THE EMPIRE DISTRICT ELECTRIC COMPANY

INTERIM REPORT IN ACCORDANCE WITH STIPULATION & AGREEMENTS

FEBRUARY 3, 2012

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INTERIM REPORT REGARDING CONTINUED PARTICIPATION IN SOUTHWEST POWER POOL

SECTION 1: EXECUTIVE SUMMARY

The Empire District Electric Company (EDE) received approval from the Missouri Public Service Commission (MPSC) to participate in Southwest Power Pool's Regional Transmission Organization in MPSC Case Nos. EO-2006-0141. The docket was resolved through approval by the MPSC of stipulations. The stipulations provide for participation in Southwest Power Pool (SPP) during an "Interim Period" that terminates effective February 1, 2014. Two years prior to the termination of this Interim Period, the company is to "file a pleading accompanied by a study ("Interim Report") comparing the costs and estimated benefits of participation in SPP during a recent twelve-month test period." On a historical basis, EDE estimates that its total company 2007 through 2010 (4 year) net savings or trade benefits was approximately $21.6 million. The 2010 total company net savings was approximately $2.4 million of which $2 million would be attributable to Missouri retail jurisdictional customers.

The stipulation further provides that the companies will "collaborate with the Staff and Public Counsel regarding issues that either party may consider to be critical to a proper cost-benefit analysis." The companies conducted such a collaborative process with the MPSC Staff and Public Counsel in late 2011 and jointly developed an analysis plan for the Interim Report that was agreeable to the parties. The analysis plan developed in collaboration with Staff and Public Counsel is contained in Attachment A, "RTO Benefit-Cost Analysis Plan". Following is the presentation and discussion of the study resulting from that analysis.

A forward looking benefit-cost analysis was developed using a combination of existing benefit-cost studies to estimate and project the net benefits associated with the various Regional Transmission Organization (RTO) service and cost categories. The benefits and costs of functioning within the SPP RTO were compared to those associated with operating EDE on a stand-alone basis without membership in an RTO. The broad categories that were analyzed are the following: reliability services, power markets, transmission facility upgrades, RTO exit fees, and administrative costs. Each of these categories was analyzed in detail as described in Attachment B with the results presented below in Table 1. The tables show the net benefits (costs) associated with the EDE operating in SPP as compared to operating on a stand-alone basis. To the extent feasible, the results were framed as the annual net benefits for the period from 2014 to 2017, inclusive. The 2017 time horizon is consistent with the analysis plan agreed to by the parties and 2014 is the first calendar year subsequent to the termination of the current Interim Period. Additionally, 2014 is the year in which SPP plans to implement its enhanced power markets, referred to as the Integrated Marketplace.The projected average annual net benefits of participating in SPP are approximately $12.2 million per year for the 2014 through 2017 study period. These results include elements that were not identified in the original analysis plan but were anticipated with a provision for factors that have impacts which are more difficult to assess. These factors include the potential for future transmission facility cost allocation adjustments by SPP, higher transmission rates, price risk, and transaction costs associated with the RTO boundary. The following sections address each of the analysis categories. A summary of the analysis is presented in Attachment B.

SECTION 2: RELIABILITY SERVICES ANALYSIS

For purposes of this report, Reliability Services consist of reliability coordination, Tariff Administration, OASIS Administration, ATC/AFC/TTC Calculations, Scheduling Agent, and Regional Transmission Planning. The estimated value of reliability coordination services is taken from existing studies.

A fundamental service SPP provides is regional reliability coordination service to its members resulting in the minimization of disturbances, system events and outages on the bulk electric system. SPP estimates that these reliability services reduce and avoid between $185 million and $280 million per year for the SPP footprint.[1] It would be very difficult for EDE to coordinate on a regional basis as a stand alone utility in the same manner as performed by SPP through its process and cooperation of its members. For EDE to provide similar services in a reduced scope where EDE independently performs calculations and studies currently provided by SPP staff and coordinates with other entities in the region would require additional resources to dedicate to these tasks. EDE's estimated incremental costs to provide these basic functions in the stand alone case are approximately $65,000 per year.[2] EDE believes the estimated annual cost of transmission service to meet EDE reserve sharing support for the stand alone vs. RTO case is insignificant.

SECTION 3: POWER MARKET OPERATIONS

For the power markets analysis, existing studies were utilized to a large extent as detailed in the following sections.

3.1 ENERGY IMBALANCE SERVICES MARKET STUDIES

On July 27, 2005, CRA provided a study of the EIS Market for SPP. A copy of this study is Attachment D of this report. This study looked at three cases: SPP in its 2005 form with no EIS market, implementation of an EIS market in the SPP transmission tariff footprint, and a stand-alone case with no EIS market and abandonment of the SPP transmission tariff. CRA concluded that the net benefit of the EIS Market for all SPP participants would be $614 million over the 10-year study period.[3] CRA concluded a 10 year present value of $47.9 million benefit of the EIS market for EDE.[4]

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[1] Southwest Power Pool Filing, MPSC Docket EO-2011-0134, In the Matter of and Investigation into Southwest Power Pool Cost Allocations and Cost Overruns, December 29, 2010, page 18.

