EXHIBIT

| | |
|---|---|
| **Exhibit No.:** | 1 |
| **Issue(s):** | FAC |
| **Witness/Type of Exhibit:** | Riley/Direct |
| **Sponsoring Party:** | Public Counsel |
| **Case No.:** | EO-2017-0065 |

FILED
August 31, 2017
Data Center
Missouri Public
Service Commission

# DIRECT TESTIMONY

# OF

# JOHN S. RILEY

Submitted on Behalf of the Office of the Public Counsel

# EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EO-2017-0065

**** Denotes Highly Confidential Information ****

May 19, 2017

OPC
Exhibit No. 1
Date 8-24-17 Reporter A.F.
File No. EO-2017-0065

HC

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**

| | | |
|---|---|---|
| In the Matter of the Sixth Prudence<br>Review of Costs Subject to the<br>Commission-Approved Fuel Adjustment<br>Clause of The Empire District<br>Electric Company | )<br>)<br>)<br>)<br>) | Case No. EO-2017-0065 |

**AFFIDAVIT OF JOHN S. RILEY**

**STATE OF MISSOURI** )
) **ss**
**COUNTY OF COLE** )

John S. Riley, of lawful age and being first duly sworn, deposes and states:

1. My name is John S. Riley. I am a Public Utility Accountant III for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

John S. Riley, C.P.A.
Public Utility Accountant III

Subscribed and sworn to me this 19th day of May 2017.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
JERENE A. BUCKMAN
My Commission Expires
August 23, 2017
Cole County
Commission #13754037

Jerene A. Buckman
Notary Public

My Commission expires August 23, 2017.

# TABLE OF CONTENTS

# DIRECT TESTIMONY

# OF

# JOHN S. RILEY

# THE EMPIRE DISTRICT ELECTRIC COMPANY

# CASE NO. EO-2017-0065

## INTRODUCTION

**Q. Please state your name and business address.**

A. John S. Riley, PO Box 2230, Jefferson City, Missouri 65102.

**Q. By whom are you employed and in what capacity?**

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Public Utility Accountant III.

**Q. Please describe your educational background.**

A. I earned a B.S. in Business Administration with a major in Accounting from Missouri State University.

**Q. Please describe your professional work experience.**

A. I was employed by the OPC from 1987 to 1990 as a Public Utility Accountant. In this capacity I participated in rate cases and other regulatory proceedings before the Public Service Commission ("Commission"). From 1994 to 2000 I was employed as an auditor with the Missouri Department of Revenue. I was employed as an Accounting Specialist with the Office of the State Court Administrator until 2013. In 2013, I accepted a position as the Court Administrator for the 19th Judicial Circuit until April, 2016 when I joined the OPC.

**Q. Are you a Certified Public Accountant ("CPA") licensed in the State of Missouri?**

A. Yes. I am also a member of the Institute of Internal Auditors ("IIA")

**Q. Have you previously filed testimony before the Missouri Public Service Commission ("Commission" or "PSC")?**

A. Yes I have.

## RECOMMENDATION AND SUMMARY OF TESTIMONY

**Q. What is the purpose of your direct testimony?**

A. The purpose of my testimony is to demonstrate that Empire District Electric Company's ("Empire" or "Company") hedging policies and practices are imprudent and have harmed ratepayers by subjecting them to substantial and unnecessary hedging losses during the 18 month prudence review timeframe.

**Q. Does OPC have a recommendation for the Commission?**

A. Yes. OPC recommends the Commission find Empire's hedging policy imprudent for the time period of March 2015 through August 2016 and order Empire to return to its customers, $13,104,811.18[1] along with interest in the first FAC rate change following the effective date of the Commission's order in this case.

**Q. How should the Commission judge the Company's conduct?**

A. The Commission's prudence standard described below has been in place now for over 20 years.

> [A] utility's costs are presumed to be prudently incurred... However, the presumption does not survive "a showing of inefficiency or

[1] Total calculations were $16,785,521.65 prior to Missouri jurisdictional and FAC allocations.

> improvidence."...[W]here some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent... .
>
> ...[T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[2]

The key take-away from this quote is that the Company's fuel hedging practices must have been "reasonable" and must be judged "prospectively" based on circumstances at the time.

**Q. Why are these important considerations?**

A. The prudence standard really comes down to determining what course of action should a utility adopt that affects its future operation and its customers, when it takes into consideration all the facts available at the time. OPC's evidence will show that given the facts that were known or should have been known by Empire at that time, a reasonable utility would not have engaged in the hedging practices that caused heavy monetary losses in Empire's natural gas purchases.

**Q. OPC witness Charles Hyneman states in his testimony that the first standard to be met in a prudence audit case is serious doubt of prudence. Would you summarize what raises serious doubt regarding the prudence of Empire's hedging costs in the prudence audit period in this case?**

A. First, the natural gas market has not been advantageous for electric utility natural gas hedging for several years and is expected to continue this way for quite a while longer.

[2] *State ex rel. Associated Natural Gas Co. v. Public Service Commission of State of Missouri,* 954 S.W.2d 520, 528-529 (Mo. Ct. App. 1997).

Secondly, Empire's rigid hedging policy resulted in ratepayers paying $13.1 million more in fuel costs during the audit period than they would have paid if Empire did not engage in natural gas hedging activities. Finally, as outlined in OPC witness Hyneman's direct testimony, the prudency of natural gas hedging has been addressed in other states at least as far back as 2010.

Recently, the Kentucky Public Service Commission ("PSC") denied a request of Columbia Gas of Kentucky and Atmos Energy Corporation to continue their gas cost hedging programs. In ending the practice, Kentucky PSC found that current conditions and the outlook for future natural gas supplies and prices are sufficiently different from those in 2001 and therefore dispel concerns regarding the potential adverse impact of price volatility on customers' bills.[3] The Kentucky PSC ended the utilities' hedging programs, finding that continued low and stable gas prices obviate the need for hedging and that it is no longer reasonable to customers.

Additionally, KCP&L – Greater Missouri Operations Company ("GMO") agreed in its recent rate case to discontinue its hedging practices. And lastly, the Kansas Corporation Commission does not allow Empire to recover hedging costs from Empire's Kansas customers.

**Q. Please summarize why Empire's hedging is imprudent.**

A. At the time natural gas purchasing decisions were made for the time period of this prudence audit, Empire's hedging policy was inflexible and was not responsive to the low cost natural gas forecasts provided by the U.S Energy Information Administration ("EIA") and consultants hired by Empire to provide natural gas forecasts specifically for Empire. Because hedging costs were included in the FAC, Empire experienced very little, if any, harm from these practices. Its rigid policy resulted in over $13 million of costs being charged to its customers in just this one FAC audit period.

[3] Enerknol Research Dec. 21,2015 "Regulators Reconsider Utility Hedging Policies Given Shifts In Natural Gas Flow

## SERIOUS DOUBT

**Q. Would you characterize the market for natural gas during the prudence review period?**

A. During the audit period, spot market natural gas prices were the lowest they had been in this century.

**Q. You have stated that it is important to know what decisions were based on to determine prudence. Would you describe the natural gas market prior to this audit period?**

A. From 2004 through 2009, the average price of natural gas never fell below $5 MMBtu.[4] From February of 2010 through today, the average price of natural gas went above $5 for only one month in the entire seven years. That one month was the "Polar Vortex" of February 2014 where the spot price on the Henry Hub reached $6 but fell $1.10 the following month. The average price was in a steady decline that very cold winter until it hit a bottom of $1.73 MMBtu in April, 2016.

**Q. What type of hedging is prudent in an environment with dropping or stable prices?**

A. As prices are falling or staying fairly constant, typical utility hedging is an expensive proposition with little or no benefit. If a company is hedging just because a certain volume level dictates (as is the case with Empire), then it would be much more likely that the price paid for the derivative or forward contract will be higher than the spot price on the current open market. If prices go down or stay close to the same when the contract comes due, then ratepayers will have paid more for the future natural gas purchase than the going market price. Unless a company is betting on the price of natural gas going down, there really isn't any hedging that is suitable for this pricing environment.

[4] Prices bases on the Monthly average at the Henry Hub terminal listed on the U.S. Energy Information Administration ("EIA") website.

Generally speaking, the market behavior since 2011 has not supported hedging natural gas to protect against price spikes in the price of natural gas.

**Q. Was Empire aware of this declining price market?**

A. Yes. Declining natural gas prices were evident several years before the March 2015 through August 2016 prudence review period when Empire was making decisions impacting this prudence audit period.

As I stated previously, natural gas prices have been on a downward trend since the last price spike in 2008. That was when the convergence of several economic and weather related factors forced natural gas to peak at nearly $13/MMBtu. This prompted oil companies to drill more wells causing supply to outpace demand. Empire officials acknowledged the downward price trend when it responded on July 3, 2013, well before this prudence audit period, to Staff questions in Docket No. EW-2013-0101: *Working Docket to Address the Hedging Practices of Electric Utilities Used to Mitigate the Rising Costs of Fuel:*

> Staff Question 12: How have changes in the natural gas market since 2009 affected the benefits, for both utilities and their customers, of hedging natural gas?....
>
> Empire's Response: As the natural gas prices have declined, both Empire and its customers have benefitted from the price declines – the customers through lower electric bills, and Empire through a lower overall revenue requirement. In addition to the lower fuel costs for Empire and its customers, the decline in natural gas prices has resulted in lower spot power prices, which have also been flowed through the FAC to the benefit of Empire's Customers.

The price decline accelerated since the "Polar Vortex" of February of 2014 as more and more natural gas entered the market. Attached as JSR-D-1 is a summary page of historical natural gas prices published by the U.S. Energy Information Administration

("EIA"). The EIA gathers information on most fuels consumed in the U.S. They publish weekly reports on many changes in commodity statistics.

Among other statistics, the EIA reports on fuel prices, number of oil rigs in production, weather expectations, coal shipped, and their expectations concerning short and medium term prices of these tracked commodities. There is one compelling data point that the EIA tracks every week that plays a significant role in whether gas prices will stay low – and that is the weekly natural gas storage report. This is a report of the current level of natural gas in storage across the country. There is a strong correlation between natural gas prices and the five year average in natural gas storage. A recent article by the investment information technology company Market Realist explained why natural gas prices have been low for an extended period of time. One take away from the analysis is quoted below:

> Natural gas prices are impacted by the spread between the natural gas inventories and their five-year average. Over the last ten years, whenever natural gas inventories have been higher than their five-year average, prices have fallen.
>
> In contrast, between December 2013 and April 2014, when inventory levels fell short of the five-year average by the highest amount in the past ten years, natural gas prices rose to $6.14 per million British Thermal units.
>
> The downturn in natural gas prices since June 2008 could be linked to higher inventories compared to the five-year average[5]

It is interesting to note that the 2016 injection season began in April with record-high start of the season natural gas storage levels and ended in October with an end-of-month record. Natural gas storage levels reached an all-time high in November.[6] Average monthly prices

[5] Robert Scott, Analyzing Natural Gas Inventories and Prices – Market Realist p. 4 of 9, http://marketrealist.com/2017/03/markets-strong-natural-gas-lagging/,
[6] EIA article "Underground Natural Gas Working Storage Capacity" April 3, 2017

for natural gas in 2016 were the lowest in this century. The Market Realist also pointed out that natural gas inventories fell below their five-year average in December 2016 for the first time in 19 months and the average price rose above $3 for the first time in over two years.

**Q. Can inventory levels predict the price of natural gas?**

A. No. Inventory levels cannot predict prices but they can give an indication that so long as there is record or near record storage levels, price spikes are suppressed. But high inventory levels by themselves will not keep market prices from rising and falling. It is not unusual, and in fact, generally expected that natural gas prices rise and fall throughout the year due to weather and expected customer usage patterns. More and more electric utilities have turned to natural gas generation plants to replace coal-fired systems and the majority of peaking capacity is natural gas fired. Consequently, the months of July and August see higher natural gas prices, as do the peak winter months. Prices tend to be lower in the Fall and Spring. There is no surprise in this market behavior.

**Q. Is this annual expected rise and fall of natural gas prices evidence of a need for extensive hedging?**

A. No. If you look at the annual gas prices from 2000 through 2010, you find that the average annual price for that timeframe was $5.69. From 2011 through 2016 the average annual price was $3.33. That is a 41.47% drop in price. As pointed out earlier in this testimony, the high volatility and upward pricing pressure has not existed since 2008 and so long as the natural gas market continues to bump up against record storage levels this excess capacity can absorb sudden demand needs and we can expect prices to remain subdued with little chance of spiking anytime soon.

Attempting to hedge prices in this type of market environment has no benefit that is worth the financial risk to the customer. The market prior to the prudence audit period was not demonstrating any risk that needed to be addressed through costly hedging. Pricing forward contracts, swaps and futures at 30% over then current market prices may help a company predict its future natural gas budget, but it certainly wasn't helping the ratepayer.

**Q. You have stated Empire's hedging policy is rigid. What is your understanding of the Company's policies governing hedging?**

A. Empire has in place an Energy Risk Management Policy, which is attached as JSR-D-2 that provides the rules and guidelines that govern the Company's actions in managing their power and natural gas commodity risk. It has had this policy in place, mostly unchanged, since 2001. By all indications, the Company has strictly adhered to these guidelines since they were developed in 2001.

**Q. Would you summarize the Company's hedging practices?**

A. Essentially, the company places natural gas hedging transactions based on a percentage of their expected natural gas volume needs for a given timeframe. Their hedging is based on volume need, not price risk. The Commission's Staff quoted from the hedging strategy section of the Company's Energy Risk Management Policy manual and included it in its prudence report in this case. It is important to display it here again so the Commission can understand how inflexible and costly this practice has been.

Very telling in this section of its Risk Management report is that Empire begins its hedging strategy section with a description of its FAC which includes the detail that hedging costs are included in its FAC.

**4. HEDGE STRATEGY**

**Electric Segment**

Prior to September 1, 2008, the electric segment's Missouri retail rates were not subject to a fuel cost adjustment clause. Effective September 1, 2008 regulators granted a fuel adjustment clause (FAC) for recovery/refund of 95% of prudent fuel expenses versus a base rate established in rate case ER-2008-0093 and any future rate cases.

> The Missouri FAC allows Empire to recover 95% of under-recovered prudent fuel expenses and return to customers 95% of any over-recovered prudent fuel expenses versus a base rate. Costs eligible for the FAC will be the total fuel costs as allocated to Missouri for fuel consumed in generating units, including the costs associated with fuel hedging programs; purchased power costs excluding demand costs; and the net of ARR/TCR/FTR activity as well as emission allowance costs and revenue. These costs will be off-set by sales activity in the SPP Integrated Marketplace.
>
> Actual costs will be accumulated during the 6 month Accumulation Period, These costs will be used to determine the Cost Adjustment Factor (CAF) that will be filed with the Missouri Public Service Commission and upon their approval will be applied to retail customer billings during the appropriate Recovery Period.

Empire's strategy description then describes that the focus of Empire's hedging strategy is to address volatility of prices to provide for predictable fuel and purchased power costs for Empire over a multi-year period and to allow for management of the Company's risk positions.

> The electric segment's strategic focus addresses the volatility of natural gas prices by attempting to protect against volatile natural gas costs for the electric segment's plants. The electric segment will apply risk management strategies in an attempt to lessen the risks associated with variances in the volume of fuel consumed relative to budgeted fuel consumption volume.
>
> The electric segment's specific hedge strategy goals are to provide for predictable fuel and purchased power costs over a multi-year period and to provide a framework to allow for management of its risk positions.

Next in its strategy, Empire provides the objectives of the strategy. Again the strategy focuses on mitigating impacts and being able to estimate fuel costs. This is the only time minimization of cost is mentioned and then it is tempered with minimization of volatility:

> ** **<u>The RMP is designed to provide the Supply Management Group (SMG) with a more comprehensive set of tools to mitigate the adverse impacts associated with changing natural gas or wholesale electricity prices.</u>**

> **Risk management strategies involve an active "mark-to-market" assessment of market conditions to match its supply portfolio to its portfolio of retail and wholesale activity.**
>
> **In effect, these strategies set out to determine how much market risk is reasonable to best minimize costs and volatility, while still providing the electric segment with reasonable fuel costs.** **

While the next section has a heading that suggests it will now provide an overview of its "hedging targets" it in fact describes how an expected natural gas burn will be determined. An overview of the electric segment's hedging targets for natural gas is outlined below:

> ** **At least yearly, the electric segment will model its electric system with a production cost model to establish an expected gas burn for each of the next four years. This budgeted gas burn will be developed utilizing a consistent methodology as that utilized in the Company's financial projections.**
>
> **From time to time as conditions change (i.e. unit outages, gas commitments, purchase power prices), the SMG shall assess the electric segment's system to establish a new "expected" gas burn for market participation.** **

The hedging strategy then describes the hedging tools that may be used by Empire.

> ** **For the electric segment's purposes hedging includes physical forward purchases, physical management tools such as pipeline imbalance tariffs, park and loan, interruptible storage, OTC swaps and exchange traded financial contracts.**
>
> **Firm storage, due to inherent injection and withdrawal restrictions and requirements to reduce inventory levels during certain periods of the year, will be considered as operational (daily balancing and reliability tool for the electric segment) and not part of the hedging plan. Although there will be occasions when favorable market conditions exist and gas will be purchased and put into firm storage, this cannot be predicted and built into the hedging plan.** **

Finally Empire lays out its hedging targets.

> The electric segment will utilize the following procurement guidelines:
>
> ** **Hedge a minimum of 10% of year four expected gas burn**
> **Hedge a minimum of 20% of year three expected gas burn**
> **Hedge a minimum of 40% of year two expected gas burn**
> **Hedge a minimum of 60% of year one expected gas burn** **
>
> ** **The SMG will have the flexibility to hedge up to 100% of the current year and 80% of any future year's expected requirements while remaining cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty in required volumes, counterparty credit, etc. should also be considered.** **
>
> ** **(By December 31 of current year we should have a minimum of 60% of the next years projected gas burn hedged.)** **
>
> ** **This progressive dollar cost averaging approach is intended to protect our customers and shareholders from volatility in the marketplace. In addition, the progressive approach allows for increasing uncertainty of gas needs inherent in forecasting events occurring further in the future.** **
>
> ** **If changes in expected gas burns occur that make us more than 100% hedged in any given month, appropriate steps will be taken following consideration of accounting guidance and review by the RMOC. Given that there is some uncertainty in our modeling efforts, an over-hedged position of 50,000 MMBtu's or less would generally not be considered material and not subject to action.** **

The only mention of Empire's customers is contained in this section of the hedging strategy. This section states the "intention" of the strategy is to protect the customers *from volatility in the marketplace*. There is no mention of minimization of costs for the customers in Empire's hedging strategy nor the mention of the only valid purpose of an electric utility hedging program – to protect against natural gas price spikes. When minimization of costs is mentioned earlier in the hedging strategy, it is clear that it is referring to minimizing costs to the electric segment of Empire.

**Q. Wouldn't that minimize costs to the customer too?**

A. Not necessarily. Because of the FAC, minimizing the cost to the electric segment of Empire is done by minimizing the difference between the actual natural gas cost and the natural gas costs included in Empire's base electric utility rates.

**Q. Why does the Company base its hedging strategy on volume as opposed to natural gas market risks?**

A. Empire started hedging natural gas long before the Commission addressed hedging to mitigate upward natural gas price spikes for Missouri's gas companies.[7] Empire was attempting to combat regulatory lag and provide price certainty. Its Energy Risk Management Policy dated August 21, 2003 and quoted below provides a different opening paragraph to its Hedge Strategy section than the current, January 14, 2015 written policy:

**2003:**

> ** **"EDE's Missouri and Kansas retail rates are not subject to a fuel cost adjustment clause. As such, the only time EDE's rates are adjusted for changes in fuel costs is during a rate proceeding. The regulatory schedule for a rate proceeding in Missouri requires 11 months from the date of filing before new rates come into effect. Adding preparation time for a rate case, this period could stretch to 12 or 13 months. This regulatory schedule combined with the volatility of natural gas necessitates that EDE focus on procuring fuel over periods longer than 18 months to help prevent EDE's revenues from lagging its costs....**
>
> **EDE's specific hedge strategy goals are to provide for predictable fuel and purchased power costs over a multi-year period and to provide a framework to allow EDE to manage its risk positions."** **

[7] 4 CSR 240-40.018 Natural Gas Price Volatility Mitigation(1)(A)originally filed May, 2003 also 4 CSR 240-20.090 Electric Utility Fuel and Purchased Power cost Recovery Mechanisms filed June, 2006



HC

In 2003, the Company hedged for regulatory lag and price certainty to help manage its risks. Empire was not focused on protecting the ratepayer from price spikes, rather it was focused on what it could recover in a rate case given regulatory lag. Now that the Company has a FAC, these opening paragraphs have been replaced with a description of the FAC but nothing within the policy is different.[8] As Mr. Blake Mertens, Vice President of Energy Supply and Delivery Operations for Empire Electric attest to in his surrebuttal in Case No. ER-2016-0023:

**Q. Does Empire have a comprehensive hedging policy in place?**

A. Yes. Empire first implemented its Energy Risk Management Policy ("RMP") in 2001. While slight modifications have been made throughout the years largely to update organizational or nomenclature changes, the most substantive of which was prior to the SPP IM going live to reflect changes in daily processes and reflect transmission congestion rights procurement practices, our natural gas hedging policy and practices have remained consistent.[9]

**Q. How is Empire having the same policy concerning natural gas purchases for over the past 16 years imprudent?**

A. The question of prudency comes in when it is realized that the Company has not changed its business policies or its practices regarding hedging while the regulatory environment and natural gas volatility and prices have changed significantly. The Company now has an FAC. Gas prices and volatility are at lows and are predicted to stay low for several more years. The Southwest Power Pool ("SPP") has initiated the Integrated Market in 2014 garnering a mention in the opening paragraphs of the hedging strategy, yet the Company keeps plowing ahead with the same hedging strategy when it should have stepped back and reviewed the business climate and natural gas forecasts. As the Commission points out within the prudence standard: "**our responsibility is to**

[8] Please review the Hedging Strategy Section quoted on page 7 of this testimony
[9] Mertens surrebuttal, page 2, first question

**determine how reasonable people would have performed the tasks that confronted the company"**[10] (emphasis added)

The facts show that, due to the Company's inflexible and unreasonable hedging strategy that resulted in millions of dollars in excessive natural gas costs, Empire conducted its natural gas purchases in an imprudent way. Given the fact that Empire's 2003 hedging strategy was to defeat regulatory lag, a reasonable person would never had made those transactions if they had not had the ratepayer as their backstop when predictions showed lower gas prices in the future.

**Q. How can the OPC make this argument when the Company has been adhering to this policy for 16 years?**

A. First of all, the Company never initiated this policy to save the ratepayer any money. It did not begin hedging to prevent ratepayer shock, pain or to protect the ratepayer from gas cost volatility. As I pointed out before, Empire implemented this policy (2001) prior to the Commission formalizing concerns about price spikes (2003) and when Empire was allowed an FAC (2008). The Company policy has never changed and its hedging practices have never changed. ** **Empire consistently, hedged 10% of year four expected burn, 20% of year three burn, 40% of year two burn and 60% of year one expected burn.** ** If a company like Empire is hedging greater than ** 60% ** of its gas needs then its hedging program is a budgeting forecaster, not a price spike mitigator.

Secondly, without highly volatile natural gas prices, this method of hedging becomes very transparent for its simplicity and cost to the ratepayer. When the hedging strategy section of the RMP is reviewed it is clear that this hedging method is a "lock and leave" approach where there is no real strategy and no loss limits or market considerations to

[10] Quote from page 2 of this testimony. *State ex rel. Associated Natural Gas Co. v. Public Service Commission of State of Missouri*, Western District Court of Appeals summarization

guide the decision making. The policy is non-discretionary and should be considered imprudent on its execution alone.

**Q. Could you explain the "lock and leave" strategy?**

A. In the case of Empire's policy, the company has a predetermined minimum percentage of its expected volume that it will hedge. As this portion of its Hedging Strategy section illustrates:

The electric segment will utilize the following procurement guidelines:

**** Hedge a minimum of 10% of year four expected gas burn**
**Hedge a minimum of 20% of year three expected gas burn**
**Hedge a minimum of 40% of year two expected gas burn**
**Hedge a minimum of 60% of year one expected gas burn**

**The SMG will have the flexibility to hedge up to 100% of the current year and 80% of any future year's expected requirements while remaining cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty in required volumes, counterparty credit, etc. should also be considered.**

**(By December 31 of current year we should have a minimum of 60% of the next years projected gas burn hedged.) ****

Empire's policy is to hedge four years ahead for any given period by hedging a set amount of volume for years 1, 2, 3 and 4. As these instructions point out, the prescribed percentages should be transacted by the year end. After reviewing its records I have found that the Company practice is to lock in purchases for year one much earlier than year end. There are no considerations other than volume and no instructions for adverse market conditions, budgets or losses. There is flexibility to hedge more volume but not less so at least the minimum amount is **locked** in and **left** in place to accept the prevailing market conditions. The problem is that the market conditions, that may have been favorable for hedging when this policy was first set in place in 2001, were not favorable for this kind of programmatic hedging once the market settled and prices began declining. The results became even more exasperated by purchasing years in advance.

