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Direct Testimony

of

Todd W. Tarter

August 2014

SERVICES YOU COUNT ON

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OF
TODD W. TARTER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. ER-2014-0351

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DIRECT TESTIMONY OF
TODD W. TARTER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO. ER-2014-0351

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Todd W. Tarter. My business address is 602 S. Joplin Avenue, Joplin, Missouri.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. The Empire District Electric Company ("Empire" or "Company"). My title is Manager of Strategic Planning.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Pittsburg State University in 1986 with a Bachelor of Science Degree in Computer Science. After graduation, I received a mathematics education certification. I began my employment with Empire in May 1989. During my tenure with Empire I have worked in the Corporate Planning, Strategic Planning, Information Technology, and Planning and Regulatory departments. My primary responsibilities during this time included work with the Company's construction budget, load forecasts, sales and revenue budgets, financial forecasts and fuel and purchased power projections, among others. In September 2004, I was promoted to my current position where I primarily work with fuel and purchased power projections, energy efficiency and integrated resource planning.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY STATE UTILITY COMMISSIONS?

A. Yes. I have testified on behalf of Empire before the Missouri Public Service Commission

("Commission"), the Kansas Corporation Commission, the Oklahoma Corporation Commission, and the Arkansas Public Service Commission. The case references are attached to this testimony as Schedule TWT-1.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE?

A. I will support Empire's proposal to continue its Fuel Adjustment Clause ("FAC") in this case. I will also support Empire's estimate of the ongoing level of on-system fuel and purchased power ("FPP") costs as part of this case. In addition, I will provide the information required by 4 CSR 240-3.161(3) for continuance of the FAC. I will also describe the adjustments for normalized coal and tire-derived fuel inventory balances and other fuel and purchased power test year adjustments.

Q. WHAT CATEGORIES OF ITEMS WILL YOU BE ADDRESSING IN REGARD TO FPP?

A. The on-system FPP expense values that I will be addressing can be grouped into the following categories: (1) normalized on-system FPP energy expense calculated with a production cost model; (2) fuel-related costs, such as unit train and undistributed and other costs associated with the normalized production cost model run; (3) natural gas-related costs, such as firm transportation, commodity charge, storage costs, undistributed and other costs and natural gas losses that are associated with the normalized production cost model run; and (4) other energy related costs, such as the cost of consumables associated with the power plants' air quality control systems ("AQCS") and revenue from the sale of renewable energy credits ("RECs"), net transmission costs and a Southwest Power Pool Integrated Marketplace ("SPP IM") adjustment. In connection with the normalized production cost run referenced above, I will describe the model, the modeling process, the results of the model run and some of the key data inputs to the model.

Q. PLEASE LIST THE ENERGY COST COMPONENTS ASSOCIATED WITH EMPIRE'S CURRENT FAC BASE.

A. Empire's current FAC base consists of FPP energy costs (including fuel related costs such as unit train, undistributed and other and variable natural gas transportation expenses), plus the cost of the AQCS consumables and net emissions cost, if any, less the net sales of RECs. The FAC base is then calculated on a per unit basis utilizing net system input expressed in kilowatt hours or megawatt hours. The current FAC base is $0.02831 per kWh. Based on the most recent analysis of the FAC cost components for the preparation of this case, Empire is proposing to raise the FAC base by approximately 7.3%, to $0.03037 per kWh, subject to any true-up adjustments that may be considered in this case. The FAC base comparison can be found in Schedule TWT-2.

Q. PLEASE EXPLAIN THE PROPOSED INCREASE IN THE FAC BASE.

A. As mentioned, the proposal is to increase the FAC base from $0.02831 per kWh to $0.03037 per kWh. However, as my testimony will later address, Empire is also proposing to make changes to the existing FAC, so this is not a direct comparison. For example, Empire is requesting to include the natural gas transportation and storage costs and net transmission costs in the FAC rider. Currently, these cost items are recovered in base rates and not in the FAC. As a comparison, the proposed FAC base would be $0.02747 per kWh or a 3 percent *reduction,* when only existing FAC components are considered. The adjusted fuel and purchased power costs included in Empire's case also include a savings adjustment for the recently implemented SPP IM.

Q. DOES THIS TESTIMONY ADDRESS ALL OF THE COSTS ASSOCIATED WITH EMPIRE'S FAC?

A. Yes, all costs associated with the FAC are either discussed in this testimony or presented in the schedules that accompany this testimony. The net transmission cost component is discussed more fully in the direct testimonies of Empire witnesses Aaron Doll and W. Scott Keith. In addition to the existing FAC eligible costs I previously described, I also am sponsoring some costs generally associated with FPP expense, such as purchase demand, natural gas firm transportation and natural gas storage costs that are not a component of the existing Empire FAC. As mentioned, Empire is proposing to include the natural gas firm transportation and storage costs in the FAC.

II. SUPPORTING INFORMATION FOR AN FAC CONTINUATION REQUEST AS REQUIRED BY 4 CSR 240.3.161(3)

Q. IS EMPIRE'S REQUEST TO CONTINUE ITS FAC DESIGNED TO COMPLY WITH THE COMMISSION'S RULES?

A. Yes. Empire has designed its FAC continuation request to comply with the Commission's rule governing the fuel adjustment process. The table below displays a list of the twenty (20) minimum filing requirements and where this information can be found in supporting schedules and testimony.

Rule Reference	Brief Description	Location
4 CSR 240.3.161 (3) (A)	Customer notice	Schedule TWT-5
4 CSR 240.3.161 (3) (B)	Example customer bill	Schedule TWT-4
5 CSR 240.3.161 (3) (C)	Proposed FAC tariff	Schedule TWT-3
4 CSR 240.3.161 (3) (D)	Explanation of FAC	Tarter Testimony
4 CSR 240.3.161 (3) (E)	FAC and opportunity to earn a fair ROE	Tarter Testimony
4 CSR 240.3.161 (3) (F)	(Over)/Under recoveries & true-up	Tarter Testimony
4 CSR 240.3.161 (3) (G)	FAC and prudence review	Tarter Testimony
4 CSR 240.3.161 (3) (H)	Specific costs and FERC accounts	Tarter Testimony
4 CSR 240.3.161 (3) (I)	Specific revenue and FERC accounts	Tarter Testimony
4 CSR 240.3.161 (3) (J)	Incentive features and benefits	Tarter Testimony
4 CSR 240.3.161 (3) (K)	Volatility mitigation	Tarter Testimony
4 CSR 240.3.161 (3) (L)	Company procedures/prudent costs	Tarter Testimony
4 CSR 240.3.161 (3) (M)	Customer class rate design	Tarter Testimony
4 CSR 240.3.161 (3) (N)	FAC, business risk and allowed ROE	Tarter & Vander Weide Testimonies
4 CSR 240.3.161 (3) (O)	How responses differ	Tarter Testimony
4 CSR 240.3.161 (3) (P)	Supply-side, Demand-side resource data	Schedule TWT-6
4 CSR 240.3.161 (3) (Q)	Unit heat rate & unit efficiency testing	Schedule TWT-7
5 CSR 240.3.161 (3) (R)	Existing IRP and objectives	Tarter Testimony
6 CSR 240.3.161 (3) (S)	Emission allowance cost/(revenue) & FAC	Tarter Testimony
7 CSR 240.3.161 (3) (T)	Authorization to release 5-years of surveillance	Tarter Testimony

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS EXISTING FAC TARIFF IN THIS CASE?

A. Yes. In addition to proposed changes to its FAC base to correctly reflect the current Missouri jurisdictional base cost of energy, Empire is requesting to include the net transmission cost to the FAC rider. For more information on this request, please refer to the direct testimonies of Empire witnesses Aaron Doll and W. Scott Keith. Additionally, Empire is proposing to include the fuel related natural gas transportation and storage costs that are not included in the existing FAC. I have attached a copy of the proposed FAC tariff sheet to my testimony as Schedule TWT-3. In general, Empire's proposed FAC tariff changes, for transmission charges/revenue and next-day market charges, are based on the existing Ameren Missouri FAC. Ameren Missouri is a participant in the Midcontinent Independent System Operator ("MISO") market. Similarly, Empire, as a member of the Southwest Power Pool ("SPP"), now operates as part of the recently implemented SPP IM or next day market. The proposed tariff contains the proposed base energy cost per kWh, and the following changes:

- Inclusion of net transmission costs and revenue recorded in FERC accounts 565 and 457, respectively;
- Inclusion of insurance premium for replacement power recorded in FERC account 924;
- Inclusion of transmission expense allocation charges recorded in FERC account 575; and
- The proposed inclusion of the natural gas transportation and storage costs are recorded in FERC account 547. This FERC account is already included in the existing Empire FAC tariff and natural gas transportation charges have been included in Empire's Missouri FAC in the past.

