BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of and Investigation into	)	
Southwest Power Pool Cost Allocations and	)	File No. EO-2011-0134
Cost Overruns	)	

SOUTHWEST POWER POOL, INC.'S COMMENTS IN RESPONSE TO THE COMMISSION'S ORDER OPENING AN INVESTIGATION INTO SOUTHWEST POWER POOL COST ALLOCATIONS AND COST OVERRUNS

COMES NOW, Southwest Power Pool, Inc. ("SPP"), by and through its counsel, and hereby submits its Comments in response to the Public Service Commission of the State of Missouri's ("Commission") Order Opening An Investigation into Southwest Power Pool Cost Allocations and Cost Overruns ("Order") issued on November 23, 2010, opening the above-styled docket.

Southwest Power Pool is a Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP currently has 61 members in nine states and serves more than 6 million households in a 370,000 square-mile area. SPP's members include 14 investor-owned utilities, 9 municipal systems, 12 generation and transmission cooperatives, 4 state agencies, 7 independent power producers, 10 power marketers and 5 independent transmission companies. As an RTO, SPP is a transmission provider currently administering Transmission Service over 48,874 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.

SPP desires to respond to the Commission in a helpful manner and provide information to address the issues raised by the Commission. In the Order, the Commission expressed concern about recent developments involving SPP and the selection and funding of large dollar amount interstate electric transmission projects and the costs that will be borne by the Missouri ratepayers of Kansas City Power & Light Company ("KCP&L"), KCP&L Greater Missouri Operations Company ("KCP&L-GMO"), and The Empire District Electric Company ("Empire"), all of which are members and transmission service customers of SPP. In response to this Order, and in an effort to assist the Commission in its investigation, SPP will provide further information and clarification on the development of procedures for addressing cost estimation, cost variances and novations, as well as the overall value of SPP, benefits realized by Empire and the implications of withdrawal.

I. Background and Overview

The Commission's Order directs investigation into several issues related to SPP's transmission planning processes and cost allocation procedures. The Order sets forth specific questions and concerns regarding the processes used to select, fund and assign cost responsibility for new transmission projects within the SPP footprint.

As part of the ordered investigation, the Commission notes the need for closer examination of the cost-benefit analyses used by SPP in selecting the "Priority Projects" and, specifically, the weight/value properly accorded to a project's "qualitative" benefits. The Commission emphasizes the importance of ensuring "...that Missouri customers are not inappropriately subsidizing economic benefits to other SPP customers," and orders the development of a report detailing the "costs and benefits of SPP membership for The Empire District Electric Company." The Commission cites to the recent cost estimate increases for the Priority Project in raising questions concerning the reliability of SPP's cost-estimation analyses and, among other inquiries, invites consideration of whether a novation – i.e., the procedure by which a Transmission Owner is permitted to transfer construction rights and all legal and financial obligations to a third party – may be contributing to project cost estimate increases.

The primary purpose of these comments is to document the steps being taken by SPP to address the issues raised in the Commission's Order. As detailed herein, many of these very issues are currently being considered by SPP's Strategic Planning Committee ("SPC") and Transmission Working Group ("TWG") in response to recommendations submitted by the Regional State Committee ("RSC") to the SPP Board of Directors ("SPP Board").[1] The recommendations, which followed a lengthy discussion regarding recent project cost estimate increases and possible refinements to current cost estimation and planning procedures, provide as follows:

> MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
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> MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011.
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> MOTION 3: RSC recommends that SPP consider establishing design and construction standards for transmission projects at 200KV and above that are regionally funded.
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> MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.[2]

The framing of the RSC motions reflects a clear commonality of issues between ongoing SPP initiatives and the Commission's recently opened investigation. It is therefore appropriate that the Commission proceed with its investigation in coordination with SPP's concurrent examination of the same core issues. In that regard, the Commission is advised that, on December 3, 2010, SPP staff presented whitepapers to the SPC setting forth preliminary

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1 The RSC adopted the motions on October 25, 2010. On October 26, 2010, the SPP Board of Directors approved the motions and assigned to the SPC and TWG responsibility for consideration of the issues raised in the RSC motions.

2 The RSC also adopted a fifth motion, which was addressed to the Cost Allocation Working Group ("CAWG") and provides as follows: "Motion 5: Move that the CAWG study various methods on how costs that exceed some standard can be addressed with different cost allocation mechanisms and recommend strategies to the RSC." The CAWG is in the process of developing a response.

responses to the RSC recommendations.[3] Further development of the steps outlined in these whitepapers will necessarily entail consideration of the project-estimation, funding and cost-benefit matters raised in the Commission's Order. Moreover, to the extent these efforts result in more rigorous cost estimation protocols, changes in the treatment of cost variances, or overall improvements to the planning process, the evaluation of RTO membership benefits, both generally and in the specific context of Empire, could be materially affected.

SPP, including staff, stakeholders, committees, and working groups, is committing significant resources to addressing the RSC recommendations. While these efforts are in their early stages with any procedural and/or policy changes ultimately subject to SPP's stakeholder review process, they are being pursued on a high-priority basis. The issues implicated by the RSC recommendations bear directly on the questions posed in the Commission's order. Accordingly, SPP urges that the Commission conduct its investigation in an open and coordinated fashion, mindful that the ongoing efforts within the SPP stakeholder process may helpfully inform the Commission in its consideration of regional transmission planning issues within the SPP RTO.

II. Discussion

A. Cost Estimation Procedures and Variances

1. SPP's Planning Role and Responsibilities Provide a Platform for Regional Solutions to Cost Estimation and Variance Issues.

SPP is aware of the issues related to cost estimation and variances and is actively working both internally as well as with stakeholders to address these issues. However, to

[3] The whitepapers presented by SPP staff at the December 3, 2010 SPC meeting setting forth preliminary reactions to the RSC recommendations are attached hereto as Exhibit 1 and are also available at: http://www.spp.org/publications/SPCAGD&BKGD120310.pdf.

provide context for these issues, and the framework for potential reforms, a basic understanding of SPP's current transmission planning processes is in order.

Under the SPP Membership Agreement and the SPP Open Access Transmission Tariff ("OATT" or "Tariff"),[4] the Transmission Owners in SPP have ceded their transmission planning responsibilities to SPP. However, the Transmission Owners remain responsible for actual construction of transmission facilities and for developing their individual revenue requirements. Section 3.3 of the SPP Membership Agreement describes SPP's planning function as follows:

> [SPP is] responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate state authorities, including the Member's governing board where it serves as that authority.

Section 3.3 of the Membership Agreement further acknowledges the recognized division of interests between the transmission planning function of SPP as the Transmission Provider and the financial and construction responsibilities and ownership interests of the Transmission Owners. Attachment O, Section VI (1), of SPP's OATT reinforces this distinction, stating that the "Transmission Provider shall not build or own transmission facilities. The Transmission Provider, with input from the Transmission Owners and other stakeholders, shall designate in a timely manner within the SPP Transmission Expansion Plan ("STEP") one or more Transmission Owners to construct, own, and/or finance each project in the plan."

Thus, responsibility for project construction and project management rests with SPP's Transmission Owners and is managed through the Transmission Owners' internal processes and interactions with appropriate regulatory authorities. That is not to say, however, that these issues cannot or should not be addressed on a regional basis as part of the evolution to regional cost

[4] The Membership Agreement and OATT are available at: http://www.spp.org/section.asp?group=215&pageID=27

allocation. To the contrary, changes in cost allocation, project cost estimates and variances are not only a concern of the Transmission Owner building the facilities, but potentially impact other SPP Transmission Owners that may share in the costs of such facilities and SPP Transmission Service Customers to whom these costs are allocated through rates. Accordingly, and as next discussed, SPP is actively working to ensure that costs are shared fairly amongst the members and customers. SPP reinforced its historical commitment to equity in cost allocation through Tariff revisions related to Unintended Consequences approved by FERC as part of the Highway/Byway cost allocation methodology filing.[5] These Tariff revisions provide for more frequent and more rigorous reviews for Unintended Consequences in cost allocation, as well as including a provision allowing a member company to go directly to the Markets and Operations Policy Committee to request relief if it believes it has an imbalanced cost allocation.[6]

SPP would like to emphasize that the Highway/Byway cost allocation methodology, as all SPP cost allocation methodologies, is the responsibility of the RSC and was approved by the RSC. A more complete history and explanation of the Highway/Byway cost allocation methodology is included in Appendix A.

2. <u>Efforts Are Ongoing to Develop Regional Enhancements to Address Cost Estimation and Variance Issues.</u>

(a) Improved Transparency Has Brought Needed Attention to Project Cost Variances.

SPP staff is currently engaged in the examination of project cost estimate variances and potential improvements to the process used to create the cost estimates. This examination by SPP staff follows the recommendations of the RSC to "review …the significant cost increases and/or overruns of transmission projects that are regionally funded" and to "…evaluate how cost

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[5] A more detailed discussion on the history of Unintended Consequences is set forth in Appendix A, hereto.

[6] Tariff, Attachment J, § III.D.4.ii.

estimates are established for transmission projects before Cost Benefit Analysis are performed."[7] To date, a preliminary "whitepaper" analysis has been prepared, with further plans in place to develop a more comprehensive examination of these issues.

It is important to note that the current discussion, which responds to the increase in particular transmission cost estimates for Priority Projects, is a product of the openness and transparency of the SPP planning processes and the regionalization of cost allocation. In the past, transmission cost estimates would have tended to remain internal to each member utility, subject only to the utility's internal review and any applicable obligations to regulatory authorities. Adjustments in these initial pre-construction cost estimates would have been handled completely within the utility's management and processes and would not have been publically released.

SPP's Attachment O Transmission Planning Process, including Balanced Portfolio, Integrated Transmission Planning ("ITP") process and Priority Projects, provides transparency into the early stages of the transmission planning process, enabling affected stakeholders access to project cost estimation information.[8] This, of course, is hardly a complete response to the cost estimation issue; however, it does demonstrate that project cost variances are not necessarily a new occurrence.

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7 These recommendations were reflected in the RSC motions that were adopted at the October 25, 2010 SPC meeting and approved by the SPP Board on October 26, 2010. See RSC Motion 1 and RSC Motion 4.

8 A comprehensive discussion of the evolution of SPP's cost allocation methodologies, including the market and regulatory changes that prompted SPP to modify its allocation and planning procedures, is contained in Appendix A, hereto. Suffice to note that the proper allocation of new facility costs is, as the FERC has recognized, more "art than science" and that allocation principles that may be appropriate in one market/regulatory/operational environment may be inappropriate in another. For that reason, SPP has periodically modified the manner by which new facilities are priced into the market, with all such proposals being vetted through the stakeholder process and presented to FERC for comment, review and approval.

(b) Proposals Are Currently Being Developed to Standardize Cost Estimation Procedures.

It seems self-evident that improvements to the cost estimation process could reduce the incidence of unexpected project cost variances. Accordingly, to obtain and ensure consistency in the development of cost estimates, SPP staff and stakeholders are working to create a standardized and transparent process for generating project estimates.

While these efforts are currently in their formative stages, the objective is to formulate specific recommendations that will then be vetted through the SPP stakeholder processes.[9] The anticipated end-product should be a significantly enhanced cost estimation process with greater latitude for variance in the early planning and screening stages and tighter variance controls as projects progress toward SPP Board approval and the issuance of Notifications to Construct ("NTCs"). Consideration is also being given to imposing more rigorous scrutiny to costs outside the variance band and assigning costs deemed to be excessive to the responsible cost zone rather than regionally.

At the SPC meeting on December 3, 2010, presentations were made by SPP staff and by Mr. Kip Fox on behalf of SPP's Transmission Owners;[10] both presentations are attached hereto as Exhibits 2 and 3, respectively. While there were some differences in the details of the proposals, both set forth specific objectives and processes that would allow project cost estimates to evolve and become more refined as projects move from conceptual to construction, with multiple points in the process where cost estimates would be updated and subjected to increasingly higher levels of scrutiny and accuracy.

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[9] Resulting changes requiring tariff modifications would be filed with FERC.

[10] The Transmission Owners involved in the concept development of and supporting the Transmission Owner Proposal were: American Electric Power, Oklahoma Gas & Electric Company, Westar Energy, Inc., XCEL Energy—Southwestern Public Service Company, Kansas City Power &Light, Sunflower Electric Power Corporation, Western Farmers Electric Cooperative, Nebraska Public Power District, Empire District Electric Company, Midwest Energy, Inc., Lincoln Electric System, and City of Springfield, Missouri.

SPP staff's proposal includes three stages, with each stage having progressively tighter requirements for cost estimate accuracy and detail of data. In stage 1, when projects are first conceived, cost estimates will be generated by SPP staff using a generic cost estimation tool. The tool will be developed in conjunction with the TWG and will include generic cost data such as cost per mile for specific voltage levels, substation cost estimates, and cost modifiers to account for regional differences, terrain, urban/rural areas, and other considerations. This will allow preliminary estimates to be more readily developed for the purpose of screening large numbers of potential projects and selecting suitable candidates for more detailed study. The output of this initial estimation tool will be a table showing the total cost estimate for each project being considered as well as all of the information used in developing the cost estimates. The availability of this information should simplify the identification of variations in cost estimates and why such variations exist. On an annual basis, SPP staff and the TWG will update the cost data contained in the estimating tool.

Stage 2 of SPP staff's proposal begins after the initial project screening is completed and the list of potential projects has been narrowed to those most likely to be selected. The incumbent Transmission Owner of each project will review and provide a more rigorous assessment of the stage 1 cost estimates to ensure more accurate data is used for subsequent analyses in the selection of projects. Any variances between the stage 1 and stage 2 cost estimates must be accompanied by a detailed explanation of the variance. While this estimate is still considered to be a high-level cost estimate, it is expected to be within a +/-50% band of final construction costs.

Stage 3 of SPP staff's proposal requires further refinement of project cost estimates after the above-referenced analyses are completed but before a final report is submitted to stakeholders and the SPP Board for approval and subsequent NTC issuance.[11] As currently proposed, the incumbent Transmission Owner will be required to submit a completed Standardized Cost Application ("SCA"), which is expected to be a very detailed estimate within a +/-25% band of final construction costs. The SCA will include, among other things, a detailed explanation of variances between the stage 2 and stage 3 estimates.

As explained above, development of the cost estimation procedures is still a significant work in progress. The whitepaper presented by SPP staff served to begin the dialogue and to put in place a framework for continued analyses. SPP commits to provide updates to the Commission as these procedures continue to develop.

(c) Improved Management of Cost Variances Is Under Active Consideration within SPP.

Project cost variances are not a new problem, nor are they unique to the SPP RTO. To the contrary, the Commission has repeatedly dealt with the issue of cost increases and overruns, generally applying a "prudence standard" as the basis for determining a utility's right to recover cost increases and overruns.[12]

SPP's current process tracks project costs and in-service dates for projects that have received an NTC. The Transmission Owner is required to submit quarterly updates of cost estimates and the expected in-service date. These updates are incorporated into a quarterly report that is submitted to the SPP Board/Members Committee, the Markets and Operations Policy Committee ("MOPC") and the RSC. Currently, project developers are required to submit

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[11] Projects that receive an authorization to proceed ("ATP") instead of an NTC will not be required to have a stage 3 estimate. ATPs are discussed in greater detail in Appendix A.

[12] See, e.g., *Union Electric*, 27 Mo. P.S.C. (N.S.) 183 (1985) and *Union Electric*, Case No. ER-2007-0002, Report and Order (May 22, 2007).

justification for variances when a cost estimate has increased by more than 20% since the previous estimate.[13]

SPP recognizes modification to the current process is needed to ensure that all variations in cost estimates are monitored with sufficient scrutiny. In this regard, SPP staff presented its initial whitepapers at the SPC meeting on December 3, 2010, proposing a structured procedure to address variances in estimated costs. The staged procedure for developing progressively more refined cost estimates is, as described above, an important component of this process. In addition, other management tools are being considered to minimize the occurrence of, and more effectively respond to, variances in cost increases and decreases.

For example, one proposal being advanced is to utilize the stage 3, or "NTC Project Estimate" ("NPE"), as the baseline for project tracking. In other words, this estimate would serve as the reference point from which all cost variances would be measured throughout the project tracking process and would be the comparative basis for purposes of determining the percentage of variance of estimate updates.

It has also been proposed by SPP staff that a Transmission Owner for a project that has an NPE in excess of $5,000,000 be required to submit updates for that project on a monthly basis, whereas projects under $5,000,000 will require updates on a quarterly basis. These updates would consist of a detailed cost breakdown that mirrors the original SCA, and include comments explaining any variances. Comments from the Transmission Owner would include relevant information regarding any sunk costs, an explanation for the revised cost estimate, and comments as to whether the project should continue. If the cost variance is outside the +/- 25% band for the NPE, the project will be reviewed by an SPP working group.

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[13] Decreases in cost estimates are also tracked, but there is currently no requirement for submission of a justification.

SPP staff's proposal envisions that reevaluation of a project by the working group will be based on data and information from both the Transmission Owner and SPP staff, including the original SCA, project tracking data updates, and any comments from SPP staff or the Transmission Owner related to the variances. Such reevaluation would include an analysis of the cost estimate variances and whether the variances are reasonable and appropriate for regional funding or more properly allocated on a zonal basis. The working group may recommend a restudy, if it deems that such is needed based upon the information it is presented with respect to the variances.[14]

Pursuant to the initial proposal by SPP staff, the working group would submit a quarterly report to the SPP RSC and SPP Board/Members Committee regarding the projects it has reevaluated. This report would include the rationale provided for each cost estimate variance as well as comments from the working group recommending whether such a change is reasonable and appropriate for regional funding. If not, the recommendation will include a proposal for further action by the SPP Board/Members Committee. Initial discussions on this matter have included suggestions that such changes that are not reasonable or not appropriate for regional funding would be assigned zonally.

A project's cost estimate may increase by such magnitude that alternative projects should be reconsidered. SPP staff has proposed that all of the following conditions must be met in order to require a restudy:

(i) Latest cost estimate must exceed $10,000,000;

[14] It is important to note that SPP staff recognizes there may be instances where resetting the baseline would be prudent. The working group would determine if and when to reset the baseline cost estimate. Should a baseline cost estimate be reset, the original NPE will still be retained as a monitoring tool.

(ii) If the benefit/cost ratio was the rationale for the project, then the b/c must have changed to be less than 1;

(iii) Actual construction of the project has not yet started; and

(iv) The cost must have increased 30% from the baseline.