[2] Attachment D Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005 Appendix 4-3 Table 2 page AII-29

[3] Attachment D: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Page IX.

[4] Attachment D: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, Table 2, Page XI.

3.2 COMPANY STUDY OF ENERGY IMBALANCE SERVICE MARKET

The Stipulation and Agreement for MPSC Case Nos. EO-2006-0141 ("Stipulation") requires EDE to file this Report documenting the benefits of participation in the SPP EIS Market over a recent twelve (12) month period. The company study covered the scope detailed in the Stipulations by looking at a recent 12-month period defined as calendar year 2010 as well as analyzed the EIS trade benefits for the first three years 2007-2009 of the SPP EIS market.

3.2.1 SCOPE OF COMPANY STUDY

The Stipulation clearly defines the nature of the pleading and report that the company should file. Quoting the Stipulation:

> Two (2) years prior to the conclusion of the Interim Period, Empire shall file a pleading accompanied by a study ("Interim Report") comparing the costs and estimated benefits of participation in SPP during a recent twelve-month test period. As described in Section II.D, the pleading shall address the merits of Empire's continued participation in SPP.

3.2.1.1 INTERIM REPORT – BENEFIT/COST ANALYSIS

The Stipulation further describes the Interim Report that is to accompany the final pleading in the footnotes. Quoting Footnote 1 of the agreement:

> What is contemplated in this Interim Report is that the actual (modeled) production costs for Empire participating in the SPP facilitated markets will be compared to an estimate of what those costs would have been absent such participation for a twelve-month period. This Interim Report does not anticipate a SPP-wide cost-benefit study.

3.2.1.2 SCOPE OF COMPANY BENEFIT/COST ANALYSIS

The benefit/cost analysis attempts to compare Empire's actual operational results as a SPP member and EIS Market participant with a model simulation of estimated stand-alone results without the EIS Market.

The aactual operational case is Empire's actual results for the test period, which includes participation in the existing SPP EIS market. The Stand-alone without the EIS Market case simulates the company fleet using actual input values i.e. identical to the aactual operational case, but without any representation of interactions with the EIS Market. These actual model inputs included fuel prices, generating unit outages and new units coming online. Additionally, *hourly* actual values were input for system load, wind farm output profiles and bilateral purchases and sales of energy. This hypothetical simulation was conducted using PROSYM, the production costing model that EDE uses for fuel and purchase power budgeting. The model output provides an estimate of the production cost for the test period. The test period of the model is the 2010 calendar year to meet the requirement that the report cover a recent twelve month period.

Actual operating parameters were used in both cases. The analysis consisted of two separate cases with participation in the EIS Market being the only significant difference in assumptions. The comparison of these cases highlights the benefit of market participation through reduced production costs.
In addition to the estimate of production cost savings discussed above, Attachment C includes a comparison of other cost/benefit factors from the CRA Study estimates versus Empire actual charges related to SPP membership and participation in the EIS Market. These factors include FERC/NERC Fees, SPP Administration Fees and EIS Market Implementation costs. This historical analysis and results are identical to the those submitted to the Arkansas Public Service Commission pursuant to Order 9 in Docket No. 04-137-U on June 29, 2010 and June, 1 2011.

3.2.2 DESCRIPTION OF PROSYM MODEL

PROSYM is a complete electric utility analysis system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour investigation of the operations of electric utilities.

Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. Empire has utilized PROSYM for planning and for fuel and purchase power budgeting for several years.

3.2.3 RESULTS OF COMPANY STUDY

This study estimates that the total company net trade/benefit from participating in the EIS market in 2010 was $2.4 million. The Missouri jurisdictional allocation is approximately $2 million for 2010. Of the total company estimate, $0.8 million is from reduced production costs due to participation in the EIS Market.

Empire estimates that, on a total company basis, a net benefit of $21.6 million has been realized over the four years (2007-2010) of participation in the EIS Market as an SPP member. Such benefits would have been primarily in the form of fuel and energy cost decreases, which would have passed through the Fuel Adjustment Clause ("FAC") to Empire's customers via a reduced FAC charge. However SPP Schedule 1A and other RTO costs are recovered through a formal rate adjustment process.

3.3 FUTURE MARKETS STUDY BY VENTYX

The day-ahead and ancillary service market impacts for all companies in the region were analyzed in a study for SPP by Ventyx. This study, titled *Southwest Power Pool, Cost Benefit Study for Future Market Design, Final Report*, was issued on April 7, 2009 and is included with this document as Attachment G. The base case in this study assumes the current EIS market, with the change cases looking at different combinations and timing of day-ahead and ancillary service markets. Change Case IIA, with the start date moved to 2014 is the most appropriate scenario to use for this report because it corresponds to SPP's current plans for future markets. The Ventyx study results are available for EDE. The Ventyx market benefits can be added to those resulting from the EIS market studies detailed in Sections 3.1 and 3.2 of this document to create an estimate of the total benefits related to the future markets planned by SPP compared to a stand-alone case.

