Exhibit No. 8
Issue: Fuel Adjustment Clause, Construction Risk
Witness: H. Edwin Overcast
Type of Exhibit: Direct Testimony
Sponsoring Party: Empire District Electric Co.
Case No.
Date Testimony Prepared: October 2007

Before the Public Service Commission
Of the State of Missouri

Direct Testimony

of

H. Edwin Overcast

October 2007

TABLE OF CONTENTS
OF
H. EDWIN OVERCAST
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

**DIRECT TESTIMONY
OF
H. EDWIN OVERCAST
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION**

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. H. Edwin Overcast, Director, R. J. Rudden, A Black & Veatch Company.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Schedule HEO-1 to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. I have been employed in the energy industry for over 33 years in various rate, regulatory and planning positions. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. My testimony has addressed a variety of issues including cost allocation, rate design, regulatory policy, open access and unbundling, bypass economics, forecasting, gas supply planning, and a number of other issues. In addition, I have been a lecturer in a number of energy industry sponsored training programs including: the Edison Electric Institute Rate Fundamentals Course and the Advanced Rate Course; the American Gas Association Rate Course and the Advanced Rate School; and the Southern Gas Association Intermediate Rate Course. Specifically, I have lectured on the principles of electric cost of service for both retail and wholesale jurisdictions.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of The Empire District Electric Company ("Empire" or "the Company").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony explains how the proposed Fuel Adjustment Clause (FAC) is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity, discusses the conceptual basis for approval of a FAC and provides support for the recovery of all prudently incurred fuel and purchased power expenses, including demand charges. In addition, my testimony discusses the risks associated with the Empire capital program and the need to allow a return higher than that of the proxy group to compensate for the risks related to that capital program.

Q. HOW IS THE TESTIMONY ORGANIZED?

A. The testimony is organized in the following sections:

Introduction
Section 1- Basis for Approval of an FAC
Section 2- A Reasonable Opportunity to Earn the Allowed Return
Section 3- Symmetric and Asymmetric Risks
Section 4- Comparable Company Regulatory Models
Section 5- The Recovery of Prudently Incurred Costs as a Regulatory Standard
Section 6- Capital Program Risks and
Section 7- Conclusions

In addition, I am sponsoring a number of schedules contained in this testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. This testimony demonstrates that in the absence of a FAC Empire does not have a reasonable opportunity to earn its allowed return. Approval of the fuel clause represents a reasonable plan to mitigate the risks associated with fuel cost volatility that results from fuel price changes, weather, plant outages (both planned and unplanned or forced outages) and a variety of other factors. Even small changes in fuel and purchased power costs cause significant impacts on the earned return. The testimony also points out that the standard for recovery of expenses requires the recovery of all prudently incurred costs.

With respect to construction program risks, the testimony demonstrates that the risks are substantial and that a combination of compensation and mitigation represents the appropriate regulatory mechanism for addressing the risks. The testimony recommends that the rate of return on equity be set at the high end of what may be considered as a range of reasonable returns to compensate for the risk. Further, the testimony recommends that for any changes in costs beyond the control of management such as storm damage, tax changes, governmental policy changes and others that the Company is allowed to defer these costs subject to future recovery in order to permit the company a reasonable opportunity to earn the allowed return.

SECTION 1- BASIS FOR APPROVAL OF A FAC

Q. PLEASE DESCRIBE THE BASIS FOR APPROVAL OF A FAC?

A. The FAC must be designed to provide a reasonable opportunity for the utility to earn the allowed return authorized by the Commission. This principle was specifically included in the Missouri statute authorizing the establishment of an FAC. Further, one of the requirements of an FAC is that it provides a utility with a sufficient opportunity to earn a fair return on equity.

Q. WHAT STANDARDS SUPPORT A FAC AS A NECESSARY CONDITION TO PERMIT A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN?

A. The Missouri Public Service Commission (the "Commission") has issued two orders that discuss the standards that indicate a FAC is a reasonable regulatory tool to permit the utility a reasonable opportunity to earn its allowed return. The conditions discussed in the Commission orders include:

1. Costs to be tracked represent a significant portion of the revenue requirement
2. The costs are volatile
3. The costs are beyond the control of the management of the utility.

These three conditions, albeit in slightly different form, seem to represent the necessary conditions for Commission approval of a FAC.

Q. DO THESE CONDITIONS REPRESENT A SET OF REASONABLE MEASURES FOR EVALUATING THE STATUTORY STANDARD OF PROVIDING A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN?

A. Actually, as applied to an FAC for fuel and purchased power cost recovery these conditions seem to create no problem. However, in general, the first condition focuses on the relation between total cost and total revenue requirement and not the impact on earnings. It seems more appropriate to determine the potential impact of cost changes on earnings rather than revenue requirement. This conclusion is based on the following fundamental facts of regulation:

1. Rates are set for a prospective period.
2. Earned return in the rate effective period is the residual after all actual costs are paid from actual revenues.

Thus, either a large variance in a small cost item or a small variance in a significant cost item may produce a significant change in the opportunity to earn the allowed return during the first twelve months the rates are effective (the Rate Effective Period). Indeed, investors focus not on the allowed return or the actual return for a prior period but on the expected earned return in the Rate Effective Period. For this reason, it is appropriate to determine the relationship between the variability in cost and the equity component of the return. This suggests that the first standard should focus on the relationship between the magnitude of cost changes and the dollars available for equity return, not the absolute cost dollars.

Q. DOES THE EMPIRE FAC SATISFY THESE CONDITIONS AS WELL AS YOUR OWN?

A. Yes. For the proposed test year revenue requirement calculation, the cost of fuel and purchased power equals 37.63 percent of the revenue requirement. More importantly, the impact of even relatively small changes in fuel and purchased power costs has a significant impact on the dollars available for return. Under the proposed revenue requirement, Empire proposes a total equity return of about $43.5 million. The equity return dollars represent only 30.6 percent of the dollars subject to FAC recovery. Given this relationship, even small changes in fuel and purchased power costs have large impacts on the earned return. For example, a five percent change in fuel costs of $8.9 million represents over 20.5 percent of the equity return dollars assuming normal weather. Fuel costs for Empire exhibit substantial volatility, as discussed more fully below. The utility has no control over the market prices for its fuels since it purchases both coal and natural gas in competitive commodity markets and delivers the fuel using regulated transportation options. Similarly, the purchased power market is a competitive market as well. In competitive markets, prices respond to changes in supply and demand creating volatility as a result of any number of variables including weather, inventories, delivery constraints, fuel prices and plant availability.

Q. PLEASE DISCUSS THE VOLATILITY OF FUEL AND PURCHASED POWER COSTS.

A. Volatility in actual fuel costs for the Rate Effective Period and beyond result from a large number of factors. To fully understand the causes of volatility and the potential impact on a reasonable opportunity to earn the allowed return, it is necessary to understand the test year normalized and annualized fuel costs by component. Schedule HEO-2 provides the components of fuel and purchased power expense for the test year. Schedule HEO-3 shows the number of hours during the test year when each fuel type or purchased power provides the marginal service. In more than half the hours, additional load due to growth or weather results in increased average fuel costs because higher than average cost gas generation or purchased power must supply the load. This provides an example of how fuel and purchased power costs vary between the test year and the Rate Effective Period even assuming no change in the cost of inputs.

Q. PLEASE PROVIDE A LIST OF OTHER FACTORS THAT IMPACT THE VOLATILITY OF FUEL AND PURCHASED POWER EXPENSE.

A. The list of factors that impact volatility includes but is not limited to the following:

- Changes in input prices- coal, gas, purchased power
- Changes in the operation of must run capacity- windmills in particular
- Changes in maintenance schedules between the test year and the Rate Effective Period
- Changes in fuel delivery constraints
- Changes in fuel characteristics, particularly coal
- Changes in plant forced outage rates for any of a number of reasons
- Changes in unit capacity ratings within the Rate Effective Period
- Changes in the timing of outages both the actual time of occurrence and the duration
- Changes in SPP settlement price volatility
- Changes in environmental considerations
- Changes in the availability of water for hydro electric generation
- Changes in the pattern of weather even if the weather on an annual basis is normal
- Changes in transmission costs under formula rates
- Non-recurring events such as flooding, low water levels, strikes, and other events

The above list is not intended to be exhaustive, nevertheless, it provides many of the factors that underlie fuel and purchased power cost volatility.

Q. PLEASE DISCUSS THE NATURE OF FUEL PRICE VOLATILITY AND ITS IMPACT ON EMPIRE.

A. Schedule HEO-4 provides a summary of fuel and purchased power cost and price volatility over a historical period for Empire. Table 1 below illustrates the impact of historic volatility on the proposed return in this proceeding.