If a restudy is required, SPP staff will develop a study scope for approval by the TWG or Economic Studies Working Group ("ESWG"). The resulting study analysis would follow the typical stakeholder process by moving through the appropriate stakeholder working groups and finally to the Board of Directors/Members Committee for final action on whether the original NTC should be revoked. Should the NTC be revoked, an NTC for the alternative project may be approved for issuance.

As the foregoing summary demonstrates, significant time and effort has been devoted by SPP to improving cost estimation procedures and minimizing/managing cost variances. Although much work remains to be done, allowing these efforts to run their course will provide the Commission valuable information concerning these issues and potentially resolve, in whole or part, concerns raised in the Commission's Order.

B. Novation

The Commission's Order raises concerns about the right of novation under SPP's current planning process and the potential that exercising this right could be contributing to increases in project cost estimates. As discussed below, while SPP believes that there are benefits in novations, a comprehensive examination of this issue is currently being undertaken to determine whether, and to what extent, the exercise of a Transmission Owner's novation rights may affect costs.

As a preliminary matter, it is important to distinguish between novations and assignments, as the terms are not interchangeable. In fact, novation and assignment represent alternative options available in cases where a Transmission Owner cannot or does not want to construct a transmission project. An assignment, as permitted by the SPP Membership Agreement, allows the designated Transmission Owner to transfer responsibility for construction of a project, but does not relieve the Transmission Owner of the financial or legal obligation to construct the project in accordance with the NTC.

In contrast, a novation allows the designated Transmission Owner to transfer all legal and financial responsibilities under the SPP Membership Agreement for the timely construction of the project to an entity that is or agrees to become qualified under SPP's process and bound to construct the project as a Transmission Owner under SPP's OATT and SPP Membership Agreement. FERC has specifically held that novation is an appropriate part of the SPP OATT and has rejected arguments seeking to limit novation rights, in whole or part.[15]

There are numerous factors that can result in the decision to assign or novate a transmission project. Funding or financing limitations, increased costs of financing and/or an inability to timely construct the project could prompt a Transmission Owner to assign or novate its responsibilities to a third party.

In an effort to address the concerns that have been raised with respect to novations, SPP staff has presented a multifaceted proposal providing increased transparency through the regional planning and cost allocation process. Specifically, SPP staff has suggested that it provide proposed novations and supporting analysis to the MOPC for review and approval as well as to

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15 *Southwest Power Pool, Inc.*, 128 FERC ¶ 61,018 at P 22.

the RSC for review, before consideration by the SPP Board/Members Committee for approval to file with FERC.

C. Design and Construction Standards

The RSC has recommended SPP consider establishing design and construction standards for transmission projects at 200kV and above that are regionally funded. SPP staff has made an initial proposal in an effort to provide a consistent and economic construction standard that can be implemented by all Transmission Owners in the SPP transmission system. Discussion of design and construction standards is still in its infancy. There are many issues, including legal and liability implications this may impart on SPP, which must be further developed prior to determining any type of construction standard, and whether it is an appropriate and/or a strategic direction desired by the membership.

In order to bring uniformity and economies of scale to regionally funded transmission projects, SPP proposes to develop and maintain design and construction standards. This effort will provide consistency in the bulk transmission system and enhance reliability while reducing compatibility issues by having standard components used by all Transmission Owners and transmission system builders. Ultimately, these standards will be established through a collaborative effort based upon the best practices of Transmission Owners, with the long term goal of better managing construction costs. The final draft of these standards will be submitted to the TWG and then the MOPC for its approval.

Although construction costs may vary based upon location and other factors, establishing standards on the basis of best practices can provide guidelines and set expectations. The initial focus of developing construction and design standards will be on the components that have the greatest variability in cost. The major components currently under consideration for the establishment of regional standards include:

(i) conductor size;

(ii) minimum ampacity value;

(iii) fiber optic ground wire construction standards;

(iv) structure and wooden pole construction specifications;

(v) foundation construction standards;

(vi) substation control room construction standards; and

(vii) insulation and insulation hardware construction specifications.

Although the development of construction and design standards is still in the initial stages, and the breadth of possible standards is unknown, SPP staff has preliminarily suggested it would interpret and apply the regional standards and track projects to ensure the standards are being followed for regionally funded projects. In some circumstances, deviation from the regional standard may be necessary; any requests for deviation would need to be submitted to SPP staff for consideration.

SPP staff's Design and Construction Standards Whitepaper proposed several examples of transmission and substation design standards, including standards for breaker configuration, terminal equipment minimum rating, transmission line design, and minimum conductor sizing. Tables and diagrams for each of these topics were provided in the whitepaper, which is attached hereto as Exhibit 1.

D. Costs and Benefits of RTO Membership and Implications of Member Withdrawal

The Commission's Order raises questions regarding the relative costs and benefits of RTO membership, generally, and in the specific context of Empire. Among other things, the

Commission seeks additional information to better understand the value of "qualitative" benefits of RTO membership and the cost impact to SPP's Missouri customers.

1. Overview of RTO Benefits vs. Costs

To address these issues, SPP has developed an estimate of the annualized value that is created through RTO membership at the aggregate SPP footprint level. The SPP Aggregate Value Proposition starts with an estimate of the value currently being realized by SPP members through the collaboration of all members, facilitated and administered by SPP staff. The additional future value improvement is also estimated based on the completion of defined market development and transmission expansion projects. The analytical framework for this estimate utilizes an economic comparison of two cases. The "base case" assumes that SPP does not exist and all current members operate on a standalone basis without collaboration of any sort. The "base case" is compared to the "change case" that reflects the SPP membership collaboration as it exists today. The SPP methodology reflects a value creation estimate for the SPP membership as an entire entity. Due to the synergy of all of the parts creating value for the entire membership, we do not believe that our methodology lends itself to assigning value to sub-categories of the membership and are therefore unable to provide this information as broken down by state or member.

Two fundamental sources of value are created by the collaboration of members as coordinated and administered by SPP: region-wide optimization and economies of scale. Region-wide optimization reflects the product of operating a power generation, transmission and market system on a regional basis, thereby creating a broader base and scope of resources for optimization. Economies of scale reflects the ability of SPP to provide centralized services to member companies at a lower unit cost than members (or Balancing Authorities) can achieve on an isolated basis.

In addition, the collaboration between SPP and its member companies creates service-related benefits in the following functional areas: reliability coordination; reserve sharing; region-wide transmission planning; and operation of open, transparent energy markets. Each category is described in more detail below.

- Reliability Coordination

SPP has an operations center that monitors all activity on the bulk electrical energy grid 24 hours per day, 7 days per week. In addition to responding to outages and coordinating the response, SPP administers a planning function that assures the grid is highly reliable – minimizing disturbances, outages, duration of outages and congestion. North American Electric Reliability Corporation statistics show that RTO members have a higher average system availability than standalone utilities. Based on estimates of the average cost of an outage multiplied by the total annual SPP load, the SPP reliability services helps its members avoid between **$185** and **$280 million** per year of outage costs.

- Reserve Sharing

SPP administers an operating reserve sharing program for a group of utilities having generation capability. SPP maintains capacity for a minimum daily contingency reserve equal to the generating capacity of the largest unit scheduled to be on-line plus one-half of the capacity of the next largest generating unit scheduled to be on-line. Members share on a pro-rata basis in the cost of this reserve. Half of the reserve is required to be a spinning reserve and the other half a supplemental reserve. This is done in lieu of each generating utility maintaining its own reserves for the loss of its largest unit. The total annual reserve requirement cost avoidance for the Reserve Sharing group is estimated to be between **$280** and **$590** million per year.

- Region-Wide Transmission Planning

SPP's engineering function develops transmission plans for the SPP region that will optimize the effectiveness and efficiency of the transmission grid to enable access to the lowest cost sources of power generation for all members. SPP identifies transmission expansion projects that benefit the region and a regional cost allocation methodology helps to build out the needed incremental transmission capacity. Projects already built have created **$5 million** per year of benefits. The Balanced Portfolio Projects and the Priority Projects are in the process of engineering and construction. When implemented over the next decade, the total value to the SPP region is estimated to be **$480 million** per year.

In addition to the above referenced studies, SPP staff conducts studies upon request for: (i) generation interconnection and transmission upgrades and (ii) aggregate studies to facilitate transmission service request, and also performs integrated planning studies over 10- and 20-year planning horizons. SPP serves as an unbiased, objective expert witness to testify at regulatory commissions on the impact of proposed projects to the integrity of the power grid. The cost to procure similar unbiased expert testimony backed by objective studies would conservatively cost **$20 million** per year.

- Operation of Open, Transparent Energy Markets

SPP operates an Energy Imbalance Service ("EIS") market. This market produces net trade benefits to the region. These benefits are defined as the amount the short-term costs of power production within the market footprint are reduced as a result of the regional security-constrained economic dispatch ("SCED") implemented for the EIS market. A study of the benefits in the first 12 months of the operation of the EIS market estimated the benefits to the SPP region to be **$100 million** per year of net trade benefits.

SPP is in the process of implementing highly liquid and efficient Day Ahead and Real Time Balancing markets. These markets will allow unit commitment to be performed on a region-wide basis. An independent study[16] has estimated the average annual net trade benefits of the proposed **Integrated Marketplace** to be approximately **$150 million** per year beginning in 2014, which is in addition to the $100 million per year of net trade benefits from the EIS market.[17] The implementation of the Consolidated Balancing Authority will centralize Balancing Authority resources and avoid approximately **$10** and **$15 million** in costs per year for SPP members.

In short, SPP provides a series of leveraged centralized services to members, customers and member Balancing Authorities. Due to the economies of scale involved, SPP can provide these services at a higher quality and lower unit cost to members than they could provide them for themselves individually. These centralized functions include: Training, Tariff Administration and Scheduling, Regulatory, Compliance, Settlements and Contract Services. The annual value of these services to the SPP region is estimated at between **$100** and **$125 million** per year.

Summary	**Annual Value (in millions)**
Value of services currently provided.	**$ 690 - 1,120**
Value of future services (transmission, markets)	**$ 640 - 645**
Grand Total – Gross Benefits	**$1,330 - 1,765**

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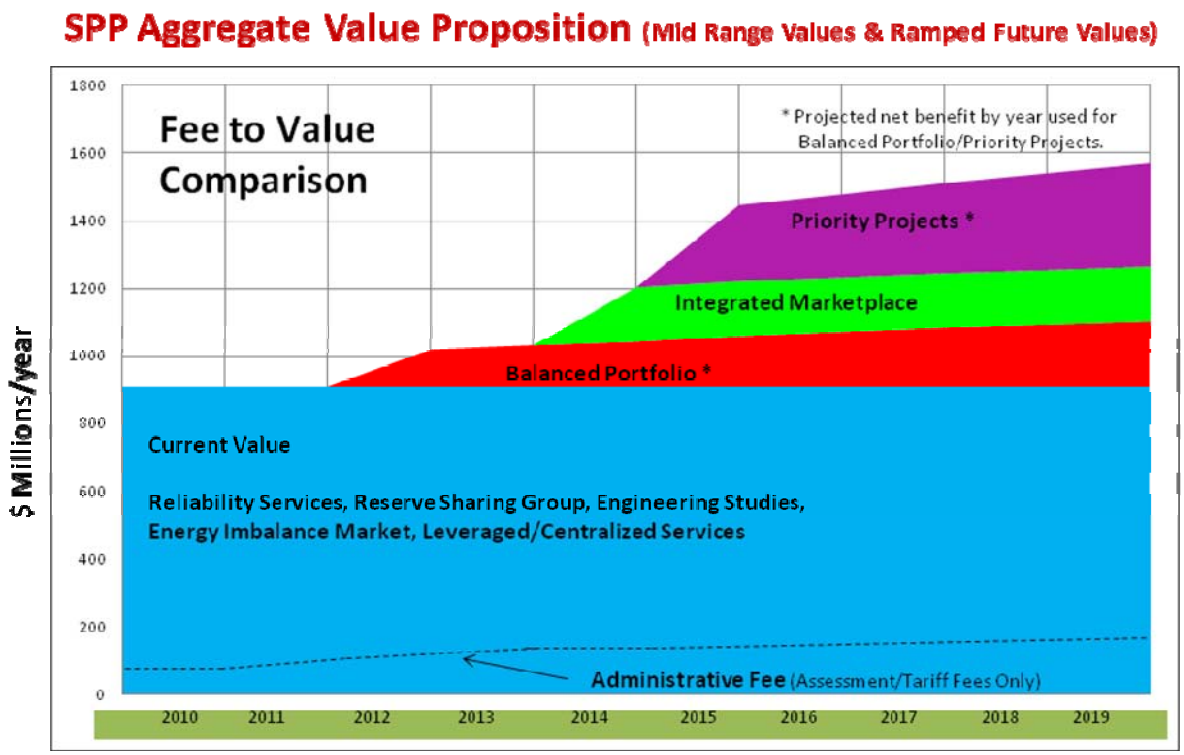
16 This study was paid for by the RSC, and was accepted and approved by the RSC. The study was performed by Ventyx and the final report was issued on April 7, 2009, a copy of which is available at: http://www.spp.org/publications/SPP%20Report%20April%20v8.pdf.

17 The value of the current EIS market is estimated to be $100 million per year.

The following chart is an initial estimate demonstrating the increasing value of SPP membership compared to the increases in the administrative fee.



2. <u>Benefits of SPP Membership for Empire District Electric Company</u>

The Commission's Order raises concerns regarding the impacts that the cost allocation of Priority Projects and the ITP[18] and the cost increases for those projects will have on Empire. With respect to the ITP, however, SPP must emphasize to the Commission that it *will not be issuing any NTCs for the 2010 ITP20-Year Assessment ("ITP20") projects*.[19] NTCs are only issued for approved projects requiring expenditures *within the financial commitment horizon*, i.e.

18 The ITP process is discussed in greater detail in Appendix A.

19 Drafts of the ITP20 Report and the ITP Manual are available at: http://www.spp.org/section.asp?pageID=128.

the next four years.[20] Although this is a topic that likely warrants a more expansive discussion, the instant comments are offered to briefly address the benefits of SPP membership that have been realized by Empire to date.

Although the level and allocation of costs for construction of transmission facilities are relevant factors, consideration of these costs must be in the broader context of the benefits that Empire enjoys through SPP membership. Any such analysis would necessarily entail examination of the services and costs that Empire would have to bear outside of the SPP RTO. A closer look at Empire's operations is an appropriate first step in this analysis.

Empire has a relatively small service area. Its service territory accounts for approximately 2-3% of the SPP transmission footprint. Consequently, but for its membership in SPP, Empire would have relatively few resource alternatives available to it.

Moreover, as an active member in the SPP stakeholder process, Empire has appropriately and prudently utilized the SPP OATT to expand its horizons and take advantage of resources outside of its service area. Access to greater (and, presumably, less costly) resource options are clearly advantageous and beneficial to Empire. Furthermore, under its SPP Network Transmission Service arrangements, Empire has approximately 542 MW of inbound transmission for external resources with virtually no net access charges, which has resulted in considerable transmission benefits at little to no incremental cost. This includes the new resources available to Empire and totaling 457 MW outside the Empire service area (Elk River, Plum Point, Iatan II and Meridian Way). This also includes 250 MW of renewable resources. Access to such renewable resources has helped Empire to satisfy Missouri Renewable Energy

[20] While no NTCs will be issued following the SPP Board's approval of the 2010 ITP20, which is anticipated in January 2011, the Board will also consider the 2010 STEP at their January 2011 meeting and it is expected that NTCs will be issued for reliability projects. A draft of the 2010 STEP is available at: http://www.spp.org/section.asp?group=2005&pageID=27.

Standards[21] , by utilizing optimal wind resources that would otherwise not be available within its service area. Empire has utilized the EIS market to manage the variability of its wind farms, and but for SPP and SPP's EIS market, Empire's use of extensive wind resources would be less feasible. Withdrawal of Empire from the SPP transmission system would require that Empire reserve at least 442 MW of SPP Point-to-Point transmission service in lieu of its current SPP Network Service in order to utilize its off-system resources located elsewhere within SPP. This would currently have an annual cost of approximately $8 million.

Empire has recognized the benefits that SPP provides. On April 13, 2010, Empire filed an application with the Arkansas Public Service Commission ("APSC") for approval of its continued participation in the SPP RTO.[22] This application was required to be filed with the APSC within 60 days after the third anniversary of the implementation of SPP's EIS market. In the application, Empire sought "authority to allow the SPP RTO to continue to have operational control and authority to direct the day-to-day operation of facilities with high-side voltage of 60kV and above in order for SPP to carry out its responsibilities as a Transmission Provider and Reliability Coordinator." Empire stated that continuing to allow the SPP RTO to have such operational control is "in the public interest." In addition, Empire's application explained that "*SPP continues to provide valuable and required services to Empire that would be more costly and expensive for Empire to replicate*." Specifically, both a June 28, 2010 letter filing by Empire and the amended direct testimony of Richard L. McCord[23] stated that the net savings to Empire from participating in the EIS market operations over a 3-year time period was $19.2 million. Mr. McCord further testified that "there are significant ratepayer benefits being

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21 Codified at RSMo 393.1020, 393.1025 and 393.1030.

22 APSC Docket No. 04-137-U

23 APSC Docket No. 04-137-U, Amended Direct Testimony of Robert McCord, filed May 20, 2010. Mr. McCord testified on behalf of Empire as Director of Supply Management.

achieved through Empire's participation in the SPP."[24] In addition, Diana Brenske, Director, APSC Electric Utilities Section, stated in reply testimony filed on May 21, 2010, that "[g]iven the positive benefits of participation in the SPP RTO and the EIS market reported by the SPP Utilities,[25] I recommend that the [APSC] approve their continued participation."

In addition, Empire has referred to other benefits that have resulted from its SPP RTO membership and market participation. If Empire was not an SPP member, it would have to build additional transmission facilities. In its 2009 fourth quarterly financial report, filed with FERC on April 19, 2010, Empire gave an example of this, stating that "[a] new combustion turbine previously scheduled to be installed by the summer of 2011 will be delayed until 2014 as our generation regulation needs are being met through a combination of our existing units and the SPP energy imbalance market."[26]

Finally, SPP notes that in 2005, Charles River Associates ("CRA") performed a Cost-Benefit Analysis ("2005 CBA") in connection with the implementation of SPP's EIS Market.[27] The final report on the results of the 2005 CBA was released on April 23, 2005, with a revised version released on July 27, 2005. While stakeholders participated throughout the study process, the final study reflected the independent analyses, findings and judgment of CRA.