The proposed Empire FAC tariff is provided as Schedule TWT-3. Several of the major features of the proposed tariff are:

- Changes in the FAC factor are based upon 95 percent of the difference between the energy cost built into base rates and the actual cost of energy;
- Costs included in the proposed FAC calculation are based upon the actual Missouri jurisdictional historical expenses recorded in FERC accounts 501, 547, 555 and 565/575, including the cost/benefits associated with Empire's fuel hedging program and FERC account 447 for off-system/SPP next day market revenue. In addition, the FAC

will include the recovery of emission allowance costs (sulfur dioxide) recorded in FERC accounts 509, 411.8 and 411.9; the Renewable Energy Credit ("REC") revenue actually earned by Empire recorded in FERC account 456 and the cost of consumables associated with AQCS at Empire's generating units recorded in FERC accounts 506 and 548;

- Costs included in the proposed FAC calculation exclude the capacity charges associated with purchased power contracts with terms in excess of one year, but include the natural gas firm transportation and storage costs;
- Only two changes in the FAC factor are made each year, one in June and one in December;
- The current Missouri jurisdictional base cost of energy under the FAC is $0.02831 per kWh, but as previously mentioned, Empire is proposing to adjust this to $0.03037 per kWh subject to any true-up adjustments that may be considered as part of this case;
- Over/under recoveries of Missouri jurisdictional energy costs are refunded/collected periodically (every six months) from Missouri retail customers through the operation of the tariff;
- Over/under recoveries of Missouri jurisdictional energy costs are recorded on the books of the Company in FERC accounts using an asset/liability account to track over/under recoveries of energy costs on the balance sheet, FERC Account No. 182 and 254 and an offsetting expense account to reflect the over/under recoveries of energy costs on the income statement, Account No. 501. This will continue to ensure that net operating income is not distorted by over/under recoveries of Missouri jurisdictional energy costs. In addition, this accounting process will leave an audit trail for internal and external

auditors. This audit trail will be very useful during the periodic prudence reviews that are required under the Commission's rules governing the fuel adjustment process. Empire has continued to restrict the recovery and refund of over/under recoveries to 95 percent of the total difference that was established in the last rate case, Case No. ER-2012-0345; and

- Carrying costs on energy costs deferred as part of the operation of the FAC are calculated on a monthly basis using Empire's embedded cost of short-term debt, and will be applied during both the accumulation period and the recovery period.

Q. DOES EMPIRE AUTHORIZE THE COMMISSION TO RELEASE THE LAST FIVE YEARS OF HISTORICAL SURVEILLANCE REPORTS TO THE PARTIES IN THIS CASE?

A. Empire agrees to release the last five years of historical surveillance information to the Commission Staff and to the Office of the Public Counsel. If other parties to this case desire to receive this information, Empire will provide it subject to the protections to confidential information that are afforded by Commission Rule 4 CSR 240-2.135. Empire is concerned about other utilities operating in Missouri that compete with Empire gaining unrestricted access to the Company's surveillance information as a result of intervening in this rate case. Empire would be competitively disadvantaged by a complete release of this information to its competitors.

Q. DOES THE PROPOSED FAC TARIFF AND THE RECOVERY/REFUND MECHANISM PROVIDE EMPIRE SUFFICIENT OPPORTUNITY TO EARN A FAIR RETURN ON EQUITY?

A. Yes and no. The proposed FAC mechanism is a significant improvement over the recovery of these costs through base rates. During periods of extreme fuel and energy price fluctuations, the FAC will recover 95 percent of the changes in energy costs, which means that the Missouri retail customers will reimburse Empire for a significant portion of its actual, prudently incurred fuel and energy costs. In the event that fuel and energy costs stabilize at or near the base established in the FAC, which has been the case since the FAC was originally implemented, the energy cost changes that pass through to the customer through the FAC would be minimal. For example, since September of 2008 through February 2014, Empire has requested to pass on to its Missouri retail customers around $17.1 million of increased fuel and energy costs through the FAC. This represents a change in Missouri jurisdictional energy costs of about 2.4 percent during the past five and a half years, and an overall change in Missouri jurisdictional retail revenue of about 0.8 percent during the last 66 months.

Although, overall, the FAC is a great improvement over the situation that existed prior to the FAC, any negative adjustment to the 95%/5% sharing mechanism could deprive Empire of a sufficient opportunity to earn a fair return on equity and thereby deny the Company one of the major benefits an FAC was designed to provide. During periods when fuel and purchased power costs increase between rate cases, the sharing mechanism requires Empire to absorb five percent of those cost increases – which directly reduces the Company's earnings – even though all those costs were prudently incurred. If the percentage of costs the Company is required to absorb under the FAC's sharing mechanism is increased above the current level, the resulting effect on net income could deprive Empire of an opportunity to earn a fair return on equity. Likewise, if energy costs would happen to fall below the FAC base, Empire's customers could be adversely impacted by what I referred to as any negative adjustment to the 95%/5% sharing mechanism.

Q. IS THE FAC DESIGNED TO COMPLY WITH THE PRUDENCE REVIEW PROCEDURES PRESCRIBED BY THE COMMISSION'S RULES?

A. Yes. Empire's proposed FAC is flexible and allows the Commission to adjust the amount of FAC recovery if any cost is disallowed as the result of a prudence review. As I mentioned earlier, the accounting procedures used by Empire will involve an audit trail that should facilitate the audit process associated with those periodic prudence reviews.

Q. DOES THE ACCOUNTING AND BILLING PROCESS IN THE PROPOSED FAC ENABLE EMPIRE TO TRACK FAC REVENUES AS A DISCRETE LINE ITEM ON CUSTOMERS' BILLS?

A. Yes. FAC changes/credits have been, and will continue to be, shown as a separate line item on each customer's bill, and the FAC revenue will continue to be segregated on the Empire books and records to facilitate the accounting and audit process.

Q. WILL EMPIRE'S CUSTOMERS BE NOTIFIED OF THE REQUEST TO CONTINUE THE FAC?

A. Yes. In addition, to the normal notice requirements for a general rate filing, Empire has prepared a notice that describes the request to continue the existing FAC. I have attached an exemplar copy of this notice as Schedule TWT-5.

Q. PLEASE DESCRIBE HOW THE FAC WORKS.

A. As shown on Schedule TWT-3, the application of the tariff involves the accumulation of actual Missouri jurisdictional energy and transportation costs, including net RTO transmission costs, over a six-month period, comparing that cost accumulation to the base cost of energy built into the Missouri jurisdictional rates, and then determining the amount of over/under recovery of energy, transportation and transmission costs. Ninety-five percent (95%) of this over/under recovery balance is then billed/credited to Empire's Missouri retail customers over a six-month billing period that immediately follows the six-month accumulation period. In addition, 95 percent of the actual Missouri jurisdictional off-system sales and SPP next day market activities are flowed through the FAC as well as the Missouri jurisdictional portion of REC sales. As shown in Schedule TWT-3, the first six-month accumulation period is September through February, and the recovery or billing period associated with this accumulation period is the following June through November. The process in the FAC involves changing the energy cost recovery factor twice each year, once in June and again in December. Empire has filed for energy cost recovery changes under the FAC, in April and October of each year since April of 2009.

Q. DO THE ENERGY COSTS ELIGIBLE FOR RECOVERY THROUGH THE PROPOSED FAC INCLUDE THE COSTS AND/OR BENEFITS ASSOCIATED WITH EMPIRE'S FUEL RISK MANAGEMENT (HEDGING) PROGRAM?

A. Yes. As indicated on Schedule TWT-3, the costs eligible for recovery through the tariff include Empire's fuel risk management costs, which are recorded in FERC accounts 501, 547 and 555.

Q. WHAT IS THE TIMING OF THE SEMI-ANNUAL FAC FILINGS IN THE FAC TARIFF?

A. The proposed tariff incorporates the following timing of actions, which are the same as those included in Empire's existing FAC:

- Filing for a change in the fuel adjustment rate ("FAR") on April 1st and October 1st each year;

- Staff recommendation on the filed FAR by May 1st and November 1st each year;
- Commission action on the FAR by June 1st and December 1st or FAR as filed is allowed to go into effect on June 1st and December 1st each year.

Q. DOES THE TIMING OF THESE ACTIONS COMPLY WITH THE COMMISSION'S RULES GOVERNING THE FILING OF PERIODIC ADJUSTMENTS TO THE FAC?

A. Yes. The Staff has thirty days from the date of a FAR filing to make its recommendation, and the Commission has sixty days from the FAR filing date in which it can render a decision concerning the cost recovery factor or allow it to go into effect by operation of law.

Q. HOW DOES THE TRUE-UP OF ENERGY COST RECOVERY TAKE PLACE, AND HOW ARE PRUDENCE REVIEWS SCHEDULED ACCORDING TO THE EXISTING FAC TARIFF?

A. The true-up of recovered energy costs takes place every six months. The exact timing of the prudence review has not been explicitly set out in the tariff, but the tariff specifies that prudence reviews will take place no less than every eighteen (18) months. Empire's operation of the FAC has been audited by the Commission Staff through February 28, 2013, and no disallowances have been recommended.

Q. DOES THE PROPOSED FAC INCLUDE ANY RATE VOLATILITY MITIGATION FEATURES?

A. Yes, the energy cost changes that occur during the accumulation period will be spread over six months. This feature will fix the FAC component of a customer's bill for six months and will tend to smooth out energy price volatility.

Q. HAS EMPIRE CONDUCTED ANY HEAT RATE TESTING ON ITS GENERATION UNITS DURING THE PREVIOUS TWENTY-FOUR MONTHS?

A. Yes. These are included as Schedule TWT-7.

Q. ARE YOU PROVIDING ANY OTHER SUPPLY-SIDE AND DEMAND-SIDE RESOURCE INFORMATION IN SUPPORT OF EMPIRE'S REQUEST TO CONTINUE THE FAC?

A. Yes. Based on the Company's most recently approved budget, adjusted for the Riverton Unit 7 retirement, I am providing the following information as required by the various subparts of 4 CSR 240-3.161(3)(P):

- Schedule TWT-6 page 1, which is a list of the supply-side and demand-side resources that the Company expects to use to meet its load for the next four (4) years;
- Schedule TWT-6 page 2, which shows the expected dispatch (generation levels) of the supply-side resources that Empire expects to utilize for the next four (4) years and explains why these expected dispatch levels are appropriate;
- Schedule TWT-6 page 3, which shows the expected heat rates for each supply-side resource that the Company expects to utilize for the next four (4) years; and
- Schedule TWT-6 page 4, which shows the fuel types utilized in each of Empire's supply-side resources.