Table 1

Historic Fuel Cost Changes and Earnings Impact

Total Fuel Costs	Change from Prior Year	Equity Return Dollars	Percent Impact
2000 $95,426,265	0	$43,500,000	0
2001 $123,808,430	$28,382,138	$43,500,000	65.25%
2002 $117,538,337	-$6,270,093	$43,500,000	-14.41%
2003 $113,574,122	-$4,004,215	$43,500,000	-9.21%
2004 $118,612,027	$5,037,905	$43.500,000	11.58%
2005 $127,540,565	$8,928,538	$43,500,000	20.53%
2006 $171,606,408	$44,065,843	$43,500,000	101.30%

The levels of historic volatility demonstrate that both the company and its customers would benefit from an FAC. The Company would have a sufficient opportunity to earn its allowed return and customers would pay no more than actual costs for fuel and purchased power.

Q. IS THERE OTHER EVIDENCE OF VOLATILITY IN FUEL AND PURCHASED POWER COSTS?

A. Yes. Schedule HEO-5 provides an example of the variability of monthly fuel costs based on the normalized test year for the 2008 calendar year forecast for a sample of the Company's generation. In addition the schedule shows the high and low cost for the test year for each fuel type. Schedules HEO-6 and HEO-7 provide data from the Energy Information Administration on natural gas price and coal price. With respect to natural gas price volatility, there is little dispute that these prices exhibit volatility. That volatility is discussed at length in a recent EIA publication entitled "**An Analysis of Price Volatility in Natural Gas Markets**". As these three schedules show, both gas and coal markets exhibit price volatility on an annual basis. More importantly, fuel and purchased power costs exhibit intra-year volatility. To some extent, gas price volatility also impacts purchased power price volatility where gas is the marginal fuel in the market. Based on the data in Schedules HEO-6 and HEO-7, average coal prices have increased by over 33 percent since 2003 and gas prices have exhibited even more volatility over the same period. Table 2 illustrates the impact of fuel prices on the Empire system.

Table 2

Dollars per MMBTU of Fuel Cost

Plant	2006	2005	2004	% Change
Coal- Iatan	$0.793	$0.786	$0.726	9.23%
Coal- Asbury	1.402	1.322	1.179	18.91%
Coal- Riverton	1.458	1.391	1.309	11.38%
Natural Gas	7.276	7.280	4.451	63.47%
Oil	6.551	5.893	6.842	(4.25)%

Fuel price changes occur both up and down over historic periods even though the general trend is upward. The combination of price trends and load variability contribute to significant variability in the cost of fuel and purchased power in the Rate Effective Period. Volatility in the Rate Effective Period also occurs due to growth in sales due to weather, customer additions or economic activity for the 2008 estimate. .

Q. IF YOU ASSUME NORMAL WEATHER OVER THE COURSE OF THE YEAR (NORMAL HEATING AND COOLING DEGREE DAYS) BUT ASSUME THAT THE WEATHER OCCURS IN A DIFFERENT PATTERN THAN THE TEST YEAR, DOES THAT IMPACT ACTUAL FUEL COSTS?

A. Yes. Not surprisingly, differing patterns of weather impact fuel costs because of factors such as scheduled maintenance and variability of fuel and purchased power costs. In addition, weather variations affect the volume of sales for the system even with normal weather. A simple example illustrates this conclusion. Consider the electricity consumption of schools. If weather is hotter than normal in July offset by cooler than normal September, schools will have lower electric use than if the reverse- hot September and cool July- occurs.

Q. DO WEATHER PATTERNS IMPACT FUEL AND PURCHASED POWER PRICES?

A. Yes. Different weather patterns influence the price of natural gas, particularly in terms of the spot market prices. As we know, market prices serve to equate supply and demand. Adverse weather conditions such as hurricanes in the Gulf of Mexico cause wells to be shut in thereby reducing the supply of natural gas to the market and raising spot market prices in the summer and potentially into the winter due to the impact on storage fill. It might be noted that the expectation for adverse weather in the Gulf of Mexico is higher in the late summer and early fall than it is in the early summer.

Q. PLEASE ILLUSTRATE THE WEATHER RELATED VARIABILITY OF GAS PRICES.

A. Schedule HEO-6 illustrates this phenomenon during the summer of 2005 when September gas prices exceeded eleven dollars per Mcf as the result of hurricanes in the Gulf.

Q. IS IT POSSIBLE TO PROVIDE ANECDOTAL EVIDENCE OF THE KIND OF EVENTS THAT MAY NOT BE SUBJECT TO MODELING BUT IMPACT FUEL AND PURCHASED POWER COSTS?

A. Yes. At my request the Company prepared Schedule HEO-8, which provides a listing of events beyond their control that have impacted fuel and purchased power costs but cannot be modeled. In a rate making context these would be non-recurring events on an individual basis. Collectively, the events represent a portion of the kinds of risk factors that occur on a regular basis that may have serious adverse impacts on earnings but could not be directly modeled. As discussed below, these events represent asymmetric risks for the utility because these types of events raise costs without the existence of countervailing events that lower the costs of fuel and purchased power. Since cost impacting events do occur with some frequency, allowing the utility a reasonable opportunity to earn its return requires some allowance for these events or the tracking of these costs through an FAC. Inclusion of an FAC represents the least cost alternative for customers.

Q. DOES MANAGEMENT HAVE THE ABILITY TO CONTROL THE FUEL AND PURCHASED POWER COSTS?

A. No. In addition to illustrating the volatility of these costs, the above data demonstrates that management has little control over the actual fuel and purchased power costs. This conclusion is supported by the fact that both fuel and purchased power markets are competitive. In competitive markets, customers obtain resources only if they pay the market price. Further, both sales and costs are subject to weather impacts that also impact both market prices for fuel and purchased power as well as the recovery of the revenue requirements associated with both the FAC related costs and the potential to earn the allowed return.

Q. HOW DOES BEING A MEMBER OF THE SOUTHWEST POWER POOL ("SPP") IMPACT UNCERTAINTY OF FUEL AND PURCHASED POWER COSTS?

A. There are several ways that membership in SPP impacts the cost of fuel and purchased power. First, members of SPP have received FERC approval of formula transmission rates. Under formula rates, the cost of transmission changes annually to reflect the cost changes occurring in the prior year. Even for SPP members without a current formula rate, the FERC has shown a willingness to adopt formula rates for transmission entities and others could obtain approval for such rate treatment. Pursuant to Attachment H of the SPP tariff, formula rate changes flow through automatically into the zonal charges under Schedule 9, Network Integration Service. These charges impact the cost of purchased power for Empire to the extent that the power flows from SPP. In addition, the SPP Tariff provides for Energy Imbalance Service (Schedule 4) that is based on Locational Imbalance Prices. Under Schedule 4, the locational imbalance prices are calculated according to Attachment AE based on the average offer curve price of the next increment of load every five minutes or twelve times per hour. Empire has no control over the prices used for this service since these costs are bid into a market. This service may produce either credits or payments as the result of the difference between loads and resources. There is no practical method for estimating these real time costs that must be included as part of the cost of service provided by Empire. Other potential costs associated with SPP participation include revenue neutrality uplift charges and over/under-scheduling charges.

These charges represent costs associated with fuel and purchased power that must be recovered as part of the FAC to prevent unexpected and unreasonable cost disallowances.

Q. WHAT DO YOU CONCLUDE REGARDING THE STANDARDS FOR APPROVAL OF THE PROPOSED FAC?

A. There is ample evidence to demonstrate that the proposed FAC should be approved. The cost of fuel and purchased power are significant relative to the revenue requirement and changes in costs have potentially large impacts on earnings. Fuel and purchased power prices are volatile. Finally the costs are, for the most part, beyond the control of management.

SECTION 2- A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN

Q. PLEASE DISCUSS THE CONCEPT OF A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN.

A. As discussed above, the statute authorizing an FAC for Missouri's electric utilities requires that the FAC be designed to provide the utility with a sufficient opportunity to earn a fair return on equity. While there is no precise definition of a sufficient opportunity, it does seem reasonable to conclude that in the absence of an FAC the Company does not have a sufficient opportunity to earn its allowed return.

Q. DOES PERMITTING A SUFFICIENT OPPORTUNITY TO EARN THE ALLOWED RETURN THROUGH AN FAC IMPLY A GURANTEE OF EARNING THE ALLOWED RETURN?

A. No. In the Rate Effective Period the FAC permits the utility to recover the actual cost of fuel and purchased power. Dollar for dollar cost recovery of one component of the revenue requirement does not mean that other costs or even the revenue for the test year equals the revenue and costs of the Rate Effective Period.

The FAC is needed to avoid the impact of unrecovered fuel and purchased power costs on earnings by causing the FAC to create no impact on earnings and, therefore, permits the Company a sufficient opportunity to earn the allowed return in the Rate Effective Period. Further, it is reasonable to assume that a historic test year as the basis for revenue requirements biases the opportunity to earn the allowed return toward a lower value because of expected inflation in costs. So a portion of the bias against earning the allowed return remains.

