to Kelco (138)	CSWS	$ 5.01	1.9%	Mitigated in part (~32%) by construction of the Seminole to Muskogee 345 kV line in southeastern Oklahoma. [4/1/2012]
TAHH59MUSFTS	Tahlequah – Hwy 59 (161) ftlo Muskogee – Fort Smith	GRDA-OGE	$ 3.98	0.5%	Danville to N. Magazine 161 kV re-conductor Project was recently completed in June 2009.
SCODEADELNEO	South Coffeyville to Dearing (138) ftlo Delaware - Neosho	CSWS / WR	$ 2.50	1.1%	The upgrade project is to rebuild the 5.02 mile Coffeyville Tap to Dearing 138 kV line, replacing 795 ACSR with 1590 ACSR. This project has an expected In-Service Date of [6/1/2010].
RSSOKMRSSEXP	Riverside St. – Okmulgee (138) ftlo Riverside St. – Explorer Okmulgee 138 kV	CSWS	$ 2.30	0.9%	Mitigated in part (~32%) by construction of the Seminole to Muskogee 345 kV line in southeastern Oklahoma. [4/1/2012]
ELPFARWICWDR	El Paso – Farber (138) ftlo Wichita - Woodring	WR	$ 2.29	2.0%	The Rose Hill to Sooner 345 kV line will potentially mitigate constraint. [12/1/2012]

The annual top ten flowgates as of September 2009 are detailed below.

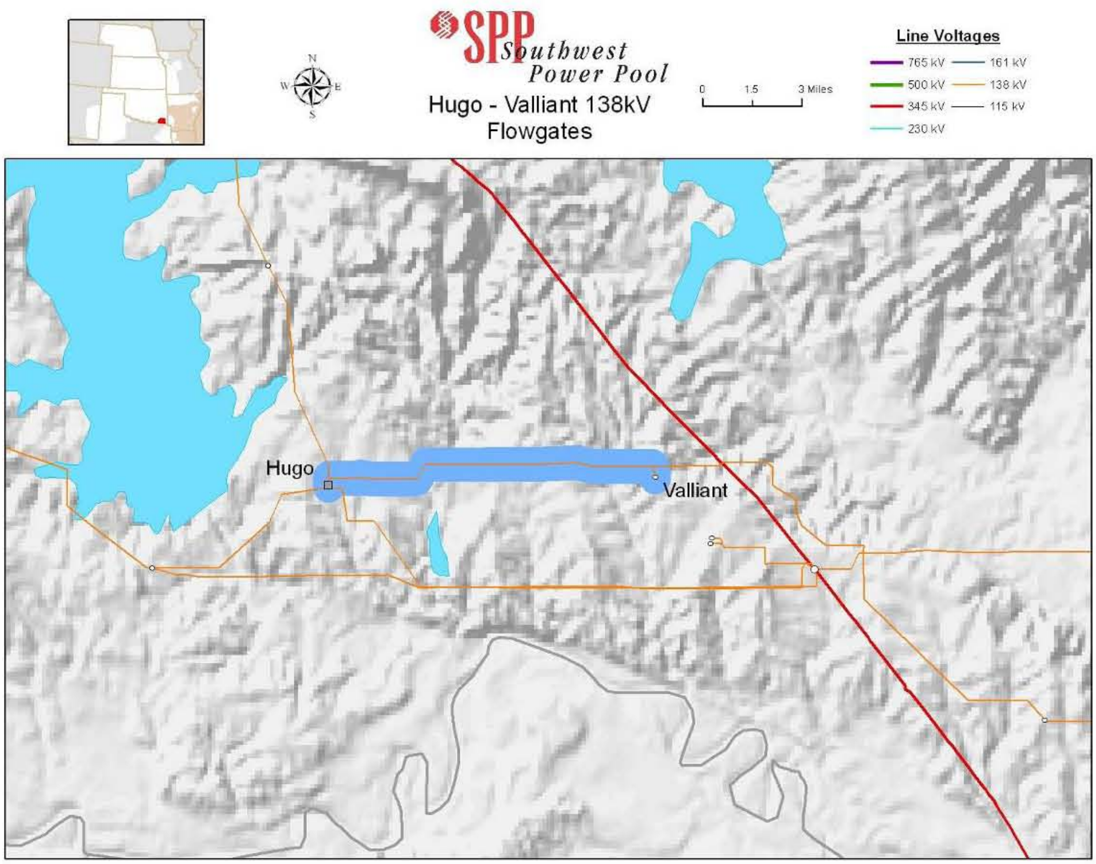
RANPALAMASAWI – Located in the Texas Panhandle

The RANPALAMASAWI flowgate monitors the 115 kV transmission line from the Randall County substation to Palo Duro for the loss of the 230 kV line from Amarillo to Swisher. The percentage of total intervals breached or binding over the last twelve months is 20.4%. This flowgate had the highest average shadow price at $29.79. The Tuco to Woodward 345 kV line in the Balanced Portfolio will potentially help mitigate congestion in this region. This line is expected to be in service in 2014.



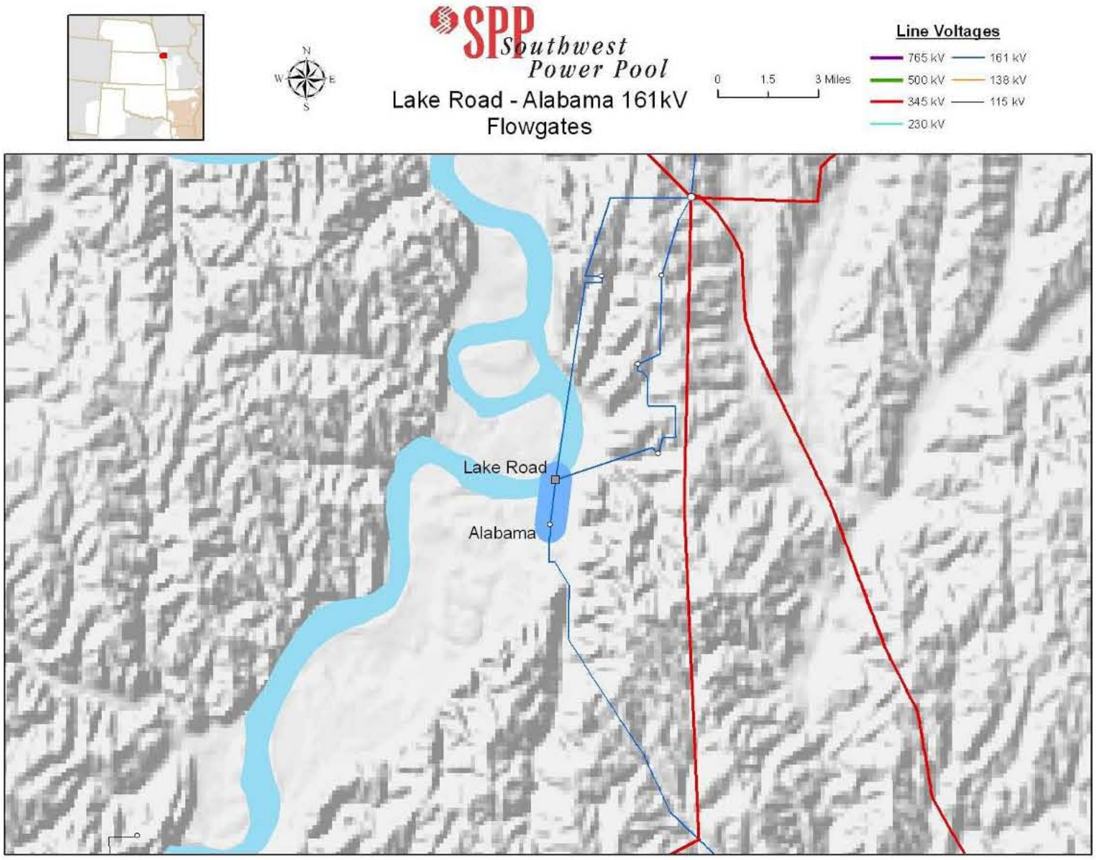
HPPVALPITVAL – Located in Southeastern Oklahoma

The HPPVALPITVAL flowgate monitors the 138 kV line from Hugo Power Plant 4 to Valliant for the loss of the 345 kV line from Pittsburg to Valliant. The percentage of total intervals breached or binding over the last twelve months is 7.6% with an average shadow price of $15.00. The new nineteen mile Hugo to Valliant 345 kV line with a 138 kV/345 kV transformer at Hugo Power Plant 4 will potentially mitigate this constraint. The in-service date of these projects is April of 2012.



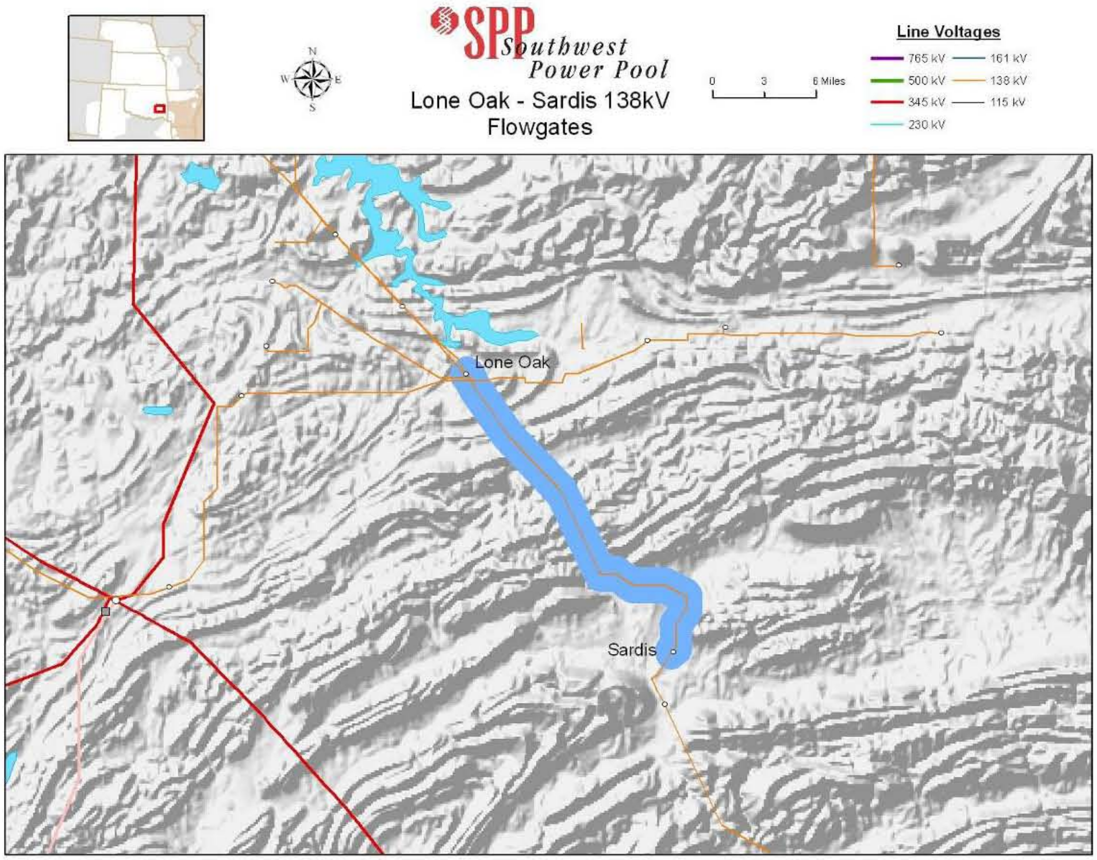
LAKALAIATSTR – Located in Northwestern Missouri

The LAKALAIATSTR flowgate monitors the 161 kV line from Lake Road to Alabama. The percentage of total intervals breached or binding over the last twelve months is 2.2% with an average shadow price of $13.30. The new 161 kV tap of the Platte City to Stranger Creek line and the Iatan 345 kV/161 kV substation will potentially help mitigate the congestion on this flowgate. These projects are expected to be in service by the end of 2009.



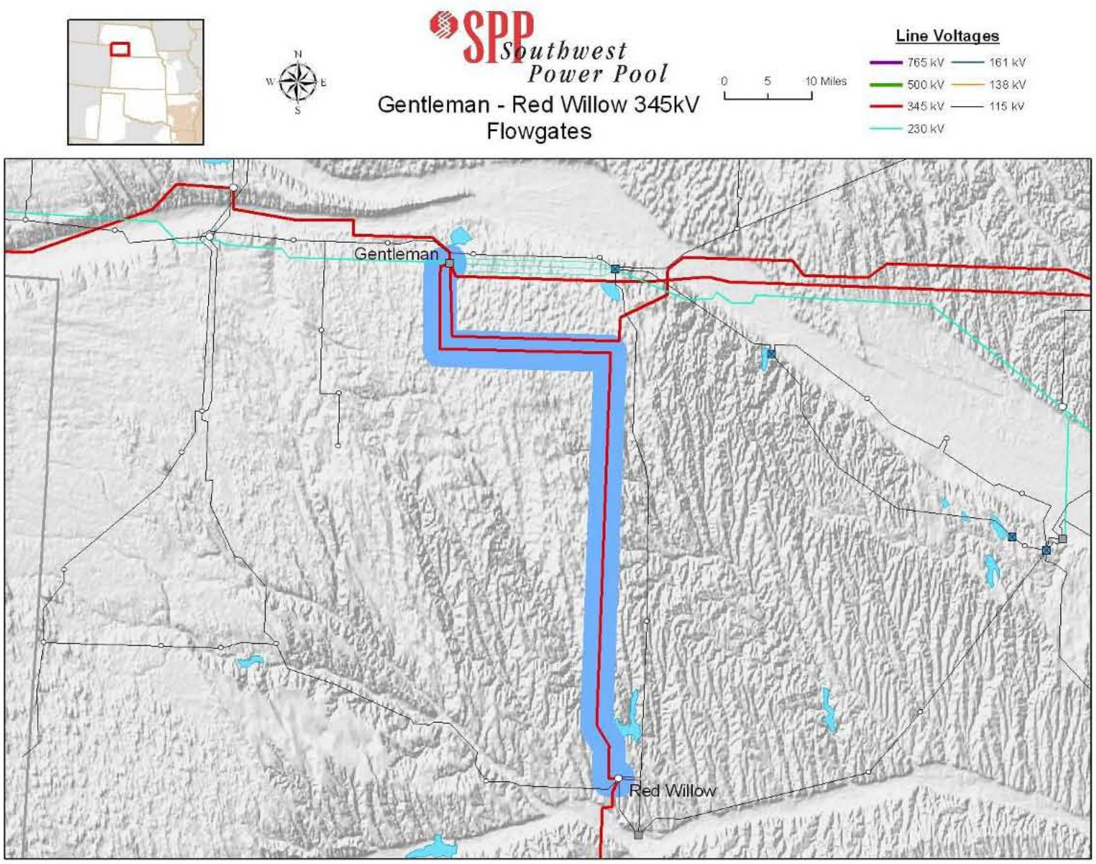
LONSARPITVAL – Located in Southeastern Oklahoma

The LONSARPITVAL flowgate monitors the 138 kV line from Lone Oak to Sardis for the loss of the 345 kV line from Pittsburg to Valliant. The percentage of total intervals breached or binding over the last twelve months is 2.3% with an average shadow price of $12.87. As with the flowgate above, the new nineteen mile Hugo to Valliant 345 kV line with a 138 kV/345 kV transformer at Hugo Power Plant 4 will potentially help mitigate this constraint. The in-service date of these projects is April of 2012.



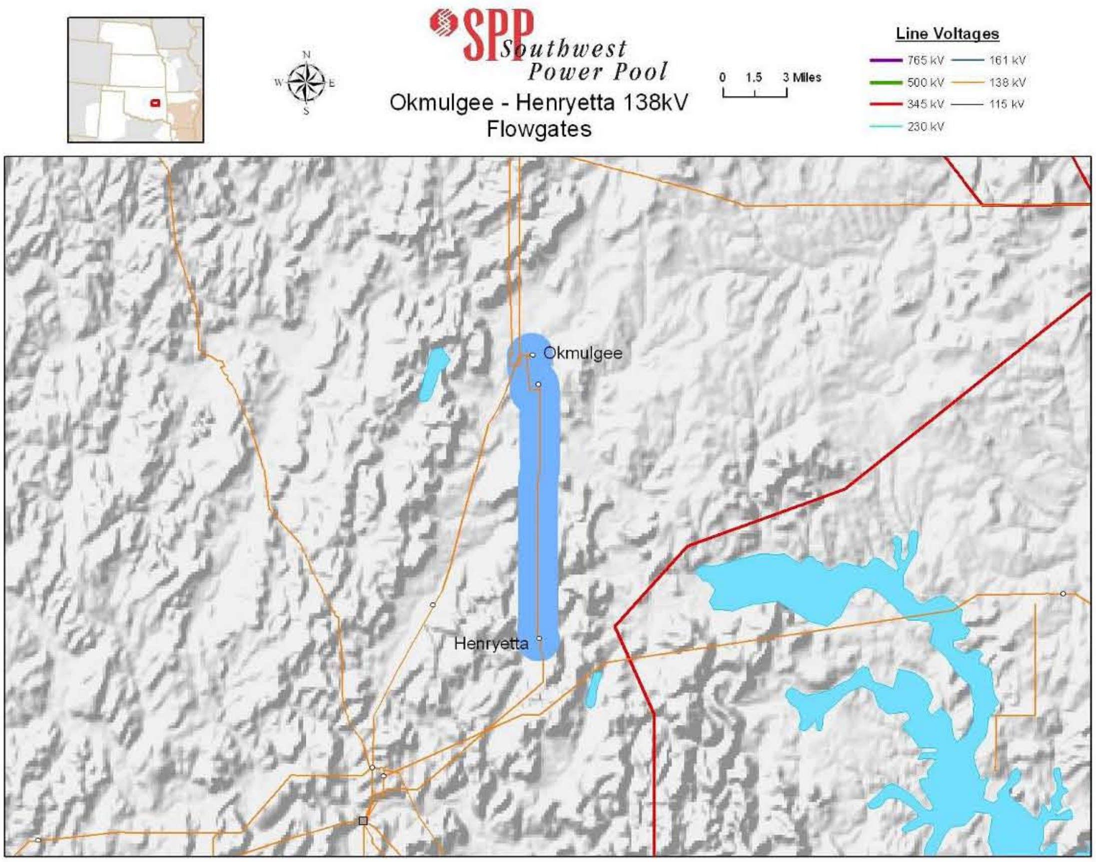
GENTLMREDWIL – Located in Southern Nebraska

The GENTLMREDWIL flowgate monitors the 345 kV line from Gentleman to Red Willow. The percentage of total intervals breached or binding over the last twelve months is 4.1% with an average shadow price of $6.03. The Balanced Portfolio-approved 345 kV line from Spearville to Axtell to Knoll will potentially help address the north–south flow from Nebraska. This project has an expected in-service date of June 2013.



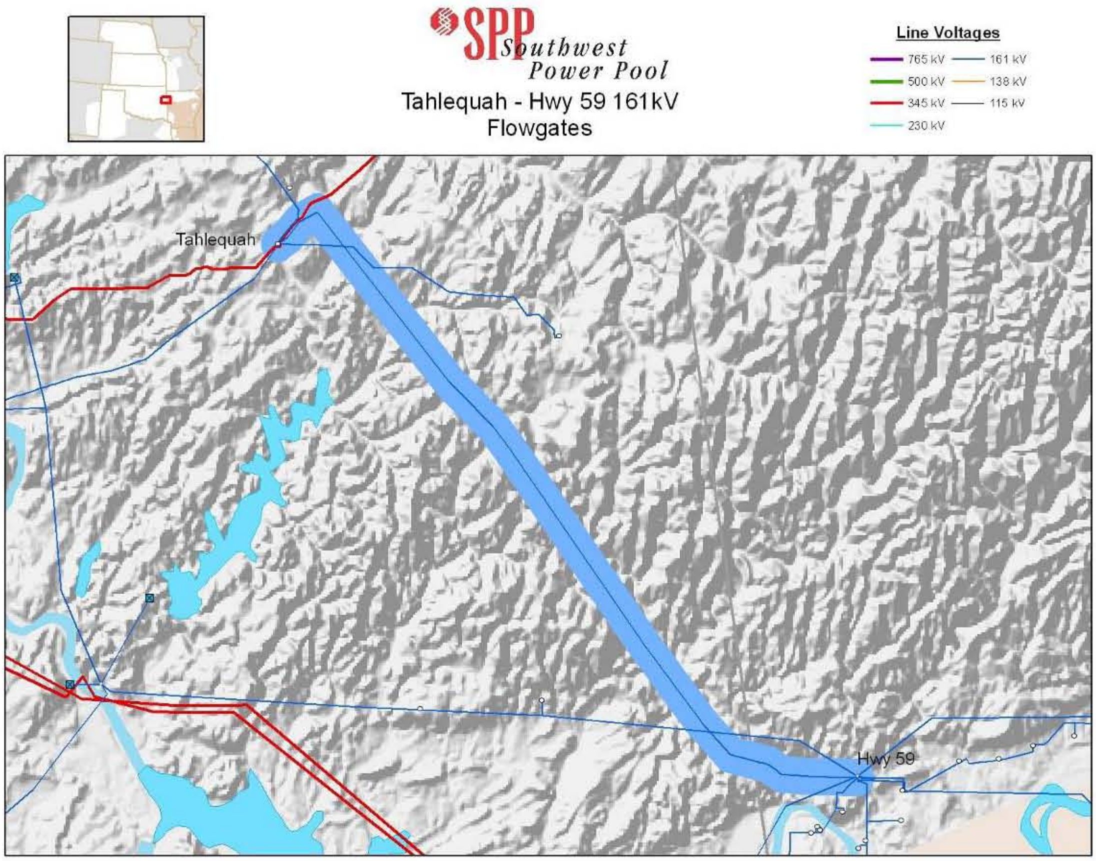
OKMHENOKMKEL – Located in Eastern Oklahoma

The OKMHENOKMKEL flowgate monitors the 138 kV line from Okmulgee to Henryetta for the loss of Okmulgee to Kelco 138 kV line. The percentage of total intervals breached or binding over the last twelve months is 1.9% with an average shadow price of $5.01. The Balanced Portfolio-approved 345 kV line from Seminole to Muskogee 345 kV will potentially help mitigate the congestion on this flowgate. This project has an expected in-service date of April 2012.



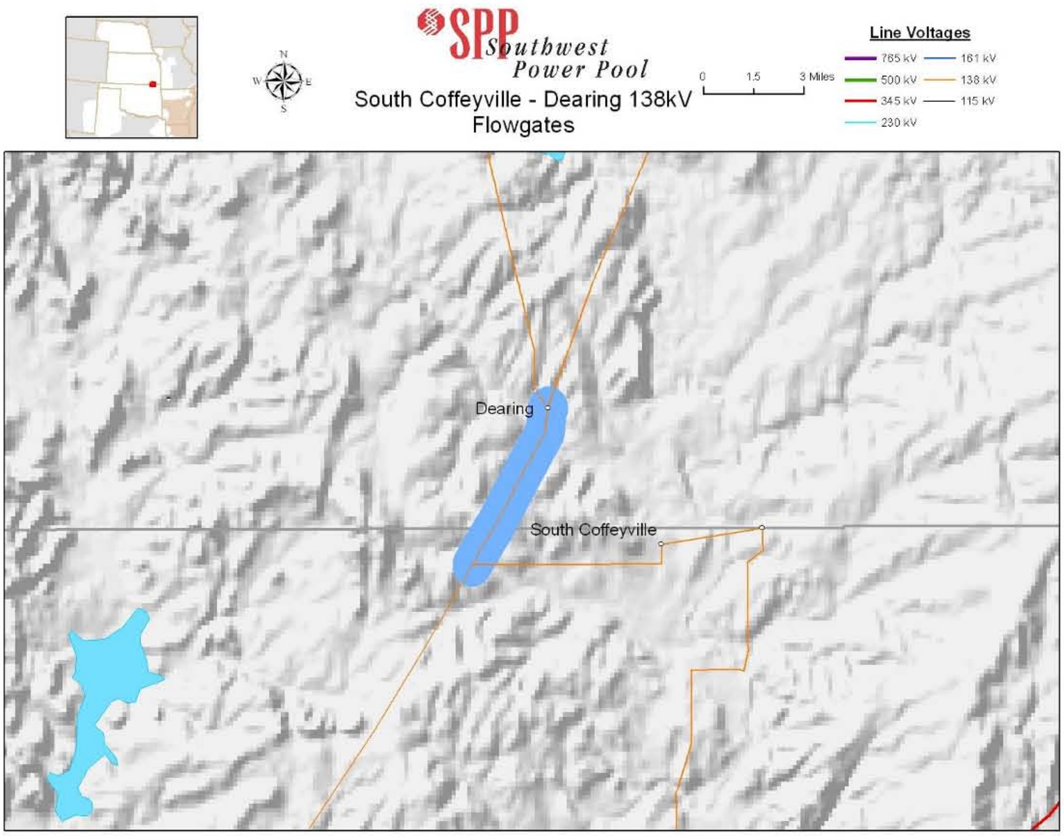
TAHH59MUSFTS – Located in Eastern Oklahoma

The TAHH59MUSFTS flowgate monitors the 161 kV line from Tahlequah to Highway 59 for the loss of the 345 kv line from Muskogee to Fort Smith. The percentage of total intervals breached or binding over the last twelve months is 0.5% with an average shadow price of $3.98. Significant mitigation on the TAHH59MUSFTS flowgate will probably not take place until a project from Ft. Smith to a location in Oklahoma, such as Chamber Springs or Pittsburgh, is developed.



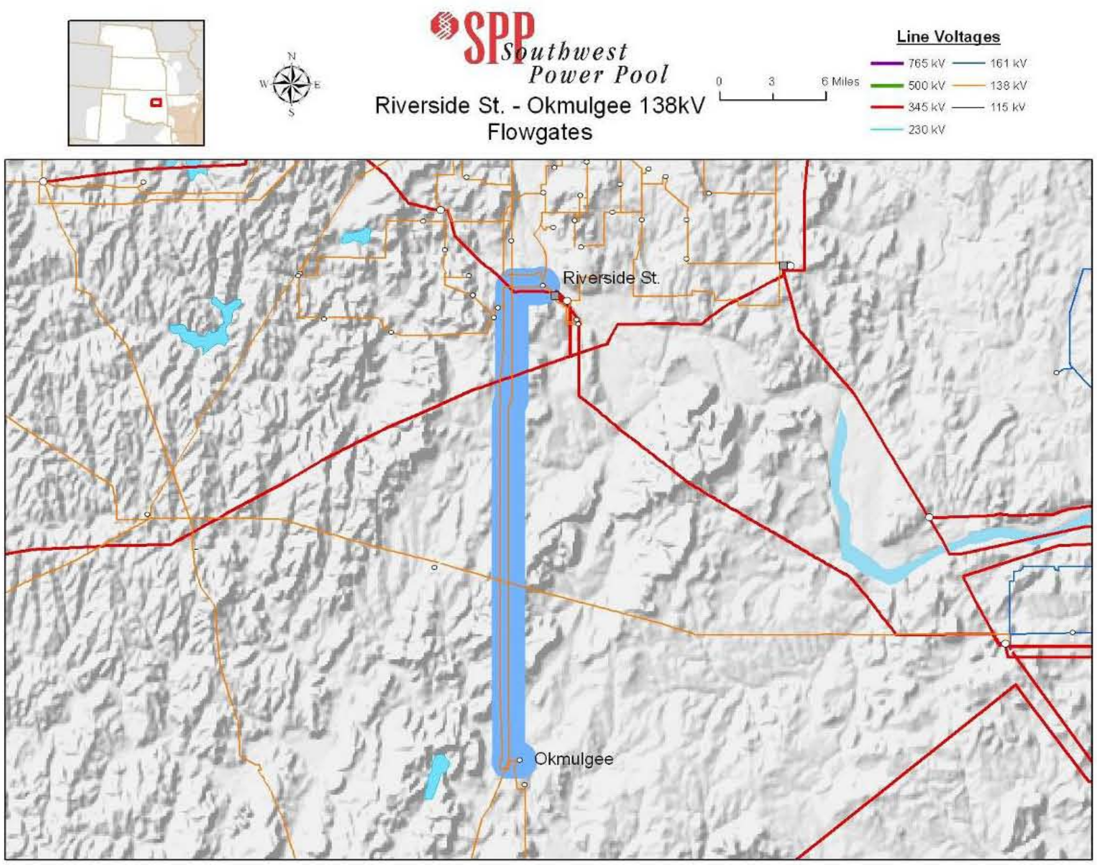
SCODEADELNEO – Located in Southeastern Kansas and Northeastern Oklahoma

The SCODEADELNEO flowgate monitors the 138 kV line from South Coffeyville to Dearing for the loss of the 345 kV line from Delaware to Neosho. The percentage of total intervals breached or binding over the last twelve months is 1.1% with an average shadow price of $2.50. The project to rebuild the 138 kV line from Coffeyville Tap to Dearing will potentially help mitigate the congestion on this flowgate. The in-service date for this project is June of 2010.



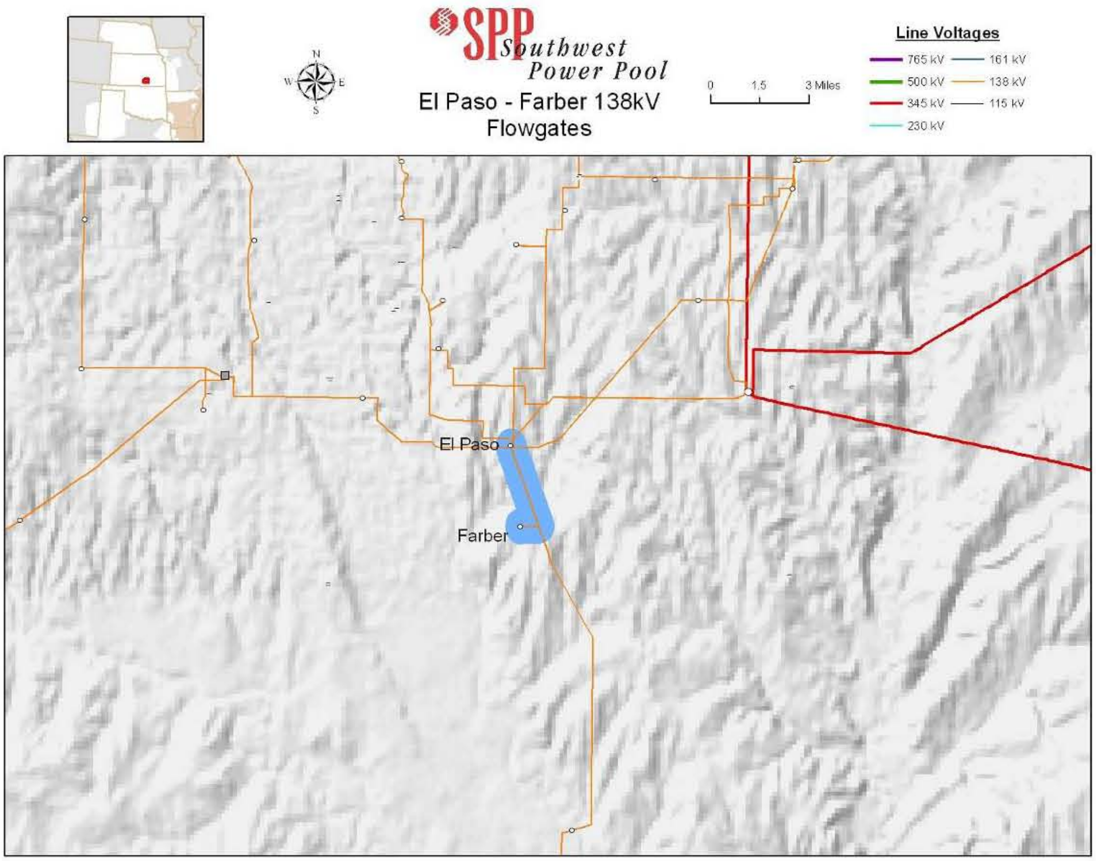
RSSOKMRSSEXP – Located in Eastern Oklahoma

The RSSOKMRSSEXP flowgate monitors the 138 kV line from Riverside Station to Okmulgee City for the loss of the 138 kV line from Riverside Station to Explorer Okmulgee. The percentage of total intervals breached or binding over the last twelve months is 0.9% with an average shadow price of $2.30. The Balanced Portfolio-approved 345 kV line from Seminole to Muskogee 345 kV will potentially help mitigate the congestion on this flowgate. This project has an expected in-service date of April 2012.



ELPFARWICWDR – Located in Southern Kansas

The ELPFARWICWDR flowgate monitors the 138 kV line from El Paso to Farber for the loss of the 345 kV line from Wichita to Woodring. The percentage of total intervals breached or binding over the last twelve months is 2.0% with an average shadow price of $2.29. The new Rose Hill to Sooner 345 kV line is a regional reliability upgrade that will potentially provide mitigation when it is completed by 12/1/2012.



6.3 Balanced Portfolio

The Balanced Portfolio is a cohesive group of economic transmission upgrades that were approved by the SPP Board of Directors (BOD) in April 2009. The benefits of these upgrades were demonstrated by model analysis to outweigh the costs, which will be allocated regionally. These upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. The projects may provide other benefits, such as increasing reliability, lowering end-use consumer costs, and allowing greater utilization of renewable resources. To provide regional "balance", portions of revenue requirement were transferred between regions.

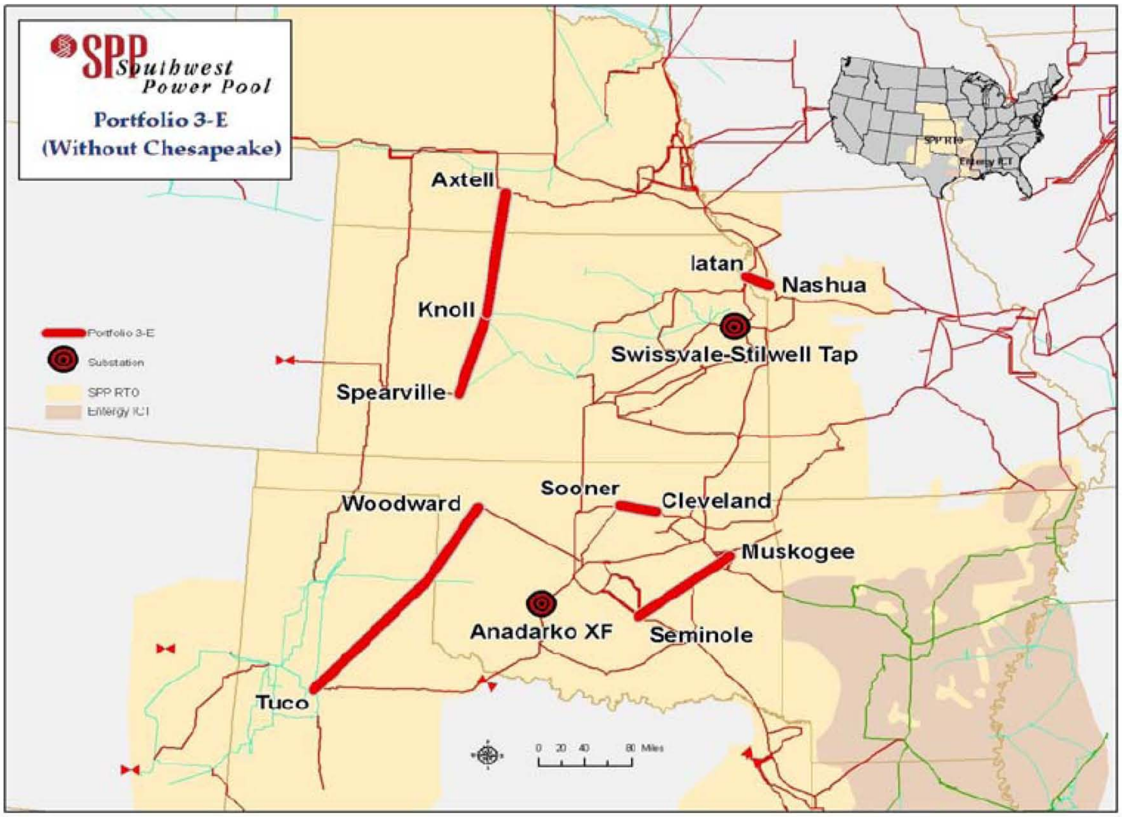
After developing and reviewing numerous iterations of the Balanced Portfolio, the Cost Allocation Working Group (CAWG) endorsed "Portfolio 3E 'Adjusted' (without Chesapeake, without Reno Co – Summit)". Portfolio 3E "Adjusted" will provide significant benefit versus cost to the SPP region, and will require lower transfers of revenue requirements necessary to achieve balance. The CAWG and the Economics Modeling and Methods Task Force (now the Economic Studies Working Group) reviewed and approved the study assumptions used in Balanced Portfolio analysis, which are listed in the appendix.

Portfolio 3E "Adjusted" contains a diverse group of 345 kV transmission projects addressing many of the top SPP flowgates. Projects in Portfolio 3E "Adjusted":

- The 250 mile "Woodward -Tuco" line between Hale County, Texas (north of Abernathy) and Woodward, Oklahoma
- The 215 mile "Spearville-Knoll-Axtell" line between Spearville, Kansas (east of Dodge City); Hays County, Kansas; and Axtell, Nebraska
- The 100 mile "Seminole-Muskogee" line between Seminole County and Muskogee, Oklahoma
- The 36 mile "Sooner-Cleveland" line between Sooner Lake in Noble County, Oklahoma and Cleveland, Oklahoma
- The 30 mile "Iatan-Nashua" line between Iatan and Nashua, Missouri (north of Kansas City)
- The Anadarko Transformer in Anadarko, Oklahoma
- The Swissvale-Stilwell Tap near Gardner, Kansas

Total engineering and construction costs: $692 million

Portfolio 3-E "Adjusted"



The CAWG-endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E "Adjusted" pending issuance of the final Balanced Portfolio report, according to the SPP Tariff. On April 28 the BOD approved the Balanced Portfolio 3-E "Adjusted" for inclusion in the SPP Transmission Expansion Plan. The BOD directed staff to finalize the Balanced Portfolio report, then issue Notification to Construct (NTC) letters for Balanced Portfolio projects.

In June 2009, SPP staff issued NTC letters to the incumbent transmission owner for the projects in Balanced Portfolio 3-E "Adjusted".

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
			Year 2010																			
20000	229	10294	AEP	06/01/10		M	02/13/08	$5,017,000	AEP	24 months	regional reliability	506960	Bentonville 279th Street 161 kV	506929	East Centerton 161 kV	1	161	5.14			429/597	Reconductor 5.14 mile Bentonville 279th St. - East Centerton 161 kV with 1590 conductor.
20016	343	10440	AEP	06/01/10		M	01/16/09	$90,000	AEP	15 months	regional reliability	508316	Winnsboro 69 kV	508299	Magnolia Tap 69 kV	1	69				73/85	Replace 69 kV switches at Winnsboro and reset CT ratios and relay settings.
20016	346	10443	AEP	06/01/10		M	01/16/09	$185,000	AEP	15 months	regional reliability	508340	Forest Hills 69 kV	508353	Quitman 69 kV	1	69				73/85	Replace Quitman 69 kV bus, switches and jumpers. Change CT and relay settings.
	893	11185	AEP	07/01/10				$1,456,000	AEP	10 months	zonal - sponsored	510897	Lone Oak 138 kV		EnoGex Wilberton 138 kV	1	138					Restore existing 9.2 mile radial de-energized 138 kV line to service. Build 138-4.16 kV station at Enogex Wilberton.
	894	11186	AEP	12/01/10				$3,550,000	AEP	15 months	zonal - sponsored	508369	Exxon-Mobil Hawkins 138 kV	508351	Perdue 138 kV	1	138		0.6		215/237	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.
	894	11187	AEP	12/01/10				$3,550,000	AEP	15 months	zonal - sponsored	508369	Exxon-Mobil Hawkins 138 kV	508358	Lake Hawkins 138 kV	1	138		0.6		261/287	Build new 0.6 mile double circuit tap from the existing Perdue - Lake Hawkins 138 kV line to a new 138 kV Exxon - Mobil Hawkins switching station.
20016	507	10652	AEP	06/01/10		M	01/16/09	$5,428,300	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507731	Fort Humbug 138 kV	1	138	3.24			438/478	Rebuild 3.24 miles of 1272 AAC with 2156 ACSR. Replace 3 138 kV switches, breaker jumpers, and reset CTs at Arsenal Hill. Replace 2 138 kV switches and jumpers at Fort Humbug.
20016	30147	50155	AEP	06/01/10		M	01/16/09	$3,005,700	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507710	Arsenal Hill 69 kV	2	138/69				224/246	Replace auto and 69 kV breaker and switches.
20016	30146	50154	AEP	06/01/10		M	01/16/09	$3,005,700	AEP	18 months	transmission service	507711	Arsenal Hill 138 kV	507710	Arsenal Hill 69 kV	1	138/69				224/246	Replace auto and 69 kV breaker and switches.
20016	30153	50161	AEP	06/01/10		M	01/16/09	$200,000	AEP	12 months	transmission service	508809	Longwood 345 kV	508808	Longwood 138 kV	1	345/138				451/503	Replace four (4) switches and upgrading bus work.
	657	10862	AEP		NTC	06/01/10		$150,000	AEP	12 months	regional reliability	510407	Pryor Junction 115 kV	510400	Pryor Junction 69 kV	1	115/69				76/100	Replace (3) 600 A switches with 1200 A switches.
19959	289	10375	AEP	06/01/10		M	10/17/06	$135,400	AEP	9 months	transmission service	511447	Clinton City 69 kV	511522	Foss Tap 69 kV	1	69				72/79	Replace wave trap at Clinton City Substation.
20000	294	10380	AEP	06/01/10		M	02/13/08	$339,000	AEP	15 months	regional reliability	508348	North Mineola 69 kV	508347	Mineola 69 kV	1	69				72/85	Replace Mineola 2 Switches & Breaker
	231	10296	AEP	12/31/10		M		$25,590,000	AEP	48 months	Generation Interconnect	507454	Turk 138 kV	508078	SE Texarkana 138 kV	1	138		34		368/512	Build new 34 mile Turk - SE Texarkana 138 kV line and add SE Texarkana 138 kV terminal.
	232	10297	AEP	12/31/10		M		$18,427,000	AEP	48 months	Generation Interconnect	507454	Turk 138 kV	508080	Sugar Hill 138 kV	1	138		24		368/512	Build new 24 mile Turk - Sugar Hill 138 kV line and add Sugar Hill 138 kV terminal.
19953	295	10381	AEP	06/01/10		M	06/26/07	$1,008,000	AEP	24 months	transmission service	510422	Coffeyville T 138 kV	533002	Dearing 138 kV	1	138	1.09			368/512	AEPW to reconductor 1.09 miles of 795 ACSR with 1590 ACSR. (Also, Westar to rebuild 3.93 miles of 795 ACSR with 1590 ACSR.) These ratings are just for the AEP facilities.
20000	297	10383	AEP	06/01/10		M	02/13/08	$3,827,000	AEP	24 months	regional reliability	508353	Quitman 69 kV	508354	Westwood 69 kV	1	69	3.91			52/68	Reconductor Quitman - Westwood 69 kV 3.91 miles of 2/0 with 795 ACSR
20016	296	10382	AEP	06/01/10		M	01/16/09	$6,252,000	AEP	24 months	transmission service	506927	Dyess 161 kV	504010	Elm Springs 161 kV	1	161	5.17			502/552	Rebuild/reconductor 5.17 mile Dyess - Elm Springs 161 kV with 2156 ACSR.
20016	348	10445	AEP	06/01/10		M	01/16/09	$224,000	AEP	12 months	regional reliability	506927	Dyess 161 kV	506957	Tontitown 161 kV	1	161				502/552	Replace 161 kV breaker, switches and CTs at Dyess.
20027	613	10784	AEP	12/01/10		M	01/27/09	$100,000	AEP	12 months	regional reliability	508831	Diana 138 kV	508297	Lone Star South 138 kV	1	138				246/287	Replace switch at Diana for higher winter rating of 287/316 MVA. Summer rating unchanged.
20027	292	10378	AEP	06/01/10		M	01/27/09	$4,047,000	AEP	24 months	regional reliability	508542	Greggton 69 kV	508551	Lake Lamond 69 kV	1	69	2.66			133/143	Reconductor 2.66 mile Greggton - Lake Lamond 69 kV with 1272 ACSR.
20027	480	10617	AEP	12/31/10		M	01/27/09	$800,000	AEP	24 months	regional reliability	511435	AEP Snyder 138 kV	521052	WFEC Snyder 138 kV	1	138		4		183/228	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV. WFEC to connect AEP Snyder to WFEC Snyder. AEP to provide 138 kV terminal at AEP Snyder.
	767	11011	AEP		NTC	06/01/10		$17,000,000	AEP	36 months	regional reliability	510946	Canadian River 138 kV	510908	McAlester City 138 kV	1	138			17	319/471	Convert 17 mile Canadian River - McAlester City line from 69 kV to 138 kV.
	767	11012	AEP		NTC	06/01/10		$8,500,000	AEP	36 months	regional reliability	515422	Canadian River 345 kV	510946	Canadian River 138 kV	1	345/138				450/495	Tap Pittsburg - Muskogee 345 kV about 33 miles north of the Pittsburg station and step down to 138 kV with a 450 MVA auto.
	767	11183	AEP		NTC	06/01/10		$2,900,000	AEP	36 months	regional reliability	510908	McAlester City 138 kV	510921	Dustin 138 kV	1	138		5.73		88/107	Rebuild McAlester City Tap, double circuiting existing line, eliminate the 'T' at McAlester City North Tap.
	767	11184	AEP		NTC	06/01/10		$2,900,000	AEP	36 months	regional reliability	510908	McAlester City 138 kV	510909	McAlester City North Tap 138 kV	1	138	5.73			96/105	Rebuild McAlester City Tap, double circuiting existing line, eliminate the 'T' at McAlester City North Tap.
20011	212	10271	CUS	06/01/10		M	02/13/08	$1,485,000	CUS	24 months	regional reliability	549928	Norton 69 kV	549930	Neergard 69 kV	1	69	3			111/115	Reconductor 3 mile 69 kV line from 336.4 kcmil ACSR to 477 kcmil ACSS/TW
	339	10436	CUS	10/01/10		M		$3,200,000	CUS	24 months	zonal - sponsored	549954	Southwest 161 kV	549893	Southwest 2 20 kV	1	161/20				334/400	Step-Up Transformer for new SWPS #2 (DNR)
	216	10275	DETEC	12/31/10		M				18 months	regional reliability - non OATT	508593	Ben Wheeler (Wood County EC) 138 kV	509246	Barton's Chapel (Rayburn County) 138 kV	1	138		10		215/215	Rayburn Project -- Build new 10 mile Ben Wheeler - Barton Chapel 138 kV.
20049	382	10495	EDE	06/01/10		M	09/18/09	$50,000	EDE	6 months	regional reliability	547601	SUB 404 - Hockerville 69 kV	547554	SUB 271 - Baxter Springs West 69 kV	1	69				51/61	Change CT setting on Breaker #6973 at Baxter #271 to 800/5 ratio.
20036	421	10547	EDE	06/01/10		M	01/27/09	$5,000	EDE	6 months	regional reliability	547537	SUB 124 - Aurora H. T. 69 kV	547540	SUB 152 - Monett H.T. 69 kV	1	69				54/65	Change CT ratio on breaker #6936 at Aurora Substation 124.
19969	338	10435	EDE	06/01/10		M	09/22/06	$1,215,000	EDE	12 months	transmission service	547471	SUB 184 -Neosho South Junction 161 kV	505486	Neosho (SWPA) 161 kV	1	161	1.7			167/167	Rebuild 1.7 mile Neosho South Jct. - Neosho SPA 161 kV from 336 ACSR to 795 ACSR and replace terminal equipment
20049	496	10641	EDE	06/01/10		06/01/15	09/18/09	$55,000	EDE	12 months	regional reliability	547539	SUB 145 - Joplin West 7TH 69 kV	547526	SUB 64 - Joplin 10TH ST. 69 kV	1	69				86/104	Replace 600 amp disconnect switches with a minimum 1,200 amp units and replace leads on Breaker #6965 at Sub #64 and #6932 at Sub #145.
20034	601	10768	GMO	06/01/10		M	01/27/09	$50,000	GMO	6 months	regional reliability	541223	Grandview East 161 kV	541224	Longview 161 kV	1	161				233/265	Replace wavetraps at Longview and Grandview East on the Grandview - Longview 161kV line.
20034	628	10816	GMO	12/01/10		M	01/27/09	$50,000	GMO	6 months	regional reliability	541221	Platte City 161 kV	541204	Smithville 161 kV	1	161				233/265	Replace wavetrap at Platte City.
20034	635	10832	GMO	07/01/10		M	01/27/09	$5,405,930	GMO	24-30 months	regional reliability	541257	Cook 161 kV	541255	Lake Road 161 kV	1	161				293/335	Build a new Edmond 161/69/34.5 kV substation between the Cook and Lake Road 161 kV substations that will pick up the loads supplied by the Lake Road 161/34.5 kV sources.
20053	30222	50226	GMO	06/01/10			09/18/09	$20,000	GMO	6 months	regional reliability											Reset the overcurrent relay at South Harper 69 kV substation to open South Harper - Freeman 69 kV line upon reaching thermal limit of Freeman – Anaconda – Harrisonville West 69 kV line
	302	10389	GRDA	06/01/10		M		$3,210,200	GRDA	24 months	zonal - sponsored	512751	Siloam Springs Tap 161 kV	512643	Siloam City 161 kV	1	161		7		347/403	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.
20001	301	10388	GRDA	06/01/10		M	02/13/08	$3,000,000	GRDA	24 months	regional reliability	512652	Sallisaw 69 kV	505550	Sallisaw 161 kV	2	161/69				75/84	Add second 161/69 kV 75 MVA autotransformer at Sallisaw
	279	10363	KCPL	06/01/10		M		$192,000	KCPL	6 months	zonal - sponsored	542978	Craig 161 kV	543038	Lenexa 161 kV	1	161				513/513	Replace Lenexa Circuit Switcher R1-4 with 2000 Amp Breaker
	200	10256	KCPL	09/30/10		M		$4,352,600	KCPL	10 months	zonal - sponsored	542991	Terrace 161 kV	543003	Boulevard 161 kV	1	161		1		259/259	New Boulevard sub and new 161kV line
	201	10257	KCPL	03/30/10		M		$4,750,000	KCPL		zonal - sponsored	542990	Crosstown 161 kV	543003	Boulevard 161 kV	1	161		1.3		259/259	New 161kV line
	714	10951	KCPL		NTC	06/01/10		$5,000	KCPL	12 months	regional reliability	543100	Amoco Pipeline 69 kV	543096	Mayview Tap 69 kv	1	69				65/73	Replace 200 A CT and 400 A wavetrap at Mayview to increase line rating.
	866	11144	LES	05/31/10		M		$621,875	SPP		zonal - sponsored	640278	Sheldon 115 kV	650238	20th & PIO 115 kV	1	115		1		240/240	Rebuild Sheldon to 20th & PIO. Upgrade based on condition of facility.
	867	11145	LES	05/31/10		M		$790,625	SPP		zonal - sponsored	650218	3rd & Vandn 115 kV	650238	20th & PIO 115 kV	1	115		1.4		139/155	Rebuild 3rd & Vandn to 20th & PIO. Upgrade based on condition of facility.
20052	30219	50223	MIDW	06/01/10			09/18/09	$1,812,500	MIDW		transmission service						34.5	14				Rebuild approximately 14.5 miles of 34.5 kV line between Rice County and Ellinwood to achieve a minimum 600 amp emergency rating
	744	10981	NPPD	11/01/10		M		$5,000,000	NPPD	24 months	transmission service	640103	Canaday 115 kV	640102	Canaday 230 kV	1	230/115				336/336	Replace Canaday transformer.
	603	10772	NPPD	10/01/10	NTC	06/01/10		$3,000,000	NPPD	48 months	regional reliability	533332	Knob Hill 115 kV	640030	Steele City 115 kV	1	115		2.4		223/245	Build 2.4 miles of new 115 kV line from Kansas/Nebraska state line to Steele City.
	605	10775	NPPD	06/01/10	NTC	M		$5,000,000	NPPD	24 months	regional reliability	640286	N. Platte 230 kV	640287	N. Platte 115 kV	2	230/115				336/336	
	606	11160	NPPD	04/01/10	NTC	M		$150,000,000	NPPD	48 months	regional reliability	640125	Columbus East 345 kV	650114	NW 68 and Holdrege 345 kV	1	345		67		1195/1195	Build new 67 mile Columbus East - NW 68th & Holdrege 345 kV line.
	606	11161	NPPD	10/13/09	NTC	M				48 months	regional reliability	640342	Shell Creek 345 kV	640125	Columbus East 345 kV	1	345		12		1195/1195	Build new 12 mile Columbus East - Shell Creek 345 kV line.
	606	10970	NPPD	04/01/10	NTC	M					regional reliability	640127	Columbus East 115 kV	640136	Columbus 115 kV	1	115				238/238	Upgrade Columbus East - Columbus line to 238 MVA.
	606	10971	NPPD	04/01/10	NTC	M				48 months	regional reliability	640316	Pawnee Lk 115 kV	640340	Seward 115 kV	1	115	6			120/120	Upgrade Pawnee Lake - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	10972	NPPD	04/01/10	NTC	M				48 months	regional reliability	640316	Pawnee Lk 115 kV	650214	NW 68th & Holdrege 115 kV	1	115	5			137/137	Upgrade Pawnee Lake - NW 68th & Holdrege line to 137 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	10973	NPPD	04/01/10	NTC	M				48 months	regional reliability	640328	Rising City 115 kV	640340	Seward 115 kV	1	115	13			120/120	Upgrade Rising City - Seward line to 120 MVA. Portion of this line will be double circuited with the Columbus East - NW 68th & Holdrege 345 kV line project.
	606	11162	NPPD	10/13/09	NTC	M				48 months	regional reliability	640127	Columbus East 115 kV	640125	Columbus East 345 kV	1	345/115				336/336	Add Columbus East 345/115/13.8 kV transformer.
	720	10957	NPPD	06/01/10		M		$6,750,000	NPPD	48 months	transmission service	640178	Geneva 115 kV	640372	Sutton 115 kV	1	115	16			240/240	Upgrade line to 240 MVA for WEC2.
	721	10958	NPPD	06/01/10		M		$200,000	NPPD	48 months	transmission service	640215	Hastings 115 kV	641088	Hastings City 115 kV	1	115				240/240	Upgrade line to 240 MVA for WEC2.
	723	10960	NPPD	06/01/10		M		$8,437,500	NPPD	48 months	transmission service	640372	Sutton 115 kV	641087	Whelan Energy Center 115 kV	1	115	20			240/240	Upgrade line to 240 MVA for WEC2.
	614	10787	OGE	03/30/10		M			OGE		Sponsored	514880	Northwest 345 kV	515375	Woodward Distric EHV 345 kV	1	345		120		2013/2013	Build 120 mile 345 kV, 3000 amp capacity line from new OG&E Woodward District EHV substation to Northwest substation
	614	10915	OGE	03/30/10		M			OGE		Sponsored	514880	Northwest 345 kV			1	345				2013/2013	At Northwest substation, install a 3000 amp 345 kV breaker and new line terminal. Relocate Spring Creek Line to new bay. Terminate line from Tatonga. Install line relays and coordinate all relays at Northwest Substation.
	614	10788	OGE	03/30/10		M		$218,000,000	OGE		Sponsored	515375	Woodward District EHV 345 kV	515376	Woodward EHV 138 kV		345/138				537/616	Install 345/138 kV transformer.
	614	10789	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514785	Woodward 138 kV	1	138		0.5		537/616	Build .5 miles of 138 kV and install terminal equipment .
	614	10790	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514785	Woodward 138 kV	2	138		0.5		537/616	Build .5 miles of 138 kV and install terminal equipment .
	614	10791	OGE	03/30/10		M			OGE		Sponsored	515376	Woodward EHV 138 kV	514796	Iodine 138 kV	1	138				268/308	Tap Iodine - Woodward 138 kV.
	892	11182	OGE		NTC	06/01/10		$5,500,000	OGE	30 months	regional reliability	515422	Canadian River 345 kV				345				1195/1195	Install Canadian River 345 kV terminal equipment at new Canadian River substation tapping the Pittsburg-Muskogee line.
	310	10391	OGE	06/01/10		M		$1,416,000	OGE		zonal - sponsored	503902	Fitzhugh 161 kV	515327	Helberg 161 kV	1	161			5	313/359	Conversion from 69kV to 161kV.
	310	10393	OGE	12/31/10		M		$660,000	OGE		zonal - sponsored	515352	Altus 161 kV	503902	Fitzhugh 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV.
	310	10395	OGE	06/01/10		M		$2,112,000	OGE		zonal - sponsored	515319	Little Spadra 161 kV	515355	Igo 161 kV	1	161			7	226/259	Conversion from 69kV to 161kV.
	309	10397	OGE	06/01/10		M		$50,000	OGE		zonal - sponsored	515177	Park Lane 69 kV	515187	Ahloso Tap 69 kV	1	69				97/111	Relay upgrade.
	310	10398	OGE	10/01/10		M		$2,973,000	OGE		zonal - sponsored	515355	Igo 161 kV	515357	Razorback 161 kV	1	161			10	134/143	Conversion from 69kV to 161kV.
	310	10399	OGE	06/01/10		M		$500,000	OGE		zonal - sponsored	515357	Razorback 161 kV	515358	Short Mountain 161 kV	1	161			14	134/143	Conversion from 69kV to 161kV.
	310	10400	OGE	10/01/10		M		$3,231,000	OGE		zonal - sponsored	515358	Short Mountain 161 kV	515316	Branch 161 kV	1	161			11	134/143	Conversion from 69kV to 161kV.
20029	354	10463	OGE	06/01/10	NTC-Modify Scope	06/01/10	01/27/09	$100,000	OGE	12 months	regional reliability	515256	Muldrow 69 kV	515307	3rd St 69 kV	1	69				77/86	Upgrade wavetrap and switches to 800 A at 3rd St. substation.
20002	395	10513	OGE	06/01/10		M	02/13/08	$347,073	OGE	12 months	regional reliability	515120	Russett 138 kV	521044	Russett 138 kV	1	138				191/191	Replace a wave trap, breaker, and increase CT ratio.
	758	11001	OPPD	02/26/10		M		$2,500,000	OPPD		zonal - sponsored	647902	SUB 902 69 kV	647983	SUB 983 69 kV	1	69	6.48			57/57	Rebuild Sub 902 - Sub 983 69 kV. The purpose of this project is to address maintenance-related issues, not to address violations of reliability criteria.
	256	10336	SEPC	06/01/10	NTC	06/01/10		$10,650,000	SPP	36 months	regional reliability	531424	Johnson 115 kV	531391	Pioneer 115 kV	1	115		.	38	165/198	Convert Johnson Corner - Pioneer line from 69 kV to 115 kV.
	315	10407	SPS	06/01/10		M		$200,000	SPP	6 months	regional reliability	524908	Roosevelt County Interchange 115 kV	524822	Curry County Interchange 115 kV		115				185/185	Upgrade terminal equipment, Rate A & B 185 MVA
20004	248	10317	SPS	06/01/10		M	02/13/08	$10,585,000	SPS	30 months	regional reliability	523797	Grave County Tap 115 kV	523796	Graves Sub 69 kV		115/69				40/40	Install 115/69 kV Graves transformer.
20004	248	10318	SPS	06/01/10		M	02/13/08		SPS	30 months	regional reliability	523777	Wheeler Interchange 230 kV	523776	Wheeler Interchange 115 kV		230/115				150/150	Install new 230/115 kV transformer at Wheeler Co (near State Line of Oklahoma and Texas)
20004	248	10319	SPS	06/01/10		M	02/13/08		SPS	30 months	regional reliability	523776	Wheeler Interchange 115 kV	523797	Graves Sub 115 kV		115		17		186/205	Build new 17 mile Wheeler Co to Graves 115 kV and modify 69 kV bus.
20004	248	10800	SPS	06/01/10		M	02/13/08	$2,000,000	SPS	12 months	regional reliability	511490	Elk City 230KV	523777	Wheeler Interchange 230 kV	1	230				319/351	Wheeler County tap
20004	248	10801	SPS	06/01/10		M	02/13/08		SPS	12 months	regional reliability	523771	Grapevine Interchange 230 kV	523777	Wheeler Interchange 230 kV	1	230				319/351	Wheeler County tap
20031	156	10326	SPS	12/31/10		M	01/27/09	$16,094,371	SPS	48 months	regional reliability	523309	Moore Co 230 kV	523095	Hitchland 230 kV	1	230		50		492/541	Build new 50 mile Moore County - Hitchland 230 kV rated at 541 MVA.
20004	156	10327	SPS	06/01/10		M	02/13/08	$12,577,500	SPP	24 months	regional reliability	523097	Hitchland 345 kV	523095	Hitchland 230 kV	1	345/230				559/559	Add 3-Winding 345/230 kV transformer at Hitchland - 560 MVA.
20004	156	10328	SPS	06/01/10		M	02/13/08	$15,848,000	SPP	36 months	regional reliability	523175	Sherman Tap 115 kV	523093	Hitchland 115 kV	1	115		28.2		146/161	Build new 28 mile Hitchland - Sherman Tap 115 kV rated at 161 MVA.
20004	156	10329	SPS	06/01/10	NTC-Modify Scope	M	02/13/08	$10,771,825	SPP	48 months	regional reliability	523168	Sherman Sub 115 kV	523228	Dallam County Interchange 115 kV	1	115		35		146/161	Add 115 kV line from Sherman to Dallam - 161 MVA.
20004	156	10200	SPS	06/01/10		M	02/13/08	$5,132,829	SPS	24 months	regional reliability	523090	Texas County Interchange 115 kV	523093	Hitchland 115 kV	2	115		9.00		146/161	Build new 9 mile Hitchland - Texas Co. 115 kV rated at 161 MVA.
20004	156	10201	SPS	06/01/10		M	02/13/08	$31,915,701	SPS	24 months	regional reliability	523093	Hitchland 115 kV	523095	Hitchland 230 kV	1	230/115				252/252	Add 2-winding 230/115 kV transformer at Hitchland - 252 MVA.
20004	156	10802	SPS	06/01/10		M	02/13/08			24 months	regional reliability	523093	Hitchland 115 kV	523195	Hansford 3 115 kV	1	115				164/180	Tap the Texas County to Hansford line.
20004	156	10805	SPS	06/01/10		M	02/13/08			12 months	regional reliability	523090	Texas County Interchange 115 kV	523093	Hitchland 115 kV	1	115				164/180	Tap the Texas County to Hansford line.
20031	554	10704	SPS	12/31/10		M	01/27/09	$27,452,677	SPS	30 months	regional reliability	523228	Dallam County Interchange 115 kV	523868	Channing 115 kV	1	115		35		246/271	Build new 35 mile Dallam - Channing 115 kV using 795 ACSR.
20031	554	10705	SPS	12/31/10		M	01/27/09		SPS	30 months	regional reliability	523868	Channing 115 kV	523875	Tascosa 115 kV	1	115			15	246/271	Convert 15 mile Channing - Tascosa line from 69 kV to 115 kV with 795 ACSR.
20031	554	10706	SPS	12/31/10		M	01/27/09		SPS	30 months	regional reliability	523875	Tascosa 115 kV	524106	Northwest Interchange 115 kV	1	115			30	246/271	Convert 30 mile Tascosa - Northwest Interchange line from 69 kV to 115 kV with 795 ACSR.
	773	11018	SPS		NTC	06/01/10		$5,670,000	SPP	24 months	regional reliability	524908	Roosevelt County Interchange 115 kV	524909	Roosevelt County Interchange 230 kV	2	230/115				252/289.8	Add 2nd 230/115 kV transformer at Roosevelt.
	776	11026	SPS	06/30/10	NTC	06/01/10		$600,000	SPP	6 months	regional reliability	524622	Deaf Smith County Interchange 115 kV	524597	Panda Energy Substation, Hereford 115 kV	1	115		1		120/154	Build new 1 mile Deaf Smith to Panda 115 kV line.
	777	11027	SPS		NTC	06/01/10		$1,100,000	SPP	12 months	regional reliability	524162	East Plant Interchange 115 kV	524224	Manhattan Sub 115 kV	1	115	2.24			226/249	Reconductor 2.24 mile East Plant - Manhattan 115 kV line.
	782	11032	SPS		NTC	06/01/10		$1,687,500	SPP	18 months	regional reliability	524322	South Georgia Interchange 115 kV	524345	Osage Switching Station 115 kV	1	115	4			227/249	Rebuild 4 mile Osage Switching Station - South Georgia Interchange 115 kV line with 795 ACSR.
	821	11084	SPS		NTC	06/01/10		$1,125,000	SPP	12 months	regional reliability	524345	Osage Switching Station 115 kV	524364	Randall County Interchange 115 kV	1	115	2			139/160	Reconductor 2 mile Osage Switching Station - Randall County Interchange 115 kV line with 795 ACSR.
	830	11097	SPS		NTC	06/01/10		$900,000	SPP	12 months	regional reliability	524354	Manhatten Tap 115 kV	524364	Randall County Interchange 115 kV	1	115	1.6			246/271	Reconductor 1.6 mile Manhattan - Randall County Interchange 115 kV line with 795 ACSR.
	851	11121	SPS	06/16/10	NTC	06/01/10		$225,000	SPP	12 months	regional reliability	523978	Harrington Mid 230 kV	524365	Randall Co 230 kV	1	230				436/502	Replace existing wavetrap with 1200 A unit.
	342	10439	SWPA	01/01/10		06/01/10		$2,200,000	SWPA	12 months	regional reliability - non OATT	505460	Bull Shoals 161 kV	338123	Bullshoals 161 kV	1	161				335/335	Upgrade the bus to 1200 amp and reconnect CT ratios to 1200/5.
	101	10125	SWPA	10/01/10		M		$3,000,000	SWPA	24 months	regional reliability - non OATT	505570	Eufaula 161 kV	505574	Eufaula 138 kV	1	161/138				200/200	Replace Eufaula161/138 kV transformer with 200 MVA unit.
20003	138	10176	WFEC	06/01/10		M	02/13/08	$1,050,000	SPP	10 months	regional reliability	514782	OGE Woodward 69 kV	521096	WFEC Woodward 69kV	1	69	3.5			91/114	Upgrade WFEC Woodward sub to 1200 A and reconductor from 336.4 ACSR to 795 ACSR; new rating 91/110 MVA.
20030	239	10305	WFEC	12/31/10		M	01/27/09	$3,373,000	SPP	16 months	regional reliability	511435	AEP Snyder 138 kV	521052	WFEC Snyder 138 kV	1	138		4		118/154	Build new 4 mile AEP Snyder - WFEC Snyder 138 kV line.
20003	241	10307	WFEC	06/01/10		M	02/13/08	$1,124,000	SPP	12 months	regional reliability	520814	Anadarko 138 kV	520923	Georgia 138 kV	1	138	2			212/264	Rebuild 2 mile Anadarko - Georgia 138 kV line from 556 to 1113 ACSR.
20003	242	10308	WFEC	06/01/10		M	02/13/08	$3,240,000	SPP	12 months	regional reliability	520898	Elmore 69 kV	521022	Paola 69 kV	1	69	10.8			47/61	Elmore - Paoli Rebuild 3/0 to 336 ACSR - 10.8 miles.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
20003	243	10309	WFEC	06/01/10		M	02/13/08	$2,753,800	SPP	16 months	regional reliability	521104	OU Switchyard 138 kV	520924	Goldsby 138 kV	1	138			4.9	183/228	Convert 5 mile Oklahoma University (OU) Switch - Goldsby from 69 kV to 138 kV.
20003	243	10310	WFEC	06/01/10		M	02/13/08	$2,250,000	SPP	16 months	regional reliability	520924	Goldsby 138 kV	520842	Canadian SW 138 kV	1	138			6	183/228	Convert 6 mile Goldsby - Canadian Switch from 69 kV to 138 kV.
20003	243	10311	WFEC	06/01/10		M	02/13/08	$5,000,000	SPP	16 months	regional reliability	521104	OU Switchyard 138 kV	521018	OU Switchyard 69 kV	1	138/69				112/112	Install 138/69 kV transformer at Oklahoma University.
20003	136	10174	WFEC	06/01/10		M	02/13/08	$6,674,000	SPP	10 months	regional reliability	520994	Meeker 138 kV	520951	Hammett 138 kV	1	138		10		219/235	Build new 10 mile Meeker - Hammett 138 kV and install terminal equipment.
20003	137	10175	WFEC	06/01/10		M	02/13/08	$5,378,750	SPP	10 months	regional reliability	521085	Wakita 69 kV	520938	Hazelton 69 kV	1	69	18.9			53/65	Reconductor 18.9 mile Wakita - Hazelton Junction 69 kV from 1/0 ACSR to 336.4 ACSR for new rating of 53/65 MVA.
20003	311	10401	WFEC	06/01/10		M	02/13/08	$2,065,000	SPP	12 months	regional reliability	520917	Franklin SW 138 kV	520802	ACME 138 kV	1	138			4.9	131.7/162.54	Convert 5 mile Acme - Franklin from 69 kV to 138 kV.
20003	311	10402	WFEC	06/01/10		M	02/13/08	$1,601,000	SPP	12 months	regional reliability	520802	ACME 138 kV	521095	West Norman 138 kV	1	138			3.8	183/228	Convert 4 mile West Norman - Acme from 69 kV to 138 kV.
20003	311	10403	WFEC	06/01/10		M	02/13/08	$1,577,000	SPP	12 months	regional reliability	521095	West Norman 138 kV	521104	OU SW 138 kV	1	138			8.3	182/228	Convert 8 mile OU - West Norman from 69 kV to 138 kV.
20030	616	10794	WFEC	06/01/10		M	01/27/09	$5,765,600	SPP	24 months	regional reliability	520882	Dover SW 138 kV	520879	Dover 138 kV	1	138			11	144/179	Convert 11 mile Dover Southwest - Dover from 69 kV to 138 kV and install terminal equipment at Dover Southwest.
20030	616	10795	WFEC	06/01/10		M	01/27/09	$5,315,700	SPP	24 months	regional reliability	520879	Dover 138 kV	521073	Twin Lakes 138 kV	1	138			12.6	144/179	Convert 12.6 mile Dover - Twin Lakes from 69 kV to 138 kV
20030	616	10796	WFEC	06/01/10		M	01/27/09	$3,164,000	SPP	24 months	regional reliability	521073	Twin Lakes 138 kV	520847	Cashion 138 kV	1	138			7.5	144/179	Convert 7.5 mile Twin Lakes - Cashion from 69 kV to 138 kV.
20030	616	10797	WFEC	06/01/10		M	01/27/09	$3,937,500	SPP	24 months	regional reliability	521073	Twin Lakes 138 kV	515377	Crescent 138 kV	1	138		7		144/179	Build new 7 mile WFEC Twin Lakes - OG&E Crescent 138 kV.
20030	617	10798	WFEC	06/01/10		M	01/27/09	$150,000	WFEC	8 months	regional reliability	520846	Carter JCT 69 kV	520978	Lake Creek 69 kV	1	69				53/65	Upgrade CTs at Lake Creek (Carter Branch) to 600A.
20030	135	10799	WFEC	06/01/10		M	01/27/09	$1,248,750	SPP	12 months	regional reliability	520977	Lindsay 69 kV	520979	Lindsay SW 69 kV	1	69	3.7			72/89	Reconductor 3.7 miles of 1/0 ACSR to 556.5 ACSR from Lindsay to Lindsay Southwest 69 kV.
20030	135	10173	WFEC	06/01/10		M	01/27/09	$2,328,750	SPP	18 months	regional reliability	520829	Bradley 69 kV	521041	Rush Springs 69 kV	1	69	6.9			53/65	Reconductor 6.9 miles of 1/0 ACSR to 336.4 ACSR from Bradley to Rush Springs 69 kV.
19985	140	10179	WFEC	06/01/10		M	02/02/07	$912,000	WFEC	8 months	regional reliability	520802	ACME 69 kV	521095	W Norman 69 kV	1	69	3.8			81/106	Reconductor 3.8 miles from 3/0 ACSR to 795 ACSR. Rate A=81MVA, Rate B=106MVA
20006	171	10220	WR	12/01/10		M	02/13/08	$2,242,907	WR	6 months	regional reliability	533604	Weaver 69 kV	533837	Rose Hill 69 kV	1	69	5.76			116/128	Rebuild Weaver-Rose Hill 69 kV
20059	182	10231	WR	06/01/10		M	09/18/09	$5,184,701	WR	8 months	regional reliability	533588	Chase 69 kV	533605	White Junction 69 kV	1	69	7.3			72/72	Rebuild approximately 7.5 miles Chase - White Junction 69 kV line. Replace existing 2/0 copper conductor to achieve a minimum 600 amp emergency rating.
19964	318	10412	WR	06/01/10		M	06/27/07	$2,819,000	WR	18 months	transmission service	510422	Coffeyville Tap 138 kV	533002	Dearing 138 kV	1	138	3.93			287/287	AEP - Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR. WERE - Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR. AEP: The limiting factor is the AEP portion of 795 ACSR conductor The estimated cost of doing a sag analysis on this line to see if it can rated for a higher limit is 6000 New ratings are for AEP only. The new limit is the 1590 ACSR conductor Per MW-Mile files, 78% WR, 22% AEP of 5.02 miles
	262	10345	WR	06/01/10		M		$100,618,016	WR	24 months	Sponsored	532771	Reno County 7 345 kV	532773	Summit 345 kV	1	345		50.55		956 / 956	Install new 50.55-mile 345 kV line from Reno county to Summit; 31 miles of 115 kV line between Circle and S Philips would be rebuilt as double circuit with the 345 kV line to minimize ROW impacts; Substation work required at Summit for new 345 kV terminal and completion of ring bus.
20006	330	10426	WR			M	02/13/08	$5,000,000	WR	18 months	regional reliability	532929	Southwest Bourbon 161 kV	532930	Fort Scott 161 kV	1	161		22		312/342	Tap Litchfield-Marmaton 161 kV with new SWBourb5 bus to Ft Scott
20006	328	10424	WR	06/01/10		M	02/13/08	$5,800,000	WR	12 months	regional reliability	533413	Circle 115 kV	533429	Moundridge 115 kV	1	115	17.12			223/245	Rebuild Circle - Moundridge 115 kV
	328	10425	WR	06/01/10				$1,700,000	WR		zonal - sponsored	533013	Moundridge 138 kV	533429	Moundridge 115 kV	2	138/115				100/110	Install New (2nd) 138/115 kV transformer at Moundridge (57429/57013). Operate both 138/115 kV transformers normally closed.
20006	170	10219	WR	06/01/10		M	02/13/08	$3,639,327	WR	6 months	regional reliability	533321	Anzio 115 kV	533328	Fort Junction	1	115	3.53			141/141	3.53 miles Anzio - Fort Junction Switching Station 115 kV
20033	621	10809	WR			M	01/27/09	$17,085,938	SPP	12 months	regional reliability	532861	E. Manhattan 230 kV	532852	JEC 230 kV	1	230				446/490	Uprate JEC-E. Manhattan 230 kV line to 100 deg C operation by raising structures.
20033	625	10813	WR	06/01/10		M	01/27/09	$2,255,250	WR	18 months	regional reliability	533786	Chisholm 69 kV	533832	Ripley 69 kV	1	69			2.37	134/147	Rebuild the 2.37 mile Chisholm - Ripley 69 kV line using single 1192.5 ACSR.
20019	578	10739	WR	06/01/10		M	11/17/08	$25,751,000	WR	36 months	regional reliability	533332	Knob Hill 115 kV	640426	Steele City 115 kV	1	115		28		223/245	New 115 kV Line from Knob Hill to Kansas/Nebraska state line.
20019	577	10738	WR	12/01/10		M	11/17/08	$5,825,000	WR	24 months	regional reliability	533217	Kelly 115 kV	533337	South Seneca 115 kV	1	115	10.3			223/245	Rebuild 10.3 mile line between Kelly and South Seneca.
20033	599	10766	WR	12/31/10		M	01/27/09	$3,890,000	WR	12 months	regional reliability	533182	Tecumseh Hill 115 kV	533187	27th & Croco 115 kV	1	115	2.72			223/240	Tear down and rebuild the 2.72 mile Tecumseh Hill - 27th & Croco 115 kV line as a single circuit.
20059	30228	50235	WR	06/01/10			09/18/09	$115,000	WR	12 months	transmission service	533646	Tioga 69 kV	533666	Chanute TAP 69 kV	1	69	4.82			72/72	Replace Jumpers to achieve a minimum 600 amp emergency rating.
20059	30229	50237	WR	06/01/10			09/18/09	$600,000	WR		transmission service	510422	Coffeyville Tap 138 kV	533002	Dearing 138 kV	1	138				382/382	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers with a minimum 2000 amp emergency rating equipment
20059	30224	50238	WR	07/01/10			09/18/09	$3,335,500	WR	18 months	transmission service	533636	Green 69 kV	533631	Coffey County No. 4 Vernon 69 kV	1	69	7.19			116/128	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	561	10711	WR	06/01/10		M	09/18/09	$5,513,000	WR	12 months	transmission service	533041	Evans Energy Center South 138 KV	533053	Lakeridge 138 KV	1	138				382/413	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers with a minimum 2000 amp emergency rating
		Year 2011																				
	283	10367	AECI	06/01/12					SPP		inter-regional	96272	Blackberry 345 kV	300740	Sportsman Acres 345	1	345		108		1369/1369	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Chouteau 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Chouteau 345kV bus a 345/161 transformer connects to Chouteau 161kV sub.
	283	10368	AECI	02/01/11					SPP		inter-regional	300740	Sportsman Acres 345	512650	GRDA 1 345 kV	1	345		5		977/977	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10369	AECI	02/01/11				$57,000,000	SPP		inter-regional	300740	Sportsman Acres 345 kV	300741	Sportsman Acres 161 kV	1	345/161				505/505	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10916	AECI	02/01/11					SPP		inter-regional	300740	Sportsman Acres 345 kV	300741	Sportsman Acres 161 kV	2	345/161				505/505	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	283	10781	AECI	02/01/11					SPP		inter-regional		Sportsman Acres 161kV	300069	Chouteau 161 kV		161				1067/1067	The proposed line connects to the Morgan - Neosho 345kV line near the Kansas border -- This is the proposed Blackberry sub. From Blackberry the 108 mile 345kV line connects to Sportsman Acres 345 kV bus which connects via a 5 mile 345kV circuit to GRDA 1 bus (GRDA 2 gen). At the Sportsman Acres 345kV bus a 345/161 transformer 161 kV line connects to Chouteau 161kV sub.
	350	10459	AEP	12/31/11				$277,000	AEP	60 months	Generation Interconnect	508054	Bann 138 kV	508075	Red Springs REC 138 kV	1	138				224/261	Replace breaker 3310.
	349	10446	AEP	06/01/11		M		$7,810,000	AEP	60 months	Generation Interconnect	507402	Ashdown REC (Millwood) 138 kV	507428	Okay 138 kV	1	138			14.3	368/512	Reconductor and convert line to 138 kV and replace switches at Ashdown REC
	349	10447	AEP	12/31/11		M		$11,431,000	AEP	60 months	Generation Interconnect	507402	Ashdown REC (Millwood) 138 kV	507431	Patterson 138 kV	1	138			5	368/512	Reconductor line and convert line to 138 kV. Convert Patterson station to breaker-and-a half configuration.
	349	10448	AEP	12/31/11		M		$1,773,000	AEP	60 months	Generation Interconnect	507409	McNab REC 115 kV	507456	Turk 115 kV	1	115		1.5		150/174	Build new McNab-Turk 115 kV line
	349	10451	AEP	12/31/11		M		$3,266,000	AEP	60 months	Generation Interconnect	507427	Okay 69 kV	507428	Okay 138 kV	1	138/69				83/92	Convert 115-69 kV station to 138-69 kV.
	349	10452	AEP	12/31/11		M		$8,170,000	AEP	60 months	Generation Interconnect	507428	Okay 138 kV	507454	Turk 138 kV	1	138	12	2		368/512	Build two mile, 138 kV, 1590ACSR line section from Turk Sub to existing Okay-Hope 115 kV line and rebuild twelve miles of 115 kV line to Okay Sub to 138 kV, 1590 ACSR , to form a Turk-Okay 138 kV line
	349	10457	AEP	12/31/11		M		$7,806,000	AEP	48 months	Generation Interconnect	507456	Turk 115 kV	507454	Turk 138 kV	1	138/115				175/234	Build Turk 138-115 kV station and relocate autotransformer (and spare) from Patterson to this new Turk station.
20027	452	10586	AEP	06/01/11		M	01/27/09	$350,000	AEP	18 months	regional reliability	508575	Whitney 138 kV	508574	Whitney 69 kV	1 & 2	138/69				140/170	Replace one breaker and four switches.
20016	349	10449	AEP	12/31/11		M	01/16/09	$540,000	AEP	60 months	transmission service	504122	McNab REC 115 kV	507456	Turk 115 kV	1	115	0.5			307/398	Reconductor about 0.5 miles of 666 ACSR with 1590 ACSR
20016	349	10450	AEP	12/31/11		M	01/16/09	$2,170,000	AEP	60 months	transmission service	504122	McNab REC 115 kV	507453	Hope 115 kV	1	115	3.55			307/398	Reconductor 3.55 miles of 666 ACSR with 1590 ACSR
20048	446	10578	AEP	06/01/11			09/18/09	$13,100,000	AEP	24 months	transmission service	510386	North Bartlesville 138 kV	510422	Coffeyville Tap 138 kV	1	138	13.11			287/287	Rebuild approximately 13 miles of line with 1590 ACSR to achieve a minimum 2000 Amp emergency rating
20048	454	10588	AEP	06/01/11			09/18/09	$8,400,000	AEP	24 months	transmission service	510391	Bartlesville Southeast 138 kV	510386	North Bartlesville 138 kV	1	138	8.37			280/287	Rebuild approximately 8.5 miles of line with 1590 ACS to achieve a minimum 2000 Amp emergency rating & reset relays at Bartlesville Southeast accordingly
	287	10373	DETEC	06/01/11				$11,299,000			zonal - sponsored	97813	Etoile 138 kV		Chireno 138 kV	1	138		12.5		215/225	Build 12 miles of 138 kV from Etoile - Chireno
19970	499	10644	EDE	06/01/11		M	01/10/08	$4,000,000	EDE	36 months	transmission service	547467	ORO110 5 161 IV	547534	ORO110 2 69 kV	1	161/69				150/150	Replace Auto transformer at ORONOGO 110 with 150 MVA rated Auto transformer due to increased generation available
19970	352	10730	EDE	06/01/11		M	01/10/08	$5,750,000	EDE	36 months	transmission service	547467	Sub 110 - Oronogo Jct.	547469	Sub 167 - Riverton	1	161	11.9			299/335	Reconductor 11.9 miles of Oronogo Jct. to Riverton 161kV Ckt. 1 from 556 ACSR to 795 ACSR, change CT settings @ Oronogo, and replace wavetrap.
	284	10370	EES	06/01/11		06/01/10		$6,000,000		36 months	inter-regional	338099	Grandview 161 kV	338682	Osage 161 kV	1	161		5.34		247/247	Entergy Planning has identified this proposed project as installing a new switching station, Grandview, on the existing 161 kV line between Table Rock Dam and Eureka Springs substation and constructing a new 161 kV line between Grandview and the existing Osage Creek substation.
20034	634	10830	GMO	11/01/11		M	01/27/09	$2,369,625	GMO	24-30 months	regional reliability	542998	Loma Vista 161 kV	541245	KC South 161 kV	1	161		4		293/335	Tap the Montrose - LomaVista 161 kV Line into KC South 161 kV substation. This project is an alternative to replace the reconductor project of the Duncan Rd - Blue Spring East and Martin City - Grandview East 161 kV lines.
	334	10431	GMO	06/01/11		M		$7,096,402	GMO	24-36 months	zonal - sponsored	541316	Lone Jack 161 kV	541218	Greenwood 161 kV	1	161		4		223/245	Radial Line From Greenwood to a new distribution sub at Lone Jack
	331	10428	GMO	06/01/11				$2,418,750	SPP	6-12 months	zonal - sponsored	541352	Clinton 161 kV				161					Tap Clinton AECI (300071) to Clinton MIPU (541242) with new Clinton bus and tie in existing Clinton transformer into new bus.
20034	650	10854	GMO	06/01/11		M	01/27/09	$2,259,673	GMO	18 months	regional reliability	542969	Stillwell 161 kV	541207	Archie 161 kV	1	161		3.6		293/335	Tap Stilwell - Archie Junction 161 kV line into South Harper 161 kV sub and make it two new 161 kV sections: Stilwell - South Harper and Archie Junction - South Harper.
	278	10361	GMO	06/01/11		M		$893,868	GMO	12~18 months	zonal - sponsored	541224	Longview 161 kV	541345	Sampson 161 kV	1	161				223/245	161kV Tap of Longview to Grandview East
	278	10362	GMO	06/01/11		M		$0	GMO	12~18 months	zonal - sponsored	541345	Sampson 161 kV	541223	Grandview East 161 kV	1	161				223/245	161kV Tap of Longview to Grandview East
	273	10356	GMO	06/01/11		M		$1,350,000	GMO	12~18 months	zonal - sponsored	541353	Cookingham 161 kV	541247	Liberty West 161 kV	1	161				223/245	161kV Tap of Nashua to Liberty West
	273	10357	GMO	06/01/11		M			GMO	12~18 months	zonal - sponsored	541203	Nashua 161 kV	541353	Cookingham 161 kV	1	161				223/245	161kV Tap of Nashua to Liberty West
20056	30223	50227	GMO	06/01/11			09/18/09	$4,400,000	SJLP	18 months	transmission service	541253	ST Joe 161 KV	541257	Cook 161 KV	1	161	4.6			446/446	Reconductor the line from 1192 ACSR to 1192 ACSS and rebuild the line terminals to 2000 amp capability
20001	393	10511	GRDA	06/01/11	NTC-Modify Timing	06/01/10	02/13/08	$2,500,000	GRDA	24 months	regional reliability	512632	Afton161 kV	512633	Afton 69 kV	1	161/69				50/50	Add 50MVA 161/69 kV transformer #2 at Afton.
	302	10390	GRDA	12/01/11		M		$8,019,000	GRDA	24 months	zonal - sponsored	512750	Siloam Springs Tap 345 kV	512751	Siloam Springs Tap 161 kV	1	345/161				75/140	Tap the GRDA 1-Flint Creek 345 kV line and build a 345/161 transformer. Then build a 161 kV line down to Siloam Springs.
20050	394	10512	GRDA	06/01/11			09/18/09	$10,450,000	GRDA	24 months	regional reliability	512634	Kerr 161 kV	512629	Pensacola 115 kV	1	161			22	162/186	Rebuild approximately 22 miles of line with 795 ACSR
20051	30218	50222	KCPL	06/01/11			09/18/09	$2,200,000	KCPL	24 months	transmission service	542969	Stilwell 161 kV	543053	Redel 161 kV	1	161	4.4			557/557	Reconductor line and upgrade terminal equipment for 2000 amps
	609	10924	OPPD	12/31/11	NTC	M			OPPD		regional reliability	646341	SUB 1341 161 kV				161					Build new 161-kV substation Sub 1341. Remove 0.06 mile of 161 kV line from Sub 1251- Sub 1305.
	609	10925	OPPD	12/31/11	NTC	M		$16,300,000	OPPD		regional reliability	646341	SUB 1341 161 kV	646251	SUB 1251 161 kV	1	161		1	0.41		Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.
	609	10926	OPPD	12/31/11	NTC	M			OPPD		regional reliability	646341	SUB 1341 161 kV	646305	SUB 1305 161 kV	1	161		1	0.34		Tap 161-kV line from Sub 1251 to Sub 1305 and route it into and out of new 161-kV substation Sub 1341.
	310	10392	OGE	03/31/11		M		$543,000	OGE		zonal - sponsored	515353	Great Lakes Carbon 161 kV	515352	Altus 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV
	310	10394	OGE	03/31/11		M		$2,994,000	OGE		zonal - sponsored	515355	Igo 161 kV	515354	Noark 161 kV	1	161			10	134/143	Conversion from 69kV to 161kV
	310	10396	OGE	03/31/11		M		$522,000	OGE		zonal - sponsored	515354	Noark 161 kV	515353	Great Lakes Carbon 161 kV	1	161			2	134/143	Conversion from 69kV to 161kV
	895	11190	OGE	04/01/11		M		$1,300,000	OGE	12 months	zonal - sponsored	514870	Stonewall138 kV	514872	Remington Park 138 kV	1	138				268/308	Three terminal line will be upgraded to 2000A with breakers. Limiting equipment will be 795AS33 conductor.
20017	30158	50166	OGE	06/01/11		M	01/16/09	$1,400,000	OGE	24 months	transmission service	515163	Rocky Point 69 kV	515166	Ardmore 69 kV	1	69	4.65			72/72	Replace 4.65 miles of line with 477AS33
20017	30162	50170	OGE	06/01/11		M	01/16/09	$50,000	OGE	12 months	transmission service	515135	Sunnyside 138 kV	515137	Uniroyal 138 kV	1	138				194/222	Replace wavetrap 800A at Uniroyal
20017	30159	50167	OGE	06/01/11		M	01/16/09	$300,000	OGE	12 months	transmission service	515142	Dillard 138 kV	515141	Healdton Tap 138 kV	1	138				191/191	Replace Differential Relaying
20029	615	10792 & 10793	OGE	06/01/11		M	01/27/09	$5,404,250	OGE	18 months	regional reliability	515377	Crescent 138 kV	514827	Cottonwood Creek 138 kV	1	138			13.64	84/104	Convert 13.64 miles of 69 kV to 138 kV from Crescent to Cottonwood Creek and install terminal equipment at Cottonwood Creek, completing loop from Crescent to Twin Lakes (WFEC).
	896	11188	OGE	05/30/11		M					zonal - sponsored	515048	Keystone West 138 kV	515369	Bell Cow 138 kV	1	138				268/287	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.
	896	11189	OGE	05/30/11		M					zonal - sponsored	515047	Warwick 138 kV	515369	Bell Cow 138 kV	1	138				268/287	Bell Cow Sub is delayed until 2011. Install Bell Cow sub and associated lines, remove chandler sub.
	304	10731	OGE	06/01/11		M			OGE		zonal - sponsored	515150	Caney Creek 138 kV			1	138					At Caney Creek remove 2 existing line terminals to the north and expand the 138 kV bus north into a ring bus
	304	10732	OGE	06/01/11		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515150	Caney Creek 138 kV	1	138		25			Construct 25 miles of 138 kV of 795AS33 line from the new Johnson County sub to Caney Creek.
	304	10733	OGE	06/01/11		M			OGE		zonal - sponsored	515809	Johnson County 345 kV	514808	Johnson County 138 kV	1	345/138				400/400	Build a new 345 EHV substation in the Sunnyside to Pittsburg line. Install a 400 MVAtransformer with 3-345kv breakers in a ring bus and 4-138kv breakers in a ring bus at new Johnson County sub.
	304	10734	OGE	06/01/11		M		$32,975,000	OGE		zonal - sponsored	515136	Sunnyside 345 kV	514809	Johnson County 345 kV	1	345					Replace relays at Sunnyside 345 kV
	304	10735	OGE	06/01/11		M			OGE		zonal - sponsored	515809	Johnson County 345 kV	510907	Pittsburg 345 kV	1	345					Replace relays at Pittsburg 345 kV
	304	10820	OGE	06/01/13		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515121	Millcreek	1	138				191/191	Tap the MillCreek to Russett 138 kV into the New Johnson County substation
	304	10821	OGE	06/01/13		M			OGE		zonal - sponsored	514808	Johnson County 138 kV	515120	Russett 138 kV 138 kV	1	138	2.99			287/287	Tap the MillCreek to Russett 138 kV into the New Johnson County substation and reconductor Jonson County to Russett Sub with 795 AS33