Although this study was completed in 2005, SPP believes it is still relevant to demonstrating the value to a Transmission Owner of membership in SPP. As stated in the Commission staff's Memorandum in Support of Stipulation in Docket No. EO-2006-0141, filed

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[24] APSC Docket No. 04-137-U, Testimony of Robert McCord, filed May 20, 2010.

[25] For purposes of Docket No. 04-137-U, the benefits of SPP RTO participation were studied for Southwestern Electric Power Company, Oklahoma Gas and Electric Company and Empire.

[26] The Empire District Electric Company FERC Financial Report, FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report, dated April 19, 2010.

[27] This study was funded by the RSC and was accepted and approved by the RSC. The results are available at: http://www.spp.org/publications/CBARevised.pdf.

February 24, 2006, the “clear result of the 2005 CBA is that SPP as an RTO is cost beneficial for the SPP Region”, and this benefit can also be specifically seen in Missouri. Empire’s membership in particular was projected to benefit its ratepayers in the approximate amount of $48.5 million as a Transmission Owner in SPP over a ten-year time period. The benefit to Missouri ratepayers as a whole was estimated to be approximately $55.4 million over a ten-year time period. CRA showed that the SPP Transmission Owners would otherwise incur an additional $70.5 million in costs by operating as stand-alone entities, with each operating under its own tariff.[28]

3. Implications of Member Withdrawal from SPP

Membership in the SPP RTO is voluntary, as is withdrawal. Any member may withdraw; however, there is a specific process for withdrawal and there are consequences to withdrawal, such as payment of an exit fee. SPP considers that a withdrawal has occurred whether a member completely withdraws from membership or decides to withdraw as a Transmission Owner and rejoin as a Non-Transmission Owner. There has been some discussion that a withdrawing member could contract for certain services with SPP; however, this is not a guaranteed option and should not be relied upon in making decisions regarding membership. Any provision of contract services must first be approved by the SPC and the Finance Committee, followed by the SPP Board/Members Committee. Historically, approval of contract services has been based upon a strategic driver to invite membership in SPP; SPP has not considered such services to facilitate the exit of a member. In addition, FERC has been very clear specifically regarding the provision

[28] Commission staff, in its *Memorandum of Support of Stipulation and Agreement* in Case No. EO-2006-0141, opined that the results of the 2005 CBA provided a strong indication of positive net benefits to Missouri ratepayers from KCP&L and Empire’s memberships in SPP. Staff also noted that “[w]ith the additional flexibility provided to the RTO to dispatch generation, the RTO is better able to manage congestion and thereby improve the reliability of the transmission system.” Staff continued to state that “[i]f anything, removing the responsibilities to also manage to provisions of transmission service should allow the TOs to put greater focus on issues related to public safety.”

of market services to non-RTO members. There is no indication today that its position has changed, so other than participation as an external generator, continued market access (and its benefits) should not be assumed in assessing membership.[29]

4. Empire is Multi-Jurisdictional

Although it is based in Joplin, Missouri, Empire's service area is not confined to the State of Missouri, and therefore Empire's membership in SPP is not a single state matter. Empire also has facilities in and is a jurisdictional utility in Kansas, Oklahoma and Arkansas. Missouri cannot order Empire to remove its facilities in all states from the SPP OATT. Empire is also FERC jurisdictional, which means that in addition to obtaining the required approvals from these state regulatory authorities, Empire would have to obtain FERC approval prior to withdrawing from SPP. FERC's analysis for addressing a requested withdrawal is discussed below.

FERC has indicated that although RTO membership is voluntary, a public utility that is FERC jurisdictional and is seeking to transfer operational control of jurisdictional facilities to or from an RTO must submit a filing to FERC under section 205 of the Federal Power Act.[30]

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[29] In 2008, MISO proposed making available a Market Service to non-members, which would differ from RTO participation in several ways. A Market Service customer would not turn over functional control of its transmission facilities and would continue to administer its own tariff and its own transmission planning. In addition, a Market Service customer would continue to charge a pancaked rate for transmission service through or out of its system. The Market Service proposal also included a Market Integration Transmission Service to provide firm transmission service over its transmission system as necessary to support its market-based generation dispatch, and would be provided on an "as available" dispatch.

FERC rejected Midwest ISO's proposal for Market Service, and explained that in determining whether a proposed RTO service is just and reasonable, that it must consider the effects of the proposal on, among other things, the ability of the RTO to satisfy its obligations under FERC Order No. 2000. FERC noted that RTOs provide increased efficiency to wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently and operating markets for energy capacity and ancillary services. FERC further opined that the competitive, efficiency, reliability and other benefits of RTOs can be best achieved if there is one transmission operator in the region, concluding that the Market Service Proposal was incompatible with these goals and could create potential disincentives for new and continued RTO membership.

[30] *Guidance on Regional Transmission Organization and Independent System Operator Filing Requirements under the Federal Power Act*, 104 FERC ¶ 61,248, at P 2 (2003) ("*RTO Guidance Order*").

Several Transmission Owners have either withdrawn or attempted to withdraw from RTOs,[31] and in none of these cases did the Transmission Owner withdraw from the RTO and take back control of all functions themselves. Instead, in each case, the Transmission Owner either committed to join a new RTO or, in the case of Louisville Gas & Electric Co. and Kentucky Utilities Co. ("LG&E"), created an independent entity to oversee certain functions and duties. In reviewing each Transmission Owner's request to withdraw from an RTO, FERC has assessed withdrawal requests on the basis of whether they fulfill existing obligations, comply with FERC orders, and are just and reasonable.

Beginning with the LG&E withdrawal from the Midwest ISO in 2006, FERC generally has utilized a three-part test for approving a Transmission Owner's request to exit an RTO. To receive approval to withdraw from an RTO, a Transmission Owner must demonstrate that: (a) the withdrawal proposal satisfies the terms of the relevant RTO agreement, such as the SPP Membership Agreement or the Midwest ISO Transmission Owners Agreement; (b) the withdrawing Transmission Owner's replacement arrangements must comply with Order Nos. 888 and 890 and any proposed deviations from the *pro forma* OATT must be demonstrated to be

[31] The transmission owners that have either withdrawn or attempted to withdraw from RTOs include: (1) Louisville Gas & Electric Co. and Kentucky Utilities Co. (collectively "LG&E") withdrew from Midwest ISO in 2006; (2) Duquesne Light Co. ("Duquesne") attempted to withdraw from PJM in 2008 but later reversed its decision; (3) American Transmission Systems Inc. ("FirstEnergy") is currently in the process of withdrawing from the Midwest ISO; and (4) Duke Energy Ohio and Duke Energy Kentucky (collectively "Duke") is currently in the process of withdrawing from the Midwest ISO.

"consistent with or superior to" the OATT; and (c) the withdrawing Transmission Owner's replacement arrangements must be just and reasonable and not unduly discriminatory.[32]

(a) Satisfaction of Relevant RTO Agreements

In each of the above cited cases, FERC has reviewed the relevant RTO Agreement provisions governing withdrawal/termination to determine whether the withdrawal proposal satisfies all contractual requirements. For example, in *LG&E*, FERC determined that LG&E had either satisfied or had committed to satisfy the withdrawal provisions of the Midwest ISO Transmission Owners Agreement, including: (1) notice of withdrawal; (2) holding existing customers harmless; (3) payment of an exit fee (subject to a final calculation of the fee upon the termination date); (4) negotiation of remaining construction obligations; and (5) receipt of all necessary regulatory approvals (subject to completion of regulatory proceedings).[33] FERC also has required withdrawing Transmission Owners to submit subsequent filings addressing obligations such as the payment of exit fees and agreements regarding continuing construction obligations.[34] The RTO withdrawal precedents make clear that FERC will hold a Transmission Owner to its obligations under the applicable RTO agreement(s) and condition any approvals on complete fulfillment of all requirements.

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[32] *See LG&E Order* at PP 3, 27. FERC has reiterated and applied this test in each subsequent transmission owner withdrawal proceeding. *See Duquesne I Order* at P 28; *FirstEnergy Order* at P 27; *Duke Order* at P 14. In the *LG&E Order*, in addition to the three-part test articulated above, FERC imposed a fourth condition on LG&E's withdrawal from the Midwest ISO. FERC had previously approved LG&E's 1997 merger on the basis of LG&E's membership in the Midwest ISO. As an additional condition of its withdrawal from the Midwest ISO, FERC required LG&E to institute a replacement arrangement that would continue to mitigate market power concerns, which LG&E satisfied by naming SPP as Independent Transmission Organization ("ITO") and the Tennessee Valley Authority as reliability coordinator. *LG&E Order* at P 80. This fourth condition has <u>not</u> been applied in subsequent cases involving transmission owner withdrawal from an RTO.

[33] *See LG&E Order* at PP 31-64. In reviewing Duquesne's request to withdraw from PJM, FERC assessed Duquesne's application to determine whether Duquesne complied with the withdrawal provisions of both the PJM Owners Agreement and the PJM Reliability Assurance Agreement. *See Duquesne I Order* at PP 5-6, 48-54, 81-99. In the *Duke Order*, FERC assessed whether Duke complied with or committed to comply with, the withdrawal requirements of the Midwest ISO Transmission Owners Agreement and the Midwest ISO Balancing Authority Agreement. *See Duke Order* at PP 70-77, 80.

[34] *See, e.g.*, *FirstEnergy Order* at PP 51-52, 54.

(b) Replacement Arrangement Compliance with Order Nos. 888 & 890 - Deviations from Pro Forma and "Consistent with or Superior to" Standard

In each of the RTO withdrawal cases except for LG&E, the Transmission Owner has proposed withdrawing from one RTO and joining another.[35] In the *Duquesne II Order*, FERC determined that switching from one RTO to another and becoming subject to the new RTO's FERC-accepted tariff satisfied the "consistent with or superior to" requirement.[36] In contrast, LG&E did not propose to align with another RTO following its withdrawal from the Midwest ISO; however, FERC conditionally accepted, subject to compliance filings providing certain revisions, deviations from the *pro forma* OATT that were necessary for LG&E to satisfy its merger conditions regarding market power, rate pancaking, curtailment, and operational independence through the creation of the ITO and reliability coordinator arrangements.[37]

(c) Just and Reasonable Replacement Arrangements

In the Duquesne withdrawal proceeding, FERC indicated that the justness and reasonable analysis includes an analysis of both the Transmission Owner's replacement arrangements and its ultimate compliance with all of its contractual withdrawal obligations.[38] Included in this analysis is an assessment of the adverse effects on remaining RTO members as a result of the Transmission Owner's withdrawal. In *Dusquesne I* and *Dusquesne II*, FERC's explained that the review of the justness and reasonableness of a proposed Transmission Owner withdrawal must take into consideration FERC policies and precedent and the possible "substantial impact on other market participants and the markets themselves."[39]

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35 FirstEnergy and Duke have proposed to withdraw from the Midwest ISO and join PJM, and Duquesne proposed to withdraw from PJM to join the Midwest ISO but subsequently decided to remain in PJM.

36 *See Duquesne II Order* at P 42.

37 *See LG&E Order* at PP 108-117, 125-128, 138-142, 166-168.

38 *Duquesne I Order* at P 127; *Duquesne II Order* at P 43.

39 *Duquesne I Order* at P 128; *Duquesne II Order* at P 32; *see also ISO New England, Inc., et al.*, 109 FERC ¶ 61,147, at P 41 (2004).

In summary, in its most recent review of a Transmission Owner request to withdraw from an RTO, FERC has continued to apply the standard first articulated in the *LG&E Order*.[40] FERC has reviewed the replacement arrangements proposed by the departing Transmission Owner to determine whether they comply with the *LG&E Order* standards, as set forth above.

III. CONCLUSION

The Commission's Order raises important issues affecting the process by which transmission projects are selected and the costs of those transmission projects are allocated into the SPP service territory. In many respects, the concerns identified by the Commission are shared by SPP, as evidenced by the considerable efforts currently underway to further improve transmission planning and project tracking within the SPP footprint. Specific proposals are being developed to inject greater discipline in the methods used to estimate and track project costs. These proposals are intended to improve the reliability of project cost estimates and reduce the incidence of cost variances. Initiatives are also underway to explore alternatives to better manage and assign responsibility for cost variances. Finally, as it has in the past, SPP will continuously monitor market, regulatory and operational conditions to ensure that its planning and cost allocation procedures are designed to optimize the benefits of RTO membership.

With respect to Empire, SPP respectfully requests that the Commission take no action at this time due to the following reasons: (a) Empire has and will continue to receive a great deal of benefit from SPP membership and its participation in the EIS market; (b) no NTCs will be issued from the ITP20, (c) the ITP10, which is scheduled to be approved in January 2012, will provide significantly greater detail on underlying, lower-voltage upgrades, benefits and costs, which should provide a greater level of clarification to the Commission; and (d) the requisite

[40] *See Duke Order* at P 14.

Unintended Consequences review is required by 2013 and under development, and the results of that analysis may ameliorate negative financial impacts to ratepayers in states where Unintended Consequences are found to exist. In addition, the Stipulation and Agreement approved by the Commission[41] in Case No. EO-2006-0141 requires Empire to file with the Commission a completed Interim Report on or before February 1, 2012. The Stipulation requires Empire to collaborate with Staff and the Public Counsel regarding issues they consider critical in a proper cost-benefit analysis. Empire's Interim Report will compare the costs and benefits of participation in SPP during a recent 12-month test period.[42] SPP believes that the Interim Report will provide important material that the Commission should consider prior to making any determinations with respect to Empire's membership in SPP.

In addition, Empire is not jurisdictional solely in Missouri and withdrawal from SPP would require approval in multiple states and by FERC. SPP membership has provided substantial benefits to Empire and because of its participation in the EIS market, Empire has been able to utilize significant wind resources, as well as avoid building new transmission facilities and delay construction of generation facilities. The Stipulation and Agreement entered into among the Empire, SPP, Commission staff, KCP&L It is important that this Commission consider the benefits provided by SPP and the costs that Empire would incur if it were operating as a stand-alone utility. Although it is an important issue, there is a great deal more to the overall equation of SPP benefits than simply looking at cost allocation.

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41 Commission Case No. EO-2006-0141, Order Approving Stipulation and Agreement, issued on June 13, 2006, with an effective date of June 23, 2006, as amended by the Amended Order Approving Stipulation and Agreement, issued on July 13, 2006, with an effective date of July 23 2006.

42 *See* Commission Case No. EO-2006-0141, Stipulation and Agreement, Sections II.A.(1) and II.D.(1).

Respectfully Submitted,

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APPENDIX A

Background on Cost Allocation Methodologies,

Transmission Planning and Unintended Consequences

APPENDIX A

Background on Cost Allocation Methodologies, Transmission Planning and Unintended Consequences

1. SPP Cost Allocation Methodologies

SPP has responded to changing market and regulatory conditions through the development of new and innovative approaches to cost allocation and regional planning. SPP's Base Plan Funding cost allocation methodology ("Base Plan Funding"), which marked the first step in SPP's attempt to address regional planning and cost allocation issues, was followed by the Balanced Portfolio approach, which built upon and expanded the regional pricing principles of Base Plan Funding. The evolution and implementation of these various initiatives ultimately led to refocused planning priorities that de-emphasized reliability-driven, localized solutions in favor of regional solutions more compatible with the development of robust transmission systems and markets. Indeed, in SPP, the notion that an extra high voltage ("EHV") upgrade is readily identifiable as a "reliability-based" versus an "economic-based" upgrade is no longer valid. The criteria that served to delineate such projects have largely blurred and become outdated, with today's economic project constituting tomorrow's reliability project. The lesson learned throughout the process is that transmission planning and cost allocations are not a static exercise – adjustments must continue to be considered, and changes implemented, as dictated by the dynamic changes taking place within the SPP Region.

As part of the effort to keep pace with ever changing market conditions, the Synergistic Planning Project Team ("SPPT") was created by the SPP Board to address: gaps and conflicts in all of SPP's transmission planning processes including Generation Interconnection and Transmission Service; to develop a holistic approach to planning that optimizes individual processes; and to position SPP to respond to national energy priorities. The SPPT observed that

SPP's processes resulted in numerous cost allocation methodologies. SPP members and staff expressed concern that such cost recovery methods were fragmented, confusing, and difficult to administer as they required a complex system to track cost by project over the life of the project. The SPPT recommended expanding and including a comprehensive review of all cost allocation methodologies for possible consolidation under a unified system using the recommended "Highway/Byway" approach.[1]

The Highway/Byway methodology is based on the FERC's core cost causation principles; namely, those who benefit from new transmission facilities should pay the costs of building the facilities. Large scale, EHV facilities tend to provide benefits across a wider region, while smaller facilities benefit more discrete areas within that region. Moreover, influenced by the realities of an integrated network[2] and FERC policy such as Order No. 890, transmission system planning in SPP has evolved from a utility-by-utility approach focusing primarily on maintaining reliability at the local level to a region-wide approach to the development of a robust transmission system that is required to take into account not only reliability issues, but economic opportunities facilitated by reduced congestion, as well as state and federal policy goals such as increased use of renewable energy resources, greater incorporation of demand response and energy efficiency technologies, and reduced carbon dioxide emissions. Guided by these

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[1] SPP filed OATT revisions to implement Highway/Byway with FERC on April 19, 2010. A copy of the complete filing is available at: http://www.spp.org/publications/2010-04-19_Highway-Byway%20Cost%20Allocation_ER10-1069.pdf. FERC approved Highway/Byway on June 17, 2010. A copy of the FERC Order approving Highway/Byway is available at : http://www.spp.org/publications/2010-06-17_Order%20-%20Highway-Byway%20Cost%20Allocation_ER10-1069.pdf.

[2] The Commission and the courts have long held that, given the integrated nature of a transmission system, rolled-in treatment for transmission upgrades is appropriate. *See, e.g.*, *Maine Public Service Co. v. FERC*, 964 F.2d 5, 8-10 (D.C. Cir. 1992); *Northeast Utilities Service Co.*, 60 FERC ¶ 61,012 (1992), *on remand from City of Holyoke Gas and Elec. Dept. v. FERC*, 954 F.2d 740, 742-43 (D.C. Cir. 1992). Moreover, the Commission has previously stated that it is "the policy of this Commission to roll-in all transmission facilities," *Idaho Power Co.*, 3 FERC ¶ 61,108, at 61,296 (1978), and that it "strongly favors the use of the rolled-in method of transmission allocations," *Niagara Mohawk Power Corp.*, 42 FERC ¶ 61,143, at 61,529 (1988) (*quoting Otter Tail Power Co.*, 12 FERC ¶ 61,169, at 61,420 (1980)).

principles, the RSC developed the Highway/Byway proposal to govern future transmission cost allocation in the SPP Region.

