Exhibit No.: 15NP
Issue: On-System Fuel and Purchased Power Expense
Witness: Todd W. Tarter
Type of Exhibit: Direct Testimony
Sponsoring Party: Empire District Electric
Case No.
Date Testimony Prepared: October 2007

Before the Public Service Commission Of the State of Missouri

Direct Testimony

of

Todd W. Tarter

October 2007

****Denotes Highly Confidential****

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OF
TODD W. TARTER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

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DIRECT TESTIMONY OF
TODD W. TARTER
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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Todd W. Tarter. My business address is 602 Joplin Street, 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 FOR THE COMMISSION.

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 have 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 integrated resource planning.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR ANY OTHER STATE UTILITY COMMISSION?

A. Yes. I testified on behalf of Empire on the topic of on-system fuel and purchased power

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expense in Missouri Case No. ER-2006-0315, and in Kansas Case No. 05-EPDE-980-RTS.

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

A. My direct testimony addresses the on-system fuel and purchased power expense in this case. I will also provide some of the forecasted data required for a Fuel Adjustment Clause ("FAC") filing. In addition, I will present figures for an annualized and normalized on-system fuel and purchased power expense developed with a production cost computer model that Empire supports for establishing fuel and purchased power costs in base rates. In connection with that, I will describe the model, the modeling process and discuss the key data inputs to the model.

II. ENERGY COST RECOVERY

Q. WHAT IS EMPIRE PROPOSING FOR ENERGY COST RECOVERY IN THIS RATE CASE?

A. Empire is proposing that the Commission approve the implementation of an FAC in this case. For a more detailed description of this request, please refer to the Direct Testimony of Empire witness Dr. H. Edwin Overcast. Empire believes that in conjunction with the FAC it is important to establish the correct level of fuel and purchased power costs for base rates (that portion of the rates that are fixed). Empire has used the PROSYM production cost model to develop this appropriate level for this case. This is the same model used by Empire in its last Missouri rate case that calculated the on-system fuel and purchased power expense level adopted by the Commission.

Q. ARE YOU PROVIDING ANY SUPPORTING INFORMATION FOR EMPIRE'S REQUEST OF AN FAC?

A. Yes. To comply with 4 CSR 240-2.090(2)(G), I am providing information as required by various of the subparts of 4 CSR 240-3.161(2):

- Schedule TWT-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 (as required by 4 CSR 240-3.161(2)(O));
- Schedule TWT-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 (as required by 4 CSR 240-3.161(2)(O));
- Schedule TWT-3, which shows the expected heat rates for each supply-side resource that the Company expects to utilize for the next four (4) years (as required by 4 CSR 240-3.161(2)(O));
- Schedule TWT-4, which shows the fuel types utilized in each of Empire's supply-side resources (as required by 4 CSR 240-3.161(2)(O)); and
- Schedule TWT-5, which establishes the fact that Empire has in place a long-term resource planning process, which has among its objectives to minimize overall delivered energy costs and to provide reliable service to customers (as required by 4 CSR 240-3.161(2)(Q)).

III. PROPOSED LEVEL OF ON-SYSTEM FUEL AND PURCHASED POWER EXPENSE FOR BASE RATES

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

A. The model run presented in this testimony is being provided as Empire's recommendation for the on-system fuel and purchased power expense to include in base rates (that portion of the rates that is fixed). At the time of filing this case, Empire recommends that a total company on-system fuel and purchased power expense, including demand charges, of \$172,032,185 be used to establish its base electric rates. This is based on a projected energy requirement of 5,425,392 MWh. On an average basis, this is 31.71 \$/MWh. A summary of the output from the computer simulation which supports this number is attached as Schedule TWT-6.

Q. HOW WAS THIS LEVEL OF FUEL AND PURCHASED POWER EXPENSE DEVELOPED?

A. This ongoing level of fuel and purchased power expense was developed by running the hourly production cost computer model known as PROSYM using normalized sales levels, growth and weather, and projected fuel and purchased power costs.