The Ventyx study looked at several scenarios of future markets. The annual net benefits of Case IIA from the report[5] are summarized below in Table 5.

Table 5: Ventyx Study - Case IIA Summary

Gross Benefits ($M)	SPP Subtotal	Unallocated Congestion	SPP Gross Benefit	EDE
2014	$209	$(73.00)	$136.00	$12.00
2015	$201	$(64.00)	$137.00	$14.00
2016	$232	$(79.00)	$153.00	$18.00
Average 2014-2016	**$214**	**$(72.00)**	**$142.00**	**$14.67**
2017				**$14.67**

The gross benefit values EDE and SPP (based on Table 4-13 of the Ventyx study) are shown in the table above. The average gross benefit for EDE is utilized in the overall benefits and cost summary as shown on the Attachment B. For 2017, EDE simply used the average gross benefit for 2014-2016; however believe this to be conservative as an increase in gross benefit is anticipated once additional SPP regional transmission projects are placed in service in 2017. Also, the EDE value is reduced by a prorated share of unallocated congestion from Table 4-13 of the Ventyx study as shown on the Future Markets line of Attachment B. The unallocated congestion deduction may well be mitigated (overstated) through the Integrated Marketplace issuances of Transmission Congestion Rights (TCRs) to EDE and congestion risk management practices.

3.4 CONSOLIDATED BALANCING AUTHORITY

The SPP consolidated balancing authority has the potential to reduce costs as compared to the current framework of individual balancing authority areas. In 2008, the SPP Consolidated Balancing Authority Steering Committee developed estimates of this potential cost savings. The savings largely result from a reduced workforce level required by individual balancing authorities and reduced regulation for load

[5] Attachment E: Ventyx, Southwest Power Pool, Cost Benefit Study for Future Market Design, Final Report, April 7, 2009, page 62.

requirements. The Steering Committee Executive Summary is included with this document as Attachment H. Although the Steering Committee only reported results through 2011, savings to 2017 have been estimated by escalating costs by 2.5% annually for additional years and are shown on the Balancing Authority Consolidation line of Attachment B.

3.5 ADDITIONAL CONSIDERATIONS

In addition to the existing market operations studies, other factors as discussed below need to be incorporated in order to provide a valid comparison between the SPP case and the stand-alone case:

3.5.1 COST TO IMPLEMENT FUTURE MARKETS

Current capital cost estimates of $1 million for both internal company and external vendor costs to implement the SPP Future Markets and the consolidated balancing authority will be added to the cost side of the SPP case. These estimated costs reflect internal and contract labor, market software license fees, hardware costs, and deal management and optimization site licenses. Amortized over a seven-year period, using a 10% interest rate, the costs equal approximately $$187,000 per year during the study period. It is estimated that $0.5 million in capital costs will be needed to interface with SPP and MISO markets if EDE is a stand-alone entity but desires to participate in these markets with resource bids/offers. This estimated cost is not included since it is optional as a stand alone entity to participate. The on-going expenses associated with new market systems and approximately six new full-time positions are about $1 million per year starting in 2014. Total estimated costs to implement integrated markets are shown in the Power Market Operations of Attachment B.

3.5.2 INCREMENTAL TRANSMISSION CHARGES FOR EXISTING RESOURCES DUE TO STAND-ALONE OPERATION

Stand-alone operations would involve significant incremental transmission charges because of the need to cross tariff boundaries for the purpose of importing power to and exporting power from EDE transmission systems.

Current estimated incremental annual costs of point-to-point transmission service to deliver energy from existing network resources to load are $9.345 Million. These estimates result from the actual MW value of reserved firm transmission service for existing network resources outside the EDE transmission system and within SPP multiplied by the expected SPP firm point-to-point through and out transmission rates for the period being considered in this report. Since EDE's StateLine Combined Cycle unit is jointly owned with Westar Energy. It is presumed that in the Stand Alone case, EDE would receive approximately $3.12Million in annual transmission revenue to offset part of the $9.345 Million SPP costs for a net of $6.225 Million in net cost for Stand Alone operations or savings by continuing membership in SPP and are included on the Transmission Service-Existing Resources line of Attachment B.

The cost of transmission upgrades associated with existing confirmed transmission reservations would be paid through the point-to-point transmission rates over the anticipated life of the reservations.

3.5.3 POSSIBLE IMPACTS INVOLVING EMPIRE'S PLUM POINT POWER STATION RESOURCE AS IT RELATES TO CONTINUED MEMBERSHIP IN SPP AND ENTERGY ARKANSAS, INC.'S POSSIBLE INTEGRATION INTO THE MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO) RTO.