Q. DO YOUR RESPONSES TO THE INFORMATION REQUIRED BY 4 CSR 240.3.161(3) IN THIS CASE DIFFER FROM THE INFORMATION FILED IN RESPONSE TO THE INFORMATION AND RESPONSES REQUIRED BY 4 CSR 240.3.161(2) (INFORMATION THAT WAS REQUIRED WHEN THE RATE

ADJUSTMENT MECHANISM WAS FIRST ESTABLISHED)?

A. Not materially. In the initial case authorizing Empire's FAC, which was governed by 4 CSR 240-3.161(2), some of the information Empire submitted dealt with the FAC tariff proposed by Empire in Case No. ER-2008-0093. In this case, which is governed by 4 CSR 240-3.161(3), we propose to continue the same basic FAC methodology. All proposed changes to the tariff have been discussed earlier, and the responses and information requirements are tailored to meet the needs of the basic FAC methodology.

III. FUEL PLANNING AND PROCUREMENT

Q. DOES EMPIRE HAVE PROCEDURES IN PLACE DESIGNED TO ENSURE THAT ITS FUEL PURCHASING IS PRUDENT?

A. Yes, it does. Empire plans its fuel procurement activity using long-term planning and maintains an active Risk Management Policy ("RMP").

Q. PLEASE DESCRIBE EMPIRE'S RMP.

A. Empire implemented its RMP in 2001 to manage natural gas price volatility. The RMP outlines the instruments that may be used to help manage volatility. In general terms, Empire's RMP allows the use of financial and physical transactions to help manage price volatility. In addition, the RMP establishes minimum quantities of natural gas in future calendar years that are required to be price protected by a certain date.

Q. DOES EMPIRE ALSO HAVE ACCESS TO OTHER SOURCES OF ELECTRIC ENERGY THAT CAN BE USED TO OFFSET NATURAL GAS PRICE VOLATILITY?

A. Yes. In addition to its coal fired generating units, Empire owns and operates the Ozark Beach hydro facility. It has a capacity of about 16 MW and has averaged about 54,689

MWh's of annual output over the past three years. The output of this unit is governed by the water released from Table Rock Lake and the level of water maintained on Bull Shoals Lake. Each of these lakes is under the control of the Corp of Engineers.

Additionally, near the end of 2005, Empire began receiving electricity from the Elk River Wind Project owned by IBERDROLA RENEWABLES, Inc. Empire has a contractual commitment to purchase 100% of the output from this project for 20 years. Empire expects to receive about 550,000 MWh's per year from this project, or about 10% of the Company's overall energy supply. The energy under this contract is purchased at a predetermined cost. Empire also entered into an agreement with Cloud County Windfarm, LLC, owned by EDP Renewables North America LLC, to purchase all of the output from Meridian Way Wind Farm since late December 2008. Empire anticipates purchasing approximately 315,000 megawatt-hours of energy under this contract annually. The energy under this contract is also purchased at a predetermined cost.

Q. HOW DOES EMPIRE ACQUIRE THE FUEL AND PURCHASED POWER USED TO SUPPLY ELECTRICITY TO ITS CUSTOMERS?

A. Empire's fuel and purchased power acquisition planning is performed using a three-step process. The steps in this process are:

- Long-term Integrated Resource Plan ("IRP");
- An annual and five-year business plans;
- Updates to the annual and five-year business plans as conditions change.

Q. PLEASE DESCRIBE THE IRP PROCESS.

A. Empire utilizes the IRP process to develop a long-term strategy to reliably serve its customers at the lowest possible cost. This planning process uses Empire's entire load in all five of its jurisdictions (Missouri, Arkansas, Kansas, Oklahoma, and the FERC). This formal IRP process has been in place since the early 1990's when Missouri implemented a formal IRP rule. Since that time, Oklahoma and Arkansas also have implemented IRP rules. Empire has thus far been allowed to use the IRP developed for filing in Missouri as the basis for the IRP filings in Oklahoma and Arkansas. The IRP process that Empire uses results in a target list of future resources designed to serve Empire's projected usage and customer levels in all jurisdictions. The process has resulted in a diverse set of resources including base load, intermediate and peaking resources using a mix of fuels from coal to natural gas, and renewable resources. Demand-side management programs are also considered as potential resources as part of the IRP process. Empire filed its latest IRP in Missouri in July 2013, in File No. EO-2013-0547. An IRP annual update report was filed in Missouri in March 2014, in File No. EO-2014-0243.

Q. HOW DOES THE SECOND STEP OF THE PLANNING PROCESS WORK?

A. In addition to the long range planning, Empire conducts annual financial and operational planning, which is used to develop a five-year business forecast. This planning process includes detailed load forecast, detailed generation unit modeling, detailed operations and maintenance cost, and capital budget planning, and revenue forecast. This plan is used to assess many things including the ability to raise capital, debt and equity, and the near term impact on the overall cost of service. The detailed generation unit modeling developed in this phase of the planning process is used as the primary source of information for the development of the fuel and purchased power procurement plan.

Q. ARE THE ANNUAL AND FIVE-YEAR BUSINESS PLANS ADJUSTED TO REFLECT CHANGES IN THE BUSINESS ENVIRONMENT?

A. Yes. The annual and five-year business plans are periodically refined to take into account changes that have occurred since the plans were initially developed. Empire takes into account changes in such things as load growth, weather, the number of customers, fuel prices, purchased power prices, rail transportation delays, and fuel availability. As these refinements are made to the near term forecasts, Empire adjusts its fuel procurement plans as necessary.

Q. PLEASE PROVIDE ANY ADDITIONAL INFORMATION THAT DEMONSTRATES THAT EMPIRE HAS A LONG-TERM RESOURCE PLANNING PROCESS IN PLACE.

A. Empire filed its most recently completed IRP in Missouri on July 1, 2013, in File No. EO-2013-0547 ("2013 IRP"). Pursuant to Commission Rule 4 CSR 240-22.080(9), Empire and the interested parties to the case submitted a joint filing regarding the 2013 IRP on January 31, 2014. On March 12, 2014, the Commission issued an order approving the remedies to the alleged IRP deficiencies and concerns proposed in the joint filing, which were developed by the signatories. The Commission's order became effective on March 22, 2014, and the file was closed on March 23, 2014. Following the 2013 IRP, Empire filed an IRP Annual Update Report in March 2014. Empire conducted an annual update workshop with the stakeholders in April 2014, in File No. EO-2013-0243, which was designed to provide an IRP update to the 2013 IRP.

Q. IS THE PROPOSED FAC DESIGNED TO PRODUCE A DIFFERENT FAR FOR DIFFERENT VOLTAGE LEVELS?

A. Yes. The proposed FAC includes a feature that reduces the FAR to those customers taking service at primary voltage or higher. The existing expansion factors were based upon the information coming from the periodic line loss studies performed by the Company.

Q. ARE THERE BENEFITS ASSOCIATED WITH THE CONTINUED USE OF A FAC FOR EMPIRE?

A. Yes.

Q. PLEASE EXPLAIN.

A. I believe there are significant benefits for all of the Company's stakeholders. First, Empire benefits by being able to recover most of its actual fuel and energy costs through the FAC. This strengthens Empire's financial profile and enhances its ability to attract the financing necessary to meet its customers' needs and to obtain that financing at the best rates possible. In addition, the need to file general rate cases for the purpose of recovering ongoing fuel and energy costs in base electric rates has essentially been eliminated. Over time, this may reduce the overall number of electric rate cases in Missouri, and a reduction in the number of general rate cases will ultimately lower Empire's regulatory costs and ultimately the cost to serve Empire's Missouri customers.

Q. DOES THE FAC BENEFIT THE CUSTOMER?

A. Yes. The FAC process produces a result that is ultimately fair to all sides. In the long run, the customer benefits from the implementation and continuation of a properly designed FAC. The customer will only reimburse Empire for the actual cost of fuel and energy, not an estimate of future energy costs. Thus, depending on the sharing mechanism and the actual costs incurred, there may be no over or under recovery of cost. Empire also has a stronger financial profile and an enhanced ability to attract the capital necessary to operate its utility system at the best rates possible. Ultimately, this should lower the cost of operations from what it would have been without the FAC. In addition, the FAC conveys a more accurate cost of electric energy to Empire's customers. If energy costs increase, the customer will know within six months and will be in a position to make an informed decision concerning any energy efficiency measures that could be implemented in an effort to lower consumption. The fixed energy pricing system that Missouri used prior to the FAC tended to shield the customer from the true cost of electric energy, which may hamper the customers' adoption of or participation in energy efficiency programs.

IV. REVIEW OF ON-SYSTEM FUEL AND PURCHASED POWER EXPENSE FOR BASE RATES

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE SOUTHWEST POWER POOL INTEGRATED MARKET PLACE ("SPP IM").

A. Empire is an original member of the SPP. SPP was approved as a Regional Transmission Organization ("RTO") by FERC in 2004 and added the Energy Imbalance Services ("EIS"), an initial step toward a full-scale energy market, in February 2007. The newest market evolution is the SPP IM, or next day market, which includes the following features:

- A Day-Ahead Market with Transmission Congestion Rights;
- A Reliability Unit Commitment process;
- A Real-Time Balancing Market;
- The incorporation of price-based Operating Reserves procurement; and
- The former Balancing Authorities within the SPP footprint combined to form a Consolidated Balancing Authority.

The SPP IM went live on March 1, 2014, creating one consolidated balancing authority in SPP. Prior to the SPP IM, there were several balancing authorities within SPP. With the advent of the IM, SPP became North America's tenth electricity power market and the sixth market to offer constrained commitment and dispatch. The SPP IM also provides a market to mitigate exposure to market price fluctuations due to transmission congestion. Financial instruments called transmission congestion rights ("TCR") provide the opportunity to hedge congestion exposure in the day ahead market. TCRs can be purchased or self-converted using rights allocated based on prior transmission investments. Essentially, Empire now purchases energy from the SPP IM to serve native load, and Empire sells generation into the SPP IM. The result is expected to be a more efficient commitment and dispatch of generation and operating reserves across the SPP footprint, taking into account the improvements to the bulk transmission system.