Q. DOES EMPIRE HAVE A SUFFICIENT OPPORTUNITY TO EARN THE ALLOWED RETURN ABSENT AN FAC?

A. No. The volatility of fuel and purchased power costs is such that under the normalized estimate of these costs, which includes near maximum operation of low cost, coal-fired baseload plants and term contract purchased power, it is unreasonable to expect that Empire has the opportunity to earn the allowed return with any significant probability. Although, it is possible that base fuel and purchased power costs could be set at a level that is high enough to compensate for the cost risks and provide Empire a sufficient opportunity to earn the allowed return. In my view, however, this violates a corresponding principal that customers have the right to just and reasonable rates. Further, it is reasonable to assume that future fuel and purchased power prices are more likely to be higher as compared to those estimated in the model. As a result, I conclude that fuel cost recovery through an FAC represents the most reasonable alternative to meet both the principles of just and reasonable rates and a reasonable opportunity to earn the allowed return. Similarly, investment analysts have concluded that "the Stable Outlook assumes EDE (Empire) receives a reasonable outcome in its planned rate case with respect to a fuel adjustment clause, storm costs and Riverton capital spending recovery." (Fitch Ratings, April 2007)

SECTION 3- SYMMETRIC AND ASYMMETRIC RISKS

Q. PLEASE DISCUSS THE CONCEPT OF SYMMETRIC AND ASYMMETRIC RISKS AS THEY APPLY TO THE FUEL AND PURCHASED POWER BASED FAC APPROVAL AND A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN.

A. Risks are symmetric if the mean value of the risk impact on earnings is zero and outcomes are normally distributed around that mean value. The assumptions that form the foundation for estimates of the required return on equity include the concept of symmetric risks. Asymmetric risks occur when the expected value of the risk impact causes either a positive or negative impact on the expected rate of return. A simple example illustrates the concept of asymmetric risks. In adopting the Interim Energy Charge (IEC) for Empire in previous years, the Commission created an asymmetric risk for the Company. Under the IEC, if fuel costs were less than the amount in the charge, the Company refunded the dollars to customers. If costs were higher than the dollars in the IEC the Company absorbed those costs and earned a lower return. Thus the Company faced two possible outcomes from the IEC namely break even or lose money. This is the essence of asymmetric risk and the Commission properly recognized that the IEC produced inadequate results. Similarly, there are certain elements of the estimated test year cost of fuel and purchased power that represent asymmetric risks as discussed more fully below. The use of hedging to purchase fuels exhibits similar asymmetric characteristics.

Q. PLEASE DESCRIBE THE ASYMMETRIC EARNINGS RISKS THAT RESULT FROM THE ESTIMATE OF TEST YEAR FUEL AND PURCHASED POWER COSTS.

A. There are several asymmetric risks that arise related to the test year cost of fuel and purchased power. Schedule HEO- 9 Basic Unit Operation Data provides an example of the asymmetric risk associated with the operation of base load units. As that schedule illustrates, the four lowest cost thermal units on the system- Iatan, Asbury 1, Riverton 7 and 8 already operate at least 90 percent and up to 94 percent of the available hours. Schedule HEO-9 calculates the operation as a percent of hours available without taking into account the expected forced outage rate. This implies that in actual operation these plants are running in nearly every hour possible. Although it is possible that the units might actually operate a few more hours, the probability that such operation occurs is much smaller than the probability that these units will operate fewer hours. If these units operate fewer hours either for maintenance, forced outages or due to higher than normal levels of wind energy, the cost of replacement power is at least $5.35 per MWH higher if Iatan is replaced by the Western Resource purchase and may easily be as much as twice the cost of the MWH. For example, for every hour that Iatan does not operate fuel costs increase by almost $400 assuming the next most efficient units meet the load. In reality, given the minimum load on the system, this cost could easily be over $3000 if the replacement power came from the State Line CC unit. This means that every one percent change in the capacity factor for Iatan increases fuel costs by about $287,000 with no change in existing fuel costs. For Asbury Unit 1, each one hour that it does not operate causes extra fuel costs in the amount of almost $7900 assuming the State Line CC unit meets the load. For every one percent change in the capacity factor of Asbury Unit 1, fuel costs increase by over $694,000 with no change in existing fuel costs. This represents over 1.6 percent of the proposed equity return. All of this analysis assumes that all of the other test year items of expense and revenue equal the filed amounts exactly. That is, there is no attrition due to the historic test year, the forecast of normalized sales by rate schedule equals the actual Rate Effective Period sales and all of the fuel and purchased power costs equal those contained in the test year. This type of asymmetric risk requires mitigation and the fuel and purchased power cost FAC represents the most appropriate and reasonable mitigation for both Empire and its customers.

Q. ARE THERE OTHER ASYMMETRIC RISKS THAT IMPACT THE COST OF FUEL AND PURCHASED POWER?

A. Yes. It turns out that given the current rate design for Empire, weather creates asymmetric risk for the Company with or without a fuel and purchased power FAC. The concept of asymmetric weather risk requires a full understanding of the basic revenue requirements equation as well as the design of rates for the Rate Effective Period. The important factual underpinnings for this conclusion relate to the factors that influence fuel cost volatility. As noted above, both more heating and cooling degree days (HDD and CDD respectively) increase both the cost of fuel through higher gas prices and the volume of sales (including higher revenue). The impact of higher HDD and CDD also impacts other costs in the revenue requirements equation. These costs include higher O&M as the result of more overtime, more maintenance expense and more outages. Anecdotal evidence of these factors includes the effect of heat on distribution transformers, unit deratings to meet cooling water discharge temperature limits and others. Higher costs also mean longer lag times in customer payment and greater working capital requirements. These expenses are on top of higher fuel and purchased power costs. Without a fuel and purchased power FAC, the expected effect that higher HDD and CDD produces higher earnings may not materialize at all. Even if earnings do increase the values are small because the incremental costs are high. That is, the higher revenues resulting from more sales may not produce significantly greater earnings because of higher incremental costs. In the case of Empire, Schedule HEO-10 illustrates the hourly marginal costs for a sample of four days, two winter days and two summer days, within the test year under normal weather conditions and under extreme weather both above and below normal. The horizontal axis represents normal weather and the extreme and mild lines illustrate the change in marginal costs resulting from weather impacts. In this example, no attempt has been made to model the change in costs associated with different gas prices despite the correlation with weather. As higher cost units are dispatched to meet load, the probability that the higher running cost alone exceeds the marginal energy charge increases. When the marginal running cost exceeds the marginal revenue, revenues available to increase earnings is not available and earnings decrease. Similarly, when lower HDD and CDD occur, there is lower fuel cost overall but the marginal cost of fuel and other expenses changes less than the drop in revenue from rates resulting in lower earnings. Since the probability of lower earnings is certain when weather is less favorable and may also be lower under more favorable conditions, the effect of weather risk is asymmetric. That is, over time earnings losses from cooler summers and warmer winters cannot be offset by weather that is warmer in the summer and colder in the winter, the Company cannot expect a reasonable opportunity to earn the allowed return absent a fuel and purchased power FAC to offset the changes in fuel costs. Even an FAC does not eliminate the weather related asymmetry but serves to mitigate a portion of the impact. The reason the FAC does not eliminate all the asymmetric effect of weather is the extra operating costs above the test year associated with high HDD and CDD is not recovered under the FAC. As weather falls below normal the test year costs largely remain fixed and do not offset the revenue losses from rates.

Q. HOW DOES RISK IMPACT THE PROBABILITY THAT THE COMPANY WILL EARN ITS ALLOWED RETURN ON AVERAGE?

A. In theory, if weather risk impacts on earnings were normally distributed the expectation of higher earnings with greater HDD and CDD would offset the lower earnings from lower HDD and CDD so that on average the expected earnings would equal the allowed return. Since this does not happen because of asymmetric weather risk, the absence of the FAC does not provide a reasonable opportunity to earn the allowed return.

SECTION 4- COMPARABLE COMPANY REGULATORY MODELS

Q. WHAT IS THE PURPOSE OF DISCUSSING THE REGULATORY MODELS OF COMPARABLE COMPANIES?

A. This section illustrates that the cost of capital estimates based on the comparable companies already includes not only a fuel clause for most of the companies but other regulatory rules relative to the cost of capital such as future test years and cost trackers for other costs beside fuel. As a result, the risk profile of Empire is no different from that of the comparable companies in regard to the institution of a fuel and purchased power FAC and is somewhat more risky in other aspects of the regulatory model and in particular with reference to its capital program requirements. Without a fuel clause, Empire is substantially more risky than the comparable company group. Even with an FAC authorized to recover all fuel and purchased power costs, Empire remains on average riskier than the group because of other adjustments and its construction program.