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	582	10747	OGE	06/01/11		M		$1,900,000	OGE		zonal - sponsored	514827	Cottonwood Creek 138 kV	514907	Arcadia 138 kV	1	138				268/287	Install Terminal equipment to remove Three terminal line
	582	10748	OGE	06/01/11		M			OGE		zonal - sponsored	514907	Arcadia 138 kV	529272	Garber 138 kV	1	138				268/287	Install Terminal equipment to remove Three terminal line
20041	709	10946	OGE	12/31/11		M	06/19/09	$15,000,000		24 months	Balanced Portfolio	515800	Anadarko (Gracemont) 345 kV	515802	Gracemont 138 kV	1	345/138				448/493	Tap Lawton East Side to Cimarron 345 kV line at Anadarko and build substation. Install a 345/138 kV transformer in substation.
20002	396	10514	OGE	10/01/11		M	02/13/08	$1,000,000	OGE	12 months	regional reliability	515156	Bodle 138 kV	515155	Bodle 138 kV	1	138					Install a 138 kV breaker at Bodle to close the normally open switch. Breaker connects 515155 Bodle 138 kV to 515156 Bodle138 kV.
	165	10214	SEPC	09/01/11		M		$10,500,000	SEPC	24 months	zonal - sponsored	539685	Phillipsburg 115 kV	531373	Rhoades 115 kV	1	115		35		165/198	Build new 35 mile Phillipsburg - Rhoades 115 kV.
20007	166	10215	SEPC	09/01/11		M	02/13/08	$3,650,000	SEPC	18 months	regional reliability	531448	Holcomb 115 kV	531393	Plymell 115 kV	1	115	11.96			230/276	Rebuild 12 mile Holcomb - Plymell 115 kV.
20014	367	10480	SEPC	09/01/11		M	09/18/08	$3,200,000	SEPC	24 months	regional reliability	531393	Plymell 115 kV	531392	Pioneer Tap 115 kV	1	115	14.87			230/276	Rebuild 15 mile Holcomb - Pioneer Tap 115kV.
	791	11040	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	525461	Newhart 230 kV	525460	Newhart 115 kV	1	230/115				150/173	Tap the Potter Interchange - Plant X Station 230 kV line for new Newhart Substation install 230/115 kV 150/173 MVA transformer.
	824	11090	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	527894	Hobbs Interchange 230 kV	527895	Hobbs Interchange 345 kV	1	345/230/13.2				515/560	New 345/230 kV transformer rated 515/560 MVA at Hobbs Interchange.
	824	11091	SPS	12/22/11	NTC	06/01/10		$11,250,000	SPP	24 months	regional reliability	527915	Midland 345 kV	522992	Midland 138 kV	1	345138/13.2				400/440	New 345/138 kV transformer rated 400/440 MVA at Midland.
	779	11029	SPS	06/25/11	NTC	06/01/10		$3,000,000	SPP	18 months	regional reliability	528355	Maddox Station 115 kV	528463	Sanger Switching Station 115 kV	1	115	6.15			226/249	Reconductor 6.15 mile Maddox - Sanger Switching Station 115kV line for 226/239 MVA rating.
	774	11019	SPS	08/24/11	NTC	06/01/10		$112,500	SPP	20 months	regional reliability	524010	Cherry Sub 230 kV	523959	Potter County Interchange 230 kV	1	230		0.1		218/239	New Tap to new Cherry 230/115 kV Transformer.
	774	11020	SPS	08/24/11	NTC	06/01/10		$4,905,000	SPP	20 months	regional reliability	524010	Cherry Sub 230 kV	524009	Cherry Sub 115 kV	1	230/115				218/239	New 230/115 kV Autotransformer at Cherry Substation.
20031	590	10757	SPS	06/01/11		06/01/10	01/27/09	$1,222,843	SPS	24 months	regional reliability	528160	Carlsbad Interchange 115 kV	528131	Ocotillo Sub 115 kV	1	115			8	54/54	Convert 8 miles of 69 kV to 115 kV from Carlsbad Interchange - Ocotillo. Convert Ocotillo substation to 115 kV.
20004	156	10325	SPS	06/01/11		M	02/13/08	$11,922,643	SPS		zonal - sponsored	523267	Pringle Interchange 230 kV	523095	Hitchland 230 kV	1	230		34		492/541	Add 230 kV line from Pringle to Hitchland - 541 MVA.
20004	156	10330	SPS	06/01/11		M	02/13/08	$10,766,250	SPS	48 months	regional reliability	523095	Hitchland 230 kV	523155	Ochiltree 230 kV	1	230		35		492/541	Add 230 kV line from Hitchland to Ochiltree - 541 MVA.
20004	156	10331	SPS	06/01/11		M	02/13/08	$5,846,295	SPS	24 months	regional reliability	523158	Perryton Interchange 115 kV	523155	Ochiltree 230 kV	1	230/115				150/172.5	Add 2-Winding 230/115 kV transformer at Ochiltree – 172.5 MVA
	783	11033	SPS	08/24/11	NTC	06/01/10		$11,250,000	SPP	20 months	regional reliability	524365	Randall County Interchange 230 kV	524364	Randall County Interchange 115 kV	2	230/115				224/239	Install second 230/115 kV transformer in Randall substation.
20031	632	10822	SPS	06/01/11		M	01/27/09	$3,937,500	SPS	24 months	regional reliability	527346	Legacy Interchange 115 kV (new interchange	527349	Boardman Tap 69 kV	1	115/69				40/46	Tap line from Tenneco - Boardman Tap 69 kV and add new 75/75 MVA 115/69 kV transformer at new Legacy Interchange substation.
20031	632	10823	SPS	06/01/11		M	01/27/09	$3,375,000	SPS	24 months	regional reliability	527340	Doss Interchange 115 kV	527346	Legacy Interchange 115 kV (new interchange and sub)	1	115		6		90/99	Build new 6 mile 115 kV line from Doss Interchange - Legacy Interchange.
20031	632	10824	SPS	06/01/11		M	01/27/09	$3,093,750	SPS	24 months	regional reliability	527322	Gaines County Interchange 115 kV	527346	Legacy Interchange 115 kV (new interchange and sub)	1	115		5.5		90/99	Build new 5.5 mile 115 kV line from Gaines County Interchange - Legacy Interchange.
20031	633	10825	SPS	04/15/11		M	01/27/09	$3,285,000	SPS	36 months	regional reliability	527710	Eagle Creek 69 kV (new sub)	527711	Eagle Creek 115 kV (new sub)	1	115/69				40/46	Tap line 69 kV from Navajo No. 2 - Navajo No. 4, tap line 115 kV from Navajo No. 3 - Navajo No. 4, and install Eagle Creek Substation and 115/69 kV transformer.
20031	633	10826	SPS	04/15/11		M	01/27/09	$281,250	SPS	36 months	regional reliability	527743	Navajo No.5 Sub 115 kV (new sub)	527739	Navajo No.4 Sub 115 kV	1	115		0.5		179/197	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 4 substation 115 kV.
20031	633	10827	SPS	04/15/11		M	01/27/09	$281,250	SPS	36 months	regional reliability	527742	Navajo No.5 Sub 115 kV (new sub)	527720	Navajo No.3 Sub 115 kV	1	115		0.5		179/197	Build new 0.5 mile 115 kV line from new Navajo No. 5 substation - Navajo No. 3 substation 115 kV.
20031	633	10828	SPS	04/15/11		M	01/27/09	$1,350,000	SPS	36 months	regional reliability	527747	Artesia Town Sub 69 kV	527775	Artesia South Rural Sub 69 kV	1	69		3		179/197	Build new 3 mile 69 kV line from Artesia Town - Artesia South Rural 69 kV.
20031	696	10829	SPS	06/01/11		06/01/11	01/27/09	$4,716,600	SPP		regional reliability	527482	Chaves County Interchange 115 kV	527564	Roswell Interchange 115 kV	1	115			11.18	54/54	Convert 11.8 miles of 69 kV line to 115 kV from Chaves County - Price - Central Valley REC-Pine Lodge - Capitan - Roswell. SPS-provided mitigation was verified by SPP staff until 12/2012 when the conversion will be completed.
	786	11036	SPS	06/25/11	NTC	06/01/11		$1,417,500	SPP	18 months	regional reliability	528355	Maddox Station 115 kV	528491	Monument Sub 115 kV	1	115	3.36			226/249	Reconductor 3.36 mile Maddox - Monument CKT 1 115 kV with 795 ACSR.
	829	11096	SPS	12/22/11	NTC	06/01/11		$1,935,000	SPP	24 months	regional reliability	523711	Kingsmill 69 kV	523712	Kingsmill 115 kV	2	115/69				75/86	Install second 115/69 kV transformer rated 75/86 MVA at Kingsmill.
19987	150	10194	SPS	-		06/01/11	02/02/07	$1,250,000	SPS	18 months	regional reliability	525191	Kress 69 kV	525192	Kress 115 kV	2	115/69				84/84	Upgrade #2 Transformer
	857	11196	SPS		NTC	06/01/11		$596,250	SPP	24 months	regional reliability	524162	East Plant 115 kV	524185	Pierce 115 kV	1	115	1.06			246/271	Reconductor EAST PLANT-PIERCE 1.06 miles 115 kV to 795 ACSR line
	580	10741	SWPA			12/01/11		$3,150,000	SPP		regional reliability - non OATT	505412	Paragould 161 kV	505414	Paragould 69 kV	1 & 2	161/69				70/70	Replace Paragould auto transformers 1 and 2 with 70 MVA units.
	612	10944	SWPA	06/01/11		06/01/10		$165,000	SPP	12 months	regional reliability - non OATT		Dardanelle 161 kV		Russellville South 161 kV	1	161				374/374	Replace wave trap, disconnect switches, current transformers, and breaker at Dardanelle
20044	705	10938	WFEC	12/31/11		M	06/19/09	$200,000			Balanced Portfolio		Anadarko (Gracemont) Tap 138 kV			1	138					Tap the existing WFEC Anadarko - Washita 138 kV line into the new Gracemont 345 kV substation.
19951	357	10467	WFEC	06/01/11		M	01/02/07	$2,000,000	WFEC	16 months	transmission service	520814	Anadarko 138 kV	520810	Anadarko 69 kV	2	138/69				224/224	'Install 2nd 112 MVA auto in parallel with existing Unit
20003	361	10471	WFEC	06/01/11		M	02/13/08	$2,000,000	WFEC	16 months	regional reliability	520911	Fletcher 69 kV	520990	Marlow Jct 69 kV	1	69	7			91/114	Upgrade 7 miles to 795 ACSR from Fletcher SW to Marlow Junction 69 kV.
	845	11114	WFEC		NTC	06/01/11		$225,000	SPP	12 months	regional reliability	521051	Snyder 69 kV	521070	Tipton 69 kV	1	69				53/65	Upgrade Snyder CTs from 400A to 600A.
20003	238	10303	WFEC	01/01/11		M	02/13/08	$8,265,000	WFEC	12 months	regional reliability	521188	Atoka West 138 kV	505600	Tupelo (WFEC) 138 kV	1	138		6.5		262/329	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Tupelo line.
20003	238	10304	WFEC	01/01/11		M	02/13/08		WFEC	12 months	regional reliability	521187	Atoka East 138 kV	520968	Lane (WFEC) 138 kV	1	138		6.5		262/329	WFEC will build a double circuit 138 kV line, approximately 6.5 miles long, from AEP's Atoka substation to the south and looping into the WFEC Tupelo-Lane 138 kV line - Atoka to Lane line.
20033	266	10349	WR	06/01/11		M	01/27/09	$710,000	WR	18 months	regional reliability	533421	Hutchinson Gas Turbine Station 115 kV	533413	Circle 115 kV	1	115	0.23			223/245	Rebuild 0.23 mile Circle - HEC GT 115 kV line.
20033	491	10636	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$2,085,000	WR	18 months	regional reliability	533234	Bismark 115 kV	533236	Farmer's Consumer Co-op 115 kV	1	115	2.9			181/181	Rebuild 2.9 mile Bismark - Farmer's Consumer Co-op 115 kV.
20006	369	10482	WR	06/01/11		M	02/13/08	$2,000,000	WR	18 months	regional reliability	533271	SW Lawrence 115 kV	533277	Wakarusa 115 kV	1	115	4.09			223/240	Rebuild SW Lawrence - Wakarusa 115 kV line.
20006	370	10483	WR	06/01/11		M	02/13/08	$760,000	WR	18 months	regional reliability	533236	Farmer's Consumer Co-op 115 kV	533277	Wakarusa 115 kV	1	115	1.53			223/240	Rebuild 1.53 miles Co-op-Wakarusa 115 kV line
	660	10866	WR		NTC	06/01/11		$3,324,375	SPP	18 months	regional reliability	533045	Gill W4 138 kV	533036	Clearwater 138 kV	1	138	7.88			534/586	Tear down and rebuild 7.88 mile Gill - Clearwater 138 kV.
20033	493	10638	WR	06/01/11		M	01/27/09	$8,050,000	WR	15 months	regional reliability	533244	Jarbalo 115 kV	533268	Stranger Creek 115	2	115	7.1			223/240	Rebuild Jarbalo - Stranger Ckt 2 7.1 miles of 115 kV and tap the existing Jarbalo - Northwest Leavenworth line into Stranger.
20033	493	10639	WR	06/01/11		M	01/27/09		WR	15 months	regional reliability	533268	Stranger Creek 115	533259	NW Leavenworth	1	115	6.5			223/240	Rebuild Stranger - Northwest Leavenworth 6.5 miles of 115 kV and tap existing Jarbalo - Northwest Leavenworth line into Stranger.
20033	618	10806	WR	12/01/11		M	01/27/09	$17,437,500	SPP	24 months	regional reliability	533333	KSU Campus 115 KV	533345	Wildcat 115 kV	1	115				223/223	Tap KSU - Wildcat 115 kV into Northwest Manhattan.
20033	618	10808	WR			M	01/27/09	$11,250,000	SPP	18 months	regional reliability	539658	Concordia 230 kV	532861	East Manhattan 230 kV	1	230				280/308	Tap the Concordia - East Manhattan 230 kV line and build new Northwest Manhattan 230/115 kV substation.
20059	30224	50239	WR	12/01/11		06/01/11	09/18/09	$3,811,500	WR	18 months	transmission service	533638	Lehigh Tap 69 kV	533651	Owl Creek 69 KV	1	69	8.47			72/72	Rebuild approximately 8.5 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.
20059	30224	50232	WR	04/01/11			09/18/09	$1,418,500	WR	18 months	transmission service	533623	Athens Switching Station 69 kV	533642	Owl Creek 69 KV	1	69	2.93			72/72	Rebuild approximately 3 miles of line with 954 kcmil ACSR to achieve a minimum 600 amp emergency rating.
20059	30230	50241	WR	06/01/11			09/18/09	$250,000	WR	6 months	transmission service	533021	Neosho 138 kV	533005	Northeast Parsons 138 kV	1	138				203/203	Replace bus and Jumpers at NE Parsons 138 kV substation
20059	30231	50242	WR	06/01/11			09/18/09	$9,360,000	WR		Zonal Reliability	532992	Timber Junction 138 kV	532984	Summer County Tap 138 KV	1	138	12				Tap Belle Plaine-Oxford 138 kV line, build a 3-breaker ring bus switching station, build approximately 12 miles 138 kV line from Sumner County 138 kV to Timber Junction 138 kV, and Install Timber Junction. 138-69 kV 100 MVA transformer with LTC.
20059	30224	50245	WR	01/01/11			09/18/09	$2,426,500	WR	18 months	transmission service	533631	Coffey County No. 4 Vernon 69 kV	533623	Athens Switching Station 69 kV	1	69	5.17			116/128	Rebuild approximately 5 miles of line with 954-KCM ACSR to achieve a minimum 1200 amp emergency rating.
20059	622	10810	WR	06/01/11			09/18/09	$2,815,000	WR	12 months	Zonal Reliability	533837	Roshe Hill Junction 69 kV	533550	Richland 69 kV	1	69	5.43			72/72	Rebuild approximately 5.5 mile Rose Hill Junction-Richland
20033	600	10767	WR	12/31/11		M	01/27/09	$3,227,500	WR	12 months	regional reliability	533188	27TH & Croco Junction 115 KV	533160	41ST & California 115 KV	1	115	3.43			223/240	Tear down and rebuild the 3.43 mile 27th & Croco - 41st & California 115 kV line as a single circuit.
20006	321	10417	WR	06/01/11		M	02/13/08	$1,292,500	WR	12 months	regional reliability	533824	Oaklawn 69 kV	533826	Oliver 69 kV	1	69	2.11			116/128	Tear down/rebuild 1.91-miles of Oaklawn - Oliver 69 kV line replacing 477 kcmil ACSR conductor with 954 kcmil ACSR conductor. Limit would be 0.2-mile 750 kcmil CU underground cable.
20033	267	10350	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$2,500,000	WR	12 months	regional reliability	533736	Halstead 69 kV	533744	Mud Creek Junction 69 kV	1	69	7.3			116/128	Tear down and rebuild 7.3-mile Halstead - Mud Creek 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.
20033	267	10351	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$360,000	WR	12 months	regional reliability	533744	Mud Creek Junction 69 kV	533741	Mid-American Junction 69 kV	1	69	1.0			116/128	Rebuild 1.0 mile Mud Creek Junction - Mid-American Junction 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil
20033	267	10352	WR	06/01/11	NTC-Modify Timing	06/01/11	01/27/09	$1,300,000	WR	12 months	regional reliability	533741	Mid-American Junction 69 kV	533745	Newton 69 kV	1	69	3.9			116/128	Rebuild 3.9 mile Mid-American Junction - Newton 69 kV line. Replace 336.4 kcmil ACSR conductor with 954 kcmil ACSR conductor and replace terminal equipment at substations.
		Year 2012																				
20015	30143	50151	AECC	04/01/12			01/16/09	$165,000	AECC		transmission service	507456	Turk 115	504122	McNab REC 115 kV	1	115					Upgrades to McNab Substation
20015	351	10460	AECC	04/01/12		M	01/16/09	$1,512,000			transmission service	503912	Fulton 115 kV	507453	Hope 115 kV	1	115	3.61			245/301	Reconductor line to 1590 ACSR the Hope-Fulton line. Build at 138 and operate at 115 kV
20015	351	10461	AECC	04/01/12		M	01/16/09	$440,000			transmission service	503912	Fulton 115 kV				115					Upgrade Fulton Switching Station
20016	30157	50165	AEP	04/01/12		M	01/16/09	$8,193,000	AEP	24 months	transmission service	508086	Texarkana Plant 69 kV	504117	South Texarkana REC 69 kV	1	69	5.92			90/121	Rebuild 5.92 miles of 266 ACSR with 795 ACSR. Replace 69 kV switches, jumpers, and reset CTs and relays at Texarkana
20016	30156	50164	AEP	04/01/12		M	01/16/09	$128,000	AEP		transmission service	508077	SE Texarkana 69 kV	508086	Texarkana Plant 69 kV	1	69				114/143	Change out the 500 Cu jumpers at Texarkana Plant.
20016	30155	50163	AEP	04/01/12		M	01/16/09	$80,000	AEP		transmission service	507427	Okay 69 kV	507415	Tollette 69 kV	1	69				71/96	Replace 69 kV switches.
20048	30148	50156	AEP	06/01/12		M	09/18/09	$273,400	AEP	24 months	transmission service	508053	Bann 69 kV	508063	Lone Star Ordinance Tap 69 kV	1	69				73/85	Replace 69 kV switch at Lone Star Ordinance Tap with a minimum 800 amp emergency rating
20016	30152	50160	AEP	06/01/12		M	01/16/09	$456,000	AEP	15 months	transmission service	507748	Powell Street 138 kV	507738	Linwood 138 kV	1	138				260/304	Replace 138 kV breaker, switches, and jumpers at Linwood. Replace circuit switcher at Powell Street.
20016	30142	50148	AEP	04/01/12		M	01/16/09	$48,580,000	AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345		33		1336/1915	Build approximately 33 miles of of 2-954 ACSR from Turk to NW Texarkana.
20016	30142	50149	AEP	04/01/12		M	01/16/09		AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345				1336/1915	Add 345 kV terminal at NW Texarkana
20016	30142	50150	AEP	04/01/12		M	01/16/09		AEP	33 months	transmission service	507455	Turk 345 kV	508072	NW Texarkana 345 kV	1	345				1336/1915	Add 345 kV terminal at Turk (Hempstead)
20016-1	349	10456	AEP	04/01/12		M	09/18/09	$7,310,000	AEP	60 months	transmission service	507454	Turk 138 kV	507455	Turk 345 kV	1	345/138				675/675	Add Turk 345/138 kV transformer
20016	288	10374	AEP	04/01/12		M	01/16/09	$3,840,000	AEP	24 months	transmission service	520929	Hugo Power Plant 345 kV	510911	Valliant 345 kV	1	345				913/1140	Install 345 kV terminal equipment at Valliant Substation
	875	11155	AEP		NTC	04/01/12		$100,000	AEP	12 months	regional reliability	508080	Sugar Hill 138 kV	508079	Sugar Hill 69 kV	1	138/69				138/180	Replace 69 kV switch 11985 and 1033 AAC jumpers at Sugar Hill.
20027	392	10510	AEP	06/01/12		M	01/27/09	$3,986,000	AEP	18 months	regional reliability	508545	Howell 69 kV	508546	Kilgore 69 kV	1	69	3.49			52/69	Rebuild 3.49 miles of Howell - Kilgore 69 kV 4/0 ACSR with 795 ACSR.
20000	387	10505	AEP	06/01/12		M	02/13/08	$125,000	AEP	15 months	regional reliability	509783	Riverside Station 138 kV	510898	Okmulgee 138 kV	1	138				202/235	Replace wave trap at Okmulgee.
20000	388	10506	AEP	06/01/12		M	02/13/08	$100,000	AEP	15 months	regional reliability	508068	North New Boston 69KV	508067	New Boston 69 kV	1	69				71/96	Replace 2 sets of New Boston switches on terminal to North New Boston.
20000	391	10509	AEP	06/01/12		M	02/13/08	$300,000	AEP	15 months	regional reliability	508297	Lone Star South 138 kV	508313	Pittsburg 138 kV	1	138				280/331	Replace 138 kV wavetraps at both ends. Reset CTs at Lone Star South. Replace138 kV switches & reset relays at Pittsburg.
20000	113	10140	AEP	06/01/12		M	02/13/08	$9,480,000	AEP	24 months	regional reliability	507736	Haughton 138 kV	507751	Red Point 138 kV	1	138			3.2	368/512	Convert Red Point-Haughton to 138 kV, 1590 ACSR (includes Red Point terminal & Haughton station conversion).
20000	113	10141	AEP	06/01/12		M	02/13/08	$19,482,000	AEP	24 months	regional reliability	507741	Mcdade 138 kV	507736	Haughton 138 kV	1	138			11.3	368/512	Convert Haughton-McDade to 138 kV, 1590 ACSR (includes McDade station conversion).
20000	113	10786	AEP	06/01/12		M	02/13/08	$11,988,400	AEP	24 months	regional reliability	507741	Mcdade 138 kV	507791	Caplis 138 kV	1	138		10		368/512	Build new Caplis-McDade 138 kV, 1590 ACSR line
	636	10834	DETEC	06/01/12				$7,617,000			zonal - sponsored		Chireno 138 kV		Martinsville 138 kV	1	138		9.5		215/225	Install new 138 kV line from Chireno to Martinsville
20036	638	10839	EDE	06/01/12	NTC-Modify Timing	06/01/10	01/27/09	$3,520,000	EDE	18 months	regional reliability	547542	SUB 170 - Nichols ST. 69 kV	547529	Sedalia 69 kV	1	69	8.92			54/65	Reconductor 8.92 mile Nichols - Sedalia 69 kV with 556 ACSR and upgrade CTs.
20036	420	10546	EDE	06/01/12		M	01/27/09	$50,000	EDE	6 months	regional reliability	300673	Jamesville 69 kV	547604	SUB 415 - Blackhawk Junction 69 kV	1	69				73/89	Replace jumpers on breaker #6950 at Blackhawk Junction with 556 ACSR for rates 73/89 MVA.
20040	698	10927	GRDA	12/31/12		M	06/19/09	$1,806,000			Balanced Portfolio	514803	Sooner 345 kV	512694	Cleveland 345 kV	1	345				1195/1195	Install terminal equipment at Cleveland Substation
20021	299	10385	GRDA	06/01/12		M	01/16/09	$4,212,500	GRDA	24 months	regional reliability	512714	Kansas Tap 161 kV	512642	W Siloam Springs 161 kV	1	161	8.8			347/403	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 8.8 mi.
20021	299	10386	GRDA	06/01/12		M	01/16/09	$1,700,000	GRDA	24 months	regional reliability	512642	W Siloam Springs 161 kV	512643	Siloam City 161 kV	1	161	4.2			347/403	Reconductor line to 1590 ACSR, A = 347, B = 403. $255K/mile @ 4.2 mi.
	718	10955	GRIS	12/01/12		M		$3,937,500	SPP		regional reliability - non OATT	642073	SUB-F 7 115 kV	640353	ST.LIB 7 115 kV	1	115		7		160/160	Adding 115 kV line from Sub F - Libory. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT
	719	10956	GRIS	04/01/12		M		$200,000	SPP		regional reliability - non OATT	642066	SUB H 115 kV	642072	SUB E 115 kV	1	115				179/179	Upgrade line to 179 MVA. City of Grand Island Owned Transmission Facility that is NOT under SPP OATT.
20018	313	10405	ITCGP	04/01/12		M	01/16/09	$18,000,000	WFEC	24 months	transmission service	521157	Hugo Power Plant 345	510911	Valliant 345 kV	1	345		19		913/1140	Install new line from Valliant 345 kV to Hugo Power Plant with 19 miles of bundled 795 ACSR conductor
20018	314	10406	ITCGP	04/01/12		M	01/16/09	$12,000,000	WFEC	24 months	transmission service	521157	Hugo Power Plant 345 kV	521158	HugoPower Plant 138 kV	1	345/138				500/500	Install new 345/138 kV transformer
20042	702	10934	KCPL	06/01/12		M	06/19/09	$2,000,000			Balanced Portfolio	542965	West Gardner 345 kV									West Gardner 345kV bus cut-in to Swissvale-Stillwell 345 kV line
	377	10490	KCPL	06/01/12		M		$2,622,850	KCPL	18 months	zonal - sponsored	543069	Paola 161 kV	543129	Middle Creek 161 kV	1	161		15		293/335	New Middle Creek sub and Paola-Middle Creek 161kV line
	378	10491	KCPL	06/01/12		M		$12,179,000	KCPL	24 months	zonal - sponsored	543058	North Louisburg 161 kV	543129	Middle Creek 161 kV	1	161		12		293/335	New North Louisburg-Middle Creek 161kV line
	414	10540	KCPL			M		$3,756,500	KCPL	24 months	zonal - sponsored	543054	Cedar Niles	543131	Clare 161 kV	1	161		4.5		293/335	New Cedar Niles-Clare 161 kV Line & Clare substation
20009	417	10543	KCPL	06/01/12		M	02/13/08	$13,000	KCPL	6 months	regional reliability	543015	Avondale 161 kV	543016	Gladstone 161 kV	1	161				293/335	Upgrade wavetrap at Gladstone from 800 A to 1200 A
	823	11086	LEA			06/01/12		$1,000,000	SPP	24 months	regional reliability - non OATT	527362	LE_ERF 115 kV	527361	LE_ERF 69 kV	1	115/69				44/44	New substation and transformer 115/69 kV 44 MVA
	823	11087	LEA			06/01/12		$1,000,000	SPP		regional reliability - non OATT	527361	LE_ERF 69 kV	528768	Lea- Ancell 69 kV	1	69				41/54	New Line 69 kV
	823	11088	LEA			06/01/12		$1,000,000	SPP		regional reliability - non OATT	527361	LE_ERF 69 kV	528776	Lea- Gaines 69 kV	1	69				41/54	New Line 69 kV
20046	707	10941	MIDW	06/01/12		M	06/19/09	$3,000,000			Balanced Portfolio	530583	Wolf 345 kV	530584	Wolf 230	1	345/230				373/373	Install new 345/230 kV transformer at Wolf
	717	10954	NPPD	11/01/12		M		$5,625,000	NPPD	48 months	zonal - sponsored	640436	Clarks 115 kV	640434	CEN.C.N7 115 kV	1	115		10		174/174	Tap CENCITY7 - Silver Creek 115 kV at CLARKS7. Build new 115 kV line from CLARKS7 - CEN.C.N7. Radial 115 kV line for TransCanada Keystone XL project.
	732	10969	NPPD	11/01/12		M		$16,031,250	NPPD	48 months	zonal - sponsored	640305	Oneill 115 kV	640441	Stuarts 115 kV	1	115		28.5		174/174	Build new line from Oneill to new STUARTS7. Radial 115 kV line for TransCanada Keystone XL project.
	738	10975	NPPD	11/01/12		M		$19,687,500	NPPD	48 months	zonal - sponsored	640318	Petersburg 115 kV	640437	Ericson 115 kV	1	115		35		174/174	Build new line from Petersburg to new ERICSON7. Radial 115 kV line for TransCanada Keystone XL project.
	749	10986	NPPD	06/01/12	NTC	06/01/12		$2,000,000	NPPD	24 months	regional reliability	640265	Maloney 115 kV	640287	North Platte 115 kV	1	115				155/155	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 155 MVA 4-hour emergency rating.
	818	11080	NPPD	06/01/12	NTC	06/01/12		$1,000,000	NPPD	24 months	regional reliability	640259	Loup City 115 kV	640284	North Loup 115 kV	1	115				137/137	Uprate conductor and terminal equipment to 100 Deg Rating by 2012. 137 MVA 4-hour emergency rating.
	629	11151	NPPD	06/01/12	NTC	M			NPPD	48 months	regional reliability	640387	Twin Church 115 kV	640424	South Sioux City 115 kV	1	115		5.5		266/266	Build new 5.5 mile double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	629	11206	NPPD	12/31/08		M		$33,000,000	NPPD		zonal - sponsored	640387	Twin Church 115 kV	640080	Belden 115 kV	1	115				99/99	Rate B was increased from 88 MVA to 99 MVA by replacing substation terminal equipment.
	629	11152	NPPD	06/01/12	NTC	M			NPPD	48 months	regional reliability	640387	Twin Church 115 kV	640424	South Sioux City 115 kV	2	115		5.5		266/266	Build new 5.5 miles double circuit line from Twin CH- new South Sioux City sub. Includes rebuild of Twin Church sub and new South Sioux City sub.
20029	583	10749	OGE	03/31/12		M	01/27/09	$4,972,000	OGE	12 months	regional reliability	515339	VBI 161 kV	515406	Adabell 161 kV	1	161				223/223	Install new tap for Adabell substation.
20029	583	10749	OGE	03/31/12		M	01/27/09	$4,972,000	OGE	12 months	regional reliability	515348	Aloca Tap 161 kV	515406	Adabell 161 kV	1	161				223/223	Install new tap for Adabell substation.
20055	523	10668	OGE	06/01/12		M	09/18/09	$45,000,000	OGE	42 months	regional reliability	514803	Sooner 345 kV	532794	Rose Hill 345 kV	1	345		53		956/1052	New 345 kV line from Sooner to Oklahoma/Kansas Stateline or the interface with the Westar Energy line segment to achieve
20041	699	10929	OGE	12/31/12		M	06/19/09	$47,200,000		32 months	Balanced Portfolio	514803	Sooner 345 kV	512694	Cleveland 345 kV	1	345		36		1195/1195	Build new 345 kV line from Sooner to Cleveland. Install terminal equipment at Sooner
20017	30161	50169	OGE	04/01/12		M	01/16/09	$200,000,000	OGE	42 months	transmission service	521157	Hugo 345 kV	515136	Sunnyside 345 kV	1	345		120		1195/1195	Add 345 kV line from Sunnyside to WFEC interception of 345 kV line from Hugo, Install 345 kV breaker, switches, and relays at Sunnyside.
20017	30163	50171	OGE	04/01/12		M	01/16/09	$10,000,000	OGE	24 months	transmission service	515136	Sunnyside 345 kV	515135	Sunnyside138 kV	2	345/138				240/240	Add 2nd 345/138 kV Auto Transformer
	551	10837	OGE	06/01/12	NTC	06/01/12		$3,200,000	OGE	24 months	regional reliability	515315	Oak Park 161 kV	515293	Johnson 161 kV	1	161		2		313/335	Install 2 miles of 161 kV from Johnson to Oak Park and install terminal equipment at Oak Park.
	551	10701	OGE	06/01/12	NTC	06/01/12		$5,500,000	OGE	24 months	regional reliability	515293	Johnson 161 kV	515343	Massard 161 kV	1	161			5.6	313/335	Convert 5.6 miles of 69 kV to 161 kV
	759	11002	OPPD	11/10/12		11/10/12		$565,000	OPPD		zonal - sponsored	646221	SUB 1221 161 kV	646255	S1255 161 kV	1	161				352/352	Replace terminal equipment so that the overall facility rating is 352 MVA.
20045	706	10939	SEPC	06/01/12		M	06/19/09	$54,000,000	ITC GP		Balanced Portfolio	531469	Spearville 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Spearville to interception point of Spearville to Knoll line.
	835	11102	SPS	11/17/12		06/01/14		$16,245,000	SPP	18 months	regional reliability	524772	EST Clovis 69 kV	524835	E Clovis 115 kV	1	115					Move load from 69 to 115 kV bus
	835	11103	SPS	12/17/12		06/01/14		$2,257,031	SPP	1 months	regional reliability	524838	FE-Clovis 115 kV	524831	FE-Holland 115 kV	1	115	5.35				Reconductor 5.35 mile FE-Clovis to Curry CKT 1 with 397.5 ACSR.
	797	11056	SPS	03/21/12	NTC	06/01/10		$11,250,000	SPP	3 months	regional reliability	522896	Caprock REC-Vealmoor 138 kV	526830	Borden County Interchange 230 kV	2	230/138				168/168	Add second 230/138kV transformer at Borden County by moving old from Midland when retired.
	791	11045	SPS	12/16/12	NTC	06/01/10		$8,438	SPP	36 months	regional reliability	525414	Lamton Interchange 115 kV	525124	Hart Industrial 115 kV	1	115		15		157/173	New 15 mile Lampton Interchange - Hart Industrial Substation 115 kV line.
	791	11041	SPS	12/16/12	NTC	06/01/10		$16,031,250	SPP	36 months	regional reliability	525461	Newhart 230 kV	525213	Swisher County Interchange 230 kV	1	230		19		492/541	New 19 mile Swisher County Interchange - Newhart 230 kV line.
	791	11042	SPS	12/16/12	NTC	06/01/10		$10,125,000	SPP	36 months	regional reliability	525192	Kress Interchange 115 kV	525460	Newhart 115 kV	1	115		18		157/173	New 18 mile Kress - Newhart 115 kV line.
	791	11043	SPS	12/16/12	NTC	06/01/10		$13,500,000	SPP	36 months	regional reliability	524746	Castro County Interchange 115 kV	525460	Newhart 115 kV	1	115		24		157/173	New 24 mile Castro County Interchange - Newhart 115 kV line.
	824	11089	SPS	01/21/12	NTC	06/01/10		$4,725,000	SPP	1 months	regional reliability	527895	Hobbs 345 kV	527915	Midland 345 kV	1	345			89.22	1475/1623	Convert existing 89.22 mile Hobbs - Midland 230 kV line to operate at 345 kV.
	774	11021	SPS	08/18/12	NTC	06/01/10		$5,062,500	SPP	30 months	regional reliability	524135	Hastings 115 kV	524135	Hastings 115 kV		115					Convert Hastings Sub from 69kV to 115 kV
	774	11022	SPS	09/01/12	NTC	06/01/10		$2,200,000	SPP	18 months	regional reliability	524135	Hastings 115 kV	524124	Bush Sub 115 kV	1	115		5		157/173	New 5 mile Hastings - Bush 115 kV line.
	789	11038	SPS	05/26/12	NTC	06/01/12		$114,000	SPP	12 months	regional reliability	527564	Roswell Interchange 115 kV	527534	Brasher Tap	1	115	0.27			146/161	Reconductor .27 mile Roswell interchange - Brasher Tap 115 kV with 397 kcmil conductor.
	704	11085	SPS		NTC-Modify Timing	06/01/12	06/19/09	$11,250,000	SPP	24 months	Balanced Portfolio	525832	Tuco Interchange 345 kV	525830	Tuco Interchange 230 kV	2	345/230/13.2				515/560	Add second 345/230/13.2 kV Tuco Interchange 515/560 MVA transformer.
	795	11052	SPS	05/21/12	NTC	06/01/11		$11,250,000	SPP	24 months	regional reliability	524897	Frio-Draw 230kV	524898	Frio-Draw 115 kV	1	230/115				252/252	New 230/115kV transformer at Frio-Draw substation.
	795	11053	SPS	05/21/12	NTC	06/01/11		$13,500,000	SPP	24 months	regional reliability	524897	Frio-Draw 230kV	524875	Oasis Interchange 230 kV	1	230		16		492/546	Build new 16 mile Frio-Draw - Oasis 230kV line.
	795	11054	SPS	11/17/12	NTC	06/01/11		$21,937,500	SPP	30 months	regional reliability	524897	Frio-Draw 230kV	524909	Roosevelt County Interchange 230 kV	1	230		26		492/546	Build new 26 mile Frio-Draw - Roosevelt County 230kV line.
	887	11176	SPS	12/16/12	NTC	6/1/2010		$7,762,500	SPP	36 months	regional reliability	524516	Canyon West 115 kV	524544	Spring Draw 115 kV	1	115		9		157/173	Build new 9 mile Canyon West - Spring Draw 115 kV line.
	888	11177	SPS	12/16/12	NTC	6/1/2010		$27,450,000	SPP	36 months	regional reliability		Randall Co 230 kV	524415	Amarillo South 230 kV	1	230		20		492/541	Build new 20 mile Randall Co - Amarillo South 230 kV line.
	102	10835	SWPA			06/01/18		$1,575,000	SPP		regional reliability - non OATT	505496	Nixa 161 kV	505501	Nixa 69 kV	2	161/69				70/70	Upgrade Nixa #2 transformer to 70 MVA
20018	30165	50173	WFEC	04/01/12		M	01/16/09	$2,000,000	WFEC	36 months	transmission service	521157	Hugo 345 kV	515136	Sunnyside 345 kV	1	345				1195/1195	Install 345 kV breaker at Hugo
20003	402	10522	WFEC	06/01/12		M	02/13/08	$1,125,000	SPP	12 months	regional reliability	521194	Grandfield 138 kV	520954	Indiahoma 138 kV	1	138			3	183/228	Convert 3 miles of 69 kV to 138 kV from Indiahoma to Grandfield.
20003	402	10523	WFEC	06/01/12		M	02/13/08	$7,306,000	SPP	24 months	regional reliability	520954	Indiahoma 138 kV	521193	Cache SW 138 kV	1	138		13.7		183/228	Tap Cache to Paradise 138 kV and install 13.7 miles of 138 kV from Cache to Indiahoma.
20003	402	10524	WFEC	06/01/12		M	02/13/08	$5,000,000	SPP	24 months	regional reliability	521194	Grandfield 138 kV	520926	Grandfield 69 kV	1	138/69				70/70	Install new 138/69 kV transformer at Grandfield
20003	399	10519	WFEC	06/01/12		M	02/13/08	$1,347,000	SPP	12 months	regional reliability	520979	Lindsay 69 kV	521087	Wallville 69 kV	1	69	4.85			53/65	Upgrade line from 1/0 to 336.4, 4.85 miles
20003	400	10520	WFEC	06/01/12		M	02/13/08	$225,000	SPP	6 months	regional reliability	505592	Pharoah 138 kV	521026	Weleetka 138 kV	1	138				223/228	WFEC will upgrade 800 A CTs, new CT limit will be 1200 A at Pharaoh.
20003	401	10521	WFEC	06/01/12		M	02/13/08	$50,000	WFEC	6 months	regional reliability	521043	WFEC Russell 138 kV	511448	AEP Altus Jct Tap 138 kV	1	138				143/143	Replace CT at WFEC Russell
	672	10878	WFEC		NTC	06/01/12		$1,950,000	WFEC	18 months	regional reliability	520892	El Reno 69 kV	520899	El Reno SW 69 kV	1	69	6.5			36/36	Reconductor 6.5 miles of 1/0 conductor with 336.4 ACSR.
20033	463	10602	WR	06/01/12		M	01/27/09	$4,100,000	WR	12 months	regional reliability	532862	East Manhattan 230kV	532861	McDowell 230kV	1	230			15.65	358/358	The East Manhattan-McDowell 115 kV is built as a 230 kV line but is operated at 115 kV. Substation work will have to be performed in order to convert this line to 230 kV operation..
	754	10995	WR	06/01/12		M		$5,625,000	SPP		zonal - sponsored	533036	Clearwater 138 kV	533073	Goddard 138 kV	1	138		10		534/586	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation
	754	10996	WR	06/01/12		M		$5,625,000	SPP		zonal - sponsored	533041	Evans Energy Center South 138 kV	533073	Goddard 138 kV	1	138		10		534/586	Build a new 138kV line from Clearwater and a new 138kV line from Evans to serve the new Goddard substation
20059	30224	50228	WR	06/01/12			09/18/09	$2,560,500	WR	12 months	transmission service	533621	Allen 69 kV	533638	Lehigh Tap 69 kV	1	69	5.69			72/72	Rebuild approximately 6 miles of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating
20006	172	10221	WR	06/01/12		M	02/13/08	$2,100,000	WR	6 months	regional reliability	533180	Tecumseh Energy Center 115 kV	533252	Midland 115 kV	1	115			19.33	117/117	Convert TEC-Midland from 161 kV to 115 kV
19964	375	10488	WR	06/01/12		M	06/27/07	$8,100,000	WR	24 months	transmission service	532794	Rose Hill 345 kV	533062	Rose Hill 138 kV	3	345/138				400/440	Install 3rd Rose Hill 345/138 kV TRANSFORMER.
20063	664	10870	WR	06/01/12		06/01/13	11/02/09	$1,000,000	SPP	12 months	regional reliability	533045	Gill Energy Center West 138 kV	533072	Waco 138 kV	1	138	1.8			534/586	Tear down and rebuild 1.8 mile Gill Energy Center West - Waco 138 kV with bundled 1192.5 ACSR conductor.
			Year 2013																			
20027	443	10575	AEP	06/01/13		M	01/27/09	$2,000,000	AEP	24 months	regional reliability	506979	Osbourne 161 kV	506980	Osbourne Tap 161 kV	1	161		1.5		428/636	Tap the South Springdale-East Fayetteville 161 kV line and build 1.5 miles of 161 kV to new Osbourne station.
	546	10695	AEP		NTC	06/01/13		$26,150,000	AEP	36 months	regional reliability	511463	Hobart Junction 138 kV	511445	Carnegie 138 kV	1	138	26.15			287/287	Rebuild the 26.2 mi Carnegie - Hobart Jct. 138 kV line from 397 ACSR to 1272 ACSR. Replace 3 switches, wave traps and jumpers. Reset CTs and relays.
	546	10696 & 10697	AEP		NTC	06/01/13		$11,030,000	AEP	36 months	regional reliability	511445	Carnegie 138 kV	511477	Southwest Station 138 kV	1	138	14.37			220/235	Reconductor the 14.37 mile Southwest Station - Carnegie 138 kV line from 795 ACSR to 1272 ACSR. Replace wave traps and jumpers.
20064	770	11015	AEP	06/01/13			11/02/09	$2,500,000	AEP	18 months	regional reliability	504124	Ashdown 138 kV	510890	Craig Junction 138 kV	1	138	2.45			265/287	Rebuild 2.45 miles of 795 ACSR with 1590 ACSR and reset relays.
20057	539	10687	CUS	06/01/13		06/01/19	09/18/09	$120,000	CUS	12 months	transmission service	549969	Brookline 161 kV	549955	Junction 161 kV	1	161				340/358	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches
20034	646	10847	GMO	06/01/13		M	01/27/09	$2,000,000	SPP	12-18 months	regional reliability	541303	Clinton 69 kV	541352	Clinton 161 kV	1	69/161				100/125	Replace Clinton 161/69 kV transformer #1 with new 100/125 MVA to match transformer #2.
	333	10430	GMO	06/01/13		M		$302,795	GMO	12~18 months	zonal - sponsored	541346	Ritchfield 161	541202	Sibley 161	1	161				223/245	161kV Tap of Hallmark to Sibley
	335	10432	GMO	06/01/13		M		$0	GMO	12~18 months	zonal - sponsored	541215	Hallmark 161	541346	Ritchfield 161	1	161				223/245	161kV Tap of Hallmark to Sibley
	414	10541	KCPL	06/01/13		M		$1,385,000	KCPL	18 months	zonal - sponsored	543037	Quarry 161 kV	#N/A	Clare 161 kV	1	161		4.5		293/335	New Quarry-Clare 161 kV Line
	418	10544	KCPL	06/01/13		M		$1,632,300	KCPL	18 months	zonal - sponsored	543030	Waldron 161 kV	546656	Maywood 161 kV	1	161				293/335	New Waldron sub cut-in
	418	10545	KCPL	06/01/13		M			KCPL		zonal - sponsored	543030	Waldron 161 kV	543017	Weatherby 161 kV	1	161				293/335	New Waldron sub cut-in
	715	10952	KCPL		NTC	06/01/13		$200,000	KCPL	24 months	regional reliability	543081	Glenare 69 kV	541262	Liberty 69 kV	1	69				70/79	Reconductor GMO portion of Glenare - Liberty 69 kV for 70/79 MVA rating.
	711	10948	LES	05/31/13		M		$11,250,000	SPP		zonal - sponsored	650214	NW68 & HOLDRIDGE 115 kV	650114	Nw68 & Holdridge 345 Kv	1	345/115/13.8				336/420	Add NW68th Holdrege 345/115kV Transformer #2. Driven by NERC Category C (TPL-003) - prior outage of one 345/115kV transformer, followed by an outage of a second 345/115kV transformer.
20046	707	10940	MIDW	06/01/13		M	06/19/09	$42,000,000			Balanced Portfolio	531469	SPEARVILLE 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Knoll to interception point of Spearville to Knoll line.
20046	707	10943	MIDW	06/01/13		M	06/19/09	$66,000,000			Balanced Portfolio	640065	Axtell 345 kV	530583	Wolf 345 kV	1	345		80		1792/1792	Build new 345 kV line from Knoll to interception point of Axtell to Knoll line.
20032	697	10914	MIDW			06/01/13	01/27/09	$6,250,000	MIDW	9 months	regional reliability	533419	Hutchinson Energy Center 115 KV	530618	Huntsville 115 kV	1	115	21.1			164/194	Rebuild 21.1 mile HEC - Huntsville 115 kV line and replace CT, wave trap and relays.
	653	10858	MKEC		NTC	06/01/13		$9,239,000	SPP	24 months	regional reliability	539696	St. John 115 kV	539687	Pratt 115 kV	1	115	21.9			165/198	Rebuild 21.9 mile St. John - Pratt 115 kV line with 795 ACSR conductor.
20047	708	10942	NPPD	06/01/13		M	06/19/09	$76,000,000	NPPD	48 months	Balanced Portfolio	640065	Axtell 345 kV	530583	Wolf 345 kV	1	345		45		1792/1792	Build new 345 kV line from Axtell to interception point of Axtell to Wolf line (Kansas Border). Includes substation expansion at Axtell and line reactor.
	817	11079	NPPD	06/01/13	NTC	06/01/13		$1,000,000	NPPD	24 months	regional reliability	640054	Albion 115 kV	640347	Spalding 115 kV	1	115				174/174	Uprate line and substation equipment to 100 Deg C Rating by 2013. 174 MVA Normal Continuous Rating. 174 MVA 4-Hour Emergency Rating.
20029	642	10843	OGE	06/01/13			01/27/09	$10,000	OGE	9 months	regional reliability	515335	Kilgore 69 kV	515336	VBI 69 kV	1	69				72/72	Remove wavetrap at VBI.
	235	10300	OGE	06/01/13	NTC	06/01/13		$2,500,000	OGE	24 months	regional reliability	515300	Fort Smith 161 kV	515345	Colony 161 kV	1	161	2.2			446/446	Reconductor 2.2 miles to 1590 kmcm ACSR and change terminal equipment at Ft. Smith and Colony substations to 2000A.
20041	700	10930	OGE	12/31/13		M	06/19/09	$131,000,000		40 months	Balanced Portfolio	515045	Seminole 345 kV	515224	Muskogee 345 kV	1	345		100		1200/1200	Build new 345 kV line from Seminole to Muskogee
20041	700	10931	OGE	12/31/13		M	06/19/09	$4,000,000		22 months	Balanced Portfolio	515044	Seminole 138 kV	515045	Seminole 345 kV	3	345/138				493/493	Install 3rd 345/138 kV transformer at Seminole
	862	11139	OPPD		NTC	06/01/13		$4,638,000	OPPD	24 months	regional reliability	647006	SUB 906 North 69 kV	647928	SUB 928 69 kV	1	69	2			111/0110	Rebuild 2 mile Sub 906 North - Sub 928 line. Change CT tap settings, and replace line jumpers for 110 MVA rating.
	864	11141	OPPD			06/01/13		$272,000	OPPD	12 months	regional reliability	647907	SUB 907 69 kV	647919	Sub 919 69 kV	1	69				76/76	Increase line clearances to allow the use of a higher conductor rating.
	791	11044	SPS	03/16/13	NTC	06/01/10		$2,250,000	SPP	15 months	regional reliability	525124	Hart Industrial 115 kV	525460	Newhart 115 kV	1	115		4		157/173	Build new 4 mile Hart Industrial Substation - Newhart Substation 115 kV line.
	774	11023	SPS	03/16/13	NTC	06/01/10		$1,700,000	SPP	4 months	regional reliability	524135	Hastings Sub 69 kV	524162	East Plant Interchange 115 kV	1	115		3.7		157/173	Build new 3.7 mile Hastings - East Plant 115kV line.
	793	11047	SPS		NTC	06/01/13		$2,320,300	SPP	18 months	regional reliability	527322	Gaines County Interchange 115 kV	527346	Legacy 115 kV	1	115	5.5			120/154	Reconductor 5.5 mile Gaines County Interchange - Legacy 115 kV line.
	795	11050	SPS	12/31/13	NTC	06/01/13		$146,250,000	SPP	48 months	regional reliability	524896	Frio-Draw 345kV	523961	Potter County Interchange 345 kV	1	345		130		1643/1793	Build new 130 mile 345 kV line from Potter to new Frio-Draw substation at Roosevelt.
	795	11051	SPS	12/31/13	NTC	06/01/13		$11,250,000	SPP	24 months	regional reliability	524896	Frio-Draw 345 kV	524897	Frio-Draw 230kV	1	345/230				560/560	Build new Frio-Draw substation with 345/230 kV transformer.
	794	11049	SPS	06/01/13	NTC	06/01/13		$900,000	SPP	24 months	regional reliability	523797	GRAVE 3 115 kv	523796	Grave 2 69 kV	2	115/69				40/40	Add a second Grave 115/69 kV transformer.
	834	11101	SPS	05/21/13	NTC	06/01/13		$3,487,500	SPP	18 months	regional reliability	524924	Portales Interchange 115 kV	524936	Zodiac 115 kV	1	115			3	157/173	Convert existing 3 mile Portales Interchange - Zodiac 69 kV line to operate at 115 kV.
	640	10841	SWPA			M		$50,000	SPP		regional reliability - non OATT	505404	Malden 69 kV	505402	New Madrid 69 kV	1	69				71/71	Resag conductor and replace some structures.
	769	11014	SWPA			06/01/13		$112,500	SPP	12 months	regional reliability - non OATT	505448	Norfolk 161 kV	338814	Southland 161 kV	1	161				223/223	Replace bus and CTs at Norfolk.
	846	11115	WFEC		NTC	06/01/13		$14,737,500	SPP	36 months	regional reliability	520814	Anadarko 138 kV	520828	Blanchard 138 kV	1	138			25.2	212/264	Rebuild 25.2 mile Anadarko - Blanchard 69 kV as 138 kV.
	846	11116	WFEC			06/01/13		$1,125,000	SPP	12 months	regional reliability	520828	Blanchard 138 kV	521104	OU Switchyard 138 kV	1	138			2	212/264	Rebuild 2 mile Blanchard - OU Switchyard 69 kV as 138 kV.
	467	10603	WR		NTC	06/01/13		$50,000	WR	18 months	regional reliability	533044	Gill Energy Center East 138 kV	533051	Interstate 138 kV	1	138				232/232	Replace wave traps on Gill - Interstate 138 kV line for a new rating of 232/256 MVA.
20033	643	10844	WR	06/01/13		M	01/27/09	$4,000,000	SPP	18 months	regional reliability	533008	TWIN VALLEY NO. 1 MOUND VALLEY 138 k	533021	Neosho 138 kV	1	138				191/210	Tap the Neosho - Twin Valley line into Altamont.
20063	645	10846	WR	06/01/13		M	11/02/09	$2,400,000	WR	18 months	regional reliability	533064	17TH Street 4 138 kV	5330840	17TH Street 2 69 kV	1	138/69				150/165	Add second transformer in 17th Street substation.
20033	533	10678	WR	06/01/13	NTC-Modify Timing	06/01/15	01/27/09	$12,622,500	WR	24 months	regional reliability	532851	Auburn 230 kV	533151	Auburn 115 kV	2	230/115				280/308	Install second Auburn Road 230/115 kV transformer.
	819	11082	WR		NTC	06/01/13		$3,127,500	SPP	18 months	regional reliability	533795	Gill Energy Center East 69 kV	533813	Macarthur 69 kV	1	69	5.56			107/116	Rebuild 5.56 mile Gill Energy Center East - MacArthur 60 kV line. Replace substation bus and jumpers at MacArthur 69 kV.
20059	30224	50233	WR	07/01/13			09/18/09	$3,340,000	WR	24 months	transmission service	533626	Burlington Junction 69 kV	533630	Coffey County No. 3 Westphalia 69 Kv	1	69	7.2			116/128	Rebuild approximately 7 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	30224	50234	WR	01/01/13			09/18/09	$1,945,000	WR	24 months	transmission service	533626	Burlington Junction 69 kV	533653	Wolf Creek 69 kV	1	69	4.1			116/128	Rebuild approximately 4 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
20059	30224	50240	WR	11/01/13			09/18/09	$593,775	WR	12 months	transmission service	533638	LEHIGH TAP 69 KV	533651	United No. 9 Conger 69 kV	1	69	0.91			72/72	Rebuild approximately 1 mile of line with 954-KCM ACSR to achieve a minimum 600 amp emergency rating.
20059	529	10674	WR	01/01/13		M	09/18/09	$84,669,696	WR	24 months	regional reliability	514803	Sooner 345 kV	532794	Rose Hill 345 kV	1	345		53		956/1052	New 345 kV line from Oklahoma/Kansas Stateline or the interface with the OG&E line segment to Rose Hill to achieve 3000 amp
			Year 2014																			
20000	450	10584	AEP	06/01/14		M	02/13/08	$13,104,000	AEP	48 months	regional reliability	507001	Shipe Road 345 kV	507002	Shipe Road 161 kV	1	345/161				675/743	Install 345/161 kV transformer at Shipe Road.
20000	450	10585	AEP	06/01/14		M	02/13/08	$34,085,000	AEP	60 months	regional reliability	506935	Flint Creek 345 kV	507001	Shipe Road 345 kV	1	345		18		1336/1915	Install 22 miles of new 345 kV, 2-954 ACSR line.
20000	450	10582	AEP	06/01/14		M	02/13/08	$11,962,000	AEP	60 months	regional reliability	507002	Shipe 161 kV	506929	East Centerton 161 kV	1	161		9		520/729	Install 2 miles of 161 kV from new Shipe Road Substation to East Centerton Substation.
20027	649	10853	AEP	06/01/14		M	01/27/09	$2,150,000	AEP	24 months	regional reliability	510399	Lone Star 115 kV	510423	Locust Grove 115 kV	1	115	2.15			120/129	Reconductor 2.15 mile section of 115 kV line with 795 ACSR.
	445	10577	AEP	06/01/14		06/01/15		$5,400,000	AEP	24 months	regional reliability	508335	Big Sandy 69 kV	508350	Perdue 69 kV	1	69	5.4			123/143	Rebuild 5.4 mile Big Sandy - Perdue 69 kV line from 477 ACSR to 1272 ACSR.
	873	11153	AEP			06/01/14		$250,000	AEP	12 months	regional reliability	508077	SE Texarkana 69 kV	508086	Texarkana 69 kV	1	69				114/155	Upgrade 600 A breaker and two switches at Texarkana Plant.
	880	11169	AEP			06/01/14		$200,000	AEP	12 months	regional reliability	509054	Beckville 69 kV	509082	Rock Hill 69 kV	1	69				90/105	Upgrade 2 sets of switches at Rock Hill and 1 set of switches at Beckville bus.
	648	10849	DETEC	06/01/14				$8,837,000			zonal - sponsored		Martinsville 138 kV		Shady Grove 138 kV	1	138			9.58	215/225	Covert from 59 kV to 138 kV
	648	10850	DETEC	06/01/14							zonal - sponsored		Shady Grove 138 kV		Central Heights 138 kV	1	138			8.82	215/225	Covert from 59 kV to 138 kV
	648	10851	DETEC	06/01/14							zonal - sponsored		Central Hieghts 138 kV		Fitze 138 kV	1	138			10.52	215/225	Covert from 59 kV to 138 kV
	648	10852	DETEC	06/01/14							zonal - sponsored		Fitze 138 kV		Tempson 138 kV	1	138			3.7	215/225	Covert from 59 kV to 138 kV
	812	11074	EDE			06/01/14		$100,000	SPP	12 months	regional reliability	547600	SUB 403 - Jasper West Tap 69 kV	547548	SUB 249 - Boston East 69 kV	1	69				33/39	Replace jumpers.
	811	11073	EDE			06/01/14		$50,000	SPP	12 months	regional reliability	547538	SUB 131 - Diamond Junction 69 kV	547582	SUB 362 - Sarcoxie Southwest 69 kV	1	69				32/44	Raise structures on Diamond Jct. - Sarcoxie Southwest 69 kV line to achieve a new rating B of 44 MVA.
	437	10567	EDE	06/01/14		06/01/15		$75,000	EDE	12 months	regional reliability	547541	Sub 167 - Riverton 69 kV	547555	SUB 278 - Galena Northeast 69 kV	1	69				76/91	Replace switch on transfer bus at Sub# 167 for Rate B = 91 MVA.
20036	202	10258	EDE			06/01/14	01/27/09	$400,000	EDE	12 months	regional reliability	547527	SUB 436 - Webb City Cardinal 69 kV	547534	SUB 110 - Oronogo Junction 69 kV	1	69	1			54/65	Reconductor 1.0 Mile of 4/0 ACSR with 336 ACSR for 65 MVA Rate E
	489	10633	MIDW			06/01/14		$5,250,000	MIDW	9 months	regional reliability	530618	Huntsville 115 kV	530624	St. John 115 kV	1	115	26.55			164/199	Rebuild 26.55 mile Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.
	816	11078	NPPD	06/01/14		06/01/14		$1,000,000	NPPD	24 months	regional reliability	640054	Albion 115 kV	640181	Genoa 115 kV	1	115				137/137	Uprate line and substation equipment to effect 100 Deg C Rating by 2014. 137 MVA Normal Continuous Rating. 137 MVA 4-Hour Emergency Rating.
	889	11143	OPPD			06/01/14		$251,000	OPPD	12 months	regional reliability	647921	Sub 921 69 kV	647942	Sub 942 69 kV	1	69				103/103	Increase line clearances to allow the use of a higher conductor rating. Change CT tap settings.
	860	11137	OPPD			06/01/14		$105,000	OPPD	12 months	regional reliability	647901	SUB 901 69 kV	647105	Junction 205 69 kV	1	69				85/85	increase line clearances to allow the use of a higher conductor rating.
	861	11138	OPPD			06/01/14		$251,000	OPPD	12 months	regional reliability	647910	SUB 910 69 kV	647105	Junction 205 69 kV	1	69				85/85	increase line clearances to allow the use of a higher conductor rating.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	865	11142	OPPD			06/01/14		$253,000	OPPD	12 months	regional reliability	647917	Sub 917 69 kV	647918	Sub 918 69 kV	1	69				70/70	Increase line clearances to allow the use of a higher conductor rating.
	897	11191	OGE	06/01/14		M					zonal - sponsored	514888	36 & Meridian 138 kV	514889	WRAirport 138 kV	1	138				233/267	New Distribution Sub - WR Airport
	897	11192	OGE	06/01/14		M					zonal - sponsored	514889	WRAirport 138 kV	514925	Pennsylvania 138 kV	1	138				233/267	New Distribution Sub - WR Airport
20041	701	10932	OGE	05/19/14		M	06/19/09	$105,000,000		40 months	Balanced Portfolio	525835	Stateline 345 kV	515375	Woodward EHV 345kv	1	345		125		1475/1623	Build new 345 kV line from Woodward EHV to Border
20041	701	10933	OGE	05/19/14		M	06/19/09	$15,000,000		24 months	Balanced Portfolio	515376	Woodward EHV 138 kV	515375	Woodward EHV 345 kV	2	345/138				448/493	Install 2nd 345/138 kV transformer at Woodward EHV
	796	11055	SPS			06/01/14		$11,250,000	SPP	24 months	regional reliability	526676	Grassland Interchange 115 kV	526677	Grassland Interchange 230 kV	2	230/115				100/115	Add second 230/115 kV transformer at Grassland Interchange.
20043	704	10936	SPS	05/19/14		M	06/19/09	$122,597,500			Balanced Portfolio	525832	Tuco Interchange 345 kV	525835	Stateline 345 kV	1	345		125		1792/1792	Build new 345 kV line from Tuco to Border
20043	704	10937	SPS	05/19/14		M	06/19/09	$14,880,000	SPP		Balanced Portfolio	525835	Stateline 345 kV				345					Build Border at interception point of Woodward to Tuco line.
	764	11007	SPS	06/01/14		06/01/14		$1,890,000	SPP	28 months	regional reliability	525154	Happy Interchange 115 kV	525153	Happy Interchange 69 kV	1	115/69				84/96	Upgrade both Happy County 115/69 kV transformers to 84 MVA.
	764	11009	SPS	06/01/14		06/01/14		$1,890,000	SPP	28 months	regional reliability	525154	Happy Interchange 115 kV	525153	Happy Interchange 69 kV	2	115/69				84/96	Upgrade both Happy County 115/69 kV transformers to 84 MVA.
	826	11093	SPS	06/01/14		06/01/14		$11,250,000	SPP	28 months	regional reliability	527482	Chaves 115 kV	527483	Chaves 230 kV	2	230/115				225/258.5	Replace existing 149/171 MVA Chaves 230/115 kV transformer with 225 MVA transformer.
	836	11104	SPS	06/01/14		06/01/14		$3,318,750	SPP	20 months	regional reliability	525017	Muleshoe 69 kV	524030	Muleshoe E 115 kV	1	115				120/120	Move load from Muleshoe 69 kV to Muleshoe 115 kV.
	839	11107	SPS	06/01/14	NTC	06/01/14		$14,737,500	SPP	36 months	regional reliability	525192	Kress Int 115 kV	525271	Plainview CTY 115 kV	1	115		22.2		157/173	Build new 22.2 mile Kress Interchange - Plainview County 115 kV.
	839	11108	SPS	06/01/14	NTC	06/01/14		$990,000	SPP	30 months	regional reliability	525270	Plainview Co 69 kV	525271	Plainview CTY 115 kV	1	115/69				44/50.6	Add new Plainview County 115/69 kV transformer with 44/50.6 MVA ratings.
	840	11109	SPS	06/01/15	NTC	06/01/14		$7,762,500	SPP	36 months	regional reliability	525326	Cox 115 kV	525271	Plainview CTY 115 kV	1	115		9.8		157/173	Build new 9.8 mile Cox - Plainview 115 kV line unit.
	852	11122	SPS	06/01/14		06/01/14		$225,000	SPP	12 months	regional reliability	526338	Jones 230 kV	526677	Grassland 230 kV	1	230				478/617	Replace wave trap with 1200 A minimum.
	883	11172	SPS	05/16/14	NTC	06/01/11		$30,395,000	SPP	36 months	regional reliability	526338	Jones 230 kV	526677	Grassland 230 kV	2	230		26.72		492/541	Build new second Jones - Grassland 230 kV line.
	900	11197	SPS			06/01/14		$315,000	SPP	24 months	regional reliability	524898	Frio Draw 115 kV	524838	Farmers Electric REC-Clovis 115 kV	1	115	0.56			246/271	Reconductor FRIO-DRAW 0.56 miles 115 kV to 795 ACSR line
	631	10819	SWPA			06/01/14		$10,095,750	SPP	18 months	regional reliability - non OATT	300056	Asherville 161 kV	505434	Idalia 161 kV	1	161	19.23			335/335	Reconductor line to 335/335 MVA.
	651	10856	SWPA			06/01/14		$5,625,000	SPP		regional reliability - non OATT		Carthage 161 kV		Carthage 69 kV	1 & 2	161/69				125/125	Replace both Carthage auto transformers with larger units.
	524	10669	WFEC			06/01/14		$900,000	SPP	18 months	regional reliability	520929	Gypsum 69 kV	521042	Russell 69 kV	1	69	3			53/65	Reconductor 3 mile Gypsum - Russell 69 kV line from 1/0 to 336.4 ACSR.
20063	563	10713	WR	06/01/13		M	11/02/09	$75,000	WR	12 months	regional reliability	533765	Litchfield 69 kV	533756	Aquarius 69 kV	1	69				80/80	Replace 69 kV disconnect switches at Aquarius with a minimum 600 amp emergency rating
20033	534	10679	WR	06/01/14	NTC-Modify Timing	06/01/11	01/27/09	$1,400,000	WR	24 months	regional reliability	533012	Halstead South 138 kV	533736	Halstead 69 kV	1	138/69				100/110	Replace Halstead 138/69/13.2 kV transformer with 100/110 MVA unit.
	469	10605	WR			M		$20,000	WR	18 months	zonal - sponsored	533733	Gatz 69 kV	533745	Newton 69 kV	1	69				116/128	Reset CTs on Moundridge - Newton 69 kV line (multiple rating changes).
	755	10997	WR			06/01/14		$3,712,500	SPP	18 months	regional reliability	533153	County Line 115 kV	533162	Goodyear Junction 115 kV	1	115	6.6			446/490	Tear down and rebuild 6.6 mile County Line - Goodyear Junction 115 kV line.
20059	30224	50236	WR	04/01/14			09/18/09	$4,249,000	WR	24 months	transmission service	533636	Green 69 kV	533630	Coffye County No. 3 Westphalia 69 kV	1	69	9.22			116/128	Rebuild approximately 9 miles of line with 954 kcmil ACSR to achieve a minimum 1200 amp emergency rating.
		Year 2015																				
	876	11156	AEP			06/01/15		$1,000,000	AEP	18 months	regional reliability	511481	Weatherford 69 kV	511517	Thomas Tap 69 kV	1	69	0.9			72/72	Rebuild 0.9 mile Weatherford - Thomas Tap 69 kV line from 4/0 ACSR with 795 ACSR. Replace Weatherford wavetrap.
20036	537	10685	EDE	06/01/15	NTC-Modify Timing	06/01/19	01/27/09	$7,369,319	EDE	48 months	regional reliability	547480	SUB 383 - Monett 161kV	547510	South Monett 161 kV	1	161		9.2		218/268	Build new 9.2 mile Substation 383 - Monett 5 161 kV line.
20036	537	10686	EDE	06/01/15	NTC-Modify Timing	06/01/19	01/27/09	$8,000,000	EDE	36 months	regional reliability	547510	South Monett 161 kV	547401	SUB 376 - Monett City South 69 kV	1	161/69				100/100	Install 3-winding transformer connecting new 161 kV bus to Monett City South 69 kV.
	536	10681	EDE	06/01/15		06/01/18		$275,000	EDE	12 months	regional reliability	547400	Monett City South Jct. 69 kV	547402	Monett City East 69 kV	1	69	1.2			54/65	Reconductor 1.2 mi with 336 ACSR.
20042	703	10935	KCPL	06/01/15		M	06/19/09	$54,444,000			Balanced Portfolio	542982	Iatan 345 kV	542980	Nashua 345 kV	1	345		30		2546/2546	Tap Nashua 345kV bus in Hawthorn - St. Joseph 345 kV line. Build new 345 kV line from Iatan to Nashua.
20042	703	10945	KCPL	06/01/15		M	06/19/09	$4,620,000			Balanced Portfolio	542980	Nashua 345 kV	543028	Nashua 161 kV	1	345/161				400/440	Install new 345/161 kV transformer at Nashua
	757	11000	OGE			06/01/15		$4,200,000	OGE	24 months	regional reliability	515785	Windfarm 138 kV	514785	Woodward District 138 kV	1	138	12.08			404/465	Reconductor 12.08 mile FPL Switch to Woodward District line to 1590 AS52.
	670	10876	OGE			06/01/15		$12,000,000	OGE	30 months	regional reliability	514908	Arcadia 345 kV	514907	Arcadia 138 kV	3	345/138				493/493	Install third Arcadia 345/138 kV autotransformer.
	858	11129	OGE			06/01/15			OGE		regional reliability	515513	Mehan 138 kV	515033	Cushing 138 kV	1	138			14	194/222	Convert 14 mile Mehan - Cushing 69 kV line to 138 kV.
	858	11130	OGE			06/01/15			OGE		regional reliability	515011	Stillwater 138 kV	515512	Spring Valley 138 kV	1	138			5.98	194/222	Convert 6 mile Stillwater - Spring Valley 69 kV line to 138 kV.
	858	11131	OGE			06/01/15		$16,000,000	OGE	36 months	regional reliability	515512	Spring Valley 138 kV	515513	Mehan 138 kV	1	138			3	194/222	Convert 3 mile Spring Valley - Mehan 69 kV line to 138 kV.
	858	11132	OGE			06/01/15			OGE		regional reliability	515512	Spring Valley 138 kV	515514	Knipe 138 kV	1	138			8.69	268/286	Convert 8.7 mile Spring Valley - Knipe 69 kV line to 138 kV.
	858	11133	OGE			06/01/15			OGE		regional reliability	515033	Cushing 138 kV	515417	Bristow 138 kV	1	138				120/120	Tap existing Cushing - Bristow 138 kV line into new Greenwood Sub 138 kV transformer bus and add new Greenwood 138/69/13.8 transformer.
	858	11134	OGE			06/01/15			OGE		regional reliability	515021	OakGrove 69 kV	515019	Hwy 99 Tap 69 kV	1	69				52/66	Tap existing Oak Grove - Hwy 99 Tap 69 kV circuit into new Greenwood Sub 69 kV transformer bus.
	899	11195	SEPC			06/01/15		$4,000,000	SEPC	24 months	regional reliability	531448	Holcomb 115 kV	531420	Fletcher 115 kV	1	115	11.1				Rebuild 11.1 miles with 954 ACSR Cardinal
	766	11010	SPS			06/01/15		$3,892,500	SPP	24 months	regional reliability	525460	Newhart 3 115 kV	525461	Newhart 6 230 kV	2	115/230				150/173	Add second Newhart 230/115 kV transformer.
	798	11057	SPS	06/01/15		06/01/15		$992,000	SPP	18 months	regional reliability	524414	Amarillo South Interchange 115 kV	524377	Farmers Sub 115 kV	1	115	2.35			246/271	Reconductor Amarillo - Farmers 115 kV Circuit 2.35 miles with 795 kcmil conductor
	801	11060	SPS			06/01/15		$3,825,000	SPP	24 months	regional reliability	528768	Lea County REC-Ancell 69 kV	528776	Lea County REC-Gaines 69 kV	1	69		8.5		41/54	Build new 8.5 mile Lea County Ancell - Gaines 69kV line.
	801	11061	SPS			06/01/15		$4,050,000	SPP	24 months	regional reliability	528763	Lea County REC-TP91 69 kV	528784	Lea County REC-Darby 69 kV	1	69		9		41/54	Build new 9 mile Lea County TP-91 - Darby 69kV line.
	801	11062	SPS			06/01/15		$11,250,000	SPP	24 months	regional reliability	527362	New ERF3 115 kV	527361	Lea County ERF 69 kV	1	115/69				44/44	Build new ERF3 substation with new 44MVA 115/69kV transformer.
	886	11175	SPS	06/01/15		6/1/2015		$6,350,000	SPP	24 months	regional reliability	525213	Swisher 230 kV	525212	Swisher 115 kV	2	230/115				150/150	Add second Swisher 230/115 kV transformer.
20004	146	10186	SPS	06/01/15		M	02/13/08	$8,920,699	SPS	48 months	regional reliability	527894	Hobbs 230 kV	527276	Seminole 230 kV	1	230		45		492/541	Add 230 kV line from Hobbs to Seminole - 541 MVA.
	694	10836	SWPA			06/01/15		$167,500	SPP	12 months	regional reliability - non OATT	300056	Asherville 161 kV	505438	Poplar Bluff 161 kV	1	161				206/206	Replace disconnect switches, replace some structures and resag line.
	444	10576	SWPA			06/01/15		$660,000	SPP	12 months	regional reliability - non OATT	505501	Nixa 69 kV	505541	Nixa DT 69 kV	1	69	2.2			72/72	Reconductor the 2.2 mi line with 795 ACSR.
	490	10635	WR	06/01/15		06/01/16		$1,950,000	WR	12 months	regional reliability	533234	Bismark 115 kV	533252	Midland 115 kV	1	115	5.2			181/181	Rebuild 5.2 miles of the Bismark to Midland 115 kV line.
20033	652	10857	WR	06/01/15	NTC-Modify Timing	06/01/13	01/27/09	$12,487,500	SPP	36 months	regional reliability	533419	Hutchinson Energy Center 115 kV	530618	Huntsville 115 kV	1	115	7.7			164/194	Rebuild the Westar portion of the 28.8 mile HEC - Huntsville 115 kV line and reset CTs at HEC.
	492	10637	WR			M		$920,000	WR	18 months	regional reliability	533798	Gill Energy Center 69 kV	533825	Oatville 69 kV	1	69	3.55			96/96	Tear down / Rebuild 3.55-mile Gill Energy Center - Gill junction portion of the Gill - Oatville 69 kV line. Replace 477 kcmil ACSR conductor with 954 kcmil ACSR and replace terminal equipment. The new rating is the CT limit.
		Year 2016																				
	882	11171	AEP			06/01/16		$11,400,000	AEP	24 months	regional reliability	509082	Rock Hill 69 kV	509056	Carthage 69 kV	1	69	11.4			123/143	Rebuild/reconductor 11.4 miles of 336 ACSR with 1272 ACSR on the Rock Hill - Carthage 69 kV line. Upgrade Carthage breaker & relay settings & Rock Hill jumpers. Upgrade switches, CT ratios, and relay settings at Rock Hill and Carthage. Remove switches in middle of line.
20000	511	10656	AEP	06/01/16		M	02/13/08	$11,000,000	AEP	60 months	regional reliability	99002	Osage 345 kV	99832	Osage 161 kV	1	345/161				400/440	Install new 345/161 kV transformer at Osage Creek
20000	511	10659	AEP	06/01/16		M	02/13/08	$24,500,000	AEP	60 months	regional reliability	507001	Shipe Road 345 kV	90001	E Rogers 345 kV	1	345		15		1336/1915	Install 9 miles of 345 kV line from Shipe Road to East Rogers
20000	511	10660	AEP	06/01/16		M	02/13/08	$65,500,000	AEP	60 months	regional reliability	90001	E Rogers 345 kV	90002	Osage 345 kV	1	345		40		1336/1915	Install 32 miles of 345 kV line from East Rogers to Osage Creek
	681	10898	AEP			06/01/16		$2,000,000	AEP	24 months	regional reliability	507716	Broadmoor 69 kV	507724	Fern Street 69 kV	1	69	2			90/105	Rebuild 2 miles of 266 ACSR with 795 ACSR and replace Fern Street Switches
	647	10848	EDE	06/01/16				$12,375,000	SPP	18 months	zonal - sponsored						69			27		Convert 27 mi of 34.5 kV to 69 kV in the Baxter Springs area
	716	10953	GMO			06/01/16		$150,000	SPP	12 months	regional reliability	541211	Blue Spring South 161 kV	541206	Prairie Lee 161 kV	1	161				229/260	Replace Wavetrap
	549	10698	GRDA			06/01/16		$370,530	GRDA	12 months	regional reliability	512626	Maid 69 kV	512681	Pryor Foundry South 69 kV	1	69	1.4			130/143	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.
	550	10699	GRDA			06/01/16		$370,530	GRDA	12 months	regional reliability	512626	Maid 69 kV	512696	Redden 69 kV	1	69	1.3			130/143	Reconductor 69 kV Line to 1272 ACSR and replace 600A switch with 1200A switch.
20002	518	10663	OGE	06/01/16			02/13/08	$250,000	OGE	12 months	regional reliability	514927	HSLEast 69 kV	514937	HSLWest 69 kV	1	69				134/143	Increase rating of HSL East kV to HSL West 69 kV line to 143 MVA. Planned by OGE in 2008.
	682	10899	OGE			06/01/16		$5,300,000	OGE	24 months	regional reliability	515088	Little River 69 kV	515054	Maud 69 kV	1	69	10.67			111/125	Rebuild 10.67 miles of line to 477AS33
	842	11111	SPS	06/01/16		06/01/11		$5,166,960	SPP	18 months	regional reliability	524209	Lawrence pk 69 kV	524321	Georgia S 69 kV	2	69		1.91		60/60	add new 69 kV Ckt Georgia-Lawrence pk pipe type cable CKT 2
	843	11112	SPS	06/01/16		06/01/16		$6,571,440	SPP	18 months	regional reliability	524216	Lawrence Pk 2 69 kV	524200	Soncy 69 kV	2	69		3.24		60/60	add new 69 kV Ckt SONCY-Lawrence pk 2 pipe type cable CKT 2
	844	11113	WFEC			06/01/16		$3,341,000	SPP	24 months	regional reliability	521005	Mustang 69kV	521058	Sunshine Canyon 69kV	1	69	9.9			91/114	Upgrade 9.9 miles of 69 kV between Mustang to Sunshine Canyon from 4/0 to 795; new rating 91/114
	847	11117	WFEC			06/01/16		$6,705,000	SPP	18 months	regional reliability	521008	Nash 69 kV	521085	Wakita 69 kV	1	69	14.9			53/65	Upgrade Wakita to Nash, 1/0 to 336.4 ACSR
	659	10865	WFEC	06/01/16		06/01/14		$3,712,500	SPP	12 months	regional reliability	521037	Reeding 138 kV	520847	Cashion 138 kV	1	138			11	144/179	Convert 11 mile Reeding - Cashion 69 kV line to 138 kV.
	663	10869	WR			06/01/16		$641,250	SPP	12 months	regional reliability	533180	Tecumseh Energy Center 115 kV	533192	Hook Jct 115 kV	1	115	1.52			223/240	Tear down and rebuild TEC - Hook Jct. - County Line 115 kV.
		Year 2017																				
	877	11157	AEP			06/01/17		$13,900,000	AEP	24 months	regional reliability	511447	Clinton City 69 kV	511517	Thomas Tap 69 kV	1	69	13.9			69/72	Rebuild 13.9 miles of 4/0 ACSR with 795 ACSR and reset Clinton City relay.
	878	11158	AEP			06/01/17		$2,700,000	AEP	24 months	regional reliability	508348	North Mineola 69 kV	508347	Mineola 69 kV	1	69	2.68			123/143	Reconductor 2.68 miles of 477 ACSR 69 kV line with 1272 ACSR and raise CT ratio and relay settings.
	504	10649	AEP			06/01/17		$4,700,000	AEP	24 months	regional reliability	507718	Brown Lee 69 kV	507745	North Market 69 kV	1	69	4.7			133/143	Rebuild 4.7 mile Brown Lee- North Market 69 kV line of 2-203 ACSR & 666 ACSR with 1272 ACSR & raise CT ratio & relay
	502	10647	AEP			06/01/17		$3,220,000	AEP	24 months	regional reliability	509075	Northwest Henderson 69 kV	509081	Poynter 69 kV	1	69	3.22			143/143	Reconductor 3.25 miles Northwest Henderson-Poynter 69 kV line with 1272 ACSR.
20036	440	10571	EDE		NTC-Modify Timing	06/01/17	01/27/09	$2,274,000	SPP	18 months	regional reliability	547538	SUB 131 - Diamond Junction 69 kV	547582	SUB 362 - Sarcoxie Southwest 69 kV	1	69	7.55			54/65	Reconductor 7.55 mile Diamond Jct. - Sarcoxie Southwest 69 kV line from 1/0 Cu to 336 ACSR.
	677	10891	EDE	06/01/17		06/01/18			EDE		regional reliability	547498	SUB 439 - Stateline 161 kV	547900	Joplin 59 161 kV	1	161			5.32		Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin 59 sub. Tear down and rebuild Joplin 59 to Gateway to Pillsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line between Joplin 59 and Gateway at Joplin 422.
	677	10892	EDE	06/01/17		06/01/18		$25,000,000		48 months	regional reliability	547900	Joplin 59 161 kV	547551	Gateway 161 kV	1	161			2.94		
	677	10893	EDE	06/01/17		06/01/18					regional reliability	547551	Gateway 161 kV	547685	Pillsbury 161 kV	1	161			1		
	677	10894	EDE	06/01/17		06/01/18					regional reliability	547685	Pillsbury 161 kV	547500	Reinmiller 161 kV	1	161			3.25		
20036	203	10259	EDE		NTC-Modify Timing	06/01/17	01/27/09	$1,277,935	EDE	18 months	regional reliability	547533	SUB 109 - Atlas Junction 69 kV	547532	SUB 108 - Carthage Northwest 69 kV	1	69	3.5			54/65	Reconductor 3.5 mile Atlas Jct. - Carthage Northwest 69 kV line from 4/0 ACSR to 336 ACSR for 65 MVA Rate B.
	565	10716	GMO	06/01/17		06/01/19		$450,000	GMO	12 months	regional reliability	541303	Clinton 69 kV	541301	Clinton Plant 69 kV	1	69	2			100/107	Reconductor with 795ACSR.
	687	10904	GMO			06/01/17		$50,000	GMO	12 months	regional reliability	541224	Longview 161 kV	541222	Western Electric 161 kV	1	161				229/260	Replace wavetraps at Longview and Western Electric
20017	30160	50168	OGE	06/01/17		M	01/16/09	$11,000,000	OGE	18 months	transmission service	515305	Fort Smith 500 kV	515300	Fort Smith 161 kV	5	500/161					Convert Ft. Smith 161 kV to 1-1/2 breaker design and install 3rd 500-161 kV transformer bank.
20017	30164	50172	OGE	06/01/17		M	01/16/09	$100,000	OGE	9 months	transmission service	515336	VBI 161 kV	504032	VBI North 161 kV	1	161				72/72	Upgrade CT
	810	11071	OGE			06/01/17		$120,000,000	OGE	48 months	regional reliability	525835	Stateline 345 kV	521126	Anadarko (Gracemont) 345 kV	1	345		100		1793/1793	Build new 100 mile 345 kV line from OGE Anadarko to Oklahoma/Texas border towards SPS's Reactor station on Woodward-Tuco 345 kV line.
	863	11140	OPPD			06/01/17		$146,000	OPPD	12 months	regional reliability	647907	SUB 907 69 kV	647911	SUB 911 69 kV	1	69				102/102	Increase line clearances to allow the use of a higher conductor rating.
	761	11004	SPS	06/01/17		06/01/17		$3,375,000	SPP	20 months	regional reliability	527482	Chaves County Interchange 115 kV	527546	Samson Sub 115 kV	1	115	7.78			226/249	Reconductor 7.78 miles with 795 kcmil conductor.
	762	11005	SPS	06/01/17		06/01/17		$3,375,000	SPP	20 months	regional reliability	527482	Chaves County Interchange 115 kV	527501	Urton Sub 115 kV	1	115	3.7			226/249	Reconductor 3.70 miles with 795 kcmil conductor.
	807	11069	SPS	06/01/17		06/01/17		$16,425,000	SPP	48 months	regional reliability	525835	Stateline 345 kV	521126	Anadarko (Gracemont) 345 kV	1	345		10		1643/1793	Build new 10 mile 345 kV line from SPS's Reactor station on Woodward-Tuco 345 kV line to Oklahoma/Texas border towards OGE Anadarko.
	808	11070	SPS	06/01/17		06/01/17		$134,325,000	SPP	48 months	regional reliability	523961	Potter County Interchange 345 kV	525835	Stateline 345 kV	1	345		115		1643/1793	Build new 115 mile 345 kV line from Potter to Stateline.
	763	11006	SPS	06/01/17		06/01/17		$1,890,000	SPP	24 months	regional reliability	523636	Gray County Interchange 115 kV	523635	Gray County Interchange 69 kV	2	115/69				84/96.6	Add second 115/69 kV transformer at Gray County substation.
	856	11127	SPS			06/01/17		2812500	SPP	18 months	regional reliability	524567	NE Hereford 115 kV	524555	Centre 115 Kv	1	115		5		157/173	Convert 69 kava load to 115 kV and build 5 mile line
	833	11100	SPS	06/01/17		06/01/17		$1,890,000	SPP	30 months	regional reliability	524567	NE Hereford 115 kV	524573	NE Hereford 69 kV	2	115/69				84/96	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2
	909	11205	WFEC			06/01/17		$2,250,000	SPP	12 months	regional reliability	521018	Oklahoma University SW 69 kV	520861	Cole 69 kV	1	69	4			72/89	Reconductor 4.0 miles with 556 kcmil conductor.
	661	10867	WR			06/01/17		$1,063,125	SPP	18 months	regional reliability	533192	Hook JCT 115 KV	533153	County Line 3 115 kV	1	115	2.52			223/223	Tear down and rebuild 2.52-mile County Line-Hook Jct 115 kV line, 1192 ACSR.
	756	10998	WR			06/01/17		$6,930,000	SPP		regional reliability	532858	Baldwin Creek 230 kV	533232	Baldwin Creek 115 kV	1	230/115				280/308	Tap Lawrence Hill-Swissvale 230 kV line near Baldwin Creek substation and Install Baldwin Creek 230/115 kV transformer
		Year 2018																				
	479	10616	AEP			06/01/18		$12,630,000	AEP	24 months	regional reliability	509064	Georgia-Pacific 138 kV	509050	Keatchie REC 138 kV	1	138	12.63			287/287	Rebuild 12.63 mi of the Georgia Pacific-Keatchie 138 kV 795 ACSR line with 1272 ACSR.
	478	10615	AEP			06/01/18		$350,000	AEP	18 months	regional reliability	507728	Forbing Tap 69 kV	507754	South Shreveport 69 kV	1	69	0.27			90/121	Rebuild 0.27 miles Forbing Road to South Shreveport 69 kV to 1272 ACSR (next limit is 500 Cu bus & jumpers).
	509	10654	AEP			06/01/18		$2,904,000	AEP	24 months	regional reliability	506980	Centerton 161 kV			1	161					Convert the 506952 Centerton 69-12.5 kV station to 161-12.5 kV. Disconnect Centerton station from the 69 kV line and connect to the 506929 East Centerton to 506960 Bentonville Hwy 279 161 kV line 2.0 miles west of 506929 East Centerton station.
	814	11076	CUS	06/01/18		M		$1,282,500	SPP		zonal - sponsored	549904	James River 69 kV	549908	South Highway 65 69 kV	1	69	3.8			153/159	Rebuild James River to South Highway 69 kV
	815	11077	CUS	06/01/18		M		$641,250	SPP		zonal - sponsored	549907	Sunset 69 kV	549908	South Highway 65 69 kV	1	69	1.9			153/159	Rebuild South Highway to Sunset 69 kV
	688	10905	GMO			06/01/18		$2,000,000	SPP	18 months	regional reliability	541229	Odessa 161kV	541267	Odessa 69kV	1	161/69				100/110	Replace Odessa 161/69kV transformer with new 100/110MVA
	667	10873	GRDA			06/01/18		$112,500	SPP	6 months	regional reliability	512681	Pryor Foundry South 69 kV	512661	CPP Transformer #2 69 kV	1	69				85/97	Replace 600A switch with 1200A switch
	850	11120	OGE			06/01/18		$25,000	OGE	12 months	regional reliability	514977	Kentucky Tap 69 kV	514924	Pennsylvania 69 kV	1	69				134/143	Upgrade the 800 amp CT in Penn Sub to 1200 amp
	804	11066	SPS			06/01/18		$13,500,000	SPP	24 months	regional reliability	525830	Tuco Interchange 230 kV	525828	Tuco Interchange 115 kV	3	230/115				250/250	Add 3rd transformer at TUCO 230/115 250 MVA CKT 3
	805	11067	SPS			06/01/18		$1,890,000	SPP	24 months	regional reliability	523748	Bowers Interchange 115 kV	523747	Bowers Interchange 69 kV	2	115/69				84/96	Add 2nd transformer at Bowers 115/69 kV CKT 2
	854	11124	SPS	06/01/18		06/01/18		$33,367,500	SPP	48 months	regional reliability	525832	Tuco 345 kV	526340	Jones 345 kV	1	345		29.66		1643/1793	Add new 345 kV line Tuco - Jones Ckt 1 29.66 miles
	854	11125	SPS			06/01/18		$22,150,000	SPP	30 months	regional reliability	526340	Jones 345 kV	526338	Jones 230 kV	1	345/230				559/559	Add new 345-230 kV 559 MVA CKT 1
	837	11105	SPS			06/01/18		$2,925,000	SPP	28 months	regional reliability	525636	Lamb Co 115 kV	525651	LC-Little 115 kV	1	115		5.2		157/173	Add new 115 kV Ckt Lamb Co to Lea County Littlefield
	884	11173	SPS	06/01/18		6/1/2018		$8,352,500	SPP	30 months	regional reliability	527800	Eddy 230 kV	527798	Eddy 115 KV	2	230/115				168/168	Add 2nd transformer Eddy Co 230-115 kV CKT 2
	885	11174	SPS	06/01/18		6/1/2018		$8,352,500	SPP	30 months	regional reliability	526161	Carlise 230 kV	526160	Carlise 115 kV	2	230/115				168/168	Add 2nd transformer Carlise 230-115 kV CKT 2