EDE is a co-owner of the Plum Point Energy Station, a recently completed 665MW megawatt, coal-fired generating facility near Osceola, Arkansas, which entered commercial operation on September 1, 2010. EDE's 7.52% ownership interest entitles it to approximately 50 MW of Plum Point's capacity and associated energy. In addition, EDE entered into a long-term (30 year) purchased power agreement for an additional 7.5% of Plum Point capacity, with the option to purchase an undivided ownership interest in 2015 in the approximately 50 MW amount covered by the purchased power agreement. EDE's entitlements to Plum Point are base-load Designated Network Resources for EDE under the SPP Open Access Transmission Tariff. Since Plum Point is physically located on Entergy Arkansas's transmission system, Empire procured long term (20 years) point to point transmission service from Entergy Services, Inc. The transmission service agreement (TSA) was entered into in August 2006 and accepted by FERC in Docket Number ER06-1436. Transmission service pricing for this firm transmission service is based on the FERC accepted Schedule 7 of Entergy Services Open Access Transmission Tariff, which is currently approximately $18.48/kW-year or $1.848MM per year. It is our understanding from both Entergy Services, Inc. and MISO representatives that Empire's transmission service for Plum Point would be immediately converted to MISO's Schedule 7 through and out transmission service, which is currently $31.03/kW-year or $3.103MM, for an increase of approximately $1.26MM plus any additional MISO market related charges.

In addition, Plum Point is located in the PLUM Balancing Authority Area within the Entergy Arkansas transmission service area. Balancing Authority services for PLUM are provided by Constellation Energy Control and Dispatch, LLC ("CECD"). It is possible that the PLUM Balancing Authority would be consolidated (continuation of the PLUM BA may be a higher cost option) with the MISO Balancing Authority and be subject to MISO's scheduling and congestion provisions, which are expected to be higher than Entergy Services for delivery of receipts of capacity and energy from PLUM to Empire.

Currently, a substantive dispute exists between SPP and MISO related to the Joint Operating Agreement that affects Missouri utilities, including EDE. SPP and the SPP members believe that MISO must be willing to amend the JOA to include other fundamental improvements in connection with the negotiation of market-to-market re-dispatch terms. In order for the parties to effectuate the most optimal and accurate market-to-market re-dispatch process, the parties must first: (1) address and improve the existing flowgate allocation methodology applicable when non-reciprocal entities join the CMP (as MISO has committed to do in previous discussions); and, (2) resolve the current market flow calculation dispute. These two foundational issues must first be resolved before a market-to-market redispatch process can be negotiated and implemented because both items materially impact the performance and precision of any such process. The current flowgate allocation methodology does not account for all negative impacts to SPP, including Missouri utilities. This will be exacerbated in the event Entergy integrates into MISO.

SECTION 4: TRANSMISSION FACILITY UPGRADE ANALYSIS

4.1 BENEFIT AND COST OF SPP PROJECTS

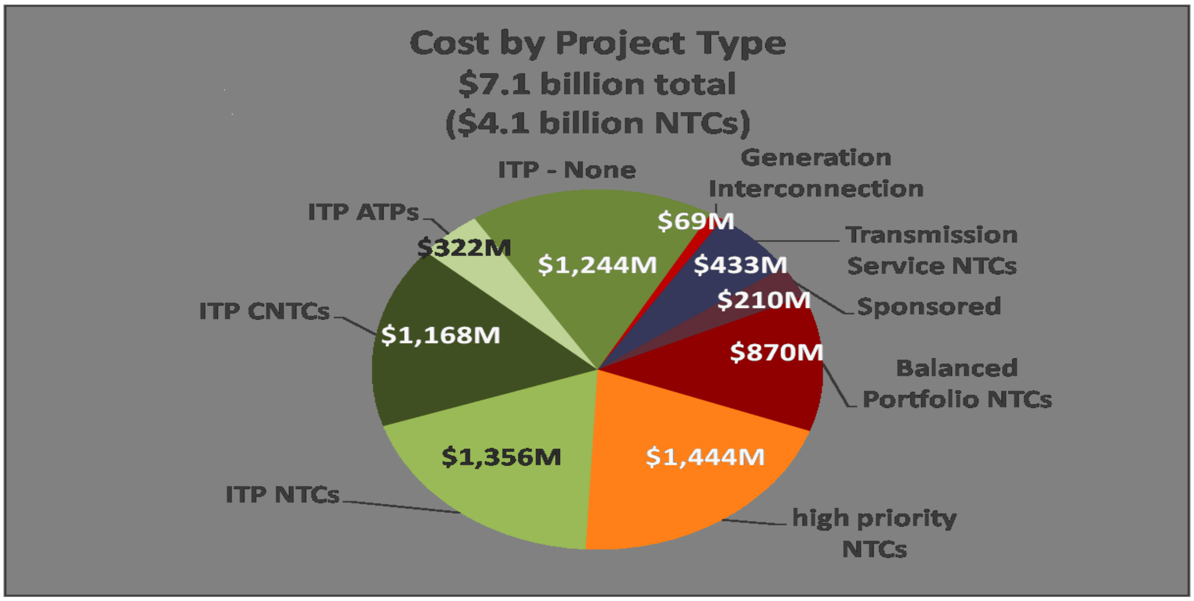
The work performed by the Regional State Committee's Rate Impact Task Force (RITF) serves as a key component of this analysis because it reflects projected costs of projects in the 2010 SPP Transmission Expansion Plan (SPP Board approved in early 2011).