Highway/Byway reflects a broader, more contemporary perspective that moves away from a reliability-based, zonally-focused cost allocation methodology to a methodology that is more closely aligned with SPP's new Integrated Transmission Planning ("ITP") process and the need for and benefits of regional, higher-voltage solutions. To that end, the Highway/Byway methodology allocates the costs of future transmission facilities based on the voltage level of the particular facility, with the cost of EHV facilities (operating at or above 300 kV) allocated 100% to the regional rate, the cost of mid-tier facilities (operating above 100 kV and below 300 kV) allocated on a one-third/two-thirds, regional to zonal basis, and the cost of low voltage facilities (operating at or below 100 kV) allocated entirely to the zonal rate. By allocating costs in this manner, the Highway/Byway methodology provides a mechanism through the SPP Open Access Transmission Tariff ("OATT" or "Tariff") that appropriately allocates the costs of projects developed in a comprehensive regional planning process.

The Highway/Byway methodology applies to all Base Plan Upgrades for which a Notification to Construct[3] is issued after June 19, 2010, including any high priority upgrades[4] approved for inclusion in the annual SPP Transmission Expansion Plan by the SPP Board of Directors, and Base Plan Upgrades associated with wind generation facilities.[5] The Highway/Byway methodology will not apply to upgrades identified in SPP's generation

[3] SPP issues Notifications to Construct pursuant to Section VIII.4 of Attachment O after a new transmission project is either approved for construction under the STEP or is required to provide service pursuant to a Service Agreement. Tariff at Attachment O § VIII.4.

[4] A high priority upgrade is an economic upgrade recommended by SPP for inclusion in the STEP based on the results of a high priority study requested by SPP stakeholders. *See id.* § IV.3.

[5] 300 kV and above Base Plan Upgrades associated with wind generation resources will be allocated 100% regionally. *See id.* at 7-9.

interconnection process or Service Upgrades identified through SPP's Aggregate Transmission Service Study process that do not qualify as Base Plan Upgrades.

2. <u>Transmission Planning</u>

(a) Priority Projects

In April 2010, SPP was directed by the SPP Board of Directors to implement the SPPT's recommendations for creating a robust, flexible, and cost-effective transmission system for the region, large enough in both scale and geography to meet SPP's future needs. Development of Priority Projects was one major recommendation[6]. SPP was charged with identifying, evaluating, and recommending Priority Projects that would improve the SPP transmission system and benefit the region, specifically projects that reduce grid congestion, improve the Generation Interconnection and Aggregate Study processes, and better integrate SPP's east and west regions. SPP has produced three series of Priority Projects reports[7] that have been completed by SPP staff with input from stakeholders and the Transmission Working Group ("TWG"), Economic Studies Working Group ("ESWG"), Cost Allocation Working Group ("CAWG") Markets and Operations Policy Committee ("MOPC"), Strategic Planning Committee ("SPC") and the Board of Directors ("SPP Board"). There were six projects that were identified as Priority Projects which achieve the strategic goals identified in the April 2009 SPPT report.[8] Analysis has demonstrated that these projects will accomplish the goals set forth in the SPPT's recommendation. There are also additional benefits, which have not been measured, but include

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6 The ITP process was also a major recommendation of the SPPT and is discussed herein.

7 The final report, the SPP Priority Projects Phase II Final Report, approved April 27, 2010, is available at: http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf.

8 The Priority Projects include: (1) the double-circuit 345-kV line from Spearville, Kansas; to Comanche County, Kansas; to Medicine Lodge, Kansas; (2) the double-circuit 345-kV line from Comanche County, Kansas, to Woodward, Oklahoma; (3) the double-circuit 345-kV line from Woodward, Oklahoma to Hitchland, Texas; (4) the 345-kV line from Nebraska City, Nebraska; to Maryville, Missouri; to Sibley, Missouri; (5) the 345-kV line from Valliant, Oklahoma to Texarkana, Texas; and (6) new equipment in Tulsa County, Oklahoma

particularly without limitation, enabling future SPP energy markets, dispatch savings, reduction in carbon emissions and required operating reserves, storm hardening, meeting future reliability needs, improving operating practices/maintenance schedules, lowering reliability margins, improving dynamic performance and grid stability during extreme events, and additional societal economic benefits.

On April 27, 2010, the SPP Board approved the Priority Projects Phase II Final Report. An initial cost estimate of the Priority Projects at that time identified the cost of constructing the Priority Projects at approximately $1.145 billion. In an effort to promote transparency and open communication, this preliminary estimate was released. Subsequent pre-construction estimates released at the October 12, 2010 MOPC meeting estimated the cost at $1.416 billion.

(b) Integrated Transmission Plan

Although the issue at hand relates to cost increases in the Priority Projects, SPP wanted to address the ITP process as it was also referenced in the Commission's Order. The first phase of the ITP, the ITP 20-Year Assessment ("ITP20"), is scheduled to be approved by the SPP Board in January 2011 and SPP thought it would be helpful to provide some additional information on the ITP process generally and the ITP20.

In response to the changing needs of the SPP Region and based upon the recommendation of the SPPT, SPP and its stakeholders developed the ITP process, which is SPP's approach to planning transmission needed to maintain reliability, provide economic benefits and achieve public policy goals to the SPP region in both the near term and long-term. The intent of the ITP is to enable SPP and its stakeholders in the development of a cost-effective, flexible, and robust transmission grid that provides regional customers with improved access to the SPP region's diverse resources. Development of the ITP was driven by planning principles developed by the SPPT, including the need to develop a transmission backbone large enough in both scale and geography to provide flexibility to meet SPP's future needs. In its 2009 report, the SPPT identified several goals for the ITP based on the evolving needs of the SPP Region, including (among other things): (1) integrating west to east portions of the SPP grid to enable renewable resources located primarily in the west to reach load centers located mostly in the east; (2) providing support for the Aggregate Transmission Service Study process; (3) providing relief to the generation interconnection queue; and (4) relieving known congestion.[9]

The ITP is an three-year study process that assesses the SPP region's transmission needs in the long- and near-term by including 20-year, 10-year and Near-Term Assessments and targeting a reasonable balance between long-term transmission investment and customer congestion costs, as well as many other benefits. The ultimate goal of the ITP process is to develop, to the extent reasonably practical, a demonstrable correlation between the actual allocation of costs and the benefits received over time.[10]

The ITP20 is the first ITP looking into the future 20 years as required by OATT Attachment O, Section III. The ITP20 is an expansion on the annual SPP Transmission Expansion Plan ("STEP"), which is the 10-year transmission expansion plan in place since 2006. The concept for this 20-year look into the future arose from the 2009 Synergistic Project Planning Team, as a means to develop a flexible EHV backbone network. The process utilizes a diverse array of power system and economic analysis tools to identify cost-effective robust backbone projects which will provide the transmission system flexibility to reasonably

9 *See* SPPT Report at 11, 16.

10 The ESWG was also formed in conjunction with the development of the ITP, and along with the TWG, will maintain the processes and metrics on an ongoing basis for qualifying and quantifying the transmission projects for the 20-year and 10-year assessments. The TWG will maintain the process on an ongoing basis for qualifying and quantifying the transmission projects for the Near-Term Assessment.

accommodate possible changes characterized by the various futures (scenarios) depicted in the assessment. Projects identified in the ITP20 provide benefits to the region across multiple futures, and create flexibility for SPP to meet future needs. This effort has been driven by numerous interactions with stakeholders and with significant support from the ESWG and TWG. This plan differs from the earlier EHV plans in the level of detail and effort that has gone into its preparation. The ITP20 will be repeated on a three year cycle.

ITP recommendations reviewed by the Market Operations and Policy Committee, the RSC and approved by the SPP Board will allow staff to issue Notices to Construct ("NTC") for approved projects *within the financial commitment horizon*, which means that NTCs will only be issued for projects in which funds are to be expended within 4 years. *SPP will not be issuing any NTC letters for projects identified in the ITP20*, as those projects are outside of the financial commitment horizon. Authorizations to Plan ("ATPs") will be issued for projects needed beyond the financial commitment horizon.[11] ATPs are defined in the ITP Manual[12] as a status given to a project which has been approved by the SPP Board and for which an NTC has not yet been issued because it is outside of the NTC financial commitment window.

The ITP Manual describes how the 20-Year and 10-Year plans will be incorporated annually into the Near-Term Assessment. Specifically, these longer range plans and the ATPs serve as part of a pool of solutions from which the nearer term plans (Near-Term Assessment, Generation Interconnection, Transmission Service Request, Screening Studies) draw to develop and conclude the best regional solution for the SPP footprint, without losing sight of the long term goals of SPP and stakeholders.

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11 All of the projects for which ATPs are issued will be posted on the SPP website.

12 A draft version of the ITP Manual is available at: http://www.spp.org/section.asp?pageID=128.

Projects with ATPs will be included in future Aggregate Study and Generation Interconnection study models if needed as solutions for those study objectives. When added, Projects with ATPs will be included in the model that corresponds to the expected in-service date of each project and all subsequent models. Projects with ATPs that have an in service date that is beyond the year being modeled, will be available for advancement as a solution in the current study if it resolves one of that study's issues. Also, projects with ATPs are re-evaluated during successive ITP studies to insure their continuing value or need.

A project subject to an ATP will only get an NTC if construction expenditures for it need to start within the NTC financial commitment window regardless of the driver for the need (Generation Interconnection, Transmission Service Request, Near-Term Assessment, ITP 10-year Assessment, or ITP20). If a project is determined to be no longer of value its ATP will be rescinded. This could result in a requirement for a different solution if there are still power system issues that need to be addressed whether those needs are a result of changes in planning scenarios, anticipated load growth, generation assets, public policy, transmission service obligations, or generation interconnection obligations.

3. Unintended Consequences Review

(a) History

In originally adopting its Base Plan Funding cost allocation methodology, SPP adopted Tariff language requiring it to review the reasonableness of the Base Plan Upgrade regional and zonal cost allocation factors at least once every five years, or more frequently if SPP or the RSC believes that circumstances warrant a review.

Additionally, for each STEP, SPP must calculate the cost allocation impacts of Base Plan Upgrades to each Transmission Customer within the SPP Region, with the results of this analysis being reviewed by the SPP Regional Tariff Working Group ("RTWG") for any unintended consequences.

Since the adoption of these requirements, SPP and its stakeholders have endeavored to ensure that transmission cost allocation does not result in unintended negative cost consequences to customers. Beginning with the 2006 STEP, SPP and the RTWG have conducted annual analyses of Base Plan Upgrade cost allocation impacts to each Transmission Customer as required by Attachment J, and SPP has submitted regular reports to the Commission reporting on the results of these analyses, as the Commission directed.[13] SPP has also taken action when unintended consequences are discovered. For example, when a review of the 2006 STEP revealed unintended consequences resulting from the use of a "net change" MW-mile cost allocation analysis, SPP and its stakeholders promptly revised its zonal cost allocation to implement a "sum of positive impact" MW-mile allocation methodology to remedy the problem, and SPP filed the change for Commission approval.[14]

(b) Highway/Byway

In the submission of the Highway/Byway cost allocation methodology to FERC for approval in April 2010, SPP proposed additional Tariff provisions to: (1) require review of the Highway/Byway cost allocation methodology and allocation factors at least every three years (rather than five years, as existed under the previous Tariff provisions); (2) authorize the RSC to recommend any adjustments to cost allocation if the unintended consequences review shows an imbalanced cost allocation in one or more Zones; (3) require the MOPC and CAWG to define the analytical methods to be used and suggest adjustments to the RSC and the Board of Directors

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[13] *See, e.g.*, Informational Report of Southwest Power Pool, Inc., Docket No. ER05-652-000 (June 1, 2009); Informational Report of Southwest Power Pool, Inc., Docket No. ER05-652-000 (Aug. 15, 2008).

[14] *See* Submission of Revisions to Open Access Transmission Tariff of Southwest Power Pool, Inc., Docket No. ER07-1248-000 (August 3, 2007). The revised MW-mile calculation was accepted by the Commission on October 18, 2007. *Sw. Power Pool Inc.*, Letter Order, Docket Nos. ER07-1248-000 and -001 (Oct. 18, 2007).

regarding any imbalance in zonal cost allocation in the SPP Region; and (4) permit any Member company, starting in 2015, to seek relief from the MOPC if it believes that it has been allocated an imbalanced amount of costs under the Highway/Byway methodology.

Specifically, SPP revised Section III.D to require review of not only the allocation factors, but the regional allocation methodology, and to require review at least every three years rather than five years. SPP also proposed revisions to the language governing its review of the unintended consequences of the cost allocation of Base Plan Upgrades to each pricing Zone within the SPP Region to include more detail. SPP will share the results of its review with the RTWG, MOPC, and RSC, and will publish the results on its website. SPP will also request that the RSC provide any recommendations to adjust cost allocations if the results of the analysis show an imbalanced cost allocation in one or more Zones. SPP proposed revisions to allow Member companies (beginning in 2015) that believe they have been allocated an imbalanced portion of costs to seek relief from the MOPC. SPP also proposed several changes to Attachment O (discussed below) to enhance its unintended consequences review.

In addition, as discussed above, SPP proposed several revisions to Attachment O to address its unintended consequences review required by Attachment J. Specifically, SPP modifed provisions in Section VI.4 of Attachment O governing its "Analysis of Transmission Alternatives to Address Needs Identified in the Reliability Assessment" to require SPP to consider the costs and benefits in selecting potential solutions by requiring:

(1) SPP to review of the scope and assumptions of the analysis with the CAWG and Economic Studies Working Group ("ESWG");

(2) financial modeling based on a 40-year time frame (with the last 20 years provided by a terminal value);

(3) quantification of the benefits from dispatch savings, loss reductions, avoided projects, reductions in carbon emissions, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics developed by the ESWG;

(4) identification and quantification of the benefits from reliability improvements to the transmission system;

(5) inclusion of different scenarios to analyze sensitivities of load forecasts, wind generation levels, fuel prices, carbon prices, and other relevant factors;

(6) assessment of both the regional costs and benefits for the SPP Region and the net cost-benefit of each scenario on a zonal and state basis; and

(7) assessment of the net impact of the transmission plan developed in accordance with Attachment O on a typical residential customer.

These revisions provide significant specificity to the analysis of alternatives and facilitate the process of conducting the unintended consequences review required by Attachment J.

All of these revisions require SPP to review its cost allocation methodology more frequently to ensure that it remains appropriate and allocates costs and benefits properly across all Zones over time and provide for more rigorous unintended consequences review than was conducted under SPP's pre-Highway/Byway Attachment J. All of the revisions proposed by SPP related to Unintended Consequences were accepted by the Commission in its June 17, 2010 order.[15]

(c) Integrated Transmission Planning

In the new SPP planning paradigm known as the ITP process, impacts of unintended consequences remains an important concern. The review contained in Section 16.7 of the 2010

[15] A copy of the FERC Order is available at: http://www.spp.org/publications/2010-06-17_Order%20-%20Highway-Byway%20Cost%20Allocation_ER10-1069.pdf.

Integrated Transmission Plan 20-Year Assessment Report ("ITP20 Report")[16] is staff's first attempt at such an effort and, while introductory and preliminary at best, should grow in quality and content over time with input from stakeholders and further development of tools used in the analysis. Now, and as ITP planning matures, it is possible to begin analyzing the costs and benefits of the added facilities, addressing rate impacts, and mitigating any unintended consequences.

Section III. D. of Attachment J to the Tariff prescribes a formal review of the base plan cost allocation methodology, including determination of any imbalanced zonal cost allocation. The discussion of benefits and costs in the ITP20 Report is **not** that review. Rather, the discussion is a preliminary, general examination of the issue of unintended consequences in an ITP20 context.

The preliminary unintended consequences assessment for 2010 ITP20 determined any deviation of the zonal distribution of production cost savings and other benefits through installation of the upgrades (benefits) from the corresponding allocation of the upgrade cost (cost). The analysis in Table A9.2 of the 2010 ITP20 Report identifies any current imbalance in the distribution of cost and benefit associated with known upgrades committed to date that are expected to exist in 2030 prior to addition of the ITP20 upgrades. It sets out the degree to which installation of the ITP20 upgrades result in a better balance of accumulated costs and benefits for each zone. Analysis of cost is a relatively straightforward endeavor. Determining zonal cost impacts from adding one or more upgrades involves distributing the associated revenue requirement to the zones pursuant to the cost allocation provisions of the OATT. The analysis of benefit, by zone, can be calculated for a discrete set of upgrades and has been completed for the

16 A draft of the ITP20 Report, which includes the tables discussed herein, is available at: http://www.spp.org/section.asp?pageID=128.

Robust Plan 1 upgrade set. The benefits amounts are derived from production cost savings, reliability upgrade deferrals or displacements and decreased losses. These benefit amounts exclude wind, gas price and local economic benefit categories.

Table A9.2 first depicts estimates of costs and benefits at year 2030 associated with all previously-committed upgrades, excluding costs and benefits of the 2010 ITP20 upgrades. A benefit-to-cost ratio for that circumstance is computed for each zone. Then the cumulative 2030 revenue requirement, including the first year revenue requirement of the 2010 ITP20 upgrades, is depicted. Only the projected adjusted production cost savings are considered zonal benefits and included in the cumulative zonal benefit, and the resultant benefit to cost ratio for that circumstance is computed for each zone.

The benefit to cost characteristics for American Electric Power Service Corporation, Nebraska Public Power District, Omaha Public Power District and Lincoln Electric System are substantially improved by the addition of the 2010 ITP20 upgrades.

Since the analysis shows four zones that continue to reflect a cumulative benefit-to-cost ratio less than one, a theoretical set of transfer payments are calculated to adjust benefits by zone to result in a minimum benefit-to-cost ratio of 1 for all zones. These transfers are similar in magnitude to the transfers required for the Balanced Portfolio project set, adjusted for inflation.

(d) Summary

The above generalizations are rough estimates of the expected impacts if Robust Plan 1 upgrades were installed. Rate impacts and unintended consequences will remain a concern and should continue to be investigated in the ITP process.