**Q. Empire's hedging strategy seems pretty straight forward and they have been executing this strategy for 16 years. What specifically makes this an imprudent practice?**

A A finding of imprudence is due to the combination of natural gas price decline with extremely long range (four years or greater) gas purchases at prices well above current and forecasted prices. As I pointed out earlier in testimony, prices have been declining for years and the major factor for this is the increased production causing near record storage. Merriam Webster's Dictionary defines imprudent as "not prudent: lacking discretion, wisdom, or good judgment, an imprudent investor"[11]

Empire recognized that prices were declining at least as early as 2009[12] yet it was still placing hedges 18-36 months in advance. In a prime example of the Company's lock and leave hedging strategy: in December of 2011, Empire hedged over ** **1 million Dekatherm ("Dth") (11% of expected volume) to be delivered in 2015 at $5.44 MMBtu.** ** (see Schedule JSR-D-3). I am mindful that the prudence standard imposes "... reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight", but in December of 2011, natural gas was $3.17.[13]

Natural gas had not been above $5.00 since February of 2010. At the time, storage levels were 12% above the 5 year average. The monthly average price for gas in 2011 had been falling nearly every month and December was the lowest average price of the year. The

[11] Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/imprudent.
[12] See quote from EW-2013-0101
[13] $3.17 was the monthly average price on the Henry Hub reported by EIA

December 2011 EIA Short Term Energy Outlook report revised the upcoming 2012 spot prices downward from their predictions from a few months before.[14]

A reasonable person under these circumstances would not purchase gas for a price not seen in almost two years, to be delivered more than three years down the road. At the time, Empire paid $5,494,400 for fuel that in 2015 (more than two years later) would have cost $2,565,400. The loss of $2,929,000 doubled the price and left it to the ratepayer to foot the bill for decisions that lacked discretion, wisdom or good judgment while Empire enjoyed an FAC that ran those costs, along with interest, through to the ratepayer in less than six months.[15] This indeed was cost minimization to Empire because it absorbed very little of this cost.

This is not an isolated incident. OPC attached the Company's gas summary reports for every month of the prudence review as JSR-D-4. These reports show the Company lost money in every month it hedged.[16]

**Q. What was the full impact of the financial hedging losses for the prudence review period?**

A. OPC concurs with Staff witness Ashley Sarver and finds that the financial hedging losses were $10,712,168 but OPC disagrees with Staff's calculations concerning the total amount of hedging losses and the calculation of the true amount of natural gas fuel costs during the 18 month period.

**Q. How did OPC calculate fuel costs?**

A. OPC doesn't question any of the Staff calculations but would rather point out that there is a difference between actual natural gas fuel and other costs that may be accounted for as

[14] December2011 EIA Short Term Energy Outlook page 1
[15] $2.54 was used from the June 30, 2015 Company Gas Position Summaries to calculate the differences
[16] Empire did not hedge in 1 of the 18 months.

a natural gas fuel expense. Hedging transactions are specific to just the cost of the natural gas commodity. The Company does not hedge firm transportation, commodity charges or miscellaneous fees. Hedging gains or losses should be reviewed against only natural gas commodity costs.

In the Sixth Prudence Review of Costs, Staff summarized the hedging review with:

> …a hedging loss on natural gas derivatives of $10,712,168. This represents approximately fifteen percent of Empire's total natural gas cost of $69,301,828 for the review period.[17]

The $69 million represents all natural gas fuel costs lumped together. When all of the non-fuel expenses are subtracted, the actual natural gas fuel costs are $49,677,485. When financial hedging losses are compared to actual fuel costs, the cost of hedging is 21.56% of natural gas fuel costs. This 21.56% premium paid by Empire's ratepayers is just the premium paid on financial hedges and does not include the premium paid on physical hedges.

**Q. Has OPC calculated a higher amount of total hedging losses than Staff?**

A. Yes. Financial hedges are the losses that are actually recorded in FERC Account 547 but the Company did more than NYMEX Swaps and Futures. In most months the Company also hedged the price of natural gas through forward contracts. They negotiated contracts sometimes several years in advance just like they did with the financial derivatives. The financial hedging and physical hedging are broken out in separate sections on the Gas Position Summary Reports that are attached to this testimony. Financial hedging is recorded on the general ledger, however, physical hedges are not required to be separated.

To isolate the cost of physical hedges, I used the Company's answer to Staff data request number 31 to calculate the cost of physical hedging for each month in the review period. I have attached the spreadsheet as Schedule JSR-D-5. In this spreadsheet, the Company

[17] Page 16 of the Staff Report

separated the true cost of natural gas by subtracting derivative losses and transportation charges. Dividing that total by the amount of natural gas consumed provides the natural gas cost/MMBtu. To calculate the cost of physical hedges, I inserted the spot market price that the Company paid in each month just below the cost/MMBtu line. This amount was generated from the monthly gas purchase report the Company submits each month as part of its FAC reporting requirements. Multiplying the spot price with the amount consumed provides the completely unhedged cost of natural gas for each month. Subtracting the "cost at spot price" from the "net actual commodity cost" determines the physical hedging total for each month. The sum of the physical hedging for the prudence review period is $6,073,353. Adding the physical hedges with the financial hedging losses and the total amount of hedging losses for the 18 month prudence period is $16,785,521 of which $13,104,811is attributable to Missouri ratepayers.

I explained earlier that the actual fuel cost from Staff's $69 million fuel expense was $49,677,485. The physical hedging of $6,073,353 is included in the $49 million because physical hedging is not required to be separated from the purchase price. The actual unhedged cost of natural gas for the period should be $43,604,132. Staff reported that hedging losses represented 15% of Empire's total natural gas cost. When in actuality, Empire's hedging losses which were passed to the customers through the FAC represent 38.5% of actual natural gas fuel costs.[18]

Q. **Can you summarize the argument for imprudence?**

A. Empire's hedging is inefficient, ineffective, inflexible and very much imprudent. Empire developed its hedging policies in 2001 in a volatile natural gas market. The natural gas market has changed significantly but Empire's hedging strategy, by its own admission, has not changed at all.

[18] $16,785,522/$43,604,132

When considering all the information that the Company had or should have had at its disposal, coupled with the rigid, 16 year old hedging policy that has not changed with the market's low gas prices and the adoption of an FAC, the Commission should find these transactions imprudent and return these imprudent hedging costs back to its customers with interest.

**Q. Does this conclude your direct testimony?**

A. Yes it does.

eia U.S. Energy Information Administration

# NATURAL GAS



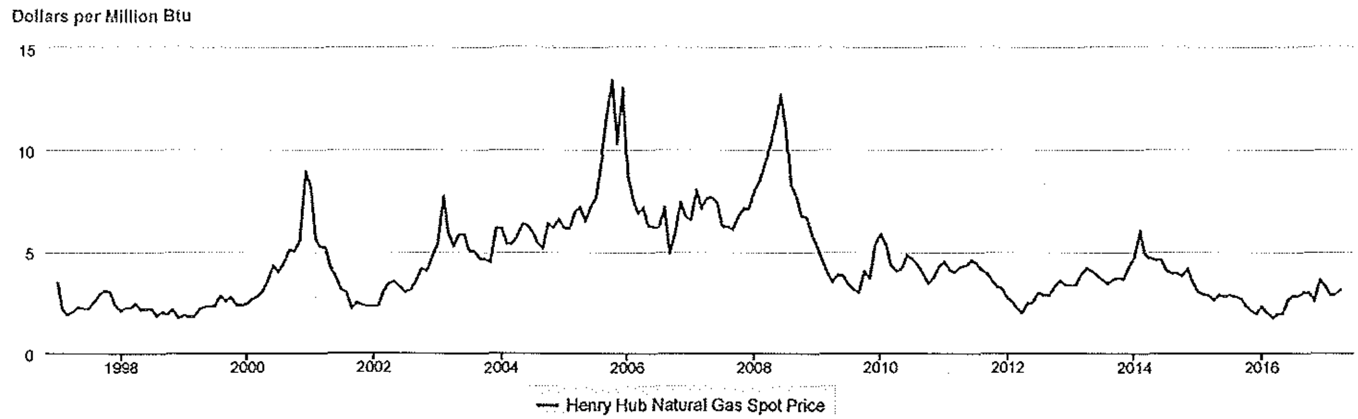
Referring Pages:

- Natural Gas Futures Prices (NYMEX)

View History: Daily Weekly Monthly Annual     Download Data (XLS File)

## Henry Hub Natural Gas Spot Price

DOWNLOAD




THOMSON REUTERS

Chart Tools

no analysis applied

This series is available through the EIA open data API and can be downloaded to Excel or embedded as an interactive chart or map on your website.

**Henry Hub Natural Gas Spot Price (Dollars per Million Btu)**

| Year | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1997** | 3.45 | 2.15 | 1.89 | 2.03 | 2.25 | 2.20 | 2.19 | 2.49 | 2.88 | 3.07 | 3.01 | 2.35 |
| **1998** | 2.09 | 2.23 | 2.24 | 2.43 | 2.14 | 2.17 | 2.17 | 1.85 | 2.02 | 1.91 | 2.12 | 1.72 |
| **1999** | 1.85 | 1.77 | 1.79 | 2.15 | 2.26 | 2.30 | 2.31 | 2.80 | 2.55 | 2.73 | 2.37 | 2.36 |
| **2000** | 2.42 | 2.66 | 2.79 | 3.04 | 3.59 | 4.29 | 3.99 | 4.43 | 5.06 | 5.02 | 5.52 | 8.90 |
| **2001** | 8.17 | 5.61 | 5.23 | 5.19 | 4.19 | 3.72 | 3.11 | 2.97 | 2.19 | 2.46 | 2.34 | 2.30 |
| **2002** | 2.32 | 2.32 | 3.03 | 3.43 | 3.50 | 3.26 | 2.99 | 3.09 | 3.55 | 4.13 | 4.04 | 4.74 |
| **2003** | 5.43 | 7.71 | 5.93 | 5.26 | 5.81 | 5.82 | 5.03 | 4.99 | 4.62 | 4.63 | 4.47 | 6.13 |
| **2004** | 6.14 | 5.37 | 5.39 | 5.71 | 6.33 | 6.27 | 5.93 | 5.41 | 5.15 | 6.35 | 6.17 | 6.58 |
| **2005** | 6.15 | 6.14 | 6.96 | 7.16 | 6.47 | 7.18 | 7.63 | 9.53 | 11.75 | 13.42 | 10.30 | 13.05 |
| **2006** | 8.69 | 7.54 | 6.89 | 7.16 | 6.25 | 6.21 | 6.17 | 7.14 | 4.90 | 5.85 | 7.41 | 6.73 |
| **2007** | 6.55 | 8.00 | 7.11 | 7.60 | 7.64 | 7.35 | 6.22 | 6.22 | 6.08 | 6.74 | 7.10 | 7.11 |
| **2008** | 7.99 | 8.54 | 9.41 | 10.18 | 11.27 | 12.69 | 11.09 | 8.26 | 7.67 | 6.74 | 6.68 | 5.82 |
| **2009** | 5.24 | 4.52 | 3.96 | 3.50 | 3.83 | 3.80 | 3.38 | 3.14 | 2.99 | 4.01 | 3.66 | 5.35 |
| **2010** | 5.83 | 5.32 | 4.29 | 4.03 | 4.14 | 4.80 | 4.63 | 4.32 | 3.89 | 3.43 | 3.71 | 4.25 |
| **2011** | 4.49 | 4.09 | 3.97 | 4.24 | 4.31 | 4.54 | 4.42 | 4.06 | 3.90 | 3.57 | 3.24 | 3.17 |
| **2012** | 2.67 | 2.51 | 2.17 | 1.95 | 2.43 | 2.46 | 2.95 | 2.84 | 2.85 | 3.32 | 3.54 | 3.34 |
| **2013** | 3.33 | 3.33 | 3.81 | 4.17 | 4.04 | 3.83 | 3.62 | 3.43 | 3.62 | 3.68 | 3.64 | 4.24 |
| **2014** | 4.71 | 6.00 | 4.90 | 4.66 | 4.58 | 4.59 | 4.05 | 3.91 | 3.92 | 3.78 | 4.12 | 3.48 |
| **2015** | 2.99 | 2.87 | 2.83 | 2.61 | 2.85 | 2.78 | 2.84 | 2.77 | 2.66 | 2.34 | 2.09 | 1.93 |
| **2016** | 2.28 | 1.99 | 1.73 | 1.92 | 1.92 | 2.59 | 2.82 | 2.82 | 2.99 | 2.98 | 2.55 | 3.59 |
| **2017** | 3.30 | 2.85 | 2.88 | 3.10 | | | | | | | | |

Schedule JSR-D-1

# THE EMPIRE DISTRICT ELECTRIC COMPANY

## ENERGY RISK MANAGEMENT POLICY

*January 14, 2015*

*Services You Count On*

## THE EMPIRE DISTRICT ELECTRIC COMPANY
## ENERGY RISK MANAGEMENT POLICY

### TABLE OF CONTENTS

# 1 STANDARDS OF OVERALL COMPANY PROGRAM

## INTRODUCTION

The purpose of the Energy Risk Management Policy (RMP) document is to define the approach and internal rules that The Empire District Electric Company (Company) will utilize to manage its power and natural gas commodity risk. The content of this document establishes and describes the Company policy in assuming, assessing, and controlling the level of natural gas commodity and power price risk exposure involved in the Company's core business activities.

## OBJECTIVES

It is the policy of the Company NOT to engage in financial or commodity transactions unless they are related to the procurement of natural gas or power for end-use customers or minimizing the overall cost for end-use customers. It is the express intention of the Company to prohibit financial or physical commodity transactions that would reasonably be considered outside of the Company's core business activities.

The following are specific RMP objectives for the Company that represents a balanced financial and operational focus:

### OBJECTIVE #1

*Provide an organizational structure to support management goals and budget performance by mitigating energy price volatility and; hence, limiting fluctuations in the cost of supplying energy to retail customers.*

The RMP provides an organizational structure for effectively assessing and managing risk associated with the Company's natural gas supply for fuel, commodity sales and wholesale power activities. It provides a framework for effective control, audit, and reporting. The procedures set forth allow for the management of operational risks without placing undue restrictions on the operations of the Company.

### OBJECTIVE #2

*Allow utilization of physical and financial tools to provide a predictably priced reasonable cost gas-supply.*

For the electric segment the cost to generate, purchase, and sell power is greatly impacted by fluctuations in the market price of energy sources such as coal, natural gas, oil, and wholesale electricity. This RMP outlines procedures on how hedge positions will be employed to limit these market fluctuations in the price of natural gas and provide the Company with tools to manage expenses to generate, purchase, and sell power on behalf of its customer base.

For the gas segment, the cost of natural gas supplies is greatly impacted by fluctuations in the market price of natural gas. This RMP outlines procedures on how hedge positions will be employed to limit these market fluctuations and provide the Company with tools to manage price volatility with regards to the purchase and supply of natural gas for its customer base.

OBJECTIVE #3

*Allow utilization of physical and financial tools to provide a predictably priced reasonable cost power-supply.*

For the electric segment the cost to provide power is impacted by fluctuations in transmission congestion due to limitations on the physical grid. This RMP outlines procedures on how the company will utilize financial rights that are awarded based on investment in the transmission system to limit exposure and provide value to the customer base.

## 2. RESPONSIBILITY FOR ENERGY RISK MANAGEMENT POLICY

The Officer Group as listed below is responsible for maintaining and overseeing the RMP:
The Officer Group is comprised as follows:

President and CEO
Vice President - Finance and CFO
Vice President/COO – Gas
Vice President/COO - Electric
Vice President - Energy Supply
Vice President - Commercial Operations

From time to time, the Officer Group will report to the Board of Directors on the risk management activities surrounding natural gas and power risk. Officer Group activities shall include:

- Providing the Risk Management Oversight Committee (RMOC) authorization to engage in those activities consistent with prudent risk management and related trading practices which correlate with serving customers energy needs for both the electric and gas segments;
- Recognizing financial instruments such as futures, swaps, options, Auction Revenue Rights, Transmission Revenue Rights, and Financial Transmission Rights as well as financial and physical market position management, can be effective transaction tools; and
- Providing sufficient management involvement, financial controls, and systems to monitor, report, and ensure the integrity of the RMP at all levels.

## RISK MANAGEMENT OVERSIGHT COMMITTEE

*The RMOC is charged with monitoring aggregate risks and ensuring they are managed in accordance with the RMP. The RMOC will meet periodically to assess aggregate risks and review EDE's market positions and exposures and strategy.*

The RMOC is comprised as follows:
Chairman
Vice President - Finance and CFO
Members:
Vice President/COO – Gas
Vice President/COO - Electric
Vice President - Energy Supply
Controller and Assistant Treasurer and Secretary
Director of Supply Management

Non-Voting Internal Control Members:
President and CEO (see exceptions at Appendix 12)
Director of Internal Audit
Manager of Fuel & Revenue Accounting
Manager of Gas Supply

Manager of Market Operations
Manager of Market Settlements & Systems
Supply Management Specialists (Specialists)
Planning Analyst – Supply Management

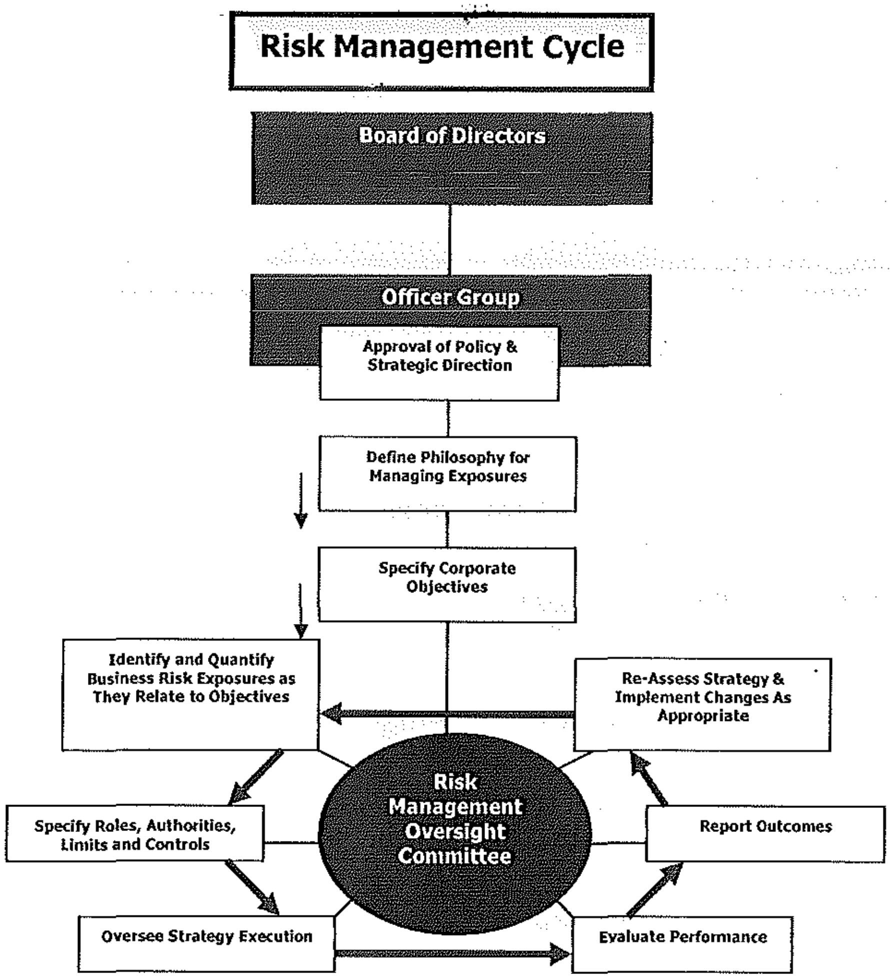
RMOC RESPONSIBILITIES

- **Approve Hedging Strategies** - Develop and approve strategies that achieve risk management objectives.
- **Individual Trading Authorization** - Approve a list of individuals authorized to establish trading relationships and execute trades. The hierarchy of oversight will include opening futures accounts, executing International Swap Dealer Association (ISDA) master agreements, placing futures orders, and entering into transactions per a master swap agreement. (See Appendix 12: Supply Management Specialist Authorization.)
- **Approve LTCR/ARR/TCR/FTR Procurement Strategies** – Approve strategies that mitigate transmission congestion exposure and provide value to the customer base.
- **Set Transaction Exposure Limits** - Approve limits on volumes and length of coverage of all outstanding physical, financial, virtual, futures, options, and Over-the-Counter (OTC) positions.
- **Ensure Credit Approval and Documentation** - The credit approval/ monitoring process is described in Appendix 1: Credit Risk / Procedures Policy.
- **Establish Procedures and Develop Reporting Systems** - Ascertain appropriate checks and balances are in place and financial reporting is correct.
- **Establish Approved Counterparty List** - Establish an approved counterparty trading list.

Any member of the RMOC has authority to call committee meetings and the responsibility to ensure that all activities are in accordance with this program. The committee may meet in person, through telephone conference calls, and/or electronic mail. The RMOC secretary (who is not a member of the RMOC) will keep regular minutes and records of meetings and actions.

At any time a RMOC member believes the committee has failed to adequately address a situation in which the member believes price or credit speculation is taking place, that member shall submit a written statement describing the concern to the President and CEO or the Director of Internal Audit.

RMOC CYCLE




## 3 RISK

### COMPANY/CUSTOMER EXPOSURE

Effective September 1, 2008, the electric segment was granted a fuel adjustment clause (FAC) for its Missouri customers. The FAC allows the electric segment to recover/refund 95% of prudent fuel and purchased power costs versus a base rate established in rate case ER-2008-0093 and any future rate cases. The Company/Customer's exposure spans activity in both the physical fuels market and the financial derivative markets that have developed to accommodate natural gas and power. Without risk management, the Company will be subject to cost and pricing uncertainty, as well as uncertainty in meeting budgeted earnings and cash flow.

The primary components of the Company'/Customer's risk exposure are operations risk, market risk, and credit risk. The RMP is designed to address the management of these risks in the aggregate.

Individual transactions for the electric segment and for the gas segment shall be transacted for the benefit of each party.

## OPERATIONS RISK

The potential increased cost for items such as: changes in load or generation capabilities, providing replacement power and natural gas due to the unscheduled outage of generation plants, interruptions of power purchases from other parties, or interruption of gas supply.

## MARKET RISK

The potential change in value of a commodity contract, liability, or cash flow caused by adverse fluctuations in market factors over a pre-defined holding period. Types of market risk include:

- **Price Risk** - Uncertainty associated with changes in the price level of power costs and commodity fuel costs.
- **Liquidity Risk** - Risk associated with the diminished market activity of a fuel commodity or transmission congestion instrument.
- **Volume Risk** - Supply or demand deviation from forecast (for example, the risk of not having enough or having too much natural gas to meet forecasted obligations). Volume risk is highly correlated with price risk because availability of wholesale electricity and natural gas is high and priced low when the weather is mild causing reduced volume need. Conversely, when weather is extreme causing an increase in our underlying needs, the price of wholesale electricity and natural gas may increase exponentially.
- **Calendar Risk** - Exposure due to time differential in commodity value between actual physical delivery and financial position expiration.
- **Basis Risk** - Exposure due to a difference in commodity value between different delivery points or markets, between cash market prices and the pricing points used in the financial markets, or the difference in the marginal congestion component between different settlement locations.

## COUNTERPARTIES/CREDIT RISK

Managing credit/counterparty risk exposure is an important component in EDE's overall risk management program. The Company/Customer's exposure is different when transacting in clearinghouses, marketplaces, or OTC counterparts.
The creditworthiness of trading partners or clearinghouses is a function of both qualitative and quantitative factors. Such factors are centered on the credit rating assigned to a company by major credit rating services and an evaluation of the company's ability to financially meet its obligations to the Company. Typical sources of credit-related information are credit rating reports (published by one or more of the

commonly recognized rating agencies, such as Dunn & Bradstreet, Standard & Poor's, or Moody's), general market intelligence, electronic news releases, and other public information sources. Based on these resources, the RMOC will provide oversight as to each approved counterparty's credit exposure limit.