Q. COULD YOU 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.

The PROSYM simulation engine is described by its developer, Global Energy Decisions, as providing the most accurate generation unit commitment logic in the world. PROSYM is used by well over 100 energy organizations around the world in both control room dispatch environments as well as in market analytic groups. Empire has been using chronological production costing models for projection purposes since 1991. Empire's five previous rate case filings in Missouri, and most recent rate case in Kansas, have

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utilized the PROSYM model.

IV. UNIT DATA USED IN THE MODEL

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

A. Data for Empire's generating units are shown in Schedule TWT-7. 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-8.

Q. ARE THERE ANY NEW GENERATING UNITS SINCE THE LAST EMPIRE RATE CASE THAT WAS USED IN THE MODEL RUN?

A. Yes. Riverton Unit 12 a Siemens V84.3A2 combustion turbine that uses natural gas as its fuel source was declared available for commercial operation on April 10, 2007. It was included in the model as a 150-megawatt unit. The unit characteristic data can be found in Schedule TWT-7, along with all of the other generating unit data.

Q. ARE THERE ANY SPECIAL CONSIDERATIONS THAT NEED TO BE MADE WHEN MODELING EMPIRE'S GENERATING UNITS?

A. Yes. There are special considerations that need to be made for modeling (1) Asbury Unit 1 and Asbury Unit 2; (2) Riverton Unit 7 and Riverton Unit 8; and (3) the State Line Combined Cycle ("SLCC").

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S ASBURY UNITS THAT NEED SPECIAL CONSIDERATION.

A. The Asbury coal plant is comprised of one boiler and two turbines. The Asbury Unit 1 turbine is rated at 193 MW and Asbury Unit 2 is rated at 17 MW. Asbury Unit 2 cannot operate while Asbury Unit 1 is off line. In addition, Asbury is not able to run on a continuous basis at 210 MW due to operational issues. Specifically, the upper convection passes in the furnace tend to plug with ash. These operational limitations have been taken into consideration in the PROSYM model.

Q. ASBURY UNIT 2 DOES NOT APPEAR TO RUN VERY MANY HOURS IN THE MODEL RUN. COULD YOU PLEASE EXPLAIN WHY?

A. Running Asbury Unit 2 increases the total cycle heat rate of the Asbury plant which decreases the plant's efficiency. It also contributes to plugging the furnace, which could lead to more forced outages. As a result Empire generally operates Asbury Unit 2 as a peaking unit. In the computer model run Asbury Unit 2 generates 1,636 MWh. In the test year (twelve months ending ("TME") June-07) Asbury Unit 2 generated 482 MWh.

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S RIVERTON COAL UNITS THAT NEED SPECIAL CONSIDERATION.

A. Riverton Unit 7 can operate to approximately 24 MW out of its 38 MW of rated capacity on a blend of coal and petroleum coke. The remainder of the Riverton Unit 7 capacity can only be obtained by over-firing natural gas. Likewise, Riverton Unit 8 can operate to approximately 45 MW out of its 54 MW rated capacity on a blend of coal and petroleum coke with the remainder of the capacity obtained by over-firing natural gas. These operational constraints were modeled in PROSYM.

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S STATE LINE COMBINED CYCLE THAT NEED SPECIAL CONSIDERATION.

A. Empire owns 300 MW, or 60%, of the 500-MW State Line combined cycle unit ("SLCC").

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The combined cycle consists of three electrical generating units—two combustion turbines ("CTs") and one steam turbine. The CTs have heat recovery steam generators ("HRSGs") on the exhaust end which utilize the high temperature exhaust gases to generate steam for use in the steam turbine. Steam can be used from one or both HRSGs to operate the steam turbine. This allows the combined cycle to be operated in one of two modes. Mode one, which I will call 1x1 mode, consists of one CT operating in conjunction with the steam turbine. Mode two, which I will call 2x1 mode, consists of both CTs operating in conjunction with the steam turbine. For this rate case filing, SLCC was modeled as two separate units. In the model, one unit running represents 1x1 mode and both units running represents the 2x1 mode configuration. Multi-step heat rates were input for each unit with the overall heat rate of the units comparing favorably to SLCC's average heat rate of approximately 7,400 Btu/kWh.