Exhibit 1

SPP Staff Whitepapers Presented at

Strategic Planning Committee Meeting on December 3, 2010

SPP Roles and Responsibilities

As SPP staff began to prepare the strawman drafts addressing the four motions adopted by the Regional State Committee ("RSC") on October 25, 2010, and assigned on October 26, 2010 by the SPP Board of Directors to the Strategic Planning Committee ("SPC") and the Transmission Working Group ("TWG"), it became apparent that the development and understanding of the strawman drafts would be advanced by a statement of the roles and responsibilities of SPP, the Transmission Owners and regulators in the planning and construction process.

The four motions assigned to SPP by the Board of Directors are as follows:

> MOTION 1: RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded. (SPC)
>
> MOTION 2: RSC recommends that SPP review the Novation Process and report to the RSC by April 2011. (SPC)
>
> MOTION 3: RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200KV & above that are regionally funded. (TWG)
>
> MOTION 4: SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed. (SPC)

Roles and Responsibilities

With the advent of SPP as a Regional Transmission Organization ("RTO") and its evolution from reliability-only planning and Base-Plan funding to Balanced Portfolio to Integrated Transmission Planning and Highway/Byway cost allocation, local member utilities that are now purchasing transmission service from SPP to serve their loads are becoming increasingly liable for rates imposed by a FERC-approved tariff for transmission projects constructed by other member utilities in other states. This situation inevitably creates greater regulatory complexity at the state level. SPP respects the desire of the state regulatory commissions, as expressed through the RSC, to explore the ramifications of this situation.

The role of SPP is not that of an arbiter of costs of its members. Section 3.3 of the Membership Agreement addresses SPP's and the Transmission Owner's respective roles and responsibilities regarding transmission planning and construction. Section 3.3 of the SPP Membership Agreement reads in total as follows:

(a) As part of its planning activities, SPP shall be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate state authorities, including the Member's governing board where it serves as that authority. Transmission Owner shall use due diligence to construct transmission facilities as directed by SPP in accordance with the OATT and this Agreement, subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals, including, as necessary, the Member's governing board where it serves as that authority. Such construction shall be performed in accordance with Good Utility Practice, applicable SPP Criteria, industry standards, Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements), and in accordance with all applicable requirements of federal or state regulatory authorities. Transmission Owner shall be fully compensated to the greatest extent permitted by FERC, or other regulatory authority for the costs of construction undertaken in accordance with the OATT.

(b) After a new transmission project has received the required approvals and been approved by SPP, SPP will direct the appropriate Transmission Owner(s) to begin implementation of the project. If the project forms a connection between facilities of a single Transmission Owner, that Transmission Owner will be designated to provide the new facilities. If the project forms a connection between facilities owned by multiple parties, all parties will be designated to provide their respective new facilities. The parties will agree among themselves as to how much of the project will be provided by each entity. If agreement cannot be reached, SPP will facilitate the ownership determination process.

(c) A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

These provisions acknowledge the recognized division of interests between the transmission planning function of SPP as the Transmission Provider and the financial and construction responsibilities and ownership interests of Transmission Owner(s). Attachment O, Section VI (1), of SPP's OATT reinforces the distinction in interests providing that:

> The Transmission Provider shall not build or own transmission facilities. The Transmission Provider, with input from the Transmission Owners and other stakeholders, shall designate in a timely manner within the SPP Transmission Expansion Plan ("STEP") one or more Transmission Owners to construct, own, and/or finance each project in the plan.

The functions of investing in transmission facilities and charging customers are within the management function of the local utilities, subject to the appropriate regulatory jurisdiction, including FERC and appropriate state regulatory authorities. Commonly, such jurisdiction is exercised via some combination of state siting or certificate authority and/or state and federal ratemaking authority. Prior to the advent of open-access transmission service and regional rates set by FERC for RTOs, each state regulatory authority generally set rates for bundled retail service, which included generation, transmission, and distribution service, based on costs incurred by the utility for construction and operation of that utility's facilities.

While the Transmission Owners in SPP have ceded their transmission planning responsibilities to SPP, they have not ceded their rights and responsibilities related to construction of transmission facilities or their rights to establish their revenue requirements to SPP. The processes of project cost estimation and project management are matters to be addressed by the Transmission Owners' through their internal processes and interactions with appropriate regulatory authorities.

The current discussion, which has arisen as a result of the escalation of some transmission cost estimates for Priority Projects, is a product of the increased openness and transparency of the SPP planning processes and the regionalization of cost allocation. In the past, transmission cost estimates would have tended to remain internal to each member utility, subject only to the utility's internal review and any applicable obligations to its regulatory authorities. Adjustments in cost estimates "prior to a spade of earth being turned" would have been handled completely within the utility's management and processes. Estimate modifications may not have been available throughout the project development process. SPP's Attachment O Transmission Planning Process, Balanced Portfolio, Integrated Transmission Planning Process ("ITP") and Priority Projects, provide additional transparency into the early stages of the transmission planning process.

By definition, SPP's transmission planning process, including the ITP process, means that each new project is part of an integrated whole. While each project has unique characteristics, it is the combination of the projects that creates the regional benefits. Modifications to a planned group of projects will necessarily impact the operation of the transmission system. Service commitments are made based on available capacity shown from models of the transmission system at the time of the request. As project commitments and service commitments are made, the models are updated to reflect those commitments. Changes to the model change the projected model flows on individual lines. Removal of a line from the model will affect flows on other lines in the model.

For SPP to function in accordance with its responsibilities and authorities, the interests and responsibilities of all stakeholders must be understood and respected: SPP to provide a transparent regional transmission planning process; the Transmission Owners to construct and own transmission facilities; and the FERC and state regulatory authorities to regulate within their statutory authority. As previously discussed, the regulatory role has been exercised via some combination of state siting or certificate authority and/or federal and state ratemaking authority. State regulatory authorities typically possess the authority to:

1. Disallow imprudent or unreasonable costs in a traditional ratemaking proceeding;
2. Impose conditions on siting approval or a certificate of public convenience and necessity that the utility provide periodic reports on the cost estimates of a particular project;
3. Intervene in another state's regulatory proceeding as an interested party;

4. Intervene before FERC in a rate case; and
5. Review and approve or reject a utility's Integrated Resource Plan;

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SPP can best serve the interests of stakeholders in addressing the issues raised in the RSC motions by maintaining its commitment to communication and transparency. While the cost estimation process must ultimately remain the responsibility of the Transmission Owner, SPP staff will structure procedures related to project screening, cost/benefit analyses, etc., before turning to the Transmission Owners to develop the final cost estimates to be used prior to the issuance of NTCs and the commencement of project tracking. By promoting a better understanding of SPP's roles and responsibilities and the roles and responsibilities of SPP's diverse stakeholders, it will be easier to determine appropriate avenues for accomplishing the goals of the RSC motions and to develop appropriate expectations of SPP staff, its member Transmission Owners and other stakeholders. To that end, SPP staff is proposing to the SPC strawman drafts to address the four motions made by the Regional State Committee and directed to SPP for consideration.

Cost Overruns/Underruns Whitepaper

RSC Motion 1

During their Monday, October 25th, 2010 meeting, the RSC passed the following as Motion 1:

> **RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.**

Introduction

SPP's current project tracking process tracks costs and in-service dates of projects that have received a Notification to Construct (NTC) from SPP staff. To ensure that cost overruns/underruns are monitored with sufficient scrutiny, some modification to the current process is needed.

Current Project Tracking Procedure

When a project receives an NTC it is entered into the Project Tracking process. The Transmission Owner (TO) is required to submit quarterly updates of cost estimates and the expected in-service date. These updates are incorporated into a quarterly report that is submitted to the Board of Directors/Members Committee (BOD/MC), the Markets and Operations Policy Committee (MOPC), and the Regional State Committee (RSC). In accordance with the guidelines provided in the NTC Whitepaper approved in early 2010, cost estimates that have increased by more than 20% since the previous estimate require the project developers to submit justification for the variance.

NTC Project Estimates

To make the Project Tracking process more rigorous, several enhancements are offered here. The cost estimate included in an NTC is the stage 3 estimate; this will be the NTC Project Estimate (NPE) for the project. The NPE will become the initial cost estimate baseline for project tracking. The baseline is the point from which the variance will be measured. This number will be the basis throughout the project tracking process to be compared with estimate updates to determine overrun/underrun percentages.

Process Enhancements

A developer who has a project whose NPE exceeds $5,000,000 will be required to submit updates on a monthly basis for that project. A developer who has a project with a cost estimate which is under $5,000,000 will be required to submit updates on a quarterly basis. Monthly and quarterly updates should consist of a detailed cost breakdown which mirrors the original Standardized Cost Application (SCA)[1]. The report will include a comments column and any changes to an estimate must be

[1] For more information regarding the SCP reference the white paper on Cost Estimates.

accompanied by a comment explaining the change. If the cost variance for a project exceeds +/- 25%[2] of the baseline, then the project will be reviewed by a new working group, Project Cost Working Group (PCWG), or assigned to an existing working group.

PCWG Review

The PCWG will only reevaluate projects whose costs have changed outside the allowable variance. The reevaluation by the PCWG will be based on data and information from both the TO and SPP staff. The PCWG will be provided with the original SCA, monthly project tracking data updates, and any comments from SPP staff or the TO related to the cost revisions. Comments from the TO should include relevant information regarding any sunk costs, an explanation for the cost overruns/underruns, and comments as to why the project should or should not continue forward. The reevaluation will include an analysis of the cost changes and whether these changes are reasonable and appropriate for regional funding. The PCWG will also recommend if a restudy of a project is required.

There are instances where resetting the baseline will be prudent as it would not be reasonable for a project to be automatically flagged for review every month following an overrun/underrun that had been previously reviewed and accepted. The PCWG will determine if and when to reset the baseline cost estimate. If a baseline cost estimate is reset, the NPE will still be retained in the monitoring tool.

PCWG Report

The PCWG will submit a quarterly report to the SPP RSC and BOD/MC regarding the reevaluated projects. This report will include the rationale for each cost change as well as comments from the PCWG stating whether the cost change is reasonable and appropriate for regional funding. If the PCWG states the cost change is either not reasonable and/or not appropriate for regional funding, the PCWG will include a recommendation.

Restudy Determination

The PCWG will be tasked with determining if a restudy is required. A change in cost may not impact the benefits a project provides. However, a cost could change by such a magnitude that other alternatives would have been considered in its place. In that instance, a study may be required to review other projects which were previously discarded since they had a higher cost than the reviewed project but now have a lower cost. SPP staff will provide the PCWG with information to consider while determining the necessity of the restudy. This information will include a list of project alternatives which were reviewed during the original study, the cost of the alternatives, and a review of the resources necessary to complete the restudy. All of the following criteria must be met in order for restudy to be required:

- Latest cost estimate must exceed $10,000,000

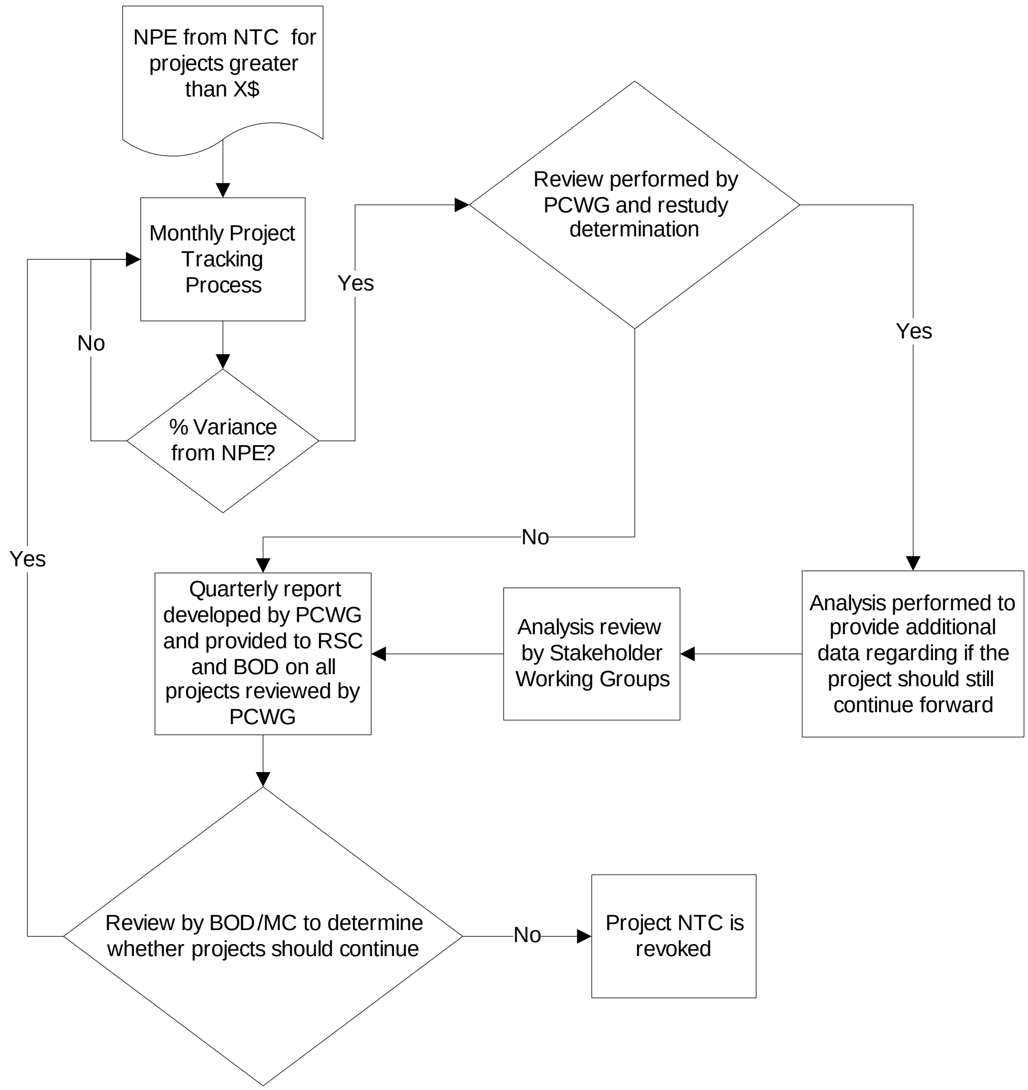
[2] This is the same percentage that is the allowable variance for the Stage 3 cost estimate in the Cost Estimate White Paper.

- If Benefit/Cost (B/C) ratio was a rationale for the project, the B/C must be less than 1
- Actual construction of the project has not yet started
- The cost must have increased 30% from the baseline

Restudy if Required

If the PCWG believes a project should be restudied, SPP staff will develop a study scope which will be approved by the TWG or ESWG. The study analysis and results would follow the typical stakeholder process by moving through the appropriate stakeholder working groups and finally to the BOD for a final decision. The BOD/MC will decide whether the original NTC will be revoked or if the project will continue forward. If the NTC is revoked by the BOD/MC, and the SPP staff analysis identified an acceptable alternative, the BOD/MC could then issue an NTC for the alternative project.

Project Tracking Flow Chart



Illustrative Monthly Cost Update Example

Project Description				
Estimate Provider				
Estimate Date				
In-Service Date				
	Details	**Initial Cost Estimate**	**Updated Cost Estimate**	**Comments**
Conductor	Size			
	Design			
	Electrical Capacity (amps)			
	Other			
Structure	Type			
	Material			
	Base			
	NESC Assumption			
	Dead Ends			
	Underbuild			
Substation	Transformers			
	Breaker Scheme			
	Protection Scheme			
	Voltage Control			
Construction Labor	Amount			
Right of Way (ROW)	ROW (Mileage)			
	ROW Condition (e.g., Urban, Rural, etc.)			
Eng. Design, Project Management, Permitting	Permitting/Certifications			
	Escalation Rate			
	Eng. Design/Proj. Mang.			
Loadings	Type 1			
Other Cost	Other Cost Factor Notes			
Total Cost				

RSC Motion 2: The Novation Process

Both the SPP Membership Agreement and Attachment O to SPP's OATT provide a designated Transmission Owner the unfettered right to assign the construction and ownership of a transmission project to a third party. Section 3.3(c) of the SPP Membership Agreement provides in part:

> A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place. If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

Section VI(6) of Attachment O of SPP's OATT provides, in relevant part:

> A Designated Transmission Owner may elect to arrange for another entity or another existing Transmission Owner to build and own all or part of the project in its place subject to the [entity having the following] qualifications . . . .
>
> i) Entities that have obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where the project is located,
>
> ii) Entities that meet the creditworthiness requirements of the Transmission Provider,
>
> iii) Entities that have signed or are capable and willing to sign the SPP Membership Agreement as a Transmission Owner upon the selection of its proposal to construct and own the project, and
>
> iv) Entities that meet such other technical, financial and managerial qualifications as are specified in the Transmission Provider's business practices.

For purposes of understanding roles and responsibilities related to the construction and ownership of transmission facilities, it is important to understand the distinction between assignment of a project and novation of a project. If a designated Transmission Owner cannot or does not want to construct a transmission project, there are two options available: assignment and novation. An assignment allows the designated Transmission Owner to transfer responsibility for construction of the project, but does not relieve the designated Transmission Owner of the financial or legal obligation to construct the project. SPP will continue to hold the designated Transmission Owner financially and legally responsible for timely construction of the project in accordance with the NTC. In contrast, a novation allows the designated Transmission Owner to transfer all legal and financial responsibility for the timely construction of the project to an existing Transmission Owner or an entity who will become qualified under SPP's process and become a Transmission Owner under SPP's OATT and Membership Agreement. SPP, through its stakeholder process, developed and documented a process for determining if an entity not currently an SPP Transmission Owner is qualified to become a Transmission Owner in SPP. That document is attached as an exhibit to this strawman. This process document is final in its form, but it is going to continually evolve as SPP develops more experience in using the process and addressing any issues or concerns that may arise from the process.

FERC accepted this process and the corresponding form of agreement, finding it was consistent with the SPP Membership Agreement, SPP's OATT and the filed rate doctrine, and would encourage third-party participation in SPP's transmission planning and construction and facilitate timely construction of needed transmission upgrades.

Reasons for assignment or novation

Numerous factors can result in a decision by a designated Transmission Owner to assign or novate a transmission project. These can include, but are not limited to, funding or financing limitations, increased costs of financing, and inability to timely construct the project.