Credit risk associated with maintaining an account with a futures clearinghouse is considerably less than that with OTC counterparts. This distinction exists because the collective clearinghouse members of NYMEX, which includes virtually every major energy company and financial institution in the country, guarantee the performance on all positions placed on the exchange. Requiring margin deposits and daily mark-to-market by clearinghouse members allows for incremental monitoring and control of transactions and eliminates the potential for sudden defaults on contracts.

Credit risk associated with SPP Market Participant (MP) default is considerably less than that with OTC counterparts. This distinction exists because the collective members of SPP share in the costs of the default by any one member. Furthermore, SPP performs a daily calculation of a Total Potential Exposure and a total TCR credit requirement for each market participant, allowing for incremental monitoring and control of transactions and eliminates the potential for sudden defaults on contracts by market participants. Additionally, SPP's TCR credit requirement is secured through a cash deposit or Irrevocable Letter of Credit[1]. This financial security is maintained for TCR activity and is not included in the Total Potential Exposure determination, but is reflected in the determination of whether there is a Total Potential Exposure violation.

<u>ESTABLISHING CREDIT RESPONSIBILITIES</u>

As defined in Appendix 1 - Credit Risk / Procedures Policy, establishing limits and creditworthiness monitoring will be done independent of the trading function and will be performed by the Manager of Fuel Accounting (MAF) in Finance (with oversight by the RMOC), in order to guarantee appropriate segregation of duties within the Company. All trading activity with a particular counterparty who no longer meets the Company's credit standards will be halted. A Counterparty Credit Exposure Report will be included as part of the weekly Gas Position Report described later. The report will summarize the total amount of exposure by counterparty by hedging instrument based on current mark-to-market amounts.

## 4. HEDGE STRATEGY

### Electric Segment

Prior to September 1, 2008, the electric segment's Missouri retail rates were not subject to a fuel cost adjustment clause. Effective September 1, 2008 regulators granted a fuel adjustment clause (FAC) for recovery/refund of 95% of prudent fuel expenses versus a base rate established in rate case ER-2008-0093 and any future rate cases.

[1] Appendix X Article 7; SPP Credit Policy

The Missouri FAC allows Empire to recover 95% of under-recovered prudent fuel expenses and return to customers 95% of any over-recovered prudent fuel expenses versus a base rate. Costs eligible for the FAC will be the total fuel costs as allocated to Missouri for fuel consumed in generating units, including the costs associated with fuel hedging programs; purchased power costs excluding demand costs; and the net of ARR/TCR/FTR activity as well as emission allowance costs and revenue. These costs will be off-set by sales activity in the SPP Integrated Marketplace.

Actual costs will be accumulated during the 6 month Accumulation Period, These costs will be used to determine the Cost Adjustment Factor (CAF) that will be filed with the Missouri Public Service Commission and upon their approval will be applied to retail customer billings during the appropriate Recovery Period.

The electric segment's strategic focus addresses the volatility of natural gas prices by attempting to protect against volatile natural gas costs for the electric segment's plants. The electric segment will apply risk management strategies in an attempt to lessen the risks associated with variances in the volume of fuel consumed relative to budgeted fuel consumption volume.

The electric segment's specific hedge strategy goals are to provide for predictable fuel and purchased power costs over a multi-year period and to provide a framework to allow for management of its risk positions.

The RMP is designed to provide the Supply Management Group (SMG) with a more comprehensive set of tools to mitigate the adverse impacts associated with changing natural gas or wholesale electricity prices.

Risk management strategies involve an active "mark-to-market" assessment of market conditions to match its supply portfolio to its portfolio of retail and wholesale activity.

In effect, these strategies set out to determine how much market risk is reasonable to best minimize costs and volatility, while still providing the electric segment with reasonable fuel costs.

An overview of the electric segment's hedging targets for natural gas is outlined below.

At least yearly, the electric segment will model its electric system with a production cost model to establish an expected gas burn for each of the next four years. This budgeted gas burn will be developed utilizing a consistent methodology as that utilized in the Company's financial projections.

From time to time as conditions change (i.e. unit outages, gas commitments, purchase power prices), the SMG shall assess the electric segment's system to establish a new "expected" gas burn for market participation.

For the electric segment's purposes hedging includes physical forward purchases, physical management tools such as pipeline imbalance tariffs, park and loan, interruptible storage, OTC swaps and exchange traded financial contracts.

Firm storage, due to inherent injection and withdrawal restrictions and requirements to reduce inventory levels during certain periods of the year, will be considered as operational (daily balancing and reliability tool for the electric segment) and not part of the hedging plan. Although there will be occasions when favorable market conditions exist and gas will be purchased and put into firm storage, this cannot be predicted and built into the hedging plan.

The electric segment will utilize the following procurement guidelines:

- Hedge a minimum of 10% of year four expected gas burn
- Hedge a minimum of 20% of year three expected gas burn
- Hedge a minimum of 40% of year two expected gas burn
- Hedge a minimum of 60% of year one expected gas burn

The SMG will have the flexibility to hedge up to 100% of the current year and 80% of any future year's expected requirements while remaining cognizant of volume risk. The 80% guideline is an annual target and volumes up to 100% can be hedged in any given month. For years beyond year four, additional factors of long term uncertainty in required volumes, counterparty credit, etc. should also be considered.

(By December 31 of current year we should have a minimum of 60% of the next years projected gas burn hedged.)

This progressive dollar cost averaging approach is intended to protect our customers and shareholders from volatility in the marketplace. In addition, the progressive approach allows for increasing uncertainty of gas needs inherent in forecasting events occurring further in the future.

If changes in expected gas burns occur that make us more than 100% hedged in any given month, appropriate steps will be taken following consideration of accounting guidance and review by the RMOC. Given that there is some uncertainty in our modeling efforts, an over-hedged position of 50,000 MMBtu's or less would generally not be considered material and not subject to action.

**Gas Segment**

The gas segment's Missouri retail rates are subject to a fuel cost adjustment clause. The gas segment is permitted to file an Actual Cost Adjustment (ACA) once a year which also includes a Purchased Gas Adjustment (PGA) filing. In addition to the ACA filing, three more optional PGA filings are allowed during the year. The gas segment's ACA year is from September 1 thru August 31 for each year. For purposes of the following discussion, a hedging year will coincide with the ACA time period.

Specific hedge strategy goals are to provide for predictable natural gas costs over a multi-year period and to provide a framework to allow the gas segment to manage price volatility for its customers.

The RMP is designed to provide the SMG with a more comprehensive set of tools to mitigate the adverse impacts associated with changing natural gas prices.

In effect, these strategies set out to determine how much market risk is reasonable to prudently minimize price volatility, while still providing the gas segment's customers with reliable and reasonably priced natural gas supply.

An overview of the gas segment's hedging targets for natural gas is outlined below.

At least yearly, the gas segment will model its natural gas systems with a natural gas usage model to establish expected natural gas usage for each of the next five years. This budgeted gas usage will be determined in a consistent manner with that utilized in the Company's financial projections.

From time to time as conditions change (i.e. new load profiles, new customers, plant expansions, plant closings), the SMG shall re-model the gas system to establish a new "expected" gas usage for native load.

The definition of the word "hedge" in this section shall be defined as including physical gas purchases, storage, as well as financial instruments.

The gas segment will utilize the following procurement guidelines to be implemented by the beginning of each hedge year:

- Hedge a minimum of 50% of year one's expected gas usage.
- Hedge up to 50% of year two's expected gas usage.
- Hedge up to 20% of year three's expected gas usage.

The SMG will hedge a minimum of 70% and have the flexibility to hedge up to 90% of each winter period's (November thru March) expected requirements while being cognizant of volume risk.

If changes in expected gas burns occur that make us more than 100% hedged in any given month, appropriate steps will be taken to reduce our hedged position to 100% or less following consideration of accounting guidance and review by the RMOC. Given that there is some uncertainty in our modeling efforts, an overhedged position of 50,000 MMBtu's or less would generally not be considered material and not subject to action.

The dollar cost averaging approach is intended to protect our customers from price volatility in the market place.

## 5. INTERNAL CONTROLS

Internal controls are essential in ensuring adherence to the RMP and include the authorization of acceptable instruments, limits, and credit standards. Additional checks and balances including segregation of departmental duties, market position monitoring, and a management reporting structure should be in place to verify and reconcile the integrity of the Company's risk management activity results. The Company's accounting policies and key controls relating to our hedging program are detailed in the Power & Fuel Cycle section of our Sarbanes/Oxley documentation.

## SEGREGATION OF DEPARTMENTAL RESPONSIBILITIES

An appropriate segregation of duties is fundamental in controlling the Company's risk management operations and includes activities such as approvals, verifications, and reconciliations. A clear separation between transacting, credit review and approval, margining and cash settlements, and accounting has been established with respect to the RMP.

The SMG, Finance, and Internal Audit are the departments most directly impacted by energy supply risk management activities.

## AUTHORIZATION PARAMETERS

### INSTRUMENTS

A primary responsibility of the RMOC is the review and approval of tools acceptable for implementation of the risk management strategy.

The various hedging instruments that the Company is authorized to use by this RMP is described as follows:

- **Physical Forward Contract** - Contract for future physical delivery of a designated quantity of a fuel source or power supply at a designated price, time, and location. Physical forward contracts obligate both the buyer and seller to accept the agreed-upon price, regardless of the market price when the delivery takes place. . All physical forward contracts are intended to constitute a normal purchase normal sale transaction as defined in Accounting Standard Codification 815-10-15 (25-39) (formerly FASB 133 paragraph 10). A normal purchase normal sale contract is one that provides for the purchase or sale of something other than a financial instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. These also comply with the normal purchase normal sale criteria for tax per IRS Regulation §1221(b)(2).
- **Futures Contract** - Standardized binding agreement to buy or sell a specified quantity or grade of a commodity at a later date. Futures contracts are freely transferable, can be traded exclusively on regulated exchanges, and are settled daily based on their current value in the marketplace.
- **Put Option / Call Option** - Contract giving the holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment. The contract also requires the writer, who receives the premium, to meet these obligations. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)

- **OTC Instrument** - Any financial or physical instrument that is customized and created by a counterpart to replicate the risk profile associated with a commodity. The OTC swap is a contractual agreement between two parties to exchange a series of cash flows, for a stipulated period of time, based on agreed-upon parameters and price fluctuations in some underlying commodity or market index. There is a monthly settlement price, which is the difference between the fixed price of the contract and the index price in the publication for that month's date. If the index price for the delivery period is higher than the fixed price of the OTC contract, then the seller pays the buyer the difference. If the index price is lower, the buyer pays the seller the difference. This policy approves the use of OTC forwards and options for natural gas and power. Power examples include: 5x16, 7x24, 5x8, 2x24, 7x8, 1x16, etc. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)

- **LTCR/ARR/TCR/FTR** - A financial instrument utilized to hedge the difference in the price of congestion between two settlement locations. An LTCR is a long-term (10 year minimum) congestion right providing a full year TCR into perpetuity with roll-over ability. An LTCR allocation is held prior to the ARR allocation and any awarded or retained LTCRs are automatically converted into TCR products which may either be held or sold for congestion management. An ARR is a financial right, awarded during the annual or monthly ARR allocation process that entitles the holder to a share of the auction revenues or charges generated in the applicable TCR/FTR auction. The ARR holder may then sell or self-convert/self-schedule the ARRs into TCR/FTR during the annual or monthly TCR/FTR auction. ARRs are either seasonal or monthly in duration and are either on or off-peak products. ARRs are priced per auction and settled daily with monthly and annual true-ups. A TCR/FTR is defined as a financial right that entitles the holder to a share of the Day-Ahead Marginal Congestion Component price differential between two specific settlement locations. TCR/FTRs are either seasonal or monthly in duration and are either on or off-peak products. TCR/FTRs are priced hourly and settled daily with monthly and annual true-ups. ARRs and TCRs may have negative or positive values. ARRs and TCRs may be underfunded hence may be valued more or less than the underlying asset. ARR,TCR, and FTR procurement will occur on paths native to Empires source/sink settlement locations. Empire may seek to obtain a TCR/FTR on a foreign path in the event that Empire is <u>both</u> 1) unable to secure a TCR/FTR to mitigate all or a portion of its expected congestion for a native path and 2) able to provide sufficient analysis demonstrating a high level of correlation with a path foreign to Empire's source/sink settlement locations.

- **Virtual Bids/Offer** – A proposal by a Market Participant to purchase or sell a specified quantity of energy at a specific price, settlement location, and period of time in the Day-Ahead market that is not associated with a physical resource or load. Virtual transactions are strictly financial and provide an opportunity to hedge physical load or generation. Empire may only seek a virtual bid or offer if the following conditions exist and/or are met: 1) uncertainty with expected load or physical supply (which will be logged daily in the *DA Operation Strategy Log*), 2) both source and sink settlement locations are native to Empires load and generation,

3) MW volume is less than or equal to the corresponding generator limits and/or day-ahead forecasted load (with consideration for forecasting error)

- **Demand Bid** – A set of price/quantity pairs that represent the financial offer to purchase energy from the Day-Ahead market at a specific settlement location and period of time. Demand bids are strictly financial and provide an opportunity to clear physical load in the Day-Ahead market. Empire may bid in energy demand in an amount not to exceed the forecasted load for the associated operating day, with consideration for forecasting error.

- **Bilateral Settlement Schedules** – A bilateral settlement schedule is a financial agreement between two market participants designating a purchaser and seller of an energy amount and settlement location for energy transactions or a purchaser and seller of an obligation percentage and reserve zone for operating reserve obligation transfer transactions. Empire may participate in a bilateral settlement schedule as a purchaser in an amount not to exceed the forecasted load for the associated operating day and only at native Empire sink settlement location(s). Empire may participate in a bilateral settlement schedule as a seller only at native Empire source settlement locations.

- **Import Transaction / Export Transaction** – An import transaction or export transaction is a proposed interchange transaction to purchase an amount of energy for delivery into or outside the SPP balancing authority at a specified location and period of time, respectively.

## LIMITS

AUTHORIZED TRADERS AND TRADING LIMITS

- **"Round Trip" Trades Prohibited** - "Round trip" transactions shall be strictly prohibited. Round trip transactions, as used herein, refer to simultaneous (or nearly simultaneous) energy purchases and sales of equal duration, price and volume in an attempt to influence the market. Employees engaging in such transaction shall be subject to progressive discipline up to and including termination of employment.

- **Off-Premise Trading** - Off-premise trading is not allowed. In the event of limited staff, one-time trades may be done off-premise with the approval of a senior officer.

Authorized traders, along with approval and transaction limits, are listed in Appendix 12.

## TRAINING

AUTHORIZED TRADER TRAINING

- **Market Participant Training** - All authorized traders transacting in markets or services provided pursuant to the SPP Tariff will receive, applicable annual training with regard to their participation under the Tariff as a condition of being authorized to transact on behalf of EDE.

## 6. POSITION REPORTING

### GAS POSITION REPORT

The Gas Position Report contains a list of all open and recently closed transactions for the Company's trade-based activity and serves as a crucial element of RMP control and management. The Gas Position Report has multiple applications for risk management review that includes account transaction tracking and evaluation as well as overall performance evaluation.

The Gas Position Report is updated as transactions occur and distributed weekly by the SMG. Its primary objectives are:

- Allow for marking individual transactions to market;
- Provide data for transactions as well as portfolio analysis; and
- Simplify accounting and program results evaluation through analysis of the closed positions list.

### CONGESTION POSITION REPORT

The Congestion Position Report contains the MW and $/MWh positions of all existing TCR/FTRs by: period (on-peak, off-peak), source and sink, and month. The Congestion Position Report will be created after the annual TCR/FTR auctions and will be updated monthly to include the monthly auction positions. The Congestion Position Report will include:

- Market value of TCR's/FTR's (TCR/FTR auction price if self-converted/self-scheduled)
- Percentage of TCR/FTR eligibility auctioned

### MARK-TO-MARKET

All positions will be mark-to-market (using the appropriate NYMEX prices or other suitable market indicator as defined by the underlying contract) weekly or as determined by the RMOC on the Gas Position Report by the SMG. This analysis is performed to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding the Company's market risk and exposure.

The SMG is responsible for updating the current market information in mark-to-market calculations through the Gas Position Report, with Finance performing a subsequent review as a check on this report's accuracy. On certain OTC positions, it may be difficult to obtain an accurate mark-to-market value. In these instances, the SMG will provide the best estimate of values and will identify the source and reliability of the data.

## ADDITIONAL MANAGEMENT REPORTING

Management reports are to be based on the principles of adequate compliance limit monitoring, accuracy of data sources, and frequency and quality of information. All reports should communicate the price risks assumed by the Company. Information pertaining to performance measurement and program evaluation will be included in required reports and will be used as a basis for RMOC discussions and future strategy setting.

### MINIMUM REPORTING REQUIREMENTS

The following table identifies the various reports to be generated by different departments or management levels, the normal regularity, and circulation of the document.

| Report | Distribution | Frequency | Originator |
|---|---|---|---|
| Gas Position Report | SMG, MFA , RMOC | Weekly & Quarter-end | SMG |
| ADMIS Account Statements via email | SMG, MFA | Daily - Others | RMI |
| RMOC Meeting Minutes | RMOC | As soon as possible after RMOC meeting (5-7 business days) | RMOC Secretary |
| Counterparty Credit Exposure Report | RMOC, SMG, MFA | Weekly | SMG (reviewed by MFA ) |
| Congestion Position Report | RMOC, SMG | Monthly (Post auction) | SMG |

SMG – Supply Management Group, MFA – Manager of Fuel Accounting, RMI – Risk Management Incorporated

On a quarterly basis the status of the Company's hedged positions and counterparty credit exposure will be reviewed with the Audit Committee of the Board of Director's.

## DISCIPLINE

Any violation by an employee of the RMP will be subject to the Progressive Discipline Policy as outlined in the Personnel Policy Manual of the Company.

## 7. POLICY REVIEW

On a periodic basis, the RMOC will review and mutually make a recommendation to the Officer Group on the adequacy of the RMP and any necessary changes.

## 8. CONFLICTS OF INTEREST

Personnel responsible for executing and managing the Company's trading activity will not be authorized to enter into energy-related commodity transactions on behalf of others or themselves unless specifically approved by the RMOC.

## 9. DUTIES AND WORK FLOW

Appendices are listed as follows:

- **Credit Risk and Procedures Policy - Appendix 1**
- **Duties for Supply Management Group - Appendix 2**
- **Duties for Finance - Appendix 3**
- **Duties for Auditing - Appendix 4**
- **Work Flow to Execute Trade - Appendix 5**
- **Procedure for Hedge Transactions and Reconciliation - Appendix 6**
- **Trade Ticket - Appendix 7**
- **Confirmation Procedure - Appendix 8**
- **Gas Position Report - Appendix 9**
- **Mark to Market Report - Appendix 10**
- **Broker Account Statement - Appendix 11**
- **Authorized Traders - Appendix 12**
- **Supply Management Group (SMG) – Purchase and/or Sale Pre-Approval Form – Appendix 13**

## APPENDIX 1

# THE EMPIRE DISTRICT ELECTRIC COMPANY

# CREDIT RISK/PROCEDURES POLICY

*January 10, 2011*

Services You Count On

## I: INTRODUCTION

The purpose of this policy is to establish a consistent process whereby the credit risk of future financial loss due to counterparty physical or financial non-performance is significantly diminished for energy purchases and / or sales. This Credit Risk/Procedures Policy will govern any energy transactions relating to natural gas and / or purchased power conducted by the Company.

## II: POLICY OVERVIEW

In general, all energy suppliers and / or purchasers will be subject to a financial review in accordance with the Company's standards for determination of creditworthiness. Evaluation of a company's financial strength and its ability to deliver its product or to pay is crucial.

A credit review cannot be viewed as the mechanism to prevent any and all losses, but it can help identify those companies where performance has been a problem in the past or may present a problem in the future. Established counterparty credit exposure limit triggers combined with proper monitoring oversight will help the Company to effectively mitigate possible losses due to counterparty insolvency.

## III: RESPONSIBILTIES

### *Risk Management Oversight Committee*

The Risk Management Oversight Committee (RMOC) shall give final approval for all credit policies and procedures. In today's business environment, a formularized credit rating approach for rating counterparties may not be practical. The RMOC will provide oversight by reviewing weekly Gas Position Reports produced by the Supply Management Group (SMG) and by formal discussions of counterparty credit limits, credit risk, credit exposure, etc. at the RMOC meetings. The Manager of Fuel Accounting will provide monthly credit rating status reports of counterparties. The SMG will report on credit exposure by counterparties in the weekly Gas Position Report.

### *RMOC Committee Members*

This group is defined in the Energy Risk Management Policy.

### *Manager of Fuel Accounting*

The Manager of Fuel Accounting (MFA) shall monitor the credit exposures created through the trading of energy and derivative products, and ensure that the RMOC is aware of any inappropriate credit exposure.

Primary Responsibilities include the following:

- On-going monitoring of existing counterparty credit/financial strength, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Monitor credit exposures created by the trading of energy and / or derivative products, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Oversee the development and administration of systems necessary to support the above activities
- Monitoring trade activity with each counterparty
- Monitor credit exposures with the RTOs created through the physical and financial positions maintained in the respective markets

### *Supply Management Group*

The Supply Management Group (SMG) optimizes the use of generation, purchased power and natural gas as outlined in the Energy Risk Management Policy.

Primary Responsibilities include the following:

- Keeping abreast of market trade talk and communicate knowledge to the Fuel Accounting Manager
- Coordination of legal documentation appropriate for each counterparty such as Master Agreements, International Swaps Derivative Agreements (ISDA), etc.

Monitoring trade activity with each counterparty

### *Legal Services*

The SMG will seek legal advice and review, internal or external, in counterparty agreement negotiations. While it is not always possible to achieve, the SMG will work with legal services to seek netting and/or set-off agreements with counterparties on all contracts.

Netting provisions allow counterparties to settle with each other the net of all transactions for a given period rather than gross amounts involved in a series of transactions. If a company buys power from a counterparty and also sells them power, the final transaction will take both aspects into consideration and pay the difference between the two. The non-defaulting party may also perform a closeout of any existing positions and include this balance in the netting calculation. This provision can eliminate a large amount of downside potential associated with counterparties that default.

Set-Off can be viewed in simple terms as netting among different governing agreements. For instance, the electric segment may be transacting both electricity and natural gas with the same counterparty under two different governing agreements. Set-Offs allow for amounts owed or received under both agreements to be netted against each other.

### *On-Going Financial/Credit Strength Monitoring Procedures*

The Manager of Fuel Accounting shall be responsible for reviewing the credit rating status of counterparties on an on-going basis. In addition, the Manager of Fuel Accounting will follow business news reports on counterparties for any potential information that may indicate a change in creditworthiness. The Manager of Fuel Accounting will also work in close contact with SMG to stay abreast of any current negative supplemental information gained from direct contact within the energy industry.

If any declining creditworthiness information develops on a counterparty, such as their credit rating is downgraded by Moody's or Standard and Poor's, the Fuel Accounting Manager will notify the RMOC of such development by email.

Furthermore, if a counterparty's credit rating is downgraded to below investment grade (Ba by Moody's, BB by Standard and Poor's) or below, the Fuel Accounting Manager will additionally notify the Chief Financial Officer, Controller and Vice-President/COO-Electric by phone of the downgrade. The Fuel Accounting Manager would also notify the SMG to halt any further trades with this counterparty until further notice. Any member of the RMOC could then call a special meeting of the RMOC for discussion or add this information to the agenda of the next regularly scheduled RMOC meeting.