Q. HOW WAS THE OZARK BEACH HYDRO UNIT MODELED?

A. Ozark Beach was modeled close to the 30-year average of the historical generation of the unit from 1977 to 2006. Hydro generation accounts for less than 1.2 percent of net system input in this normalized model run. Historical data for Ozark Beach are shown as Schedule TWT-9.

V. FUEL DATA USED IN THE MODEL

Q. BRIEFLY EXPLAIN THE BASIS FOR THE SOLID FUEL COSTS INCLUDED IN THE PRODUCTION COST MODEL.

A. All coal and petroleum coke prices are based on the expected 2008 delivered cost (initial and freight). Other costs associated with solid fuel, including handling and unit train costs are not included in the solid fuel costs in the model. These fuel related costs will be discussed in Section VII, Other Fuel Related Costs. The following solid fuel types were modeled: (1) Asbury western coal; (2) Asbury blend coal; (3) Riverton western coal; (4) Riverton petroleum coke; and (5) Iatan western coal.

Q. WHAT FUEL BLEND RATES ARE USED IN THE MODEL?

A. In the model on an MMBtu basis, Asbury burns 87% western coal and 13% blend coal; Riverton Unit 7 and Riverton Unit 8 burn 66% western coal and 34% petroleum coke; and Iatan burns 100% western coal. On a tonnage basis this is approximately equivalent to the following: Asbury 90% western coal and 10% blend coal; Riverton Unit 7 and Riverton Unit 8 75% western coal and 25% petroleum coke; and Iatan 100% western coal.

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

A. In the computer model, the gas-fired units can burn natural gas from two sources—from hedged natural gas and from spot market natural gas. The hedged gas represents Empire's current hedged position for 2008 (as of August 10, 2007). The hedged natural gas is a limited fuel type. Gas-fired generating units can burn this fuel until a specified MMBtu level is reached. After the limit is reached, the computer models the generating units as if they must operate on spot market gas.

Q. WHAT IS THE 2008 HEDGED NATURAL GAS POSITION THAT WAS USED IN THE MODEL?

A. The following table summarizes the 2008 hedged natural gas position that was used in the model. As of August 10, 2007, 7,826,000 MMBtu of natural gas are hedged for calendar year 2008, at an average price of about 6.852 $/MMBtu.

2008 Natural Gas Hedged Position
As of August 10, 2007

Month	MMBtu	Avg Price $/MMBtu
Jan	** ______ **	** ______ **

Feb	** **	** **
Mar	** **	** **
Apr	** **	** **
May	** **	** **
Jun	** **	** **
Jul	** **	** **
Aug	** **	** **
Sep	** **	** **
Oct	** **	** **
Nov	** **	** **
Dec	** **	** **
	7,826,000	6.852

Q. HOW WERE THE SPOT MARKET NATURAL GAS PRICES DEVELOPED FOR THE MODEL RUN?

A. The spot market natural gas prices in the model are based on NYMEX gas futures for 2008 as of August 10, 2007, with a basis adjustment. The data is summarized in the following table.

2008 Estimated Spot Natural Gas Prices
August 10, 2007 NYMEX with Basis Adjustment

Month	NYMEX $/MMBtu	Basis Adj	Spot Gas Modeled $/MMBtu
Jan	8.914	-1.195	7.719
Feb	8.914	-1.195	7.719
Mar	8.679	-1.195	7.484
Apr	7.939	-1.160	6.779
May	7.904	-1.160	6.744
Jun	7.986	-1.160	6.826
Jul	8.081	-1.160	6.921
Aug	8.146	-1.160	6.986
Sep	8.199	-1.160	7.039
Oct	8.319	-1.160	7.159
Nov	8.769	-1.182	7.587
Dec	9.214	-1.182	8.032
Average			7.250

Q. COULD YOU BRIEFLY EXPLAIN THE NATURAL GAS BASIS ADJUSTMENT?

A. NYMEX natural gas prices are based on a standard contract point at the Henry Hub in Louisiana. Since Empire takes gas delivery from the Southern Star Central Gas Pipeline

("Southern Star"), formerly known as Williams Gas Pipeline, NYMEX prices have been adjusted to reflect the cost from Southern Star. Empire subscribes to a service from Risk Management Inc. called Mark-It View basis valuations to determine the basis adjustment estimates. The NYMEX prices adjusted for Southern Star delivery point were used in the model.