Q. WHAT COMPARABLE COMPANIES HAVE YOU ANALYZED?

A. The comparable companies subject to analysis include all of the companies used by Dr. Vander Weide to estimate the cost of capital. The extent that Empire faces greater risks than these companies is a factor that the Commission should consider when determining Empire's equity return in this case.

Q. HOW HAVE YOU ANALYZED THESE COMPANIES?

A. The analysis consisted of a variety of steps including reviewing some or all of the following as necessary: tariffs, information provided by the companies on their websites, analysts' reports, SEC filings, regulatory decisions and other materials such as Regulatory Research Reports.

Q. WHAT RATEMAKING ELEMENTS HAVE YOU REVIEWED RELATIVE TO THESE COMPANIES?

A. The items reviewed included whether the companies have fuel adjustment clauses or the equivalent, whether they have other adjustment clauses to recover costs, the type of test year used in rate cases and the availability of any programs that provide incentives for earnings.

Q. HOW MANY OF THE COMPARABLE COMPANIES HAVE FUEL ADJUSTMENT CLAUSES OR THE EQUIVALENT?

A. Based on a review of the companies and the jurisdictions in which they operate; there is no company that operates without a fuel clause in some jurisdiction. With the exception of Missouri, the states in which the comparable companies operate without some form of FAC have either had a fuel and purchased power clause eliminated because of legislation opening the market to competition or the utility has agreed to the elimination of the clause. Most companies in open market states retain some method for recovering the actual cost of service provided under the supplier of last resort obligation. Some clauses are of recent vintage because of the impact of market based power prices or other events. Some clauses have unique statutory requirements concerning filing and approval. Some clauses are automatic adjustment clauses and others require regulatory review. The important point is that the comparable companies all have some earnings protection from the volatility of fuel and purchased power costs.

Q. HAVE YOU DEVELOPED A SCHEDULE THAT SUPPORTS YOUR CONCLUSIONS RELATIVE TO FAC TYPE FUEL AND PURCHASED POWER COST RECOVERY?

A. Yes. Schedule HEO-11 provides the information relative to the type of fuel cost recovery for each company in each jurisdiction. In addition, the schedule shows that a number of companies have other adjustment type clauses that track other costs under various regulatory mechanisms. Thirty two of the thirty-seven companies have fuel clauses in every jurisdiction. Almost half of the companies also have other types of cost adjustments that provide increased opportunity for the utility to earn its allowed return. These other adjustment clauses permit recovery of other costs such as uncollectible accounts expenses, transmission expense trackers and in some cases full decoupling of revenues.

Q. PLEASE DISCUSS THE SIGNIFICANCE OF THE TEST YEAR RELATIVE TO THE OPPORTUNITY TO EARN THE ALLOWED RETURN.

A. The purpose of the test year is to provide a reasonable estimate of the costs the utility will incur and the revenues the utility will receive during the Rate Effective Period. The use of a historical test year, even with adjustments, does not provide a realistic estimate of the costs or revenues during the Rate Effective Period. To the extent that a bias exists from historical test periods, this bias has understated both costs and revenues for many utilities and most certainly for those investing in new rate base to meet load growth. As discussed above, the issue of load growth or increased sales due to weather, impacts Empire in a unique way relative to earnings risk because its marginal energy costs are dominated by higher cost fuels relative to the average cost of fuel included in base rates. This means that Empire has unique risks relative to the recovery of fixed cost revenue requirements in the absence of a FAC mechanism to recover fuel and purchased power costs. The implication for Empire is that the historic test year represents more risk than that faced by other utilities in the comparable company set even with the proposed FAC.

Q. HOW MANY OF THE COMPANIES HAVE ALTERNATIVE TEST YEARS THAT REPRESENT A PERIOD CLOSER TO THE RATE EFFECTIVE PERIOD?

A. The basis for the test year varies by different jurisdiction and by the types of adjustments allowed to test year data. Schedule HEO-12 provides a summary of test year information for the comparable companies. As that schedule illustrates, the sample of comparable companies contains a variety of test years and adjustments. There are a number of states that use partially or fully forecasted test years as part of the regulatory process. Even where states use historic test years, there are provisions designed to reduce or eliminate the inflation risk such as inflation adjustments for operating and maintenance expenses, revenue adjustments to permit earnings within a predetermined band and adjustments for other expenses beyond the utilities control.

Q. WHAT DO THESE VARIOUS ADJUSTMENTS AND REGULATORY MODELS IMPLY REGARDING A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN?

A. In recognition of regulatory challenges facing utilities, regulators and legislators use many tools in an attempt to satisfy the requirement to provide utilities with a reasonable opportunity to earn the allowed return. Each combination of polices and procedures is valued in the expectations of investors regarding the required return. The ultimate test from the Wall Street point of view is, however, based on the actual return achieved. In the absence of a FAC to recover fuel costs, Empire would require much higher returns than those used as comparable companies to compensate for the fuel cost risk alone. Even with the approval of a full cost tracking FAC, Empire faces, on average, more risk than the group of comparable companies. Schedule HEO-13 provides the actual earned return on equity for the Company during the period 2001-2006. During this period, the Company has not earned an equity return higher than 8.4 percent and has earned a return as low as

3.9 percent. These values represent returns below any reasonable estimate of the cost of capital in that period as the average electric allowed return for those years demonstrates. Since those average returns include most utilities with fuel and other risk mitigation adjustments, Empire's returns should have been substantially above the average. Further, the actual results represent the impact of the factors discussed above such as the use of historic test years and the absence of fuel cost recovery mechanisms among other things.

SECTION 5- THE RECOVERY OF PRUDENTLY INCURRED COSTS AS A REGULATORY STANDARD

Q. WHAT IS THE REGULATORY STANDARD FOR COST RECOVERY?

A. The standard for cost recovery is that a utility is allowed to recover its prudently incurred costs. Cost recovery includes both the return of and the return on the book value of the assets as well as operating expenses and taxes.

Q. HOW DOES THIS STANDARD APPLY TO THE FUEL AND PURCHASED POWER FAC?

A. This standard suggests that the FAC must be comprehensive to include all of the prudently incurred costs associated with the fuel and purchased power segment of the business. As a practical matter, this implies that 100% of the costs of fuel, purchased power (including demand charges, energy charges and transmission costs) and carrying charges (positive or negative related to over or under recovered balances) at a minimum should flow through the FAC. There should be periodic audits to determine if the costs are prudent. The standard for prudence should be based on the facts reasonably known and knowable at the time the costs were incurred. There should be no second guessing based on actual outcomes after the decision since those factors do not influence prudence. All prudently incurred costs should be recovered and imprudent costs refunded to customers with interest.

Q. DOES 100 PERCENT RECOVERY OF FUEL COSTS CREATE INCENTIVES FOR THE COMPANY TO BE WASTEFUL OR IMPRUDENT IN MANAGING FUEL AND PURCHASED POWER EXPENSE?

A. No. The full recovery of cost is a fundamental right of the utility under regulation so long as the costs are prudently incurred. Further, courts have found it appropriate to assume that utility management acts in good faith. The additional aspects of the post recovery audit and refund obligation for imprudent expenses serves to provide additional incentives for management to operate its system and purchase power efficiently. Finally, there are market incentives for utilities to manage cost. Since higher prices result in less consumption of electricity (all else being equal), the utility faces loss of volumetric revenue to recover its fixed cost and therefore earnings erosion. This is also an incentive to manage fuel and purchased power costs efficiently and prudently.

SECTION 6- CAPITAL PROGRAM RISKS

Q. PLEASE DESCRIBE THE EMPIRE CAPITAL PROGRAM.

A. Empire has a significant capital program required to provide safe and reliable service to its customers. Over the next three years (2008-2010) Empire expects to spend over $200 million to add new generating capacity, almost $50 million on retrofits to existing plants, over $150 million for transmission and distribution facilities to serve new and existing customers for a total of almost $440 million in new capital for its regulated operations. At the end of 2006, Empire had net plant investment of just over one billion dollars. As such, the new investment in the capital program will add over 40% to the existing plant investment. The capital program represents a significant impact on the company and its customers.

Q. HAVE THE COMMISSION AND VARIOUS PARTIES TO THE REGULATORY PROCESS RECOGNIZED THE SIGNIFICANCE OF THE CAPITAL PROGRAM.

A. Yes. The Commission accepted the Stipulation and Agreement entered into by the Company and other parties in Case No. EO- 2005-0263 (Stipulation). The stated purpose for adopting the amortization provision of that agreement is to permit Empire to maintain an investment grade for its debt financing related to its cost of new capacity additions. Maintaining the investment grade requires that Empire actually earn its allowed return in the Rate Effective Period since the rating agencies look at actual financial performance not the allowed return. In addition, the amortization agreement assumes for purposes of calculating the dollars to be amortized that the cash flow from actual earnings supports the debt coverages contained in the existing bond indentures.