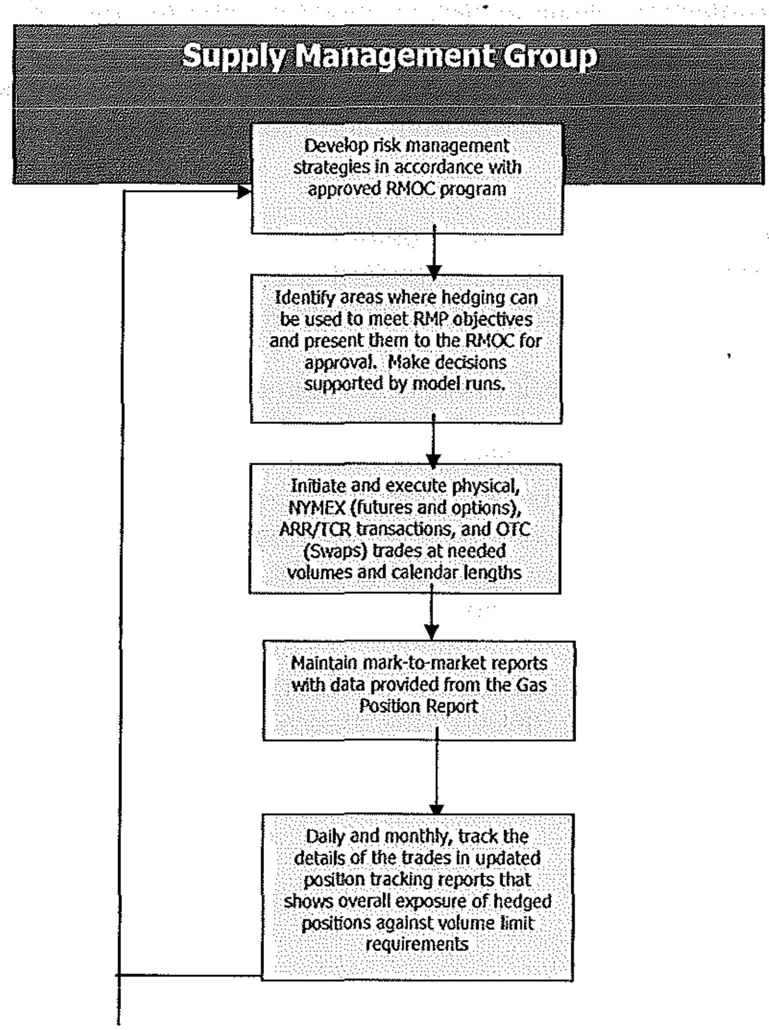
Once a counterparty breaches the established credit exposure limit trigger, the Fuel Accounting Manager will notify the RMOC of the breach. This will be put on the agenda of the next RMOC meeting for discussion.

# APPENDIX 2

## SUPPLY MANAGEMENT GROUP

Responsible for analyzing the market and developing appropriate strategies and tactics in line with the RMP.

Responsibilities include the following:



# APPENDIX 3

## FINANCE

Responsible for the provision of financing the SMG's hedge transactions. In addition, Finance will crosscheck hedge positions placed by the SMG in physicals, swaps, futures, and options for accuracy and accordance with the Company's RMP. Accountable for review of account balances for any associated margin requirements with day-to-day activity and also responsible for the following:

**Finance**

Perform credit analysis, approval, and limit monitoring *(On-going)*

↓

Reconcile daily activity reports from SMG and daily statements from brokers and banks independent of the Gas Position report

↓

Approve, send, and verify wire transfers in or out of trading accounts

↓

Decide whether or not to put trading funds into interest bearing treasury bills or cash

↓

Review accuracy of monthly account statements from broker pertaining to margin account balances

↓

Alert RMOC when transactions taken exceed the limits and standards of the RMP on any discrepancies from this policy as well as any other irregularity, which could expose the Company to financial or legal liability

↓

Develop and apply accounting policies to physical and financial transactions compliant with ASC 815 (formerly FASB 133) and compliant with applicable tax regulations

# APPENDIX 4

## INTERNAL AUDIT

Review documentation as needed to verify the RMP defined limits of the Company's hedge transactions and operations and will periodically confirm the internal controls in place are effective in protecting the objectives of the Company's risk management program.

# APPENDIX 5

## FOR ANY HEDGE TRANSACTION

(Physical, Exchange-Traded or OTC)

**Please reference Appendix 6 for a graphical representation of this process*

## DAILY

**1. Monitor Market Prices/Identify Need for a Hedge in line with Hedging Strategy Objectives**

✓ The SMG will monitor prices for opportunities to meet RMP hedge goals and objectives.

**2. Determine Best Strategy within Limits to Achieve Hedging Objective**

✓ Within the RMOC approved limits, the SMG will determine the best hedge strategies to implement in line with objectives.

✓ For any chosen strategies that exceed a specified time period or dollar limit, the Vice President – Energy Supply must verify that the chosen hedge transaction meets objectives.

**3. Confirm Counterparty Meets Credit Requirements**

✓ For an OTC transaction, the prospective counterparty must be crosschecked with the Approved Counterparty Credit List for credit verification.

**4. Implement Transaction**

✓ The SMG prepares internal documentation for current order.

**5. Communicate Order**

✓ The SMG executes a hedge with broker and/or counterpart by picking up the phone and calling in information that is simultaneously recorded via a trading ticket (*reference example in Appendix 7 in next section*) which is date/time stamped and entered into a position tracking report and Commodity XL software.

**6. Broker Documents and Executes Transaction**

✓ In addition, the broker and the NYMEX floor representatives keep their own trading tickets to document the transaction.

**7. Verify Transaction (Verbal and Written)**

✓ Broker and/or counterpart verifies hedge fill via phone initially to the SMG.

✓ Written confirmations will be sent to the SMG and Finance the following business day via e-mail or fax. Instant messaging is used to verify physical transactions up to one week out. The confirmation/contract is examined by the SMG Specialist for accuracy by crosschecking to the input on the trading ticket. If everything is in agreement, the appropriate SMG representative (as defined in Appendix 12, Trading

Authorities) will sign the confirmation/contract and fax back to the counterparty. If there are disagreements, these will be resolved and then the confirmation/contract will be signed and faxed to the counterparty.. A copy of the trading ticket is sent to the Manager of Fuel Accounting to be matched up with the confirmation/contract.

**8. Confirm Accuracy of Transaction**

- ✓ The SMG crosschecks daily broker Account Statement confirmations against internal Position Report for accuracy
- ✓ The SMG provides mark-to-market reports that tracks the value of the hedge based on current market price.

**9. Track Positions**

- ✓ This SMG Position Report is forwarded to Finance as a check for accuracy on market value and is compared to the broker daily Account Statement report.

**10. Reconcile Positions Daily with Broker via Finance**

- ✓ On a daily basis, Finance will determine and verify cash flow receipts and obligations. If the Company is on margin call, funds will be wired to the broker to keep the hedge account equity in line with the current market value.

## MONTHLY AND ON-GOING

**1. Reconcile Monthly Account Statements**

- ✓ Finance reconciles broker and/or counterpart statements with internal Position Report and FUTRAK software.

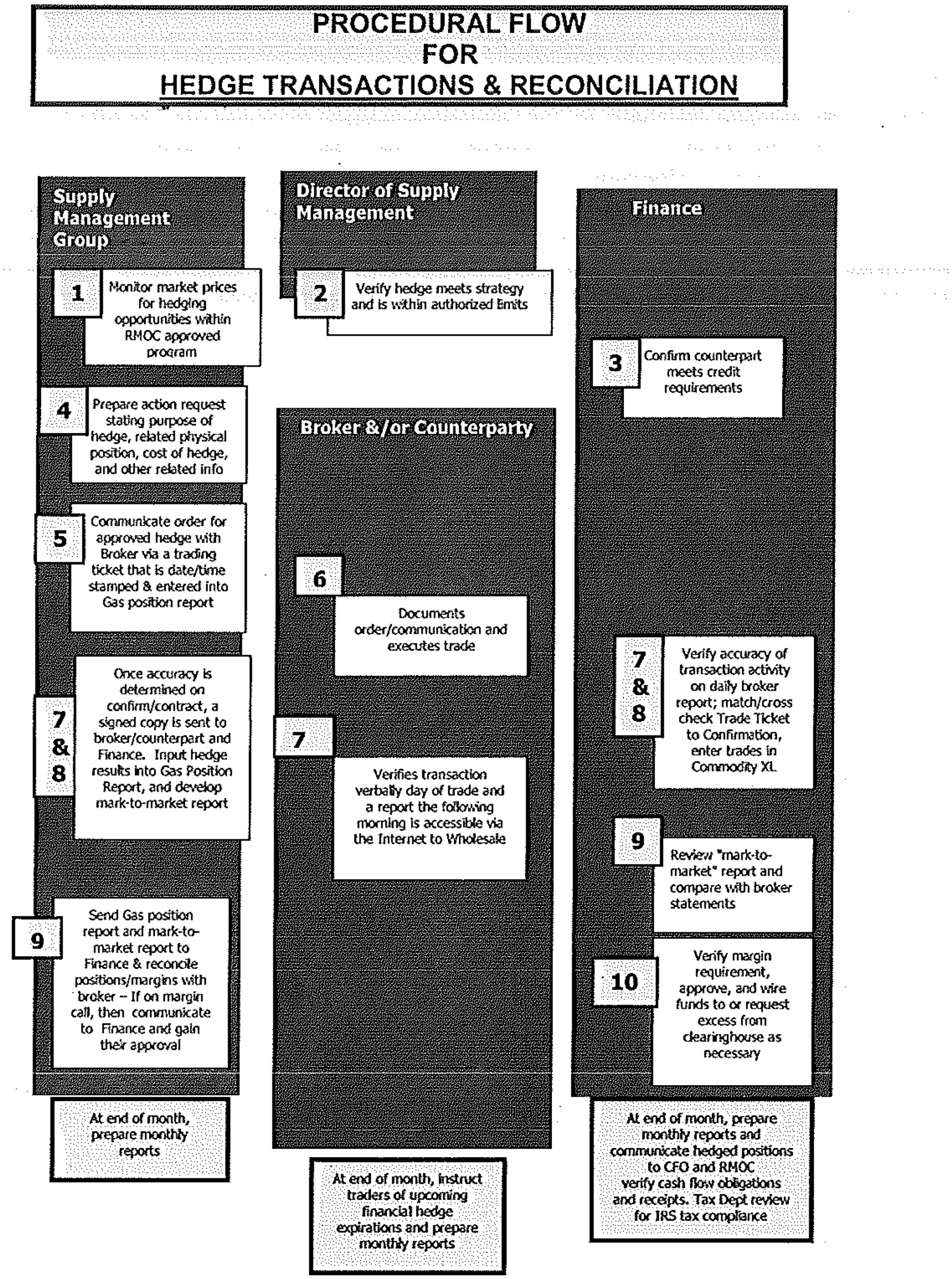
**2. Review of Transaction/Reporting**

- ✓ On a monthly basis, the SMG will review with the RMOC the strategy and positions taken. On at least a semi-annual basis, the results of the RMP hedge strategy will be reported to the Board of Directors by the RMOC.

**3. Review for Tax Compliance**

On a monthly basis, the Manager of Tax or his designee will review all trade tickets for compliance with tax regulations and RMOC Policy that all physical trades meet the normal purchase normal sale criteria for tax purpose.

# APPENDIX 6




**Internal Audit will periodically review process to verify accuracy and compliance*

# APPENDIX 7

## TRADE TICKET

The ability to internally track hedge transactions is crucial to providing an audit trail whereby all parties involved in the decision-making process are notified of a hedge position. This notification of a transaction is also the primary document in tracking a hedge and providing information for the Gas Position Report. Included in the document will be the volumes hedged, the price or instrument used, the length of time for the hedge, and the counterpart to the transaction. Once a transaction is confirmed, the completed Trade Ticket will be sent to Finance in PDF by email on the trade date. An Internal Trade Transaction Ticket is included on the following page.

Empire District Electric Company
Internal Trade Transaction Ticket

Trade Ticket No. BB16E
Trade Date 4/21/2010
Trade Time 13:45

| Buy/Sell | Instrument | Type | | Strike Price | Market |
|---|---|---|---|---|---|
| Buy | Physical | | Jul-14 | $5.2950 | OTC |
| Business Unit | Number of Bids | | | | |
| EDE | 5/5 | | | Premium | |

| Location | Quality | Delivery Start Date | Exercise Date |
|---|---|---|---|
| SSCGP | Firm | 1-Jan-11 | 21-Apr-10 |
| | | Delivery End Date | Settlement Date |
| | | 1-Feb-11 | 1-Feb-11 |

| Price Type | Price Differential / Basis | Volumetric | Quantity | Rate | Quantity(Dth) |
|---|---|---|---|---|---|
| Fixed | | | | $5.295 | 155,000 |

Transmission/Transport Charges

Scheduling Requirement

Settlement

Counterparty
Anadarko\Kelly

Mark-to-Market Point

Broker Commission

Energy Trader: Brian Berkstresser

General Comments
OneOk offering 5.295, ConocoPhillips offering 5.35 Tenaska offering $5.35, CIMA offering $5.38

Energy Trader's Initial

This transaction complies with the RMOC Policy regarding the purchase and definition of physical contracts. Thus, it is in compliance with ASC 815-10-15 (formerly FASB 133 paragraph 10) and IRS Reg.§1221(b)(2) in meeting normal purchase normal sale criteria.

Temporary Approval - New Counterparty

Transaction Objective Based on Empire's Risk Management Policy

Impact on forward month hedge position, as of: 21-Apr-10

| Period | Prior to Purchase (percent) Percent Hedged | Policy Minimum Guidelines % | After Purchase (percent) Percent Hedged |
|---|---|---|---|
| Year 2011 | 71% | 60% | 75% |

Middle Office - Risk Management ______ Bob Ellis

Back Office - Accounting ______ Bob Ellis

Back Office - Tax Accounting ______ Jay Williams

This Transaction complies with:
Ordinary Property Obligations
(IRC Section 1221 (a)(7))

Distribution: Energy Supply
Risk Management
Tax Accounting

Identification Requirements
(Treas. Regs. Section 1.1221-2(e))

# APPENDIX 8

## CONFIRMATION PROCEDURE

### Exchange Traded Confirmations

The SMG will verbally confirm every transaction with broker and/or counterpart on the trade date. Trade confirmations on the daily open position statements will be sent by the broker (on the following business day) to the SMG and Finance. The SMG must check for accuracy on the following business day, input updates into the position report, maintain a mark-to-market report, and forward said report to Finance. Finance is responsible for verifying the confirmation against the transacting records and entering the transaction into Commodity XL.

### Physical and OTC Financial Confirmations

The SMG must verbally confirm every transaction with the broker/counterpart on the trade date. For financially settled OTC transactions, written or email confirmations of the applicable terms and conditions will be completed by the SMG and forwarded to Finance by the end of the second business day following the trade date. Finance is responsible for verifying the confirmation against transacting records and entering the transaction into FUTRAK.

For physical transactions, instant messaging (IM), written, or email confirmations of the applicable terms and conditions will be completed by the SMG and forwarded to Finance by the end of the second business day following the trade date. IM can be used to verify next day, weekend, and gas transactions up to one week out. Written or email confirmations will be required for all other physical forward transactions. Finance is responsible for verifying the confirmation against transacting records and entering the transaction into Commodity XL if necessary.

### The following procedures will be adhered to at all times:

- The trader will review a copy of the confirmation for completeness and initial the confirmation.
- The trader will enter the trade into the Gas Position Report. The Fuel Accounting Manager will enter all financial trades into Commodity XL.
- Confirmations will be completed, signed, and sent to the counterparty by the SMG within two business days.
- Original trade tickets and confirmations will be kept by Finance until after the transaction has settled. Once the transactions have settled, the confirmations and tickets will be maintained by Finance.

# APPENDIX 9
## POSITION REPORTS

The Empire District ELECTRIC Company
Gas Position Summary as of September 29, 2006

| | October 2006 | November 2006 | December 2006 | Oct-Dec 2006 | Year 2007 60% min | Year 2008 40% min | Year 2009 20% min | Year 2010 10% min | Year 2011 0% min | 2012 thru 2013 0% min | Net All Years |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Budget DTh (3) | 8,100 | 90,400 | 593,500 | 692,000 | 9,700,000 | 10,640,300 | 11,103,400 | 8,796,600 | 8,796,600 | 17,593,200 | 67,322,100 |
| Expected DTh (3) | 200,000 | 200,000 | 593,500 | 993,500 | 10,363,900 | 10,640,300 | 11,103,400 | 8,875,200 | 8,875,200 | 17,593,200 | 68,444,700 |
| Policy minimum hedged DTh (2) | 120,000 | 120,000 | 356,100 | 596,100 | 6,218,340 | 4,256,120 | 2,220,680 | 887,520 | - | - | 14,178,760 |
| Policy maximum hedged DTh | 200,000 | 200,000 | 593,500 | 993,500 | 8,291,120 | 8,512,240 | 8,882,720 | 7,100,160 | - | - | 33,779,740 |
| Amount Hedged from Upside Volatility Dth | 100,000 | 170,000 | 520,000 | 790,000 | 7,249,980 | 4,300,000 | 3,696,000 | 3,696,000 | 3,696,000 | 2,400,000 | 25,827,980 |
| percentage | **50%** | **85%** | **88%** | **80%** | **70%** | **40%** | **33%** | **42%** | **42%** | **14%** | **38%** |
| Bookout per physical Dth, all positions | 7.295 | 8.420 | 11.150 | 8.955 | 6.827 | 6.635 | 4.589 | 4.602 | 4.596 | 7.295 | 6.168 |
| **Average Cost per Dth hedged** | **7.295** | **7.149** | **6.682** | **6.860** | **6.561** | **6.585** | **5.422** | **5.422** | **5.422** | **7.295** | **6.153** |
| Net All Positions Marked to Market $ (1) | (368,400) | (417,750) | (581,472) | (1,367,622) | (4,123,250) | (918,320) | 2,842,314 | 2,795,768 | 2,606,411 | (824,703) | 1,210,598 |
| **PHYSICAL HEDGES** | | | | | | | | | | | |
| Purchased Dth | 100,000 | 100,000 | 100,000 | 300,000 | 4,559,980 | 3,100,000 | 1,696,000 | 1,696,000 | 1,696,000 | 2,400,000 | 15,447,980 |
| Purchased $ | 729,500 | 729,500 | 729,500 | 2,188,500 | 32,724,285 | 22,751,500 | 10,998,400 | 10,998,400 | 10,998,400 | 17,508,000 | 108,167,485 |
| Purchased $/DTh | **7.295** | **7.295** | **7.295** | **7.295** | **7.176** | **7.339** | **6.485** | **6.485** | **6.485** | **7.295** | **7.002** |
| Market $ | 361,100 | 424,260 | 533,560 | 1,318,920 | 27,006,395 | 19,650,650 | 10,626,014 | 10,600,468 | 10,600,911 | 16,683,297 | 96,486,655 |
| Market $/Dth (on Southern Star Pipeline) | **3.611** | **4.243** | **5.336** | **4.396** | **5.922** | **6.339** | **6.265** | **6.250** | **6.251** | **6.951** | **6.246** |
| Gain/(Loss) versus current market | (368,400) | (305,240) | (195,940) | (869,580) | (5,717,890) | (3,100,850) | (372,386) | (397,932) | (397,489) | (824,703) | (11,680,830) |
| **FINANCIAL HEDGES** | | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | 0 | - | 350,000 | 350,000 | 2,400,000 | 1,200,000 | 2,000,000 | 2,000,000 | 2,000,000 | - | 9,950,000 |
| Net Cost, $/Dth | **0.000** | **0.000** | **5.643** | **5.111** | **4.779** | **4.635** | **4.520** | **4.520** | **4.520** | **0.000** | **4.617** |
| Market $/Dth (at Swap location) | **0.000** | **0.000** | **4.897** | **4.358** | **5.700** | **6.454** | **6.127** | **6.117** | **6.122** | **0.000** | **5.998** |
| Swap Settlement - Receipt / (Payment) | - | (2,610) | (260,932) | (263,542) | 2,211,181 | 2,182,530 | 3,214,700 | 3,193,700 | 3,203,900 | - | 13,742,468 |
| **Swap/Futures Dth Sold or Settle** | - | - | - | - | - | - | - | - | - | - | - |
| Net Cost, $/Dth | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | |
| Market $/Dth (at Swap location) | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | |
| Swap Settlement - Receipt / (Payment) | - | - | - | - | - | - | - | - | - | - | - |
| **Call Dth (Buy a Call)** | - | 70,000 | 70,000 | 140,000 | 290,000 | - | - | - | - | - | 430,000 |
| Call Strike $/Dth | **0.000** | **9.600** | **11.000** | **10.300** | **11.624** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **11.193** |
| Market $/Dth (at Henry Hub or Swap location) | **0.000** | **5.620** | **7.345** | **6.483** | **7.838** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **7.396** |
| Cost of Call $/Dth | **0.000** | **1.570** | **1.780** | **1.675** | **2.126** | **0.000** | **0.000** | **0.000** | **0.000** | **0.000** | **1.979** |
| Value $ of Call Position | - | - | - | - | - | - | - | - | - | - | 0 |
| (Cost) $ of Call Position | - | (109,900) | (124,600) | (234,500) | (616,540) | - | - | - | - | - | (851,040) |

**Empire District GAS Company**
Gas Position Summary as of September 29, 2006

| | Beginning Storage | October 2006 | November 2006 | December 2006 | January 2007 | February 2007 | March 2007 | April 2007 | May 2007 | June 2007 | July 2007 | August 2007 | September 2007 | Net 12 Months | Winter Season |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Tariff Budget DTh (3) | | 235,187 | 639,351 | 971,444 | 1,062,152 | 826,794 | 654,058 | 335,237 | 166,416 | 135,804 | 126,905 | 123,268 | 118,548 | 5,415,163 | 4,153,799 |
| Tariff Expected DTh (3) | | 235,187 | 639,351 | 971,444 | 1,062,152 | 826,794 | 654,058 | 335,237 | 166,416 | 135,804 | 126,905 | 123,268 | 118,548 | 5,415,163 | 4,153,799 |
| Storage Activity DTh (2) | | - | -347,130 | -347,130 | -347,130 | -347,130 | -347,130 | - | - | - | - | - | - | -1,735,652 | -1,735,652 |
| Net Requirement DTh | | 235,187 | 292,221 | 624,314 | 715,022 | 479,664 | 306,928 | 335,237 | 166,416 | 135,804 | 126,905 | 123,268 | 118,548 | 3,679,511 | 2,418,147 |
| Amount Hedged Dth | | 234,670 | 507,130 | 687,133 | 727,133 | 587,142 | 507,138 | 0 | - | - | - | - | - | 3,250,349 | 3,015,678 |
| percentage | | 100% | 79% | 71% | 68% | 71% | 78% | 0% | 0% | 0% | 0% | 0% | 0% | 60% | 73% |
| **Average Cost per Dth hedged** | | 3.603 | 6.865 | 7.553 | 7.905 | 7.505 | 7.340 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 7.197 | 7.477 |
| Net All Positions Marked to Market $ (1) | | 4,135 | (354,740) | (749,133) | (911,776) | (511,793) | (339,393) | - | - | - | - | - | - | (2,662,705) | (2,666,840) |
| | | | | | | | | | | | | | Avg cost net of Basis >>> | | 7.313 |
| **STORAGE Balances** (end-of-month estimate) (5) | | | | | | | | | | | | | | | |
| S Star Storage Dth | 752,189 | 752,189 | 609,669 | 467,149 | 324,629 | 182,109 | 39,589 | 39,569 | 39,569 | 39,569 | 39,569 | 39,569 | 39,569 | | |
| S Star Storage $ | 5,169,537 | | | | | | | | | | | | | | |
| S Star Storage (Avg) $/DTh | 6.873 | | | | | | | | | | | | | | |
| PEPL Storage Dth | 709,195 | 709,195 | 574,821 | 440,447 | 306,074 | 171,700 | 37,326 | 37,326 | 37,326 | 37,326 | 37,326 | 37,326 | 37,326 | | |
| PEPL Storage $ | 4,847,266 | | | | | | | | | | | | | | |
| PEPL Storage (Avg) $/DTh | 6.835 | | | | | | | | | | | | | | |
| ANR Storage Dth | 370,693 | 370,693 | 300,456 | 230,220 | 159,983 | 69,747 | 19,510 | 19,510 | 19,510 | 19,510 | 19,510 | 19,510 | 19,510 | | |
| ANR Storage $ | 2,465,295 | | | | | | | | | | | | | | |
| ANR Storage (Avg) $/DTh | 6.651 | | | | | | | | | | | | | | |
| Total Storage Dth | 1,832,077 | 1,832,077 | 1,484,947 | 1,137,816 | 790,686 | 443,555 | 96,425 | 96,425 | 96,425 | 96,425 | 96,425 | 96,425 | 96,425 | | |
| Total Storage $ | 12,482,098 | | | | | | | | | | | | | | |
| Total Storage (Avg) $/Dth | 6.813 | | | | | | | | | | | | | | |
| Target Balance (95% of Cap.) | 1,910,653 | | | | | | | | | | | | | | |
| percent of Target | 96% | 96% | 78% | 60% | 41% | 23% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | | |
| **PHYSICAL PROCURED** | | | | | | | | | | | | | | | |
| Purchased Dth | | 234,670 | 100,000 | 210,003 | 220,003 | 160,012 | 100,008 | 0 | - | - | - | - | - | 1,024,696 | 790,026 |
| Purchased $ | | 845,497 | 619,100 | 1,554,667 | 1,707,618 | 1,202,493 | 740,737 | 0 | - | - | - | - | - | 6,670,102 | 5,824,615 |
| Purchased $/DTh | | 3.603 | 6.191 | 7.403 | 7.762 | 7.515 | 7.407 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 6.509 | 7.373 |
| **FINANCIAL HEDGES** | | | | | | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | | - | 60,000 | 130,000 | 160,000 | 80,000 | 60,000 | 0 | - | - | - | - | - | 490,000 | 490,000 |
| Net Cost, $/Dth | | 0.000 | 8.285 | 9.773 | 10.470 | 10.483 | 10.280 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 9.997 | 9.997 |

Should include a copy of the Congestion Position Report once we complete it with actual numbers

# APPENDIX 10

## MARK-TO-MARKET REPORTING

As mentioned previously, all positions will be "mark-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) weekly. This analysis is performed by the SMG to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding the Company's market risk and exposure. The SMG is responsible for verifying the validity and accuracy of the market data used in mark-to-market calculations through the Gas Position Report on a weekly basis. All positions will be "marked-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) at the end of each month using Commodity XL accounting software by the Manager of Fuel Accounting. The resulting entries will then be recorded in the Company's general ledger

# APPENDIX 11

## DAILY BROKER ACCOUNT STATEMENT

The RMI Account Statement shown below is an illustration of the daily report that the SMG and Finance can access on the Internet daily to confirm the previous day's trading activities. Separate accounts are maintained for the electric and gas segments.