As the Transmission Provider for the region, SPP is required to meet specific transmission service obligations and transmission planning functions. Transmission solutions for transmission service and generation interconnection requests are developed in order to effectively deliver various capacity and energy resources to load centers. Reliability upgrades are identified and planned within a robust transmission planning process in order to meet North American Electric Reliability Corporation (NERC) reliability standards for bulk electric system stability and ultimately end-use customer reliability. In addition, due to emerging market development, SPP has developed economic-based project sets that improve the region's generation and trade benefits, reduce grid congestion, deliver large-scale renewable generation such as wind power, and enable regional generation resource futures.

The resulting transmission obligations are apportioned to members according to specified provisions within SPP's FERC-approved transmission tariff. Some transmission upgrades have primarily zonal reliability benefits and are therefore cost allocated to that zone. Others transmission projects provide a wide set of regional benefits for which the costs are shared among all members in the region. The resulting set of annual transmission revenue requirements (ATRR) assessed to members is therefore a combination of these plans and cost allocations.

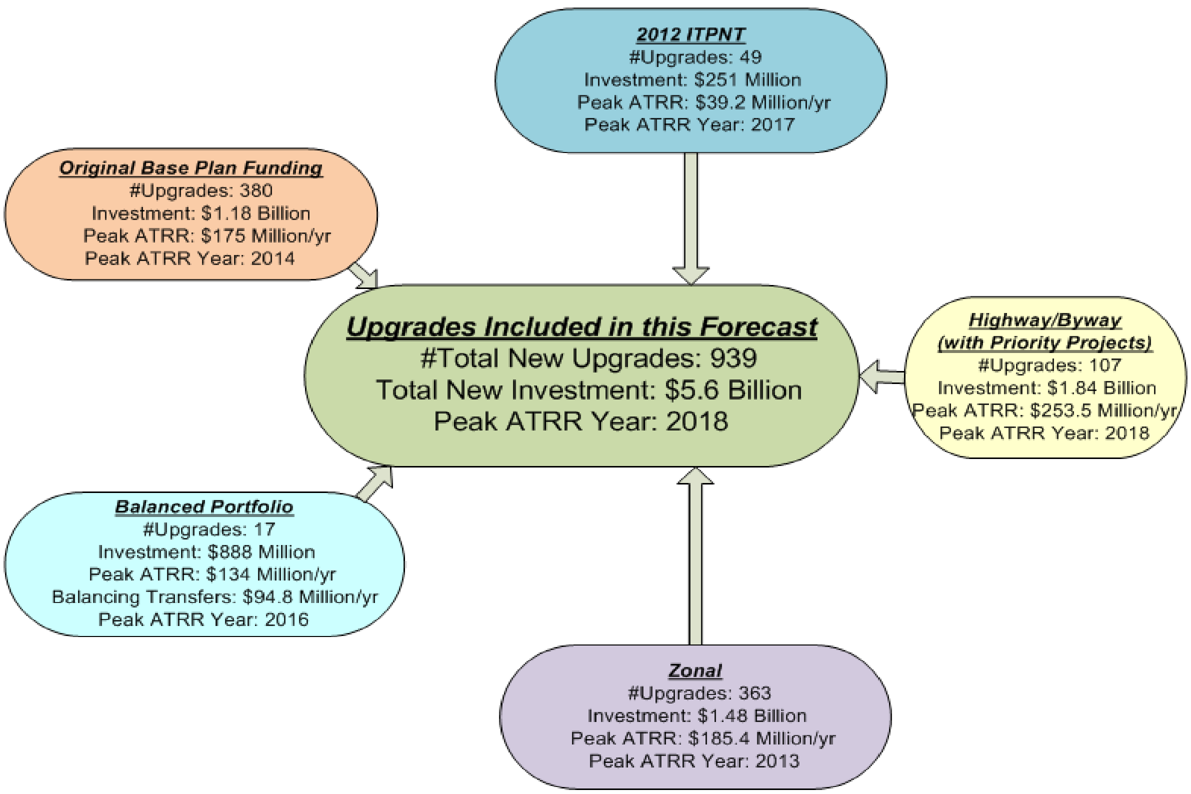
Included as Attachment F is the SPP ATRR Forecast Report to the SPP Regional Tariff Working Group and the SPP Regional State Committee, January 2012. This information was used to estimate EDE's average annual regional transmission allocation expense of $8.116 Million over the 4 year study period as stated in Attachment B. The analysis includes SPP's implementation of the Balanced Portfolio transfer credits that would be applicable to EDE as a benefit deficient zone beginning in 2012 through 2021.

On January 31, 2012, the SPP BOD approved the 2012 SPP Transmission Expansion Plan (STEP) which includes $7.1Billion (Figure 2012) in transmission projects that are under construction, noticed for construction, or planned for construction.



EDE hopes to obtain benefits from these transmission infrastructure additions: grid reliability, production and trade benefits, renewable integration, and delivery of generation to load centers. While not all reliability projects and additions for transmission service have quantifiable benefits, the economic-based project sets have defined and quantified benefits to the members and region. For SPP's Balanced Portfolio and Priority Projects combined project sets, SPP estimates the benefits are $480 million per year for the SPP footprint.