Q. HAS EMPIRE CONSIDERED THE SPP IM FOR THE PROPOSED FAC BASE IN THIS RATE CASE FILING?

A. Yes. Empire has made an adjustment for anticipated SPP IM savings outside of the supply model used in this case. This SPP IM adjustment reduces the model generated energy cost. It was determined that this "post processing" approach would be best for this rate filing since the SPP IM has been in place for just a few months. While Empire has analyzed the market approach with models, it will take some time for the SPP IM to mature, to gain history and for modelers to gain confidence in the market based modelling approach. Additionally, Empire believes that for the purpose of developing an overall normalized energy cost for establishing a new FAC base in this case, it was important to model the system consistent with previous general rate case filings and make the SPP IM adjustment exogenous to the generation model for transparency purposes.

Q. WHAT LEVEL OF ON-SYSTEM FUEL AND PURCHASED POWER EXPENSE IS EMPIRE PROPOSING IN THIS CASE?

A. Empire has developed an on-system energy cost level for base rates with a computer production cost model that will be discussed in this testimony. On an average cost basis, Empire estimates that the ongoing energy cost is close to the level currently in base rates. However, with the proposed FAC modifications to include the natural gas transportation and storage and net RTO transmission costs, the proposed FAC base is about 7.3 percent higher than the existing FAC base on a per unit basis, as shown in Schedule TWT-2. Schedule TWT-2 also shows an adjustment to recognize the expected annual savings from the SPP IM.

Q. PLEASE DESCRIBE THE MODELED ON-SYSTEM FUEL AND PURCHASED POWER EXPENSE LEVEL THAT EMPIRE DEVLOPED FOR PURPOSES OF THIS CASE.

A. The FPP cost presented in this testimony is being provided as Empire's review of the ongoing level of variable on-system FPP expense. The dispatch model run produced a total company on-system FPP expense, excluding demand charges, natural gas transportation and natural gas storage costs AQCS consumables, net transmission, emission costs and RECs ("other energy costs"), of $147,996,678. The projected net system energy requirement is 5,350,830 MWh. On an average basis, this equals an average cost of $27.66/MWh (excluding other energy costs). This represents the model generated cost prior to any post processing adjustments. A cost summary from this model run is provided as Schedule TWT-8.

Q. HOW DID YOU ARRIVE AT THE ONGOING LEVEL OF FUEL AND PURCHASED POWER EXPENSES FOR THIS CASE?

A. This ongoing level of expense was developed by running the hourly production cost computer model known as PROSYM using normalized sales levels, growth, weather and outage data, and projected fuel and purchased power prices. Again, this is prior to adding other energy costs or making any adjustments for the SPP IM.

Q. BRIEFLY DESCRIBE THE PROSYM MODEL.

A. The PROSYM model is a chronological computer model that dispatches resources to meet demand requirements on an hourly basis. The model commits resources based on fuel costs, unit start-up costs, and variable operation and maintenance ("O&M") costs after accounting for operational characteristics of a utility system that may override economic dispatch. Empire has been using chronological production costing models for projection purposes since 1991. Empire has used the PROSYM model in its eight previous rate case filings in Missouri.

V. UNIT DATA USED IN THE MODEL

Q. ARE THERE ANY SIGNIFICANT GENERATING UNIT CHANGES USED IN YOUR CURRENT MODEL RUN OF ESTIMATED FPP COSTS THAT SHOULD BE NOTED?

A Yes, there are few changes of note. First, the model takes into account the retirement of Asbury Unit 2 (14 MW), which was removed from service as of midnight December 31, 2013. At the time of its retirement, this unit had been used only for peaking purposes. As planned, this unit was retired in conjunction with the Asbury AQCS and turbine project. The model has also been updated to account for the new unit characteristics of the Asbury Unit 1 coal-fired unit following its AQCS and turbine project. This includes changes to the units rated capacity and heat rate curve. During the tie-in of the new AQCS, certain turbine hardware will be replaced. These components utilize a newer design, increasing unit efficiency and capacity. The additional capacity will partially offset the capacity lost due to the retirement of Asbury Unit 2 and due to the additional auxiliary loads imposed by the new AQCS. The other change to the model accounts for the retirement of Riverton Unit 7, which was officially removed from service on June 30, 2014. This unit had operated as a small coal unit for many years, before being transitioned to full operation on natural gas in September of 2012. After its transition to a natural gas only unit, it had operated zero service hours. The unit was about 64 years old at the time of its retirement.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DATA USED FOR MODELING EMPIRE'S GENERATING UNITS.

A. Data used to model Empire's generating units are shown in Schedule TWT-9. These data include each unit's rated capacity, maximum capacity, minimum capacity, heat rate curve information, ramp rate, forced outage rate information, mean repair time, minimum down time, minimum up time, fuel ratio, start-up fuel requirements and associated cost, and variable O&M. The normalized outage schedule is provided in Schedule TWT-10.

<u>VI. FUEL DATA USED IN THE MODEL</u>

Q. PLEASE EXPLAIN THE BASIS FOR THE COAL COSTS INCLUDED IN EMPIRE'S PRODUCTION COST MODEL.

A. All coal costs are based on the expected 2015 delivered cost (initial and freight). The following solid fuel types were modeled: (1) Asbury western coal; (2) Asbury blend coal; (3) Iatan western coal; and (4) Plum Point western coal.

Q. PLEASE EXPLAIN HOW THE FUTURE NATURAL GAS PRICES WERE DEVELOPED FOR USE IN THE MODEL.

A. The model includes the assumption that Empire's gas-fired units first burn natural gas from the Company's natural gas hedging efforts, and second from the spot natural gas market, as needed. All spot market natural gas prices are estimates for delivered prices to the Southern Star Central Gas Pipeline, where Empire takes natural gas delivery. Both the hedged natural gas and spot market natural gas data that were utilized in the normalized model run are based upon the expected natural gas data for calendar year 2015. The 2015 data were taken from Empire's natural gas position report dated June 13, 2014.

Q. WHAT WEIGHTED AVERAGE NATURAL GAS COST RESULTED FROM THE MODEL RUN?

A. In the PROSYM run, with the model utilizing a combination of the hedged and spot market natural gas fuel types, the weighted average price of the natural gas consumed by the generating units was approximately $4.35 /MMBtu.

VII. PURCHASED POWER DATA USED IN THE MODEL

Q. HOW WERE THE POWER PURCHASES MODELED?

A. In the model, purchased power can be divided into the following categories: (1) 50 MW Plum Point purchased power agreement ("PPA") (a coal-fired contract purchase); (2) 150 MW Elk River Wind Farm PPA and 105 MW Meridian Way Wind Farm PPA (wind contract purchases); and (3) the wholesale power market, also referred to as spot purchases or non-contract purchases. These non-contract purchases refer to the types of purchases made prior to the advent of the SPP IM.

Q. PLEASE DESCRIBE HOW THE PLUM POINT PPA WAS MODELED.

A. Empire has an ownership portion and a PPA portion of the Plum Point coal-fired unit. Both portions were modeled at 50 MW each, for a total capacity from this facility of 100 MW. Since the ownership portion and PPA portion will both be sourced from the same unit, Plum Point was modeled as 100 MW, so the ownership and PPA portions would retain the same random forced outage draws in the model. In the model, half of the energy is assigned to the ownership portion and half to the PPA portion. From the standpoint of on-system FPP costs, the 50 MW PPA portion does have some additional costs associated with it. The proportionate share of operating and maintenance costs, unit train costs, and environmental emissions costs were added to the Plum Point 50 MW PPA contract purchase for the normalized on-system FPP cost estimate.

Q. PLEASE DESCRIBE HOW THE WIND FARM PURCHASES WERE MODELED.

A. The 150 MW Elk River and 105 MW Meridian Way PPAs were modeled as "must take" purchases with hourly load profiles. Elk River was modeled at around a 42% capacity factor, while Meridian Way was modeled at around a 34% capacity factor. The energy prices used in the model for both of these contracts were based on contract prices for 2015.

Q. WHAT PRICES WERE UTILIZED FOR THE SPOT OR NON-CONTRACT PURCHASED ENERGY?

A. The spot purchase data in the model represent a forecast of the wholesale power market. The data are comprised of 8,760 hourly prices. The prices used in the model were developed by the consulting firm Ventyx, an ABB Company, using computer models that generate market price estimates for the SPP-KSMO market area based on the same natural gas price assumptions used in the PROSYM production cost model. The power prices used in the dispatch model in this case are those forecasted for year 2015.

VIII. OTHER FUEL RELATED COSTS

Q. BRIEFLY DESCRIBE THE OTHER FUEL RELATED COSTS THAT ARE INCLUDED IN THE ESTIMATE OF TOTAL COMPANY ON-SYSTEM FUEL

AND PURCHASED POWER EXPENSE OF $147,996,678, OR $27.66 /MWH (PRIOR TO POST PROCESSING ADJUSTMENTS).

A. The other fuel related costs, in addition to the energy costs from the PROSYM model, are: (1) coal related costs, such as unit train and undistributed and other costs; and (2) natural gas transportation related costs, such as commodity charges, undistributed and other costs and natural gas pipeline losses.

Q. PLEASE DESCRIBE ANY PURCHASED POWER DEMAND CHARGES.

A. Although it is not included in the current base energy cost component for the FAC, there is a monthly demand charge for the 50 MW Plum Point PPA. The demand charge rate ($ /KW/month), which is established by contract, escalates at 2% annually for the first several years of the contract. The annualized value has been utilized in this case representing the expected demand charges for calendar year 2015, which will be the first calendar year in which the rates coming out of this case are in place.