ADM
141 W. Jackson Blvd. • Suite 1600A
Chicago, Illinois 60604-3190

STATEMENT DATE: FEB 28, 2011
ACCOUNT NUMBER: 312 15611
SALESMAN NUMBER: 312 SM01
INTRODUCED BY: RISK MANAGEMENT INC
(312)373-8250

THE EMPIRE DISTRICT ELECTRIC CO-
ELECTRIC
PO BOX 127
JOPLIN MO 64801

ATTN KRESTIN BJORNSSON

IF YOU HAVE ANY QUESTIONS OR ISSUES REGARDING YOUR STATEMENT THAT YOU ARE UNABLE TO RESOLVE WITH YOUR BROKER. PLEASE CONTACT ADMIS CUSTOMER SERVICE AT 1/800/654-0461 or 312/242-7200.

* * * * * * * * * * Y O U R   A C T I V I T Y   T H I S   M O N T H * * * * * * * * * * * * * * *

| DATE | LONG/BUY | SHRT/SELL | DESCRIPTION | EX | PRICE/LEGND | CC | DEBIT | CREDIT |
|---|---|---|---|---|---|---|---|---|
| 2/15/1 | | | WIRE TRANSFER REC<br>WIRE TRANSFER RECEIVED | | WIREREC | US | | 24,700.00 |
| 2/17/1 | | 21 | SEP 11 NATURAL GAS<br>GLOBEX TRADE | C | FEE/COMM | US | 387.87 | |
| 2/17/1 | | | WIRE TRANSFER REC<br>WIRE TRANSFER RECEIVED | | WIREREC | US | | 43,775.00 |

* * * * * * * * * * * * * * * P O S I T I O N S   I N   Y O U R   A C C O U N T * * * * * * * * * * * * * * * *

| DATE | LONG/BUY | SHRT/SELL | DESCRIPTION | EX | PRICE/LEGND | CC | DEBIT | CREDIT |
|---|---|---|---|---|---|---|---|---|
| 2/17/1 | | 21<br>21* | SEP 11 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE SHORT: 4.20000 | C | 4.200<br>4.275 | US | 15,750.00<br>15,750.00* | |
| 9/08/9 | 31<br>31* | | JAN 12 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 7.13000 | C | 7.130<br>4.905 | US | 689,750.00<br>689,750.00* | |
| 8/06/9 | 40<br>40* | | JUL 12 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 6.69000 | C | 5.690<br>4.788 | US | 760,800.00<br>760,800.00* | |
| 8/06/9 | 40<br>40* | | AUG 12 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 6.76000 | C | 6.760<br>4.818 | US | 776,800.00<br>776,800.00* | |
| 9/08/9 | 31<br>31* | | DEC 12 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 7.08000 | C | 7.080<br>5.243 | US | 569,470.00<br>569,470.00* | |
| 4/16/0 | 31<br>31* | | JUL 14 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 6.08000 | C | 6.080<br>5.383 | US | 216,070.00<br>216,070.00* | |
| 4/16/0 | 31<br>31* | | AUG 14 NATURAL GAS<br>OPEN TRADE EQUITY<br>AVERAGE LONG: 6.15000 | C | 6.150<br>5.418 | US | 226,920.00<br>226,920.00* | |

| | *** SEG USD *** |
|---|---|
| 1. BEGINNING ACCT BALANCE | 3,877,587.95 |
| 2. P&L AND CASH ACTIVITY | 68,087.13 |
| 3. ENDING ACCT BALANCE | 3,945,675.09 |
| 4. NET FUTURES P&L | 387.87- |
| 6. FUT OPEN TRADE EQUITY | 3,255,560.00- |
| 9. ACCT VALUE AT MARKET | 690,115.09 |
| 11. CONVERTED ACCT VALUE US | 690,115.09 |

ADM INVESTOR SERVICES, INC. a wholly owned subsidiary of the Archer Daniels Midland Company.

PLEASE REPORT ANY DIFFERENCES OR OBJECTIONS IMMEDIATELY. YOUR FAILURE TO IMMEDIATELY EXERCISE YOUR RIGHT TO HAVE DIFFERENCES OR OBJECTIONS CORRECTED WILL BE DEEMED YOUR AGREEMENT THAT THIS STATEMENT IS CORRECT AND RATIFIED

**APPENDIX13**

## Supply Management Group
## Purchase and/or Sale Pre-Approval Form

This form is to convey pre-approval of the Officers or RMOC for purchases and/or sales that are beyond the approval limits of the members of the Supply Management Group as set forth in *Appendix 12 - Trading Authorization* of the Energy Risk Management Policy.

| | (circle one) | | (circle one) |
|---|---|---|---|
| Approval for: | Purchase<br>Sale | | Nat Gas<br>Power |

Quantity — Minimum ______________ Maximum ______________

Price — Minimum ______________ Maximum ______________

Timeframe — Months ______________ Years ______________

| | Total $ Value |
|---|---|
| Minimum | $ - |
| Maximum | $ - |

Other Comments:

Approval is valid until: Filled ______________ Date ______________

| Signatures | Name: ______________ | Name: ______________ |
|---|---|---|
| | Title: ______________ | Title: ______________ |
| | Date: ______________ | Date: ______________ |

# APPENDIX X

## Annual LTCR/ARR/TCR/FTR Approval Process

### Annual Auction

**1** Present congestion management strategy to RMOC for approval
Approval Level - 1

**2** Execute approved strategy for LTCR/ARR nomination/surrender & TCR auction rounds 1-3
Execution Level - 3

**2a** Document & propose deviations from approved strategy due to expected or actual nomination or auction results that limit effectiveness of the strategy
Execution Level - 3

**2b** Approve deviations from RMOC approved plan
Approval Level - 2

**2c** Execute approved deviations from RMOC approved plan
Execution Level - 3

**3** Present results of nomination and auction, including any deviations from plan, to RMOC in congestion management report
Execution Level - 3

### Approval/Execution Levels

| | | |
|---|---|---|
| Level 1 | RMOC | Committee vote |
| Level 2 | VP of Energy Supply<br>Director of Supply Management | Both |
| Level 3 | Manager of Market Systems & Settlements<br>Manager of Market Operations | Either |

### Congestion Management Strategy

At a minimum, the congestion management strategy will consist of the following:

- An analysis of the congestion exposure the company anticipates during the next 12 month cycle
- The congestion exposure that is expected to be mitigated with ARR/TCR procurement
    - Including percentage hedged & acquisition cost
    - Stress test[1] based on historical hourly MCC
    - Credit requirements to execute plan

[1]Using historical path values and statistical probabilities to determine the likelihood and extent of unfavorable positions to the TCR/FTR holder
In the event historical values are unavailable, forecasted values may be substituted

## APPENDIX Y

Monthly ARR/TCR Approval Process

### Monthly Auction

1 Continue with congestion management strategy approved by RMOC

Execution Level - 2

2 Execute approved strategy for monthly nominations and auctions

Execution Level - 2

2a Document & propose deviations from approved strategy due to expected or actual nomination or auction results that limit effectiveness of the strategy

Execution Level - 2

2b Approve deviations from RMOC approved plan

Approval Level - 1

2c Execute approved deviations from RMOC approved plan

Execution Level - 2

3 Present results of nomination and auction, including any deviations from plan, to RMOC in congestion management report

Execution Level - 2

### Approval/Execution Levels

Level 1 VP of Energy Supply
Director of Supply Management
Either

Level 2 Manager of Market Systems & Settlements
Manager of Market Operations
Either

### Congestion Management Strategy

At a minimum, the congestion management strategy will consist of the following:

- An analysis of the congestion exposure the company anticipates during the next 12 month cycle
- The congestion exposure that is expected to be mitigated with ARR/TCR/FTR procurement
  - Including percentage hedged & acquisition cost
  - Stress test[1] based on historical hourly MCC
  - Credit requirements to execute plan



[1]Using historical path values and statistical probabilities to determine the likelihood and extent of unfavorable positions to the TCR/FTR holder In the event historical values are unavailable, forecasted values may be substituted

OK

| The Empire District ELECTRIC Company<br>Gas Position Summary as of December 31, 2011 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | January 2012 | February 2012 | March 2012 | Apr-Dec 2012 | Jan-Dec 2012 | Year 2013 40% min | Year 2014 20% min | Year 2015 10% min | Year 2016 0% min | Net All Years |
| Budget DTh (3) | 559,136 | 486,011 | 379,467 | 4,781,112 | 6,205,726 | 8,338,329 | 7,850,700 | 10,249,828 | - | 32,644,583 |
| Expected DTh (3) | 573,561 | 634,152 | 337,725 | 4,864,967 | 6,410,405 | 7,937,162 | 8,515,810 | 9,283,249 | 9,699,357 | 41,845,982 |
| Policy minimum hedged DTh (2) | 344,137 | 380,491 | 202,635 | 2,918,980 | 3,846,243 | 3,174,865 | 1,703,162 | 928,325 | - | 9,652,594 |
| Policy maximum hedged DTh | 573,561 | 634,152 | 337,725 | 4,864,967 | 6,410,405 | 6,349,730 | 6,812,648 | 7,426,599 | 7,759,486 | 34,758,867 |
| Amount Hedged from Upside Volatility Dth | 410,000 | 200,000 | 100,000 | 3,221,000 | 3,931,000 | 3,460,000 | 1,700,000 | 1,010,000 | - | 10,101,000 |
| percentage | **71%** | **32%** | **30%** | **66%** | **61%** | **44%** | **20%** | **11%** | **0%** | **24%** |
| **Average Cost per Dth hedged** | **7.170** | **6.133** | **7.295** | **6.363** | **6.459** | **6.079** | **5.514** | **5.439** | **0.000** | **6.068** |
| Net All Positions $ (1) | (1,684,860) | (647,700) | (437,400) | (10,232,088) | (13,002,048) | (7,797,560) | (2,224,875) | (919,720) | - | (23,944,203) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| Purchased Dth | 100,000 | 200,000 | 100,000 | 2,111,000 | 2,511,000 | 2,020,000 | 460,000 | - | - | 4,991,000 |
| Purchased $ | 729,500 | 1,226,500 | 729,500 | 12,920,215 | 15,605,715 | 12,933,800 | 2,420,575 | - | - | 30,960,090 |
| Purchased $/DTh | **7.295** | **6.133** | **7.295** | **6.120** | **6.215** | **6.403** | **5.262** | **0.000** | **0.000** | **6.203** |
| Market $ | 298,900 | 578,800 | 292,100 | 6,490,657 | 7,660,457 | 7,572,510 | 1,834,640 | - | - | 17,067,607 |
| Market $/Dth (on Southern Star Pipeline) | **2.989** | **2.894** | **2.921** | **3.075** | **3.051** | **3.749** | **3.988** | **0.000** | **0.000** | **3.420** |
| Difference ($) versus current market | (430,600) | (647,700) | (437,400) | (6,429,558) | (7,945,258) | (5,361,290) | (585,935) | - | - | (13,892,483) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | 310,000 | - | - | 1,110,000 | 1,420,000 | 1,440,000 | 1,240,000 | 1,010,000 | - | 5,110,000 |
| Net Cost, $/Dth | **7.130** | **0.000** | **0.000** | **6.824** | **6.891** | **5.625** | **5.607** | **5.439** | **0.000** | **5.935** |
| Market $/Dth (at Swap location) | **3.084** | **0.000** | **0.000** | **3.398** | **3.330** | **3.933** | **4.285** | **4.528** | **0.000** | **3.968** |
| Difference ($) versus current market | (1,254,260) | - | - | (3,802,530) | (5,056,790) | (2,436,270) | (1,638,940) | (919,720) | - | (10,051,720) |

| Storage Estimates | |
|---|---|
| Balance Dth | 667,149 |
| WACOG $/Dth | 4.367 |

Note 1: Market data using NYMEX Close Prices as of December 30, 2011.
Note 2: Policy minimums are 12/31/2011 targets.
Note 3: For 2011 through 2015, Budgeted Dth are from FINAL FPP Budget for 2011 (Planning & Regulatory, 9/28/2010).
For Dec 2011, Expected Dth were revised to Updated Outage schedule scenario (P&R 1/31/2011).
For 2012-2016, Expected Dth are from PRELIMINARY F&PP scenario (Planning & Regulatory as of 10/13/2011).
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.

Note 5: Storage and Park&Loan balance and usage are estimates based on most current information available.

**The Empire District ELECTRIC Company**
Gas Position Summary as of March 31, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | April 2015 | May 2015 | June 2015 | Jul - Dec 2015 | Apr - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 444,733 | 740,493 | 1,061,717 | 5,495,407 | 7,742,349 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 48,349,888 |
| Expected Dth (3) | 444,733 | 740,493 | 1,061,717 | 5,495,407 | 7,742,349 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 48,349,888 |
| Policy minimum hedged Dth (2) | 266,840 | 444,296 | 637,030 | 3,297,244 | 4,645,410 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 17,704,927 |
| Policy Maximum hedged Dth | 444,733 | 740,493 | 1,061,717 | 5,495,407 | 7,742,349 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 40,228,380 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 200,000 | 300,000 | 700,000 | 3,210,000 | 4,410,000 | 4,076,000 | 2,082,900 | 1,065,000 | - | 11,633,900 |
| percentage | **45%** | **41%** | **66%** | **58%** | **57%** | **42%** | **20%** | **10%** | **0%** | **24%** |
| Amount Hedged from Downside Volitility Dth | $ 200,000 | $ 300,000 | $ 700,000 | $ 3,210,000 | $ 4,410,000 | $ 4,076,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 11,633,900 |
| percentage | **45%** | **41%** | **66%** | **58%** | **57%** | **42%** | **20%** | **10%** | **0%** | **24%** |
| **Average Cost per Dth hedged** | **$ 3.919** | **$ 3.961** | **$ 3.450** | **$ 4.688** | **$ 4.407** | **$ 4.103** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.226** |
| Net all Positions $ (1) | $ (302,700) | $ (424,600) | $ (591,200) | $ (6,108,380) | $ (7,426,880) | $ (5,074,276) | $ (2,119,242) | $ (1,071,660) | $ - | $ (15,692,058) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 100,000 | $ 100,000 | $ 200,000 | $ 400,000 | $ 800,000 | $ 1,976,000 | $ 782,900 | $ 565,000 | $ - | $ 4,123,900 |
| Purchased $ | $ 391,500 | $ 391,500 | $ 785,500 | $ 1,571,000 | $ 3,139,500 | $ 7,454,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 15,588,100 |
| Purchased $/Dth | **$ 3.915** | **$ 3.915** | **$ 3.928** | **$ 3.928** | **$ 3.924** | **$ 3.773** | **$ 3.657** | **$ 3.771** | $ - | **$ 3.780** |
| Market $ | $ 222,000 | $ 235,600 | $ 478,000 | $ 993,200 | $ 1,928,800 | $ 5,120,024 | $ 2,213,178 | $ 1,635,540 | $ - | $ 10,897,542 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.220** | **$ 2.356** | **$ 2.390** | **$ 2.483** | **$ 2.411** | **$ 2.591** | **$ 2.827** | **$ 2.895** | $ - | **$ 2.643** |
| Difference ($) versus current market | $ (169,500) | $ (155,900) | $ (307,500) | $ (577,800) | $ (1,210,700) | $ (2,334,776) | $ (650,172) | $ (494,910) | $ - | $ (4,690,558) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 100,000 | $ 200,000 | $ 500,000 | $ 2,810,000 | $ 3,610,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 7,510,000 |
| Net Cost, $/Dth | **$ 3.922** | **$ 3.984** | **$ 3.258** | **$ 4.797** | **$ 4.514** | **$ 4.415** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.470** |
| Market $/Dth (at Swap location) | **$ 2.590** | **$ 2.640** | **$ 2.691** | **$ 2.829** | **$ 2.792** | **$ 3.110** | **$ 3.290** | **$ 3.363** | $ - | **$ 3.005** |
| Difference ($) versus current Market | $ (133,200) | $ (268,700) | $ (283,700) | $ (5,530,580) | $ (6,216,180) | $ (2,739,500) | $ (1,469,070) | $ (576,750) | $ - | $ (11,001,500) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of March 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 107,663 |
| WACOG $/Dth | 3.187 |

**The Empire District ELECTRIC Company**
Gas Position Summary as of April 30, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | May 2015 | June 2015 | July 2015 | Aug - Dec 2015 | May - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 740,493 | 1,061,717 | 1,593,182 | 3,902,225 | 7,297,616 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 47,905,155 |
| Expected Dth (3) | 740,493 | 1,061,717 | 1,593,182 | 3,902,225 | 7,297,616 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 47,905,155 |
| Policy minimum hedged Dth (2) | 444,296 | 637,030 | 955,909 | 2,341,335 | 4,378,570 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 17,438,087 |
| Policy Maximum hedged Dth | 740,493 | 1,061,717 | 1,593,182 | 3,902,225 | 7,297,616 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 39,783,647 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 300,000 | 700,000 | 1,200,000 | 2,010,000 | 4,210,000 | 4,776,000 | 2,082,900 | 1,065,000 | - | 12,133,900 |
| percentage | 41% | 66% | 75% | 52% | 58% | 49% | 20% | 10% | 0% | 25% |
| Amount Hedged from Downside Volitility Dth | $ 300,000 | $ 700,000 | $ 1,200,000 | $ 2,010,000 | $ 4,210,000 | $ 4,776,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 12,133,900 |
| percentage | 41% | 66% | 75% | 52% | 58% | 49% | 20% | 10% | 0% | 25% |
| **Average Cost per Dth hedged** | **$ 3.961** | **$ 3.450** | **$ 5.014** | **$ 4.494** | **$ 4.431** | **$ 3.898** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.143** |
| Net all Positions $ (1) | $ (460,800) | $ (540,400) | $ (2,704,600) | $ (3,243,600) | $ (6,949,400) | $ (4,839,670) | $ (2,090,248) | $ (1,057,830) | $ - | $ (14,937,148) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 100,000 | $ 200,000 | $ 200,000 | $ 200,000 | $ 700,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,723,900 |
| Purchased $ | $ 391,500 | $ 785,500 | $ 785,500 | $ 785,500 | $ 2,748,000 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 17,086,600 |
| Purchased $/Dth | **$ 3.915** | **$ 3.928** | **$ 3.928** | **$ 3.928** | **$ 3.926** | **$ 3.492** | **$ 3.657** | **$ 3.771** | **$ -** | **$ 3.617** |
| Market $ | $ 224,000 | $ 498,800 | $ 509,600 | $ 514,000 | $ 1,746,400 | $ 7,198,230 | $ 2,250,592 | $ 1,653,620 | $ - | $ 12,848,842 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.240** | **$ 2.494** | **$ 2.548** | **$ 2.570** | **$ 2.495** | **$ 2.690** | **$ 2.875** | **$ 2.927** | **$ -** | **$ 2.720** |
| Difference ($) versus current market | $ (167,500) | $ (286,700) | $ (275,900) | $ (271,500) | $ (1,001,600) | $ (2,146,570) | $ (612,758) | $ (476,830) | $ - | $ (4,237,758) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 200,000 | $ 500,000 | $ 1,000,000 | $ 1,810,000 | $ 3,510,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 7,410,000 |
| Net Cost, $/Dth | **$ 3.984** | **$ 3.258** | **$ 5.231** | **$ 4.557** | **$ 4.531** | **$ 4.415** | **$ 4.420** | **$ 4.516** | **$ -** | **$ 4.478** |
| Market $/Dth (at Swap location) | **$ 2.517** | **$ 2.751** | **$ 2.802** | **$ 2.915** | **$ 2.837** | **$ 3.132** | **$ 3.283** | **$ 3.354** | **$ -** | **$ 3.034** |
| Difference ($) versus current Market | $ (293,300) | $ (253,700) | $ (2,428,700) | $ (2,972,100) | $ (5,947,800) | $ (2,693,100) | $ (1,477,490) | $ (581,000) | $ - | $ (10,699,390) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of April 30, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 221,498 |
| WACOG $/Dth | 2.973 |

**The Empire District ELECTRIC Company**
Gas Position Summary as of May 31, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | June 2015 | July 2015 | August 2015 | Sep - Dec 2015 | Jun - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 1,061,717 | 1,593,182 | 1,847,835 | 2,054,390 | 6,557,124 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 47,164,662 |
| Expected Dth (3) | 1,061,717 | 1,593,182 | 1,847,835 | 2,054,390 | 6,557,124 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 47,164,662 |
| Policy minimum hedged Dth (2) | 637,030 | 955,909 | 1,108,701 | 1,232,634 | 3,934,274 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 16,993,792 |
| Policy Maximum hedged Dth | 1,061,717 | 1,593,182 | 1,847,835 | 2,054,390 | 6,557,124 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 39,043,154 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 700,000 | 1,200,000 | 1,310,000 | 700,000 | 3,910,000 | 4,776,000 | 2,082,900 | 1,065,000 | - | 11,833,900 |
| percentage | **66%** | **75%** | **71%** | **34%** | **60%** | **49%** | **20%** | **10%** | **0%** | **25%** |
| Amount Hedged from Downside Volitility Dth | $ 700,000 | $ 1,200,000 | $ 1,310,000 | $ 700,000 | $ 3,910,000 | $ 4,776,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 11,833,900 |
| percentage | **66%** | **75%** | **71%** | **34%** | **60%** | **49%** | **20%** | **10%** | **0%** | **25%** |
| **Average Cost per Dth hedged** | **$ 3.450** | **$ 5.014** | **$ 4.527** | **$ 4.433** | **$ 4.467** | **$ 3.898** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.147** |
| Net all Positions $ (1) | $ (497,700) | $ (2,897,200) | $ (2,490,050) | $ (1,046,700) | $ (6,931,650) | $ (5,172,704) | $ (2,193,104) | $ (1,087,013) | $ - | $ (15,384,471) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 200,000 | $ 200,000 | $ 200,000 | $ - | $ 600,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,623,900 |
| Purchased $ | $ 785,500 | $ 785,500 | $ 785,500 | $ - | $ 2,356,500 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 16,695,100 |
| Purchased $/Dth | **$ 3.928** | **$ 3.928** | **$ 3.928** | $ - | **$ 3.928** | **$ 3.492** | **$ 3.657** | **$ 3.771** | $ - | **$ 3.611** |
| Market $ | $ 512,000 | $ 477,000 | $ 482,200 | $ - | $ 1,471,200 | $ 7,000,496 | $ 2,199,116 | $ 1,636,438 | $ - | $ 12,307,249 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.560** | **$ 2.385** | **$ 2.411** | $ - | **$ 2.452** | **$ 2.616** | **$ 2.809** | **$ 2.896** | $ - | **$ 2.662** |
| Difference ($) versus current market | $ (273,500) | $ (308,500) | $ (303,300) | $ - | $ (885,300) | $ (2,344,304) | $ (664,234) | $ (494,013) | $ - | $ (4,387,851) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 500,000 | $ 1,000,000 | $ 1,110,000 | $ 700,000 | $ 3,310,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 7,210,000 |
| Net Cost, $/Dth | **$ 3.258** | **$ 5.231** | **$ 4.635** | **$ 4.433** | **$ 4.564** | **$ 4.415** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.491** |
| Market $/Dth (at Swap location) | **$ 2.810** | **$ 2.642** | **$ 2.665** | **$ 2.938** | **$ 2.738** | **$ 3.068** | **$ 3.244** | **$ 3.330** | $ - | **$ 2.966** |
| Difference ($) versus current Market | $ (224,200) | $ (2,588,700) | $ (2,186,750) | $ (1,046,700) | $ (6,046,350) | $ (2,828,400) | $ (1,528,870) | $ (593,000) | $ - | $ (10,996,620) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| Storage Estimates | |
|---|---|
| Balance Dth | 243,770 |
| WACOG $/Dth | 2.937 |