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	From Bus Number used in SPP MDWG new bus	From Bus Name	To Bus Number used in SPP MDWG new bus	To Bus Name	Circuit	Voltages (kV)	Number of Reconductor	Number of New	Number of Voltage Conversion	Summer Rating Normal/Emergency	Project Description/Comments
	679	10896	SWPA			06/01/18		$2,250,000	SPP		regional reliability - non OATT	505436	Poplar Bluff 69 kV	505438	Poplar Bluff 161 kV	2	161/69				70/70	Replace Poplar Bluff 2nd transformer with larger transformer, 70/70 MVA unit.
	433	10563	WR			M		$150,000	SPP	18 months	regional reliability	533747	Yost 69 kV	533742	Moundridge 69 kV	1	69				108/108	Reset ct's. New Rate A:108 B:108
	820	11083	WR			06/01/18		$1,687,500	SPP	12 months	regional reliability	533175	17th & Fairlawn 115 kV	533166	Indian Hills 115 kV	1	115	3			240/240	Tear down and rebuild 17th & Fairlawn - Indian Hills 115kV Ckt 1
			Year 2019																			
	481	10619	AEP			06/01/19		$6,000,000	AEP	36 months	regional reliability	507189	North Huntington 161 kV	507196	Midland REC 161 kV	1	161			4	429/597	Rebuild and reconductor 4.0 miles of 4/0 ACSR 69 kV to 1590 ACSR 161 kV from converting North Huntington to Midland REC to 161 kV. Add 161 kV terminal at North Huntington.
	481	10620	AEP			06/01/19		$1,500,000	AEP	36 months	regional reliability	507196	Midland REC 161 kV	507202	Midland 161 kV	1	161			1.25	429/597	Rebuild and reconductor Midland REC-Midland from 69 kV 4/0 ACSR to 161 kV 1590 ACSR.
	481	10621	AEP			06/01/19		$2,500,000	AEP	36 months	regional reliability	507202	Midland 161 kV	507187	Midland 69 kV	1	161/69				90/102	Add 161/69 kV autotransformer at Midland.
	481	10624	AEP			06/01/19		$17,000,000	AEP	36 months	regional reliability	515261	Bonanza Tap 161 kV	507202	Midland 161 kV	1	161		6	8.9	429/597	Build Bonanza-Midland 1590 ACSR 161 kV line. Old Midland-Excelsior section to be converted from 69 kV to 161 kV. Add 4-161 kV breakers at Bonanza.
	879	11158	AEP			06/01/19		$9,000,000	AEP	24 months	regional reliability	515242	Bluebell 138 kV	509758	Prattville 138 kV	1	138	9			287/287	Rebuild 9.0 mile Prattville-Bluebell 138 kV line from 795 ACSR to 1590 ACSR. New summer ratings 287/287 limited by breaker, switches, CTs, wave trap.
	501	10646	AEP			06/01/19		$200,000	AEP	12 months	regional reliability	509061	Evenside 69 kV	509075	NW Henderson 69 kV	1	69				65/76	Replace 600 A breaker with 1200A at Evenside 69 kV.
	473	10609	CUS	06/01/19		06/01/19		$979,000	CUS	24 months	regional reliability	549904	James River 69 kV	549933	Twin Oaks 69 kV	1	69	3			153/159	Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW
	671	10877	OGE			06/01/19		$450,000	OGE	12 months	regional reliability	515166	Ardmore 69 kV	515170	Chickasaw 69 kV	1	69				97/111	Increase CT ratio at both Chickasaw and Ardmore. Also possibly change out relay
	30212	10999	OGE			06/01/19		$250,000	OGE	12 months	regional reliability	514840	Jones Tap 138 kV	514839	Bryant 138 kV	1	138				478/478	Replace Jones Tap bus 1200A switch with 2000A switch.
	849	11119	OGE			06/01/19		$60,000	OGE	12 months	regional reliability	514976	Kentucky 69 kV	514977	Kentucky Tap 69 kV	1	69				134/143	Upgrade the existing 600 amp 69 kV switches in Kentucky Sub to 1200 amp
	910	11207	OGE			06/01/19		$225,000	SPP	12 months	regional reliability	514839	Bryant 138 kV	514835	Memorial 138 kV	1	138					Replace wavetrap
	689	10906	KCPL			06/01/19		$2,000,000	KCPL	24 months	regional reliability	543063	South Waverly 161kV	543094	South Waverly 69kV	1	161/69				30/33	Replace South Waverly 161/69kV transformer with larger 30/33MVA model; interim mitigation is to move 20% of load off S Waverly 161kV bus starting in 2010
	859	11136	KCPL			06/01/19		$1,670,625	SPP	24 months	regional reliability	543020	Birmingham 161kV	542973	Hawthorn 161kV	1	161	3.3				Reconductor Hawthorn - Birmingham 161kV
	30211	10994	MKEC			06/01/19		$3,825,000	SPP	24 months	regional reliability	539674	Medicine Lodge 138 kV	539673	Medicine Lodge 115 kV	1	138/115				147/170	Replace Medicine Lodge 138/115 kV transformer with a larger 147/170 MVA transformer
	30208	10991	MKEC			06/01/19		$3,150,000	SPP	18 months	regional reliability	533036	Clearwater 138 kV	539675	Milan Tap 138 kV	1	138	5.6			534/534	Rebuild MKEC portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)
	30210	10993	MKEC			06/01/19		$225,000	SPP	12 months	regional reliability	539668	Harper 138 kV	539675	Milan Tap 138 kV		138				120/120	Replace Wave Trap at Harper Substation.
	753	10990	NPPD	06/01/19		06/01/19		$6,000,000	NPPD	24 months	regional reliability	640076	Beatrice 115 kV	640208	Harbine 115 kV	1	115	10			240/240	Reconductor and upgrade terminal equipment to effect higher rating by 2019. 240 MVA Normal Continuous Rating. 240 MVA 4-Hour Emergency Rating.
20031	151	10195	SPS			06/01/19	01/27/09	$1,260,000	SPP	24 months	regional reliability	525826	Tuco 69 kV	525828	Tuco 115 kV	1	115/69				84/84	Add third Tuco 115/69 kV autotransformer with 84/84 MVA rating.
20031	153	10197	SPS			06/01/19	01/27/09	$600,000	SPP	24 months	regional reliability	527961	Potash Junc 69 kV	527962	Potash Junc 115 kV	1	115/69				40/40	Add third Potash Junction Interchange 115/69 kV transformer.
	825	11092	SPS			06/01/19		$225,000	SPP	18 months	regional reliability	527701	Artesia 69 kV	527754	CV-Artesia 69 kV	1	69	0.45			120/154	Reconductor 0.45 miles 69 kV from 4/0 to 397.5 ACSR
	827	11094	SPS			06/01/19		$3,518,438	SPP	18 months	regional reliability	524009	Cherry 115 kV	524106	Northwest 115 kV	1	115	8.34			226/249	Reconductor 8.34 miles 115 kV from 397.5 to 750 ACSR
	832	11099	SPS			06/01/19		$1,890,000	SPP	28 months	regional reliability	524105	Northwest 69 kV	524106	Northwest 115 kV	2	115/69				84/96	Add 2nd transformer 115/69 kV 84/96 MVA CKT 2
	838	11106	SPS			06/01/19		$3,037,500	SPP	18 months	regional reliability	526020	Hockley Co 115 kV	526058	E Levelland 115 Kv	1	115		5.4		157/173	Add new 115 kV Ckt Hockley Co-E Levelland Co
	855	11126	SPS			06/01/19		85375	SPP	18 months	regional reliability	526075	Stanton 69 kV	526076	Stanton 69 kV	1	69			0.2		convert 69 kV load onto 115 kV
	901	11198	SPS			06/01/19		$450,000	SPP	6 months	regional reliability	524044	Nichols Station 230 kV	524415	Amarillo South Interchange 230 kV	1	230				436/502	Replace NICHOLS Line Trap with 1200 Amp B unit 230 kV
	655	10860	SWPA			06/01/19		$825,000	SPP		regional reliability - non OATT	505492	Springfield 161 kV	505494	Springfield 69 kV	1	161/69				70/70	Replace Springfield transformer #1 three winding transformer with 70 MVA auto transformer.
	898	11193	WR	06/01/19		M		$8,521,875	SPP		zonal - sponsored	533153	County Line 115 kV	533482	Valley Falls 115 kV	1	115			20.2	223/245	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115
	898	11194	WR	06/01/19		M		$9,534,375	SPP		zonal - sponsored	533211	Arnold 115 kV	533482	Valley Falls 115 kV	1	115			22.6	223/245	convert County Line - Arnold to 115 kV. Valley Falls sub converted to 115
	30209	10992	WR			06/01/19		$3,431,250	SPP	18 months	regional reliability	533036	Clearwater 138 kV	539675	Milan Tap 138 kV	1	138	6.1			534/534	Rebuild Westar portion of the Clearwater-Milan tap 115 kV with bundled 1192.5 kcmil ACSR conductor (Bunting)
			Withdraw																			
20000	347	10444	AEP	06/01/11	NTC-Withdraw	D	02/13/08	$2,000,000	AEP	18 months		508830	Baldwin 69 kV	508842	Woodlawn 69 kV	1	69	2.7			72/83	Reconductor with 2.7 miles 477 ACSR 69 kV Woodlawn-Baldwin. Reset relays.
20027	477	10614	AEP	06/01/13	NTC-Withdraw	D	01/27/09	$6,900,000	AEP	24 months		508830	Baldwin 69 kV	508836	Karnack Tap 69 kV	1	69	6.9			72/83	Reconductor 6.9 miles with 477 ACSR 69 kV from Baldwin - Karnack Tap.
20016	345	10442	AEP	06/01/10	NTC-Withdraw	D	01/16/09	$125,000	AEP	15 months		508299	Quitman-Magnolia 69 kV	508340	Forest Hills REC 69 kV	1	69				143/143	Replace 69 kV switch at Magnola tap for new emergency limit 85 MVA.
20011	441	10572	CUS	06/01/12	NTC-Withdraw	D	02/13/08	$805,000	CUS	24 months		549906	Kickapoo 69 kV	549907	Sunset 69 kV	1	69	1			153/159	Reconductor 69kV line from 636 ACSR to 762.8 ACSS/TW
20009	379	10492	KCPL	06/01/15	NTC-Withdraw	D	02/13/08	$5,418,700	KCPL	24 months		543121	Hillsdale 161 kV	543054	Cedar Niles 161 kV	1	161		8		293/335	New Hillsdale-Cedar Niles 161 kV Line and Cedar Niles ring bus
20002	397	10515	OGE	06/01/12	NTC-Withdraw	D	02/13/08	$6,850,000	OGE	24 months		514861	Mustang 138 kV	514886	Yukon 138 kV	1	138			7	268/308	Convert 7 mile Mustang -Yukon 69 kV line to 138 kV.
20002	397	10516	OGE	06/01/12	NTC-Withdraw	D	02/13/08	$3,500,000	OGE	24 months		514886	Yukon 138 kV	514898	Cimarron 138 kV	1	138			3	268/308	Convert 3 mile Yukon - Cimarron 69 kV line to 138 kV.
20033	623	10811	WR	12/31/10	NTC-Withdraw	D	01/27/09	$7,415,000	WR	24 months		533558	Timber Junction 69 kV	533561	City Of Winfield 69 Kv	1	69	14.63			132/145	Rebuild the 14.63 miles of 69 kV line from Timber Junction - Winfield.
20033	624	10812	WR	06/01/11	NTC-Withdraw	D	01/27/09	$4,927,500	SPP	24 months		533328	Fort Junction Switching Station 115 kV	533342	West Junction City 115 kV	1	115		8.76		240/240	Build new 8.76 mile Fort Junction - West Junction City 115 kV line that follows the path of the JEC - Summit 345 kV line. Remove old double circuit and West Junction City Junction (East) - West Junction City 115 kV line.
20006	410	10536	WR		NTC-Withdraw	D	02/13/08	$2,306,250	SPP	12 months		533412	Ark Valley 115 kV	533455	Tower 33 115 kV	1	115	4.1			223/245	Rebuild Ark Valley-Tower 33 115 kV
20033	495	10640	WR		NTC-Withdraw	D	01/27/09	$2,377,448	WR	18 months		533250	Lawrence Hill 115kV	533253	Mockingbird Hill 115 kV	1	115	5.49			223/240	Rebuild the 5.49 mile Lawrence Hill to Mockingbird Hill 115 kV line.
20033	169	10218	WR	06/01/17	NTC-Withdraw	D	01/27/09	$10,000	WR	12 months		533362	Chapman 115 kV	533323	Clay Center Junction 115 KV	1	115				72/72	Uprate CT ratio on Chapman - Clay Center 115 kV line.

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	Device Type	SPP MDWG Bus Number 2007 series	Location	Voltage	Total Rating	Project Description
Year 2010																	
	30248	50286	CRE			06/01/10		$1,166,400	SPP	12 months	regional reliability - non OATT	Cap Bank	522973	CR-S. Midland 138 kV	138	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30249	50287	CRE			06/01/10		$583,200	SPP	12 months	regional reliability - non OATT	Cap Bank	522914	CR-Salem	138	14.4 Mvar	Install 2 Blocks of 7.2 Mvar
20010	30078	50084	EDE	12/01/10		M	02/13/08	$2,600,000	EDE	24 months	Zonal Reliability	Cap Bank	547497	SUB 438 - Riverside 161 kV	161	66 Mvar	Install (3) 22 Mvar capacitor banks for a total of 66 Mvar at Riverside Sub #43
20053	30221	50225	GMO	06/01/10			09/18/09	$486,000	GMO	12 months	regional reliability	Cap Bank	541279	Ralph Green 69 kV	69	12 Mvar	Add 12 Mvar cap bank at Ralph Greer
20028	30072	50078	GRDA	06/01/10		M	01/27/09	$800,000	GRDA	18 months	regional reliability	Cap Bank	512633	Afton 69 kV	69	21.6 Mvar	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Afton 69 kV bus
20009	30077	50083	KCPL	06/01/10		M	02/13/08	$1,057,630	KCPL	12 months	Zonal Reliability	Cap Bank	542978	Craig 161 kV	161	50 Mvar	New Craig 50 Mvar capacitor bank
20054	30062	50068	MKEC	05/01/10		M	09/18/09	$1,400,000	MKEC	3 months	regional reliability	Cap Bank	539668	Harper 138 kV	138	20 Mvar	Add 138 kV 20 Mvar cap bank at Harpe
20007	30061	50067	MKEC	03/01/10		M	02/13/08	$2,300,000	MKEC	7 months	regional reliability	Cap Bank	539687	Pratt 115 kV	115	24 Mvar	Install (2) 12 Mvar capacitor banks at Pratt 115kV
	30195	50202	NPPD	06/01/10		M		$375,000	NPPD	24 months	zonal - sponsored	Cap Bank	640408	Westminster 34.5 kV	34.5	7.2 Mvar	Add one 7.2 Mvar cap at Westminster
	30240	50252	OGE		NTC	06/01/10		$360,000	SPP	12 months	regional reliability	Cap Bank	515413	Cushing Oil2 69kV	69	9 Mvar	Install 9 Mvar capacitor bank at Cushing Oil 69kV bus
	30240	50253	OGE		NTC	06/01/10		$240,000	SPP	12 months	regional reliability	Cap Bank	515027	Tiger Creek2 69kV	69	6 Mvar	Install 6 Mvar capacitor bank at Tiger Creek 69kV bus
	30234	50246	SEPC		NTC	06/01/10		$1,000,000	SEPC	18 months	regional reliability	Cap Bank	531424	Johnson Corner 115 kV	115	12 Mvar	Install 12 Mvar capacitor bank at Johnson Corner 115 kV substation.
	30213	50217	SPS		NTC	06/01/10		$2,025,000	SPP	12 months	regional reliability	Cap Bank	524162	East Plant 115 kV	115	50 Mvar	Install 50 Mvar capacitor bank at East Plant 115 kV bus configured as two blocks of 25 Mvar.
	30250	50288	SPS	06/01/10		M		$288,000	SPP		zonal - sponsorec		523157	Perryton Interchange 69 kV	69	7.2 Mvar	Install 1 stage of 7.2 Mvar
	30251	50289	SPS	06/01/10		M		$288,000	SPP		zonal - sponsorec		524745	Castro County Interchange 69 kV	69	7.2 Mvar	Install a 7.2 Mvar cap at Castro County 69 kV
	30244	50257	SPS		NTC	06/01/10		$225,000	SPP	12 months	regional reliability	Line Trap	523978	Harrington Station Mid Bus 230 kV	230	1200 Amp	Replace 800A wave trap with 1200A.
20003	30079	50085	WFEC	06/01/10		M	02/13/08	$324,000	SPP	12 months	regional reliability	Cap Bank	520846	Carter 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Carter Jct which makes at total of 24 Mvar
20030	30172	50180	WFEC	06/01/10		M	01/27/09	$300,000	SPP	12 months	regional reliability	Cap Bank	520890	Eagle Chief 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Eagle Chief Southwest 69 kV bus
20006	30056	50062	WR	06/01/10	NTC-Modify Timing & Scope	06/01/17	02/13/08	$588,600	WR	18 months	regional reliability	Cap Bank	533348	Trans Canada / Seneca 115 kV	115	10.9 Mvar	Add 10.9 Mvar capacitor bank at Trans Canada 115 kV instead of Seneca
	30252	50290	WR	12/01/10		M		$3,072,000	SPP		zonal - sponsorec	Cap Bank	532986	Benton 138 kV	138		Add 76.8 Mvar bank at Benton
19986	30082	50088	WR	6/1/2010		M	02/02/07	$500,000	WR	18 months	Zonal Reliability	Cap Bank	533435	3rd & VanBuren 115 kV	115	17 Mvar	Install switched capacitor bank.
19986	30057	50063	WR	6/1/2010		M	02/02/07	$715,000	WR	18 months	Zonal Reliability	Cap Bank	533481	Nortonville 69 kV	69	15 Mvar	Install 15 Mvar capacitor at Nortonville 69 kV (bus #533481)
Year 2011																	
	30187	50194	GMO		NTC	06/01/11		$810,000	SPP	12 months	regional reliability	Cap Bank	541240	Adrian 161kV	161	20 Mvar	Add 20 Mvar capacitor bank at Adrian 161 kV
20053	30220	50224	GMO	06/01/11			09/18/09	$1,400,000	GMO	18 months	regional reliability	Cap Bank	541205	Blue Springs East 161 kV	161	50 Mvar	Add 50 Mvar cap bank at Blue Springs Eas
20001	30086	50092	GRDA	06/01/11		M	02/13/08	$800,000	GRDA	18 months	regional reliability	Cap Bank	512720	Jay Gr2 69 kV	69	21.8 Mvar	Install 21.8 Mvar capacitor at Jay 69 kV substation
20051	30217	50221	KCPL	06/01/11			09/18/09	$50,000	KCPL	18 months	transmission service	Cap Bank		Craig 161 kV	161	20 Mvar	Add 20 Mvar cap bank to make a total of 70 Mvar at Craig 161kV
20032	30176	50184	MIDW	06/01/11	NTC-Modify Scope	06/01/11	01/27/09	$300,000	MIDW	12 months	regional reliability	Cap Bank	530619	Kinsley 115 kV	115	5 Mvar	Install 5 Mvar Cap at Kinsley 115 kV
	30190	50197	MIDW		NTC	06/01/11		$300,000	MIDW	12 months	regional reliability	Cap Bank	530621	Pawnee 115 kV	115	5 MVar	Install 5 Mvar capacitor bank at Pawnee 115 kV.
20007	30090	50096	MKEC	06/01/11		M	02/13/08	$1,300,000	MKEC	18 months	regional reliability	Cap Bank	539701	Russell 115 kV	115	9.6 Mvar	Add 9.6 Mvar capacitor at Russell 115 kV
	30204	50211	NPPD	06/01/11	NTC	06/01/11		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640392	Valentine 115 kV	115	10.8 Mvar	Install 10.8 Mvar capacitor bank at Valentine 115 kV.
	304	50148	OGE	03/01/11				$264,000	OGE	12 months	zonal - sponsorec	Cap Bank	515158	Madill Industries 138 kV	138	9 Mvar	Add 9 Mvar of emergency capacitors
	30235	50247	SEPC		NTC	06/01/11		$650,000	SEPC	12 months	regional reliability	Cap Bank	531424	Johnson Corner 115 kV	115	12 Mvar	Install 2nd 115 kV 12 Mvar cap bank at Johnson Corner substation.
	30246	50259	SPS		NTC	06/01/11		$583,200	SPP	12 months	regional reliability	Cap Bank	525224	Kress Rural 69 kV	69	14.4 Mvar	Install 2 Blocks of 7.2 Mvar capacitor bank at Kress 69 kV.
20059	30232	50243	WR	06/01/11			09/18/09	$1,215,000	WR		transmission service	Cap Bank		Timber 138 kV	138	30 Mvar	Add 138 kV 30 Mvar Cap bank at Timber
20059	30233	50244	WR	06/01/11			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533646	Tioga 69 kV	69	15 Mvar	Add 69 kV 15 Mvar Cap bank at Tioga
	30253	50291	WR	06/01/11		M		$384,000	SPP		zonal - sponsorec	Cap Bank	533319	Riley 115 kV	115	9.6 Mvar	one stage of 9.6 Mvar
	30254	50292	WR	12/01/11		M		$3,072,000	SPP		zonal - sponsorec	Cap Bank	533062	Rose Hill 138 kV	138	76.8 Mvar	Install 2nd block of 76.8 Mvar
	30255	50293	WR	06/01/11		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533861	Butler County No. 5-Furley 69 kV	69	10.8 Mvar	one stage of 10.8 Mvar
Year 2012																	
	30070	50076	AEP	12/1/2012				$500,000	AEP		zonal - sponsorec	Station	504186	Sugar Loaf 69 kV	69		Add tap and switches for new delivery point along 69 kV line from 507187 Midland to old 507185 Excelsior station sit
20028	30074	50080	GRDA	07/01/12		M	01/27/09	$779,000	GRDA	12 months	regional reliability	Cap Bank	300971	Tahlequah West 69 kV	69	21.6 Mvar	Install (3) 7.2 Mvar capacitors for a total of 21.6 Mvar at Tahlequah West 69 kV.
20007	30098	50104	MKEC	06/01/12		M	02/13/08	$1,600,000	MKEC	18 months	regional reliability	Cap Bank	539686	Plainville 115 kV	115	20 Mvar	Install 20 Mvar capacitor bank at Plainville 115 kV
	30236	50248	NPPD	06/01/12	NTC	06/01/12		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640250	Kearney 115 kV	115	36 Mvar	Install 36 Mvar capacitor bank at Kearney 115 kV.
	30200	50207	NPPD	11/01/12	NTC	11/01/12		$607,500	SPP	24 months	regional reliability	Cap Bank	640318	Petersburg 115 kV	115	15 Mvar	Add one 15 Mvar cap at Petersburg.
	30201	50208	NPPD	11/01/12	NTC	11/01/12		$729,000	SPP	24 months	regional reliability	Cap Bank	640436	Clarks 115 kV	115	18 Mvar	Add one 18 Mvar cap at Clarks 7.
	30202	50209	NPPD	11/01/12	NTC	11/01/12		$50,000	NPPD	24 months	regional reliability	Cap Bank	640051	Ainsworth 115 kV	115	18 Mvar	Expand existing 9 Mvar cap to 18 Mvar cap at Ainsworth
	30199	50206	NPPD	11/01/12		11/01/12		$364,500	SPP	24 months	zonal - sponsored	Cap Bank	640306	Oneill 69 kV	69	9 Mvar	Add one 9 Mvar cap at Oneill 69 kV
	30203	50210	NPPD	11/01/12	NTC	11/01/12		$729,000	SPP	24 months	regional reliability	Cap Bank	640305	Oneill 115 kV	115	36 Mvar	Add one 18 Mvar cap at Oneill 115
20058	30104	50110	SEPC	06/01/12			09/18/09	$2,500,000	SEPC	18 months	regional reliability	Cap Bank	531455	North Cimarron 115 kV	115	24 Mvar	Add 24 Mvar Cap bank at North Cimarror
	30257	50294	WAPA	06/01/12				$405,000	SPP	12 months	regional reliability - non OATT	Cap Bank	652478	Gregory 115 kV	115	10 Mvar	10 Mvar cap at Gregory WAPA
	30258	50296	WAPA	06/01/12				$874,800	SPP	12 months	regional reliability - non OATT	Cap Bank	652479	Martin 115 kV	115	21.6 Mvar	21.6 Mvar cap at Martin WAPA
	30259	50297	WAPA	06/01/12				$1,215,000	SPP	12 months	regional reliability - non OATT	Cap Bank	652487	Phillips 115 kV	115	30 Mvar	30 Mvar cap bank at PHILLIPS WAPA
19985	30041	50047	WFEC	06/01/12		M	02/02/07	$350,000	WFEC	12 months	regional reliability	Cap Bank	520864	Comanche 138 kV	138	12 Mvar	Install 12 Mvar capacitor at Comanche 138 kV bus
20003	30093	50099	WFEC	06/01/12		M	02/13/08	$324,000	SPP	12 months	regional reliability	Cap Bank	520971	Latta Junction 138 kV	138	12 Mvar	Install 12 Mvar capacitor at Latta Junction 138 kV
20006	30096	50102	WR	06/01/12		M	02/13/08	$580,000	WR	18 months	Zonal Reliability	Cap Bank	533240	Eudora 115 kV	115	20 Mvar	Install 20 Mvar capacitor bank at Eudora 115 kV
20059	30225	50229	WR	06/01/12			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533621	Allen 69 kV	69	15 Mvar	Add 15 Mvar Cap bank at Allen
	30256	50295	WR	06/01/12		M		$1,120,000	SPP		zonal - sponsorec	Cap Bank	533036	Clearwater 138 kV	138	28.8 Mvar	Install 2nd block of 14.4 Mvar
Year 2013																	
	30206	50213	NPPD	06/01/12	NTC	06/01/13		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640192	Gordon 138 kV	115	9 Mvar	Install 9 Mvar capacitor bank at Gordon 115 kV.
20030	30178	50186	WFEC	06/01/13	NTC-Modify Timing	06/01/11	01/27/09	$240,000	SPP	12 months	regional reliability	Cap Bank	520894	Electra 69 kV	69	6 Mvar	Install 6 Mvar capacitor bank at Electra 69 kV bus for a total of 18 Mvar at this locatior
20006	30105	50111	WR	06/01/13		M	02/13/08	$1,000,000	WR	18 months	Zonal Reliability	Cap Bank	533267	Springhill 115 kV	115	30 Mvar	Install 30 Mvar capacitor at Springhill 115 kV
20059	30227	50231	WR	06/01/13			09/18/09	$607,500	WR	12 months	transmission service	Cap Bank	533623	Athens 69 kV	69	15 Mvar	Add 15 Mvar Cap bank at Athens
	30260	50298	WR	06/01/13		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533173	Scranton 115 kV	115	10.8 Mvar	1 stage of 10.8 Mvar
	30261	50299	WR	06/01/13		M		$432,000	SPP		zonal - sponsorec	Cap Bank	533176	Shawnee Heights 115 kV	115	10.8 Mvar	1 stage of 10.8 Mvar
Year 2014																	
	30247	50260	GRDA			06/01/14		$291,600	SPP	12 months	regional reliability	Cap Bank	512697	Wagoner 69 kV	69	7.2 Mvar	Install 7.2 Mvar capacitor bank at Wagner 69 kV
	30237	50249	NPPD	06/01/14		06/01/14		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640224	Holdrege 115 kV	115	18 Mvar	Install 18 Mvar capacitor bank at Holdrege 115 kV
	30262	50275	SPS			06/01/14		$291,600	SPP	12 months	regional reliability	Cap Bank	523579	Canadian 115 kV	115	7.2 Mvar	Install 7.2 Mvar at Canadian Sub
	30113	50119	SWPA	06/01/14		06/01/14		$1,215,000	SPP	12 months	regional reliability - non OATT	Cap Bank	504080	Glencoe 161 kV	161	30 Mvar	Install 30 Mvar capacitor at Glencoe 161 kV substation
20003	30039	50045	WFEC	06/01/14		M	01/27/09	$243,000	SPP	12 months	regional reliability	Cap Bank	520904	Esquandale 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Esquandale 69 kV
20059	30226	50230	WR	06/01/14			09/18/09	$607,500	WR	18 months	transmission service	Cap Bank	533673	Altoona East 69 kV	69	6 Mvar	Add 6 Mvar Cap bank at Altoona Eas
Year 2015																	
	30191	50198	MIDW			06/01/15		$180,000	MIDW	12 months	regional reliability	Cap Bank	530619	Kinsley 115 kV	115	3 Mvar	Install 3 additional Mvar cap at Kinsley 115 kV for a total 8 Mva
	30192	50199	MIDW			06/01/15		$180,000	MIDW	12 months	regional reliability	Cap Bank	530621	Pawnee 115 kV	115	3 Mvar	Install 3 additional Mvar cap at Pawnee 115 kV for a total 8 Mva
	766	50215	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525192	Kress 115 kV	115	28.8 Mvar	Add 28.8 Mvar capacitor at Kress 115 kV bus.
	766	50216	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525212	Swisher 115 kV	115	28.8 Mvar	Add 28.8 Mvar capacitor at Swisher 115 kV bus.
	30263	50300	SPS			06/01/15		$583,200	SPP	12 months	regional reliability	Cap Bank	528547	JAL 138 kV	138	14.4 Mvar	Install 2 Blocks of 7.2 Mvar
	30264	50301	SPS			06/01/15		$1,166,400	SPP	12 months	regional reliability	Cap Bank	528505	Lea Road 138 kV	138	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30272	50285	WFEC			06/01/15		$300,000	SPP	12 months	regional reliability	Cap Bank	520861	Cole 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Cole 69 kV bus.
	30180	50189	WFEC	06/01/15		06/01/13		$243,000	WFEC	12 months	regional reliability	Cap Bank	520804	Altus Air Force Base 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Altus Air Force Base 69 kV bus
	30188	50195	WFEC			06/01/15		$729,000	SPP	12 months	regional reliability	Cap Bank	520903	Erick 138kV	138	18 Mvar	Install 18 Mvar capacitor at Erick 138 kV bus
Year 2016																	
	30238	50250	NPPD	06/01/16		06/01/16		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640331	Riverdale 115 kV	115	36 Mvar	Add one 36 Mvar cap at Riverdale
	30239	50251	NPPD	06/01/16		06/01/16		$500,000	NPPD	24 months	zonal - sponsorec	Cap Bank	640073	Battle Creek 69 kV	69	9 Mvar	Add one 9 Mvar cap at Battle Creel
	30265	50302	SPS			06/01/16		$583,200	SPP	12 months	regional reliability - non OATT	Cap Bank	527361	LE_ERF sub 69 kV	69	14.4 Mvar	Install min. 2 blocks 7.2 Mvar

NTC_ID	PID	UID	Facility Owner	In-Service Date	2009 STEP BOD Action	2009 STEP Date	Latest Letter of notification to construct issue date	Cost Estimate	Estimated Cost Source	Project Lead Time	2009 Project Type	Device Type	SPP MDWG Bus Number 2007 series	Location	Voltage	Total Rating	Project Description
Year 2017																	
	30243	50256	AEP			06/01/17		$500,000	AEP	18 months	regional reliability	Cap Bank	508055	Bloomburg 69 kV	69	12 Mvar	Install 12 Mvar cap bank at Bloomburg 69 kV
	30207	50214	NPPD	06/01/17		06/01/17		$1,000,000	NPPD	24 months	regional reliability	Cap Bank	640144	Cozad 115 kV	115	18 Mvar	18 Mvar 115 KV CAP BANK AT COZAD
	30216	50220	SPS			06/01/17		$4,050,000	SPP	12 months	regional reliability	Cap Bank	522914	Wheeler 230 kV	230	50 Mvar	Install 50 Mvar capacitor bank at Wheeler min. 2 Blocks 25Mvar
	30266	50303	SPS			06/01/17		$583,200	SPP	12 months	regional reliability	Cap Bank	525027	Bailey Co 69 kV	69	14.4 Mvar	Install additional BLOCK 14.4 Mvar
	30140	50146	SWPA			06/01/17		$145,800	SPP	12 months	regional reliability - non OATT	Cap Bank	505458	China 69 kV	69	3.6 Mvar	Install 3.6 Mvar capacitor at China
Year 2018																	
	30184	50193	AEP			06/01/18		$600,000	AEP	18 months	regional reliability	Cap Bank	507434	South Nashville 138 kV	138	6 Mvar	Install 6 Mvar capacitor for a total of 12 Mvar at South Nashville
	30130	50136	CUS	06/01/18		06/01/18		$750,000	CUS	24 months	regional reliability	Cap Bank	549933	Twin Oaks 69 kV	69	30 Mvar	Install 30 MVAR capacitor at Twin Oaks Substation
	30267	50304	WR	06/01/18		M		$432,000	SPP		zonal - sponsored		533621	Allen 69 kV	69	20 Mvar	add one stage of 10 Mvar to existing 10 Mvar
	30268	50305	WR	06/01/18		M		$432,000	SPP		zonal - sponsored		533623	Athens 69 kV	69	20 Mvar	add one stage of 10 Mvar to existing 10 Mvar
Year 2019																	
	30241	50254	OPPD			06/01/19		$2,213,000	OPPD	12 Months	regional reliability	Cap Bank	647401	Neb City U Sub 903 69 kV	69	21.6 Mvar	Install 21.6 Mvar capacitor bank
	30269	50306	SPS			06/01/19		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525636	Lamb Co 115 kV	115	28.8 Mvar	Install 2 Blocks of 14.4 Mvar
	30270	50307	SPS			06/01/19		$1,166,400	SPP	12 months	regional reliability	Cap Bank	525622	Deaf Smith 115 kV	115	28.8 Mvar	Install min. 2 blocks 14.4 Mvar
Withdraw																	
20034	30174	50182	GMO		NTC-Withdraw	D	01/27/09	$350,000	SPP	12 months		Cap Bank	541365	Craig 69 kV	69	5 Mvar	Install 5 Mvar capacitor at Craig 69 kV bus
20034	30076	50082	GMO		NTC-Withdraw	D	01/27/09	$409,900	GMO	12 months		Cap Bank	541277	Warsaw 69 kV	69	12 Mvar	Install 12 Mvar capacitor at Warsaw 69 kV bus
20028	30177	50185	GRDA		NTC-Withdraw	D	1/27/2009	$291,600	GRDA	12 months		Cap Bank	300971	Tahlequah West 69 kV	69	7.2 Mvar	Add additional 7.2 Mvar capacitor at Tahlequah West, for a 28.8 Mvar total.
20003	30094	50100	WFEC		NTC-Withdraw	D	02/13/08	$162,000	SPP	12 months		Cap Bank	521005	Mustang 69 kV	69	6 Mvar	Install 6 Mvar capacitor at Mustang 69 kV

EXHIBIT NO. OGE-11

SPP
Notification to Construct

January 16, 2009 SPP-NTC- 20017

Mr. Mel Perkins
Oklahoma Gas and Electric Co.
PO Box 321, M/C ME10
Oklahoma City, OK 73101

RE: Transmission System Upgrade Notification to Construct for Transmission Service request resulting from Aggregate Transmission Service Study SPP-2006-AG3-AFS-11

Dear Mr. Perkins,

Southwest Power Pool has filed Service Agreement FERC Docket ER09-439, ER09-342, ER08-1206 for Transmission Service for customers in SPP-2006-AG3-AFS-11. In the facility study conducted in the assessment of these requests, SPP concluded that system upgrades are required on the Oklahoma Gas and Electric Co. system as detailed in Aggregate Facility Study SPP-2006-AG3-AFS-11.

As a result of transmission service customers confirmation of transmission service requests requiring network upgrades, SPP is notifying Oklahoma Gas and Electric Co. as the upgrade owner to move forward with the development of the following upgrades/mitigations to alleviate associated transmission service concerns.

New Network Upgrades

Project ID: 30158
Project Name: ARDMORE - ROCKY POINT 69KV CKT 1
RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $1,627,500

> **Upgrade ID:** 50166
> **Upgrade Description:** Replace 4.65 miles of line with 477AS33
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 10/16/2007

Project ID: 30159
Project Name: DILLARD4 - HEALDTON TAP 138KV CKT 1

RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $300,000

Upgrade ID: 50167
Upgrade Description: Replace Differential Relaying
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 10/16/2007

Project ID: 30160
Project Name: FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3
RTO Determined Need Date for Project: 6/1/2017
Estimated In Service Date: 6/1/2017
Estimated Cost for Project: $11,000,000

Upgrade ID: 50168
Upgrade Description: Convert Ft. Smith 161KV to 1-1/2 breaker design and install 3rd 500-161KV transformer bank.
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 7/30/2008

Project ID: 30161
Project Name: HUGO - SUNNYSIDE 345KV OKGE
RTO Determined Need Date for Project: 4/1/2012
Estimated In Service Date: 4/1/2012
Estimated Cost for Project: $75,000,000

Upgrade ID: 50169
Upgrade Description: Add 345 KV line from SunnySide to WFEC interception of 345KV line from Hugo, Install 345KV breaker, switches, and relays at Sunnyside
Categorization: Service Upgrade
Upgrade Justifications: SPP-2006-AG3-AFS-11
Source of funding for Upgrade: Full Base Plan funded
Estimated Cost Source: OKGE
Date of Estimated Cost: 8/18/2008

Project ID: 30162
Project Name: SUNNYSIDE - UNIROYAL 138KV CKT 1

RTO Determined Need Date for Project: 6/1/2011
Estimated In Service Date: 6/1/2011
Estimated Cost for Project: $50,000

> **Upgrade ID:** 50170
> **Upgrade Description:** Replace wavetrap 800A at Uniroyal
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Project ID: 30163
Project Name: SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1
RTO Determined Need Date for Project: 4/1/2012
Estimated In Service Date: 4/1/2012
Estimated Cost for Project: $6,750,000

> **Upgrade ID:** 50171
> **Upgrade Description:** Add 2nd 345/138KV Auto Transformer
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Project ID: 30164
Project Name: VBI - VBI NORTH 69KV CKT 1
RTO Determined Need Date for Project: 6/1/2017
Estimated In Service Date: 6/1/2017
Estimated Cost for Project: $100,000

> **Upgrade ID:** 50172
> **Upgrade Description:** Upgrade CT
> **Categorization:** Service Upgrade
> **Upgrade Justifications:** SPP-2006-AG3-AFS-11
> **Source of funding for Upgrade:** Full Base Plan funded
> **Estimated Cost Source:** OKGE
> **Date of Estimated Cost:** 8/18/2008

Oklahoma Gas and Electric Co. shall submit a notification of commercial operation for each listed Upgrade ID# to SPP at the email address of SPPprojecttracking@spp.org as soon as the upgrade is complete and in service. Please provide SPP with the actual costs

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of these upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Please send SPP written commitment to construct these projects within 90 days in addition to providing a construction schedule for the accepted upgrades. For project tracking, SPP will request on a quarterly basis in conjunction with the SPP Board of Directors meetings that Oklahoma Gas and Electric Co. submit updates to the upgrade schedule status. Consistent with Section 32.10 of the SPP Tariff, please keep SPP advised of any inability on Oklahoma Gas and Electric Co.'s part to complete the approved upgrades. If it is anticipated that the completion of any approved upgrade will be delayed past the estimated in service date, SPP requires a mitigation plan be filed within 60 days of the determination of expected delay in the upgrade schedule.

Don't hesitate to contact me if you have questions or comments about these requests. Thank you for the important role that you plan in maintaining the reliability of our electric grid.

Sincerely,

John E. Mills

John Mills
Manager, Tariff Studies
Phone (501) 614-3356 • Fax: (501) 666-0376 • jmills@spp.org

cc: Carl Monroe, Les Dillahunty, Pat Bourne, Jay Caspary, SPPprojecttracking@spp.org, Phil Crissup, Travis Hyde, Jacob Langthorn

EXHIBIT NO. OGE-12

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SPP
Notification to Construct

September 18, 2009 SPP-NTC- 20055

Mr. Mel Perkins
Oklahoma Gas and Electric Co.
M/C 1103
Oklahoma City, OK 73101

RE: Notification to Construct for Transmission Service request resulting from Aggregate Transmission Service Study SPP-2007-AG1-AFS-12

Dear Mr. Perkins,

Pursuant to Section 3.3 of the Southwest Power Pool, Inc. ("SPP") Membership Agreement and Attachment O, Section VIII, of the SPP Open Access Transmission Tariff ("OATT"), SPP provides this Notification to Construct ("NTC") directing Oklahoma Gas and Electric Co., as the Designated Transmission Owner, to construct the Network Upgrades.

Southwest Power Pool has filed Service Agreement FERC Docket ER09-1397, ER09-1504, ER09-1506 for Transmission Service for customers in SPP-2007-AG1-AFS-12. In the facility study conducted in the assessment of these requests, SPP concluded that system upgrades are required on the Oklahoma Gas and Electric Co. system as detailed in Aggregate Facility Study SPP-2007-AG1-AFS-12.

Upgrades with Modifications

Previous NTC Number: 19961
Previous NTC Issue Date: 6/27/2007
Project ID: 523
Project Name: ROSE HILL - SOONER 345KV CKT 1 OKGE
RTO Determined Need Date for Project: 6/1/2012
Estimated In Service Date: 6/1/2012
Estimated Cost for Project: $45,000,000

> **Network Upgrade ID:** 10668
> **Network Upgrade Description:** New 345 kV line from Sooner to Oklahoma/Kansas Stateline or the interface with the Westar Energy line segment to achieve 3000 amp or greater emergency rating
> **Reason For Change:** The project is needed at an earlier in service date than previous NTC identified
> **Categorization:** Regional Reliability Upgrade

Network Upgrade Specifications: All elements and conductor must have at least an emergency rating of 1743 MVA, but is not limited to that amount.
Network Upgrade Justifications: SPP-2007-AG1-AFS-12
Source of Funding for Network Upgrade: Full Base Plan Funding
Estimated Cost Source: OKGE
Date of Estimated Cost: 1/1/2009

Commitment to Construct

Please provide to SPP a written commitment to construct the Network Upgrade(s) within 90 days of the date of this Notification to Construct, pursuant to Attachment O, Section VIII.6 of the SPP Open Access Transmission Tariff, in addition to providing a construction schedule for the Network Upgrade(s). Failure to provide a sufficient written commitment to construct as required by Attachment O could result in the Network Upgrade(s) being assigned to another entity.

Notification of Commercial Operation

Please submit a notification of commercial operation for each listed Network Upgrade to SPP at the email address of SPPprojecttracking@spp.org as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of these Network Upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

Mitigation Plan

The Need Date or Estimated In-Service Date repesents the timing required for the Network Upgrade(s) to address the identified need. Your prompt attention is required to formulation and approval of any necessary mitigation plans for the Network Upgrade(s) included in the Network Upgrades(s) if the Need Date or Estimated In-Service Date is not feasible. Additionally, if it is anticipated that the complettion if any Network Upgrade will be delayed past the Need Date or Estimated In-Service Date, SPP requires a mitigation plan be filed within 60 days of determination of expected delays.

Notification of Progress

On an ongoing basis, please keep SPP advised of any ability on OKGE's part to complete the approved Network Upgrade(s). For project tracking, SPP requires OKGE to submit updates on the status of the Network Upgrade(s) on a quarterly basis in conjunction with the SPP Board of Directors meetings. However consistent with Section 20.1 and 32.10 of the SPP Tariff, OKGE shall also advise SPP of any inability to comply with the Project Scheduke as as the inability becomes apparent. All terms and conditions of the SPP OATT and the membership Agreement shall apply to this Project and nothing in this letter shall cary such terms and conditions.

Don't hesitate to contact me if you have questions or comments about these requests. Thank you for the important role that you plan in maintaining the reliability of our electric grid.

Southwest Power Pool

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Sincerely,

John E. Mills

John Mills
Manager, Tariff Studies
Phone (501) 614-3356 • Fax: (501) 666-0376 • jmills@spp.org

cc: Carl Monroe, Les Dillahunty, Bruce Rew, Pat Bourne, Jay Caspary, SPPprojecttracking@spp.org, Phil Crissup, Travis Hyde, Jacob Langthorn IV, Colin Whitley, Tom Littleton, Wende Oliaro, Scott Davidson, Grant Wilkerson

EXHIBIT NO. OGE-13

Southwest Power Pool

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SPP
Notification to Construct

June 19, 2009 SPP-NTC-20041

Mr. Jacob Langthorn, IV
Oklahoma Gas and Electric Co.
301 North Harvey
Oklahoma City, OK 73102

RE: Notification to Construct Approved Balanced Portfolio Network Upgrades

Dear Mr. Langthorn:

Pursuant to Section 3.3 of the Southwest Power Pool, Inc. ("SPP") Membership Agreement and Attachment O, Section VIII, of the SPP Open Access Transmission Tariff ("OATT"), SPP provides this Notification to Construct ("NTC") directing Oklahoma Gas and Electric Company ("OKGE"), as the Designated Transmission Owner, to construct the following approved Network Upgrades.

During the April 28, 2009 meeting, the SPP Board of Directors approved Balanced Portfolio 3E "adjusted" and directed the following Network Upgrades to be constructed contingent upon the approval of the Balanced Portfolio Report by the Markets and Operations Policy Committee ("MOPC"). On June 12, 2009 the MOPC approved the 2009 Balanced Portfolio Report.

Project ID: 699
Project Name: Sooner – Cleveland 345 kV line
Estimated In-Service Date for Project: 12/31/2012
Estimated Cost for project: $17,000,000

> **Network Upgrade ID:** 10929
> **Network Upgrade Description:** 345 kV line from OKGE Sooner substation to GRDA interception of 345 kV line from Grand River Dam Authority ("GRDA") Cleveland substation.
> **Network Upgrade Owner:** OKGE
> **MOPC Representative:** Jacob Langthorn, IV
> **Categorization:** Balanced Portfolio Network Upgrade
> **Network Upgrade Specifications:** Construct 18 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Sooner substation to GRDA interception and acquire the necessary right-of-way to accommodate the 345 kV line. Upgrade the Sooner substation with the necessary breakers, relays and ring-bus.
> **Network Upgrade Justification:** Balanced Portfolio 3E "adjusted"
> **Estimated In-Service Date for Network Upgrade:** 12/31/2012
> **Estimated Cost for Network Upgrade (current day dollars):** $17,000,000
> **Source of funding for Network Upgrade:** Region-wide charge as specified by Attachment J, SPP OATT
> **Source of Cost Estimate:** OKGE
> **Date of Cost Estimate:** April 2009

Project ID: 700
Project Name: Seminole – Muskogee 345 kV line
Estimated In-Service Date for Project: 12/31/2013
Estimated Cost for project: $131,000,000

Network Upgrade ID: 10930
Network Upgrade Description: 345 kV line from the OKGE Seminole substation to OKGE Muskogee substation.
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Construct 100 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Seminole substation to OKGE Muskogee substation and acquire right-of-way able to accommodate the 345 kV line. Upgrade the Muskogee substation to include any necessary terminal equipment.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 12/31/2013
Estimated Cost for Network Upgrade (current day dollars): $127,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Network Upgrade ID: 10931
Network Upgrade Description: Seminole 345/138 kV Transformer
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Upgrade the OKGE Seminole substation with a 345/138 kV 400 MVA transformer and any other necessary terminal equipment.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 12/31/2013
Estimated Cost for Network Upgrade (current day dollars): $4,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Project ID: 701
Project Name: Tuco – Woodward District EHV 345 kV line
Estimated In-Service Date for Project: 5/19/2014
Estimated Cost for project: $79,000,000

Network Upgrade ID: 10932
Network Upgrade Description: 345 kV line from OKGE Woodward District EHV substation to Southwestern Public Service ("SPS") interception of 345 kV line at the Oklahoma/Texas state line.
Network Upgrade Owner: OKGE

MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Construct 72 miles of 345 kV, 3000 amp or greater capacity transmission line from OKGE Woodward District EHV to the SPS interception from SPS Tuco substation and acquire right-of-way able to accommodate the 345 kV line.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 5/19/2014
Estimated Cost for Network Upgrade (current day dollars): $64,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Network Upgrade ID: 10933
Network Upgrade Description: Woodward District EHV 345/138 kV Transformer and 50 MVAR reactor bank
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Upgrade the OKGE Woodward District EHV substation with a 345/138 kV 400 MVA auto transformer with a 345 kV ring bus configuration.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 5/19/2014
Estimated Cost for Network Upgrade (current day dollars): $15,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OKGE
Date of Cost Estimate: April 2009

Project ID: 709
Project Name: Anadarko Substation
Estimated In-Service Date for Project: 12/31/2011
Estimated Cost for project: $8,000,000

Network Upgrade ID: 10946
Network Upgrade Description: Anadarko Substation
Network Upgrade Owner: OKGE
MOPC Representative: Jacob Langthorn, IV
Categorization: Balanced Portfolio Network Upgrade
Network Upgrade Specifications: Tap the existing Cimarron – Lawton Eastside 345 kV line at the existing Western Farmers Electric Coop. Anadarko 138 kV substation and install new 345/138 kV 450 MVA transformer at a new substation.
Network Upgrade Justification: Balanced Portfolio 3E "adjusted"
Estimated In-Service Date for Network Upgrade: 12/31/2011
Estimated Cost for Network Upgrade (current day dollars): $8,000,000
Source of funding for Network Upgrade: Region-wide charge as specified by Attachment J, SPP OATT
Source of Cost Estimate: OGKE

Date of Cost Estimate: April 2009

OKGE is responsible for coordinating these jointly owned projects with other constructing Designated Transmission Owners. Coordination includes but is not limited to construction specifications, facility ratings, interception location, and construction timing.

Please provide to SPP a written commitment to construct the Network Upgrades within 90 days of the date of this Notification to Construct, pursuant to Attachment O, Section VIII.6 of the SPP OATT, in addition to providing a construction schedule for the Network Upgrades. Failure to provide a sufficient written commitment to construct as required by Attachment O could result in the Network Upgrades being assigned to another entity.

Please submit a notification of commercial operation for each listed Network Upgrade to SPP as soon as the Network Upgrade is complete and in-service. Please provide SPP with the actual costs of these Network Upgrades as soon as possible after completion of construction. This will facilitate the timely billing by SPP based on actual costs.

On an ongoing basis, please keep SPP advised of any inability on OKGE's part to complete the approved Network Upgrades. For project tracking purposes, SPP requires OKGE to submit updates on the status of the Network Upgrades on a quarterly basis in conjunction with the SPP Board of Directors meetings. However, OKGE shall also advise SPP of any inability to comply with the Project Schedule as soon as the inability becomes apparent.

All terms and conditions of the SPP OATT and the SPP Membership Agreement shall apply to this Project, and nothing in this letter shall vary such terms and conditions.

Feel free to contact me if you have questions or comments regarding these instructions. Thank you for the important role that you play in maintaining the reliability of our electric grid.

Sincerely,

Bruce A. Rew

Bruce Rew
Vice President, Engineering
Phone (501) 614-3214 • Fax: (501) 821-3198 • brew@spp.org

cc: Carl Monroe, Les Dillahunty, Pat Bourne, Jay Caspary, Keith Tynes, SPPProjecttracking@spp.org, Phil Crissup, Travis Hyde, GRDA Joe Fultz, GRDA Anthony Due, GRDA Mike Herron, SPS John Fulton, SPS William Grant, WFEC Alan Derichsweiler, WFEC Ron Cunningham, WFEC Mitchell Williams

EXHIBIT NO. OGE-14

Aggregate Facility Study
SPP-2006-AG3-AFS-11
For Transmission Service
Requested by
Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

Table of Contents

1. <u>Executive Summary</u>

Pursuant to Attachment Z1 of the Southwest Power Pool Open Access Transmission Tariff (OATT), 1488 MW of long-term transmission service requests have been restudied in this Aggregate Facility Study (AFS). The first phase of the AFS consisted of a revision of the impact study to reflect the withdrawal of requests for which an Aggregate Facility Study Agreement was not executed. The principal objective of the AFS is to identify system problems and potential modifications necessary to facilitate these transfers while maintaining or improving system reliability as well as summarizing the operating limits and determination of the financial characteristics associated with facility upgrades. Facility upgrade costs are allocated on a prorated basis to all requests positively impacting any individual overloaded facility. Further, Attachment Z2 provides for facility upgrade cost recovery by stating that “Transmission Customers paying Directly Assigned Upgrade Costs for Service Upgrades or that are in excess of the Safe Harbor Cost Limit for Network Upgrades associated with new or changed Designated Resources and Project Sponsors paying Directly Assigned Upgrade Costs for Sponsored Upgrades shall receive revenue credits in accordance with Attachment Z2.”