SPP has issued NTCs for assigned a number of large 345 kV projects to smaller Transmission Owners, several of which happen to be RUS borrowers. As a general matter, the RUS denies loans that comprise an undue risk to a borrowing cooperative, i.e., loans that are unusually large or that are for purposes that are not normally undertaken by the cooperative for its own power supply purposes. The availability of a loan also depends upon congressional appropriations that are sufficient to meet RUS' funding plans. Consequently, the availability of an RUS loan may not be known for a year or more after a request is made and the loan may not actually be funded for two years or more after the request. These factors make the availability of RUS funding highly uncertain for large regional transmission projects. As an alternative to RUS borrowing, cooperatives are able to finance projects with private capital. RUS borrowers have typically mortgaged all of their facilities to the RUS to securitize their RUS loans. In order to fund a new project with private capital, RUS borrowers must implement a lien accommodation with the RUS to exempt the privately financed facilities from the RUS lien. This accommodation, if successfully achieved, typically takes a number of months to achieve. Private financing can be expected to cost at least two to three hundred basis points more than a RUS loan. Accordingly, the expectations that SPP's smaller Transmission Owners can make timely commitments to construct projects directed to them for construction at a cost reflecting their historic carrying charge rates have not proven to be realistic.

FERC Incentives

In response to the Energy Policy Act of 2005, FERC issued Order No. 679[1] implementing new policies regarding Transmission Owners' cost of service. FERC explained its rationale for providing incentives to Transmission Owners in setting rates:

> 25. These challenges and risks [associated with siting large new transmission projects] are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind currents), not simply on a "local" basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be "obligated" to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability. Our policies also must encourage all other needed transmission investments, whether they are regional or local, designed to improve reliability or to lower the delivered cost of power.
>
> 26. To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment. The Final Rule identifies several policies that should be adjusted, where appropriate on the facts of a particular case, to encourage new transmission investment or otherwise remove impediments to such investment. Although each reform adopted by the Final Rule constitutes an "incentive" as that term is used by section 219, this label has caused some confusion in the comments. It is true that our reforms adopted in the Final Rule provide "incentives" to construct new transmission, but they do not constitute an "incentive" in the sense of a "bonus" for good behavior. Rather, as we explain below, each will be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case and

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

considering the fact that our traditional policies have not adequately encouraged the construction of new transmission.[2]

Among other things, FERC Order No. 679 allowed Transmission Owners to propose to include 100% of prudently-incurred Construction Work in Progress (CWIP) in rate base, thereby permitting Transmission Owners to avoid accounting for and collecting a return on and a return of Allowances for Funds Used During Construction (AFUDC), to permit higher returns on equity which in turn affects the Net Plant Carrying Charge (NPCC), and to permit a hypothetical capital structure.

FERC explained that it adopted the CWIP incentive because recovery of 100% of CWIP in rate base relieves "pressures on [utility] finances caused by transmission development programs" and provides "up-front regulatory certainty" and "improved cash flow[s]" for utilities and rate stability for customers.[3] FERC also stressed that CWIP recovery provides utilities "a higher credit rating and lower cost of capital, thus benefiting customers."[4] A higher credit rating and lower cost of capital makes it cheaper and easier for a utility to attract capital investment and borrow money to construct facilities, which benefits customers because the utility has fewer costs to recover from customers for new facilities.[5] Pursuant to Order No. 679, FERC has approved CWIP in rate base because it helps transmission projects stay on schedule, it offers a prompt return on investment, it improves utility cash flow, it enhances the utilities' credit quality and debt ratings,[6] and it results in better rate stability for customers.[7] FERC found that including CWIP in rate base passes on costs to customers during the construction period, which raises prices to customers earlier. The rise in prices results in reduction in customer demand, which allows the utility to avoid investing in unnecessary capacity expansion. Based on this logic, FERC found that "CWIP will generally allow utilities to pursue least *total* cost strategies to meeting their customers' electric power demands,"[8] which results in cost savings for customers.

FERC incentives are available to those jurisdictional utilities that seek permission for and justify the need for the incentive. Furthermore, because FERC required utilities seeking CWIP recovery to submit additional information about their construction programs, the recovery of CWIP allows FERC the "opportunity to review and judge the prudence of costs as those costs are incurred and claimed in rate

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[2] Order No. 679 at PP 25, 26.

[3] Order No. 679 at P 115.

[4] *Id*. In the comments supporting FERC's notice of proposed rulemaking prior to Order No. 679, parties stated that the CWIP incentive allows the utility to balance the short and long-term impact on rates, and avoid rate shock on customers. *See e.g.*, Comments of San Diego Gas & Electric Company, Docket No. RM06-4-000, at 15 (Jan 11, 2006) ("Including CWIP in rate base instead of accruing allowance for funds used during construction will increase short-term rates during the construction period but reduce long-term rates once the project goes into commercial service.").

[5] *See* Order No. 679 at 115.

[6] *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 6 (2008); *see also id.* at P 42 (FERC approved PPL's request to recover 100% of CWIP in rate base because FERC found that the incentive " enhance[s] [PPL's] cash flow, reduce[s] interest expense, assist[s] Petitioners with financing, and improve[s] Petitioners' coverage ratios used by rating agencies to determine credit quality by replacing non-cash AFUDC with cash earnings…[t]his, in turn, will reduce the risk of a down grade in Petitioners' debt ratings."); *see also ITC Great Plains, LLC*, 126 FERC ¶ 61,223, at PP 80-82 (2009); *Otter Tail Power Co.*, 129 FERC ¶ 61,287, at PP 32-33 (2009); *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284, at PP 57-61 (2007).

[7] *See Green Power Express LP*, 127 FERC ¶ 61,031, at P 67 (2009); *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 42 (2008) ("By allowing CWIP for the Project, the rate impact of the Project can be spread over the entire construction period and will help consumers avoid a return on and of capitalized AFUDC.").

[8] *Id*. at 24,331.

base, rather than at a later point in time when a project is completed or abandoned and a potentially unwise investment has already been made."[9] Therefore, another benefit of CWIP is a regulatory agency's ability to review CWIP expenses to determine the prudence of the utilities' investments as they are incurred, which protects customers from imprudent costs

To date within SPP, FERC has approved rates including CWIP only for transcos, i.e., ITC-Great Plains, Prairie Wind, and Tall Grass. SPP's analysis of the projects novated to ITC-Great Plains and proposed to be novated to Prairie Wind has demonstrated that, for the same cost of capital, the cost of CWIP and AFUDC are essentially the same over time. The primary benefit of CWIP to the builder is that capital markets perceive less risk in funding projects receiving CWIP treatment in rates and consequently should fund projects eligible for CWIP at a lower cost of capital than an AFUDC only project. SPP has not analyzed the effect of CWIP treatment on a project's cost of capital. While holding cost of capital equivalent, SPP has analyzed the effect of CWIP's increased short-term rate impact versus AFUDC's increased long-term rate impact and has found them to be approximately rate neutral when viewed from the perspective of the present value to the transmission customer. To the extent that CWIP rate treatment of a project does result in a lower cost of capital than AFUDC would, SPP believes that CWIP will provide benefit to customers based on SPP's conclusion that the CWIP is otherwise equivalent to AFUDC.

Creating a definitive side-by-side comparison of the impacts of rate-making factors such as NPCC, CWIP, and AFUDC would be challenging for several reasons:

1. There is no adequate baseline for a comparison, as it may not be financially feasible for the original designated Transmission Owner to build the project, at least not at its traditional cost of service. The original designated Transmission Owner that decides to assign or novate a project may not deem it necessary to estimate the project cost.
2. The various cost components are interrelated. Neither SPP, the original designated Transmission Owner, nor a third-party builder, is able to precisely determine its financing costs in the project estimation phase.
3. The final rate is dependent on a FERC determination regarding the justness and reasonableness of the appropriate incentives.
4. The rate impact will depend on the Transmission Owner to which the project is assigned.

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Conclusion

In an effort to address the concerns raised by the Motions from the RSC, SPP Staff suggests the solution is multi-faceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:

(1) SPP will provide proposed Novations and supporting analysis to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC.

(2) Staff will increase efforts to communicate with state commissions and state commission staff members about how the regional planning and cost allocation processes work, and more specifically

[9] Order No. 298 at 30,515.

how and when estimates for transmission projects are requested by SPP and provided by Transmission Owners to SPP, including opportunities for adjustments.

SPP also suggests increased communication between jurisdictional transmission owners and state commissions might result in a better understanding of the Transmission Owners' processes for development of cost estimates and causes for variances in cost estimates.

Design and Construction Standards Whitepaper

RSC Motion 3

RSC recommends that SPP consider establishing design and construction standards for transmission projects at 200kv and above that are regionally funded.

Purpose

Provide a consistent and economic construction standard that can be implemented by all transmission owners and builders on the SPP transmission system.

Initial Proposal

To bring uniformity and economies of scale to regionally funded transmission projects, SPP will develop and maintain design and construction standards. The effort will provide consistency in the bulk transmission system. It also enhances reliability and reduces compatibility issues by having standard components used by all builders of the transmission system. Use of the same transmission protection standards eliminates any compatibility issues and ultimately increases reliability of the system. SPP will establish these standards as a result of a collaborative effort based upon the best practices being followed by members. The final draft of the standards will be approved by Transmission Working Group (TWG), followed by the Markets and Operations Policy Committee (MOPC). A long-term goal is to better manage construction costs. The initial focus of this task will be on the components that have the greatest variability in cost. The major components suggested for establishment of regional standards are detailed in the list below.

Though construction cost for transmission projects vary based upon location and other factors, establishing regional construction standards on the basis of best practices can provide guidelines and set expectations for construction standards that may be considered on a regional basis. These include:

- Conductor size
- Minimum ampacity value
- Fiber optic ground wire construction standards
- Structure/wooden pole construction specifications
- Foundation construction standards
- Substation control room construction standards
- Insulation and insulation hardware construction specifications

Interpretation of Standards and Tracking

SPP staff will be responsible for interpretation and application of regional standards and will track projects to ensure regional standards are being followed for regionally funded projects.

In some special circumstances, it may be necessary to deviate from the regional standard. Any requests for deviation/exception to the regional standard will need to be submitted to SPP staff for approval.

Example of Transmission and Substation Design Standard

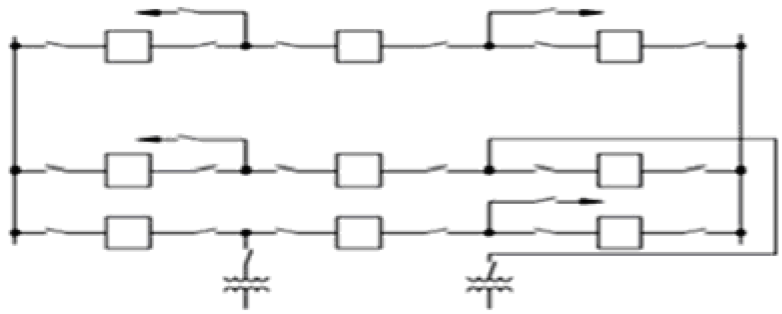
Breaker Configuration

Each new substation 230 kV and above should have an initial one-line of the substation and ultimate one-line of the substation. SPP staff should review the initial and ultimate substation arrangements. The SPP staff review should ensure substations are designed to accommodate future expansion of the EHV system. The following table lists the basic design for substation arrangements. The substation should be designed to accommodate the ultimate substation arrangement. This includes the purchase of land to accommodate the ultimate substation.

Voltage	Number of terminals	Substation Arrangement
230 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four	Ring Bus
	Five	Ring Bus
	Six	Ring Bus
	Seven or greater	Breaker and a half
345 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Ring Bus
765 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Breaker and a half

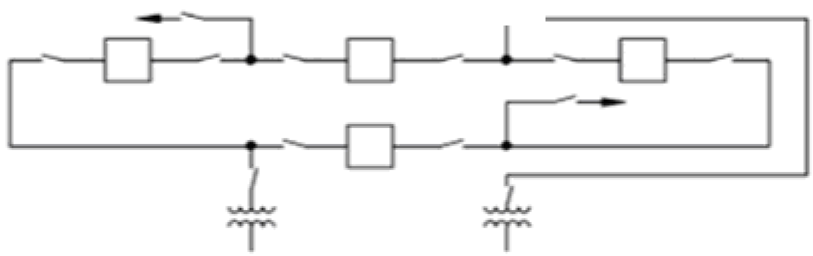
The following drawings show typical breaker arrangement for ring bus and breaker and a half.

Breaker-and-a-Half



Typical One-Line Diagram

Ring Bus



Typical One-Line Diagram

Terminal Equipment Minimum Rating

Minimum terminal rating substation equipment may be as follows:

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Transmission Line Design

The transmission line strength needed depends on several factors including geographic location, weather conditions, overhead ground wire and support structures of the line.

When selecting the appropiate design load, the engineer designing the transmission line should evaluate the climatic conditions and previous line operation experience. The National Electrical Safety Code (NESC) indicates the structure clearence requirements and component strength. All of these factors need to be considered in the transmission line design. The design engineer should complete an economic study to determine structure configuration and type (wood, steel or prestressed concrete). The economic structure should be selected. Exceptions to the economic structures should be reviewed by SPP staff.

Minimum Conductor sizing

SPP Criteria 12.2 addresses rating for transmission circuits. Minimum ampere rating for 230 kV and above transmission circuits are noted below. Any exceptions must be proposed and approved through the appropriate SPP process.

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Cost Estimate Whitepaper

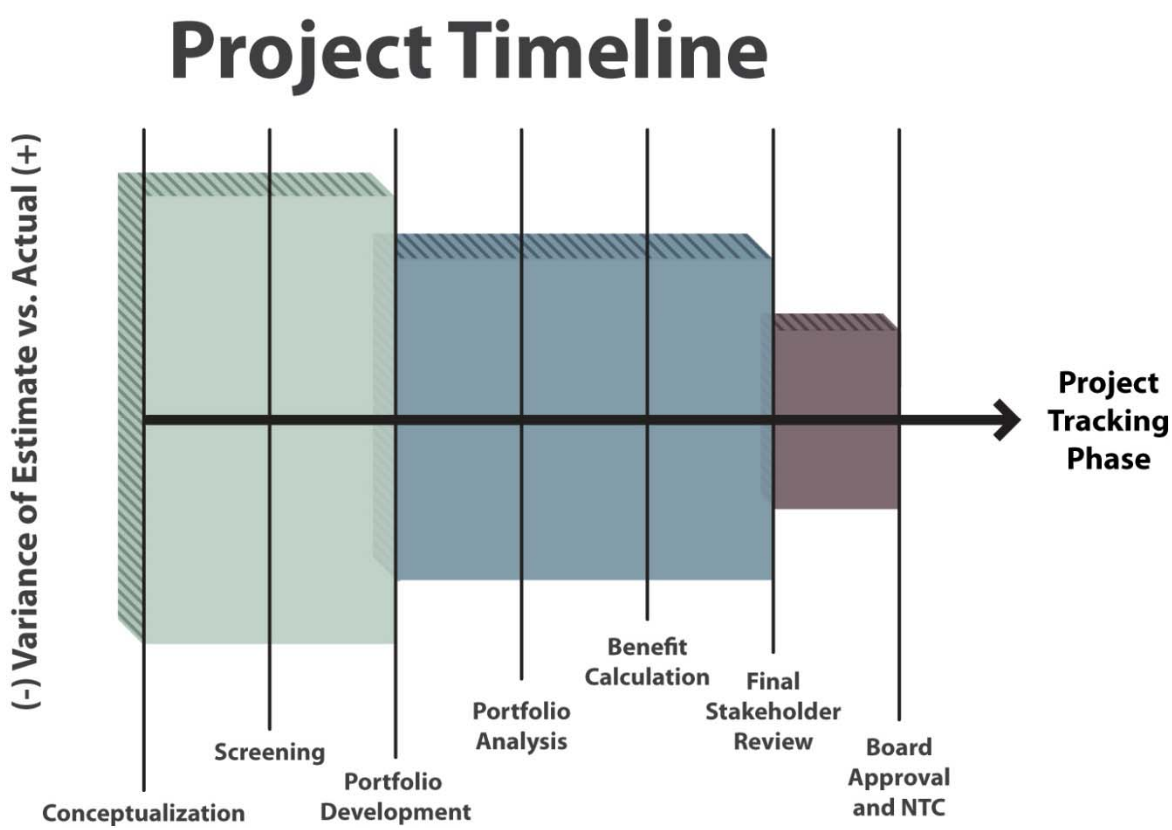
RSC Motion 4

During their Monday, October 25th, 2010 meeting, the RSC passed the following as Motion 4:

> **SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.**

Introduction

To ensure consistency in the development of cost estimates, SPP staff and stakeholders will create a standardized and transparent method for generating estimates. To allow estimates to evolve and become more refined as projects move from concept to construction, there will be multiple points in the planning process where cost estimates will be updated and increasingly higher levels of accuracy will be required. The Project Timeline illustration below shows how the planning process is broken into three stages. Each of these stages will have progressively tighter requirements on cost estimate accuracy and detail of data.



Stage 1

When projects are first conceived, cost estimates will be developed by SPP staff using a generic cost estimate tool. The tool will be developed in conjunction with the Transmission Working Group (TWG). The estimating tool will include generic cost data such as cost per mile for specific voltage levels, substation cost estimates, and cost modifiers for different regions, terrain, urban/rural, etc. This will allow estimates to be easily developed for the purpose of screening large numbers of potential projects and selecting suitable candidates for more detailed study. The simplified example below shows how a cost estimation tool might be developed. To estimate the cost of a project, the cost/mile of conductor and right of way (ROW) for a particular voltage class would be multiplied by the line length. Then the estimated cost would be multiplied by the applicable ROW multipliers to account for factors that can affect the cost of line construction. Finally the substation costs would be calculated and added to the total project cost estimate.