Note 1: Market data using NYMEX Close Prices as of May 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| The Empire District ELECTRIC Company<br>Gas Position Summary as of June 30, 2015 | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | July<br>2015 | August<br>2015 | September<br>2015 | Oct - Dec<br>2015 | Jul - Dec<br>2015 | Year 2016<br>60% min | Year 2017<br>40% min | Year 2018<br>20% min | Year 2019<br>10% min | Net<br>All Years |
| Budget Dth (3) | 1,593,182 | 1,847,835 | 776,747 | 1,277,643 | 5,495,407 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 46,102,945 |
| Expected Dth (3) | 1,593,182 | 1,847,835 | 776,747 | 1,277,643 | 5,495,407 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 46,102,945 |
| Policy minimum hedged Dth (2) | 955,909 | 1,108,701 | 466,048 | 766,586 | 3,297,244 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 16,356,762 |
| Policy Maximum hedged Dth | 1,593,182 | 1,847,835 | 776,747 | 1,277,643 | 5,495,407 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 37,981,438 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 1,269,017 | 1,310,000 | 100,000 | 600,000 | 3,279,017 | 4,776,000 | 2,082,900 | 1,065,000 | - | 11,202,917 |
| percentage | 80% | 71% | 13% | 47% | 60% | 49% | 20% | 10% | 0% | 24% |
| Amount Hedged from Downside Volitility Dth | $ 1,269,017 | $ 1,310,000 | $ 100,000 | $ 600,000 | $ 3,279,017 | $ 4,776,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 11,202,917 |
| percentage | 80% | 71% | 13% | 47% | 60% | 49% | 20% | 10% | 0% | 24% |
| **Average Cost per Dth hedged** | **$ 4.887** | **$ 4.529** | **$ 4.115** | **$ 4.486** | **$ 4.647** | **$ 3.898** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.182** |
| Net all Positions $ (1) | $ (2,744,992) | $ (2,257,480) | $ (127,300) | $ (828,200) | $ (5,957,972) | $ (4,601,582) | $ (2,096,771) | $ (1,065,565) | $ - | $ (13,721,890) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 269,017 | $ 200,000 | $ - | $ - | $ 469,017 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,492,917 |
| Purchased $ | $ 970,595 | $ 787,500 | $ - | $ - | $ 1,758,095 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 16,096,695 |
| Purchased $/Dth | **$ 3.608** | **$ 3.938** | $ - | $ - | **$ 3.748** | **$ 3.492** | **$ 3.657** | **$ 3.771** | $ - | **$ 3.583** |
| Market $ | $ 683,303 | $ 531,400 | $ - | $ - | $ 1,214,703 | $ 7,359,018 | $ 2,221,349 | $ 1,642,885 | $ - | $ 12,437,955 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.540** | **$ 2.657** | $ - | $ - | **$ 2.590** | **$ 2.750** | **$ 2.837** | **$ 2.908** | $ - | **$ 2.768** |
| Difference ($) versus current market | $ (287,292) | $ (256,100) | $ - | $ - | $ (543,392) | $ (1,985,782) | $ (642,001) | $ (487,565) | $ - | $ (3,658,740) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 1,000,000 | $ 1,110,000 | $ 100,000 | $ 600,000 | $ 2,810,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 6,710,000 |
| Net Cost, $/Dth | **$ 5.231** | **$ 4.635** | **$ 4.115** | **$ 4.486** | **$ 4.797** | **$ 4.415** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.583** |
| Market $/Dth (at Swap location) | **$ 2.773** | **$ 2.832** | **$ 2.842** | **$ 3.106** | **$ 2.870** | **$ 3.169** | **$ 3.301** | **$ 3.360** | $ - | **$ 3.083** |
| Difference ($) versus current Market | $ (2,457,700) | $ (2,001,380) | $ (127,300) | $ (828,200) | $ (5,414,580) | $ (2,615,800) | $ (1,454,770) | $ (578,000) | $ - | $ (10,063,150) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of June 30, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 322,858 |
| WACOG $/Dth | 2.856 |

Schedule JSR-D-4
Proprietary

**The Empire District ELECTRIC Company**
Gas Position Summary as of July 31, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | August 2015 | September 2015 | October 2015 | Nov - Dec 2015 | Aug - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 1,847,835 | 776,747 | 510,885 | 766,758 | 3,902,225 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 44,509,763 |
| Expected Dth (3) | 1,847,835 | 776,747 | 510,885 | 766,758 | 3,902,225 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 44,509,763 |
| Policy minimum hedged Dth (2) | 1,108,701 | 466,048 | 306,531 | 460,055 | 2,341,335 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 15,400,852 |
| Policy Maximum hedged Dth | 1,847,835 | 776,747 | 510,885 | 766,758 | 3,902,225 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 36,388,255 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 1,445,000 | 100,000 | - | 600,000 | 2,145,000 | 4,776,000 | 2,082,900 | 1,065,000 | - | 10,068,900 |
| percentage | **78%** | **13%** | **0%** | **78%** | **55%** | **49%** | **20%** | **10%** | **0%** | **23%** |
| Amount Hedged from Downside Volitility Dth | $ 1,445,000 | $ 100,000 | $ - | $ 600,000 | $ 2,145,000 | $ 4,776,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 10,068,900 |
| percentage | **78%** | **13%** | **0%** | **78%** | **55%** | **49%** | **20%** | **10%** | **0%** | **23%** |
| **Average Cost per Dth hedged** | **$ 4.352** | **$ 4.115** | **$ -** | **$ 4.486** | **$ 4.379** | **$ 3.898** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.072** |
| Net all Positions $ (1) | $ (2,184,340) | $ (139,900) | $ - | $ (883,900) | $ (3,208,140) | $ (5,022,398) | $ (2,371,315) | $ (1,207,010) | $ - | $ (11,808,863) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 335,000 | $ - | $ - | $ - | $ 335,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,358,900 |
| Purchased $ | $ 1,144,050 | $ - | $ - | $ - | $ 1,144,050 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 15,482,650 |
| Purchased $/Dth | **$ 3.415** | $ - | $ - | $ - | **$ 3.415** | **$ 3.492** | **$ 3.657** | **$ 3.771** | $ - | **$ 3.552** |
| Market $ | $ 901,150 | $ - | $ - | $ - | $ 901,150 | $ 7,150,502 | $ 2,098,905 | $ 1,550,690 | $ - | $ 11,701,247 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.690** | $ - | $ - | $ - | **$ 2.690** | **$ 2.672** | **$ 2.681** | **$ 2.745** | $ - | **$ 2.684** |
| Difference ($) versus current market | $ (242,900) | $ - | $ - | $ - | $ (242,900) | $ (2,194,298) | $ (764,445) | $ (579,760) | $ - | $ (3,781,403) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 1,110,000 | $ 100,000 | $ - | $ 600,000 | $ 1,810,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 5,710,000 |
| Net Cost, $/Dth | **$ 4.635** | **$ 4.115** | $ - | **$ 4.486** | **$ 4.557** | **$ 4.415** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.470** |
| Market $/Dth (at Swap location) | **$ 2.886** | **$ 2.716** | $ - | **$ 3.013** | **$ 2.919** | **$ 3.068** | **$ 3.184** | **$ 3.262** | $ - | **$ 3.064** |
| Difference ($) versus current Market | $ (1,941,440) | $ (139,900) | $ - | $ (883,900) | $ (2,965,240) | $ (2,828,100) | $ (1,606,870) | $ (627,250) | $ - | $ (8,027,460) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of July 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 411,946 |
| WACOG $/Dth | 2.806 |

Schedule JSR-D-4
Proprietary

**The Empire District ELECTRIC Company**
Gas Position Summary as of August 31, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | September 2015 | October 2015 | November 2015 | Dec - Dec 2015 | Sep - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 776,747 | 510,885 | 388,808 | 377,951 | 2,054,390 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 42,661,928 |
| Expected Dth (3) | 776,747 | 510,885 | 388,808 | 377,951 | 2,054,390 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 42,661,928 |
| Policy minimum hedged Dth (2) | 466,048 | 306,531 | 233,285 | 226,770 | 1,232,634 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 14,292,151 |
| Policy Maximum hedged Dth | 776,747 | 510,885 | 388,808 | 377,951 | 2,054,390 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 34,540,420 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 110,000 | - | 100,000 | 500,000 | 710,000 | 4,776,000 | 2,082,900 | 1,065,000 | - | 8,633,900 |
| percentage | 14% | 0% | 26% | 132% | 35% | 49% | 20% | 10% | 0% | 20% |
| Amount Hedged from Downside Volitility Dth | $ 110,000 | $ - | $ 100,000 | $ 500,000 | $ 710,000 | $ 4,776,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 8,633,900 |
| percentage | 14% | 0% | 26% | 132% | 35% | 49% | 20% | 10% | 0% | 20% |
| **Average Cost per Dth hedged** | **$ 3.965** | **$ -** | **$ 4.202** | **$ 4.543** | **$ 4.405** | **$ 3.898** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 4.024** |
| Net all Positions $ (1) | $ (148,050) | $ - | $ (144,100) | $ (819,000) | $ (1,111,150) | $ (5,376,626) | $ (2,627,871) | $ (1,348,235) | $ - | $ (10,463,882) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 10,000 | $ - | $ - | $ - | $ 10,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,033,900 |
| Purchased $ | $ 24,650 | $ - | $ - | $ - | $ 24,650 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 14,363,250 |
| Purchased $/Dth | **$ 2.465** | $ - | $ - | $ - | **$ 2.465** | **$ 3.492** | **$ 3.657** | **$ 3.771** | $ - | **$ 3.561** |
| Market $ | $ 24,300 | $ - | $ - | $ - | $ 24,300 | $ 7,076,374 | $ 2,033,449 | $ 1,491,465 | $ - | $ 10,625,588 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.430** | $ - | $ - | $ - | **$ 2.430** | **$ 2.644** | **$ 2.597** | **$ 2.640** | $ - | **$ 2.634** |
| Difference ($) versus current market | $ (350) | $ - | $ - | $ - | $ (350) | $ (2,268,426) | $ (829,901) | $ (638,985) | $ - | $ (3,737,662) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 100,000 | $ - | $ 100,000 | $ 500,000 | $ 700,000 | $ 2,100,000 | $ 1,300,000 | $ 500,000 | $ - | $ 4,600,000 |
| Net Cost, $/Dth | **$ 4.115** | $ - | **$ 4.202** | **$ 4.543** | **$ 4.433** | **$ 4.415** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.430** |
| Market $/Dth (at Swap location) | **$ 2.638** | $ - | **$ 2.761** | **$ 2.905** | **$ 2.846** | **$ 2.935** | **$ 3.037** | **$ 3.098** | $ - | **$ 2.968** |
| Difference ($) versus current Market | $ (147,700) | $ - | $ (144,100) | $ (819,000) | $ (1,110,800) | $ (3,108,200) | $ (1,797,970) | $ (709,250) | $ - | $ (6,726,220) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of August 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 500,799 |
| WACOG $/Dth | 2.779 |

**The Empire District ELECTRIC Company**
Gas Position Summary as of September 30, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | October 2015 | November 2015 | December 2015 | Jan - Dec 2016 | Oct - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 510,885 | 388,808 | 377,951 | 9,757,650 | 1,277,643 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 41,885,181 |
| Expected Dth (3) | 510,885 | 388,808 | 377,951 | 9,757,650 | 1,277,643 | 9,757,650 | 10,310,058 | 10,269,212 | 10,270,618 | 41,885,181 |
| Policy minimum hedged Dth (2) | 306,531 | 233,285 | 226,770 | 5,854,590 | 766,586 | 5,854,590 | 4,124,023 | 2,053,842 | 1,027,062 | 13,826,103 |
| Policy Maximum hedged Dth | 510,885 | 388,808 | 377,951 | 9,757,650 | 1,277,643 | 7,806,120 | 8,248,047 | 8,215,369 | 8,216,495 | 33,763,674 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 35,000 | 100,000 | 500,000 | 5,256,000 | 635,000 | 5,256,000 | 2,082,900 | 1,065,000 | - | 9,038,900 |
| percentage | **7%** | **26%** | **132%** | **54%** | **50%** | **54%** | **20%** | **10%** | **0%** | **22%** |
| Amount Hedged from Downside Volitility Dth | $ 35,000 | $ 100,000 | $ 500,000 | $ 5,256,000 | $ 635,000 | $ 5,256,000 | $ 2,082,900 | $ 1,065,000 | $ - | $ 9,038,900 |
| percentage | **7%** | **26%** | **132%** | **54%** | **50%** | **54%** | **20%** | **10%** | **0%** | **22%** |
| **Average Cost per Dth hedged** | **$ 2.349** | **$ 4.202** | **$ 4.543** | **$ 3.795** | **$ 4.368** | **$ 3.795** | **$ 4.133** | **$ 4.121** | **$ -** | **$ 3.894** |
| Net all Positions $ (1) | $ 2,125 | $ (167,800) | $ (921,000) | $ (5,966,314) | $ (1,086,675) | $ (5,966,314) | $ (2,844,762) | $ (1,479,753) | $ - | $ (11,377,503) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 35,000 | $ - | $ - | $ 2,676,000 | $ 35,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,058,900 |
| Purchased $ | $ 82,225 | $ - | $ - | $ 9,344,800 | $ 82,225 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 14,420,825 |
| Purchased $/Dth | **$ 2.349** | **$ -** | **$ -** | **$ 3.492** | **$ 2.349** | **$ 3.492** | **$ 3.657** | **$ 3.771** | **$ -** | **$ 3.553** |
| Market $ | $ 84,350 | $ - | $ - | $ 6,761,506 | $ 84,350 | $ 6,761,506 | $ 1,969,778 | $ 1,429,448 | $ - | $ 10,245,082 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.410** | **$ -** | **$ -** | **$ 2.527** | **$ 2.410** | **$ 2.527** | **$ 2.516** | **$ 2.530** | **$ -** | **$ 2.524** |
| Difference ($) versus current market | $ 2,125 | $ - | $ - | $ (2,583,294) | $ 2,125 | $ (2,583,294) | $ (893,572) | $ (701,003) | $ - | $ (4,175,743) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ - | $ 100,000 | $ 500,000 | $ 2,580,000 | $ 600,000 | $ 2,580,000 | $ 1,300,000 | $ 500,000 | $ - | $ 4,980,000 |
| Net Cost, $/Dth | $ - | **$ 4.202** | **$ 4.543** | **$ 4.110** | **$ 4.486** | **$ 4.110** | **$ 4.420** | **$ 4.516** | $ - | **$ 4.277** |
| Market $/Dth (at Swap location) | $ - | **$ 2.524** | **$ 2.701** | **$ 2.799** | **$ 2.672** | **$ 2.799** | **$ 2.919** | **$ 2.959** | $ - | **$ 2.831** |
| Difference ($) versus current Market | $ - | $ (167,800) | $ (921,000) | $ (3,383,020) | $ (1,088,800) | $ (3,383,020) | $ (1,951,190) | $ (778,750) | $ - | $ (7,201,760) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of September 30, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 649,279 |
| WACOG $/Dth | 2.710 |

Schedule JSR-D-4
Proprietary

| The Empire District ELECTRIC Company<br>Gas Position Summary as of October 31, 2015 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Current/Upcoming Year | | | | All Years | | | | | Total |
| | November 2015 | December 2015 | January 2016 | Feb - Dec 2016 | Nov - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 388,808 | 962,200 | 1,181,400 | 13,046,100 | 1,351,008 | 14,227,500 | 10,310,058 | 10,269,212 | 10,270,618 | 46,428,396 |
| Expected Dth (3) | 388,808 | 962,200 | 1,181,400 | 13,046,100 | 1,351,008 | 14,227,500 | 10,310,058 | 10,269,212 | 10,270,618 | 46,428,396 |
| Policy minimum hedged Dth (2) | 233,285 | 577,320 | 708,840 | 7,827,660 | 810,605 | 8,536,500 | 4,124,023 | 2,053,842 | 1,027,062 | 16,552,032 |
| Policy Maximum hedged Dth | 388,808 | 962,200 | 1,181,400 | 13,046,100 | 1,351,008 | 11,382,000 | 8,248,047 | 8,215,369 | 8,216,495 | 37,412,919 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 134,000 | 500,000 | 920,000 | 7,696,000 | 634,000 | 8,616,000 | 4,002,900 | 1,785,000 | - | 15,037,900 |
| percentage | 34% | 52% | 78% | 59% | 47% | 61% | 39% | 17% | 0% | 32% |
| Amount Hedged from Downside Volitility Dth | $ 134,000 | $ 500,000 | $ 920,000 | $ 7,696,000 | $ 634,000 | $ 8,616,000 | $ 4,002,900 | $ 1,785,000 | $ - | $ 15,037,900 |
| percentage | 34% | 52% | 78% | 59% | 47% | 61% | 39% | 17% | 0% | 32% |
| **Average Cost per Dth hedged** | $ **3.564** | $ **4.543** | $ **3.127** | $ **3.406** | $ **4.336** | $ **3.376** | $ **3.549** | $ **3.666** | $ - | $ **3.453** |
| Net all Positions $ (1) | $ (210,350) | $ (1,111,000) | $ (585,600) | $ (6,720,028) | $ (1,321,350) | $ (7,305,628) | $ (3,337,512) | $ (1,660,728) | $ - | $ (13,625,217) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 34,000 | $ - | $ - | $ 2,676,000 | $ 34,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,057,900 |
| Purchased $ | $ 57,410 | $ - | $ - | $ 9,344,800 | $ 57,410 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 14,396,010 |
| Purchased $/Dth | $ **1.689** | $ - | $ - | $ **3.492** | $ **1.689** | $ **3.492** | $ **3.657** | $ **3.771** | $ - | $ **3.548** |
| Market $ | $ 64,260 | $ - | $ - | $ 6,365,762 | $ 64,260 | $ 6,365,762 | $ 1,865,228 | $ 1,384,913 | $ - | $ 9,680,163 |
| Market $/Dth (on Southern Start Pipeline) | $ **1.890** | $ - | $ - | $ **2.379** | $ **1.890** | $ **2.379** | $ **2.382** | $ **2.451** | $ - | $ **2.386** |
| Difference ($) versus current market | $ 6,850 | $ - | $ - | $ (2,979,038) | $ 6,850 | $ (2,979,038) | $ (998,122) | $ (745,538) | $ - | $ (4,715,847) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 100,000 | $ 500,000 | $ 920,000 | $ 5,020,000 | $ 600,000 | $ 5,940,000 | $ 3,220,000 | $ 1,220,000 | $ - | $ 10,980,000 |
| Net Cost, $/Dth | $ **4.202** | $ **4.543** | $ **3.127** | $ **3.360** | $ **4.486** | $ **3.324** | $ **3.522** | $ **3.617** | $ - | $ **3.478** |
| Market $/Dth (at Swap location) | $ **2.030** | $ **2.321** | $ **2.490** | $ **2.614** | $ **2.273** | $ **2.595** | $ **2.796** | $ **2.867** | $ - | $ **2.667** |
| Difference ($) versus current Market | $ (217,200) | $ (1,111,000) | $ (585,600) | $ (3,740,990) | $ (1,328,200) | $ (4,326,590) | $ (2,339,390) | $ (915,190) | $ - | $ (8,909,370) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| Storage Estimates | |
|---|---|
| Balance Dth | 703,817 |
| WACOG $/Dth | 2.658 |

Note 1: Market data using NYMEX Close Prices as of October 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from FINAL F&PP Budget for 2015. *12/15-12/16 updated 10/20/2015 based on Preliminary 2016
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

**The Empire District ELECTRIC Company**
Gas Position Summary as of November 30, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | December 2015 | January 2016 | February 2016 | Mar - Dec 2016 | Dec - Dec 2015 | Year 2016 60% min | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Net All Years |
| Budget Dth (3) | 962,200 | 1,181,400 | 939,700 | 12,106,400 | 962,200 | 14,227,500 | 14,671,030 | 14,766,560 | 14,382,698 | 59,009,988 |
| Expected Dth (3) | 962,200 | 1,181,400 | 939,700 | 12,106,400 | 962,200 | 14,227,500 | 14,671,030 | 14,766,560 | 14,382,698 | 59,009,988 |
| Policy minimum hedged Dth (2) | 577,320 | 708,840 | 563,820 | 7,263,840 | 577,320 | 8,536,500 | 5,868,412 | 2,953,312 | 1,438,270 | 19,373,814 |
| Policy Maximum hedged Dth | 962,200 | 1,181,400 | 939,700 | 12,106,400 | 962,200 | 11,382,000 | 11,736,824 | 11,813,248 | 11,506,158 | 47,400,430 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 508,888 | 920,000 | 720,000 | 6,976,000 | 508,888 | 8,616,000 | 5,992,900 | 3,025,000 | 1,460,000 | 19,602,788 |
| percentage | **53%** | **78%** | **77%** | **58%** | **53%** | **61%** | **41%** | **20%** | **10%** | **33%** |
| Amount Hedged from Downside Volitility Dth | $ 508,888 | $ 920,000 | $ 720,000 | $ 6,976,000 | $ 508,888 | $ 8,616,000 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ 19,602,788 |
| percentage | **53%** | **78%** | **77%** | **58%** | **53%** | **61%** | **41%** | **20%** | **10%** | **33%** |
| **Average Cost per Dth hedged** | **$ 4.500** | **$ 3.127** | **$ 2.725** | **$ 3.476** | **$ 4.500** | **$ 3.376** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ 3.364** |
| Net all Positions $ (1) | $ (1,168,553) | $ (820,200) | $ (312,960) | $ (7,346,888) | $ (1,168,553) | $ (8,480,048) | $ (3,679,412) | $ (1,829,640) | $ 168,500 | $ (14,989,153) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 8,888 | $ - | $ - | $ 2,676,000 | $ 8,888 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ 4,032,788 |
| Purchased $ | $ 18,718 | $ - | $ - | $ 9,344,800 | $ 18,718 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ 14,357,318 |
| Purchased $/Dth | **$ 2.106** | **$ -** | **$ -** | **$ 3.492** | **$ 2.106** | **$ 3.492** | **$ 3.657** | **$ 3.771** | **$ -** | **$ 3.560** |
| Market $ | $ 18,665 | $ - | $ - | $ 6,010,502 | $ 18,665 | $ 6,010,502 | $ 1,833,478 | $ 1,356,430 | $ - | $ 9,219,075 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.100** | **$ -** | **$ -** | **$ 2.246** | **$ 2.100** | **$ 2.246** | **$ 2.342** | **$ 2.401** | **$ -** | **$ 2.286** |
| Difference ($) versus current market | $ (53) | $ - | $ - | $ (3,334,298) | $ (53) | $ (3,334,298) | $ (1,029,872) | $ (774,020) | $ - | $ (5,138,243) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 500,000 | $ 920,000 | $ 720,000 | $ 4,300,000 | $ 500,000 | $ 5,940,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ 15,570,000 |
| Net Cost, $/Dth | **$ 4.543** | **$ 3.127** | **$ 2.725** | **$ 3.466** | **$ 4.543** | **$ 3.324** | **$ 3.300** | **$ 3.234** | **$ 2.955** | **$ 3.306** |
| Market $/Dth (at Swap location) | **$ 2.206** | **$ 2.235** | **$ 2.290** | **$ 2.533** | **$ 2.206** | **$ 2.457** | **$ 2.792** | **$ 2.805** | **$ 3.070** | **$ 2.673** |
| Difference ($) versus current Market | $ (1,168,500) | $ (820,200) | $ (312,960) | $ (4,012,590) | $ (1,168,500) | $ (5,145,750) | $ (2,649,540) | $ (1,055,620) | $ 168,500 | $ (9,850,910) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of November 30, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2019, Budgeted & Expected Dth are from PRELIMINARY F&PP Budget for 2016.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 589,756 |
| WACOG $/Dth | 2.651 |