Q. HOW DOES EMPIRE INTEND TO FUND THIS CAPITAL PROGRAM?

A. The capital program must be funded by both internally generated funds and by external financing-both new equity issues and new debt issues. Internally generated cash flows result from both depreciation expense and retained earnings. Retained earnings are dependent on the actual earned return on equity resulting from the effect of costs and revenues in the Rate Effective Period and the dividend payout ratio. Retained earnings also play a role in maintaining the appropriate capital structure. For the Company, the impact of retained earnings in the capital plan is small for the years of 2008 and 2009 (the period encompassing the Rate Effective Period) at under $9 million dollars. The assumptions regarding net income for this period rely heavily on assumptions such as constant short term interest rates on investments, modest increases in the interest rates on short term debt of 50 basis points, constant contributions in aid of construction from new customers, no state or federal tax increases and limited increases in annual O&M at 2.5% over 2008 budget levels. Changes in any of these variables could adversely impact the construction program and the ability of the Company to maintain its investment grade debt rating.

Q. IS IT POSSIBLE TO DETERMINE THE LEVEL OF EQUITY RETURN NECESSARY TO SUPPORT THE CAPITAL PROGRAM?

A. It is impossible to know exactly the required return needed to support the capital program and maintain an investment grade debt rating because of the risks associated with the construction program. The risks for Empire are significant despite the approval of the amortization provision of the Stipulation. This is particularly so because in calculating the amortization amounts for rate case purposes the formula uses the allowed return from the rate case. Despite the best efforts of all parties, the proforma test year expenses and revenues may not provide a reasonable opportunity for Empire to earn the allowed return in the Rate Effective Period and in the subsequent period prior to the next rate case. In order to fund the construction program and maintain an investment grade debt rating, it will be the actual results in the Rate Effective Period and beyond that result in the investment grade debt rating. Further, as noted above the Missouri regulatory model biases the actual return below the authorized return given any reasonable expectation of economic conditions and assuming the existence of a fully tracking fuel adjustment clause. In addition to the bias that exists in the use of the historic test year, there is also the asymmetric weather risk, the risk of unforeseen additional capital expenditures from storm damages and so forth. These risks are compounded by the limited financial reserve strength resulting from a history of returns below the allowed return. Schedule HEO-13 provides a comparison of the allowed returns and the actual earned returns over the last six years.

Q. IF IT IS IMPOSSIBLE TO KNOW EXACTLY HOW MUCH EARNED RETURN THE COMPANY NEEDS IN THE RATE EFFECTIVE PERIOD, HOW DOES THE COMMISSION KNOW THE AMOUNT OF ADDITIONAL RETURN OVER THE ESTIMATED RETURN TO GRANT THE COMPANY?

A. The Commission has available several proxies that provide insight in the magnitude of the dollars of return at risk. The Commission has two tools for addressing risk- compensation and mitigation. These tools may be used separately or in conjunction with one another. Thus the Commission may choose to either grant the Company additional return to compensate for those risks, provide another means of mitigation through the ratemaking process or adopt some combination of the two. With respect to any risk, the options for meeting the standard of a return commensurate with the risk always include both additional return and mitigation. As discussed above, commissions use regulatory models that incorporate both tools as a means of providing a reasonable opportunity of earning the allowed return. These models vary by jurisdiction and include the Rate Stabilization and Equalization (RSE) in Alabama that adjusts rates quarterly to fall within a dead band around the allowed ROE based on a forecast test year to Wisconsin that uses a forecast test year and permits a current return on 50 percent of construction work in progress.

Q. PLEASE DISCUSS SOME OF THE PROXIES THAT ALLOW THE COMMISSION TO MEASURE THE RISKS ASSOCIATED WITH A REASONABLE OPPORTUNITY TO EARN THE ALLOWED RETURN IN THE RATE EFECTIVE PERIOD.

A. The use of historical operation and maintenance expense contributes to the bias because the payroll component will almost certainly increase as a result of inflation less an adjustment for improved productivity. This conclusion is consistent with the planning assumption of 2.5 percent escalation in O&M expense each year in the Empire plan. Since the Rate Effective Period will begin about nine months after the end of the historic test period, the impact of inflation on test period costs is one measure of the potential risk that the Company will not earn its allowed return. Further, it is reasonable to expect that these rates will remain in effect until after Iatan 2 is in service. The rates approved in this case will need to support the construction program for about two years. In addition, the costs of materials and equipment for electric utilities are rising because of increases in raw materials and other costs. This suggests that the cost of plant estimates may be less than the actual cost. As discussed below, this is one of the risk factors with a construction program.

Q. PLEASE DISCUSS THE RISKS ASSOCIATED WITH A MAJOR CONSTRUTION PROGRAM.

A. There are substantial risks associated with any construction program. Some risks are specific to different types of construction and some risks are general risks related to construction for any utility. The following list addresses the general risks borne by a utility with a major construction program particularly involving new generation facilities.

- Completion risk
- Rate base disallowance risk
- Construction cost risk
- Financing cost risk
- Project delay
- Ratings change risk
- Equity dilution risk
- Earnings quality risk (AFUDC is non-cash earnings)
- Capital structure risk from excess debt
- Counterparty risk
- Interdependent project risk
- Environmental risk
- Political risk
- Regulatory risk

Each of these risks represent additional risks that some of the comparable group do not face at all because they no longer provide generation service. For those comparable companies that have major construction programs some include CWIP in rate base and others have pre-approval of their construction program as part of regulatory review. Finally, most of the comparable companies are large enough to be the primary owner of the capacity and therefore have more control relative to the actual timing of the construction and cash outlays.

Q. PLEASE DISCUSS THE VARIOUS RISKS NOTED ABOVE.

A. Completion risk represents the risk that the construction of the plant fails to be completed. This could occur for reasons related to cost over-runs, unforeseen problems at the site, failure of the principal owner to obtain financing, etc. Failure to complete strands Empire's investment to that point in the project and absent regulatory approval of amortization represents a loss to shareholders. Completion risk also arises relative to the failure of the plant to meet the requirements for commercial operation. In either case absent Commission approval, any plant not included in base rates represents a loss to shareholders through the reduction in equity associated with the write off of investment.

Rate base disallowance risk results from two potential regulatory rulings. First, there may be an issue of whether the plant is used and useful. This issue seems to be addressed as to the signatories of the Stipulation thus limiting this risk to parties not signatory to the Stipulation. The second issue relates to the prudence of the capital cost for the plant. Expenditures not considered prudent may be disallowed. In the case of this risk, although Empire participates in the construction management for the plants and attempts to influence decisions and assure prudence, as a minority owner they have little direct control over project decisions. Further, Empire has given up its right to use that position as a response thereby facing this risk by proxy based on the final decisions of the plants primary owner. Rate base disallowance would reduce equity because it is borne by shareholders.

Construction cost risk means that the ultimate plant cost is higher than the estimated cost. This risk has a number of dimensions related to cash calls for construction, additional financing, capital structure changes and little or no flexibility as to timing of new issues. The net result is higher costs for the plant and potentially for the cost of capital. The concern here is that the financial stress will impact bond ratings and access to capital markets. This is of particular concern to Empire because it has very little reserve strength to weather an adverse cost change. Further, as noted above, current cost considerations almost certainly will raise the cost for construction of the plant from the original budget levels.

Financing cost risk represents the impact of several factors on the cost of capital. These include higher interest rates that other things being equal reduces the coverage ratio, inadequate equity from retained earnings due to the inability to earn the allowed return, inadequate authorized ROE to permit adequate coverages even with the Stipulation amortization, share price dilution due to inadequate returns and other potential adverse financial concerns. It should be noted that the amortization provision relates to a historic period and does not apply prospectively to the Rate Effective Period and thus may not adequately provide cash flow to satisfy investment grade debt rating requirements. This is an important risk because of the history of under earning from the Missouri jurisdiction and the prospect for a fuel adjustment that may not recover all costs. Even a one percent under recovery of fuel costs represents about $1.4 million or about 3.2 percent of jurisdictional earnings.

Project delay risk impacts both the cost of the project and the cash flows required to support the project. There are two issues that create concern. First, the accrual of AFUDC represents non-cash earnings and represents a lower quality of earnings. Second, delay also likely means increased cost of construction due to rising labor rates and material costs, thus increasing the probability of issues related to construction cost risk.

Ratings change risk has two dimensions. First, rating agencies periodically adjust their views related to treatment of financial risks. The treatment of long term leases represents one such recent example. To the extent that changes increase requirements for coverage or for capital structure the parties have agreed to discuss ways to maintain the investment grade but have not agreed to a method for adjusting cash flows absent a rate case filing that will delay the required cash flow infusion. Second, Empire faces the risk that it cannot maintain investment grade ratings even with the Stipulation because of its inability to maintain its equity position through retained earnings and new equity issues. Given the limited financial reserve strength, small changes in interest costs, earned equity returns, plant cost increases or other capital requirements such as storm damages may cause Empire to lose the investment grade bond rating beyond its reasonable control.