Simplified Illustrative Example

	Conductor/Structure Cost per Mile	ROW Cost per Mile
115	$	$
230	$$	$$
345	$$$	$$$

	ROW Multipliers
Urban	1.5
Rural	0.8
Plains	0.8
Mountains	1.5

	Substation Adder
Breaker	$
Xfer	$
New Sub	$

The output of the tool will be a table giving the total cost for each project being considered as well as all of the information that went into developing those. This will make it easy to see the variations in cost estimates between projects and why those variations exist. An example of this output is shown below

Simplified Illustrative Estimate Tool Output

Project Owner	Owner 1	Owner 2	Owner 3
Project Name	Project 1	Project 2	Project 3
Voltage	115	230	345
Length (miles)	10	50	100
Conductor/Structure Cost per Mile	$	$$	$$$
ROW Cost per Mile	$	$$	$$$
ROW Conditions	Rural/Plains	Urban/Plains	Rural/Mountains
ROW Multipliers	0.8*0.8	1.5*0.8	1.5*0.8
Substation Adders	$	$	$
Total Cost	$	$$$	$$$$$

On an annual basis SPP staff, in conjunction with the TWG, will update the cost data contained in the cost estimating tool. To assist with this effort, SPP staff will provide a report which gives an aggregate summary of final cost data collected in the project tracking process. [1] This will ensure that the cost estimate tool can be kept up-to-date and will help refine the tool to match actual final cost data.

Stage 2

Stage 2 begins after the initial project screening is completed and the list of potential projects has been narrowed to those most likely to be selected. It will be necessary for the incumbent Transmission Owner (TO) of each project to review and provide updates to the stage 1 cost estimates. This will help ensure that more accurate stakeholder provided data is used for the analysis and subsequent selection of projects. Differences between the stage 1 and stage 2 cost estimates must be accompanied by detailed explanations of the changes. This estimate is still considered to be a high level cost estimate; however, it is still expected to be within +/-50% variance from final construction cost.

Stage 3

The stage 3 estimates will be required after the analysis is completed but before a final report is submitted to stakeholders for approval and NTC issuance. Projects that will receive an ATP instead of an NTC will not be required to have a stage 3 estimate. The incumbent TOs will be required to submit a completed Standardized Cost Application (SCA). This is expected to be a very detailed estimate and should be within +/-25% variance of final construction costs. The SCA will include among other things a detailed explanation of changes between the stage 2 and stage 3 estimates. All stage 3 SCAs will be reviewed by SPP staff.

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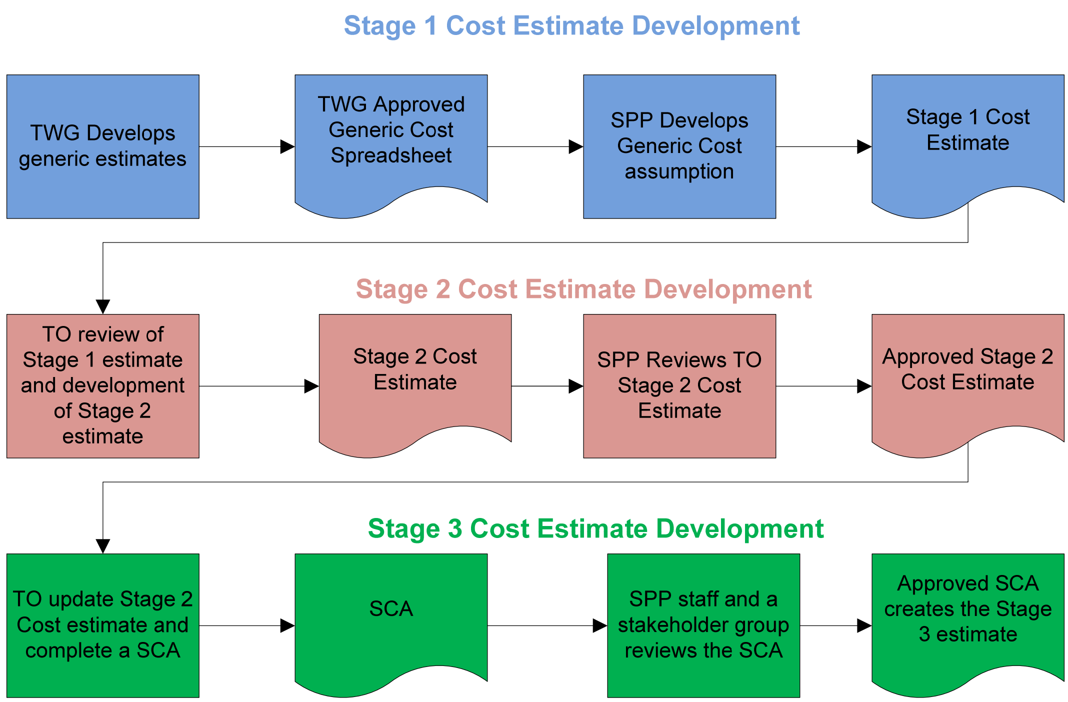
[1] The project tracking process is explained in the Cost Overruns/Underruns White Paper.

Cost Estimate Flowchart

Following is a flowchart of the three stages in the standardized cost estimating process.



Standardized Cost Application

The SCA is used to ensure that all cost estimates are in a consistent format which provides the following benefits:

- Provides consistent format among all estimates
- Facilitates the project tracking process[2]
- Ensures the appropriate level of detail is required

At the end of this paper is an illustrative example of a cost application which contains some of the detail which may be developed for an SCA.

[2] The project tracking process is explained in the Cost Overruns/Underruns White Paper.

Illustrative Cost Application Example

Project Description			
Estimate Provider			
Estimate Date			
In-Service Date			
	Details	**Cost Estimate**	**Comments**
Conductor	Size		
	Design		
	Electrical Capacity (amps)		
	Other		
Structure	Type		
	Material		
	Base		
	NESC Assumption		
	Dead Ends		
	Underbuild		
Substations	Transformers		
	Breaker Scheme		
	Protection Scheme		
	Voltage Control		
Construction Labor	Amount		
Right of Way (ROW)	ROW (Mileage)		
	ROW Condition (e.g., Urban, Rural, etc.)		
Eng. Design, Project Management, Permitting	Permitting/Certifications		
	Escalation Rate		
	Eng. Design/Proj. Mang.		
Loadings	Type 1		
Other Cost	Other Cost Factor Notes		
Total Cost			

Exhibit 2

SPP Staff Presentations on RSC Recommendations

Presented at Strategic Planning Committee Meeting on December 3, 2010

SPP Southwest Power Pool

Helping our members work together
to keep the lights on... today
and in the future

Helping our members work together to keep the lights on... today and in the future

SPP Southwest Power Pool

SPP Response to RSC Motions

Background

1. Priority Projects update provided to RSC and SPP BOD October 25-26, 2010
2. Updated report showed individual project cost estimate increases/decreases
3. Priority Projects cost estimates have increased a total of 24% or $217,000,000
4. RSC expressed concern over increases and presented four motions to SPP to address

RSC Motions

- RSC recommends that SPP review what is the best manner to address significant cost increases and/or overruns of transmission projects that are regionally funded.
- RSC recommends that SPP review the Novation Process and report to the RSC by April 2011.
- RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200kV & above that are regionally funded.
- SPP evaluate how cost estimates are established for transmission projects before Cost Benefit Analysis are performed.

Roles and Responsibilities

Section 3.3, SPP Membership Agreement

- SPP is responsible for planning and for directing or arranging necessary transmission expansions, additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service
- SPP will direct the appropriate Transmission Owners (TO) to being implementation of projects upon approval of the projects
- SPP will solicit and evaluate proposals and select a replacement where a designated TO cannot or does not implement project timely

SPP OATT – Attachment O, Section VI (1)

- SPP shall not build or own transmission facilities
- SPP designates timely TOs to construct, own and/or finance each project in the SPP Transmission Expansion Plan

Traditional process for transmission project cost estimates

- Project cost estimation and project management addressed by each TO through their internal processes
- Adjustments to cost estimates prior to “a spade of earth being turned” would have remained internal to the TO

Today: RTOs and Regional Cost Allocation

- SPP's open and transparent planning processes provide more information earlier than ever before
- Regional cost allocation has increased awareness of the value and necessity of accurate project cost estimation
- ITP planning process

  Each project is part of an integrated whole

  The combination of the projects provides the regional benefits

  Changes to one piece of the whole affects the whole

Role of State Regulatory Authorities

- Disallow imprudent or unreasonable costs
- Impose conditions on siting approval or CCN to require periodic reports on cost estimates of a project
- Intervene in another state's regulatory proceeding
- Intervene at FERC in rate cases
- Review and/or approve a utility's Integrated Resource Plan

Pieces of the Puzzle

- SPP – Responsible to provide a transparent regional transmission planning process
- SPP TOs – Responsible to construct and own transmission facilities
- SPP Regulators – Responsible to regulate within their statutory authority and construct

Southwest Power Pool

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and in the future

Cost Overrun/Underrun Monitoring Proposal

SPP Staff

SPP Southwest Power Pool

Purpose

- Response to recent transmission project cost estimate increases after project approval
- Improvement of SPP's current Project Tracking
  - Mechanism to help control cost overruns/underruns
  - Provide greater transparency
  - Increase data sharing

SPP 4

SPP Project Tracking Prior to 2007

- Projects reported through Transmission Planning
  - Projects reported by type of planning activity
    - Contained project description, in-service date, cost estimate, and engineering data
  - In 2006 annual Expansion Plan presented to Market and Operations Committee (MOPC) with list of projects
  - In April 2007, first quarterly Project Tracking Report delivered to MOPC with Project Status
    - Complete
    - On schedule
    - Mitigation
    - Delayed

5

SPP

2007 - Strategic Planning Committee

- January 30, 2007 Strategic Plan approved by Board
  - Establish SPP Transmission Project Tracking process
    - Monitor STEP transmission projects
  - Develop quarterly tracking and reporting tool
  - Proactive support of members
    - Project approval
    - Siting
    - Cost recovery
  - Annual Report to BOD evaluating transmission projects

6

SPP

SPP Project Tracking after Order 890

- Formal project tracking started with Order 890 in December 2007
  - Sections VIII.1 and VIII.3 of Order 890 ensure projects built on time or with acceptable mitigation plans
  - Established project reporting on a quarterly basis with emphasis on project status and time of completion
    - Supported efforts already underway from SPP Strategic Plan
  - Project Tracking Reports posted to SPP website

7

SPP

Current Project Tracking Process

- Notification to Construct (NTC)
  - Establishes commitments for each upgrade
- Active Project Tracking
  - Transmission Owners communicate progress quarterly on key components of active projects
    - Status, in service date, estimated cost, final cost
  - Quarterly Project Tracking Report produced
    - Executive Summary, project metrics for active portfolio
  - SPP provides analysis for changes in dates and estimated costs
  - Actions taken for cost increases and mitigations

8

SPP

Project Status

- Project Status enhanced
  - Previous reports limited on description of status

Green	On Schedule
Orange	Unknown
Red	Delayed

Footnotes:

S	Project On Schedule
D	Delayed *Note: Information on Deferred projects currently being solicited from the T.O.*
C	Cancelled
X	Project Complete

  - Since 2008, report statuses expanded with further explanation

COMPLETE	Complete.
ON SCHEDULE <4	On Schedule 4 Year Horizon.
ON SCHEDULE >4	On Schedule beyond 4 Year Horizon.
NTC- COMMITMENT WINDOW	NTC issued, still within the 90 day written commitment to construct window and no commitment received
MITIGATION	Behind schedule, interim mitigation provided or project may change but time permits the implementation of project.
RE-EVALUATION	Behind schedule, require re-evaluation due to anticipated load forecast changes.
DELAY- NO MITIGATION	Delayed beyond the RTO Determined need date and no mitigation plan provided

SPP

Estimated Cost

- Estimated Cost analyzed for change
  - Since late 2009 SPP tracks and verifies cost changes greater than 20% with Transmission Owner
    - Follows guidelines of NTC White Paper approved by members
  - SPP will add Original Cost Estimate to analysis in 4th quarter of 2010

Cost Change Letter Sent	NTC_ID	Project Name	Project Type	Previous Cost Estimate	Current Cost Estimate	Cost Change Percent
11/8/2010	20014	Line - Plymell - Pioneer Tap 115 kV	regional reliability	$3,200,000	$5,534,364	72.95%
11/8/2010	20079	Line - Pratt - St. John 115 kV rebuild	regional reliability	$9,239,000	$13,418,922	45.24%
	20091	Line - Allen - Lehigh Tap 69 kV	transmission service	$4,131,000	$4,900,000	18.62%
	20091	Line - Athens - Owl Creek 69 kV	transmission service	$2,227,000	$2,633,000	18.23%
	20086	XFR - Halstead South 138/69 kV Ckt 1	regional reliability	$1,400,000	$1,650,000	17.86%

SPP

Project Tracking Report

- **Project Tracking Report provides analysis and comparisons on project portfolio**
  - **Early Reports included a short Executive Summary and a list of outstanding projects**

SPP 4th Quarter 2007 Project Tracking Report

Executive Summary

1.No upgrades classified as (RED) in this summary.

#2. To date in 2007, SPP project owners have completed 125 miles of new or upgraded transmission and related equipment representing an investment of $116 million.

#3.14 upgrades have been completed this quarter. $ 7 million in transmission lines and facilities were added from Richards - Piedmont and ReinMiller – Tipton Ford.

#4. SPP is tracking the development of 70 upgrades currently requiring mitigation plans (YELLOW).

Project Tracking Report

- **Project Tracking Report more robust as members and executives require further information**

4th Quarter Projected Transmission Miles Complete				
Voltage	Number of Upgrades	New Miles	Reconductor Miles	Total Miles
69	4	0	22.18	22.18
115	9	111.4	13.02	124.42
138	5	14	12	26
161	5	0	0	0
230	0	0	0	0
345	0	0	0	0
Totals	23	125.4	47.2	172.6

Scheduled Complete Next Quarter	
First day of Quarter	Last Day of Quarter
[illegible]	12/31/2010
Reliability	25 [illegible]
Reliability Non OATT	2 [illegible]
Zonal Reliability	2 [illegible]
Transmission Service	1 [illegible]
Generation Interconnect	0 $0
Balanced Portfolio	0 $0
Sponsored	0 $0
Zonal Sponsored	4 [illegible]
Total	34 [illegible]

Scheduled Complete Next 12 Months	
First day of Reporting Year	Last Day of Reporting Year
[illegible]	[illegible]
Reliability	75 [illegible]
Reliability Non OATT	9 [illegible]
Zonal Reliability	2 [illegible]
Transmission Service	14 [illegible]
Generation Interconnect	2 [illegible]
Balanced Portfolio	0 $0
Sponsored	0 $0
Zonal Sponsored	22 [illegible]
Total	124 [illegible]

3rd Quarter 2010 Project Tracking Status

Top number is number of upgrades in category
Bottom number is estimated cost of upgrades in category

Upgrade Type	Total	Complete	On Schedule	On Schedule - Later in 10 yr Horizon (NTCs Issued)	Behind Schedule - With Mitigation	Behind Schedule - Without Mitigation	Withdrawn, Cancelled, blank, or within NTC Window
Reliability	312 $1,739,071,038	48 $198,906,254	80 $419,288,938	16 $178,225,254	145 $872,813,581	14 $50,093,466	9 $19,743,545
Transmission Service	77 $548,684,487	16 $27,806,325	28 $324,830,147	5 $28,732,500	10 $80,965,773	0 $0	18 $86,349,742
Generation Interconnect	17 $104,464,731	7 $19,064,731	8 $58,960,000	0 $0	1 $25,590,000	0 $0	1 $850,000
Balanced Portfolio	17 $837,064,596	0 $0	12 $618,023,096	4 $207,791,500	1 $11,250,000	0 $0	0 $0
High Priority	25 $1,144,856,481	0 $0	1 $842,847	24 $1,144,013,634	0 $0	0 $0	0 $0

Current Process Overview

- SPP Project Tracking has evolved with the change and growth in transmission projects
  - Order 890 formalized process
  - Quarterly updates with Transmission Owners, quarterly reporting to executives
  - Project Status initial focus, expanded to all aspects of projects including estimated and final costs
  - SPP continues to improve and update process for accuracy and deliverability of project data
    - Project Tracking Database implementation
    - Cost estimate and overrun white paper in development

Other Organizations' Processes

- CREZ
  - Detailed monthly reporting
  - Baseline starts 6 months after CCN approval
  - Cost increases are reviewed and must be reasonable to be included in their rate case with the PUCT
- ISO-NE
  - Transmission costs that exceed reasonable variance become localized costs
  - ISO-NE can request an update at random but requires three per year

Other Organizations' Processes

- NYISO
  - Risk profile included with cost estimate and is approved by NYISO working group
  - Risk profile addresses what parties are responsible for cost overruns, otherwise the cost remains with the developer
  - Quarterly updates
- MISO
  - Quarterly reporting
  - No enforcement mechanism

SPP 15

Proposed Process Improvements

- Baseline is the Stage 3 cost estimate used in the NTC called the NTC Project Estimate (NPE)
- Only projects with a cost over $5,000,000 will report monthly
- Projects with a cost less than $5,000,000 will report quarterly
- The update will be a detailed cost breakout which mirrors the Standardized Cost-Estimate Application (SCA)
- Updates required even if there is no change

SPP 16

Process Improvements (continued)

- NPE maintained throughout whole process for tracking purposes
- All cost estimate changes must be explained by the TO
- If overrun/underrun percentage exceeds 25% of the NPE, then project will be reviewed by Project Cost Working Group (PCWG)

SPP 17

Review Process

- All projects outside the 25% variance
- Relevant data provided to the PCWG
  - Original SCA, Monthly Reports, Comments from TO & SPP
- Inquiry into reasonability of cost increases
- PCWG decides if project needs to be restudied by SPP
- PCWG provides report to RSC and BOD quarterly
  - Report posted on SPP website

SPP 18

PCWG

- Meet monthly (via teleconference) to review project tracking updates
- Quarterly report from the PCWG provided to the RSC and BOD
- Report on reasonability of cost overruns/underruns, project delays, impacts, etc.
- Determines if there is a need to restudy the project

PCWG Report to RSC and BOD

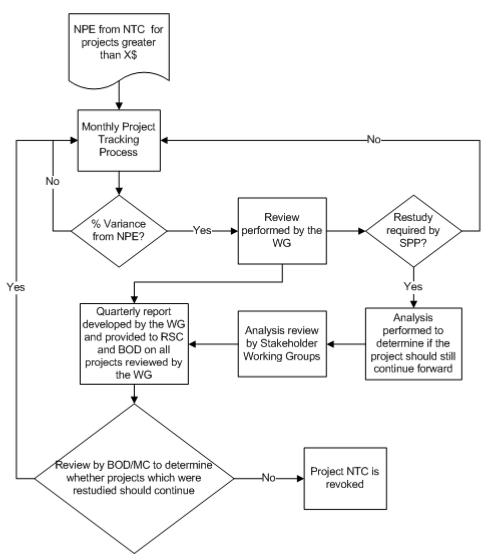
- Issues results of inquiry into reasonability of cost increases
- Provides comment as to if the overruns/underruns should be regionalized
- Recommends if a new baseline for the project cost is appropriate
  - Original NPE will still be maintained

BOD Action

- Multiple options for projects whose costs exceed the allowable variance
- Revoke NTC
- Allocate overruns/underruns locally or to developer
- Allow project to continue and reset baseline

SPP 21

Process Flowchart



SPP 22

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and in the future

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SPP Response to RSC Motions

RSC Motion 2: The Novation Process

Section 3.3(c), SPP Membership Agreement

- A designated provider for a project can elect to arrange for a new entity or another Transmission Owner to build and/or own the project in its place
- If a designated provider(s) does not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement.