**The Empire District ELECTRIC Company**
Gas Position Summary as of December 31, 2015

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | January 2016 | February 2016 | March 2016 | Apr - Dec 2016 | Jan - Dec 2016 | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Year 2020 0% min | Net All Years |
| Budget Dth (3) | 1,181,400 | 939,700 | 417,400 | 11,689,000 | 14,227,500 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 72,534,728 |
| Expected Dth (3) | 1,181,400 | 939,700 | 417,400 | 11,689,000 | 14,227,500 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 72,534,728 |
| Policy minimum hedged Dth (2) | 708,840 | 563,820 | 250,440 | 7,013,400 | 8,536,500 | 5,868,412 | 2,953,312 | 1,438,270 | - | 18,796,494 |
| Policy Maximum hedged Dth | 1,181,400 | 939,700 | 417,400 | 11,689,000 | 14,227,500 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 60,873,282 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 950,000 | 720,000 | 240,000 | 6,736,000 | 8,646,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 19,123,900 |
| percentage | **80%** | **77%** | **57%** | **58%** | **61%** | **41%** | **20%** | **10%** | **0%** | **26%** |
| Amount Hedged from Downside Volitility Dth | $ 950,000 | $ 720,000 | $ 240,000 | $ 6,736,000 | $ 8,646,000 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 19,123,900 |
| percentage | **80%** | **77%** | **57%** | **58%** | **61%** | **41%** | **20%** | **10%** | **0%** | **26%** |
| **Average Cost per Dth hedged** | **$ 3.100** | **$ 2.725** | **$ 2.552** | **$ 3.509** | **$ 3.372** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ -** | **$ 3.326** |
| Net all Positions $ (1) | $ (698,210) | $ (279,120) | $ (45,360) | $ (7,130,124) | $ (8,152,814) | $ (3,625,894) | $ (1,738,665) | $ 196,240 | $ - | $ (13,321,133) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 30,000 | $ - | $ - | $ 2,676,000 | $ 2,706,000 | $ 782,900 | $ 565,000 | $ - | $ - | $ 4,053,900 |
| Purchased $ | $ 68,550 | $ - | $ - | $ 9,344,800 | $ 9,413,350 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 14,407,150 |
| Purchased $/Dth | **$ 2.285** | **$ -** | **$ -** | **$ 3.492** | **$ 3.479** | **$ 3.657** | **$ 3.771** | **$ -** | **$ -** | **$ 3.554** |
| Market $ | $ 64,500 | $ - | $ - | $ 6,080,646 | $ 6,145,146 | $ 1,864,446 | $ 1,387,405 | $ - | $ - | $ 9,396,997 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.150** | **$ -** | **$ -** | **$ 2.272** | **$ 2.271** | **$ 2.381** | **$ 2.456** | **$ -** | **$ -** | **$ 2.318** |
| Difference ($) versus current market | $ (4,050) | $ - | $ - | $ (3,264,154) | $ (3,268,204) | $ (998,904) | $ (743,045) | $ - | $ - | $ (5,010,153) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 920,000 | $ 720,000 | $ 240,000 | $ 4,060,000 | $ 5,940,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 15,070,000 |
| Net Cost, $/Dth | **$ 3.127** | **$ 2.725** | **$ 2.552** | **$ 3.520** | **$ 3.324** | **$ 3.300** | **$ 3.234** | **$ 2.955** | **$ -** | **$ 3.265** |
| Market $/Dth (at Swap location) | **$ 2.372** | **$ 2.337** | **$ 2.363** | **$ 2.568** | **$ 2.501** | **$ 2.796** | **$ 2.829** | **$ 3.089** | **$ -** | **$ 2.714** |
| Difference ($) versus current Market | $ (694,160) | $ (279,120) | $ (45,360) | $ (3,865,970) | $ (4,884,610) | $ (2,626,990) | $ (995,620) | $ 196,240 | $ - | $ (8,310,980) |
| **Swap/Futures Dth Sold or Settle** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of December 31, 2015.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | 418,118 |
| WACOG $/Dth | 2.634 |

**The Empire District ELECTRIC Company**
Gas Position Summary as of January 31, 2016

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | February 2016 | March 2016 | April 2016 | May - Dec 2016 | Feb - Dec 2016 | Year 2017 40% min | Year 2018 20% min | Year 2019 10% min | Year 2020 0% min | Net All Years |
| Budget Dth (3) | 939,700 | 417,400 | 670,700 | 11,018,300 | 13,046,100 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 71,353,328 |
| Expected Dth (3) | 939,700 | 417,400 | 670,700 | 11,018,300 | 13,046,100 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 71,353,328 |
| Policy minimum hedged Dth (2) | 563,820 | 250,440 | 402,420 | 6,610,980 | 7,827,660 | 5,868,412 | 2,953,312 | 1,438,270 | - | 18,087,654 |
| Policy Maximum hedged Dth | 939,700 | 417,400 | 670,700 | 11,018,300 | 13,046,100 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 59,691,882 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 720,000 | 240,000 | 200,000 | 6,336,000 | 7,496,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 17,973,900 |
| percentage | 77% | 57% | 30% | 58% | 57% | 41% | 20% | 10% | 0% | 25% |
| Amount Hedged from Downside Volitility Dth | $ 720,000 | $ 240,000 | $ 200,000 | $ 6,336,000 | $ 7,496,000 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 17,973,900 |
| percentage | 77% | 57% | 30% | 58% | 57% | 41% | 20% | 10% | 0% | 25% |
| **Average Cost per Dth hedged** | $ 2.725 | $ 2.552 | $ 3.990 | $ 3.522 | $ 3.427 | $ 3.347 | $ 3.334 | $ 2.955 | $ - | $ 3.346 |
| Net all Positions $ (1) | $ (385,680) | $ (60,960) | $ (378,400) | $ (7,122,610) | $ (7,947,650) | $ (3,847,320) | $ (1,848,508) | $ 153,900 | $ - | $ (13,489,578) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ - | $ - | $ 200,000 | $ 2,476,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ - | $ 4,023,900 |
| Purchased $ | $ - | $ - | $ 798,000 | $ 8,546,800 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 14,338,600 |
| Purchased $/Dth | $ - | $ - | $ 3.990 | $ 3.452 | $ 3.492 | $ 3.657 | $ 3.771 | $ - | $ - | $ 3.563 |
| Market $ | $ - | $ - | $ 419,600 | $ 5,485,900 | $ 5,905,500 | $ 1,817,760 | $ 1,354,803 | $ - | $ - | $ 9,078,062 |
| Market $/Dth (on Southern Start Pipeline) | $ - | $ - | $ 2.098 | $ 2.216 | $ 2.207 | $ 2.322 | $ 2.398 | $ - | $ - | $ 2.256 |
| Difference ($) versus current market | $ - | $ - | $ (378,400) | $ (3,060,900) | $ (3,439,300) | $ (1,045,590) | $ (775,648) | $ - | $ - | $ (5,260,538) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 720,000 | $ 240,000 | $ - | $ 4,060,000 | $ 5,020,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 14,150,000 |
| Net Cost, $/Dth | $ 2.725 | $ 2.552 | $ - | $ 3.520 | $ 3.360 | $ 3.300 | $ 3.234 | $ 2.955 | $ - | $ 3.274 |
| Market $/Dth (at Swap location) | $ 2.189 | $ 2.298 | $ - | $ 2.520 | $ 2.462 | $ 2.763 | $ 2.798 | $ 3.060 | $ - | $ 2.693 |
| Difference ($) versus current Market | $ (385,680) | $ (60,960) | $ - | $ (4,061,710) | $ (4,508,350) | $ (2,801,730) | $ (1,072,860) | $ 153,900 | $ - | $ (8,229,040) |
| **Swap/Futures Dth Sold or Settle** | $ - | $ - | $ - | $ (200,000.00) | $ (200,000.00) | $ - | $ - | $ - | $ - | $ (200,000.00) |
| Net Cost, $/Dth | $ - | $ - | $ - | $ 2.61 | $ 2.61 | $ - | $ - | $ - | $ - | $ 2.61 |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ 2.47 | $ 2.47 | $ - | $ - | $ - | $ - | $ 2.47 |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ (0.14) | $ (0.14) | $ - | $ - | $ - | $ - | $ (0.14) |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| Storage Estimates | |
|---|---|
| Balance Dth | 328,118 |
| WACOG $/Dth | 2.634 |

Note 1: Market data using NYMEX Close Prices as of January 31, 2016.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

**The Empire District ELECTRIC Company**
Gas Position Summary as of February 29, 2016

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | March 2016 | April 2016 | May 2016 | Jun - Dec 2016 | Mar - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| Budget Dth (3) | 417,400 | 670,700 | 1,017,300 | 10,001,000 | 12,106,400 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 70,413,628 |
| Expected Dth (3) | 417,400 | 670,700 | 1,017,300 | 10,001,000 | 12,106,400 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 70,413,628 |
| Policy minimum hedged Dth (2) | 250,440 | 402,420 | 610,380 | 6,000,600 | 7,263,840 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 26,298,316 |
| Policy Maximum hedged Dth | 417,400 | 670,700 | 1,017,300 | 10,001,000 | 12,106,400 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 58,752,182 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 258,400 | 200,000 | 440,000 | 5,896,000 | 6,794,400 | 5,992,900 | 3,025,000 | 1,460,000 | - | 17,272,300 |
| percentage | 62% | 30% | 43% | 59% | 56% | 41% | 20% | 10% | 0% | 25% |
| Amount Hedged from Downside Volitility Dth | $ 258,400 | $ 200,000 | $ 440,000 | $ 5,896,000 | $ 6,794,400 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 17,272,300 |
| percentage | 62% | 30% | 43% | 59% | 56% | 41% | 20% | 10% | 0% | 25% |
| **Average Cost per Dth hedged** | $ 2.470 | $ 3.990 | $ 3.189 | $ 3.547 | $ 3.496 | $ 3.347 | $ 3.334 | $ 2.955 | $ - | $ 3.370 |
| Net all Positions $ (1) | $ (284,542) | $ (497,600) | $ (659,720) | $ (9,330,373) | $ (10,772,234) | $ (5,144,921) | $ (2,601,900) | $ (547,000) | $ - | $ (19,066,056) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 18,400 | $ 200,000 | $ 200,000 | $ 2,276,000 | $ 2,694,400 | $ 782,900 | $ 565,000 | $ - | $ - | $ 4,042,300 |
| Purchased $ | $ 26,118 | $ 798,000 | $ 798,000 | $ 7,748,800 | $ 9,370,918 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 14,364,718 |
| Purchased $/Dth | $ 1.419 | $ 3.990 | $ 3.990 | $ 3.405 | $ 3.478 | $ 3.657 | $ 3.771 | $ - | $ - | $ 3.554 |
| Market $ | $ 27,416 | $ 300,400 | $ 309,400 | $ 4,005,878 | $ 4,643,094 | $ 1,704,179 | $ 1,245,890 | $ - | $ - | $ 7,593,163 |
| Market $/Dth (on Southern Start Pipeline) | $ 1.490 | $ 1.502 | $ 1.547 | $ 1.760 | $ 1.723 | $ 2.177 | $ 2.205 | $ - | $ - | $ 1.878 |
| Difference ($) versus current market | $ 1,298 | $ (497,600) | $ (488,600) | $ (3,742,922) | $ (4,727,824) | $ (1,159,171) | $ (884,560) | $ - | $ - | $ (6,771,555) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 480,000 | $ - | $ 240,000 | $ 3,820,000 | $ 4,540,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 13,670,000 |
| Net Cost, $/Dth | $ 2.307 | $ - | $ 2.521 | $ 3.583 | $ 3.392 | $ 3.300 | $ 3.234 | $ 2.955 | $ - | $ 3.282 |
| Market $/Dth (at Swap location) | $ 1.711 | $ - | $ 1.808 | $ 2.120 | $ 2.060 | $ 2.535 | $ 2.536 | $ 2.580 | $ - | $ 2.382 |
| Difference ($) versus current Market | $ (285,840) | $ - | $ (171,120) | $ (5,587,450) | $ (6,044,410) | $ (3,985,750) | $ (1,717,340) | $ (547,000) | $ - | $ (12,294,500) |
| **Swap/Futures Dth Sold or Settle** | $ (240,000.00) | $ - | $ - | $ (200,000.00) | $ (440,000.00) | $ - | $ - | $ - | $ - | $ (440,000.00) |
| Net Cost, $/Dth | $ 2.06 | $ - | $ - | $ 2.61 | $ 2.31 | $ - | $ - | $ - | $ - | $ 2.31 |
| Market $/Dth (at Swap location) | $ 1.71 | $ - | $ - | $ 2.03 | $ 1.86 | $ - | $ - | $ - | $ - | $ 1.86 |
| Swap Settlement - Receipt / (Payment) | $ (0.35) | $ - | $ - | $ (0.57) | $ (0.45) | $ - | $ - | $ - | $ - | $ (0.45) |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| Storage Estimates | |
|---|---|
| Balance Dth | 46,118 |
| WACOG $/Dth | 2.631 |

Note 1: Market data using NYMEX Close Prices as of February 29, 2016.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

**The Empire District ELECTRIC Company**
Gas Position Summary as of March 31, 2016

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | April 2016 | May 2016 | June 2016 | Jul - Dec 2016 | Apr - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| Budget Dth (3) | 670,700 | 1,017,300 | 1,091,600 | 8,909,400 | 11,689,000 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 69,996,228 |
| Expected Dth (3) | 670,700 | 1,017,300 | 1,091,600 | 8,909,400 | 11,689,000 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 69,996,228 |
| Policy minimum hedged Dth (2) | 402,420 | 610,380 | 654,960 | 5,345,640 | 7,013,400 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 26,047,876 |
| Policy Maximum hedged Dth | 670,700 | 1,017,300 | 1,091,600 | 8,909,400 | 11,689,000 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 58,334,782 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Voltility Dth | 200,000 | 440,000 | 540,000 | 5,356,000 | 6,536,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 17,013,900 |
| percentage | 30% | 43% | 49% | 60% | 56% | 41% | 20% | 10% | 0% | 24% |
| Amount Hedged from Downside Voltility Dth | $ 200,000 | $ 440,000 | $ 540,000 | $ 5,356,000 | $ 6,536,000 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 17,013,900 |
| percentage | 30% | 43% | 49% | 60% | 56% | 41% | 20% | 10% | 0% | 24% |
| **Average Cost per Dth hedged** | **$ 3.990** | **$ 3.189** | **$ 3.844** | **$ 3.517** | **$ 3.537** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ -** | **$ 3.384** |
| Net all Positions $ (1) | $ (476,000) | $ (588,080) | $ (1,072,820) | $ (7,074,392) | $ (9,211,292) | $ (3,685,650) | $ (1,823,803) | $ (166,440) | $ - | $ (14,887,185) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 200,000 | $ 200,000 | $ 440,000 | $ 1,836,000 | $ 2,676,000 | $ 782,900 | $ 565,000 | $ - | $ - | $ 4,023,900 |
| Purchased $ | $ 798,000 | $ 798,000 | $ 1,650,000 | $ 6,098,800 | $ 9,344,800 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 14,338,600 |
| Purchased $/Dth | **$ 3.990** | **$ 3.990** | **$ 3.750** | **$ 3.322** | **$ 3.492** | **$ 3.657** | **$ 3.771** | $ - | $ - | **$ 3.563** |
| Market $ | $ 322,000 | $ 344,800 | $ 797,280 | $ 3,632,118 | $ 5,096,198 | $ 1,890,550 | $ 1,409,508 | $ - | $ - | $ 8,396,256 |
| Market $/Dth (on Southern Start Pipeline) | **$ 1.610** | **$ 1.724** | **$ 1.812** | **$ 1.978** | **$ 1.904** | **$ 2.415** | **$ 2.495** | $ - | $ - | **$ 2.087** |
| Difference ($) versus current market | $ (476,000) | $ (453,200) | $ (852,720) | $ (2,466,682) | $ (4,248,602) | $ (972,800) | $ (720,943) | $ - | $ - | $ (5,942,344) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ - | $ 240,000 | $ 100,000 | $ 3,720,000 | $ 4,060,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 13,190,000 |
| Net Cost, $/Dth | $ - | **$ 2.521** | **$ 4.255** | **$ 3.565** | **$ 3.520** | **$ 3.300** | **$ 3.234** | **$ 2.955** | $ - | **$ 3.317** |
| Market $/Dth (at Swap location) | $ - | **$ 1.959** | **$ 2.054** | **$ 2.326** | **$ 2.298** | **$ 2.780** | **$ 2.785** | **$ 2.841** | $ - | **$ 2.639** |
| Difference ($) versus current Market | $ - | $ (134,880) | $ (220,100) | $ (4,607,710) | $ (4,962,690) | $ (2,712,850) | $ (1,102,860) | $ (166,440) | $ - | $ (8,944,840) |
| **Swap/Futures Dth Sold or Settle** | $ - | $ - | $ - | $ (200,000.00) | $ (200,000.00) | $ - | $ - | $ - | $ - | $ (200,000.00) |
| Net Cost, $/Dth | $ - | $ - | $ - | **$ 2.61** | **$ 2.61** | $ - | $ - | $ - | $ - | **$ 2.61** |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | **$ 2.21** | **$ 2.21** | $ - | $ - | $ - | $ - | **$ 2.21** |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ (0.39) | $ (0.39) | $ - | $ - | $ - | $ - | $ (0.39) |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of March 31, 2016.
Note 2: Policy minimums are 12/31/2015 targets.
Note 3: For 2015 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

| The Empire District Electric Company<br>Gas Position Summary as of April 30, 2016 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Current/Upcoming Year | | | | All Years | | | | | Total |
| | May 2016 | June 2016 | July 2016 | Aug - Dec 2016 | May - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| **SUMMARY** | | | | | | | | | | |
| Budget Dth (3) | 1,017,300 | 1,091,600 | 2,085,200 | 6,824,200 | 11,018,300 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 69,325,528 |
| Expected Dth (3) | 1,017,300 | 1,091,600 | 2,085,200 | 6,824,200 | 11,018,300 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 69,325,528 |
| Policy minimum hedged Dth (2) | 610,380 | 654,960 | 1,251,120 | 4,094,520 | 6,610,980 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 25,645,456 |
| Policy Maximum hedged Dth | 1,017,300 | 1,091,600 | 2,085,200 | 6,824,200 | 11,018,300 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 57,664,082 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 490,000 | 540,000 | 2,078,000 | 3,278,000 | 6,386,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 16,863,900 |
| percentage | 48% | 49% | 100% | 48% | 58% | 41% | 20% | 10% | 0% | 24% |
| Amount Hedged from Downside Volitility Dth | $ 490,000 | $ 540,000 | $ 2,078,000 | $ 3,278,000 | $ 6,386,000 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 16,863,900 |
| percentage | 48% | 49% | 100% | 48% | 58% | 41% | 20% | 10% | 0% | 24% |
| **Average Cost per Dth hedged** | $ 3.045 | $ 3.844 | $ 3.577 | $ 3.479 | $ 3.509 | $ 3.347 | $ 3.334 | $ 2.955 | $ - | $ 3.372 |
| Net all Positions $ (1) | $ (573,490) | $ (979,020) | $ (2,763,912) | $ (3,141,712) | $ (7,458,134) | $ (2,173,162) | $ (1,302,363) | $ (21,880) | $ - | $ (10,955,539) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 250,000 | $ 440,000 | $ 798,000 | $ 1,038,000 | $ 2,526,000 | $ 782,900 | $ 565,000 | $ - | $ - | $ 3,873,900 |
| Purchased $ | $ 887,250 | $ 1,650,000 | $ 2,623,400 | $ 3,475,400 | $ 8,636,050 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 13,629,850 |
| Purchased $/Dth | $ 3.549 | $ 3.750 | $ 3.287 | $ 3.348 | $ 3.419 | $ 3.657 | $ 3.771 | $ - | $ - | $ 3.518 |
| Market $ | $ 440,000 | $ 878,680 | $ 1,696,548 | $ 2,305,818 | $ 5,321,046 | $ 2,143,398 | $ 1,545,208 | $ - | $ - | $ 9,009,652 |
| Market $/Dth (on Southern Start Pipeline) | $ 1.760 | $ 1.997 | $ 2.126 | $ 2.221 | $ 2.107 | $ 2.738 | $ 2.735 | $ - | $ - | $ 2.326 |
| Difference ($) versus current market | $ (447,250) | $ (771,320) | $ (926,852) | $ (1,169,582) | $ (3,315,004) | $ (719,952) | $ (585,243) | $ - | $ - | $ (4,620,198) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 240,000 | $ 100,000 | $ 1,280,000 | $ 2,440,000 | $ 4,060,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 13,190,000 |
| Net Cost, $/Dth | $ 2.521 | $ 4.255 | $ 3.757 | $ 3.464 | $ 3.520 | $ 3.300 | $ 3.234 | $ 2.955 | $ - | $ 3.317 |
| Market $/Dth (at Swap location) | $ 1.995 | $ 2.178 | $ 2.322 | $ 2.655 | $ 2.499 | $ 3.021 | $ 2.942 | $ 2.940 | $ - | $ 2.837 |
| Difference ($) versus current Market | $ (126,240) | $ (207,700) | $ (1,837,060) | $ (1,972,130) | $ (4,143,130) | $ (1,453,210) | $ (717,120) | $ (21,880) | $ - | $ (6,335,340) |
| **Swap/Futures Dth Sold or Settle** | $ - | $ - | $ - | $ (200,000.00) | $ (200,000.00) | $ - | $ - | $ - | $ - | $ (200,000.00) |
| Net Cost, $/Dth | $ - | $ - | $ - | $ 2.61 | $ 2.61 | $ - | $ - | $ - | $ - | $ 2.61 |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ 2.41 | $ 2.41 | $ - | $ - | $ - | $ - | $ 2.41 |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ (0.19) | $ (0.19) | $ - | $ - | $ - | $ - | $ (0.19) |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of April 30, 2016.
Note 2: Policy minimums are 12/31/2016 targets.
Note 3: For 2016 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

Schedule JSR-D-4
Proprietary

| The Empire District Electric Company<br>Gas Position Summary as of May 31, 2016 | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Current/Upcoming Year | | | | All Years | | | | | Total |
| | June 2016 | July 2016 | August 2016 | Sep - Dec 2016 | Jun - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| **SUMMARY** | | | | | | | | | | |
| Budget Dth (3) | 1,091,600 | 2,085,200 | 1,930,300 | 4,893,900 | 10,001,000 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 68,308,228 |
| Expected Dth (3) | 1,091,600 | 2,085,200 | 1,930,300 | 4,893,900 | 10,001,000 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 68,308,228 |
| Policy minimum hedged Dth (2) | 654,960 | 1,251,120 | 1,158,180 | 2,936,340 | 6,000,600 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 25,035,076 |
| Policy Maximum hedged Dth | 1,091,600 | 2,085,200 | 1,930,300 | 4,893,900 | 10,001,000 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 56,646,782 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 609,017 | 2,078,000 | 1,878,000 | 1,400,000 | 5,965,017 | 5,992,900 | 3,025,000 | 1,460,000 | - | 16,442,917 |
| percentage | 56% | 100% | 97% | 29% | 60% | 41% | 20% | 10% | 0% | 24% |
| Amount Hedged from Downside Volitility Dth | $ 609,017 | $ 2,078,000 | $ 1,878,000 | $ 1,400,000 | $ 5,965,017 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 16,442,917 |
| percentage | 56% | 100% | 97% | 29% | 60% | 41% | 20% | 10% | 0% | 24% |
| **Average Cost per Dth hedged** | **$ 3.625** | **$ 3.577** | **$ 3.691** | **$ 3.196** | **$ 3.528** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ -** | **$ 3.376** |
| Net all Positions $ (1) | $ (1,105,402) | $ (2,789,876) | $ (2,612,526) | $ (559,450) | $ (7,067,254) | $ (2,187,867) | $ (1,313,098) | $ 10,240 | $ - | $ (10,557,979) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 509,017 | $ 798,000 | $ 798,000 | $ 240,000 | $ 2,345,017 | $ 782,900 | $ 565,000 | $ - | $ - | $ 3,692,917 |
| Purchased $ | $ 1,782,252 | $ 2,623,400 | $ 2,623,400 | $ 852,000 | $ 7,881,052 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 12,874,852 |
| Purchased $/Dth | **$ 3.501** | **$ 3.287** | **$ 3.287** | **$ 3.550** | **$ 3.361** | **$ 3.657** | **$ 3.771** | $ - | $ - | **$ 3.486** |
| Market $ | $ 906,050 | $ 1,714,104 | $ 1,789,914 | $ 550,320 | $ 4,960,388 | $ 2,156,373 | $ 1,552,653 | $ - | $ - | $ 8,669,414 |
| Market $/Dth (on Southern Start Pipeline) | **$ 1.780** | **$ 2.148** | **$ 2.243** | **$ 2.293** | **$ 2.115** | **$ 2.754** | **$ 2.748** | $ - | $ - | **$ 2.348** |
| Difference ($) versus current market | $ (876,202) | $ (909,296) | $ (833,486) | $ (301,680) | $ (2,920,664) | $ (706,977) | $ (577,798) | $ - | $ - | $ (4,205,438) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 100,000 | $ 1,280,000 | $ 1,280,000 | $ 1,160,000 | $ 3,820,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 12,950,000 |
| Net Cost, $/Dth | **$ 4.255** | **$ 3.757** | **$ 3.773** | **$ 3.122** | **$ 3.583** | **$ 3.300** | **$ 3.234** | **$ 2.955** | $ - | **$ 3.332** |
| Market $/Dth (at Swap location) | **$ 1.963** | **$ 2.288** | **$ 2.383** | **$ 2.900** | **$ 2.497** | **$ 3.016** | **$ 2.935** | **$ 2.962** | $ - | **$ 2.841** |
| Difference ($) versus current Market | $ (229,200) | $ (1,880,580) | $ (1,779,040) | $ (257,770) | $ (4,146,590) | $ (1,480,890) | $ (735,300) | $ 10,240 | $ - | $ (6,352,540) |
| **Swap/Futures Dth Sold or Settle** | $ - | $ - | $ (200,000.00) | $ - | $ (200,000.00) | $ - | $ - | $ - | $ - | $ (200,000.00) |
| Net Cost, $/Dth | $ - | $ - | **$ 2.61** | $ - | **$ 2.61** | $ - | $ - | $ - | $ - | **$ 2.61** |
| Market $/Dth (at Swap location) | $ - | $ - | **$ 2.38** | $ - | **$ 2.38** | $ - | $ - | $ - | $ - | **$ 2.38** |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ (0.22) | $ - | $ (0.22) | $ - | $ - | $ - | $ - | $ (0.22) |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of May 31, 2016.
Note 2: Policy minimums are 12/31/2016 targets.
Note 3: For 2016 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