The total assigned facility upgrade Engineering and Construction (E &C) cost determined by the AFS is $247 Million. Additionally an indeterminate amount of assigned E & C cost for 3rd party facility upgrades are assignable to the customer. The total upgrade levelized revenue requirement for all transmission requests is $ 710 Million. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. AFS data table 3 reflects the allocation of upgrade costs to each request without potential base plan funding based on either the requested reservation period or the deferred reservation period if applicable. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $9 Million.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service. These include both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are indeterminate.

The Transmission Provider will tender a Letter of Intent on September 16, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by October 1st, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

At the conclusion of the ATSS, Service Agreements for each request for service will be tendered identifying the terms and conditions of the confirmed service.

If customers withdraw from the ATSS after posting of this AFS, the AFS will be re-performed to determine final cost allocation and Available Transmission Capability (ATC) in consideration of the remaining ATSS participants. All allocated revenue requirements for facility upgrades are assigned to the customer in the AFS data tables. Potential base plan funding allowable is contingent upon validation of designated resources meeting Attachment J, Section III B criteria.

2. Introduction

On January 21, 2005, the Federal Energy Regulatory Commission accepted Southwest Power Pool’s proposed aggregate transmission study procedures in Docket ER05-109 to become effective February 1, 2005. In compliance with this Order, the third open season of 2006 commenced on October 1, 2006. All requests for long-term transmission service received prior to October 1, 2006 with a signed study agreement were then included in this third Aggregate Transmission Service Study (ATSS) of 2006.

Approximately 1488 MW of long-term transmission service has been restudied in this Aggregate Facility Study (AFS) with over $247 Million in transmission upgrades being proposed. The results of the AFS are detailed in Tables 1 through 7. A highly tangible benefit of studying transmission requests aggregately under the SPP OATT Attachment Z1 is the sharing of costs among customers using the same facility. The detailed results show individual upgrade costs by study as well as potential base plan allowances as determined by Attachments J and Z1. The following URL can be used to access the SPP OATT: (http://www.spp.org/Publications/SPP_Tariff.pdf). In order to understand the extent to which base plan upgrades may be applied to both point-to-point and network transmission services, it is necessary to highlight the definition of Designated Resource. Per Section 1.9a of the SPP OATT, a Designated Resource is "[a]ny designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis." Therefore, not only network service, but also point-to-point service has potential for base plan funding if the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J are met.

Pursuant to Attachment J, Section III B of the SPP OATT, the Transmission Customer must provide SPP information necessary to verify that the new or changed Designated Resource meets the following conditions:

1. Transmission Customer's commitment to the requested new or changed Designated Resource must have a duration of at least five years.

2. During the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer's existing Designated Resources plus the lesser of (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer's projected system peak responsibility determined pursuant to SPP Criteria 2.

According to Attachment Z1 Section VI.A, Point-to-Point customers pay the higher of the monthly transmission access charge (base rate) or the monthly revenue requirement associated with the assigned facility upgrades including any prepayments for redispatch required during construction.

Network Integration Service customers pay the total monthly transmission access charges and the monthly revenue requirement associated with the facility upgrades including any prepayments for redispatch during construction.

Transmission Customers paying for a directly assigned network upgrade shall receive credits for new transmission service using the facility as specified in Attachment Z2.

Facilities identified as limiting the requested Transmission Service have been reviewed to determine the required in-service date of each Network Upgrade. The year that each Network Upgrade is required to accommodate a request is determined by interpolating between the applicable model years given the respective loading data. Both previously assigned facilities and the facilities assigned to this request for Transmission Service were evaluated.

In some instances due to lead times for engineering and construction, Network Upgrades may not be available when required to accommodate a request for Transmission Service. When this occurs, the ATC with available Network Upgrades will be less than the capacity requested during either a portion of or all of the requested reservation period. As a result, the lowest seasonal allocated ATC within the requested reservation period will be offered to the Transmission Customer on an applicable annual basis as listed in Table 1. The ATC may be limited by transmission owner planned projects, expansion plan projects, or customer assigned upgrades.

Some constraints identified in the AFS were not assigned to the Customer as the Transmission Provider determined that upgrades are not required due to various reasons or the Transmission Owner has construction plans pending for these upgrades. These facilities are listed by reservation in Table 3. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer. Table 6 lists possible redispatch pairs to allow start of service prior to completion of assigned network upgrades. Table 7 (if applicable) lists deferment of expansion plan projects with different upgrades with the new required in service date as a result of this AFS.

A. <u>Financial Analysis</u>

The AFS utilizes the allocated customer E & C cost in a present worth analysis to determine the monthly levelized revenue requirement of each facility upgrade over the term of the reservation. In some cases, network upgrades cannot be completed within the requested reservation period, thus deferred reservation periods will be utilized in the present worth analysis. If the Customer chose Option 2, Redispatch, in the Letter of Intent sent coincident with the initial AFS, the present worth analysis of revenue requirements will be based on the deferred term with redispatch in the subsequent AFS. The upgrade levelized revenue requirement includes interest, depreciation, and carrying costs.

Each request for Transmission Service is evaluated independently as the cost associated with each Network Upgrade is assigned to a request. When facilities are upgraded throughout the reservation period, the Transmission Customer shall 1) pay the total E & C costs and other annual operating costs associated with the new facilities, and 2) receive credits associated with the depreciated book value of removed usable facilities, salvage value of removed non-usable facilities, and the carrying charges, excluding depreciation, associated with all removed usable facilities based on their respective book values.

In the event that the engineering and construction of a previously assigned Network Upgrade may be expedited, with no additional upgrades, to accommodate a new request for Transmission Service, then the levelized present worth of only the incremental expenses though the reservation period of the new request, excluding depreciation, shall be assigned to the new request. These incremental expenses, excluding depreciation, include 1) the levelized difference in present worth of the engineering and construction expenses given the change in date to complete construction to account for additional interest expense and reduced engineering and construction expense due to inflation, 2) the levelized present worth of all expediting fees, and 3) the levelized present worth of the incremental annual carrying charges, excluding depreciation and interest, during the new reservation period taking into account both a) the reservation in which the project was originally assigned, and b) a reservation, if any, in which the project was previously expedited.

Achievable Base Plan Avoided Revenue Requirements in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.B methodology. A deferred Base Plan upgrade being defined as a different requested network upgrade needed at an earlier date that negates the need for the initial base plan upgrade within the planning horizon. A displaced Base Plan upgrade being defined as the same network upgrade being displaced by a requested upgrade needed at an earlier date. Assumption of a 40 year service life is utilized for Base Plan funded projects unless provided otherwise by the Transmission Owner. A present worth analysis of revenue requirements on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan revenue requirements due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The difference in present worth between the Base Plan and Requested Upgrades is assigned to the transmission requests impacting this upgrade based on the displacement or deferral.

B. <u>Third Party Facilities</u>

For third-party facilities listed in Table 3 and Table 5, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the Transmission Provider's OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are indeterminate. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making arrangements for necessary engineering, permitting, and construction of the third-party facilities. Third-party facility upgrade engineering and construction cost estimates are not utilized to determine the present worth value of levelized revenue requirements for SPP system network upgrades.

All modeled facilities within the Transmission Provider system were monitored during the development of this Study as well as certain facilities in first-tier neighboring systems. Third-party facilities must be upgraded when it is determined that they are overloaded while accommodating the requested Transmission Service. An agreement between the Customer and 3rd Party Owner detailing the mitigation of the 3rd party impact must be provided to the Transmission Provider prior to tendering of a Transmission Service Agreement. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT. Upgrades on the Southwest Power Administration network requires prepayment of the upgrade cost prior to construction of the upgrade.

Third-party facilities are evaluated for only those requests whose load sinks within the SPP footprint. The Customer must arrange for study of 3rd party facilities for load that sinks outside the SPP footprint with the applicable Transmission Providers.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Reliability Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The upper bound and lower bound of the normal voltage range monitored is 110% and 90%. The upper bound and lower bound of the emergency voltage range monitored is 110% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 98.5% due to transmission operating procedure.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the control areas with SPP reserve share program redispatch. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 115 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

B. Model Development

SPP used twelve seasonal models to study the aggregate transfers of 1488 MW over a variety of requested service periods. The SPP MDWG 2007 Series Cases Update 2 2007/08 Winter Peak (07WP), 2008 April (08AP), 2008 Spring Peak (08G), 2008 Summer Peak (08SP), 2008 Summer Shoulder (08SH), 2008 Fall Peak (08FA), 2008/09 Winter Peak (08WP), 2009 Summer Peak (09SP), 2009/10 Winter Peak (09WP), 2012 Summer Peak (12SP), 2012/13 Winter Peak (12WP),and 2017 Summer Peak (17SP) were used to study the impact of the requested service on the transmission system. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. Five groups of requests were developed from the aggregate of 1488 MW in order to minimize counter flows among requested service. Each request was included in at least two of the four groups depending on the requested path. All requests were included in group five. From the twelve seasonal models, five system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2007 Series Cases flowing in a West to East direction with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS importing from the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2007 Series Cases flowing in an East to West direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a South to North direction with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie. Scenario 4 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a North to South direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie. Scenario 5 include all transmission not already included in the SPP 2007 Series Cases with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie. The system scenarios were developed to minimize counter flows from previously confirmed, higher priority requests not included in the MDWG Base Case.

C. Transmission Request Modeling

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. The Generation to Load modeling is accomplished by developing a pre-transfer case by redispatching the existing designated network resource(s) down by the new designated network resource request amount and scaling down the applicable network load by the same amount proportionally. The post-transfer case for comparison is developed by scaling the network load back to the forecasted amount and dispatching the new designated network resource being requested. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource and the impacts on transmission system are determined accordingly. If the Network Integration Transmission Service request application clearly documents that the existing designated network resource(s) is being replaced or undesignated by the new designated network resource then MW impact credits will be given to the request as is done for a redirect of existing transmission service. Point-To-

Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

D. Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02 change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. Curtailment and Redispatch Evaluation

During any period when SPP determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, SPP will take whatever actions that are reasonably necessary to maintain the reliability of the Transmission System. To the extent SPP determines that the reliability of the Transmission System can be maintained by redispatching resources, SPP will evaluate interim curtailment of existing confirmed service or interim redispatch of units to provide service prior to completion of any assigned network upgrades. Any redispatch may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Transmission Customer's use of the Transmission System to serve its designated load. Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades. Curtailment of existing confirmed service is evaluated to provide only interim service. Curtailment of existing confirmed service is only evaluated at the request of the transmission customer.

SPP determined potential relief pairs to relieve the incremental MW impact on limiting facilities as identified in Table 6. Using the selected cases where the limiting facilities were identified, potential incremental and decremental units were identified by determining the generation amount available for increasing and decreasing from the units generation amount, maximum generation amount, and minimum generation amount. If the incremental or decremental amount was greater than 1 MW, the unit was considered as a potential incremental or decremental unit. Generation shift factors were calculated for the potential incremental and decremental units using Managing and Utilizing System Transmission (MUST). Relief pairs from the generation shift factors for the incremental and decremental units with a greater than 3% TDF on the limiting constraint were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. If the aggregate redispatch amount for the potential relief pair was determined to be three times greater than the lower of the increment or decrement then the pair was determined not to be feasible and is not included. If transmission customer would like to see additional relief pairs beyond the relief pairs determined, the transmission customer can request SPP to provide the additional pairs. The potential relief pairs **were not** evaluated to determine impacts on limiting facilities in the SPP and 1st-Tier systems. The redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the steady-state analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates both with and without redispatch (based on customer selection of redispatch if available), the minimum annual allocated ATC without upgrades and season of first impact. Table 2 identifies total E & C cost allocated to each Transmission Customer, letter of credit requirements, third party E & C cost assignments, potential base plan E & C funding (lower of allocated E & C or Attachment J Section III B criteria) , total revenue requirements for assigned upgrades without consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades with consideration of potential base plan funding, and final total cost allocation to the Transmission Customer. Table 3 provides additional details for each request including all assigned facility upgrades required, allocated E & C costs, allocated revenue requirements for upgrades, upgrades not assigned to customer but required for service to be confirmed, credits to be paid for previously assigned AFS facility upgrades, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Minimum ATC per upgrade with season of impact, Earliest Date Upgrade is required (DUN), Estimated Date the upgrade will be completed and in service (EOC), and Estimated E & C cost. Table 5 lists identified Third-Party constrained facilities. Table 6 identifies potential redispatch pairs available to relieve the aggregate impacts on identified constraints to prevent deferral of start of service. Table 7 (if applicable) identifies deferred expansion plan projects that were replaced with requested upgrades at earlier dates.

The potential base plan funding allowable is contingent upon meeting each of the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J. If the additional capacity of the new or changed designated resource exceeds the 125% resource to load forecast for the year of start of service, the requested resource is not eligible for base plan funding of required network upgrades and the full cost of the upgrades is assignable to the customer. If the 5 year term and 125% resource to load criteria are met, the lesser of the planned maximum net dependable capacity (NDC) or the requested capacity is multiplied by $180,000 to determine the potential base plan funding allowable. When calculating Base Plan Funding amounts that include a wind farm, the amount used is 10% of the requested amount of service, or the NDC. The Maximum Potential Base Plan Funding Allowable may be less than the potential base plan funding allowable due to the E & C Cost allocated to the customer being lower than the potential amount allowable to the customer. The customer is responsible for any assigned upgrade costs in excess of Potential Base Plan Engineering and Construction Funding Allowable.

Regarding application of base plan funding for PTP requests, if PTP base rate exceeds upgrade revenue requirements without taking into effect the reduction of revenue requirements by potential base plan funding, then the base rate revenue pays back the Transmission Owner for upgrades and no base plan funding is applicable as the access charge must be paid as it is the higher of “OR” pricing.

However, if initially the upgrade revenue requirements exceed the PTP base rate, then potential base plan funding would be applicable. The test of the higher of “OR” pricing would then be made against the remaining assignable revenue requirements versus PTP base rate. Examples are as follows:

Example A:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 47 million with the difference of 27 million E & C assignable to the customer. If the revenue requirements for the assignable portion is 54 million and the PTP base rate is 101 million, the customer will pay the higher “OR” pricing of 101 million base rate of which 54 million revenue requirements will be paid back to the Transmission Owners for the upgrades and the remaining revenue requirements of (140-54) or 86 million will be paid by base plan funding.

Example B:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 10 million with the difference of 64 million E & C assignable to the customer. If the revenue requirements for this assignable portion is 128 million and the PTP base rate is 101 million the customer will pay the higher "OR" pricing of 128 million revenue requirements to be paid back to the Transmission Owners and the remaining revenue requirements of (140-128) or 12 million will be paid by base plan funding.

Example C:

E & C allocated for upgrades is 25 million with revenue requirements of 50 million and PTP base rate of 101 million. Potential base plan funding is 10 million. Base plan funding is not applicable as the higher "OR" pricing of PTP base rate of 101 million must be paid and the 50 million revenue requirements will be paid from this.

The 125% resource to load determination is performed on a per request basis and is not based on a total of designated resource requests per Customer. A footnote will provide the maximum resource designation allowable for base plan funding consideration per Customer basis per year.

Base plan funding verification requires that each Transmission Customer with potential for base plan funding provide SPP attestation statements verifying that the firm capacity of the requested designated resource is committed for a minimum five year duration.

B. <u>Study Definitions</u>

The Date Upgrade Needed Date (DUN) is the earliest date the upgrade is required to alleviate a constraint considering all requests. End of Construction (EOC) is the estimated date the upgrade will be completed and in service. The Total Engineering and Construction Cost (E & C) is the upgrade solution cost as determined by the transmission owner. The Transmission Customer Allocation Cost is the estimated engineering and construction cost based upon the allocation of costs to all Transmission Customers in the AFS who positively impact facilities by at least 3% subsequently overloaded by the AFS. Minimum ATC is the portion of the requested capacity that can be accommodated with out upgrading facilities. Annual ATC allocated to the Transmission Customer is determined by the least amount of allocated seasonal ATC within each year of a reservation period.

5. Conclusion

The results of the AFS show that limiting constraints exist in many areas of the regional transmission system. Due to these constraints, transmission service cannot be granted unless noted in Table 3.

The Transmission Provider will tender a Letter of Intent on September 16, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by October 1, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

The Transmission Provider must receive an unconditional and irrevocable letter of credit in the amount of the total allocated Engineering and Construction costs assigned to the Customer. This letter of credit is not required for those facilities that are base plan funded. This amount is for all assignable Network Upgrades less pre-payment requirements. The amount of the letter of credit will be adjusted down on an annual basis to reflect amortization of these costs. The Transmission Provider will issue letters of authorization to construct facility upgrades to the constructing Transmission Owner. This date is determined by the engineering and construction lead time provided for each facility upgrade.

6. Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits – Apply immediately
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
MW mismatch tolerance – 0.5
Contingency case rating – Rate B
Percent of rating – 100
Output code – Summary
Min flow change in overload report – 3mw
Excld cases w/ no overloads form report – YES
Exclude interfaces from report – NO
Perform voltage limit check – YES
Elements in available capacity table – 60000
Cutoff threshold for available capacity table – 99999.0
Min. contng. case Vltg chng for report – 0.02
Sorted output – None
Newton Solution:
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits - Apply automatically
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch		Mimimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period
AECC	AG3-2006-001	1161209	CSWS	CSWS	70	6/1/2011	6/1/2031	4/1/2012	4/1/2032	6/1/2011	6/1/2031		0	12SP
AEPM	AG3-2006-039	1158760	CSWS	CSWS	160	7/1/2007	7/1/2012	6/1/2011	6/1/2016	10/1/2008	10/1/2013	[2]	0	12SP
AEPM	AG3-2006-040	1158761	CSWS	CSWS	160	11/1/2007	11/1/2012	6/1/2011	6/1/2016	10/1/2008	10/1/2013	[2]	0	12SP
AEPM	AG3-2006-044	1162214	CSWS	CSWS	455	6/1/2011	6/1/2031	4/1/2012	4/1/2032	6/1/2011	6/1/2031		0	12SP
AEPM	AG3-2006-094	1163062	CSWS	CSWS	550	6/1/2010	6/1/2015						0	12SP
NTEC	AG3-2006-035	1161974	CSWS	CSWS	52	6/1/2011	6/1/2031	4/1/2012	4/1/2032	6/1/2011	6/1/2031		0	12SP
OMPA	AG3-2006-028	1159596	CSWS	CSWS	41	6/1/2011	6/1/2031	4/1/2012	4/1/2032	6/1/2011	6/1/2031		0	12SP
					1488									

Note 1: Disregard Redispatch shown in Table 6 for limitations identified earlier than the start date with redispatch with the exception of limitations identified in the 2007 Summer Shoulder, and 2007 Fall Peak

Note 2: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Customer	Study Number	Reservation	Engineering and Construction Cost of Upgrades Allocated to Customer for Revenue Requirements	[1]Letter of Credit Amount Required	[2]Potential Base Plan Engineering and Construction Funding Allowable	Notes	[4]Additional Engineering and Construction Cost for 3rd Party Upgrades	[3] Total Revenue Requirements for Assigned Upgrades over term of reservation without potential base plan funding allocation	[3 5] Total Revenue Requirements for Assigned Upgrades over term of reservation WITH potential base plan funding allocation	Point-to-Point Base Rate over reservation period	[4]Total Cost of Reservation Assignable to Customer contingent upon base plan funding
AECC	AG3-2006-001	1161209	$ 31,284,158	$ -	$ 30,083,845	6		$ 96,513,356	$ -		$ 1,200,313
AEPM	AG3-2006-039	1158760	$ 12,859,942	$ -	$ 12,859,942		$ -	$ 20,883,146	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-040	1158761	$ 12,859,942	$ -	$ 12,859,942		$ -	$ 20,883,146	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-044	1162214	$ 116,025,695	$ -	$ 116,025,695		$ -	$ 377,900,681	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-094	1163062	$ 59,953,658	$ -	$ 52,797,654	6	$ -	$ 101,773,430	$ -	$ -	$ 7,156,004
NTEC	AG3-2006-035	1161974	$ 11,157,264	$ -	$ 11,157,264		$ -	$ 34,179,722	$ -	$ -	Schedule 9 charges
OMPA	AG3-2006-028	1159596	$ 18,629,556	$ -	$ 17,985,873	6	$ -	$ 58,531,336	$ -	$ -	$ 643,683
Totals			$ 262,770,214					$ 710,664,817			

Note 1: Letter of Credit required for financial security for transmission owner for network upgrades is determined by allocated engineering and construction costs less engineering and construction costs for upgrades when network customer is the transmission owner less the E & C allocation of expedited projects. Letter of Credit is not required for base plan funded upgrades. The LOC listed is based on meeting OATT Attachment J requirements for base plan funding.

Note 2. If potential base plan funding is applicable, this value is the lesser of the Engineering and Construction costs of assignable upgrades or the value of base plan funding calculated pursuant to Attachment J, Section III B criteria. Allocation of base plan funding is contingent upon verification of customer agreements meeting Attachment J, Section II B criteria. Not applicable if PTP base rate exceeds revenue requirements.

Note 3: Revenue Requirements (RR) are based upon deferred end dates if applicable. Deferred dates are based upon customer's choice to pursue redispatch. Achievable Base Plan Avoided RR in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.C methodology. Assumption of a 40 year service life is utilized for Base Plan funded projects. A present worth analysis of RR on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan RR due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The incremental increase in present worth of a Requested Upgrade on a common year basis as a Base Plan upgrade is assigned to the transmission requests impacting the upgrade based on the displacement or deferral. If the displacement analysis results in lower RR due the shorter amortization period of the requested upgrade when compared to a base plan amortization period, then no direct assignment of the upgrade cost is made due to the displacement to an earlier start date.

Note 4. For PTP requests, total cost is based on the higher of the base rate or assigned upgrade revenue requirements. For Network requests, the total cost is based on the assigned upgrade revenue requirement. Allocation of base plan funding will be determined after verification of designated resource meeting Attachment J, Section II B Criteria. Additionally E & C of 3rd Party upgrades is assignable to Customer. This includes prepayments required for any SWPA upgrades. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements with confirmation of base plan funding. Customer is responsible for negotiating redispatch costs if applicable. Customer is also responsible to pay credits for previously assigned upgrades that are impacted by their request. Credits can be paid from base plan funding if applicable.

Note 5: RR with base plan funding may increase or decrease even if no base plan funding is applicable to a particular request if another request that shares the upgrade is now full base plan funded resulting in a different amortization period for the upgrade and thus different RR.

Note 6: SWPA upgrade assignment requires prepayment and is not Base Plan fundable.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
AECC	AG3-2006-001

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
AECC	1161209	CSWS	CSWS	70	6/1/2011	6/1/2031	4/1/2012	4/1/2032	$ 30,083,845	$ -	$ 31,284,158	$ 96,513,356
									$ 30,083,845	$ -	$ 31,284,158	$ 96,513,356

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1161209	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 149,920	$ 1,627,500	$ 632,269
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012			$ 1,200,313	$ 9,000,000	$ -
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 27,959	$ 300,000	$ 117,914
	DYESS - ELM SPRINGS REC 161KV CKT 1 #1	6/1/2008	6/1/2008			$ 5,302	$ 100,000	$ 21,828
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 253,074	$ 4,800,000	$ 923,407
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 60,318	$ 500,000	$ 227,822
	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	6/1/2017	6/1/2017			$ 7,212,152	$ 9,750,000	$ 19,466,603
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 252,732	$ 2,090,000	$ 750,984
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 1,085,764	$ 9,000,000	$ 3,726,662
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	7/1/2012			$ 6,181,819	$ 57,530,000	$ 21,785,206
	Hugo - SunnySide 345kV OKGE	4/1/2008	4/1/2012			$ 4,681,683	$ 75,000,000	$ 22,436,827
	Hugo - SunnySide 345kV WFEC	4/1/2008	10/1/2011			$ 3,192,057	$ 45,000,000	$ 7,676,835
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 14,665	$ 100,000	$ 48,473
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 2,081	$ 19,364	$ 7,141
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 4,359	$ 35,000	$ 15,163
	SOUTH TEXARKANA REC - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 4,750,000	$ 4,750,000	$ 16,304,653
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 4,480	$ 50,000	$ 19,243
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 478,809	$ 6,750,000	$ 2,078,584
	VBI - VBI NORTH 69KV CKT 1	6/1/2017	6/1/2017			$ 100,000	$ 100,000	$ 273,741
					Total	$ 29,657,487	$ 226,501,864	$ 96,513,356

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1161209	412SUB - KANSAS TAP 161KV CKT 1	6/1/2012	6/1/2012		
	412SUB - KERR 161KV CKT 1	6/1/2012	6/1/2012		
	BONANZA - BONANZA TAP 161KV CKT 1	6/1/2011	6/1/2011		
	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	BULL SHOALS - BULL SHOALS 161KV CKT 1	6/1/2012	6/1/2012		
	CHAMBER SPRINGS - FARMINGTON AECC 161KV CKT 1	6/1/2017	6/1/2017		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	Device - Cox Cap	6/1/2013	6/1/2013		
	Device - Main Cap	6/1/2013	6/1/2013		
	Device - Mill Cap	6/1/2013	6/1/2013		
	Device - Norton Cap	6/1/2013	6/1/2013		
	EAST CENTERTON - FLINT CREEK 161 KV CKT 1	6/1/2014	6/1/2014		
	ELM SPRINGS REC - TONTITOWN 161KV CKT 1	6/1/2016	6/1/2016		
	FLINT CREEK - GENTRY REC 161KV CKT 1	6/1/2017	6/1/2017		
	KANSAS TAP - WEST SILOAM SPRINGS 161KV CKT 1	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	SILOAM CITY - WEST SILOAM SPRINGS 161KV CKT 1	6/1/2012	6/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1161209	Device - Sunset	6/1/2013	6/1/2013		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Credits required for the following network upgrades directly assigned to generation interconnection customer

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1161209	ASHDOWN REC (MILLWOOD) - OKAY 138KV CKT 1	1/1/2011	1/1/2011			$ 182,221	$ 10,739,857
	ASHDOWN REC (MILLWOOD) - PATTERSON 138KV CKT 1	1/1/2011	1/1/2011			$ 104,220	$ 6,453,589
	BANN - RED SPRINGS REC 138KV CKT 1	1/1/2011	1/1/2011			$ 2,775	$ 290,266
	MCNAB REC - TURK 115KV CKT 1	1/1/2011	1/1/2011			$ 21,820	$ 1,520,000
	OKAY - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 202,702	$ 8,891,827
	OKAY 138/69KV TRANSFORMER CKT 1	1/1/2011	1/1/2011			$ 56,431	$ 3,289,686
	SE TEXARKANA - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 413,535	$ 25,978,842
	SUGAR HILL - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 367,598	$ 19,060,827
	TURK (HEMP 1) 138/115/13.8KV TRANSFORMER CKT 1	1/1/2011	1/1/2011			$ 275,367	$ 8,765,106
					Total	$ 1,626,671	$ 84,990,000

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
AEPM	AG3-2006-039

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
AEPM	1158760	CSWS	CSWS	160	7/1/2007	7/1/2012	6/1/2011	6/1/2016	$ 12,859,942	$ -	$ 12,859,942	$ 20,883,146
									$ 12,859,942	$ -	$ 12,859,942	$ 20,883,146

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1158760	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 27,603	$ 1,782,291	$ 38,246
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 508	$ 32,833	$ 730
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 2,273,463	$ 4,800,000	$ 3,874,215
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 219,841	$ 500,000	$ 387,799
	Hugo - SunnySide 345kV OKGE	10/1/2008	4/1/2012		Yes	$ 5,104,124	$ 75,000,000	$ 9,349,731
	Hugo - SunnySide 345kV WFEC	10/1/2008	10/1/2011		Yes	$ 3,062,474	$ 45,000,000	$ 4,821,606
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 435,803	$ 4,560,000	$ 636,468
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	6/1/2009	6/1/2009			$ 62,500	$ 125,000	$ 95,682
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 94,930	$ 456,000	$ 143,035
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	10/1/2008	6/1/2010		Yes	$ 52,506	$ 200,000	$ 669,461
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2011		Yes	$ 459,371	$ 6,750,000	$ 866,173
					Total	$ 11,793,123	$ 139,206,124	$ 20,883,146

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158760	FULTON - HOPE 115KV CKT 1 AEPW	6/1/2012	6/1/2012		
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	10/1/2008	6/1/2009		Yes
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1158760	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012			$ 144,165	$ 2,500,000
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012			$ 922,654	$ 16,000,000
					Total	$ 1,066,819	$ 18,500,000

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158760	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2009		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	10/1/2008	6/1/2009		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
AEPM AG3-2006-040

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
AEPM	1158761	CSWS	CSWS	160	11/1/2007	11/1/2012	6/1/2011	6/1/2016	$ 12,859,942	$ -	$ 12,859,942	$ 20,883,146
									$ 12,859,942	$ -	$ 12,859,942	$ 20,883,146

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1158761	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 27,603	$ 1,782,291	$ 38,246
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 508	$ 32,833	$ 730
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 2,273,463	$ 4,800,000	$ 3,874,215
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 219,841	$ 500,000	$ 387,799
	Hugo - SunnySide 345kV OKGE	10/1/2008	4/1/2012		Yes	$ 5,104,124	$ 75,000,000	$ 9,349,731
	Hugo - SunnySide 345kV WFEC	10/1/2008	10/1/2011		Yes	$ 3,062,474	$ 45,000,000	$ 4,821,606
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 435,803	$ 4,560,000	$ 636,468
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	6/1/2009	6/1/2009			$ 62,500	$ 125,000	$ 95,682
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 94,930	$ 456,000	$ 143,035
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	10/1/2008	6/1/2010		Yes	$ 52,506	$ 200,000	$ 669,461
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2011		Yes	$ 459,371	$ 6,750,000	$ 866,173
					Total	$ 11,793,123	$ 139,206,124	$ 20,883,146

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158761	FULTON - HOPE 115KV CKT 1 AEPW	6/1/2012	6/1/2012		
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	10/1/2008	6/1/2009		Yes
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		Yes

Credits required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1158761	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012			$ 144,165	$ 2,500,000
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012			$ 922,654	$ 16,000,000
					Total	$ 1,066,819	$ 18,500,000

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158761	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2009		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	10/1/2008	6/1/2009		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
AEPM	AG3-2006-044

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
AEPM	1162214	CSWS	CSWS	455	6/1/2011	6/1/2031	4/1/2012	4/1/2032	$ 116,025,695	$ -	$ 116,025,695	$ 377,900,681
									$ 116,025,695	$ -	$ 116,025,695	$ 377,900,681

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1162214	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 764,916	$ 1,627,500	$ 3,225,937
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 141,602	$ 300,000	$ 597,189
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 1,540,361	$ 2,090,000	$ 4,577,129
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 6,711,928	$ 9,000,000	$ 23,037,314
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	7/1/2012			$ 42,406,792	$ 57,530,000	$ 149,444,802
	Hugo - SunnySide 345kV OKGE	10/1/2008	4/1/2012			$ 31,015,428	$ 75,000,000	$ 130,803,657
	Hugo - SunnySide 345kV WFEC	10/1/2008	10/1/2011			$ 18,609,257	$ 45,000,000	$ 44,754,903
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 1,701,079	$ 4,560,000	$ 5,319,374
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 266,140	$ 456,000	$ 858,617
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	10/1/2008	6/1/2010			$ 74,975	$ 200,000	$ 2,922,767
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 14,274	$ 19,364	$ 48,992
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 26,340	$ 35,000	$ 91,625
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 23,401	$ 50,000	$ 100,516
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2011			$ 2,791,389	$ 6,750,000	$ 12,117,860
					Total	$ 106,087,882	$ 202,617,864	$ 377,900,681

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1162214	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	6/1/2017	6/1/2017		
	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	6/1/2017	6/1/2017		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1162214	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2009		
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	10/1/2008	6/1/2009		

Credits required for the following network upgrades directly assigned to generation interconnection customer

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1162214	ASHDOWN REC (MILLWOOD) - OKAY 138KV CKT 1	1/1/2011	1/1/2011			$ 1,116,482	$ 10,739,857
	ASHDOWN REC (MILLWOOD) - PATTERSON 138KV CKT 1	1/1/2011	1/1/2011			$ 670,895	$ 6,453,589
	BANN - RED SPRINGS REC 138KV CKT 1	1/1/2011	1/1/2011			$ 26,915	$ 290,266
	MCNAB REC - TURK 115KV CKT 1	1/1/2011	1/1/2011			$ 134,538	$ 1,520,000
	OKAY - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 1,105,083	$ 8,891,827
	SE TEXARKANA - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 2,757,702	$ 25,978,842
	SUGAR HILL - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 2,428,519	$ 19,060,827
	TURK (HEMP 1) 138/115/13.8KV TRANSFORMER CKT 1	1/1/2011	1/1/2011			$ 1,697,679	$ 8,765,106
					Total	$ 9,937,813	$ 81,700,314

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
AEPM	AG3-2006-094

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
AEPM	1163062	CSWS	CSWS	550	6/1/2010	6/1/2015			$ 52,797,654	$ -	$ 59,953,658	$ 101,773,430
									$ 52,797,654	$ -	$ 59,953,658	$ 101,773,430

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1163062	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 565,829	$ 1,627,500	$ 1,244,659
	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 1,727,085	$ 1,782,291	$ 2,821,470
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 31,816	$ 32,833	$ 53,841
	ARSENAL HILL - WATERWORKS 69KV CKT 1	6/1/2010	6/1/2010			$ 3,898,800	$ 3,898,800	$ 6,196,459
	ARSENAL HILL (ARSHILL1) 138/69/12.47KV TRANSFORMER CKT 1	6/1/2010	6/1/2010			$ 3,005,700	$ 3,005,700	$ 4,777,033
	ARSENAL HILL (ARSHILL2) 138/69/14.5KV TRANSFORMER CKT 2	6/1/2010	6/1/2010			$ 3,005,700	$ 3,005,700	$ 4,777,033
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012			$ 7,156,004	$ 9,000,000	$ -
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 100,335	$ 300,000	$ 220,708
	Hugo - SunnySide 345kV OKGE	4/1/2008	4/1/2012			$ 22,924,913	$ 75,000,000	$ 50,428,147
	Hugo - SunnySide 345kV WFEC	4/1/2008	10/1/2011			$ 13,754,948	$ 45,000,000	$ 23,604,975
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 1,623,622	$ 4,560,000	$ 2,795,771
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 77,887	$ 100,000	$ 141,762
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 17,778	$ 50,000	$ 39,828
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 2,063,242	$ 6,750,000	$ 4,671,744
					Total	$ 59,953,658	$ 154,112,824	$ 101,773,430

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1163062	ARSENAL HILL - NORTH MARKET 69KV CKT 1	6/1/2010	6/1/2010		
	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	PORT ROBSON - REDPOINT 138kV	6/1/2012	6/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
NTEC	AG3-2006-035

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
NTEC	1161974	CSWS	CSWS	52	6/1/2011	6/1/2031	4/1/2012	4/1/2032	$ 11,157,264	$ -	$ 11,157,264	$ 34,179,722
									$ 11,157,264	$ -	$ 11,157,264	$ 34,179,722

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1161974	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #2	6/1/2012	6/1/2012			$ 4,250,000	$ 4,250,000	$ 13,711,295
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 141,961	$ 2,090,000	$ 421,832
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 574,865	$ 9,000,000	$ 1,973,106
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	7/1/2012			$ 5,065,246	$ 57,530,000	$ 17,850,317
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	6/1/2008	6/1/2010			$ 20,013	$ 200,000	$ 208,258
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 1,705	$ 19,364	$ 5,852
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 2,605	$ 35,000	$ 9,062
					Total	$ 10,056,395	$ 73,124,364	$ 34,179,722

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1161974	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #1	6/1/2012	6/1/2012		
	BIG SANDY - HAWKINS 69KV CKT 1	6/1/2014	6/1/2014		
	BIG SANDY - PERDUE 69KV CKT 1	6/1/2014	6/1/2014		
	CARTHAGE REC POD - ROCK HILL 138KV CKT 1	6/1/2017	6/1/2017		
	FOREST HILLS REC - MAGNOLIA TAP 69KV CKT 1	6/1/2010	6/1/2010		
	FOREST HILLS REC - QUITMAN 69KV CKT 1	6/1/2010	6/1/2010		
	GEORGIA-PACIFIC - KEATCHIE REC 138KV CKT 1	6/1/2015	6/1/2015		
	LONE STAR SOUTH - PITTSBURG 138KV CKT 1	6/1/2015	6/1/2015		
	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	6/1/2017	6/1/2017		
	MAGNOLIA TAP - WINNSBORO 69KV CKT 1	6/1/2010	6/1/2010		
	NORTH MINEOLA - QUITMAN 69KV CKT 1	6/1/2016	6/1/2016		
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	6/1/2008	6/1/2009		
	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	6/1/2017	6/1/2017		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1161974	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	10/1/2008	6/1/2009		
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	10/1/2008	6/1/2009		

Credits required for the following network upgrades directly assigned to generation interconnection customer

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1161974	ASHDOWN REC (MILLWOOD) - OKAY 138KV CKT 1	1/1/2011	1/1/2011			$ 124,194.69	$ 10,739,857
	ASHDOWN REC (MILLWOOD) - PATTERSON 138KV CKT 1	1/1/2011	1/1/2011			$ 74,628.70	$ 6,453,589
	BANN - RED SPRINGS REC 138KV CKT 1	1/1/2011	1/1/2011			$ 5,842.07	$ 290,266
	MCNAB REC - TURK 115KV CKT 1	1/1/2011	1/1/2011			$ 11,531.81	$ 1,520,000
	OKAY - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 117,011.58	$ 8,891,827
	SE TEXARKANA - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 334,664.32	$ 25,978,842
	SUGAR HILL - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 287,572.77	$ 19,060,827
	TURK (HEMP 1) 138/115/13.8KV TRANSFORMER CKT 1	1/1/2011	1/1/2011			$ 145,422.85	$ 8,765,106
					Total	$ 1,100,869	$ 81,700,314

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
OMPA	AG3-2006-028

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
OMPA	1159596	CSWS	CSWS	41	6/1/2011	6/1/2031	4/1/2012	4/1/2032	$ 17,985,873	$ -	$ 18,629,556	$ 58,531,336
									$ 17,985,873	$ -	$ 18,629,556	$ 58,531,336

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1159596	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 146,834	$ 1,627,500	$ 619,254
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012			$ 643,683	$ 9,000,000	$ -
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 30,104	$ 300,000	$ 126,960
	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	6/1/2017	6/1/2017			$ 2,537,848	$ 9,750,000	$ 6,850,005
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 154,945	$ 2,090,000	$ 460,414
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 627,443	$ 9,000,000	$ 2,153,569
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	7/1/2012			$ 3,876,143	$ 57,530,000	$ 13,659,827
	Hugo - SunnySide 345kV OKGE	4/1/2008	4/1/2012			$ 5,531,317	$ 75,000,000	$ 23,327,632
	Hugo - SunnySide 345kV WFEC	4/1/2008	10/1/2011			$ 3,318,790	$ 45,000,000	$ 7,981,626
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 363,694	$ 4,560,000	$ 1,137,293
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 7,448	$ 100,000	$ 24,618
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 1,305	$ 19,364	$ 4,478
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 1,696	$ 35,000	$ 5,900
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 4,343	$ 50,000	$ 18,652
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 497,819	$ 6,750,000	$ 2,161,110
					Total	$ 17,743,411	$ 220,811,864	$ 58,531,336

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1159596	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	BROWN - RUSSETT 138KV CKT 1 WFEC	6/1/2011	6/1/2011		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2011	6/1/2011		
	RUSSETT - RUSSETT 138KV CKT 1 OKGE	12/1/2012	12/1/2012		
	RUSSETT - RUSSETT 138KV CKT 1 WFEC	12/1/2012	12/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

Credits required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Total Revenue Requirements	Total E & C Cost
1159596	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006			$ 67,571	$ 10,183,486
					Total	$ 67,571	$ 10,183,486

Credits required for the following network upgrades directly assigned to generation interconnection customer

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1159596	ASHDOWN REC (MILLWOOD) - OKAY 138KV CKT 1	1/1/2011	1/1/2011			$ 102,197.08	$ 10,739,857
	ASHDOWN REC (MILLWOOD) - PATTERSON 138KV CKT 1	1/1/2011	1/1/2011			$ 61,410.32	$ 6,453,589
	BANN - RED SPRINGS REC 138KV CKT 1	1/1/2011	1/1/2011			$ 1,770.09	$ 290,266
	MCNAB REC - TURK 115KV CKT 1	1/1/2011	1/1/2011			$ 12,610.06	$ 1,520,000
	OKAY - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 37,380.98	$ 3,289,686
	SE TEXARKANA - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 235,889.41	$ 25,978,842
	SUGAR HILL - TURK 138KV CKT 1	1/1/2011	1/1/2011			$ 208,240.65	$ 19,060,827
	TURK (HEMP 1) 138/115/13.8KV TRANSFORMER CKT 1	1/1/2011	1/1/2011			$ 159,074.69	$ 8,765,106
					Total	$ 818,573	$ 76,098,173

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AECC	FULTON - HOPE 115KV CKT 1 AECC	Upgrades to Fulton Switching Station, Reconductor the Fulton to Hope 115/138kV Line, Upgrades to McNab Substation	06/01/11	06/01/11	$ 2,090,000
AEPW	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	Rebuild 3.24 miles of 1272 AAC with 2156 ACSR. Replace 3 switches, breaker jumpers, and reset CTs @ Arsenal Hill. Replace 2 switches and jumpers @ Fort Humbug	06/01/10	06/01/10	$ 1,782,291
AEPW	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	Replace Arsenal Hill switches and jumpers	06/01/10	06/01/10	$ 32,833
AEPW	ARSENAL HILL - WATERWORKS 69KV CKT 1	Rebuild 2.55 miles of 666 ACSR with 1272 ACSR	06/01/10	06/01/10	$ 3,898,800
AEPW	ARSENAL HILL (ARSHILL1) 138/69/12.47KV TRANSFORMER CKT 1	Replace auto & 69 kV breaker and switches	06/01/10	06/01/10	$ 3,005,700
AEPW	ARSENAL HILL (ARSHILL2) 138/69/14.5KV TRANSFORMER CKT 2	Replace auto & 69 kV breaker and switches	06/01/10	06/01/10	$ 3,005,700
AEPW	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #2	Reset relays @ Bann and replace switch @ Lone Star Ordinance Tap. Rebuild 4.14 miles of 397 ACSR with 795 ACSR.	06/01/12	06/01/12	$ 4,250,000
AEPW	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	Rebuild 5.17 miles of line.	06/01/10	06/01/10	$ 4,800,000
AEPW	DYESS - TONTITOWN 161KV CKT 1	Replace Dyess Breaker, Switches, & wavetrap	06/01/10	06/01/10	$ 500,000
AEPW	HEMPSTEAD - HOPE 115KV CKT 1	Reconductor from Hempstead to Hope 666 ACSR with 1590 ACSR, replace jumpers, circuit switcher, one span of conductor at Hope	06/01/11	06/01/11	$ 9,000,000
AEPW	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	Build 33 miles of 2-795MCM ACSR from Turk NW Texarkana, Add 345kV terminal at NW Texarkana, Add 345kV terminal at Turk	06/01/11	07/01/12	$ 57,530,000
AEPW	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	Replace Auto with new 450 MVA auto	12/01/12	12/01/12	$ 4,560,000
AEPW	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	Replace Linwood Switches 10872 & 10873 and replace breaker jumpers	06/01/09	06/01/09	$ 125,000
AEPW	LINWOOD - POWELL STREET 138KV CKT 1	Replace Breaker, Switches, & Jumpers @ Linwood. Replace circuit switcher @ Powell Street	06/01/12	06/01/12	$ 456,000
AEPW	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	Replac four (4) switches and upgrading bus work	06/01/08	06/01/10	$ 200,000
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	Replace Jumpers @ N. Magazine	06/01/12	06/01/12	$ 100,000
AEPW	OKAY - TOLLETTE 69KV CKT 1 Displacement	Replace switches	06/01/11	06/01/11	$ 19,364
AEPW	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	Change out the 500 CU jumpers @ Texarkana Plant	06/01/11	06/01/11	$ 35,000
AEPW	SOUTH TEXARKANA REC - TEXARKANA PLANT 69KV CKT 1	Rebuild 5.92 miles of 266 ACSR with 795 ACSR. Replace switches, jumpers, and reset CTs & relays @ Texarkana Plant	06/01/11	06/01/11	$ 4,750,000
OKGE	ARDMORE - ROCKY POINT 69KV CKT 1	Replace 4.65 miles of line w/477AS33	06/01/11	06/01/11	$ 1,627,500
OKGE	DILLARD4 - HEALDTON TAP 138KV CKT 1	Replace Differential Relaying	06/01/11	06/01/11	$ 300,000
OKGE	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	Convert Ft. Smith 161kv to 1-1/2 breaker design and install 3rd 500-161kV transformer bank.	06/01/17	06/01/17	$ 9,750,000
OKGE	Hugo - SunnySide 345kV OKGE	Add 345 line from Hugo to SunnySide, Install breaker, switches, and relays	04/01/08	04/01/12	$ 75,000,000
OKGE	SUNNYSIDE - UNIROYAL 138KV CKT 1	Replace wavetrap 800A at Uniroyal	06/01/11	06/01/11	$ 50,000
OKGE	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	Add 2nd 345/138V Auto Transformer	04/01/08	06/01/11	$ 6,750,000
OKGE	VBI - VBI NORTH 69KV CKT 1	Upgrade CT	06/01/17	06/01/17	$ 100,000
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	Reconductor 34.4 mile line	06/01/12	06/01/12	$ 9,000,000
WFEC	Hugo - SunnySide 345kV WFEC	Add 345 line from Hugo to SunnySide	04/01/08	10/01/11	$ 45,000,000

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	Using IEEE Guide for Loading of Mineral-Oil Immersed Power Transformers (C57.91-2000) Re-rate the autos. Replace .two 138 kV breakers and five 138 kV switches. Reset relays and CTs	04/01/08	06/01/09
AEPW	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	Replace Auto, two 138 kV breakers and five 138 kV switches. Reset relays and CTs	04/01/08	06/01/09
SPRM	Device - Sunset	30 Mvar Capacitor Bank at Sunset	06/01/13	06/01/13

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	ARSENAL HILL - NORTH MARKET 69KV CKT 1	Rebuild 2.3 miles of 666 ACSR with 1272 ACSR	06/01/10	06/01/10
AEPW	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #1	Relay at Bann New limits will be 65/72 MVA summer (line conductor/Lone Star switch) and 72/72 MVA winter (Lone Star Switch)	06/01/12	06/01/12
AEPW	BIG SANDY - HAWKINS 69KV CKT 1	Rebuild 5.5 miles of 477 ACSR with 1272 ACSR.	06/01/14	06/01/14
AEPW	BIG SANDY - PERDUE 69KV CKT 1	Rebuild 5.4 miles of 477 ACSR with 1272 ACSR.	06/01/14	06/01/14
AEPW	BONANZA - BONANZA TAP 161KV CKT 1	Rebuild 0.06 miles of 397 ACSR with 1272 ACSR & reset relay @ Bonanza or Bonanza T-Excelsior-Midland-N. Huntington 161 kV loop	06/01/11	06/01/11
AEPW	BONANZA - EXCELSIOR 161KV CKT 1	New 161 kV from Bonanza to Excelsior (includes Bonanza station)	06/01/14	06/01/14
AEPW	CARTHAGE REC POD - ROCK HILL 138KV CKT 1	Replace transformer differential relay and reset cts	06/01/17	06/01/17
AEPW	CHAMBER SPRINGS - FARMINGTON AECC 161KV CKT 1	Rebuild / reconductor 10.24 miles of line with 2156 ACSR.	06/01/17	06/01/17
AEPW	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	06/01/11	06/01/11
AEPW	EAST CENTERTON - FLINT CREEK 161 KV CKT 1	Reconductor Flint Creek-East Centerton 161 kV with 2156 conductor	06/01/14	06/01/14
AEPW	ELM SPRINGS REC - TONTITOWN 161KV CKT 1	Replace Wavetrap and switch jumpers	06/01/16	06/01/16
AEPW	FLINT CREEK - GENTRY REC 161KV CKT 1	Rebuild 1.09 miles of 2-397.5 ACSR with 2156 ACSR. Replace Flint Creek wavetrap & jumpers	06/01/17	06/01/17
AEPW	FOREST HILLS REC - MAGNOLIA TAP 69KV CKT 1	Replace switch 9116	06/01/10	06/01/10
AEPW	FOREST HILLS REC - QUITMAN 69KV CKT 1	Replace Quitman bus, switches & jumpers. Change CT & relay settings @ Quitman	06/01/10	06/01/10
AEPW	FULTON - HOPE 115KV CKT 1 AEPW	Replace strain bus in Hope Substation	06/01/12	06/01/12
AEPW	GEORGIA-PACIFIC - KEATCHIE REC 138KV CKT 1	Rebuild 12.63 miles of 795 ACSR with 1272 ACSR	06/01/15	06/01/15
AEPW	LONE STAR SOUTH - PITTSBURG 138KV CKT 1	Replace wavetraps at both ends. Reset CTs @ Lone Star South. Replace switches & reset relays @ Pittsburg	06/01/15	06/01/15
AEPW	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	Reconductor 1.8 miles of 666 ACSR with 1272 ACSR	06/01/17	06/01/17
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	Rebuild 7.43 miles of 250 CWC with 795 ACSR	06/01/11	06/01/11
AEPW	MAGNOLIA TAP - WINNSBORO 69KV CKT 1	Replace switch # 9114 @. Replace switches @ Winnsboro. Reset Cts and relay settings at Winnsboro.	06/01/10	06/01/10
AEPW	NORTH MINEOLA - QUITMAN 69KV CKT 1	Mineola to Quipman 69 kV up grade switches and sub conductor N Mineola and Quipman subs	06/01/16	06/01/16
AEPW	PORT ROBSON - REDPOINT 138kV	New 138 kV line from Port Robson - Red Point via McDade & Haughton. Convert McDade & Haughton to 138 kV.	06/01/12	06/01/12
AEPW	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	Rebuild 2.29 miles of 2-397.5 ACSR with 2-795 ACSR. Double Circuit the line and add terminal @ SW Shreveport to eliminate three terminal line.	06/01/08	06/01/09
AEPW	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	Rebuild 2.9 miles of 2-795 ACSR with 2156 ACSR. Replace switch 1647 @ Western Electric "T". Replace switch 10237 & reset relays @ SW Shreveport.	06/01/17	06/01/17
AEPW	Wallace Lake - Port Robson - RedPoint 138 kV	Convert Red Point - Haughton-McDade to 138 kV, 1590 ACSR (includes McDade station conversion)	06/01/08	06/01/10
EMDE	SUB 124 - AURORA H.T. 161KV	Install 3 - stages of 22 MVAR each for total of 66 MVAR capacitor bank at Aurora Sub #124 bus# 547537	06/01/14	06/01/14
EMDE	SUB 438 - RIVERSIDE 161KV	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 547497	06/01/14	06/01/14
GRDA	412SUB - KANSAS TAP 161KV CKT 1	Reconductor 9.7 miles with 1590MCM ACSR.	06/01/12	06/01/12
GRDA	412SUB - KERR 161KV CKT 1	Reconductor 8/10ths of mile out of Kerr Dam	06/01/12	06/01/12
GRDA	KANSAS TAP - WEST SILOAM SPRINGS 161KV CKT 1	Rebuild line to 1590 ACSR	06/01/12	06/01/12
GRDA	SILOAM CITY - WEST SILOAM SPRINGS 161KV CKT 1	Rebuild line to 1590 ACSR	06/01/12	06/01/12
OKGE	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	06/01/11	06/01/12
OKGE	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	Rebuild 7.43 miles of 250 CWC with 795 ACSR	06/01/11	06/01/11
OKGE	RUSSETT - RUSSETT 138KV CKT 1 OKGE	Replace trap and increase CTR. Pending verification of relays.	12/01/12	12/01/12
SPRM	Device - Cox Cap	Install 30 Mvar capacitor at Cox 69 kV bus	06/01/13	06/01/13
SPRM	Device - Main Cap	Install 30 Mvar capacitor at Main 161 kv bus	06/01/13	06/01/13
SPRM	Device - Mill Cap	Install 30 Mvar capacitor at Mill 161 kV bus	06/01/13	06/01/13
SPRM	Device - Norton Cap	Install 30 Mvar capacitor at Norton 161 kV bus	06/01/13	06/01/13
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1	Replace buswork in Bull Shoals switchyard.	06/01/12	06/01/12
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	Remove wavetrap. Install fiber.	06/01/12	06/01/12
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	Replace wave trap, disconnect switches, current transformers, and breaker. Replace bus.	06/01/12	06/01/12
WFEC	BROWN - RUSSETT 138KV CKT 1 WFEC	Change CTs at Russett from 300A to 600A	06/01/11	06/01/11
WFEC	RUSSETT - RUSSETT 138KV CKT 1 WFEC	Upgrade Terminal Equip CTs at Russett	12/01/12	12/01/12

Previously Assigned Aggregate Study Upgrades requiring credits to Previous Aggregate Study Customers.

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	HUGO POWER PLANT - VALLIANT 345 KV AEPW	Vallient 345 KV line terminal	07/01/12	07/01/12	$ 2,500,000
KACP	LACYGNE - WEST GARDNER 345KV CKT 1	KCPL Sponsored Project to Reconductor Line to be In-Service by 6/1/2006	06/01/06	06/01/06	$ 10,183,486
WFEC	HUGO POWER PLANT - VALLIANT 345 KV WFEC	New 345/138 kv Auto, and 19 miles 345 KV	07/01/12	07/01/12	$ 16,000,000

Previously Assigned Generation Interconnection Upgrades requiring credits

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	ASHDOWN REC (MILLWOOD) - OKAY 138KV CKT 1	Recunductor and convert line to 138 kV and replace switches at Ashdown REC	07/01/12	07/01/12	$ 10,739,857
AEPW	ASHDOWN REC (MILLWOOD) - PATTERSON 138KV CKT 1	Reconductor Line & Convert Line to 138 kV and convert Patterson station to breaker-and-a half cofiguration	07/01/12	07/01/12	$ 6,453,589
AEPW	BANN - RED SPRINGS REC 138KV CKT 1	Replace 138 kV breakers 3300 & 3310	07/01/12	07/01/12	$ 290,266
AEPW	MCNAB REC - TURK 115KV CKT 1	Build a new two mile, 138 kV, 1590 ACSR line section (operated at 115 kV) from Turk Substation to the existing Okay- Hope 115 kV line to form a Turk - Hope 115 kV line.	07/01/12	07/01/12	$ 1,520,000
AEPW	OKAY - TURK 138KV CKT 1	Build two mile, 138 kV, 1590ACSR line section from Turk Sub to existing Okay-Hope 115 kV line and rebuild twelve miles of 115 kV line to Okay Sub to 138 kV, 1590 ACSR , to form a Turk-Okay 138 kV line	07/01/12	07/01/12	$ 8,891,827
AEPW	OKAY 138/69KV TRANSFORMER CKT 1	Replace three single-phase 115-69 kV autotransformers with one 90 MVA, three-phase 138-69 kV autotransformer and convert high side of station to 138 kV	07/01/12	07/01/12	$ 3,289,686
AEPW	SE TEXARKANA - TURK 138KV CKT 1	Build new Turk-SE Texarkana 138 kV line and add SE Texarkana 138 kV terminal.	07/01/12	07/01/12	$ 25,978,842
AEPW	SUGAR HILL - TURK 138KV CKT 1	Build new Turk-Sugar Hill 138 kV line and add Sugar Hill 138 kV terminal.	07/01/12	07/01/12	$ 19,060,827
AEPW	TURK (HEMP 1) 138/115/13.8KV TRANSFORMER CKT 1	Build Turk 138-115 kV station and relocate autotransformer (and spare) from Patterson to this new Turk station	07/01/12	07/01/12	$ 8,765,106

EXHIBIT NO. OGE-15

Southwest Power Pool

Aggregate Facility Study SPP-2007-AG1-AFS-12 For Transmission Service Requested by Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

Table of Contents

1. Executive Summary

Pursuant to Attachment Z1 of the Southwest Power Pool Open Access Transmission Tariff (OATT), 1359 MW of long-term transmission service requests have been restudied in this Aggregate Facility Study (AFS). The first phase of the AFS consisted of a revision of the impact study to reflect the withdrawal of requests for which an Aggregate Facility Study Agreement was not executed. The principal objective of the AFS is to identify system problems and potential modifications necessary to facilitate these transfers while maintaining or improving system reliability as well as summarizing the operating limits and determination of the financial characteristics associated with facility upgrades. Facility upgrade costs are allocated on a prorated basis to all requests positively impacting any individual overloaded facility. Further, Attachment Z2 provides for facility upgrade cost recovery by stating that "Transmission Customers paying Directly Assigned Upgrade Costs for Service Upgrades or that are in excess of the Safe Harbor Cost Limit for Network Upgrades associated with new or changed Designated Resources and Project Sponsors paying Directly Assigned Upgrade Costs for Sponsored Upgrades shall receive revenue credits in accordance with Attachment Z2. Generation Interconnection Customers paying for Network Upgrades shall receive credits for new transmission service using the facility as specified in Attachment Z1."

The total assigned facility upgrade Engineering and Construction (E &C) cost determined by the AFS is $60 Million. Additionally $145 Thousand of assigned E & C cost for 3rd party facility upgrades are assignable to the customer. The total upgrade levelized revenue requirement for all transmission requests is $ 170 Million. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. AFS data table 3 reflects the allocation of upgrade costs to each request without potential base plan funding based on either the requested reservation period or the deferred reservation period if applicable. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $58 Million.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service. These include both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are listed in Table 5.

The Transmission Provider tendered a Letter of Intent on December 10th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by December 25th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

At the conclusion of the ATSS, Service Agreements for each request for service will be tendered identifying the terms and conditions of the confirmed service.

If customers withdraw from the ATSS after posting of this AFS, the AFS will be re-performed to determine final cost allocation and Available Transmission Capability (ATC) in consideration of the remaining ATSS participants. All allocated revenue requirements for facility upgrades are assigned to the customer in the AFS data tables. Potential base plan funding allowable is contingent upon validation of designated resources meeting Attachment J, Section III B criteria.

2. Introduction

On January 21, 2005, the Federal Energy Regulatory Commission accepted Southwest Power Pool's proposed aggregate transmission study procedures in Docket ER05-109 to become effective February 1, 2005. In compliance with this Order, the first open season of 2007 commenced on October 1, 2006. All requests for long-term transmission service received prior to February 1, 2007 with a signed study agreement were then included in this first Aggregate Transmission Service Study (ATSS) of 2007.

Approximately 1359 MW of long-term transmission service has been restudied in this Aggregate Facility Study (AFS) with over $60 Million in transmission upgrades being proposed. The results of the AFS are detailed in Tables 1 through 7. A highly tangible benefit of studying transmission requests aggregately under the SPP OATT Attachment Z1 is the sharing of costs among customers using the same facility. The detailed results show individual upgrade costs by study as well as potential base plan allowances as determined by Attachments J and Z1. The following URL can be used to access the SPP OATT: (http://www.spp.org/Publications/SPP_Tariff.pdf). In order to understand the extent to which base plan upgrades may be applied to both point-to-point and network transmission services, it is necessary to highlight the definition of Designated Resource. Per Section 1.9a of the SPP OATT, a Designated Resource is "[a]ny designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis." Therefore, not only network service, but also point-to-point service has potential for base plan funding if the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J are met.

Pursuant to Attachment J, Section III B of the SPP OATT, the Transmission Customer must provide SPP information necessary to verify that the new or changed Designated Resource meets the following conditions:

1. Transmission Customer's commitment to the requested new or changed Designated Resource must have a duration of at least five years.

2. During the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer's existing Designated Resources plus the lesser of (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer's projected system peak responsibility determined pursuant to SPP Criteria 2.

According to Attachment Z1 Section VI.A, Point-to-Point customers pay the higher of the monthly transmission access charge (base rate) or the monthly revenue requirement associated with the assigned facility upgrades including any prepayments for redispatch required during construction.

Network Integration Service customers pay the total monthly transmission access charges and the monthly revenue requirement associated with the facility upgrades including any prepayments for redispatch during construction.

Transmission Customers paying for a directly assigned network upgrade shall receive credits for new transmission service using the facility as specified in Attachment Z2.

Facilities identified as limiting the requested Transmission Service have been reviewed to determine the required in-service date of each Network Upgrade. The year that each Network Upgrade is required to accommodate a request is determined by interpolating between the applicable model years given the respective loading data. Both previously assigned facilities and the facilities assigned to this request for Transmission Service were evaluated.

In some instances due to lead times for engineering and construction, Network Upgrades may not be available when required to accommodate a request for Transmission Service. When this occurs, the ATC with available Network Upgrades will be less than the capacity requested during either a portion of or all of the requested reservation period. As a result, the lowest seasonal allocated ATC within the requested reservation period will be offered to the Transmission Customer on an applicable annual basis as listed in Table 1. The ATC may be limited by transmission owner planned projects, expansion plan projects, or customer assigned upgrades.

Some constraints identified in the AFS were not assigned to the Customer as the Transmission Provider determined that upgrades are not required due to various reasons or the Transmission Owner has construction plans pending for these upgrades. These facilities are listed by reservation in Table 3. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer. Table 6 lists possible redispatch pairs to allow start of service prior to completion of assigned network upgrades. Table 7 (if applicable) lists deferment of expansion plan projects with different upgrades with the new required in service date as a result of this AFS.

A. Financial Analysis

The AFS utilizes the allocated customer E & C cost in a present worth analysis to determine the monthly levelized revenue requirement of each facility upgrade over the term of the reservation. In some cases, network upgrades cannot be completed within the requested reservation period, thus deferred reservation periods will be utilized in the present worth analysis. If the Customer chose Option 2, Redispatch, in the Letter of Intent sent coincident with the initial AFS, the present worth analysis of revenue requirements will be based on the deferred term with redispatch in the subsequent AFS. The upgrade levelized revenue requirement includes interest, depreciation, and carrying costs.

Each request for Transmission Service is evaluated independently as the cost associated with each Network Upgrade is assigned to a request. When facilities are upgraded throughout the reservation period, the Transmission Customer shall 1) pay the total E & C costs and other annual operating costs associated with the new facilities, and 2) receive credits associated with the depreciated book value of removed usable facilities, salvage value of removed non-usable facilities, and the carrying charges, excluding depreciation, associated with all removed usable facilities based on their respective book values.

In the event that the engineering and construction of a previously assigned Network Upgrade may be expedited, with no additional upgrades, to accommodate a new request for Transmission Service, then the levelized present worth of only the incremental expenses though the reservation period of the new request, excluding depreciation, shall be assigned to the new request. These incremental expenses, excluding depreciation, include 1) the levelized difference in present worth of the engineering and construction expenses given the change in date to complete construction to account for additional interest expense and reduced engineering and construction expense due to inflation, 2) the levelized present worth of all expediting fees, and 3) the levelized present worth of the incremental annual carrying charges, excluding depreciation and interest, during the new reservation period taking into account both a) the reservation in which the project was originally assigned, and b) a reservation, if any, in which the project was previously expedited.

Achievable Base Plan Avoided Revenue Requirements in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.B methodology. A deferred Base Plan upgrade being defined as a different requested network upgrade needed at an earlier date that negates the need for the initial base plan upgrade within the planning horizon. A displaced Base Plan upgrade being defined as the same network upgrade being displaced by a requested upgrade needed at an earlier date. Assumption of a 40 year service life is utilized for Base Plan funded projects unless provided otherwise by the Transmission Owner. A present worth analysis of revenue requirements on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan revenue requirements due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The difference in present worth between the Base Plan and Requested Upgrades is assigned to the transmission requests impacting this upgrade based on the displacement or deferral.

B. Third Party Facilities

For third-party facilities listed in Table 3 and Table 5, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the Transmission Provider's OATT. In this AFS, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are listed in Table 5. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making arrangements for necessary engineering, permitting, and construction of the third-party facilities. Third-party facility upgrade engineering and construction cost estimates are not utilized to determine the present worth value of levelized revenue requirements for SPP system network upgrades.

All modeled facilities within the Transmission Provider system were monitored during the development of this Study as well as certain facilities in first-tier neighboring systems. Third-party facilities must be upgraded when it is determined that they are overloaded while accommodating the requested Transmission Service. An agreement between the Customer and 3rd Party Owner detailing the mitigation of the 3rd party impact must be provided to the Transmission Provider prior to tendering of a Transmission Service Agreement. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT. Upgrades on the Southwest Power Administration network requires prepayment of the upgrade cost prior to construction of the upgrade.

Third-party facilities are evaluated for only those requests whose load sinks within the SPP footprint. The Customer must arrange for study of 3rd party facilities for load that sinks outside the SPP footprint with the applicable Transmission Providers.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Reliability Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The upper bound and lower bound of the normal voltage range monitored is 105% and 95%. The upper bound and lower bound of the emergency voltage range monitored is 105% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 103.5% and 98.5% due to transmission operating procedure.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the control areas with SPP reserve share program redispatch. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 115 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

B. Model Development

SPP used eleven seasonal models to study the aggregate transfers of 1359 MW over a variety of requested service periods. The SPP MDWG 2007 Series Cases Update 2 2008 April (08AP), 2008 Spring Peak (08G), 2008 Summer Peak (08SP), 2008 Summer Shoulder (08SH), 2008 Fall Peak (08FA), 2008/09 Winter Peak (08WP), 2009 Summer Peak (09SP), 2009/10 Winter Peak (09WP), 2012 Summer Peak (12SP), 2012/13 Winter Peak (12WP),and 2017 Summer Peak (17SP) were used to study the impact of the requested service on the transmission system. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. Five groups of requests were developed from the aggregate of 1359 MW in order to minimize counter flows among requested service. Each request was included in at least two of the four groups depending on the requested path. All requests were included in group five. From the twelve seasonal models, five system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2007 Series Cases flowing in a West to East direction with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS importing from the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2007 Series Cases flowing in an East to West direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a South to North direction with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and SPS exporting to the Lamar HVDC Tie. Scenario 4 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a North to South direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie. Scenario 5 include all transmission not already included in the SPP 2007 Series Cases with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to the Lamar HVDC tie. The system scenarios were developed to minimize counter flows from previously confirmed, higher priority requests not included in the MDWG Base Case.

C. <u>Transmission Request Modeling</u>

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. The Generation to Load modeling is accomplished by developing a pre-transfer case by redispatching the existing designated network resource(s) down by the new designated network resource request amount and scaling down the applicable network load by the same amount proportionally. The post-transfer case for comparison is developed by scaling the network load back to the forecasted amount and dispatching the new designated network resource being requested. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to

Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource and the impacts on transmission system are determined accordingly. If the Network Integration Transmission Service request application clearly documents that the existing designated network resource(s) is being replaced or undesignated by the new designated network resource then MW impact credits will be given to the request as is done for a redirect of existing transmission service. Point-To-Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

D. Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02 change) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. Curtailment and Redispatch Evaluation

During any period when SPP determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, SPP will take whatever actions that are reasonably necessary to maintain the reliability of the Transmission System. To the extent SPP determines that the reliability of the Transmission System can be maintained by redispatching resources, SPP will evaluate interim curtailment of existing confirmed service or interim redispatch of units to provide service prior to completion of any assigned network upgrades. Any redispatch may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Transmission Customer's use of the Transmission System to serve its designated load.

Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades. Curtailment of existing confirmed service is evaluated to provide only interim service. Curtailment of existing confirmed service is only evaluated at the request of the transmission customer.

SPP determined potential relief pairs to relieve the incremental MW impact on limiting facilities as identified in Table 6. Using the selected cases where the limiting facilities were identified, potential incremental and decremental units were identified by determining the generation amount available for increasing and decreasing from the units generation amount, maximum generation amount, and minimum generation amount. If the incremental or decremental amount was greater than 1 MW, the unit was considered as a potential incremental or decremental unit. Generation shift factors were calculated for the potential incremental and decremental units using Managing and Utilizing System Transmission (MUST). Relief pairs from the generation shift factors for the incremental and decremental units with a greater than 3% TDF on the limiting constraint were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. If the aggregate redispatch amount for the potential relief pair was determined to be three times greater than the lower of the increment or decrement then the pair was determined not to be feasible and is not included. If transmission customer would like to see additional relief pairs beyond the relief pairs determined, the transmission customer can request SPP to provide the additional pairs. The potential relief pairs **were not** evaluated to determine impacts on limiting facilities in the SPP and 1st-Tier systems. The redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the steady-state analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates both with and without redispatch (based on customer selection of redispatch if available), the minimum annual allocated ATC without upgrades and season of first impact. Table 2 identifies total E & C cost allocated to each Transmission Customer, letter of credit requirements, third party E & C cost assignments, potential base plan E & C funding (lower of allocated E & C or Attachment J Section III B criteria) , total revenue requirements for assigned upgrades without consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades with consideration of potential base plan funding, and final total cost allocation to the Transmission Customer. In addition, Table 2 identifies SWPA upgrade costs which require prepayment in addition to other allocated costs. Table 3 provides additional details for each request including all assigned facility upgrades required, allocated E & C costs, allocated revenue requirements for upgrades, upgrades not assigned to customer but required for service to be confirmed, credits to be paid for previously assigned AFS or GI network upgrades, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Minimum ATC per upgrade with season of impact, Earliest Date Upgrade is required (DUN), Estimated Date the upgrade will be completed and in service (EOC), and Estimated E & C cost. Table 5 lists identified Third-Party constrained facilities. Table 6 identifies potential redispatch pairs available to relieve the aggregate impacts on identified constraints to prevent deferral of start of service. Table 7 (if applicable) identifies deferred expansion plan projects that were replaced with requested upgrades at earlier dates.

The potential base plan funding allowable is contingent upon meeting each of the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in

Section III.B of Attachment J. If the additional capacity of the new or changed designated resource exceeds the 125% resource to load forecast for the year of start of service, the requested resource is not eligible for base plan funding of required network upgrades and the full cost of the upgrades is assignable to the customer. If the 5 year term and 125% resource to load criteria are met, the lesser of the planned maximum net dependable capacity (NDC) or the requested capacity is multiplied by $180,000 to determine the potential base plan funding allowable. When calculating Base Plan Funding amounts that include a wind farm, the amount used is 10% of the requested amount of service, or the NDC. The Maximum Potential Base Plan Funding Allowable may be less than the potential base plan funding allowable due to the E & C Cost allocated to the customer being lower than the potential amount allowable to the customer. The customer is responsible for any assigned upgrade costs in excess of Potential Base Plan Engineering and Construction Funding Allowable.

Regarding application of base plan funding for PTP requests, if PTP base rate exceeds upgrade revenue requirements without taking into effect the reduction of revenue requirements by potential base plan funding, then the base rate revenue pays back the Transmission Owner for upgrades and no base plan funding is applicable as the access charge must be paid as it is the higher of "OR" pricing.

However, if initially the upgrade revenue requirements exceed the PTP base rate, then potential base plan funding would be applicable. The test of the higher of "OR" pricing would then be made against the remaining assignable revenue requirements versus PTP base rate. Examples are as follows:

Example A:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 47 million with the difference of 27 million E & C assignable to the customer. If the revenue requirements for the assignable portion is 54 million and the PTP base rate is 101 million, the customer will pay the higher “OR” pricing of 101 million base rate of which 54 million revenue requirements will be paid back to the Transmission Owners for the upgrades and the remaining revenue requirements of (140-54) or 86 million will be paid by base plan funding.

Example B:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 10 million with the difference of 64 million E & C assignable to the customer. If the revenue requirements for this assignable portion is 128 million and the PTP base rate is 101 million the customer will pay the higher “OR” pricing of 128 million revenue requirements to be paid back to the Transmission Owners and the remaining revenue requirements of (140-128) or 12 million will be paid by base plan funding.

Example C:

E & C allocated for upgrades is 25 million with revenue requirements of 50 million and PTP base rate of 101 million. Potential base plan funding is 10 million. Base plan funding is not applicable as the higher “OR” pricing of PTP base rate of 101 million must be paid and the 50 million revenue requirements will be paid from this.

The 125% resource to load determination is performed on a per request basis and is not based on a total of designated resource requests per Customer. A footnote will provide the maximum resource designation allowable for base plan funding consideration per Customer basis per year.

Base plan funding verification requires that each Transmission Customer with potential for base plan funding provide SPP attestation statements verifying that the firm capacity of the requested designated resource is committed for a minimum five year duration.

B. Study Definitions

The Date Upgrade Needed Date (DUN) is the earliest date the upgrade is required to alleviate a constraint considering all requests. End of Construction (EOC) is the estimated date the upgrade will be completed and in service. The Total Engineering and Construction Cost (E & C) is the upgrade solution cost as determined by the transmission owner. The Transmission Customer Allocation Cost is the estimated engineering and construction cost based upon the allocation of costs to all Transmission Customers in the AFS who positively impact facilities by at least 3% subsequently overloaded by the AFS. Minimum ATC is the portion of the requested capacity that can be accommodated with out upgrading facilities. Annual ATC allocated to the Transmission Customer is determined by the least amount of allocated seasonal ATC within each year of a reservation period.

5. Conclusion

The results of the AFS show that limiting constraints exist in many areas of the regional transmission system. Due to these constraints, transmission service cannot be granted unless noted in Table 3.

The Transmission Provider tendered a Letter of Intent on December 10th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by December 25th, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

The Transmission Provider must receive an unconditional and irrevocable letter of credit in the amount of the total allocated Engineering and Construction costs assigned to the Customer. This letter of credit is not required for those facilities that are base plan funded. This amount is for all assignable Network Upgrades less pre-payment requirements. The amount of the letter of credit will be adjusted down on an annual basis to reflect amortization of these costs. The Transmission Provider will issue notifications to construct facility upgrades to the constructing Transmission Owner. This date is determined by the engineering and construction lead time provided for each facility upgrade.

6. Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits – Apply immediately
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
MW mismatch tolerance – 0.5
Contingency case rating – Rate B
Percent of rating – 100
Output code – Summary
Min flow change in overload report – 3mw
Excld cases w/ no overloads form report – YES
Exclude interfaces from report – NO
Perform voltage limit check – YES
Elements in available capacity table – 60000
Cutoff threshold for available capacity table – 99999.0
Min. contng. case Vltg chng for report – 0.02
Sorted output – None
Newton Solution:
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits - Apply automatically
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch	Minimum Allocated ATC (MW) withing reservation period	Season of Minimum Allocated ATC within reservation period
EDE	AG1-2007-051	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	2/1/2009	2/1/2029	0	09SP
INDP	AG1-2007-045	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	6/1/2009	6/1/2034	0	09SP
KBPU	AG1-2007-043D	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2011	6/1/2021	7/1/2010	7/1/2020	0	17SP
KBPU	AG1-2007-044D	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2011	6/1/2031	5/1/2009	5/1/2029	0	08SP
KCPS	AG1-2007-080	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
KPP	AG1-2007-052	1222644	WR	WR	333	6/1/2007	6/1/2017	4/1/2014	4/1/2024	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-054	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	1/1/2011	1/1/2021	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-055	1222932	WR	WR	45	6/1/2007	6/1/2027	4/1/2014	4/1/2034	5/1/2009	5/1/2029	0	07SP
KPP	AG1-2007-056	1222937	WR	WPEK	5	6/1/2007	6/1/2027	1/1/2011	1/1/2031	5/1/2009	5/1/2029	0	07SP
KPP	AG1-2007-058	1222955	WR	WR	20	6/1/2007	6/1/2017	4/1/2014	4/1/2024	5/1/2009	5/1/2019	0	07SP
KPP	AG1-2007-064	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	1/1/2011	1/1/2021	5/1/2009	5/1/2019	0	07SP
SPRM	AG1-2007-042	1220082	SPA	SPA	275	10/1/2010	10/1/2050	10/1/2010	10/1/2050	10/1/2010	10/1/2050	0	17SP
UCU	AG1-2007-025D	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
UCU	AG1-2007-023D	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2011	6/1/2016	5/1/2009	5/1/2014	0	07SP
UCU	AG1-2007-060D	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
UCU	AG1-2007-060D	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	10/1/2009	10/1/2029	0	09SP
WRGS	AG1-2007-001D	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	6/1/2013	6/1/2024	0	08SP
WRGS	AG1-2007-047D	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	5/1/2009	5/1/2012	0	08SP
					1359								

Note 1: Disregard Redispatch shown in Table 6 for limitations identified earlier than the start date with redispatch with the exception of limitations identified in the 2008 Summer Shoulder, and 2008 Fall Peak

Note 2: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Customer	Study Number	Reservation	Engineering and Construction Cost of Upgrades Allocated to Customer for Revenue Requirements	[1]Letter of Credit Amount Required	[2]Potential Base Plan Engineering and Construction Funding Allowable	Notes	[4]Additional Engineering and Construction Cost for 3rd Party Upgrades	[3] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITHOUT Potential Base Plan Funding Allocation	[3 5] Total Revenue Requirements for Assigned Upgrades Over Term of Reservation WITH Potential Base Plan Funding Allocation	Point-to-Point Base Rate Over Reservation Period	[4]Total Cost of Reservation Assignable to Customer Contingent Upon Base Plan Funding
EDE	AG1-2007-051	1222640	$ 14,074	$ -	$ 14,074		$ -	$ 51,511	$ -	$ -	Schedule 9 Charges
INDP	AG1-2007-045	1221966	$ 60,805	$ -	$ -			$ 301,338	$ 301,338	$ 1,584,000	$ 1,584,000
KBPU	AG1-2007-043D	1221923	$ 1,531,640	$ -	$ -			$ 4,115,216	$ 4,115,216	$ 4,118,400	$ 4,118,400
KBPU	AG1-2007-044D	1221925	$ 202,479	$ -	$ -			$ 840,070	$ 840,070	$ 5,280,000	$ 5,280,000
KCPS	AG1-2007-080	1223159	$ -	$ -	$ -			$ -	$ -	$ 2,964,000	$ 2,964,000
KPP	AG1-2007-052	1222644	$ 33,385,752	$ -	$ 33,385,752			$ 77,517,217	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-054	1222904	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-055	1222932	$ 10,731,093	$ -	$ 10,731,093			$ 33,976,175	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-056	1222937	$ 24,921	$ -	$ 24,921			$ 85,863	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-058	1222955	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
KPP	AG1-2007-064	1223078	$ -	$ -	$ -			$ -	$ -	$ -	Schedule 9 Charges
SPRM	AG1-2007-042	1220082	$ 120,000	$ -	$ 120,000			$ 619,237	$ -	$ -	Schedule 9 Charges
UCU	AG1-2007-023D	1214269	$ 179	$ -	$ -			$ 389	$ 389	$ 105,600	$ 105,600
UCU	AG1-2007-025D	1214263	$ 3,807	$ -	$ -			$ 8,220	$ 8,220	$ 143,940	$ 143,940
UCU	AG1-2007-060D	1223092	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223093	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223094	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
UCU	AG1-2007-060D	1223095	$ 3,370,077	$ -	$ -		$ 36,250	$ 12,843,052	$ 12,843,052	$ 28,998,000	$ 29,033,000
WRGS	AG1-2007-001D	1197077	$ 28,867	$ -	$ 28,867		$ -	$ 73,595	$ -	$ -	Schedule 9 Charges
WRGS	AG1-2007-047D	1222005	$ 637,995	$ -	$ -			$ 1,248,037	$ 1,248,037	$ 3,625,200	$ 3,625,200
Grand Total			$ 60,221,920		$ 44,304,707			$ 170,209,076	$ 57,885,477		

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Note 1: Letter of Credit required for financial security for transmission owner for network upgrades is determined by allocated engineering and construction costs less engineering and construction costs for upgrades when network customer is the transmission owner less the E & C allocation of expedited projects. Letter of Credit is not required for base plan funded upgrades or if upgrades are funded by point to point base rate. The Letter Of Credit Amount listed is based on meeting OATT Attachment J requirements for base plan funding.