Q. PLEASE LIST THE OTHER SOLID FUEL RELATED EXPENSES.

A. The other fuel related expenses include undistributed and other costs at the coal-fired facilities, unit train lease, unit train maintenance, unit train depreciation and unit train property taxes.

Q. PLEASE DESCRIBE THE NATURAL GAS FUEL RELATED EXPENSES.

A. The natural gas fuel related expenses include undistributed and other costs for the natural gas plants, the costs associated with commodity charges, and natural gas pipeline losses. The commodity charge estimates are based on a rate of $0.0186 /MMBtu. The interstate pipeline natural gas losses are based on a natural gas loss rate of 2.62%.

Q. PLEASE DESCRIBE ANY OTHER COSTS ASSOCIATED WITH THE NATURAL

GAS STORAGE AND DELIVERY.

A. Although not included in the current base energy cost component for the FAC, other natural gas fuel related expenses include the costs associated with natural gas *transportation* service, including storage costs established by contract. The annualized natural gas transportation and storage costs utilized in this case represent the expected costs for calendar year 2015. As mentioned earlier, Empire is requesting to include these costs in the FAC.

Q. PLEASE DESCRIBE THE AQCS CONSUMABLES.

A. As mentioned previously, the AQCS consumables are a component of Empire's existing FAC. The environmental equipment at the generating stations consumes these products in order to perform their air quality control functions. A selective catalytic reduction ("SCR") system, which removes nitrogen oxides ("NOx"), utilizes ammonia. A wet scrubber, used for the removal of sulfur oxides ("SOx"), utilizes limestone, while dry scrubbers utilize lime. A powder activated carbon system is used for the removal of mercury. In this testimony, ammonia, lime, limestone, and powder activated carbon are collectively referred to as the AQCS consumables.

Q. PLEASE LIST THE EMPIRE GENERATING UNITS THAT UTILIZE AQCS CONSUMABLES AND DESCRIBE THE LEVEL OF COSTS BEING PROPOSED.

A. Ammonia is used by the SCRs at the Asbury coal-fired unit and at the State Line Combined Cycle gas-fired unit. Empire also pays for its share of all the aforementioned ACQS consumables used by the jointly-owned Iatan Unit 1, Iatan Unit 2, and Plum Point coal-fired units. The AQCS consumable costs are highly correlated to the amount of fuel consumed and/or electric generation produced by these generating units, and, like fuel costs, the prices for the AQCS consumables are subject to variability. The annualized value of consumables that have been utilized in this case represents the expected level for calendar year 2015 based on the generating unit operation in the model run that was described earlier. The ongoing AQCS cost is about 61% higher than the level in Empire's existing FAC base primarily due to the new Asbury AQCS that was described earlier. Asbury will be adding powder activated carbon injection and lime reagent as a result of the environmental retrofit.

Q. PLEASE DESCRIBE THE REVENUES FROM THE SALE OF RECS AND DESCRIBE THE LEVEL OF REC OFFSET TO THE FAC BASE THAT IS BEING PROPOSED.

A. Empire currently receives energy from two Kansas wind farms through long-term PPAs. Empire also receives the renewable energy credits or RECs from these resources. Empire currently sells a portion of the RECs from these wind farms on the open market, and flows the revenue from these REC sales net of sales-related expenses through the FAC as an offset to energy costs. The annualized value of RECs that have been utilized in this case represents the expected level for calendar year 2015 based on the wind farm production in the model run described earlier. The annualized REC revenue is about 49.2% lower than the level in Empire's existing FAC base. This reflects the fact that in recent years, the average price received per REC sold has declined as the supply of RECs from various sources has increased. In addition, Empire had a long-term contract for the sale of RECS in prior years, but that contract has expired. The current REC market prices are much lower than the prices in the expired long-term contract.

Q. PLEASE PROVIDE THE TEST YEAR ADJUSTMENT MADE TO FAC

REVENUE.

A. The FAC revenue must be removed from the test year revenue so that in the future, this revenue will be collected in base rates rather than through the fuel adjustment clause. As a result, revenue was increased by $1,765,858 on a Missouri jurisdictional basis.

Q. PLEASE PROVIDE A CHART OF THE ADJUSTMENTS MADE TO FUEL AND PURCHASED POWER YOU ARE SPONSORING.

A.

	Test Year	Pro Forma	Adjustment
Net F&PP	167,543,612	160,387,608	(7,156,004)
Construction Accounting	(150,432)	(150,432)	-
SWPA Amortization	(2,839,085)	(2,839,085)	-
Total Net On-System F&PP	164,554,095	157,398,091	(7,156,004)
Consumables	1,523,679	4,416,024	2,892,345
Renewable Energy Credits	(1,162,426)	(840,515)	321,911

IX. NORMALIZED COAL AND TIRE DERIVED FUEL ("TDF") INVENTORY BALANCES

Q. WHAT ADJUSTMENTS WERE MADE TO NORMALIZE EMPIRE'S RATE BASE FOR COAL INVENTORY?

A. Empire used the results of the fuel model, which was described earlier, to calculate the annual amount of coal on a MMBtu basis for the various types of coal at each generating plant to meet its total company normalized native load. Native load is the kilowatt or megawatt demand placed on Empire's electric system by its regulated customers. To determine the normalized amount of coal inventory, the average daily burn by generating unit must be calculated. The average daily burn is derived by dividing the annualized MMBtu from the fuel model by the difference between 365 days and the number of annual normalized planned outage days. The average daily burn is then multiplied by the target number of days on hand for coal inventory. The target inventory days on hand which Empire expects to maintain is 60 days. The result is then multiplied by the cost of fuel on a $/MMBtu basis to arrive at an annualized dollar value for coal inventory. Also included in inventory balances for the Asbury and Iatan units is an estimated level of basemat coal. The Plum Point inventory excludes basemat coal since the basemat coal has been capitalized as part of the plant. Basemat coal is the bottom layer of a coal pile that is not usable as fuel due to contamination by soil, clay, and other contaminants. The normalization of the coal inventory resulted in an adjustment that decreased coal inventory by $1,680,296, on a total company basis. The Missouri jurisdictional adjustment is a decrease of $1,385,590.

Q. WHAT ADJUSTMENTS WERE MADE TO NORMALIZE EMPIRE'S RATE BASE FOR TDF?

A. A review of the test year level of TDF was undertaken and adjusted based on maintaining an inventory of 100 tons of TDF. The normalization of the TDF inventory resulted in an adjustment that decreased TDF inventory by $803 on a total company basis. The Missouri jurisdictional adjustment is a decrease of $662.

X. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR DIRECT TESTIMONY.

A. In this case Empire is requesting the continuation of its FAC, with modifications. In conjunction with the continuation of the current FAC, Empire has estimated the level of 2015 on-system energy expenses in order to rebase the FAC as part of this case. Empire has simulated a dispatch of its generation system using the PROSYM production cost model to determine an estimate of annualized and normalized total company energy expense and then made some post processing adjustments to include the impact of transportation costs, fuel and net RTO transmission costs and the expected annual benefits associated with the SPP IM. Empire is also proposing the following changes to the FAC: include natural gas transportation and storage costs and include net RTO transmission costs. Schedule TWT-8 is a summary of the PROSYM model run, and Schedule TWT-2 is a comparison of Empire's existing FAC base and the proposed FAC base in this case.

Q. HOW DOES THIS ESTIMATED COST LEVEL COMPARE TO THE AVERAGE BASE ENERGY COSTS BUILT INTO EMPIRE'S EXISTING MISSOURI RATES AND EMPIRE'S EXISTING MISSOURI FAC?

A. The average FAC energy costs built into Empire's current base rates (excluding purchase demand charges, natural gas firm transportation and natural gas storage costs) equals $28.31 MWh. The proposed FAC energy costs presented in this case equals $30.37 per MWh, an increase of about $2.07 per MWh or approximately 7.3 percent. This proposed FAC base includes adjustments to all of the cost components in Empire's existing FAC, plus the addition of net RTO transmission costs, all natural gas transportation and storage costs and an expected annual SPP IM benefit. However, utilizing only existing FAC components, for comparison purposes, the proposed FAC base is being *reduced* by about 3 percent. The existing FAC base is $28.31 per MWh, and a comparable value without proposed changes would be $27.47 per MWh.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