Q. WHAT WAS THE WEIGHTED AVERAGE NATURAL GAS PRICE FROM THE MODEL RUN?

A. In the PROSYM run for this case, with the model utilizing the hedged and spot market natural gas fuel types, the weighted average of the natural gas consumed was about 6.91 $/MMBtu.

Q. HOW MUCH NATURAL GAS WAS DELIVERED IN THE MODEL RUN, AND HOW DOES THIS COMPARE TO HISTORY?

A. In the model run, 8,299,672 MMBtu of natural gas was delivered (8,106,732 burned plus 192,940 MMBtu losses). In 2005, Empire delivered **________** MMBtu. In the filed test year (TME June-07) Empire delivered **________** MMBtu. In 2006, Empire delivered **________** MMBtu. The primary reason that the model run reflects a lower natural gas delivery than the calendar year 2005 level is due to the Elk River wind purchase.

<u>VI. PURCHASED POWER DATA IN THE MODEL</u>

Q. BRIEFLY OUTLINE THE PURCHASES THAT WERE MODELED.

A. In the model, purchased power can be grouped into three categories: (1) 162 MW Westar – Jeffrey contract purchase; (2) 150 MW Elk River Wind Farm contract purchase; and (3) the wholesale power market also referred to as spot purchases or non-contract purchases.

Q. PLEASE DESCRIBE HOW THE WESTAR - JEFFREY PURCHASE WAS

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MODELED.

A. The energy and capacity for this 162 MW contract purchase comes from the three different coal units at the Jeffrey Energy Center (54 MW each). The purchase is represented as three units in PROSYM, all with the same energy costs, but each with separate scheduled maintenance outages. The test year average energy price with losses from this purchase was **____** $/MWh. In 2006, the average energy price with losses was **____** $/MWh. In the model, the expected 2008 level of **_____** $/MWh was used. This purchase also has a fixed demand charge which will be discussed in Section VII, Other Fuel Related Costs.

Q. PLEASE DESCRIBE HOW THE ELK RIVER WIND FARM PURCHASE WAS MODELED.

A. This purchase was modeled as a must take purchase with an hourly load profile from calendar year 2006 (the only full calendar year of actual operational data at this time). In the model run, the annual energy purchased was **_____** MWh or about a **____** capacity factor. The energy price used in the model is based on the agreed to contract price for 2008.

Q. WHAT PRICE WAS USED FOR THE NON-CONTRACT PURCHASED ENERGY?

A. The non-contract purchase data in the model represents the wholesale power market. The data is comprised of 8,760 hourly prices. The prices were developed by Global Energy Decisions using regional models for the Southwest Power Pool North region. The prices are forecasted for year 2008, utilizing the same spot natural gas forecast with basis adjustments described in this testimony. The average non-contract purchase price in the model run is 53.11 $/MWh. The test year average (TME June-07) was about **_____**

$/MWh. In 2006, the average price was about **_____** $/MWh. In 2005, the average price was about **_____** $/MWh.

VII. OTHER FUEL RELATED COSTS

Q. BRIEFLY OUTLINE THE OTHER FUEL RELATED COSTS THAT ARE INCLUDED IN THE TOTAL COMPANY ON-SYSTEM FUEL AND PURCHASED POWER EXPENSES OF $172,032,185.

A. The other fuel related costs are: (1) Purchased power demand charge; (2) natural gas demand charges; and (3) unit train and undistributed and other costs.

Q. PLEASE DESCRIBE THE PURCHASED POWER DEMAND CHARGE.

A. There is a monthly demand charge for the 162 MW Westar – Jeffrey purchase. By contract this is 8.33 $/Kw/month which is $1,349,460 monthly and $16,193,520 annually. This contract expires May 31, 2010.

Q. PLEASE DESCRIBE THE NATURAL GAS DEMAND CHARGES.

A. When I describe the natural gas demand charges I am referring to the following three components: (1) fixed cost for firm transportation service; (2) commodity charge; and (3) natural gas losses.

Empire's contract fixed costs for firm natural gas transportation service is based on the three contracts TA-0907, TA-8251 and TA-8385. The total 2008 expected level for all of these contracts is **_________**. The commodity charge is based on **______** $/MMBtu for a total of **_______** (**________** x 8,106,732 MMBtu in the model run). The losses are based on a natural gas loss rate of **_____** for a total of **_________** (**____** x 8,106,732 MMBtu in the model run x 6.911294 $/MMBtu average natural gas cost in the model). These three components result in a total gas

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demand cost of **__________**.

Q. PLEASE DESCRIBE THE OTHER FUEL RELATED EXPENSES.

A. The other fuel related expenses include undistributed and other costs, unit train lease, unit train maintenance, unit train depreciation and unit train property taxes. A five-year average (adjusted for nonrecurring expenses) of approximately $1,706,507 was used in this rate filing. These are shown in Schedule TWT-10.

Q. HAVE YOU DESCRIBED IN GENERAL, THE OPERATIONS OF THE COMPUTER MODEL AND THE DATA INPUTS FOR THE SIMULATION THAT WAS PERFORMED?

A. Yes. And I have reviewed all of the inputs and outputs and compared them to actual situations such that I am confident that the result is accurate and reasonable for the use to which we are putting it in this case.

VIII. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR DIRECT TESTIMONY.

A. In this case Empire is requesting an FAC. In conjunction with an FAC it is important to correctly set the appropriate level of on-system fuel and purchased power expense in base rates. Empire has made a computer simulation run with the PROSYM production cost model to determine the appropriate level of an annualized and normalized total company fuel and purchased power expense including demand charges. Based on this model run Empire supports a value of $172,032,185 or 31.71 $/MWh to be used to establish its base electric rates in this case pending any true up runs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

The Empire District Electric Company
Load and Capability Forecast

Based on Budgeted Load Forecast 2007-2011

****Highly Confidential in its Entirety****

BUDGET ON-SYSTEM ENERGY MWHS
****Highly Confidential in its Entirety****

These resources were economically dispatched with the PROSYM production cost model. The model 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 costs after accounting for operational characteristics of a utility system.

BUDGET HEAT RATES (BTU/KWH)
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Fuel Types For Each Supply Side Resource

	Primary Fuel	Secondary Fuel	Start Fuel	Additiona Fuel
Asbury 1	Asbury PRB Coal (~87%)	Asbury Blend Coal (~13%)	Oil	Tire derived F
Asbury 2	Asbury PRB Coal (~87%)	Asbury Blend Coal (~13%)	-	Tire derived F
Iatan	Iatan Western Coal		Oil	
Riverton 7	Riverton PRB Coal (~66%)	Riverton Petroleum Coke (~34%)	Natural Gas	Natural Gas
Riverton 8	Riverton PRB Coal (~66%)	Riverton Petroleum Coke (~34%)	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 are on an MMBtu basis

PRB is an abbreviation for Powder River Basin

* Riverton 7 has a rated capacity of 38 MW but a modeled max of 24 MW on coal & petroleum coke. Over firing with natural gas needed to reach 3

** Riverton 8 has a rated capacity of 54 MW but a modeled max of 45 MW on coal & petroleum coke. Over firing with natural gas needed to reach 5

CTs with oil as an additional fuel can burn oil if natural gas is unavailable or if oil is more economical

Long-Term Resource Planning Process in Missouri

Since October 1999 Empire has been meeting with the Missouri Commission Staff (Staff), Missouri Office of Public Counsel (OPC) and Missouri Department of Natural Resources (MDNR) twice each year as an alternative to electric utility resource plan filings. As part of the stipulation and agreement (S&A) in the experimental regulatory plan Case No. EO-2005-0263, Empire submitted a new resource plan to Missouri in July 2006. Empire presented this resource plan to all interested non-IOU Signatory Parties (Parties) on August 25, 2006. The requirements of this resource plan can be found in the S&A. The S&A states that for the duration that the S&A is in effect, Empire will continue to hold Integrated Resource Plan (IRP) presentations semiannually, and invite the Parties. The S&A also established the Empire Customer Programs Collaborative (CPC). This group comprised of the Parties, serves as a collaborative that makes decisions pertaining to the development, implementation, monitoring and evaluation of Empire's Affordability, Energy Efficiency and Demand Response Programs.

In September 2007, Empire filed a Missouri IRP in Case No. EO-2008-0069 to comply with the requirements of 4 CSR 240-22. Empire formally requested variances and clarifications from the Missouri Public Service Commission for those instances in which the IRP does not comply with 4 CSR 240-22. The Commission granted Empire's request for waivers in Case No. EE-2008-0025. This periodic IRP analysis in conjunction with Empire's normal planning process assists Empire in making decisions concerning the timing and type of system expansion that should occur. In addition to the formal IRP filing, Empire develops an annual and five year business plan each year, and makes updates to these plans as conditions change.

According to 4 CSR 240-22.010 Policy Objectives, "the fundamental objective of the Missouri resource planning process at electric utilities is to provide the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest." As stated in Empire's recent IRP filing, integrated resource planning for electric utilities has evolved considerably over the past twenty years and can no longer solely identify the least cost resources; such a plan must explicitly consider risks and uncertainties. Empire's objectives in preparing its 2007 IRP reflect its commitment to provide cost-effective, safe, and reliable electric service to its customers:

- to generate and provide reliable electricity service while complying with all environmental requirements
- to minimize rate impacts for customers
- to achieve and/or maintain investment grade ratings on its debt; thus providing for corporate financial stability and minimizing the financing costs included in the rates paid by Empire's customers
- to accommodate and manage cost, environmental, and load growth uncertainties.

Schedule TWT-6

On-System F&PP Summary
2008 MO Rate Case Run - October 2007 (Direct Testimony)
** Highly Confidential in its Entirety**

	GWH	CF	F &PP Cost ($000) Incl Start	$/MWH		Starts	Hours	GBTU	Avg HR	
Asbury 1	** **	** **	** **	** **		** **	** **	** **	** **	
Asbury 2	** **	** **	** **	** **		** **	** **	** **	** **	
Total Asbury	** **	** **	** **	** **		** **	** **	** **	** **	
Iatan	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 7	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 8	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 9	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 10	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 11	** **	** **	** **	** **		** **	** **	** **	** **	
Riverton 12	** **	** **	** **	** **		** **	** **	** **	** **	
Total Riverton	** **	** **	** **	** **		** **	** **	** **	** **	
Energy Center 1	** **	** **	** **	** **		** **	** **	** **	** **	
Energy Center 2	** **	** **	** **	** **		** **	** **	** **	** **	
Energy Center 3	** **	** **	** **	** **		** **	** **	** **	** **	
Energy Center 4	** **	** **	** **	** **		** **	** **	** **	** **	
Total EC	** **	** **	** **	** **		** **	** **	** **	** **	
State Line 1	** **	** **	** **	** **		** **	** **	** **	** **	
State Line CC	** **	** **	** **	** **		** **	** **	** **	** **	
Total SL	** **	** **	** **	** **		** **	** **	** **	** **	
Gas Turbines	** **		** **	** **		** **	** **	** **	** **	
Total Thermal	** **		** **	** **				** **	** **	
Ozark Beach	** **	** **								
Total EDE (less fixed)	** **		** **	** **						
WR-JP	** **	** **	** **	** **						
Spot Purch	** **		** **	** **					** **	** **
Total Purch	** **		** **	** **	** **					
								** **	** **	** **
Wind Energy	** **	** **	** **	** **	** **			** **	** **	** **
								** **	** **	** **
Total Model	** **		** **	** **						
								** **	** **	** **
Purch Power Demand Charge			** **					** **	** **	** **
								** **	** **	** **
Undist-Oth-Train			** **					** **	** **	** **
								** **	** **	** **
Gas Fixed FT			** **							
Gas Dmd Commodity Chg			** **							
Gas Dmd Losses Chg			** **	** **	** **					
Total Gas DMD			** **					** **	** **	
								** **	** **	
(Dump)/Short Adj	** **		** **	** **				** **	** **	
								** **	** **	
								** **	** **	
Total FPP NSI	5,425.39		172,032.19	31.71						

Unidst-Oth-Train and Gas FT not allocated to generating units in this summary report
Slight inconsistencies may occur due to rounding

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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)
Asbury 1	193	189	105	110 140 162 188 191	11485 11230 11135 11180 11210	90	30	6.5%	60	90	
Asbury 2	17	16	4	4 17	18300 18200	8	30	20%	60	60	
Iatan	80	80	40	70 80	10100 10025	90	30	7.5%	60	60	
Riverton 7	38	24	20	20 27 38	12700 12500 17000	40	25	4.5%	48	90	
Riverton 8	54	45	32	30 46 54	12080 11980 21610	40	25	6%	72	90	
Riverton 9	12	12	4	4 12	18500 17500	6	16	10%	60	24	8
Riverton 10	16	16	6	6 16	18500 17500	8	16	10%	60	24	8
Riverton 11	16	16	10	10 16	18500 18000	8	16	10%	60	24	8
Riverton 12	150	150	118	90 105 120 135 150	11774 11106 10604 10230 9932	60	16	10%	72	10	14
Energy Center 1	86	76	30	30 42 67 98	19500 16500 14800 13600	60	25	10%	72	24	12
Energy Center 2	84	75	30	30 42 72 95	20200 17200 14500 13900	60	25	10%	72	24	12
Energy Center 3	50	50	25	30 62	12240 10100	40	16	10%	60	2	2
Energy Center 4	50	50	25	30 62	12240 10100	40	16	10%	60	2	2
State Line 1	96	89	80	60 85	14750 13425	60	25	10%	120	24	24
SLCC 1x1	150	150	72	72 96 120 144 150	8700 8025 7500 7250 7200	90	30	7%	72	36	72
SLCC 2x1	150	150	90	90 120 135 145 150	7075 6900 6875 6875 6875	20	30	14%	72	36	72

Normalized Outage Schedule
The Empire District Electric Company

	Jan-08					Feb-08				Mar-08				Apr-08				May-08					Jun-08				Jul-08					Aug-08				Sep-08				
Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	31	32	33	34	36	37	38	39	4
Date	30	6	13	20	27	3	10	17	24	2	9	16	23	30	6	13	20	27	4	11	18	25	1	8	15	22	29	6	13	20	27	3	10	17	24	31	7	14	21	2

	Days	Outage
ıry	30	30 Mar 15-Apr 13
ı 1	30	30 Feb 15-Mar 16
rton 7	25	25 Mar 29-Apr 22
rton 8	25	25 Apr 26-May 20
rton 9	16	16 Mar 15-30
rton 10	16	16 Apr 19-May 4
rton 11	16	16 S
rton 12	16	
gy Center 1	25	25 Mar 8- Apr 1
gy Center 2	25	25 Apr 5-29
gy Center 3	16	16 May 3-18
gy Center 4	16	
e Line 1	25	
C	30	
JEC 1	30	30 Mar 15-Apr 13
JEC 2	30	30 Apr 19-May 18
JEC 3	30	