Note 2. If potential base plan funding is applicable, this value is the lesser of the Engineering and Construction costs of assignable upgrades or the value of base plan funding calculated pursuant to Attachment J, Section III B criteria. Allocation of base plan funding is contingent upon verification of customer agreements meeting Attachment J, Section II B criteria. Not applicable if Point-to-Point base rate exceeds revenue requirements.

Note 3: Revenue Requirements (RR) are based upon deferred end dates if applicable. Deferred dates are based upon customer's choice to pursue redispatch. Achievable Base Plan Avoided RR in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.C methodology. Assumption of a 40 year service life is utilized for Base Plan funded projects. A present worth analysis of RR on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan RR due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The incremental increase in present worth of a Requested Upgrade on a common year basis as a Base Plan upgrade is assigned to the transmission requests impacting the upgrade based on the displacement or deferral. If the displacement analysis results in lower RR due to the shorter amortization period of the requested upgrade when compared to a base plan amortization period, then no direct assignment of the upgrade cost is made due to the displacement to an earlier start date.

Note 4. For Point-to-Point requests, total cost is based on the higher of the base rate or assigned upgrade revenue requirements. For Network requests, the total cost is based on the assigned upgrade revenue requirement. Allocation of base plan funding will be determined after verification of designated resource meeting Attachment J, Section II B Criteria. Additionally E & C of 3rd Party upgrades is assignable to Customer. This includes prepayments required for any SWPA upgrades. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements with confirmation of base plan funding. Customer is responsible for negotiating redispatch costs if applicable. Customer is also responsible to pay credits for previously assigned upgrades that are impacted by their request. Credits can be paid from base plan funding if applicable.

Note 5: RR with base plan funding may increase or decrease even if no base plan funding is applicable to a particular request if another request that shares the upgrade is now full base plan funded resulting in a different amortization period for the upgrade and thus different RR.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer EDE
Study Number AG1-2007-051

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
EDE	1222640	WPEK	EDE	100	11/1/2008	11/1/2028	6/1/2013	6/1/2033	$ 14,074	$ -	$ 14,074	$ 51,511
									$ 14,074	$ -	$ 14,074	$ 51,511

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222640	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 14,074	$ 50,000	$ 51,511
					Total	$ 14,074	$ 50,000	$ 51,511

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BULL SHOALS - BULL SHOALS 161KV CKT 1	6/1/2009	6/1/2011		Yes
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	6/1/2015	6/1/2015		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	6/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	6/1/2014	6/1/2012		
	KERR - PENSACOLA 115KV CKT 1	12/1/2012	6/1/2011		
	Multi - Stateline - Joplin - Reinmiller conversion	6/1/2012	6/1/2013		Yes
	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	6/1/2009	6/1/2010	10/1/2009	
	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	6/1/2010	6/1/2010		
	SUB 170 - NICHOLS ST. - SUB 80 - SEDALIA 69KV CKT 1	6/1/2012	6/1/2012		
	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1	12/1/2010	6/1/2010		

Planned Projects

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2012		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222640	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*EMDE has worked out a contractual arrangement regarding the Huben transformer with AECI. The executed contractual arrangement between AECI and EMDE will facilitate the ability of SPP to provide the firm transmission service to EMDE.
**Entergy limitations were identified through the ICT Affected System Study ASA-2008-003. ST. JOE – HILL TOP 161KV CKT 1 and EVERTON - HARRISON-EAST 161KV CKT 1 can be mitigated by redispatch identified in Table 6.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
INDP	AG1-2007-045

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
INDP	1221966	OPPD	INDN	6	6/1/2009	6/1/2034	6/1/2011	6/1/2036	$ -	$ 1,584,000	$ 60,805	$ 301,338
									$ -	$ 1,584,000	$ 60,805	$ 301,338

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221966	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes*	$ 40,075	$ 4,400,000	$ 204,509
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 748	$ 50,000	$ 3,279
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes*	$ 19,982	$ 2,200,000	$ 93,550
					Total	$ 60,805	$ 6,650,000	$ 301,338

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes*
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes*
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	SUBSTATION M 161/69KV TRANSFORMER CKT 2	6/1/2010	6/1/2011	10/1/2010	Yes*

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221966	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	MERRIAM - ROELAND PARK 161KV CKT 1	6/1/2017	6/1/2017		

*Requested evaluation of the curtailment of existing service is provided in addition to redispatch in report tables. Refer to INDN Curtailment tab.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KBPU	AG1-2007-043D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KBPU	1221923	SPA	KACY	39	7/1/2010	7/1/2020	6/1/2011	6/1/2021	$ -	$ 4,118,400	$ 1,531,640	$ 4,115,216
									$ -	$ 4,118,400	$ 1,531,640	$ 4,115,216

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221923	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 498,594	$ 8,400,000	$ 1,299,516
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 777,569	$ 13,100,000	$ 1,984,267
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 147,349	$ 4,400,000	$ 493,877
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,317	$ 50,000	$ 9,716
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 104,811	$ 2,200,000	$ 327,840
					Total	$ 1,531,640	$ 28,150,000	$ 4,115,216

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221923	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KBPU	AG1-2007-044D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KBPU	1221925	WR	KACY	25	1/1/2008	1/1/2028	6/1/2011	6/1/2031	$ -	$ 5,280,000	$ 202,479	$ 840,070
									$ -	$ 5,280,000	$ 202,479	$ 840,070

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1221925	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 99,516	$ 4,400,000	$ 430,008
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 4,420	$ 50,000	$ 16,529
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 98,543	$ 2,200,000	$ 393,533
					Total	$ 202,479	$ 6,650,000	$ 840,070

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1221925	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KCPS	AG1-2007-080

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KCPS	1223159	KCPL	EES	52	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 2,964,000	$ -	$ -
									$ -	$ 2,964,000	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223159	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223159	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
KPP	AG1-2007-052

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222644	WR	WR	333	6/1/2007	6/1/2017	4/1/2014	4/1/2024	$ 33,385,752	$ -	$ 33,385,752	$ 77,517,217
									$ 33,385,752	$ -	$ 33,385,752	$ 77,517,217

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222644	ALLEN - LEHIGH TAP 69KV CKT 1	6/1/2009	6/1/2012		Yes	$ 2,040,323	$ 2,560,500	$ 4,629,105
	ALLEN 69KV Capacitor	5/1/2009	6/1/2012		Yes***	$ 491,390	$ 607,500	$ 1,177,343
	ALTOONA EAST 69KV Capacitor	6/1/2009	6/1/2014			$ 350,750	$ 607,500	$ 862,348
	ATHENS 69KV Capacitor	5/1/2009	6/1/2013		Yes***	$ 491,390	$ 607,500	$ 1,139,251
	Athens to Owl Creek 69 kV	5/1/2009	4/1/2011		Yes***	$ 1,194,323	$ 1,418,500	$ 2,813,948
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 3,920,148	$ 8,400,000	$ 9,280,660
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	5/1/2009	7/1/2013		Yes***	$ 2,808,717	$ 3,340,000	$ 6,494,183
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	5/1/2009	1/1/2013		Yes***	$ 1,306,071	$ 1,945,000	$ 3,069,608
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2010			$ 92,996	$ 115,000	$ 224,973
	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes~~	~~$ 1,467,168~~	~~$ 1,800,000~~	~~$ 3,501,701~~
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	5/1/2009	4/1/2014		Yes***	$ 3,573,125	$ 4,249,000	$ 8,055,645
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 458,585	$ 600,000	$ 1,109,394
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 6,113,563	$ 13,100,000	$ 14,170,900
	Green to Vernon 69 kV	5/1/2009	7/1/2010		Yes***	$ 2,804,933	$ 3,335,500	$ 6,768,017
	LEHIGH TAP - OWL CREEK 69KV CKT 1	5/1/2009	12/1/2011		Yes***	$ 3,209,137	$ 3,811,500	$ 7,400,336
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	6/1/2009	6/1/2011		Yes***	$ 483,983	$ 593,775	$ 1,178,500
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 183,112	$ 250,000	$ 493,839
	Rice County to Ellinwood 34.5KV	6/1/2009	6/1/2010		Yes***	$ 1,331,292	$ 1,812,500	$ 2,587,479
	TIOGA 69KV Capacitor	5/1/2009	6/1/2011			$ 491,390	$ 607,500	$ 1,216,105
	Vernon to Athens 69 kV	5/1/2009	1/1/2011		Yes***	$ 2,040,524	$ 2,426,500	$ 4,845,584
					Total	$ 33,385,752	$ 50,387,775	$ 77,517,217

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2009	12/1/2010		Yes
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	6/1/2009	6/1/2011		Yes***
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012		Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013		Yes
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		Yes***

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222644	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		

*Reservation 1222644 and 1222955 were studied as one request
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-054

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KPP	1222904	WPEK	WPEK	3	6/1/2007	6/1/2017	1/1/2011	1/1/2021	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222904	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1223078 and 1222904 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-055

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222932	WR	WR	45	6/1/2007	6/1/2027	4/1/2014	4/1/2034	$ 10,731,093	$ -	$ 10,731,093	$ 33,976,175
									$ 10,731,093	$ -	$ 10,731,093	$ 33,976,175

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222932	ALLEN - LEHIGH TAP 69KV CKT 1	6/1/2009	6/1/2012		Yes	$ 520,177	$ 2,560,500	$ 1,590,294
	ALLEN 69KV Capacitor	5/1/2009	6/1/2012		Yes***	$ 116,110	$ 607,500	$ 374,865
	ALTOONA EAST 69KV Capacitor	6/1/2009	6/1/2014			$ 256,750	$ 607,500	$ 850,596
	~~ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement~~	~~6/1/2009~~	~~6/1/2010~~	~~10/1/2009~~	~~Yes~~	~~$ 3,983~~	~~$ 3,983~~	~~$ 14,435~~
	ATHENS 69KV Capacitor	5/1/2009	6/1/2013		Yes***	$ 116,110	$ 607,500	$ 362,736
	Athens to Owl Creek 69 kV	5/1/2009	4/1/2011		Yes***	$ 224,177	$ 1,418,500	$ 711,727
	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,006,487	$ 8,400,000	$ 3,314,094
	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	5/1/2009	7/1/2013		Yes***	$ 531,283	$ 3,340,000	$ 1,655,277
	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	5/1/2009	1/1/2013		Yes***	$ 638,929	$ 1,945,000	$ 2,023,471
	CHANUTE TAP - TIOGA 69KV CKT 1	6/1/2010	6/1/2010			$ 22,004	$ 115,000	$ 71,729
	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes~~	~~$ 332,832~~	~~$ 1,800,000~~	~~$ 1,070,416~~
	CITY OF WINFIELD - RAINBOW 69KV CKT 1	6/1/2009	6/1/2011		Yes***	$ 1,645,279	$ 1,645,279	$ 5,240,607
	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	5/1/2009	4/1/2014		Yes***	$ 675,875	$ 4,249,000	$ 2,053,273
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 133,906	$ 600,000	$ 436,510
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,569,640	$ 13,100,000	$ 5,060,382
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 4,834	$ 50,000	$ 18,077
	~~CRESWELL - OAK 69KV CKT 1 #1 Displacement~~	~~6/1/2009~~	~~6/1/2010~~	~~10/1/2009~~	~~Yes~~	~~$ 13,655~~	~~$ 13,655~~	~~$ 48,696~~
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 156,994	$ 201,238	$ 540,449
	Green to Vernon 69 kV	5/1/2009	7/1/2010		Yes***	$ 530,567	$ 3,335,500	$ 1,725,073
	LEHIGH TAP - OWL CREEK 69KV CKT 1	5/1/2009	12/1/2011		Yes***	$ 602,363	$ 3,811,500	$ 1,871,758
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	6/1/2009	6/1/2011			$ 109,792	$ 593,775	$ 360,245
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 63,914	$ 250,000	$ 232,270
	~~OAK - RAINBOW 69KV CKT 1~~	~~6/1/2009~~	~~6/1/2011~~	~~10/1/2010~~	~~Yes***~~	~~$ 1,900,000~~	~~$ 1,900,000~~	~~$ 6,051,954~~
	~~OXFORD 138KV Capacitor Displacement~~	~~6/1/2009~~	~~6/1/2011~~		~~Yes***~~	~~$ 17,871~~	~~$ 27,618~~	~~$ 57,475~~
	Rice County to Ellinwood 34.5KV	6/1/2009	6/1/2010		Yes***	$ 481,208	$ 1,812,500	$ 1,270,649
	TIMBER JCT CAP BANK	6/1/2009	6/1/2011		Yes***	$ 822,608	$ 1,215,000	$ 2,589,813
	TIOGA 69KV Capacitor	5/1/2009	6/1/2011			$ 116,110	$ 607,500	$ 387,206
	Vernon to Athens 69 kV	5/1/2009	1/1/2011		Yes***	$ 385,976	$ 2,426,500	$ 1,235,074
					Total	$ 10,731,093	$ 53,499,292	$ 33,976,175

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	~~RICHLAND - ROSE HILL JUNCTION 69KV CKT 1~~	~~4/1/2009~~	~~6/1/2011~~		~~Yes***~~
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2009	12/1/2010		Yes
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		Yes
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	6/1/2009	6/1/2011		Yes***
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		Yes***

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222932	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-056

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222937	WR	WPEK	5	6/1/2007	6/1/2027	1/1/2011	1/1/2031	$ 24,921	$ -	$ 24,921	$ 85,863
									$ 24,921	$ -	$ 24,921	$ 85,863

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222937	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 243	$ 50,000	$ 909
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 24,678	$ 201,238	$ 84,954
					Total	$ 24,921	$ 251,238	$ 85,863

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	6/1/2015	6/1/2015		
	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	6/1/2015	6/1/2015		
	Cimarron Plant Substation Expansion	6/1/2012	1/1/2010		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		Yes***
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	6/1/2017	6/1/2017		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2016	6/1/2016		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	6/1/2017	6/1/2017		
	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	6/1/2016	6/1/2016		
	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	6/1/2016	6/1/2016		
	HUNTSVILLE - ST_JOHN 115KV CKT 1	6/1/2016	6/1/2016		
	NORTH CIMARRON CAPACITOR	6/1/2012	12/1/2008		
	PRATT - ST JOHN 115KV CKT 1	6/1/2017	6/1/2017		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222937	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

**A Transmission Operating Directive will need to be developed to document the minimum allowable generation per season in order maintain system reliability and evaluation of short term transmission service requests.
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer KPP
Study Number AG1-2007-058

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1222955	WR	WR	20	6/1/2007	6/1/2017	4/1/2014	4/1/2024	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222955	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Reservation 1222644 and 1222955 were studied as one request

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
KPP	AG1-2007-064

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KPP	1223078	WPEK	WPEK	15	6/1/2007	6/1/2017	1/1/2011	1/1/2021	$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223078	None					$ -	$ -	$ -
					Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	Cimarron Plant Substation Expansion	6/1/2012	1/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		Yes***
	HOLCOMB - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	KELLY - SOUTH SENECA 115KV CKT 1	5/1/2009	1/1/2011		Yes
	Knob Hill - Steele City 115 kV	6/1/2010	6/1/2010		
	PIONEER TAP - PLYMELL 115KV CKT 1	12/1/2009	12/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	NORTH CIMARRON CAPACITOR	6/1/2012	12/1/2008		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223078	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

*Reservation 1223078 and 1222904 were studied as one request
***Redispatch is available with additional Long-Term Firm Import Capacity requirements in Table 8

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
SPRM	AG1-2007-042

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
SPRM	1220082	SPA	SPA	275	10/1/2010	10/1/2050			$ 120,000	$ -	$ 120,000	$ 619,237
									$ 120,000	$ -	$ 120,000	$ 619,237

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1220082	BROOKLINE - JUNCTION 161KV CKT 1	6/1/2013	6/1/2013			$ 120,000	$ 120,000	$ 619,237
					Total	$ 120,000	$ 120,000	$ 619,237

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	KICKAPOO - SUNSET 69KV CKT 1	6/1/2014	6/1/2012		
	NEERGARD - NORTON 69KV CKT 1	10/1/2010	6/1/2010		
	SPRINGFIELD (SPF X1) 161/69/13.8KV TRANSFORMER CKT 1	6/1/2016	6/1/2016		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	JAMES RIVER - TWIN OAKS 69KV CKT 1	6/1/2015	6/1/2014		

Planned Projects

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1220082	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	6/1/2013	6/1/2012		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-023D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214269	MPS	KCPL	2	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 105,600	$ 179	$ 389
									$ -	$ 105,600	$ 179	$ 389

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214269	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 179	$ 50,000	$ 389
					Total	$ 179	$ 50,000	$ 389

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214269	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
UCU	AG1-2007-025D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1214263	MPS	WR	1	6/1/2007	6/1/2012	6/1/2011	6/1/2016	$ -	$ 143,940	$ 3,807	$ 8,220
									$ -	$ 143,940	$ 3,807	$ 8,220

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 589	$ 600,000	$ 1,208
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 2,874	$ 201,238	$ 6,225
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 344	$ 250,000	$ 787
					Total	$ 3,807	$ 1,051,238	$ 8,220

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	ALABAMA - LAKE ROAD 161KV CKT 1	6/1/2010	6/1/2010		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		Yes

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV	6/1/2009	6/1/2011		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1214263	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	Study Number
UCU	AG1-2007-060D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	1223092	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223093	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223094	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
UCU	1223095	EES	MPS	75	3/1/2009	3/1/2029	6/1/2011	6/1/2031	$ -	$ 28,998,000	$ 3,370,077	$ 12,843,052
									$ -	$ 115,992,000	$ 13,480,308	$ 51,372,210

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1223092	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223093	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223094	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052
1223095	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 743,693	$ 8,400,000	$ 2,534,848
	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	6/1/2009	6/1/2011		Yes	$ 1,159,807	$ 13,100,000	$ 3,870,531
	COOK - ST JOE 161KV CKT 1	6/1/2010	6/1/2011	10/1/2010	Yes	$ 1,028,265	$ 4,400,000	$ 4,622,058
	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 3,196	$ 50,000	$ 12,403
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes	$ 435,116	$ 2,200,000	$ 1,803,212
					Total	$ 3,370,077	$ 28,150,000	$ 12,843,052

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223093	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223094	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
1223095	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
	EDMOND SUB	6/1/2009	6/1/2011	10/1/2010	Yes
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223093	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223094	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes
1223095	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BONANZA - NORTH HUNTINGTON 69KV	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	6/1/2012	6/1/2012		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	6/1/2009	6/1/2010	10/1/2009	No
	RALPH GREEN 12MVAR CAPACITOR	6/1/2010	6/1/2010		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012	10/1/2010	Yes
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013	10/1/2010	Yes
	South Harper - Freeman 69 kV	6/1/2009	6/1/2010	10/1/2009	Yes

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223093	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223094	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		
1223095	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	6/1/2012	6/1/2012		
	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	Yes
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	Yes
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2009	6/1/2009		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2009	6/1/2009		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1223092	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223093	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223094	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		
1223095	HUGO POWER PLANT - VALLIANT 345 KV AEPW	7/1/2012	7/1/2012		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	7/1/2012	7/1/2012		
	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Third Party Limitations.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1223092	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223093	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223094	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000
1223095	5CALCR - NORFORK 161KV CKT 1 SWPA	6/1/2009	6/1/2010	10/1/2009	No	$ 25,000	$ 100,000
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	6/1/2010	6/1/2010			$ 11,250	$ 45,000
					Total	$ 36,250	$ 145,000

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
WRGS	AG1-2007-001D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WRGS	1197077	EDE	WR	32	9/1/2007	9/1/2018	6/1/2013	6/1/2024	$ 28,867	$ -	$ 28,867	$ 73,595
									$ 28,867	$ -	$ 28,867	$ 73,595

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	6/1/2010	6/1/2010			$ 6,920	$ 600,000	$ 17,279
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 16,692	$ 201,238	$ 44,015
	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	6/1/2014	6/1/2014			$ 2,626	$ 2,626	$ 4,983
	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	6/1/2011	6/1/2011			$ 2,629	$ 250,000	$ 7,318
					Total	$ 28,867	$ 1,053,864	$ 73,595

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	6/1/2016	6/1/2016		
	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	6/1/2017	6/1/2017		
	Fort Scott - SW Bourbon 161 kV	6/1/2010	6/1/2010		
	Fort Scott 161/69kV Transformer CKT 1	6/1/2010	6/1/2010		
	~~GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1~~	~~6/1/2016~~	~~6/1/2014~~		
	HARPER 138KV Capacitor	6/1/2009	10/1/2009		
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	6/1/2015	6/1/2015		
	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	6/1/2015	6/1/2015		
	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	6/1/2009	6/1/2009		
	SUB 438 - RIVERSIDE 161KV	6/1/2011	12/1/2010		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV	6/1/2009	6/1/2011		
	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	6/1/2016	6/1/2016		
	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	6/1/2016	6/1/2016		
	Multi - Stateline - Joplin - Reinmiller conversion	6/1/2012	6/1/2013		
	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	6/1/2015	6/1/2015		
	Sooner to Rose Hill 345 kV OKGE	6/1/2009	6/1/2012		
	Sooner to Rose Hill 345 kV WERE	6/1/2009	1/1/2013		
	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	6/1/2017	6/1/2017		

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	6/1/2009	6/1/2010	10/1/2009	
	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	6/1/2009	6/1/2010	10/1/2009	
	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	5/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1197077	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	12/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer	**Study Number**
WRGS	AG1-2007-047D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WRGS	1222005	WR	EES	106	10/1/2007	10/1/2010	6/1/2011	6/1/2014	$ -	$ 3,625,200	$ 637,995	$ 1,248,037
									$ -	$ 3,625,200	$ 637,995	$ 1,248,037

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1222005	Craig 161kV 20MVar Cap Bank Upgrade	6/1/2011	6/1/2011			$ 9,401	$ 50,000	$ 18,786
	~~OXFORD 138KV Capacitor Displacement~~	~~6/1/2009~~	~~6/1/2011~~			~~$ 9,747~~	~~$ 27,618~~	~~$ 18,402~~
	REDEL - STILWELL 161KV CKT 1	6/1/2009	6/1/2011		Yes****	$ 236,202	$ 2,200,000	$ 504,055
	TIMBER JCT CAP BANK	6/1/2009	6/1/2011			$ 392,392	$ 1,215,000	$ 725,196
					Total	$ 637,995	$ 3,465,000	$ 1,248,037

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	6/1/2013	6/1/2013		
	EAST MANHATTAN - NW MANHATTAN 230/115KV	6/1/2011	6/1/2012		
	East Manhattan to Mcdowell 230 kV	6/1/2011	6/1/2011		
	Grandview East - Sampson - Longview 161kV Ckt 1	6/1/2009	6/1/2009		
	Loma Vista - Montrose 161kV Tap into K.C. South	6/1/2009	6/1/2011		Yes****
	~~SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1~~	~~6/1/2016~~	~~6/1/2016~~		
	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	6/1/2009	11/1/2010	10/1/2010	Yes****
	STRANGER CREEK - NW LEAVENWORTH 115KV	6/1/2011	6/1/2011		
	STRANGER CREEK TRANSFORMER CKT 2	6/1/2009	6/1/2009		
	Summit - NE Saline 115 kV	5/1/2009	1/1/2010		

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	BLUE SPRINGS EAST CAP BANK	6/1/2011	6/1/2011		
	CHASE - WHITE JUNCTION 69KV CKT 1	6/1/2009	6/1/2010		
	Sumner County to Timber Junction 138/69 kV	6/1/2009	6/1/2011		

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	DUN	EOC	Earliest Service Date	Redispatch Available
1222005	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		
	RENO 345/115KV CKT 1	12/15/2008	12/15/2008		
	RENO 345/115KV CKT 2	12/1/2009	8/1/2009		
	SUMMIT - RENO 345KV	6/1/2010	6/1/2010		
	WICHITA - RENO 345KV	12/15/2008	12/15/2008		

****Requested evaluation of the curtailment of existing service is provided in addition to redispatch in report tables. Refer to WRGS Curtailment tab.

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 8.37 miles of 795 ACSR with 1590 ACSR & reset relays @ BSE	6/1/2009	6/1/2011	$8,400,000.00
AEPW	COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	Rebuild 13.11 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2011	$13,100,000.00
KACP	Craig 161kV 20MVar Cap Bank Upgrade	Additional 20 MVAR to make a total of 70 MVAR at Craig 542978	6/1/2011	6/1/2011	$50,000.00
	REDEL - STILWELL 161KV CKT 1	Reconductor line with 1192 ACSS and upgrade terminal equipment for 2000 amps	6/1/2009	6/1/2011	$2,200,000.00
MIDW	Rice County to Ellinwood 34.5KV	Rebuild 14.5 miles of 34.5 kV line between Rice County to Ellinwood	6/1/2009	6/1/2010	$1,812,500.00
SJLP	COOK - ST JOE 161KV CKT 1	Conductor, Switch, Relay	6/1/2010	6/1/2011	$4,400,000.00
SPRM	BROOKLINE - JUNCTION 161KV CKT 1	Brookline: Replace 1,200 amp switches with 2,000 amp units and replace metering CTs. Junction: Replace 1,200 amp switches with 2,000 amp units.	6/1/2013	6/1/2013	$120,000.00
WERE	ALLEN - LEHIGH TAP 69KV CKT 1	Tear down / Rebuild 5.69-mile line; 954-KCM ACSR	6/1/2009	6/1/2012	$2,560,500.00
WERE	ALLEN 69KV Capacitor	Allen 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2012	$607,500.00
WERE	ALTOONA EAST 69KV Capacitor	ALTOONA EAST 69KV 6 MVAR Capacitor Addition	6/1/2009	6/1/2014	$607,500.00
~~WERE~~	~~ARKANSAS CITY - PARIS 69KV CKT 1 #1 Displacement~~	~~Replace Disconnect Switches and Bus Jumpers at Paris and Ark City 69 kV substations~~	~~6/1/2009~~	~~6/1/2010~~	~~$ 3,983~~
WERE	ATHENS 69KV Capacitor	Athens 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2013	$607,500.00
WERE	Athens to Owl Creek 69 kV	Rebuild 2.93 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	4/1/2011	$1,418,500.00
WERE	BURLINGTON JUNCTION - COFFEY COUNTY NO. 3 WESTPHALIA 69KV CKT 1	Rebuild 7.2 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	7/1/2013	$3,340,000.00
WERE	BURLINGTON JUNCTION - WOLF CREEK 69KV CKT 1	Rebuild 4.1 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	1/1/2013	$1,945,000.00
WERE	CHANUTE TAP - TIOGA 69KV CKT 1	Replace Jumpers	6/1/2010	6/1/2010	$115,000.00
~~WERE~~	~~CITY OF IOLA - UNITED NO. 9 CONGER 69KV CKT 1~~	~~Tear down / Rebuild 4-mile 69 kV line; 954 kcmiol ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,800,000~~
~~WERE~~	~~CITY OF WINFIELD - RAINBOW 69KV CKT 1~~	~~Rebuild 3.99-mile Rainbow-Winfield 69 kV line, 954 ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,645,279~~
WERE	COFFEY COUNTY NO. 3 WESTPHALIA - GREEN 69KV CKT 1	Rebuild 9.22 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	4/1/2014	$4,249,000.00
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE #2	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$600,000.00
~~WERE~~	~~CRESWELL - OAK 69KV CKT 1 #1 Displacement~~	~~Replace jumpers and bus, and reset CTs and relaying. Rebuild substations.~~	~~6/1/2009~~	~~6/1/2010~~	~~$ 13,655~~
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 Displacement	Replace Disconnect Switches, Wavetrap, Breaker, Jumpers	6/1/2010	6/1/2010	$201,238.00
WERE	Green to Vernon 69 kV	Rebuild 7.19 miles with 954 kcmil ACSR (138kV/69kV Operation)	5/1/2009	7/1/2010	$3,335,500.00
WERE	LEHIGH TAP - OWL CREEK 69KV CKT 1	Tear down / Rebuild 8.47-mile 69 kV line with 954-KCM ACSR (138kV/69kV Operation)	5/1/2009	12/1/2011	$3,811,500.00
	LEHIGH TAP - UNITED NO. 9 CONGER 69KV CKT 1	Tear down / Rebuild 0.91-mile 69 kV line; 954-KCM ACSR (138kV/69kV Operation)	6/1/2009	6/1/2011	$593,775.00
WERE	LITCHFIELD - AQUARIUS - HUDSON JUNCTION 69KV CKT 1 Displacement	Replace 69 kV disconnect switches at Aquarius.	6/1/2014	6/1/2014	$2,626.00
WERE	NEOSHO - NORTHEAST PARSONS 138KV CKT 1	Replace bus and Jumpers at NE Parsons 138 kV substation	6/1/2011	6/1/2011	$250,000.00
~~WERE~~	~~OAK - RAINBOW 69KV CKT 1~~	~~Tear down / Rebuild 5.10-mile Oak-Rainbow 69 kV using 954 kcmil ACSR~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 1,900,000~~
~~WERE~~	~~OXFORD 138KV Capacitor Displacement~~	~~Install 30 MVAR Capacitor Bank at Oxford 138 kV~~	~~6/1/2009~~	~~6/1/2011~~	~~$ 27,618~~
WERE	TIMBER JCT 138 kV Capacitor	Install 30 MVAR Cap bank at new Timber Junction 138kV	6/1/2009	6/1/2011	$1,215,000.00
WERE	TIOGA 69KV Capacitor	Tioga 69 kV 15 MVAR Capacitor Addition	5/1/2009	6/1/2011	$607,500.00
WERE	Vernon to Athens 69 kV	Rebuild 5.17 miles with 954 KCM-ACSR (138kV/69kV Operation)	5/1/2009	1/1/2011	$2,426,500.00

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	COFFEYVILLE TAP - DEARING 138KV CKT 1 AEPW	Tie Line, Reconductor 1.09 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2010
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
OKGE	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	Rebuild 7.43 miles of 250 CWC with 795 ACSR	6/1/2009	6/1/2009
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #2	Reconductor Clarksville-Dardanelle line	6/1/2012	6/1/2012
WERE	COFFEYVILLE TAP - DEARING 138KV CKT 1 WERE	Tie Line, Rebuild 3.93 miles of 795 ACSR with 1590 ACSR.	6/1/2009	6/1/2010
WERE	ROSE HILL (ROSEHL1X) 345/138/13.8KV TRANSFORMER CKT 3 Displacement	Add third 345-138 kV transformer at Rose Hill	5/1/2009	6/1/2011

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
SPRM	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1	SOUTHWEST - SOUTHWEST DISPOSAL 161KV CKT 1: Reconductor 161kV Line 1192 MCM AAC to 954 kcmil ACSS/TW 0.67 miles and Upgrade Teminal Equipment	6/1/2013	6/1/2012

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	6/1/2009	6/1/2009
AEPW	FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE 345KV	Install new 345kV line from FLINT CREEK - SHIPE ROAD - EAST ROGERS - OSAGE	6/1/2017	6/1/2014
EMDE	SUB 376 - MONETT CITY SOUTH 161/69/12.5KV TRANSFORMER CKT 1	Install 3-wind transformer from 161 kV new Sub MONETT 5 to Monett city south 69kV	6/1/2015	6/1/2015
EMDE	SUB 383 - MONETT - SUB 376 - MONETT CITY SOUTH 161KV CKT 1	Install new line from Sub #383 to new Sub MONETT 5	6/1/2015	6/1/2015
EMDE	SUB 389 - JOPLIN SOUTHWEST - SUB 422 - JOPLIN 24TH & CONNECTICUT 161KV CKT 1	Change CT Ratio at Sub #389 on Breaker #16170 for 268 MVA Rate B	6/1/2009	6/1/2009
EMDE	SUB 438 - RIVERSIDE 161KV	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 547497	6/1/2011	12/1/2010
INDN	SUBSTATION M 161/69KV TRANSFORMER CKT 2	Add second 100 MVA xfr at Subsation M	6/1/2010	6/1/2011
MIPU	ALABAMA - LAKE ROAD 161KV CKT 1	re-set the over current relay to trip the Lake Road-Alabama section when flow goes above 161 MVA	6/1/2010	6/1/2010
MIPU	EDMOND SUB	Add a new 161/34.5 kV Sub at Edmond tapping the Cook to Lake Road 161 kV line	6/1/2009	6/1/2011
MIPU	Grandview East - Sampson - Longview 161kV Ckt 1	Replace wavetraps at Grandview East and Longview.	6/1/2009	6/1/2009
MIPU	Loma Vista - Montrose 161kV Tap into K.C. South	To tap the Montrose-LomaVista 161 kV Line into KC South 161 kV sub.	6/1/2009	6/1/2011
MIPU	South Harper 161 kV cut-in to Stilwell-Archie JCT 161 kV line	To tap Stilwell-Archie JCT 161 kV line into South Harper 161 kV sub and make it two new 161 kV sections: Stilwell-South Harper and Archie JCT- South Harper .	6/1/2009	11/1/2010
MKEC	Cimarron Plant Substation Expansion	Integrate SUNC North Cimarron Top into reconfigured WEPL Cimarron Plant Sub	6/1/2012	1/1/2010
MKEC	HARPER 138KV Capacitor	Install 1 - 20 MVar capacitor bank	6/1/2009	10/1/2009
OKGE	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	6/1/2009	6/1/2009
SPRM	KICKAPOO - SUNSET 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 1.35 miles.	6/1/2014	6/1/2012
SPRM	NEERGARD - NORTON 69KV CKT 1	Transfer load & Reconductor 336.4 kcmil ACSR with 477 ACSS/TW	10/1/2010	6/1/2010
SUNC	HOLCOMB - PLYMELL 115KV CKT 1	Rebuild Holcomb to Plymell	12/1/2009	12/1/2009
SUNC	PIONEER TAP - PLYMELL 115KV CKT 1	Rebuild Plymell to Pioneer Tap	12/1/2009	12/1/2009
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1	Replace buswork in Bull Shoals switchyard.	6/1/2009	6/1/2011
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #1	Replace wave trap, disconnect switches, current transformers, and breaker. Bus will limit rating to 1340 amps.	6/1/2009	6/1/2010
SWPA	SPRINGFIELD (SPF X1) 161/69/13.8KV TRANSFORMER CKT 1	Replace Springfield xfmr #1 three winding transformer with 70 MVA auto transformer.	6/1/2016	6/1/2016
WERE	AUBURN ROAD (AUBRN77X) 230/115/13.8KV TRANSFORMER CKT 2	Add second Auburn 230-115 kV transformer.	6/1/2016	6/1/2016
WERE	BISMARK JUNCTION SWITCHING STATION - FARMERS CONSUMER CO-OP 115KV CKT 1	Rebuild 2.9 mi 115 kV line Bismark to COOP	6/1/2015	6/1/2015
WERE	BISMARK JUNCTION SWITCHING STATION - MIDLAND JUNCTION 115KV CKT 1	Rebuild 5.2 miles Bismark to Midland 115 kV line	6/1/2015	6/1/2015
WERE	EAST MANHATTAN - JEFFREY ENERGY CENTER 230KV CKT 1	Uprate JEC- E.Manhattan 230 kV line to 100 deg C operation by raising structures	6/1/2013	6/1/2013
WERE	EAST MANHATTAN - NW MANHATTAN 230/115KV	Tap the Concordia - East Manhattan 230kV line and add a new substation"NW Manhattan"; Add a 230kV/115kV transformer and tap the KSU - Wildcat 115kV line into NW Manhattan	6/1/2011	6/1/2012
WERE	East Manhattan to Mcdowell 230 kV	The East Manhattan-McDowell 115 kV is built as a 230 kV line, but is operated at 115 kV. Substation work will have to be performed in order to convert this line.	6/1/2011	6/1/2011
WERE	FARMERS CONSUMER CO-OP - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 1.53-mile Co-op-Wakarusa 115 kV line.	6/1/2017	6/1/2017
WERE	Fort Scott - SW Bourbon 161 kV	Tap Litchfield-Marmaton 161 kV with new SW Bourbon Sub to Ft Scott.	6/1/2010	6/1/2010
WERE	Fort Scott 161/69kV Transformer CKT 1	New 161/69 kV transformer at Ft Scott.	6/1/2010	6/1/2010
WERE	KELLY - SOUTH SENECA 115KV CKT 1	Rebuild 10.28 mile line with 1192.5 kcmil ACSR and replace CTs.	5/1/2009	1/1/2011
WERE	Knob Hill - Steele City 115 kV	New 115 kV Line from Knob Hill to Kansas/Nebraska state line.	6/1/2010	6/1/2010
WERE	LAWRENCE HILL - MOCKINGBIRD HILL SWITCHING STATION 115KV CKT 1	Rebuild 5.49 mile line	6/1/2017	6/1/2017
WERE	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	Rebuild 5.73 mile Weaver-Rose Hill Junction as a 138 kV line but operate at 69 kV.	6/1/2009	12/1/2010
WERE	SOUTHWEST LAWRENCE - WAKARUSA JUNCTION SWITCHING STATION 115KV CKT 1	Rebuild 4.09 mile SW Lawrence-Wakarusa 115 kV line	6/1/2016	6/1/2016
WERE	STRANGER CREEK - NW LEAVENWORTH 115KV	Rebuild 11.62-mile Jarbalo-NW Leavenworth 115 kV line and tap in & out of Stranger 115 kV	6/1/2011	6/1/2011
WERE	STRANGER CREEK TRANSFORMER CKT 2	Install second Stranger Creek 345-115 transformer	6/1/2009	6/1/2009
WERE	Summit - NE Saline 115 kV	Build 6.5-mile Summit-Southgate 115 kV, 1192.5 kcmil ACSR Tear down Northview-South Gate 115 kV	5/1/2009	12/1/2010

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Reliability Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	BONANZA - NORTH HUNTINGTON 69KV	Convert from 69KV to 161KV	6/1/2014	6/1/2014
EMDE	JAMESVILLE - SUB 415 - BLACKHAWK JCT. 69KV CKT 1 EMDE	Replace Jumpers to breaker #6950 at Blackhawk Jct.	6/1/2014	6/1/2012
EMDE	Multi - Stateline - Joplin - Reinmiller conversion	Tear down the Riverton to Joplin 59 69 kV line, rebuilding the line to 161 kV from Stateline to outside Joplin 59 sub. Tear down and rebuild Joplin 59 to Gateway to Pillsbury to Reinmiller, converting those 69 kV lines to 161 kV. Tap the 161 kV line betwe	6/1/2012	6/1/2013
EMDE	SUB 124 - AURORA H.T. - SUB 152 - MONETT H.T. 69KV CKT 1	Change CT Ratio on breaker #6936 at Aurora #124	6/1/2009	6/1/2010
EMDE	SUB 124 - AURORA H.T. - SUB 383 - MONETT 161KV CKT 1	Change CT Ratio at Sub #383 on Breaker #16186 for 268 MVA Rate B	6/1/2017	6/1/2017
EMDE	SUB 145 - JOPLIN WEST 7TH - SUB 64 - JOPLIN 10TH ST. 69KV CKT 1	Replace Disconnect Switches and Leads on Breaker #6965 at Sub #64 and #6932 at Sub #145	6/1/2010	6/1/2010
EMDE	SUB 170 - NICHOLS ST. - SUB 80 - SEDALIA 69KV CKT 1	Reconductor 8.92 mile line from 1/0 CU to 556 ACSR and replace Jumpers in Sub #80 and Upgrade CTs	6/1/2012	6/1/2012
EMDE	SUB 271 - BAXTER SPRINGS WEST - SUB 404 - HOCKERVILLE 69KV CKT 1	Change CT setting on Breaker #6973 at Baxter #271	12/1/2010	6/1/2010
GRDA	KERR - PENSACOLA 115KV CKT 1	Rebuild 22 miles of line from 4/0 Cu to 795 ACSR for 161kV	12/1/2012	6/1/2011
KACP	MERRIAM - ROELAND PARK 161KV CKT 1	reconductor with 1192 acsr; upgrade term equip 1200 A	6/1/2017	6/1/2017
MIDW	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 MIDW	Tear down and rebuild 73.4% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
MIDW	HUNTSVILLE - ST_JOHN 115KV CKT 1	Rebuild 26.5 miles Huntsville - St. John 115 kV line and replace CT, wavetrap, breakers, and relays.	6/1/2016	6/1/2016
MIPU	BLUE SPRINGS EAST CAP BANK	Add 50 MVAR cap bank at Blue Springs East	6/1/2011	6/1/2011
MIPU	RALPH GREEN 12MVAR CAPACITOR	12MVAR at Ralph Green	6/1/2010	6/1/2010
MIPU	South Harper - Freeman 69 kV	re-set the overcurrent relay at South Harper 69 kV Bus to open SouthHarper-Freeman 69 kV line	6/1/2009	6/1/2010
MKEC	PRATT - ST JOHN 115KV CKT 1	Replace terminal equipment	6/1/2017	6/1/2017
OKGE	Sooner to Rose Hill 345 kV OKGE	New 345 kV line from Sooner to Oklahoma/Kansas	6/1/2009	1/1/2013
SPRM	JAMES RIVER - TWIN OAKS 69KV CKT 1	Reconductor 69kV Line 636 MCM ACSR to 762.8 kcmil ACSS/TW 3.103 miles.	6/1/2015	6/1/2014
SUNC	NORTH CIMARRON CAPACITOR	Install 24 MVAR Capacitor bank at North Cimarron	6/1/2012	12/1/2008
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1 #1	Remove wavetrap. Install fiber	6/1/2012	6/1/2012
WERE	95TH & WAVERLY - CAPTAIN JUNCTION 115KV CKT 1	Rebuild 7.61 miles from 95th & Waverly-Captain Junction 115 kV line.	6/1/2017	6/1/2017
WERE	BPU - CITY OF MCPHERSON JOHNS-MANVILLE - EAST MCPHERSON SWITCHING STATION 115KV CKT 1	Rebuild Line	6/1/2009	6/1/2011
WERE	CHASE - WHITE JUNCTION 69KV CKT 1	Tear down / Rebuild 7.3-mile Chase - White Junction 69 kV line. Replace existing 2/0 copper conductor with 795 kcmil ACSR conductor.	6/1/2009	6/1/2010
WERE	EVANS ENERGY CENTER SOUTH - LAKERIDGE 138KV CKT 1 #2	Reconductor 8.02 miles with Bundled 1192.5 ACSR	6/1/2016	6/1/2016
WERE	GILL ENERGY CENTER EAST - INTERSTATE 138KV CKT 1	Replace wave trap	6/1/2016	6/1/2016
WERE	HUNTSVILLE - HUTCHINSON ENERGY CENTER 115KV CKT 1 WERE	Tear down and rebuild 26.6% Ownership 28.79 mile HEC-Huntsville 115 kV line and replace CT, wavetrap and relays.	6/1/2016	6/1/2016
WERE	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	Rebuild 5.43 mile Rose Hill Junction-Richland as a 138 kV line but operate at 69 kV.	6/1/2009	6/1/2011
WERE	SEVENTEENTH () 138/69/11.295KV TRANSFORMER CKT 2	Install second 17th St. 138-69 kV transformer	6/1/2015	6/1/2015
WERE	Sooner to Rose Hill 345 kV WERE	New 345 kV line from Oklahoma/Kansas Stateline to Rose Hill	6/1/2009	1/1/2013
WERE	Sumner County to Timber Junction 138/69 kV	Tap Belle Plaine-Oxford 138 kV line, build a 3-breaker ring bus switching station, build 12-mile 138 kV line from Sumner County 138 kV to Timber Junction 138 kV, and Install Timber Junction. 138-69 kV 100 MVA transformer with LTC.	6/1/2009	6/1/2011

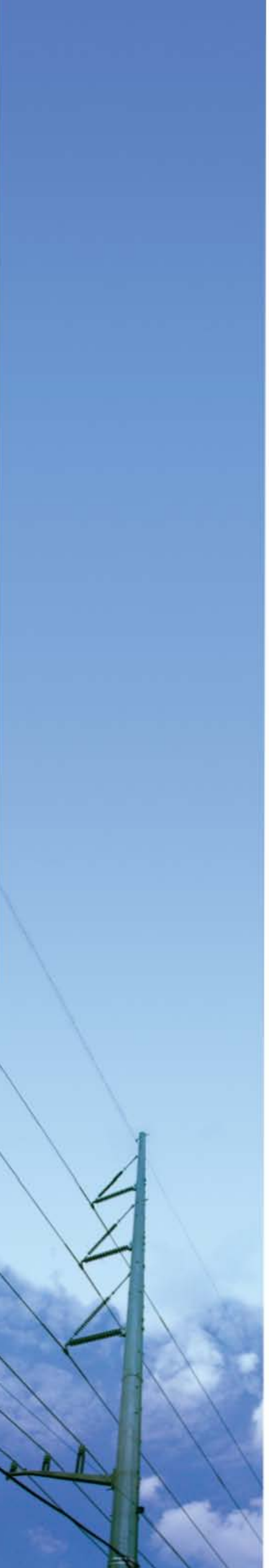
Previously Assigned Aggregate Study Upgrades requiring credits to Previous Aggregate Study Customers.

Transmission Owner	Upgrade	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)
AEPW	HUGO POWER PLANT - VALLIANT 345 KV AEPW	Vallient 345 KV line terminal	7/1/2012	7/1/2012
KACP	LACYGNE - WEST GARDNER 345KV CKT 1	KCPL Sponsored Project to Reconductor Line to be In-Service by 6/1/2006	6/1/2006	6/1/2006
WERE	RENO 345/115KV CKT 1	New stepdown transformer at a new substation in Reno County east northeast of Hutchinson	12/15/2008	12/15/2008
WERE	RENO 345/115KV CKT 2	Install 2nd stepdown transformer at Reno County substation east northeast of Hutchinson	12/1/2009	8/1/2009
WERE	SUMMIT - RENO 345KV	Install new 50.55-mile 345 kV line from Reno county to Summit; 31 miles of 115 kV line between Circle and S Philips would be rebuilt as double circuit with the 345 kV line to minimize ROW impacts; Substation work required at Summit for new 345 kV terminal	6/1/2010	6/1/2010
WERE	WICHITA - RENO 345KV	40 mile 345 kV transmission line from existing Wichita 345 kV substation to a new 345-115 kV substation in Reno County east northeast of Hutchinson (Wichita to Reno)	12/15/2008	12/15/2008
WFEC	HUGO POWER PLANT - VALLIANT 345 KV WFEC	New 19 miles 345 KV	7/1/2012	7/1/2012

Table 5 - Third Party Facility Constraints

Transmission Owner	UpgradeName	Solution	Earliest Date Upgrade Required (DUN)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
SWPA	5CALCR - NORFORK 161KV CKT 1 SWPA	At Norfork Sub, Replace bus between bay MOD switch 67 and disconnect switch 63, reset metering CT ratio and replace wavetrap	6/1/2009	6/1/2010	$ 100,000
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA #2	Replace the bus between auxilliary bus and MOD switch 57, between disconnect switch 57 and disconnect switch 53, and between disconnect switch 51 and the main bus.	6/1/2009	6/1/2010	$ 45,000

EXHIBIT NO. OGE-16



SPP Balanced Portfolio Report

MAINTAINED BY
Engineering/Planning

PUBLISHED: 06/23/2009
CAWG Accepted 06/05/2009
MOPC Accepted 06/12/2009
LATEST REVISION: 06/23/2009

Southwest Power Pool

TABLE OF CONTENTS

Executive Summary

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e., increasing reliability and lowering required reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. “Balanced” is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio.

After development and review of the Balanced Portfolio, the CAWG endorsed Portfolio 3E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3E “Adjusted” provides a significant benefit vs. cost to the SPP region, and would require lower transfer requirements necessary to achieve balance. The CAWG along with the Economics Modeling and Methods Task Force (“EMMTF”, now called the Economic Studies Working Group “ESWG”) reviewed and approved the study assumptions used in the analysis of the Balanced Portfolio. These assumptions are listed in the appendix. Portfolio 3E “Adjusted” contains a diverse group of 345kV transmission projects addressing many of the top SPP flowgates. The projects associated with Portfolio 3E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The CAWG endorsed Balanced Portfolio was presented to the Markets and Operations Policy Committee (MOPC) on April 15th, 2009. The MOPC reviewed and discussed the portfolio options and the impact on the SPP footprint. After discussion, the MOPC endorsed the Balanced Portfolio 3E “Adjusted” pending issuance of the final report, according to SPP Tariff.

Portfolio 3E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58.

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

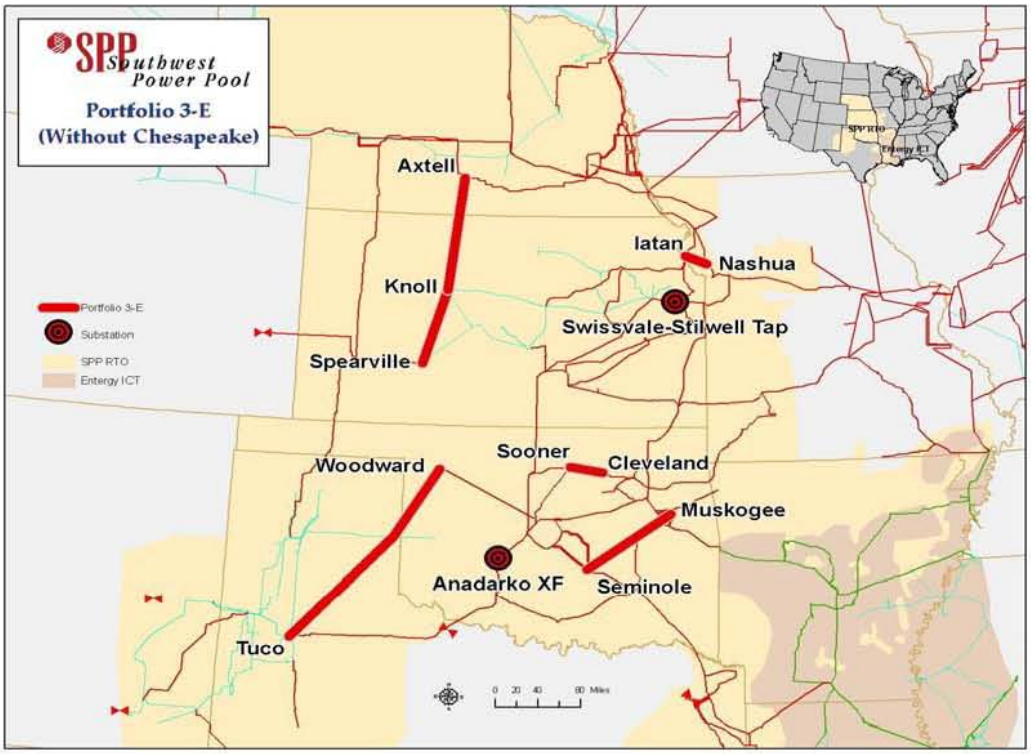
Portfolio 3-E "Adjusted"			Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR (Million of Dollars)	Reliability Cost	Cost (E&C) $ 692 Annual
2012			$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017			$ 193.2	$ 12.4	$ 93.73	$ 2.53	Total Annual
2022			$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The table below outlines the benefits by zones for the 10 year analysis of Portfolio 3E "adjusted".

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		**$176**	**$95**	**-$31**	**$31**	**$0**	**$81**	**1.86**

Portfolio 3-E "Adjusted"



Introduction

The Balanced Portfolio is an SPP strategic initiative to develop a cohesive grouping of economic upgrades that benefit the SPP region and allocates the cost of those upgrades regionally. Projects in the Balanced Portfolio include transmission upgrades of 345 kV* projects that will provide customers with potential savings that exceed project costs. These economic upgrades are intended to reduce congestion on the SPP transmission system, resulting in savings in generation production costs. Economic upgrades may provide other benefits to the power grid; i.e. increasing reliability and lowering reserve margins, deferring reliability upgrades, and providing environmental benefits due to more efficient operation of assets and greater utilization of renewable resources.

The Cost Allocation Working Group (CAWG), of the Regional State Committee (RSC), has worked diligently over an extended period through a stakeholder process to identify upgrades for inclusion in a portfolio that will provide a balanced benefit to customers over the specified ten-year payback period. "Balanced" is defined by the SPP Regional Tariff in Attachment O, such that for each Zone, the sum of the benefits of the potential Balanced Portfolio must equal or exceed the sum of the costs. The Tariff allows for the adjustment of revenue requirements to achieve balance for the portfolio†.

Economic Benefits: Adjusted Production Cost

Balanced Portfolio development began with an economic screening of projects identified by stakeholders and SPP staff. After receiving stakeholder feedback, SPP staff compiled a list of economic projects with potential for a positive return.

The first step is to conduct an economic analysis individually on each project considered for the Balanced Portfolio. This process is done by determining the adjusted production cost metric for each project in the screen. Adjusted production cost is defined as:

Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

Where:

Revenues from Sales = Export x Zonal $\text{LMP}_{\text{Gen Weighted}}$

and

Cost of Purchases = Import x Zonal $\text{LMP}_{\text{Load Weighted}}$

Production cost for each unit is based on fuel, variable O&M costs, environmental costs and both scheduled and forced outages‡. Adjusted production cost savings account for the economy purchase and sale of power in the modeling footprint. This is important when benefits are being calculated for zones within the SPP as well as in differentiating overall benefits from the portfolio compared to the benefits accruing to SPP members.

To calculate adjustments to production costs due to an economic transmission project, commercial production cost analysis software is used to estimate hourly unit commitment and dispatch of modeled

* Upgrades of voltages less than 345 kV can be included if needed to deliver the benefits of the extra high voltage (EHV) upgrade, where the cost of the lower voltage facilities does not exceed the cost of the EHV facilities.

† The Tariff allows for deficient zones to be balanced by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual transmission Revenue Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.

‡ SPP is currently using probabilistic techniques to simulate a single draw of outages to simulate forced outages

generators within a context of a modeled transmission system and load delivery points. The commitment and dispatch of the generators is constrained by the software to ensure that no overloads will occur on any monitored transmission element, typically referred to as the NERC book of flowgates, but can include additional congestion points of interest. The software produces a security constrained economic dispatch and unit commitment.

Adjusted Production Cost was the only benefit metric used in the economic analysis. There are other potential benefits which have not been directly quantified such as lowering reserve margins, reducing losses, and providing environmental benefits. For the purpose of this study, these benefit metrics are not used to determine overall portfolio benefits to the region.

Balanced Portfolio Development

The following table provides a timeline for the development of the various candidate portfolios that were developed by the SPP staff and presented during the regularly scheduled CAWG meetings

Table: CAWG Timeline for Balanced Portfolio Development

Months/Year	Key Discussions at CAWG
Aug-Nov 2007	Screening of Candidate Upgrades for Portfolio
Feb –Apr 2008	Initial Portfolios 1, 2, 3 and 4
May 2008	Trapped Generation Issues Discussion Begins
Jun 2008	Spearville-Knoll-Axtell Added to Portfolios 2 and 3
Jul 2008	Portfolios 2 and 3 at 2008 Wind Levels and Turk
Aug 2008	Portfolios 2 and 3: Firm Wind Sensitivities
Sep 2008	Introduction of Portfolios 3-A and 3-B at 345 and 765 kV costs
Oct 2008	Portfolio 3 (high wind) and 3-A (current wind) Analysis
Dec 2008	Portfolio 3-C (modify 3 for high wind)
Jan 2009	Further Analysis of Portfolios 3-A and 3-C with Nebraska
Feb 2009	EMMTF Effort initiated to update and refine economic models
Mar 2009	Final Balanced Portfolio Analysis
Apr 2009	Balanced Portfolio Summit & Balanced Portfolio Recommendation

<u>August-November, 2007</u>: Screening of Candidate Upgrades for Portfolios

Over fifty candidate transmission upgrades for screening were gathered by SPP staff. As agreed by stakeholders, the initial screening analysis was performed based on using only the summer months. A discussion at the CAWG led to additional analyses to include spring-fall months in the calculations of adjusted production cost benefits. The screening analysis was then performed for the summer months and the spring-fall months starting with the spring of March 1, 2012. These estimates of annual benefits were compared to the estimates of engineering and construction (E&C) cost obtained by SPP staff from transmission owners. All projects screened were ranked from highest to lowest according to their benefit-to-cost (B/C) ratios. The SPP staff then used these rankings as a basis for developing a collection of economic upgrades as alternative portfolios[§].

<u>February-April, 2008</u>: Initial Four Portfolios

SPP staff developed four initial portfolios, labeled as Portfolios 1, 2, 3 and 4. Each portfolio had specific criteria for determining which projects to include.

1. Portfolio 1 was a collection of every project from the economic project screening process that had a B/C ratio greater than 1.0.

[§] Note: Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note in the original analysis was the inclusion of Holcomb 2, Red Rock, Hugo 2 as well as 4,600 MW of generic wind capacity which affected the calculated benefits of certain projects.

2. Portfolio 2 was a subset of Portfolio 1 where projects with similar benefits were narrowed to remove upgrades that would not provide additional benefits.

3. Portfolio 3 was assembled with the intent of ensuring each Zone within the SPP region received a project (projects that crossed multiple zones were considered for each zone), with the most beneficial project chosen in each zone.

4. Portfolio 4 was a collection of projects that would be mutually beneficial, thereby raising the overall benefit of the entire portfolio.

These four portfolios, along with their B/C screening ratios, are shown in the following exhibits.

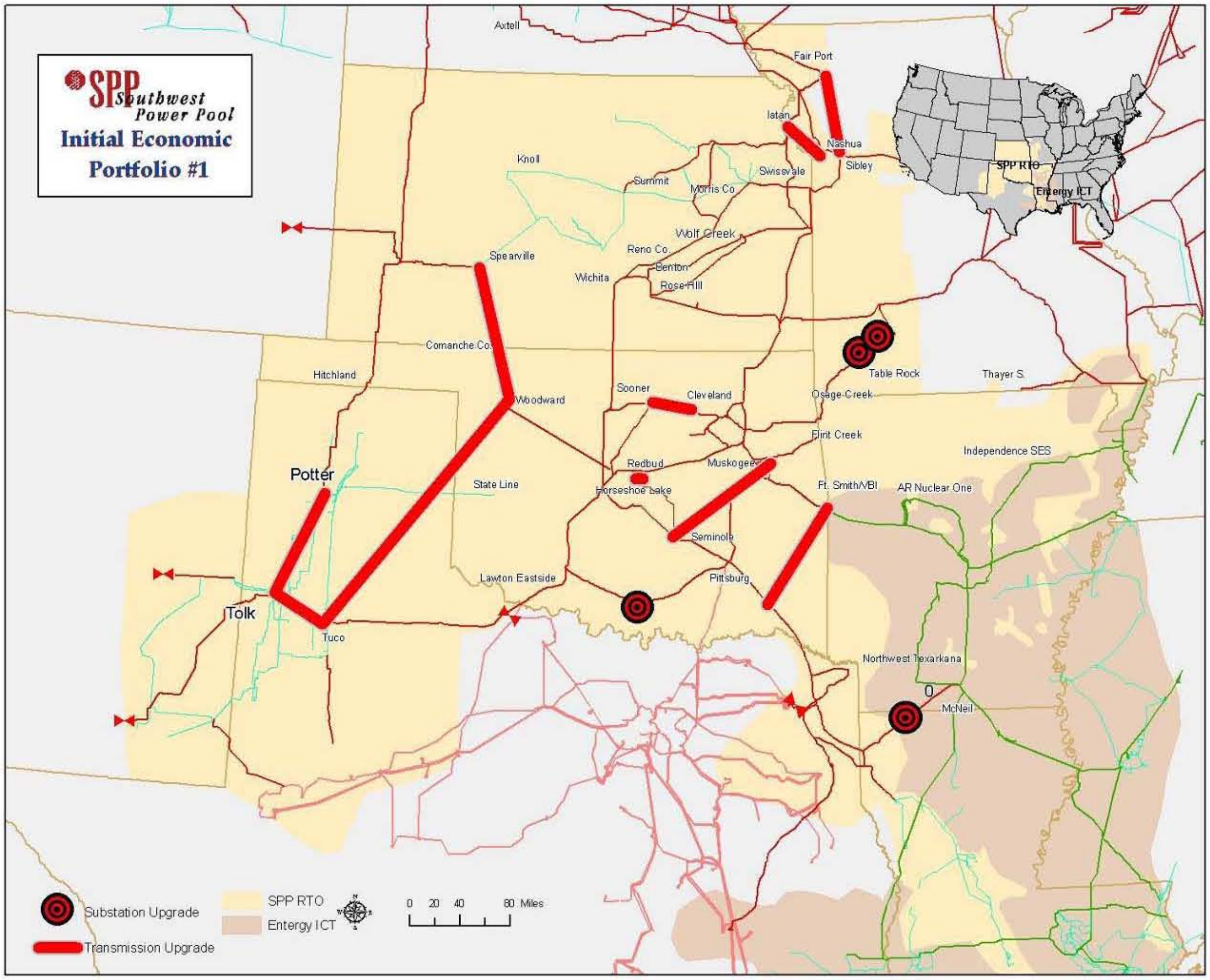
Screening of Proposed Economic Upgrades

Project	Screening B/C Ratio	P1	P2	P3	P4
Tolk - Potter	7.20			+	
El Dorado - Longwood	3.36	+	+	+	
Iatan - Nashua	2.95	+	+	+	+
SWPS - Battlefield	2.66	+	+		
Chesapeake XF	2.26	+	+	+	
Tuco - Tolk - Potter	1.73	+	+		+
Fairport - Sibley	1.31	+			+
Pittsburg - Ft Smith	1.17	+	+	+	
Spearville-Mooreland/Woodward-Tuco	1.13	+	+	+	+
Seminole - Muskogee	1.08	+			
Monett XF	1.04	+			
Redbud - Horseshoe Lake	1.01	+			
Cleveland - Sooner	0.91	+	+	+	+
Sunnyside XF	0.89	+	+		
Northwest XF	0.89	+	+		+
Swissvale - Stilwell	0.67			+	
Anadarko XF	0.48			+	
Turk - McNeil	0.46				+
Mooreland/Woodward - Wichita	0.14				+
Mooreland/Woodward - Northwest	(0.00)				+

(NOTE: "Tolk – Potter" project is a subset of the "Tuco – Tolk – Potter" project.)

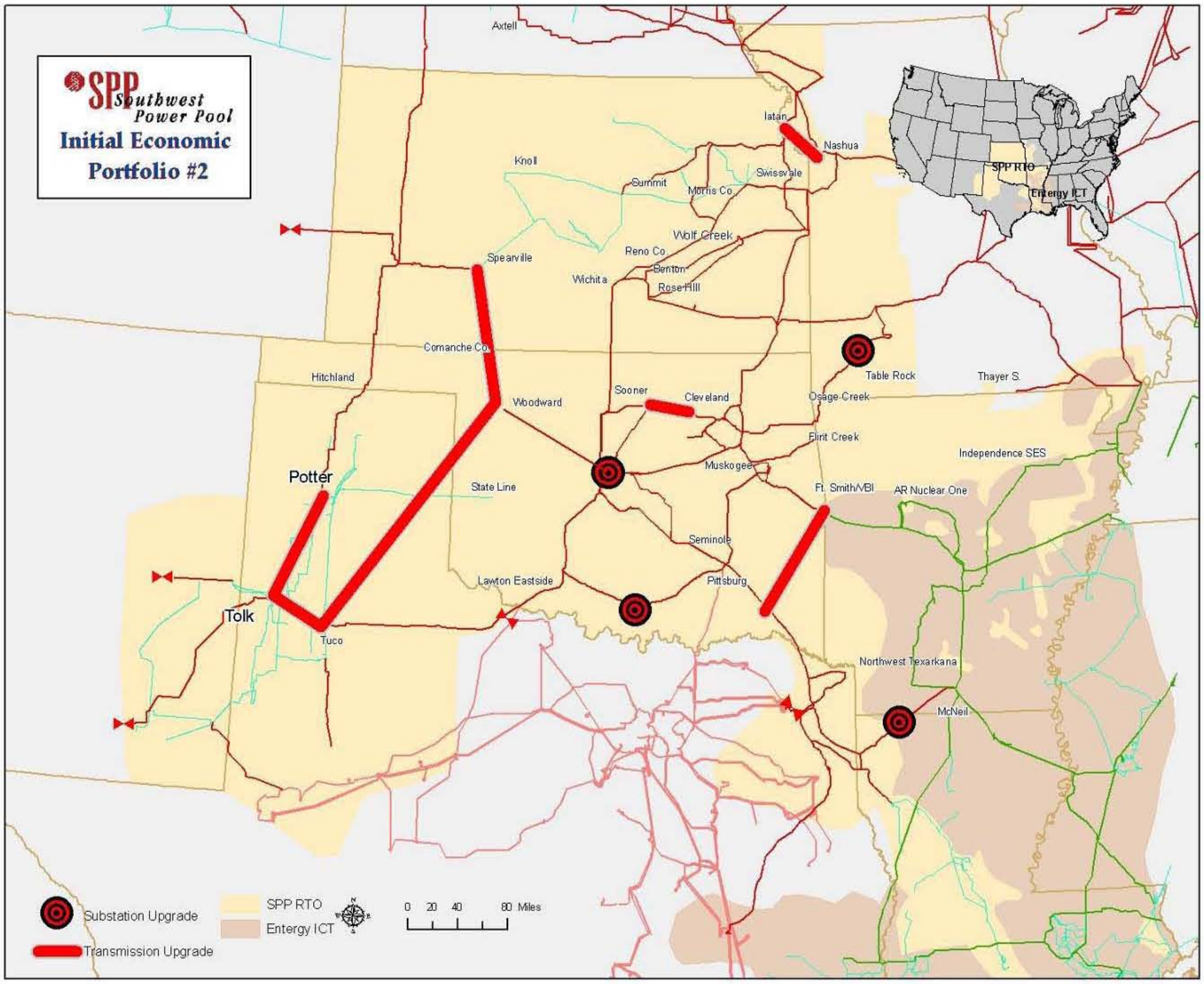
The Balanced Portfolio screening analysis considered assumptions for generation not contained in the subsequent portfolio analysis. Of note was the inclusion of Holcomb 2, Red Rock, and Hugo 2 as well as 4,600 MW of generic wind capacity, each of which affected the calculated benefits of certain projects.

Portfolio 1

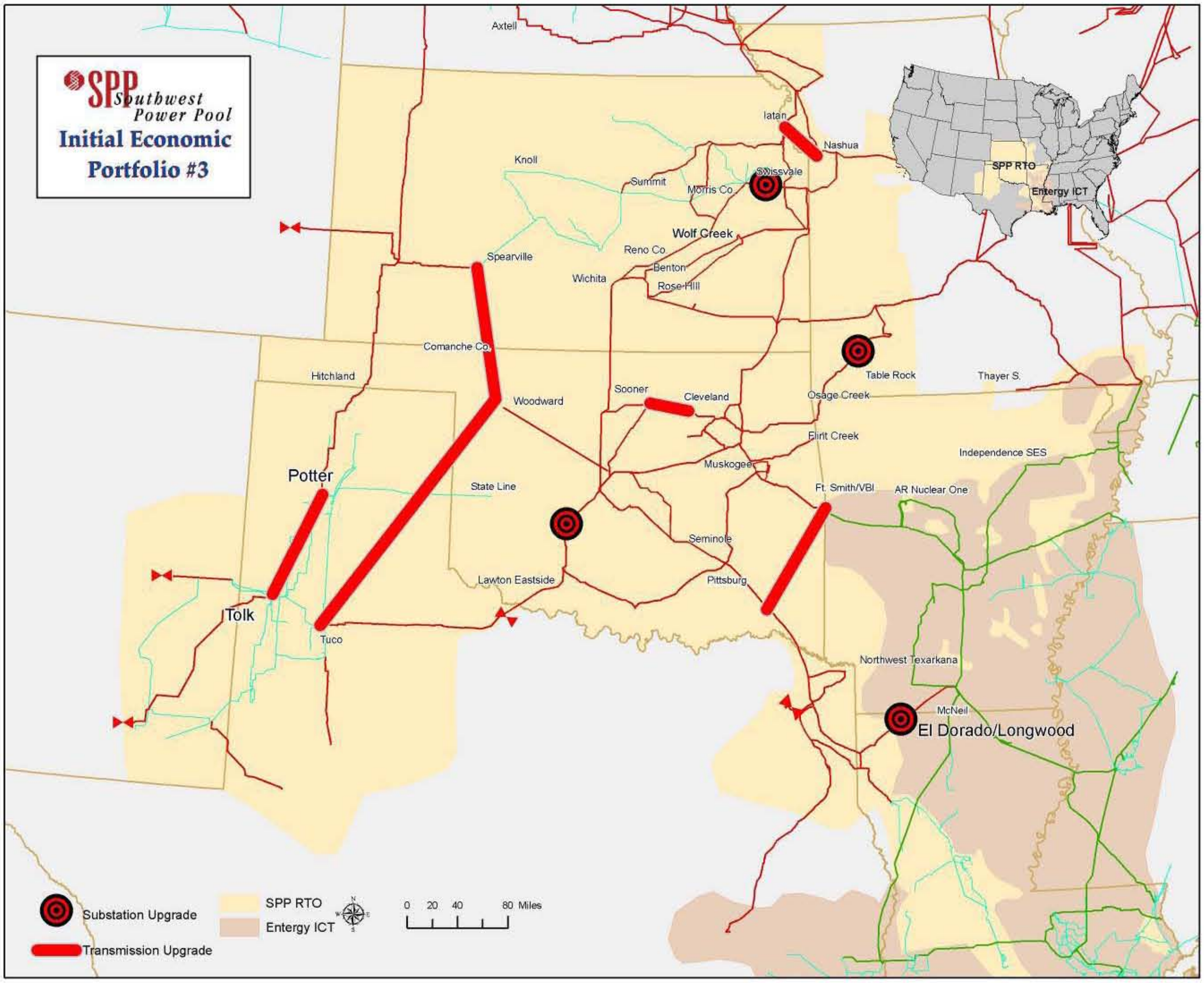


Because Portfolio 2 eliminated duplicative upgrades from Portfolio 1, Portfolio 1 was not carried forward as a possible Balanced Portfolio candidate.

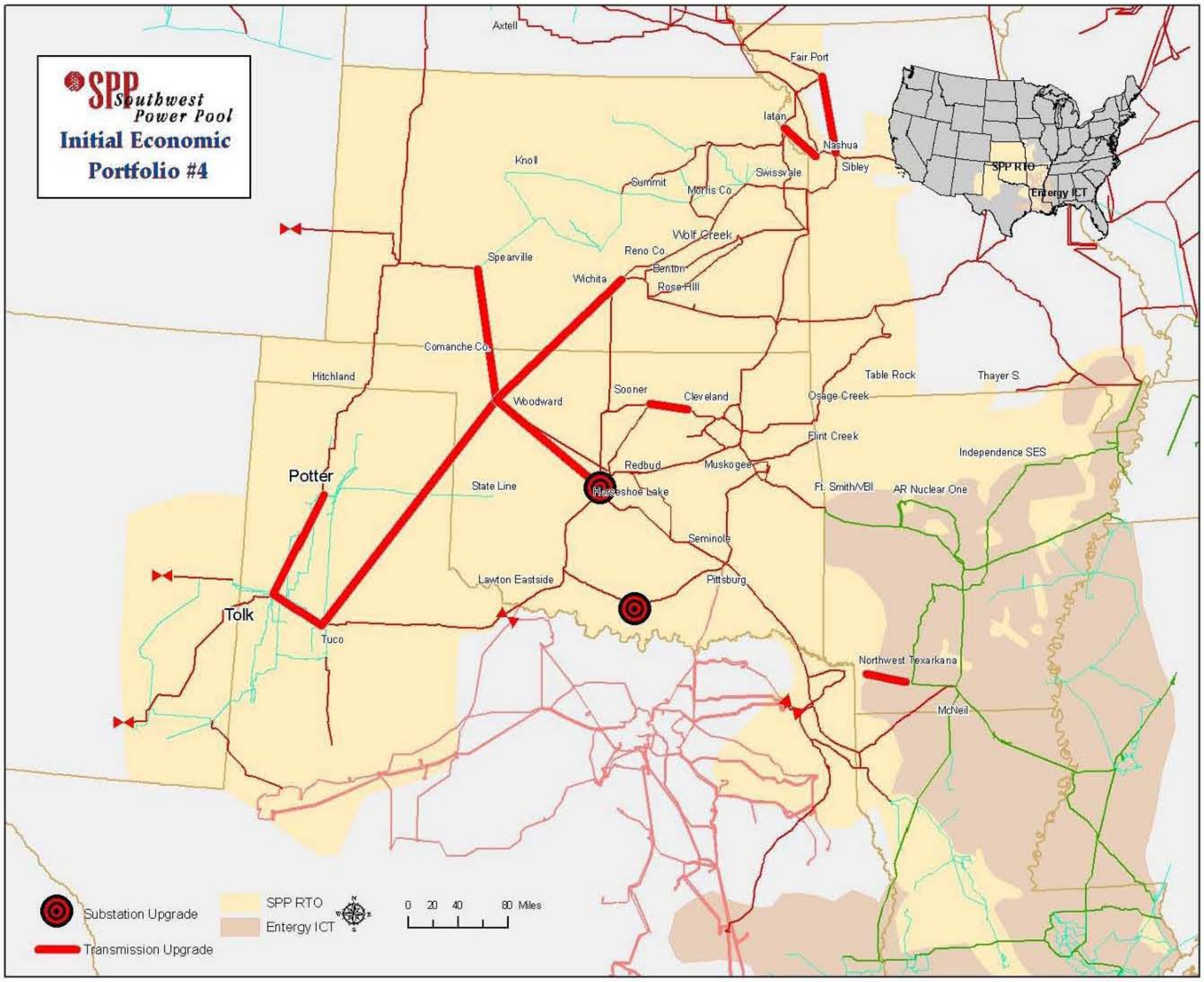
Portfolio 2


Southwest Power Pool
Initial Economic Portfolio #2
Axtell
Iatan
Nashua
Knoll
Summit
Morris Co.
Swissvale
Wolf Creek
Spearville
Reno Co.
Benton
Wichita
Rose Hill
Comanche Co.
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
State Line
Muskogee
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

Portfolio 3


Southwest Power Pool
Initial Economic Portfolio #3
Axtell
Iatan
Nashua
Knoll
Summit
Swissvale
Morris Co.
Wolf Creek
Spearville
Reno Co
Benton
Wichita
Rose Hill
Comanche Co.
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
Muskogee
State Line
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
El Dorado/Longwood
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

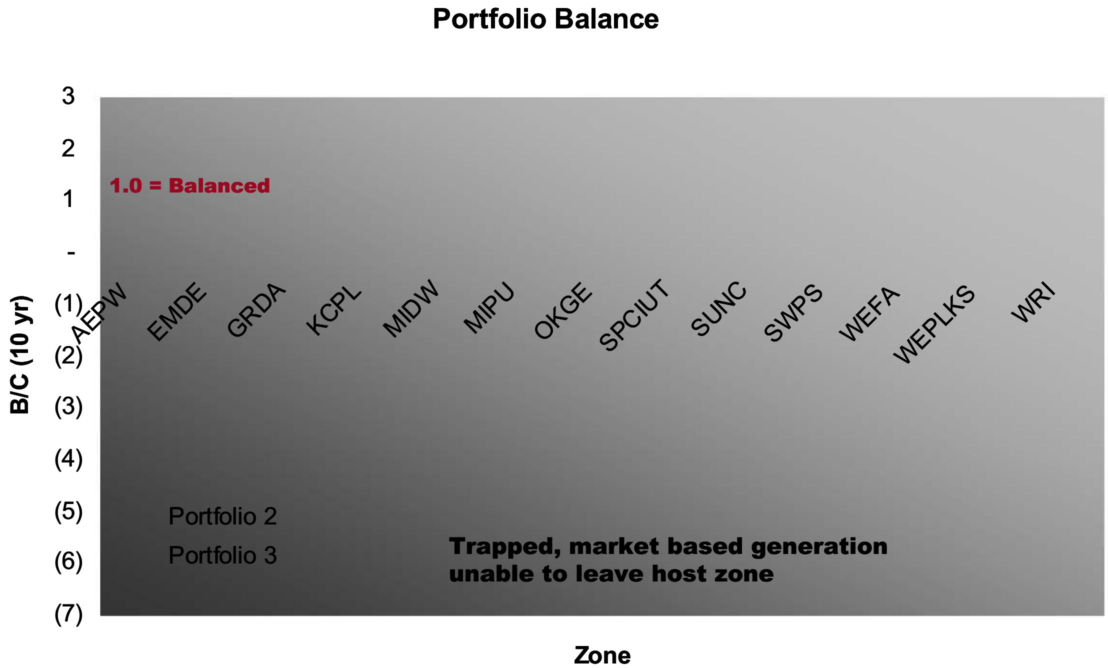
Portfolio 4


Southwest Power Pool
Initial Economic Portfolio #4
Axtell
Fair Port
Iatan
Nashua
Sibley
Swissvale
Knoll
Summit
Morris Co
Wolf Creek
Reno Co
Benton
Rose Hill
Spearville
Wichita
Comanche Co
Hitchland
Woodward
Sooner
Cleveland
Table Rock
Thayer S.
Osage Creek
Flint Creek
Independence SES
Potter
State Line
Redbud
Muskogee
Horseshoe Lake
Ft. Smith/VBI
AR Nuclear One
Seminole
Lawton Eastside
Pittsburg
Tolk
Tuco
Northwest Texarkana
McNeil
SPP RTO
Entergy ICT
Substation Upgrade
Transmission Upgrade
0 20 40 80 Miles

May 2008: Trapped Generation

The CAWG review of the four portfolios, including high wind sensitivities, discovered that the production cost analysis contained significant levels of "trapped generation" (generation that cannot get power out of the host zone due to transmission constraints, significantly impacting the modeling results) related to wind generation. The CAWG initiated the Trapped Generation Task Force (TGTF) to address this issue. The following graph demonstrates effects of trapped generation on portfolio B/C ratios.