Cases with Filed Written Testimony of Todd W. Tarter

Before the Missouri Public Service Commission

- Rate Cases

ER-2006-0315, ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345

- Fuel Adjustment Cases

ER-2011-0320, ER-2012-0098, ER-2012-0326, ER-2013-0122, ER-2013-0442, ER-2014-0087, ER-2014-0264

- Fuel Adjustment True-Up

EO-2014-0088, EO-2014-0265

Before the Kansas Corporation Commission

- Rate Docket

05-EPDE-980-RTS

- Energy Cost Adjustment ACA Docket

KS-12-EPDE-392-ACA, KS-13-EPDE-385-ACA

Before the Oklahoma Corporation Commission

- Rate Cause

PUD 201100082

- Fuel Prudence Review Causes

PUD 201100131, PUD 201200170, PUD 201300131

- Energy Efficiency Cause

PUD 201300142, PUD 201300203

Before the Arkansas Public Service Commission

- Energy Efficiency Docket

07-076-TF

- Net Metering Docket

12-060-R

- Rate Docket

13-11-U

FAC Comparison

Description	Current FAC Base Total Company	Proposed FAC Base Total Company	Difference	% Change
Based on Gas Price of:	$ 4.92	$ 4.35		
FUEL				
Fuel	$ 94,646,651	$ 93,248,864	$ (1,397,787)	-1.5%
Gas Transportation - Variable	$ 180,171	$ 176,041	$ (4,130)	-2.3%
Gas losses (LUF) at Cost of Gas	$ 1,005,564	$ 1,002,457	$ (3,107)	-0.3%
AQCS Consumables (Ammonia, Limestone, PAC)-Variable	$ 2,742,393	$ 4,416,024	$ 1,673,631	61.0%
Staff Removed from FERC 501 (Admin/Labor)	$ (252,962)	$ -	$ 252,962	-100.0%
Freeze Control Coal Adder	$ 18,281	$ -	$ (18,281)	-100.0%
Other Fuel Related (Undistributed & Other and Unit Train)	$ 3,693,120	$ 3,734,044	$ 40,924	1.1%
TOTAL FUEL AND RELATED COSTS	**$ 102,033,218**	**$ 102,577,430**	$ 544,212	0.5%
PURCHASED POWER ENERGY CHARGES				
Purchased power energy (Plum Point PPA, Wind PPAs and Market Purch)	$ 46,585,213	$ 45,716,671	$ (868,542)	-1.9%
50 MW Plum Point O&M Cost-Variable	$ 3,365,823	$ 4,118,601	$ 752,778	22.4%
Purchased power energy	$ 49,951,036	$ 49,835,272	$ (115,764)	-0.2%
SPP INTEGRATED MARKETPLACE (IM) ADJUSTMENT				
3% Savings Adjustment	-	$ (4,572,381)	$ (4,572,381)	
OTHER ENERGY COSTS				
Net Emission Allowances	$ (87,956)	$ -	$ 87,956	-100.0%
Net Transmission	$ -	$ 8,436,594	$ 8,436,594	
Gas Transportation and Storage		$ 7,093,952	$ 7,093,952	
LESS: Net Renewable Energy Credits (REC)	$ (1,655,878)	$ (840,515)	$ 815,363	-49.2%
LESS: Off-System Sales Revenue	$ (1,000,000)	$ -	$ 1,000,000	-100.0%
TOTAL FUEL AND PURCHASED POWER FOR EMPIRE FAC BASE	**$ 149,240,420**	**$ 162,530,351**	$ 13,289,931	8.9%
Total kWh's	5,271,935,340	5,350,830,000	78,894,660	1.5%
Base Cost per kWh	**$ 0.02831**	**$ 0.03037**	$ 0.0021	7.3%
Base Cost per MWh	**$ 28.31**	**$ 30.37**	$ 2.07	7.3%

Other Energy Related Costs not in the Existing FAC

Description	Current FAC Base Total Company	Proposed FAC Base Total Company	Difference	% Change
Gas Transportation	$ 5,948,773	$ 5,962,452	$ 13,679	0.2%
Plum Point PPA Demand Charge	$ 9,037,350	$ 9,869,360	$ 832,010	9.2%
SSCGP Natural Gas Storage	$ 1,131,500	$ 1,131,500	$ -	0.0%

For Comparison Purposes Only

Description	Current FAC Base Total Company	Proposed FAC Base Total Company	Difference	% Change
TOTAL F&PP MODEL WITH GAS FT and PURCHASE DMD	$ 165,359,484	$ 164,959,989	$ (399,495)	-0.2%
(excludes consumables, RECs, environmental, OSS, trans, SPP Adjustment)	$ 31.37	$ 30.83	$ (0.54)	-1.7%
Without proposed net transmission $	$ 149,240,420	$ 154,093,757	$ 4,853,337	3.3%
Without proposed net transmission $/MWh	$ 28.31	$ 28.80	$ 0.49	1.7%
Without proposed nat gas transportation and storage $	$ 149,240,420	$ 155,436,399	$ 6,195,979	4.2%
Without proposed nat gas transportation and storage $/MWh	$ 28.31	$ 29.05	$ 0.74	2.6%
Existing FAC components w/o proposed SPP IM Adjustment $	$ 149,240,420	$ 151,572,186	$ 2,331,766	1.6%
Existing FAC components w/o proposed SPP IM Adjustment $/MWh	$ 28.31	$ 28.75	$ 0.44	1.6%
With only existing FAC components $	$ 149,240,420	$ 146,999,805	$ (2,240,615)	-1.5%
With only existing FAC components $/MWh	$ 28.31	$ 27.47	$ (0.84)	-3.0%

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 171

Canceling P.S.C. Mo. No. ________ Sec. ________ ________ Original Sheet No. ________

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after

The two six-month accumulation periods, the two six-month recovery periods and filing dates are set forth in the following table:

Accumulation Periods	Filing Dates	Recovery Periods
September – February	By April 1	June – November
March – August	By October 1	December – May

The Company will make a Fuel Adjustment Rate ("FAR") filing by each Filing Date. The new FAR rates for which a filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

DEFINITIONS

ACCUMULATION PERIOD:
The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purpose of determining the FAR.

RECOVERY PERIOD:
The billing months during which a FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis.

BASE ENERGY COST AND REVENUES:
Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchase Power Adjustment ("FPA").

BASE FACTOR ("BF"):
The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case. BF = $0.03037 per kWh for each accumulation period.

DATE OF ISSUE ________________ DATE EFFECTIVE ________________
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 ________ Original Sheet No. 17m

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For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after

APPLICATION
FUEL & PURCHASE POWER ADJUSTMENT

$$FPA = \{[(FC + PP + E - OSSR - REC - B) * J] * 0.95\} + T + I + P$$

Where:

FC = Fuel Costs Incurred to Support Sales:

The following costs reflected in Federal Energy Regulatory Commission (FERC) Accounts 501 and 506: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuels (i.e. tires, bio-fuel and landfill gas), fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments assessed by coal suppliers, fuel hedging costs, fuel adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, combustion product disposal revenues and expenses, consumable costs related to Air Quality Control Systems (AQCS) operation, such as ammonia, lime, limestone, power activated carbon, urea, sodium bicarbonate, and trona and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

The following costs reflected in FERC Accounts 547 and 548: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging costs for natural gas, oil, and natural gas used to cross-hedge purchased power, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions, fees and revenues and expenses resulting from fuel and transportation portfolio optimization activities.

PP = Purchased Power Costs:

1. The following costs or revenues reflected in FERC Accounts 555 - 575: purchased power costs, purchased power demand costs associated with purchased power contracts with a duration of one year or less, settlements, insurance recoveries, and subrogation recoveries for purchased power expenses, virtual energy charges, generating unit price adjustments, load/export charges, energy position charges, ancillary services including penalty and distribution charges, broker commissions, fees and margins and SPP energy market charges including:

   A. SPP costs or revenues for SPP's energy and operating market settlement charge types and market settlement clearing costs or revenue including but not limited to:

      i. Energy;
      ii. Ancillary Services;

DATE OF ISSUE ________ DATE EFFECTIVE ________
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

iii. Revenue Sufficiency;
iv. Losses;
v. Revenue neutrality;
vi. Congestion Management;
vii. Demand Reduction;
viii. Grandfathered Agreements;
ix. Virtual Transaction Fee;
x. Pseudo-tie;
xi. Miscellaneous;

and

B. Non-SPP costs or revenue as follows:

i. If received from a centrally administered market (e.g. PJM / MISO), costs or revenues of an equivalent nature to those identified for the SPP costs or revenues specified in subpart A of part 1 above;

ii. If not received from a centrally administered market:
   a. Costs for purchases of energy; and
   b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and
   c. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

2. Insurance premiums in FERC Account 924 for replacement power insurance. Costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles; and

THE EMPIRE DISTRICT ELECTRIC COMPANY

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Canceling P.S.C. Mo. No. ______ Sec. ______ Original Sheet No. ______

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after

3. All transmission service costs reflected in FERC Account 565 and all transmission service point-to-point revenues reflected in FERC Account 457. Such transmission service costs and revenues include:

   A. SPP costs and revenues associated with:

      i. SPP NITS Service charges (SPP Schedule 11, or its successors);

      ii. SPP Point-to-point transmission service revenue (SPP Schedules 1, 7 and 8 or their successors);

      iii. SPP Schedule 1a, or its successor; and

      iv. SPP Schedule 12;

   B. Non-SPP costs and revenues associated with:

      i. Network transmission service;

      ii. Point-to-point transmission service;

      iii. System control and dispatch; and

      iv. Reactive supply and voltage control

4. Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which SPP or another market participant bills / credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the SPP or another market participant implement a charge type not listed in Empire's FAC:

   A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to another party's right to challenge the inclusion (or failure to include) as outlined in E. below;

DATE OF ISSUE ______ DATE EFFECTIVE ______
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17p

Canceling P.S.C. Mo. No. ______ Sec. ______ ______ Original Sheet No. ______

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after

B. The Company will include in its monthly reports required by the Commission's fuel adjustment clause rules, notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such notice shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the existing market charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

E. If the Company includes a new charge type cost or revenue in a FAR filing and a party challenges the inclusion (or if the Company does not include a new charge type cost or revenue and a party challenges the failure to include it), such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. To challenge the failure to include a new charge type, a party shall make a filing with the Commission based upon that party's contention that the new charge type costs or revenues at issue should have been included, because they do possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. In the event of a challenge, the Company shall bear the burden of proof to support its decision to include or exclude or its failure to include or exclude a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

E = Net Emission Costs:

The following costs and revenues reflected in FERC Accounts 509, 411.8 and 411.9 (or any other account FERC may designate for emissions expense in the future): emission allowance costs offset by revenues from the sale of emission allowances including any associated hedging costs, broker commissions, fees, commodity based services and margins.