Annual benefits to EDE for the Balanced Portfolio and Priority Project sets for the 2014 to 2017 study period were derived from existing SPP project development analysis work with additional annualized calculations applied as shown in Attachment B. EDE has taken a conservative approach for the inclusion of these project set benefits ($0). As an example, gas price impacts, originally included in the Priority Project benefit totals, are excluded from the benefit calculations for EDE. As of January 14, 2012, below are the transmission upgrades approved by SPP with approximated annual transmission revenue requirements (ATRR). Regional transmission benefits that are realized by EDE will most likely be in the form of reduced energy/wholesale energy costs or increased sales margins that will flow through to the customer in a timely manner, whereas the actual SPP allocation of regional and zonal costs (Schedule 11) and RTO administrative fees (Schedule 1A) will be recoverable through a future general rate case in Missouri. In Arkansas and Oklahoma, the Commissions have approved and implemented SPP transmission recovery riders for the jurisdictional SPP members, including EDE.



Attachment F indicates the ATRR obligations for each SPP member which includes those projects after regional cost allocation and base plan funding were implemented. These are shown in the upper set of figures labeled as "Legacy Tariff Not Included with CWIP" and represent those forecasted transmission obligations in ATRR values from years since regional funding was instituted in 2006. They exclude those original "legacy" transmission obligations related to each member's original zonal network transmission assets.

SECTION 5 SPP EXIT FEE ANALYSIS

For the stand-alone case, an estimate of potential exit fees is necessary. It is expected that the framework for such fees will soon be modified as a result of SPP stakeholder discussions now addressing this issue.

Withdrawal obligations to SPP are based on existing transmission tariff and membership provisions that address facilities, systems and financial commitments necessary to maintain and implement transmission and energy market services to members. The portion of estimated withdrawal obligations attributable to EDE as of June 1, 2011 was $4.5 Million. SPP's projected EDE withdrawal obligation for February 1, 2014 is estimated to be $6.8 Million assuming the current withdrawal obligation method of determination remains unchanged. However, it appears the SPP will be filing at the FERC in 2012 for a change in withdrawal obligation methodology that would also include financial obligation related to regional transmission project long term allocations. Based on an SPP estimate of such SPP Open Access Tariff Schedule 11 cost allocation liabilities to EDE for regional projects approved to date, including the SPP 2012 STEP Near Term Projects, EDE's withdrawal obligation would be approximately $148Million ($6.8 Million plus $141MM (payable over a 10 year period)) in transmission allocation obligation. As previously mentioned the SPP has not finalized its change in withdrawal obligation policy and plan to obtain SPP BOD approval in 2012 with implementation in late 2012/2013.

SECTION 6 ADMINISTRATIVE COST ANALYSIS

On a stand-alone basis, EDE would be required to provide additional administrative functions for tariff administration, OASIS administration, transmission capacity calculations, transmission billing and settlements, scheduling agent, and regional transmission planning. These services are currently provided within SPP and relate to specific requirements and obligations that would be necessary for EDE to maintain and operate as a stand-alone transmission provider. One aspect that is not quantified in estimates is the potential for EDE to be required, as a condition for leaving the RTO, to engage a third party to conduct various administrative and planning functions to fulfill its obligations as a stand-alone transmission provider. The 2005 CRA study estimated administrative costs for EDE in Appendix 4-3, Table 2[6], which shows the EDE projected annual stand-alone administrative costs with a 10-year present value of $5,079,000. This amortized at a discount rate of 10% equals $827,000 per year. The study also shows additional-present value standalone costs of $707,000. This amortized at a discount rate of 10% equals $115,000 per year. The value above is utilized in the overall benefits and cost summary as shown on the Administrative Costs line of Attachment B.

SPP's current administrative cost/Schedule 1A is $0.255 cents/MWH of total load requirements for 2012. SPP's latest projections for Schedule 1A for the 4 year study period are $0.28/MWH (2014), $0.335/MWH (2015), $0.337/MWH (2016), and $0.338/MWH (2017).

SECTION 7 ADDITIONAL FACTORS

There are other factors that have a bearing on the benefits and costs of RTO participation that were not specifically addressed in the analysis plan for this study. Factors not readily quantifiable were provided for in the final section of the analysis plan with the statement that "they will be identified as additional considerations with an indication of the potential impact and direction in which the results likely would be affected." Such elements identified by the company include the potential for future cost responsibility to be shifted in order to balance project costs and benefits under the SPP tariff and the potential impacts of stand-alone operation on wholesale market transactions that were not fully captured in the studies. Although projecting the effects

[6] Attachment D: Charles River Associates; Cost-Benefit Analysis Performed for the SPP Regional State Committee, Final Report, Revised July 27, 2005, page AII-29.

of these elements presents additional challenges, the potential impacts are very substantial and should be considered in evaluating the overall benefit-cost results and the complete SPP value proposition over the long term.