Equity dilution risk arises for a number of reasons during major construction programs. Obvious reasons include lower earnings quality, the need for greater retained earnings to support equity in the capital structure and the sale of new equity issues below the market because investors recognize the risk associated with the construction program and demand higher earned returns on the investment.

Earnings quality risk relates to the fact that AFUDC does not provide cash flow to support construction expenditures and therefore must be financed as well. At the extreme, it is possible that dividend payments may become return of capital.

Capital structure risk from excess debt relates to the financial inflexibility that results from high leverage. This may cause higher interest rates on debt requiring more coverage. It may mean greater use of short term debt to manage cash calls and the associated interest expense not included in the cost of service and resulting in lower equity returns.

Counterparty risk arises because project completion relies on other participants for funding and no one party has the financial strength to undertake project completion in the case of a party default. The existence of counterparty risk increases the probability of project delay and non-completion. There are any number of cases where the failure of one party in a multi-party project has jeopardized completion and caused delay until another party could be found to fund the project.

Interdependent project risk is a unique element associated with generation that is not within the existing system. This risk arises because other projects, in particular new transmission, represent a critical element in the ability to use the capacity. The cost of transmission represents additional capital outlay and faces possible issues related to siting the facility and receiving construction approval. There may also be delays in the completion of the needed transmission that cause the plant to value to be reduced. This leads to the potential for disallowance in rate base based on the concept of used and useful plant.

Environmental risks arise from the cost of compliance as rules change including the possibility of carbon sequestering, costs for emission trading or other costs that impact the projects capital cost prior to in service or delay the in service date. In addition, environmental risks increase the probability of project delay and the potential for interdependent project risks.

Political and regulatory risks impact many of the above risks including rate base disallowance, project delay, financial risks and others.

Q. HOW DO THESE RISKS RELATE TO THE COST OF COMMON EQUITY?

A. In terms of the estimated cost of equity for comparable companies, Empire faces higher risk and thus requires additional risk compensation as part of this decision. Indeed, some of the comparable companies no longer have the responsibility to build additional generation.

Q. HAVE OTHER REGULATORY AGENCIES RECOGNIZED THE ADDITIONAL RISK ASSOCIATED WITH A MAJOR CONSTRUCTION PROGRAM?

A. Yes. For example, the FERC has adopted a policy position in Order No. 679 that incentive ROEs represent a way to encourage new construction of transmission facilities to relieve congestion and improve reliability. The Empire construction program improves reliability and assures adequate capacity to meet customer load growth. The incentive discussed by the FERC allows for the utility to receive an ROE at the high end of what may be considered as a range of reasonable returns. The Missouri Commission has also granted an incentive return for KCPL in Case No. ER-2006-0314 recognizing the magnitude of risk associated with a construction program.

Q. HOW SHOULD THE COMMISSION DETERMINE THE ADDITIONAL RETURN ASSOCIATED WITH THESE RISKS?

A. The Commission need not determine a specific adjustment to the cost of capital in order to recognize the construction program risks or for that matter any of the other risks that Empire faces that distinguish it from the comparable companies mentioned earlier. Rather, the Commission may recognize the risk by awarding Empire its requested return of 11.6% which will likely be the upper end of the recommended returns for the Company in this case. This represents a reasonable means of compensating Empire for the construction program risks. In addition, the Commission should consider a mitigation strategy designed to allow Empire deferred accounting treatment and assure probable recovery for any unusual expenses or changes in costs beyond the control of management occurring in the Rate Effective Period. Such costs include storm damage, vegetation management expense, changes in governmental policy and other items not included in test year costs subject to review and audit prior to amortization.

SECTION 7- CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE NECESSITY OF AN FAC.

A. Empire requires an FAC because fuel price changes have significant earnings impacts such that in the absence of a fuel and purchased power related FAC the Company has no reasonable opportunity of earning its allowed return. Fuel prices are market driven resulting in both volatility and the inability of management to control those costs. The volatility of prices and the inability of management to control costs provide additional support and justification for a fuel and purchased power FAC. The testimony provides a number of fact based illustrations supporting each of these considerations. The testimony demonstrates the panoply of factors that impact the total fuel and purchased power costs including prices, weather, customer demand, operating characteristics of the system, plant maintenance, power market conditions, wind production and so forth. The most cost effective option to benefit customers and permit the company a reasonable opportunity to earn the allowed return is mitigation of the fuel cost risk through a fuel and purchased power cost FAC. Indeed, most states and most companies use this option to the long term benefit of all stakeholders.

Q. WHAT HAVE YOU CONCLUDED WITH REGARD TO CONSTRUCTION COST RISKS?

A. The testimony concludes that the construction program represents substantial risks for Empire. The long list of risks is particularly unique for the Company because of its limited financial flexibility and the size of the overall undertaking. As a result, the Commission should recognize the risks by allowing Empire both compensation and mitigation combined to permit the Company to maintain its investment grade debt rating. In recognition of the risk, the appropriate compensation sets the allowed equity return at the upper end of Empire request, which may be at what might be considered as a range of reasonable returns. The appropriate mitigation permits Empire to have deferred accounting treatment and assure probable recovery for any unusual expenses or changes in costs beyond the control of management occurring in the Rate Effective Period.

AFFIDAVIT OF H. EDWIN OVERCAST

STATE OF Georgia)
) ss
COUNTY OF Henry)

On the 28 day of September, 2007, before me appeared H. Edwin Overcast, to me personally known, who, being by me first duly sworn, states that he is Director of R. J. Rudden, A Black & Veatch Company and acknowledged 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.

H. Edwin Overcast

Subscribed and sworn to before me this 28 day of September, 2007

Notary Public

My commission expires:____________________

DARLENE N. PATTON
Notary Public-Henry County, Georgia
My Commission Expires May 9, 2009

LIST OF SCHEDULES

Schedule No.	Description
HEO-1	Summary of Qualifications
HEO-2	Components of Test Year Fuel and Purchased Power Costs
HEO-3	Hours Where Each Source Is at the Margin
HEO-4	Fuel and Purchased Power Price Volatility
HEO-5	Monthly Fuel Cost Volatility
HEO-6	EIA Gas Price Data
HEO-7	EIA Coal Price Data
HEO-8	Impact of Fuel Price Increases
HEO-9	Weather Impacts on Fuel Costs
HEO-10	Comparison of Normal Weather to Alternative Runs
HEO-11	Cost and Revenue Impacts of Alternative Weather
HEO-12	Base Case Assumptions
HEO-13	Maintenance Schedules for Test Year and Rate Effective Period
HEO-14	Heat Rate Curves
HEO-15	Listing of Events that Impact Fuel Costs
HEO-16	Basic Unit Operating Data
HEO-17	Hourly Marginal Costs under Differing Weather Conditions
HEO-18	Comparable Company Fuel Cost Recovery Mechanisms and other Adjustments
HEO-19	Comparable Company Test Periods
HEO-20	Historical Earned Returns for Empire

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Ohio Public Utilities Commission, New York Public Service Commission and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the division and subsequently was promoted to Director, his current position. He is responsible for the open access and unbundling practice area and provides economic and regulatory consulting to clients of the firm.

Dr. Overcast has served as an instructor in the A.G.A. Rate Fundamentals Course, the AGA Advanced Rate Course and the S.G.A. Intermediate Level Rates Course.