Trapped Generation in Economic Models



The TGTF developed guidelines for including generation in the production cost modeling, that were reviewed by the Economic Modeling and Methods Task Force ("EMMTF", now called the Economic Studies Working Group, "ESWG"). The TGTF decided that the base case models should contain wind levels consistent with current wind in service. These models contained 2,600 MW of nameplate wind,** down from 4,600 MW of generic wind included in previous models. Change cases could include additional wind generation, but the TGTF recommended that the additional wind above existing levels must be matched with the transmission upgrades that would be needed to deliver the additional wind to the SPP energy market.

June 2008: Wind and Spearville-Knoll-Axtell (SKA)

SPP staff updated the study models after the TGTF determined that 2,600 MW of wind should be used in the base case. The following table illustrates the resultant B/C ratios for Portfolios 2 through 4, where 2,600 MW of wind is also included in the change case. The adjusted production costs

** This coincides with the amount of wind in the SPP footprint at the end of 2008, as well as the transmission upgrades required to delivery wind with firm service.

shown are changes in adjusted production costs. Therefore, a red parenthetical represents lower adjusted production costs after an upgrade takes place, and it is the estimate of overall benefit.

Preliminary Portfolio Results, post-TGTF (June 26, 2008 CAWG Meeting)

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_June08	($50,482,000)	($41,409,000)	($9,073,000)	$ 371	0.92
Economic Portfolio - P3_June08	($53,325,000)	($42,060,000)	($11,266,000)	$ 347	1.04
Economic Portfolio - P4_June08	($48,429,000)	($38,581,000)	($9,848,000)	$ 608	0.54

SPP staff conducted a sensitivity analysis of Spearville-Knoll-Axtell on the above portfolios to determine its impact. The Spearville-Knoll-Axtell (SKA) 345kV line is a transmission upgrade for which the Kansas Electric Transmission Authority (KETA) issued a Notice of Intent to Proceed with Construction on July 25, 2007. Additionally, the SPP Board of Directors approved this transmission upgrade for inclusion in the SPP Transmission Expansion Plan (STEP). The SPP Board of Directors requested that all projects of 345 kV and above approved for inclusion in the STEP also be considered candidates in the Balanced Portfolio analyses. It was found in the analyses that the SKA project uniformly raised the B/C ratios of all portfolios, and it appeared that the SKA project should be included for consideration, although a similar analysis was not conducted for other low B/C ratio projects that were not included in the original portfolios. The results are shown in the following table.

Impact of Spearville – Knoll – Axtell

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C
Economic Portfolio - P2_SKA_June08	($90,215,000)	($71,327,000)	($18,889,000)	$ 539	1.13
Economic Portfolio - P3_SKA_June08	($92,307,000)	($72,235,000)	($20,072,000)	$ 515	1.22
Economic Portfolio - P4_SKA_June08	($84,031,000)	($64,709,000)	($19,322,000)	$ 776	0.73

Because Portfolio 4 had a B/C ratio well below one, it was not included in further analyses in the Balanced Portfolio development process.

July 2008: Update Designated Resources

Portfolios 2 and 3 were updated to include the Turk Plant, a Designated Resource planned to be on line by 2012. This change lowered the benefit to cost ratios below one, as shown in the following table. These results were based on the 2008 wind levels in SPP (2,600 MW) but do not include the Spearville-Knoll-Axtell line.

Impact of Updates on Portfolios 2 and 3

Project	Total Adjusted Production Cost	SPP	TIER1	Cost ($M)	B/C	SPP B/C
Portfolio 2 - July 08	($38,291,000)	($28,825,000)	($9,466,000)	$ 371	0.70	0.53
Portfolio 3 - July 08	($42,033,000)	($32,281,000)	($9,751,000)	$ 347	0.82	0.63

August 2008: Firm Wind Sensitivities

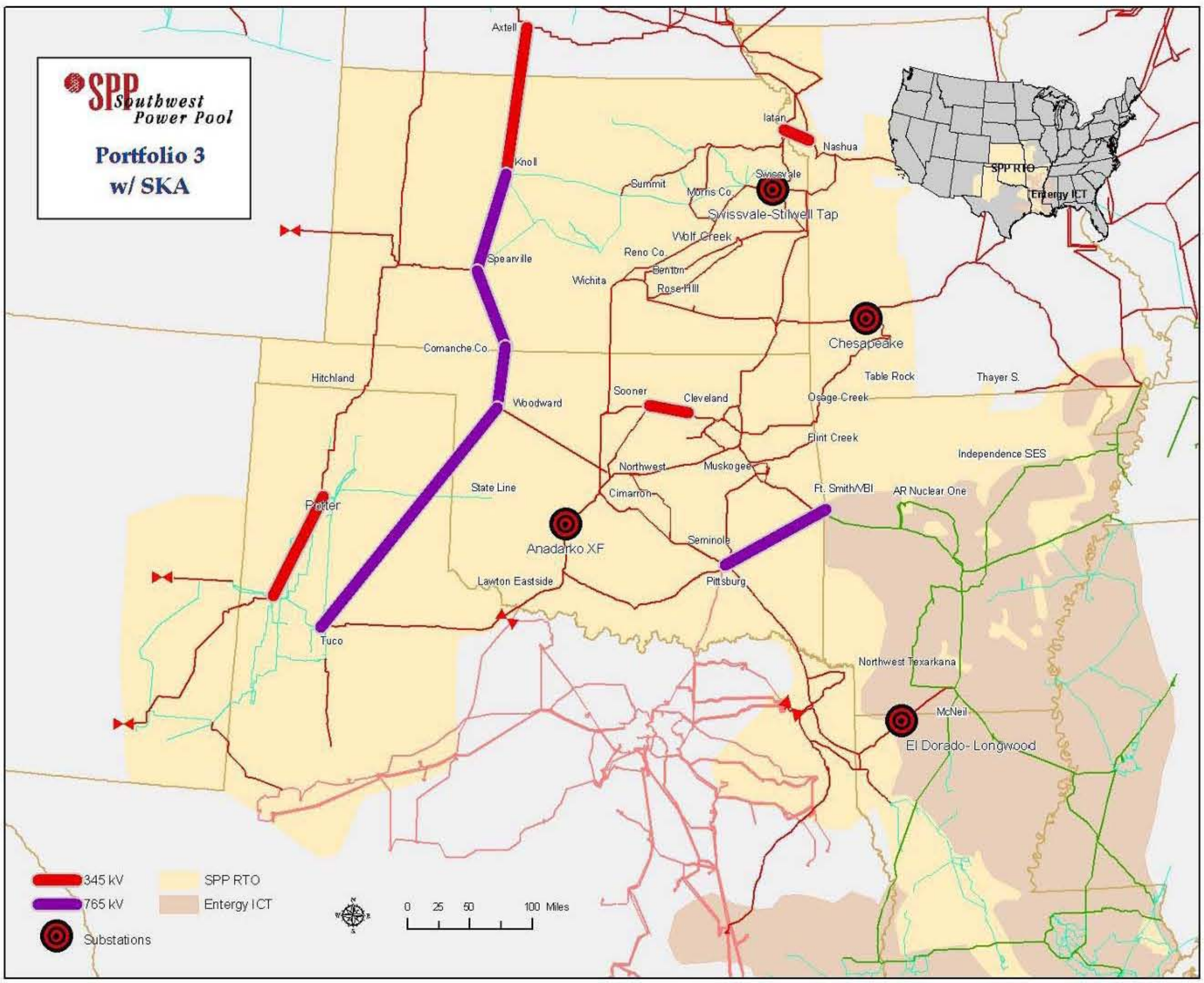
Additional wind sensitivities were conducted for Portfolios 2 and 3 to determine the impact that the amount of wind assumed in the model would have on the benefits. Benefits were estimated for 700 MW of firm wind in the base case and an additional 1,900 MW of market-based wind in the change case. The results showed a significant increase in production cost savings for both Portfolios 2 and 3. The changes in benefits from adding the market-based wind without transmission upgrades were calculated to show the impact of trapped generation. Stakeholders supported the inclusion of all existing wind in the portfolios even though wind without firm transmission service would lower the B/C ratios.

September 2008: Introduction of Portfolio Variations 3-A and 3-B

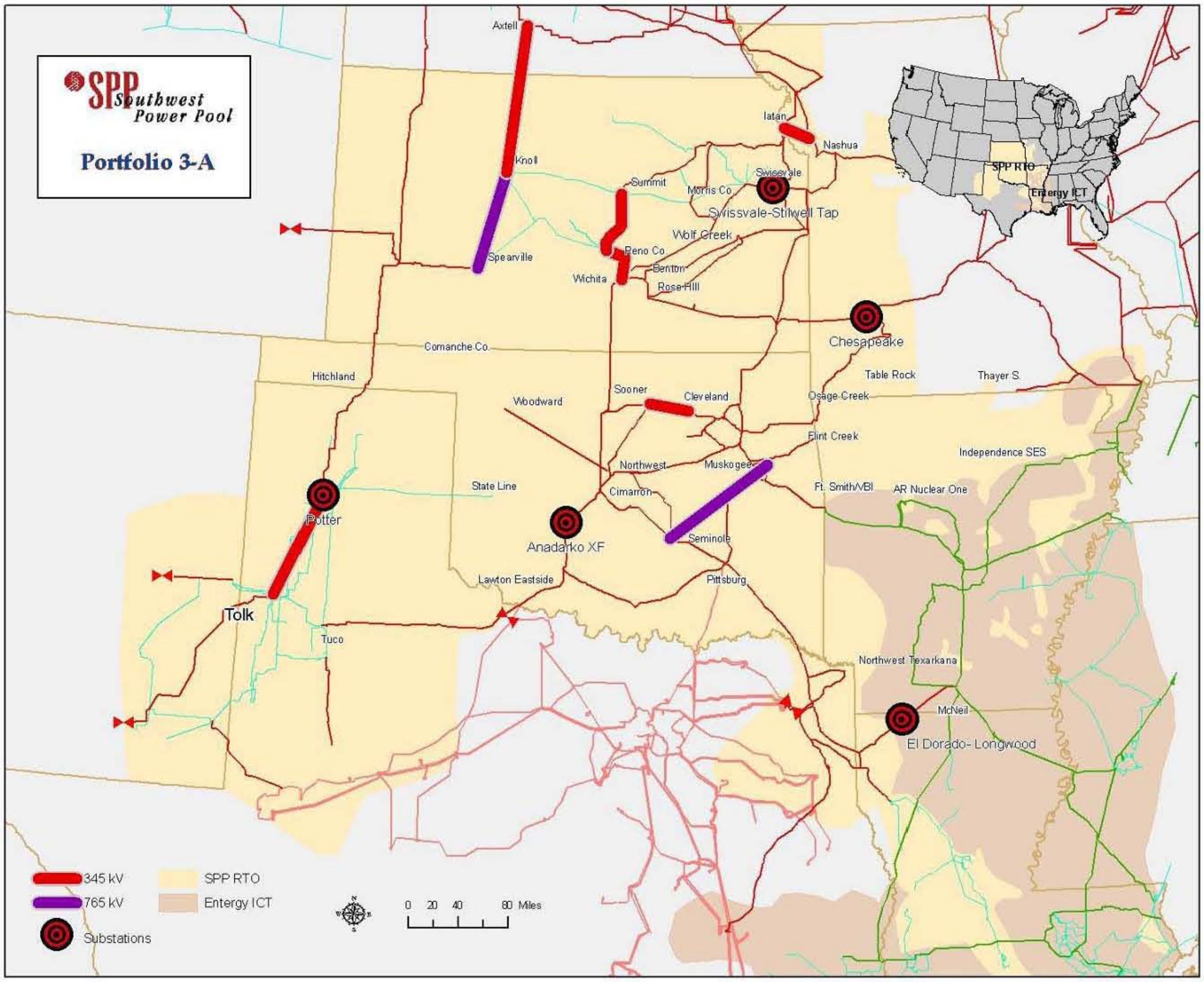
SPP staff developed two modified portfolios based on Portfolio 3. Adjustments to Portfolio 3 included an upgrade of the Wichita – Reno Co - Summit line and carried through the addition of Spearville-Knoll-Axtell. From this modification of Portfolio 3 two variations were developed and labeled 3-A and 3-B. These portfolios are shown pictorially below.

Since many sections of Portfolio 3 included transmission paths that are also in the proposed EHV Overlay Plan, the CAWG decided to consider these common corridor projects for 765 kV construction in the balanced portfolio. The purple lines in the following maps illustrate this construction.

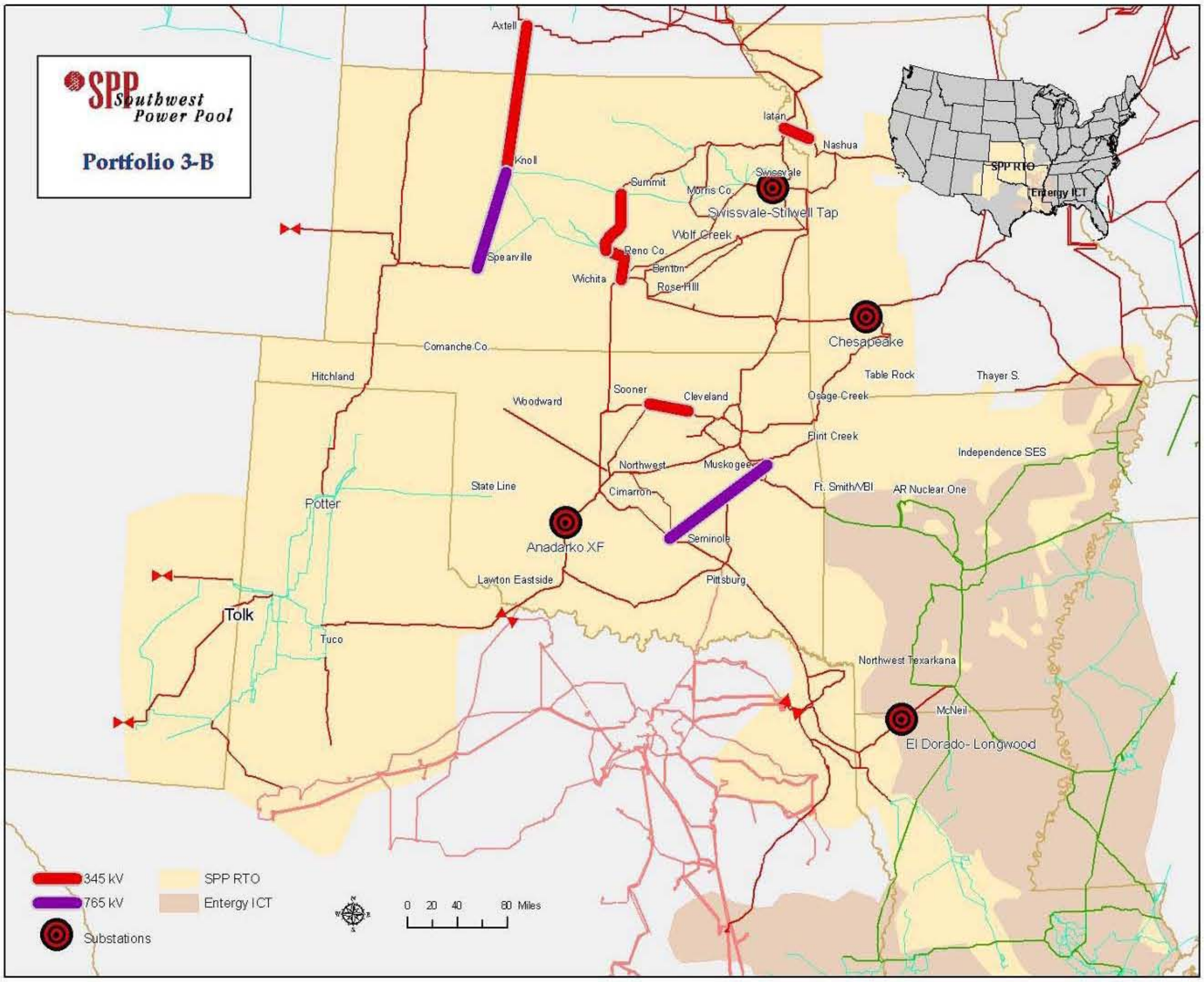
Portfolio 3, with Spearville – Knoll – Axtell (SKA)



Portfolio 3-A with Wichita - Reno Co - Summit



Portfolio 3-B with Wichita – Reno Co - Summit



Modeling assumptions for the dispatch of wind were still an issue in these results where SPP staff used a wind offer price of $20/MWh. Given this caveat, the results showed that both Portfolios 3-A and 3-B had B/C ratios greater than one using 345 kV costs, but were marginal when 765 kV costs were used in the calculations. Portfolio 3-B is a sensitivity of Portfolio 3-A used to test whether or not the Tolk-Potter upgrades would increase the B/C ratio. Since they did, the SPP staff recommended going forward with Portfolio 3-A, as well as subsequent consideration of additional variations of Portfolio 3.

Initial Results for Portfolios 3-A and 3-B

Project	Cost ($M)	Proj 10 Year SPP Benefit ($M)	SPP B/C
Portfolio 3-A	$585	$776	1.33
Portfolio 3-B	$545	$693	1.27
Portfolio 3-A	$761	$776	1.02
Portfolio 3-B	$721	$693	0.96

October 2008: Portfolio 3 (High Wind) and 3-A (Current Wind)

Two different types of analyses were considered for Portfolios 3 and 3-A. Since Portfolio 3 has upgrades similar to those on the western portion of the proposed EHV system, the SPP staff evaluated Portfolio 3 using a high wind (7 GW) scenario with specific wind locations for wind capacity above the current 2008 level of 2.6 GWs. In particular, the B/C ratio was calculated for both 345 kV and 765 kV costs to get a feel for whether or not Portfolio 3 could support a portion of the EHV upgrades in the western SPP region.

High Wind (7 GW) for Portfolio 3

Scenario	SPP 10 Yr Benefit	Cost ($M)	B/C
Portfolio 3 - 345 kV	$ 1,920,593,438	829	2.32
Portfolio 3 - 765 kV*	$ 1,920,593,438	1,213	1.58

SPP staff used Portfolio 3-A to test the sensitivity of a carbon tax on the estimate of benefits from savings in the adjusted production costs. The results indicated that keeping wind at its current levels and imposing a carbon tax would, as expected, result in a significant decrease in benefits for Portfolio 3-A.

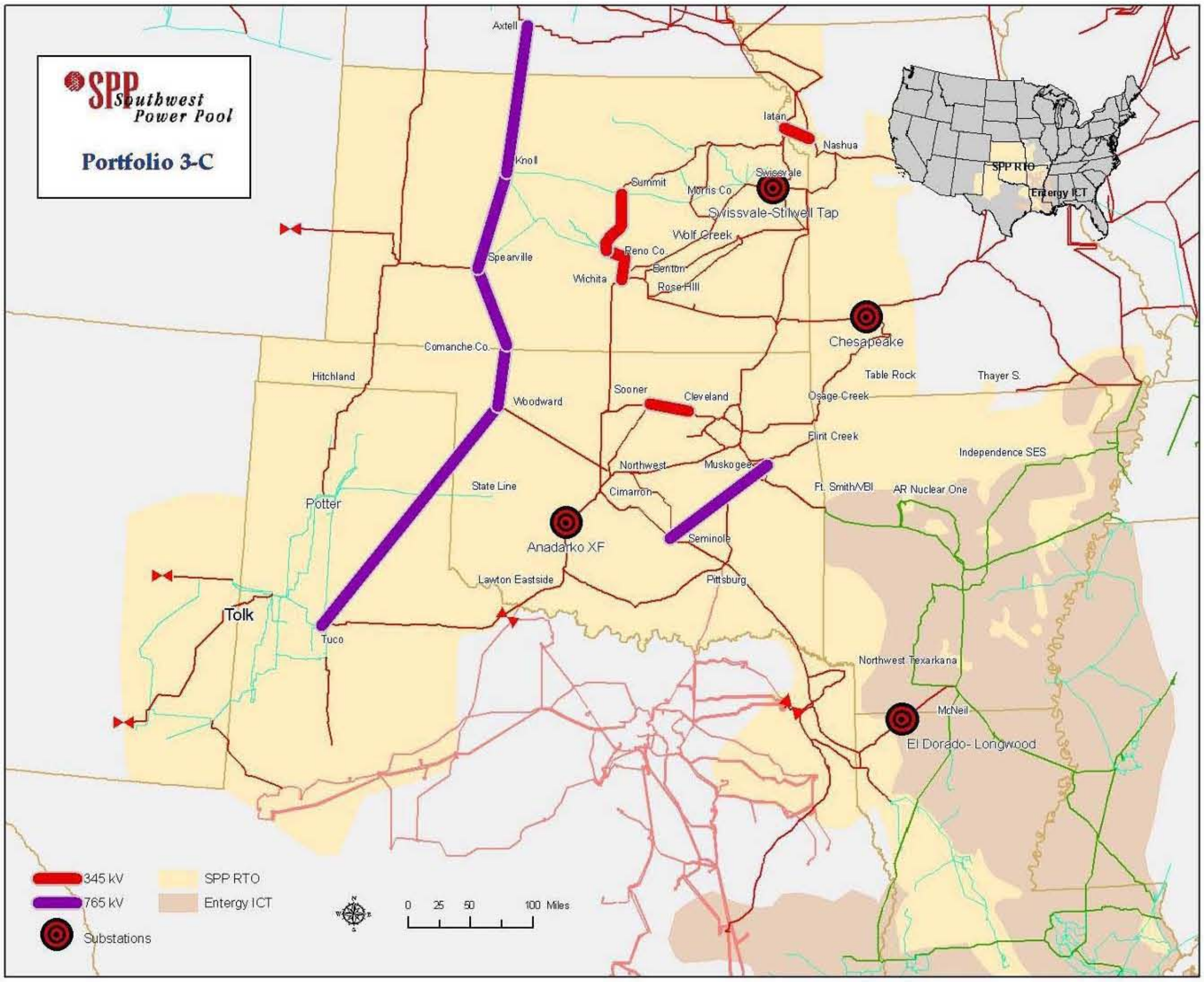
Carbon Tax Sensitivity Results for Portfolio 3-A at Current Wind (2.6 GW)

Project	Total Adjusted Production Cost	SPP NON-OATT	SPP OATT	TIER1	Cost	SPP B/C
Portfolio - P3A - Base	($119,180,000)	($2,454,920)	($111,931,080)	($4,794,000)	$ 597	1.27
Portfolio - P3A - $15 Carbon Tax	($60,140,000)	($4,000)	($52,699,000)	($5,543,000)	$ 597	0.60
Portfolio - P3A - $40 Carbon Tax	($17,992,000)	($317,000)	($16,926,000)	($1,630,000)	$ 597	0.19

December 2008: Portfolio 3-C (Modify Portfolio 3)

Portfolio 3-C was developed as a hybrid of Portfolios 3 and 3-A by removing the Tolk - Potter upgrades but adding the Spearville – Knoll - Axtell and Wichita – Reno Co - Summit lines. The following graph pictorially represents Portfolio 3-C.

Portfolio 3-C



It should be noted that by this time SPP staff had resolved a problem with its application of the PROMOD that had resulted in dispatching wind on a small number of days, resulting in what appeared to be a significant “trapped generation” problem. With the resolution of that issue, wind was now being dispatched from specified injection points at $0.05/MWh. Note that this was an offer price for the wind injection into the market since using an offer price of $0/MWh which caused problems in the modeling. The final clearing price of wind is at the marginal zonal market price for each hour, which is significantly higher than the offer price; i.e. wind in the actual production cost models is priced at the marginal zonal market price.

SPP staff used Portfolio 3-C to perform an analysis of an integration plan for the EHV Overlay. For this effort, scenarios were conducted at 3,300 MW of wind injection in 2012, 7,000 MW of wind injection in 2017, and 13,500 MW of wind injection in 2023, with 765 kV transmission being added to the analysis to accommodate the higher wind levels assumed for wind. The following table shows the B/C ratio that would apply had the results of year 2012 been distributed uniformly over a ten-year period and compared to the ten-year cost. In addition, the results are shown using ten years of Annual Transmission Revenue Requirements (ATRR) for the EHV projects contained in the study periods 2012, 2017 and 2023.

Portfolio 3-C + EHV Build Out		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C (P3-C)	0.74	0.66
10 yr vs E&C (P3-C+West EHV)	0.79	0.72
10 yr vs E&C (P-3C+West & Central EHV)	2.43	1.45
10 yr vs ATRR	**0.71**	**0.49**
Annual B/C (final year)	1.99	1.19

SPP staff reran portfolio 3-A at 3,300 MW of wind to determine the impact of adding 700 MW of market-based wind to the benefits of this portfolio. The following table gives the results for Portfolio 3-A using 765 kV costs.

Portfolio 3-A		
Benefit - Cost	**Total B/C**	**SPP B/C**
10 yr vs E&C	1.46	1.30
10 yr vs ATRR	**1.19**	**1.06**
Annual B/C (final year)	1.46	1.29

In addition to the adjusted production cost and cost benefit analysis, SPP Staff analyzed the impacts of the portfolio options on basic reliability. Portfolios 3-C and 3-A were considered in this analysis. The results of the total Engineering and Construction (E&C) cost impacts on regional reliability are shown in the table below with 3-C yielding the greatest benefits by reducing reliability needs to a net amount of $31M. More detailed impacts are shown in Appendix D.

P3-A and 3-C impact on STEP reliability assessment

Project	New Violations	Solved Violations	Net
Portfolio 3-A	$4,385,000	$4,004,900	**-$380,100**
Portfolio 3-C	$4,585,000	$35,265,250	**$30,680,250**

<u>January 2009</u>: Further Analysis of Portfolios 3-A and 3-C With Nebraska

At the December 2008 CAWG meeting, further analysis of Portfolios 3-A and 3-C was requested, including the addition of the three pricing zones in Nebraska as a result of the Nebraska entities decision to join the Southwest Power Pool. The emphasis on Portfolio 3-A was in regard to the balance of this portfolio when the Nebraska zones were added, and to compare this balance when Portfolio 3-A upgrades are priced at 345 kV versus 765 kV costs. With the addition of Nebraska, the B/C ratio for Portfolio 3-A at 765 kV increased from 1.06 to 1.11, and at 345 kV from 1.27 to 1.50. The higher costs at 765 kV resulted in significant levels of cost transfers needed to balance the portfolio compared to the lower costs at 345 kV.

Portfolio Balance With Transfers for Portfolio 3-A at 345 KV Costs

#	Zone	Benefits	Costs	Transfer Allocation	Transfer Out	Transfer Net	Net Benefit	B/C	Original B/C
1	AEPW	$20,880,672	$24,939,597	$14,640,350	-$18,699,275	-$4,058,925	$0	1.00	0.84
2	EMDE	$5,828,820	$2,923,755	$1,716,339	$0	$1,716,339	$1,188,726	1.26	1.99
3	GRDA	$1,797,527	$2,170,293	$1,274,032	-$1,646,798	-$372,766	$0	1.00	0.83
4	KCPL	$8,337,354	$8,571,771	$5,031,907	-$5,266,324	-$234,417	$0	1.00	0.97
5	MIDW	$1,590,879	$798,241	$468,593	$0	$468,593	$324,045	1.26	1.99
6	MIPU	$1,598,074	$4,491,010	$2,636,368	-$5,529,303	-$2,892,935	$0	1.00	0.36
7	MKEC	$5,294,897	$1,243,893	$730,206	$0	$730,206	$3,320,798	2.68	4.26
8	OKGE	$44,982,968	$15,731,003	$9,234,607	$0	$9,234,607	$20,017,358	1.80	2.86
9	SPRM	-$29,773	$1,719,556	$1,009,435	-$2,758,764	-$1,749,329	$0	1.00	-0.02
10	SUNC	$389,069	$1,185,151	$695,722	-$1,491,804	-$796,082	$0	1.00	0.33
11	SWPS	$43,102,775	$12,809,661	$7,519,685	$0	$7,519,685	$22,773,429	2.12	3.36
12	WEFA	$11,792,345	$3,508,023	$2,059,323	$0	$2,059,323	$6,224,999	2.12	3.36
13	WRI	$23,072,688	$12,818,241	$7,524,722	$0	$7,524,722	$2,729,725	1.13	1.80
14	NPPD	-$608,956	$8,896,109	$5,222,303	-$14,727,368	-$9,505,065	$0	1.00	-0.07
15	OPPD	-$472,047	$6,896,029	$4,048,192	-$11,416,267	-$7,368,075	$0	1.00	-0.07
16	LES	-$145,808	$2,130,072	$1,250,421	-$3,526,301	-$2,275,880	$0	1.00	-0.07
Total		**$167,411,485**	**$110,832,404**	**$65,062,205**	**-$65,062,205**	**$0**	**$56,579,080**	**1.51**	**1.51**

All numbers in the above table represent annualized costs for Portfolio 3-A over a ten-year period.

Transfers out of a zone represent the dollars that must be moved from the zonal rates to a region-wide rate in order to achieve balance. Two measures of the degree of balance of a portfolio include: a) the number of zones with positive net benefits after the transfers (in this case: 7 of 16 total zones); and b) the ratio of the transfers out to the costs of the upgrades (in this case: 58.7%).

Additional analysis of the EHV upgrades in Portfolio 3-C were performed with and without Portfolio 3-A to determine whether or not portfolio 3-A added more benefits than costs to a zone that would include parts of the EHV (765 kV) overlay. The results indicated that Portfolio 3-A did add more benefits than costs.

Analysis of Portfolio 3-C showed a B/C ratio of 0.58 using 765kV costs and a ratio of 0.94 using 345 kV costs.

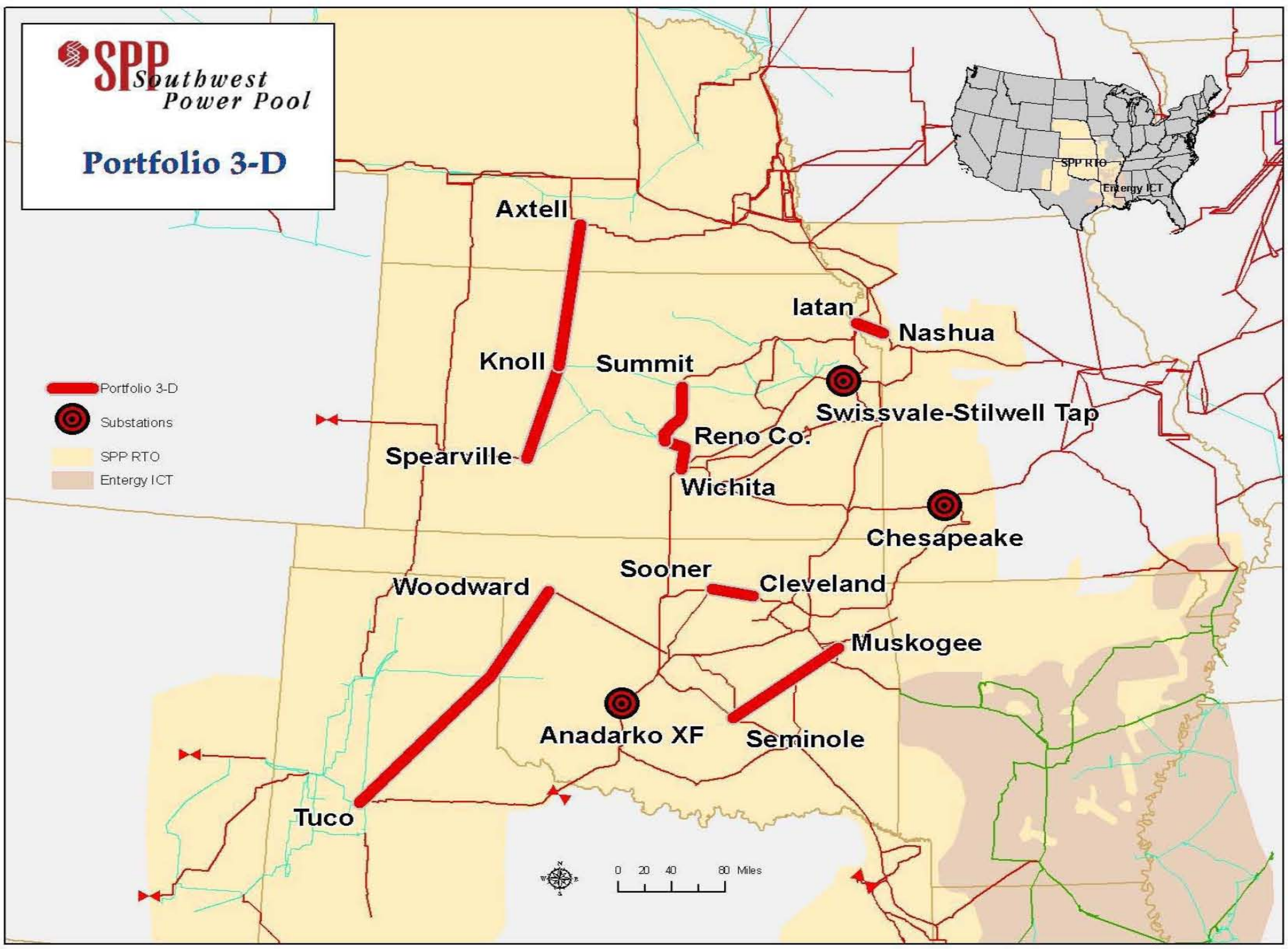
CAWG Response

Due to the difficulty in balancing a portfolio that includes 765 kV projects, as well the high level of uncertainty concerning the level of wind available to the SPP footprint on the planning horizon, it was decided in February 2009 that the Balanced Portfolio should include only existing wind generation in service or under construction. The CAWG directed SPP staff to update the economic models to reflect these changes and to work through the EMMTF to ensure that the models were vetted through the stakeholder process to ensure that all member data was represented accurately. Additionally, the CAWG requested that the Nebraska modeling parameters be updated to include a better, more expansive representation for utilities beyond Nebraska to better account for the economic interchange of energy beyond the Nebraska zones. Lastly, the CAWG requested that SPP Staff work with the EMMTF to update all costs associated with the construction of portfolio projects. The E&C costs had shown a significant degree of variability throughout the course of the Balanced Portfolio effort to date due to changes in the economic climate, leading the CAWG to seek an accurate, updated account of these associated construction costs from each respective constructing member.

SPP Staff Action Plan

SPP staff, in response to the CAWG, developed an action plan to address the issues raised and also developed a timeline for the completion of the Balanced Portfolio analysis that would conclude with a staff recommendation in April 2009. This action plan detailed how SPP staff would work with the EMMTF to address any outstanding modeling and cost issues for the simulation of the Balanced Portfolio. Additionally, the action plan, corresponding to the suggestion by the CAWG, defined that the analysis would consider only existing wind resources. SPP staff worked with stakeholders to determine the exact levels of existing wind resources on the system in the process of facilitating the modeling refinements through the EMMTF. Also, as the RSC directed, Portfolios 3, 3-A and 3-C were used as a starting point for these additional analyses. Lastly, Portfolio 3-D (shown below) was developed and included in the analysis. This action plan was presented to the CAWG at the end of January 2009.

Portfolio 3-D



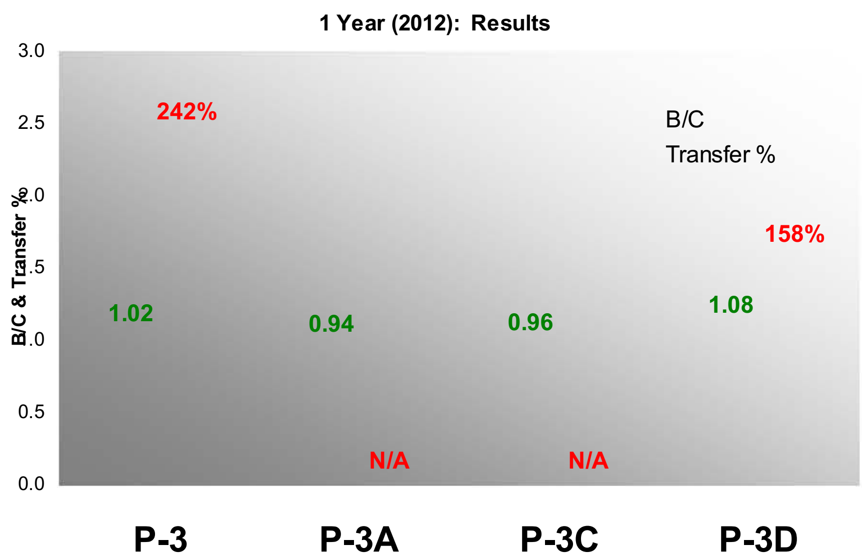
March 2009: Final Balanced Portfolio Analysis

Further material pertaining to the Balanced Portfolio was not presented until the March 2009 CAWG meeting. staff and stakeholders spent the majority of February working through the EMMTF on updating process and refining the engineering models used for the analysis. Additionally, the EMMTF members reviewed their respective output data and provided feedback to SPP staff. The data was checked for the reasonableness of the output results as well as the accuracy of the input into the production cost modeling. These changes were included in the Balanced Portfolio analysis.

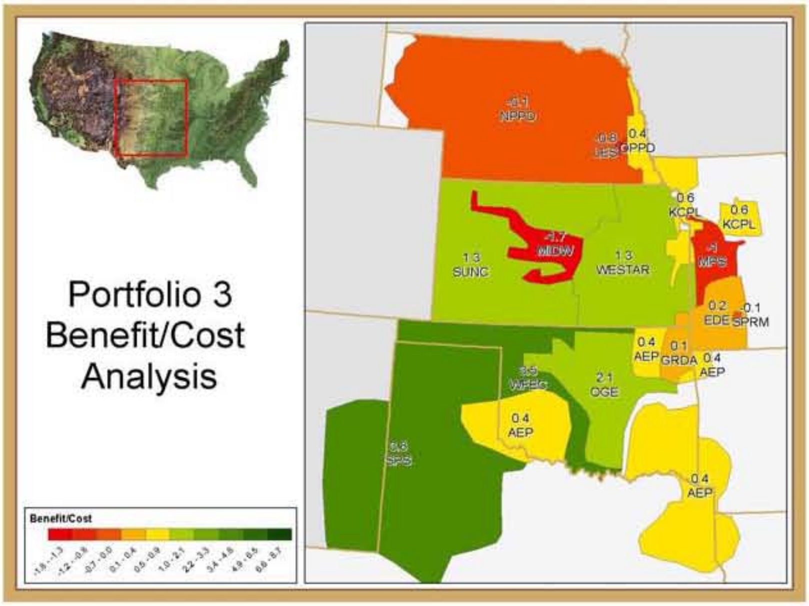
During the March 2009 CAWG meeting, the results from the analysis described above were presented. SPP staff started with a screening analysis on Portfolios 3, 3-A, 3-C, and 3-D. This analysis was conducted on the 2012 model and taken as an annual benefit to cost basis. The results are shown in the following exhibits.

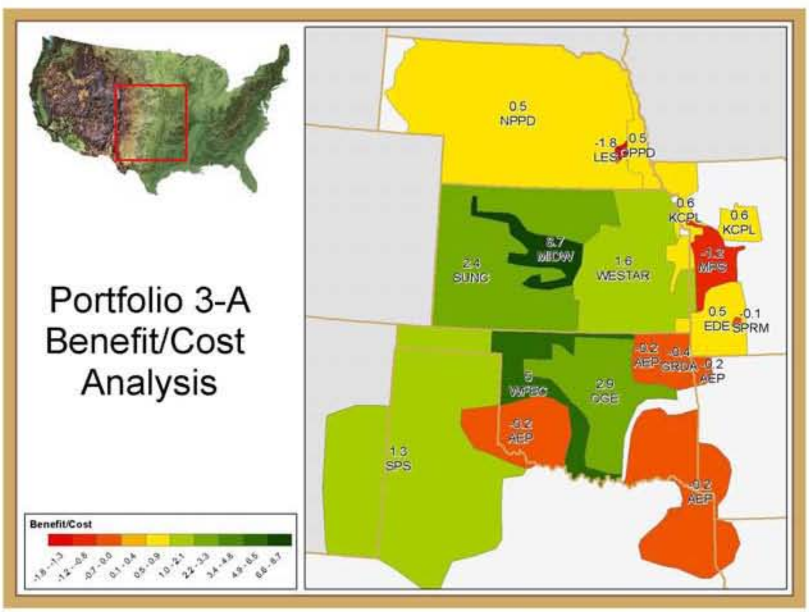
1 Year (2012) Screening Results

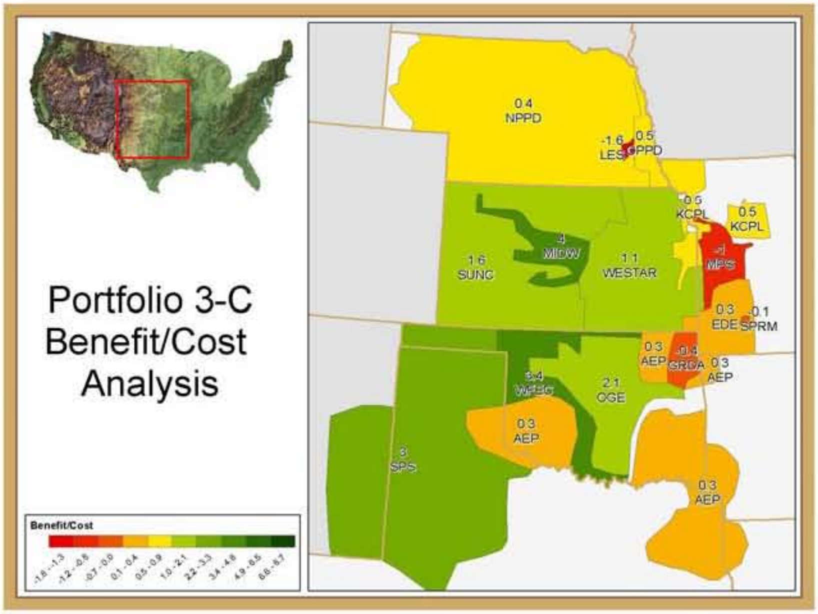
Project	Total APC Benefit ($M)	SPP OATT Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3	$124	$122	$2.6	$ 120	**1.02**	**242%**
P-3A	$117	$114	$2.7	$ 121	**0.94**	**n/a**
P-3C	$159	$159	($0.4)	$ 166	**0.96**	**n/a**
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**	**158%**

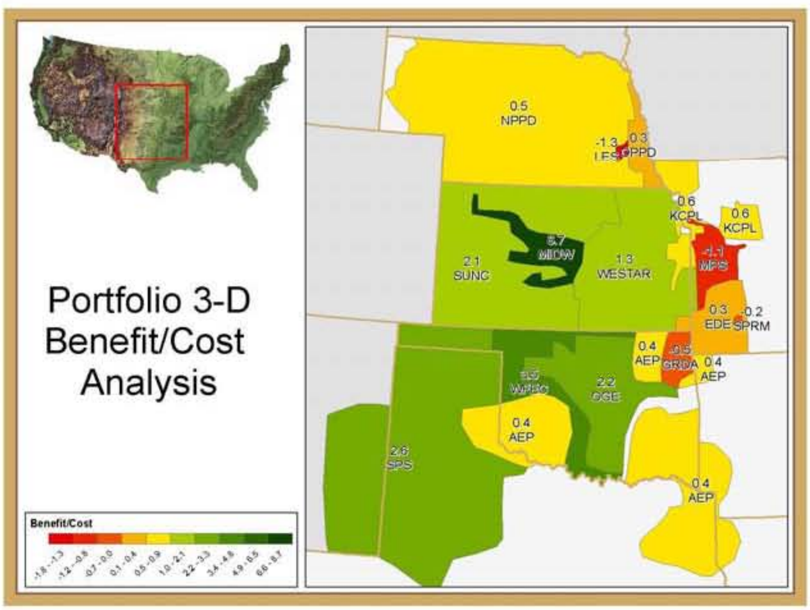


The Benefit to Cost ratio per zone is shown for the respective portfolios in the following pictures. The B/Cs shown here are before transfers have been conducted to balance the respective portfolios.









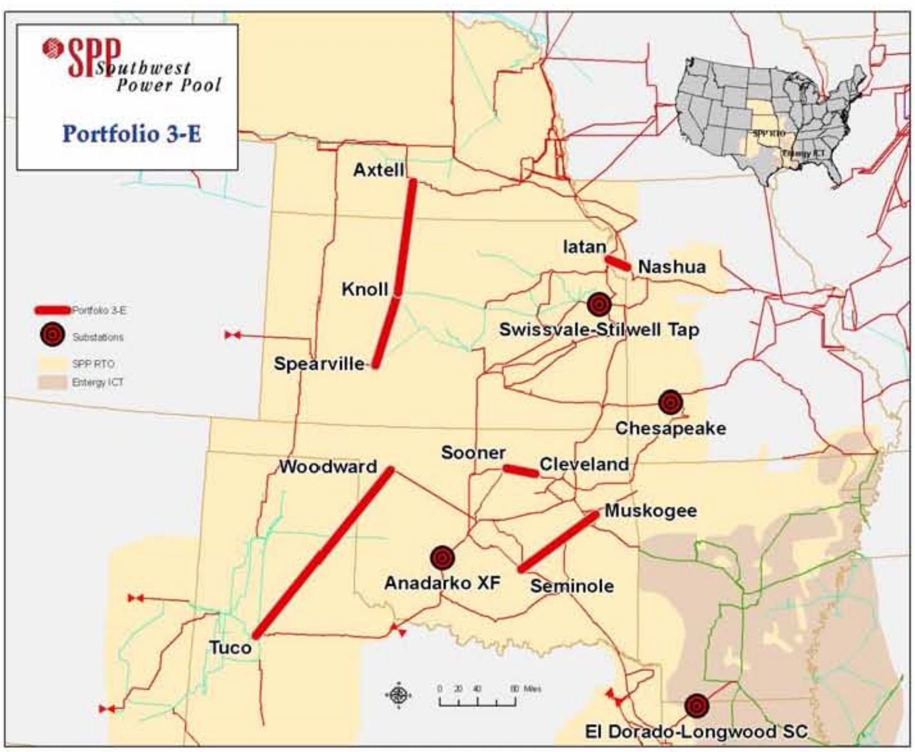
Portfolio 3-D had the highest B/C ratio of the four portfolios screened and was selected for further development. In this analysis, each of the individual projects in the Portfolio was removed to determine the impact of the project on the portfolio as a whole. These results are shown in the following table. The table is divided into total Adjusted Production Cost (APC) benefit, benefit for SPP Open Access Transmission Tariff (OATT) members as well as benefits to areas outside the region, shown here as Tier 1 benefits. The transfer percentage (%) shown is the percentage of the total portfolio cost in dollars that must be transferred, following tariff provisions, to balance the respective portfolios shown below. Ideally, the goal is a lower transfer percentage is desirable with a higher B/C.

Portfolio 3-D Refinement Analysis

Project	Total APC Benefit ($M)	SPP Benefit ($M)	Tier 1 Benefit ($M)	Annual Total Portfolio Cost ($M)	B/C	Transfer %
P-3D	**$148**	**$149**	**($1.3)**	***$ 139***	**1.08**	**158%**
Portfolio 3D sensitivities						
no WRS (P-3E)	**$137**	**$132**	**$4.3**	**$ 107**	**1.24**	**121%**
no SKA	**$127**	**$128**	**($0.8)**	**$ 114**	**1.12**	**111%**
no TW	$121	$116	($1.1)	$ 105	**1.10**	**324%**
no Ches	$146	$148	($1.4)	$ 136	**1.09**	**156%**
no SM	$116	$122	($6.6)	$ 115	**1.06**	**183%**
no IN	$143	$142	$0.5	$ 132	**1.08**	**168%**
no WGard	$152	$149	($1.6)	$ 138	**1.08**	**160%**
no ADK	$146	$147	($0.9)	$ 137	**1.07**	**159%**
no SC	$120	$122	($1.2)	$ 135	**0.90**	**n/a**

The projects that were the best candidates for removal from Portfolio 3-D were (1) Wichita – Reno Co. – Summit, (2) Spearville – Knoll – Axtell and (3) the Chesapeake Transformer. SPP staff recommended during the March 2009 CAWG meeting that the Wichita – Reno Co. – Summit line be removed from the portfolio, but also recommended Spearville – Knoll – Axtell and Chesapeake stay in the portfolio to maintain balance. This Portfolio was labeled Portfolio 3-E and is shown in the following map.

Portfolio 3-E



Portfolio 3-D and 3-E were selected as the candidates for the full 10-year analysis of portfolios as required by the Tariff. The following tables demonstrate the results of the 10-year analysis, with interpolation between simulated years, 2012, 2017 and 2022. The results are discounted back to present worth, using an 8% discount rate. Levelized annual values were also calculated. The annual cost of the each portfolio is given such that the host utility carrying charge rate is assumed to be used for the construction of the project.

Portfolio 3-D: 10 Year Benefit vs. Costs

				Million of Dollars			
Portfolio 3-D			**Total Benefit**	**Incremental Benefit**	**Total Cost SPP OATT ATRR**	**Incremental Cost**	**Cost (E&C)**
2012			$ 149.0		$ 138.55		826.4
2017			$ 208.5	$ 11.904	$ 138.55	$ -	**Annual**
2022			$ 260.3	$ 10.364	$ 138.55	$ -	138.5
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 149	$ 149	$ 139	$ 139	**1.08**
2013	2	0.93	$ 161	$ 149	$ 139	$ 128	1.16
2014	3	0.86	$ 173	$ 148	$ 139	$ 119	1.25
2015	4	0.79	$ 185	$ 147	$ 139	$ 110	1.33
2016	5	0.74	$ 197	$ 145	$ 139	$ 102	1.42
2017	6	0.68	$ 209	$ 142	$ 139	$ 94	**1.50**
2018	7	0.63	$ 219	$ 138	$ 139	$ 87	1.58
2019	8	0.58	$ 229	$ 134	$ 139	$ 81	1.65
2020	9	0.54	$ 240	$ 129	$ 139	$ 75	1.73
2021	10	0.50	$ 250	$ 125	$ 139	$ 69	1.80
2022	11	0.46	$ 260	$ 121	$ 139	$ 64	**1.88**
Ten Year Totals	Yrs 1-10	7.25	$ 2,010	$ 1,405	$ 1,385	$ 1,004	**1.40**
Per Year Levelized				**$ 194**		**$ 139**	**1.40**

Portfolio 3-DE: 10 Year Benefit vs. Costs

Portfolio 3-E			Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
			Million of Dollars				
2012			$ 132.3		$ 106.63		657.4
2017			$ 181.2	$ 9.786	$ 106.63	$ -	Annual
2022			$ 229.5	$ 9.652	$ 106.63	$ -	106.6
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 107	$ 107	**1.24**
2013	2	0.93	$ 144	$ 133	$ 107	$ 99	1.35
2014	3	0.86	$ 156	$ 134	$ 107	$ 91	1.46
2015	4	0.79	$ 168	$ 133	$ 107	$ 85	1.58
2016	5	0.74	$ 180	$ 132	$ 107	$ 78	1.69
2017	6	0.68	$ 181	$ 123	$ 107	$ 73	**1.70**
2018	7	0.63	$ 192	$ 121	$ 107	$ 67	1.80
2019	8	0.58	$ 202	$ 118	$ 107	$ 62	1.89
2020	9	0.54	$ 212	$ 115	$ 107	$ 58	1.99
2021	10	0.50	$ 223	$ 111	$ 107	$ 53	2.09
2022	11	0.46	$ 229	$ 106	$ 107	$ 49	**2.15**
Ten Year Totals	Yrs 1-10	7.25	$ 1,790	$ 1,253	$ 1,066	$ 773	**1.62**
Per Year Levelized				**$ 173**		**$ 107**	**1.62**

A reliability impact analysis was conducted on the portfolio projects to determine the impact of the Balanced Portfolio on the STEP reliability analysis as well as on Tier 1 entities, third parties to SPP. This analysis was conducted in the same manner and with the same methodologies used in the 2008 STEP 10 year reliability analysis. The analysis was conducted for the entire collection of portfolio projects considered for the March CAWG meeting. The results are broken into (1) advanced projects, those projects that would be moved up in the reliability timeline due to the Balanced Portfolio; (2) new projects, projects which are now needed that were not identified in the original 10 year reliability planning horizon, but may have been needed beyond that horizon; (3) third party impacts or projects needed on neighboring systems due to the Balanced Portfolio; and (4) deferred projects, projects which are either deferred beyond the planning horizon or mitigated entirely due to the portfolio. A summary of these results is shown in the table below.

Reliability Impact (E&C Dollars)

Portfolio	Advanced Projects	New Projects	3rd Party Impacts	Deferred Projects	Net Benefit
P-3	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3A	$ 1.0	$ 3.4	$ 10.2	$ 27.7	$ 13.1
P-3C	$ 1.0	$ 3.4	$ 10.2	$ 42.1	$ 27.5
P-3D	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7
P-3E	$ 1.0	$ 19.2	$ 10.2	$ 42.1	$ 11.7

April 2009: Balanced Portfolio Summit

The material from the March 2009 CAWG meeting was presented at an open meeting in Dallas, TX, April 1, 2009 as an SPP open stakeholder summit. Stakeholder comments and feedback were collected during this summit and incorporated in the final analysis used in the subsequent recommendation to the CAWG on an April 10th conference call.

Feedback from stakeholders and the CAWG included a request to consider the inclusion of a portion of the Wichita – Reno Co – Summit in the final recommendation, if it was feasible, and to include the project given its benefit and costs. Additionally, Empire District Electric Company staff requested that the Chesapeake transformer project be removed from the Balanced Portfolio recommendation due to the complex nature of the project and the associated third party impacts. Also, the CAWG directed SPP to further refine cost estimates of the projects in the portfolio to include greater granularity in the itemization of project costs associated with the portfolio projects, including but not limited to material costs, right of way requirements, labor, etc. Lastly, SPP staff was directed to determine the appropriate carrying charge rates to be used for each host zone to ensure that consistent values were being applied to all projects so that they could be considered on a consistent and reasonable basis.

April 2009: CAWG Conference Call

The work presented during the April SPP open stakeholder summit was refined to reflect the stakeholder feedback and comments and presented to the CAWG on April 10 via conference call.

The first portfolio change was to consider the removal of the Chesapeake transformer. The results are shown in the following tables.

Portfolio 3-E No Chesapeake: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches			Total Benefit (Million of Dollars)	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012			$ 132.3		$ 93.73		691.9
2017			$ 181.2	$ 9.79	$ 93.73	$ -	Annual
2022			$ 229.5	$ 9.65	$ 93.73	$ -	93.7
Year	**8.00%** Year #	**Discount Factor**	**Annual Benefits**	**Discounted Benefits**	**Annual Costs**	**Discounted Costs**	**B/C**
2012	1	1.00	$ 132	$ 132	$ 94	$ 94	**1.41**
2013	2	0.93	$ 145	$ 134	$ 94	$ 87	1.55
2014	3	0.86	$ 158	$ 135	$ 94	$ 80	1.68
2015	4	0.79	$ 171	$ 136	$ 94	$ 74	1.82
2016	5	0.74	$ 184	$ 135	$ 94	$ 69	1.96
2017	6	0.68	$ 181	$ 123	$ 94	$ 64	**1.93**
2018	7	0.63	$ 191	$ 120	$ 94	$ 59	2.04
2019	8	0.58	$ 201	$ 117	$ 94	$ 55	2.14
2020	9	0.54	$ 210	$ 114	$ 94	$ 51	2.24
2021	10	0.50	$ 220	$ 110	$ 94	$ 47	2.35
2022	11	0.46	$ 229	$ 106	$ 94	$ 43	**2.45**
Ten Year Totals	Yrs 1-10	7.25	$ 1,792	$ 1,257	$ 937	$ 679	**1.85**
Per Year Levelized				**$ 173**		**$ 94**	**1.85**

The transfer analysis for portfolio 3-E without Chesapeake is shown in the following table. The analysis concluded that $32M of transfers were required to balance this portfolio.

Attachment H Transfer Adjustments - Portfolio 3E no Ches - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.8	$21.1	$0.0	$7.2	$7.2	$2.5	1.1
2	EMDE	($0.4)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.8	$1.8	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.3	$7.2	($1.4)	$2.5	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.6)	$3.8	($6.7)	$1.3	($5.4)	$0.0	1.0
7	MKEC	$11.7	$1.1	$0.0	$0.4	$0.4	$10.2	8.3
8	OKGE	$26.5	$13.3	$0.0	$4.6	$4.6	$8.6	1.5
9	SPRM	($0.2)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.2	$1.0	$0.0	$0.3	$0.3	$1.9	2.4
11	SWPS	$56.0	$10.8	$0.0	$3.7	$3.7	$41.5	3.9
12	WEFA	$7.9	$3.0	$0.0	$1.0	$1.0	$3.9	2.0
13	WRI	$14.2	$10.8	($0.4)	$3.7	$3.4	$0.0	1.0
14	NPPD	$5.5	$7.5	($4.6)	$2.6	($2.0)	$0.0	1.0
15	OPPD	$2.2	$5.8	($5.7)	$2.0	($3.7)	$0.0	1.0
16	LES	($3.5)	$1.8	($5.9)	$0.6	($5.3)	$0.0	1.0
Total		$174	$94	-$32	$32	$0	$80	1.9

Next, the inclusion of the Reno Co – Summit portion of the Wichita – Reno Co. – Summit Project was considered for inclusion after the removal of the Chesapeake transformer. These results are shown below.

Portfolio 3-E No Chesapeake, with Reno Co. - Summit: 10 Year Benefit vs. Costs

Portfolio 3-E No Ches, With RS — Million of Dollars

	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Incremental Cost	Cost (E&C)
2012	$ 178.0		$ 105.56		789.0
2017	$ 242.1	$ 12.816	$ 105.56	$ -	Annual
2022	$ 290.4	$ 9.658	$ 105.56	$ -	105.6

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 178	$ 178	$ 106	$ 106	1.69
2013	2	0.93	$ 191	$ 177	$ 106	$ 98	1.81
2014	3	0.86	$ 204	$ 175	$ 106	$ 90	1.93
2015	4	0.79	$ 216	$ 172	$ 106	$ 84	2.05
2016	5	0.74	$ 229	$ 169	$ 106	$ 78	2.17
2017	6	0.68	$ 242	$ 165	$ 106	$ 72	2.29
2018	7	0.63	$ 252	$ 159	$ 106	$ 67	2.38
2019	8	0.58	$ 261	$ 153	$ 106	$ 62	2.48
2020	9	0.54	$ 271	$ 146	$ 106	$ 57	2.57
2021	10	0.50	$ 281	$ 140	$ 106	$ 53	2.66
2022	11	0.46	$ 290	$ 135	$ 106	$ 49	2.75
Ten Year Totals	Yrs 1-10	7.25	$ 2,325	$ 1,632	$ 1,056	$ 765	2.13
Per Year Levelized				$ 225		$ 106	2.13

The transfer analysis for portfolio 3-E without Chesapeake but including with Reno Co. - Summit is shown in the following table. The analysis concluded that $62M of transfers were required to balanced this portfolio

Attachment H Transfer Adjustments - Portfolio 3E no Ches with RS - Annualized

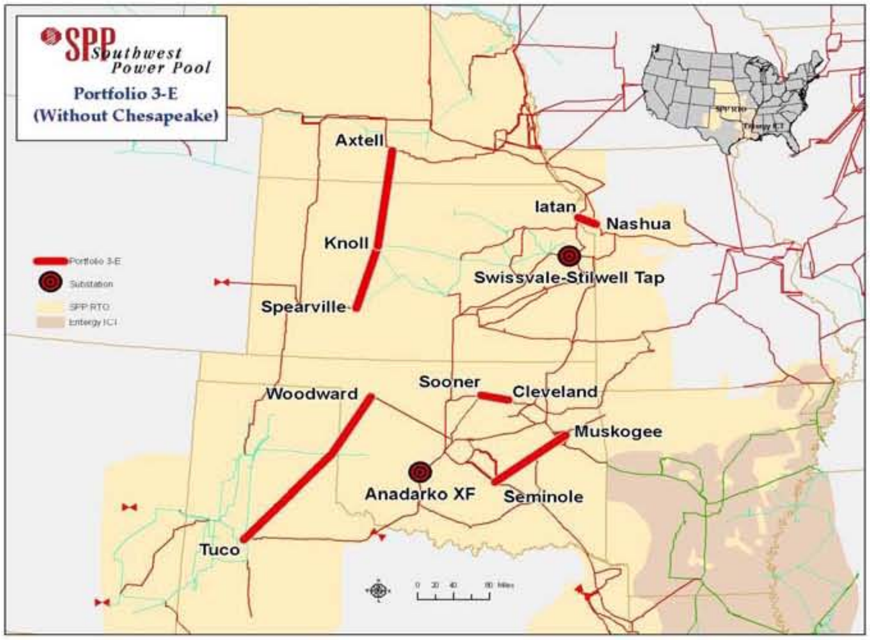
#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$25.8	$23.7	($11.8)	$13.9	$2.1	$0.0	1.0
2	EMDE	($0.1)	$2.8	($4.5)	$1.6	($2.9)	$0.0	1.0
3	GRDA	$0.1	$2.1	($3.2)	$1.2	($1.9)	$0.0	1.0
4	KCPL	$8.7	$8.2	($4.2)	$4.8	$0.5	$0.0	1.0
5	MIDW	$12.8	$0.8	$0.0	$0.4	$0.4	$11.6	10.7
6	MIPU	($5.6)	$4.3	($12.4)	$2.5	($9.9)	$0.0	1.0
7	MKEC	$11.3	$1.2	$0.0	$0.7	$0.7	$9.4	6.0
8	OKGE	$36.8	$15.0	$0.0	$8.8	$8.8	$13.0	1.5
9	SPRM	($0.3)	$1.6	($2.9)	$1.0	($1.9)	$0.0	1.0
10	SUNC	$3.6	$1.1	$0.0	$0.7	$0.7	$1.8	2.0
11	SWPS	$55.9	$12.2	$0.0	$7.1	$7.1	$36.6	2.9
12	WEFA	$11.8	$3.3	$0.0	$2.0	$2.0	$6.5	2.2
13	WRI	$59.9	$12.2	$0.0	$7.1	$7.1	$40.6	3.1
14	NPPD	$5.4	$8.5	($8.0)	$5.0	($3.0)	$0.0	1.0
15	OPPD	$2.7	$6.6	($7.7)	$3.8	($3.8)	$0.0	1.0
16	LES	($3.9)	$2.0	($7.1)	$1.2	($5.9)	$0.0	1.0
Total		$225	$106	-$62	$62	$0	$120	2.1

An analysis was conducted to determine the impact on total Annual Transmission Revenue Requirement (ATRR) for each zone in the tariff. The results are shown for portfolio 3-E, "3-E no Chesapeake" and "3-E no Chesapeake with Reno Co – Summit". These results are shown in the following table.

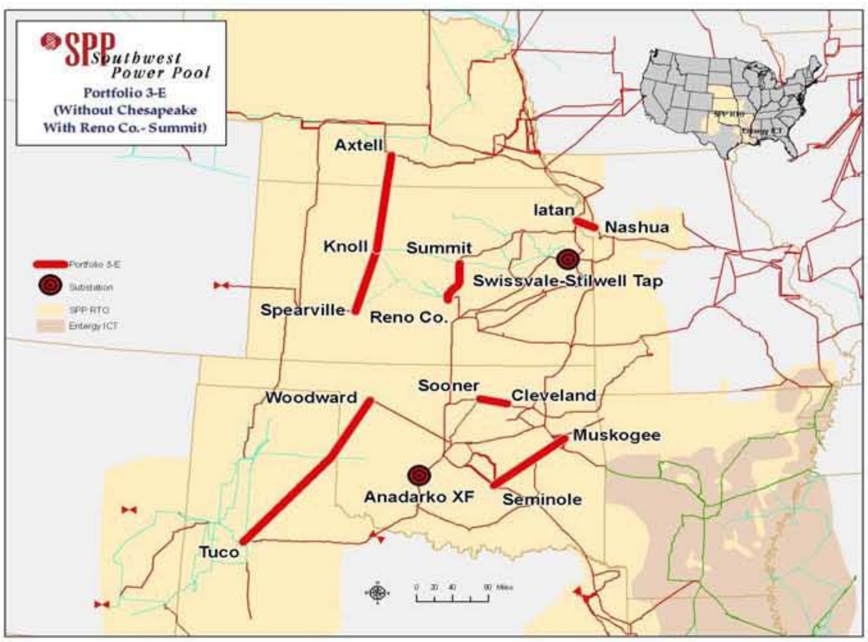
Total ATRR for Proposed Balanced Portfolios

	BP 3E	3E no Ches	BP 3E no Ches w RS
Zone	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR	Annual Zonal plus Annual Base Plan Zonal plus Annual Region Wide RR
AEPW	$ 175,484,688	$ 177,104,393	$ 174,641,806
SPRM	$ 8,934,262	$ 8,659,884	$ 8,524,079
EMDE	$ 14,660,746	$ 14,007,997	$ 14,294,209
GRDA	$ 25,891,875	$ 26,032,862	$ 25,312,950
KCPL	$ 43,661,239	$ 44,709,872	$ 45,060,781
OKGE	$ 118,952,010	$ 116,849,771	$ 122,735,245
MIDW	$ 5,277,346	$ 5,170,672	$ 5,469,320
MIPU	$ 19,618,726	$ 19,420,118	$ 15,471,824
SWPA	$ 9,431,500	$ 9,431,500	$ 9,431,500
SWPS	$ 104,700,870	$ 102,989,030	$ 107,781,536
SUNC	$ 16,092,722	$ 15,934,343	$ 16,377,746
WEFA	$ 25,545,806	$ 25,077,005	$ 26,389,469
WRI	$ 128,845,823	$ 129,135,340	$ 134,286,149
MKEC	$ 7,723,354	$ 7,557,124	$ 8,022,505
LES	$ 8,877,057	$ 8,718,252	$ 8,313,564
NPPD	$ 53,140,390	$ 53,181,895	$ 53,125,563
OPPD	$ 38,645,990	$ 38,661,265	$ 39,227,136
	$ 805,484,404	**$ 802,641,325**	**$ 814,465,382**

Portfolio 3-E "Adjusted"



Portfolio 3-E with Reno Co – Summit, without Chesapeake



Recommendation

The CAWG endorsed portfolio 3-E “Adjusted” (without Chesapeake, without Reno Co – Summit). Portfolio 3-E “Adjusted” provides a significant benefit vs. cost to the SPP region, as well as having lower balance transfer requirements. Portfolio 3-E “Adjusted” contains a comprehensive group of economic projects addressing many of the top constraints in the SPP. The projects associated with portfolio 3-E “Adjusted” are as follows:

- Tuco – Woodward District EHV, $229M
- Iatan – Nashua, $54M
- Swissvale – Stilwell tap at W. Gardner, $2M
- Spearville – Knoll – Axtell, $236M
- Sooner – Cleveland, $34M
- Seminole – Muskogee, $129M
- Anadarko Tap, $8M

- Total E&C Costs: $692M

The supporting material for portfolio 3-E was presented to the Markets and Operations Policy Committee (MOPC) in April 2009. The MOPC reviewed and discussed the portfolio options and the impact on the footprint. After discussion, the MOPC endorsed the recommendation for Balanced Portfolio 3-E “Adjusted” pending issuance of the final report, according to the SPP Tariff.

Portfolio 3-E “Adjusted” provides substantial benefit to customers in the SPP footprint. Based on a 1,000 kWh/month usage of a residential customer, the Portfolio provides an estimated net benefit of $0.78/month ($1.66/mo on average versus a cost of $0.88/mo). The existing transmission revenue requirements for the SPP region in this typical monthly residential customer bill are estimated to be $7.58. Additionally, it should be noted that the Portfolio could incur a construction cost increase of up to 113%, or more than double the estimated construction cost, and still provide a benefit to cost ratio of 1.0 for the region. Therefore, the Balanced Portfolio could have a total E&C final cost of over $1.4B and still provide benefits greater than costs.

Estimated SPP average customer impact (based on 1,000 kWh/month usage)

Existing Zonal ATRR	Base Plan		New Base Plan NTCs		P-3E Costs
	1/3	2/3	1/3	2/3	Annual
$688M	$7M	$14M	$33M	$66M	$106 M
Total: $808M					13%
Avg. Cost Per Customer Per Month: $7.58					**88 ¢**

P-3E "Adjusted" Benefit = $1.66

The CAWG and MOPC recommendation of Portfolio 3-E “Adjusted” was presented to the SPP Regional State Committee (RSC) during their April 27, 2009 meeting in Oklahoma City where Portfolio 3-E “Adjusted” was endorsed by the RSC. Staff then presented to the MOPC and RSC the recommended Portfolio during the SPP Board of Directors meeting on April 28th. The SPP Board approved the projects in Balanced Portfolio 3-E “Adjusted” for inclusion in the SPP Transmission Expansion Plan. The SPP Board went on to direct staff to finalize the Balanced Portfolio Report in accordance with the SPP tariff. Furthermore, the Board directed that Notification To Construct letters for the Projects in the Balanced Portfolio be issued once the required Balanced Portfolio Report is finalized after CAWG review and MOPC approval.

Balanced Portfolio Stakeholder Process
The SPP Regional State Committee (**RSC**) requested the Cost Allocation Working Group (CAWG) to consider alternative cost allocations for economic upgrades.

Cost Allocation Working Group (**CAWG**)
The CAWG has been the primary stakeholder group overseeing development of the Balanced Portfolio. The CAWG created the Economic Concepts whitepaper. Many representatives from other SPP stakeholder groups attend the CAWG's monthly meetings.

Trapped Generation Task Force (**TGTF**)
This CAWG Task Force determined wind assumptions in the Adjusted Production Cost (**APC**) models.

Economic Modeling and Methods Task Force (EMMTF)
The EMMTF focused on the planning process and development of additional economic benefit metrics. It initially worked to acquire detailed data on generation units in the model. The EMMTF addressed confidential issues. The EMMTF is currently the Economic Studies Working Group (ESWG)

Regional Tariff Working Group (RTWG)
The RTWG facilitated acquiring FERC approval of Attachment O language for the Balanced Portfolio process.

Markets and Operations Policy Committee (MOPC), Board of Directors (BOD), Regional State Committee (RSC)
These groups will review and approve the Balanced Portfolio.

Planning Summits
Proposed Balanced Portfolios and related concepts were shared at planning summits in May and August.

Posting
Portfolios and associated information are posted on SPP.org:
http://www.spp.org/section.asp?pageID=120

Appendix

Final Benefit to Cost Results for the Balanced Portfolio

The following table demonstrates the full, 10 year portfolio analysis including reliability costs and benefits. These costs and benefits accrue in the years that the portfolio projects impact the reliability plan.

Portfolio 3-E "Adjusted" 10 yr B/C with Reliability Impact

Million of Dollars

Portfolio 3-E "Adjusted"	Total Benefit	Incremental Benefit	Total Cost SPP OATT ATRR	Reliability Cost	Cost (E&C) $ 692 Annual
2012	$ 131.2		$ 93.73	$ 0.03	$ 93.7
2017	$ 193.2	$ 12.4	$ 93.73	$ 2.53	**Total Annual**
2022	$ 239.0	$ 9.2	$ 93.73	$ 2.53	$ 93.8

Year	8.00% Year #	Discount Factor	Annual Benefits	Discounted Benefits	Annual Costs	Discounted Costs	B/C
2012	1	1.00	$ 131	$ 131	$ 94	$ 94	**1.40**
2013	2	0.93	$ 144	$ 133	$ 94	$ 87	1.53
2014	3	0.86	$ 156	$ 134	$ 94	$ 80	1.66
2015	4	0.79	$ 168	$ 134	$ 94	$ 74	1.80
2016	5	0.74	$ 181	$ 133	$ 94	$ 69	1.93
2017	6	0.68	$ 193	$ 131	$ 96	$ 66	**2.01**
2018	7	0.63	$ 202	$ 128	$ 96	$ 61	2.10
2019	8	0.58	$ 212	$ 123	$ 96	$ 56	2.20
2020	9	0.54	$ 221	$ 119	$ 96	$ 52	2.29
2021	10	0.50	$ 230	$ 115	$ 96	$ 48	2.39
2022	11	0.46	$ 239	$ 111	$ 96	$ 45	**2.48**
Ten Year Totals	Yrs 1-10	7.25	$ 1,837	$ 1,281	$ 950	$ 687	**1.87**
Per Year Levelized				**$ 177**		**$ 95**	**1.87**

The following three tables break out the benefits from the economic analysis. These tables do not include the reliability benefits. The numbers represent a change between the change and base cases, with the change case including the Balanced Portfolio. A negative number denotes a reduction in cost which is considered a benefit. Likewise a positive number is a cost increase.

2012 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$21,285,000	($14,003,000)	$31,439,000	($24,155,000)
EMDE	$2,990,000	($2,096,000)	$207,000	$687,000
GRDA	$72,000	$159,000	$982,000	($751,000)
KCPL	$4,273,000	($637,000)	$9,994,000	($6,358,000)
LES	$1,297,000	$1,226,000	$0	$2,523,000
MIDW	($350,000)	($8,783,000)	$0	($9,133,000)
MIPU	$6,027,000	($3,968,000)	($5,000)	$2,064,000
MKEC	($7,563,000)	($2,015,000)	($925,000)	($8,653,000)
NPPD	$6,519,000	($28,000)	$11,726,000	($5,235,000)
OKGE	($85,787,000)	$52,737,000	($9,386,000)	($23,664,000)
OPPD	$2,165,000	$160,000	$4,247,000	($1,922,000)
SPRM	$734,000	($42,000)	$668,000	$24,000
SUNC	($5,206,000)	($2,096,000)	($5,171,000)	($2,131,000)
SWPS	($70,516,000)	$31,769,000	($519,000)	($38,228,000)
WEFA	($13,163,000)	$4,105,000	($375,000)	($8,682,000)
WRI	($5,257,000)	($359,000)	$2,131,000	($7,747,000)

2017 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$55,943,000	($17,738,000)	$71,548,000	($33,344,000)
EMDE	$3,525,000	($3,272,000)	$100,000	$153,000
GRDA	($28,000)	$163,000	$889,000	($754,000)
KCPL	$6,229,000	($3,576,000)	$11,897,000	($9,244,000)
LES	$2,019,000	$1,970,000	$0	$3,989,000
MIDW	($764,000)	($14,046,000)	$0	($14,810,000)
MIPU	$5,483,000	($3,915,000)	$79,000	$1,489,000
MKEC	($10,893,000)	($2,667,000)	($793,000)	($12,767,000)
NPPD	$5,842,000	($779,000)	$10,741,000	($5,678,000)
OKGE	($129,794,000)	$88,180,000	($14,032,000)	($27,582,472)
OPPD	$3,030,000	$276,000	$5,663,000	($2,357,000)
SPRM	$603,000	($60,000)	$251,000	$292,000
SUNC	($7,575,000)	($2,386,000)	($6,776,000)	($3,185,000)
SWPS	($80,497,000)	$18,914,000	($924,000)	($60,659,000)
WEFA	($22,863,000)	$14,785,000	($468,000)	($7,610,000)
WRI	($14,392,000)	($1,073,000)	$1,674,000	($17,139,000)

2022 Balanced Portfolio 3E "Adjusted" Benefits

Zone	SumOfChange in Production Cost	SumOfDelta Purchases	SumOfDelta Sales	Adjusted Production Cost
AEPW	$67,322,000	($22,618,000)	$83,884,000	($39,181,000)
EMDE	$4,703,000	($4,421,000)	$91,000	$191,000
GRDA	($480,000)	$123,000	$1,003,000	($1,360,000)
KCPL	$6,624,000	($2,828,000)	$14,974,000	($11,178,000)
LES	$2,249,000	$2,150,000	$0	$4,399,000
MIDW	($736,000)	($14,659,000)	$0	($15,395,000)
MIPU	$2,680,000	($1,044,000)	($19,000)	$1,655,000
MKEC	($14,429,000)	($1,525,000)	($287,000)	($15,667,000)
NPPD	$6,488,000	($1,250,000)	$10,748,000	($5,510,000)
OKGE	($138,499,000)	$85,998,000	($22,388,000)	($30,113,000)
OPPD	$3,787,000	$378,000	$6,258,000	($2,093,000)
SPRM	$637,000	($317,000)	$301,000	$19,000
SUNC	($7,360,000)	($2,495,000)	($3,923,000)	($5,932,000)
SWPS	($89,381,000)	$2,205,000	($1,184,000)	($85,992,000)
WEFA	($20,837,000)	$13,197,000	($575,000)	($7,065,000)
WRI	($11,595,000)	($6,705,000)	$2,730,000	($21,030,000)

The following table demonstrates the benefits, costs and transfers on an annualized basis after the resulting reliability impacts, both the advancement and deferral, are accounted for. The net B/C impact of the reliability projects was an approximate marginal increase of .01 of the total Portfolio.