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ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17q

Canceling P.S.C. Mo. No. ______ Sec. ______ ______ Original Sheet No.______

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after April 1, 2013

OSSR = Revenue from Off-System Sales:

The following revenues or costs reflected in FERC Account 447: all revenues from off-system sales but excluding revenues from full and partial requirements sales to municipalities that are associated with Empire, and SPP energy market revenues including but not limited to the following: (see Note A. below)

i. Energy
ii. Ancillary Services
iii. Revenue Sufficiency;
iv. Losses;
v. Revenue neutrality;
vi. Demand Reduction;
vii. Grandfathered Agreements;
viii. Pseudo-tie;
ix. Miscellaneous;

REC = Renewable Energy Credit revenue:

Revenues reflected in FERC Account 456 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard.

HEDGING COSTS:
Hedging costs are defined as realized losses and costs (including broker commission fees and margins) minus realized gains associated with mitigating volatility in the Company's cost of fuel, fuel additives, fuel transportation, emission allowances and purchased power costs, including but not limited to, the Company's use of derivatives whether over-the-counter or exchanged traded including, without limitation, futures or forward contracts, puts, calls, caps, floors, collars and swaps.

Note A. Should FERC require any item covered by factors FC, PP, E, REC or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E, REC or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = Net base energy cost is calculated as follows:

$B = (S_{AP} * \$0.03037)$

S_{AP} = Actual net system input at the generation level for the accumulation period.

DATE OF ISSUE ______________ DATE EFFECTIVE ______________
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17r

Canceling P.S.C. Mo. No. ________ Sec. ________ ________ Original Sheet No.________

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FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after April 1, 2013

J = $\frac{\text{Missouri retail kWh sales}}{\text{Total system kWh sales}}$

Where Total system kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

T = True-up of over/under recovery of FAC balance from prior recovery period as included in the deferred energy cost balancing account. Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission.

I = Interest applicable to (i) the difference between Total energy cost (FC + PP + E – OSSR – REC) and Net base energy costs ("B") multiplied by the Missouri energy ratio ("J") for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

FUEL ADJUSTMENT RATE

The FAR is the result of dividing the FPA by estimated recovery period S_{RP} kWh, rounded to the nearest \$0.00000. The FAR shall be adjusted to reflect the differences in line losses that occur at primary and secondary voltage by multiplying the average cost at the generator by 1.0466 and 1.0662, respectively. Any FAR authorized by the Commission shall be billed based upon customers' energy usage on and after the authorized effective date of the FAR. The formula for the FPA is displayed below.

$$FAR = \frac{FPA}{S_{RP}}$$

Where:

S_{RP} = Forecasted Missouri NSI kWh for the recovery period.

= Forecasted total system NSI * $\frac{\text{Forecasted Missouri retail kWh sales}}{\text{Forecasted total system kWh sales}}$

Where Forecasted total system NSI kWh sales includes sales to municipalities that are associated with Empire and excludes off-system sales.

DATE OF ISSUE ____________________ DATE EFFECTIVE ____________________
ISSUED BY Kelly S. Walters, Vice President, Joplin, MO

THE EMPIRE DISTRICT ELECTRIC COMPANY

P.S.C. Mo. No. 5 Sec. 4 Original Sheet No. 17s

Canceling P.S.C. Mo. No. ________ Sec. ________ ________ Original Sheet No. ________

For ALL TERRITORY

FUEL & PURCHASE POWER ADJUSTMENT CLAUSE
RIDER FAC
For service on and after April 1, 2013

PRUDENCE REVIEW

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

TRUE-UP OF FPA

In conjunction with an adjustment to its FAR, the Company will make a true-up filing with an adjustment to its FAC on the first Filing Date that occurs after completion of each Recovery Period. The true-up adjustment shall be the difference between the FPA revenues billed and the FPA revenues authorized for collection during the true-up recovery period, i.e. the true-up adjustment. Any true-up adjustments or refunds shall be reflected in item T above and shall include interest calculated as provided for in item I above.

DATE OF ISSUE ________________ DATE EFFECTIVE ________________
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Example Customer Bill

Account Detail

8 **Electric 000011-11-001** 9 For Service at 101 Main Street, Anywhere, MO 11111			Rate: RG-Residential	
10 Read for: 00118237 From 05/08/14 to 06/06/14 (29 Days), Curr Read - 13701 Prev Read - 12701. Totaling 1,000 KwH				
11 06/08/14	Customer Charge	1 x 12.52	$12.52	
12 06/08/14	Usage Charge	600KWH x .1149	$68.94	
06/08/14	Usage Charge	400KWH x .0934	$37.36	
13 06/08/14	Energy Efficiency Program Cost	1000KWH x .00027	$0.27	
14 06/08/14	Fuel Adjust Charge	1000KWH x .00173	$1.73	
15 06/08/14	Anywhere County Tax	111.18 x .00875	$0.97	
		16 **Current Months Charges:**	**$121.79**	
06/08/14	17 APP Installment			$125.00
		18 **Billed Charges:**		**$125.00**
Contract Update				
APP	19 Status before payment is $2.64, after payment in full $.57. This account will be reevaluated in May.			

8) 11-digit location number to report outages or to use automated account information by phone.

9) Service address - this is important for customers who have multiple accounts with Empire.

10) Meter number, previous meter read, current meter read, and usage information.

11) Empire service includes a fixed monthly customer charge, no matter how much electricity is used.

12) The usage charge is for the kilowatt hours (KWH) used by a customer. The charge for each KWH used by a customer from June 16 through September 16 is $0.1149 per KWH. The charge for electricity for the other eight months of each year is $0.1149 per KWH for the first 600KWH and $0.0934 for each KWH thereafter.

13) The cost to provide programs for customers to improve the energy efficiency of their homes and businesses.

14) The charge for the difference between fuel and purchased power costs established in the current rate structure and the actual fuel and purchased power costs incurred by Empire. This rate changes twice a year. If fuel costs are less than what is established by the current rates, customers will see a credit in the Fuel Charge line. The cost includes no mark-up or profit for Empire.

15) Taxes, fees, and other assessments.

16) Total charges for the billing period.

17) APP, average payment plan, is a payment contract that calculates a customer's expected annual usage and divides it into 12 equal payments. Each month one payment installment is due from the customer. At the end of 12 months the actual usage is reviewed and a customer's contract and installments are adjusted for the next 12 months.

18) The amount due from the customer by the due date.

19) Important information about a customer's payment contract.

SCHEDULE TWT-5

EXEMPLARY NOTICE

On August x, 2014 The Empire District Electric Company filed revised electric service tariff sheets with the Missouri Public Service Commission (PSC) which would increase the Company's Missouri jurisdictional annual gross revenues by $24.3 million or approximately 5.5 percent. For a residential customer using 1,000 kilowatt-hours of electricity a month, the proposed increase would be approximately $9.87 each month.

The Company is also asking to continue the use of the Fuel Adjustment Clause (FAC) with an updated base cost of energy and other modifications. The continuation of the FAC will allow the Company to adjust customers' bills twice each year, on June 1st and December 1st, based on the varying costs of fuel used to generate electricity at the Company's generating units and electric energy the Company purchases on behalf of its customers.

Local public hearings have been set before the PSC as follows:

– At (time), (day of the week), (month) (day), 20xx, at Webster Hall, Missouri Southern State University, 3950 E. Newman Road, Joplin, Missouri.

– At (time), (day of the week), (month) (day), 20xx, at Webster Hall, Missouri Southern State University, 3950 E. Newman Road, Joplin, Missouri.

– At (time) (day of the week), (month) (day), 20xx, at the Tri-Lakes TCRC, University of Missouri Extension at Reeds Spring High School, ITV Room, 20277 State Highway 413 (in the South Wing of Reeds Spring High School), Reeds Spring, Missouri.

***A question-and-answer session will be held one-half hour before the beginning of each hearing.**

If you wish to comment or secure information, you may contact the Office of the Public Counsel, P.O. Box 2230, Jefferson City, Missouri 65102, telephone (866) 922-2959, email opcservice@ded.mo.gov or the Missouri Public Service Commission, Post Office Box 360 Jefferson City, Missouri 65102, telephone 800-392-4211,email pscinfo@psc.mo.gov.

The Commission will also conduct an evidentiary hearing at its offices in Jefferson City during the weeks of (month) (day) through (month) (day), and (month) (day) through (month) (day), beginning at 8:30 a.m.

The hearings and local public hearings will be held in buildings that meet accessibility standards required by the Americans with Disabilities Act. If a customer needs additional accommodations to participate in these hearings, please call the Public Service Commission's Hotline at 1-800-392-4211 (voice) or Relay Missouri at 711 prior to the hearing.