Schedule JSR-D-4
Proprietary
15/18

## The Empire District Electric Company

### Gas Position Summary as of June 30, 2016

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | July 2016 | August 2016 | September 2016 | Oct - Dec 2016 | Jul - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Not All Years |
| **SUMMARY** | | | | | | | | | | |
| Budget Dth (3) | 2,085,200 | 1,930,300 | 1,398,500 | 3,495,400 | 8,909,400 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 67,216,628 |
| Expected Dth (3) | 2,085,200 | 1,930,300 | 1,398,500 | 3,495,400 | 8,909,400 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 67,216,628 |
| Policy minimum hedged Dth (2) | 1,251,120 | 1,158,180 | 839,100 | 2,097,240 | 5,345,640 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 24,380,116 |
| Policy Maximum hedged Dth | 2,085,200 | 1,930,300 | 1,398,500 | 3,495,400 | 8,909,400 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 55,555,182 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 2,145,017 | 1,878,000 | 240,000 | 1,160,000 | 5,423,017 | 5,992,900 | 3,025,000 | 1,460,000 | - | 15,900,917 |
| percentage | 103% | 97% | 17% | 33% | 61% | 41% | 20% | 10% | 0% | 24% |
| Amount Hedged from Downside Volitility Dth | $ 2,145,017 | $ 1,878,000 | $ 240,000 | $ 1,160,000 | $ 5,423,017 | $ 5,992,900 | $ 3,025,000 | $ 1,460,000 | $ - | $ 15,900,917 |
| percentage | 103% | 97% | 17% | 33% | 61% | 41% | 20% | 10% | 0% | 24% |
| **Average Cost per Dth hedged** | $ 3.548 | $ 3.691 | $ 3.550 | $ 3.122 | $ 3.507 | $ 3.347 | $ 3.334 | $ 2.955 | $ - | $ 3.363 |
| Net all Positions $ (1) | $ (1,731,583) | $ (1,483,540) | $ (183,840) | $ 139,030 | $ (3,259,933) | $ (1,025,891) | $ (1,455,133) | $ (72,480) | $ - | $ (5,813,436) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | $ 865,017 | $ 798,000 | $ 240,000 | $ - | $ 1,903,017 | $ 782,900 | $ 565,000 | $ - | $ - | $ 3,250,917 |
| Purchased $ | $ 2,801,365 | $ 2,623,400 | $ 852,000 | $ - | $ 6,276,765 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 11,270,565 |
| Purchased $/Dth | $ 3.239 | $ 3.287 | $ 3.550 | $ - | $ 3.298 | $ 3.657 | $ 3.771 | $ - | $ - | $ 3.467 |
| Market $ | $ 2,145,242 | $ 2,226,420 | $ 668,160 | $ - | $ 5,039,822 | $ 2,263,719 | $ 1,505,558 | $ - | $ - | $ 8,809,098 |
| Market $/Dth (on Southern Start Pipeline) | $ 2.480 | $ 2.790 | $ 2.784 | $ - | $ 2.648 | $ 2.891 | $ 2.665 | $ - | $ - | $ 2.710 |
| Difference ($) versus current market | $ (656,123) | $ (396,980) | $ (183,840) | $ - | $ (1,236,943) | $ (599,631) | $ (624,893) | $ - | $ - | $ (2,461,467) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | $ 1,280,000 | $ 1,280,000 | $ - | $ 1,160,000 | $ 3,720,000 | $ 5,210,000 | $ 2,460,000 | $ 1,460,000 | $ - | $ 12,850,000 |
| Net Cost, $/Dth | $ 3.757 | $ 3.773 | $ - | $ 3.122 | $ 3.565 | $ 3.300 | $ 3.234 | $ 2.955 | $ - | $ 3.325 |
| Market $/Dth (at Swap location) | $ 2.917 | $ 2.924 | $ - | $ 3.242 | $ 3.021 | $ 3.219 | $ 2.896 | $ 2.905 | $ - | $ 3.064 |
| Difference ($) versus current Market | $ (1,075,460) | $ (1,086,560) | $ - | $ 139,030 | $ (2,022,990) | $ (426,260) | $ (830,240) | $ (72,480) | $ - | $ (3,351,970) |
| **Swap/Futures Dth Sold or Settle** | $ - | $(200,000.00) | $ - | $ - | $ (200,000.00) | $ - | $ - | $ - | $ - | $ (200,000.00) |
| Net Cost, $/Dth | $ - | $ 2.61 | $ - | $ - | $ 2.61 | $ - | $ - | $ - | $ - | $ 2.61 |
| Market $/Dth (at Swap location) | $ - | $ 2.92 | $ - | $ - | $ 2.92 | $ - | $ - | $ - | $ - | $ 2.92 |
| Swap Settlement - Receipt / (Payment) | $ - | $ 0.32 | $ - | $ - | $ 0.32 | $ - | $ - | $ - | $ - | $ 0.32 |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of June 30, 2016.
Note 2: Policy minimums are 12/31/2016 targets.
Note 3: For 2016 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

| The Empire District Electric Company<br>Gas Position Summary as of July 31, 2016 | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | August 2016 | September 2016 | October 2016 | Nov - Dec 2016 | Aug - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| **SUMMARY** | | | | | | | | | | |
| Budget Dth (3) | 1,930,300 | 1,398,500 | 1,065,700 | 2,429,700 | 6,824,200 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 65,131,428 |
| Expected Dth (3) | 1,930,300 | 1,398,500 | 1,065,700 | 2,429,700 | 6,824,200 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 65,131,428 |
| Policy minimum hedged Dth (2) | 1,158,180 | 839,100 | 639,420 | 1,457,820 | 4,094,520 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 23,128,996 |
| Policy Maximum hedged Dth | 1,930,300 | 1,398,500 | 1,065,700 | 2,429,700 | 6,824,200 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 53,469,982 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 1,878,000 | 240,000 | 240,000 | 920,000 | 3,278,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 13,755,900 |
| percentage | **97%** | **17%** | **23%** | **38%** | **48%** | **41%** | **20%** | **10%** | **0%** | **21%** |
| Amount Hedged from Downside Volitility Dth | 1,878,000 | 240,000 | 240,000 | 920,000 | 3,278,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 13,755,900 |
| percentage | **97%** | **17%** | **23%** | **38%** | **48%** | **41%** | **20%** | **10%** | **0%** | **21%** |
| **Average Cost per Dth hedged** | **$ 3.691** | **$ 3.550** | **$ 2.598** | **$ 3.259** | **$ 3.479** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ -** | **$ 3.334** |
| Net all Positions $ (1) | $ (2,045,500) | $ (216,720) | $ 76,560 | $ 55,950 | $ (2,129,710) | $ (1,022,100) | $ (1,463,955) | $ (69,060) | $ - | $ (4,684,825) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | 798,000 | 240,000 | - | - | 1,038,000 | 782,900 | 565,000 | - | - | 2,385,900 |
| Purchased $ | $ 2,623,400 | $ 852,000 | $ - | $ - | $ 3,475,400 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 8,469,200 |
| Purchased $/Dth | **$ 3.287** | **$ 3.550** | $ - | $ - | **$ 3.348** | **$ 3.657** | **$ 3.771** | $ - | $ - | **$ 3.550** |
| Market $ | $ 1,987,020 | $ 635,280 | $ - | $ - | $ 2,622,300 | $ 2,250,600 | $ 1,492,795 | $ - | $ - | $ 6,365,695 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.490** | **$ 2.647** | $ - | $ - | **$ 2.526** | **$ 2.875** | **$ 2.642** | $ - | $ - | **$ 2.668** |
| Difference ($) versus current market | $ (636,380) | $ (216,720) | $ - | $ - | $ (853,100) | $ (612,750) | $ (637,655) | $ - | $ - | $ (2,103,505) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | 1,280,000 | - | 240,000 | 920,000 | 2,440,000 | 5,210,000 | 2,460,000 | 1,460,000 | - | 11,570,000 |
| Net Cost, $/Dth | **$ 3.773** | $ - | **$ 2.598** | **$ 3.259** | **$ 3.464** | **$ 3.300** | **$ 3.234** | **$ 2.955** | $ - | **$ 3.277** |
| Market $/Dth (at Swap location) | **$ 2.672** | $ - | **$ 2.917** | **$ 3.320** | **$ 2.940** | **$ 3.222** | **$ 2.898** | **$ 2.907** | $ - | **$ 3.054** |
| Difference ($) versus current Market | $ (1,409,120) | $ - | $ 76,560 | $ 55,950 | $ (1,276,610) | $ (409,350) | $ (826,300) | $ (69,060) | $ - | $ (2,581,320) |
| **Swap/Futures Dth Sold or Settle** | (200,000) | - | - | - | (200,000) | - | - | - | - | (200,000) |
| Net Cost, $/Dth | **$ 2.61** | $ - | $ - | $ - | **$ 2.61** | $ - | $ - | $ - | $ - | **$ 2.61** |
| Market $/Dth (at Swap location) | **$ 2.67** | $ - | $ - | $ - | **$ 2.67** | $ - | $ - | $ - | $ - | **$ 2.67** |
| Swap Settlement - Receipt / (Payment) | $ 0.07 | $ - | $ - | $ - | $ 0.07 | $ - | $ - | $ - | $ - | $ 0.07 |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of July 31, 2016.
Note 2: Policy minimums are 12/31/2016 targets.
Note 3: For 2016 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

## The Empire District Electric Company

### Gas Position Summary as of August 31, 2016

| | Current/Upcoming Year | | | | All Years | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | September 2016 | October 2016 | November 2016 | Dec - Dec 2016 | Sep - Dec 2016 | Year 2017 60% min | Year 2018 40% min | Year 2019 20% min | Year 2020 10% min | Net All Years |
| **SUMMARY** | | | | | | | | | | |
| Budget Dth (3) | 1,398,500 | 1,065,700 | 824,400 | 1,605,300 | 4,893,900 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 63,201,128 |
| Expected Dth (3) | 1,398,500 | 1,065,700 | 824,400 | 1,605,300 | 4,893,900 | 14,671,030 | 14,766,560 | 14,382,698 | 14,486,940 | 63,201,128 |
| Policy minimum hedged Dth (2) | 839,100 | 639,420 | 494,640 | 963,180 | 2,936,340 | 8,802,618 | 5,906,624 | 2,876,540 | 1,448,694 | 21,970,816 |
| Policy Maximum hedged Dth | 1,398,500 | 1,065,700 | 824,400 | 1,605,300 | 4,893,900 | 11,736,824 | 11,813,248 | 11,506,158 | 11,589,552 | 51,539,682 |
| Amount de-designated from Hedge amount | | | | | | | | | | - |
| Amount Hedged from Upside Volitility Dth | 240,000 | 240,000 | - | 920,000 | 1,400,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 11,877,900 |
| percentage | **17%** | **23%** | **0%** | **57%** | **29%** | **41%** | **20%** | **10%** | **0%** | **19%** |
| Amount Hedged from Downside Volitility Dth | 240,000 | 240,000 | - | 920,000 | 1,400,000 | 5,992,900 | 3,025,000 | 1,460,000 | - | 11,877,900 |
| percentage | **17%** | **23%** | **0%** | **57%** | **29%** | **41%** | **20%** | **10%** | **0%** | **19%** |
| **Average Cost per Dth hedged** | **$ 3.550** | **$ 2.598** | **$ -** | **$ 3.259** | **$ 3.196** | **$ 3.347** | **$ 3.334** | **$ 2.955** | **$ -** | **$ 3.278** |
| Net all Positions $ (1) | $ (228,000) | $ 69,360 | $ - | $ (51,690) | $ (210,330) | $ (1,428,985) | $ (1,604,160) | $ (116,280) | $ - | $ (3,359,755) |
| **PHYSICAL HEDGES** | | | | | | | | | | |
| **Purchased Dth** | 240,000 | - | - | - | 240,000 | 782,900 | 565,000 | - | - | 1,587,900 |
| Purchased $ | $ 852,000 | $ - | $ - | $ - | $ 852,000 | $ 2,863,350 | $ 2,130,450 | $ - | $ - | $ 5,845,800 |
| Purchased $/Dth | **$ 3.550** | $ - | $ - | $ - | **$ 3.550** | **$ 3.657** | **$ 3.771** | $ - | $ - | **$ 3.681** |
| Market $ | $ 624,000 | $ - | $ - | $ - | $ 624,000 | $ 2,203,365 | $ 1,447,030 | $ - | $ - | $ 4,274,395 |
| Market $/Dth (on Southern Start Pipeline) | **$ 2.600** | $ - | $ - | $ - | **$ 2.600** | **$ 2.814** | **$ 2.561** | $ - | $ - | **$ 2.692** |
| Difference ($) versus current market | $ (228,000) | $ - | $ - | $ - | $ (228,000) | $ (659,985) | $ (683,420) | $ - | $ - | $ (1,571,405) |
| **FINANCIAL HEDGES** | | | | | | | | | | |
| **Swap/Futures Dth Purchased** | - | 240,000 | - | 920,000 | 1,160,000 | 5,210,000 | 2,460,000 | 1,460,000 | - | 10,290,000 |
| Net Cost, $/Dth | $ - | **$ 2.598** | $ - | **$ 3.259** | **$ 3.122** | **$ 3.300** | **$ 3.234** | **$ 2.955** | $ - | **$ 3.215** |
| Market $/Dth (at Swap location) | $ - | **$ 2.887** | $ - | **$ 3.203** | **$ 3.138** | **$ 3.153** | **$ 2.859** | **$ 2.875** | $ - | **$ 3.042** |
| Difference ($) versus current Market | $ - | $ 69,360 | $ - | $ (51,690) | $ 17,670 | $ (769,000) | $ (920,740) | $ (116,280) | $ - | $ (1,788,350) |
| **Swap/Futures Dth Sold or Settle** | - | - | - | - | - | - | - | - | - | - |
| Net Cost, $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Swap Settlement - Receipt / (Payment) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Call Dth (Buy a Call)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Call Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (At Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Call $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Call Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Collar Dth** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Cost of Floor $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value of Ceiling $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) / Value $ of Collar Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Put Dth (Sell a Put)** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| Put Strike $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Market $/Dth (at Henry Hub or Swap location) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Revenue from Put $/Dth | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Value $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| (Cost) $ of Put Position | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note 1: Market data using NYMEX Close Prices as of August 31, 2016.
Note 2: Policy minimums are 12/31/2016 targets.
Note 3: For 2016 through 2020, Budgeted & Expected Dth are from Final F&PP Budget for 2016-2020.
Note 4: Empire currently has no positions utilizing "options" and therefore the options section of this report is not shown.
Note 5: Storage and usage are estimates based on most current information available.

| Storage Estimates | |
|---|---|
| Balance Dth | - |
| WACOG $/Dth | 0.000 |

Schedule JSR-D-4
Proprietary

EO-2017-0065 DR 0031

**Natural Gas Costs**
**March 2015 - August 2016**

| | Mar-15 | Apr-15 | May-15 | Jun-15 | Jul-15 | Aug-15 | Sep-15 | Oct-15 | Nov-15 |
|---|---|---|---|---|---|---|---|---|---|
| Total Consumed - MMBTU | 916,854 | 222,650 | 268,657 | 1,242,552 | 1,442,604 | 1,223,154 | 869,501 | 590,446 | 706,083 |
| Total Cost | $3,387,281.67 | $ 1,272,880.60 | $1,738,915.73 | $4,764,816.69 | $6,065,292.32 | $6,146,807.26 | $3,174,926.43 | $1,921,173.76 | $2,632,683.85 |
| Less: | | | | | | | | | |
| (Gain)/Loss on Derivatives | 134,743.28 | 170,200.71 | 321,334.24 | 520,205.00 | 2,204,861.36 | 1,962,407.82 | 147,777.20 | - | 206,951.00 |
| Firm Transportation | 476,256.64 | 352,320.06 | 546,647.97 | 560,347.48 | 518,730.86 | 573,252.93 | 557,767.18 | 519,453.18 | 486,351.37 |
| Commodity Transportation | 40,323.01 | 6,260.45 | 6,260.45 | 6,515.30 | 43,152.70 | 34,383.26 | 26,422.41 | 23,612.42 | 12,707.21 |
| Other Costs | 238.31 | 763.79 | 1,180.60 | 2,310.49 | 1,590.09 | 822.49 | 1,492.10 | 11,393.61 | 9,720.28 |
| Net Actual Commodity Cost | $2,735,719.73 | $ 743,344.68 | $ 863,483.57 | $3,657,238.42 | $4,196,957.31 | $3,575,650.78 | $2,441,466.54 | $1,366,714.55 | $1,915,063.09 |
| Cost/ Mmbtu | $ 2.984 | $ 3.338 | $ 3.214 | $ 2.943 | $ 2.909 | $ 2.923 | $ 2.808 | $ 2.280 | $ 2.403 |
| Spot Purchases from Gas Purchse Rpt | $ 2.546 | $ 2.319 | $ 2.676 | $ 2.561 | $ 2.690 | $ 2.640 | $ 2.480 | $ 2.153 | $ 1.976 |
| Cost at Spot Price | $2,334,310.28 | $ 516,346.22 | $ 718,926.13 | $3,182,175.67 | $3,880,846.86 | $3,229,126.56 | $2,156,585.68 | $1,290,607.24 | $1,574,838.41 |
| Physical Hedging Costs | $ 401,409.45 | $ 226,998.46 | $ 144,557.44 | $ 475,062.75 | $ 316,110.45 | $ 346,724.22 | $ 284,880.86 | $ 76,107.31 | $ 340,225.58 |
| Total Cost of Fuel at spot prices | | | | | | | | | |
| Total Hedging Costs | | | | | | | | | |
| Proof: | | | | | | | | | |
| Cost - Gas & Commodity Charges | 2,948,684.24 | 701,070.28 | 869,844.87 | 3,661,003.66 | 4,203,280.97 | 3,620,038.08 | 2,477,432.88 | 1,402,541.18 | 1,045,777.22 |
| Cost - Gas & Commodity Chg (Adj) | (172,640.60) | 48,534.85 | (100.85) | 2,750.06 | 36,829.04 | (9,804.04) | (9,543.03) | (12,214.21) | (17,916.02) |
| | 2,776,043.64 | 749,605.13 | 869,744.02 | 3,663,753.72 | 4,240,110.01 | 3,610,234.04 | 2,467,889.05 | 1,390,326.97 | 1,027,861.20 |
| From Above: | | | | | | | | | |
| Line 14 Commodity Transport | 40,323.01 | 6,260.45 | 6,260.45 | 6,515.30 | 43,152.70 | 34,383.26 | 26,422.41 | 23,612.42 | 12,707.21 |
| Line 17 Commodity Cost | 2,735,719.73 | 743,344.68 | 863,483.57 | 3,657,238.42 | 4,196,957.31 | 3,575,650.78 | 2,441,466.54 | 1,366,714.55 | 1,915,063.09 |
| | 2,776,043.64 | 749,605.13 | 869,744.02 | 3,663,753.72 | 4,240,110.01 | 3,610,234.04 | 2,467,889.05 | 1,390,326.97 | 1,027,861.20 |
| Difference - Should be zero | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

| | Dec-15 | Jan-16 | Feb-16 | Mar-16 | Apr-16 | May-16 | Jun-16 | Jul-16 | Aug-16 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Total Consumed - MMBTU | 440,618 | 597,690 | 757,384 | 832,003 | 1,144,181 | 1,505,891 | 2,115,056 | 1,945,303 | 1,027,961 | |
| Total Cost | $2,723,663.65 | $2,598,424.16 | $2,311,986.99 | $1,747,597.65 | $2,638,182.40 | $4,369,629.17 | $6,317,200.23 | $7,194,427.22 | $7,395,030.06 | $ 69,301,828.15 |
| Less: | | | | | | | | | | |
| (Gain)/Loss on Derivatives | 1,168,463.65 | 730,103.70 | 386,806.78 | 201,000.00 | - | 127,378.97 | 220,222.67 | 1,077,502.51 | 1,104,510.40 | $ 10,712,168.40 |
| Firm Transportation | 508,546.29 | 420,327.70 | 318,526.79 | 189,063.70 | 305,646.63 | 524,782.02 | 528,929.78 | 473,757.11 | 527,464.73 | |
| Commodity Transportation | 15,474.22 | 11,143.27 | 10,230.53 | 18,987.58 | 28,656.83 | 33,416.24 | 31,323.02 | 60,324.75 | 44,096.70 | |
| Other Costs | 2,098.04 | 1,065.68 | 1,074.18 | 325.20 | 1,116.18 | 517.06 | 2,574.16 | 2,203.10 | 244.52 | |
| Net Actual Commodity Cost | $1,029,081.25 | $1,416,883.72 | $1,586,348.71 | $1,337,621.08 | $2,302,760.76 | $3,683,654.88 | $5,525,150.60 | $5,580,639.75 | $5,719,604.71 | $ 49,677,485.03 |
| Cost/ Mmbtu | $ 2.336 | $ 2.371 | $ 2.095 | $ 1.608 | $ 2.013 | $ 2.446 | $ 2.612 | $ 2.869 | $ 2.067 | |
| Spot Purchases from Gas Purchse Rpt | $ 2.342 | $ 2.325 | $ 1.806 | $ 1.520 | $ 1.732 | $ 1.807 | $ 2.383 | $ 2.562 | $ 2.582 | |
| Cost at Spot Price | $1,031,927.36 | $1,389,650.18 | $1,367,799.38 | $1,264,644.56 | $1,981,721.49 | $2,721,145.04 | $5,040,178.45 | $4,983,866.29 | $4,939,436.08 | |
| Physical Hedging Costs | $ (2,846.11) | $ 27,233.55 | $ 218,549.33 | $ 72,976.52 | $ 321,039.27 | $ 962,409.84 | $ 484,972.15 | $ 596,773.46 | $ 780,168.63 | $ 6,073,353.16 |
| Total Cost of Fuel at spot prices | | | | | | | | | | $ 43,604,131.88 |
| Total Hedging Costs | | | | | | | | | | $ 16,785,621.66 |
| | | | | | | | | | | 38.50% |
| Proof: | | | | | | | | | | |
| Cost - Gas & Commodity Charges | 1,030,880.66 | 1,432,510.27 | 1,604,381.70 | 1,354,576.20 | 2,196,903.52 | 3,817,213.45 | 5,567,307.76 | 5,612,610.50 | 5,751,903.50 | |
| Cost - Gas & Commodity Chg (Adj) | 13,674.81 | (4,483.28) | 1,197.54 | 2,032.37 | 134,514.07 | (100,242.33) | (10,834.14) | 28,353.91 | 11,797.91 | |
| | 1,044,555.47 | 1,428,026.99 | 1,605,579.24 | 1,356,608.66 | 2,331,417.59 | 3,716,971.12 | 5,556,473.62 | 5,640,964.50 | 5,763,701.41 | |
| From Above: | | | | | | | | | | |
| Line 14 Commodity Transport | 15,474.22 | 11,143.27 | 19,230.53 | 18,987.58 | 28,656.83 | 33,416.24 | 31,323.02 | 60,324.75 | 44,096.70 | |
| Line 17 Commodity Cost | 1,029,081.25 | 1,416,883.72 | 1,586,348.71 | 1,337,621.08 | 2,302,760.76 | 3,683,554.88 | 5,525,150.60 | 5,580,639.75 | 5,719,604.71 | |
| | 1,044,555.47 | 1,428,026.99 | 1,605,579.24 | 1,356,608.66 | 2,331,417.59 | 3,716,971.12 | 5,556,473.62 | 5,640,964.50 | 5,763,701.41 | |
| Difference - Should be zero | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |