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Witness: Jill S. Tietjen
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Case No.
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Before the Public Service Commission
of the State of Missouri

Direct Testimony

Of

Jill S. Tietjen

April 2004

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OF
JILL S. TIETJEN
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
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I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jill S. Tietjen. My business address is 7377 S. Hudson Way, Littleton, Colorado.

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

A. I am self-employed as an engineering consultant.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND WORK BACKGROUND.

A. I graduated from the University of Virginia with a BS in Applied Mathematics (minor in Electrical Engineering) in 1976. I began my career with Duke Power Company and spent five years as a Planning Engineer in the System Planning Department (1976-1981). While at Duke Power Company, I earned my MBA from the University of North Carolina at Charlotte in 1979. I subsequently joined Mobil Oil Corporation's Mining and Coal Division where I worked from 1981-1984 as a planning analyst. I became a registered professional engineer in Colorado in 1982. I joined Stone & Webster Management Consultants in 1984 and by the time I left in 1992 had progressed to Assistant Vice President. I served as Principal and leader of the utility planning practice at Hagler Bailly Consulting during 1992-1995. In 1995, I rejoined Stone & Webster Management Consultants as an Assistant Vice President and office manager for the Denver office, a position that I served in through 1997. Since 1997, I have been on staff at the University of Colorado at Boulder and have also been self-employed as an engineering consultant. Also in 1997, I was elected as an outside director on the Board of Directors of Georgia Transmission Corporation and still serve in that capacity. I work on a part-time, as needed basis as a senior engineer for McNeil Technologies and as a senior management consultant for R. W. Beck. My resume, testimony listing, and a publications listing are shown as Schedule JST-0.

Q. HAVE YOU FILED TESTIMONY PREVIOUSLY BEFORE THE COMMISSION?

A. Yes. In 1995, I filed testimony on behalf of The Empire District Electric Company in Case No. EC-95-28 under my previous name, Jill S. Baylor. I filed rebuttal testimony on behalf of The Empire District Electric Company in Case No. ER-2002-424 in September 2002.

Q. COULD YOU BRIEFLY PROVIDE THE TOPICS AND JURISDICTIONS IN WHICH YOU HAVE PREVIOUSLY PRESENTED EXPERT TESTIMONY?

A. I have prepared testimony or filed affidavits for cases before the Federal Energy Regulatory Commission and before regulatory agencies in the states of Illinois, Kansas, Kentucky, Maine, Missouri, Ohio, South Dakota, and Wyoming. Topics have included fuel procurement practices, policies, and procedures; integrated resource planning; nonutility generation markets; economic dispatch practices; avoided costs; fuel and purchased power expenses; and electric system reliability. I am currently serving as a member of a team advising the Iowa Utilities Board on matters related to establishing a priori ratemaking principles prior to utility construction of power plants.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony describes the production cost model used for estimation of fuel and purchased power expenses. I then provide the rationale supporting the values used by The Empire District Electric Company (Empire) for gas prices (and associated policies) and purchased power prices and availability in the test year for this rate case. Further, my testimony argues in favor of the establishment of an interim energy charge (IEC) or a fuel adjustment clause (FAC) for Empire to assist the Missouri Public Service Commission in meeting its two goals: 1) ensuring safe, reliable, and economic service to Empire's ratepayers and 2) ensuring fair and equitable cost recovery to Empire and its stockholders. Finally, I discuss the output of the production cost model runs and the resulting levels of fuel and purchased power expense that should be considered for an FAC or IEC.

<u>II. Production Cost Model</u>

Q. DID EMPIRE USE A PRODUCTION COST MODEL TO DETERMINE THE LEVEL OF EXPENSE FOR FUEL AND PURCHASED POWER?

A. Yes, Empire used the PROSYM production cost model.

Q. BRIEFLY DESCRIBE THE PROSYM MODEL.

A. The PROSYM model is a chronological dispatch 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. Electric production is modeled at the generation unit level while system loads are modeled on an hourly basis.

Q. IS THE PROSYM MODEL AN ACCEPTED PRODUCTION COST MODEL IN THE ENERGY INDUSTRY?

A. Yes. The PROSYM simulation engine is described by Henwood Energy, its developer, as providing the most accurate generation unit commitment logic in the world. This description is justified by the fact that PROSYM is employed by well over 100 energy organizations around the world in both control room dispatch environments as well as in market analytic groups. PROSYM serves as the power market simulation engine for the RISKSYM model, the model that Henwood Energy developed for risk analysis and planning.

Q. DESCRIBE EMPIRE'S EXPERIENCE WORKING WITH THE PROSYM MODEL.

A. Empire has been using chronological production costing models for projection purposes since 1991. Empire's three previous rate case filings in Missouri utilized the PROSYM model.

Q. HOW DOES EMPIRE VALIDATE THE OUTPUT OF PROSYM?

A. Empire compares the generation output of the model with actual historical generation for each unit. The dispatch of Empire's thermal units falls within a reasonable range of historical generation.

Q. PLEASE DESCRIBE THE EVOLUTION OF PRODUCTION COST MODELS IN THE ELECTRIC UTILITY INDUSTRY.

A. Production cost models have evolved as computer capability has evolved. Early models used load duration curves to simulate generation commitment and dispatch. At that time, hourly dispatch was desirable but computers were not yet capable of turning around analysis in a timely manner. As the computers became more capable, deterministic hourly dispatch models were used. All the input data for these models were deterministic – one load forecast, one set of fuel prices, one set of heat rate curves, one set of planned maintenance schedules. These models provide a snapshot of outcomes under a set of assumed input conditions. The most current models today use stochastic analysis to look at the risks associated with load forecasting, natural gas pricing, availability and cost of non-contract purchased power, and forced outages on units. The new models include RISKSYM, which was developed by Henwood Energy.

Q. WOULD IT BE YOUR OPINION THAT RISK ANALYSIS IS BECOMING THE STANDARD FOR INTEGRATED RESOURCE PLANNING PROCESSES AND THAT SINGLE CASE OUTCOMES ARE NO LONGER THE NORM FOR UTILITIES ACROSS THE COUNTRY?

A. Yes. Utilities and commissions across the country have realized for many years that any "base case" prepared by a utility for a rate case or an integrated resource plan was just one view of a future that had many uncertainties. Scenario analysis was often conducted to look at higher and lower load forecasts, higher and lower inflation, higher and lower natural gas prices, and so forth. Risk analysis takes into account the uncertainties associated with many of these key variables and provides the opportunity for a utility to undertake a strategic analysis. Risky, uncertain environments are one reason why an Interim Energy Charge or Fuel Adjustment Clause help Commissions to ensure safe, reliable, and economic electric service to customers while setting fair rates for electric utilities.

III. Modeling Parameters

Q. WHAT ARE THE VARIABLES THAT DRIVE THE ENERGY COSTS ON EMPIRE'S SYSTEM?

A. Key variables include transmission cost and availability, coal and natural gas prices, purchased power prices and capacity availability, planned and forced outages of thermal units, weather, heat rates, and water availability for the Ozark Beach hydro units. Specific parameters for modeling the generating units are described in this section of the testimony.

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

A. Data for Empire's generating units are shown on Schedule JST-1. These data include each unit's rated capacity, maximum capacity, minimum capacity, heat rate curve information, ramp rate, normalized outage, 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.

Q. WHAT IS THE BASIS FOR THE HEAT RATES USED IN THE PRODUCTION COST MODEL?

A. Multi-step heat rates are input for each unit such that the final output heat rate for each unit is near the historical five-year average heat rate for the unit, or the average heat rate for those years that the unit has been operational if the unit has less than five years of operating history. Historical heat rates for Empire's units are attached as Schedule JST-2.

Q. HOW WERE THE FORCED OUTAGE RATES USED IN THE PRODUCTION COST MODEL DETERMINED?

A. Empire tracks historical forced outage rates for its units. These historical rates are attached to my testimony as Schedule JST-3. The historical forced outage rates served as a basis for the forced outage rate used in the model for all Empire units except for Energy Center Units 3 and 4. Because of their limited operational history, forced outage rates were used that are representative of similar units in the industry. The historical equivalent forced outages as compared to industry data (referred to as GADS data) are shown on Schedule JST-4.

Q. WHAT OPERATIONAL CONSTRAINTS WERE CONSIDERED WHEN DETERMINING THE FORCED OUTAGE RATES TO BE USED FOR THE COAL UNITS AND STATE LINE COMBINED CYCLE ("SLCC") IN THE MODELING?

A. Some of Empire's units, especially at Asbury, experience extended periods of operational derations due to opacity or other constraints. Such derations are captured in the calculation of the equivalent forced outage rate but not in the calculation of the standard forced outage rate. To accurately reflect the actual and expected operation of its units, Empire used the equivalent forced outage rate and not the forced outage rate in the production cost model.

Q. HOW WERE THE PLANNED OUTAGE SCHEDULES USED IN THE PRODUCTION COST MODEL DETERMINED?

A. The planned outage schedules are based on the average of the actual scheduled maintenance days from the past five (5) years (1999-2003). Those outages are shown on Schedule JST-5. Normalized scheduled outages are reflected on Schedule JST-6.

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

A. On a million British thermal unit ("MMBtu") basis, Asbury burns 91% western coal and 9% local coal, Riverton 7 burns 75% western coal and 25% local coal, and Iatan burns 87% western coal and 13% local coal. Coal prices used in the model that are based on 2004 rates are shown on Schedule JST-7.

Q. HOW WAS THE COMBINED CYCLE UNIT AT STATE LINE MODELED?

A. Empire owns 300 MW (60 percent) of the 500-MW combined cycle unit at State Line (SLCC). For this rate case filing, SLCC was modeled as two separate units, one being 250 MW and the other being 50 MW. 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 for 2003 of approximately 7,500 Btu/kWh.

Q. WHY WAS THE UNIT MODELED AS TWO SEPARATE UNITS WITH DIFFERENT CAPACITIES INSTEAD OF A SINGLE 300 MW UNIT?

A. SLCC is comprised of two combustion turbines that share a single steam turbine. The unit can operate as a single combustion turbine in conjunction with the steam turbine (1 x 1 mode) or as two combustion turbines in conjunction with the steam turbine (2 x 1 mode). Since the commercial operation of this unit, the norm has been for either Empire to solely be dispatching its share of the unit or for Empire and Westar to be dispatching their shares of the unit at the same time; rarely, if ever, has Westar dispatched their share of the unit without Empire utilizing at least a portion of its share of the unit. Since the unit is most efficient when the combustion turbines are operating at or near their maximum output level, Empire often dispatches the unit in 1 x 1 mode at high output ranges rather than run the unit in 2 x 1 mode at minimum, less efficient load levels. This means that Empire is often only utilizing 250 of its 300 MW share of the unit. When Westar decides to dispatch its share of the unit, the unit will then be in 2 x 1 mode and Empire is capable of utilizing its additional 50 MW share of the unit in an efficient manner. This reflection of actual operating parameters explains why SLCC was modeled as two separate units.

Q. HOW WAS THE OZARK BEACH HYDRO UNIT MODELED?

A. Ozark Beach was modeled based on the average of the historical capacity factors over the past five (5) years. Hydro generation accounts for less than 1.5 percent of Net System Input (NSI). Historical data for Ozark Beach are shown as Schedule JST-8.

Q. ARE THERE ANY OPERATING CHARACTERISTICS FOR EMPIRE'S ASBURY UNITS THAT NEED SPECIAL CONSIDERATION?

A. Yes. Asbury 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. This operational limitation combined with Unit 2 operating costs causes Empire to operate Unit 2 as a peaking unit that is normally used only during the summer months. These constraints have been taken into consideration in the PROSYM model.

Q. ARE THERE ANY OPERATING CHARACTERISTICS FOR EMPIRE'S RIVERTON UNITS THAT NEED SPECIAL CONSIDERATION?

A. Yes. Riverton Unit 7 can operate to approximately 26 MW out of its 38 MW of rated capacity on coal fuel alone. 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 53 MW rated capacity on coal fuel alone with the remainder of the capacity obtained by over-firing natural gas. These operational constraints were modeled in PROSYM.

Q. WHAT ARE THE BASES FOR THE COAL COSTS INCLUDED IN THE PRODUCTION COST MODEL?

A. All costs are based on current delivered initial and freight prices. Coal handling costs are added to the initial and freight costs to obtain the appropriate coal costs to include in the model for accurate dispatching. Costs for unit train operation are included as an Undistributed & Other cost, which were added after the model run and are attached as Schedule JST-9.

Q. HOW HAS THE GENERATION OF THE EMPIRE UNITS VARIED OVER TIME AND HOW DO THEY COMPARE WITH THE ESTIMATES DERIVED FOR THE BASE RUN IN THIS CASE?

A. A generation history for the Empire units is provided as Schedule JST-10. Comparing this history to the results from the Base Run (Run 1) for a normalized test year (attached as Schedule JST-11), one will notice that generation from all of the coal units is at or above the five-year average production levels. Conversely, generation from some of our older, less efficient combustion turbines (namely, Energy Center 1 and 2, and Riverton 9, 10, and 11) falls below the five-year average levels. This generation is displaced by more efficient gas turbines (Energy Center 3 and 4) and increased production from SLCC. SLCC production is above the historical average. This is due to SLCC's limited operational history (commercial operation as of June 2001) and because Empire was able to procure favorably priced purchased power through short-term contracts with American Electric Power (AEP) during 2002 and 2003, which offset some of the generation that would normally have come from SLCC had these short-term contracts not been in place. The five-year average level for non-contract purchased power is near 435,000 MWh. Non-contract purchased power from the Base Run totaled 358,000 MWh, well within the normal range.

<u>IV. Gas Price Estimation</u>

Q. PLEASE EXPLAIN WHAT LEVELS OF GAS PRICES EMPIRE USED IN THE PRODUCTION COST MODELING.

A. Empire used the gas prices that it expects to pay in calendar year 2005, the time frame in which new rates resulting from this rate proceeding would likely go into effect. These prices assume that 4,200,000 MMBtu is hedged and the rest will be purchased on the spot market at the prevailing spot market price. The monthly hedged and spot market values as used in the test year are shown in Schedule JST-12.

Q. YOU HAVE USED THE TERM "HEDGED." PLEASE EXPLAIN WHAT THE TERM "HEDGED" MEANS.

A. Hedging is a strategy used to offset investment or price risk, specifically to protect against upward price movements. Hedging can be used by individual investors as well as companies and financial institutions. Empire's Risk Management Policy, described in more detail in Brad Beecher's testimony, has been implemented to protect Empire's customers against adverse price movements in natural gas.

Q. WHAT DETERMINES HOW MUCH NATURAL GAS IS HEDGED BY EMPIRE AND WHEN SUCH NATURAL GAS IS HEDGED?

A. Empire originally enacted a Risk Management Policy (RMP) in 2001 that establishes the approach and internal rules that Empire will use to manage specifically its power and natural gas commodity risk. The policy is revised approximately annually to reflect lessons learned and changes in markets and financial instruments. The RMP targets for hedging of natural gas are:

A minimum of 10% of year four expected gas burn
A minimum of 20% of year three expected gas burn
A minimum of 40% of year two expected gas burn
A minimum of 60% of year one expected gas burn
Up to 80% of any year's expected requirement can be hedged if appropriate given the associated volume risk.

Q. HAS HEDGING BEEN A VALUABLE STRATEGY FOR EMPIRE TO USE IN THE PAST?

A. Yes. Empire's use of a hedging strategy has saved its customers and shareholders a significant amount of money. Just in 2003, Empire would have paid approximately $13.5 million more in natural gas prices had Empire not hedged its natural gas purchases. As shown on schedule JST-13, Empire paid an average hedged price in 2003 of $3.02/MMBtu for natural gas. If that natural gas had not been hedged, the average price would have been a higher value of approximately $5.12/MMBtu based on NYMEX historical closing prices.

Q. WHAT ARE THE APPROPRIATE NATURAL GAS PRICES TO BE USED FOR PRODUCTION COST MODELING FOR THE TEST YEAR?

A. The answer to this question is that "it varies." If you have to pick a specific price and you are a member of the staff of a regulatory agency or consumer advocate, in my experience the answer usually is the lowest gas price forecast possible to assume. If you are a utility company employee, the answer is the highest gas price forecast that can be assumed. Natural gas spot market prices are extremely volatile and truthfully can not be known in advance. They are one of the two areas in which Empire and the Commission Staff have historically argued vehemently in each rate case (the other being purchased power prices and capacity availability). The volatility associated with natural gas spot market prices and the significant financial inequities that can result for Empire, its customers, and its shareholders if an inaccurate price is assumed for ratemaking purposes lead to the observation that fighting about future natural gas prices is not productive. An effective means of dealing with natural gas price volatility is the implementation of either an Interim Energy Charge (IEC) or a Fuel Adjustment Charge (FAC). Empire witness Brad Beecher describes these two possible rate making processes in more detail in his testimony.

V. Purchased Power

Q. HOW WAS THE COST OF THE JEFFREY ENERGY CENTER (JEC) CONTRACT PURCHASE ENERGY DETERMINED?

A. The JEC contract energy purchase price is based on the actual cost of the energy out of the three JEC coal units. The three JEC units were assigned planned outages based on NERC GADS data and unplanned outages are similar to those modeled for the Iatan plant, which is comparable in size and age. The average energy cost in the base run is $13.39/MWh.

Q. DOES EMPIRE PARTICIPATE IN THE NON-CONTRACT PURCHASE ENERGY MARKET?

A. Empire evaluates the non-contract energy purchase market on a daily and hourly basis. The Company will participate in such markets whenever it makes economic sense to do so. However, the Commission and the Staff should be aware that modeling the price and availability of non-contract purchased power is a difficult task with the ever evolving and uncertain price and availability of energy and transmission. This area, in addition to natural gas pricing, has been one of the biggest sources of contention between Empire and the Commission Staff in previous rate cases.

Q. WHY IS IT DIFFICULT FOR EMPIRE AND THE COMMISSION STAFF TO AGREE ON MODELING PARAMETERS FOR NON-CONTRACT PURCHASED POWER?

Like natural gas, neither Empire nor the Commission Staff can accurately predict future prices of purchased power nor the amount of purchased power that will be available during any given hour on any day in any year in the future. And, due to the structure of the market, the price of non-contract purchased power is becoming more and more closely tied with the price of natural gas. The price and capacity of purchased power are so uncertain because they depend on the situation not only at Empire at any given point in time, but also on the conditions at surrounding utilities including the weather, transmission availability, unit outages, natural gas prices, coal prices, water availability, and perceptions about what is transpiring in the market. The uncertainty associated with purchased power prices, like the risks associated with natural gas prices, leads to one conclusion – either an IEC or an FAC should be enacted or Empire should be allowed a higher return on equity recognizing the risks that it is shouldering for both natural gas price uncertainty and purchase power price and capacity fluctuations.

Q. WHAT PROCESS DID EMPIRE UNDERTAKE FOR THIS RATE CASE TO MODEL NON-CONTRACT PURCHASED POWER PRICES AND CAPACITY AVAILABILITY?

A. Empire determined that it should attempt to use the model normally utilized by Commission Staff to project non-contract purchased power prices and capacity availability during the test year which is summarized in a Commission Staff provided document entitled "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market" dated March 18, 1996. During that process, Empire uncovered numerous instances of data anomalies that if provided to the Commission Staff could have caused them to mischaracterize other types of transactions as non-contract purchased power. Although Empire believes that the data that it will provide Commission Staff for the quantities and prices of non-contract purchased power for the test year will be significantly improved over past years, it does not negate the fact that neither Staff nor Empire can accurately forecast non-contract purchased power prices and capacity availability. In addition, when the gas price, and therefore the non-contract purchased power price is underestimated, the amount of generation projected for Empire's natural gas-fired units is also significantly underestimated.

Q. DID EMPIRE MAKE ANY MODIFICATIONS TO COMMISSION STAFF'S METHODOLOGY FOR SPOT MARKET PURCHASED POWER?

A. Yes. In the methodology presented by Commission Staff, Step 25 (found on page Appendix A-3) states "Calculate the 24 maximum hourly amount of MW's for each hour. Assign this amount of MW's for the hours in the month.". Empire and I believe this to be a flawed assumption. To say that the maximum amount of MW's purchased in an hour are available for all similar hours in that month, regardless of the price of that energy, is simply not realistic. Empire assumed that the average capacity of all similar hours in a month was a better representation of the amount of non-contract purchased power that may be available in that hour of the month. Again, Empire will not try to contend that they know for a certainty that this is the amount of non-contract purchased power that will be available on the market (it could be less or more), but they do believe it is more likely for the average to be available than the maximum on a daily basis.

Q. DID EMPIRE MODEL NON-CONTRACT PURCHASED POWER USING BOTH METHODS FOR ASCERTAINING THE AMOUNT OF CAPACITY AVAILABLE ON AN HOURLY BASIS?

A. Yes. Empire modeled non-contract purchased power capacity availability in PROSYM using the Step 25 method ("maximum availability") and a method that averages availability across hours of a month ("average availability"). The difference in average availability versus maximum availability assumptions alone caused an $8,000,000 change in projected annual revenue requirements.

Q. IS THERE A WAY THESE DIFFERENCES IN PURCHASED POWER MODELING COULD BE MINIMIZED?

A. Yes. To mitigate the "battle of the models" that has been common in the past, I agree with Empire's recommendation to implement an IEC or an FAC to account for the volatility of both natural gas prices and non-contract purchased power prices and capacity availability.

VI. Production Cost Modeling Results

Q. WHAT WERE THE RESULTS OF EMPIRE'S BASE PRODUCTION COST MODEL RUN?

A. Empire's Base Run, which is summarized in Schedule JST-11 as Run 1, calculated a total company on-system fuel and purchased power cost of $123,017,390 or $24.39/MWh. This run assumes the gas prices and non-contract purchased power prices and availability described in my testimony above.

Q. HOW DOES THIS COMPARE TO THE $121,665,153 THAT EMPIRE WITNESS MR. BEECHER PRESENTED IN HIS TESTIMONY FOR ON-SYTSTEM FUEL AND PURCHASED POWER EXPENSE USING HIS STRAIGHT FORWARD, FIVE ADJUSTMENT METHOD?

A. As Mr. Beecher states, the difference between his method and the output of the base model run is only $1.35 million or 1.1 percent of total on-system fuel and purchased power costs. Considering that the model is making dispatching decisions on an hourly basis and that the dispatch decisions are based on a number of variables, a difference would obviously be expected. However, Mr. Beecher's straight forward approach does bring merit and support to the results of the production cost model.

Q. DID EMPIRE PERFORM ANY ADDITIONAL PRODUCTION COST MODEL RUNS TO DETERMINE WHAT LEVEL OF RISK THEY WOULD BE EXPOSED TO IF GAS OR PURCHASED POWER PRICES WERE HIGHER?

A. Yes. Empire performed several model runs that keyed on three main variables to get a better understanding of their effects on total fuel and purchased power expenses. These three variables were natural gas price, non-contract purchased power price, and non-contract purchased power availability. These are the three variables that are the most uncertain in the future and have also been the most debated in previous rate proceedings. The results of these runs (Run 2 through Run 12) are presented in Schedule JST-14.

Q. PLEASE DISCUSS HOW THE THREE VARIABLES WERE CHANGED IN THE RUNS.

A. Several runs were made that varied the natural gas price from approximately $3.00/MMBtu all the way up to $5.50/MMBtu. At each gas price, a run was made where the availability of non-contract purchased power was changed between maximum availability and average availability (based on 2003 actual purchases). A couple of additional runs were made using the base gas price assumptions but using non-contract purchased power prices for each hour of the year that were output from a regional production cost model and again varying the availability of non-contract purchased power between maximum and average.

Q. PLEASE SUMMARIZE THE RESULTS OF THESE PRODUCTION COST MODELING RUNS.

A. The results of these runs provided a range of $102,544,000 ($20.33/MWh) to $129,720,000 ($25.72/MWh) for levels of fuel and purchased power expenses. It is worth noting that this range is a little more than $25,000,000 and that the natural gas cost assumptions vary by approximately $2.50/MMBtu at these minimum and maximum levels of expense. In a normal year Empire estimates that it will burn approximately 10,000,000 MMBtu of natural gas. Using this assumption and the $2.50/MMBtu gas range, it is quite apparent that the $25,000,000 difference in the runs is largely due to the natural gas cost input. Thus, the price of natural gas has an enormous impact on the expected revenue requirements in the model affecting the fuel expense itself, the level of purchased power bought, and the projected level of operation of each of Empire's generating units.

Q. WITH THESE RUNS IN MIND, WHAT WOULD BE YOUR RECOMMENDATION IN TERMS OF AN IEC FOR EMPIRE?

A. While fuel and purchased power expenses of nearly $130,000,000 may seem high compared to recent levels, Empire did experience twelve month ending on-system fuel and purchased power expenses that were in excess of $123,000,000 in July of 2001. Because of current projections of natural gas prices, it is not out of the question that fuel and purchased power expenses could approach $130,000,000 in the near future at Empire. Again, no one can predict with any certainty the future price of natural gas or non-contract purchased power. Because of these uncertainties, I believe an IEC that had a $20,000,000 true-up range would be equitable to Empire, its customers, and its shareholders. This $20,000,000 range would roughly equate to a $2.00/MMBtu range of natural gas prices. A range from $105,000,000 ($20.82/MWh) in total fuel and purchased power to a base subject to refund of $125,000,000 ($24.79/MWh) for the test year, as presented in Mr. Beecher's testimony, would seem equitable in this case. Recent history shows that there is a possibility, if conditions are favorable, that fuel and purchased power prices could dip slightly below $105,000,000 and the model runs show that if conditions are right they could go above $125,000,000, meaning that both Empire, its customers, and its shareholders, have a minimal amount of exposure to under- or over-recovery. This range of total on-system fuel and purchased power expense would roughly equate to a gas price range of $3.25/MMBtu to $5.25/MMBtu.

<u>VII. Summary</u>

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. The model that Empire uses for production costing modeling is a chronological dispatch model that is well-known and widely used throughout the electric utility industry. Empire has carefully and conscientiously developed data to model its generating units that reflect actual operation and historical averages for most input parameters. However, there is no way to avoid the fact that forecasting of natural gas prices and non-contract purchase power prices and capacity availability generally end up in a "battle of the models" between the Company and the Commission Staff over the appropriate level of fuel and purchased power expense due to the great volatility and uncertainty associated with the projection of these parameters. Such unproductive battles over significant unknowns, that cannot ever be known in advance, leads me to the conclusion that the implementation of an IEC or an FAC is in order to recognize the risks and uncertainty associated with rate making for fuel and purchased power expense based on deterministic modeling in a risky world.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.