Portfolio 3-E "Adjusted" Annualized Benefits, Costs and Transfers, including Reliability Impacts

Attachment H Transfer Adjustments - Portfolio 3E "Adjusted" - Annualized

#	Zone	Portfolio Benefits	Portfolio Costs	Zonal ATRR Transfers Out (Col. 5 Attach H)	Regional Allocation of Zonal ATRR Transfers	Net of Zonal Transfers and Transfer Allocation	Net Benefit	B/C
1	AEPW	$30.9	$21.3	$0.0	$7.0	$7.0	$2.6	1.1
2	EMDE	($0.3)	$2.5	($3.7)	$0.8	($2.8)	$0.0	1.0
3	GRDA	$0.9	$1.9	($1.6)	$0.6	($1.0)	$0.0	1.0
4	KCPL	$8.4	$7.3	($1.3)	$2.4	$1.1	$0.0	1.0
5	MIDW	$12.8	$0.7	$0.0	$0.2	$0.2	$11.9	14.1
6	MIPU	($1.3)	$3.8	($6.4)	$1.3	($5.2)	$0.0	1.0
7	MKEC	$11.8	$1.1	$0.0	$0.3	$0.3	$10.4	8.3
8	OKGE	$26.6	$13.4	$0.0	$4.4	$4.4	$8.7	1.5
9	SPRM	($0.1)	$1.5	($2.1)	$0.5	($1.6)	$0.0	1.0
10	SUNC	$3.7	$1.0	$0.0	$0.3	$0.3	$2.3	2.7
11	SWPS	$56.1	$10.9	$0.0	$3.6	$3.6	$41.5	3.9
12	WEFA	$8.0	$3.0	$0.0	$1.0	$1.0	$4.0	2.0
13	WRI	$14.2	$11.0	($0.4)	$3.6	$3.2	$0.0	1.0
14	NPPD	$5.5	$7.6	($4.6)	$2.5	($2.1)	$0.0	1.0
15	OPPD	$2.3	$5.9	($5.6)	$1.9	($3.6)	$0.0	1.0
16	LES	($3.1)	$1.8	($5.5)	$0.6	($4.9)	$0.0	1.0
Total		$176	$95	-$31	$31	$0	$81	1.86

The spreadsheet which was used to calculate the transfers in the above table can be found on the Balanced Portfolio section of the SPP Website.[††]

[††] http://www.spp.org/section.asp?pageID=120

The table shown below demonstrates the MW-mi impact of the deferred reliability projects. This impact is used to determine who receives the benefit for the deferral of each reliability project from the portfolio.

Portfolio 3-E – Reliability Impact MW-mi analysis

	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	CLEARWATER-GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	EL RENO- EL RENO SW 69KV CKT 1 - Upgrade	LONGVIEW-WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps
Date	**2015**	**2015**	**2016**	**2017**	**2018**
AEPW		1.6%			
EMDE					
GRDA					
KCPL					
MIDW	46.7%	16.2%			
MIPU					100.0%
MKEC	19.4%	36.0%			
OKGE	1.3%	5.3%		24.7%	
SPRM					
SUNC	9.9%	10.9%			
SWPS		4.4%			
WEFA				75.3%	
WRI	22.6%	22.1%	100.0%		
NPPD		3.6%			
OPPD					
LES					
	100.0%	100.0%	100.0%	100.0%	100.0%

Reliability Results

The reliability results for the Portfolio 3E "Adjusted" are shown in the following table. The projects are broken into "deferred" and "mitigated" issues and "new" issues. Additionally, projects are shown for potential third party impacts. Note that a project highlighted in yellow (e.g. EARLSBORO – FIXICO) indicates that the project is merely advanced in time and not an entirely new issue.

Portfolio 3e without Chesapeake

Costs of STEP Projects Solved by Portfolio 3e, with STEP date

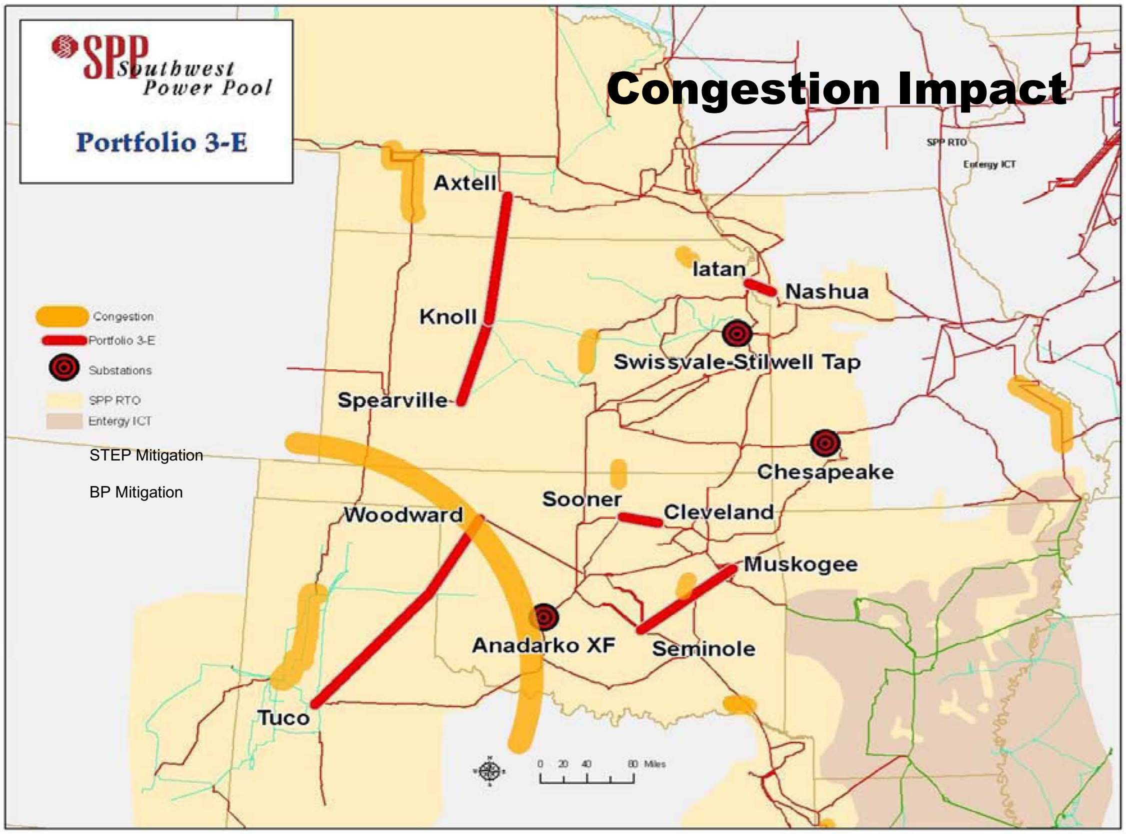
Issue Type	Project Name	Area	STEP Date	Deferred costs to TO: STEP projects solved by BP
Overload	CLEARWATER - GILL ENERGY CENTER WEST 138KV CKT 1 - Rebuild	WERE	16SP	$3,324,375
Overload	EL RENO - EL RENO SW 69KV CKT 1 - Upgrade	WFEC	17SP	$1,950,000
Overload	HUNTSVILLE - HEC 115KV CKT 1 - Rebuild	WERE	15SP	$12,487,500
Overload	HUNTSVILLE - ST_JOHN 115KV CKT 1 - Rebuild	MIDW	15SP	$7,965,000
Overload	LONGVIEW - WESTERN ELECTRIC 161KV CKT 1 - Replace Wavetraps	MIPU	18SP	$50,000
Voltages	None			
			Totals	**$25,776,875**

Cost of potential mitigation for New issues due to implementation of portfolio improvements

Description	Project Name	Area	Date of Needed Mitigation	SPP New Issues, Cost	Third Party Issues: Cost
Overloads-SPP	EARLSBORO - FIXICO 69KV CKT 1 - Increase limits (trap, CT ratio)	OKGE	13SP	$150,000	
Overloads-SPP	MED LODGE-PRATT, ST.JOHN-GREATBENDTAP 115 KV LINE REBUILD	MKEC	18SP	$15,840,000	
Overloads-Third Party	PLATTE CITY 161/69KV TRANSFORMER CKT 1 - Replace AECI XFMR	MIPU-AECI	13WP		$7,500,000
Voltages	None				
			Totals	**$15,990,000**	**$7,500,000**
			Grand Total	**$23,490,000**	
			Net: Solved Minus SPP New	**$9,786,875**	
			Net: Solved Minus Total New	**$2,286,875**	

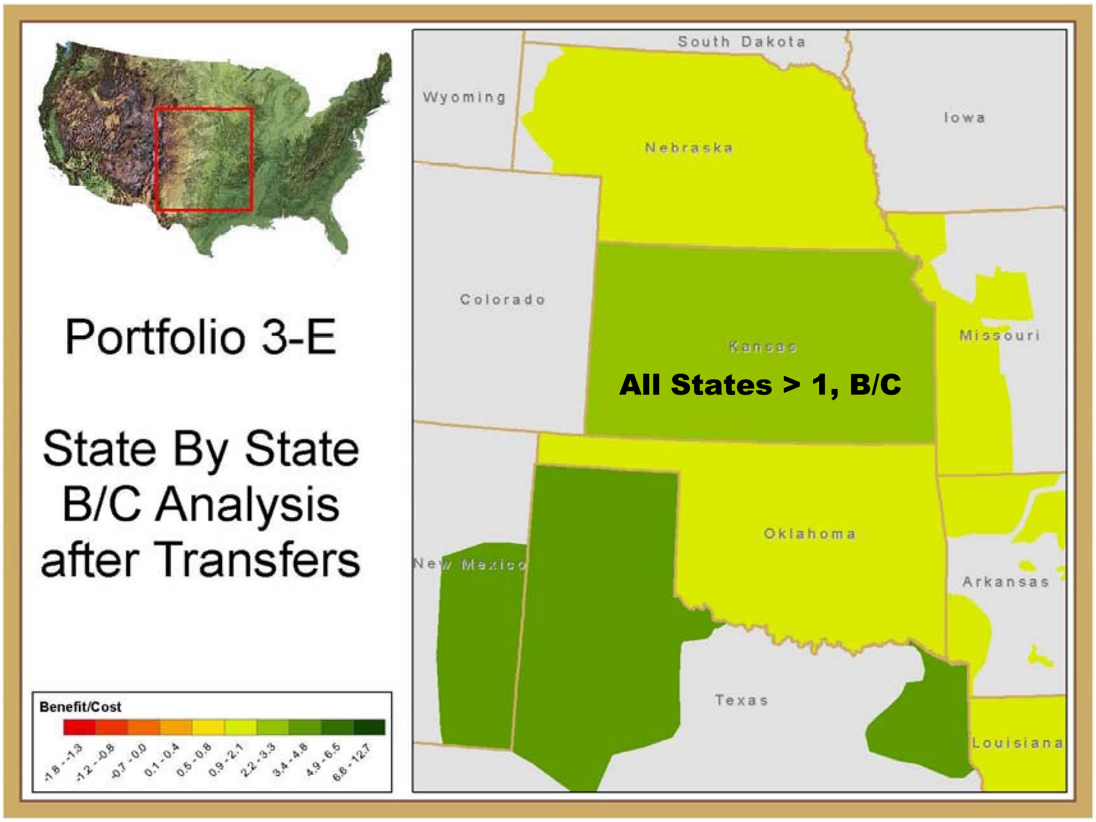
It should be noted that the third party impact of Platte City 161/69 kV transformer was coordinated with Associated Electric Cooperative, Inc. (AECI) staff. AECI staff did not see the same issue in their analysis.

Congestion Impact



The graphic shown above represents the top flowgates in the SPP EIS Market as they exist today. Congestion here is shown as an orange highlight. Portfolio projects, shown on the map as bold red highlight lines, relieve or mitigate much of the congestion that exists today. The congestion relief provided by the portfolio is shown as a green circle. Projects in the 10-year STEP plan that provide additional congestion relief are shown in light blue.

B/C by State



The diagram above demonstrates the B/C ratio of the Balanced Portfolio divided by state boundaries. While it should be noted that the portfolio of projects provides broad, regional benefits to all SPP members, this diagram is a good representation of the balance aspect of the portfolio broken into the respective state boundaries. This picture represents the balance of the portfolio after transfers have taken place in order to balance all zones. As can be seen from the diagram, all states have a B/C ratio greater than 1

SPP Balanced Portfolio Report

	Zone	OKGE	OKGE	OKGE	SPS	KCPL	NPPD	ITC	KCPL	OKGE
	Project	Sooner - Cleveland	Seminole - Muskogee	Tuco - Woodward	Tuco - Woodward	Iatan - Nashua	Knoll - Axtell	Spearville - Knoll - Axtell	Swissvale - Stilwell Tap	Andadarko Sub
	Projected In-Service Date	12/31/2012	12/31/2013	5/19/2014	5/19/2014	6/1/2015	6/1/2013	6/1/2013	6/1/2012	12/31/2011
Cost	Total Cost	$33,530,000	$129,000,000	$79,000,000	$148,727,500	$54,444,000	$71,377,015	$165,180,000	$2,00,000	$8,000,000
	Cost Per Mile	$900,000	$1,250,000	$900,000	$688,750	$1,214,800	$1,416,667	$846,000		$666,666
	Miles	36	100	72	178	30	45	170		3
	Substation Cost	$1,130,000	$4,000,000	$15,000,000	$26,130,000	$18,000,000	$6,827,000	$16,800,000		
	Fixed Charge Rates	15.1%	15.1%	15.1%	12.1%	15.1%	13.5%	12.0%	15.1%	15.1%
Conductor	Size	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 795 ACSR	2 Conductor Bundle 1192.5, 38/19 Grackle TW	2 Conductor Bundle 477 T2 Hawk	2 Conductor Bundle 1590 ACSR	2 Conductor Bundle 795 ACSR	138 kV line
	Design	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit	Single Circuit		
	Electrical Capacity	2578 Amps 1540 MVA at 345kV	3000 Amps 1800 MVA at 345kV	2578 Amps 1540 MVA at 345kV	2468 Amps Normal	4,100A	2,324 amps per bundle	3,000 amps		
	Other	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire	Fiber-optic Shield wire					
Structure	Type	H-frame	Single Pole	H-frame	H-frame	H-frame	Single Pole	H-frame		
	Materials	Steel	Steel	Steel	Steel	Steel	Steel	Steel		
	Base	Direct buried w/ aggregate backfill	Steel base plate reinforced concrete	Direct buried w/ aggregate backfill	Direct buried with aggregate or natural backfill	Direct Embed	Poured concrete anchor bolt	Direct embed concrete piers		
	NESC Assumption	Heavy	Heavy	Heavy	Heavy	Heavy	Heavy, 1.5 inch ice load			
	Dead Ends	Unknown	Unknown	Unknown	Unknown @ $65,000 each	16 @ $50,000 each	20 @ $140,000 each	60 @ $50,000 each	2 to 3 Deadends	
	Under build	No	No	No	No	No	No	No		
Substations	Transformers	Breakers and Relays	Two 345/138kV	345/138kV 50 MVAR reactor bank	345/230kV 560 MVA	600 MVA	None	345/230kV 200 MVA		345/138 kV
	Breaker Scheme	Ring-bus	Ring-bus, replace 2 2,000 A breakers	Ring-bus	345kV Ring	Ring-bus	Ring-bus	Ring-bus	2 breakers, breaker disconnects, line panels	
	Protection Scheme	included in sub cost	included in sub cost	included in sub cost	$1,000,000	$400,000	$156,000	$220,000		included in sub cost
	Voltage Control			+\- 50 MVAR						
	Cost (millions)	$1	$4	$15	$26	$18	$4	$14		
Construction Labor	Amount	1/3 of line construction	1/3 of line construction	1/3 of line construction						
	Cost (millions)	$14	$52	$27	$18	$7	$17	$49		
Eng Design, Project Management, Permitting	ROW	150ft @$5,500 an acre	200ft @$5,500 an acre	150ft @ $5,500 an acre	150ft	160ft	200ft	150ft		
	ROW Condition	rural, pasture	rural, pasture, hill, rock, high tree clearing cost	rural, pasture	Farmland and Pasture	50% Urban 50% Rural	rural farmland rainwater basin	rural, agri, pasture, range land	No ROW acquisition required	
	Permitting/Certifications	RR and Highway	RR and Highway	RR and Highway	Texas CCN, Highway, storm water, RR, County roads	Yes	NE Power Review Board, NPSC, RR, Airport, etc	Included		
	Escalation Rate	2.5% per year	2.5% per year	2.5% per year		2.5% per year	3% per year	0% for 2 years		
	Eng. Design / Proj. Mang.				Included	$349,000	$8,798,000	$13,770,000		
	Total Cost (millions)	cost included	cost included	cost included	$15	$26	$18	$24		
Loadings and Overheads	Type 1	Included in total cost	Included in total cost	Included in total cost	Included in total cost	$123,000	Included in total cost	20% of line and substation work, $26.7 million		
Other Cost Factors and Notes			$25,000/ mile cost included for tree clearing		Included in substation cost is $6.52 mil for mid-point reactor station	Large portion involves developed urban areas	Environmentally sensitive areas, possible double-circuit for 10 miles	$4.56 mil addition contingency added		

Study Assumptions

Fuel Price Assumptions – Fuel price assumptions are taken from EIA forecasts and updated according to member specific data for particular plants. For the purpose of this study, the average gas price is $6.50/MMBtu starting in 2012. The price is then escalated for inflation for the years 2017 and 2022 at the rate of 1.81%.

Environmental Costs - Carbon sensitivities have been conducted, but were not included in the portfolio selection process. A price of $15 and $40 per metric ton was used in these sensitivities. No sensitivity analysis was conducted for higher SO_2 or NO_X prices. SO_2 and NO_X were priced at $466.50 and $1742.16 per ton respectively.

Plant Outages – Stakeholders provided outage and maintenance rates to SPP staff through the EMMTF data collection effort. Forced outages were taken as a single draw and locked for the change and the base case. Similarly, maintenance outages were also locked down from a single scheduled pattern. These outage rages were plant specific and provided by each member.

Load Forecast – Load forecasts for the region were provided by each stakeholder in early 2009 for the projected years of 2012, 2017 and 2022 through the EMMTF update effort. These non coincident peak loads for the region were, in aggregate, as follows: 2012 - 43,068MW, 2017 – 47,109 MW, 2022 – 51,530 MW. The zonal shares of the 2012 load submittals were used to allocate the costs on a load ratio share basis.

Resource Forecast – The CAWG and EMMTF determined the criteria for inclusion of new resources into the Balanced Portfolio analysis. It was determined that only plants with firm transmission service and signed agreements or plants that were currently under construction would be included in the analysis. The following units are those which were included as a future resource.

- Turk (618 MW)
- Whelan Energy Center 2 (220 MW)
- Iatan 2 (900 MW)
- Central Plains (99 MW)
- Cloud County (201 MW)
- Flat Ridge (100 MW)
- Red Hills (120 MW)
- Smoky Hills (359 MW)

Hurdle Rates – A dispatch hurdle rate of $5/MW and a commit hurdle rate of $8/MW was used to commit resources across regional boundaries.

Demand Side Management – Interruptible load was modeled as supplied by the LSE's.

Market Structure – The simulation was conducted considering a single balancing authority and a day-ahead market structure for the SPP region.

Flowgate Assumptions – The NERC Book of Flowgates was used as the source for flowgates used in the analysis.

DC Tie Profiles - Historical DC Tie profiles were used to simulate best known profiles for all DC Ties in the SPP region.

Wind Profiles – Historical wind profiles were used to simulate the wind output at each wind farm.

Load Profiles – Load profiles were simulated as supplied by each LSE through the EMMTF effort.

RMR Requirements – Each Balancing Authority submitted their respective Reliability Must Run (RMR) requirements to be simulated in the analysis.

Operating Reserves – SPP's current reserve sharing program (as of 2008) was used in the simulation for operating reserves.

EXHIBIT NO. OGE-17

U.S. FISH AND WILDLIFE SERVICE
SPECIES ASSESSMENT AND LISTING PRIORITY ASSIGNMENT FORM

SCIENTIFIC NAME: *Tympanuchus pallidicinctus*

COMMON NAME: lesser prairie-chicken

LEAD REGION: 2

INFORMATION CURRENT AS OF: April, 2010

STATUS/ACTION

___ Species assessment - determined we do not have sufficient information on file to support a proposal to list the species and, therefore, it was not elevated to Candidate status
___ New candidate
_X_ Continuing candidate
___ Non-petitioned
_X_ Petitioned - Date petition received: October 5, 1995
_ 90-day positive - FR date: July 8, 1997
_ 12-month warranted but precluded - FR date: June 9, 1998
_ Did the petition request a reclassification of a listed species? NO

FOR PETITIONED CANDIDATE SPECIES:
a. Is listing warranted (if yes, see summary of threats below)? YES
b. To date, has publication of a proposal to list been precluded by other higher priority listing actions? YES
c. If the answer to a. and b. is "yes", provide an explanation of why the action is precluded.
Higher priority listing actions, including court-approved settlements, court-ordered statutory deadlines for petition findings and listing determinations, emergency listing determinations, and responses to litigation, continue to preclude the proposed and final listing rules for the species. We continue to monitor populations and will change its status or implement an emergency listing if necessary. The "Progress on Revising the Lists" section of the current CNOR (*http://endangered.fws.gov/*) provides information on listing actions taken during the last 12 months.

___ Listing priority change
Former LP: ___
New LP: ___

Date when the species first became a Candidate (as currently defined): June 9, 1998

___ Candidate removal: Former LPN: ___
___ A – Taxon is more abundant or widespread than previously believed or not subject to

the degree of threats sufficient to warrant issuance of a proposed listing or continuance of candidate status.

____U – Taxon not subject to the degree of threats sufficient to warrant issuance of a proposed listing or continuance of candidate status due, in part or totally, to conservation efforts that remove or reduce the threats to the species.

___ F – Range is no longer a U.S. territory.

___ I – Insufficient information exists on biological vulnerability and threats to support listing.

___ M – Taxon mistakenly included in past notice of review.

___ N – Taxon does not meet the Act's definition of "species."

___ X – Taxon believed to be extinct.

ANIMAL/PLANT GROUP AND FAMILY: Birds; Phasianidae

HISTORICAL STATES/TERRITORIES/COUNTRIES OF OCCURRENCE: Colorado, Kansas, New Mexico, Oklahoma, Texas

CURRENT STATES/COUNTIES/TERRITORIES/COUNTRIES OF OCCURRENCE: Colorado, Kansas, New Mexico, Oklahoma, Texas

LAND OWNERSHIP: Currently, about 95 percent (61,163 square kilometers (sq km); 23,615 square miles (sq mi)) of occupied range is privately owned; 4 percent (3,251 sq km; 1,255 sq mi) is managed by the Bureau of Land Management (BLM) in New Mexico, and the U.S. Forest Service (USFS) in Colorado, Kansas, Oklahoma, and New Mexico; 1 percent is State owned land.

LEAD REGION CONTACT: Sarah Quamme, (505) 248-6788

LEAD FIELD OFFICE CONTACT: Ecological Services, Tulsa, Oklahoma, Kenneth Collins; (918) 382-4510; Ken_Collins@fws.gov

BIOLOGICAL INFORMATION

Species Description

The lesser prairie-chicken (*Tympanuchus pallidicinctus*) (LEPC) is a species of prairie grouse endemic to the southern high plains of the United States, commonly recognized for its feathered feet, stout build, ground-dwelling habit, and mating behavior. Plumage of the lesser prairie-chicken is characterized by a cryptic pattern of alternating brown and buff-colored barring, and is similar in appearance and mating behavior to greater prairie-chicken (*T. cupido pinnatus*), although somewhat lighter in color. LEPC body length ranges from 38-41 centimeters (cm) (15-16 inches (in)) (Johnsgard 1973, p. 275). Males have long tufts of feathers (pinnae) on the sides of the neck that are erected during courtship displays. Males also display brilliant yellow supraorbital eyecombs and reddish esophageal air sacs during courtship displays (Copelin 1963, p. 12; Johnsgard 1983, p. 318).

LEPC are polygynous (a mating pattern in which a male mates with more than one female in a single breeding season) and exhibit a lek mating system. The lek is a place where males gather to conduct a competitive mating display. Male LEPC gather to display on leks at dusk and dawn beginning in late February through early May (Copelin 1963, p. 26; Hoffman 1963, p. 730; Crawford and Bolen 1976, p. 97). Dominant older males occupy the center of the lek, while younger males occupy the periphery and compete for central access (Ehrlich *et al*. 1988, p. 259). Females arrive at the lek in early spring; peak hen attendance at leks is during mid-April (Copelin 1963, p. 26; Haukos 1988, p. 49). The sequence of vocalizations and posturing of males, often described as “booming, gobbling, yodeling, bubbling, or duetting,” has been described by Johnsgard (1983, p. 336) and Haukos (1988, pp. 44-45).

After mating, the hen selects a nest site, usually 1 to 3 km (0.6 to 2 mi) from the lek (Giesen 1994a, p. 97), constructs a nest, and lays an average clutch of 10-14 eggs (Bent 1932, p. 282). Nests generally consist of bowl shaped depressions in the soil (Giesen 1998, p. 9). Nests are lined with dried grasses, leaves, and feathers and there is no evidence that nests are reused in subsequent years (Giesen 1998, p. 9). Second nests may occur when the first attempt is unsuccessful. Incubation lasts 23-26 days and young leave the nest within hours of hatching (Coats 1955, p. 5). Broods may remain with females for 6-8 weeks. Giesen (1998, pp. 2-9) provides a comprehensive summary of LEPC breeding behavior, habitat, and phenology (relationship between periodic biological phenomena and climatic conditions).

Home range varies both by sex and by season. Males tend to have smaller home ranges than do females, with the males generally remaining closer to the leks than do the females (Giesen 1998, p. 11). In Colorado, Giesen (1998, p. 11) observed that spring and summer home ranges for males were 211 hectares (ha) (512 acres (ac)) and for females were 596 ha (1,473 ac). In Texas, Taylor and Guthery (1980a, p. 522) found that winter monthly home ranges for males could be as large as 1,945 ha (4,806 ac) and that subadults tended to have larger home ranges than did adults. Based on observations from New Mexico and Oklahoma, LEPC home ranges increase during periods of drought (Giesen 1998, p. 11). Davis (2005, p. 3) states that the combined home range of all LEPC at a single lek is about 49 sq km (19 sq mi or 12,100 ac).

Diet of the LEPC consists primarily of insects, seeds, leaves, buds, and cultivated grains (Giesen 1998, p. 4). Juveniles tend to forage primarily on insects such as grasshoppers and beetles while adults tend to consume a higher percentage of vegetative material (Giesen 1998, p. 4). This is particularly true in the fall and winter when insects are less abundant. More detailed information on LEPC diet can be found in Jones (1963, pp. 764-765), Crawford and Bolen (1976, p. 143,), Davis *et al*. (1980, pp. 76-78) and Riley *et al*. (1993, pp. 188).

LEPC have a relatively short life span and high annual mortality. Campbell (1972, p. 689), using nine years of band recovery data, estimated annual mortality for males to be 65 percent. Hagen *et al*. (2005, p. 82) specifically examined survival in male LEPC and found apparent survival varied by year and declined with age. Annual mortality was estimated to be 0.55 (Hagen *et al*. 2005, p. 83). In female LEPC, Hagen *et al*. (2007, p. 522) estimated that annual mortality in Kansas was about 0.5 at Site I and about 0.65 at Site II. Juvenile mortality from hatching to first breeding season was estimated to be about 0.88, but was not considered to be representative of juvenile mortality in other Kansas LEPC populations (Pitman *et al*. 2006, p. 679-680). Campbell (1972, p. 694) estimated a 5-year maximum life span, although an individual nearly 7 years old has been documented in the wild by the Sutton Avian Research Center (Wolfe 2010).

Taxonomy

The LEPC is in the Order Galliformes, Family Phasianidae, subfamily Tetraoninae, and is recognized as a species separate from the greater prairie-chicken (American Ornithologist's Union 1998, p. 122; Jones 1964, pp. 65-73). The LEPC was first described as a subspecies of the greater prairie-chicken (Ridgway 1873, p. 199), but was named a full species in 1885 (Ridgway 1885). A more thorough discussion of LEPC taxonomy is found in Giesen (1998, pp. 2, 3).

Habitat

The preferred habitat of the LEPC is native short- and mixed-grass prairies having a shrub component dominated by sand sagebrush (*Artemesia filifolia*) or shinnery oak (*Quercus havardii*) (hereafter described as native rangeland) (Taylor and Guthery 1980b, p. 6; Giesen 1998, pp. 3-4). Small shrubs are important for summer shade, winter protection, and as supplemental foods (Johnsgard 1979, p. 112). Trees and other tall woody vegetation are typically absent from these grassland ecosystems, except along water courses. Landscapes supporting less than 63 percent native rangeland appear incapable of supporting self-sustaining LEPC populations (Giesen 1998, p. 4). Correspondingly, Crawford and Bolen (1976, p. 102) found that landscapes having greater than 20 to 37 percent cultivation may not support stable LEPC populations.

The shinnery oak vegetation type is endemic to the southern great plains and is estimated to have historically covered an area of 2.3 million ha (over 5.6 million ac), although its current range has been considerably reduced through eradication (Mayes *et al*. 1998, p. 1609). The distribution of shinnery oak overlaps much of the historic LEPC range in New Mexico, Oklahoma, and Texas (Peterson and Boyd 1998, p. 2). Shinnery oak is a rhizomatous (a horizontal, usually underground stem that often sends out roots and shoots from its nodes) shrub that reproduces slowly and does not invade previously unoccupied areas (Dhillion *et al*. 1994, p. 52). Mayes *et al*. (1998, p. 1611) documented that a single rhizomatous shinnery oak can occupy an area exceeding 7,000 sq meters (m) (1.7 ac). While not confirmed through extensive research throughout the plant's range, it has been observed that shinnery oak in some areas multiplies by slow rhizomatous spread and eventual fracturing of underground stems from the original plant. In this way, single clones have been documented to occupy up to 81 ha (200 ac) over an estimated timeframe of 13,000 years (Cook 1985, p. 264; Anonymous 1997, p. 483), making shinnery oak possibly the largest and longest-lived plant species in the world.

The importance of shinnery oak as a component of LEPC habitat has been demonstrated by several studies (Fuhlendorf *et al*. 2002, pp. 624-626; Bell 2005 pp. 15, 19-25). In a study conducted in west Texas, Haukos and Smith (1989, p. 625) documented strong nesting avoidance by LEPC of shinnery oak rangelands that had been treated with the herbicide tebuthiuron (also see "Herbicide" discussion under Factor E). Similar behavior was confirmed by three recent studies in New Mexico examining aspects of LEPC habitat use, survival, and reproduction relative to shinnery oak density and herbicide application to control shinnery oak. First, Bell (2005, pp. 20-21) documented strong thermal selection for, and dependency of LEPC broods on, dominance of shinnery oak in shrubland habitats. In this study, LEPC hens and broods used sites within the shinnery oak community that had statistically higher percent cover and greater density of shrubs. Within these sites, microclimate differed statistically between occupied and random sites, and LEPC survival was statistically higher in microhabitat that was cooler, more humid, and less exposed to the wind. Survivorship was statistically higher for LEPC that used sites with greater than 20 percent cover of shrubs than for those choosing 10–20 percent cover; in turn, survivorship was statistically higher for LEPC choosing 10–20 percent cover than for those choosing less than 10 percent cover.

In a second study, Johnson *et al*. (2004, pp. 338-342) observed through telemetry methods that shinnery oak was the most common vegetation type in LEPC hen home ranges. Hens were detected more often than randomly in or near pastures that had not been treated to control shinnery oak. Although hens were detected in both treated and untreated habitats in this study, 13 of 14 nests were located in untreated pastures, and all nests were located in areas dominated by shinnery oak. Areas immediately surrounding nests also had higher shrub composition than the surrounding pastures. This study suggested that herbicide treatment to control shinnery oak adversely impacts nesting LEPC.

Finally, a third study conducted by the Sutton Avian Research Center (Sutton Center), in cooperation with New Mexico Department of Game and Fish (NMDGF), showed that over the course of four years and five nesting seasons, LEPC in the core of occupied range in New Mexico distributed themselves non-randomly among shinnery oak rangelands treated and untreated with tebuthiuron (Patten *et al*. 2005a, 1273-1274). They demonstrated statistically that LEPC strongly avoided habitat blocks treated with tebuthiuron, but were not influenced by presence of cattle grazing. Further, herbicide treatment explained nearly 90 percent of the variation in occurrence among treated and untreated areas. Over time, radio-collared LEPC spent progressively less time in treated habitat blocks, with almost no use of treated pastures in the fourth year following herbicide application (25 percent in 2001, 16 percent in 2002, 3 percent in 2003, and 1 percent in 2004).

Leks are characterized by sparse vegetation and are generally located on elevated features such as ridges or grassy knolls (Giesen 1998, p. 4). Vegetative cover characteristics, primarily height and density, may have a greater influence on lek establishment than elevation (Giesen 1998, p. 4). Copelin (1963, p. 26) observed display grounds within short grass meadows of valleys where sand sagebrush was tall and dense on the adjacent ridges. Early spring fires also encouraged lek establishment when residual vegetation likely was too high (0.6-1.0 m (2.0-3.3 feet (ft))) to facilitate displays (Cannon and Knopf 1979, pp. 44-45). Several authors, as discussed in Giesen (1998, p. 4), observed that roads, oil and gas pads, and similar forms of human disturbance create habitat conditions which may encourage lek establishment. However, Taylor (1979, p. 707) emphasized that human disturbance, which is often associated with these artificial lek sites, is detrimental during the breeding season and did not encourage construction of potential lek sites in areas subject to human disturbance. Giesen (1998, p. 9) reported that hens usually nest and rear broods within 3 km (1.7 mi) of leks and usually nest near a lek other than the one on which they mated.

Typical nesting habitat can be described as native rangeland, although there is some evidence that the height and density of forbs (broad-leaved herb other than a grass) and residual grasses is greater at nesting locations than on adjacent rangeland (Giesen 1998, p. 9). Nests are often located on north and northeast facing slopes as protection from direct sunlight and the prevailing southwest winds (Giesen 1998, p. 9). Giesen (1998, p. 9) reports that habitat used by young is similar to that of adults and the daily movements of the broods is usually 300 m (984 ft) or less. After the broods break up, the juveniles form mixed flocks with adult birds (Giesen 1998, p. 9) and juvenile habitat use is similar to that of adult birds. Giesen (1998, p. 4) reports that wintering habitat is similar to that used for breeding with the exception that small grain fields are used more heavily during this period than during the breeding season.

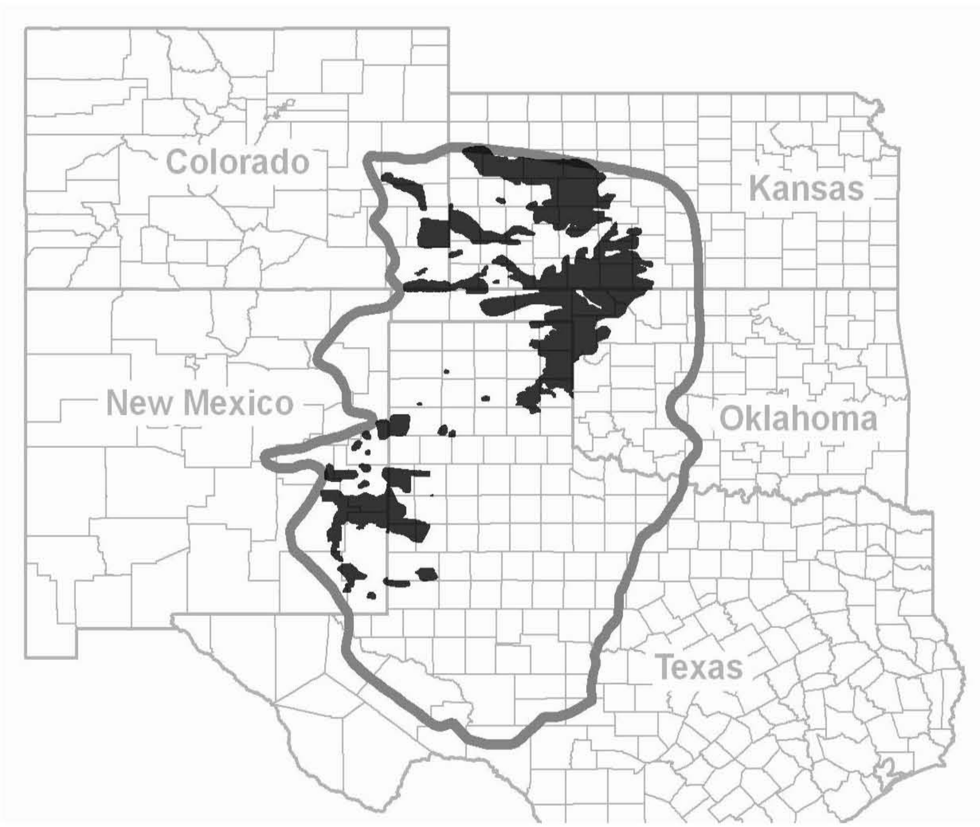
Prairie grouse, including the LEPC, require large expanses (i.e., 1,024-10,000 ha (2,530-24,710 ac)) of unfragmented, ecologically diverse native rangelands to complete their life cycles (Woodward *et al*. 2001, p. 261; Flock 2002, p. 130; Fuhlendorf *et al*. 2002, p. 618; Davis 2005, p. 3), more so than almost any other grassland bird (Johnsgard 2002, p. 124). Although precise values have yet to be quantified, home range size and movements of individual animals help provide a rough estimate of the extent of land that may be required to sustain a population of LEPC. As reported by Giesen (1998, p. 11) and Taylor and Guthery (1980a, p. 522), a single LEPC may have a home range of 211 ha (512 ac) to 1,945 ha (4,806 ac). More recently, studies in Kansas demonstrated some birds may move as much as 50 km (31 mi) from their point of capture (Hagen *et al*. 2004, p. 71). While some overlap in home ranges is expected, rarely would those home ranges be expected to overlap completely. Taylor and Guthery (1980b, p. 11) used LEPC movements in west Texas to estimate the area needed to meet the minimum requirements of a lek population. They determined that a contiguous area of at least 32 sq km (3,200 ha; 7,900 ac) and having no less than 63 percent rangeland habitat are need to support a LEPC population long-term. More recently, observations by scientists involved in LEPC conservation have speculated that over 16,000 ha (40,000 ac) may actually be needed to sustain a single LEPC lek (Wolfe 2008). Because LEPC typically nest and rear their broods in proximity to a lek other than the one used for mating (Giesen 1998, p. 9), a complex of two or more leks is likely required to sustain a viable population of LEPC. Hagen *et al*. (2004, p. 76) recommended that LEPC management areas be at least 4,096 sq km (1,581 sq mi) in size. A population viability analysis for the LEPC, once conducted, would allow a more precise estimation of the amount of suitable habitat needed to sustain a single, viable LEPC population.

<u>Historical Range/Distribution</u>
Historically, the LEPC occupied native rangeland in portions of southeastern Colorado (Giesen 1994b, pp. 175-182), southwestern Kansas (Schwilling 1955, p. 10), western Oklahoma (Duck and Fletcher 1944, p. 68), the Texas panhandle (Henika 1940, p. 15; Oberholser 1974, p. 268), and eastern New Mexico (Ligon 1927, pp. 123-127). Johnsgard (2002, p. 32) estimates the maximum historical range encompassed some 260,000 to 388,500 sq km (100,000 to 150,000 sq mi), with about two-thirds of the range occurring in Texas. In 2007, cooperative mapping efforts by the Colorado Division of Wildlife (CDOW), Kansas Department of Wildlife and Parks (KDWP), NMGDF, Oklahoma Department of Wildlife Conservation (ODWC), and Texas Parks and Wildlife Department (TPWD), in cooperation with the Playa Lakes Joint Venture, re-estimated the maximum historical and occupied ranges (see Figure 1). They determined the maximum occupied range, prior to European settlement, to have been approximately 456,087 sq km (176,096 sq mi) (Playa Lakes Joint Venture 2007, p. 1). The approximate historical range,

by state, based on this cooperative mapping effort is 21,911 sq km (8,460 sq mi) in Colorado, 76,757 sq km (29,640 sq mi) in Kansas, 52,571 sq km (20,300 sq mi) in New Mexico, 68,452 sq km (26,430 sq mi) in Oklahoma, and 236,398 sq km (91,280 sq mi) in Texas.

By the 1880s, the area occupied by LEPC was estimated at 358,000 sq km (138,225 sq mi), and by 1969, the occupied range had declined to an estimated 125,000 sq km (48,263 sq mi) due to wide scale conversion of native prairie to cultivated cropland (Taylor and Guthery 1980b, p. 1, based on Aldrich 1963, p. 537). By 1980, occupied range was estimated at 27,300 sq km (10,541 sq mi) (Taylor and Guthery 1980b, p. 4).

Figure 1. Estimated historic (perimeter circle) and current (black polygons) occupied LEPC range in Colorado, Kansas, New Mexico, Oklahoma, and Texas. Current (2007) range map layer courtesy of TPWD.



Current Range/Distribution
LEPC still occur within each state (Giesen 1998, p. 3). During the 2007 mapping effort (Playa Lakes Joint Venture 2007, p. 1), the State wildlife agencies estimated the current LEPC occupied range encompassed 64,414 sq km (24,871 sq mi) (Fig. 1). The approximate occupied range, by state, based on this cooperative mapping effort is 4,216 sq km (1,630 sq mi) in Colorado, 29,130 sq km (11,250 sq mi) in Kansas, 8,570 sq km (3,310 sq mi) in New Mexico, 10,969 sq km (4,235 sq mi) in Oklahoma, and 12,126 sq km (4,680 sq mi) in Texas.

The overall distribution of LEPC within all states except Kansas has declined sharply, and the species is generally restricted to limited parcels of untilled native rangeland (Taylor and Guthery 1980b, pp. 2-5) or areas with significant Conservation Reserve Program (CRP) enrollments that were initially seeded with native grasses (Rodgers and Hoffman 2005, pp. 122-123). The estimated current occupied range represents an 86 percent reduction in overall occupied range since pre-European settlement.

Population Estimates

Little information is available on LEPC population size prior to 1900. Litton (1978, p. 1) suggested that as many as two million birds may have occurred in Texas alone prior to 1900. Although, we are not aware of any independent analysis to corroborate Litton's estimate, and the basis for his estimate is unknown, the LEPC was reportedly quite common throughout its range in Colorado, Kansas, New Mexico, Oklahoma, and Texas in the early twentieth century (Bent 1932, pp. 280-281,283; Baker 1953, p. 8; Bailey and Niedrach 1965, p. 51; Sands 1968, p. 454; Fleharty 1995, pp. 38-44). By the 1930s, the species had begun to disappear from areas where it had been considered abundant and the decline was attributed to extensive cultivation, overgrazing by livestock, and drought (Bent 1932, pp. 283-284; Baker 1953, p. 8; Bailey and Niedrach 1965, p. 51; Davison 1940, p. 58; Lee 1950, p. 475; Oberholser 1974, p. 268; Sands 1968, p. 454). LEPC abundance appeared to fluctuate somewhat during the 1940s and 1950s (Copelin 1963, p. 24; Snyder 1967, p. 121; Crawford 1980, p. 2), and by the early 1970s the total fall population may have been reduced to about 60,000 birds (Crawford 1980, p. 2). By 1980, the estimate of the total fall population was approximately 44,000 to 53,000 birds (Crawford 1980, p. 3).

State-by-State Information on Population Status

Each of the State wildlife agencies within the occupied range of the LEPC provided us with information regarding the current status of the LEPC within their respective states, and most of the following information was taken directly from agency reports, memos, and other status documents. Population survey data are collected from spring lek surveys in the form of one or both of the following indices: average lek size (*i.e.*, number of males or total birds per lek); or density of birds or leks within a given area. Most typically the data are collected along fixed survey routes where the number of displaying males counted is assumed to be proportional to the population size or the number of leks heard is assumed to be an index of population size or occupied range. These techniques are useful in detecting trends and determining occupancy/distribution but are very limited in their usefulness for reliably determining population size. However, in the absence of more reliable estimators of bird density, total counts of active leks over large areas was recommended as the most reliable trend index for prairie grouse populations (Cannon and Knopf 1981, p. 777; Hagen *et al*. 2004, p. 79). Texas is currently evaluating the usefulness of aerial surveys as a means of detecting leks and counting the number of birds attending the identified lek (McRoberts 2009, pp. 9-10)

Colorado. LEPC were likely resident in six counties in Colorado prior to European settlement (Giesen 2000, p. 140). At present, LEPC are known to occupy portions of Baca, Cheyenne, Prowers, and Kiowa counties, but are not known to persist in Bent and Kit Carson counties. Populations in Kiowa and Cheyenne counties number less than 100 individuals and appear to be isolated from other populations in Colorado and adjacent states (Giesen 2000, p. 144). The

In 2009, four leks were detected, down only slightly from 2008 (Beauprez 2009, p. 11). Best *et al*. (2003, p. 232) concluded anthropogenic factors have, in part, rendered LEPC habitat south of Highway 380 inhospitable for long-term survival of LEPC in southeastern New Mexico. Similarly, NMDGF suggests that habitat quality likely limits recovery of these populations (Beauprez 2009, p. 13).

Of the 29 standard routes, 15 have been surveyed repeatedly since 1998. On the original 15 routes, the number of leks detected has fluctuated, ranging from a low of 22 in 1998 to a high of 90 in 2008 (Beauprez 2009, p. 8). Overall, when the 29 routes are considered collectively, the number of leks detected over the 12 years has increased significantly but there has been no significant trend in the average numbers of LEPC per lek (Beauprez 2009, p. 9).

The New Mexico State Game Commission owns and manages 29 Prairie-chicken Areas ranging in size from 10 to 3,171 ha (29 to 7,800 ac) within the core of occupied range in east central New Mexico. These Prairie-chicken Areas total 109 sq km (42 sq mi), or roughly 1.6 percent of the total occupied LEPC range in New Mexico. Instead of the typical roadside counts, the NMDGF conducts "saturation" surveys on each individual Prairie-chicken Area to determine the presence of LEPC leks and individual birds over the entire Prairie-chicken Area (Beauprez 2009, p. 7). Adjacent lands are included within these surveys including other State Trust Lands, some adjacent BLM lands, and adjacent private lands. In 2009, 125 leks were detected, either audibly or visually (Beauprez 2009, p. 13), down from the 171 leks detected in 2008 (Beauprez 2008, p. 15). However, only 28 Prairie-chicken Areas were surveyed in 2008. In 2007, 26 Prairie-chicken Areas were surveyed with 164 leks detected, either audibly or visually, on or near the Prairie-chicken Areas and in 2006, 27 Prairie-chicken Areas were surveyed, with 183 leks detected (Beauprez 2008, p. 15). The number of LEPC observed and counted in 2009 was 639 birds distributed over a total of 80 leks (Beauprez 2009, p. 13). In comparison, the number of LEPC observed and counted in 2008, 2007, and 2006 were 844, 1,117, and 757, respectively (Beauprez 2008, p. 15). The Prairie-chicken Areas are obviously important to persistence of the LEPC in New Mexico. However, considering the overall areal extent of the Prairie-chicken Areas and that many Prairie-chicken Areas are small and isolated, continued management of the surrounding private and federal lands is integral to viability of the LEPC in New Mexico.

The Nature Conservancy in New Mexico surveyed about 11,331 ha (28,000 ac) of their Milnesand Prairie Preserve, located in southern Roosevelt County, in 2009 (Beauprez 2009, p. 16). A total of 54 active leks and 441 LEPC were reported.

Oklahoma. LEPC historically occurred in 22 Oklahoma counties. By 1961, Copelin (1963, p. 53) reported LEPC from only 12 counties. By 1979, LEPC were verified in eight counties, and the remaining population fragments encompassed an estimated area totaling 2,792 sq km (1,078 sq mi), a decrease of approximately 72 percent since 1944. At present, the ODWC reports LEPC continue to persist in eight counties with an estimated occupied range of approximately 950 sq km (367 sq mi). Horton (2000, p. 189) estimated the entire Oklahoma LEPC population numbered fewer than 3,000 birds by 2000. A more recent estimate has not been conducted.

Long-term abundance estimates suggest a history of dramatic population fluctuations. Between 1968 and 2001, mean number of males per active lek varied from a high of 16.5 in 1975 to a low of 2.3 in 1995 (ODWC 2007, p. 6). Despite the wide fluctuation in numbers of males per active lek, the counts demonstrate a downward trend. During the period from 1968 to 1978, the mean number of males per lek averaged 12.5. From 1979 to 1989, the mean number of males per lek averaged 8.5. During the period from 1990 to 2001, the mean number of males per lek averaged 5.1. Beginning with the 2002 survey, male counts at leks were replaced with flush counts, which did not differentiate between the sexes of birds flushed from the surveyed lek (ODWC 2007, pp. 2, 6).

The number of roadside listening routes currently surveyed annually in Oklahoma has varied from 5 to 7 over the last 20 years. Between 1987 and 2008, the estimated density of active leks within occupied habitat varied from a high of 0.12 leks per sq km (0.33 per sq mi) in 1988 to a low of 0.02 leks per sq km (0.05 per sq mi) in 2004 and again in 2006. In 2009, the estimated density of LEPC leks in Oklahoma was 0.02 leks per sq km (0.05 per sq mi) down slightly from 2008 (Schoeling 2010, p. 3). Over the last 10 years the density of active leks has varied from a low of 0.02 leks per sq km (0.05 leks per sq mi) in 2004, 2006, and 2009, to a high of 0.03 leks per sq km (0.09 leks per sq mi) in 2005 and 2007 (Schoeling 2010, p. 3).

The ODWC is aware of 96 known historic and currently occupied leks in Oklahoma. During the mid-1990's all of these leks were active. Recent survey efforts are lacking for most of these known lek locations and the exact number of currently active or occupied leks in Oklahoma is unknown.

<u>Texas</u>. Systematic surveys to identify Texas counties inhabited by LEPC began in 1940 (Henika 1940, p. 4). From the early (Henika 1940, p. 15; Sullivan *et al*. 2000) to mid 1940's (Litton 1978, pp. 11-12) to the early 1950's (Seyffert 2001, pp. 108-112), the range of the LEPC in Texas was estimated to encompass all or portions of 34 counties. Species experts considered the occupied range at that time to be a reduction from the pre-settlement range. By 1989, TPWD estimated occupied range encompassed all or portions of only 12 counties (Sullivan *et al*. 2000, p. 179). In 2005, TPWD reported that the number of occupied counties likely has not changed since the 1989 estimate. In March 2007, TPWD reported that LEPC were confirmed from portions of 13 counties (Ochiltree, Lipscomb, Roberts, Hemphill, Gray, Wheeler, Donley, Bailey, Lamb, Cochran, Hockley, Yoakum, and Terry) and suspected in portions of another 8 counties (Moore, Carson, Oldham, Deaf Smith, Randall, Swisher, Gaines, and Andrews).

Maximum occupied acreage in Texas, as of September 2007, was estimated to be 12,787 sq km (4,937.1 sq mi) based on habitat conditions in 20 panhandle counties (Davis *et al*. 2008, p 23). Conservatively, based on those portions of the 13 counties where LEPC are known to persist, the area occupied by LEPC in Texas is 7,234.2 sq km (2,793.1 sq mi). Using an estimated mean density of 0.0088 LEPC per ac (range 0.0034-0.0135 LEPC per ac), the Texas population is estimated at a mean of 15,730 with a broad range in the estimate of 6,077 to 24,132 LEPC in the 13 counties where LEPC are known to occur (Davis *et al*. 2008, p. 24). LEPC populations in Texas currently persist in two disjunctive regions; the Permian Basin/Western Panhandle region and the Northeastern Panhandle region (see Fig. 1).

Annual surveys to determine population trends of LEPC in Texas were initiated in 1952 on two study areas, one encompassing 40,469 ha (100,000 ac) in Hemphill County and another supporting that species.

Table 1. Range and current population estimates for LEPC by state.

State	Historical Range	Current Range	Extent (based on Figure 1) Historical	Current	Current Population Estimates
Colorado	6 counties	4 counties	21,910.9 sq km (8,459.8 sq mi)	4,216.5 sq km (1,628.0 sq mi)	1,500 (in 2000)
Kansas	38 counties	35 counties	76,757.4 sq km (29,636.2 sq mi)	29,130.2 sq km (11,247.2 sq mi)	19,700 – 31,100 (in 2006)
New Mexico	7 counties	7 counties	52,571.2 sq km (20,297.9 sq mi)	8,570.1 sq km (3,308.9 sq mi)	4,968 (in 2009)
Oklahoma	22 counties	8 counties	68,452.1 sq km (26,429.5 sq mi)	10,969.1 sq km (4,235.2 sq mi)	< 3,000 (in 2000)
Texas	34 counties (1940's-50's)	13 counties	236,396.2 sq km (91,273.1 sq mi)	12,126.5 sq km (4,682.1 sq mi)	6,077 – 24, 132 (in 2007)
TOTAL	107 counties	67 counties	456,087.8 sq km (176,096.5 sq mi)	65,012.4 sq km (25,101.4 sq mi)	

THREATS

A. <u>The present or threatened destruction, modification, or curtailment of its habitat or range</u>.

<u>Conversion to Cultivated Agriculture</u>

Because LEPC require large areas (i.e., 1,024-10,000 ha) of intact landscapes of mixed-grass, short-grass, and shrubland habitats (Giesen 1998, pp. 3-4; Bidwell *et al*. 2002, pp. 1-3; Hagen *et al*. 2004, pp. 71,77), fragmentation and conversion of these mixed-grass, short-grass, and shrubland habitats have contributed to a significant reduction in the extent of LEPC occupied range. Woodward *et al*. (2001, p. 271) concluded that habitat stability, particularly in shrublands, was extremely important to persistence of LEPC within the landscape. Many habitats, once converted to other uses such as cultivated cropland, no longer provide suitable reproductive habitat for the LEPC and restoration of ecologically meaningful amounts of converted rangeland is doubtful in the short term.

Several LEPC experts have identified conversion of native sand sagebrush and shinnery oak rangeland to cultivation as an important factor in the decline of LEPC populations (Copelin 1963, p. 8; Jackson and DeArment 1963, p. 733; Crawford and Bolen 1976, p. 102; Crawford 1980, p. 2; Taylor and Guthery 1980b, p. 2; Braun *et al*. 1994, pp. 429, 432-433; LEPC Interstate Working Group 1997, p. 3). Between 1915 and 1925, considerable areas of prairie sod were plowed in the Great Plains to grow wheat (Laycock 1987, p. 4). By the 1930s, Bent (1932, pp. 283-284) speculated that extensive cultivation and overgrazing had already caused the species to disappear from areas where it had once been abundant. Because cultivated grain crops may have provided increased or more dependable winter food supplies (Braun *et al*. 1994, p. 429), the initial conversion of some native prairie to cultivation may have been beneficial to the species. However, landscapes having greater than 20 to 37 percent cultivation may not support stable LEPC populations (Crawford and Bolen 1976, p. 102). In the 1940s, 1970s, and 1980s, additional acres of previously unbroken grassland were brought into cultivation (Laycock 1987, pp. 4-5). Bragg and Steuter (1996, p. 61) estimated that by 1993, only 8 percent of the bluestem-grama association and 58 percent of the mesquite-buffalo grass association as described by Kuchler (1985) remained.

In the U.S. Fish and Wildlife Service's (Service) June 7, 1998, 12-month finding for the LEPC (63 FR 31400), the Service assessed the loss of native rangeland using the National Resources Inventory of the U. S. Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS). The 1992 National Resources Inventory Summary Report provided estimates of change in rangeland acreage between 1982 and 1992, for each state. When considered state-wide, each of the five states with LEPC showed a decline in the amount of rangeland acreage over that time period, indicating that loss of important LEPC habitat may have continued to occur since the 1980s. However, estimates of rangeland between 1982 and 1992, for counties specifically within LEPC range, showed no statistically significant change, possibly due to small sample size and large variation about the mean.

The CRP was authorized in the 1985 Food Security Act and since that time has facilitated restoration of millions of acres of marginal and highly erosive cropland to grassland, shrubland, and forest habitats (Riffell and Burger 2006, p. 6). The CRP is a program administered by the USDA's Farm Service Agency and was established to control soil erosion on cropland by converting cropped areas to a vegetative cover such as perennial grassland. Farmers receive an annual rental payment for the duration of a multi-year CRP contract. Cost sharing is provided to assist in the establishment of the vegetative cover practices. Once the CRP contract expires, typically after 10 to 15 years, landowners must decide if the land should be re-enrolled in the program, converted back to cropland, or left in permanent vegetative cover.

CRP habitat encompasses a very significant portion of currently occupied range in most LEPC states, but particularly in Kansas where expansion of the LEPC population is directly related to the amount of land enrolled in the CRP. Estimates of the extent of CRP lands in habitat occupied by LEPC, as derived from the cooperative mapping effort delineated in Figure 1, is available for Kansas, Oklahoma, and Texas. Kansas has just over 363,000 ha (897,000 ac), Oklahoma has over 91,600 ha (226,000 ac), and Texas some 167,600 ha (414,000 ac) in CRP. Based on the estimated amount of occupied habitat remaining in these states (Figure 1), CRP fields in Kansas comprise some 12.5 percent of the occupied LEPC range, 8.3 percent of the occupied range in Oklahoma, and 13.8 percent of the occupied range in Texas.

The importance of CRP habitat to the status and survival of LEPC was recently emphasized by Rodgers and Hoffman (2005, pp. 122-123). They determined that the presence of CRP lands which had been planted to native species of grasses facilitated the expansion of LEPC range in Colorado, Kansas, and New Mexico. The range expansion in Kansas resulted in strong population increases there (Rodgers and Hoffman 2005, pp. 122-123). In Oklahoma and Texas, and some portions of New Mexico, CRP fields were planted with a monoculture of introduced grasses. Where introduced grasses were planted, LEPC did not demonstrate a range expansion or an increase in population size (Rodgers and Hoffman 2005, p. 123). Reductions in CRP acreages, either by reduced enrollments or by conversion back to cultivation upon expiration of existing contracts, would further diminish the amount of suitable LEPC habitat. This is particularly relevant in Kansas where CRP acreages planted to native grass mixtures facilitated an expansion of LEPC range in that state. A reduction in CRP acreage could lead to contraction of the currently occupied range and reduced numbers of LEPC rangewide.

The possibility exists that escalating grain prices due to the recent emphasis on generating domestic energy from biofuels, such as ethanol from corn, grain sorghum, and switchgrass, combined with recent federal budget proposals that would reduce or eliminate CRP enrollments and renewals through Fiscal Year 2010, will result in an unprecedented conversion of existing CRP acreage within the Great Plains (Babcock and Hart 2008, p. 6). In 2006, the USDA's Farm Service Agency provided a small percentage of current CRP contract holders whose contracts are set to expire during 2007-2010 period with an opportunity (termed REX) to re-enroll (10-15 year terms) or extend (2-5 year terms) their contracts. The opportunity to re-enroll or extend their contracts was based on the relative environmental benefits of each contract. The Farm Service Agency conducted REX offers in two parts. The first part targeted contracts expiring in 2007 and was held in spring 2006. The second, for 2008-2010 expiring contracts, was held in summer of 2006. The Farm Service Agency required that holders of contracts set to expire in 2007 make known to the Farm Service Agency, by September 30, 2006, their intention to either re-enroll their existing contract or allow it to expire. The Farm Service Agency also requested that holders of 2008-2010 expiring contracts make their intentions known to the Farm Service Agency by December 31, 2006. In March of 2007, the USDA expected that some 9.7 million ha (23.9 million ac) out of the total 11.3 million ha (28 million ac) of eligible CRP contracts would be re-enrolled. The remaining 1.7 million ha (4.1 million ac) would be eligible for conversion to crop production or other uses.

Although the large scale loss of CRP habitat poses a threat to the status of existing LEPC populations, some eventual benefits have been identified. In particular, an analysis of LEPC habitat quality within a subsample of 1,019 CRP contracts across all five LEPC states was recently conducted by the Rocky Mountain Bird Observatory (Ripper and VerCauteren 2007, pp. 1-42). They found that, particularly in Oklahoma and Texas, early signup contracts allowed planting of exotic monoculture grasses, such as old-world bluestem (*Bothriochloa* sp.) and weeping lovegrass (*Eragrostis curvula*), which provides poor quality habitat for LEPC (Ripper and VerCauteren 2007, p. 11). While the report identified areas for habitat improvement among all CRP areas in all states, converting exotic grass fields to taller native grass species and enhancing the diversity of native forbs and shrubs within these contracts was recommended as a top priority for LEPC recovery. Consequently, conversion of exotic fields to short-term farming activities, but eventual re-enrollment in native CRP, could improve local habitat quality in the long term above current conditions. However, the extent to which this might occur is currently unknown.

<u>Livestock Grazing</u>

Habitats used by LEPC are largely dominated by a diversity of drought tolerant perennial grasses and shrubs. Grazing has long been an ecological driving force within the ecosystems of the Great Plains (Stebbins 1981, p. 84). The evolutionary history of the mixed-grass prairie has resulted in endemic bird species adapted to an ever-changing mosaic of lightly to severely grazed grasslands (Bragg and Steuter 1996, p. 54; Knopf and Samson 1997, pp. 277-279, 283). Domestic livestock grazing regimes tend to favor more uniform utilization and are typically confined to specific pastures. While livestock grazing is not inherently harmful to LEPC, levels of grazing that alter the composition and structure of mixed grass habitats historically used by the LEPC can be detrimental. Much of the remaining remnants of mixed-grass prairie and rangeland, while still important to LEPC, differ from conditions prior to European settlement. The present grazing, fire (usually to promote forage quality for livestock), and water management regimes (usually for livestock watering) are vastly different and less variable than historic conditions. These changes have considerably altered the composition and structure of mixed grass habitats historically used by the LEPC. While native rangeland still persists in many areas of LEPC historic range, modification of that rangeland has altered the suitability of those areas for LEPC.

Because LEPC depend on medium and tall grass species that are preferentially grazed by cattle, in regions of low rainfall, LEPC habitat is easily overgrazed (Hamerstrom and Hamerstrom 1961, p. 290). Livestock grazing, particularly overgrazing or overutilization, and related deteriorated range condition is most readily observed through changes in plant composition and other vegetative characteristics (Fleischner 1994, pp 630-631; Stoddart *et al*. 1975, p. 267). Typical vegetative indicators include changes in the composition and proportion of desired plant species, leading to overall reduction in forage. Plant height and density may decline, particularly when plant regeneration is hindered, and composition shifts to increased proportions of less desirable species. When grasslands are in a deteriorated condition due to overgrazing and overutilization, the soils have less water-holding capacity, and the availability of succulent vegetation and insects utilized by LEPC chicks are reduced. The effects of overgrazing and overutilization on habitat quality are similar to drought and are likely exacerbated by actual drought conditions (Davis *et al*. 1979, p. 122; Merchant 1982, pp. 31-33) (see Factor E).

Grazing management favorable to persistence of LEPC must ensure that a diversity of plants and cover types, including shrubs, remain on the landscape (Taylor and Guthery 1980b, p. 7; Bell 2005, p. 4) and that utilization levels leave sufficient cover in the spring to ensure that LEPC nests are adequately concealed from predators. Information on the extent of overgrazing and overutilization throughout LEPC habitat is lacking. However, some studies have shown that overgrazing in portions of LEPC occupied range has been detrimental to the LEPC. Taylor and Guthery (1980b, p. 2) believed overgrazing explained the demise of the LEPC in Texas but thought LEPC could maintain low populations in some areas with high intensity, long-term grazing. In New Mexico, Patten *et al*. (2006, pp. 11, 16) found that grazing did not have an overall influence on where LEPC occurred within their study areas, but there was evidence that LEPC did not nest in portions of the study area subjected to cattle grazing. In some areas within LEPC range, long-term high intensity grazing results in reduced availability of lightly grazed habitat available to support successful nesting (Jackson and DeArment 1963, p. 737; Davis *et al*. 1979, pp. 56, 116; Taylor and Guthery 1980b, p. 12; Davies 1992, pp. 8, 13). Grazing of native rangelands with domestic livestock often differs from grazing regimes historically present when these areas were grazed by free roaming herds of bison. Grazing by domestic livestock tends to be less patchy, particularly when livestock are confined to specific pastures. Where uniform grazing regimes leave inadequate residual cover in the spring, the effects are detrimental to LEPC populations (Bent 1932, p. 280; Davis *et al*. 1979, pp. 56, 116; Cannon and Knopf 1980, pp. 73-74; Crawford 1980, p. 3; Bidwell and Peoples 1991, pp. 1-2; Riley *et al*. 1992, p. 387; Giesen 1994a, p. 97) because grass height is reduced below that necessary to provide adequate nesting cover and desirable food plants are markedly reduced. Superior cover at and around nests is thought to increase nest success because the nest is better concealed from predators (Davis *et al*. 1979, p. 49; Wisdom 1980, p. 33; Riley *et al*. 1992, p. 386; Giesen 1994a, p. 98). Fencing to facilitate livestock management, while often necessary, leads to structural fragmentation of the landscape. Fencing and related structural fragmentation can be particularly detrimental to LEPC in areas, such as western Oklahoma, where initial settlement patterns favored larger numbers of smaller parcels for individual settlers (Patten *et al*. 2005b, p. 245). Additional information on fragmentation and the effects of fencing can be found in the section below and in the discussion under Factor E.

<u>Fragmentation</u>

Fragmentation results when processes transform a large expanse of habitat into a number of smaller habitat patches which are isolated from each other by a matrix of habitat unlike the original (Wilcove *et al*. 1986, p. 237). Because much suitable habitat for LEPC has been destroyed due to agricultural conversion, and many remaining habitats negatively modified through grazing practices, fire suppression, and other land uses that result in habitat conditions unsuitable for LEPC, fragmentation of the remaining suitable habitat contributes to further alteration of LEPC range (Crawford 1980, p. 5; Braun *et al*. 1994, pp. 432-433; Knopf 1996, p 146; Patten *et al*. 2005b, pp. 235-236). Spatial habitat fragmentation often has a negative impact on population persistence and may exacerbate the species extinction process through several mechanisms (Wilcove *et al*. 1986, p. 246). Once fragmented, the remaining fragments may be inadequate to support crucial life history requirements (Samson 1980, p. 297). Habitat between remaining suitable fragments may support high densities of predators or brood parasites (organisms which rely on the nesting organism to raise their young); and the probability of recolonization of unoccupied fragments decreases as distance from the nearest suitable habitat increases (Wilcove *et al*. 1986, p. 248). As a group, grouse are considered to be particularly intolerant of extensive habitat fragmentation due to their short dispersal distances and other life history characteristics, such as specialized food habits and generalized anti-predator strategies (Braun *et al*. 1994, p. 432). Patten *et al*. (2005b, p. 245), based on observations of radio tracked LEPC in Oklahoma and New Mexico, suggested that increased fragmentation in Oklahoma resulted in higher rates of mortality than in the less fragmented habitat in New Mexico. In summarizing much of the literature on LEPC conservation, Hagen *et al*. (2004, pp. 76-77) stated that most experts agree that LEPC are area sensitive species and that large quantities of suitable habitat are essential for population growth.

In addition to spatial habitat fragmentation, structural habitat fragmentation has been shown to be detrimental to LEPC and forces avoidance or abandonment of otherwise suitable habitats (Hagen *et al*. 2004, pp. 74-75; Robel *et al*. 2004, pp. 260-262). Structural habitat fragmentation is caused by the construction and operation of vertical structures, including towers, utility lines, fences, wind turbines, oil and gas wells, buildings, and compressor stations. Ongoing research increasingly indicates that vertical features and structural habitat fragmentation may have significant negative impacts, such as general habitat avoidance and displacement, on LEPC and other prairie grouse.

Most large remaining tracts of untilled native rangeland, and hence LEPC habitat, occur on topographic ridges. Leks, the traditional mating grounds of prairie grouse, are consistently located on elevated grassland sites with few vertical obstructions (Flock 2002, p. 35). Because of the increased elevation, these ridges also are prime sites for wind turbine development. Telemetry research on LEPC (Pitman *et al*. 2005, pp. 1267-1268) indicate that prairie grouse exhibit strong avoidance of tall vertical features such as utility transmission lines. Robel (2002, p. 23) estimates that a single commercial-scale wind turbine creates a habitat avoidance zone for the greater prairie-chicken that extends as far as 1.6 km (1 mi) from the structure.

In a recent study (Pitman *et al*. 2005, pp. 1267-1268), avoidance of elevated structures by LEPCs has been identified, with no nesting or brood rearing within 300 m (984 ft) of power lines. This research also found no LEPC nesting or lekking within 0.8 km (0.5 mi) of a gas line compressor station. LEPC generally avoided human activity and seldom nested within 0.4 km (0.25 mi) of inhabited dwellings; LEPC also were documented to avoid habitat within a 1.6 km (1 mi) radius of a coal-fired power plant (Pitman *et al*. 2005, pp. 1267-1268).

Oil and gas development activities, particularly drilling, and road and highway construction also contributes to surface fragmentation of LEPC habitat for many of the same reasons observed with other artificial structures (Hunt and Best 2004, p. 92). The incidence of oil and gas exploration has been rapidly expanding within the range of the LEPC. A more thorough discussion of oil and gas activities within the range of the LEPC is discussed below.

Wind Energy Development

Wind power is a form of renewable energy that is increasingly being utilized to meet electricity demands in the United States. The tubular towers of most commercial, utility scale onshore wind turbines are between 65 m (213 ft) and 100 m (328 ft) tall. The most common system utilizes three rotor blades and can have a diameter of as much as 100 m (328 ft). The total height of the system is measured when a turbine blade is in the 12 o’clock position and will vary depending on the length of the blade. With blades in place, a typical system will easily exceed 100 m (328 ft) in height. A wind farm will vary in size depending on the size of the turbines and amount of land available. Spacing between turbines is usually 5 to 10 rotor diameters to avoid interference between turbines.

Commercial wind energy developments cannot be a viable enterprise without the ability to transmit the power to the users. Any discussion of the effects of wind energy development on the LEPC also must take into consideration the influence of the transmission lines critical to distribution of the energy generated by these structures. Transmission lines can traverse long distances across the landscape and can be both above ground and underground. Most of the impacts associated with transmission lines are with the above ground systems. Support structures vary in height depending on the size of the line. Most high voltage powerline towers are 30 to 38 m (98 to 125 ft) high but can be higher if the need arises. Local distribution lines are usually much shorter in height but all contribute to vertical fragmentation of the landscape.

As discussed in the previous section on structural habitat fragmentation, prairie grouse, including the LEPC, did not evolve with tall vertical structures present on the landscape. The addition of wind turbines and their supporting infrastructure represents a significant change in the species’ environment. Placement of vertical structures is a relatively new phenomenon over the evolutionary history of these species and the effects of these structures on their life history are only beginning to be evaluated. However, some information on the behavioral response of prairie grouse to these structures is available.

In general, prairie grouse have low tolerance to tall structures. Anderson (1969, pp. 640-641) observed that greater prairie-chickens abandoned lek territories when a 4 m (13 ft) tall wind break was artificially erected 52 m (170 ft) from an active lek. Robel (2002, p. 23) estimates that a single commercial-scale wind turbine creates a habitat avoidance zone for the greater prairie-chicken that extends as far as 1.6 km (1 mi) from the structure. Structural habitat fragmentation caused by energy development also has been shown to cause LEPC to avoid or abandon otherwise suitable habitats due to potential for increased predation by raptors or due to visual obstructions on the landscape (Hagen *et al*. 2004, pp. 74-75). Pitman (2005, pp. 1267-1268) observed that female LEPC selected nest sites that were significantly further from powerlines, roads, buildings, and oil and gas wellheads than would be expected at random. Specifically, they seldom found LEPC nests within 400 m (1,312 ft) of transmission lines and improved roads. Similarly, Hagen *et al* (2004, p. 75) indicated that areas used by LEPC were significantly further from these same types of features than areas that were not used by LEPC. The Service has recommended that, due to behavioral avoidance of wind turbines, an 8 km (5 mi) voluntary no construction buffer be established around prairie grouse leks (Manville 2004, p. 1). Although considerably more study is needed, the available information clearly demonstrates that vertical structures are avoided by LEPC and likely render otherwise suitable habitat unsuitable.

Wind energy development and its associated infrastructure is already occurring within the historic range of the LEPC, some of which has impacted occupied habitat. At the close of 1999, the installed capacity, in megawatts (MW), of wind power facilities within the five LEPC states was 209 MW, the majority, 184 MW, was provided by the state of Texas (U.S. Department of Energy, National Renewable Energy Laboratory 2010a p. 1). By the close of 2009, the installed capacity within the five LEPC states had grown to 13,296 MW (U.S. Department of Energy, National Renewable Energy Laboratory 2010a, p. 1). The five LEPC states are all within the top 20 states nationally for installed wind capacity (American Wind Energy Association (AWEA) 2010a, pp. 1-2). Although not all of this installed capacity is located within the historic range of the LEPC, there is considerable overlap with the historic range and those areas having good to excellent wind potential.

Identification of the actual number of proposed wind energy projects that will be built in any future timeframe is difficult to accurately discern. An analysis of the Federal Aviation Administration's obstacle database provides some insight into the number of existing and proposed wind generation towers. The Federal Aviation Administration is responsible for ensuring wind towers and other vertical structures are constructed in a manner that ensures the safety and efficient use of the navigable airspace. In accomplishing this mission, they evaluate applications submitted by the party responsible for the proposed construction and alteration of these structures. Included in the application is information on the precise location of the proposed structure. This information can be used, in conjunction with other electronic databases, to determine the number of existing and proposed wind generation towers within the historical and occupied range of the LEPC. Analysis of this information, as available in April 2010, reveals that there are 6,279 constructed towers within the historical range of the LEPC. Some 8,501 towers have been approved for construction and another 1,693 towers are pending approval within the historical range of the LEPC. While not all of these structures are wind generation towers, the vast majority are.

A similar analysis was conducted on LEPC occupied range. Within the occupied range, as of April of 2010, 173 towers have been constructed. Some 1,950 towers have been approved for construction and another 250 towers are awaiting approval. Additionally, the Southwest Power Pool (SPP) provides public access to its Generation Interconnection Queue (https://studies.spp.org/GenInterHomePage.cfm), which provides all of the active requests for connection from new energy generation sources requiring SPP approval prior to connecting with the transmission grid. Currently, in the SPP portion of Kansas, New Mexico, Oklahoma, and Texas, there are 177 wind generation interconnection study requests totaling 31,883 MW. A maximum development scenario, assuming all of these projects are built and they all install 2.3 MW wind turbines, would result in approximately 13,862 wind turbines being erected in these four states.

All five LEPC states are within the top 15 states nationally for potential wind capacity, with Texas ranking as number 2 for potential wind energy capacity and Kansas ranking as number 3 (AWEAb 2010, p. 1). The potential for wind development within the historical range of the LEPC is apparent from the wind potential estimates developed by the U.S. Department of Energy's National Renewable Energy Laboratory and AWS Truewind. These estimates present the predicted mean annual wind speeds at a height of 80 m (262 ft). Areas with an average wind speed of 6.5 m/s (21.3 ft/s) and greater at a height of 80 m (262 ft) are generally considered to have a suitable wind resource for development. All of the historical and current range of the LEPC occurs in determined to have 6.5 m/s (21.3 ft/s) or higher average wind speed (U.S. Department of Energy, National Renewable Energy Laboratory 2010b p. 1). The vast majority of the occupied range lies within areas of 7.5 m/s (24.6 ft/s) or higher.

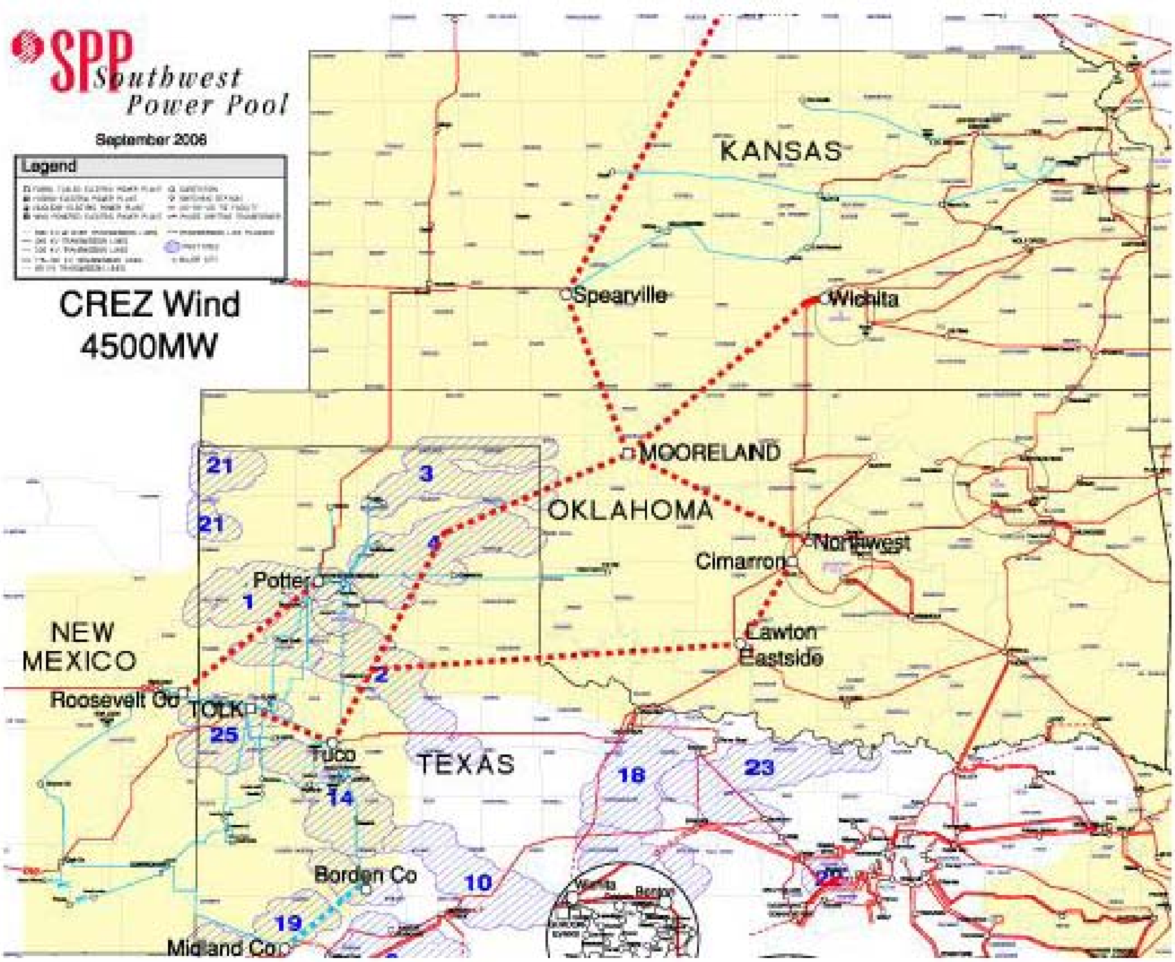
The potential influence of anticipated wind energy development on the status of the LEPC can readily be evaluated for Oklahoma. In cooperation with ODWC, Service personnel in 2005 quantified the potential degree of wind energy development in relation to existing populations of LEPC in Oklahoma. Using ArcView mapping software, all active and historic LEPC lek locations in Oklahoma, as of the mid 1990s (n = 96), and the current occupied range, were compared with the Oklahoma Neural Net Wind Power Development Potential Model map created by the Oklahoma Wind Power Assessment project. The mapping analysis revealed that 35 percent of the recently occupied range in Oklahoma is within areas designated by the Oklahoma Wind Power Assessment as "excellent" for wind energy development. When both the "excellent" and "good" wind energy development classes are combined, some 55 percent of the occupied range lies within those two classes.

When leks were examined, the same analysis revealed a nearly complete overlap on all known active and historic lek locations, based on the known active leks during the mid 1990s. Roughly 91 percent of the known LEPC lek sites in Oklahoma are within 8 km (5 mi) of land classified as "excellent" for wind development (O'Meilia 2005). The analysis revealed that over half (53 percent) of all known lek sites occur within 1.6 km (1 mi) of lands classified as "excellent" for commercial wind energy development. This second metric is particularly relevant given the average home range for a LEPC is about 10 sq km (4 sq mi) and that a majority of LEPC nesting generally occurs, on average, within 1.2 and 3.4 km (0.7 and 2.1 mi) of active leks (Hagen and Giesen 2005, p. 2). Using Robel's (2002) estimate derived for the greater prairie chicken of the zone of avoidance for a single commercial-scale wind turbine (1.6 km or 1 mi), development of commercial wind farms likely will have a significant adverse influence on reproduction of the LEPC.

Unfortunately, similar analyses are not available for the other states due to a lack of appropriate data layers for those states. However, southwestern Kansas currently supports the largest population and distribution of LEPC of all states. The influence of wind energy development on the LEPC in Kansas would likely be no less severe than in Oklahoma. In 2006, the Governor of Kansas initiated the Governor's 2015 Renewable Energy Challenge, an objective of which is to have 1,000 megawatts (MW) of renewable energy capacity in Kansas by 2015 (Cita *et al*. 2008, p. 1). A cost-benefit study (Cita *et al*. 2008, Appendix B) found that wind was the most cost effective and likely renewable energy resource for Kansas. Modestly assuming an average of 2 MW per turbine—most commercial scale turbines are between 1.5 and 2.5 MW—some 500 turbines would be erected in Kansas if this goal is to be met. While not all of those turbines would directly overlap occupied range, the best wind potential in Kansas occurs in the western portions of the state which largely overlaps currently occupied LEPC range (U.S. Department of Energy, National Renewable energy Laboratory 2010b, p. 1). Inappropriate siting of wind energy facilities and associated facilities, including electrical transmission lines, appears to be a serious threat to LEPC in western Kansas within the near future (Rodgers 2007a).

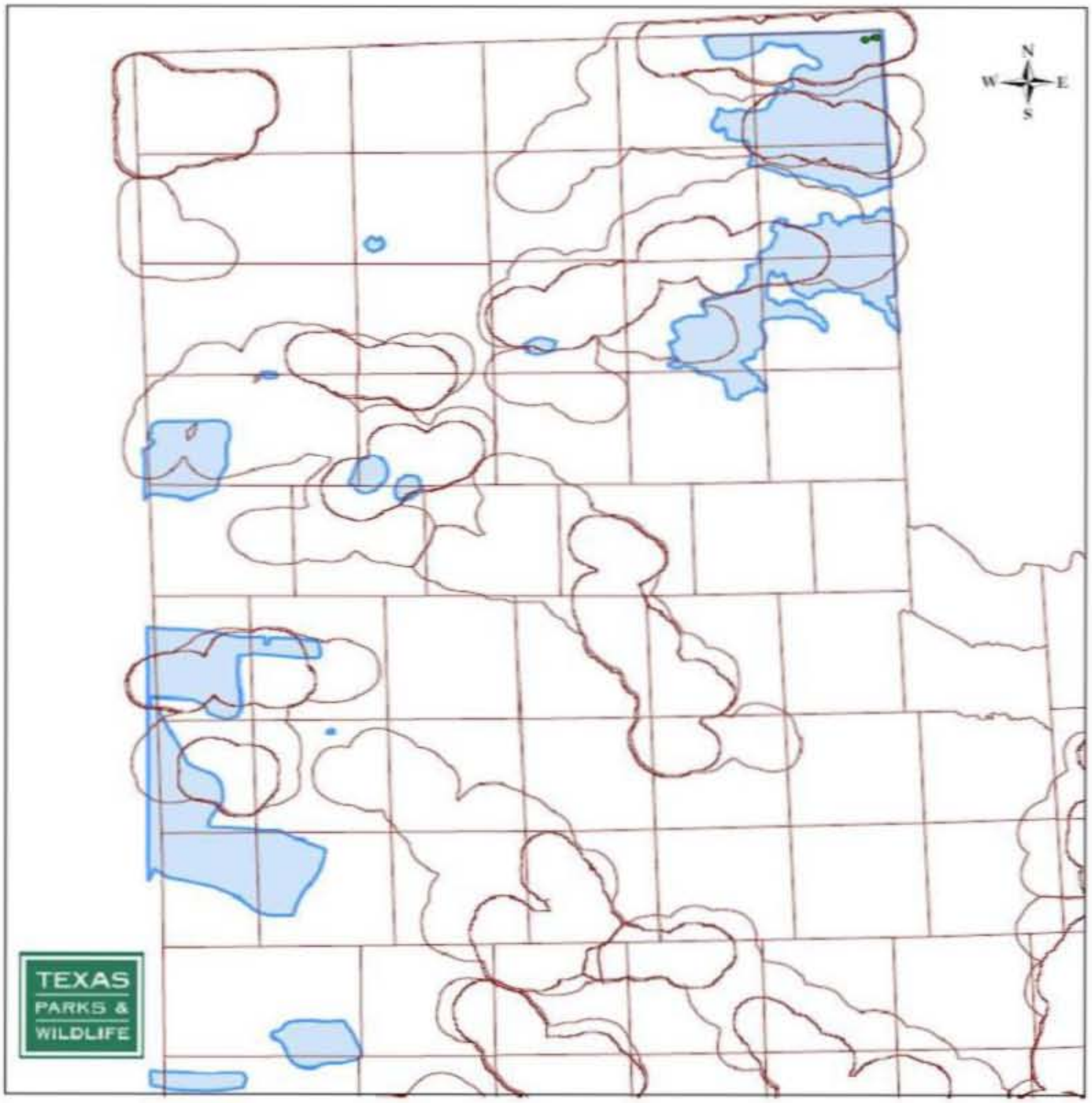
In Texas, the Public Utility Commission of Texas recently directed the Electric Reliability Council of Texas (ERCOT) to develop transmission plans for wind capacity to accommodate between 10,000 and 25,000 MW of power (AWEA 2007b, pp. 2-3). ERCOT is a regional transmission organization with jurisdiction over most of Texas. The remainder of Texas, largely the Texas panhandle, lies within the jurisdiction of the Southwest Power Pool (SPP). A recent assessment from ERCOT identified more than 130,000 MW of high-quality wind sites in Texas, more electricity than the entire state currently uses. The establishment of Competitive Renewable Energy Zones by ERCOT within the state of Texas will facilitate wind energy development throughout western Texas (see Figure 2). The Competitive Renewable Energy Zones, as shown on Figure 2, are identified by a number that indicates the development priority of each zone. The top four zones are located within occupied and historic LEPC habitat in the Texas panhandle.

Figure 2. Competitive Renewable Energy Zones (in blue) and planned transmission lines (dashed red lines) in portions of New Mexico, Texas, Oklahoma, and Kansas.



The TPWD reports that commercial wind energy development, based on the existing Competitive Renewable Energy Zones, threatens remaining LEPC populations in both the Permian Basin/Western Panhandle and the Northeastern Panhandle regions of Texas (Whitlaw 2007, p. 4; see Figure 2). The high level of overlap between the LEPC currently occupied range in Texas and the Competitive Renewable Energy Zones which are designated for future wind energy development in the Texas panhandle is shown in Figure 3.

Figure 3. Map depicting the degree of overlap between occupied LEPC habitat in Texas (shaded) and Competitive Renewable Energy Zones designated for future wind energy development in the Texas panhandle.



Development of high capacity transmission lines is critical to the development of the anticipated wind energy resources. According to ERCOT (AWEA 2007a, p. 9), every $1 billion invested in new transmission capacity enables the construction of $6 billion of new wind farms. Depicted on Figure 2 are the proposed electric transmission line upgrades which were provided to the Service by the SPP. The SPP is a Regional Transmission Organization which overlaps all or portions of nine states and functions to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. This map identifies approximately 423 km (263 mi) of proposed new transmission lines, commonly referred to as the “X Plan”, that were being evaluated during the transmission planning process. Transmission planning continues to move forward and numerous alternatives are being evaluated, much of which will connect transmission capacity throughout all or portions of occupied LEPC range and serve to catalyze extensive wind energy development throughout much of the remaining occupied LEPC range in Kansas, Oklahoma, and Texas. Some recent priority transmission expansion projects identified by the SPP include: a 765 kV line from Spearville, Kansas to a planned substation in Comanche County, Kansas; a 345 kv line from Wichita, Kansas through a planned substation at

Medicine Lodge, Kansas to the planned substation in Comanche County, Kansas; a 765 kV line from the planned Comanche County, Kansas substation to a planned substation near Woodward, Oklahoma; and a 345 kV double circuit line from the proposed Woodward substation through the panhandle of Oklahoma to an existing substation located south of Guymon, Oklahoma (Pennel 2009, p.1).

Wind energy development in the Texas panhandle and portions of west Texas represents a serious threat to extant LEPC populations in the state. Once established, wind farms and associated transmission features would severely hamper future efforts to restore population connectivity and gene flow (transfer of genetic information from one population to another) between existing populations which are currently separated by unfavorable land use in the Texas panhandle.

In Colorado, the U.S. Department of Energy, National Renewable Energy Laboratory (2010b, p. 1) rated the southeastern corner of Colorado as having good wind resources, the largest area of Colorado with that ranking. The area almost completely overlaps the currently occupied range of the LEPC in Colorado. CDOW reported that commercial wind development is occurring in Colorado, but that most of the effort is currently centered north of the occupied range of LEPC in southeastern Colorado.

Wind energy development in New Mexico is a lower priority than other states within the range of the LEPC. In New Mexico, the suitability for wind energy development in the currently occupied range of the LEPC is only rated as fair (U.S. Department of Energy, National Renewable Energy Laboratory 2010b, p. 1). However some parts of northeastern New Mexico within LEPC historical range have been rated as excellent. Northeastern New Mexico is important to LEPC conservation because this area is vital to efforts to re-establish or re-connect the New Mexico LEPC population to those in Colorado and the Texas panhandle.

In summary, wind energy and associated infrastructure development is occurring within occupied portions of LEPC habitat. Where such development has occurred, these areas are no longer suitable for LEPC even though many of the typical habitat components used by LEPC remain. Proposed transmission line improvements will serve to facilitate further development of additional wind energy resources. Future wind energy developments, based on the known locations of areas with excellent to good wind energy development potential, likely will have substantial overlap with known LEPC populations. Additional areas that are currently unoccupied but lie within the historic range and provide suitable habitat for the LEPC also could be developed. These areas of unfragmented habitat are crucial to ongoing efforts to conserve the LEPC. Fragmentation of these areas would further modify or curtail the range of the LEPC and hamper efforts to conserve the species. Therefore, the Service considers the ongoing and large-scale potential for commercial wind power development, particularly in western Kansas, northwestern Oklahoma, and the Texas panhandle, to be a high-level threat to the survival of the species in the near future. Siting of wind farms and transmission lines in a manner that avoids fragmentation of LEPC habitat is important and some wind power developers appear sensitive to concerns about siting such facilities.

Oil and Gas Development

Oil and gas development affects LEPC by disrupting reproductive behavior (Hunt and Best 2004, p. 41) and through habitat fragmentation and conversion (Hunt and Best 2004, p. 92). Smith *et al*. (1998, p. 3) observed that almost one-half, 13 of 29, of the abandoned leks examined in southeastern New Mexico had a moderate to high level of noise. Hunt and Best (2004, p. 92) found that abandoned leks in southeastern New Mexico had more active wells, more total wells, and greater length of access road than active leks. They concluded that petroleum development at intensive levels is likely not compatible with populations of LEPC (Hunt and Best 2004, p. 92)

Impacts from oil and gas development and exploration are two reasons thought to be responsible for the species' near absence throughout previously occupied portions of the Carlsbad BLM unit in southeastern New Mexico (Belinda 2003, p. 3). This is supported by research examining LEPC losses over the past twenty years on Carlsbad BLM lands (Hunt and Best 2004, pp. 114-115). In this study, factor analysis (a statistical method used to describe variability among observed variables in reference to a number of unobserved variables) of characters associated with active and abandoned leks was conducted to determine which potential causes were associated with the population decline. Those variables associated with oil and gas development explained 32 percent of observed lek abandonment (Hunt and Best 2004) and the consequent population extirpation.

Well densities are increasing dramatically throughout many portions of LEPC range. Although the Service presently lacks the information to specifically quantify and analyze drilling activity throughout the entire historic and occupied range of the LEPC, known activity within certain areas of the historic range demonstrates the magnitude of the threat. For example, the amount of habitat fragmentation due to oil and gas extraction in the Texas panhandle and western Oklahoma associated with the Buffalo Wallow oil and gas field within the Granite Wash formation of the Anadarko Basin has steadily increased over time. In 1982, the rules for the Buffalo Wallow field allowed one well per 130 ha (320 ac). In May of 2005, the Texas Railroad Commission changed the field rule regulations for the Buffalo Wallow oil and gas field to allow oil and gas well spacing to a maximum density of one well per 8 ha (20 ac) (Texas Railroad Commission 2007). When fully developed at this density, the region will have experienced a 16 fold increase in habitat fragmentation in comparison with the rates allowed prior to 2005. Since 2005, TPWD and Service biologists report that new oil and gas well development within prime occupied habitat in the northeastern portion of the Texas panhandle within portions of Hemphill, Lipscomb, and Wheeler counties, Texas is occurring at a rapid rate (Whitlaw 2007. p. 4; Hughes 2008). Although the specific rate of expansion is unquantified, at least one company has reported that they have drilled 150 wells in this formation since 2005 (Forest Oil Corporation 2008).

In the BLM's special status species record of decision and approved resource management plan amendment (RMPA) some limited protections for the LEPC in New Mexico are provided by reducing the number of drilling locations, decreasing the size of well pads, reducing the number and length of roads, reducing the number of powerlines and pipelines, and implementing best management practices for development and reclamation (BLM 2008, pp. 5-31). The RMPA provides guidance for management of approximately 344,000 ha (850,000 ac) of public land and 121,000 ha (300,000 ac) of federal minerals in Chaves, Eddy, Lea, and Roosevelt counties in

New Mexico. Implementation of these restrictions, particularly curtailment of new mineral leases, would be greatest in the Core Management and Primary Population Areas (BLM 2008, pp. 9-11). The Core Management and Primary Population Areas are located in the core of the LEPC occupied range in New Mexico. The effect of these best management practices on the status of the LEPC is unknown, particularly considering about 60,000 ha (149,000 ac) have already been leased in those areas (BLM 2008, p. 8). The plan does stipulate that measures designed to protect the LEPC and sand dune lizard (*Sceloporus arenicolus*) may not allow approval of all spacing unit locations or full development of the lease (BLM 2008, p. 8).

Oil and gas development and exploration is ongoing in the remaining states although the precise extent is currently unknown. Some development is anticipated in Baca County, Colorado, although the timeframe for initiation of those activities is uncertain (CDOW 2007, p. 2). In Oklahoma, oil and gas exploration statewide continues at a high level. Since 2002, the average number of active drilling rigs in Oklahoma has steadily risen (Boyd 2009, p. 1). Since 2004, the number of active drilling rigs has remained above 150, reflecting the highest level of sustained activity since the ‘boom’ years from the late 1970s through the mid-1980s in Oklahoma (Boyd 2007, p. 1).

<u>Fire Suppression</u>

The frequency and intensity of disturbances are critical to ecological processes, biological diversity, and heterogeneity across multiple spatial scales in grassland ecosystems which evolved with fire and ungulate grazing, such as those in the Great Plains where LEPC occur (Collins 1992, pp. 2003-2005; Fuhlendorf and Smeins 1999, pp. 732, 737). North American grasslands and shrub lands evolved under, and are maintained by, ungulate grazing and frequent fire. Both grazing patterns (discussed in section on “Livestock Grazing” above) and fire frequency have been drastically altered since European settlement of the Great Plains. With few exceptions, burning of native rangelands was, and continues to be, perceived by landowners as destructive to rangelands, undesirable for maximizing cattle production, and likely to create wind erosion or “blowouts” in sandy soils. As a result, virtually all wildfires throughout LEPC range were historically suppressed, and relatively little prescribed burning now occurs on private land.

While prescribed burning is now recognized as the preferred method to control and prevent tree invasion of native rangeland, prescribed fire is generally employed only after significant invasion has already occurred and landowners believe that forage production for cattle is becoming diminished. The threshold of tree invasion at which forage production is significantly reduced is far greater than the threshold at which grassland dependent and grassland obligate birds such as LEPC can survive. For example, Coppedge *et al*. (2001, pp. 51-57) examined bird response to eastern red cedar (*Juniperus virginianus*) invasion into native and CRP grasslands in western Oklahoma using Breeding Bird Survey data spanning from the time period 1965 to 1995. They found that grassland bird populations declined or exhibited negative associations with woody vegetation gradients. In particular, western meadowlark (*Sturnella neglecta*) populations declined across a gradient of increasing encroachment, and were extirpated from areas with the most eastern red cedar. Woody plant invasion also affected habitat patch size, and areas with the least amount of woody cover retained core areas suitable for species associated with core patch size.

Because LEPC habitat is characterized by extensive patches of treeless grassland and shrubland habitat (Giesen 1998, pp. 3-4), the invasion of remaining native habitat within LEPC range by woody species such as eastern red cedar is a growing concern. An analysis of the rate of spread of eastern red cedar trees in Oklahoma by Oklahoma State University and the Oklahoma Cooperative Extension Service indicated that by 1995, eastern red cedar invasion would consume approximately 308 ha (762 ac) of rangeland habitats in Oklahoma each day, on average, amounting to over 113,312 ha (280,000 ac) annually (Bidwell *et al*. 2000, p. 4). More recently, a time series infrared satellite mapping analysis conducted by the Oklahoma NRCS in 2005 revealed that eastern red cedar trees alone are invading native rangelands in western Oklahoma at a rate of approximately 5 percent per year (Eckroat 2007). Given that southern Kansas and the northeastern Texas panhandle have similar rates of precipitation, fire exclusion, and grazing pressure compared to western Oklahoma, this rate of spread may be occurring throughout occupied LEPC range in these areas.

Tree invasion in native rangeland has the potential to render significant portions of remaining occupied habitat unsuitable within the near term. Woodward *et al.* (2001, pp. 270-271) documented a negative association between landscapes with increased woody cover and LEPC population indices. Similarly, Fuhlendorf *et al*. (2002, p. 625) examined the effect of landscape structure and change on population dynamics of LEPC in western Oklahoma and northern Texas. They found that landscapes with declining LEPC populations had significantly greater increases in tree cover types (riparian, windbreaks, and eastern red cedar encroachment) than landscapes with sustained LEPC populations.

<u>Summary of Factor A</u>

The curtailment of LEPC range has occurred throughout large portions of four of the five states occupied by LEPC. Estimates reveal that some 86 percent of the historically occupied range has been lost due to a variety of mechanisms including conversion of rangeland to cultivated cropland, energy development, and habitat fragmentation. In Kansas, the loss of suitable habitat has been offset by the restoration of native grasslands due to implementation of CRP. However, these short-term gains are expected to be negated as CRP contracts expire and the lands are converted to other uses. Rangewide destruction and modification of remaining LEPC habitat continues to occur. Within the next few years, the possible conversion of over a million acres of currently enrolled CRP grasslands to cropland and other less suitable land uses has the potential to destroy or modify some 14 percent of the remaining occupied habitat. Wind energy development with its associated infrastructure development is ongoing and the potential for additional wind energy facilities is substantial within nearly all occupied habitat in all states except New Mexico, where it may impact historical habitat important to linking the New Mexico population to populations to the north. Additionally, the continued loss and degradation of currently occupied habitat in several areas in the form of heavy grazing by livestock, woody plant invasion due to fire suppression, oil and gas development, and fragmentation are rendering portions of the range uninhabitable for the species.

B. <u>Overutilization for commercial, recreational, scientific, or educational purposes</u>.

probability of recolonization decreases as the distance between suitable habitat patches expands. Existing regulatory mechanisms have not been adequate to halt the decline of LEPC populations and habitat.

Based on the information described above, we find that this species is warranted for listing throughout all of its range. Therefore, it is unnecessary to analyze whether it is threatened or endangered in a significant portion of its range.

For species that are being removed from candidate status:

____Is the removal based in whole or in part on one or more individual conservation efforts that you determined met the standards in the Policy for Evaluation of Conservation Efforts When Making Listing Decisions (PECE)?

RECOMMENDED CONSERVATION MEASURES:

1. Reduce or eliminate upland construction of fence lines and utility lines within occupied habitat and for 8 km (5 mi) surrounding all occupied habitat, especially near leks. If fence lines cannot be removed, it is recommended that the top and third wires of lines near active LEPC leks be conspicuously marked to minimize collision mortality.
2. Limit or eliminate the federally-funded application of tebuthiuron herbicide in remaining shinnery oak habitats and 2, 4-D herbicide in sand sagebrush habitats.
3. Encourage rangewide adherence to the Service's Voluntary Interim Guidelines to Avoid and Minimize Wildlife Impacts from Wind Turbines, released in July 2003, (*http://www.fws.gov/habitatconservation/wind.pdf*)
4. Work cooperatively with energy-related industry to avoid, minimize, and compensate for impacts to LEPC populations and habitats.
5. Work with partners to target re-enrollments and new contracts under CRP and related agricultural conservation programs to benefit LEPC.
6. Minimize further fragmentation of remaining Federal lands within current and historic LEPC range by abandoning the use of ineffective timing, noise, and distance stipulations near active or historic leks. Instead, future energy leasing, exploration, and development, or other fragmenting human land uses within essential LEPC habitats should be limited.
7. Establish secure and well-funded financial incentive mechanisms for private landowners to provide light to moderately grazed native rangeland habitats that are suitable for LEPC use, and are not subject to herbicidal shrub control practices.
8. Encourage increased use of prescribed fire and patch burn grazing concepts to facilitate habitat heterogeneity in LEPC range and decrease encroachment of woody vegetation. Patch burn grazing is a system that utilizes prescribed fire to encourage intensive grazing on a portion of a pasture each year while resting the remainder of the pasture.

LISTING PRIORITY

THREAT			
Magnitude	Immediacy	Taxonomy	Priority
High	**Imminent**	Monotypic genus	1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) Docket No. ER11-___-000

AFFIDAVIT

State of Oklahoma

County of Oklahoma

I, PHILIP L. CRISSUP, being first duly sworn, depose and state that I am the witness identified in the foregoing Direct Testimony and Exhibits, that I prepared the testimony and exhibits and am familiar with their content, and that the facts set forth therein are true and correct to the best of my knowledge, information and belief.

Philip L. Crissup

Philip L. Crissup

Subscribed and sworn before me this 17th day of February, 2011.

Kelly B. Hamilton

Notary Public #01009409

My commission expires: July 6, 2013

ATTACHMENT 3

DIRECT TESTIMONY AND EXHIBITS OF DONALD R. ROWLETT

EXHIBIT NO. OGE-18

Exhibit No. OGE-18

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER11-___-000

DIRECT TESTIMONY AND EXHIBITS OF
DONALD R. ROWLETT

February 18, 2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)	Docket No. ER11-___-000

<u>DIRECT TESTIMONY AND EXHIBITS OF DONALD R. ROWLETT</u>

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A. My name is Donald R. Rowlett. My business address is 321 N. Harvey Ave., P.O. Box 321, Oklahoma City, Oklahoma 73101. I am the Director of Regulatory Policy and Compliance at Oklahoma Gas and Electric Company ("OG&E").

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. I am responsible for the analysis, development and communication of regulatory policy for OG&E. This includes establishing policies to be followed by OG&E in the Oklahoma and Arkansas and the Federal Energy Regulatory Commission ("FERC" or "Commission") jurisdictions and monitoring compliance with those policies.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I earned a Bachelor of Science degree in Business with an accounting emphasis (1980) and a Masters in Business Administration (1992), from Oklahoma City University. In 1983, I became a Certified Public Accountant, licensed to practice in Oklahoma. Prior to joining OG&E, I was employed by Arthur Anderson & Co.

as a financial consultant and audit manager. I joined OG&E in 1989 and have worked in a number of positions including Vice President and Controller and my present position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION OR BEFORE A STATE REGULATORY AGENCY?

A. Yes. At the FERC, I submitted testimony in 2007 in support of a Federal Power Act Section 205 filing by Oklahoma Gas and Electric Company in Docket No. ER08-281-000. I also submitted testimony in 2008 on behalf of Tallgrass Transmission LLC in Docket No. ER09-35-000. Most recently, I submitted testimony in October of 2010 in support of OG&E's request for transmission rate incentives in Docket No. ER11-112-000.

I also have filed testimony in numerous proceedings before the Oklahoma Corporation Commission ("OCC") and the Arkansas Public Service Commission ("APSC"). Additionally, I have submitted testimony and appeared before the United States Senate Environmental and Public Works Committee.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS TESTIMONY.

A. On October 12, 2010, OG&E submitted an FPA Section 205 filing requesting approval of certain transmission incentives for eight transmission projects to be constructed within SPP. On December 30, 2010, FERC issued an order which granted this request for two projects but denied the request for transmission incentives for the remaining six projects.[1] In the December 30 Order, FERC

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[1] *Oklahoma Gas and Electric Co.*, 133 FERC ¶ 61,274 (2010) ("December 30 Order").

found that "OG&E has adequately demonstrated that the Projects will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion, and therefore meet the requirements of FPA section 219 for incentive rate treatment."[2] However, it also found that a different applicant's filing in an unrelated docket "revealed the necessity to change Commission policy with respect to the application of the nexus test to groups of projects."[3] Applying this revised standard, FERC held that OG&E had failed to demonstrate the required nexus between the requested incentives and the specific investments being made with regard to the remaining six projects.[4] This finding was "without prejudice to OG&E refiling to demonstrate how each of these six remaining projects meets the nexus requirement."[5]

In response to the December 30 Order, OG&E, through the filing which includes this testimony, is requesting FERC authorization to implement two specific transmission rate incentives in connection with five of the specific transmission projects that were previously included in OG&E's October 12, 2010 filing. Those projects are further described in the testimony of Philip L. Crissup at Exhibit No. OGE-1. The purpose of my testimony is to describe the transmission rate incentives that OG&E is seeking in this proceeding for the Projects as well as the financial risks and challenges presented by, and the benefits to OG&E and its customers provided by, the requested incentives. I also

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[2] December 30 Order at P 35.

[3] *Id.* at P 39 (footnote omitted).

[4] *Id.* at PP 42, 44.

[5] *Id.* at P 44.

will describe the Construction Work In Progress ("CWIP") related accounting procedures that OG&E plans to implement in accordance with the Commission's regulations.

II. COSTS OF THE PROJECTS

Q. WHAT ARE THE ESTIMATED COSTS OF THE PROJECTS?

A. The estimated combined cost of the Projects is approximately $608 million. The following table details the cost of each project and the current estimate of how the costs of these projects will be spread over the next four years:

Project	2010	2011	2012	2013	2014	Total
Sooner-Cleveland	$2.385	$19.074	$41.069	$1.536	$0	$64.064
Seminole-Muskogee	0	$11.1	$101	$67	$0	$179.1
Tuco-Woodward	0	$4.7	$23	$62.7	$29.6	$120
Sunnyside-Hugo	$25.105	$140.28	$21.904	$0	$0	$187.289
Sooner-Rose Hill	$10.858	$33.931	$13.045	$0	$0	$57.834
Total	$38.348	$209.085	$200.018	$131.236	$29.6	$608.287

Q. HOW DOES OG&E'S LEVEL OF INVESTMENT IN THE PROJECTS COMPARE TO OG&E'S OTHER INVESTMENTS IN TRANSMISSION?

A. The estimated total cost of the Projects, approximately $608 million, is greater than OG&E's current net transmission plant, which is $558 million. New transmission investments of this magnitude are unprecedented for OG&E. Over the past five years, OG&E's annual expenditures for capital additions have averaged approximately $53 million.

Q. HOW DOES OG&E INTEND TO FINANCE THE DEVELOPMENT AND CONSTRUCTION OF THE PROJECTS?

A. OG&E intends to finance these projects with a mix of long-term debt and equity consistent with the current capital structure.

Q. WILL OG&E FINANCE THESE PROJECTS ON A PROJECT-BY-PROJECT BASIS?

A. No. Each of the unique transmission projects included in this application was subjected to the Company's annual capital budgeting process. The specific merits of each project were evaluated during this process and while each of the transmission projects has its individual risks and challenges they have been included in OG&E's overall capital expenditure plan. Once OG&E's overall capital expenditure budget has been approved the Company then obtains financing for the budget as a whole. OG&E does not separately finance individual projects.

Q. WILL OG&E BE UNDERTAKING OTHER EXTRAORDINARY TRANSMISSION PROJECTS AT THE SAME TIME THAT THESE FIVE PROJECTS ARE BEING CONSTRUCTED AND PLACED INTO SERVICE?

A. Yes. In the December 30 Order, FERC authorized transmission rate incentives for two large-scale transmission infrastructure projects to be constructed by OG&E within SPP. These projects have a total estimated cost of $313 million and are expected to be completed in 2014. Accordingly, OG&E will need to finance the five projects for which incentives are requested in this filing at the same time it is financing the construction of the projects approved by the December 30 Order.

III. FINANCIAL RISKS AND CHALLENGES

Q. PLEASE SUMMARIZE THE FINANCIAL RISKS AND CHALLENGES OG&E FACES WITH RESPECT TO THE DEVELOPMENT AND CONSTRUCTION OF THE PROJECTS.

A. The size of the investment required for the Projects – over $600 million – will present a number of financial challenges for OG&E. First, funding projects of this size and scope will require significant outlays of cash, decreasing OG&E's cash flow. Second, these expenditures will increase OG&E's debt and will burden OG&E's financial metrics, raising the risk of a credit downgrade. Third, internal competition for capital with other OG&E expenditures raises additional financing challenges. Fourth, the long lead times associated with the Projects will compound each of these risks.

Q. PLEASE DESCRIBE THE IMPACT ON CASH FLOW OF THE PROJECTS.

A. The large investment required by the Projects will depress OG&E's cash flow during the construction phase of the Projects. Over the next four years, OG&E will face a negative cash flow position as a result of meeting the extensive level of capital expenditures required by the Projects. Cash flows generated from operations will not be sufficient to cover these transmission projects. The decreased cash flow will put stress on OG&E's credit metrics. A decreased cash flow increases the risk that a utility may not be able to satisfy its financial obligations and can harm a utility's credit ratings. A recent S&P report highlighted the importance of cash flow in connection with large-scale capital projects:

> Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays.[6]

Q. PLEASE DESCRIBE HOW NEGATIVE CASH FLOW IMPACTS CREDIT RATINGS.

A. When assessing a company's ability to meet its financial obligations, the credit rating agencies rely largely on two financial ratios to determine if the company has a sufficient level of cash flow to satisfy its obligations. These two metrics are Funds From Operations to Interest Expense ("FFO/Interest") and the ratio of Funds From Operations to Total Debt ("FFO/Total Debt"). Funds From Operations is largely composed of net income and depreciation expense. The more debt and other fixed contractual obligations a company has, the higher the adjusted interest expense and total adjusted debt and the lower the cash flow coverage ratios. This problem is most acute during the construction cycle of large projects at which time the denominator of both formulas increases while the numerator decreases.

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[6] Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-23 at 6.

Q. IS THERE ANY SPECIFIC EVIDENCE THAT OG&E'S PLANNED TRANSMISSION EXPENDITURES MAY HAVE AN IMPACT ON OG&E'S CREDIT RATINGS?

A. Yes. On June 29, 2010, Fitch Ratings downgraded the Issuers Default Rating ("IDR") of OG&E from A+ to A. Fitch stated

> The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The capex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period.[7]

Q. WHY ARE A UTILITY'S CREDIT RATINGS IMPORTANT?

A. Credit ratings determine the cost of borrowing funds for the utility, *i.e.*, the stronger the rating, the lower the borrowing cost. Reduced borrowing costs reduce costs to customers. Credit ratings also determine the ability to access capital markets and define a company's overall risk profile.

Q. ARE THERE OTHER FINANCIAL RISKS AND CHALLENGES ASSOCIATED WITH THE PROJECTS?

A. Yes. OG&E has a number of additional capital expenditures that will compete with the Projects for financing. OG&E is facing aging utility infrastructure that will require investments higher than historical levels several years into the future. Additionally, OG&E is investing in new Smart Grid technology over the next

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[7] Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010), Exhibit No. OGE-22 at 1.

three years and has additional obligations in renewable energy and environmental initiatives. OG&E's total projected base transmission, distribution, generation and other capital expenditures through 2014, plus the expenditures for the Projects, will be over $3.2 billion. To put this in perspective, these projected expenditures are only slightly less than the Company's current total rate base. The sheer volume of these capital expenditures means that a lot of capital projects will be competing with the Projects for funding priority.

Q. HOW DO THE LONG LEAD TIMES ASSOCIATED WITH THE PROJECTS IMPACT THE FINANCIAL RISKS ON OG&E?

A. Projects of this size and scope will require long lead times to site, construct, and ultimately place into operation due to the need to acquire rights-of-way, materials and sophisticated labor resources. Certain of the Projects will not be placed into service until December of 2013 or 2014, even though OG&E will incur significant costs in connection with those Projects starting right away. This creates risk in terms of cost increases, construction delays and continually building carrying costs.

IV. REQUEST FOR INCENTIVES

Q. WHICH TRANSMISSION RATE INCENTIVES IS OG&E SEEKING FOR THE PROJECTS?

A. OG&E seeks approval to include 100 percent of construction work in progress, or CWIP, in rate base and to recover 100 percent of prudently incurred costs should the Projects need to be abandoned for reasons outside OG&E's control ("Abandoned Plant").

Q. HOW DID OG&E DECIDE WHICH INCENTIVES TO REQUEST?

A. OG&E considered which incentives would help alleviate the risks and challenges presented by the Projects. The requested incentives are specific to the Projects and will help facilitate the timely completion of the Projects while allowing OG&E to continue to meet its other financial obligations.

V. BENEFITS OF THE CWIP INCENTIVE

Q. PLEASE DESCRIBE THE BENEFITS TO OG&E OF THE CWIP INCENTIVE.

A. The ability to include 100 percent of CWIP in rate base will give OG&E upfront regulatory certainty and rate stability. The CWIP incentive also will improve cash flow. As discussed above, OG&E will face a negative cash flow position as a result of its investment in the Projects. As the credit rating agencies have recognized, certain regulatory mechanisms – including CWIP – can strengthen a utility's cash flow. For example, S&P stated "[a]llowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program."[8]

A more stable cash flow, in turn, bolsters a utility's credit ratings. In its report describing the recent downgrade in OG&E's IDR, Fitch noted that "[o]ther favorable regulatory mechanisms if implemented, such as cash recovery of capital

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[8] Shipman, Todd, *Assessing U.S. Utility Regulatory Environments in Standard & Poor's Global Credit Portal: RatingsDirect* (March 11, 2010), Exhibit No. OGE-23 at 6.

costs during construction work in progress, would be viewed as credit enhancing by Fitch."[9] As noted by Fitch, the CWIP incentive can prevent a possible credit downgrade by providing more stable cash flow and decreasing financial risk. Because 100 percent CWIP recovery reduces downward pressure on OG&E's credit ratings, OG&E would be able to borrow money at a lower cost. Not having to finance AFUDC costs would also help OG&E to minimize the total costs associated with financing the construction of the Projects.

Q. WHAT ARE OG&E'S PROJECTED CWIP BALANCES FOR THE PROJECTS?

A. The CWIP balances for the Projects for 2011 are reflected in the populated version of the formula rate template included as Attachment 1 to OG&E's filing. The table set out at page 5 of my testimony provides the estimated CWIP balances on a project-by-project basis for 2011 through 2014.

Q. WHAT IS THE ALTERNATIVE TO 100 PERCENT CWIP RECOVERY?

A. With 100 percent CWIP recovery, OG&E would earn a return on the financing costs of construction on a current basis rather than recovering these costs in rate base after construction is complete. The alternative to 100 percent CWIP recovery is to recover the cost to finance construction in the form of Allowance for Funds Used During Construction ("AFUDC") when the Projects go into service. Just like with the AFUDC approach, under the CWIP approach, a project does not begin to depreciate until it is placed into service. As discussed in more detail below, overall costs ultimately will be lower under the CWIP approach, as

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[9] Fitch Ratings, "Fitch Downgrades OG&E's IDR to 'A'" (June 28, 2010), Exhibit No. OGE-22 at 1.

compared to the AFUDC approach, benefiting OG&E's financial metrics and helping OG&E lower its cost of debt, which is to the benefit of transmission customers.

Q. WHAT IS THE IMPACT ON CASH FLOW OF THE PROJECTS TAKING INTO ACCOUNT THE CWIP INCENTIVE VERSUS THE AFUDC APPROACH?

A. I have included an exhibit, summarized in the table below, which demonstrates the difference in cash flow OG&E would experience between receiving 100 percent CWIP as compared to AFUDC treatment.[10]

($ millions)	2011	2012	2013	2014	Total
100% CWIP	**$9.9**	**$28.9**	**$51.6**	**$64.4**	**$154.8**
AFUDC	**(2.8)**	**10.7**	**41.2**	**64.3**	**$113.4**
Difference	**$12.7**	**$18.2**	**$10.4**	**$.1**	**$41.4**

Also included as Exhibit No. OGE-20 is a summary of the cash flow to debt impact of CWIP in rate base. This exhibit demonstrates that without CWIP in rate base OG&E's ability to pay the interest on its debt decreases because there is no liquidity provided by the accrual of AFUDC. This reduced liquidity is reflected in the percentage of funds generated from operations as a percent of debt.

10 *See* Exhibit No. OGE-19.

Q. ARE THERE OTHER WAYS IN WHICH THE CWIP INCENTIVE IMPROVES OG&E'S FINANCIAL METRICS?

A. Yes. Under the AFUDC approach, customers essentially pay a return (*i.e.*, the utility's authorized return) on a return (*i.e.*, the utility's carrying costs on CWIP), which results in higher overall construction costs and higher depreciation amounts. These expenses are lower with the CWIP incentive in place. Exhibit No. OGE-19 shows the difference in OG&E's net cash from operations that would result with CWIP included in rate base as compared to the AFUDC approach. As shown in the exhibit, over four years, OG&E would avoid the need to finance approximately $41.4 million of costs through the inclusion of CWIP in rate base. In this example, interest costs would be approximately $6.8 million less when CWIP is included in rate base. This reduction in interest costs will improve OG&E's interest coverage ratios (*i.e.*, FFO/Interest).

Q. HOW WILL THE CWIP INCENTIVE BENEFIT OG&E'S CUSTOMERS?

A. As discussed above, a decrease in cash flow can impact credit ratings. Because investors consider credit ratings when determining the return they require to lend money, if the credit rating of a utility such as OG&E is downgraded, it increases the cost of debt. This, in turn, increases costs paid by OG&E transmission customers.

Q. ARE THERE ANY OTHER BENEFITS TO CUSTOMERS OF THE CWIP INCENTIVE?

A. Yes. Rate shock can result when large-scale projects such as the ones included in this filing are placed into service and several years of construction costs are included in rate base all at once. By providing for a current return on construction costs, the CWIP incentive will stabilize rates and help avoid rate shock to OG&E's transmission customers.

VI. BENEFIT OF ABANDONED PLANT INCENTIVE

Q. WHAT IS THE BENEFIT TO OG&E OF THE ABANDONED PLANT INCENTIVE?

A. The Abandoned Plant incentive will provide OG&E, as well as potential lenders, the assurance that all prudently incurred costs will be recoverable even if the Projects need to be abandoned due to the substantial risks and challenges presented by the Projects, which are described in Mr. Crissup's testimony.

VII. ACCOUNTING AND OTHER CWIP REQUIREMENTS

Q. PLEASE DESCRIBE HOW OG&E WILL CHANGE ITS ACCOUNTING PROCEDURES TO ACCOUNT FOR THE CWIP INCENTIVE.

A. The Commission's regulations require that any utility that includes CWIP in rate base must discontinue the capitalization of AFUDC in rate base with respect to the projects at issue.[11] The regulations also require that such utility propose accounting procedures that "[e]nsure that wholesale customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP proposed to be included in rate base;" and "[e]nsure that wholesale customers will not be charged for any corresponding AFUDC capitalized as a result of different accounting or ratemaking treatments accorded CWIP by state or local regulatory authorities."[12]

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[11] 18 C.F.R. § 35.25(e) (2010).

[12] 18 C.F.R. § 35.25(f) (2010).

To satisfy these requirements, OG&E will not accrue AFUDC in Account 107, Construction Work in Progress.

Moreover, OG&E will use the SAP plant accounting system to maintain its accounting records for CWIP electric plant assets during construction and after the Projects are placed into service. The SAP system includes the capability to identify specific work orders that should not be included in the calculation and capitalization of AFUDC. The work orders related to the Projects will be identified in SAP, and no AFUDC will be calculated on their balances. This will prevent a double-recovery of CWIP and capitalized AFUDC on the same rate base items. If OG&E is accorded different ratemaking treatment of CWIP by the OCC or APSC, any accrued AFUDC would be recorded in FERC Account 182.3 Other Regulatory Assets. The AFUDC regulatory asset would be amortized over the depreciable life of the Projects. The amortization amount would be debited to FERC Account 407.3 Regulatory Debits. The AFUDC regulatory asset and associated amortization would not be included in the rate charged to OG&E's wholesale transmission customers.

Q. HOW DOES OG&E PROPOSE TO COMPLY WITH THE SPECIFIC ACCOUNTING TREATMENT THE COMMISSION HAS REQUIRED WHEN A UTILITY PROPOSES TO RECOVER A CURRENT RETURN ON CWIP?

A. The Commission has noted that, where a utility proposes to recover a current return on CWIP, this cost is recovered in a different period than ordinarily would occur under the Uniform System of Accounts. Accordingly, to maintain the comparability of financial information among entities, the Commission has required utilities recovering a current return on CWIP to "debit through FERC Account 407.3, Regulatory Debits, and credit through FERC Account 254, Other Regulatory Liabilities, in accordance with the objectives of those accounts. Amounts recorded in FERC Account 254 related to return on the proposed Project[s] must be deducted from the rate base."[13] However, the Commission has granted waiver of that accounting treatment and permitted utilities to use footnote disclosures.[14] Consistent with this precedent, OG&E requests waiver of the specific accounting treatment and proposes instead to use footnote disclosures.

Q. HAS OG&E PREPARED STATEMENT BM, CONSTRUCTION PROGRAM STATEMENT?

A. Yes. Statement BM, Construction Program Statement, is attached to my testimony as Exhibit No. OGE-21.

Q. PLEASE SUMMARIZE THE CONTENTS OF THE STATEMENT BM YOU HAVE PREPARED.

A. Statement BM explains how the proposed Projects are prudent and consistent with a least-cost energy supply program. This statement describes how the SPP planning processes relevant to the Projects identify reliability and economic upgrades and how alternatives were considered to reduce costs to customers.

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13 *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 106 (2006), *order on reh'g*, 118 FERC ¶ 61,042 (2007).

14 *See, e.g.*, *Tallgrass Transmission*, LLC, 125 FERC ¶ 61,248 at P 80 (2008) (referencing *American Transmission Company LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 at PP 16-17 (2004); *Trans-Allegheny Interstate Line Company*, 119 FERC ¶ 61,219 (2007), *order on reh'g*, 121 FERC ¶ 61,009 (2007); and *Southern California Edison Company*, 122 FERC ¶ 61,187 (2008)).

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT NO. OGE-19

Summary of Cash Flow and Interest Impact

	2011	2012	2013	2014	4yr Total
No CWIP in Rate Base					
Net Cash from Operations	$ (2,810,953)	$ 10,753,805	$ 41,190,383	$ 64,280,281	$ 113,413,515
Interest on Debt	$ 4,605,855	$ 9,925,255	$ 12,864,651	$ 11,784,577	$ 39,180,337
Debt	$ 117,799,489	$ 192,364,736	$ 209,655,592	$ 158,612,431	N/A
CWIP in Rate Base					
Net Cash from Operations	$ 9,876,173	$ 28,950,557	$ 51,601,852	$ 64,375,885	$ 154,804,467
Interest on Debt	$ 4,199,867	$ 8,530,983	$ 10,554,915	$ 9,138,615	$ 32,424,380
Debt	$ 105,112,363	$ 161,480,858	$ 168,360,244	$ 117,221,480	N/A
Increase (Decrease)					
Net Cash from Operations	$ 12,687,126	$ 18,196,752	$ 10,411,469	$ 95,604	$ 41,390,951
Interest on Debt	$ (405,988)	$ (1,394,272)	$ (2,309,735)	$ (2,645,962)	$ (6,755,957)
Debt	$ (12,687,126)	$ (30,883,878)	$ (41,295,347)	$ (41,390,951)	N/A

Notes:

1. The projections shown above only represent the incremental cash from operations and interest expense associated with the 345kv transmission projects and do not contain any impacts from OG&E's other business
2. These projections make simplifying assumptions concerning timing of cap-ex spend and in-service dates
   a. Spending is assumed to be made ratably throughout the year
   b. Individual projects go in-service mid-year in the final year of planned cap-ex spend
   c. As a result, 2011 values may not be entirely consistent with OG&E's formula rate filing

EXHIBIT NO. OGE-20

Summary of Cash Flow to Debt Impact

2010 FFO/Debt	
Net income	215,712,000
Depreciation	208,700,000
Change in deferred tax	118,800,000
Adj deferred tax to 5yr avg	(34,059,892)
Other non working capital	(50,657,000)
FFO	$ 458,495,108
Debt	$ 1,541,800,000
FFO / Debt	29.7%

2010 FFO/Debt Pro forma 345kv transmission projects without CWIP in Rate Base

	2010	2011	2012	2013	2014
Base FFO	$ 458,495,108	$ 458,495,108	$ 458,495,108	$ 458,495,108	$ 458,495,108
Change in cash flow	-	(2,853,270)	10,709,802	41,144,627	64,232,702
Pro forma FFO	$ 458,495,108	$ 455,641,838	$ 469,204,910	$ 499,639,736	$ 522,727,811
Debt	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000
Incremental debt	-	118,904,049	193,513,299	210,849,910	159,854,327
Pro forma debt	$ 1,541,800,000	$ 1,660,704,049	$ 1,735,313,299	$ 1,752,649,910	$ 1,701,654,327
Pro forma FFO / Debt	29.7%	27.4%	27.0%	28.5%	30.7%

2010 FFO/Debt Pro forma 345kv transmission projects with CWIP in Rate Base

	2010	2011	2012	2013	2014
Base FFO	$ 458,495,108	$ 458,495,108	$ 458,495,108	$ 458,495,108	$ 458,495,108
Change in cash flow	2,891,148	9,949,031	29,026,318	51,680,631	64,457,802
Pro forma FFO	$ 461,386,256	$ 468,444,139	$ 487,521,426	$ 510,175,740	$ 522,952,910
Debt	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000	$ 1,541,800,000
Incremental debt	(2,891,148)	103,210,600	159,503,334	166,303,941	115,083,259
Pro forma debt	$ 1,538,908,852	$ 1,645,010,600	$ 1,701,303,334	$ 1,708,103,941	$ 1,656,883,259
Pro forma FFO / Debt	30.0%	28.5%	28.7%	29.9%	31.6%
Increase due to CWIP in Rate Base	**0.2%**	**1.0%**	**1.6%**	**1.4%**	**0.8%**

EXHIBIT NO. OGE-21

STATEMENT BM
OKLAHOMA GAS AND ELECTRIC COMPANY
CONSTRUCTION PROGRAM STATEMENT

OG&E seeks authorization to include 100 percent of Construction Work In Progress ("CWIP") costs associated with the OG&E Projects ("Projects") in rate base. This Statement supplements the information provided elsewhere in this filing and provides the information required to satisfy the Commission's CWIP regulations at 18 C.F.R. § 35.13(h)(38) (2010) (Statement BM).

Under Section 35.13(h)(38) of the Commission's regulations, an applicant seeking to include CWIP in rate base is required to submit Statement BM in support of its request. Statement BM requires the applicant to explain, among other things, that the proposed project is prudent and consistent with a least-cost energy supply program. OG&E submits that the information provided below and elsewhere in this filing demonstrate that the Projects are prudent and consistent with a least-cost energy supply program.

As discussed in detail in the Crissup Testimony (Exhibit No. OGE-1), the Southwest Power Pool ("SPP") implements its Transmission Expansion Plan ("STEP") each year to plan ahead for transmission needs. STEP identifies both reliability and economic upgrades, and it accounts for upgrades paid for by SPP stakeholders and upgrades requested by customers during open seasons. The Projects are five 345-kV transmission projects within the State of Oklahoma that have been approved by SPP through STEP. These Projects include:

1. The Sunnyside-Hugo Project ("Sunnyside-Hugo") is a 345-kV, 120-mile transmission line to be built from OG&E's Sunnyside substation to the Western Farmers Electric Cooperative's Hugo Generation Plant, as well as associated upgrades to the

Sunnyside substation. Sunnyside-Hugo is estimated to cost $187 million and has an estimated in-service date of April 1, 2012;

2. The Sooner-Rose Hill Project ("Sooner-Rose Hill") is a 345-kV, 88-mile transmission line to be constructed from OG&E's Sooner substation to Westar Energy's Rose Hill substation near Wichita, Kansas. The OG&E portion of the Sooner-Rose Hill line is 43 miles in length, will terminate at the interface with the Westar segment at the Oklahoma-Kansas state line, is estimated to cost $57.8 million and has an estimated in-service date of June 1, 2012;

3. The Sooner-Cleveland Project ("Sooner-Cleveland") is a 345-kV, 38-mile transmission line to be constructed from OG&E's Sooner substation to the Grand River Dam Authority's Cleveland substation, plus associated upgrades to the Sooner substation. This project is estimated to cost $64 million, and has an expected in-service date of March 31, 2013;

4. The Seminole-Muskogee Project ("Seminole-Muskogee") is a single-circuit, 345-kV, 120-mile transmission line to be built from OG&E's Seminole substation to OG&E's Muskogee substation, as well as associated upgrades to both the Seminole and the Muskogee substations. Seminole-Muskogee has an estimated cost of $179.1 million and an estimated in-service date of December 31, 2013; and

5. The Tuco-Woodward Project ("Tuco-Woodward") is a 345-kV, 250-mile transmission line from OG&E's Woodward District EHV to the SPS Tuco substation. The OG&E portion of the Tuco-Woodward project is 72 miles in length and will terminate at a reactor station to be constructed at approximately the Oklahoma-Texas

state border. The project has an estimated cost of $120 million with an estimated in-service date of May 19, 2014.

The Projects are consistent with SPP planning studies, will improve reliability, eliminate existing and anticipated congestion on the transmission system and will reduce losses. The Projects are also part of a greater SPP regional Extra High Voltage ("EHV") transmission network that, in addition to the benefits listed above, will bring the benefits of wind generation developed in the western half of the SPP to load centers throughout the SPP region and, potentially, to densely populated areas outside of the region.

As discussed in detail in the Crissup Testimony (Exhibit No. OGE-1), each of the Projects was evaluated and approved by SPP through regional planning processes and subsequently included in the 2009 SPP Transmission Expansion Plan. Projects vetted and selected through SPP's planning processes strengthen the reliability of SPP's system and provide regional benefits by relieving congestion that already exists or that will exist due to requests for new transmission service. Each approved project must demonstrate a benefit-to-cost ratio of 1:1.

These SPP processes consider multiple alternatives that include general location of the transmission assets, voltage, costs, economic benefits and reliability considerations. For example, the primary goals of the Aggregate Facilities Study ("AFS") process, through which SPP determined Sunnyside-Hugo and Sooner-Rose Hill are necessary upgrades, are identifying and resolving system constraints and maintaining reliability.[1] Through the AFS process, SPP also must determine which "alternative solutions would reduce overall costs to customers."[2]

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[1] SPP OATT, Attachment Z1.

[2] *Id.*

Moreover, SPP's Balanced Portfolio projects, which include Sooner-Cleveland, Seminole-Muskogee, and Tuco-Woodward, are intended "to reduce congestion on the SPP transmission system, resulting in savings in generation production costs."[3] To select these projects, SPP conducted an analysis of the adjusted production cost of several alternative projects. A final group of projects was selected based on a comparison of costs to benefits.[4] These SPP studies resulted in the inclusion of the OG&E Projects in the 2009 SPP Transmission Expansion Plan and subsequent approval by the SPP Board of Directors.

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3 SPP Balanced Portfolio Report (last revised June 23, 2009) at 3.

4 *Id.* at 6.

EXHIBIT NO. OGE-22

Fitch Downgrades OG&E's IDR to 'A'; Outlook Stable; Affirms OGE Energy and Enogex Ratings
28 Jun 2010 4:45 PM (EDT)

Fitch Ratings-New York-28 June 2010: Fitch Ratings has downgraded the Issuer Default Rating (IDR) of Oklahoma Gas & Electric Company (OG&E) to 'A' from 'A+'. In addition, Fitch has affirmed the 'A' IDR of OGE Energy Corp (OGE) and 'BBB' IDR of Enogex LLC (Enogex). The Outlook for all entities is Stable. Around $2.1 billion of debt is affected by these actions. See the full list of rating actions at the end of this release.

The one-notch downgrade of OG&E is driven by downward-trending credit metrics at the utility as it continues with a capital expenditure program that is significantly higher than the historical norm. The capex, which is being primarily channeled into wind, transmission and smart grid investments, is expected to remain elevated over the next several years based on known and committed projects. While OG&E enjoys constructive regulatory treatment for these investments and has minimal regulatory lag once these projects become operational, there is expected to be pressure on credit metrics during the construction period. Post 2011, as capex subsides, the credit metrics improve, but are forecasted to remain below Fitch's guideline ratios for the 'A+' category. Fitch expects OG&E's funds flow from operations (FFO)-to-total debt to stabilize around 22% and total debt to EBITDA at 3.4 times (x).

While evaluating the ratings for OG&E, Fitch acknowledges the positive regulatory environment that the utility enjoys, the diversity and size of capital projects being undertaken, and the constructive regulatory mechanisms for recovery on those projects. OG&E has been quite successful in obtaining pre-approval and recovery for the capital projects it has undertaken through rate riders that minimize regulatory lag by permitting it to recover costs associated with the project upon completion before the next general rate case proceeding. The riders ensure recovery of capital, operating costs and a return on investment. Notable examples include riders for the Redbud acquisition, storm recovery, system hardening, Windspeed transmission line and OU Spirit Wind project. Recently, OG&E reached a settlement with all the intervenors on its smart grid application. It also has an application pending before the Oklahoma Corporation Commission (OCC) regarding pre-approval and rider recovery for the Crossroads Wind project, a 200 megawatt (MW) proposed wind farm in Oklahoma.

Fitch's financial projections for OG&E assume a 1%-1.5% growth rate in electric sales over the forecast period, continued control over O&M expenses, and constructive regulatory outcomes in the pending and future rate proceedings. It is Fitch's expectation that OG&E will not undertake any large capital investment without obtaining a pre-approval from OCC that ensures a clear recovery mechanism. Other favorable regulatory mechanisms if implemented, such as cash recovery of capital costs during construction work in progress, would be viewed as credit enhancing by Fitch.

Enogex's ratings are supported by strong cash flows generated by its existing portfolio of natural gas transportation, storage, gathering and processing businesses that reflect moderate business risk. The ratings reflect the success management has achieved in shifting its processing revenue toward more fixed-fee contracts and hedging a majority of its commodity exposure over the next two years. Volume of fixed-fee contracts in the processing segment has increased from 8% in 2006 to a projected 30% in 2010. Furthermore, a majority of commodity risk in its keep-whole and percentage of liquids contracts has been hedged for years 2010 and 2011, respectively, providing visibility to credit metrics. In addition, the curtailment of capex and O&M over the last two years has benefited cash flows in times of commodity stress.

Enogex's assets are strategically located in the Oklahoma and Texas Panhandle, two areas that are very strong for natural gas production. Gathering operations have remained strong and are forecasted to grow by 7% in 2010. The unhedged processing segment is expected to benefit from the recovery in natural gas liquids prices in 2010. Looking forward, it is Fitch's expectation that Enogex would continue to migrate its commodity linked contracts to fixed fee and/or hedge a majority of its commodity risk.

Fitch expects Enogex to generate free cash flow after known and committed capex and upstream dividend payments to the parent over the forecast period. Fitch views Enogex's affiliation with its parent, OGE Energy, positively. Management has run Enogex conservatively with the aim to generate consistent stable cash flows and maintain an investment grade profile.

Despite strong credit metrics, the 'BBB' IDR is appropriate for Enogex in Fitch's view given the company is exposed to relatively higher commodity risk beyond 2011, since a very small amount of processing margin has been hedged. In addition, management's past attempts to monetize its interest in Enogex induce a level of uncertainty regarding future strategy for the company that Fitch is mindful of. Fitch would be concerned if management were to pursue a riskier business model, debt financed expansion strategy, or disproportionately grow commodity sensitive, non-fee based businesses.

OGE's ratings are supported by upstream dividend payments from its subsidiaries, OG&E and Enogex, relatively low leverage, consistent credit quality over our forecast period and prudent management of commodity exposure. Fitch expects OGE to derive more than 72% of its consolidated operating income from regulated businesses in 2010 and this proportion is expected to increase over Fitch's forecast period given the scale of capital expenditure at the utility. In Fitch's estimate, another 23% of consolidated income over the next two years is derived from predictable, stable cash flow businesses at Enogex that constitute natural gas transportation, storage, gathering and processing hedged and fixed-fee contracts, leaving the balance (5%) exposed to commodity prices. OGE and its subsidiaries have access to short-term liquidity through $1.23 billion of revolving credit facilities, of which $0.84 billion is currently available. There are no maturities of long-term debt till 2014.

Fitch would be concerned if OGE takes on additional leverage to support the heavy capex program at its utility. Other concerns include management of commodity risk at its Enogex subsidiary and uncertainty around future transactions involving Enogex.

The Stable Outlook for OGE, OG&E and Enogex assumes that the electric utility and the midstream businesses will continue to perform well, and the sensitivity of cash flows and working capital needs to changes in commodity prices will remain low. The Stable Outlook also assumes that the proportion of regulated and non-regulated fee-based businesses will continue to increase as a percentage of the consolidated operating income.

What would lead to consideration of a negative rating action?

--Increase in the proportion of commodity sensitive non-regulated businesses or a change in hedging strategy that would increase company's exposure to commodity prices;
--Aggressive capital expenditure program at OG&E not supported by pre-approved regulatory riders;
--Pursuing a more aggressive business model at Enogex.

What would lead to consideration of a positive rating action?

--At Enogex, a long-dated hedged profile or higher proportion of fixed-fee businesses that improve predictability of cash flows.

Fitch has downgraded the following ratings:

Oklahoma Gas & Electric Company
--Long-term IDR to 'A' from 'A+';
--Senior unsecured febt to 'A+' from 'AA-'.

Fitch affirms the following ratings:

Oklahoma Gas & Electric Company
--Short-term IDR and commercial paper (CP) at 'F1';

--Outlook Stable.

OGE Energy Corp
--Long-term IDR at 'A';
--Senior Unsecured Debt at 'A';
--Short-term IDR and CP at 'F1';
--Outlook Stable.

Enogex LLC
--Long-term IDR at 'BBB';
--Senior unsecured debt at 'BBB';
--Outlook Stable.

Applicable criteria available on Fitch's website at 'www.fitchratings.com' include:

--'Corporate Rating Methodology' Nov. 24, 2009;
--'Credit Rating Guidelines for Regulated Utility Companies' July 31, 2007;
--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines' Aug. 22, 2007;
-- 'Utilities Sector Notching and Recovery Ratings' (March 16, 2010); and
-- Parent and Subsidiary Ratings Linkage (Fitch's Approach to Rating Entities within the Corporate Group Structure)' (June 19, 2007).

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Additional information is available at 'www.fitchratings.com'.

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EXHIBIT NO. OGE-23

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March 11, 2010

Assessing U.S. Utility Regulatory Environments

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Assessing U.S. Utility Regulatory Environments

*(**Editor's Note:** For our latest comments on regulated utility subsidiaries, please see "Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent," published March 11, 2010, on RatingsDirect.)*

The assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk. Each of the other four factors we examine--markets, operations, competitiveness, and management--can affect the quality of the regulation a utility experiences, but we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most. In our credit analysis, we evaluate regulatory risk on a company-specific basis. A utility management's skill in managing regulatory risk can in many cases overcome a difficult regulatory environment. Conversely, other companies can experience greater regulatory risk even with supportive regulatory regimes if management fails to devote the necessary time and resources to the important task of managing regulatory risk. Operating in a state with a regulatory structure that is conducive to maintaining credit quality will improve the chances for a utility to successfully negotiate the regulatory maze.

This commentary discusses our views on what constitutes a favorable regulatory climate. We then use those factors to create assessments of the regulatory environments in states that regulate the electric and gas utilities that we rate. (See the table at the end of this article.) Our intention is to provide a common base for our own analysis of regulatory risk and to better communicate to investors, issuers, and regulators how various elements of regulation can affect credit quality. The exercise is also expected to enhance our ability to evaluate management by highlighting instances where our opinion of a company's regulatory risk diverges significantly from the fundamental quality of the regulatory jurisdictions where it operates.

The assessments of relevant jurisdictions are based on quantitative and qualitative factors. Importantly, we make our assessments from a credit perspective. We plan to update them annually or when significant events occur that have an important impact on the regulatory climate in a particular jurisdiction. The new regulatory assessment information augments the methodology applied to regulated utilities today.

Our introduction of these regulatory assessments coincides with what we view as the increasing influence of regulatory matters on the rated utilities' risk profiles and greater credit market awareness of the importance of understanding the regulatory process. Our goal in explaining our views on regulatory practices and policies and their effect on Standard & Poor's analysis of the credit quality of utilities is to provide additional transparency to the market.

Background

State utility regulation is almost as old as credit ratings. Standard & Poor's predecessor, Standard Statistics Bureau, was formed in 1906, and the first state utility commissions, as we know them today, appeared in 1907. Regulation has always been a factor in Standard & Poor's analysis of utility ratings, but its importance to our analysis has shifted with industry trends over time.

Before the 1970s, regulators presided for the most part over stable or decreasing rates as economic growth, rising consumption, and economies of scale drove costs down. The advent of inflation, rising and volatile fuel costs, and nuclear power missteps led to higher rates and, in our view, greater regulatory influence on credit quality during the 1980s. Restructuring in the natural gas and then the electric industries marked the 1990s and the first years of the new millennium, and the importance of regulatory issues in our analysis again started to subside. In our view, we are now in another era of increasing and unstable costs and some semblance of a return to traditional utility regulation. Consequently, the quality of regulation is at the forefront of our analysis of utility creditworthiness.

We have historically focused on regulatory risk on a company-specific basis. Nothing in what follows will change that approach. Utility commissions regulate diverse industries and adopt different approaches to different types of businesses. Treatment of utilities within the same industry can vary significantly in the same jurisdiction. The quality of the regulation experienced by a company is often the product of the company's management and business strategy as much as its regulators. The regulatory climate assessments only serve as a baseline of our opinion on the fundamental attitude of a jurisdiction toward the credit quality of the utilities in that state, and they are the starting point for Standard & Poor's analysis of the regulatory risk of each rated utility. Our goal is to achieve greater consistency and continuity in utility ratings.

Assessing Regulatory Jurisdictions

We assess jurisdictions on one basic attribute--the fundamental approach to controlling utility rates--and then in three major categories. The resulting assessments are based primarily on various measures of regulatory risk that are discussed briefly below. With respect to qualitative factors, we look for long-term, historical characteristics of the jurisdiction, as well as transient regulatory and political developments.

The foundation of our opinion of the regulation in a jurisdiction is the degree to which competitive market forces are allowed to influence rates. In order of credit-friendliness, a state will rely either on full cost-based regulation for all components of the utility bill, market-based mechanisms for generation, and (more rarely) retail markets, or a hybrid of the two to control the amount charged and the terms on which that service is offered. It may surprise some to learn that we consider a hybrid setup, which in most cases exists because the transition to some sort of competition has stalled, to harbor more risk for bondholders than a system that is committed to letting market prices set a major part of the customer's bill.

The risk inherent in the market-based model is straightforward: the price for electricity can be more volatile when based on a market than when it is based on embedded costs, and regulators are apt to resist full and timely recovery when changes in generation costs are abrupt and substantial (and perhaps misunderstood). The risks in a hybrid or transitional model are less apparent, but, in our opinion, potentially more significant. First, we consider the uncertainty of the timing of reaching the end state--and what that end state will look like--to be a negative factor from a credit perspective. Second, in some cases, the hybrid model may result in a "lower-of-cost-or-market" approach that allows generation rates to reflect one or the other at different times depending on which one suits ratepayers best. A utility and its bondholders may then face a prolonged period of potential exposure to market risk (the downside) with little or no opportunity to participate in the benefits of competition (the upside of greater returns).

After identifying the fundamental regulatory paradigm, our analysis turns to factors that influence the utility's business risk climate in the jurisdiction. The factors fall into three broad categories: ratemaking, political environment, and financial stability. Broadly speaking, the ratemaking and financial stability factors influence our assessments more than the paradigm and political factors.

Ratemaking Practices And Procedures

The main, and often the most contentious, task of a regulator is to set the rates a utility may charge its customers. We analyze specific rate decisions as part of the surveillance of each utility. Our regulatory assessments focus on the jurisdiction's overall approach to setting rates and the process it uses to conduct and manage base rate filings. Practices pertaining to separate tariff clauses for large expense items are examined in the third category of the analysis (see below). In this part of the assessment, we concentrate on whether established base rates fairly reflect the cost structure of a utility and allow management an opportunity to earn a compensatory return that provides bondholders with a financial cushion that promotes credit quality.

Notably, the analysis does not revolve around "authorized" returns, but rather on actual earned returns. We note the many examples of utilities with healthy authorized returns that, we believe, have no meaningful expectation of actually earning that return because of rate case lag, expense disallowances, etc. Although, in general, the absolute level of financial returns is less important to our analysis than how that return is earned, we recognize that, all else being equal, higher earned returns translate into better credit metrics and a more comfortable equity cushion for bondholders. A regulatory approach that allows utilities the opportunity to consistently earn a reasonable return is a positive factor in our view of credit quality.

The rates of return and capital structures used to generate the revenue requirement in rate proceedings may not be the primary focus of the assessment, but those and other decisions made in the ratemaking process are still noted. We consider those decisions to be potential signals from regulators on their attitude toward credit quality. We believe that the capital structure in particular is a handy and direct indication from the regulator as to whether or not creditworthiness is an important consideration in its deliberations when setting rates. Obviously, any pronouncements from a regulator that explicitly address credit ratings or ratemaking practices that incorporate credit-minded adjustments (e.g., the use of double-leveraged capital structures or off-balance-sheet debt-like obligations) are considered in the Standard & Poor's assessment.

We analyze the issue of "regulatory lag" in a comprehensive manner and not just as a matter of the efficiency of the regulator in completing rate cases. As part of this analysis, we evaluate the timeliness of rate decisions, coupled with an evaluation of the test year. In addition, we take into account the timing of interim rates, and other practices that affect the appropriateness of rates periodically established by the regulator. We do not view the issue of regulatory lag as an intermittent concern, consequential only during times of acute inflation or rising capital spending, but as a consistent part of our credit analysis. Accordingly, in our regulatory assessments we focus on whether the regulator efficiently prosecutes rate requests and bases its decisions with respect to rate setting on the most current information.

In our view, the prevalence of rate case settlements is not necessarily an important credit consideration. Although the common assumption among market participants seems to be that a settlement must be in the best interest of a utility, we believe this assumption disregards the possibility that management will sometimes make decisions based on its effect on earnings at the expense of cash flow considerations. This does not mean we dismiss the ability of stipulations to reach a fair resolution of difficult matters that help regulators issue timely and constructive rate decisions. It just means that frequent settlements do not, in our view, directly lead to a conclusion that the regulatory environment in a state enhances credit quality.

An important policy-related issue outside of individual rate cases that falls under this part of the assessment is the regulatory oversight of large capital projects with long lead times that carry out-sized risks to a utility and its bondholders. In our opinion, practices such as legislative or regulatory recognition of the need for pre-approval of such endeavors, periodic reviews that substantively involve the regulator in the progress of the project, and rolling prudence determinations during construction can reduce the general level of risk associated with a utility committing substantial capital well in advance of the rate proceeding that results in the project being placed into rate base. Before committing to such projects, a resource-procurement process that uses objective guidelines to evaluate competing proposals to meet load obligations and keeps the regulator informed and involved in the decisions can, in our view, help to reduce the risk of subsequent disallowances. If the jurisdiction has an Integrated Resource Plan or similar mechanism that includes the participation of many parties and is used to definitively establish the need for new generation, we consider credit risk to be further diminished.

One more factor that we examine in this part of the analysis is whether a jurisdiction employs nontraditional ratemaking practices. Examples of what we may view to be potentially credit-enhancing regulatory mechanisms include weather normalization and incentive ratemaking. We believe that the beneficial effect on credit quality of a tariff clause that smooths out cash flows that can vary with outside influences like weather is self evident. The benefits of incentives incorporated into the regulatory regime may be less clear. Well-designed incentives can be at least credit neutral. A moderate amount of incentives can be credit supportive. We generally view incentive provisions (whether tied to cost control, reliability, or operational performance) as being beneficial for credit quality if they are linked to fair and objective benchmarks. Incentives that lack some or all of those features, such as a plain, long-term rate freeze, can be, in our opinion, detrimental to credit quality.

Political Insulation

The role of politics in utility regulation is often misunderstood. In most jurisdictions, legislatures created regulatory commissions and invested them with the power to set and enforce utility rates and service standards. Regardless of how a regulatory commission is statutorily organized, its function is to set and regulate rates and service standards with due regard not only for the interests of those who advance the capital needed to provide safe and reliable utility service but for other constituents as well. In this regard, bondholders should recognize that the setting of utility rates invariably reflects political as well as economic factors. Therefore, the potential for political considerations to affect utility regulation can be a key determinant when we assess a regulatory jurisdiction.

A primary factor in this part of our assessment is the method of selecting utility commissioners. In some jurisdictions, the governors appoint regulatory commissioners. In others, the same voters who pay utility bills directly elect commissioners. The regulatory risk associated with that model can sometimes be managed, but there is an inherent level of risk in elected regulatory bodies that we reflect in the assessment. Standard & Poor's also analyzes the track record of the involvement of the executive branch or the legislature in utility matters, and the relative visibility of utility issues in the political arena.

The ability of a regulator to deliver sound, fair, and timely rate decisions and set prudent regulatory policies that assist utility managers in managing business and financial risk can be affected by the overall atmosphere that it operates in. The tone can be set by the governor or legislature, the history and tradition of independence accorded to the regulatory body, and the behavior of important constituent groups that intervene in utility proceedings.

Cash Flow Support And Stability

The final set of factors in our assessment of regulatory environments is arguably the most important. The phrase "cash is king" can be overused, but it does highlight an essential part of the credit analysis. A regulatory jurisdiction that recognizes the significance of cash flow in its decision making is one that will appeal to bondholders. Generating cash is a function of the actions of utility management, but the regulator can supply (or withhold) the tools that can affect the company's essential ability to actually realize the intended level of cash flow.

The most prominent factor in this part of the analysis is the application of separate tariff provisions for major expenses such as fuel and purchased power. The timely adjustment of rates in response to changing commodity prices and other expenses that are largely out of the control of utility management is a key component of a credit-enhancing regulatory jurisdiction. We analyze the quality of special tariff mechanisms to determine their effectiveness in producing the cash flow stability they are designed to achieve. The frequency of rate adjustments, the ability to quickly react to unusual market volatility, and the control of opportunities to engage in hindsight disallowances of costs could affect the analysis almost as much as whether the tariff provisions exist at all. The record of disallowances plays a part in the regulatory assessment.

The commission's policies and oversight covering hedging activities may also be a factor in this part of the review if a utility has sought regulatory approval. For utilities that attempt to manage commodity risks, we look for a clearly-stated hedging policy and a track record of activity that conforms to that policy. The responsibility for communicating the policy and demonstrating the prudence of the hedging activity rests with the utility, but the initial response to a hedging program and the history of the regulator's treatment of the results of the program could influence our assessment.

Regulators can employ other ratemaking techniques that promote stable cash flows. We consider a commission's decisions on rate design in assessing its attitude on credit quality. For example, we take into account the relative size of the typical monthly customer charge, a decoupling mechanism that severs the direct relationship between revenues and customer usage, or other rate design features that bolster credit quality.

Especially during upswings in the capital expenditure cycle, such as we are experiencing now, a jurisdiction's willingness to support large capital projects with cash during the construction phase is an important aspect of our analysis. This is especially true for ventures with big budgets and long lead times, such as baseload coal-fired or nuclear power plants and high-voltage transmission lines that are susceptible to construction delays. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were considered extraordinary measures for use in unusual circumstances, but in today's environment of rising construction costs and possible inflationary pressures, cash flow support could be crucial in maintaining credit quality through the spending program.

Jurisdictional Assessments

The table below shows Standard & Poor's assessments of regulatory jurisdictions. The category titles are designed to communicate one other important point regarding utility regulation and its effect on ratings. All categories are denoted as "credit-supportive". To one degree or another, all U.S. utility regulation sustains credit quality when compared with the rest of corporate ratings at Standard & Poor's. The presence of regulators, no matter where in the spectrum of our assessments, reduces business risk and generally supports all U.S. utility ratings.

Regulatory Jurisdictions For Utilities Among U.S. States

Most credit supportive	More credit supportive	Credit supportive	Less credit supportive	Least credit supportive
	Alabama	Arkansas	Louisiana	Arizona
	California	Colorado	Maine	Delaware
	Florida	Connecticut	Missouri	Dist. of Columbia
	Georgia	Hawaii	Montana	Illinois
	Indiana	Idaho	New York	Maryland
	Iowa	Kansas	Oklahoma	New Mexico
	South Carolina	Kentucky	Rhode Island	
	Wisconsin	Massachusetts	Texas	
		Michigan	Utah	
		Minnesota	Vermont	
		Mississippi	Washington	
		Nevada	West Virginia	
		New Hampshire	Wyoming	
		New Jersey		
		North Carolina		
		North Dakota		
		Ohio		
		Oregon		
		Pennsylvania		
		South Dakota		
		Virginia		

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company) **Docket No. ER11-___-000**

AFFIDAVIT

State of Oklahoma

County of Oklahoma

I, DONALD R. ROWLETT, being first duly sworn, depose and state that I am the witness identified in the foregoing Direct Testimony and Exhibits, that I prepared the testimony and exhibits and am familiar with their content, and that the facts set forth therein are true and correct to the best of my knowledge, information and belief.

Donald R. Rowlett

Donald R. Rowlett

Subscribed and sworn before me this 17th day of February, 2011

Kerry G. HamiltonCoyle

Notary Public # 01009409

My commission expires: July 6, 2013

ATTACHMENT 4

ATTESTATIONS AS REQUIRED BY 18 C.F.R. § 35.13(D)(6) (2010)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Oklahoma Gas and Electric Company	)))	Docket No. ER11-__-000

ATTESTATION

I, R. Sean Trauschke, being duly sworn, attests that he is **Vice President, Chief Financial Officer**for Oklahoma Gas and Electric Company, and that, to the best of his knowledge, information, and belief, the cost of service statements and other supporting data submitted as part of this filing are true, accurate, and current representations of the utility's books, budgets, or other corporate documents.

R. Sean Trauschke

R. Sean Trauschke
Vice President, Chief Financial Officer

Subscribed and sworn before me, this 17th day of

February, 2011.

Kelly G. Hamilton-Conyer
Notary Public # 01009409

My Commission expires:

July 6, 2013