7.1 REGIONAL COST ALLOCATION REVIEW

In order to mitigate the risk that SPP members could obtain future benefits insufficient to offset the costs of installed transmission projects, SPP has established specific tariff provisions in order to address such potential effects. These tariff provisions are being implemented through the Regional Allocation Review Task Force (RARTF) – a group composed of state commission representatives from the Regional State Committee and member representatives from the Markets and Operations Policy Committee, including an EDE representative. The scope and objective of these efforts was to develop the analytical methodology that will be used as a basis for any necessary forward-looking adjustments to cost allocations or project sets in order to minimize or eliminate inequitable cost-benefit effects on members. EDE expects that these provisions and the resulting cost-benefit adjustments will provide significant protections in connection with ongoing SPP membership cost allocations.

Obviously, the impact of such future policy changes and resulting adjustments cannot be determined at this time. However, a potential effect could be the implementation of adjustments to make whole those parties that have a negative net benefit resulting from the Priority Projects and future ITP projects approved for construction.

The SPP RSC and BOD unanimously approved the recommendations as to how SPP should conduct the Regional Cost Allocation Review. This included a recommendation of applying ten principles as a guide to conducting the review. These principles include: simplicity; acknowledgment of the “roughly commensurate” legal standard; equity over time; the use of best quantifiable information available; consistency; transparency; stakeholder input; the use of real dollars values; and the inclusion in the review of Board approved transmission plans with more weight being given to nearer term projects. Applying these principles the RARTF recommended and the SPP MOPC, RSC, and BOD approved that the review would contain two evaluations; (1) as required by SPP's OATT, the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a Notification to Construct (NTC) has been issued since June 2010 and (2) the evaluation of the benefits and costs of all SPP Board approved transmission projects for which a NTC has been issued since June 2010 plus Board approved transmission projects that have received an Authorization to Plan (ATP) with in-service dates of ten years or less.

The RCA review will apply a 0.75 weighting for ATP projects due to the less certain nature of these projects as well as their costs and benefits. The review be integrated with the 10 Year ITP Plan schedule and be undertaken after its completion. The review will use the aggregate value of dollars for all projects studied under the SPPHighway/Byway cost allocation methodology in dollars current to the year the review is conducted. To remain consistent with SPP's OATT, the review will use a 40-year horizon to evaluate all transmission projects. The information used in the review be the most up to date and that all assumptions be vetted through SPP's stakeholder process. Through the work of the Economic Studies Working Group (ESWG) certain benefits will be measured in the review. These benefits include: adjusted production costs; positive impact on capacity required for losses; improvements in reliability; remedy benefits in future reviews; reduction of emission rates and values; reduced operating reserves benefits; improvements to import/export limits; and public policy benefits. Additionally, the Report contains a recommendation regarding the establishment of a Benefit to Cost (B/C) threshold. The recommended B/C) threshold would be the basis for SPP staff and stakeholders to evaluate remedies for any zone falling below the threshold. Specifically, the Report recommends that: a threshold be set at a B/C ratio of 0.8. With this benchmark, if the review shows that any zones fall below this threshold; SPP Staff will study and report on potential remedies for these zones.

A list of recommended mitigation remedies was also approved for SPP staff to study and report on for any zone below the 0.8 threshold. The recommended list of remedies in preferential order includes, but is not limited to: (1) acceleration of planned upgrades; (2) issuance of new upgrades; (3) applying highway funding to one or more byway projects; (4) applying highway funding to one or more seams projects; (5) zonal transfers (similar to balanced portfolio transfers) to offset costs or a lack of benefits to a zone; (6) exemptions for cost associated with the next set of projects; and (7) changes to cost allocation percentage. Since EDE was a benefit deficit zone for the balanced portfolio, priority projects, and ITP10 projects, EDE believes this policy of cost allocation impacts and implementation of remedies to improve EDE's benefit/cost for regionally funded and allocated projects is vitally important to maintain and grow benefits related to SPP membership.

7.2 IMPACT ON WHOLESALE TRANSACTIONS

Transmission service priority, transaction costs, price risk, and point-to-point transmission rates all have material impacts on market operations. Each of these will have a negative effect on EDE if the company operates on a stand-alone basis rather than in the SPP footprint.

With regard to service priority, potential counterparties are less likely to enter into transactions with EDE when the transmission path crosses a tariff boundary because of the inability to secure a path that is as firm as what could be obtained if transacting with another party in the RTO footprint. The loss of potential counterparties due to increased risk of curtailments could materially impact the operating cost of the company. It is difficult to calculate the potential curtailments that might be incurred as a stand-alone entity because few market participants currently utilize lower priority non-firm point-to-point service for wholesale transactions. The company anticipates the increased use of non-firm point-to-point transmission service associated with stand-alone operations will result in an increased level of schedule curtailments impacting off-system sales volumes.

Another factor influencing the level of counterparty transactions across an RTO boundary is the cost and ease with which transactions in the same RTO can be conducted, as compared to transactions with an external entity. This consideration of transaction cost pushes market participants toward sales and purchases that do not cross an RTO boundary.