OZARK BEACH GROSS* GENERATION HISTORY

	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV
1	1977	8,481	3,139	3,265	1,661	700	2,811	3,334	1,784	4,330	4,576	6,338
2	1978	6,309	5,939	6,177	8,495	9,359	8,385	7,473	3,800	5,270	5,959	4,413
3	1979	5,591	3,494	7,601	6,534	3,450	850	2,095	6,284	7,179	2,865	4,702
4	1980	2,494	3,581	6,119	4,997	5,132	7,752	8,203	5,522	3,279	1,163	3,208
5	1981	1,530	2,182	2,046	803	1,382	2,137	2,625	2,537	1,772	1,306	2,372
6	1982	7,881	8,784	9,468	4,486	1,695	7,036	4,775	3,950	2,759	2,912	4,459
7	1983	1,215	8,097	9,186	9,066	7,463	4,227	7,933	7,644	3,324	1,234	4,512
8	1984	2,689	3,187	8,764	9,338	7,725	5,286	4,203	6,326	2,720	4,402	5,816
9	1985	352	3,270	5,781	2,831	840	516	903	2,450	5,504	4,765	5,938
10	1986	7,537	6,842	8,644	9,923	8,226	5,732	7,756	5,463	5,126	5,484	8,602
11	1987	2,114	5,969	11,330	10,469	6,860	3,422	3,902	3,296	2,379	1,471	6,061
12	1988	10,605	9,533	11,647	9,268	6,440	4,306	3,283	7,010	4,375	3,429	3,360
13	1989	4,860	7,443	7,671	8,439	6,325	6,409	4,499	4,824	3,226	5,909	3,219
14	1990	1,526	8,451	10,173	8,770	2,966	-13	464	3,240	7,540	5,292	2,372
15	1991	10,249	9,226	7,348	9,338	6,189	2,852	3,979	5,252	3,389	5,199	8,201
16	1992	6,810	7,576	6,541	3,675	1,876	7,335	5,124	5,684	6,968	8,527	6,676
17	1993	9,701	9,900	11,285	10,841	9,000	10,060	10,832	7,029	5,459	6,415	6,903
18	1994	9,680	9,062	10,772	9,834	3,836	2,727	6,008	9,355	5,060	2,690	6,958
19	1995*	9,981	9,716	10,582	8,692	7,149	4,545	2,743	6,208	4,834	2,934	3,077
20	1996*	2,717	4,822	3,636	3,450	6,212	2,952	2,666	6,329	5,076	6,706	9,089
21	1997*	10,149	7,255	10,246	9,531	4,351	2,856	8,387	6,731	5,869	6,031	3,406
22	1998*	8,187	9,626	10,524	6,874	4,895	6,166	6,980	8,171	4,909	2,049	1,407
23	1999*	4,032	7,854	11,966	10,694	7,729	8,210	10,769	9,442	4,815	3,489	1,928
24	2000*	4,584	2,221	761	423	574	3,511	10,858	11,824	3,894	1,182	4,586
25	2001*	4,372	6,707	7,578	3,024	1,486	2,520	7,267	7,001	1,788	3,174	3,932
26	2002*	4,811	7,455	7,630	5,910	1,415	0	171	1,050	4,212	3,624	5,518
27	2003*	6,274	5,554	4,879	2,640	4,802	4,302	7,962	9,149	3,443	2,466	2,970
28	2004*	5,265	2,614	6,718	7,626	3,076	2,097	8,236	7,099	3,226	2,133	6,174
29	2005*	7,910	9,102	9,250	8,869	1,209	3,967	6,090	7,244	2,877	1,245	2,011
30	2006*	924	562	880	987	2,546	656	5,272	4,952	1,458	1,031	976
	30 year Average	5,628	6,305	7,616	6,583	4,497	4,120	5,493	5,888	4,202	3,655	4,639

*Net Generation values are presented starting in 1995.

THE EMPIRE DISTRICT ELECTRIC COMPANY
HISTORICAL UNDISTRIBUTED AND OTHER COSTS

	2002	2003	2004	2005	2006
Asbury	613,783.51	569,227.05	662,735.60	624,074.36	674,5
Riverton 7 & 8	126,809.25	133,382.32	185,705.99	154,872.48	174,1
Iatan	798,278.48	497,808.64	228,060.83	261,299.72	323,6
Total Coal	1,538,871.24	1,200,418.01	1,076,502.42	1,040,246.56	1,172,2
SLCC	8,240.35	869,744.44	18,108.04	7,943.93	3,8
Riverton CT's	-	27,332.21	1,145.22	3.90	.
State Line 1 & 2	1,027.26	53,272.99	1,004.05	959.33	5,7
Energy Center CT's	881.13	59,300.54	1,923.67	(3,432.59)	5,0
Total Gas	10,148.74	1,009,650.18	22,180.98	5,474.57	14,6
Total	1,549,019.98	2,210,068.19	1,098,683.40	1,047,109.98	1,186,9
Adjustments					
Enron (Gas)		(1,000,000.00)			
Adjusted Total	**1,549,019.98**	**1,210,068.19**	**1,098,683.40**	**1,047,109.98**	**1,186,9**

** ______________________ **

Total

Rate Case I