The Empire District Electric Company
Load and Capability Forecast
Based on Budgeted Load Forecast 2014-2017 adjusted for the Riverton 7 Retirement

Highly Confidential in its Entirety

NP

BUDGET ON-SYSTEM ENERGY MWHS
Highly Confidential in its Entirety

NP

BUDGET HEAT RATES (BTU/KWH)
Highly Confidential in its Entirety

NP

Fuel Types For Each Supply Side Resource

	Primary Fuel	Secondary Fuel	Start Fuel	Additional Fuel
Asbury 1	Asbury PRB Coal (~91.5%)	Asbury Blend Coal (~8.5%)	Oil	Tire Derived Fuel
Asbury 2	Asbury PRB Coal (~91.5%)	Asbury Blend Coal (~8.5%)	-	Tire Derived Fuel
Iatan 1-2	Iatan Western Coal		Oil	
Plum Point	Plum Point Western Coal		Oil	
Riverton 8	Natural Gas		Natural Gas	
Riverton 9	Natural Gas		Natural Gas	Oil
Riverton 10	Natural Gas		Natural Gas	
Riverton 11	Natural Gas		Natural Gas	
Riverton 12	Natural Gas		Natural Gas	
Energy Center 1	Natural Gas		Natural Gas	Oil
Energy Center 2	Natural Gas		Natural Gas	Oil
Energy Center 3	Natural Gas		-	Oil
Energy Center 4	Natural Gas		-	Oil
State Line 1	Natural Gas		Natural Gas	Oil
SLCC 1x1	Natural Gas		Natural Gas	
SLCC 2x1	Natural Gas		Natural Gas	

Approximate % blends in the table are on an MMBtu basis (91.5%/8.5% for Asbury)
Corresponding approximate % blends on a weight (ton) basis are (93%/7% for Asbury)
PRB is an abbreviation for Powder River Basin
CTs with oil as an additional fuel can burn oil if natural gas is unavailable or if oil is more economical

SCHEDULE TWT-7

Unit	Date of test	Heat rate (Btu/kWh)
Asbury	7/24/2012	10,907
Riverton 7	8/3/2012	13,320
Riverton 8	9/15/2012	12,018
Riverton 9	8/9/2012	17,398
Riverton 10	9/26/2012	16,034
Riverton 11	9/26/2012	15,696
Riverton 12	6/26/2012	10,279
Energy Center 1	7/30/2012	13,354
Energy Center 2	7/25/2012	13,868
Energy Center 3	7/27/2012	10,664
Energy Center 4	7/23/2012	10,580
State Line 1	7/30/2012	11,520
SLCC	7/24/2012	7,040
Iatan 1	*	*
Iatan 2	*	*
Plum Point	2/20/2013	9,763

* Please refer to the KCP&L filing

Denotes Highly Confidential SCHEDULE TWT-8

On-System F&PP Summary
MO Rate Case Run

	GWH	CF	F &PP Cost ($000) Incl Start	$/MWH	Starts	Hours	GBTU	Avg HR
Asbury	1,224.78	72.1%	28,518.62	23.28	14	7,477	13,293.35	10,854
Iatan 1	539.38	72.4%	9,172.77	17.01	12	7,418	5,434.72	10,076
Iatan 2	686.38	74.6%	10,651.58	15.52	13	7,371	6,330.71	9,223
Total Iatan	1,225.77	72.8%	19,824.35	16.17	25	14,789	11,765.44	9,598
Plum Point (100 MW)	636.62	72.7%	13,288.33	20.87	13	7,258	6,221.80	9,773
Plum Point PPA O&M			3,471.91					
Plum Point PPA Env			1.83					
Plum Point PPA UT			644.86					
Riverton 8	-	0.0%	-	-	0	-	-	-
Riverton 9	-	0.0%	-	-	0	-	-	-
Riverton 10	-	0.0%	-	-	0	-	-	-
Riverton 11	0.22	0.2%	18.17	81.34	1	19	4.16	18,620
Riverton 12	104.03	8.4%	4,982.09	47.89	33	943	1,141.34	10,971
Total Riverton	104.25	4.3%	5,000.26	47.96	34	962	1,145.50	10,988
Energy Center 1	3.97	0.6%	310.88	78.31	6	98	69.27	17,449
Energy Center 2	5.40	0.8%	412.14	76.33	4	128	94.71	17,539
Energy Center 3	19.37	4.5%	934.23	48.22	85	481	213.72	11,031
Energy Center 4	10.41	2.4%	501.27	48.15	43	253	114.51	10,998
Total EC	39.16	1.7%	2,158.51	55.13	138	960	492.20	12,571
State Line 1	8.86	1.1%	540.36	60.96	3	108	120.84	13,632
State Line CC	941.18	36.2%	30,562.59	32.47	66	4,598	7,043.49	7,484
Total SL	950.04	27.7%	31,102.95	32.74	69	4,706	7,164.32	7,541
Gas Turbines	1,093.45		38,261.73	34.99	241	6,628	8,802.03	8,050
Total Thermal	4,180.61		104,011.63	24.88			27,530.10	6,585
Ozark Beach	53.96	38.5%						
Total EDE (less demand)	4,234.57		104,011.63	24.56				
Spot Purch	302.90		10,910.95	36.02				
Elk River Wind	553.05	42.1%	** **	** **				
Meridian Way Wind	315.47	34.3%	** **	** **				
Total Model	5,405.99		144,353.98	26.70				
Purch Power Demand Charge			9,869.36					
Undist-Oth-Train			3,734.04					
Gas FT			5,962.45					
Gas Dmd Commodity Chg			176.04					
Gas Dmd Losses Chg			1,002.46	230.61 additional GBTUs for losses (2.62%)				
Gas Storage			1,131.50					
Total Gas DMD			8,272.45					
(Dump)/Short Adj	(55.16)		(1,269.84)	23.02				
Energy Cost Only	5,350.83		147,996.678	27.66 (Excludes purchase demand, gas FT, gas storage)				
Total FPP NSI	5,350.83		164,959.989	30.79				

GBTU Gas	8,802.03
GBTU with losses	9,032.65
GCF Gas	8,545.66
Heat Cont Gas	1.03
Avg Gas Cost	4.35

Undist-Oth-Train and Gas FT not allocated to generating units in this summary report
In this summary report SLCC hours and starts are from the PROSYM model. Later both are recalculated from the hourly data for more accuracy
Slight inconsistencies may occur due to rounding

NP

Thermal Unit Model Inputs

	Rated Capacity (MW)	Modeld Max Capacity (MW)	Modeld Min Capacity (MW)	Heat Rate Curve Capacity (MW)	Heat Rate Curve Heat Rate (Btu/kWh)	Ramp Rate (MW/hr)	Normalized Outage (Days)	Forced Outage Rate (%)	Mean Repair Time (Hours)	Min Down Time (Hours)	Min Up Time (Hours)	Fuel Ratio (MMBtu)	Start Fuel (MMBtu)	Start Cost ($)	Variable O&M ($/MWh)
Asbury 1	194	186	135	113 144 166 193 194	11110 10863 10771 10815 10844	90	30	5.5%	60	90		91.5% / 8.5%	1200 (oil)	2500	0.60
Iatan 1	85	82	40	70 85	10100 10025	90	29	8.0%	60	60	168	100%	1200 (oil)	2500	0.60
Iatan 2	102	100	60	60 102	9200 9200	90	27	8.1%	60	60	168	100%	1200 (oil)	2500	0.60
Plum Point	100	100	60	60 100	9750 9750	90	27	8.3%	60	60	168	100%	1200 (oil)	2500	0.60
Riverton 8 (Gas)	54	50	30	30 46 54	12300 12300 12300	40	12	2%	72	90	8		600 (gas)	3000	4.00
Riverton 9	12	12	4	4 12	18500 17500	6	12	10%	60	24	8		50 (gas)	1500	3.75
Riverton 10	16	16	6	6 16	18500 17500	8	12	10%	60	24	8		50 (gas)	1500	3.75
Riverton 11	17	17	10	10 16	18500 18000	8	12	10%	60	24	8		50 (gas)	1500	3.75
Riverton 12	Summer 142 Winter 160	142	118	90 105 120 135 142	11774 11106 10604 10230 10000	60	9	10%	72	10	14		150 (gas)	11,000	3.62
Energy Center 1	82	76	30	30 42 67 98	19500 16500 14800 13600	60	17	10%	72	24	12		150 (gas)	5000	3.00
Energy Center 2	82	75	30	30 42 72 95	20200 17200 14500 13900	60	17	10%	72	24	12		150 (gas)	5000	3.00
Energy Center 3	49 Summer 55 Winter	49 Summer 55 Winter	25	30 62	12240 10100	40	15	10%	60	2	2		0	300	3.00
Energy Center 4	49 Summer 55 Winter	49 Summer 55 Winter	25	30 62	12240 10100	40	15	10%	60	2	2		0	300	3.00
State Line 1	94	89	80	60 85	14750 13425	60	15	10%	120	24	24		150 (gas)	5000	3.00
SLCC 1x1	Summer 149 Winter 167	149	72	72 90 120 144 149	8700 8025 7500 7250 7200	90	26	7%	72	36	72		300 (gas)	13,000	3.50
SLCC 2x1	Summer 149 Winter 167	149	90	90 120 135 145 149	7075 6900 6875 6875 6875	20	26	14%	72	36	72		300 (gas)	2500	3.00

SCHEDULE TWT-10

Normalized Maintenance Schedule Used for Modelling

Unit	Annual Days	Outage 1		Outage 2	
		Start Date	Days Out	Start Date	Days Out
ASBURY	30	12-Mar	21	2-Nov	8
IATAN 1	27	2-Apr	27		
IATAN 2	28	1-May	28		
PLUM POINT	27	1-Oct	27		
RIVERTON 8	12	23-Apr	12		
RIVERTON 9	12	14-May	12		
RIVERTON 10	12	2-Nov	12		
RIVERTON 11	12	28-May	12		
RIVERTON 12	9	23-Apr	9		
ENERGY CENTER 1	17	30-Mar	10	5-Nov	7
ENERGY CENTER 2	17	9-Apr	10	1-Oct	7
ENERGY CENTER 3	15	7-May	10	15-Oct	5
ENERGY CENTER 4	15	22-May	10	22-Oct	5
STATELINE 1	15	5-Mar	10	12-Nov	5
SLCC 1X1	26	26-Mar	26		
SLCC 2X1	26	8-Oct	26		

AFFIDAVIT OF TODD W. TARTER

STATE OF MISSOURI)
) ss
COUNTY OF JASPER)

On the 26th day of August, 2014, before me appeared Todd W. Tarter, to me personally known, who, being by me first duly sworn, states that he is Manager of Strategic Planning of The Empire District Electric Company and acknowledges that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

Todd W. Tarter

Todd W. Tarter

Subscribed and sworn to before me this 26th day of August, 2014.

ANGELA M. CLOVEN
Notary Public - Notary Seal
State of Missouri
Commissioned for Jasper County
My Commission Expires: November 01, 2015
Commission Number: 11262659

Notary Public

My commission expires: 11/01/2015.