A third factor is price risk associated with external transactions, which typically cannot be hedged as easily as transactions within the RTO footprint. In the day-ahead integrated marketplace energy market under development by SPP, the price risk within the market can be managed through Transmission Congestion Rights, but price risk on transactions with external entities cannot be fully addressed in that manner.

A final element that impedes external transactions is the rate “pancaking” effect resulting from the assessment of point-to-point charges on one or both legs of the transmission path across an RTO border**.** Whereas, under the RTO, non-firm network service is utilized to make economical purchases from any source within the entire SPP region there would be an additional charge equal to the through and out rate for SPP added to the cost of these transactions. As an estimate for a typical year, EDE imports approximately 300,000 - 500,000 MWHrs of economy energy. If one applies an additional transmission charge of $4/MWH for imported energy, this would equal to an additional annual costs of $1.2Million to $2 Million or cause such transactions to be replaced by internal EDE generation. For 2014-2017 projections were made that serve as estimates of the rates that will be paid by an external entity to import power from SPP during that time period. Although the same numbers do not necessarily serve as projections of the wheeling rates for power exported from EDE as an entity external to SPP, including these rates in simulation of such power sales does recognize the effect of inefficiencies associated with the other factors described above (i.e., lower priority transmission service, transaction costs, and price risk).

EDE is not a large exporter of wholesale energy today and as a stand alone entity future sales would be further reduced due to increased wheeling costs for exports.

It is likely that the distribution of these wholesale transaction impacts is not symmetric and that the effect on the companies' adjusted production costs can be substantially greater in regard to purchase power than the impact from lost sales However, it was not feasible to quantify such effects with any certainty. Historically, member companies see a significant reduction in bilateral wholesale transactions with entities outside the RTO footprint. For example, a SPP member experienced a substantial decrease in transactions with parties in the MISO footprint after start-up of the MISO market. Similarly, a large company within MISO has reported that its wholesale transactions outside the RTO footprint nearly ceased when it joined the MISO market. Thus, external entities have less opportunity for sales and purchases than those inside an RTO, with consequent effects on those external companies' adjusted production costs.

7.3 ENVIRONMENTAL LAW AND REGULATION CONSIDERATION

On August 30, 2011, the Commission opened Case Number EW-2012-0065 to investigate the cost of complying with federal environmental regulations. EDE plans to actively participate in the process as the Staff works toward submitting its findings and recommendations to the Commission on May 1, 2012.

The public policy initiatives related to state and federal renewable energy standards and governmental regulation of emissions, environmental impacts, and public health could affect the future of long-term transmission planning. For instance, in June 2010, the Environmental Protection Agency (EPA) announced an emissions standard that will impact coal-fired electric generation facilities. Under this new standard, emissions from power plants and other industrial facilities will be required to meet a new "1-hour standard" designed to reduce short term exposure to Sulfur Dioxide (SO2). Additionally in 2010, the EPA opened rulemaking dockets to develop and implement standards to reduce the transfer of SO2 and nitrogen oxide (NOx) through the air and to regulate coal-ash, which is a by-product of traditional electric generation processes. These proposed rules, once implemented, will have an associated compliance cost that will be borne by industry participants and ratepayers. SPP is keenly aware and supportive of our efforts to respond to and defend such policies that could adversely affect our customers. In 2011, SPP sent two letters to the EPA regarding the pending regulations. SPP expressed its and its members concerns regarding the multiple pending regulations. The regulations of concern that the letter addressed include: the Clean Air Transport Rule, now finalized as the Cross-State Air Pollution Rule (CSAPR); the Coal Combustion Residuals Rule; revisions to section 316(b) of the Clean Water Act; and the Hazardous Air Pollutants changes for the regulation of mercury emissions from electricity generation units.

The finalized CSAPR utilized the EPA‟s Integrated Planning Model (IPM), and a review by SPP found the model did not dispatch several key generators in the SPP footprint. The removal of those generators from the SPP region could cause major reliability issues in SPP‟s current summer peak load flow models. SPP sent a letter regarding these issues to the EPA on September 20, 2011. The reliability issues included N-1 contingency violations totaling 1047 circumstances where voltage was 90% of nominal on 167 different buses and 220 cases where line ratings exceeded the 100% applicable emergency rating.

An even clearer representation of reliability violations was found by applying higher operability limits of 120% to the overloads, in which there were 16 such overloads on the system. Using a similar out of normal range, there were 93 circumstances where voltage dropped below 85% of nominal. These “clear-cut” examples of reliability standards violations represent well-founded concerns regarding the timeline with which the CSAPR would be instituted. In addition to these issues, there were 11 reliability cases that could not be solved in SPP‟s models. Such violations are clearly indicative of the EPA IPM‟s failure to account for reliability standard thresholds that SPP is required to maintain in accordance with Federal Energy Regulatory Commission approved standards. Through SPP’s leadership, EDE and other members are currently evaluating operational impacts due to compliance for 2013, 2014 and 2015.

There is no doubt that compliance implementation of these environmental requirements will affect operations and costs to our customers, however we do believe that the planned transmission expansion in the SPP and potential transmission expansion in the Southwest Missouri area will enable EDE to mitigate some of the negative impacts of such laws and requirements.