SPP OATT – Attachment O, Section VI (6)

- A Designated TO may elect to arrange for another entity or another existing TO to build and own all or part of the project in its place subject to:
  - Entities that have obtained all state regulatory authority necessary to construct, own and operate transmission facilities within the state(s) where project is located
  - Entities that meet the creditworthiness requirements of the Transmission Provider
  - Entities that have signed or are capable and willing to sign the SPP Membership Agreement as a Transmission Owner upon selection of its proposal to construct and own the project, and
  - Entities that meet such other technical, financial and managerial qualifications as are specified in the Transmission Provider's business practices

Assignment versus Novation

- Assignment: TO can transfer responsibility for a project but remains legally and financially obligated to construct the project
- Novation: TO may seek to transfer all legal and financial responsibility and be relieved of all obligation for a project to an existing TO or an entity capable of becoming a TO in accordance with SPP OATT and Membership Agreement

Novation Process Documents

- To facilitate novations, SPP created a standard agreement that has been filed with and approved by FERC
- SPP, through the stakeholder process, developed a Transmission Owner Selection process document to address the process for determining if an entity meets the qualifications to become a TO

Reasons for Assignment or Novation

- Factors that can result in a decision by a TO to assign or novate a project
  - Funding or financing limitations
  - Increased costs of funding
  - Inability to timely construct the project
- Example of limitations/restrictions of RUS funding

FERC Incentives

- In response to the Energy Policy Act of 2005, FERC Order 679 implementing new policies regarding TOs' cost of service – providing incentives
- Allowed TOs to include 100% of CWIP in rate base
- FERC incentives are available to jurisdictional utilities who seek permission for and provide justification of the need for incentives
- To date within SPP, FERC has approved rates including CWIP only for transcos

Challenges to Side-by-Side Comparison

- Creating a definitive side-by-side comparison of the impacts of ratemaking factors such as NPCC, CWIP, and AFUDC would be challenging for several reasons
  - There is no adequate baseline for a comparison, as it may not be financially feasible for the original designated TO to build the project, at least not at its traditional cost of service. The original designated TO that decides to assign or novate a project may not deem it necessary to estimate project cost
  - The various cost components are interrelated. Neither SPP, the original designated TO, nor a third-party builder is able to precisely determine its financing costs in the project estimation phase
  - The final rate is dependent on a FERC determination regarding the justness and reasonableness of the appropriate incentives
  - The rate impact will depend on the TO which the project is assigned.

Conclusion

The solution to addressing the concerns raised by RSC Motions is multifaceted. Staff believes increased transparency through the regional planning and cost allocation processes is beneficial, so proposes the following:

- SPP will provide proposed Novations and analyses to the RSC for review and discussion prior to submission to the MOPC and Board of Directors/Members Committee for approval for filing with FERC
- SPP Staff will increase efforts to communicate with state commissions and commission staff about the regional planning and cost allocation processes, and more specifically how and when estimates for projects are requested by SPP and provided by TOs, including opportunities for adjustments

SPP also suggests increased communication between jurisdictional TOs and state commissions might result in a better understanding of the TOs' processes for development of cost estimates and causes for variations in cost estimates.

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Regional Standards Whitepaper

RSC Motion 3

- **RSC recommends that SPP consider establishing design & construction standards for transmission projects at 200 kV and above that are regionally funded.**

Purpose

- **Provide a consistent and economic construction standard that can be implemented by all transmission owners and builders on the SPP transmission system.**

SOUTHWEST POWER POOL

Benefits of Regional Standard

- Uniformity throughout SPP footprint
- Reduces compatibility issues
- Enhance reliability
- Create level playing field for all builders

SPP.ORG 5

SOUTHWEST POWER POOL

Design of the Standard

- SPP staff in collaboration with TWG will develop a draft of the Standard
- Initial focus will be tasks that may cause cost overruns
- TWG and MOPC will approve the final standard

SPP.ORG 6

Major Components that may be considered for Design Standards

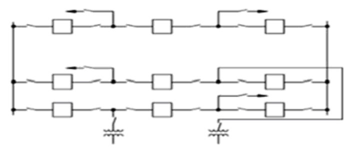
- Fiber optic ground wire construction standards
- Structure/wooden pole construction specifications
- Foundation construction standards
- Substation control room construction standards
- Insulation and insulation hardware construction specifications
- Conductor size
- Minimum ampacity value

SPP Proposed Substation Bus Arrangement

Voltage	Number of terminals	Substation Arrangement
230 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four	Ring Bus
	Five	Ring Bus
	Six	Ring Bus
	Seven or greater	Breaker and a half
345 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Ring Bus
765 kV	One	Single Bus
	Two	Single Bus
	Three	Ring Bus
	Four or greater	Breaker and a half

Proposed Minimum Terminal Equipment Rating

Breaker-and-a-Half



Typical One-Line Diagram

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Proposed Conductor Size

Voltage	Amps
230	2,000
345	3,000
500	3,000
765	4,000

Structure type

- Structure design should be based on National Electrical Safety Code
- The transmission line design engineer should complete an economic study to determine the correct structure type (wood, steel, or prestressed concrete).
- The economic structure type should be selected

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Cost Estimate Improvements

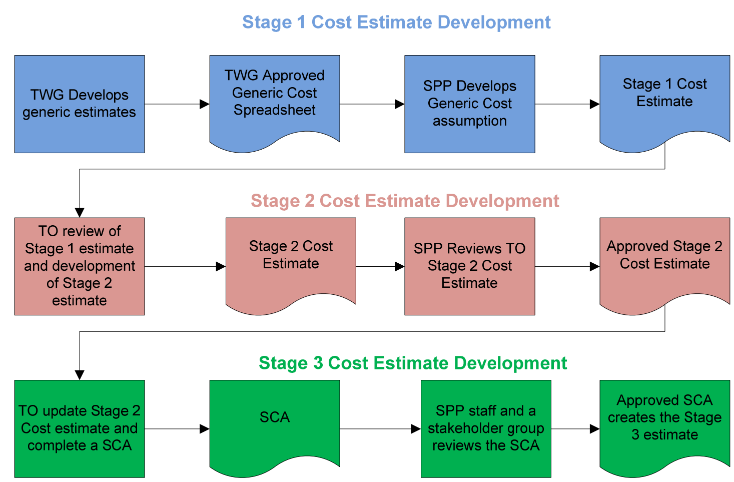
SPP Staff

SPP Southwest Power Pool

Purpose

- Improve Cost Estimate Process
  - Higher accuracy
  - Standardized Format
  - Increased Detail
  - Greater accountability

Cost Estimate Flow Chart



SPP 5

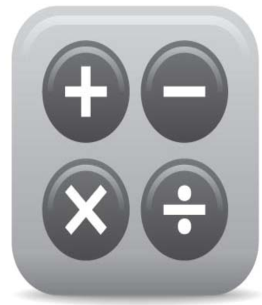
Stage 1: Project Concept Stage

- Estimates developed by SPP
- Estimate tool developed in conjunction with TWG
- Expected to be a high level estimate
- Used for screening large numbers of projects

SPP 6

Stage 2: Project Analysis Stage

- TO asked to review and update Stage 1 estimate
- TO will provide detailed explanations of changes
- Expected to be within 50% variance from final cost



Stage 3: Review and Approval Stage

- Updated estimate before final report
- Only applies to projects expected to receive an NTC
- Standardized Cost-Estimate Application (SCA)
  - TOs will be required to submit a completed SCA before the project can be approved
- High level of detail estimate
- 25% variance allowed from final construction costs
- SCAs will be reviewed by SPP and working group(s)

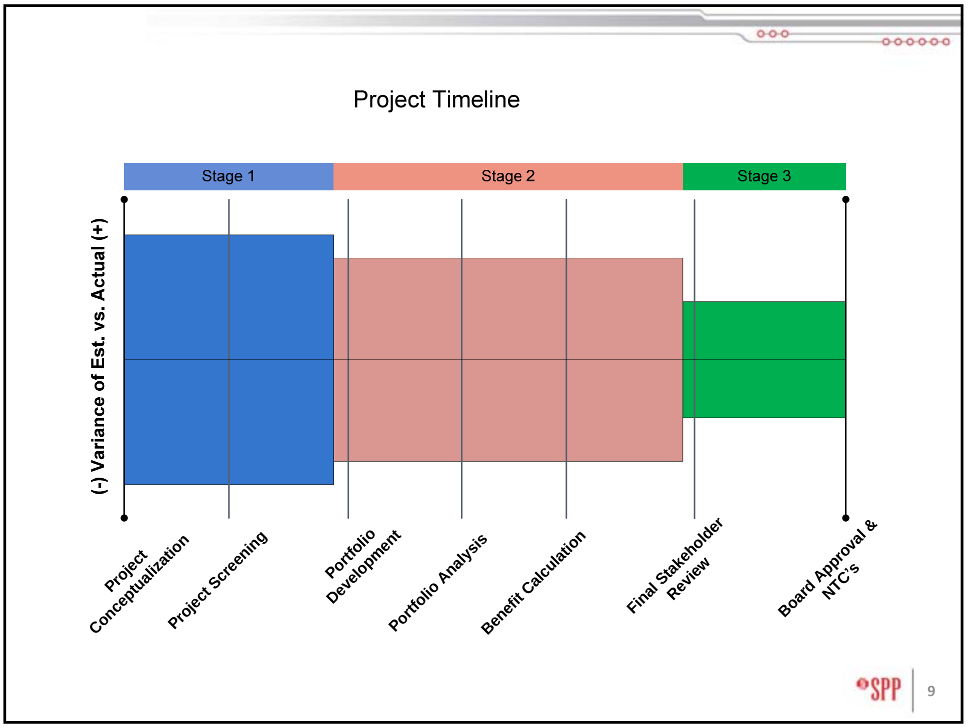

Project Timeline
Stage 1
Stage 2
Stage 3
(-) Variance of Est. vs. Actual (+)
Project Conceptualization
Project Screening
Portfolio Development
Portfolio Analysis
Benefit Calculation
Final Stakeholder Review
Board Approval & NTC's
SPP
9

Exhibit 3

Transmission Owner Proposal for Cost Estimation Review Process

for SPP Regionally Funded Transmission

Presented at Strategic Planning Committee Meeting on December 3, 2010

PROPOSAL FOR COST ESTIMATION REVIEW PROCESS FOR SPP REGIONALLY FUNDED TRANSMISSION

Presented on behalf of
SPP's Transmission Owners

SPP Strategic Planning Committee Meeting
December 3, 2010

REGIONALLY FUNDED TRANSMISSION

- SPP has regionally funded transmission since 2006
- Current Highway / Byway Cost Allocation:
  - Below 100 kV to host zone
  - Greater than 100 kV or less than 300 kV - 1/3 regionally allocated, 2/3 allocated to the host zone
  - Greater than 300 kV – 100 % regionally allocated

2

COST CONCERNS

- The RSC and SPP BOD have raised concerns regarding cost estimate increases after a project has been approved by SPP to be included in the regional rate
- Increases in estimates vs. what the actual costs will be

The Purpose of this Presentation
is to propose Cost Estimation concepts
to address those concerns

3

PROPOSAL TO ADDRESS COST ESTIMATION & CONTROL CONCERNS

- SPP's Transmission Owners (TOs) offer a proposal for consideration to address the cost concerns raised by the RSC and SPP BOD
- Concepts proposed herein are generally supported by the majority of SPP's TOs
- SPP Staff has participated in the development of these concepts and process

This is a Collaborative Effort

4

TO's INVOLVED IN THIS CONCEPT DEVELOPMENT

- AEP
- OG&E
- WESTAR
- XCEL – SPS
- KCP&L
- SUNFLOWER
- WESTERN FARMERS
- NPPD
- EMPIRE DISTRICT
- MIDWEST ENERGY
- LES
- City of Springfield
- OPPD*
- SELECTED SPP STAFF

* Invited but could not participate
*

5

PURPOSE

Develop guidelines that provide:

- Greater transparency with respect to the cost of transmission projects that are supported through SPP's Highway rate* (>300 kV),
- Regulators greater certainty with respect to the cost of transmission projects supported through the Highway rate
- Transmission Owners/Constructor's increased certainty that the approved project will be constructed
  - The "Right" Project
  - The "Right" Estimate for SPP analysis
- A streamlined, low cost process for reviewing such projects

*Note projects with a 1/3rd highway portion (less than 300kV or greater than 100kV) could be addressed at a later date

6

COST REVIEW PROCESS

The guidelines will provide guidance on:

- What projects are subject to cost review
- What information for cost review the Transmission Owner/Constructor must provide to SPP, using a standard format and the process for SPP's review of a Transmission Owner/Constructor's estimate
- Reasonable timeframe Transmission Owner/Constructor's need to create more accurate cost estimates
- Creation of a process for SPP's review of a project
- Periodic reporting of project estimated costs

7

COST REVIEW PROCESS

- Development and implementation of a standardized SPP cost review process for regionally funded projects (>300kV) would:
  - Provide consistent reporting of information regarding transmission projects
  - Increase the level of confidence regarding the accuracy of the cost estimates
  - Recognize that SPP needs accurate information regarding the estimated cost of transmission projects that are issued for a NTC in addition to adequate time for Transmission Owner/Constructor to prepare an estimate
  - Provide standardized guidelines to be used by Transmission Owner/Constructor to provide cost estimates to SPP
  - Provide guidance on when cost estimates need to be updated and for SPP to develop a review process for approving costs that flow through the regional rate

8

CURRENT PROCESS AND ADDITIONS

What SPP Does Today

1. Quarterly updates of estimates
   i. Identification of Projects over budget or behind schedule
   ii. Review capability by all (TO, SPP, Board, RSC and publicly available)
2. Cost estimates as directed by the OATT:
   i. Planning grade cost estimate and schedule (Att. O VII. f) page 1360
   ii. Interconnection Facility cost estimates (page 1466)
3. Work with TO on specific potential projects for evaluation by SPP.

In Addition (New)

1. Standard Template for Consistency of Estimates
2. Additional detail for projects ≥ $20 million and more detail for projects ≥ $100 million
3. Bandwidth of error to determine when new review/approvals are needed
4. Detail process outlining the estimating needs for a given project
5. Detail process providing adequate time to develop the appropriate cost estimate in each phase of a project from concept to construction
6. Estimate detail for the appropriate phase from Pre-NTC to Post-NTC

9

COST REVIEW THRESHOLDS

– If a cost estimate becomes greater than a pre-defined ***bandwidth*** of the previous estimate, updated detailed cost estimates and explanations would need to be provided to SPP for its review and consideration (Policy Issue)

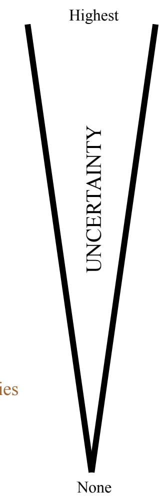
10

ESTIMATING BEFORE AND AFTER AN NTC

- Conceptual Estimate
  - Based on historical costs
  - Rough straight line path – no detail
- Study Estimate
  - Rough measure of Distance
  - Based on Historical Costs
  - More refined review provided to SPP

NTC Issued

- NTC response (90 days)
- Design Estimate
  - Detailed alternatives
  - Firm Routing
  - Known Environmental Issues
- Construction Estimate
  - All Labor, Material, Equipment, Contingencies
- Actual Cost



11

COST REVIEW PROCESS

- A cost review process would provide guidance as to:
  - when a cost estimate should be re-submitted to SPP and define what process SPP would follow to review the updated project costs allowing SPP to determine what action to take, if any, for that project
  - a template that would be completed with detailed information such as:
    - Project details (i.e., H-frame wood pole, monopole steel, monopole concrete, towers, conductor size, ratings, wind and ice loading, etc...)
    - Contingency costs (i.e., Routing risk, environmental risk, land-use risk, commodity unknowns, etc…)
    - Overhead costs (AFUDC, A&G, Regulatory costs, etc…)

12

COST REVIEW THRESHOLDS

- In order to conserve SPP's administrative resources, the level of SPP review would vary based on the magnitude of the project:
  - Projects less than 300 kV would not be subject to this review
  - Projects less than $20M would not be subject to this review
  - Projects greater than $20M but less than or equal to $100M would need to provide:
    - An overall project cost estimate and categorized cost breakdown for construction labor, materials, engineering and permitting.
    - An overall cost estimate of each alternative and their cost comparison.
    - Map and one-line diagrams.

13

COST REVIEW THRESHOLDS

(cont'd)

- Projects greater than $100M would need to provide:
  - An overall project cost estimate and detailed description of the categorized cost estimates for construction labor, materials, engineering and permitting.
  - An overall project cost estimate of each alternative; SPP may request a detailed description of the categorized cost estimates for construction labor, materials, engineering and permitting of each alternative.
  - Map and one-line diagrams.

- At SPP's request, a stakeholder meeting for all projects greater than $100M may be held

14

RECOMMENDATION

- A Task Force should be formed under TWG to develop the detail procedures and process clarification from the concepts outlined in this presentation.
  - The Task Force should be made up of Transmission Construction and Cost Estimation experts from SPP Member companies.
  - Policy issue on conditions when controls exceeded for SPC
- An initial Bandwidth aligned with AACE/EPRI/PMI standards as a starting point.

15

KEY TAKE AWAYS

1. Process addresses projects more than $20 million or high voltage projects (more than 300 kV) initially.
2. Improve the cost estimation process by creating:
   1. Templates for consistency among TO’s
   2. Guidelines for when reviews are required (Policy)
   3. Bandwidths when estimates need to re-approved
   4. Modified existing Quarterly Review Process
3. Create a Task Force under TWG to develop detail as a Business Process.
   1. SPC deal with policy issues

16