Schedule HEO-6

U.S. Natural Gas Electric Power Price (Dollars per Thousand Cubic Feet)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	3.10	2.86	3.37	3.80	3.78	3.61	3.49	3.42	3.71	4.19	4.35	4.72
2003	5.33	6.47	7.05	5.38	5.70	6.08	5.45	5.23	5.12	4.98	4.85	5.69
2004	6.37	5.76	5.50	5.74	6.30	6.52	6.24	5.97	5.39	6.05	6.71	6.88
2005	6.72	6.42	6.84	7.27	6.83	7.08	7.58	8.67	11.01	11.85	9.87	11.28
2006	9.09	7.99	7.35	7.31	6.87	6.67	6.67	7.52	6.32	5.75	7.48	7.56
2007	7.04	8.17	7.64	NA	NA							

Source EIA Gas Price Data

EIA Coal Price Data

Year	Bituminous Coal		Subbituminous Coal		Lignite [1]		Anthracite		Total	
	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]
2000	24.15	24.15	7.12	7.12	11.41	11.41	40.9	40.9	16.78	16.78
2001	25.36	24.77	6.67	6.51	11.52	11.25	47.67	46.55	17.38	16.97
2002	26.57	25.5	7.34	7.05	11.07	10.63	47.78	45.86	17.98	17.26
2003	26.73	25.12 [R]	7.73	7.26 [R]	11.2	10.53 [R]	49.87	46.87 [R]	17.85	16.78
2004	30.56	27.93 [R]	8.12	7.42 [R]	12.27	11.21 [R]	39.77	36.34 [R]	19.93	18.21
2005	36.8 [R]	32.64 [R]	8.68 [R]	7.7 [R]	13.49	11.97 [R]	41 [R]	36.37 [R]	23.59 [R]	20.92
2006[E]	37.51	32.32	10.26	8.84	14.01	12.07	42.86	36.93	23.78	20.49

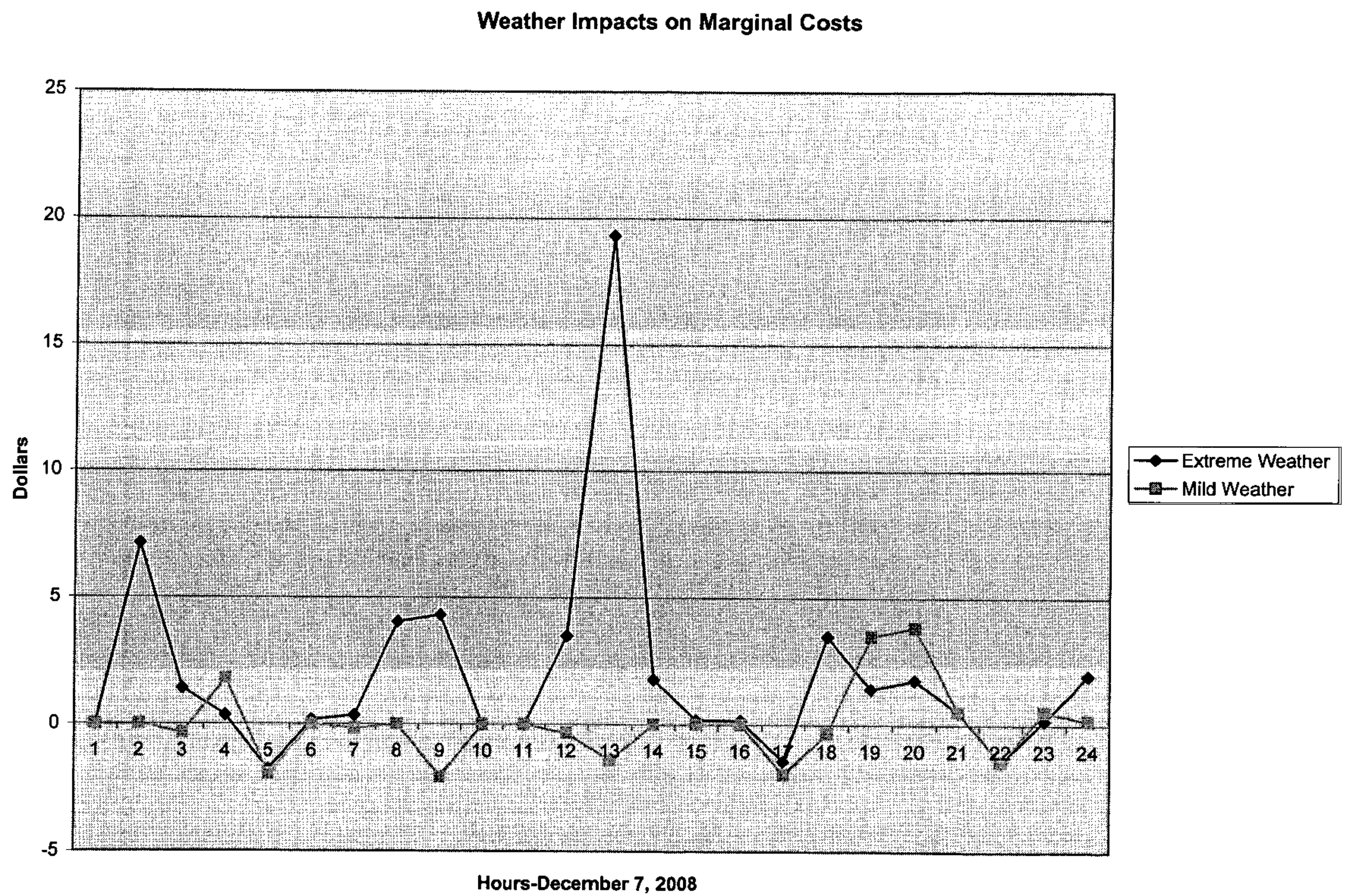
Annual Energy Review 2006
Report No. DOE/EIA-0384(2006)
Posted: June 27, 2007
Next Update: June 2008

Schedule HEO-8

Abnormal Causes for Fuel and Purchased Power (F&PP) Variance (2005 – July 2007)

- May 2007 – The Iatan coal plant had a 20-plus day unscheduled outage related to flood mitigation and a subsequent accident at the plant
- February 2007 – Problems with a circulation water pump caused delays in the Iatan coal unit's return to service after their scheduled maintenance outage.
- January 2007 – A severe ice storm disrupted power supply for much of Empire's Missouri and Arkansas service area.
- Year of 2006 – The Ozark Beach hyrdo-electric station had the lowest annual generation output in at least the last 30 years due to a lack of rainfall in the region. The 2006 generation was 22,673 MWh which was about 65% lower than the previous 30-year average of 65,390 MWh.
- August 2006 – The Asbury coal plant's cost was negatively impacted by a coal inventory adjustment
- January 2006 – Since this was the warmest January in the last 73 years, peaking units did not run and F&PP costs were well below budget.
- May 2005 through April 2006 – The May 2005 train derailments in Wyoming, constrain the movement of coal out of the Powder River Basin. During this period coal conservation began in the Midwest region due to these rail transportation issues. This coal conservation negatively impacted the Company's Jeffrey Energy Center contract purchase from Westar and Empire's share of the Iatan Plant output. Additionally, the costs for Asbury and Riverton plants were negatively impacted by using higher cost fuels as part of coal conservation efforts.
- February 2006 – The Asbury coal plant was out of service on unplanned outage for about 15 days due to a blade failure.
- Final four months of 2005 – Unprecedented high natural gas prices (along with high natural-gas-price-correlated purchased power prices) persist following major hurricanes in the Gulf Coast.
- August 2005 - Empire was able to lower fuel expense by over $5 million by unwinding a forward natural gas contract it had entered into as a result of its Risk Management Policy
- March 2005 – The Asbury coal plant had six days of unplanned outages due to the furnace plugging and a gate failure on the main steam valve.

Schedule HEO-10



Empire Comparable Companies

Line No.	Company	Jurisdictions	Regulatory Model
1	Ameren Corp.	Illinois, Missouri	Illinois-1, Missouri-2
2	Amer. Elec. Power	Ohio, Texas, Virginia, Tennessee, West Virginia, Indiana, Michigan, Kentucky, Oklahoma, Louisiana, Arkansas	Ohio-4 Texas-1&4 Virginia-3, Tennessee-1, West Virginia-2, Indiana-1, Michigan- 1 Kentucky-1, Oklahoma-1, Louisiana-1 Arkansas-1
3	Black Hills	South Dakota, Wyoming	South Dakota-1, Wyoming-1
4	Constellation Energy	Maryland	Maryland-4
5	Dominion Resources	Virginia, North Carolina	Virginia-2, North Carolina-1
6	DPL Inc.	Ohio	Ohio-4
7	DTE Energy	Michigan	Michigan-3
8	Consol. Edison	New York, Pennsylvania, New Jersey	New York-4, Pennsylvania- 3, New Jersey-4
9	Edison Int'l	California	California-4
10	Entergy Corp.	Arkansas, Louisiana, Mississippi	Arkansas-1, Louisiana-1, Missippi-3
11	Exelon Corp.	Illinois, Pennsylvania	Illinois-1, Pennsylvania-3
12	FirstEnergy Corp.	Ohio, New Jersey,	Ohio-4, New Jersey-

		Pennsylvania	4, Pennsylvania-3
13	FPL Group	Florida	Florida-3
14	G't Plains Energy	Missouri, Kansas	Missouri-2, Kansas-3
15	Hawaiian Elec.	Hawaii	Hawaii-1
16	IDACORP Inc.	Idaho	Idaho-1
17	Alliant Energy	Iowa, Wisconsin	Iowa-3, Wisconsin-1
18	MDU Resources	Montana, North Dakota, South Dakota, Wyoming	Montana-3, North Dakota-3, South Dakota-1, Wyoming-1
19	NiSource Inc.	Indiana	Indiana-1
20	NSTAR	Massachusetts	Massachusetts-4
21	Northeast Utilities	Connecticut, Massachusetts, New Hampshire	Connecticut-1, Massachusetts-4, New Hampshire-3
22	Otter Tail Corp.	Minnesota	Minnesota-3
23	PG&E Corp.	California	California-4
24	Progress Energy	North Carolina, Florida	North Carolina-1, Florida-3
25	PNM Resources	New Mexico, Texas	New Mexico-2, Texas-4
26	Pinnacle West Capital	Arizona	Arizona-3
27	Pepco Holdings	D.C., Maryland, Delaware, New Jersey	D.C.-4, Maryland-4, Delaware-4, New Jersey-4
28	PPL Corp.	Pennsylvania	Pennsylvania-3
29	Puget Energy Inc.	Washington	Washington-1
30	SCANA Corp.	South Carolina	South Carolina-1
31	Southern Co.	Alabama, Georgia, Mississippi, Florida	Alabama-3, Georgia-1, Mississippi-3,

			Florida-3
32	Sempra Energy	California	California-4
33	Integrys Energy	Wisconsin, Michigan	Wisconsin-1, Michigan-1
34	Vectren Corp.	Indiana	Indiana-3
35	Wisconsin Energy	Wisconsin, Michigan	Wisconsin-1, Michigan-1
36	Westar Energy	Kansas	Kansas-1
37	Xcel Energy Inc.	Minnesota, Wisconsin, Colorado, Texas, New Mexico, North Dakota, South Dakota, Michigan	Minnesota-3, Wisconsin-1, Colorado-3, Texas-1, New Mexico-1, North Dakota-1, South Dakota-1, Michigan-1

[redacted]

Notes: 1 means that the utility recovers all fuel and purchased power costs under an approved provision subject to prudence review.
2 means the utility has no fuel and purchased power adjustment
3 means that the utility has both a fuel and purchased power adjustment clause and other regulatory cost adjustment features
4 means market based rates from standard offer solicitations

Empire Comparable Companies

Line No.	Company	Jurisdictions	Test Year	Adjustments
1	Ameren Corp.	Illinois, Missouri	Illinois-1, 2, 3 Missouri-1	Missouri may permit post test year known and measurable changes
2	Amer. Elec. Power	Ohio, Texas, Virginia, Tennessee, West Virginia, Indiana, Michigan, Kentucky, Oklahoma, Louisiana, Arkansas	Ohio-2 Texas-1 Virginia-1 Indiana-1 Michigan-1 Kentucky-1,3 Oklahoma-1 Louisiana-1 Arkansas-2	Ohio-all data must be actual Texas-post test year additions and retirements may be recognized Virginia- may recognize post test year changes Indiana- known and measurable changes within 12 months of the test period Michigan- inflation adjustment and known and measurable changes Kentucky- adjust historical periods for known and measurable changes Oklahoma- adjust for known and measurable changes within 6 months of test period and CWIP for new plants Arkansas-known and measurable changes within 12 months of the end of the test period
3	Black Hills	South Dakota, Wyoming	South Dakota-1 Wyoming1,3	South Dakota- known and measurable changes Wyoming-known and measurable

				changes
4	Constellation Energy	Maryland	Maryland-2	Maryland- updated during the hearing
5	Dominion Resources	Virginia, North Carolina	Virginia-1 North Carolina-1	Virginia- may recognize post test year changes North Carolina- adjust for changes known before the close of hearings
6	DPL Inc.	Ohio	Ohio-2	Ohio-all data must be actual
7	DTE Energy	Michigan	Michigan-1	Michigan- inflation adjustment and known and measurable changes
8	Consol. Edison	New York, Pennsylvania, New Jersey	New York-3 Pennsylvania-3 New Jersey-2	Pennsylvania- Test period is actual by the time of the decision New Jersey- data is actual before the decision
9	Edison Int'l	California	California-3	
10	Entergy Corp.	Arkansas, Louisiana, Mississippi	Arkansas-2 Louisiana-1 Mississippi-3	Arkansas-known and measurable changes within 12 months of the end of the test period
11	Exelon Corp.	Illinois, Pennsylvania	Illinois-1,2,3 Pennsylvania-3	Pennsylvania- Test period is actual by the time of the decision
12	FirstEnergy Corp.	Ohio, New Jersey, Pennsylvania	Ohio-2 New Jersey-2 Pennsylvania-3	Ohio-all data must be actual New Jersey- data is actual before the decision Pennsylvania- Test period is actual by the time of the decision
13	FPL Group	Florida	Florida-3	Florida- permits CWIP
14	G't Plains Energy	Missouri, Kansas	Missouri-1 Kansas-1	Missouri may permit post test year

				known and measurable changes Kansas- permits certain other changes
15	Hawaiian Elec.	Hawaii	Hawaii-3	Hawaii- test period is partially historic by decision
16	IDACORP Inc.	Idaho	Idaho-1	Idaho- major plant additions afforded year end rate base treatment
17	Alliant Energy	Iowa, Wisconsin	Iowa-1 Wisconsin-3	Iowa-known and measurable changes
18	MDU Resources	Montana, North Dakota, South Dakota, Wyoming	Montana-1 North Dakota-1,2,3 South Dakota-1 Wyoming-1,3	Montana- known and measurable changes up to twelve months after test period North Dakota- permits CWIP on transmission and environmental investments South Dakota- known and measurable changes Wyoming-known and measurable changes
19	NiSource Inc.	Indiana	Indiana-1	Indiana- known and measurable changes within 12 months of the test period
20	NSTAR	Massachusetts	Massachusetts-1	Massachusetts- year end rate base and known and measurable changes that meet a threshold test for rate base
21	Northeast Utilities	Connecticut, Massachusetts, New Hampshire	Connecticut-1 Massachusetts-1 New Hampshire-1	Connecticut- adjustments to revenues expenses to the mid-point of the rate year

				Massachusetts- year end rate base and known and measurable changes that meet a threshold test for rate base New Hampshire- adjustments for known and measurable changes
22	Otter Tail Corp.	Minnesota	Minnesota-2	Minnesota- test year partly forecasted at decision
23	PG&E Corp.	California	California-3	
24	Progress Energy	North Carolina, Florida	North Carolina-1 Florida-3	North Carolina- adjust for changes known before the close of hearings Florida- permits CWIP
25	PNM Resources	New Mexico, Texas	New Mexico-1 Texas-1	New Mexico-known and measurable changes Texas-post test year additions and retirements may be recognized
26	Pinnacle West Capital	Arizona	Arizona-1	Arizona-known and measurable changes
27	Pepco Holdings	D.C., Maryland, Delaware, New Jersey	D.C.-2 Maryland-2 Delaware-2 New Jersey-2	D.C.- relies on actual data Maryland- updated during the hearing New Jersey- data is actual before the decision
28	PPL Corp.	Pennsylvania	Pennsylvania-3	Pennsylvania- Test period is actual by the time of the decision
29	Puget Energy Inc.	Washington	Washington-1	Washington-known and measurable changes and sometimes attrition allowances

30	SCANA Corp.	South Carolina	South Carolina-1	South Carolina-permits adjustments
31	Southern Co.	Alabama, Georgia, Mississippi, Florida	Alabama-1 Georgia-3 Mississippi-3 Florida-3	Georgia-test year partially forecast at decision Florida- permits CWIP
32	Sempra Energy	California	California-3	
33	Integrys Energy	Wisconsin, Michigan	Wisconsin-3 Michigan-1	Michigan- inflation adjustment and known and measurable changes
34	Vectren Corp.	Indiana	Indiana-1	Indiana- known and measurable changes within 12 months of the test period
35	Wisconsin Energy	Wisconsin, Michigan	Wisconsin-3 Michigan-1	Michigan- inflation adjustment and known and measurable changes
36	Westar Energy	Kansas	Kansas-1	Kansas- permits certain other changes
37	Xcel Energy Inc.	Minnesota, Wisconsin, Colorado, Texas, New Mexico, North Dakota, South Dakota, Michigan	Minnesota-2 Wisconsin-3 Colorado-1 Texas-1 New Mexico-1 North Dakota-1,2,3 South Dakota-1 Michigan-1	Minnesota- test year partly forecasted at decision Texas-post test year additions and retirements may be recognized New Mexico-known and measurable changes North Dakota-permits CWIP on transmission and environmental investments South Dakota-known and measurable changes Michigan- inflation adjustment and known and measurable changes

NOTES: 1 means historic test year, 2 means estimated based on actual data and estimated data, 3 means forecast test year

Empire Earned Returns

	2006	2005	2004	2003	2002	2001
Net Income	39,280,166	23,768,111	21,847,534	29,450,308	25,524,118	10,402,915
Equity	468,609,339	393,411,169	379,180,390	378,824,830	329,314,661	268,307,971
ROE	8.38%	6.04%	5.76%	7.77%	7.75%	3.88%
Average Electric ROE*	10.36%	10.54%	10.75%	10.97%	11.16%	11.09%

*Regolatory Focus July 2007, RegulatoryResearch Associates- Allowed ROEs